Reserves and Contingent Resources Statement for Atlanta Field, Brazil as of December 31, 2024

Prepared for

Brava Energía S.A.

March 26, 2025

Gaffney Cline

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Dear Mr. Mastrangelo,

Reserves and Contingent Resources Statement for Atlanta Field, Brazil as of December 31, 2024

This Reserves and Contingent Resources statement has been prepared by Gaffney, Cline & Associates (GaffneyCline) and issued on March 26, 2025 at the request of Brava Energía S.A. (Brava or "the Client"), operator of and 80% interest participant in the Atlanta field in the Santos basin, offshore Brazil. The remaining 20% was sold to Westlawn Americas Offshore in September 2024, effective November 1, 2023. Brava was formed in September 2024 by the merger of Enauta Energia S.A. (Enauta), the prior 100% interest holder in Atlanta, and 3R Petroleum.

In addition to Brava's internal use, this report is intended for release in connection with Brava's public market-related filings. GaffneyCline will provide consent for release once proposed details are available.

On May 19, 2022, Enauta received from the ANP (Agência Nacional do Petróleo, Gás Natural e Biocombustíveis) approval for its revised development plan for the Atlanta field which provided an extension of the concession until June 30, 2044, with, inter alia, the following provisos related to the Atlanta field:

- That the FPSO of the Definitive Production System (SDP) starts operations by June 30, 2024.
  - The FPSO was on site by June 30, 2024 and is being commissioned. First production occurred on December 31, 2024 following ANP approval.
- That Enauta will drill and complete three wells by December 31, 2023.
  - Well P06 (now named 5H) was drilled and put into production in March 2023, P09 (now 7H) and P12 (now 6H) were drilled during 2023 and will be put into production once the new FPSO is operational.

- That Enauta will drill and complete two wells by the end of 2027 and two wells by the end of 2029.
    - P08 and NE-01 are planned to be onstream by March 2027 and the others by mid-2028.

This report relates specifically and solely to the subject matter as defined in the scope of work in the Proposal for Services and is conditional upon the assumptions described herein. The report must be considered in its entirety and must only be used for the purpose for which it is intended.

GaffneyCline conducted an independent audit examination and estimation, as of December 31, 2024, of the crude oil reserves and contingent resources of the Atlanta field. On the basis of technical and other information made available to GaffneyCline concerning this property unit, GaffneyCline hereby provides the Reserves statement in Table 1 and Contingent Resources statement in Table 2.

Table 1: Statement of Crude Oil Reserves Volumes
Atlanta Field, Santos Basin, Brazil
as of December 31, 2024

Category	Oil Gross (100%) Field Volumes			Oil Reserves Net (NRI) to Brava's Interest		
	Developed (MMstb)	Undeveloped (MMstb)	Total (MMstb)	Developed (MMstb)	Undeveloped (MMstb)	Total (MMstb)
1P	85.6	41.8	127.4	68.0	33.4	101.4
2P	112.5	59.8	172.4	88.2	48.3	136.5
3P	141.2	49.6	190.8	111.4	39.1	150.5

Notes to Table 1:

1. Gross field Reserves volumes are 100% of the volumes estimated to be commercially recoverable from the twelve wells (six existing plus six new wells) under the intended development plan before the end of the extended concession on June 30, 2044.
2. Oil reserves are net to Brava's 80% working interest. Brazilian Petroleum Law, Article 47 states, "… royalties are to be paid on a monthly basis, in national currency …" and, therefore, royalties (7.8%) are treated as cash deductions rather than a reduction to volumes.
3. Oil reserves net to Brava exclude oil consumed in operations (CiO) as fuel.
4. Totals may not exactly equal the sum of the individual entries because of rounding.

Table 2: Statement of Crude Oil Contingent Resources Volumes
Atlanta Field, Santos Basin, Brazil
as of December 31, 2024

Category	Oil Gross (100%) Field Volumes (MMstb)	Company Net (NRI) Contingent Resources (MMstb)
1C	0.0	0.0
2C	7.2	5.8
3C	34.1	26.4

Notes to Table 2:

1. Gross field Contingent Resources are 100% of the volumes estimated to be recoverable from the field under the intended development plan, assuming that a further concession extension is granted after the end of the extended concession from July 2044 through June 2054 (an additional 10 years) or until the production becomes uneconomic, assuming the same fiscal terns, and subject to the same economic limit assumptions as used for reserves.
2. Oil contingent resources in this table are net to Brava's 80% working interest. Brazilian Petroleum Law, Article 47 states, "… royalties are to be paid on a monthly basis, in national currency …" and, therefore, royalties (7.8%) are treated as cash deductions rather than a reduction to volumes.
3. Oil contingent resources net to Brava exclude oil consumed in operations (CiO) as fuel.
4. The volumes reported here are "unrisked" in the sense that no adjustment has been made for the risk that a further concession extension may not be granted (i.e., no "Chance of Development" (Pd) factor has been applied).
5. Contingent Resources should not be aggregated with Reserves because of the different levels of risk involved.

Crude oil estimated to be recovered during field separation is reported in millions of barrels (MMstb). Natural gas produced will be used in the field, and it has not been reported as reserves.

Field Description

The Atlanta field is located in the northern area of the Santos basin in Block BS-4, 185 km offshore, southeast of Rio de Janeiro, in approximately 1,550 m water depth (Figure 1). It was discovered by well 1-SHEL-4-RJS drilled by Shell in April 2001. The well found heavy oil of 14 °API in Eocene turbiditic sandstones at -2,315 m subsea depth. The structure defined by 3D seismic is a faulted anticline with a main fault running SW to NE (Figures 2 and 3). The main part of the accumulation is located in the footwall (east of the fault). Pay zone in the footwall is around 130 m thick while in the hanging wall is around 30 m. The oil-water contact also is clearly seen in the seismic image as a flat spot.

Petrophysical parameters for these sandstones comprise high porosities (around 34%), permeabilities of several Darcies, and high rock compressibility. Oil properties include high oil viscosities (230 cp at reservoir conditions) and an initial solution gas oil ratio of 246 scf/stb.

Figure 1: Atlanta Field Location Map

Source: Brava Energia S.A.

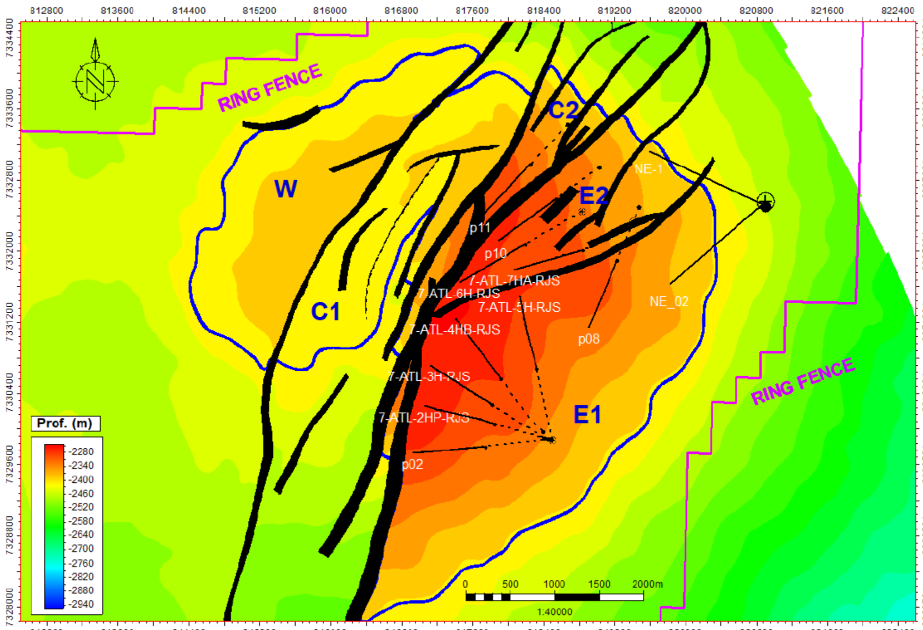
The initial development plan considered a total of 10 wells to be drilled into the Main Eocene reservoir in blocks E1, E2 and C2 (see Figure 2 and Figure 3). In addition to the currently drilled six wells (2HP, 3H, 4HB, 5H, 6H and 7H), four additional locations are scheduled to be drilled in 2027 and 2028: P02 and P08 in block E1, P10 in E2 and P11 into C2.

Further studies were undertaken on the shallower Eocene unit that was confirmed to be oil bearing in block E2 by well 9-SHEL-19D-RJS[1] (Figure 4). During 2023, Brava drilled well 8DP[2] as a slightly deviated pilot well into block E2 to gather more data. This well confirmed a slightly different oil-water contact of 2,399 mss in the Main Eocene formation compared to the oil-water contact of 2,404 m penetrated in block E1 and confirmed the oil accumulation in Eocene NE.

[1] Appraisal well drilled in 2006.

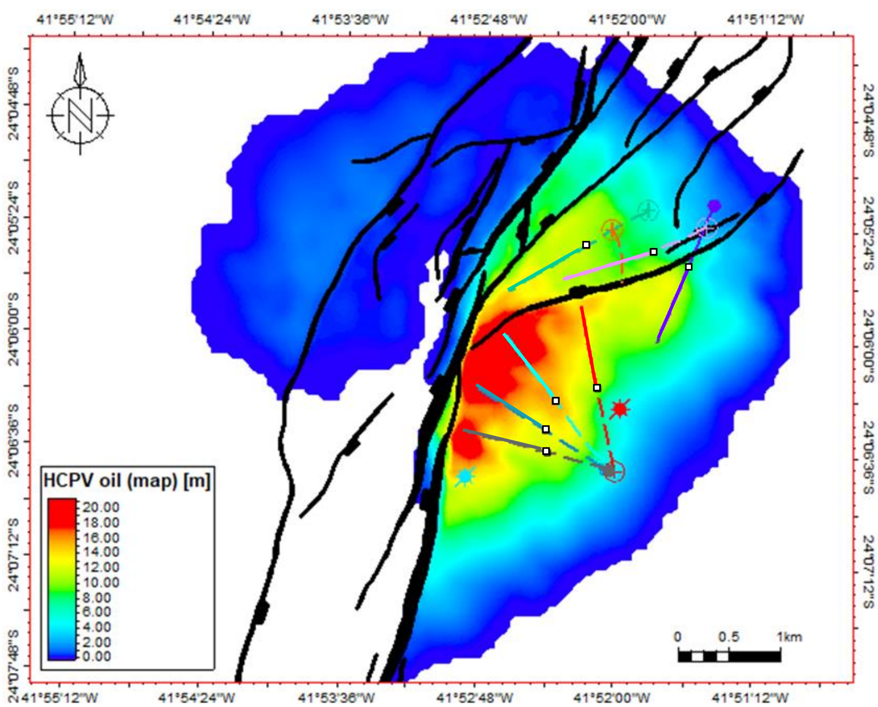
[2] Well 8DP was a deviated well that was drilled to appraise the Eocene NE reservoir and was later sidetracked as 7H into the Main Eocene reservoir.

Figure 2: Atlanta Field – Main Eocene Structure Map and Development Plan



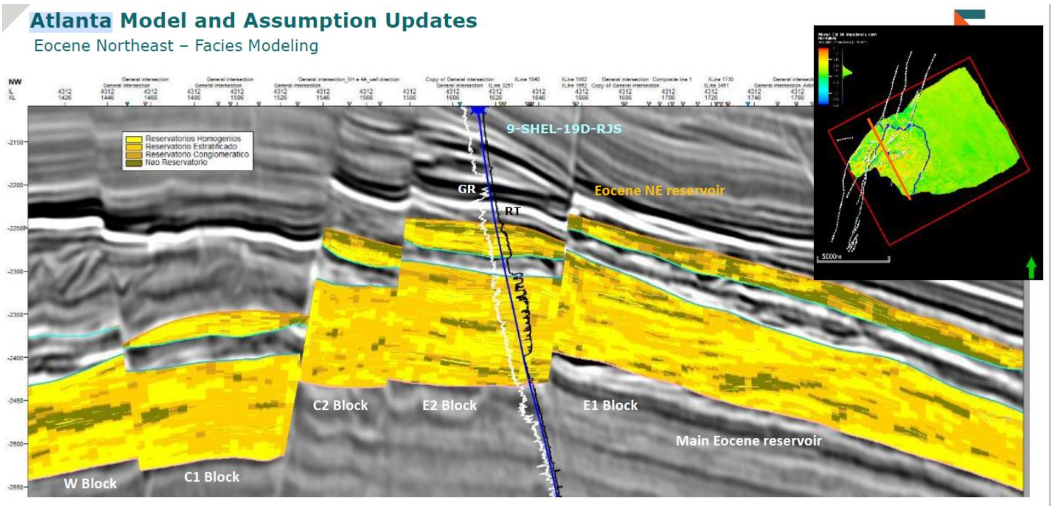
Source: Brava Energia

Figure 3: Atlanta Field – Main Eocene Net Pay Map



Source: Brava Energia

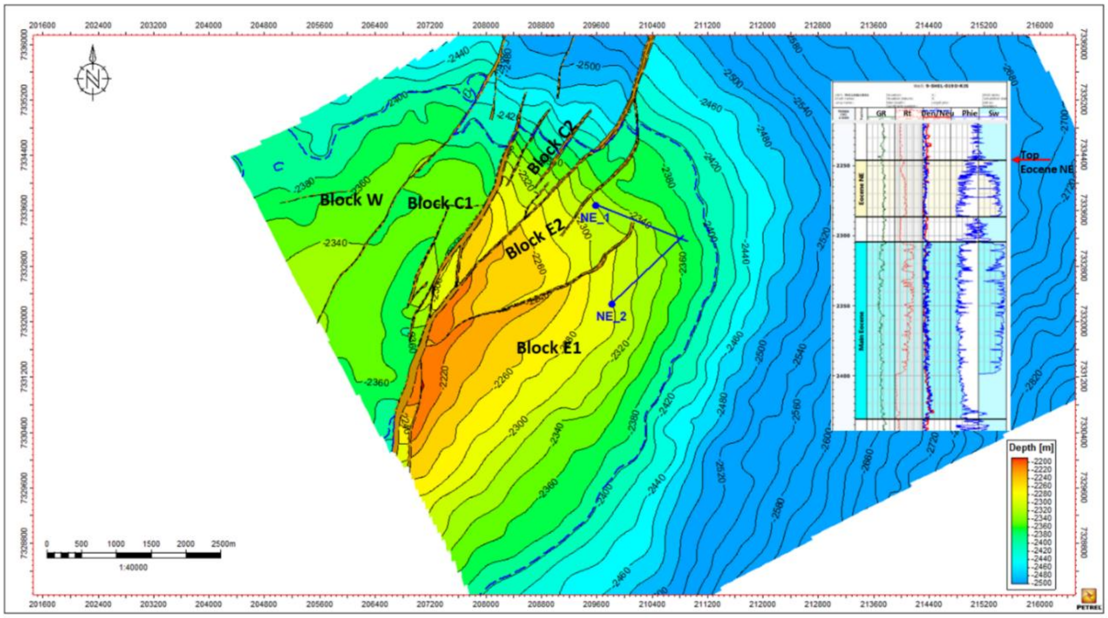
Figure 4: Atlanta Field – NW-SE Cross-Section Showing Main Eocene and Eocene NE



Source: Brava Energia

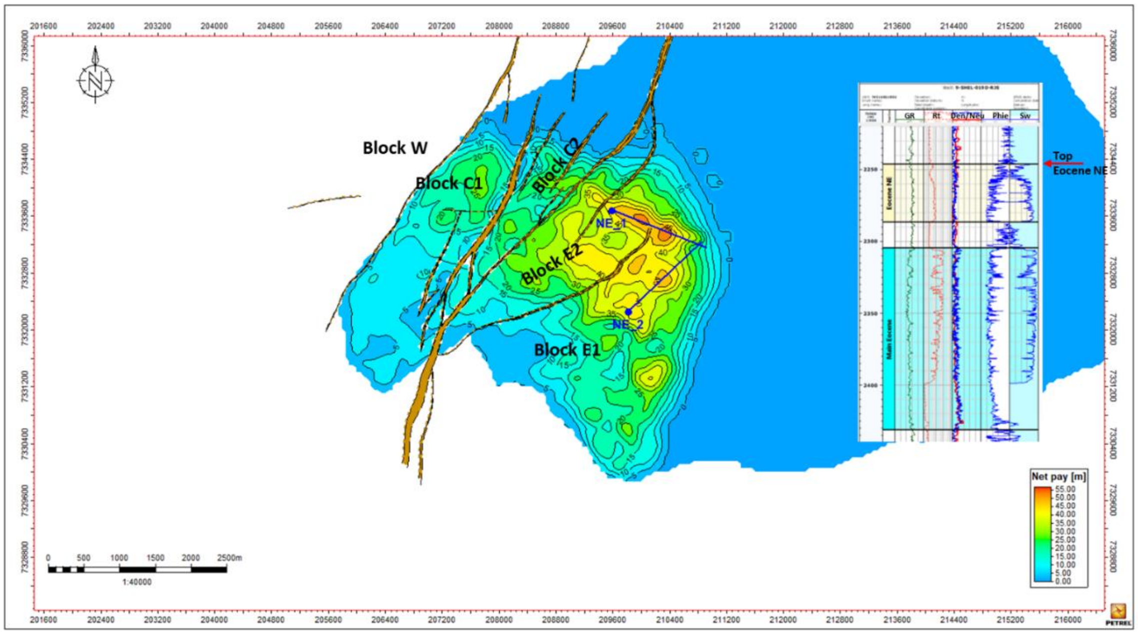
A revised field development update including the Eocene NE was approved by Enauta in 2023, including two additional wells in the northeast area of the field in 2027 and 2028 in blocks E1 (well NE02) and E2 (well NE01), bringing the total development to 12 wells, see Figure 5 and Figure 6.

Figure 5: Atlanta Field – Eocene NE Structure Map and Development Plan



Source: Brava Energia

Figure 6: Atlanta Field – Eocene NE Net Pay Map



Source: Brava Energia

The field started production in 2018 from two wells (2HP and 3H) with a third well, 4HB, starting in 2019, all drilled into block E1 (see Figure 2). The wells experienced initial problems with the downhole ESPs with production then relying on seafloor ESPs. Well 5H, also in block E1, was drilled and put on production in March 2023.

Wells 6H and 7H[3] were drilled into block E2. They are being brought into production with first oil through the Atlanta FPSO occurring on December 31, 2024. No wells have yet been drilled into block C2.

Until October 2024, production was processed on the Petrojarl I FPSO which had a capacity of 30,000 bopd. Oil was sold free-on-board (FOB) and offloaded by shuttle tankers. The small quantities of gas produced were used as fuel. The Petrojarl was then decommissioned. The maximum production rate during 2024 was about 20,500 bopd in February 2024.

As of December 31, 2024, the Atlanta FPSO was being commissioned with oil from wells 6H and 7H. It has a nominal capacity of 50,000 bopd capacity, but Brava states that it will be capable of handling up to 60,000 bopd considering the 10% design margin and other adjustments to operating parameters. GaffneyCline has limited oil production to 50,000 bopd in the low case. In the best and high cases the average monthly forecast production does not exceed 55,000 bopd and this has been retained.

[3] Well 8DP was a deviated well that was drilled to appraise the Eocene NE reservoir and was later sidetracked as 7H into the Main Eocene reservoir.

Total nominal liquid handling capacity of the Atlanta FPSO is 149,000 blpd. However, Brava has stated that considering the 10% design margin and other adjustments to operating parameters it will be possible to reach 178,000 blpd. The capital for a debottlenecking project to increase total capacity to 201,000 blpd is included in all cases. The average monthly maximum forecast liquid production is about 190,000 blpd in all cases.

The Atlanta FPSO was sold to Yinson Bouvardia Holdings Pte. Ltd (Yinson) and Brava has contracted the Atlanta FPSO for 20 years. Repayment of a loan to Yinson is treated as a reduction in operating cost to Brava.

Reserves and Contingent Resources Assessment

GaffneyCline has estimated Reserves up to the extended contract deadline of June 30, 2044, with the remainder of the economically producible production from the 12 wells being classified as Contingent Resources until June 2054 assuming a potential further extension of the concession for 10 years or until the economic limit, whichever comes first. These volumes are candidates to be promoted to the Reserves class if a further contract extension is granted.

However, as reserves and resources are evaluated periodically, changes in physical, economic, or regulatory conditions could prevent the automatic promotion of Contingent Resources to Reserves when the contingency is fulfilled.

Produced gas will be consumed as fuel and, in addition, a small amount of oil and diesel will be required. The quoted net reserves and contingent resources exclude the oil consumed, estimated to amount (in the best case) to 1.7 MMstb up to June 2044. No additional fuel is projected after that date in the developed plus undeveloped best case. The diesel cost has been included in the operating expenses.

Brava estimated future production through reservoir simulation. Currently, the Main Eocene formation and the Eocene NE formation are projected in separate numerical models. GaffneyCline reviewed the seismic interpretation[4] and confirmed that the horizons and main faults are clearly imaged and that the seismic was reasonably matched to well data. Brava used seismic attributes to project formation properties away from well control which, although reasonable, is subject to uncertainty because of the low resolution of the seismic data.

During 2024, Brava revised the relative permeability curves in the well 4HB and 5H regions, resulting in an improved history match. Also, the well path for future well P08 (due onstream in 2027) was revised to access the same formation location, but being drilled from the north towards the south.

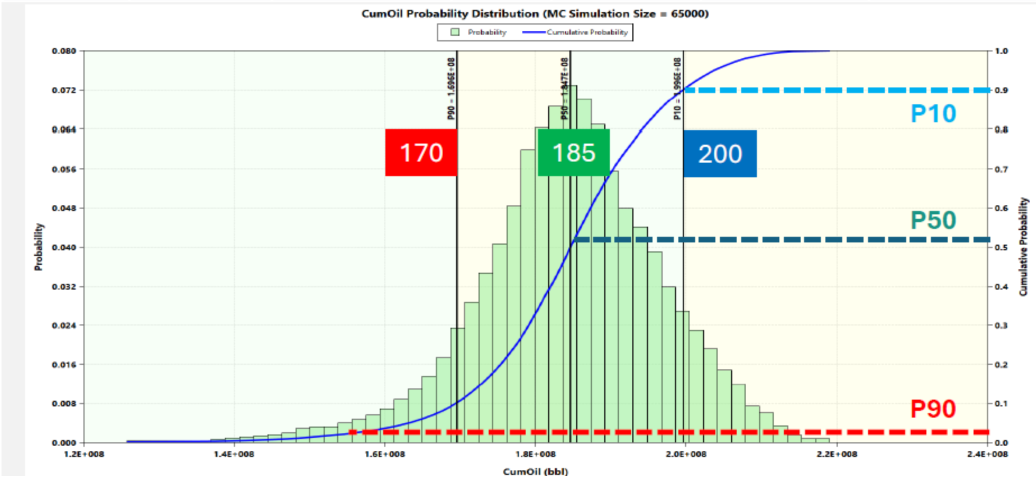
Brava prepared a range of recoverable volumes using uncertainty analysis for the Main Eocene reservoir. The factors varied included the oil initially in place, the size of the connected aquifer, rock compressibility and relative permeability. After completing a Monte Carlo analysis using these parameters, Brava selected three cases to represent the low, best and high outcomes (1P, 2P and 3P estimates are 147 MMstb, 187 MMstb and 199 MMstb, respectively) (Figure 7). Note

[4] Pre-stack depth migrated and reprocessed in 2021.

that the selected low (P90) case (147 MMstb) is more conservative than the Monte Carlo P90 value (170 MMstb).

Figure 7: Main Eocene Uncertainty Analysis

Scenario	STOIP Multiplier	Aquifer	Rel. Perm.	Rock Comp. (10^{-6} 1/psi)	OOIP (MMbbl)	Cum Oil @ 2045
1P	0.92	8300 ft (WOR = 7x)	5H	44	1,197	147
2P	1.00	8600 ft (WOR = 13x)	5H	44	1,274	187
3P	1.10	8700 ft (WOR = 15 x)	5H	60	1,369	199

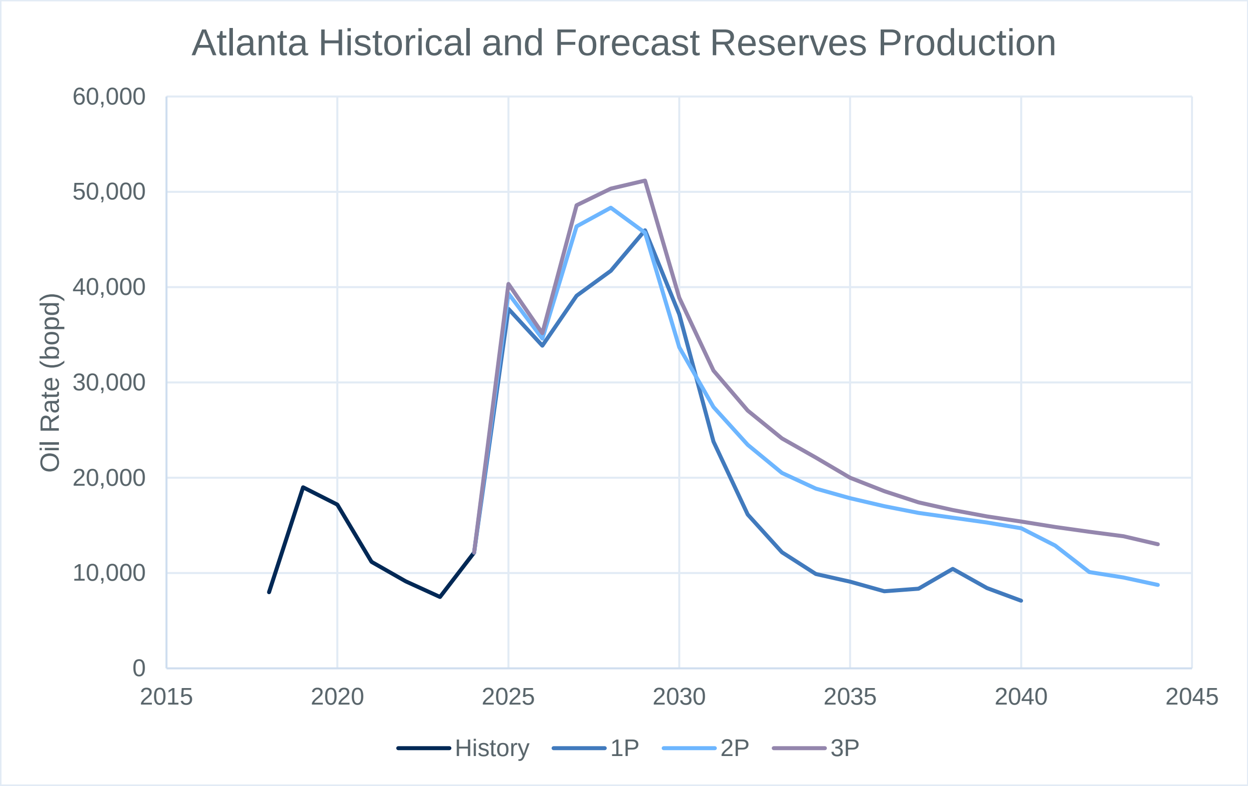


Source: Brava Energia

A similar uncertainty analysis was carried out for the Eocene NE reservoir resulting in 1P, 2P and 3P estimates of 12 MMstb, 20 MMstb and 29 MMstb, respectively. GaffneyCline considers that these assumptions provide a reasonable estimate of the range of potential recovery.

The simulation cases include an allowance of 5% downtime for the Atlanta FPSO. The oil production profiles are shown in Figure 8.

Figure 8: Atlanta Field – Historical and Forecast Reserves Production (100% field)



This audit examination was based on reserves estimates and other information provided by Brava to GaffneyCline through March 11, 2025, and included such tests, procedures and adjustments as were considered necessary. All questions that arose during the audit process were resolved to GaffneyCline's satisfaction.

Economic Analysis

The economic tests for the December 31, 2024 reserves and contingent resources volumes were based on Brent forward oil prices as of December 2024, along with estimates for the Atlanta quality and location premium, which GaffneyCline consider reasonable (Table 3).

Table 3: Oil Sales Prices

Year	Brent Oil Price (US$/bbl)	Premium (US$/bbl)	Atlanta Oil Price (US$/bbl)
2025	75.00	2.00	77.00
2026	70.00	2.00	72.00
2027	70.00	2.00	72.00
2028+	70.00	2.00	72.00

Future capital costs and operating expenses estimated by Brava were derived from development program forecasts for the field. The main remaining capital costs include drilling and completing of the remaining six firm horizontal wells plus costs related to submarine facilities, such as risers, umbilicals, service manifolds, skids for the seabed pumps and subsea installation. Total future capital is estimated to be US$1,071 million (net to Brava).

Operating expenses are mainly fixed, devoted to FPSO operating costs, and its support from land, and seabed booster pump replacements. Now that the Atlanta FPSO is in place, Brava estimated a total fixed opex of about US$100 million rising to US$150 million per year (net to Brava and net of the Yinson loan repayment).

At Brava’s request, capital, operating and abandonment costs have not been escalated for inflation. Present abandonment costs at contract end in the reserves case were estimated by Brava at US$173 million (net to Brava). GaffneyCline has found that projected capital investments and operating expenses are sufficient to economically produce the projected volumes.

Royalty is 7.8%. Brava advised that royalty payments are calculated based on ANP’s reference price, which has historically been less than 80% of the actual sales price (which has averaged about US$2/bbl above Brent). In the cash flow tables, royalty has been calculated based on 80% of the Atlanta price.

Taxes are 9.25% (PIS, COFINS) applied to gas and condensate gross income and include the Special Participation Tax (SPT) for deep-water fields and Research and Development of 1%. Brava has prepared all costs net of PIS/COFINS taxes (9.25%) based on the expectation that it will be possible to offset those taxes against the same taxes paid on gross income. A net undepreciated balance of US$656.5 million as of December 31, 2024, as advised by Brava, has been included in the SPT calculation. Cash flow statements were prepared before corporate income taxes.

It is GaffneyCline's opinion that the estimates of total remaining recoverable hydrocarbon liquid volumes, as of December 31, 2024, are, in the aggregate, reasonable and the reserves and resources classification and categorization are appropriate and consistent with the definition of reserves and resources in the Petroleum Resources Management System (PRMS), which was approved by the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists, the Society of Petroleum Evaluation Engineers, the Society of Exploration Geophysicists, the Society of Petrophysicists and Well Log Analysts, and the European Association of Geoscientists and Engineers in June 2018, version 1.03 (see Appendix II).

A glossary of terms is provided in Appendix III.

Basis of Opinion

This document reflects GaffneyCline’s informed professional judgment based on accepted standards of professional investigation and, as applicable, the data and information provided by the Client, the limited scope of engagement, and the time permitted to conduct the evaluation.

In line with those accepted standards, this document does not in any way constitute or make a guarantee or prediction of results, and no warranty is implied or expressed that actual outcome will conform to the outcomes presented herein. GaffneyCline has not independently verified any information provided by, or at the direction of, the Client, and has accepted the accuracy and completeness of this data. GaffneyCline has no reason to believe that any material facts have been withheld but does not warrant that its inquiries have revealed all of the matters that a more extensive examination might otherwise disclose.

The opinions expressed herein are subject to and fully qualified by the generally accepted uncertainties associated with the interpretation of geoscience and engineering data and do not reflect the totality of circumstances, scenarios and information that could potentially affect decisions made by the report’s recipients and/or actual results. The opinions and statements contained in this report are made in good faith and in the belief that such opinions and statements are representative of prevailing physical and economic circumstances.

There are numerous uncertainties inherent in estimating reserves and resources, and in projecting future production, development expenditures, operating expenses and cash flows. Oil and gas resources assessments must be recognized as a subjective process of estimating subsurface accumulations of oil and gas that cannot be measured in an exact way. Estimates of oil and gas resources prepared by other parties may differ, perhaps materially, from those contained within this report.

The accuracy of any reserves or resources estimate is a function of the quality of the available data and of engineering and geological interpretation. Results of drilling, testing and production that post-date the preparation of the estimates may justify revisions, some or all of which may be material. Accordingly, reserves and resources estimates are often different from the quantities of oil and gas that are ultimately recovered, and the timing and cost of those volumes that are recovered may vary from that assumed.

GaffneyCline’s review and audit involved reviewing pertinent facts, interpretations and assumptions made by the Client or others in preparing estimates of reserves and resources. GaffneyCline performed procedures necessary to enable it to render an opinion on the appropriateness of the methodologies employed, adequacy and quality of the data relied on, depth and thoroughness of the reserves and resources estimation process, classification and categorization of reserves and resources appropriate to the relevant definitions used, and reasonableness of the estimates.

Definition of Reserves and Contingent Resources

Reserves are those quantities of petroleum that are anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria, based on the development project(s) applied: discovered, recoverable, commercial and remaining (as of the evaluation date).

Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by development and production status. All categories of reserves volumes quoted herein have been derived within the context of an economic limit test (ELT) assessment (pre-tax and exclusive of accumulated depreciation amounts) prior to any Net Present Value (NPV) analysis.

Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development because of one or more contingencies. Contingent Resources may include, for example, projects for which there are currently no evident 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 level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status.

It must be appreciated that the Contingent Resources reported herein are unrisked in terms of economic uncertainty and commerciality. There is no certainty that it will be commercially viable to produce any portion of the Contingent Resources. Once discovered, the chance that the accumulation will be commercially developed is referred to as the “chance of development”.

GaffneyCline has not undertaken a site visit and inspection because it was not included in the scope of work. As such, GaffneyCline is not in a position to comment on the operations or facilities in place, their appropriateness and condition, or whether they are in compliance with the regulations pertaining to such operations. Further, GaffneyCline is not in a position to comment on any aspect of health, safety, or environment of such operation.

This report has been prepared based on GaffneyCline’s understanding of the effects of petroleum legislation and other regulations that currently apply to these properties. However, GaffneyCline is not in a position to attest to property title or rights, conditions of these rights (including environmental and abandonment obligations), or any necessary licenses and consents (including planning permission, financial interest relationships, or encumbrances thereon for any part of the appraised properties).

GaffneyCline is not aware of any potential changes in regulations applicable to these fields that could affect the ability of the Client to produce the estimated reserves.

GaffneyCline is not aware of any carbon pricing impost or GHG emissions related regulations that are applicable to the evaluation of the assets that are the subject of this report. GaffneyCline has also not included the impact of any potential carbon pricing scheme or regulatory compliance costs for GHG emissions that may be implemented in the future.

Use of Net Present Values

It should be clearly understood that the NPVs contained herein do not represent a GaffneyCline opinion as to the market value of the subject property, nor any interest in it.

In assessing a likely market value, it would be necessary to take into account a number of additional factors including reserves risk (i.e., that Proved and/or Probable and/or Possible reserves may not be realized within the anticipated timeframe for their exploitation); perceptions of economic and sovereign risk, including potential change in regulations; potential upside; other benefits, encumbrances or charges that may pertain to a particular interest; and, the competitive state of the market at the time. GaffneyCline has explicitly not taken such factors into account in deriving the NPVs presented herein.

Qualifications

In performing this study, GaffneyCline is not aware that any conflict of interest has existed. As an independent consultancy, GaffneyCline is providing impartial technical, commercial, and strategic advice within the energy sector. GaffneyCline's remuneration was not in any way contingent on the contents of this report.

In the preparation of this document, GaffneyCline has maintained, and continues to maintain, a strict independent consultant-client relationship with Brava. Furthermore, the management and employees of GaffneyCline have no interest in any of the assets evaluated or related with the analysis performed, as part of this report.

Staff members who prepared this report hold appropriate professional and educational qualifications and have the necessary levels of experience and expertise to perform the work.

Notice

This document is confidential and has been prepared for the exclusive use of the Client or parties named herein. It may not be distributed or made available, in whole or in part, to any other company or person without the prior knowledge and written consent of Gaffney, Cline & Associates (GaffneyCline). No person or company other than those for whom it is intended may directly or indirectly rely upon its contents. GaffneyCline is acting in an advisory capacity only and, to the fullest extent permitted by law, disclaims all liability for actions or losses derived from any actual or purported reliance on this document (or any other statements or opinions of GaffneyCline) by the Client or by any other person or entity.

Yours sincerely,

Gaffney, Cline & Associates

Project Manager
Rawdon Seager,
Senior Technical Director

Reviewed by
Gustavo Ritondale,
Principal Advisor

Appendices

Appendix I	Atlanta Cash Flows
Appendix II	PRMS Reserves and Resources Definitions
Appendix III	Glossary

Appendix I
Atlanta Cash Flows

Brava Net Interest Reserves Cashflows
as of December 31, 2024
Atlanta Field

1P Developed Reserves Case

Year	Oil Production	Oil Sales	Oil Price	Gross Revenue	Royalty	Special Participation	R & D Tax	Operating Cost	Capital Expenditures	Abandonment Cost	Cashflow BIT Net	Cashflow BIT Cumulative	10% Disc Cashflow
	MMBbl	MMBbl	US$/Bbl	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2025	11.0	11.0	77.00	847	53	8	0	104	119	12	551	551	525
2026	9.9	9.9	72.00	710	44	3	7	94	20	0	543	1,093	470
2027	7.9	7.8	72.00	565	35	0	6	83	7	0	433	1,526	341
2028	6.3	6.2	72.00	449	28	0	0	88	7	0	326	1,853	234
2029	5.3	5.3	72.00	379	24	0	0	90	7	0	259	2,111	168
2030	4.7	4.6	72.00	330	21	0	0	92	7	0	211	2,322	125
2031	4.2	4.1	72.00	293	18	0	0	92	7	0	176	2,498	94
2032	3.7	3.6	72.00	263	16	0	0	90	7	0	149	2,647	73
2033	3.3	3.3	72.00	235	15	0	0	86	7	0	127	2,774	56
2034	2.9	2.9	72.00	210	13	0	0	80	7	0	110	2,884	44
2035	2.5	2.5	72.00	181	11	0	0	78	7	0	84	2,968	31
2036	2.0	2.0	72.00	145	9	0	0	93	7	0	36	3,004	12
2037	1.8	1.8	72.00	126	8	0	0	92	4	0	22	3,025	7
2038	1.6	1.6	72.00	113	7	0	0	93	0	0	13	3,038	4
2039	1.4	1.4	72.00	101	6	0	0	77	0	0	18	3,057	5
2040										96	-96	2,961	-22
Total	68.5	68.0		4,948	309	11	12	1,331	216	107	2,961		2,168

2P Developed Reserves Case

Year	Oil Production	Oil Sales	Oil Price	Gross Revenue	Royalty	Special Participation	R & D Tax	Operating Cost	Capital Expenditures	Abandonment Cost	Cashflow BIT Net	Cashflow BIT Cumulative	10% Disc Cashflow
	MMBbl	MMBbl	US$/Bbl	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2025	11.4	11.4	77.00	880	55	11	0	104	119	12	579	579	552
2026	10.1	10.1	72.00	727	45	4	6	94	20	0	558	1,137	484
2027	8.7	8.6	72.00	622	39	0	5	82	7	0	489	1,627	386
2028	7.1	7.1	72.00	509	32	0	0	86	7	0	384	2,010	275
2029	5.9	5.8	72.00	416	26	0	0	90	7	0	293	2,303	191
2030	5.1	5.0	72.00	359	22	0	0	93	7	0	237	2,540	140
2031	4.5	4.4	72.00	319	20	0	0	95	7	0	197	2,737	106
2032	4.1	4.0	72.00	291	18	0	0	97	7	0	169	2,906	83
2033	3.8	3.7	72.00	266	17	0	0	112	7	0	130	3,036	58
2034	3.5	3.4	72.00	246	15	0	0	113	7	0	110	3,145	44
2035	3.3	3.2	72.00	229	14	0	0	115	7	0	93	3,238	34
2036	3.1	3.0	72.00	216	13	0	0	101	7	0	94	3,332	31
2037	2.9	2.8	72.00	204	13	0	0	102	4	0	85	3,417	26
2038	2.8	2.7	72.00	194	12	0	0	103	0	0	79	3,496	22
2039	2.7	2.6	72.00	185	12	0	0	101	0	0	72	3,568	18
2040	2.6	2.5	72.00	178	11	0	0	120	0	0	47	3,616	11
2041	2.5	2.4	72.00	171	11	0	0	119	0	0	41	3,656	8
2042	2.4	2.3	72.00	165	10	0	0	119	0	0	36	3,692	7
2043	2.3	2.2	72.00	159	10	0	0	118	0	0	32	3,724	5
2044	1.1	1.0	72.00	73	5	0	0	58	0	0	10	3,734	2
2045										96	-96	3,639	-14
	90.0	88.2		6,410	400	15	11	2,022	216	107	3,639		2,469

3P Developed Reserves Case

Year	Oil Production	Oil Sales	Oil Price	Gross Revenue	Royalty	Special Participation	R & D Tax	Operating Cost	Capital Expenditures	Abandonment Cost	Cashflow BIT Net	Cashflow BIT Cumulative	10% Disc Cashflow
	MMBbl	MMBbl	US$/Bbl	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2025	11.7	11.7	77.00	901	56	12	0	104	119	12	597	597	570
2026	12.9	12.9	72.00	925	58	16	7	94	20	0	731	1,328	633
2027	11.3	11.2	72.00	809	50	9	6	82	7	0	654	1,982	515
2028	9.3	9.3	72.00	669	42	1	5	86	7	0	527	2,509	378
2029	7.6	7.6	72.00	545	34	0	4	90	7	0	409	2,918	266
2030	6.6	6.5	72.00	467	29	0	0	93	7	0	338	3,256	200
2031	5.8	5.8	72.00	415	26	0	0	95	7	0	287	3,543	154
2032	5.3	5.2	72.00	377	24	0	0	97	7	0	250	3,793	122
2033	4.9	4.8	72.00	345	22	0	0	112	7	0	204	3,997	91
2034	4.5	4.4	72.00	318	20	0	0	113	7	0	178	4,174	72
2035	4.2	4.1	72.00	297	19	0	0	115	7	0	156	4,330	57
2036	4.0	3.9	72.00	279	17	0	0	101	7	0	153	4,484	51
2037	3.8	3.7	72.00	264	16	0	0	102	4	0	141	4,624	43
2038	3.6	3.5	72.00	251	16	0	0	103	0	0	132	4,757	37
2039	3.4	3.3	72.00	240	15	0	0	101	0	0	124	4,880	31
2040	3.3	3.2	72.00	231	14	0	0	120	0	0	97	4,977	22
2041	3.2	3.1	72.00	222	14	0	0	119	0	0	89	5,066	18
2042	3.1	3.0	72.00	215	13	0	0	119	0	0	83	5,148	16
2043	3.0	2.9	72.00	208	13	0	0	118	0	0	77	5,226	13
2044	1.5	1.4	72.00	99	6	0	0	58	0	0	34	5,260	5
2045										96	-96	5,164	-14
Total	112.9	111.4		8,076	504	39	24	2,022	216	107	5,164		3,281

Currency in million US Dollars

1. All figures are net to Brava's 80% working interest according to the fiscal terms that govern the asset.
2. Cash flows are shown up to the Economic Limit or to the end of the concession on 30 June 2044, whichever comes first.
3. The NPVs reported here do not represent an opinion as to the market value of a property or any interest therein.
4. Oil prices and costs have not been adjusted for inflation.
5. Totals may not exactly equal the sum of the individual entries because of rounding.

GaffneyCline Engineer: RJHS Reviewed by: GR

Brava Net Interest Reserves Cashflows
as of December 31, 2024
Atlanta Field

Total 1P Reserves Case

Year	Oil Production MMBbl	Oil Sales MMBbl	Oil Price US$/Bbl	Gross Revenue MMUS$	Royalty MMUS$	Special Participation MMUS$	R & D Tax MMUS$	Operating Cost MMUS$	Capital Expenditures MMUS$	Abandonment Cost MMUS$	Cashflow BIT Net MMUS$	Cashflow BIT Cumulative MMUS$	10% Disc Cashflow MMUS$
2025	11.0	10.9	77.00	842	53	9	0	106	159	12	504	504	481
2026	9.9	9.8	72.00	705	44	3	6	96	170	0	386	890	335
2027	11.4	11.4	72.00	817	51	9	7	93	71	0	587	1,477	462
2028	12.2	12.1	72.00	874	55	12	7	92	7	0	702	2,179	503
2029	13.4	13.4	72.00	964	60	17	8	92	415	0	373	2,551	243
2030	10.8	10.8	72.00	777	49	5	6	108	129	0	480	3,032	284
2031	6.9	6.9	72.00	499	31	0	4	90	21	0	353	3,385	190
2032	4.7	4.7	72.00	340	21	0	0	86	12	0	220	3,606	108
2033	3.6	3.6	72.00	256	16	0	0	96	12	0	132	3,738	59
2034	2.9	2.9	72.00	208	13	0	0	83	12	0	100	3,838	40
2035	2.7	2.7	72.00	191	12	0	0	84	12	0	83	3,921	31
2036	2.4	2.3	72.00	168	10	0	0	118	12	0	27	3,948	9
2037	2.4	2.4	72.00	172	11	0	0	109	9	0	43	3,991	13
2038	3.0	3.0	72.00	216	14	0	0	107	5	0	91	4,082	25
2039	2.5	2.4	72.00	175	11	0	0	98	5	0	61	4,144	15
2040	2.1	2.1	72.00	148	9	0	0	104	5	0	30	4,173	7
2041										173	-173	4,000	-36
Total	101.9	101.4		7,354	459	55	37	1,562	1,056	185	4,000		2,769

Total 2P Reserves Case

Year	Oil Production MMBbl	Oil Sales MMBbl	Oil Price US$/Bbl	Gross Revenue MMUS$	Royalty MMUS$	Special Participation MMUS$	R & D Tax MMUS$	Operating Cost MMUS$	Capital Expenditures MMUS$	Abandonment Cost MMUS$	Cashflow BIT Net MMUS$	Cashflow BIT Cumulative MMUS$	10% Disc Cashflow MMUS$
2025	11.5	11.4	77.00	879	55	11	0	106	159	12	536	536	511
2026	10.1	10.0	72.00	721	45	4	6	97	170	0	400	936	346
2027	13.5	13.5	72.00	972	61	19	8	92	71	0	722	1,657	569
2028	14.1	14.1	72.00	1,014	63	21	8	92	7	0	822	2,479	589
2029	13.3	13.3	72.00	958	60	18	8	96	415	0	362	2,841	236
2030	9.8	9.8	72.00	702	44	3	6	118	129	0	403	3,245	239
2031	8.0	7.9	72.00	569	35	0	5	111	21	0	397	3,642	214
2032	6.9	6.7	72.00	484	30	0	0	114	12	0	328	3,969	160
2033	6.0	5.8	72.00	421	26	0	0	128	12	0	255	4,224	113
2034	5.5	5.4	72.00	386	24	0	0	118	12	0	232	4,456	94
2035	5.2	5.1	72.00	364	23	0	0	119	12	0	211	4,666	77
2036	5.0	4.8	72.00	348	22	0	0	147	12	0	167	4,834	56
2037	4.8	4.6	72.00	334	21	0	0	131	9	0	174	5,007	53
2038	4.6	4.5	72.00	326	20	0	0	124	5	0	177	5,185	49
2039	4.5	4.4	72.00	320	20	0	0	107	5	0	188	5,373	47
2040	4.3	4.3	72.00	309	19	0	0	108	5	0	177	5,550	40
2041	3.8	3.8	72.00	271	17	0	0	124	5	0	125	5,675	26
2042	2.9	2.9	72.00	212	13	0	0	136	5	0	58	5,733	11
2043	2.8	2.8	72.00	200	13	0	0	109	5	0	74	5,807	13
2044	1.3	1.3	72.00	94	6	0	0	55	0	0	34	5,840	5
2045										173	-173	5,667	-25
	137.9	136.5		9,886	617	75	39	2,231	1,071	185	5,667		3,424

Total 3P Reserves Case

Year	Oil Production MMBbl	Oil Sales MMBbl	Oil Price US$/Bbl	Gross Revenue MMUS$	Royalty MMUS$	Special Participation MMUS$	R & D Tax MMUS$	Operating Cost MMUS$	Capital Expenditures MMUS$	Abandonment Cost MMUS$	Cashflow BIT Net MMUS$	Cashflow BIT Cumulative MMUS$	10% Disc Cashflow MMUS$
2025	11.8	11.7	77.00	902	56	13	0	105	159	12	556	556	531
2026	10.3	10.2	72.00	733	46	5	6	96	170	0	410	967	356
2027	14.2	14.2	72.00	1,019	64	22	8	89	71	0	765	1,732	603
2028	14.7	14.7	72.00	1,057	66	24	8	90	7	0	861	2,593	616
2029	14.9	14.9	72.00	1,075	67	25	9	91	415	0	468	3,060	305
2030	11.4	11.3	72.00	813	51	8	7	113	129	0	506	3,566	300
2031	9.1	9.0	72.00	650	41	0	5	106	21	0	477	4,043	257
2032	7.9	7.8	72.00	560	35	0	4	110	12	0	399	4,442	195
2033	7.1	6.9	72.00	499	31	0	0	124	12	0	331	4,773	147
2034	6.5	6.3	72.00	455	28	0	0	114	12	0	301	5,074	122
2035	5.8	5.7	72.00	410	26	0	0	116	12	0	256	5,330	94
2036	5.4	5.3	72.00	380	24	0	0	146	12	0	198	5,528	66
2037	5.1	4.9	72.00	355	22	0	0	135	9	0	189	5,717	57
2038	4.9	4.7	72.00	338	21	0	0	136	5	0	176	5,893	49
2039	4.7	4.5	72.00	323	20	0	0	131	5	0	168	6,061	42
2040	4.5	4.3	72.00	312	19	0	0	137	5	0	151	6,213	35
2041	4.3	4.2	72.00	302	19	0	0	151	5	0	127	6,339	26
2042	4.2	4.1	72.00	292	18	0	0	162	5	0	107	6,446	20
2043	4.0	3.9	72.00	283	18	0	0	131	5	0	129	6,576	22
2044	1.9	1.9	72.00	133	8	0	0	64	0	0	61	6,636	9
2045										173	-173	6,463	-25
Total	152.6	150.5		10,892	680	97	47	2,350	1,071	185	6,463		3,827

Currency in million US Dollars

1. All figures are net to Brava's 80% working interest according to the fiscal terms that govern the asset.
2. Cash flows are shown up to the Economic Limit or to the end of the concession on 30 June 2044, whichever comes first.
3. The NPVs reported here do not represent an opinion as to the market value of a property or any interest therein.
4. Oil prices and costs have not been adjusted for inflation.
5. Totals may not exactly equal the sum of the individual entries because of rounding.

GaffneyCline Engineer: RJHS Reviewed by: GR

Brava Net Interest Reserves and Contingent Resources Cashflows
as of December 31, 2024
Atlanta Field

Total 1P + 1C Case

Year	Oil Production	Oil Sales	Oil Price	Gross Revenue	Royalty	Special Participation	R & D Tax	Operating Cost	Capital Expenditures	Abandonment Cost	Cashflow BIT Net	Cashflow BIT Cumulative	10% Disc Cashflow
	MMBbl	MMBbl	US$/Bbl	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2025	11.0	10.9	77.00	842	53	9	0	106	159	12	504	504	481
2026	9.9	9.8	72.00	705	44	3	6	96	170	0	386	890	335
2027	11.4	11.4	72.00	817	51	9	7	93	71	0	587	1,477	462
2028	12.2	12.1	72.00	874	55	12	7	92	7	0	702	2,179	503
2029	13.4	13.4	72.00	964	60	17	8	92	415	0	373	2,551	243
2030	10.8	10.8	72.00	777	49	5	6	108	129	0	480	3,032	284
2031	6.9	6.9	72.00	499	31	0	4	90	21	0	353	3,385	190
2032	4.7	4.7	72.00	340	21	0	0	86	12	0	220	3,606	108
2033	3.6	3.6	72.00	256	16	0	0	96	12	0	132	3,738	59
2034	2.9	2.9	72.00	208	13	0	0	83	12	0	100	3,838	40
2035	2.7	2.7	72.00	191	12	0	0	84	12	0	83	3,921	31
2036	2.4	2.3	72.00	168	10	0	0	118	12	0	27	3,948	9
2037	2.4	2.4	72.00	172	11	0	0	109	9	0	43	3,991	13
2038	3.0	3.0	72.00	216	14	0	0	107	5	0	91	4,082	25
2039	2.5	2.4	72.00	175	11	0	0	98	5	0	61	4,144	15
2040	2.1	2.1	72.00	148	9	0	0	104	5	0	30	4,173	7
2041										173	-173	4,000	-36
Total	101.9	101.4		7,354	459	55	37	1,562	1,056	185	4,000		2,769

Total 2P + 2C Case

Year	Oil Production	Oil Sales	Oil Price	Gross Revenue	Royalty	Special Participation	R & D Tax	Operating Cost	Capital Expenditures	Abandonment Cost	Cashflow BIT Net	Cashflow BIT Cumulative	10% Disc Cashflow
	MMBbl	MMBbl	US$/Bbl	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2025	11.5	11.4	77.00	879	55	11	0	106	159	12	536	536	511
2026	10.1	10.0	72.00	721	45	4	6	97	170	0	400	936	346
2027	13.5	13.5	72.00	972	61	19	8	92	71	0	722	1,657	569
2028	14.1	14.1	72.00	1,014	63	21	8	92	7	0	822	2,479	589
2029	13.3	13.3	72.00	958	60	18	8	96	415	0	362	2,841	236
2030	9.8	9.8	72.00	702	44	3	6	118	129	0	403	3,244	239
2031	8.0	7.9	72.00	569	35	0	5	111	21	0	397	3,641	214
2032	6.9	6.7	72.00	484	30	0	0	114	12	0	328	3,969	160
2033	6.0	5.8	72.00	421	26	0	0	128	12	0	255	4,224	113
2034	5.5	5.4	72.00	386	24	0	0	118	12	0	232	4,455	94
2035	5.2	5.1	72.00	364	23	0	0	119	12	0	211	4,666	77
2036	5.0	4.8	72.00	348	22	0	0	147	12	0	167	4,833	56
2037	4.8	4.6	72.00	334	21	0	0	131	9	0	174	5,007	53
2038	4.6	4.5	72.00	326	20	0	0	124	5	0	177	5,184	49
2039	4.5	4.4	72.00	320	20	0	0	107	5	0	188	5,372	47
2040	4.3	4.3	72.00	309	19	0	0	108	5	0	177	5,550	40
2041	3.8	3.8	72.00	271	17	0	0	124	5	0	125	5,675	26
2042	2.9	2.9	72.00	212	13	0	0	136	5	0	58	5,733	11
2043	2.8	2.8	72.00	200	13	0	0	109	5	0	74	5,806	13
2044	2.6	2.6	72.00	188	12	0	0	110	0	0	67	5,874	10
2045	2.4	2.4	72.00	170	11	0	0	122	0	0	37	5,911	5
2046	2.1	2.1	72.00	151	9	0	0	109	0	0	32	5,943	4
2047										173	-173	5,770	-20
Total	143.6	142.3		10,300	643	76	39	2,517	1,071	185	5,770		3,442

Currency in million US Dollars

1. All figures are net to Brava's 80% working interest according to the fiscal terms that govern the asset.
2. Cash flows are shown up to the Economic Limit or to the end of a potential further extension to June 2054, whichever comes first.
3. The NPVs reported here do not represent an opinion as to the market value of a property or any interest therein.
4. Oil prices and costs have not been adjusted for inflation.
5. Totals may not exactly equal the sum of the individual entries because of rounding.

GaffneyCline Engineer: RJHS Reviewed by: GR

Brava Net Interest Reserves and Contingent Resources Cashflows
as of December 31, 2024
Atlanta Field

Total 3P + 3C Case

Year	Oil Production	Oil Sales	Oil Price	Gross Revenue	Royalty	Special Participation	R & D Tax	Operating Cost	Capital Expenditures	Abandonment Cost	Cashflow BIT Net	Cashflow BIT Cumulative	10% Disc Cashflow
	MMBbl	MMBbl	US$/Bbl	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2025	11.8	11.7	77.00	902	56	13	0	105	159	12	556	556	530
2026	10.3	10.2	72.00	733	46	5	6	96	170	0	411	967	356
2027	14.2	14.2	72.00	1,019	64	16	8	89	71	0	771	1,739	608
2028	14.7	14.7	72.00	1,057	66	18	8	90	7	0	867	2,605	621
2029	14.9	14.9	72.00	1,075	67	21	9	91	415	0	472	3,078	308
2030	11.4	11.3	72.00	813	51	6	7	113	129	0	508	3,586	301
2031	9.1	9.0	72.00	650	41	0	5	106	21	0	477	4,063	257
2032	7.9	7.8	72.00	560	35	0	4	110	12	0	399	4,461	195
2033	7.1	6.9	72.00	499	31	0	0	124	12	0	331	4,793	147
2034	6.5	6.3	72.00	455	28	0	0	114	12	0	301	5,093	122
2035	5.8	5.7	72.00	410	26	0	0	116	12	0	256	5,349	94
2036	5.4	5.3	72.00	380	24	0	0	146	12	0	198	5,548	66
2037	5.1	4.9	72.00	355	22	0	0	135	9	0	189	5,736	57
2038	4.9	4.7	72.00	338	21	0	0	136	5	0	176	5,913	49
2039	4.7	4.5	72.00	323	20	0	0	131	5	0	168	6,081	42
2040	4.5	4.3	72.00	312	19	0	0	137	5	0	151	6,232	35
2041	4.3	4.2	72.00	302	19	0	0	151	5	0	127	6,359	26
2042	4.2	4.1	72.00	292	18	0	0	162	5	0	107	6,465	20
2043	4.0	3.9	72.00	283	18	0	0	131	5	0	129	6,595	22
2044	3.9	3.8	72.00	274	17	0	0	129	0	0	128	6,723	20
2045	3.8	3.7	72.00	264	16	0	0	141	0	0	107	6,830	15
2046	3.6	3.5	72.00	254	16	0	0	128	0	0	110	6,940	14
2047	3.2	3.1	72.00	222	14	0	0	144	0	0	64	7,004	8
2048	2.8	2.7	72.00	193	12	0	0	156	0	0	25	7,029	3
2049	2.6	2.5	72.00	180	11	0	0	144	0	0	25	7,055	2
2050	2.4	2.3	72.00	169	11	0	0	144	0	0	14	7,068	1
2051	2.5	2.4	72.00	176	11	0	0	129	0	0	36	7,105	3
2052	2.3	2.2	72.00	156	10	0	0	129	0	0	17	7,122	1
2053	2.2	2.1	72.00	150	9	0	0	130	0	0	11	7,133	1
2054										173	-173	6,960	-10
2055													
Total	180.0	176.9		12,797	799	78	47	3,658	1,071	185	6,960		3,914

Currency in million US Dollars

1. All figures are net to Brava's 80% working interest according to the fiscal terms that govern the asset.
2. Cash flows are shown up to the Economic Limit or to the end of a potential further extension to June 2054, whichever comes first.
3. The NPVs reported here do not represent an opinion as to the market value of a property or any interest therein.
4. Oil prices and costs have not been adjusted for inflation.
5. Totals may not exactly equal the sum of the individual entries because of rounding.

GaffneyCline Engineer: RJHS Reviewed by: GR

Appendix II
PRMS Reserves and Resources Definitions

Society of Petroleum Engineers, World Petroleum Council,
American Association of Petroleum Geologists, Society of Petroleum Evaluation Engineers,
Society of Exploration Geophysicists, Society of Petrophysicists and Well Log Analysts,
and European Association of Geoscientists & Engineers

Petroleum Resources Management System

Definitions and Guidelines ([5])

Revised 2018 (v. 1.03)

Table 1—Recoverable Resources Classes and Sub-Classes

Class/Sub-Class	Definition	Guidelines
Reserves	Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.	Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by the development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability (see Section 2.1.2, Determination of Commerciality). This includes the requirement that there is evidence of firm intention to proceed with development within a reasonable time-frame. A reasonable time-frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time-frame could be applied where, for example, development of an economic project is deferred at the option of the producer for, among other things, market-related reasons or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented. To be included in the Reserves class, there must be a high confidence in the commercial maturity and economic producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.

[5] These Definitions and Guidelines are extracted from the full Petroleum Resources Management System (revised 2018 (v. 1.03)) document.

Class/Sub-Class	Definition	Guidelines
On Production	The development project is currently producing or capable of producing and selling petroleum to market.	The key criterion is that the project is receiving income from sales, rather than that the approved development project is necessarily complete. Includes Developed Producing Reserves. The project decision gate is the decision to initiate or continue economic production from the project.
Approved for Development	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is ready to begin or is under way.	At this point, it must be certain that the development project is going ahead. The project must not be subject to any contingencies, such as outstanding regulatory approvals or sales contracts. Forecast capital expenditures should be included in the reporting entity's current or following year's approved budget. The project decision gate is the decision to start investing capital in the construction of production facilities and/or drilling development wells.
Justified for Development	Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.	To move to this level of project maturity, and hence have Reserves associated with it, the development project must be commercially viable at the time of reporting (see Section 2.1.2, Determination of Commerciality) and the specific circumstances of the project. All participating entities have agreed and there is evidence of a committed project (firm intention to proceed with development within a reasonable time-frame}) There must be no known contingencies that could preclude the development from proceeding (see Reserves class). The project decision gate is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time.
Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable owing to one or more contingencies.	Contingent Resources may include, for example, projects for which there are currently no viable markets, where commercial recovery is dependent on technology under development, where evaluation of the accumulation is insufficient to clearly assess commerciality, where the development plan is not yet approved, or where regulatory or social acceptance issues may exist. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by the economic status.

Class/Sub-Class	Definition	Guidelines
Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.	The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g., drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable time-frame. Note that disappointing appraisal/evaluation results could lead to a reclassification of the project to On Hold or Not Viable status. The project decision gate is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production.
Development on Hold	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.	The project is seen to have potential for commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a probable chance that a critical contingency can be removed in the foreseeable future, could lead to a reclassification of the project to Not Viable status. The project decision gate is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies.
Development Unclarified	A discovered accumulation where project activities are under evaluation and where justification as a commercial development is unknown based on available information.	The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are ongoing to clarify the potential for eventual commercial development. This sub-class requires active appraisal or evaluation and should not be maintained without a plan for future evaluation. The sub-class should reflect the actions required to move a project toward commercial maturity and economic production.
Development Not Viable	A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time because of limited commercial potential.	The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions. The project decision gate is the decision not to undertake further data acquisition or studies on the project for the foreseeable future.

Class/Sub-Class	Definition	Guidelines
Prospective Resources	Those quantities of petroleum that are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.	Potential accumulations are evaluated according to the chance of geologic discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.
Prospect	A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.	Project activities are focused on assessing the chance of geologic discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.
Lead	A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation to be classified as a Prospect.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the Lead can be matured into a Prospect. Such evaluation includes the assessment of the chance of geologic discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.
Play	A project associated with a prospective trend of potential prospects, but that requires more data acquisition and/or evaluation to define specific Leads or Prospects.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific Leads or Prospects for more detailed analysis of their chance of geologic discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

Table 2—Reserves Status Definitions and Guidelines

Status	Definition	Guidelines
Developed Reserves	Expected quantities to be recovered from existing wells and facilities.	Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-producing.
Developed Producing Reserves	Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.	Improved recovery Reserves are considered producing only after the improved recovery project is in operation.
Developed Non-Producing Reserves	Shut-in and behind-pipe Reserves.	Shut-in Reserves are expected to be recovered from (1) completion intervals that are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.
Undeveloped Reserves	Quantities expected to be recovered through future significant investments.	Undeveloped Reserves are to be produced (1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g., when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

Table 3—Reserves Category Definitions and Guidelines

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

Category	Definition	Guidelines
Probable Reserves	Those additional Reserves that analysis of geoscience and engineering data indicates are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves.	It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate. Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria. Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.
Possible Reserves	Those additional reserves that analysis of geoscience and engineering data indicates are less likely to be recoverable than Probable Reserves.	The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high-estimate scenario. When probabilistic methods are used, there should be at least a 10% probability (P10) that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves may be assigned to areas of a reservoir adjacent to Probable where data control and interpretations of available data are progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of economic production from the reservoir by a defined, commercially mature project. Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.
Probable and Possible Reserves	See above for separate criteria for Probable Reserves and Possible Reserves.	The 2P and 3P estimates may be based on reasonable alternative technical interpretations within the reservoir and/or subject project that are clearly documented, including comparisons to results in successful similar projects. In conventional accumulations, Probable and/or Possible Reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from Proved areas by minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally higher than the Proved area. Possible (and in some cases, Probable) Reserves may be assigned to areas that are structurally lower than the adjacent Proved or 2P area. Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major, potentially sealing faults until this reservoir is penetrated and evaluated as commercially mature and economically productive. Justification for assigning

Category	Definition	Guidelines
		Reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from a known accumulation by non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results); such areas may contain Prospective Resources. In conventional accumulations, where drilling has defined a highest known oil elevation and there exists the potential for an associated gas cap, Proved Reserves of oil should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations.

Figure 1.1—Resources classification framework

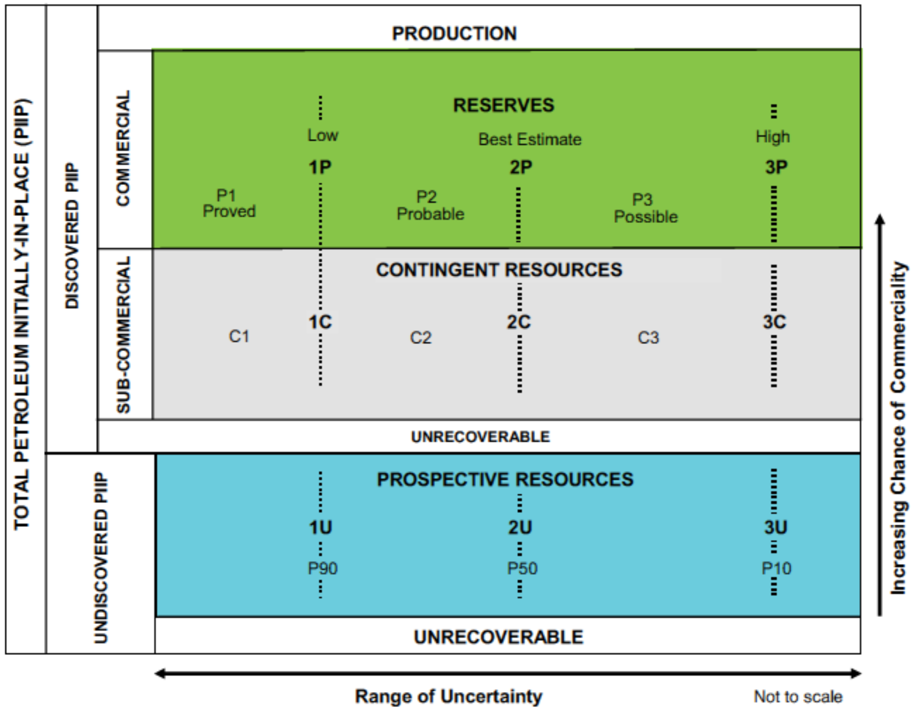
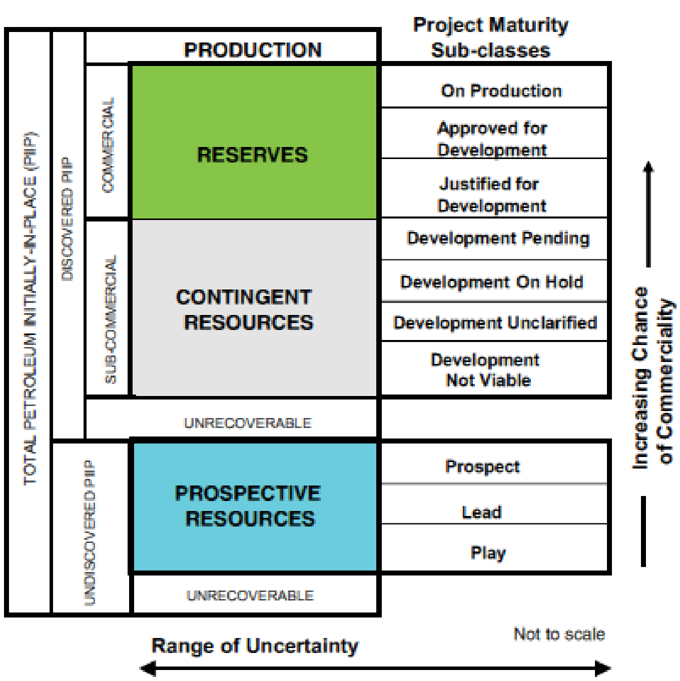


Figure 2.1—Sub-classes based on project maturity



Appendix III
Glossary

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Glossary – Standard Oil Industry Terms and Abbreviations

%	Percentage
1H05	First half (6 months) of 2005 (example)
2Q06	Second quarter (3 months) of 2006 (example)
2D	Two dimensional
3D	Three dimensional
4D	Four dimensional
1P	Proved Reserves
2P	Proved plus Probable Reserves
3P	Proved plus Probable plus Possible Reserves
ABEX	Abandonment Expenditure
ACQ	Annual Contract Quantity
^{o}API	Degrees API (American Petroleum Institute)
AAPG	American Association of Petroleum Geologists
AVO	Amplitude versus Offset
A$	Australian Dollars
B	Billion (10^9)
Bbl	Barrels
/Bbl	per barrel
BBbl	Billion Barrels
BHA	Bottom Hole Assembly
BHC	Bottom Hole Compensated
Bscf or Bcf	Billion standard cubic feet
Bscfd or Bcfd	Billion standard cubic feet per day
Bm^3	Billion cubic metres
bcpd	Barrels of condensate per day
BHP	Bottom Hole Pressure
blpd	Barrels of liquid per day
bpd	Barrels per day
boe	Barrels of oil equivalent @ xxx mcf/Bbl
boepd	Barrels of oil equivalent per day @ xxx mcf/Bbl
BOP	Blow Out Preventer
bopd	Barrels oil per day
bwpd	Barrels of water per day
BS&W	Bottom sediment and water
BTU	British Thermal Units
bwpd	Barrels water per day
CBM	Coal Bed Methane
CO_2	Carbon Dioxide
CAPEX	Capital Expenditure

CCGT	Combined Cycle Gas Turbine
cm	centimetres
CMM	Coal Mine Methane
CNG	Compressed Natural Gas
Cp	Centipoise (a measure of viscosity)
CSG	Coal Seam Gas
CT	Corporation Tax
D1BM	Design 1 Build Many
DCQ	Daily Contract Quantity
Deg C	Degrees Celsius
Deg F	Degrees Fahrenheit
DHI	Direct Hydrocarbon Indicator
DLIS	Digital Log Interchange Standard
DST	Drill Stem Test
DWT	Dead-weight ton
E&A	Exploration & Appraisal
E&P	Exploration and Production
EBIT	Earnings before Interest and Tax
EBITDA	Earnings before interest, tax, depreciation and amortisation
ECS	Elemental Capture Spectroscopy
EI	Entitlement Interest
EIA	Environmental Impact Assessment
ELT	Economic Limit Test
EMV	Expected Monetary Value
EOR	Enhanced Oil Recovery
EUR	Estimated Ultimate Recovery
FDP	Field Development Plan
FEED	Front End Engineering and Design
FPSO	Floating Production Storage and Offloading
FSO	Floating Storage and Offloading
FWL	Free Water Level
ft	Foot/feet
Fx	Foreign Exchange Rate
g	gram
g/cc	grams per cubic centimetre
gal	gallon
gal/d	gallons per day
G&A	General and Administrative costs
GBP	Pounds Sterling
GCoS	Geological Chance of Success
GDT	Gas Down to

GIIP	Gas Initially In Place
GJ	Gigajoules (one billion Joules)
GOC	Gas Oil Contact
GOR	Gas Oil Ratio
GRV	Gross Rock Volumes
GTL	Gas to Liquids
GWC	Gas water contact
HDT	Hydrocarbons Down to
HSE	Health, Safety and Environment
HSFO	High Sulphur Fuel Oil
HUT	Hydrocarbons up to
H_2S	Hydrogen Sulphide
IOR	Improved Oil Recovery
IPP	Independent Power Producer
IRR	Internal Rate of Return
J	Joule (Metric measurement of energy) I kilojoule = 0.9478 BTU)
k	Permeability
KB	Kelly Bushing
KJ	Kilojoules (one Thousand Joules)
kl	Kilolitres
km	Kilometres
km^2	Square kilometres
kPa	Thousands of Pascals (measurement of pressure)
KW	Kilowatt
KWh	Kilowatt hour
LAS	Log ASCII Standard
LKG	Lowest Known Gas
LKH	Lowest Known Hydrocarbons
LKO	Lowest Known Oil
LNG	Liquefied Natural Gas
LoF	Life of Field
LPG	Liquefied Petroleum Gas
LTI	Lost Time Injury
LWD	Logging while drilling
m	Metres
M	Thousand
m^3	Cubic metres
Mcf or Mscf	Thousand standard cubic feet
MCM	Management Committee Meeting
MMcf or MMscf	Million standard cubic feet
m^3/d	Cubic metres per day
mD	Measure of Permeability in millidarcies
MD	Measured Depth
MDT	Modular Dynamic Tester
Mean	Arithmetic average of a set of numbers

Median	Middle value in a set of values
MFT	Multi Formation Tester
mg/l	milligrams per litre
MJ	Megajoules (One Million Joules)
Mm^3	Thousand Cubic metres
Mm^3/d	Thousand Cubic metres per day
MM	Million
MMm^3	Million Cubic metres
MMm^3/d	Million Cubic metres per day
MMBbl	Millions of barrels
MMBTU	Millions of British Thermal Units
Mode	Value that exists most frequently in a set of values = most likely
Mscfd	Thousand standard cubic feet per day
MMscfd	Million standard cubic feet per day
MT	Thousands of metric tonnes
MW	Megawatt
MWD	Measuring While Drilling
MWh	Megawatt hour
mya	Million years ago
NGL	Natural Gas Liquids
N_2	Nitrogen
NTG	Net/Gross Ratio
NPV	Net Present Value
OBM	Oil Based Mud
OCM	Operating Committee Meeting
ODT	Oil-Down-To
OGIP	Original Gas in Place
OIIP	Oil Initially In Place
OOIP	Original Oil in Place
OPEX	Operating Expenditure
OWC	Oil Water Contact
p.a.	Per annum
Pa	Pascals (metric measurement of pressure)
P&A	Plugged and Abandoned
PDP	Proved Developed Producing
Phie	effective porosity
PI	Productivity Index
PIIP	Petroleum Initially In Place
PJ	Petajoules (10^{15} Joules)
PSDM	Post Stack Depth Migration
psi	Pounds per square inch
psia	Pounds per square inch absolute
psig	Pounds per square inch gauge
PUD	Proved Undeveloped
PVT	Pressure, Volume and Temperature

P10	10% Probability
P50	50% Probability
P90	90% Probability
RF	Recovery factor
RFT	Repeat Formation Tester
RT	Rotary Table
R/P	Reserve to Production
R_w	Resistivity of water
SCAL	Special core analysis
cf or scf	Standard Cubic Feet
cfd or scfd	Standard Cubic Feet per day
scf/ton	Standard cubic foot per ton
SL	Straight line (for depreciation)
s_o	Oil Saturation
SPM	Single Point Mooring
SPE	Society of Petroleum Engineers
SPEE	Society of Petroleum Evaluation Engineers
SPS	Subsea Production System
SS	Subsea
stb	Stock tank barrel
STOIIP	Stock tank oil initially in place
Swi	irreducible water saturation
s_w	Water Saturation
T	Tonnes
TD	Total Depth
Te	Tonnes equivalent
THP	Tubing Head Pressure
TJ	Terajoules (10^{12} Joules)
Tscf or Tcf	Trillion standard cubic feet
TCM	Technical Committee Meeting
TOC	Total Organic Carbon
TOP	Take or Pay
Tpd	Tonnes per day
TVD	True Vertical Depth
TVDss	True Vertical Depth Subsea
UFR	Umbilical Flow Lines and Risers
USGS	United States Geological Survey
US$	United States dollar
VLCC	Very Large Crude Carrier
Vsh	shale volume
VSP	Vertical Seismic Profiling
WC	Water Cut
WI	Working Interest
WPC	World Petroleum Council
WTI	West Texas Intermediate
wt%	Weight percent