Gaffney Cline

Reserves Audit of Alagoas Cluster, Brazil as of July 31, 2024

Prepared for

Origem Energía

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Gaffney, Cline & Associates, Inc.
Av. Juana Manso 205, 4th Floor
Dock 4, Puerto Madero
C1007CBE – Buenos Aires, AR

Tel: 5411 3378 6497

February 20, 2025

Nathan Biddle
E&P Director
Origem Energía
Rio de Janeiro
Brazil

nb@origemenergia.com

Dear Nathan,

Reserves Audit of Alagoas cluster, Brazil as of July 31, 2024

Introduction

At the request of Origem Energía (Origem or "the Client"), Gaffney, Cline & Associates (GaffneyCline) has performed a reserves audit of the Alagoas onshore cluster located onshore in the Sergipe-Alagoas Basin, state of Alagoas, Brazil, as of July 31, 2024 in which Origem is the legal operator of seven blocks with a 100% participating interest of a concession contract expiring on December 31, 2052. In the preparation of this report, GaffneyCline has used data available through July 31, 2024 only. We have requested and reviewed field activities after the effective date and nothing has transpired that would materially alter the reserves statements made in this report.

In addition to Origem's internal use, this report is intended for release to financial institutions. GaffneyCline will provide consent for release once proposed details are available.

The Alagoas cluster comprises six onshore concessions: Pilar, Furado, Anambé, Arapacu, Cidade de Sao Miguel dos Campos (CSMC), Sao Miguel dos Campos and one shallow water offshore concession (Paru). Table 1 summarizes the production of each block:

Table 1: Production and Wells by Concession as of June 2024*

	Pilar	Anambé	Furado	CSMC	Sao Miguel	Paru	Arapacu
Wells drilled	294	21	180	39	54	5	2
Active Producers	41	12	18	6	7	1	1
Main fluid	Oil/Gas	Oil	Oil	Gas	Gas	Gas	Gas
Gas Rate (Mm^3/d)	552	107	190	149	205	158	19
Oil Rate (bbl/d)	2,087	682	346	26	14	68	0

*Data are as of June 2024 because there was a general shut down from June 15 to August 2024 due to ANP audit.

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

For the purposes of this report, we used technical and economic data provided by Origem including, but not limited to, well logs, geologic maps, well test and production data, historical prices, cost information and property ownership interests as discussed in subsequent paragraphs of this report.

In addition to these data, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with development plans as provided to us by Origem.

Origem ran future net cash flows based on the recoverable volumes quoted from GaffneyCline using a reasonable oil price outlook as of July 31, 2024. Cashflows are presented in Appendix I.

The estimates in this report have been prepared in accordance with the definitions and guidelines set forth in the June 2018 v1.03 Petroleum Resources Management System (PRMS) (Appendix II). In Appendix III is a list of abbreviations used in this report.

Summary

GaffneyCline conducted an independent audit examination and estimation, as of July 31, 2024, of the gas, oil and condensate Reserves of the Alagoas cluster. On the basis of technical and other information made available to GaffneyCline concerning these property units, GaffneyCline hereby provides the Reserves statement in Table 2.

Table 2: Statement of Reserves, Alagoas Cluster, Brazil, as of July 31, 2024

Category	Gross (100%) Field Volumes			Net (NRI) Reserves			Gross Consumption
	Liquids (MMbbl)	Gas (MMm^3)	Oil Equivalent (MMBOE)	Liquids (MMbbl)	Gas sales (MMm^3)	LPG (Mton)	Gas (MMm^3)
Proved Developed Producing	4.5	2,279	19	5.3	2,045	182	118
Proved Developed Non-Producing	16.4	11,634	90	20.2	10,441	931	604
Total Proved	**21.0**	**13,913**	**109**	**25.4**	**12,486**	**1,113**	**723**
Probable	5.9	8,169	57	8.5	7,331	654	424
Possible	3.5	5,444	38	5.3	4,885	435	283

Notes:

1. Gross (100%) field volumes are 100% of the volumes estimated to be commercially recoverable from the fields under the intended development plans to the end of the concessions on December 31, 2052. Gas gross volume includes gas consumed in operations (CiO) and shrinkage. Liquids gross volumes include oil only.
2. Gross gas volumes were converted to barrels of oil equivalent volumes (BOE) using the conversion factors of $1Mm^3$ of gas = 6.29 BOE
3. Net revenue interest (NRI) Reserves are Origem´s net economic entitlement volumes. Liquids volumes include C5+ estimates. Net gas Reserves exclude volumes consumed in operations (CiO, or fuel), which are also reported separately.
4. Brazilian Petroleum Law, Article 47 states, "… royalties are to be paid on a monthly basis, in national currency …" and, therefore, royalties (7.5%) plus landowner rights (1%) are treated as cash deductions rather than a reduction to volumes.
5. Totals may not exactly equal the sum of the individual entries because of rounding.

Liquids represents oil and condensate volumes reported in millions (10^6) of barrels at stock tank conditions (MMbbl). LPG represents propane and butane volumes reported in thousand (10^3) of metric tonnes (Mton)

Natural gas volumes presented in Table 2 have been quoted in millions (10^9) of standard cubic meters (MMm^3). Standard conditions are defined as 1 atmosphere and 20°C.

Net gas Reserves exclude volumes consumed in operations (CiO, or fuel gas). Gas consumed in operations was estimated as 5.2% for all reserves categories. Shrinkage is 5.1%.

GaffneyCline concludes that the methodologies employed by Origem in the derivation of the Reserves estimates are appropriate, and that the quality of the data relied upon, and the depth and thoroughness of the estimation process are adequate.

Discussion

This audit examination was based on volume estimates and other information provided by Origem to GaffneyCline, 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.

The Proved Developed Producing (PDP) Reserves for gas and oil was estimated using conventional decline analysis. The Proved Developed non-producing (PDNP), Proved Undeveloped (PUD), Probable (P2) and Possible (P3) categories include many activities presented by Origem in each concession development plan (see Table 3). All activities in PDNP will be performed on a timeframe of 7 years (2024 to 2030). P2 activities will be performed up to 2033. The incremental volumes quoted for these activities were based on results of analogous activities performed in the past. LPG volumes were estimated as a percentage of gas production with a yield of 0.08 tonne/MMm^{3C}.

Table 3: Activity counts and categorization

Activity	PDNP	P2	P3
Perforating	224	72	40
Stim job	59	34	9
Perforating + ALS	32	7	1
Install Beam Unit	35	16	6
Water Injection	4	15	15
Install ESP	8	6	-
Perforting+Stim Job	5	19	7
Install GL	-	2	4
Install PCP	35	-	-
Drilling	2	7	22
Drilling Deep Objectives	-	2	-
Sidetrack Opportunity	-	5	3
Total Activities	**404**	**185**	**107**

Notes:

1. Drilling Deep Objectives activities are projects targeting the Barra Itauba formation.

The economic tests for the recoverable volumes were based on Origem's future scenario of Brent oil prices with a discount of US$6.00/bbl, which GaffneyCline considers reasonable (see Table 4).

The working interest is 100% and Origem represented the end of all concessions is December 2052.

Taxes do not include the Special Participation tax. Other taxes such as the PIS (Program of Social Integration), Cofins (Contribution for the Financing of Social Security) and ICMS (tax on the circulation of goods transportation and communication services) are financially recovered by Origem and therefore were not included.

Future capital costs and operating expenses estimated by Origem were derived from development programs planned for each field. Most capital costs are associated with the future activity shown in Table 3.

The drilling and completion costs for the future wells were estimated at US$6.4 million and US$8.0 million per well for the shallow and deep drilling project, respectively. A few sidetrack works were estimated at US$4.0 million per well.

Artificial lift jobs were estimated at US$0.74 million, US$0.83 million, US$0.65 million, and US$0.64 million per well for beam unit, ESPs, gas lift, and PCP installs, respectively. Workover costs were estimated at US$0.49 million per well for new perforations, US$0.53 million per well for stimulation jobs and US$0.56 million per well for combinations of perforation plus stimulation jobs. Infrastructure cost was estimated at US$3,500 per incremental Mboe/d and includes mainly associated infrastructure required for upstream flow.

Abandonment costs were estimated at US$78 million for legacy wells and infrastructure plus abandonment costs estimated at US$0.090 million per well with 2 new wells to abandon in 1P, 14 new wells to abandon in the P2 category and 25 new wells in the P3 category.[1]

GaffneyCline conducted a review of the operating expenses estimated by Origem based on the information provided. For year 2024, total operating costs were estimated at US$107 million and included operational costs, personnel, utilities and others. Yearly cost from 2025 is around US$107 million plus inflation and production change factor.

Logistics (OPMAC pipeline and Transpetro storage) costs for oil were estimated considering the following assumptions:

- Base volume: 0.84 MMbbl/year
- Logistics cost for base volume 2024 = US$ 3.23/bbl
- Logistics cost for base volume 2025 onward = US$1.55/bbl

Logistics cost from 2025 drops by 50% considering that Origem won the bid to operate the oil terminal from 2025.

GaffneyCline has found that projected capital investments and operating expenses are sufficient to economically produce the projected volumes.

Capital and operating costs have been indexed 2% per year. Cash flows are included in Appendix I.

The economic limit test and cashflows shown in Appendix I are based on prices provided by Origem as shown in Table 4, which GaffneyCline considers reasonable:

[1] Abandonment of 69 legacy wells is on charge of former operator, abandonment of all remaining wells and infrastructure is at cost of Origem and included in total abandonment costs as approved by National Petroleum Agency (ANP)

Table 4: Origem's Effective Price Scenario

Year	Brent Oil Price (US$/bbl)	Net Oil Price (US$/bbl)	Gas Price (US$/MMBtu)	LPG (US$/T)	C5+ Eff.Price (US$/bbl)
2024	81.02	75.02	8.61	534.4	85.02
2025	73.19	67.19	7.78	505.56	77.19
2026	71.00	65.00	7.55	476.01	75.00
2027	73.00	67.00	7.76	447.07	77.00
2028	71.00	65.00	7.55	449.91	75.00
2029	68.65	62.65	7.30	452.83	72.65
2030	65.00	59.00	6.91	455.81	69.00

Note:

1. Origem can sell C5+ due tanking and pipes for separate offloading.

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 Origem, 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 Origem 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.

In the preparation of this report, GaffneyCline has used definitions contained within 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).

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 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, 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.

Oil and condensate volumes are reported in millions (10^6) of barrels at stock tank conditions (MMbbl). Natural gas volumes have been quoted in millions (10^6) of standard cubic meters (MMm^3) Standard conditions are defined as 14.7 psia and 60°F.

GaffneyCline's review and audit involved reviewing pertinent facts, interpretations and assumptions made by Origem 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

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 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.

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.

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.

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 Origem to produce the estimated reserves.

Use of Net Present Values

It should be clearly understood that the Net Present Values (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 realised 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 Origem. Furthermore, the management and employees of GaffneyCline have no interest in any of the assets evaluated or are 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 Origem 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 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 Origem or by any other person or entity.

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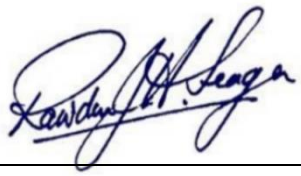
It has been a pleasure preparing this Reserves audit of Alagoas Cluster, Brazil as of July 31, 2024 for Origem Energía. Please contact the undersigned if you have any questions.

Yours sincerely,

Gaffney, Cline & Associates



Project Manager
Eduardo Sanchez Principal Advisor



Rawdon Seager
Director

Appendices

Appendix I	Net Cashflows
Appendix II	PRMS Guidelines
Appendix III	Glossary

Appendix I
Net Cashflows

Origem's PDP net cashflow as of July 31, 2024, Alagoas Cluster

Proved Developed Producing (PDP)

Year	Oil Production	Gas Sales Voume	LPG Volume	C5+	Net Revenues	Royalties	Opex & Logistics	Total Capex	Abandonment	Undiscounted Cash Flow	NPV @10%
	MMbbl	MMm³	Mton	MMbbl	US$ MM	US$ MM	US$ MM	US$ MM	US$ MM	US$ MM	US$ MM
2023	-	-	-	-	-	-	-	-	-	-	-
2024	0.41	154.5	13.8	0.055	92.4	(6.5)	(26.1)	(4.2)	-	55.6	46.0
2025	0.79	296.8	26.5	0.106	160.9	(11.2)	(39.7)	(1.3)	-	108.7	81.7
2026	0.61	228.6	20.4	0.082	119.5	(8.3)	(26.5)	(0.9)	-	83.8	57.2
2027	0.47	183.4	16.4	0.065	97.2	(6.8)	(19.9)	(0.6)	-	69.9	43.4
2028	0.38	151.8	13.5	0.054	80.7	(5.7)	(15.6)	(0.5)	-	58.9	33.3
2029	0.31	127.4	11.4	0.045	66.3	(4.7)	(12.8)	(0.4)	-	48.5	24.9
2030	0.25	108.9	9.7	0.039	56.0	(3.9)	(10.9)	(0.3)	-	40.9	19.1
2031	0.21	94.0	8.4	0.034	48.8	(3.4)	(9.3)	(0.3)	-	35.9	15.2
2032	0.17	82.0	7.3	0.029	43.0	(3.0)	(8.3)	(0.2)	-	31.4	12.1
2033	0.15	71.8	6.4	0.026	38.1	(2.7)	(7.0)	(0.2)	-	28.2	9.9
2034	0.12	63.4	5.6	0.023	34.0	(2.4)	(6.0)	(0.2)	-	25.4	8.1
2035	0.10	56.2	5.0	0.020	30.5	(2.1)	(5.2)	(0.2)	-	22.9	6.6
2036	0.09	50.2	4.5	0.018	27.5	(1.9)	(5.0)	(0.2)	-	20.4	5.4
2037	0.08	44.8	4.0	0.016	24.9	(1.7)	(4.5)	(0.2)	-	18.4	4.4
2038	0.06	40.2	3.6	0.014	22.6	(1.6)	(4.3)	(0.2)	-	16.5	3.6
2039	0.06	36.2	3.2	0.013	20.6	(1.4)	(4.1)	(0.2)	-	14.9	2.9
2040	0.05	32.7	2.9	0.012	18.8	(1.3)	(3.8)	-	-	13.6	2.4
2041	0.04	29.5	2.6	0.011	17.1	(1.2)	(3.6)	-	-	12.3	2.0
2042	0.03	26.7	2.4	0.010	15.7	(1.1)	(3.3)	-	-	11.2	1.7
2043	0.03	24.1	2.2	0.009	14.4	(1.0)	(3.4)	-	-	10.0	1.3
2044	0.03	21.9	2.0	0.008	13.2	(0.9)	(3.5)	-	-	8.8	1.1
2045	0.02	19.9	1.8	0.007	12.2	(0.9)	(3.6)	-	-	7.7	0.9
2046	0.02	18.2	1.6	0.006	11.4	(0.8)	(3.8)	-	-	6.8	0.7
2047	0.02	16.7	1.5	0.006	10.6	(0.7)	(3.9)	-	-	5.9	0.5
2048	0.01	15.3	1.4	0.005	9.8	(0.7)	(4.0)	-	-	5.1	0.4
2049	0.01	14.0	1.2	0.005	9.1	(0.6)	(4.2)	-	-	4.3	0.3
2050	0.01	12.8	1.1	0.005	8.4	(0.6)	(4.3)	-	-	3.5	0.2
2051	0.01	11.8	1.1	0.004	7.9	(0.6)	(4.4)	-	-	2.9	0.2
2052	0.01	10.8	1.0	0.004	7.4	(0.5)	(5.1)	-	-	1.8	0.1
2053	-	-	-	-	-	-	-	-	(156.8)	(156.8)	(8.2)
TOTAL	**4.5**	**2,044.9**	**182.3**	**0.729**	**1,119.0**	**(78.4)**	**(256.1)**	**(10.1)**	**(156.8)**	**617.5**	**377.5**

Notes:

1. Cash flows are shown up to the end of the concession. All volumes meet the economic limit test.
2. Volumes represent Origem's net entitlement as per the concession that govern the asset(s).
3. The NPVs reported here do not represent an opinion as to the market value of a property or any interest therein.
4. Totals may not exactly equal the sum of the individual entries because of rounding.

Origem's 1P net cashflow as of July 31, 2024, Alagoas Cluster

Total Proved (1P)

Year	Oil Production	Gas Sales Voume	LPG Volume	C5+	Net Revenues	Royalties	Opex	Total Capex	Abandonment	Undiscounted Cash Flow	NPV @10%
	MMbbl	MMm³	M ton	MMbbl	US$ MM	US$ MM	US$ MM	US$ MM	US$ MM	US$ MM	US$ MM
2023	-	-	-	-	-	-	-	-	-	-	-
2024	0.49	253.9	22.6	0.1	137.9	(9.6)	(32.1)	(16.7)	-	79.5	65.7
2025	1.44	796.4	71.0	0.3	385.8	(26.6)	(95.1)	(74.8)	-	189.3	142.2
2026	1.62	924.2	82.4	0.3	429.1	(29.6)	(96.4)	(84.2)	-	219.0	149.5
2027	1.76	1,029.9	91.8	0.4	485.0	(33.7)	(100.5)	(54.1)	-	296.7	184.2
2028	1.86	1,063.0	94.8	0.4	507.7	(35.3)	(99.9)	(50.5)	-	321.9	181.7
2029	1.85	1,084.5	96.7	0.4	510.8	(35.5)	(100.2)	(36.9)	-	338.2	173.6
2030	1.77	1,046.3	93.3	0.4	494.2	(34.3)	(97.1)	(28.5)	-	334.2	155.9
2031	1.57	924.5	82.4	0.3	447.3	(31.1)	(85.8)	(4.6)	-	325.8	138.2
2032	1.34	792.9	70.7	0.3	391.7	(27.3)	(76.3)	(2.2)	-	285.8	110.2
2033	1.13	673.7	60.1	0.2	340.3	(23.7)	(62.5)	(2.1)	-	251.9	88.3
2034	0.96	576.9	51.4	0.2	297.6	(20.8)	(52.6)	(1.9)	-	222.3	70.8
2035	0.82	495.9	44.2	0.2	261.1	(18.3)	(44.7)	(1.7)	-	196.4	56.9
2036	0.70	426.9	38.1	0.2	229.6	(16.1)	(41.7)	(1.6)	-	170.2	44.8
2037	0.59	365.9	32.6	0.1	201.0	(14.1)	(36.8)	(1.6)	-	148.5	35.6
2038	0.50	310.8	27.7	0.1	174.9	(12.3)	(33.2)	(1.6)	-	127.8	27.8
2039	0.43	267.2	23.8	0.1	153.6	(10.8)	(30.2)	(1.6)	-	111.0	22.0
2040	0.37	231.0	20.6	0.1	135.5	(9.5)	(27.7)	-	-	98.2	17.7
2041	0.31	199.6	17.8	0.1	119.4	(8.4)	(25.0)	-	-	86.0	14.1
2042	0.26	174.9	15.6	0.1	106.4	(7.5)	(22.5)	-	-	76.4	11.4
2043	0.23	152.6	13.6	0.1	94.5	(6.7)	(22.1)	-	-	65.8	8.9
2044	0.19	127.2	11.3	0.0	81.1	(5.7)	(21.3)	-	-	54.1	6.6
2045	0.16	109.9	9.8	0.0	71.5	(5.1)	(21.1)	-	-	45.4	5.1
2046	0.14	95.8	8.5	0.0	63.5	(4.5)	(20.9)	-	-	38.2	3.9
2047	0.12	83.5	7.4	0.0	56.4	(4.0)	(20.5)	-	-	31.9	2.9
2048	0.10	73.0	6.5	0.0	50.3	(3.6)	(20.4)	-	-	26.4	2.2
2049	0.09	63.4	5.7	0.0	44.5	(3.2)	(20.0)	-	-	21.4	1.6
2050	0.07	55.5	4.9	0.0	39.7	(2.8)	(19.8)	-	-	17.1	1.2
2051	0.06	48.6	4.3	0.0	35.4	(2.5)	(19.5)	-	-	13.4	0.8
2052	0.06	37.9	3.4	0.0	28.9	(2.1)	(19.3)	-	-	7.6	0.4
2053	-	-	-	-	-	-	-	-	(156.8)	(156.8)	(8.2)
TOTAL	**21.0**	**12,485.8**	**1,113.0**	**4.5**	**6,374.7**	**(444.6)**	**(1,365.3)**	**(364.7)**	**(156.8)**	**4,043.3**	**1,716.0**

Notes:

1. Cash flows are shown up to the end of the concession. All volumes meet the economic limit test.
2. Volumes represent Origem's net entitlement as per the concession that govern the asset(s).
3. The NPVs reported here do not represent an opinion as to the market value of a property or any interest therein.
4. Totals may not exactly equal the sum of the individual entries because of rounding.

Origem's 2P net cashflow as of July 31, 2024, Alagoas Cluster

Total Proved + Probable (2P)

Year	Oil Production	Gas Sales Voume	LPG Volume	C5+	Net Revenues	Royalties	Opex	Total Capex	Abandonment	Undiscounted Cash Flow	NPV @10%
	MMbbl	MMm³	M ton	MMbbl	US$ MM	US$ MM	US$ MM	US$ MM	US$ MM	US$ MM	US$ MM
2023	-	-	-	-	-	-	-	-	-	-	-
2024	0.49	255.8	22.8	0.1	139.0	(9.6)	(32.2)	(17.5)	-	79.7	65.8
2025	1.51	918.9	81.9	0.3	434.5	(29.9)	(107.1)	(96.7)	-	200.8	150.9
2026	1.71	1,090.9	97.2	0.4	493.6	(34.0)	(111.1)	(101.1)	-	247.4	169.0
2027	1.93	1,272.6	113.4	0.5	583.1	(40.5)	(121.2)	(78.0)	-	343.4	213.2
2028	2.08	1,385.0	123.5	0.5	636.2	(44.1)	(126.0)	(66.5)	-	399.6	225.6
2029	2.08	1,442.4	128.6	0.5	651.8	(45.1)	(128.8)	(55.4)	-	422.5	216.8
2030	2.07	1,491.6	133.0	0.5	673.1	(46.6)	(133.0)	(58.1)	-	435.4	203.1
2031	1.98	1,469.6	131.0	0.5	674.6	(46.7)	(130.2)	(42.6)	-	455.1	193.0
2032	1.88	1,385.4	123.5	0.5	651.9	(45.2)	(127.9)	(27.5)	-	451.3	174.0
2033	1.71	1,292.1	115.2	0.5	618.7	(42.9)	(114.4)	(34.7)	-	426.6	149.5
2034	1.50	1,178.4	105.0	0.4	572.8	(39.8)	(102.1)	(3.6)	-	427.2	136.1
2035	1.27	1,010.5	90.1	0.4	501.5	(34.9)	(86.6)	(3.3)	-	376.7	109.1
2036	1.08	868.8	77.5	0.3	440.5	(30.7)	(80.7)	(3.2)	-	326.0	85.8
2037	0.92	743.7	66.3	0.3	385.2	(26.9)	(71.1)	(3.1)	-	284.2	68.0
2038	0.78	634.3	56.5	0.2	336.0	(23.5)	(64.4)	(3.1)	-	245.0	53.3
2039	0.66	543.0	48.4	0.2	294.1	(20.6)	(58.2)	(3.2)	-	212.1	42.0
2040	0.56	468.8	41.8	0.2	259.2	(18.1)	(53.3)	-	-	187.7	33.8
2041	0.48	398.3	35.5	0.1	225.3	(15.8)	(47.4)	-	-	162.0	26.5
2042	0.40	345.8	30.8	0.1	199.4	(14.0)	(42.3)	-	-	143.0	21.3
2043	0.34	299.9	26.7	0.1	176.2	(12.4)	(41.5)	-	-	122.4	16.5
2044	0.29	254.4	22.7	0.1	153.0	(10.8)	(40.5)	-	-	101.8	12.5
2045	0.25	212.6	19.0	0.1	131.4	(9.3)	(39.1)	-	-	83.1	9.3
2046	0.21	182.5	16.3	0.1	115.3	(8.1)	(38.2)	-	-	69.0	7.0
2047	0.18	158.3	14.1	0.1	102.1	(7.2)	(37.5)	-	-	57.4	5.3
2048	0.15	136.1	12.1	0.0	89.7	(6.3)	(36.6)	-	-	46.8	3.9
2049	0.13	117.7	10.5	0.0	79.2	(5.6)	(35.9)	-	-	37.7	2.9
2050	0.11	102.5	9.1	0.0	70.2	(5.0)	(35.3)	-	-	29.9	2.1
2051	0.09	89.2	8.0	0.0	62.4	(4.4)	(34.7)	-	-	23.2	1.5
2052	0.08	67.8	6.0	0.0	49.7	(3.5)	(33.4)	-	(1.6)	11.1	0.6
2053	-	-	-	-	-	-	-	-	(156.8)	(156.8)	(8.2)
TOTAL	**26.9**	**19,817.1**	**1,766.6**	**7.1**	**9,799.5**	**(681.3)**	**(2,111.0)**	**(597.6)**	**(158.4)**	**6,251.2**	**2,390.2**

Notes:

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3. The NPVs reported here do not represent an opinion as to the market value of a property or any interest therein.
4. Totals may not exactly equal the sum of the individual entries because of rounding.

Origem's 3P net cashflow as of July 31, 2024, Alagoas Cluster

Total Proved + Probable + Possible (3P)

Year	Oil Production	Gas Sales Voume	LPG Volume	C5+	Net Revenues	Royalties	Opex	Total Capex	Abandonment	Undiscounted Cash Flow	NPV @10%
	MMbbl	MMm³	M ton	MMbbl	US$ MM	US$ MM	US$ MM	US$ MM	US$ MM	US$ MM	US$ MM
2023	-	-	-	-	-	-	-	-	-	-	-
2024	0.49	255.8	22.8	0.1	139.0	(9.6)	(32.2)	(17.5)	-	79.7	65.8
2025	1.51	918.9	81.9	0.3	434.5	(29.9)	(107.1)	(96.7)	-	200.8	150.9
2026	1.71	1,108.6	98.8	0.4	499.8	(34.4)	(112.6)	(115.2)	-	237.6	162.3
2027	1.93	1,288.9	114.9	0.5	589.4	(40.9)	(122.5)	(85.1)	-	340.9	211.7
2028	2.11	1,400.8	124.9	0.5	644.1	(44.7)	(127.6)	(73.7)	-	398.1	224.7
2029	2.21	1,480.1	131.9	0.5	674.2	(46.7)	(133.0)	(77.5)	-	416.9	214.0
2030	2.19	1,532.1	136.6	0.5	695.6	(48.1)	(137.4)	(69.0)	-	441.1	205.8
2031	2.10	1,616.1	144.1	0.6	736.4	(50.9)	(142.3)	(77.8)	-	465.3	197.3
2032	2.01	1,587.7	141.5	0.6	736.2	(51.0)	(144.7)	(53.5)	-	487.0	187.8
2033	1.85	1,498.3	133.6	0.5	707.6	(49.1)	(131.1)	(44.0)	-	483.4	169.4
2034	1.74	1,472.7	131.3	0.5	705.7	(49.0)	(126.0)	(72.1)	-	458.6	146.1
2035	1.58	1,431.0	127.6	0.5	693.1	(48.1)	(120.1)	(27.7)	-	497.3	144.0
2036	1.41	1,320.7	117.7	0.5	651.2	(45.2)	(119.8)	(23.7)	-	462.5	121.8
2037	1.23	1,202.5	107.2	0.4	602.1	(41.9)	(111.6)	(4.8)	-	443.8	106.2
2038	1.05	1,036.6	92.4	0.4	530.5	(36.9)	(102.2)	(5.0)	-	386.5	84.1
2039	0.90	895.7	79.8	0.3	468.3	(32.6)	(93.2)	(5.1)	-	337.4	66.7
2040	0.76	767.1	68.4	0.3	410.0	(28.6)	(84.7)	-	-	296.7	53.4
2041	0.64	657.4	58.6	0.2	358.9	(25.1)	(75.9)	-	-	257.9	42.2
2042	0.55	569.0	50.7	0.2	317.1	(22.2)	(67.6)	-	-	227.3	33.8
2043	0.47	492.1	43.9	0.2	280.0	(19.6)	(66.2)	-	-	194.2	26.2
2044	0.40	415.5	37.0	0.1	242.2	(17.0)	(64.4)	-	-	160.8	19.8
2045	0.34	350.5	31.2	0.1	209.4	(14.7)	(62.6)	-	-	132.0	14.7
2046	0.29	301.2	26.9	0.1	183.9	(12.9)	(61.3)	-	-	109.7	11.1
2047	0.24	260.6	23.2	0.1	162.5	(11.4)	(60.0)	-	-	91.1	8.4
2048	0.21	224.6	20.0	0.1	143.2	(10.1)	(58.8)	-	-	74.3	6.2
2049	0.18	193.8	17.3	0.1	126.2	(8.9)	(57.6)	-	-	59.7	4.6
2050	0.15	168.2	15.0	0.1	111.7	(7.9)	(56.5)	-	-	47.3	3.3
2051	0.13	146.0	13.0	0.1	99.0	(7.0)	(55.5)	-	-	36.5	2.3
2052	0.11	109.6	9.8	0.0	77.7	(5.5)	(52.7)	-	(3.9)	15.6	0.9
2053	-	-	-	-	-	-	-	-	(156.8)	(156.8)	(8.2)
TOTAL	**30.4**	**24,702.3**	**2,202.0**	**8.8**	**12,229.5**	**(849.9)**	**(2,687.1)**	**(848.4)**	**(160.7)**	**7,683.4**	**2,677.4**

Notes:

1. Cash flows are shown up to the end of the concession. All volumes meet the economic limit test.
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Appendix II
PRMS Guidelines

**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 ([2])

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.

[2] 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

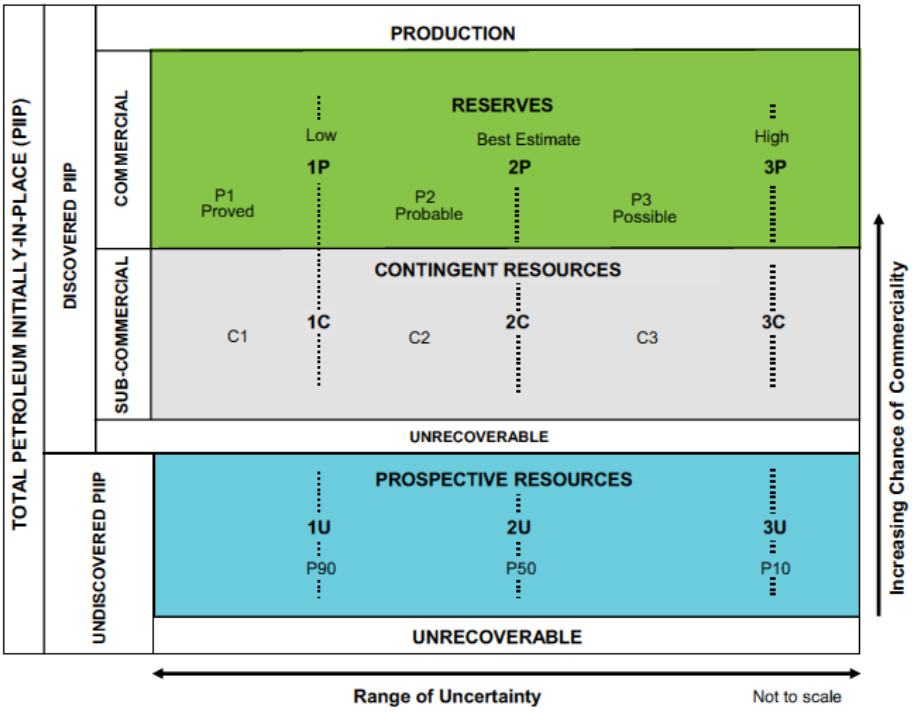
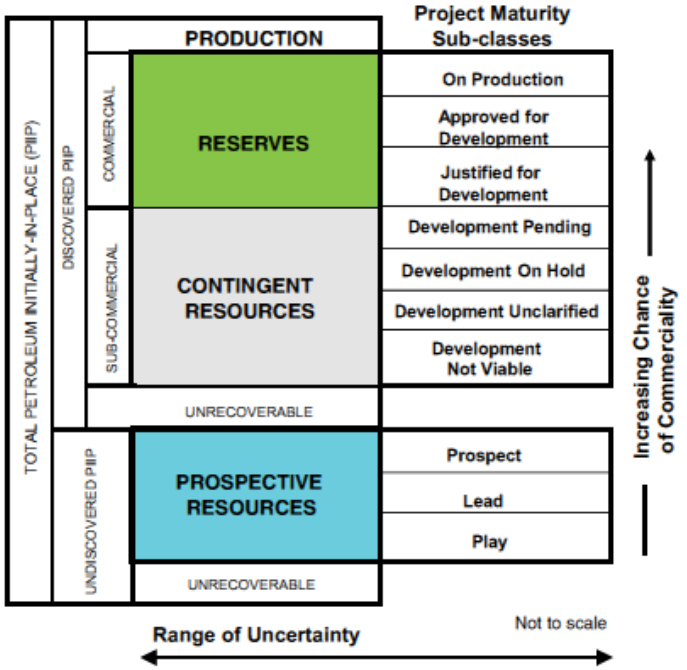


Figure 2.1—Sub-classes based on project maturity



Appendix III
Glossary

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