Gaffney, Cline & Associates

# Reserves and Resources Statement for Ambrosía, Río Opia, Mana, LLA-47 and Altair Areas, Colombia as of December 31, 2019

Prepared for

## Interoil Colombia E&P

**March 2020**

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March 24, 2020

Mr. Leandro Carbone
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## Reserves and Resources Statement for Ambrosía, Río Opia, Maná, LLA-47 and Altair Areas, Colombia as of December 31, 2019

Dear Mr. Carbone,

This reserves and resources statement has been prepared by Gaffney, Cline & Associates (GCA) and issued on March 24, 2020 at the request of Interoil Colombia E&P (Interoil or "the Client"), operator of and a variable interest participant in the Ambrosía, Río Opia and Maná concessions of the "Valle Medio del Magdalena Basin" and the Altair and LLA-47 concessions of the "Llanos Orientales Basin" in the Casanare province, Colombia. This report is intended for use in conjunction with the preparation of Interoil's Annual Statement of Reserves and Resources and to be presented to the Agencia Nacional de Hidrocarburos (ANH) of Colombia.

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 was intended.

GCA has conducted an independent audit examination, as of December 31, 2019, of the crude oil and natural gas volumes expected to be produced in the Ambrosía, Río Opia, Maná, LLA-47 and Altair concessions. On the basis of technical and other information made available to GCA concerning these property units, GCA hereby provides the reserves statement in Table 1:

Disclosure "In compliance with your instructions, and the accepted definitions for reserves we have evaluated the Interoil's assets as of December 31,2019, using a reasonable oil and gas price outlook as of that date. We would note that since the effective date various events have resulted in a material downward movement in the current oil price. If the current oil prices remain low and the long term oil price outlook is revised downward, there may be a material revision to the volumes classified as reserves [as well as any NPVs if included] summarized in this report."

**Table 1**
**Statement of Remaining Hydrocarbon Volumes**
**Ambrosía, Río Opia, Maná, LLA-47 and Altair Areas, Colombia**
**as of December 31, 2019**

| Reserves | Gross (100%) Volumes | | Interoil's Working Interest volumes | | Reserves Net to Interoil's Interest | |
|---|---|---|---|---|---|---|
| | Liquids (MMBbl) | Gas (Bcf) | Liquids (MMBbl) | Gas (Bcf) | Liquids (MMBbl) | Gas (Bcf) |
| Proved | | | | | | |
| Developed | 0.85 | 2.96 | 0.60 | 2.07 | 0.56 | 1.94 |
| Undeveloped | 0.16 | 0.90 | 0.11 | 0.63 | 0.10 | 0.59 |
| **Total 1P** | **1.01** | **3.86** | **0.71** | **2.70** | **0.66** | **2.53** |
| Total 2P | 1.69 | 8.80 | 1.18 | 6.16 | 1.09 | 5.76 |
| Total 3P | 1.69 | 8.80 | 1.18 | 6.16 | 1.09 | 5.76 |

Note: Totals may not add due to rounding

Hydrocarbon liquid volumes represent crude oil estimated to be recovered during field separation and are reported in millions of stock tank barrels (MMBbl). Natural gas volumes are reported in billion ($10^9$) standard cubic feet (Bcf) at standard condition of 14.7 psia and 60°F. Net interest gas reserves represent expected gas sales with the discount of gas for consumption in the field (7.1%). Royalties payable to the state and other royalty interest owners have been deducted from reported net interest volumes. Individual reserves statements for each area are provided in Appendix I.

Gas reserves sales volumes are based on firm and existing gas contracts, or on the reasonable expectation of a contract or on the reasonable expectation that any such existing gas sales contracts will be renewed on similar terms in the future.

Contingent Resources for the 1C, 2C and 3C categories were estimated as the extrapolation of the production of the concessions to December 2044 corresponding to the existing wells and to 39 future wells to be drilled according to Interoil's development program. The program includes one location categorized as C1 in LLA-47, 16 locations as C2 in Mana (seven), Ambrosia (eight) and Rio Opia (one), and 22 locations as C3 in Mana (eleven), Ambrosia (nine) and Rio Opia (two). Resources for each location were estimated by analogy with existing wells in each area. Table 2 summarizes these estimations:

**Table 2**
**Statement of Contingent Resources**
**Maná, Rio Opia, Ambrosía, LLA-47 and Altair Areas, Colombia**
**Gross (100%) Volumes as of December 31, 2019**

| Area | Crude Oil (MMBbl) | | | Natural Gas (Bcf) | | |
|---|---|---|---|---|---|---|
| | 1C | 2C | 3C | 1C | 2C | 3C |
| Llanos 47 | 0.88 | 0.88 | 0.88 | - | - | - |
| Altair | 0.92 | 4.11 | 4.11 | - | - | - |
| Ambrosia | 0.11 | 0.84 | 1.58 | - | 0.39 | 0.79 |
| Río Opia | - | 0.29 | 0.48 | - | 1.35 | 2.32 |
| Maná | 0.06 | 0.76 | 1.61 | 0.25 | 7.09 | 15.66 |
| Total | **1.96** | **6.87** | **8.65** | **0.25** | **8.84** | **18.77** |

Note: Totals may not add due to rounding

Hydrocarbon liquid volumes represent crude oil estimated to be recovered during field separation and are reported in million barrel increments (MMBbl). Natural gas volumes are reported in billion ($10^9$) standard cubic feet (Bcf) at standard condition of 14.7 psia and 60°F.

Volumes reported as Contingent Resources represent gross (100% interest) volumes without royalty or gas consumption deductions.

## Ambrosía, Maná and Río Opia Areas

Interoil operates these three areas under concession contracts with the following characteristics (Table 3):

**Table 3**
**Contract Characteristics**

| Area | Working Interest (%) | Royalty Oil (%) | Royalty Gas (%) | Contract Deadline |
|---|---|---|---|---|
| Ambrosía | 70 | 8 | 6.4 | 27-Dec-2027 |
| Río Opia | 70 | 8 | 6.4 | 23-Jun-2030 |
| Maná | 70 | 8 | 6.4 | 12-Nov-2028 |

Developed Producing reserves were estimated by extrapolating the present production trend by decline curve analysis.

Undeveloped reserves for each category were estimated by Interoil, and reviewed by GCA, for the workover campaign (two wells in Ambrosía, one in Maná, two in Rio Opia and one well in LLA-47). The estimates for each location were based on performance of similar existing wells in the area. The drilling plan includes five wells in Mana, one well in Ambrosia and one well in Rio Opia.

Drilling reserves were estimated by analogy with neighbor existing wells for each location.

Solution gas reserves in Maná and Río Opia were estimated through extrapolation of the producing gas-oil ratios. The resulting volumes were reduced by 7.1 % for consumption (3.47% in Mana and 3.61% in Río Opia).

## LLA-47 and Altair Areas

These areas are operated by Interoil under the following conditions (Table 4):

**Table 4**
**Operations Conditions**

| Area | Working Interest (%) | Royalty Oil (%) | Royalty Gas (%) | Contract Deadline |
|---|---|---|---|---|
| Altair | 90 | 8 | --- | 27-Dec-2035 |
| LLA-47 | 78 / 60 | 8 | --- | 07-Feb-2021 |

Interoil operates the Altair area under an exploitation contract that expires in 2035. The field is currently shut in due to environmental issues.

Interoil also operates the LLA-47 area with 78% participation on the production and on the operating expenses. Capital expenses participation is of 61%. Royalty of 8% and ANH participation of 15% on the production are paid in cash as stated by contract and are considered expenses rather than participations in the production. The LLA-47 area is under an exploration contract that expires in 2021. The area has one well (Vikingo-1) drilled in 2017 producing from the C5 layer of the Carbonera Formation.

Developed producing reserves were estimated from the extrapolation of the current oil production until the present contract end.

Developed non-producing reserves were estimated by Interoil reviewed by GCA. Vikingo-1 C7 layer of the Carbonera Formation will be put back on production by removing a plug and produced commingled with the current C5 interval through the end of the contract.

The extrapolation of the production beyond the present exploration contract deadline and up to December 31, 2044 has been classified as Contingent Resources.

Undeveloped Contingent Resources were assigned to a new well, Malevo-1, scheduled after the present contract deadline. The well will target the same reservoirs found at the Vikingo-1 well.

## Economic Limit Tests

The economic limit tests for the December 31, 2019 reserves volumes were based on a crude oil price scenario provided by Interoil of US$60.60/Bbl for 2020, based on the average Brent price. The oil sales price for Río Opia, Maná and Ambrosía was estimated as the Brent scenario with a discount of US$3.00/Bbl while for the Altair and Llanos 47 areas the discount was of US$0.50/Bbl.

The Mana and Río Opia gas sales price for 2020 was estimated by Interoil at 2.82 US$/Mscf for Mana and Río Opia. Oil and gas prices were indexed at 1% per year starting at 2021.

Future capital costs were derived from development program forecasts prepared by Interoil for each field with an average development well cost of US$ 2.2 million/well, and US$ 0.25 million on workovers and facilities. Recent historical operating expense data were used as the basis for operating cost projections. Estimated Open drivers and transportation costs for 2020 are presented in Table 5:

**Table 5**
**OPEX Drivers and Transportation Costs for 2020**

| Drivers and Costs | Ambrosia | Rio Opia | Maná | LLA- 47 |
|---|---|---|---|---|
| Fixed OPEX (US$M/yr) | 45.4 | 24.1 | 834 | 359 |
| Variable OPEX (US$/Bbl) | 0.85 | 0.85 | 0.97 | 9.35 |
| Variable OPEX (US$M/yr/well) | 25.61 | 34.76 | 27.97 | 18.79 |
| Oil Transportation (US$/Bbl) | 5.86 | 5.82 | 5.87 | 9.95 |

Starting at 2021, Capex, Opex and abandonment costs were indexed at 1% per year. Resulting cash flows are provided in Appendix II.

Upon Client request, GCA provided cash flows for the Agencia Nacional de Hidrocarburos de Colombia" (ANH), with a different oil price scenario. They were estimated using a constant oil reference price of US$55.69/Bbl without deductions for quality or location. This ANH price was based on the average 2019 WTI price. Capex Opex and abandonment costs were indexed at 1% per year starting at 2021. These cash flows are included in Appendix V.

## Reserves and Resources Assessment

This audit examination was based on reserves and resources estimates and other information provided by Interoil to GCA through February 2020, and included such tests, procedures and adjustments as were considered necessary. All questions that arose during the audit process were resolved to GCA's satisfaction.

GCA reviewed the field development plan and decided to classify as reserve only the proposed 2020 activity. GCA re classified all further activity presented as contingent resources or prospective resources.

It is GCA's opinion that the estimates of total remaining recoverable hydrocarbon liquid and gas volumes, as of December 31, 2019, are, in the aggregate, reasonable and the reserves and resources categorization is appropriate and consistent with the definitions for 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 and the Society of Petroleum Evaluation Engineers in June 2018 (see Appendix III).

GCA concludes that the methodologies employed by Interoil in the derivation of the reserves and resources estimates are appropriate, and that the quality of the data relied upon and the depth and thoroughness of the reserves and resources estimation process is adequate.

## Basis of Opinion

This document reflects GCA'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. GCA 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. GCA 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 resource 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, resource 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.

GCA's review and audit involved reviewing pertinent facts, interpretations and assumptions made by the Client or others in preparing estimates of reserves and resources. GCA 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 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).

GCA 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 and resources.

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" (per PRMS).

GCA has not undertaken a site visit or inspection because it was not considered relevant for the purpose of this report. As such, GCA 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, GCA 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 GCA's understanding of the effects of petroleum legislation and other regulations that currently apply to these properties. However, GCA 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).

**Qualifications**

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

In the preparation of this document, GCA has maintained, and continues to maintain, a strict independent consultant-client relationship with the Client. Furthermore, the management and employees of GCA 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 (GCA). No person or company other than those for whom it is intended may directly or indirectly rely upon its contents. GCA 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 GCA) by the Client or by any other person or entity.

Yours sincerely,

**Gaffney, Cline & Associates**

Project Manager
Joaquin Ramirez, Senior Advisor

Reviewed by
Roberto Wainhaus, Technical Director

**Appendices**

| | |
|---|---|
| Appendix I | Field Reserves Statements |
| Appendix II | Reserves Cash Flows |
| Appendix III | PRMS Reserves Definitions |
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# Appendix I
# Field Reserves Statements

**Statement of Remaining Hydrocarbon Volumes**
**Ambrosía, Río Opia, Maná, and Llanos 47 Areas, Colombia**
**as of December 31, 2019**

| Reserves | | Gross (100%) Field Volumes | | Interoil's Working Interest | | Reserves Net to Interoil's Interest | |
|---|---|---|---|---|---|---|---|
| | | Crude Oil (MMstb) | Natural Gas (Bscf) | Crude Oil (MMstb) | Natural Gas (Bscf) | Crude Oil (MMstb) | Natural Gas (Bscf) |
| Total | Proved | | | | | | |
| | Developed | 0.85 | 2.95 | 0.60 | 2.07 | 0.56 | 1.93 |
| | Developed NP | | | | | | |
| | Undeveloped | 0.16 | 0.91 | 0.11 | 0.63 | 0.10 | 0.59 |
| | Total 1P | 1.01 | 3.86 | 0.71 | 2.70 | 0.66 | 2.53 |
| | Total 2P | 1.69 | 8.80 | 1.19 | 6.16 | 1.10 | 5.76 |
| | Total 3P | 1.69 | 8.80 | 1.19 | 6.16 | 1.10 | 5.76 |
| Llanos | Proved | | | | | | |
| | Developed | 0.061 | 0.000 | 0.048 | 0.000 | 0.048 | 0.000 |
| | Developed NP | 0.004 | 0.000 | 0.003 | 0.000 | 0.003 | 0.000 |
| | Undeveloped | | | | | | |
| | Total 1P | 0.066 | 0.000 | 0.051 | 0.000 | 0.051 | 0.000 |
| | Total 2P | 0.066 | 0.000 | 0.051 | 0.000 | 0.051 | 0.000 |
| | Total 3P | 0.066 | 0.000 | 0.051 | 0.000 | 0.051 | 0.000 |
| Ambrosia | Proved | | | | | | |
| | Developed | 0.069 | 0.000 | 0.048 | 0.000 | 0.044 | 0.000 |
| | Undeveloped | 0.044 | 0.000 | 0.030 | 0.000 | 0.028 | 0.000 |
| | Total 1P | 0.112 | 0.000 | 0.079 | 0.000 | 0.072 | 0.000 |
| | Total 2P | 0.194 | 0.000 | 0.136 | 0.000 | 0.125 | 0.000 |
| | Total 3P | 0.194 | 0.000 | 0.136 | 0.000 | 0.125 | 0.000 |
| Rio Opia | Proved | | | | | | |
| | Developed | 0.023 | 0.060 | 0.016 | 0.042 | 0.015 | 0.039 |
| | Undeveloped | 0.077 | 0.310 | 0.054 | 0.217 | 0.050 | 0.203 |
| | Total 1P | 0.100 | 0.370 | 0.070 | 0.259 | 0.064 | 0.242 |
| | Total 2P | 0.195 | 0.772 | 0.137 | 0.540 | 0.126 | 0.506 |
| | Total 3P | 0.195 | 0.772 | 0.137 | 0.540 | 0.126 | 0.506 |
| Mana | Proved | | | | | | |
| | Developed | 0.697 | 2.891 | 0.488 | 2.024 | 0.449 | 1.894 |
| | Undeveloped | 0.035 | 0.596 | 0.024 | 0.417 | 0.022 | 0.390 |
| | Total 1P | 0.731 | 3.487 | 0.512 | 2.441 | 0.471 | 2.284 |
| | Total 2P | 1.234 | 8.027 | 0.864 | 5.619 | 0.795 | 5.259 |
| | Total 3P | 1.234 | 8.027 | 0.864 | 5.619 | 0.795 | 5.259 |

# Appendix II
# Reserves Cash Flows

## Cashflow for Reserves, Net working interest after royalties

**Mana**

**Proved Developed Reserves (PD)**

| Year | Production | | Gas | Gross | Oil | Operating | Investment | Net | 10 % Discount |
|---|---|---|---|---|---|---|---|---|---|
| | Liquids | Gas | Sales | Income | Transport | Expenses | | Cashflow | Cashflow |
| | MBO | MMCF | MMCF | MMUS$ | MMUS$ | MMUS$ | MMUS$ | MMUS$ | MMUS$ |
| 2020 | 92.3 | 404 | 390 | 6.45 | 0.59 | 1.44 | | 4.42 | 4.21 |
| 2021 | 77.0 | 337 | 325 | 5.43 | 0.50 | 1.42 | | 3.51 | 3.04 |
| 2022 | 64.4 | 282 | 272 | 4.58 | 0.42 | 1.36 | | 2.80 | 2.21 |
| 2023 | 53.9 | 236 | 227 | 3.87 | 0.35 | 1.37 | | 2.15 | 1.54 |
| 2024 | 45.2 | 198 | 191 | 3.27 | 0.30 | 1.37 | | 1.60 | 1.04 |
| 2025 | 37.7 | 165 | 159 | 2.75 | 0.25 | 1.29 | | 1.21 | 0.71 |
| 2026 | 31.5 | 138 | 133 | 2.32 | 0.21 | 1.22 | | 0.89 | 0.48 |
| 2027 | 26.4 | 115 | 111 | 1.96 | 0.18 | 1.14 | | 0.64 | 0.31 |
| 2028 | 20.3 | 89 | 86 | 1.52 | 0.14 | 0.93 | | 0.45 | 0.20 |
| 2029 | | | | | | | 2.41 | (2.41) | (0.98) |
| **TOTAL** | **448.5** | **1,962** | **1,894** | **32.16** | **2.94** | **11.55** | **2.41** | **15.25** | **12.78** |

**Mana**

**Proved Reserves (1P)**

| Year | Production | | Gas | Gross | Oil | Operating | Investment | Net | 10 % Discount |
|---|---|---|---|---|---|---|---|---|---|
| | Liquids | Gas | Sales | Income | Transport | Expenses | | Cashflow | Cashflow |
| | MBO | MMCF | MMCF | MMUS$ | MMUS$ | MMUS$ | MMUS$ | MMUS$ | MMUS$ |
| 2020 | 97.9 | 494 | 477 | 7.03 | 0.62 | 1.47 | 0.18 | 4.76 | 4.54 |
| 2021 | 82.4 | 430 | 415 | 6.01 | 0.53 | 1.45 | | 4.03 | 3.49 |
| 2022 | 68.1 | 350 | 338 | 5.00 | 0.44 | 1.39 | | 3.16 | 2.49 |
| 2023 | 56.5 | 285 | 276 | 4.16 | 0.37 | 1.39 | | 2.40 | 1.72 |
| 2024 | 47.0 | 234 | 226 | 3.48 | 0.31 | 1.39 | | 1.78 | 1.16 |
| 2025 | 38.9 | 191 | 184 | 2.90 | 0.26 | 1.31 | | 1.32 | 0.78 |
| 2026 | 32.4 | 156 | 151 | 2.43 | 0.22 | 1.24 | | 0.97 | 0.52 |
| 2027 | 27.0 | 129 | 124 | 2.03 | 0.18 | 1.16 | | 0.69 | 0.34 |
| 2028 | 20.7 | 97 | 94 | 1.57 | 0.14 | 0.95 | | 0.47 | 0.21 |
| 2029 | | | | | | | 2.47 | (2.47) | (1.00) |
| **TOTAL** | **470.8** | **2,367** | **2,284** | **34.61** | **3.09** | **11.75** | **2.65** | **17.12** | **14.26** |

**Mana**

**Proved & Probable Reserves (2P)**

| Year | Production Liquids MBO | Production Gas MMCF | Gas Sales MMCF | Gross Income MMUS$ | Oil Transport MMUS$ | Operating Expenses MMUS$ | Investment MMUS$ | Net Cashflow MMUS$ | 10 % Discount Cashflow MMUS$ |
|---|---|---|---|---|---|---|---|---|---|
| 2020 | 151.4 | 1,011 | 975 | 11.57 | 0.97 | 1.62 | 7.88 | 1.11 | 1.06 |
| 2021 | 174.0 | 1,296 | 1,251 | 13.68 | 1.12 | 1.64 | | 10.91 | 9.46 |
| 2022 | 130.1 | 937 | 905 | 10.14 | 0.85 | 1.55 | | 7.74 | 6.10 |
| 2023 | 98.4 | 683 | 660 | 7.60 | 0.65 | 1.54 | | 5.41 | 3.88 |
| 2024 | 75.5 | 504 | 487 | 5.77 | 0.50 | 1.53 | | 3.74 | 2.44 |
| 2025 | 58.2 | 374 | 361 | 4.40 | 0.39 | 1.44 | | 2.57 | 1.52 |
| 2026 | 45.4 | 280 | 271 | 3.41 | 0.31 | 1.36 | | 1.74 | 0.94 |
| 2027 | 35.8 | 213 | 205 | 2.66 | 0.24 | 1.27 | | 1.14 | 0.56 |
| 2028 | 26.1 | 150 | 145 | 1.93 | 0.18 | 1.06 | | 0.69 | 0.31 |
| 2029 | | | | | | | 2.78 | (2.78) | (1.13) |
| **TOTAL** | **795.0** | **5,448** | **5,259** | **61.16** | **5.21** | **13.01** | **10.66** | **32.28** | **25.13** |

**Mana**

**Proved, Probable & Possible Reserves (3P)**

| Year | Production Liquids MBO | Production Gas MMCF | Gas Sales MMCF | Gross Income MMUS$ | Oil Transport MMUS$ | Operating Expenses MMUS$ | Investment MMUS$ | Net Cashflow MMUS$ | 10 % Discount Cashflow MMUS$ |
|---|---|---|---|---|---|---|---|---|---|
| 2020 | 151.4 | 1,011 | 975 | 11.57 | 0.97 | 1.62 | 7.88 | 1.11 | 1.06 |
| 2021 | 174.0 | 1,296 | 1,251 | 13.78 | 1.12 | 1.64 | | 11.02 | 9.55 |
| 2022 | 130.1 | 937 | 905 | 10.30 | 0.85 | 1.55 | | 7.90 | 6.22 |
| 2023 | 98.4 | 683 | 660 | 7.78 | 0.65 | 1.54 | | 5.59 | 4.01 |
| 2024 | 75.5 | 504 | 487 | 5.96 | 0.50 | 1.53 | | 3.93 | 2.56 |
| 2025 | 58.2 | 374 | 361 | 4.58 | 0.39 | 1.44 | | 2.75 | 1.63 |
| 2026 | 45.4 | 280 | 271 | 3.58 | 0.31 | 1.36 | | 1.91 | 1.03 |
| 2027 | 35.8 | 213 | 205 | 2.82 | 0.24 | 1.27 | | 1.30 | 0.64 |
| 2028 | 26.1 | 150 | 145 | 2.06 | 0.18 | 1.06 | | 0.82 | 0.37 |
| 2029 | | | | | | | 2.78 | (2.78) | (1.13) |
| **TOTAL** | **795.0** | **5,448** | **5,259** | **62.42** | **5.21** | **13.01** | **10.66** | **33.55** | **25.93** |

# Cashflow for Reserves, Net working interest after royalties

**Llanos 47 Vikingo**

**Proved Developed Reserves (PD)**

| Year | Production Liquids MBO | Production Gas MMCF | Gross Income MMUS$ | Oil Transport MMUS$ | Operating Expenses MMUS$ | Investment MMUS$ | Net Cashflow MMUS$ | 10 % Discount Cashflow MMUS$ |
|---|---|---|---|---|---|---|---|---|
| 2020 | 47.8 | | 2.87 | 0.48 | 0.74 | | 1.66 | 1.58 |
| 2021 | | | | | | | | |
| 2022 | | | | | | | | |
| 2023 | | | | | | | | |
| 2024 | | | | | | | | |
| 2025 | | | | | | | | |
| 2026 | | | | | | | | |
| 2027 | | | | | | | | |
| 2028 | | | | | | | | |
| 2029 | | | | | | | | |
| **TOTAL** | **47.8** | **0** | **2.87** | **0.48** | **0.74** | **0.00** | **1.66** | **1.58** |

**Llanos 47 Vikingo**

**Proved Reserves (1P)**

| Year | Production Liquids MBO | Production Gas MMCF | Gross Income MMUS$ | Oil Transport MMUS$ | Operating Expenses MMUS$ | Investment MMUS$ | Net Cashflow MMUS$ | 10 % Discount Cashflow MMUS$ |
|---|---|---|---|---|---|---|---|---|
| 2020 | 51.1 | | 3.07 | 0.51 | 0.77 | 0.06 | 1.73 | 1.65 |
| 2021 | | | | | | | | |
| 2022 | | | | | | | | |
| 2023 | | | | | | | | |
| 2024 | | | | | | | | |
| 2025 | | | | | | | | |
| 2026 | | | | | | | | |
| 2027 | | | | | | | | |
| 2028 | | | | | | | | |
| 2029 | | | | | | | | |
| **TOTAL** | **51.1** | **0** | **3.07** | **0.51** | **0.77** | **0.06** | **1.73** | **1.65** |

**Llanos 47 Vikingo**
**Proved & Probable Reserves (2P)**

| Year | Production | | Gross | Oil | Operating | Investment | Net | 10 % Discount |
|---|---|---|---|---|---|---|---|---|
| | Liquids | Gas | Income | Transport | Expenses | | Cashflow | Cashflow |
| | MBO | MMCF | MMUS$ | MMUS$ | MMUS$ | MMUS$ | MMUS$ | MMUS$ |
| 2020 | 51.1 | | 3.07 | 0.51 | 0.77 | 0.06 | 1.73 | 1.65 |
| 2021 | | | | | | | | |
| 2022 | | | | | | | | |
| 2023 | | | | | | | | |
| 2024 | | | | | | | | |
| 2025 | | | | | | | | |
| 2026 | | | | | | | | |
| 2027 | | | | | | | | |
| 2028 | | | | | | | | |
| 2029 | | | | | | | | |
| **TOTAL** | **51.1** | **0** | **3.07** | **0.51** | **0.77** | **0.06** | **1.73** | **1.65** |

**Llanos 47 Vikingo**
**Proved, Probable & Possible Reserves (3P)**

| Year | Production | | Gross | Oil | Operating | Investment | Net | 10 % Discount |
|---|---|---|---|---|---|---|---|---|
| | Liquids | Gas | Income | Transport | Expenses | | Cashflow | Cashflow |
| | MBO | MMCF | MMUS$ | MMUS$ | MMUS$ | MMUS$ | MMUS$ | MMUS$ |
| 2020 | 51.1 | | 3.07 | 0.51 | 0.77 | 0.06 | 1.73 | 1.65 |
| 2021 | | | | | | | | |
| 2022 | | | | | | | | |
| 2023 | | | | | | | | |
| 2024 | | | | | | | | |
| 2025 | | | | | | | | |
| 2026 | | | | | | | | |
| 2027 | | | | | | | | |
| 2028 | | | | | | | | |
| 2029 | | | | | | | | |
| **TOTAL** | **51.1** | **0** | **3.07** | **0.51** | **0.77** | **0.06** | **1.73** | **1.65** |

# Cashflow for Reserves, Net working interest after royalties

**Ambrosia**

**Proved Developed Reserves (PD)**

| Year | Production | | Gross Income | Oil Transport | Operating Expenses | Investment | Net Cashflow | 10 % Discount Cashflow |
|---|---|---|---|---|---|---|---|---|
| | Liquids MBO | Gas MMCF | MMUS$ | MMUS$ | MMUS$ | MMUS$ | MMUS$ | MMUS$ |
| 2020 | 6.8 | 4.2 | 0.40 | 0.04 | 0.09 | | 0.27 | 0.26 |
| 2021 | 6.4 | 3.9 | 0.38 | 0.04 | 0.09 | | 0.25 | 0.22 |
| 2022 | 6.0 | 3.7 | 0.36 | 0.04 | 0.09 | | 0.23 | 0.18 |
| 2023 | 5.6 | 3.4 | 0.35 | 0.04 | 0.09 | | 0.21 | 0.15 |
| 2024 | 5.3 | 3.2 | 0.33 | 0.04 | 0.09 | | 0.20 | 0.13 |
| 2025 | 5.0 | 3.0 | 0.31 | 0.03 | 0.09 | | 0.18 | 0.11 |
| 2026 | 4.7 | 2.9 | 0.30 | 0.03 | 0.10 | | 0.17 | 0.09 |
| 2027 | 4.4 | 2.7 | 0.28 | 0.03 | 0.10 | | 0.15 | 0.08 |
| 2028 | | | | | | 0.19 | (0.19) | (0.08) |
| 2029 | | | | | | | | |
| **TOTAL** | **44.2** | **27** | **2.71** | **0.29** | **0.75** | **0.19** | **1.48** | **1.13** |

**Ambrosia**

**Proved Reserves (1P)**

| Year | Production | | Gross Income | Oil Transport | Operating Expenses | Investment | Net Cashflow | 10 % Discount Cashflow |
|---|---|---|---|---|---|---|---|---|
| | Liquids MBO | Gas MMCF | MMUS$ | MMUS$ | MMUS$ | MMUS$ | MMUS$ | MMUS$ |
| 2020 | 10.6 | 6.5 | 0.63 | 0.07 | 0.13 | 0.35 | 0.08 | 0.08 |
| 2021 | 10.7 | 6.5 | 0.64 | 0.07 | 0.13 | | 0.44 | 0.38 |
| 2022 | 10.0 | 6.2 | 0.60 | 0.06 | 0.13 | | 0.41 | 0.32 |
| 2023 | 9.3 | 5.8 | 0.57 | 0.06 | 0.13 | | 0.38 | 0.27 |
| 2024 | 8.7 | 5.5 | 0.54 | 0.06 | 0.13 | | 0.35 | 0.23 |
| 2025 | 8.2 | 5.2 | 0.51 | 0.05 | 0.14 | | 0.32 | 0.19 |
| 2026 | 7.6 | 4.9 | 0.48 | 0.05 | 0.14 | | 0.29 | 0.16 |
| 2027 | 7.1 | 4.6 | 0.46 | 0.05 | 0.14 | | 0.27 | 0.13 |
| 2028 | | | | | | 0.19 | (0.19) | (0.08) |
| 2029 | | | | | | | | |
| **TOTAL** | **72.2** | **45** | **4.43** | **0.48** | **1.07** | **0.54** | **2.35** | **1.67** |

**Ambrosia**

**Proved & Probable Reserves (2P)**

| Year | Production | | Gross | Oil | Operating | Investment | Net | 10 % Discount |
|---|---|---|---|---|---|---|---|---|
| | Liquids | Gas | Income | Transport | Expenses | | Cashflow | Cashflow |
| | MBO | MMCF | MMUS$ | MMUS$ | MMUS$ | MMUS$ | MMUS$ | MMUS$ |
| 2020 | 12.2 | 7.3 | 0.73 | 0.08 | 0.15 | 1.89 | (1.39) | (1.33) |
| 2021 | 26.5 | 14.6 | 1.58 | 0.17 | 0.17 | | 1.25 | 1.08 |
| 2022 | 21.4 | 12.1 | 1.29 | 0.14 | 0.16 | | 0.99 | 0.78 |
| 2023 | 17.6 | 10.2 | 1.08 | 0.12 | 0.16 | | 0.80 | 0.57 |
| 2024 | 14.8 | 8.8 | 0.91 | 0.10 | 0.16 | | 0.65 | 0.43 |
| 2025 | 12.5 | 7.6 | 0.78 | 0.08 | 0.16 | | 0.54 | 0.32 |
| 2026 | 10.8 | 6.6 | 0.68 | 0.07 | 0.16 | | 0.45 | 0.24 |
| 2027 | 9.4 | 5.9 | 0.60 | 0.06 | 0.16 | | 0.38 | 0.18 |
| 2028 | | | | | | 0.25 | (0.25) | (0.11) |
| 2029 | | | | | | | | |
| **TOTAL** | **125.1** | **73** | **7.65** | **0.82** | **1.27** | **2.14** | **3.42** | **2.17** |

**Ambrosia**

**Proved, Probable & Possible Reserves (3P)**

| Year | Production | | Gross | Oil | Operating | Investment | Net | 10 % Discount |
|---|---|---|---|---|---|---|---|---|
| | Liquids | Gas | Income | Transport | Expenses | | Cashflow | Cashflow |
| | MBO | MMCF | MMUS$ | MMUS$ | MMUS$ | MMUS$ | MMUS$ | MMUS$ |
| 2020 | 12.2 | 7.3 | 0.73 | 0.08 | 0.15 | 1.89 | (1.39) | (1.33) |
| 2021 | 26.5 | 14.6 | 1.58 | 0.17 | 0.17 | | 1.25 | 1.08 |
| 2022 | 21.4 | 12.1 | 1.29 | 0.14 | 0.16 | | 0.99 | 0.78 |
| 2023 | 17.6 | 10.2 | 1.08 | 0.12 | 0.16 | | 0.80 | 0.57 |
| 2024 | 14.8 | 8.8 | 0.91 | 0.10 | 0.16 | | 0.65 | 0.43 |
| 2025 | 12.5 | 7.6 | 0.78 | 0.08 | 0.16 | | 0.54 | 0.32 |
| 2026 | 10.8 | 6.6 | 0.68 | 0.07 | 0.16 | | 0.45 | 0.24 |
| 2027 | 9.4 | 5.9 | 0.60 | 0.06 | 0.16 | | 0.38 | 0.18 |
| 2028 | | | | | | 0.25 | (0.25) | (0.11) |
| 2029 | | | | | | | | |
| **TOTAL** | **125.1** | **73** | **7.65** | **0.82** | **1.27** | **2.14** | **3.42** | **2.17** |

# Cashflow for Reserves, Net working interest after royalties

**Rio Opia**
**Proved Developed Reserves (PD)**

| Year | Production Liquids MBO | Production Gas MMCF | Gas Sales MMCF | Gross Income MMUS$ | Oil Transport MMUS$ | Operating Expenses MMUS$ | Investment MMUS$ | Net Cashflow MMUS$ | 10 % Discount Cashflow MMUS$ |
|---|---|---|---|---|---|---|---|---|---|
| 2020 | 3.8 | 8 | 7 | 0.242 | 0.024 | 0.118 | | 0.10 | 0.10 |
| 2021 | 3.3 | 10 | 10 | 0.221 | 0.021 | 0.118 | | 0.08 | 0.07 |
| 2022 | 2.9 | 9 | 8 | 0.194 | 0.018 | 0.119 | | 0.06 | 0.04 |
| 2023 | 2.5 | 8 | 7 | 0.170 | 0.016 | 0.120 | | 0.03 | 0.02 |
| 2024 | 2.2 | 7 | 6 | 0.149 | 0.014 | 0.121 | | 0.01 | 0.01 |
| 2025 | | | | | | | 0.25 | (0.25) | (0.15) |
| 2026 | | | | | | | | | |
| 2027 | | | | | | | | | |
| 2028 | | | | | | | | | |
| 2029 | | | | | | | | | |
| **TOTAL** | **14.6** | **41** | **39** | **0.98** | **0.09** | **0.60** | **0.25** | **0.04** | **0.10** |

**Rio Opia**
**Proved Reserves (1P)**

| Year | Production Liquids MBO | Production Gas MMCF | Gas Sales MMCF | Gross Income MMUS$ | Oil Transport MMUS$ | Operating Expenses MMUS$ | Investment MMUS$ | Net Cashflow MMUS$ | 10 % Discount Cashflow MMUS$ |
|---|---|---|---|---|---|---|---|---|---|
| 2020 | 15.7 | 56 | 54 | 1.064 | 0.099 | 0.177 | 0.35 | 0.44 | 0.42 |
| 2021 | 13.7 | 54 | 52 | 0.953 | 0.087 | 0.177 | | 0.69 | 0.60 |
| 2022 | 10.3 | 41 | 40 | 0.724 | 0.066 | 0.176 | | 0.48 | 0.38 |
| 2023 | 7.8 | 32 | 30 | 0.554 | 0.051 | 0.175 | | 0.33 | 0.23 |
| 2024 | 5.9 | 24 | 23 | 0.428 | 0.039 | 0.175 | | 0.21 | 0.14 |
| 2025 | 4.6 | 19 | 18 | 0.331 | 0.030 | 0.176 | | 0.13 | 0.07 |
| 2026 | 3.5 | 14 | 14 | 0.259 | 0.024 | 0.176 | | 0.06 | 0.03 |
| 2027 | 2.8 | 11 | 11 | 0.205 | 0.019 | 0.177 | | 0.01 | 0.00 |
| 2028 | | | | | | | 0.25 | (0.25) | (0.11) |
| 2029 | | | | | | | | | |
| **TOTAL** | **64.2** | **252** | **242** | **4.52** | **0.42** | **1.41** | **0.60** | **2.09** | **1.77** |

**Rio Opia**

**Proved & Probable Reserves (2P)**

| Year | Production Liquids MBO | Production Gas MMCF | Gas Sales MMCF | Gross Income MMUS$ | Oil Transport MMUS$ | Operating Expenses MMUS$ | Investment MMUS$ | Net Cashflow MMUS$ | 10 % Discount Cashflow MMUS$ |
|---|---|---|---|---|---|---|---|---|---|
| 2020 | 19.8 | 73 | 70 | 1.351 | 0.125 | 0.205 | 1.89 | (0.87) | (0.83) |
| 2021 | 32.9 | 135 | 130 | 2.308 | 0.210 | 0.220 | | 1.88 | 1.63 |
| 2022 | 23.1 | 98 | 94 | 1.639 | 0.149 | 0.213 | | 1.28 | 1.01 |
| 2023 | 16.3 | 70 | 68 | 1.171 | 0.106 | 0.208 | | 0.86 | 0.61 |
| 2024 | 11.6 | 51 | 49 | 0.846 | 0.077 | 0.206 | | 0.56 | 0.37 |
| 2025 | 8.3 | 37 | 35 | 0.612 | 0.055 | 0.205 | | 0.35 | 0.21 |
| 2026 | 6.0 | 27 | 26 | 0.448 | 0.041 | 0.205 | | 0.20 | 0.11 |
| 2027 | 4.4 | 20 | 19 | 0.332 | 0.030 | 0.205 | | 0.10 | 0.05 |
| 2028 | 3.3 | 15 | 14 | 0.250 | 0.023 | 0.206 | | 0.02 | 0.01 |
| 2029 | | | | | | | 0.31 | (0.31) | (0.13) |
| **TOTAL** | **125.8** | **525** | **506** | **8.96** | **0.82** | **1.87** | **2.20** | **4.07** | **3.03** |

**Rio Opia**

**Proved, Probable & Possible Reserves (3P)**

| Year | Production Liquids MBO | Production Gas MMCF | Gas Sales MMCF | Gross Income MMUS$ | Oil Transport MMUS$ | Operating Expenses MMUS$ | Investment MMUS$ | Net Cashflow MMUS$ | 10 % Discount Cashflow MMUS$ |
|---|---|---|---|---|---|---|---|---|---|
| 2020 | 19.8 | 73 | 70 | 1.351 | 0.125 | 0.205 | 1.89 | (0.87) | (0.83) |
| 2021 | 32.9 | 135 | 130 | 2.308 | 0.210 | 0.220 | | 1.88 | 1.63 |
| 2022 | 23.1 | 98 | 94 | 1.639 | 0.149 | 0.213 | | 1.28 | 1.01 |
| 2023 | 16.3 | 70 | 68 | 1.171 | 0.106 | 0.208 | | 0.86 | 0.61 |
| 2024 | 11.6 | 51 | 49 | 0.846 | 0.077 | 0.206 | | 0.56 | 0.37 |
| 2025 | 8.3 | 37 | 35 | 0.612 | 0.055 | 0.205 | | 0.35 | 0.21 |
| 2026 | 6.0 | 27 | 26 | 0.448 | 0.041 | 0.205 | | 0.20 | 0.11 |
| 2027 | 4.4 | 20 | 19 | 0.332 | 0.030 | 0.205 | | 0.10 | 0.05 |
| 2028 | 3.3 | 15 | 14 | 0.250 | 0.023 | 0.206 | | 0.02 | 0.01 |
| 2029 | | | | | | | 0.31 | (0.31) | (0.13) |
| **TOTAL** | **125.8** | **525** | **506** | **8.96** | **0.82** | **1.87** | **2.20** | **4.07** | **3.03** |

Gaffney,
Cline &
Associates

# Appendix III
# PRMS Reserves 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 ([1])

## (Revised June 2018)

## Table 1—Recoverable Resources Classes and Sub-Classes

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

[1] These Definitions and Guidelines are extracted from the full Petroleum Resources Management System (revised June 2018) 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.<br><br>The project decision gate is the decision to initiate or continue economic production from the project. |
| **Approved for Development** | All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is ready to begin or is under way. | At this point, it must be certain that the development project is going ahead. The project must not be subject to any contingencies, such as outstanding regulatory approvals or sales contracts. Forecast capital expenditures should be included in the reporting entity's current or following year's approved budget.<br><br>The project decision gate is the decision to start investing capital in the construction of production facilities and/or drilling development wells. |
| **Justified for Development** | Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained. | To move to this level of project maturity, and hence have Reserves associated with it, the development project must be commercially viable at the time of reporting (see Section 2.1.2, Determination of Commerciality) and the specific circumstances of the project. All participating entities have agreed and there is evidence of a committed project (firm intention to proceed with development within a reasonable time-frame}) There must be no known contingencies that could preclude the development from proceeding (see Reserves class).<br><br>The project decision gate is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time. |
| **Contingent Resources** | Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable owing to one or more contingencies. | Contingent Resources may include, for example, projects for which there are currently no viable markets, where commercial recovery is dependent on technology under development, where evaluation of the accumulation is insufficient to clearly assess commerciality, where the development plan is not yet approved, or where regulatory or social acceptance issues may exist.<br><br>Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by the economic status. |

| 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.<br><br>The project decision gate is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production. |
| **Development on Hold** | A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay. | The project is seen to have potential for commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a probable chance that a critical contingency can be removed in the foreseeable future, could lead to a reclassification of the project to Not Viable status.<br><br>The project decision gate is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies. |
| **Development Unclarified** | A discovered accumulation where project activities are under evaluation and where justification as a commercial development is unknown based on available information. | The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are ongoing to clarify the potential for eventual commercial development.<br><br>This sub-class requires active appraisal or evaluation and should not be maintained without a plan for future evaluation. The sub-class should reflect the actions required to move a project toward commercial maturity and economic production. |
| **Development Not Viable** | A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time because of limited production potential. | The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions.<br><br>The project decision gate is the decision not to undertake further data acquisition or studies on the project for the foreseeable future. |

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

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

Figure 1.1—RESOURCES CLASSIFICATION FRAMEWORK

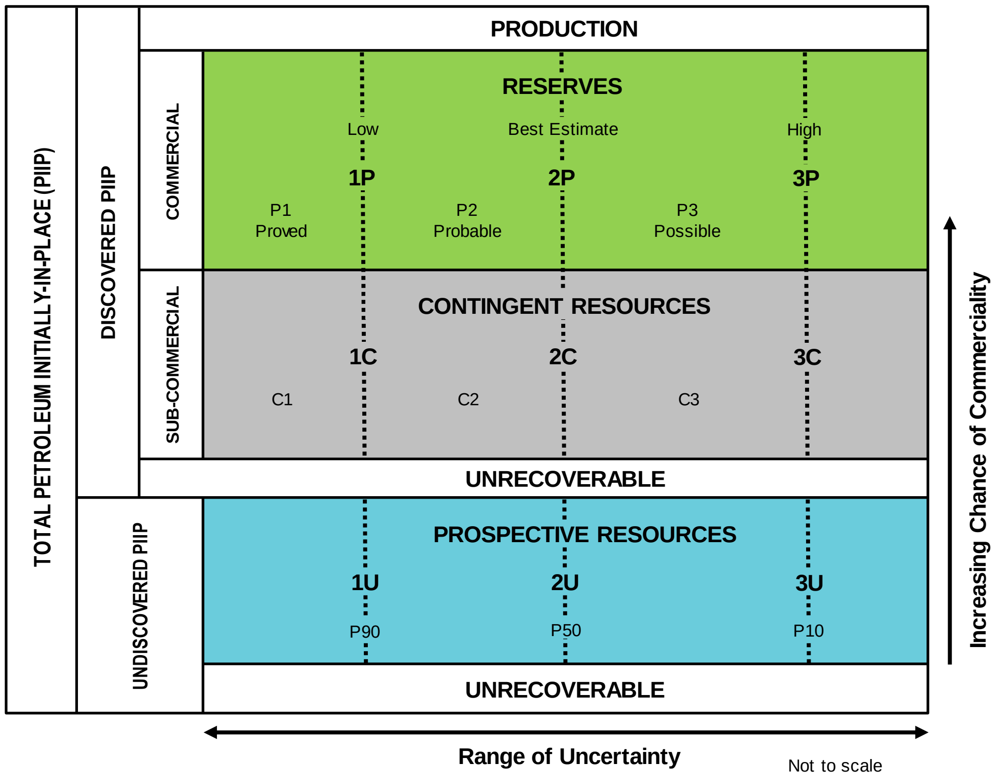
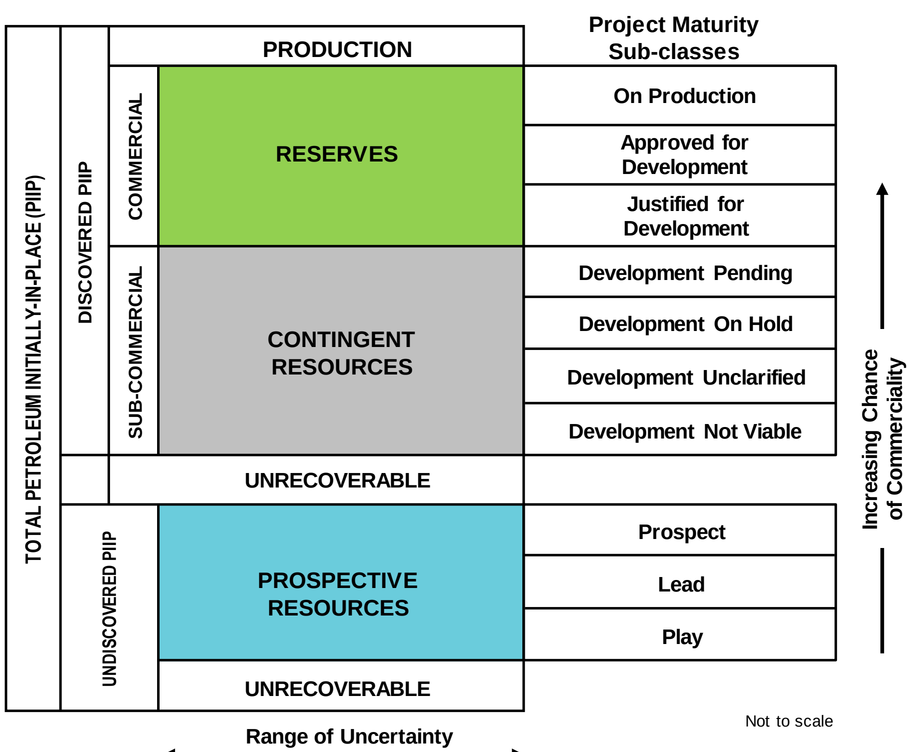



Figure 2.1—SUB-CLASSES BASED ON PROJECT MATURITY



# Appendix IV
# Glossary

## Glossary – Standard Oil Industry Terms and Abbreviations

Gaffney, Cline & Associates

| | |
|---|---|
| % | 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 |
| 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 |
| OOIP | Original Oil in Place |
| OPEX | Operating Expenditure |
| OWC | Oil Water Contact |
| p.a. | Per annum |

Gaffney, Cline & Associates

| | |
|---|---|
| Pa | Pascals (metric measurement of pressure) |
| P&A | Plugged and Abandoned |
| PDP | Proved Developed Producing |
| 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 |
| $s_w$ | 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 |
| VSP | Vertical Seismic Profiling |
| WC | Water Cut |
| WI | Working Interest |
| WPC | World Petroleum Council |
| WTI | West Texas Intermediate |
| wt% | Weight percent |

# Appendix V
# Reserves Cash Flows @ ANH reference oil price

Interoil Colombia E&P
March 24, 2020

# Cashflow for Reserves, Net working interest after royalties

**Mana**

**Proved Developed Reserves (PD)**

| Year | Production | | Gas | Gross | Oil | Operating | Investment | Net | 10 % Discount |
|---|---|---|---|---|---|---|---|---|---|
| | Liquids | Gas | Sales | Income | Transport | Expenses | | Cashflow | Cashflow |
| | MBbl | MMCF | MMCF | MMUS$ | MMUS$ | MMUS$ | MMUS$ | MMUS$ | MMUS$ |
| 2020 | 92.3 | 404 | 390 | 6.27 | 0.59 | 1.44 | | 4.24 | 4.04 |
| 2021 | 77.0 | 337 | 325 | 5.23 | 0.50 | 1.42 | | 3.31 | 2.87 |
| 2022 | 64.4 | 282 | 272 | 4.38 | 0.42 | 1.36 | | 2.59 | 2.04 |
| 2023 | 53.9 | 236 | 227 | 3.66 | 0.35 | 1.37 | | 1.94 | 1.39 |
| 2024 | 45.2 | 198 | 191 | 3.07 | 0.30 | 1.37 | | 1.40 | 0.91 |
| 2025 | 37.7 | 165 | 159 | 2.56 | 0.25 | 1.29 | | 1.02 | 0.60 |
| 2026 | 31.5 | 138 | 133 | 2.14 | 0.21 | 1.22 | | 0.71 | 0.38 |
| 2027 | 26.4 | 115 | 111 | 1.79 | 0.18 | 1.14 | | 0.47 | 0.23 |
| 2028 | 20.3 | 89 | 86 | 1.38 | 0.14 | 0.93 | | 0.30 | 0.14 |
| 2029 | | | | | | | 2.41 | (2.41) | (0.98) |
| **TOTAL** | **448.5** | **1,962** | **1,894** | **30.49** | **2.94** | **11.55** | **2.41** | **13.58** | **11.64** |

**Mana**

**Proved Reserves (1P)**

| Year | Production | | Gas | Gross | Oil | Operating | Investment | Net | 10 % Discount |
|---|---|---|---|---|---|---|---|---|---|
| | Liquids | Gas | Sales | Income | Transport | Expenses | | Cashflow | Cashflow |
| | MBbl | MMCF | MMCF | MMUS$ | MMUS$ | MMUS$ | MMUS$ | MMUS$ | MMUS$ |
| 2020 | 97.9 | 494 | 477 | 6.84 | 0.62 | 1.47 | 0.18 | 4.57 | 4.36 |
| 2021 | 82.4 | 430 | 415 | 5.80 | 0.53 | 1.45 | | 3.82 | 3.31 |
| 2022 | 68.1 | 350 | 338 | 4.78 | 0.44 | 1.39 | | 2.95 | 2.32 |
| 2023 | 56.5 | 285 | 276 | 3.95 | 0.37 | 1.39 | | 2.19 | 1.57 |
| 2024 | 47.0 | 234 | 226 | 3.27 | 0.31 | 1.39 | | 1.57 | 1.02 |
| 2025 | 38.9 | 191 | 184 | 2.70 | 0.26 | 1.31 | | 1.13 | 0.67 |
| 2026 | 32.4 | 156 | 151 | 2.24 | 0.22 | 1.24 | | 0.78 | 0.42 |
| 2027 | 27.0 | 129 | 124 | 1.86 | 0.18 | 1.16 | | 0.52 | 0.25 |
| 2028 | 20.7 | 97 | 94 | 1.42 | 0.14 | 0.95 | | 0.33 | 0.15 |
| 2029 | | | | | | | 2.47 | (2.47) | (1.00) |
| **TOTAL** | **470.8** | **2,367** | **2,284** | **32.87** | **3.09** | **11.75** | **2.65** | **15.38** | **13.07** |

**Mana**

**Proved & Probable Reserves (2P)**

| Year | Production Liquids MBbl | Production Gas MMCF | Gas Sales MMCF | Gross Income MMUS$ | Oil Transport MMUS$ | Operating Expenses MMUS$ | Investment MMUS$ | Net Cashflow MMUS$ | 10 % Discount Cashflow MMUS$ |
|---|---|---|---|---|---|---|---|---|---|
| 2020 | 151.4 | 1,011 | 975 | 11.28 | 0.97 | 1.62 | 7.88 | 0.82 | 0.78 |
| 2021 | 174.0 | 1,296 | 1,251 | 13.34 | 1.12 | 1.64 | | 10.58 | 9.17 |
| 2022 | 130.1 | 937 | 905 | 9.89 | 0.85 | 1.55 | | 7.49 | 5.90 |
| 2023 | 98.4 | 683 | 660 | 7.41 | 0.65 | 1.54 | | 5.22 | 3.74 |
| 2024 | 75.5 | 504 | 487 | 5.62 | 0.50 | 1.53 | | 3.60 | 2.34 |
| 2025 | 58.2 | 374 | 361 | 4.29 | 0.39 | 1.44 | | 2.46 | 1.46 |
| 2026 | 45.4 | 280 | 271 | 3.32 | 0.31 | 1.36 | | 1.65 | 0.89 |
| 2027 | 35.8 | 213 | 205 | 2.59 | 0.24 | 1.27 | | 1.07 | 0.52 |
| 2028 | 26.1 | 150 | 145 | 1.88 | 0.18 | 1.06 | | 0.64 | 0.28 |
| 2029 | | | | | | | 2.78 | (2.78) | (1.13) |
| **TOTAL** | **795.0** | **5,448** | **5,259** | **59.61** | **5.21** | **13.01** | **10.66** | **30.74** | **23.96** |

**Mana**

**Proved, Probable & Possible Reserves (3P)**

| Year | Production Liquids MBbl | Production Gas MMCF | Gas Sales MMCF | Gross Income MMUS$ | Oil Transport MMUS$ | Operating Expenses MMUS$ | Investment MMUS$ | Net Cashflow MMUS$ | 10 % Discount Cashflow MMUS$ |
|---|---|---|---|---|---|---|---|---|---|
| 2020 | 151.4 | 1,011 | 975 | 11.28 | 0.97 | 1.62 | 7.88 | 0.82 | 0.78 |
| 2021 | 174.0 | 1,296 | 1,251 | 13.34 | 1.12 | 1.64 | | 10.58 | 9.17 |
| 2022 | 130.1 | 937 | 905 | 9.89 | 0.85 | 1.55 | | 7.49 | 5.90 |
| 2023 | 98.4 | 683 | 660 | 7.41 | 0.65 | 1.54 | | 5.22 | 3.74 |
| 2024 | 75.5 | 504 | 487 | 5.62 | 0.50 | 1.53 | | 3.60 | 2.34 |
| 2025 | 58.2 | 374 | 361 | 4.29 | 0.39 | 1.44 | | 2.46 | 1.46 |
| 2026 | 45.4 | 280 | 271 | 3.32 | 0.31 | 1.36 | | 1.65 | 0.89 |
| 2027 | 35.8 | 213 | 205 | 2.59 | 0.24 | 1.27 | | 1.07 | 0.52 |
| 2028 | 26.1 | 150 | 145 | 1.88 | 0.18 | 1.06 | | 0.64 | 0.28 |
| 2029 | | | | | | | 2.78 | (2.78) | (1.13) |
| **TOTAL** | **795.0** | **5,448** | **5,259** | **59.61** | **5.21** | **13.01** | **10.66** | **30.74** | **23.96** |

# Cashflow for Reserves, Net working interest after royalties

**Llanos 47 Vikingo**

**Proved Developed Reserves (PD)**

| Year | Production | | Gross | Oil | Operating | Investment | Net | 10 % Discount |
|---|---|---|---|---|---|---|---|---|
| | Liquids | Gas | Income | Transport | Expenses | | Cashflow | Cashflow |
| | MBbl | MMCF | MMUS$ | MMUS$ | MMUS$ | MMUS$ | MMUS$ | MMUS$ |
| 2020 | 47.8 | | 2.66 | 0.48 | 0.74 | | 1.44 | 1.38 |
| 2021 | | | | | | | | |
| 2022 | | | | | | | | |
| 2023 | | | | | | | | |
| 2024 | | | | | | | | |
| 2025 | | | | | | | | |
| 2026 | | | | | | | | |
| 2027 | | | | | | | | |
| 2028 | | | | | | | | |
| 2029 | | | | | | | | |
| **TOTAL** | **47.8** | **0** | **2.66** | **0.48** | **0.74** | **0.00** | **1.44** | **1.38** |

**Llanos 47 Vikingo**

**Proved Reserves (1P)**

| Year | Production | | Gross | Oil | Operating | Investment | Net | 10 % Discount |
|---|---|---|---|---|---|---|---|---|
| | Liquids | Gas | Income | Transport | Expenses | | Cashflow | Cashflow |
| | MBbl | MMCF | MMUS$ | MMUS$ | MMUS$ | MMUS$ | MMUS$ | MMUS$ |
| 2020 | 51.1 | | 2.85 | 0.51 | 0.77 | 0.06 | 1.51 | 1.44 |
| 2021 | | | | | | | | |
| 2022 | | | | | | | | |
| 2023 | | | | | | | | |
| 2024 | | | | | | | | |
| 2025 | | | | | | | | |
| 2026 | | | | | | | | |
| 2027 | | | | | | | | |
| 2028 | | | | | | | | |
| 2029 | | | | | | | | |
| **TOTAL** | **51.1** | **0** | **2.85** | **0.51** | **0.77** | **0.06** | **1.51** | **1.44** |

**Llanos 47 Vikingo**

**Proved & Probable Reserves (2P)**

| Year | Production | | Gross | Oil | Operating | Investment | Net | 10 % Discount |
|---|---|---|---|---|---|---|---|---|
| | Liquids | Gas | Income | Transport | Expenses | | Cashflow | Cashflow |
| | MBbl | MMCF | MMUS$ | MMUS$ | MMUS$ | MMUS$ | MMUS$ | MMUS$ |
| 2020 | 51.1 | | 2.85 | 0.51 | 0.77 | 0.06 | 1.51 | 1.44 |
| 2021 | | | | | | | | |
| 2022 | | | | | | | | |
| 2023 | | | | | | | | |
| 2024 | | | | | | | | |
| 2025 | | | | | | | | |
| 2026 | | | | | | | | |
| 2027 | | | | | | | | |
| 2028 | | | | | | | | |
| 2029 | | | | | | | | |
| **TOTAL** | **51.1** | **0** | **2.85** | **0.51** | **0.77** | **0.06** | **1.51** | **1.44** |

**Llanos 47 Vikingo**

**Proved, Probable & Possible Reserves (3P)**

| Year | Production | | Gross | Oil | Operating | Investment | Net | 10 % Discount |
|---|---|---|---|---|---|---|---|---|
| | Liquids | Gas | Income | Transport | Expenses | | Cashflow | Cashflow |
| | MBbl | MMCF | MMUS$ | MMUS$ | MMUS$ | MMUS$ | MMUS$ | MMUS$ |
| 2020 | 51.1 | | 2.85 | 0.51 | 0.77 | 0.06 | 1.51 | 1.44 |
| 2021 | | | | | | | | |
| 2022 | | | | | | | | |
| 2023 | | | | | | | | |
| 2024 | | | | | | | | |
| 2025 | | | | | | | | |
| 2026 | | | | | | | | |
| 2027 | | | | | | | | |
| 2028 | | | | | | | | |
| 2029 | | | | | | | | |
| **TOTAL** | **51.1** | **0** | **2.85** | **0.51** | **0.77** | **0.06** | **1.51** | **1.44** |

# Cashflow for Reserves, Net working interest after royalties

**Ambrosia**

**Proved Developed Reserves (PD)**

| Year | Production Liquids MBbl | Production Gas MMCF | Gross Income MMUS$ | Oil Transport MMUS$ | Operating Expenses MMUS$ | Investment MMUS$ | Net Cashflow MMUS$ | 10 % Discount Cashflow MMUS$ |
|---|---|---|---|---|---|---|---|---|
| 2020 | 6.8 | 4.2 | 0.388 | 0.04 | 0.09 | | 0.25 | 0.24 |
| 2021 | 6.4 | 3.9 | 0.363 | 0.04 | 0.09 | | 0.23 | 0.20 |
| 2022 | 6.0 | 3.7 | 0.341 | 0.04 | 0.09 | | 0.21 | 0.17 |
| 2023 | 5.6 | 3.4 | 0.321 | 0.04 | 0.09 | | 0.19 | 0.14 |
| 2024 | 5.3 | 3.2 | 0.302 | 0.04 | 0.09 | | 0.17 | 0.11 |
| 2025 | 5.0 | 3.0 | 0.283 | 0.03 | 0.09 | | 0.15 | 0.09 |
| 2026 | 4.7 | 2.9 | 0.266 | 0.03 | 0.10 | | 0.14 | 0.07 |
| 2027 | 4.4 | 2.7 | 0.250 | 0.03 | 0.10 | | 0.12 | 0.06 |
| 2028 | | | | | | 0.19 | (0.19) | (0.08) |
| 2029 | | | | | | | | |
| **TOTAL** | **44.2** | **27** | **2.51** | **0.29** | **0.75** | **0.19** | **1.29** | **1.00** |

**Ambrosia**

**Proved Reserves (1P)**

| Year | Production Liquids MBbl | Production Gas MMCF | Gross Income MMUS$ | Oil Transport MMUS$ | Operating Expenses MMUS$ | Investment MMUS$ | Net Cashflow MMUS$ | 10 % Discount Cashflow MMUS$ |
|---|---|---|---|---|---|---|---|---|
| 2020 | 10.6 | 6.5 | 0.608 | 0.07 | 0.13 | 0.35 | 0.06 | 0.06 |
| 2021 | 10.7 | 6.5 | 0.609 | 0.07 | 0.13 | | 0.41 | 0.35 |
| 2022 | 10.0 | 6.2 | 0.569 | 0.06 | 0.13 | | 0.37 | 0.29 |
| 2023 | 9.3 | 5.8 | 0.532 | 0.06 | 0.13 | | 0.34 | 0.24 |
| 2024 | 8.7 | 5.5 | 0.499 | 0.06 | 0.13 | | 0.31 | 0.20 |
| 2025 | 8.2 | 5.2 | 0.466 | 0.05 | 0.14 | | 0.28 | 0.16 |
| 2026 | 7.6 | 4.9 | 0.436 | 0.05 | 0.14 | | 0.25 | 0.13 |
| 2027 | 7.1 | 4.6 | 0.407 | 0.05 | 0.14 | | 0.22 | 0.11 |
| 2028 | | | | | | 0.19 | (0.19) | (0.08) |
| 2029 | | | | | | | | |
| **TOTAL** | **72.2** | **45** | **4.13** | **0.48** | **1.07** | **0.54** | **2.04** | **1.47** |

**Ambrosia**
**Proved & Probable Reserves (2P)**

| Year | Production | | Gross | Oil | Operating | Investment | Net | 10 % Discount |
|---|---|---|---|---|---|---|---|---|
| | Liquids | Gas | Income | Transport | Expenses | | Cashflow | Cashflow |
| | MBbl | MMCF | MMUS$ | MMUS$ | MMUS$ | MMUS$ | MMUS$ | MMUS$ |
| 2020 | 12.2 | 7.3 | 0.699 | 0.08 | 0.15 | 1.89 | (1.42) | (1.35) |
| 2021 | 26.5 | 14.6 | 1.513 | 0.17 | 0.17 | | 1.18 | 1.02 |
| 2022 | 21.4 | 12.1 | 1.224 | 0.14 | 0.16 | | 0.92 | 0.73 |
| 2023 | 17.6 | 10.2 | 1.006 | 0.12 | 0.16 | | 0.73 | 0.52 |
| 2024 | 14.8 | 8.8 | 0.843 | 0.10 | 0.16 | | 0.59 | 0.38 |
| 2025 | 12.5 | 7.6 | 0.714 | 0.08 | 0.16 | | 0.47 | 0.28 |
| 2026 | 10.8 | 6.6 | 0.615 | 0.07 | 0.16 | | 0.38 | 0.21 |
| 2027 | 9.4 | 5.9 | 0.537 | 0.06 | 0.16 | | 0.31 | 0.15 |
| 2028 | | | | | | 0.25 | (0.25) | (0.11) |
| 2029 | | | | | | | | |
| **TOTAL** | **125.1** | **73** | **7.15** | **0.82** | **1.27** | **2.14** | **2.92** | **1.83** |

**Ambrosia**
**Proved, Probable & Possible Reserves (3P)**

| Year | Production | | Gross | Oil | Operating | Investment | Net | 10 % Discount |
|---|---|---|---|---|---|---|---|---|
| | Liquids | Gas | Income | Transport | Expenses | | Cashflow | Cashflow |
| | MBbl | MMCF | MMUS$ | MMUS$ | MMUS$ | MMUS$ | MMUS$ | MMUS$ |
| 2020 | 12.2 | 7.3 | 0.699 | 0.08 | 0.15 | 1.89 | (1.42) | (1.35) |
| 2021 | 26.5 | 14.6 | 1.513 | 0.17 | 0.17 | | 1.18 | 1.02 |
| 2022 | 21.4 | 12.1 | 1.224 | 0.14 | 0.16 | | 0.92 | 0.73 |
| 2023 | 17.6 | 10.2 | 1.006 | 0.12 | 0.16 | | 0.73 | 0.52 |
| 2024 | 14.8 | 8.8 | 0.843 | 0.10 | 0.16 | | 0.59 | 0.38 |
| 2025 | 12.5 | 7.6 | 0.714 | 0.08 | 0.16 | | 0.47 | 0.28 |
| 2026 | 10.8 | 6.6 | 0.615 | 0.07 | 0.16 | | 0.38 | 0.21 |
| 2027 | 9.4 | 5.9 | 0.537 | 0.06 | 0.16 | | 0.31 | 0.15 |
| 2028 | | | | | | 0.25 | (0.25) | (0.11) |
| 2029 | | | | | | | | |
| **TOTAL** | **125.1** | **73** | **7.15** | **0.82** | **1.27** | **2.14** | **2.92** | **1.83** |

# Cashflow for Reserves, Net working interest after royalties

**Rio Opia**

**Proved Developed Reserves (PD)**

| Year | Production | | Gas | Gross | Oil | Operating | Investment | Net | 10 % Discount |
|---|---|---|---|---|---|---|---|---|---|
| | Liquids | Gas | Sales | Income | Transport | Expenses | | Cashflow | Cashflow |
| | MBO | MMCF | MMCF | MMUS$ | MMUS$ | MMUS$ | MMUS$ | MMUS$ | MMUS$ |
| 2020 | 3.8 | 8 | 7 | 0.242 | 0.024 | 0.118 | | 0.10 | 0.10 |
| 2021 | 3.3 | 10 | 10 | 0.221 | 0.021 | 0.118 | | 0.08 | 0.07 |
| 2022 | 2.9 | 9 | 8 | 0.194 | 0.018 | 0.119 | | 0.06 | 0.04 |
| 2023 | 2.5 | 8 | 7 | 0.170 | 0.016 | 0.120 | | 0.03 | 0.02 |
| 2024 | 2.2 | 7 | 6 | 0.149 | 0.014 | 0.121 | | 0.01 | 0.01 |
| 2025 | | | | | | | 0.25 | (0.25) | (0.15) |
| 2026 | | | | | | | | | |
| 2027 | | | | | | | | | |
| 2028 | | | | | | | | | |
| 2029 | | | | | | | | | |
| **TOTAL** | **14.6** | **41** | **39** | **0.98** | **0.09** | **0.60** | **0.25** | **0.04** | **0.10** |

**Rio Opia**

**Proved Reserves (1P)**

| Year | Production | | Gas | Gross | Oil | Operating | Investment | Net | 10 % Discount |
|---|---|---|---|---|---|---|---|---|---|
| | Liquids | Gas | Sales | Income | Transport | Expenses | | Cashflow | Cashflow |
| | MBO | MMCF | MMCF | MMUS$ | MMUS$ | MMUS$ | MMUS$ | MMUS$ | MMUS$ |
| 2020 | 15.7 | 56 | 54 | 1.064 | 0.099 | 0.177 | 0.35 | 0.44 | 0.42 |
| 2021 | 13.7 | 54 | 52 | 0.953 | 0.087 | 0.177 | | 0.69 | 0.60 |
| 2022 | 10.3 | 41 | 40 | 0.724 | 0.066 | 0.176 | | 0.48 | 0.38 |
| 2023 | 7.8 | 32 | 30 | 0.554 | 0.051 | 0.175 | | 0.33 | 0.23 |
| 2024 | 5.9 | 24 | 23 | 0.428 | 0.039 | 0.175 | | 0.21 | 0.14 |
| 2025 | 4.6 | 19 | 18 | 0.331 | 0.030 | 0.176 | | 0.13 | 0.07 |
| 2026 | 3.5 | 14 | 14 | 0.259 | 0.024 | 0.176 | | 0.06 | 0.03 |
| 2027 | 2.8 | 11 | 11 | 0.205 | 0.019 | 0.177 | | 0.01 | 0.00 |
| 2028 | | | | | | | 0.25 | (0.25) | (0.11) |
| 2029 | | | | | | | | | |
| **TOTAL** | **64.2** | **252** | **242** | **4.52** | **0.42** | **1.41** | **0.60** | **2.09** | **1.77** |

**Rio Opia**

**Proved & Probable Reserves (2P)**

| Year | Production | | Gas | Gross | Oil | Operating | Investment | Net | 10 % Discount |
|---|---|---|---|---|---|---|---|---|---|
| | Liquids | Gas | Sales | Income | Transport | Expenses | | Cashflow | Cashflow |
| | MBO | MMCF | MMCF | MMUS$ | MMUS$ | MMUS$ | MMUS$ | MMUS$ | MMUS$ |
| 2020 | 19.8 | 73 | 70 | 1.351 | 0.125 | 0.205 | 1.89 | (0.87) | (0.83) |
| 2021 | 32.9 | 135 | 130 | 2.308 | 0.210 | 0.220 | | 1.88 | 1.63 |
| 2022 | 23.1 | 98 | 94 | 1.639 | 0.149 | 0.213 | | 1.28 | 1.01 |
| 2023 | 16.3 | 70 | 68 | 1.171 | 0.106 | 0.208 | | 0.86 | 0.61 |
| 2024 | 11.6 | 51 | 49 | 0.846 | 0.077 | 0.206 | | 0.56 | 0.37 |
| 2025 | 8.3 | 37 | 35 | 0.612 | 0.055 | 0.205 | | 0.35 | 0.21 |
| 2026 | 6.0 | 27 | 26 | 0.448 | 0.041 | 0.205 | | 0.20 | 0.11 |
| 2027 | 4.4 | 20 | 19 | 0.332 | 0.030 | 0.205 | | 0.10 | 0.05 |
| 2028 | 3.3 | 15 | 14 | 0.250 | 0.023 | 0.206 | | 0.02 | 0.01 |
| 2029 | | | | | | | 0.31 | (0.31) | (0.13) |
| **TOTAL** | **125.8** | **525** | **506** | **8.96** | **0.82** | **1.87** | **2.20** | **4.07** | **3.03** |

**Rio Opia**

**Proved, Probable & Possible Reserves (3P)**

| Year | Production | | Gas | Gross | Oil | Operating | Investment | Net | 10 % Discount |
|---|---|---|---|---|---|---|---|---|---|
| | Liquids | Gas | Sales | Income | Transport | Expenses | | Cashflow | Cashflow |
| | MBO | MMCF | MMCF | MMUS$ | MMUS$ | MMUS$ | MMUS$ | MMUS$ | MMUS$ |
| 2020 | 19.8 | 73 | 70 | 1.351 | 0.125 | 0.205 | 1.89 | (0.87) | (0.83) |
| 2021 | 32.9 | 135 | 130 | 2.308 | 0.210 | 0.220 | | 1.88 | 1.63 |
| 2022 | 23.1 | 98 | 94 | 1.639 | 0.149 | 0.213 | | 1.28 | 1.01 |
| 2023 | 16.3 | 70 | 68 | 1.171 | 0.106 | 0.208 | | 0.86 | 0.61 |
| 2024 | 11.6 | 51 | 49 | 0.846 | 0.077 | 0.206 | | 0.56 | 0.37 |
| 2025 | 8.3 | 37 | 35 | 0.612 | 0.055 | 0.205 | | 0.35 | 0.21 |
| 2026 | 6.0 | 27 | 26 | 0.448 | 0.041 | 0.205 | | 0.20 | 0.11 |
| 2027 | 4.4 | 20 | 19 | 0.332 | 0.030 | 0.205 | | 0.10 | 0.05 |
| 2028 | 3.3 | 15 | 14 | 0.250 | 0.023 | 0.206 | | 0.02 | 0.01 |
| 2029 | | | | | | | 0.31 | (0.31) | (0.13) |
| **TOTAL** | **125.8** | **525** | **506** | **8.96** | **0.82** | **1.87** | **2.20** | **4.07** | **3.03** |

# Appendix VI
# CV’s GCA Staff

# Roberto J. Wainhaus

Gaffney, Cline & Associates

Roberto has over 40 years of experience in reservoir engineering and reserves evaluations. His work has included field development planning and execution, well testing, waterflooding projects, reservoir simulation, economic evaluations, and reserves estimations and audits. Roberto has extensive use with commercial simulation and evaluation tools and software of his own design for engineering calculations such as nodal analysis, material balance, Monte Carlo simulation, etc.

## Key Areas of Expertise

- Reserves and Resources estimation and auditing
- Field development planning and execution
- Economic evaluations
- Waterflooding and enhanced oil recovery (EOR) projects
- Shale and tight gas and oil fields evaluation
- Reservoir simulation

## Professional Experience

2000 – Present: ***Senior Advisor, Reservoir Engineer*** – Gaffney, Cline & Associates
- Performs Reserves and Resources audits and assessments for most of the Argentine fields
- Performs Reserve evaluations of fields in Brazil, Peru, Bolivia, Colombia, Ecuador and Venezuela

1996 – 2000: ***Senior Reservoir Engineer*** – Compañía General de Combustibles S.A.
- In charge of reservoir engineering, development planning and Reserves estimations for fields in the Austral and Northwest basins in Argentina
- Performed reservoir simulation of the Onado field, Monagás, Venezuela
- Conducted asset evaluation for exploration and development projects

1994 – 1995: ***Senior Reservoir Engineer*** – Gaffney, Cline & Associates
- Provided reservoir engineering for projects studied in Buenos Aires
- Performed Reserves and Resources audits and assessments

1993 – 1996: ***Reservoir Simulation Professor*** *(Reservoir Engineering Career)* – Buenos Aires Technological Institute (ITBA)

1977 – 1994: ***Reservoir Engineer*** – Astra CAPSA Exploration & Production
- Conducted reservoir studies for San Jorge and Cuyana basins
- Performed EOR evaluation for surfactant-polymer injection
- Performed reservoir simulation for fields in Cuyana basin
- Provided secondary recovery project design and follow up for fields in the San Jorge basin
- Workovers and stimulations

1975 – 1977: YPF Research and Development Laboratory (Reservoir Simulation Department)
Developed black oil reservoir simulator and material balance model

1973 – 1974: ***Lecturer*** – Buenos Aires University and Universidad Tecnológica Nacional
Presented lectures on mechanics and electromagnetism, at several levels, in the Physics Department of both universities

## Professional Societies

- Argentinean Petroleum and Gas Institute
- Society of Petroleum Engineers (SPE)

## Languages

- Spanish (*native*)
- English

## Education

- 1977 Post-graduate course in Petroleum Mining Engineering, Buenos Aires University
- 1973 Degree in Physics Sciences, Buenos Aires University

# Joaquín Ramírez

Gaffney, Cline & Associates

Joaquín has over 30 years of experience in the international oil and gas industry. He is an accomplished reservoir engineer, working on reservoir characterization and simulation, mature fields monitoring and rehabilitation, and reserves determination and calculation. Joaquín has worked in heavy oil fields with Waterflood projects and EOR methods, such as steam injection (alternate and continuous).

## Key Areas of Expertise

- Static and dynamic reservoir characterization
- Reservoir conventional and unconventional analysis and numerical simulation
- Oil and gas reserves estimation
- Production forecasts and economic project evaluation

## Professional Experience

2019 – Present: ***Independent Consultant***

2017 – 2018: ***Various roles*** – YPF

- ***Reservoir Engineer, Referent Conventional and Non-conventional***
  - Reviewed analogue information and elaborated on expected production and pressure performance for conventional and non-conventional reservoirs
  - Established criteria for success, predicting delineation and development plan of area and associated resources and reserves
  - Provided technical leadership in evaluations / integration of projects into exploration processes

- ***Team Lead, Pilot Projects***
  - Directed execution of processes and activities in visualization, conceptualization and definition phases, integrating all technical specialties, cross-cutting areas and interested parties
  - Controlled compliance with deadlines, costs and quality standards
  - Worked with facilities engineering team to refresh and develop conceptual development plans for all existing and new investment opportunities

2012 – 2017: ***Product Champion Non-Conventional Reservoirs*** – YPF-YTEC

- Provided technologies/ best practices to implement in Vaca Muerta shale exploration/ development
- Optimized and implemented new artificial lift for unconventional reservoirs
- Involved in development of RTA and PTA models for Vaca Muerta shale
- Well production optimization for development phase, and production analysis for fractured wells

2007 – 2012: ***Various roles*** – REPSOL-YPF

- 2011-2012: ***Reservoir Engineer, Non-Conventional Reservoirs***
  - Developed reservoir transient analysis models for Vaca Muerta shale
  - Performed reserves estimation, and integrated production system modeling and prediction
  - Involved in field development plans for Vaca Muerta shale

- 2010-2011: ***Technical Team Lead, Barranca Baya Field Unit***
  - Supported development projects using corporate methodology VCD
  - Coordinated water conformance studies to increase recovery factor

- 2008-2010: ***Technical Team Lead, El Portón Field Unit***
  - Estimated reservoir behavior with analytical methods (MBAL) / numerical simulation (Eclipse)
  - Estimated and calculated reserves decline as traditional methods Arps, fetckovich, etc.

  - Reserves development plan for reservoirs assigned as chief of reservoir development units
  - Participated in internal & external audits per reservoir under SEC regulations

- 2007-2008: ***Reservoir Engineer, El Portón Field Unit***
  - Monitored Chihuido de la Salina Norte, Centro Norte and Centro Sur field water injection projects, with a 3D simulation model, using Eclipse
  - Specified development plans for assigned areas, and economic evaluations
  - Managed repairs and technical support for wellsite locations
  - Updated simulation model for El Portón Sur Area fields, using Eclipse, Mbal, Prosper, etc.
  - Field job supervision (Stimulation, Acid jobs, PLT, MDT, Build UP, etc.)

2005 – 2007: ***Consultant Reservoir Engineer*** – CBM Mexico

- Prepared proposals for vertical, re-entries, sidetrack, inclined and horizontal wells using FEL
- Applied FEL methodology for a reservoir characterization project
- Reviewed Ogarrio, Lacamango, Magallanes and Blasillo fields
- Developed drilling and repair proposals, reserves estimation and economic evaluations

2003 – 2005: ***Consultant Reservoir Engineer*** – EPCI, Venezuela

- Reserves estimation and pressure analysis for wells in Mene Grande field, using PANSYSTEM
- Taught courses for reservoir simulation, EOR and alternate steam injection for University of Venezuela and New Professions Institute
- Evaluated Maracaibo Lake fields for UNDER BALANCED DRILLING for Weatherford Co.
- Reviewed and updated Quiriquire steam pilot project in Maturin Venezuela

2000 – 2003: ***Reservoir Engineer*** – PDVSA S.A, Venezuela

- Monitored Motatán field water injection project, south dome, with a 3D simulation model, using Eclipse; specified development plans for assigned areas, and economic evaluations
- Managed repairs and technical support for wellsite locations
- Updated simulation model for Barúa and Motatán fields, using Eclipse 100/Office

1999 – 2000: ***Reservoir Engineer*** – REPSOL-YPF, Venezuela

1998 – 1999: ***Reservoir Engineer*** – YPF-MAXUS, Venezuela and Dallas, TX

1988 – 1998: ***Reservoir Engineer*** – MARAVEN S.A, Venezuela

## Professional Societies

- Society of Petroleum Engineers (SPE)

## Languages

- Spanish (*native*)
- English (*intermediate*)

## Education

- 1989 Petroleum Engineer, Central University of Venezuela