Interoil Exploration and Production ASA

2018 annual statement of reserves

Summary

Interoil Exploration & Production ASA ("Interoil") currently owns and operates four producing fields: Ambrosia, Mana, Rio Opia and Vikingo, located within two exploitation contracts, Puli C and LLA-47; additionally the company owns and operates two exploration contracts: Altair and LLA-47.

The proven reserves ("1P") amount 1.2 mmboe net after royalties, the 2P reserves are 1.5 mmboe net after royalties and 3P reserves are 1.9 mmboe net after royalties. This represents a decrease of 0.9 mmboe on the 1P, a decrease of 1.4 mmboe on the 2P, and a decrease of 1.8 mmboe on 3P compared with 31 December 2017.

The reserves and the volumes underlying have been estimated and classified according to the "petroleum resources management system" ("PRMS"), which was approved by the Society of Petroleum Engineers, the World Petroleum Council, the American Society of Petroleum Geologist and Society of Petroleum Evaluations Engineers in June 2018, and have been audited by the independent petroleum engineering firm of Gaffney, Cline and Associates Inc. The corresponding report is included in this statement.

Quantitative Information

A summary of the 1P, 2P and 3P reserves as at 31 December 2018 are shown in *Table 1.* The reserves have been further subdivided into Prove Developed and Undeveloped, in line with the PRMS definitions of these categories.

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	0.94	2.87	0.66	2.01	0.62	1.88
Undeveloped	0.22	0.92	0.16	0.64	0.14	0.60
Total 1P	1.16	3.79	0.82	2.65	0.76	2.48
Total 2P	1.42	4.63	1.01	3.24	0.94	3.03
Total 3P	1.84	6.20	1.30	4.34	1.21	4.06

Table 1. Summary of the 1P, 2P and 3P reserves as at 31 December 2018

Management´s Discussion and Analysis

Methodology

Interoil´s reserves were calculated based on natural reservoir depletion from actives wells plus production flowing from future activities, i.e. in-fill wells, work-over and opening of new layers from known producing reservoirs.

The oil price scenario for each field were based on GCA Brent oil price minus Vasconia Oil Terminal discount price as detailed in table #1.

Year	Gross Oil Price USD$/Bbl	Vasconia Differential USD$/Bbl	Sales Oil Price USD$/Bbl
2018	$ 62.00	$ 3.00	$ 59.00
2019	$ 62.00	$ 3.00	$ 59.00
2020	$ 62.00	$ 3.00	$ 59.00
2021	$ 62.00	$ 3.00	$ 59.00
2022	$ 62.00	$ 3.00	$ 59.00
2023	$ 62.00	$ 3.00	$ 59.00
2024	$ 62.00	$ 3.00	$ 59.00
2025	$ 62.00	$ 3.00	$ 59.00
2026	$ 62.00	$ 3.00	$ 59.00
2027	$ 62.00	$ 3.00	$ 59.00
2028	$ 62.00	$ 3.00	$ 59.00
2029	$ 62.00	$ 3.00	$ 59.00
2030	$ 62.00	$ 3.00	$ 59.00
2031	$ 62.00	$ 3.00	$ 59.00

Figure 1. Oil Sales Price Scenarios Ambrosía, Rio Opia Maná, Altaír and LLA-47.

The gas price scenario used for the Puli C exploitation contract was based on Turgas selling contract at USD$ 2.90/Mscf.

Ambrosía, Maná and Río Opia Áreas

In the Puli C fields, Interoil participation interest, royalty for oil and gas and contract expiration dates are detailed in the table below.

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

Figure 2. Contract deadline, working interest and royalties, Ambrosía, Maná and Rio Opia.

During 2018, Interoil implemented a strong maintenance program including pump changes, paraffin cut, flushing tubing and surface lines with hot and inhibited oil, in order to diminish the deferred production due to malfunction in the subsurface and surface equipment.

Interoil technical team has been working on a new static model to then generate a dynamic model that will help better understand reservoir behavior in either Doima and UOB producing formations. This work includes redefinition of the geological framework, stratigraphic sequences, zonation, and generation of a petrophysical model together with all the open hole logs and core-sides together with our 3D geophysical seismic interpretation model. This work is still in progress but it has allowed us to identify undeveloped reserves, and reviewed and validated by GCA, to target a drilling campaign of four wells in Maná and one well in a new structure named UCO west to Mana field plus a workover campaign including five wells in the Maná field and one in the Rio Opia field.

Lla-47 and Altaír Areas

These exploration blocks are operated by Interoil under the following contractual terms:

Area	Working Interest (%)	Royalty Oil (%)	X Factor (%)	Contract Deadline
Altaír	100	8	10	27-December-2035
LLA-47	100	8	15	10-February-2020

Figure 3. Contract deadline, working interest and royalties, Altaír and LLA-47.

Interoil holds and operates the Altaír Block where the well Altair-1 is temporarily shut-in waiting for an environmental permit to be granted by the Colombia Authority. The company plans to drill a second exploration well, Yagan-x1, in the eastern portion of the block once all the environmental permits plus the right of ways and land permits are granted by both authorities and landowners.

In the nearby area, Interoil holds and operates LLA-47 where Vikingo-x1, the first successful exploratory well, was drilled in 2017. This well is flowing around 250 bopd of dry oil from the C5 layer in the Carbonera Formation. In this formation there is another producing interval, the C7 layer, currently shut-in waiting to be on stream once C5 is depleted and then could both layers be commingled produced .

Interoil plans to drill a second exploration well, Malevo-x1, from the Vikingo's well site targeting the Gacheta Formation, a known producing layer in the nearby fields.

These projects together with some others once that are being studied in commingle provide interesting Contingent Resources for the company.

<u>Summary</u>

Interoil's net reserves after royalties had a significant technical adjustment mainly because of a change in the depletion curve from the producing wells assumed by the certifier. Hence, gas reserves are also reduced because most of its flows come from gas contained within the oil at reservoir condition, technically known as Gas Oil Ratio (GOR).

Reserves	Reserves 2017		Production 2018		Technical adjustment		Reserves 2018	
	Gross (100%) Volumes		Gross Production		2017-2018		Gross (100%) Volumes	
	Liquids (MMbbl)	Gas (Bscf)	Liquids (MMbbl)	Gas (Bscf)	Liquids (MMbbl)	Gas (Bscf)	Liquids (MMbbl)	Gas (Bscf)
Total 1P	1.9	8.1	(0.3)	(0.9)	(0.4)	(3.4)	1.2	3.8
Total 2P	2.6	10.6	0.0	0.0	(1.2)	(6.0)	1.4	4.6
Total 3P	3.4	13.3	0.0	0.0	(1.6)	(7.1)	1.8	6.2

Table 2. Shows the reconciliation of the changes in net reserves over the year.

Oslo 22 April 2019

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Interoil Exploration & Production ASA

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March 18, 2019

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Reserves and Resources Statement for Ambrosía, Río Opia, Maná, Llanos 47 and Altair Areas, Colombia as of December 31, 2018

Dear Mr. Carbone,

This reserves and resources statement has been prepared by Gaffney, Cline & Associates (GCA) and issued on March 18, 2019 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 Río Magdalena basin and the Altair and Llanos 47 concessions 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 Hydrocarbon National Agency (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, 2018, of the crude oil and natural gas volumes expected to be produced in the Ambrosía, Río Opia, Maná, Llanos 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 the following table:

Statement of Remaining Hydrocarbon Volumes
Ambrosía, Río Opia, Maná, Llanos 47 and Altair Areas, Colombia
as of December 31, 2018

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	0.94	2.87	0.66	2.01	0.62	1.88
Undeveloped	0.22	0.92	0.16	0.64	0.14	0.60
Total 1P	1.16	3.79	0.82	2.65	0.76	2.48
Total 2P	1.42	4.63	1.01	3.24	0.94	3.03
Total 3P	1.84	6.20	1.30	4.34	1.21	4.06

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 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 and have been reduced for fuel usage in the field (6.9%). 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 2042 corresponding to the existing wells and ten future wells from the development program, without any consideration of commerciality, as follows:

Statement of Contingent Resources
Maná, Rio Opia, Ambrosía, Llanos 47 and Altair Areas, Colombia
Gross (100%) Volumes as of December 31, 2018

Area	Crude Oil (MMBbl)			Natural Gas (Bcf)		
	1C	2C	3C	1C	2C	3C
Llanos 47	0.384	0.685	1.075	-	-	-
Altair	-	-	-	-	-	-
Ambrosia	0.035	0.066	0.126	-	-	-
Río Opia	0.026	0.065	0.131	0.054	0.126	0.245
Maná	0.143	0.651	1.285	0.437	1.816	3.531
Total	0.588	1.467	2.618	0.491	1.942	3.776

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:

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 by decline curve analysis.

Undeveloped reserves for each category were estimated by Interoil, and reviewed by GCA, for the proposed 2019 drilling campaign (four wells in Maná) and workover campaign (Five wells in Maná and one in Rio Opia). The estimates for each location were based on performance of similar existing wells in the area.

Solution gas reserves in Maná and Río Opia were estimated through extrapolation of the producing gas-oil ratios. The resulting volumes were reduced by 6.9% for consumption.

Llanos 47 and Altair Areas

These areas are operated by Interoil under the following conditions

Area	Working Interest (%)	Royalty Oil (%)	Royalty Gas (%)	Contract Deadline
Altair	90	8	---	27-Dec-2035
Llanos 47	78 / 60	8	---	10-Feb-2020

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 Llanos 47 area with 78% participation on the production and on the operating expenses. Capital expenses participation is of 60%. 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 Llanos 47 area is under an exploration contract that expires in 2020.

The area has one well (Vikingo) 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, and reviewed by GCA. Vikingo 1 C7 formation will be put back on production by removing a plug and produced commingle with the current C5 interval through the end of the contract.

The extrapolation of the production beyond contract end up to December 31, 2042 has been classified as Contingent Resources.

Undeveloped Contingent Resources were assigned to a second well (Malevo) to be drilled in the future, south of the former and targeting the same reservoirs found by the Vikingo well.

The commerciality declaration of the Vikingo / Malevo area inside of the Llanos 47 exploration area, expected to be issued by Interoil in 2019 would allow the mentioned Contingent Resources be re-classified under the Reserves category.

Economic Limit Tests

The economic tests for the December 31, 2018 reserves volumes were based on a crude oil price scenario provided by Interoil of US$62.00/Bbl for the 2019 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 2019 was estimated by Interoil at US$2.90/Mscf.

Future capital costs were derived from development program forecasts prepared by Interoil for each field with an average development well cost of US$ 1.05 million/well, and US$ 0.1 million on workovers and facilities. Recent historical operating expense data were used as the basis for operating cost projections. Estimated OPEX drivers and transportation costs for 2019 are presented in the following table:

OPEX Drivers and Transportation Costs for 2019

Drivers and Costs	Ambrosia	Rio Opia	Maná	Llanos 47
Fixed OPEX (US$M/yr)	76.4	100	1,754	900
Variable OPEX (US$/Bbl)	0.68	1.47	2.17	5.52
Variable OPEX (US$M/yr/well)	13.03	10.62	17.76	18.00
Oil Transportation (US$/Bbl)	5.85	5.85	5.84	11.48

Resulting cash flows are provided in Appendix II.

Upon Client request cash flows for the Agencia Nacional de Hidrocarburos" (ANH) of Colombia, are provided at an oil reference price of US$64.56/BBl 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 2019, 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.

It is GCA's opinion that the estimates of total remaining recoverable hydrocarbon liquid and gas volumes, as of December 31, 2018, 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
Rafael Cullen, *Reservoir Engineer*

Reviewed by
Roberto Wainhaus, *Technical Director*

Appendices

Appendix I	Field Reserves Statements
Appendix II	Reserves Cash Flows
Appendix III	PRMS Reserves Definitions
Appendix IV	Glossary
Appendix V	Reserves Cash Flows @ ANH reference oil price

Appendix I
Field Reserves Statements

Statement of Remaining Hydrocarbon Volumes
Ambrosía, Río Opia, Maná and Llanos 47 Concessions, Colombia
as of December 31, 2018

		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	0.904	2.873	0.639	2.011	0.593	1.883
	Developed NP	0.033	0.000	0.026	0.000	0.026	0.000
	Undeveloped	0.223	0.915	0.156	0.641	0.144	0.600
	Total 1P	1.16	3.79	0.82	2.65	0.76	2.48
	Total 2P	1.42	4.63	1.01	3.24	0.94	3.03
	Total 3P	1.84	6.20	1.30	4.34	1.21	4.06
Llanos	Proved						
	Developed	0.079	0.000	0.062	0.000	0.062	0.000
	Developed NP	0.033	0.000	0.026	0.000	0.026	0.000
	Undeveloped	0.000	0.000	0.000	0.000	0.000	0.000
	Total 1P	0.112	0.000	0.088	0.000	0.088	0.000
	Total 2P	0.156	0.000	0.122	0.000	0.122	0.000
	Total 3P	0.190	0.000	0.148	0.000	0.148	0.000
Ambrosia	Proved						
	Developed	0.058	0.000	0.041	0.000	0.037	0.000
	Undeveloped	0.000	0.000	0.000	0.000	0.000	0.000
	Total 1P	0.058	0.000	0.041	0.000	0.037	0.000
	Total 2P	0.060	0.000	0.042	0.000	0.039	0.000
	Total 3P	0.061	0.000	0.043	0.000	0.040	0.000
Rio Opia	Proved						
	Developed	0.034	0.142	0.024	0.099	0.022	0.093
	Undeveloped	0.002	0.010	0.002	0.007	0.001	0.006
	Total 1P	0.036	0.151	0.026	0.106	0.023	0.099
	Total 2P	0.047	0.195	0.033	0.136	0.030	0.128
	Total 3P	0.059	0.248	0.042	0.173	0.038	0.162
Mana	Proved						
	Developed	0.733	2.732	0.513	1.912	0.472	1.790
	Undeveloped	0.221	0.906	0.155	0.634	0.142	0.593
	Total 1P	0.954	3.637	0.668	2.546	0.614	2.383
	Total 2P	1.157	4.432	0.810	3.103	0.745	2.904
	Total 3P	1.528	5.951	1.070	4.166	0.984	3.899

Note 1: Crude oil in thousands of stock tank barrels. Natural gas in millions of cubic feet.

Note 2: Totals may not add due to rounding

Interoil Colombia E&P
March 18, 2019

Appendix II
Reserves Cash Flows

Interoil Colombia Exploración y Producción
Net Revenue Interest Reserve Cash Flows
Properties in Colombia
as of December 31, 2018

Mana

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$
2019	105.7	452	421	7.46	0.67	1.68	0.14	4.97
2020	86.6	366	340	6.10	0.55	1.59	0.00	3.96
2021	70.0	288	268	4.91	0.44	1.48	0.00	2.99
2022	56.8	232	216	3.98	0.36	1.37	0.00	2.24
2023	45.3	179	167	3.16	0.29	1.26	0.00	1.61
2024	36.3	140	130	2.52	0.23	1.15	0.00	1.14
2025	29.1	110	102	2.01	0.18	1.06	0.00	0.77
2026	23.2	86	81	1.60	0.15	0.97	0.00	0.49
2027	18.7	69	64	1.29	0.12	0.89	0.00	0.28
2028	0.0	0	0	0.00	0.00	0.00	0.00	0.00
2029	0.0	0	0	0.00	0.00	0.00	0.00	0.00
TOTAL	471.8	1,922	1,790	33.03	2.99	11.45	0.14	18.44

Mana

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$
2019	129.3	558	519	9.13	0.82	1.72	3.50	3.09
2020	137.2	592	551	9.69	0.87	1.72	0.00	7.09
2021	100.4	424	395	7.07	0.64	1.57	0.00	4.86
2022	74.5	311	290	5.24	0.47	1.44	0.00	3.32
2023	55.9	227	211	3.91	0.35	1.32	0.00	2.24
2024	42.6	168	156	2.97	0.27	1.21	0.00	1.48
2025	32.4	125	116	2.25	0.21	1.12	0.00	0.92
2026	23.2	87	81	1.60	0.15	0.97	0.00	0.49
2027	18.7	69	64	1.29	0.12	0.90	0.00	0.27
2028	0.0	0	0	0.00	0.00	0.00	0.00	0.00
2029	0.0	0	0	0.00	0.00	0.00	0.00	0.00
TOTAL	614.1	2,560	2,383	43.15	3.90	11.98	3.50	23.77

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$
2019	144.5	620	578	10.20	0.92	1.76	3.50	4.02
2020	170.1	735	684	12.02	1.08	1.81		9.13
2021	122.7	520	484	8.64	0.78	1.65		6.21
2022	91.0	382	355	6.40	0.58	1.52		4.30
2023	67.9	281	262	4.77	0.43	1.39		2.95
2024	52.4	209	194	3.65	0.33	1.28		2.04
2025	40.8	160	149	2.84	0.26	1.19		1.39
2026	32.5	125	116	2.25	0.21	1.10		0.95
2027	23.4	87	81	1.62	0.15	0.95		0.52
2028								
2029								
TOTAL	745.1	3,119	2,904	52.38	4.73	12.64	3.50	31.52

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$
2019	175.2	758	706	12.38	1.11	1.82	3.50	5.95
2020	241.0	1,053	980	17.06	1.53	1.94		13.59
2021	167.3	721	671	11.82	1.06	1.75		9.01
2022	119.6	509	474	8.43	0.76	1.59		6.08
2023	88.4	374	348	6.23	0.56	1.46		4.20
2024	66.4	275	256	4.66	0.42	1.34		2.89
2025	51.9	208	193	3.62	0.33	1.26		2.04
2026	41.0	161	150	2.86	0.26	1.16		1.43
2027	33.5	129	120	2.33	0.21	1.08		1.04
2028								
2029								
TOTAL	984.2	4,188	3,899	69.38	6.25	13.39	3.50	46.24

Llanos

Proved Developed Reserves (PD)

Year	Production		Gross	Oil	Operating	Investment	Net
	Liquids	Gas	Income	Transport	Expenses		Cashflow
	MBO	MMCF	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2019	56.4		3.47	0.55	0.96		1.96
2020	5.5		0.34	0.05	0.16		0.12
2021							
2022							
2023							
2024							
2025							
2026							
2027							
2028							
2029							
TOTAL	61.9	0	3.80	0.60	1.12	0.00	2.08

Llanos

Proved Reserves (1P)

Year	Production		Gross	Oil	Operating	Investment	Net
	Liquids	Gas	Income	Transport	Expenses		Cashflow
	MBO	MMCF	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2019	78.0		4.80	0.76	1.01	0.02	3.01
2020	9.6		0.59	0.09	0.17		0.33
2021							
2022							
2023							
2024							
2025							
2026							
2027							
2028							
2029							
TOTAL	87.6	0	5.39	0.85	1.18	0.02	3.34

Llanos

Proved & Probable Reserves (2P)

Year	Production Liquids MBO	Production Gas MMCF	Gross Income MMUS$	Oil Transport MMUS$	Operating Expenses MMUS$	Investment MMUS$	Net Cashflow MMUS$
2019	106.4		6.55	1.04	1.08	0.02	4.41
2020	15.6		0.96	0.15	0.18		0.62
2021							
2022							
2023							
2024							
2025							
2026							
2027							
2028							
2029							
TOTAL	122.0	0	7.50	1.19	1.26	0.02	5.04

Llanos

Proved, Probable & Possible Reserves (3P)

Year	Production Liquids MBO	Production Gas MMCF	Gross Income MMUS$	Oil Transport MMUS$	Operating Expenses MMUS$	Investment MMUS$	Net Cashflow MMUS$
2019	127.4		7.84	1.24	1.13	0.02	5.45
2020	20.5		1.26	0.20	0.19		0.87
2021							
2022							
2023							
2024							
2025							
2026							
2027							
2028							
2029							
TOTAL	147.9	0	9.10	1.44	1.32	0.02	6.32

Ambrosia

Proved Developed Reserves (PD)

Year	Production		Gross	Oil	Operating	Investment	Net
	Liquids	Gas	Income	Transport	Expenses		Cashflow
	MBO	MMCF	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2019	6.6		0.39	0.04	0.09		0.26
2020	5.6		0.33	0.04	0.09		0.21
2021	4.7		0.28	0.03	0.08		0.16
2022	3.7		0.22	0.02	0.07		0.12
2023	3.4		0.20	0.02	0.07		0.10
2024	3.2		0.19	0.02	0.07		0.09
2025	2.9		0.17	0.02	0.07		0.08
2026	2.7		0.16	0.02	0.07		0.07
2027	2.5		0.15	0.02	0.07		0.06
2028	2.3		0.14	0.01	0.07		0.05
2029							
TOTAL	37.5	0	2.21	0.24	0.77	0.00	1.20

Ambrosia

Proved Reserves (1P)

Year	Production		Gross	Oil	Operating	Investment	Net
	Liquids	Gas	Income	Transport	Expenses		Cashflow
	MBO	MMCF	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2019	6.6		0.39	0.04	0.09		0.26
2020	5.6		0.33	0.04	0.09		0.21
2021	4.7		0.28	0.03	0.08		0.16
2022	3.7		0.22	0.02	0.07		0.12
2023	3.4		0.20	0.02	0.07		0.10
2024	3.2		0.19	0.02	0.07		0.09
2025	2.9		0.17	0.02	0.07		0.08
2026	2.7		0.16	0.02	0.07		0.07
2027	2.5		0.15	0.02	0.07		0.06
2028	2.3		0.14	0.01	0.07		0.05
2029							
TOTAL	37.5	0	2.21	0.24	0.77	0.00	1.20

Ambrosia

Proved & Probable Reserves (2P)

Year	Production		Gross	Oil	Operating	Investment	Net
	Liquids	Gas	Income	Transport	Expenses		Cashflow
	MBO	MMCF	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2019	6.6		0.39	0.04	0.09		0.26
2020	5.7		0.33	0.04	0.09		0.21
2021	4.9		0.29	0.03	0.08		0.17
2022	3.9		0.23	0.02	0.07		0.13
2023	3.5		0.20	0.02	0.07		0.11
2024	3.2		0.19	0.02	0.07		0.10
2025	3.0		0.18	0.02	0.07		0.08
2026	2.8		0.16	0.02	0.07		0.07
2027	2.6		0.15	0.02	0.07		0.06
2028	2.4		0.14	0.02	0.07		0.05
2029							
TOTAL	38.5	0	2.27	0.24	0.77	0.00	1.25

Ambrosia

Proved, Probable & Possible Reserves (3P)

Year	Production		Gross	Oil	Operating	Investment	Net
	Liquids	Gas	Income	Transport	Expenses		Cashflow
	MBO	MMCF	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2019	6.6		0.39	0.04	0.09		0.26
2020	5.7		0.34	0.04	0.09		0.22
2021	5.0		0.30	0.03	0.08		0.18
2022	4.3		0.25	0.03	0.08		0.14
2023	3.5		0.21	0.02	0.07		0.11
2024	3.3		0.19	0.02	0.07		0.10
2025	3.1		0.18	0.02	0.07		0.09
2026	2.9		0.17	0.02	0.07		0.08
2027	2.7		0.16	0.02	0.07		0.07
2028	2.5		0.15	0.02	0.07		0.06
2029							
TOTAL	39.6	0	2.34	0.25	0.78	0.00	1.30

Rio Opia

Proved Developed Reserves (PD)

Year	Production		Gas	Gross	Oil	Operating	Investment	Net
	Liquids	Gas	Sales	Income	Transport	Expenses		Cashflow
	MBO	MMCF	MMCF	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2019	6.1	26	24	0.43	0.04	0.09		0.30
2020	4.9	21	20	0.35	0.03	0.09		0.23
2021	3.9	17	16	0.28	0.03	0.09		0.16
2022	2.7	12	11	0.19	0.02	0.08		0.10
2023	1.8	9	9	0.13	0.01	0.07		0.05
2024	1.5	8	7	0.11	0.01	0.07		0.03
2025	0.9	6	6	0.07	0.01	0.06		0.00
2026								
2027								
2028								
2029								
TOTAL	22.0	100	93	1.57	0.14	0.56	0.00	0.87

Rio Opia

Proved Reserves (1P)

Year	Production		Gas	Gross	Oil	Operating	Investment	Net
	Liquids	Gas	Sales	Income	Transport	Expenses		Cashflow
	MBO	MMCF	MMCF	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2019	6.9	30	28	0.48	0.04	0.09	0.05	0.30
2020	5.7	25	23	0.40	0.04	0.09		0.27
2021	3.9	17	16	0.28	0.03	0.09		0.16
2022	2.7	12	11	0.19	0.02	0.08		0.10
2023	1.8	9	9	0.13	0.01	0.07		0.05
2024	1.5	8	7	0.11	0.01	0.07		0.03
2025	0.9	6	6	0.07	0.01	0.06		0.00
2026								
2027								
2028								
2029								
TOTAL	23.5	106	99	1.67	0.15	0.56	0.05	0.91

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$
2019	7.6	33	31	0.54	0.05	0.09	0.05	0.34
2020	6.6	29	27	0.47	0.04	0.09		0.33
2021	5.3	23	22	0.37	0.03	0.09		0.25
2022	4.1	18	17	0.29	0.03	0.09		0.17
2023	2.4	12	11	0.17	0.02	0.07		0.09
2024	1.7	9	8	0.12	0.01	0.07		0.04
2025	1.4	7	7	0.10	0.01	0.07		0.02
2026	1.0	6	6	0.07	0.01	0.06		0.00
2027								
2028								
2029								
TOTAL	30.1	137	128	2.14	0.19	0.65	0.05	1.26

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$
2019	8.2	36	33	0.58	0.05	0.09	0.05	0.38
2020	7.4	33	30	0.52	0.05	0.09		0.38
2021	6.0	26	25	0.42	0.04	0.09		0.29
2022	4.9	22	20	0.35	0.03	0.09		0.23
2023	3.5	16	15	0.25	0.02	0.07		0.15
2024	2.8	14	13	0.20	0.02	0.07		0.11
2025	2.4	12	11	0.18	0.02	0.07		0.09
2026	1.8	9	9	0.13	0.01	0.07		0.05
2027	1.1	6	6	0.08	0.01	0.07		0.01
2028								
2029								
TOTAL	38.2	174	162	2.72	0.24	0.73	0.05	1.70

Gaffney,
Cline &
Associates

Appendix III
PRMS Reserves Definitions

Interoil Colombia E&P
March 18, 2019

**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. 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.

[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. 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 production potential.	The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions. The project decision gate is the decision not to undertake further data acquisition or studies on the project for the foreseeable future.

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 in undeveloped locations may be classified as Proved provided that: A. The locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially mature and economically productive. B. Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations. For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.
Probable Reserves	Those additional Reserves that analysis of geoscience and engineering data indicates are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves.	It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate. Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria. Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.

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

Figure 1.1—RESOURCES CLASSIFICATION FRAMEWORK

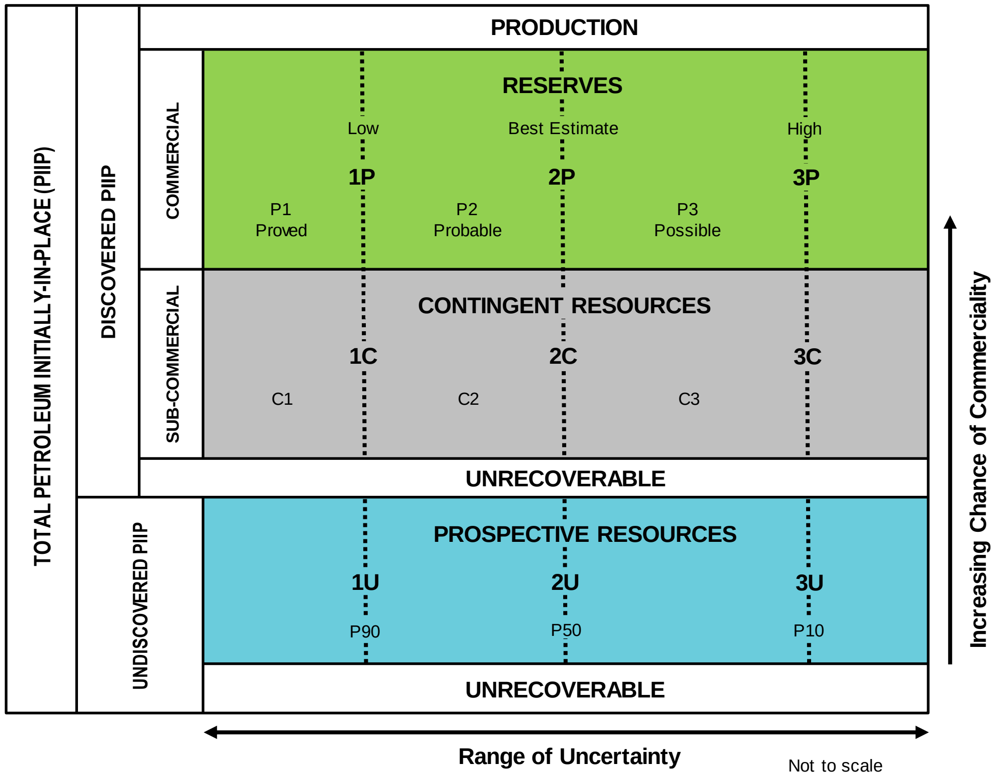
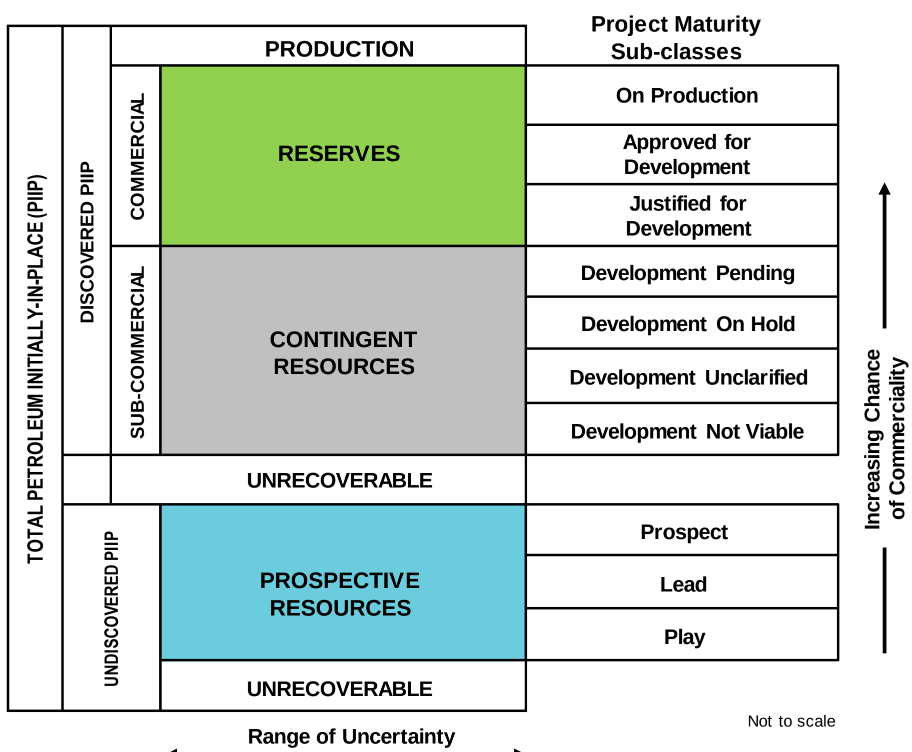


Figure 2.1—SUB-CLASSES BASED ON PROJECT MATURITY



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

Glossary – Standard Oil Industry Terms and Abbreviations

Gaffney, Cline & Associates

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

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 Exploración y Producción
Net Revenue Interest Reserve Cash Flows
Properties in Colombia
as of December 31, 2018

Mana (ANH price)

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$
2019	105.7	452	421	7.77	0.67	1.68	0.14	5.29
2020	86.6	366	340	6.36	0.55	1.59		4.22
2021	70.0	288	268	5.12	0.44	1.48		3.20
2022	56.8	232	216	4.15	0.36	1.37		2.41
2023	45.3	179	167	3.30	0.29	1.26		1.75
2024	36.3	140	130	2.63	0.23	1.15		1.25
2025	29.1	110	102	2.10	0.18	1.06		0.85
2026	23.2	86	81	1.67	0.15	0.97		0.56
2027	18.7	69	64	1.34	0.12	0.89		0.34
2028								
2029								
TOTAL	471.8	1,922	1,790	34.44	2.99	11.45	0.14	19.85

Mana (ANH price)

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$
2019	129.3	558	519	9.52	0.82	1.72	3.50	3.48
2020	137.2	592	551	10.10	0.87	1.72		7.51
2021	100.4	424	395	7.37	0.64	1.57		5.16
2022	74.5	311	290	5.46	0.47	1.44		3.54
2023	55.9	227	211	4.08	0.35	1.32		2.41
2024	42.6	168	156	3.09	0.27	1.21		1.61
2025	32.4	125	116	2.35	0.21	1.12		1.02
2026	23.2	87	81	1.67	0.15	0.97		0.56
2027	18.7	69	64	1.34	0.12	0.90		0.32
2028								
2029								
TOTAL	614.1	2,560	2,383	44.99	3.90	11.98	3.50	25.61

Mana (ANH price)

Proved & Probable Reserves (2P)

Year	Production		Gas	Gross	Oil	Operating	Investment	Net
	Liquids	Gas	Sales	Income	Transport	Expenses		Cashflow
	MBO	MMCF	MMCF	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2019	144.5	620	578	10.63	0.92	1.76	3.50	4.45
2020	170.1	735	684	12.53	1.08	1.81		9.64
2021	122.7	520	484	9.01	0.78	1.65		6.58
2022	91.0	382	355	6.67	0.58	1.52		4.57
2023	67.9	281	262	4.97	0.43	1.39		3.15
2024	52.4	209	194	3.81	0.33	1.28		2.20
2025	40.8	160	149	2.96	0.26	1.19		1.52
2026	32.5	125	116	2.35	0.21	1.10		1.05
2027	23.4	87	81	1.69	0.15	0.95		0.59
2028								
2029								
TOTAL	745.1	3,119	2,904	54.62	4.73	12.64	3.50	33.75

Mana (ANH price)

Proved, Probable & Possible Reserves (3P)

Year	Production		Gas	Gross	Oil	Operating	Investment	Net
	Liquids	Gas	Sales	Income	Transport	Expenses		Cashflow
	MBO	MMCF	MMCF	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2019	175.2	758	706	12.91	1.11	1.82	3.50	6.48
2020	241.0	1,053	980	17.78	1.53	1.94		14.31
2021	167.3	721	671	12.32	1.06	1.75		9.51
2022	119.6	509	474	8.79	0.76	1.59		6.44
2023	88.4	374	348	6.49	0.56	1.46		4.47
2024	66.4	275	256	4.86	0.42	1.34		3.09
2025	51.9	208	193	3.78	0.33	1.26		2.19
2026	41.0	161	150	2.98	0.26	1.16		1.56
2027	33.5	129	120	2.43	0.21	1.08		1.14
2028								
2029								
TOTAL	984.2	4,188	3,899	72.33	6.25	13.39	3.50	49.19

Llanos (ANH price)
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$
2019	56.4		3.64	0.55	0.96		2.13
2020	5.5		0.35	0.05	0.16		0.14
2021							
2022							
2023							
2024							
2025							
2026							
2027							
2028							
2029							
TOTAL	61.9	0	3.99	0.60	1.12	0.00	2.27

Llanos (ANH price)
Proved Reserves (1P)

Year	Production Liquids MBO	Production Gas MMCF	Gross Income MMUS$	Oil Transport MMUS$	Operating Expenses MMUS$	Investment MMUS$	Net Cashflow MMUS$
2019	78.0		5.03	0.76	1.01	0.02	3.24
2020	9.6		0.62	0.09	0.17		0.36
2021							
2022							
2023							
2024							
2025							
2026							
2027							
2028							
2029							
TOTAL	87.6	0	5.65	0.85	1.18	0.02	3.60

Llanos (ANH price)
Proved & Probable Reserves (2P)

Year	Production Liquids MBO	Production Gas MMCF	Gross Income MMUS$	Oil Transport MMUS$	Operating Expenses MMUS$	Investment MMUS$	Net Cashflow MMUS$
2019	106.4		6.86	1.04	1.08	0.02	4.73
2020	15.6		1.01	0.15	0.18		0.67
2021							
2022							
2023							
2024							
2025							
2026							
2027							
2028							
2029							
TOTAL	122.0	0	7.87	1.19	1.26	0.02	5.40

Llanos (ANH price)
Proved, Probable & Possible Reserves (3P)

Year	Production Liquids MBO	Production Gas MMCF	Gross Income MMUS$	Oil Transport MMUS$	Operating Expenses MMUS$	Investment MMUS$	Net Cashflow MMUS$
2019	127.4		8.22	1.24	1.13	0.02	5.83
2020	20.5		1.32	0.20	0.19		0.93
2021							
2022							
2023							
2024							
2025							
2026							
2027							
2028							
2029							
TOTAL	147.9	0	9.54	1.44	1.32	0.02	6.76

Ambrosia(ANH price)
Proved Developed Reserves (PD)

Year	Production		Gross	Oil	Operating	Investment	Net
	Liquids	Gas	Income	Transport	Expenses		Cashflow
	MBO	MMCF	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2019	6.6		0.41	0.04	0.09		0.28
2020	5.6		0.35	0.04	0.09		0.23
2021	4.7		0.29	0.03	0.08		0.18
2022	3.7		0.23	0.02	0.07		0.13
2023	3.4		0.21	0.02	0.07		0.12
2024	3.2		0.20	0.02	0.07		0.10
2025	2.9		0.18	0.02	0.07		0.09
2026	2.7		0.17	0.02	0.07		0.08
2027	2.5		0.15	0.02	0.07		0.06
2028	2.3		0.14	0.01	0.07		0.05
2029							
TOTAL	37.5	0	2.32	0.24	0.77	0.00	1.31

Ambrosia(ANH price)
Proved Reserves (1P)

Year	Production		Gross	Oil	Operating	Investment	Net
	Liquids	Gas	Income	Transport	Expenses		Cashflow
	MBO	MMCF	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2019	6.6		0.41	0.04	0.09		0.28
2020	5.6		0.35	0.04	0.09		0.23
2021	4.7		0.29	0.03	0.08		0.18
2022	3.7		0.23	0.02	0.07		0.13
2023	3.4		0.21	0.02	0.07		0.12
2024	3.2		0.20	0.02	0.07		0.10
2025	2.9		0.18	0.02	0.07		0.09
2026	2.7		0.17	0.02	0.07		0.08
2027	2.5		0.15	0.02	0.07		0.06
2028	2.3		0.14	0.01	0.07		0.05
2029							
TOTAL	37.5	0	2.32	0.24	0.77	0.00	1.31

Ambrosia(ANH price)

Proved & Probable Reserves (2P)

Year	Production		Gross	Oil	Operating	Investment	Net
	Liquids	Gas	Income	Transport	Expenses		Cashflow
	MBO	MMCF	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2019	6.6		0.41	0.04	0.09		0.28
2020	5.7		0.35	0.04	0.09		0.23
2021	4.9		0.30	0.03	0.08		0.19
2022	3.9		0.24	0.02	0.07		0.14
2023	3.5		0.21	0.02	0.07		0.12
2024	3.2		0.20	0.02	0.07		0.10
2025	3.0		0.18	0.02	0.07		0.09
2026	2.8		0.17	0.02	0.07		0.08
2027	2.6		0.16	0.02	0.07		0.07
2028	2.4		0.15	0.02	0.07		0.06
2029							
TOTAL	38.5	0	2.39	0.24	0.77	0.00	1.37

Ambrosia(ANH price)

Proved, Probable & Possible Reserves (3P)

Year	Production		Gross	Oil	Operating	Investment	Net
	Liquids	Gas	Income	Transport	Expenses		Cashflow
	MBO	MMCF	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2019	6.6		0.41	0.04	0.09		0.28
2020	5.7		0.35	0.04	0.09		0.23
2021	5.0		0.31	0.03	0.08		0.19
2022	4.3		0.27	0.03	0.08		0.16
2023	3.5		0.22	0.02	0.07		0.12
2024	3.3		0.20	0.02	0.07		0.11
2025	3.1		0.19	0.02	0.07		0.10
2026	2.9		0.18	0.02	0.07		0.09
2027	2.7		0.17	0.02	0.07		0.08
2028	2.5		0.16	0.02	0.07		0.07
2029							
TOTAL	39.6	0	2.45	0.25	0.78	0.00	1.42

Rio Opia(ANH price)

Proved Developed Reserves (PD)

Year	Production		Gas	Gross	Oil	Operating	Investment	Net
	Liquids	Gas	Sales	Income	Transport	Expenses		Cashflow
	MBO	MMCF	MMCF	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2019	6.1	26	24	0.45	0.04	0.09		0.32
2020	4.9	21	20	0.36	0.03	0.09		0.24
2021	3.9	17	16	0.29	0.03	0.09		0.18
2022	2.7	12	11	0.20	0.02	0.08		0.10
2023	1.8	9	9	0.14	0.01	0.07		0.06
2024	1.5	8	7	0.11	0.01	0.07		0.03
2025	0.9	6	6	0.07	0.01	0.06		0.01
2026								
2027								
2028								
2029								
TOTAL	22.0	100	93	1.64	0.14	0.56	0.00	0.94

Rio Opia(ANH price)

Proved Reserves (1P)

Year	Production		Gas	Gross	Oil	Operating	Investment	Net
	Liquids	Gas	Sales	Income	Transport	Expenses		Cashflow
	MBO	MMCF	MMCF	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2019	6.9	30	28	0.51	0.04	0.09	0.05	0.32
2020	5.7	25	23	0.42	0.04	0.09		0.29
2021	3.9	17	16	0.29	0.03	0.09		0.18
2022	2.7	12	11	0.20	0.02	0.08		0.10
2023	1.8	9	9	0.14	0.01	0.07		0.06
2024	1.5	8	7	0.11	0.01	0.07		0.03
2025	0.9	6	6	0.07	0.01	0.06		0.01
2026								
2027								
2028								
2029								
TOTAL	23.5	106	99	1.74	0.15	0.56	0.05	0.98

Rio Opia(ANH price)
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$
2019	7.6	33	31	0.56	0.05	0.09	0.05	0.37
2020	6.6	29	27	0.49	0.04	0.09		0.35
2021	5.3	23	22	0.39	0.03	0.09		0.27
2022	4.1	18	17	0.30	0.03	0.09		0.18
2023	2.4	12	11	0.18	0.02	0.07		0.09
2024	1.7	9	8	0.13	0.01	0.07		0.05
2025	1.4	7	7	0.11	0.01	0.07		0.03
2026	1.0	6	6	0.08	0.01	0.06		0.01
2027								
2028								
2029								
TOTAL	30.1	137	128	2.23	0.19	0.65	0.05	1.35

Rio Opia(ANH price)
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$
2019	8.2	36	33	0.60	0.05	0.09	0.05	0.41
2020	7.4	33	30	0.55	0.05	0.09		0.41
2021	6.0	26	25	0.44	0.04	0.09		0.31
2022	4.9	22	20	0.36	0.03	0.09		0.24
2023	3.5	16	15	0.26	0.02	0.07		0.16
2024	2.8	14	13	0.21	0.02	0.07		0.12
2025	2.4	12	11	0.18	0.02	0.07		0.10
2026	1.8	9	9	0.14	0.01	0.07		0.06
2027	1.1	6	6	0.09	0.01	0.07		0.01
2028								
2029								
TOTAL	38.2	174	162	2.84	0.24	0.73	0.05	1.81