Oslo, Buenos Aires, Bogota – 28 April 2023

Interoil Exploration and production ASA

Reserves Statement end 2022

Interoil Exploration & Production ASA ("Interoil") operates oil and gas fields plus some exploration concessions in Colombia and Argentina. The exploration blocks are placed in a promising and attractive hydrocarbon province and surrounded by producing oil and gas fields. The exploitation concessions have matured producing fields, still with interesting, underdeveloped acreage.

The table here below summarizes Interoil's hydrocarbon reserves classified as: P1 (Proven), 2P (Prove + Probable) and 3P (Prove + Probable + Possible) as of 31 December 2022 (see Table 1) following the PMRS definitions.

Table 1. Reserves Summary

Interoil Certif Reserves net W.I. after royalties		P1			2P		
		Gas [BCF]	Oil [MMbbl]	Total [Mmboe]	Gas [BCF]	Oil [MMbbl]	Total [Mmboe]
2022	Puli C	1.976	0.401	0.753	2.212	0.482	0.876
	Vikingo	-	0.067	0.067	-	0.142	0.142
	Colombia	1.976	0.468	0.820	2.212	0.624	1.018
	MMO	-	-	-	2.411	0.494	0.924
	SC	0.580	0.018	0.121	0.650	0.021	0.137
	Argentina	0.580	0.018	0.121	3.061	0.515	1.061
	Interoil	2.556	0.486	**0.942**	5.273	1.139	**2.079**

Note: all reserves volumes have been certified by SGS Nederland B.V. All of them are intended for the use in conjunction with the preparation of Interoil's Annual Statement of Reserves and Resources of crude oil and natural gas volumes expected to be produced among all the fields owned and operated in Argentina and Colombia.

Interoil total proven (P1) hydrocarbon net reserves after royalties amounts to 942 Mboe which represents a reduction of 412 Mboe compared with the previous year. Consistently, the proven + probable (2P) hydrocarbon net reserves after royalty account for 2.1 MMboe, also a reduction of 1.2 MMboe. These changes are mainly explained by the adjustment of the drilling program in Puli C, the work program in Mata Magallanes Oeste (MMO) and the hydrocarbon produced along 2022, in line with the natural depletion of the exploitation fields either in Argentina and Colombia.

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17th February, 2023

Reserves and Contingent Resources Statement for
Ambrosía, Río Opia, Maná,
Llanos 47 and Altair Areas, Colombia
as of December 31, 2022

Dear Mr. Carbone,

This reserves- and contingent resources statement has been prepared by SGS Nederland BV and issued on February 17th, 2023 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 Middle Magdalena Valley and the Altair and Llanos 47 concessions in the Llanos basin at the Casanare province in Colombia. This report is intended for use in conjunction with the preparation of InterOil's Annual Statement of Reserves and Resources for the Oslo Stock Exchange.
The report must be considered in its entirety and must only be used for the purpose for which it was intended. The scope of work was restricted to the contents of the project proposal agreed upon with InterOil on commencement of the project and should be considered as such.
SGS has conducted an independent reserves audit, as of December 31, 2022, 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 commercial information made available to SGS concerning these properties, SGS herewith presents a detailed outline of the developments, production- and costs profiles, as well as fiscal assumptions. In addition, a statement by SGS is provided on the estimated reserves and contingent resources, in accordance with SPE-PRMS-2018 guidelines.

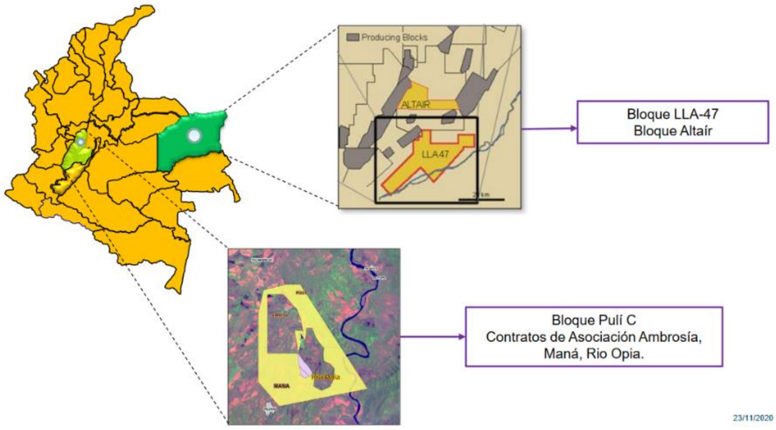

Figure 1 Location maps all concessions

Legal overview of assets

Introduction

Puli C license

The assets reviewed for this audit are operated by InterOil Colombia E&P under the umbrella of a “Contrato de Asociación” with Ecopetrol. In 2002 an agreement was reached between the parties by which InterOil (previously MERCANTILE COLOMBIA OIL AND GAS MOCG) will explore and exploit for hydrocarbons under the property of the state in the PULI-C Block, for an exploration period of 36 months and a subsequent exploitation period of 25 years.
As per the contract definitions, in terms of exploration expenses, Ecopetrol will reimburse a fixed percentage of the direct costs of exploration to the operator once the assets have been declared commercial and subsequently production can be commenced. A sole risk clause also allows the operator to perform certain development and exploration activities, should he wish to do so, in case Ecopetrol has not approved the commerciality of the hydrocarbon accumulation.
Under the asset exploitation period, the operator is required to present its annual development plan to Ecopetrol before May of the previous year and a 3 month-period is required to obtain the Executive Committee approval to the plan, and hence budget, is approved.
A fixed royalty percentage established by law should also be considered and the operator must deliver to Ecopetrol that percentage of the total asset production. Once the royalty has been paid, the remaining asset production is to be split between the parties in defined percentages.

Llanos 47 & Altair concession

Llanos 47 and Altair assets are governed by “Contrato de Exploración y Producción de Hidrocarburos”, signed between InterOil Colombia and ANH, by which InterOil has the right to exclusively explore the area under the contract and to produce conventional hydrocarbons. The contract stipulates an exploration period of 6 years plus extensions and a subsequent production period of 24 years from the date of reception by ANH of the “Declaración de Comercialidad” issued by the Operator.
The contract stipulates that the Contractor will have to comply with the legal 8% oil royalties that will be paid to ANH plus a 15% of participation right after royalties to ANH that InterOil pay in cash on a monthly basis.
Reserves are therefore entitled to InterOil up to its working interest in the concession until the economic limit of the contract.

Equity specifications

The assets are subject to the following general terms and conditions:

Table 1 Puli-C concession

Area	Acres	IOC Working Interest (%)	Royalty Oil (%)	Royalty Gas (%)	Start Date	Contract Expiry Date
Ambrosia	3800	70	8	6,4	Dec/02	27/Dec/27
Rio Opia	998	70	8	6,4	Jun/02	23/Jun/30
Mana	13000	70	8	6,4	Nov/03	11/Nov/28

Table 2 Altair / Llanos 47 Concessions

Area	Acres	IOC Working Interest (%)	Royalty Oil (%)	Royalty Gas (%)	Start Date	Contract Expiry Date
Altair	39500	90	8	Do not apply	Nov/08	27/Apr/21
Llanos 47	110500	78 / 60	8	Do not apply	May/11	20/May/44

License aspects

InterOil operates the Altair area under an exploitation contract that expires in 2021, following a 12 + 1 year period started in November 2008.
InterOil also operates the Llanos 47 area with a 78% participation in the production and operating expenses. The 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. In the case of Llanos 47, Interoil has declared commerciality for the area surrounding the Vikingo-1 well development in 2020, and is in the process of reviewing its alternatives on the remainder of Llanos 47 concession. The reserves and resources as estimated in this report belong exclusively to the Vikingo-1 development.

SGS reviewed the contract terms and all the documents that InterOil presented to ANH, including the corresponding “Declaración de Comercialidad” issued on May 20th, 2020, plus the formal presentation of the Development Plan proposed for the area, SGS has assumed that there is a reasonable expectation that the production permit for the area corresponding to Vikingo-1 is extended up to 2044. Interoil has complied with all the administrative steps in order to secure its rights over this development.

Geological overview of the assets

The assets of InterOil, Rio Opia, Ambrosia and Mana are located in the productive basins of the Valle Medio del Magdalena and Llanos 47 and Altair in Los Llanos Orientales.
The Rio Opia, Mana and Ambrosia fields are located on the western edge of the Valle Medio del Magdalena basin. In this sector, a tertiary-age continental sedimentary wedge lays directly on the basement (see Figure 2).

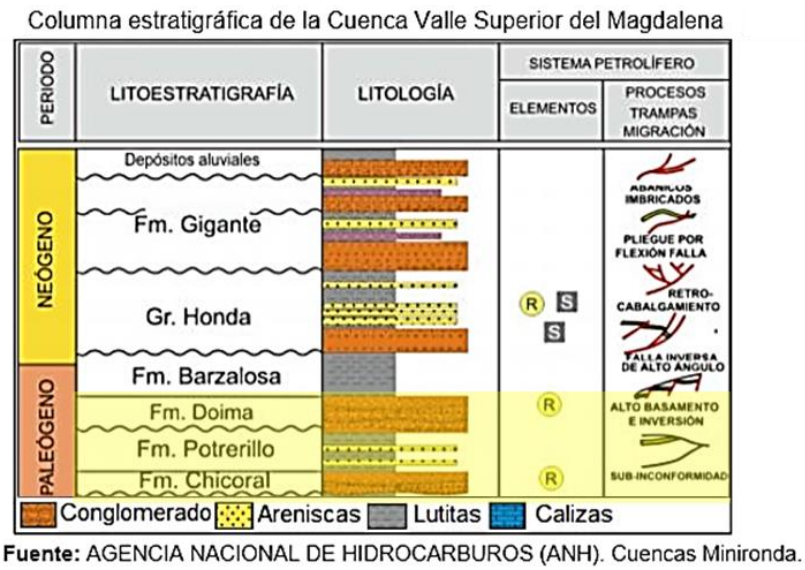

Figure 2 Stratigraphic column

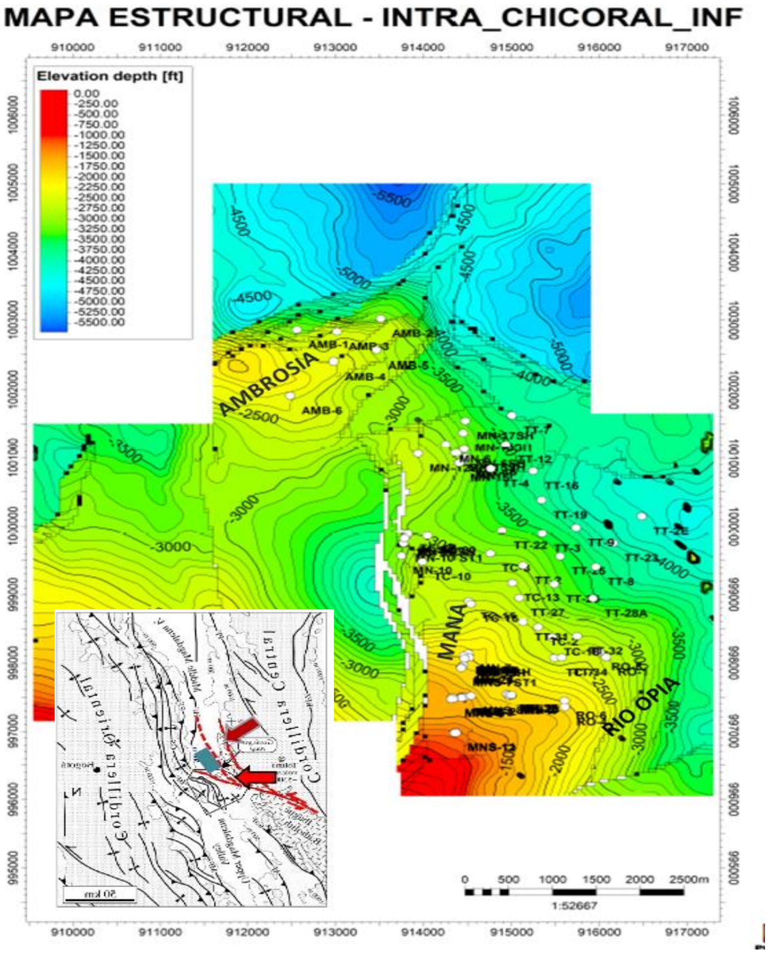

Figure 3 Top structure map Puli-C license

The regional structural style is compressional, developed in a fold and thrust belt environment. Faults originating in the basement were reactivated by transgressive stresses that affected the sedimentary wedge, creating the structures that model the oil traps of the region.

The Río Opia, Mana and Ambrosia fields are typical anticline-style structural traps whose main culmination is to the southwest. Río Opia and Mana are three-way closures limited to the west by a north-south fault, while Ambrosia develops a high with a four-way closure (Figure 3).

The Chicoral and Doima productive formations present reservoirs of alluvial and fluvial origin with sub-environments of braided and meandering channels.

The Potrerillos formation constitutes a mostly pelitic section of lagoon and floodplain environments that separates both the Chicoral and Doima production units. Floodplain environments act as a seal for the productive reservoirs. (Figure 2).

The Doima reservoir shows average porosities of 11%, permeability of 42 md and produces oil of 23 ° API. Chicoral reservoir has an average porosity of 11%, permeability of 90 md and produces oil of 24.5 ° API.

The Llanos 47 and Altair blocks are located in the Llanos Orientales basin, close to the most productive areas. The trap style at this region is structural highs against normal faults with three-way closures. Both Llanos 47 and Altair blocks have remaining exploratory potential associated with these types of traps, aligned with the main regional faults of the basin (Figure 4)

The key producing formation at the blocks is the Oligocene age Carbonera Fm; it shows mixed to marine-proximal sediments with average porosities of 22% and produce black oil of 26° API.

The Carbonera Formation is subdivided into sections: C7 and C5 sections constitute the main reservoir; layers C4 and C6 constitute the seals. The Altair block adds production from the Gacheta Fm. with marine-proximal sediments of Cretaceous age.

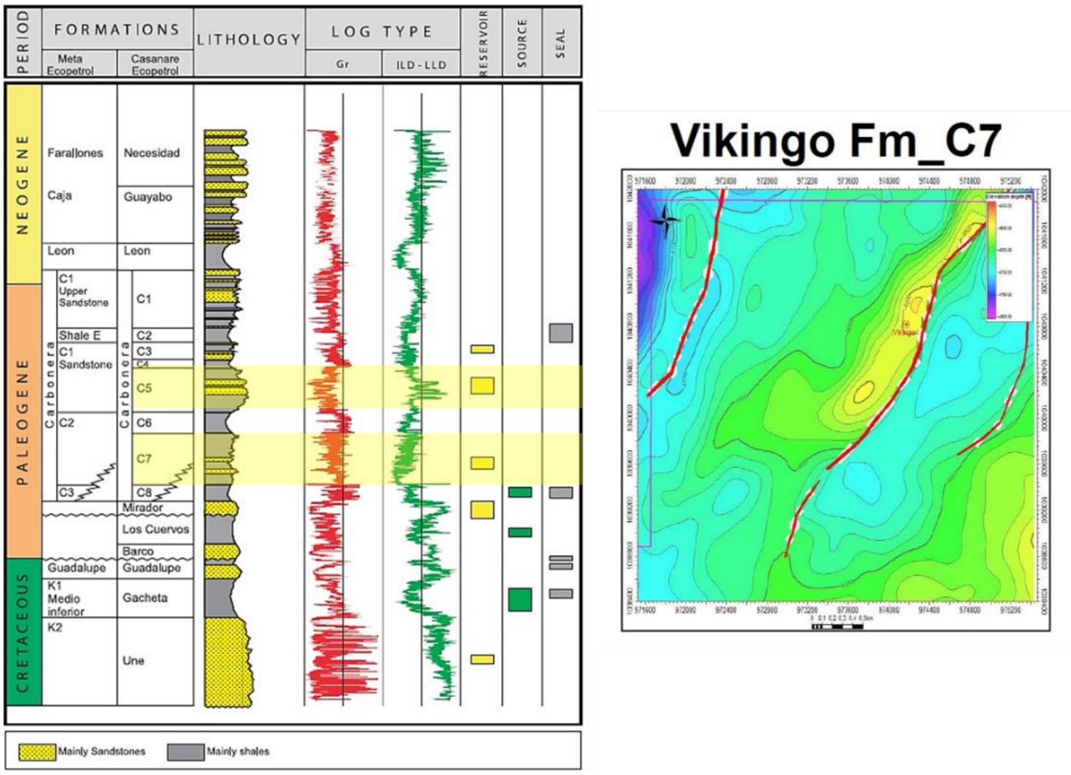

Figure 4 Top structure map and type log Llanos 47 concession

Development plans

Introduction

InterOil proposed 6 workovers and 3 wells to be drilled as part of their activity plan for the years 2022 and 2023 during last year´s audit. Due to recent developments in the country, mainly related to fiscal aspects, the company has decided to postpone, with no estimated new date, its drilling campaign. Only projects, with relatively minor investments, are being considered in the work plan for 2023 and 2024.

In the case of the workovers for Puli-C, the 2 workovers aimed for gas production have not been approved by Hocol and have been cancelled. Two new workovers in wells RO-4 and MN-6SH have been proposed, technically reviewed by SGS and incorporated in the workplan. The remaining 4 workovers are the same ones that were included in last year’s audit (RO-4, AMB-1, AMB-4 and VIK-1).
Even though the company plans to perform 5 of these workovers in 2023, SGS has decided to consider a conservative schedule in which 2 workovers per year are performed, based on the companies’ operational track record in the last 3 years.

Workover for Vikingo-1 is scheduled for the beginning of 2025, and it will depend on the behaviour of formation C5, which is still producing, as of the date of this report.
SGS has reviewed each of these activities and has performed its own individual assessment based on the pertinent data provided by the operator.

The company does not have firm plans to drill the 3 wells as per previous year's program anymore. Therefore, SGS has decided to move the corresponding project with previously calculated reserves to the category of contingent resources in the "Development on Hold" category.

Overview of development plans/projects

Mana Field

Two workovers are scheduled to be performed during 2023 in this field.
An oil workover in MNS-2, with new intervals to be opened and other old intervals to be reperforated with a relatively new hydromechanic perforation technology, which has proven to be very effective in RO-4 and RO-6. This is the same workover that was included in last year's audit plan.
A new workover on MN-6SH is proposed to recover production from Doima formation by reopening sandy intervals using the hydromechanics perforation technology.
Industry standard techniques were applied to generate low- best and high case production forecasts for these projects.

Río Opia Field

Based on the successful results of the hydromechanics perforation technology in RO-6, the company has decided to reperforate existing intervals in RO-4, aiming for incorporating oil production both in Doima and in Chicoral (UOB) formations.
Industry standard techniques were applied to generate low- best and high case production forecasts for these projects.

Ambrosia Field

The same two workovers than in last year's audit are planned to be carried out in AMB-1 and AMB-4 wells, in which the operator plans to apply the proven hydromechanics perforation technology, instead of the initially planned hydraulic fracturing.
Industry standard techniques were applied to generate low- best and high case production forecasts for these projects.

Llanos Field

A workover to Vikingo-1 well is scheduled for 2025, in which a plug will be removed and C7 formation will be placed back on production, while isolating C5 formation. Once reservoir pressures in C5 and C7 are similar, commingled production is assumed to take place (somewhere in 2026 according to our estimations).

Contingent Resources

Contingent resources have been sub-classified as "Development on Hold" or "Development Unclarified" up to end of 2043. All contingent resources from existing developments, which are considered to be uneconomic, prior to the end of 2043 have not been included in the overview of contingent resources, except the develop producing part beyond the economic limit has been marked as contingent resources prior to end of each license expiry .

70 new wells, plus the 3 wells that were considered in the reserves category as per last year's audit, have been included in the contingent resources category which have been identified by the operator as part of a full field development plan and reviewed by the reserve's auditor. 29 wells are proposed in the northern part of the PULI-C area targeting the Doima and Chicoral Formations (17 wells) and only to Doima Formation (12 wells). 44 wells are proposed in the southeastern part of the asset targeting both Doima and Chicoral Formations (25 wells) and only Doima Formation (19 wells).

To mature these contingent resources into reserves, technically- and commercially mature projects should be further defined. Out of these 73 wells, 25 have been sub-classified as ""Development on Hold." Their proposed locations have strong technical- and geological potential and are located in an updip structural position. However, a key contingency is the expected future potentially worsening fiscal regime, according to InterOil, with adverse impact on the economic viability. In addition, there is a lack of firm plans to further mature these projects in the foreseeable future. 48 wells have been sub-classified as "Development Unclarified" based on their proposed locations and the fact that further data acquisition should be carried out to justify their technical maturity. In addition, commercial aspects should also be addressed in order to re-classify these contingent resources into reserves.

In order to quantify the resources per field, the 29 northern wells were assigned to Ambrosia field, and out of the 44 southern wells, 10 have been assigned to Mana field and 34 have been assigned to Rio Opia field.

Industry standard techniques were applied to generate low- best and high case production forecasts.

Reserves and contingent resources statement

On the basis of technical and commercial information made available to SGS concerning these assets, SGS hereby provides the reserves statement as per 31-Dec-2022:

Table 3 Reserves statement - all fields

		GROSS (100%) FIELD VOLUMES		INTEROIL WORKING INTEREST		NET RESERVES TO INTEROIL WI	
		Crude Oil (MMstb)	Natural Gas (BScf)	Crude Oil (MMstb)	Natural Gas (BScf)	Crude Oil (MMstb)	Natural Gas (BScf)
ALL FIELDS	PROVED						
	Developed	0.560	2.763	0.395	1.934	0.366	1.934
	Developed NP	0.047	0.124	0.033	0.087	0.030	0.087
	Undeveloped	0.050	0.000	0.039	0.000	0.039	0.000
	Total 1P	**0.657**	**2.887**	**0.467**	**2.021**	**0.435**	**2.021**
	Total 2P	**0.870**	**3.313**	**0.624**	**2.319**	**0.585**	**2.319**
	Total 3P	**1.351**	**3.675**	**0.991**	**2.572**	**0.947**	**2.572**

M: refers to thousands
MM: refers to millions
B: refers to billions

Hydrocarbon liquid volumes represent crude oil estimated to be recovered during field separation and are reported in millions of stock tank barrels (MMstb). Natural gas volumes are reported in billion standard cubic feet (Bscf) at standard condition of 14.7 psia and 60°F. Net interest gas reserves represent expected gas sales and fuel usage in the field (4%). 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 Exhibit-I.
Gas reserves sales volumes are based on firm 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. The gas contract signed by InterOil and Turgas in January 2008 has been renewed on several occasions in the previous years and on a regular basis. Therefore, there is a reasonable expectation that the contract remains applicable until the expiration of the individual licenses.

"Developed Producing reserves" were estimated by extrapolating the present production by decline curve analysis. "Developed Non-Producing reserves" for each category were estimated by SGS, for the planned 2023 workover campaign (five wells in PULI-C), based on technical- and commercial information provided by InterOil. Solution gas reserves in Maná and Río Opia were estimated through extrapolation of the producing gas-oil ratios. The resulting volumes were reduced by 4% for consumption in own operations (CiO).

Contingent resources for infills wells proposed by InterOil, which do not classify as reserves have been sub-classified either as "Development on Hold" or "Development Unclarified" with production up to December 2043, regardless of economic viability.
Production from existing developments which are deemed uneconomic have been sub-classified as "Development Not Viable" up to the end of December 2043. Note that for Llanos 47 in the "Development Not Viable" class 1C is higher than 3C. This can be accounted to the fact that in the high case, all production from Llanos 47 is marked as reserves.

Area	OIL - Development Pending (MMstb)			OIL - Development Unclarified (MMstb)			OIL - Development Not Viable (MMstb)			OIL - Total (MMstb)		
	1C	2C	3C	1C	2C	3C	1C	2C	3C	1C	2C	3C
Mana	0.320	0.600	0.920	0.000	0.000	0.000	0.239	0.359	0.577	0.559	0.959	1.497
Rio Opia	0.128	0.240	0.368	0.960	1.800	2.760	0.013	0.024	0.038	1.101	2.064	3.166
Ambrosia	0.407	0.759	1.177	0.666	1.242	1.926	0.079	0.124	0.169	1.152	2.125	3.272
Llanos	0.000	0.000	0.000	0.000	0.000	0.000	0.099	0.096	0.057	0.099	0.096	0.057
Altair	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	**0.855**	**1.599**	**2.465**	**1.626**	**3.042**	**4.686**	**0.430**	**0.602**	**0.842**	**2.911**	**5.243**	**7.993**

Table 4 Overview oil contingent resources - all fields

Area	GAS - Development Pending (Bscf)			GAS - Development Unclarified (Bscf)			GAS - Development Not Viable (Bscf)			GAS - Total (Bscf)		
	1C	2C	3C	1C	2C	3C	1C	2C	3C	1C	2C	3C
Mana	0.960	1.800	2.760	0.000	0.000	0.000	2.236	3.391	4.983	3.196	5.191	7.743
Rio Opia	0.384	0.720	1.104	2.880	5.400	8.280	0.114	0.138	0.170	3.378	6.258	9.554
Ambrosia	1.221	2.277	3.531	1.998	3.726	5.778	0.040	0.068	0.091	3.259	6.071	9.400
Llanos	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Altair	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	**2.565**	**4.797**	**7.395**	**4.878**	**9.126**	**14.058**	**2.390**	**3.597**	**5.245**	**9.833**	**17.520**	**26.698**

Table 5 - Overview gas contingent resources - all fields

M: refers to thousands
MM: refers to millions
B: refers to billions

Hydrocarbon liquid volumes represent crude oil estimated to be recovered during field separation and are reported in million-barrel increments (MMstb). Natural gas volumes are reported in billion standard cubic feet (Bscf) at standard condition of 14.7 psia and 60°F.
Volumes reported as Contingent Resources represent gross (100% working interest) volumes without royalty or gas consumption deductions.

Inter-annual comparison

The following tables show the main reasons for reserves change between year-end 2021 and year-end 2022 (gross volumes) at the company level, for each of the fields in Puli-C and for the Llanos-47 concession:

Table 6 - Reserves change Year End 2021-2022 - IOC

RESERVES DEVELOPMENT (GROSS 100% VOLUME)				
	Crude Oil (MMstb)		Gas (Bscf)	
	1P	2P	1P	2P
Balance (as of year and last full year)	0.824	1.502	3.926	5.444
Production 2022	0.224		0.700	
Acquisitions / Disposals				
Extensions / Discoveries	0.000	0.000	0.000	0.000
New Developments	0.000	0.000	0.000	0.000
Revisions of previous estimates	0.057	0.408	0.339	1.432
Balance (as of 31-Dec-2022)	**0.657**	**0.870**	**2.887**	**3.313**

M: refers to thousands
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Numbers in red refer to negative values

In the case of crude oil reserves, the main reduction in the “Revisions of previous estimates” category for the 2P case refers to abandoning of the plan to drill the 3 new wells in the foreseeable future. (2 wells in Mana, and 1 well in Rio Opia).
In the case of gas, reduction in both 1P and 2P cases are mainly driven by the cancellation of the Mana gas cap project consisting of 2 workovers and also impacted by the removal of the 3 new wells. These 2 workovers have not been approved by Hocol, the state oil and gas company, with a leading decision making right in the development.
Revisions in the other 2 fields are mainly related to minor adjustments to the decline rates as part of this year’s audit.

Table 7 - Reserves change Year End 2021-2022 - Mana Field

RESERVES DEVELOPMENT (GROSS 100% VOLUME)				
	Crude Oil (MMstb)		**Gas (Bscf)**	
	1P	**2P**	**1P**	**2P**
Balance (as of year and last full year)	0.562	0.888	3.757	4.982
Production 2022	0.132		0.672	
Acquisitions / Disposals				
Extensions / Discoveries				
New Developments				
Revisions of previous estimates	0.044	0.199	0.363	1.185
Balance (as of 31-Dec-2022)	**0.474**	**0.557**	**2.722**	**3.125**

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Numbers in red refer to negative values

Table 8 - Reserves change Year End 2021-2022 - Ambrosia Field

RESERVES DEVELOPMENT (GROSS 100% VOLUME)				
	Crude Oil (MMstb)		**Gas (Bscf)**	
	1P	**2P**	**1P**	**2P**
Balance (as of year and last full year)	0.071	0.102	0.039	0.055
Production 2022	0.012		0.005	
Acquisitions / Disposals				
Extensions / Discoveries				
New Developments				
Revisions of previous estimates	0.001	0.008	0.004	0.008
Balance (as of 31-Dec-2022)	**0.058**	**0.082**	**0.030**	**0.041**

M: refers to thousands
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B: refers to billions
Numbers in red refer to negative values

Table 9 - Reserves change Year End 2021-2022 - Rio Opia Field

RESERVES DEVELOPMENT (GROSS 100% VOLUME)				
	Crude Oil (MMstb)		**Gas (Bscf)**	
	1P	**2P**	**1P**	**2P**
Balance (as of year and last full year)	0.056	0.162	0.130	0.407
Production 2022	0.012		0.022	
Acquisitions / Disposals				
Extensions / Discoveries				
New Developments				
Revisions of previous estimates	0.004	0.100	0.028	0.239
Balance (as of 31-Dec-2022)	**0.040**	**0.050**	**0.135**	**0.146**

M: refers to thousands
MM: refers to millions
B: refers to billions

Numbers in red refer to negative values

Table 10 - Reserves change Year End 2021-2022 - Llanos 47 Concession

RESERVES DEVELOPMENT (GROSS 100% VOLUME)	Crude Oil (MMstb)		Gas (Bscf)	
	1P	2P	1P	2P
Balance (as of year and last full year)	0.135	0.350	0.000	0.000
Production 2022	0.067			
Acquisitions / Disposals				
Extensions / Discoveries				
New Developments				
Revisions of previous estimates	0.018	0.101		
Balance (as of 31-Dec-2022)	**0.085**	**0.182**	**0.000**	**0.000**

M: refers to thousands
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B: refers to billions
Numbers in red refer to negative values

Operator’s reserve estimate

SGS has not found any substantial difference with the operator´s view in any of the assets mentioned above. Differences may refer to subjective considerations such as decline curve coefficients and are not material.

Commercial considerations

The ICE (Intercontinental Exchange) Brent crude forecast estimation has been applied, based on forward curves on the 4th of January 2023, up to end of 2029. A discount of 6% is considered for Vasconia blend and this discount is escalated proportionally to the crude forecast variations.

The gas price assumed is based on long term agreements with Turgas, all gas in excess is to be sold at a price resulting from a contract formula. The gas price in 2023 amounts to 2,90 US$/MMBtu and is subsequently escalated by 1% on a yearly basis.

Table 11 Brent and contractual gas price forecast (MOD) 2023-2029

Year	Oil Price (US$/bbl)	Gas Price (US$/MMBtu)
2023	78,43	2,90
2024	74,55	2,93
2025	71,89	2,96
2026	69,79	2,99
2027	67,95	3,02
2028	66,52	3,05
2029	65,62	3,08

2023 budget estimated costs and expenses have been reviewed and compared to 2022 costs to predict future expenses for each of the fields. According to the analysis of these expenses, provided by the operator and reviewed by SGS, the following costs have been applied for the economic evaluation:

Table 12 Overview cost aspects

Category	Mana	Ambrosia	Rio Opia	Llanos 47
Fixed Opex (MUS$/yr)	1.321	124	124	582
Variable Opex (US$/bbl)	8,77	8,77	8,77	8,35
G&A Allocation (MUS$/yr)	460	43	43	14
Oil transportation (US$/bbl)	6,00	6,00	6,00	11,20

The abandonment cost of a well was provided by InterOil and is considered to be 120 kUS$ (RT22).

All costs, as per the above table, are escalated by 6% on a yearly basis. The 6% is based on the Colombian inflation rate since a significant part of these costs are to be paid in Colombian Pesos. Based on previous variations, oil transportation is escalated only by 1% on a yearly basis, and the escalation factor is lower than inflation rate mainly because this expense is incurred in US$ dollars.

G&A expenses have been distributed on a variable basis between the 4 fields and proportional to the number of active wells per field.

An income tax over net benefit of 30% applies to activities in Colombia.

Historic development overview of individual fields

InterOil Colombia has operations in Valle Superior de Magdalena Basin and in Llanos Orientales Basin. The first is located in Piedras, Tolima area and the other one in Oroucué in Casanare. The production, as of December 2022, is 550 bbo/d and 1.5 Mscf/d day. 63 wells were drilled in the five blocks and 38 of them are on production today. The cumulative oil production is 6.93 MMbbl and 18.1 Bscf of gas have been produced.
Target locations have been selected based on a 3D seismic and subsequent static modelling by InterOil. From the analysis of production logging, it can be inferred that the formation units can be divided in separate subunits. A petrophysical model was built and new zones were identified to be perforated based on the latest technology advances in perforation techniques.
Infrastructure is relatively well established at Puli-C. All the wells are connected to the main facility at Mana where the oil is processed and stored in tanks before subsequent transportation through trucking.

Figure 5 shows the wells drilled by InterOil since the beginning of the contract.

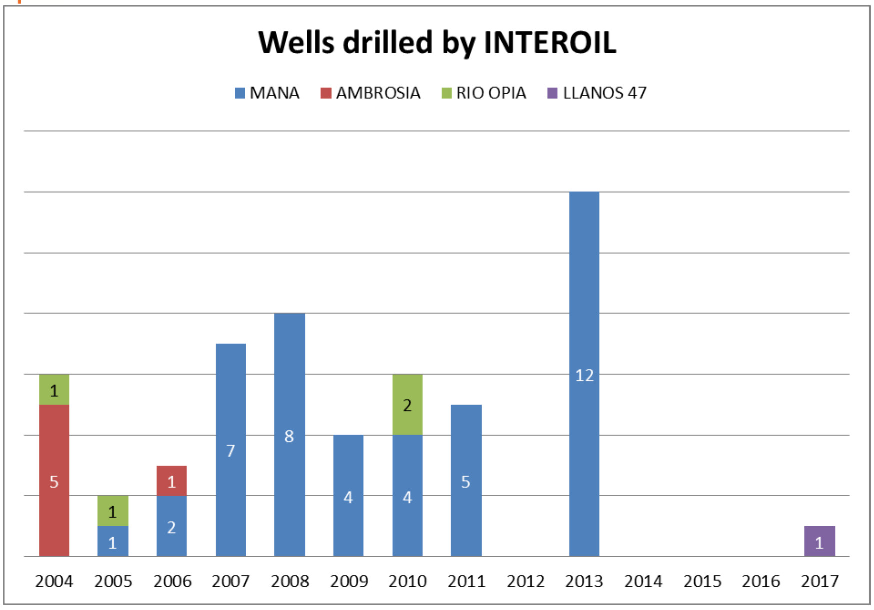


Figure 5 Wells drilled by InterOil Colombia historically

Mana field

The Mana field was discovered in 2004 and produces oil and gas from the Doima and Chicoral Formations. The average depth of the wells is around 3,850 ft with wells drilled between 2,800/5,000 feet and the primary production mechanism is solution-gas drive. Current oil production is 334 bbl/d and 1.4 Mscf/d of gas. Since the beginning of the field exploitation, 46 wells were drilled and only 4 of them have already been abandoned. By December 2022, 32 wells were on production and the remaining ones closed and under study.

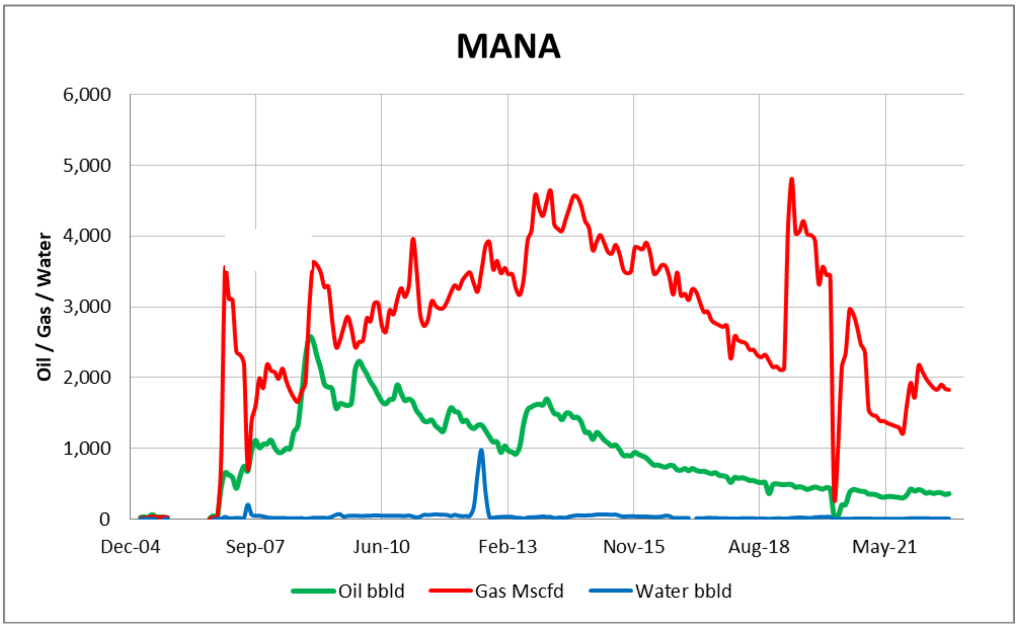


Figure 6 Historical production Mana field

The OOIP for Doima and Chicoral combined is approximately 115 MMbbl with a current recovery factor of 5%. Cumulative oil production is 5.83 Mbbl and 17.3 MMscf cumulative gas.

Rio Opia field

Rio Opia field was discovered in 2004 and produces oil and gas from Doima and Chicoral formations. The average depth of the wells is around 4,350 ft with wells drilled between 3,850/4,750 feet and the primary production mechanism is solution gas drive. Current oil production, as of December 2022, is 28 bbl/d and 58 Mscf/d of gas. 3 wells are currently on production, while 2 of the wells were abandoned due to poor reservoir performance ("Bunde wells").

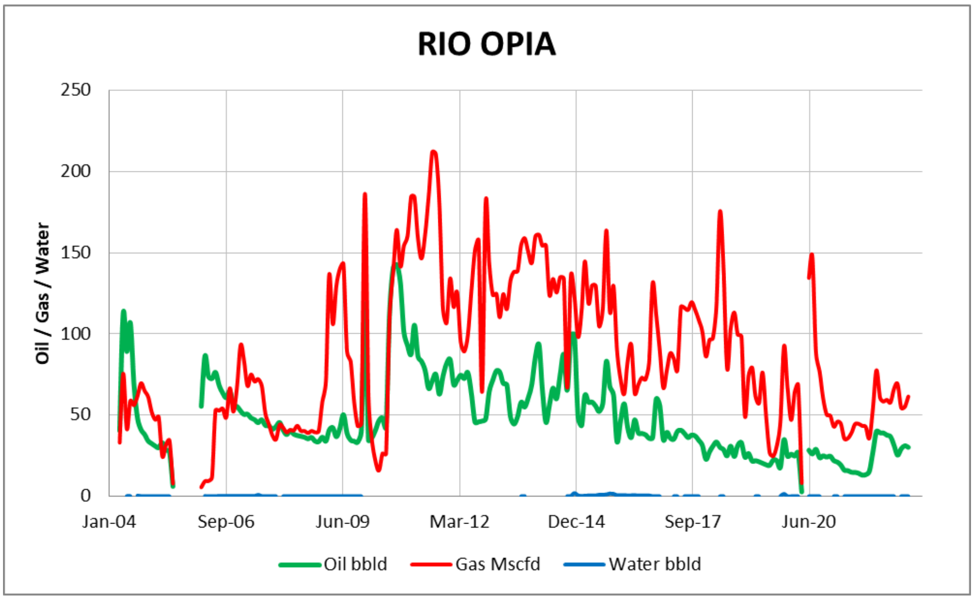


Figure 7 Historical production Rio Opia field

The OOIP for the Doima and Chicoral formations is approximately 47 MMbbl with a current recovery factor of 1%. Cumulative oil production is 319 Mbbl and 577 MMscf cumulative gas.

Ambrosia field

Ambrosia field was discovered in 2004 and produces oil and gas from Doima Formation. The average depth of the wells is around 4,100 ft with wells drilled between 3300/5300 feet and the primary production mechanism is solution-gas drive. Current oil production, as of December 2022, is 31 bbl/d and 15 Mscf/d of gas. 6 wells were drilled and 3 of them are currently on production, while 3 wells were already abandoned.

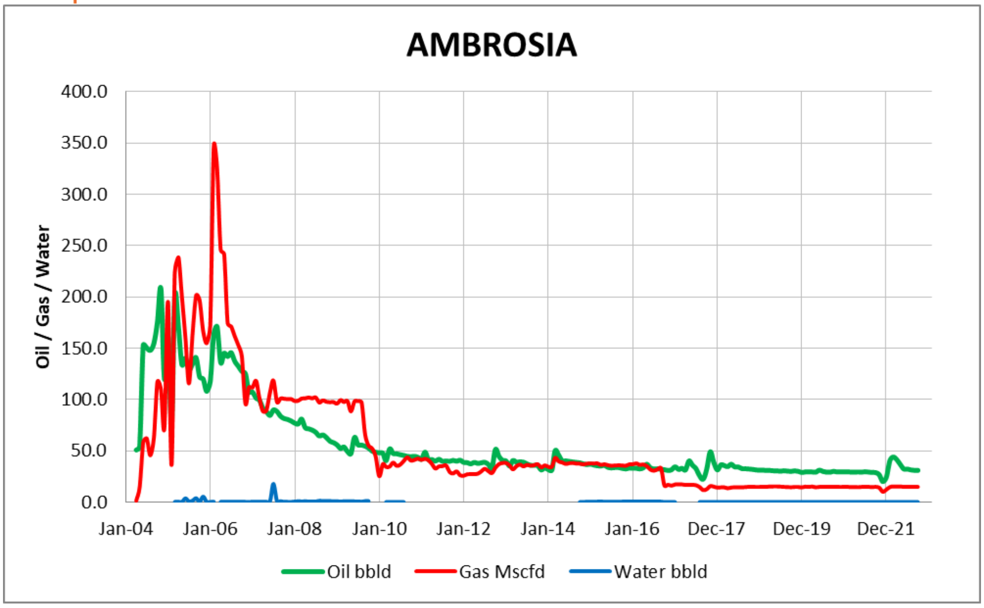


Figure 8 Historical production Ambrosia field

The OOIP for Doima is approximately 32 MMbbl with a current recovery factor of 1%. Cumulative oil production is 382 Mbbl and 374 MMscf cumulative gas.

Llanos 47 field

Llanos 47 field was discovered in 2008. In 2017, InterOil successfully drilled Vikingo-1, the first of the committed exploration wells in the block and produces oil from the C5 Formation. The depth of the well is 5,900 feet and the primary production mechanism is depletion drive. The current oil production, as of December 2022, is 155 bbl/d. 3 wells were drilled and 1 of them is currently on production. The other 2 wells are shut-in due to poor reservoir performance.

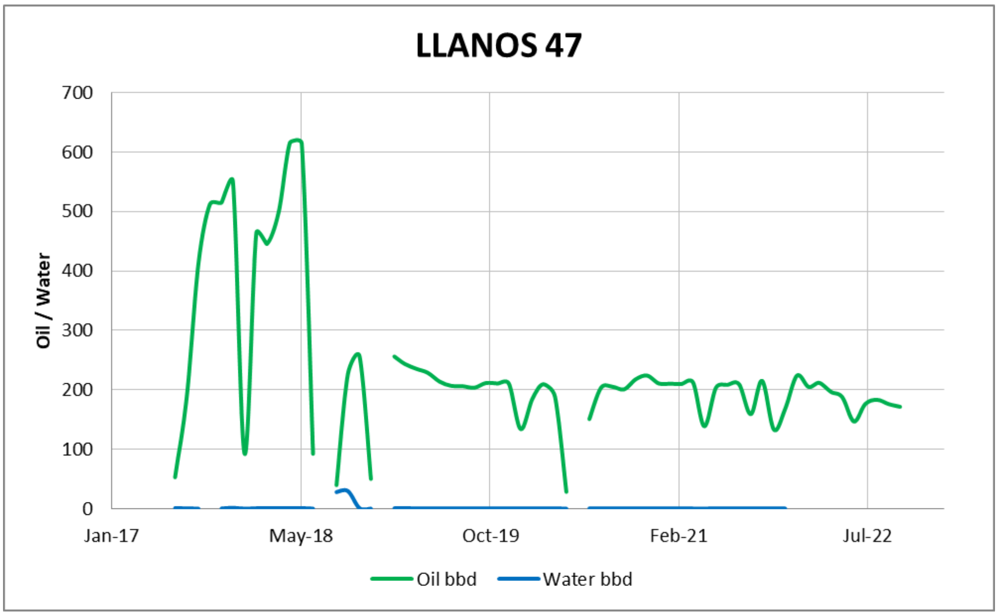


Figure 9 Historical production Llanos-47 field

The OOIP for C5 is approximately 2,37 MMbbl with a current recovery factor of 18%. Cumulative oil production is 440 Mbbls.
The well is currently being produced with a jet pump and this system has been lowering the flowing bottomhole pressure in order to maintain a production level between 160-180 bopd.

Altair field

Altair field was discovered in 2010 and produced oil from C3, C5 and C7 formations. The average depth of the wells is 4,200 feet and the primary production mechanism is depletion drive. 6 wells were drilled, and Altair-1 was productive but is closed due to environmental issues. Mizar well proved production from Gacheta and Carbonera C7.

Basis of opinion

SGS is the world's leading inspection, verification, testing and certification company. SGS is recognized as the global benchmark for quality and integrity. With more than 89,000 employees, SGS operates a network of more than 2,600 offices and laboratories around the world. The core services of SGS can be divided into four categories: inspection; testing; certification and verification.

This report has been prepared by SGS for public disclosure in its entirety, in conjunction with Interoil's Annual Statement of Reserves and Resources for the Oslo Stock Exchange. SGS has made every effort to ensure that the interpretations, conclusions and recommendations presented herein are accurate and reliable in accordance with good industry practice and its own quality management procedures. SGS does not, however, guarantee the correctness of any such interpretations, conclusions, and recommendations. Barring any agreement to the contrary, all assignments and documents are performed and issued on the basis of the general conditions of SGS. The general conditions provide for a limitation of liability. SGS will not accept responsibility or liability for any loss, costs, damages or expenses incurred or sustained by any third party (parties or persons other than Interoil) resulting from any interpretation, conclusion or recommendation made by any of its officers, agents, employees or representatives. SGS makes no guarantee or prediction of results and makes no warranty, either express or implied, with respect to the actual reserves and resources available.

This report is based on data, methodology and interpretations provided by Interoil to SGS through November and December 2022. SGS has not independently verified any information provided by Interoil. Based on SGS' review, it is SGS' opinion that the overall procedures, methodologies and thoroughness used by Interoil in the reserves estimation process are appropriate and that a thorough approach has been followed, using methods considered sound in the determination of the reserves. The quality of the data relied upon and the depth and thoroughness of the reserves estimation process as well as the classification and categorization of the reserves by Interoil are appropriate.

Standard geological and engineering techniques accepted by the petroleum industry were used in estimating recoverable hydrocarbons. Several uncertainties associated to the estimation of oil and gas reserves exist, as subsurface accumulations of oil and gas cannot be measured in an exact manner. The techniques used rely on engineering and geo-scientific interpretation and judgment; hence the resources included in this evaluation are estimates only and should not be construed to be exact quantities. It should be recognized that such estimates of hydrocarbon resources may increase or decrease in future if there are changes to the technical interpretation, economic criteria, sales volumes or regulatory requirements. Property descriptions, details of interests held, well data, and commercial terms and conditions including fiscal, as obtained from Interoil or public sources, were accepted as represented.

Interoil acknowledges that the report reflects the facts as received by SGS at that time only and within the limits of the instructions received from Interoil. The scope of the report is limited and may not cover all areas which may potentially be interesting for the report's recipients and/or actual results. The report must always be presented in its entirety. This report shall not be reproduced, distributed, quoted or made available to any company, person, regulatory body, or organization without the complete contents of the report. References to and citations from the report are accompanied by the report in its entirety. Interoil warrants that the meaning of the text as intended by the author of the report is not distorted by the manner in which text is reproduced in citations or the manner in which the text is otherwise referenced.

Definitions of Reserves and contingent resources are based on SPE-PRMS-2018 guidelines and are presented in Exhibit-IV. SGS has carried out a reserves- and resources audit with a strong assessment component. The contingent resources have been subclassified in accordance with SPE-PRMS-2018 guidelines to provide an indication of chance of development.
SGS has performed an economic limit test to establish the cessation of production, for the purpose of determination of reserves.

SGS has not made any field examination of the property. As a result, SGS is not able to comment on the (appropriateness and conditions of) operations or facilities in place. Furthermore, SGS is not able to comment on health, safety and environmental aspects. No consideration was given in this report to potential environmental liabilities that may exist. No investigation was made into either the legal titles held or any operating agreements in place relating to the subject properties.

SGS is not obliged to update or amend the report to the factual developments or developments in the legislation, regulation or case law after the date of the report. SGS is not able to attest to property title or rights, or any required licenses and consents.

SGS is known for its independency and impartiality. In preparing this report, SGS has not been aware of any conflict of interest. The SGS Group nor any of its subsidiaries have any financial interests in Interoil or in any of its affiliates. This includes potential shares in Interoil. The remuneration of SGS has been compatible to the services provided, not contingent on the contents of the report. The report has been prepared by a well-experienced team. The qualifications of the technical person primarily responsible for the execution of this audit are provided below.

Niek Dousi was the primary technical- and commercial person and project manager for this project. He is a Senior Reservoir Engineer and holds an MSc in Petroleum Engineering from Delft University of Technology, The Netherlands, and has over 17 years of relevant professional experience. His key competences are classical reservoir engineering, Reserves evaluations, dynamic modelling, addressing commercial aspects and project management. He has taken part in numerous integrated field development studies, analyzing oil and gas assets in the North Sea, Continental Europe, North & West Africa, Oman and Russia, among others. Between 2008 and 2016 he has been part of asset valuation teams, evaluating various North Sea, Continental European and West African assets. Other activities involved participation in specialized subsurface studies, such as reserves certifications, using SEC&SPE-PRMS, UGS- and Geomechanics studies, both as a seasoned reservoir engineer and as project manager. Niek is also experienced in performing and supervising economic analyses. Between 2016 and 2020 he has managed more than six large reserves certification studies on Dutch, Gabonese, East African- and Omani assets, among smaller reserves audits. He has worked on numerous oil- and gas assets worldwide, including tight gas, gas-condensates, heavy oil, fluvial-, stacked- and fractured carbonate reservoirs. Niek has participated in projects for majors small/midsized operators and non-operators. Recently in 2019, Niek was part of a special team to support a large middle eastern NOC in building a detailed country portfolio model comprising of assets with many multi billion barrels of in place oil volume. He is a longstanding member of the Society of Petroleum Engineers and has published several papers for the SPE and EAGE.

Niek Dousi

Project Manager

Primary technical- and commercial person

Richard Keen

Business Manager

Exhibit-I Overview of Reserves

Statement of Remaining Hydrocarbon Volumes Ambrosía, Río Opia, Maná and Llanos 47 Concessions, Colombia as of December 31, 2022

		GROSS (100%) FIELD VOLUMES		INTEROIL WORKING INTEREST		NET RESERVES TO INTEROIL WI	
		Crude Oil (MMstb)	Natural Gas (BScf)	Crude Oil (MMstb)	Natural Gas (BScf)	Crude Oil (MMstb)	Natural Gas (BScf)
ALL FIELDS	PROVED						
	Developed	0,560	2,763	0,395	1,934	0,366	1,934
	Developed NP	0,047	0,124	0,033	0,087	0,030	0,087
	Undeveloped	0,050	0,000	0,039	0,000	0,039	0,000
	Total 1P	**0,657**	**2,887**	**0,467**	**2,021**	**0,435**	**2,021**
	Total 2P	**0,870**	**3,313**	**0,624**	**2,319**	**0,585**	**2,319**
	Total 3P	**1,351**	**3,675**	**0,991**	**2,572**	**0,947**	**2,572**
MANA	PROVED						
	Developed	0,454	2,619	0,318	1,833	0,292	1,833
	Developed NP	0,020	0,103	0,014	0,072	0,013	0,072
	Undeveloped	0,000	0,000	0,000	0,000	0,000	0,000
	Total 1P	0,474	2,722	0,332	1,905	0,305	1,905
	Total 2P	0,557	3,125	0,390	2,188	0,359	2,188
	Total 3P	0,630	3,468	0,441	2,428	0,406	2,428
RIO OPIA	PROVED						
	Developed	0,034	0,123	0,024	0,086	0,022	0,086
	Developed NP	0,006	0,012	0,004	0,008	0,004	0,008
	Undeveloped	0,000	0,000	0,000	0,000	0,000	0,000
	Total 1P	0,040	0,135	0,028	0,095	0,026	0,095
	Total 2P	0,050	0,146	0,035	0,102	0,032	0,102
	Total 3P	0,057	0,157	0,040	0,110	0,037	0,110
AMBROSIA	PROVED						
	Developed	0,038	0,021	0,026	0,015	0,024	0,015
	Developed NP	0,021	0,009	0,014	0,006	0,013	0,006
	Undeveloped	0,000	0,000	0,000	0,000	0,000	0,000
	Total 1P	0,058	0,030	0,041	0,021	0,037	0,021
	Total 2P	0,082	0,041	0,057	0,029	0,053	0,029
	Total 3P	0,101	0,050	0,071	0,035	0,065	0,035
LLANOS	PROVED						
	Developed	0,035	0,000	0,027	0,000	0,027	0,000
	Developed NP	0,000	0,000	0,000	0,000	0,000	0,000
	Undeveloped	0,050	0,000	0,039	0,000	0,039	0,000
	Total 1P	0,085	0,000	0,067	0,000	0,067	0,000
	Total 2P	0,182	0,000	0,142	0,000	0,142	0,000
	Total 3P	0,563	0,000	0,439	0,000	0,439	0,000

Exhibit-II Detailed overview reserves and costs

InterOil Colombia Exploración y Producción

Net Revenue Interest Reserve Cash Flows Properties in Colombia as of December 31, 2022 (MOD),

M: refers to thousands
MM: refers to millions
B: refers to billions

Mana

Proved Developed Reserves

Year	Production Forecast Oil - Mstb	Gas - MMscf	Gas Sales MMscf	Gross Income MUS$	Oil Transport MUS$	Operating Expenses MUS$	Abandonment MUS$	Investment MUS$	Pre-Tax Cashflow MUS$
2023	71	432	415	6443	462	2006	672	142	3161
2024	59	386	371	5265	391	1895	168	124	2687
2025	54	337	323	4635	361	1897	336	0	2041
2026	49	292	280	4086	331	1984	252	0	1518
2027	41	254	244	3337	275	1772	336	0	954
2028	31	205	197	2539	212	1589	336	0	402

Proved Reserves (1P)

Year	Production Forecast Oil - Mstb	Gas - MMscf	Gas Sales MMscf	Gross Income MUS$	Oil Transport MUS$	Operating Expenses MUS$	Abandonment MUS$	Investment MUS$	Pre-Tax Cashflow MUS$
2023	71	432	415	6443	462	2006	672	142	3161
2024	59	386	371	5265	391	1895	168	124	2687
2025	54	337	323	4635	361	1897	336	0	2041
2026	49	292	280	4086	331	1984	252	0	1518
2027	41	254	244	3337	275	1772	336	0	954
2028	31	205	197	2539	212	1589	336	0	402

2P Reserves

Year	Production Forecast Oil - Mstb	Gas - MMscf	Gas Sales MMscf	Gross Income MUS$	Oil Transport MUS$	Operating Expenses MUS$	Abandonment MUS$	Investment MUS$	Pre-Tax Cashflow MUS$
2023	77	457	439	6985	503	2070	672	142	3598
2024	71	433	415	6244	471	2016	84	124	3550
2025	65	388	373	5532	434	2006	168	0	2924
2026	58	345	331	4786	387	2063	252	0	2085
2027	49	309	296	4022	331	1850	168	0	1674
2028	38	256	246	3153	262	1659	168	0	1063

3P Reserves

Year	Production Forecast Oil - Mstb	Gas - MMscf	Gas Sales MMscf	Gross Income MUS$	Oil Transport MUS$	Operating Expenses MUS$	Abandonment MUS$	Investment MUS$	Pre-Tax Cashflow MUS$
2023	80	472	453	7251	523	2099	672	142	3815
2024	78	461	443	6764	512	2077	0	124	4051
2025	73	428	411	6202	489	2086	0	0	3627
2026	67	393	377	5537	450	2153	168	0	2767
2027	59	363	349	4844	401	1951	84	0	2409
2028	48	311	298	3944	331	1758	84	0	1771

Rio Opia

Proved Developed Reserves									
	Production Forecast		Gas Sales	Gross Income	Oil Transport	Operating Expenses	Abandonment	Investment	Pre-Tax Cashflow
Year	Oil - Mstb	Gas - MMscf	MMscf	MUS$	MUS$	MUS$	MUS$	MUS$	MUS$
2023	6	14	14	470	38	172	0	0	260
2024	5	13	13	354	29	200	0	0	125
2025	4	15	15	348	29	221	84	137	-123
2026	3	14	13	265	22	112	0	0	130
2027	3	12	12	212	18	114	0	0	80
2028	2	11	11	173	15	108	0	0	50
2029	2	10	10	144	12	103	0	0	29
2030	1	5	5	66	5	47	0	0	14

Proved Reserves (1P)									
	Production Forecast		Gas Sales	Gross Income	Oil Transport	Operating Expenses	Abandonment	Investment	Pre-Tax Cashflow
Year	Oil - Mstb	Gas - MMscf	MMscf	MUS$	MUS$	MUS$	MUS$	MUS$	MUS$
2023	6	14	14	470	38	172	0	0	260
2024	5	13	13	354	29	200	0	0	125
2025	4	15	15	348	29	221	84	137	-123
2026	3	14	13	265	22	112	0	0	130
2027	3	12	12	212	18	114	0	0	80
2028	2	11	11	173	15	108	0	0	50
2029	2	10	10	144	12	103	0	0	29
2030	1	5	5	66	5	47	0	0	14

2P Reserves									
	Production Forecast		Gas Sales	Gross Income	Oil Transport	Operating Expenses	Abandonment	Investment	Pre-Tax Cashflow
Year	Oil - Mstb	Gas - MMscf	MMscf	MUS$	MUS$	MUS$	MUS$	MUS$	MUS$
2023	6	14	14	508	41	177	0	0	289
2024	6	13	13	428	36	210	0	0	183
2025	6	17	16	453	39	235	0	137	42
2026	4	15	15	328	28	121	0	0	179
2027	4	14	13	264	23	121	0	0	120
2028	3	12	12	219	19	115	168	0	-83
2029	2	11	11	187	16	109	0	0	62
2030	1	5	5	87	7	48	0	0	32

3P Reserves									
	Production Forecast		Gas Sales	Gross Income	Oil Transport	Operating Expenses	Abandonment	Investment	Pre-Tax Cashflow
Year	Oil - Mstb	Gas - MMscf	MMscf	MUS$	MUS$	MUS$	MUS$	MUS$	MUS$
2023	7	14	14	527	43	180	0	0	304
2024	6	14	13	470	40	215	0	0	215
2025	7	17	17	496	43	241	0	137	76
2026	5	17	16	370	32	127	0	0	212
2027	4	15	14	315	28	128	0	0	159
2028	4	14	13	273	24	122	0	0	127
2029	3	13	12	242	21	117	0	0	104
2030	2	6	6	116	10	50	0	0	56

Ambrosia

Proved Developed Reserves									
Year	Production Forecast Oil - Mstb	Gas CIO MMscf	Gas Sales MMscf	Gross Income MUS$	Oil Transport MUS$	Operating Expenses MUS$	Abandonment MUS$	Investment MUS$	Pre-Tax Cashflow MUS$
2023	10	5	0	711	63	209	0	108	332
2024	9	5	0	642	60	244	0	97	241
2025	7	4	0	490	48	247	0	0	195
2026	6	4	0	391	40	296	0	0	55
2027	6	3	0	356	38	316	0	0	3

Proved Reserves (1P)									
Year	Production Forecast Oil - Mstb	Gas CIO MMscf	Gas Sales MMscf	Gross Income MUS$	Oil Transport MUS$	Operating Expenses MUS$	Abandonment MUS$	Investment MUS$	Pre-Tax Cashflow MUS$
2023	10	5	0	711	63	209	0	108	332
2024	9	5	0	642	60	244	0	97	241
2025	7	4	0	490	48	247	0	0	195
2026	6	4	0	391	40	296	0	0	55
2027	6	3	0	356	38	316	0	0	3

2P Reserves									
Year	Production Forecast Oil - Mstb	Gas CIO MMscf	Gas Sales MMscf	Gross Income MUS$	Oil Transport MUS$	Operating Expenses MUS$	Abandonment MUS$	Investment MUS$	Pre-Tax Cashflow MUS$
2023	13	6	0	943	83	238	0	108	514
2024	13	6	0	902	84	279	0	97	441
2025	10	6	0	701	69	276	0	0	356
2026	9	5	0	568	58	322	0	0	189
2027	8	5	0	521	55	340	0	0	126

3P Reserves									
Year	Production Forecast Oil - MMstb	Gas CIO MMscf	Gas Sales MMscf	Gross Income MUS$	Oil Transport MUS$	Operating Expenses MUS$	Abandonment MUS$	Investment MUS$	Pre-Tax Cashflow MUS$
2023	15	8	0	1135	100	263	0	108	664
2024	16	8	0	1104	103	306	0	97	597
2025	13	7	0	877	86	301	0	0	490
2026	11	7	0	722	74	344	0	0	304
2027	10	6	0	667	71	362	0	0	234

Llanos 47

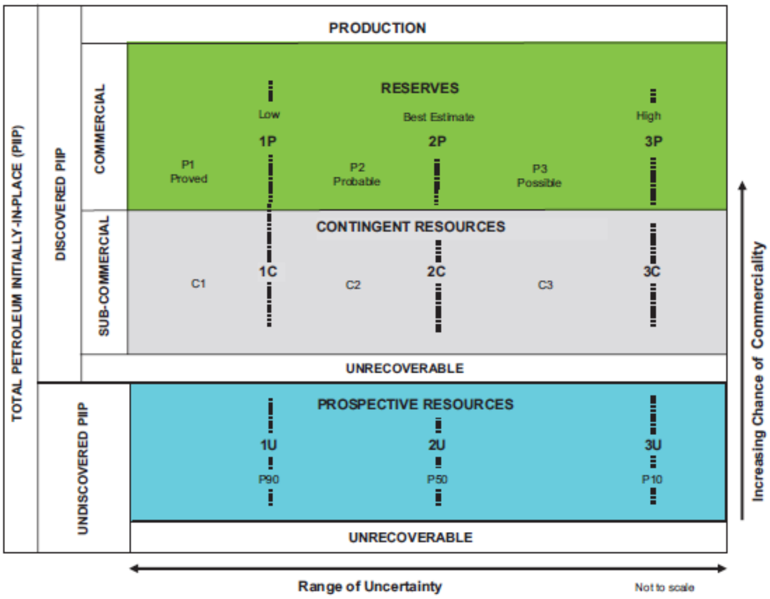
Proved Developed Reserves							
Production Forecast		Gross Income	Oil Transport	Operating Expenses	Abandonment	Investment	Pre-Tax Cashflow
Year	Oil - Mstb	MUS$	MUS$	MUS$	MUS$	MUS$	MUS$
2023	27	2012	304	970	0	0	738
2024	8	574	91	616	0	0	-134

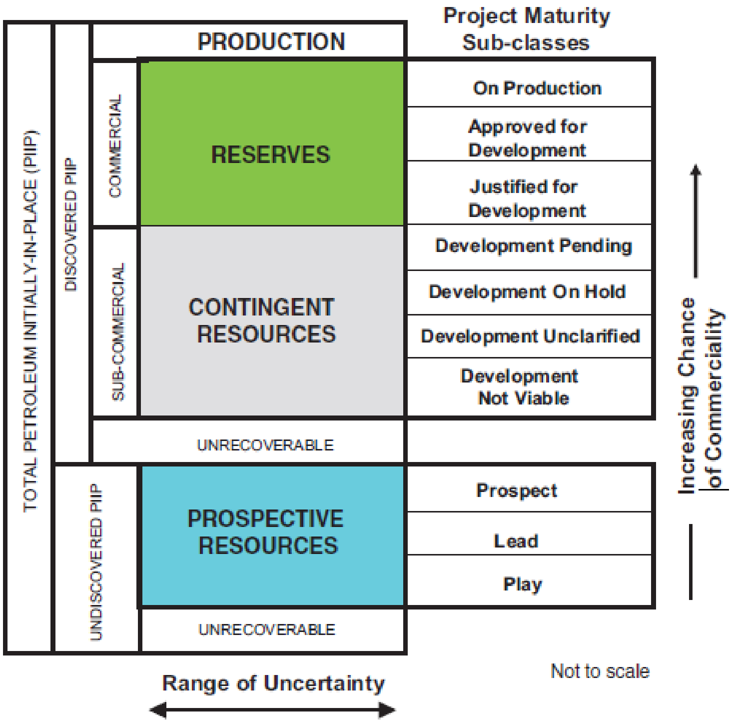
Proved Reserves (1P)							
Production Forecast		Gross Income	Oil Transport	Operating Expenses	Abandonment	Investment	Pre-Tax Cashflow
Year	Oil - Mstb	MUS$	MUS$	MUS$	MUS$	MUS$	MUS$
2023	27	2012	304	970	0	0	738
2024	8	574	91	616	0	0	-134
2025	18	1222	202	790	0	78	152
2026	13	870	148	707	0	0	15
2027	13	852	149	707	0	117	-121

2P Reserves							
Production Forecast		Gross Income	Oil Transport	Operating Expenses	Abandonment	Investment	Pre-Tax Cashflow
Year	Oil - Mstb	MUS$	MUS$	MUS$	MUS$	MUS$	MUS$
2023	37	2759	417	1157	0	0	1185
2024	23	1586	252	876	0	0	458
2025	25	1700	280	915	0	78	427
2026	19	1269	216	813	0	0	241
2027	22	1388	242	851	0	117	178
2028	16	998	178	754	0	0	66
2029	13	782	141	717	0	0	-76

3P Reserves							
Production Forecast		Gross Income	Oil Transport	Operating Expenses	Abandonment	Investment	Pre-Tax Cashflow
Year	Oil - Mstb	MUS$	MUS$	MUS$	MUS$	MUS$	MUS$
2023	46	3370	510	1310	0	0	1550
2024	43	3053	486	1252	0	0	1315
2025	36	2430	401	1105	0	78	846
2026	32	2130	362	1041	0	0	728
2027	64	4113	718	1582	0	117	1696
2028	59	3684	657	1482	0	0	1545
2029	54	3336	603	1414	0	0	1319
2030	47	2946	522	1299	0	0	1124
2031	28	1835	319	995	0	0	522
2032	18	1169	199	764	0	0	206
2033	12	820	137	669	0	0	14
2034	9	623	102	616	0	0	-95

Exhibit-III SPE-PRMS-2018 classification and guidelines





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.
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.

Class/Sub-Class	Definition	Guidelines
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.
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.

Class/Sub-Class	Definition	Guidelines
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.
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.

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.

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23rd February, 2023

Reserves and Contingent Resources Statement for
Mata Magallanes Oeste concession, Argentina
as of December 31, 2022

Dear Mr. Carbone,

This reserves- and contingent resources statement has been prepared by SGS Nederland BV and issued on February 23rd, 2023 at the request of InterOil Argentina (InterOil or “the Client”), operator of and a variable interest participant in the Mata Magallanes Oeste concession of the Golfo San Jorge Basin at the Chubut province in Argentina (Figure 1). This report is intended for use in conjunction with the preparation of InterOil’s Annual Statement of Reserves and Resources for the Oslo Stock Exchange.
The report must be considered in its entirety and must only be used for the purpose for which it was intended. The scope of work was restricted to the contents of the project proposal and should be considered as such.
SGS has conducted an independent reserves audit, as of December 31, 2022, of the crude oil and natural gas volumes expected to be produced in the Mata Magallanes Oeste concession. On the basis of technical and commercial information made available to SGS concerning these properties, SGS herewith presents a detailed outline of the developments, production- and costs profiles, as well as fiscal assumptions. In addition, a statement by SGS is provided on the estimated reserves and contingent resources, in accordance with SPE-PRMS-2018 guidelines.

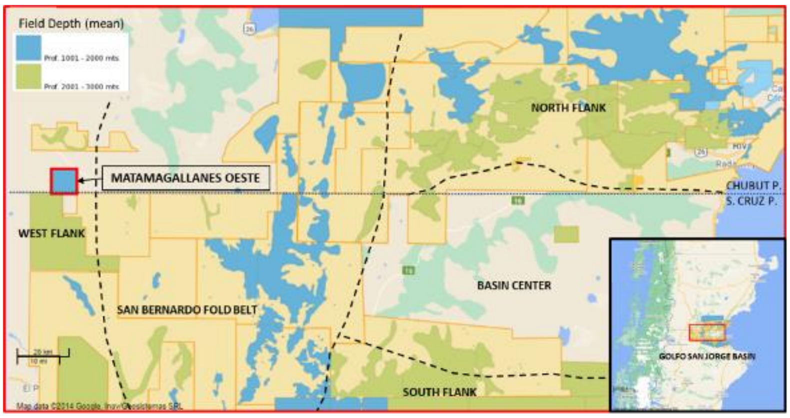


Figure 1 Location map - All concessions

Legal overview of assets

Introduction

The asset reviewed for this audit belongs to Interoil Argentina under a “Concesión de Explotación” subject to the Argentinian Law of Hydrocarbons, Law 17.319, from 1967. InterOil Argentina has a participation of 80 % in this asset and is responsible for the field operations, for which they subcontract Selva Maria Oil S.A.
With the latest changes to the Hydrocarbon Law, by Law 27.007, the different Provinces in Argentina became the owners of the hydrocarbon resources under their land and they are responsible for issuing the area permits and concessions.
Under the above mentioned law, companies are entitled to ask for a “Permiso de Exploración” in an area with no reserves, which if declared commercial, gives the permit holder the right to ask for a “Concesión de Explotación” for 25 years plus 10 year successive extensions, in the case of conventional reservoirs.
In case an area is reverted to the Province by a previous holder and having production or reserves, an interested company can directly ask for a “Concesión de Explotación”.
Royalties by law can vary between 5% and 12% of the oil and gas production and since Law 27.007 was passed, the Provinces are also retaining a 3% to 6% extra right to exploit the areas under their territories so total royalties can amount up to 18%.

Equity specifications

The asset under this audit, Mata Magallanes Oeste is subject to a 12% royalty both for oil and gas, payable to Chubut Province. Interoil holds an 80% working interest and the remainder 20% belongs to Petrominera Chubut.
Mata Magallanes Oeste is under a “Concesión de Explotación” which expires in April, 2043.

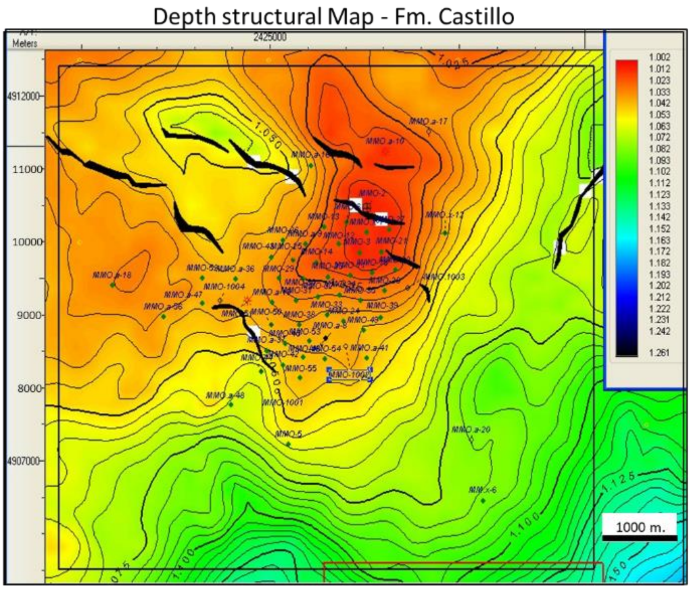
License aspects

Mata Magallanes Oeste was awarded to Interoil in 2018, following a public bid by which the company acquired the right to exploit the asset for a 25-year period, with a possible 10-year extension.
As part of this commitment, Interoil presented a development plan including the drilling of several new wells and the reactivation of many of the wells in the field.

Geological overview of the assets

Interoil's asset Mata Magallanes Oeste (MMO) is located in the Golfo San Jorge productive basin, in the argentine Patagonia.
The Mata Magallanes Oeste area is in a region called the western flank of the Golfo San Jorge Basin in the province of Chubut (Figure 1). The Cretaceous age Castillo and Bajo Barreal Formations are the productive units within the stratigraphic column and are composed of continental sediments developed in fluvio-deltaic and lacustrine environments (Figure 2). The reservoirs are constituted by the braided and meandering channels and the seals by the shales of the associated floodplains.
The petrophysical properties of the Castillo Fm. sandstones present average porosities of 24% and permeabilities of 94 mD. The Bajo Barreal Fm. presents average porosities of 25% and permeabilities of 90 mD. Both reservoirs produce saturated oil with a current GOR of 300 m3/m3. The oil density is of 21° API in average.

The MMO field trap is a NNE-SSW elongated anticline, limited at the north by a segmented NW-SE fault system (Figure 2)



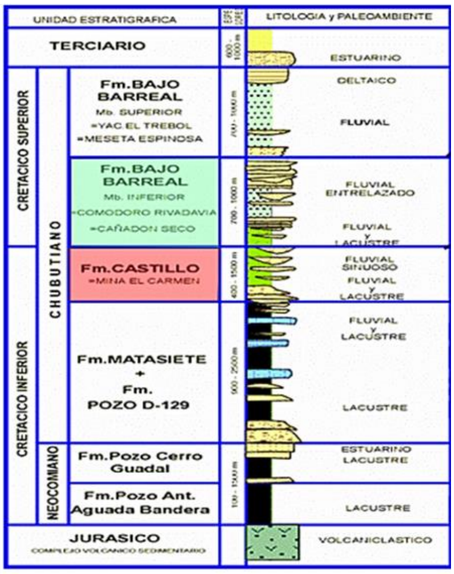


Figure 2 Top Castillo Fm. structural map and San Jorge basin stratigraphic column

Development Plan

Interoil has presented to the auditors the current development plan for Mata Magallanes Oeste (MMO), which is identical to the plan presented at Year-End 2021. It includes the reactivation of 15 oil wells (following a workover program of 2 gas wells), the workover of 8 wells and the drilling of several new wells to increase the oil recovery from the field.

During several months in 2022, the MMO field was not operational due to environmental issues that the company managed to resolve. The operator resumed operations in October 2022 after realizing an agreement with the Chubut government. The company is currently waiting for the rig to arrive at the field to perform the 2 gas workovers. The future gas produced will serve as fuel gas, enabling the re-instatement of the 15 oil wells. An agreement to lease the pulling rig from the UTE Santa Cruz has been presented to the auditors as a proof of the company's intentions to proceed with the workovers of the wells.

1. *Reactivation of closed wells*

The first project to be considered involves the reactivation of 15 shut-in oil wells and the workover of 2 gas wells, identified in an area of the field containing some gas layers.

These gas workovers, delayed due to the environmental issues as indicated above, will be performed during the first half of 2023 in MMO-30 and MMO-15. It has an estimated investment cost of 800 MUS$, plus the revamping of some surface facilities with an estimated investment of 400 MUS$.

The purpose of these workovers is to generate gas that will be consumed in field operations, i.e. running of the surface facilities and the well artificial lift systems. This gas production will enable the re-opening of 15 oil wells.

The company is currently in the process of securing the investment for this project with a reasonable expectation that financing can be realized.

2. *Workover of the oil/gas wells*

Interoil has also 8 workovers included in their field development plan (7 oil workovers and 1 gas workover), aiming to increase oil production mainly from Bajo Barreal Fm. These workovers will be performed, by tapping into oil in new and previously perforated intervals. SGS has reviewed the plans and technically endorses the proposed workovers.
Even though the company plans to perform 4 of these workovers in late 2023, SGS has decided to consider a conservative schedule in which 2 workovers per year are performed, based on the companies' operational track record in the last 3 years.

The company states that it plans to finance the cost of the workovers with its own funds.

3. *Drilling of new oil wells*

Interoil is also retaining its plan to drill 3 new wells, that were presented to SGS during the Year-End 2021 audit. The company shared their proposed locations and corresponding technical justification. The recovery from these wells have currently been classified as contingent resources by SGS, since the company has not presented enough evidence of a firm commitment to proceed and does not have a justifiable financing plan to proceed with the project.

Contingent Resources

Contingent resources in this report are related to:

1. production of the 3 new wells which may be drilled in the coming years
2. 4 oil wells included in the reactivation project.

4 oil wells of re-activation program are not economic in the best estimate case under the current oil price scenario in Argentina. In addition, 6 oil wells to be re-opened and 2 oil workovers are not economic in the low case and have therefore been included in 1C contingent resources.

All the production beyond the economic limit and up to the license expiry date has also been considered as contingent resources. No production beyond April 2043, has also been considered since, based on current best estimates, the oil rate will be under 1 m3/d at that moment in time.

Reserves and contingent resources statement

On the basis of technical and commercial information made available to SGS concerning these assets, SGS provides the reserves statement (Table 1) as per 31-Dec-2022:

Table 1 - Reserves statement - summary

		GROSS (100%) FIELD VOLUMES		INTEROIL WORKING INTEREST		NET RESERVES TO INTEROIL WI	
		Crude Oil (Mstb)	Natural Gas (MMScf)	Crude Oil (Mstb)	Natural Gas (MMScf)	Crude Oil (Mstb)	Natural Gas (MMScf)
MATA MAGALLANES OESTE	PROVED						
	Developed	214	357	171	285	151	251
	Undeveloped	0	0	0	0	0	0
	Total 1P	**214**	**357**	**171**	**285**	**151**	**251**
	Total 2P	**761**	**3179**	**609**	**2543**	**536**	**2238**
	Total 3P	**1101**	**7264**	**881**	**5812**	**775**	**5114**

M: refers to thousands
MM: refers to millions

Hydrocarbon liquid volumes represent crude oil estimated to be recovered during field separation and are reported in thousands of stock tank barrels (Mstb). Natural gas volumes are reported in million standard cubic feet (MMscf) at standard condition of 14.7 psia and 60°F. Net interest gas reserves represent expected gas sales and fuel usage in the field. Royalties payable to the state and other royalty interest owners have been deducted from reported net interest volumes. Individual reserves statements are provided in Exhibit-I.

"Developed Producing Reserves" were estimated by extrapolating the present production by decline curve analysis.

Solution gas production was estimated through extrapolation of the producing gas-oil ratios. Gas to be produced from the workovers was calculated using standard industry techniques. All of the stated gas volumes, though considered as reserves, are classified as consumed in own operations (CiO). Therefore, no gas sales are considered.

Table 2 - Gas Consumed in Operations (CIO) per year

Gas Consumed in Operations (MMscf) - at Interoil WI			
Year	1P	2P	3P
2023	14	294	790
2024	35	273	681
2025	42	258	608
2026	41	238	538
2027	47	221	467
2028	40	186	390
2029	34	156	325
2030	29	133	275
2031	26	114	232
2032	23	97	196
2033	20	83	166
2034	17	71	140
2035	15	61	119
2036	0	53	101
2037	0	45	86
2038	0	35	68
2038	0	0	56

The extrapolation of the production beyond the field´s economic limit and the activity as per previous description has been classified as Contingent Resources (Table 3), regardless of assumptions on commerciality.

Table 3 - Contingent Resources statement - summary

		GROSS (100%) FIELD VOLUMES		INTEROIL WORKING INTEREST		NET RESOURCES TO INTEROIL WI	
		Crude Oil (Mstb)	Natural Gas (MMScf)	Crude Oil (Mstb)	Natural Gas (MMScf)	Crude Oil (Mstb)	Natural Gas (MMScf)
MATA MAGALLANES OESTE	Total 1C	542	914	434	731	382	643
	Total 2C	534	899	427	719	376	633
	Total 3C	696	1172	557	937	490	825

Hydrocarbon liquid volumes represent crude oil estimated to be recovered during field separation and are reported in thousands of barrels (Mstb). Natural gas volumes are reported in million standard cubic feet (MMscf) at standard condition of 14.7 psia and 60°F.
Volumes reported as Contingent Resources represent gross (100% working interest) volumes without royalty or gas consumption deductions.

Inter-annual comparison

Table 4 shows the main reasons for reserves change between year-end 2021 and year-end 2022 (gross volumes):

Table 4 - Reserves evolution year-end 2021-2022

RESERVES DEVELOPMENT (GROSS 100% VOLUME)				
	Crude Oil (Mstb)		Gas (MMscf)	
	1P	2P	1P	2P
Balance (as of year and last full year)	226	821	378	3308
Production 2022	3,8		19,7	
Acquisitions / Disposals				
Extensions / Discoveries				
New Developments				
Revisions of previous estimates	-8	-56	-1	-109
Balance (as of 31-Dec-2022)	**214**	**761**	**357**	**3179**

M: refers to thousands

MM: refers to millions

The minor reduction included in "Revisions of previous estimates" refers to an adjustment to the production forecast of the 15 wells to be reactivated plus the change in schedule for the 8 proposed workovers (will start in 2024 based on a 2 activities per year program).

Operator's reserve estimate

SGS has not found any substantial difference with the operator´s view in any of the assets mentioned above. Differences may refer to subjective considerations such as decline curve coefficients and are not material.

Interoil has presented evidence of having sufficient capital to perform the proposed operations as included in their 2023 Work Plan. According to IOA, the projects have passed their internal economic hurdle rate.

However, it is important to remark that, due to force majeure reasons (COVID) in 2020 and 2021 and due to environmental issues impacting the field operations in 2022, no significant activity has taken place in MMO field during the last 3 years. However, SGS assumes that there is a reasonable expectation that normal operations can resume in 2023 with the workover of the 2 gas wells. Interoil has a track record in carrying out some activities in Argentina, e.g. on the Santa Cruz asset.

Commercial considerations

Although the auditor commonly applies the (Intercontinental Exchange) Brent crude forward curve forecast for its estimations, oil prices in Argentina are primarily affected by local market conditions and its corresponding forecast should be used for reserves determination purposes.

Table 5 states the "local market" price forecast used for this estimation over a 10-year period, and the Brent forecast used as the reference for this local market price adjustment.

No gas price scenario has been assumed since no gas sales are being considered and all the produced gas volumes are consumed in field operations.

Table 5 – Market and Brent Price Forecast 2023-2030

Price Forecast - US$/bbl		
Year	**Brent**	**Local Market**
2023	78,43	56,43
2024	74,55	52,55
2025	71,89	49,89
2026	69,79	47,79
2027	67,95	45,95
2028	66,52	44,52
2029	65,62	43,62
2030	63,62	41,62
2031	64,89	42,89

2023 budget estimated costs have been reviewed to assign future expenses to the development. According to the analysis of these expenses, provided by the operator and reviewed by SGS, the following annual costs and variable expenses (Table 6) have been applied for the economic evaluation:

Table 6 - Overview cost aspects

Category	Value
Fixed Opex (MUS$/yr)	672
Variable Opex (US$/bbl)	1,52
Oil transportation (US$/bbl)	2,00

The abandonment cost of a well was provided by InterOil and is considered to be 100 kUS$ (RT22).

Field costs, as per the above table, are escalated by 3% on a yearly basis since most of the expenses are incurred in US$ dollars.

An income tax over net benefit of 30% applies to activities in Argentina.

Historic development overview of individual fields

Mata Magallanes Oeste is located in the Golfo San Jorge basin in the south of Argentina, the most prolific oil production basin in the country. Operations in this field started in 1985 and 55 wells have been drilled since the beginning of the field exploitation. As of December 2022, only 1 well (MMO-3) is in continuous production, mainly due to the lack of gas production needed to run the surface facilities and the well artificial lift systems.

The field has reached a cumulative production of 190 MMstb of oil and 13 Bscf of gas during its entire life.

Gas production has not been of interest so far, although some sands have been found to produce gas, as per initial well tests. All the produced gas is used for internal consumption, hence the importance of identifying the existing wells with these gas intervals that can be opened and put in production.

The field historical production is shown below (Figure 3):

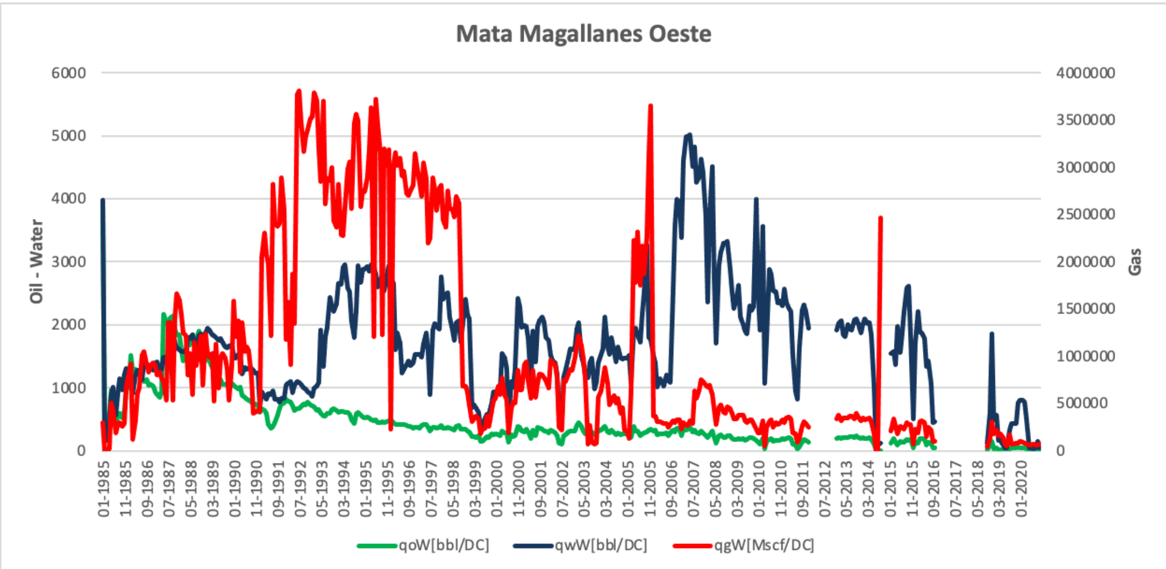


Figure 3 Mata Magallanes Oeste historical production

Basis of opinion

SGS is the world's leading inspection, verification, testing and certification company. SGS is recognized as the global benchmark for quality and integrity. With more than 89,000 employees, SGS operates a network of more than 2,600 offices and laboratories around the world. The core services of SGS can be divided into four categories: inspection; testing; certification and verification.

This report has been prepared by SGS for public disclosure in its entirety, in conjunction with Interoil's Annual Statement of Reserves and Resources for the Oslo Stock Exchange. SGS has made every effort to ensure that the interpretations, conclusions and recommendations presented herein are accurate and reliable in accordance with good industry practice and its own quality management procedures. SGS does not, however, guarantee the correctness of any such interpretations, conclusions and recommendations. Barring any agreement to the contrary, all assignments and documents are performed and issued on the basis of the general conditions of SGS. The general conditions provide for a limitation of liability. SGS will not accept responsibility or liability for any loss, costs, damages or expenses incurred or sustained by any third party (parties or persons other than Interoil) resulting from any interpretation, conclusion or recommendation made by any of its officers, agents, employees or representatives. SGS makes no guarantee or prediction of results and makes no warranty, either express or implied, with respect to the actual reserves and resources available.

This report is based on data, methodology and interpretations provided by Interoil to SGS through November and December 2022. SGS has not independently verified any information provided by Interoil. Based on SGS' review, it is SGS' opinion that the overall procedures, methodologies and thoroughness used by Interoil in the reserves estimation process are appropriate and that a thorough approach has been followed, using methods considered sound in the determination of the reserves. The quality of the data relied upon and the depth and thoroughness of the reserves estimation process as well as the classification and categorization of the reserves by Interoil are appropriate.

Standard geological and engineering techniques accepted by the petroleum industry were used in estimating recoverable hydrocarbons. Several uncertainties associated to the estimation of oil and gas reserves exist, as subsurface accumulations of oil and gas cannot be measured in an exact manner. The techniques used rely on engineering and geo-scientific interpretation and judgment; hence the resources included in this evaluation are estimates only and should not be construed to be exact quantities. It should be recognized that such estimates of hydrocarbon resources may increase or decrease in future if there are changes to the technical interpretation, economic criteria, sales volumes or regulatory requirements. Property descriptions, details of interests held, well data, and commercial terms and conditions including fiscal, as obtained from Interoil or public sources, were accepted as represented.

Interoil acknowledges that the report reflects the facts as received by SGS at that time only and within the limits of the instructions received from Interoil. The scope of the report is limited and may not cover all areas which may potentially be interesting for the report's recipients and/or actual results. The report must always be presented in its entirety. This report shall not be reproduced, distributed, quoted or made available to any company, person, regulatory body, or organization without the complete contents of the report. References to and citations from the report are accompanied by the report in its entirety. Interoil warrants that the meaning of the text as intended by the author of the report is not distorted by the manner in which text is reproduced in citations or the manner in which the text is otherwise referenced.

Definitions of Reserves and contingent resources are based on SPE-PRMS-2018 guidelines and are presented in Exhibit-III. SGS has carried out a reserves- and resources audit with a strong assessment component. SGS did not assess the chance of commerciality or subclassified the contingent resources presented. SGS has performed an economic limit test to establish the cessation of production, for the purpose of determination of reserves.

SGS has not made any field examination of the property. As a result, SGS is not able to comment on the (appropriateness and conditions of) operations or facilities in place. Furthermore, SGS is not able to comment on health, safety and environmental aspects. No consideration was given in this report to potential environmental liabilities that may exist. No investigation was made into either the legal titles held or any operating agreements in place relating to the subject properties.

SGS is not obliged to update or amend the report to the factual developments or developments in the legislation, regulation or case law after the date of the report. SGS is not able to attest to property title or rights, or any required licenses and consents.

SGS is known for its independency and impartiality. In preparing this report, SGS has not been aware of any conflict of interest. The SGS Group nor any of its subsidiaries have any financial interests in Interoil or in any of its affiliates. This includes potential shares in Interoil. The remuneration of SGS has been compatible to the services provided, not contingent on the contents of the report. The report has been prepared by a well-experienced team. The qualifications of the technical person primarily responsible for the execution of this audit are provided below.

Niek Dousi was the primary technical- and commercial person and project manager for this project. He is a Senior Reservoir Engineer and holds an MSc in Petroleum Engineering from Delft University of Technology, The Netherlands, and has over 17 years of relevant professional experience. His key competences are classical reservoir engineering, Reserves evaluations, dynamic modeling, addressing commercial aspects and project management. He has taken part in numerous integrated field development studies, analyzing oil and gas assets in the North Sea, Continental Europe, North & West Africa, Oman and Russia, among others. Between 2008 and 2016 he has been part of asset valuation teams, evaluating various North Sea, Continental European and West African assets. Other activities involved participation in specialized subsurface studies, such as reserves certifications, using SEC&SPE-PRMS, UGS- and Geomechanics studies, both as a seasoned reservoir engineer and as project manager. Niek is also experienced in performing and supervising economic analyses. Between 2016 and 2021 he has managed more than eight (some annualy) large reserves certification studies on Dutch, Gabonese, East African- and Omani assets, among smaller reserves audits. He has worked on numerous oil- and gas assets worldwide, including tight gas, gas-condensates, heavy oil, fluvial-, stacked- and fractured carbonate reservoirs. Niek has participated in projects for majors small/midsized operators and non-operators. Recently in 2019, Niek was part of a special team to support a large middle eastern NOC in building a detailed country portfolio model comprising of assets with many multi billion barrels of in place oil volume. He is a longstanding member of the Society of Petroleum Engineers and has published several papers for the SPE and EAGE.

Niek Dousi

Project Manager

Primary technical- and commercial person

Richard Keen

Business Manager

Exhibit-I Overview of Reserves and Contingent resources

Statement of Remaining Hydrocarbon Volumes Mata Magallanes Oeste Concession, Argentina as of December 31, 2022

		GROSS (100%) FIELD VOLUMES		INTEROIL WORKING INTEREST		NET RESERVES TO INTEROIL WI	
		Crude Oil (Mstb)	Natural Gas (MMScf)	Crude Oil (Mstb)	Natural Gas (MMScf)	Crude Oil (Mstb)	Natural Gas (MMScf)
MATA MAGALLANES OESTE	PROVED						
	Developed	214	357	171	285	151	251
	Undeveloped	0	0	0	0	0	0
	Total 1P	**214**	**357**	**171**	**285**	**151**	**251**
	Total 2P	**761**	**3179**	**609**	**2543**	**536**	**2238**
	Total 3P	**1101**	**7264**	**881**	**5812**	**775**	**5114**

M: refers to thousands
MM: refers to millions

		GROSS (100%) FIELD VOLUMES		INTEROIL WORKING INTEREST		NET RESOURCES TO INTEROIL WI	
		Crude Oil (Mstb)	Natural Gas (MMScf)	Crude Oil (Mstb)	Natural Gas (MMScf)	Crude Oil (Mstb)	Natural Gas (MMScf)
MATA MAGALLANES OESTE	**Total 1C**	**542**	**914**	**434**	**731**	**382**	**643**
	Total 2C	**534**	**899**	**427**	**719**	**376**	**633**
	Total 3C	**696**	**1172**	**557**	**937**	**490**	**825**

M: refers to thousands
MM: refers to millions

Exhibit-II Detailed overview reserves and costs

InterOil Argentina

Net Revenue Interest Reserve Cash Flows Properties in Chubut, Argentina as of December 31, 2022 (MOD)

An analysis on post-tax cash flow was performed applying “unit of production” depreciation and tax losses, if applicable, were carried forward for a 5-year period. SGS acknowledges that the Argentinian tax law is rather complex and therefore it should be regarded as an uncertainty, mainly in the low case.

Mata Magallanes Oeste

Proved Developed Reserves								
	Production Forecast		Gas Sales	Gross Income	Oil Transport	Operating Expenses	Investment	Pre-Tax Cashflow
Year	Oil - Mstb	Gas - MMscf	MMscf	MUS$	MUS$	MUS$	MUS$	MUS$
2023	9	14	0	493	20	553	549	-630
2024	22	35	0	1106	49	591	640	-175
2025	25	42	0	1196	56	613	320	206
2026	24	41	0	1129	55	630	320	124
2027	28	47	0	1243	63	653	320	206
2028	23	40	0	1003	53	664	0	287
2029	20	34	0	838	45	676	0	117
2030	17	29	0	699	39	691	0	-32

M: refers to thousands
MM: refers to millions

Proved Reserves (1P)								
	Production Forecast		Gas Sales	Gross Income	Oil Transport	Operating Expenses	Investment	Pre-Tax Cashflow
Year	Oil - Mstb	Gas - MMscf	MMscf	MUS$	MUS$	MUS$	MUS$	MUS$
2023	9	14	0	493	20	553	549	-630
2024	22	35	0	1106	49	591	640	-175
2025	25	42	0	1196	56	613	320	206
2026	24	41	0	1129	55	630	320	124
2027	28	47	0	1243	63	653	320	206
2028	23	40	0	1003	53	664	0	287
2029	20	34	0	838	45	676	0	117
2030	17	29	0	699	39	691	0	-32

M: refers to thousands
MM: refers to millions

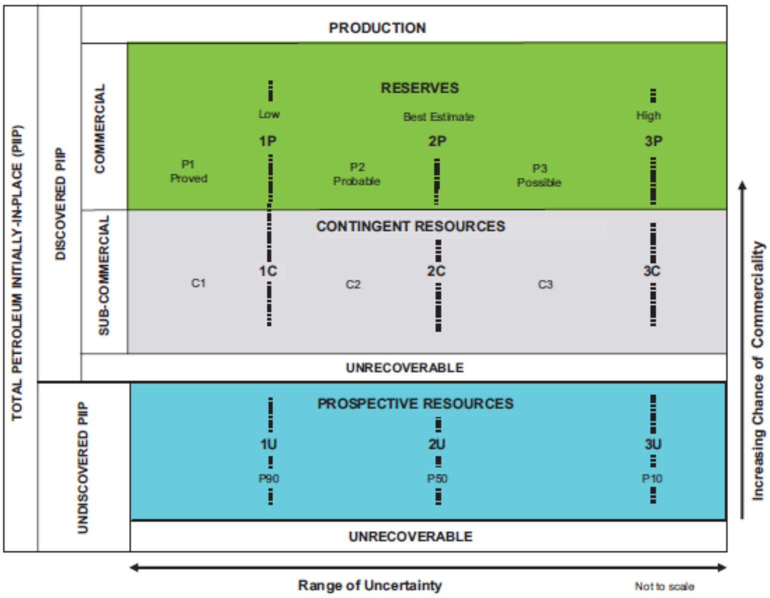
2P Reserves								
	Production Forecast		Gas Sales	Gross Income	Oil Transport	Operating Expenses	Investment	Pre-Tax Cashflow
Year	Oil - Mstb	Gas - MMscf	MMscf	MUS$	MUS$	MUS$	MUS$	MUS$
2023	22	294	0	1212	50	576	829	-244
2024	45	273	0	2269	101	631	640	897
2025	48	258	0	2309	108	653	640	908
2026	55	238	0	2573	126	684	640	1123
2027	65	221	0	2881	147	717	640	1377
2028	54	186	0	2340	123	717	0	1500
2029	46	156	0	1958	105	722	0	1131
2030	41	133	0	1643	93	732	0	819
2031	36	114	0	1490	81	743	0	666
2032	32	97	0	1352	72	756	0	524
2033	28	83	0	1227	63	771	0	393
2034	24	71	0	1113	56	787	0	271
2035	22	61	0	1011	49	804	0	157
2036	19	53	0	918	43	823	0	52
2037	17	45	0	822	38	842	0	-57

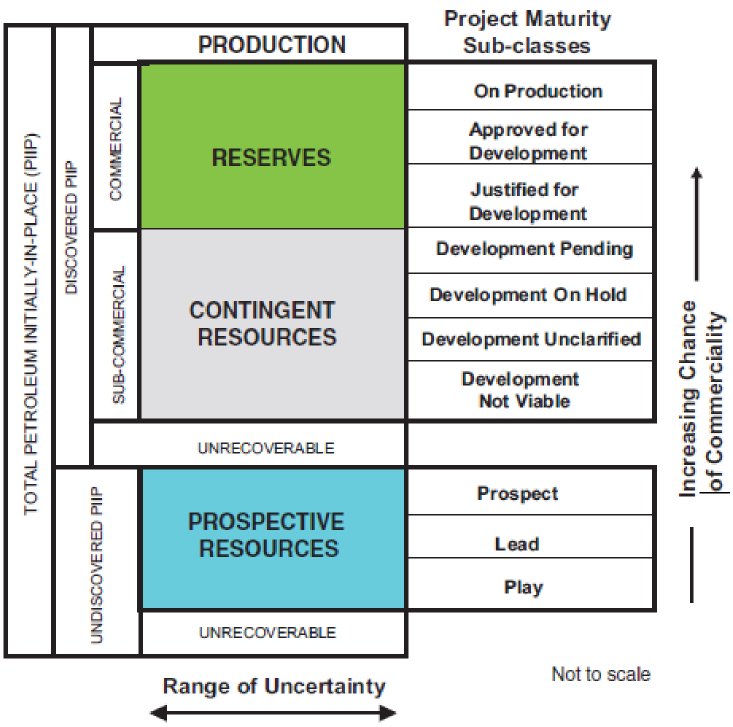
M: refers to thousands
MM: refers to millions

3P Reserves								
	Production Forecast		Gas Sales	Gross Income	Oil Transport	Operating Expenses	Investment	Pre-Tax Cashflow
Year	Oil - Mstb	Gas - MMscf	MMscf	MUS$	MUS$	MUS$	MUS$	MUS$
2023	31	790	0	1675	70	591	829	186
2024	63	681	0	3224	144	663	640	1777
2025	69	608	0	3335	157	690	640	1848
2026	80	538	0	3702	182	726	640	2155
2027	90	467	0	4006	204	761	640	2401
2028	75	390	0	3256	171	754	0	2331
2029	65	325	0	2731	147	754	0	1831
2030	57	275	0	2291	129	760	0	1402
2031	50	232	0	2076	113	768	0	1195
2032	44	196	0	1882	100	778	0	1005
2033	39	166	1	1707	88	790	0	829
2034	34	140	2	1548	77	803	0	667
2035	30	119	3	1404	68	819	0	517
2036	26	101	4	1274	60	836	0	378
2037	23	86	5	1140	52	853	0	234
2038	17	68	6	880	39	868	0	-27

M: refers to thousands
MM: refers to millions

Exhibit-III SPE-PRMS-2018 classification and guidelines





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.
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.

Class/Sub-Class	Definition	Guidelines
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.
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.

Class/Sub-Class	Definition	Guidelines
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.
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.

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.

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17th of February 2023

Reserves and Contingent Resources Statement for
La Brea concession, Argentina
as of December 31, 2022

Dear Mr. Carbone,

This reserves- and contingent resources statement has been prepared by SGS Nederland BV and issued on February 17th , 2023 at the request of InterOil Argentina (InterOil or "the Client"), operator of and a variable interest participant in the La Brea concession of the Noroeste Basin at the Jujuy province in Argentina (Figure 1). This report is intended for use in conjunction with the preparation of InterOil's Annual Statement of Reserves and Resources for the Oslo Stock Exchange.
The report must be considered in its entirety and must only be used for the purpose for which it was intended. The scope of work was restricted to the contents of the project proposal and should be considered as such.
SGS has conducted an independent reserves audit, as of December 31, 2022, of the crude oil and natural gas volumes expected to be produced in the La Brea concession. On the basis of technical and commercial information made available to SGS concerning these properties, SGS herewith presents a detailed outline of the developments, production- and costs profiles, as well as fiscal assumptions. In addition, a statement by SGS is provided on the estimated reserves and contingent resources, in accordance with SPE-PRMS-2018 guidelines.

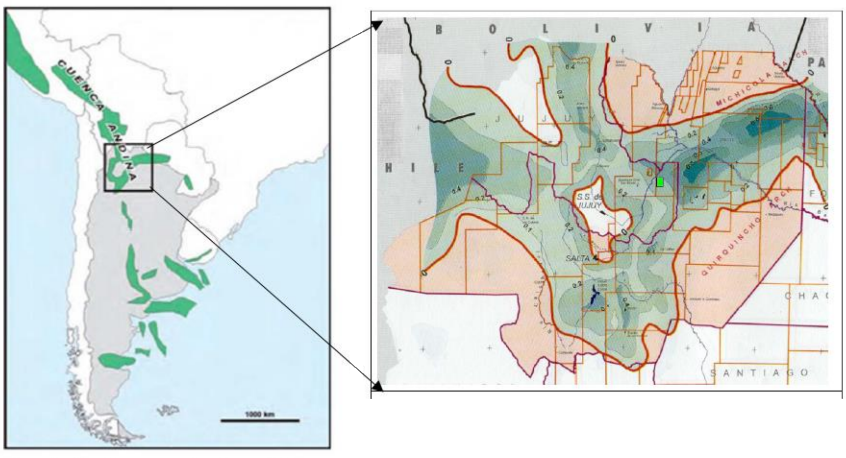


Figure 1 Location map - All concessions

Legal overview of assets

Introduction

The asset reviewed for this audit belongs to Interoil Argentina under a “Concesión de Explotación” subject to the Argentinian Law of Hydrocarbons, Law 17.319, from 1967. InterOil Argentina has a participation of 15 % in this asset and is responsible for the field operations.
With the latest changes to the Hydrocarbon Law, by Law 27.007, the different Provinces in Argentina became the owners of the hydrocarbon resources under their land and they are responsible for issuing the area permits and concessions.
Under the above mentioned law, companies are entitled to ask for a “Permiso de Exploración” in an area with no reserves, which if declared commercial, it gives the permit holder the right to ask for a “Concesión de Explotación” for 25 years plus 10 year successive extensions, in the case of conventional reservoirs.
In case an area is reverted to the Province by a previous holder and having production or reserves, an interested company can directly ask for a “Concesión de Explotación”.
Royalties by law can vary between 5% and 12% of the oil and gas production and since Law 27.007 was passed, the Provinces are also retaining a 3% to 6% extra right to exploit the areas under their territories so total royalties can amount upto 18%.

Equity specifications

The asset under this audit, La Brea is subject to a 12% royalty both for oil and gas, payable to Jujuy Province. Interoil holds a 15% working interest and the remainder 85% belongs to ATM Oil&Gas (80%) and JEMSE (5%).
La Brea is under a “Concesión de Explotación” which expires in 2042.

License aspects

La Brea was awarded to Interoil in 2017. The company acquired the right to exploit the asset for a 25-year period, with a possible 10-year extension.
As part of this commitment, Interoil presented a development plan including the drilling of new wells and the reactivation of many of wells in the field.

Geological overview of the assets

La Brea Field (Figure 1Figure 1 Location map - All concessions) is located near Caimancito (one of the most prolific oil fields in the Noroeste basin) eastern of Calilegua hills, in sub-Andean foothill, at the Jujuy province, Argentina. The main reservoir is composed by fractured dolomites and limestones of the Yacoraite Formation with an average porosity of 6-8 % and permeability from 0.1 mD to 8.1 mD and some values up to 250 mD.
The fractures observed in the Caimancito borehole images and dip-meter are high dipping angle with three different main trends: E-W and NW-SE (Type I) interpreted as open and N-S (Type II) as closed. The sets fracture intersections produce rectangular blocks varying in size according to the lithology and stratigraphy. The fractures tend to be in carbonates rather than in siliciclastic. The fracture intensity increases as the bed thinning.
The trends of the reverse faults are N-S parallel to the Andean hills and the normal faults are E-W trend.

The so-called Noroeste Basin is made up of two basins, the Paleozoic Basin of Tarija, in the extreme North of Argentina and South of Bolivia, and the Cretaceous Basin, immediately south of the Tarija Basin with the Michicola Arch dividing the two basins (Figure 1).

The stratigraphic column in the Noroeste Basin (Figure 2) shows the main producing formations in the area

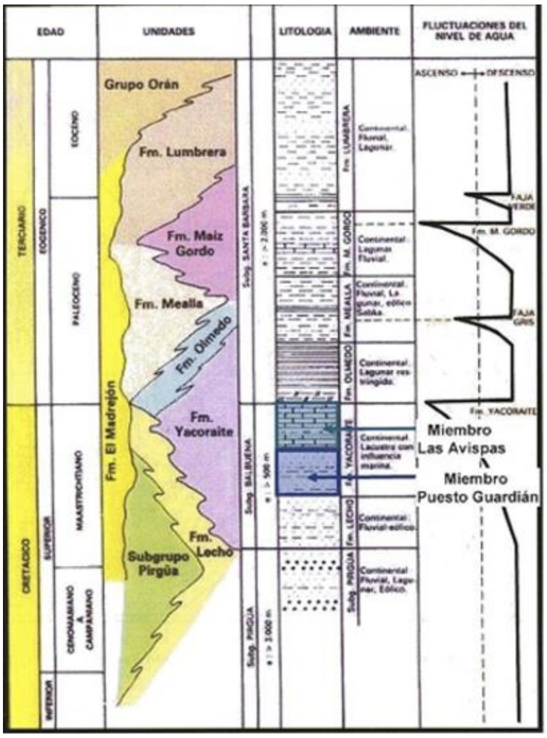


Figure 2 Stratigraphic column in the Noroeste Basin

The productive unit is the Fm. Yacoraite, which is divided into two Members: Las Avispas and Post Guardian.

In La Brea concession, the traps are made up of two anticlines called La Brea Este and El Oculto. Both prospects were defined based on seismic interpretations and supported by the control of the concession wells (Figure 3).

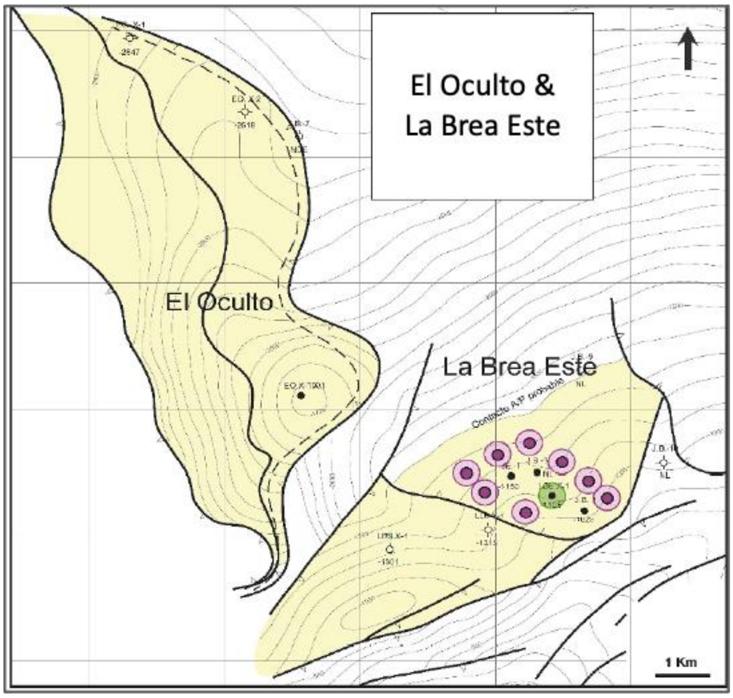


Figure 3 Map showing the La Brea main accumulations

Development plan

Interoil´s plan for rehabilitating and putting into production the La Brea field, comprises of hydraulically fracturing the YPF.Jj.LBEx-1 well and the drilling and fracturing of 8 wells in the La Brea Este accumulation.
Currently, the company has no firm plan to perform these activities and correspondingly no re-development schedule has been presented to the auditor.
A pilot test should be performed to demonstrate economic rates after stimulation, prior to potential re-classification to reserves. SGS has classified these resources as "Development Unclarified."

These activities will be preceded by the acquisition of 3D seismic with the objective of achieving a better structural and stratigraphic description of the deposit. The 8 wells locations will be better defined after processing this seismic.

Several wells have been drilled in the past in El Oculto accumulation, found some non-commercial hydrocarbons volumes and that area remains as a resource area yet to be fully explored. Volumes associated to El Oculto have been estimated and are considered as Contingent Resources and subclassified as Development Not Viable.

Reserves and contingent resources statement

Since the company has no firm plans at the moment to move forward with the development of the field, no reserves have been assigned to La Brea concession and only contingent resources for La Brea Este and El Oculto have been considered.

On the basis of technical and commercial information made available to SGS concerning these assets, SGS provides the contingent resources statement (Table 1) as per 31-Dec-2022:

Table 1 – Contingent resources statement - summary

CONTINGENT RESOURCES		GROSS (100%) FIELD VOLUMES Crude Oil (MMstb)	INTEROIL WORKING INTEREST Crude Oil (MMstb)	NET RESOURCES TO INTEROIL WI Crude Oil (MMstb)
LA BREA	Total 1C	5.039	0.756	0.665
	Total 2C	8.502	1.275	1.122
	Total 3C	13.598	2.040	1.795

CONTINGENT RESOURCES		GROSS (100%) FIELD VOLUMES Gas (Bscf)	INTEROIL WORKING INTEREST Gas (Bscf)	NET RESOURCES TO INTEROIL WI Gas (Bscf)
LA BREA	Total 1C	7.073	1.061	0.934
	Total 2C	11.933	1.790	1.575
	Total 3C	19.086	2.863	2.519

Hydrocarbon liquid volumes represent crude oil estimated to be recovered during field separation and are reported in millions of stock tank barrels (MMstb). Natural gas volumes are reported in billion standard cubic feet (Bscf) at standard condition of 14.7 psia and 60°F.

Contingent Resources

Contingent resources, categories 2C and 3C, have been estimated based on probabilistic volumetric analyses. The area of the wells located at La Brea Este and El Oculto has been proven hydrocarbon bearing. The seismic- and well log information define a structure closure and contact limit, as well as oil presence.
Contingent resources in the 1C category correspond to the hydraulic fracturing of the YPF.Jj.LBEx-1 well, and should be considered as "Development Unclarified", as more data acquisition is required to reduce the range of uncertainty in STOIIP, well productivity and recovery efficiency.

Operator’s reserve estimate

SGS has not found any substantial difference with the operator´s view in any of the assets mentioned above. Differences may refer to subjective considerations such as decline curve coefficients and are not material.

Commercial considerations

No commercial analysis has been performed on the contingent resources.

Historic development overview

La Brea Este Field lies on an area of 15,821 sqkm and is located at the south-east corner of the La Brea concession and east of the El Oculto fault block, in a structure limited by faults (Figure 3).

Seven wells have been drilled in the La Brea Este area and only 4 wells were productive with cumulative productions ranging from 2,000 to 75,000 barrels of oil. Information taken from wells YPF.Jj.LBE.-1, YPF.Jj.JB.-3 and YPF.Jj.JB.-1 was used to estimate the parameters as input for the volumetric resource estimation.

The area is currently shut-in and has not produced since 2013.

Basis of opinion

SGS is the world’s leading inspection, verification, testing and certification company. SGS is recognized as the global benchmark for quality and integrity. With more than 89,000 employees, SGS operates a network of more than 2,600 offices and laboratories around the world. The core services of SGS can be divided into four categories: inspection; testing; certification and verification.

This report has been prepared by SGS for public disclosure in its entirety, in conjunction with Interoil’s Annual Statement of Reserves and Resources for the Oslo Stock Exchange. SGS has made every effort to ensure that the interpretations, conclusions and recommendations presented herein are accurate and reliable in accordance with good industry practice and its own quality management procedures. SGS does not, however, guarantee the correctness of any such interpretations, conclusions and recommendations. Barring any agreement to the contrary, all assignments and documents are performed and issued on the basis of the general conditions of SGS. The general conditions provide for a limitation of liability. SGS will not accept responsibility or liability for any loss, costs, damages or expenses incurred or sustained by any third party (parties or persons other than Interoil) resulting from any interpretation, conclusion or recommendation made by any of its officers, agents, employees or representatives. SGS makes no guarantee or prediction of results and makes no warranty, either express or implied, with respect to the actual reserves and resources available.

This report is based on data, methodology and interpretations provided by Interoil to SGS through November and December 2022. SGS has not independently verified any information provided by Interoil. Based on SGS’ review, it is SGS’ opinion that the overall procedures, methodologies and thoroughness used by Interoil in the reserves estimation process are appropriate and that a thorough approach has been followed, using methods considered sound in the determination of the reserves. The quality of the data relied upon and the depth and thoroughness of the reserves estimation process as well as the classification and categorization of the reserves by Interoil are appropriate.

Standard geological and engineering techniques accepted by the petroleum industry were used in estimating recoverable hydrocarbons. Several uncertainties associated to the estimation of oil and gas reserves exist, as subsurface accumulations of oil and gas cannot be measured in an exact manner. The techniques used rely on engineering and geo-scientific interpretation and judgment; hence the resources included in this evaluation are estimates only and should not be construed to be exact quantities. It should be recognized that such estimates of hydrocarbon resources may increase or decrease in future if there are changes to the technical interpretation, economic criteria, sales volumes or regulatory requirements. Property descriptions, details of interests held, well data, and commercial terms and conditions including fiscal, as obtained from Interoil or public sources, were accepted as represented.

Interoil acknowledges that the report reflects the facts as received by SGS at that time only and within the limits of the instructions received from Interoil. The scope of the report is limited and may not cover all areas which may potentially be interesting for the report's recipients and/or actual results. The report must always be presented in its entirety. This report shall not be reproduced, distributed, quoted or made available to any company, person, regulatory body, or organization without the complete contents of the report. References to and citations from the report are accompanied by the report in its entirety. Interoil warrants that the meaning of the text as intended by the author of the report is not distorted by the manner in which text is reproduced in citations or the manner in which the text is otherwise referenced.

Definitions of Reserves and contingent resources are based on SPE-PRMS-2018 guidelines and are presented in Exhibit-III. SGS has carried out a contingent resources audit with a strong assessment component. SGS did not assess the chance of commerciality for the contingent resources presented. SGS has not performed an economic limit test to establish the cessation of production, for the purpose of determination of reserves.

SGS has not made any field examination of the property. As a result, SGS is not able to comment on the (appropriateness and conditions of) operations or facilities in place. Furthermore, SGS is not able to comment on health, safety and environmental aspects. No consideration was given in this report to potential environmental liabilities that may exist. No investigation was made into either the legal titles held or any operating agreements in place relating to the subject properties.

SGS is not obliged to update or amend the report to the factual developments or developments in the legislation, regulation or case law after the date of the report. SGS is not able to attest to property title or rights, or any required licenses and consents.

SGS is known for its independency and impartiality. In preparing this report, SGS has not been aware of any conflict of interest. The SGS Group nor any of its subsidiaries have any financial interests in Interoil or in any of its affiliates. This includes potential shares in Interoil. The remuneration of SGS has been compatible to the services provided, not contingent on the contents of the report. The report has been prepared by a well-experienced team. The qualifications of the technical person primarily responsible for the execution of this audit are provided below.

Niek Dousi was the primary technical- and commercial person and project manager for this project. He is a Senior Reservoir Engineer and holds an MSc in Petroleum Engineering from Delft University of Technology, The Netherlands, and has over 17 years of relevant professional experience. His key competences are classical reservoir engineering, Reserves evaluations, dynamic modeling, addressing commercial aspects and project management. He has taken part in numerous integrated field development studies, analyzing oil and gas assets in the North Sea, Continental Europe, North & West Africa, Oman and Russia, among others. Between 2008 and 2016 he has been part of asset valuation teams, evaluating various North Sea, Continental European and West African assets. Other activities involved participation in specialized subsurface studies, such as reserves certifications, using SEC&SPE-PRMS, UGS- and Geomechanics studies, both as a seasoned reservoir engineer and as project manager. Niek is also experienced in performing and supervising economic analyses. Between 2016 and 2020 he has managed more than six large (partially annually) reserves certification studies on Dutch, Gabonese, East African- and Omani assets, among smaller reserves audits. He has worked on numerous oil- and gas assets worldwide, including tight gas, gas-condensates, heavy oil, fluvial-, stacked- and fractured carbonate reservoirs. Niek has participated in projects for majors small/midsized operators and non-operators. Recently in 2019, Niek was part of a special team to support a large middle eastern NOC in building a detailed country portfolio model comprising of assets with many multi billion barrels of in place oil volume. He is a longstanding member of the Society of Petroleum Engineers and has published several papers for the SPE and EAGE.

Niek Dousi

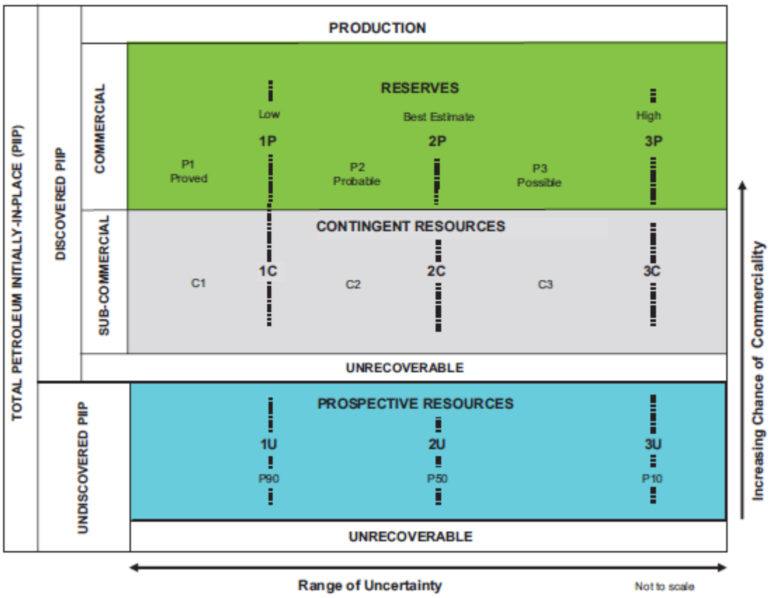
Richard Keen

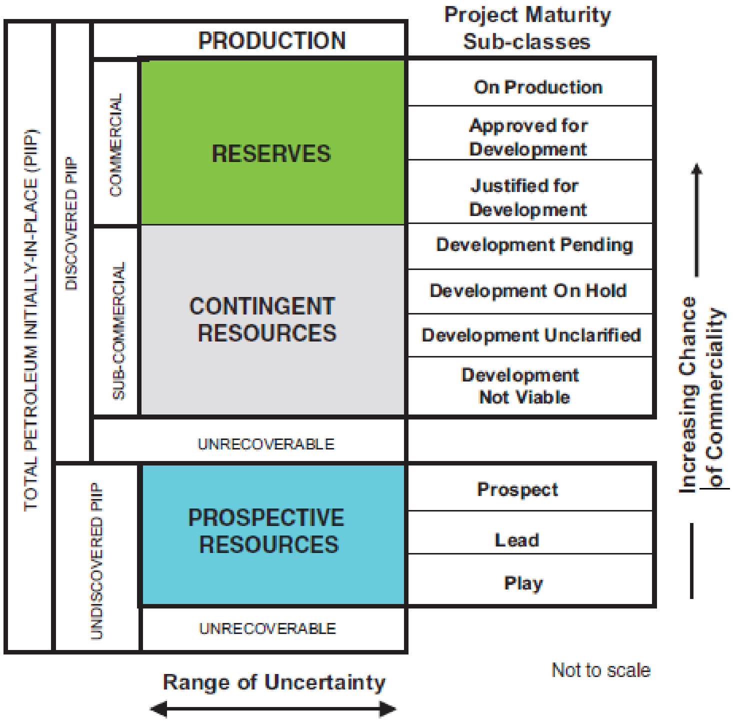
Project Manager

Business Manager

Primary technical- and
commercial person

Exhibit-I SPE-PRMS-2018 classification and guidelines





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.
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.

Class/Sub-Class	Definition	Guidelines
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.
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.

Class/Sub-Class	Definition	Guidelines
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.
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.

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.

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The Netherlands

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Chief Executive Officer
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Ciudad Autónoma de Buenos Aires, Argentina
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17th of February, 2023

Reserves and Contingent Resources Statement for
Santa Cruz Assets (Campo Bremen, Chorrllos, Moy Aike, Oceano
and Palermo Aike concessions) in Argentina
as of December 31, 2022

Dear Mr. Carbone,

This reserves- and contingent resources statement has been prepared by SGS Nederland BV and issued on February 17th, 2023 at the request of InterOil Argentina (InterOil or ³the Client´), operator of and a variable interest participant in the Campo Bremen, Chorrillos, Moy Aike, Oceano and Palermo Aike concessions of the Austral Basin at the Santa Cruz province in Argentina. This report is intended for use in conjunction with the preparation of InterOil's Annual Statement of Reserves and Resources for the Oslo Stock Exchange.
The report must be considered in its entirety and must only be used for the purpose for which it was intended. The scope of work was restricted to the contents of the project proposal and should be considered as such.
SGS has conducted an independent reserves audit, as of December 31, 2022, of the crude oil and natural gas volumes expected to be produced in the Campo Bremen, Chorrillos, Moy Aike, Oceano and Palermo Aike concessions. On the basis of technical and commercial information made available to SGS concerning these properties, SGS herewith presents a detailed outline of the developments, production- and costs profiles, as well as fiscal assumptions. In addition, a statement by SGS is provided on the estimated reserves and contingent resources, in accordance with SPE-PRMS-2018 guidelines.

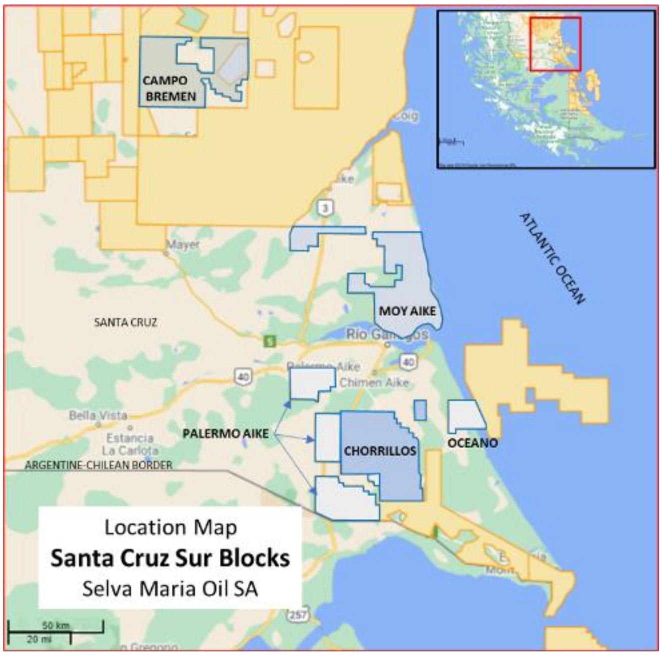


Figure 1 Location map - All concessions

Legal overview of assets

Introduction

The assets reviewed for this audit are operated by InterOil Argentina under a "Concesión de Explotación" and the concession is subject to the Argentinian Law of Hydrocarbons, Law 17.319, from 1967. InterOil Argentina has a participation of 8,34 % in these assets and is responsible for the field operations.
With the latest changes to the Hydrocarbon Law, by Law 27.007, the different Provinces in Argentina became the owners of the hydrocarbon resources under their land and they are responsible for issuing the area permits and concessions.
Under the above mentioned law, companies are entitled to ask for a "Permiso de Exploración" in an area with no reserves, which if declared commercial, it gives the permit holder the right to ask for a "Concesión de Explotación" for 25 years plus 10 year successive extensions, in the case of conventional reservoirs.
In case an area is reverted to the Province by a previous holder and having production or reserves, an interested company can directly ask for a "Concesión de Explotación".
Royalties by law can vary between 5% and 12% of the oil and gas production and since Law 27.007 was passed, the Provinces are also retaining a 3% to 6% extra right to exploit the areas under their territories so total royalties can amount up to 18%.

Equity specifications

The assets under this audit are subject to the following general terms and conditions (Table 1):

Table 1 Santa Cruz concessions

Area	Working Interest (%)	Royalty Oil (%)	Royalty Gas (%)	Contract Expiry Date
Palermo Aike	8,34	15	15	16/Aug/26
Campo Bremen	8,34	15	15	18/Apr/26
Chorrillos	8,34	15	15	18/Apr/26
Moy Aike	8,34	15	15	18/Apr/26
Oceano	8,34	15	15	16/Aug/26

License aspects

The above-mentioned assets were acquired by Interoil at the end of 2019 and taken over from a national company called ROCH. The five assets are part of independent concessions, and each concession has its own independent expiry date.
The company has performed an extensive review on the existing wells (shut-in and in production) and has identified those wells in conditions to be put back in production. Technical work on the G&G aspects is still being performed that will eventually result in an integral field development plan for these assets.
Once the license expires during 2026 for the different assets, Interoil will be entitled to ask for a 10 year extension period and will have to present a robust development plan to obtain formal approval from the Province of Santa Cruz.

Geological overview of the assets

Interoil's assets, in Argentina Santa Cruz Sur, called Chorrillos, Moy Aike, Océano, Campo Bremen and Palermo Aike are located in the Austral basin, in southernmost Argentine Patagonia.
All named assets are located on the onshore of the Austral basin in the province of Santa Cruz, Argentina (Figure 1). The stratigraphic column of shallow marine to Littoral origin sediments of Lower Cretaceous-Tertiary age, lies on a technical basement of volcanic origin rocks of Upper Jurassic age (Tobifera Serie) that acts as a reservoir in several fields of the Interoil blocks (Figure 2).

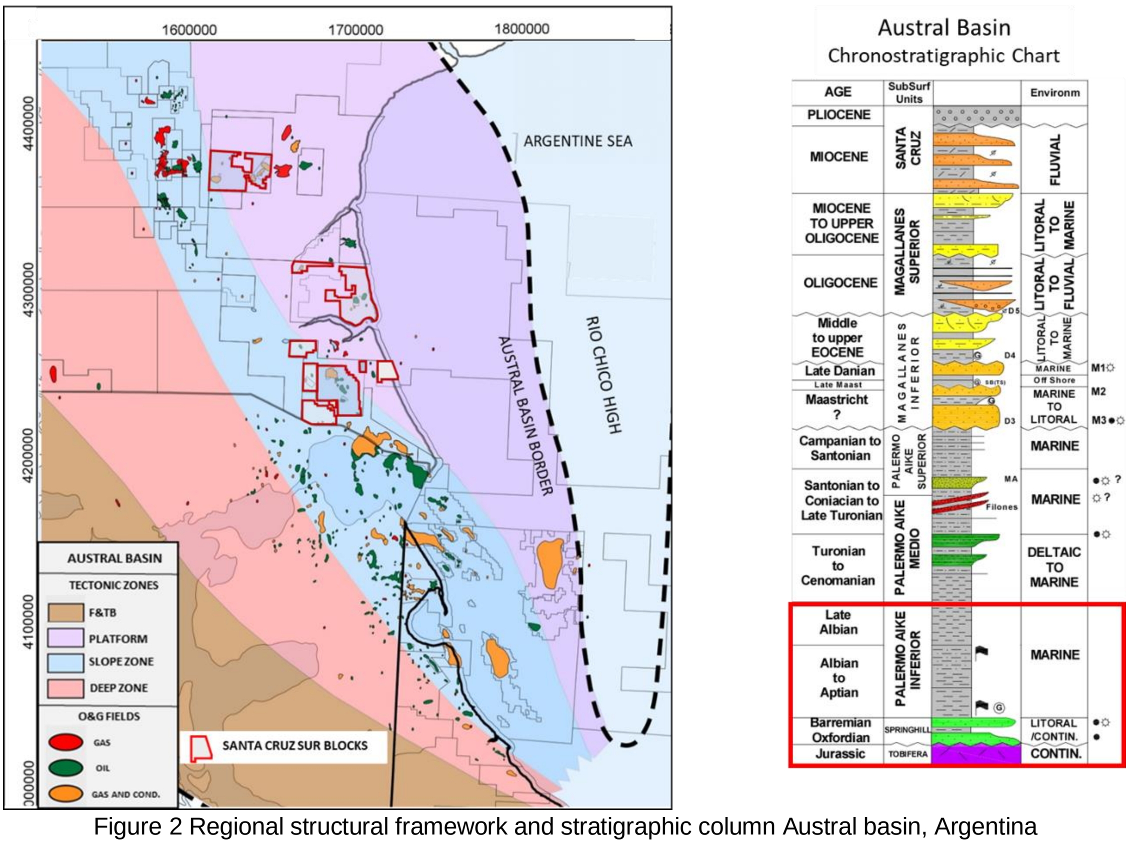


Figure 2 Regional structural framework and stratigraphic column Austral basin, Argentina

Santa Cruz Sur blocks are located on the platform and slope zones of a Foreland type basin with the Folded and Trusted Belt to the west (Figure 2). The regional structural style is extensional, and the traps of the Santa Cruz Sur blocks are mostly combined with a main structural component. In general, the structures are the result of the faulting of the basement with the consequent deformation of the overlying sedimentary coverage, giving rise to faulted anticlines and 4WC anticlines (Figure 3). Marine shales and marls of the overlying Palermo Aike Fm. are the regional seal rock of the traps of the Santa Cruz Sur fields (Figure 2).

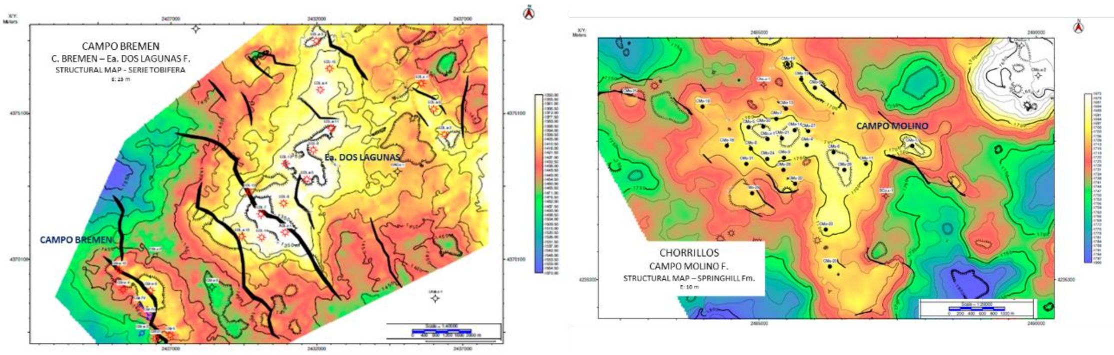


Figure 3 Examples of Structural Trap types in Campo Bremen and Chorrillos Concessions

The Fm. Springhill and the Tobífera Series are the main reservoirs of the Santa Cruz Sur oil and gas fields. The Serie Tobifera is composed of volcanic and subvolcanic rocks. The Fm. Springhill, the most important and prolific reservoir in the basin, is the product of the Cretaceous marine transgression that covers the Serie Tobífera (Figure 2**Error! Reference source not found.**), depositing mixed, littoral and shallow marine sandstones. It is characteristic in this region the development of the named "bold high" where the Fm. Springhill is wedged against the heights of the Serie Tobifera giving rise to accumulations of two reservoirs with partially interconnected porous systems that add complexity and geological risk to the development of the fields. The petrophysical properties of the sandstones of the Fm. Springhill presents average porosities from 20 to 23% and variable permeabilities from 1 to 100 md. The Serie Tobifera presents average porosities of 17-18% and permeabilities of 0.1-1 md. The Tobifera Series is a producer of free gas and gas and condensate, and the Springhill Fm produces free gas, gas and condensate and black oil of 35° API average.

Development plans

InterOil Argentina still needs to define their development plans in terms of drilling and workover activities for each of the above-mentioned assets.

The company´s 2023 activities plan includes an investment of 2,712 MUS$ to continue the works for the installation of a mercury removing facility for which a technical study, as well as a costing overview, was presented to the auditor in 2022. This plant will allow a considerable reduction in the mercury content of the produced oil impacting favourably in the oil sale price and marketability.
The investment also comprises of additional power generation and compression upgrades. This revamping- and expansion project is ongoing, which will lead to a substantial increase in the amount of oil and gas that can be processed in the facilities. The project has already started in 2022 and is planned to be completed in 2023.
As part of the total investment for 2023, an amount of 250 MUS$, out of the 2,712 MUS$, will be allocated to build new pipelines.
In April 2022, the compressor was successfully upgraded, which will allow an increase in the gas production.
The company successfully installed all three additional power generation units on schedule in the respective fields over August 2022, with the unit installed in the larger Cerro Molino Oeste field commissioned and available to support existing and future production levels.

Some other minor investment amounts were considered for well interventions, if necessary, aimed to put back in production 30 temporarily closed-in wells.

Contingent Resources

No contingent resources other than uneconomic volumes and developed production beyond license expiry date were considered for these assets since no activity (new drilling and/or workover) is planned at this point by the operator. Once an integral study has been finalised, activities arising from this plan will be subject to a technical and commercial assessment and resources will be allocated, if justified.

Resources estimation for this audit results from the developed producing volumes estimated after the economic limit, and considering a 10 year extension period, regardless of any assumptions on commerciality.

Reserves and contingent resources statement

On the basis of technical and commercial information made available to SGS concerning these assets, SGS hereby provides the reserves statement as per 31-Dec-2022 (Table 2):

Table 2 Reserves statement – Santa Cruz assets

		GROSS (100%) FIELD VOLUMES		INTEROIL WORKING INTEREST		NET RESERVES TO INTEROIL WI	
		Crude Oil (Mstb)	Natural Gas (BScf)	Crude Oil (Mstb)	Natural Gas (BScf)	Crude Oil (Mstb)	Natural Gas (BScf)
SANTA CRUZ ASSETS	PROVED						
	Developed	211	6.55	18	0.55	15	0.46
	Developed NP	45	1.52	4	0.13	3	0.11
	Undeveloped	0	0.00	0	0.00	0	0.00
	Total 1P	**256**	**8.07**	**21**	**0.67**	**18**	**0.57**
	Total 2P	**286**	**9.12**	**24**	**0.76**	**20**	**0.65**
	Total 3P	**436**	**14.38**	**36**	**1.20**	**31**	**1.02**

M: refers to thousands
MM: refers to millions
B: refers to billions

Hydrocarbon liquid volumes represent crude oil estimated to be recovered during field separation and are reported in thousands of stock tank barrels (Mstb). Natural gas volumes are reported in billion standard cubic feet (Bscf) at standard condition of 14.7 psia and 60°F. Net interest gas reserves represent expected gas sales and fuel usage in the field (with percentage of gas consumption variable amongst the assets). 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 Exhibit-I.
Gas reserves sales volumes are based on firm 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.

"Developed Producing reserves" were estimated by extrapolating the present production by decline curve analysis. Solution gas reserves were estimated through extrapolation of the producing gas-oil ratios. The resulting volumes were reduced for consumption (Table 3) in own operations (CiO).

Table 3 Yearly Gas Consumed in Operations

	Gas Consumed in Operations (MMscf) - Gross 100%		
Year	**1P**	**2P**	**3P**
2023	351	415	440
2024	299	406	451
2025	270	352	403
2026	242	308	363

The extrapolation of the production beyond economic limit and for a 10 year extension period has been classified as Contingent Resources, regardless of assumptions on commerciality (Table 4).

Table 4 Gross Contingent Resources statement - per concession

Field	OIL - Development Not Viable (Mstb)		
	1C	2C	3C
Campo Bremen	30	57	64
Chorrillos	311	428	469
Moy Aike	108	161	182
Oceano	20	28	44
Palermo Aike	0	0	0
Total	**469**	**674**	**759**

Field	GAS - Development Not Viable (Bscf)		
	1C	2C	3C
Campo Bremen	4.1	4.7	4.5
Chorrillos	9.5	14.0	15.7
Moy Aike	0.2	0.3	0.3
Oceano	4.2	5.2	6.3
Palermo Aike	0.0	0.0	0.0
Total	**18.0**	**24.2**	**26.8**

Hydrocarbon liquid volumes represent crude oil estimated to be recovered during field separation and are reported in million-barrel increments (MMstb). Natural gas volumes are reported in billion standard cubic feet (Bscf) at standard condition of 14.7 psia and 60°F.
Volumes reported as Contingent Resources represent gross (100% working interest) volumes without royalty or gas consumption deductions.

Inter-annual comparison

Table 5 shows the main reasons for reserves change between year-end 2021 and year-end 2022 (gross volumes):

Table 5 - Reserves evolution year-end 2021-2022

RESERVES DEVELOPMENT (GROSS 100% VOLUME)				
	Crude Oil (Mstb)		**Gas (MMscf)**	
	1P	**2P**	**1P**	**2P**
Balance (as of year and last full year)	371	397	7.11	7.26
Production 2022	138		3.67	
Acquisitions / Disposals				
Extensions / Discoveries				
New Developments				
Revisions of previous estimates	23	27	4.63	5.53
Balance (as of 31-Dec-2022)	**256**	**286**	**8.07**	**9.12**

M: refers to thousands
MM: refers to millions

The increase in "Revisions of previous estimates" for gas is explained as a result of the well-by-well review performed by Interoil Argentina that ended up with the proposed intervention of new gas wells, mainly in Campo Bremen and Chorrillos assets. As a result of the increase in compression potential due to the planned investments, more wells will be able to produce extra gas due to this compression throughput capacity increase, with similar suction pressures.

There are no significant changes in the oil reserves since the wells have been producing in the line of the estimated forecasts.

Operator's reserve estimate

SGS has not found any substantial difference with the operator´s view in any of the assets mentioned above. Differences may refer to subjective considerations such as decline curve coefficients and are not material.

Commercial considerations

Although the auditor commonly applies the (Intercontinental Exchange) Brent crude forward curve forecast for its estimations, oil prices in Argentina are subject to local market conditions, with only 3 main refining companies that drive the prices in each region of the country. During 2022, oil prices for the South of Argentina have remained between 50 and 60 US$/bbl, depending on the oil composition and geographic area of production. Hence, oil price forecast has been adjusted, in the case of these Santa Cruz assets, to reflect this condition.

An oil price of 58,43 US$/bbl, as a result of different crudes being produced from the different fields, is established as a current reference level. The evolution of this oil price is then tied to the Brent forecast estimated for this exercise.

Table 6 states the oil price and Brent forecast used for this estimation over a 10-year period.

The gas price assumed is based on long term agreements, commitments for gas delivery of the Province of Santa Cruz and market spot price.

Table 6 Oil and gas price forecast (MOD) 2023-2026

Year	Oil Price US$/bbl	Brent Price US$/bbl	Gas Price US$/MMBtu
2023	58,43	78,43	3,99
2024	54,55	74,55	4,02
2025	51,89	71,89	4,07
2026	49,79	69,79	4,11

2023 budget costs, as presented by the operator, have been reviewed to predict future expenses for each of the fields. According to the analysis of these expenses, provided by the operator and reviewed by SGS, the following annual costs and variable expenses, as in Table 7 have been applied for the economic evaluation:

Table 7 Overview cost aspects

Expense	2023
G&A Fixed Costs - MUS$	2566
Fixed Opex, incl salaries - MUS$	9888
Variable Opex - US$/boe	3,55
Transp, Treatment, Storage - US$/bbl	5,03

The abandonment cost of a well was provided by InterOil and is considered to be 100 kUS$ (RT22).

Field costs, as per the above table, are escalated by 3% on a yearly basis considering the current scenario in Argentina.

An income tax over net benefit of 30% applies to activities in Argentina.

Historic development overview of individual fields

InterOil Argentina started its operation in Austral Basin at the end of 2019. Currently, they have five concessions: Campo Bremen, Chorrillos, Moy Aike, Océano and Palermo Aike.
The current production for these five blocks is approximately 464 bopd and 11,600 Mscf/d of gas as of November 30, 2022.
340 wells were drilled in total and 43 of them are on production or injection today. The cumulative oil production is 23 MMbbl and 387 Bscf of gas have been produced. The main target formations are Serie Tobífera and Formación Springhill.

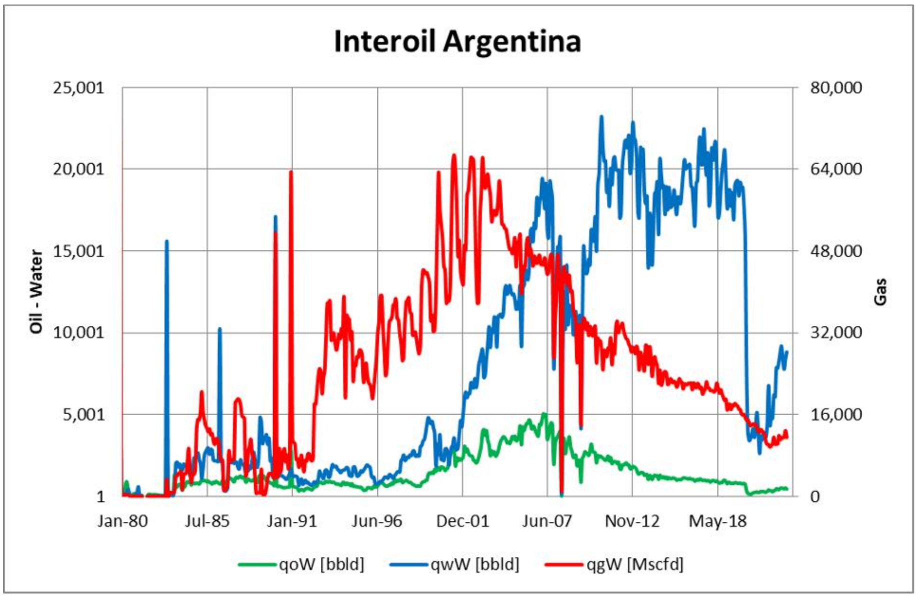


Figure 4 Historical Production – Santa Cruz assets

Figure 5 shows the wells drilled by in these assets by the former operator in the last six years.

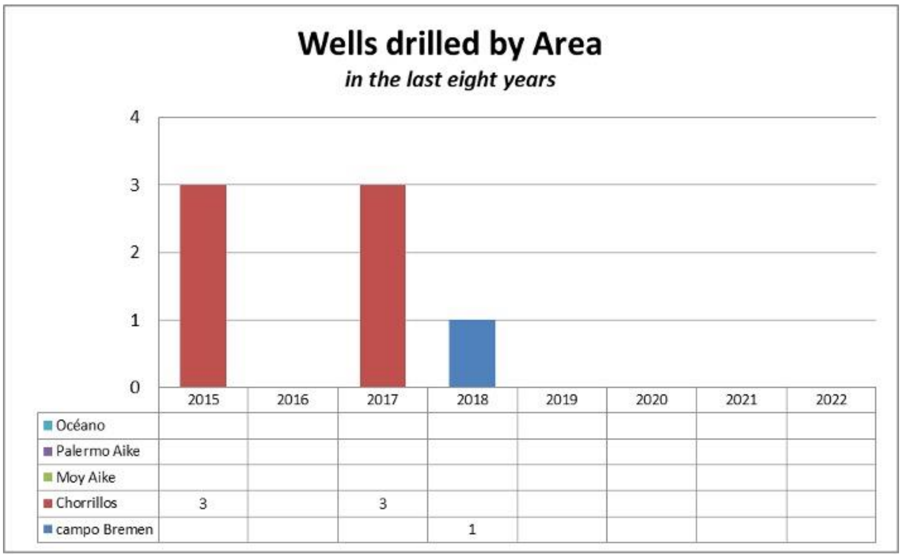


Figure 5 Wells drilled in Santa Cruz assets in the last eight years

Campo Bremen concession

Campo Bremen is located in the Santa Cruz province Northwest of Rio Gallego city. It includes the following 5 fields;

- Campo Bremen
- Estancia Dos Lagunas
- Filomena
- Laguna El Palo
- Nortero Noreste

The wells in these fields produce mainly gas and condensate from the Springhill Formation and Serie Tobifera, being Serie Tobifera the main gas reservoir. The average depth of the wells is 6,900 feet and the primary production mechanisms are gas expansion and water drive. Current condensate production is 55 bbl/d and 3,000 Mscf/d of gas. 53 wells were drilled in the concession, and only 10 of them are flowing as of November 2022.

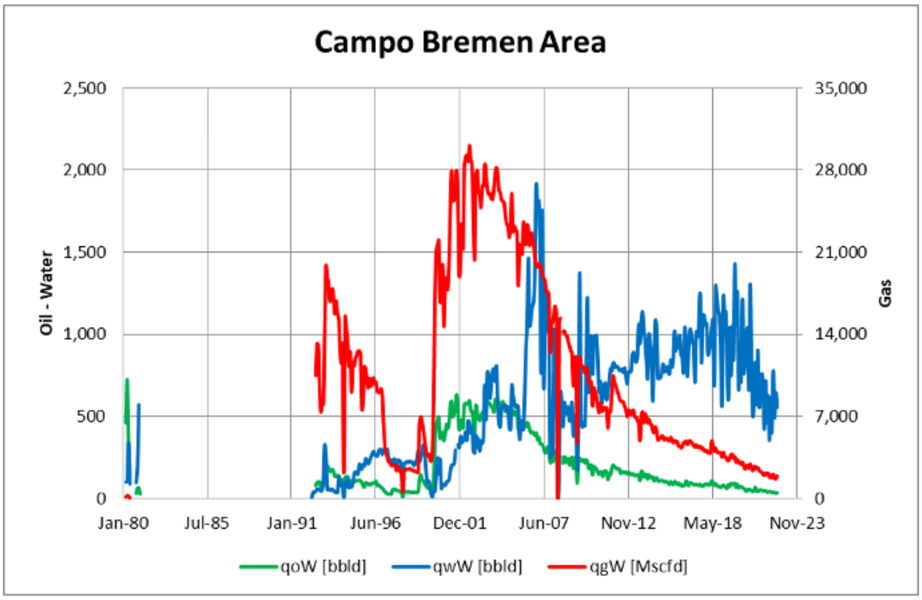


Figure 6 Historical production Campo Bremen

Chorrillos concession

Chorrillos is located in the Santa Cruz province, south of Rio Gallego city. It includes the following 7 fields;

- Campo Molino
- Cerro Convento
- Cerro Norte
- Cerro Norte Oeste
- Chorrillos
- Tres Colinas
- Zuri

The Cerro Norte and Cerro Norte Oeste fields produce gas and condensate, while the other fields produce mainly oil. These fields produce from the Formación Springhill and Serie Tobifera. The average depth of the wells is 6,127 feet and the primary production mechanisms are gas expansion and water drive. Current condensate production is 303 bbl/d and current gas production is 5,900 Mscf/d. 136 wells were drilled in the concession and only 23 of them are flowing as of November 2022.

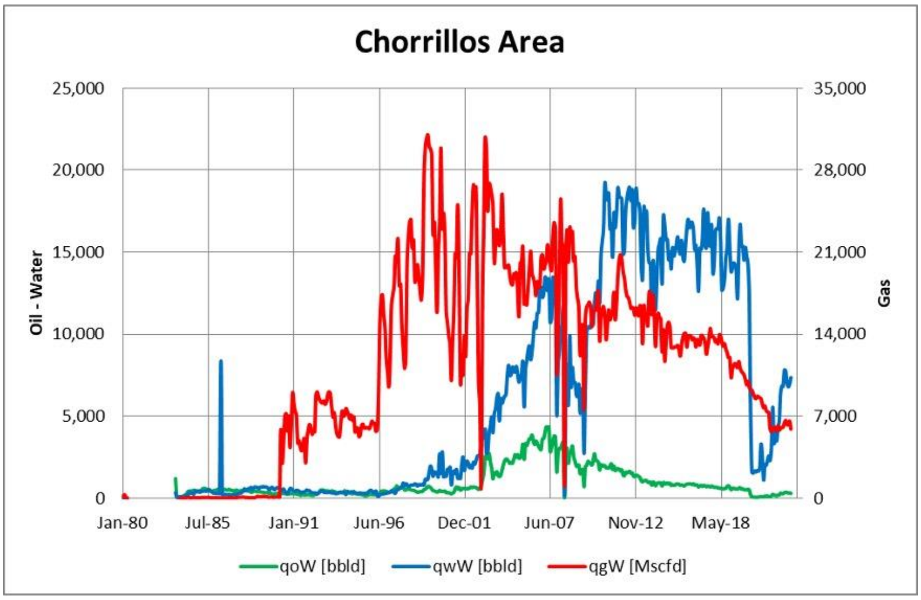


Figure 7 Historical production Chorrillos

Moy Aike concession

Moy Aike is located in the Santa Cruz province, north of Rio Gallego city. It includes the following 4 fields;

- El Indio Oeste
- El Indio
- Moy Aike
- El Gancho

The El Indio Oeste and El Indio fields produce oil and gas. Moy Aike field produces gas and El Gancho produces gas with condensate. These fields produce from the Formación Springhill and Serie Tobifera. The average depth of the wells is 5,061 feet and the primary production mechanisms are gas expansion and water drive. Current condensate production is 78 bbl/d and current gas production is 142 Mscf/d. 62 wells were drilled in the area and only 4 of them are flowing as of November 2022.

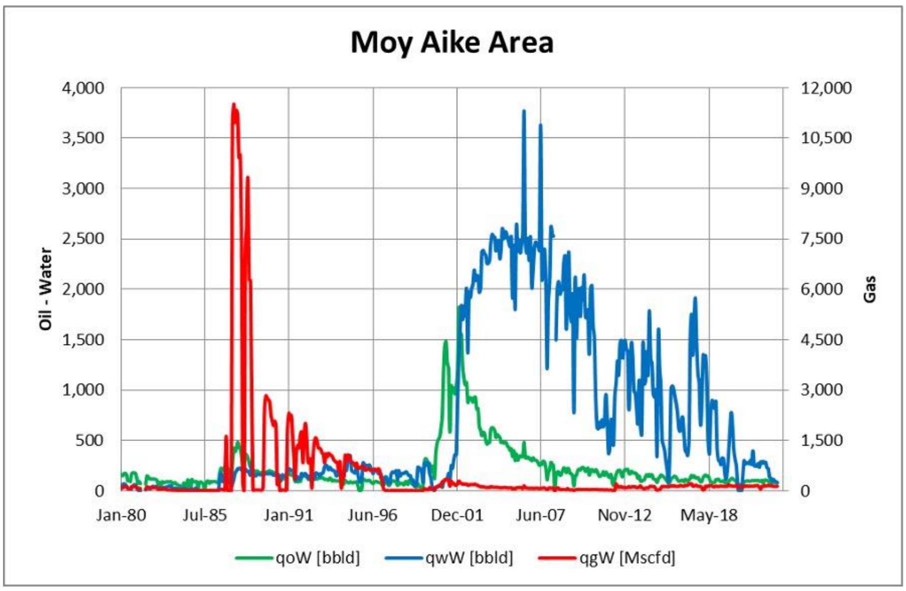


Figure 8 Historical production Moy Aike

Oceano concession

Océano is located in the Santa Cruz province, southeast of Rio Gallego city. It only has 1 field, named Oceano that produces gas and condensate from Serie Tobifera and Formación Springhill.
The average depth of the wells is 4,497 feet and the primary production mechanism is gas expansion and there is also a gas cap. Current condensate production is 28 bbl/d and current gas production is 2,500 Mscf/d. 47 wells were drilled in the area, and only 7 of them are flowing as of November 2022. As the field is offshore, most of the wells were drilled from the coast and deviated to penetrate the reservoirs.

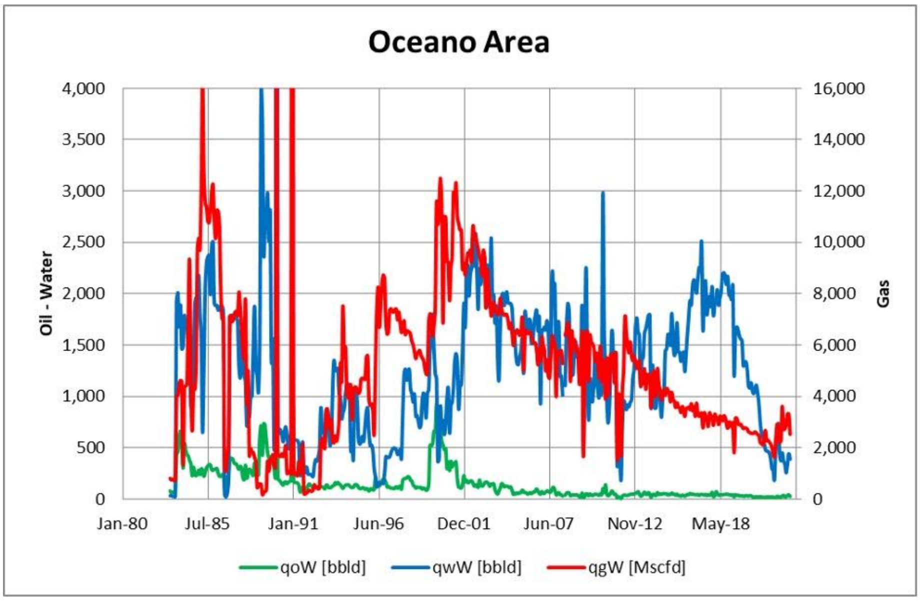


Figure 9 Historical production Océano

Palermo Aike concession

Palermo Aike is located in the Santa Cruz province, south of Rio Gallego city. It includes the following 5 fields;

- Campo Límiete
- Palermo Aike
- Cerro Tres Hermanos
- Monte Aymond
- Hito Trece

All of the fields produce oil and gas and condensate from Serie Tobifera and Formación Springhill. The average depth of the wells is 6,809 feet and the primary production mechanism is gas expansion. There is no production as of November 2022. 41 wells were drilled in the area.

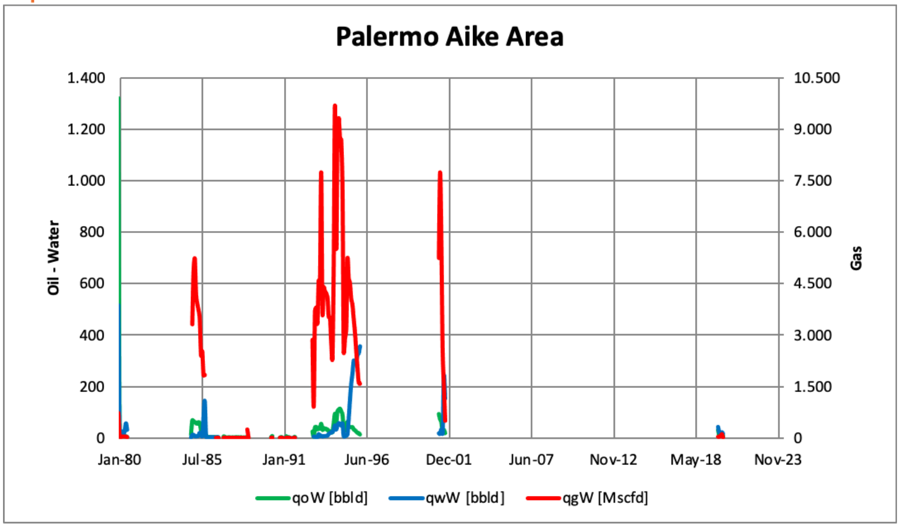


Figure 10 Historical production Palermo Aike

Basis of opinion

SGS is the world's leading inspection, verification, testing and certification company. SGS is recognized as the global benchmark for quality and integrity. With more than 89,000 employees, SGS operates a network of more than 2,600 offices and laboratories around the world. The core services of SGS can be divided into four categories: inspection; testing; certification and verification.

This report has been prepared by SGS for public disclosure in its entirety, in conjunction with Interoil's Annual Statement of Reserves and Resources for the Oslo Stock Exchange. SGS has made every effort to ensure that the interpretations, conclusions and recommendations presented herein are accurate and reliable in accordance with good industry practice and its own quality management procedures. SGS does not, however, guarantee the correctness of any such interpretations, conclusions and recommendations. Barring any agreement to the contrary, all assignments and documents are performed and issued on the basis of the general conditions of SGS. The general conditions provide for a limitation of liability. SGS will not accept responsibility or liability for any loss, costs, damages or expenses incurred or sustained by any third party (parties or persons other than Interoil) resulting from any interpretation, conclusion or recommendation made by any of its officers, agents, employees or representatives. SGS makes no guarantee or prediction of results and makes no warranty, either express or implied, with respect to the actual reserves and resources available.

This report is based on data, methodology and interpretations provided by Interoil to SGS through November and December 2022. SGS has not independently verified any information provided by Interoil. Based on SGS' review, it is SGS' opinion that the overall procedures, methodologies and thoroughness used by Interoil in the reserves estimation process are appropriate and that a thorough approach has been followed, using methods considered sound in the determination of the reserves. The quality of the data relied upon and the depth and thoroughness of the reserves estimation process as well as the classification and categorization of the reserves by Interoil are appropriate.

Standard geological and engineering techniques accepted by the petroleum industry were used in estimating recoverable hydrocarbons. Several uncertainties associated to the estimation of oil and gas reserves exist, as subsurface accumulations of oil and gas cannot be measured in an exact manner. The techniques used rely on engineering and geo-scientific interpretation and judgment; hence the resources included in this evaluation are estimates only and should not be construed to be exact quantities. It should be recognized that such estimates of hydrocarbon resources may increase or decrease in future if there are changes to the technical interpretation, economic criteria, sales volumes or regulatory requirements. Property descriptions, details of interests held, well data, and commercial terms and conditions including fiscal, as obtained from Interoil or public sources, were accepted as represented.

Interoil acknowledges that the report reflects the facts as received by SGS at that time only and within the limits of the instructions received from Interoil. The scope of the report is limited and may not cover all areas which may potentially be interesting for the report's recipients and/or actual results. The report must always be presented in its entirety. This report shall not be reproduced, distributed, quoted or made available to any company, person, regulatory body, or organization without the complete contents of the report. References to and citations from the report are accompanied by the report in its entirety. Interoil warrants that the meaning of the text as intended by the author of the report is not distorted by the manner in which text is reproduced in citations or the manner in which the text is otherwise referenced.

Definitions of Reserves and contingent resources are based on SPE-PRMS-2018 guidelines and are presented in Exhibit-IV. SGS has carried out a reserves- and resources audit with a strong assessment component. The contingent resources have not been subclassified in accordance with SPE-PRMS-2018 guidelines.

SGS has performed an economic limit test to establish the cessation of production, for the purpose of determination of reserves.

SGS has not made any field examination of the property. As a result, SGS is not able to comment on the (appropriateness and conditions of) operations or facilities in place. Furthermore, SGS is not able to comment on health, safety and environmental aspects. No consideration was given in this report to potential environmental liabilities that may exist. No investigation was made into either the legal titles held or any operating agreements in place relating to the subject properties.

SGS is not obliged to update or amend the report to the factual developments or developments in the legislation, regulation or case law after the date of the report. SGS is not able to attest to property title or rights, or any required licenses and consents.

SGS is known for its independency and impartiality. In preparing this report, SGS has not been aware of any conflict of interest. The SGS Group nor any of its subsidiaries have any financial interests in Interoil or in any of its affiliates. This includes potential shares in Interoil. The remuneration of SGS has been compatible to the services provided, not contingent on the contents of the report. The report has been prepared by a well-experienced team. The qualifications of the technical person primarily responsible for the execution of this audit are provided below.

Niek Dousi was the primary technical- and commercial person and project manager for this project. He is a Senior Reservoir Engineer and holds an MSc in Petroleum Engineering from Delft University of Technology, The Netherlands, and has over 17 years of relevant professional experience. His key competences are classical reservoir engineering, Reserves evaluations, dynamic modeling, addressing commercial aspects and project management. He has taken part in numerous integrated field development studies, analyzing oil and gas assets in the North Sea, Continental Europe, North & West Africa, Oman and Russia, among others. Between 2008 and 2016 he has been part of asset valuation teams, evaluating various North Sea, Continental European and West African assets. Other activities involved participation in specialized subsurface studies, such as reserves certifications, using SEC&SPE-PRMS, UGS- and Geomechanics studies, both as a seasoned reservoir engineer and as project manager. Niek is also experienced in performing and supervising economic analyses. Between 2016 and 2020 he has managed more than six large reserves certification studies on Dutch, Gabonese, East African- and Omani assets, among smaller reserves audits. He has worked on numerous oil- and gas assets worldwide, including tight gas, gas-condensates, heavy oil, fluvial-, stacked- and fractured carbonate reservoirs. Niek has participated in projects for majors small/midsized operators and non-operators. Recently in 2019, Niek was part of a special team to support a large middle eastern NOC in building a detailed country portfolio model comprising of assets with many multi billion barrels of in place oil volume. He is a longstanding member of the Society of Petroleum Engineers and has published several papers for the SPE and EAGE.

Niek Dousi

Project Manager

Primary technical- and commercial person

Richard Keen

Business Manager

Exhibit-I Overview of Reserves and Contingent resources

Statement of Remaining Hydrocarbon Volumes Campo Bremen, Chorrillos, Moy Aike, Oceano and Palermo Aike Concessions, Argentina as of December 31, 2022

		GROSS (100%) FIELD VOLUMES		INTEROIL WORKING INTEREST		NET RESERVES TO INTEROIL WI	
		Crude Oil (Mstb)	Natural Gas (BScf)	Crude Oil (Mstb)	Natural Gas (BScf)	Crude Oil (Mstb)	Natural Gas (BScf)
SANTA CRUZ ASSETS	PROVED						
	Developed	211	6.55	18	0.55	15	0.46
	Developed NP	45	1.52	4	0.13	3	0.11
	Undeveloped	0	0.00	0	0.00	0	0.00
	Total 1P	**256**	**8.07**	**21**	**0.67**	**18**	**0.57**
	Total 2P	**286**	**9.12**	**24**	**0.76**	**20**	**0.65**
	Total 3P	**436**	**14.38**	**36**	**1.20**	**31**	**1.02**
CAMPO BREMEN	PROVED						
	Developed	20	1.31	2	0.11	1	0.09
	Developed NP	0	0.23	0	0.02	0	0.02
	Undeveloped	0	0.00	0	0.00	0	0.00
	Total 1P	20	1.53	2	0.13	1	0.11
	Total 2P	24	1.65	2	0.14	2	0.12
	Total 3P	35	2.48	3	0.21	2	0.18
CHORRILLOS	PROVED						
	Developed	140	3.74	12	0.31	10	0.27
	Developed NP	26	1.20	2	0.10	2	0.09
	Undeveloped	0	0.00	0	0.00	0	0.00
	Total 1P	166	4.95	14	0.41	12	0.35
	Total 2P	180	5.78	15	0.48	13	0.41
	Total 3P	271	9.25	23	0.77	19	0.66
MOY AIKE	PROVED						
	Developed	41	0.07	3	0.01	3	0.01
	Developed NP	18	0.01	1	0.00	1	0.00
	Undeveloped	0	0.00	0	0.00	0	0.00
	Total 1P	58	0.08	5	0.01	4	0.01
	Total 2P	69	0.09	6	0.01	5	0.01
	Total 3P	110	0.14	9	0.01	8	0.01
OCEANO	PROVED						
	Developed	11	1.43	1	0.12	1	0.10
	Developed NP	0	0.07	0	0.01	0	0.01
	Undeveloped	0	0.00	0	0.00	0	0.00
	Total 1P	12	1.50	1	0.12	1	0.11
	Total 2P	13	1.58	1	0.13	1	0.11
	Total 3P	19	2.51	2	0.21	1	0.18

Exhibit-II Detailed overview reserves and costs

InterOil Argentina

Net Revenue Interest Reserve Cash Flows Properties in Santa Cruz, Argentina as of December 31, 2022 (MOD)

M: refers to thousands
MM: refers to millions
B: refers to billions

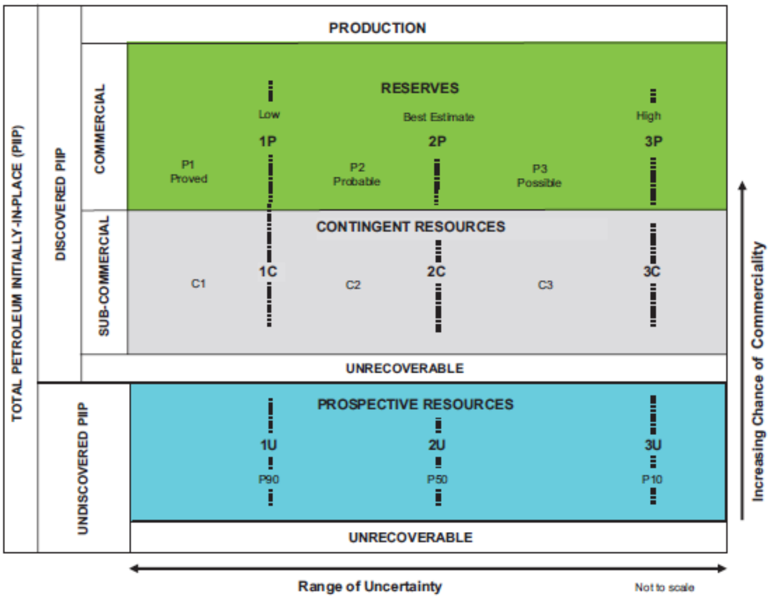
Proved Developed Reserves							
	Production Forecast		Gas Sales	Gross Income	Operating Expenses	Investment	Pre-Tax Cashflow
Year	Oil - Mstb	Gas - Bscf	Bscf	MUS$	MUS$	MUS$	MUS$
2023	9,8	0,30	0,27	1559	1292	226	-18
2024	8,3	0,27	0,25	1368	1292	0	27
2025	6,7	0,23	0,21	1128	1280	0	-192

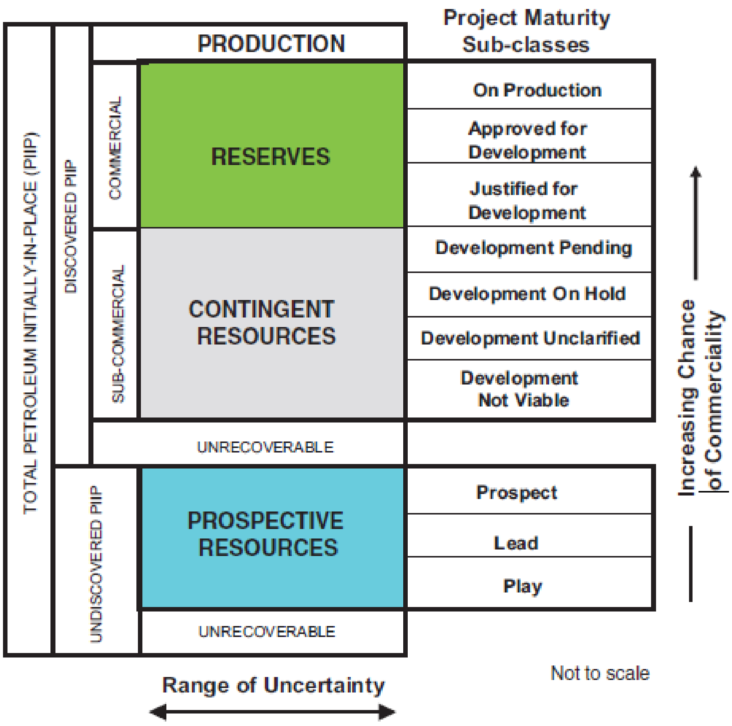
Proved Reserves (1P)							
	Production Forecast		Gas Sales	Gross Income	Operating Expenses	Investment	Pre-Tax Cashflow
Year	Oil - Mstb	Gas - Bscf	Bscf	MUS$	MUS$	MUS$	MUS$
2023	9,8	0,30	0,27	1559	1292	226	-18
2024	8,3	0,27	0,25	1368	1292	0	27
2025	6,7	0,23	0,21	1128	1280	0	-192

2P Reserves							
	Production Forecast		Gas Sales	Gross Income	Operating Expenses	Investment	Pre-Tax Cashflow
Year	Oil - Mstb	Gas - Bscf	Bscf	MUS$	MUS$	MUS$	MUS$
2023	10,7	0,33	0,30	1700	1315	226	95
2024	9,6	0,32	0,29	1593	1330	0	207
2025	8,1	0,28	0,25	1361	1319	0	-6

3P Reserves							
	Production Forecast		Gas Sales	Gross Income	Operating Expenses	Investment	Pre-Tax Cashflow
Year	Oil - Mstb	Gas - Bscf	Bscf	MUS$	MUS$	MUS$	MUS$
2023	11,2	0,35	0,32	1800	1332	226	175
2024	10,5	0,36	0,32	1764	1359	0	342
2025	9,2	0,32	0,29	1555	1352	0	148
2026	8,2	0,29	0,26	1389	1352	0	-11

Exhibit-III SPE-PRMS-2018 classification and guidelines





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.
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.

Class/Sub-Class	Definition	Guidelines
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.
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.

Class/Sub-Class	Definition	Guidelines
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.
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.

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.