Interoil Exploration and production ASA
Reserves Statement end 2021

Oslo, Buenos Aires, Bogota – 25 April 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, especially in Argentina.

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 2021 (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]
2021	Puli C	2.748	0.437	0.927	3.811	0.731	1.410
	Vikingo	-	0.105	0.105	-	0.273	0.273
	Colombia	2.748	0.542	1.032	3.811	1.004	1.683
	MMO	0.266	0.159	0.206	2.329	0.578	0.993
	SC	0.500	0.026	0.115	0.280	0.510	0.560
	Argentina	0.766	0.185	0.322	2.609	1.088	1.553
	Interoil	3.514	0.727	**1.353**	6.420	2.092	**3.236**

These reserves volumes have been certified by SGS Nederland B.V. 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 P1 hydrocarbon net reserves after royalties amounts to 1.35 MMboe which represents a slightly reduction of 0.14 MMboe with respect to last year. On the other hand, 2P hydrocarbon net reserves after royalty accounts for 3.24 MMboe, an increment by 0.75 MMboe; mainly explained by the reserves associated with the work program in Mata Magallanes Oeste (MMO) and Santa Cruz (SC) operations.

When comparing this year with last year reserves figures, there main reduction in oil reserves is explained by Vikingo's downward adjustment to its C5 formation reserves values. Last year reservoir pressure measurement has indicated that the reservoir is not recovering pressure as expected and a lower recovery factor has been assigned accelerating its depletion type of behavior; thus, reducing Vikingo's C5 ultimate oil reserves figure. For the Puli C fields, Mana, Ambrosia and Rio Opia, a minor adjustment to their decline rates have slightly modified their final figures.

Reserves comparison figures in Argentina have been increased mainly due to the work program in Mata Magallanes Oeste including of 8 workovers to Bajo Barreal Fm escalating flowing oil barrels with their associated gas. Likewise in the Santa Cruz operation, new field program related with the undeveloped oil reserves (and its associated gas) generated by the upgrade of the surface facilities aimed at adding oil production flows with their associated gas.

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24th March, 2022

Reserves and Contingent Resources Statement for
Ambrosía, Río Opia, Maná,
Llanos 47 and Altair Areas, Colombia
as of December 31, 2021

Dear Mr. Carbone,

This reserves- and contingent resources statement has been prepared by SGS Nederland BV and issued on March 24th, 2022 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, 2021, 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.

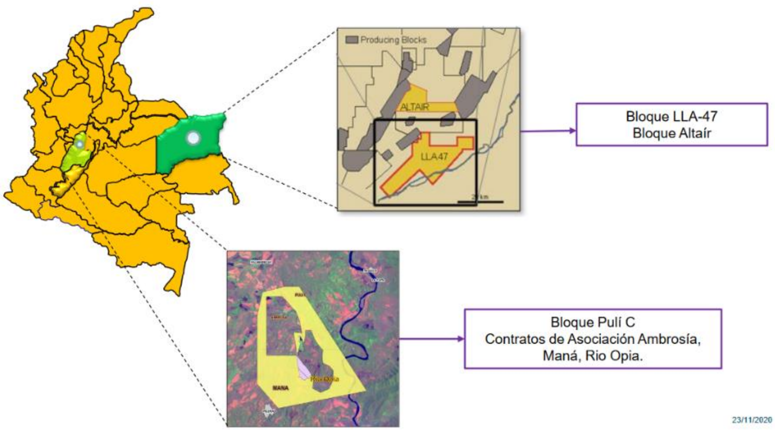

Figure 1 Location maps all concessions

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 contractor.

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

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. The Llanos 47 area is under an exploration contract that expires in 2022, following a 10 + 1 year exploitation contract started in 2011.

During last year´s audit, 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 is extended up to 2044.

Before the end of 2021, Interoil Colombia was granted a 1-year extension on the exploration period, while the company is still in the administrative process of securing the exploitation concession.

There is a reasonable expectation the outstanding environmental permit will be awarded as new exploration wells will not be drilled in environmentally sensitive areas and there is a track record of the environmental agency in awarding environmental permits for similar cases.

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).

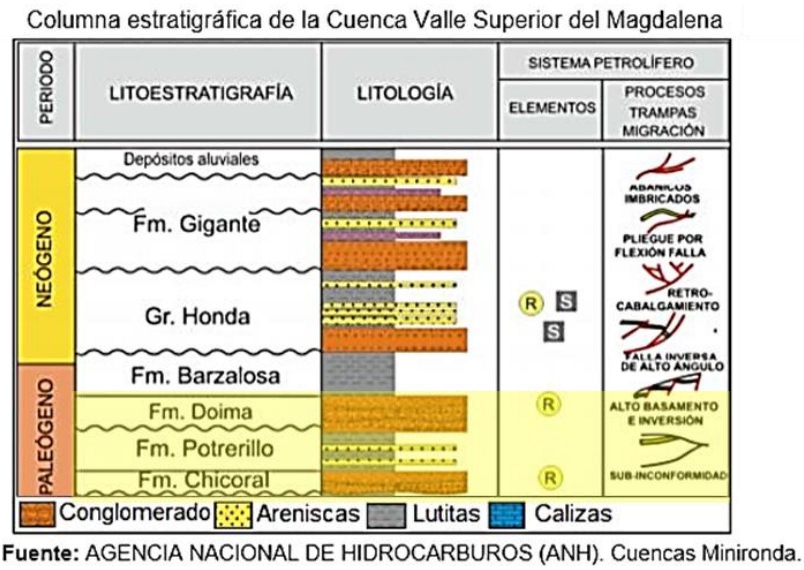

Figure 2 Stratigraphic column

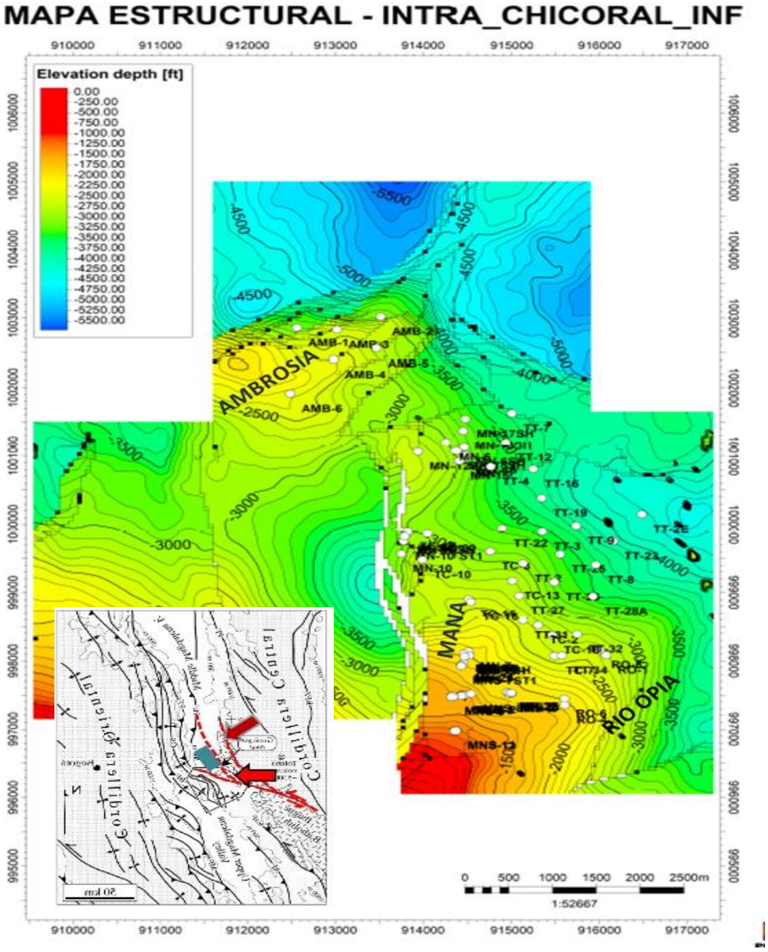

Figure 3 Top structure map Puli-C license

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 map).

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. (see 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 type of traps, aligned with the main regional faults of the basin.

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.

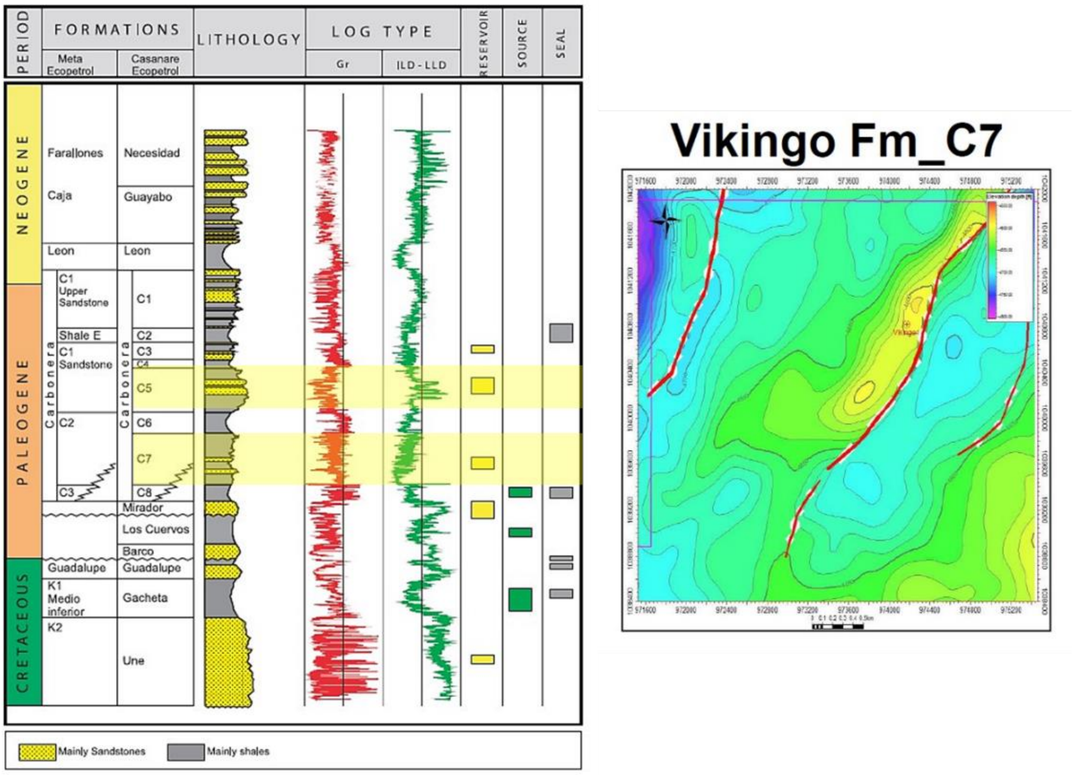

Figure 4 Top structure map and type log Llanos 47 concession

Development plans

Introduction

InterOil has proposed 6 workovers and 3 wells to be drilled as part of their activity plan for the years 2022 and 2023. Workovers for Puli-C are scheduled to be performed during April and May 2022 and the first well to be drilled will spud in July 2022, followed by the other 2 wells. Workover for Vikingo-1 is scheduled for mid 2024, after getting formal approval from ANH on the license extension.
SGS has reviewed each of these activities and has performed its own individual assessment based on the pertinent data provided by the operator.

The project, comprising of 3 infill wells, is judged to be “Justified for development,” by SGS as per SPE-PRMS-2018, as there is a firm intention by the client to proceed with the development and SGS considers the project to be commercial with a high chance of commerciality (>90%). This has been concluded, as key evidence has been presented by InterOil, such as but not limited to, provision of detailed work programs, which are budgetary supported, mature financing plans exist within InterOil and all necessary commercial- and contractual obligations are forthcoming or fulfilled. SGS has performed a standard cashflow calculation and based on this analysis, the project is deemed economic in the best estimate and, according to InterOil, the project has passed their internal economic screening criteria.

Overview of development plans/projects

Mana Field

Three workovers are scheduled to be performed during 2022 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. Two workovers are proposed in MN-6 and MN-11 wells respectively, in which InterOil will open new intervals, aiming to produce from the gas cap.
2 new wells (MNS-13 and MNS-14) are scheduled to be drilled, starting July 2022, targeting the UOB7 Chicoral formation intervals in the centre of the PULI-C area.
Industry standard techniques were applied to generate low- best and high case production forecasts for these projects.

Río Opia Field

No workover activity is scheduled for this field after the recent workovers performed in RO-5 and RO-6, having shown different results. RO-6 has proven successful results with the new hydromechanics perforation technology while in RO-5, aiming to produce from unconsolidated formations, the technology did not work.
1 new well (RO-7) is scheduled to be drilled, after completion of the 2 MNS new wells.
Industry standard techniques were applied to generate low- best and high case production forecasts for these projects.

Ambrosia Field

Two workovers 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 mid 2024, 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.

Contingent Resources

Contingent resources have been sub-classified as “Development Pending” or “Development Unclarified” up to end of 2040. All contingent resources from existing developments, which are considered to be uneconomic, prior to the end of 2040 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 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 reserves 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). 41 wells are proposed in the south eastern part of the asset targeting both Doima and Chicoral Formations (25 wells) and only Doima Formation (16 wells).

To mature these contingent resources into reserves, technically- and commercially mature projects should be further defined. Out of these 70 wells, 22 have been sub-classified as “Development Pending” due to their proposed locations with strong technical- and geological potential and updip structural position. 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 41 southern wells, 8 have been assigned to Mana field and 33 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-2021:

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	0.695	3.882	0.491	2.717	0.448	2.717
	Developed NP	0.049	0.044	0.034	0.031	0.031	0.031
	Undeveloped	0.080	0.000	0.063	0.000	0.063	0.000
	Total 1P	**0.824**	**3.926**	**0.587**	**2.748**	**0.542**	**2.748**
	Total 2P	**1.502**	**5.444**	**1.079**	**3.811**	**1.004**	**3.811**
	Total 3P	**2.490**	**7.544**	**1.808**	**5.281**	**1.714**	**5.281**

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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 2022 workover campaign (five wells in PULI-C), based on technical- and commercial information provided by InterOil. “Undeveloped reserves” were estimated by SGS, based on technical and commercial information provided by InterOil, for the scheduled 2022 drilling campaign (two wells in Maná and one in Río Opia). 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 new infills wells proposed by InterOil, which do not classify as reserves have been sub-classified either as “Development Pending” or “Development Unclarified” with production up to December 2041, 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 the December 2041. 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.

Table 4 Overview oil contingent resources - all fields

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	0.256	0.480	0.736	0.000	0.000	0.000	0.337	0.372	0.682	0.593	0.852	1.418
Rio Opia	0.096	0.180	0.276	0.960	1.800	2.760	0.095	0.074	0.119	1.151	2.054	3.155
Ambrosia	0.407	0.759	1.177	0.666	1.242	1.926	0.097	0.138	0.186	1.170	2.139	3.289
Llanos	0.000	0.000	0.000	0.000	0.000	0.000	0.059	0.037	0.024	0.059	0.037	0.024
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	**0.759**	**1.419**	**2.189**	**1.626**	**3.042**	**4.686**	**0.589**	**0.621**	**1.011**	**2.974**	**5.082**	**7.886**

Table 5 - Overview gas 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	0.768	1.440	2.208	0.000	0.000	0.000	1.791	2.343	4.217	2.559	3.783	6.425
Rio Opia	0.288	0.540	0.828	2.880	5.400	8.280	0.266	0.208	0.342	3.434	6.148	9.450
Ambrosia	1.221	2.277	3.531	1.998	3.726	5.778	0.064	0.090	0.125	3.283	6.093	9.434
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	**2.277**	**4.257**	**6.567**	**4.878**	**9.126**	**14.058**	**2.121**	**2.641**	**4.684**	**9.276**	**16.024**	**25.309**

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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 2020 and year-end 2021 (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 2020-2021 - IOC

RESERVES DEVELOPMENT (GROSS 100% VOLUME)				
	Crude Oil (MMstb)		**Gas (Bscf)**	
	1P	**2P**	**1P**	**2P**
Balance (as of year and last full year)	1.252	2.183	3.677	5.939
Production 2021	0.196		0.527	
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	0.232	0.485	0.776	0.032
Balance (as of 31-Dec-2021)	**0.824**	**1.502**	**3.926**	**5.444**

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The main reduction in the "Revisions of previous estimates" category refers to the downward adjustment in the reserves for the Vikingo-1 well completed on the C5 (Llanos -47). The operator has recently provided SGS with reservoir pressure measurement information, which indicates that the reservoir is not recovering pressure as expected and a lower recovery factor has been assigned to account for this more depletion type of behaviour.
Revisions in the other 3 fields are mainly related to minor adjustments to the decline rates as part of this year's audit.

Table 7 - Reserves change Year End 2020-2021 - Mana Field

RESERVES DEVELOPMENT (GROSS 100% VOLUME)				
	Crude Oil (MMstb)		Gas (Bscf)	
	1P	2P	1P	2P
Balance (as of year and last full year)	0.553	0.986	3.503	5.444
Production 2020	0.121		0.507	
Acquisitions / Disposals				
Extensions / Discoveries				
New Developments				
Revisions of previous estimates	0.130	0.023	0.761	0.045
Balance (as of 31-Dec-2020)	**0.562**	**0.888**	**3.757**	**4.982**

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Table 8 - Reserves change Year End 2020-2021 - Ambrosia Field

RESERVES DEVELOPMENT (GROSS 100% VOLUME)				
	Crude Oil (MMstb)		Gas (Bscf)	
	1P	2P	1P	2P
Balance (as of year and last full year)	0.076	0.102	0.053	0.089
Production 2020	0.010		0.005	
Acquisitions / Disposals				
Extensions / Discoveries				
New Developments				
Revisions of previous estimates	0.005	0.010	0.009	0.029
Balance (as of 31-Dec-2020)	**0.071**	**0.102**	**0.039**	**0.055**

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Table 9 - Reserves change Year End 2020-2021 - 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)	0.039	0.140	0.121	0.406
Production 2020	0.006		0.015	
Acquisitions / Disposals				
Extensions / Discoveries				
New Developments				
Revisions of previous estimates	0.023	0.028	0.024	0.016
Balance (as of 31-Dec-2020)	**0.056**	**0.162**	**0.130**	**0.407**

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Table 10 - Reserves change Year End 2020-2021 - 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)	0.584	0.955	0.000	0.000
Production 2020	0.059			
Acquisitions / Disposals				
Extensions / Discoveries				
New Developments				
Revisions of previous estimates	0.390	0.546		
Balance (as of 31-Dec-2020)	**0.135**	**0.350**	**0.000**	**0.000**

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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 31st of December 2021, up to end of 2029 and thereafter inflated by 2% per annum. A discount of 2,7 US$/bbl 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 2022 amounts to 2,82 US$/MMBtu and is subsequently escalated by 1% on a yearly basis.

Table 11 Brent and contractual gas price forecast (MOD) 2022-2033

Year	Oil Price (US$/bbl)	Gas Price (US$/MMBtu)
2022	78,73	2,82
2023	73,28	2,85
2024	69,79	2,88
2025	67,37	2,91
2026	65,95	2,93
2027	65,30	2,96
2028	65,20	2,99
2029	65,27	3,02
2030	66,58	3,05
2031	67,91	3,08
2032	69,27	3,12
2033	70,65	3,15

2022 budget estimated costs and expenses have been reviewed and compared to 2021 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 (kUS$/yr)	1.510	142	142	345
Variable Opex (US$/bbl)	7,01	7,01	7,01	9,18
G&A Allocation (kUS$/yr)	693	65	65	22
Oil transportation (US$/bbl)	6,20	6,20	6,20	9,95

The abandonment cost of a well was provided by InterOil and is considered to 120 kUS$ (RT21).

All costs, as per the above table, as well as abandonment costs are escalated by 3% on a yearly basis. The 3% 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 current production is approximately 653 bbl/d and 2.05 Mscf/d day as of December 31, 2021. 63 wells were drilled in the five blocks and 38 of them are on production today. The cumulative oil production is 6.7 MMbbl and 17.4 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.

SGS

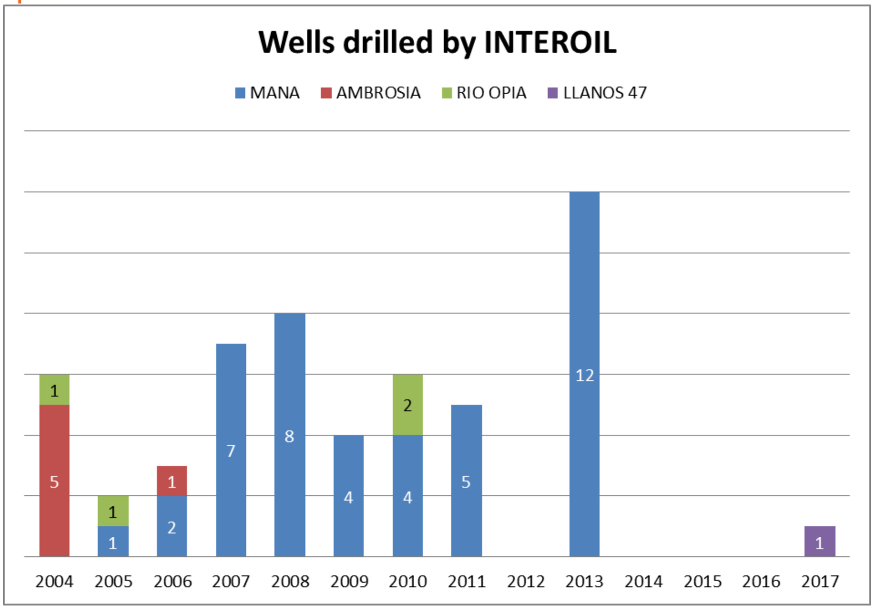


Figure 5 Wells drilled by InterOil Colombia historically

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 404 bbl/d and 1.97 Mscf/d of gas. Since the beginning of the field exploitation, 43 wells were drilled and only 4 of them have already been abandoned. By December 2021, 34 wells were on production and the remaining ones closed and under study.

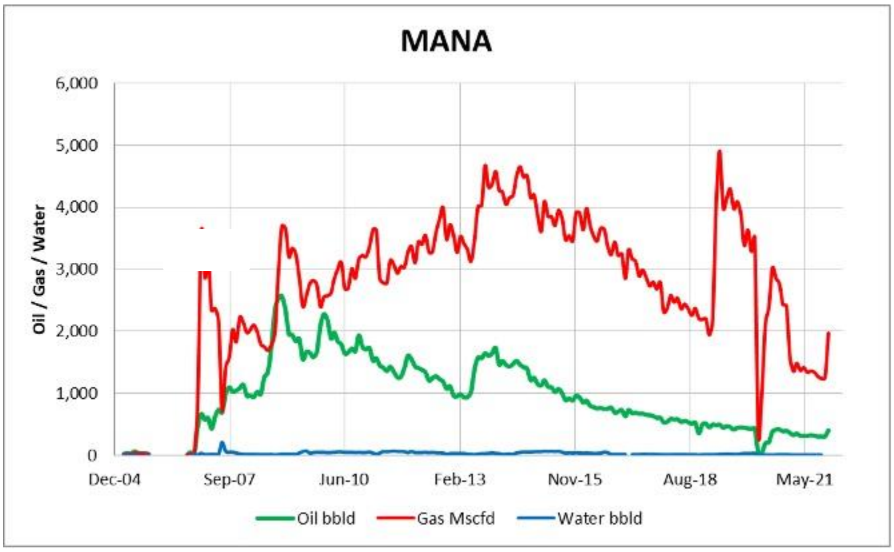


Figure 6 Historical production Mana field

The OOIP for Doima and Chicoral combined is approximately 115 MMbbl with a current recovery factor of 5%. Cumulative oil production is 5.7 Mbbl and 16.5 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 is 33 bbl/d and 64 Mscf/d of gas. 3 wells are currently on production, while 2 of the wells were abandoned due to poor reservoir performance ("Bunde wells").

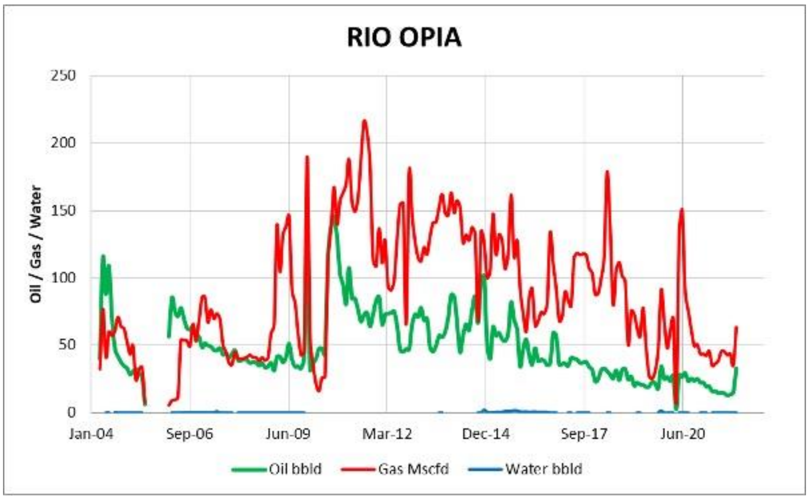


Figure 7 Historical production Rio Opia field

The OOIP for the Doima and Chicoral formations is approximately 47 MMbbl with a current recovery factor of 1%. Cumulative oil production is 307 Mbbl and 556 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 is 20 bbl/d and 10 Mscf/d of gas. 6 wells were drilled and 2 of them are currently on production, while 3 wells were already abandoned.

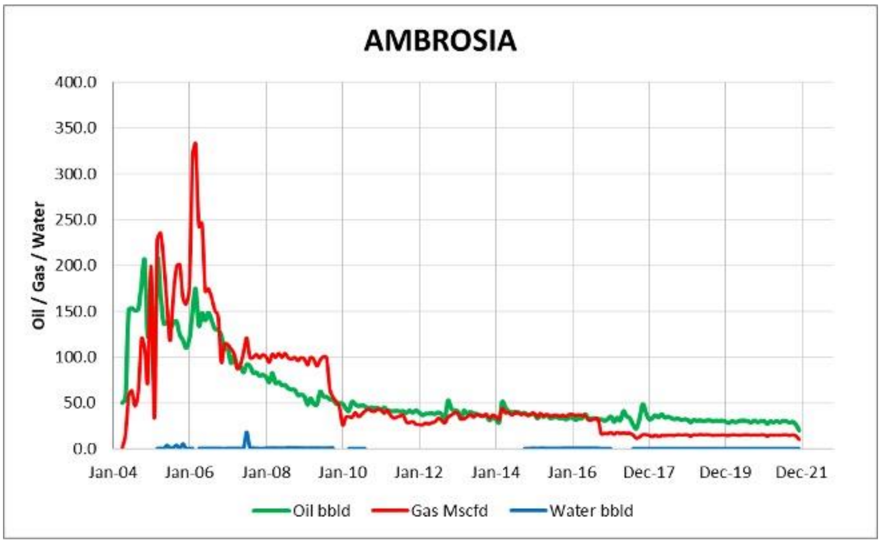


Figure 8 Historical production Ambrosia field

The OOIP for Doima is approximately 32 MMbbl with a current recovery factor of 1%. Cumulative oil production is 370 Mbbl and 369 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 is 196 bbl/d. 3 wells were drilled and 1 of them is currently on production. The other 2 wells are shutin due to poor reservoir performance.

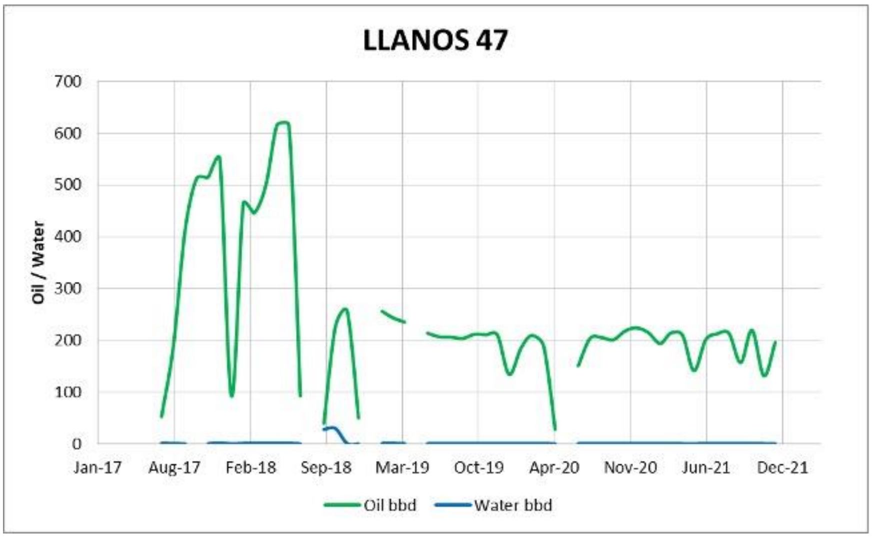


Figure 9 Historical production Llanos-47 field

The OOIP for C5 is approximately 2,37 MMbbl with a current recovery factor of 15,5%. Cumulative oil production is 373 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 190-200 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 2021. 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 16 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, 2021

		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	0.695	3.882	0.491	2.717	0.448	2.717
	Developed NP	0.049	0.044	0.034	0.031	0.031	0.031
	Undeveloped	0.080	0.000	0.063	0.000	0.063	0.000
	Total 1P	**0.824**	**3.926**	**0.587**	**2.748**	**0.542**	**2.748**
	Total 2P	**1.502**	**5.444**	**1.079**	**3.811**	**1.004**	**3.811**
	Total 3P	**2.490**	**7.544**	**1.808**	**5.281**	**1.714**	**5.281**
MANA	PROVED						
	Developed	0.550	3.733	0.385	2.613	0.355	2.613
	Developed NP	0.012	0.024	0.008	0.017	0.007	0.017
	Undeveloped	0.000	0.000	0.000	0.000	0.000	0.000
	Total 1P	0.562	3.757	0.393	2.630	0.362	2.630
	Total 2P	0.888	4.982	0.622	3.487	0.572	3.487
	Total 3P	1.324	6.915	0.927	4.841	0.853	4.841
RIO OPIA	PROVED						
	Developed	0.056	0.130	0.039	0.091	0.029	0.091
	Developed NP	0.000	0.000	0.000	0.000	0.000	0.000
	Undeveloped	0.000	0.000	0.000	0.000	0.000	0.000
	Total 1P	0.056	0.130	0.039	0.091	0.029	0.091
	Total 2P	0.162	0.407	0.114	0.285	0.094	0.285
	Total 3P	0.225	0.561	0.157	0.392	0.145	0.392
AMBROSIA	PROVED						
	Developed	0.034	0.019	0.024	0.013	0.022	0.013
	Developed NP	0.037	0.020	0.026	0.014	0.024	0.014
	Undeveloped	0.000	0.000	0.000	0.000	0.000	0.000
	Total 1P	0.071	0.039	0.050	0.028	0.046	0.028
	Total 2P	0.102	0.055	0.071	0.039	0.065	0.039
	Total 3P	0.126	0.068	0.088	0.048	0.081	0.048
LLANOS	PROVED						
	Developed	0.055	0.000	0.043	0.000	0.043	0.000
	Developed NP	0.000	0.000	0.000	0.000	0.000	0.000
	Undeveloped	0.080	0.000	0.063	0.000	0.063	0.000
	Total 1P	0.135	0.000	0.105	0.000	0.105	0.000
	Total 2P	0.350	0.000	0.273	0.000	0.273	0.000
	Total 3P	0.814	0.000	0.635	0.000	0.635	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, 2021 (MOD)

Mana

Proved Developed Reserves

	Production Forecast		Gas Sales	Gross Income	Oil Transport	Operating Expenses	Abandonment	Investment	Pre-Tax Cashflow
Year	Oil - Mstb	Gas - MMscf	MMscf	KUS$	KUS$	KUS$	KUS$	KUS$	KUS$
2022	86	574	552	7691	580	2257	672	565	3617
2023	71	519	499	6195	485	2056	168	0	3487
2024	58	432	414	4937	402	1928	336	0	2271
2025	48	361	346	3996	334	1903	252	0	1507
2026	40	301	289	3269	279	1710	336	0	944
2027	33	251	241	2697	233	1565	336	0	562
2028	25	193	185	2064	180	1671	168	0	46

Proved Reserves (1P)

	Production Forecast		Gas Sales	Gross Income	Oil Transport	Operating Expenses	Abandonment	Investment	Pre-Tax Cashflow
Year	Oil - Mstb	Gas - MMscf	MMscf	KUS$	KUS$	KUS$	KUS$	KUS$	KUS$
2022	86	574	552	7691	580	2257	672	565	3617
2023	71	519	499	6195	485	2056	168	0	3487
2024	58	432	414	4937	402	1928	336	0	2271
2025	48	361	346	3996	334	1903	252	0	1507
2026	40	301	289	3269	279	1710	336	0	944
2027	33	251	241	2697	233	1565	336	0	562
2028	25	193	185	2064	180	1671	168	0	46

2P Reserves

	Production Forecast		Gas Sales	Gross Income	Oil Transport	Operating Expenses	Abandonment	Investment	Pre-Tax Cashflow
Year	Oil - Mstb	Gas - MMscf	MMscf	KUS$	KUS$	KUS$	KUS$	KUS$	KUS$
2022	130	737	707	11253	875	2601	672	4117	2988
2023	122	709	681	10124	831	2456	84	0	6753
2024	91	564	542	7405	627	2187	168	0	4422
2025	74	471	452	5898	513	2106	252	0	3027
2026	61	398	382	4864	431	1883	168	0	2382
2027	52	340	326	4098	368	1718	168	0	1844
2028	41	269	258	3235	293	1799	84	0	1059

3P Reserves

	Production Forecast		Gas Sales	Gross Income	Oil Transport	Operating Expenses	Abandonment	Investment	Pre-Tax Cashflow
Year	Oil - Mstb	Gas - MMscf	MMscf	KUS$	KUS$	KUS$	KUS$	KUS$	KUS$
2022	180	962	924	15413	1210	2984	672	4117	6429
2023	189	998	958	15382	1285	2970	0	0	11126
2024	136	779	748	10896	938	2537	0	0	7421
2025	110	653	627	8643	763	2385	168	0	5327
2026	93	561	539	7224	650	2124	84	0	4366
2027	80	490	470	6233	569	1938	84	0	3642
2028	65	397	381	5049	465	1986	0	0	2598

Rio Opia

Rio Opia
Proved Developed Reserves

Year	Production Forecast Oil - Mstb	Production Forecast Gas - MMscf	Gas Sales MMscf	Gross Income KUS$	Oil Transport KUS$	Operating Expenses KUS$	Abandonment KUS$	Investment KUS$	Pre-Tax Cashflow KUS$
2022	7	15	15	556	49	200	0	0	308
2023	6	15	14	424	39	226	0	0	159
2024	5	13	12	356	34	234	168	0	89
2025	4	11	11	303	29	116	0	0	158
2026	4	10	10	261	26	120	0	0	115
2027	3	9	8	226	22	116	0	0	87
2028	3	8	7	197	20	114	0	0	64
2029	3	7	6	172	17	111	0	0	44
2030	1	3	3	77	8	54	0	0	15

Rio Opia
Proved Reserves (1P)

Year	Production Forecast Oil - Mstb	Production Forecast Gas - MMscf	Gas Sales MMscf	Gross Income KUS$	Oil Transport KUS$	Operating Expenses KUS$	Abandonment KUS$	Investment KUS$	Pre-Tax Cashflow KUS$
2022	7	15	15	556	49	200	0	0	308
2023	6	15	14	424	39	226	0	0	159
2024	5	13	12	356	34	234	168	0	89
2025	4	11	11	303	29	116	0	0	158
2026	4	10	10	261	26	120	0	0	115
2027	3	9	8	226	22	116	0	0	87
2028	3	8	7	197	20	114	0	0	64
2029	3	7	6	172	17	111	0	0	44
2030	1	3	3	77	8	54	0	0	15

Rio Opia
2P Reserves

Year	Production Forecast Oil - Mstb	Production Forecast Gas - MMscf	Gas Sales MMscf	Gross Income KUS$	Oil Transport KUS$	Operating Expenses KUS$	Abandonment KUS$	Investment KUS$	Pre-Tax Cashflow KUS$
2022	15	35	34	1191	103	262	0	1776	-950
2023	20	56	54	1521	138	338	0	0	1045
2024	16	43	42	1131	106	316	0	0	709
2025	13	36	35	907	88	182	0	0	637
2026	11	31	30	759	74	175	0	0	510
2027	10	27	26	654	65	164	168	0	426
2028	8	24	23	575	57	156	0	0	363
2029	7	22	21	511	51	149	0	0	312
2030	3	10	10	234	23	72	0	0	139

Rio Opia
3P Reserves

Year	Production Forecast Oil - Mstb	Production Forecast Gas - MMscf	Gas Sales MMscf	Gross Income KUS$	Oil Transport KUS$	Operating Expenses KUS$	Abandonment KUS$	Investment KUS$	Pre-Tax Cashflow KUS$
2022	19	43	42	1490	130	291	0	1776	-707
2023	27	73	70	2012	182	389	0	0	1441
2024	22	59	57	1560	147	362	0	0	1051
2025	18	50	48	1279	124	222	0	0	933
2026	16	44	42	1088	107	212	0	0	770
2027	14	39	38	950	94	197	0	0	659
2028	12	35	34	846	84	186	0	0	576
2029	11	32	31	760	75	176	0	0	508
2030	5	15	15	352	35	85	0	0	232

Ambrosia

Year	Production Forecast Oil - Mstb	Gas CIO MMscf	Gas Sales MMscf	Gross Income KUS$	Oil Transport KUS$	Operating Expenses KUS$	Abandonment KUS$	Investment KUS$	Pre-Tax Cashflow KUS$
2022	9	4	0	650	61	214	0	175	200
2023	8	4	0	569	58	247	0	0	264
2024	8	4	0	493	53	254	0	0	186
2025	7	3	0	447	50	303	0	0	94
2026	7	3	0	411	47	324	0	0	40
2027	6	3	0	380	45	320	0	0	15

Ambrosia
Proved Reserves (1P)

Year	Production Forecast Oil - Mstb	Gas CIO MMscf	Gas Sales MMscf	Gross Income KUS$	Oil Transport KUS$	Operating Expenses KUS$	Abandonment KUS$	Investment KUS$	Pre-Tax Cashflow KUS$
2022	9	4	0	650	61	214	0	175	200
2023	8	4	0	569	58	247	0	0	264
2024	8	4	0	493	53	254	0	0	186
2025	7	3	0	447	50	303	0	0	94
2026	7	3	0	411	47	324	0	0	40
2027	6	3	0	380	45	320	0	0	15

Ambrosia
2P Reserves

Year	Production Forecast Oil - Mstb	Gas CIO MMscf	Gas Sales MMscf	Gross Income KUS$	Oil Transport KUS$	Operating Expenses KUS$	Abandonment KUS$	Investment KUS$	Pre-Tax Cashflow KUS$
2022	13	7	0	931	88	244	0	350	249
2023	12	7	0	816	83	275	0	0	458
2024	11	6	0	700	75	279	0	0	346
2025	10	6	0	641	72	327	0	0	243
2026	10	6	0	594	68	347	0	0	179
2027	9	6	0	556	65	342	0	0	148

Ambrosia
3P Reserves

Year	Production Forecast Oil - MMstb	Gas CIO MMscf	Gas Sales MMscf	Gross Income KUS$	Oil Transport KUS$	Operating Expenses KUS$	Abandonment KUS$	Investment KUS$	Pre-Tax Cashflow KUS$
2022	16	9	0	1146	108	267	0	350	421
2023	15	9	0	1006	102	297	0	0	606
2024	13	8	0	863	93	298	0	0	472
2025	13	8	0	796	89	346	0	0	361
2026	12	7	0	744	86	366	0	0	293
2027	12	7	0	701	82	361	0	0	258

Llanos 47

Llanos 47							
Proved Developed Reserves							
Production Forecast		Gross Income	Oil Transport	Operating Expenses	Abandonment	Investment	Pre-Tax Cashflow
Year	Oil - Mstb	KUS$	KUS$	KUS$	KUS$	KUS$	KUS$
2022	33	2325	324	585	0	0	1415
2023	10	668	99	382	0	0	187
2024	2	124	19	310	0	0	-205

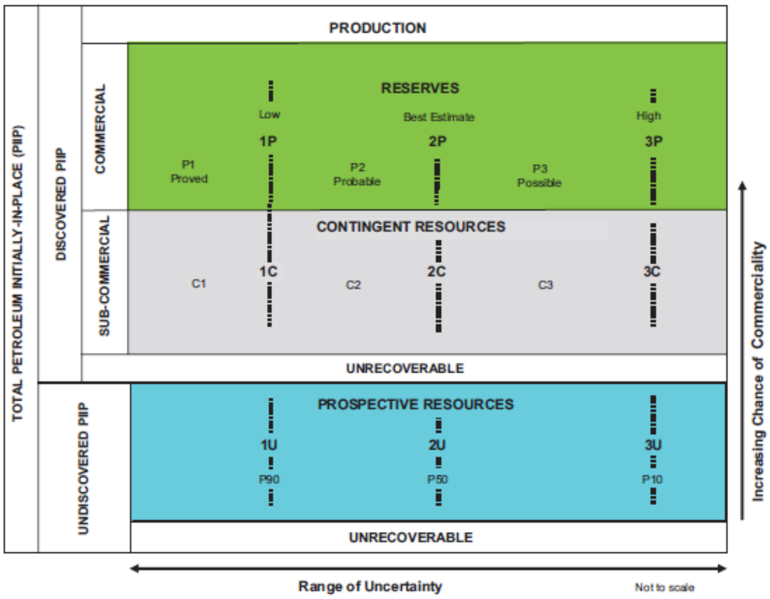
Llanos 47							
Proved Reserves (1P)							
Production Forecast		Gross Income	Oil Transport	Operating Expenses	Abandonment	Investment	Pre-Tax Cashflow
Year	Oil - Mstb	KUS$	KUS$	KUS$	KUS$	KUS$	KUS$
2022	33	2325	324	585	0	0	1415
2023	10	668	99	382	0	0	187
2024	13	830	129	411	0	78	212
2025	15	951	152	438	0	0	360
2026	13	767	125	416	0	0	226
2027	12	708	117	414	0	78	99
2028	10	601	100	424	0	0	77
2029	8	479	80	405	0	0	-6

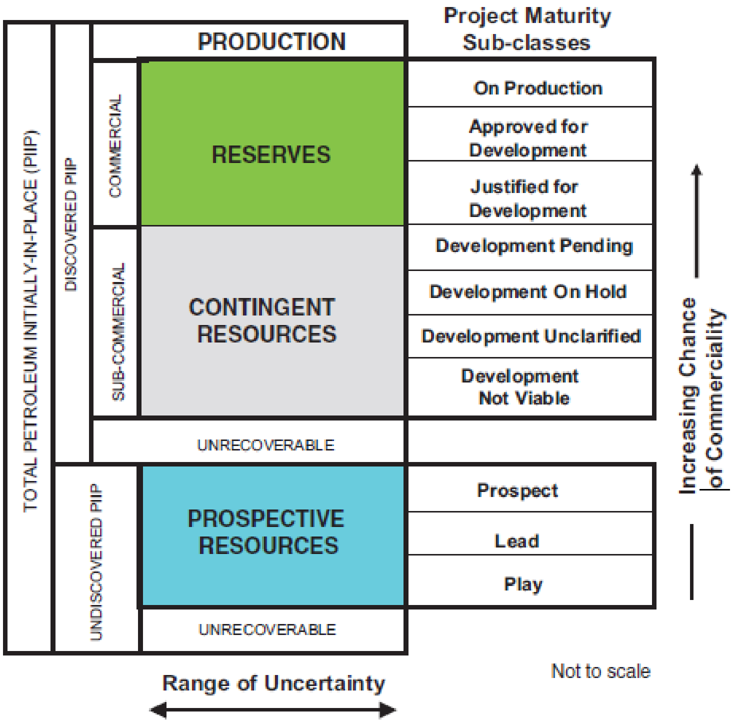
2P Reserves							
Production Forecast		Gross Income	Oil Transport	Operating Expenses	Abandonment	Investment	Pre-Tax Cashflow
Year	Oil - Mstb	KUS$	KUS$	KUS$	KUS$	KUS$	KUS$
2022	51	3612	504	751	0	0	2357
2023	49	3315	492	744	0	0	2078
2024	38	2423	376	639	0	78	1330
2025	21	1323	212	493	0	0	618
2026	18	1067	174	461	0	0	432
2027	29	1739	288	572	0	78	802
2028	26	1553	258	569	0	0	726
2029	15	920	153	473	0	0	294
2030	11	641	107	431	0	0	103
2031	8	497	83	346	0	0	68
2032	7	407	68	332	0	0	7
2033	6	338	57	321	0	0	-40

3P Reserves

Production Forecast Year	Oil - Mstb	Gross Income KUS$	Oil Transport KUS$	Operating Expenses KUS$	Abandonment KUS$	Investment KUS$	Pre-Tax Cashflow KUS$
2022	51	3612	504	751	0	0	2357
2023	49	3315	492	744	0	0	2078
2024	46	2961	460	716	0	78	1707
2025	30	1892	303	578	0	0	1011
2026	25	1526	249	530	0	0	746
2027	45	2727	451	722	0	78	1476
2028	65	3916	649	931	0	0	2336
2029	61	3671	611	896	0	0	2164
2030	58	3452	578	865	0	0	2010
2031	55	3272	547	774	0	0	1950
2032	52	3111	520	749	0	0	1841
2033	46	2717	455	689	0	0	1574
2034	26	1575	263	512	0	0	799
2035	15	871	146	404	0	0	322
2036	9	531	89	351	0	0	91
2037	6	357	60	324	0	0	-27

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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14th of April, 2022

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, 2021

Dear Mr. Carbone,

This reserves- and contingent resources statement has been prepared by SGS Nederland BV and issued on April 14th, 2022 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, 2021, 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.

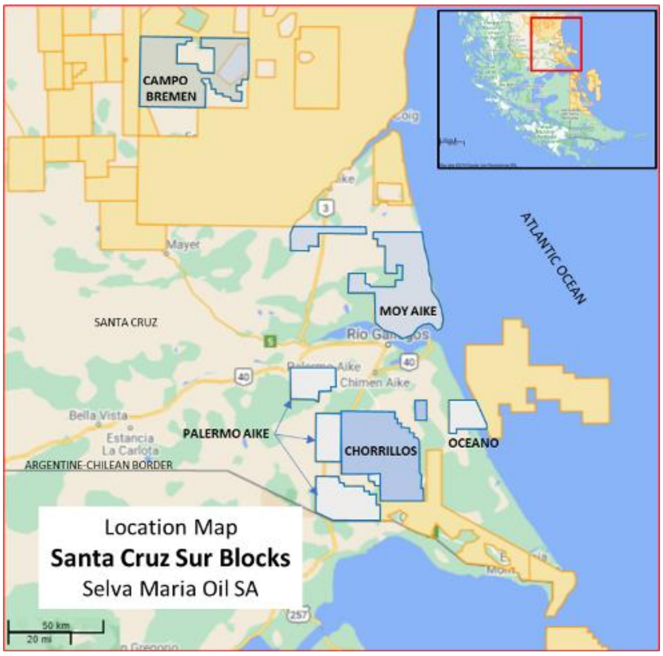


Figure 1 Location map - All concessions

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 is still working on a detailed study in which they will review the outstanding information, reinterpret the geophysical, geological and reservoir engineering data available from the different assets and will define a development plan for the coming 5 years.
The previous operator development plans in terms of drilling of new wells and workover activities in the existing wells is still under revision.
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).

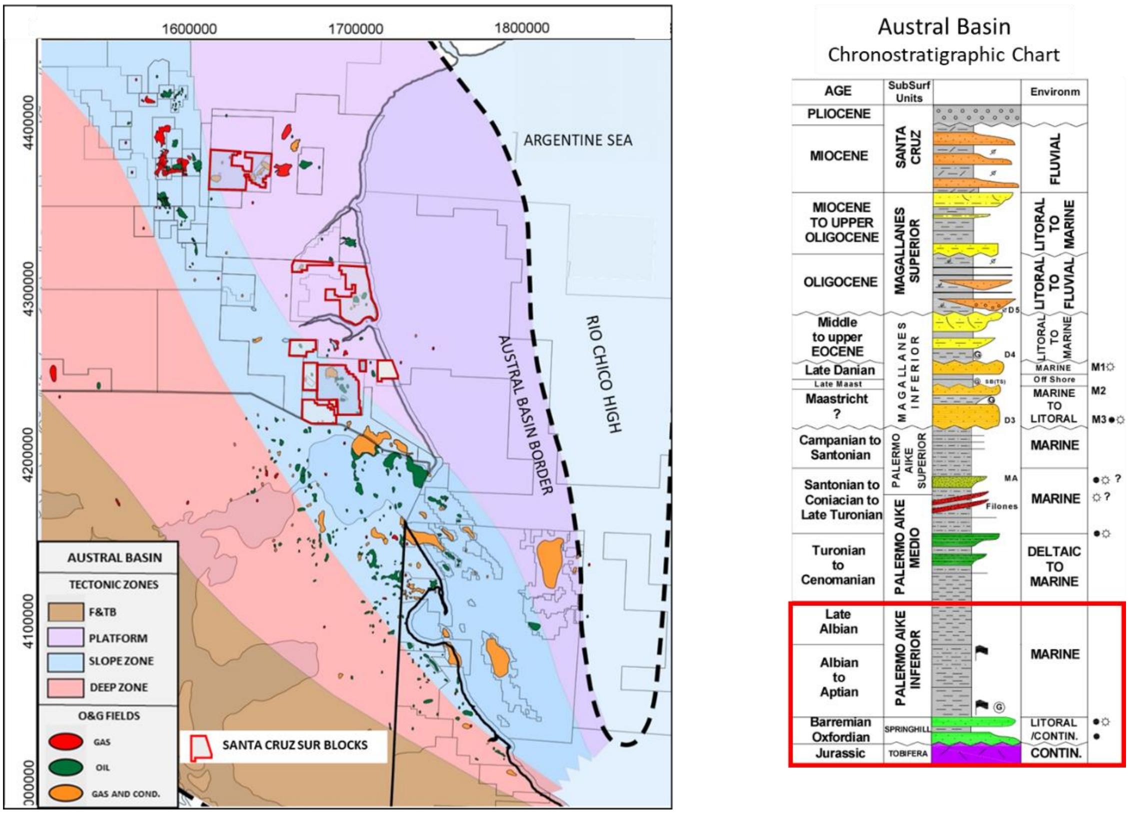


Figure 2 Regional structural framework and stratigraphic column Austral basin, Argentina

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).

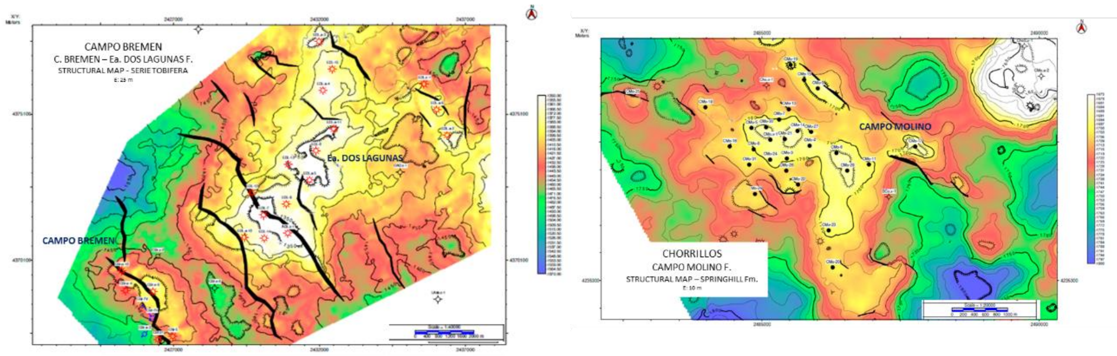


Figure 3 Examples of Structural Trap types in Campo Bremen and Chorrillos Concessions

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 is still going through a process of technically reviewing all the available information for each of these 5 assets.
Once the technical review is completed, Interoil will redefine their development plans in terms of drilling and workover activities for each of the above mentioned assets.

The company´s 2022 partner approved development plan includes an investment of 357 MUS$ for installation of a mercury removing facility for which a technical study, as well as a costing overview, was presented to the auditor. This plant will allow a considerable reduction in the mercury content of the produced oil impacting favourably in the oil sale price and marketability.
Extra power generation and compression is also part of the planned activities for 2022. This will favour the amount of oil and gas that can be processed in the facilities, estimating the company an increase of more than 250 bopd and its associated gas due to this action. The project has been classified as “Justified for Development”, and undeveloped reserves have been attributed to this project. Formal FID is still pending.

Some other minor investment amounts were considered for small well interventions, if necessary, aimed to put back in production 27 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 the integral study has been finalised, activities arising from this plan will be subject to a technical and commercial audit 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. Other assumptions on commerciality have not been considered.

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	233	6.65	19	0.55	16.6	0.47
	Developed NP	0	0.00	0	0.00	0.0	0.00
	Undeveloped	137	0.46	11	0.04	9.7	0.03
	Total 1P	**371**	**7.11**	**31**	**0.59**	**26.3**	**0.50**
	Total 2P	**397**	**7.26**	**33**	**0.61**	**28.1**	**0.51**
	Total 3P	**646**	**10.93**	**54**	**0.91**	**45.8**	**0.77**

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**
2022	390	399	404
2023	332	355	369
2024	300	327	347
2025	269	299	324

The extrapolation of the production beyond economic limit and for a 10 year extension period has been classified as Contingent Resources. Other assumptions on commerciality have not been considered. (Table 4).

Table 4 Gross Contingent Resources statement - per concession

Field	OIL - Development Not Viable (Mstb)		
	1C	2C	3C
Campo Bremen	56	70	81
Chorrillos	873	1186	1267
Moy Aike	156	178	188
Oceano	30	35	42
Palermo Aike	0	0	0
Total	**1114**	**1469**	**1578**

Field	GAS - Development Not Vianle (Bscf)		
	1C	2C	3C
Campo Bremen	3.8	4.4	4.7
Chorrillos	13.5	15.8	16.5
Moy Aike	0.4	0.4	0.4
Oceano	3.7	4.0	3.9
Palermo Aike	0.0	0.0	0.0
Total	**17.5**	**20.7**	**24.5**

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 2020 and year-end 2021 (gross volumes):

Table 5 - Reserves evolution year-end 2020-2021

RESERVES DEVELOPMENT (GROSS 100% VOLUME)				
	Crude Oil (Mstb)		Gas (MMscf)	
	1P	2P	1P	2P
Balance (as of year and last full year)	387	398	8.58	8.75
Production 2021	117		4.15	
Acquisitions / Disposals				
Extensions / Discoveries				
New Developments	137	159	0.46	0.20
Revisions of previous estimates	37	43	2.22	2.46
Balance (as of 31-Dec-2021)	**371**	**397**	**7.11**	**7.26**

M: refers to thousands
MM: refers to millions

The reduction included in “Revisions of previous estimates” for oil is explained by the lower performance of the producing wells from what was previously anticipated. Gas wells, on the other hand, have performed better than expected.

New developments refer to the oil reserves (and its associated gas) generated by the investment and installation of the surface facilities that will allow a total of 27 wells to be put back on production.

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 are currently affected in Argentina by a federal government regulation imposing a “barril criollo” of reference and its corresponding forecast should be used for reserves determination purposes.

An oil price of 60,50 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) 2022-2026

Year	Oil Price US$/bbl	Brent Price US$/bbl	Gas Price US$/MMBtu
2022	60,50	78,70	3,66
2023	56,35	73,30	3,69
2024	53,66	69,80	3,73
2025	51,81	67,40	3,77
2026	50,66	65,90	3,80

2022 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 in the economic evaluation:

Table 7 Overview cost aspects

Expense	2022
G&A Fixed Costs - kUS$	2000
Salaries - kUS$	7885
Fixed Opex - kUS$	2415
Variable Opex - US$/bbl	6,42
Transp, Treatment, Storage - US$/bbl	incl in Opex

The abandonment cost of a well was provided by InterOil and is considered to be 100 MUS$ (RT21).

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

InterOil Argentina started its operation in Austral Basin at the end of 2019. Currently, they have a share in five concessions: Campo Bremen, Chorrillos, Moy Aike, Océano and Palermo Aike.

The current production for these five blocks is approximately 351 bopd and 9,730 Mscf/d of gas as of December 31, 2021.
340 wells were drilled in total and 52 of them are on production or injection today. The cumulative oil production is 23 MMbbl and 379 Bscf of gas have been produced. The main target formations are Serie Tobífera and Formación Springhill.

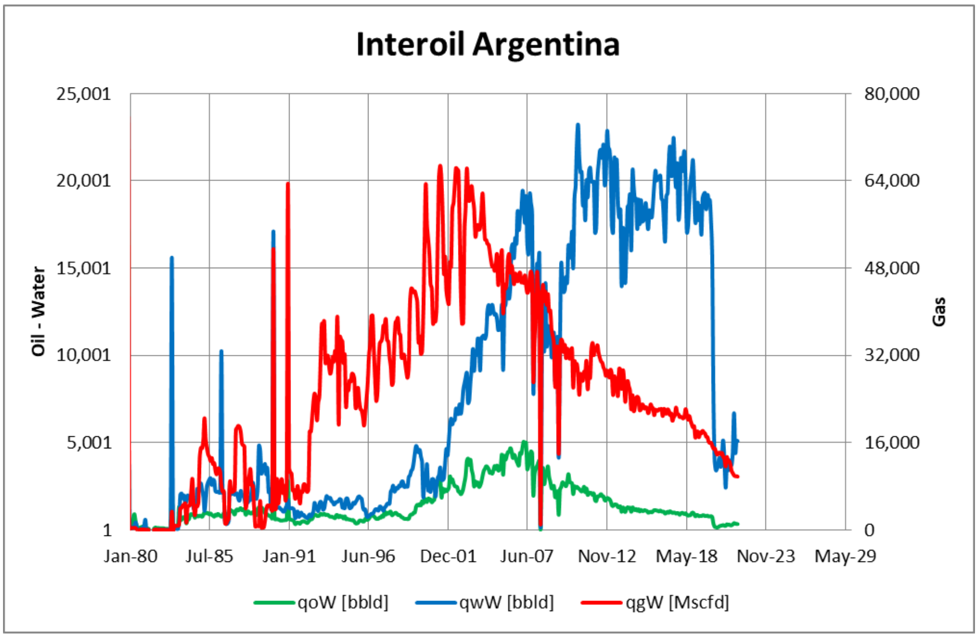


Figure 4 Historical Production – Santa Cruz assets

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

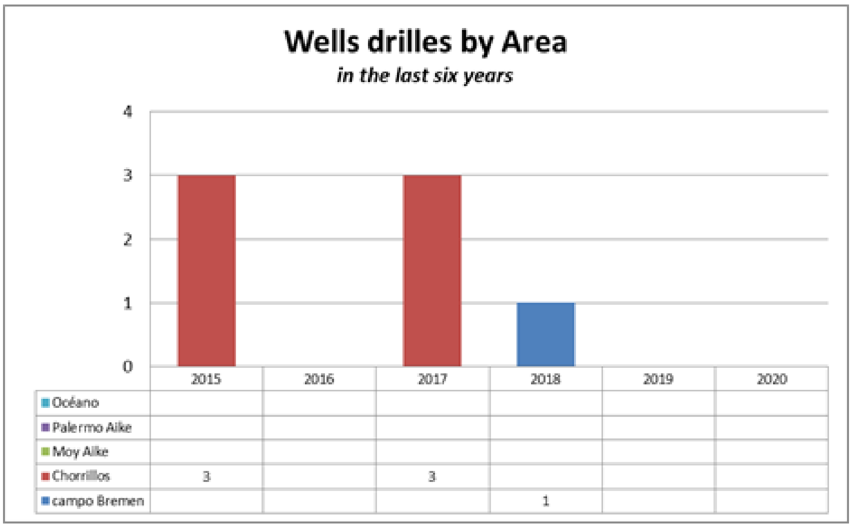


Figure 5 Wells drilled in Santa Cruz assets in the last six years

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 47 bbl/d and 2,100 Mscf/d of gas. 53 wells were drilled in the concession, and only 6 of them are flowing as of December 2021.

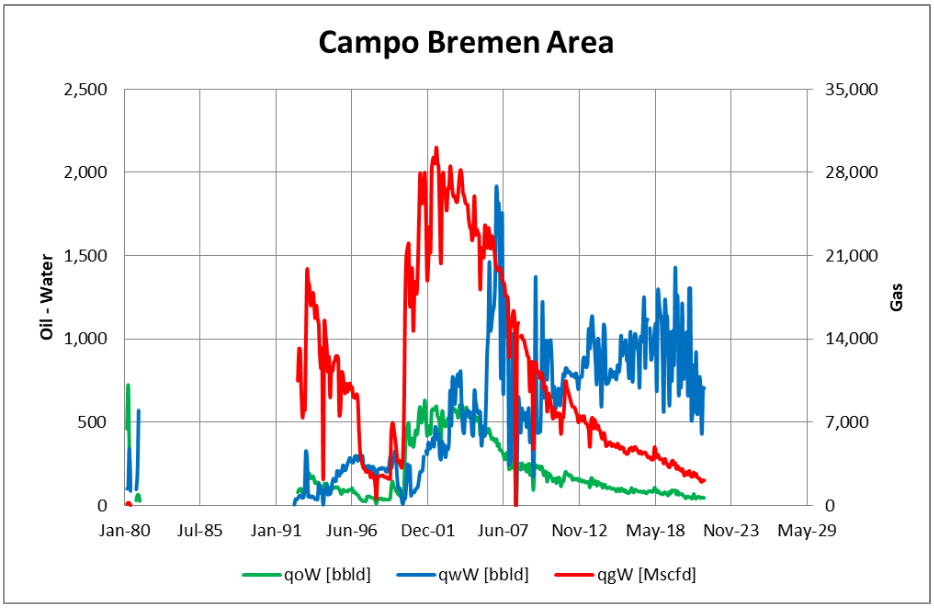


Figure 6 Historical production Campo Bremen

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 188 bbl/d and current gas production is 5,900 Mscf/d. 136 wells were drilled in the concession and only 24 of them are flowing as of December 2021.

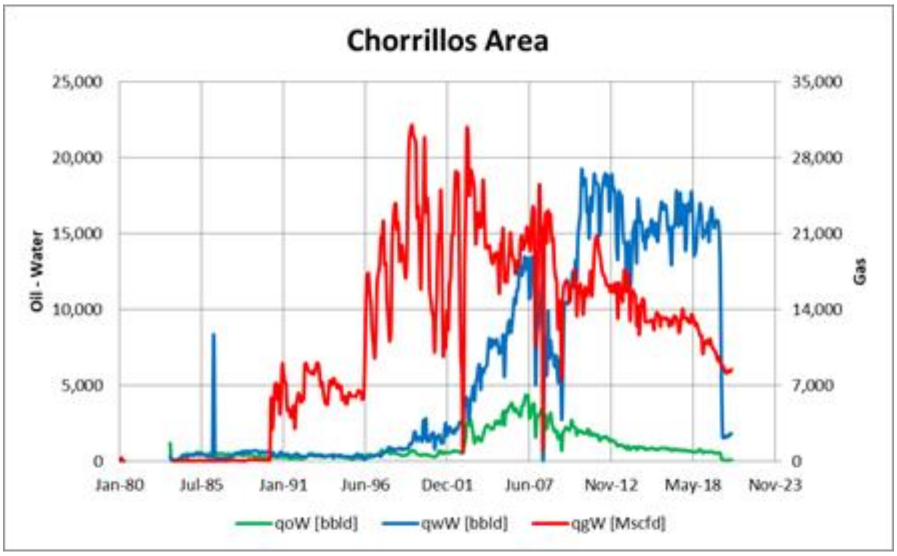


Figure 7 Historical production Chorrillos

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 100 bbl/d and current gas production is 106 Mscf/d. 62 wells were drilled in the area and only 6 of them are flowing as of December 2021.

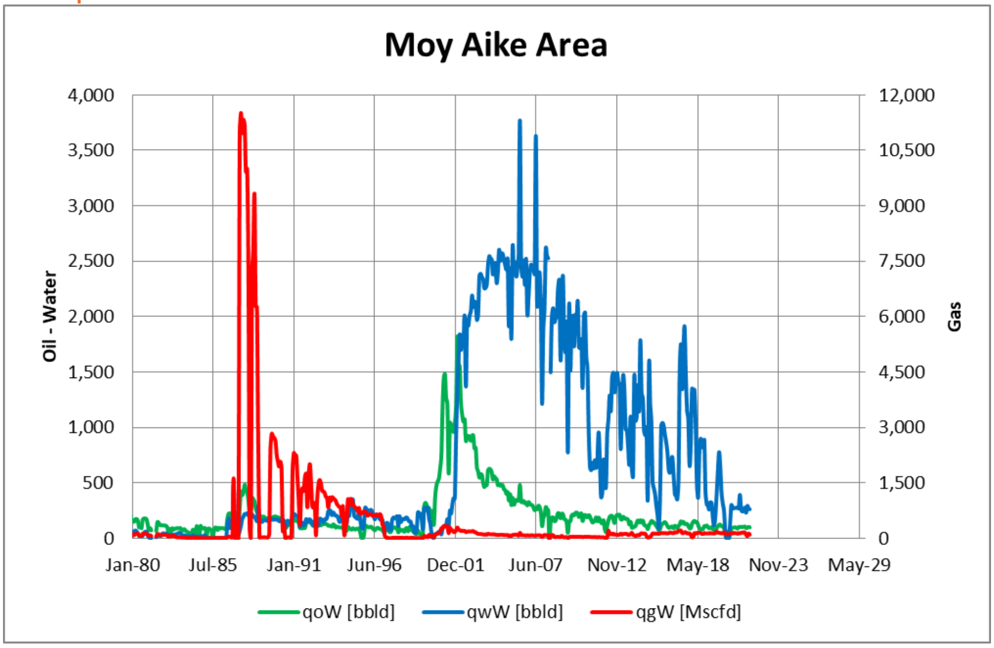


Figure 8 Historical production Moy Aike

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 16 bbl/d and current gas production is 1,624 Mscf/d. 47 wells were drilled in the area, and only 5 of them are flowing as of December 2021. As the field is offshore, most of the wells were drilled from the coast and deviated to penetrate the reservoirs.

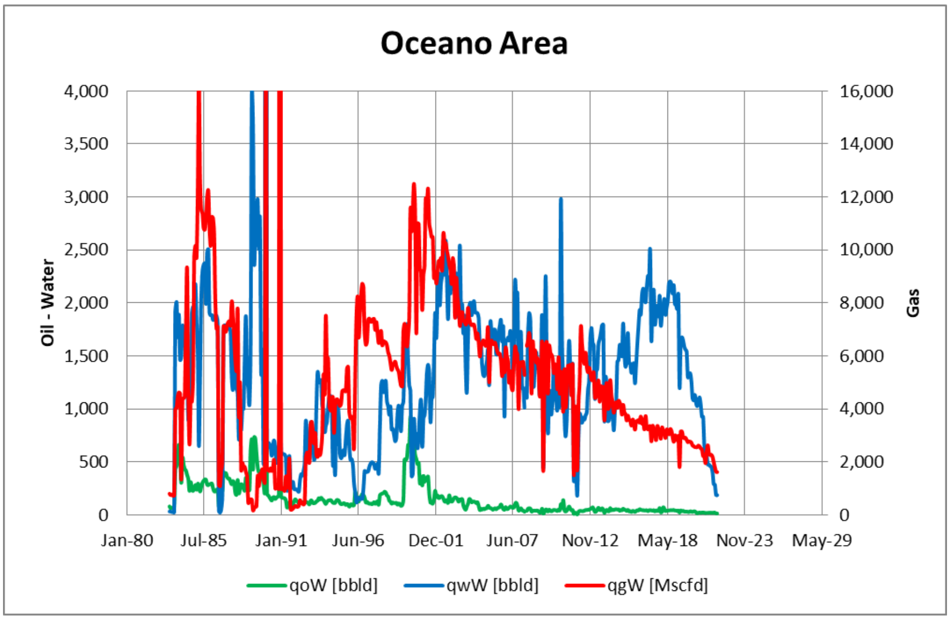


Figure 9 Historical production Océano

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 31 of December 2021. 41 wells were drilled in the area.

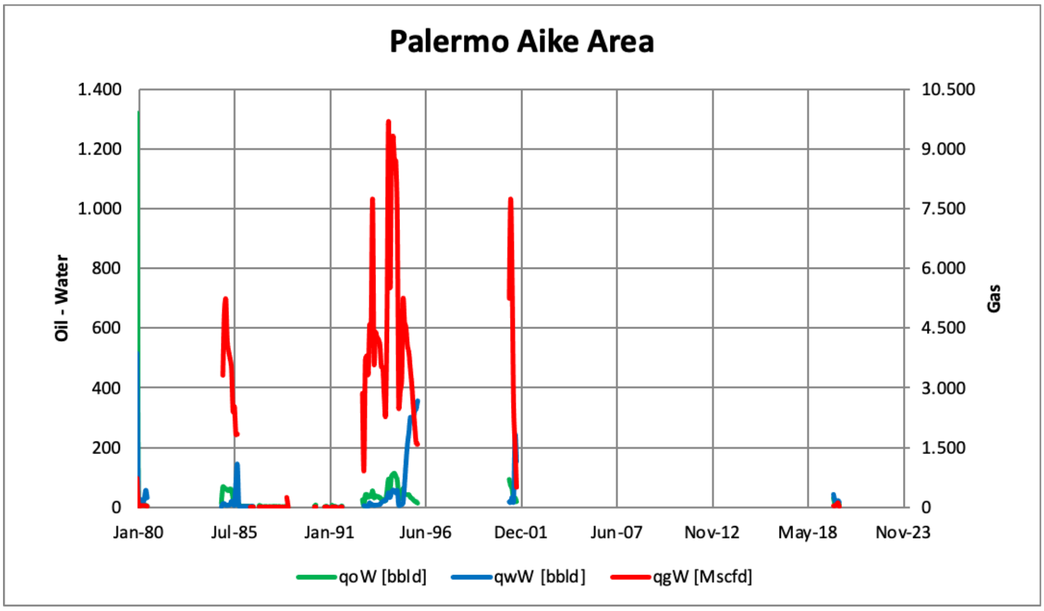


Figure 10 Historical production Palermo Aike

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 2021. 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 further 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 16 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, 2021

		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	233	6.65	19	0.55	17	0.47
	Developed NP	0	0.00	0	0.00	0	0.00
	Undeveloped	137	0.46	11	0.04	10	0.03
	Total 1P	**371**	**7.11**	**31**	**0.59**	**26**	**0.50**
	Total 2P	**397**	**7.26**	**33**	**0.61**	**28**	**0.51**
	Total 3P	**646**	**10.93**	**54**	**0.91**	**46**	**0.77**
CAMPO BREMEN	PROVED						
	Developed	29	1.41	2	0.12	2	0.10
	Developed NP	0	0.00	0	0.00	0	0.00
	Undeveloped	0	0.00	0	0.00	0	0.00
	Total 1P	29	1.41	2	0.12	2	0.10
	Total 2P	29	1.43	2	0.12	2	0.10
	Total 3P	43	2.11	4	0.18	3	0.15
CHORRILLOS	PROVED						
	Developed	128	4.03	11	0.34	9	0.29
	Developed NP	0	0.00	0	0.00	0	0.00
	Undeveloped	137	0.46	11	0.04	10	0.03
	Total 1P	265	4.49	22	0.37	19	0.32
	Total 2P	290	4.61	24	0.38	21	0.33
	Total 3P	490	7.02	41	0.59	35	0.50
MOY AIKE	PROVED						
	Developed	66	0.10	5	0.01	5	0.01
	Developed NP	0	0.00	0	0.00	0	0.00
	Undeveloped	0	0.00	0	0.00	0	0.00
	Total 1P	66	0.10	5	0.01	5	0.01
	Total 2P	67	0.10	6	0.01	5	0.01
	Total 3P	96	0.14	8	0.01	7	0.01
OCEANO	PROVED						
	Developed	11	1.12	1	0.09	1	0.08
	Developed NP	0	0.00	0	0.00	0	0.00
	Undeveloped	0	0.00	0	0.00	0	0.00
	Total 1P	11	1.12	1	0.09	1	0.08
	Total 2P	11	1.12	1	0.09	1	0.08
	Total 3P	17	1.65	1	0.14	1	0.12

Exhibit-II Detailed overview reserves and costs

InterOil Argentina

Net Revenue Interest Reserve Cash Flows Properties in Santa Cruz, Argentina as of December 31, 2021 (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 10-year period.

Proved Developed Reserves

Production Forecast			Gas Sales	Gross Income	Operating Expenses	Investment	Pre-Tax Cashflow
Year	Oil - Mstb	Gas - Bscf	Bscf	KUS$	KUS$	KUS$	KUS$
2022	4,8	0,28	0,25	1135	1101	0	34
2023	4,1	0,24	0,21	958	1116	0	-158
2024	3,5	0,21	0,19	853	1136	0	-283
2025	3,0	0,19	0,17	758	1157	0	-399
2026	2,6	0,17	0,16	678	1180	0	-502

Proved Reserves (1P)

Production Forecast			Gas Sales	Gross Income	Operating Expenses	Investment	Pre-Tax Cashflow
Year	Oil - Mstb	Gas - Bscf	Bscf	KUS$	KUS$	KUS$	KUS$
2022	12,0	0,26	0,24	1485	1452	64	-31
2023	14,3	0,25	0,22	1520	1477	0	43
2024	12,9	0,22	0,20	1353	1464	0	-111
2025	11,0	0,20	0,18	1172	1447	0	-275
2026	9,5	0,18	0,16	1027	1437	0	-411

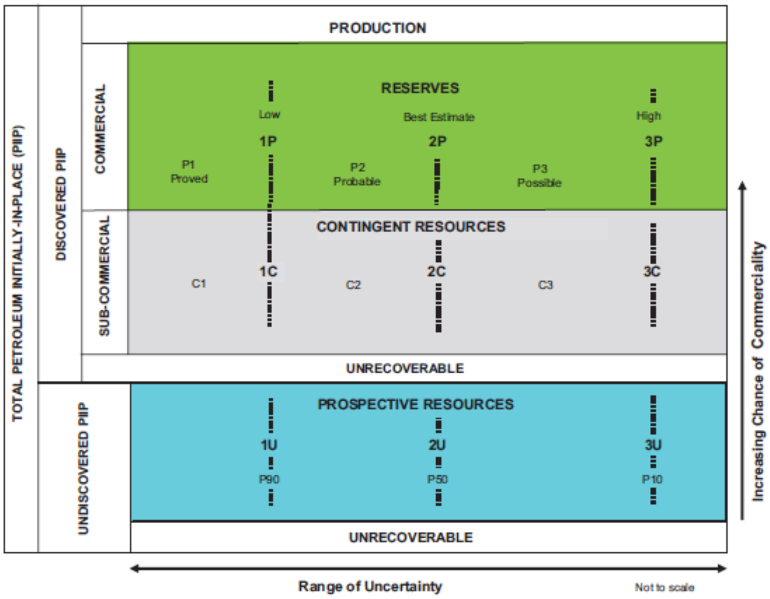
2P Reserves

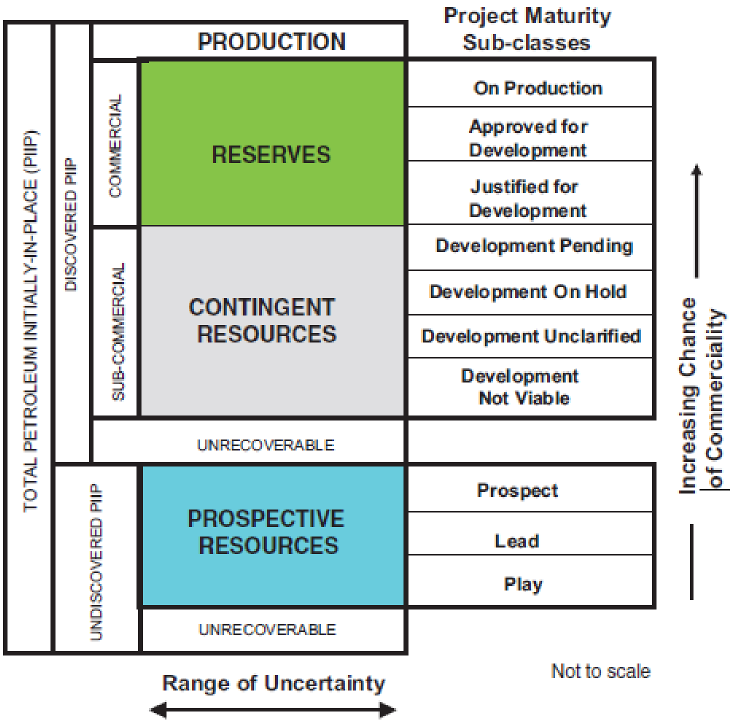
Production Forecast			Gas Sales	Gross Income	Operating Expenses	Investment	Pre-Tax Cashflow
Year	Oil - Mstb	Gas - Bscf	Bscf	KUS$	KUS$	KUS$	KUS$
2022	12,4	0,26	0,24	1516	1458	64	-6
2023	15,7	0,25	0,23	1619	1499	0	121
2024	14,7	0,23	0,21	1476	1492	0	-16
2025	13,1	0,21	0,19	1315	1481	0	-166
2026	11,6	0,20	0,18	1183	1475	0	-292

3P Reserves

Production Forecast			Gas Sales	Gross Income	Operating Expenses	Investment	Pre-Tax Cashflow
Year	Oil - Mstb	Gas - Bscf	Bscf	KUS$	KUS$	KUS$	KUS$
2022	12,8	0,26	0,24	1546	1465	64	17
2023	16,9	0,26	0,24	1710	1520	0	190
2024	16,1	0,25	0,23	1591	1521	0	70
2025	14,7	0,23	0,21	1452	1516	0	-65
2026	13,5	0,22	0,20	1340	1517	0	-177

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.

SGS

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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7th of April, 2022

Reserves and Contingent Resources Statement for
Mata Magallanes Oeste concession, Argentina
as of December 31, 2021

Dear Mr. Carbone,

This reserves- and contingent resources statement has been prepared by SGS Nederland BV and issued on April 7th, 2022 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, 2021, 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.

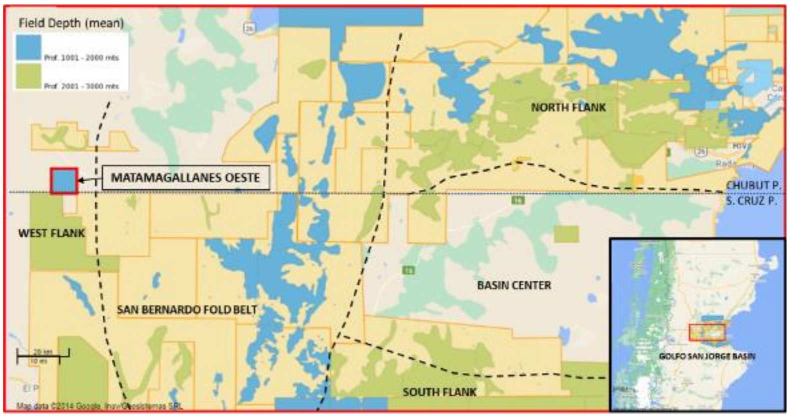

Figure 1 Location map - All concessions

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)

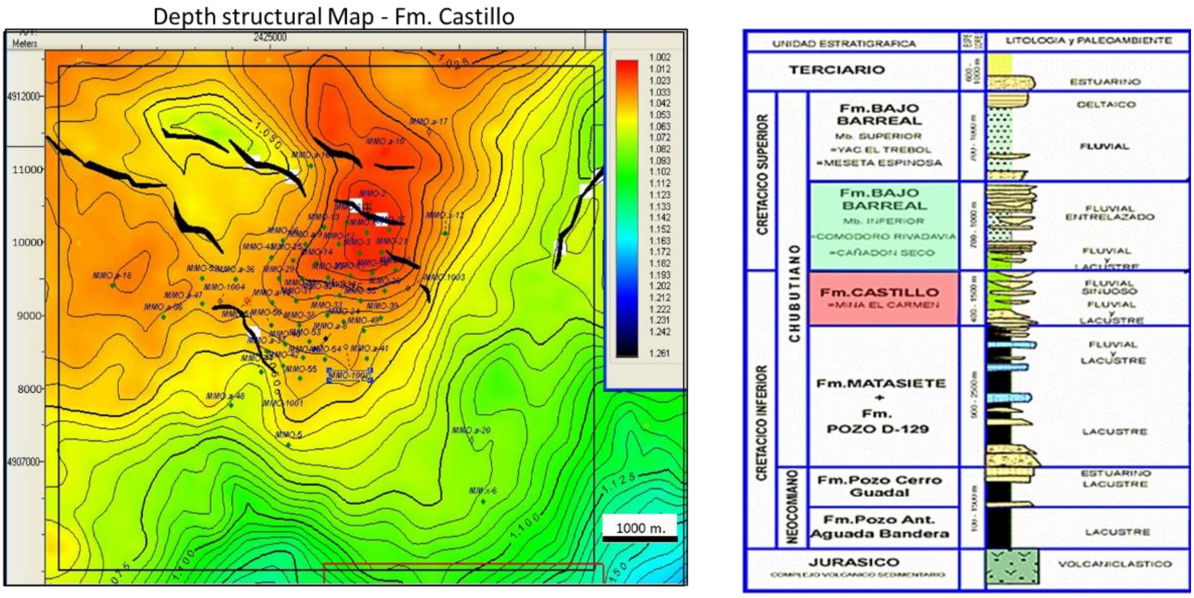

Figure 2 Top Castillo Fm. structural map and San Jorge basin stratigraphic column

Development Plan

Interoil´s updated development plan for Mata Magallanes Oeste accounts for the reactivation of 15 oil wells, the workover of 8 oil wells and the drilling of several new wells to increase the recovery factor of the field.

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 Covid situation from the 2021 Work Program, will be performed during the first half of 2022 in MMO-30 (replacing MMO-15 gas workover on 2021 Audit) and MMO-31. It has an estimated investment cost of 850 MUS$, including the revamping of some surface facilities.

The purpose of these workovers is to generate gas that will be consumed in the field for running the surface facilities and the well artificial lift systems. This gas production will enable the reopening 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 achieved.

2. *Workover of the oil wells*

Interoil has planned for 8 workovers, aiming to increase oil production mainly from Bajo Barreal Fm. They will take place between 2022 and 2023. These workovers will be performed tapping into oil in new and previously perforated intervals. SGS has reviewed the plans and technically endorses the proposed workovers, 4 of which are scheduled for the second half of 2022, and 4 are scheduled for 2023. The cost of each of the proposed workovers ranges between 350 and 450 MUS$.

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

3. *Drilling of new oil wells*

The audit also includes reviewing the proposal of 3 new wells, that were presented to SGS with its proposed location and corresponding technical justification. 1 of the wells is scheduled to be drilled in 2023 and 2 of the wells are to be drilled during 2024. These wells have been classified as contingent resources since the company has not presented enough evidence of a firm commitment to proceed and does not have a justifiable finance plan to proceed with the project at the moment.

Contingent Resources

As stated in the above chapter, contingent resources in this report account for the 3 new wells to be drilled in 2023-2024, 1 of the proposed oil workovers and 4 producing wells included in the reactivation project, which are not economic for the best estimate case under the current oil price scenario in Argentina.

All the developed production after the economic limit and up to the license expiry date has also been considered as contingent resources. No production beyond this date, April 2043, has been considered since from our 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-2021:

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	226	378	181	303	159	266
	Undeveloped	0	0	0	0	0	0
	Total 1P	**226**	**378**	**181**	**303**	**159**	**266**
	Total 2P	**821**	**3308**	**657**	**2647**	**578**	**2329**
	Total 3P	**1164**	**7435**	**931**	**5948**	**819**	**5234**

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 reserves were estimated through extrapolation of the producing gas-oil ratios and gas to be produced from the workovers was added to the gas reserves figures. All of the stated gas volumes, though considered as reserves, are classified as consumed in own operations (CiO) and 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
2022	19	306	804
2023	50	380	883
2024	49	296	648
2025	39	235	514
2026	33	199	431
2027	29	169	362
2028	25	144	305
2029	22	122	257
2030	19	104	216
2031	16	89	183
2032	14	76	154
2033	12	65	130
2034	11	56	110
2035	0	48	94
2036	0	41	80
2037	0	33	64
2038	0	0	44

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**	**314**	**528**	**251**	**422**	**221**	**372**
	Total 2C	**442**	**745**	**354**	**596**	**311**	**524**
	Total 3C	**554**	**933**	**443**	**746**	**390**	**656**

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 2020 and year-end 2021 (gross volumes):

Table 4 - Reserves evolution year-end 2020-2021

RESERVES DEVELOPMENT (GROSS 100% VOLUME)				
	Crude Oil (Mstb)		Gas (MMscf)	
	1P	2P	1P	2P
Balance (as of year and last full year)	193	399	676	1438
Production 2020	4,7			
Acquisitions / Disposals				
Extensions / Discoveries				
New Developments	240	525	404	884
Revisions of previous estimates	-202	-98	-702	987
Balance (as of 31-Dec-2020)	**226**	**821**	**378**	**3308**

M: refers to thousands
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The increase in the "New Developments" category refers to the inclusion of 8 workovers to Bajo Barreal Fm and its associated gas.

The reduction due to “Revisions of previous estimates” refers to an adjustment to the production forecast of the 15 wells to be reactivated.

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 2022 and 2023 Work Plan. According to IOA the projects has passed their internal economic hurdle rate.

However, it is important to remark that due to force majeure reasons (COVID), no significant activity has taken place in MMO field during 2020 and 2021. However, SGS assumes that there is a reasonable expectation that operations can commence in 2022 and beyond considering the improved COVID situation. Upstream operational activities are being normalised in the basin.

Commercial considerations

Although the auditor commonly applies the (Intercontinental Exchange) Brent crude forward curve forecast for its estimations, oil prices are currently capped in Argentina by a federal government regulation imposing a “barril criollo” of reference and its corresponding forecast should be used for reserves determination purposes.

Table 5 states the “barril criollo” forecast used for this estimation over a 10-year period.

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 - “Barrill Criollo” 2022-2031

"Barril Criollo" Price	
Year	**US$ / bbl**
2022	40,00
2023	41,00
2024	42,00
2025	43,00
2026	44,00
2027	45,00
2028	45,00
2029	45,00
2030	45,00
2031	45,00

2022 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	MMO
Fixed Opex (kUS$/yr)	320
Variable Opex (US$/bbl)	8,00
Fixed G&A (kUS$/yr)	45,0
Oil transportation (US$/bbl)	4,50

The abandonment cost of a well was provided by InterOil and is considered to be 100 kUS$ (RT21).

Field costs, as per the above table, are escalated by 1% 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 2021, 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. 4 wells have produced intermittently during 2021.

The field has reached a cumulative production of 185 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):

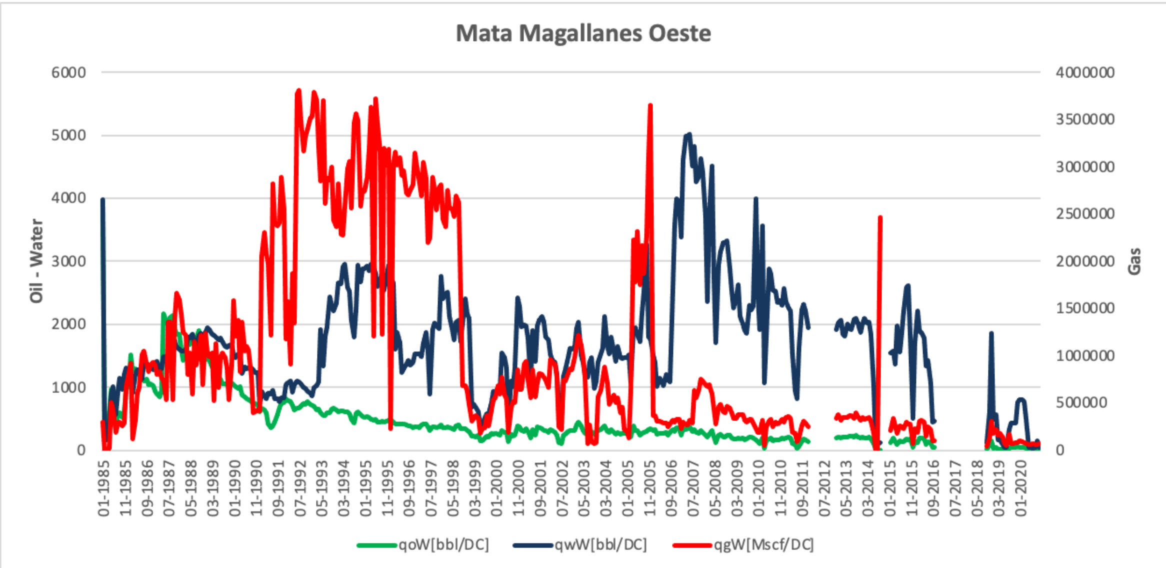

Figure 3 Mata Magallanes Oeste historical production

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 2021. 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 for 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 16 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, 2021

		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	226	378	181	303	159	266
	Undeveloped	0	0	0	0	0	0
	Total 1P	**226**	**378**	**181**	**303**	**159**	**266**
	Total 2P	**821**	**3308**	**657**	**2647**	**578**	**2329**
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		Crude Oil (Mstb)	Natural Gas (MMScf)	Crude Oil (Mstb)	Natural Gas (MMScf)	Crude Oil (Mstb)	Natural Gas (MMScf)
MATA MAGALLANES OESTE	**Total 1C**	**314**	**528**	**251**	**422**	**221**	**372**
	Total 2C	**442**	**745**	**354**	**596**	**311**	**524**
	Total 3C	**554**	**933**	**443**	**746**	**390**	**656**

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Exhibit-II Detailed overview reserves and costs

InterOil Argentina

Net Revenue Interest Reserve Cash Flows Properties in Chubut, Argentina as of December 31, 2021 (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 10-year period

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$
2022	14	19	0	535	71	417	736	-689
2023	30	50	0	1205	155	575	960	-485
2024	29	49	0	1166	146	568	0	452
2025	23	39	0	945	116	522	0	308
2026	19	33	0	832	100	501	0	231
2027	17	29	0	737	86	486	0	165
2028	15	25	0	639	75	475	0	90
2029	13	22	0	555	65	466	0	23
2030	11	19	0	481	56	461	0	-36

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$
2022	14	19	0	535	71	417	736	-689
2023	30	50	0	1205	155	575	960	-485
2024	29	49	1	1166	146	568	0	452
2025	23	39	2	945	116	522	0	308
2026	19	33	3	832	100	501	0	231
2027	17	29	4	737	86	486	0	165
2028	15	25	5	639	75	475	0	90
2029	13	22	6	555	65	466	0	23
2030	11	19	7	481	56	461	0	-36

M: refers to thousands
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2P Reserves

Year	Production Forecast Oil - Mstb	Gas - MMscf	Gas Sales MMscf	Gross Income MUS$	Oil Transport MUS$	Operating Expenses MUS$	Investment MUS$	Pre-Tax Cashflow MUS$
2022	33	306	0	1279	169	592	3096	-2577
2023	78	380	1	3100	399	1008	1320	373
2024	75	296	2	3038	381	985	0	1671
2025	61	235	3	2532	310	868	0	1354
2026	53	199	4	2259	271	805	0	1183
2027	46	169	5	2028	238	755	0	1036
2028	41	144	6	1782	209	713	0	860
2029	36	122	7	1566	183	677	0	705
2030	32	104	8	1377	161	647	0	568
2031	28	89	9	1211	142	622	0	447
2032	24	76	10	1066	125	602	0	339
2033	21	65	11	938	110	586	0	243
2034	19	56	12	827	97	573	0	157
2035	17	48	13	729	85	564	0	80
2036	15	41	14	643	75	557	0	10
2037	11	33	15	492	58	537	0	-103

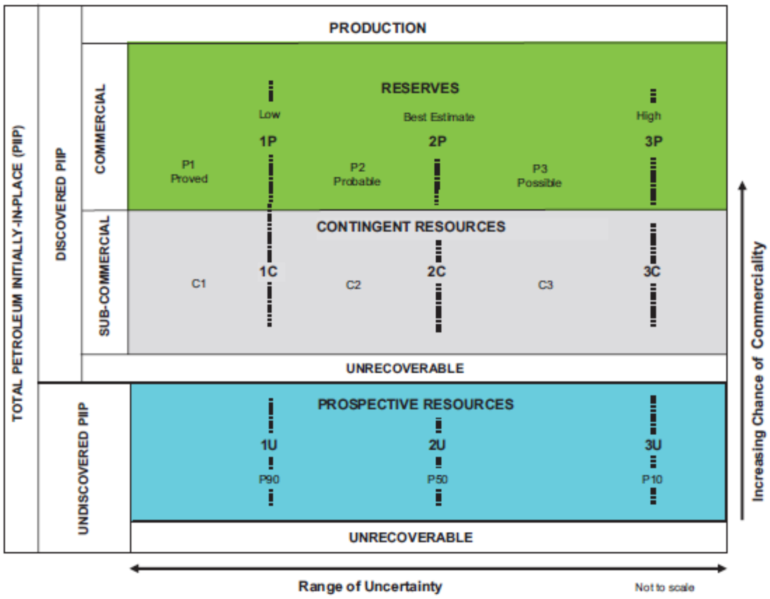
M: refers to thousands
MM: refers to millions

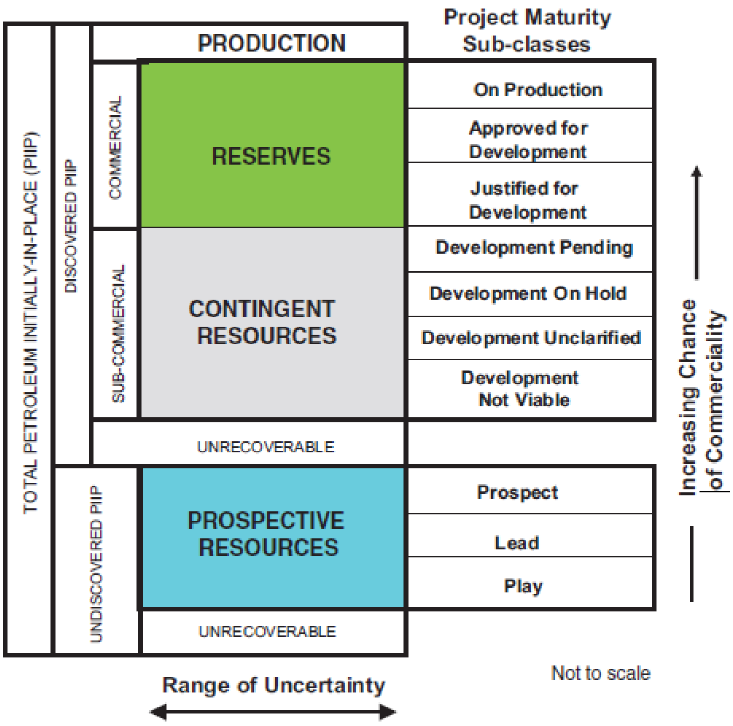
3P Reserves

Year	Production Forecast Oil - Mstb	Gas - MMscf	Gas Sales MMscf	Gross Income MUS$	Oil Transport MUS$	Operating Expenses MUS$	Investment MUS$	Pre-Tax Cashflow MUS$
2022	44	804	0	1717	226	694	3096	-2300
2023	109	883	0	4324	556	1288	1320	1160
2024	104	648	0	4243	533	1254	0	2456
2025	85	514	0	3533	433	1086	0	2014
2026	74	431	0	3152	378	995	0	1779
2027	65	362	0	2829	331	922	0	1576
2028	57	305	0	2484	291	859	0	1334
2029	50	257	0	2182	256	805	0	1121
2030	44	216	0	1917	225	760	0	933
2031	39	183	0	1686	197	721	0	767
2032	34	154	1	1483	174	689	0	621
2033	30	130	2	1304	153	662	0	489
2034	26	110	3	1149	135	640	0	374
2035	23	94	4	1011	118	623	0	270
2036	20	80	5	892	105	609	0	179
2037	16	64	6	678	79	576	0	22
2038	8	44	7	331	39	516	0	-223

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.

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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.

SGS

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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Mr. Leandro Carbone
Chief Executive Officer
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Ciudad Autónoma de Buenos Aires, Argentina
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7th of April 2022

Reserves and Contingent Resources Statement for
La Brea concession, Argentina
as of December 31, 2021

Dear Mr. Carbone,

This reserves- and contingent resources statement has been prepared by SGS Nederland BV and issued on April 7th , 2022 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, 2021, 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.

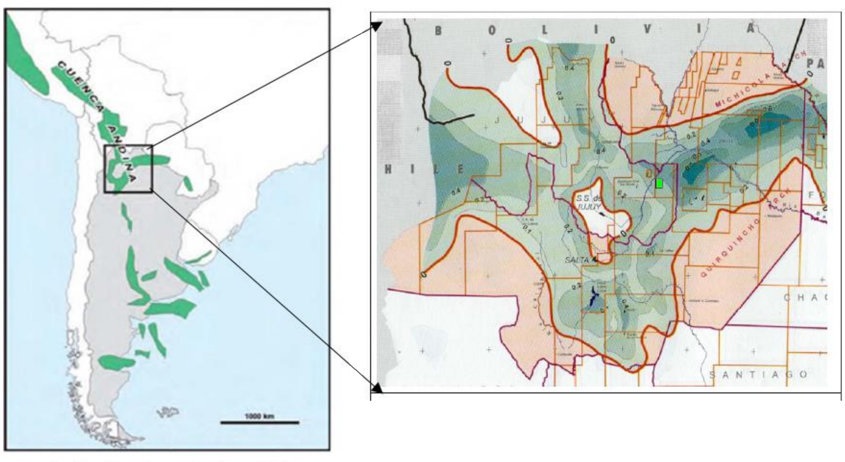


Figure 1 Location map - All concessions

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

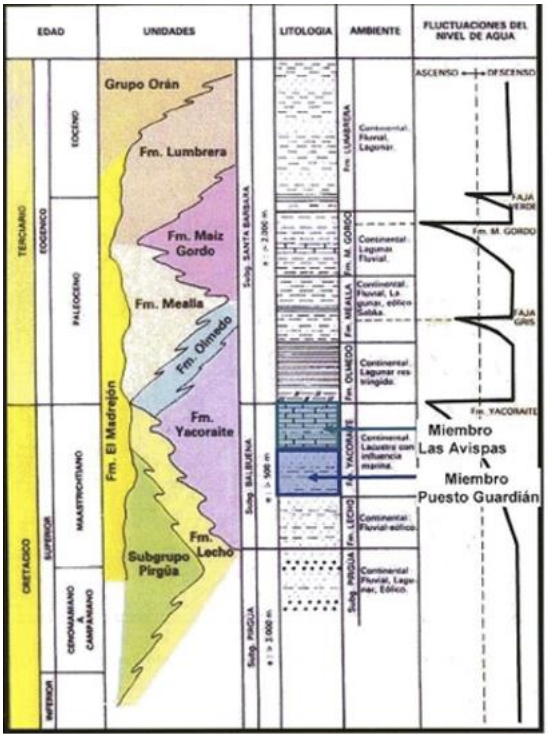


Figure 2 Stratigraphic column in the Noroeste Basin

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).

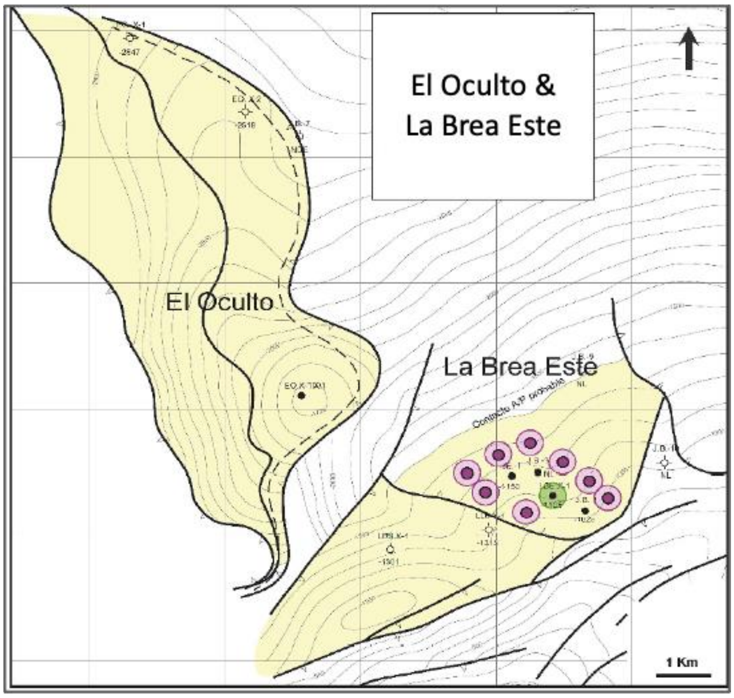


Figure 3 Map showing the La Brea main accumulations

Development plan

Interoil´s plan for La Brea for rehabilitating and putting into production the field includes a hydraulic fracture of YPF.Jj.LBEx-1 well and the drilling and fracturing of 8 wells in La Brea Este accumulation. This program is exactly the same that the company presented to SGS during last year´s audit.
A pilot test should be performed to demonstrate economic rates after stimulation, prior to potential re-classification to reserves.

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 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-2021:

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 on a probabilistic volumetric analysis, considering the proven wells located at La Brea Este and El Oculto and the seismic and well logs information to define a structure closure and contact limit.
Contingent resources in the 1C category correspond to the hydraulic fracture of 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 2021. 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 16 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

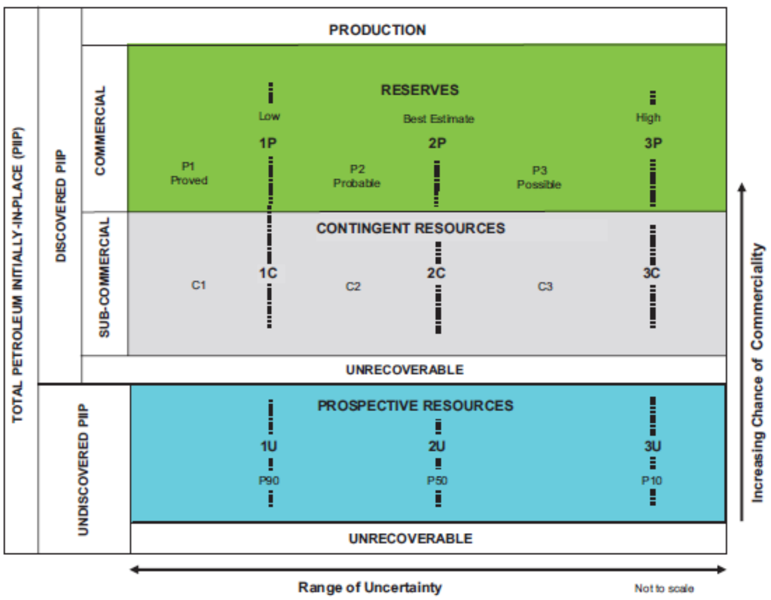
Project Manager

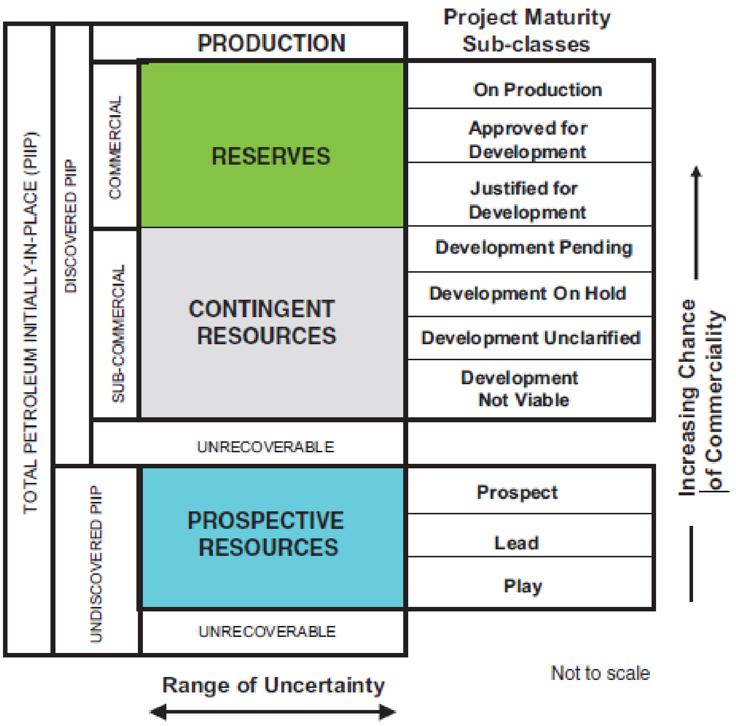
Primary technical- and commercial person

Richard Keen

Business Manager

Exhibit-I SPE-PRMS-2018 classification and guidelines





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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.