Interoil Exploration and production ASA 2020 annual statement of reserves

Interoil Exploration & Production ASA ("Interoil") operates oil and gas fields where in Colombia there are two exploration blocks plus five producing fields and in Argentina a total of seven exploitation licenses, involving a total of 15 producing fields, plus one exploration block.

A summary of the reserves P1 (Proven), 2P (Proven + Probable) and 3P (Proven + Probable + Possible) reserves as of 31 December 2020 are shown in Table 1 for Colombia and the same in Table 2 for Argentina. Then, each table has been further subdivided into a Proven Developed Producing (PDP), Proven Developed Non-producing (PNDP) categories, in line with the PMRS definitions.

Table 1. Colombia Reserves Summary

Colombia	Gross Volumes (100%)		Interoil Working Interest Volumes		Net Interoil Equity Volumes	
	Liquid [MMbbl]	Gas [Bscf]	Liquid [MMbbl]	Gas [Bscf]	Liquid [MMbbl]	Gas [Bscf]
PDP	1.08	2.65	0.80	1.85	0.76	1.85
PNDP	0.17	1.03	0.13	0.72	0.13	0.72
P1	**1.25**	**3.68**	**0.92**	**2.57**	**0.89**	**2.57**
2P	2.18	5.94	1.60	4.16	1.54	4.16
3P	3.23	8.41	2.38	5.89	2.27	5.89

Table 2. Argentina Reserves Summary

Argentina	Gross Volumes (100%)		Interoil Working Interest Volumes		Net Interoil Equity Volumes	
	Liquid [MMbbl]	Gas [Bscf]	Liquid [MMbbl]	Gas [Bscf]	Liquid [MMbbl]	Gas [Bscf]
PDP	0.58	9.26	0.19	1.26	0.16	1.09
PNDP	-.-	-.-	-.-	-.-	-.-	-.-
P1	**0.58**	**9.26**	**0.19**	**1.26**	**0.16**	**1.09**
2P	0.80	10.19	0.35	1.88	0.31	1.63
3P	1.06	11.20	0.56	2.56	0.49	2.22

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 as of December 31, 2020 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 1.58 MMboe which represents an increase of 124 Mboe with respect to last year Interoil's figures. On the other hand, 2P hydrocarbon net reserves after royalty accounts for 2.67 MMboe, a reduction by 290 Mboe; mainly related with COVID-19 pandemic and global economic crisis that impacted the 2020 investment program on the producing fields.

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19th of February, 2021

Reserves and Contingent Resources Statement for
Ambrosía, Río Opia, Maná,
Llanos 47 and Altair Areas, Colombia
as of December 31, 2020

Dear Mr. Carbone,

This reserves- and contingent resources statement has been prepared by SGS Nederland B.V. (henceforth SGS) and issued on February 19th , 2021 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 in 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, 2020, 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 areas, SGS herewith presents a detailed outline of the developments, production and cost 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.

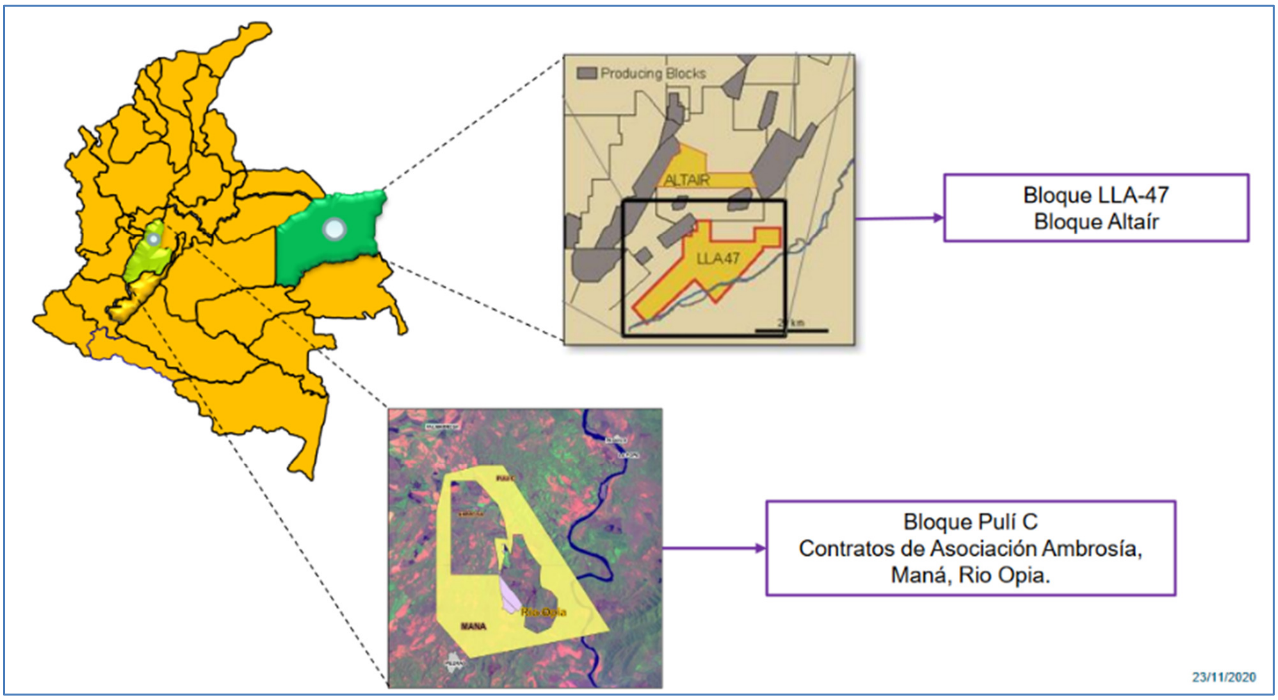


Figure 1 Location maps all concessions

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

The Llanos 47 and Altair assets are governed by the "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

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 which started in 2011.
SGS has 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.
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).

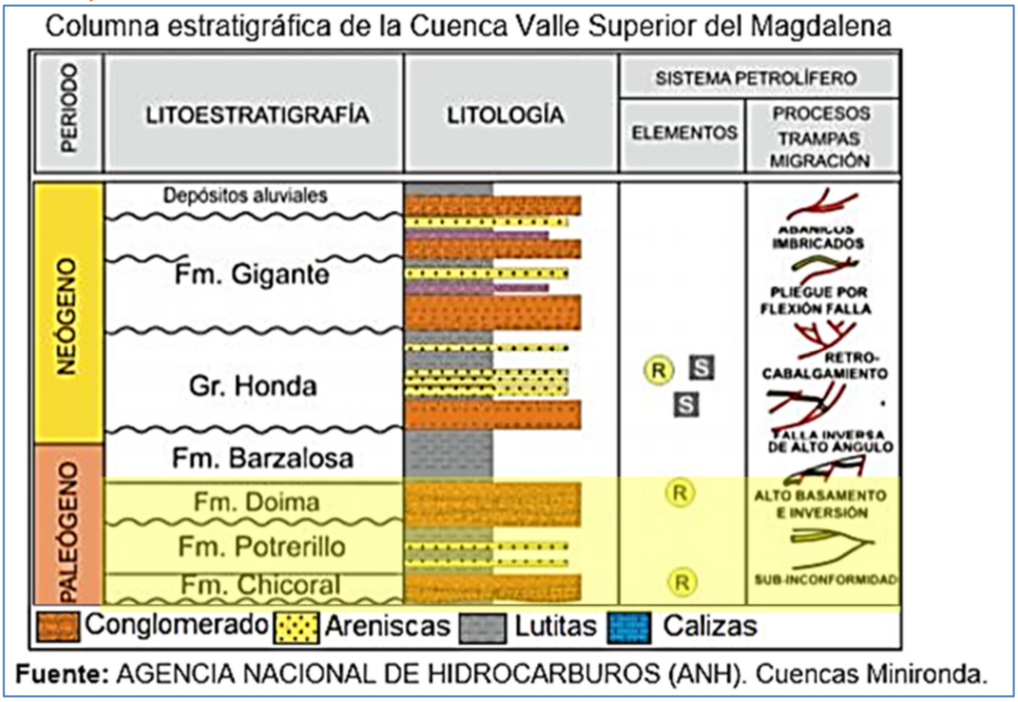


Figure 2 Stratigraphic column

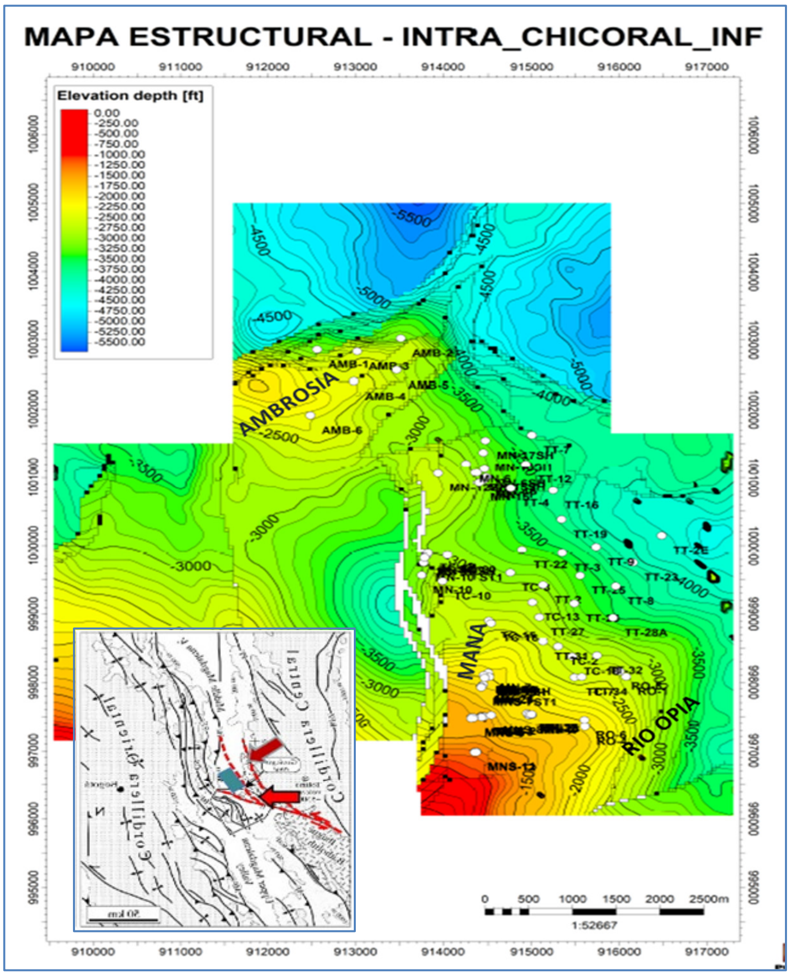


Figure 3 Top structure map Puli-C license

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 typify 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 represent reservoirs of alluvial and fluvial origin with sub-environments of braided and meandering channels.
The Potrerillos formation constitutes a mostly pelitic section of lagoonal and floodplain environments that separates both the Chicoral and Doima production units. Floodplain deposits 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 of this region is structural highs against normal faults with three-way closures. Both Llanos 47 and Altair blocks have remaining exploratory potential associated with these types of traps, aligned with the main regional faults of the basin.
The key producing formation in these blocks is the Oligocene age Carbonera Formation a sequence of mixed to marine-proximal sediments with average porosities of 22% and producing 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.

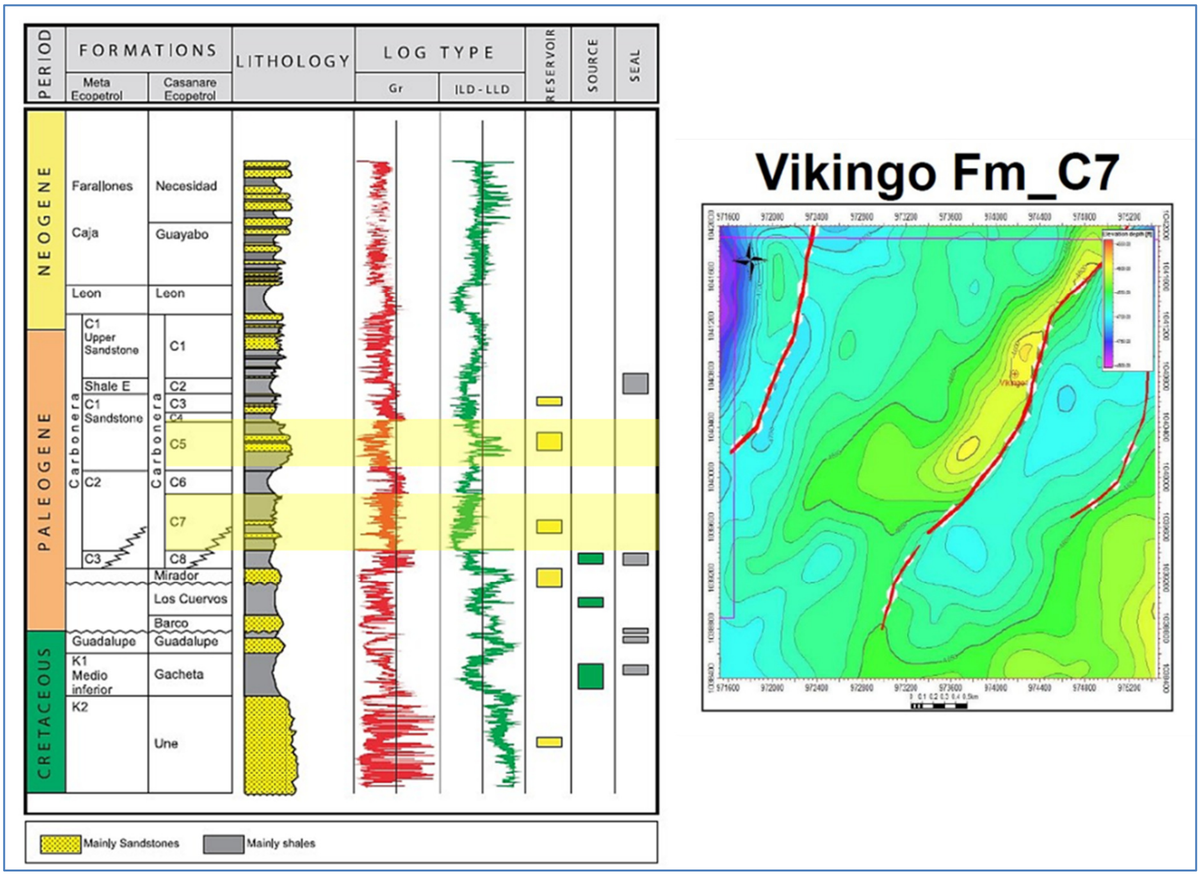


Figure 4 Top structure map and type log Llanos 47 concession

Development plans

Introduction

InterOil has proposed 8 workovers and 3 wells to be drilled as part of their activity plan for the year 2021. Workovers for Puli-C are scheduled to be performed during May and June 2021 and the first well to be drilled will spud in July 2021, followed by the other 2 wells. Workover for Vikingo-1 is scheduled by the end of 2021, 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 2021 in this field. An oil workover in MNS-2, with new intervals to be opened and other old intervals to be re-perforated with a relatively new hydro-mechanic perforation technology, which has proven to be very effective in the recent past. 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 2021, 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

Two workovers are planned to be carried out in wells RO-5 and RO-6, in which new intervals will be perforated and other old intervals will be reperforated using hydro-mechanic perforation technology. These workovers have been identified, based on the results of the RO-4 workover performed in 2019. One new well (RO-7) is scheduled to be drilled, after completion of the two 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 wells AMB-1 and AMB-4, in which the operator plans to perform hydraulic fracturing, based on the recent success of applying this technology in AMB-3 in 2019. Industry standard techniques were applied to generate low, best and high case production forecasts for these projects.

Llanos Field

A workover of the Vikingo-1 well is scheduled for the end of 2021, in which a plug will be removed and the C7 formation will be placed back on commingled production with the upper producing layers.

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-2020:

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	1.08	2.65	0.80	1.85	0.76	1.85
	Developed NP	0.17	1.03	0.13	0.72	0.13	0.72
	Undeveloped	0.00	0.00	0.00	0.00	0.00	0.00
	Total 1P	**1.25**	**3.68**	**0.92**	**2.57**	**0.89**	**2.57**
	Total 2P	**2.18**	**5.94**	**1.60**	**4.16**	**1.54**	**4.16**
	Total 3P	**3.23**	**8.41**	**2.38**	**5.89**	**2.27**	**5.89**

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℉. 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 2021 workover campaign (seven 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 2021 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 2040, 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 2040. 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. 1C resources have an economic cutoff earlier than December 2040.

Table 4 Overview 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	0.26	0.48	0.74	0,00	0,00	0,00	0.31	0.40	0.63	0.57	0.88	1.37
Rio Opia	0.10	0.18	0.28	0.96	1.80	2.76	0.02	0.07	0.11	1.07	2.05	3.14
Ambrosia	0.41	0.76	1.18	0.67	1.24	1.93	0.07	0.11	0.16	1.15	2.11	3.26
Llanos	0,00	0,00	0,00	0,00	0,00	0,00	0.16	0.16	0,00	0.16	0.16	0,00
Altair	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Total	**0.76**	**1.42**	**2.19**	**1.63**	**3.04**	**4.69**	**0.57**	**0.73**	**0.90**	**2.95**	**5.19**	**7.77**

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	0.77	1.44	2.21	0.00	0.00	0.00	1.56	2.68	4.30	2.32	4.12	6.50
Rio Opia	0.29	0.54	0.83	2.88	5.40	8.28	0.06	0.22	0.38	3.22	6.16	9.49
Ambrosia	1.22	2.28	3.53	2.00	3.73	5.78	0.06	0.10	0.16	3.28	6.11	9.46
Llanos	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Altair	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	**2.28**	**4.26**	**6.57**	**4.88**	**9.13**	**14.06**	**1.67**	**3.00**	**4.83**	**8.83**	**16.38**	**25.45**

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

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 2020, up to end of 2028 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 2021 amounts to 2,98 US$/MMBtu and is subsequently escalated by 1% on a yearly basis.

Table 5 Brent and contractual gas price forecast (MOD) 2021-2032

Year	Oil Price (US$/bbl)	Gas Price (US$/MMBtu)
2021	51,06	2,98
2022	50,17	2,98
2023	49,62	3,01
2024	49,39	3,04
2025	49,26	3,07
2026	49,22	3,10
2027	49,21	3,13
2028	49,19	3,16
2029	50,17	3,19
2030	51,17	3,23
2031	52,20	3,26
2032	53,24	3,29

Realized 2020 costs for the period between January and September 2020 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 costs have been applied for the economic evaluation:

Table 6 Overview cost aspects

Category	Mana	Ambrosia	Rio Opia	Llanos 47
Fixed Cost (kUS$/yr)	1.109	55	46	558
Variable Opex (US$/bbl)	1,78	0,63	1,21	7,59
Variable WO Cost (kUS$/well/yr)	32,9	31,3	23,1	18,8
Oil transportation (US$/bbl)	5,81	5,86	5,82	9,95

The abandonment cost of a well was provided by InterOil and is considered to be 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 current 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.

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 the Piedras, Tolima area and the other one in Oroucué in Casanare. The current production is approximately 636 bbl/d and 2.4 Mscf/d day as of December 31, 2020. 63 wells were drilled in the five blocks and 39 of them are on production today. The cumulative oil production is 6.2 MMbbl and 16.5 Bscf of gas have been produced.
Target locations have been selected based on a 3D seismic and subsequent static modelling by InterOil. From the analysis of production logging, it can be inferred that the formation units can be divided in separate subunits. A petrophysical model was built and new zones were identified to be perforated based on the latest technology advances in perforation techniques.
Infrastructure is relatively well established at Puli-C. All the wells are connected to the main facility at Mana where the oil is processed and stored in tanks before subsequent transportation through trucking.

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

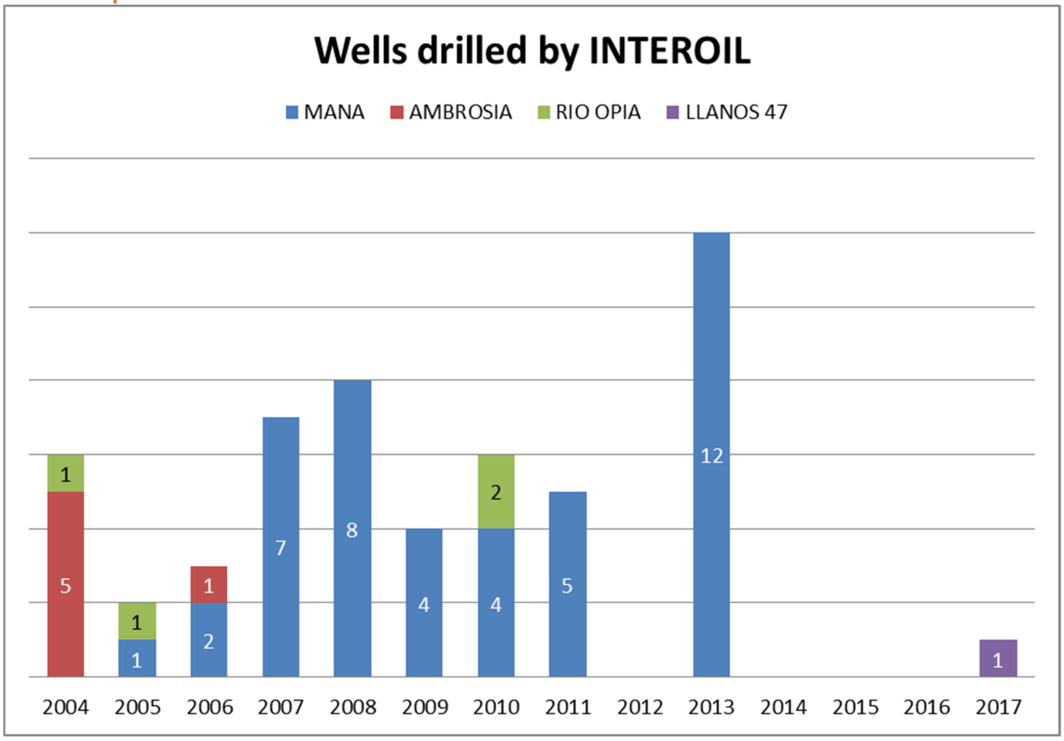


Figure 5 Wells drilled by InterOil Colombia historically

Mana field

The Mana field was discovered in 2004 and produces oil and gas from the Doima and Chicoral Formations. The average depth of the wells is around 3,850 ft with wells drilled between 2,800/5,000 feet and the primary production mechanism is solution-gas drive. Current oil production is 388 bbl/d and 2.4 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 2020, 32 wells were on production and the remaining ones closed and under study.

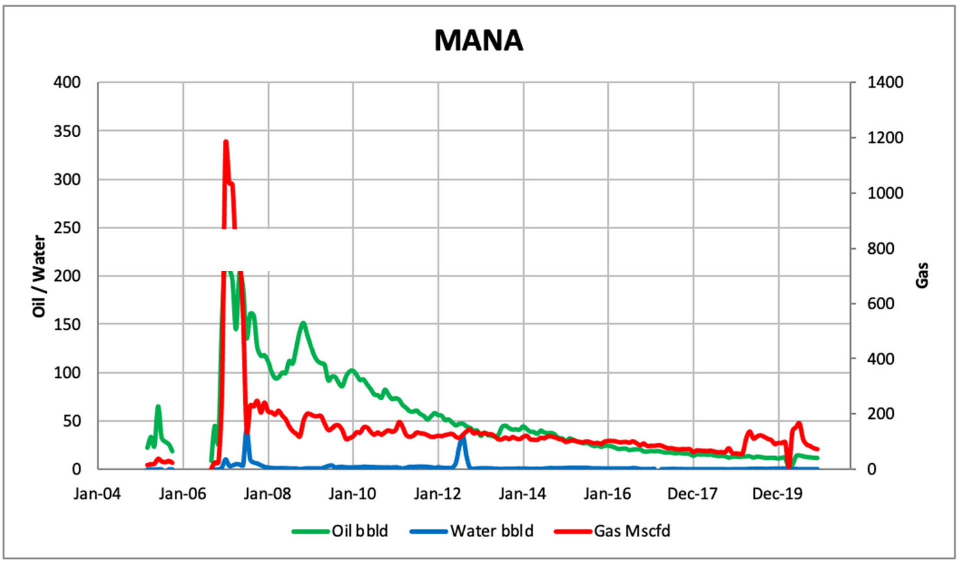


Figure 6 Historical production Mana field

The OOIP for Doima and Chicoral combined is approximately 115 MMbbl with a current recovery factor of 5%. Cumulative oil production is 5.588 Mbbl and 16.060 MMscf cumulative gas.

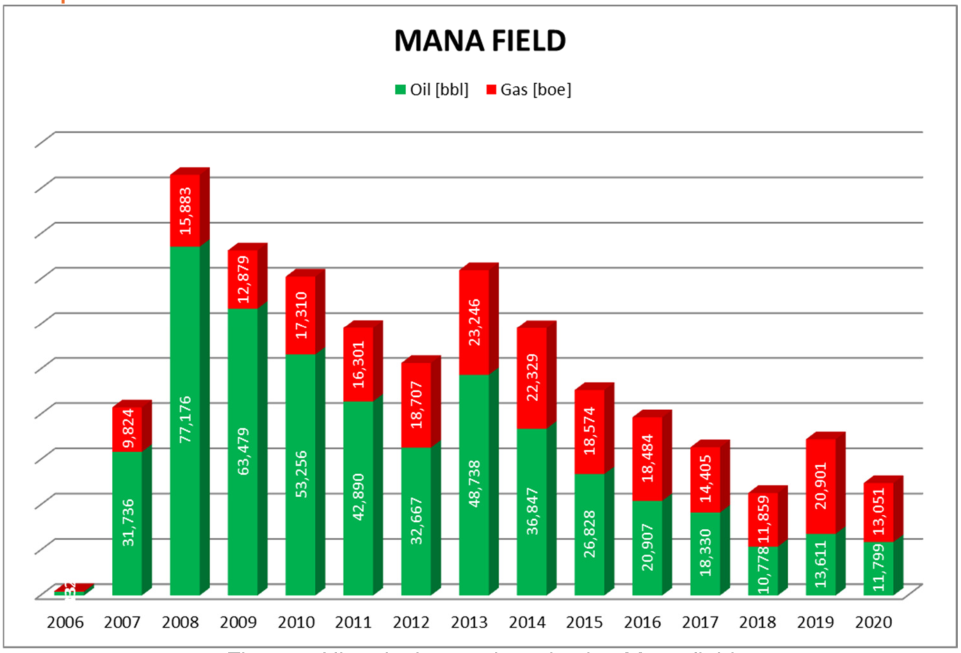


Figure 7 Historical annual production Mana field

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 25 bbl/d and 50 Mscf/d of gas. 3 wells are currently on production, while 2 of the wells were abandoned due to poor reservoir performance (“Bunde wells”).

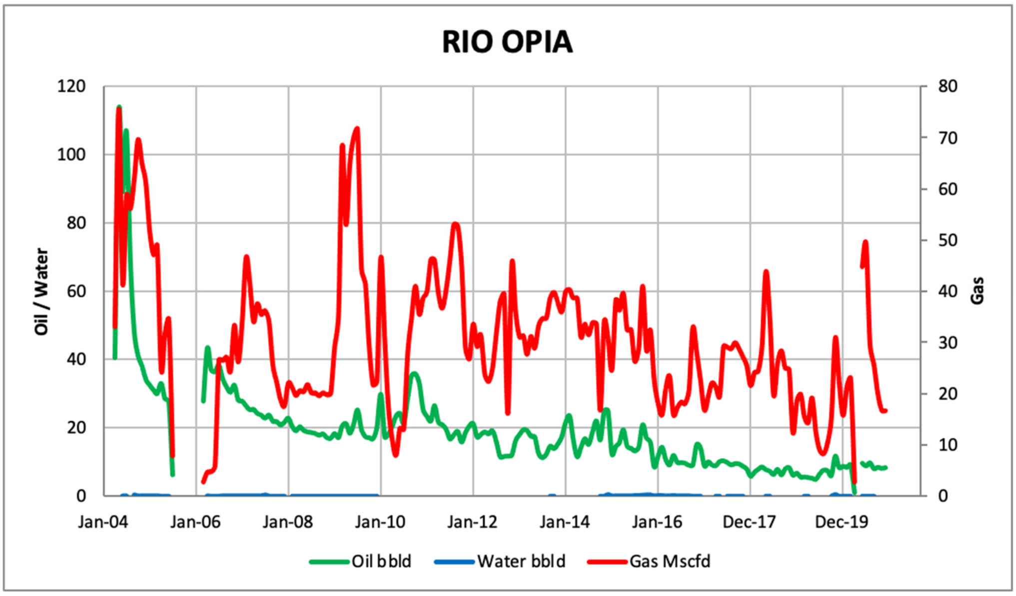


Figure 8 Historical production Rio Opia field

The OOIP for the Doima and Chicoral formations is approximately 47 MMbbl with a current recovery factor of 1%. Cumulative oil production is 295 Mbbl and 520 MMscf cumulative gas.

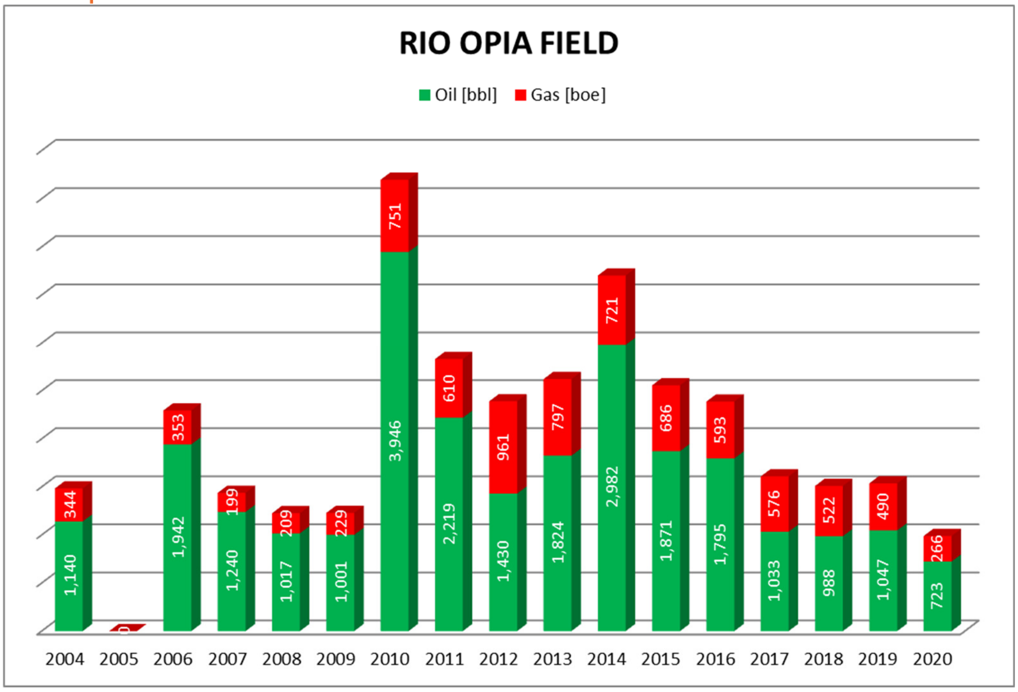


Figure 9 Historical annual production Rio Opia field

Ambrosia field

The Ambrosia field was discovered in 2004 and produces oil and gas from the 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 29 bbl/d and 15 Mscf/d of gas. 6 wells were drilled and 3 of them are currently on production, while 3 wells were already abandoned.

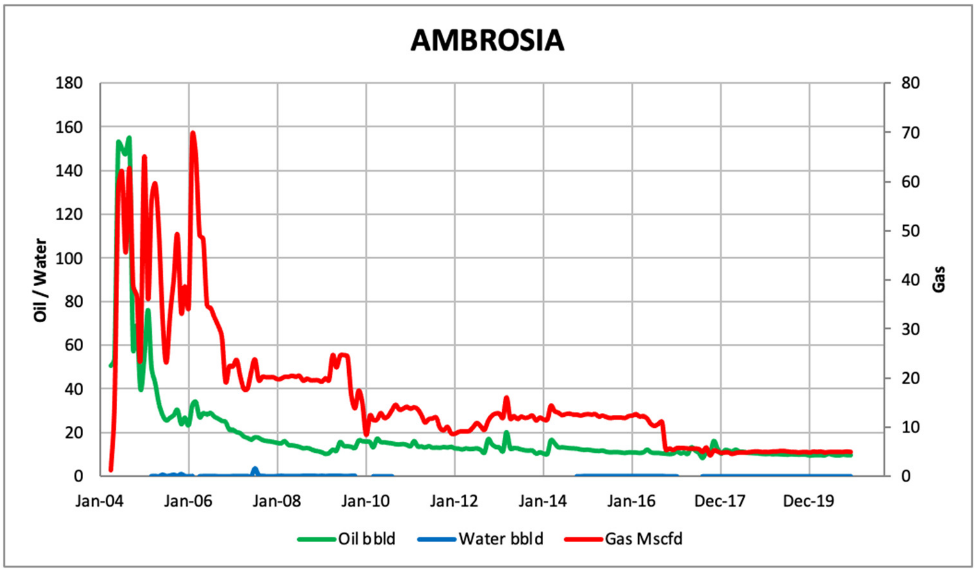


Figure 10 Historical production Ambrosia field

The OOIP for Doima is approximately 32 MMbbl with a current recovery factor of 1%. Cumulative oil production is 359 Mbbl and 364 MMscf cumulative gas.

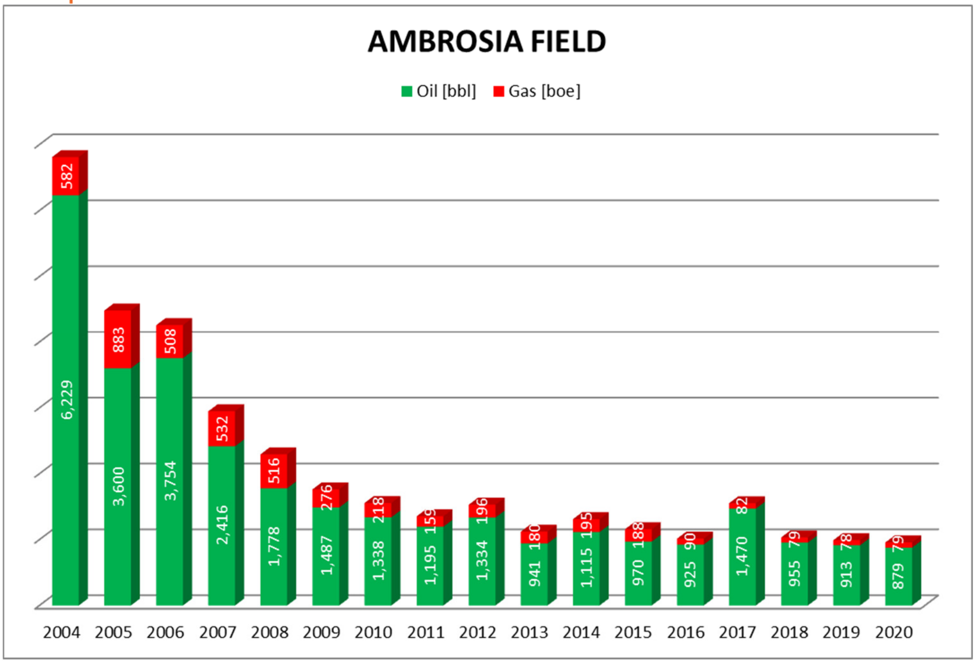


Figure 11 Historical annual production Ambrosia field

Llanos 47 field

The 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 produced 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 224 bbl/d. 3 wells were drilled and 1 of them is currently on production. The other 2 wells are shut-in due to poor reservoir performance.

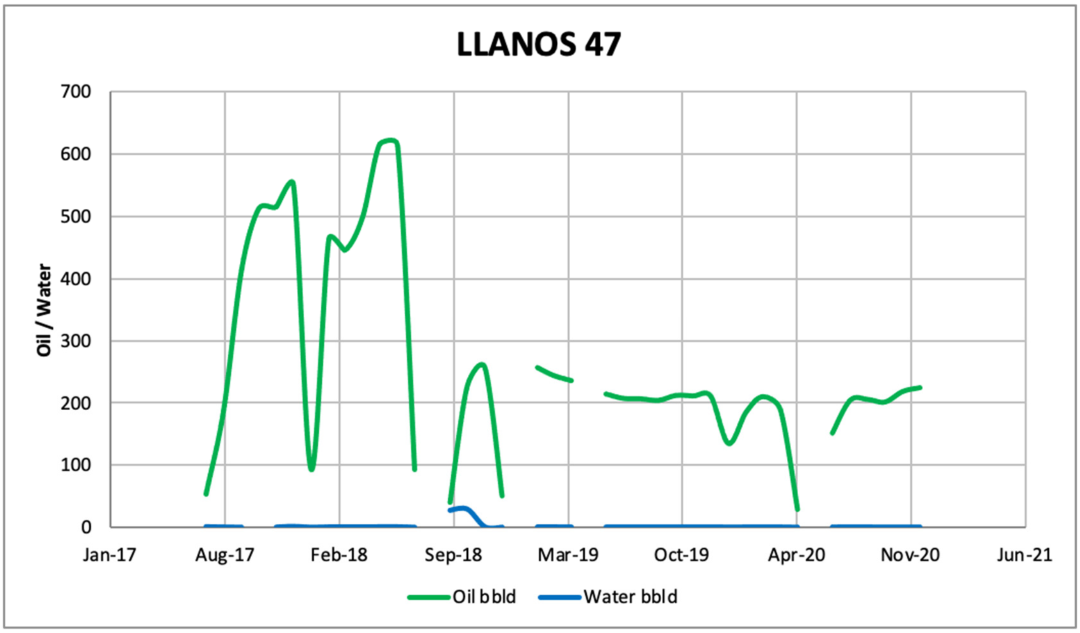


Figure 12 Historical production Llanos-47 field

The OOIP for C5 is approximately 2,37 MMbbl with a current recovery factor of 12,5%. Cumulative oil production is 317 Mbbls.

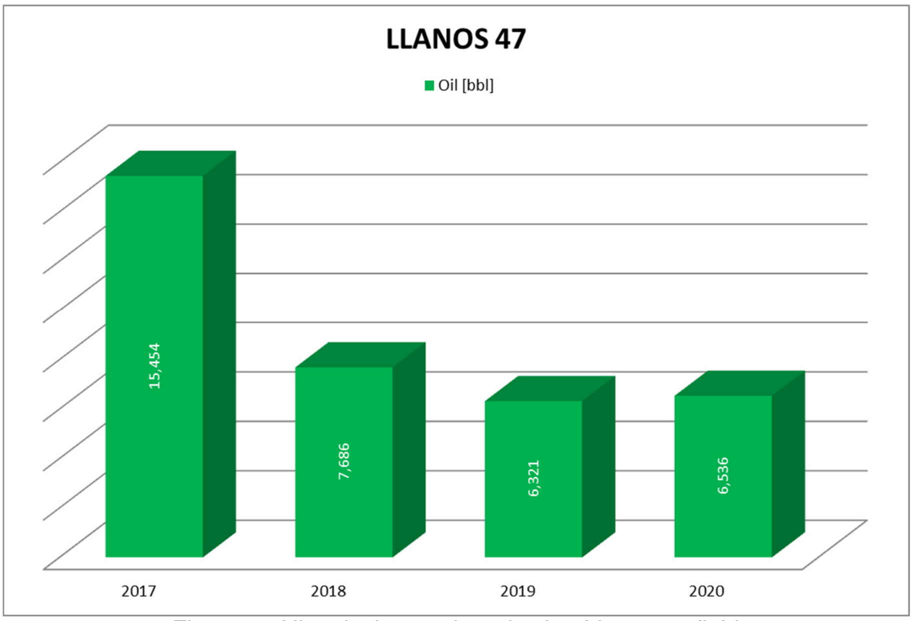


Figure 13 Historical annual production Llanos-47 field

Altair field

The 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 2020. 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 assets. 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 does not 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 15 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, analysing 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, 2020

		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	1.08	2.65	0.80	1.85	0.76	1.85
	Developed NP	0.17	1.03	0.13	0.72	0.13	0.72
	Undeveloped	0.00	0.00	0.00	0.00	0.00	0.00
	Total 1P	**1.25**	**3.68**	**0.92**	**2.57**	**0.89**	**2.57**
	Total 2P	**2.18**	**5.94**	**1.60**	**4.16**	**1.54**	**4.16**
	Total 3P	**3.23**	**8.41**	**2.38**	**5.89**	**2.27**	**5.89**
MANA	PROVED						
	Developed	0.55	2.51	0.38	1.76	0.35	1.76
	Developed NP	0.01	0.99	0.01	0.70	0.00	0.70
	Undeveloped	0.00	0.00	0.00	0.00	0.00	0.00
	Total 1P	0.55	3.50	0.39	2.45	0.36	2.45
	Total 2P	0.99	5.44	0.69	3.81	0.63	3.81
	Total 3P	1.45	7.54	1.01	5.28	0.93	5.28
RIO OPIA	PROVED						
	Developed	0.03	0.10	0.02	0.07	0.02	0.07
	Developed NP	0.01	0.02	0.00	0.01	0.00	0.00
	Undeveloped	0.00	0.00	0.00	0.00	0.00	0.00
	Total 1P	0.04	0.12	0.03	0.08	0.03	0.08
	Total 2P	0.14	0.41	0.10	0.28	0.09	0.28
	Total 3P	0.23	0.73	0.16	0.51	0.15	0.51
AMBROSIA	PROVED						
	Developed	0.06	0.03	0.04	0.02	0.04	0.02
	Developed NP	0.02	0.02	0.01	0.01	0.01	0.01
	Undeveloped	0.00	0.00	0.00	0.00	0.00	0.00
	Total 1P	0.08	0.05	0.05	0.04	0.05	0.04
	Total 2P	0.10	0.09	0.07	0.06	0.07	0.06
	Total 3P	0.13	0.13	0.09	0.09	0.09	0.09
LLANOS	PROVED						
	Developed	0.45	0.00	0.35	0.00	0.35	0.00
	Developed NP	0.14	0.00	0.11	0.00	0.11	0.00
	Undeveloped	0.00	0.00	0.00	0.00	0.00	0.00
	Total 1P	0.58	0.00	0.46	0.00	0.46	0.00
	Total 2P	0.95	0.00	0.74	0.00	0.74	0.00
	Total 3P	1.42	0.00	1.10	0.00	1.10	0.00

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, 2020 (MOD)

Mana

Mana								
Proved Developed Reserves								
	Production Forecast		Gas Sales	Gross Income	Oil Transport	Operating Expenses	Investment	Pre-Tax Cashflow
Year	Oil - Mstb	Gas - MMscf	MMscf	KUS$	KUS$	KUS$	KUS$	KUS$
2021	86	635	610	5976	550	2103	565	2757
2022	73	527	506	4971	471	2088	0	2412
2023	62	420	403	4124	404	2092	0	1627
2024	53	344	331	3473	348	2007	0	1118
2025	44	286	275	2913	295	2042	0	575
2026	38	239	230	2457	252	2082	0	123
2027	32	201	193	2103	218	2128	0	-243

Mana								
Proved Reserves (1P)								
	Production Forecast		Gas Sales	Gross Income	Oil Transport	Operating Expenses	Investment	Pre-Tax Cashflow
Year	Oil - Mstb	Gas - MMscf	MMscf	KUS$	KUS$	KUS$	KUS$	KUS$
2021	86	635	610	5976	550	2103	565	2757
2022	73	527	506	4971	471	2088	0	2412
2023	62	420	403	4124	404	2092	0	1627
2024	53	344	331	3473	348	2007	0	1118
2025	44	286	275	2913	295	2042	0	575
2026	38	239	230	2457	252	2082	0	123
2027	32	201	193	2103	218	2128	0	-243

Mana								
Probable Reserves (2P)								
	Production Forecast		Gas Sales	Gross Income	Oil Transport	Operating Expenses	Investment	Pre-Tax Cashflow
Year	Oil - Mstb	Gas - MMscf	MMscf	KUS$	KUS$	KUS$	KUS$	KUS$
2021	128	799	767	8476	819	2029	4117	1511
2022	122	725	696	7834	783	2236	0	4815
2023	93	565	542	5992	605	2203	0	3184
2024	77	466	447	4964	508	2124	0	2332
2025	66	393	377	4232	439	2207	0	1587
2026	58	336	322	3672	386	2140	0	1147
2027	50	290	278	3178	336	2180	0	661
2028	41	238	229	2637	282	2218	0	137

Mana								
Possible Reserves (3P)								
	Production Forecast		Gas Sales	Gross Income	Oil Transport	Operating Expenses	Investment	Pre-Tax Cashflow
Year	Oil - Mstb	Gas - MMscf	MMscf	KUS$	KUS$	KUS$	KUS$	KUS$
2021	181	1032	990	11653	1151	2155	4117	4231
2022	189	1022	981	11876	1218	2237	0	8422
2023	138	784	753	8710	895	2320	0	5495
2024	112	647	621	7097	734	2219	0	4144
2025	95	551	529	6047	631	2290	0	3125
2026	83	477	458	5284	557	2349	0	2377
2027	74	418	401	4686	500	2391	0	1795
2028	63	351	336	3984	430	2512	0	1041

Rio Opia

Rio Opia								
Proved Developed Reserves								
	Production Forecast		Gas Sales	Gross Income	Oil Transport	Operating Expenses	Investment	Pre-Tax Cashflow
Year	Oil - Mstb	Gas - MMscf	MMscf	KUS$	KUS$	KUS$	KUS$	KUS$
2021	6	19	19	344	38	106	350	-150
2022	5	17	17	296	34	108	0	154
2023	4	15	14	249	29	110	0	111
2024	4	13	12	212	25	112	0	75
2025	3	11	11	181	21	115	0	45
2026	3	9	9	154	18	117	0	19
2027	2	8	8	114	13	119	0	-18

Rio Opia								
Proved Reserves (1P)								
	Production Forecast		Gas Sales	Gross Income	Oil Transport	Operating Expenses	Investment	Pre-Tax Cashflow
Year	Oil - Mstb	Gas - MMscf	MMscf	KUS$	KUS$	KUS$	KUS$	KUS$
2021	6	19	19	344	38	106	350	-150
2022	5	17	17	296	34	108	0	154
2023	4	15	14	249	29	110	0	111
2024	4	13	12	212	25	112	0	75
2025	3	11	11	181	21	115	0	45
2026	3	9	9	154	18	117	0	19
2027	2	8	8	114	13	119	0	-18

Rio Opia								
Probable Reserves (2P)								
	Production Forecast		Gas Sales	Gross Income	Oil Transport	Operating Expenses	Investment	Pre-Tax Cashflow
Year	Oil - Mstb	Gas - MMscf	MMscf	KUS$	KUS$	KUS$	KUS$	KUS$
2021	14	42	40	788	88	118	2126	-1544
2022	20	62	60	1143	131	149	0	863
2023	16	49	47	870	101	162	0	606
2024	13	40	39	709	83	268	0	357
2025	11	34	33	598	71	346	0	181
2026	9	30	29	515	62	372	0	81
2027	8	26	25	450	54	381	0	14
2028	7	23	22	397	48	391	0	-42

Rio Opia								
Possible Reserves (3P)								
	Production Forecast		Gas Sales	Gross Income	Oil Transport	Operating Expenses	Investment	Pre-Tax Cashflow
Year	Oil - Mstb	Gas - MMscf	MMscf	KUS$	KUS$	KUS$	KUS$	KUS$
2021	17	57	55	1007	112	124	2126	-1354
2022	28	89	86	1561	178	144	0	1240
2023	22	74	71	1251	144	174	0	933
2024	19	63	61	1055	123	279	0	654
2025	16	56	54	914	107	356	0	451
2026	14	50	48	806	95	457	0	255
2027	13	45	43	721	85	390	0	245
2028	11	41	39	650	77	400	0	173
2029	10	37	36	600	71	409	0	120
2030	4	16	16	266	31	410	0	-175

Ambrosia

Ambrosia								
Proved Developed Reserves								
Year	Production Forecast Oil - Mstb	Gas CIO MMscf	Gas Sales MMscf	Gross Income KUS$	Oil Transport KUS$	Operating Expenses KUS$	Investment KUS$	Pre-Tax Cashflow KUS$
2021	9	6	0	411	55	110	350	-104
2022	8	6	0	379	52	113	0	214
2023	7	6	0	349	49	116	0	185
2024	7	6	0	325	46	119	0	160
2025	7	5	0	303	43	123	0	137
2026	6	5	0	283	41	126	0	116
2027	5	4	0	243	35	129	0	79

Ambrosia								
Proved Reserves (1P)								
Year	Production Forecast Oil - Mstb	Gas CIO MMscf	Gas Sales MMscf	Gross Income KUS$	Oil Transport KUS$	Operating Expenses KUS$	Investment KUS$	Pre-Tax Cashflow KUS$
2021	9	6	0	411	55	110	350	-104
2022	8	6	0	379	52	113	0	214
2023	7	6	0	349	49	116	0	185
2024	7	6	0	325	46	119	0	160
2025	7	5	0	303	43	123	0	137
2026	6	5	0	283	41	126	0	116
2027	5	4	0	243	35	129	0	79

Ambrosia								
Probable Reserves (2P)								
Year	Production Forecast Oil - Mstb	Gas CIO MMscf	Gas Sales MMscf	Gross Income KUS$	Oil Transport KUS$	Operating Expenses KUS$	Investment KUS$	Pre-Tax Cashflow KUS$
2021	11	9	0	529	70	112	350	-3
2022	10	9	0	495	67	115	0	313
2023	10	9	0	462	64	188	0	210
2024	9	9	0	434	61	217	0	156
2025	9	9	0	409	58	223	0	128
2026	8	9	0	387	56	229	0	102
2027	8	8	0	363	53	236	0	74

Ambrosia								
Possible Reserves (3P)								
Year	Production Forecast Oil - MMstb	Gas CIO MMscf	Gas Sales MMscf	Gross Income KUS$	Oil Transport KUS$	Operating Expenses KUS$	Investment KUS$	Pre-Tax Cashflow KUS$
2021	14	13	0	672	90	114	350	118
2022	14	14	0	643	88	117	0	437
2023	13	14	0	600	84	190	0	326
2024	12	13	0	567	81	219	0	267
2025	12	13	0	537	77	225	0	234
2026	11	13	0	510	74	282	0	153
2027	10	12	0	480	71	317	0	93

Llanos

Llanos 47								
Proved Developed Reserves								
Production Forecast			Gas Sales	Gross Income	Oil Transport	Operating Expenses	Investment	Pre-Tax Cashflow
Year	Oil - Mstb	Gas - MMscf	MMscf	KUS$	KUS$	KUS$	KUS$	KUS$
2021	62	0	0	2999	625	922	78	1374
2022	72	0	0	3428	734	1029	0	1664
2023	61	0	0	2842	622	981	0	1239
2024	53	0	0	2480	551	949	0	980
2025	47	0	0	2169	488	921	0	760
2026	41	0	0	1902	432	899	0	571
2027	36	0	0	1669	383	880	0	405
2028	32	0	0	1464	340	866	0	259
2029	28	0	0	1311	301	855	0	155
2030	24	0	0	1174	267	847	0	60
2031	21	0	0	1052	237	842	0	-27

Llanos 47								
Proved Reserves (1P)								
Production Forecast			Gas Sales	Gross Income	Oil Transport	Operating Expenses	Investment	Pre-Tax Cashflow
Year	Oil - Mstb	Gas - MMscf	MMscf	KUS$	KUS$	KUS$	KUS$	KUS$
2021	62	0	0	2999	625	922	78	1374
2022	72	0	0	3428	734	1029	0	1664
2023	61	0	0	2842	622	981	0	1239
2024	53	0	0	2480	551	949	0	980
2025	47	0	0	2169	488	921	0	760
2026	41	0	0	1902	432	899	0	571
2027	36	0	0	1669	383	880	0	405
2028	32	0	0	1464	340	866	0	259
2029	28	0	0	1311	301	855	0	155
2030	24	0	0	1174	267	847	0	60
2031	21	0	0	1052	237	842	0	-27

Llanos 47								
Probable Reserves (2P)								
Production Forecast			Gas Sales	Gross Income	Oil Transport	Operating Expenses	Investment	Pre-Tax Cashflow
Year	Oil - Mstb	Gas - MMscf	MMscf	KUS$	KUS$	KUS$	KUS$	KUS$
2021	64	0	0	3100	646	938	78	1438
2022	83	0	0	3950	846	1115	0	1988
2023	71	0	0	3345	732	1068	0	1545
2024	65	0	0	3018	670	1045	0	1303
2025	59	0	0	2736	615	1026	0	1095
2026	54	0	0	2492	566	1011	0	915
2027	49	0	0	2277	523	999	0	755
2028	45	0	0	2085	484	991	0	611
2029	41	0	0	1953	449	985	0	519
2030	38	0	0	1834	417	982	0	435
2031	35	0	0	1727	389	982	0	356
2032	32	0	0	1628	363	984	0	282
2033	30	0	0	1540	340	988	0	212
2034	28	0	0	1459	319	993	0	147
2035	26	0	0	1385	300	1001	0	84
2036	24	0	0	1317	282	1010	0	25
2037	23	0	0	1256	267	1021	0	-32

Llanos 47								
Possible Reserves (3P)								
	Production Forecast		Gas Sales	Gross Income	Oil Transport	Operating Expenses	Investment	Pre-Tax Cashflow
Year	Oil - Mstb	Gas - MMscf	MMscf	KUS$	KUS$	KUS$	KUS$	KUS$
2021	67	0	0	3212	669	956	78	1508
2022	98	0	0	4632	992	1228	0	2411
2023	84	0	0	3941	862	1170	0	1908
2024	78	0	0	3622	804	1152	0	1666
2025	72	0	0	3350	753	1138	0	1459
2026	67	0	0	3118	709	1129	0	1280
2027	63	0	0	2914	669	1123	0	1122
2028	59	0	0	2733	634	1121	0	978
2029	55	0	0	2625	603	1103	0	919
2030	52	0	0	2530	576	1125	0	830
2031	50	0	0	2447	551	1111	0	784
2032	47	0	0	2373	529	1139	0	704
2033	45	0	0	2308	510	1150	0	648
2034	43	0	0	2250	492	1162	0	596
2035	41	0	0	2199	476	1176	0	547
2036	40	0	0	2155	462	1192	0	500
2037	38	0	0	2115	449	1210	0	456
2038	37	0	0	2079	437	1229	0	413
2039	35	0	0	2049	427	1250	0	373
2040	34	0	0	2022	417	1272	0	333

Exhibit-III Reserves Consolidation

Mana

RESERVES DEVELOPMENT (GROSS 100% VOLUME)	Crude Oil (MMstb)		Gas (Bscf)	
	1P	2P	1P	2P
Balance (as of year and last full year)	0.73	1.23	3.49	8.03
Production 2020	0.11		0.90	
Acquisitions / Disposals				
Extensions / Discoveries				
New Developments	0.01	0.01	0.99	1.21
Revisions of previous estimates	0.07	0.15	0.08	2.89
Balance (as of 31-Dec-2020)	**0.55**	**0.99**	**3.50**	**5.44**

Rio Opia

RESERVES DEVELOPMENT (GROSS 100% VOLUME)	Crude Oil (MMstb)		Gas (Bscf)	
	1P	2P	1P	2P
Balance (as of year and last full year)	0.10	0.20	0.37	0.77
Production 2020	0.00		0.01	
Acquisitions / Disposals				
Extensions / Discoveries				
New Developments	0.01	0.03	0.02	0.09
Revisions of previous estimates	0.06	0.08	0.25	0.44
Balance (as of 31-Dec-2020)	**0.04**	**0.14**	**0.12**	**0.41**

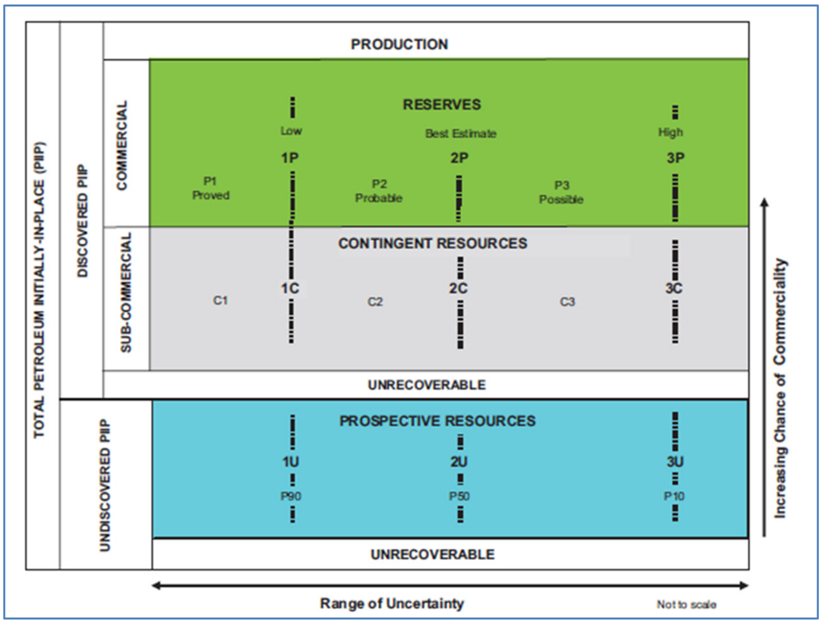
Ambrosia

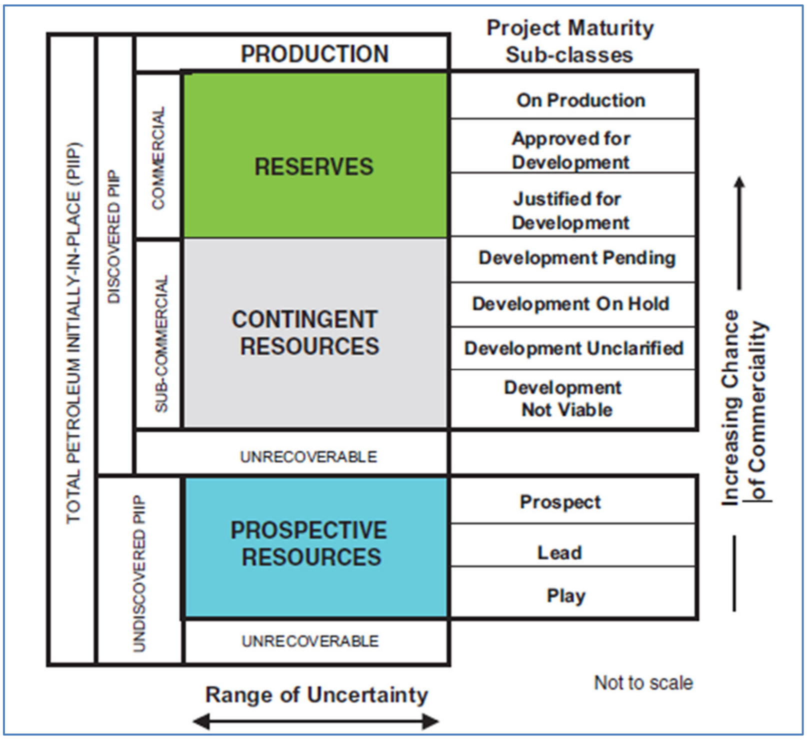
RESERVES DEVELOPMENT (GROSS 100% VOLUME)	Crude Oil (MMstb)		Gas (Bscf)	
	1P	2P	1P	2P
Balance (as of year and last full year)	0.11	0.19	0.00	0.00
Production 2020	0.01		0.01	
Acquisitions / Disposals				
Extensions / Discoveries				
New Developments	0.02	0.04	0.02	0.05
Revisions of previous estimates	0.04	0.12	0.04	0.05
Balance (as of 31-Dec-2020)	**0.08**	**0.10**	**0.05**	**0.09**

Llanos 47

RESERVES DEVELOPMENT (GROSS 100% VOLUME)	Crude Oil (MMstb)		Gas (Bscf)	
	1P	2P	1P	2P
Balance (as of year and last full year)	0.07	0.07	0.00	0.00
Production 2020	0.06			
Acquisitions / Disposals				
Extensions / Discoveries	0.58	0.95		
New Developments				
Revisions of previous estimates				
Balance (as of 31-Dec-2020)	**0.58**	**0.95**	**0.00**	**0.00**

Exhibit-IV 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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12th of March, 2021

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, 2020

Dear Mr. Carbone,

This reserves- and contingent resources statement has been prepared by SGS Nederland B.V. (henceforth 'SGS') and issued on March 12th, 2021 at the request of InterOil Argentina (InterOil or 'the 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, 2020, 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.

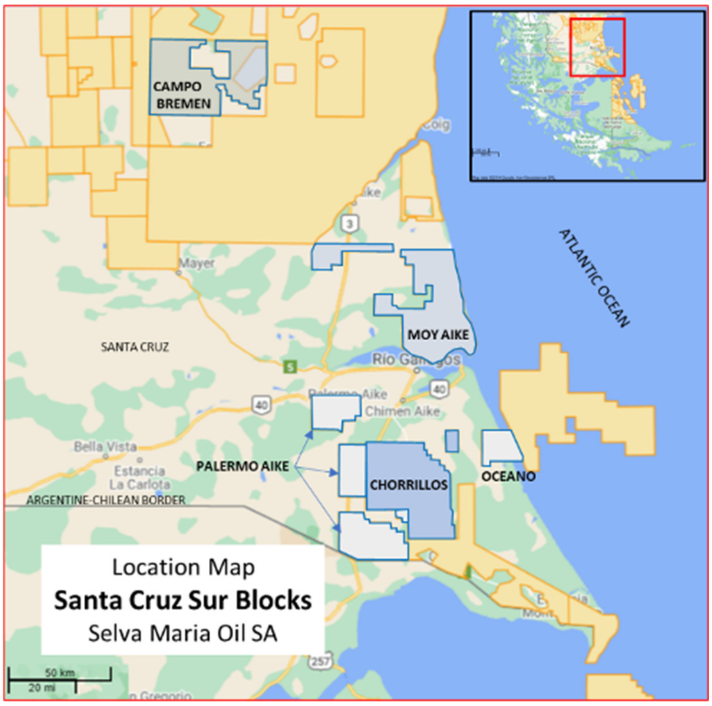


Figure 1 Location map - All concessions

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, 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 being discovered.

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 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 now starting 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 6 years.
The previous operator development plans in terms of drilling of new wells and workover activities in the existing wells is subject to a full technical review.
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 reasonable 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 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).

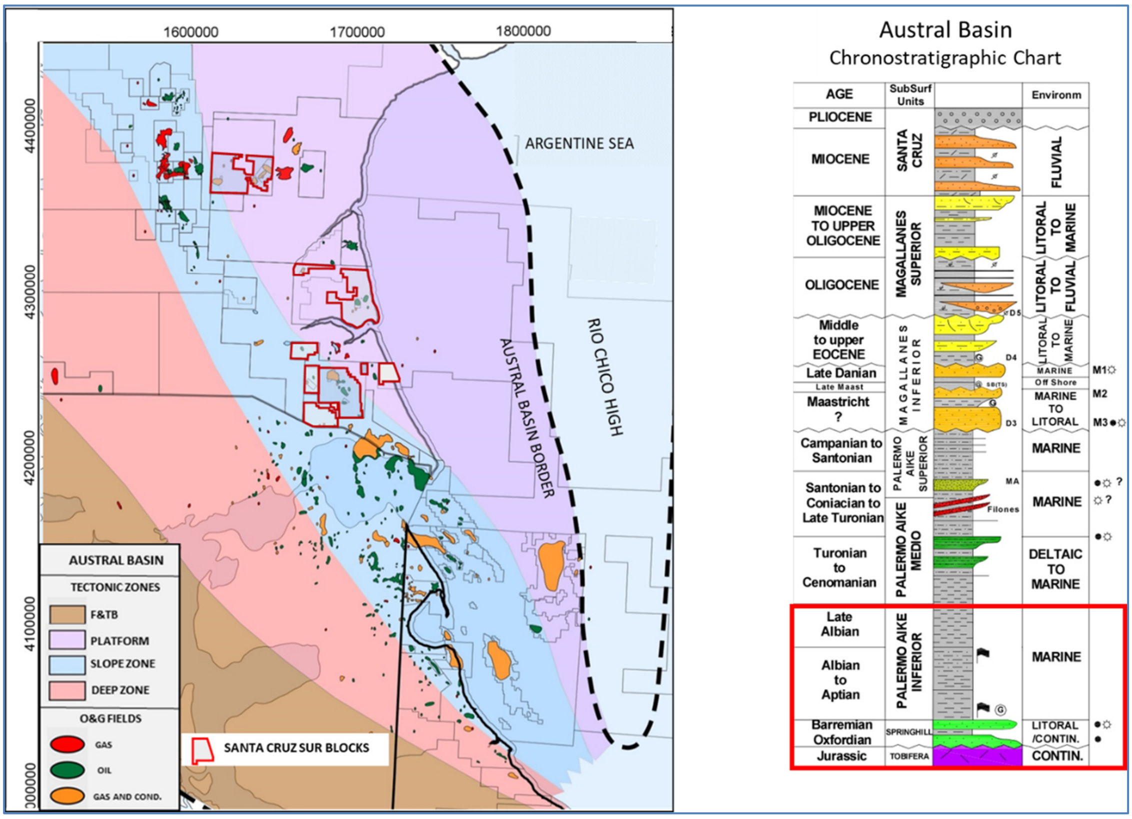


Figure 2 Regional structural framework and stratigraphic column Austral basin, Argentina

The 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 mostly have 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 four way closure 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).

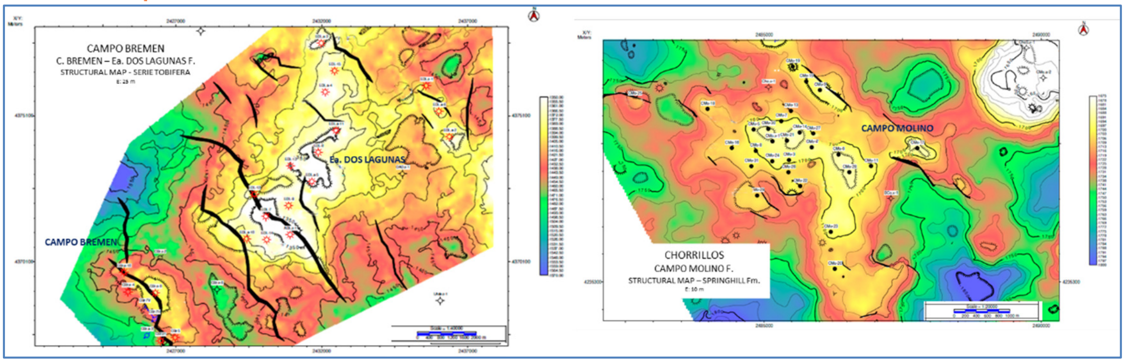


Figure 3 Examples of Structural Trap types in Campo Bremen and Chorrillos Concessions

The Springhill Fm. 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 Springhill Fm., 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. In a characteristic style for this region, the development of the named "bold high" where the Springhill Fm. 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 Springhill Fm. 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 currently in a process of technically reviewing all the available information for each of these 5 assets. As part of the development plan several of their subsurface facilities for 2021 will be refurbished, including for example, the construction of an aqueduct to optimize the water handling in the field.

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.

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, regardless of any assumptions on commerciality.

Reserves and contingent resources statement

On the basis of technical and commercial information made available to SGS concerning these assets, SGS hereby provides the reserves statement as per 31-Dec-2020:

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	387	8.58	32	0.72	27	0.61
	Developed NP	0	0.00	0	0.00	0	0.00
	Undeveloped	0	0.00	0	0.00	0	0.00
	Total 1P	**387**	**8.58**	**32**	**0.72**	**27**	**0.61**
	Total 2P	**398**	**8.75**	**33**	**0.73**	**28**	**0.62**
	Total 3P	**406**	**8.94**	**34**	**0.75**	**29**	**0.63**

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 CIO - MMscf		
Year	**1P**	**2P**	**3P**
2021	576	583	590
2022	439	453	468

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

Table 4 Contingent Resources statement - per concession

	OIL - Developed Producing (Mstb)		
Area	1C	2C	3C
Campo Bremen	53	70	89
Chorrillos	566	675	795
Moy Aike	128	190	224
Oceano	38	42	46
Palermo Aike	0	0	0
Total	**785**	**976**	**1154**

	GAS - Developed Producing (Bscf)		
Area	1C	2C	3C
Campo Bremen	2.6	3.4	4.3
Chorrillos	11.0	13.0	15.5
Moy Aike	0.2	0.3	0.3
Oceano	3.6	4.0	4.4
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.

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 2020, up to end of 2028 and thereafter inflated by 2% per annum. A discount of 10 US$/bbl has been applied for Maria Ines blend.

The gas price assumed is based on long term agreements, commitments for gas delivery of the Province of Santa Cruz and market spot price. Gas price forecast and percentages of gas commercialised for each of these segments were presented by the operator and reviewed and accepted by the auditor.

Table 5 Brent and gas price forecast (MOD) 2021-2032

		Gas Price (US$/MMBtu)		
Year	Oil Price (US$/bbl)	LT Contracts	Province	Spot
2021	51,06	2,10	2,11	2,24
2022	50,17	2,12	2,13	2,26
2023	49,62	2,14	2,15	2,29
2024	49,39	2,16	2,17	2,31
2025	49,26	2,19	2,19	2,33
2026	49,22	2,21	2,22	2,35
2027	49,21	2,23	2,24	2,38
2028	49,19	2,25	2,26	2,40
2029	50,17	2,27	2,28	2,43
2030	51,17	2,30	2,31	2,45
2031	52,20	2,32	2,33	2,47
2032	53,24	2,34	2,35	2,50

Realized 2020 costs 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 have been applied for the economic evaluation:

Table 6 Overview cost aspects

Expenses	Santa Cruz
G & A Fixed Costs - KUS$	1899
Salaries - kUS$	2820
Fixed Opex - kUS$	2773
Variable Opex - US$/boe	4,50
Transportation & Storage - US$/bbl	0,99
Treatment Fee - US$/bbl	3,50

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 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 the Austral Basin at the end of 2019. Currently, they have five concessions: Campo Bremen, Chorrillos, Moy Aike, Océano and Palermo Aike.
The current production for these five blocks is approximately 293 bopd and 13,450 Mscf/d of gas as of December 31, 2020.
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.

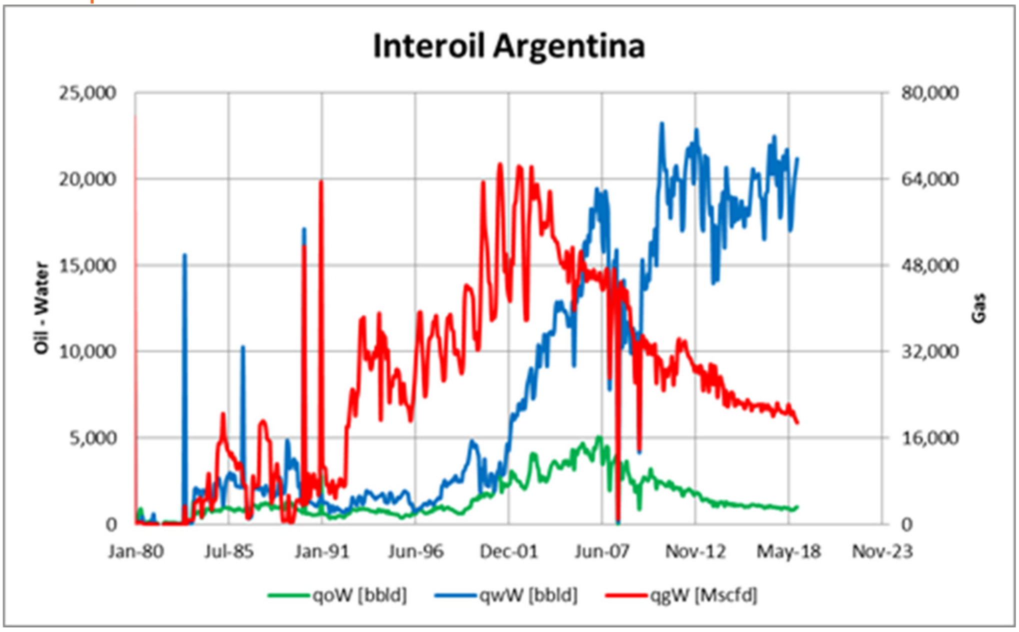


Figure 4 Historical Production – Santa Cruz assets

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

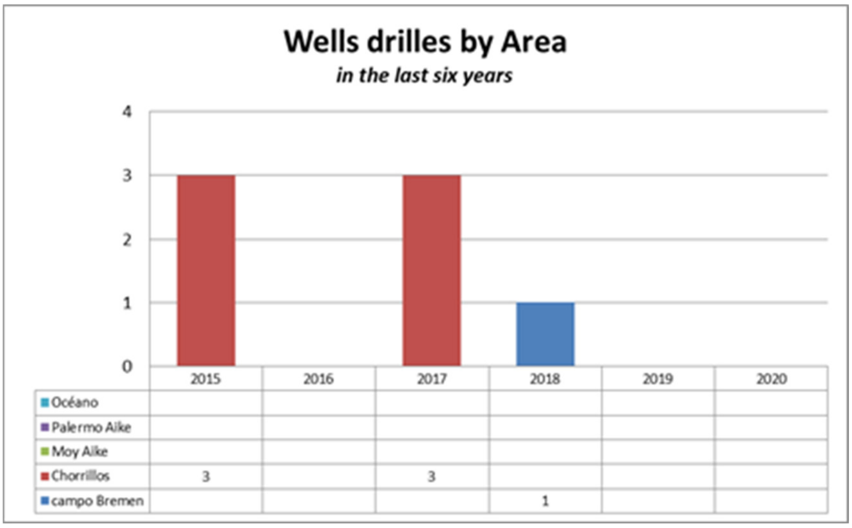


Figure 5 Wells drilled in Santa Cruz assets in the last six years

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, with Serie Tobifera being 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 51 bbl/d and 2,605 Mscf/d of gas. 53 wells were drilled in the concession, and only 11 of them are flowing as of December 2020.

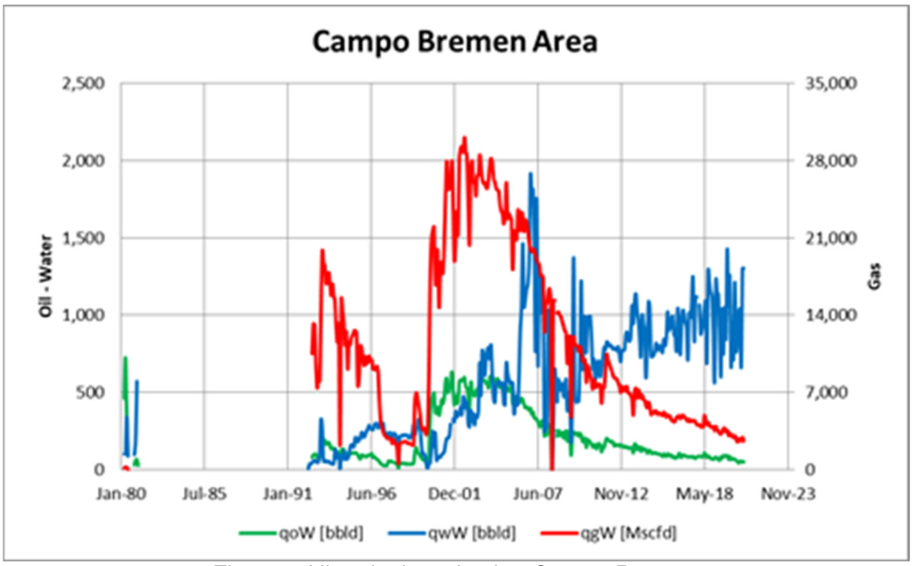


Figure 6 Historical production Campo Bremen

A summary on the estimated OGIP by the operator for the different fields and their current estimated recovery factors are shown below:

Table 7 Campo Bremen OGIP & RF

Campo Bremen Area		OGIP	CUM Gas	RF
Field	Formation	Bcf	Bcf	fraction
Campo Bremen	Springhill/Tobifera	*42*	*19*	*0.44*
Estancia Dos Lagunas	Springhill/Tobifera	*143*	*87*	*0.61*
Nortero Noreste	Springhill	*8*	*4*	*0.49*

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 111 bbl/d and current gas production is 8,494 Mscf/d. 136 wells were drilled in the concession and only 24 of them are flowing as of December 2020.

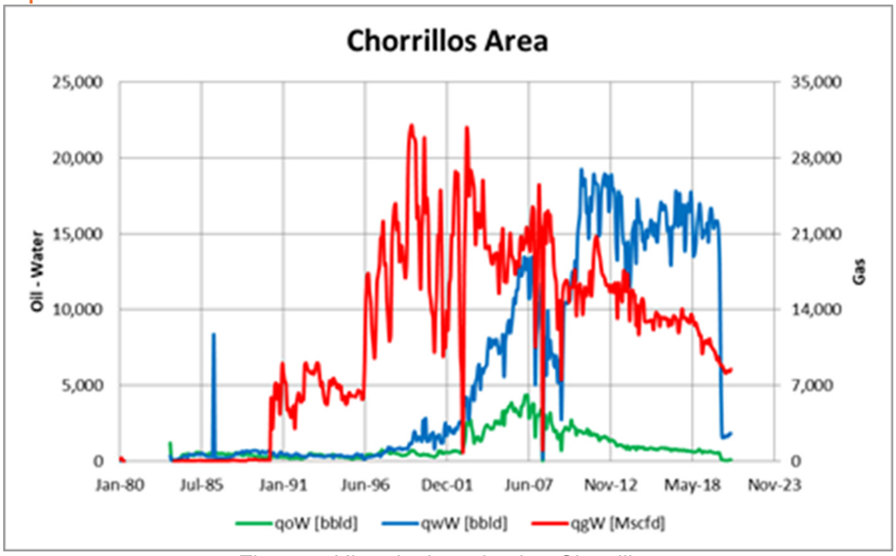


Figure 7 Historical production Chorrillos

A summary on the estimated OGIP & OOIP by the operator for the different fields and their current estimated recovery factors are shown below:

Table 8 Chorrillos OGIP, OOIP & RF

Chorrillos Area		OOIP	OGIP	CUM OIL	CUM GAS	RF OIL	RF GAS
Field	Formation	MMbbl	Bcf	MMbbl	Bcf	fraction	fraction
Campo Molino	Springhill/Tobifera	72	18	7	2	0.10	0.13
Cerro Convento	Tobifera	11	11	1	4	0.11	0.36
Cerro Convento Sur	Springhill				1		
Cerro Norte	Springhill/Tobifera	4	228	0	123	0.00	0.54
Cerro Norte Oeste	Tobifera		49		12		0.24
Chorrillos	Springhill/Tobifera	32	39	3	3	0.08	0.08
Tres Colinas	Springhill/Tobifera	6	1	0	0	0.02	0.02
Zuri	Springhill/Tobifera	34	33	1	9	0.02	0.27

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 105 bbl/d and current gas production is 142 Mscf/d. 62 wells were drilled in the area and only 9 of them are flowing as of December 2020.

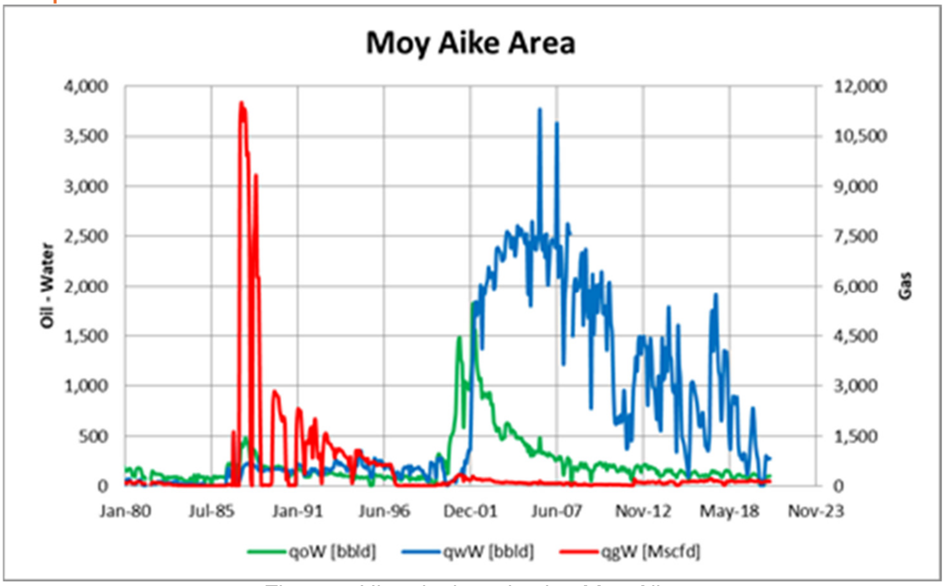


Figure 8 Historical production Moy Aike

A summary on the estimated OGIP & OOIP by the operator for the different fields and their current estimated recovery factors are shown below:

Table 9 Moy Aike OGIP, OOIP & RF

Moy Aike Area		OOIP	OGIP	CUM OIL	CUM GAS	RF OIL	RF GAS
Field	Formation	MMbbl	Bcf	MMbbl	Bcf	fraction	fraction
El Indio Oeste	Tobifera/Springhill	20.3	2.2	2.4	0.6	0.12	0.25
Moy Aike	Springhill	0.0	33.0	0.1	6.8		0.20

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 25 bbl/d and current gas production is 2,209 Mscf/d. 47 wells were drilled in the area, and only 7 of them are flowing as of December 2020. As the field is offshore, most of the wells were drilled from the coast and deviated to penetrate the reservoirs.

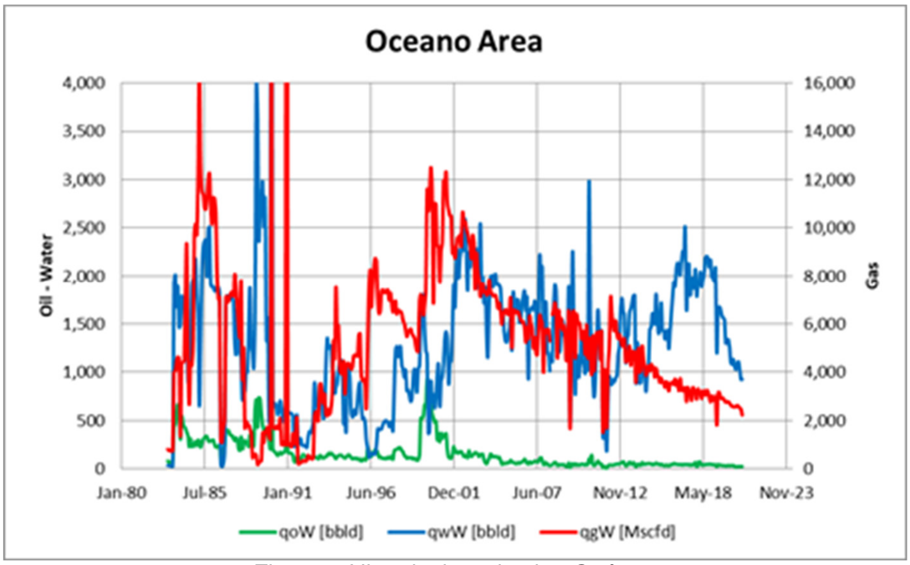


Figure 9 Historical production Océano

A summary on the estimated OGIP & OOIP by the operator for the different fields and their current estimated recovery factors are shown below:

Table 10 Océano OGIP, OOIP & RF

Oceano Area		OOIP	OGIP	CUM OIL	CUM GAS	RF OIL	RF GAS
Field	Formation	MMbbl	Bcf	MMbbl	Bcf	fraction	fraction
Oceano	Springhill/Tobifera	12	159	2	49	0.14	0.31

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 2020. 41 wells have been drilled in the area.

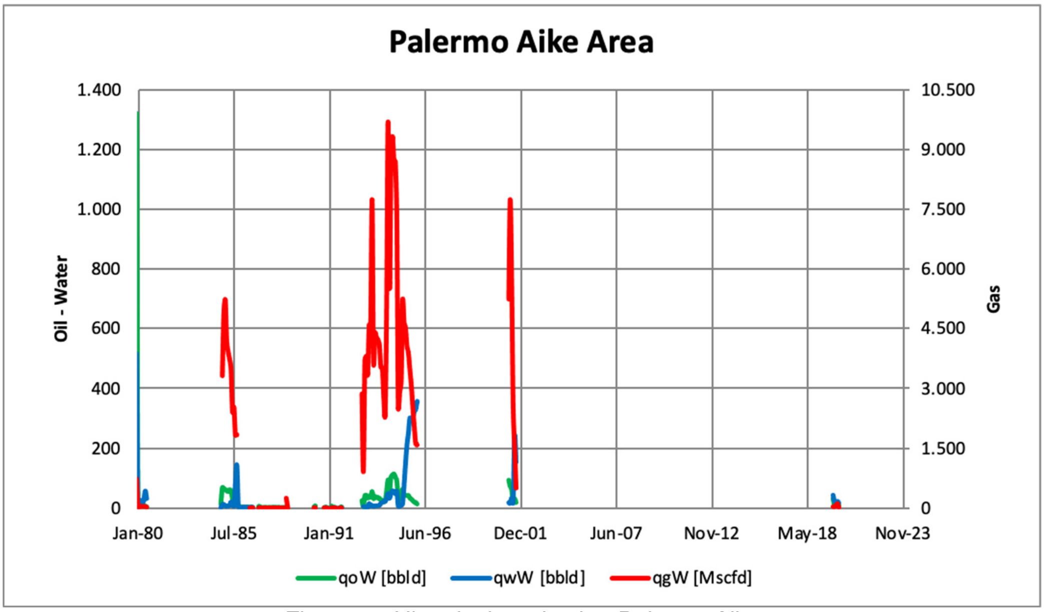


Figure 10 Historical production Palermo Aike

A summary on the estimated OGIP & OOIP by the operator for the different fields and their current estimated recovery factors are shown below:

Table 11 Palermo Aike OGIP, OOIP & RF

Palermo Aike Area		OOIP	OGIP	CUM OIL	CUM GAS	RF OIL	RF GAS
Field	Formation	MMbbl	Bcf	MMbbl	Bcf	fraction	fraction
Palermo Aike	Springhill	0.3	0.1	0.1	0.0	0.16	0.73
Cerro Tres Hermanos	Springhill	0.0	0.9	0.0	0.7		0.80
Campo Límite	Springhill	0.0	3.9	0.0	3.1		0.80
Monte Aymond	Springhill	0.0	1.4	0.0	1.1		0.80
Tres Hermanos	Springhill	0.0	2.6	0.0	2.1		0.80

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 2020. 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. No chance of commerciality has been determined for the contingent resources. 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 15 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 liaison

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, 2020

		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	387	8.58	32	0.72	27	0.61
	Developed NP	0	0.00	0	0.00	0	0.00
	Undeveloped	0	0.00	0	0.00	0	0.00
	Total 1P	**387**	**8.58**	**32**	**0.72**	**27**	**0.61**
	Total 2P	**398**	**8.75**	**33**	**0.73**	**28**	**0.62**
	Total 3P	**406**	**8.94**	**34**	**0.75**	**29**	**0.63**
CAMPO BREMEN	PROVED						
	Developed	34	1.56	3	0.13	2	0.11
	Developed NP	0	0.00	0	0.00	0	0.00
	Undeveloped	0	0.00	0	0.00	0	0.00
	Total 1P	34	1.56	3	0.13	2	0.11
	Total 2P	35	1.61	3	0.14	2	0.11
	Total 3P	36	1.67	3	0.14	3	0.12
CHORRILLOS	PROVED						
	Developed	276	5.35	23	0.45	20	0.38
	Developed NP	0	0.00	0	0.00	0	0.00
	Undeveloped	0	0.00	0	0.00	0	0.00
	Total 1P	276	5.35	23	0.45	20	0.38
	Total 2P	281	5.46	23	0.46	20	0.39
	Total 3P	286	5.58	24	0.47	20	0.40
MOY AIKE	PROVED						
	Developed	61	0.09	5	0.01	4	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	61	0.09	5	0.01	4	0.01
	Total 2P	65	0.09	5	0.01	5	0.01
	Total 3P	67	0.09	6	0.01	5	0.01
OCEANO	PROVED						
	Developed	17	1.58	1	0.13	1	0.11
	Developed NP	0	0.00	0	0.00	0	0.00
	Undeveloped	0	0.00	0	0.00	0	0.00
	Total 1P	17	1.58	1	0.13	1	0.11
	Total 2P	17	1.59	1	0.13	1	0.11
	Total 3P	17	1.60	1	0.13	1	0.11

Exhibit-II Detailed overview reserves and costs

InterOil Argentina

Net Revenue Interest Reserve Cash Flows Properties in Santa Cruz, Argentina as of December 31, 2020

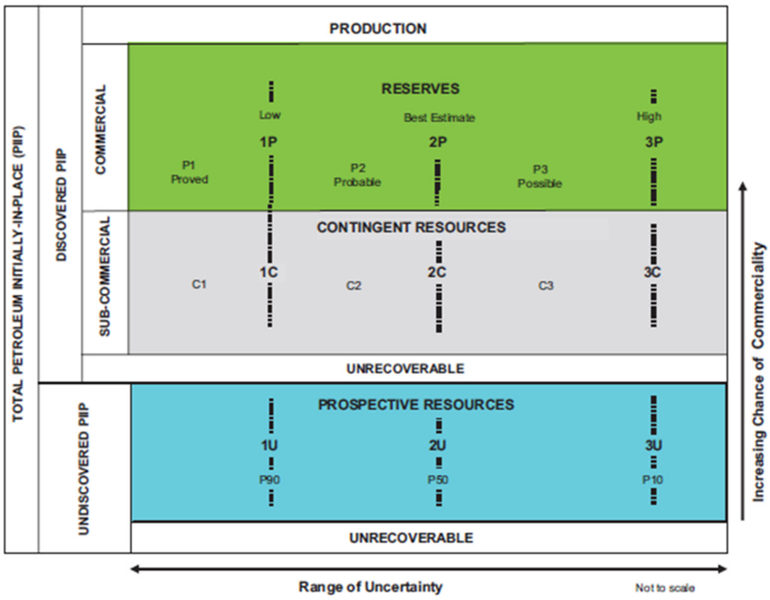
Santa Cruz Assets								
Proved Developed Reserves								
	Production Forecast		Gas Sales	Gross Income	Oil Transport	Operating Expenses	Investment	Pre-Tax Cashflow
Year	Oil - MMstb	Gas - Bscf	MMscf	KUS$	KUS$	KUS$	KUS$	KUS$
2021	0,015	0,345	0,304	1222	80	869	89	184
2022	0,012	0,263	0,232	960	65	817	44	34
2023	0,010	0,219	0,193	797	54	795	37	-89

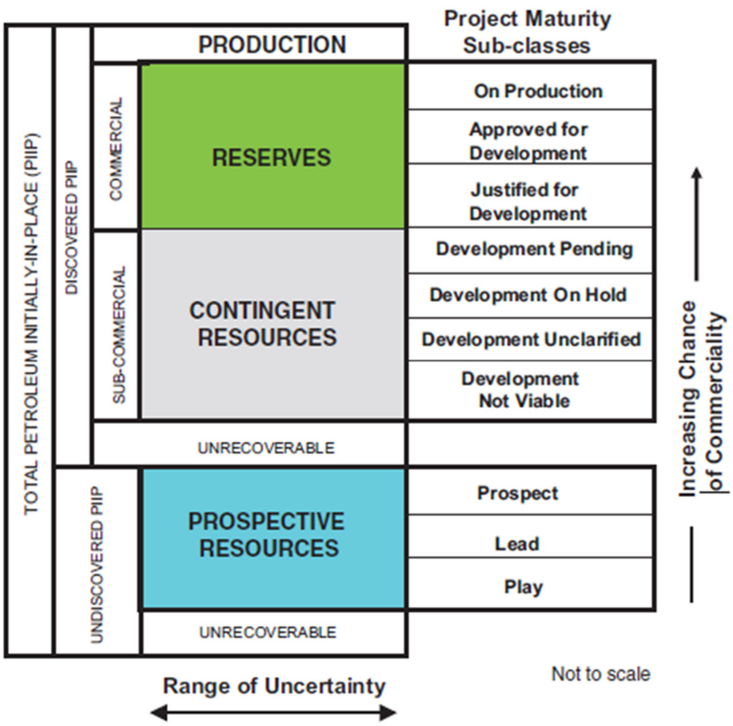
Santa Cruz Assets								
Proved Reserves (1P)								
	Production Forecast		Gas Sales	Gross Income	Oil Transport	Operating Expenses	Investment	Pre-Tax Cashflow
Year	Oil - MMstb	Gas - Bscf	MMscf	KUS$	KUS$	KUS$	KUS$	KUS$
2021	0,015	0,345	0,304	1222	80	869	89	184
2022	0,012	0,263	0,232	960	65	817	44	34
2023	0,010	0,219	0,193	797	54	795	37	-89

Santa Cruz Assets								
Probable Reserves (2P)								
	Production Forecast		Gas Sales	Gross Income	Oil Transport	Operating Expenses	Investment	Pre-Tax Cashflow
Year	Oil - MMstb	Gas - Bscf	MMscf	KUS$	KUS$	KUS$	KUS$	KUS$
2021	0,015	0,349	0,308	1238	81	872	89	196
2022	0,013	0,271	0,239	995	68	822	44	61
2023	0,011	0,232	0,204	849	58	803	37	-50

Santa Cruz Assets								
Possible Reserves (3P)								
	Production Forecast		Gas Sales	Gross Income	Oil Transport	Operating Expenses	Investment	Pre-Tax Cashflow
Year	Oil - MMstb	Gas - Bscf	MMscf	KUS$	KUS$	KUS$	KUS$	KUS$
2021	0,015	0,353	0,312	1252	82	875	89	206
2022	0,013	0,281	0,247	1028	70	829	44	85
2023	0,012	0,245	0,216	896	61	812	37	-15

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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The Netherlands

Mr. Leandro Carbone
Chief Executive Officer
Interoil Argentina
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Ciudad Autónoma de Buenos Aires, Argentina
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2nd of March, 2021

Reserves and Contingent Resources Statement for
Mata Magallanes Oeste concession, Argentina
as of December 31, 2020

Dear Mr. Carbone,

This reserves and contingent resources statement has been prepared by SGS Nederland B.V. (hereafter SGS) and issued on March 2nd, 2021 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, located in 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, 2020, 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.

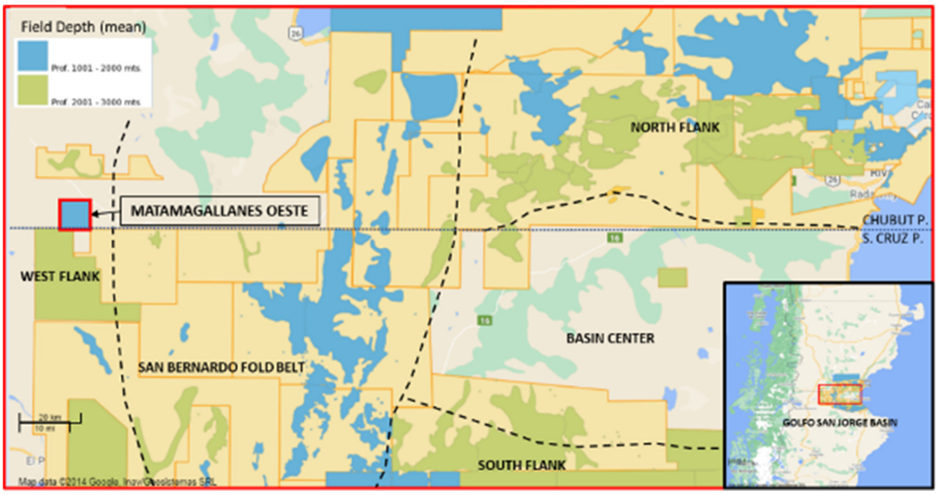


Figure 1 Location map - All concessions

Legal overview of assets

Introduction

The asset reviewed for this audit is operated by Selva Maria Oil S.A. and 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 remaining 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 is located in the Golfo San Jorge productive basins located in the Argentine Patagonia. The Mata Magallanes Oeste area is located on 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 reservoirs of the Mata Magallanes Oeste block and are composed of continental sediments developed in environments of fluvial-deltaic and lacustrine origin (Figure 2). The reservoirs are represented by the braided and meandering channels and the seals by the shales of the associated floodplains.
The petrophysical properties of the sandstones of the Castillo Fm. 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 are producers of saturated oil with a current GOR of 300 m3/m3. Oil density is 21° API on average.

The MMO field trap is an anticline elongated in a north-south direction and is limited to the north by segmented fault oriented NW-SE (Figure 2)

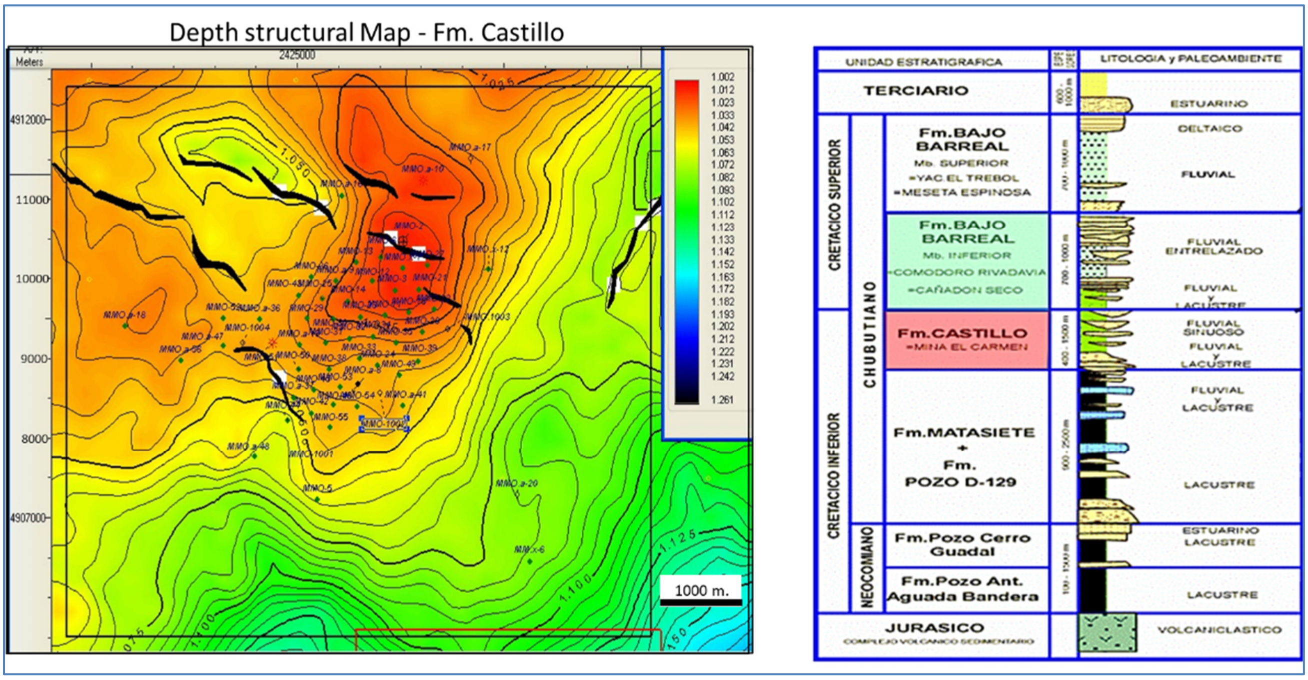


Figure 2 Top Castillo Fm. structural map and San Jorge basin stratigraphic column

Development plans

Interoil´s plan for Mata Magallanes Oeste includes the reactivation of 23 oil wells that have gone out of production due to the lack of gas to run their artificial lift systems, as well as the drilling of several new wells to increase the recovery factor of the field.

Interoil has planned 6 workovers that will take place between 2021 and 2022. The first 2 workovers will be performed during the second half of 2021 in MMO-15 and MMO-31, where some gas intervals have been identified and will be opened to provide gas for running the surface facilities and the well artificial lift systems. Interoil plans to achieve around 20 Mm3/d of gas that will ensure the full field operation and the reactivation of several closed-in oil wells. 4 workovers will also be performed looking for new hydrocarbons in new and previously perforated intervals. SGS has reviewed the proposed workovers and classified 3 of them as contingent resources since they are not economic as per the reference date of the evaluation.

The plan also includes the drilling of 6 new wells that were presented to SGS with its proposed location and the corresponding technical details. 3 of the wells are scheduled to be drilled in 2022 and 3 of the wells are to be drilled during 2023. These wells have also been classified as contingent resources, as the best estimate production forecasts are not economic under the current price scenario.

Contingent Resources

As per the current prices and costs scenario, and as stated in the above chapter, contingent resources in this report account for the 6 new wells to be drilled in 2022-2023 and the 3 workovers targeting oil, to be performed during 2021-2022.

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 is under 1 m3/d by that point 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-2020:

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	193	676	154	541	136	476
	Undeveloped	0	0	0	0	0	0
	Total 1P	**193**	**676**	**154**	**541**	**136**	**476**
	Total 2P	**399**	**1438**	**319**	**1150**	**281**	**1012**
	Total 3P	**658**	**2257**	**526**	**1806**	**463**	**1589**

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 conditions of 14.7 psia and 60℉._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 2 of the workovers was added to the gas reserves figures. All 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**
2021	48	92	159
2022	79	151	240
2023	67	127	201
2024	57	109	171
2025	49	93	145
2026	42	80	124
2027	36	68	105
2028	31	58	90
2029	26	50	77
2030	23	43	66
2031	20	37	56
2032	17	32	48
2033	15	28	42
2034	0	24	36
2035	0	19	29

The extrapolation of the production beyond the field´s economic limit and the activities as per previous description have 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**	**431**	**725**	**344**	**580**	**303**	**511**
	Total 2C	**645**	**1087**	**516**	**869**	**454**	**765**
	Total 3C	**878**	**1480**	**703**	**1184**	**618**	**1042**

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

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 2020, up to end of 2028 and thereafter inflated by 2% per annum (Table 4). A discount of 3,73 US$/bbl has been applied for Escalante blend.

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 4 - Brent forecast (MOD) 2021-2032

Year	Oil Price (US$/bbl)
2021	51,06
2022	50,17
2023	49,62
2024	49,39
2025	49,26
2026	49,22
2027	49,21
2028	49,19
2029	50,17
2030	51,17
2031	52,20
2032	53,24

2021 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 5) have been applied for the economic evaluation:

Table 5 - Overview cost aspects

Category	MMO
Fixed Cost (kUS$/yr)	200
Variable Opex (US$/bbl)	2,50
Fixed G&A (kUS$/yr)	84,0
Oil transportation (US$/bbl)	4,33

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 2020, only 2 wells are in production, mainly due to the lack of gas production required to run the surface facilities and the well artificial lift systems.

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 placed on production.

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

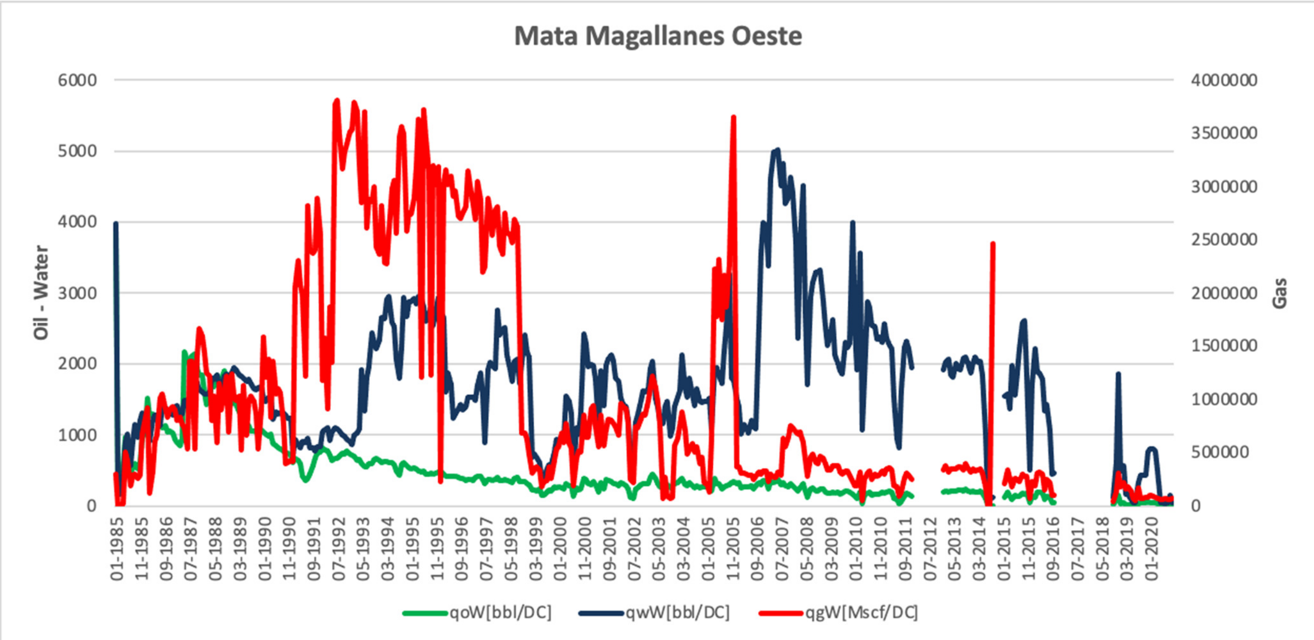


Figure 3 Mata Magallanes Oeste historical production

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 2020. 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 15 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	Richard Keen
Project Manager	Business Manager
Primary technical and commercial support	

Exhibit I - Overview of Reserves and Contingent resources

Statement of Remaining Hydrocarbon Volumes Mata Magallanes Oeste Concession, Argentina as of December 31, 2020

		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	193	676	154	541	136	476
	Undeveloped	0	0	0	0	0	0
	Total 1P	**193**	**676**	**154**	**541**	**136**	**476**
	Total 2P	**399**	**1438**	**319**	**1150**	**281**	**1012**
	Total 3P	**658**	**2257**	**526**	**1806**	**463**	**1589**

Exhibit II - Detailed overview reserves and costs

InterOil Argentina

Net Revenue Interest Reserve Cash Flows Properties in Chubut, Argentina as of December 31, 2020 (MOD)

Mata Magallanes Oeste

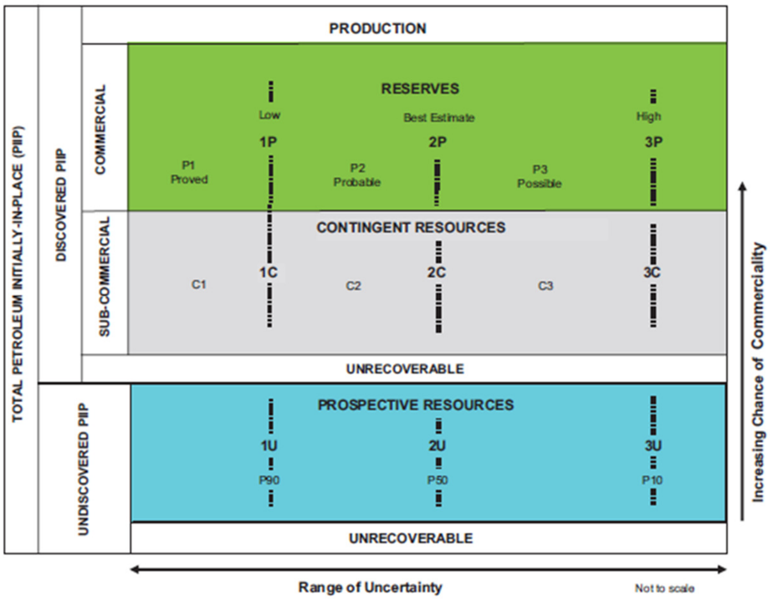
Mata Magallanes Oeste								
Proved Developed Reserves								
	Production Forecast		Gas Sales	Gross Income	Oil Transport	Operating Expenses	Investment	Pre-Tax Cashflow
Year	Oil - Mstb	Gas - MMscf	MMscf	MUS$	MUS$	MUS$	MUS$	MUS$
2021	12	48	0	621	67	266	1488	-1199
2022	21	79	0	924	101	287	0	536
2023	18	67	0	800	88	281	0	430
2024	16	57	0	698	78	277	0	344
2025	14	49	0	611	68	273	0	270
2026	12	42	0	537	60	270	0	207
2027	11	36	0	473	53	268	0	153
2028	10	31	0	417	47	266	0	105
2029	8	26	0	376	41	264	0	71
2030	7	23	0	339	36	263	0	40
2031	7	20	0	307	32	262	0	12
2032	6	17	0	277	28	262	0	-13
2033	5	15	0	251	25	262	0	-36

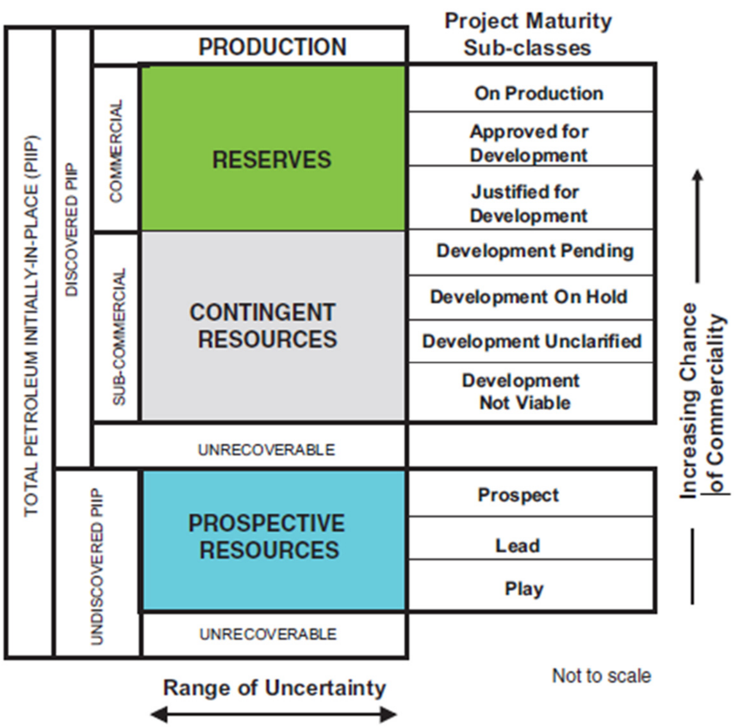
Mata Magallanes Oeste								
Proved Reserves (1P)								
	Production Forecast		Gas Sales	Gross Income	Oil Transport	Operating Expenses	Investment	Pre-Tax Cashflow
Year	Oil - Mstb	Gas - MMscf	MMscf	MUS$	MUS$	MUS$	MUS$	MUS$
2021	12	48	0	621	67	266	1488	-1199
2022	21	79	0	924	101	287	0	536
2023	18	67	0	800	88	281	0	430
2024	16	57	0	698	78	277	0	344
2025	14	49	0	611	68	273	0	270
2026	12	42	0	537	60	270	0	207
2027	11	36	0	473	53	268	0	153
2028	10	31	0	417	47	266	0	105
2029	8	26	0	376	41	264	0	71
2030	7	23	0	339	36	263	0	40
2031	7	20	0	307	32	262	0	12
2032	6	17	0	277	28	262	0	-13
2033	5	15	0	251	25	262	0	-36

Mata Magallanes Oeste								
Probable Reserves (2P)								
	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$
2021	22	92	0	1146	123	298	1488	-763
2022	38	151	0	1682	184	335	0	1163
2023	33	127	0	1454	161	323	0	970
2024	29	109	0	1267	141	313	0	813
2025	25	93	0	1108	123	305	0	680
2026	22	80	0	972	108	298	0	566
2027	20	68	0	855	95	292	0	467
2028	17	58	0	752	84	287	0	381
2029	15	50	0	678	74	283	0	320
2030	13	43	0	611	65	280	0	266
2031	12	37	0	552	58	277	0	217
2032	10	32	0	499	51	275	0	172
2033	9	28	0	451	45	274	0	132
2034	8	24	0	406	40	272	0	94
2035	7	19	0	332	32	270	0	30
2036	3	9	0	162	15	262	0	-115

Mata Magallanes Oeste								
Possible Reserves (3P)								
	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$
2021	45	159	0	2311	248	370	1488	205
2022	64	240	0	2863	313	409	0	2141
2023	56	201	0	2442	270	386	0	1786
2024	48	171	0	2099	233	367	0	1499
2025	42	145	0	1812	202	350	0	1260
2026	36	124	0	1571	175	336	0	1059
2027	31	105	0	1364	152	325	0	887
2028	27	90	0	1187	132	315	0	739
2029	24	77	0	1057	115	307	0	634
2030	21	66	0	943	101	300	0	542
2031	18	56	0	844	88	295	0	460
2032	16	48	0	755	77	290	0	387
2033	14	42	0	677	68	287	0	323
2034	12	36	0	605	59	284	0	262
2035	10	29	0	506	49	279	0	178
2036	5	13	0	254	24	267	0	-37

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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The Netherlands

Mr. Leandro Carbone
Chief Executive Officer
Interoil Argentina
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Ciudad Autónoma de Buenos Aires, Argentina
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15th of March 2021

Reserves and Contingent Resources Statement for
La Brea concession, Argentina
as of December 31, 2020

Dear Mr. Carbone,

This reserves- and contingent resources statement has been prepared by SGS Nederland B.V. (hereafter 'SGS') and issued on March 15th, 2021 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, 2020, 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.

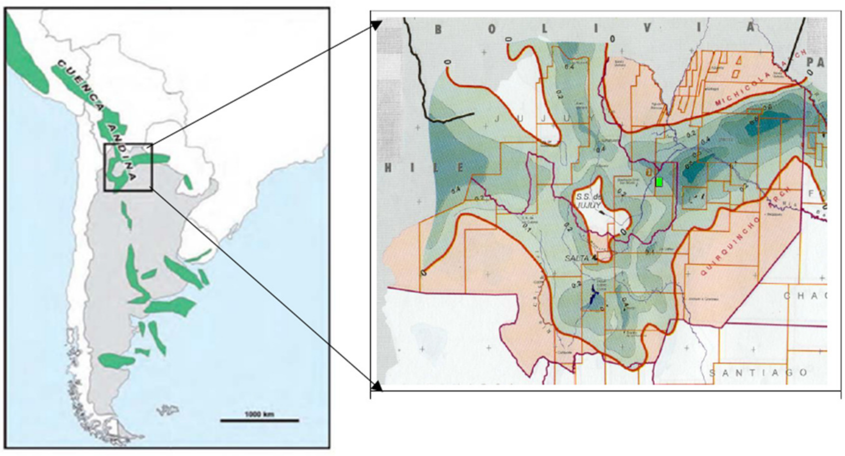


Figure 1 Location map - All concessions

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 being discovered.
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, 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 foothills, in Jujuy province, Argentina. The main reservoir is composed of 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) interpreted as closed. The fracture sets 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 beds thin.
The trends of the reverse faults are N-S parallel to the Andean hills and the normal faults are E-W trending.

The Noroeste Basin is actually 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

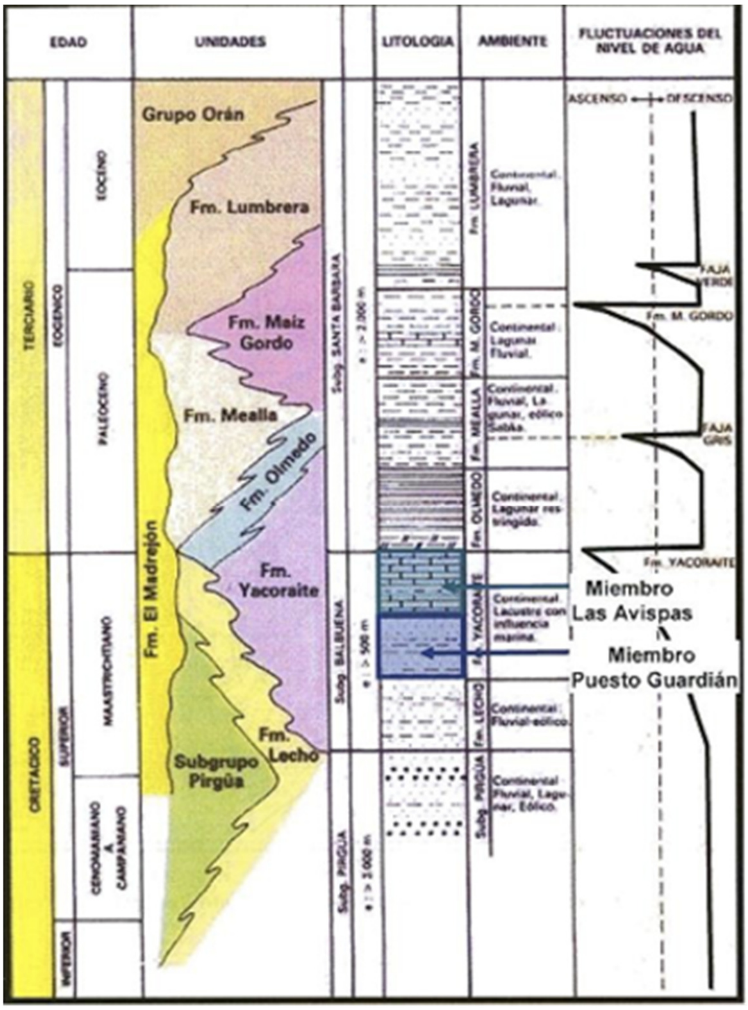


Figure 2 Stratigraphic column in the Noroeste Basin

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

In the 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 are supported by the control of the concession wells (Figure 3).

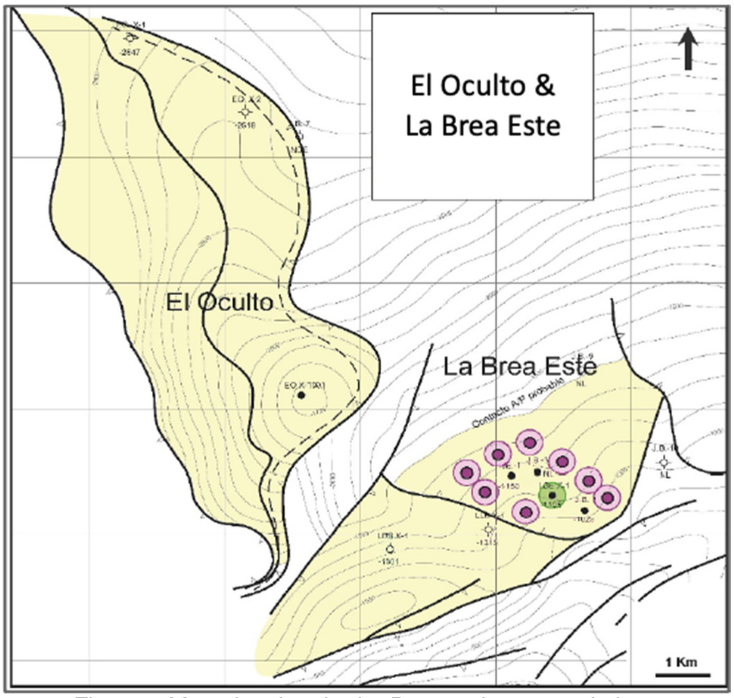


Figure 3 Map showing the La Brea main accumulations

Development plans

Interoil´s plan for La Brea for rehabilitating and putting into production the field includes a hydraulic fracture of well YPF.Jj.LBEx-1 and the drilling and fracturing of 8 wells in the La Brea Este accumulation.

These activities were presented to SGS by Interoil and 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 the El Oculto accumulation and found some non-commercial hydrocarbon volumes. That area remains as a resource area yet to be fully explored. Volumes associated with El Oculto have been estimated and are considered as Contingent Resources and subclassified as Development Not Viable. Effectiveness of fraccing techniques should be considered and further studied

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 Est 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-2020:

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 well YPF.Jj.LBEx-1, and should be considered as Development Pending.

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 in an area of 15,821 km^2 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 2020. 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 15 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

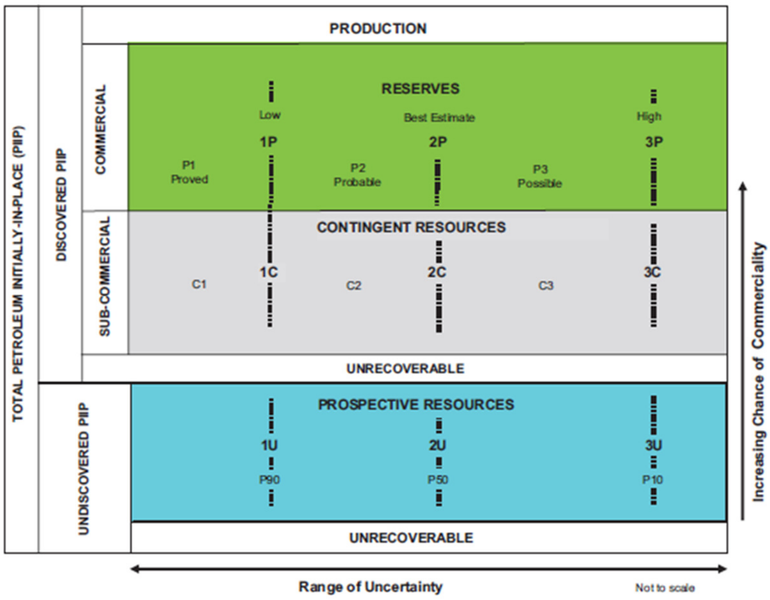
Project Manager

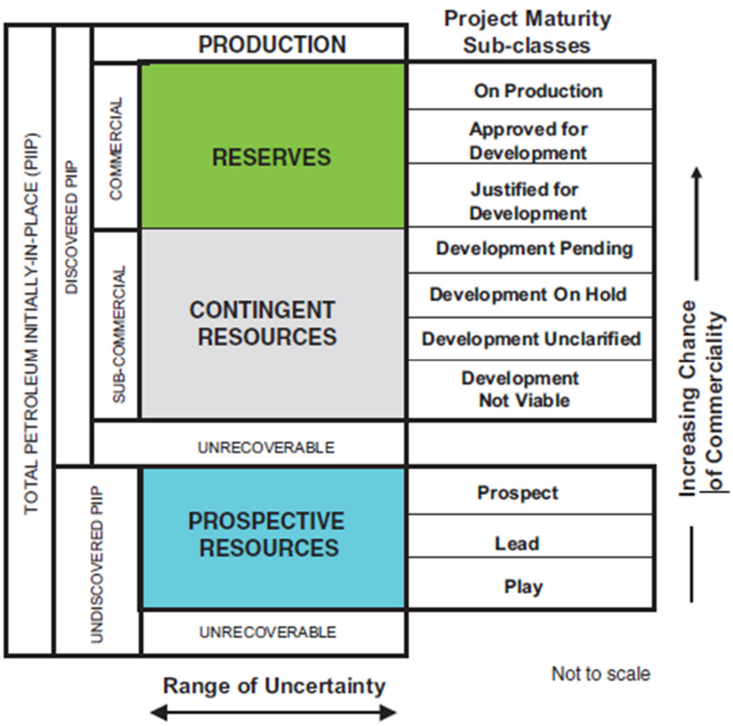
Primary technical- and
commercial liaison

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.