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MSc in Petroleum Engineering

Individual Project Report 2019

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**Determination of the Minimum Economical Prospect Size of
two prospects offshore Uruguay**

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Declaration

I Cecilia Romeu confirm that this work submitted for assessment is my own and is expressed in my own words. Any uses made within it of the works of other authors in any form (e.g. ideas, equations, figures, text, tables, programs) are properly acknowledged at the point of their use. A list of the references employed is included.

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Date: August 8th, 2019

Acknowledgements

The author would like to thank Project Supervisor Mark Bentley, for his support and the insight and advice provided during this project.

Additionally, the author would like to thank ANCAP for give permission to use proprietary data for this project, and to colleagues of E&P of ANCAP for their constant help and support.

1. Summary

Several prospects have been identified by International Oil Companies (IOCs), through the available 2D and 3D seismic data in offshore Uruguay, where no oil or gas has been discovered yet. The main elements and processes of the petroleum system were identified for these prospects; however, the high geological risk together with high drilling costs compared with prevailing international oil prices lead many IOCs to conclude their exploratory activity in these areas.

The characterization of the selected offshore prospects by means of the estimation of its prospective resources and the determination of their Minimum Economical Prospect Size (MEPS) is considered very valuable for Uruguay in order to quantify its resources and promote its offshore exploratory opportunities. This study will also serve as a reference in future Rounds of awarding areas for hydrocarbons exploration and production, as a tool to attract IOCs that may be interested in carrying out exploratory activities offshore Uruguay.

2. Objectives

This project aims to determine the Minimum Economical Prospect Size (MEPS) of two selected prospects offshore Uruguay. Two offshore development scenarios were considered: one prospect in shallow waters and one prospect in deep waters, in different geological settings and considering oil with associated gas production in each case. In order to meet the previous objective, this study includes the probabilistic resources' volume estimation by means of the Pallisade tool, @Risk. The inputs to perform the probabilistic volumetric estimation of prospective resources were the prospects' main geological features and petroleum systems identified.

An economic assessment of three prospective resource scenarios (best estimate, high estimate and low estimate), taking into consideration the fiscal terms applied in the actual Round system of awarding exploration and production areas was also conducted. Several project parameters, such as Net Present Value (NPV), Internal Rate of Return (IRR), Maximum Capital Outlay (MCO), Payback period, Ultimate Cash Surplus and Profit to Investment Ratio (PIR) were determined.

3. Introduction

Exploratory activity Offshore Uruguay

The exploratory activity in Uruguay's offshore began in the 70s with the acquisition of 2D seismic and drilling of two exploratory wells (Gaviotín and Lobo). The Gaviotín X_1 (total depth of 3631 m) and Lobo X_1 (total depth 2713 m) were drilled in 1976 by Chevron in very shallow waters (between 40 and 50 m) and both were declared dry; they did not find significant source rock intervals due to their placement in basement highs, and close to the basin depositional and erosional limit (ANCAP 2017). Unfortunately, these results had a negative impact on the basin, and contributed to the absence of activity for the next 30 years.

Around 10,000 Km of new seismic data acquired in 2007 and 2008 showed interesting prospectivity and renewed the interest from IOCs. After that, the exploratory activity offshore Uruguay experienced a sharp increase following Exploration and Exploitation contracts signed between the Administración Nacional de Combustibles, Alcohol y Portland (ANCAP), which is the Uruguayan National Oil Company (NOC), and IOCs after the bidding processes in Uruguay Round 2009 and Uruguay Round II (2012). These signed contracts are Production Sharing Contracts (PSC), typically used in petroleum industry. As a result, several important major oil companies were awarded with exploration and exploitation areas (Fig. 1).

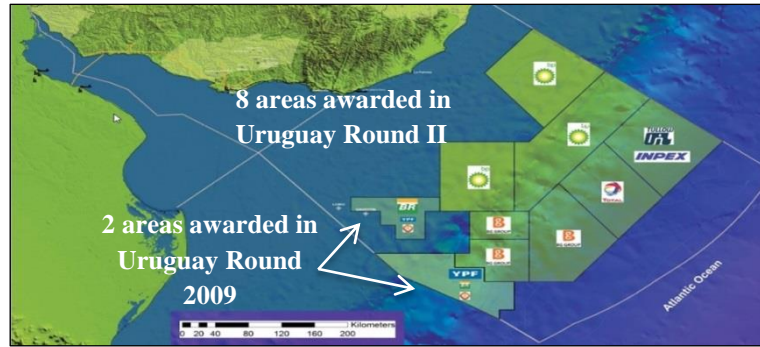


Fig. 1: Awarded areas as a result of Uruguay Round 2009 and Uruguay Round II (courtesy of ANCAP)

All the before mentioned processes led to the acquisition of approximately 41,000 Km of 2D seismic and 41,000 Km² of 3D seismic, covering all the offshore basins. These seismic data allowed the identification of numerous stratigraphic and structural prospects, but with limited information from exploratory wells. Only three exploratory wells were drilled in the offshore; two of them are located in Punta del Este Basin (Lobo X_1 and Gaviotín X_1) and the other in Pelotas Basin (Raya X_1). The latter was drilled in 2016 by Total as part of the committed exploratory program under the Uruguay Round II framework. This well reached a world-water depth record of 3404 m, with total depth approximately 2400 m below sea level. Although it reached a 135-meter-thick, high-porosity sand body, no hydrocarbon accumulations were found (ANCAP 2017).

In addition to the bidding processes previously referenced, the signature of multi-client speculative agreements between ANCAP and the most important service companies have contributed to significantly enhance the knowledge of the Uruguayan frontier basins by means of the remarkable amount of geological and geophysical data acquired.

Geology overview

Regional Geology

There are three basins identified offshore Uruguay (Fig. 2): Punta del Este to the west, Pelotas to the east and the ultra-deep water Oriental del Plata Basin to the south; these three basins cover an area of approximately 125,000 Km², up to the 200 nautical – mile

limit, and contain a maximum volcano-sedimentary fill of 8000 m, based on seismic data. The water depths range from less than 20 m to more than 4000 m (Conti et al. 2016). The genesis of these basins is related to the break-up of Gondwana and the opening of the South Atlantic Ocean in the Late Jurassic-Early Cretaceous (Conti et al. 2016), and share a genesis in common with Orange and Walvis basins of the offshore margin of South Africa and Namibia (Fig. 3) (ANCAP 2017).

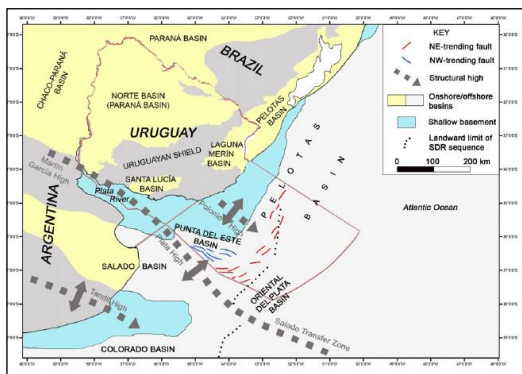


Fig. 2 Location of Uruguayan offshore basins (Soto et al. 2011)



Fig. 3: Paleogeographic restoration for the Aptian showing South Atlantic Basins (Mohriak et al. 2003)

Offshore basins

The prospects selected in this work are located in Punta del Este Basin (Fig. 4), that is described below.

The Punta del Este Basin is a funnel-shaped aulacogen which is separated from the Pelotas Basin to the east by a basement high named Polonio High (Fig. 2) (Ferro et al. 2015).

Three megasequences can be recognized in this basin: pre-rift, syn-rift, and post-rift.

Pre-rift:

The pre-rift megasequence is represented by Permian sedimentary rocks which are correlated with Permian units that develop onshore in Norte Basin (Paraná Basin). This megasequence was reached by the Gaviotín well (Conti et al. 2017).

Syn-rift

The deposits commonly encountered in this megasequence are alluvial-fluvial and lacustrine interbedded with volcanic and volcanoclastic rocks. These deposits fill a series of asymmetric half-grabens (ANCAP 2017).

Post-rift

Transition and Drift are the two main sequences that can be interpreted in the post-rift stage (ANCAP 2017).

The transition sequence (which would contain dark organic-rich shales) includes fluvial-deltaic systems and distal marine systems (the latter are not present in the more proximal region where the Lobo and Gaviotín wells were drilled) and its probable age is Aptian, based on regional correlation. The sequence has a maximum thickness of 900 m and shows a transgressive character, with the development of marine deposits for the first time in the basin and is equivalent to the transitional sequence of the Orange Basin and other productive South Atlantic basins (Bray and Lawrence 1999).

Seismic data revealed that the drift sequence has a maximum total thickness of 5500 m, and can be divided in a Cretaceous early drift and a Cenozoic late drift. The Late Cretaceous is represented by regressive deposits, proximally represented by deltaic sandstones, which were found both in Lobo and Gaviotín wells and onshore basins, and it is represented distally by deep marine deposits which includes submarine fan sandstones, according to seismic interpretation (ANCAP 2017).

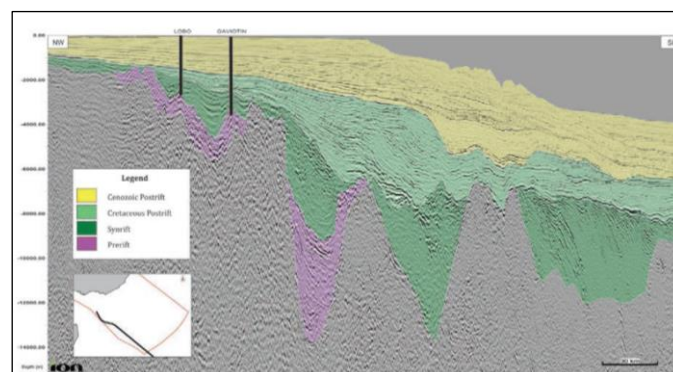


Fig. 4: Punta del Este and Oriental del Plata Basins (ANCAP 2017)

Petroleum system

In this section we will discuss the main elements of the petroleum systems in Punta del Este Basin: source rock, reservoir, seal, migration pathway and traps.

Although Gaviotín and Lobo wells were dry, fluid inclusions of light oil (32° API) and gas were shown to be present throughout the sedimentary column of both wells, especially in the Cretaceous sequence (Soto, Conti, et al. 2015), proving the presence of an active petroleum system.

Source rocks

The main source rocks in the Punta del Este Basin are lacustrine Barremian shales from the half-grabens of the syn-rift sequence and Aptian and Turonian marine shales from the post-rift sequence (Conti et al. 2017). The Aptian and Turonian sequences are world class source rocks that have contributed 29% of the global oil and gas reserves (Ulmishek and Klemme 1990).

The half-grabens have not been drilled yet, but seismic data suggest that some of them are composed of thick lacustrine shales that could contain high quality source rocks (TOC values >10%) as was proven in the time-equivalent African continental margin by the AJ-1 well in Orange Basin offshore South Africa (Jungslager 1999).

Reservoir rocks

Reservoir rocks of high quality have been encountered in the sedimentary record of the Uruguayan offshore basins through the petrographic analysis of Lobo and Gaviotín wells samples with porosity values between 18 and 25%. The best reservoirs are related to alluvial-fluvial systems of the syn-rift sequence, the fluvial-deltaic sandstones of the early drift sequence, and the lowstand deposits of the early and late drift sequences (ANCAP 2017).

Seal rocks

Several stratigraphic levels are identified as potential local (syn-rift lacustrine shales as well as early drift distal marine deposits) and regional seal rocks (marine deposits of the Paleocene transgression, also recorded in Argentinian basins, known in Uruguay as Gaviotín Formation) (ANCAP 2017).

Migration pathways

During the Late Jurassic and Early Cretaceous rifting stage, normal faults generated the half-graben structures; hence the most significant faults identified in the basin are associated with the syn-rift sequence. However, the seismic data indicate some normal faults affected the Cretaceous post-rift sequence, which are of great importance because they are connecting potential source and reservoirs rocks (Fig. 5). In some cases, faults are associated with probable gas chimneys and canyons that constitute a vertical migration pathway. Other hydrocarbon migration mechanisms are lateral migration through carrier beds in contact with the source rocks (ANCAP 2017).

Traps

The absence of salt layers as in Campos and Santos Basin (Assine, Santos Corrêa, and Chang 2008) and the lack of associated deformation processes means the focus is on stratigraphic trapping to define prospects. The stratigraphic prospects are mainly pinch-out geometries associated with channelization or submarine fan margins.

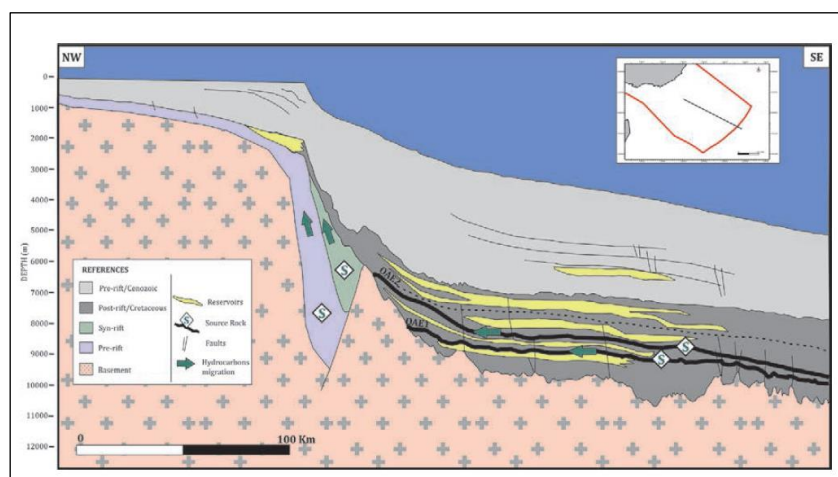


Fig. 5: Offshore Uruguay exploratory model (ANCAP 2017)

4. Data

The input parameters for the volumetric estimation of prospective resources were obtained from the following sources:

- 2D and 3D seismic data acquired in Punta del Este Basin
- Petrophysics data from the 3 wells drilled offshore Uruguay
- Analogue field data

It is important to highlight at this point that the use of seismic attributes were crucial to select the prospects and to identify potential hydrocarbon accumulations. In this project, amplitude anomalies in reservoir-prone intervals were used as a potential hydrocarbon indicator. However, it has to be considered that an abrupt increase in seismic amplitude could also be associated with processing problems on the seismic, or changes in lithology (Schlumberger n.d.). If that was the case, the amplitude anomaly could be interpreted as a false positive.

Location

Prospect 1

Prospect 1 is represented by a deep marine channel of the Upper Cretaceous and its location is presented in Fig. 6. Its shape was defined by means of 3D seismic data acquired by BG (Fig. 8), which also helped in the construction of a structural map showing its top horizon (Fig. 7). This structural map allowed the determination of a maximum (P10, Fig. 9) and minimum (P90) areal extent, P90 being determined by the area with the highest amplitude values (Fig. 10).

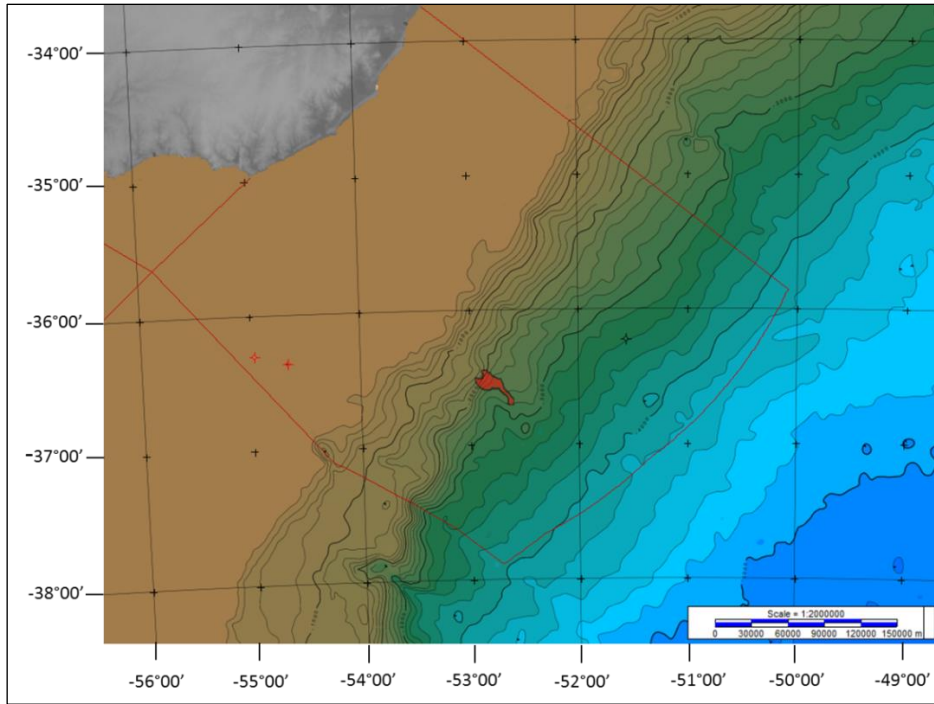


Fig. 6: Prospect 1 location (courtesy of ANCAP)

The main features of the petroleum system associated to Prospect 1 are presented in

Table 1:

Source rock:	Aptian marine source rock associated with the first anoxic event of the Cretaceous.
Reservoir:	Siliciclastic Upper Cretaceous sandstone.
Seal:	Regional Paleocene shale associated with a marine transgression.
Trap:	Channel associated with an Upper Cretaceous contouritic sequence that pinches out up-dip.
Migration pathways:	Sub-vertical faults that connect the source rock with the reservoir.

Table 1: Main features of Prospect 1 petroleum system

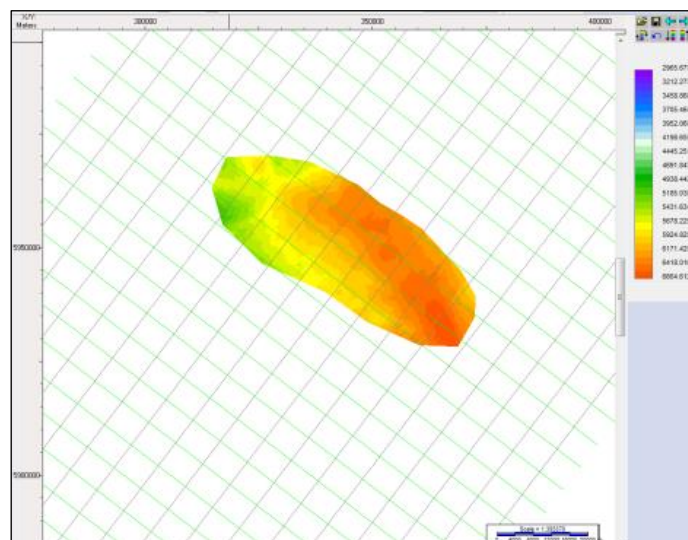


Fig. 7: Structural map-top horizon of Prospect 1 (courtesy of ANCAP)

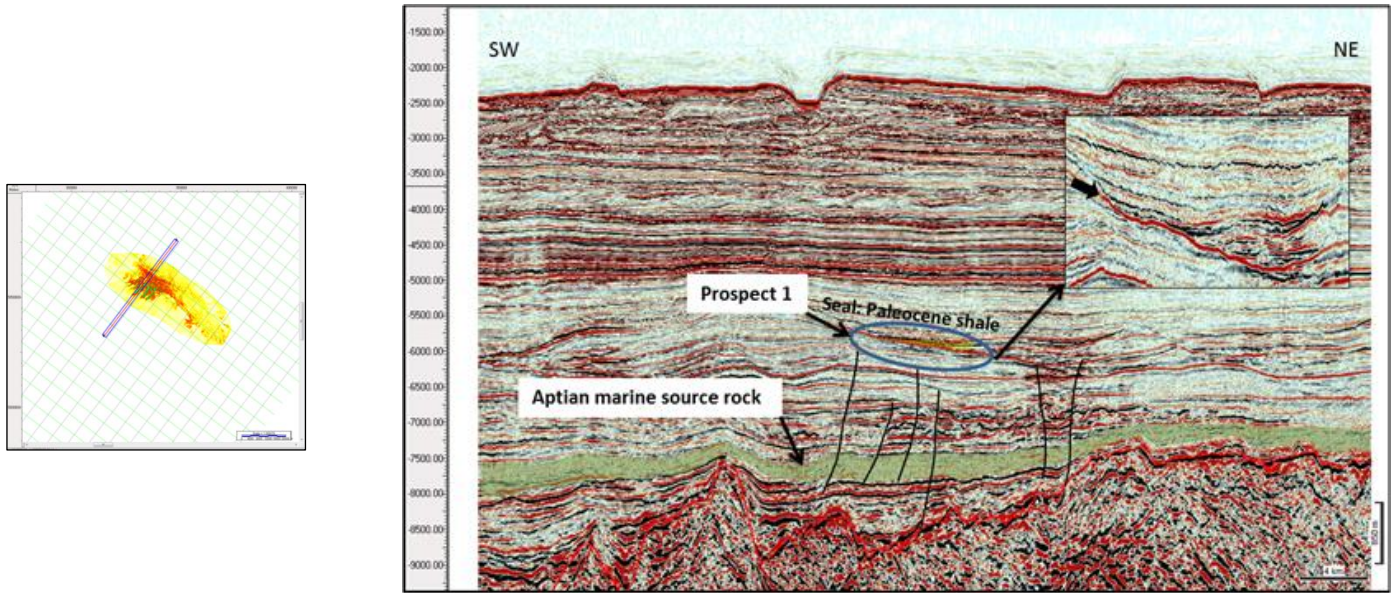


Fig. 8: Arbitrary strike line across Prospect 1 showing the main elements of the petroleum system (courtesy of ANCAP)

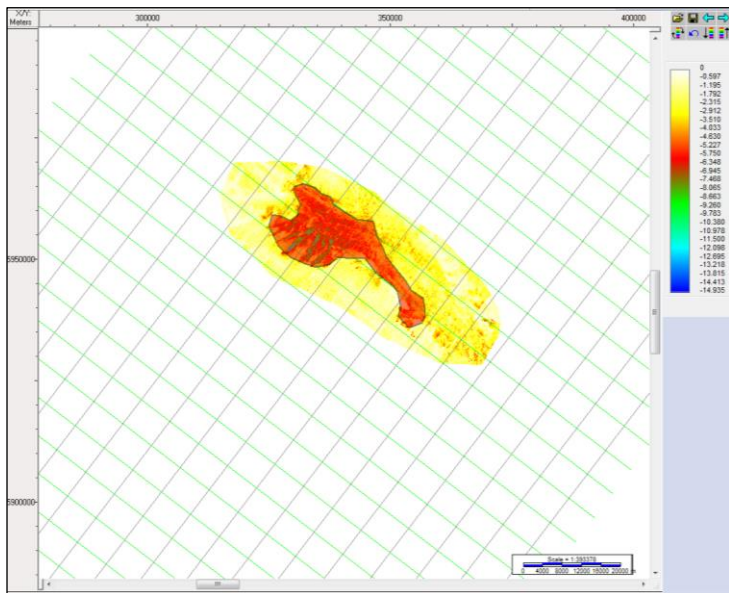


Fig. 9: Prospect 1 amplitude map showing P10 areal extent (courtesy of ANCAP)

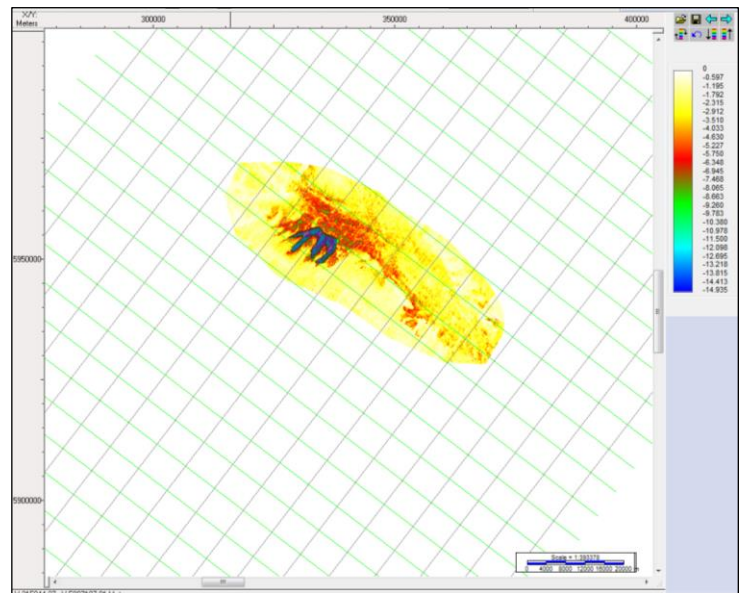


Fig. 10: Prospect 1 amplitude map showing P90 areal extent (courtesy of ANCAP)

Other main features of Prospect 1 are presented below:

- Bathymetry: minimum: 2027,95 m, maximum: 2785 m
- Distance to shore: 235 Km
- Area (from amplitude maps - Fig. 9, Fig. 10-): P90: 30 Km², P10: 292,7 Km²
- Sedimentary thickness: P90: 2843 m, P10: 3552 m
- Reservoir thickness (h): low estimate: 40 m, high estimate: 80 m

Prospect 2

Prospect 2 is represented by shallow marine deposits of the Upper Cretaceous that pinch out landward; its location is presented in Fig. 11. Its shape was defined by means of a dense 2D seismic survey (more than 15 lines; distance between dip lines: 3 Km, distance between strike lines: 7 Km), property of ANCAP (Fig. 16), used to construct the structural map in Fig. 12.

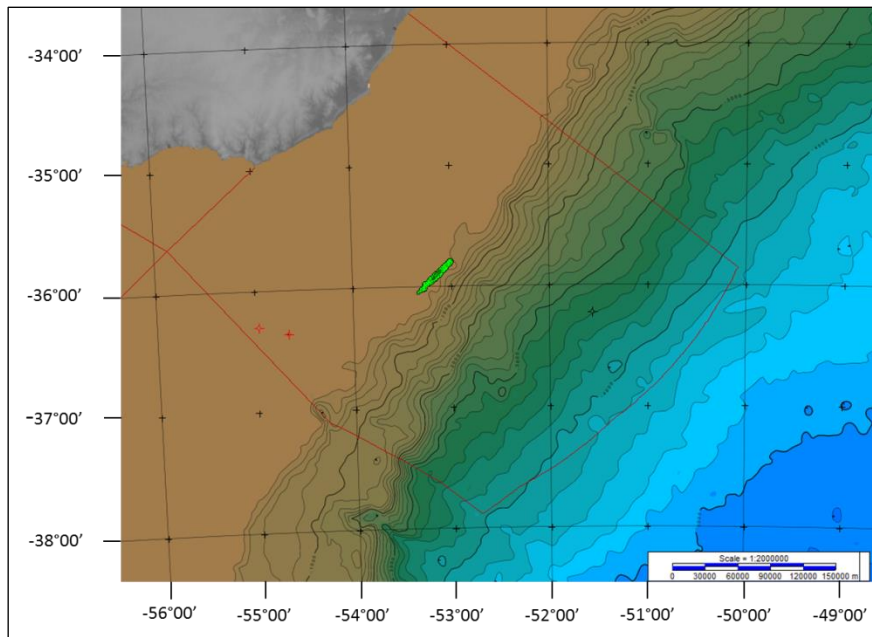


Fig. 11: Prospect 2 location (courtesy of ANCAP)

The main features of the petroleum system associated to Prospect 2 are presented in Table 2:

Source rock:	Barremian lacustrine source rock associated with half-grabens of the syn-rift sequence.
Reservoir:	Shallow marine Upper Cretaceous sandstone.
Seal:	Regional Paleocene shale associated with a marine transgression.
Trap:	Stratigraphic pinch out.
Migration pathways:	Lateral migration through carrier beds in contact with the source rocks.

Table 2: Main features of Prospect 2 petroleum system

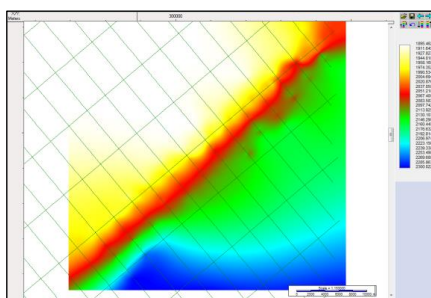


Fig. 12: Structural map-top horizon of the Prospect 2 (courtesy of ANCAP)

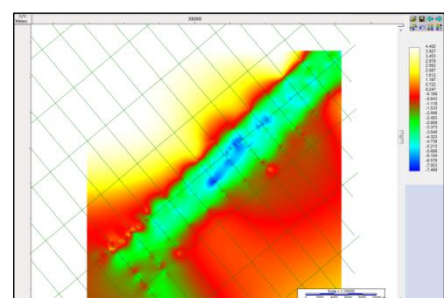


Fig. 13: Amplitude map-top of reservoir-Prospect 2 (courtesy of ANCAP)

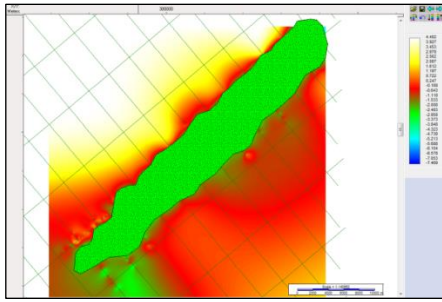


Fig. 14: Prospect 2 amplitude map showing P10 areal extent (courtesy of ANCAP)

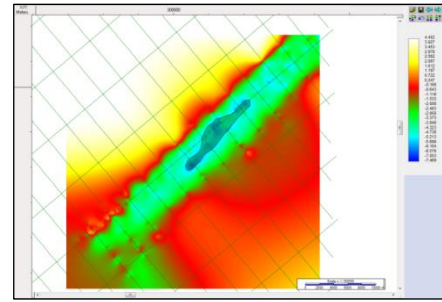


Fig. 15: Prospect 2 amplitude map showing P90 areal extent (courtesy of ANCAP)

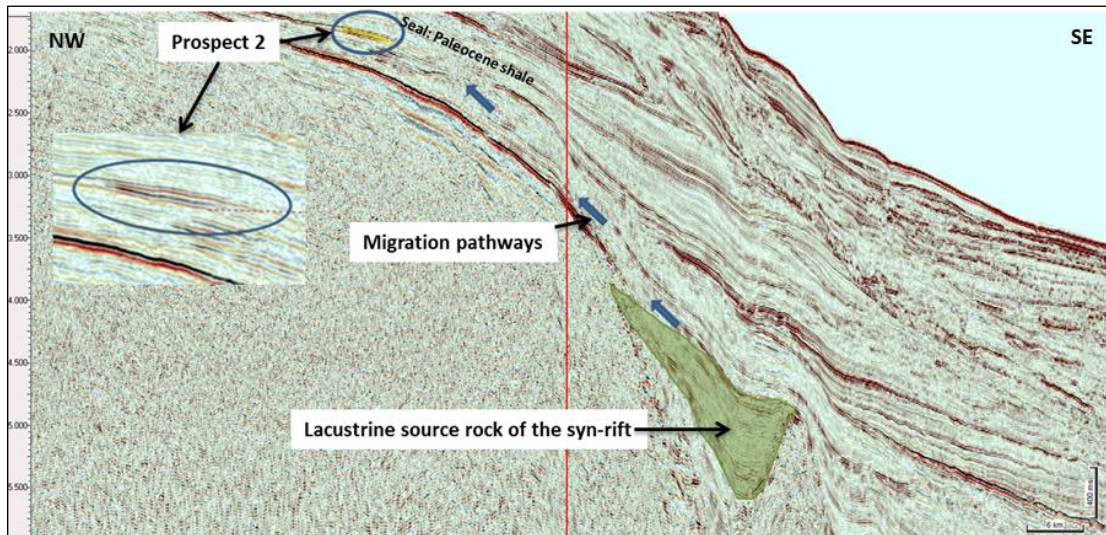


Fig. 16: Dip line across Prospect 2 showing the main elements of the petroleum system (courtesy of ANCAP)

It is important to point out the presence of a good analogue of Prospect 2, located on Block 11B/12B in the Outeniqua Basin, 175 kilometres of the southern coast of South Africa (Africa Oil+Gas Report 2019), where Total has made a gas-condensate discovery on the Brulpadda prospects (Fig. 17). The target was a Cretaceous pinch out showing a Direct Hydrocarbon Indicator (DHI) associated with a change in amplitude.

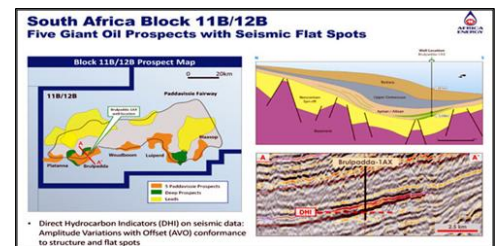


Fig. 17: Brulpadda discovery well in South Africa with location, geological model and seismic showing the pinch out prospect with DHI (Africa Oil+Gas Report 2019)

Other main features of Prospect 2 are presented below:

- Bathymetry: minimum: 132 m, maximum: 144 m
- Distance to shore: 163 Km
- Area (from amplitude maps -Fig. 14, Fig. 15-): P90: 19,5 Km², P10: 257 Km²
- Sedimentary thickness: P90: 1832 m, P10: 1959 m
- Reservoir thickness (h): low estimate: 36 m, high estimate: 106 m

5. Methodology

Chance of success

An assessment on the probability (or chance) of making a discovery must be performed (Davies, Whiteside, and Young 1991). This geological risk is generally known as the Chance of Success (CoS), and is used for the calculation of risked prospective resources. To obtain CoS, the probability of occurrence of individual geological risk factors are multiplied. The determination of these probabilities of occurrence of the geological factors is usually based on subjective judgments, which biases the assessment of geological risks (Milkov 2015). Milkov therefore proposed the use of systematic risk tables for probabilities of six geological risk factors (structure, presence of reservoir facies and reservoir deliverability, seal, source presence and maturity and migration) in order to significantly reduce subjectivity. These risk tables were used as a tool to estimate the CoS for both prospects of this work (Table 7).

Classification of hydrocarbon resources

In order to define, classify and estimate hydrocarbon resources in a consistent and reliable manner, the Society of Petroleum Engineers (SPE) Oil and Gas Reserves Committee developed the Petroleum Resources Management System (PRMS) (Society of Petroleum Engineers n.d.) (Fig. 18).

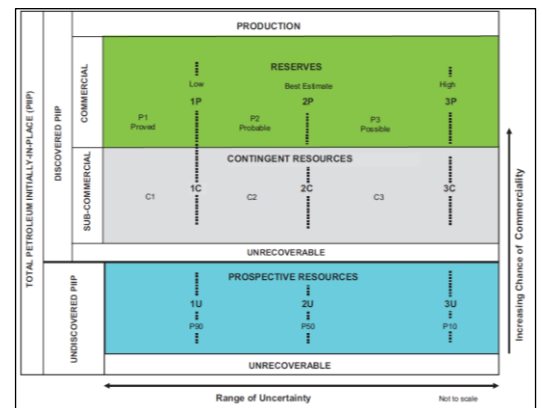


Fig. 18: PRMS Resources Classification Framework (Society of Petroleum Engineers (SPE) et al. 2018)

Due to the frontier condition of the Uruguayan offshore sedimentary basins, where no hydrocarbon discovery has been made yet, and where only limited information from wells is available, their resources can be classified as “Prospective Resources”, according to the PRMS definitions. The general cumulative terms low/best/high estimates showed in Fig. 18 are denoted as 1U/2U/3U respectively in the case of Prospective Resources (Society of Petroleum Engineers (SPE) et al. 2018).

Volumetric estimation methods

A volumetric estimate of the Total **Stock Tank Oil Initially-In-Place (STOIIP)** is given by Equation 1:

$$STOIIP (MMSTB) = \frac{A \cdot h \cdot GCF \cdot N/G \cdot \phi \cdot (1 - S_w)}{(9,29E - 8) \cdot 5,615 \cdot 1,000,000 \cdot B_o}$$

Equation 1: STOIIP determination

Where,

- 9,29E-8 is a conversion factor (Km²/ft²)
- 5,615 is a conversion factor (ft³/bbl)
- A is the prospect's area (Km²)
- h is the reservoir thickness (ft)
- GCF is the Geometry Correction Factor
- N/G is the Net to Gross ratio
- ϕ is the average porosity (fraction)
- S_w is the water saturation (fraction)
- B_o is the Oil Formation Volume Factor (RB/STB)

The **Estimated Ultimate Recovery (EUR)** can be then calculated from the Equation 2 by applying an appropriate recovery factor (RF).

$$EUR (MMSTB) = STOIIP \times RF$$

Equation 2: EUR determination

There are three principal approaches to hydrocarbon resource estimation: deterministic, multiple stochastic (probabilistic) and multiple deterministic (Bentley and Smith 2008).

The deterministic method provides a single value for each input parameter used in Equation 1 and Equation 2, therefore, it constitutes a single volume estimation (Worthington 2007), being possible the determination of a low, best, and high volume estimates (Society of Petroleum Engineers (SPE) et al. 2018).

The probabilistic approach assigns a probabilistic distribution to each parameter used in the Equation 1 and Equation 2, and combines them many times to provide a distribution

of estimated prospective resources (Worthington 2007). This method is generally used to account for the uncertainties in volumetric resources calculations at early phases of exploration, appraisal and development projects (Society of Petroleum Engineers (SPE) et al. 2018).

The multiple deterministic begins with the definition of multiple deterministic concepts that generates a spread of outcomes; this technique is not anchored as no initial base case needs to be selected. The other two approaches start with a base case (Bentley and Smith 2008).

Taking into account the frontier nature of the Uruguayan basins, the probabilistic approach was selected in this work for the estimation of the Uruguayan prospective resources.

Specific methodology

For the purpose of this study, the probabilistic volumetric estimation of the prospective resources was performed by a Monte Carlo Simulation of 10,000 iterations, by means of the Palissade Analysis tool, @Risk, and using Latin Hypercube sampling methodology. The results of these evaluations are presented in the form of cumulative probability distribution functions. From the number of possible outcomes, the low (1U), best (2U), and high estimates (3U) were determined such that:

- There should be at least a 90% probability (1U) that the quantities actually recovered will equal or exceed the low estimate (Society of Petroleum Engineers (SPE) et al. 2018);
- There should be at least a 50% probability (2U) that the quantities actually recovered will equal or exceed the best estimate (Society of Petroleum Engineers (SPE) et al. 2018);

- There should be at least a 10% probability (3U) that the quantities actually recovered will equal or exceed the high estimate (Society of Petroleum Engineers (SPE) et al. 2018).

These 1U, 2U and 3U volumes were then used to perform the economic assessment of a hypothetical field development of each prospect, by means of a cash flow model in constant money terms, considering the terms of an average contract, with 40-years of economic lifetime (30-year contract plus 10-year extension) (ANCAP 2019), the production profiles generated, oil and gas prices, costs and the fiscal regime in force in Uruguay and assuming oil with associated gas production.

As a result of this analysis, three values of NPV corresponding to 1U, 2U and 3U scenarios and the Contractor, Uruguayan State and ANCAP's profit oil split were obtained. A sensitivity analysis of the results to oil and gas price, Capital Expenditures (CAPEX) and variable Operating Expenditures (OPEX) was conducted. An assessment of the Expected Monetary Value (EMV) was also carried out.

Input parameters for volumetric estimation

Analogue fields' data

In order to best determine the parameters to be used in the volumetric equation, analogue field's data from developed fields from West Africa, Brazil, Guyana and Falkland Island prospects that proved the potential of the time-equivalent African continental margin were analyzed.

The applicability of West African analogue fields to the prospects of the Atlantic equatorial margin of South America has been proved after the recent discoveries in offshore French Guyana and Brazil's Ceará and Sergipe Basins. An important deep-water play concept is the Jubilee Field in the Tano Basin of Ghana, with 1,2 Bbl of oil (37°API); after this, other discoveries that confirmed the regional extent of Jubilee's play type have been made in Ghana, Ivory Coast, Liberia and Sierra Leone. In 2011, the

same play concept was proven to exist in the Zaedius Oil field, in French Guyana's Upper Cretaceous turbidites, with an estimation of 800 MMbbls of recoverable oil (36°API). Moreover, an Upper Cretaceous turbidite play containing light oil was encountered in the deep-water Sergipe Basin in Brazil (Favera et al. 2013). Additionally, the Barremian-lower Aptian sequence is found in the gas producing Kudu Field in Namibia (Paton et al. 2007), which makes it an analogue play to the Uruguayan case.

IOCs are using this "Mirror Image Theory" when they decide to select areas on the opposite side of the Atlantic after making discoveries on one side (Alleyne, Layne, and Soroush 2018). The discoveries in West Africa and the associated regional geology revealed basin-scale trends which also helped in the characterization of petroleum systems (Wells et al. 2012). Annex 1 summarizes the information obtained from the analogues assessed.

The input parameters to be used in Equation 1 for STOIP estimation were defined below:

Area

To define the area of each prospect, the interpretation of amplitude anomalies of the available 2D and 3D seismic data was performed (Prospect 1: P90: 30 Km², P10: 292,7 Km²; Prospect 2: P90: 19,5 Km², P10: 257 Km²).

Reservoir thickness, Geometry Correction Factor and Net-to-Gross

The reservoir thickness (h) and the Geometry Correction Factor (GCF) were also inferred from seismic. The Net-to-Gross value was inferred from analogue fields, and was considered to vary between 0,15 and 0,8 (see Annex 4).

Porosity distributions

The porosity distributions for each prospect were constructed based on the burial effect by means of the porosity vs depth datasets provided by Ehrenberg and Nadeau

(Ehrenberg and Nadeau 2005) (see Annex 2). The best estimate for porosity was determined to be 13,8% and 18,1% for Prospect 1 and 2 respectively.

Fluid characterization

Taking into consideration the available results of fluid inclusion analysis performed on cuttings from Lobo and Gaviotin wells, which revealed the presence of light oil of approximately 32° API (Tavella and Wright 1996), the type of fluid anticipated for this particular study was considered to be a black oil of 32° API. For this type of fluid, the typical gas/oil ratio (GOR) values are between 100 and 2500 Scf/STB and the specific gas gravity (γ_g) between 0,8 and 0,65 (air =1) (Heriot-Watt University 2016b). It will then be considered for the purposes of this work a $\gamma_g = 0,8$ and a GOR between 100 and 2100 Scf/STB, taking into account the black oil correlation and their ranges of application (Heriot-Watt University 2016a).

Hydrocarbon saturation

The hydrocarbon saturation values used vary from 0,1 to 0,4, according to analogue fields' data.

Formation Volume Factor

The corresponding Oil Formation Volume Factor (B_o) was estimated by means of the correlation proposed by Levitan (Levitan 1999), considering the most probable fluid scenario in an undersaturated system and each prospect's depth (see Annex 3). The B_o for Prospect 1 was determined to vary from a low estimate of 1,015 scf/STB to a high estimate of 1,5 scf/STB. For Prospect 2, B_o determination ranges from 1,014 scf/STB (low estimate) to 1,498 scf/STB (high estimate).

Recovery factor (RF)

The recovery factor was considered to vary between 20% (P90) and 45% (P10) as it was proposed by (Rose & Associates, n.d.), for a water drive mechanism and for the type of

fluid anticipated. After reviewing data from analogue fields, a typical recovery factor is approximately 25%, which is consistent with this RF range.

Determination of STOIP and EUR

The simulation was performed over Equation 1 and Equation 2; to do so, a distribution function was assigned to each of the parameters involved for Prospects 1 and 2 (summarized in Annex 4).

Development plans considered

Drilling and production concepts

The drainage strategy will be designed in order to optimize the number of wells, by drilling from a single rig, and by avoiding unnecessary process equipment to optimize the costs involved. The concept selection was based on each prospect's water depth. For Prospect 1 (bathymetry: 2028-2785 m) a drillship is proposed, while for Prospect 2 (bathymetry: 132-144 m) a jack-up rig is sufficient, as it is traditionally designed for water depths up to 150 m approximately (Gudmestad, Zolotukhin, & Jarlsby, 2010). In the event that it would be necessary to produce the 3U scenario, two drillships/jack ups will be required to work in parallel to meet the drilling requirements.

The production in both cases will be evacuated via a Floating, Production, Storage and Offloading (FPSO) vessel, connected to the wells below by flexible risers. The FPSO hosts all the normal platform functions such as oil production, separation and water injection equipment. (Gudmestad, Zolotukhin, & Jarlsby, 2010). The FPSO was selected in order to be able to produce the peak oil per day, the peak of natural gas per day of each prospect, as well as the daily water injection requirements.

Secondary recovery

In order to provide good well productivity and to sustain reservoir pressure, a water injection plan is proposed, due to its high associated recovery and the availability of the injection fluid (Heriot-Watt University 2016c).

Export facilities

In the area where prospects 1 and 2 are located, there are no oil export facilities in place; oil produced is proposed to be offloaded by shuttle tankers. Regarding natural gas production, 4% is used to power the offshore facilities; for the remaining gas production, two possible scenarios are proposed: export to shore or re-injection into the reservoir. Uruguay showed a maximum domestic natural gas demand of 15 MMm³ during 2018 and 2019 (Ministry of Industry 2019), which is nowadays imported from Argentina. This means that the transportation of the produced gas to shore would contribute to reduce the amount of imported gas.

The existing gas pipeline facilities (Fig. 19) comprise a subsea pipeline (57 Km length, outside diameter: 24", maximum design pressure: 95 bar) that connects Argentina and Uruguay (Colonia Department) and an onshore pipeline (145 Km length, outside diameter: 18", maximum design pressure: 80 bar) from Colonia to Montevideo Department (GCDS 2019). A dedicated gas pipeline system must therefore be built in order to transport the produced and treated gas from the FPSO unit to the onshore existing pipeline.

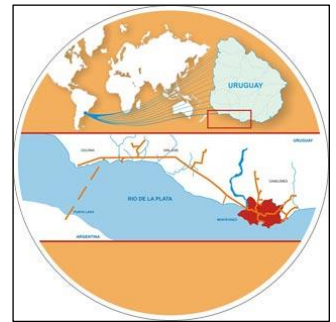


Fig. 19: Existing natural gas facilities (GCDS 2019)

Field Development Plan (FDP)

The amount of wells required to develop Prospect 1 and Prospect 2 is presented in Table 3 and Table 4 respectively. The wells of each prospect will be tied back to an independent FPSO for the purposes of this work. The procedure employed to calculate the amount of wells, as well as a brief description of the subsea equipment proposed is presented in Annex 5.

Prospect 1							
					N° of wells		
	Oil (MMBOE)	Associated gas (TCF)	Peak oil production (Mbbl/d)	Peak NG production (MMscf/d)	Oil producers	Water injectors	NG injectors
1U Low estimate	147,32	0,092	48,14	28,90	8	5	3
2U Best estimate	502,43	0,54	167,37	172,95	27	10	3
3U High estimate	1341,74	1,96	449,14	629,29	71	18	7

Table 3: Amount of wells required to develop Prospect 1

Prospect 2							
					N° of wells		
	Oil (MMBOE)	Associated gas (TCF)	Peak oil production (MBbl/d)	Peak NG production (MMscf/d)	Oil producers	Water injectors	NG injectors
1U Low estimate	192,02	0,13	63,34	39,91	11	7	4
2U Best estimate	695,87	0,74	229,60	234,27	37	14	4
3U High estimate	1954,80	2,79	653,86	894,80	103	27	9

Table 4: Amount of wells required to develop Prospect 2

Production profiles

The expected production profile is generated from the calculated EUR. The production forecast determined is used to define the requirements for processing and storage capacities. Fig. 20 shows the production profile of the 2U scenario for Prospect 1.

Assumptions for production profile determination

- The plateau production (Peak Oil) is assumed to be 10% of the EUR, and it was considered to reasonably last three years. (Gudmestad, Zolotukhin y Jarlsby 2010).
- An exponential decline curve was considered. An annual nominal decline rate of 9% was assumed based on the public information of Libra Project offshore Brazil (Open Oil 2017).

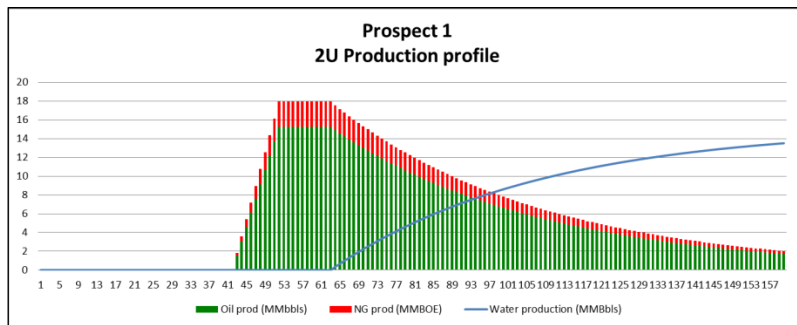


Fig. 20: Prospect 1 production profile for 2U and gas sold scenario

Economic assessment

Cash flow model assumptions

The cash flow model assumptions proposed for this work are summarized below:

- The profit oil split considered is presented in Table 6, with $X=0$ in case of oil production and $XG=0$ in case of natural gas production.
- Oil and Natural Gas prices are selected according to the requirements stated in the Uruguayan bidding terms (ANCAP 2019), described in Annex 8.
- Discount factor: 10 %
- Percentage of ANCAP's association: 30%
- 1 exploratory well is drilled.
- The appraisal period is considered to last two years, during which two appraisal wells will be drilled. One year will be dedicated to the Field Development Planning (FDP), while the development phase is considered to last two years, during which the production facilities will be installed. The contract term is 30 years, which could be extended an additional term of up to 10 years, with the previous approval of the Executive Branch, as it is stated in Uruguayan PSC (ANCAP 2019).
- 10% of development wells are logged.
- The GOR values considered are presented in Table 5.

	Low estimate	Best estimate	High estimate
GOR Prospect 1 (scf/STB)	625,3	1076,0	1459,5
GOR Prospect 2 (scf/STB)	656,4	1062,9	1425,5

Table 5: GOR values in scf/STB estimated for prospects 1 and 2

R Factor	% Profit Oil for Uruguayan Government (oil production scenario)	% Profit Oil for Uruguayan Government (natural gas production scenario)
< 1	$8 + X$	$8 + XG$
1 – 1,5	$15 + X$	$15 + XG$
1,5 - 2	$20 + X$	$20 + XG$
> 2	$30 + X$	$30 + XG$

Table 6: % Profit Oil Uruguayan State vs. R factor

A description of the costs used to perform the cash flow is presented in Annex 6 and a summary of the most remarkable features of the Uruguayan Fiscal regime is presented in Annex 7.

Expected Monetary Value

The Expected Monetary Value (EMV), which represents an estimate of the likely average return over a series of similar investments (Heriot-Watt University 2015), was calculated for each prospect's scenario. To do so, a decision tree, with two probability nodes was generated. The first node takes into consideration the CoS; if there is geological success and the decision is to drill an exploratory well, the second probability node accounts for the probability of finding a hydrocarbon volume that justifies its development, which means, a volume at least equal to the MEPS. This probability of economic success (Pe), was calculated as the area below the NPV graph, generated by means of @Risk, by assigning triangular distributions to the OPEX, the most relevant costs that comprises the CAPEX (daily cost of drilling rig, subsea equipment, gas pipeline installation), and the prices of oil and natural gas.

6. Discussion

Chance of Success (CoS)

	Probability of occurrence	
	Prospect 1	Prospect 2
Geological risk factors		
Structure (closure, geometry, container)	0,5	0,4
Presence of reservoir facies	0,65	0,95
Reservoir deliverability	0,5	0,75
Seal (*)	0,65	0,65
Source rock presence and maturity	0,7	0,7
Migration from mature kitchen	0,7	0,9
CoS (%)	5,2	11,7

Table 7: Chance of Geological success for prospects 1 and 2

(*) Despite the fact of not existing nearby (<100 Km away) exploratory wells, the existence of a good Paleocene regional seal that covers both prospects is proven; the probability assigned to this geological risk factor was therefore increased to 0,65.

A value between 0 and 1 was assigned to each of the different geological risk factors assessed for each prospect (Table 7), according to the guidelines provided by Milkov.

Both prospects show a relatively low CoS, being estimated as 5,2% for Prospect 1 and 11,7% for Prospect 2. These values are consistent with the chance of geological success for a frontier basin with no discoveries. Considering all the geological risks, the structural factor is the most critical for both prospects, due to the stratigraphic nature of the traps involved.

Prospective resources' volume estimation

Simulation outputs

Fig. 21 shows the EUR simulation outputs for both prospects, while Fig. 22 and Table 8 present the results for the low estimate (1U), best estimate (2U) and high estimate (3U) scenarios of the stochastic volume estimation performed.

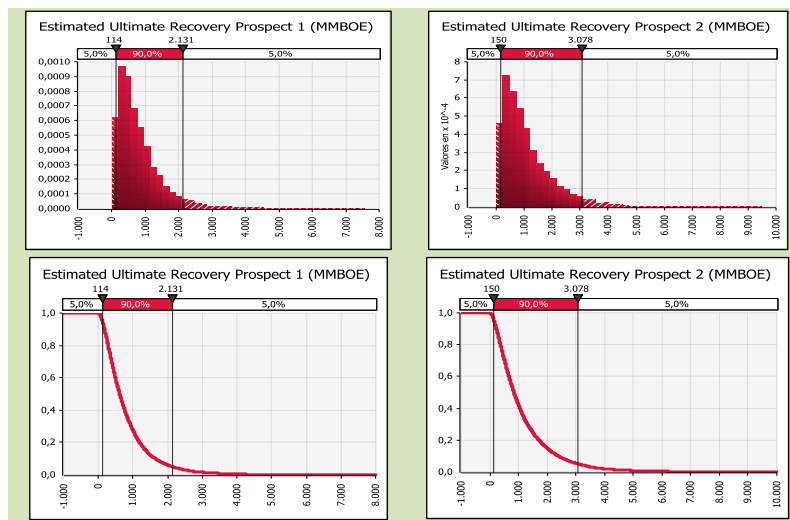


Fig. 21: Simulation output of EUR (MMBOE) for prospects 1 and 2

	Prospect 1			Prospect 2		
	1U	2U	3U	1U	2U	3U
STOIP (MMSTB)	488,0	1610,3	4032,2	622,8	2220,5	5844,5
EUR (MMSTB)	147,3	502,4	1341,7	192,0	695,9	1954,8
EUR (MMBOE)	175,7	610,9	1639,4	231,2	838,0	2386,6
Associated gas (MMBOE)	15,9	93,2	337,6	21,7	127,5	480,4
Associated gas (MMm³)	2608,9	15315,7	55457,7	3569,6	20946,4	78917,4
Associated gas (MMscf)	92120,4	540798,0	1958209,8	126043,2	739618,2	2786572,7
GOR (scf/STB)	625,3	1076,4	1459,5	656,4	1062,9	1425,5

Table 8: STOIP, EUR and associated gas results for prospects 1 and 2

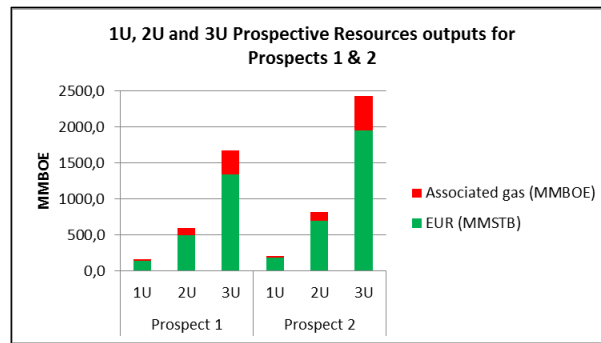


Fig. 22: EUR outputs for prospects 1 and 2

Prospective resources estimation results

The stochastic analysis of prospective resource volumes revealed that Prospect 1 has a EUR of 611 MMBOE while Prospect 2 has a EUR of 838 MMBOE for 2U scenario; this means that the prospective resources of Prospect 2 are 37% greater than Prospect 1 for this scenario. The amount of associated gas for 2U is 540,798 MMscf and 739,618 MMscf for prospects 1 and 2 respectively.

Sensitivity analysis results

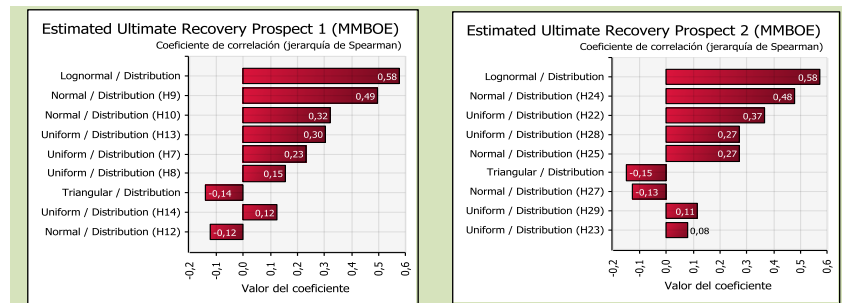


Fig. 23: Simulation tornado chart of EUR for Prospects 1 and 2

Both Prospects revealed that the most influential variable in the EUR estimation is the area, followed by N/G, with positive correlation in both cases (an increase in both parameters will produce an increase in the EUR). The third variable that affects the EUR estimation is S_w , showing a negative correlation; this means that an increase in S_w will lead to a decrease in EUR. The same behavior is observed for B_o (Fig. 23).

Economic assessment results

In the following section the results derived from the economic analysis in the scenario in which natural gas is sold are presented.

Prospect 1

Cash flow results

Costs

In terms of costs, Capex ranges from 4693 MMUSD for 1U to 29,260 MMUSD for 3U scenario, with a 2U scenario of 11,796 MMUSD. The sum of CAPEX plus OPEX represents 16,5 % of gross income for 2U (Fig. 24). Another notable feature of the analysis is the cost per BOE produced, with the 1U scenario exhibiting the highest costs (Fig. 25).

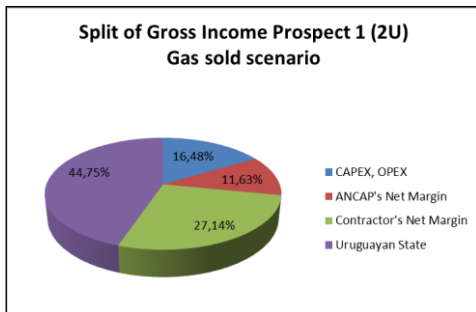


Fig. 24: Prospect 1 split of gross income (2U, gas sold scenario)

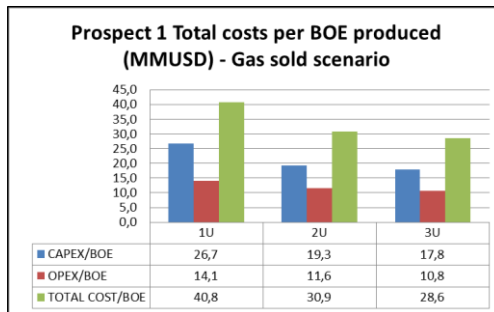


Fig. 25: Prospect 1 total costs per BOE produced, for 1U, 2U and 3U (gas sold scenario)

NPV

The NPV results for Prospect 1 are presented in Fig. 26:

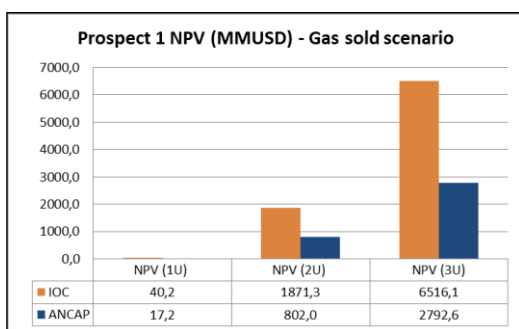


Fig. 26: Prospect 1 NPV results (1U, 2U and 3U; gas sold)

The first conclusion is that the NPV for the low estimate scenario (1U) is positive, but very close to zero, while for 2U and 3U it is considerably greater than zero.

The cumulative cash flow diagram for the NOC ANCAP and for the IOC shows the typical shape for an upstream project (Fig. 27), in which the Maximum Capital Outlay (MCO), the Payback period and the Ultimate Cash Surplus can be observed.

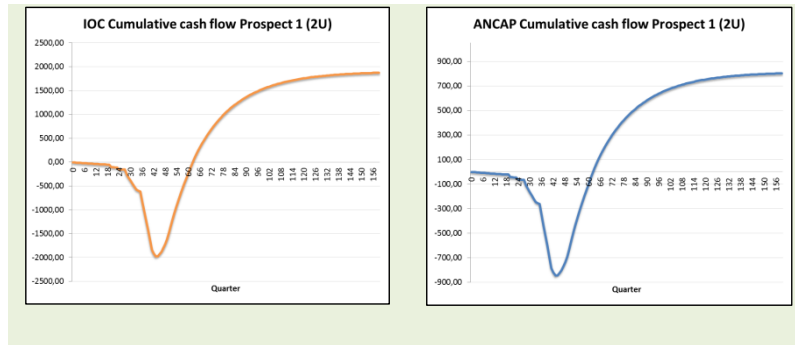


Fig. 27: Prospect 1 IOC's and ANCAP's cumulative cash flow (2U, gas sold scenario)

Key economic parameters were determined for 2U and 3U (Table 9), revealing a project Internal Rate of Return of 9% and a payback period of 15,5 years for 2U.

	Prospect 1				Prospect 2			
	2U		3U		2U		3U	
	IOC	ANCAP	IOC	ANCAP	IOC	ANCAP	IOC	ANCAP
NPV (MMUSD)	1.871,3	802	6.516,1	2.792,6	3.579,7	1.534,1	11.600,2	4.971,5
IRR (%)	9	9	14,1	14,1	16,3	16,3	21,1	21,1
PAYBACK (years)	15,5	15,5	14,3	14,3	13,8	13,8	13,3	13,3
PIR	3,11	4,51	3,44	4,87	5,40	7,65	5,79	8,07
MCO (MMUSD)	-1973	-846	-4297	-1841	-1878	-805	-4831	-2070

Table 9: Prospect 1 and 2 Economic parameters (2U, 3U) for gas sold scenario

Sensitivity analysis

A sensitivity analysis for the 2U and gas sold scenario was performed. The variables considered were oil price, gas price, variable OPEX and CAPEX. A spider diagram was then constructed by implementing proportional changes of 25%, 50%, 75% and 100% from the base case in both directions (favorable and unfavorable) (Fig. 28). The impact that each variable has on project NPV can also be assessed by means of a tornado chart (Fig. 29).

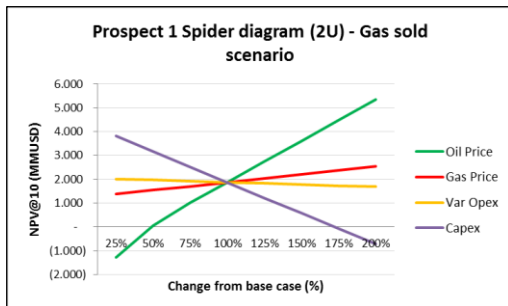


Fig. 28: Prospect 1 Spider diagram (2U, gas sold)

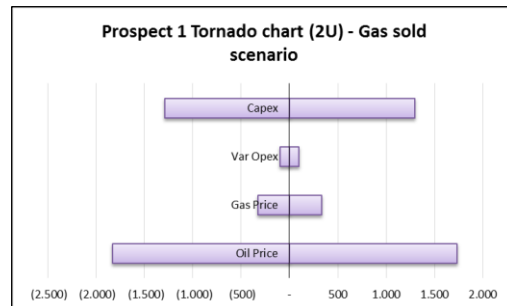


Fig. 29: Prospect 1 Tornado chart (2U, gas sold)

From Fig. 28 and Fig. 29, it can be concluded that the variable which impacts the most on NPV is oil price, followed by CAPEX; a decrease in the oil price of 50% from the base case (61,6 USD/bbl) makes this scenario unprofitable, with a negative NPV. On the other hand, an increase of oil price from the base case produces a sharp increase in NPV (approximately 186% increase of NPV when the oil price increases 200% from the base case). Gas price follows the same trend as oil price, but its impact is significantly less than that produced by the oil price. In terms of CAPEX, its increase causes the NPV to decrease significantly, becoming unprofitable when CAPEX increases to values greater than 75% from the base case (11,796 MMUSD). The variable that has the smallest impact on NPV project is the variable OPEX, remaining almost flat.

Minimum Economical Prospect Size (MEPS)

The minimum EUR volume that makes Prospect 1 development profitable (MEPS) was estimated to be 200 MMBOE, by drawing the line that best fits the points generated by the graph of NPV vs EUR for 1U, 2U and 3U scenarios (Fig. 30).

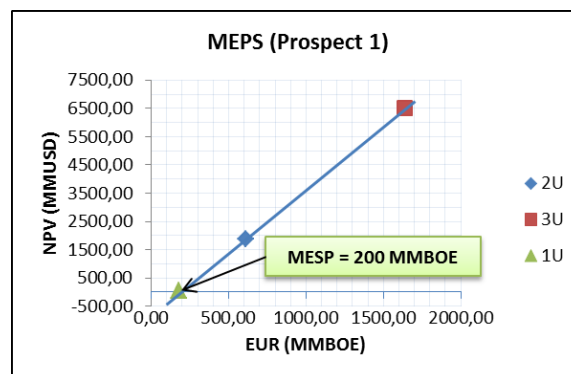


Fig. 30: Estimated Minimum Economical Prospect Size (MEPS) for Prospect 1 (gas sold)

Expected Monetary Value (EMV)

The calculation of the EMV involves the probability of geological success (CoS) and the probability of economic success (Pe).

As it can be seen in Fig. 31, the Pe for 1U is 51,1%, while for 2U is 99,8% (Fig. 32). These results are reasonable as EUR for 2U is 611 MMBOE, which is much greater than MEPS (200 MMBOE). On the other hand, the EUR for 1U (176 MMBOE) is low

given the cost of the associated development project; therefore, a much lower Pe is obtained. The calculated Pe for 3U is 100%.

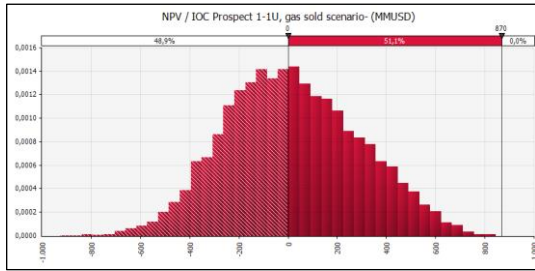


Fig. 31: Pe for scenario 1U of Prospect 1

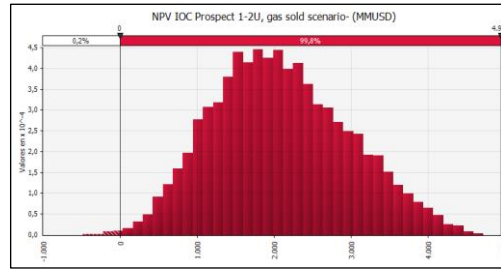


Fig. 32: Pe for scenario 2U of Prospect 1

A decision tree was then generated in order to check if the decision of drilling an exploratory well in Prospect 1 gives a positive EMV (Fig. 33).

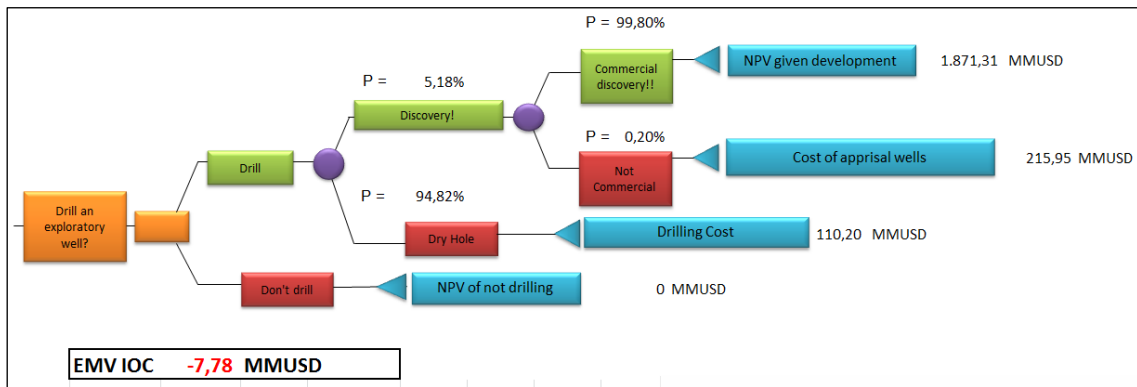


Fig. 33: Prospect 1 decision tree (2U)

As it can be seen in Fig. 33, the EMV calculated is negative for the CoS of 5,2% and Pe of 99,8% (2U scenario). This EMV result indicates that drilling an exploratory well in Prospect 1 has no value. A CoS of 5,6% makes EMV equal to zero; therefore, a CoS greater than this value would make feasible the decision of drilling for 2U. A positive EMV (233 MMUSD) was obtained for 3U scenario, while a negative EMV was obtained for 1U (-109 MMUSD). In the latter scenario, with a Pe of 51,1%, the project will not be feasible, even for greater values of CoS. This is explained by the fact that the EUR for 1U is lower than the estimated MEPS.

For the scenario in which gas is reinjected in the reservoir, the economic analysis revealed similar trends than those observed for the gas sold scenario in terms of NPV:

values are greater than zero for the three scenarios considered. Regarding the EMV, 1U shows a negative EMV while for 2U and 3U it is greater than zero. In the case of 1U, EMV is lower than zero disregarding the CoS. The MEPS for this scenario is estimated to be 180 MMBOE, a slightly lower value than the obtained for the gas sold scenario.

Prospect 2

Cash flow results

Costs

In terms of costs, Capex ranges from 3453 MMUSD for 1U to 26,605 for 3U scenario, with a 2U scenario of 9772 MMUSD. The sum of CAPEX plus OPEX represents 15,6 % of gross income for 2U (Fig. 34) and the total cost per BOE produced is 23 MMUSD for 2U (Fig. 35).

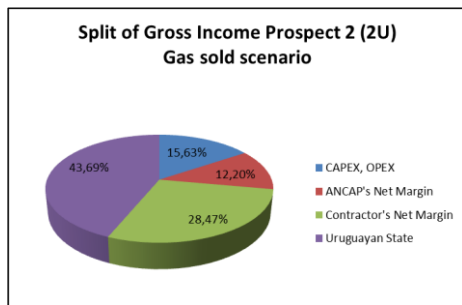


Fig. 34: Prospect 2 split of gross income (2U, gas sold scenario)

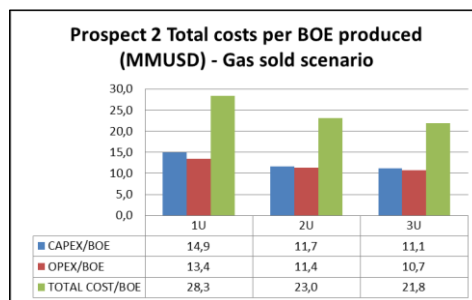


Fig. 35: Prospect 2 total costs per BOE produced, for 1U, 2U and 3U (gas sold scenario)

NPV

The NPV results for Prospect 2 are presented in Fig. 36:

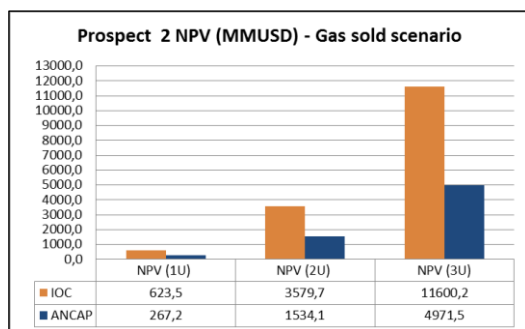


Fig. 36: Prospect 2 NPV results (1U, 2U and 3U; gas sold)

The first conclusion is that the NPV for the low estimate scenario (1U) is 15,5 times greater than that from Prospect 1. Moreover, NPV for 2U and 3U are considerably greater than zero.

The cumulative cash flow diagram for the NOC ANCAP and for the IOC shows the typical shape for an upstream project, as in Prospect 1.

Key economic parameters were determined for 2U and 3U (Table 9), revealing a project Internal Rate of Return of 16,3% and a payback period of 13,8 years for 2U.

Sensitivity analysis

A sensitivity analysis for the 2U and gas sold scenario was performed, considering the same variables and variations from the base case as in Prospect 1.

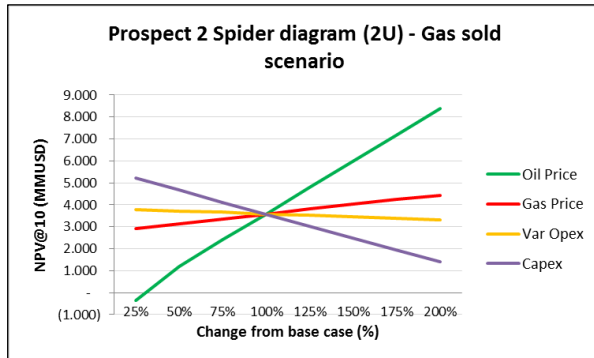


Fig. 37: Prospect 2 Spider diagram (2U, gas sold scenario)

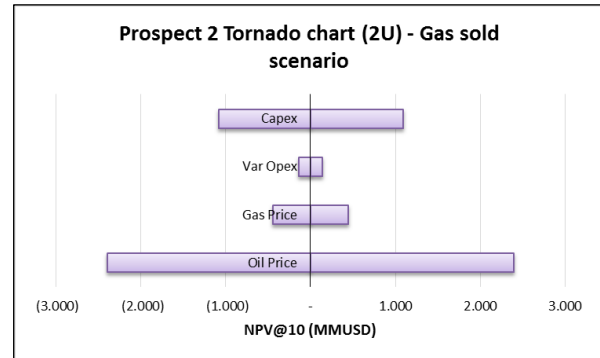


Fig. 38: Prospect 2 Tornado chart (2U, gas sold scenario)

From Fig. 37 and Fig. 38 it can be observed the same trends as in Prospect 1: the variable which impacts the most on NPV is oil price, followed by CAPEX, being the OPEX the variable that has the smallest impact on NPV project. For this Prospect, oil price needs to decrease 25% from the base case (61,6 USD/bbl) to produce a negative NPV. The rest of the scenarios considered generate a positive NPV. In terms of CAPEX, its increase causes the NPV to decrease but not as abruptly as it does in Prospect 1; even in scenarios where CAPEX is 200% of the base case (9772 MMUSD), the project is still profitable with a NPV greater than zero.

It is interesting to analyze the result of the spider diagram for 1U scenario of Prospect 2: as it can be seen in Fig. 39, the project is robust to gas price and variable OPEX, and it requires a considerable CAPEX overrun or a major fall in oil price to be uneconomic.

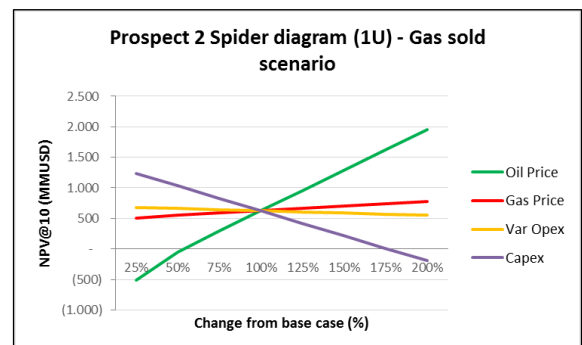


Fig. 39: Prospect 2 Spider diagram (1U, gas sold scenario)

Minimum Economical Prospect Size (MEPS)

The minimum EUR volume that makes Prospect 2 development profitable (MEPS) was estimated to be **125 MMBOE**, by drawing the line that best fits the points generated by the graph of NPV vs EUR for 1U, 2U and 3U scenarios (Fig. 40).

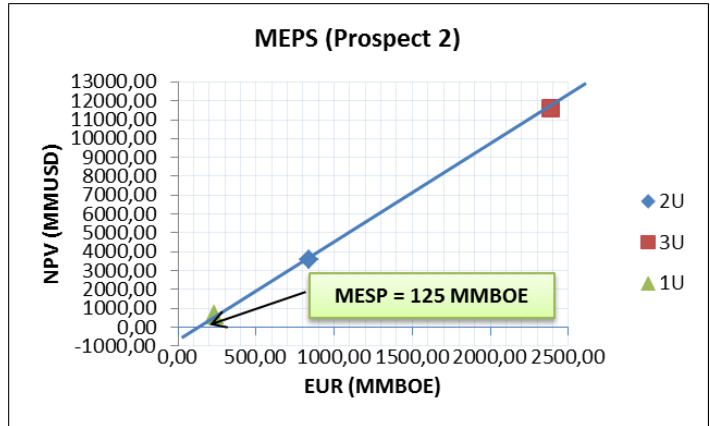


Fig. 40: Estimated Minimum Economical Prospect Size (MEPS) for Prospect 2 (gas sold)

Expected Monetary Value (EMV)

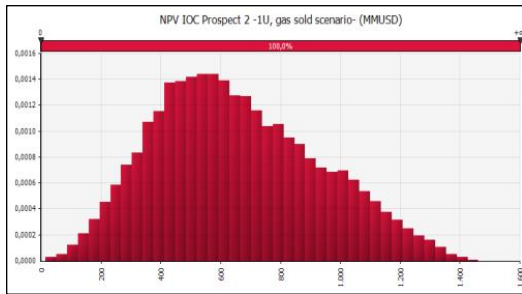


Fig. 41: Pe for Prospect 2 (1U scenario, gas sold)

The Pe for 1U is 100% (Fig. 41), as well as for 2U and 3U.

A decision tree was then generated in order to check if the decision of drilling an exploratory well in Prospect 2 gives a positive EMV. The EMV calculated is greater than zero (56 MMUSD) for the CoS estimated of 11,7% and Pe of 100% of 1U scenario. A positive EMV was also obtained for 2U (401 MMUSD) and for 3U (1337 MMUSD). With these results, the drilling of an exploratory well would be feasible for all three scenarios considered for Prospect 2.

For the scenario in which gas is reinjected in the reservoir, the economic analysis revealed similar trends than those observed for the gas sold scenario. NPV values are greater than zero for the three scenarios considered, as well as the EMV values. The MEPS for this scenario is estimated to be slightly lower than the corresponding to the gas sold scenario (100 MMBOE).

Fiscal Regime analysis - Contractor's and Government take

In order to obtain the Government, ANCAP and IOC's take, a Production Sharing Contract flow diagram was constructed (Fig. 42) (Johnston 1994).

NOC	Contractor		Government
		Gross Revenues	
		71.019,89	
		Royalty	
		0,00	→ 0,00
		Net Revenues	
		71.019,89	
		Total Cost	
		11.703,66	
3.511,10	8.192,56 ←		
		Total Profit	
		59.316,23	
		Profit Split	
			→ 22.606,18
11.013,02	25.697,04 ←		
		Taxable Income	
		36710,05	
		Tax Rate	
		25,00%	
-2.753,25	6.424,26 →		→ 9.177,51
		Division of Gross Revenues	
11.770,86	27.465,34		31.783,69
		Division of Cash Flow	
8.259,76	19.272,78		31.783,69
		Entitlement	
20,45%	47,72%		31,83%
		Take	
13,92%	32,45%		53,58%
		NOC Participation	
8.259,76		30,00%	8.259,76
	32,45%		67,51%

Fig. 42: PSC flow diagram for Prospect 1 (2U, gas sold)

For 2U scenario of Prospect 1, in the event that gas is sold, the Contractor's take is 32,5%, ANCAP's is 13,9% and the Government take equals 53,6% (Fig. 42). These results give a Uruguayan State's take equal to 67,5%. A similar trend was observed in Prospect 2. In the scenario where gas is re-injected, the Contractor's take is 30%, ANCAP's is 12,9% and the Government take equals 57,1% for 2U of Prospect 1 (see Annex 9). These results give a Uruguayan State's take equal to 70%. Similar trends were observed for Prospect 2.

7. Conclusions

For the 1U scenario of Prospect 1, the development would not be feasible because the EUR is lower than the estimated MEPS. For the 2U scenario, the CoS needs to be at least 5,6% to make the development of Prospect 1 profitable in the event that gas is sold. These results may be attributed to the high drilling costs associated with the development in deep waters. In the event that natural gas is reinjected into the reservoir a negative EMV was obtained for 1U while positive EMV were obtained for 2U and 3U. On the other hand, Prospect 2 exhibits an EMV greater than zero for 1U, 2U and 3U scenarios; therefore, the development of Prospect 2 would be feasible under all the cash flow model assumptions of this work.

According to the sensitivity analysis performed, Prospect 2 is robust to the gas price and variable OPEX, and it requires a considerable CAPEX overrun or a major fall in oil price to be uneconomic. On the other hand, a decrease in oil price of 50% from the base case of 61,6 USD/bbl and an increase in CAPEX to values greater than 75% from the base case of 11,796 MMUSD, produces a negative NPV in 2U of Prospect 1.

With ANCAP's association equal to 30% and with no incremental profit oil for the state considered, the results revealed that for both prospects the Uruguayan State's take is close to the global average (70%) and comparable to the Government Take of many hydrocarbons producing countries (see Daniel Johnston's Chart of Worldwide Government Takes, Annex 9).

The methodology applied in this work, based on the probabilistic resource volume determination followed by the economic and risk assessment of the 1U, 2U and 3U volumes previously obtained, is considered to be satisfactory to perform a preliminary screening on the development feasibility of Uruguayan hydrocarbons prospects.

Although there are high geological risks, the potential field size is large and therefore the prospects, especially Prospect 2, would be attractive to companies who have the right portfolio fit.

8. Suggestions and way forward

The conclusions arisen in this work are considered positive for the prospects analyzed, encouraged by the African analogues encountered and the large potential field sizes indicated from seismic attributes.

For further work, it is proposed that those prospects demonstrated to be feasible through the preliminary screening procedure, should be subjected to a more detailed analysis, by performing a comprehensive probabilistic assessment, that integrates all possible costs

scenarios, and prospective resource volumes, considering all possible values associated with the fiscal regime, such as ANCAP's association percentage and the values of incremental profit oil for the Uruguayan state.

9. References

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10. Appendices

Annex 1: Analogue fields' assessment

Country	Brazil			
Field	Roncador			
Basin	Campos			
Age	Upper Cretaceous			
	Most likely	Low estimate	High estimate	Reference
Water depth (m)	1700	1500	1900	(Rodriguez-Suarez et al. 2003)
Porosity (fraction)	0,25	0,27	0,3	(Rodriguez-Suarez et al. 2003)
GOR (scf/stb)	614			(Minami et al. 2000)
N/G (fraction)		0,580	0,63	(Pádua et al. 1998)
Bo (rm3/sm3)		1,18	1,29	(Pádua et al. 1998)
Water saturation (fraction)		0,18	0,23	(Pádua et al. 1998)
Type of fluid	Northern block: light oil; southern block: heavy oil			(Pádua et al. 1998)
Stock tank oil gravity (°API)		19	31	(Rodriguez-Suarez et al. 2003)
Viscosity (cP)		2 (light oil)	18 (heavy oil)	(Pádua et al. 1998)
Initial Reservoir Temperature (°F) across field		145 (southern block)	147 (northern block)	(Pádua et al. 1998)
Initial Reservoir Pressure (psia)		315 (southern block)	355 (northern block)	(Pádua et al. 1998)
Pressure range across field (psia)				
Gas gravity				
Bubble point pressure (psi)				
Permeability (mD)		200	4000	(Rodriguez-Suarez et al. 2003)
Reservoir thickness (m)			300	(Rodriguez-Suarez et al. 2003)
Net pay (m)	270			
Area (Km2)	132			(Minami et al. 2000)
RF (%)	25			(Rangel, Santos, and Quintaes 1998)

Country	Brazil			
Field	Albacora			
Basin	Campos			
Age	Lower Cretaceous (Albian)			
	Most likely	Low estimate	High estimate	Reference
Water depth (m)		200	500	(Awad 1997)
Porosity (fraction)	0,17			(Souza et al. 1989)
GOR (m3/m3)	65			(Souza et al. 1989)
N/G (fraction)				
Bo (rm3/sm3)				
Water saturation (fraction)	0,307			
Type of fluid				
Stock tank oil gravity (°API)		25,4	30,6	(Awad 1997)
Viscosity (cP)				
Initial Reservoir Temperature (°F) across field				
Initial Reservoir Pressure (psia)				
Pressure range across field (psia)				
Gas gravity				
Bubble point pressure (psi)				
Effective Permeability (mD)		11	71	(Souza et al. 1989)
Reservoir thickness (m)	80		145	(Souza et al. 1989)
Average Net pay (m)	29,9			(Souza et al. 1989)
Area (Km2)	235			(Souza et al. 1989)

Country	Namibia			
Exploratory well	Murombe-1			
Basin	Walvis			
	Upper			
Age	Cretaceous Confined channel complex (Santonian)			
	Most likely	Low estimate	High estimate	Reference
Water depth (m)	1417			(Negonga 2014)
Porosity (fraction)	0,19			(Magazine 2017)
GOR (scf/stb)				
N/G (fraction)	0,15			(Magazine 2017)
Bo				
Water saturation (fraction)				
Type of fluid		Light oil		
Stock tank oil gravity (°API)		38	42	(Spectrum 2017)
Viscosity (cP)				
Initial Reservoir Temperature (°F) across field				
Initial Reservoir Pressure (psia)				
Pressure range across field (psia)				
Gas gravity				
Bubble point pressure (psi)				
Permeability (mD)				
Reservoir thickness (m)				
Net sand (m) of second target (Baobab)	36			(Negonga 2014)
Total depth (m)	5729			(Negonga 2014)

Country	Ghana			
Field	Jubilee			
Basin	Tano			
	Upper			
Age	Cretaceous (Turonian)			
	Most likely	Low estimate	High estimate	Reference
Water depth (m)		1200	1500	(McLaughlin 2012)
Porosity (fraction)	0,21	0,15	0,3	(Sils and Agyapong 2012)
GOR (scf/stb)	1200	1250	1580	(Alleyne, Layne, and Soroush 2018) (Sils and Agyapong 2012)
N/G (fraction)		0,3	0,8	(Hanley et al., n.d.)
Initial formation volume factor Bo (RB/Mscf)		1,57	1,69	(Sils and Agyapong 2012)
Water saturation (fraction)		0,1	0,4	(Hanley et al., n.d.)
Type of fluid		Light oil under-saturated moderately volatile black oil		(Alleyne, Layne, and Soroush 2018)
Stock tank oil gravity (°API)	37	36	38	(Sils and Agyapong 2012)
Viscosity (cP)	0,21	0,16	0,3	(Sils and Agyapong 2012) (Dailly et al. 2017)
Initial Reservoir Temperature (°F) across field		196	225	(Sils and Agyapong 2012)
Initial Reservoir Pressure (psia) @ 3463 m TV	5295	5000	5700	(Sils and Agyapong 2012)
Pressure range across field (psia)		5000	5700	(Alleyne, Layne, and Soroush 2018)
Gas gravity	0,63	0,58	0,68	(Sils and Agyapong 2012)
Bubble point pressure (psi)	8500			(Alleyne, Layne, and Soroush 2018)
Permeability (mD)		100	1000	(Sils and Agyapong 2012)
Reservoir thickness (m)	250			
Net pay (m)		20	100	(Dailly et al. 2017)
Area (Km2)	110			(McLaughlin 2012)
Total depth (m subsea)		3000	4000	(Hanley et al., n.d.)

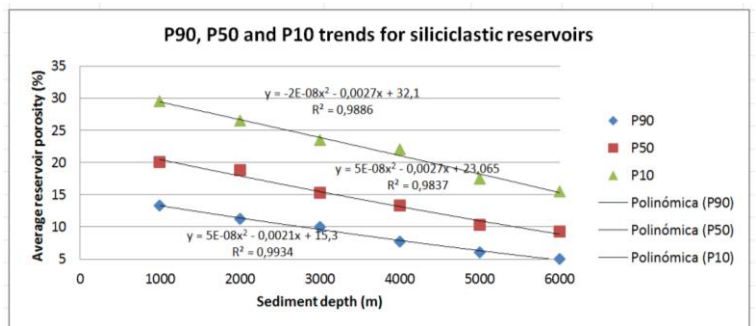
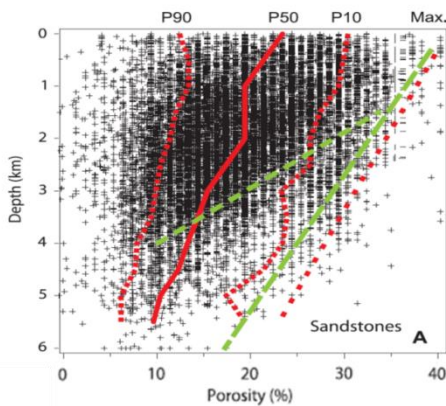
Country		Falkland Islands		
Field		Sea Lion		
Basin		North Falkland		
Age		Lower Cretaceous		
	Most likely	Low estimate	High estimate	Reference
Water depth (m)	450			(Lopez Marmolejo et al. 2018)
Porosity (fraction)	0,19	0,1	0,28	(Offshore Technology n.d.)
GOR (scf/stb)	327			(Farrimond, Green, and Williams 2015)
N/G (fraction)	0,75			(Lopez Marmolejo et al. 2018)
Bo		0,750	1	(Lopez Marmolejo et al. 2018)
Water saturation (fraction)	0,21	0,12	0,73	(Crombie, Holdoway, and Scallon 2013)
Type of fluid		Waxy black oil		
Stock tank oil gravity (°API)		24,5	29,3	(Lopez Marmolejo et al. 2018)
Viscosity (cP)				
Initial Reservoir Temperature (°F) across field				
Initial Reservoir Pressure (psia)				
Pressure range across field (psia)				
Gas gravity				
Bubble point pressure (psi)				
Absolute horizontal permeability (mD)	157	approx 10	1500	(Lopez Marmolejo et al. 2018)
Reservoir thickness (m)				
Gross oil column (m)	217			(Offshore Technology n.d.)
Net pay (m)	53			(Offshore Technology n.d.)
Area (Km2)	115			(Bunt 2015)
RF (%)		20	40	(Crombie, Holdoway, and Scallon 2013)

References reviewed to perform the previous analysis:

(Rodriguez-Suarez et al. 2003), (Minami et al. 2000), (Pádua et al. 1998), (McLaughlin 2012), (Sills and Agyapong 2012), (Alleyne, Layne, and Soroush 2018), (Hanley et al., n.d.), (Tullow oil n.d.), (Awad 1997), (Souza et al. 1989), (Negonga 2014), (Magazine 2017), (Spectrum 2017), (Griffiths 2015), (Farrimond, Green, and Williams 2015), (Lopez Marmolejo et al. 2018), (Favera et al. 2013), (Davis et al. 2018), (Offshore Technology n.d.), (Dailly et al. 2017), (Bunt 2015), (Rangel, Santos, and Quintaes 1998), (Crombie, Holdoway, and Scallon 2013) (Africa Oil+Gas Report 2019)

Annex 2: Porosity determination

The porosity distributions for each prospect were constructed taking into account the burial effect by means of the porosity vs depth datasets provided by Ehrenberg and Nadeau (Ehrenberg and Nadeau 2005); the P10, P50 and P90 porosity values were also obtained from this source. After analyzing this data, the polynomial functions were determined to best fit the P10, P50 and P90 data. The P90, P50 and P10 porosity values for prospects 1 and 2 were obtained by means of these equations, taking into account each prospect's sediment depth.



P90, P50 and P10 porosity trends for siliciclastic reservoirs

Average porosity vs. top depth for global petroleum sandstone reservoirs (Ehrenberg and Nadeau 2005)

Average reservoir porosity Prospect 1 (%)		
P90	P50	P10
8,2	13,8	21,9

Average reservoir porosity Prospect 2 (%)		
P90	P50	P10
11,5	18,1	26,9

P90, P50 and P10 porosity values for Prospect 1 and Prospect 2

Annex 3: B_o determination

$$B_o \left(\frac{\text{scf}}{\text{STB}} \right) = 1 + 0,0005 * GOR * \left(\frac{\gamma_g}{\gamma_o} \right)^{0,25} + 0,2 * \frac{(T_r - T_o)}{T_o * \gamma_g * \gamma_o}$$

Leviton correlation for determining B_o

Where: T_r = reservoir temperature; T_o is the standard Rankine temperature (520 °R); γ_g is the relative gas gravity (γ_g = 0,8; air = 1); γ_o is the relative oil density (water = 1).

		Estimated Reservoir T					
		Sediment depth (Km)	Estimated seabed T (°C)	Geothermal gradient (°C/Km) (*)	°C	°F	°R
Prospect 1	1U	2,843	2	30	87,29	189,1	649,1
	2U	3,1975	2	30	97,925	208,3	668,3
	3U	3,552	2	30	108,56	227,4	687,4
Prospect 2	1U	1,832	2	30	56,96	134,5	594,5
	2U	1,8955	2	30	58,865	138,0	598,0
	3U	1,959	2	30	60,77	141,4	601,4

(*) (Schlumberger n.d.)

Estimated reservoir temperature for prospects 1 and 2

	Prospect 1		Prospect 2	
	Low estimate	High estimate	Low estimate	High estimate
B_o (scf/STB)	1,015	1,5	1,014	1,498

High and low estimation of oil formation volume factor for prospects 1 and 2

Annex 4: Volumetric input parameters

Prospect 1						
	Most likely	Low estimate	High estimate	Distribution	Truncation values	Source
Area (Km ²)	160	30	292,7	Lognormal	Min: 10; max: 350	Seismic
h (m)		40	80	Uniform		Seismic
GCF		0,6	0,9	Uniform		Seismic
N/G		0,15	0,8	Normal	Mn: 0,05; max: 1	Analogue fields' data
Porosity (fraction)	0,138	0,0823	0,219	Normal	Min: 0,05; max: 0,476	(Ehrenberg and Nadeau 2005)
Water saturation (fraction)	0,25	0,1	0,4	Triangular	Min: 0,05; max: 0,5	Analogue fields' data
B _o (RB/STB)		1,015	1,500	Normal	Min:1; max: 2	Correlation (Levitan 1999)
RF (%)		20	45	Uniform		Analogue fields' data
GOR (scf/STB)		100	2100	Uniform		Analogue fields' data

Prospect 1 simulation input parameters

Prospect 2						
	Most likely	Low estimate	High estimate	Distribution	Truncation values	Source
Area (Km ²)	138	19,5	257	Lognormal	Min: 10; max: 350	Seismic
h (m)		36	106	Uniform		Seismic
GCF		0,7	0,9	Uniform		Seismic
N/G		0,15	0,8	Normal	Mn: 0,05; max: 1	Analogue fields' data
Porosity (fraction)	0,181	0,115	0,269	Normal	Min: 0,05; max: 0,476	(Ehrenberg and Nadeau 2005)
Water saturation (fraction)	0,25	0,1	0,4	Triangular	Min: 0,05; max: 0,5	Analogue fields' data
B _o (RB/STB)		1,014	1,498	Normal	Min:1; max: 2	Correlation (Levitan 1999)
RF (%)		20	45	Uniform		Analogue fields' data
GOR (scf/STB)		100	2100	Uniform		Analogue fields' data

Prospect 2 simulation input parameters

Annex 5: Field Development Plan

The number of production wells required was determined as the maximum value of the following: oil prospective resources (MMbbl) divided by the cumulative production estimated per well (MMbbl) or peak oil production (bopd) divided by the productivity per well (bopd). The cumulative production per well is estimated to be 19 MMbbl (Weijermars et al. 2017). According to research performed by (Bruhn et al. 2003), deepwater wells must be designed to allow productivities between 10,000 and 15,000 bopd in Campos Basin in Brazil while in the analogous Jubilee Field values between 10,000 and 25,000 bopd are encountered (Wheaton and Manu 2012); for the purposes of this work, a minimum of 10,000 bopd, a most probable value of 17,000 bopd and a maximum of 25,000 bopd were considered.

The number of water injection wells was calculated as the peak water injection (bwpd) divided by the water injection rate per well (bwpd). The peak water injection is calculated as the peak oil production (bopd) multiplied by a water injection rate, which was assumed to be 1,1 bbl water/bbl oil (Kaichun et al. 2017).

For the re-injection approach, the number of reinjection wells is determined by dividing the natural gas peak production (Mscf/d) by the productivity per well which was estimated as a most probable value of 60,000 Mscf/d, a minimum of 10,000 Mscf/d and a maximum of 100,000 Mscf/d, after performing a research of other gas reinjection projects in offshore Brazil and other African analogue fields (Etuhoko and Lewis 2004), (Silva et al. 2007), (Agrawal, Kumar, and Draoui 2016), (Wheaton and Manu 2012).

The FPSO was selected in order to be able to produce the peak oil and the peak of natural gas production. In the 3U scenario, an additional FPSO is envisaged.

Regarding the subsea facilities, the following system is proposed: a drilling riser (8" diameter), a subsea well system (includes two subsea trees –manifold- to collect, commingle, and export the flow from the several subsea wells to the FPSO facility, through 8" flexible production risers; flow lines and umbilicals connect each well to the manifold), a subsea production system (subsea control system, manifolds, intervention systems and subsea processing systems), water injection and gas injection subsea manifold which connects the FPSO and the 8" dedicated riser for each purpose.

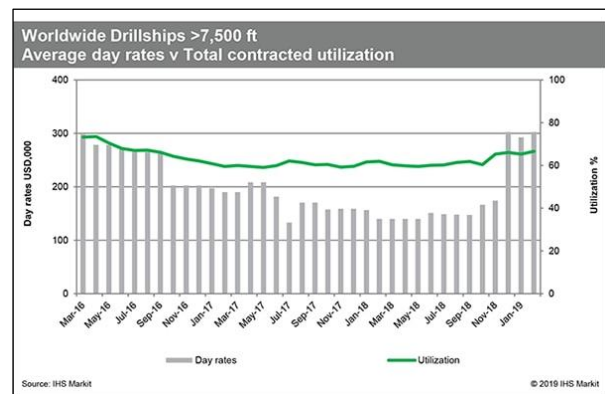
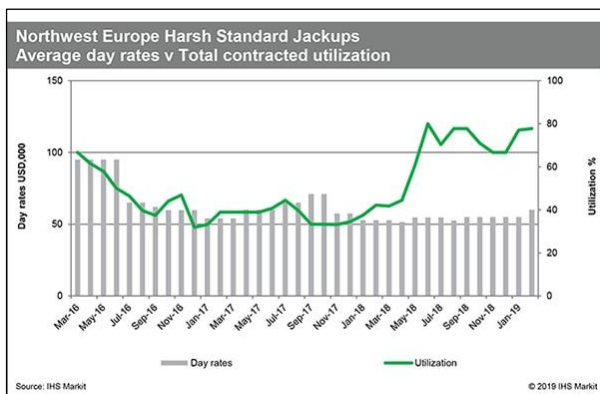
Annex 6: Costs

Exploration, Appraisal, Development and Production Costs

The capital expenditure (CAPEX) for the development of prospects 1 and 2 comprises the following categories:

Drilling expenditures (Drillex):

For Prospect 1, a drillship with an average day rate of 0,3 MMUSD/d was proposed (IHS Markit 2019b). In the case of Prospect 2, a jack-up rig was proposed, with average day rate of 0,067 MMUSD/d (IHS Markit 2019a). In addition to these values, mobilization-demobilization costs, drilling rate (m/d), consumables, interventions, logging and well test time, were also considered to estimate the drillex, based on the information provided by IOCs that worked in Uruguay's offshore.



Average day rates for jack-ups (IHS Markit 2019a) and drillships (IHS Markit 2019b)

Subsea equipment:

The Subsea equipment cost was estimated to be 7 USD/BOE, from the information obtained from Liza project in Brazil offshore (Oil Now 2018).

Natural gas transport:

In the scenario that natural gas is sold, the investment associated with the dedicated gas pipeline installation was estimated to be 1277,8 MMUSD, to offload gas from Prospect 1 and 886,3 MMUSD for Prospect 2. These estimations were obtained from similar investments in pre-salt region in Brazil (Petrobras 2018a), (Petrobras 2018b), (Lemos, Santos, Furley dos Santos, and da Silva Alves 2015), and considering the distance to shore of each prospect.

Decommissioning:

The total decommissioning cost is assumed to be 5% of total CAPEX. According to Uruguay PSC terms, the Decommissioning Fund shall be constituted as follows:

In the first quarter in which it is envisaged that the cumulative production will be greater than the 50% of the total reserves of the Prospect, the amount to be deposited in the Decommissioning Fund will be calculated according to the equation below:

$$FD_i = CD \times \frac{(NP_i - EUR \times 0,5)}{EUR \times 0,5} - FDD_i$$

Sum to deposit in the Fund in quarter i

Where:

FD_i: Sum to deposit in the Fund in quarter i

CD: Total updated decommissioning cost (USD)

NP_i: Cumulative production up to beginning of quarter i (BOE)

FDD_i: Total amount of sums paid to the Decommissioning Fund previously to quarter i (USD)

From the beginning of production, 250,000 USD must be deposited in the Fund, in case the aforementioned condition is not fulfilled or the amount calculated through the previous equation is less than 250,000 USD.

Operating Expenditures (OPEX)

OPEX comprises Fixed and Variable categories. Fixed OPEX involves administration, personnel and services costs; it was estimated a fixed OPEX of 2,5 MMUSD/quarter, based on the information provided by IOCs that worked in Uruguay's offshore. Variable OPEX comprises the FPSO lease and the oil transport costs via shuttle tanker and was estimated to be 9 USD/BOE (Oil&Gas Journal 2008) (Institute of Petroleum Engineering (Heriot-Watt University) 2015).

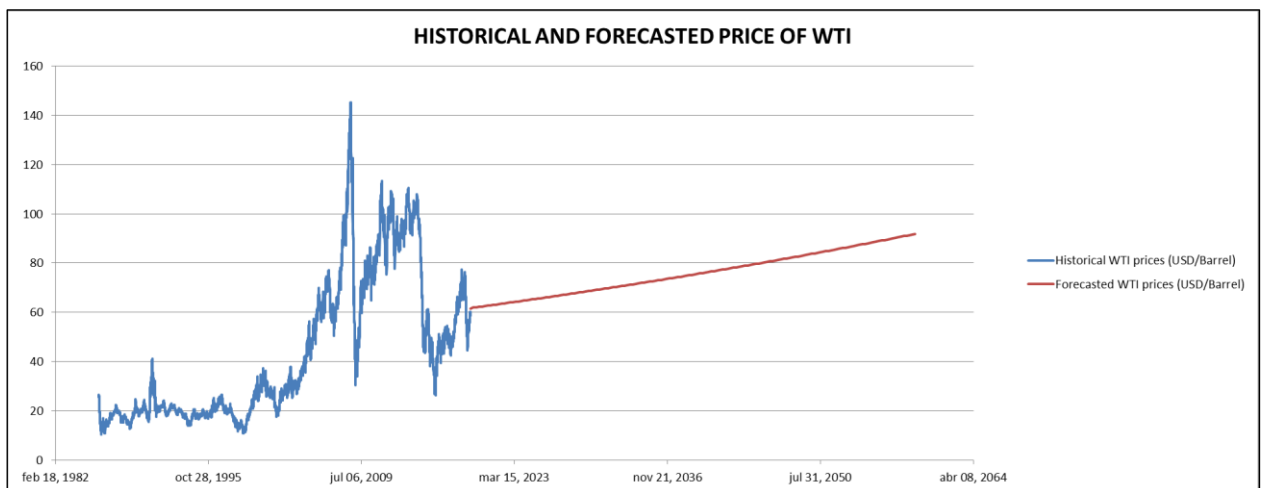
Annex 7: Uruguayan Oil and Gas Fiscal Regime

In order to perform the cash flow, the following aspects of the Uruguayan Oil and Gas Fiscal Regime were assessed:

- Cost Oil is deduced from gross income before sharing the production profit; profit oil is split between the State and the Contractor and the State share increases with an R factor, defined as the relationship between gross income and total costs for each hydrocarbon type (heavy oils, light oils and natural gas).
- ANCAP's association percentage ranges from 20% up to a maximum that is biddable in the event of a commercial discovery and cannot exceed 40%.
- No royalties neither bonus is paid by Contractors.
- Cost recovery limits represent 60% of gross income in the scenario of oil production and 80% in case of natural gas production. Operating costs are recovered quarterly while capital investments are recovered in 20 quarterly installments.
- The Contractor pays Income Tax of 25% on its share of Profit Oil. ('Tax Law N°1803' 2006).

Annex 8: Price

- Oil price is selected on the basis of a basket of petroleum prices with similar characteristics to the anticipated fluid. For the purposes of this work, WTI Spot Price FOB oil was considered. It is also assumed to grow monotonically at an annual escalation rate of 1% throughout the life of the project.
- Natural Gas (NG) price is considered as an average of four terms or prices: Henry Hub in USD/MMBTU; National Balancing Point in UK in USD/MMBTU; a regional price agreed between the Contractor and ANCAP; and a parity formula relating NG price to the oil price: $0,1 * P - 3$, where P is the oil price (ANCAP 2019). The Henry Hub was estimated to be 2,62 USD/MMBTU (Markets Insider 2019), the NBP 4,18 USD/MMBTU (Tradingview 2019) and for the regional natural gas price, it was assumed 15 USD/MMBTU, the average value at which Uruguay imported natural gas from Argentina during 2018; this value was obtained after internal consultancy to the natural gas department of ANCAP.



Historical and forecast analysis of the oil price (EIA 2019)

Oil Price	61,6	USD/bbl
NG Price	6,24	USD/MMBtu
HH NG Price	2,62	USD/MMBtu
NBP NG Price	4,18	USD/MMBtu
Regional NG Price	15	USD/MMBtu
Annual Price escalation	1	%

Year	Quarter	Quarter cum	Oil Price (USD/bbl)	NG Price (USD/Mscf)	NG Price (USD/BOE)
0	1	1,00	61,59	6,24	36,20
0	2	2,00	61,90	6,27	36,38
0	3	3,00	62,05	6,29	36,47
0	4	4,00	62,21	6,30	36,56
1	1	5,00	62,36	6,32	36,65
1	2	6,00	62,52	6,33	36,74
1	3	7,00	62,68	6,35	36,83
1	4	8,00	62,83	6,37	36,93
2	1	9,00	62,99	6,38	37,02
2	2	10,00	63,15	6,40	37,11
2	3	11,00	63,31	6,41	37,20
2	4	12,00	63,46	6,43	37,30
3	1	13,00	63,62	6,45	37,39
3	2	14,00	63,78	6,46	37,48
3	3	15,00	63,94	6,48	37,58
3	4	16,00	64,10	6,50	37,67
4	1	17,00	64,26	6,51	37,77
4	2	18,00	64,42	6,53	37,86
4	3	19,00	64,58	6,54	37,95
4	4	20,00	64,74	6,56	38,05
5	1	21,00	64,91	6,58	38,14
5	2	22,00	65,07	6,59	38,24
5	3	23,00	65,23	6,61	38,34
5	4	24,00	65,39	6,63	38,43
6	1	25,00	65,56	6,64	38,53
6	2	26,00	65,72	6,66	38,62
6	3	27,00	65,89	6,68	38,72
6	4	28,00	66,05	6,69	38,82
7	1	29,00	66,22	6,71	38,91
7	2	30,00	66,38	6,73	39,01
7	3	31,00	66,55	6,74	39,11
7	4	32,00	66,71	6,76	39,21
8	1	33,00	66,88	6,78	39,31
8	2	34,00	67,05	6,79	39,40
8	3	35,00	67,21	6,81	39,50
8	4	36,00	67,38	6,83	39,60
9	1	37,00	67,55	6,84	39,70
9	2	38,00	67,72	6,86	39,80
9	3	39,00	67,89	6,88	39,90
9	4	40,00	68,06	6,90	40,00
10	1	41,00	68,23	6,91	40,10
10	2	42,00	68,40	6,93	40,20
10	3	43,00	68,57	6,95	40,30

10	4	44,00	68,74	6,97	40,40
11	1	45,00	68,91	6,98	40,50
11	2	46,00	69,09	7,00	40,60
11	3	47,00	69,26	7,02	40,70
11	4	48,00	69,43	7,04	40,81
12	1	49,00	69,61	7,05	40,91
12	2	50,00	69,78	7,07	41,01
12	3	51,00	69,95	7,09	41,11
12	4	52,00	70,13	7,11	41,21
13	1	53,00	70,30	7,12	41,32
13	2	54,00	70,48	7,14	41,42
13	3	55,00	70,66	7,16	41,52
13	4	56,00	70,83	7,18	41,63
14	1	57,00	71,01	7,20	41,73
14	2	58,00	71,19	7,21	41,84
14	3	59,00	71,37	7,23	41,94
14	4	60,00	71,54	7,25	42,05
15	1	61,00	71,72	7,27	42,15
15	2	62,00	71,90	7,29	42,26
15	3	63,00	72,08	7,30	42,36
15	4	64,00	72,26	7,32	42,47
16	1	65,00	72,44	7,34	42,57
16	2	66,00	72,62	7,36	42,68
16	3	67,00	72,81	7,38	42,79
16	4	68,00	72,99	7,40	42,89
17	1	69,00	73,17	7,41	43,00
17	2	70,00	73,35	7,43	43,11
17	3	71,00	73,54	7,45	43,22
17	4	72,00	73,72	7,47	43,33
18	1	73,00	73,90	7,49	43,43
18	2	74,00	74,09	7,51	43,54
18	3	75,00	74,27	7,53	43,65
18	4	76,00	74,46	7,54	43,76
19	1	77,00	74,65	7,56	43,87
19	2	78,00	74,83	7,58	43,98
19	3	79,00	75,02	7,60	44,09
19	4	80,00	75,21	7,62	44,20
20	1	81,00	75,40	7,64	44,31
20	2	82,00	75,58	7,66	44,42
20	3	83,00	75,77	7,68	44,53
20	4	84,00	75,96	7,70	44,64
21	1	85,00	76,15	7,72	44,75
21	2	86,00	76,34	7,74	44,87
21	3	87,00	76,53	7,75	44,98
21	4	88,00	76,72	7,77	45,09
22	1	89,00	76,92	7,79	45,20

22	2	90,00	77,11	7,81	45,32
22	3	91,00	77,30	7,83	45,43
22	4	92,00	77,49	7,85	45,54
23	1	93,00	77,69	7,87	45,66
23	2	94,00	77,88	7,89	45,77
23	3	95,00	78,08	7,91	45,89
23	4	96,00	78,27	7,93	46,00
24	1	97,00	78,47	7,95	46,12
24	2	98,00	78,66	7,97	46,23
24	3	99,00	78,86	7,99	46,35
24	4	100,00	79,06	8,01	46,46
25	1	101,00	79,26	8,03	46,58
25	2	102,00	79,45	8,05	46,70
25	3	103,00	79,65	8,07	46,81
25	4	104,00	79,85	8,09	46,93
26	1	105,00	80,05	8,11	47,05
26	2	106,00	80,25	8,13	47,16
26	3	107,00	80,45	8,15	47,28
26	4	108,00	80,65	8,17	47,40
27	1	109,00	80,86	8,19	47,52
27	2	110,00	81,06	8,21	47,64
27	3	111,00	81,26	8,23	47,76
27	4	112,00	81,46	8,25	47,88
28	1	113,00	81,67	8,28	48,00
28	2	114,00	81,87	8,30	48,12
28	3	115,00	82,08	8,32	48,24
28	4	116,00	82,28	8,34	48,36
29	1	117,00	82,49	8,36	48,48
29	2	118,00	82,69	8,38	48,60
29	3	119,00	82,90	8,40	48,72
29	4	120,00	83,11	8,42	48,84
30	1	121,00	83,31	8,44	48,96
30	2	122,00	83,52	8,46	49,09
30	3	123,00	83,73	8,48	49,21
30	4	124,00	83,94	8,51	49,33
31	1	125,00	84,15	8,53	49,46
31	2	126,00	84,36	8,55	49,58
31	3	127,00	84,57	8,57	49,70
31	4	128,00	84,78	8,59	49,83
32	1	129,00	85,00	8,61	49,95
32	2	130,00	85,21	8,63	50,08
32	3	131,00	85,42	8,66	50,20
32	4	132,00	85,63	8,68	50,33
33	1	133,00	85,85	8,70	50,45
33	2	134,00	86,06	8,72	50,58
33	3	135,00	86,28	8,74	50,71

33	4	136,00	86,49	8,76	50,83
34	1	137,00	86,71	8,79	50,96
34	2	138,00	86,93	8,81	51,09
34	3	139,00	87,14	8,83	51,21
34	4	140,00	87,36	8,85	51,34
35	1	141,00	87,58	8,87	51,47
35	2	142,00	87,80	8,90	51,60
35	3	143,00	88,02	8,92	51,73
35	4	144,00	88,24	8,94	51,86
36	1	145,00	88,46	8,96	51,99
36	2	146,00	88,68	8,99	52,12
36	3	147,00	88,90	9,01	52,25
36	4	148,00	89,12	9,03	52,38
37	1	149,00	89,35	9,05	52,51
37	2	150,00	89,57	9,08	52,64
37	3	151,00	89,79	9,10	52,77
37	4	152,00	90,02	9,12	52,90
38	1	153,00	90,24	9,14	53,04
38	2	154,00	90,47	9,17	53,17
38	3	155,00	90,70	9,19	53,30
38	4	156,00	90,92	9,21	53,44
39	1	157,00	91,15	9,24	53,57
39	2	158,00	91,38	9,26	53,70
39	3	159,00	91,61	9,28	53,84
39	4	160,00	91,84	9,31	53,97

Oil and gas price estimation for the entire project life

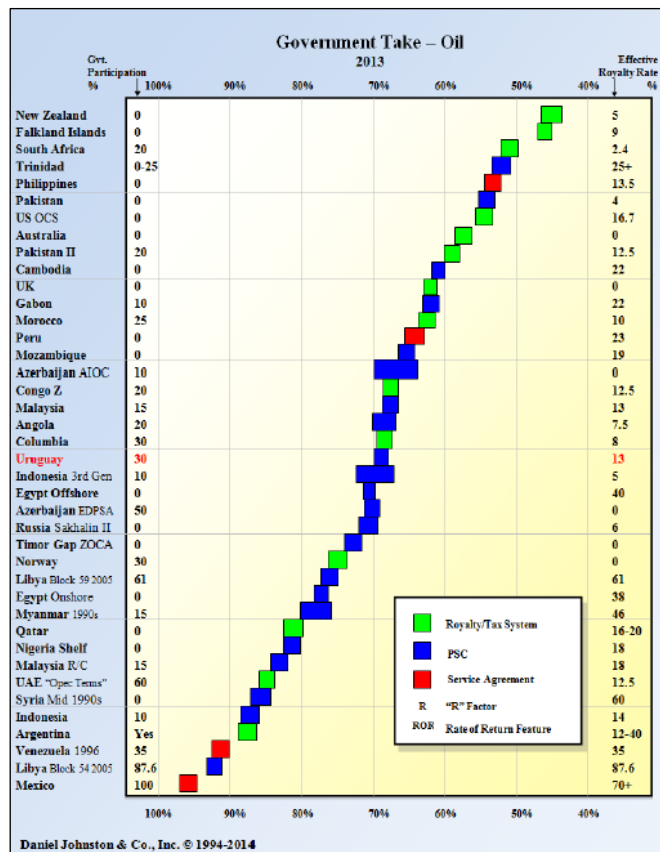
Annex 9: Government take

		Contractor's take (%)	ANCAP's take (%)	Government take (%)
Prospect 1	1U	36,22	15,52	48,26
	2U	32,49	13,92	53,58
	3U	34,76	14,90	50,35
Prospect 2	1U	30,37	13,02	56,62
	2U	33,75	14,46	51,79
	3U	34,61	14,83	50,56

PSC share for Prospects 1 and 2 (gas sold scenario)

		Contractor's take (%)	ANCAP's take (%)	Government take (%)
Prospect 1	1U	31,80	13,63	54,57
	2U	30	12,86	57,14
	3U	32,31	13,85	53,84
Prospect 2	1U	28,26	12,11	59,62
	2U	31,88	13,66	54,46
	3U	32,67	14,00	53,33

PSC share for Prospects 1 and 2 (re injection of natural gas scenario)



Daniel Johnston's Chart of Worldwide Government Takes