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CO2-RICH HYDROCARBON BEARING RESERVOIRS IN CAÑADON SECO FORMATION, GOLFO SAN JORGE BASIN, ARGENTINA. PRODUCTION FEASIBILITY AND ITS ASSOCIATED RESERVES.

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Palabras claves:

Dióxido de carbono, Formación Cañadón Seco, El Huemul.

Resumen

Los reservorios productores de hidrocarburos alojados en la Formación Cañadón Seco en posiciones Central y Este del Flanco de la Cuenca del Golfo San Jorge, contienen un amplio rango de dióxido de carbono (CO2) asociado. La producción de este gas varía desde valores inferiores a 1% a más del 90%, con un valor promedio del 40%. El CO2 es usualmente nocivo tanto para las instalaciones de producción del pozo como para las facilidades en superficie, las cuales usualmente no presentan las condiciones necesarias para producir hidrocarburos con CO2 asociado. De acuerdo con las regulaciones ambientales actuales, el venteo de gas a la atmosfera no puede excederse por periodos superiores a un mes. Mas aun, la producción de CO2 se ve restringida en el campo debido a las limitaciones de las instalaciones de producción para tal fin. Debido a esto, la mayoría de los reservorios con CO2 asociado permanecen aislados detrás de la cañería de producción, aun conociendo su potencial. Como consecuencia, las reservas del yacimiento no suelen estar cuantificadas apropiadamente. Finalmente, el potencial de producción de hidrocarburos está subestimado, como también el valor real de la Compañía.
Conociendo las limitaciones de producción y enfocado en producir económicamente cualquier porcentaje de CO2 asociado, se analizó un proyecto piloto a través de diferentes escenarios de desarrollo mediante la propuesta de intervención de pozos y/o la perforación de nuevas locaciones.
El estudio se basa en un enfoque convencional con mapas estructurales y de arena permeable; predicción de fluidos por medio de interpretación de perfiles; estimación de volumen de hidrocarburos aislados detrás de la cañería de producción y presión actual de reservorios producidos; instalaciones de producción necesarias para el manejo de CO2; costos de operación y capital requeridos para ejecutar el trabajo.
Se consideraron distintos escenarios y se obtuvo una evaluación económica positiva, por lo que 141,7 x10^3 m3 petróleo y 169,7 x10^6 m3 gas se incorporaron al libro de reservas de la Compañía.
La presencia de CO2 asociado en numerosos bloques del yacimiento promueve la extensión de esta metodología en toda el área. A corto plazo, la expectativa se enfoca en el incremento de la producción debido a la implementación del piloto. A mediano y largo plazo, las reservas de hidrocarburos con CO2 asociado deberían incrementarse en los sucesivos ejercicios de reservas, acrecentando el valor de la Compañía.

Palabras claves:

Carbon Dioxide, Cañadón Seco Formation, El Huemul, Reserves Increase

Abstract

Hydrocarbon bearing reservoirs located in Cañadón Seco Formation across Central and Eastern Flank regions of Golfo San Jorge Basin, present a wide range of associated CO2 content. CO2 production may vary from less than 1% to values higher than 90%, being 40% the average value. This gas is usually harmful both for production assemblies and production facilities, so conventional surface installations are not sufficient to commercially put these intervals into production.

According to current environmental regulations in Argentina, gas venting cannot extend for more than 1-month long. Moreover, CO2 production is restricted throughout the field due to current facilities limitations.

Therefore, most of CO2 associated reservoirs are left behind pipe during completions regardless of their potential, so the field's reserves are not being properly quantified. At the end of the day, hydrocarbon production is underestimated, hence the company's real value.

Acknowledging all presented limitations and aiming to economically produce as many CO2 associated reservoirs as possible, a pilot project was studied where different development scenarios were proposed considering workovers and drilling campaigns. A conventional approach was carried out to achieve our goal: structure analysis and net sand mapping, fluid prediction from well log interpretation, behind-pipe hydrocarbon volume estimation, reservoir pressure estimation from produced reservoirs, required surface facilities for CO2 management, and operating and capital costs to execute all required jobs.

Economics returned positive outcomes for all scenarios, so almost 2 MMBOE were incorporated to the reserves book. Many other blocks present similar conditions within Sinopec's fields, which encourages to spread this concept to all other areas with similar characteristics. In the short term, hydrocarbon production is expected to increase due to the implementation of this pilot project. For mid and long term, CO2 associated reserves should increase throughout subsequent booking exercises, increasing the company's value from these non-evaluated reservoirs until this date.

Location

"El Huemul" field (EH) is one out of fifteen concession blocks granted to Sinopec Argentina since 2011. Hydrocarbon exploration and production started in the region during the 60´s with YPF (Argentinian oil national company), and after a succession of take-overs, Sinopec Argentina is consolidated as an operator of oil fields in the Argentine energy industry, acquiring 100% of Occidental's concessions in the country.
The field is located in the Southern Flank of the *Golfo San Jorge* Basin (GSJB), approximately 60 km to the West of *Caleta Olivia* City in *Santa Cruz* Province, Argentina (Fig. 1).

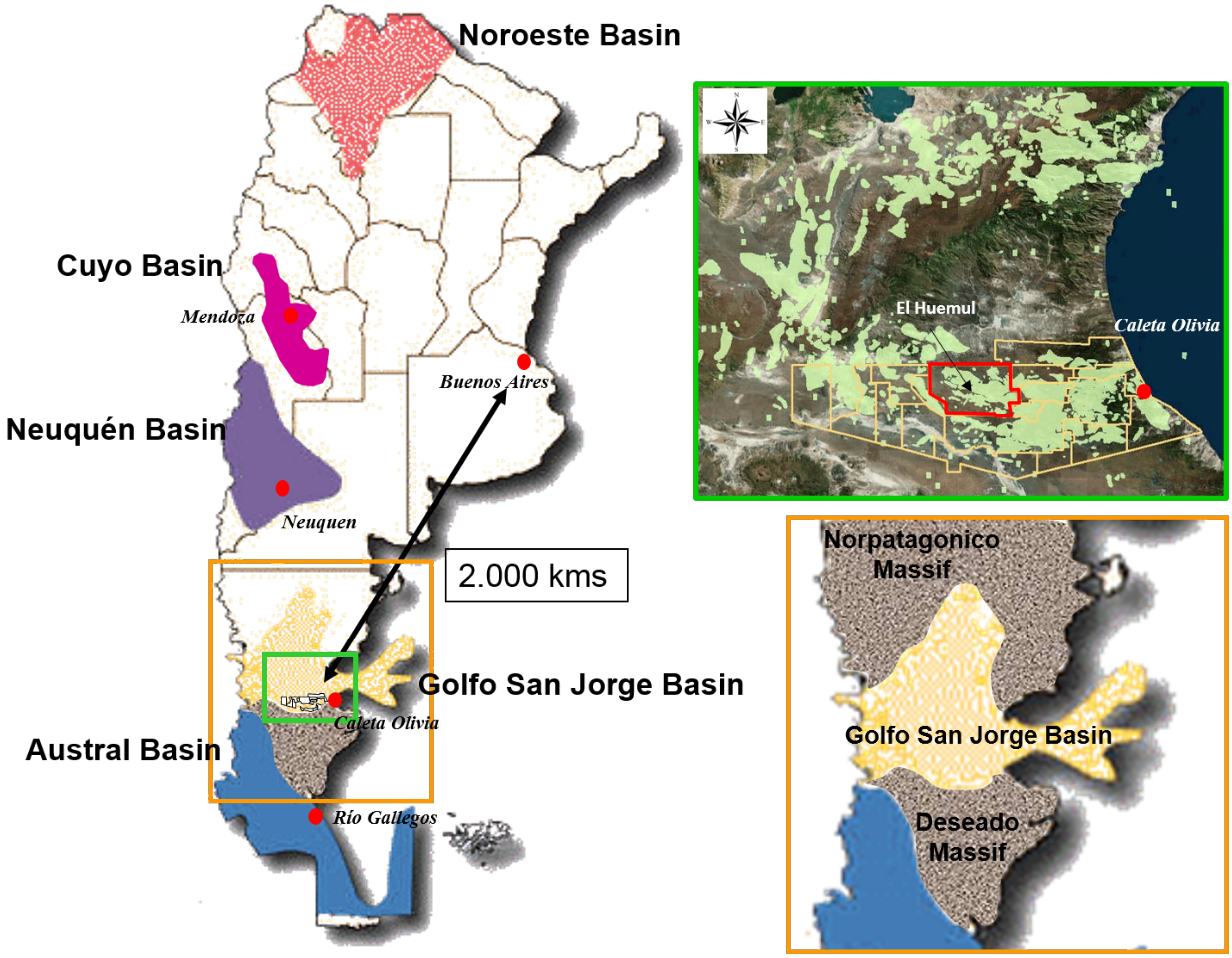

Fig. 1- Golfo San Jorge Basin location map. Reference distance from Buenos Aires to Caleta Olivia cities and Deseado and Norpatagonico Massif limiting the basing toward South and North respectively. Sinopec Argentina concessions (orange); "El Huemul" field highlighted in red.

Introduction

Since oil and gas production started in El Huemul field, a lot of targeted reservoirs showed variable rates of CO2 gas associated to hydrocarbons. CO2 portion in production fluid ranges from less than 1% to values higher than 90%. After considering all individual and multi-tested zones during completion programs, the average percentage of produced CO2 is around 40%. Production of this gas is usually harmful both for production assemblies and production facilities, so acid and sweet gas tend to be vented to the atmosphere.
Facilities limitations for CO2 production varies depending on the field location and according to local regulations, among punctual exceptions, sweet and/or acid gas venting cannot be extended for more than one-month period due to environmental issues. These are the main reasons why most of hydrocarbon intervals with associated CO2 are not opened during completion. Therefore, the real hydrocarbon production potential of the field has not been quantified. This is finally limiting economic predictions and results, as well as Sinopec Argentina's real value.
The main objective of this study is to quantify those potential oil and gas bearing reservoirs with associated CO2, mapping structural and net sand for each of them, to finally estimate the hydrocarbon volume usually left behind pipe. Economics have been run to know the feasibility of putting these layers into production, accounting for the associated facilities which are needed to produce these reservoirs. Finally, the target aims to increase Sinopec Argentina's reserves.
The capacity to handle CO2 in the field depends on the distance to facilities developed for that purpose. In practice, production team can currently manage 4% of CO2 associated to commingled well's production.
Even though most of the tests are located on the Eastern portion of the field, it does not necessarily mean that CO2 is not present towards Western EH (Fig. 2).
From the beginning, the idea was to map all tested reservoirs. However, CO2 mud logging measurements show that, in many wells, this gas should be present in other multiple intervals never opened. As a result, all CO2 mud logging picks were summarized and assigned (by cross checking with open hole logs - OHL) to a reservoir interval.

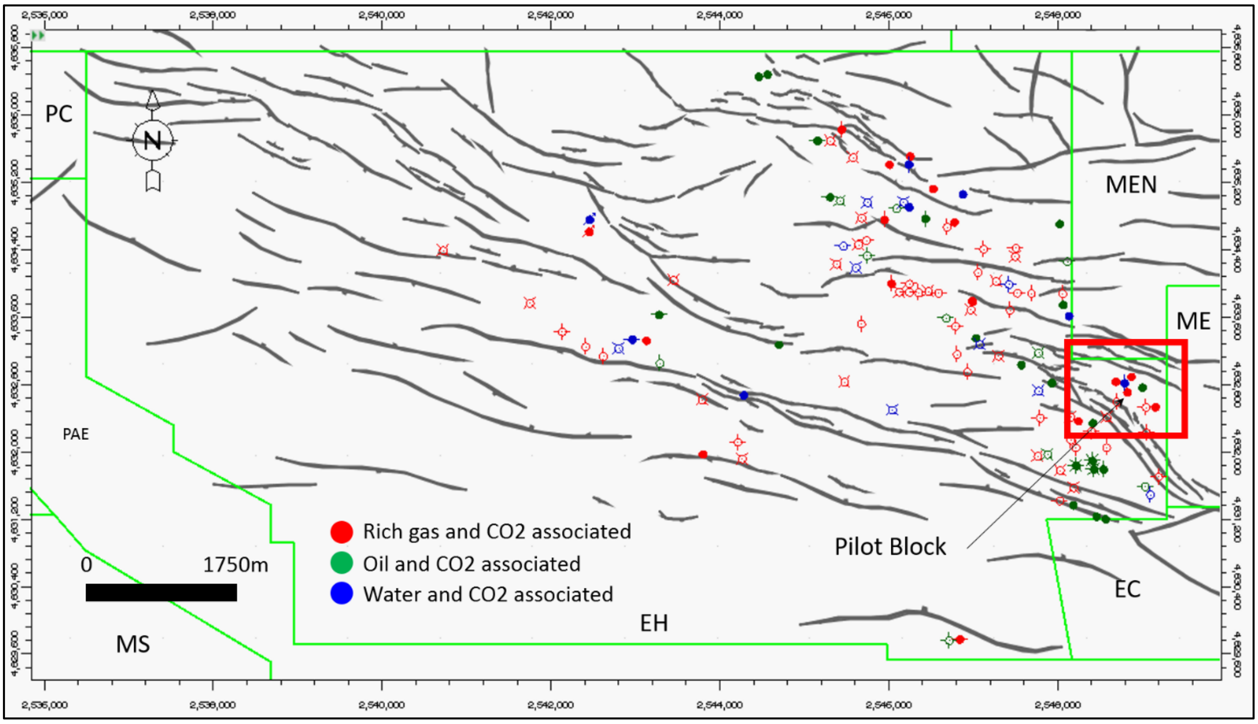

Fig. 2- Gas, oil and water tests with associated CO2 along El Huemul Field. Wells which reported mainly gas, oil or water with ≥ 5% of CO2 were highlighted in red, green and blue respectively. Symbol per well represents the current well status according to Sinopec´s well naming convention.

This zone was finally selected mainly because most wells in the area have been recently drilled and have similar open hole log information. Eighteen wells were correlated and 75 individual oil and gas bearing reservoirs with associated CO2 were recognized.
During reservoir correlation 4 individual faults were recognized. Most of the wells are affected by at least one of these faults creating compartments in the reservoir located into the analyzed productive section.
Multiple reservoirs were identified per well, but usually few of them were tested and even less have CO2 content information. When CO2 content is not reported, its estimation is provided from mud logging information and the CO2 gas readings.
After well correlation, a set of structure and net sand map was generated for each reservoir with potential to produce hydrocarbon with associated CO2. Test results and fluid prognosis allowed to define fluid distribution per reservoir (and faulted compartments if available) throughout the interpretation of the lowest known gas (LKG), highest known oil (HKO), lowest known oil (LKO) and highest known water (HKW).
Estimated oil and gas reservoir volume associated to high CO2 content varies between a maximum and a conservative scenario essentially linked to the position of the LKO and LKG, and to the experimental measurements in laboratory over rock samples. Irreducible water saturation (Swirr) ranging between 29,6% and 53,7% introduced the main impact in OGIP and OOIP calculations over the oil and gas volumetric factors (Bo and Bg).
Completion reports provided fluid information (type -oil, gas-, %CO2, rate), which was base information for hydrocarbon production allocation process. Having summarized this information for all wells and associating the results to each correlated and/or mapped reservoir, cumulative production volume was allocated to each layer. By means of the Material Balance Equation (MBE), current reservoir pressure was estimated, allowing to define which reservoir is a workover candidate.
Several parameters were analyzed and weighted, to finally establish a reasonable development schedule for CO2-rich hydrocarbon bearing reservoirs. Two main scenarios were assumed:

- Workover jobs in drilled wells on one hand,
- Workover jobs in drilled wells plus drilling of new-well locations

The second case contemplates the full potential development of this pilot block.
Economic evaluations for alternative scenarios are presented, providing support to decide what development strategy fits best to the company's goals.
It is important to mention that 2P reserves were booked in Yr. 2019 reserves exercise due to this pilot project. The project's added value is represented by the possibility to extend this concept not only to El Huemul field, but also to all the concessions in which CO2 is a problem.

Tectonic and sedimentary framework

Within the geotectonic framework, Golfo San Jorge Basin is located towards the Southern extreme of the Southamerican Plate, which converges with Nazca and Antarctic Plate toward West (Sylwan *et al.*, 2011).
In the center of patagonia argentina, to Upper Paleozoic, the region showed paleogeographic relationship with Malvinas Island, Antartic Peninsula and minor fragments of previous Gondwana Supercontinent (Suero 1962; Lesta *et al.*, 1980; Fitzgerald *et al.*, 1990; Peroni *et al.*, 1995; Ramos 1984 y 1996). Pankhurst *et al.*, (2006), stablished the relationship of the basin origin with the relative movements and collision during Carboniferous time, between The Deseado and Norpatagonico Massifs (located toward South and North of the basin respectively).
Even though, some pre-Dogger sedimentary units were described in the region, during this time the main rifting activity took place in the area. As a result of the generalized extensional tectonism, grabens and hemi-grabens NW-SE and NE-SW oriented were developed. The space created due to rifting activity was filled by volcaniclastic material, marine and lacustrine sediments which are grouped in Las Heras Group (Gianni *et al.*, 2015). The Barremian Patagonidic tectonic phase (compressional) in the Andean Ranges resulted in an eastward shifting of the main depocenters of the basin and the incorporation of large volumes of pyroclastic detritus. At the same time, the generation of new WNW-ESE to E-W striking normal faults (Uliana *et al.*, 1989; Paredes *et al.*, 2013; Ramos 2015) resulted in the creation of accommodation space for the deposition, in unconformity above Las Heras Group, the Chubut Group (Barremian to Campanian?). The new sediments are associated to fluvial and lacustrine environments (Hechem *et al.*, 1990; Hechem and Strelkov 2002). In term of thickness and hydrocarbon potentiality, this section is the most important sedimentary sequence and is the materialization of a late extensional phase associated to the thermal subsidence cycle of the basin

(Fitzgerald *et al*., 1990). This sedimentary section is formed by marine deposits to the West region changing to silicoclastic units to the East (Feruglio 1950). Besides lateral variation, from bottom to top, the Chubut Group is divided into Pozo D-129 (main source rock), Castillo and Bajo Barreal formations (Fig. 3).

Pozo D-129 Formation is the result of sedimentation of green mudstones and very fine-grained sandstones that were deposited in lacustrine environments. Laterally in transition, pass to fluvial deposits of Matasiete Formation dominated by conglomerates, sandstones, mudstones and tuffs outcropped in the San Bernardo Fold Belt, where it covers the Pozo D-129 Formation (Paredes *et al*., 2007). These two units are covered by Mina del Carmen Formation (Lesta 1968) which represents the transition from lacustrine environment to a low-energy fluvial environment, whose sedimentation is composed of cross-bedded sandstones, tuffaceous sandstones and tuffs. This unit is overlain by the Cañadón Seco and Meseta Espinosa Formations (Senomanian to Campanian?). These intervals are represented by sandstone and tuffaceous sandstones which are the result of a fluvial environment with increase in sinuosity to upper section of the column. Main channel fluvial facies change laterally to ephemeral shallow lakes as representatives of the proximal flood plain (Feruglio 1950; Teruggi and Rosetto 1963; Sciutto 1981). In general, they comprise coarse-grained sandstones and some conglomerates, which form multi-storey channels separated by alluvial plain successions made up of mudstones, tuffaceous mudstones and very fine-grained sandstones (Umazano *et al*., 2008).

Together, these two deposits are the main hydrocarbon target in the basin and constitute the main oil system together with Pozo D-129 Formation.

In response to Cenozoic tectonic reactivation of Jurassic to Early Cretaceous normal faults (compressive scenario) (Homovc *et al*., 1995), Westward of the basin, the San Bernardo fold and thrust belt NNW-SSE oriented was developed. The Cenozoic evolution in the region is related both, to the Andean activity and to the development of the Atlantic passive margin in the East (Legarreta *et al*., 1990; Legarreta and Uliana 1994; Bellosi 1995; Malumian 1999).

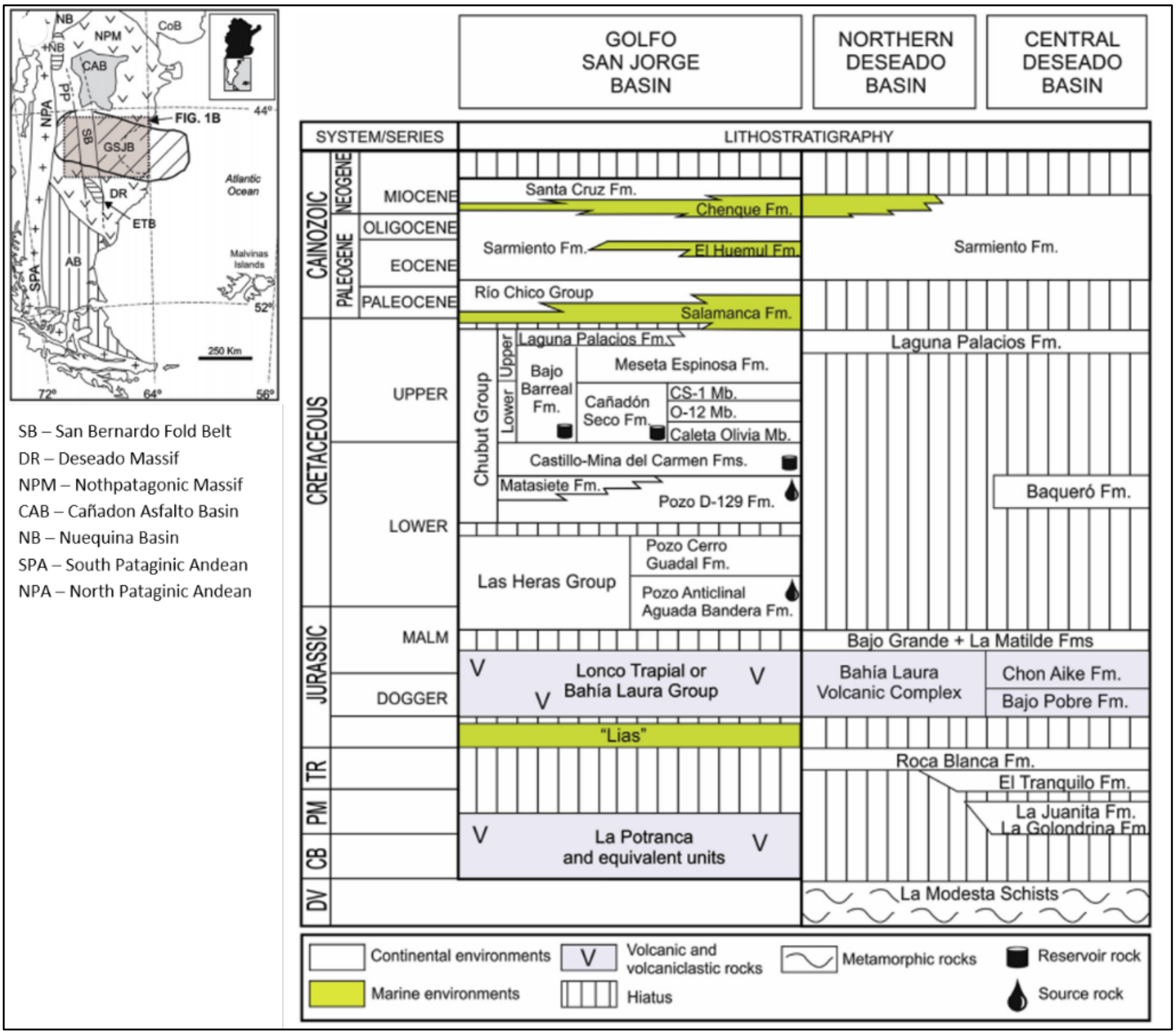

Fig. 3- Stratigraphy of Golfo San Jorge Basin and equivalent units in the nearby Deseado Region, with indication of main source and reservoir rocks (from Paredes *et al*., 2018).

Low rates of subsidence favored continental sedimentation in the basin, with periodically inundation by marine transgressive deposits (Paredes *et al*., 2015). Intraplate volcanism was also common during the Cenozoic, and large parts of Central Patagonia were currently covered by their products (Ardolino *et al*., 1999; Panza and Franchi, 2002).

Data and Project evaluation

As mentioned in the introduction section, the capacity to handle CO2 in the field depends on the distance to facilities developed for that purpose. In practice, production team can manage around 4% of CO2 associated to commingled well's production. Based on this limitation, all individual tests loaded in the data base were initially filtered by ≥ 5% of CO2 cutoff, to recognize those zones in which the study should be focused.
Carbon Dioxide gas readings from mud logging show, in many wells, that this gas should be present in multiple intervals which have been never opened during well completions. As a result, all CO2 mud logging picks were summarized and assigned to all intervals with potential reservoir features based on open hole log information (Fig. 4).

Reservoir Name	GS (m)	NS (m)	Fluid Tested	Movility (Md/cp)	Caudal (l/h)	CO2 (%)	Choke (mm)	CO2 (ML - ppm)	Prognosis from ML	Prognosis from OHL	
fCS-mbCS1-r37	3,5	1,3	G	7,62		47	10		P-CI		Cañadon Seco Fm./CS1 Mb
fCS-mbCS1-r49	6,4	3,5	OM	1,38	2.500			15.000	PI		
fCS-mbCS1-r50	4,8	1,7	NT	0,11				9.000	PI		
fCS-mbCS1-r50.5	6,3	0,0						9.000	PI	DRY	
fCS-mbCS1-r51.5	3,7	0,0								DRY	
fCS-mbCS1-r57	8,4	0,0							SI	DRY	
fCS-mbCS1-r77.5	6,9	4,5	O	2,66	2.400		50	21.000	P-CI		
fCS-mbCS1-r78	10,6	5,5	OM	0,50				21.000	P-CI		
fCS-mbCO-r15	10,7	3,5						20.000	SI	W	Cañadon Seco Fm./Caleta Olivia Mb
fCS-mbCO-r10	10,0	0,0								DRY	
fCS-mbCO-r36	6,1	4,5		18,13				21.000	PI	G	
fCS-mbCO-r37	7,1	1,5		2,82					SI	G	
fCS-mbCO-r160	10,9	1,8							SI	W	
fCS-mbCO-r44	6,1	4,0						21.000	P-SI	G	
fCS-mbCO-r45	6,4	3,0						10.000		W	
fCS-mbCO-r52.5	4,3	0,0							SI	DRY	
fCS-mbCO-r50	2,5	0,5						10.000	SI	G	
fCS-mbCO-r54	5,2	2,5						3.000	P-SI	G	
fCS-mbCO-r56	3,5	2,0	NT	0,96				10.000	PI		
fCS-mbCO-r60	3,7	2,0						6.000	SI	W	
fCS-mbCO-r65	5,2	0,0							SI	DRY	
fMDC-r10	4,5	0,0	DRY	0,13				6.000	PI		Mina del Carmen Fm.
fMDC-r14	10,4	2,3		0,32				7.000	P-CI	O	
fMDC-r21	7,7	3,5						4.000	P-CI	O	
fMDC-r24	3,1	0,0						3.000	SI	DRY	
fMDC-r26	8,7	4,0		0,38					PI	W	
fMDC-r370	3,8	0,0								DRY	
fMDC-r20	8,3	2,0	O	6,66	1.200				PI		

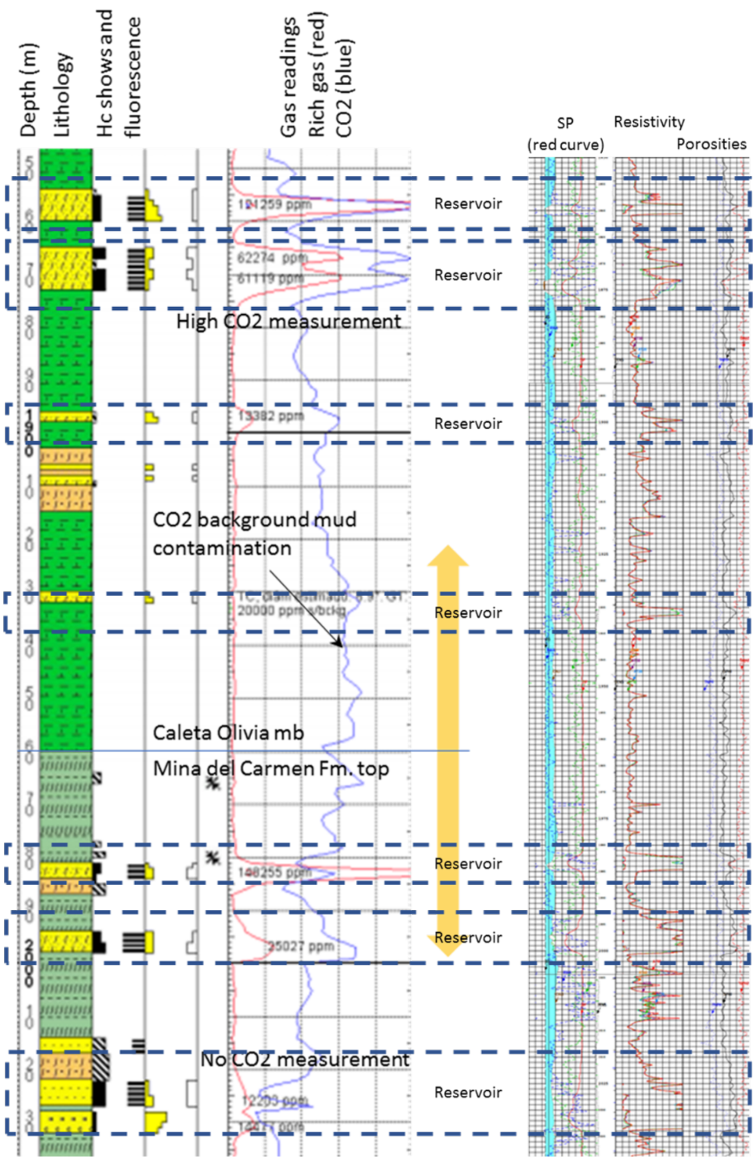

Fig. 4- Outcome spreadsheet for one well in which several intervals were listed (fCS-mbCS1-r78, fCS-mbCO-r20, fMDC-r33, etc.). CO2 mud logging systematically measures significative differences between Cañadon Seco Formation versus Mina del Carmen Formation (fMDC). The most regional continuous members of Cañadon Seco Fm. (CS1 and Caleta Olivia) concentrate most of the high CO2 detection, while in fMDC CO2 detection decreases even considering a CO2 background due to drilling mud contamination. Reservoir identification by cross checking between mud logging and OHL information (Dash blue rectangles).

The example shown in figure 4 summarizes all numbered reservoirs in one well, how many of them were tested and how many times CO2 was reported. Regarding this last item, the reservoir named fCS-mbCS1-r37, produces gas with 47% of CO2, but no CO2 measurement was reported for the other 4 tested zones. The reservoir fCS-mbCS1-r77.5 proved oil flow; its CO2 production potential is assumed by the mud logging information with CO2 reading of 21.000 ppm.
The column “Prognosis from OHL” in figure 4, is the result of considering tests in surrounding opened intervals, mud logging information and a qualitative open hole log analysis. The purpose is to provide additional information regarding fluid prediction for tested or non-tested intervals in the same block.
The total number of correlated reservoirs is 75, but 69 appear in more than one well. After considering these 69 reservoirs, completion tests and open hole log features lead to select 46 intervals to be mapped. Main tops for CS1 and Caleta Olivia members and Mina del Carmen Formation (fCS-mbCS1, fCS-mbCO and fMDC) are distributed approximately 1.000 m along the stratigraphic column thickness. Therefore, one set of fault polygons was created for each marker. Then, a range of reservoirs located above and below some marker were mapped considering a single set of fault polygons. In this sense, for sand bodies lying on the same block, the volume for those located above the nearest marker will be overestimated while it will be punished for those located below it (Fig. 5).

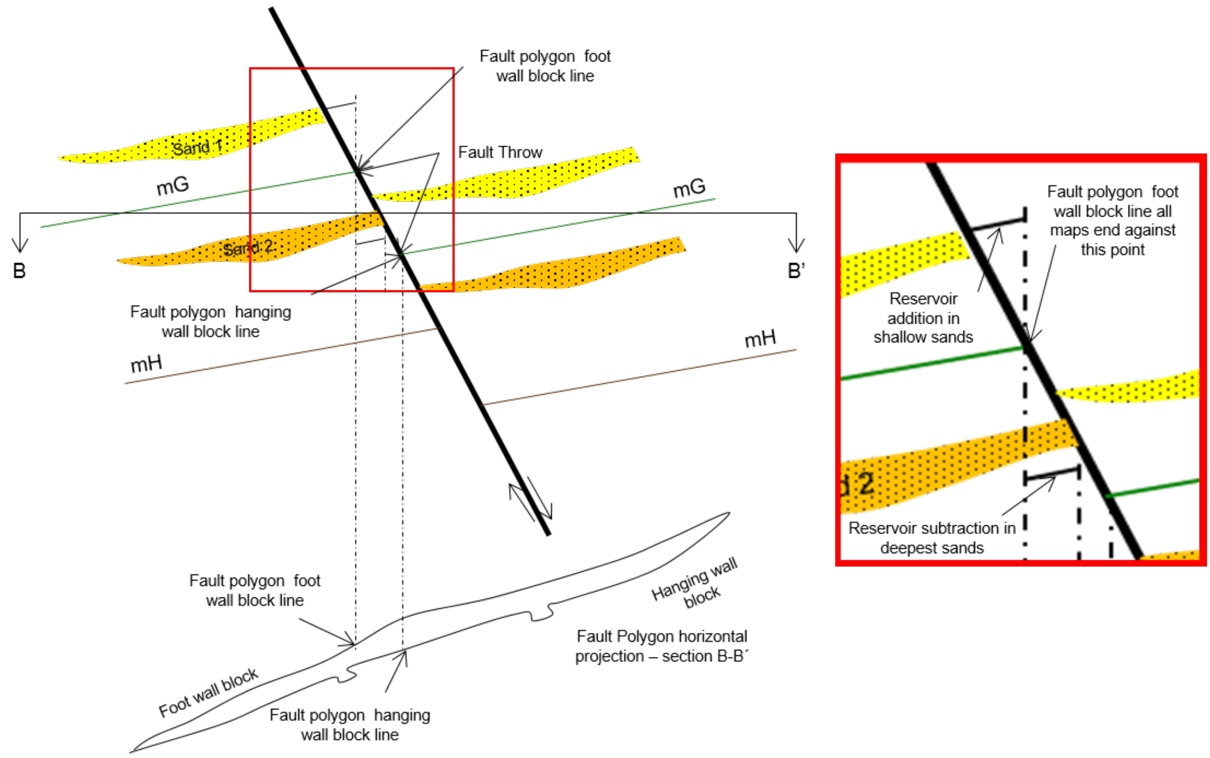

Fig. 5- Schematic perpendicular section where fault projection over reservoirs is showed including how sand volumetric is overestimated or punished depending on the block in which the reservoir of interest is located. Horizons mG and mH are just for reference.

Oriented to build net pay maps for volumetric calculations, the Lowest Known Gas (LKG), Highest Known Oil (HKO), Lowest Known Oil (LKO) and Highest Known Water (HKW) were summarized for each of those 46 intervals with potential to produce hydrocarbon with associated CO2. Areal extension sensitivities were also done. So, for both produced and non-produced reservoirs, maximum and conservative scenarios were calculated considering volume variations according to:

- Fluid contacts position
  - If estimated to HKW, this is a maximum case scenario
  - If estimated to LKO, this is a conservative scenario
- Arbitrarily defined areal extension
  - Considering reservoir extension and structural position

Both situations add or subtract rock volume to the calculus, represented in Fig. 6.

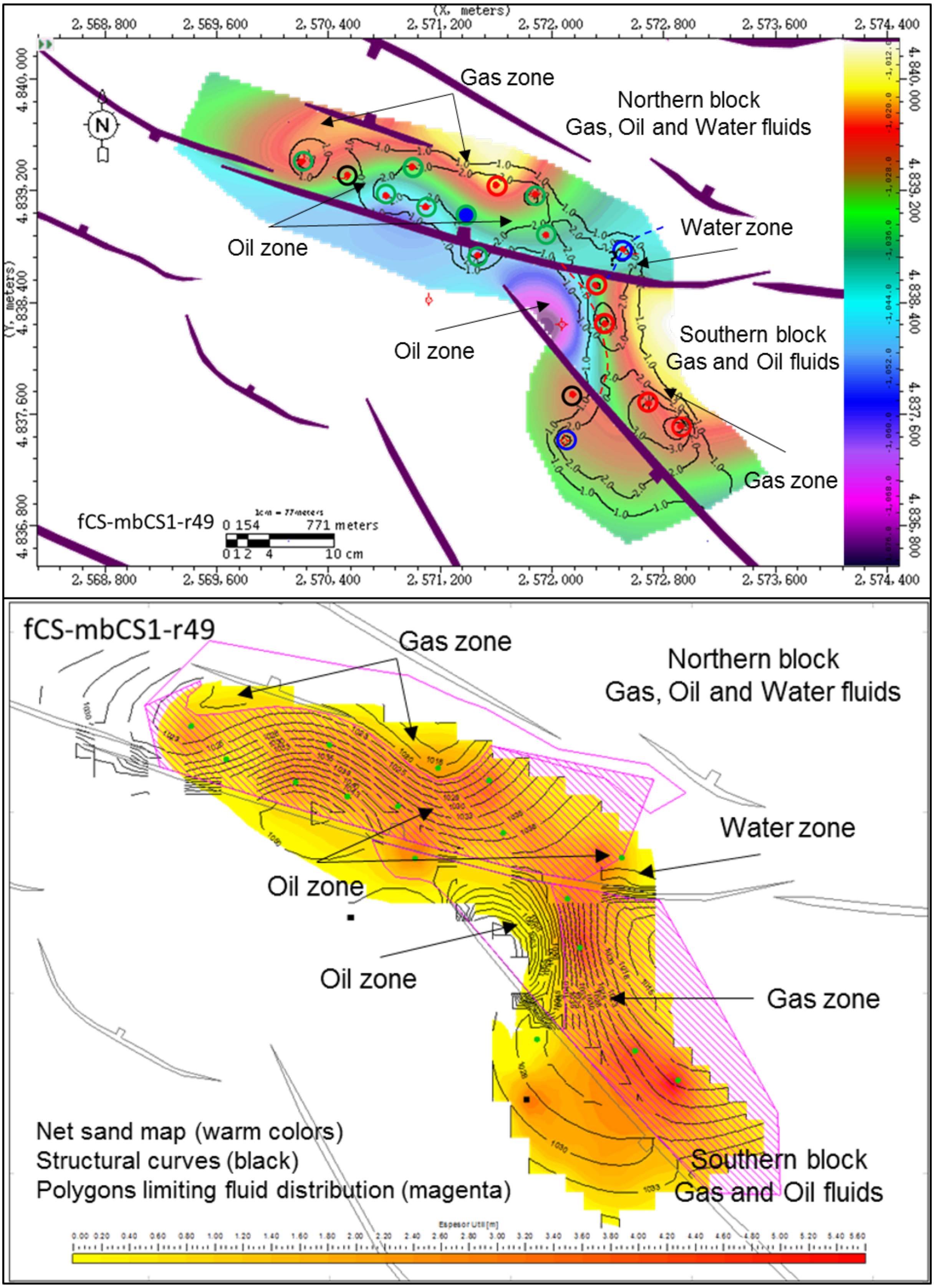

Fig. 6- Structure sand map in color scale with overlapped net sand contour lines and wells in which the reservoir is present. Tests represented by full filled circles and reservoir prognosis in empty circles (red, green and blue for gas, oil and water respectively) (upper map). Polygons limiting block compartments and fluids into the same compartment to volume calculations (lower map).

Reservoir fCS-mbCS1-r49 in figure 6, is an example of multiple fluids distribution varying from Northern to Southern blocks. Gas volume in the Southern block is included within the dashed magenta polygon, while oil

volume is the result of the subtracting the full magenta polygon minus the gas volume. The same methodology was applied for the Northern block but in reverse order, gas volume is the result of subtracting the volume of the full magenta polygon minus the oil volume, provided by the dashed magenta polygon.
For the total number of mapped reservoirs, the oil-bearing estimated rock volume ranges from 26 x10^6 m3 and 22 x10^6 m3 while, for gas, rock volume varies from 34 x10^6 m3 to 31 x10^6 m3.
When calculating volumetric OOIP and OGIP, all variables (rock volume, reservoir porosity, water saturation, Bo and Bg) must be defined.

$$OOIP = Rock\ volume\ \times porosity\ \times (1 - Sw) \div Bo\ , \quad \text{Ec. A}$$
$$OGIP = Rock\ volume\ \times porosity\ \times (1 - Sw) \div Bg\ , \quad \text{Ec. B}$$

Porosity values were obtained from open hole log petrophysical interpretation, and an average porosity value was calculated for each reservoir per well. For reservoirs present in different wells, a new average was calculated to have a unique porosity value. Although reservoir porosity ranges from 13% to 18%, the input value for OGIP and OOIP calculations resulted in the average of all values included within that range. Then, the porosity value cutoff which discriminate productive reservoirs from non-reservoir is 14%.
Meanwhile, assuming hydrocarbon presence in all intervals located above the OWC, assumed water saturation for OOIP and OGIP estimations was considered as irreducible water saturation (Swirr). Besides some exceptions, permeability values generally vary from 0.01 mD to few tens of mD (let say for example 50 mD). Due to similarity between reservoirs properties, SCAL analysis performed over EH-4052 rotary side wall cores (RSWC) were used as reference for Swirr values. Finally, three possible scenarios were considered,

1. Swirr = 29,6% coming from a reservoir of 23,5 mD
2. Swirr = 37,1% coming from a reservoir of 6,4 mD
3. Swirr = 53,7% coming from a reservoir of 1,4 mD

On the other hand, original reservoir pressure condition was assumed for Bo and Bg. The values were taken from PVT data, acquired from reservoirs located in fCS-mbCS1 and fCS-mbCO members in wells throughout El Huemul field. Although there is also available information for oil in fMDC Formation, fluid properties seem to be widely different compared to the shallower intervals (Cañadon Seco Formation) (Fig. 7).

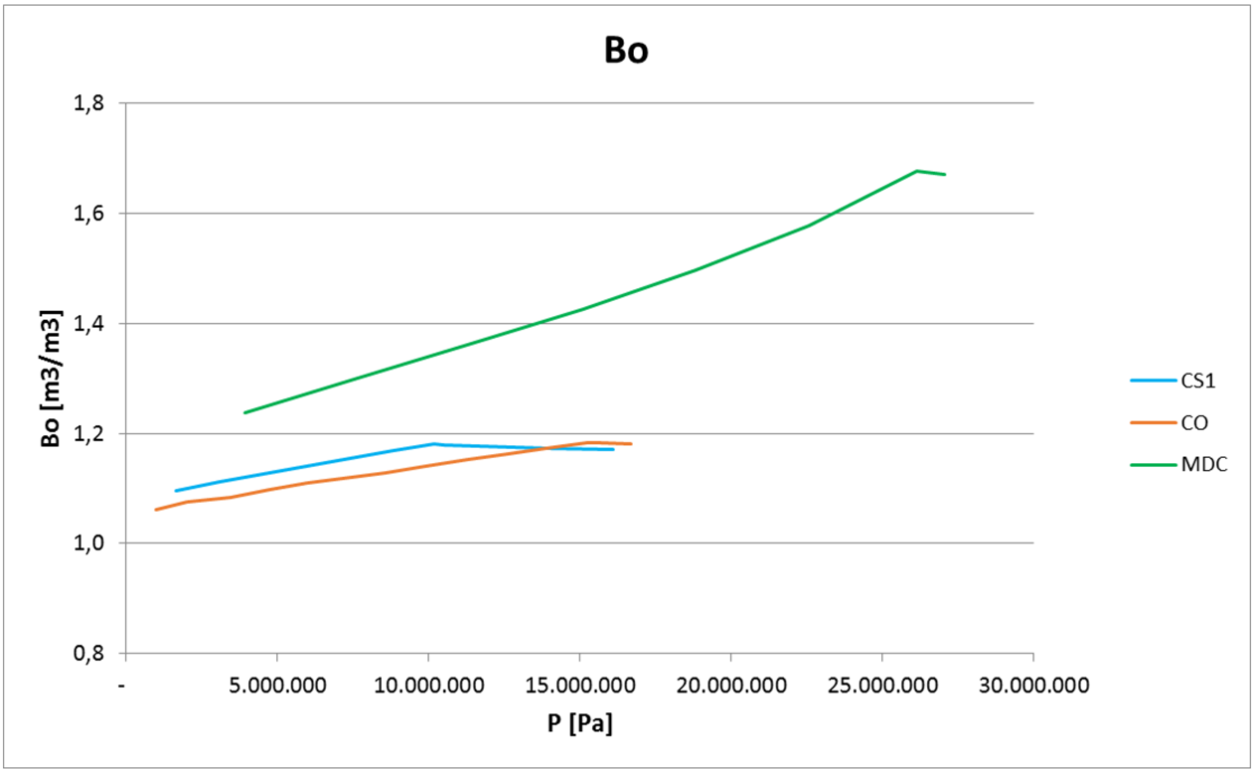

Fig. 7- Volumetric factor comparison between data from CS1 (blue) and CO (orange) members, and Mina del Carmen Fm (green).

Given the fluid properties differences, PVT data from upper layers was considered for this analysis. This difference can be seen in figure 7, where initial Bo for CS1 and CO fluids is around 1,18 m3/m3, while Bo for MDC fluid is higher than 1,6 m3/m3. Although reservoir pressure is slightly different between CS1 and CO intervals, initial Bo values are similar for both intervals. Then, the average (BoCS1+BoCO)/2 was considered for OOIP calculations. Results are very similar for Bg. CS1 and CO Bg values are 0,01289 m3/m3 and 0,0101 m3/m3 respectively, while for MDC, Bg is 0,00551 m3/m3. Like Bo, OGIP volume was calculated with an average Bg value, (BgCS1+BgCO)/2. Finally, considered Bo and Bg values were 1,1756 m3/m3 and 0,011495 m3/m3 respectively.
OOIP and OGIP volumes are summarized in figure 8. Oil and Gas rock volumes have been accounted as different groups, considering OGIP volume associated to free gas reservoirs. Although a constant value was used for porosity as well as Bo and Bg, three different scenarios were proposed for water saturation and, as a result, six scenarios for OGIP and OOIP are presented (Fig. 8).

OOIP & OGIP calculations

	Rock Volume (m3)		Porosity (Constant value - average/reservoir) (%)	Swirr (RSWC) (%)	Bo & Bg (CS1 & CO) (m3/m3)	OOIG & OGIP scenarios (m3)	
Gas	Maximum	33.829.015	14	29,6	0,011495	315.831.528	Maximum
						285.884.990	Conservative
				37,1		282.184.703	Maximum
						255.428.493	Conservative
	Consevative	30.774.040		53,7		207.578.477	Maximum
						187.896.285	Consevative
Oil	Maximum	26.235.510		29,6	1,175600	2.338.482	Maximum
						1.987.346	Conservative
				37,1		2.089.354	Maximum
						1.775.626	Conservative
	Consevative	22.082.148		53,7		1.536.954	Maximum
						1.306.172	Conservative

Fig. 8- OGIP and OOIP summary spreadsheet coming from the static model.

After having estimated In-Place Hydrocarbon Volume for the 46 mapped layers, the next step was to determine oil and gas production allocation for each of them. The final objective of this stage was to evaluate each reservoir's production history, hence their pressure depletion and the associated recovery factor. Finally, this information will indicate whether a reservoir is still in good conditions (or not) to continue its development in wells where it has not been produced.
To properly visualize and understand each well's available information, completion and workover schematics were built: perforated intervals, layer names (for those correlated and/or mapped), test results, CO2 content (if measured), fractured intervals and production assembly. Figure 9 shows an example of the completion diagram for Well-1. Reservoir names like fCS-mbCS1-r40, fCS-mbCO-r15 or fMDC-r24 were renamed as r40_A, r15_B and r24_C for practical purposes. Then, _A, _B and _C refer to Cañadon Seco member, Caleta Olivia member and Mina del Carmen Formation respectively.

Well-1			
Layer	CO2 [%]	Test	Stimulation
r40_A	51%	Rate 400 l/h, WC 20% FL 1.189 m, WHP_BU 142 psi	
r24_C		Rate 150 l/h Flow, WC 90% WHP_F 85 psi, CHK 11 mm, WHP_BU 996 psi	
r20_C		Rate 900 l/h, WC 5% FL 1973 m	FRACTURED
NN	16%	Rate 4.000 l/h Flow, WC 5% WHP_F 550 psi, CHK 11 mm, WHP_BU 1.100 psi	

Fig. 9- Basic information of Well-1's completion diagram. Each reservoir has its associated test (l/h – liters per hour; WC – water cut; FL – fluid level; CHK – choke diameter; WHP_F – flowing wellhead pressure; WHP_BU – build up wellhead pressure), together with CO2 and stimulation information if available/corresponding. Other perforated intervals are not represented in this diagram.

Oil and gas production allocation was based on Productivity Index (PI) calculations (Eq. C), to finally compare Absolute Open Flow (AOF) rates between each individual test. Reservoir pressure (Pr) was obtained from El Huemul's pressure gradient, while the bottom hole flowing pressure (Pwf) was estimated from wellhead pressure data (for flowing tests) or fluid level data (for swab tests). Some considerations were assumed, since Pwf is not directly measured and not all tests result in flowing rates; pseudosteady-state flow was assumed (Ahmed 1946).

$$PI = \frac{q}{P_r - P_{wf}}, \quad \text{Eq. C}$$

In case a fracture was performed, and no post-fracture test was carried out, rates were numerically estimated with available information (or assumed in case of missing data), together with its corresponding reservoir and fluid parameters as shown in equation D.

$$Q_o = \frac{0{,}00708kh\left(P_r - P_{wf}\right)}{\mu_o B_o\left[ln\left(\frac{r_e}{r_w}\right) - \frac{3}{4} + S\right]}, \quad \text{Eq. D}$$

Gas rates associated to dissolved gas were estimated with an internal spreadsheet based on empirical data from oil flow tests. Choke diameter, oil rate and wellhead pressure are the input variables to calculate gas rates. Figure 10 shows the example for a given interval in Well-1.

Given the available production information, PI per reservoir was assumed to be constant throughout each well's production cycle, until any significant change modifies the well's production allocation (i.e. workover job).

Hydrocarbon production was assumed to be zero for open-no-test layers. This criterion was arbitrarily defined, considering that the most interesting reservoirs (according to net thickness, resistivity arrangement, porosity, XPT (reservoir pressure data), etc.) were selected to be tested, since the petrophysics evaluation suggested that they should produce at the highest rates compared to any other reservoir in the well. Although these layers should certainly have associated production, it is considered negligible versus the tested and/or fractured layers.

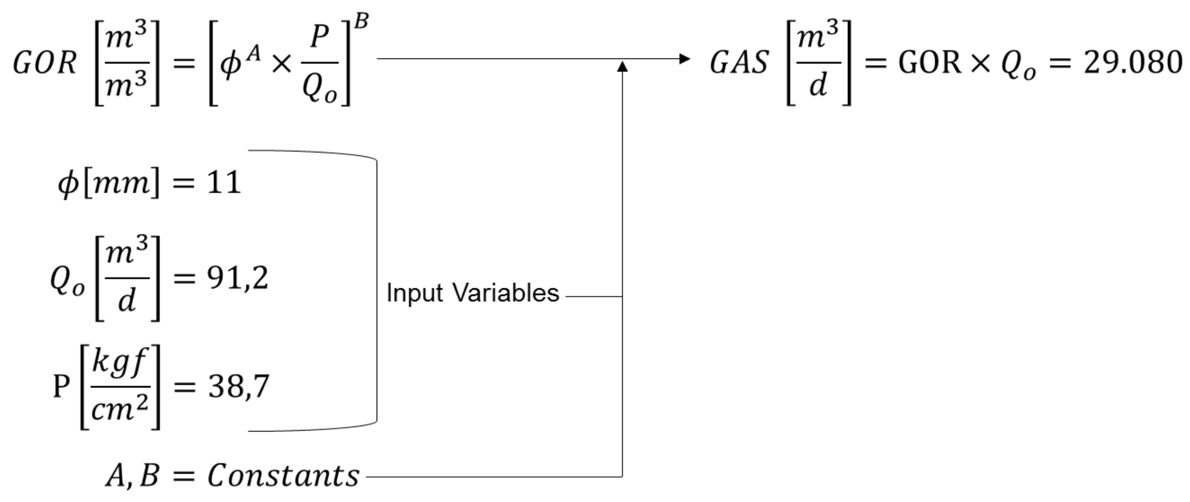

Fig. 10- Associated gas rate calculation workflow for an oil flow test. Choke diameter (ϕ), oil rate (*Qo*) and flowing wellhead pressure (P) data are needed for calculation purposes.

Along with this analysis, each well's intervention has its associated cumulative production. For instance, Well-1 produced 21.200 m3 of oil and 12.600.000 m3 of gas under the previously shown condition.
This procedure was repeated for each well, so finally cumulative oil and gas volumes were added for each mapped and tested reservoir.
The previously described workflow was performed to analyze, by means of a Material Balance Equation (MBE), the current condition of each mapped and produced reservoir, that may be potentially interesting for the CO2 pilot project development.
To this point, relevant data was assembled to calculate the MBE for each layer:

- Geology: Thickness and Structural maps, Rock Volume
- Petrophysics: Phi, Sw, Formation Compressibility
- PVT: Bo, Bg, Co, Rs
    - 1 for CS1 member, 3 for CO member, 1 for MDC Fm.
- Tests: Rates, %WC, Pressure
- Production: Oil & gas cumulative volume, Drive Mechanism:
    - Solution Gas Drive (SGD)
    - Gas Cap Expansion (GC)
    - Water Drive (WD)
    - Fluid Expansion and Pore Shrinkage (FE&PS)

The general expression for the MBE is as follows (Eq. E) (Dake 1998, Schilthuis 1936):

$$\begin{bmatrix} Initial\ Oil \\ Volume \end{bmatrix} = \begin{bmatrix} Present \\ Oil \\ Volume \end{bmatrix} + \begin{bmatrix} Freed \\ Solution \\ Gas \end{bmatrix} + \begin{bmatrix} Gas\ Cap \\ Expansion \end{bmatrix} + \begin{bmatrix} Rock\ and \\ Water \\ Expansion \end{bmatrix} + \begin{bmatrix} Net \\ Water \\ Influx \end{bmatrix} + \begin{bmatrix} Injected \\ Volumes \end{bmatrix}, \quad \text{Eq. E}$$

Each term was considered or neglected according to each drainage mechanism. The general expression was simplified, having neglected by default both Net Water Influx and Injected Volumes given that no waterflooding project is ongoing within the surroundings, target reservoirs present, on average, low water cut, and production decline rate doesn´t prove water drive mechanism,
Reservoir r40_A is briefly described as an example:
R40_A is a relatively small reservoir (Fig. 11) which was tested only in Well-1 during the completion, it correlates with Well-2 and is interpreted as oil prognosis in this latter well (Fig. 12).

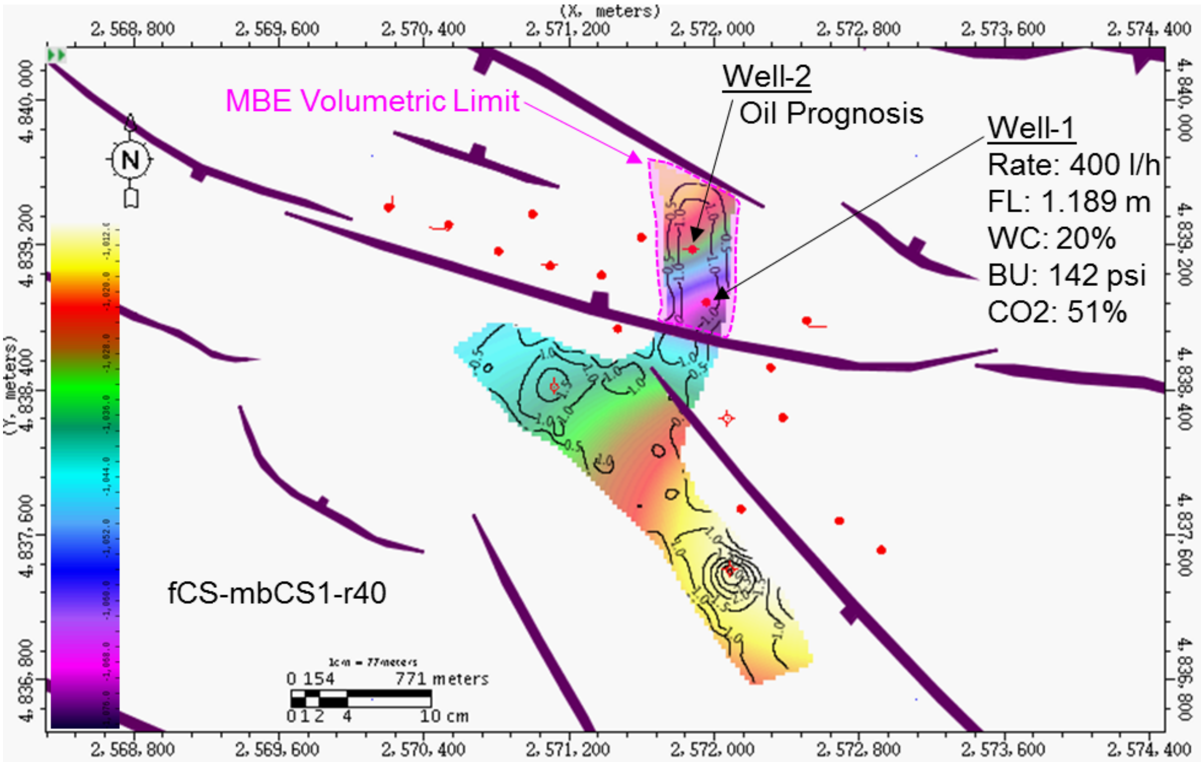

Fig. 11- Structural and Net Thickness map showing MBE limits; fluids distribution according to test results in Well-1 and its prognosis in Well-2 for layer r40_A.

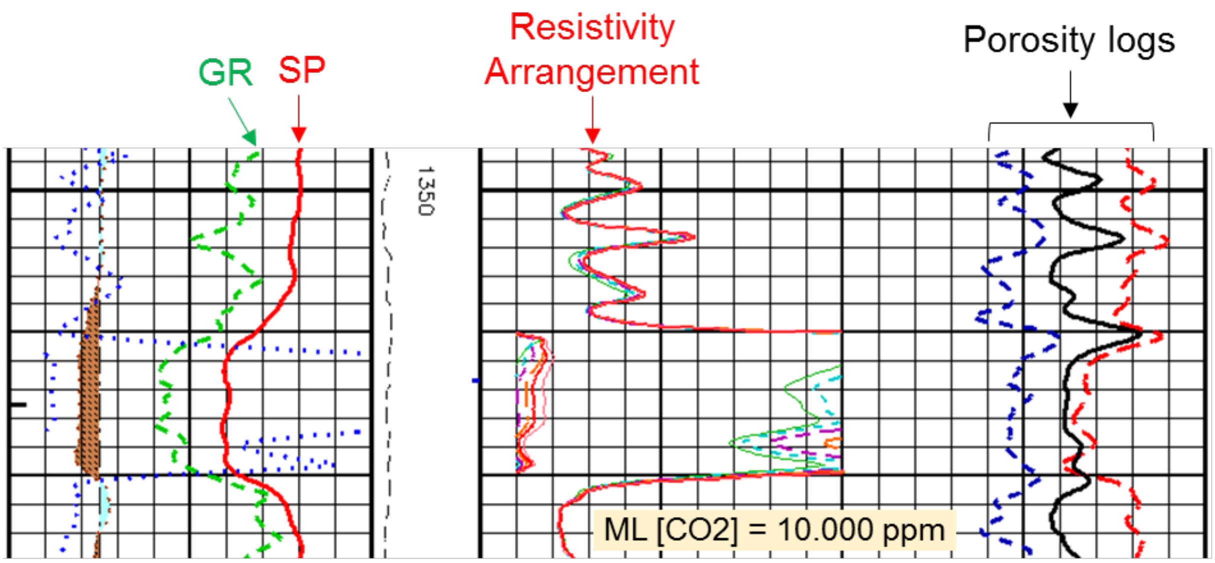

Fig. 12- OH log for Well-2, layer r40_A which correlates with Well-1. According to available information, it is interpreted as oil prognosis. CO2 data from Mud Logging = 10.000 ppm.

Well-1's test resulted in 400 l/h, fluid level 1.189 m, 20% water cut. A gas sample was taken for CO2 content determination: it confirmed 51% CO2. In line with the test, the reservoir's drainage mechanism could either be interpreted as Fluid Expansion and Pore Shrinkage or Solution Gas drive. For sensitivity purposes, both models were calculated, accounting for each case all different PVT models together with the three Sw possible values.

Each case returns a different reservoir pressure and recovery factor. The range of results for all reservoirs were analyzed and interpreted. Based on geological and reservoir criteria, the most reasonable results were defined as the final estimation for each case. Continuing with r40_A example, Solution Gas Drive seems to be the most reasonable Drainage Mechanism, and current reservoir pressure is estimated to be at values from 60 to 75% of the original pressure.

Out of the 46 mapped reservoirs, only 11 of them were liable to apply the MBE since these layers were opened, tested, and had hydrocarbon production allocation. The remaining 35 reservoirs were either not perforated in any well, or might have been perforated but with no swab test to perform hydrocarbon production allocation. As mentioned previously, these cases were arbitrarily assigned no cumulative volume.
Table 1 presents a summary with the estimated current reservoir pressure range for each reservoir, as a fraction of the original pressure.

Reservoir	Pressure Range Low ≤ Pr ≤ High	Drive Mechanis	% CO2
r34_A	84% ≤ Pr ≤ 94%	GC	52%
r40_A	60% ≤ Pr ≤ 75%	SGD	51%
r49_A	55% ≤ Pr ≤ 75%	SGD + GC	68%
r50_A	99% ≤ Pr ≤ 100%	GC	68%
r77.5_A	5% ≤ Pr ≤ 15%	SGD	-
r78_A	55% ≤ Pr ≤ 60%	SGD	82%
r65_B	40% ≤ Pr ≤ 50%	SGD	-
r90_C	91% ≤ Pr ≤ 92%	SGD	6%
r21_C	60% ≤ Pr ≤ 70%	SGD + GC	7%
r20_C	34% ≤ Pr ≤ 34%	SGD + GC	3%
r33_C	60% ≤ Pr ≤ 85%	SGD	15%

Table 1- Current reservoir pressure ranges according to MBE results, with its associated production mechanism and CO2 content.

This information is useful, on one hand, to know which reservoirs tested CO2 and their concentration; therefore, it is known which intervals need to be tested to get the volumetric CO2 distribution. On the other hand, these results indicate which reservoirs are under good pressure conditions to be produced in neighbor wells. All remaining CS1 and CO member reservoirs within the study zone are assumed to be at 100% original pressure, hence they stand as candidates to be put on production in case OHL data shows good reservoir properties, together with the expected fluid content (oil or gas prognosis).
Workover potential identification for all block wells was the following step of this pilot project, to develop CO2-rich reservoirs. The following key parameters were analyzed:

- Key wells to obtain CO2 data
  - non-produced layers
  - open-non-tested layers
  - CO2 content validation, already measured in old wells
- Workover economic feasibility
  - Fluid prognosis (oil or gas bearing reservoirs)
  - Reservoir quality (test and/or fracture candidates)
  - Potential CO2 content (manageable with current facilities)
  - Well integrity (mainly cement quality)

Open Hole logs were analyzed for each well, and it was found that all 14 wells have good free gas reservoirs to put into production. Anyway, gas production is limited by two issues:

- El Huemul's power plant is currently flaring excess gas
- Summer season has low gas demand, compared to winter

For the above reasons, it would be useless to execute gas workovers in the short term. Therefore, it was concluded that the best way to start CO2's areal and vertical distribution identification would be by those wells which have attractive oil prognosis reservoirs: CO2 content would still be evaluated with relatively low gas

production (hence feasible to be produced), and early oil production may be beneficial for a larger scale pilot project, aiming to acquire a CO_2 treatment plant to increase oil and gas reserves.
So, out of the 14 drilled wells that make up the pilot project, 6 of them were identified as oil workover candidates that would achieve the expected production (at least 2 fracture candidates). The inconvenience of these candidates is that most of them currently produce attractive oil and gas rates, so there is a very high opportunity cost in case the workovers are executed on these wells. Given this situation, it would be appropriate to wait for each well's production decline to finally execute the interventions. Anyway, 2 or 3 candidates are closely followed up since they could be done in the short term.
A development plan was proposed, pursuing the final objective to book incremental oil and gas reserves from high CO_2 content reservoirs. Finally, this pilot aims to encourage the quantification of all producible hydrocarbon volume, which have not been accounted yet due to facilities restrictions.
The following premises were used as guidelines to propose a reasonable development campaign with the current rig availability, accounting all 14 drilled wells; economics will finally define the resources/reserves category of the in-place hydrocarbon volume.

- Test as many different reservoirs as possible, focusing on CO_2 data acquisition.
    - Start campaign with oil prognosis workovers, 6 identified in total. Assumption: associated CO_2-rich gas production is manageable
    - Continue campaign with gas workovers on the remaining 8 wells
- Expected rig availability: 2 Workover rigs, 1 Drilling rig; Two tie-in scenarios:
    - 1 workover job every 2 months
    - 1 workover job every 4 months
- Campaign start, May-2019
- Average workover activity (hence CAPEX) was established, having analyzed individual requirements for every well, supported by operations department.
    - CAPEX was divided into oil and gas workovers, since each of them has different activity
- According to available CO_2 data, an average of 50% CO_2 content was assumed in all gas rates, both for associated gas and free gas reservoirs
- CO_2 processing capacities
    - Associated block's battery
        - Currently 100.000 sm3/d gas
        - Additional 150.000 sm3/d gas processing capacity
        - No CO_2 limits
    - Power Plant
        - Current consumption 280.000 to 290.000 sm3/d gas at 50% CO_2
        - 20.000 to 30.000 sm3/d gas surplus flared
        - CO_2 range: 45 to 57%
    - New CO_2 treatment plant design conditions
        - Example input rates: 700.000 sm3/d gas at 6.5% CO_2; 400 ksm3gpd at 30% CO_2. Other alternatives available
        - Output condition: < 2% CO_2
        - Assumed to be built during oil workovers execution, ready to be used for free gas workovers tie-in
- Operative costs and sales prices according to planning department assumptions
- Economic limit evaluation
    - Specified date at end of concession period (EOC)
    - Calculated date, assuming contract extension (EL)

In accordance with the mentioned premises, the following production scenarios are depicted in figures 13 and 14.

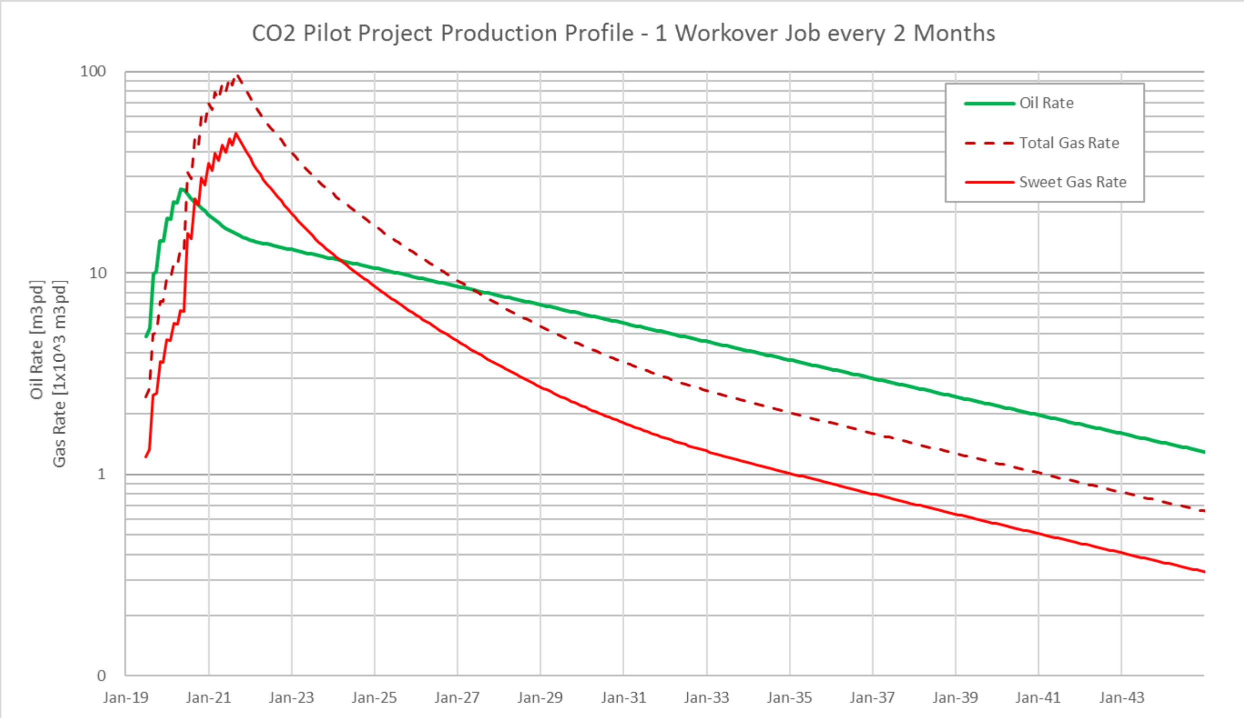

Fig. 13- Pilot's production profile, assuming activity scenario of 1 workover job every 2 months. Green profile stands for oil production, red profile stands for sweet gas production, dark red dotted profile stands for total gas rate.

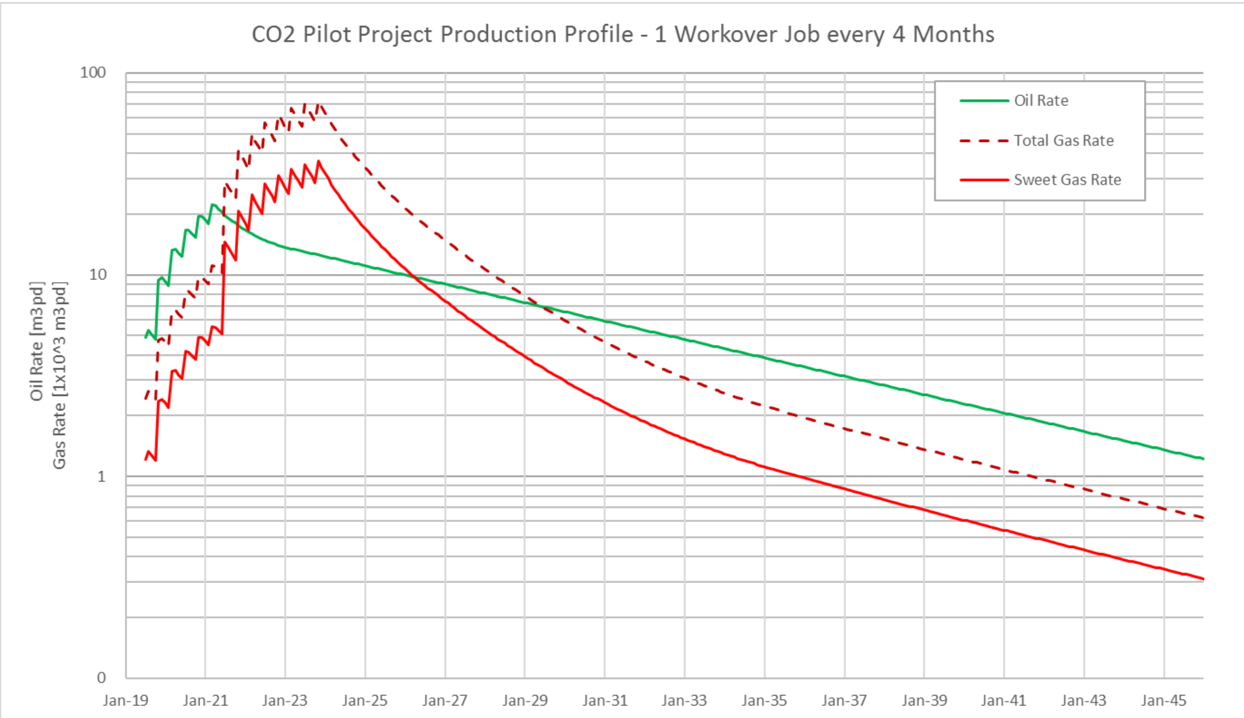

Fig. 14- Pilot's production profile, assuming activity scenario of 1 workover job every 4 months. Green profile stands for oil production, red profile stands for sweet gas production, dark red dotted profile stands for total gas rate.

Key parameters for each scenario are summarized in table 2.

Development Scenario - WO			Workover Schedule			
6 Oil WO Jobs, 8 Gas WO Jobs			1 job / 2 Months		1 job / 4 Months	
Economic Limit Date			EOC	EL	EOC	EL
Peak oil rate		[m3pd]	26,1	26,1	22,1	22,1
Peak sweet gas rate		[m3pd]	49.584	49.584	36.563	36.563
Peak total gas rate		[m3pd]	99.168	99.168	73.125	73.125
Reserves	Oil	[m3]	-	-	-	-
	Gas	[m3]	-	-	-	-
Resources	Oil	[m3]	34.023	53.102	32.910	53.102
	Gas	[m3]	71.160.118	72.944.077	68.413.389	72.915.760

Table 2- Development scenarios key parameters assuming only workover jobs: 6 oil workover jobs, 8 gas workover jobs. Calculated oil and gas volume at EOC and EL period.

According to the company's current internal economic parameters, the proposed development schedule is not economically attractive (Etherington and Ritter 2007). Moreover, these results don't represent the total block's potential; the project's added value involves the assessment of the full pilot area's potential. Therefore, drilling of future approved new-well locations were considered once the previously mentioned workover campaign should conclude. The following maps show the total net thickness of the mapped reservoirs with today's drilled wells on one hand (Fig. 15), and with the approved new-well locations on the other hand (Fig. 16). This may help to visualize the full potential of the pilot project.

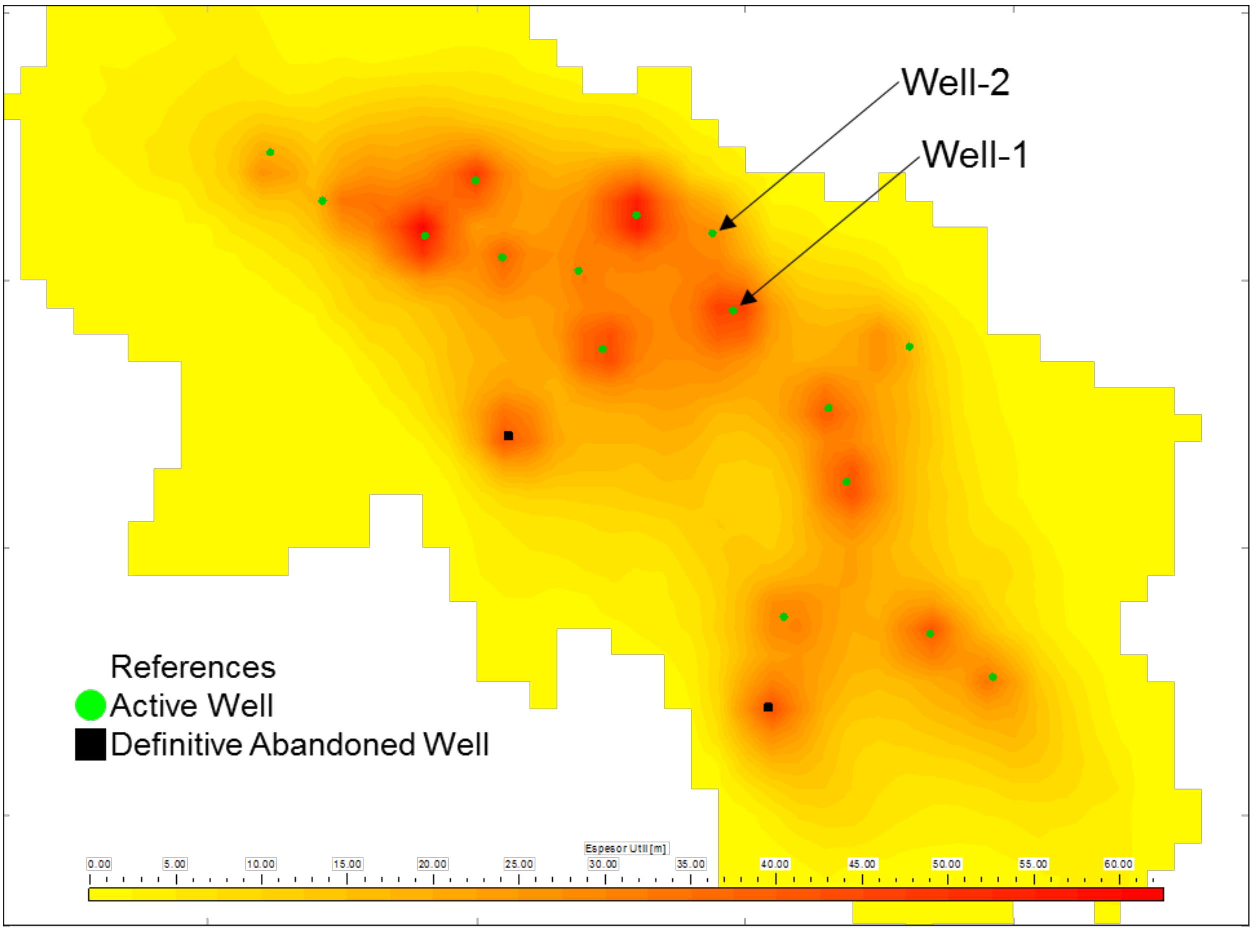

Fig. 15- Total Net Thickness map with drilled wells on pilot area. Green circles represent currently active wells, black squares represent definitive abandoned wells.

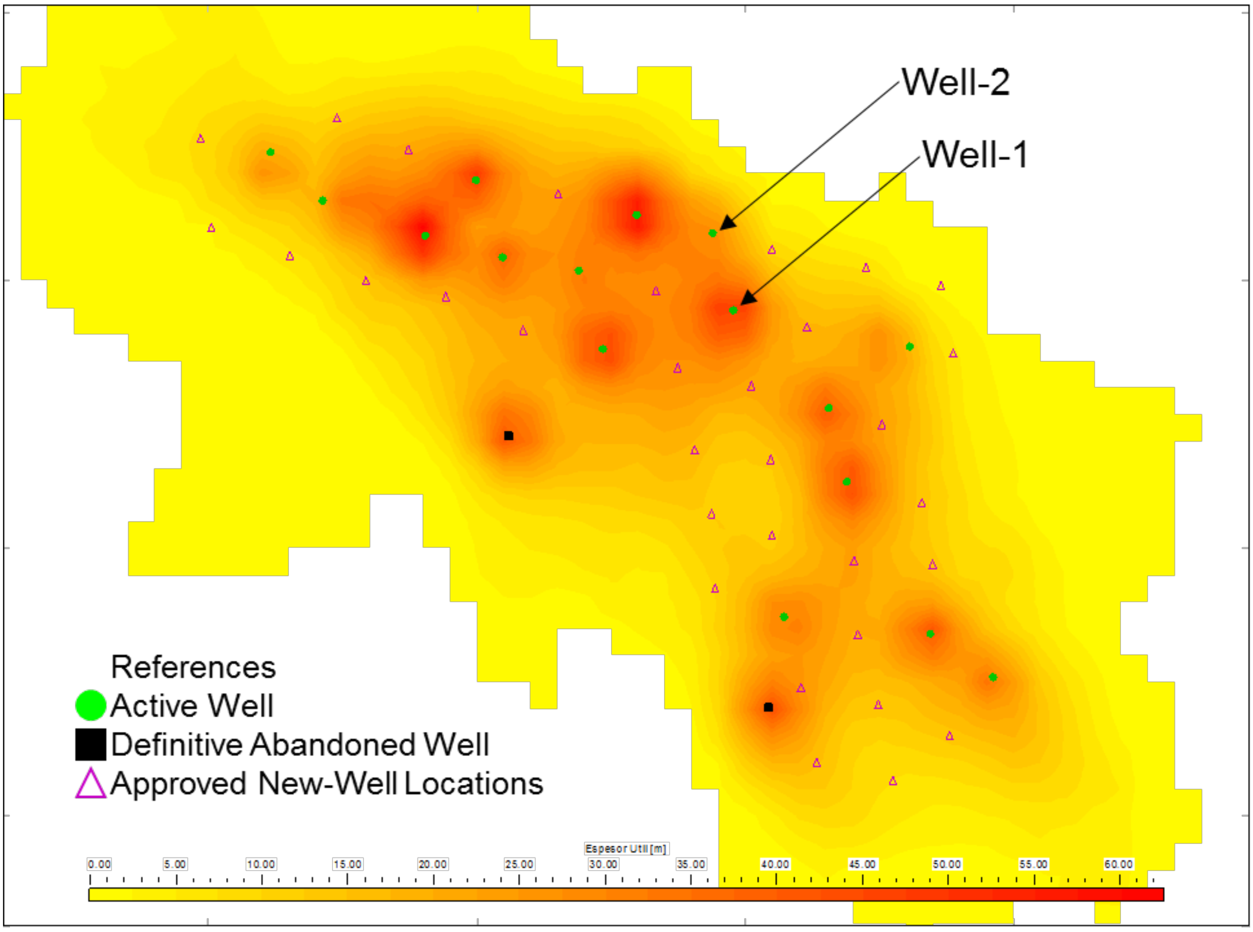

Fig. 16- Total Net Thickness map with drilled wells and approved new-well locations on pilot area. Green circles represent currently active wells, black squares represent definitive abandoned wells, purple triangles represent approved new-well locations.

Although all approved locations within the pilot zone target MDC reservoirs, it was assumed that shallow CO2-rich reservoirs were also put into production during completion. Therefore, only the associated incremental production of CS1 and CO member reservoirs were considered for economics, as well as its associated CAPEX. So, additional to the previously evaluated scenarios, assumptions for the approved new-well locations development are as follows:

- Production forecasts per well consider only CS1 and CO member reservoirs incremental production
- Out of 32 new-well locations
  - 10 oil prognosis wells
  - 10 gas prognosis wells
  - 12 wells considered with no potential
- Like the former scenarios, average workover activity (hence CAPEX) was established as an outcome of having analyzed net pay maps, potential fluid distribution and average activity of the drilled wells for CS1 and CO members.
  - Once more, CAPEX was divided into oil and gas workovers, since each of them has different associated activity
- Tie-in scenarios:
  - 1 workover job every 2 months. Once the schedule is concluded, 1 new-well every 4 months
  - 1 workover job every 4 months. Once the schedule is concluded, 1 new-well every 4 months

The production scenarios are depicted in figures 17 and 18 according to the mentioned premises.

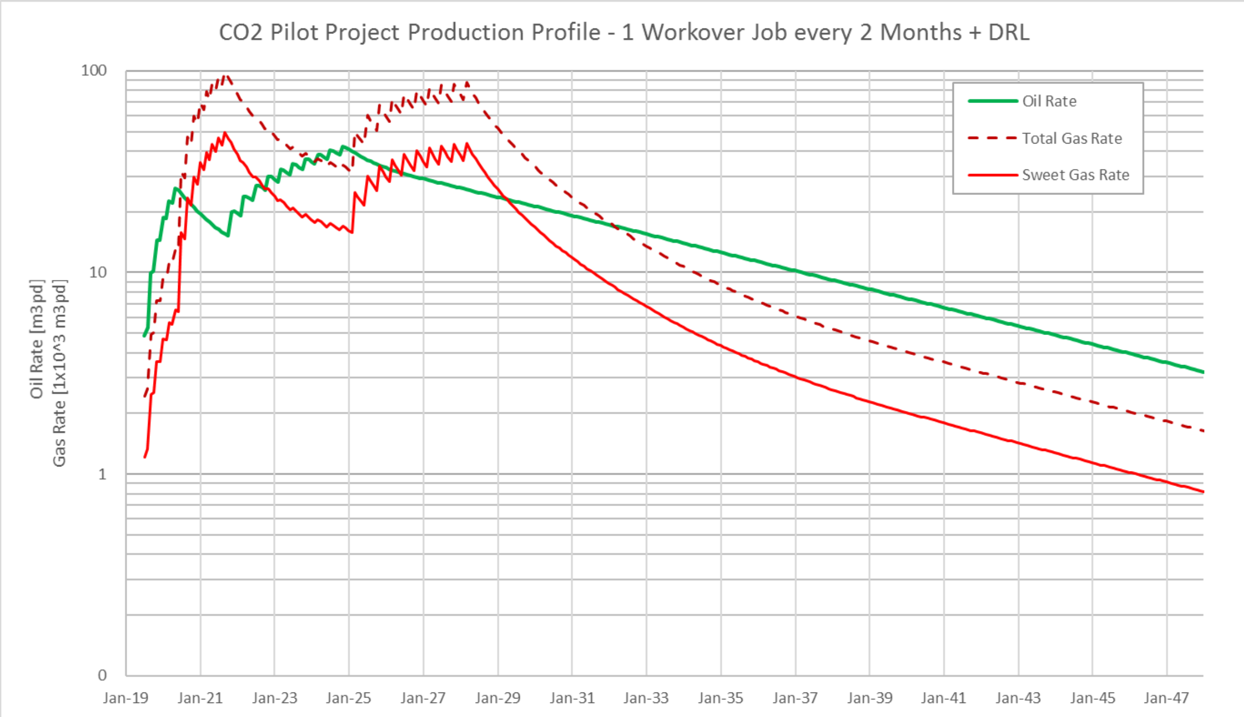

Fig. 17- Pilot's production profile, assuming activity scenario of 1 workover job every 2 months plus drilling activity. Green profile stands for oil production, red profile stands for sweet gas production, dark red dotted profile stands for total gas rate.

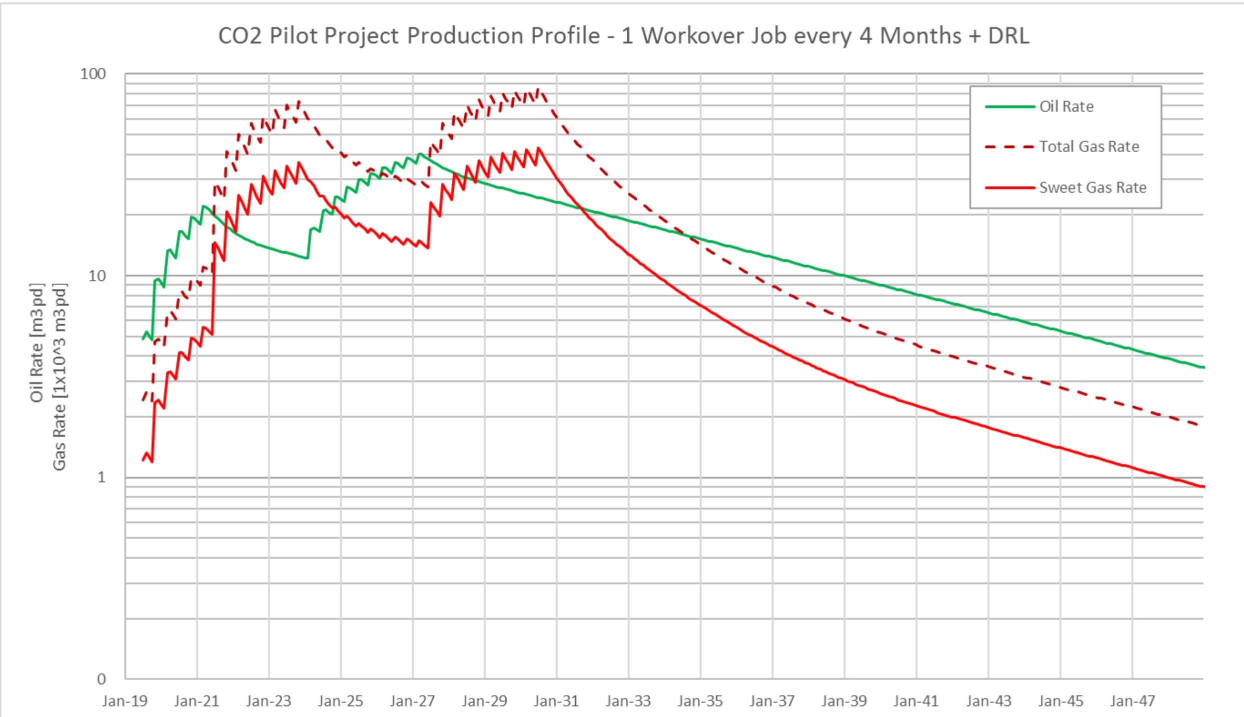

Fig. 18- Pilot's production profile, assuming activity scenario of 1 workover job every 4 months plus drilling activity. Green profile stands for oil production, red profile stands for sweet gas production, dark red dotted profile stands for total gas rate.

Key parameters for each scenario are summarized in table 3.

Development Scenario - WO + DRL 6 Oil WO Jobs, 8 Gas WO Jobs, 20 DRL Jobs				Workover Schedule			
				1 job / 2 Months		1 job / 4 Months	
Economic Limit Date				EOC	EL	EOC	EL
	Peak oil rate		[m3pd]	42,2	42,2	40,2	40,2
	Peak sweet gas rate		[m3pd]	49.584	49.584	36.563	43.021
	Peak total gas rate		[m3pd]	99.168	99.168	73.125	86.041
Reserves		Oil	[m3]	73.770	141.658	-	141.340
		Gas	[m3]	120.827.786	169.702.582	-	169.391.098
Resources		Oil	[m3]	-	-	57.076	-
		Gas	[m3]	-	-	77.899.517	-

Table 3- Development scenarios key parameters assuming workover jobs plus drilling activity: 6 oil workover jobs, 8 gas workover jobs, 20 drilling jobs. Calculated oil and gas volume at EOC and EL period.

Economic evaluations show a maximum of almost 1.900 MBOE reserves increase (141.658 m3 oil and 169.702.582 m3 gas), associated to the acquisition of a CO2 treating plant with the objective to develop hydrocarbon bearing reservoirs with high CO2 content. This is the best-case scenario, and it would require a contract extension for El Huemul concession to obtain higher profits associated to this pilot project. Furthermore, it is very important to consider that this pilot project is not limited to the studied area, but it is extensible to any other project within the company´s concession areas that may take advantage of the idle capacity of the CO2 treating plant.
In case the contract extension is not granted, the project is still economic if approved new-well locations are drilled. Moreover, 2P reserves volume has been booked for 2019 annual reserves process.
Apart from the economic evaluations, it is important to point out the consistency of the estimated In-Place Hydrocarbon Volume, according to the predominant production mechanism. Tables 4 and 5 show this information.

Recovery parameters for Workover development scenarios

Development Scenario - WO 6 Oil WO Jobs, 8 Gas WO Jobs			Workover Schedule			
			1 job / 2 Mos		1 job / 4 Mos	
Economic Limit Date			EOC	EL	EOC	EL
Recovery Factor [%]	Oil Bearing Reservoirs	Min	1,7	2,6	1,6	2,6
		Max	3,0	4,8	2,9	4,8
	Free Gas Bearing Reservoirs	Min	26,1	28,7	25,1	28,7
		Max	43,6	47,9	41,9	47,9

Table 4- Recovery factor range for development scenarios considering activity only in drilled wells.

Recovery parameters for Workover + Drilling development scenarios

Development Scenario - WO + DRL 6 Oil WO Jobs, 8 Gas WO Jobs, 20 DRL Jobs			Workover Schedule			
			1 job / 2 Mos		1 job / 4 Mos	
Economic Limit Date			EOC	EL	EOC	EL
Recovery Factor [%]	Oil Bearing Reservoirs	Min	3,6	7,0	2,8	7,0
		Max	6,6	12,7	5,1	12,7
	Free Gas Bearing Reservoirs	Min	44,4	66,7	28,6	66,7
		Max	74,0	111,2	47,7	111,2

Table 5- Recovery factor range for development scenarios considering activity in drilled wells plus drilling activity in new-well locations.

From table 5, it can be noted that maximum recovery factor is greater than 100% for free gas bearing reservoirs at Economic Limit evaluation period. Although this result is physically impossible to occur, it is important to know that this case was calculated upon the most conservative OGIP calculation:

- Swirr = 53,7% is the unlikeliest case given the completion & workover tests, added to the OHL information and fluid prognosis.
- Conservative rock volume: this case assumes the smallest rock volume.

Finally, this is the most conservative case of all, and, despite the results, it is still at a reasonable order of magnitude compared to the expected recovery factor for dry gas reservoirs.

Summary

1. *The analyzed group of wells constitutes a pilot project in El Huemul concession in which the real development potential was estimated for CO_2-rich oil and gas bearing reservoirs.*
2. *The study recognizes a maximum of almost 1.900 MBOE (141.658 m3 oil and 169.702.582 m3 gas) as 2P + 2C net reserves and resources for Economic Limit evaluation period, assuming El Huemul concession obtains a contract extension.*
3. *The study recognizes a minimum of 1.175 MBOE (73.770 m3 oil and 120.827.786 m3 gas) as 2P net reserves at End of Concession period.*
4. *Based on current economic internal parameter requirements, estimated volume in bullet #3 has been booked as 2P reserves for 2019 annual reserves processes.*
5. *According to the areal distribution of CO_2-rich oil and gas tests (Fig. 2), there is high potential to add several new blocks throughout El Huemul field.*
6. *Besides current EOC date, additional blocks are being evaluated to capture all resources in the area.*
7. *Once all hydrocarbon volume has been evaluated, an integral project must be faced to optimize human resources and maximize productivity.*

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