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# UNCONVENTIONAL EOR

## Lab Tests, Design and Modeling of a Black Oil Cyclic Gas Injection Process in Vaca Muerta

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**Palabras claves**

EOR, Unconventional, Compositional Simulation, Shale Oil, Vaca Muerta

**Abstract**

In unconventionals, and more specifically, in shale plays, oil recovery relies almost exclusively on “primary” recovery with practically no account for enhanced recovery (known as EOR, Enhanced Oil Recovery). However, in the last 5 to 8 years, some operators of unconventional assets have reported substantial increase in production with incremental recoveries multiples that covers a wide range, from 1.2X to 2X, using cyclic (huff n puff) miscible gas and/or solvents injection.

As tight oil unconventional wells tend to have a rapid primary maturation (steep decline curves) the early design and piloting of any selected EOR technique becomes of paramount importance for capturing the full cycle asset’s value.

Our work explores the feasibility of applying these techniques in the Vaca Muerta shale play to assess the optimal operational parameters for its specific rock and fluids characteristics. There are no public records of this technique being applied in Vaca Muerta yet, so our work focuses on both, lab tests and numerical simulation models that have been developed to quantify the impact of the most important drivers, determine the ranges of optimal operational parameters and estimate a range of incremental oil.

The numerical model is quite simple in its grid configuration (1/4 stage symmetry element ) but complex on the formulation as to handle all the most impactful phenomena such as (i) compositional changes to both, the produced fluid and the injectant, (ii) dual porosity-dual permeability grids to account for the differential effects in both matrix and fractures, (iii) hydraulic fracture and secondary fracture systems permeability changes with distance from the fracs, (iv) geomechanical effects and mechanical hysteresis (HnP will inflate and deflate and this effect most likely will not be fully reversible), (v) Matrix-Frac interaction (sigma) to model the intensity of the transport and diffusion phenomena and its evolution throughout the process.

Results show that depending on the well size and primary depletion degree, for a typical black oil in the VM main target zone, there is a “fillup” period of approx. 2-3 months until a reasonable working pressure of approx. 400 Kg/cm2 (5,000 psi) marks the start of the puff. The optimization of operational parameters to maximize economic value (being the injection costs the main one) shows a tendency to have shorter huff periods, no soaking needed and producing (Puff) BHP’s above bubble pressure. Under these operational parameter’s ranges, the process shows a very interesting incremental production (from 50 to 70% incremental), which is also in line with the ones informed in technical literature by US Operators and researchers.

## Introduction

Despite some significant advances in exploration, characterization, and exploitation of unconventional resources identified as Shales, final recovery is almost solely based on primary production (depletion) with relatively few documented experiments to include improved recovery processes as a complementary process (Sorensen, 2020). This type of exploitation has a characteristic production profile which could be divided in three characteristic periods, (i) high initial rate, (ii) steep decline and (iii) a "tail" of low rate and low decline (usually, with the installation of some sort of artificial lift). The duration of such periods will depend on the characteristics of the resource (quality, pressures, etc.) and the effectiveness of the stimulation treatment (hydraulic fracturing). However, we could roughly estimate the duration periods by the analysis of the normalized rate (normalized by lateral length) over time, in many legacy wells both in the Vaca Muerta Shale Play and some of the US Shale Plays.

**Fig 1**. shows an overlay of the normalized % of the maximum oil rate, for the largest development projects in Vaca Muerta basin (dots, triangles and green continuous lines) for different drilling campaigns and a green dotted line which represents the same data for the Permian basin in the US. It can be clearly seen how there is a "Pareto" behavior in which during the first 2-3 years, the rate drops to less than 20%, incorporating fewer additional resources in the following years.

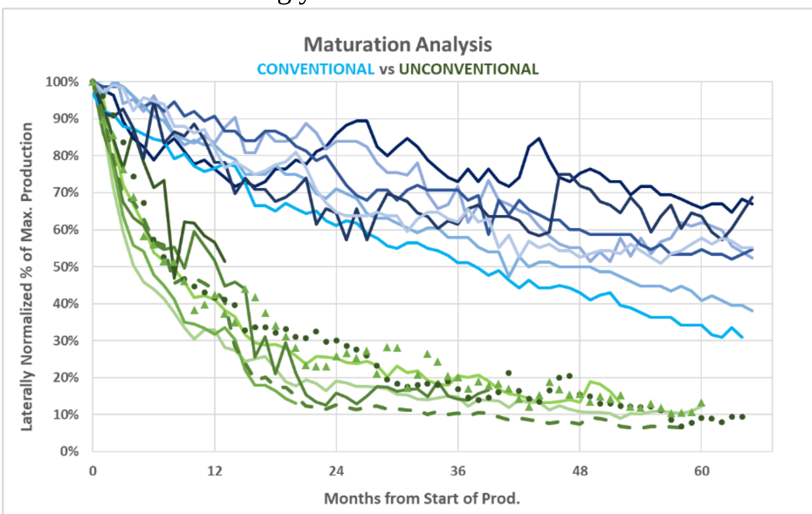



*Fig.-1 – Maturation Analysis – Unconventional main fields in Vaca Muerta (green colors) vs Conventional assets in Neuquen basin (blue colors)*

The blue lines are some of the largest conventional fields in the Neuquen basin. It can be clearly seen that these show a different pattern, one with a softer decline (the chart cannot be used to make any judgement whether there is a better or worse way of depleting conventional or unconventional reservoirs, only pinpoints the fast maturation of unconventionals). Despite the fact that these wells might achieve commerciality in relatively short times (14 to 20 months according to local operators, Sagasti, AOG, 2022), if we consider its mechanical condition, we can conclude that these fields "mature very fast" while they are "still in good mechanical shape". Taking into account that the recovery factor of these low perm formations is typically low (in the order of 2 to 10%, Hoffman 2012) and mainly by primary energy, it seems an obvious step to at least consider methods to increase recovery by means of an Enhanced Oil Recovery (EOR) technique.

Many pilot tests and even some mid-sized projects are reported in the literature (Bodini 2018, Balasubramanian 2018, Jacobs 2020) involving the injection of water, chemical enhanced water/gas injection, natural gas liquids (NGL), rich/lean gas and CO2. However, the most commonly reported and mentioned in the literature is the gas "Huff n Puff" one in which the same well alternates injection and production and more rarely, the "direct" method (one well injects while the other one produces).

The workflow is the following:

(i) Revision of Technical Literature and Shale IOR proprietary CGEOR US Results Report (2020)

(ii) Lab Experiment & Matching of an Equation of State (EOS) for a Black Oil type of reservoir fluid.

(iii) Numerical Modeling:

- Primary Numerical Modeling (History Matching of Fracture and Primary Depletion Stage)
- Feasibility Analysis of a Gas Huff n Puff process (single well)
    - Main Drivers & Sensitivities
    - Operational Parameters Optimization.

(iv) Estimation of Potential Ranges of Incremental Oil under CGEOR

**Discussion, could Vaca Muerta be a Suitable Candidate for Cyclic Gas Injection?**

The Vaca Muerta shale play, located in the Neuquen basin in Argentina, is a prolific marine source rock of type-II kerogen deposited as part of a highly prograding depositional system from the late Jurassic to the early Cretaceous period (Pose et al. 2014; Belobraydic et al. 2017; Licitra et al. 2015). Thicknesses range from 25 m in the proximal areas up to 450 m in the basin center. Due to its burial depth and migration, it has a grading fluid quality from Dry Gas to Black Oil similar to what happens in some US shale plays (i.e. Eagleford, **Fig 2**).

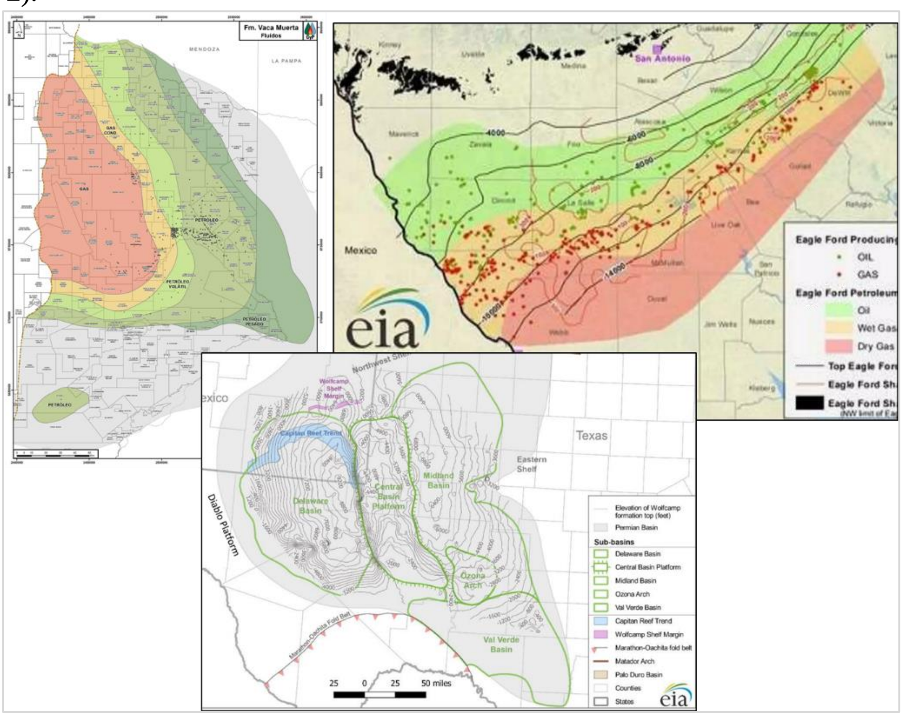



*Fig.-2 – Comparison to scale, of the Vaca Muerta shale play with the two most prolific plays in the US (Eagleford and Permian)*

**i. Revision of Technical Literature and Shale IOR proprietary CGEOR US Results Report Revision (2020)**

There are many technical papers partially covering some of the main gas injection EOR projects across the US unconventional basins but many of them have big information gaps, as only public data can be accessed which is always scarce. However, some insightful conclusions were driven by the review of such publications, being the main one that the process appears to have promising results, and that during the last 5 years, there was an upsurge in the number of projects that were being implemented (Jacobs T., 2020).

US based company SHALE IOR LLC managed to analyze the full spectrum of ongoing EOR project in the US main basins (Bakken, Eagleford and Permian) using public and proprietary information combined with air and drone surveys. Their comprehensive report (Grinestaff, 2019) includes the review of more than 50 pilots or development gas EOR projects in the three basins. From these partial results surveys, we were not only able to better understand the main drivers and processes as to improve our modeling workflows, to gain insight of the potential benefits and main operational issues associated with this methodology and to evaluate its applicability to Vaca Muerta.

### ii. Lab Experiment & Matching of an EOS

Main mechanisms of the CGEOR process is the extraction of volatile components, followed by oil swelling, reduction in viscosity, gas diffusion, reduction of interfacial tension, etc. (Thomas B., 2019) the first step to evaluate if Vaca Muerta´s fluids are a potential candidate for this type of EOR method, is to characterize its PVT properties, construct and match an EOS (Equation of State) and explore gas injection behavior at different pressures to obtain miscibility to foster enhanced recovery.

As the authors of many relevant papers regarding this subject express, there are two types of what is called in general the “miscibility pressure” of a mix of oil and gas in petroleum systems, First Contact Miscibility (FCM), which is the “traditional” definition and Multi-Contact (MCM), which takes into account the dynamics of the displacement process of a reservoir fluid by an injection gas, partially mixing with local composition variations, component exchange controlled by phase equilibria (K-values) and different compositions flowing at different velocities in the porous medium (Whitson C., 2019). Because the Huff and Puff (HnP) process is not a displacement process, the knowledge and metrics developed for such conventional displacement experiments are less relevant.

Shale-type scenarios have some characteristics that are very difficult to reproduce in a representative way on a laboratory scale. However, lab measurements are useful as they sometimes allow to better isolate effects in order to gain insight on how one specific phenomenon impacts the system behavior, using real field´s fluid and rocks.

Some conditioning lab limitations are that:

- It is not possible to “clean” the rock from its native fluids and homogeneously re-saturate it with a new fluid, as the "cleaning" process includes the adsorbed/dispersed components in the kerogen whose elimination by washing is done in a totally different way than that of "production" by depletion. Additionally, the re-saturation process with a "conditioned" fluid would find traces of the original fluid, giving rise to an inhomogeneous distribution of components.
- Liquid-Vapor “equilibria” occur very fast (due to the large contact surface) but are usually incomplete due to the very low permeability of the rock. In other words, while a pseudo-equilibrium composition between the gas being injected and the contacted liquid is expected to be reached quickly, the subsequent diffusion, to homogenize the entire fluid, is expected to be slow.

Therefore, laboratory results, are more suitable when used in relative terms rather than in absolute terms, because the geometries and contact times are different from those of the reservoir and the results might not be scalable if the thermodynamic equilibria are not complete. Instead of the traditional “miscibility pressure”, the experiments were intended to reasonably estimate a “minimum injection pressure” to “maximize the extraction” of volatile components, at a given time.

**Lab Workflow**

The laboratory experiment was structured according to the following sequence:

1. Fragmentation of the material to a mesh of 2 to 4 mm in order to obtain sufficient uniform material, allowing comparative studies on the same sample quality, as working in conventional "plugs" would not guarantee that the fluids retained in different samples could be comparable (**Fig .3**)
2. Loading of the sample in the measurement cell and of the gas in the feeding bottle and heating of the system to the average reservoir temperature (while raising the pressure in the measurement cell to the test pressure).
3. Rest for one hour after reaching the working temperature and pressure.

4. Extraction of a gas aliquot from the measurement cell and collection in a Tedlar bag with an adequate content of Toluene, to retain the "heavy" components of the gas.
5. Additional rest for extraction of samples at 24 & 48 hrs of contact between the gas and the fragmented rock
6. Repetition of the entire sequence, starting from point 4, at two more “contact pressures”.

On the extracted gas samples, a chromatographic measurement was made, of the gas and liquid in equilibrium at room temperature, with mass quantification by adding internal standard (n-C10).


*Fig.-3 – Lab procedure to generate the crushed rock sample*

The crushed sample was systematically sieved to retain the fragments between the 2 mm and 4 mm ASTM meshes. The material was stored in a glass jar with an airtight lid and kept in a refrigerator to minimize possible additional losses of water or hydrocarbons due to evaporation. With the collected material, three samples of approximately 150 grams were prepared, which were used in the three loops.
With the remaining material, the quantity and composition of the retained hydrocarbons was obtained by additional grinding in a closed tube and extract by contact with Dichloromethane.

**Lab Results**
The compositional results of this first sequence of measurements are shown as molar fraction in **Fig. 4**.

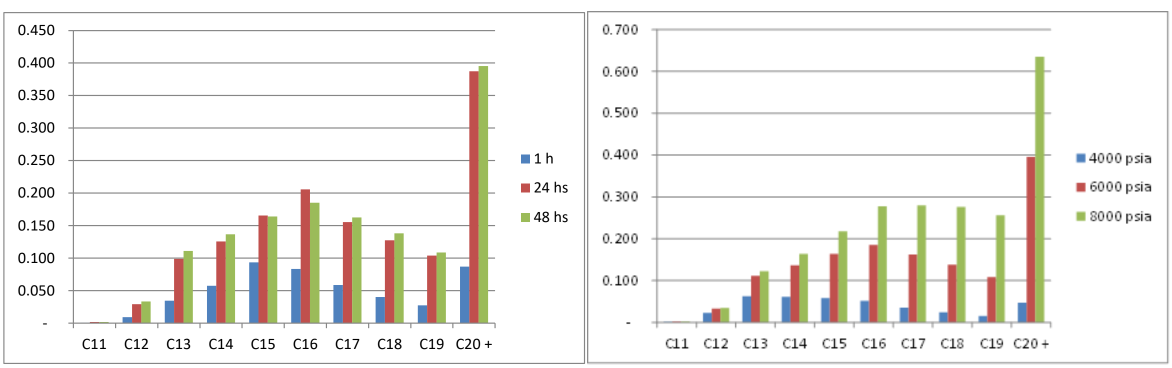



*Fig. 4 – Left: Sensitivity to Contact Time@6000 psia- Right: Sensitivity to Pressure@Contact Time 24h*

Despite an important change in the extraction of components between 1 and 24 hours, no significant changes are seen in the following 24 hours, so it can be concluded that the Liquid-Vapor equilibrium between the liquid dispersed in the rock and the gas injected into the cell, proceeds relatively quickly despite the fact that the system remained static throughout the whole period.
The second round was done using a lower pressure (4,000 psia) and, although the amount of "heavy" components extracted in the gas, was markedly lower than the one obtained at 6,000 psia, the tendency to reach vapor-liquid equilibrium in the first 24 hours was maintained.

Consequently, the third study was made at 8,000 psia and shorter times, with samples taken at 1 h, 6 h and 24 h. A greater amount of "heavy" components were extracted and, the times of liquid-vapor equilibrium would be located close to 24 hours, as the two initial studies suggest.
The amount of extracted mass continued to increase with increasing contacting pressure, leading to the expected conclusion that the higher the working pressure, the more effective the mechanism of oil extraction by volatilization of intermediate components during the EOR process by gas injection.
Note: This analysis did not contemplate the real composition of the reservoir fluid (only components with more than 11 carbon atoms are preserved). Thus, for the simulation, Liquid-Vapor equilibria were calculated taking into account the "complete" live oil composition.

### iii. Numerical Modeling

During the last decade, a plethora of different methodologies and techniques have been proposed to model unconventional shale oil performance and optimize completion treatments, from simple analytical "RTA" (Rate Transient Analysis), to complex numerical multi well, multi-million cell integrated coupled geomechanical & flow models. As it always happens in modeling complex systems, there is a "trade-off" between including all geological complex features & relevant physical phenomena and delivering results in reasonable times typically with limited resources.
For this work, a "hybrid model" was used that contains both, explicit fracture planes coupled with a dual porosity, dual permeability grid in a compositional numerical simulator. A symmetry element (1/4 of a stage and 10,000 grid cells) is assumed to be a representative "building block" of a multi-fractured horizontal well, while allocating most of the modeling effort to properly include the main phenomena needed to represent the complex fluid interaction with matrix and natural and hydraulic fracture networks. The grid includes the needed frac clusters represented as explicit frac planes and a logarithmically spaced 3D grid with varying properties away from fracs, the possibility of varying the cluster efficiency and spacing and varying both the enhanced frac region (Xi) and frac half length (Xf) (**Fig.5**). Each region (matrix and fracs) has independent geomechanical modification tables for both, pore volumes (inflating & deflating) and permeability (enhancement while fracturing or injecting and degrading while depleting).

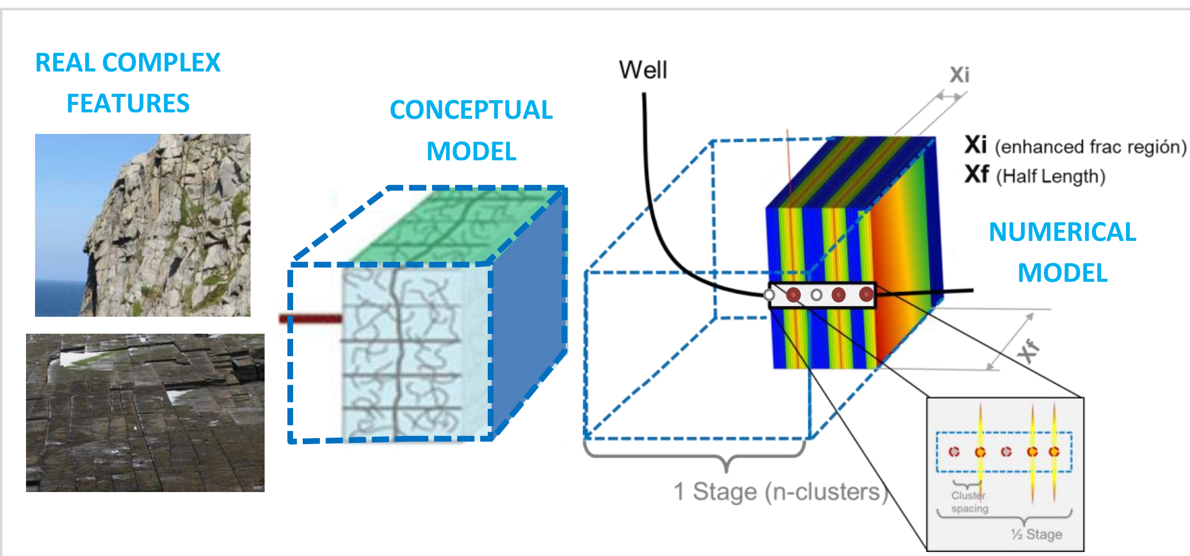



*Fig.-5 – Representation of the real, conceptual and numerical models to simulate the CGEOR process*

The main phenomena captured in the model accounts for:

- Initial hydraulic stimulation: As water is injected, included capillary effects foster imbibition that permits to model early oil production (hysteresis in saturation functions are needed to model such phenomena). In addition, variation in Pore Volumes and Permeability of both the hydraulic fractures and revitalization of natural fractures is included via geomechanical properties vs pressure (**Fig 6**) and a range of the SIGMA parameter (natural fractures coupling factor, which is a sort of “area/volume” ratio, important for both, primary behavior and EOR if applied).

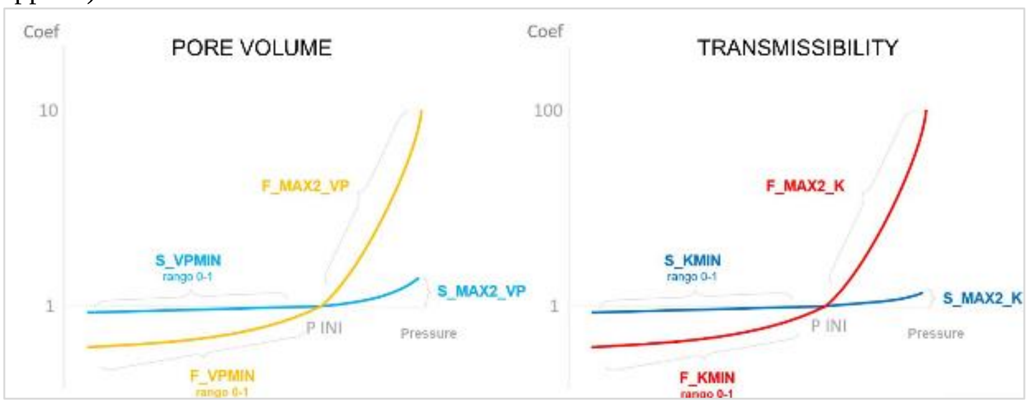



*Fig.-6 – Geomechanical functions used to model the fracture flow and transport properties*

- Using statistical data from one of the HFTS in the Eagleford (Raterman K., et al 2018), a reasonable range of SIGMA was assumed and then used as a history matching parameter within those bounds (**Fig 7**, shows the rationale behind the ranges effectively used for matching in both geomech parameters such as Pressure Dependent Permeability (PDP), Pressure Dependent Pore Volume (PDPV) (top) and SIGMA and frac aperture, (bottom).

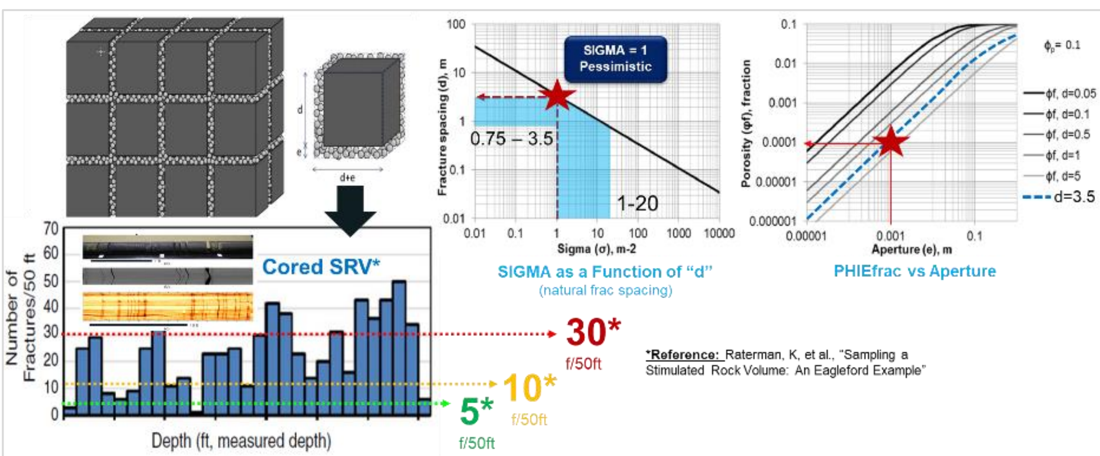



*Fig.-7 – Workflow and sources of data, to populate the frac model (SIGMA) and frac porosity*

- Primary production: These “enhanced” geomechanical & flow properties gradually revert following a descendent path through the mechanical set of curves with hysteresis (See following bullet).
- Cyclic Gas Injection: On one hand, as we expect the need to model complex fluid interactions when injecting a potentially miscible fluid, the model needs to be run in compositional mode. On the other hand, and most importantly, the aforementioned geomechanical properties need to be modeled using mechanical hysteresis due to the subsequent injection or production cycles which will “inflate” or “deflate” the SRV over time (this process could be modeled as completely irreversible, being the worst case scenario for gas injection, fully reversible or with hysteresis, using different envelope

curves that could be modified (**Fig 8**). For the EOR simulation scenarios, sensitivities were included for evaluating the full range of possible outcomes.

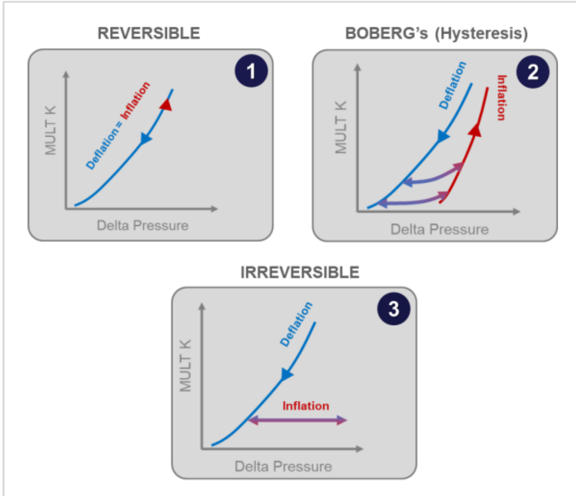



*Fig.-8 – Mechanical Hysteresis modeling possibilities (the selected model was No.2, with hysteresis)*

- **Primary Depletion Modeling & History Match**

An isolated (not a pad) multistage horizontal well located in the black oil window fluid area of Vaca Muerta, was selected as a representative potential candidate for evaluating a CGEOR process. The 5,500 ft of lateral length was fractured using natural sand and slick water and naturally flowed for approximately 1.5 years. The treatment, was a HDF (high density fracture) one with tight cluster spacing, 40 bbl/ft of fluid intensity and 2,000 lbs/ft of proppant intensity. The production history of Oil, Water and BHP shows the typical Vaca Muerta behavior having an initially high oil peak, followed by a steep decline.

An initial matching was attempted using numerical RTA analysis to have a "ballpark" number on some of the critical fracture dimension parameters such as Xi, Xf, Cluster Efficiency, Matrix and Fracture perms, geomechanical behavior and build the ranges for the numerical model Assisted History Match (AHA).

The main parameters coming out of the RTA analysis were the following (**Fig 9**):

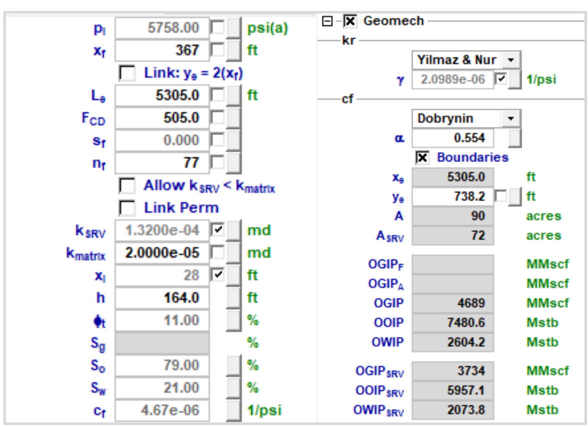



*Fig.-9 – RTA Base Case matching parameters (used as seed in the first approach of the numerical model)*

The multiphase numerical RTA matching was somewhat straight forward and the results were reasonable for that landing zone and area in Vaca Muerta (Xf in the order of 350 ft, tight enhanced region Xi of a few feet approx. 30 ft, matrix and SRV perms in the range of 200 and more than 1,000 nD respectively, porosities in the 10% range, low initial Sw of approx. 20% and typical "jail-like" matrix rel perms suitable for these tight formations (Esmail, E., 2020).

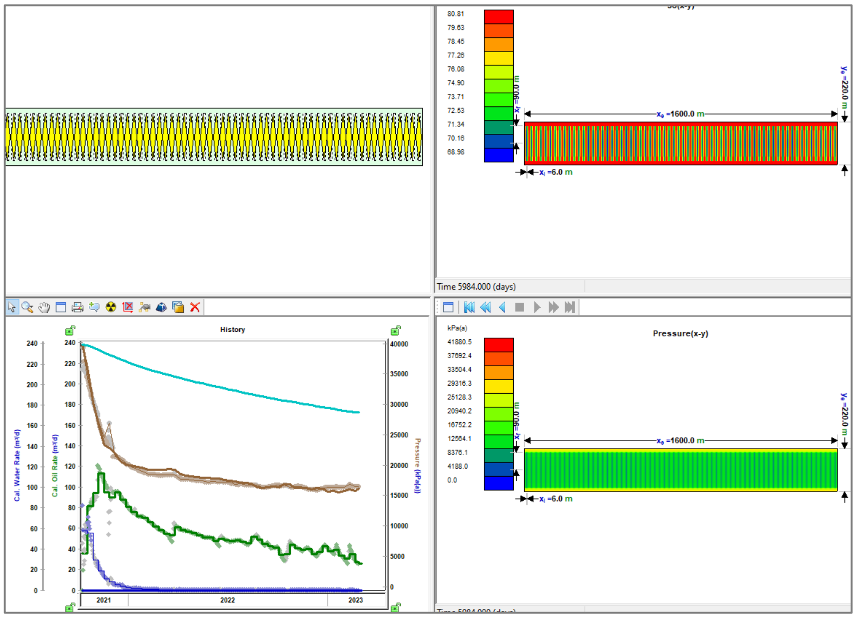



*Fig.-10 – Numerical Multiphase RTA history matching results*

Such values were input in our numerical model and the production history was divided by 88 due to the ¼ stage approach (the conversion factor to go from the "full well" to the ¼ stage in this case is 88, made by Stage Count x 4 = 42stages x 4 = 88).

When using these derived RTA resulting parameters as inputs for the 3D compositional numerical simulator model, the history match (let's call it "First Pass") was of course not exactly the same as the RTA one. This behavior is expected as the RTA model and the 3D numerical one, treat differently several physical phenomena such as capillary pressures & saturation hysteresis, dual poro dual perm, spatially detailed gridding and does not consider the water injected during the hydraulic fracturing process. This "First Pass" run, had its cumulative fluids close to achieving a good match, but had less water than historically produced, peak oil rates were exaggerated and the BHP was higher than the historic one (WHP converted) **Fig 11** shows the First Pass numerical model matching results.

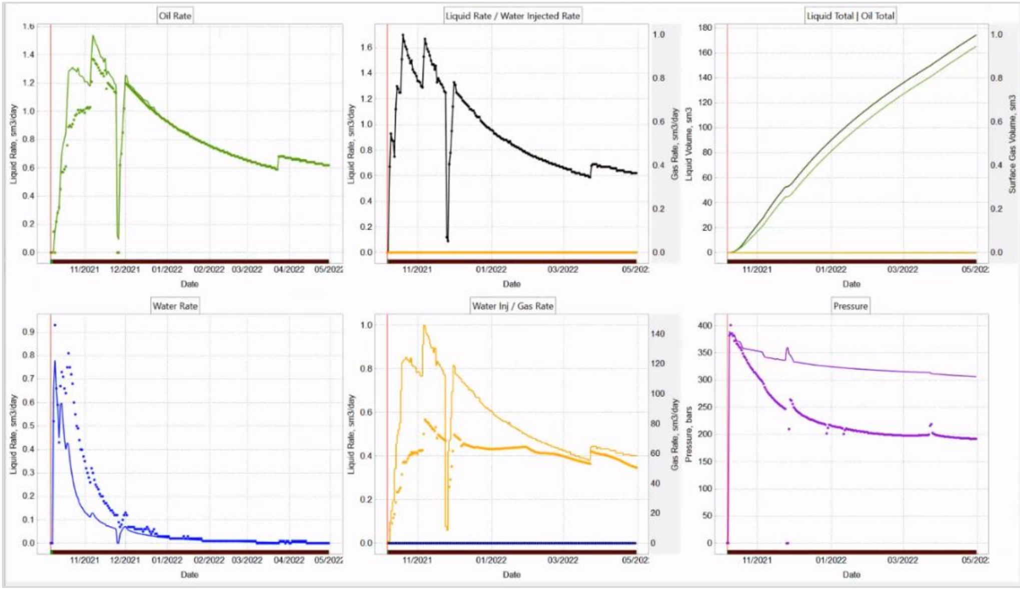



*Fig.-11 – Production History and Bottomhole pressures for the ¼ stage symmetry element of the selected Vaca Muerta well*

To history match our numerical model, we kept almost unaltered the main parameters used in the RTA analysis that were associated with reservoir characteristics such as thickness, Porosity, initial total compressibility, water saturation, matrix permeability and rel perms. We then selected a pool of the most uncertain parameters with high impact, such as fracture grid permeability, fracture half length, geomechanical behavior and SIGMA to be used as matching parameters.
The selected algorithm for sampling was Particle Swarm Optimization and the Objective Function adopted was one that considered oil and water rates and BHPs, with equal weights during the whole production history. **Fig 12** shows a selection of 30 out of 500 runs that minimize the Objective Function (OF) (i.e. best match).

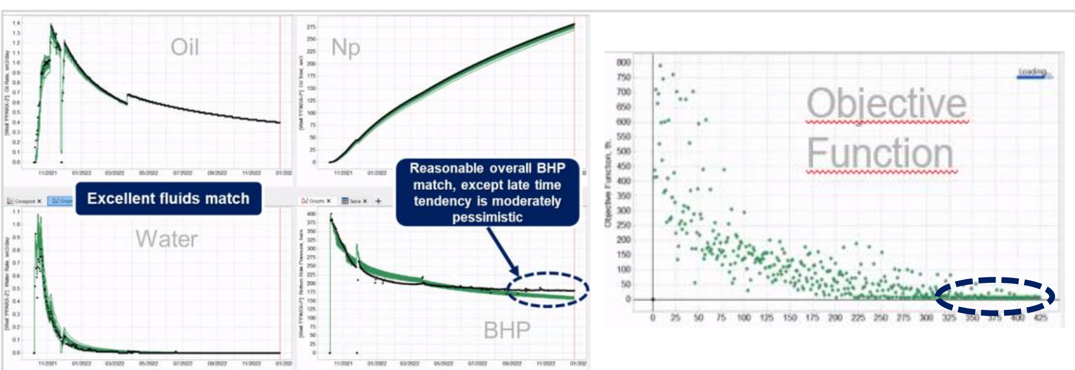



*Fig.-12 – 1st Loop matching results (Left: 30 best OF runs) – (Right: Objective Function convergence chart vs number of runs)*

The second loop (HM#2), aimed at getting a better BHP match in the late time portion of the data, supposedly more influenced by matrix (volumetric) parameters. Thus, we constructed the ensemble using the best MH#1 run parameters as seeds and including two new parameters, Matrix perm and Porosity, varying between 100 to 800 nD and 6 to 11 % respectively. **Fig 13** shows HM#2 results in purple, while keeping the HM#1 ones in green for comparison purposes. Fluids are similarly matched as HM#1 (so we replaced the bottom-left water chart of **Fig 12** by the Objective Function one for better visuals).

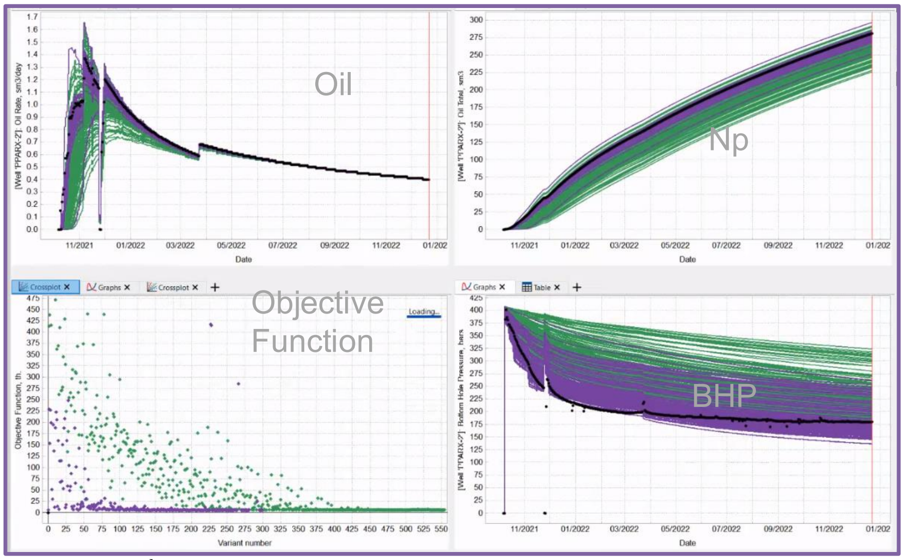



*Fig.-13 – 2nd Loop Numerical matching results (purple) with HM#1 in green*

The third loop (HM#3) of 400 runs, was constructed using a combination of the best match parameters of HM#2 as seeds, including new uncertain completion parameters such as cluster efficiency (hoy many clusters actually created a fracture swarm or not) and location (position in the ¼ stage element, see **Fig 5**), Xi (Enhanced frac region, which stands for how far from the cluster frac there is stimulated matrix) and SIGMA. The matching algorithm was changed from PSO to Differential Evolution to favor combination of parameters. **Fig 14** shows the full loop (in grey) and the pool of the best 40 runs highlighted in brown.

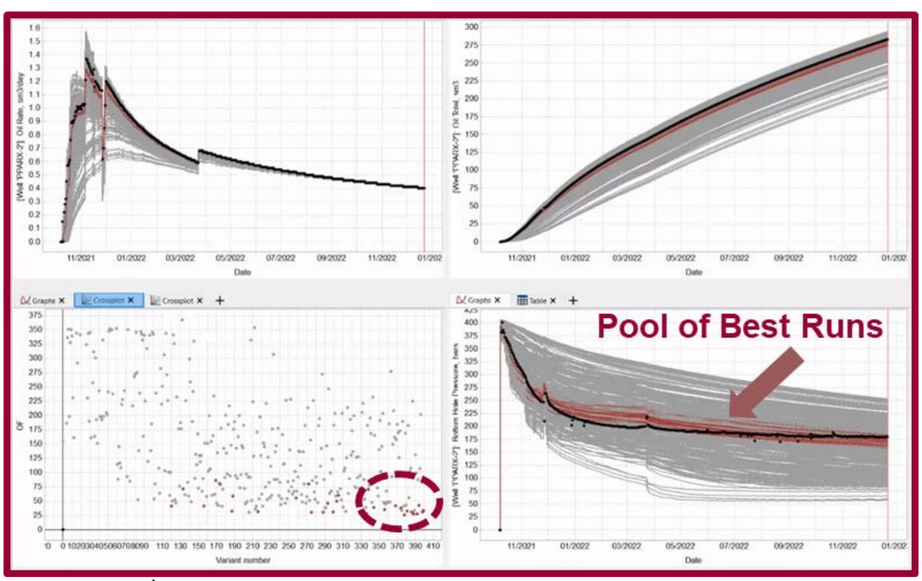



*Fig.-14 – 3rd Loop history matching results (brown) with non-selected in grey*

The final matched ensemble is a combination of the three loops, using different input parameters with high and low ranges, producing a series of equi-probable and similarly matched runs. This ensemble will be used to produce both, primary depletion forecasts to obtain an EUR range to compare recoveries with the Cyclic Gas EOR (CGEOR) scheme.

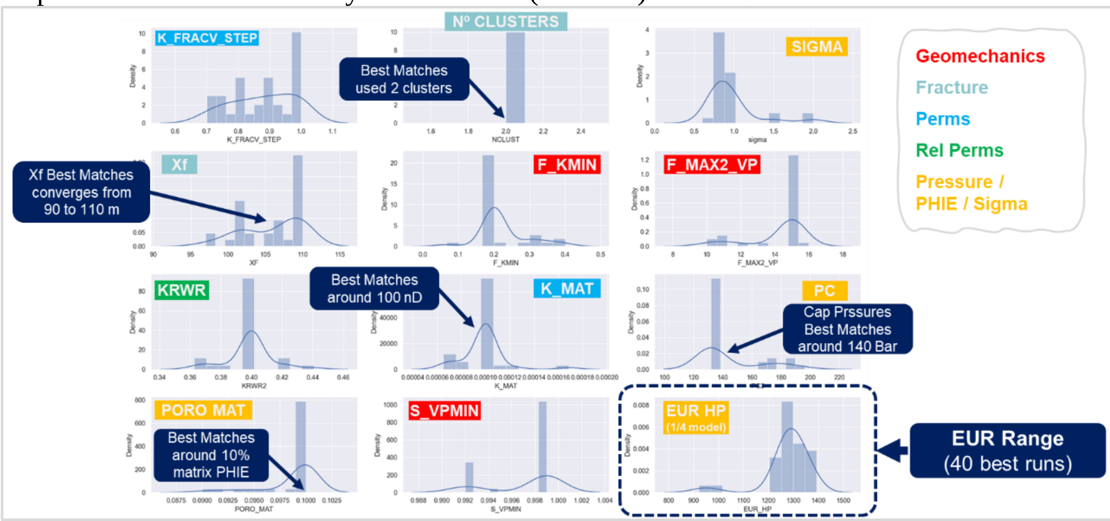
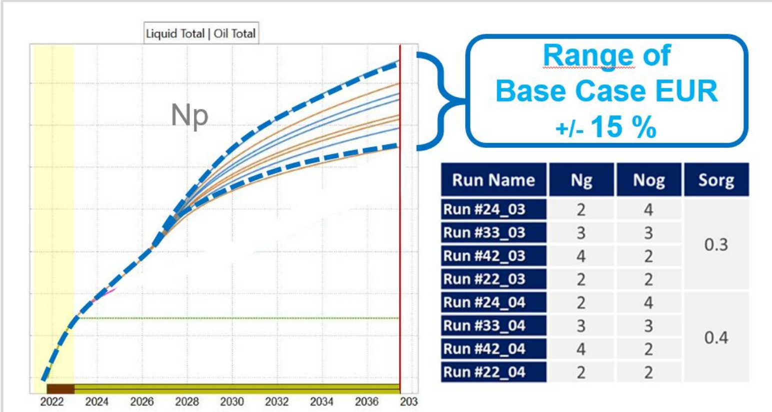



*Fig.-15 – 3rd Loop Numerical Multiphase RTA history matching results (brown) with non-selected in grey*

When exploring the input "matching" parameter distributions of **Fig 15**, (constructed with the successive values each matching parameter took for each one of the 500 runs of the HM#3 loop) we see that even though there are variations, those tend to be somewhat narrow (example: Xf range goes from 98 to 110 m). The cluster efficiency (how many clusters take fluid and proppant) clearly converges to 2 clusters only. In addition, the input probabilistic distributions do not show highly skewed shapes to one of the boundaries (left nor right) meaning that the initial input ranges were wide enough to find a good solution within those bounds. On the contrary, highly skewed distributions can be a symptom of choosing too narrow upper or lower bounds. In those cases, the algorithm finds a better matching tendency towards one of the limits, improving the Objective Function, and tries to "push" it further, concentrating the number of runs to that extreme only.

An additional consideration to forecast primary depletion must be accounted for, as the historical BHP data for the well, never goes below bubble pressure. This means there is no free gas saturation during our historical production period, thus, no impact of the Gas-Oil Relative Permeabilities nor Capillary Pressures could be evaluated. However, to forecast the primary EUR, the BHP typically does go below Bubble Pressure. Thus, to account for the impact on the BHP, taking an initial somewhat aggressive depletion profile followed by a constant BHP of 50 Bar (700 psi) trying to mimic the installation of an artificial lift system starting approximately mid-2027.
Similarly, Gas Oil Rel Perm which neither impacts the History Matching process, do have an impact on the Base Case Primary EUR estimation and will surely affect the CGEOR process evaluation. To account for this, we added a set of combinations of gas Rel Perms to cover reasonable ranges of the most impactful parameters such as Nog (Corey Oil-Gas Exponent), Ng (Corey Gas Exponent) and Sorg (Residual Oil by Gas Displacement). **Fig 16** contains the parameters of the 8 different combinations and, the well's forecast (15 yrs) with the range of primary EUR. It is important to note, that runs 24_04 (high/low gas/oil mobility plus higher irreducible oil, 40%) and 42_03 (low/high gas/oil mobility plus lower irreducible oil, 30%) make the Minimum and a Maximum recovery cases respectively.




| Run Name | Ng | Nog | Sorg |
|---|---|---|---|
| Run #24_03 | 2 | 4 | 0.3 |
| Run #33_03 | 3 | 3 | |
| Run #42_03 | 4 | 2 | |
| Run #22_03 | 2 | 2 | |
| Run #24_04 | 2 | 4 | 0.4 |
| Run #33_04 | 3 | 3 | |
| Run #42_04 | 4 | 2 | |
| Run #22_04 | 2 | 2 | |

*Fig.-16 – Primary Depletion Forecasts for a BHP scenario and 8 different Gas Rel Perm combinations*

The well's EUR@15yrs range goes from 95 to 130 k.m3 (600 to 800 th.bbls). For comparison purposes only, RTA forecast EUR under equivalent schedule and rel perms conditions, was equivalent to the higher values of the aforementioned range (meaning that for this example, the RTA is optimistic).

- **Feasibility Analysis of a Gas Huff n Puff process (single well)**

The following section is dedicated to analyze the potential of Cyclic Gas Injection EOR (CGEOR) in Vaca Muerta as a means to improve current final recoveries of shale oil wells. This methodology has been proved successful in some projects of US shale basins during the last decade, so this work aims to analyze if the rock, fluids and completions characteristics found in Vaca Muerta, make it a good candidate for CGEOR. To do this, we are using the aforementioned history matched calibrated model and testing different working hypothesis on a single multi-fractured horizontal shale oil well. Many authors agree on the fact that Huff-n-Puff EOR in unconventionals is not a displacement process, and that requires maximum mixing of the injection gas and reservoir oil near the wellbore (Whitson C., et al, 2020). Unconventionals might favor this mechanism in the sense they have a large available surface area exposed through a complex network of natural and hydraulically created fractures.

A high surface-area ration (high fracture complexity) will increase the mixing of the injected gas with the reservoir oil, swelling the resulting "lighter mix" and extracting heavier components. This might be the main mechanism of CGEOR increments (Hoffmann, T., 2019) followed by other important phenomena like Gravity Assisted Drainage (GAD) of the SRV, IFT and viscosity reduction, diffusion and re-pressurization.

Some will contribute more or less depending on the type of reservoir fluids, injectant composition, rock & completion characteristics and operational considerations involving rates, volumes, time and pressures of the injected gas. Therefore, it becomes of great importance to better understand those interactions in the Vaca Muerta environment of rock and fluids, as to come out with an operationally optimal design to propose an efficient Pilot Test to confirm/discard what works and what doesn't to eventually pursue a Multi-Well EOR full field development.

- **Modeling of the CGEOR Process**

To better understand the contribution of the main phenomena and operational parameters to the EOR process, we selected a representative run (with average input parameters) to explore the treatment sensitivity to:

1. **Operational Parameters (Schedule):** Fillup time/volume, Huff & Puff cycle times, Gas Injection Rates, Injection and/or Production Pressures, Soaking Time and number of cycles. **Fig**

**17** shows a schematic view of one cycle of the CGEOR process. After a certain production period, an injection one (being the first a “Fillup” period) followed by an optional shut-in (sometimes referred as “soaking”) and finished by a production period.

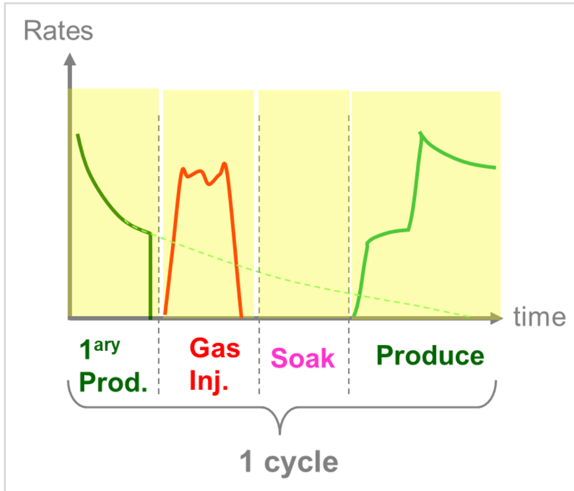



*Fig.-17 – Schematic stages (schedule) of a Cyclic Gas EOR process*

To evaluate the impact of the operational parameters, a Grid Search algorithm was used (with one representative run of the Primary HM ensemble) to explore the individual impact on each one. **Fig 18** shows the incremental CGEOR recoveries, for multiple combinations of cycle times, pressures and gas injection rates under similar production schedule profile (the last longer period corresponds to the “blowdown” of the well). The range of incremental EUR is quite sparse, showing a high impact of the operational design parameters.

| Parameter | Low Range | High Range | Unit | Algorithm |
|---|---|---|---|---|
| Fillup Time | 80 | 300 | days | |
| Huff Time | 20 | 120 | days | Grid Search |
| Puff Time | 20 | 120 | days | |
| $BHP_{puff}$ | 150 | 300 | bar | Latin Hypercube |
| Iny. Gas Rate | 25 | 110 | km3/d | |

50 runs

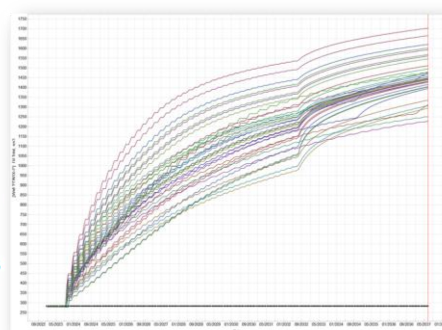


*Fig.-18 – Sensitivity Runs for Analyzing the Impact of Operational Parameters in CGEOR*

**Fig 19** show the individual impact of each main parameter regarding the EUR@15yrs. An almost obvious conclusion (that is also described in the available technical literature (Thomas, B., 2019) is that the most impactful parameter is the Gas Injection Rate. This is because the highest the rate, the highest the gas volume and pressure obtained for a certain time, facilitating the miscibility and enhancing the mixing/swelling mechanisms. However, achieving high rates (and pressures) is something that comes with a cost (compression) and also presents many technical and operational challenges limiting the improvement that can be achieved.

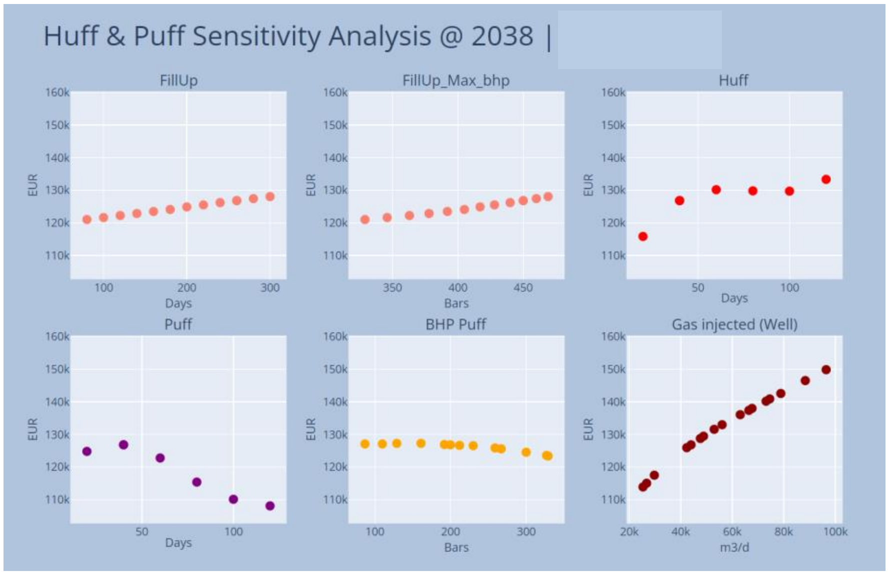



*Fig.-19 – CGEOR Sensitivity to Operational Parameters (Schedule) and its impact on EUR*

In addition, BHP Puff pressure seems to be indistinct for the selected range. The Huff period has a sort of plateau from 40 to 100 days while the Puff period seems to have an "optimum" value in shorter periods, approximately 30 to 40 days.

Note that the soaking time has been left out the analysis as it was detrimental to the recoveries. A separate experiment was considered with different soaking times (no soaking, 15d and 30 d, see **Fig 20**) supporting the conclusion that no soaking time is desired. This could be explained by the rapid thermodynamic equilibrium occurring in the vast and complex fracture network that provides a sufficient mixing area. Lab experiments also showed this, as after 24 hs of soaking, no significant composition changes were observed (**Fig. 4**). However, one must be careful to extrapolate such conclusion, as the Lab favors this, with higher surface area ratios (crushed rock).

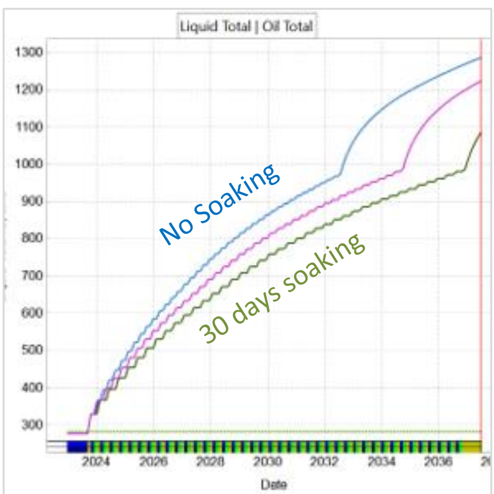



*Fig.-20 – Impact of Soaking Time on Oil Cumulative for the CGEOR process*

<u>Note about Cycles Length:</u> In this work, we have considered for simplicity, that all cycles are equal and the BHP limits while injecting vary with time. As the process evolves, the reservoir fluid is expected to change its composition (at least in the stimulated volume vicinity) thus, the Huff and

Puff periods might need to be adapted over time (different cycle lengths). If the reservoir fluid composition becomes “heavier” after each cycle, then, it is reasonable to expect that the cycles need to be progressively larger (we will have less intermediate components in the accessible volume, so we must inject more gas to a higher pressure to extract a similar amount of oil). This is one “operational” simplification we included in the model, but it is being addressed and could be included in future work as a sensitivity.

2. **Depletion (Time) Before EOR Starts:** Delaying the start of the CGEOR process will have an impact in many fronts. On one hand, if the primary depletion is high, a large gas volume/time will be needed to fill-up and build pressure. On the other hand, the SRV perm (fracture network connectivity) might be severely diminished, and, if the process tends to be an irreversible one, the lower the perm reached during depletion, the hardest to re-open those frac networks and access additional area in contact with the oil to foster mixing. **Fig 21**, shows the CGEOR incremental EUR for three cases, implying that the impact has a larger effect on delaying income than it has over final EUR (+/- 10%).

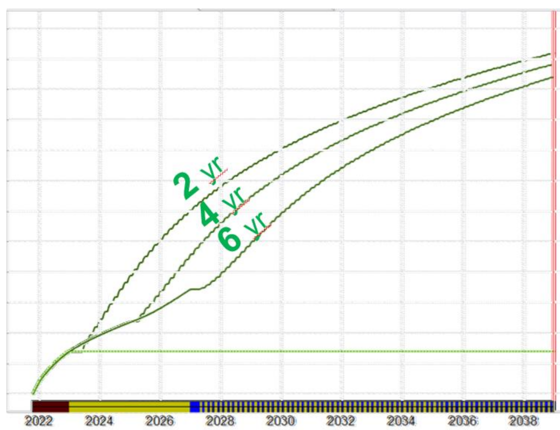



*Fig.-21 – Impact of delaying the CGEOR process*

3. **Injection Gas Composition:** Enrichment of the injection gas might have an important impact as it can influence the extraction/swelling process. Some authors have reported better incremental recoveries using enriched gas (REF enrichment) and some even have proposed liquid injection (propane) as an improved method over gas (Bustin A., 2022). To test the impact of enrichment, we tested two potential scenarios

   (i) Processed gas (for example, in a Dew Point Plant) having an approximate molar % of 88 methane and 10% of C2-C3 and

   (ii) Production gas coming out of the primary separation of a produced oil having approx. 65% methane and 25% of C3-C3.

**Fig. 22** shows the composition comparison on the left and the EUR@15yrs difference on the right. Note that the contribution of the enrichment to the production increment is as high as 40%. Despite the fact that we are injecting part of what is being produced, in terms of mass, the net “lighter” components that are injected and produced are almost even, but, they do induce a drastic improvement in the extraction of heavier fractions that provide the net increase of 40% in the oil stream.

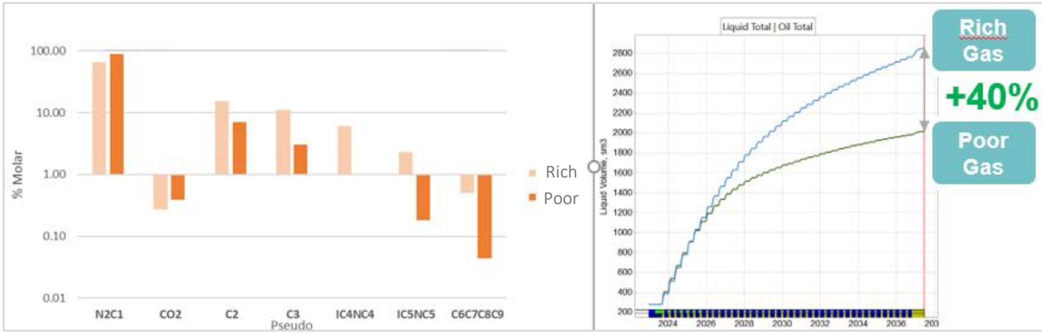



*Fig.-22 – Impact of gas enrichment on the CGEOR process*

4. **Mechanical Hysteresis:** As CGEOR is a cyclic process, the progressive geomechanical response (inflating and deflating) of the SRV to this stimulus will definitively have an impact on how much area is available for mixing after each cycle. Previously showed **Fig 8** explained the three modeling alternatives to account for these effects. The best and worst case scenarios for mechanical hysteresis, will be REVERSIBLE and IRREVERSIBLE respectively. **Fig 23** shows the impact of these two cases.

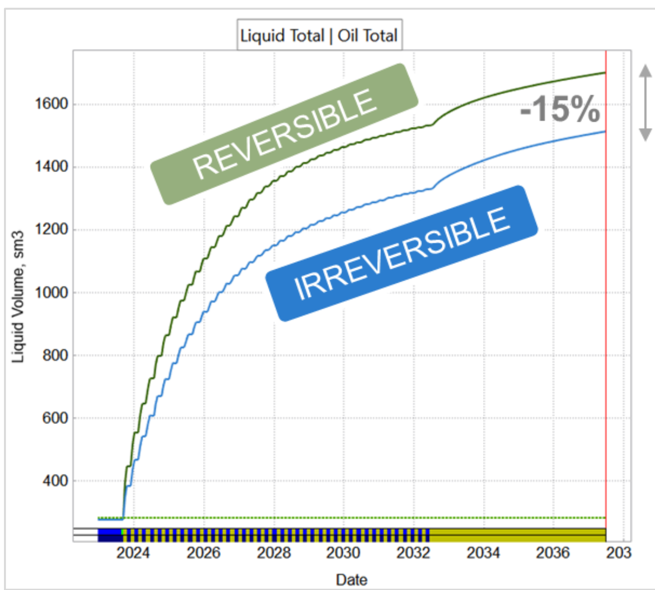



*Fig.-23 – Impact of Mechanical Hysteresis on the CGEOR process*

- **Operational Parameters Optimization**

  From all the parameters affecting the EOR process, there are some that can be controlled by the operator, named in this work, as "operational" parameters or Schedule, while the rest are given by the configuration of the reservoir, fluids and completion characteristics, the primary depletion strategy and the starting of the CGEOR process. Even though the last two are indeed operational, they are more related to previous practices already dictated by the operator.

  To evaluate an optimal set of operational parameters (schedule) a Net Present Value function was created that accounts for the oil sales income and the injection gas "purchase" (or lack of its sales) which we call Objective Function (OF). The idea behind the Optimization is to find a schedule that maximizes the value. To do this, we provided a set of ranges for the main operational parameters and run an optimization algorithm (Differential Evolution) to maximize the OF.

**Fig 24** shows a conceptual scheme on how this efficiency curve or “envelope” might look like (left), the actual one (right) and the CGEOR oil cumulative runs of the whole ensemble (below).

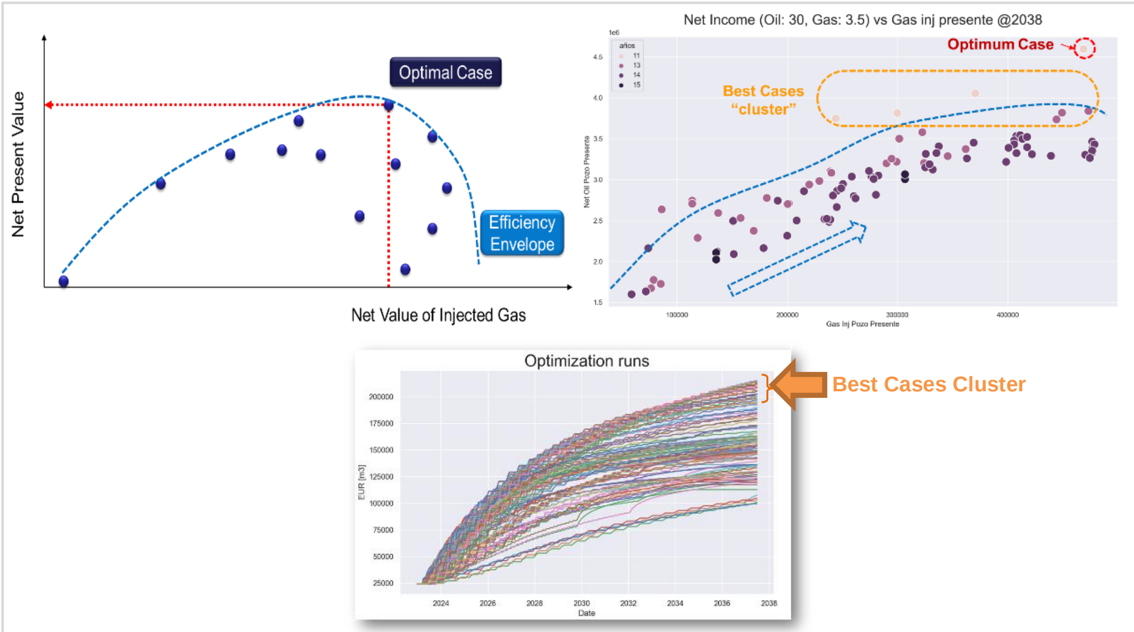



*Fig.-24 –CGEOR Optimization of NPV Objective Function with different Operational Parameters (Schedule)*

The resulting “optimal” case, carries the information on how to operate the EOR treatment for maximizing value. However, this might be too specific for a certain reservoir and completion case, thus, we expanded the possible cases to a group of outcomes named in **Fig.24**, as “Best Cases Cluster”. **Fig 25** show the cluster’s parameters ranges, and the average optimal schedule.
The results show that the best cases choose the highest possible gas injection rates (as expected), long 90-day injection periods (more gas), no soaking and a short 30-day production period. The 250 day fillup period, is strongly influenced, among other things, by the current exploitation degree of the chosen well, thus it might vary substantially in different cases.

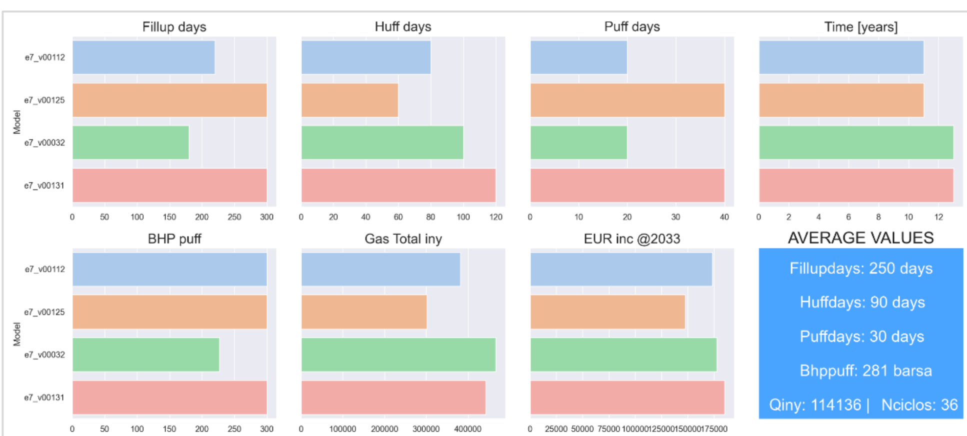



*Fig.-25 – Ranges of Operational Parameters for the best cases of the Optimization process (Cluster)*

### iv. Estimation of Potential Ranges of Incremental Oil under CGEOR

Once we have defined an Average Optimal Schedule (AOS), we would like to apply it to certain specific runs to capture the impact of main uncertainties such as gas relative permeabilities, mechanical hysteresis, gas enrichment and time of EOR start, to have a range of Min., Avg. and Max. EOR incrementals compared to its homonymous primary depletion cases. These are probably going to be extreme runs, optimistic and pessimistic as we are combining the worst and best input cases, thus, the P90-P10 range (which should be combinations of those) must be contained into these.

**Table I** shows these runs compared to its primary depletion correlative cases and its EOR Multiples (ratio of EOR incremental to primary one). All the EOR runs, were constructed with the Average Optimum Schedule. **Fig 26**, shows the cumulative incremental CGEOR oil for the Min, Avg and Max cases. Note that the relative increment for the Avg and Max cases are similar, that is because some parameters such as gas rel perms impacts the CGEOR and the Primary process too and other parameters such as CGEOR start date, "shifts" the cumulative curves to the right loosing EUR at a certain unique comparison date.

| Case | Type of Uncertainty (All Runs w/Optimal Schedule & 115 km3/d Gas inj. Rate) | | | | EUR @2038 (K.m3) | | EOR Multiple 1.x | Yield (Mcf/bbl) |
|---|---|---|---|---|---|---|---|---|
| | Gas Rel Perms | Mech. Hysteresis | Gas Enrichment | Time of EOR start | Primary | CG EOR | | |
| **Min.** | Unfavorable | Irrevers. | Dry | 6 yrs | 95 | 105 | 1.1 | > 100 |
| **Avg** | Mid | Boberg | Rich | 4 yrs | 115 | 175 | 1.5 | 30 |
| **Max.** | Favorable | Revers. | | 2 yrs | 130 | 195 | 1.5 | 32 |

*TABLE I- Range of CGEOR incremental Oil for the MAX, AVG and MIN runs (based on Optimum Schedule)*

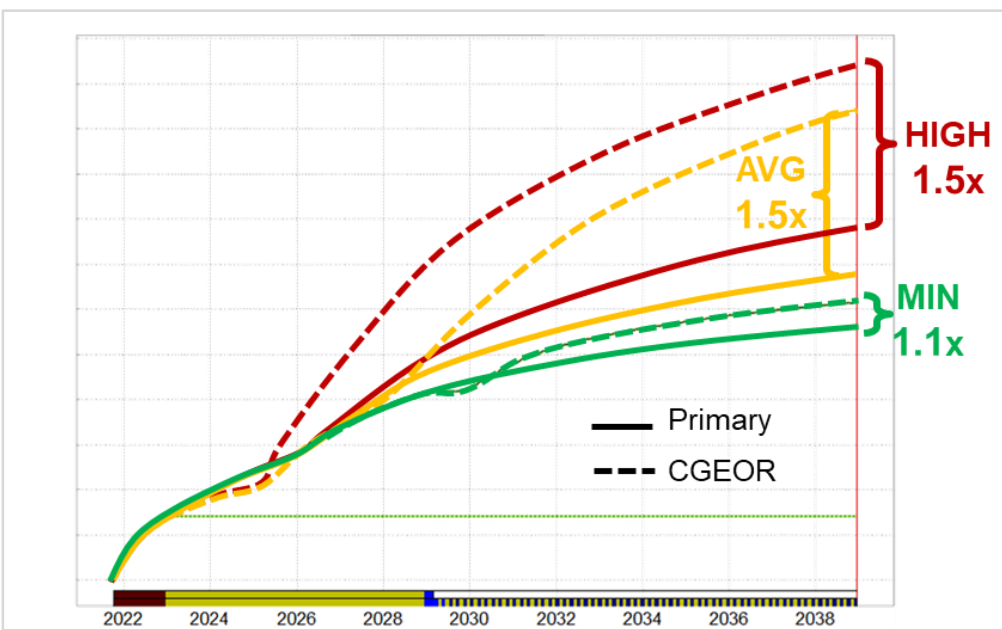



*Fig.-26 – Incremental oil respect to primary depletion for MIN, AVG and MAX Cases*

Another interesting parameter to monitor is the CGEOR Yield, which is the ratio between the injected gas and the incremental oil. For the average run, is 30 mcf/bbl, similar to the average Yield of ongoing projects/pilots in the Eagleford, US which is 26 mcf/bbl (Source: Shale IOR CGEOR Report, 2019).

Despite the fact that this modeling exercise, fulfils our initial objective to provide a quantitative basis to guide a CGEOR evaluation in the Vaca Muerta black oil window, we must consider the inherent limitations of it being a highly simplified model. This means, that to validate the methodology and the model itself, data should be gathered preferably on a field pilot to calibrate the most relevant uncertainties such as geomechanics and free gas behavior and work on a full well scale modeling (integrated model from hydraulic fracturing, primary depletion to EOR, all in one model).

Monitoring of recurrent data such as pressures, rates and compositions are indispensable to better understand the impact of the different phenomena and calibrate the models.

In addition, we must also consider that in a full field deployment, probably the multiplicity of wells (pads), added to the non-homogeneous pressure depletion and fracture network interactions, will create a much more challenging scenario to both, optimize gas placement and schedules (which will most likely vary between cases) and bring a new problematic not studied in this work which is, Gas Containment (Karacaer C., 2023), as another issue to monitor in enhanced recovery projects.

## ○ Conclusions

1. Simple lab tests on crushed rock using Vaca Muerta cores and black oil, showed a positive and rapid response, increasing the oil recovery by miscible Huff n Puff lean gas injection.
2. A numerical dual-poro, dual-perm hybrid compositional 3D model was constructed and history matched to quantitatively estimate the range of potential incremental oil for a typical Vaca Muerta black oil single horizontal multifractured well under a Cyclic Gas EOR process (CGEOR).
3. The most important phenomena governing the performance of this kind of EOR process were analyzed as sensitivities, grouped into two main families, (i) sub-surface related (such as gas-oil relative perms, completion parameters, geomechanics, hysteresis and fluid behavior) and (ii) operational (timing of events such as start of EOR process, fillup, huff n puff periods, pressures and injection rates).
4. The History Matching process, aimed at calibrating the first set of uncertainties while the second set was used to both, optimize what can be influenced by operations (Schedule) and explicitly treat the rest as ranges to account for the associated risk.
5. An optimization of the main operational parameters (Schedule), suggests that given a max lean gas rate available of approx. 110 km3/d, fluids compositions and current depletion status, this Vaca Muerta well, needs a fillup period of 250 days, huff n puff periods of 90 and 30 days respectively, no soaking and production pressures of around 280 Kg/cm2.
6. Delaying the EOR process (equivalent to a higher depletion of the SRV) plays a role, not only because it affects the incremental recovery, but also because of the needed planning for these logistically complex projects, and to include them as an integral part of the development strategy.
7. To estimate the Max, Average and Min. incremental oil case scenarios, we combined the sub-surface uncertainties to evaluate an extreme range of possible outcomes (w/Optimized Schedule), resulting in an incremental oil (EOR incremental at 15 years forecast) that ranges from 10% to 50% (sometimes expressed also as 1.1 to 1.5 x) compared to each homonymous Base Case (primary depletion). The Yield (injected gas to incremental oil) ratio for the Average Case, was 30 Mcf/bbl.

8. These results, are in line of those observed by US operators and reported in the technical literature available for US basins such as Eagleford and Permian with multiples ranging from 1.1 to 2.0x and yields from 20 to 40 with an avg. of 26 Mcf/bbl).
9. The resulting incremental oil is very encouraging, as even in the worst case scenario modeled, some incremental was observed and increments as high as 50% are expected for the Average and Max. cases.
10. The implementation of this kind of Unconventional EOR as a part of the development, will have to deal with multi-well issues such as connectivity and containment of the injected gas. However, if proved successful, will help not only to increase and provide more stable oil production rates on average, but also extend the life of these wells and provide the possibility of using stranded gas during low consumption periods (summer-winter swing) or take advantage of spot market conditions, more efficiently.

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