DYNAMIC MODELLING AS A DECISION-MAKING TOOL: THE BARRANCAS FIELD CASE

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Abstract

Several mature fields in Argentina still contain significant remaining hydrocarbon volumes that may represent economic redevelopment opportunities, once a methodology to locate and quantify them is established.

In the case of the Barrancas Field, in the Cuyana basin, (Cretaceous Barrancas Formation as main reservoir) different geological scenarios, supported by dynamic simulations and history match, were used to propose a redevelopment plan, after 64 years of oil production and 48 years of water-flood development.

Through a full-field history match, engineers could understand aquifer advancement along the western flank of the Barrancas anticline, identifying the best area with remaining hydrocarbons, to be tapped through a new field development plan.

Due to the paucity of data in the poorly perforated western flank, a stochastic analysis of geologically plausible scenarios was used to capture reservoir facies thickness and areal distribution ranges.

Based on the dynamic simulation results of the range of geological scenarios, project economics and decision trees were run and analyzed. New wells drilled during the 2014 to 2016 campaign, encountered the forecasted oil saturations, confirming the robustness of our redevelopment methodology which led to an increase in economic reserves and field production of ~25%.

Introduction

Main objective of this work is to present the use of a static-dynamic 3D reservoir model, as a tool to locate remaining hydrocarbon bearing zones and to evaluate new possible developments in mature fields.

The 3D static-dynamic model includes approximately 450 wells, and was built by a multi-disciplinary team of geologists, geophysicists, petrophysicists and reservoir engineers during a period of two years.

In order to use the static-dynamic model as a decision making tool for future field developments, the 64 years of field production history needed to be matched; we considered this historical match as the necessary requirement for reliable forecasts of new drilling activity.

During the process of history matching, a number of potential areas with poor development and oil sweep started to appear in the field. These areas were ranked according to their geological risk and one of them, the western flank of the Barrancas anticline, was selected as main target for the next drilling campaign.

The area, being scarcely drilled, could not count on well data; pushing the team to apply a stochastic methodology to account for model uncertainties and to reduce risk associated to the proposed development plan.

The Field: Barrancas

The Barrancas oil field is located in the Cuyana Basin in Argentina, 35 Km to the south of Mendoza (Fig. 1). It is a mature field, producing oil from several reservoirs since 1939. Specifically, the reservoir associated to the siliciclastic alluvial-fluvial sediments of the Cretaceous, Barrancas Formation, began to be exploited in 1952. The water injection development started initially as a pilot in 1967 was then expanded at field scale in 1973, giving an excellent incremental oil response. To date the field has approximately 450 wells drilled, of which 106 are active producers and 58 active water injectors. The produced oil is 33º API with viscosity of 4.3 cP at initial reservoir conditions.

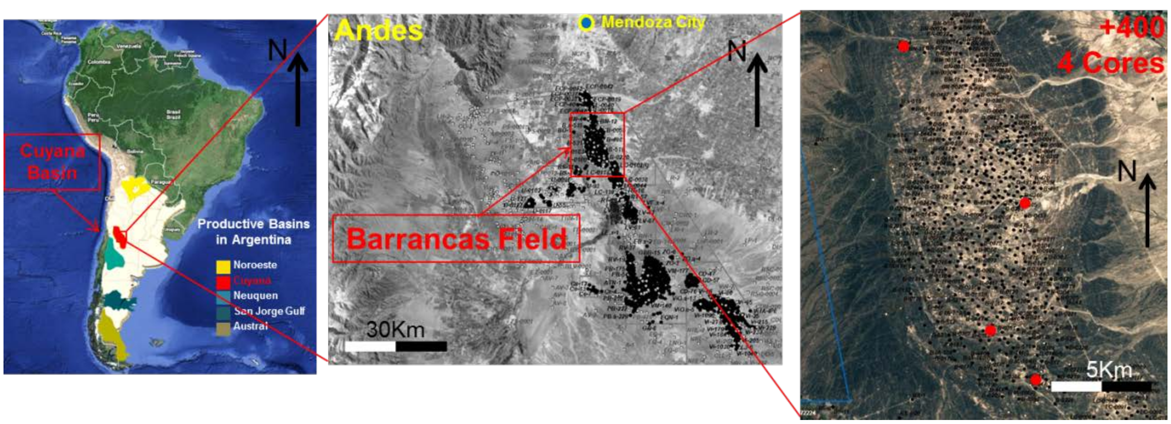

Fig. 1 a) Map of the argentinian depositional basins with Cuyana Basin marked in red. b) Map of the Cuyana Basin showing the Barrancas Field. c) Map of the Barrancas Field showing well distribution.

Modelling Methodology

From the beginning of the study, we aimed at obtaining a 3D dynamic model that representing fluid distribution in the field, could reveal areas with hydrocarbon remaining potential. It was considered that in order to forecast such fluid distribution, the dynamic model needed to achieve a full-field history match. For this purpose, a full-field static model was built, honoring reservoir rock characteristics and oil saturation distribution.

The workflow to achieve a history-matched model was iterative (Fig. 2), through a back-and-forth process of testing geologic scenarios through dynamic runs. Geologists and petrophysicists would build and update the 3D static model based on the feedback given by simulation results. This continuous loop led in the end, to a unique deterministic static-dynamic model.

This model (*history match driven)* is the one that explains better the production history of the existing wells and the one that minimizes the difference between simulation results and measured data.

Finally, different redevelopment and drilling scenarios were tested through the dynamic 3D model.

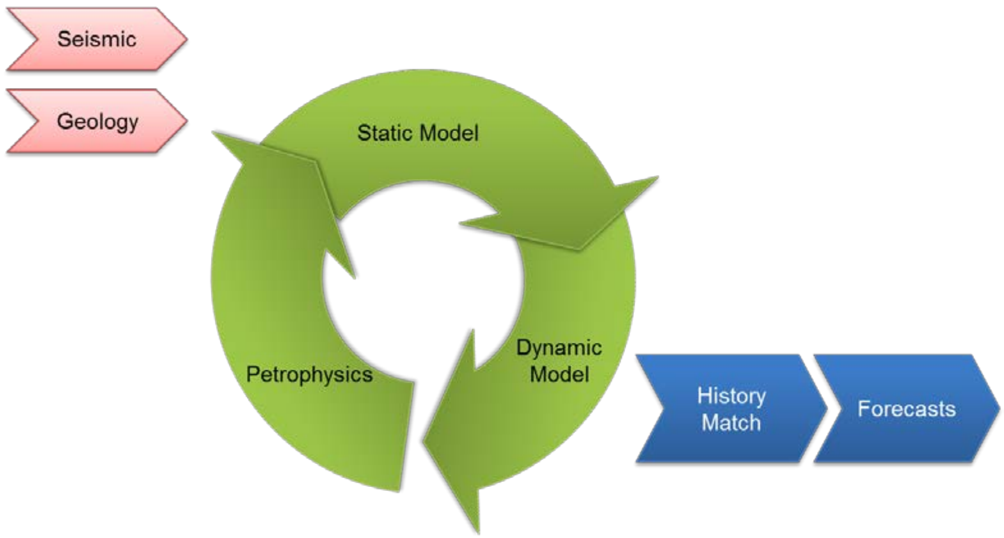

Fig. 2 Iterative process followed by the team to obtain a history-match driven model.

Summary of the Static Model

Based on the analysis of all rock material available in the field (only 4 cores) and on the analogy with field outcrop, a depositional model was proposed for the Barrancas Formation in the area of the Barrancas Field (Fig. 3). Facies associations and facies stacking pattern were analyzed on each core, to establish the paleoenvironmental framework. Together with the depositional model, a new sequence stratigraphic scheme, based on facies stacking and its resultant key surfaces, was built.

According to our depositional model, the Barrancas reservoir represents an ephemeral fluvial-alluvial system, arranged according to progradational and retrogradational sequences or pulses (6 architectural sequences, Fig. 3), possibly responding to climatically driven variation in sediment supply.

Prograding cycles consist of conglomerates and sands with the best reservoir characteristics (porosity values between 8 and 20%; permeability values between 1-800mD. Retrograding cycles are dominated by fine sands and shales with poor reservoir characteristics (effective porosity values < 8% and permeability values< 1mD).

The depositional system shows a South-North polarity following a proximal to distal trend; best reservoir facies of proximal alluvial setting are in the southern and central portion of the field. This results in thick and connected sand bodies. The northern portion of the field, changing to more distal settings, shows a degradation of reservoir quality, with thinner and less connected sand bodies, especially in the upper most cycles (cycles 1 and 3, Fig. 3). Lateral continuity and no relevant changes in total sand thickness, are observed in an East-West direction of the depositional system.

This conceptual model, together with the seismic interpretation of the main fault lineaments of the field, represented the skeleton of a 3D static model. The 6 depositional sequences determined through geological modelling became 6 individual dynamic flow units in the dynamic model, without intermediate upscaling process.

Porosity and permeability properties were then populated according to facies distribution and used as the main input for reservoir properties in the dynamic model. Reservoir engineers would feed back to geologists, in the iterative workflow described above, any adjustment needed in property distribution, in order to improve history match would only occur if considered plausible within the range of geological data and scenarios.

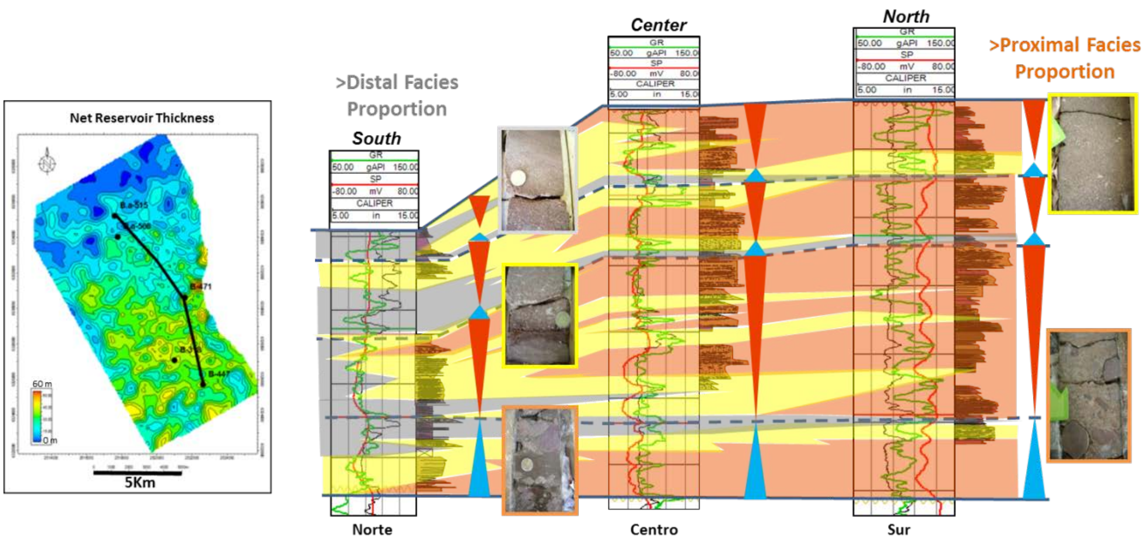

Fig. 3 Stratigraphic scheme showing the 3 main key correlation surfaces and the North-South polarity of facies distribution.

Summary of the Dynamic Model

Dynamic model was constructed using all available production history data. Based on validated PVT analysis, the reservoir was simulated as black oil (live oil and dry gas). Transition zones (capillary pressure) were modelled using J-function.

Production and injection history was modelled in 350 wells out of 480 wells used for static modelling (wells with logging in Barrancas but producers from other formations). Wells were arranged in 18 groups to facilitate history matching analysis.

At the beginning of the history match process, we initialized the model using two water-oil contact (WOC) values, inherited from previous field studies. These two contacts were separated artificially, by an arbitrary discontinuity.

Subsequently, based on well history match and seismic re-interpretation of main horizons and faults, we decided to change the WOC to a deeper unified depth along the structure. This new depth unlocked a volume of oil to be exploited in the western flank of the structure, between the main field and the WOC.

After the history-match phase was completed, the simulation results were analyzed to identify areas with poor oil sweep. The remaining oil saturation was visualized in 2D maps and 3D grids. We chose to map the thickness of reservoir sands with permeability and water saturation cut-offs, as the best way for showing remaining opportunities. (Fig 3)

$$h_{map} = \sum_{\substack{i=1 \\ S_o>0,5 \\ k>100\ mD}}^{N} h_i \qquad \textbf{[1]}$$

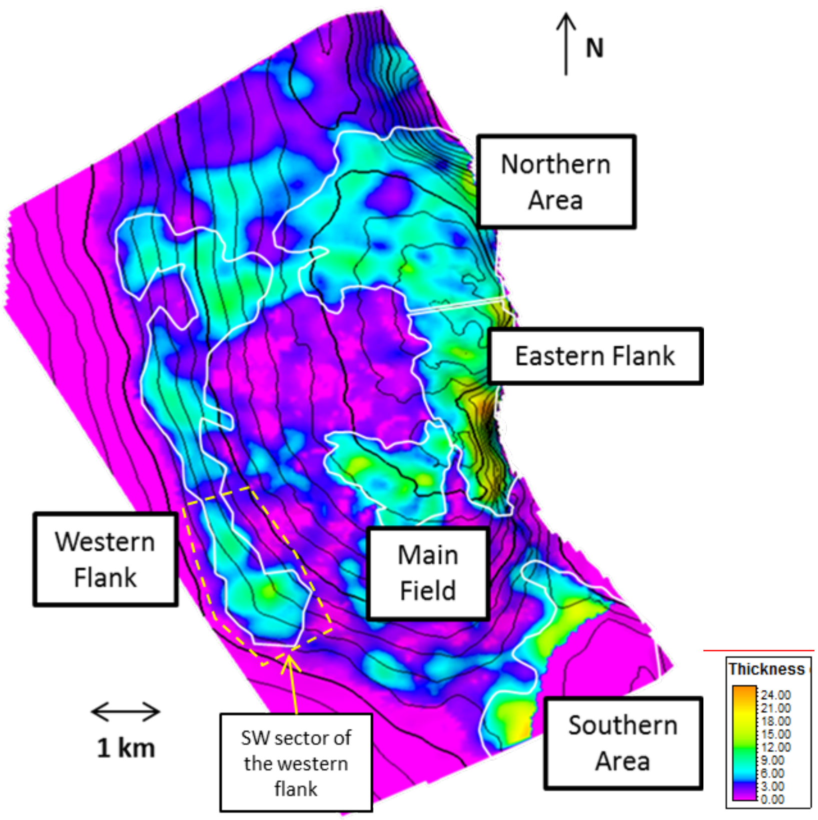

Fig. 4 Map of oil thickness height (as defined in [1]) showing the new opportunities found in the field that have been ranked The map also shows the SW sector that has been analized through the stochastic methodology (polygon in dashed yellow lines).

These maps showed 5 different zones with significant remaining oil (Fig. 4). Static and dynamic risk was evaluated per zone, resulting in the following ranking (from higher to lower risk):

1. East-Flank area: high degree of structural uncertainty due to low seismic resolution and faulted zones.

2. <u>Main Field area</u>: despite the remaining opportunity, this area is considered difficult to produce due to its low pressure; issues on waterflooding patterns arrangement, makes the area difficult to redevelop.

3. <u>Southern area</u>: despite showing the highest remaining oil saturation, the southern area of the Barrancas field may be in hydraulic connection to the next field to its south. To decrease uncertainty in this area, a dynamic model of the next field is needed in order to assess the real remaining oil saturations.

4. <u>Northern area</u>: as the few wells in the area show poor reservoir quality in the upper cycles, the reservoir connectivity to the North remains uncertain, with consequent risk considered moderate to high.

5. <u>West-Flank area</u>: conditioned to the definition of the new oil-water contact (OWC), the area bears low uncertainty in terms of reservoir thickness and quality.

Finally, from this ranking, the western flank zone was selected as the development target. Main risk there was associated to the new OWC position reinterpreted in the history-match process.

Furthermore, as the reservoir quality bears more uncertainties towards the north of the field (at least for the uppermost 2 stratigraphic cycles), the south sector of the West Flank area was considered more promising as first target of field redevelopment ("SW sector" in Fig. 4).

Looking in detail at the simulation model of the western flank, we could understand which mechanism was possibly determining the presence of remaining oil.

As field pressure drops due to historical primary oil production, water advances from the flank up into the structure, sweeping mostly the lower reservoir cycles, due to gravity forces. Later on, when water injection begins, the aquifer stops advancing, contrasted by water injection pressure, and water starts moving down flank in different layers, according to their permeability.

The model shows that drainage of the upper layers stays poor, having still mobile oil recoverable. The bottom cycles show only residual oil saturation, with non-recoverable oil in them. Fig. 5 explains the details of this mechanism.

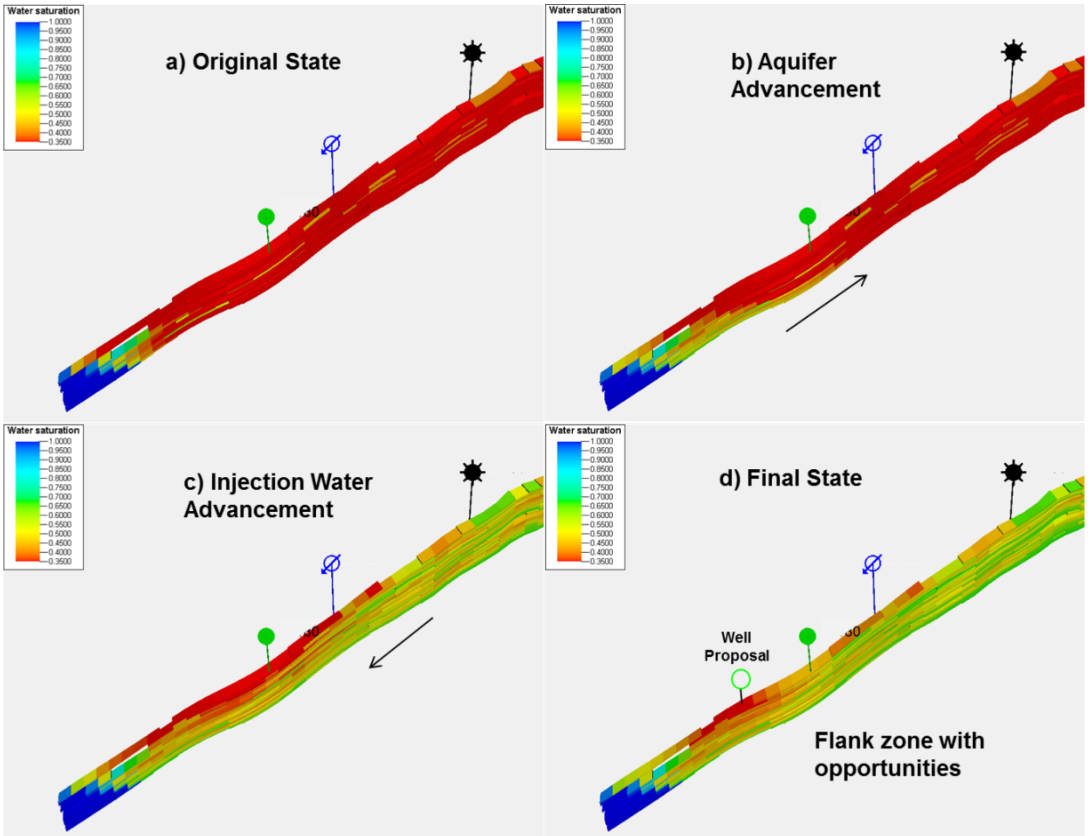

Fig. 5 Sector of the simulation grid showing the flank water saturation behavior during production history. a) beginning of production; b) beginning of water injection; c) water injection reaching the flank; d) saturation model showing nowadays situation.

Quantification of the Opportunity

Once the target area was chosen through the rank risking process, an area of interest was delimited ("SW sector" in Fig. 4).

In the main field area, where plenty of well data is available, the model is well constrained. On the contrary, away from well control, with SIS algorithm only constrained by statistics, reservoir distribution can change significantly depending on the seed value (see Fig. 6).

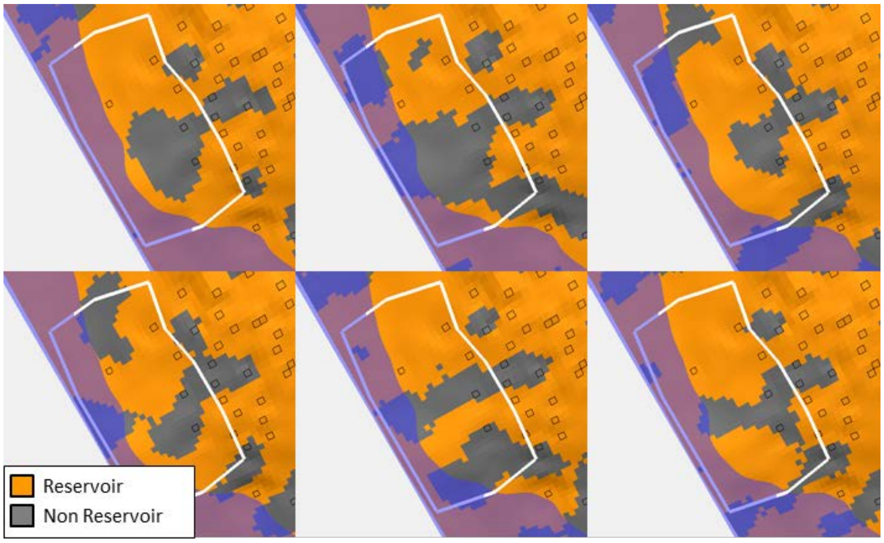

Fig. 6 Different facies distribution created by the SIS algorithm within the same geological model (close-up of the southern flank). The figure shows how much model can change far from well data control; observe how changes are minor near existing wells (black squares).

It was hence necessary to make more than 100 geological realizations and a stochastic analysis to assess the uncertainties linked to them. These realizations evaluated the impact of reservoir facies quantity and distribution variations on the resulting oil in place calculation. Each of the mentioned scenarios is given by different sand thickness and distribution, following a seed value used by the SIS algorithm.

Each of these 100 equivalent scenarios has an original oil-in-place (OOIP) calculation with a distribution around a mean value (Fig. 7). To evaluate the different proposed plans, as a first approach, we selected 3 different cases: Low (P99), Mid (P50) and High (P1) Case.

The three scenarios correspond to different thickness and continuity of the reservoir facies in the static model (Fig. 8). The High Case shows the most connected and wider sandstone bodies (lowermost accommodation rate scenario). The Low Case shows the less connected and thinner sandstone bodies (highest accommodation rate scenario).

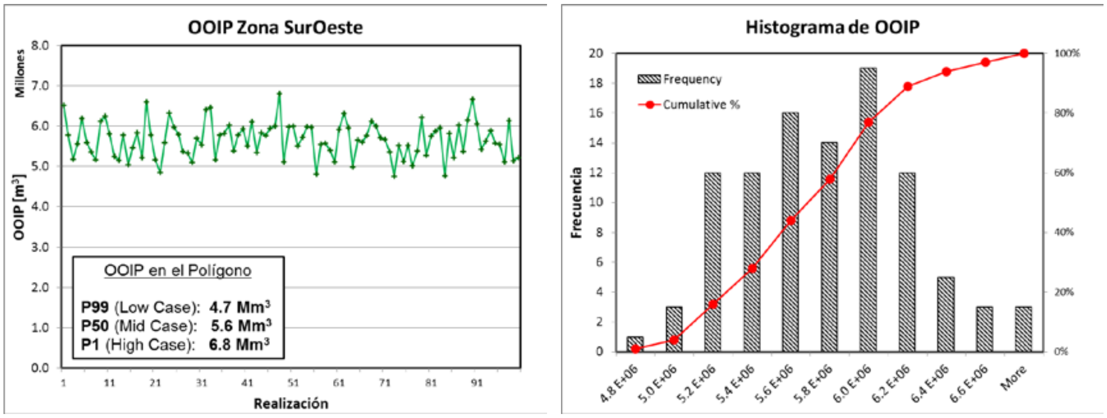

Fig. 7 OOIP distribution resulting from the 100 geological scenarios of the SW sector.

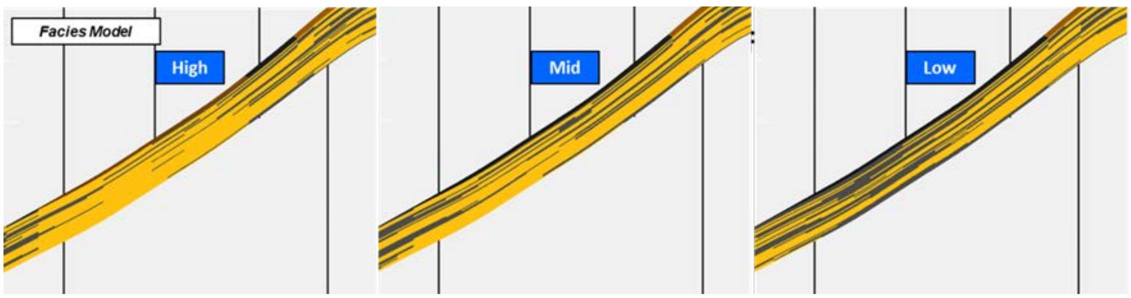

Fig. 8 Different facies distribution related to different geological scenarios of the SW sector. As in Fig. 6, note that there is little changes near wells influence.

These scenarios account for all the range of uncertainties.

The models were generated reaching a similar history-match quality than the “final history matched case” (Fig. 9). This result was expected as models are similar near the historical wells, were static and dynamic control is higher than anywhere else. Constructing again the map of opportunities in Fig. 4 for the three cases, we obtained different size and position of the oil bearing zone across the flank (Fig. 10). This shows a range of uncertainty existing in the development prize.

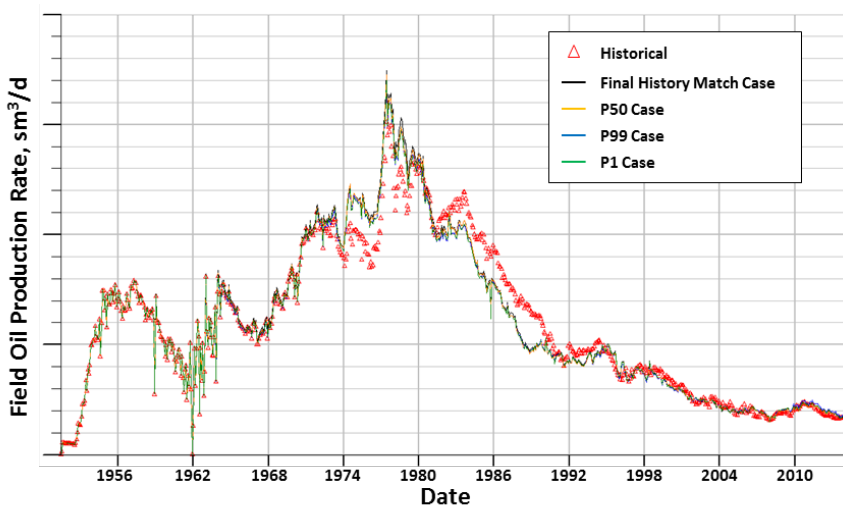

Fig. 9 Plot showing no history-match changes for the different scenarios.

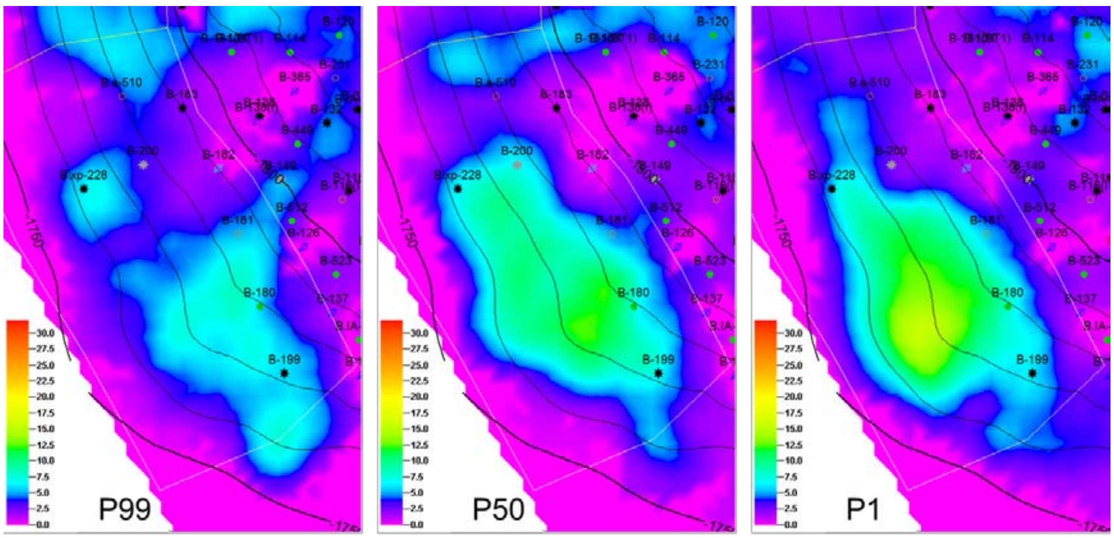

Fig. 10 Map of the SW sector of the field showing the oil bearing zone and its variations according to the 3 different cases. Note the difference in shape with Figure 3.

On the 3 cases, different development scenarios were run, modifying well patterns and spacing (Fig. 11). These scenarios were simulated and optimized in the three mentioned cases, finally selecting the development plan that gave better recovery per number of wells, the 22-wells case.

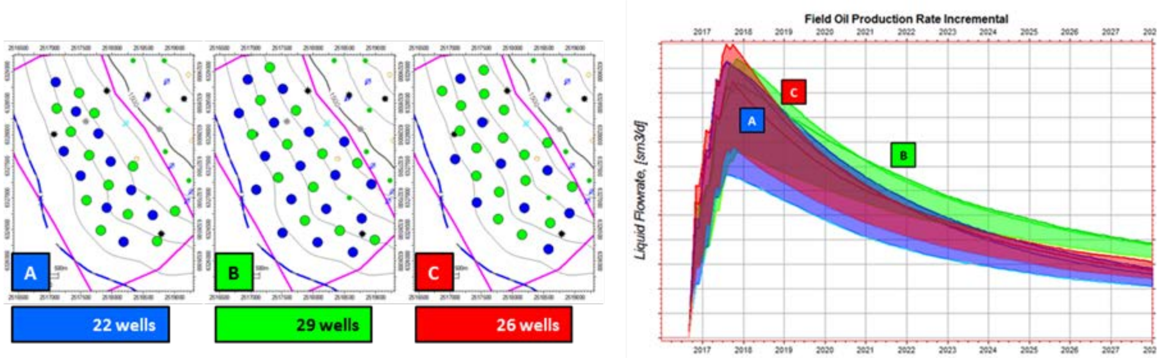

Fig. 11 Example of some of the different patterns tested in the southern flank area. a) 22 wells, 5-spot, 380 m spacing, b) 29 wells, 5-spot, 450 m spacing, c) 26 wells, 7-spot, 400 m spacing. The selected pattern was the 22-wells one (Figure A).

Once the optimal development plan was selected, we needed to assess the real expected value of the forecasted oil volumes to be produced by this plan. Having available 100 geological cases, we simulated them all, to produce more robust statistics of possible outcomes.

For each geological scenario, three different simulation runs were needed: the historical case (with field oil production from the beginning of exploitation to date), the base forecast case (a no-further-action case) and the planned forecast case (the selected 22-wells case) to calculate the incremental oil.

Each run lasted approximately 12 hours including the historical case, the base forecast and the planned forecast; working concurrently with 8 CPUs, it took around 8 days to simulate all the 300 runs.

Once results of runs were available, we calculated the obtained increment above the base case, and plotted in a histogram to obtain the statistics of incremental oil (Fig. 12).

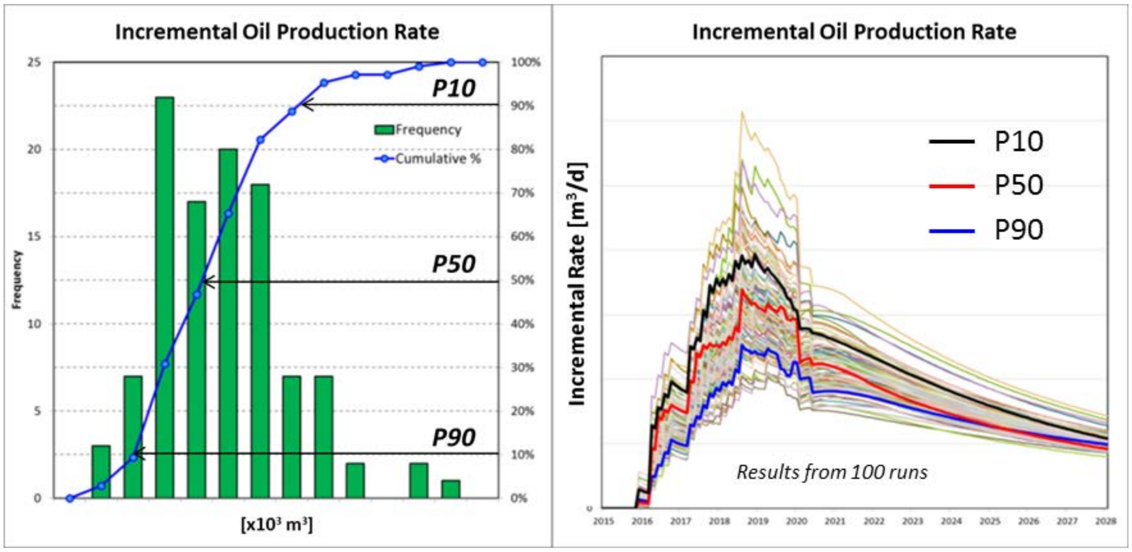

Fig. 12 A) Incremental oil volume histogram for SW sector development with the 22 wells plan. B) Simulation outputs for each of the 100 runs with the P10, P50 and P90 cases highlighted. Each curve is calculated from the subtraction between the 22 wells plan simulation and the base case for the same scenario.

Economic Evaluation

Based on simulation results, a pre-feasibility economic evaluation of the project was performed. The statistical values for P10, P50 and P90 of expected incremental oil production were used.

Over the three simulated production forecasts, four possible economic outcomes were considered: High (P10), Mid (P50), Low (P90) and a fourth possible outcome named “Fail case”. In all cases, 12 production wells and 10 injectors are to be drilled, with the exception of the Fail case; this latter account for the perforation of only 4 wells, all of which have to result100% water bearing. In this case, the project is stopped.

Being Barrancas a mature field, significant information related to new wells and operating costs is available. The estimation of CAPEX and OPEX has therefore been adjusted based on historical data.

Fig. 13 shows the production forecasts for the three scenarios. Results of the economic evaluation of these outcomes are shown in Table 1.

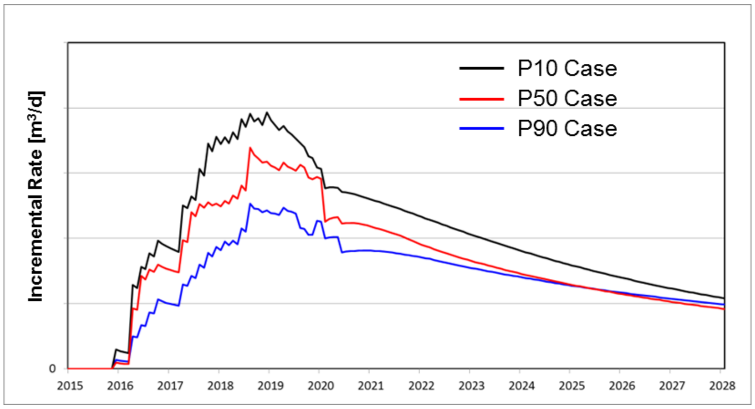

Fig. 13 Initial Production forecast for economic evaluation.

	New Wells	Production wells	Injection Wells	NPV [MUSD]
High –P10	22	12	10	>0
Med- P50	22	12	10	>0
Low- P90	22	12	10	<0

Table 1 Initial economic evaluation for the different outcomes.

As observable, project development is non profitable in the case of the worst forecast. The "Low-P90" outcome, would not meet the minimum economic parameters required to develop the project.

After this preliminary analysis, a new case for the "Low-P90" outcome was built. Instead of considering the subsequent drilling of all 22 wells, we assumed that after the drilling of the first four wells, if production is observed similar or inferior to the one forecasted for the P90 case, the drilling activity stops.

Thus, production profiles became the following ones (Fig. 14).

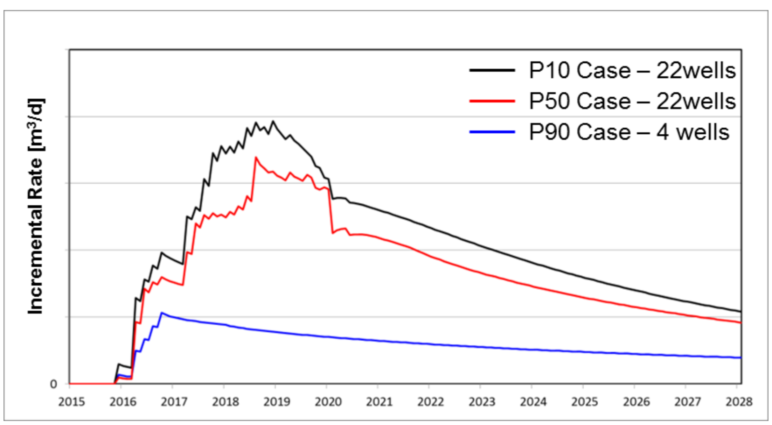

Fig. 14 Production profiles considered for economic evaluation.

As observed in Table 2, the “Low-90" branch only considers now the drilling of the first 4 wells. Thereby, more favorable economic indicators are obtained.

	New Wells	Production Wells	Injection Wells	NPV [MUSD]
High –P10	22	12	10	>0
Med- P50	22	12	10	>0
Low- P90	4	4	-	>0

Table 2 Economic evaluation summary for the different outcomes. Note difference with Table 1.

Assuming a 10% chance for total failure (4 dry hole wells), and applying Swanson´s rule for the production forecast (30%-40%-30% for P10, P50, P90 respectively), the resulting decision tree probability is as shown in Table 3.

	Probability
High	27% (30%*90%)
Med	36% (40%*90%)
Low	27% (30%*90%)
Fail	10%

Table 3 Assigned probabilities of success.

As mentioned, a decision tree (Fig. 15) was made considering the different outcomes and its probabilities of occurrence.

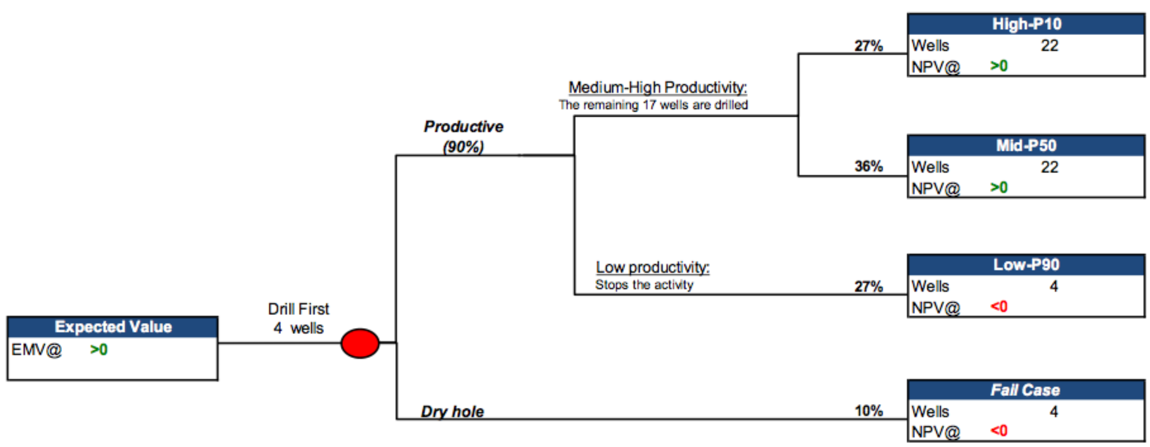

Fig. 15 Project Decision Tree.

The expected value is the result of each branch by its probability of occurrence. The project has a positive Expected Monetary Value (EMV).

Project Results

Based on this study, in the year 2014, a well drilled in the northern part of the flank, showed very good oil production and low water cut (<10%),confirming model's predictions. Subsequently, in 2015, two more wells were drilled in the same zone: one to the north with lower productivity and 35% water cut, and one to the south with similar oil rate and 40% water cut, both in agreement with model predictions. During 2016 two additional wells were drilled, both with high rates and 15-20% water cut.

Still in 2015, a well was drilled in the southern part of the flank, confirming good oil saturations in the upper cycles. The well started with very good oil rate and 12% water cut, although water cut is increasing at this stage. Fig. 16 shows the impact of these wells in the field oil production.

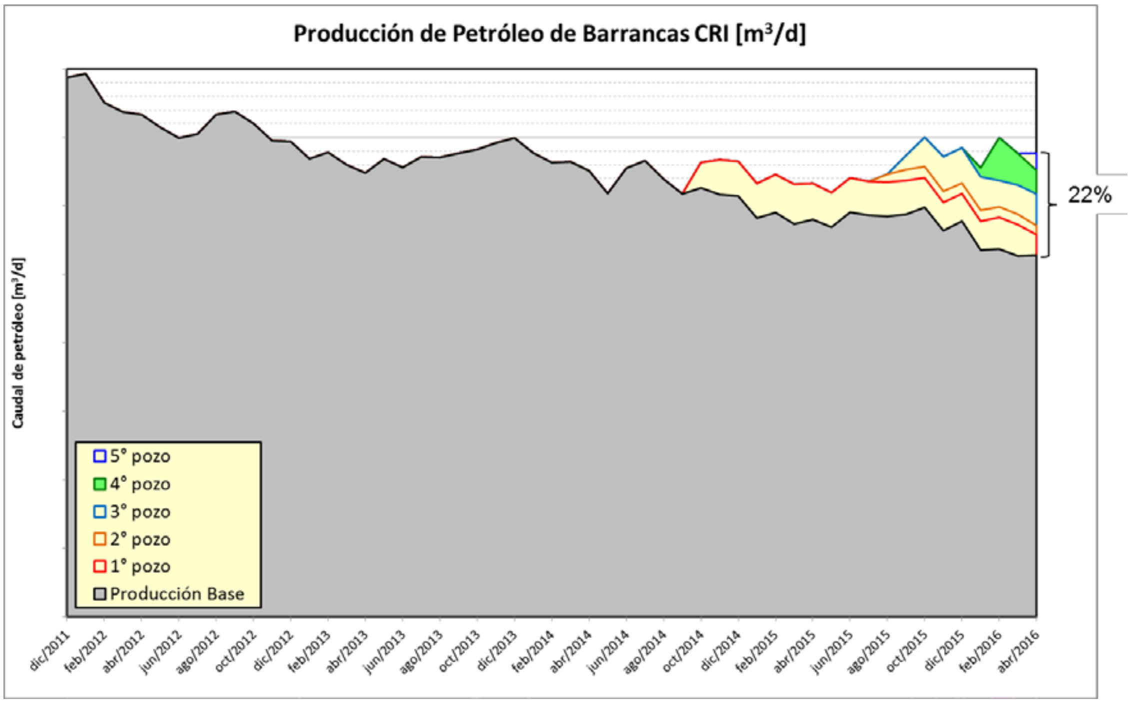

Fig. 16 Field results showing the percentage of the field production represented by the project activity.

Drilling results have confirmed to date model predictions. The proposed field development plan is under execution, representing at the moment the main drilling activity in the field. Static and dynamic models are updated regularly on the basis of drilling activity results.

Conclusions

The dynamic model was demonstrated to be the tool to evaluate the development plan. Although the iterative workflow followed led to a deterministic model, it can be used as an input to evaluate the uncertainty in oil production forecasts in a stochastic methodology.

The economic evaluation can include the uncertainty output from the simulation model to optimize the decision making.

To the date the wells drilled according to this model have been successful, so the development plan will continue as designed. The model will be updated with the information provided by the new wells to reevaluate the decision tree.

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