Field Development Extensions of Orocual Field and Prediction of Expected Performance in a Fractured Reservoir


Abstract

The Orocual Field is made up of four structurally compartmentalized fault blocks. The upper two, San Juan 3 (SJ3) and San Juan 6 (SJ6) are more developed. The lower block structures, San Juan 7 (SJ7) and San Juan 9 (SJ9), are more than 1500 feet deeper and are separated by a major thrust fault. These reservoirs primarily consist of light condensate. Recent development suggests that significant potential exists in the SJ6 and SJ7 areas. The difficulty in defining the hydrocarbon column associated with each block, because of limited development, shows significant sensitivity in calculating oil reserves. The San Juan formation is a naturally fractured sandstone reservoir, and has historically produced low sustained rates of less than 1000 BOPD. New techniques in the area have been studied to increase sustained rates to at least 3000 BOPD.

This project was designed to develop a method to analyze the probable results of a development program. A reservoir simulation model was constructed as part of an integrated study focused on geostatistics modeling of tight matrix and fracture systems to predict production by extending the proven area of the field. The producing areas have limited data, and previous studies did not consider the fractured nature of the reservoir. The application of geostatistical methods for reservoir characterization, and the use of simulation to assess the static model heterogeneity were identified objectives. The complex structure and fluid columns add to the uncertainty. Various sensitivities were run by applying different constraints to the permeability model, variance in fluid definitions, and well design.

The reservoir simulation model shows sensitivity to matrix characterization and less to fracture characterization. This sensitivity is related to well productivity as a function of matrix permeability. The matrix is so tight that a multiple increase of permeability has little effect on well productivity. The permeability appears to be predominately from fractures. Fracture density or fracture permeability shows less effect to change well productivity than matrix permeability. Over 100 simulations were run to predict well and reservoir behavior. Results allow realistic assessment of risk in both reserves and production and to rank alternatives.

Introduction

The Orocual Field is located approximately 20 kilometers northwest of Maturin, in the Maturin and Piar districts of Monagas state, as illustrated in Figure 1. The field was discovered in 1933 with the drilling and evaluation of the ORC-002 well in the Las Piedras formation. However, this well was abandoned because it was not economic at the time. The Orocual field is identified geologically as being part of the Maturin sub-basin that has been deformed by compression faulting. The Orocual field has three major formations that have produced oil and gas since the discovery. The separate accumulations are identified with the Las Piedras, Carapita and San Juan formations. Other formations have shown potential for production such as the Caratas, Los Jabillos, Vidoño and San Antonio, but have not been developed.

The project is part of a PDVSA effort called, “Proyecto Delineación Desarrollo,(PDD)” translated as, “Delineation Development Project.” These are special projects to focus on expanding known areas of production to increase reserves, production, and to evaluate new technologies to pursue development of challenging areas.

This study focuses on the San Juan formation development, that has both condensate and oil production. The study represents a sequential phase of previous studies begun in the late 1980’s. Production from the San Juan formation was established in 1958 with drilling and completion of the ORC-015 well located in the SJ6 area. This well is still an active
producer, although production has dropped to approximately 500 BOPD with a high GOR of approximately 10000 scf/stb.

The proven SJ6 area was tested again down structure in 1978 with the ORC-017. This well produced less than 300 BOPD of low GOR, 28° API oil. The SJ3 area was discovered in 1985 with the ORC-052 well. The well produced from 1100 to 1600 BOPD on 3/8" choke. The production rate was not considered sufficient for economic reasons and so the San Juan was abandoned. A development plan for the SJ3 to produce condensate and light oils was designed in 1989, eventually resulting in 15 production and injection wells. In January 1997, a gas injection program was initiated to increase recovery.

A major change in analysis of the field occurred in 1999 with the integration of the fractured reservoir characterization. The objective of the study was to identify an interpretation that allows a fair evaluation of the formation, the production mechanism, reserves, and future development potential. The field has been divided into five recognized accumulations, herein defined as the San Juan Complex, with 4 major areas of interest as shown in Figure 2. The SJ3 is the area where the most wells have been drilled. The SJ6 area is divided into two regions, the first being in the area of development, and the second identified as the prospective area. The SJ7 area now has two wells (the most recent completed in October 2000) and the SJ9 area has one well. Both areas are designated for future development potential.

### 3D Seismic Interpretation

A new 3D seismic volume was available to update the structure interpretation. Data was available over approximately 75% of the proven San Juan Complex. The area east of SJ7 and SJ6 was not complete with 3-D coverage. Some 2-D seismic lines were available and were used. The top surface of the San Juan formation is identified in seismic time and depth as the base of the Vidoño carbonate formation, with thickness from 10 to 200 feet. Much of the rock below the Vidoño is shale until the top sand of San Juan Superior is found. This thickness can vary from 50 to 150 feet.

Figure 3 shows a cross section of the 3-D seismic interpretation. The ORC-025 well is in green. The new well, ORC-030 that was proposed as a result of the integrated study, is shown in blue. The yellow, pink, and green surfaces are associated with the interpreted stratigraphic surfaces of Carapita Superior, Carapita Inferior, and the base of the Vidoño formations, respectively. At the end of the interpretation process, a correction was required to move the top surface mapped in seismic time and depth to the top of San Juan Superior. This difference in depth is from 50 to 150 feet.

One objective of the study was to include the San Juan Superior in the analysis of production potential, even though a small amount of production comes from this zone.

### Stratigraphy

A study and analysis of depositional environment, fracture character, core interpretation, and rock typing was performed in 1998 and 1999. The main product of this study was a foot-by-foot description of stratigraphic rock type. The integration of this data into the petrophysics and geostatistics was a goal of the study. Vargas wrote a report of the regional depositional changes

### Petrophysics

Accurate and appropriate evaluation of permeability, especially in non-cored wells, is probably the biggest challenge in any integrated study. A re-evaluation of the petrophysics was finished in mid-1999. Sufficient core porosity and permeability data exists to provide control of all types of rock, especially those of interest in simulation. The specific objective was made that simulation cell values of porosity and permeability match average petrophysics values from the static model.

Special focus was applied to identify natural formation fractures. This is the main and most significant difference between the 1994 and 1999 studies. The identification of productive rock from petrophysical evaluation was defined by three algorithms: 1) Sandstone with no fractures, 2) Sandstone with fractures, and 3) Non-reservoir rock including shale and limestone with fractures.

The evaluation of net pay is complex because of the possible combinations and outcomes due to the three algorithms. Simple definitions of net sand using single porosity or permeability cutoffs can not be used in this situation. Thus, total rock characterization was needed, which is best treated with geostatistics. The result is a sophisticated analysis based on the petrophysical database and stratigraphic and structural interpretations.

### Geostatistics

Geostatistic methods provide a method of estimating geological properties in unknown areas based on data acquired from known areas. The method uses as much of the data as possible to define geological character on a foot-by-foot basis to define the total character of the formation, including all rock types. The confidence of interpretation is usually defined by mathematical singularity, meaning that defined properties are equal to observations, where limits and distributions of observed data are never exceeded. A common problem occurs when data is poorly defined, such as open-hole log porosity and estimated permeability, and does not match core data.

The effort to calibrate the data by limits and distribution was a priority. During the processing of the first geostatistic realization, an analysis of the cumulative distribution of log derived matrix permeability showed a skewed distribution of values greater than 27 md (millidarcy).

The reason was the petrophysical model sometimes predicted permeability values in fracture zones that were very high (>15000 md). The realization was constrained to model only matrix properties in this phase, so the high values needed to be modified to a more realistic value. Thus, the realization permeability distribution was normalized to match core data, and all high values from the petrophysical log evaluation were changed to 27 md, identified as the upper statistical limit. At
the same time, the porosity distribution was also modified to match the core porosity distribution.

Figures 4 and 5 show the distribution of the core permeability and porosity data available from San Juan formation conventional core analysis. These figures summarize the analysis of the data. Figure 5 shows the porosity distribution where three distributions are most likely representing very tight matrix, normal matrix porosity, and fracture plus matrix porosity. The key figure is Figure 4 as it clearly shows the majority of core has a permeability less than 1 md with the most common value being less than 0.01 md.

This distribution was used to normalize the data during the construction of the geostatistical model because the open-hole log petrophysical results did not show the same distribution trend as core data.

A simulation model of 21 layers was defined from the top of San Juan Superior to the base of the San Juan Inferior. By definition, the top of each sequence, San Juan Superior, San Juan Medio, and San Juan Inferior were defined to be layers of shale that coincides with the stratigraphic nomenclature and selection of the main sedimentology sequences.

Simulation Philosophy
The previous sections touched on the static model interpretation and observations and conclusions related to the characterization of rock properties of the San Juan formation. The need to define a simulation model that takes into account the identified properties was a primary objective.

The first step was to define a static geological model grid for geostatistics equal to the simulation model grid. This was done by the preliminary analysis of the spatial distribution of available data, well spacing, and geological structural components. This grid was used during the up-scaling process to propagate the static model properties into the simulation grid.

The study team agreed that it was important for the simulation model to be representative of the fractured reservoir and by definition, to show the characterization is heterogeneous. If so, the simulator predicts variation in production similar to field observations. If not, then the model may not be representative.

Porosity and Permeability Distribution
Figure 6 shows the model distribution of the full field model (FFM) property of porosity in layer 10 of the model corresponding to the upper layer of San Juan Medio. The distribution of up-scaled matrix porosity shows that there are both high and low concentrations of porosity. Review of this data was acceptable to the team, as it appears to reproduce expected distributions based on the depositional environment.

Note that there are no apparent values of porosity above 9%, and that the majority of the distribution is less than 7%. Fracture porosity is assumed at 1%. The total porosity of the system (fracture + matrix) was defined to be equal to the total core porosity. Cells that were identified as fractured reservoir were assigned a porosity of 1%. The coincident matrix cell porosity was reduced by an equal amount. This preserves the observed total porosity to be as close to the calibrated porosity as possible. Matrix permeability is also distributed following similar guidelines.

Net-to-Gross Distribution
Net-to-Gross has similar constraints and has limits of 0.0 and 1.0 describing pure shale or non-reservoir rock, and clean reservoir sand, respectively.

Fracture System and Simulation Parameters
The description and definition of the fracture system was based on simulation experience, outcrop inspection, and the subjective observations of well history in the San Juan Complex. Experience in eastern Venezuela has shown that faults, and most likely fracture zones associated with faults, are the primary mechanism which permit vertical communication.

The definition of the fracture system took into consideration the probability that fractures exist in the main body of the formation but is not continuous or homogeneous through the field. A recent well was drilled in the north area between the SJ3 and SJ6 areas and produced less than expected. This fact is important to identify model confidence, because the model should be able to predict, in random fashion, historically high and low production rates. It is a main assumption that the probability is very high that fractures are associated with faults and that the density of the fractures is higher closer to faults than matrix fractures. Matrix fractures should not be as extensive or common.

Figure 7 shows the distribution of cells that are defined using the method described above. The distribution is assumed to exist equally in all layers of the model. A maximum of 25% of all cells were assumed to be fractured. A distribution algorithm was defined that first used a probability function to define fracture cells close to faults with a control value of “2”. Second, the “1” value fractured matrix cells were defined using a second probability function.

Three variables to predict the presence of fractures were defined, one for high density fractures, one for low density fractures, and the third where fractures do not exist. Values of sigma (σ), as proposed by Kazemi, of 12.0, 0.12, and 0.012 were used in sensitivity analysis.

The FFM has used two specifications for σ in the model. The first is for dual porosity coupling of the matrix with fracture blocks, and the second for gravity segregation of condensate liquid for the dual porosity coupling of matrix and a fracture cells.

PVT Fluids Characterization
The characterization and formulation of an equation-of-state(EoS) was initiated in April of 1999, tested and used for this work.

Simulation Modeling
Five simulation models were extracted from the FFM to meet the objectives of the study. For purposes of this paper, only one, SJ7, will be discussed to illustrate the method.
Simulation Results and Predictions
San Juan 7. The SJ7 model was selected as the first model to study and analyze. Figure 8 shows the model grid in relation to the San Juan Complex. This structure has two wells, the first is ORC-025, that currently produces approximately 500 BOPD with a GOR of over 10000 scf/stb. The second, ORC-030 is being tested at this time.

The objectives of the first phase of simulation in this project were identified as: 1) Evaluate potential reserves of the structure. 2) Verify that the geostatistical model offers reasonable and expected variation in reservoir quality, supplying a heterogeneous model following expected stratigraphic interpretations. 3) Evaluate basic sensitivities to model parameters such as assumed fracture permeability and matrix permeability. 4) Assess the risk of new well development using medium high angle wells, and 5) Evaluate a potential development plan and its associated production.

Objective 1 – History Match. The ORC-025 has produced approximately 1.49 Million stb and 21.72 Billion scf as of January 1, 2000. In order to satisfy the first objective, a material balance was performed using the simulator and a match of the pressure history and production rates. Figures 9 and 10 show the match of the simulated results compared to the historical data.

Objectives 2 and 3 – Well Design and Model Confidence. Drilling locations are environmentally difficult and expensive to construct, and drilling is expensive, so economic considerations were taken into account in this work. A decision was taken that all development drilling will use existing drill sites, thus requiring angled and deviated wells. Wells assume an angle of 45 degrees from vertical and a maximum offset of 1000 meters ( +/- 100 meters). In total, 12 well trajectories were calculated and modeled.

The hypothesis of this part of the study is, “If a statistical variation can be predicted from arbitrarily positioned wells in the model, then this indicates that the geological model is heterogeneous.” Then, the project can continue with the first geostatistical realization.

The third objective was met by designing a model with wells placed in arbitrary positions of the structure. Theoretically, an infinite number of wells could be modeled, but it was decided that time was a consideration so the first test location was selected based on the new 3-D seismic interpretation. This well is identified as well 115 (now ORC-030). In addition to the ORC-025 well, 12 hypothetical well trajectories were modeled with the difference being the azimuth of the well path. The wells were named based on the azimuth direction, with 0 and 360 equal to North. The wells designated for modeling are listed by name and azimuth as: 065, 080, 095, 115, 130, 145, 160, 175, 190, 205, 220, and 235.

Figure 11 shows a 3D view of the structure and relative position of the 12 simulated wells. ORC-025 is the vertical well in the middle of the cluster, on the top of the structure. Note also the dimensional components caused by faulting. A realistic variable is introduced to this process by predicting reservoir penetration length which can both be increased or reduced by fault block displacement, penetration points, and well deviation angle.

Sensitivity Cases. Five sensitivity cases were defined to test various model parameters. The current producing GOR for the ORC-025 well is 10,000 scf/stb, with an average liquid rate of 500 stb/day. An assumption in all case runs is that this well would be closed to conserve reservoir energy. The five cases are identified as follows:

Case 1: All of the San Juan formation is assumed to be productive, including San Juan Superior, Inferior and Medio. The main assumption is that possible open-hole or slotted liner completions can increase well productivity if the complete San Juan interval is open to production. Skin damage (S) is assumed to be +40 which corresponds to analyses of usable pressure transient build-up data.

Case 2: The San Juan Superior interval is closed.

Case 3: The same as case 2, except S is assumed to be +2.0 to model potential increase in productivity if well drilling damage is minimized.

Case 4: Similar to Case 2, but with the primary difference being in the distribution of porosity and permeability that creates a second realization of these properties. (Please see the following section, ORC-026 Core Data Normalization, for clarification of this case.)

Case 5: Nearly identical to Case 4, the main difference is that fracture permeability defined in the fractures is 10 md as compared to 100 md in Cases 1, 2, 3 and 4.

Review of the results of Cases 1, 2 and 3, showed that well productivity was optimistic because production plateaus were predicted; an unlikely scenario based on historical results of field wells. From these observations, the decision was made to review the matrix permeability distribution to determine if a different definition would produce more realistic results, closer to field history results and observations.

ORC-026 Core Data Normalization. A detailed analysis of the ORC-026 core was made available in October 1999, after modeling had started, providing previously unavailable characterization data. The distribution of the measured permeability was analyzed and the data indicated that a different distribution of permeability could be defined for sensitivity purposes.

In addition to the conventional core analysis, mini-permeameter data was also provided. Figure 12, a histogram of the mini-permeameter data, shows a much higher percentage of very tight matrix sand exists, as compared to the distribution seen in other cores and demonstrated in Figure 4. The distributions of porosity and permeability in this well clearly show that the matrix properties are very poor. The data also provided explanations for field observations such as: 1) High drawdown pressures. 2) Sand production (from unhealed fractures). 3) Many poor producing intervals, and 4) Poor results from hydraulic fracturing procedures.

Since a goal of the work was to define the most realistic model possible, the decision was taken to use a second distribution of permeability to provide sensitivity results. The permeability distribution of Figure 12 was used to normalize the original permeability distribution. The realization was re-
stricted to follow the cumulative distributions so that low values stayed low and high values remained high.

Cases 4 and 5 represent the results from the normalization with the original permeability distribution being substituted as described. The initial assumption of fracture permeability was arbitrarily selected to be 100 md. Common knowledge is that fractured rock may have essentially infinite transmissibility, and micro-fractured rock typically shows orders of magnitude difference between fracture permeability and matrix permeability. Since the selected value was arbitrary, a simulation sensitivity was chosen by specifying a fracture permeability of 10 md.

In total, 60 simulations of single well productivity were run for the SJ7 analysis using the 12 hypothetical well trajectories. Analysis of the first two cases showed almost no difference from including San Juan Superior in the model. Figure 13 shows a comparison of predicted production for one well for Cases 1 to 5. Table 1 shows the summary of the average results of initial production rate, the rate of production at 5 years, and the 5-year cumulative oil and gas for cases 3, 4 and 5.

The first 24 simulations from Cases 1 and 2 were considered optimistic and not representative. These wells were deleted from the analysis so that a more representative distribution of results could be defined. Figure 14 shows the distribution of the remaining 36 runs using the results of Cases 3, 4 and 5. The initial predicted rate is shown in the right series in black and white, and on the left side of the figure is the distribution of predicted rates at the end of 5 years. It is important to understand that these results are for 36 single well simulations only, and are used primarily to assess the quality of the model.

Assuming the model is representative and reasonable, these results indicate that there is approximately a 50% chance that a drilled well could produce 2250 stb/day under initial conditions. After 5 years, there would be a 50% chance that the same wells could be producing less than 750 stb/day, on average.

It is observed and concluded that: 1) Additional production from San Juan Superior is insignificant, and thus this group of sensitivities can be discarded. 2) The results show that there is significant difference in the predicted performances of the hypothetical wells. 3) The average initial production distribution appears reasonable and is similar to field observations. 4) The recovery mechanism is fluid expansion and gravity drainage.

**Objective 4 – Simulation Model Heterogeneity.** Based on the results, this objective has been satisfied and conclusions can be stated that the model is heterogeneous and reasonably predicts well performance. It appears that the possibility of drilling a new well will result with rates of at least 2000 and up to 3000 stb/day and that expected cumulative production could be 2.75 to 3.0 Million stb with 37 Billion scf of gas, assuming no other development and the completion method follows modeling assumptions.

**Objective 5 – Field Development.** The last objective was to define potential for possible field development. Three wells were selected to do development analysis based on the size of the structure and spacing limitations. The 115 (ORC-030) well was identified as the first development well, so two additional wells were required to fill spacing requirements of 1200 meters. Wells 065 and 205 were selected following these criteria. For all cases, the ORC-030 is drilled in year 2000 and put on production in November. Well 065 is drilled in 2001 and put on production in June 2001, and well 205 is drilled in 2002 and put on production in July 2002.

These results show that a 3 well development will likely not be justified on economic parameters based on minimum expected results for wells at this depth. Additional studies can be performed to determine the potential effect of drilling either 1 or 2 additional wells in the future.

**Results**

The ORC-030 was drilled in mid-2000. The well was completed using conventional cemented casing design, and is presently being tested in one interval in San Juan Inferior and Medio at approximately 745 stb/day with a GOR of 12000 scf/stb. Although this is less than predicted using an slotted liner completion in all of San Juan Medio and Inferior, potential exists for opening other zones and increasing production.

**Conclusions**

- The San Juan formation has very poor matrix properties of porosity and permeability. The apparent source of formation permeability is natural fractures.
- The San Juan formation most likely has extensive natural fracture systems associated with faulting and structural deformation but is not a fractured formation, as is commonly identified with low porosity carbonates where the matrix is heavily fractured.
- The productive capacity of any well drilled in the field is related to the ability to intersect natural fractures either by drilling or by fracture stimulation.
- Production rates from new wells have a higher potential of producing an average of 3000 BOPD per well if formation damage is kept to a minimum. Optimal effect may occur if natural fractures are penetrated, and if completion techniques optimize fracture connectivity to the well, such as using open-hole completions or slotted liners.
- Simulation results clearly show that San Juan Superior has very low production potential, even with fracture characteristics. No appreciable loss in predicted production is noted in simulation results if the San Juan Superior section is not included.
- The assigned value of fracture permeability demonstrates a minor sensitivity in the results.
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Nomenclature
GOR = Gas oil ratio, scf/stb
scf = Standard cubic feet
stb = Stock tank barrel
ft = feet
σ = sigma
FFM = Full field Model

SI Metric Conversion Factors
ºAPI 141.5/(131.5+ºAPI) = g/cm³
bbl x 1.589 874 E - 01 = m³
ft x 3.048* E - 01 = m
°F ((F - 32)/1.8 = ºC
°F ((F + 459.67)/1.8 = °K
lbm x 4.535 924 E - 01 = kg
psi x 6.894 757 E + 00 = kPa
*Conversion factor is exact.

Figure 1: The Orocuau Field is located in the northeast part of Venezuela, near the town of Maturin. Shown here is the global perspective of the location in South America.

Figure 2: The Orocuau Complex is shown here as interpreted using 3-D seismic data. Note the lower parallel structures of SJ7 and SJ9. (30 km perspective left to right)

Figure 3: The San Juan 7 field compartment is shown in cross section from north (left) to south (right) The green vertical line is the ORC-025 well and the blue vertical curve is first project well designated as “115” and later named ORC-030.
Figure 4: The distribution of core permeability for the San Juan formation from whole core.

Figure 5: The distribution of core porosity for the San Juan formation from whole core.

Figure 6: The porosity distribution from the geostatistical model for layer 10 of the simulation model.

Figure 7: The statistical distribution of fracture cells identified for fracture cells, red are dense fractures, yellow are matrix fractures, black are non-fractured matrix.

Figure 8: The San Juan 7 simulation grid in reference to the San Juan Complex.

Figure 9: The history match of oil and gas production versus time for ORC-025.
Figure 10: The history match of observed well and reservoir pressure versus time for ORC-025.

Figure 11: Hypothetical well trajectories to test the SJ7 structure.

Figure 12: Mini-permeameter data for the ORC-026 well.

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Table 1: Summary of predicted initial rates and after 5 years for hypothetical well trajectories in the SJ7 model for Cases 3, 4 and 5.