

Integrated Modeling of the Taratunich Field, Bay of Campeche, Southern Mexico*

By

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Introduction

Taratunich Field is located about 80 km northwest of Ciudad del Carmen in the Bay of Campeche, southern Mexico and is part of a series of prolific oil reservoirs that include Cantarell and Abkatun-Pol-Chuc fields (Figure 1). Since its discovery in 1989, the field has produced over 150 MMSTB of oil from Jurassic and Cretaceous/Paleocene carbonates. A multidisciplinary team consisting of engineers, geologists, geophysicists and petrophysicists was assembled to characterize and simulate the Taratunich Field with the objective of developing a reservoir management plan that would increase daily production and ultimate recovery. The following documents the methodologies used and the results from this effort.

Geology

The geologic structure of Taratunich field is a doubly plunging, WNW-ESE aligned, reverse-faulted antiform with a salt piercement diapir/swell at the center of the structure (Figure 2), as mapped from a 3-D seismic survey and verified by well data. Two normal faults are present over the area of the salt piercement structure and are oriented nearly perpendicular to the reverse faults, creating a small graben over the salt dome. No wells exist in the block to verify the seismic correlations. The field is divided into separate compartments by the faults, which are designated blocks 101-401 (Figure 2). Two wells have crossed the southern reverse fault(s), but there is no oil production from the areas south of the main field. There is, however, oil production from block 101, north of block 201 and the northern reverse fault. No wells penetrate the faulted compartment north of block 301 as water is expected in this block because of the lower structural position NW of block 101.

A generalized stratigraphic column for the Bay of Campeche is shown in Figure 3. Production is from a thick (>750 m) Jurassic (Kimmeridgian) oolitic grainstone unit that has been dolomitized in part, and a thinner (60-120m) sedimentary gravity flow breccia and grainstone interval of Late Cretaceous to Paleocene age (“Brecha” Formation). The

diapir is interpreted to have completely penetrated the Kimmeridgian and at least part of the overlying Tithonian section. Movement of the salt probably took place during Late Jurassic and Early Cretaceous times. Thinning of the Tithonian through Paleocene sections toward the salt dome provides evidence of a paleotopographic high that formed as a response to syndimentary salt movement.

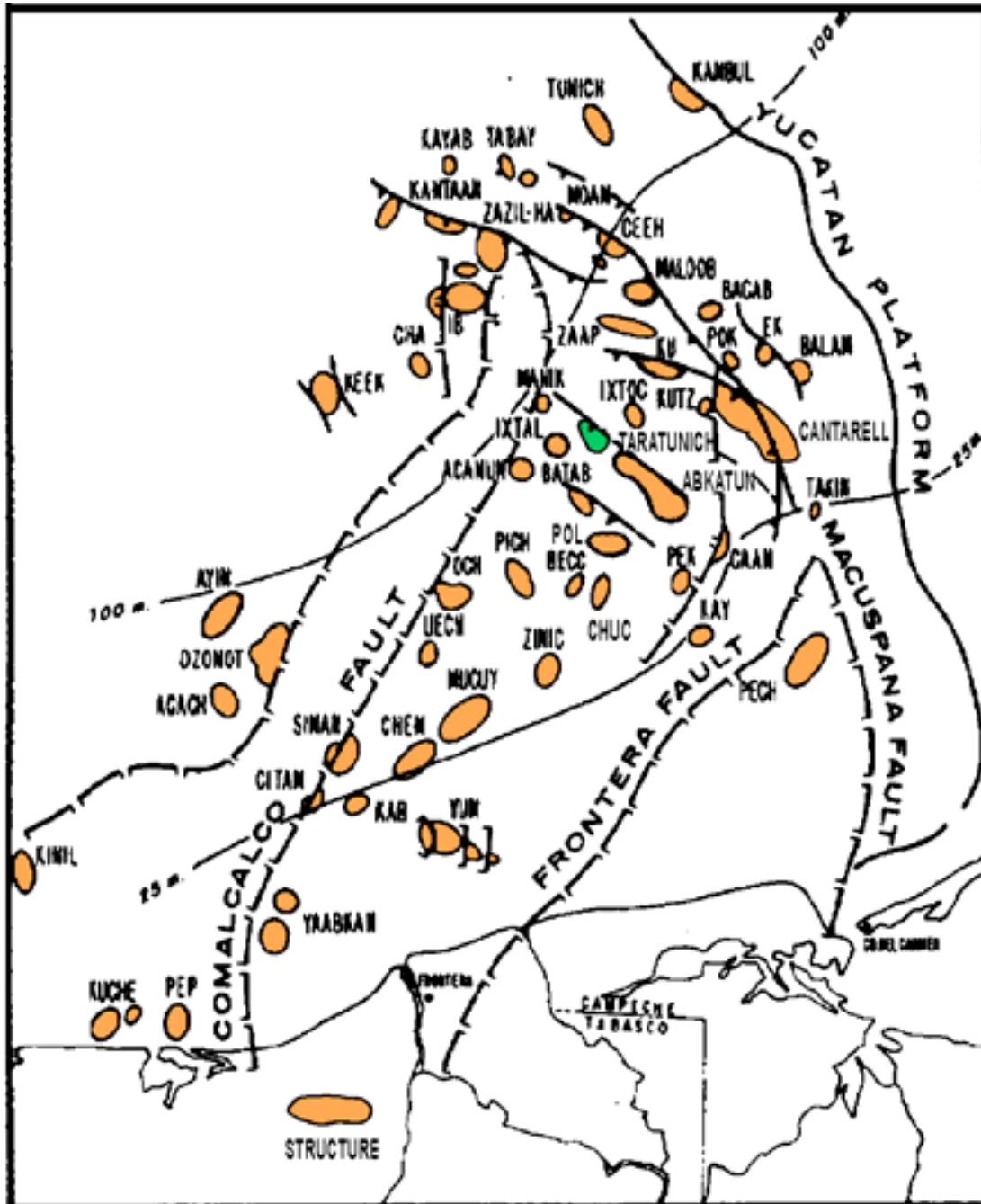


Figure 1. Location of Taratunich Field on map of main tectonic features of Bay of Campeche area (after Santiago and Baro, 1992).

The Kimmeridgian section (JsK) consists of peloidal, oolitic, and pisolitic grainstones that were almost completely dolomitized on the western side of the salt swell (block 301). To the east (blocks 101 and 201), the JsK is comprised of tightly cemented limestones. The JsK was subdivided into 6 major shallowing-upward sequences bounded by maximum-flooding surfaces. In the upper reservoir intervals (where most log data were available), sequences were further subdivided into parasequence sets based on internal-flooding surfaces (Figure 3). Shale is more prominent in blocks 101 and 201 and served as the basis for defining the sequences in these areas. Dolomitization in block 301 was accompanied by dissolution of the original clasts and the development of round moldic pores. Moldic pores range from about 1mm to 5mm, are generally not touching, and are connected by intercrystalline dolomite pores and microfractures. No moldic pores are present in the limestone.

The Tithonian consists of argillaceous and silty/sandy, deep-water limestones. The Cretaceous section is pelagic lime mudstones with grainstone and organic-rich beds in the Upper Cretaceous section. The “Brecha” interval (BPT-Ks: Figure 3) consists of coarse mud-matrix breccia facies of debris-flow origin, channelized and non-channelized skeletal grainstones interpreted as turbidite flows, and pelagic mudstones. Debris for the gravity deposits was derived from the collapsing carbonate platform to the east of Taratunich field in the Yucatan area.

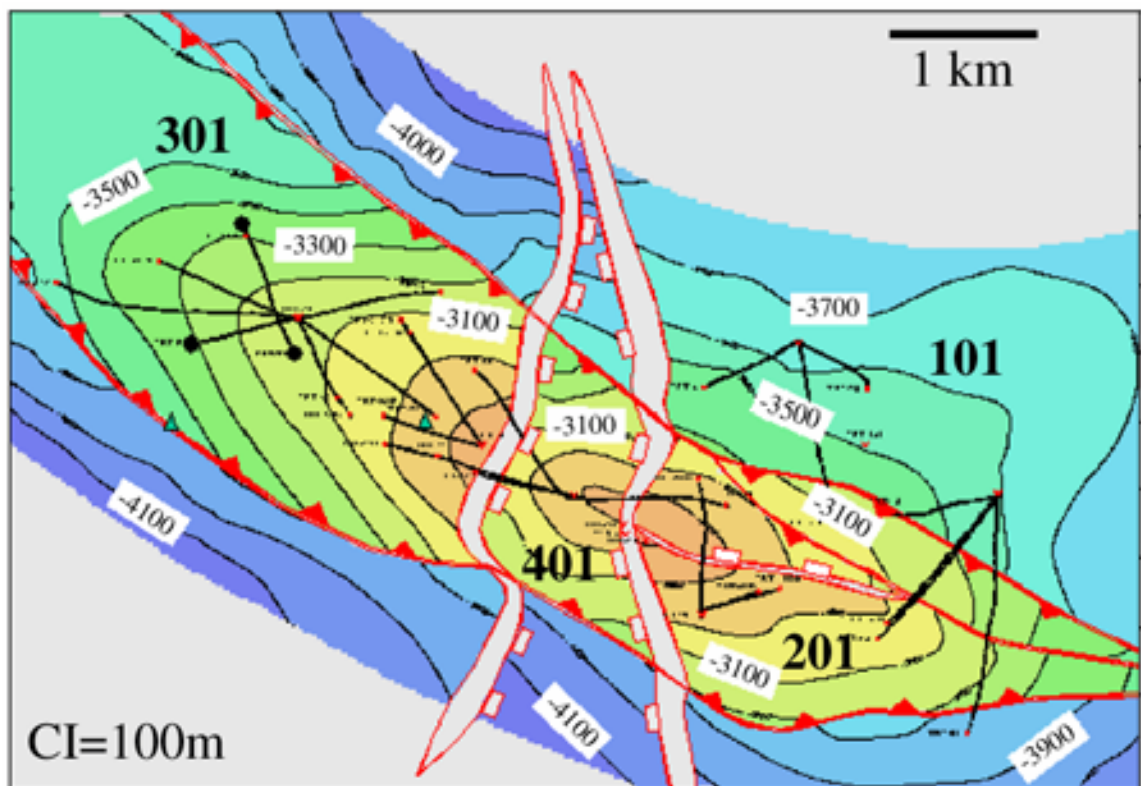


Figure 2. Structure map at top “Brecha” (BPT-Ks). Reservoir block numbers are shown in bold (e.g., block 101). Well paths are shown as black lines. The salt does not penetrate up to this level and is present below block 401 as a piercement structure confined approximately by the faults. Salt is present under the entire area and influenced sedimentation as well as the present structural configuration of the field.

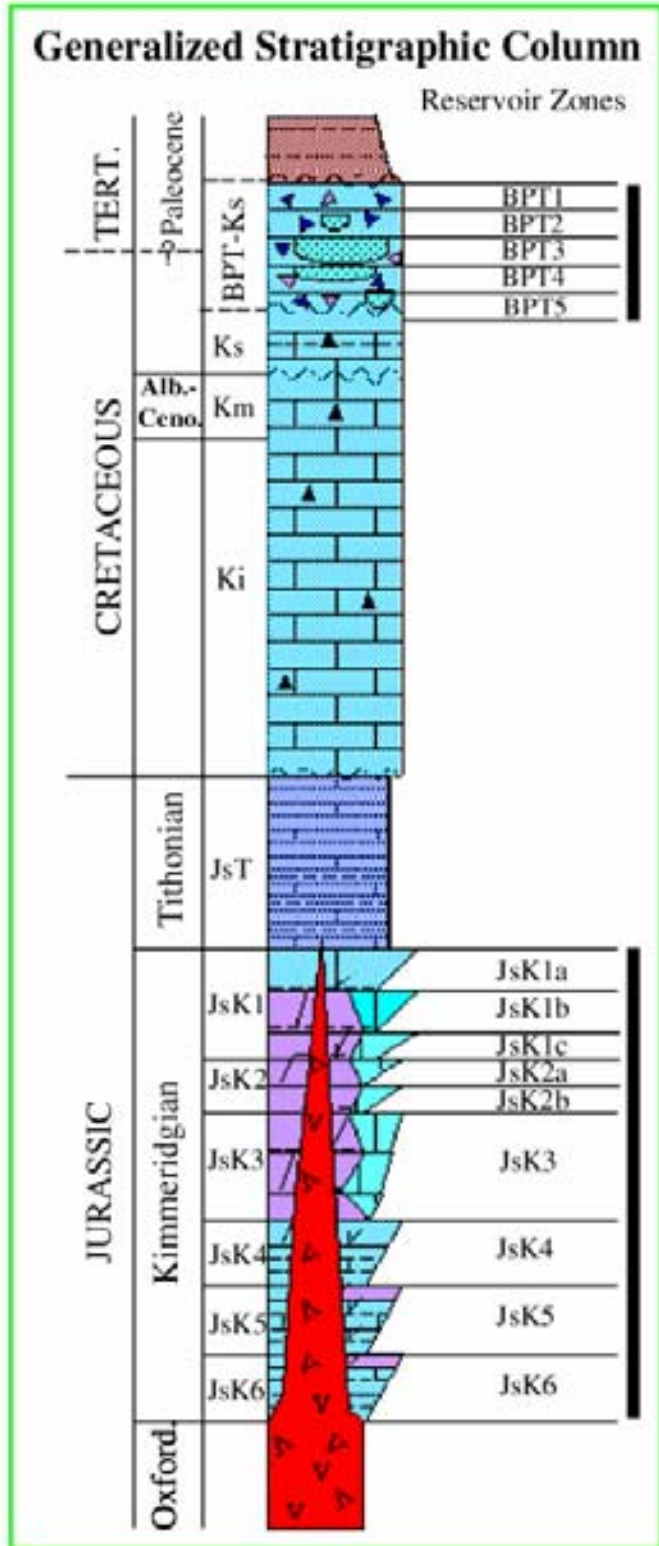


Figure 3. Generalized stratigraphic column for the Bay of Campeche area, Mexico. Black bars indicate reservoir zones.

Porosity

Three porosity types were identified in varying proportions in each reservoir: matrix, vugs, and fractures. Routine core analysis, neutron magnetic resonance (NMR), and capillary-pressure tests provided matrix and vug porosity and permeability, and wireline logs provided matrix and some portion of vug and fracture porosity. Oomoldic porosity in the JsK was a challenge to quantify, and image-log techniques were used to estimate this porosity. The reservoir model was prepared for dual porosity flow simulation by combining matrix and non-connected vugs into one component and fractures and connected vugs into the other component. Property maps including all porosity types, thickness, net, and log-derived permeability were prepared for each reservoir layer, upscaled and input into the reservoir simulator.

Fracture Modeling

Fractures occur throughout the entire stratigraphic interval, and enhance the permeability of the Kimmeridgian and “Brecha” reservoirs. However, in the Tithonian and most of the Cretaceous interval, matrix porosity is very low and fractures do not contribute to flow because of cementation and/or low fracture density. Software was used to balance the 3-D structure and to model fractures in the Kimmeridgian and “Brecha” intervals. This was accomplished by flattening at the tops of these two reservoirs and then restoring the flattened structure to its present day configuration. The fractures were then propagated with modeled strain analysis. The resulting fracture patterns were constrained using core, image log, and pressure data. Fractures generated by modeling were concentric around and radiating outward from the area of the salt piercement structure (Figure 4), fitting the patterns observed in the image logs. The fracture patterns and curvature analysis were used to develop a discrete fracture network (DFN), which was conditioned with well-test-analysis results and other engineering data.

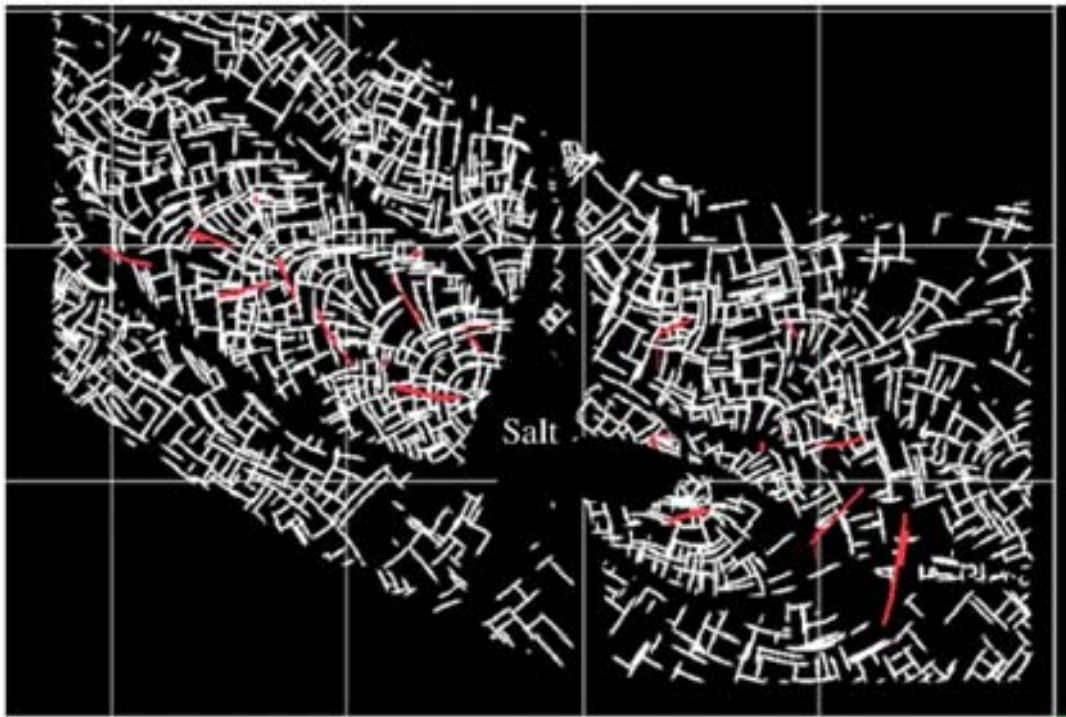


Figure 4. Fracture pattern generated at the top Kimmeridgian reservoir by modeling.

Reservoir Engineering

Based on the analysis of the well and reservoir-performance data, special laboratory fluid and core studies were designed and conducted in an attempt to understand the problem of asphaltene precipitation, which is a major problem in this field. Subsurface oil samples were collected for use in the laboratory tests to determine the composition, phase behavior, and onset pressures of asphaltene and wax precipitation and its effects on fluid flow. The fluid-analysis tests showed asphaltene precipitation within a range of reservoir pressure, and flow tests revealed that the effective permeability of the rock decreases as

reservoir pressure declines and asphaltene precipitation occurs. The changes were modeled with the Eclipse*¹ reservoir simulator.

Analysis of the total porosity (matrix, fractures, and vugs) and sample-compressibility data showed that pore-volume compressibility increases as secondary porosity increases. This dependence, which is strong at low net stresses, gradually disappears as the reservoir pressure decreases or the net stress increases. Based on these results, pore-volume compressibility was generated for various effective and secondary porosity values that were used in the numerical flow models.

Numerical simulation flow models of the Taratunich field were constructed to capture the essential features of the BPT-Ks and JsK reservoirs from the static model and the flow properties discussed above. The major structural and fault trends, reservoir heterogeneity, drilled and possible infill well locations, the locations of their completion intervals and past, present, and anticipated producing mechanisms of the reservoirs, and development strategies, such as water and gas injection, were considered in the design of the grid system (Figure 5) and flow models. The cells of the grid system were seeded with properties from the static model and reservoir- and production-engineering analyses.

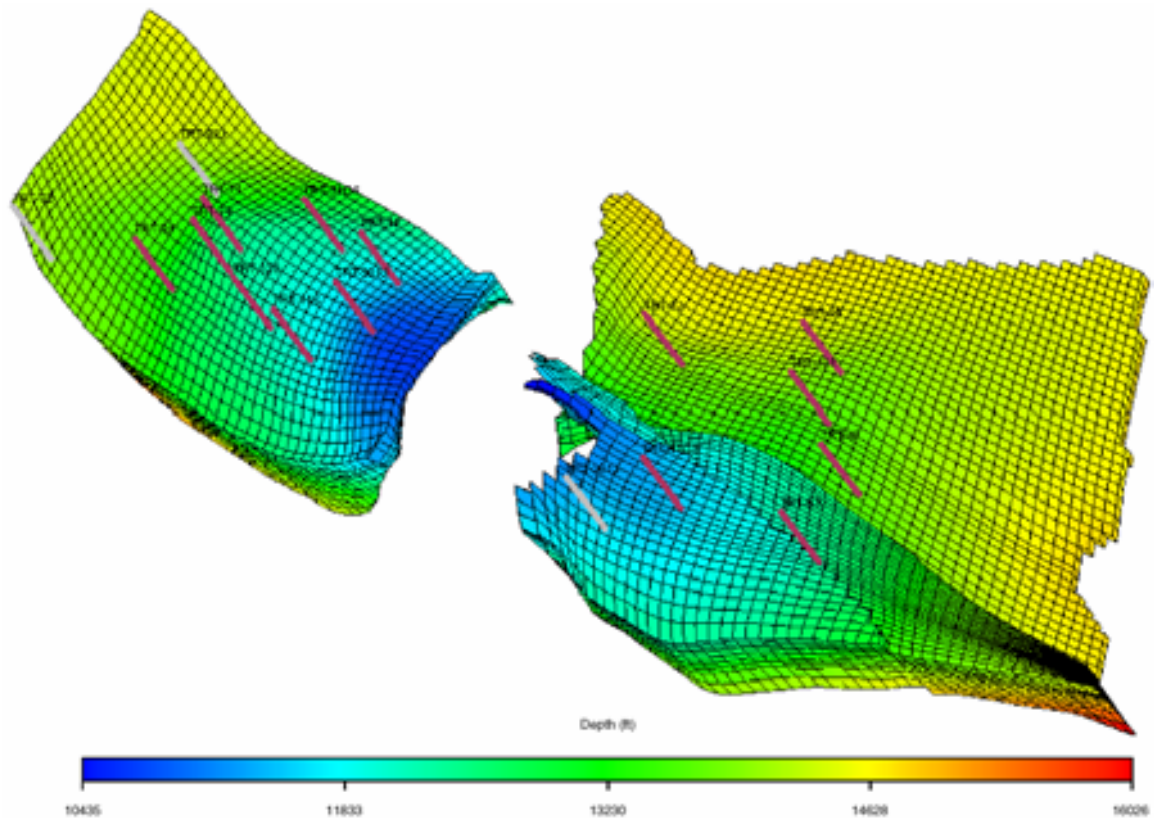


Figure 5. Oblique view toward the north of Taratunich Field JsK formation simulation grid, showing depth ranging from approximately 10000 feet subsea (dark blue) to 16000 feet subsea (red).

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The flow models were calibrated against the historical performance of every well. During the model calibration or history matching process, the initial reservoir descriptions were adjusted until the individual well and field performance were closely matched. Generally, the fracture-pore volume, permeability and sigma factors (matrix to fracture transfer coefficient) were modified to match the observed performance. Communication between wells in the respective blocks also was adjusted using transmissibility barriers, such as faults or change in rock flow properties. Based on the results of the flow-model calibration and production forecast, infill wells were proposed; new log suites and special core tests were recommended. Some of these recommendations have already been implemented in the field.

Conclusions

Taratunich field is a complex and heterogeneous carbonate reservoir that presented a challenge for adequately modeling. The main problem was to represent realistically the triple porosity system in a manner consistent with the geology and transforming it into a dual porosity numerical model. The calibrated model was used to predict field performance and guide economic decisions. Our integrated team approach was very effective in modeling and simulating Taratunich Field.

Reference

Santiago, Jose, and Alfonso Baro, 1992, Mexico's giant fields, 1978-1988 decade, in Giant oil and gas fields of the decade 1978-1988: AAPG Memoir 54, p. 73-99.