Application of Deepwater Outcrop Analog Data to 3-D Reservoir Modeling: An Example from the Diana Field, Western Gulf of Mexico

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Introduction

The challenge at Diana field was to predict the production performance of a channelized deepwater reservoir with a relatively thin oil rim and a large gas cap. Associated development costs are high requiring an optimization program to ensure a viable project. These predictions were further challenged by variable quality seismic data, a reservoir thickness expressed by a single cycle seismic event, only limited appraisal wells, and the likelihood for sub-seismic reservoir variability that could control the economic viability of the project. To assist with reserve assessments and optimization of depletion strategies, deepwater outcrop analog data were integrated with seismic and well data to produce a detailed object-based model for more accurate reservoir characterization.

The Diana field is situated in the western Gulf of Mexico 160 miles south f Galveston in approximately 4700 ft of water (Figure 1). Exxon is the operator with 66% interest while BP holds a 33% interest. Diana is the second largest of several discoveries recently made in the Diana Basin and has in excess of 100 MOEB of recoverable hydrocarbons from the Upper Pliocene A-50 reservoir. The turbiditic sandstones and mudstones that comprise the A-50 reservoir at the Diana field were deposited as a lowstand fan within an intraslope basin setting. The field is located on the east flank of a north-south trending salt-cored ridge. Hydrocarbons are trapped by a combination of structure and stratigraphic onlap, with a large gas cap(>1000 ft column height) and a relatively thin oil column (approximately 240 ft column height). The Diana Basin is relatively large, consisting of 2 narrow feeder-corridors to the north which open into a large low relief basin approximately 20 miles wide by 20 miles

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long, or about 3-4 times the size of the next largest up-dip intraslope basin.

Diana Subsurface Data

Based on detailed analysis, the 3-D seismic data at Diana field appears to be of variable quality and does not allow direct geometric analysis of reservoir elements. Seismic amplitude extractions display distinct stripes in the inline direction that are interpreted to be related to the acquisition of the survey (Figure 2). This complicates any quantitative attribute analysis of the reservoir and does not allow seismic amplitude map patterns to be used to delineate sandbody dimensions. Qualitative examination of vertical seismic in-lines and cross-lines, however, provides valuable information concerning the architecture of the reservoir elements. The A-50 sands are low impedance where they are hydrocarbon charged and are represented by a single cycle seismic event (tough-peak pair) with a trough (red-negative impedance boundary) at the top and a peak (black-positive impedance boundary) at the base (Figures 3 & 4). The proximal portion of the Diana field (wells Diana 2 and Diana 3) is represented by high amplitude, continuous (HAC) seismic character (Figure 3). This suggests that if variation in net to gross ratios (N:G) exists in this portion of the reservoir it is below seismic detection. The medial to distal portion of the reservoir (Diana 1 well) has a distinctly different seismic character than the updip portion of the reservoir (Diana 2 / Diana 3) and is represented by high amplitude, semicontinuous (HASC) seismic character (Figure 4). This variation in seismic amplitude suggests ratios exist. Well penetrations confirm this interpretation: Diana 2 and Diana 3 were drilled in the higher amplitude portions of the reservoir and have approximately 85% N:G, whereas Diana 1 is drilled in a lower amplitude and the N:G is approximately 65%.

Although the seismic data is of variable quality and the reservoir is only expressed by a single cycle seismic event, the excellent core coverage enables close calibration of seismic and well data. Based on the well-log data and the association of facies observed in core, the A-50 is interpreted as a channelized deepwater complex (Figure 5). The cored interval is comprised of higher order, sharp-based, upward-fining channels and individual channel-fill successions that can be further subdivided into channel-axis, and channel-margin associations. Channel-axis deposits are characterized by highly amalgamated massive sandstones. The channel off-axis association is composed of stacked, semi- to non-amalgamated, massive to planar stratified sandstones and interlaminated mudstones. The channel-margin deposits contain a variety of lithofacies and are characterized by a heterolithic mixture of interbedded sandstones and mudstones. Statistical foot by foot comparison of log curves versus core described lithofacies was used to interpret depositional facies in uncored portions of well. Blocked wells were further used to condition the object-based model and to control distribution of channel elements and vertical stacking patterns.

The updip portion of the A-50 reservoir (Diana 2/Diana 3) is represented by a high amplitude continuous (HAC) seismic character dominated by amalgamated high concentration turbidites suggesting a relatively channelized depositional setting. The medial portion of the A-50 reservoir (Diana 1) is represented by high amplitude semi-continuous seismic character (HASC) dominated by non-amalgamated, high-concentration turbidites suggesting a less channelized and more sheet-like depositional setting with limited axial (amalgamated) reservoir updip, becoming more distributive and sheet-like downdip.

This subsurface data, however, did not have the resolution to provide the dimensional and architectural data required to condition a geologic model for flow simulation and well-performance prediction. To solve these uncertainties outcrop analog data from analogous deepwater out crops were integrated with seismic and well data from the Diana field to provide geometric and architectural data below the resolution of the seismic data.

Deepwater Outcrop Analogs

Outcrops span a critical gap in both scale and resolution between seismic and well-bore data and integration of Diana specific seismic, well-log core and appropriate outcrop analogs provided the detailed geometric properties required for interpreting the reservoir architecture at a sub-seismic or flow unit scale. The Lower Permian Skoorsteenberg Formation in Tanqua Karoo Basin, South Africa and the Lower Carboniferous Ross Sandstone in the Clare Basin, western Ireland are both composed of stacked turbiditic sandstones and mudstones deposited within a channelized basin-floor fan setting. These laterally continuous outcrops provide an excellent opportunity to characterize detailed bed-scale reservoir architecture and internal heterogeneities that affect the producibility of deepwater sandbodies in both depositional strike and dip perspectives. The Skoorsteenberg Formation and Ross Sandstone also have a sediment composition and architecture very similar to the A50 reservoir at Diana based on seismic, well-log and core data. Dimensional and architectural data from these outcrops can therefore be used to help constrain 3D geologic and reservoir models which ill be used to predict well performance, connected volumes and recovery efficiencies for the Diana Development. Based on this detailed characterization, the deepwater sandstones present in the South Africa and western Ireland can be divided into proximal, medial and distal fan settings, each with its own set of key characteristics(Figure 6).

Dominating the most proximal exposures are compensationally stacked, erosional based, narrow (low aspect ratio) channels and interchannel sheets. Channels are filled from axes to margins by amalgamated, thick-bedded massive sandstones which pass upward into non-amalgamated massive to ripple laminated sandstones representing channel avulsion and/or abandonment. The interchannel strata are comprised of non-amalgamated thin- to thick-bedded current ripple laminated sandstones and interbedded silty mudstones. Medial fan deposits are comprised of broad channels or what more correctly can be termed sheets. The bases of these sandstone-prone sheet complexes tend to be nonerosional or only slightly erosional. Individual sheets have narrow, amalgamated axes and sheet-like, layered margins. Axes are erosionally based, and filled with highly amalgamated massive sandstones. Away form the axes, amalgamated massive sandstones are replaced by interbedded mudstones. Overall this is a very layered reservoir with most of the amalgamation of channel/sheet complexes occurring where erosional axes cut into underlying sandbodies. Dominating the distal fan deposits are non-amalgamated turbidite sheets which are sharp-based and highly amalgamated in their narrow axial portion. Importantly, the sandstones present even is this extremely distal fan position are predominantly high quality, massive sandstones.

In summary, proximal fan deposits are dominated by narrow, amalgamated channels, medial fan deposits are comprised of semi-amalgamated sheets and distal fan deposits are dominated by non-amalgamated sheets, similar to the interpreted updip to downdip architecture of the A-50 reservoir at Diana (Figure 6). Channel and bed scale reservoir architectures were quantified with photo-mosaics and by correlation of closely spaced measured sections from a variety of channel types to condition the model (Figure 7). Dimensional and architectural data from these outcrops were compared to Diana specific seismic and well data and adjusted accordingly. From these measurements a spectrum of channel dimensions and shapes were collected to condition the modeled objects, In additional to the collection of channel dimensions and shapes, bed continuity, and lateral and vertical facies variability data were collected from a variety of channel types to condition the reservoir behavior.

Object-based Modeling

Object-based models consist of discrete objects (facies bodies) each with specific dimensions, facies juxtapositions and continuity that incorporates geologic interpretation an honors all available data (Figure 8a). The facies objects are first inserted so as to honor all well data, and subsequently inserted stochastically into inner-well regions according to geologic constraints (i.e. vertical stacking patterns) until volume targets are met. In the Diana model, the reservoir is represented by a series of stacked channel bodies that are meant to represent deepwater channels. Individual channels are narrow updip and become wider and less amalgamated downdip, as suggested by the integration of the seismic, well-log, core and analog outcrop data. The final model contains over 100 individual channels each one stochastically generated from a range of possible widths and thicknesses (Figure 8b). Modeled channels are divided into proximal, medial and distal regions with their own specific set of characteristics. Channels are further subdivided into axis, off-axis and margin associations. Each facies and subfacies body was then populated with petrophysical properties using Gaussian simulation drawn from sub-facies property histograms generated from available well data. Facies bodies dimensions, architecture and facies proportions were generated from the integration of subsurface and outcrop data.

The ultimate goal of this integrated analysis was to predict architectural controls on the producibility of the relatively thin, yet economically important oil rim which following the discovery at Hoover became economically viable (Figure 9). Initially, oil will be produced from horizontal wells high in the oil rim. Once water breaks through in significant quantities these wells will be recompleted in the gas cap. The goal is to maximize oil production while minimizing water production and movement of oil into the gas cap. Typically reservoir models are scaled up for flow simulation, but in this case the updip portion of the reservoir was actually scaled down in order to preserve its more channelized nature. Based on this modeling effort and flow simulation, significant variations in reservoir performance exist from updip to downdip. The updip portion of the reservoir has higher initial oil saturations due to its higher porosities and also starts making high water cuts earlier than the downdip portion of the reservoir due to its more amalgamated nature and better reservoir quality. This therefore predicts that significant variations in reservoir producibility exists from updip to downdip and these varying characteristics must be considered in the final development plan.

Conclusions

Architectural styles of sandbodies deposited in deepwater settings are highly variable and this variability in sandbody geometry and continuity affects both the exploration and production potential of deepwater sandstones. Outcrops provide constrained geometric and architectural data which fill the gaps between wells or stochastic modeling uncertainties below the resolution of seismic data. Dimensional and architectural data from outcrops can therefore be used to help populate object-based models which will be used to more accurately predict well performance, connected volumes and recovery efficiencies for newly discovered fields. Furthermore, the integration of seismic, well, core and outcrop data with object-based models provides the framework for optimal placement of wells to maximize the architectural controls on reservoir performance.

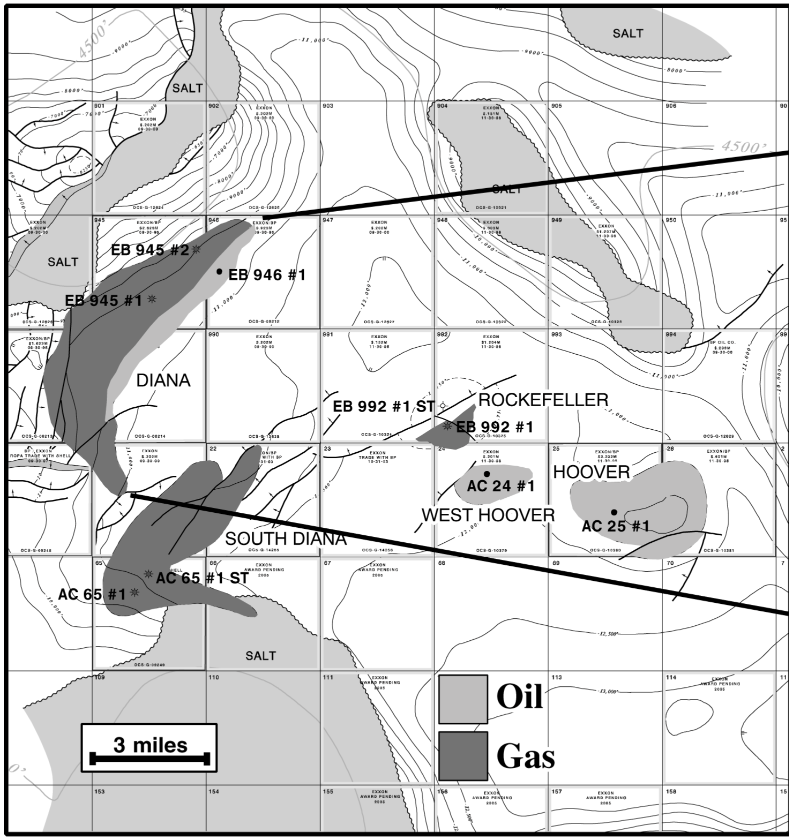

Figure 1: The Diana field is located in the western Gulf of Mexico 160 miles south of Galveston

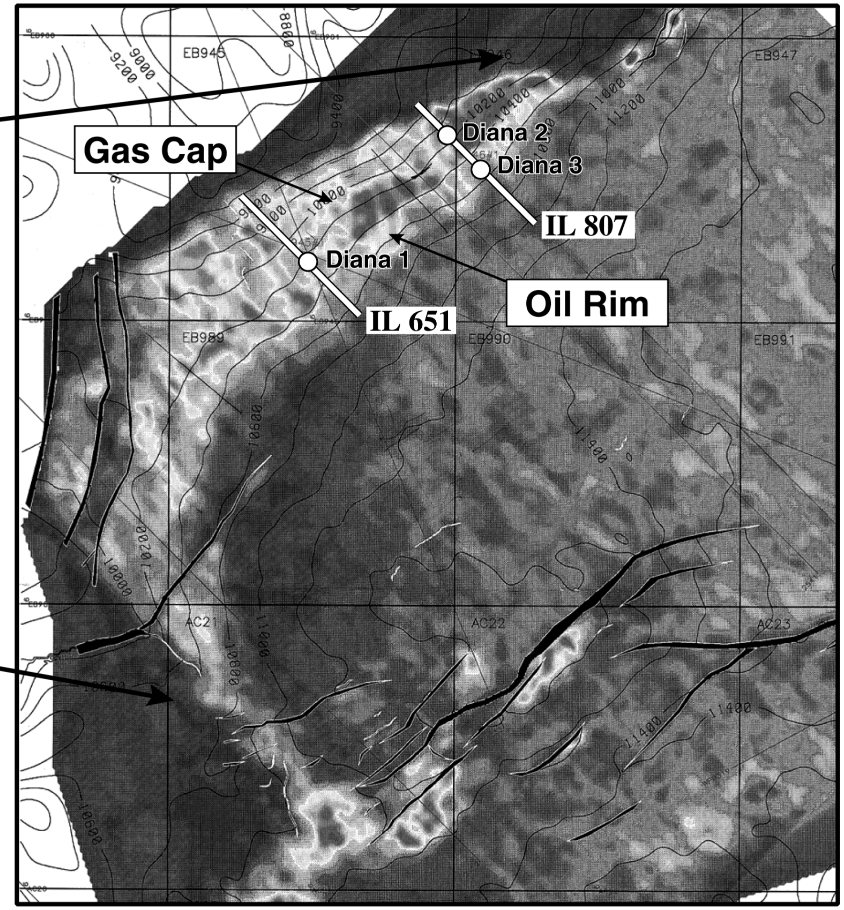

Figure 2: Combined structure and composite amplitude extraction for the Upper Pliocene A-50 reservoir. Structural contours are in 200 ft intervals. Note NW-SE “stripes” in this amplitude extraction.

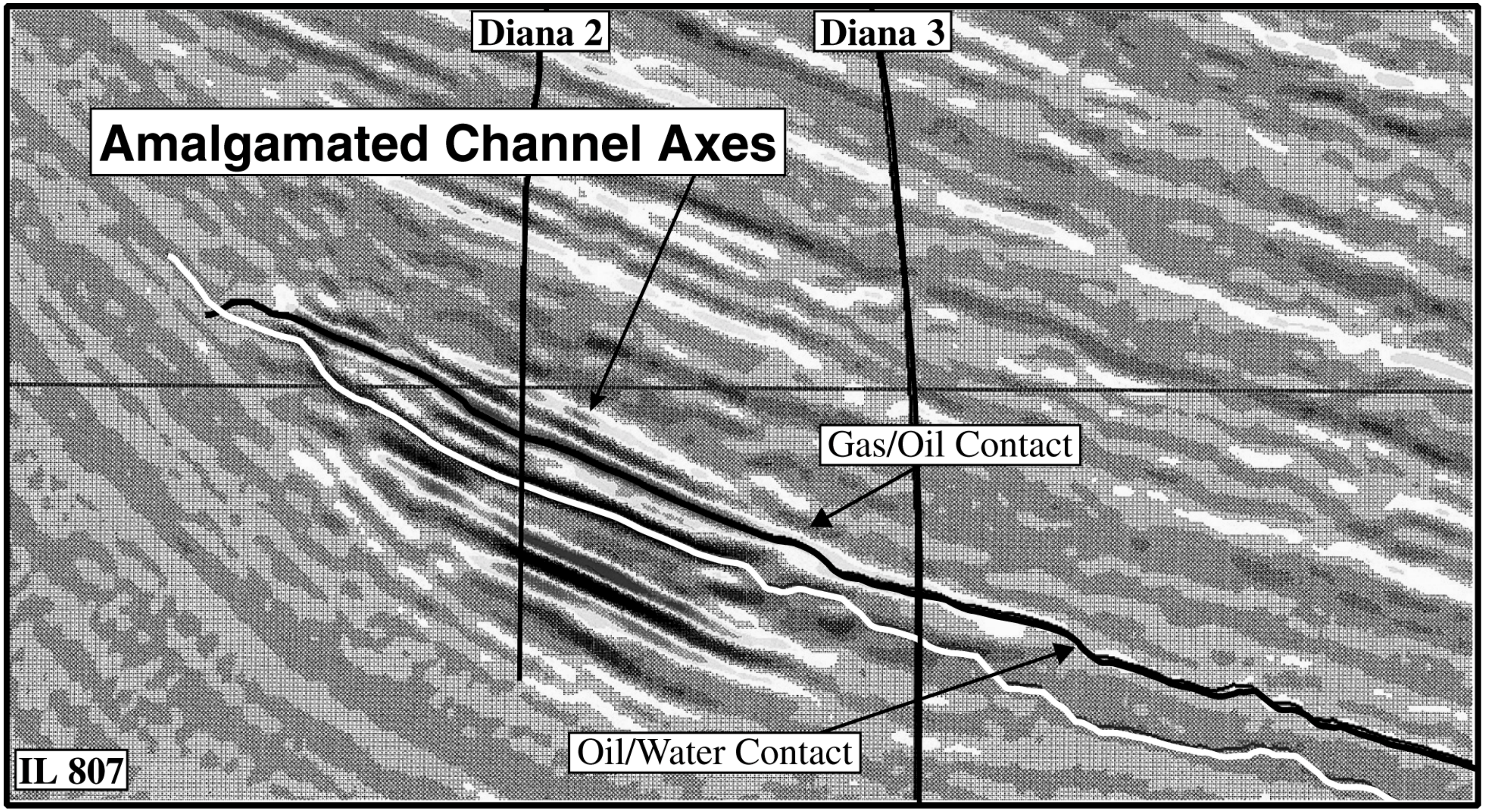

Figure 3 : Depositional strike section through the reservoir. Variation in amplitude between the Diana 2 and Diana 3 wells is related to the changed from gas (bright) to oil (moderately dim) to water (dim).

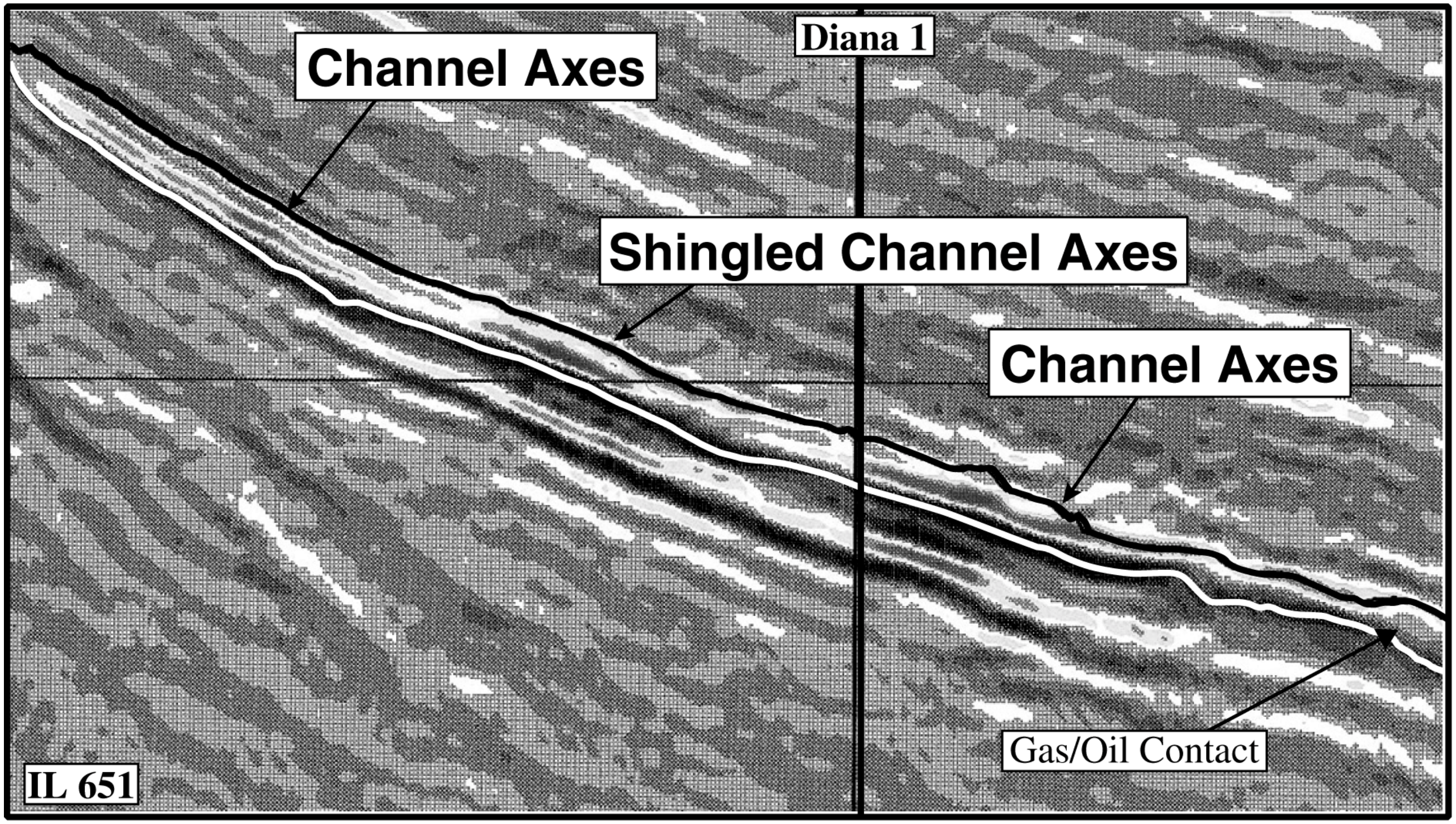

Figure 4: Diana 1 is located 2 miles down depositional dip from Diana 2 & 3. Variation in amplitude is not fluid related as this interval is entirely within the gas cap.

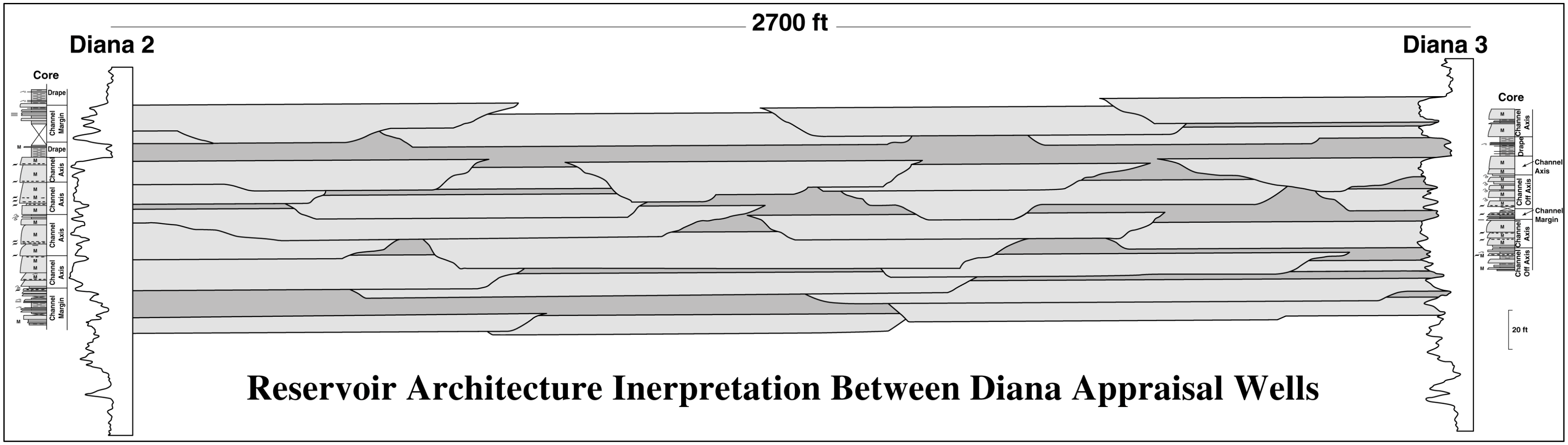

Figure 5: Integration of Diana seismic, well log, core and appropriate outcrop analog data provided the detailed geometric data required for interpreting the reservoir architecture at a sub-seismic scale.

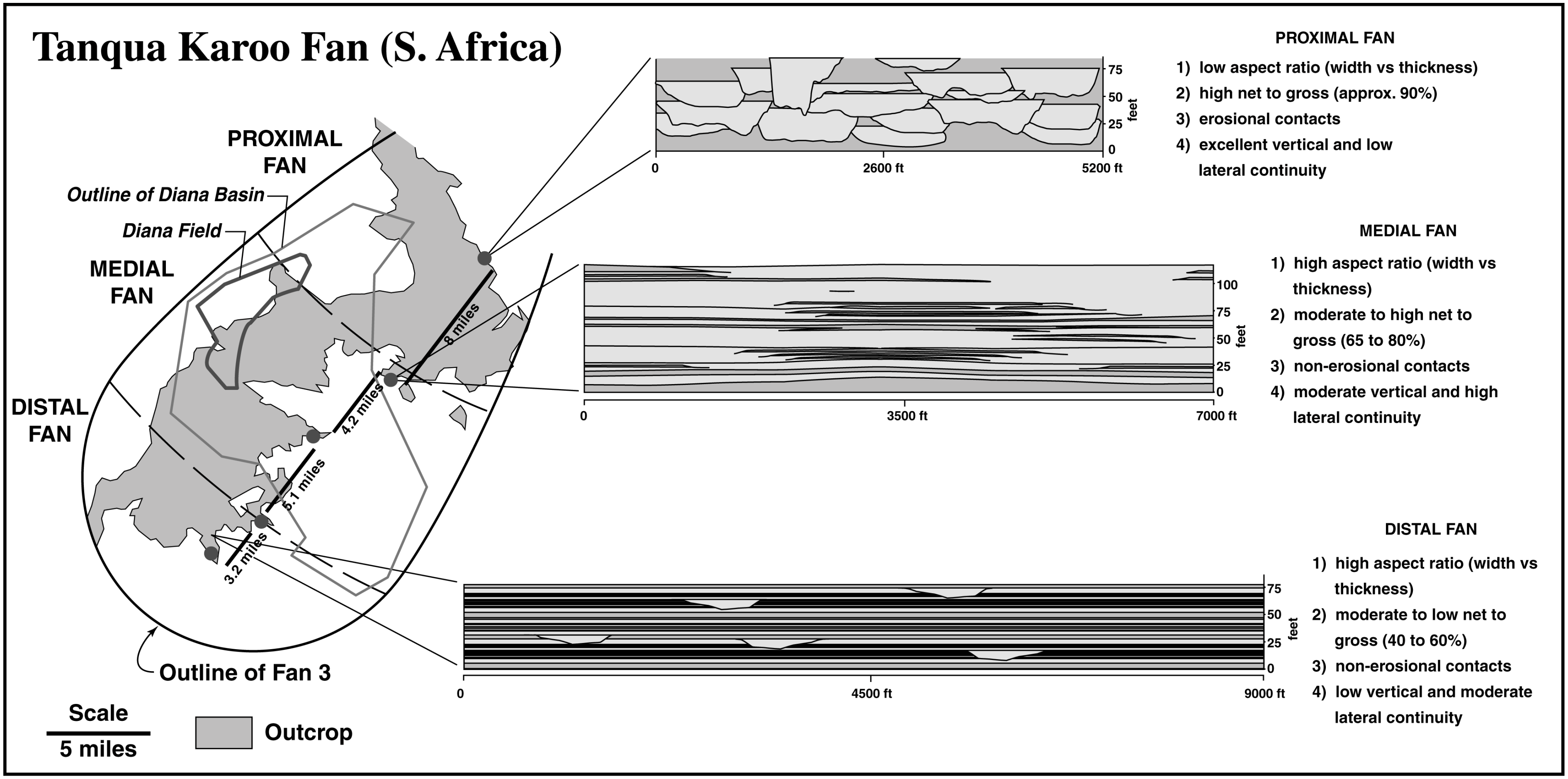

Figure 6: Based on detailed characterization, deepwater outcrops such as these from the Tanqua Karoo basin in S. Africa can be divided into proximal, medial and distal settings, each with their own set of key characteristics.

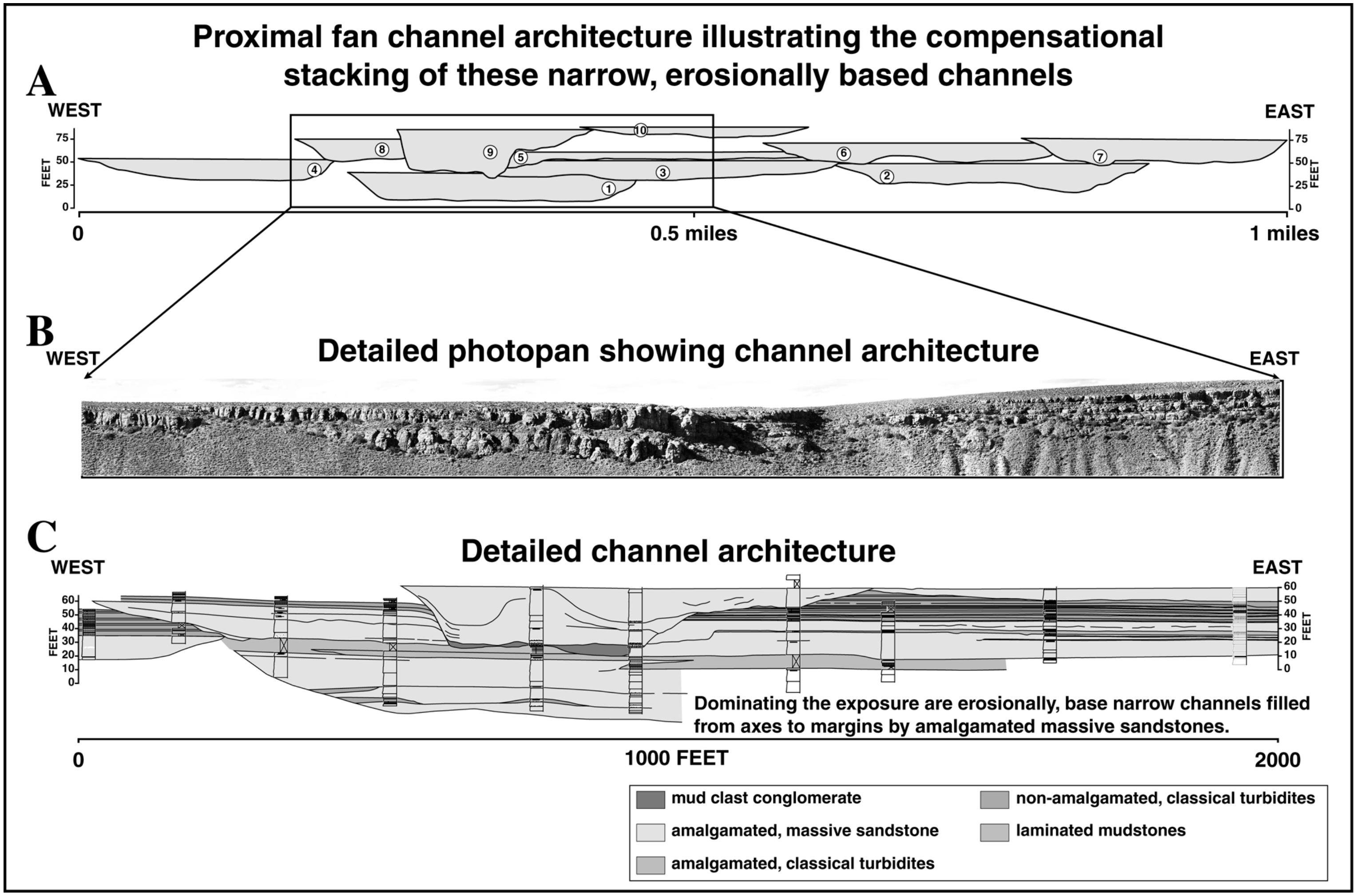

Figure 7: Shown here is one of the laterally continuous outcrops that was quantified with photo mosaics and by bed scale correlations. **7a** & **7b** Channel scale reservoir architectures were quantified to condition the modeled objects by measuring channel widths and thicknesses from calibrated photo mosaics. **7c** Bed scale reservoir architectures were quantified by correlation of closely spaced measured sections.

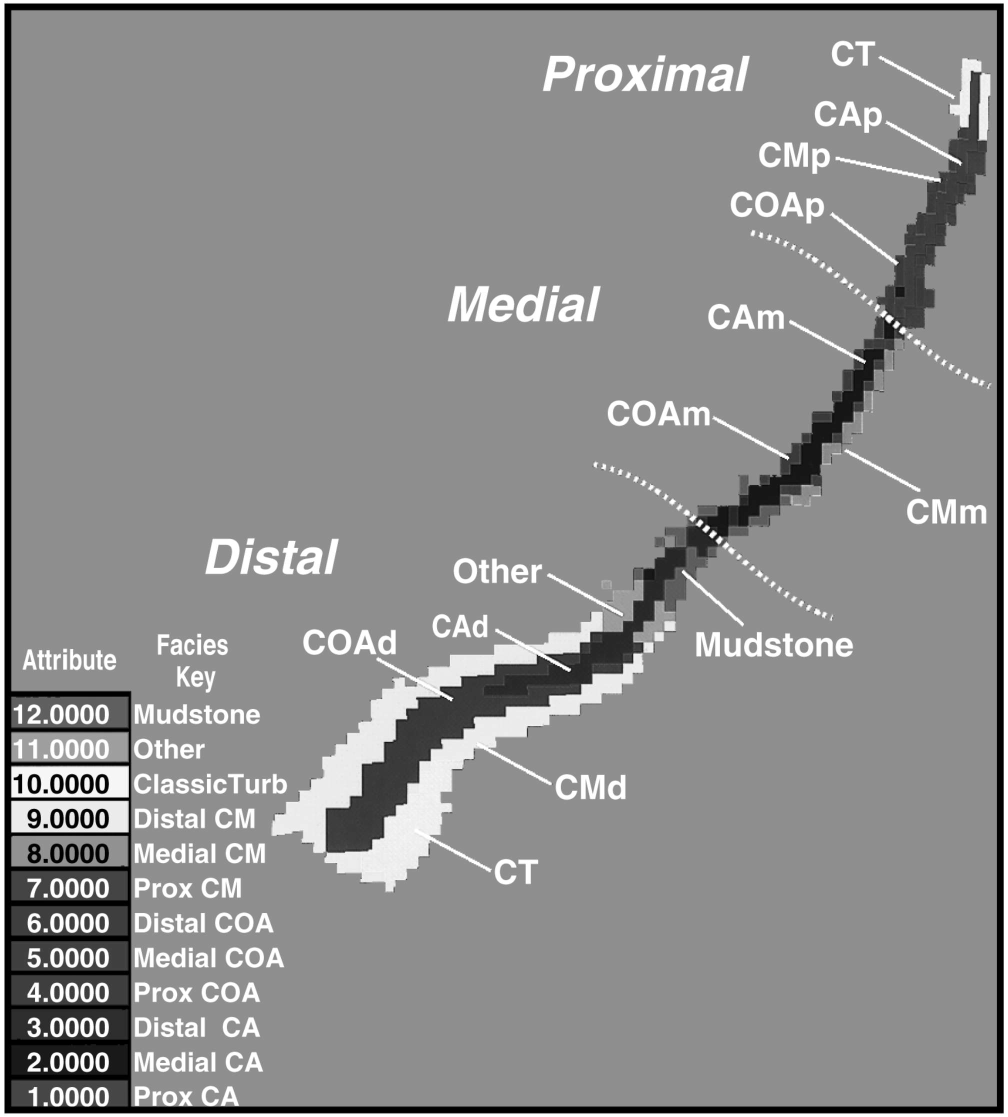

Figure 8a: Single channel (facies body) model. Modeled channels are divided into proximal, medial and distal regions each with their specific set of characteristics. Channels are further subdivided into axis (CA), channel off-axis (COA) and margin associations (CM). The final model contains over 100 individual channels generated from a range of possible widths and thicknesses.

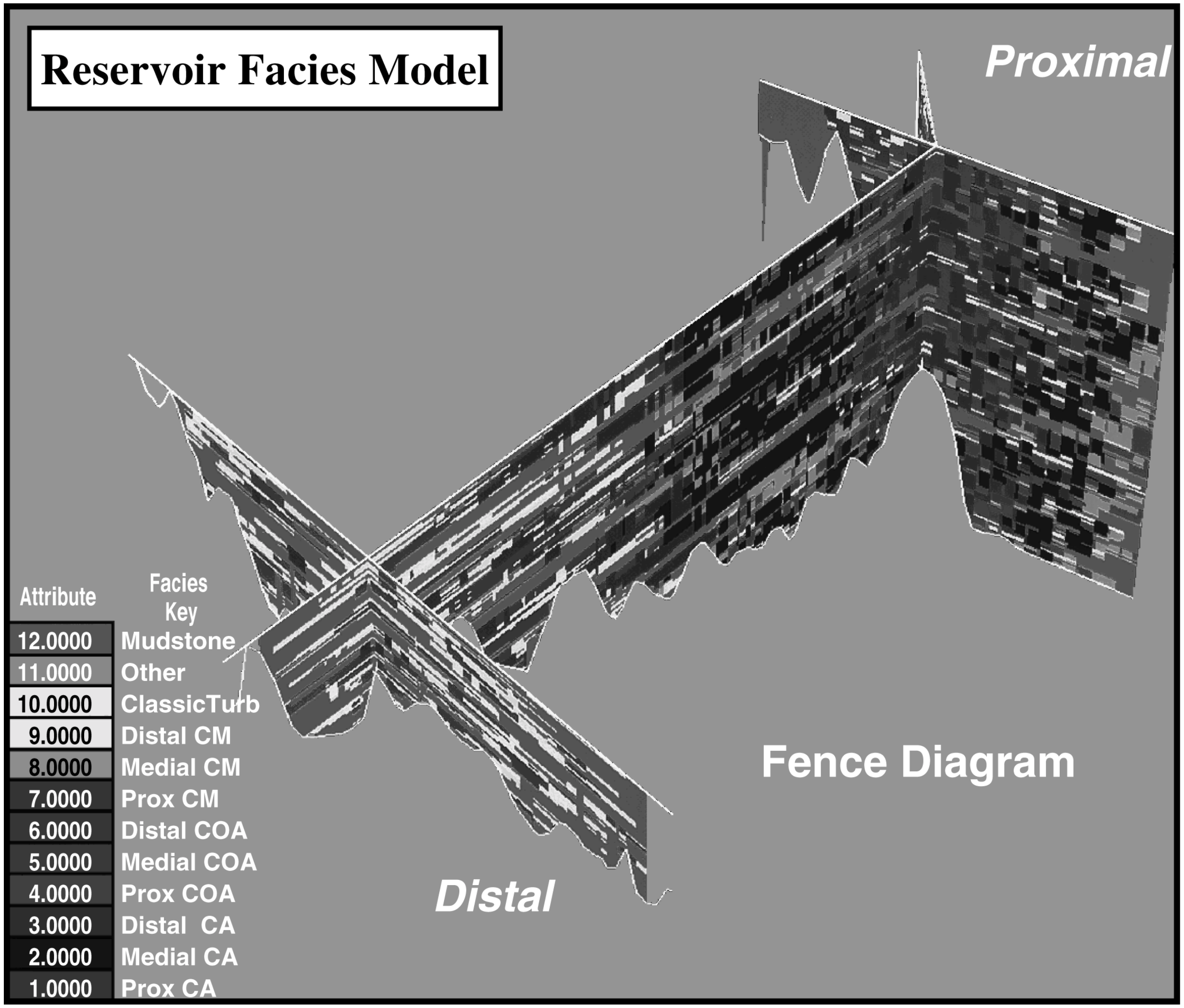

Figure 8b Based on this modeling effort, notable variability exists in both the vertical and lateral continuity of the reservoir facies from up dip to down dip. This is illustrated by the change in cell dimensions from thicker and more equal dimensional (amalgamated) updip to thinner and more elongate (non-amalgamated) downdip.

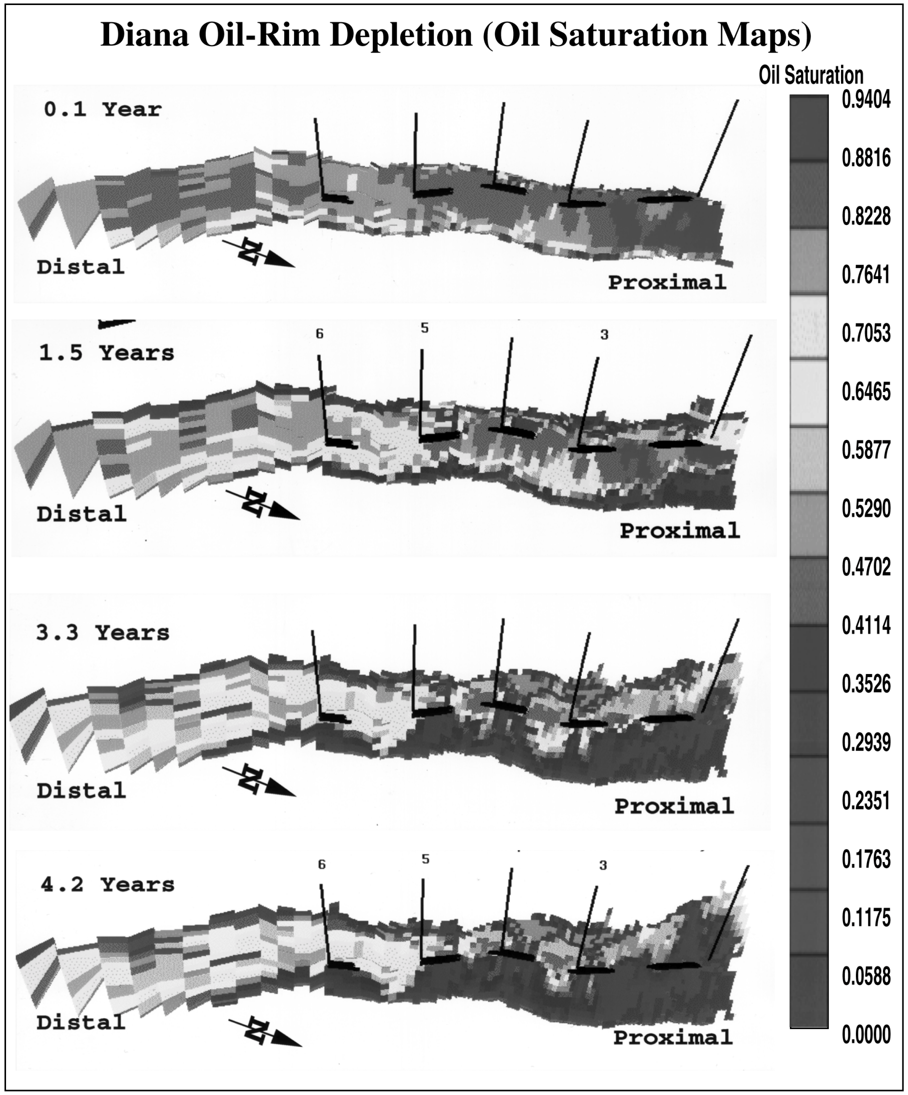

Figure 9: Oil saturation maps for the Diana oil-rim for the first 4 years of production. Note that Diana gas cap and aquifer are not shown. The updip portion of the reservoir has higher initial oil saturations due to its higher porosities and also starts making high water cuts earlier than the downdip portion of the reservoir due to its more amalgamated character and better reservoir quality.