Synthetic Seismic to Real Data Cross Correlation: A Forward Modeling Technique to Determine Reservoir Porosity from Seismic Amplitude Data

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ABSTRACT

The average porosities and net thickness of three associated Early Cretaceous carbonate ramp reservoirs are mapped away from well control using reprocessed 2-D seismic data for a Middle East oil field which is in the reservoir appraisal stage of field development. Initially the constraints on the properties of the reservoir rocks and the numerical inter-relationships of the rock layers were determined by mathematical analysis. Then, using forward modeling techniques, a series of synthetic seismic traces were created to cover the expected range of reservoir variation. Using the seismic attribute analysis capabilities of a Geoscience workstation, these model traces were then cross-correlated with the interpreted seismic data to identify the best model match to each seismic trace. As both the seismic rock property values and the geometry of the model traces are known, the field's aggregate reservoir properties of porosity and thickness can be estimated.

INTRODUCTION

Seismic multiples have long been recognized as a problem in the Middle East. Multiples can distort or even obscure the true amplitudes of a reservoir horizon and hence make the estimates of porosity calculated from seismic data incorrect. In this study the seismic window over the reservoir of a Middle East oil field is clear of multiple interference thereby providing confidence that the observed reflections are representative of the reservoir properties.

DATA AND METHODOLOGY

The study of this field was carried out using six zero-phase 2-D seismic lines of two vintages (late 1970s and late 1980s). The earlier lines have a Common Depth Point (CDP) spacing of 25 metres (m) while the later lines have a CDP spacing of 12.5 m. Nine wells were analysed and include a range of porosities (ϕ) from the high values at the field's crest ($\phi = 25\%$) to the lower porosity flanks of the accumulation ($\phi = 9\%$).

The geophysical analysis was carried out on both a MicroVax Geoscience workstation and a Macintosh personal computer and consisted of several stages. Initially the borehole data was used to establish constraints for the petrophysical, geometrical and geological characteristics of the field. The borehole data was also used to correlate the acoustic impedance and porosity; the bed-to-bed porosity and the bed-to-bed layer thickness.

The seismic data analysis involved the following steps: (1) seismic wavelet extraction; (2) synthetic trace generation at the well and tying each reservoir unit to the seismic events; (3) picking the seismic amplitude maxima and minima of the reservoir horizons; (4) model creation (template design and rock property selection); and (5) attribute analysis using a cross-correlation technique to establish the field's gross porosity and thickness variation.

Data Constraints Analysis

Using Microsoft Excel (a Macintosh-based numerical analysis application) the reservoir zonal average properties for the field area were established from well control. The average reservoir interval values of thickness, density and velocity for each unit were recorded for the nine wells in the study area. Using these well parameters the average (mean) thickness, density, velocity and acoustic impedance (AAI) values were calculated for the reservoir units.

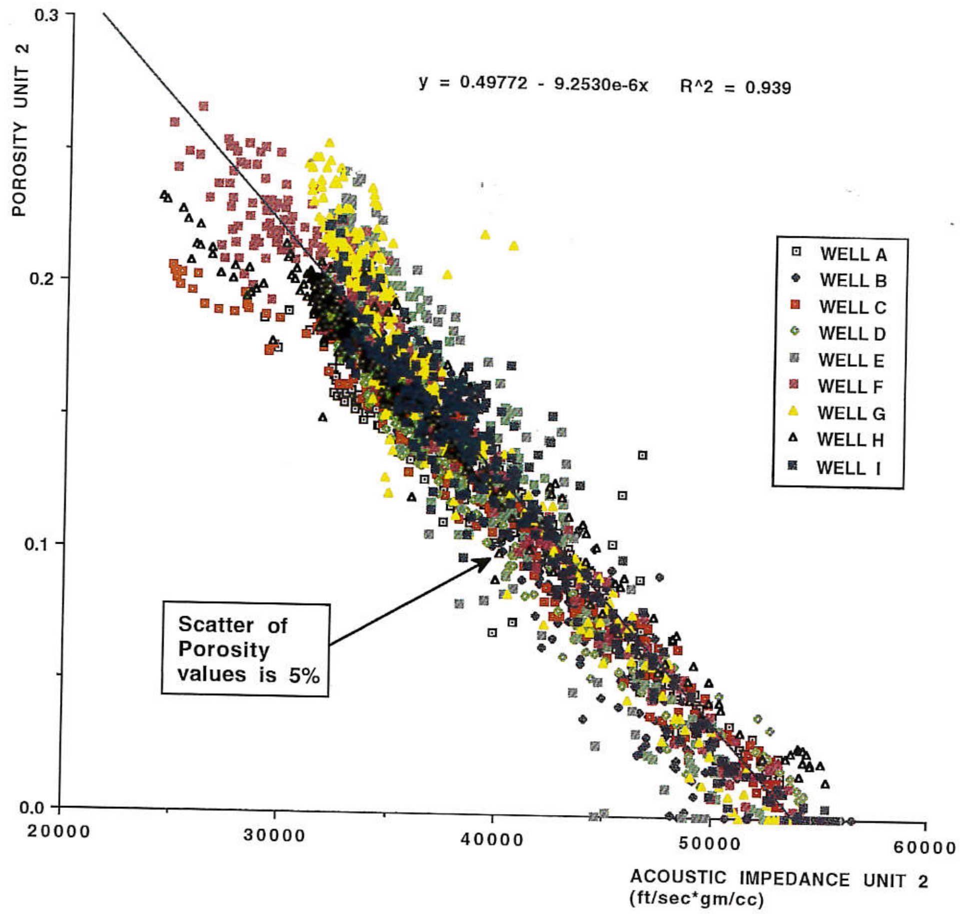

Figure 1: AAI/porosity cross-plot carbonate reservoir Unit 2.

In order to study the likely limits to the rock parameter variation over the field, the standard deviation of the well data were also calculated. The field values were seen to lie approximately within the limits of the mean plus or minus twice the standard deviation (lower to upper limit). The three established statistics were then used to define the constraints on variability in the four reservoir properties of thickness, density, interval velocity and AAI. These rock property constraints were used to build the five reservoir models for the forward modeling study.

Data Correlation Analysis

Using CricketGraph (a Macintosh based graphical analysis package) four relationships were identified within the data. First, the reservoir seismic interval velocity is generally insensitive to depth over the 70 m of field topography as recorded by the well data. Second, an excellent correlation (90% plus) between acoustic impedance and average (zonal) reservoir porosity was observed from well data for reservoir Units 2 and 3 (Figure 1). This analysis suggest that variations of 5% porosity can be distinguished by measuring the seismic interval velocity (assuming 100% accuracy). Thirdly, a strong inverse correlation between reservoir thickness and overlying seal thickness was established. This relationship implies that gross interval thickness for the beds Top Carbonate to base Unit 3 reservoir is relatively constant over the field area. Finally, a strong correlation between the gross interval porosity in reservoir Unit 1 and that of Unit 2 as recorded at the wells. There is a similar, but less marked porosity relationship between Units 2 and 3.

Seismic Wavelet Extraction

The seismic signal quality at the reservoir level was studied to determine the optimum CDP location which ties each line to the well. A seismic wavelet is the signal present in the seismic survey. It is used to match the geology (well sequences), the petrophysics (well logs) and the geophysics (seismic data) at a borehole. The shape of a seismic wavelet is a measure of the quality of the seismic data and hence the survey's reliability.

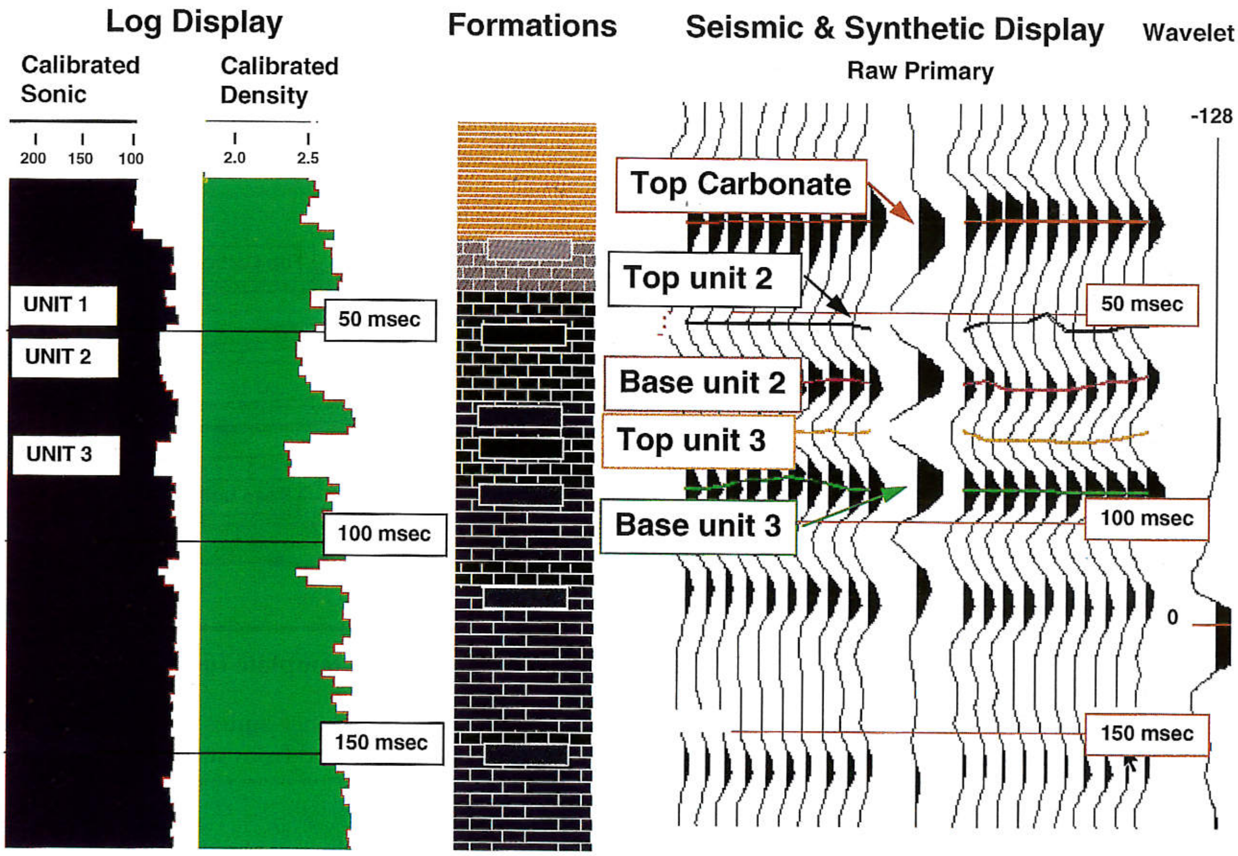

Figure 2: Petrophysics/Geology/Geophysics tie for well G.

Using the Geoscience workstation, seismic wavelet extractions were performed for each of the eight field wells that lie close to seismic lines. In total, ten wavelet extractions were done with varying degrees of success with the tie from well G achieving the best zero-phase wavelet (Figure 2).

Well Synthetic (1-D) Modeling and Well Tying

The purpose of this stage of the analysis is to identify the seismic reflection character of the reservoir boundaries at each well location and determine the presence of any multiples in the data. Using the appropriate seismic wavelet, a "primaries only" synthetic l-D trace was created (Figure 2).

The l-D synthetic tie demonstrates that the following five important seismic events can be seen. The three black peaks of Top Carbonate, Base Unit 2 and Base Unit 3 and the two intervening white troughs of Top Unit 2 and Top Unit 3. The good match shows the data is multiple free over this small interval (60 milliseconds - msec). The match also demonstrates that reservoir Unit 1 cannot be observed on this seismic data.

Seismic Amplitude Tracking

Using the capabilities of the geoscience workstation the raw amplitude maxima (or minima) were picked for each horizon by setting auto-correlation gate to its minimum value of 4 msec (i.e. no two way time smoothing). After the auto-tracking process a careful manual quality check was performed to discard any amplitude values recognised as noise (e.g. diffraction trains and multiples).

Seismic Model Creation

Using the Geoscience workstation's modeling capabilities a "SLAB" model was constructed which consisted of an alternating stack of wedge shaped rock units arranged to take account of the observed inverse thickness relationship between reservoir and seal units of the field. That is, where the reservoir units are thickest, the seal units are thinnest and vice versa (Figure 3).

The slab model is built such that the mid-point consists of a stack of average stratigraphic unit thickness for the field. The left-hand edge consists of the thinnest expected seal units (mean minus twice the standard deviation) over the thickest expected reservoir units (mean plus twice the standard deviation). Conversely, the right-hand edge of the slab consists of the thickest expected seal units over the thinnest expected reservoir units. The overall thickness of the interval Top Carbonate to Base Unit 3 varies between 135 m and 136 m across the model.

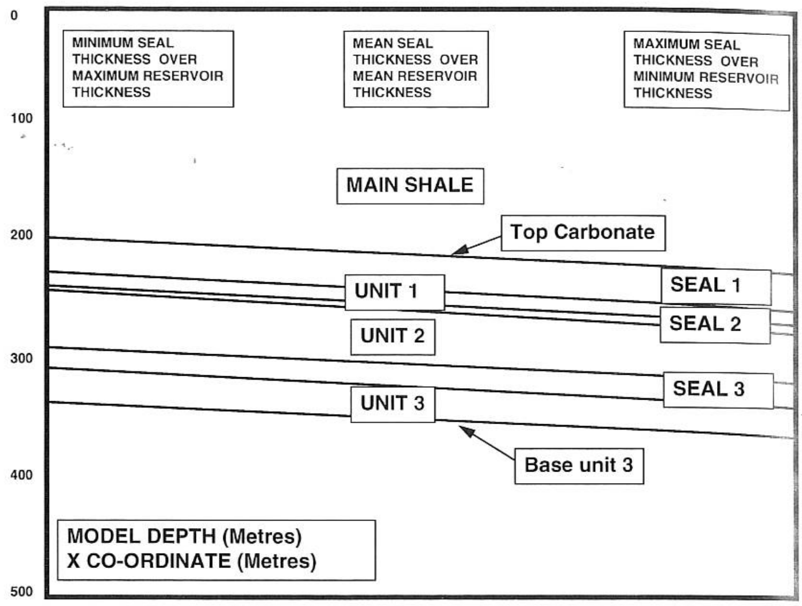

Figure 3: Slab model depth template (meters).

The slab model was then used as a template to contain various values of acoustic impedance for each of the rock layers for the field's reservoir unit (Figure 4). These acoustic impedance suites of EXTREMA 1, EXTREMA 2, MINIMA, MEAN and MAXIMA are those previously established from statistical analysis of the well data and described below:

EXTREMA 1 rock values consists of an alternating suite of minima and maxima AAI values arranged so that the three reservoir layers have the lowest expected AAI (i.e. highest reservoir porosity with the tightest seal units). EXTREMA 2 rock values consists of an alternating suite of maxima and minima AAI values arranged so that the three reservoir layers have the highest expected AAI (i.e. lowest reservoir porosity with the weakest seal units).

MINIMA rock values contain the zonal minimum AAI (minimum is defined as mean minus twice the standard deviation) and equates with the highest expected reservoir porosity. MEAN rock values contain the zonal average AAI values established for the Field. MAXIMA rock values contain the zonal maximum AAI values (maximum is defined as mean plus twice the standard deviation) and equates with the lowest expected reservoir porosity.

For the reservoir layers only EXTREMA 1 is equivalent to MINIMA and EXTREMA 2 is equivalent to MAXIMA. The difference between the suites of data is that EXTREMA 1 has the greatest expected rock property contrast at the reservoir boundaries and therefore the strongest seismic amplitudes. Suite EXTREMA 2 however, has the least expected rock property contrast at the reservoir boundaries and therefore the weakest seismic amplitudes.

Limitations

Four assumptions have been made in creating the models: (1) the most, and also least, porous area for Units 1, 2 and 3 are co-located within the field; (2) the gross interval thickness Top Carbonate to Base Unit 3 is constant at 135.5 m over the area of interest; (3) the inverse thickness relationship between reservoir units and overlying seals is valid away from well control; and (4) the range of rock property variations as determined from well control is valid away from these wells.

Attribute (Cross Correlation) Analysis

Using the best wavelet extracted from Well G (Figure 2), a series of synthetic seismic traces were created for the field's reservoir sequence using the five models established above. Twenty one traces were created for each acoustic impedance model and the full concatenated suite of 105 traces are displayed in Figure 5.

Traces 1 to 21 are from model EXTREMA 1, which corresponds to the best reservoir porosity and strongest reflection contrast. Traces 21 to 42 are from model EXTREMA 2 (worst reservoir porosity, weakest

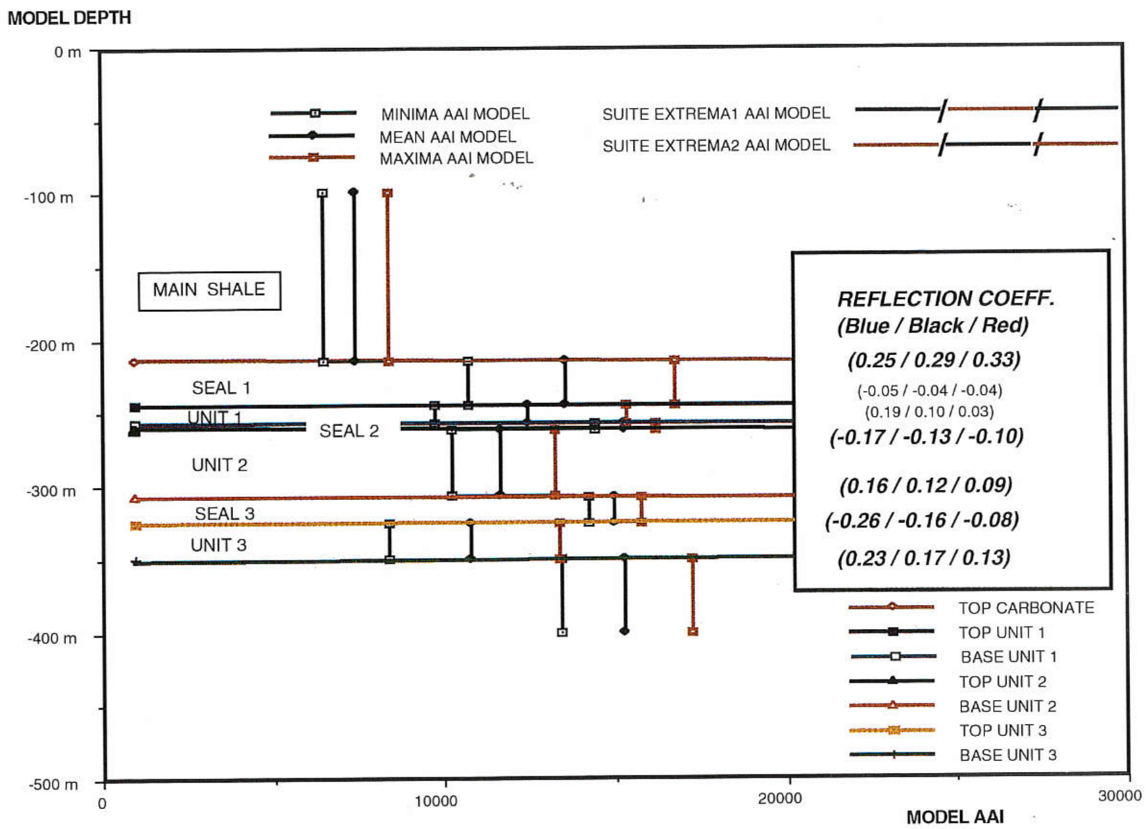

Figure 4: Rock properties model AAI/Depth.

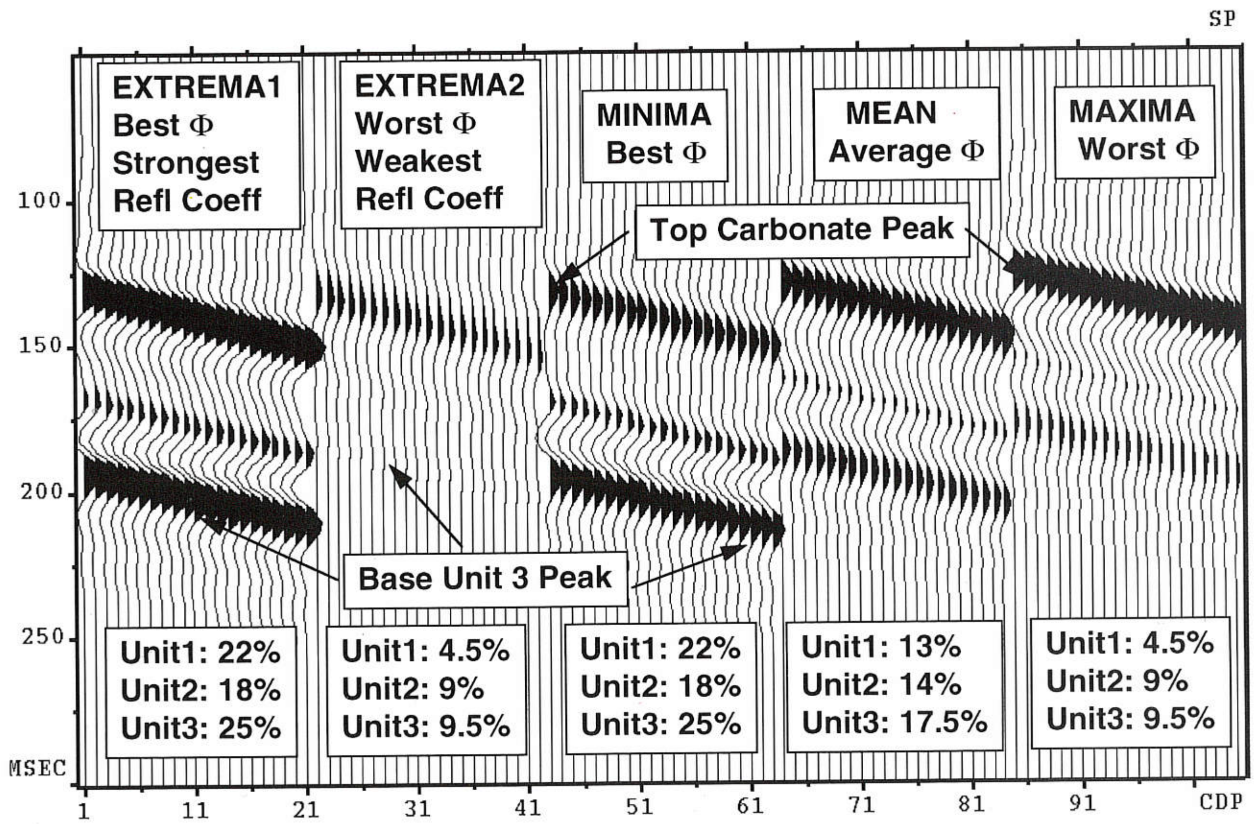

Figure 5: Slab model synthetic seismic lines (concatenated).

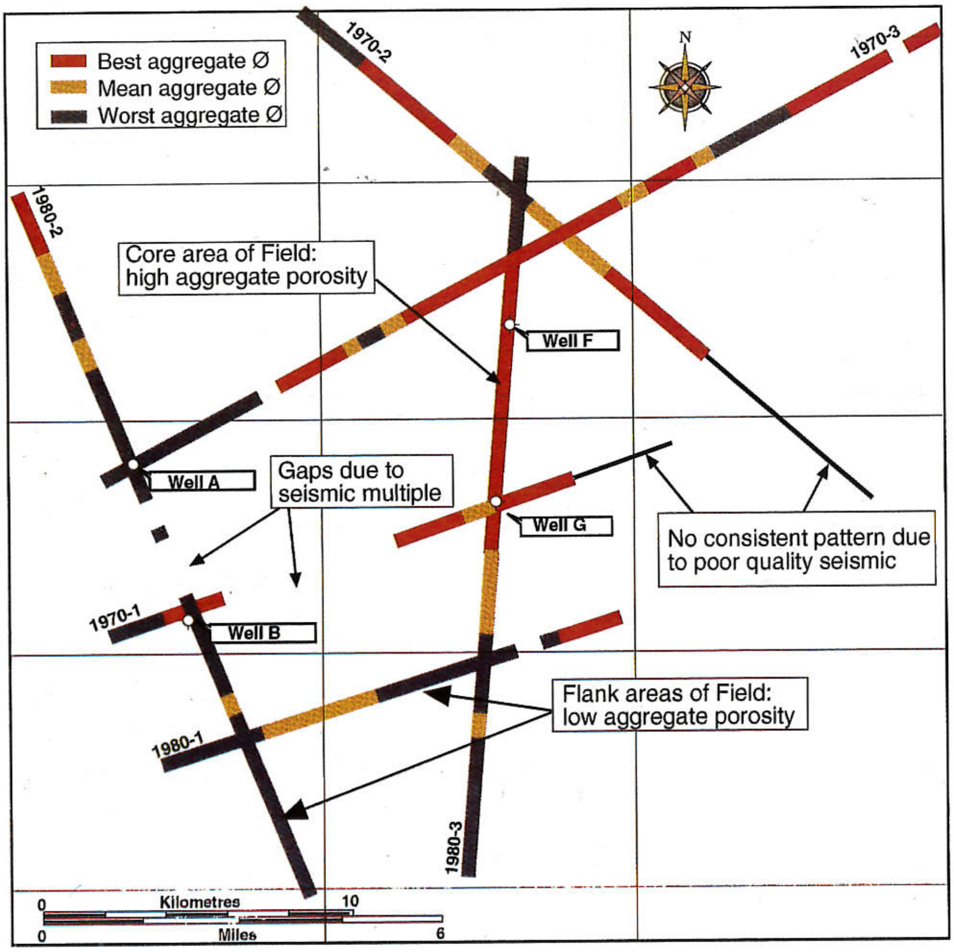

Figure 6: Aggregrate reservoir porosity distribution (model X correlation).

reflection contrast). Traces 43 to 63 are from model MINIMA (best aggregate reservoir porosity). Traces 64 to 84 are from model MEAN (average aggregate reservoir porosity). Traces 85 to 105 are from model MAXIMA (worst aggregate reservoir porosity).

Using the seismic attribute analysis capabilities of the geoscience workstation these model traces where cross-correlated with the seismic data over the field, using the previously established reservoir horizon picks. This process determines the best match of each model trace to the real data for the isochron interval Top Carbonate peak to Base Unit 3 peak. The maximum isochron of 64 msec occurs over the field's crest, this suggests that the interval velocity is low here (i.e. low AAI) and hence the aggregate reservoir porosities are highest at this location (N.B. the field has an overall consistent reservoir isopach).

RESULTS

Figure 6 shows the slab model trace variation in reservoir porosity across the field. Red shows the areas of good porosity (Unit 1: 22%, U2: 18% and U3: 25%), orange shows the areas of average (mean) porosity (Unit 1: 13%, U2: 14% and U3: 17.5%) and blue shows the areas of poor porosity (Unit 1: 4.5%, U2: 9% and U3: 9.5%). The field's core area of good porosity (red) is developed around wells F and G and the poor porosity (blue) around wells A and B on the field's flanks.

Figure 7 shows the slab model's variation in gross reservoir thickness (Units 1, 2 and 3 aggregate) across the field. Red are areas of maximum reservoir isopach (89 m), orange are areas of average reservoir isopach (82 m) and blue are areas of minimum reservoir isopach (75 m).

Figure 8 shows the confidence values of the respective correlations of slab model trace (Figure 5) to real data CDP. The confidence level for the high porosity values predicted in the core area of the field between wells F and G is over 95% (red), while confidence for the low porosity values predicted in the area south of well B is similarly over 95%. The synthetic traces used in the slab model were created with a wavelet extracted from the 1980s seismic lines. Figure 8 shows that there is a better match to these lines (maximum correlation 95%: red) as compared to the 1970s seismic lines (maximum correlation 85%: orange).

DISCUSSION

This field's geoscience data set has a number of features that permit the calculation of average reservoir porosity and thickness from seismic data, but also restrictions that limit both the sensitivity of the calculation and also the choice of technique that can be used. The features of the data that permit the calculation of porosity derive from the geological nature of the reservoirs and their associated petrophysical properties:-

- The reservoir units were deposited in an inner to mid-carbonate ramp environment which produced a wide-spread and uniformly layered sequence of rocks. Consequently the field has a uniform geometric thickness that results in a predictable pattern of seismic events which can be recognized and tied to observed lithological boundaries in the wells.

- The reservoir units consist of peloidal and intraclastic grainstones and packstones and have a good correlation between porosity and seismic velocity. Whereas the surrounding limestone seals consist of tight outer carbonate ramp bioclastic and foraminiferal packstones and wackestones. The rock property contrast between reservoir and seal produces a seismic reflection whose amplitude can be correlated with the porosity contrast between the adjacent units.

- Analysis of the well's bed thickness values demonstrated the existence of a strong inverse correlation between reservoir isopach and the overlying seal isopach (i.e. when the reservoir is thick the seal is thin and vice versa). This relationship is a significant constraint to model building that reduces the range of models required to form an adequate geometric template for the field.

- Petrophysical analysis demonstrated that the average porosity values for closely spaced reservoir units can be correlated. This relationship implies that these beds have a common diagenetic history and that rock property values can be linked between adjacent reservoir units. A constraint of this nature is a second valuable control of great importance as it also significantly reduces the number of models required for the study.

The features of the data that hinder the calculation of porosity from seismic data derive from the nature of the field's location, its overburden and the associated petrophysical properties.

- The presence of seismic multiples in the data can produce interference with the primary amplitude information derived from the reservoir boundaries. This interference degrades the quality of the amplitude information and produces zones where no successful estimate of porosity can be made.

- The flat nature of the reservoir units makes seismic migration of 2-D lines difficult to achieve. Acoustic impedance processing requires good quality migrated seismic data of known and stable phase (preferably zero-phase). The lack of migrated data means that AI inversion is disadvantaged compared to other simpler but less rigorous porosity prediction techniques such as seismic forward modeling.

- The frequency content of any seismic data is a primary control in its ability to resolve closely spaced seismic events. This 2-D data has a frequency content of 25 to 50 Hz and is therefore unable to resolve reservoir Unit 1 unit which has an average thickness of 12 m. Consequently, porosity estimates for the field can only be attempted for the reservoir Units 2 (45 m) and 3 (25 m) using this data.

- The field setting and data quality issues listed above mean with this poor quality data, successful estimation of reservoir porosity can only be achieved by using tight geological constraints.

Having established the need for careful modeling and also a complete understanding of the data set, porosity estimation using an attribute analysis technique, was performed on the data. This work demonstrated that a good estimate of aggregate porosity and its likely distribution could be achieved. The

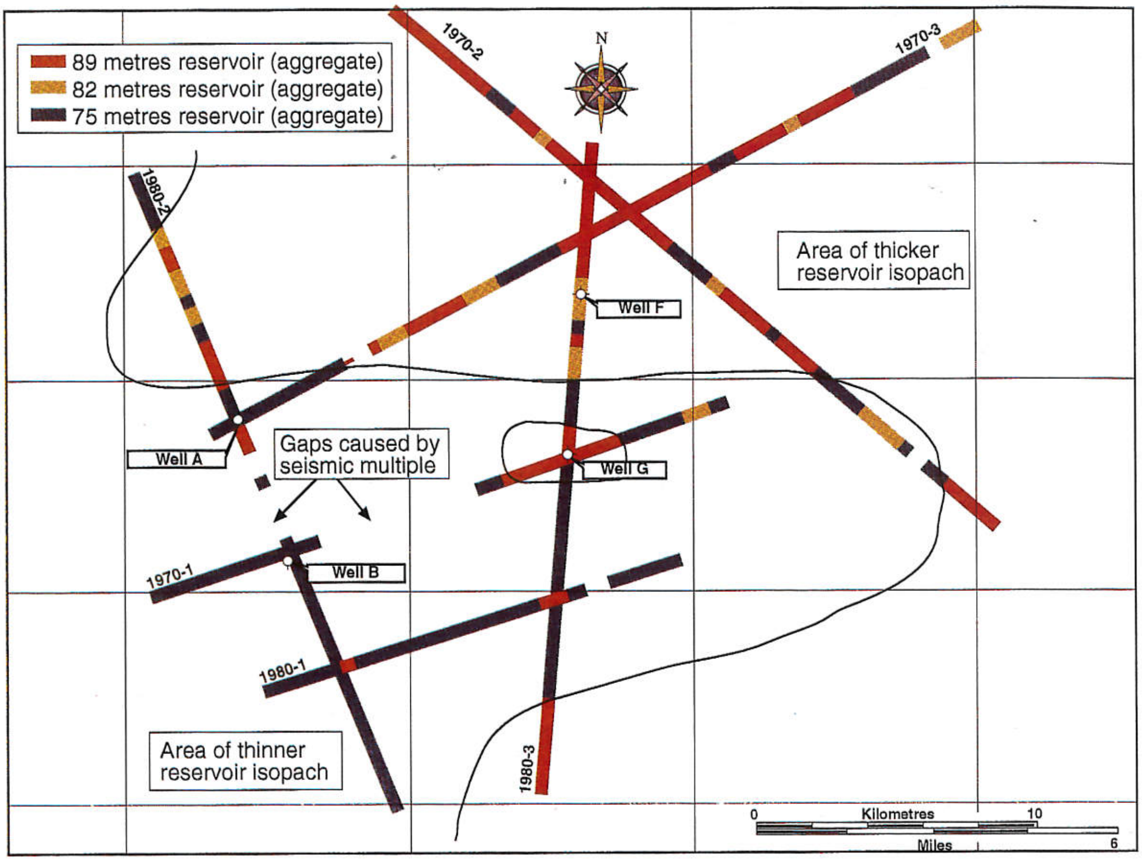

Figure 7: Aggregate reservoir thickness distribution (model X correlation).

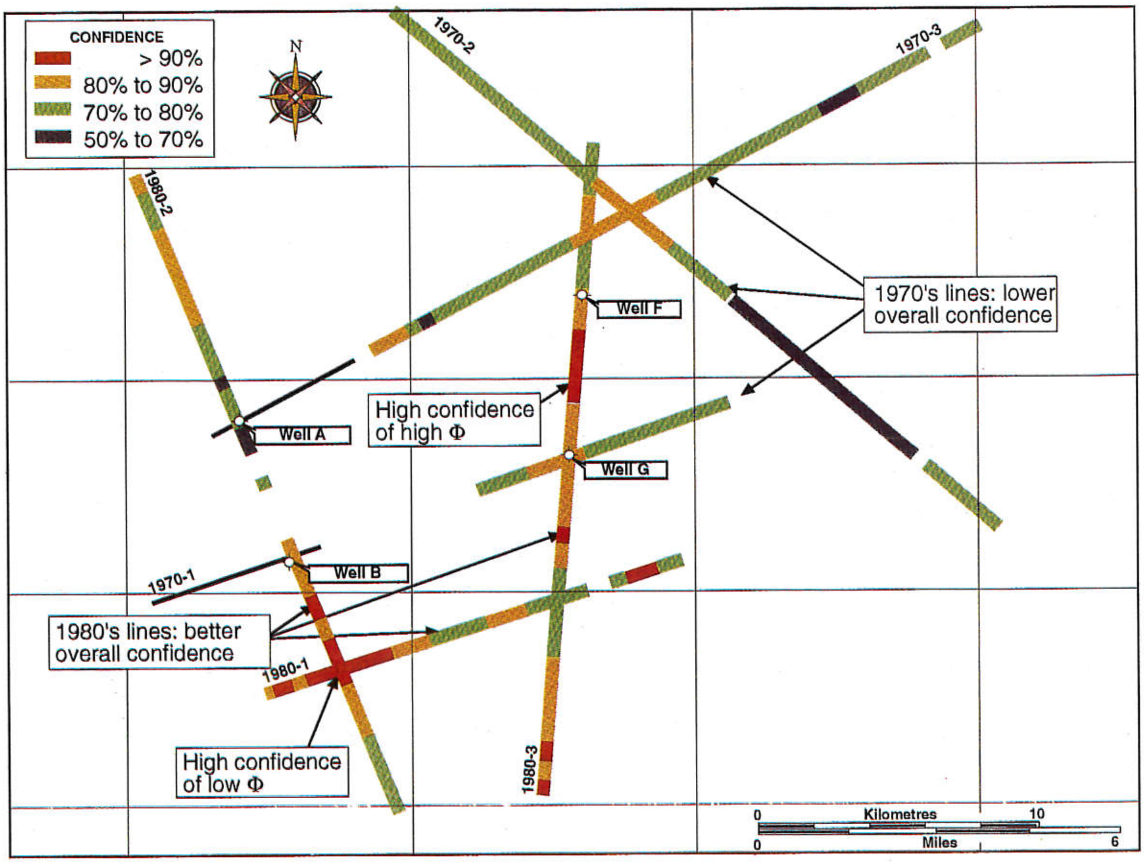

Figure 8: Confidence values (model X correlation).

success of the technique derives from the limited number of models that need to be built to encompass the likely range of rock conditions that can be resolved using seismic data.

CONCLUSIONS

Forward modeling is a vital step in any data analysis, as the process permits a detailed investigation of the likely factors underlying the observed variations in the acquired data (Neff, 1993). The seismic attribute (cross-correlation) modeling method has the potential to incorporate many of the geological and petrophysical constraints which underlie the observed genuine seismic amplitude variations over the field. It provides the interpreter with a valuable method of matching models with known and expected rock parameters to the real seismic data. It also incorporates a confidence measure of the model's fit to the data and allows identification of those areas that have poor quality data. It is a simple and rapid procedure for estimating lateral variations in reservoir porosity from seismic data.

The technique also shows the potential for determining aggregate reservoir thickness in areas where the data constraints are well established. The technique is most appropriate for use in appraisal studies. It can be used in areas where the geological constraints are well established and the likely variations in the reservoir properties are well understood. For example this often means carbonate ramp environments, which usually have tramline seismic and good interval velocity to reservoir porosity correlation.

REFERENCES

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About the Author

Philip Mulholland has been a Geophysicist with BP Exploration since 1988. He graduated with a B.A. in Environmental Science in 1974 from the University of Lancaster and an M.Sc. in Conservation in 1980 from University College, London. He was employed by the Institute of Geological Sciences between 1975 and 1979. In 1981 he joined the British Geological Survey. Philip is a member of PESGB and a fellow of the Geological Society. He is interested in Reservoir Characterization and Structural Analysis using 3-D Seismic Data.