Seismic reservoir characterisation in 'total space'; a Middle Eastern example

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Abstract

In addition to the structural framework of the subsurface, seismic measurements, also carry information about rock and fluid properties in the subsurface. This type of information is valuable from an economic perspective by characterising zones of interest, such as hydrocarbon reservoirs. This process of inferring information about the subsurface properties from the seismic measurements is called *seismic reservoir characterisation*. It plays an important role in total field development and reservoir management. The type of information that can be extracted from the seismic signals can help production geologists and reservoir engineers in explaining flow unit distribution, connectivity, drainage and injection models in addition to giving an indication of net oil in place.

TNO and the Norwegian R&D organisation SINTEF co-operated in the Probe project which aimed at developing a seismic reservoir characterisation method around stochastic modelling and artificial neural networks. The Probe project resulted in the 'total space inversion' method and the GeoProbe software system.

In 'total space inversion' the seismic reservoir characterisation process is approached from a geologic perspective. In the method stratigraphic information and well data are combined with seismic signals via an *integration framework*. Factual and simulated wells can, in this way, be combined in a dataset that is representative of the geological and physical variations in the target zone and which can be used for the characterisation process.

Total space inversion was applied to a Middle Eastern reservoir. The dataset comprised 3D seismic data and information from 88 different wells. The target was the oil-bearing sands of a clastic reservoir. The seismic response around the top reservoir horizon was segmented into 4 classes using an 'Unsupervised Vector Quantiser' (UVQ) neural network. Application of the same UVQ classifier to the representative dataset that was constructed in 'total space', revealed the stratigraphic and physical reasons underlying the seismic patterns. Through the use of the integration framework, segmentation patterns could be related to depositional facies and sediment architecture. Such knowledge improves reservoir models and, hence, leads to improved production schemes.

Introduction

Conventional lateral prediction comprises a group of techniques in which seismic reflection amplitudes are analysed and transformed via true-amplitude processing and integration into acoustic impedance values. The acoustic impedance values are subsequently interpreted in terms of reservoir properties. Most conventional lateral prediction techniques can be applied to both 2D- and 3D-seismic data. The term 'conventional' is used here to indicate that these techniques are applied to post-stack seismic data involving only P-waves (compressional waves).

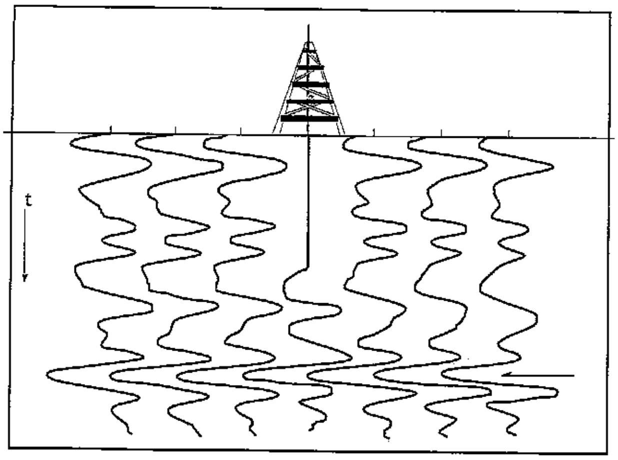


Figure 1. Well-to-seismic calibration. The synthetic seismic trace is spliced into the surface seismic section at the well location (Courtesy K. J.Weber., Delft University of Technology)

The basic concept in conventional lateral prediction is calibration of the seismic response to well log measurements. Variations in the response, away from the well, are assumed to reflect changes in rock properties. Seismic data can be calibrated at well locations with the aid of acoustic impedance and reflectivity logs. Acoustic impedance is defined as the product of seismic wave propagation velocity and medium density. Therefore, an acoustic impedance log may be derived from sonic and density logs. A reflectivity log can be derived from the acoustic impedance log. The reflectivity logs are converted from depth to time and resampled to the seismic sampling rate. After convolution with the seismic wavelet, the resulting synthetic seismic trace can be compared with the recorded field seismic traces. Seismic events can now be identified and tied to the well data. It should be noted that, after wavelet processing, the synthetic seismograms and the field seismic traces should have the same amplitude and phase characteristics. A separate trace balancing step might be required should the amplitudes differ due to different processing histories. An example of a well-to-seismic calibration is shown in Fig. 1.

Seismic reservoir characterisation techniques can be, arbitrarily, divided into three groups. The first group uses attributes derived from the seismic response to predict reservoir properties. The second group aims to increase the vertical seismic resolution by transforming the seismic time response into broad-band acoustic impedance profiles. This is known as acoustic impedance inversion. The third group is that of stochastic simulations where objects or properties are generated and distributed in space. In this paper a new method containing elements of each of the existing techniques is introduced: the 'total space inversion' method.

Total space Inversion

As described above, various techniques have been, and are being, employed to extract reservoir properties from seismic data. These techniques have a common requirement to integrate data from other sources. There are three reasons for this requirement:

- The seismic signals must be calibrated and transformed to meaningful reservoir properties.
- Additional non-seismic information is required to constrain the inherent non-unique seismic inversion solution.
- The seismic reservoir characterisation result delineates and describes only part of a reservoir model. This result must be consistent with results obtained from other sources such as production history matching results and high resolution sequence stratigraphic interpretations.

Here, it is argued that the only way to obtain seismic reservoir characterisations that are consistent with other data inversion and interpretation results, is to use a common subsurface model for all data descriptions. It is further argued that this subsurface model must be based on geologic parameters (lithology, sequence stratigraphy, bed-thickness etc.) rather than physical parameters (density, wave-propagation velocity etc.). The argument is based on the fact that geological events have a one-to-many relation with physical parameters. In other words many physical parameters can be attached to a single geological event such as a sandstone layer.

Integration of subsurface data and information is not trivial because of the varying datatypes, scales and accuracies involved. Another major problem is that well data is often limited and geological knowledge and reasoning can only be entered into the problem via stochastic methods. Hence, there is a requirement to combine stochastic and deterministic data.

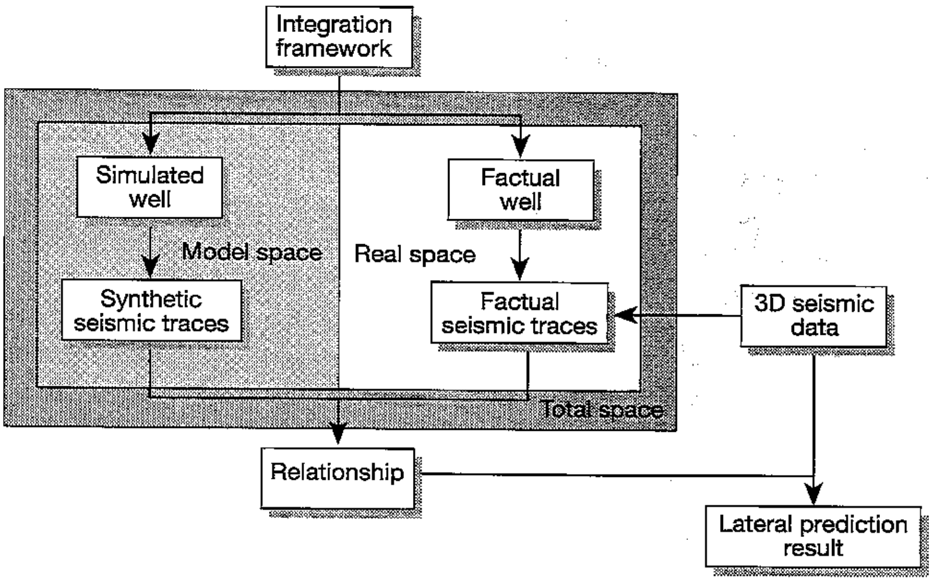


Figure 2. Total space inversion concept

In the 'Total Space Inversion' method relevant data, from a seismic reservoir characterisation perspective, are described, in terms of an *integration framework*. Factual wells, i.e. one-dimensional (1D) stratigraphic profiles with attached physical properties, and simulated wells, described in terms of the integration framework, are commensurable. The factual well data is combined with the surface seismic traces at the well locations. This part of the problem space is defined as *real space*. Simulated wells and their corresponding synthetic seismograms are part of the problem space that is defined as *model space*. The combination of real space and model space is defined as *total space*. Datasets consisting of wells with corresponding seismic responses can then be compiled from factual and/or simulated data. The objective is to arrive at a dataset that is representative of the target zone in a particular study area. The seismic reservoir characterisation technique uses the representative dataset to establish relations between seismic response and underlying salient well properties, Fig. 2. The technique is referred to as *total space inversion*.

Within the GeoProbe software system two approaches within the total space inversion concept are supported:

- Direct inversion: in this approach the representative dataset is tested for relations between seismic response and salient reservoir properties. The established relations are subsequently applied to a factual seismic horizon slice, yielding lateral prediction results.
- Segmentation: in this approach the factual seismic response is segmented into a number of classes. A representative dataset is subsequently segmented by the same classifier and the well information is analysed to arrive at a geological description of the seismic classes.

In GeoProbe, artificial neural networks are employed in the inversion phase. Unsupervised Vector Quantisers (UVQs) are used in the segmentation approach and Multi-Layer-Perceptrons (MLP) and Radial Basis Functions (RBF) networks are used in the direct inversion.

An algorithm is used for the simulation of wells, which combines geological reasoning with stochastic input. The algorithm makes use of an innovative Monte Carlo statistics procedure in which correlated multi-variate stochastic variables are drawn one-by-one.

Integration framework

In the integration framework the geology of the target zone is generically defined in terms of acoustic-stratigraphic entities, Table 1. These entities are grouped at three hierarchical scale levels; units, sub-units and lithologies, respectively. The smallest scale level (the lithology level) typically corresponds to beds in the 1-10 m range with a similar lithological composition, .e.g. sand, shale, silt etc. The intermediate scale level (the sub-unit level) typically corresponds to a stratigraphic para-sequence or depositional facies consisting of one or more, lithologies. The largest scale level (the units level) typically corresponds to a lower order stratigraphic sequence and consists of one, or more, sub-units. It is stressed that the scale levels are user-defined and should not be confused with, or constrained to, strict geological stratigraphic classifications. They are chosen, such, that the geological setting can be optimally represented. This is area and target dependent. It is very possible to define an integration framework based on a combination for litho-stratigraphy, sequence-stratigraphy and genetic units. The key issue to be addressed during definition of the integration framework, is how important geological entities must be specified. These entities can then used to describe factual and simulated wells. Individual codes for each entity ensure that all elements of the model can be uniquely identified.

Table 1. Part of an integration framework, showing the hierarchy of scale levels

Unit	Sub-unit	Lithology	Rocktype	Code
A	I	a	reservoir	A.I.a
		b	seal	A.I.b
B	II	a	reservoir	B.II.a
		c	waste	B.II.c
	I	a	reservoir	B.I.a
		b	waste	B.I.b
		c	reservoir	B.I.c
C	III	d	reservoir	B.III.d

A rocktype is assigned to each lithology in the framework, to accommodate the requirement for entering fluid contents. Three rocktypes are defined: seals, reservoirs and waste rocks. Seals are used to attach hydrocarbon columns. Reservoir rocks are defined as lithologies that can have a moveable fluid-fill. Waste rocks are considered non-economic but non-sealing. The requirement of integrating other properties is fulfilled by allowing user-defined parameters to be attached to any framework entity. For example it is possible to attach a production rate either to the entire framework, or, to any defined entity in the framework, either unit, sub-unit or individual lithology.

Wells (factual and simulated) can now be described in terms of the integration framework. The following rules for this description apply:
- Units always occur in the sequence that they have been entered into the integration framework. They are, either, present, or, absent. They cannot repeat.
- Sub-units may occur in any order and multiple times within the unit they belong to or they may be missingentirely. Sub-units occurring more than once get an occurrence number attached to the code, such that they can be identified uniquely. Sub-units can be ordered if necessary.
- Lithologies can occur in any order and multiple times within the sub-unit they

belong to. Alternatively they may be missing entirely. Lithologies occurring more than once get an occurrence number attached to the code, such that they can be identified uniquely. Again, lithologies can be ordered or random as required.

When the stratigraphy of the well has been described, the acoustic properties can be entered. These are attached to the smallest scale entities: the lithology level, or, in case of reservoir layers, acoustic blocks with similar fluid contents. The acoustic properties: sonic logs (i.e. acoustic slowness) and density logs, are parameterised at top and bottom of each block (Fig. 3). The boundaries of the acoustic blocks must coincide with those of the most basic framework entities. User-defined physical properties, such as production rates, permeabilities etc., are also entered (or simulated).

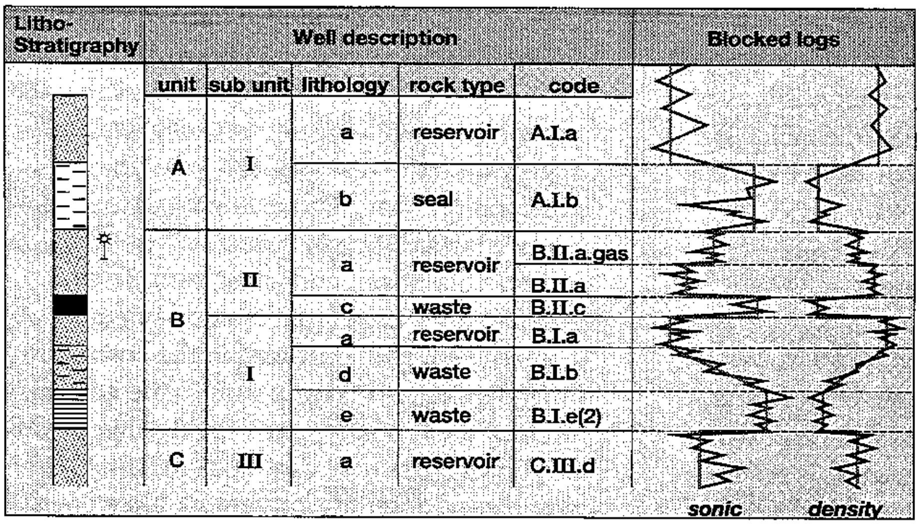


Figure 3. Description of well information in terms of the integration framework. Acoustic information is parameterised at the top and bottom of the smallest scale framework entities (lithologies, or reservoir layers with similar fluid content)

When a number of factual wells have been described in this way, the physical properties can be analysed. Each property can be analysed at each scale level of the integration framework. For example it is possible to study the thickness variations associated with unit A, or sub-unit II of unit B, or all lithologies 'a' within sub-unit II of unit B. It is even possible to examine variations in physical properties associated with, say the fifth occurrence of lithology 'a' within the second occurrence of sub-unit II of unit B, should the need arise.

Middle Eastern case study

General

The Middle Eastern study area is covered by a 1992 vintage 3D-seismic dataset. The top reservoir horizon as mapped by the client has been used in this study as the reference horizon. The well database consisted of 88 wells. Not all wells, however, had a complete set of information. Eventually, 61 wells were loaded into GeoProbe, 49 of which fell inside the 3D-seismic data area.

Geology

The zone of interest can be divided stratigraphically into three components. The lowermost formation is the 'source' unit comprising shales which are unconformably overlain by the 'reservoir' formation which in turn is conformably overlain by the sealing 'carbonate' formation comprising carbonates and anhydrites.

Within the study area the source unit comprises marine shales with a moderately high clay content and correspondingly high gamma ray signature. The shales are massive in nature where encountered.

The reservoir formation is of Late Carboniferous to Early Permian in age. Its base is an unconformity which in the study area is eroded into the top of the source unit shales. The reservoir comprises terriginous clastic material in an alluvial plane setting. To the south of the study area the lowermost beds of the formation are comprised of massive silty-shales and sands which appear to infill the erosion topography at the basal unconformity. In the east of the area there is a trough like structure which is infilled with massive sands. It is impossible to correlate major events from well to well over any great distance. No laterally extensive vertical layering in the reservoir unit is discernible. The final few beds in the reservoir unit comprise restricted marine sandstones with caliche and root horizons towards the top. There is occasionally evidence for a thin limestone horizon below the carbonate unit. The upper surface of the reservoir unit can be considered to be a peniplain. The upper beds mark the development of a marine transgression and development of a carbonate shelf. Oil is trapped in the sands and silts. The oil column is limited to the upper beds of the reservoir, which has a maximum thickness of app. 200 m in the study area.

Conformably overlying the reservoir formation are the capping carbonates and anhydrites of the carbonate unit. This formation is of Middle Permian to Late Permian in age. The carbonate unit represents the formation of an extensive evoporitic carbonate platform shelf (Murris, 1980) and is divided into four members A, B, C and D. The lowermost carbonate is the D member which was included in our study. The member comprises well bedded limestone-shale alternations at its base. These alternations become progressively more massive towards the top of the D unit where the limestones become more dolomitic. The succession contains more bedded anhydrite towards the upper D member which is capped by a massive anhydrite layer. All well logs were blocked to the top of the massive D unit anhydrite. The D unit is constant and unvarying throughout the study area and was in turn overlain by a thick succession of C member carbonates.

Oil is trapped in the sands and silts of the reservoir formation. The reservoir unit is capped by the D unit carbonate-shales in a gentle dome structure. The oil column is limited to the upper beds of the reservoir, which has a maximum thickness of app. 200 m in the study area. The source unit shales are considered regional source rocks by Beydoun (1991) and are possibly the source for the oil in the field.

Integration framework

The framework for this case study is defined as follows (Table 2):

- The framework consists of 4 main units. Each unit has one or several sub-units (geological or seismic). The third column shows the lithologies used, and the fourth column shows the GeoProbe codes given.
- The four main units occur sequentially as shown in the framework. Sub-units within the carbonate units occur sequentially while sub-units within the reservoir can vary. The reservoir unit has been divided into four sub-units: Massive Type 3, Massive Type 2, Massive Silt-Shale, and Laminated. This subdivision is based on common grouping of certain lithologies observed in the Formation Analysis logs and corresponds to the genetic units of the formation. In individual wells, the sub-units order may vary. Sub-unit could be completely absent or present multiple times.
- Each sub-unit is assigned several lithologies. The lithological composition of an interval determines a particular sub-unit type. Type 3 sandstones, for example, can only occur in Massive Type3 sub-unit or Laminated sub-unit while Type 2 sandstones will only be found in Laminated or massive Type 2. Lithologies could occur in any order, repeat themselves, or be completely absent.

- Oil-bearing sands occur only in the reservoir unit. Essentially, all sand lithologies, regardless of which sub-unit they belong to, are considered to be producing if they occur within the oil column. The fine grained non-producing sandstones, silts and shales were grouped into one lithotype (Silt/Shale) for the purposes of this study and are considered waste zones.
- There is only one hydrocarbon column, which is attached to the overlying seal at the base of the carbonate unit.

Table 2. Middle Eastern case study integration framework

Unit	Sub-unit	Lithology	Code
Carbonate C	Carbonate	Carbonate Shale	crbc.crb.crb crbc.crb.shl
Carbonate D	Massive	Anhydrite Carbonate	crbd.msv.anh crbd.msv.crb
	Anhydrite	Anhydrite Carbonate Shale	crbd.anh.anh crbd.anh.crb crbd.anh.shl
	Alternating	Carbonate Shale	crbd.alt.crb crbd.alt.shl
Seal	Seal	Seal	seal.seal.seal
Reservoir	Massive Type 3	Type 3 Sand Silt/Shale	res.mt3.t3s res.mt3.slt
	Massive Type 2	Type 2 Sand Silt/Shale	res.mt2.t2s res.mt2.slt
	Massive SiltShale	Silt/Shale Type 2 or 3 Sand	res.msl.slt res.msl.snd
	Laminated	Type 2 or 3 Sand Silt/Shale	res.lam.snd res.lam.slt
Source	Marine	Shale	sou.mar.shl

seismic dataset was created by selecting 25 (5x5) traces around the factual well locations. Seismic data was selected in a gate of -50 to +50 ms around the top reservoir reference horizon (Fig. 4). This seismic response was balanced using a 100 ms RMS equalisation[1]. A gate of -8 to 32 ms around the reference horizon (10 samples) was used to train the UVQ's. The seismic response of the reservoir unit has, in this way, been segmented into 4 classes (Fig. 5). Given the remarkably constant acoustic impedance profile of the overlying carbonate unit and the unvarying nature of the source unit, any variation in the seismic must be due to lateral variations within the reservoir formation.

Segmentation

In this case study the segmentation approach was applied with the aim of visualising and interpreting the resulting seismic patterns. Segmentation requires the classifier (the UVQ network) to be trained on a representative seismic dataset. In this case the representative

In order to understand the seismic patterns the seismic traces at the well locations were selected and offered to the trained 4 class UVQ classifier (Fig. 6). The resulting subsets were subsequently analysed for their geological content (Fig. 7 and 8).

[1] Trace balancing was applied because it was anticipated that simulated wells with corresponding synthetic seismic traces would be used in the analysis. It was later decided to analyse factual wells only, making the trace balancing step unnecessary.

It was concluded that:

- Class 1 has the largest amount of the massive Silt/Shale sub-unit (43%) and the largest amount of the silt/shale lithology (38%). The overall sand content is 46% (Fig. 7) which is the lowest for any class. The predominance of silty shale in the massive trend indicated by the analyses points to this class being the trend of abandoned channels that filled with ponded and suspended-load sediments. Porous, high producing, sands do occur but are less likely than in the other classes.
- Class 2 while containing relatively high percentages of Massive Type 2 and Laminated sub-units (29 and 36%, respectively, Fig. 7) also contains the highest percentage Type 3 sand lithology producing oil. This lithology is the most productive of all the sand lithologies due to its coarseness and high porosity and permeability. Class 2 is the most silt/shale poor and represents a sand rich channel trend whose distribution (NE-SW) corresponds to similar trends observed in the palaeo-relief.
- Class 3 has the highest percentage of the Laminated sub-unit (53%). While the overall sand percentage is only 49% and the class is high in silt, high production rates can be achieved from the coarser, of what are thin and probably laterally more extensive, sheet sands. The Laminated sub-unit of Class 3 represents the well-bedded flood plain deposits where sheet sand and suspended load deposits alternated away from the massive channel trends. Class 3 corresponds to the locations of the highs in the palaeo-topography.
- Class 4 has the highest percentage of the Massive Type 2 sub-unit (33%) in addition to the laminated sub-unit (32%). The overall sand content is high (54%). Examinations of the wells associated with Class 4 show the Massive Type 2 sub-unit to be predominantly associated with very massive Type 2 sand

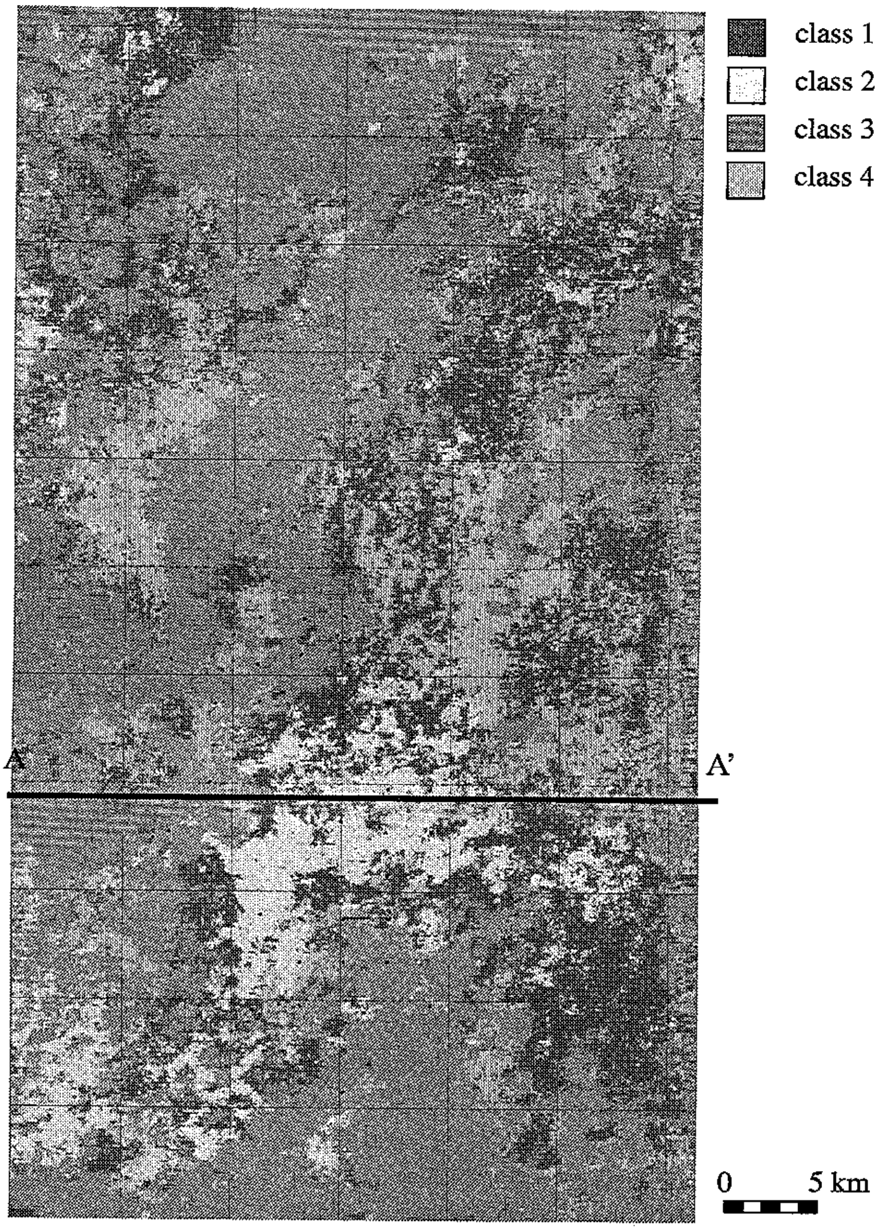


Figure 4. Segmentation result for 4 classes

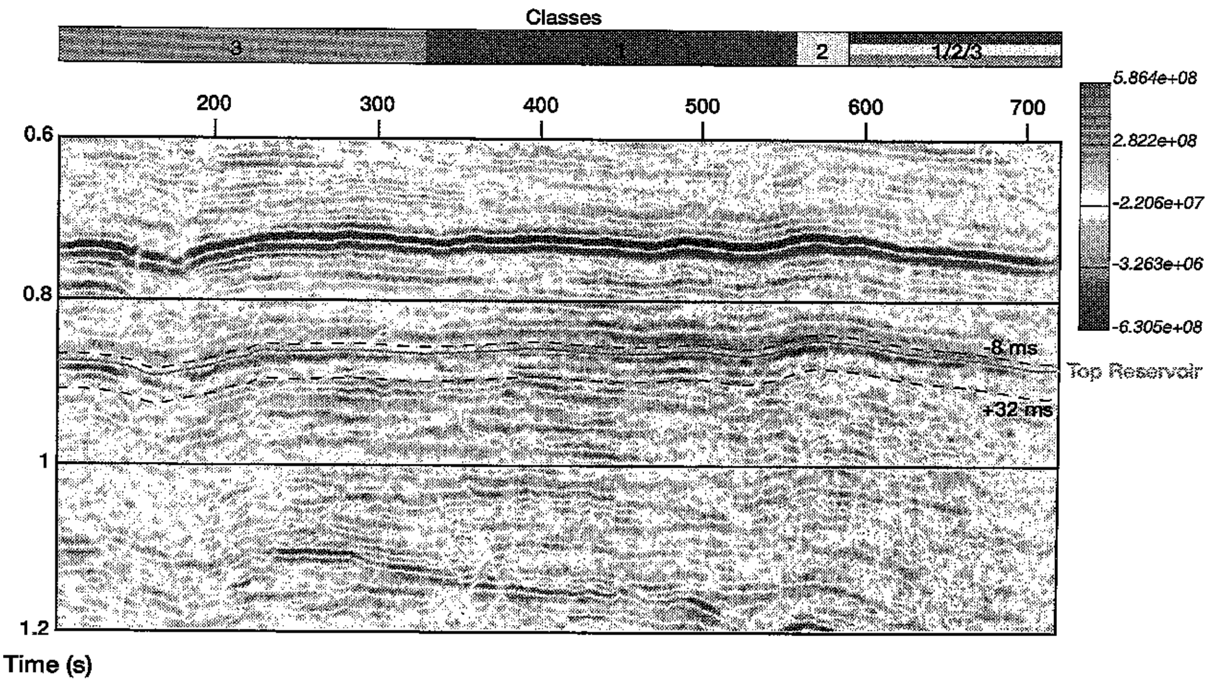
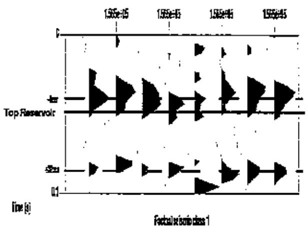
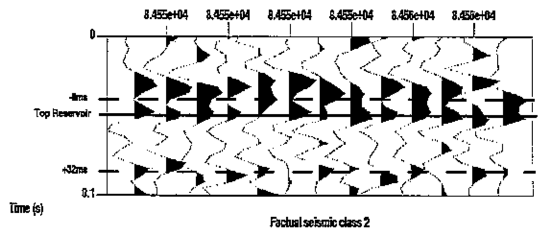
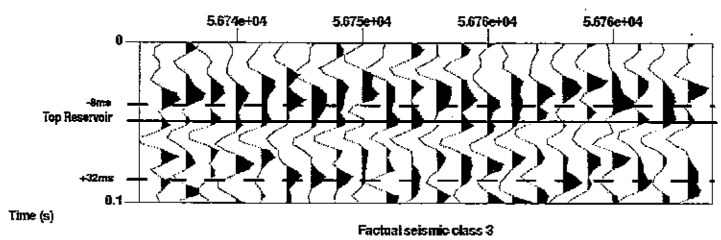


Figure 5. Middle Eastern case study. Seismic line A-A' (see Fig. 4)

beds that appear to fill in the palaeo-relief of the base reservoir unit. The aerial distribution of this class corresponds to this hypothesis while the relatively high percentage of Laminated sub-unit would indicate that the relief had been filled and a 'normal' alluvial distributory architecture had been established halfway during the deposition of the reservoir formation.







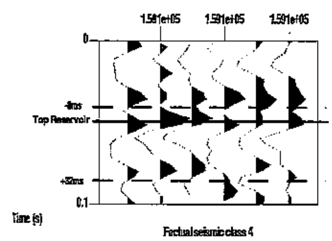


Figure 6. Factual seismic traces at real well locations, classified by the trained UVQ network into 4 classes. Classification is based on the seismic response in a gate of -8 to 32 ms relative to the top reservoir horizon.

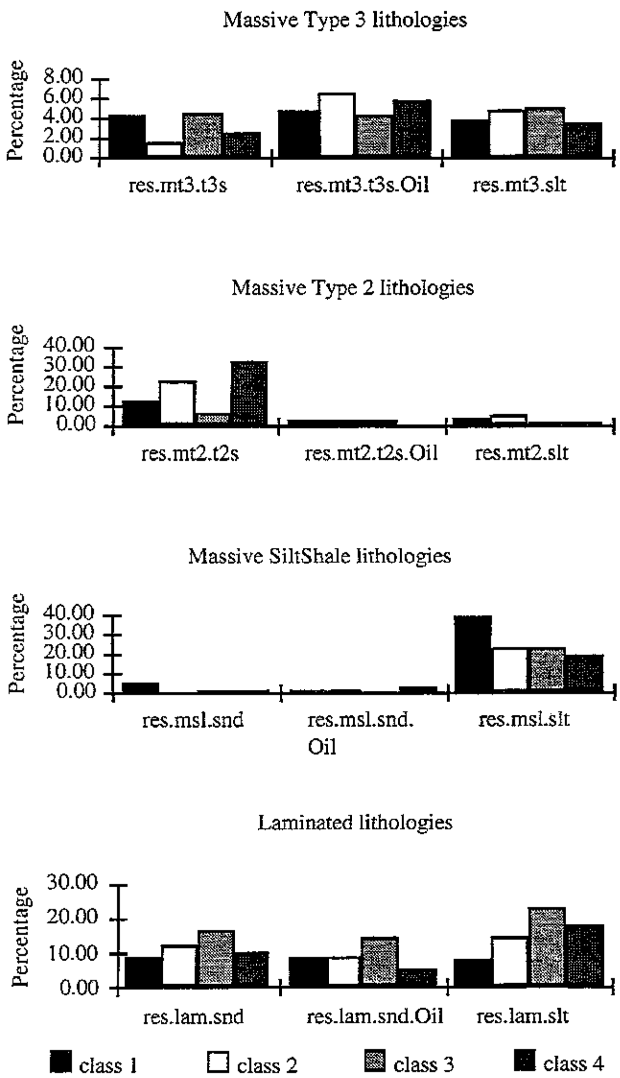


Figure 7. Relative proportion of framework litologies per sub-unit and per class. Total thickness of the reservoir unit per class equals 100%

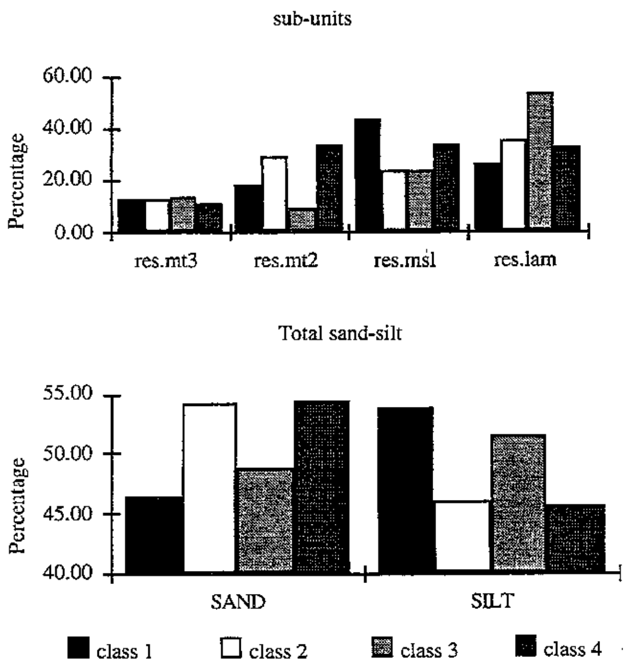


Figure 8. Relative proportion of framework sub-units and relative proportion sand and silt per class. Total thickness of the reservoir unit per class equals 100%.

Conclusions

In this paper the total space inversion method for seismic reservoir characterisation has been described and illustrated with a Middle Eastern fluviatile oil field. In this study, UVQ segmentation revealed the dominant sedimentary architecture of a labyrinth-type reservoir. Analysis showed that the classes corresponded to different levels and trends of channelised sandbodies within an avulsing floodplain formation.

Such knowledge about the sediment architecture and distribution of flow units improves reservoir models and, hence, should lead to increased field productivity.

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