Delineating thin sand connectivity in a complex fluvial system in Mangala field, India, using high resolution seismic data

Sreedurga Somasundaram*, Amlan Das and Sanjay Kumar present the results of a project to characterize the channelized sands and build up the geocellular model of a hydrocarbon system.

The Mangala field is located in the northern part of the onshore Barmer Basin in India. The primary reservoir in the field is the Fatehgarh Formation, deposited during the rifting phase that created the Barmer Basin during the Late Cretaceous to Early Paleocene period. The majority of reservoir oil is contained within the Upper FM1 member of the Fatehgarh Formation, composed of single storey and multi-storey stacked, meandering channel sands. The average gross thickness of FM1 is 80 m, and individual sands vary in thickness from 3 to 7 m, with net-to-gross ratio ranging from 18% to 78% due to inherent heterogeneity within FM1 as evident from core data. For such a heterogeneous fluvial system, correlation of fluvial channel sands and flood plain shales poses a major challenge for reservoir characterization when based on well data alone.

Detecting or mapping the lateral continuity of these thin fluvial channel sands is difficult because they are below seismic resolution in conventional seismic data. We applied sparse-layer reflectivity inversion (Zhang and Castagna, 2011) to the 3D stack PSTM data, which resulted in a data-set with improved detectability and resolution. The 7-50 Hz bandwidth of the input seismic data increased to 7-100 Hz through the inversion process. Results were validated using well log and production data. The new data contributed to greater understanding of the lateral connectivity of the FM1 fluvial channel sands, and enabled geobody extraction for reservoir static modelling.

The basin is a Tertiary rift, containing predominantly Paleocene to Eocene clastic sediments. The field was discovered in 2004 with the drilling of Mangala-1, and was subsequently appraised and developed. Commercial production commenced in 2009.

The Mangala field is contained within a simple tilted fault block structure dipping approximately nine degrees to the south-east (Figure 1). The primary reservoir in the field is the Fatehgarh Formation, consisting of inter-bedded sands and shales (Figure 1c). The Fatehgarh Formation is broadly divided into the Lower and Upper Fatehgarh Formations, which are further subdivided into five litho-stratigraphic units. The Lower Fatehgarh Formation consists of well-connected sheet-flood and multi-storey braided channel sand

Figure 1 (a) Mangala field Top Fatehgarh Time structure map. (b) A W-E dip-oriented seismic section. (c) Type log of Fatehgarh formation

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Information from high-resolution Spectral Decomposition, (Puryear et al., 2012) of the seismic data is used to constrain the inversion process. Thin beds below tuning thickness can be imaged by inverting the frequency spectra for layer thickness using complex spectral analysis. The process does not limit the minimum thickness of the layers.

The inversion algorithm does not use well data for prediction of closely spaced bed reflections. Instead, inversion is performed trace by trace, with no continuity constraints or other spatial conveyance of information. Thus, lateral continuity of stratigraphic features in the inversion data that are consistent with the geologic model is an indication of the stability and robustness of the algorithm. Modelling tests show that Sparse Layer inversion is better at resolving thin beds than comparable Sparse Spike inversion. The closely spaced reflection coefficients that are produced during Sparse Layer inversion effectively increase the bandwidth of the seismic data.

Sparse Layer reflectivity inversion results at Mangala are shown in Figure 2. Inversion increased the bandwidth of the input seismic data from 7-50 Hz to 7-100 Hz; the high-resolution process thus doubled the original seismic data bandwidth. The increase in bandwidth and resolution is a result of increased reflectivity detail obtained through the inversion process. Improved imaging of the channel geometries has provided a greater understanding of the lateral continuity of the thin FM1 fluvial reservoir units.

In order to validate the inversion results, well-to-seismic ties were performed using both original and high-resolution seismic data. Figure 3 shows such a comparison, for Well EP1. The dominant frequency of the wavelet in the input seismic data is 25 Hz, yielding vertical resolution of about 20 m. Although the well tie with input seismic data (Figure 3a) yields a high correlation of 88% within the zone of interest, usefulness of the data is limited to detecting gross lithological packages only. The corresponding well-seismic tie using the high-resolution seismic data with dominant frequency of 55 Hz (Figure 3b), however, shows that individual thin sands are detected or resolved.

High-resolution seismic data and analysis

Sparse Layer reflectivity inversion (Zhang and Castagna, 2011) of seismic reflection data yields closely spaced reflection coefficients through incorporation of a priori information and Spectral Decomposition in the inversion process. The inversion is accomplished by building a dictionary of functions representing reflectivity patterns, and constructing the seismic trace as a superposition of these patterns. When the dictionary of functions is chosen to be a wedge model of reflection coefficient pairs, the resulting reflectivity inversion is a Sparse Layer inversion, as opposed to a Sparse Spike inversion.

The Mangala field is covered by 3D seismic data acquired and PSTM-processed in 2008. The dominant frequency of the seismic data is 25 Hz, yielding a vertical resolution of 20 m within the Fatehgarh interval. Individual FM1 member sands that range in thickness from 3 to 7 m are therefore not resolved. Thus, seismic data provide limited information to characterize the channelized sands when building the geocellular model. To improve the seismic resolution, we applied high-resolution sparse-layer inversion (Zhang and Castagna, 2011).

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Seismic attribute based facies mapping

Sands within the Fatehgarh Formation are acoustically softer than the surrounding Intra-Fatehgarh mudstones, with the tops of individual sand bodies represented by a (red) trough and the top of mudstone units by a (blue) peak in synthetic seismograms and in zero phase seismic data (Figure 3b).

Quadrature phase data provide an approximation to bandlimited impedance data, obtained by rotating zero phase reflectivity data by 90 degrees. Peaks and troughs corresponding to reflectivity spikes in seismic data transform to zero-crossings in quadrature data representing strata. Conversion to a layer-based property allows matching seismic polarity to lithology. Figure 4a shows a quadrature seismic section extracted using the high-resolution seismic data, with sand units demarcated as (red) trough cycles and mudstone units as (blue) peak cycles.

To further improve detectability of thin sand units for solid body extraction for reservoir modelling, we created a hybrid seismic attribute volume by scaling instantaneous frequency with quadrature phase. Figure 4b shows a frequency scaled quadrature phase seismic section where thin sand and shale units are more sharply delineated compared to Figure 4a (black circles). In this new seismic attribute volume, sand units are represented by (red) cycle troughs and mudstone units by (blue) cycle peaks.

In order to demonstrate the improved definition of thin stratal units in frequency-scaled quadrature attribute data, we constructed a simple 2D seismic model (Figure 5). The model contains two dipping 10 m thick sand layers, encased within shale overburden and underburden. The sand units in turn encase a wedge containing shales and a thin sand with maximum thickness of 6 m. The model depicts the vertical and lateral heterogeneity of the FM1 unit at Mangala.

Figure 5b shows the Quadrature phase equivalent of the 2D synthetic seismic data corresponding to the 2D model. The Instantaneous Frequency attribute extracted from the...
of the channel geometry of the heterogeneous FM1 fluvial reservoir units.

**Seismic 3D facies extraction**

A ‘Frequency-scaled Quadrature Phase Attribute’ volume was generated from the high-resolution 3D seismic data and used for facies (geobody) extraction for reservoir modelling. In order to extract three dimensional geobodies in the FM1 unit the seismic attribute volume needs to be trimmed to contain only the section of interest. To do this, a horizon-guided slab was created between Top and Base FM1 for formation sculpting. In addition, to capture only the FM1 fluvial sandstone units, an opacity filter was applied to the sculpted data (red trough cycles that denote sand units) as opaque, and irrelevant data (blue peak cycles) were set transparent. The sculpted and opacity filtered volume that only captures the seismically delineated fluvial sandstone units in FM1 was converted to a 3D Geobody volume as shown in Figure 6.

A geobody is an interpreted 3D object comprising connected model cells (voxels) with similar seismic attributes and can comprise one or more contiguous sandstone bodies. With an average net-to-gross ratio of 48%, FM1 fluvial sandstone units are expected to be statically well-connected either directly or indirectly through amalgamation. Spatially separating and delineating individual thin channel storeys is difficult because of lateral and vertical amalgamation. It was therefore decided to extract a 3D geobody volume to analyse and validate ‘reservoir connectivity’ (sandstones spatially connected to wells) using dynamic connectivity data (reservoir fluid type and flow behaviour under production conditions). The 3D geobody volume can further be used as a three-dimensional trend to populate the facies in building a static reservoir model.

**Validation of seismic facies**

The extracted geobody volume is qualitatively validated against well data using Gamma Ray (GR) and density logs.

2D synthetic data is shown in Figure 5c. Note the anomalies (blue ovals) seen in Instantaneous frequency attribute data where stratal units are thin and difficult to detect in the Quadrature phase data.

Figure 5d shows the Frequency-scaled Quadrature phase attribute data (computed by multiplying the data in Figures 5b and 5c). Detectability of thin sand units is improved in this attribute data compared to the original Quadrature phase data. Use of this attribute should allow for better tracking of the areal distribution of individual thin sand units, thereby providing improved understanding of the channel geometry of the heterogeneous FM1 fluvial reservoir units.
The high-resolution seismic data has doubled the original seismic resolution and has provided a greater understanding of the lateral connectivity of these thin fluvial reservoir units. However, not all of the individual sands with 3 to 7 m thickness are resolved in the high-resolution seismic data, yielding composite responses of several thin streaks of sands at places.

The 3D geobody volume is further analysed to validate the reservoir connectivity using the dynamic flow behaviour. The FM1 reservoir interval, characterized by heterogeneous fluvial units, is currently being developed with pattern ‘hot water’ flood wells to optimize reserves recovery.

To understand injector support for pattern producers in the FM1 reservoir and qualitatively and quantitatively gauge fluid flow dynamics, different ‘conservative’ tracer chemicals were strategically injected in the crestal pattern injectors (Figure 7a). Producers in the same pattern and some nearby producers have acted as observation wells for regular monitoring of tracer output signal. Blue arrows in Figure 7a indicate fluid flow direction to observation well (producer) in which tracer breakthrough has been observed.

Qualitative analysis of tracer data shows injector support to the pattern producers. This information, when combined with production log data (PLT) and the 3D geobody data helps in identifying the injecting or producing sands and connectivity. For producer wells with artificial lift, well completion design does not support PLT data acquisition. However, reservoir saturation data (RST) against zones not under production/injection can be acquired in nearby producers and injectors. This further provides qualitative information on possible connectivity of sand units based on the current saturation state of individual sandstones in the target area being studied. Hence, the combination of tracer data with PLT, seismic geobody and RST data builds understanding of possible fluid (production/injection) movement in the reservoir, thereby helping to optimize production, improve sweep and maximize recovery from the field.

Tracer data (no support/full support) have been utilized to cross-validate reservoir sand connectivity as described by the geobody volume.

The tracer injected in well A-I has been observed to breakthrough in the observation wells shown by blue arrows. The producer well AP3 at a 400 m distance from the A-I injector had the earliest tracer breakthrough, whereas, in a similar direction, well AP2 (200 m distance) had no tracer response. In order to investigate this, the geobody sections were analysed from the injector A-I to producer wells AP3 and AP2 and are shown in Figure 7b and 7c respectively. Based on the PLT data, injector A-I is predominantly injecting in the lower sands as highlighted by a blue rectangular box. It is observed that the injecting sands in well A-I are disconnected to producer AP2 whereas they is well-connected to producer AP3 (Figure 7).

To examine Enhanced Oil Recovery (EOR) Options, a pilot area (100 m x 100 m) in the south of the field was defined in 2010 to test the Polymer-ASP flood EOR in a closely spaced eight-well pattern (plan view in Figure 8a). Prior to start-up of the pilot, multi-well pulse testing was performed to enhance understanding of reservoir connectivity.

A pressure pulse applied to the upper sand in well MEOR-2 (blue rectangle in Figure 8) created a response in the stratigraphically equivalent sands in MEOR-5 and MEOR-4 which are 15 m structurally downdip. However, the equivalent sand in well MEOR-6, located at a similar ~95 m distance and only 4 m downdip, showed no response suggesting a local pressure barrier. A geobody section through wells MEOR-2, MEOR-5 and MEOR-4 (Figure 8b) suggests the upper sands are well disconnected compared to the middle and lower sands.
connected despite structural dip changes. This contrasts with the geobody section through wells MEOR-2 and MEOR-6 (Figure 8c) which implies the presence of two stratigraphically disconnected channel sands.

To augment definition and validation of reservoir connectivity through geobody extraction, additional evidence from a connected injector-producer pair as observed through flow performance has been analysed. Well DP1 has a permanent down-hole gauge installed which shows strong interference following variation in well D-I injection rates. Furthermore, the water cut rise in well DP1 post start-up of injection in well D-I was also very fast. Production log data

Figure 8 (a) Plan view of Mangala FM1 EOR pilot. (b) Geobody section along wells MEOR-2, 5 and 4 showing well-connected upper sands. (c) Geobody section along well MEOR-2 and MEOR-6 showing stratigraphically disconnected upper sands.

Figure 9 Geobody section between injector(D-I)–producer(DP1) pair, showing sand connectivity in dotted lines and the injecting and producing sand units as highlighted from PLT data.

Figure 10 Geobody section between wells E-I, IN-EP2 and EP1, showing sand connectivity with injecting and producing sand units as highlighted in PLT data.
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(PLT) from well DP1 verifies that water is being produced from the well-connected sands that are taking injection water in well D-I. The geobody section showing well-connected sands between wells D-I and DP1 is shown in Figure 9.

The Mangala field is in an advanced development phase with more than 300 wells drilled to date. The ongoing development or infill drilling campaign continues to provide new insights on dynamic connectivity of individual sand units.

Resistivity logs acquired in recent wells provide valuable desaturation information indicating areal sweep and injection support. For example, a recent infill well IN-EP2 was placed between injector-producer pair E-I and EP1. Not all the individual sands in well IN-EP2 could be resolved in the high-resolution geobody data (Figure 10). However, three sands that show flushing in IN-EP2 (Figure 10, red arrows) are identified as being well connected to sands taking injection water in well E-I (PLT data). The geobody section between wells E-I, IN-EP2 and EP1 (Figure 10) indicates sand connectivity from injector through to producers at the stratigraphic levels where flushing is identified and PLT data has verified injection and production.

Conclusion
The FM1 reservoirs of the Mangala field are characterized by thin, meandering fluvial channel systems. For optimal field development, capturing the channel geometry and reservoir sand connectivity is of utmost importance to assess sweep efficiency, to plan corrective actions and to maximize recovery from the field. Realizing production and injection conformance is a major challenge in such systems. Therefore detailed understanding of reservoir sand connectivity is required to improve reservoir modelling, to help explain production performance data, saturation changes, pressure data, pulse testing data, and tracer survey information from producers and injectors across the field. The thin FM1 reservoir sands however, are well below conventional seismic resolution and as a result, seismic data provided limited support in reservoir characterization.

In order to more accurately characterize the thin channelized reservoir sands at Mangala, Sparse Layer reflectivity inversion constrained by high-resolution Spectral Decomposition was performed on the 3D PSTM stack seismic data covering the field. The process doubled the effective bandwidth of seismic data, allowing for significantly improved definition of thin stratigraphic units. Results were validated with well-seismic ties and by field dynamic measurements. This has provided a greater understanding of the distribution and lateral connectivity of the thin fluvial reservoir sands at Mangala. In order to further improve thin sand definition a hybrid seismic attribute volume having components of quadrature phase and instantaneous frequency was created. This volume, with improved thin sand detectability, has enabled geobody extraction for reservoir modelling.

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