Increasing the Effective Bandwidth of Seismic Data through Sparse Layer Inversion: A Case Study from the Mangala Field, Rajasthan

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The Mangala field is located in the northern part of the onshore Barmer Basin in Rajasthan. The field, with in the Rajasthan block (RJ-ON-90/1) was discovered by Cairn India Ltd. in 2004 and brought into production in 2009. Currently, production from the Rajasthan block averages ~200,000 boepd of which Mangala field is the largest contributor. The primary reservoir in the field is the Fatehgarh Formation, deposited during the rifting phase that created the Barmer Basin, in the late Cretaceous to early Paleocene period. Hydrocarbons in Mangala are trapped in an east dipping tilted fault block created during rifting. Lateral seal to the west is provided by the west dipping main bounding fault of the tilted fault block structure with juxtaposition of the tight Barmer Hill, and Dharvi Dunger Formations. Vertical seal is provided by the tight Barmer Hill formation that overlies the Fatehgarh. The bulk of reservoir oil is contained within the upper FM1 member of the Fatehgarh formation, composed of single story and multi-story stacked, meandering channel sands. These reservoir sands are of excellent quality with porosities ranging from 23% to 25 % with a permeability range of 1 to 3 Darcies. Based on well results the FM1 member consists of 3 meters to 7 meters thick individual sands with net-to-gross ranging from 18% to 78 %. Correlation of flood plain shales and fluvial sands based on well data alone in such a highly heterogenous fluvial system poses a major challenge for reservoir characterization.

The field is covered by 3D seismic data acquired and PSTM processed in 2008. Data quality varies from poor around the main bounding fault in the west to good within the east dipping flank of the structure. Well seismic ties show a similar variation in correlation quality, ranging from 45% to 80 % using logs and check shot data from vertical wells. The dominant frequency of the seismic wavelet is 35 Hz, which means that individual sands within the FM1 member that range in thickness from 3 to 7 meters are not resolved. This resolution problem poses a challenge to reservoir modeling as seismic data are of limited use in characterizing the channelized sand units when building the reservoir static model. Structural definition of the static model comes from a combination of seismic picks of the Top FM1 reflection and well data- based isopaching. The Facies modeling is done by Sequential Indicator Simulation constrained to well data with no input from seismic data. The property model is created by Geostatistical means (Sequential Gaussian Simulation) based on well and core data. The latter process is non-optimal for a reservoir containing spatially variant stacked fluvial sands due to under sampling, given the lateral width (around 100-150 meters) of channels versus an average well spacing of 200-250 meters. Various techniques including spectral decomposition have been attempted to resolve individual channels in seismic data for more accurate reservoir modeling, with limited success.

We recently performed sparse layer inversion of the 3D stack PSTM data over Mangala field. Sparse layer inversion (Zhang and Castagna, 2011), of seismic reflection data yields closely spaced reflection coefficients through incorporating a priori information in the inversion process. The inversion is accomplished by building a dictionary of functions representing reflectivity patterns, and constituting the seismic trace as a superposition of these patterns. Basis Pursuit decomposition is used to find a sparse number of patterns that sum to form the seismic trace. 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 sparse layer inversion is performed trace by trace, with no continuity constraints or other spatial conveyance of information. Thus, the lateral continuity of the results is an indication of the stability and robustness of the algorithm. Synthetic tests indicate that sparse-layer inversion using Basis Pursuit can better resolve thin beds than a comparable sparse-spike inversion. The closely spaced reflection coefficients that are produced during sparse layer inversion effectively increase the bandwidth of the seismic data.

Application of sparse-layer inversion to the Mangala field data has resulted in improved detectability, resolution, and understanding of lateral continuity of thin reservoir units. This further improves the

ability to delineate the channel geometry by mapping geobodies for use in static modeling. While the bandwidth of the input seismic data is from 7 – 60 Hz, inversion increased the effective bandwidth to 7 – 105 Hz. The inversion result was validated with well-seismic ties using wavelets extracted from the broadband seismic data (Fig. 1). Thin, channelized sand units within the FM1 unit that were unresolved in the input seismic data are resolved in the broadband inversion data. Datum slice attribute maps using the broadband seismic data depict channelized sand units that will enable their inclusion in building a more accurate static model (Fig. 2).

Figure 1 Sparse layer inversion data resolves thin sands which are not visible in the input seismic data.

Seismic attribute comparison: input versus broadband inversion data

Figure 2 Sparse layer inversion data resolves more sinuous meandering features that are not resolved in the input seismic.

References

Zhang, R. and Castagna, J.P. [2011] Seismic sparse-layer reflectivity inversion using basis pursuit decomposition. *Geophysics*, **76**(6), R147-R158.