Interpretation of full-azimuth broadband land data from Saudi Arabia and implications for improved inversion, reservoir characterization, and exploration

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Abstract

Interpretation of conventional land seismic data over a Permian-age gas field in Eastern Saudi Arabia has proven difficult over time due to low signal-to-noise ratio and limited bandwidth in the seismic volume. In an effort to improve the signal and broaden the bandwidth, newly acquired seismic data over this field have employed point receiver technology, dense wavefield sampling, a full azimuth geometry, and a specially designed sweep with useful frequencies as low as three hertz. The resulting data display enhanced reflection continuity and improved resolution. With the extension of low frequencies and improved interpretability, acoustic impedance inversion results are more robust and allow greater flexibility in reservoir characterization and prediction. In addition, because inversion to acoustic impedance is no longer completely tied to a wells-only low-frequency model, there are positive implications for exploration.

Introduction

The Permian Unayzah A member of the subsurface Unayzah Formation (Melvin and Sprague, 2006; Melvin et al., 2010) contains reservoir quality sandstones that are predominantly Eolian in origin (Heine et al., 1998; Melvin and Heine, 2004). Although there is some suggestion of gross homogeneity in the reservoir sands on a seismic scale, complexity is evidenced by geologic descriptions of the reservoir interval (Melvin et al., 2010) and by the presence of several distinct free-water levels within the main productive field. In the study area, whose general location is shown in Figure 1, the Unayzah A member is unconformably bounded by marginal marine basal Khuff clastics above and by the Carboniferous Unayzah C member — a quartz-cemented, low-porosity glaciogenic clastic unit — below (Figure 2).

In terms of subsurface structural style, regional, albeit subtle Mesozoic contraction is the event of greatest structural significance in Saudi Arabia, as this event produced gentle folds in the Permian to Mesozoic sediments which form the primary traps for the country’s major oil and gas fields (Nicholson and Groshong, 2006). Multiple regional unconformities in the Jurassic and Cretaceous section in eastern and central Saudi Arabia, together with quantitative analyses of these growth folds, indicate that contraction and fold growth continued episodically throughout the Mesozoic, culminating between the Turonian and the Maastrichtian (Paul Nicholson, personal communication). This protracted contraction event produced broad, low-relief, asymmetric anticlines that formed above a moderate to high angle (45°–70°) master reverse fault rooted in the Neoproterozoic basement (Nicholson, 2000), as the one covered by this survey (D. L. Cantrell, personal communication).

The 3D seismic volume historically used to characterize the reservoir sands was acquired in 2004–2005 and has proven to be relatively successful in predicting the presence/absence of reservoir and general reservoir distribution. Using acoustic impedance inversion, reservoir potential was assessed on a well by well basis and general reservoir characteristics were estimated for the proposed well bore. Interpretation problems have persisted and hamper complete characterization of the Unayzah A reservoir. First, despite the presence of a distinct impedance change as denoted by well logs (Figure 2), there was insufficient seismic signature defining the top of the reservoir section and it was therefore never directly mapped. Instead, the seismic reflector defined by the interface between Permian Khuff carbonates and the underlying basal Khuff clastics was used as a proxy to the top of the reservoir section in the manner of Hardage et al. (1994). In addition to the pitfalls associated with the use of a horizon-phantom (Pennington et al., 2004), the base of the Khuff carbonates is itself challenging to pick and contains several inaccuracies. Second, the base of the reservoir...
— an even stronger impedance change from the porous Unayzah A reservoir section to the quartz-cemented sands of the Unayzah C — is poorly imaged as well. We treated the base of the reservoir section similarly, using, again, the base of the Khuff carbonate reflection as a proxy. Finally, although acoustic impedance inversion gave much-needed continuity to the reservoir section and improved predictability, the impedance of basal Khuff clastics is in connection with the impedance of the Unayzah reservoir making extraction of geobodies specific to the Unayzah A reservoir difficult (Figure 3).

Characteristics of the seismic volume that contribute to these interpretation issues are a poor signal-to-noise ratio (S/N) in the target interval, surface-generated and interbed multiple contamination of primary reflections, and poor high-frequency recovery with a usable high-end frequency of, at best, 30 Hz.

This paper will show the improvement in interpretation, the enhancement of reservoir characterization and the implications to exploration due to the use of broadband, full azimuth seismic data acquired in 2010–2011 over the subject field. Using new acquisition parameters, each of the aforementioned problems has been addressed and improved leading to more detailed interpretation of the Unayzah A reservoir.

**Acquisition and processing**

The acquisition of land 3D seismic data in Saudi Arabia has traditionally consisted of asymmetric orthogonal geometries with relatively long receiver lines but an overall recording patch aspect ratio of 0.6 or less. Because geometries have historically been tailored for shallow reservoirs, full azimuth acquisition using a 1:1 aspect ratio for improved imaging of deep targets have gone largely untested.

To address the issues of poor high-frequency recovery and high noise levels, and at the same time recognizing that future work with deep gas reservoirs will require data that are less compromised and more flexible, we have begun acquiring data using geometries more consistent with these goals. In short, our new acquisition parameters seek to achieve (1) coherent broadband signal, (2) significant noise reduction at deeper stratigraphic levels, and (3) a framework for working with azimuthally sensitive data components.

Our new acquisition has, as its centerpiece, single sensor or point receiver technology. Advantages to the use of point receivers have been described by various authors (Baeten et al., 2000; Vermeer, 2002; Quigley, 2004; Bagaini et al., 2010), but Pecholcs et al. (2012) have described probably the most important aspect as concerns our current acquisition — access to 12.5-m receiver station sampling for improved noise wavefield definition. Our prior use of large arrays of

**Figure 1.** Map of the Eastern Region of Saudi Arabia showing the survey area (rhomboid) and the Ghawar Oil Field for reference.

**Figure 2.** Geologic column from the study area relating major stratigraphic units with a representative impedance log. Note that there are several places where strong reflections are expected based on impedance. These include the top and base of the Unayzah reservoir and the top of the Sarah Sandstone.
geophones summing into a single channel — 72 geophones per station spaced at 50 m for the original seismic data used for comparison in this paper — was successful at eliminating low-velocity direct arrival noise from the source. These larger arrays fail to capture interarray statics, and allow significant aliasing of slow-velocity, low-frequency noise. With the high number of channels in our new geometries, using 72-geophone stations is impractical and cost prohibitive.

Similar to receiver station interval, the shot interval has also been reduced to 12.5 m; in addition, the spacing of shot and receiver lines is now 125 m for both, as opposed to 200 and 100 m, respectively, for the original data set. The maximum crossline offset in the new acquisition design is 5875 m and the maximum inline offset is 6000 m. Additional information regarding the geometry of our current acquisition may be seen in Pecholcs et al. (2012) and Pecholcs and El Emam (2012). These elements all combine for a final raw data product with nominal fold of 9216 per 12.5 m bin versus an original nominal fold of 121 in the same equivalent bin.

The last piece of our new acquisition parameter puzzle includes the use of recent advances in vibroseis technology. Although we are most interested in recovering the highest coherent frequency possible, we also have great interest in low-frequency acquisition for two reasons: first is the obvious penetration power of low-frequency signal (Dragoset and Gabitzch, 2007) for interpretation of the deepest portions of the sedimentary section, and second is the predicted uplift in acoustic impedance inversion. We therefore chose vibroseis with the capability of sweeping from 2 to 94 Hz.

The data should be considered as symmetrically sampled (Vermeer, 2002) and therefore, have all the advantages in processing and final prestack migrated product: equivalent crossline and inline amplitudes and offset vector tile sorting yield data sets that can be exploited for azimuthal information. There is also a reasonable expectation from symmetric sampling that anisotropic PSTM will potentially yield velocity differences that can be exploited in the search for deep, fractured reservoirs.

Results

Interpretation

When we examined the resultant full azimuth seismic data set, two key findings were evident: a significant increase in bandwidth spanning now from 3 to 45 Hz (−12 dB to −12 dB, respectively) and a significant decrease in the noise levels. Addressing the first finding, when our full azimuth acquisition was originally planned, we had hoped for a greater increase in high-frequency content such as that attained by new acquisition in Qatar (Seeni et al., 2009; Seeni et al., 2011) and Kuwait (El-Emam and Khalil, 2012). Although the increase to 45 Hz is gratifying, the acquisition of coherent, high-frequency data in eastern Saudi Arabia is still problematic owing to scattering in the near-surface by complex surface and nonsurface-consistent velocity anomalies (Pecholcs and El-Emam, 2012) or some other as-yet undetermined issue.

The increase in low-frequency signal has had as dramatic an effect on the data as we had expected from an increase in high frequencies. When comparing the two vintages of seismic data (Figure 4), we note that the
newer data appear to be more “interpretable”, with an apparent increase in reflector continuity. This presumed increase in reflection continuity can be documented using a simple test. Figure 5 shows a comparison between two autotracked horizons from the original data and the new full azimuth data. In each case, the autotrack parameters were set conservatively and a single autotrack pass performed. Parameters for the autotrack algorithm included crosscorrelation tracking with minimum correlation of 90% over a centered 56 ms window, a maximum “jump” of 12 ms (three voxels) to look for a match, and an evolving seed where an “accepted” trace becomes a viable seed for continued tracking. The resultant horizons show stark differences in completeness and character that we ascribe largely to the increase in low-frequency bandwidth. The test is not offered as an endorsement of rapid autotracking techniques that allow fast picking of entire volumes. We largely agree with the conclusions of Brown (2012) that the greatest value in using the autotracker is in the precision of picking that it affords. Our test points out the observed improvements in data quality caused by improved vibroseis sweep, improved spread geometry, and the flat response single sensor accelerometer as contributing factors. We believe that the untracked points of our original data set are teaching us something about the data themselves in addition to the underlying geology (Brown, 2012).

The impact on interpretation from the addition of 3–7 Hz frequencies into the seismic data is perhaps most evident in our results from colored inversion (CI) (Lancaster and Whitcombe, 2000). As part of our exploration workflow, we typically derive this relative acoustic impedance prior to moving forward with full inversion. We use CI data mostly for reconnaissance work and horizon picking in conjunction with the reflection seismic data set. The CI is also used for initial geobody extraction and as a quality check of any subsequent absolute acoustic impedance (AAI) inversion (Latimer et al., 2000).

The CI calculated from our original seismic data volume (Figure 6a) appears monochromatic (Wallick et al., 2012) and lacks the necessary frequency content to completely segregate, for example, the Khuff carbonates from the overlying low impedance Sudair shale. By contrast, the CI calculated from our new data (Figure 6b) shows the ability to discriminate gross lithological layers, as with the shale and carbonate previously mentioned, and improved high-frequency response. In essence, the CI of the new data is giving a close approximation to the trends seen in absolute acoustic impedance inversion without the necessity of a well log-derived low-frequency model. Figure 7 shows this clearly in a direct comparison of the new CI in the right-hand panel and our AAI from the original data on the left. This has clear implications for exploration, especially when dealing with large data sets. Frequencies of 5 Hz and lower embedded in the seismic data allow for more dependable and consistent lateral correlations and identification of intervals of interest away from well control.

The second visible change in the data concerns the presence (or absence) of noise. The section from the Triassic Jilh strata through the target reservoir has traditionally been difficult to tie with well log-derived synthetic seismograms owing to the presence of surface-generated and interbed multiple contamination — a well-established issue in eastern Saudi Arabia (Wallick et al., 2006; Al-Khalid et al., 2008). In addition, a poorly defined, chaotic, or hummocky (Mitchum et al., 1977) character has been visible between distinct seismic events in areas where we expect the seismic data to reflect a more straightforward layered stratigraphy (Figure 4).
We have observed in the past that an increase in crossline fold has decreased noise levels in the final seismic product and we have been expanding the data acquisition in the crossline direction accordingly. In the current survey, we have achieved a full 1:1 recording patch aspect ratio thereby maximizing crossline fold. Whether the noise reduction evident in the new data is the result of (1) an increase in crossline fold, (2) an increase in wavefield sampling density, or (3) an overall increase in fold is difficult to assess. It is clear, however, that one or possibly a combination of all three of these changes has resulted in data that — albeit not entirely noise-free — are clearer and more interpretable.

Focusing on the reservoir section, the results of the previously described observations of changes in the new data are apparent. As noted, the top of the Unayzah A reservoir displays a sharp acoustic impedance contrast with the overlying clastic section as calculated from log data (Figure 2). Drilling results have largely confirmed the more widespread distribution of the gross reservoir package in contrast to the expectations of a more “patchy” reservoir as interpreted from the original seismic volume. Figure 8 shows a comparison between the two seismic vintages and demonstrates the increased clarity, coherence, and continuity of the top reflector of the reservoir package. Just as important, the base of the reservoir section now shows a very strong and sharp reflection when contrasted with the same event on the old data. This reflector marks not only a sharp change in impedance from porous, friable sandstones to dense quartz-cemented sandstones, but also a hiatus in geologic time.

From an exploration standpoint, all the concepts previously mentioned also have a significant impact on exploration at deep Paleozoic levels, from the top of the Unayzah C member to below the Qusaiba shale source rock. Because we now have recovered low frequencies that appear to suffer little or no attenuation at our depths of interest and we have a higher S/N in our final product, we are able to obtain what we believe is a superior representation of the variability of the subsurface at increased depths (times). Not only are the identification and tracking of key horizons accomplished with greater confidence, but the subjective quality of the surfaces generated, in terms of continuity and detail, have increased our confidence in the picture conveyed by the data.

**Inversion**

The previous AAI inversion computed from the original seismic volume used 11 wells in the construction of the low-frequency model and used a cost-function approach and 1D elasto-dynamic interbed multiple modeling in an attempt to minimize the effects of interbed multiples on the final solution (e.g., Al-Khaled et al., 2008). Setting aside the issue of whether the process delivered on the premise on interbed multiple minimization, we thought at the time the solution was superior to that achieved by other means and it therefore was the model of choice. Without the ability to map the upper and lower boundaries of the target reservoir to constrain inversion, and lacking sufficient high-frequency content to separate the overlying clastic section from the reservoir sands, this inversion had limited potential for mapping separate reservoir compartments and

![Figure 6](image-url)  
**Figure 6.** A comparison of two colored inversion (CI) volumes side-by-side at a representative well. The CI on the left of the panel (a) was calculated from the original seismic data and has a somewhat "monochromatic" look with alternating bands of high and low impedance lacking the definition of distinct strata. The CI calculated from the new data to the right of the well (b) shows distinct layering that more closely resembles that observed in the displayed acoustic impedance log. The difference between these two inversions is based largely on extended low-frequency information in the new seismic volume. Refer to Figure 3 for identification of reservoir and lithostratigraphy.

![Figure 7](image-url)  
**Figure 7.** Comparison of an absolute acoustic impedance (AAI) volume as calculated from the original data (a) and CI volume as calculated from the new data (b) at a representative well. Although the scaling of each is different (absolute versus relative impedance), note that the various layers of clastics and carbonates match up well. Note also the higher frequency detail in the new CI. Refer to Figure 3 for identification of reservoir and lithostratigraphy.
providing a reasonable approximation of the distribution of porosity as an input to geocellular reservoir modeling.

With the new broadband full azimuth data set, we are now able to confidently build a framework of horizon interpretation which includes previously unmapped horizons. Using this framework and the log data from six of 34 wells, the new data were inverted for AAI in the poststack domain. Lindseth (1979) and Russell (1988) showed that the critical velocity information defining step changes and/or ramps were contained within the 0–5 Hz band. Martin and Stewart (1994) took this further, suggesting the loss of 1 Hz is sufficient to remove critical velocity change information. Inversion of our new data set to AAI therefore still requires well data to provide the missing 0.1–3 Hz information despite the presence of very low frequencies in our new data set. Although we are unable to produce a “seismic only” initial model due to the band-limited nature of our new volume (no sub-3 Hz data), the low-frequency content from the seismic contribute to the final accuracy of reservoir prediction (Latimer et al., 2000) and provide much-needed lateral variability that is not available from a standard wells-only initial model.

A comparison of the two inversion results shows the improvements noted in the newer seismic volume (Figure 9). First, the new inversion shows a very sharp base to the reservoir section, consistent with our previous observations as opposed to the more transitional look in the original inversion. Second, the “bleeding” of the upper low impedance, unproductive clastic section into the reservoir section has largely been stemmed in the new data. And finally, the new inversion appears to provide a level of internal architectural detail to the reservoir section that was previously unattainable.

**Geobody extraction and reservoir properties**

Using the new AAI volume, we extracted geobodies at the reservoir level using two different parameters to define the extent of the bodies and the geometry of the reservoir. As we have clear separation of the reservoir from the overlying clastic section, this is now possible. The first extraction used 32,250 g·ft/cm³·s as an upper limit parameter and resulted in one large geobody in the southern part of the field and several geobodies in the northern half (Figure 10a). Well data largely confirm this distribution of reservoir quality sand with one exception: the geobody at the location of wells A, B, and C. Well A is updip and wet, as compared with the gas-bearing wells B and C, so the likelihood that these wells share a single compartment as shown in the illustration is small.

A second extraction (Figure 10b) using more constrained parameters (maximum value 32,000 g·ft/cm³·s) shows the number of geobodies in the north has predictably grown. Note in this solution that wells A and B still show as being in the same compartment, but this time well C has been separated as its own compartment. In this scenario, most (but not all) wells fit the reservoir distribution; any smaller change in impedance (31,750 g·ft/cm³·s or less) results in a poor fit of the extracted geobodies to the well data.

We think that the solution is somewhere between 32,250 and 32,000 g·ft/cm³·s and that each of these solutions may serve the part of two separate reservoirs.

![Figure 8](https://pubs.geoscienceworld.org/interpretation/article-pdf/1/2/T167/3006B45/INT-2013-0065.pdf)
realizations. Interestingly, these values are consistent with what was originally considered the upper limits of gas-bearing reservoir quality sands, taken in part from rock physics work from this field and from the results of drilling. And as previously described, values as low as 32,000 g·ft/cm³·s in the original data caused considerable contamination of reservoir extractions by the overlying clastics of the Khuff Formation and were given low confidence. With the present two solutions, knowledge of the variability of impedance values within each body, and a reasonable rock physics model, calculation of average reservoir porosity is now possible.

Discussion

The evidence suggests that our new data set is superior to that which we were using before; it extends the frequency on the high and low ends, has less noise and appears to provide a more accurate picture of the subsurface. We also use the phrase “more interpretable,” although this quality is elusive and subjective. This is the first data set in several years in which we will be able to truly expand our ability to exploit the deep subsurface. The question of the ultimate cost of this quality has yet to be answered.

Pecholcs et al. (2012) recognized that the effort for improved data quality has caused a revolution in data acquisition and processing. In the case of the current survey, we are no longer talking about Terabytes but rather Petabytes.
of data — an increase that in and of itself is highly significant. With 100,000 channels active, the amount of data coming back to disk storage in the field is enormous and all efforts at quality control that were traditionally employed now have to be rethought as a result of the enormous amount of information.

This issue carries through to processing as well. An unprepared data processing facility could be quickly overwhelmed by the volume of data streaming in from the field. Similar to the story above with acquisition QC and testing, the volumes of data from such a recording spread no longer allow experimentation on a small scale with various processing parameters to see which results in the highest quality product because a “test” data set with full fold over one or two lines may result in a volume of data and processing time similar to a full-size project using traditional acquisition methodologies. On top of this, local processing centers are currently ill-equipped to deal with the noisy shot gathers resulting from the use of point receivers. Although we have a final data set which evidence suggests has greatly reduced noise levels, we nonetheless are aware that noise removal at the onset is potentially heavy-handed and this aspect of processing can and likely does bleed through into the final product.

We have already discussed in some detail the results that demonstrate the uplift in our data from the broadening of the spectrum with low-frequency input. In addition, deep-seated faulting as derived from attribute extractions on the new data set is better described and appears to have sharper definition when compared with similar extractions from the original data set (Figure 11a and 11b). Interestingly, we still find good definition of the master faults of the main structure below 2.5 s in the 0–8 Hz band.

Outside of the uplift in low frequency, it is still unclear which of the remaining changes to the acquisition parameters has given us the greatest uplift to the data. We have the following changes yet to address: use of single sensor receivers, increased sampling density, and symmetrical distribution of shots and receivers. Of these, the last is probably the easiest on which to make a reasoned and definitive statement. The use of symmetrical shot and receiver stations allows us to sort and migrate using offset vector tiles and, hence, has the best opportunity for the analysis of azimuthal information. Any future work with fracture detection in the deep Paleozoic section will most likely rely on our ability to look at P-wave velocity in an azimuthal sense and analyze horizontal transverse isotropy.

The remaining parameters were intended to assist in our goals of improving high-frequency recovery and noise reduction and it is in these areas that questions remain unanswered. We have stated previously that we have improved recovery of high-frequency data, but whether this uplift is the result of high sample density, single sensor deployment, symmetrical orthogonal layout or some combination of all three is yet to be determined. We currently take the position that all these issues are inextricably intertwined and contribute to the final fabric of the resultant data set. It remains yet to analyze whether — in the interest of cost and efficiency — one or more of the aforementioned parameters may be compromised and result in the same quality data set.

In the end, our final data set delivered for full interpretation is not just the last link of a chain which started with acquisition, connected to processing and then connected to interpretation, a flow probably recognizable to many interpreters. It is rather the product of a collaboration of each of these groups (and more) from the onset before the first shot was acquired.

Conclusions

Although there are still outstanding questions, the evidence points to a significant uplift in our interpretation from new acquisition parameters and subsequent processing applied to our study area. The largest and most easily definable uplifts are the boost in coherent high-frequency signal which adds a higher level of detail to our interpretation and the extension of the bandwidth down to 3 Hz from the original 8–9 Hz low end. In particular, the latter has given us the single largest contribution to the overall data set. The penetration power of these low sub-8 Hz frequencies provides much needed continuity to the data and a less noisy seismic data set in which to explore and examine deep Paleozoic reservoirs and tectonic features. There is a big uplift from the low-frequency extension to our final AAI. We do not assert that an AAI can be calculated with any accuracy without the use of a well log-derived low-frequency model. In an exploration sense, the embedded
low-frequency content of the data gives a greater measure of confidence in impedance results away from well control by reducing interpretational bias.

The other major area of uplift is in noise reduction. Although we are certain that the dense sampling of the shot and receiver lines gives us a more accurate picture of the entire noise wavefield, we have not quantified whether this is a more significant contribution than the other variables, notably single sensor receivers and symmetrical, full azimuth sampling and careful seismic processing. With further testing, we may find that one or more of these parameters may be adjusted without significant impact on our final interpretation products.

Finally, we conclude that the quality of the data and ultimately the quality of the interpreter’s deliverables are directly proportional to the collaborative effort expended from the beginning of the process; the more the interpreter commits to the process at each step, the better the final product.

Acknowledgments

The authors would like to extend thanks to Saudi Aramco for permission to publish and present this work. We would also like to thank our colleagues at Saudi Aramco, Western Geco, and Schlumberger for the collaborative effort that spawned this and additional work. In addition, this manuscript has benefited greatly from the input of several reviewers that include Peter Crisi, Eunice El Ouair, Paul Nicholson, Johannes DeAngelo, Mehdi Far, Steven Roche, and Ran Zhou. Finally, we would like to thank the Editor, Yonghe Sun, for his helpful insights.

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