When Is a Discovery Not So Great?

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Many small to medium-sized oil and gas prospects are successful in that they are classified as discoveries – and are perhaps even completed and produce hydrocarbons – but then are abandoned before even a small fraction of the reserves estimated to be present have been produced.

Sometimes, a 3-D seismic survey is used after the discovery to appraise it for efficient development, and this shows that the prospect's size has been grossly exaggerated in the previous interpretation based on 2-D seismic data, especially if the prospect is based on reflection amplitude anomalies ("bright spots") rather than a well-defined structural trap.

In this case, development of the discovery is usually no longer economical.

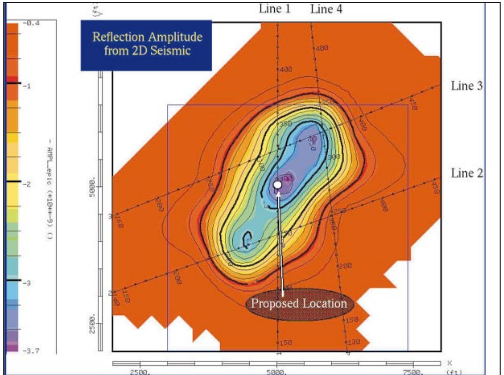

Figure 1

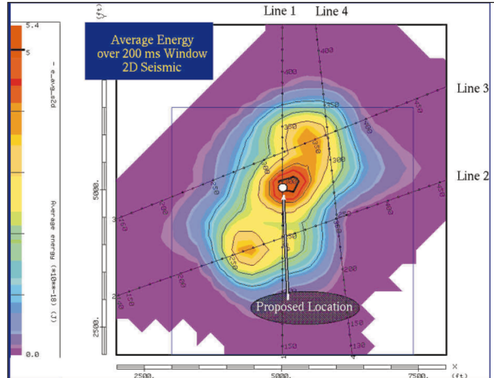

Figure 2

Analyzing the Errors

We used a simple computer model representing a small, gas-filled sand bar.

Four synthetic 2-D seismic lines were generated across this model prospect. Two of the lines were dip lines and two were strike lines. We interpreted these four lines as if they were real data, and used them to generate maps of the amplitude anomaly.

Figure 1 is seismic reflection amplitude, and figure 2 is average energy over a 200 ms window.

A location for an exploration well was picked at the center of the amplitude anomaly.

The Model

The sand bar computer model consists of two layers of shale (with slightly different physical properties) separated by a horizontal interface at a depth of 1,555 meters (5,100 feet). The sand body lies on this interface; it is flat on the bottom, and ellipsoidal on top.

The length of the sand bar is 800 meters (2,600 feet); it is 60 meters (200 feet) wide; and it is five meters (16 feet) thick at its thickest point.

The physical properties used for the model are shown in table 1, and the model is shown in figure 3 (page 35).

We chose the dimensions and physical properties of the model arbitrarily, but they were intended to represent a shallow gas pool that is too small to be commercial (0.1 bcf), in an area where even small fields can be economically viable.

Raytracing

We used normally-reflected rays to model the seismic data, which simulates unmigrated, stacked seismic data.

Diffractions were not modeled. It is reasonable, in the case of real data, to assume that migration would not be needed, because the reflection with the bright spot has no measurable dip.

The modeling used a trace interval of 6.25 meters (20 feet), and for each line there were 400 traces. The 30 Hz zero-phase Ricker wavelet used in the modeling approximates the effective wavelet of real data from the type of prospect modeled.

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Table 1

Unit	V_P (m/s) P velocity	V_S (m/s) S velocity	ρ(kg/m³) Density	Q_P P-Wave Q Factor
Upper Shale	2,621	1,504	2,210	126
Gas Sand	2,134	1,496	2,000	82
Lower Shale	2,606	1,494	2,210	125

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Results – 2-D Data

The modeled seismic data shows a strong amplitude anomaly on each of the lines, including those that do not cut across the sand bar (figures 4 and 5). This is the result of the Fresnel Zone effect (as shown in figure 6 of the October EXPLORER "Geophysical Corner").

There is practically no structure visible across the amplitude anomaly (figures 4, 5, 6 and 7). The reflection amplitudes tied at line intersections and the amplitude anomaly was mapped (figures 1 and 2).

If we empirically compare such an anomaly with anomalies over nearby known gas fields, we might find that similar anomalies are produced by gas sands 10-15 meters (33-50 feet) thick. Making the assumption that sand thickness is proportional and assuming that the maximum thickness of sand is 12 meters (40 feet), we get the sand thickness shown in figure 8 (page 36), and reserves of 3.5 bcf.

Discovery vs. Model

A well drilled closest to the center of the anomaly (SP 295 on line 1) would find about 5 meters (16 feet) of sand – and, again assuming sand thickness is proportional to reflection amplitude, would give the sand thickness map shown in figure 9 (page 36) and gas reserves of about 1.3 bcf.

This is not as much as might have been hoped before drilling, but it might still be commercial.

The theoretical reserves for this model study are actually 0.1 bcf gas. We can see clearly then that proceeding with completion of the discovery well would be unwise.

What Went Wrong?

Here we have a prospect that matches many of the characteristics of known fields nearby:

❒ There was a seismic (2-D) reflection amplitude anomaly comparable in magnitude with those associated with nearby commercial gas pools.

❒ The calculated reserves for the area of the anomaly were large enough to justify drilling.

❒ The drilled well discovered a gas-filled sand at the expected depth, and although the sand is thinner than hoped, the new computed reserves are still sufficient to justify completion.

See **Geophysical**, next page

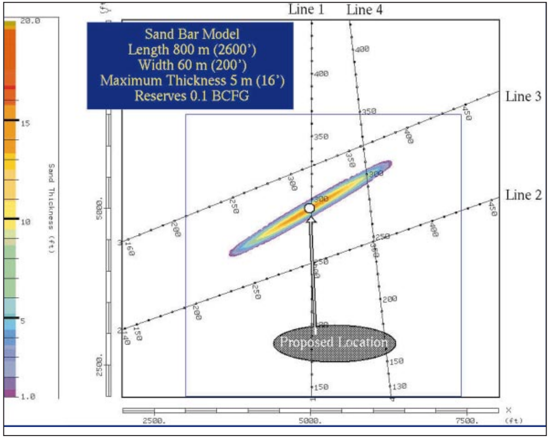

Figure 3

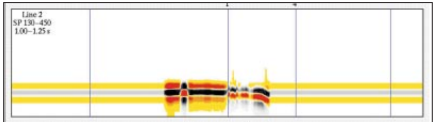

Figure 4

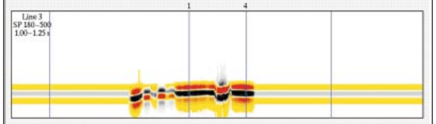

Figure 5

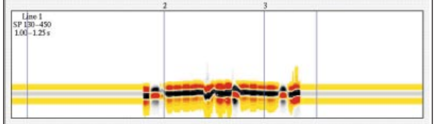

Figure 6

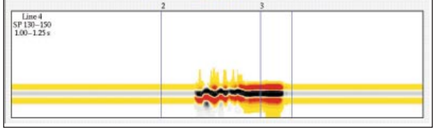

Figure 7

Geophysical

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But we know – because it is a model – that the reserves are actually very much smaller.

Explanation

The fundamental defect in the interpretation is ignoring the Fresnel Zone.

The high amplitude reflection from the top of the sand has been recorded at distances more than 350 meters (1,150 feet) to each side of the sand bar. If we migrated the seismic data, the lines that cross the bar more or less normal to its strike would show a narrower anomaly, but the lines parallel to the sandbar would be unchanged.

An interpreter would always be strongly tempted to include the anomalies on these lines in the interpreted area of the anomaly. In practice, migration of the data would have only a minor effect on the interpretation.

Thus, this type of interpretation error is almost always in the direction which makes the anomaly apparently larger.

In this case, the feature being convex upward, the sand actually has significant dip on its upper surface. However, even without this dip, the edges of the feature would diffract seismic energy to give much the same effect.

What *Should* Be Done

There are potentially three methods of avoiding this error:

1. Map using unmigrated seismic data and then migrate the map using a suitable method.
2. Map the anomaly using conventional migrated seismic data, but only use seismic data in the exact dip direction, at right angles to the strike of the geological feature.
3. Use 3-D seismic data, which is more or less correctly migrated in three dimensions.

The first approach can be seen to be impractical even in this simple case. Here the buried focus on each side of the sand bar creates crossing reflection events which cannot be picked precisely.

Furthermore, the accuracy of the migration is critically dependent on the accuracy of the velocity used for migration, and because only a small number of points are being migrated (unlike when the actual seismic data are being migrated) the focusing effect of correct migration may be difficult to distinguish.

Mapping with 2-D migrated data, and restricting the interpretation to dip lines will work if only dip lines are used, and only if there are enough of them. The edge of the anomaly must be made up of approximately straight segments, each one longer than the depth of the feature – and this most certainly does not apply in the model studied, because only two lines cut the bar at right angles, and two points are not enough to show that the feature is linear, nor to measure its length.

In the real world the only way to ensure that a reflection amplitude anomaly is mapped correctly is to use 3-D seismic data. That is the only way of migrating the reflections from the anomaly correctly in three dimensions.

We did this for the model, and the amplitude anomaly mapped by the 3-D survey is shown in figure 10. The anomaly is clearly visible on time slices (figure 11).

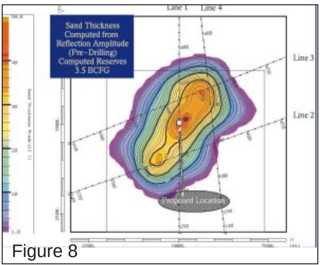

Figure 8

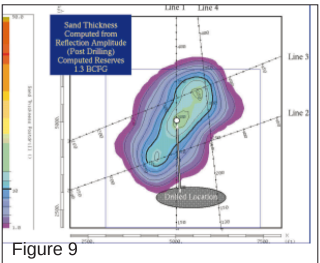

Figure 9

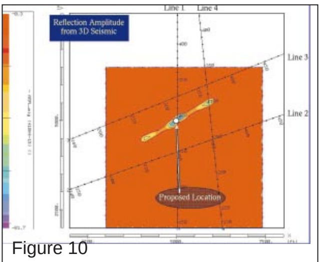

Figure 10

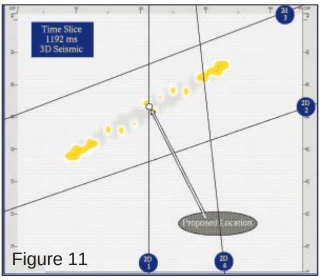

Figure 11

Compare both of these with the original model (figure 3).

The problem becomes more critical as a prospect becomes smaller in area, for two reasons:

❒ The error in lateral position of the edge of a feature depends almost entirely on the line orientation and the depth of the feature.

The size of the feature has little effect on the size of the error. The modeled example expanded in width from 60 meters (200 feet) to 750 meters (2,550 feet); if the sand bar had been 160 meters (520 feet) wide, the interpreted width would probably be about 850 meters (2,790 feet) wide with the same spacing of seismic lines.

The exaggeration is (in this case) a shift outward of the edge of the anomaly by about 350 meters (1,150 feet). Thus there is a twelve-fold exaggeration of the 60-meter wide sand bar, but only a five-fold exaggeration of the 160-meter wide sandbar.

❒ Correct migration is more important for a smaller prospect because the economics of the prospect are more likely to be marginal.

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Conclusion

Interpretation of conventional 2-D seismic data tends to exaggerate the size of a petroleum prospect – especially if the prospect is defined by an amplitude anomaly in an area of flat dip.

This exaggeration is much larger (12-fold for our model) for smaller prospects. The use of 3-D seismic surveys to define the prospect can minimize the leasing costs as well as the possibility of drilling a discovery well on a small, uneconomical prospect.

A 3-D survey is absolutely necessary if multiple development wells are needed to efficiently drain the field. ❏