5D interpolation to improve AVO and AVAz: a quantitative case history

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ABSTRACT

5D interpolation followed by azimuthal prestack migration results in better conditioned gathers for Amplitude Versus Offset (AVO) and Amplitude Versus Azimuth (AVAz) analysis. The data should be prestack migrated prior to AVO or AVAz analysis, but this often proves problematic for land data due to the poor sampling of the data in offset and azimuth. This sparse sampling results in incomplete constructive and destructive interference of the migration operator resulting in migration noise. By 5D interpolating the data, the wavefield is better sampled leading to better migrated gathers and AVO or AVAz results.

This is demonstrated quantitatively on a 3D dataset from Western Canada. This dataset has been processed with different interpolation/migration flow combinations and then analyzed for AVO and AVAz. The AVO data has been correlated to 69 wells at the Viking level. These correlations show that by including the 5D interpolation, better AVO predictions of the Viking porosity thickness (Phi-h) are obtained. When the study was originally performed only 29 wells had been drilled. Since then, the exploration area was enlarged and an additional 19 wells were drilled for the Viking based on this new methodology resulting in an increase in the drilling success rate and the economic return.

An AVAz study was subsequently performed on the Nordegg reservoir with the results being calibrated to two horizontal wells with image log data. Because of the extra dimensionality of this analysis, the data was remigrated. Both azimuthally sectored and Common Offset Vector (COV) Kirchhoff prestack time migrations were performed along with several different interpolation strategies. Each interpolated/migrated result was then analyzed for AVAz using the near offset Ricker equation, the results of which were compared to the image log data in a series of scatter plots. The correlation coefficients between the image log data and the AVAz results that were obtained using a flow which employed interpolation were superior to those obtained using a flow which did not employ interpolation.

Introduction

It is well known that seismic data processed for subsequent AVO analysis should be prestack migrated (Moshier et al., 1996), provided that a correct amplitude preserving algorithm is used. Implementing this in practice for land seismic data can be problematic because of the relatively large source and receiver line spacing typical of land acquisition. Migration assumes uniform and dense enough sampling to prevent operator aliasing. Inadequate, non-uniform sampling can result in the migration operator not being able to constructively and destructively interfere, resulting in migration artifacts. This paper describes how 5D Minimum Weighted Norm Interpolation (MWNII) (Trad, 2009) may be used to mitigate these issues and improve the AVO and AVAz results. This is shown quantitatively on a seismic dataset from West Central Alberta, Canada which contains multiple geologic targets.

This study was initiated in 2007 with the goal of showing that the 5D interpolated seismic data would improve the Viking AVO estimates in a quantitatively measurable fashion. AVO attribute estimates of the Viking reservoir were generated from multiple processing flows with and without prestack interpolation. The resulting AVO attributes were then compared to Phi-h values from 29 wells. Downton et al (2008) and Hunt et al. (2010a) summarized this work demonstrating that 5D MWNII can be used to improve the sampling within each offset volume, resulting in better prestack time migrated (PSTM) gathers and consequently better AVO results. Since the initial work was done, 19 additional wells for the Viking have been drilled. The first part of this paper summarizes the original work, while the last part of this paper describes subsequent drilling results and the economic impact of this work. These new wells have on average 21% greater three month initial production (IP) and 31% higher Net Present Value (NPV).

Based on the improvement seen in the AVO results, it was felt that this methodology should also improve the Azimuthal AVO (AVAz) estimates. Data migrated for AVAz analysis must preserve the azimuth in addition to the offset, introducing extra dimensionality to the problem. This places greater demands on the data sampling and the migration. The second part of this paper tests the hypothesis that 5D interpolation followed by prestack azimuthal migration will improve the AVAz estimates. This study was performed on the Nordegg Formation, which in this area is a naturally fractured reservoir. It is believed the fracture intensity is of critical importance in determining production. Micro imaging logs were recorded in two of the wells in this study area. Fracture density values were interpreted from these logs and were used to quantitatively compare the different AVAz processing flows. We tested several different interpolation strategies and azimuthal migrations. For our origi-
The Viking Formation reservoir in our study area is composed of shoreface sandstone assemblages that often retain 12-14 percent porosity over 0 to 7 metres thickness, and occur at depths greater than 2800m. The sandstones have low permeabilities (< 1 mD) but are commonly overpressured and gas bearing with typical recoverable hydrocarbons of 8 Bcf and 80,000 bbls condensate per section. The structural setting for the area includes both extensional and compressional tectonic elements. Figure 1 shows logs from two wells from the 3D survey. These wells were selected for the modeling work as they had full wireline log suites including shear and compressional sonic logs and core data. The preserved porosity in Well A is associated with the upper shoreface deposits. In Well B the Viking is a tight lower shoreface and basinal deposit with no reservoir quality. In general the Viking can be described as a more competent material sitting under a less competent half-space (the BFS zone). Thus the Viking is a peak on a zero phase stacked section. When porous and gas-charged, a well resolved Viking zone may exhibit a Type II AVO response (Rutherford and Williams, 1989), in which the weak peak goes towards smaller amplitudes with increasing offset. Log data from Well A and B illustrate this response with the good quality reservoir in Well A versus the absent reservoir in Well B. The different responses suggest that reservoir quality may be robustly characterized by exploiting this contrasting AVO effect. The productive reservoir, which may be entirely or partially eroded, is never greater than 1/15 of a seismic wavelength in thickness. These variables contribute to a poor correlation between seismic amplitude and measures of porosity thickness (Phi-h), which is the quantity that we are trying to predict with the seismic.

The Nordegg Formation

The Nordegg Formation in West Central Alberta is challenging because this gas charged reservoir is deep, structured, and has low permeability. The Nordegg Formation is composed of a lower chert/carbonate rock type overlain by an upper porous quartz-arenite sandstone reservoir which is unconformably overlain by the Poker Chip shale (Figure 2). The sandstone reservoir unit is charged with gas. The Nordegg interval within the study area averages about 12m of net pay (> 6% sandstone matrix porosity) with an average log porosity of 7% and 14% water saturation. The core permeability ranges from .01-1 mD. The preponderance of the deliverability and enhanced permeability within the Nordegg is interpreted to come from the area’s complex system of faults and fractures associated with regional strike-slip style faulting. The fracture density and the production capability of wells drilled into the Nordegg vary materially. Thus it is expected this fracturing will affect the behaviour of the Nordegg in many ways, from drilling, to the way that the reservoir behaves under fracture stimulation (Hunt et al. 2010b).

Two horizontal wells were drilled into several of the interpreted structural archetypes present in the area. Figure 3 illustrates these structural archetypes and the relative positions of the
wells with image logs. Well A was drilled along the strike of an anticlinal feature, while Well B was drilled into a major strike slip feature. The image log tool provides its electrical image from micro-resistivity measurements. Fracture orientation, aperture, porosity, and density can be interpreted from this log, and were used in this study. Hunt et al. (2010b) analyzed 1800m of image log data from the horizontal wells A and B to show that the fractures are vertical and aligned in a preferred orientation. Some 85 percent of the fracture angles are at or greater than 80 degrees to horizontal. The azimuthal data show a dominant strike azimuth of about 50 degrees east of north. This suggests that the assumptions behind the azimuthal AVO analysis are met. Furthermore, Figures 3 through 10 of Hunt et al. (2010b) show that the AVAZ estimates share similar statistics to the well control.

In order to compare the AVAZ estimates quantitatively with the fracture estimates from the well control we need to be able to plot and analyze the two datasets at the same locations along the two horizontal wells A & B. This presents challenges regarding scale and support. The image log data are recorded with a resolution on the millimetre scale, and are sampled with average values at a fraction of a metre along a thin well bore. The seismic attributes are processed with a 30m by 60m bin size. In order to compare these, the image log fracture density data were averaged over a 10m bin interval along the horizontal well bore. By calculating the image log bins much smaller than the 3D seismic bins, we gained some flexibility in further averaging the image log data.

3D seismic data

The 3D seismic data in this area is an orthogonal survey of roughly 600 square kilometres. The nominal source and receiver line spacings of this 3D survey are 660m and 600m respectively. Figure 4 shows the original source lines and the outline of the survey. The source and receiver lines are irregular due to surface considerations, and can be as wide as 1000m in some areas. The shot interval was 120m, and the receiver interval was 60m resulting in a nominal fold at the zone of interest of 27. The data are band-limited to about 55Hz. It was suspected that this acquisition geometry was sampled so coarsely that area weighting and fold compensation (Canning and Gardner, 1998; Zheng et al, 2001) would fail to sufficiently minimize the migration artefacts.

5D MWNI Interpolation

Minimum weighted norm interpolation (Liu and Sacchi, 2004) was implemented in five-dimensions (Trad, 2009) prior to migration to address this problem. The 5D interpolation is performed by solving a large inverse problem. The forward problem is described via the following expression

$$d = Tx,$$

where $x$ is the ideal fully sampled 5D dataset, $d$ is the dataset actually recorded in the field and $T$ is the sampling operator. The sampling operator $T$ maps the fully sampled dataset into the dataset actually acquired as illustrated by the toy example.
The actual problem is solved in the temporal and spatial frequency domain one frequency slice at a time. The frequency slices are coupled following the technique of Herrmann et al. (2000) in which information from the final solution at the previous temporal frequency is used to constrain the solution at the current frequency. The underdetermined inverse problem is solved by minimizing the objective function

\[ J = \|d - Tx\|^2 + \lambda \|x\|_w, \]

where the model norm \(\|x\|_w\) is defined by long-tailed distributions such as the Cauchy-norm or the L1 norm (Sacchi and Ulrych, 1995). Both of these norms have the effect of selecting, among all possible solutions, those that predict the data with less number of elements. These models are known in optimization as “sparse models” and imply that in the spatial frequency domain at least one or two of the dimensions may be characterized by a relatively simple spectrum. This is generally true since even if complex structure exists in the in-line and cross-line domain, the amplitude can typically be modeled by simple relationships in the offset and azimuth domain. This is supported by the multitude of linearized polynomial relationships describing AVO and AVAZ existing in the literature (Gidlow et al. 1992, Rüger, 1996).

The 5D interpolation solves for the fully sampled 5D dataset, but due to input/output size (I/O) constraints only some portion of the fully sampled dataset is typically output. There are a number of factors to consider in choosing the output geometry. It is important to choose a geometry that meets the input and sampling requirements of the particular migration which will be subsequently run. For example, if one is to run a reverse time migration which has been implemented in the shot and receiver domain, then one would want to output the data to a surface consistent geometry. Another important consideration is whether one wants to retain the original data. If the original data is kept, it is easy to quality control the interpolated data by comparing the two (Figure 5). For the purposes of migration, ideally it is best to output to a regular geometry. However, a consequence of this is that most of the original data will not be retained since land 3D data is not typically acquired in a perfectly regular fashion. One has to have a high degree of confidence in the interpolation to throw away all the original data. Interpolation is an underdetermined problem, and some uncertainty will always remain as to how accurately it is describing the full wavefield.

In our case, we used a Kirchhoff prestack migration that was implemented in the shot and receiver domain so we chose to output our data to a surface consistent geometry. For the AVO study we wanted to retain our original data so we chose to improve the wavefield sampling by doubling the number of source and receiver lines retaining the original source and receiver positions. Fold maps at various offset ranges were observed to determine if additional source and receiver locations were needed to obtain uniform offset fold. For example, in Figure 4, around the x-coordinate 17,500 two extra source lines rather than one were output in order to provide sufficient near-offset fold. Figure 5a shows the original data for one CMP while Figure 5b shows the same CMP after interpolation. The difficulty of detecting which traces are interpolated and which are original is an indication that the data complexities and amplitude variations are well preserved. Furthermore, as the original data are preserved in this implementation, it is possible to verify that the original AVO trend is unchanged by the interpolation.

Figure 6 shows a comparison of the prestack time migrated (PSTM) gathers (a) without and (b) with interpolation. The migrations for both the interpolated data and the original data are run on limited offset volumes. The offset range of the volumes varies according to the sampling of the data. That is, the poorly sampled near offsets of the non-interpolated data have a range that is three times greater than the more finely sampled far offsets. Area weighting and fold compensation were also tested and applied when appropriate. Despite the use of these techniques, the data

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**Figure 5.** CMP gather before (a) and after interpolation (b).

**Figure 6.** PSTM migrated gathers (a) without and (b) with interpolation.
input to PSTM after interpolation are more continuously sampled within each offset volume. This results in PSTM gathers with fewer migration artefacts and better signal-to-noise. The determination of AVO attributes is sensitive to noise within the dataset so it is expected that the interpolated migrated gathers should lead to better AVO results.

**Viking AVO analysis**

To test the hypothesis that the 5D interpolation would improve the AVO results we ran a series of different processing flows comparing the AVO results quantitatively to the well control. It was anticipated that the interaction of the interpolation and the migration would be key to the improvement so different migration flows were also tested. In one flow no migration was performed, in another flow poststack migration was performed on the AVO attributes, and in the last flow the data were prestack time migrated. These different migration flows were tested on both 5D interpolated and non-interpolated data. The impact of generating supergathers prior to the AVO analysis was also tested. These different flow combinations were compared in a variety of different ways as described by Hunt et al. (2010a). In this summary we focus only on the AVO attributes analyzed at the Viking horizon.

Fractional elastic parameters such as the compressional (Rp) and shear reflectivity (Rs) may be estimated from the prestack seismic data by AVO Inversion such as the two-term approximation to the Gidlow et al. (1992) equation:

\[
R(\theta) = R_p \sec^2 \theta - 8 \gamma^2 \sin^2 \theta,
\]

where \( \theta \) is the average angle of incidence and \( \gamma \) is the average S-wave to P-wave velocity ratio. There exists a wide variety of AVO attributes that could have been used for mapping and validation. We chose a very simple parameter, the damped Rp to Rs ratio. The gas-charged porous Viking reservoir should illustrate a drop in the Rp to Rs ratio relative to the tighter reservoir.

**Figure 7. Maps comparing the \( R_p/R_s \) Ratio attributes involving the inclusion or exclusion of interpolation and migration. The flows include (a) after PSTM but no interpolation; (b) after no interpolation and no migration; (c) after interpolation plus migration; (d) after no data migration but simple poststack migration of AVO attributes. The PSTM based on the (c) interpolated gathers has a better S/N ratio and less footprint than that (a) without. The maps generated (b) without any migration and (d) poststack migrating the AVO attributes do not correlate to the well control. The Phi-H values are posted on top of the well control.**
When the original work was done the 3D survey contained 29 Viking penetrations. Since the primary geologic goal was to predict Phi-h in any new prospective well we compared the Phi-h values from the well control with the $R_p/R_s$ ratio at the Viking level for each of the processing flows described above. Figure 7 compares a portion of the interpolated PSTM Viking attribute map to the non-migrated CDP input AVO flow, the poststack migrated AVO flow, and PSTM AVO flow without interpolation. The results derived from the raw CDP gathers without any migration correlate poorly to the well control. Poststack migration of the AVO attributes does not seem to help. The interpolated PSTM AVO flow behaves in the most geologically reasonable fashion and correlates best to the available well control. This flow also seems to have fewer footprint artefacts than the PSTM flow without the aid of interpolation. The two PSTM results are similar with subtle differences that show up under careful scrutiny at the well locations and are reflected in the correlation coefficients in Table 1.

Table 1 summarizes the correlation coefficients of the linear fit linking the $R_p/R_s$ ratio attribute to the Phi-h at each well point, calculated in 2008. Note that the interpolated PSTM has the highest correlation coefficient. The PSTM versions have consistently higher correlation coefficients when compared to the poststack migrated results or those not imaged at all. Interestingly, super-binning did not yield a uniformly better correlation coefficient. Super-binning is often performed prior to AVO to improve the sampling and fold. It entails binning adjacent in-line and cross-line bins. In this case we binned 5 in- lines and 3 cross-lines, increasing the fold be a factor of 15. We suspect the structural and stratigraphic smearing introduced by the super-binning compromised this technique here. The results based on the raw CMP gather flow correlate poorly with the well control. In the regression and on the maps, it is clear that the new interpolated PSTM method yielded the best results.

<table>
<thead>
<tr>
<th>Correlation coefficient w. Phi-h</th>
<th>No Migration</th>
<th>Poststack Migration</th>
<th>Prestack Migration</th>
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<tbody>
<tr>
<td>Raw gathers</td>
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<tr>
<td>Super binning</td>
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<tr>
<td>Interpolated gathers</td>
<td>0.18</td>
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Table 1. The correlation coefficients after performing a linear regression between phi-h from well control and $R_p/R_s$ estimates generated from various prestack data processing strategies.

Since the original work was done, nineteen new wells targeting the Viking have been drilled testing these predictions (Table 3). The new wells based on the AVO analysis on the 5D MWINI prestack migrated gathers have on average 32% greater Phi-h values than wells drilled before this study. This increase is surprising since normally as the field is developed the best locations are drilled first.

Nordegg AVAz analysis

To perform the azimuthal AVO analysis the seismic data needed to be migrated with a migration scheme which preserved information across both azimuth and offset directions. Two different azimuthal migration strategies were tried. The data were originally migrated with an azimuthally sectored migration that used the interpolated gathers generated in part I. Subsequent to this the azimuthally sectored migration was run on the non-interpolated data. The data were also migrated using a COV migration. Two different interpolation target geometries were tested for the COV migration.

The azimuthally sectored migration operates on azimuthally sectored sub-volumes. The migration consisted of 8 azimuth sectors, each 45 degrees wide with 22.5 degrees of overlap. Even with these procedures in place, we were unable to achieve good spatial sampling for the azimuthally sectored migration on the non-interpolated data. One sector in particular was poorly sampled and this negatively impacted the result. The migration employed bin borrowing and area weighting (Zheng et al., 2001) in order to deal with near offset sampling issues. Figure 8 a) and b) shows the azimuthally sectored offset-and-azimuth-limited migrated gathers at well A with and without 5D interpolation. Note the improvement in frequency content and signal-to-noise on the interpolated result.

The second type of azimuthal migration performed is based on COV processing (Cary, 1999; Vermeer, 2002). Li (2008) provides an excellent tutorial on this. The basic concept is that for orthogonally acquired seismic surveys, the data may be regularly binned in the offset x and offset y directions generating a series of subvolumes which exhibit single fold coverage across the cmp coordinates and which are approximately localized in offset and azimuth. Each one of these volumes is called an Offset Vector Tile gather (OVT gather). Each OVT gather has an average offset x and offset y and so can be described as a vector from which the offset magnitude and azimuth can be calculated. The prestack migration is performed on each of these one fold volumes.
In practice, there are a number of issues and limitations with this approach. The generation of one fold OVT gathers requires regular acquisition geometry with evenly spaced source line, receiver line, source intervals and receiver intervals. As can be seen in Figure 4 this is rarely the case. Departures from these assumptions lead to fold variations in the OVT gathers leading to migration artifacts. This can be addressed by specifying that the 5D interpolation output data which conforms to the above assumptions.

A more serious issue is the size of the smear in offset-x and offset-y within the OVT gathers. In order to get one fold OVT gathers, the offset x and y bin size should be two times the source and receiver line spacing. In our case this results in OVT gathers that are 1200 m by 1320 m. Offset bins this large result in too much smearing and normally preclude this type of analysis. However, the 5D interpolation may be used to reduce the source and receiver line spacing resulting in smaller OVTs. Figure 8c shows a COV migrated gather where the data was interpolated so that data was regularly output for a source and receiver line spacing of 240 m.

Even with this tighter receiver spacing afforded by 5d interpolation, a small remnant amount of offset variation in both in the x- and y-direction still persists within each OVT gather. This variation gets larger as the offset-x and offset-y bin size gets larger and can lead to an acquisition footprint showing up in the Azimuthal AVO attributes (Downton, 2010). To avoid this, it is possible to 5D interpolate the data so it is regular in offset x and offset y. A consequence of this the data are no longer surface consistent which required us to use a different migration than the other tests. Figure 8d shows a prestack migrated gather with data regularized in offset x and y as input. Note that all the interpolated prestack migrated gathers appear to have better S/N ratios than that of the gathers without interpolation.

The AVAZ analysis used in this paper is based on the near offset Rüger (1996) equation

$$R(\theta, \phi) = A + (B_{iso} + B_{ani} \sin^2 (\phi - \phi_{iso})) \sin^2 \theta,$$

(5)

The equation models the seismic amplitude R as a function of azimuth $\phi$ for narrow angles of incidence $\theta$ in an isotropic half-space over an HTI anisotropic half-space. The equation is parameterized in terms of the P-wave impedance reflectivity, A, the isotropic gradient, $B_{iso}$, the anisotropic gradient, $B_{ani}$ and the isotropy plane azimuth of the HTI anisotropic media, $\phi_{iso}$. For HTI anisotropy due to one dominant fracture set the isotropy plane azimuth is parallel to the fracture strike. Assuming the crack theory of Hudson (1981), the anisotropic gradient is proportional to the fracture density and can be quantitatively related to the image log data from the well control. We may thus objectively compare different processing flows in similar fashion as we did in the first part of this paper.

Figure 9 shows the anisotropic gradient calculated for the different processing flows at both the horizontal well logs with image log information. The horizontal wellbores are shown in black while the anisotropic gradient is shown in the background in color. Hot colors such as reds and yellows indicate high values of fracture intensity. The image log shown in yellow related to the image log data from the well control. We may thus objectively compare different processing flows in similar fashion as we did in the first part of this paper.

Figure 9. The anisotropic gradient is shown in profile view through the horizontal wells A and B drawn in black. Hot colors (yellow and red) correspond to large values. The image log fracture intensity is shown in yellow with high vertical deviations indicating greater fracture intensity. To improve the S/N ratio the AVA is run on supergather for panels (b) through (e). Panel (a) shows the AVAZ results after azimuthally sectored migration without interpolation or the use of supergathers. The azimuthally sectored migration with interpolation (c) has a better S/N ratio than that without interpolation (b). The COV migrations (d) and (e) tie better at well A. The COV migration shown in (d) was based on a 5D interpolation which produces regular data in a surface consistent fashion while that in (e) was based on a 5D interpolation which produces regular data in offset x and y.
is superimposed on top, with the vertical excursion being proportional to the fracture density. Figure 9a shows the azimuthally sectored migration results without interpolation at well A and B. The results appeared noisy so subsequent AVAZ analyses were performed on 5X3 supergathers to increase the fold. Figures 9b shows the improvement is S/N ratio due to the supergathers. There appears to be a good correlation at well A at inline 1150 however the high fracture density at inline 1140 is missed. There is also a good correlation at Well B where the overall fracture density is lower. Including the 5D interpolation significantly improves the S/N ratio (Figure 9c). The COV migrations (Figure 9d and 9e) also improve the S/N ratio. They seem to improve the well tie at well A where fracture density gives a good tie throughout the length of the well bore (inline 1440 to 1170). There appears to be little to differentiate the two interpolation schemes (offset regularization versus surface consistent regularization).

Figure 10 shows the anisotropic gradient at the Nordegg horizon in plan view with the two horizontal well logs superimposed. The anisotropic gradient attribute was extracted using various window sizes ranging from 8 ms to 42 ms. The overall trends remained the same in all cases but we found that the 32 ms window gave the best results. The image log data using 10 m binning is superimposed with a similar color scale on top of anisotropic gradient. Once again the interpolated results appear to be less noisy than the results without interpolation and appear to have better correlations to the well control. Examining Figure 10 to determine the quality and accuracy of the three interpolated results is subjective.

In order to objectively and quantitatively compare these results, scatterplots were generated (Figure 11) and linear regressions calculated between the anisotropic gradient for each of the processing flows and fracture density from the image logs. The interpolated azimuthally sectored migration has a significantly higher correlation coefficient than the result without interpolation (Table 2). In both cases performing the analysis on supergathers improves the correlation coefficient. It seems for the Nordegg the positive consequences of improving the fold are more important than negative consequences of smearing. This might be due to the extra demands of preserving the azimuth in addition to the offset for this relatively sparsely acquired seismic dataset. Table 2 shows that the COV migrated results are slightly superior to the azimuthally sectored migrated results. There is little to differentiate between the two COV regularization schemes, but from a data processing point of view we found it advantageous to preserve surface consistency as this allowed us more flexibility in choosing processing algorithms and flows.

**Technical Contribution**

With the limitations inherent in most land seismic data acquisition, the use of 5D interpolation creates a better sampled seismic wavefield resulting in prestack migrations with less migration noise and artefacts. This results in better conditioned gathers for subsequent prestack amplitude analysis.

The Viking case study shows quantitatively that using the 5D MWNI prestack migrated gathers as the input to an Amplitude Versus Offset (AVO) analysis results in more accurate estimates of the reservoir quality as compared to the non-interpolated gathers.
5D interpolation to improve AVO and AVA\zh: a quantitative case history

<table>
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<th>Economic models</th>
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<th>% Diff</th>
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<th>EUR Prediction (mmcf)</th>
<th>NPV 10</th>
<th>IRR high price deck (%)</th>
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Table 3. New drilling results and their economic impact.

The Nordegg case study shows quantitatively that using 5D MWNI prestack migrated gathers as the input to the Azimuthal AVO analysis results in more accurate predictions of fractures (image log data). This was true for both the azimuthal migration schemes considered.

Economical Contribution

Since the 2008 Viking AVO study was completed nineteen new wells targeting the Viking have been drilled to test these predictions (Table 3). The new wells based on the AVO analysis performed on the 5D MWNI PSTM gathers have on average 32% greater Phi-h values than those drilled previous to the study.

Estimating the economic implications of this is not simple. On many of the wells the production was comingled from other reservoir levels. On the subset of wells solely producing from the Viking reservoir it was possible to calculate a relationship linking the Phi-h values with the estimated ultimate recovery (EUR). This relationship was then used to calculate the EUR for each of the well data subsets. In a similar fashion it is also possible calculate the 3 month initial production (IP). Given the (EUR) and the production it is possible to calculate the net present value (NPV) and internal rate of return (IRR) for each class (Table 3). The conclusion of this is that each well drilled targeting the Viking using the new methodology has on average over 1 million dollars of added NPV.

Conclusions

Including 5D MWNI in the processing sequence in both these examples improves the AVO and AVA\zh results as compared quantitatively to the well control. This improvement is a result of sampling the wavefield better prior to the migration resulting in better migrated images. By performing the interpolation in 5D it is possible to interpolate gaps that would be challenging for interpolations in lower dimensions (i.e. 3D).

In the case of the Viking, the new AVO methodology including the insertion of 5D MWNI interpolation in the flow has had a material impact on improving the drilling success. The new wells drilled for the Viking have higher Phi-h values, initial production, and estimated ultimate recoveries.

The 5D MWNI interpolation also improved the AVA\zh estimates for the Nordegg as measured by the image logs from the two horizontal wells. In this case different output target geometries for the interpolation were also experimented with and compared. The geometries were designed to provide the optimal input for the COV migration within the limitations of the original acquisition. The COV migration using surface consistent regularized flow gave the best results as measured by the correlation coefficient to the well control.

The use of 5D MWNI should not be viewed as a justification to acquire sparser seismic data. The interpolation inverse problem is undetermined. If insufficient data are acquired then the interpolation will be unable to properly reconstruct the data. For example, interpolation cannot reliably construct wide-azimuth traces from a narrow-azimuth field experiment.

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