for hydrocarbon exploration, in all the wells drilled up to the present time, consists primarily of a shale section interbedded with relatively thin sand beds. The sand beds appear to be lenticular, and the development of the sand buildups are probably controlled by faulting and local structural highs.

In late 1975, Texas Pacific Oil Company took a farmout on four blocks in the Gulf of Thailand, blocks 14 and 15 from Tenneco and blocks 16 and 17 from British Petroleum. Along with these farmouts came about 13600 kilometers of conventional 2D seismic data covering a number of years of data collection.

In a paper given by Dr Charan Achalabhuti, Director of the Natural Gas Organization of Thailand, at the Circum-Pacific Energy Conference in August 1978, he pointed out that exploration in the Texas Pacific concession in blocks 15 and 16 has passed into a field development stage with reserves estimated at 2 to 3.4 trillion cubic feet of gas.

The interpretative value of the existing 2D seismic information was limited due both to the coarseness of the grid and to the fact that the information represented a composite of several seismic surveys distributed over several years. New information was needed/ first, to establish with confidence the relationship between blocks 15 and 16/ secondly, to obtain better data to make new locations which would be productive/ and finally, to assist in determining optimum locations for platforms. The key to successful exploration in the area, basically a hinge line play, was a detailed understanding of the complex mosaic of fault patterns controlling the hydrocarbon traps.

To meet all these criteria, it was decided to shoot a sizeable 3D program over the major gas area. At the time the survey was conducted, the summer of 1977, it was one of the largest 3D programs in the world and the first one undertaken in the Far East.

The 3D program consisted of 1280 kilometers, with the seismic lines shot at 100 meter intervals, enclosing an area of 130 sq. kilometers. A total of 128 lines were shot in an east-west direction over the prospect, roughly rectangular in shape, and an additional ten diagonal lines running north-west were shot at the north end. Since the prospect was located 160 to 220 kilometers offshore, two complete and complementary survey systems were used in the data collection phase, one for accuracy in distance and one for lane count, to obtain the required density and accuracy in location. A streamer tracking system was employed which, when combined with the basic boat navigation data, provided an X and Y co-ordinate for every shot and receiver location.

The densely spaced data were processed with a 3D wave equation migration algorithm to produce the set of seismic traces representing the data vertically below a grid of depth points spaced at 33 1/3 by 100 meters over the prospect.

The interpretation of the 3D data was constructed from the conventional vertical sections and a series of two-dimensional horizontal slices, produced at 4 millisecond intervals, through the 3D data volume. In general, the vertical sections were used to identify key horizons, dips, and fault locations. The horizontal sections provided information about how to connect up the faults, the strike, and the spatial distribution of the geologic formations.

Using both the 3D vertical sections and the horizontal sections, two maps were constructed, a shallow one near a reflection time of 1.2 seconds and a deeper one at 1.8 seconds. Both maps display the general shape of a more or less elongated central area striking approximately north-south with dip to the east and to the west from the central graben. Comparisons drawn between the maps made from the 3D program and the more conventional 2D grid shooting show that both 2D maps exhibit excessive overall structural relief. The faults are both more numerous and differently placed on the 3D. Since one of the criteria for selecting favourable drilling sites is fault location, the value of the increased density became important. Studies based on amplitude contour maps made at several key horizons combined with seismic interval velocity logs derived from an inversion process suggest that areas of favourable sand thickness in excess of 50 feet may be successfully predicted.

Several new drillable prospects have been identified. It is believed that the wells can now be located to optimize the development of the reservoir sands. Probably more important, the 3D data set generated by the survey appears to be accurate enough/ first, to locate the fault blocks defining intra-field producing boundaries/ second, to select the most favourable sites for platform locations/ and third, to assist in developing quantitative reserve estimates. To a considerable degree it is believed that the drilling of some wells can be traded for the much less expensive 3D seismic surveys. If such a tradeoff is achieveable, the ultimate development costs can be substantially decreased by reducing the elapsed time from the discovery to the production stage.

The cost of development wells in this area ranges between 3.5 and 5.5 million U.S. dollars. With the cost of a 3D survey at approximately 5.5 thousand dollars per square kilometer, 640 square kilometers of 3D coverage can be obtained for the cost of one 3.5 million dollar development well. The leverage seems excellent for 3D seismic to pay for itself may times over in terms of reducing the eventual number of development wells. There is, in addition, the opportunity to obtain more recoverable reserves through finding new or secondary traps which might be otherwise missed by conventional means.

DEPTH CONVERSION OF SEISMIC DATA USING VELOCITY ANALYSES

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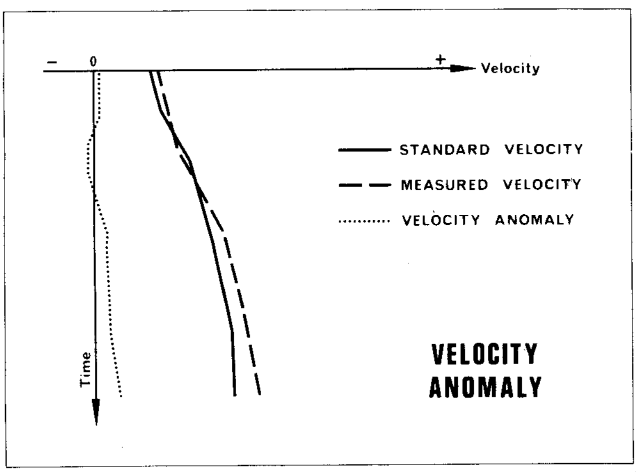
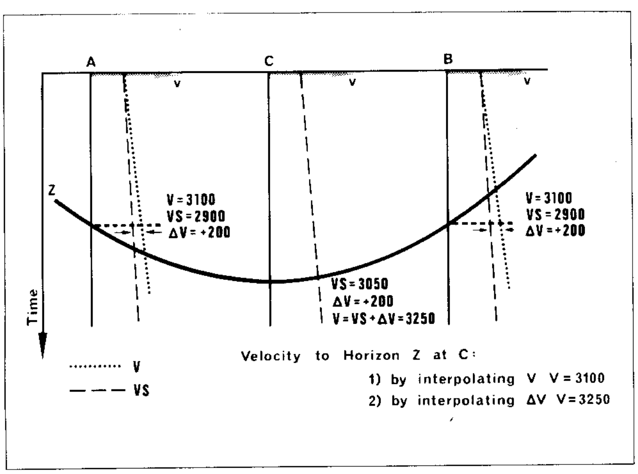
Velocity analyses are now routinely produced in the processing of seismic data. These are used for a number of purposes in processing and for interpretation. Although the display format varies for different velocity analyses they all are similar in that, when interpreted, they give a curve of moveout velocity against time at a specific location on a line. From this moveout velocity it is possible to calculate the average velocity to any reflection, subject to a number of assumptions.

Unfortunately, there are a number of sources of error in velocity analyses, only some of which can be corrected for, so that the random error in the velocities is always much greater than that in the reflection times. However, there are real velocity variations which must be allowed for. Separating these real variations from the random variations can be done by assuming that the rapid or high frequency variations are noise, and the slow or low frequency variations are real.

If this is done simply by smoothing or averaging the velocity analyses, the results are acceptable, unless there is also significant structure on the reflections. If this is the case the velocity varies with depth of burial which may change rapidly, for example at a fault.





An alternative method is to adopt a standard curve of change in velocity with reflection time, and to smooth the difference between the velocity and the standard velocity, referred to as velocity anomaly. The concept of velocity anomaly can be illustrated with a plot (Figure 1) showing the curves for standard velocity, measured velocity (from analyses) and velocity anomaly plotted against time. This concept may be applied to either moveout velocity or average velocity.

Figure-2 shows the difference in results compared to using average velocity for smoothing. In this case a cross-section in reflection time is shown, with a seismic horizon Z. Velocity data is from analyses at points A and B. If the velocities are averaged the velocity at C is 3100, whereas if the velocity anomaly, ΔV, is averaged the velocity is 3250. This is closer to the real value provided only that the slope of the standard curve is closer to the slope of the real time/velocity curve than the assumption of no variation with depth. In general this requirement can be easily met, using either well data or the analyses themselves.

In practice it is necessary in marine data to correct the standard curve for water depth at each point, as it has been found that the increase in velocity with depth depends on depth of burial below sea floor, not depth below sea level.

In the area of Kingfish Field in Gippsland this method gave a standard deviation of 17 m in the random variation of depth ties with 45 wells. This is equivalent to 0.75% of depth. Most of the variation is due to velocity variation although some, in fact, may be due to errors in well depths. By comparison, the real variation in velocity, from both well and seismic data is about 10%.

SHOULD WE INVEST IN TELEMETRY SYSTEMS?

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Introduction

Over the years we have experienced increasing numbers of recording channels in reflection seismic data acquisition systems, from 24 through 120 for technical and economic reasons. Perhaps maximum feasible achievable spread lengths have been attained, however, trends to high resolution techniques demand more channels at lesser station intervals for a given spread length. Also, trends to a real (3-D) techniques demand more channels although not necessarily at lesser station intervals.

Conventional seismic cables become increasingly heavier, more expensive and fragile with increase in number of pairs and contribute alarmingly to crew down-time despite increased maintenance effort.

In practice, conventional cables would seem to be limited to 120 pairs while an increase in the number of recording channels in conventional systems beyond 96 are accompanied by an unacceptable reduction in sampling rate. Beyond 100 channels telemetry techniques offer the only practicable solution.

Before replacing existing conventional equipment a company may ask: "Should we invest in Telemetry?"