Geol. Soc. Malaysia, Bulletin 22, December 1988; pp. 209 – 227

Some 3D Seismic Applications Offshore Sarawak

RONALD HOOGENBOOM
Sarawak Shell Berhad, Lutong, Sarawak

Abstract: 3D seismic surveys with exploration, appraisal and development objectives, have been acquired in Shell-operated offshore Sarawak acreage since 1984. In all, 10 surveys have been performed covering an area of almost 1500 sq. km. 3D surveys offer improved structural delineation and reduce the risk of an inconclusive well, particularly in geologically complicated areas. In the case of success, 3D surveys allow follow-up appraisal plans to be matured quickly since further infill shooting should not be required (as happens with 2D seismic surveys).

The very significant effect of 3D seismic acquisition and processing is illustrated by a comparison using a conventional 2D seismic line extracted from a 3D survey and a 3D processed section along the same subsurface trajectory. Contour maps using 3D seismic data have been proved by drilling to be more accurate than maps constructed using only 2D seismic, particularly in complexly faulted areas.

Time-slices can be used directly for fault and contour interpretation, and these aspects are illustrated by various examples.

It is vital to identify and map out potential drilling hazards. In some instances the dense 3D coverage can aid in the delineation of shallow gas anomalies and sea-bottom channels. In addition to the superior structure maps, 3D seismic could potentially be used to make detailed maps of lithostratigraphy under ideal conditions. A pilot study to map the lateral extent of a channel, seen in one of the development wells, gave encouraging results.

INTRODUCTION

In the late 1970's, after several years of successful 3D surveys on land and following improved technology in streamer positioning, 3D seismic for marine surveys became more common. Marine seismic acquisition is characterized by a high density of parallel lines to obtain a uniform subsurface coverage, generally 15 to 30 traces per bin or area units of subsurface location. Acquisition time has been drastically reduced with the introduction in Sarawak in 1986 of dual sources and dual streamers (Kong, 1986). For every ship traverse four subsurface lines, 25 metres apart, are recorded. The typical bin size is thus 25 m (line separation) by 12.5 m (in-line Common Depth Point spacing).

Offshore 3D seismic surveys with production and exploration objectives have been shot is SSB's acreage since 1984. Including the 1987 seismic, 10 surveys have been acquired with a total coverage of 1490 aq km (Table 1). About half of SSB's concession area under the 1976 Production Sharing. Contract with PETRONAS in the Balingian and SW Luconia Provinces is now covered with 3D. The objective of the first surveys was to obtain a better structural definition prior to development drilling. Later, the surveys were extended to cover exploration leads in the vicinity of the development fields under development.

2D VERSUS 3D SEISMIC PROCESSING

Improved structural definition, particularly in structurally complex areas, is the main advantage of 3D seismic over conventional 2D. Streamer cable positioning errors in the

---

Presented at GSM Petroleum Geology Seminar 1987

acquisition of 2D seismic surveys can reach up to 200 m (i.e. a feathering of 10 degrees and 2400 m streamer length). The effect of proper positioning and 3D process following example.

TABLE 1

YEAR SHOT	NUMBER OF SURVEYS	TOTAL AREA SQ. KM.
1984	2	175
1985	2	277
1986	3	639
1987	3	399
	10	1,49

A schematic flow diagram of a 3D seismic processing sequence is given in Figure 1. During seismic acquisition, source and receiver positions are accurately recorded. The data are used for navigation processing to calculate the midpoint position for each shot and receiver pair. After pre-stack processing and velocity analysis, the seismic data are binned. The binning process selects traces belonging to the same bin using the navigation processing results. After binning, traces with different offset ranges belonging to the same bin are stacked using a 3-dimensional velocity field. Figure 2 shows a seismic line obtained from a 3D seismic survey, processed as a conventional 2D line (no binning and 2D inline migration only). Figure 3 shows the seismic line along the same subsurface trajectory after binning to correct for feathering, but with 2D post-stack migration only. The difference around 1.5 seconds between these two sections, as indicated by the bar at the left hand side, is the result of proper positioning in the binning process.

Proper imaging of the seismic data is obtained, after post-stack processing, by 3-dimensional migration, using either a one step or a two-step algorithm but always using a 3-dimensional migration velocity field. Figure 4 shows the same seismic line (Fig. 3), after 3D migration. The significant difference and improvement around 2 seconds, as indicated by the bar at the right-hand side, is the result of proper 3 dimensional imaging by crossline (out of plane) migration.

This comparison illustrates the improvements in structural integrity of 3D seismic compared to 2D. These improvements result in more accurate maps as will be discussed in the next chapter.

2D VERSUS 3D SEISMIC INTERPRETATION

Because of the high data density and the 3-dimensional approach in acquisition and processing, maps based on 3D seismic are more accurate than maps over the same area based on 2D data. Two examples to illustrate the improved structural definition using 3D seismic.

Development Area DP-A

The first example is from one of the development fields offshore Sarawak. Prior to development drilling, a dense 2D seismic grid of 200 m line spacing was acquired over the

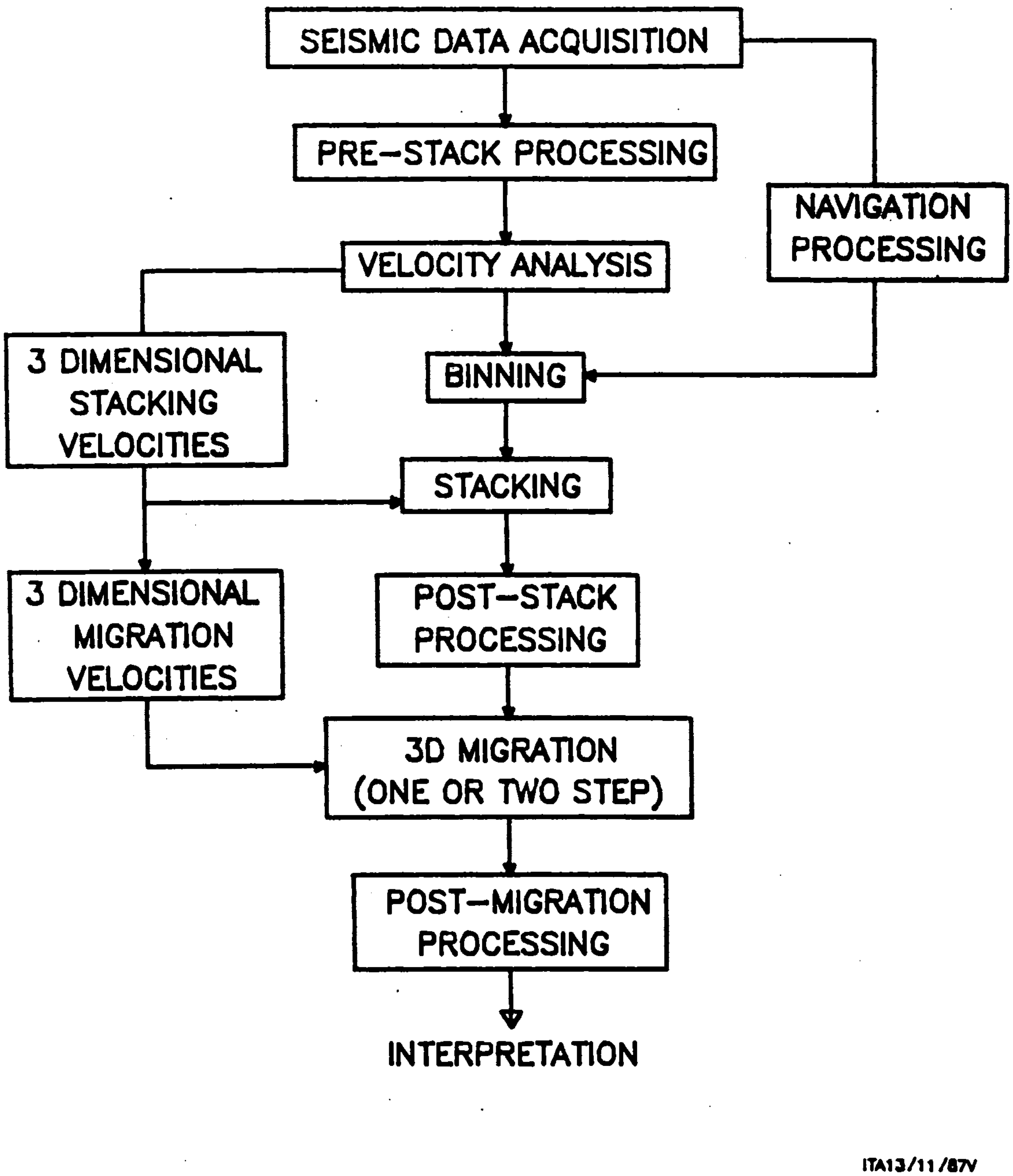


Figure 1: A schematic flow diagram of a 3D seismic processing sequence.

area. The structure contour map at reservoir level based on 2D seismic is given in Figure 5. Hydrocarbons are trapped in a main anticlinal fault block bounded in the south by a large E-W trending normal fault. Oil from the western flank of the structure is produced from a platform DP-A.

To support an infill drilling campaign and additional development, a 3D survey was shot over the area in 1986. The interpretation revealed a similar structure (Fig. 6); however the single southern normal fault appears to be a set of *en echelon* faults. There is a break in the southern fault system just at the oil-water contact, thus explaining the spill point of this structure. This example illustrates the risk of fault aliasing due to under-sampling using 2D seismic data, even 200 m line spacing.

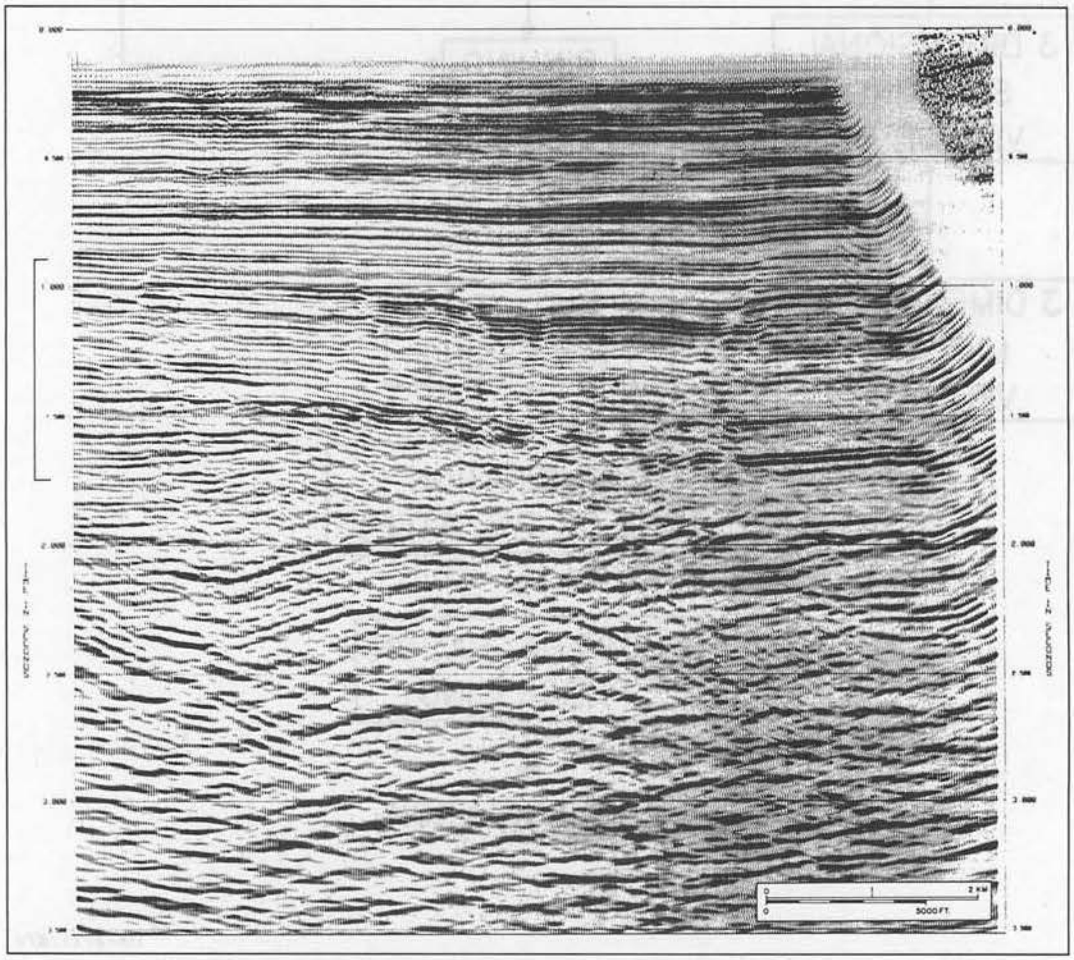


Figure 2: Seismic line obtained from a 3D seismic survey processed as a conventional 2D line (no binding and 2D migration only).

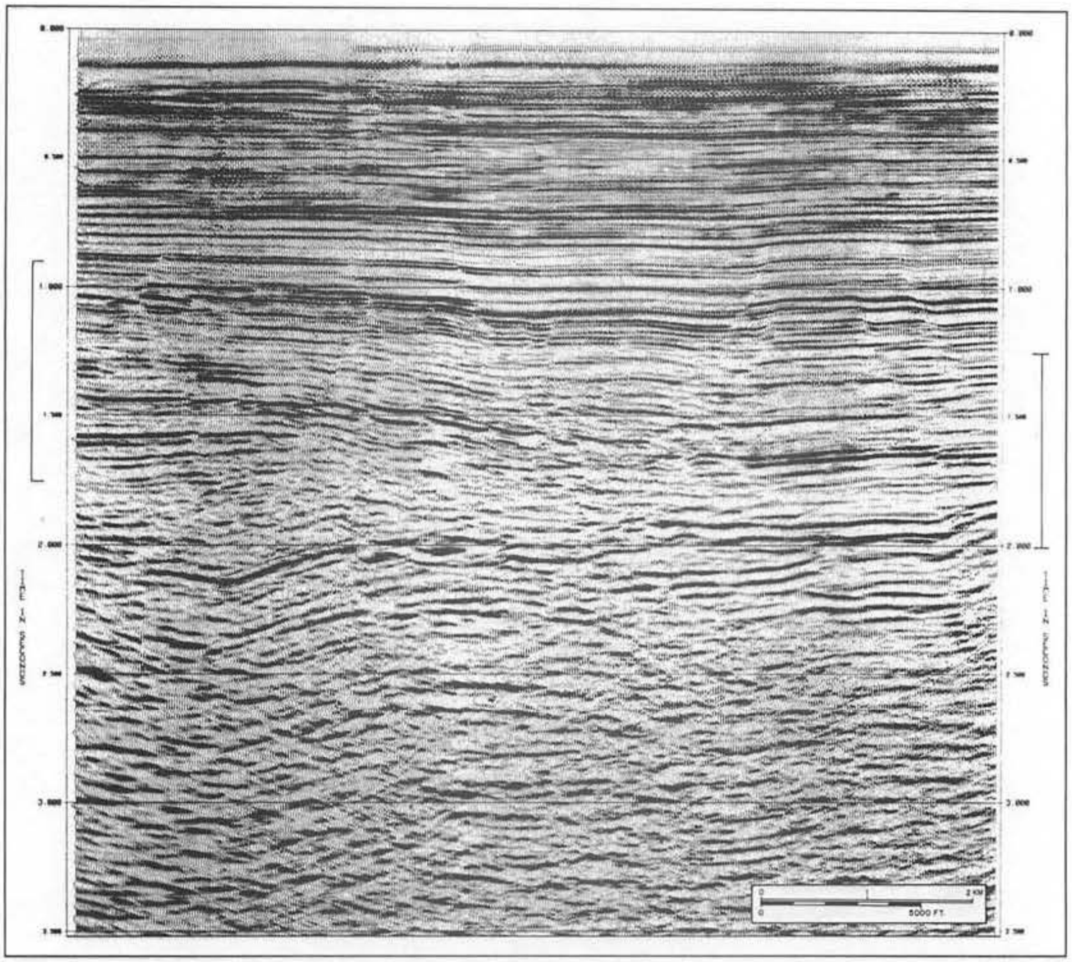


Figure 3: Seismic line obtained from a 3D seismic survey along the same subsurface trajectory as the 2D line (Fig. 2) after binning to correct for feathering but with 2D inline migration only.

Development Area MP-A

The second example is from another producing field offshore Sarawak. Exploration and subsequent appraisal drilling was based in 2D data. The depth contour map at reservoir level, based on several vintages of 2D seismic data, is given in Figure 7. Prior to installation and development drilling from platform MP-A, a 3D survey was acquired over the area in 1984 and interpreted. The depth contour map at the same reservoir level, based on 3D data, revealed a much more complicated fault pattern in the north-east and south of the structure (Fig. 8). The single fault in the NE appeared to be a set of *en echelon* faults. Note also the two normal faults in the centre dissecting the structure between the two appraisal wells 3 and 5.

More important in this case is the steeper structural dip on the southeastern flank of the structure. This reduced the extent of the field and brought the water closer to the platform.

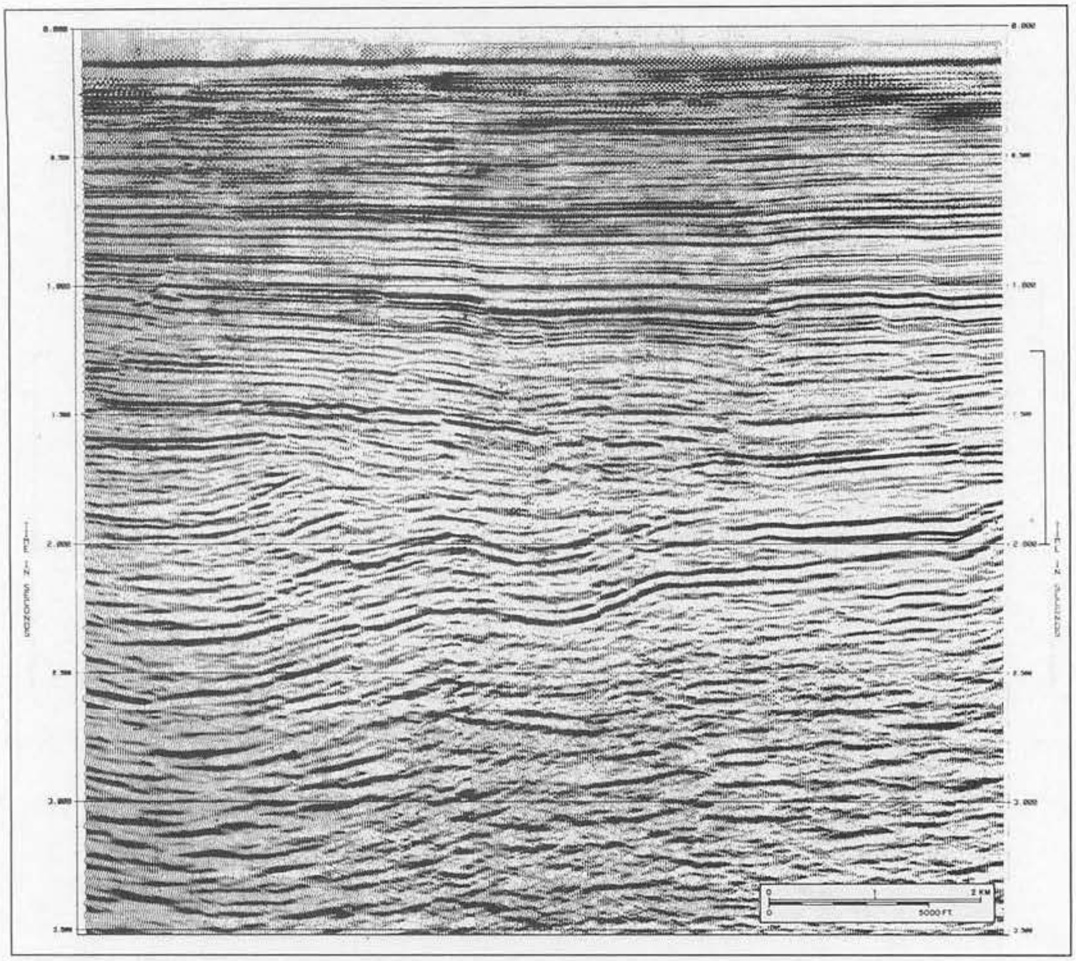


Figure 4: Same seismic line as shown in figure 3, but after 3D migration.

Based on the 3D map, the development locations had to be re-targetted and came in after drilling in 1986 close to prognosis (Fig. 9). The map needed only minor adjustments to the contours to accommodate the well result. This would not have been the case had the original 2D map been used to target the wells.

This example illustrates the direct cost-saving aspect of 3D seismic interpretation. The improved structural delineation of the objective interval saved abandonment and side-tracking costs of at least one, if not all four of the development wells.

TIME SLICES

Time-slices, which are horizontal cross-sections or time planes through the 3D seismic data volume, offer an additional dimension in seismic interpretation. Time-slices can be used

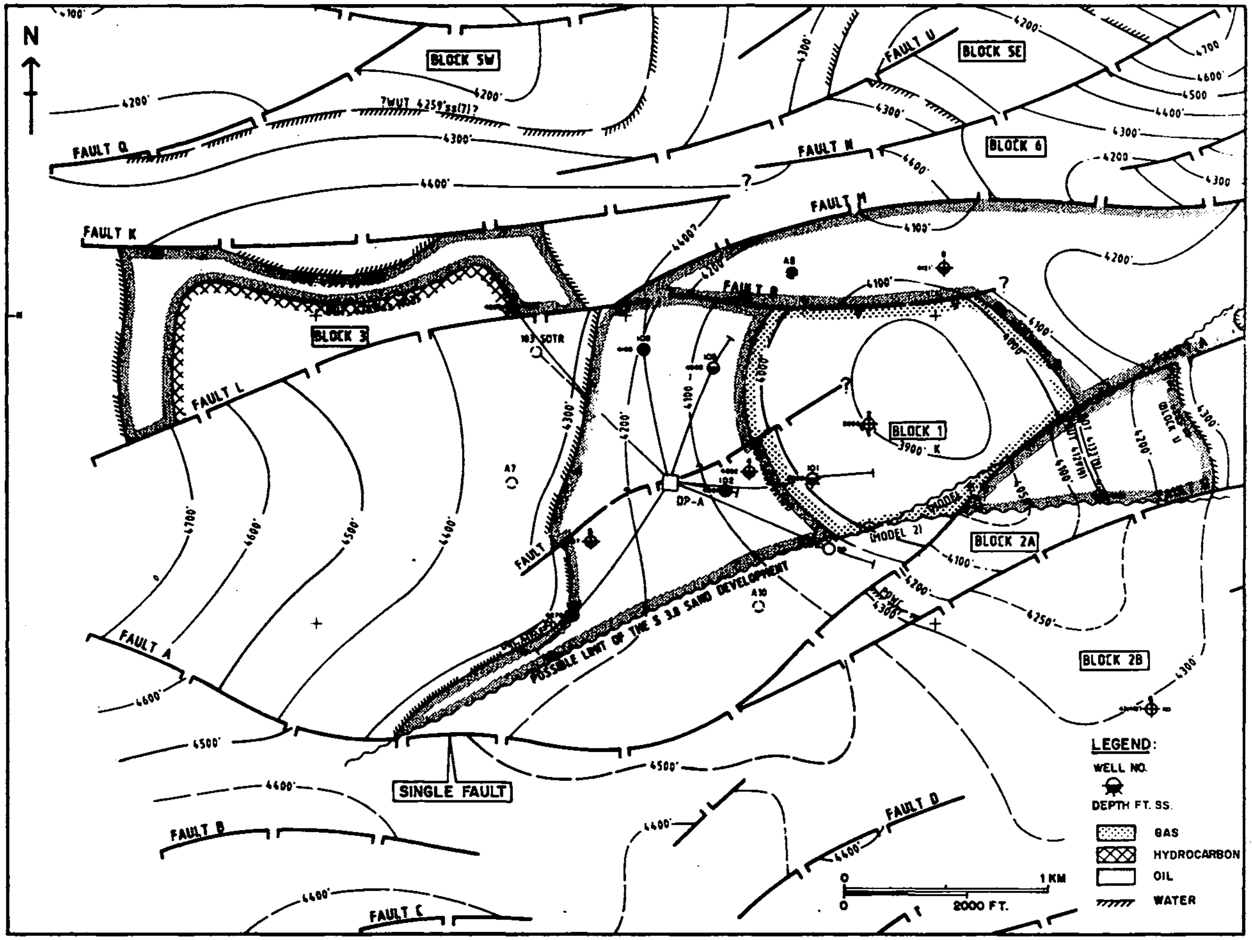


Figure 5: DEVELOPMENT AREA DP-A. Depth contour map at reservoir level based on dense 2D seismic (200 m line spacing).

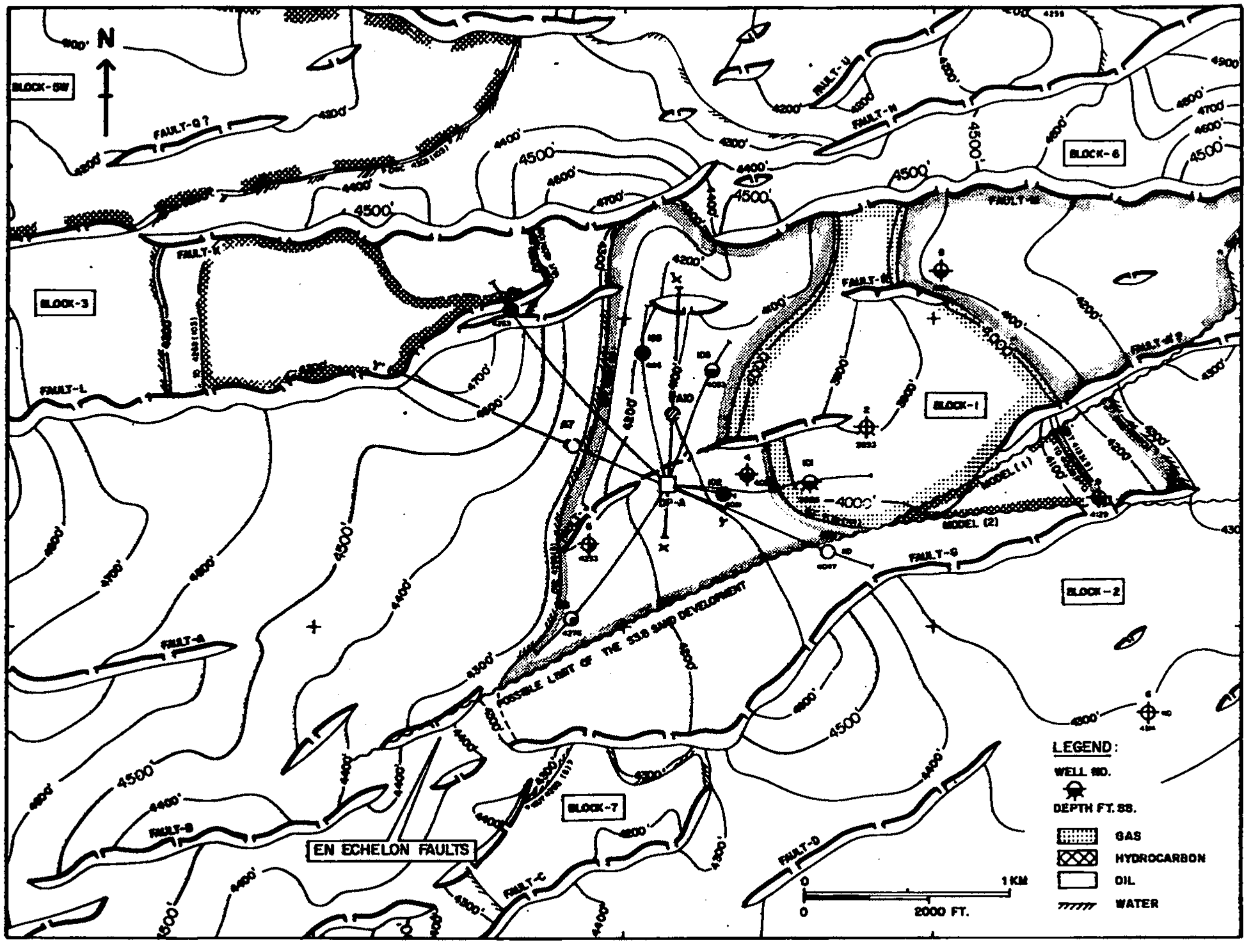


Figure 6: DEVELOPMENT AREA DP-A. Depth contour map at reservoir level based on 2D seismic data.

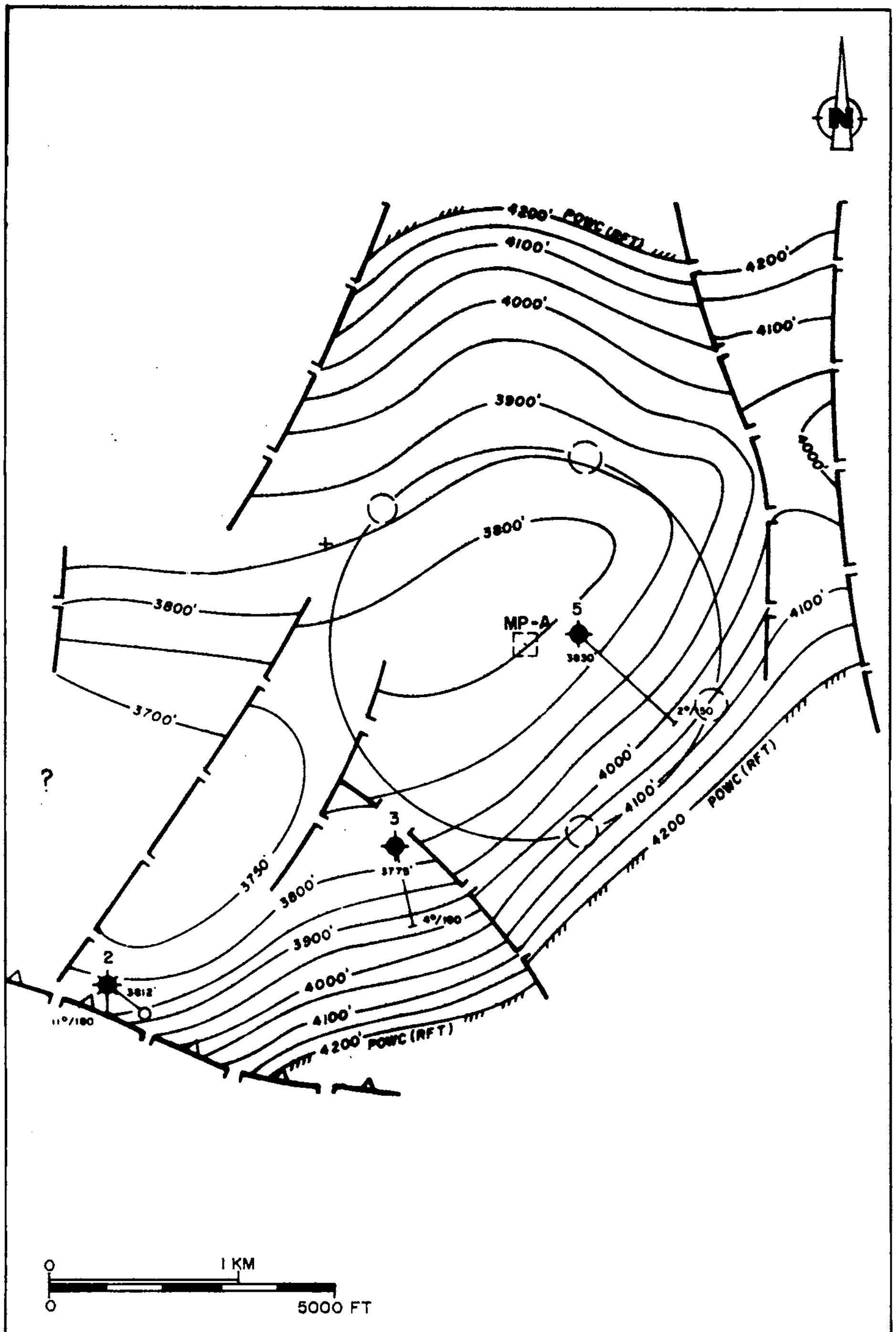


Figure 7 : DEVELOPMENT AREA MP-A. Depth contour map at reservoir level based on 2D seismic data.

Figure 8: DEVELOPMENT AREA MP-A. Depth contour map at reservoir level based on 3D seismic data.

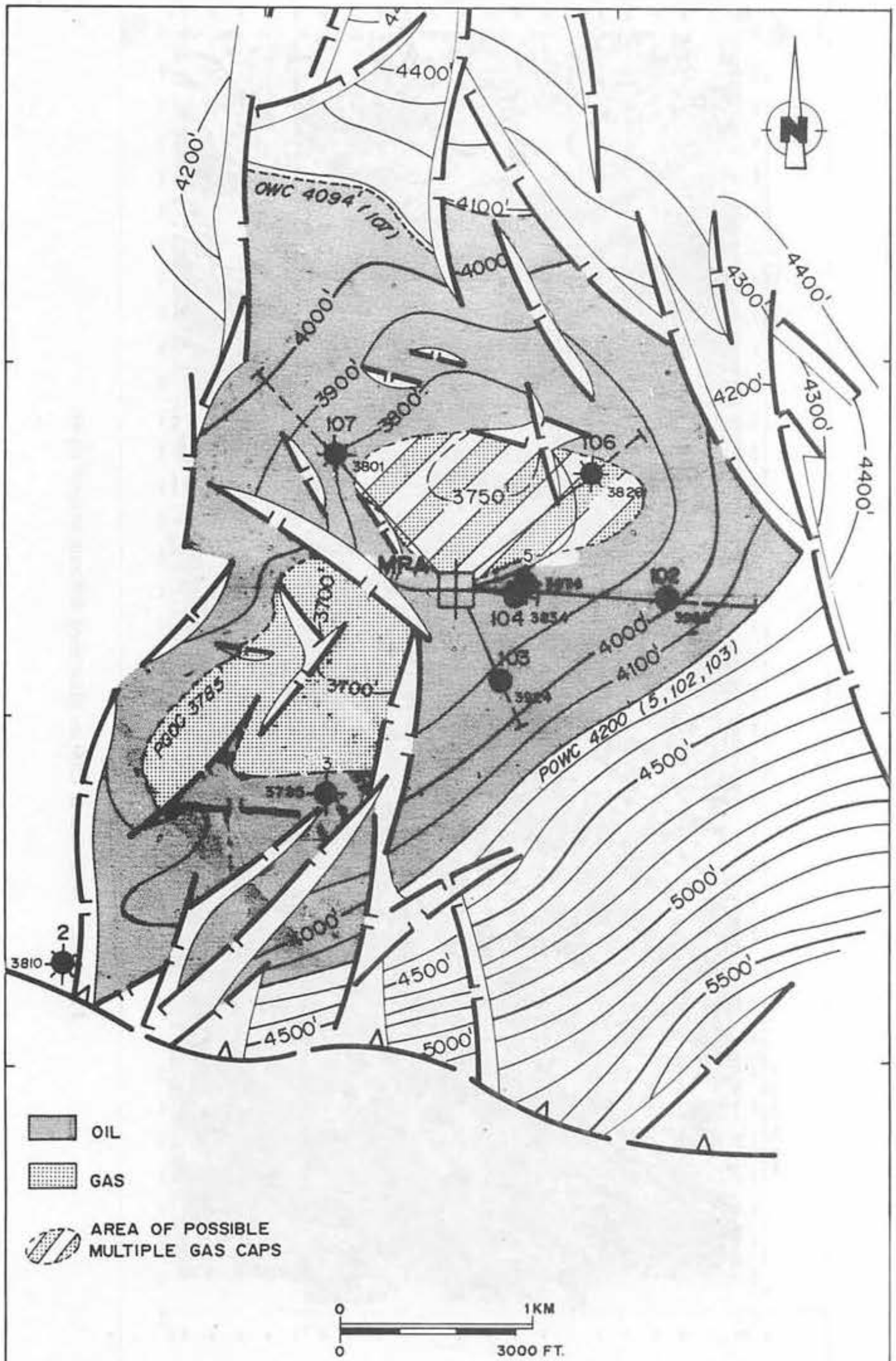


Figure 9: DEVELOPMENT AREA MP-A. Depth contour map at reservoir level based on 3D seismic including the drilling results.

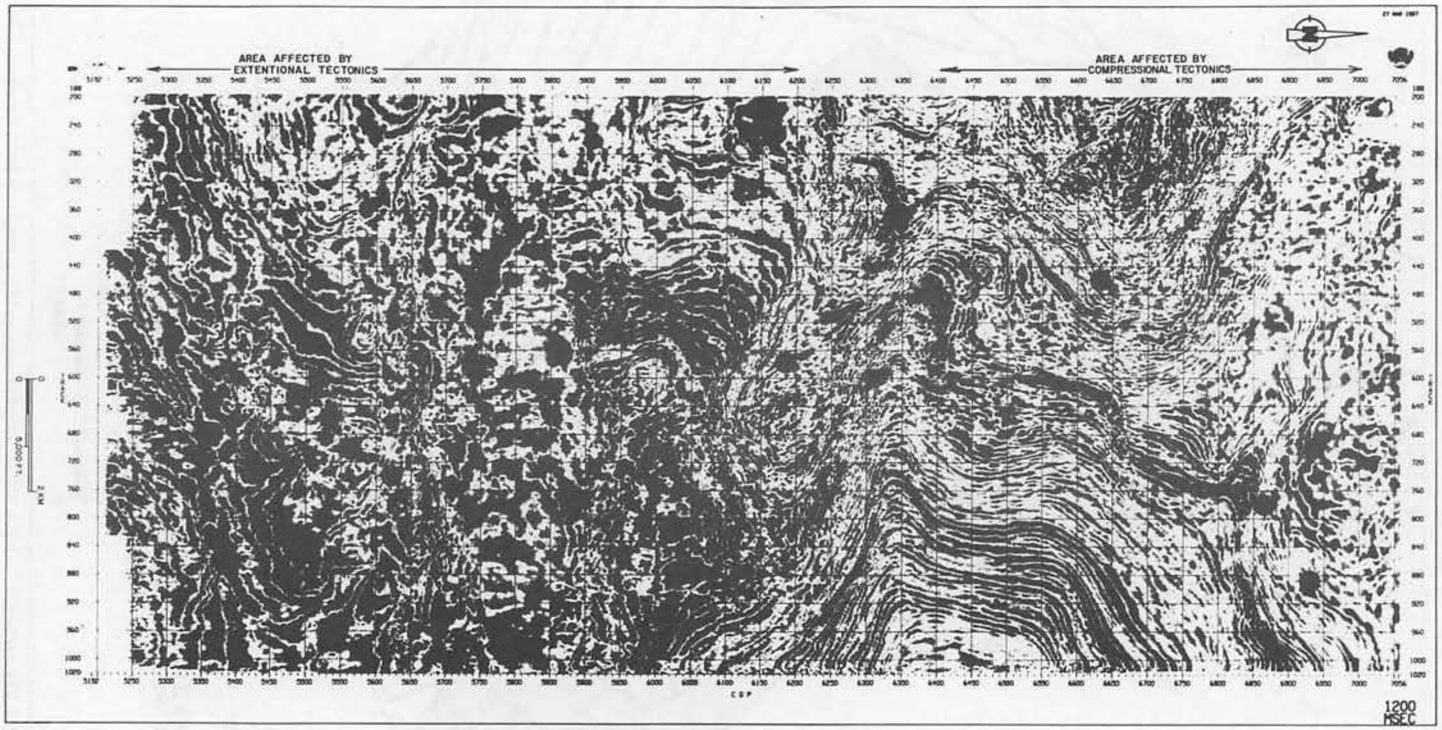


Figure 10: Time slice at 1200 ms illustrating different tectonic styles.

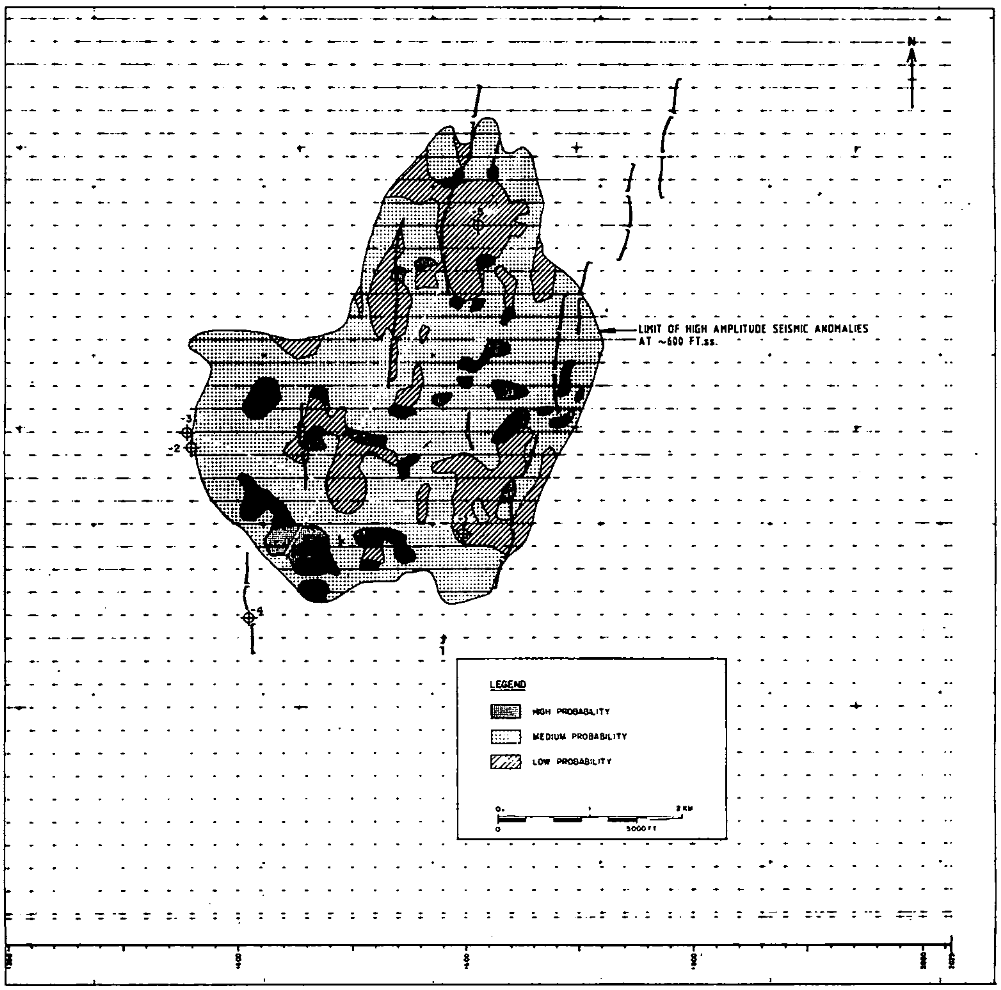


Figure 11: Map of potential drilling hazards based on time-slice interpretation.

a potential development target, a pilot study was initiated to map the lateral extent of this channel sand.

The structural setting is given by the time contour map near the channel sand level (Fig. 15). The structure is an east-plunging nose dissected by numerous faults. The shaded zone indicates the extent of the actual study area. An additional complication in this case is the presence of a major unconformity boundary just above the channel sand. This unconformity was mapped using horizon flattening on a 3D inteactive interpretation workstation.

An enlarged seismic section through the development well -102 and the appraisal well -5 is given in Figure 16. The channel, characterized by a laterally variable behaviour, can be seen at the location of -102 just above the "coaly" package of strong reflections *around 1* for direct fault and contour interpretation, and they often directly illustrate differences in tectonic styles. This is illustrated by a time-slice at 200 ms from one of SSB's 1986 3D surveys (Fig. 10). The southern half has a rather low frequency character indicating relatively flat structure. This part is mainly effected by extensional tectonics. The northern half is mainly high frequency, indicating steep dips. This part is affected by compressional tectonics.

For 3D seismic interpretation, shallow relatively simple intervals are directly mapped from time-slices. For deeper levels, severely affected by faulting, time slices are used for quality control and correlation purposes.

Processing of SSB's 3D surveys is carried out in such a way that shallow (near seabed) information can be obtained from time-slices to enable mapping of shallow gas occurrences, small reefs, sub-sea bottom channels and other potential drilling hazards.

Shallow gas, as present in one of SSB's devlopment fields, appears on seismic as a disturbed zone with amplitude anomalies. The level of these amplitude anomalies was mapped over a stack of time -slices and a map of potential shallow hazards was produced (Fig. 11). The objective of this study was to confirm the suitability of the platform location. The area is subdivided into three categories of low, medium and high probability of potential shallow hazards. The tentative platform location was chosen in an area with minimal risks. The final platform location still has to be confirmed by a high resolution site survey, as normal seismic has insufficient resolution for accurate mapping of the shallow interval above 500 feet sub-sea depth.

The time-slice at 92 ms highlights a prominent meandering channel presumably flowing north-west (Fig. 12). The channel is about 1400 m wide and about 25-30 meters below the seabed. Based on direct comparison with present-day channels, the cut-banks on the outside bends of the meander channels are sharply defined, and show as marked high-amplitude (dark) linear areas. The inside bends, generally less distinctly defined, face these cut-banks and may present point bars. The meandering channel cuts through an older straight channel in the north. An additional striking feature is the apparent dendritic drainage network on the northeastern flank of the channel belt. This feature may be analogous to the small drainage channels characteristic of coastal swamps. A similar channel can be seen in the east of the survey areas.

The time-slice example at 112 ms from another 3D survey shows an apparent network of coalescing channels (Fig. 13). The pattern of anastomosing,low-sinuosity channels suggests a braided river system which flowed northward.

CHANNEL MAPPING

In addition to the superior structural maps, 3D seismic potentially can be used to make detailed lithostratigraphic maps as will be illustrated by the results of a channel mapping study carried out on one of our 3D surveys.

A development well -102, drilled from the production plaatform MP-A, found an oil bearing channel sand around 3600 ft. This sand was not seen (Fig. 14). As this channel formed

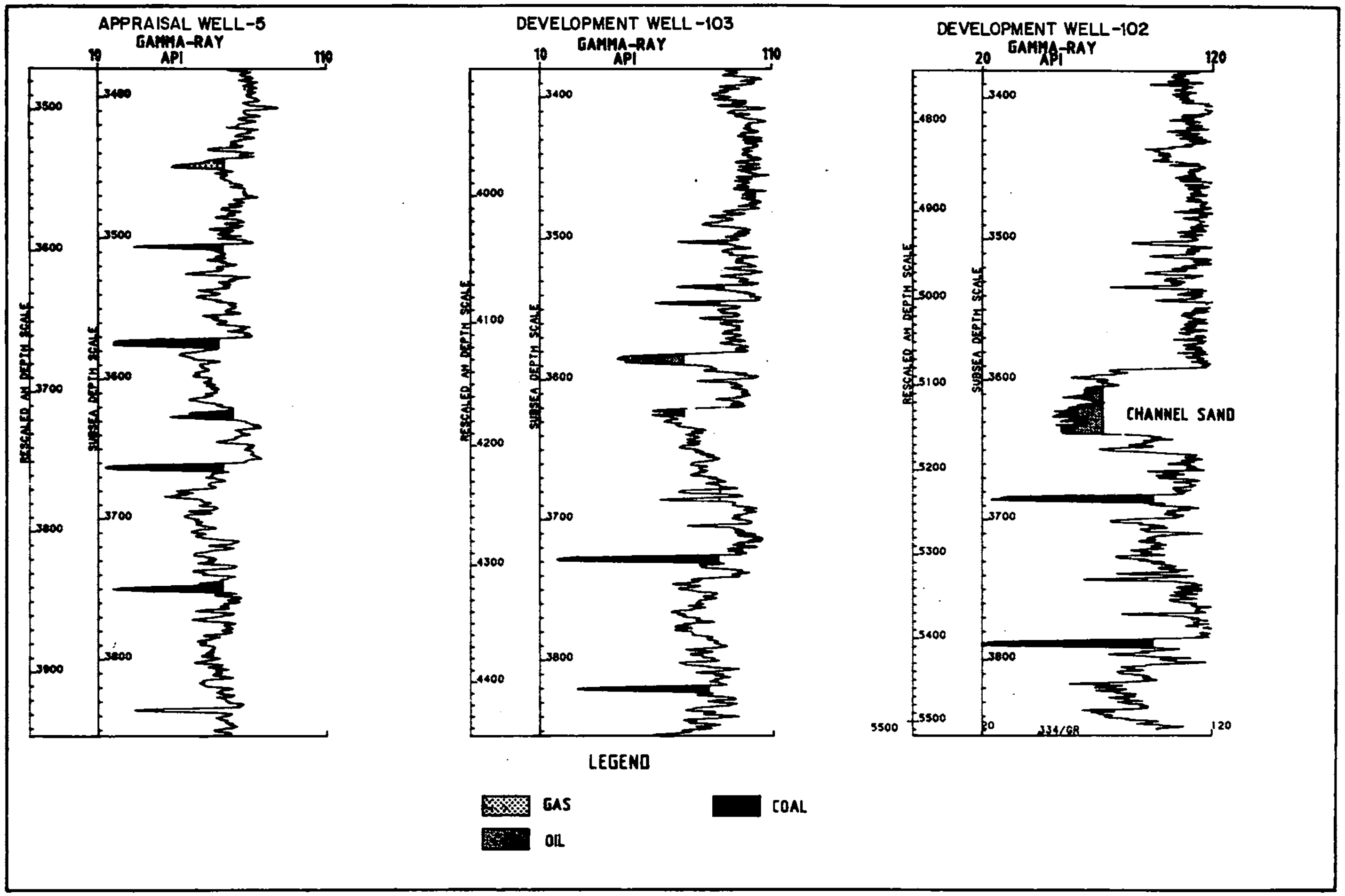


Figure 14: DEVELOPMENT AREA MP-A. Gamma ray logs from wells -5, 103 and -102.

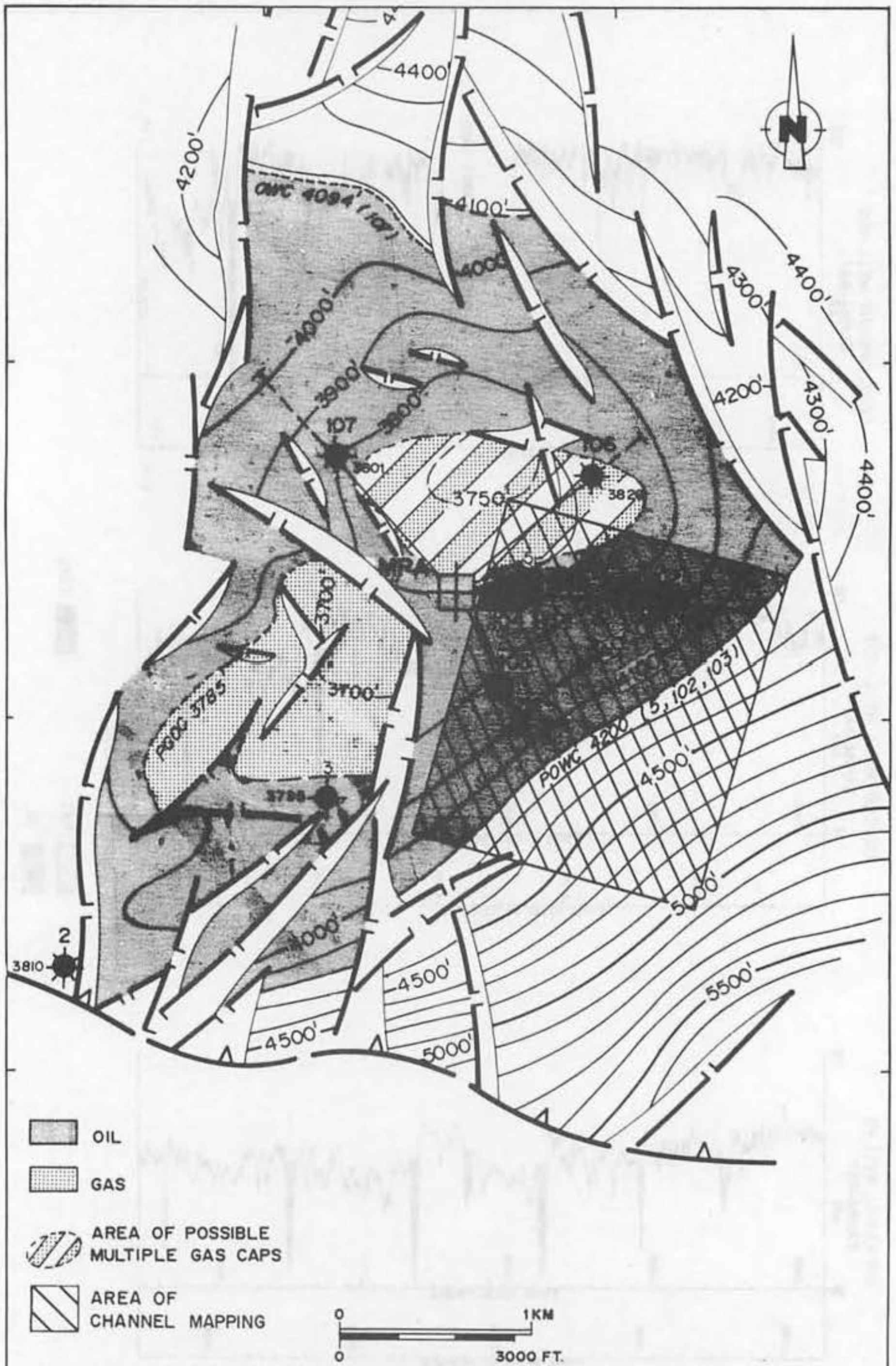


Figure 15: DEVELOPMENT AREA MP-A. Depth contour map near channel sand level showing area of channel mapping by amplitude.

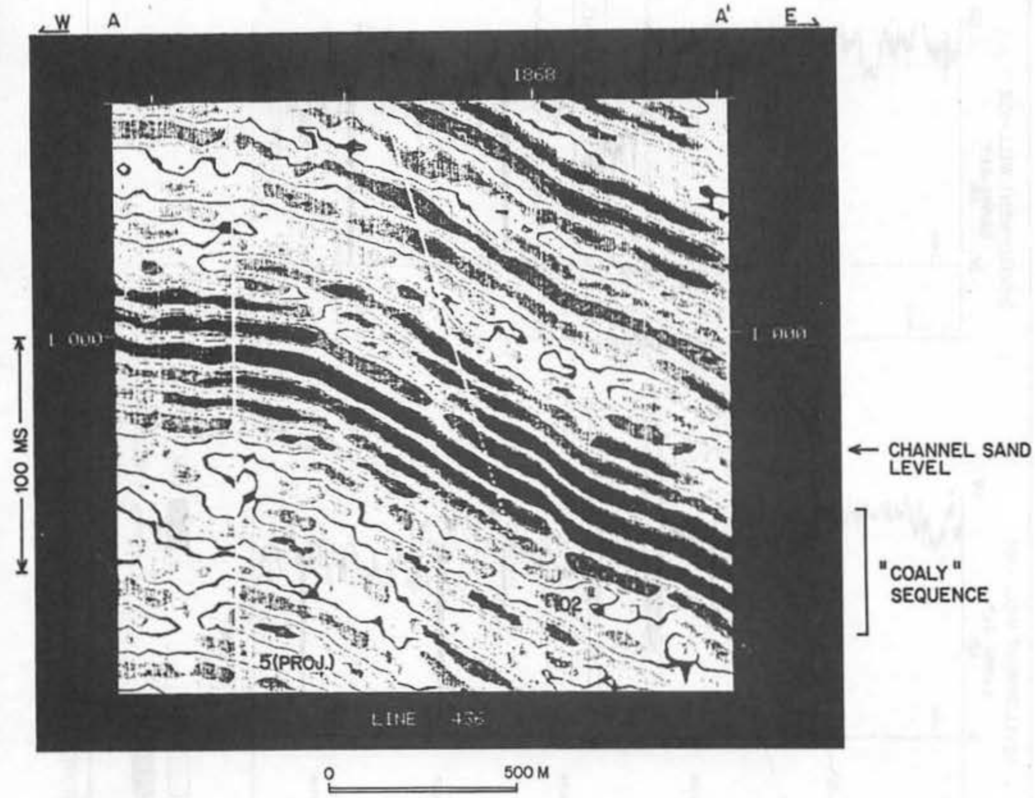


Figure 16: DEVELOPMENT AREA MP-A. Enlarged cross section near well -102.

second. A horizon at the channel level was accurately mapped on every line.

Amplitudes were extracted from the 3D survey along this horizon. The amplitude map (Fig. 17) shows a distinct linear feature (which is not a fault) which was interpreted as a southwest-northeast running channel that develops in the northeast into a possible distributary complex. The model shows that the development well -102 penetrated the edge of a distributary channel, that well -103 narrowly missed the main channel, and well -5 penetrated flood-plain deposits. The reservoir level has been eroded in the north and northwest and was seen by the development wells -106 and -107.

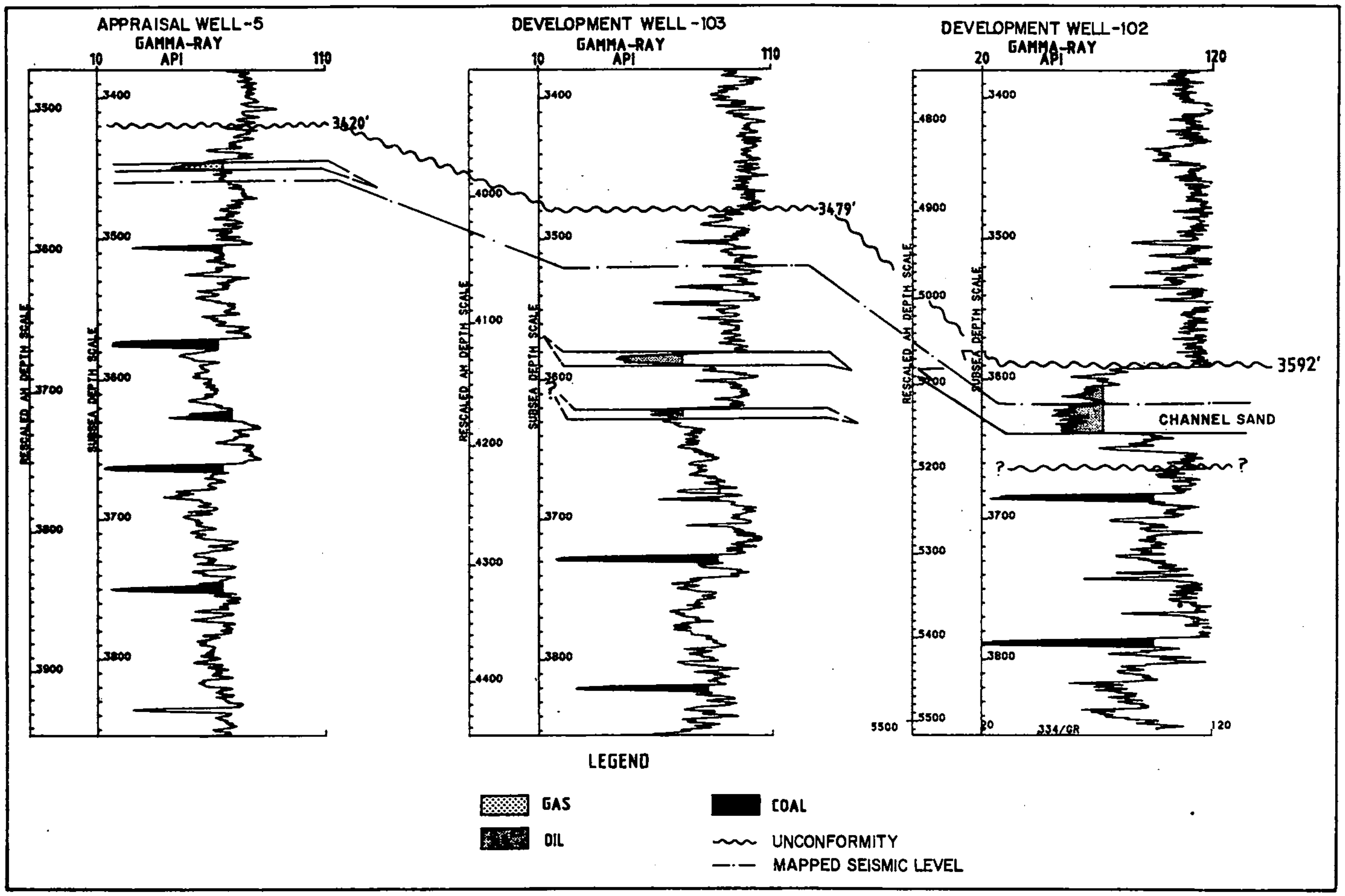


Figure 18: DEVELOPMENT AREA MP-A. Correlation panel for wells -5, -103 and -102

This interpretation is confirmed by a sedimentological model obtained from well data. The correlation panel for the three wells, which includes the results of this study, is given in Figure 18.

This study, with encouraging results, shows that the dense sampling of 3D seismic makes it possible to recognize relatively small scale geological features. Currently other deep channel mapping projects are in progress in SSB.

CONCLUSIONS

The improved structural delineation from 3D seismic data has resulted in superior maps and improved fault interpretation, in particular in geologically complicated areas. More accurate well prognoses have reduced drilling costs. Similar results can be expected from ongoing 3D interpretation projects. In addition, it may be possible in future to target wells using 3D lithostratigraphic maps in addition to 3D structure maps.

The third dimension in 3D seismic displays, the time-slice domain, has proved to be very useful in mapping potential shallow hazard such as sea bottom channels and shallow gas. Moreover, time-slices can be effective in structural mapping, particularly in illustrating differences in tectonic styles.

3D seismic is an integral part of field delineation and development and can result in significant cost savings.

REFERENCES

KONG, VINCENT, 1986. Multiple Streamers and Sources in 3D Marine Seismic Surveys, offshore Sarawak. Paper presented at the Geological Society of Malaysia Petroleum Geology Seminar 1986.

Manuscript received 7 November 1988

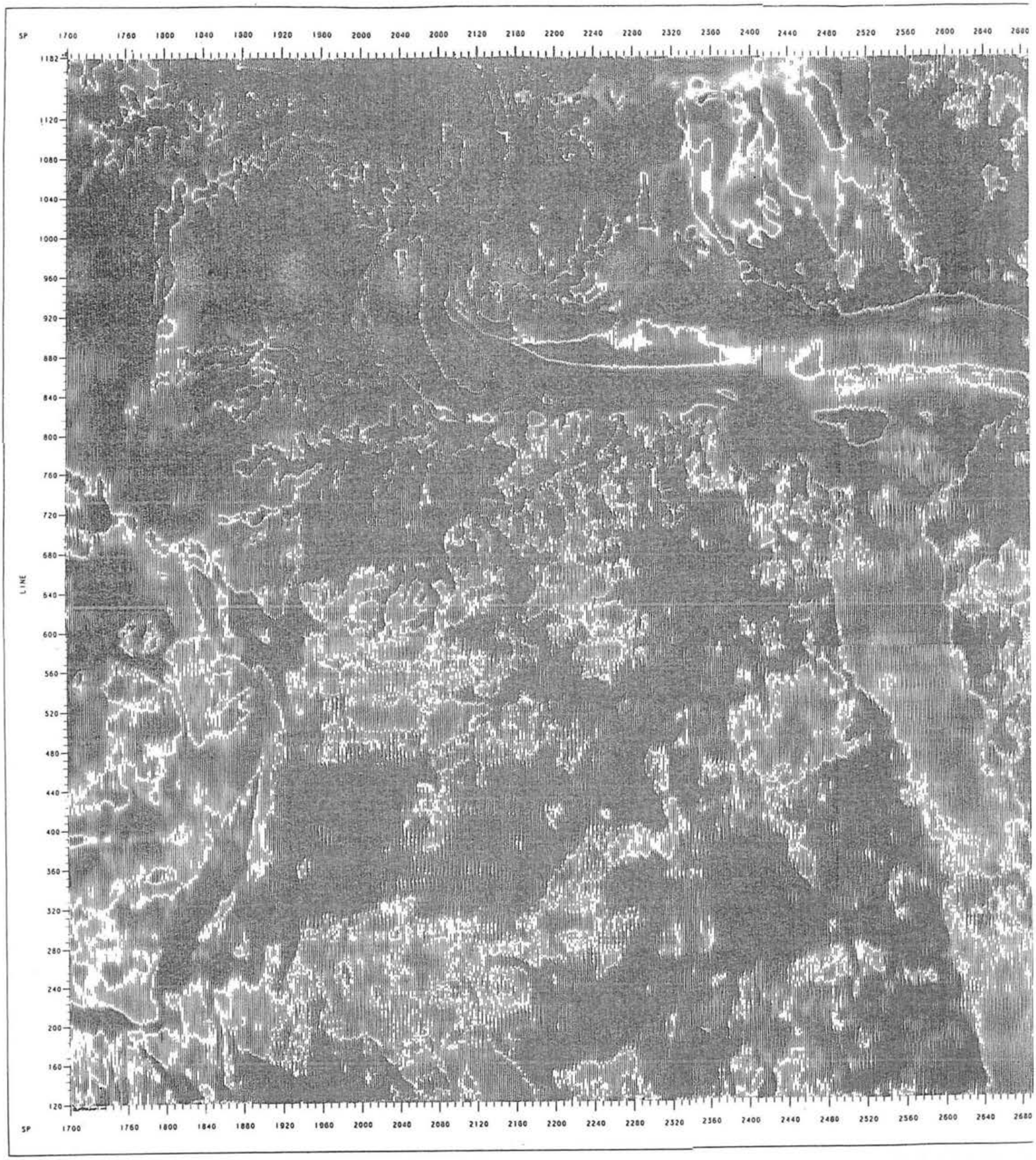
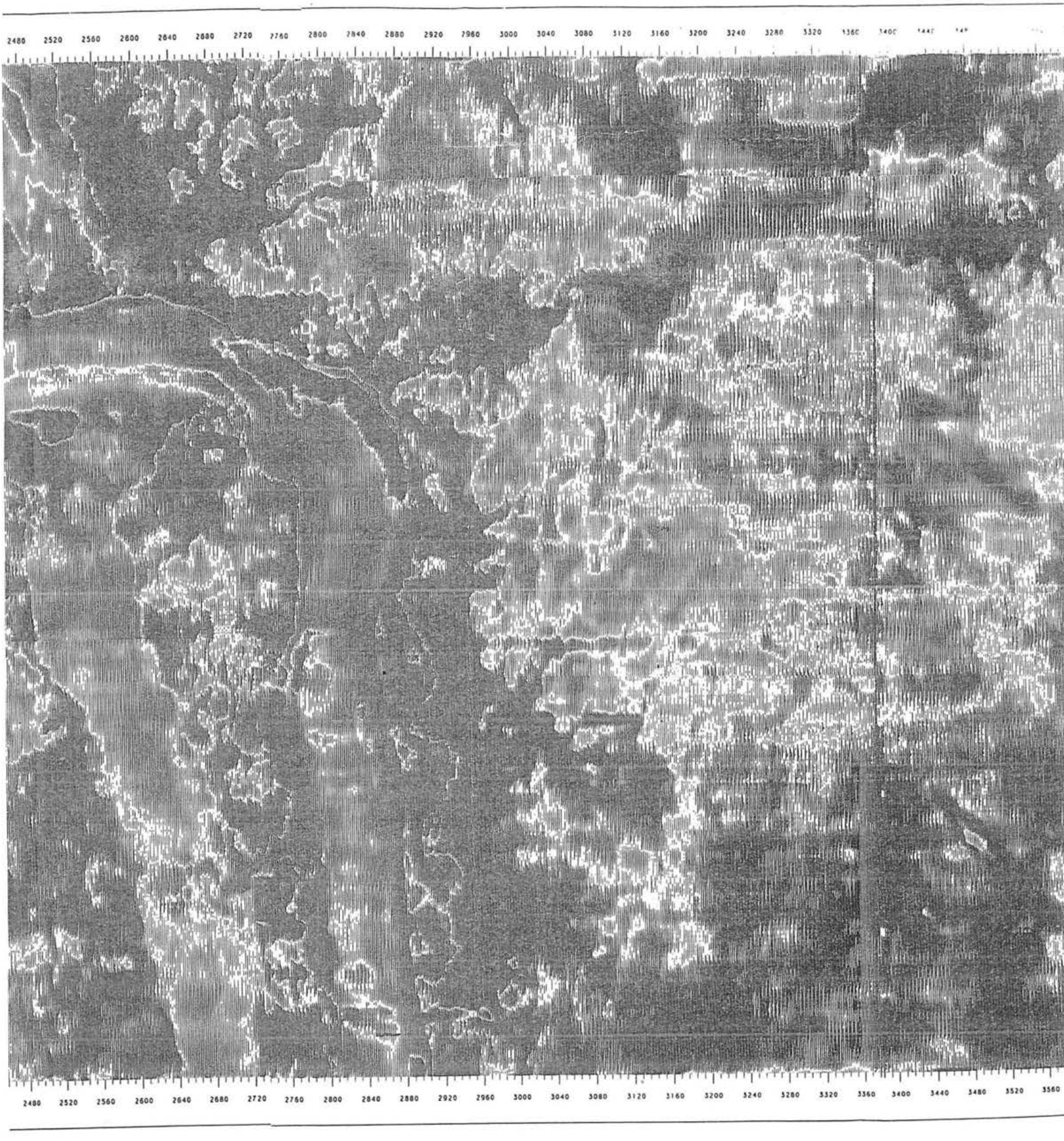
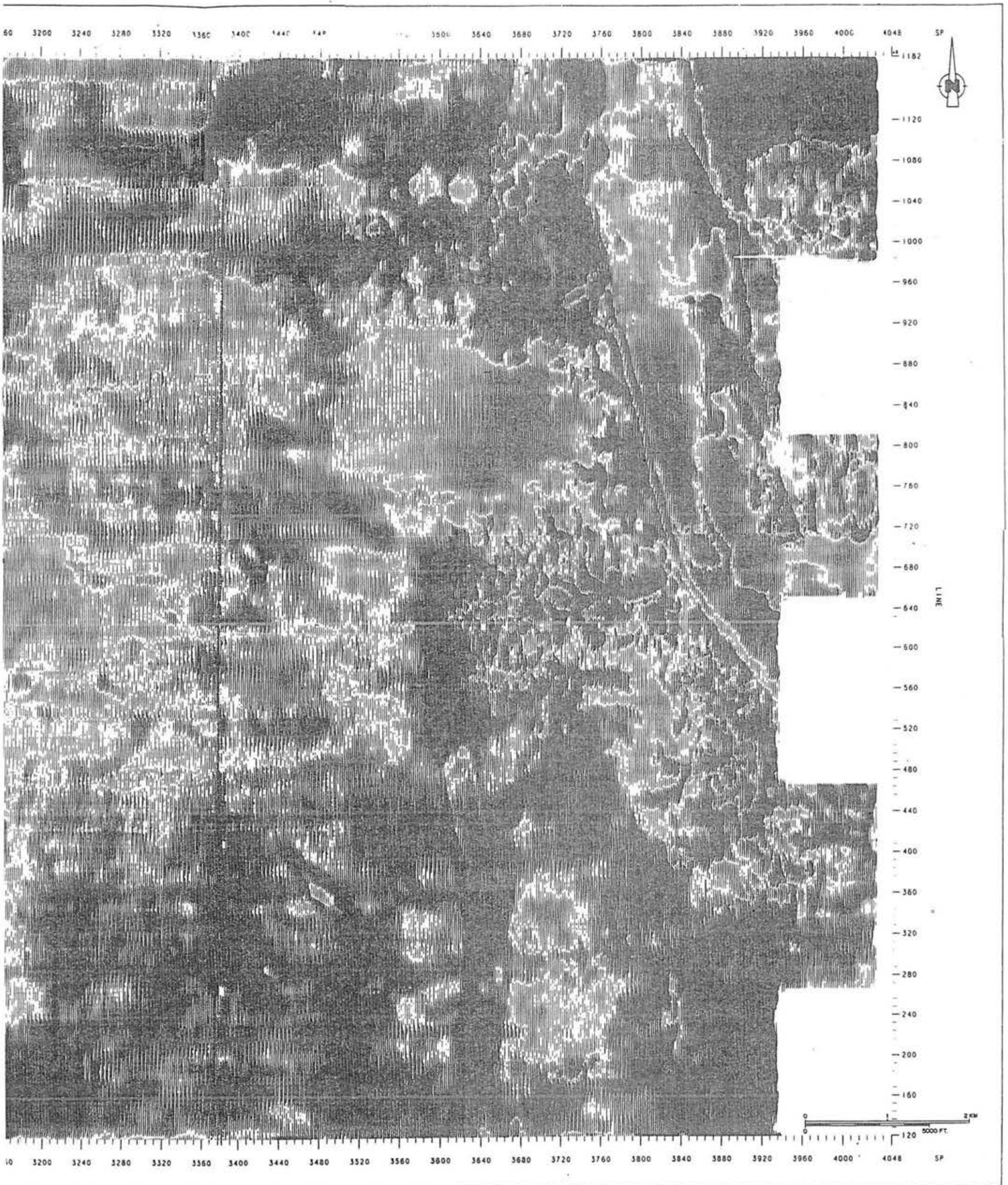


Figure 12: Sub-sea bottom channels, time-slice at 92 ms.


2480 2520 2560 2600 2640 2680 2720 2760 2800 2840 2880 2920 2960 3000 3040 3080 3120 3160 3200 3240 3280 3320 3360 3400
2480 2520 2560 2600 2640 2680 2720 2760 2800 2840 2880 2920 2960 3000 3040 3080 3120 3160 3200 3240 3280 3320 3360 3400 3440 3480 3520 3560


3200
3240
3280
3320
3360
3400
3440
3480
3520
3560
3600
3640
3680
3720
3760
3800
3840
3880
3920
3960
4000
4048
SP
1182
1120
1080
1040
1000
960
920
880
840
800
760
720
680
640
600
560
520
480
440
400
360
320
280
240
200
160
120
LINE
2 KM
5000 FT.

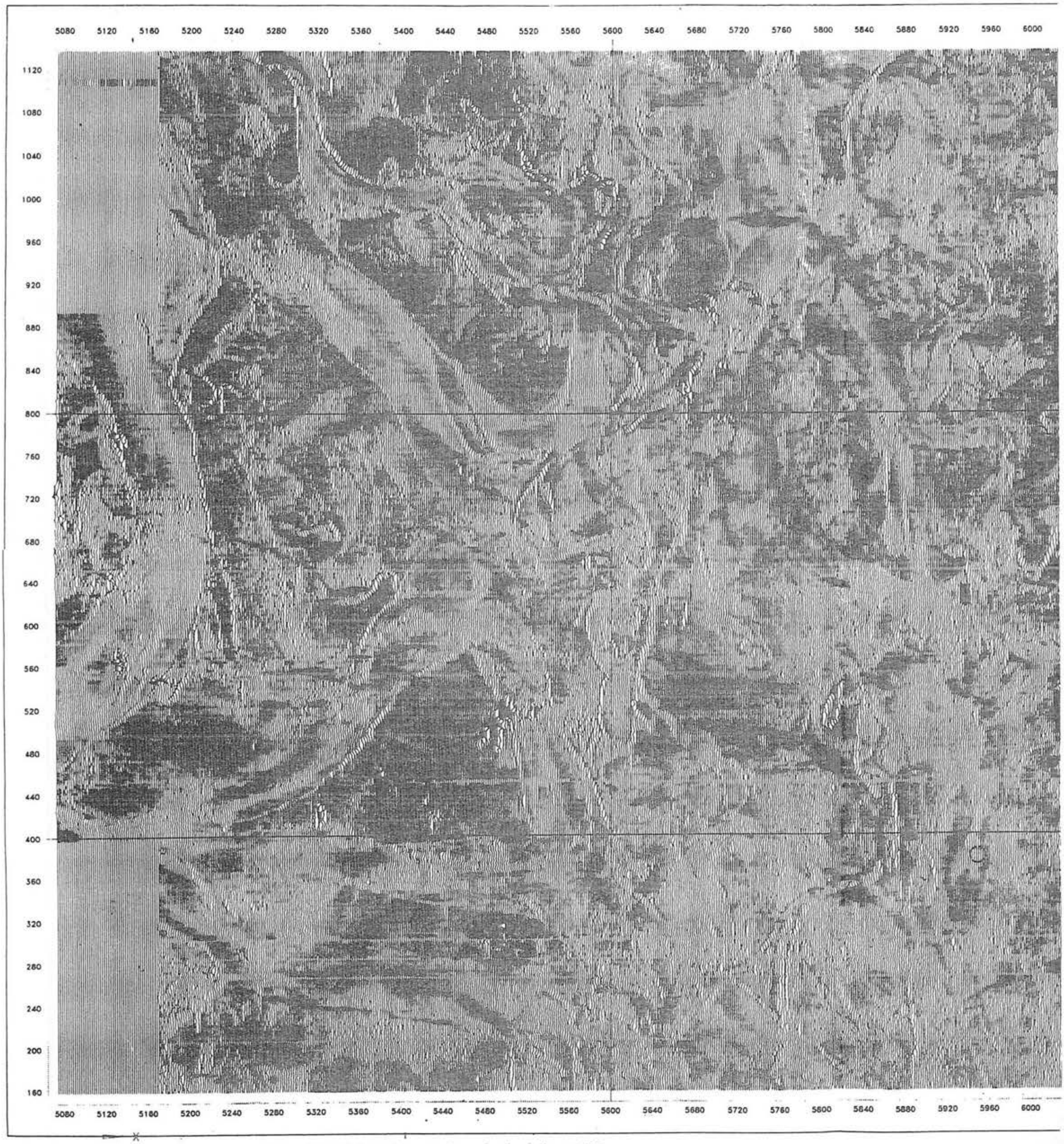
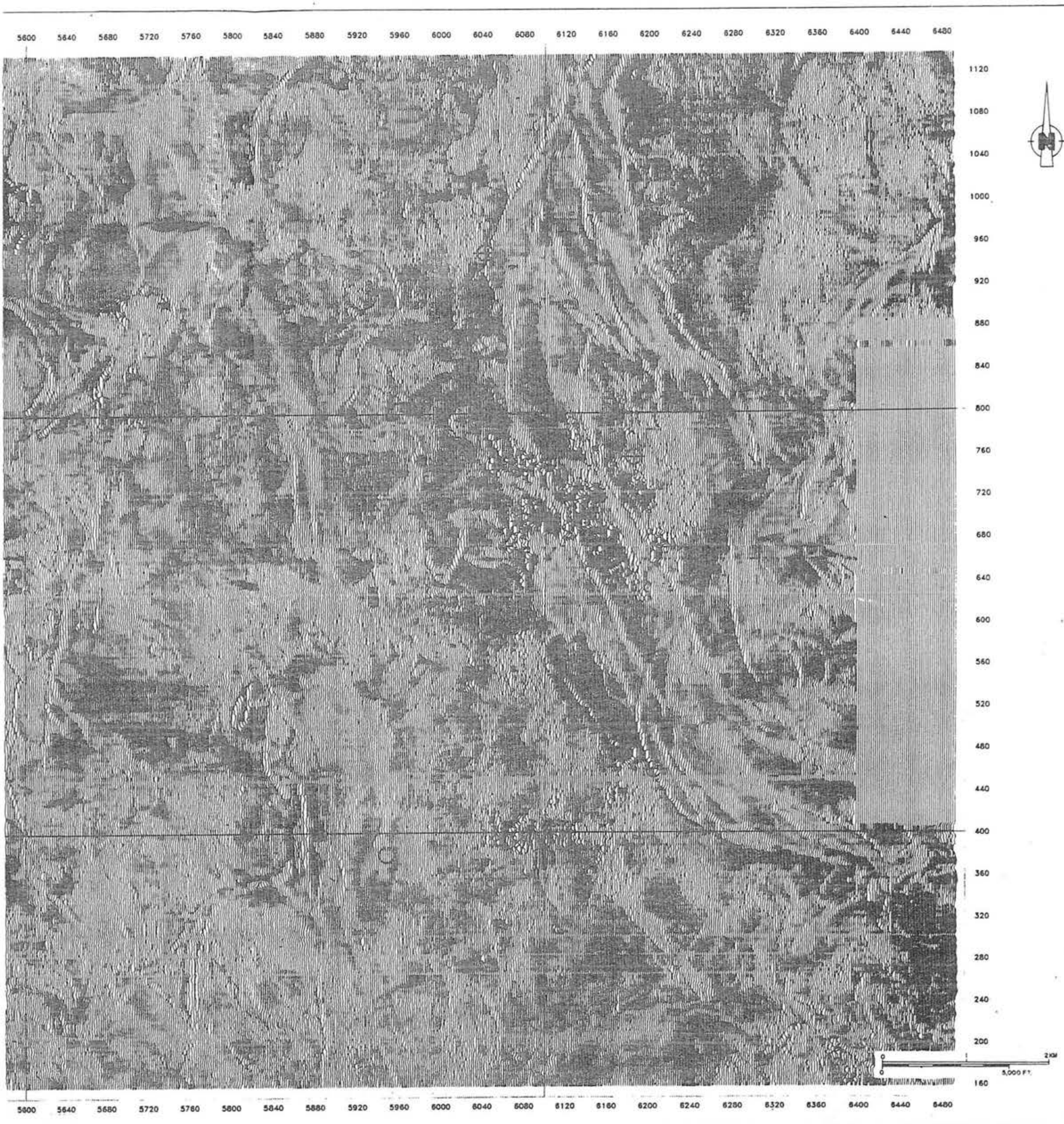


Figure 13: Sub-sea bottom channels, time-slice at 112 ms.


5600 5640 5680 5720 5760 5800 5840 5880 5920 5960 6000 6040 6080 6120 6160 6200 6240 6280 6320 6360 6400 6440 6480
1120 1080 1040 1000 960 920 880 840 800 760 720 680 640 600 560 520 480 440 400 360 320 280 240 200 160
0
2 KM
0
5,000 FT.
5600 5640 5680 5720 5760 5800 5840 5880 5920 5960 6000 6040 6080 6120 6160 6200 6240 6280 6320 6360 6400 6440 6480

12 ms.

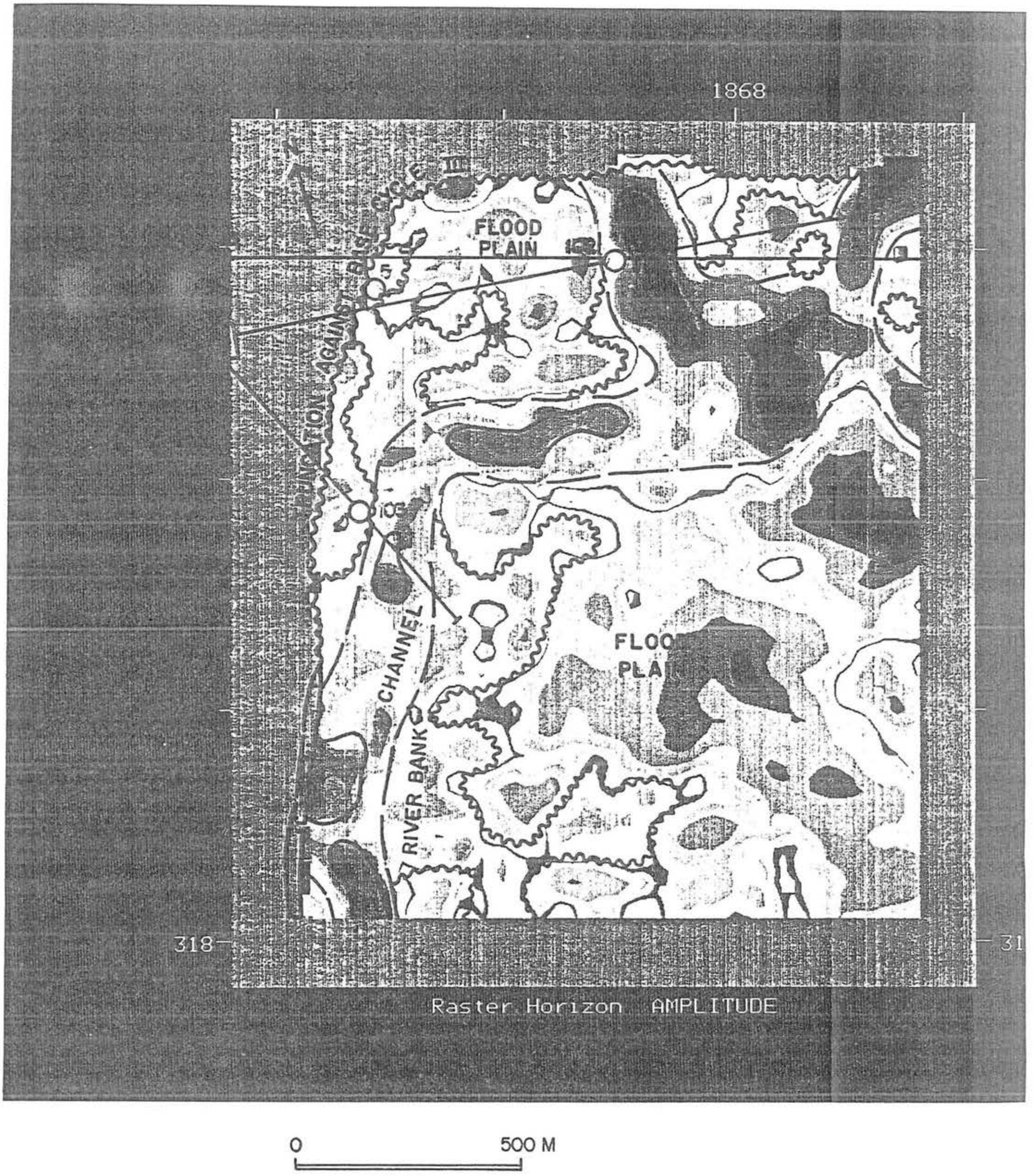
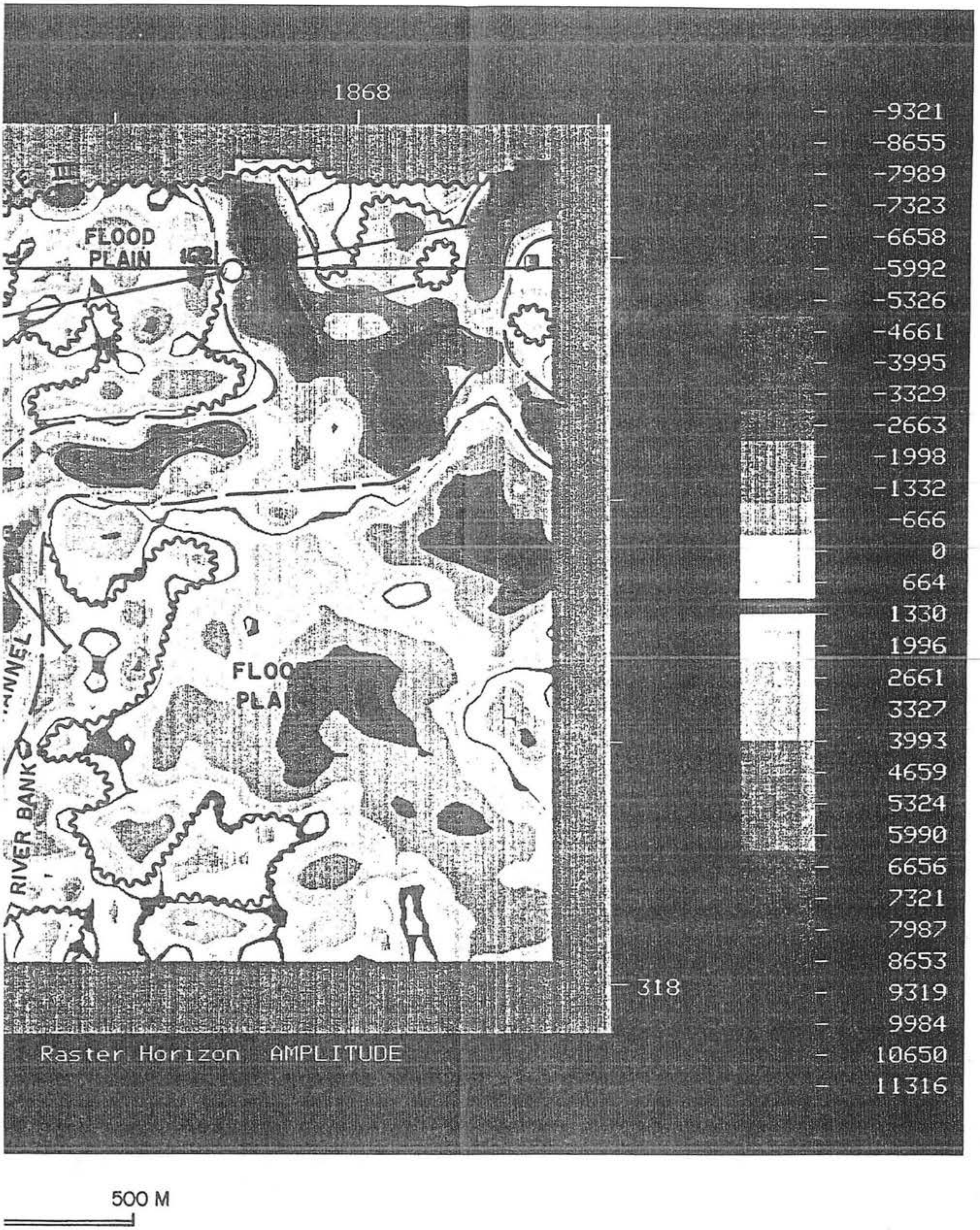


Figure 17: DEVELOPMENT AREA MP-A. Colour coded amplitude map at reservoir level and interpretation of the amplitude distribution.



l amplitude map at reservoir level and interpretation of the amplitude distribution.