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Block 34/10 – Delta East

Supplement to Commerciality Study

GEOLOGICAL RE-EVALUATION AFTER RESULTS OF 34/10–11

May 1981

BLOCK 34/10 - DELTA EAST

SUPPLEMENT TO
COMMERCIALITY STUDY

GEOLOGICAL RE-EVALUATION
AFTER RESULTS OF
34/10-11

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GEOLOGICAL RE-EVALUATION
AFTER RESULTS OF
34/10-11

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I SUMMARY

The results of well 34/10-11, which was completed in February 1981, and the following seismic studies showed that a horst is present on the eastern side of the Delta East structure.

Oil bearing sandstone of Amundsen, Statfjord and Triassic, with a total gross oil column of 215 m, were encountered immediately beneath the Kimmerian unconformity at 1868 m (RKB).

The erosion by the Kimmerian unconformity of the horst in the eastern part has led to a decrease in the areal extension of the Brent and Cook reservoir compared with the earlier interpretation (report November 1980).

The geographic distribution of the oil bearing reserves now shows that Brent reserves are confined to the western and central part of the structure, the Cook to the central area and Statfjord largely to the eastern areas.

The Brent is considered to contain circa 70% of the recoverable reserves, while the Cook and the Statfjord contain 17% and 12% respectively. The total recoverable reserves are calculated to be 242×10^6 m^3 oil and $29 \times 10^9 Sm^3$ gas. This represents an increase of circa 5% relative to the values in the commerciality report.

Three areas of geological uncertainty in the eastern part of the structure are currently defined as requiring appraisal drilling.

II CONCLUSIONS AND RECOMMENDATIONS

Conclusions.

1. Current recoverable reserve estimates for the Delta East field are $242x10^6$ Sm^3 oil and $29x10^9$ Sm^3 gas. This represents an increase of circa 5% relative to the previous estimate.

2. The stratigraphic distribution of reserves now shows that Brent, Cook and Statfjord reservoirs all contain significant volumes of hydrocarbons. The Brent is considered to contain 70% of recoverable reserves while the Cook and Statfjord contain 17% and 12% respectively.

3. The geographic distribution of these oil bearing reservoirs shows that Statfjord reserves are largely confined to the eastern part of the structure, Cook reserves to the central area and Brent reserves to the central and western areas.

4. The presence of oil bearing Statfjord formation in the east of the structure is related to its elevation in a narrow but prominent horst feature which has now been identified on the east side of the structure.

5. There remain three areas of relatively high uncertainty with respect to the seismic interpretation and hence the volume of reserves. The area of major doubt is the southern part of the horst, the doubts being due to the poor quality of the seismic data in this area. The northern and southern limits of the central area have also not been adequately delineated and hence further control is required in these areas.

Recommendations

1. Three main areas remain to be appraised and it is suggested that three further wells will be required to adequately test these areas.

2. Priority should be given to drilling the next appraisal well in the southern part of the horst block.

3. The possibility of deepening this well as an exploration test of the deeper ?Triassic horizon, should be considered.

1. INTRODUCTION

This report is a supplement to the geological/geophysical part of the commerciality study of November 1980 of the Delta East field, Block 34/10 (see fig.1).

Further exploration drilling in the field has continued since that date and following receipt of the results from well 34/10-11, completed in February 1981 it was considered important to report on modifications to our interpretation which are relevant to the commerciality study.

1.1 Object

The report presents revised structural mapping of the eastern part of the field and includes a full discussion of the Statfjord formation, shown to be a significant reservoir by well 34/10-11, and also of the limited reservoirs in the Amundsen Formation and the Triassic.

As mentioned in the 1980 report further work has been undertaken on the Cook reservoir and this is briefly reviewed here.

As no additional information on the stratigraphy and reservoir characteristics of the Brent reservoir was obtained from 34/10-11 no comments have been made on these aspects.

However, because of new structural mapping, reserves have been recalculated for all reservoirs and the distribution of reserves for each reservoir is indicated.

1.2 Data base

This supplement is based on data from the recent well 34/10-11 in addition to the data used in the commerciality study completed last year.

The geophysical interpretation was based on a re-examination of the 3D seismic survey of 1979, integrating with the results of 34/10-11.

1.3 Results of 34/10-11

Well 34/10-11 shows that a horst is present on the eastern side of the Delta East structure and that an oil bearing Statfjord Formation is present almost immediately below the Kimmerian unconformity. The Brent Group is totally eroded in this area.

In well 34/10-11 (figure 2) the late Kimmerian unconformity was encountered at 1868 mRKB, underlain by 22 m of sandy Amundsen Formation, which is in part oil bearing. This is underlain by 138 m of oil bearing Statfjord formation, and an interbedded Triassic sequence of sandstones and mudstones in which the sandstones are also oil bearing down to 2083 mRKB (2058 mss). The Statfjord Formation was penetrated 420 metres higher than it was prognosed suggesting that the eastern limit of the structure, adjacent to the main Viking graben, is a small but prominent horst feature (fig. 3) structurally different from the sequence of dipping fault blocks further west. The difference in structural style was recognised previously but the throw of the faults on the west side of the horst was underestimated.

Drill stem test results in the Statfjord Formation showed the oil to be similar in gravity and gas/oil ratio to that in the Cook reservoir and higher than the oil in the Brent reservoir to the west. Detailed discussion of the revised structural interpretation, sedimentology and reservoir characteristics is given in the relevant sections which follow.

2 STRUCTURAL INTERPRETATION

2.1 Geophysical interpretation

2.1.1 Data Base

The data base used for the reinterpretation of the seismic data following the drilling results from 34/10-11 was the same as that used in the earlier interpretations except for the addition of logs and well velocity results from well 34/10-11.

2.1.2 Data quality

The interpretation of the data and the seismic reflections which are identified in 34/10-11 strengthened the impression that there is a lateral variation in data character and this can also cause problems particularly in correlation over the larger faults.

In addition to the routine interpretation of seismic sections, the seiscrop data was also examined using a specialised projector. This did not improve the data quality but made the work on the seiscrop data simpler and quicker. The log data from 34/10-11 was poorer than normal due to disturbance caused by the cement plug which was set in the reservoir interval.

2.1.3 Seismic interpretation

In addition to the seismic reflectors which were earlier interpreted and mapped, a strong intra-Statfjord reflector was also identified in well 34/10-11. This reflector is thought to correlate with a shale horizon in Unit 2 (Eiriksson Member). Exact correlation with the well logs is uncertain because of the change in log character caused by the cement plug in the reservoir.

The reflector is clear on the seismic line through 34/10-11 and this is possibly a result of interference between multiple energy and true reflection. The reflector is laterally continuous in the easterly area but however shows a particular character change which can be caused by the divergence of direct and multiple energy.

The seismic reflections from the top and bottom of the Statfjord Formation, are as earlier interpreted, shown to be much poorer. Using the intra-Statfjord reflector as a guide, structure maps have been made for the top and base of the Statfjord Formation. An isopach of the interval between top Statfjord and top Cook (fig. 21) was used to construct the top Cook map.

Reinterpretation of the data has also resulted in specific changes in the interpretation of the area between wells 34/10-9 and 34/10-11. This has mainly involved a change in the fault picture such that the easterly limit of the Brent and Cook reservoir has been brought further west.

2.1.4 Velocity and depth conversion

Velocity information from 34/10-11 together with some other minor changes to the previous interpretation have resulted in a modified map of the average velocity from mean sea level to top Jurassic (Fig. 11). In the eastern part of the Delta East field, where the Statfjord Formation has been mapped, an approximate constant interval velocity, corresponding to the velocity information in well 34/10-11, has been used for depth conversion.

2.1.5 Structure Maps

The structure maps and the interpreted seismic sections (Figs. 4-10 and 12-14) demonstrate the results of the new interpretation.

The interpretation still shows the easterly part of the structure to be broken up by smaller faults. The north south running, westerly downthrowing fault, which lies east of 34/10-7 and west of 34/10-11, is considerably larger than previously interpreted and is the major fault which acts as the westerly boundary of the horst on which 34/10-11 was drilled. The easterly border of the north south running horst coincides with the eastern border of the Delta structure.

The faults in the area west of this horst and directly west of well 34/10-9 are seen as compensating faults in a process whereby the Delta structure was broken up into rotating fault blocks, while the easterly area, the horst, was the stable element. The fault throw seen in the Jurassic sequence on the west side of the horst can thus be larger than for deeper horizons.

There are no indications from the interpretation of stratigraphic sealing of the fault immediately west of 34/10-9. From the known differences in oil/water contacts and other reservoir data it is however suggested that this fault could have become sealed in the faulting process.

2.1.6 Discussion of the maps

A comprehensive examination of the "seiscrop" maps together with the earlier contouring has resulted in small modifications to the structure maps in the westerly part of the Delta East field. These changes have not resulted in any significant changes to the reservoir horizons. In the easterly part of the field the "seiscrop" maps are not of sufficiently good quality that they can be directly used for following seismic reflectors in detail, but the trends in the data confirm the interpreted structural picture.

Thus it is possible to identify the structural elevation of the Statfjord Formation just south of 34/10-11 on the horst, and in the adjacent area just west of the horst at 34/10-7.

2.2 Development of the Delta structure

The structural development of Delta East was discussed in the commerciality study but the results from 34/10-11 suggest some changes are required to the interpretation of the pre Cretaceous development. The easterly part of the structure, which projects as a high nose into the Viking graben, is now interpreted as a major north south horst, bounded to the west by a major north south fault and bounded to the east by the graben edge fault. The horst is also truncated at its northern and southern limits by oblique faults. In the area of the horst the lower part of the Dunlin Group subcrops the Kimmerian unconformity, and the Brent and Cook reservoirs are absent, together with the Upper Jurassic sequence. Towards the northern and southern limits of the horst the Statfjord and eventually the Triassic sections subcrop the unconformity.

In the westerly part of the Delta East structure the series of westerly dipping fault blocks is still recognised although these are now considered as subsidiary rotating fault blocks, resulting from subsidence in the west contrasting with a stable high horst block in the east. These areas of contrasting structure are separated by an intermediate zone of relatively flat lying beds, although local flexuring and dip variations can be expected, as shown by well 34/10-7. The fault throw against the west side of the horst is large within the Jurassic section, and probably larger than indicated deeper within the Triassic, suggesting that much of the movement occurred as growth faulting during deposition of the sequence, and that significant fault related slumping also took place.

Although the major fault trend within the structure is north south and parallels the regional trend of the southern extension of the graben, a southwest northeast fault trend is also prominent; this latter is related to the more dominant trend further north and to the Shetland Møre alignment. This trend is considered to have become more active at a later stage and the southerly limit of the horst may be related to movements on this trend in the Lower Cretaceous. The north south faults were rejuvenated however and some influence can be seen within the Paleocene.

3. STRATIGRAPHY AND SEDIMENTOLOGY OF THE STATFJORD FORMATION

The discovery of an extensive oil column in the Statfjord formation of well 34/10-11 has led to a more detailed examination of that interval in the wells on the Delta East structure which have penetrated it.

In addition the well 34/10-2, drilled on the Alpha structure, was also examined due to its proximity to Delta and because of the considerable amount of data available from this well.

3.1 Data available

Eight wells have been drilled into the Statfjord Formation in block 34/10 and of these it is considered that seven have penetrated the entire Statfjord sequence and encountered Triassic. Of these wells only three have been cored in the Statfjord and from two of these the total core recovered amounted to only 10 metres(6 m in 34/10-4 and 4 m in 34/10-9).40 m of core was recovered from 34/10-11,(mostly from the Statfjord Formation) and 50 m was recovered from 34/10-2.

The core from 34/10-2 reflects a different structural regime from the Delta East structure and therefore cannot be used to indicate reservoir characteristics in the Delta structure, although it is useful in indicating regional trends in sediment thickness and facies.

In addition to the limited amount of core data, cuttings and sidewall core samples have been examined, while the basic well correlation was carried out using gamma ray, FDC-CNL and dipmeter logs.

3.2 Correlation (Figure 15)

The base of the Statfjord Formation in the 34/10 area has previously been identified at a high point on the gamma curve within a well developed shale sequence. This point is difficult to correlate from well to well as it is poorly defined. It also does not relate to the definition for the base of the Statfjord Formation by Deegan and Scull(1977), who refer to the base being picked at the base of the main sandstone development. The occurrence of red shales in cuttings and sidewall cores was examined to see if any clear correlation could be obtained. The highest occurrence of red shale in sidewall cores could be approximately related to shale underlying the sand horizon thought to indicate the base of the Statfjord. In addition, in well 34/10-1 the dipmeter indicates an increase in structural dip at about this depth although in other wells dipmeter patterns are not conclusive. This is suggestive of some local structural movement although over much of the structure it is likely that sedimentation was continuous from the Triassic into the Jurassic.

The top of the Statfjord Formation is picked at the transition from a relatively clean normally medium to coarse grained sandstone to the thick dark grey micaceous shale sequence of the Dunlin Formation, the lowest member of which is called the Amundsen Member. The Amundsen Member generally consists of non-calcareous shale and siltstone and occassionally contains thin sandstone intervals. It is interpreted as a marine deposit. In well 34/10-11, a thin sequence of the Amundsen Member was present between the Kimmerian unconformity and the top Statfjord Formation and the lower part of this and the contact with the Statfjord was cored. Although no erosional contact is indicated there is a fairly abrupt transition from laminated, non bioturbated fairly clean sands of the

Statfjord Formation into the intensely bioturbated, fine grained, silty sands of the Amundsen Member.

An isopach map for the Statfjord Formation (figure 16) was constructed using estimated thicknesses for those wells having an indication of faulting. This was considered the most realistic case. A further map was constructed, (Model 2, figure 17) using the actual thicknesses present in all wells, assuming that all wells are unfaulted in the Statfjord Formation. The two maps were later compared when gross rock volumes were calculated.

The isopachs show a general thickening of the section towards the west, the thinnest section occurring over the eastern horst block. The Model 2 isopach shows the thinnest section to lie in the south east of the field.

3.3 Subdivision of the Statfjord Formation.

The Statfjord Formation has been subdivided into three units which can be broadly related to the three members defined by Deegan and Scull (1977), namely the Raude, Eiriksson and Nansen members. However it is recognised that the units correlated in the 34/10 Delta East structure cannot be related directly to the previously defined members, although the subdivision is considered to reflect the basic lithological units in the sequence. The basic relationship is as follows:

34/10 units	Deegan and Scull (1977)
Unit 3	Nansen
Unit 2	Eiriksson
Unit 1	Raude

Correlation of the units is illustrated in the stratigraphic profile of the Statfjord Formation (figure 15).

The profile also indicates the positions of faults cutting those wells having reduced sedimentary section. In well 34/10-1 a fault is considered to cut at 2309 mRKB and an estimated 96 metres of section is missing, largely from unit 2 but including also the base of unit 3. The dipmeter also suggests faulting at this level.

In well 34/10-7 a fault clearly cuts out about 60 m of the lower section of the Amundsen Member of the Dunlin Formation. Correlation of the Amundsen Member in other wells on the structure shows that there is little change in thickness or lithological character so an alternative explanation is unlikely. It is also estimated that 15 m of unit 3 is cut out by this fault. A clear indication of fault drag is shown by the increasing dip of the Amundsen just above the fault intersection.

Faulting is also indicated in well 34/10-4, where a thick section of unit 2 is estimated to be cut out.

3.4 Desciption of the Units.

3.4.1 Unit 1

This unit is not affected by faulting in the 34/10 wells and it varies from 24 m to 47 m across the Delta structure and is 50 m thick in 34/10-2 on Alpha structure. The unit isopach (figure 18) shows a thickening of the section towards the north west of the structure while in the central and eastern part there is little thickness variation.

The base of the unit is equivalent to the base of the Statfjord Formation while the top is picked at the top of a thin but fairly distinctive shale section. The unit generally consists of a basal sand interval which passes into a shale sequence, this being followed by a repetition of the same type of sand-shale cycle. The lower sandstone interval is not present in well 34/10-1 and this is thought to be related to a small local unconformity or pinch-out at this location. There is also some palaeontological evidence for a break in the succession in this well.

The sandstone sections show a variation in log character but many have fining up sequences which continue into the shales. No cores are available from this unit and sedimentological study is limited to cuttings and sidewall core material.

The sandstones range from very coarse to fine grained, occasionally becoming conglomeratic; some calcite cementation can occur but the grains are often uncemented, and generally angular to subrounded, and well sorted. The shales vary in colour from light to dark grey, greenish, and dark brown and red. They can be very silty in parts, occasionally calcareous and micromicaceous.

3.4.2 Unit 2

This unit varies in thickness across the structure from 60 m in 34/10-7 to 81 m in wells 34/10-3 and 34/10-5. A thicker sequence of 104 m is shown by 34/10-2, to the south of the structure. The unit isopach (figure 19) indicates a westerly thickening with a lobate outline suggesting a thin section over the easterly part of the structure, which could be related to the structural development. The unit is considered to be faulted in wells 34/10-1 and 34/10-4. In 34/10-1 an upper section of 67 m is thought to be cut out.

The top of the unit is clearly defined in wells 34/10-3 and 34/10-5 at the top of the thick shaley section in the underlying unit. The clear correlation between these two wells probably reflects the similarity in their structural position. In these wells the unit consists of a well developed sandstone sequence with occasional shale horizons, overlain by a distinctive shale sequence.

The same sequence, and hence the correlation, is not so clear in the remaining wells across the block. In wells 34/10-1 and 34/10-4 the section is thinner due to faulting while in 34/10-11 a similar sandstone interval is present, but the overlying shale is considerably thinner. Further south, in 34/10-7, the shaly sequence has almost disappeared and is replaced by a more sandy facies, while to the south of the structure in well 34/10-2 the entire sequence is sandy with interbeds of shale.

The log character in this unit shows a more blocky nature with well defined boundaries between sandstone and shale. This contrasts with the more gradual transitions of unit 1.

The sandstones are quartzose, medium to very coarse grained, with variable sorting. They are generally micaceous, with traces of lignite and pyrite. The shales are light to dark grey, occasionally brown to red brown, generally non calcareous, micaceous and silty in parts.

3.4.3 Unit 3

This unit varies in thickness across the structure from an estimated 43 m in 34/10-7 to 86 m in 34/10-5. Faulting affects wells 34/10-1 and 34/10-7. The fault in 34/10-1 is considered to cut out the basal 29 m, while in 34/10-7 the upper 15 m is missing.

The unit isopach (figure 20) indicates a westerly thickening. The base is recognised in 34/10-5 and

34/10-3 as the base of a major sand interval and in both these wells the unit is dominantly sandy with a thin shale section about half way up. This shale horizon can be recognised in most of the other wells. The top of the unit is clearly defined on logs as the transition into clay sediments of the Dunlin Group.

The unit consists of fine to coarse grained sandstones with occasional thin beds of shale and occasionally coal. The sandstones are generally calcareous and thin calcite cemented horizons are common. In well 34/10-4 the large amount of calcite cement is probably related to nearby faulting.

This unit has been extensively cored in well 34/10-11 (figure 22) and in well 34/10-2 on Alpha structure. A small amount of core has also been obtained from wells 34/10-4 and 9. Both core and log data show that the sandstones commonly consist of fining up sequences which range from very coarse or conglomeratic sandstones at the base to fine sandstone, siltstone and shale at the top. These fining up cycles are very well defined in well 34/10-2 where 4 distinct cycles occur. Elsewhere thick fairly homogenous clean coarse sandstones occur and these are often uncemented. These contain occasional large fragments of lignite.

3.5 Depositional Environment

The Statfjord Formation is described as a dominantly fluviatile sequence representing the transitional period from the terrestrial conditions of the Cormorant Formation to the fully marine conditions indicated by the Dunlin Group. The base of the Formation is also associated with the gradual replacement of the red bed sequence, consisting dominantly of shale in the 34/10 area to an interbedded sequence of clean coarse sands and grey shales. Unit 1 suggests a relatively low energy environment characterised by meandering streams. Unit 2 deposits were probably associated with higher energy conditions such as a braided stream environment, although the higher energy may be related to more marine conditions. Unit 3 appears to be similar to Unit 1 in depositional conditions, with lower energy sand deposition again prevailing, although generally less distinct than previously and with very little shale deposition.

Within Unit 1 two depositional cycles can be recognised, each consisting of a sand to shale sequence. Four such cycles can be recognised in Unit 3 of 34/10-2. The base of all 3 units is marked by sand deposition. Both units 1 and 2 show a broad upward transition to shale conditions. Unit 3 passes gradually into the marine shales of the Amundsen Formation. Further sedimentological study is planned to improve our understanding of the depositional environment.

4. RESERVOIR PROPERTIES OF THE STATFJORD FORMATION

The reservoir properties of the Statfjord Formation are illustrated by the reservoir log (figure 23). Properties have been examined on the basis of the stratigraphic subdivision proposed and the details are listed in table 2. The values used in reserve calculations are listed in table 3. Units in which a fault cut has been interpreted have not been used in the discussion of average values or trends.

4.1 Net/Gross ratio.

For unit 1 the highest values of >0.50 are obtained in wells 34/10-7 and 11 in the east of the field while the lowest value of 0.32 is shown by well 34/10-4 in the central area. In the area of hydrocarbons the unit can be interpreted as having a net/gross ratio of 0.50.

In Unit 2, values are similarly high in the eastern part of the field and decrease from circa 0.65 to 0.38 in the north west at well 34/10-3, and 0.65 has been used for reserve calculations.

High net/gross ratios are generally found in unit 3 although 34/10-4, in the centre of the field, is significantly lower than the other values. A value of 0.70 has been used as representative for the hydrocarbon bearing section.

In 34/10-11, which is considered representative of the area of oil bearing Statfjord Formation, the net/gross ratio increases upwards from Unit 1 through Unit 2 to Unit 3.

4.2 Porosity.

In each unit average porosity values are higher for well 34/10-11 than for all other wells on the structure. The Statfjord Formation in this well is significantly higher than in other wells and a broad depth relationship can be shown, although this is complicated by the presence of oil in 34/10-11. Geographically the porosity values appear to decrease towards the south east. As the area of oil bearing Statfjord formation is restricted to the east of the Delta East field, and largely east of well 34/10-7, values close to those in 34/10-11 have been used to calculate the hydrocarbon pore volume.

4.3 Water Saturation.

Water saturation values were calculated for well 34/10-11 using standard log procedures. A low average value was obtained for Unit 3 consistent with its high porosity and permeability, while slightly higher average values were obtained for Units 1 and 2, these being affected by thin zones with relatively high values, and by a slight increase in Sw in the thick porous sections. These values were used for reserve calculations in the area of 34/10-11. In the fault blocks further west slightly higher values were used to reflect the proximity of the water zone.

4.4 Flow Barriers.

Correlation within the Statfjord Formation suggests that there are two shale horizons which are likely to be continuous throughout the oil zone. The most prominent shale horizon is that at the top of unit 2 and in 34/10-11 it is about 18 m thick. Further west it thickens to nearly 40 m. A thinner but continuous shale occurs at the top of Unit 1 throughout the field although in 34/10-11 it is poorly developed. Other shale horizons occur throughout the Statfjord Formation but no obvious correlation can be made with other wells.

4.5 Permeability

Horizontal and vertical permeability measurements were made for unit 3 on core samples from well 34/10-11. Within the cored interval the permeability data was used to calibrate porosity values and hence provide estimates of permeability for the non cored part of the reservoir. These are illustrated in the reservoir log (figure 22). High permeabilites of over 300 md are interpreted for most of the porous intervals while values exceeding 1000 md are estimated for the main reservoir section (1905-1920 mRKB) in unit 3.

5. THE AMUNDSEN FORMATION

In well 34/10-11 22 metres of Amundsen Formation were encountered immediately below the late Kimmerian unconformity and 13 metres of core were recovered from this interval. Core and log data indicated a sandy oil bearing section immediately overlying the Statfjord Formation. The sandstones are medium to very fine grained and poorly sorted, with abundant clay and silt. Occasional coarse grains occur with some fossil fragments. The entire section is intensely bioturbated and is interpreted as having been deposited in a shallow marine environment. The lateral extent of this thin Amundsen reservoir must be limited as no reservoir was found in the other wells on the structure.

The section encountered in 34/10-11 was used to estimate the reservoir characteristics in the area of the horst feature, although this may be considered a rather optimistic estimate in view of the lack of reservoir in other wells. A net thickness of 11.5 metres was interpreted as having an average porosity of 26%, although individual core porosities were as high as 35%. Core permeabilities of up to 200 md were also found although values generally ranged from 1 to 100 md. Average water saturation for the net pay was 28%.

6. THE TRIASSIC INTERVAL

Six wells were drilled into the Triassic sediments of the Delta structure but none of the wells penetrated the entire section. Oil bearing Triassic sediments were found in well 34/10-11 down to a depth of 2083 mRKB. Maximum thickness penetrated on the structure was 130 metres in wells 34/10-11 and 34/10-4 and in 34/10-2 196 metres were drilled. Correlation of the top Triassic was related to the top of a major shale interval in which red brown shales commonly occur.

Correlation within the Triassic has not been attempted but the data indicate a similar sequence in all the wells across the field. The top of the sequence generally consists of a shale of about 50 -60 m thickness, with some interbedded sandstone horizons which are probably not continuous. Underlying this a sequence of sand shale interbeds occurs, the sandstones commonly consisting of fining-up cycles. The sandstones vary in grain size from very coarse sand downwards and they are commonly silty and argillaceous.

In well 34/10-11 three distinct sandstone sections, with sands of 10 m or more in thickness, occur towards the base of the well, and the oil water contact was identified in the uppermost part of the upper section. As well 34/10-11 lies close to the structural crest it is unlikely that these sand horizons will contribute significantly to the reserves.

The net/gross ratio for the entire Triassic interval in the well is 0.36 but this is much higher than that which could be expected in the oil zone. A more realistic value of 0.17 for the oil bearing section was used in reserve calculation (table 5). Porosities in the three sandstone sections are relatively high, reaching values up to 30%. In the thinner poorer quality sand within the shale sequence and the oil zone they are generally under 25%. The average porosity for the hydrocarbon bearing interval is circa 23%. Water saturation is generally high (c. 50%) in this interval.

THE COOK FORMATION

A description of the Cook Formation was given in the last report (November 1980, volume II) and no changes have yet been suggested. Meanwhile a new petrophysical study has been made (February 1981) of wells 34/10-7 and 34/10-9, which are the most significant wells, having oil bearing Cook sand.

This study has resulted in amended values for net/gross ratio, porosity and hydrocarbon saturation. These values were derived from improved methods in calculating corrections for thin beds, clay mineral and mica content. Results are given in table 6.

For the volume calculation for the Cook Formation average values have been used from wells 34/10-7 and -9. For Unit 2 more weight has been placed on well 34/10-7, which is oil bearing throughout the interval. For the water saturation in Unit 3, values have been chosen close to those in 34/10-7.

Average values	Net/Gross	Ø	S_w
Unit 3	0.80	0.30	0.23
Unit 2	0.70	0.26	0.40

8 RESERVES

8.1 Brent

Tables 8 and 9 list the gross rock volume and the hydrocarbon pore volume subdivided into the various reservoir units and fault blocks.

The same method of reserve calculation has been used as before (November 1980), and the same computer programme has been used for the volume calculation. The data base is also the same, except that the structural map on the base Brent, upon which the results are based, has been changed, particularly in the eastern part. The other parameters have not been changed, except for the depth dependent parameters, porosity and water saturation. Here a change in the depth map results in an automatic adjustment in the parameter maps. The gross thickness over oil water contact is shown in figure 24. The oil water contact was retained at 1947 mss.

Fault block 1 now contains no Brent reserves and in fault block 2 a slight reduction is indicated in the reservoir volume, when compared to the commerciality study (November 1980). In the other fault blocks very little change in reserves is indicated. Fault blocks 2A and 2B have been grouped together as the latest interpretation does not show a continuous separating fault.

Total reserves of oil and gas are indicated in table 12, and here the results are compared with the previous figures. For Brent reserves alone a reduction of 12% is indicated for the recoverable reserves, and this is mainly due to the new information in the eastern part of the field.

Total recoverable reserves from the Brent reservoir are calculated as 168.5×10^6 Sm^3 oil and 16.9×10^9 Sm^3 gas.

8.2 Cook

Table 10 lists the reserves for the Cook reservoir.

For the Cook the volume calculation has been made manually as before. From the interpreted isopach maps (enclosures 82 and 83 from November 1980) and the new depth map of the top Cook (figure 8) a gross thickness over oil water contact map has been constructed for each unit (figs 25 and 26). For fault block 2 an oil water contact of 2090 mss, as indicated in well 34/10-9, has been used. For block 3 an oil water contact of 1947 mss has been used, as in the Brent reservoir. Constant reservoir parameters have been used in calculation of the hydrocarbon pore volume.

The reserves are concentrated in fault block 2 which in the south is split into a number of smaller blocks. However, 20% of the Cook reserves are interpreted in fault blocks 3 and 4B.

Results have also been subdivided into the two reservoir units and it is seen that the major proportion of the reserves occurs in unit 2.

The gross reservoir volume is smaller than previously calculated but the improvement of the net/gross ratio in Unit 2 resulting from the petrophysical studies has resulted in a relatively small decrease in the oil in place.

Total recoverable reserves for the Cook formation are calculated as 40×10^6 Sm^3 oil and 5.3×10^9 Sm^3 gas. Compared with the previous results no change is indicated.

8.3 Amundsen

Table 11 illustrates the reserves calculated for the Amundsen reservoir.

The Amundsen reserves were estimated as a thin slab overlying the Statfjord Formation in fault block 1. There is no evidence elsewhere, apart from 34/10-11, that the Amundsen Formation is oil bearing and hence reserves have not been estimated for other fault blocks.

Doubt also exists on the likelihood of reservoir in this section in the south of fault block 1, but reserve estimates have been included here as the thin reservoir found in 34/10-11 is found to immediately overlie the Statfjord reservoir and forms a continuous reservoir sequence.

Recoverable reserves are estimated at $2.8x10^6$ Sm^3 oil and $0.6x10^9$ Sm^3 gas.

8.4 Statfjord

Statfjord reserves are listed in table 11.

The Statfjord reserves are calculated in the same way as the Cook Formation. Gross thickness maps over oil water contact were constructed from the depth map of the top Statfjord and the interpreted isopach maps (figs 27-30). The alternative isopach map for the Statfjord (model 2, fig. 17) was used to plot an alternative gross thickness map over oil water contact. The resulting oil bearing gross rock volume was 3% lower than that calculated for the preferred model. Constant reservoir parameters were used for the calculation of the hydrocarbon pore volume.

The oil water contact of 2058 mss in the Trias of 34/10-11 was used for the Statfjord volume calculation in fault block 1. In fault blocks 2 and 3 the oil water contact of 2043 mss found in 34/10-7 was used.

Reserves are found in fault blocks 1, 2 and 3, but are concentrated in block 1. 20% of the total Statfjord reserves are considered to lie in block 2 although some of the reserve is contained in small separate blocks in the south. Fault block 3 contains negligible reserves.

Recoverable reserves are now estimated at 30.3×10^6 Sm^3 oil and 6.2×10^9 Sm^3 gas. Previous estimates suggested that Statfjord reserves were negligible.

8.5 Trias

Triassic reserves of fault block 1 are indicated in table 11.

The Trias reservoir is estimated as a "skull" under the top Trias depth map (Figure 10) and the oil water contact of 2058 mss found in 34/10-11 was used for the volume calculation. This value was also used for calculation of the Statfjord reserves.

The present seismic interpretation suggests that the Triassic reserves, which are limited to fault block 1, are insignificant. Although a significant volume of Triassic overlies the OWC in fault block 1, the net/-gross ratio of the uppermost section in well 34/10-11 results in a low resultant hydrocarbon pore volume. The subdivision of the reserves into thin poor quality zones suggests that these could not be effectively produced.

For comparison with other results a recoverable reserve was calculated at 0.5×10^6 Sm^3 oil.

8.6 Total Reserves

Total recoverable reserves for the 34/10 Delta East structure are now considered to be 242×10^6 Sm^3 oil and 29×10^9 Sm^3 gas (Table 12). The Brent group forms the dominant reservoir in the field although the Cook and Statfjord reservoirs contain significant reserves, each contributing 17% and 12% respectively of the total. The Amundsen Formation can be considered to add a small additional reserve to the Statfjord accumulation, but the Triassic reservoir is not thought to have any significance in the present interpretation.

The geographic distribution of reserves is such that the Brent group, about which most is known, forms the reservoir in the west and west central area, while in the east central area a complex of Brent, Cook and Statfjord reservoirs is indicated. In the east of the field only Statfjord reserves are found.

9 CHANGES SINCE PREVIOUS INTERPRETATION

The major modification to the geological understanding of the Delta East structure concerns the horst block in the east. The presence of a prominent horst in this area, brings Statfjord and Triassic reservoirs higher than previously expected in this part of the structure.

Oil bearing Statfjord and Triassic sands were encountered and the Statfjord Formation must now be considered a significant contribution to the reserves within the structure.

The geographic distribution of reserves is related to the stratigraphy. In the western area only Brent reserves are present, in the central area a complex of Brent, Cook and Statfjord reserves occurs, while in the east only Statfjord reserves are present.

Total recoverable reserves from the structure are estimated to be slightly higher than previously, although the increase is only circa 5%. Reserves are distributed into three major stratigraphic intervals, the Brent (70%), the Cook (17%) and the Statfjord (12%).

10 UNCERTAINTIES

10.1 Structural uncertainties

Figure 31 outlines areas of varying levels of uncertainty in the seismic interpretation. Three main areas of medium to high uncertainty are outlined. These are:

10.1.1 Northern area, fault block 2

The area between wells 6 and 11 in the northern part of fault block 2 is poorly defined and there are some doubts on the interpretation.

10.1.2 Southern area, fault block 1

A problem exists with the identification of the mid-Statfjord reflector in this area, due to the poor quality of the seismic. It might well be possible that the Statfjord is downthrown by undetected E-W trending faulting below the estimated OWC in the southern part of this block.

10.1.3 Southern area, fault block 2

The main problem in this area is the character correlation of the seismic reflectors over the numerous faults. The Brent might hence for example be much more upthrown and eroded or more downthrown below the OWC.

10.2 Uncertainties in estimated OWC's

10.2.1 Brent

No OWC has so far been penetrated in the Brent of blocks 2 and 3. The OWC in these blocks might hence vary between the lowest oil found in well 9 at 1920 mss and the highest water found in well 6 at 2050 mss, if the fault separating block 4 from blocks 2 and 3 is sealing. The OWC will of course lie at 1947 mss when the faults between block 2, 3 and 4 are not sealing for the Brent.

10.2.2 Cook

No OWC has so far been penetrated in the Cook, in fault block 3 and for purposes of reserve calculations a value of 1947 mss has been used, the same as that used for the Brent in that block. The highest water found in the Cook in fault block 3 is at 1997 mss.

10.2.3 Statfjord

No OWC has so far been penetrated in the Statfjord in block 1 and hence the OWC has still to be firmed up.

The OWC at 2058 m found in the Trias of 34/10-11 and the OWC at 2043 m found in the Statfjord of block 2 in 34/10-7 indicate however that the OWC of the Statfjord in block 1 will be around 2050 mss.

10.3 Uncertainties in Depositional Trends

10.3.1 Brent

A facies model has been proposed for the Brent group suggesting that the overall trend relates to a deltaic progradation from the southwest, such that an initial shallow marine sequence becomes covered by a deltaic complex, which eventually retreats during a regressive phase. The detailed relationship of the various facies displayed in the wells has not been fully evaluated, and the relationship to the unit isopachs needs further examination. An overall thinning of the Brent Group over the structure is indicated and this suggests some structural control on the pattern of sedimentation.

10.3.2 Cook

The Cook Formation has been interpreted as a regressive sequence deposited in a shallow marine environment. However, as yet no distinct depositional trends have yet been identified.

10.3.3 Statfjord

Although no clear indication has yet been obtained on sediment transport direction and detailed facies the formation thickens westwards off structure and is thinnest over the high horst area on the eastern side. There is hence a suggestion that the structure influenced the sedimentation pattern in the lower Jurassic.

10.4 Reserves

Figures 32-35 illustrate the distribution of "proven" and "possible additional" reserves for each reservoir and for all reservoirs combined, and values are indicated in table 13.

For the Brent reservoir three major areas of "possible additional" reserves are outlined. The first is a small area in the south west of the field, a further area exists in the region of well 34/10-10, while the largest area lies north of well 34/10-9. It is estimated that about half of the "possible additional" Brent reserves lie in this area, which would thus contain about 10% (i.e. $17x10^6m^3$) of the total estimate for Brent reserves.

Only 25% of the estimated Cook reserves are considered "proven" and these lie in the areas of wells 34/10-7 and 9. A large area of "possible additional" reserves lies east of well 34/10-1 while a smaller area is also indicated in the north-east.

In the Statfjord formation approximately half of the reserves are considered "proven", these lying in the areas around wells 34/10-7 and 11. Further "possible additional" reserves lie in the area south and south-west of well 34/10-7 and in the southern part of fault block 1, south of well 34/10-11.

The overall distribution (figure 35) shows that the major areas of "possible additional" reserves lie in the south-east and north-east parts of the field.

11 PLANNED SEISMIC AND GEOLOGICAL STUDIES

11.1 Seismic Aquisition

The possibility of shooting north-south lines over Delta while the Alpha survey is being shot is being considered. Ideally at least one north-south line should be shot within each fault block. This would mean about 10 lines (i.e. about 125 km).

11.2 Seismic Processing

Ca. ten random lines in strike direction will be processed, using the existing 3D data set (See map giving location of lines).

Traces will be interpolated between the dip lines (which are 75 m apart) to make the generated random strike lines easier to interpret.

The lines will be used to confirm the structural interpretation of the eastern part of the Delta Structure and to help to select the optimal location of possible appraisal wells (See section 12).

Work on synthetic seismograms will be started soonest.

The efforts to plot improved synthetic seismograms with the existing seismic data set might give leads to inproved processing of the 3D data.

11.3 Seismic Interpretation

A structural interpretation of the intra Triassic reflector at ca. 3000 m is planned soonest (See section 12).

11.4 Reservoir Geological Studies

Further work is planned on the facies analysis, depositional trends and shale continuity of the reservoir sections, and this will be aimed at improving the understanding of geological controls on the reservoir properties.

Initially this work will concentrate on the Brent reservoir, although some petrographic study is also being undertaken for the Statfjord.

12 APPRAISAL PLANNING

The current interpretation of the structure suggests that 3 further appraisal wells are required, to test the 3 major areas of uncertainty, discussed in section 10.

The first of these three appraisal wells is proposed to test the southern extension of fault block 1.

It is scheduled to be drilled in the second half of 1981.

This location is seen to have the highest priority of the three appraisal locations currently planned to firm-up the eastern part of the Delta-East structure.

It will firm-up the area of the highest uncertainty and is foreseen to prove-up more reserves than the other two appraisal wells.

Its results might be important for the planning of the second platform.

The confirmation of the structural situation of the southern part of block 1 might also give leads to a more accurate interpretation of the southern part of block 2 and therefore influence the optimal location of an appraisal well in that area.

The well might furthermore test for the first time the deeper Triassic intervals in the Delta structure which correspond with a strong reflector at ca. 3000 m.

The outcome of the seismic studies discussed in section 11.2 and 11.3 will be awaited prior to making a final decision on location and total depth of the first well.

Two areas of uncertainty remain to be tested after block 1 has been firmed-up by the well in 1981:

- The area between wells 6 and 11 in the northern part of block 2B. Mapping of the Brent in this area is poorly defined and the oil-water contact in this block has still to be proven.

- The heavily faulted area in the southern part of the Field in block 2 near well 10.

The information of the well in the northern part of block 2B might influence the final decision on the location of the second platform and is hence scheduled in 1982, one year before the planned soil test for this platform.

The well to test the southern part of block 2 is planned for 1983.

13 REFERENCES

1. Commerciality study, November 1980.

2. Petrophysical Evaluation well 34/10-7 and 34/10-9. Formation: Cook & Statfjord. T. Helgøy, Statoil, February 1981.

Table 1

STATIGRAPHIC SUBDIVISION OF THE STATFJORD FORMATION

(Depth: mRKB) RKB = 25 m

Jan. 1982

unit \ well		34/10-1 xx	34/10-2	34/10-3	34/10-4 xx	34/10-5	34/10-7 xx	34/10-9	34/10-11	34/10-13
Statfjord fm	top	2268	3325	2495	2340	2562	2053	2375	1890	1924
	thickness	? (177) 81	208	195	? (162) 129	196	? (127) 112	46+	138	128
Unit 3	top	2268	3325	2495	2340	2562	2053	2375	1890	1924
	thickness	? (70) 41	54	67	58	86	? (43) 28	46+	45	41
Unit 2	top	2309	3379	2562	2398	2648	2081		1935	1965
	thickness	? (80) 13	104	81	? (70) 37	81	60		65	52
Unit 1	top	2322	3483	2643	2435	2729	2141		2000	2017
	thickness	27	50	47	34	29	24		28	35
Trias	top	2349	3533	2690	2470	2758	2165		2028	2052
	thickness	113+	196+	112+	130+	22+	85+		130+	98+
TD		2462 m	3729 m	2802 m	2600 m	2780 m	2250 m	2421 m	2158 m	2150 m

(NB: (xx) Thickness in parenthesis is assumed full thickness including fault throw).

Table 2

Statfjord Formation, Reservoir Characteristics.

Jan. 1982

Unit / Well	Interval	N/G	Ø	S_w
Unit 3				
34/10 - 1 (F)	2268-2309	0.90	27.2	100,-
2	3325-3379	0.56	15.9	20,5
3	2495-2562	0.73	20.2	100,-
4	2340-2398	0,45	21.3	100,-
5	2562-2648	0.85	22.9	100,-
7 (F)	2053-2081	0.59	24.9	100,- *
9	2375-2421	0.80	26.3	100,-
11	1890-1935	0.72	30.1	9,6
13	1924-1965	0.75	27.8	22.2
Unit 2				
34/10 - 1 (F)	2309-2322	0.88	27.3	100,-
2	3379-3483	0.55	17.4	56,8
3	2562-2643	0.38	17.8	100,-
4 (F)	2398-2435	0.69	24.2	100,-
5	2648-2729	0.43	20.7	100,-
7	2081-2141	0.68	24.8	100,-
9				
11	1935-2000	0.64	26.7	14,3
13	1965-2017	0.57	26.9	20.8
Unit 1				
34/10 - 1	2322-2349	0.47	20.8	100,-
2	3483-3533	0.33	16.1	60,-
3	2643-2690	0.41	17.5	100,-
4	2435-2470	0.32	25.7	100,-
5	2729-2758	0.405	18.5	100,-
7	2141-2165	0.53	23.6	100,-
9				
11	2000-2028	0.52	26.7	19,8
13	2017-2052	0.20	22.9	39.1

* For Hydrocarbon internal Ø = 26.9 S_w = 37.9

Table 3 Statfjord Formation, Reservoir Parameters used in Reserve Calculations

Unit	Net/ Gross		Porosity	Water Saturation		
		thickn.		Fault block 1	Remaining area	equiv. prov.
3	0.70	45	0.30	0.10	0.15	8.27
2	0.65	65	0.26	0.15	0.20	9.06
1	0.50	28	0.26	0.20	0.25	2.82
		138 m			→	20.15
well 13 →		127 m			→	15.09

Formation Volume Factor: 1.60

Recovery Factor: 0.45

Oil Water Contacts:

Fault block 1 2058 mss

Remaining area 2043 mss

Gas Oil Ratio 203 Sm^3/Sm^3

138/127 × 15.09 → 16.37

16.37/20.15 : .81%

proven reserves are ca. 15% less than the possible addit.

Table 4. Amundsen Formation, Reservoir characteristics.

Net /Gross Ratio	0.52
Porosity	0.26
Water Saturation	0.28
Formation Volume Factor	1.60
Recovery Factor	0.40
Oil Water Contact	2085mss
Gas oil ratio	203 Sm^3/Sm^3

Table 5. Trias, Reservoir Parameters used in Reserve Calculations.

Net/Gross Ratio	0.17
Porosity	0.23
Water Saturation	0.49
Formation Volume Factor	1.60
Recovery Factor	0.40
Oil Water Contact	2058 mss
Gas oil ratio	203 Sm^3/Sm^3

Table 6

Petrophysical Parameters of the Cook Formation. (March 1981)

Well	Unit	Internal (m.RKB)	Net "pay" / Net sand	Average porosity	Average Water-saturation Gj.snitt vannmetning	net/gross ratio
34/10-7	Unit 3	1810-1825	10.8	0.316	0.169	0.72
34/10-9	Unit 3	2083-2097	11.3	0.294	0.320	0.86
34/10-7	Unit 2	1825-1882	45 / 53	0.264 / 0.250	0.366 / 0.427	0.78 / 0.92
34/10-9	Unit 2	2097-2150	3,5 / 16,25	0.237 / 0.225	0.61 / 0.73	0.06 / 0.43

min. Criteria: VSH = 100%
Ø = 12%
S_w = 65%

Net "pay" / Net s d

Table 7

COOK FORMATION

RESERVOIR CHARACTERISTICS

USED IN RESERVE CALCULATION

	NET/GROSS	POROSITY	WATER SAT^N
UNIT 3	0.80	0.30	0.23 ≃ 0.1848
UNIT 2	0.70 ✓	0.26 ✓	0.40 = 0.1092

<u>FORMATION VOLUME FACTOR</u> 1.40

<u>RECOVERY FACTOR</u> 0.40 (UNDER EVALUATION)

<u>OIL WATER CONTACTS</u>

FAULT BLOCK 2 2090 MSS

FAULT BLOCKS 3, 4 1947 MSS

<u>GAS OIL RATIO</u> 132 SM^3/SM^3

(AVERAGE VALUE FROM
34/10-7 AND 34/10-9)

Table 8 BRENT GROUP, GROSS ROCK VOLUME

GROSS ROCK VOLUME 10^6 m^3 OWC - 1947m

	Block 2A+2B	Block 2C	Block 2D	Block 3	Block 4A	Block 4B	Block 5A	Block 5B	Block 6	Total
Unit 6	0.1	0.	0.	72.9	1.2	1.7	0.	0.	0.	75.9
Unit 5B	0.	0.	0.	7.1	202.7	11.4	29.7	20.3	23.6	294.8
Unit 5A	19.3	0.	0.	67.7	67.9	9.9	2.8	1.0	1.5	170.1
Unit 4	107.9	2.7	3.7	227.6	302.5	71.8	3.6	1.5	3.5	724.8
Unit 3	87.4	16.3	15.4	154.4	105.8	44.9	0.	0.	0.	424.2
Unit 2	271.6	46.4	33.9	252.2	109.5	60.2	0.	0.	0.	773.8
Unit 1	61.2	22.8	15.0	66.3	18.2	17.2	0.	0.	0.	200.7
Total	547.5	88.2	68.0	348.2	807.8	217.1	36.1	22.8	28.6	2664.3

Calculated using CPS programme package ACK/KCG.

Table 9 BRENT GROUP, HYDROCARBON PORE VOLUME

GROSS ROCK VOLUME * NET/GROSS-RATIO * POROSITY * OILSATURATION; OWC= - 1947m

HCPV, 10^6 m^3

	Block 2A+2B	Block 2C	Block 2D	Block 3	Block 4A	Block 4B	Block 5A	Block 5B	Block 6	Total
Unit 6	0.	0.	0.	17.0	0.4	0.5	0.	0.	0.	17.9
Unit 5B	0.	0.	0.	1.4	43.4	2.8	5.4	3.8	4.4	61.2
Unit 5A	1.7	0.	0.	6.2	4.9	1.0	0.1	0.	0.	13.9
Unit 4	7.5	0.3	0.4	16.7	25.6	8.4	0.1	0.1	0.2	59.3
Unit 3	19.3	5.3	5.0	41.8	26.8	13.1	0.	0.	0.	111.3
Unit 2	61.4	15.0	10.5	66.2	23.3	13.8	0.	0.	0.	190.2
Unit 1	6.5	3.4	2.1	7.3	1.0	1.2	0.	0.	0.	21.5
Total	96.4	24.0	18.0	156.6	125.4	40.8	5.6	3.9	4.6	475.3

Calculated using CPS programme package ACK/KCG.

Table 10

COOK RESERVES

34/10-DELTA EAST

	Gross Rock Vol. 10^6 M^3		HCPV $10^6 M^3$		Recoverable res oil $10^6 M^3$ - 40%		Rec. Gas $10^9 M^3$
Fault Block	Unit 3 / Unit 2		Unit 3 / Unit 2		Unit 3 / Unit 2		
2 A+B	134 143	653	24.8	81.5	7.5	24	
	519 581		56.7		16.5		
2 C+D+E	60 64.4	216	11.1	28,1	3	8	
	156 186.8		17.0		5		
3	53 37.1	179	9.8	23.6	3	7	
	126 72.8		13.8		4		
4B	8 .72	44	1.5	5.4	0.3	1.3	
	36 5.8		3.9		1.0		
Total	259	1104	47.9	140.2	14	40	5.3
	845	1092	92.3		26		

OVK = -2090 M FOR 2

OKV = -1947 M FOR 3 OG 4

Table 11

Amundsen, Statfjord, Triàs Reserves

Fault Block	Formation /Unit	GROSS ROCK VOL. $10^6 M^3$		HCPV $10^6 M^3$		RECOVERABLE OIL RES. $10^6 m^3$		RECOVERABLE GAS RES. $10^9 Sm^3$
1	Amundsen	-	95	-	11	-	2.8	0.6
1	Statfjord Unit 3	177	559	33	84	9.3	23.6	4.8
1	Statfjord Unit 2	282		41		11.5		
1	Statfjord Unit 1	100		10		2.8		
1	Trias	-	100	-	2	-	0.5	-
2 A	Statfjord Unit 3	71	89	11	14	3.1	3.9	0.8
2 A	Statfjord Unit 2	18		3		0.8		
2 A	Statfjord Unit 1							
2 C,D	Statfjord Unit 3	42	56	7	9	2	2.5	0.5
2 C,D	Statfjord Unit 2	14		2		0.5		
3	Statfjord Unit 3	5	5	1	1	0.3	0.3	-
Total Statfjord Reserves.		295	709	52	108	14.7	30.3	6.2
		314		46		12.8		
		100		10		2.8		
Total Reserves in Amundsen Statfjord and Trias.							33.6	7.2

Table 12 Total Reserves

	Gross Rock Vol $10^6 m^3$	HCPV $10^6 m^3$	Recoverable Reserves*	
			oil $10^6 m^3$	gas $10^9 m^3$
Brent	2664	475	168.5 (190)	16.9 (19)
Cook	1104	140	40 (40)	5.3 (5)
Amundsen	95	11	3 (0)	0.6 (0)
Statfjord	709	108	30 (2.4)	6.2 (0)
Trias	100	2	0.5 (0)	- (0)
Total	4672	736	242 (230)	29 (24)

* ( ) reserve estimates from November 1980.

Table 13

ESTIMATE OF PROVEN AND POSSIBLE RESERVES

Reserves / Reservoir	Proven reserves		Possible additional		Total	
	Oil $10^6 m^3$	Gas $10^9 m^3$	Oil $10^6 m^3$	Gas $10^9 m^3$	Oil $10^6 m^3$	Gas $10^9 m^3$
Brent	135 (135)	13 (13)	34.5 (55)	4 (6)	168.5 (190)	17 (19)
Cook	10 (8)	1 (1)	30 (32)	4 (4)	40 (40)	5 (5)
Amundsen Statfjord Triassic	16 (-)	3 (-)	17.5 (2)	4 (-)	33.5 (2)	7 (-)
Total	161 (143)	17 (14)	82 (89)	12 (10)	242 (230)	29 (24)

( ) Reserve estimates in commerciality report November 1980.

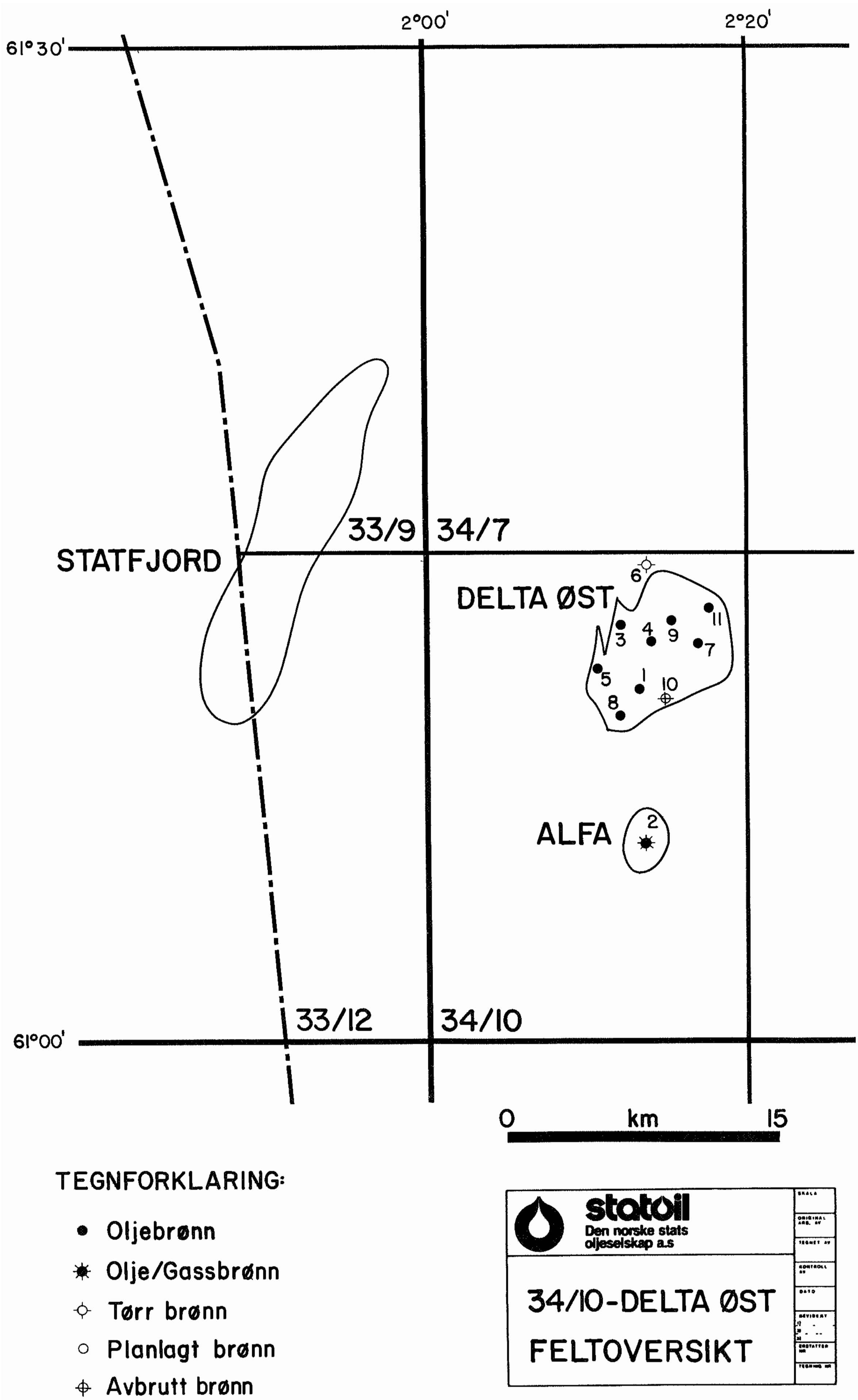

2°00'
2°20'
61°30'
STATFJORD
33/9
34/7
DELTA ØST
6
3
4
9
11
7
5
1
10
8
ALFA
2
33/12
34/10
61°00'
0
km
15
TEGNFORKLARING:
Oljebrønn
Olje/Gassbrønn
Tørr brønn
Planlagt brønn
Avbrutt brønn
statoil
Den norske stats oljeselskap a.s
34/10-DELTA ØST
FELTOVERSIKT

Fig. 1

34/10-11

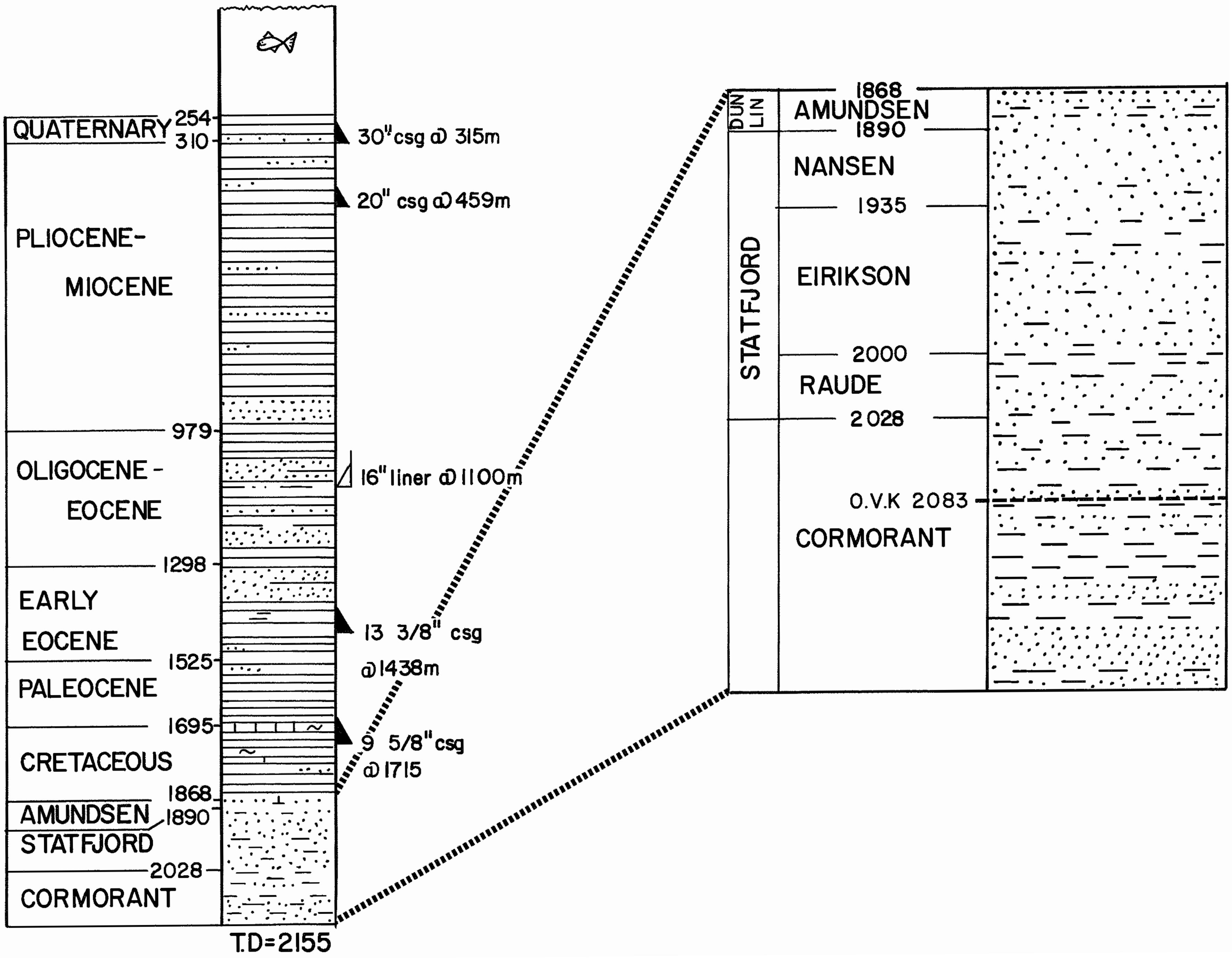

QUATERNARY
254
310
30" csg @ 315m
20" csg @ 459m
PLIOCENE-
MIOCENE
979
OLIGOCENE -
EOCENE
16" liner @ 1100m
1298
EARLY
EOCENE
13 3/8" csg
@ 1438m
1525
PALEOCENE
1695
9 5/8" csg
@ 1715
CRETACEOUS
1868
AMUNDSEN
1890
STATFJORD
2028
CORMORANT
T.D=2155
DUN
LIN
STATFJORD
1868
AMUNDSEN
1890
NANSEN
1935
EIRIKSON
2000
RAUDE
2028
O.V.K 2083
CORMORANT

Fig. 2

34/10-DELTA ØST

STRUKTURELL PROFIL

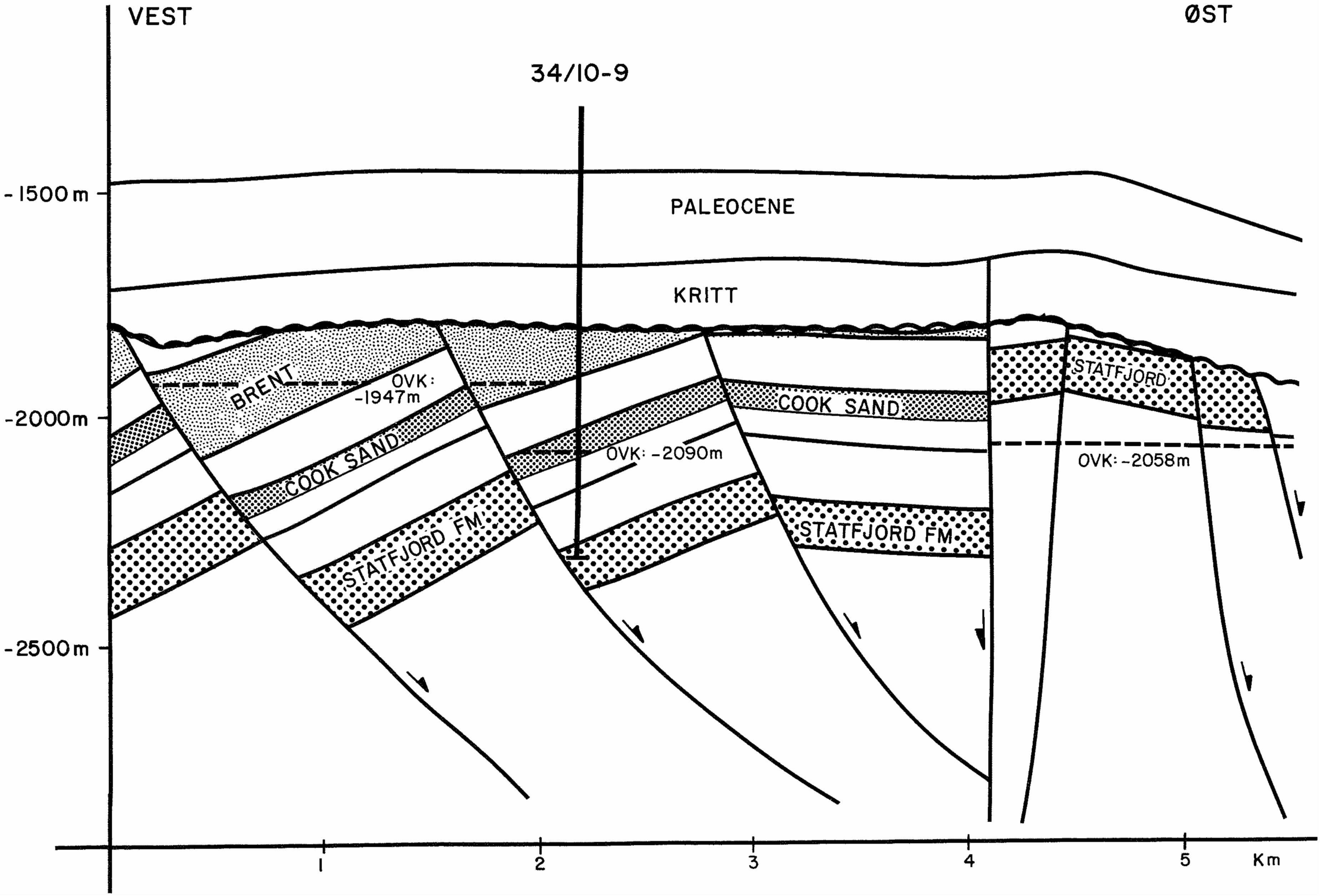
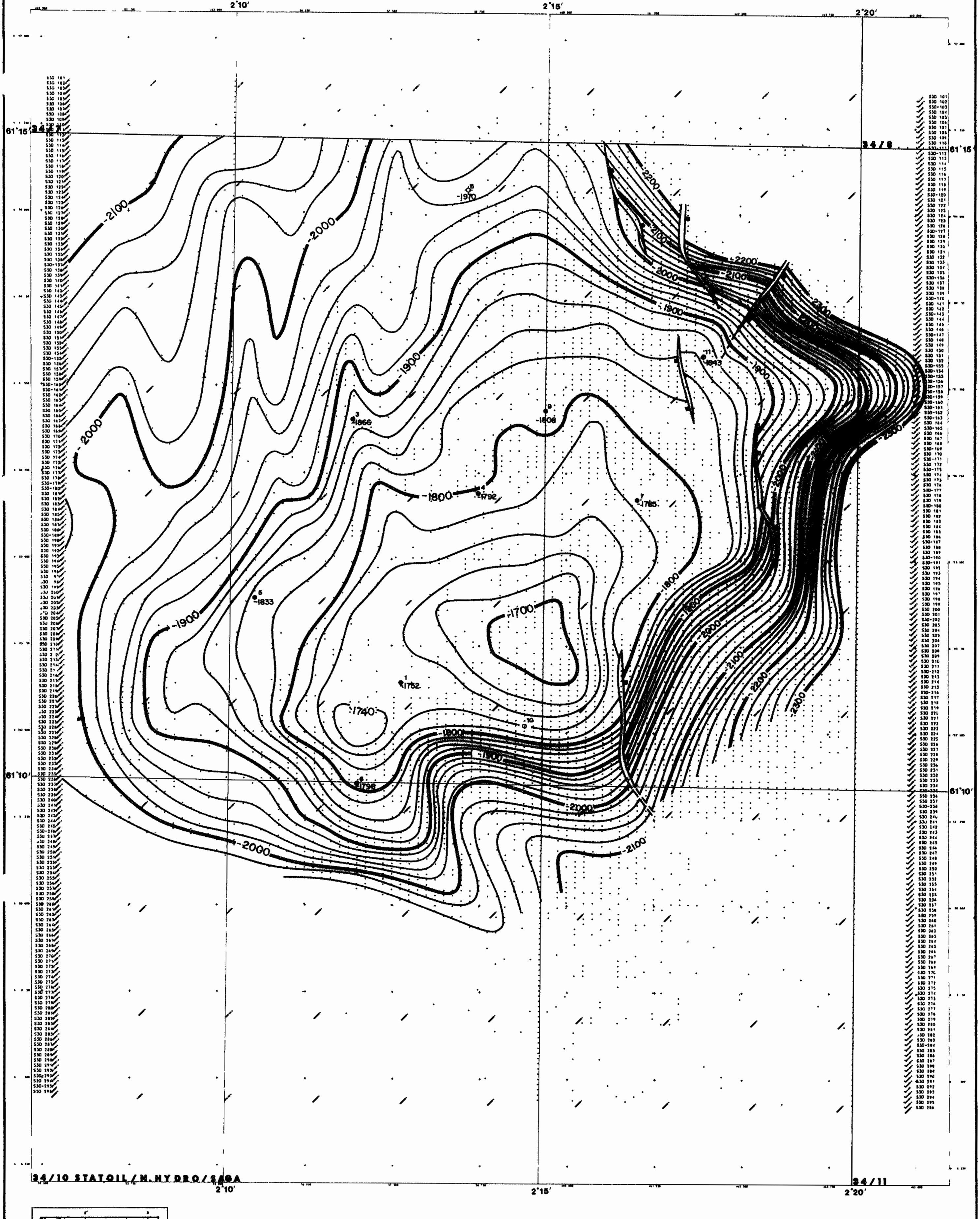
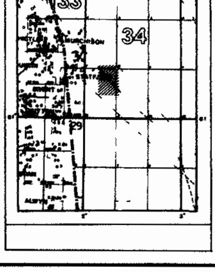


Fig. 3





0 1 km 2,5

1:

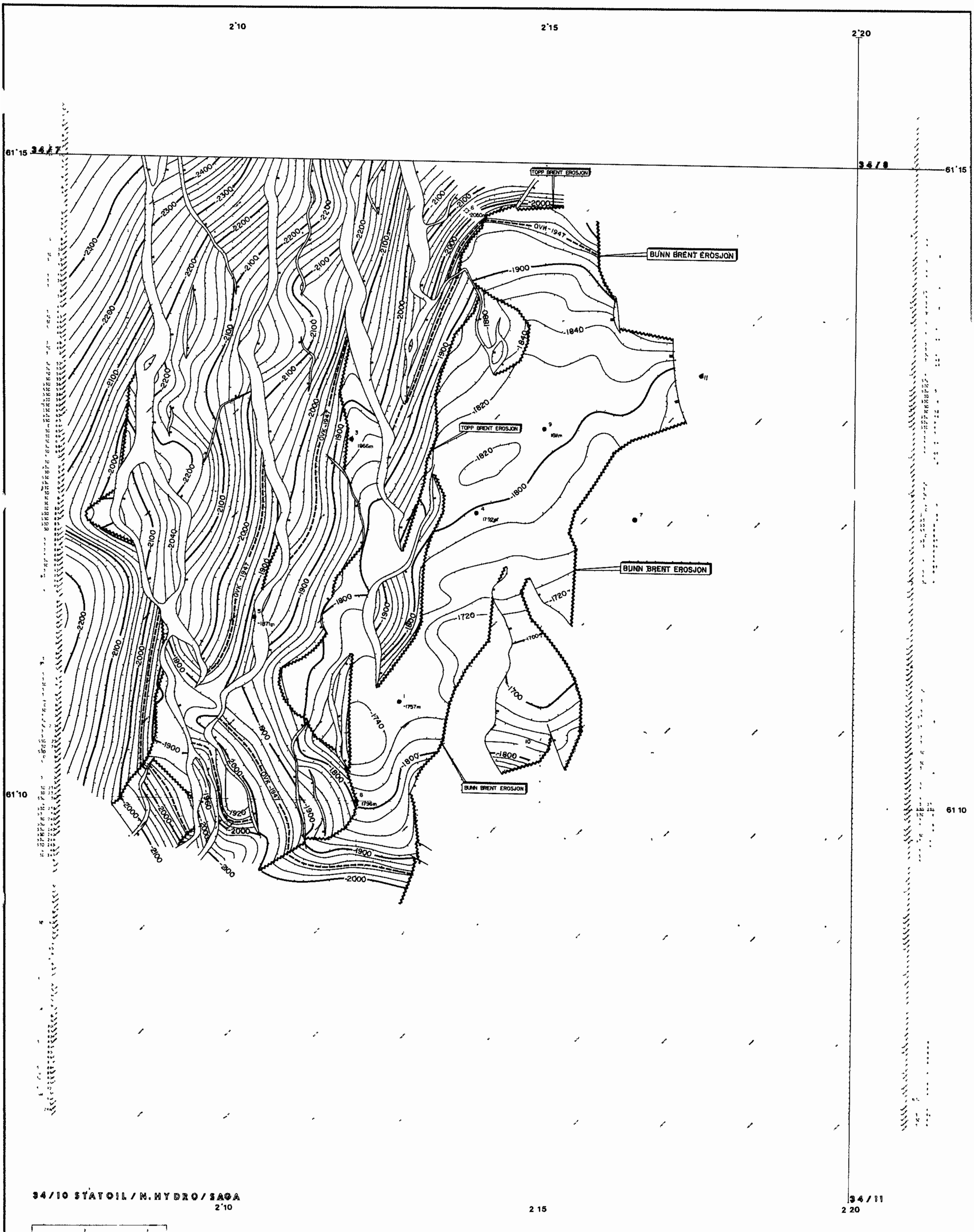
Fig. 4

TOLKNING 3-D SEISMIKK
DYBDEKONVERTERING
GJENNOMSNITTSHASTIGHET
HAVNIVÅ TIL TOPP JURA

statoil
Den norske stats oljeselskap a.s

34/10 - DELTA ØST
TOPP JURA
Strukturelt dybdekart
Dyp i meter fra havnivå
K I = 20 m GTS/GSS

GrH



0 1 km 2,5

1:

Fig. 5

statoil
Den norske stats oljeselskap a.s

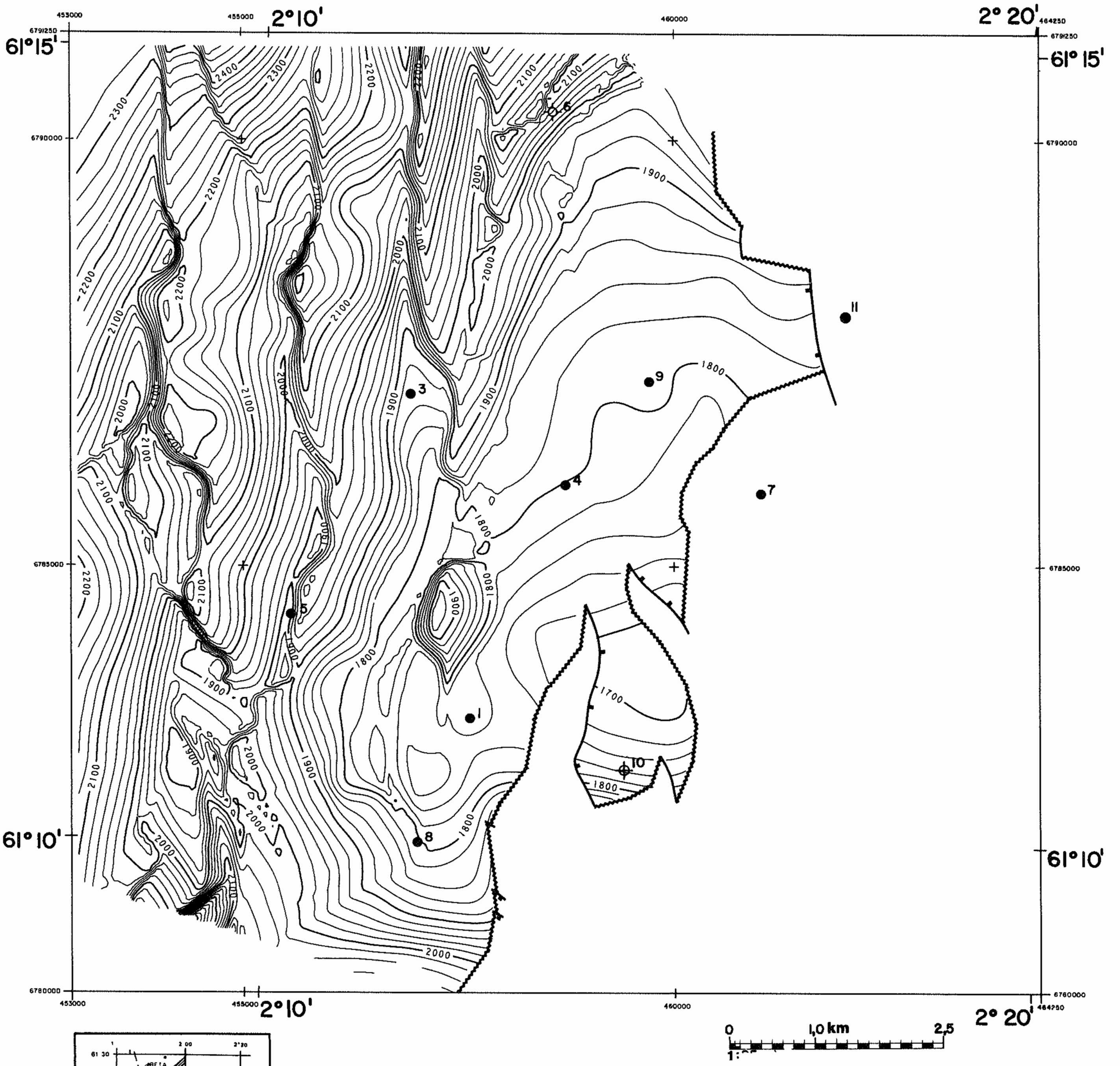
Blokk 34/10 - Delta Øst

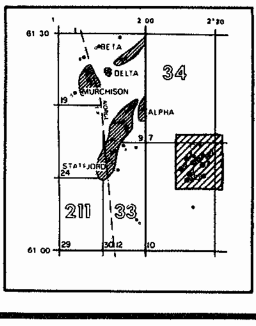
TOPP BRENT

Strukturelt dybdekart

25000

22 5 81





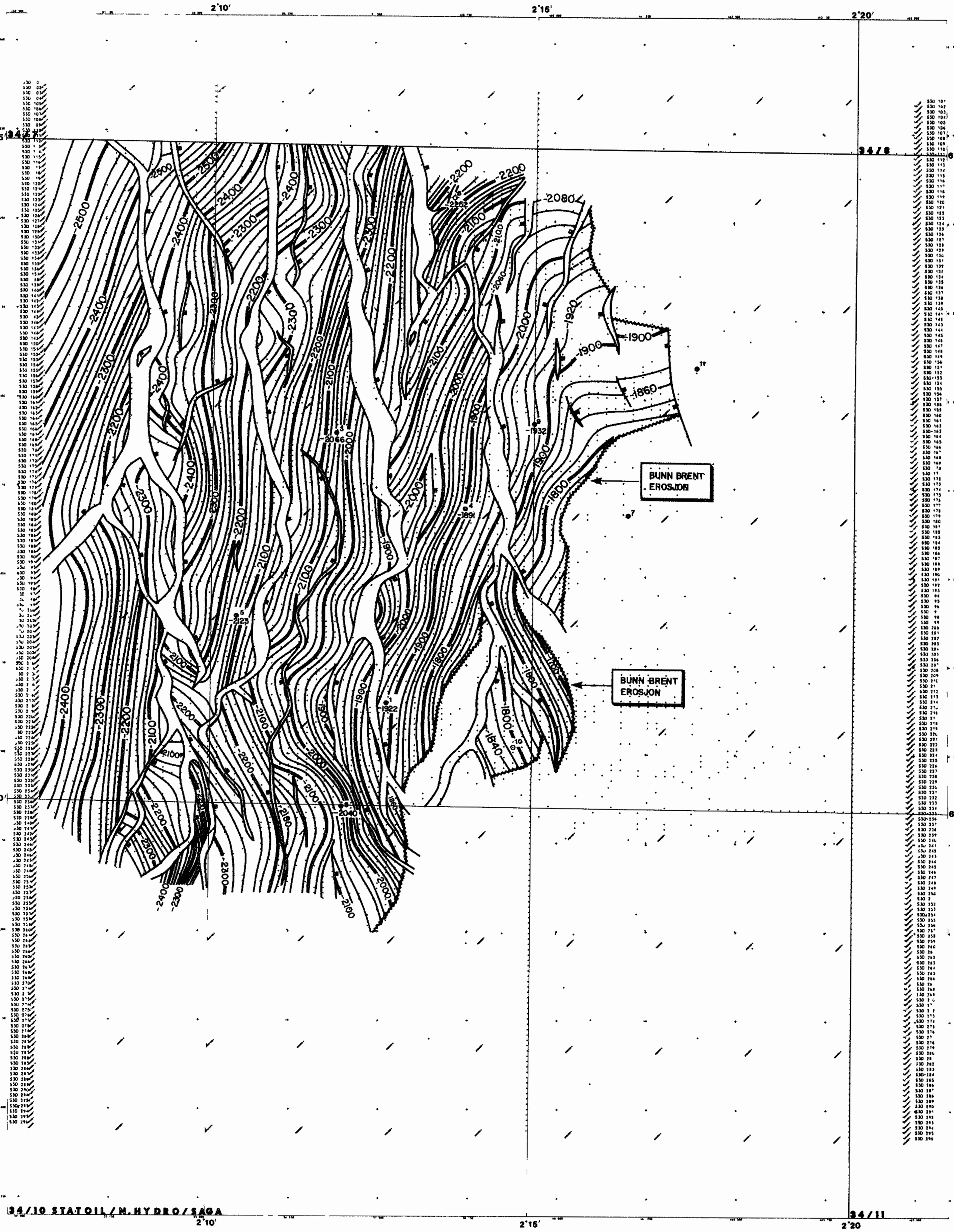
* Se også håndkonturert dybdekart for Topp Brent

statoil
Den norske stats oljeselskap a.s

34/10 - DELTA ØST
TOPP BRENT
Strukturelt dybdekart
* EDB konturert
Benyttet for volumberegning
K I 20 m
K Grindstad / A Storli

Skala	1:25 000
Original arb. av	KCG/ASI
Tegnet av	GrH
Dato	18-5-81
Tegning nr.	X-03806

Fig. 6



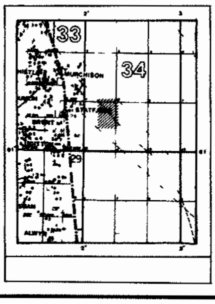
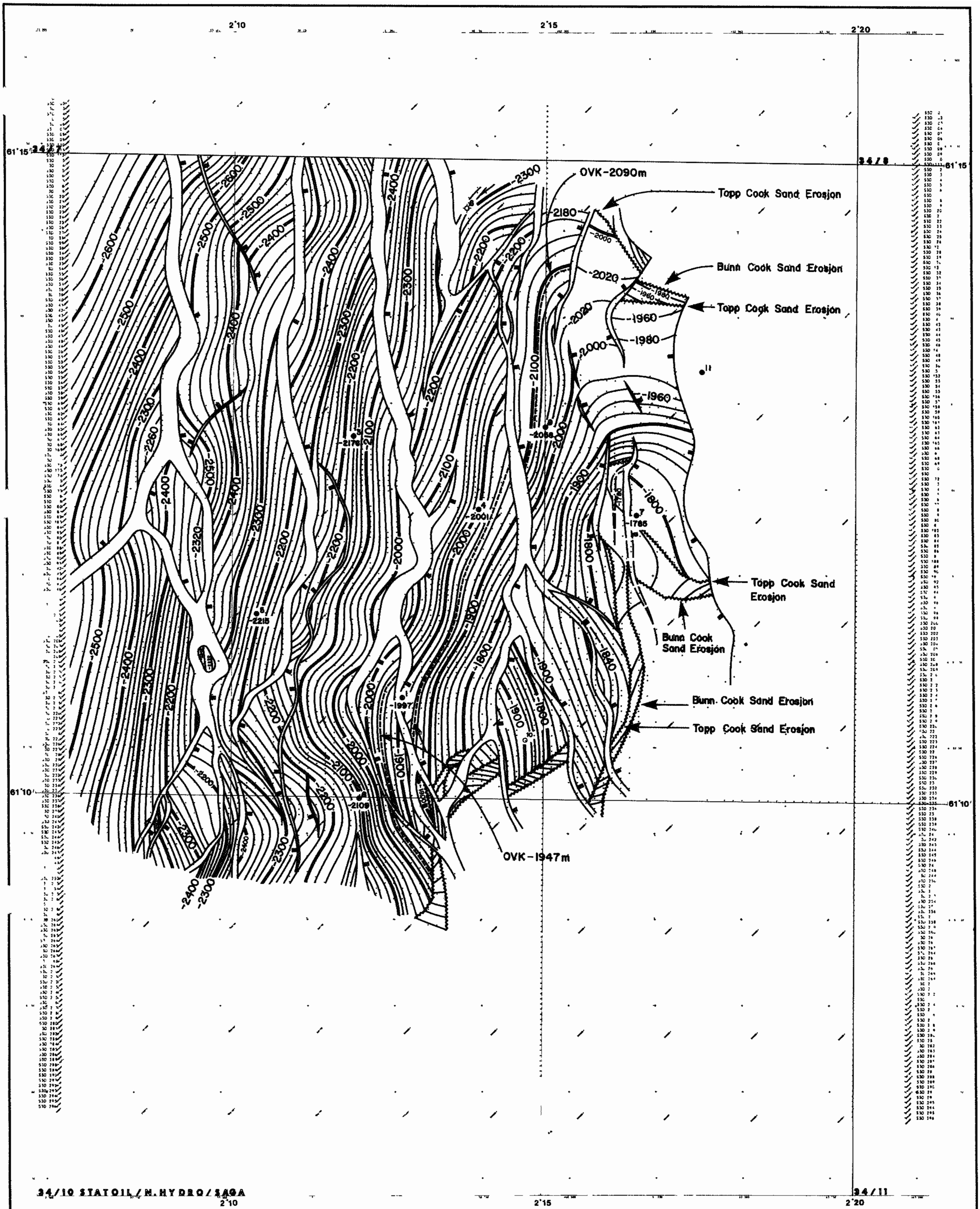


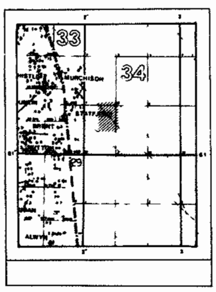
Fig. 7

statoil
Den norske stats oljeselskap a.s

34/10 - DELTA ØST
BUNN BRENT
Strukturelt dybdekart

K I = 20m GSS/GTS





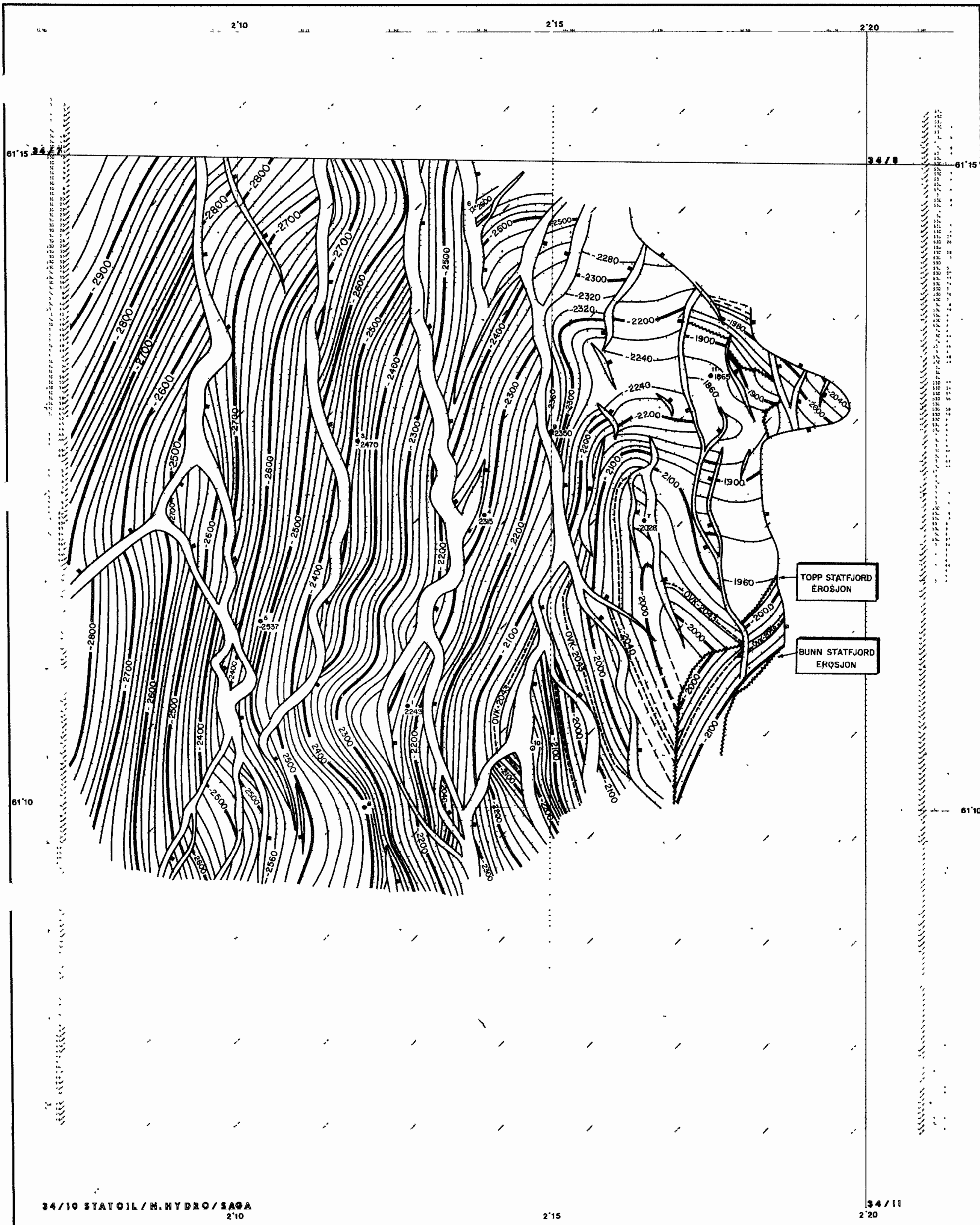
0 1 km 2,5

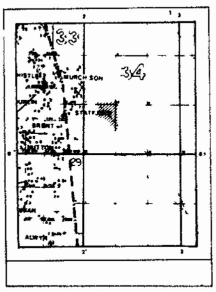
1:

Fig. 8

statoil
Den norske stats oljeselskap a.s

34/10 - DELTA ØST
TOPP COOK SAND
Strukturelt dybdekart
K.I = 20m
GSS/GTS





0 km 2,5

1:

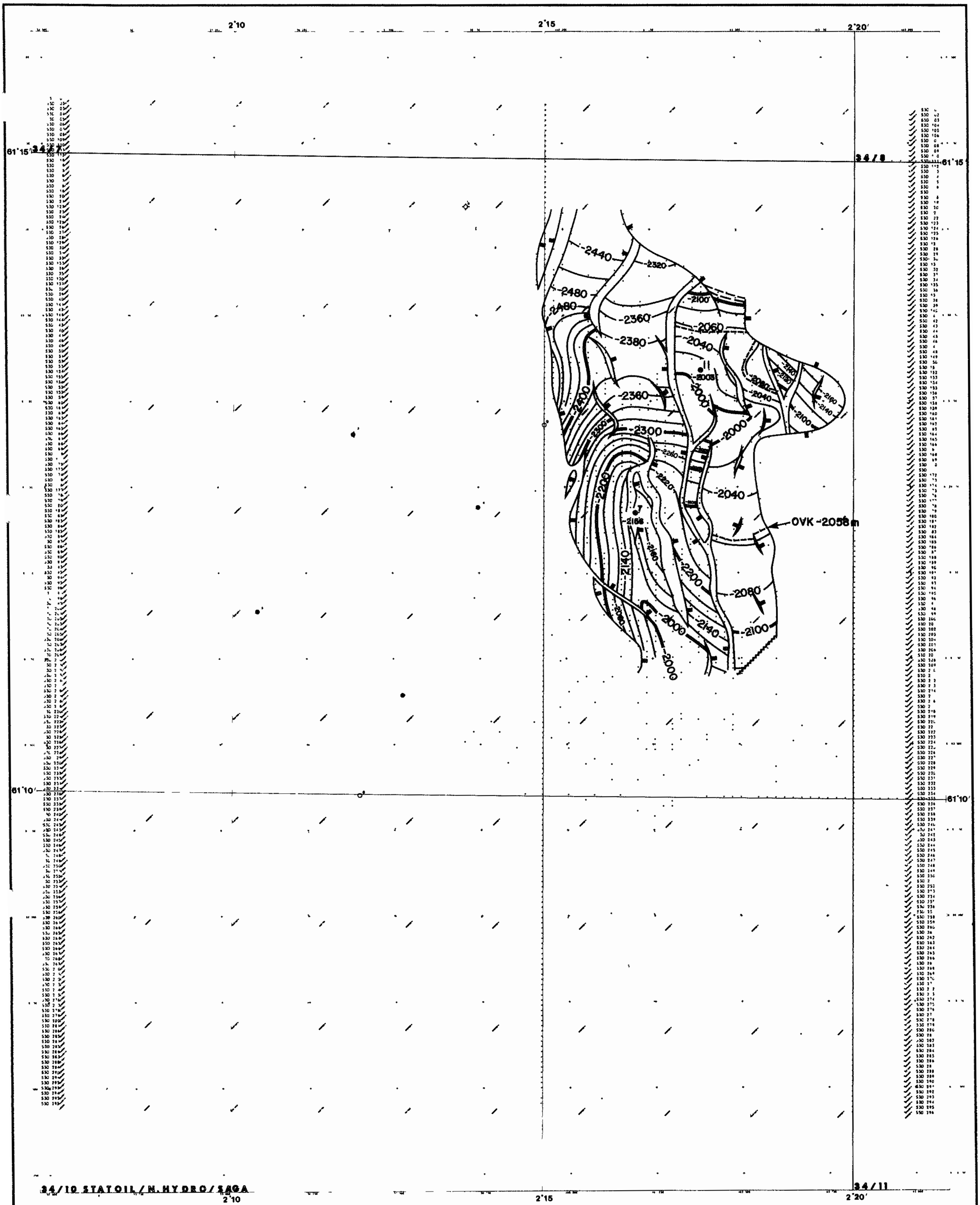
Fig. 9

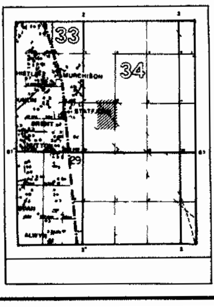
statoil
Den norske stats oljeselskap a.s

34/10 - DELTA ØST
TOPP STATFJORD
Strukturelt dybdekart

K I = 20 m GSS/GTS

GrH
9 4-85





0 1 km 2,5

1:

Fig. 10

statoil
Den norske stats oljeselskap a.s

34/10 DELTA ØST

TOPP TRIAS

Strukturelt dybdekart

K.I. = 20 m GSS/GTS

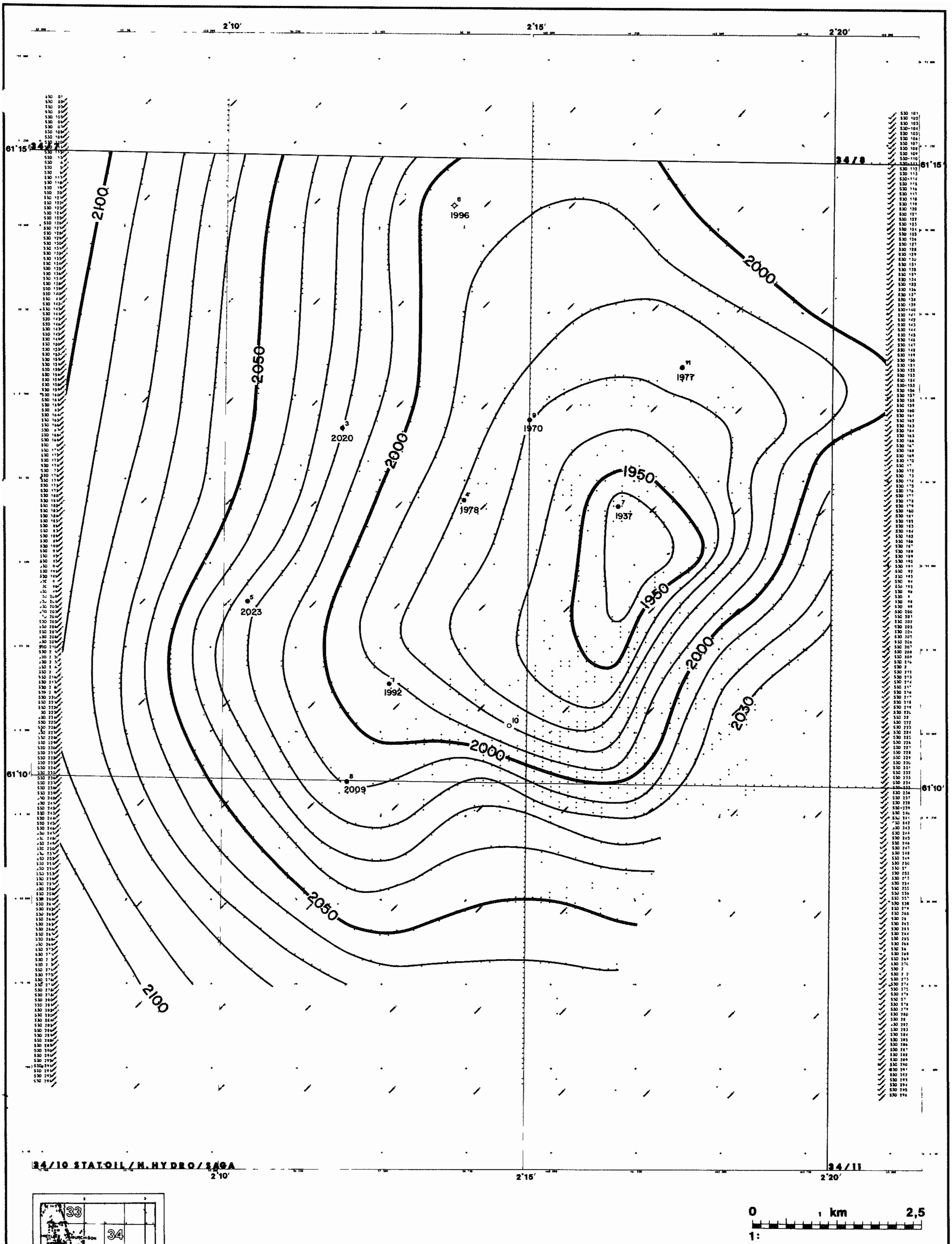


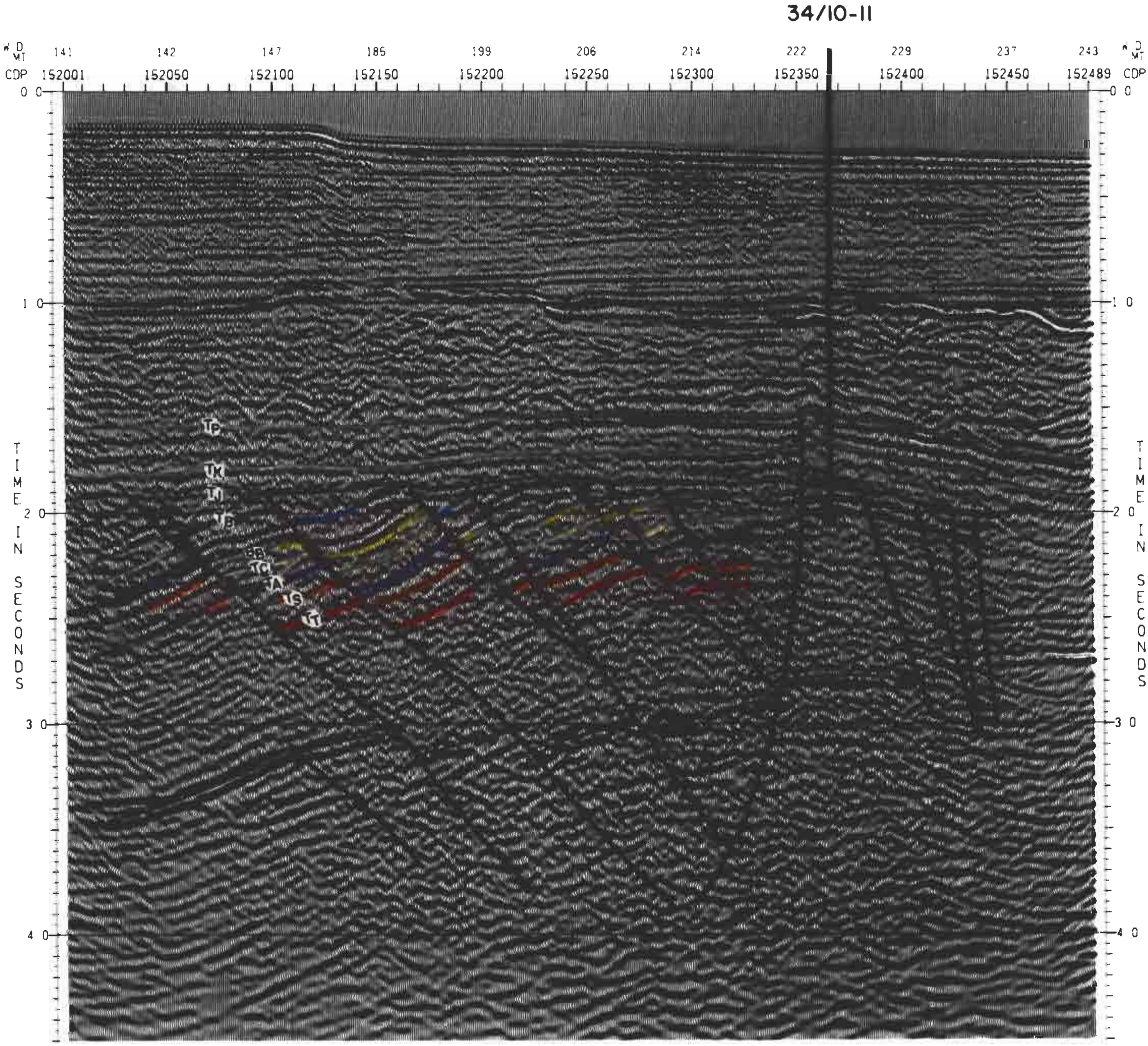
Fig. 11

statoil
Den norske stats oljeselskap a.s

34/10-DELTA ØST
TOPP JURA
GJENNOMSNITTS HASTIGHET
DATUM HAVNIVÅ
K I = 10 m/s
GTS/GSS

34/10-DELTA EAST

TRACK S3D-152

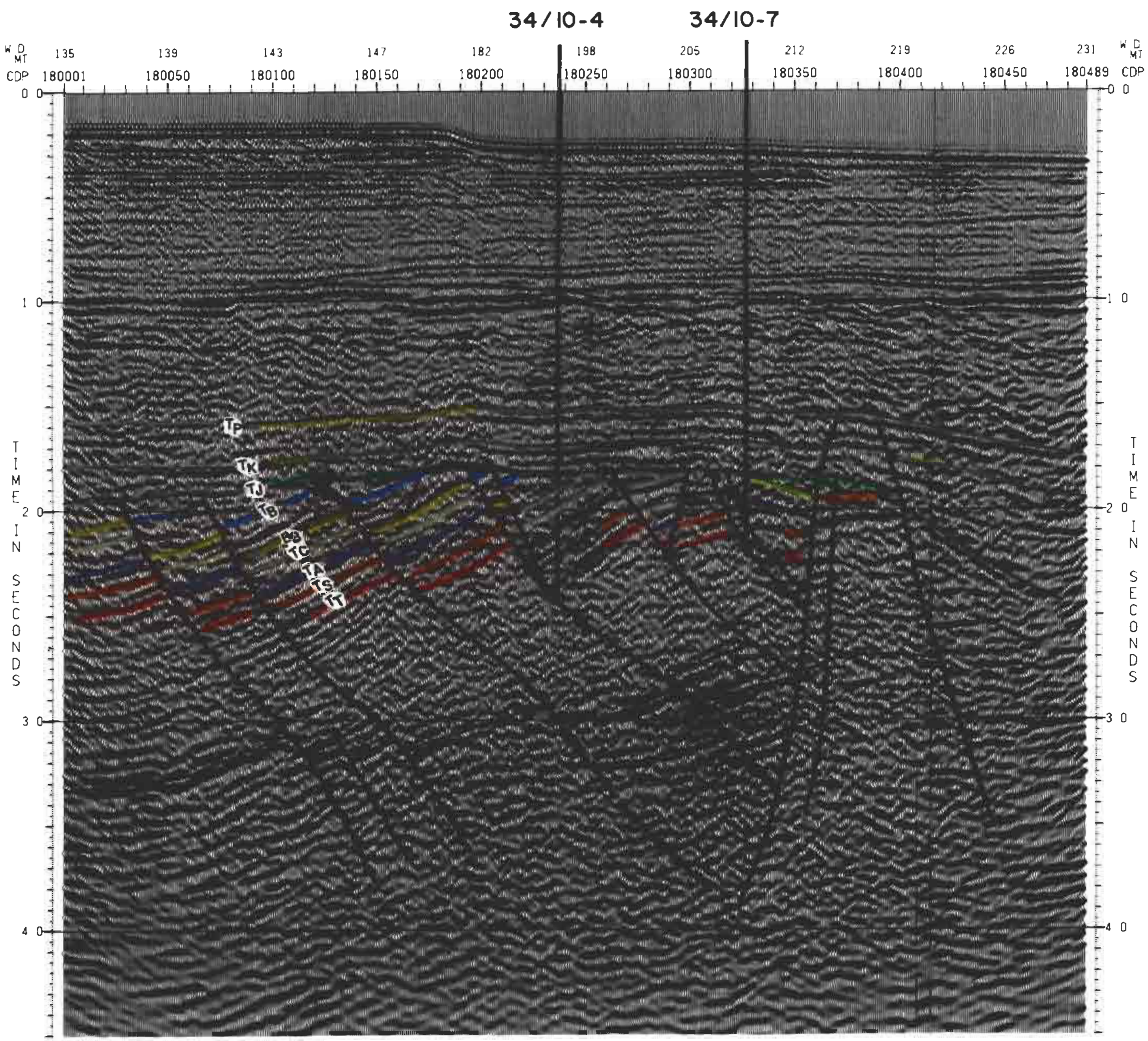


KODE:

T_P	Topp Paleocene	T_C	Topp Cook
T_K	Topp Kritt	T_A	Topp Amundsen
T_J	Topp Jura	T_S	Topp Statfjord
T_B	Topp Brent	T_T	Topp Trias
B_B	Bunn Brent		

Fig. 12

34/[redacted]0-DELTA EAST TRACK S3D-[redacted]0

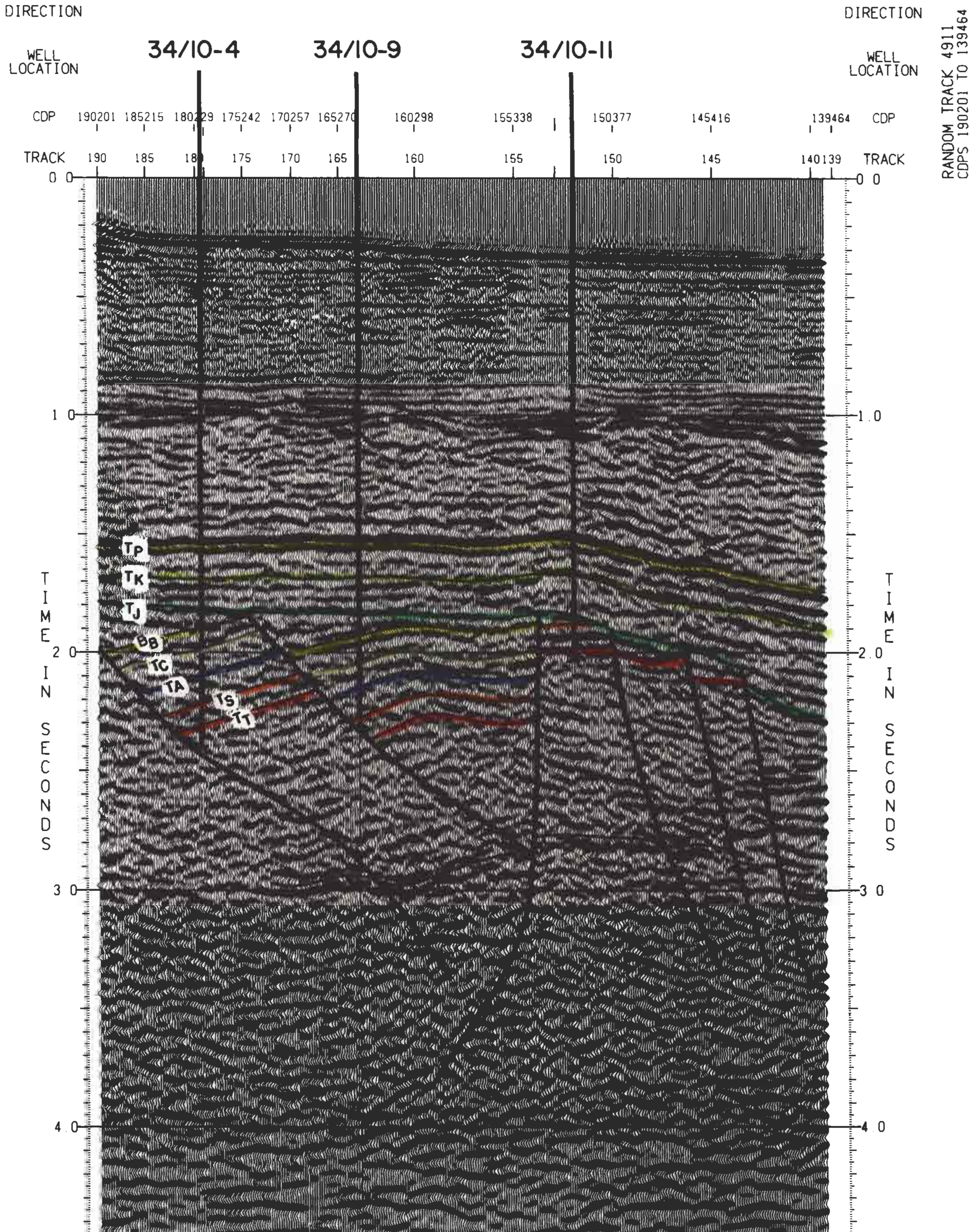


KODE:

T_P	Topp Paleocene	T_C	Topp Cook
T_K	Topp Kritt	T_A	Topp Amundsen
T_J	Topp Jura	T_S	Topp Statfjord
T_B	Topp Brent	T_T	Topp Trias
B_B	Bunn Brent		

Fig. 13

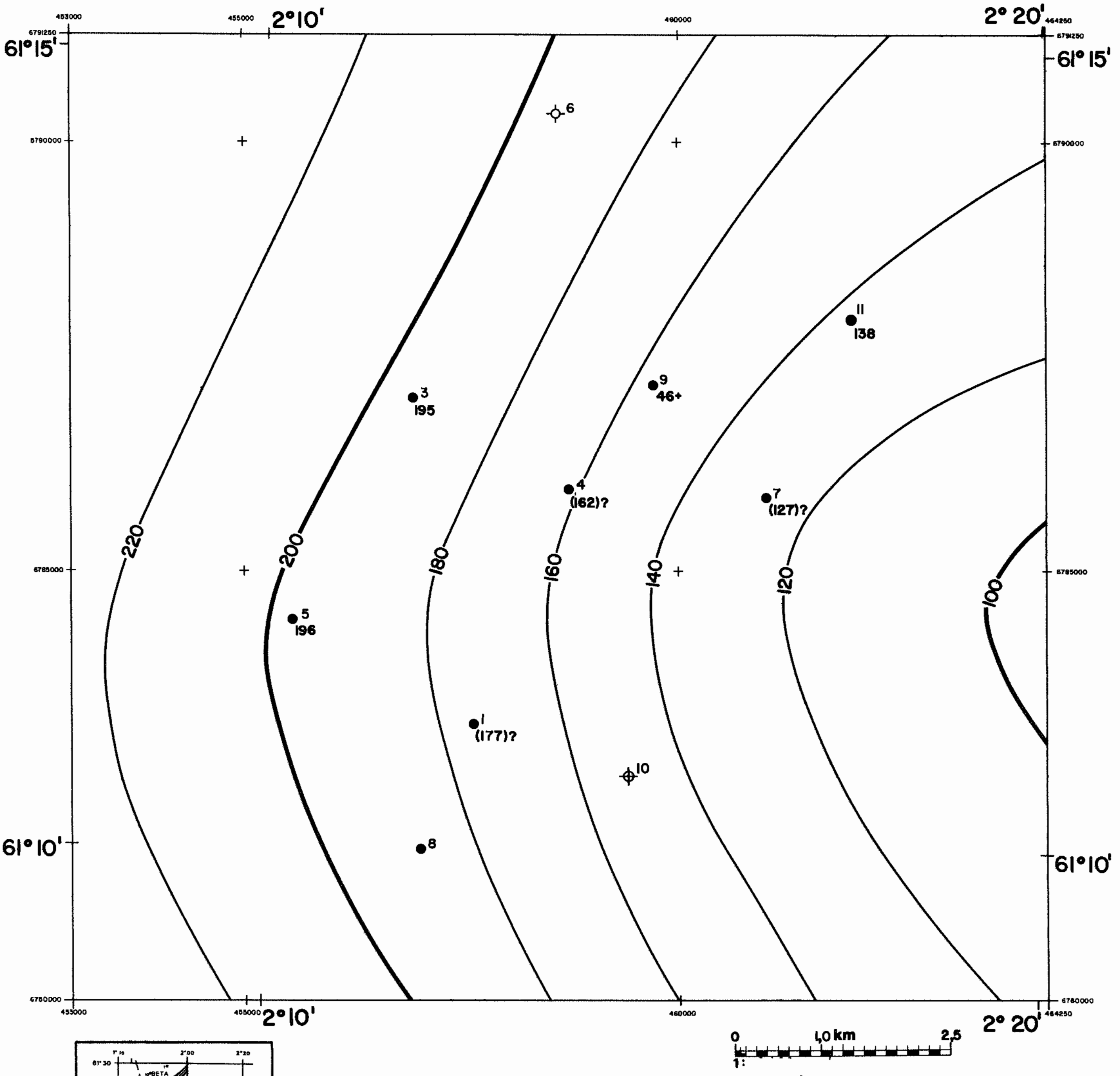
34/10-DELTA EAST
RANDOM TRACK 4911

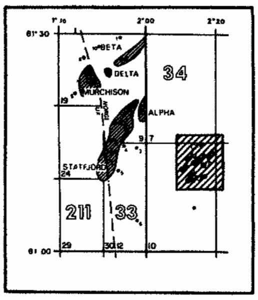


KODE:

T_P	Topp Paleocene	T_C	Topp Cook
T_K	Topp Kritt	T_A	Topp Amundsen
T_J	Topp Jura	T_S	Topp Statfjord
T_B	Topp Brent	T_T	Topp Trias
B_B	Bunn Brent		

Fig. 14





NB. STATFJORD-FM. ER ANTATT
Å VÆRE GJENNOMSKÅRET AV
FORKASTNINGER I BRØNNENE
34/10-1, 4 OG 7. ESTIMERT
FULL TYKKELSE ER GITT I PARENTES.

statoil
Den norske stats oljeselskap a.s

34/10-DELTA ØST
STATFJORD FORM.
ISOPAK TOTAL TYKKELSE
(Opprinnelig tykkelse)
K.I = 20m

AsH
J.I.
17/3-81

Fig. 16

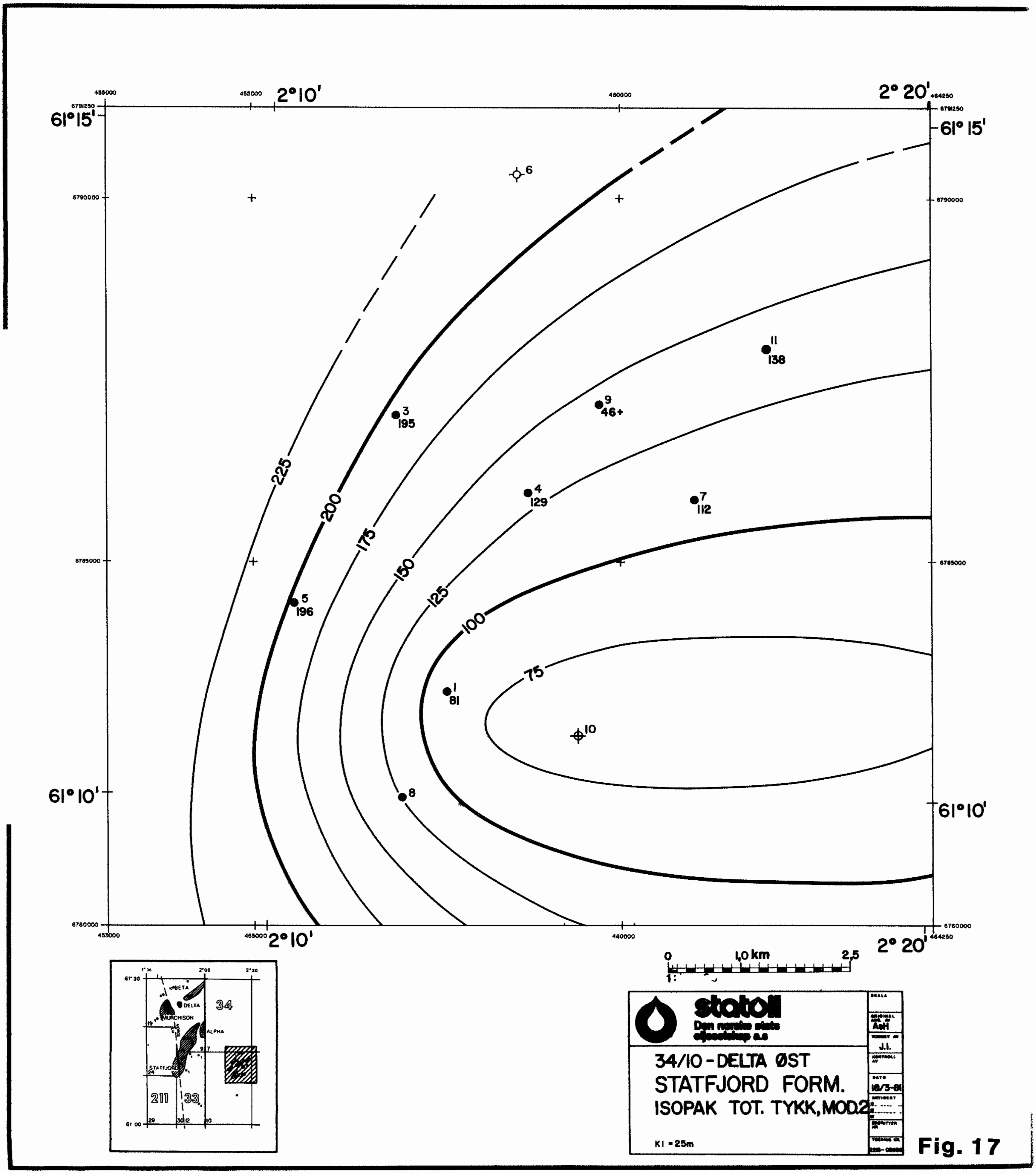
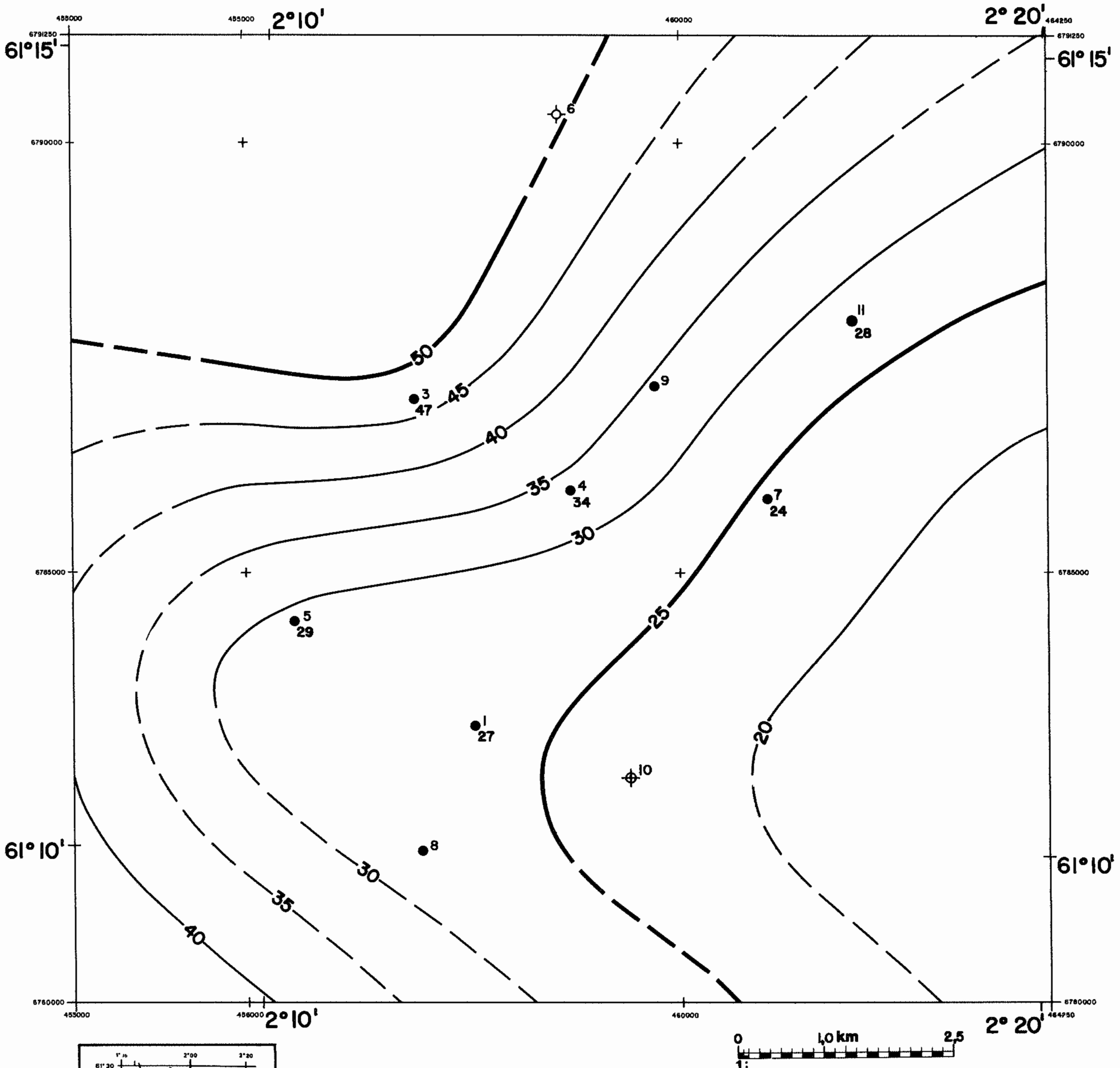
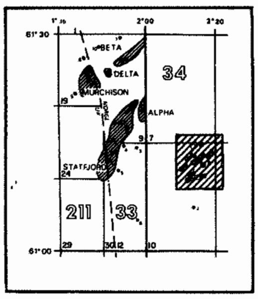

2°10'
2° 20'
61°15'
61°10'
225
200
175
150
125
100
75
3
195
5
196
4
129
9
46+
11
138
7
112
1
81
6
10
8
0
1,0 km
2,5
34
211
33
BETA
DELTA
MURCHISON
ALPHA
STATFJORD
statoil
Den norske stats oljeselskap a.s
34/10 - DELTA ØST
STATFJORD FORM.
ISOPAK TOT. TYKK, MOD.2
KI = 25m
AsH
J.I.

Fig. 17





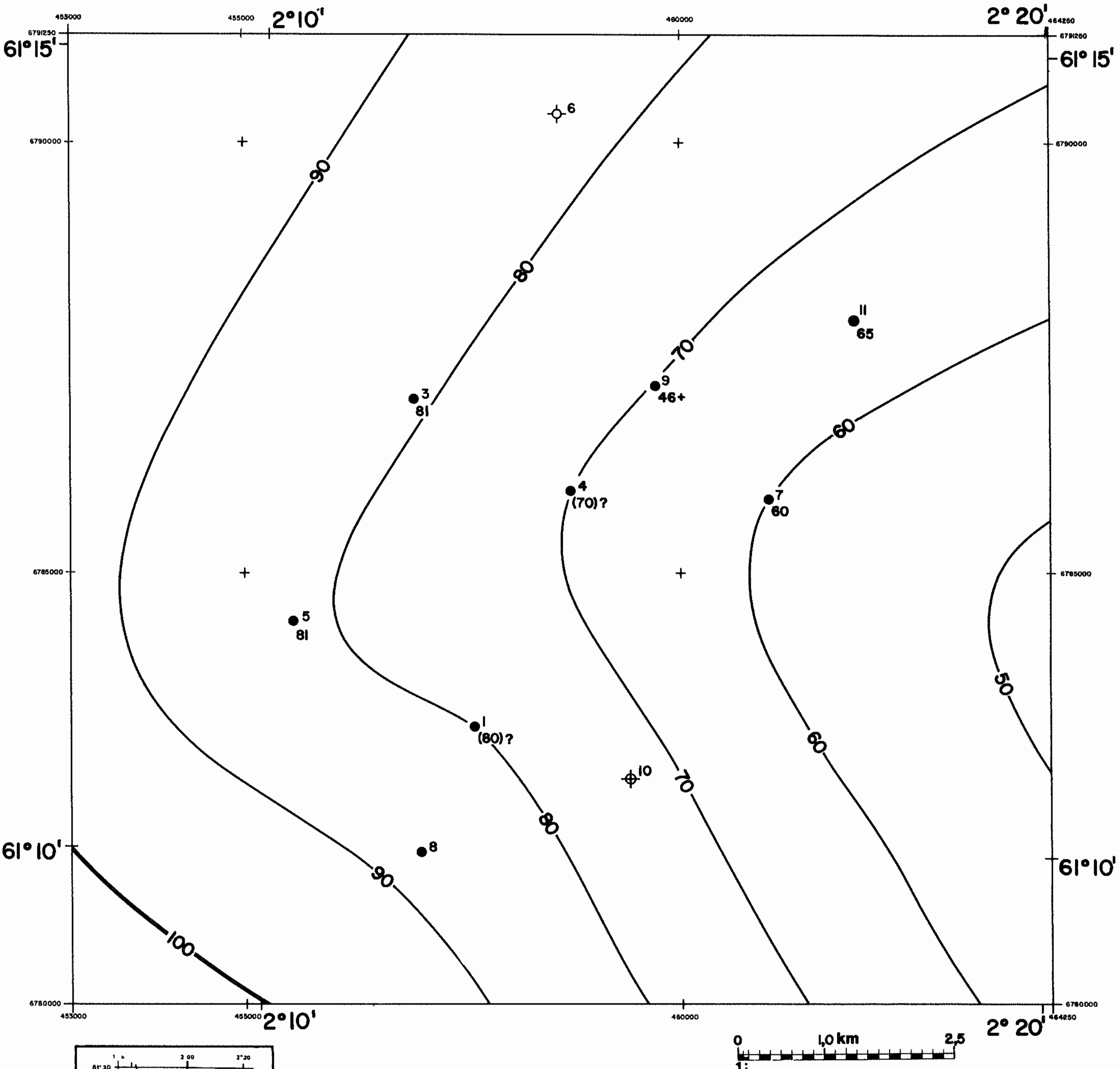
statoil
Den norske stats oljeselskap a.s

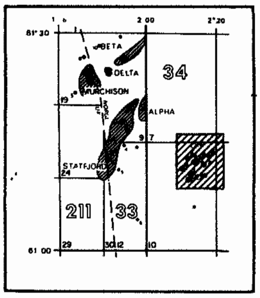
34/10 - DELTA ØST
STATFJORD FORM.
ISOPAK ENHET I

(Opprinnelig tykkelse)
KL = 5m

SKALA	
ORIGINAL UTF. AV	AsH
TEGNET AV	J.I.
KONTROLL AV	
DATO	17/3-81
REVIDERT	
ERSTATTER NR	
TEGNING NR	2213-03694

Fig. 18





NB: DENNE ENHETEN ER ANTATT Å VÆRE GJENNOMSKÅRET AV FORKASTNINGER I BRØNNENE 34/10-1 OG 4, ESTIMERT FULL TYKKELSE ER GITT I PARENTES.

statoil
Den norske stats oljeselskap a.s

34/10 - DELTA ØST
STATFJORD FORM.
ISOPAK ENHET 2
(Opprinnelig tykkelse)
KI = 10m

AsH.
J.I.
16/3-81

Fig. 19

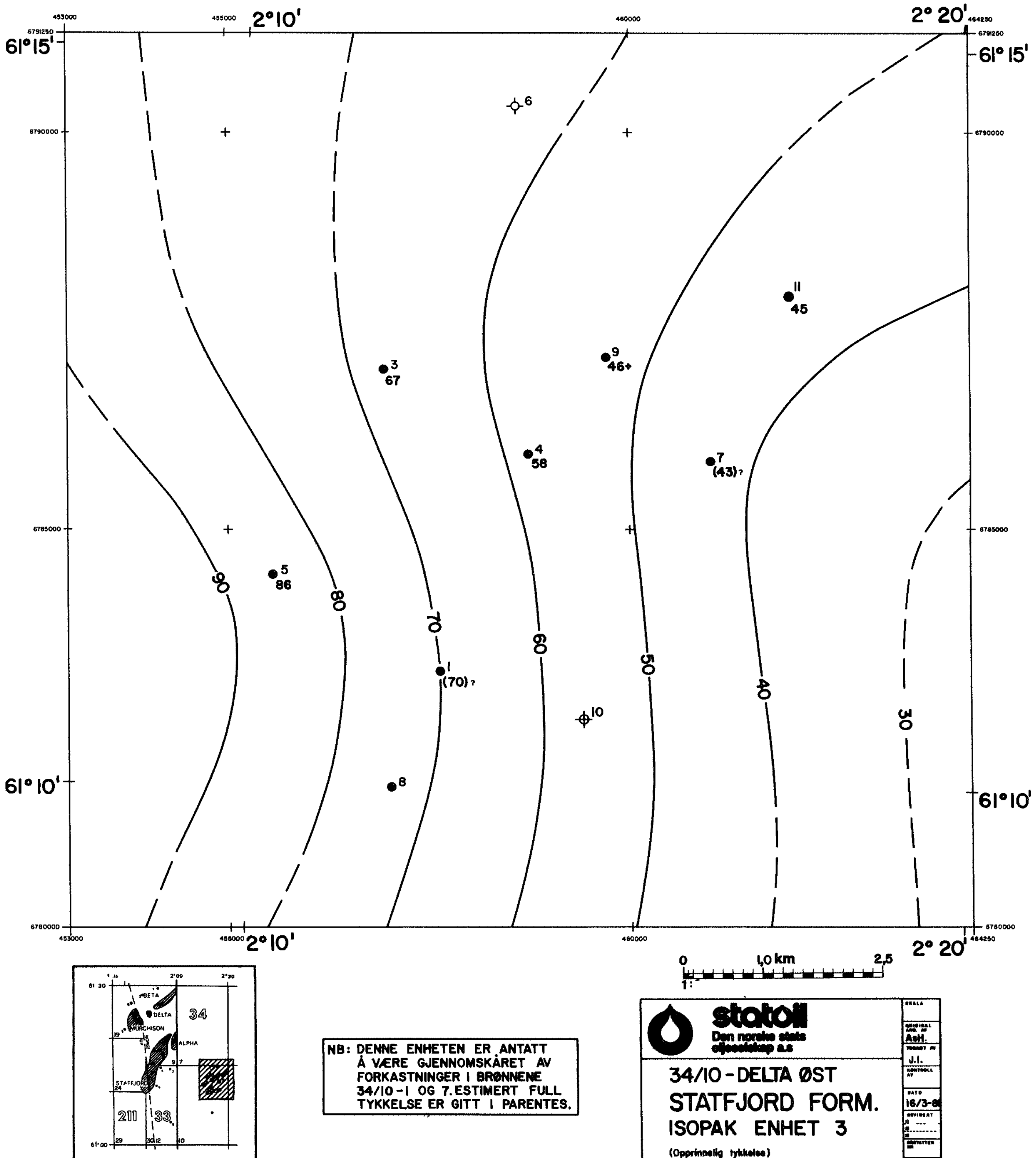
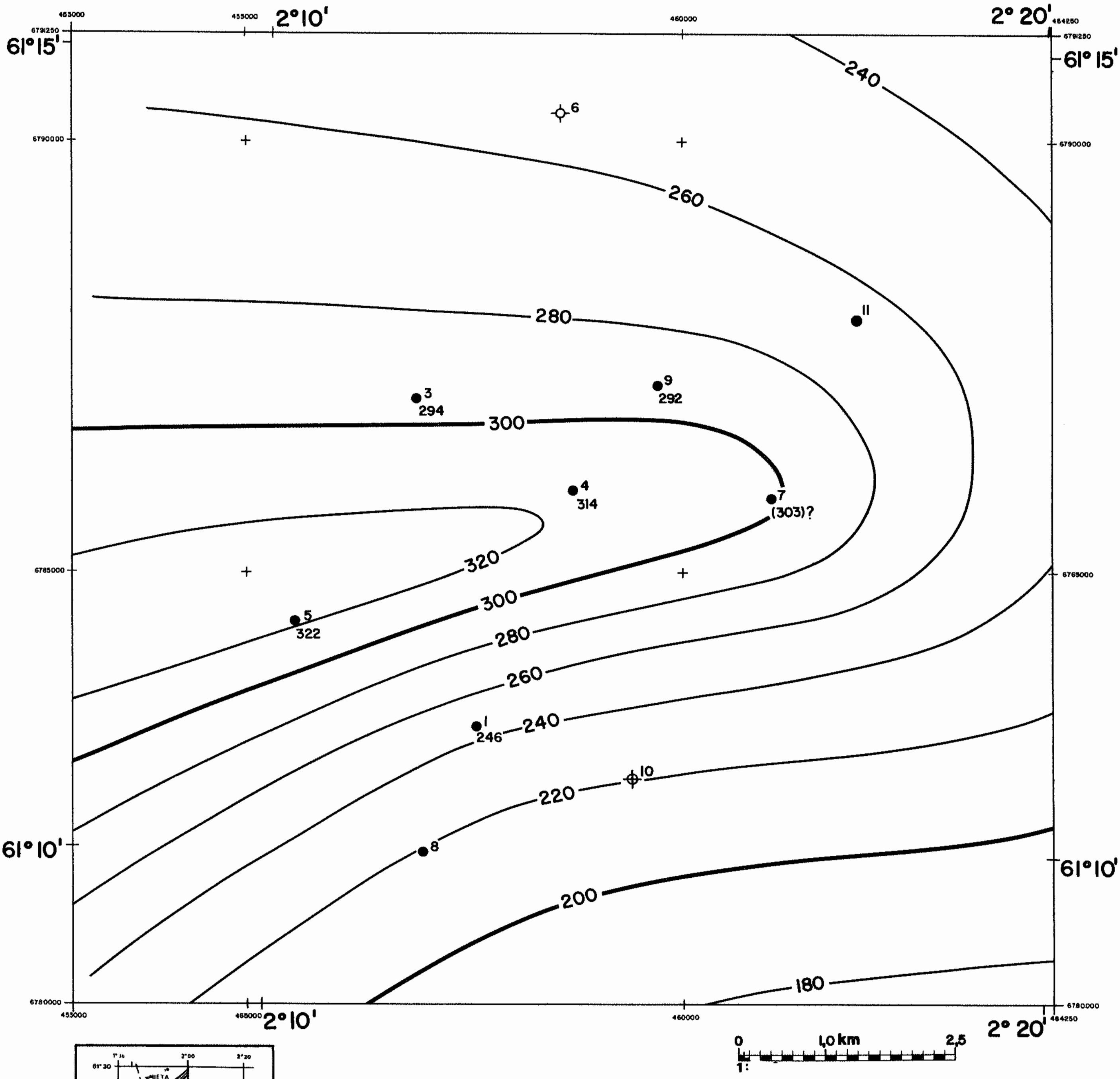
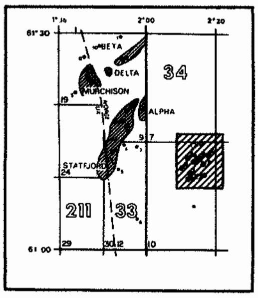

2°10'
2° 20'
61°15'
61°10'
453000
455000
460000
464250
6791250
6790000
6785000
6780000
90
80
70
60
50
40
30
5
86
3
67
1
(70)?
8
4
58
6
9
46+
10
11
45
7
(43)?
0
1,0 km
2,5
34
211
33
DELTA
BETA
MURCHISON
ALPHA
STATFJORD
NB: DENNE ENHETEN ER ANTATT Å VÆRE GJENNOMSKÅRET AV FORKASTNINGER I BRØNNENE 34/10-1 OG 7. ESTIMERT FULL TYKKELSE ER GITT I PARENTES.
statoil
Den norske stats oljeselskap a.s
34/10-DELTA ØST
STATFJORD FORM.
ISOPAK ENHET 3
(Opprinnelig tykkelse)
KI 10m
AsH.
J.I.

Fig. 20





NB : DEN NEDRE DELEN AV DUNLIN-GRUPPEN ER ANTATT Å VÆRE GJENNOMSKÅRET AV FORKASTNING I BRØNN 34/10-7 ESTIMERT FULL TYKKELSE ER GITT I PARANTES

statoil
Den norske stats oljeselskap a.s

34/10 - DELTA ØST
DUNLIN - GRUPPEN
ISOPAK TOPP COOK - TOPP STATFJORD
K I 20 m

SKALA 1:25000
TEGNET AV GrH
DATO 16-3-81

Fig. 21

SPECIAL CORE DESCRIPTION

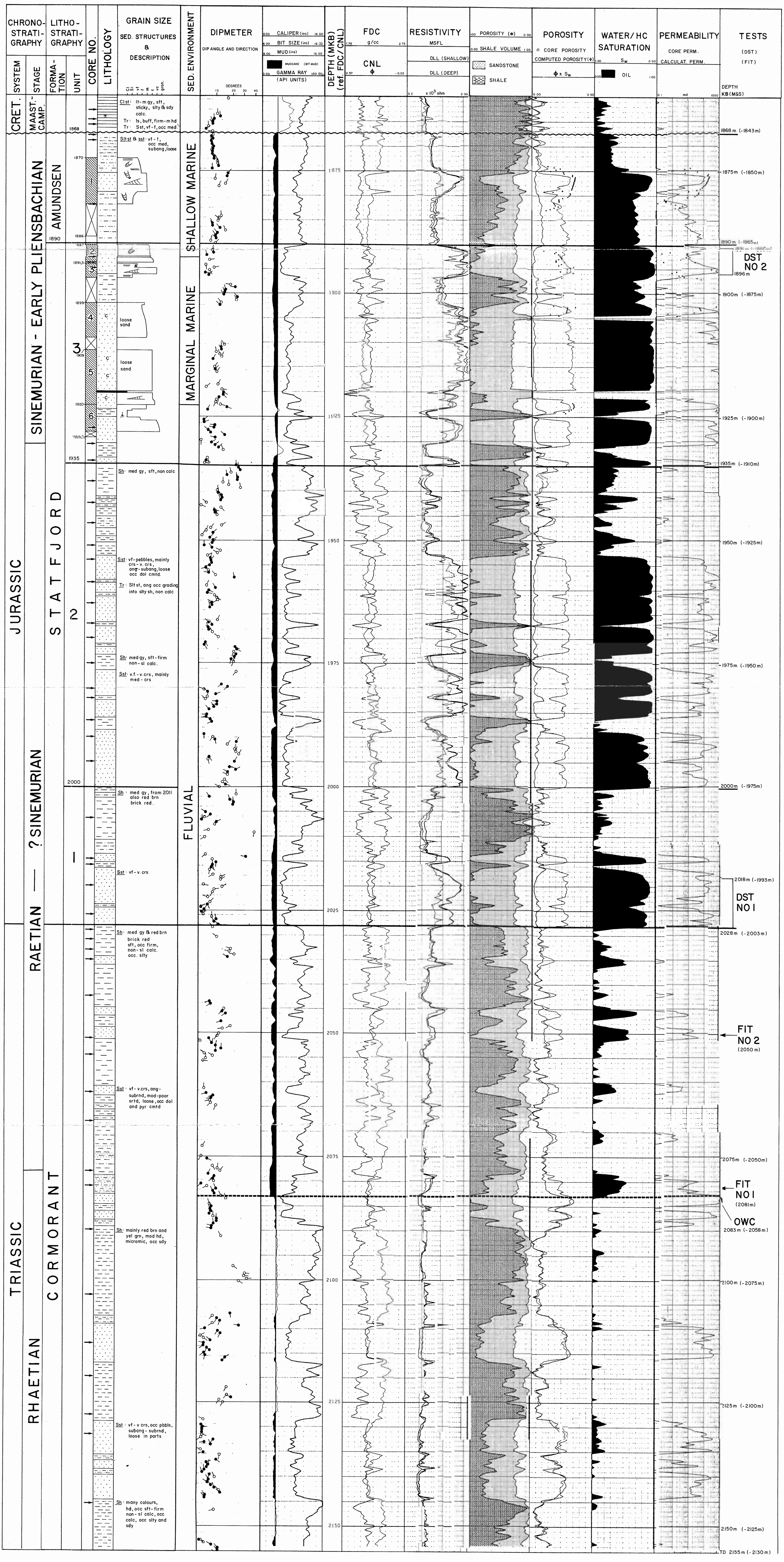
FIELD 34/10 - DELTA EAST — WELL NO. 34/10-11 — AREA NORTH SEA

CORE NO. 1, 2, 3, 4, 5 & 6 — INTERVAL from 1870 to 1925.6m — REMARKS

FORM. AMUNDSEN/STATFJ. — GEOLOGIST A. ELVSBORG/A. STORLI — DATE 17-3-81

RESERVOIR LOG

34/10-11



SYMBOLS

- SAND SANDSTONE
- SHALE
- SILT SILTSTONE
- LIMESTONE
- CLAY CLAYSTONE
- COAL LIGNITE
- UNCONFORMITY
- SIDEWALL CORE

DST NO 1: (2018 - 2028) m RKB
OIL: 2542 STB/D, CHOKE 24/64"
GAS: 2.15×10^6 SCF/D
GOR: 846 SCF/STB
DENSITY OIL: 0.83 (36.5 API°)

DST NO 2: (1891 - 1896) m RKB
OIL: 2500 STB/D, CHOKE 24/64"
GAS: 2.38×10^6 SCF/D
GOR: 952 SCF/STB
DENSITY OIL: 0.83 (36.5 API°)

FIT NO 1: (2081 m RKB)
~ 3000 cc oil SP. GR: 0.85
~ 7000 cc water

FIT NO 2: (2050 m RKB)
NO RECOVERY

statoil
Den norske stats oljeselskap a.s

34/10-11
RESERVOIR LOG

A. STORLI / T. HELGØY / M. HELLE

SKALA | ORIGINAL ARB. AV | ERSTATTER NR | TEGNING NR

Fig. 23

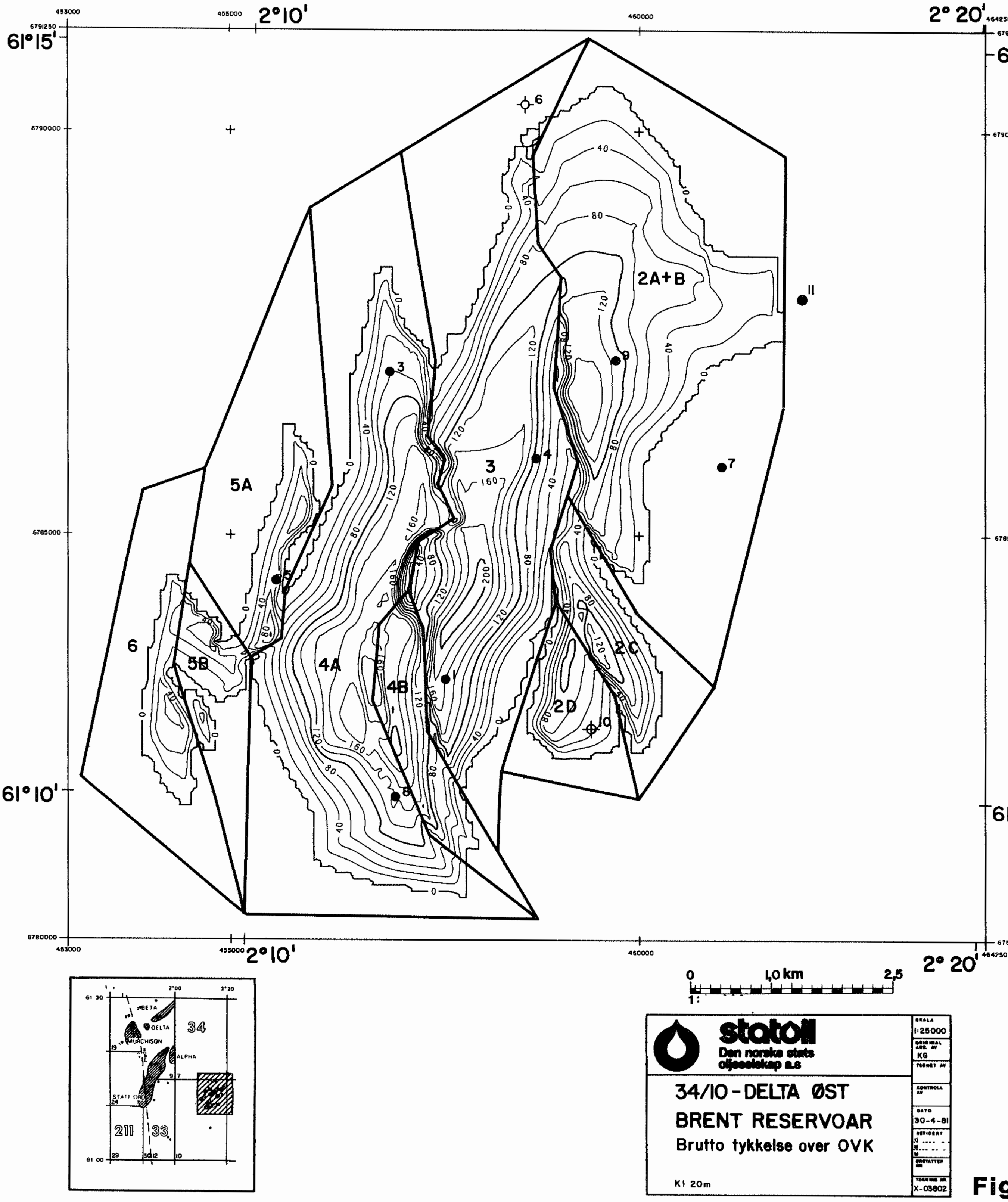
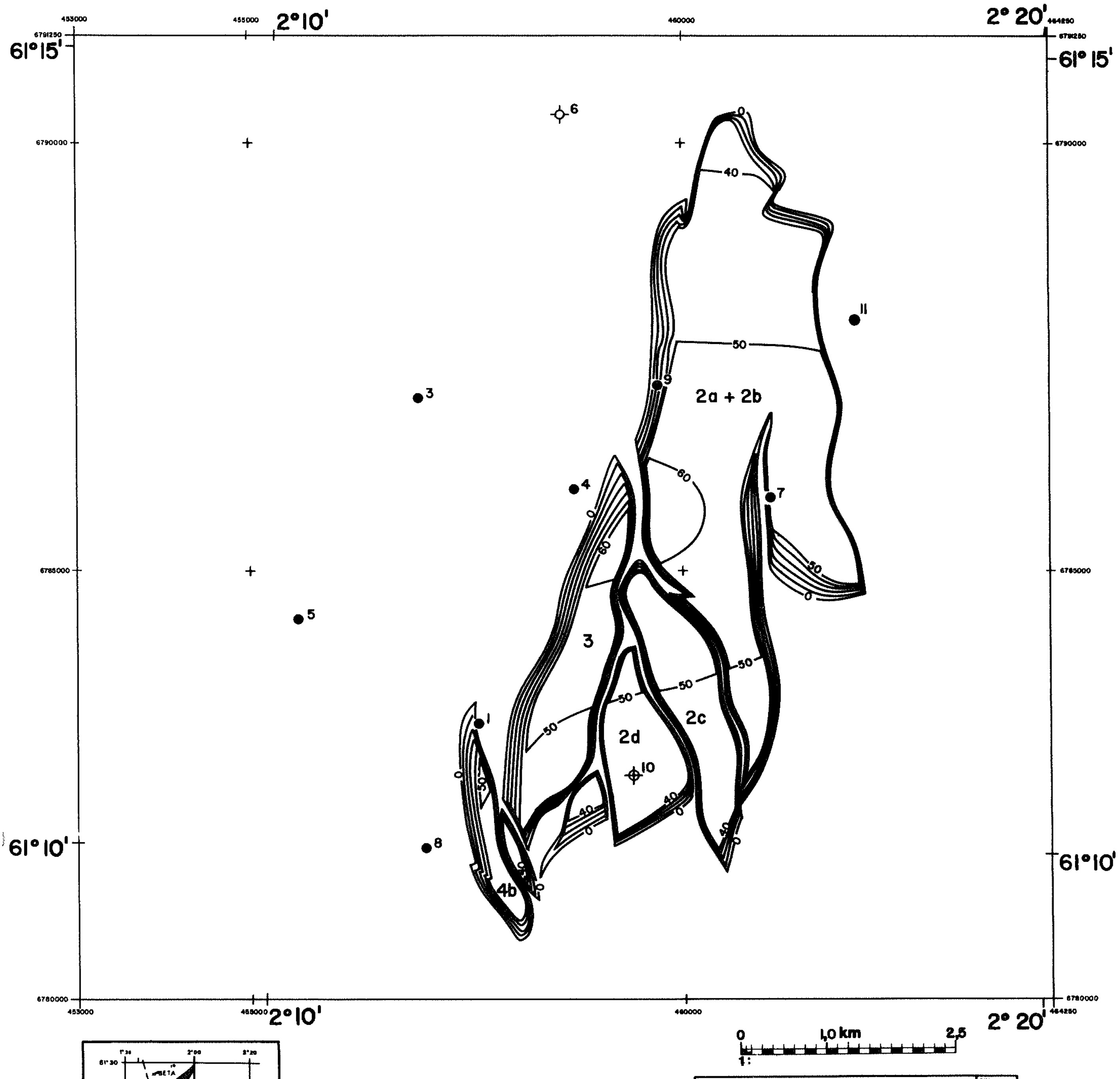
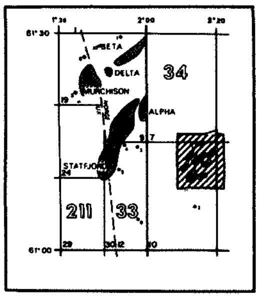

2°10'
2° 20'
61°15'
61°10'
453000
455000
460000
464250
6791250
6790000
6785000
6780000
2A+B
2C
2D
3
4A
4B
5A
5B
6
0
1,0 km
2,5
1:
statoil
Den norske stats oljeselskap a.s
34/10-DELTA ØST
BRENT RESERVOAR
Brutto tykkelse over OVK
Ki 20m
1:25000
KG
30-4-81
X-03802
34
DELTA
MURCHISON
ALPHA
STATFJORD
211
33

Fig. 24





statoil
Den norske stats oljeselskap a.s

34/10 - DELTA ØST

COOK FORMASJONEN

Brutto tykkelse over OVK

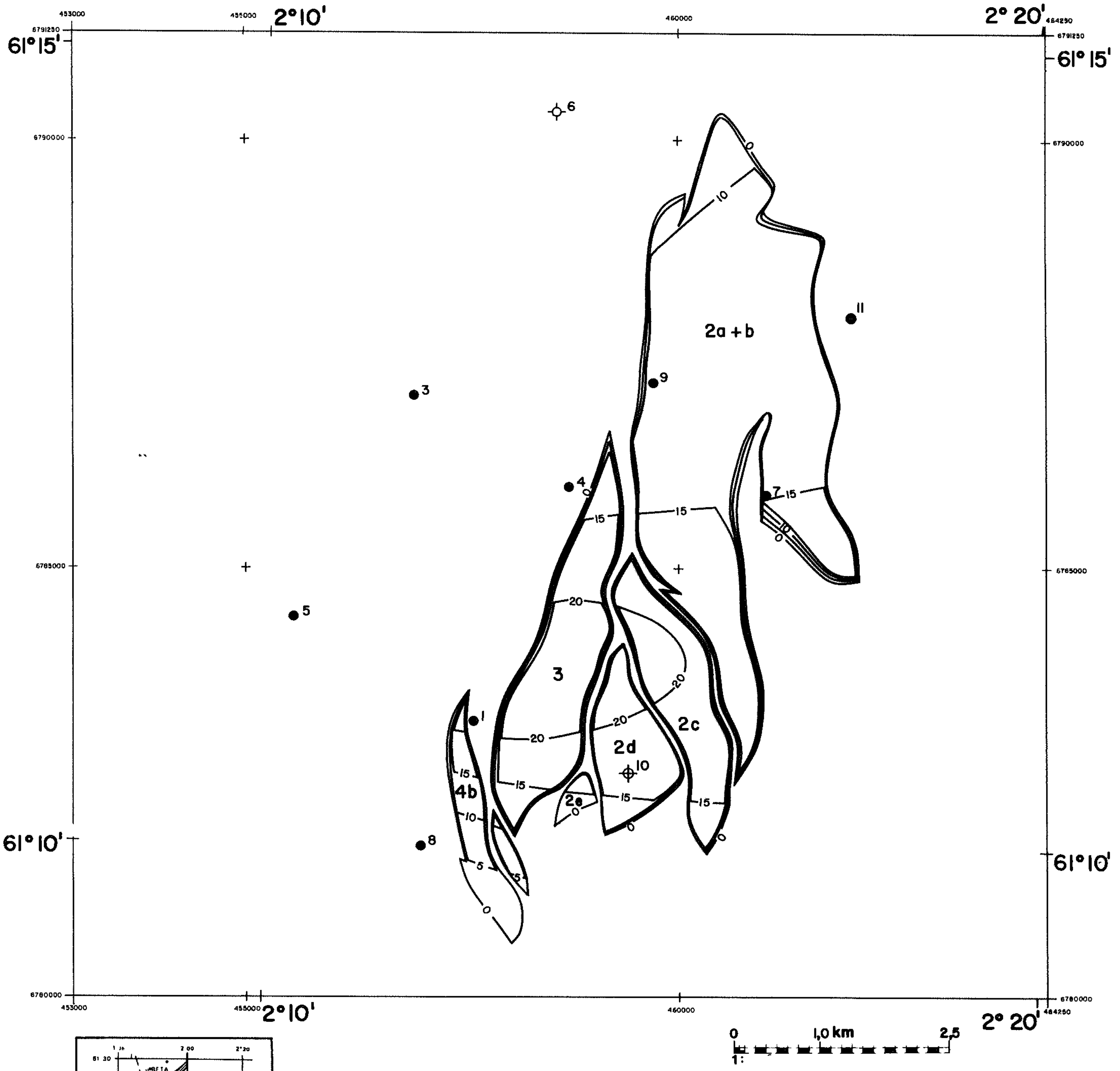
Enhet 2

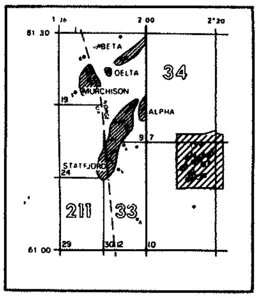
K.i 10m

A. Hage

SKALA	1:
ORIGINAL AGL. AV	AsH
TEGNET AV	I.O.
KONTROLL AV	
DATO	26.3.81
TEGNING NR.	X-03794

Fig. 25





statoil
Den norske stats oljeselskap a.s

34/10 - DELTA ØST

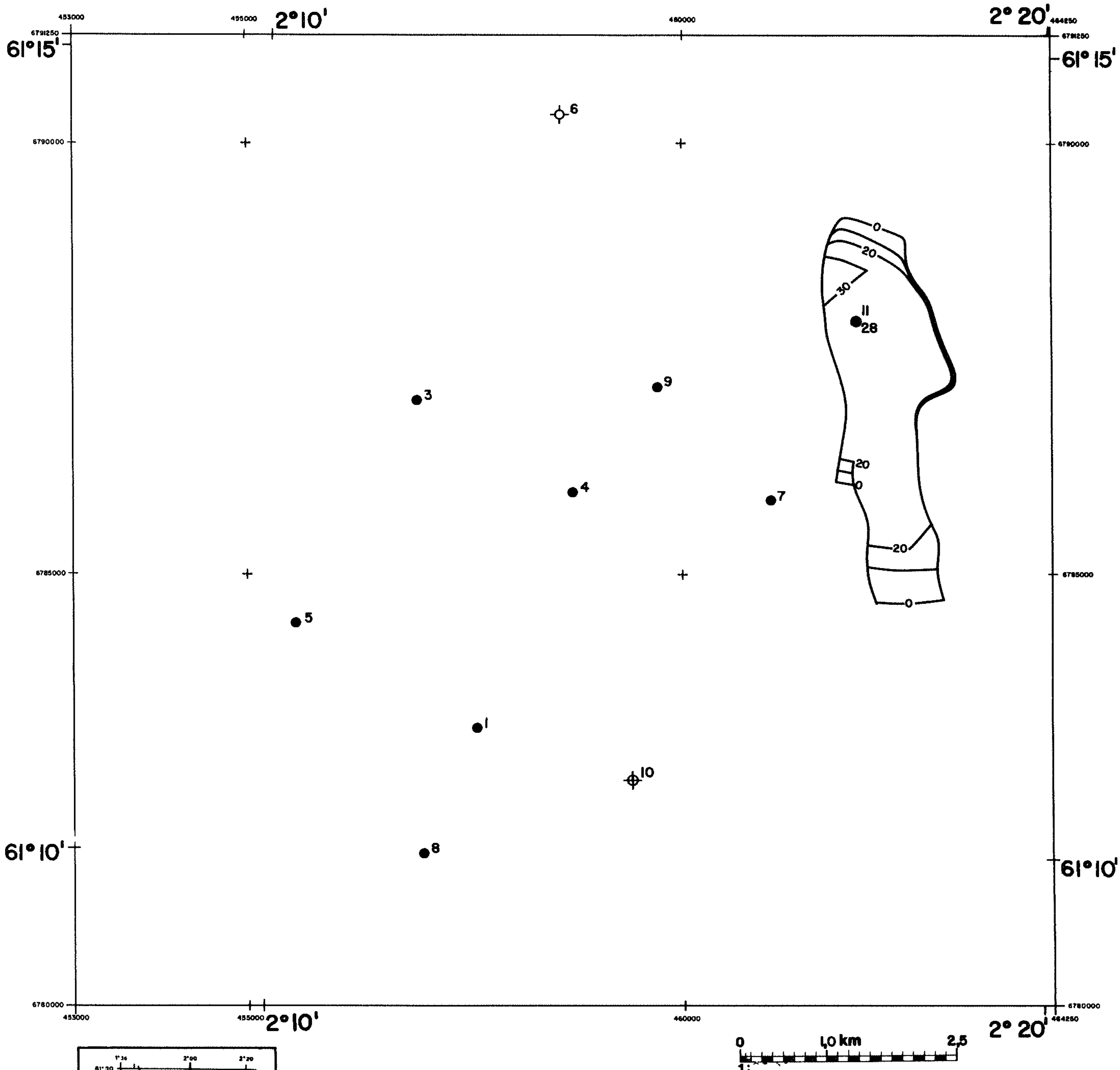
COOK FORMASJONEN

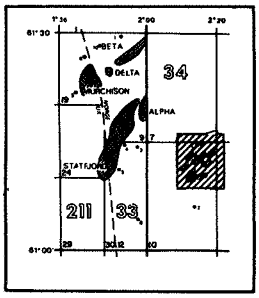
Brutto tykkelse over OVK
Enhet 3
Kl 5m

A Hage

AsH
10
26/3-86
X-03789

Fig. 26





statoil
Den norske stats oljeselskap a.s

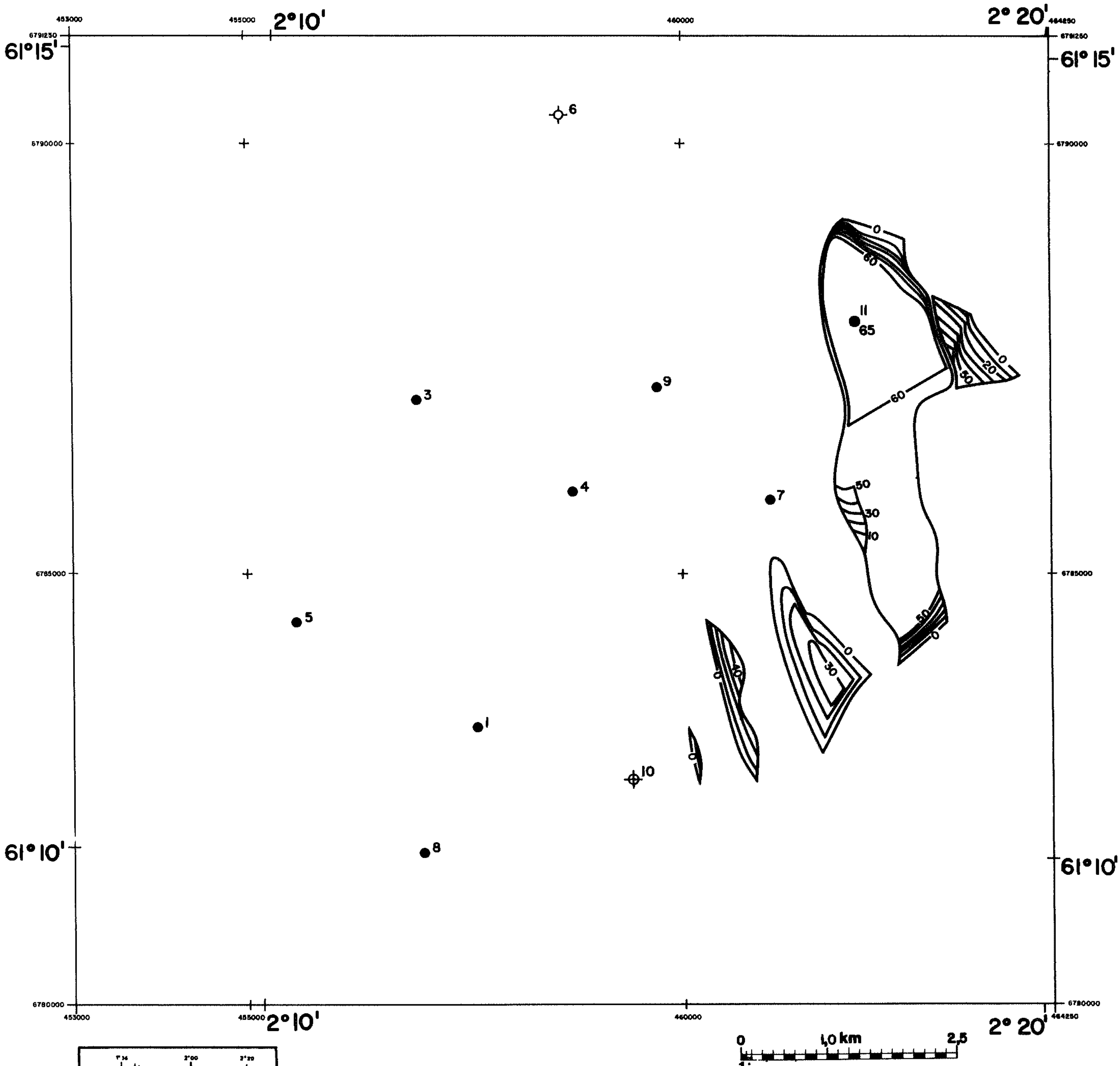
34/10 - DELTA ØST

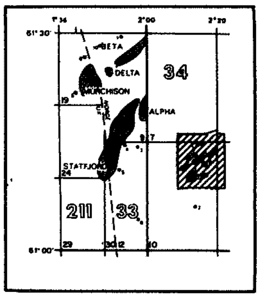
STATFJORD FORMASJONEN

Brutto tykkelse over OVK
Enhet I
Kl 10 m D.South

D.S.
I.O.
23.4.81
X-03790

Fig. 27





statoil
Den norske stats oljeselskap a.s

34/10 - DELTA ØST

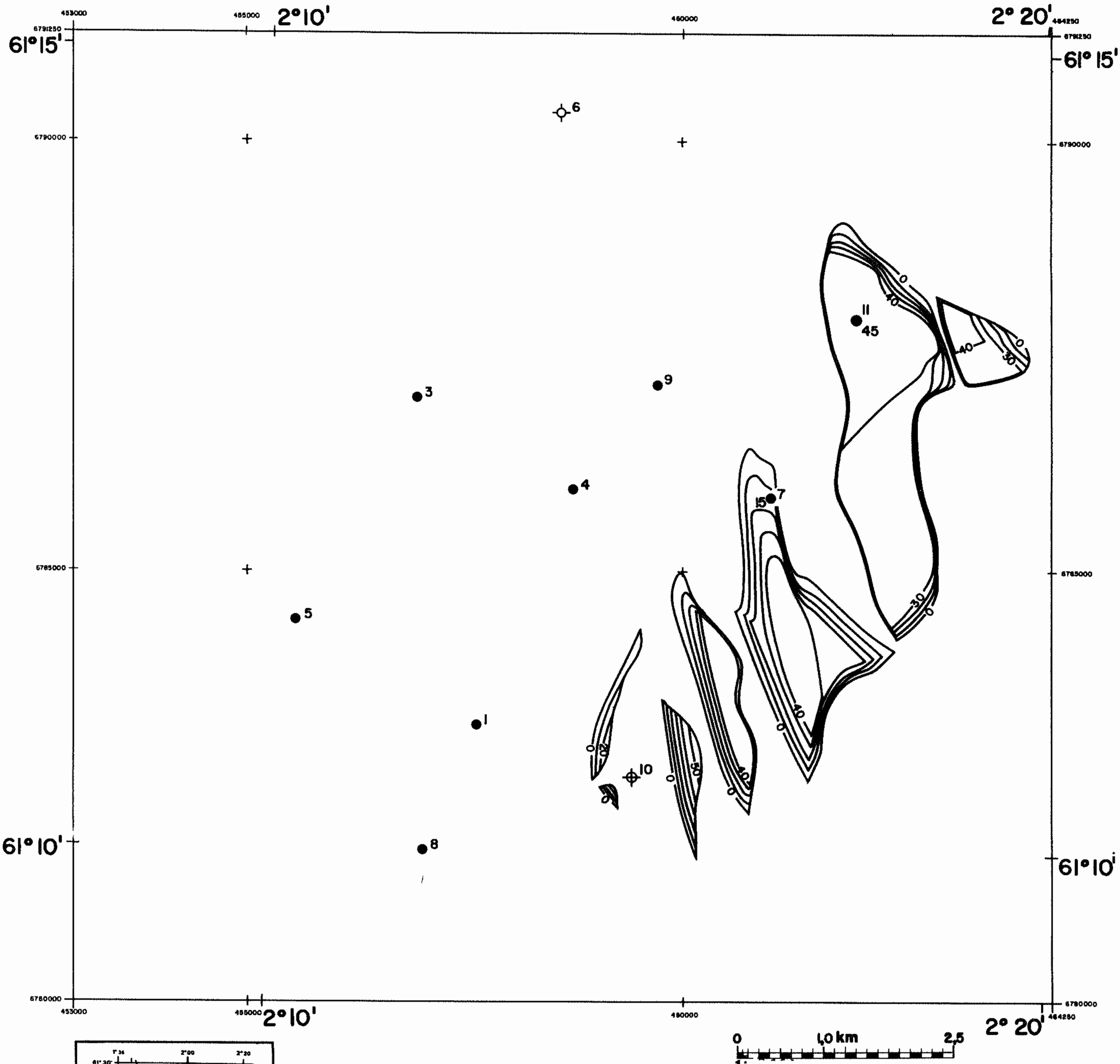
STATFJORD FORMASJONEN

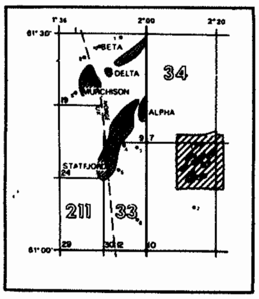
Brutto tykkelse over OVK
Enhet 2
K.I 10m

D Saeth

D.S.
I.O.
22.4.81
X-03791

Fig. 28





statoil
Den norske stats oljeselskap a.s

34/10 - DELTA ØST

STATFJORD FORMASJONEN

Brutto tykkelse over OVK

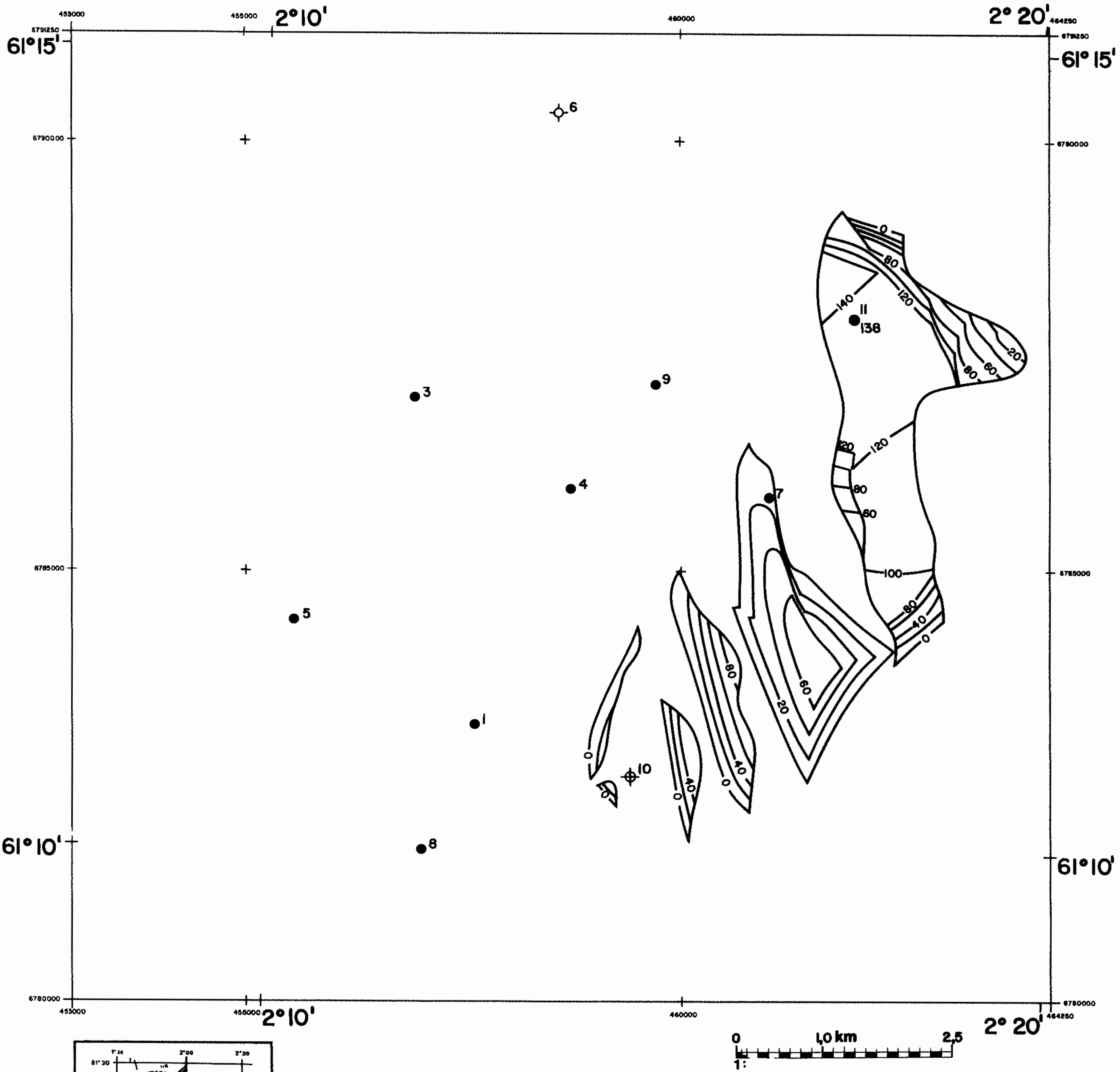
Enhet 3

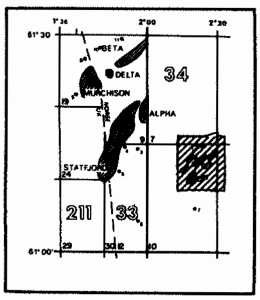
K.I 10m

D South

SKALA	1:
ORIGINAL ANS. AV	D.S
TEGNET AV	I.O
KONTROLL AV	
DATO	23.4.81
REVIDERT	
ERSTATTER	
TEGNING NR	X-03792

Fig. 29





statoil
Den norske stats oljeselskap a.s

34/10 - DELTA ØST

STATFJORD FORMASJONEN

Total brutto tykkelse over OVK

K.I 20m D South

SKALA	1:
ORIGINAL ARB. AV	D.S
TEGNET AV	I O
KONTROLL AV	
DATO	22.4.81
REVIDERT	
ERSTATTER NR	
TEGNING NR	X-03795

Fig. 30

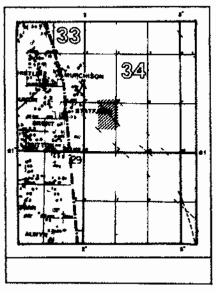
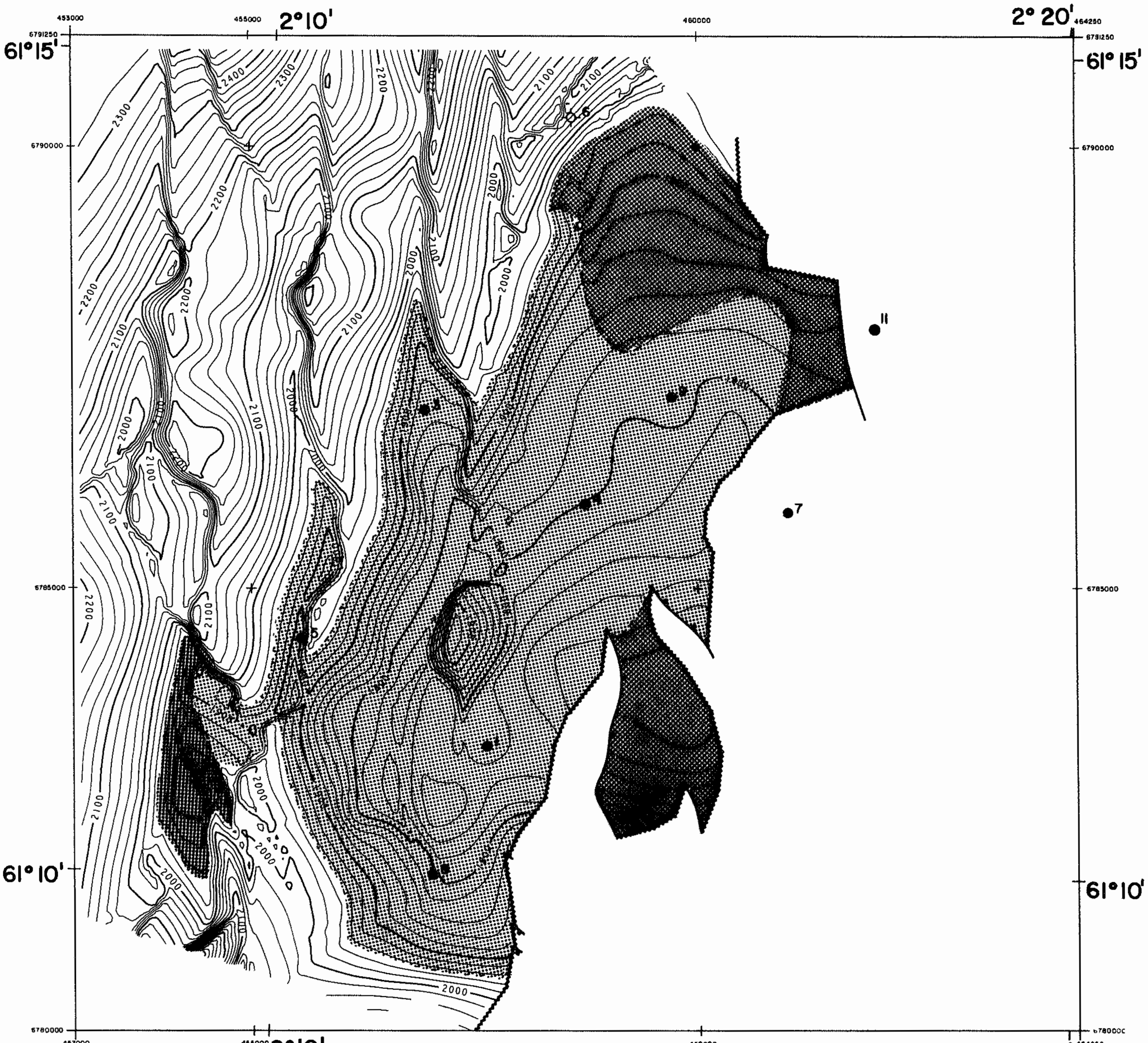
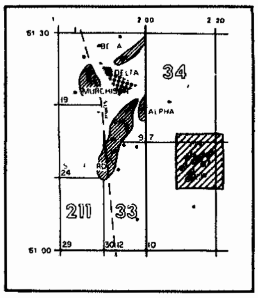


Fig. 31

statoil
Den norske stats oljeselskap a.s

34/10-DELTA ØST
USIKKERHETS-
FORDELING
GEOLOGISK / SEISMISK
TOLKNING





Påviste reserver

Mulige tilleggsreserver

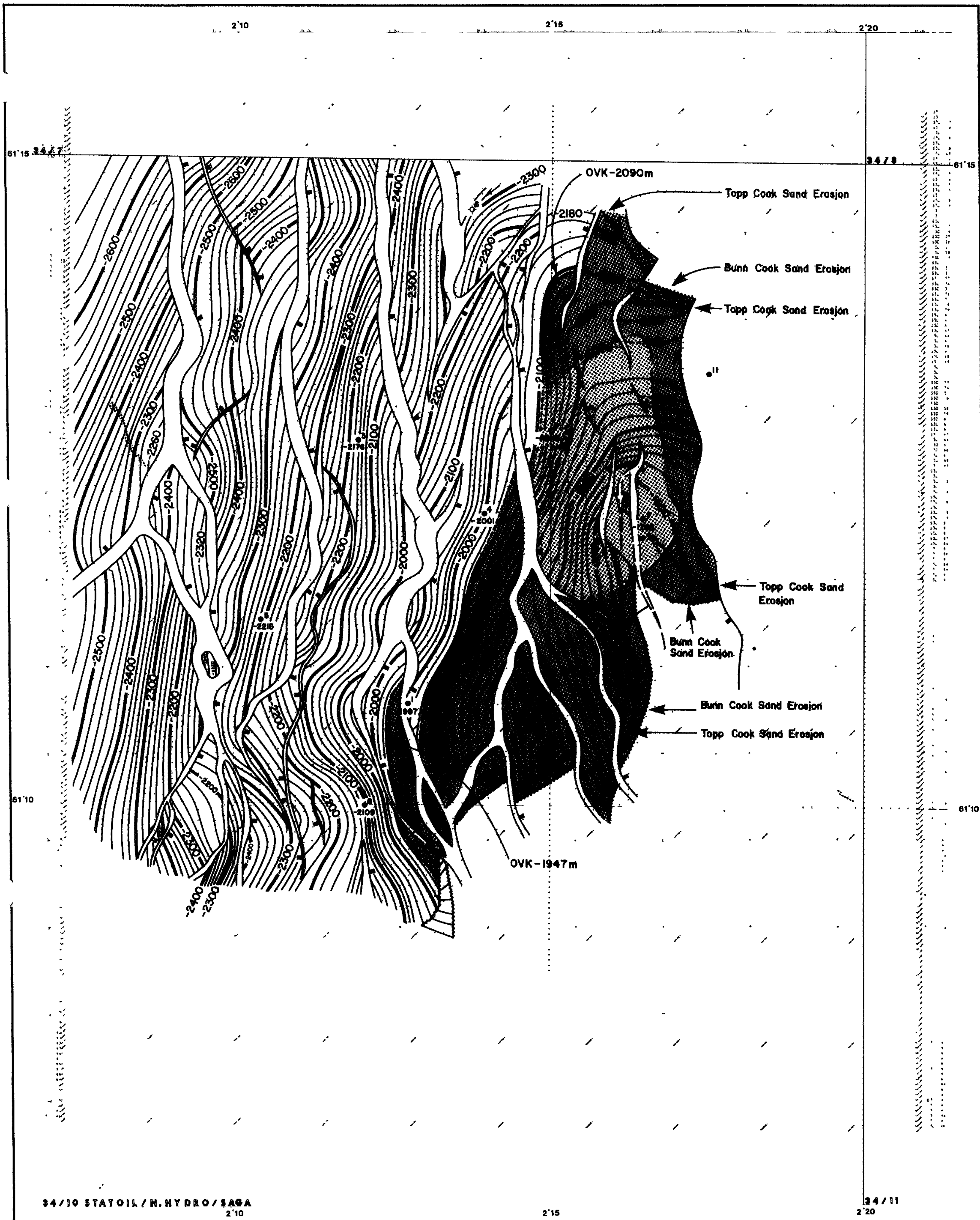
*Se også håndkonturert dybdekart for Topp Brent

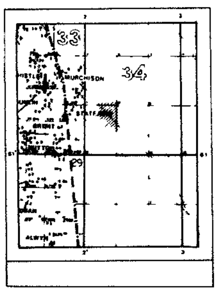
statoil
Den norske stats oljeselskap a.s

34/10 - DELTA ØST
TOPP BRENT
Strukturelt dybdekart
* EDB konturert
Benyttet for volumberegning
Ki 20m
K Grindstad / A Storli

SKALA	1:25 000
ORIGINAL AV	KCG/AS1
TEGNET AV	GrH
KONTROLL AV	
DATO	18-5-81
REVIDERT	
ERSTATTER	
TEGNING NR	X-03806

Fig. 32





Påviste reserver

Mulige tilleggsreserver

0 1 km 2,5

1:

Fig. 33

statoil
Den norske stats oljeselskap a.s

34/10 - DELTA ØST
TOPP COOK SAND
Strukturelt dybdekart
K I = 20m GSS/GTS

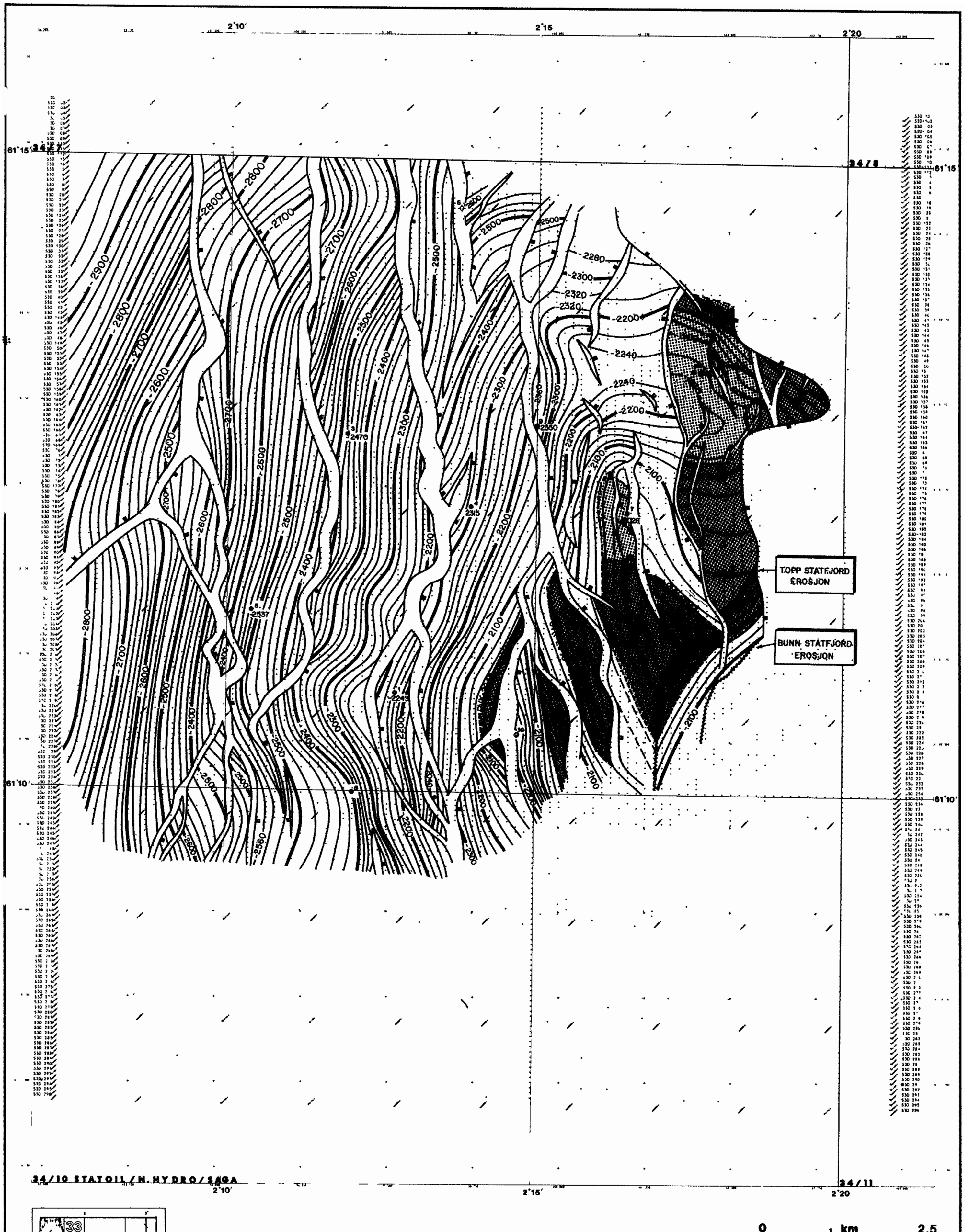
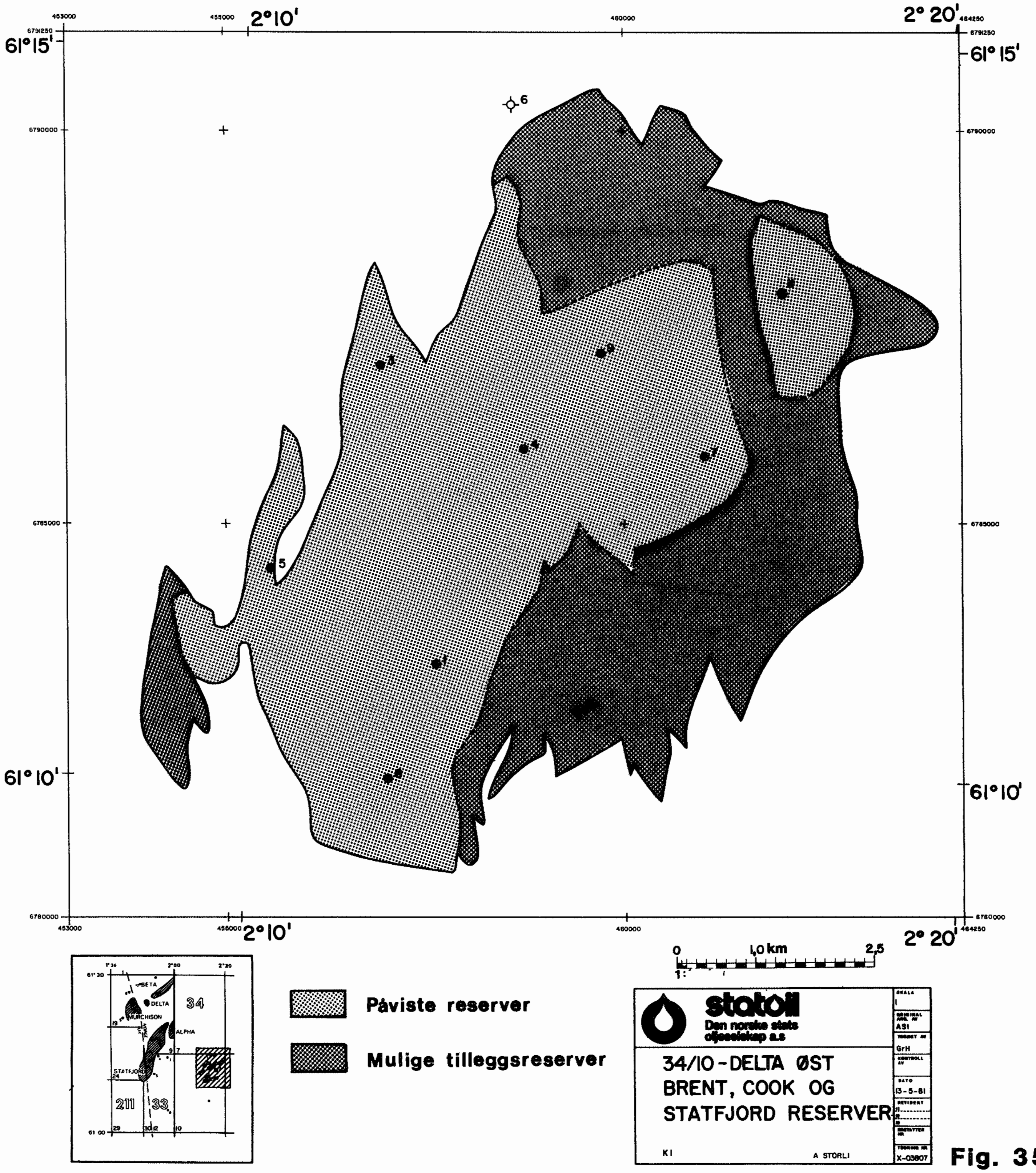


Fig. 34

statoil
Den norske stats oljeselskap a.s

34/10 - DELTA ØST
TOPP STATFJORD
Strukturelt dybdekart

K I = 20 m GSS/GTS



2°10'
2° 20'
61°15'
61° 15'
61°10'
61°10'
453000
455000
460000
464250
6790000
6785000
6780000
6
5
0
1,0 km
2,5
BETA
DELTA
MURCHISON
ALPHA
STATFJORD
34
211
33
Påviste reserver
Mulige tilleggsreserver
statoil
Den norske stats oljeselskap a.s
34/10-DELTA ØST
BRENT, COOK OG
STATFJORD RESERVER
KI
A STORLI
ASt
GrH
13-5-81
X-03807

Fig. 35