96: 3942.

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GREAT SOUTHLAND MINERALS PTY LTD

ACN 068 650 386

ANNUAL REPORT

EL 1/88, EL 9/95, EL 21/95

1996

EL 1/88 See folio 32
EL 9/95 See folio 29
EL 21/95 See folio 27.

Dr Julian Amos
Managing Director

November 1996

357002

APPENDIX

PUBLICATIONS AND REPORTS, 1996

Geophysics

Leaman, D., (1991) - Progress Report - Interpretation of Gravity and Magnetic Data on EL 1/88. (as received by the company, April 1996)

Leaman, D., (1996) - Interpretation of AGSO seismic lines Tasmanian Basin

Geochemistry

Carne, G., (1996) - Valuation of Petroleum Exploration Tenements EL 21/95, EL 1/88, and EL 9/95 - Tasmania (for Condor Investments P/L)

Carne, G., (1996) - Great Southland Minerals P/L Exploration Strategy

Cass, D., (1996) - Methane and TOC analyses from Shittim #1 AMDEL

Davies, N., (1996) - Analysis of Shittim #1 trip gas 1528m. CSL University of Tasmania

Higgins, C., (1996) - Shittim 1A - Hydrocarbon Well Logging Interpretive Review 60mm (BQ) hole Section

Watson, B., (1996) - Shittim #1 - Rock and gas samples AMDEL Report LQ 5147 1-4

Wythe, S., (1996) - Rock eval Pyrolysis from Shittim #1 at 1043m. AMDEL

Whythe, S. and Watson, B. (1996) - Geochemical evaluation of an oil seep sample from Lonnavale, Tasmania AMDEL

Geology

Burrett, C., (1996) - Oil and Gas in the onshore Tasmanian Basin

Maynard, B., (1996) - Reservoir Characteristics of the Liffey Group, Unpublished Honours Thesis, University of Tasmania.

Young, R., (1996) - Potential of Oil and Gas in the Tasmanian Onshore Basin

THE EXPLORATION PROGRAM

During 1996, the company decided to pursue a more vigorous exploration program, involving both a seismic and a drilling program. This program has been lodged with the Department and a variation to the existing program sought. An independent report from Carne (1996) shows the program as designed to be a sound one.

The company is actively pursuing further funds to support the on-going program.

All of the issues mentioned below are the subject of more detailed reports, a list of which is contained as an Appendix to this document.

SEISMIC

AGSO ran a series of seismic lines throughout Tasmania during late 1995. The company arranged for an interpretation of the T4 seismic line by Dr David Leaman, which showed that seismic can be used to "see" through the dolerite.

This discovery has caused the company to reappraise its exploration program, and it commissioned Jonathan Knight to develop a seismic exploration program to precede and dovetail with the drilling program.

Some preliminary seismic work has commenced on Bruny, at Bothwell and at Lonnavale.

DRILLING

For the drilling program to proceed

- proper blowout prevention equipment was required, and for the particular drilling program that the company was engaged in, this equipment had to be sourced from the USA
- the drill rig needed to be upgraded so that the rig could drill at depth.

The company eventually decided to re-enter the Shittim #1 stratigraphic hole on Bruny Island and proceed to an economic basement. At the time of writing the depth of the fully cored hole has reached 1620 m and is the deepest hole ever drilled on the Tasmanian Basin.

Continuing shows of gas were encountered, being mainly hydrogen and methane. Ethane was also discovered in two gas shows as drilling continued through a second deeper dolerite sill. The gas was analysed by both AMDEL laboratories in Adelaide and the Central Science Laboratory at the University of Tasmania. Carbon isotope analysis has shown the gas samples to fall in the mid range of thermogenesis.

The Division has been kept fully informed as the drilling has progressed.

A full report on the Shittim #1 hole is presently being compiled and will be available once the hole is completed.

Well prognoses for Bruny (Gilgal, Jericho), Huntersone and Lonnavale are at an advanced stage, and will be available by the end of the calendar year.

OIL SEEPS

An oil seep was discovered by the Tasmanian Mines Division on a property at Lonnavale, on EL 9/95. Independent analyses of the seep by both the Tasmanian Mines Division and the company have shown that the oil has a Permian Tasmanite signature.

RESEARCH

The company has continued to support an active research program, including further studies on the reservoir characteristics and age of sequences of the Tasmanian Basin.

PAST ACTIVITY

In light of recent comments regarding the present state of knowledge of the prospectivity of the Tasmanian Basin, the company has decided to put together a report detailing the past activities of itself and its predecessors in the basin, either on their own volition or as part of a co-operative project with other organisations..

Although not comprehensive, the following list is indicative and represents a level of commitment far in excess of $1 million:

seismic program with Mines Dept
seismic survey with Shell et al
    processing of same by Shell

gravity survey with Mines Dept

aeromagnetic database collection

geochemical analyses (various)

support of postgraduate programs

payment of licence fees

Appx 1

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LEAMAN GEOPHYSICS

Survey Review, Specification, Reduction, Interpretation
Gravity, Magnetic and Seismic Methods
Structure and Prospect Evaluation

Registered office:
3 MALUKA STREET, BELLERIVE, TAS. 7018
All correspondence to:
GPO BOX 320 D, HOBART, TAS. 7001
Telephone: (002) 44 1233
Fax: (002) 44 6674

GP 3

PROGRESS REPORT
INTERPRETATION OF GRAVITY AND MAGNETIC DATA
EL 1/88 CENTRAL TASMANIA
CONGA OIL

by
Dr. D. E. Leaman

February 1991

SUMMARY

This report outlines initial work undertaken as part of the interpretation of gravity and magnetic data acquired by Conga Oil within its tenements in Tasmania since 1988.

This data has been available since 1989 but the interpretation has only recently been authorised. Time and budgetary constraints have restricted the nature and goals of the interpretation. The style of interpretation and form of results must reflect an array of compromises.

This progress report describes the nature of those results and compromises and some indication of concealed structural conditions in central Tasmania.
The work is incomplete and must not be used as a basis for drilling or structural targetting at this stage.

Geochemical research by Conga Oil has suggested that Ordovician rocks are important elements in the hydrocarbon prospectivity of the Tasmania province. Seepage studies have shown occurrences to be common and to occur in formations and areas which would not be expected to bear, or conceal, Ordovician rocks. Pre Carboniferous structure is clearly important.

This preliminary work suggests that pre Devonian rocks are folded and multiply overthrust and the structural slabs include all formations younger than Late Precambrian. Many pieces of Cambrian and Ordovician sequences have been preserved beneath the Upper Carboniferous unconformity.

One of these fragments underlies the central Derwent valley. valley.

This report outlines the interpretive sequence and early results leading to these conclusions and more detailed work in the Derwent Valley.

INTRODUCTION

EL 1/88 covers most of the eastern half of Tasmania and is held by Conga Oil Pty Ltd for hydrocarbon exploration.

The last detailed analysis of any part of this area was reported in the Annual Report for 1988 in respect of the area south of Hobart, known as the D'Entrecasteaux region. This work was undertaken prior to the claiming of Central Tasmania and the subsequent consolidation of areas held.

The enlarged area was covered by an aeromagnetic survey and the state gravity data base was infilled in many areas.

This data was to have been interpreted to a status equivalent to the trail blazing D'Entrecasteaux work and then used to focus seismic or other targetting techniques. Detailed evaluation of D'Entrecasteaux type is necessary across the entire area if realistic and sensible relinquishment and targetting decisions are to be made. Budgeting and management decisions have not been made. Finally, in late 1990, the interpretation was authorised with a limited budget.

This delayed start, a large area, and difficult geology has meant that it is unlikely that a detailed interpretation of the entire tenement will be obtained prior to some relinquishment or drilling. Some compromises have been required; some of which may risk the reliability of the whole.

This progress report describes

1 - elements of regional analysis designed to verify crustal scale issues and their effect on the data and to define the general distribution of pre Permian rocks.

2 - more advanced evaluation of one interesting area as requested; the central Derwent Valley.

The report is intended only as a progress statement. It is not final and should not be used or referred to as such. Many critical issues remain to be resolved or clarified.

DATA USED

Gravity and magnetic data are available.

The aeromagnetic survey of the D'Entrecasteaux region has been previously described. Its large augment across central Tasmania forms the basis of much of the present interpretation.
This survey was flown by Austirex International in March 1989 at a barometric elevation of 1600 m. Flight lines were specified at 5 km intervals with 25 km tie lines and a sampling of 20 m.

The survey revealed a number of marked trends, some of which can be directly correlated with ultramafics - as at Beaconsfield. Many large spikes have also been observed; few of these can be correlated with surface topography, with or without dolerite. Most anomalies are sourced beneath the Permo-Triassic cover.

The gravity compilation is based on the Department of Mines and Mineral Resources Tasmanian data base. This was infilled in parts of eastern, central and northern Tasmania to provide larger blocks of data with station spacings of 1 to 2.5 km. The infilling survey was undertaken by the Mines Department Geophysics Division to a budget and nominal coverage specified by Conga Oil. There remains much scope for further acquisition.
All observations have been reduced compatibly with the data base at a density of 2.67 gm/cc and terrain corrected to a radius of 22 km. Precision of reductions is controlled by the accuracy of barometric elevation determinations (about 0.4 mGal in Bouguer anomaly).

The Bouguer anomalies have been processed using the crustal model known as Mantle88 (Leaman & Richardson, 1989) to yield residual anomalies. The reliability of this process is not known in central Tasmania since the concept was developed in western and northern Tasmania and extrapolated elsewhere pending availability of data and modelling.

The residual anomalies are dominated by large positive effects near the Derwent Valley, the strong negative effects which extend from Scottsdale to Port Arthur and marked gradients and steps from near neutral values north and east of the Great Western Tiers with positive values southwest of Poatina.

Density values used for all modelling have been based on experience and the Tasmanian rock property data base held by the Department of Mines.

INTERPRETATION

AIMS

Several objectives were set for the initial and subsequent study. A comprehensive programme was defined.
This included evaluation of the residual separation process and reliability in Central Tasmania and use of upgraded residual values. This would necessitate long line modelling involving the continental margin and all batholiths.
Development of the regional implications of the long line modelling for use as guides to deep structure and distribution of rock units.
The preliminary guides should define relatively small areas in which a prospective combination of structures and rock types is present. Any such evaluation to be supported by compilation of seep sightings.
The target areas were then to be evaluated in some detail in order to generate more specific targets or sites for stratigraphic or control drilling. This detailed work must include appraisal of detailed structuring and thickness of the Permo-Triassic cover - including dolerite intrusions.

This relatively relaxed programme has not been possible due to budgeting and management delays and a number of compromises and overlaps have been made in order to assemble a reasonable view in the shortest time.
Some of the risks inherent in this process have not been assessed as yet but further stages, time permitting, may resolve many of the ambiguities and increase confidence.

METHODS

Two dimensional profile methods have been used to date. These are efficient and rapidly lead to a general guide for structures and lithological distributions.

All work has been controlled and defined in terms of the 250 000 scale geological map sheets of Tasmania. Nothing better exists for much of the area studied and it will not be possible to generate a detailed outline comparable to the D'Entrecasteaux Project without some mapping review. This need must be satisfied for any areas requiring detailed study for site targetting or refined evaluation where 1:50000 mapping does not exist. This deficiency has not caused problems for the guide modelling.

Both data sets have been treated comparably until consistent models, or model options, have been derived. This work cannot yet be considered exhaustive and the solutions are far from unique in most cases. Samples of each profile position are reproduced in this report; none are in final state.
The Figures provide a snapshot view of the current status of the interpretation.
It will be noted that various profiles are reproduced which show gross crustal effects, effects of major crustal blocks and sometimes details of dolerite structure. These threads of interpretation have been necessary to maintain confidence in the residual fields being used and to satisfy the array of objectives.

DISCUSSION

REGIONAL STUDY

This report outlines the first two stages of interpretation - each undertaken as a compromise treating all aspects of the objectives.

The regional study considers the entire area and the primary issues of the reliability and any limitations in the the data sets as well as development of a gross structural guide.

This primary work has identified a small group of areas in which more detailed analysis is justified. One of these, the central Derwent Valley, was nominated for immediate review and current progress on this evaluation is included below.

REGIONAL STUDY

The Figures provided suggest the nature of structuring in eastern Tasmania and brief comments have been provided for each diagram.
Note that all Figures are provisional.

The location of all profiles is marked in the Map (folder).

Figure 1 reviews the regional and crustal construction of southern Tasmania. The model suggests that only minor revision of the Mantle88 concept is required and this does not affect preliminary work. (It should be corrected for detailed studies, however). The shift parameters and crustal depth scale are consistent with those required in northwest Tamania. Granites are dominant in southwest and eastern Tasmania.

Figures 3, 4 and 5 treat profile 2. Figure 3 provides a crustal guide which is consistent with Figure 1 (above). Model fit deficiencies near the coast are not relevant to the present work and reflect poor discrimination across the continental shelf and margin due to poor bathymetric control.
Figure 4 provides a subsample of Figure 3 in residual format. This suggests that the midlands of Tasmania is underlain by dense units up to 5 km thick containing structured slabs with steeper dips and greater density contrasts. The structures repeat.
Magnetic data (Figure 5) indicate that parts of the dense slab is magnetic - and presumably contains Cambrian volcanics - and that these parts lie between the very dense steeply dipping (relative term - note vertical exaggeration in models) units. The dense units (positive gravity anomalies) *do not correlate with magnetic anomalies and* hence the source of these features is neither mafic, ultramafic and almost certainly not igneous in origin.
The properties are consistent with thick dolomites. Such units are known in parts of the Late Precambrian.
The models would imply that these formations are structurally repeated in a manner not consistent with folding. Thrust faulting is suggested.

Figures 6, 7 and 8 examine profile 3. The more localised gravity and magnetic models support conclusions based on profile 2. But along this profile the structure is asymmetric. A significant mafic source - probably ultramafics - is inferred along the eastern margin of the westernost slab. A thrust rider?
The reduced gravity anomaly to the west of Tarraleah can be interpreted in two ways; either a granite at shallow depth or a synclinorium involving Ordovician and Silurian rocks. Review of anomaly distribution and correlation to outcrop further west indicates the latter. See other sections.
The origin of magnetic spikes in this region is dealt with below; all large spikes reflect ultramafics, only medium spikes may reflect dolerite effects or feeders. The large spikes at 75 and 100 km correlate with marked gravity boundaries and implied structures.
The repeated structuring incorporates ultramafics on a general basis.

Figures 9, 10 and 11 present a view of profile 4.
The detailed gravity and magnetic models reveal matching structures dipping to the east at low angle and which contain ultramafics. One block includes volcanics.

Figures 12 and 13 review profile 5. The gravity profiles are complicated by the effects of Tertiary basins but the magnetics demonstrates the presence of several deep seated mafic junctions. These either mark the edge of the structural controls upon Tertiary developments or delimit the primary blocks. The Tiers Fault is thus indicated with much older precursors than Jurassic feeder occupation. See Map for position.

Figures 14, 15 and 16 examine profile 7.
This profile is transverse to all others and presents a test and check view. The crustal model is directly linked to the region of good control in northwest Tasmania. The more detailed profiles stress the nature of the sub east-west junction across central Tasmania near Great Lake (see Map).
The magnetic and gravity data can only be interpreted consistently in terms of contrasting crustal or structural blocks; one with and one without a thick pile of dolomitic Precambrian formations. The boundary includes ultramafics which wrap into the structure at depth. The magnetic model crudely suggests this.

Figure 17 details profile 8. Magnetic data offer support for the boundaries but the model is capable of two interpretations within the zone east of Miena. The dense units could continue beneath some light cover or the more siliceous basement blocks could be infaulted as shown. Light cover here may be taken to mean Ordovician-Silurian formations.

This type of factor is demonstrated in Figure 18 for profile 21. A concealed syncline of Ordovician and Silurian rocks may be inferred to account for the depression in anomaly at 40 km. It is difficult to account for this character in any other manner. (See also some Derwent sections).

Figure 19 suggests relationships between Great Lake and eastern Tasmania. There is limited discrimination between Mathinna Beds and the general sequence of Lower Palaeozoic or Precambrian rocks. It should be noted that the general density used for all formations beneath the Permian cover is consistent with much of the Cambrian and Precambrian succession. Magnetic data define the structures and junctions since many of these contain ultramafic slices.

Figure 20 supports many of these comments while drawing attention to the character prevalent further south and west of Great Lake. A magnetically bounded slab of structurally discordant material may be defined. The model also examines the effect of a large dolerite feeder at this scale and shows it to be of little consequence. The anomalies defined are sourced by large geological blocks.

Many of these elements of the structure have been condensed in map form (pocket). The map attempts to convey the most likely distribution of materials beneath the Permian cover within the terms of this gross treatment. As such it can only suggest thick elements.

The primary work has shown that no major modifications to the residual separation process are required across central Tasmania although some changes are needed and must be enacted prior to any final or very detailed evaluations.
It has also been established that ultramafics are common but are located at block edges. Cambrian volcanics are also present but are not general and are restricted to particular slabs or structurally controlled belts. The largest areas of these materials extend SSE from Poatina, near north Great Lake and in the lower midlands near Bagdad and Broadmarsh.

The general style of structuring deduced from the present work has been summarised in Figure 21.
This suggests the structural pattern which appears to extend from the Devonian batholiths of eastern Tasmania to the region of Maydena and Adamsfield.
Repeated slices are implied, some containing Cambrian volcanics and younger Palaeozoic rocks (the target materials for hydrocarbons), but most involving the late Precambrian dolomites. The basal structural runner would appear to be within these formations. Strips of them have been peeled upward, pushed westward and folded. Some of the structuring may well have been Cambrian in age and the whole patternd re-arranged during Devonian orogeny. This re-arrangement has been facilitated by the ultramafic slices.
The general westward push of the structural compression has produced a thickening of the sequence west of the Derwent River and this accounts for the extreme gravity anomalies.
Lateral limits to the structures, perhaps ramps, exist and bisect the structures with a NE-SW and E-W pattern; the largest traversing the region near Miena.
Major deep structures of this type, actively rejuvenated during the Tertiary period, explains the widespread distribution of Tertiary basalts in the western plateau region.

Although this preliminary work lacks some discrimination it [illegible]

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seep sightings definition of areas worthy of further attention. These include

- the Cygnet / Huonville region (project D'Entrecasteaux)
- the Southport region (project D'Entrecasteaux)
- the Frankford / Launcestone region
- the region south of Mole Creek
- the region southwest of Poatina toward Miena
- the region south of Richmond / Clifton
- the region between Tarraleah / Gretna

All demonstrably involve Ordovician and/or Silurian rocks. No rating can be inferred at this stage.

THE DERWENT STUDY

The following notes represent comments on unfinished analysis of the Tarraleah / Gretna region and its relationship with the exposed formations of the Florentine Valley west of Maydena.

The Figures are in raw state and simply reflect current thinking and model status. Many refinements are possible. Only primary issues and ideas which integrate the data sets have been considered to date.

All profile positions are shown on the map (folder).

Figures 22 and 23 consider line A.
These provide a consistent view in which large slabs of dense formations have been translated. Mafic and ultramafic materials define many of the surfaces. This is a universal observation but it is not yet established how many of these surfaces represent faults or thrusts. Some junctions may be stratigraphic in that the ultramafics are in correct place in time terms. This type includes the slice of material which underlies, and has been folded with the Ordovician rocks beneath Tarraleah, and perhaps the slices at 15 and 80 km. It is not the case with the slice beneath the slab at 55 km. That implies thrusting unambiguously. These relationships recur in most profiles and more detailed work is required to establish all relationships.
The gravity profile stresses the effect of the presence of Ordovician and Silurian rocks. The negative response cannot be generated by post Carboniferous rocks and no such relationship exists even when Tertiary materials are present. This type of response is an initial guide to the presence of such materials. Such responses must then be tested.

Figures 24 and 25 review line B.
The pattern of line A is repeated; mafic rocks define many boundaries. At least two of them imply thrust slices. The modest depression in the gravity field at 60 km has been taken to suggest Ordovician-Silurian rocks and to be a muted form of the outcrop response near 25 km. The reduced Bouguer anomaly to the east may imply similar presence but the overall regional pattern indicates thinning Precambrian only.

This effect is emphasized in Figures 26 and 27 for line C. Anomalies generated in the post Carboniferous cover are not significant but will be important to specific targetting and well prognoses. Note that the magnetic slices match the edges of the dense slab; the vertical scale distorts the correlation between the figures.
Figure 27 stresses the inconsequential character of dolerite- based sources.

Figure 28 (line D) indicates the nature of extreme and localised dolerite effects. A very large feeder is implied. The nature of the anomaly is not consistent with any source generated beneath the cover unless it extends into the cover and to surface. The magnetic response is low key compared to the smaller and deeper Cambrian mafic sources.
Figure 29 stresses this association while also showing that ultramafics have been folded into the structure as a quasi stratigraphic mass in the same way as occurs in the Huskisson Syncline northwest of Rosebery in western Tasmania.
The relationships inferred in lines A to D are wholly consistent in structural and stratigraphic style with those defined in western Tasmania and there is no reason to propose any different evolution for parts of Tasmania.

Figures 30 and 31 examine line E. The magnetic models are well developed and consistent with other lines. The gravity model overstates mass west of 20 km and understates it near 60 km. It does show that no dolerite source, even if a large feeder, can generate the anomalies observed. A major slice of dense rock is implied.
The gravimetric response of the exposed Gordon Group is not significant on this line indicating a relatively small volume.

The difference in volume and depth extent of Ordovician rocks is shown in Figures 32 and 33 (line G) where the scale of the fold is confirmed by the enclosed ultramafics. The more limited nature of the dense slab to the east is also clearly defined. It is possible that more Gordon Group is present at the eastern end of the profile although the effect may be part of the strong east west gradient which defines the major change in composition about the northing of Great Lake. Further evaluation is required.

No such controversy applies to Line H (Figures 34 and 35).
Figure 34 examines the bulk amount of Cambrian and Precambrian sequences implied but the effect of the exposed Ordovician and Silurian rocks, though obvious, has not been modelled.
The magnetic model demonstrates that even giant dolerite feeders do not generate the large spikes of the magnetic field. Such feeders do, however, appear to be intruded into older structures - some of which are marked by ultramafics.

Figures 36 and 37, line I, examine the gross patterns of the field which are sometimes observed. A strong asymmetry is apparent in the magnetics and may be explained by a wedge of of Cambrian rocks within the western block. The spikes are inferred to reflect dolerite effects and mafic junctions within the basement rocks. The gravity profile stresses the risk of ambiguity in assuming that all low, in relative terms, anomaly values reflect Gordon Group. The model shows that this need not be the case; simply the absence of dense slabs. The anomaly on this line at 65 km, near the Derwent River, could be assigned to cover rocks of various types until inspection of the distribution of the anomalies shows that the patterns are not consistent with surface rocks. The anomaly on this line requires much more analysis since it might well reflect underlying interest.

Line J (Figures 38 and 39) is dominated by the presence of a thick slab of dolomitic Precambrian etched by dolerite feeders and perhaps mafic slices of Cambrian age. The western end of the profile is controlled by the presence of a large granite mass within south west Tasmania. Its roof is barely more than 1 km deep.

Similar character is evident on Line K (Figures 40 and 41). The dip in gravity anomaly at 55 km may indicate a thin skin of Gordon Group. The magnetic model needs refinement but indicates a large fold within the older rocks which involves both mafic volcanics and ultramafic defined boundaries.

Line L (Figures 42 and 43) stresses the relative contribution of structures and rock types. The regional thinning of the sequence to the east accounts for large trends while the granite to the west cancels the attraction of the thickened Precambrian structures. No Gordon Group is implied anywhere. The small gravity spike at 53 km may represent a dolerite feeder.
The magnetic model examines the possibility of a thick Cambrian volcanic sequence in the Bagdad-Broadmarsh area.

Figure 44 presents the magnetic model for tie line Z. It reinforces conclusions based on other lines for the presence of mafic volcanics and junction ultramafics.

Many of the implications of these profiles have been compiled in the Map. ← missing
The regional and more detailed work has stressed that the covering rocks, including dolerite, are not especially significant geophysically. They produce useful responses which will need to be taken into account in any refined interpretation but are not sources of primary ambiguity in terms of gross evaluations.

Ordovician-Devonian rocks generate distinctive gravity anomalies within the Maydena-Derwent Valley region but are generally present as syncline remnants, sometimes of considerable volume. The upper surfaces are truncated by the Carboniferous erosion surface. The structures can often be defined in detail by the ultramafics which underlie them and which have been structurally emplaced, eroded, and then folded with the Gordon Group.

Inspection of many sections will show that the axes of many blocks are often well defined but that the edges are not. The existence of large Precambrian dolomitic slabs within thrust slices which reach to the Permian unconformity and represent exposed material during the Carboniferous offers a caution for any rushed exploration. It would be too easy to drill such a block. Its presence, and that of the unconformity seal, may be vital factors in preservation of hydrocarbons.

Present work has defined the scale of the Florentine structures west of Maydena and shown that little of similar scale has been preserved to the east with the exception of an extension of the Florentine structure to the NE and the possible presence of thinner sequences near the axis of the River Derwent.
The significance of these conclusions cannot be appraised until compared with implications for other areas defined by the regional study. Small, but encouraging, areas must then be reviewed in greater detail.

One comparison is already possible. There would appear to be a greater thickness of Gordon Group and associated rocks in the Maydena and Derwent areas than in the Huon-Cygnet or Picton-La Perouse areas examined as part of project D'Entrecasteaux. The significance of this observation can only be rated by comparison with seep evidence but it may be observed that parts of the Derwent region contain much greater thicknesses of Permo-Triassic cover; averaging 1.2 to 1.5 km compared to 0.8 to 1.2 km in the Huon region.

REFERENCES

Leaman, D.E., and Richardson, R.G., 1989. Production of a Residual Gravity Field Map for Tasmania and some implications. Exploration Geophysics, 20, 181-184.

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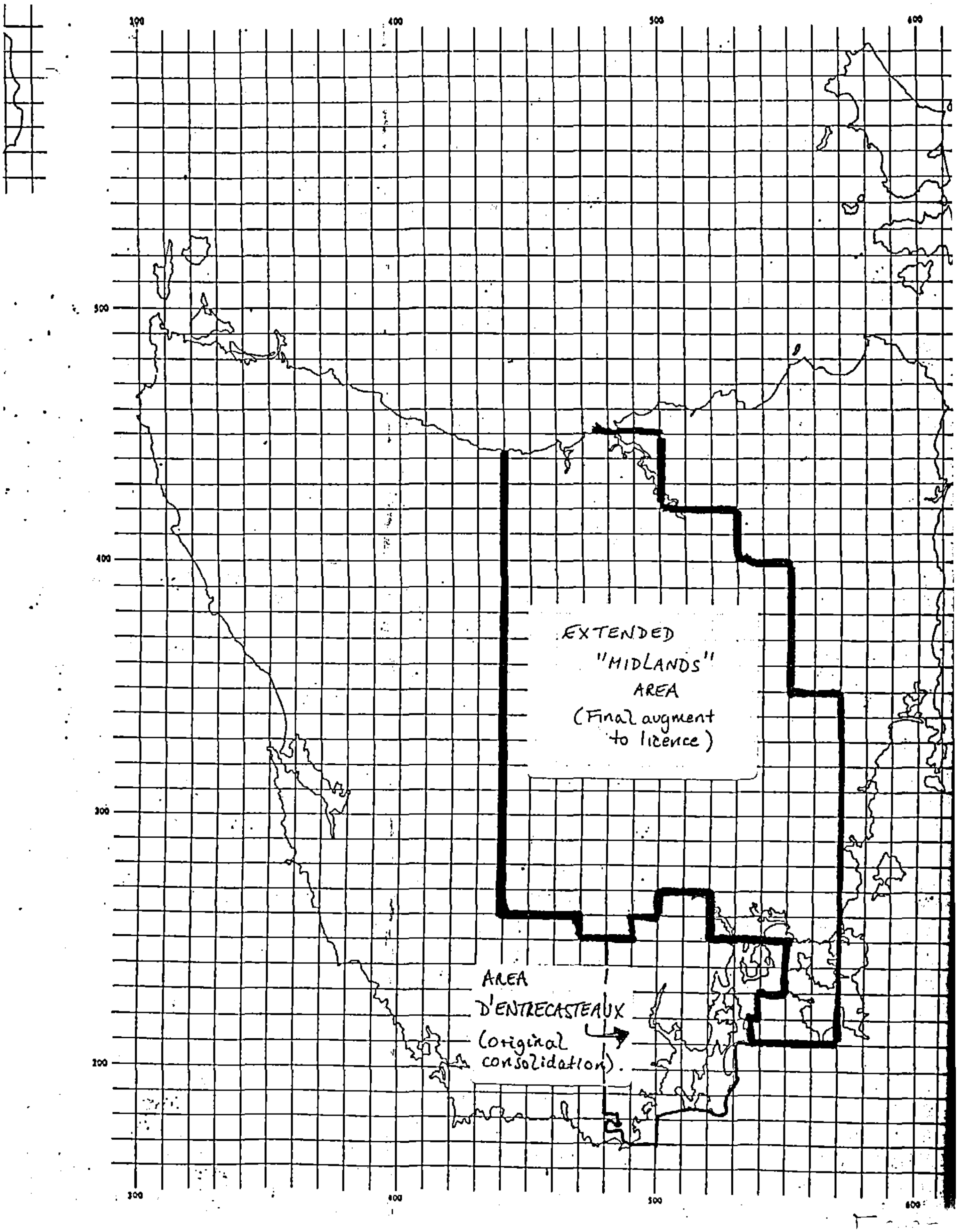
EL 1/88



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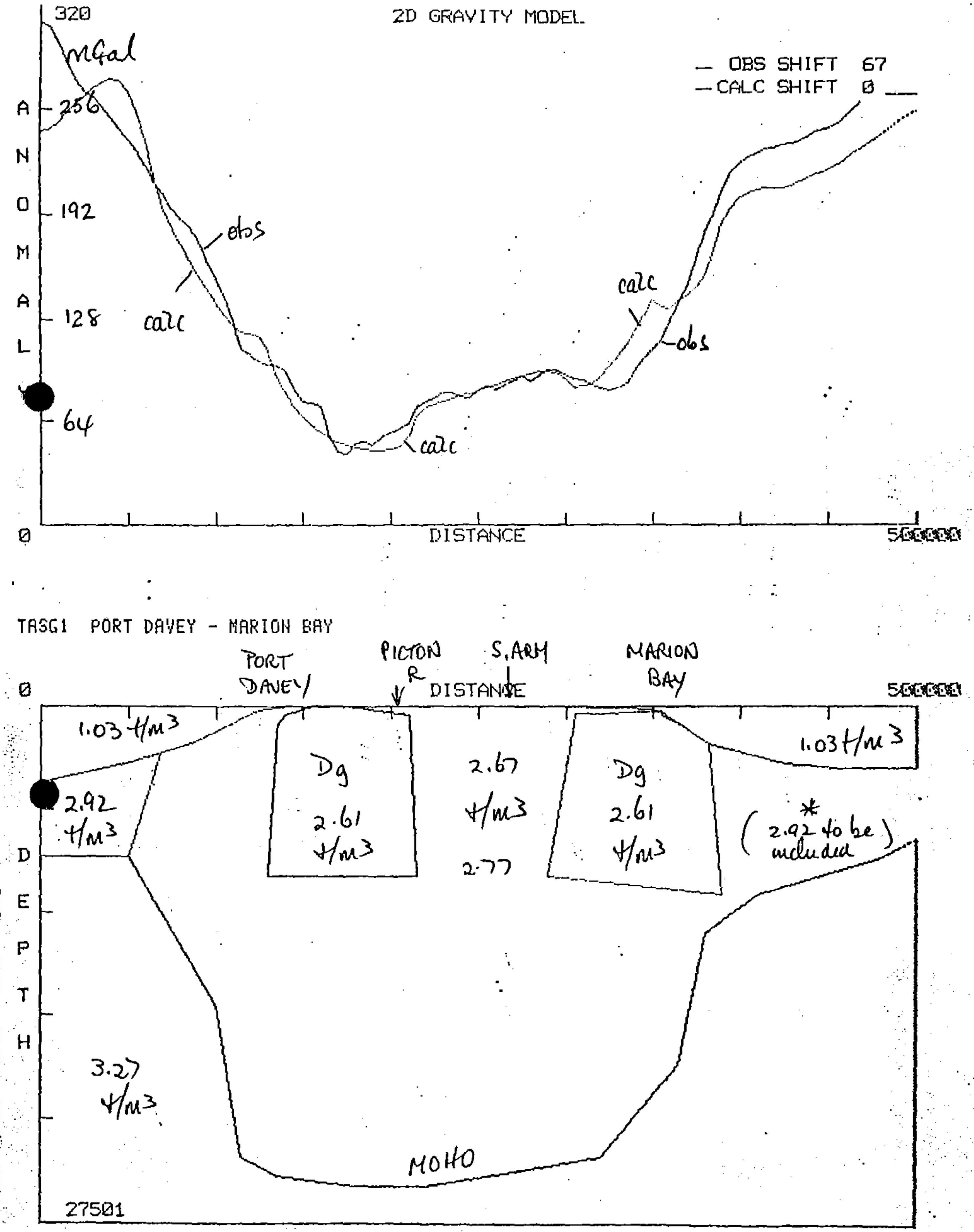

FIGURE 2

TASG2 ELLIOTT BAY - SCHOUTEN ISLAND

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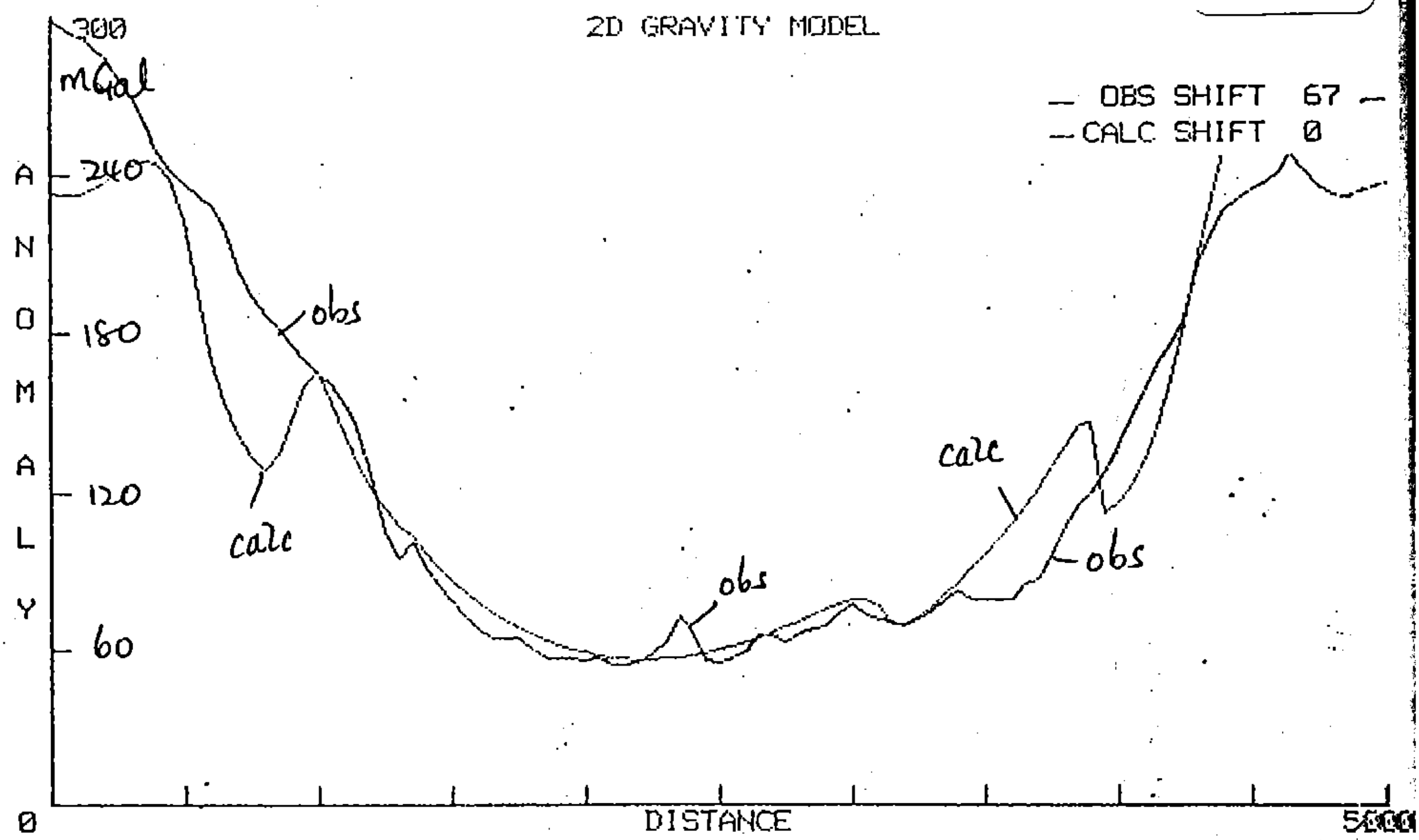

TASG2 ELLIOTT BAY - SCHOUTEN ISLAND

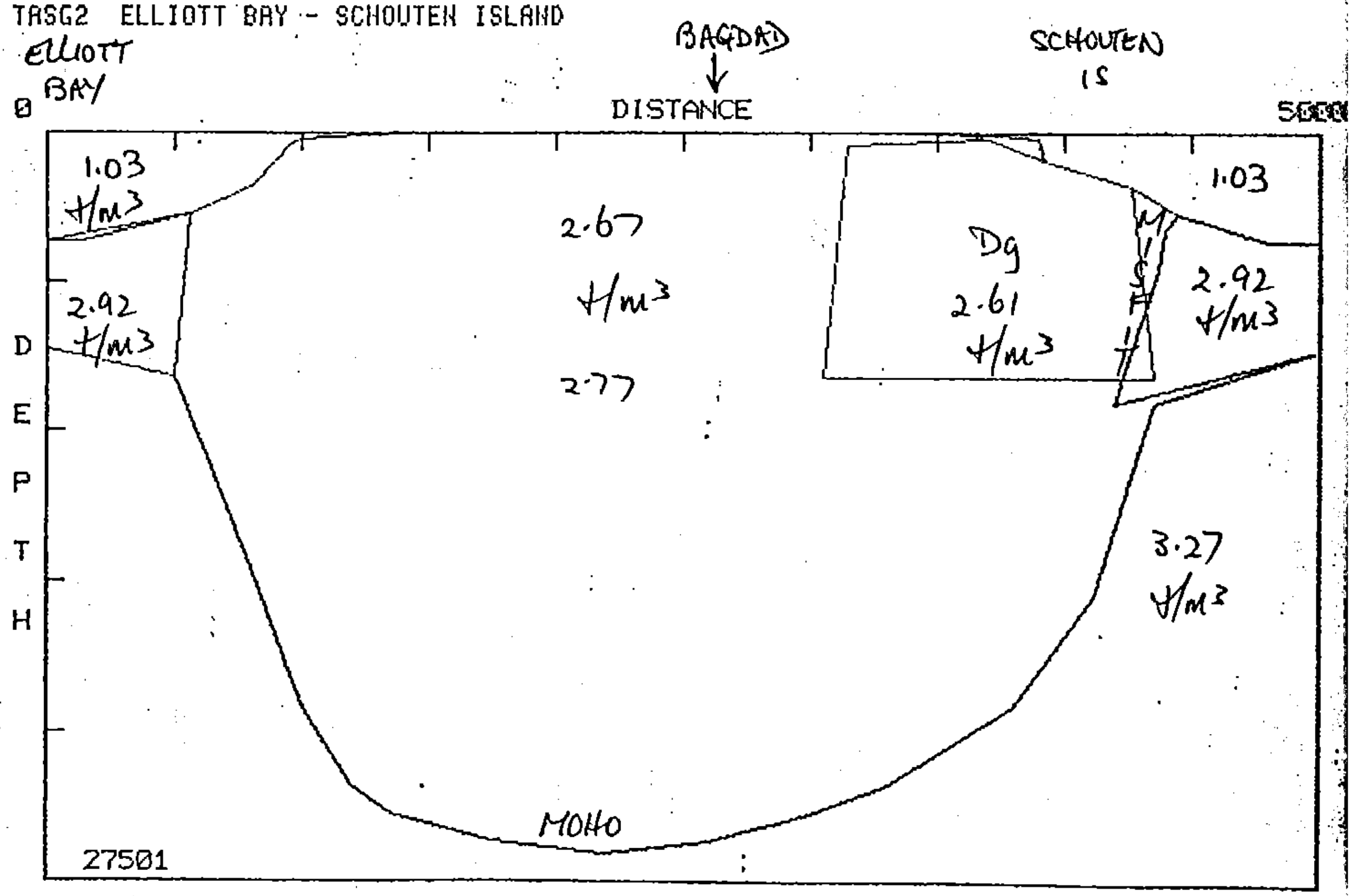

FIGURE 3

LINE PARAMETERS - ORIGIN,LIMIT,INCR : 0 140000 2500

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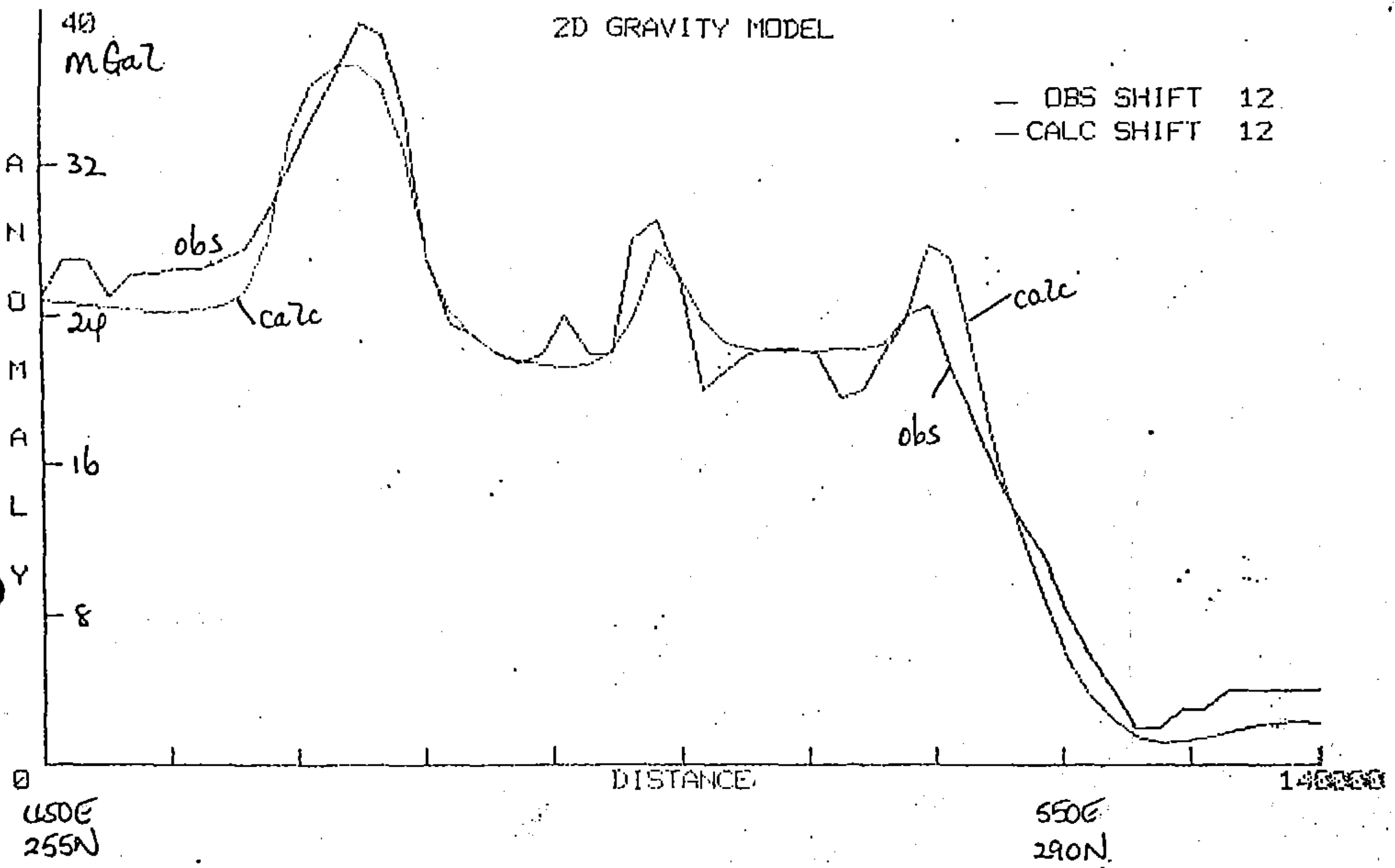
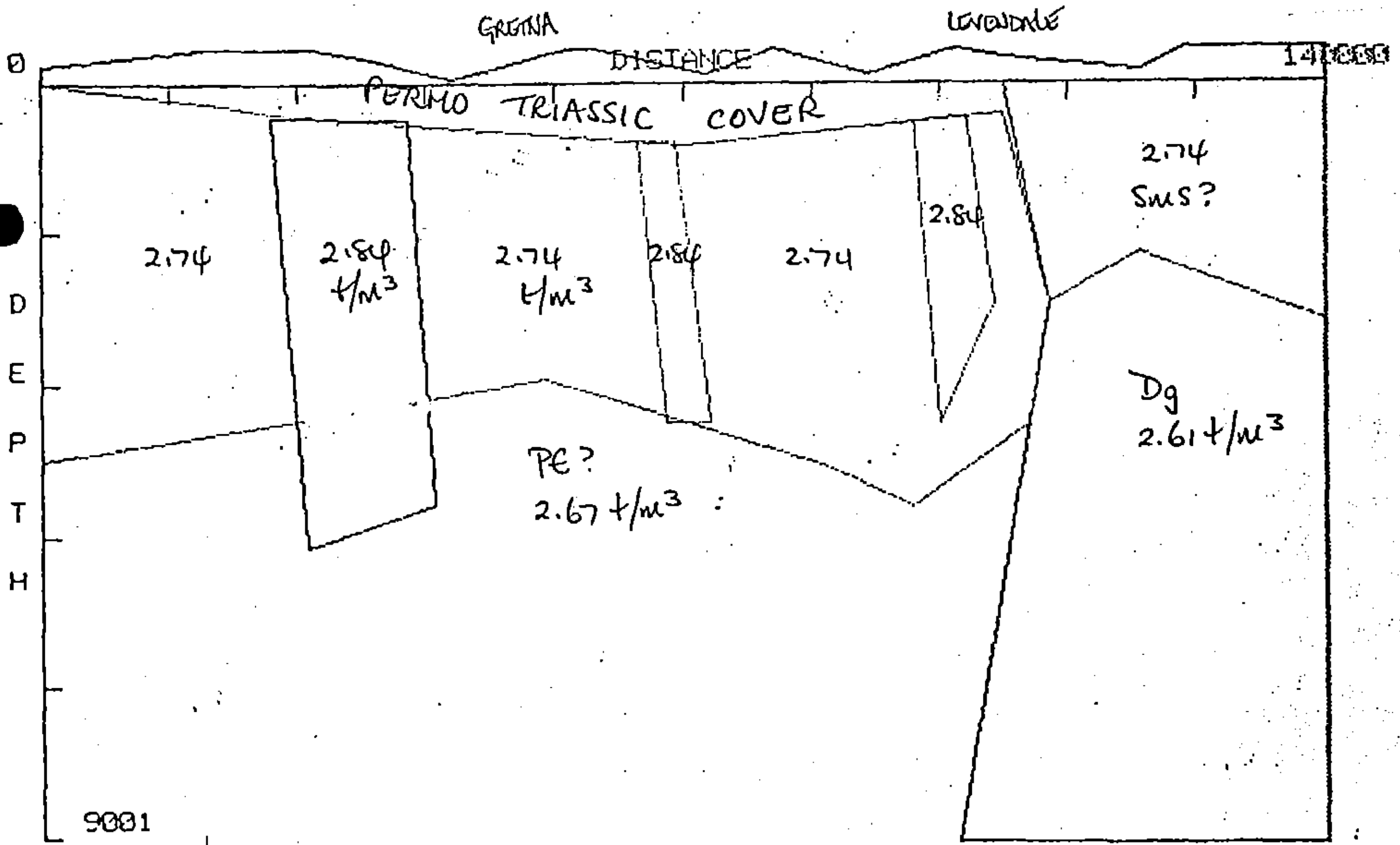


TASRG2 LOWER MIDLANDS GRETNA-LEVENDALE



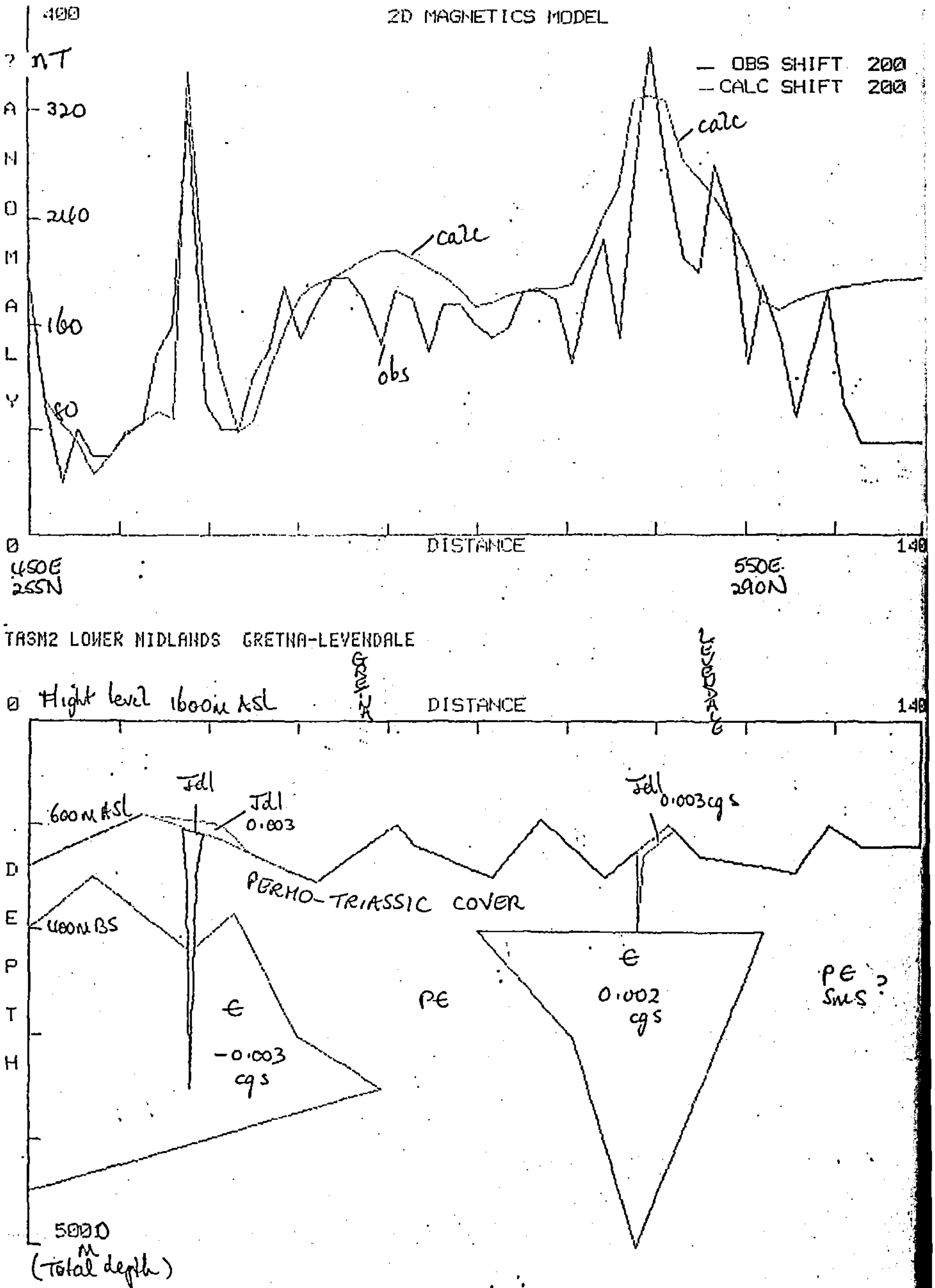
LEAMAN GEOPHYSICS
G.P.O. Box 320 D,
Hobart, Tasmania 7001

62000.0 -71.0 13.0 0.0 70.0

LINE PARAMETERS - ORIGIN,LIMIT,INCR : 0 140000 2500

357022

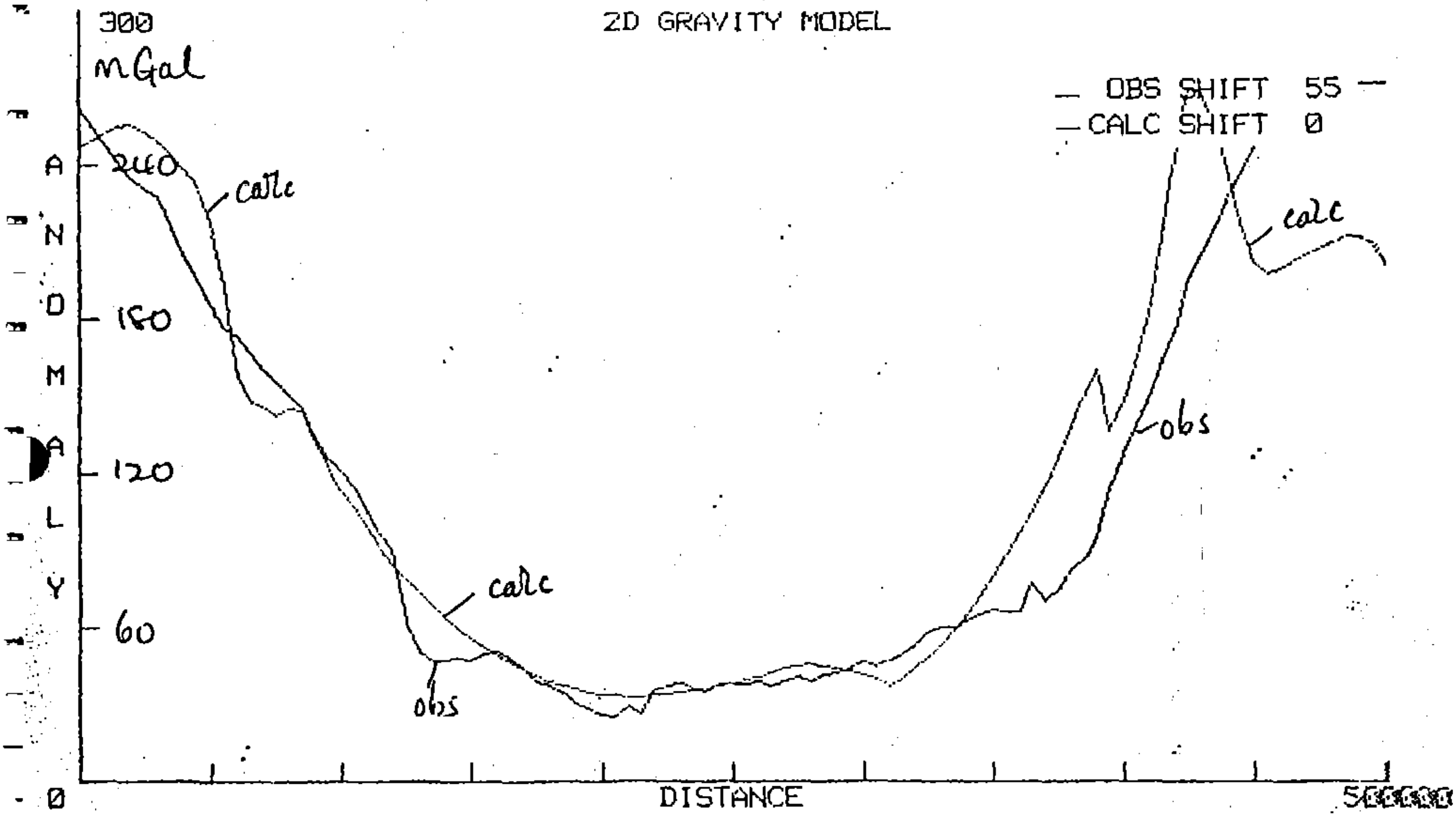
LEAMAN GEOPHYSICS
G.P.O. Box 320 D,
Hobart, Tasmania 7001



MAGNETIC MODEL LINE 2 (WITH DOLERITE EXAMPLES) FIGURE

TASG3 POINT HIBBS - FRIENDLY BEACHES

LINE PARAMETERS - ORIGIN,LIMIT,INCR : 0 500000 5000



TASG3 POINT HIBBS - FRIENDLY BEACHES

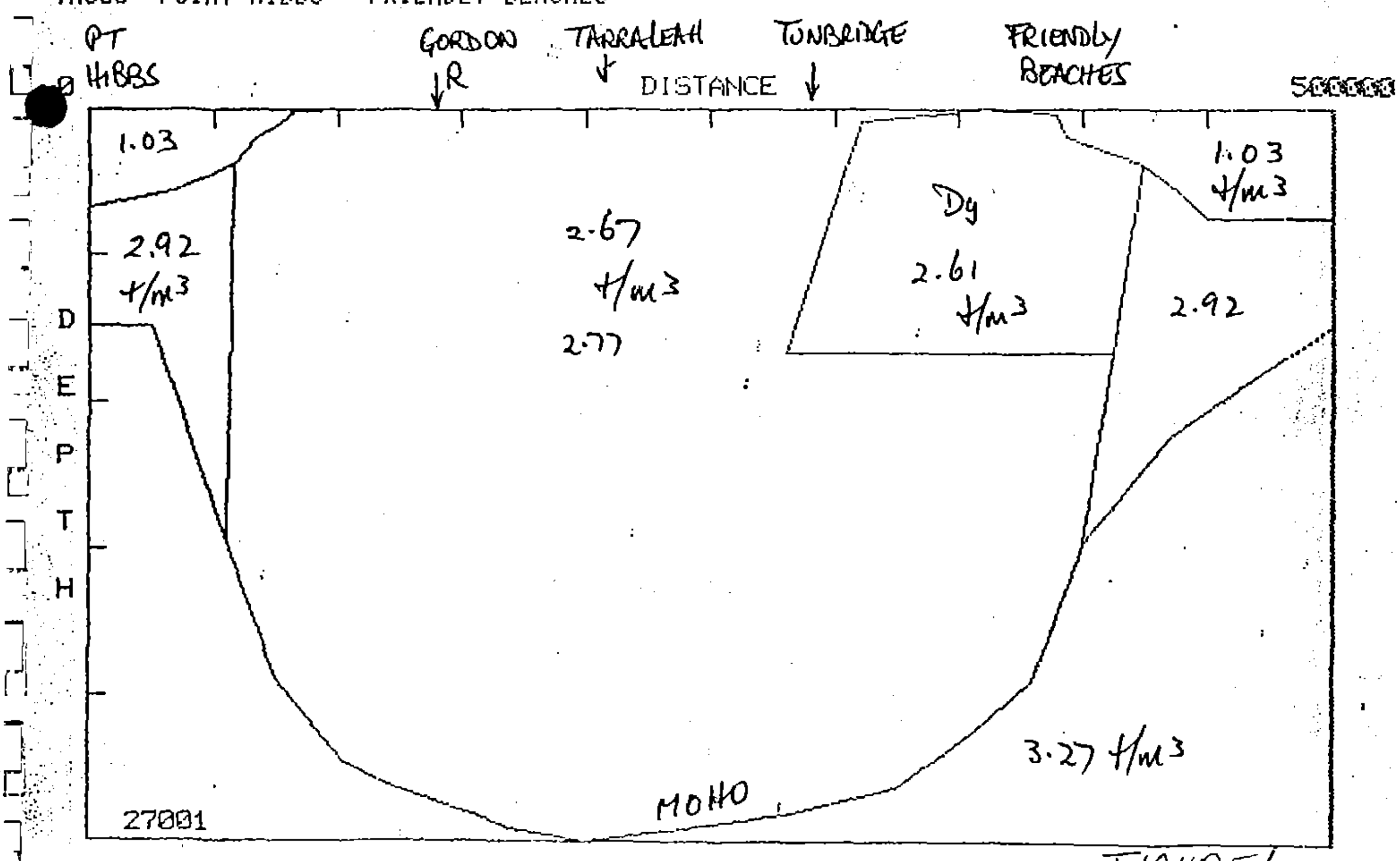


FIGURE 6

LINE PARAMETERS - ORIGIN,LIMIT,INCR : 0 140000 2500

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357024

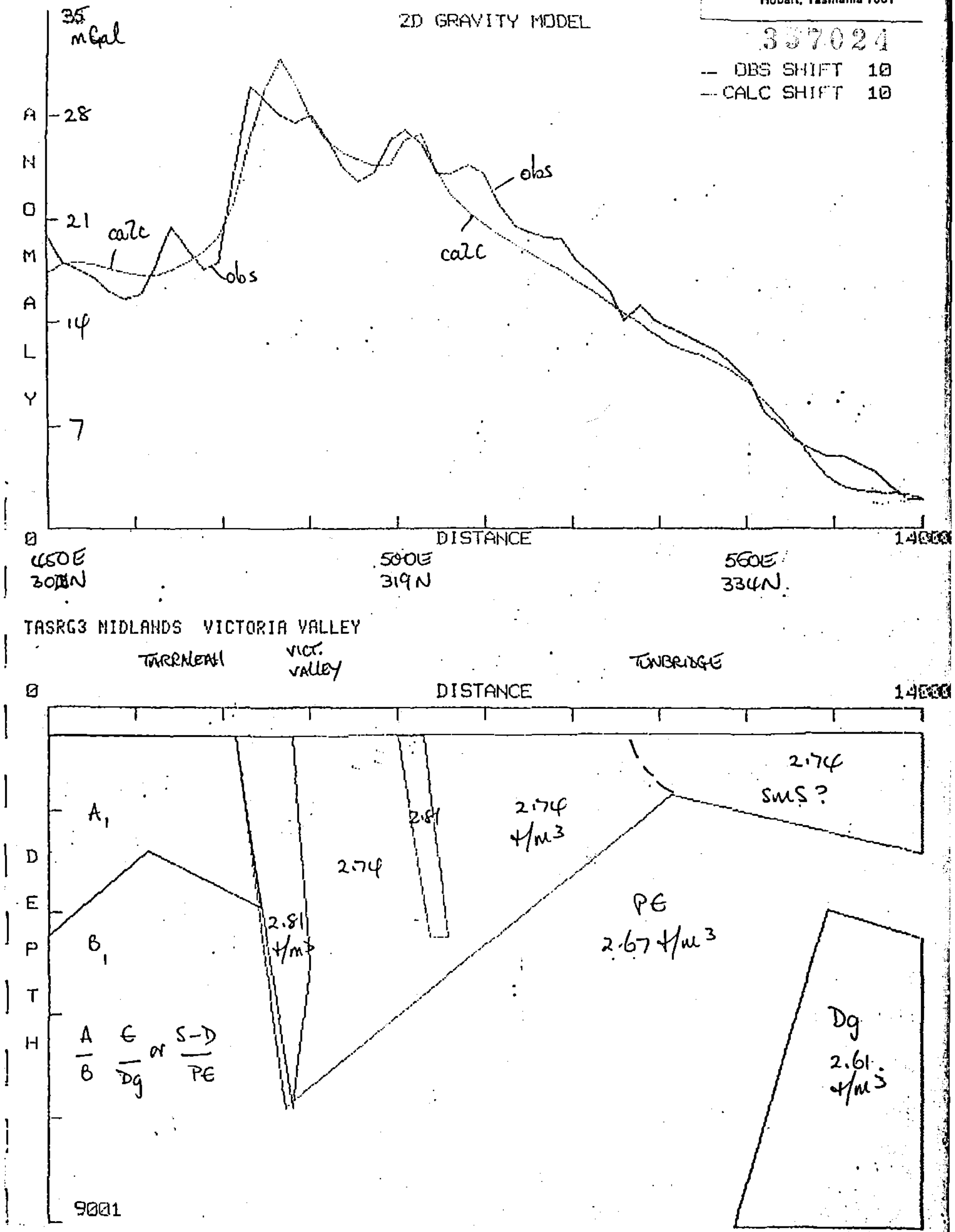


FIGURE 7

GRAVITY MODEL LINE 3

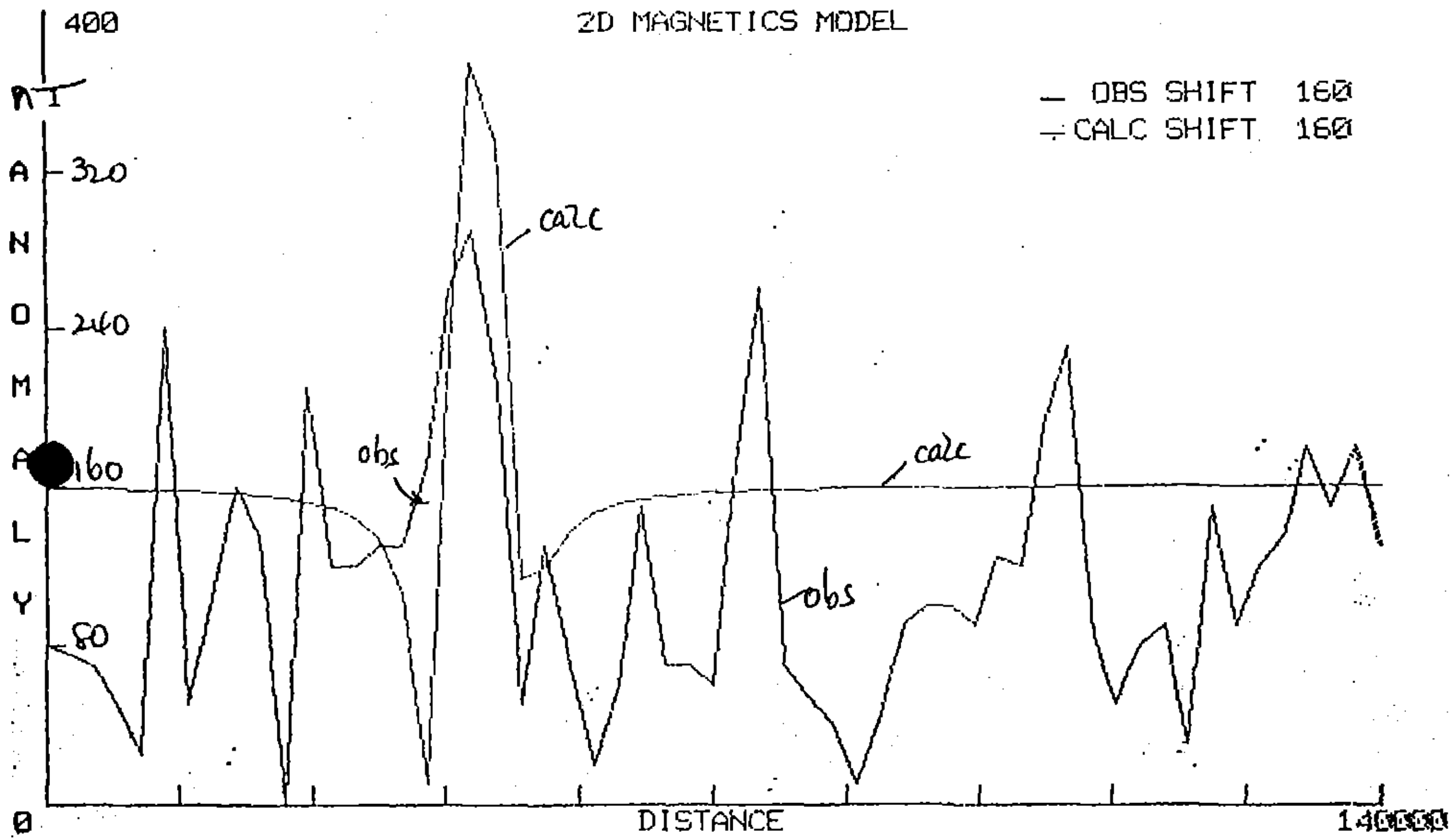
BODY DATA

357025

	SUSC	REM MAG	REM INC	REM DEC	
1.0	4.0	0.0	0.0	0.0	UNITS CGS* 1000

40000 600 50000 700 46000 1500 44000 1500

LINE PARAMETERS - ORIGIN,LIMIT,INCR : 0 140000 2500



TASM3 MIDLANDS VICTORIA VALLEY

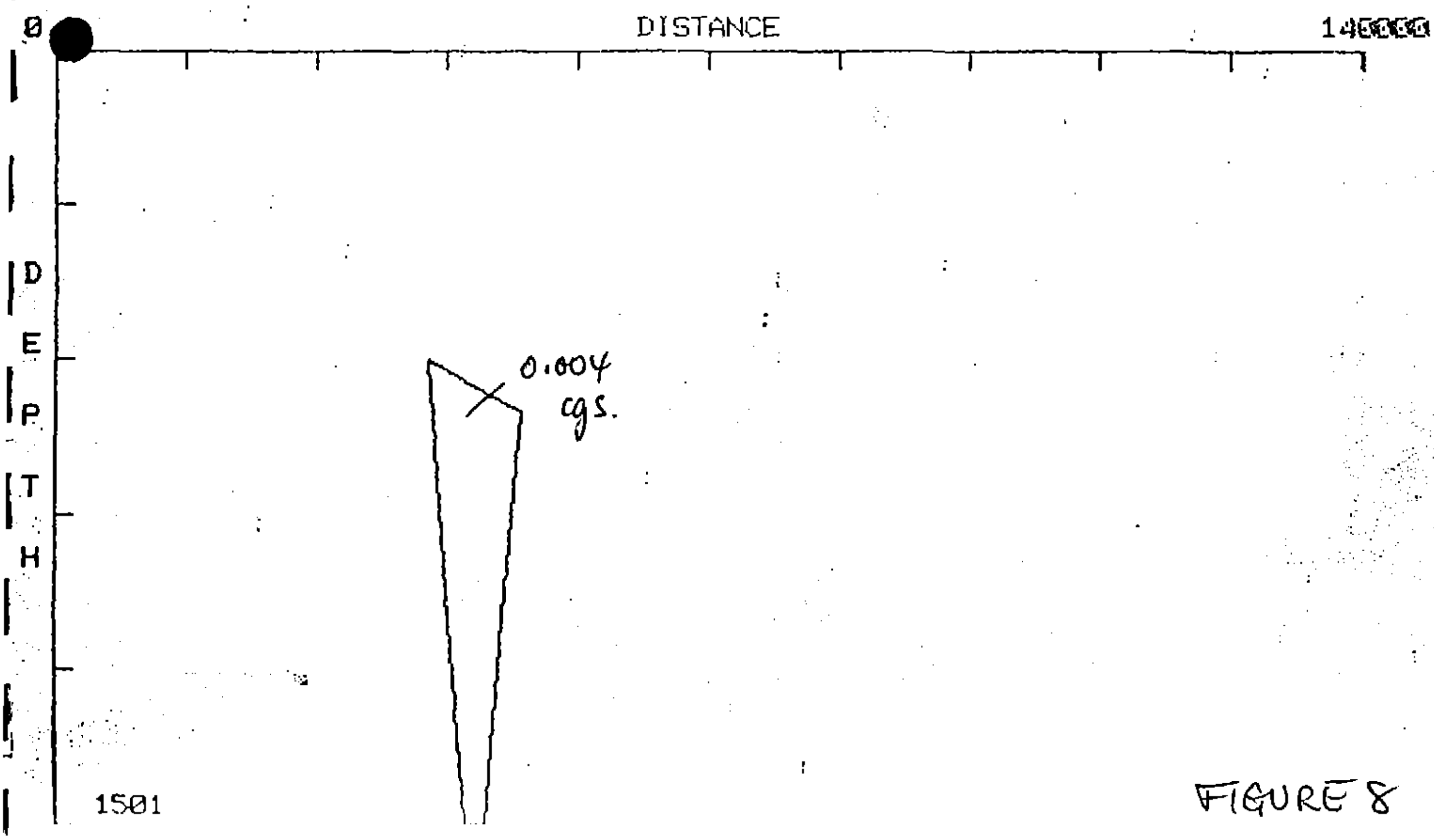
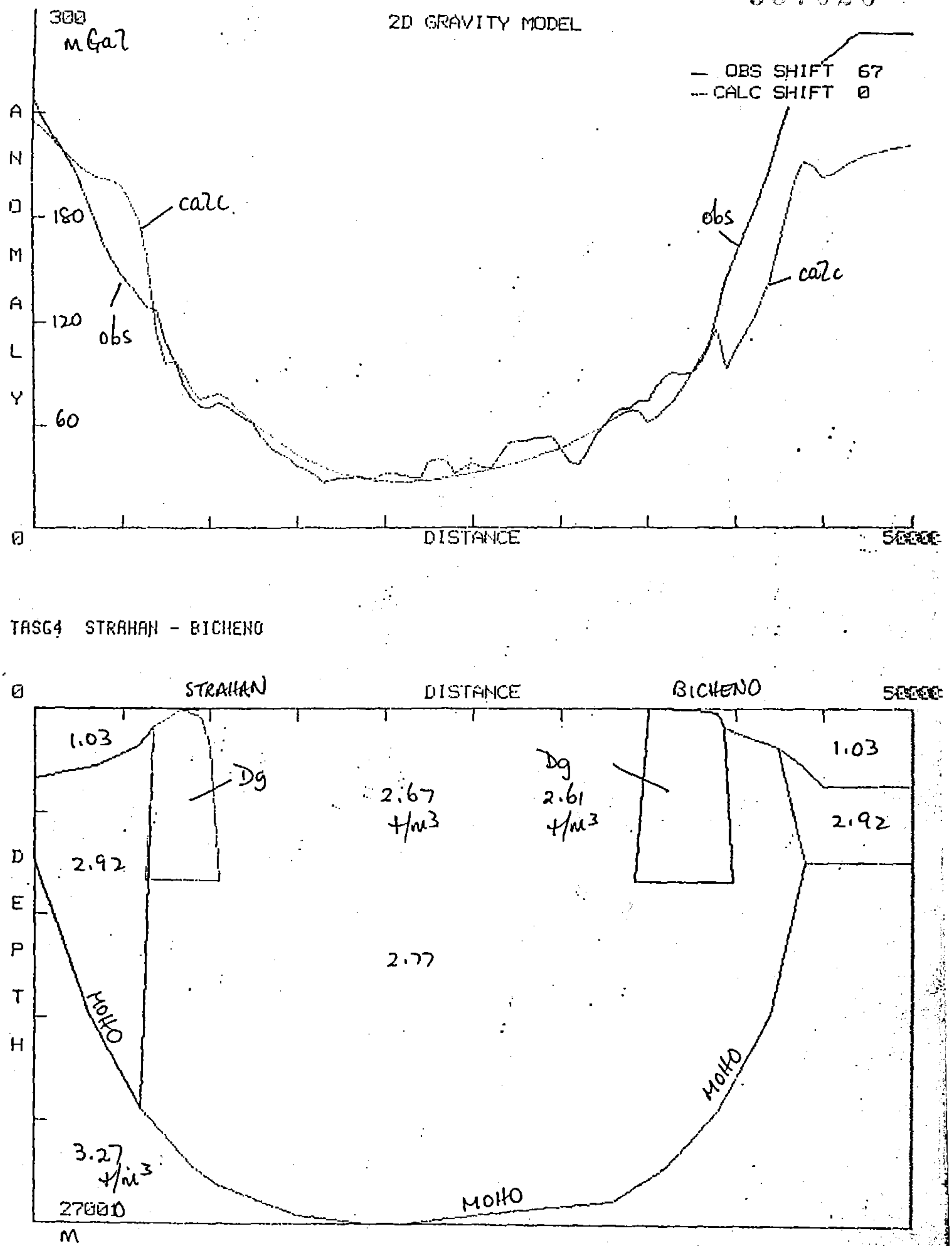


FIGURE 8

357026



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REGIONAL GRAVITY MODEL TASMANIAN CRUST LINE 4 FIGURE 9

357027

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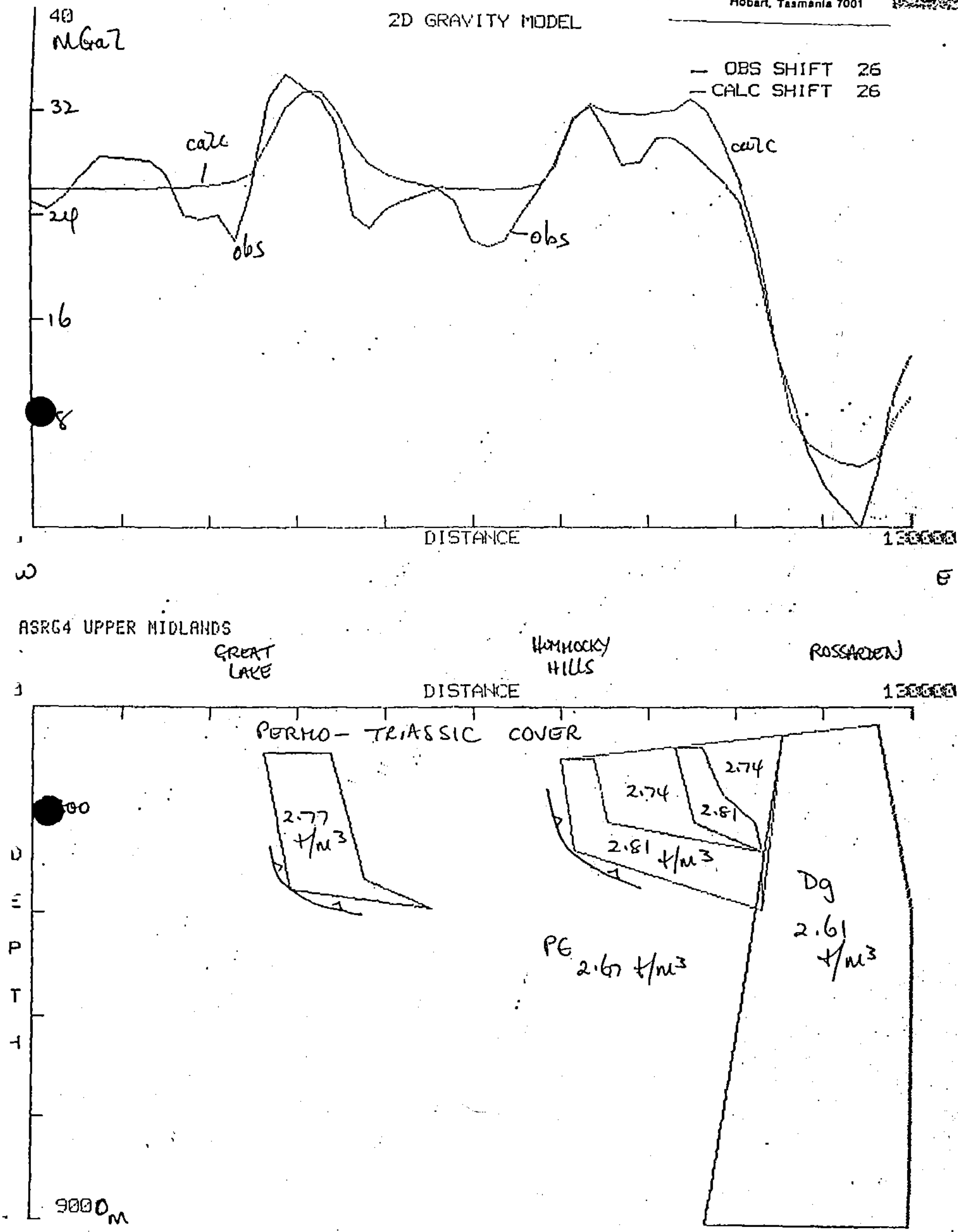

FIGURE 10

357023

LINE PARAMETERS - ORIGIN,LIMIT,INCR : 0 130000 2500

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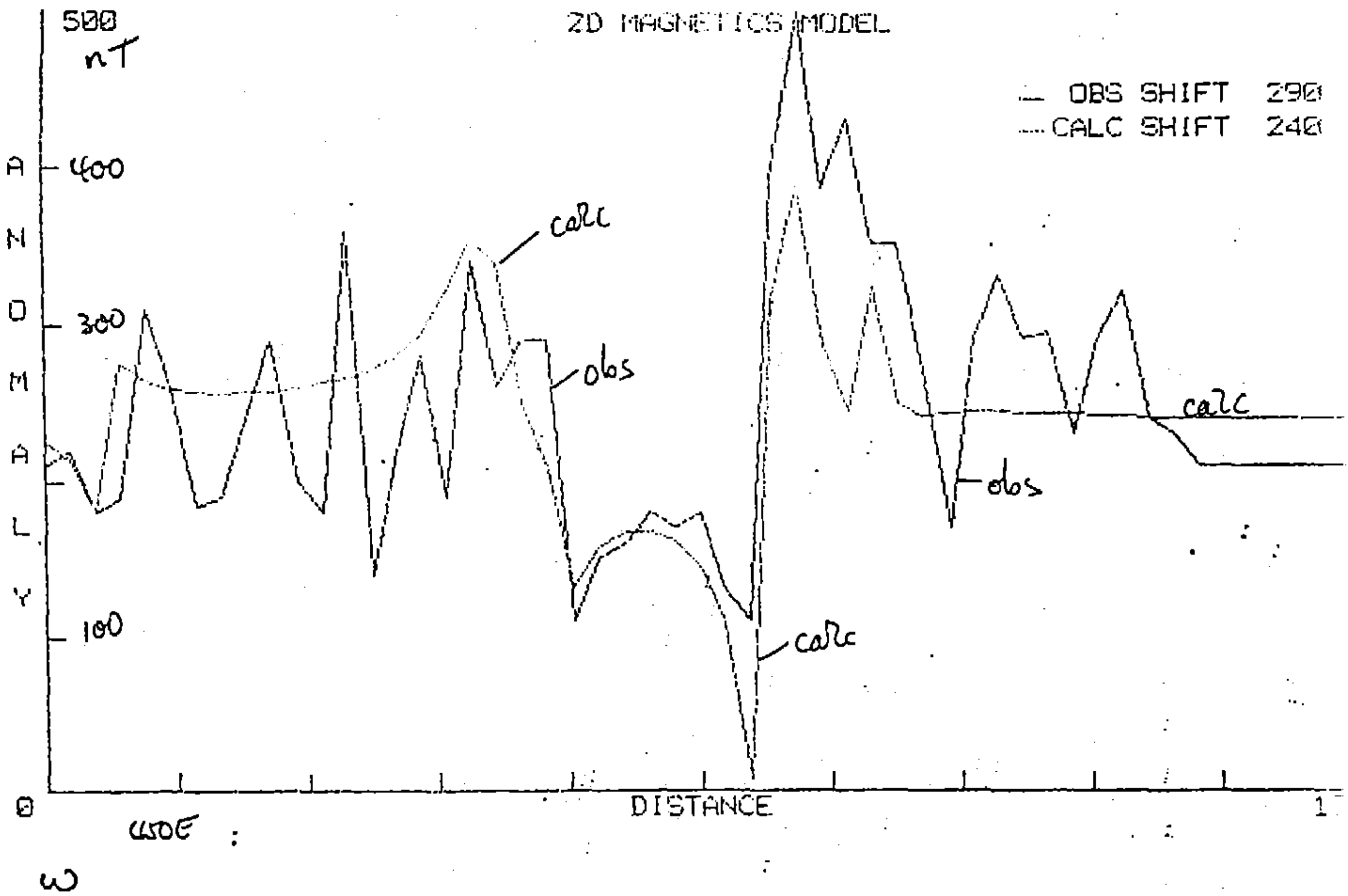
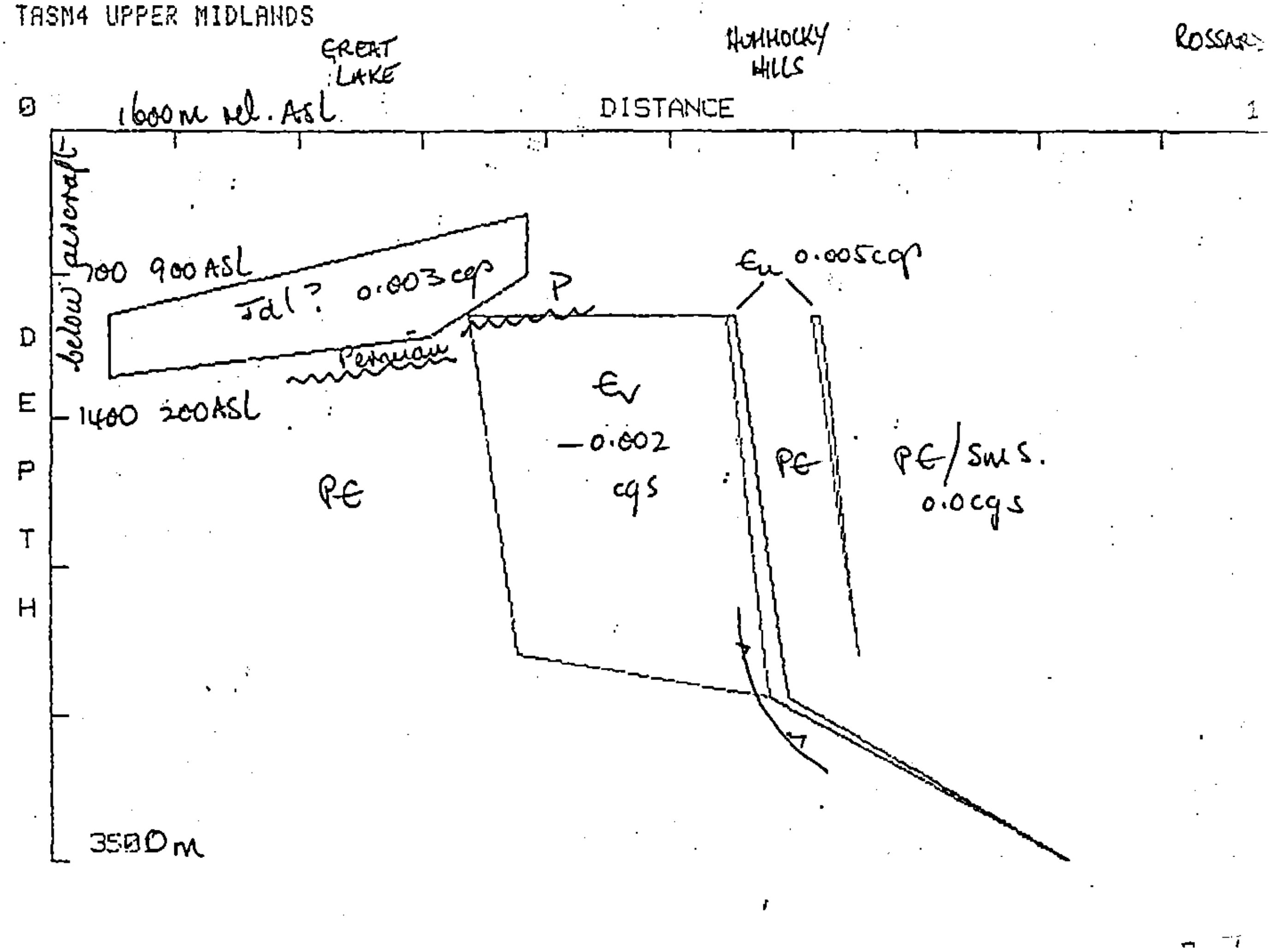
TASM4 UPPER MIDLANDS



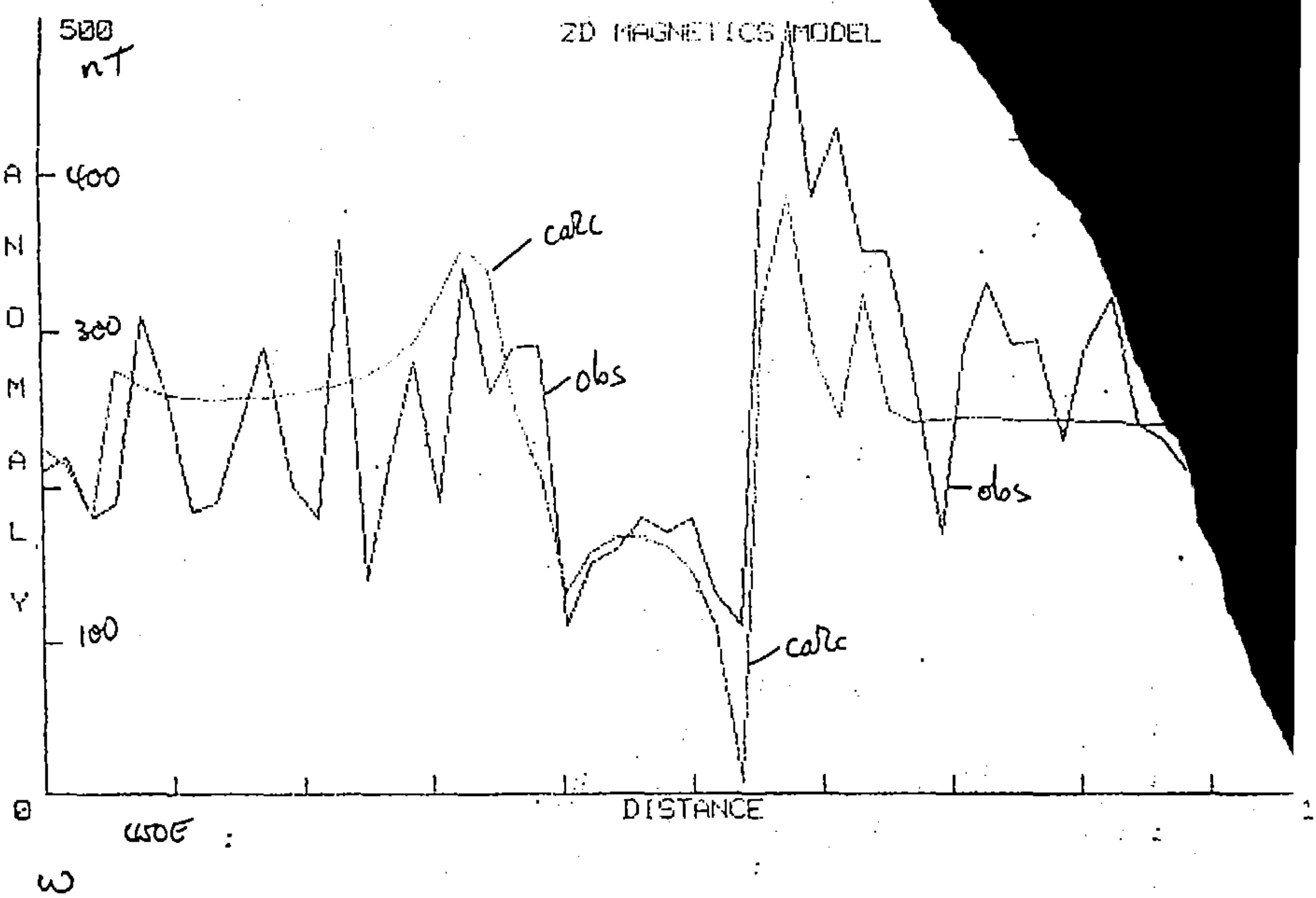
TASM4 UPPER MIDLANDS



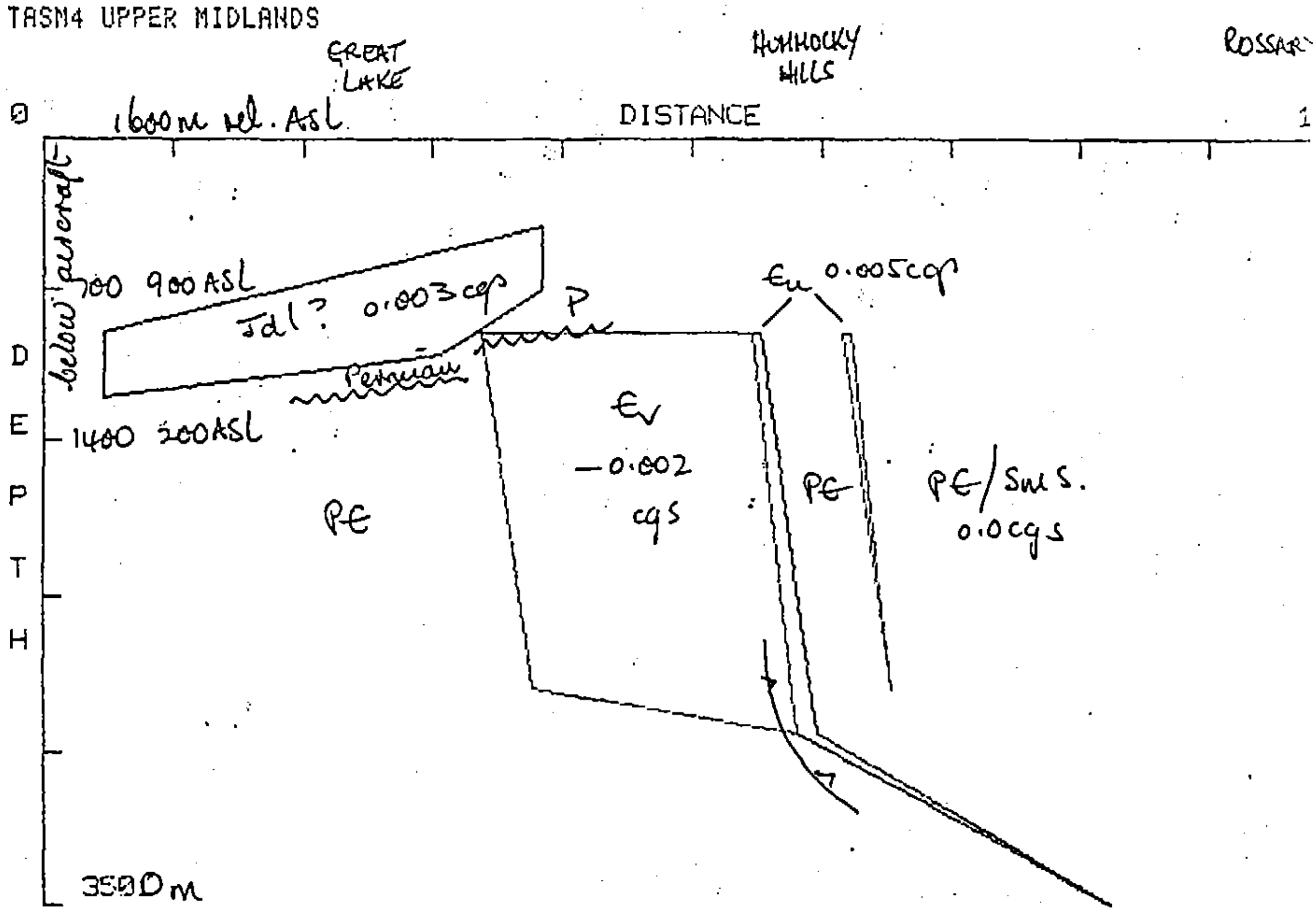
357 024

LINE PARAMETERS - ORIGIN,LIMIT,INCR : 0   130000

TASM4 UPPER MIDLANDS



TASM4 UPPER MIDLANDS



52501 9500 160000 2500 160000 9000 132501 9000

-LINE PARAMETERS - ORIGIN,LIMIT,INCR : 0 132500 2500

357030

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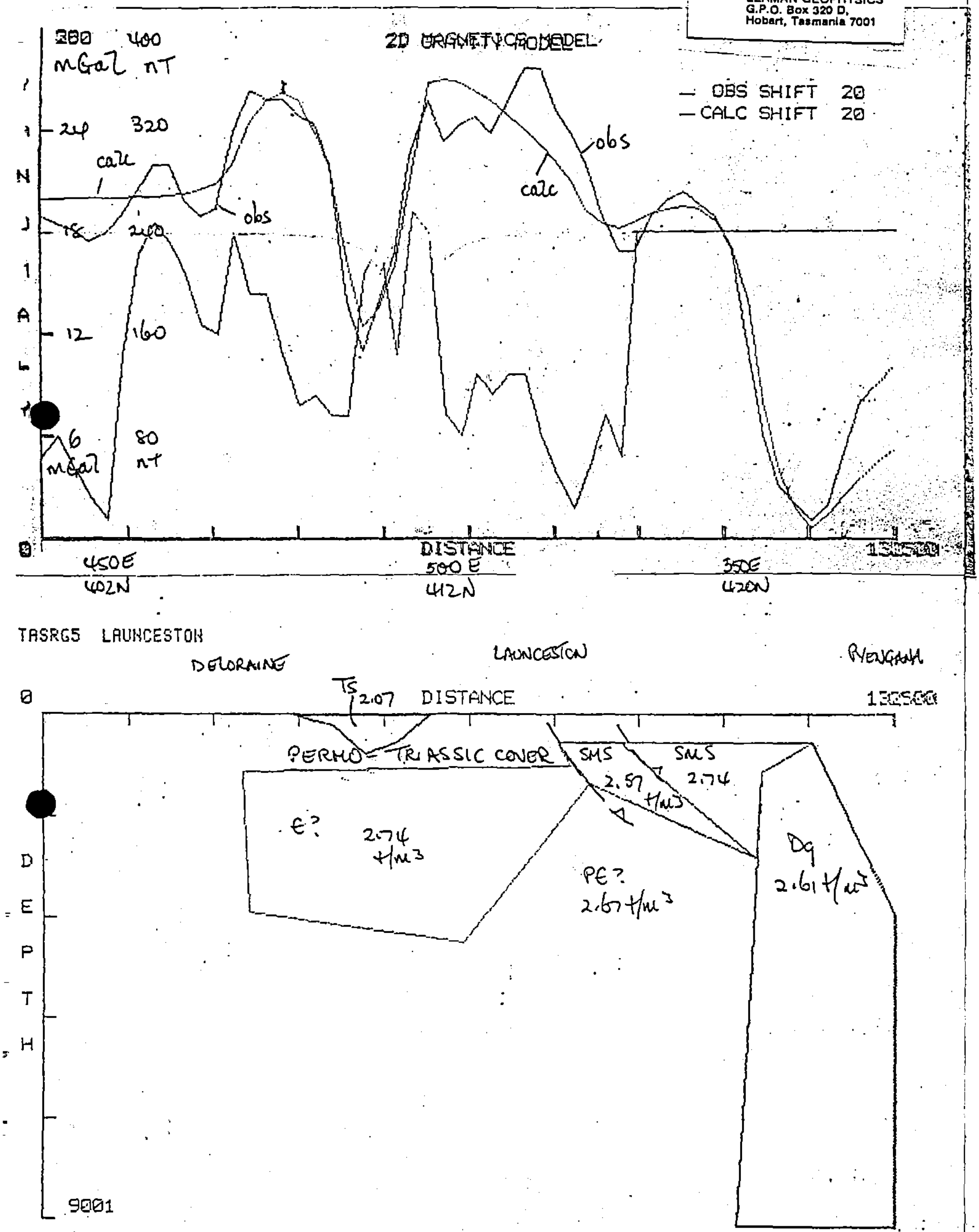


GRAVITY MODEL LINE 5 (incl magnetic profile) FIGURE 32

LINE PARAMETERS ORIGIN/LIMIT/INCR : 0 132500 2500

357031

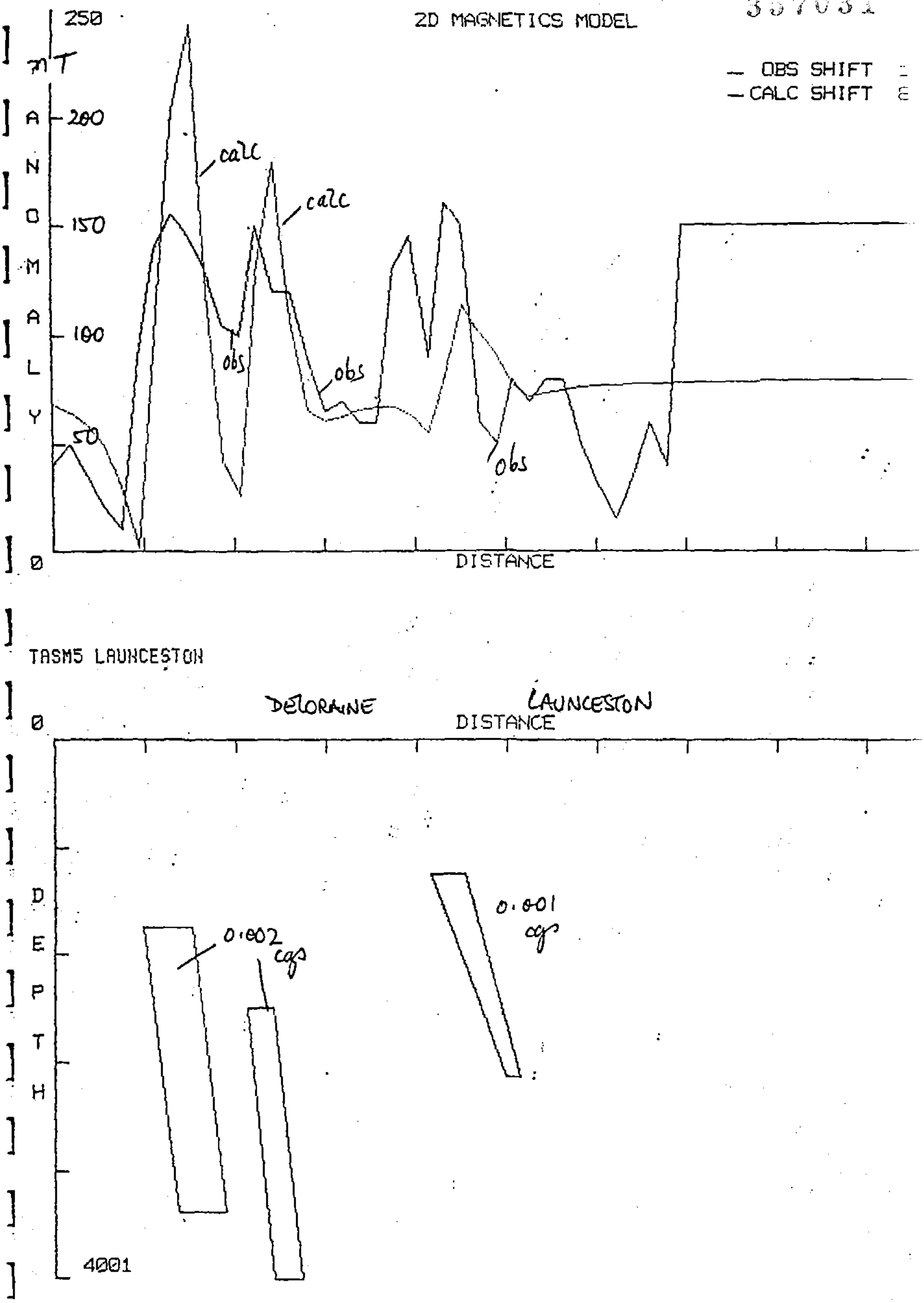
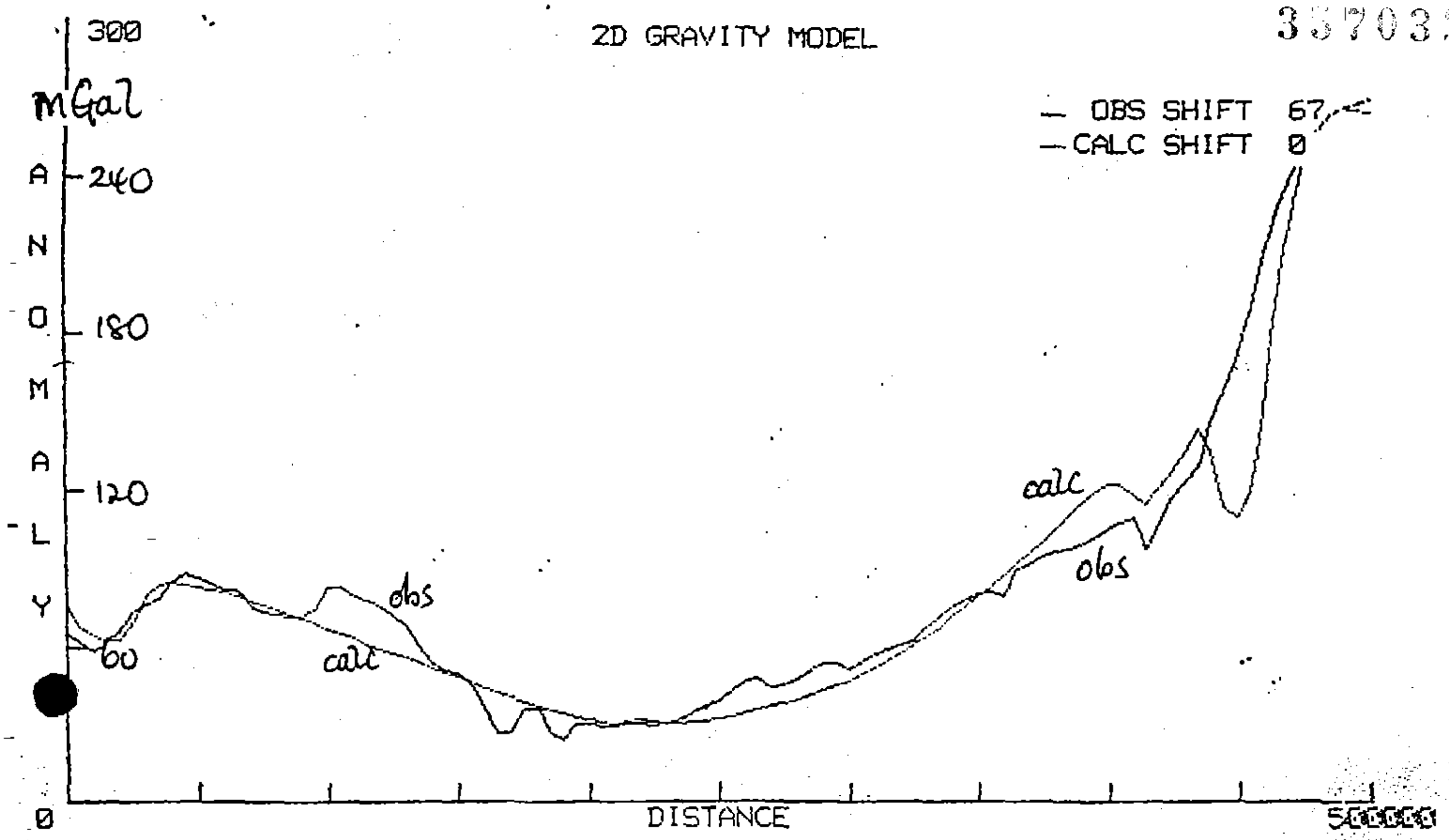


FIGURE 1

LINE PARAMETERS - ORIGIN,LIMIT,INCR . 0 500000 5000

357032



TASG7 THREE HUMMOCK - PORT ARTHUR

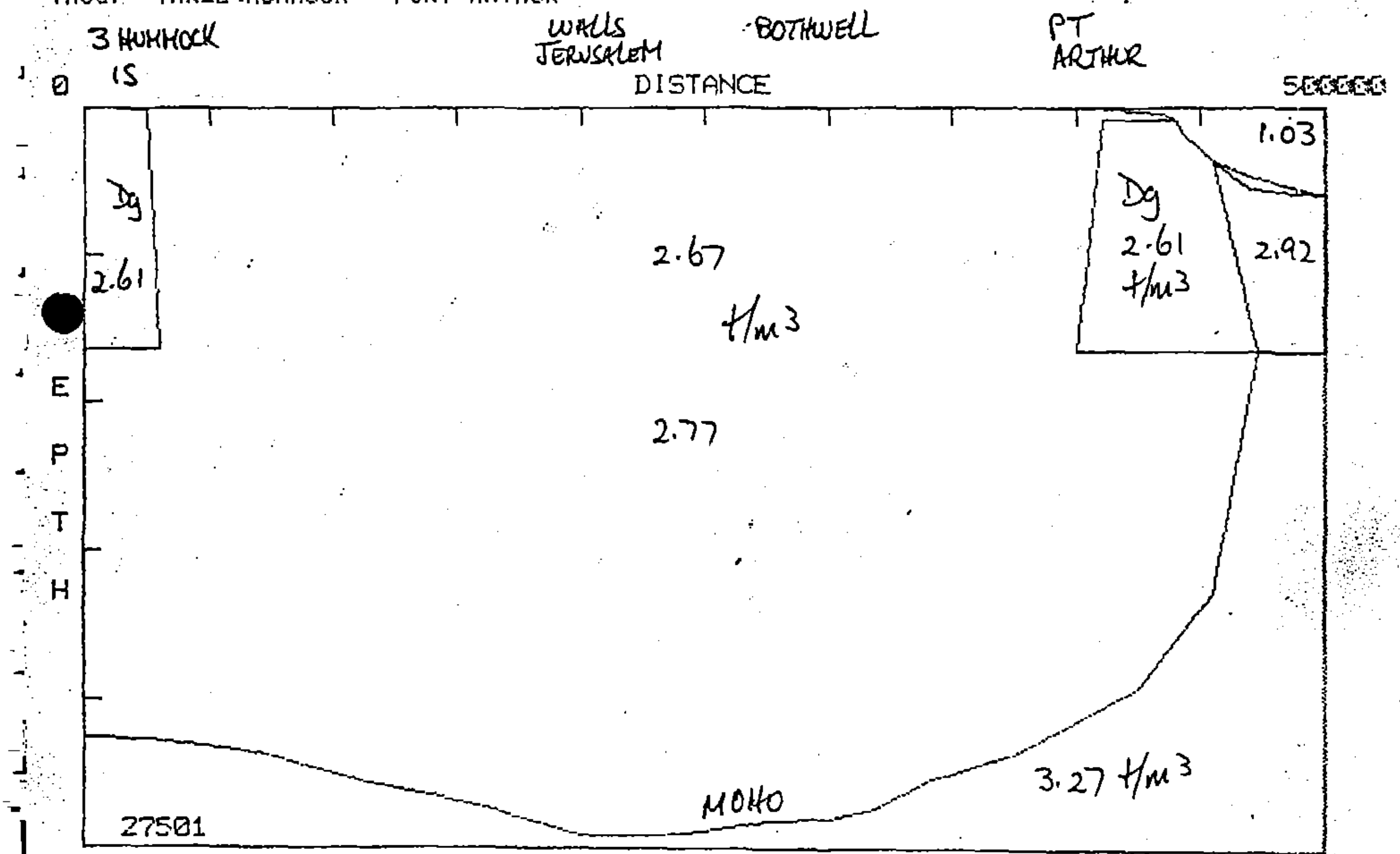
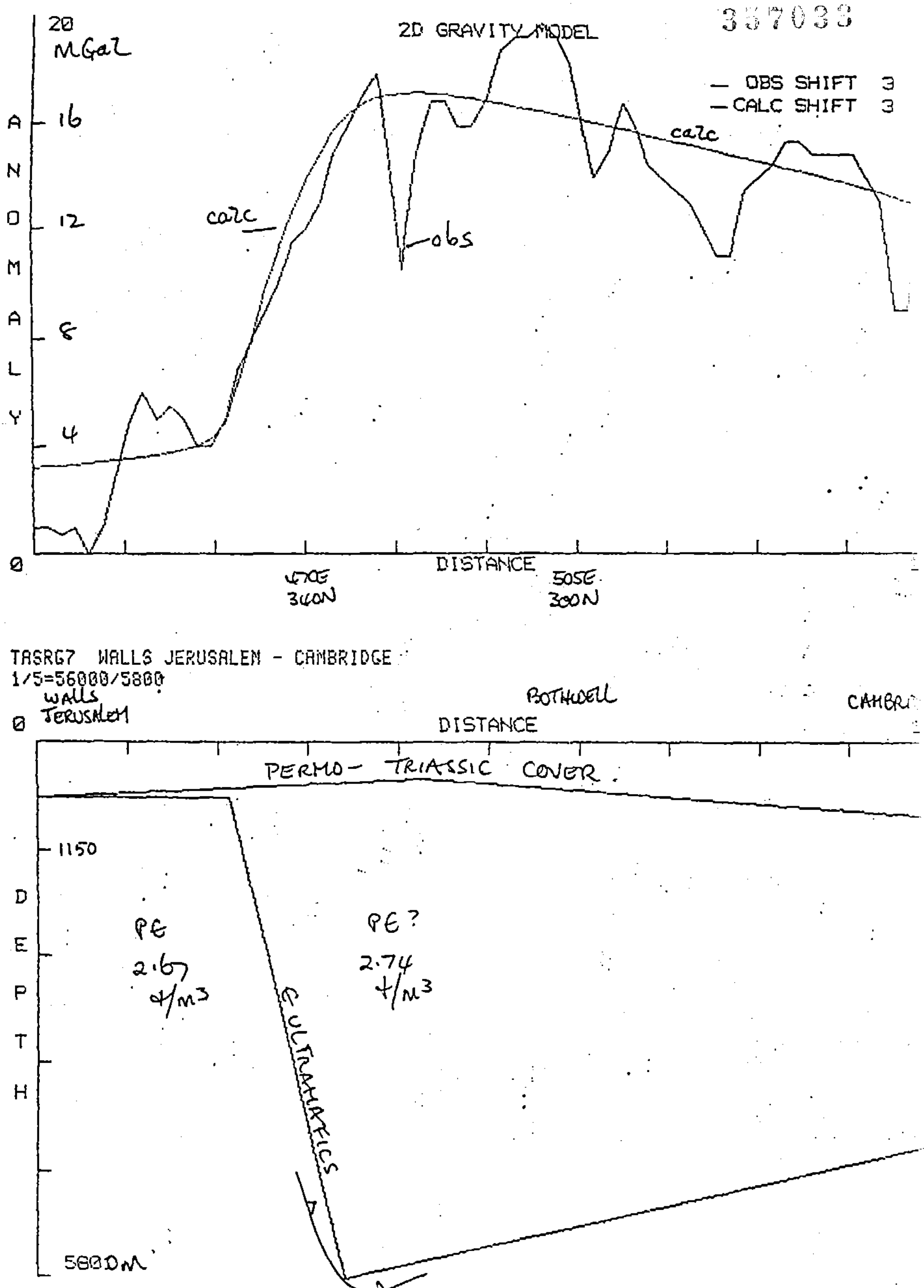


FIGURE 14

357033



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Hobart, Tasmania

GRAVITY MODEL LINE 7

FIGURE 15

LINE PARAMETERS - ORIGIN,LIMIT,INCR : 0 165000 2500

357034

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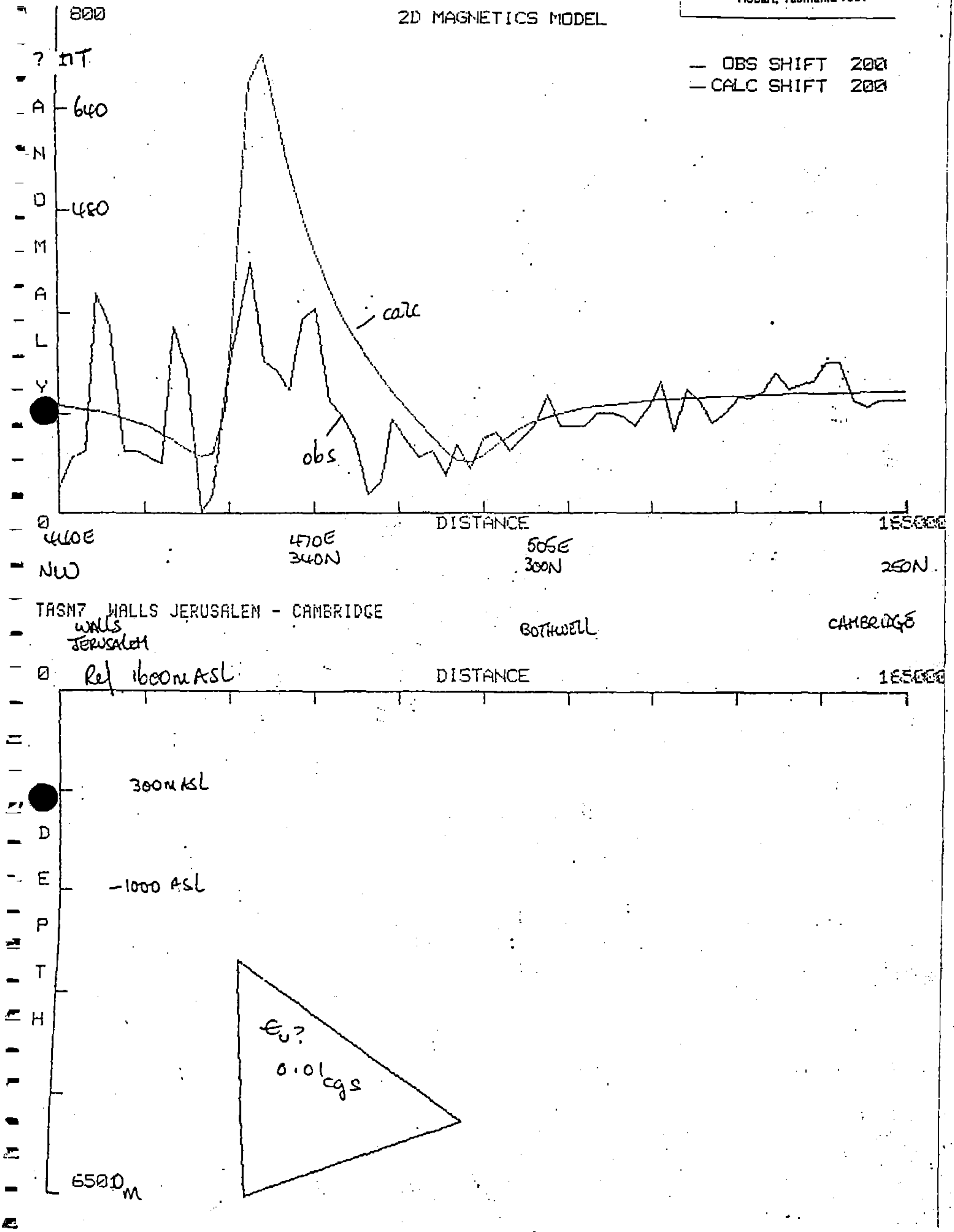

MAGNETIC MODEL LINE 7

FIGURE 16

357035

LEAMAN GEOPHYSICS
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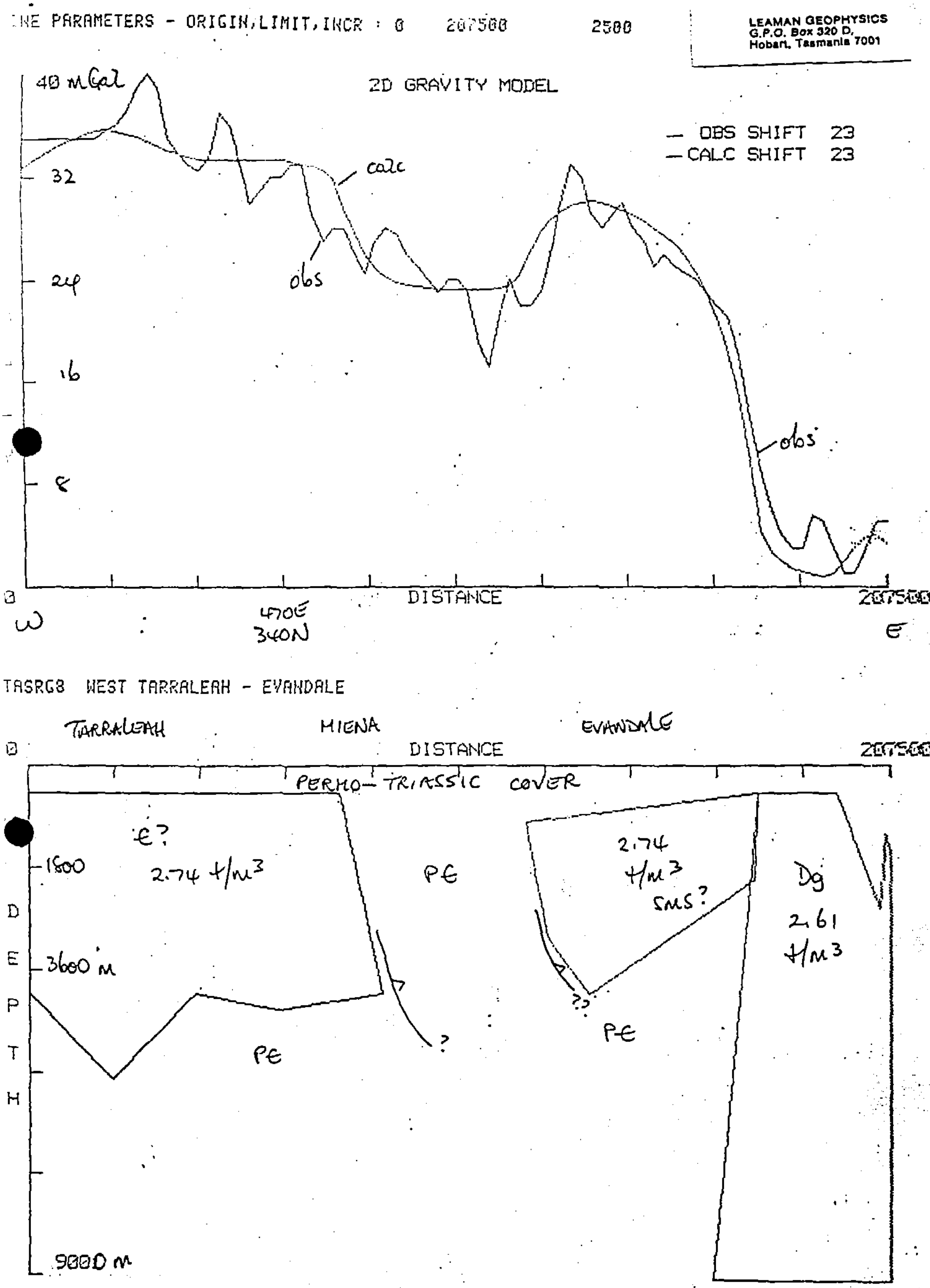
Hobart, Tasmania 7001



GRAVITY MODEL LINE 8

FIGURE 17

3570367

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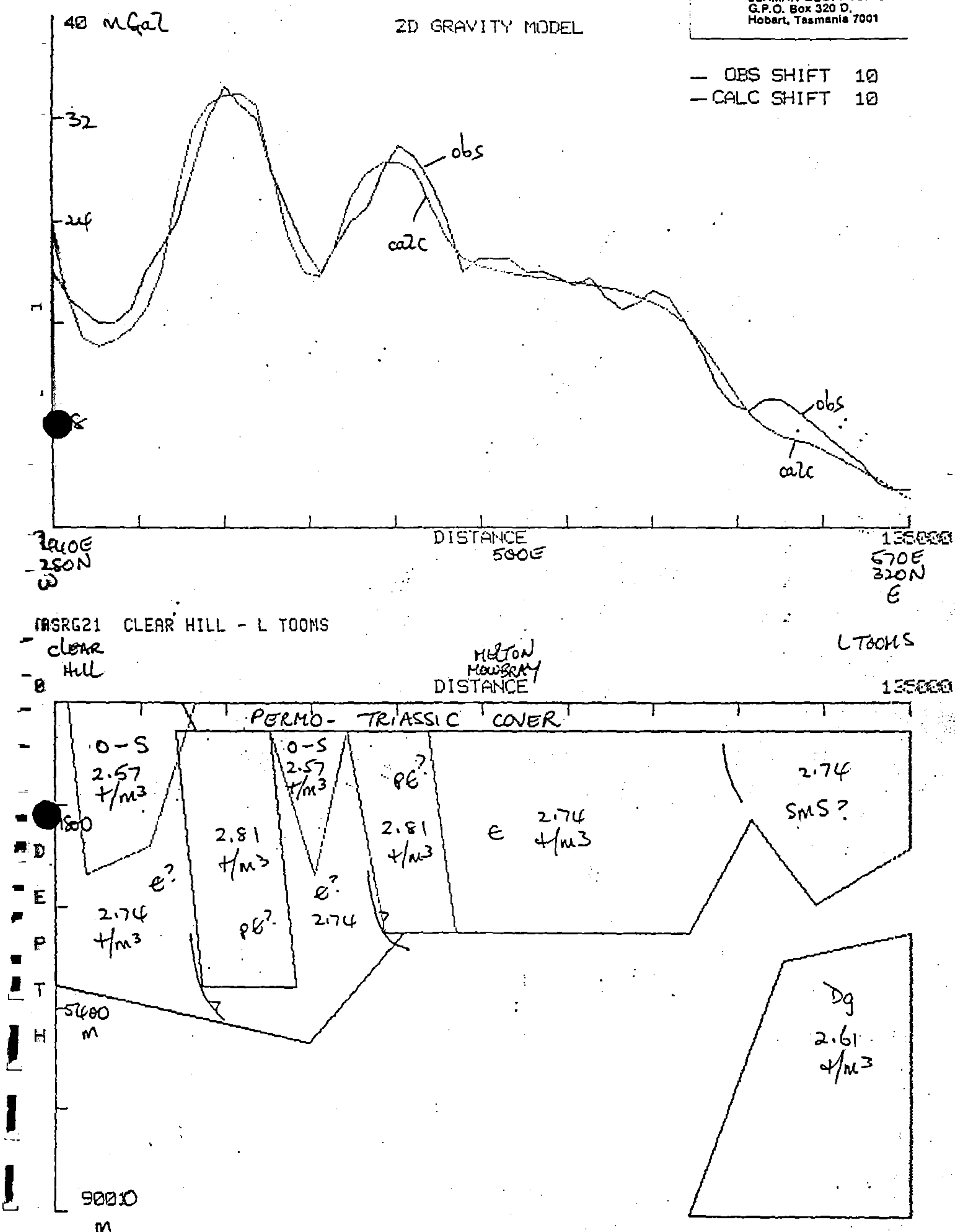
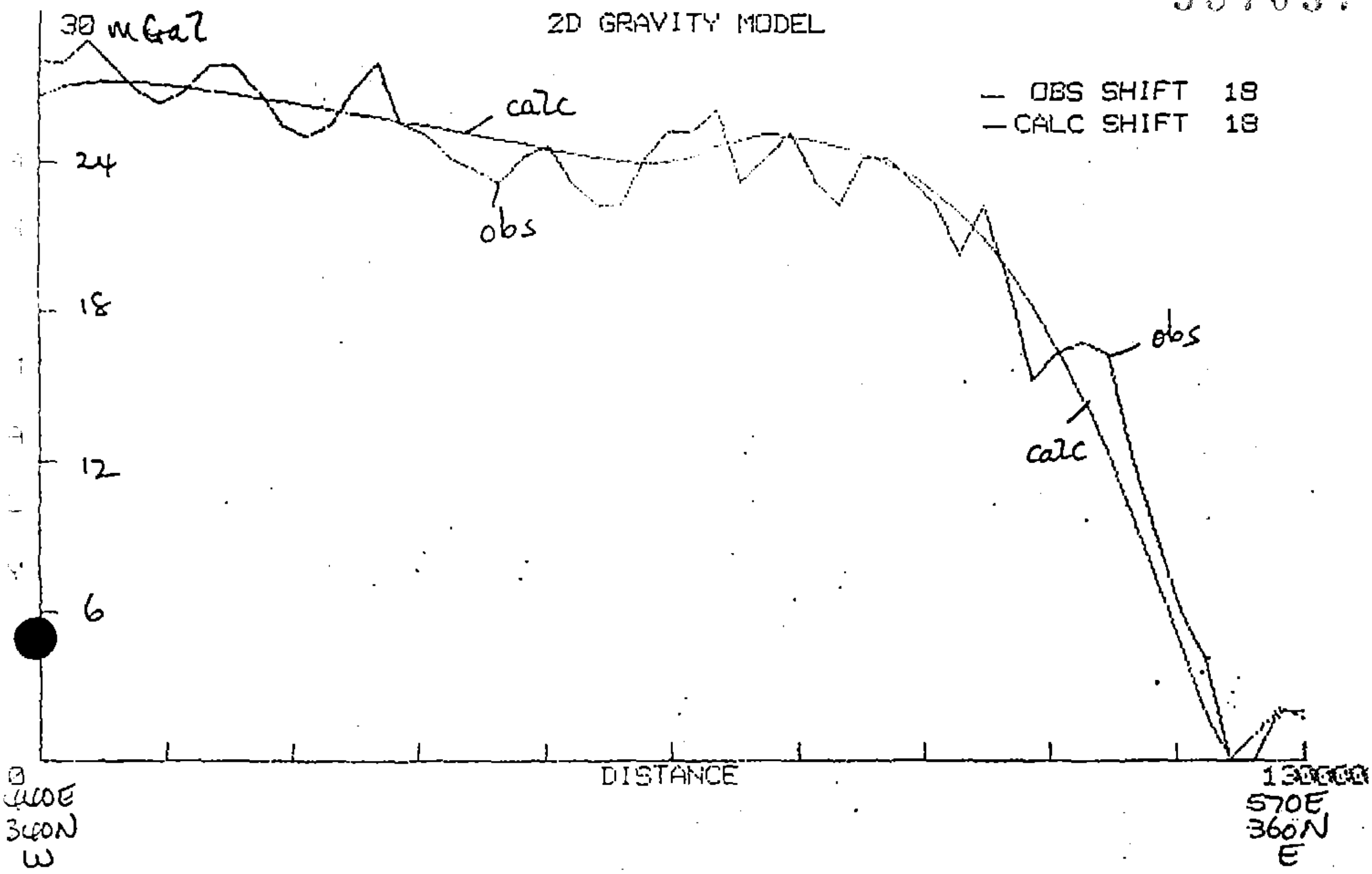


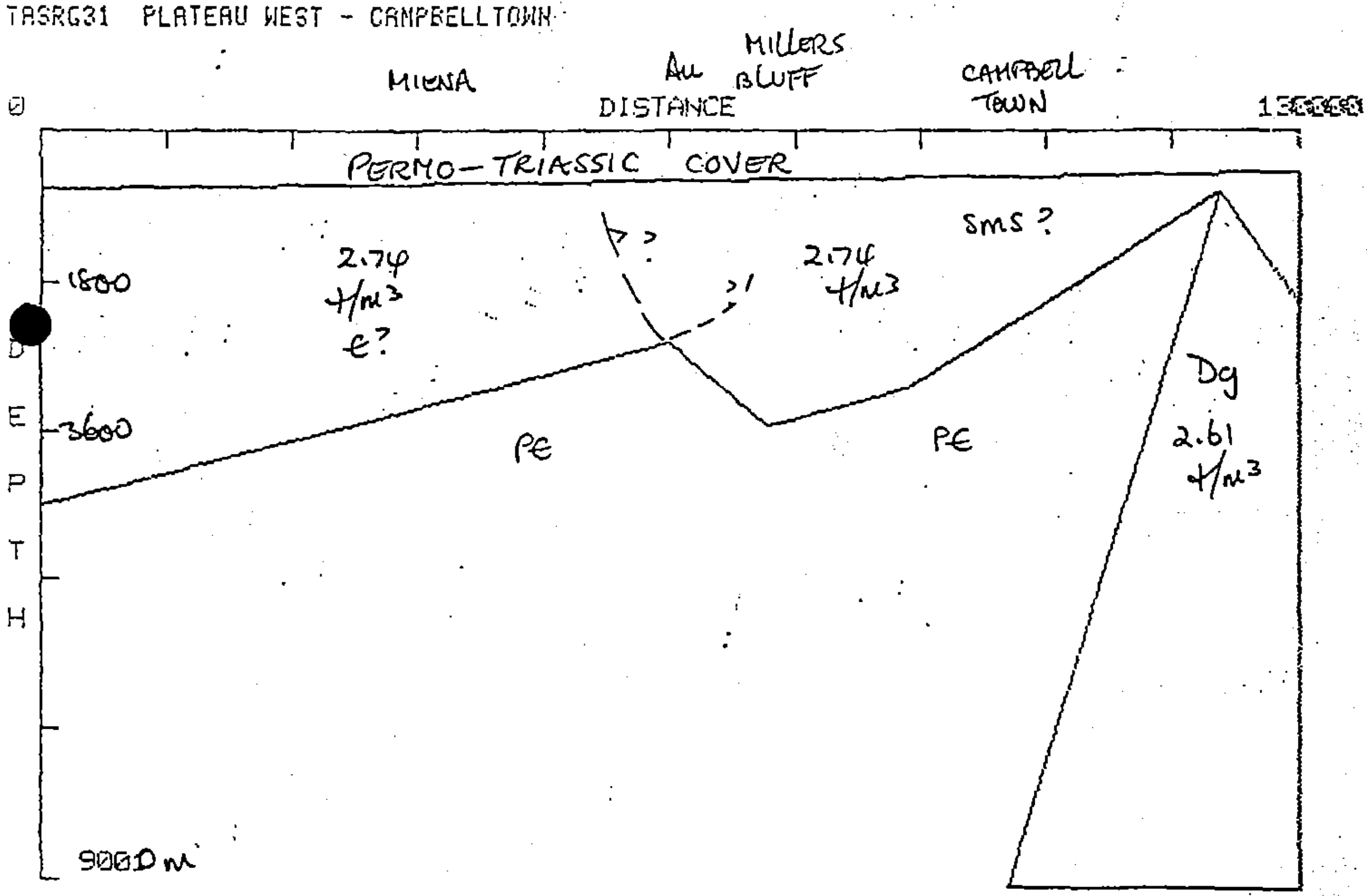
GRAVITY MODEL LINE 21

FIGURE 18

357037



TASRG31 PLATEAU WEST - CAMPBELLTOWN



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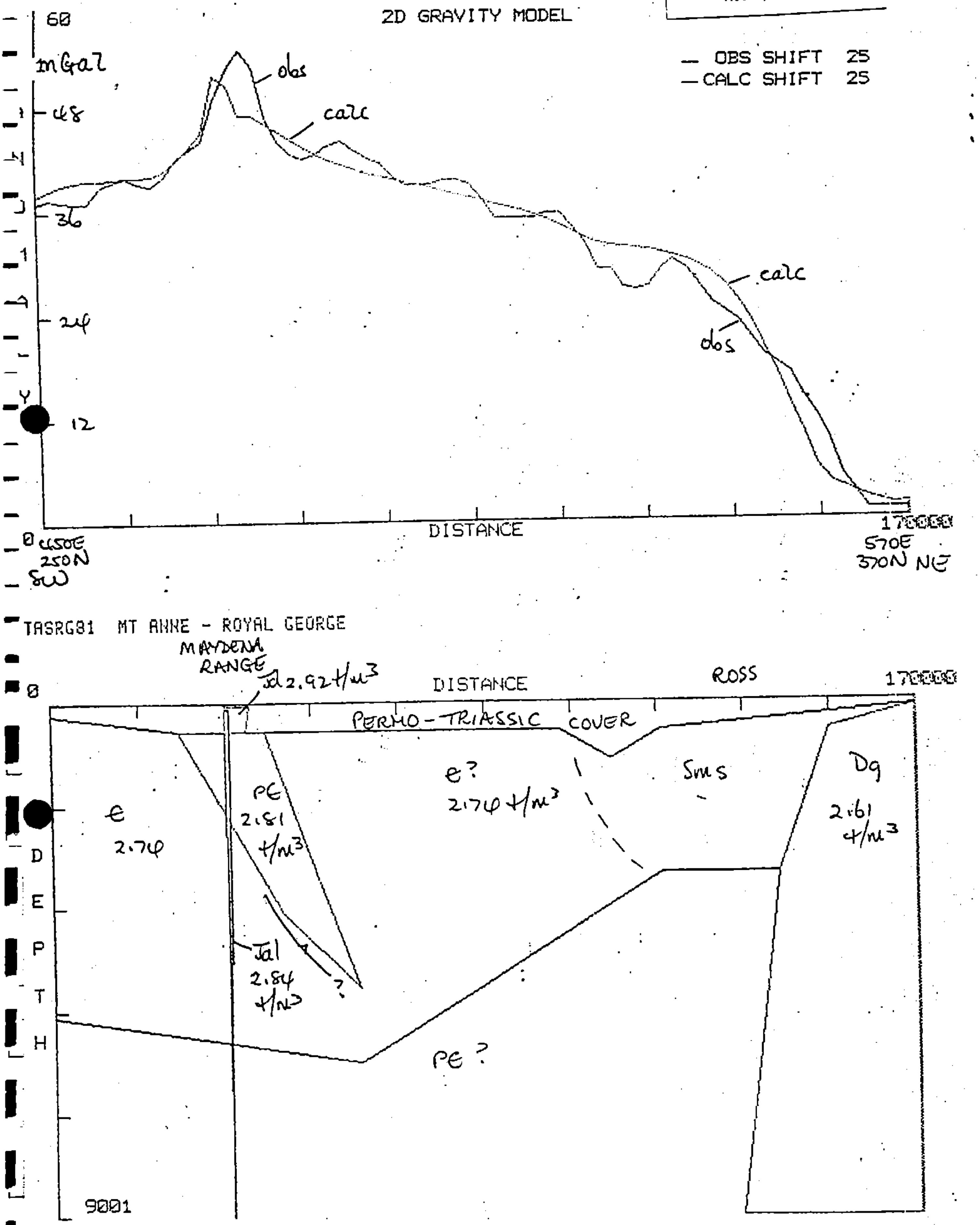
357038

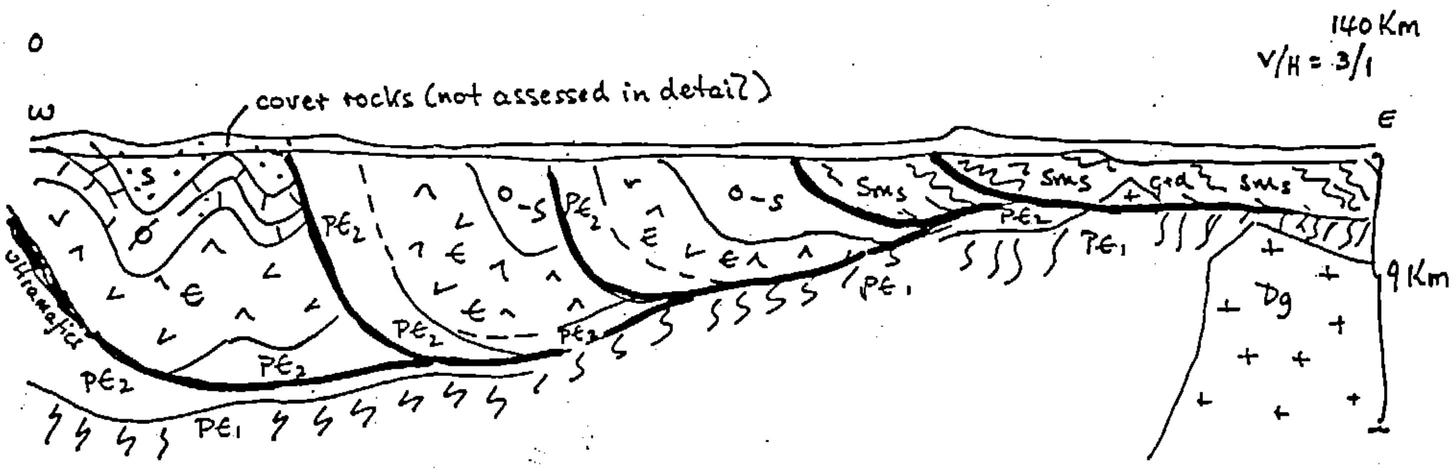
LEAMAN GEOPHYSICS
G.P.O. Box 320 D,
Hobart, Tasmania 7001



GRAVITY MODEL LINE 81

FIGURE 20

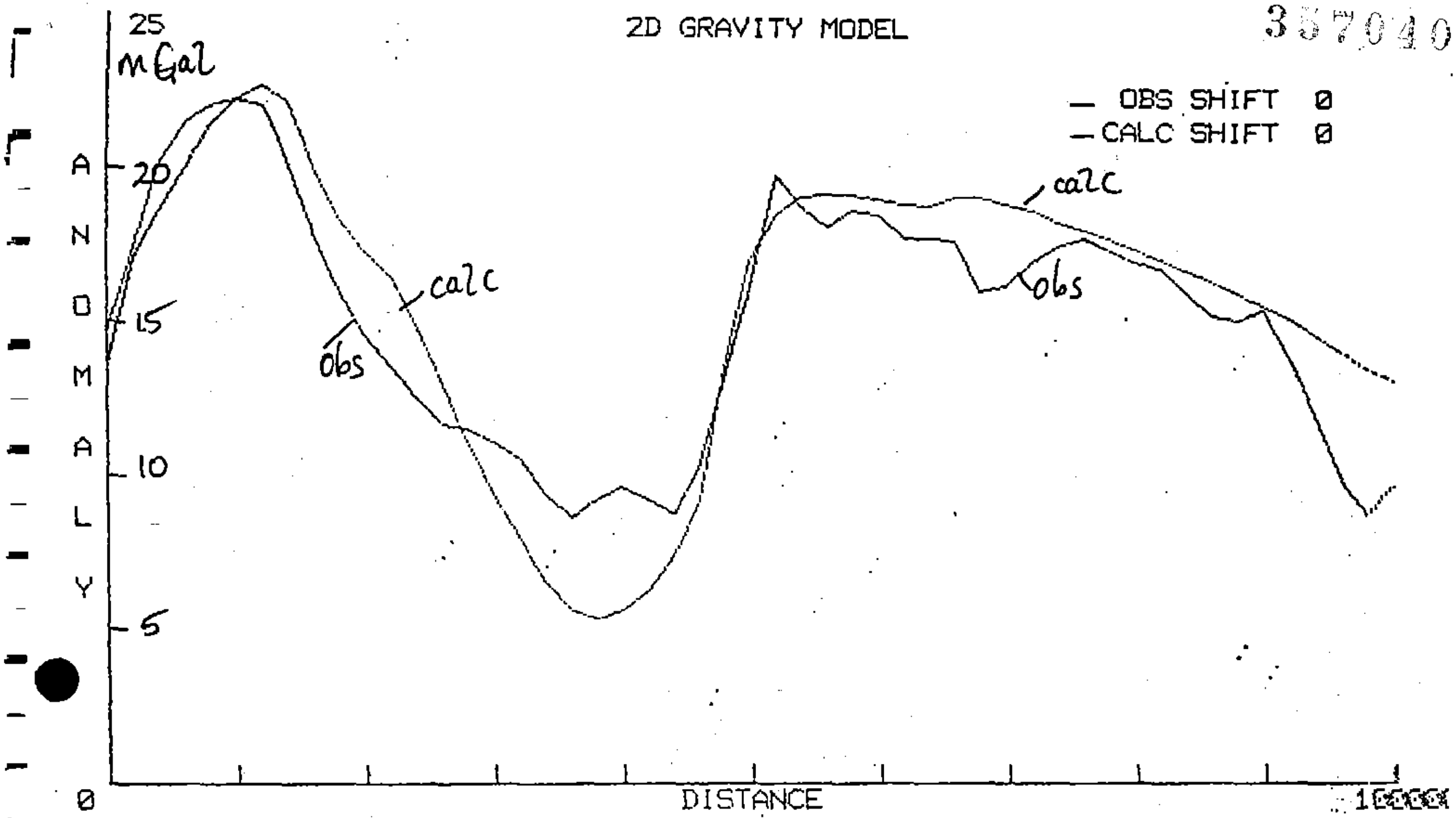
387039



SUGGESTED RELATIONSHIPS AND STRUCTURAL STYLE
(Region of profile 3).

FIGURE 21

357040



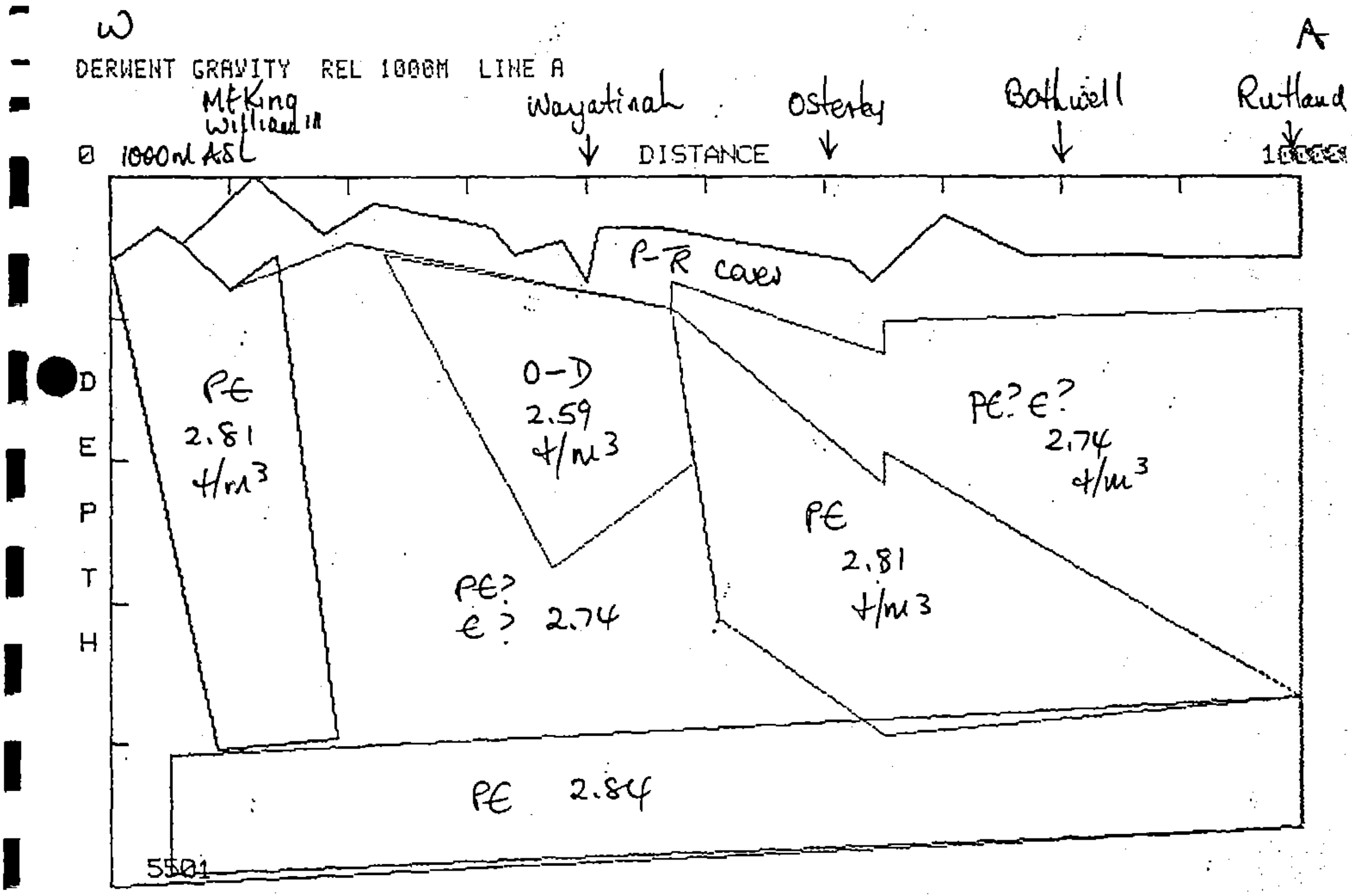


FIGURE 22

357041

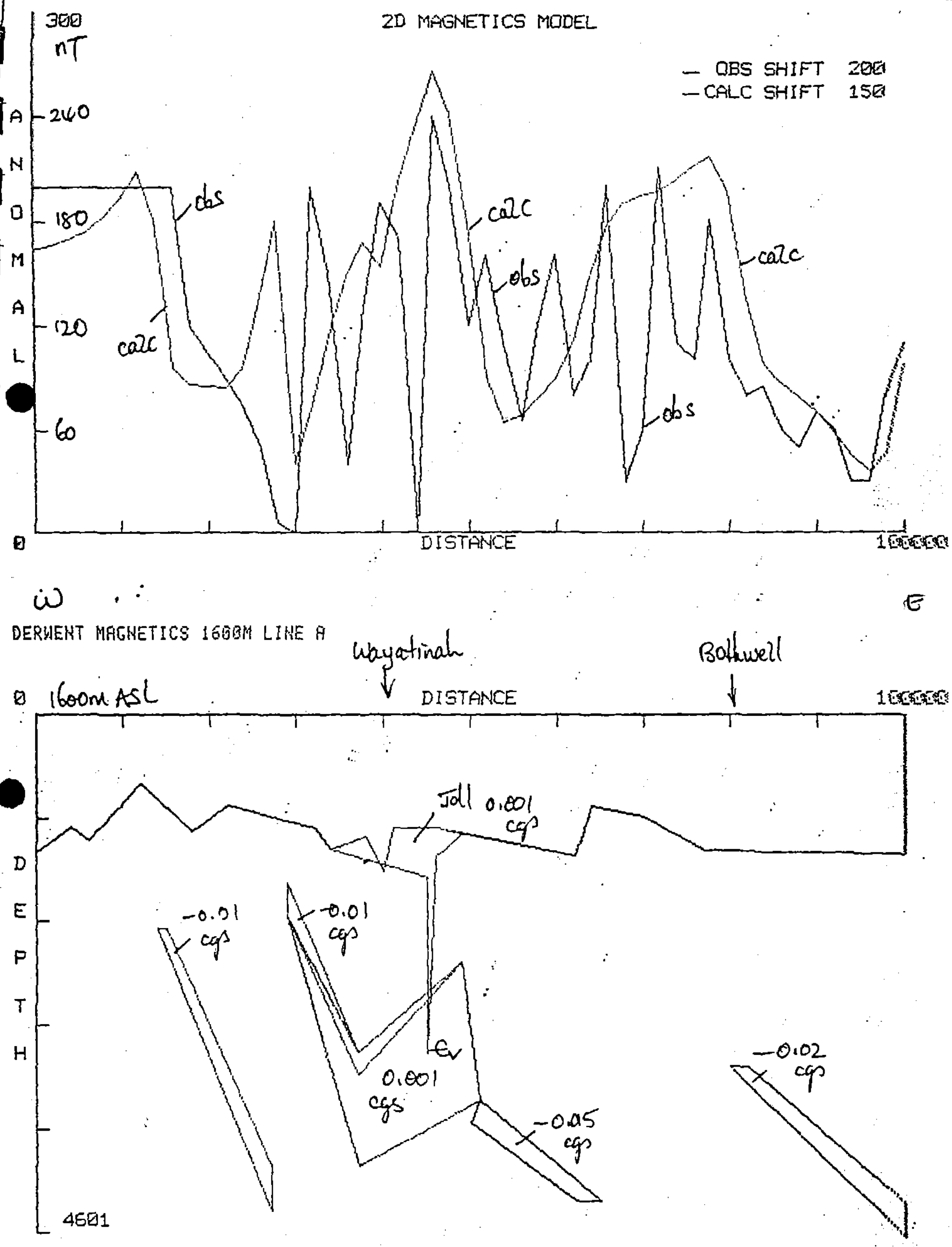
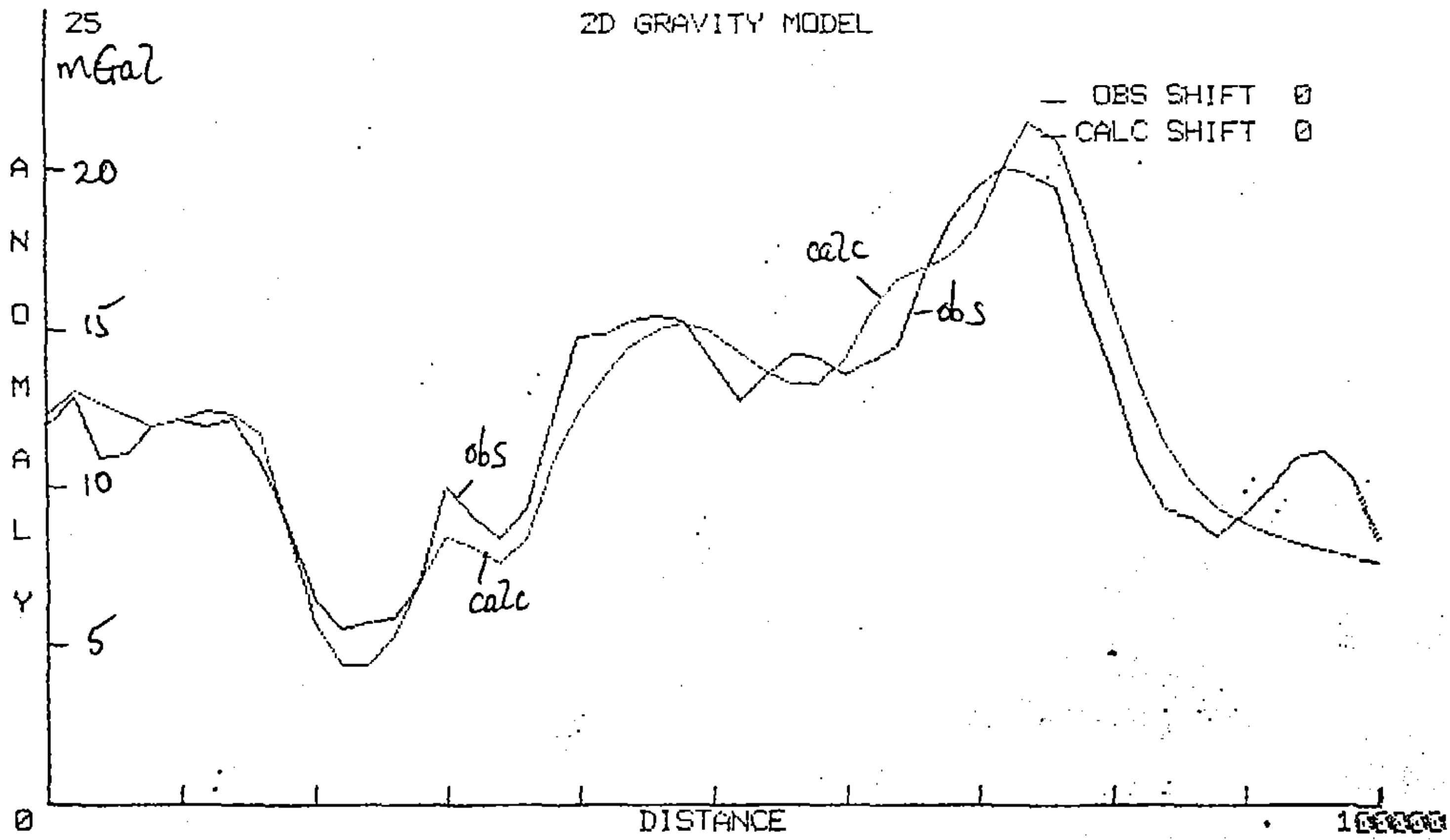


FIGURE 23

DERWENT GRAVITY 1000M LINE B

357042

LINE PARAMETERS - ORIGIN,LIMIT,INCR : 0 100000 2000



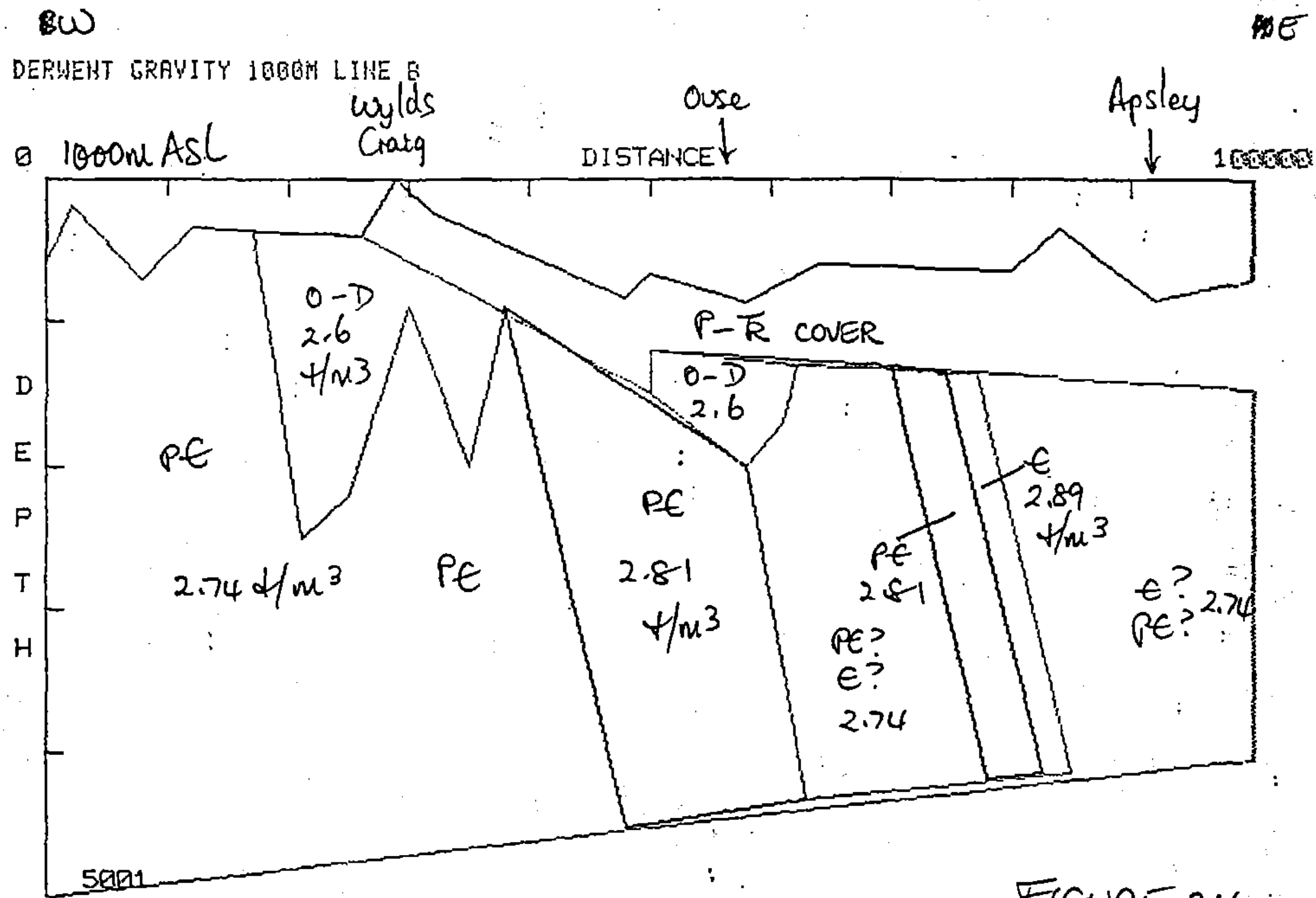


FIGURE 24

LINE PARAMETERS - ORIGIN,LIMIT,INCR : 0 100000 2000

357043

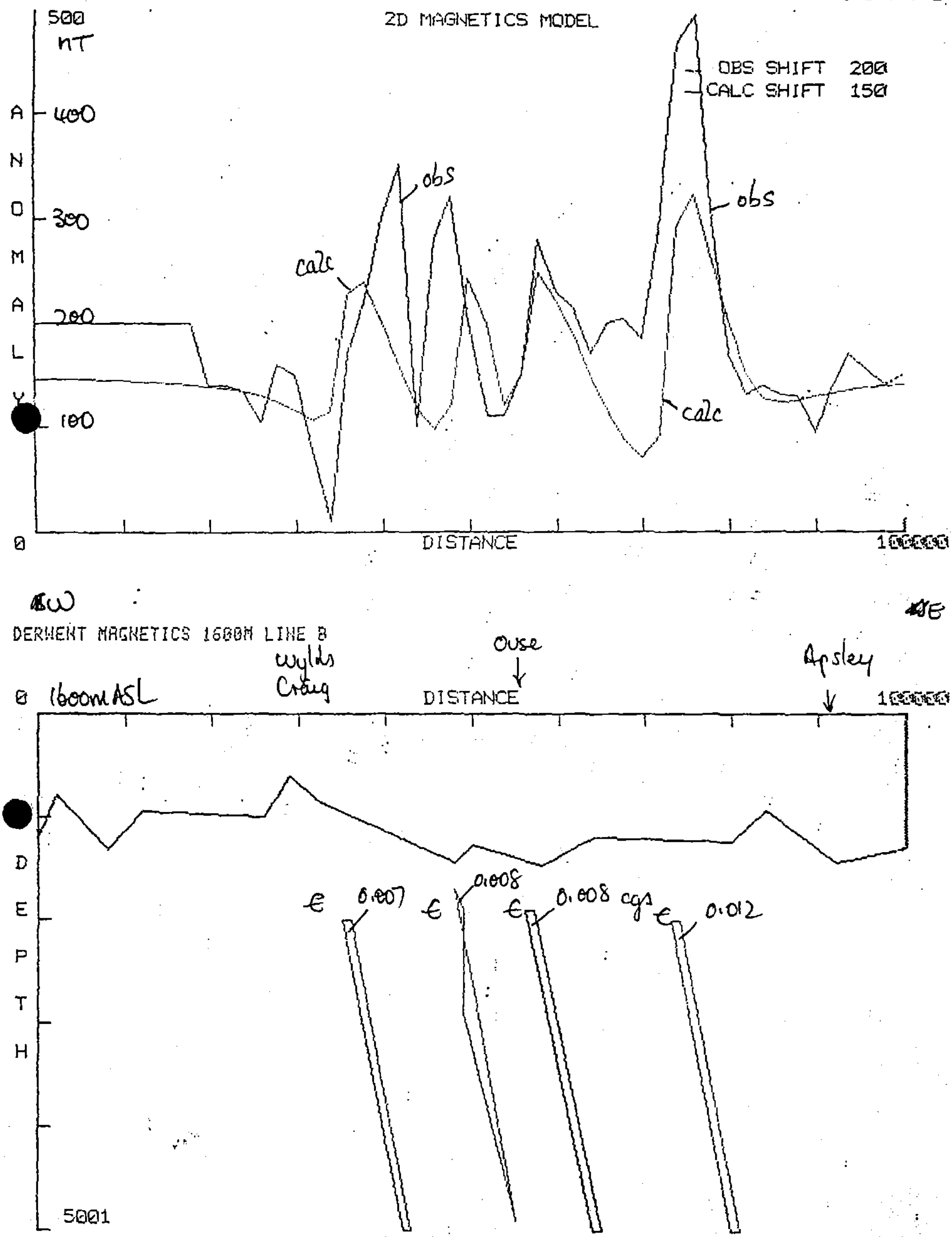


FIGURE 25

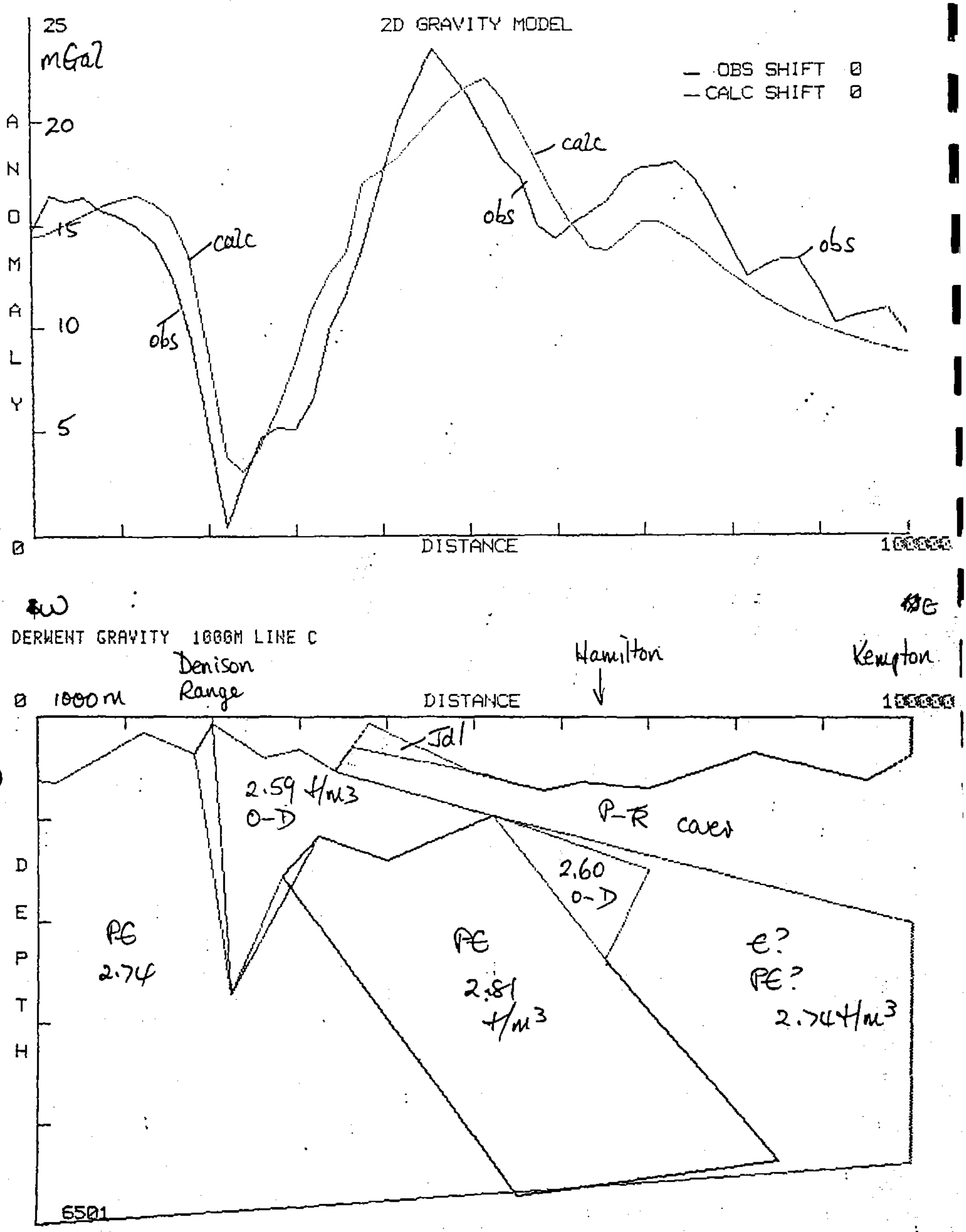
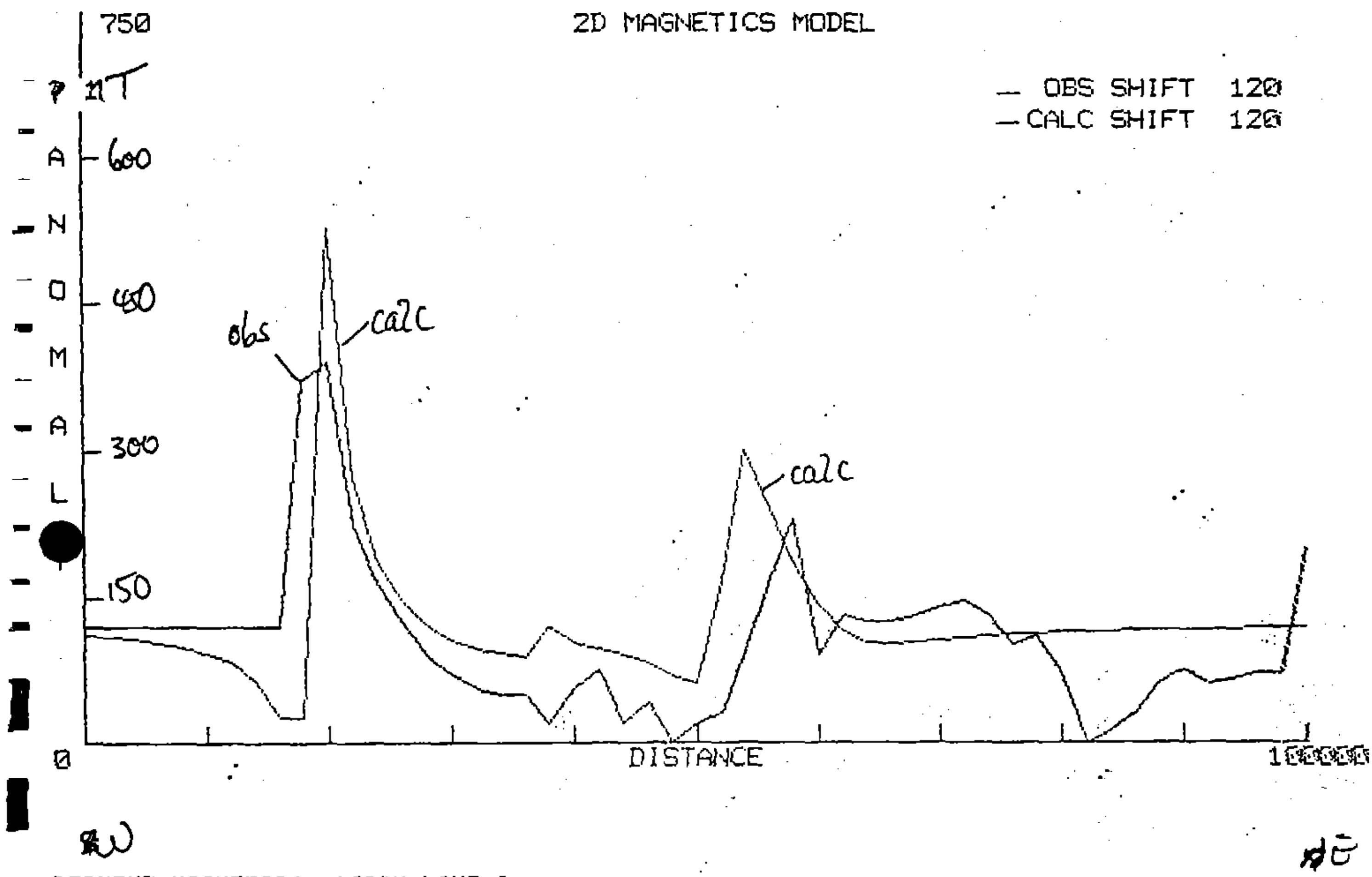

2D GRAVITY MODEL
25
mGal
OBS SHIFT 0
CALC SHIFT 0
ANOMALY
20
15
10
5
0
calc
obs
calc
obs
obs
DISTANCE
W
E
DERWENT GRAVITY 1000M LINE C
Denison Range
Hamilton
Kempton
0 1000m
DISTANCE
Jdl
2.59 t/m3
O-D
P-R cover
2.60
O-D
PЄ
2.74
PЄ
2.81
t/m3
Є?
PЄ?
2.74 t/m3
DEPTH
6501

FIGURE 26

62200.0 -71.0 13.0 0.0 90.0

357045

LINE PARAMETERS - ORIGIN,LIMIT,INCR : 0 100000 2000



DERWENT MAGNETICS 1600M LINE C

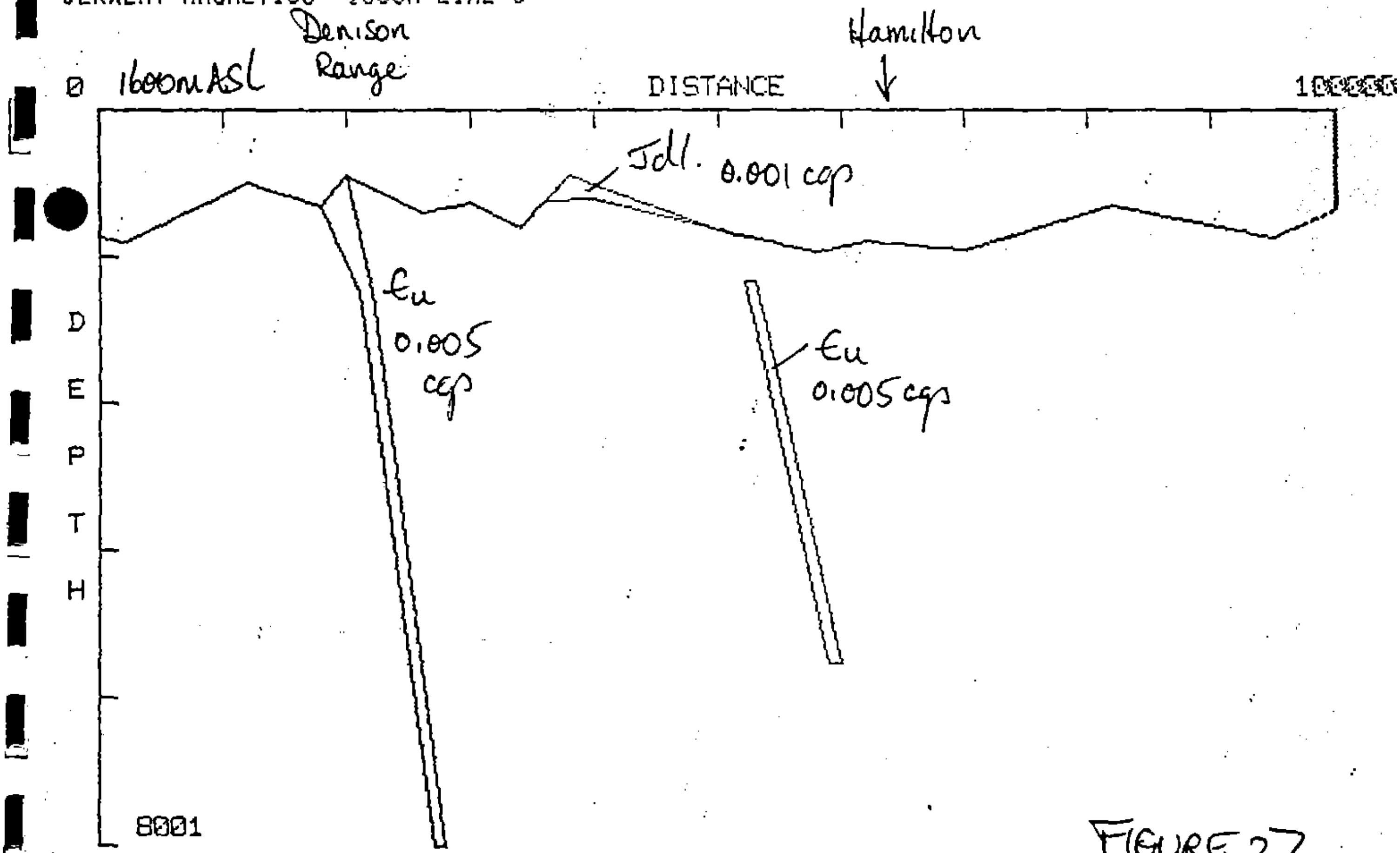


FIGURE 27

337046

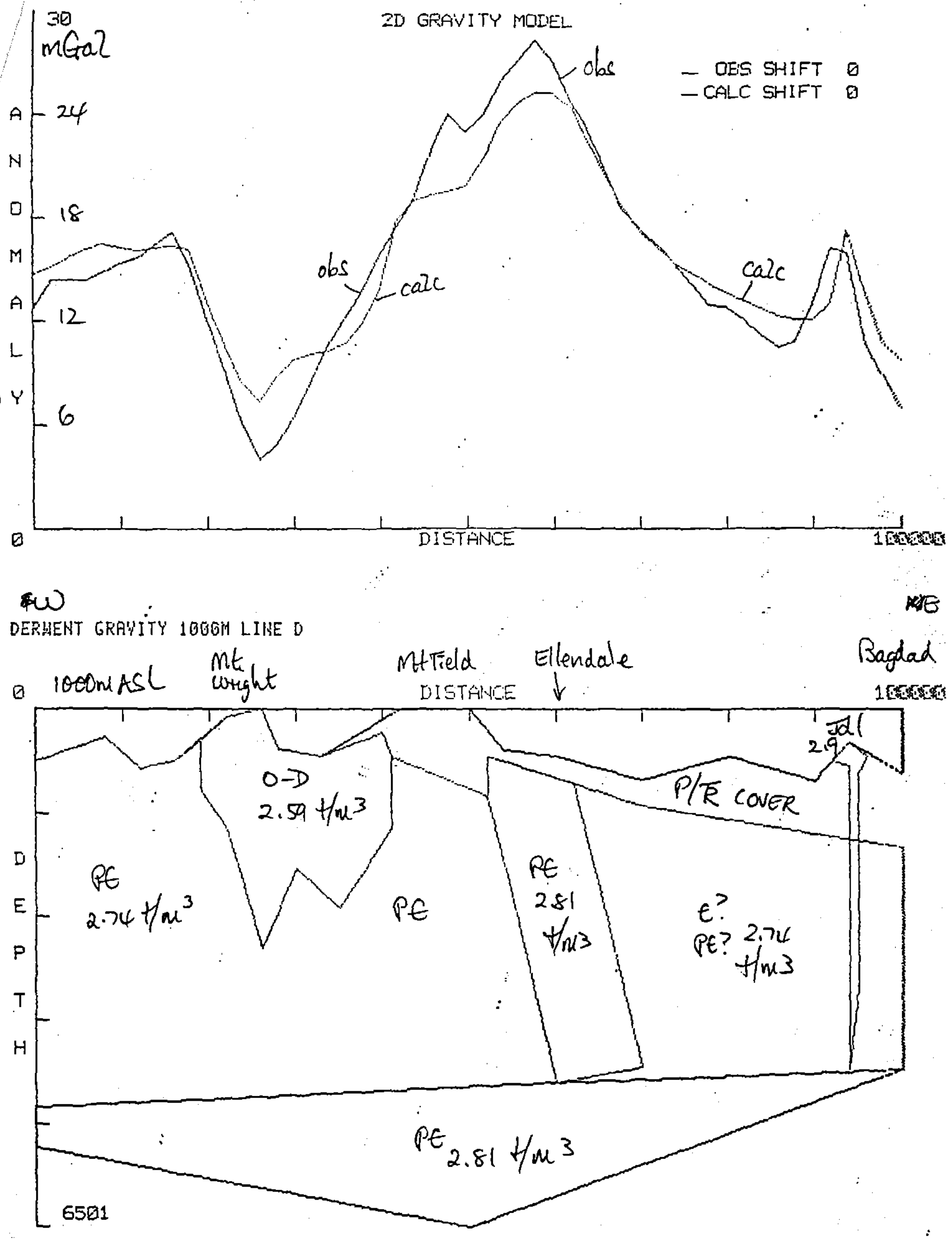


FIGURE 28

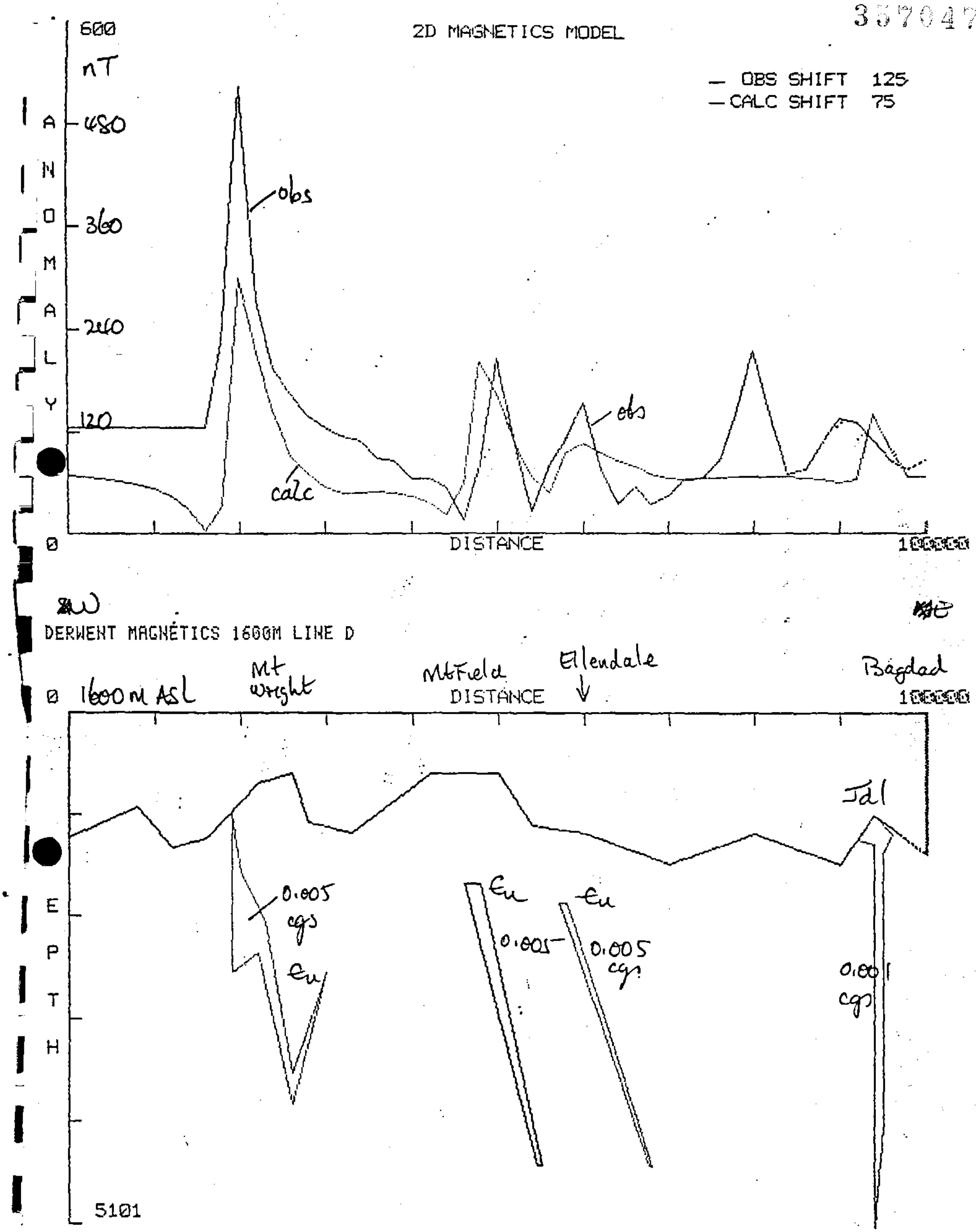
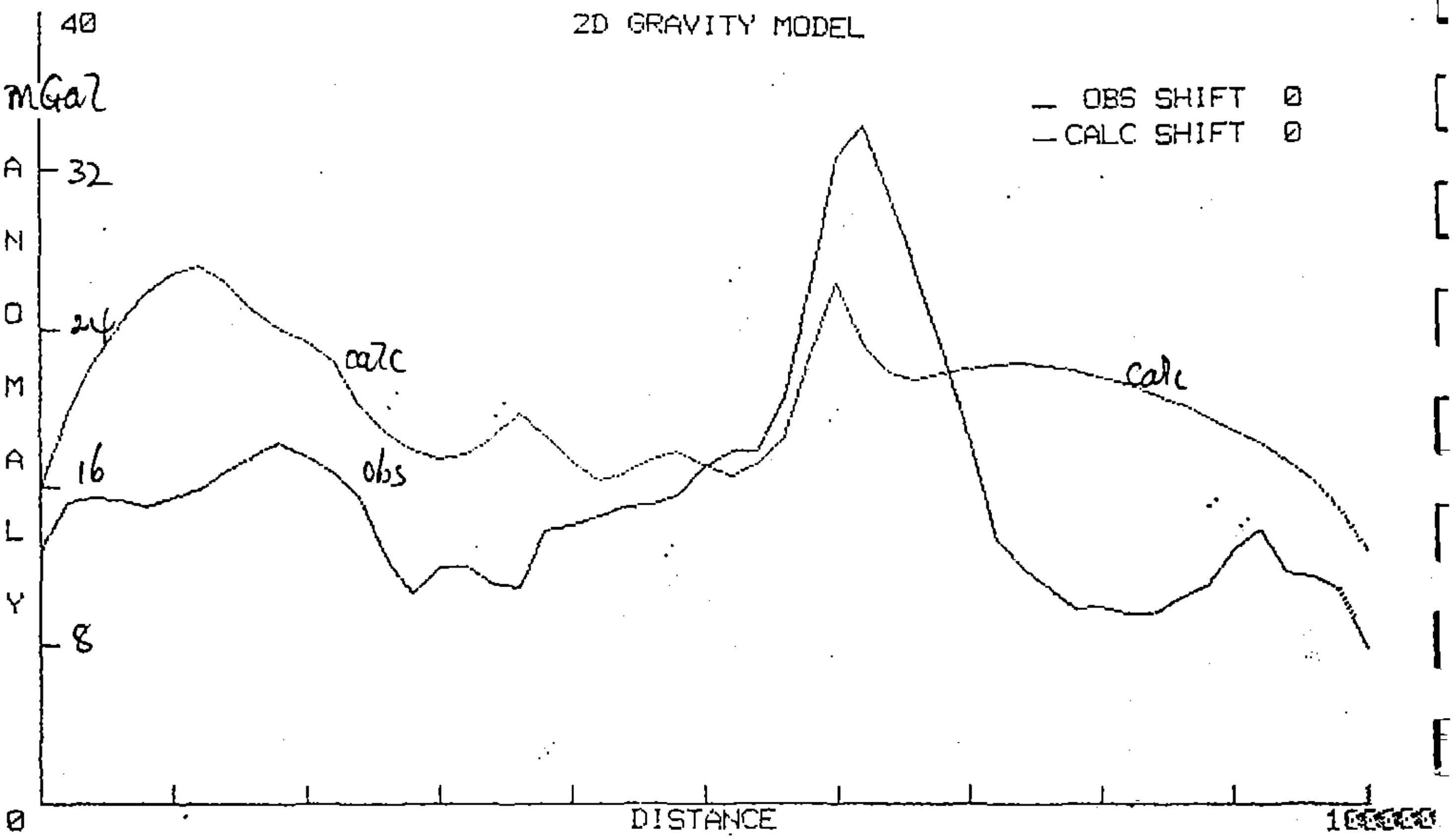

2D MAGNETICS MODEL
600
nT
OBS SHIFT 125
CALC SHIFT 75
A N O M A L Y
480
360
240
120
obs
calc
0
DISTANCE
100000
SW
NE
DERWENT MAGNETICS 1600M LINE D
0 1600M ASL
Mt Wright
MtField
Ellendale
Bagdad
DISTANCE
100000
Jdl
0.005 cgs
Eu
0.005
0.005 cgs
0.001 cgs
D E P T H
5101

FIGURE 29

LINE PARAMETERS - ORIGIN,LIMIT,INCR : 0 100000 2000



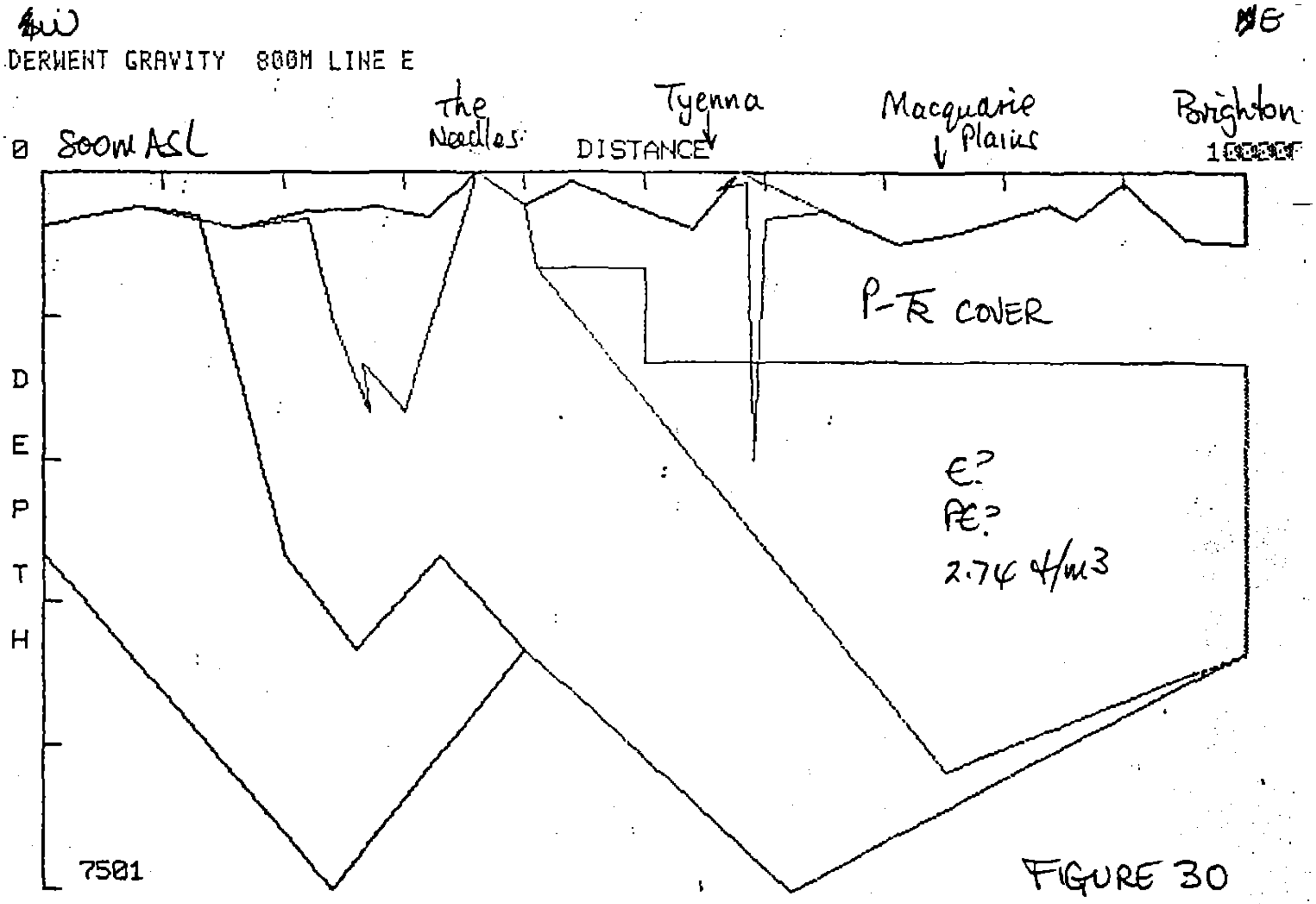
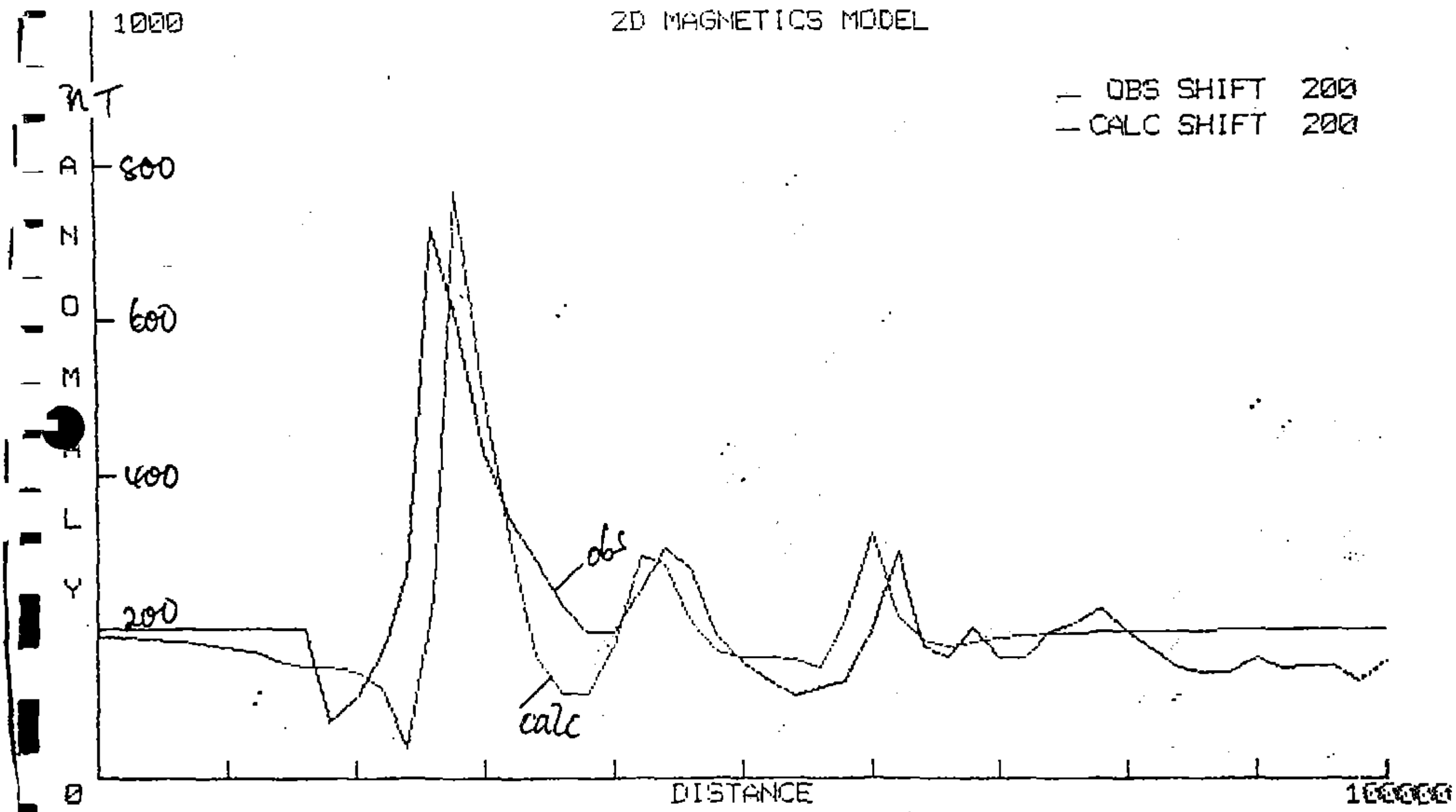


FIGURE 30

58500 900
4.0 1.0 0.0 0.0 0.0
14000 1250 16000 1380 22000 1200 28000 1860 31000 2000
25000 2300
5.0 10.0 0.0 0.0 0.0
40000 2000 43000 3000 46000 4000 43000 3600

357049

LINE PARAMETERS - ORIGIN,LIMIT,INCR : 0 100000 2000



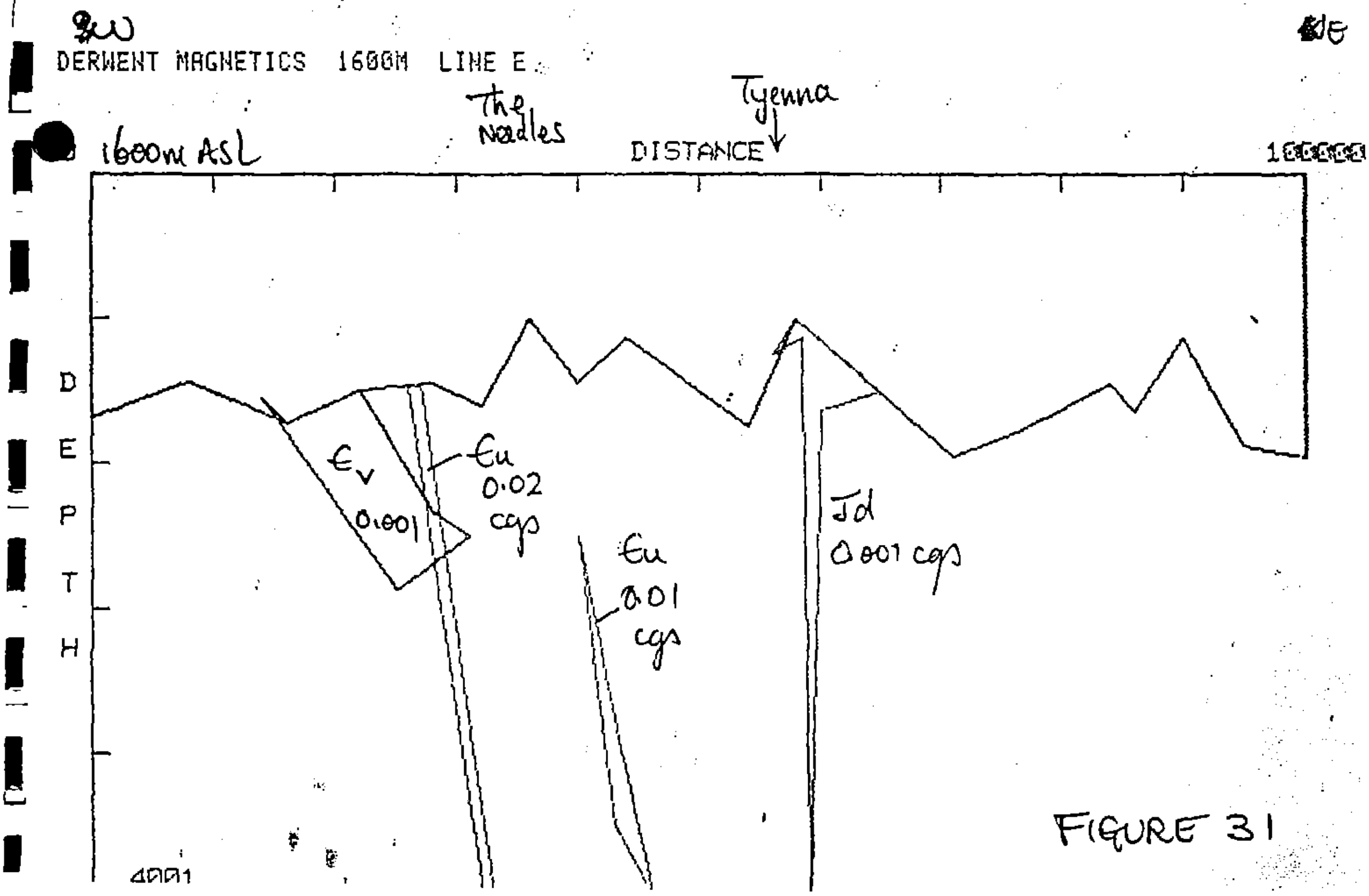
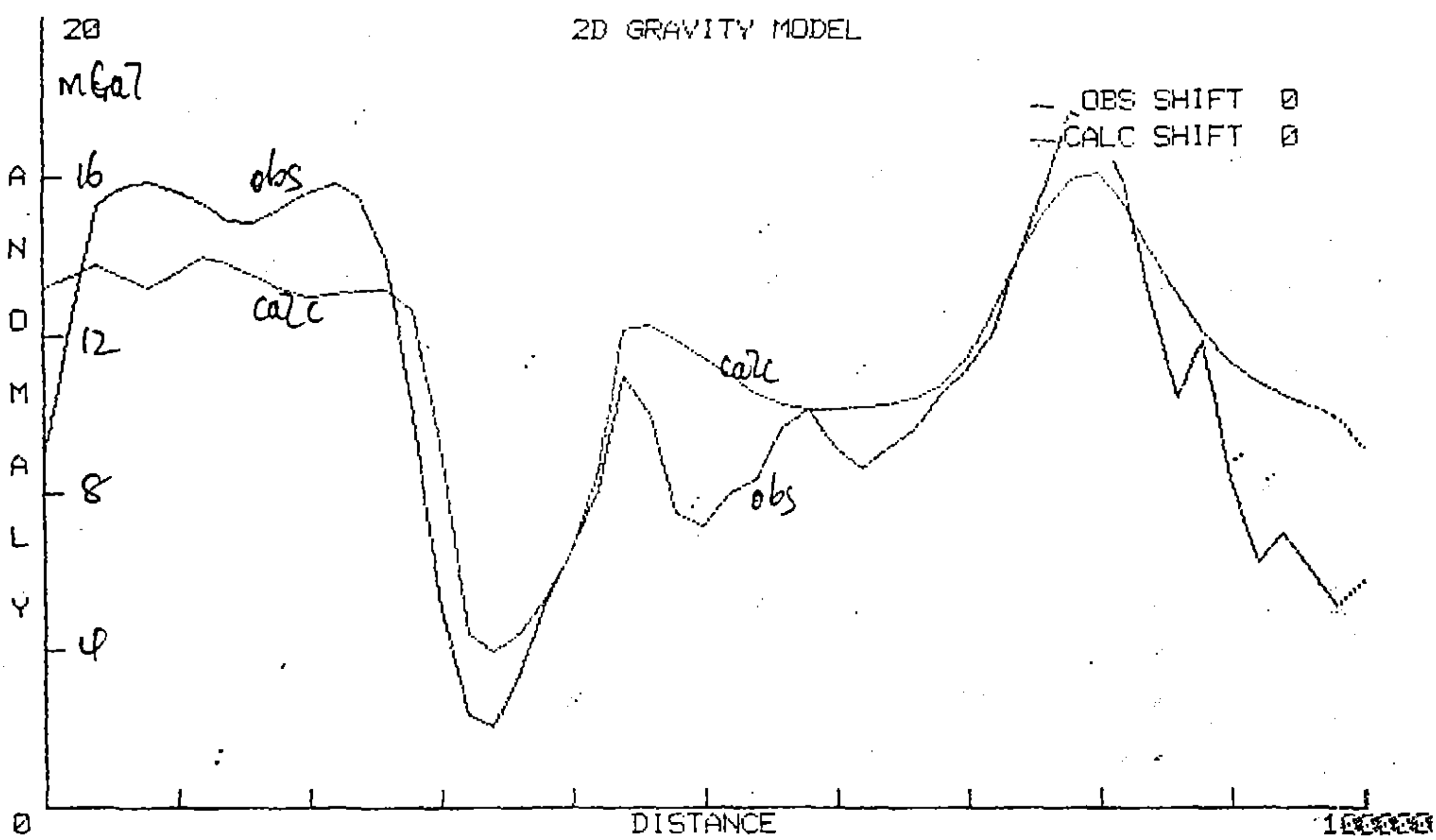


FIGURE 31

LEAMAN GEOPHYSICS

DERWENT GRAVITY 1000M LINE G 357050

LINE PARAMETERS - ORIGIN,LIMIT,INCR : 0 100000 2000



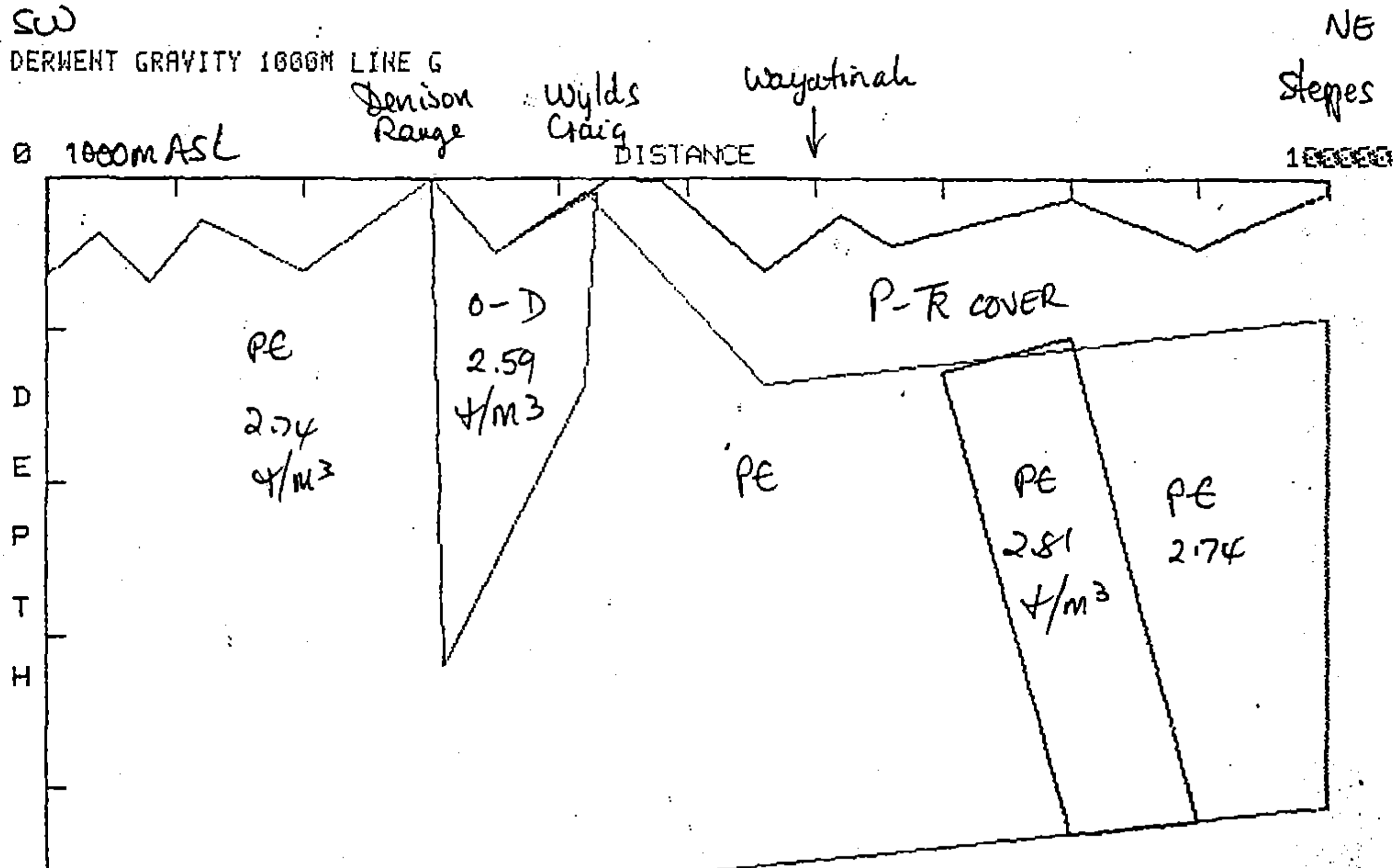


FIGURE 32

LINE PARAMETERS - ORIGIN,LIMIT,INCR : 0   100000   2000

357051

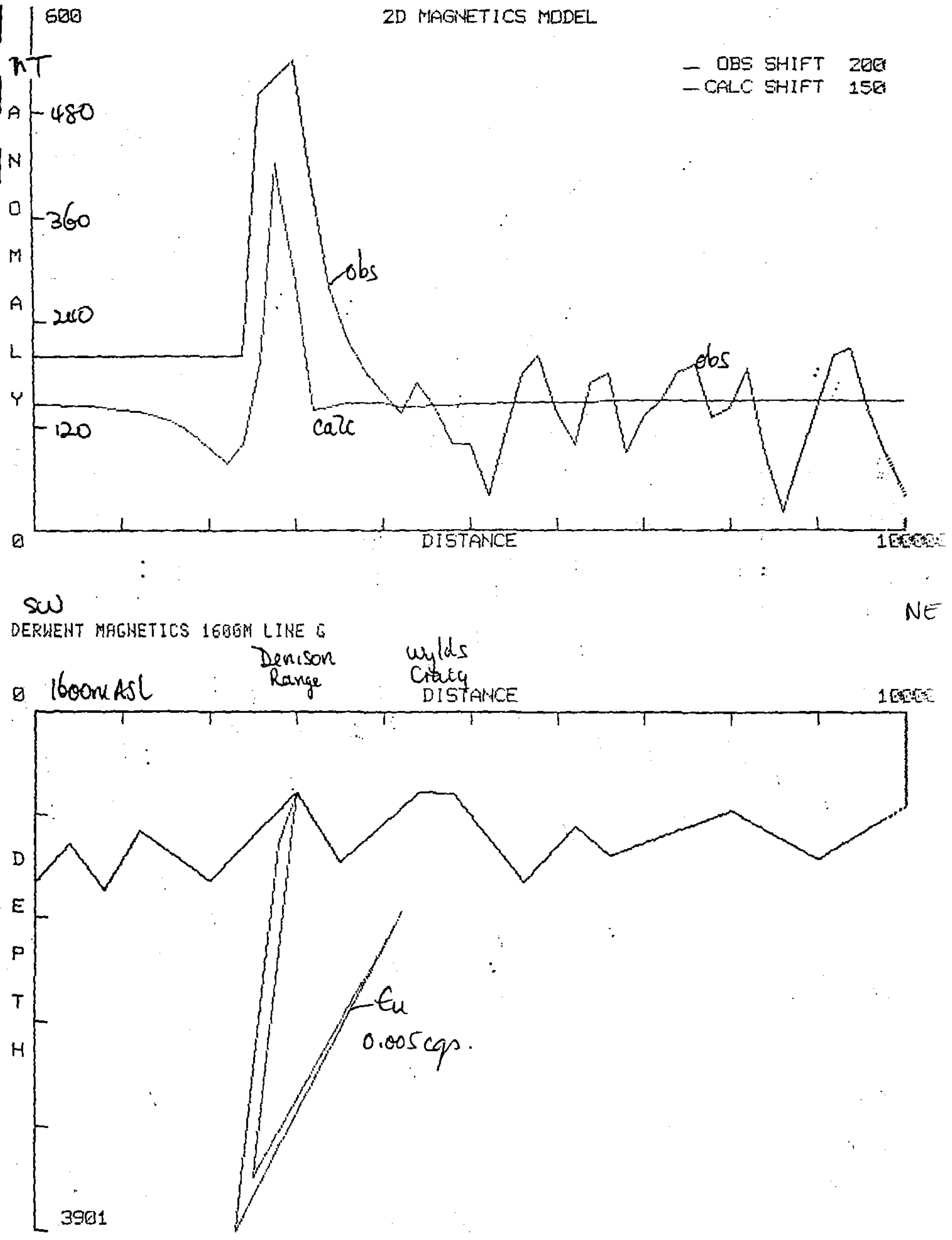


FIGURE 3

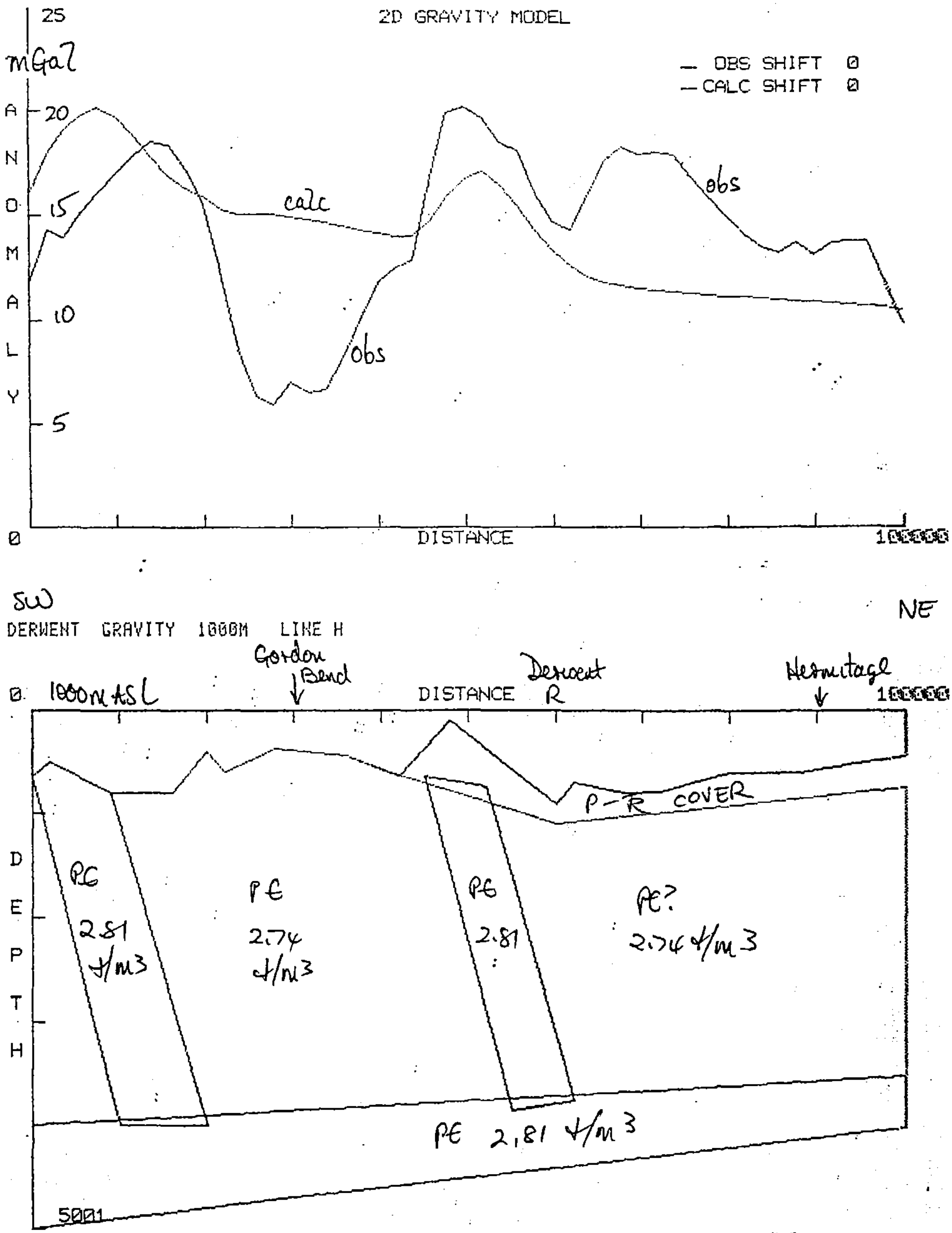

25
2D GRAVITY MODEL
mGal
OBS SHIFT 0
CALC SHIFT 0
ANOMALY
20
15
10
5
calc
obs
obs
0
DISTANCE
SW
NE
DERWENT GRAVITY 1000M LINE H
Gordon Bend
Derwent R
Hermitage
0. 1000m ASL
DISTANCE
P-R COVER
DEPTH
PЄ 2.81 t/m3
PЄ 2.74 t/m3
PЄ 2.81
PЄ? 2.74 t/m3
PЄ 2,81 t/m3
5001

FIGURE 34

357053

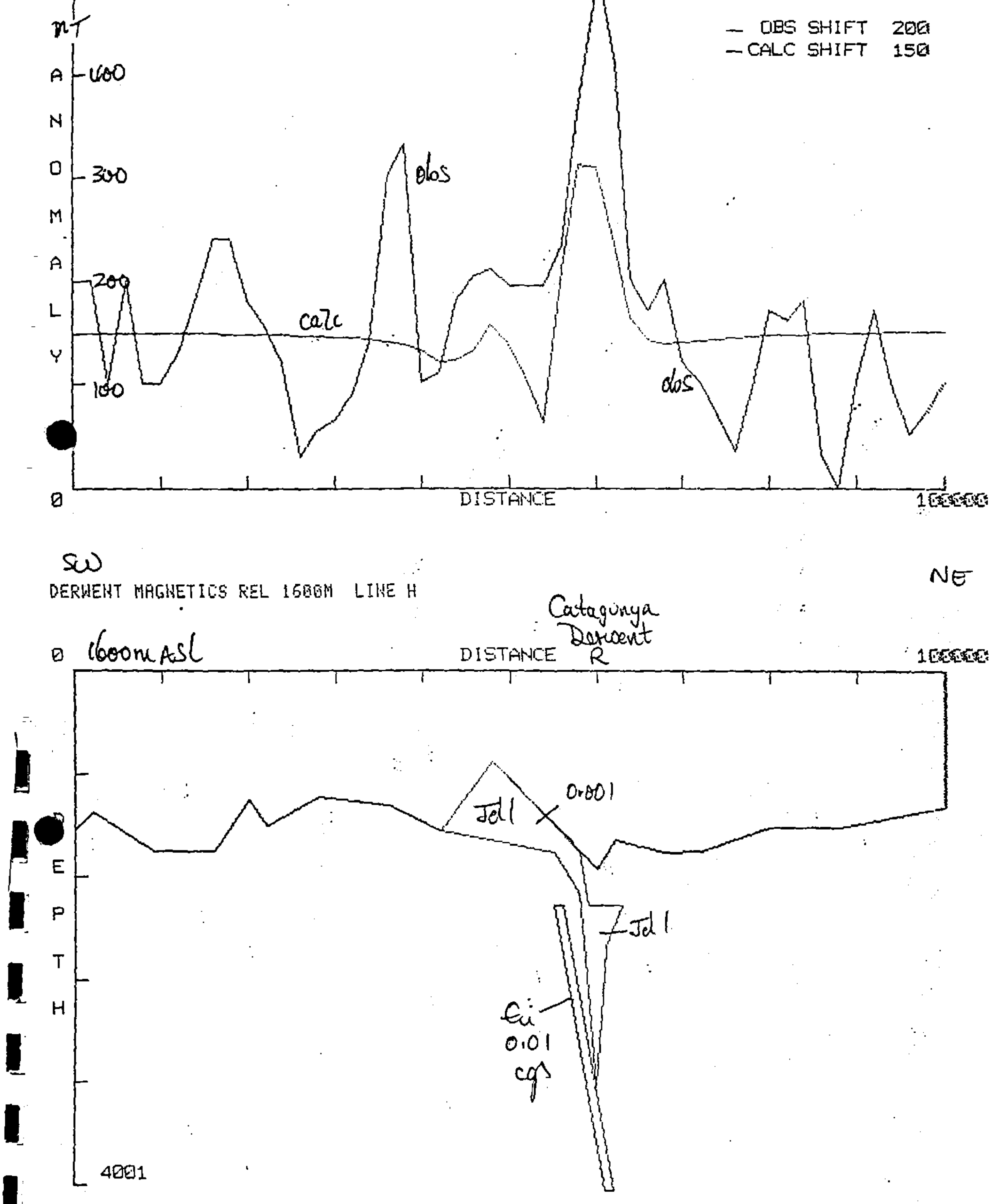


FIGURE 35

337054

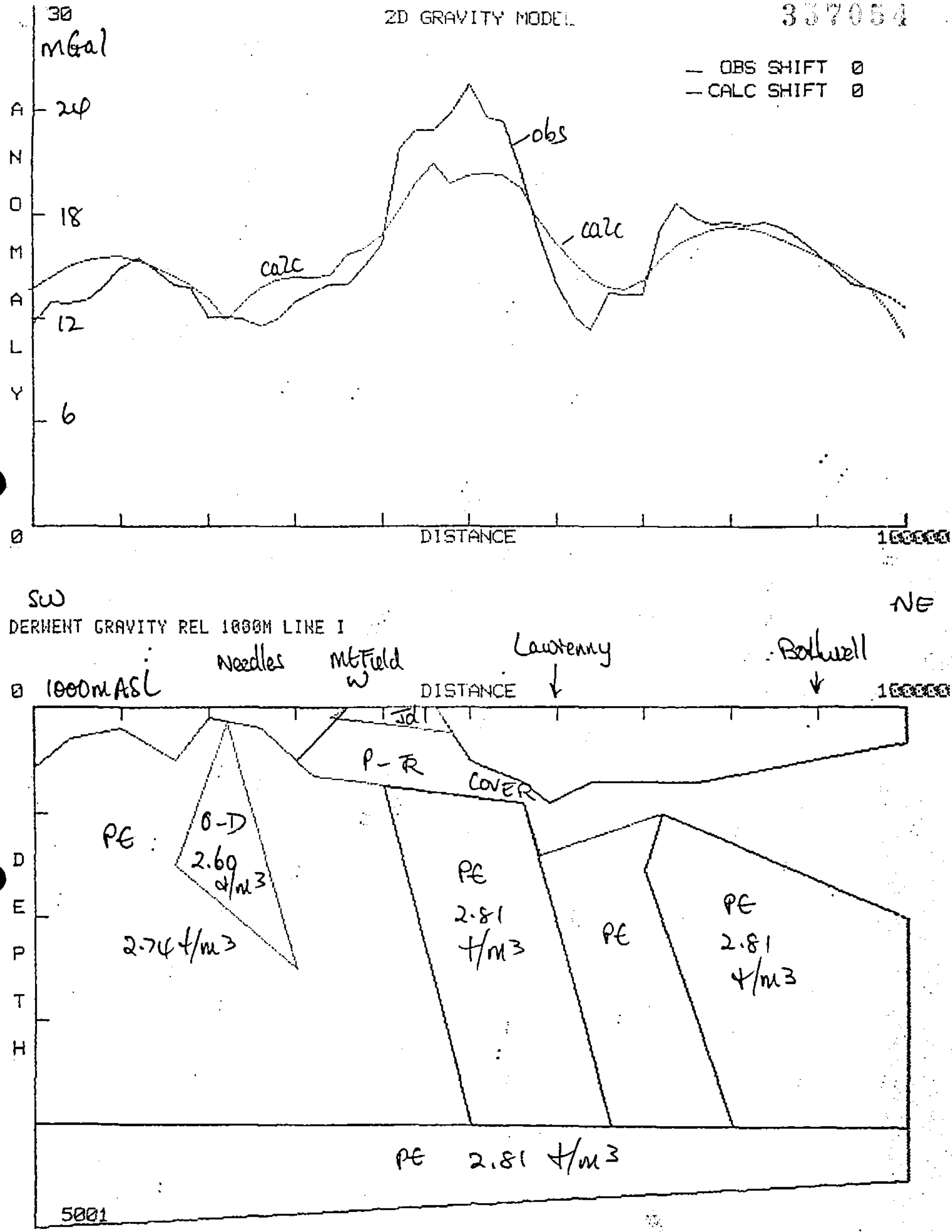
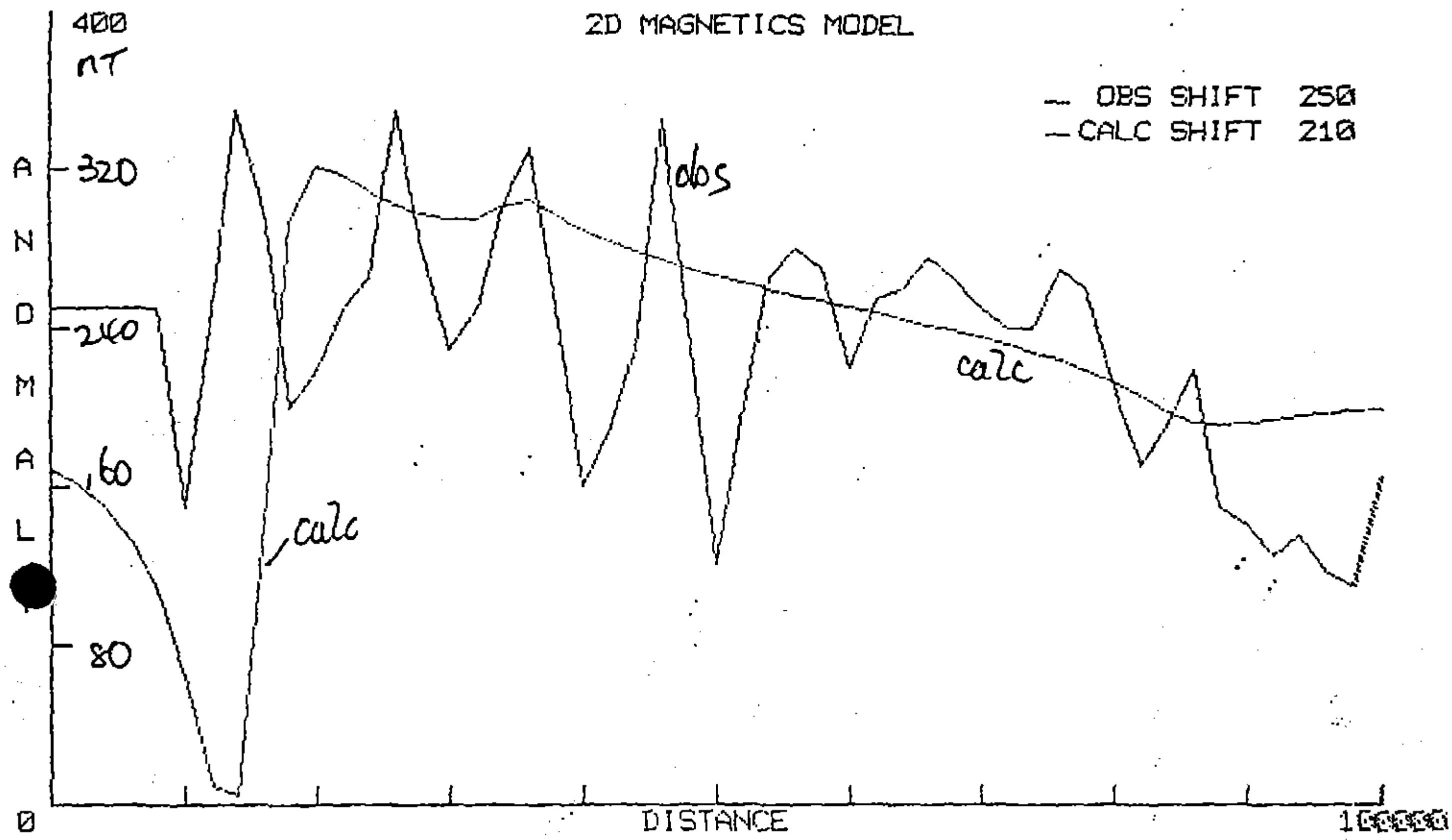


FIGURE 36

LINE PARAMETERS - ORIGIN,LIMIT,INCR : 0 100000 2000



SW NE
DERWENT MAGNETICS 1600M LINE I

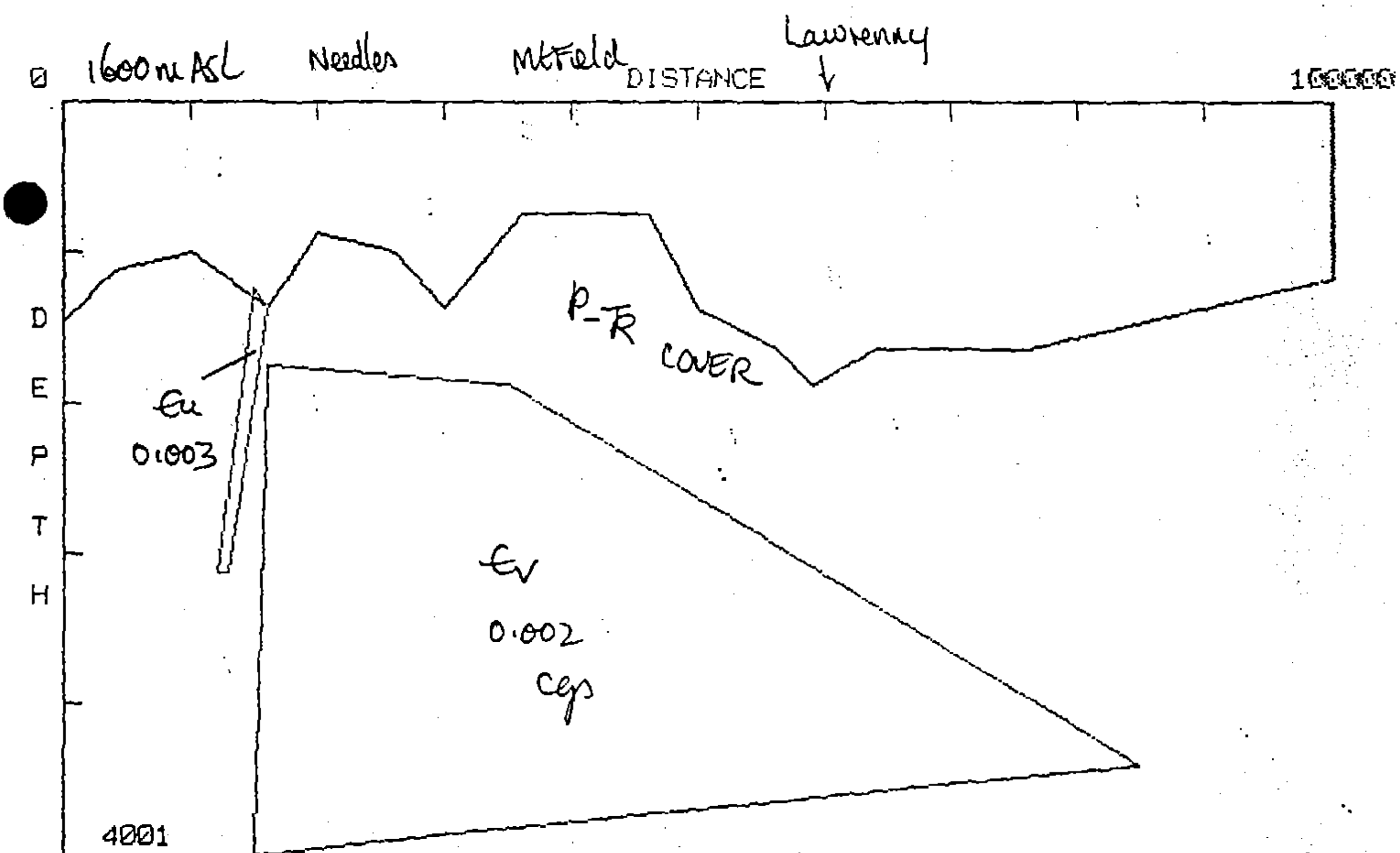
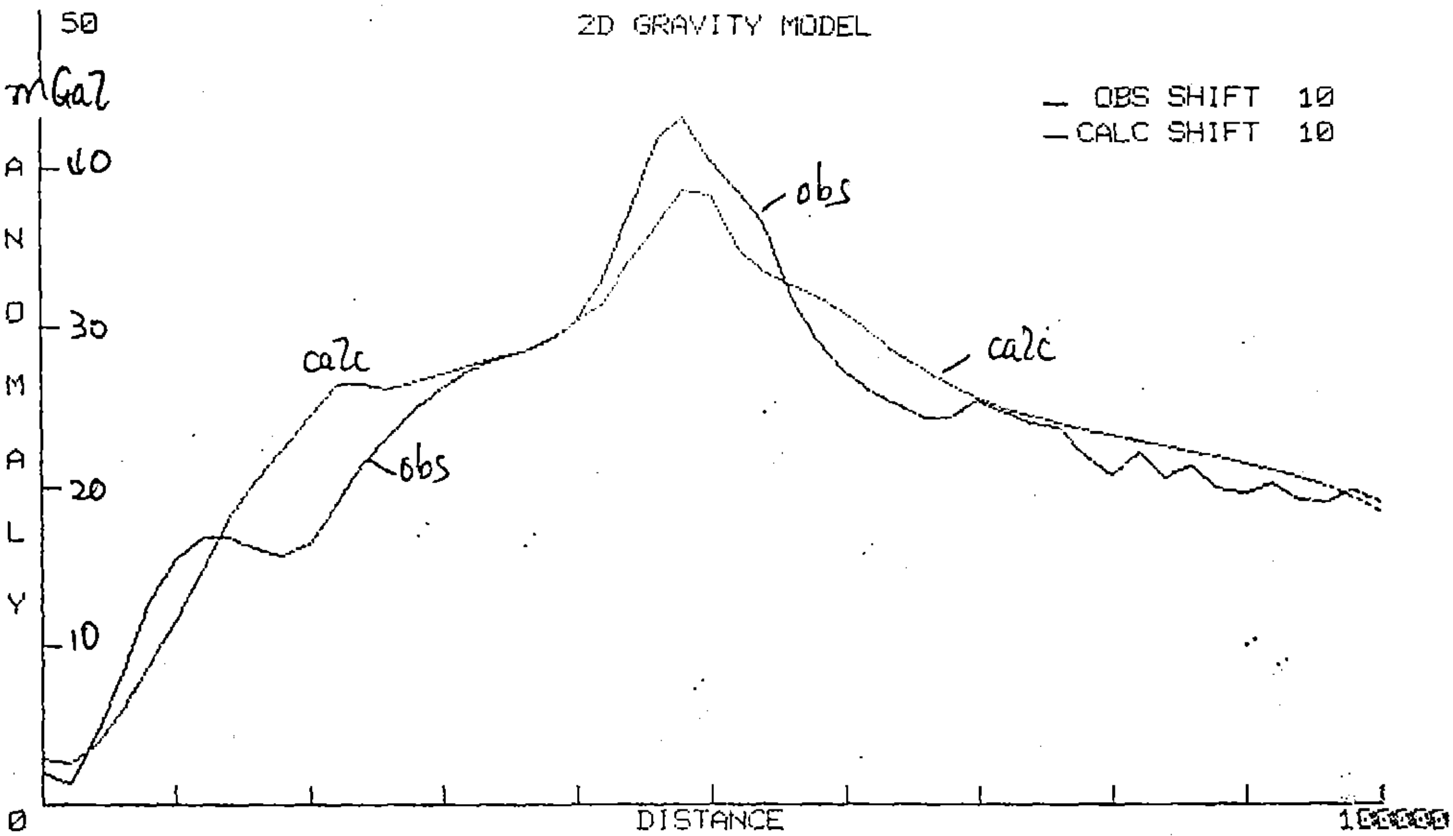


FIGURE 37

LINE PARAMETERS - ORIGIN,LIMIT,INCR : 0 100000 2000

357056



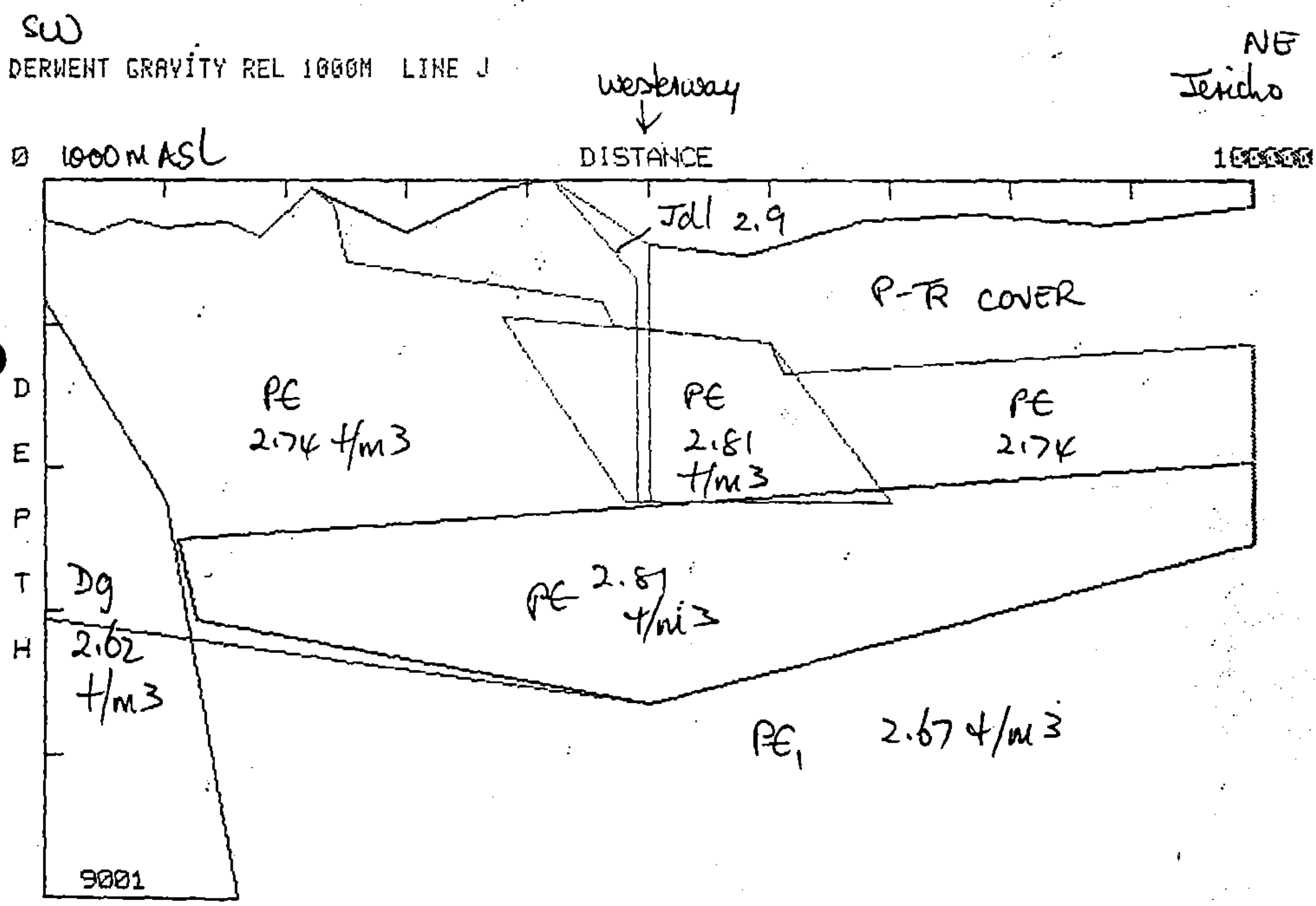
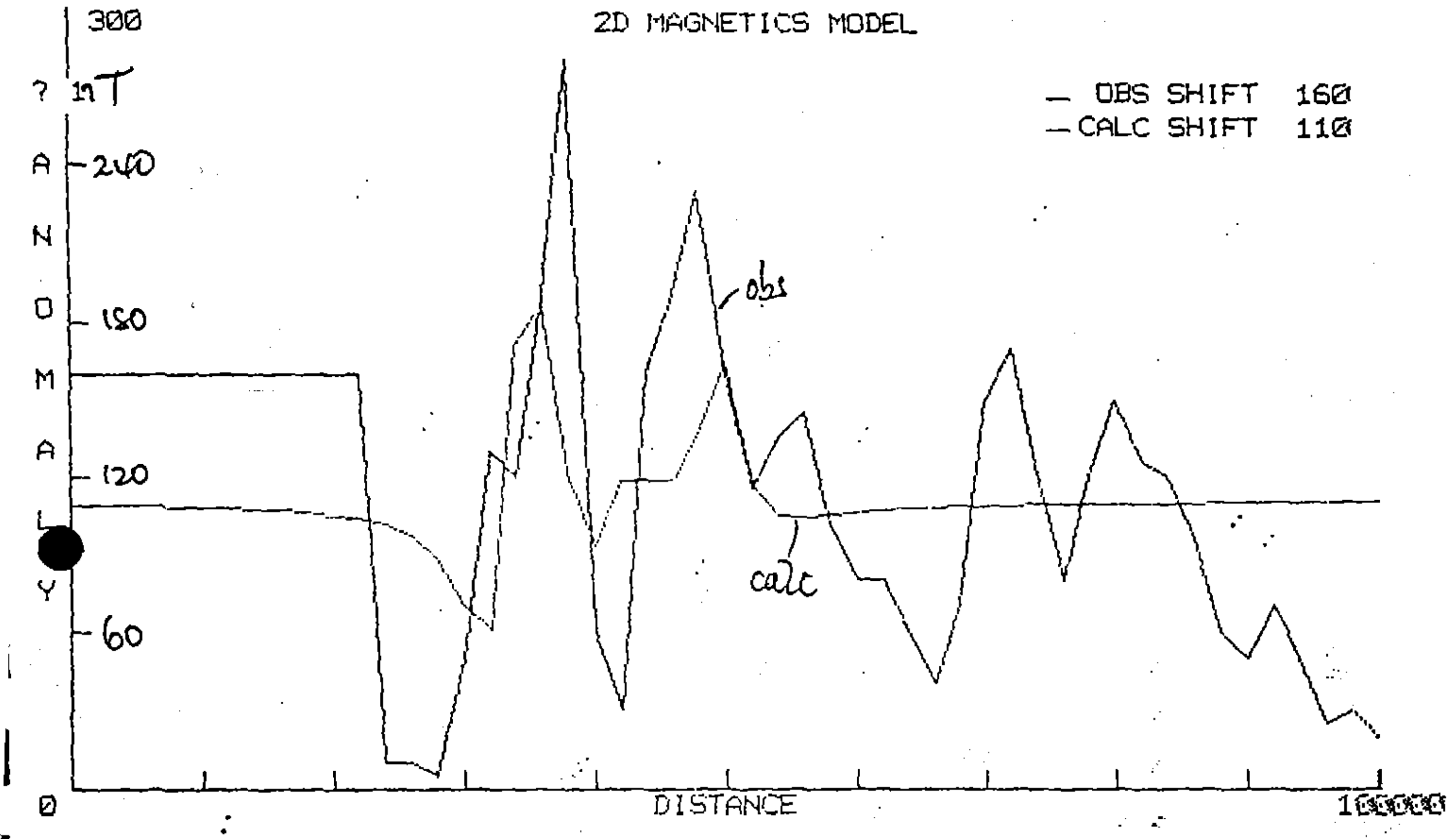


FIGURE 38

INTENSITY	INCLINATION	DECLINATION	OBS LEVEL	LINE DIRECTION
62200.0	-71.0	13.0	0.0	45.0

357057

LINE PARAMETERS - ORIGIN,LIMIT,INCR : 0 100000 2000



SW

DERWENT MAGNETICS 1600M LINE J

NE

Westerway

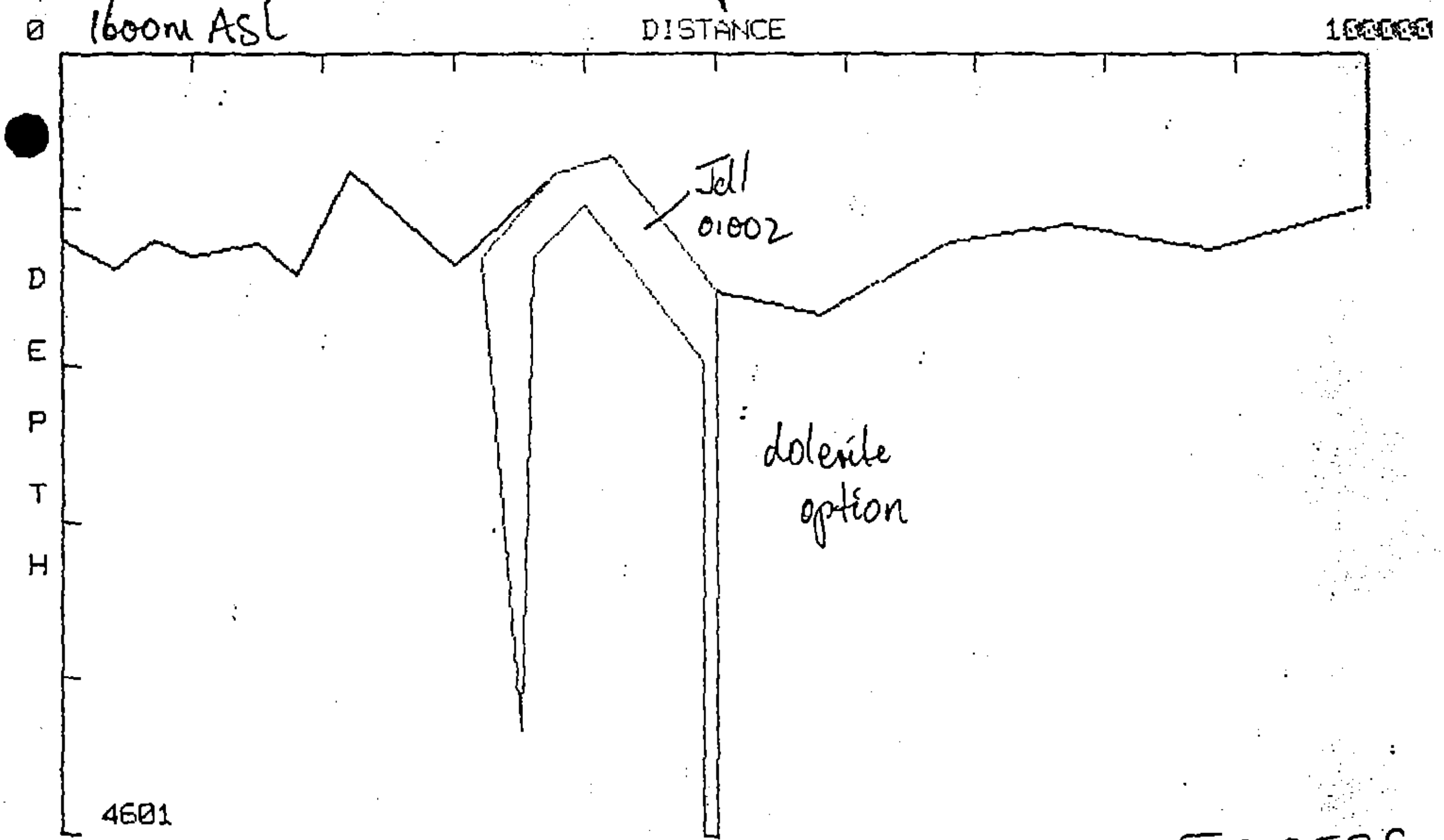


FIGURE 39

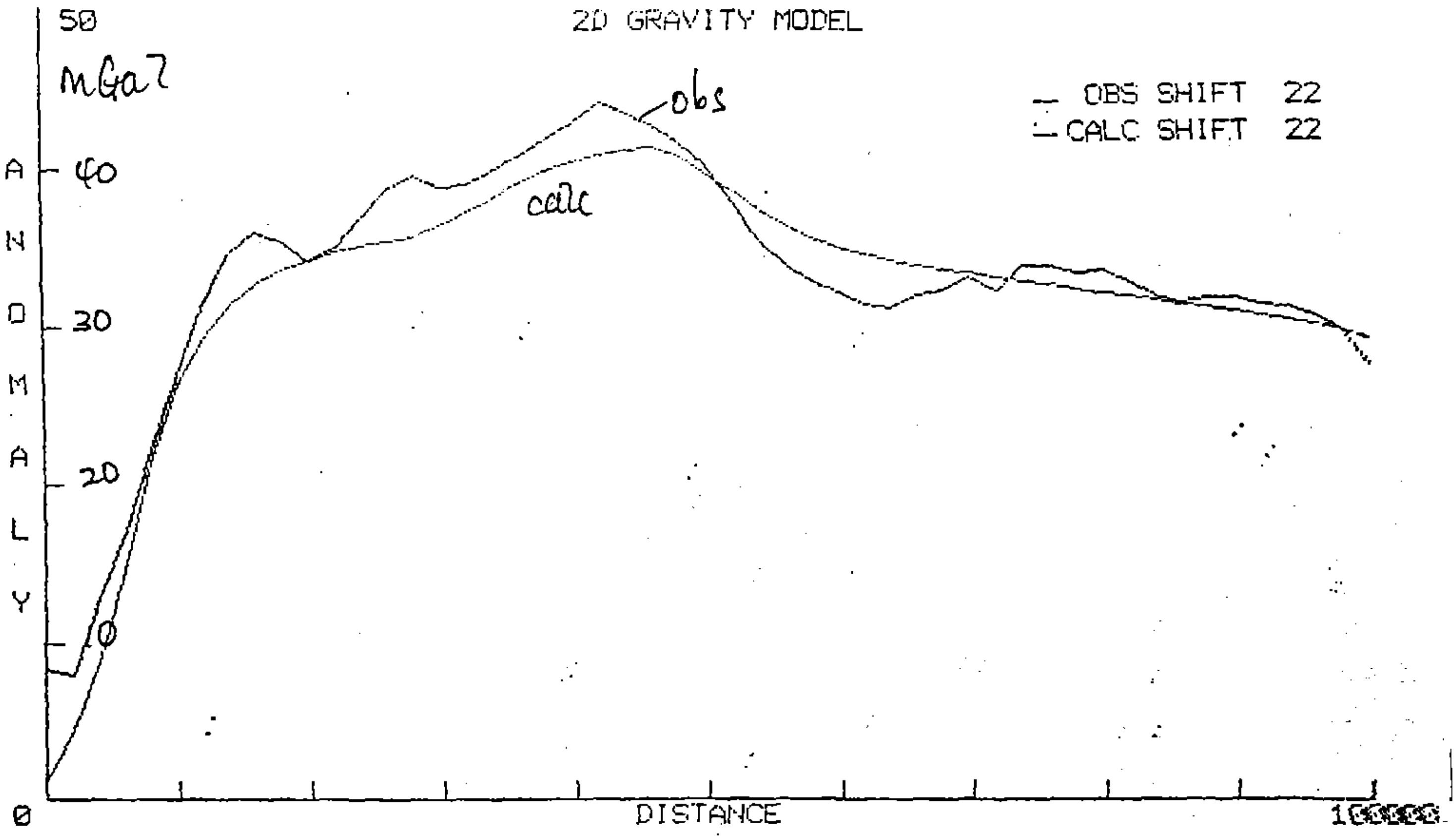
GRAVED

LEAMAN GEOPHYSICS

357058

DERWENT GRAVITY REL 1000M LINE K

LINE PARAMETERS - ORIGIN,LIMIT,INCR : 0 100000 2000



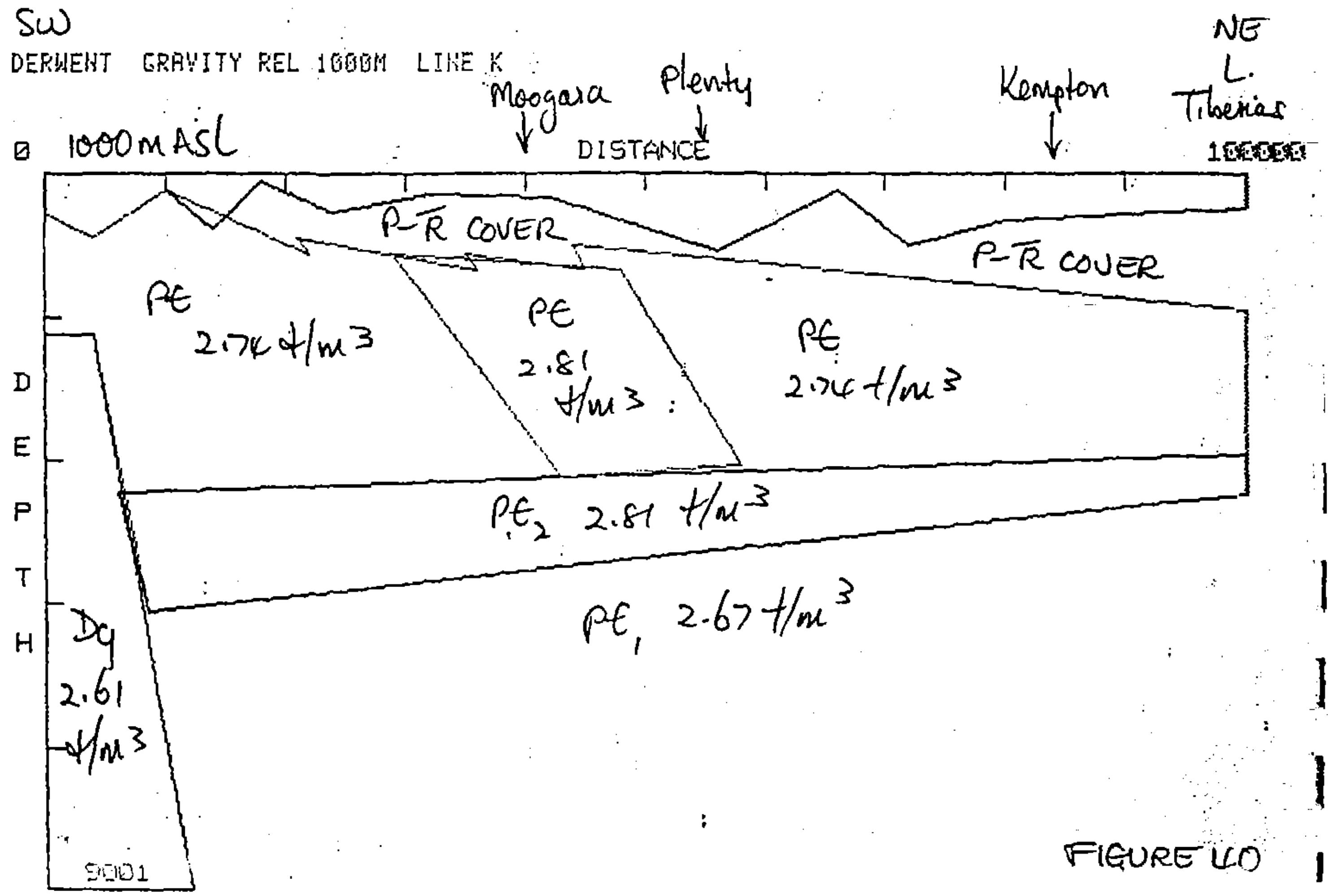
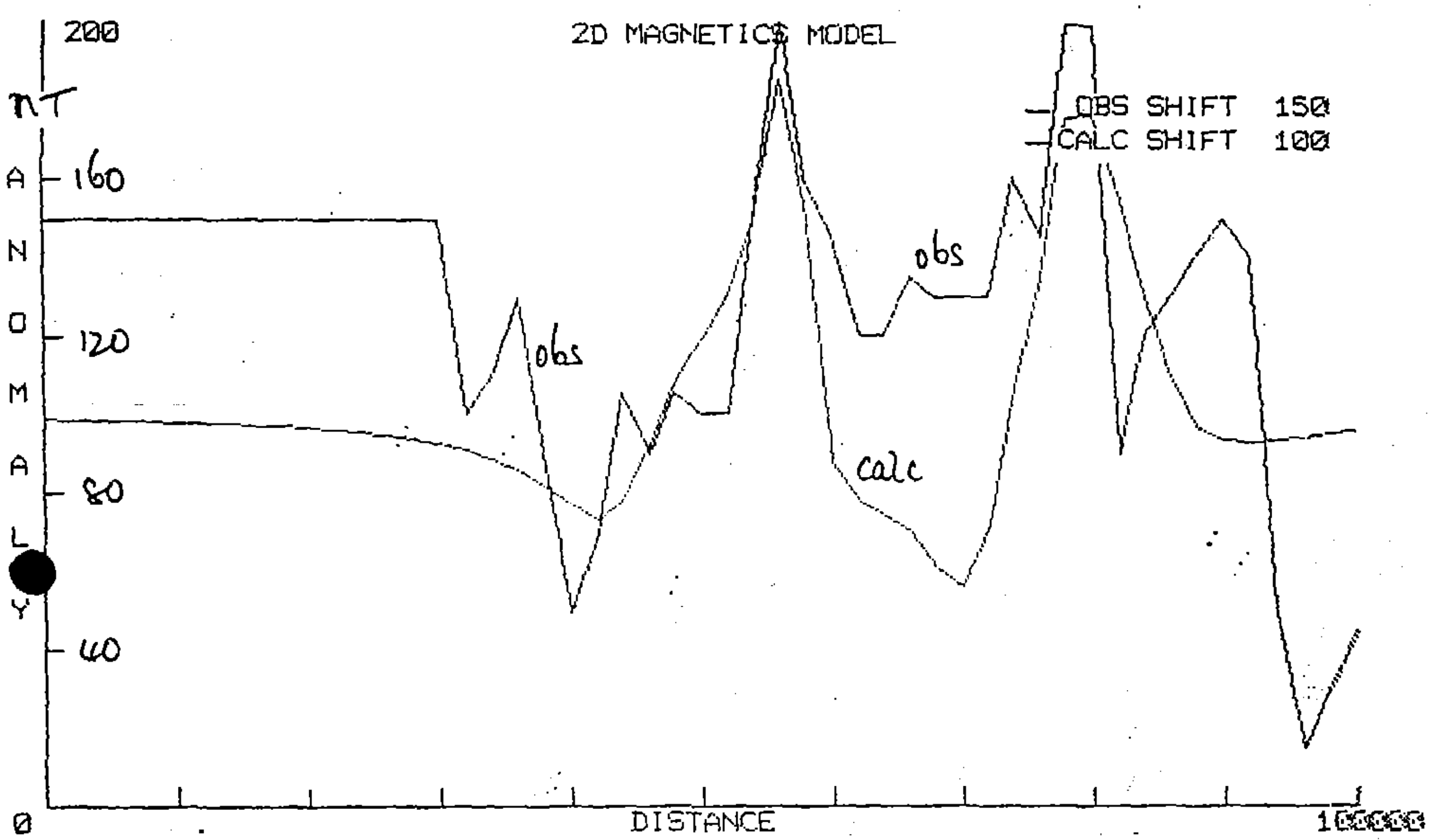


FIGURE 40

INTENSITY INCLINATION DECLINATION OBS LEVEL LINE DIRECTION
62200.0 -71.0 13.0 0.0 45.0

357059

LINE PARAMETERS - ORIGIN,LIMIT,INCR : 0 100000 2000



DERWENT MAGNETICS REL 1600M LINE K

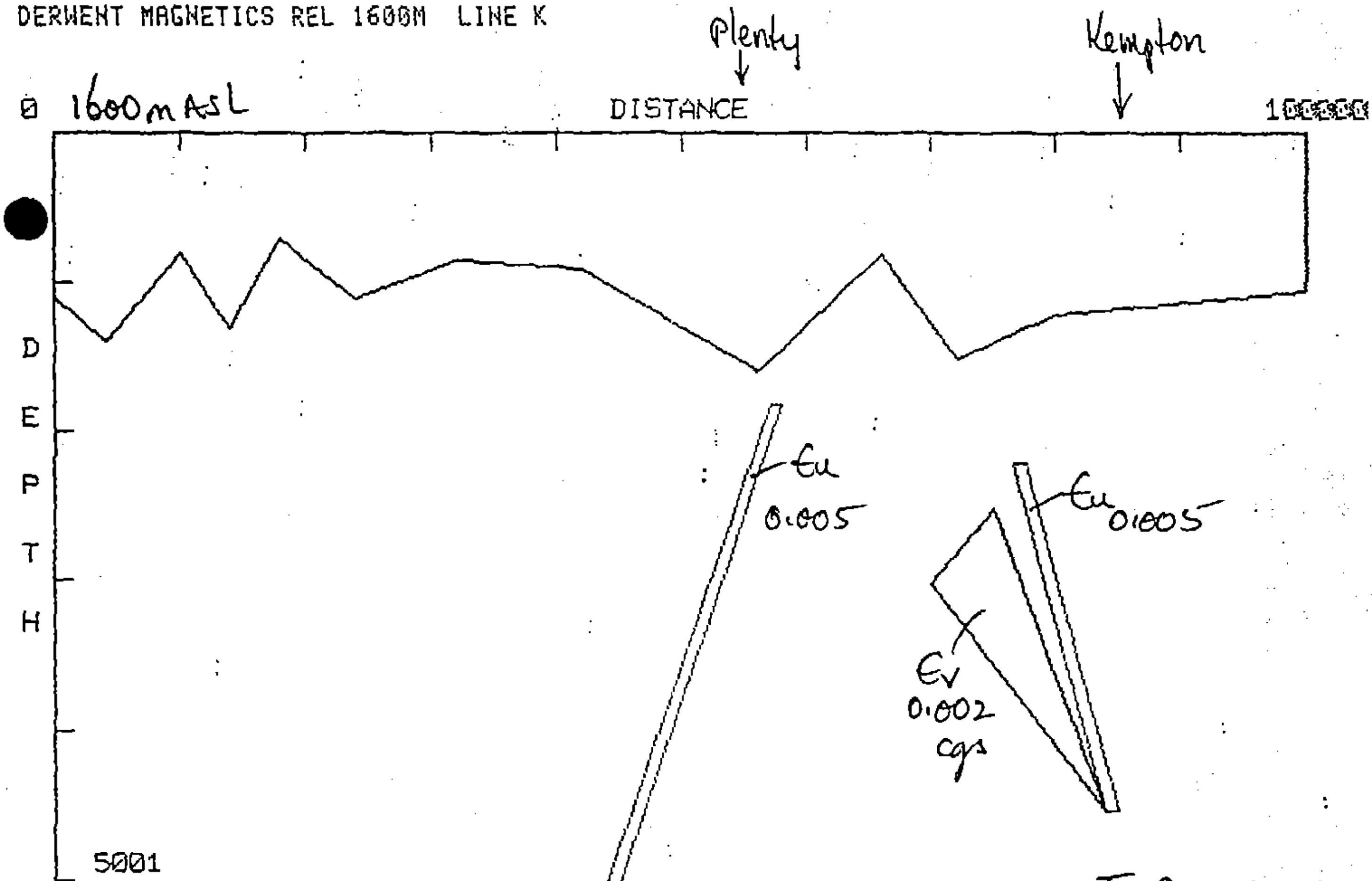
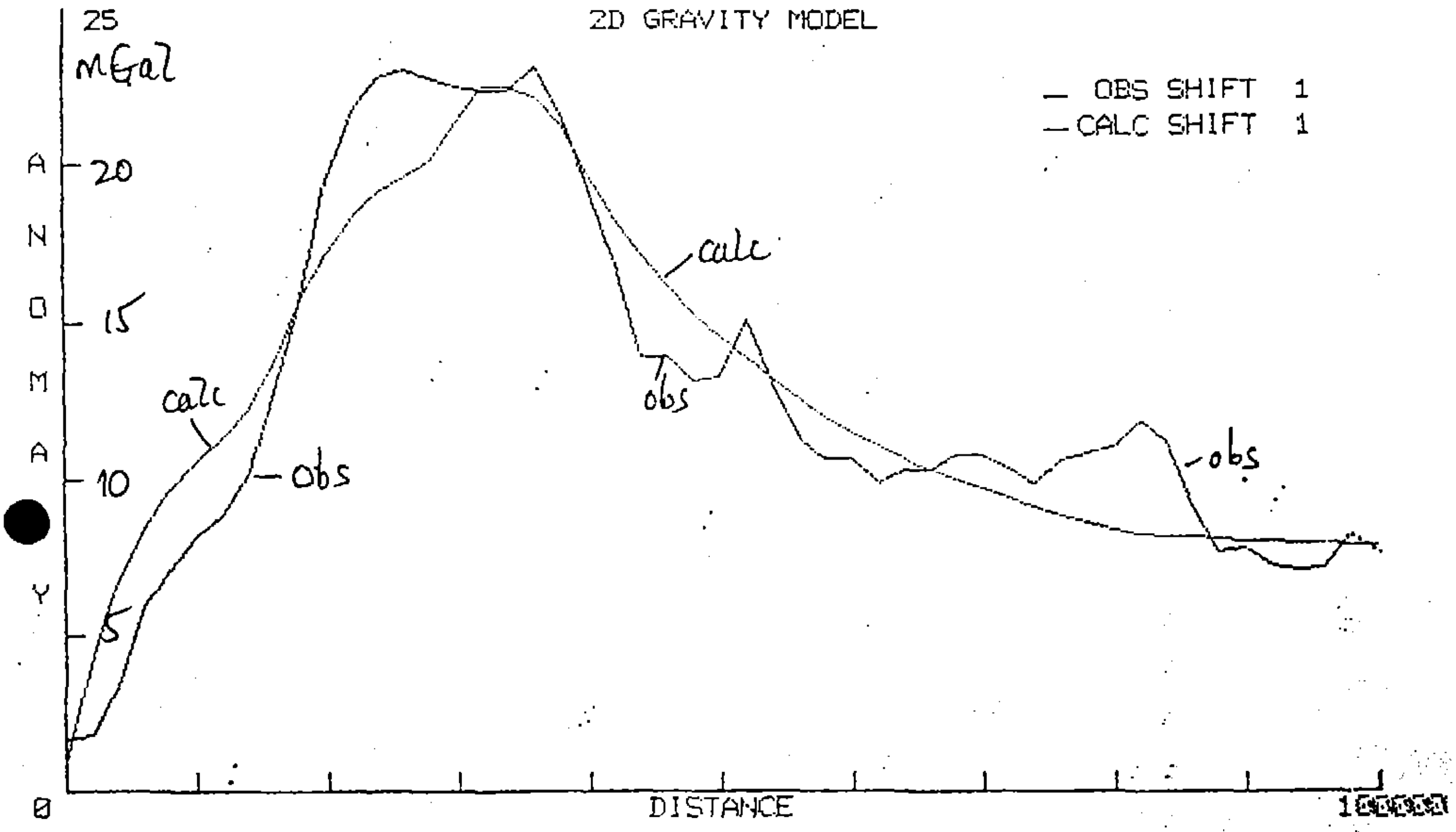


FIGURE 41

DERWENT GRAVITY REL 1000M LINE L

357060

LINE PARAMETERS - ORIGIN,LIMIT,INCR : 0 100000 2000



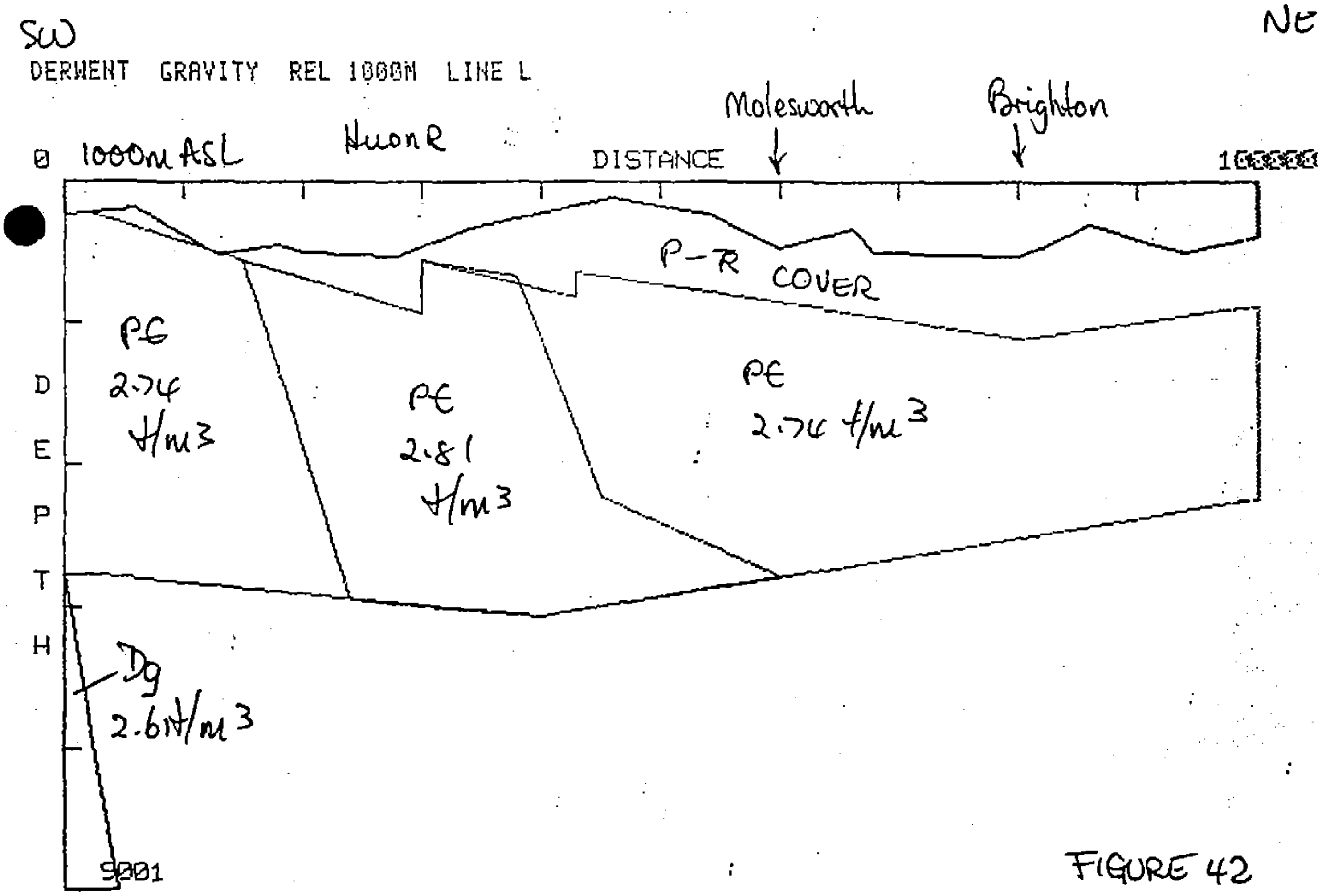
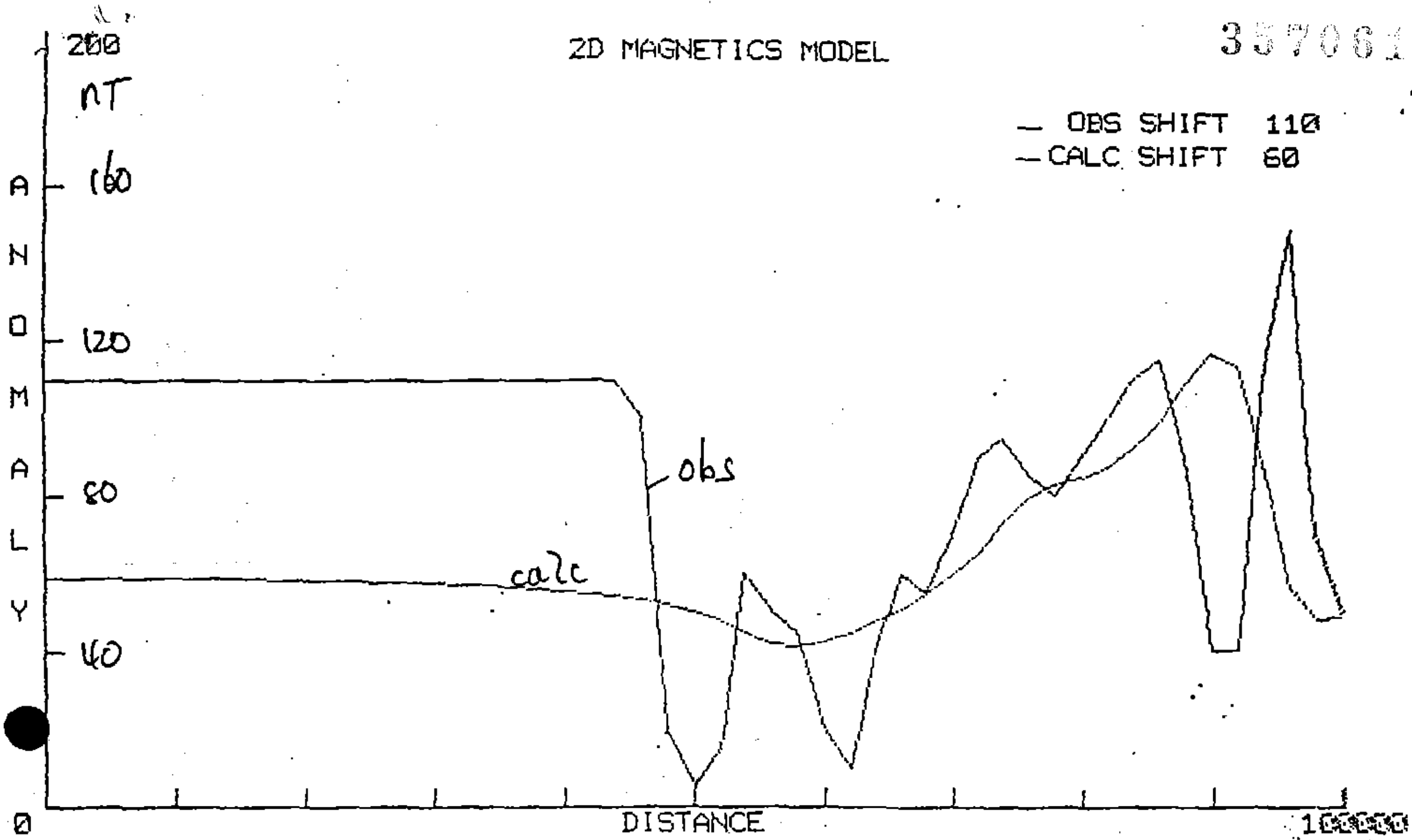


FIGURE 42

2D MAGNETICS MODEL



SW

DERWENT MAGNETICS REL 1600M LINE L

NE

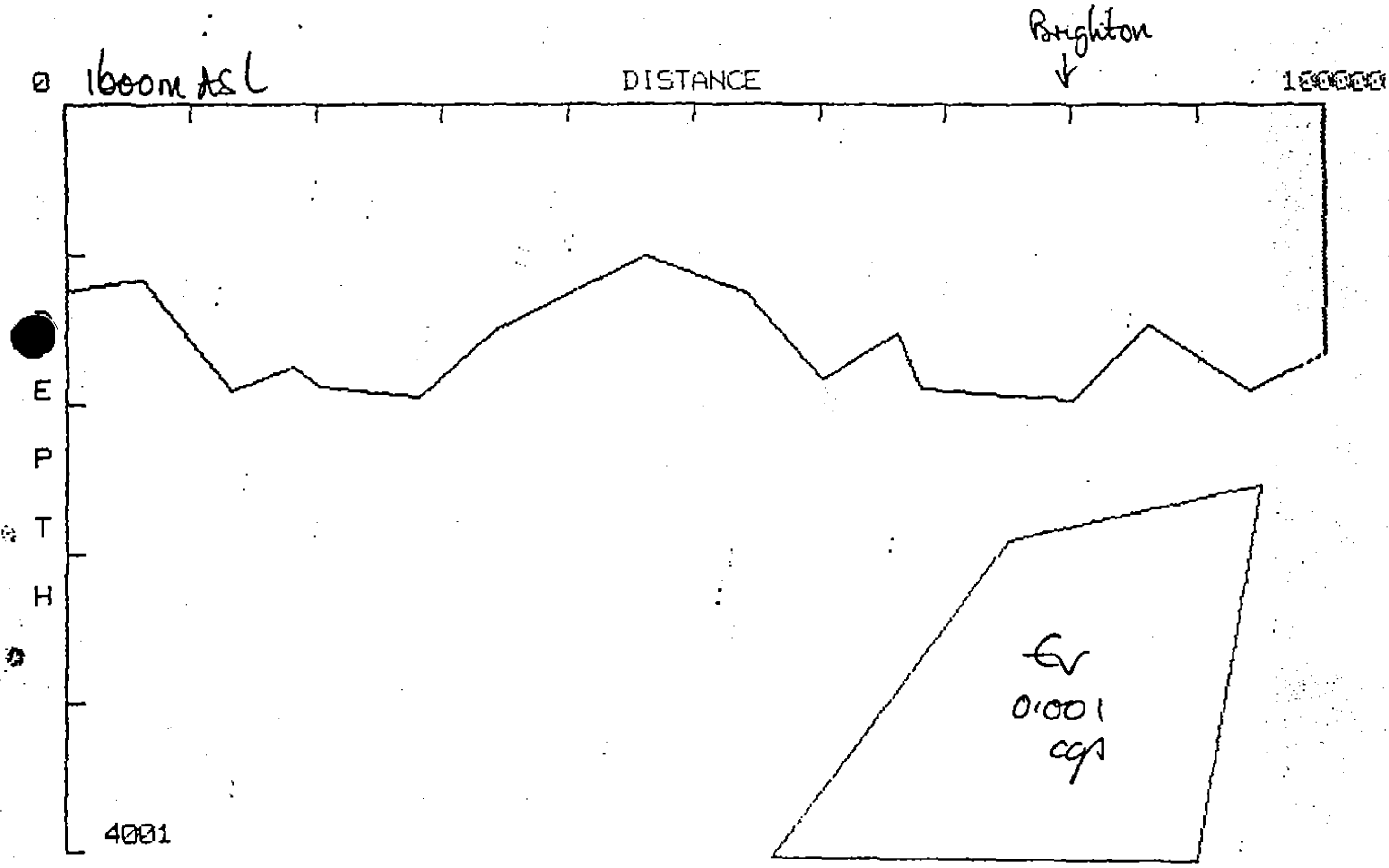
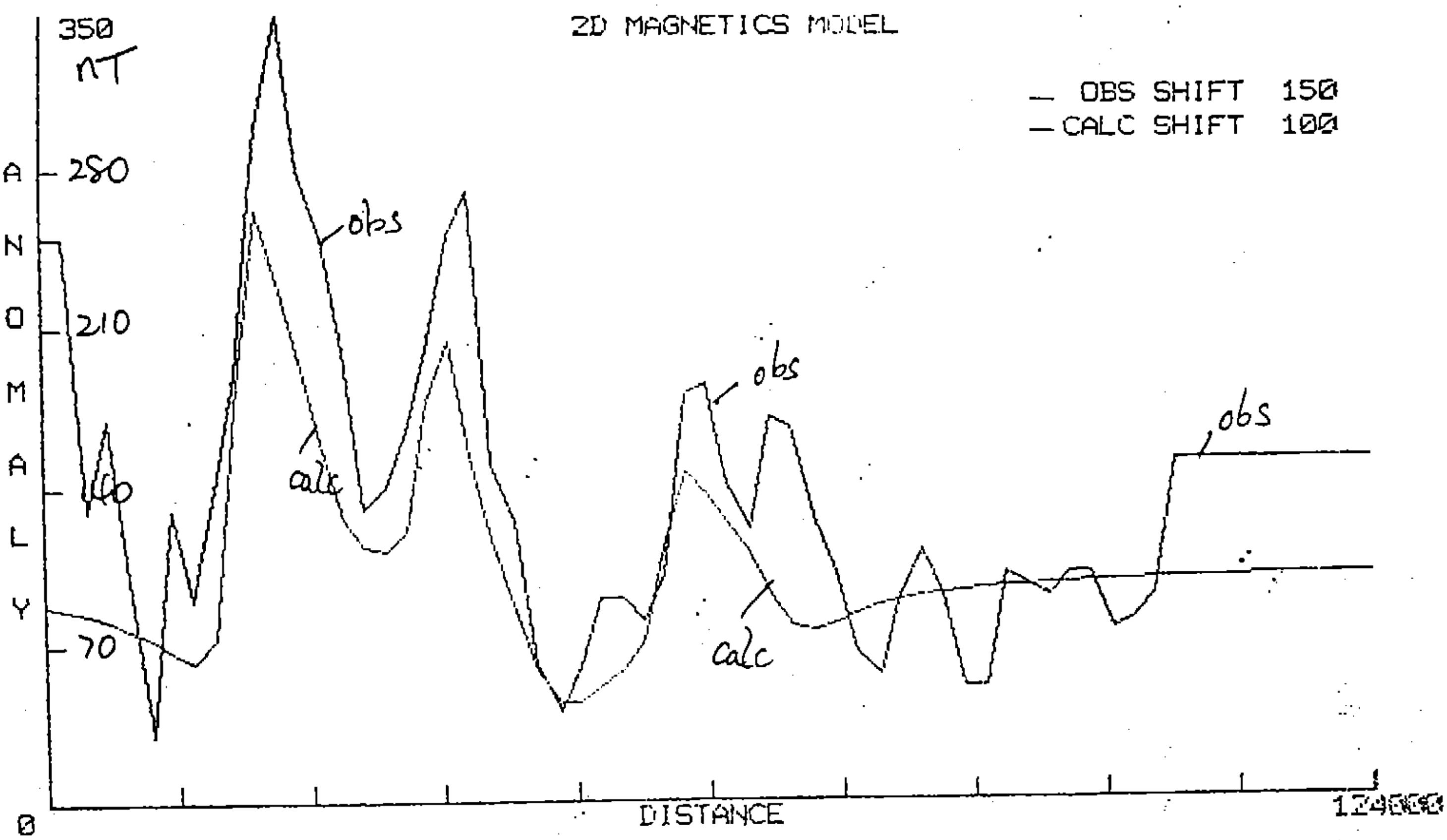


FIGURE 43.

LINE PARAMETERS - ORIGIN,LIMIT,INCR : 0 124000 2000

337062



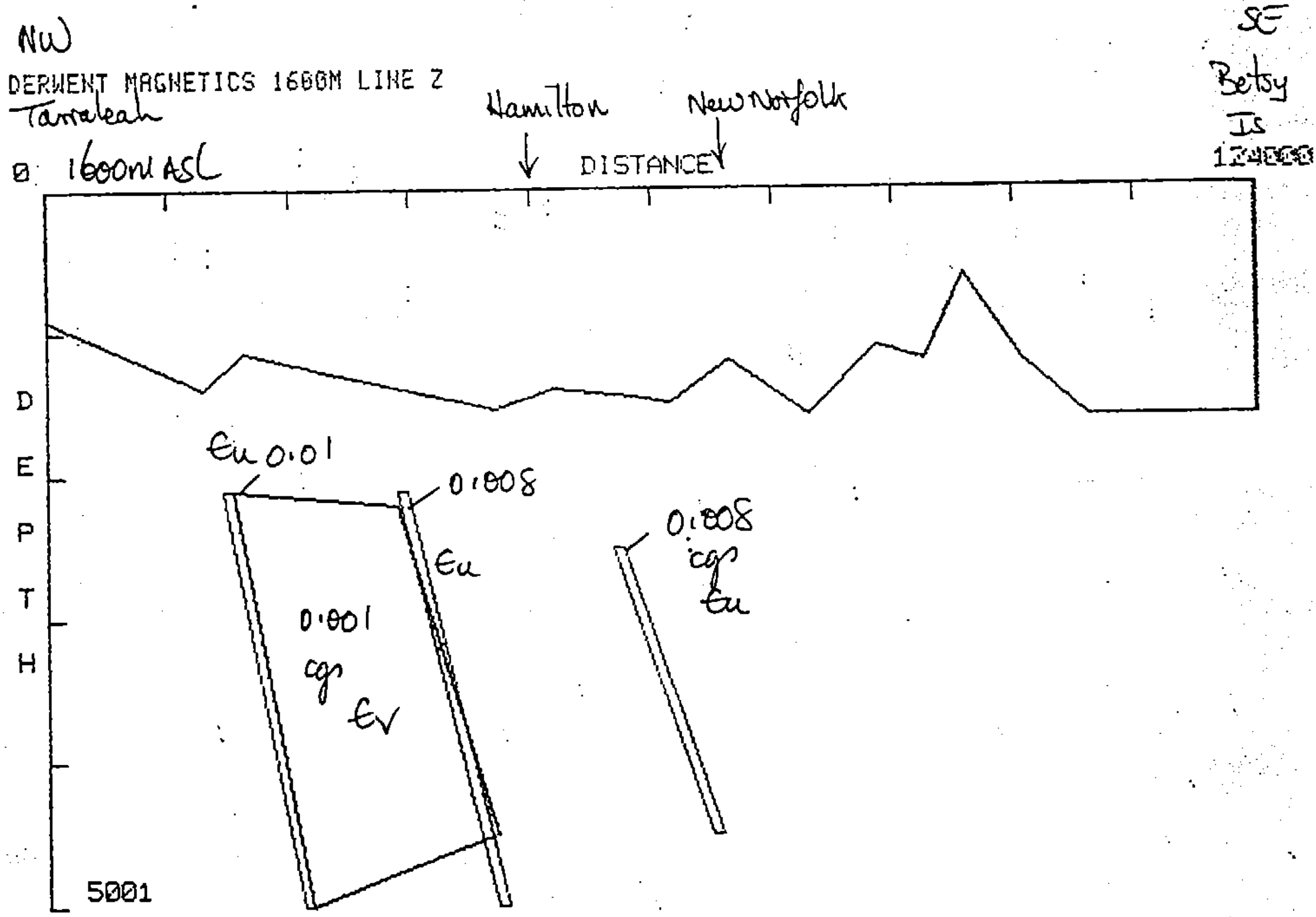


FIGURE 44

PRELIMINARY STRUCTURAL INTERPRETATION EASTERN TASMANIA

for Conga Oil EL 1/88
by D.E. Leaman Leaman Geophysics
Feb 1991
PROVISIONAL - SUBJECT TO VARIATION

Appx 2

357064

J. Amos

357065

VALUATION OF PETROLEUM EXPLORATION TENEMENTS EL 21/95, EL 1/88, AND EL 9/95 - TASMANIA IN WHICH CONDOR INVESTMENTS HOLDS INTERESTS

Prepared by G. E. Carne and Associates

08-83327730

for

Condor Investments Pty Ltd

-confidential-

Adelaide

September 1996

337066

1.0 Opinion

G. E. Carne and Associates has been commissioned by Condor Investments Pty Ltd to prepare an independent valuation of onshore Tasmania Petroleum Licences EL 1/88, EL 21/95 and El 9/95. It is understood that the valuation which follows is not to be used for any purpose other than for discussions between Condor and its bankers and potential financiers, without first receiving written consent from G. E. Carne and Associates.

In obtaining a value for the three Licence areas, the following valuation methods have been considered:

1. Cash Value - what monetary value the current Licence holders could expect to receive if the licences were offered for sale.

2. Farmout Value - terms that a potential farminee might be willing to agree to in order to obtain a working interest in the permits.

3. Comparative Acreage - a comparison of the hydrocarbon potential of the Tasmanian Basin with other onshore sedimentary basins in Australia that are currently being explored.

4. Minimum Viable Reserves Analysis - the minimum viable reserves of both oil and gas, that would be necessary to present a commercial development opportunity in Tasmania.

G. E. Carne and Associates here place a value range of between $2.5 million and $6.0 million for a 100 percent interest in the three onshore Tasmania Petroleum Exploration Licences, with a most likely value of around $4.0 million.

As a commercial discovery of petroleum has not been made in the Tasmanian Basin, and as exploration for petroleum in Tasmania is at a very early stage, the above value quoted for the acreage holdings must be considered as being highly subjective.

For the purpose of this valuation, the three Licence areas are considered as one entity. It is probable that some additional value would be obtained by the Great Southland Minerals Consortium by offering Bruny Island separate from the rest of their acreage holdings.

In July of this year, Great Southland began to deepen their Shittim 1 well, originally spudded in November 1994, on Bruny Island. Significant shows of both methane and hydrogen have been continuously recorded in poorly permeable marls, shales and tillites from 1025 metres, when Great Southland first began to record gas levels in the well, to the present depth of 1290 metres. Success at Bruny Island would considerably increase the assigned value of the Licence areas; failure at Bruny Island would not significantly affect the assigned value.

2.0 Introduction

Mr Malcolm Bendall, Director of Condor Investments, realised that there was considerable potential for commercial accumulations of both oil and gas in Tasmania, and in 1989, began an exhaustive review of the hydrocarbon potential of the State. This led to the listing and mapping of historical oil seepage reportings. It was found that the reported seepages were abundant in number and that most had occurred along major geological lineaments interpreted to represent the surface exposures of thrust faults.

In 1995 Great Southland Minerals P/L Pty Ltd acquired onshore Tasmania Petroleum Exploration Licence El 1/88 from Condor Investments. This was soon followed by the acquisition of contiguous onshore licences EL 21/95 and EL 9/95 from the Tasmania State Government. Together, the three areas held occupy some 13,200 square kilometres; approximately 56 percent of the entire oil and gas prospective area of the Tasmanian Basin.Condor retains a 10 percent working interest in all three of the Licence areas. Application has been made by Great Southland and Condor to acquire a small area adjacent to and to the east of EL 21/95.

Since the acquisition of the three permits, Great Southland has attempted to drill three slim-hole, stratigraphic wells on a site on Bruny Island in the south-east of the State, where seepages have been recorded and small volumes of oil were reportedly produced from Johnson's Well in 1929. As the drilling rig being used was not fitted with a Blow Out Preventor (BOP), all three of Great Southland's wells were abandoned prematurely after encountering unknown volumes of natural gas under pressure.

Great Southland has installed a Blow Out Preventor on their Shittim 1A well and has reentered the well with the purpose of drilling deeper. Good shows of both methane and, unexpectedly, hydrogen have been encountered throughout the newly drilled interval

3.0 Hydrocarbon Prospectivity of Great Southland Licences

Until Condor (then Conga) took an interest, the Tasmanian Basin was considered by most explorers as being non-prospective for oil and gas. The Tasmanian Basin now, however, appears to possess all of the criteria required for the generation and entrapment of commercial volumes of oil and gas. Organically rich, oil prone source rocks have been identified and analysed geochemically. The *Tasmanites* oil shales are of very good source rock quality and there is good evidence that potential source rocks lie within the oil window across much of the Basin. Considerable work remains to be carried out on reservoir distribution and quality, but several potential, porous reservoirs have already been identified, in particular in the Permian and older rock units. Permeability relationships must still be verified. The integrity of seals has been challenged many times in the past, but there appear to be an abundance of seals. Structures have not been adequately defined, there being extremely limited seismic control in Tasmania, but the Tasmanian Basin, and in particular the Early Palaeozoic basin which underlies it, appears to be a typical thrust-fold province which should offer a broad spectrum of structural and stratigraphic trapping possibilities. Maturation modelling indicates that structures were formed prior to the primary periods of peak oil and gas generation.

Numerous past reportings of oil and gas seepages provide considerable encouragement and small volumes of oil and gas have been recovered in recent years from shallow bore-holes. The Derwent Valley in the central part of the State appears to be the most prospective region of the Tasmanian Basin in a structural sense, but this area has not been penetrated by a even a shallow well bore.

The presence of stacked, dolerite sills within the near surface Jurassic sequence, however, makes it difficult to resolve subsurface structure and hence identify suitable closures that might contain hydrocarbon accumulations using conventional seismic methods. The inability to date, to resolve subsurface structure is of considerable concern, but modern seismic techniques should overcome some of this problem.

The gas shows encountered through the drilling of Great Southland's first three wells on Bruny Island provide considerable encouragement that commercial volumes of gas and/or oil may one day be found in Tasmania.

4.0 Current Drilling Program

Great Southland Minerals is currently in the process of deepening their Shittim 1A well. The well, located on North Bruny Island, was spudded in November 1994 and reached a total depth of 1021.4 metres in July 1995. Abnormally large volumes of Hydrogen gas (up to 32 units) were recorded as drilling progressed to present depth through non reservoir tillites, marls and shales. Methane gas (varying between 100 to 1000 PPM) was also recorded. At the time of this reporting, the drilling rig had reached its maximum drilling depth, and Great Southland is making modifications that are expected to allow the rig to penetrate a further 300 metres. The Operator believes the present drilling depth is proximal to a major unconformity, and is hoping that a sub-unconformity reservoir will be encountered within the 300 metre interval that the well is to be deepened by.

Because the hydrogen molecule is so minute and as hydrogen is extremely reactive, it has not been encountered as a commercial accumulation any where in the world. The hydrogen that is being encountered at Shittim 1A is therefore believed to have been recently generated through reactions of organic material contained in the shales and marls, to associated uranium. A hydrogen accumulation of commercial significance should not be expected, although considerable hydrogen may be still present within the poorly permeable source rock interval. The ability to tap such reserves is open to conjecture, but seems unlikely. A commercial volume of methane, however, may, be present should 1) a reservoir quality interval be encountered within the next approximately 300 metres that is to be drilled and 2) should either structural or stratigraphic closure be present at the drilling location.

Success at Shittim 1A would significantly increase the value here assigned to the three Exploration Licences. As Bruny Island occupies only a small part of Great Southland's Tasmanian acreage holdings, the failure to locate commercial volumes of oil or gas at Shittim 1A would not result in a lowering of the assigned value.

5.0 Valuation

5.1 Cash Value

The cash value for the three Licences is assessed on the monetary value the Great Southland consortium could expect to receive if their interests in the Licences were offered, either fully or in part, for sale. This value is very subjective as some explorers no doubt would assess the Tasmanian Basin as having no monetary value, while others, seeing the considerable potential of the basin, may be prepared to pay a premium price to assume a controlling interest in the area at a 'grass roots' stage.

The value of EL 1/88, EL 9/95 and EL 21/95 are here valued on the basis of past exploration undertaken by Conga Oil, Condor Investments and Great Southland. Expenditures to date have been as follows:

Expenditures Conga/Condor to 1992 (approx)	$3.3 million
Expenditure Great Southland Minerals 1995-1996 (approx)	$1.0 million
Total Expenditure to Date	$4.3 million

In addition, the Australian Geological Survey Organisation (AGSO) recently acquired $3.0 million of regional seismic in the central part of Tasmania.

The more important elements of the recent exploration programme that has been carried out in onshore Tasmania are:

- location and identification of oil seepages reported over the past century
- acquisition of three Exploration Licences and application for a fourth Licence area
- gravity and magnetics surveying of the D'Entrecastreaux region
- the structural interpretation of gravity and magnetics data in Tasmania
- source rock sampling and analysis
- geochemical analysis of seep material
- preparation of professional paper addressing the hydrocarbon potential of onshore Tasmania and presentation of this paper to the Australian Petroleum Exploration Association (APEA) in 1991
- test seismic surveying in the D'Entrecastreaux region
- acquisition and interpretation of offshore seismic data that was physically acquired by the Bureau of Mineral Resources over the D'Entrecastreaux Channel

- acquisition and interpretation of seismic data physically acquired by the Australian Geological Survey Organisation (AGSO) in central Tasmania

- slim hole drilling of the Shittim 1 (1021m), Gilgal-1 (50m) and Jericho-1 (228m) wells

These are all critical to the understanding of the presence of petroleum in Tasmania and have substantially upgraded the value of acreage within the Tasmanian Basin. It is believed that a buyer would be willing to pay the amount already expended by Great Southland Minerals and its immediate predecessors in exploration of the Tasmanian Basin, plus a small premium, to assume full ownership of the three exploration Licences.

5.2 Farmout Value

We believe a farminee would be willing to pay certain future exploration costs to assume a participating interest in one or all of the Licence areas currently owned by Great Southland Minerals. It is expected that a potential farminee would be prepared to pay for the acquisition and processing of 250 line kilometres of seismic and pay for the drilling of two slim hole and one conventional exploration wells to earn a 50 percent interest in the three Licences.

250 km seismic at $4000 per km		$1,000,000
2 wells:	two slim hole wells logged and tested	$400,000
	one conventional well logged and tested	$800,000
Total expenditure for the above program would be		$2,200,000

This gives the Licences a value of $4.40 MM (100 percent interest).

5.3 Comparative Acreage

The nearby Otway Basin is geographically the closest onshore sedimentary basin to the Tasmanian Basin, but unlike the Tasmanian Basin, it has been delineated with considerable modern seismic data and evaluated by numerous petroleum exploration wells. Given the magnitude of exploration that has been conducted, the results of exploration in the onshore Otway Basin to date, have proven to be very disappointing, there being an apparent lack of organically rich and mature source rocks in communication with potential reservoir intervals. Many explorers expect future discoveries in the Otway Basin will be few in number and of small volume.

Exploration in the Surat/Bowen Basin commenced in the early 1900s, with pipelines to deliver oil and gas being built in the 1960s. Seismic coverage is dense over much of the basin and nearly 500 petroleum wells have been drilled to date. Undrilled structures are known to be small, and all of the obvious, lower risk structures have been drilled.

The Cooper/Eromanga Basin has been and remains Australia's most important onshore hydrocarbon producing province. The most prospective acreage (PELs 5 and 6) is held by a consortium led by Santos Ltd and further interests in the more prospective parts of the Basin are not available.

The Tasmanian Basin, on the other hand, remains virtually untested, and given that effective source rocks and reservoirs have been identified, the hydrocarbon potential of the basin therefore remains high. There is extremely little seismic coverage within the Tasmanian Basin, (only a few short lines) and no conventional petroleum wells have been drilled. Only a few, shallow, slim hole wells have been drilled, but nevertheless, potential reservoir intervals and organically rich and mature source rocks have been penetrated. Data obtained through Conga/Condor and Great Southland Minerals suggest that both the Permian and the Pre-Permian intervals of the Tasmanian Basin offer potential for both oil and gas. The Cooper Basin's gas production is largely from Permian reservoirs.

The near lack of subsurface structural control limits the value that can be placed on acreage within the Basin, as a considerable amount of seismic will have to be acquired to delineate valid drilling targets. Several domes with surface expression are currently being considered for drilling.

As there is currently very little onshore acreage that has the potential for hosting significant volumes of undiscovered oil and gas, available in Australia, the Tasmanian Basin, with proper promotion, should attract considerable interest and funding.

5.4 Minimum Viable Reserves Analysis

We have attempted to quantify the minimum viable reserves, both for oil and gas, that would be necessary to present a development opportunity in Tasmania.

Minimum viable reserves (MVR) are defined as those quantities that would provide project cash flow with a rate of return (ROR) of not less than 10 percent after tax.

The MVR is a function of well productivity, project life, quality of resource and size of potential market.

We have utilised cash flow modelling with a range of well parameters and resource qualities to identify the respective MVRs. Four gas and four oil cases have been developed and costed in conjunction with product values of $2.30 per Mscf for gas and $22.00 per barrel for oil. The cash flow modelling which applies fiscal parameters specific to Tasmanian legislation, provided a matrix of results from which the MVR can be interpolated. These results are summarised on the attached sheets together with graphical presentations.

In general terms, the results show that:

1. For gas prospects,
   the minimum viable reserves are greater than 40 Bscf,
   the market needs to be greater than 15 MMscfd, and
   the project life must be greater than 15 years.

2. For oil prospects,
   in central Tasmania,
   the minimum viable reserve is between 1 and 2 million barrels,
   the minimum initial well rate is approximately 200 BOPD, and
   the project life should be greater than 9 years.

   on Bruny Island,
   the minimum viable reserve is about 4 million barrels,
   the minimum initial well rate is approximately 400 BOPD, and
   the project life should be greater than 10 years.

3. For a large oil project development (Case 8) in central Tasmania,
   the minimum viable reserve is greater than 8 million barrels,
   initial well rates must be greater than 400 BOPD, and
   the project life should be greater than 13 years.

The above reserve thresholds and well rates are considered to be well within the bounds of reasonable expectancies.

5.5 Values Previously Assigned to the Tasmania Basin

In November 1989, McIntosh Corporate Ltd, assigned a value range of between $0.48 million to $1.20 million, to Conga Oil Pty Ltd Licence EL 1/88. The Licence occupied 24,620 acres of the Tasmania Basin and adjacent lands. Much has been done by Conga/Condor and Great Southland subsequent to the McIntosh evaluation, to increase the perceived prospectivity and consequently the value of acreage in the Basin.

5.6 Special Issue of Ordinary Shares

On the 2nd September 1996, the Directors of Great Southland Minerals Pty Ltd approved an arrangement to facilitate raising up to $2.5 million to fund the Company's 1996-1997 exploration program, from sources outside of the Company. The Directors have been authorised to make a special issue of ordinary shares in the capital of the Company to be offered only to contributors to the Company's exploration funding program under the fund raising proposal.

Investors are being sought, each to contribute a minimum of $250,000, in an attempt to raise the $2.5 million in drilling funds. Should a discovery (ies) be made, a royalty of up to 50 percent of well head value of product for five years will be divided pro-rata between the contributors. A special issue of ordinary shares of up to 25 percent of the final issued share capital will be made available to persons who have participated in the exploration program. The shares will be issued with a premium of $2.00.

Declaration

The preparation of this valuation has been undertaken at the request of Mr Malcolm Bendall, a Director of Condor Investments, to assist Condor in its discussions with its bankers.

The individuals involved in this valuation have no pecuniary interest in Condor, other than professional fees receivable for the preparation and submission of this report.

In carrying out our task, we have considered and relied upon information provided by Condor. Such information was evaluated by us through analysis, enquiry and review and we believe on reasonable grounds that it is reliable and complete. We have no reason to believe that any material facts have been withheld from us but we do not warrant that our enquiries have revealed all of the matters which an extensive examination might disclose.

In the preparation of the cost data used in the evaluation process, we have relied upon our experience elsewhere in Australia, and information supplied by Condor and others. We have checked the validity of such data against that available from other sources in which similar operating conditions apply and we have incorporated such other data, modified as necessary, in our case analyses. Time has not permitted any auditing of the data, other than by verbal query. However, we are satisfied that the resulting data incorporated in our models, are sufficiently accurate to enable a reasonable valuation to be made.

We believe our review and findings are accurate but no warranty of accuracy or reliability is given. Our statements and opinions are given in good faith and in the belief that such statements are not false or misleading.

Qualifications

The individuals responsible for this review and analyses have experience and qualifications relevant to the task performed.

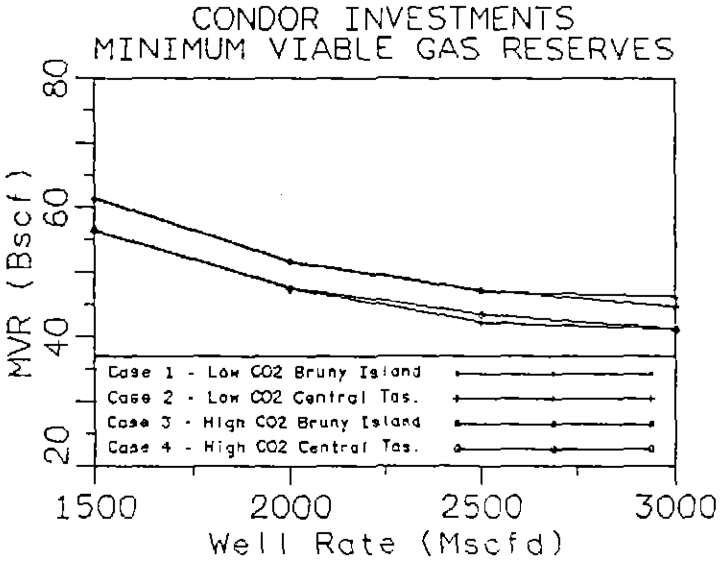
Gerald Carne has 25 years of petroleum related experience with major international and domestic oil companies in Canada, Indonesia and Australia including senior posts with TEXACO, Santos Ltd and Petroleum Consultant Group, Petroleum Management Associates. He was a founding member and Managing Director of Questa Australia Pty Ltd, a petroleum consultancy formed in 1988. He became an independent consultant in 1994.

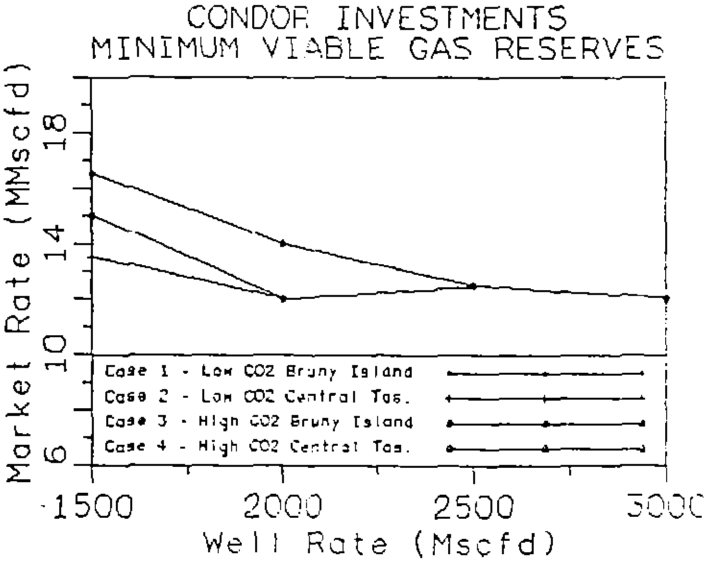
Geoffrey Burdon has over 24 years of experience in petroleum reservoir engineering and has held senior posts with major Australian companies including SANTOS Ltd and Western Mining Corporation. He has worked as an independent consultant since 1987. He is a founding member and Director of the PETRA GROUP Pty Ltd, a petroleum consultancy.

CONDOR INVESTMENTS

Gas Scenarios — Minimum Viable Reserve (gas)

Case No. Comments	Well Rate (Mscfd)	Day Rate (MMscfd)	No. Wells	MVR (Bscf sales)	GIIP req'd (Bscf)	Project Life (yrs)
1						
low CO2	1000	N/A	N/A	N/A	N/A	N/A
Bruny Island	1500	16.5	11	61.15	76.44	15.1
	2000	14.0	7	51.47	64.34	15.2
	2500	12.5	5	47.02	58.78	15.3
	3000	12.0	4	46.11	57.64	15.3
2						
low CO2	1000	N/A	N/A	N/A	N/A	N/A
Central Tas.	1500	13.5	10	56.19	85.00	15.2
	2000	12.0	6	47.32	59.15	15.2
	2500	12.5	5	42.23	54.04	15.3
	3000	12.0	4	40.93	51.17	15.3
3						
high CO2	1000	N/A	N/A	N/A	N/A	N/A
Bruny Island	1500	16.5	11	61.37	122.74	15.1
	2000	14.0	7	51.66	103.32	15.2
	2500	12.5	5	47.20	94.39	15.3
	3000	12.0	4	44.69	89.38	15.3
4						
high CO2	1000	N/A	N/A	N/A	N/A	N/A
Central Tas.	1500	15.0	10	56.44	112.88	15.1
	2000	12.0	6	47.53	95.06	15.2
	2500	12.5	5	43.43	86.85	15.3
	3000	12.0	4	41.12	82.24	15.3

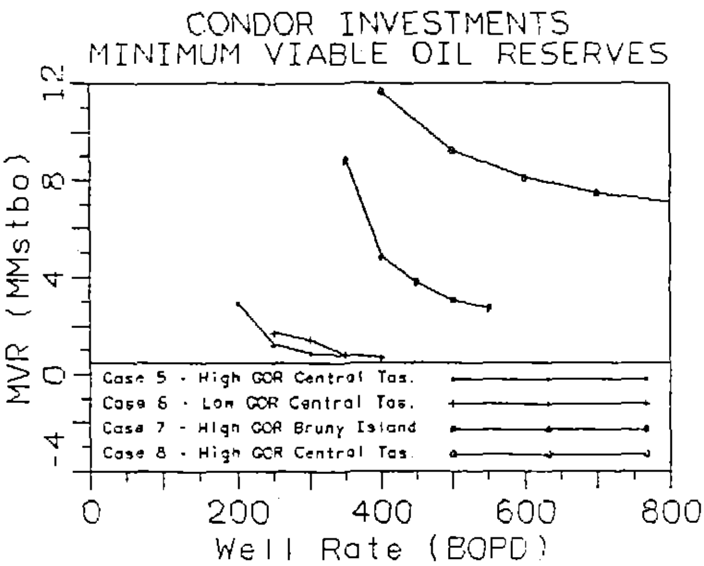


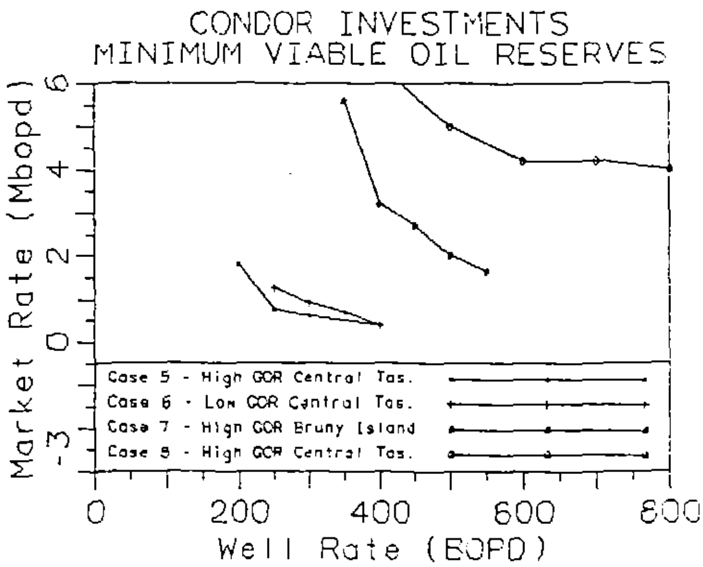


CONDOR INVESTMENTS

Oil Scenarios — Minimum Viable Reserve (oil)

Case No. Comments	Well Rate (BOPD)	Day Rate (BOPD)	No. Wells	MVR (BBLS'000)	OIIP req'd (BBLS'000)	Project Life (yrs)
5						
High GOR	150	N/A	N/A	N/A	N/A	N/A
Central Tas.	200	1800	9	2927	9750	9.5
RF 30%	250	750	3	1208	4027	9.6
	300	600	2	866	2887	9.6
	400	400	1	689	2297	9.9
6						
Low GOR	150	N/A	N/A	N/A	N/A	N/A
Central Tas.	200	N/A	N/A	N/A	N/A	N/A
RF 15%	250	1250	5	1731	11540	8.5
	300	900	3	1371	9141	8.8
	350	700	2	810	5403	8.8
	400	400	1	701	4676	9.1
7						
High GOR	300	N/A	N/A	N/A	N/A	N/A
Bruny Island	350	5600	16	8800	29340	10.0
RF 30%	400	3200	8	4840	16140	9.8
	450	2700	6	3790	12620	9.8
	500	2000	4	3060	10200	9.7
	550	1650	3	2720	9080	9.5
8						
High GOR	300	N/A	N/A	N/A	N/A	N/A
Central Tas.	400	6400	16	11640	38810	12.6
RF 30%	500	5000	10	9240	30790	12.7
	600	4200	7	8110	27050	12.8
	700	4200	6	7480	24920	12.9
	800	4000	5	7080	23590	12.9





RISKED VIABLE RESERVES TABLE
****

Exploration Success Ratio = 1.00

Initial per Well mscf/day	No.of Wells	Economic Life Years	Ultimate Recovery mmscf	NET PV ($ooo's) at 10.00 % Pretax $ of Year	After Tax $ of Year	After Tax (REAL $)
1000	4	13.49	14928	-22395	-22395	-21075
1000	6	13.93	22854	-17873	-17873	-18006
1000	8	14.19	29352	-12639	-12875	-14734
1000	10	14.38	37098	-8101	-9755	-12672
1000	12	14.51	44843	-3545	-6940	-10913
1000	14	14.61	52588	1023	-4209	-9252
1000	16	14.69	60333	5597	-1504	-7624
1000	18	14.76	68078	10175	1191	-6004
1000	20	14.81	75824	14757	3838	-4424
1000	22	14.86	83569	19342	6486	-2844
1500	4	14.19	22006	-12376	-12376	-13638
1500	6	14.62	33823	-3096	-5679	-8879
1500	8	14.89	45640	6231	112	-4949
1500	10	15.07	57458	15625	5642	-1199
1500	12	15.20	69275	24999	11364	2640
1500	14	15.30	81093	34385	17097	6485
1500	16	15.38	92910	43779	22838	10335
1500	18	15.45	104727	53178	28584	14187
1500	20	15.50	116545	62581	34335	18042
1500	22	15.55	128363	71987	40082	21891
2000	4	14.68	30150	-2943	-5264	-8205
2000	6	15.11	46039	11190	3444	-2092
2000	8	15.38	61929	25363	12275	4028
2000	10	15.56	77818	39564	21134	10161
2000	12	15.69	93708	53785	30009	16299
2000	14	15.79	109597	68016	38833	22399
2000	16	15.87	125487	82255	47650	28493
2000	18	15.93	141376	96500	56469	34589
2000	20	15.98	157266	110748	65291	40687
2000	22	16.03	173155	125059	73780	46622

SUMMARY OF RVR RESULTS

357077

RISKED VIABLE RESERVES TABLE
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Exploration Success Ratio = 1.00

Initial per Well mscf/day	No.of Wells	Economic Life Years	Ultimate Recovery mmscf	NET PV ($ooo's) at 10.00 % Pretax $ of Year	After Tax $ of Year	After Tax (REAL $)
2500	4	15.06	38294	6586	802	-3673
2500	6	15.49	58256	25555	12741	4728
2500	8	15.75	78217	44585	24711	13140
2500	10	15.93	98179	63648	36612	21493
2500	12	16.06	118140	82766	48317	29750
2500	14	16.16	138102	101859	60233	38111
2500	16	16.23	158063	120959	72155	46476
2500	18	16.30	178025	140064	84083	54843
2500	20	16.35	197986	159173	96014	63212
2500	22	16.39	217948	178284	107948	71583
3000	4	15.37	46438	16151	6990	870
3000	6	15.80	70472	39987	22055	11554
3000	8	16.06	94505	63916	36893	22096
3000	10	16.23	118539	87848	51915	32726
3000	12	16.36	142573	111797	66954	43365
3000	14	16.46	166607	135757	82004	54010
3000	16	16.53	190640	159723	97061	64659
3000	18	16.59	214674	183695	112122	75311
3000	20	16.65	238708	207670	127188	85964
3000	22	16.69	262741	231648	142256	96619

SUMMARY OF RVR RESULTS

RVRAUST 875.22 (960805)

Corporate Tax		Royalty Parameters	
Tax Rate (percent)	36.00		
Depreciation Trunklines (years)	10	State Royalty Rate (percent)	10.00
Depreciation Other Capex (years)	10	Override Royalty Rate (percent)	0.00
Negative Tax IS NOT Valid		Overhead Costs Allowable (percent)	50.00
Fiscal Quarter in which Tax Paid	1	Allowable Common Capex (percent)	50.00
Tax is paid in Year of Assessment		Limit on Deductions (percent of Gross)	100.00
		Debt Ratio for Interest (percent)	0.00
Federal Excise Data		Date of Start of Amortization	Expenditure Date
		Capital Amortization Period(years)	10
Exemption Threshold (ooo's STB)	30000.00	Interest Rate Allowed (percent)	0.00
Excise Prod. Level 1 (ooo's STB/year)	3146.00	Excise is NOT an allowable deduction for Royalty	
Excise Tariff Rate 1 (% of VOLWARE)	10.00		
Excise Prod. Level 2 (ooo's STB/year)	3776.00		
Excise Tariff Rate 2 (% of VOLWARE)	20.00		
Excise Prod. Level 3 (ooo's STB/year)	4405.00		
Excise Tariff Rate 3 (% of VOLWARE)	30.00		
Excise Prod. Level 4 (ooo's STB/year)	5034.00		
Excise Tariff Rate 4 (% of VOLWARE)	35.00		

Case Notes:

This scenario looks at a low CO2 content gas development of possible discoveries on Bruny Island. A nominal 8 inch diameter subsea pipeline 50 km long delivers gas to Hobart and nearby townships.

EXPLANATORY NOTES AND FISCAL DATA

RVRAUST 875.22 (960805)

Project Timing

Month/Year of Project Start	8/ 1996
Month/Year of Issue of Licence	7/ 1997
Month/Year of Start of Development	7/ 1998
Month/Year of Start of Drilling	7/ 1998
Month/Year of End of Development	1/ 2000
Month/Year of Production Start	1/ 2000

Production Data

Decline Type is Exponential	
Initial Decline Rate (% per Year)	45.00
Production Plateau (Years)	10
Production Downtime (%)	5.00

Risk Assessment Data

Exploration Success Ratio	1.00

Product Value (REAL $)

Gas Value ($ per MSCF)	2.30

Capital Costs (REAL $)

Exploration/Appraisal Costs	($ooo's)	0.00
Base Field Capital Costs	($ooo's)	25630.00
Rate Increment per MMSCFD	($ooo's)	40.00
Increment per Producing Well	($ooo's)	350.00
Drill/Complete Cost per Development Well	($ooo's)	1055.00
Number of Existing Wells Completed		0
Completion Cost per Existing Well	($ooo's)	0.00
Fixed Rig Cost (e.g. Mob/Demob)	($ooo's)	500.00
Base Abandonment Costs	($ooo's)	500.00
Increment per Well	($ooo's)	100.00

Operating Costs (REAL $)

Base Field Costs	($ooo's/yr)	1538.00
Increment per MMSCFD	($ooo's/yr)	7.00
Base Head Office Costs	($ooo's/yr)	61.00
Increment per MMSCFD	($ooo's/yr)	1.50
Increment per Well	($ooo's/yr)	30.00
Lifting Cost per Well	($ooo's/yr)	148.00
Unit Cost of Transport	($ per MSCF)	0.00
Other Unit Costs	($ per MSCF)	0.00

Inflation Factors

Capital Cost Inflation	(% per year)	4.00
Operating Cost Inflation	(% per year)	4.00
Product Value Escalation	(% per year)	4.00
Cash Flow Deflator	(% per year)	4.00

Matrix Data

Start Well Numbers at		4
End Well Numbers at		22
Increment Well Numbers in steps of		2
Start Well Initials at	(MSCFD)	1000.00
End Well Initials at	(MSCFD)	3000.00
Increment in steps of	(MSCFD)	500.00

SUMMARY OF RVR INPUT DATA

RISKED VIABLE RESERVES TABLE
****

Exploration Success Ratio = 1.00

Initial per Well mscf/day	No.of Wells	Economic Life Years	Ultimate Recovery mmscf	NET PV ($ooo's) at 10.00 % Pretax $ of Year	After Tax $ of Year	After Tax (REAL $)
1000	2	0.00	0	0	0	0
1000	4	13.59	15005	-19805	-19805	-18840
1000	6	14.01	21741	-14685	-14685	-15424
1000	8	14.27	29487	-10155	-10795	-12844
1000	10	14.44	37232	-5609	-7816	-10919
1000	12	14.57	44978	-1047	-5059	-9225
1000	14	14.67	52723	3527	-2345	-7586
1000	16	14.74	60468	8103	362	-5958
1000	18	14.80	68213	12683	3019	-4369
1000	20	14.86	75960	17268	5667	-2789
1500	2	13.42	11155	-19910	-19910	-18557
1500	4	14.29	22141	-9878	-10078	-11605
1500	6	14.71	33958	-591	-3791	-7186
1500	8	14.96	45776	8750	1955	-3299
1500	10	15.14	57593	18149	7491	446
1500	12	15.26	69410	27529	13219	4289
1500	14	15.36	81228	36920	18957	8137
1500	16	15.43	93045	46317	24702	11988
1500	18	15.49	104863	55720	30451	15843
1500	20	15.54	116680	65125	36200	19694
2000	2	13.92	15231	-15162	-15162	-14987
2000	4	14.78	30285	-434	-3395	-6522
2000	6	15.20	46174	13719	5299	-441
2000	8	15.45	62064	27902	14139	5682
2000	10	15.62	77953	42112	23007	11820
2000	12	15.75	93843	56338	31869	17944
2000	14	15.84	109733	70575	40683	24038
2000	16	15.91	125622	84818	49501	30134
2000	18	15.97	141511	99065	58323	36231
2000	20	16.02	157401	113372	66835	42177

SUMMARY OF RVR RESULTS

RISKED VIABLE RESERVES TABLE
****

Exploration Success Ratio = 1.00

Initial per Well mscf/day	No.of Wells	Economic Life Years	Ultimate Recovery mmscf	NET PV ($ooo's) at 10.00 % Pretax $ of Year	After Tax $ of Year	After Tax (REAL $)
2500	2	14.30	18467	-9769	-9769	-11031
2500	4	15.16	38429	9113	2655	-2023
2500	6	15.57	58391	28100	14611	6385
2500	8	15.82	78353	47142	26561	14780
2500	10	15.99	98314	66214	38466	23134
2500	12	16.12	118276	85336	50186	31399
2500	14	16.21	138237	104434	62106	39763
2500	16	16.28	158199	123537	74032	48129
2500	18	16.34	178161	142645	85962	56498
2500	20	16.39	198123	161757	97896	64869
3000	2	14.62	22539	-5024	-6176	-8248
3000	4	15.47	46573	18693	8857	2528
3000	6	15.88	70607	42547	23909	13198
3000	8	16.13	94641	66486	38762	23745
3000	10	16.29	118674	90426	53792	34379
3000	12	16.41	142708	114381	68837	45022
3000	14	16.51	166742	138346	83891	55669
3000	16	16.58	190776	162316	98951	66320
3000	18	16.64	214809	186290	114016	76973
3000	20	16.68	238842	210268	129083	87627

SUMMARY OF RVR RESULTS

RVRAUST 875.22 (960805)

Corporate Tax		Royalty Parameters	
Tax Rate (percent)	36.00		
Depreciation Trunklines (years)	10	State Royalty Rate (percent)	10.00
Depreciation Other Capex (years)	10	Override Royalty Rate (percent)	0.00
Negative Tax IS NOT Valid		Overhead Costs Allowable (percent)	50.00
Fiscal Quarter in which Tax Paid	1	Allowable Common Capex (percent)	50.00
Tax is paid in Year of Assessment		Limit on Deductions (percent of Gross)	100.00
		Debt Ratio for Interest (percent)	0.00
Federal Excise Data		Date of Start of Amortization	Expenditure Date
		Capital Amortization Period(years)	10
Exemption Threshold (ooo's STB)	30000.00	Interest Rate Allowed (percent)	0.00
Excise Prod. Level 1 (ooo's STB/year)	3146.00	Excise is NOT an allowable deduction for Royalty	
Excise Tariff Rate 1 (% of VOLWARE)	10.00		
Excise Prod. Level 2 (ooo's STB/year)	3776.00		
Excise Tariff Rate 2 (% of VOLWARE)	20.00		
Excise Prod. Level 3 (ooo's STB/year)	4405.00		
Excise Tariff Rate 3 (% of VOLWARE)	30.00		
Excise Prod. Level 4 (ooo's STB/year)	5034.00		
Excise Tariff Rate 4 (% of VOLWARE)	35.00		

Case Notes:

This scenario looks at a low CO2 content gas development of possible discoveries in Central Tasmania. A nominal 8 inch diameter pipeline 80 km long delivers gas to Launceston in the north or Hobart in the south.

EXPLANATORY NOTES AND FISCAL DATA

RVRAUST 875.22 (960805)

Project Timing

Month/Year of Project Start	8/ 1996
Month/Year of Issue of Licence	7/ 1997
Month/Year of Start of Development	7/ 1998
Month/Year of Start of Drilling	7/ 1998
Month/Year of End of Development	1/ 2000
Month/Year of Production Start	1/ 2000

Production Data

Decline Type is Exponential

Initial Decline Rate (% per Year)	45.00
Production Plateau (Years)	10
Production Downtime (%)	5.00

Risk Assessment Data

Exploration Success Ratio	1.00

Product Value (REAL $)

Gas Value ($ per MSCF)	2.30

Capital Costs (REAL $)

Exploration/Appraisal Costs	($ooo's)	0.00
Base Field Capital Costs	($ooo's)	23510.00
Rate Increment per MMSCFD	($ooo's)	40.00
Increment per Producing Well	($ooo's)	350.00
Drill/Complete Cost per Development Well	($ooo's)	1055.00
Number of Existing Wells Completed		0
Completion Cost per Existing Well	($ooo's)	0.00
Fixed Rig Cost (e.g. Mob/Demob)	($ooo's)	500.00
Base Abandonment Costs	($ooo's)	500.00
Increment per Well	($ooo's)	100.00

Operating Costs (REAL $)

Base Field Costs	($ooo's/yr)	1405.00
Increment per MMSCFD	($ooo's/yr)	7.00
Base Head Office Costs	($ooo's/yr)	61.00
Increment per MMSCFD	($ooo's/yr)	1.50
Increment per Well	($ooo's/yr)	30.00
Lifting Cost per Well	($ooo's/yr)	148.00
Unit Cost of Transport	($ per MSCF)	0.00
Other Unit Costs	($ per MSCF)	0.00

Inflation Factors

Capital Cost Inflation	(% per year)	4.00
Operating Cost Inflation	(% per year)	4.00
Product Value Escalation	(% per year)	4.00
Cash Flow Deflator	(% per year)	4.00

Matrix Data

Start Well Numbers at		2
End Well Numbers at		20
Increment Well Numbers in steps of		2
Start Well Initials at	(MSCFD)	1000.00
End Well Initials at	(MSCFD)	3000.00
Increment in steps of	(MSCFD)	500.00

SUMMARY OF RVR INPUT DATA

357084

RISKED VIABLE RESERVES TABLE
****

Exploration Success Ratio = 1.00

Initial per Well mscf/day	No.of Wells	Economic Life Years	Ultimate Recovery mmscf	NET PV ($ooo's) at 10.00 % Pretax $ of Year	After Tax $ of Year	After Tax (REAL $)
1000	2	0.00	0	0	0	0
1000	4	13.49	14930	-22495	-22495	-21168
1000	6	13.93	22855	-17968	-17968	-18096
1000	8	14.20	29355	-12731	-12958	-14817
1000	10	14.38	37100	-8193	-9832	-12750
1000	12	14.51	44845	-3637	-7014	-10988
1000	14	14.61	52591	932	-4282	-9326
1000	16	14.70	60337	5506	-1576	-7697
1000	18	14.76	68081	10084	1117	-6077
1000	20	14.81	75826	14666	3765	-4497
1500	2	13.30	11080	-22588	-22588	-20878
1500	4	14.19	22008	-12469	-12469	-13727
1500	6	14.63	33826	-3187	-5754	-8955
1500	8	14.89	45643	6140	39	-5023
1500	10	15.07	57461	15535	5570	-1271
1500	12	15.20	69278	24909	11292	2567
1500	14	15.31	81095	34295	17025	6413
1500	16	15.38	92913	43689	22766	10262
1500	18	15.45	104730	53088	28513	14115
1500	20	15.50	116548	62491	34263	17970
2000	2	13.80	15156	-17871	-17871	-17326
2000	4	14.68	30153	-3034	-5339	-8280
2000	6	15.12	46042	11100	3372	-2164
2000	8	15.38	61932	25273	12203	3956
2000	10	15.56	77821	39474	21063	10089
2000	12	15.69	93710	53695	29938	16228
2000	14	15.79	109600	67926	38762	22327
2000	16	15.87	125490	82166	47578	28421
2000	18	15.93	141379	96410	56398	34518
2000	20	15.98	157269	110659	65220	40615

SUMMARY OF RVR RESULTS

RISKED VIABLE RESERVES TABLE
****

Exploration Success Ratio = 1.00

Initial per Well mscf/day	No.of Wells	Economic Life Years	Ultimate Recovery mmscf	NET PV ($ooo's) at 10.00 % Pretax $ of Year	After Tax $ of Year	After Tax (REAL $)
2500	2	14.19	18335	-12406	-12406	-13320
2500	4	15.07	38297	6495	729	-3746
2500	6	15.49	58258	25465	12669	4656
2500	8	15.75	78220	44495	24639	13067
2500	10	15.93	98182	63558	36540	21421
2500	12	16.06	118144	82676	48246	29679
2500	14	16.16	138105	101769	60162	38040
2500	16	16.24	158067	120870	72085	46404
2500	18	16.30	178028	139975	84012	54772
2500	20	16.35	197990	159084	95943	63141
3000	2	14.50	22407	-7629	-8279	-10163
3000	4	15.37	46441	16061	6918	798
3000	6	15.80	70475	39897	21983	11482
3000	8	16.06	94508	63826	36822	22024
3000	10	16.23	118542	87758	51844	32654
3000	12	16.36	142576	111708	66883	43294
3000	14	16.46	166610	135668	81933	53939
3000	16	16.53	190643	159634	96990	64588
3000	18	16.60	214677	183606	112052	75239
3000	20	16.65	238711	207581	127117	85893

SUMMARY OF RVR RESULTS

RVRAUST 875.22 (960805)

Corporate Tax		*	Royalty Parameters	
Tax Rate (percent)	36.00	*	------------------	
Depreciation Trunklines (years)	10	*	State Royalty Rate (percent)	10.00
Depreciation Other Capex (years)	10	*	Override Royalty Rate (percent)	0.00
Negative Tax IS NOT Valid		*	Overhead Costs Allowable (percent)	50.00
Fiscal Quarter in which Tax Paid	1	*	Allowable Common Capex (percent)	50.00
Tax is paid in Year of Assessment		*	Limit on Deductions (percent of Gross)	100.00
		*	Debt Ratio for Interest (percent)	0.00
Federal Excise Data		*	Date of Start of Amortization	Expenditure Date
--------------------		*	Capital Amortization Period(years)	10
Exemption Threshold (ooo's STB)	30000.00	*	Interest Rate Allowed (percent)	0.00
Excise Prod. Level 1 (ooo's STB/year)	3146.00	*	Excise is NOT an allowable deduction for Royalty	
Excise Tariff Rate 1 (% of VOLWARE)	10.00	*		
Excise Prod. Level 2 (ooo's STB/year)	3776.00	*		
Excise Tariff Rate 2 (% of VOLWARE)	20.00	*		
Excise Prod. Level 3 (ooo's STB/year)	4405.00	*		
Excise Tariff Rate 3 (% of VOLWARE)	30.00	*		
Excise Prod. Level 4 (ooo's STB/year)	5034.00	*		
Excise Tariff Rate 4 (% of VOLWARE)	35.00	*		

Case Notes:

This scenario looks at a high CO_2 content gas development of possible discoveries on Bruny Island. A nominal 8 inch diameter subsea pipeline 50 km long delivers gas to Hobart and nearby townships.

EXPLANATORY NOTES AND FISCAL DATA

RVRAUST 875.22 (960805)

Project Timing			Production Data		
Month/Year of Project Start		8/ 1996	Decline Type is Exponential		
Month/Year of Issue of Licence		7/ 1997	Initial Decline Rate (% per Year)		45.00
Month/Year of Start of Development		7/ 1998	Production Plateau (Years)		10
Month/Year of Start of Drilling		7/ 1998	Production Downtime (%)		5.00
Month/Year of End of Development		1/ 2000			
Month/Year of Production Start		1/ 2000			

Risk Assessment Data			Product Value (REAL $)		
Exploration Success Ratio		1.00	Gas Value ($ per MSCF)		2.30

Capital Costs (REAL $)			Operating Costs (REAL $)		
Exploration/Appraisal Costs	($ooo's)	0.00	Base Field Costs	($ooo's/yr)	1535.00
Base Field Capital Costs	($ooo's)	25770.00	Increment per MMSCFD	($ooo's/yr)	7.00
Rate Increment per MMSCFD	($ooo's)	40.00	Base Head Office Costs	($ooo's/yr)	61.00
Increment per Producing Well	($ooo's)	350.00	Increment per MMSCFD	($ooo's/yr)	1.50
Drill/Complete Cost per Development Well	($ooo's)	1055.00	Increment per Well	($ooo's/yr)	30.00
Number of Existing Wells Completed		0	Lifting Cost per Well	($ooo's/yr)	148.00
Completion Cost per Existing Well	($ooo's)	0.00	Unit Cost of Transport	($ per MSCF)	0.00
Fixed Rig Cost (e.g. Mob/Demob)	($ooo's)	500.00	Other Unit Costs	($ per MSCF)	0.00
Base Abandonment Costs	($ooo's)	500.00			
Increment per Well	($ooo's)	100.00			

Inflation Factors			Matrix Data		
Capital Cost Inflation	(% per year)	4.00	Start Well Numbers at		2
Operating Cost Inflation	(% per year)	4.00	End Well Numbers at		20
Product Value Escalation	(% per year)	4.00	Increment Well Numbers in steps of		2
Cash Flow Deflator	(% per year)	4.00			
			Start Well Initials at	(MSCFD)	1000.00
			End Well Initials at	(MSCFD)	3000.00
			Increment in steps of	(MSCFD)	500.00

SUMMARY OF BASIC INPUT DATA

RISKED VIABLE RESERVES TABLE
****

Exploration Success Ratio = 1.00

Initial per Well mscf/day	No.of Wells	Economic Life Years	Ultimate Recovery mmscf	NET PV ($ooo's) at 10.00 % Pretax $ of Year	After Tax $ of Year	After Tax (REAL $)
1000	2	0.00	0	0	0	0
1000	4	13.59	15005	-19923	-19923	-18948
1000	6	14.01	21741	-14795	-14795	-15526
1000	8	14.27	29487	-10265	-10890	-12936
1000	10	14.44	37232	-5720	-7905	-11005
1000	12	14.57	44978	-1157	-5145	-9309
1000	14	14.67	52723	3417	-2431	-7668
1000	16	14.74	60468	7993	276	-6041
1000	18	14.80	68213	12573	2934	-4450
1000	20	14.86	75960	17158	5582	-2871
1500	2	13.42	11155	-20028	-20028	-18665
1500	4	14.29	22141	-9988	-10175	-11698
1500	6	14.71	33958	-701	-3878	-7270
1500	8	14.96	45776	8640	1870	-3381
1500	10	15.14	57593	18039	7406	365
1500	12	15.26	69410	27419	13134	4207
1500	14	15.36	81228	36810	18872	8055
1500	16	15.43	93045	46207	24617	11907
1500	18	15.49	104863	55610	30367	15761
1500	20	15.54	116680	65015	36116	19613
2000	2	13.92	15231	-15280	-15280	-15094
2000	4	14.78	30285	-544	-3482	-6606
2000	6	15.20	46174	13609	5214	-523
2000	8	15.45	62064	27792	14054	5600
2000	10	15.62	77953	42002	22922	11738
2000	12	15.75	93843	56228	31784	17863
2000	14	15.84	109733	70465	40599	23957
2000	16	15.91	125622	84708	49417	30053
2000	18	15.97	141511	98955	58238	36150
2000	20	16.02	157401	113262	66751	42096

SUMMARY OF RVR RESULTS

RISKED VIABLE RESERVES TABLE
****

Exploration Success Ratio = 1.00

Initial per Well mscf/day	No.of Wells	Economic Life Years	Ultimate Recovery mmscf	NET PV ($ooo's) at 10.00 % Pretax $ of Year	After Tax $ of Year	After Tax (REAL $)
2500	2	14.30	18467	-9880	-9880	-11134
2500	4	15.16	38429	9002	2570	-2105
2500	6	15.57	58391	27990	14526	6304
2500	8	15.82	78353	47033	26477	14699
2500	10	15.99	98314	66104	38382	23053
2500	12	16.12	118276	85226	50101	31318
2500	14	16.21	138237	104324	62021	39682
2500	16	16.28	158199	123427	73947	48048
2500	18	16.34	178161	142535	85878	56417
2500	20	16.39	198123	161647	97812	64787
3000	2	14.62	22539	-5135	-6267	-8336
3000	4	15.47	46573	18583	8772	2446
3000	6	15.88	70607	42437	23825	13117
3000	8	16.13	94641	66376	38677	23664
3000	10	16.29	118674	90316	53707	34298
3000	12	16.41	142708	114271	68752	44941
3000	14	16.51	166742	138236	83806	55588
3000	16	16.58	190776	162206	98867	66239
3000	18	16.64	214809	186180	113931	76892
3000	20	16.68	238842	210158	128999	87546

SUMMARY OF RVR RESULTS

RVRAUST 875.22 (960805)

Corporate Tax		Royalty Parameters	
Tax Rate (percent)	36.00		
Depreciation Trunklines (years)	10	State Royalty Rate (percent)	10.00
Depreciation Other Capex (years)	10	Override Royalty Rate (percent)	0.00
Negative Tax IS NOT Valid		Overhead Costs Allowable (percent)	50.00
Fiscal Quarter in which Tax Paid	1	Allowable Common Capex (percent)	50.00
Tax is paid in Year of Assessment		Limit on Deductions (percent of Gross)	100.00
		Debt Ratio for Interest (percent)	0.00
Federal Excise Data		Date of Start of Amortization	Expenditure Date
		Capital Amortization Period(years)	10
Exemption Threshold (ooo's STB)	30000.00	Interest Rate Allowed (percent)	0.00
Excise Prod. Level 1 (ooo's STB/year)	3146.00	Excise is NOT an allowable deduction for Royalty	
Excise Tariff Rate 1 (% of VOLWARE)	10.00		
Excise Prod. Level 2 (ooo's STB/year)	3776.00		
Excise Tariff Rate 2 (% of VOLWARE)	20.00		
Excise Prod. Level 3 (ooo's STB/year)	4405.00		
Excise Tariff Rate 3 (% of VOLWARE)	30.00		
Excise Prod. Level 4 (ooo's STB/year)	5034.00		
Excise Tariff Rate 4 (% of VOLWARE)	35.00		

Case Notes:

This scenario looks at a high CO2 content gas development of possible discoveries in Central Tasmania. A nominal 8 inch diameter pipeline 80 km long delivers gas to Hobart or Launceston.

EXPLANATORY NOTES AND FISCAL DATA

RVRAUST 875.22 (960805)

Project Timing

Month/Year of Project Start	8/ 1996
Month/Year of Issue of Licence	7/ 1997
Month/Year of Start of Development	7/ 1998
Month/Year of Start of Drilling	7/ 1998
Month/Year of End of Development	1/ 2000
Month/Year of Production Start	1/ 2000

Production Data

Decline Type is Exponential	
Initial Decline Rate (% per Year)	45.00
Production Plateau (Years)	10
Production Downtime (%)	5.00

Risk Assessment Data

Exploration Success Ratio	1.00

Product Value (REAL $)

Gas Value ($ per MSCF)	2.30

Capital Costs (REAL $)

Exploration/Appraisal Costs	($000's)	0.00
Base Field Capital Costs	($000's)	23650.00
Rate Increment per MMSCFD	($000's)	40.00
Increment per Producing Well	($000's)	350.00
Drill/Complete Cost per Development Well	($000's)	1055.00
Number of Existing Wells Completed		0
Completion Cost per Existing Well	($000's)	0.00
Fixed Rig Cost (e.g. Mob/Demob)	($000's)	500.00
Base Abandonment Costs	($000's)	500.00
Increment per Well	($000's)	100.00

Operating Costs (REAL $)

Base Field Costs	($000's/yr)	1405.00
Increment per MMSCFD	($000's/yr)	7.00
Base Head Office Costs	($000's/yr)	61.00
Increment per MMSCFD	($000's/yr)	1.50
Increment per Well	($000's/yr)	30.00
Lifting Cost per Well	($000's/yr)	148.00
Unit Cost of Transport	($ per MSCF)	0.00
Other Unit Costs	($ per MSCF)	0.00

Inflation Factors

Capital Cost Inflation	(% per year)	4.00
Operating Cost Inflation	(% per year)	4.00
Product Value Escalation	(% per year)	4.00
Cash Flow Deflator	(% per year)	4.00

Matrix Data

Start Well Numbers at		2
End Well Numbers at		20
Increment Well Numbers in steps of		2
Start Well Initials at	(MSCFD)	1000.00
End Well Initials at	(MSCFD)	3000.00
Increment in steps of	(MSCFD)	500.00

SUMMARY OF RVR INPUT DATA

RISKED VIABLE RESERVES TABLE
****

Exploration Success Ratio = 1.00

Initial per Well bbls/day	No.of Wells	Economic Life Years	Ultimate Recovery M bbls	NET PV ($ooo's) at 10.00 % Pretax $ of Year	After Tax $ of Year	After Tax (REAL $)
150	1	5.78	163	-2223	-2223	-2106
150	2	7.03	401	-2214	-2214	-2155
150	3	7.55	640	-2172	-2236	-2258
150	4	7.83	880	-2121	-2325	-2422
150	5	8.01	1119	-2047	-2556	-2697
150	6	8.13	1359	-1979	-2676	-2889
150	7	8.22	1599	-1908	-2794	-3079
150	8	8.29	1839	-1842	-2915	-3272
150	9	8.34	2079	-1775	-3037	-3465
150	10	8.39	2319	-1707	-3158	-3657
200	1	6.99	266	-1629	-1629	-1576
200	2	8.24	610	-896	-1229	-1301
200	3	8.75	956	-139	-857	-1075
200	4	9.03	1302	648	-608	-947
200	5	9.21	1648	1432	-260	-743
200	6	9.33	1994	2212	86	-541
200	7	9.42	2341	2995	434	-338
200	8	9.49	2687	3778	778	-137
200	9	9.54	3034	4563	1118	61
200	10	9.58	3380	5349	1460	259
250	1	7.93	370	-974	-1068	-1081
250	2	9.17	822	507	-319	-523
250	3	9.67	1275	2009	514	90
250	4	9.95	1729	3525	1347	702
250	5	10.13	2182	5067	2067	1226
250	6	10.25	2636	6594	2886	1826
250	7	10.34	3090	8120	3696	2420
250	8	10.41	3545	9648	4507	3014
250	9	10.46	3999	11176	5319	3609
250	10	10.50	4453	12706	6132	4204

SUMMARY OF RVR RESULTS

357093

RISKED VIABLE RESERVES TABLE
****

Exploration Success Ratio = 1.00

Initial per Well bbls/day	No.of Wells	Economic Life Years	Ultimate Recovery M bbls	NET PV ($ooo's) at 10.00 % Pretax $ of Year	After Tax $ of Year	After Tax (REAL $)
300	1	8.69	476	-280	-620	-694
300	2	9.92	1035	1948	659	301
300	3	10.43	1597	4226	1910	1271
300	4	10.70	2158	6500	3215	2280
300	5	10.88	2721	8781	4527	3294
300	6	11.00	3283	11066	5842	4310
300	7	11.09	3845	13385	7170	5347
300	8	11.15	4407	15673	8484	6362
300	9	11.21	4970	17961	9793	7375
300	10	11.25	5532	20251	11103	8387
********						
350	1	9.33	582	437	-174	-311
350	2	10.56	1250	3438	1586	1088
350	3	11.06	1920	6493	3409	2536
350	4	11.33	2591	9537	5214	3964
350	5	11.51	3261	12587	7022	5394
350	6	11.63	3932	15641	8833	6826
350	7	11.71	4603	18696	10646	8259
350	8	11.78	5274	21753	12460	9693
350	9	11.84	5946	24811	14275	11127
350	10	11.88	6616	27870	16091	12562
********						
400	1	9.88	689	1160	315	101
400	2	11.10	1466	4958	2593	1938
400	3	11.60	2245	8765	4896	3783
400	4	11.88	3025	12587	7212	5636
400	5	12.05	3804	16443	9546	7513
400	6	12.17	4584	20273	11850	9360
400	7	12.26	5364	24106	14155	11207
400	8	12.32	6144	27940	16462	13055
400	9	12.38	6924	31774	18770	14904
400	10	12.42	7705	35609	21078	16753
********						

SUMMARY OF RVR RESULTS

RVRAUST 875.22 (960805)

****

Corporate Tax		*	Royalty Parameters	
Tax Rate (percent)	36.00	*	------------------	
Depreciation Trunklines (years)	10	*	State Royalty Rate (percent)	10.00
Depreciation Other Capex (years)	10	*	Override Royalty Rate (percent)	0.00
Negative Tax IS NOT Valid		*	Overhead Costs Allowable (percent)	50.00
Fiscal Quarter in which Tax Paid	1	*	Allowable Common Capex (percent)	50.00
Tax is paid in Year of Assessment		*	Limit on Deductions (percent of Gross)	100.00
		*	Debt Ratio for Interest (percent)	0.00
**				
Federal Excise Data		*	Date of Start of Amortization	Expenditure Date
-------------------		*	Capital Amortization Period(years)	10
Exemption Threshold (ooo's STB)	30000.00	*	Interest Rate Allowed (percent)	0.00
Excise Prod. Level 1 (ooo's STB/year)	3146.00	*	Excise is NOT an allowable deduction for Royalty	
Excise Tariff Rate 1 (% of VOLWARE)	10.00	*		
Excise Prod. Level 2 (ooo's STB/year)	3776.00	*		
Excise Tariff Rate 2 (% of VOLWARE)	20.00	*		
Excise Prod. Level 3 (ooo's STB/year)	4405.00	*		
Excise Tariff Rate 3 (% of VOLWARE)	30.00	*		
Excise Prod. Level 4 (ooo's STB/year)	5034.00	*		
Excise Tariff Rate 4 (% of VOLWARE)	35.00	*		
		*		

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Case Notes:

This scenario investigates a small oil field development in Central Tasmania (<10 wells) with a high gas/oil ratio.

Artificial lift: Beam Pump
Produced Gas: Fuel usage and flare

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EXPLANATORY NOTES AND FISCAL DATA

RVRAUST 875.22 (960805)

Project Timing

Month/Year of Project Start	8/ 1996
Month/Year of Issue of Licence	7/ 1997
Month/Year of Start of Development	7/ 1997
Month/Year of Start of Drilling	1/ 1998
Month/Year of End of Development	7/ 1998
Month/Year of Production Start	7/ 1998

Production Data

Decline Type is Exponential	
Initial Decline Rate (% per Year)	20.00
Production Plateau (Years)	2
Production Downtime (%)	15.00

Risk Assessment Data

Exploration Success Ratio	1.00

Product Value (REAL $)

Oil Value ($ per STB)	22.00

Capital Costs (REAL $)

Exploration/Appraisal Costs	($ooo's)	0.00
Base Field Capital Costs	($ooo's)	855.00
Rate Increment per MSTBOD	($ooo's)	0.00
Increment per Producing Well	($ooo's)	300.00
Drill/Complete Cost per Development Well	($ooo's)	910.00
Number of Existing Wells Completed		0
Completion Cost per Existing Well	($ooo's)	0.00
Fixed Rig Cost (e.g. Mob/Demob)	($ooo's)	500.00
Base Abandonment Costs	($ooo's)	500.00
Increment per Well	($ooo's)	100.00

Operating Costs (REAL $)

Base Field Costs	($ooo's/yr)	170.00
Increment per MSTBOD	($ooo's/yr)	16.50
Base Head Office Costs	($ooo's/yr)	35.00
Increment per MSTBOD	($ooo's/yr)	0.00
Increment per Well	($ooo's/yr)	54.00
Lifting Cost per Well	($ooo's/yr)	125.00
Unit Cost of Transport	($ per STB)	1.12
Other Unit Costs	($ per STB)	5.53

Inflation Factors

Capital Cost Inflation	(% per year)	4.00
Operating Cost Inflation	(% per year)	4.00
Product Value Escalation	(% per year)	1.00
Cash Flow Deflator	(% per year)	4.00

Matrix Data

Start Well Numbers at		1
End Well Numbers at		10
Increment Well Numbers in steps of		1
Start Well Initials at	(STBOD)	150.00
End Well Initials at	(STBOD)	400.00
Increment in steps of	(STBOD)	50.00

SUMMARY OF RVR INPUT DATA

DATA FILE :conoil01.TST
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CONDOR INVESTMENTS
Oil Scenario ..01

RISKED VIABLE RESERVES TABLE
****

Exploration Success Ratio = 1.00

Initial per Well bbls/day	No.of Wells	Economic Life Years	Ultimate Recovery M bbls	NET PV ($ooo's) at 10.00 % Pretax $ of Year	After Tax $ of Year	After Tax (REAL $)
150	1	4.88	167	-2462	-2462	-2323
150	2	5.80	328	-2744	-2744	-2626
150	3	6.15	526	-3044	-3044	-2945
150	4	6.34	725	-3349	-3349	-3281
150	5	6.46	923	-3654	-3654	-3618
150	6	6.54	1121	-3956	-3956	-3952
150	7	6.59	1320	-4256	-4256	-4286
150	8	6.64	1519	-4555	-4555	-4618
150	9	6.67	1717	-4854	-4854	-4950
150	10	6.70	1916	-5152	-5172	-5298
200	1	6.10	232	-1870	-1870	-1777
200	2	7.01	533	-1561	-1662	-1655
200	3	7.36	836	-1227	-1555	-1638
200	4	7.55	1138	-890	-1469	-1639
200	5	7.67	1441	-548	-1384	-1641
200	6	7.75	1744	-203	-1295	-1642
200	7	7.80	2047	143	-1206	-1641
200	8	7.85	2350	491	-1115	-1639
200	9	7.88	2653	839	-1024	-1636
200	10	7.91	2956	1187	-932	-1634
250	1	7.04	335	-1266	-1299	-1268
250	2	7.95	742	-277	-732	-857
250	3	8.30	1150	763	-267	-528
250	4	8.48	1558	1792	255	-158
250	5	8.60	1967	2826	781	215
250	6	8.68	2376	3863	1310	590
250	7	8.73	2784	4901	1841	967
250	8	8.78	3193	5939	2372	1344
250	9	8.81	3602	6979	2904	1721
250	10	8.84	4010	8019	3436	2099

SUMMARY OF RVR RESULTS

RISKED VIABLE RESERVES TABLE
****

Exploration Success Ratio = 1.00

Initial per Well bbls/day	No.of Wells	Economic Life Years	Ultimate Recovery M bbls	NET PV ($ooo's) at 10.00 % Pretax $ of Year	After Tax $ of Year	After Tax (REAL $)
300	1	7.81	439	-625	-824	-860
300	2	8.71	953	1096	135	-112
300	3	9.06	1467	2855	1057	604
300	4	9.24	1982	4608	2033	1359
300	5	9.36	2498	6360	3009	2114
300	6	9.44	3013	8116	3987	2871
300	7	9.49	3528	9872	4967	3629
300	8	9.54	4044	11629	5947	4387
300	9	9.57	4559	13387	6928	5146
300	10	9.60	5074	15146	7910	5905
350	1	8.45	544	61	-393	-487
350	2	9.35	1165	2522	1024	648
350	3	9.70	1787	4998	2484	1812
350	4	9.88	2409	7485	3953	2982
350	5	9.99	3032	9976	5412	4145
350	6	10.07	3655	12494	6730	5198
350	7	10.13	4277	14990	8170	6345
350	8	10.17	4900	17484	9609	7491
350	9	10.21	5523	19979	11049	8638
350	10	10.23	6146	22475	12489	9785
400	1	9.01	650	767	42	-111
400	2	9.90	1379	3965	1989	1464
400	3	10.25	2109	7210	3854	2976
400	4	10.43	2839	10445	5781	4532
400	5	10.54	3569	13683	7711	6092
400	6	10.62	4300	16925	9644	7653
400	7	10.68	5030	20167	11574	9211
400	8	10.72	5761	23410	13500	10768
400	9	10.75	6491	26654	15427	12324
400	10	10.78	7222	29898	17354	13881

SUMMARY OF RVR RESULTS

R/RAUST 875.22 (960805)

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Corporate Tax		*	Royalty Parameters	
Tax Rate (percent)	36.00	*	------------------	
Depreciation Trunklines (years)	10	*	State Royalty Rate (percent)	10.00
Depreciation Other Capex (years)	10	*	Override Royalty Rate (percent)	0.00
Negative Tax IS NOT Valid		*	Overhead Costs Allowable (percent)	50.00
Fiscal Quarter in which Tax Paid	1	*	Allowable Common Capex (percent)	50.00
Tax is paid in Year of Assessment		*	Limit on Deductions (percent of Gross)	100.00
		*	Debt Ratio for Interest (percent)	0.00
**				
Federal Excise Data		*	Date of Start of Amortization	Expenditure Date
-------------------		*	Capital Amortization Period(years)	10
Exemption Threshold (ooo's STB)	30000.00	*	Interest Rate Allowed (percent)	0.00
Excise Prod. Level 1 (ooo's STB/year)	3146.00	*	Excise is NOT an allowable deduction for Royalty	
Excise Tariff Rate 1 (% of VOLWARE)	10.00	*		
Excise Prod. Level 2 (ooo's STB/year)	3776.00	*		
Excise Tariff Rate 2 (% of VOLWARE)	20.00	*		
Excise Prod. Level 3 (ooo's STB/year)	4405.00	*		
Excise Tariff Rate 3 (% of VOLWARE)	30.00	*		
Excise Prod. Level 4 (ooo's STB/year)	5034.00	*		
Excise Tariff Rate 4 (% of VOLWARE)	35.00	*		
		*		

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Case Notes:

This scenario investigates a small oil field development in Central Tasmania (<10 wells) with a low gas/oil ratio.

Artificial lift: Beam Pump

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EXPLANATORY NOTES AND FISCAL DATA

357099

RVRAUST 875.22 (960805)

Project Timing			Production Data		
Month/Year of Project Start		8/ 1996	Decline Type is Exponential		
Month/Year of Issue of Licence		7/ 1997	Initial Decline Rate (% per Year)		20.00
Month/Year of Start of Development		7/ 1997	Production Plateau (Years)		2
Month/Year of Start of Drilling		1/ 1998	Production Downtime (%)		15.00
Month/Year of End of Development		7/ 1998			
Month/Year of Production Start		7/ 1998			

Risk Assessment Data			Product Value (REAL $)		
Exploration Success Ratio		1.00	Oil Value ($ per STB)		22.00

Capital Costs (REAL $)			Operating Costs (REAL $)		
Exploration/Appraisal Costs	($ooo's)	0.00	Base Field Costs	($ooo's/yr)	160.00
Base Field Capital Costs	($ooo's)	855.00	Increment per MSTBOD	($ooo's/yr)	16.50
Rate Increment per MSTBOD	($ooo's)	0.00	Base Head Office Costs	($ooo's/yr)	31.50
Increment per Producing Well	($ooo's)	220.00	Increment per MSTBOD	($ooo's/yr)	0.00
Drill/Complete Cost per Development Well	($ooo's)	910.00	Increment per Well	($ooo's/yr)	57.00
Number of Existing Wells Completed		0	Lifting Cost per Well	($ooo's/yr)	220.00
Completion Cost per Existing Well	($ooo's)	0.00	Unit Cost of Transport	($ per STB)	1.12
Fixed Rig Cost (e.g. Mob/Demob)	($ooo's)	500.00	Other Unit Costs	($ per STB)	5.53
Base Abandonment Costs	($ooo's)	500.00			
Increment per Well	($ooo's)	100.00			

Inflation Factors			Matrix Data		
Capital Cost Inflation	(% per year)	4.00	Start Well Numbers at		1
Operating Cost Inflation	(% per year)	4.00	End Well Numbers at		10
Product Value Escalation	(% per year)	1.00	Increment Well Numbers in steps of		1
Cash Flow Deflator	(% per year)	4.00			
			Start Well Initials at	(STBOD)	150.00
			End Well Initials at	(STBOD)	400.00
			Increment in steps of	(STBOD)	50.00

SUMMARY OF BASIC INPUT DATA

357100

RISKED VIABLE RESERVES TABLE
****

Exploration Success Ratio = 1.00

Initial per Well bbls/day	No.of Wells	Economic Life Years	Ultimate Recovery M bbls	NET PV ($ooo's) at 10.00 % Pretax $ of Year	After Tax $ of Year	After Tax (REAL $)
300	2	6.04	549	-6407	-6407	-6039
300	4	7.63	1518	-5473	-5473	-5558
300	6	8.33	2496	-4128	-4940	-5446
300	8	8.71	3477	-2654	-4385	-5341
300	10	8.97	4459	-1118	-3784	-5209
300	12	9.14	5443	423	-3783	-5573
300	14	9.27	6426	2033	-3248	-5502
300	16	9.38	7411	3618	-2745	-5454
300	18	9.45	8394	5212	-2232	-5400
300	20	9.52	9379	6813	-1713	-5341
350	2	6.71	752	-5399	-5399	-5188
350	4	8.30	1936	-3015	-3688	-4071
350	6	8.99	3128	-190	-2186	-3200
350	8	9.38	4324	2757	-1096	-2680
350	10	9.63	5521	5748	359	-1864
350	12	9.80	6718	8775	1849	-1025
350	14	9.93	7917	11822	3361	-170
350	16	10.03	9115	14831	4100	60
350	18	10.11	10313	17910	5520	837
350	20	10.18	11512	20997	6946	1620
400	2	7.29	958	-4322	-4322	-4270
400	4	8.88	2357	-398	-1859	-2579
400	6	9.56	3765	3927	246	-1234
400	8	9.95	5175	8373	2702	383
400	10	10.20	6588	12868	4642	1580
400	12	10.37	8001	17399	7017	3126
400	14	10.50	9415	21936	9398	4676
400	16	10.60	10829	26486	11792	6234
400	18	10.68	12243	31045	14195	7798
400	20	10.74	13657	35609	16603	9366

SUMMARY OF RVR RESULTS

RISKED VIABLE RESERVES TABLE
****

Exploration Success Ratio = 1.00

Initial per Well bbls/day	No.of Wells	Economic Life Years	Ultimate Recovery M bbls	NET PV ($ooo's) at 10.00 % Pretax $ of Year	After Tax $ of Year	After Tax (REAL $)
450	2	7.80	1166	-3131	-3153	-3297
450	4	9.38	2780	2327	-272	-1292
450	6	10.06	4404	8160	2759	793
450	8	10.45	6032	14151	6099	3112
450	10	10.70	7660	20171	9468	5451
450	12	10.87	9290	26224	12869	7812
450	14	11.00	10920	32299	15878	9872
450	16	11.10	12550	38400	19230	12192
450	18	11.18	14181	44488	22568	14504
450	20	11.24	15811	50574	25905	16814
500	2	8.26	1375	-1900	-2434	-2694
500	4	9.83	3206	5123	1616	231
500	6	10.51	5047	12530	5643	3107
500	8	10.90	6891	20049	10015	6246
500	10	11.14	8737	27646	14095	9160
500	12	11.32	10583	35235	18409	12252
500	14	11.45	12430	42842	22742	15355
500	16	11.54	14278	50462	27086	18467
500	18	11.62	16125	58089	31439	21583
500	20	11.69	17973	65722	35797	24703
550	2	8.67	1585	-596	-1522	-1949
550	4	10.24	3633	7989	3258	1555
550	6	10.92	5692	16961	8581	5459
550	8	11.30	7753	26061	13683	9189
550	10	11.55	9817	35186	19007	13083
550	12	11.72	11881	44342	24362	16997
550	14	11.85	13945	53516	29736	20923
550	16	11.95	16010	62702	35094	24839
550	18	12.02	18075	71961	40475	28793
550	20	12.09	20140	81154	45825	32705

SUMMARY OF RVR RESULTS

RISKED VIABLE RESERVES TABLE
****

Exploration Success Ratio = 1.00

Initial per Well bbls/day	No.of Wells	Economic Life Years	Ultimate Recovery M bbls	NET PV ($ooo's) at 10.00 % Pretax $ of Year	After Tax $ of Year	After Tax (REAL $)
600	2	9.04	1796	726	-791	-1351
600	4	10.61	4062	10911	5189	3104
600	6	11.28	6338	21474	11319	7657
600	8	11.67	8618	32124	17643	12347
600	10	11.91	10899	42832	24006	17061
600	12	12.08	13181	53612	30372	21796
600	14	12.21	15463	64354	36723	26504
600	16	12.31	17746	75107	43085	31218
600	18	12.39	20029	85868	49449	35933
600	20	12.45	22312	96635	55796	40638
650	2	9.38	2008	2104	133	-604
650	4	10.95	4492	13874	7142	4667
650	6	11.62	6987	26016	14285	10023
650	8	12.00	9485	38302	21654	15552
650	10	12.25	11984	50585	28999	21051
650	12	12.42	14484	62896	36350	26553
650	14	12.54	16985	75224	43695	32051
650	16	12.64	19486	87563	51050	37555
650	18	12.72	21988	99910	58414	43065
650	20	12.78	24489	112262	65783	48577
700	2	9.70	2221	3503	1078	159
700	4	11.26	4923	16887	8956	6126
700	6	11.93	7636	30611	17274	12403
700	8	12.31	10353	44476	25638	18723
700	10	12.56	13071	58354	33972	25008
700	12	12.73	15790	72262	42331	31310
700	14	12.85	18509	86186	50709	37623
700	16	12.95	21229	100122	59097	43943
700	18	13.03	23949	114127	67388	50229
700	20	13.09	26668	128069	75740	56529

SUMMARY OF RVR RESULTS

EVRAUST 875.22 (960805)

****

Corporate Tax

Tax Rate (percent)	36.00
Depreciation Trunklines (years)	10
Depreciation Other Capex (years)	10
Negative Tax IS NOT Valid	
Fiscal Quarter in which Tax Paid	1
Tax is paid in Year of Assessment	

Royalty Parameters

State Royalty Rate (percent)	10.00
Override Royalty Rate (percent)	0.00
Overhead Costs Allowable (percent)	50.00
Allowable Common Capex (percent)	50.00
Limit on Deductions (percent of Gross)	100.00
Debt Ratio for Interest (percent)	0.00
Date of Start of Amortization	Expenditure Date
Capital Amortization Period(years)	10
Interest Rate Allowed (percent)	0.00
Excise is NOT an allowable deduction for Royalty	

Federal Excise Data

Exemption Threshold (ooo's STB)	30000.00
Excise Prod. Level 1 (ooo's STB/year)	3146.00
Excise Tariff Rate 1 (% of VOLWARE)	10.00
Excise Prod. Level 2 (ooo's STB/year)	3776.00
Excise Tariff Rate 2 (% of VOLWARE)	20.00
Excise Prod. Level 3 (ooo's STB/year)	4405.00
Excise Tariff Rate 3 (% of VOLWARE)	30.00
Excise Prod. Level 4 (ooo's STB/year)	5034.00
Excise Tariff Rate 4 (% of VOLWARE)	35.00

****

Case Notes:

This scenario investigates a medium/large oil field development on Bruny Island (>10 wells) with a high gas/oil ratio.

Artificial lift: Gas Lift
Water disposal: Injection Well
Produced gas: Gas Lift/Fuel/Reinjection
Storage: 250,000 BBls
Export: Subsea pipeline/CALM buoy/Export Tanker

****

EXPLANATORY NOTES AND FISCAL DATA

RVRAUST 875.22 (960805)

Project Timing

Month/Year of Project Start	8/ 1996
Month/Year of Issue of Licence	7/ 1997
Month/Year of Start of Development	7/ 1997
Month/Year of Start of Drilling	1/ 1998
Month/Year of End of Development	7/ 1999
Month/Year of Production Start	7/ 1999

Production Data

Decline Type is Exponential

Initial Decline Rate (% per Year)	20.00
Production Plateau (Years)	2
Production Downtime (%)	15.00

Risk Assessment Data

Exploration Success Ratio	1.00

Product Value (REAL $)

Oil Value ($ per STB)	22.00

Capital Costs (REAL $)

Exploration/Appraisal Costs	($ooo's)	0.00
Base Field Capital Costs	($ooo's)	3080.00
Rate Increment per MSTBOD	($ooo's)	910.00
Increment per Producing Well	($ooo's)	740.00
Drill/Complete Cost per Development Well	($ooo's)	1125.00
Number of Existing Wells Completed		0
Completion Cost per Existing Well	($ooo's)	0.00
Fixed Rig Cost (e.g. Mob/Demob)	($ooo's)	500.00
Base Abandonment Costs	($ooo's)	700.00
Increment per Well	($ooo's)	100.00

Operating Costs (REAL $)

Base Field Costs	($ooo's/yr)	1105.00
Increment per MSTBOD	($ooo's/yr)	22.00
Base Head Office Costs	($ooo's/yr)	220.00
Increment per MSTBOD	($ooo's/yr)	11.00
Increment per Well	($ooo's/yr)	45.00
Lifting Cost per Well	($ooo's/yr)	335.00
Unit Cost of Transport	($ per STB)	0.00
Other Unit Costs	($ per STB)	4.33

Inflation Factors

Capital Cost Inflation	(% per year)	4.00
Operating Cost Inflation	(% per year)	4.00
Product Value Escalation	(% per year)	1.00
Cash Flow Deflator	(% per year)	4.00

Matrix Data

Start Well Numbers at		2
End Well Numbers at		20
Increment Well Numbers in steps of		2
Start Well Initials at	(STBOD)	300.00
End Well Initials at	(STBOD)	700.00
Increment in steps of	(STBOD)	50.00

SUMMARY OF RVR INPUT DATA

RISKED VIABLE RESERVES TABLE
****

Exploration Success Ratio = 1.00

Initial per Well bbls/day	No.of Wells	Economic Life Years	Ultimate Recovery M bbls	NET PV ($ooo's) at 10.00 % Pretax $ of Year	After Tax $ of Year	After Tax (REAL $)
400	2	7.42	978	-22644	-22644	-21561
400	4	9.65	2528	-16071	-16071	-16480
400	6	10.74	4096	-9579	-11550	-13223
400	8	11.41	5671	-2860	-7729	-10589
400	10	11.87	7251	3947	-3684	-7782
400	12	12.20	8831	10836	378	-4950
400	14	12.45	10413	17713	4412	-2155
400	16	12.65	11996	24620	8419	619
400	18	12.82	13580	31547	12447	3406
400	20	12.95	15164	38488	16490	6202
500	2	8.38	1395	-19894	-19894	-19267
500	4	10.59	3382	-10330	-11605	-12874
500	6	11.67	5388	-563	-5568	-8484
500	8	12.33	7402	9383	570	-4016
500	10	12.78	9419	19387	6657	398
500	12	13.11	11438	29503	12829	4884
500	14	13.36	13459	39600	18775	9207
500	16	13.56	15480	49725	24733	13533
500	18	13.72	17502	59868	30710	17871
500	20	13.85	19525	70025	36701	22217
600	2	9.15	1816	-16921	-16921	-16812
600	4	11.35	4241	-4365	-7627	-9712
600	6	12.43	6687	8660	670	-3546
600	8	13.08	9140	21850	8883	2550
600	10	13.53	11597	35096	16871	8485
600	12	13.85	14056	48406	24870	14419
600	14	14.10	16516	61802	32846	20362
600	16	14.29	18977	75165	40844	26298
600	18	14.45	21439	88545	48860	32244
600	20	14.58	23901	101937	56888	38198

SUMMARY OF RVR RESULTS

RISKED VIABLE RESERVES TABLE
****

Exploration Success Ratio = 1.00

Initial per Well bbls/day	No.of Wells	Economic Life Years	Ultimate Recovery M bbls	NET PV ($ooo's) at 10.00 % Pretax $ of Year	After Tax $ of Year	After Tax (REAL $)
700	2	9.81	2241	-13942	-13942	-14378
700	4	11.99	5105	1763	-3409	-6383
700	6	13.06	7991	18023	6910	1383
700	8	13.70	10884	34430	16933	8924
700	10	14.14	13782	50984	26932	16460
700	12	14.46	16681	67545	36965	24001
700	14	14.71	19581	84143	47034	31563
700	16	14.90	22482	100766	57129	39140
700	18	15.05	25385	117462	67181	46714
700	20	15.18	28288	134105	77256	54282
800	2	10.37	2667	-11105	-11681	-12543
800	4	12.54	5973	7941	773	-3075
800	6	13.60	9299	27446	12969	6179
800	8	14.24	12633	47166	24985	15307
800	10	14.67	15971	66943	37068	24462
800	12	14.99	19311	86780	49212	33652
800	14	15.23	22653	106684	61292	42824
800	16	15.42	25995	126565	73426	52009
800	18	15.57	29338	146463	85577	61203
800	20	15.70	32682	166372	97739	70405
900	2	10.87	3096	-8116	-9473	-10781
900	4	13.03	6842	14197	4938	216
900	6	14.07	10610	36988	19006	10967
900	8	14.70	14385	59945	33105	21715
900	10	15.13	18165	83040	47250	32506
900	12	15.45	21946	106140	61424	43299
900	14	15.68	25729	129274	75634	54111
900	16	15.87	29512	152431	89866	64937
900	18	16.02	33297	175659	104064	75764
900	20	16.15	37082	198835	118278	86580

SUMMARY OF RVR RESULTS

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RISKED VIABLE RESERVES TABLE
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Exploration Success Ratio = 1.00

Initial per Well bbls/day	No.of Wells	Economic Life Years	Ultimate Recovery M bbls	NET PV ($ooo's) at 10.00 % Pretax $ of Year	After Tax $ of Year	After Tax (REAL $)
1000	2	11.31	3526	-5140	-7598	-9290
1000	4	13.45	7714	20467	9011	3436
1000	6	14.49	11923	46545	25070	15758
1000	8	15.12	16140	72827	41249	28151
1000	10	15.54	20361	99155	57474	40557
1000	12	15.85	24584	125539	73755	52995
1000	14	16.08	28809	151998	90010	65436
1000	16	16.27	33034	178425	106287	77873
1000	18	16.42	37260	204867	122578	90317
1000	20	16.54	41486	231320	138880	102768

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SUMMARY OF RVR RESULTS

RVRAUST 875.22 (960805)

Corporate Tax		Royalty Parameters	
Tax Rate (percent)	36.00		
Depreciation Trunklines (years)	10	State Royalty Rate (percent)	10.00
Depreciation Other Capex (years)	10	Override Royalty Rate (percent)	0.00
Negative Tax IS NOT Valid		Overhead Costs Allowable (percent)	50.00
Fiscal Quarter in which Tax Paid	1	Allowable Common Capex (percent)	50.00
Tax is paid in Year of Assessment		Limit on Deductions (percent of Gross)	100.00
		Debt Ratio for Interest (percent)	0.00

Federal Excise Data			
		Date of Start of Amortization	Expenditure Date
		Capital Amortization Period(years)	10
Exemption Threshold (ooo's STB)	30000.00	Interest Rate Allowed (percent)	0.00
Excise Prod. Level 1 (ooo's STB/year)	3146.00	Excise is NOT an allowable deduction for Royalty	
Excise Tariff Rate 1 (% of VOLWARE)	10.00		
Excise Prod. Level 2 (ooo's STB/year)	3776.00		
Excise Tariff Rate 2 (% of VOLWARE)	20.00		
Excise Prod. Level 3 (ooo's STB/year)	4405.00		
Excise Tariff Rate 3 (% of VOLWARE)	30.00		
Excise Prod. Level 4 (ooo's STB/year)	5034.00		
Excise Tariff Rate 4 (% of VOLWARE)	35.00		

Case Notes:

This scenario investigates a medium/large oil field development in Central Tasmania (>10 wells) with a high gas/oil ratio.

Artificial lift: Gas Lift
Water disposal: Injection Well
Produced gas: Gas Lift/Fuel/Reinjection
Storage: 250,000 BBls
Export: 80 km pipeline 6 inch diam/Export Tanker Terminal at Hobart

RVRAUST 875.22 (960805)

Project Timing

Month/Year of Project Start	8/ 1996
Month/Year of Issue of Licence	7/ 1997
Month/Year of Start of Development	7/ 1997
Month/Year of Start of Drilling	1/ 1998
Month/Year of End of Development	7/ 1999
Month/Year of Production Start	7/ 1999

Production Data

Decline Type is Exponential	
Initial Decline Rate (% per Year)	20.00
Production Plateau (Years)	2
Production Downtime (%)	15.00

Risk Assessment Data

Exploration Success Ratio	1.00

Product Value (REAL $)

Oil Value ($ per STB)	22.00

Capital Costs (REAL $)

Exploration/Appraisal Costs	($ooo's)	0.00
Base Field Capital Costs	($ooo's)	24145.00
Rate Increment per MSTBOD	($ooo's)	984.50
Increment per Producing Well	($ooo's)	740.00
Drill/Complete Cost per Development Well	($ooo's)	1125.00
Number of Existing Wells Completed		0
Completion Cost per Existing Well	($ooo's)	0.00
Fixed Rig Cost (e.g. Mob/Demob)	($ooo's)	500.00
Base Abandonment Costs	($ooo's)	700.00
Increment per Well	($ooo's)	100.00

Operating Costs (REAL $)

Base Field Costs	($ooo's/yr)	1415.00
Increment per MSTBOD	($ooo's/yr)	27.00
Base Head Office Costs	($ooo's/yr)	280.00
Increment per MSTBOD	($ooo's/yr)	17.00
Increment per Well	($ooo's/yr)	45.00
Lifting Cost per Well	($ooo's/yr)	135.00
Unit Cost of Transport	($ per STB)	0.00
Other Unit Costs	($ per STB)	4.33

Inflation Factors

Capital Cost Inflation	(% per year)	4.00
Operating Cost Inflation	(% per year)	4.00
Product Value Escalation	(% per year)	1.00
Cash Flow Deflator	(% per year)	4.00

Matrix Data

Start Well Numbers at		2
End Well Numbers at		20
Increment Well Numbers in steps of		2
Start Well Initials at	(STBOD)	400.00
End Well Initials at	(STBOD)	1000.00
Increment in steps of	(STBOD)	100.00

SUMMARY OF RVR INPUT DATA

Appx 3

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ATTN Julian AMOS

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GERALD E. CARNE & ASSOCIATES

PETROLEUM DEVELOPMENT and EXPLORATION CONSULTANTS

-INTERNATIONAL AND DOMESTIC-

118 HEWITT AVENUE, TOORAK GARDENS, SOUTH AUSTRALIA 5065

Telephone and Fax (08) 332 7730

22 September 1996

Mr Chris Davey
Manager of Project and Structured Finance
First National Limited
National Australia Bank Group
Level 2
271 Collins Street
MELBOURNE VIC 3000

Dear Mr Davey

Re: Great Southland Minerals Pty Ltd Exploration Strategy

I have been asked by Mr Malcolm Bendall, Director of Condor Investments, to provide you with my personal impressions and considerations regarding their exploration strategy and proposed exploration program, in Tasmania. I believe that it is important that I also make comment on the level of technical expertise that is guiding Condor in their exploration planning and in the subsequent execution of these plans.

Drilling funds are currently being sought to carry Great Southland through their proposed 1996-1997 exploration program. It is my understanding that one of the primary objectives of the 1996-1997 exploration program is to establish a level of subsurface information that will attract an active, medium sized petroleum exploration company that will be willing to provide both the expertise and funding required to further advance petroleum exploration in Tasmania, while maintaining Great Southland's involvement in the Tasmanian Basin at an acceptable level. Great Southland would gain through farming-out an interest(s) in their exploration Licences, either through being carried through future work programs, by being given a 'lump-sum' settlement of some magnitude, or through a combination of these two.

In order to attract genuine interest in the Tasmania Basin, Great Southland must first clearly demonstrate that there are prospective strata in the central portions of mainland Tasmania, and that there are structures of sufficient magnitude to be capable of hosting commercial volumes of oil and/or gas. Of paramount importance, Great Southland must clearly demonstrate that modern seismic methods will be able to resolve structural expression in the subsurface of the Tasmanian Basin, beneath the ubiquitous dolerite sills. Further, Great Southland must be able to satisfy interested parties that their existing Petroleum Exploration Licences are in good standing with the State Government, and that they will be will be retained by the current interest holders for a period of time sufficient to adequately evaluate their hydrocarbon potential

Exploration Program October 1996 - April 1997

The proposed drilling of six wells and the acquisition of 175 km of reflection seismic data highlight Great Southland's 1996-1997 exploration program. The Shittim 1 well is currently being drilled on Bruny Island. The recording of methane in the Tillite sequence is considered significant and important and has no doubt added value to the Great Southland acreage holdings. The other five wells are to be located on the main Island of Tasmania. Together, the six wells should provide excellent stratigraphic (source rock, reservoir, seal) control over the southern part of the area now held by Great Southland, and should also provide subsurface velocity information that is essential to the acquisition of good quality seismic data.

One might argue that fewer than six bore holes would provide sufficient subsurface information to attract outside exploration interest, if the central parts of the Tasmanian Basin are indeed prospective. The proposed drilling locations, however, appear to be carefully and well positioned and no doubt will provide a much improved understanding of the hydrocarbon potential of the Basin as a whole. The more control there is, the easier it is for an exploration company to make the decision to commit itself to a new basin. Nevertheless, I believe that Great Southland could satisfy their main objectives with the drilling of say two of the remaining five wells in the program. If positive results are not found in the two wells, additional wells would then have to be drilled. I expect that the additional wells would not be required.

One might also argue that the acquisition and processing of seismic data should be completed prior to selecting well locations. The primary purpose of drilling the wells, however, is to acquire subsurface stratigraphic knowledge and not, necessarily, to find hydrocarbon accumulations; - the structural positions of the wells are therefore not of utmost importance.

At least two of the forthcoming wells are to be located on surface defined domes. It may be advantageous to acquire seismic across the domes prior to locating the respective wells. The structural axis of potential reservoir intervals in the subsurface may not coincide with surface defined axis, and wells located on the basis of surface features alone will not necessarily intersect potential reservoirs in optimum structural positions. Seismic should assist considerably in identifying the optimum structural position of strata at reservoir level. On the other hand, and as indicated above, information gained from the drilling of the wells in advance of seismic, will assist in selecting optimal parameters for subsequent seismic acquisition.

I understand that Great Southland intend to shoot two normally intersecting seismic lines through each of their six well locations. This is a valid exploration strategy, but I am not certain that all of the 175 km will be required to traverse the six drill sites. Hopefully, the seismic will demonstrate that large, closed structures are present in the Tasmanian Basin .

I am concerned that Great Southland has been quoted the small sum of $429,000 for the acquisition and processing of 175 km of seismic (only $2451.00 per km). This indeed is a surprisingly low cost, and perhaps one should be a little wary about the quality of data that is to be acquired, but I am told that a company owned by a Director of Great Southland, will be drilling the shot-holes and this could significantly keep the cost down. I would expect that the proposal submitted by the seismic company quoting $408,000 for acquisition, has been reviewed by Great Southland's Geophysicist, Dr. David Leaman and should therefore be technically sound. If it costs more to get the required quality of data, it would be wise to settle for a smaller program to stay within current budget The main purpose of the seismic expenditure is to demonstrate that good quality subsurface data is obtainable.

The budget presented to me by Mr Bendall suggests that the wells will be adequately tested. logged, and otherwise evaluated.

An early concern I had was that Great Southland were using a drilling rig that was incapable of drilling adequate diameter holes to reservoir depths I am told the rig that is being used to drill the six stratigraphic/exploration wells is currently being modified to provide more power and to handle greater drilling stresses and that it will be capable of reaching drill depths of up to nearly 2000 metres

Technical Expertise Available

Most of the technical initiative and drive for Great Southland is provided by Malcolm Bendall It is Mr Bendall who first realised that the Tasmanian Basin offers considerable hydrocarbon potential and without his insight, it is very unlikely that anyone would be prepared to carry out exploration in the basin. Mr Bendall is heavily involved in both the petroleum geology and drilling apects (engineering) of the Company, although he is relatively inexperienced and still on a learning curve. Nevertheless, he seems to be making rapid progress in his understanding of the field of petroleum exploration.

Dr Clive Burrett is Chief Geologist for Great Southland. Dr Burrett's background is largely that of an educator. He has been teaching soft rock geology for more than 20 years and therefore must be considered an expert in the rocks that host oil and gas accumulations. I do not know what practical experience Dr Burrett has. Considerable research regarding the petroleum potntial of the Tasmanian Basin is being undertaken by Dr Burrett and some of his honour's students.

Dr David Leaman, a geophysicist with the University of Tasmania, has since the late 1980s, been regularly commissioned by Condor/Great Southland to advise on geophysical matters, and to interpret gravity, magnetic and seismic data. Dr Leaman is an expert geophysicist and would have to be considered the person most knowledgeable about the structure of the Tasmanian Basin.

Jack Mulready, a very experienced independent consultant currently engaged by Melbourne based Lakes Petroleum (Otway Basin), has prepared reports for Condor/Great Southland on an irregular basis. It does not appear, however, that he has been significantly involved in either strategic planning or operational aspects of Great Southland's exploration program. Dr David Gravestock (an exceptionally knowledgable geologist with Mines and Energy South Australia) has provided information and advice to Great Southland on a long term, but intermittent basis.

Mr Robert Young, a former Chief geologist for Getty Oil and therefore a person of considerable experience, was commissioned by Great Southland earlier this year to provide his opinion about the hydrocarbon potential of the Tasmanian Basin, and to offer advice on the exploration strategy that should be taken to efficiently explore the basin. Mr Young seems very positive in his comments.

Opinion

It is my opinion that the exploration strategy being undertaken by Great Southland is sound, although perhaps fewer than the six proposed wells should be drilled in the first instance, and perhaps seismic should be acquired prior to drilling wells on the surface defined domal features. Arguement can be made, however, that there are advantages in drilling all of the wells prior to acquiring seismic over them. One of their primary objectives should be to demonstrate that good subsurface structural expression can be obtained in the Tamanian Basin using modern seismic techniques. It is also important that stratigraphic control be gained in the central parts of the Tasmanian Basin through the drilling of low cost, small diameter wells. The identification of seismically defined leads and prospects would also assist significantly in attracting a farmin partner.

It appears that Great Southland's proposed 1996-1997 work program can be fully executed if their drilling fund initiative is successful and $2.5 million raised

The October 1996 to April 1997 budget prepared by Great Southland allows for an expenditure of $12,000 for Dr Leaman to interpret the forthcoming seismic program, and a further $10,000 for independent advise from geologists Jack Mulready and Robert Young. It would be hoped that the major part of this expenditure would be directed towards obtaining advise, rather than for promotional purposes.

Yours sincerely

G. E. Carne

Appx 4

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amdel

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A.C.N. 008 127 802

FACSIMILE TRANSMISSION FROM:

AMDEL LIMITED PETROLEUM SERVICES
35-37 STIRLING STREET, THEBARTON SA 5031
FACSIMILE NO: (08) 234 2933 or (08) 234 2760
TELEPHONE NO: (08) 416 5240

TO:	Clive Burrett		
COMPANY:	University of Tasmania		
FAX NO:	03 62 232547	DATE:	2 October, 1996
COPY TO:			
FROM:	Diane Cass	TOTAL PAGES:	1

Clive,

Results for Shittim-1A are as follows:
The methane yielded an isotope value of -50.1‰ PDB.

Composition

	Mol%	ppm	
methane		739ppm	
ethane		3.9ppm	
CO_2	1.68		(0.035%)
O_2+ Ar	15.59		(21%)
N_2	82.66		(78%)

TOC

	%TOC	
1179.5m	0.19	negligible
1056.5m	0.34	
1215.9m	0.04	
1147m	0.11	
1034m	0.57	slight source potential
1046.4m	0.30	negligible

Regards,

D.L. Cass

Diane Cass
Petroleum Chemist
Petroleum Services

Appx 5

357118

October 1996

UNIVERSITY OF TASMANIA

Central Science Laboratory
GPO Box 252C
Hobart
Tasmania 7001
Australia

Analysis of Shittim 1B Trip Gas - 1528m

Four samples were received in inverted test tubes, fitted with rubber stoppers with a small amount of water in contact with the stopper. The samples were analysed for normal air gases (nitrogen, oxygen, argon and carbon dioxide), methane, ethane and hydrogen by GC-MS using a combination of full scan methods and target compound detection via selected ion monitoring. Analyses for methane, ethane and hydrogen were each carried out separately. The contribution of water vapour was ignored.

	Sample 1	Sample 2	Sample 3	Sample 4
nitrogen	78.6%	78.6%	78.7%	78.7%
oxygen	19.4%	19.6%	19.8%	19.4%
argon	0.95%	0.94%	0.94%	0.95%
carbon dioxide	0.13%	0.12%	0.15%	0.14%
hydrogen	70ppm	500ppm	600ppm	600ppm
(labelled levels	200ppm	500ppm	500ppm	200ppm)
methane	9250ppm	5800ppm	5500ppm	9500ppm
(labelled levels	34000ppm	19780ppm	21167ppm	34000ppm)
ethane	~4ppm	~2ppm	~2ppm	~4 ppm

Quoted values for normal atmosphere are 78.1% nitrogen, 21.0% oxygen, 0.93% argon and 0.03% carbon dioxide. The method had a Relative Standard Deviation of 1.0% for the major gases. Values are quoted on a volume/volume basis.

Noel Davies

Dr Noel Davies

Officer-in-Charge, Organic Mass Spectrometry

Appx 6

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357120

Colin Higgins & Associates
18 Purdie Avenue, Ardross, W.A. 6153
Telephone: (09) 364 6165 Facsimile: (09) 364 6165
A.C.N. 009 394 362

12 September 1996

Shittim-1A

Hydrocarbon Well Logging Interpretive Review 60 mm (BQ) Hole Section

Colin Higgins & Associates provided a comprehensive hydrocarbon well logging service to monitor, record and display; depth, rate of penetration, total combustible gas level, chromatographic gas compositional analysis, lithological description and flouroscopic inspection whilst coring the 60 mm (BQ) section of the Shittim-1A well in EL 1/88 of the Tasmanian Basin.

For most of the hole section, ditch gas was sampled from the upper part of the return flow line as the conventional gas trap proved ineffective whilst coring with very low viscosity circulating fluid allowing gasses to break out almost immediately at atmospheric pressure. Coring in the BQ section commenced at 1020.5 m in very dark grey to black organic carbon rich shales - probably deposited in a reducing marine environment. Combustible gasses comprised methane with some hydrogen as determined by reducing the hotwire total gas detector filament voltage from 6 Volts to 2 Volts to burn only Hydrogen. This simple but effective test was carried out periodically to estimate the proportion of Hydrogen before switching back to 6 Volts to measure all combustible gasses present. The flame ionisation gas chromatograph sampled the gas stream every 2½ minutes and provided accurate and reliable compositional analyses of the hydrocarbon gas with only methane found to be present. Both total gas and chromatograph were calibrated regularly with known gas concentrations and found to give stable and repeatable results.

Liberated gas level through the shale section was maintained at 8 to 12 gas units (1% methane in air gives 100 units or 100 ppm is 1 unit) through the shale interval to a depth of 1055.6 m. Gas levels whilst circulating are generally lower but very consistent through the rest of the well at 5 to 7.5 units with no significant responses to change in penetration rate. Significant gas increases were observed whenever circulation was stopped and it is clear that the primary influence on gas level in the return drilling fluid is time and not depth. It is also clear that the tillite/dropstone that comprises almost the entire section below the shale has no significant intergranular porosity and hence no environment from which hydrocarbons could be liberated. The most likely source for the methane recorded whilst drilling this hole section is the shale itself bleeding gas into the wellbore at a very slow and steady rate from micropores and bedding planes/fractures. This is a common phenomenon in high total organic carbon rich source rocks which are bounded by impermeable strata preventing the escape of generated hydrocarbons. The shales appear to be internally overpressured (geopressured) and the core breaks into thin wafers at atmospheric temperature and pressure. Examples can be found in the Horn Valley siltstone of the Amadeus Basin (Wells: Tent Hill-1 and Tempe Vale-1 1964) and in many of CRA Pacific Oil and Gas's Georgina Basin slimholes.

No adequate explanation can be given for the varying amounts of hydrogen gas recorded in the well. This is probably in part related to complex chemical (corrosion) reactions between the steel casing/drill rods and the drilling fluid. Maintaining a pH higher than 9.5 will normally arrest this reaction and free hydrogen will no longer be detected. This was not the case in Shittim-1A and hydrogen level seemed to vary with methane level over most of the section. It can only be interpreted that the hydrogen has the same origin as the methane and may be related to the shale over the interval 1020.5 - 1055.6 m.

No visual hydrocarbon shows were observed though the BQ hole section in Shittim-1A and no producible hydrocarbons are indicated in the 60 mm hole section.

C Higgins

Colin Higgins
Geologist/Director

Appx 7

357122

357123

Amdel Limited
A.C.N. 008 127 802

Petroleum Services
PO Box 338
Torrensville Plaza SA 5031

Telephone: (08) 8416 5240
Facsimile: (08) 8234 2933

11 November, 1996

University of Tasmania
Department of Geology
GPO Box 252-79
HOBART TAS 7001

Attention: Clive Burrett

REPORT LQ5147

CLIENT REFERENCE:

WELL NAME/RE: Shittem-1

MATERIAL: Rock and Gas Samples

WORK REQUIRED: Gas Isotope, TOC, Rock-Eval Pyrolysis and Kerogen Analysis

Please direct technical enquiries regarding this work to the signatory below under whose supervision the work was carried out.

Brian Watson

Brian L. Watson
Manager
Petroleum Services

1. INTRODUCTION

Six (6) duplicate gas samples and six (6) shale samples were received from Shittem-1. Gas compositional and carbon isotopic analysis was requested on the gas samples and total organic carbon (TOC) analysis, Rock-Eval pyrolysis and kerogen typing was requested on the shale samples. This report is a formal presentation of results forwarded by facsimile as they became available.

2. ANALYTICAL PROCEDURES

2.1 Gas Composition

Gas compositional and carbon isotopic analysis was performed at CSIRO Division of Petroleum Resources in North Ryde, NSW.

2.2 Total Organic Carbon (TOC)

Total organic carbon was determined by digestion of a known weight (approximately 0.2 g) of powdered rock in HCl to remove carbonates, followed by combustion in oxygen in the induction furnace of a Leco WR-12 Carbon Determinator and measurement of the resultant CO_2 by infra-red detection.

2.3 Rock-Eval Pyrolysis

A 100 mg portion of powdered rock was analysed by the Rock-Eval pyrolysis technique (Girdel IFP-Fina Mark 2 instrument; operating mode, Cycle 1).

2.4 Kerogen Typing

Kerogen typing was performed after kerogen isolation of the sample using standard techniques.

3. RESULTS

TOC and Rock-Eval pyrolysis results are presented on the following pages. Note that the Rock-Eval pyrolysis data indicates that the 1034 m depth sample has extremely poor source richness for the generation of hydrocarbons ($S_1 + S_2 = 0.00$ kg H/C / tonne).

Component	Air Included Composition	Air Corrected Composition
Methane	739 ppm	0.26 %
Ethane	3.9 ppm	13.5 ppm
CO_2	1.68 %	5.76 %
O_2 + Ar	15.59 %	-
N_2	82.66 %	93.98 %

The carbon isotopic value for methane was determined to be -50.1‰.

Kerogen Typing data is detailed below.

KEROGEN: Abundant OM, Vitrinite 0%, Inertinite 25%, Exinite 0%, Sapropel 75%

TAI: If in situ, then three specimens of probable leiospheres with spore colours of light brown would suggest a TAI of 3.00 suggesting a VRE of about 0.80%.

However, if these samples are caved, then the absence of any other palynomorphs except some black ?cuticle fragments would suggest a TAI of 4.00 with VRE >1.40%.

REMARKS: The inertinite comprised rounded to subangular, well sorted particles that appear to be derived from the degradation and oxidation of organic matter. The sapropel is approaching particles that could be described as micrinite, however, the character is more in the nature of very oxidised granular sapropel.

If the ?leiospheres are in situ, a possible distal, but oxidising sub-aqueous setting is suggested. If they are, however, a contamination, then no inference as to the original organic matter should be drawn.

Appx 8

357126

357127

amdel

A.C.N. 008 127 802

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COMPANY:	University of Tasmania		
FAX NO:	03 6223 2547	DATE:	23 October, 1996
COPY TO:			
FROM:	Scott Wythe	TOTAL PAGES:	2

Clive,

Rock-Eval pyrolysis results follow for the Shittem-1 sample with the highest TOC content.

Best regards,

Scott Wythe
Petroleum Geochemist
Petroleum Services

amdel

AMDEL PETROLEUM SERVICES

357128

Rock-Eval Pyrolysis

DATE 23/10/96

Client: University of Tasmania

Well: Shittem-1

Depth (m)	T Max	S1	S2	S3	S1+S2	PI	S2/S3	PC	TOC	HI	OI
1034	427	0.00	0.00	0.13	0.00	0.00	0.00	0.00	0.57	0	22
1046.4									0.30		
1056.5									0.34		
1147									0.11		
1179.5									0.19		
1215.9									0.04		

amdel

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357129

Rock-Eval Pyrolysis

DATE 23/10/96

Client: *University of Tasmania*

Well: Shittem-1

Depth (m)	T Max	S1	S2	S3	S1+S2	PI	S2/S3	PC	TOC	HI	OI
1034	427	0.00	0.00	0.13	0.00	0.00	0.00	0.00	0.57	0	22
1046.4									0.30		
1056.5									0.34		
1147									0.11		
1179.5									0.19		
1215.9									0.04		

Appx 9

357130

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357131

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FACSIMILE TRANSMISSION FROM:

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35-37 STIRLING STREET, THEBARTON SA 5031
FACSIMILE NO: (08) 8234 2933 or (08) 8234 2760
TELEPHONE NO: (08) 8416 5240

TO:	Clive Burrett		
COMPANY:	University of Tasmania		
FAX NO:	03 6223 2547	DATE:	25 October, 1996
COPY TO:	-		
FROM:	Scott Wythe	TOTAL PAGES:	2

Clive,

Shittem-1, 1034 m - kerogen typing results are given below.

KEROGEN: Abundant OM, Vitrinite 0 %, Inertinite 25 %, Exinite 0 %, Sapropel 75 %

TAI: If in situ, then three specimens of probable leiospheres with spore colours of light brown would suggest a TAI of 3.00 suggesting a VRE of about 0.80 %.

However, if these samples are caved, then the absence of any other palynomorphs except some Black ?cuticle fragments would suggest a TAI of 4.00 with VRE >1.40 %.

REMARKS: The inertinite comprised rounded to subangular, well sorted particles that appear to be derived from the degradation and oxidation of organic matter. The sapropel is approaching particles that could be described as *micrinite*, however, the character is more in the nature of very oxidised granular sapropel.

If the ?leiospheres are in situ, a possible distal, but oxidising sub-aqueous setting is suggested. If they are, however, a contamination, then no inference as to the original organic matter should be drawn.

A formal report on all of the Shittem-1 analyses will follow shortly. 357132

Regards

Scott Wythe
Petroleum Geochemist
Petroleum Services

Appx 10

357133

357134

GEOCHEMICAL EVALUATION OF AN OIL SEEP SAMPLE FROM

LONNAVALE, TASMANIA

REPORT LQ4496 FOR

GREAT SOUTHLAND MINERALS PTY LTD

BY

SCOTT WYTHE

BRIAN WATSON

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2. ANALYTICAL PROCEDURES 1

3. RESULTS 1

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   4.3 Post Pooling Alteration and Migration 3

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2. Gas Chromatogram of Saturates Fraction
3. Bulk Composition of Seep Oil sample
4. Genetic Affinity based on Isoprenoid/Alkane Ratios
5. GC-MS of Aromatic Fraction
6. Araucariacean Resin Biomarker Plot
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9. Sterane Distributions

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1. Analytical Procedures
2. GC-MS of Branched/Cyclic Alkanes

1. INTRODUCTION

One oil seep sample was received from Lonnavale, Tasmania for physical testing and petroleum geochemical analyses. This report is a formal presentation of results forwarded by facsimile on 15 January 1996.

2. ANALYTICAL PROCEDURES

The analytical procedures used in this study are provided in Appendix 1.

3. RESULTS

Analytical data is presented in this report as follows:

Analysis	Table	Figure
Bulk Composition and GC of Whole Oils and Saturates	1	1 - 4
GC-MS of aromatic hydrocarbons	2	5 - 6
GC-MS of branched/cyclic hydrocarbons	3	7 - 9 Appendix 2

Due to the bituminous nature of the sample and its close association with an unidentified solid material no physical testing of the sample was possible. However sulphur analysis was performed on both a portion of the whole sample (including the solid material) and on the solid material alone following extraction of the oil. Both were found to contain 0.1% sulphur. This suggests a low sulphur content for the oil (ie.<0.1%).

4. GEOCHEMICAL INTERPRETATION OF SEEP SAMPLE

4.1 Maturity

Aromatic maturity indicators for the Lonnavale seep indicate that the sample was generated and expulsed from an early mature to mature source interval (Parameters A, C, E and F, Table 2). Parameter A indicates a maturity of VR_{equiv}=0.85%.

Maturities indicated for this sample by saturated biomarker maturity parameters are less precise than the aromatic derived biomarker ratios. These parameters (ie, C_{29} steranes and isosteranes - Biomarker Parameters 4 & 6, C_{27} diasteranes - Biomarker

Parameter 5, C_{27}, C_{30} & C_{32} hopanes - Biomarker Parameter 11, Table 2) all indicate that the sample has a moderate maturity.

The isoprenoid/n-alkane ratios (Figure 4) is unreliable for assessment of maturity due to pristane, phytane, n-C_{17} and n-C_{18} being affected by biodegradation and light end loss.

4.2 Source Affinity

The Lonnavale seep sample is aromatic-naphthenic in composition (Figure 2).

The pristane/phytane ratio (Table 1, Figures 1 & 7) is likely to be affected by biodegradation and light end loss. However despite these effects the ratio is still considered to indicate generation from sources deposited in anoxic conditions typical of a marine environment.

GC-MS of branched/cyclic alkanes for the sample has sterane and diasterane distributions (m/z 217, 218, 259; Table 3, Figures 7 & 9, Appendix 2) which contain significant C_{29} homologues of higher plant origin (Biomarker parameters 1, 2 & 3, Table 3) suggesting some terrestrial input into the precursor organic matter.

Tricyclic terpane distributions (m/z 191, Appendix 2) show that C_{19} - C_{31} tricyclics are the dominant compounds present in the sample. Such a distribution is characteristic of precursor organic matter rich in *Tasmanites* alga. Tasmanite is thought to have been deposited in a low energy, nearshore marine environment.

Hopane signatures (m/z 191, Appendix 2) are unreliable due to the dominance of tricyclic compounds. However the C_{29} norhopane is likely to be more abundant than the C_{30} hopane suggesting a likely carbonate source. The presence of significant amounts of diasteranes usually associated with clay-rich environments though suggests otherwise.

No significant amount of botryococcane was detected (m/z 183, Appendix 2).

This data suggests that the precursor organic matter of the Lonnavale oil seep sample has been derived from a somewhat mixed algal/terrestrial source containing abundant *Tasmanites* alga deposited in an anoxic, probably nearshore, marine environment.

The ratios of 1-methylphenanthrene/9-methylphenanthrene and 1,2,5-trimethylnaphthalene/1,3,6-trimethylnaphthalene (Figure 7) has been used to indicate source input from Araucariacean derived plant resins (trees from the Kauri pine group) which were most prominent in Early to Middle Jurassic times. The low relative abundance of 1-methylphenanthrene and 1,2,5-trimethylnaphthalene implies that these resins were not significant components of the precursor organic matter. However, this does not preclude the possibility that this oil was generated from a source of Jurassic/Cretaceous age.

4.3 Post Pooling Alteration and Migration

The abundance of cycloalkanes and corresponding lack of n-alkanes in the sample (Figures 1 & 3) suggests that this condensate may have been subjected to light biodegradation. No evidence of significant biodegradation was observed in any of the biomarker compounds.

Figure 8 suggests that the sample is likely to have undergone a degree of migration since generation from its source interval.

5. CONCLUSIONS

5.1 Aromatic maturity indicators for the Lonnavale oil seep indicate that it was generated and expulsed from a moderately mature source interval ($VR_{equiv} \approx 0.80\%$). Saturated biomarker maturity indicators ratios support this level of maturity.

5.2 Various aspects of the molecular composition of the sample indicates that the precursor organic matter of the oil seep is likely to have been derived from a mixed algal/terrestrial source containing abundant *Tasmanites* alga deposited in an anoxic, possibly nearshore, marine environment.

5.3 The sample appears to have been subjected to light biodegradation.

5.4 The extract is likely to have undergone some migration since generation from its source interval.

TABLE 1

C_{12+} BULK COMPOSITION AND ALKANE RATIOS, LONNAVALE SEEP

EOM (%)	Composition (%)				Alkane Ratios			
	n+iso	Naph	Arom	NSO	Np/Pr	Pr/Ph	Pr/n-C_{17}	Ph/n-C_{18}
20.32	4.1	36.5	26.2	9.7	-	0.44	0.36	0.64

EOM = extractable organic matter
n+iso = normal + iso-alkanes
Naph = naphthenes (branched and cyclic alkanes)
Arom = aromatic hydrocarbons
NSO = compounds containing nitrogen, sulphur and oxygen

Np = norpristane
Pr = pristane
Ph = phytane
n-C_{17} = n-heptadecane
n-C_{18} = n-octadecane

TABLE 2

AROMATIC MATURITY DATA, LONNAVALE SEEP

MPI	MPR	DNR	MPDF	VR CALC (%)					
				A	B	C	D	E	F
0.756	1.306	14.58	0.454	0.85	1.85	1.05	7.60	0.75	0.85

KEY TO AROMATIC MATURITY INDICATORS

Methylphenanthrene index (MPI), methylphenanthrene ratio (MPR), dimethylnaphthalene ratio (DNR) and calculated vitrinite reflectance (VR_{calc}) are derived from the following equations (after Radke and Welte, 1983; Radke *et al*, (1984):

$$\text{MPI} = \frac{1.5(\text{2-MP} + \text{3-MP})}{\text{P} + \text{1-MP} + \text{9-MP}}$$

$$VR_{calc}\,(a) = 0.6\ \text{MPI} + 0.4 \text{ (for VR} < 1.35\%)$$

$$VR_{calc}\,(b) = -0.6\ \text{MPI} + 2.3 \text{ (for VR} > 1.35\%)$$

$$\text{MPR} = \frac{\text{2-MP}}{\text{1-MP}}$$

$$VR_{calc}\,(c) = 0.99 \log_{10} \text{MPR} + 0.94 \text{(VR} = 0.5\text{-}1.7\%)$$

$$\text{DNR} = \frac{\text{2,6-DMN} + \text{2,7-DMN}}{\text{1,5-DMN}}$$

$$VR_{calc}\,(d) \quad 0.46\ \text{DNR} + 0.89 \text{ (for VR} = 0.9\text{-}1.5\%)$$

Where
P = phenanthrene
1-MP = 1-methylphenanthrene
2-MP = 2-methylphenanthrene
3-MP = 3-methylphenanthrene
9-MP = 9-methylphenanthrene
1,5-DMN = 1,5-dimethylnaphthalene
2,6-DMN = 2,6-dimethylnaphthalene
2,7-DMN = 2,7-dimethylnaphthalene

Peak areas measured from m/z 156 (dimethylnaphthalene), m/z 178 (phenanthrene) and m/z 192 (methylphenanthrene) mass fragmentograms of diaromatic and triaromatic hydrocarbon fraction isolated by thin layer chromatography.

Recalibration of the methylphenanthrene index using data from a suite of Australian coals has given rise to another equation for calculated vitrinite reflectance (after Boreham *et al*, 1988):

$$VR_{calc}\,(e) = 0.7\ \text{MPI} + 0.22 \text{ (for VR} < 1.7\%)$$

The methylphenanthrene distribution ratio (MPDF) and calculated vitrinite reflectance VR_{calc} (f) is derived from the following equation (after Kvalheim *et al*, 1987):

$$\text{MPDF} = \frac{(\text{2-MP} + \text{3-MP})}{(\text{2-MP} + \text{3-MP} + \text{1-MP} + \text{9-MP})}$$

$$VR_{calc}\,(f) = -0.166 + 2.242\ \text{MPDF}$$

TABLE 3

BIOMARKER PARAMETERS OF SOURCE, MATURITY, MIGRATION AND BIODEGRADATION, LONNAVALE SEEP

Steranes							Terpanes						Acyclic Alkanes		
Parameter															
1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
29:30:41	1.38	1.14	1.41	1.25	1.72	0.91	-	-	-	6.37	-	-	0.44	0.36	0.64

- = not determined

KEY TO BIOMARKER PARAMETERS OF SOURCE, MIGRATION AND BIODEGRADATION

Parameter	Derivation*	Specificity
1	C_{27}:C_{28}:C_{29} 5α(H)14α(H)17α(H) 20S steranes	Source
2	C_{29} 5α(H)14α(H)17α(H) 20S sterane/C_{27} 5α(H)14α(H)17α(H) 20S sterane	Source
3	C_{29} 13β(H)17α(H) 20R diasterane/C_{27} 13β(H)17α(H) 20R diasterane	Source
4	C_{29} 5α(H)14α(H)17α(H) 20S sterane/C_{29} 5α(H)14α(H)17α(H) 20R sterane	Maturity, Biodegradation
5	C_{27} 13β(H)17α(H) 20S diasterane/C_{27} 13β(H)17α(H) 20R diasterane	Maturity
6	C_{29} 5α(H)14β(H)17β(H) 20R sterane/C_{29} 5α(H)14α(H)17α(H) 20R sterane	Maturity, Migration
7	C_{29} 13β(H)17α(H) 20R+20S diasteranes/C_{29} 5α(H) steranes	Migration, Source
8	18α(H)-30-norneohopane (C_{29}Ts)/C_{29} 17α(H) hopane + C_{29}Ts	Maturity, Source
9	17α(H) diahopane/18α(H)-30-norneohopane (C_{30}*/C_{29}TS)	Source, Maturity
10	C_{27} 18α(H)-22,29,30-trisnorhopane (Ts)/C_{27} 17α(H)-22,29,30-trisnorhopane (Tm)+ Ts	Maturity, Source
11	T_s/C_{30} 17α(H)21β(H) hopane	Maturity
12	C_{32} 17α(H)21β(H) 22S homohopane/C_{32} 17α(H)21β(H) 22R homohopane	Maturity
13	C_{30} 17β(H)21α(H) moretane/C_{30} 17α(H)21β(H) hopane	Maturity
14	pristane/phytane	Source
15	pristane/n-heptadecane	Source, Biodegradation, Maturity
16	phytane/n-octadecane	Source, Biodegradation, Maturity

* Ratios calculated from peak areas as follows:

Parameters	1-7	m/z = 217, 218, 259	mass fragmentograms
Parameters	8 - 13	m/z = 191	mass fragmentogram
Parameters	14 - 16	capillary gas chromatogram of alkanes or whole oil/extract	

357145

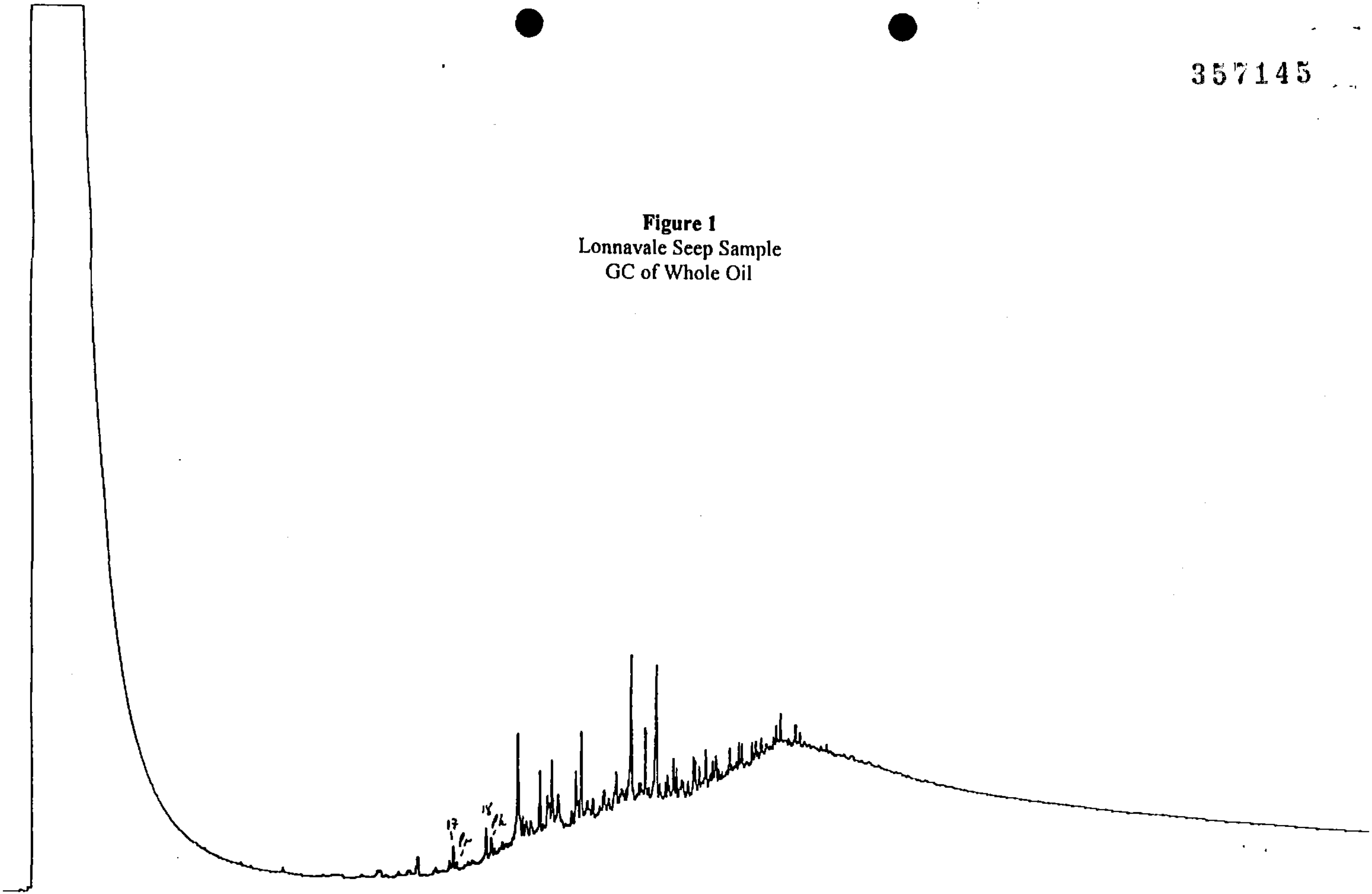

Figure 1
Lonnavale Seep Sample
GC of Whole Oil

357146

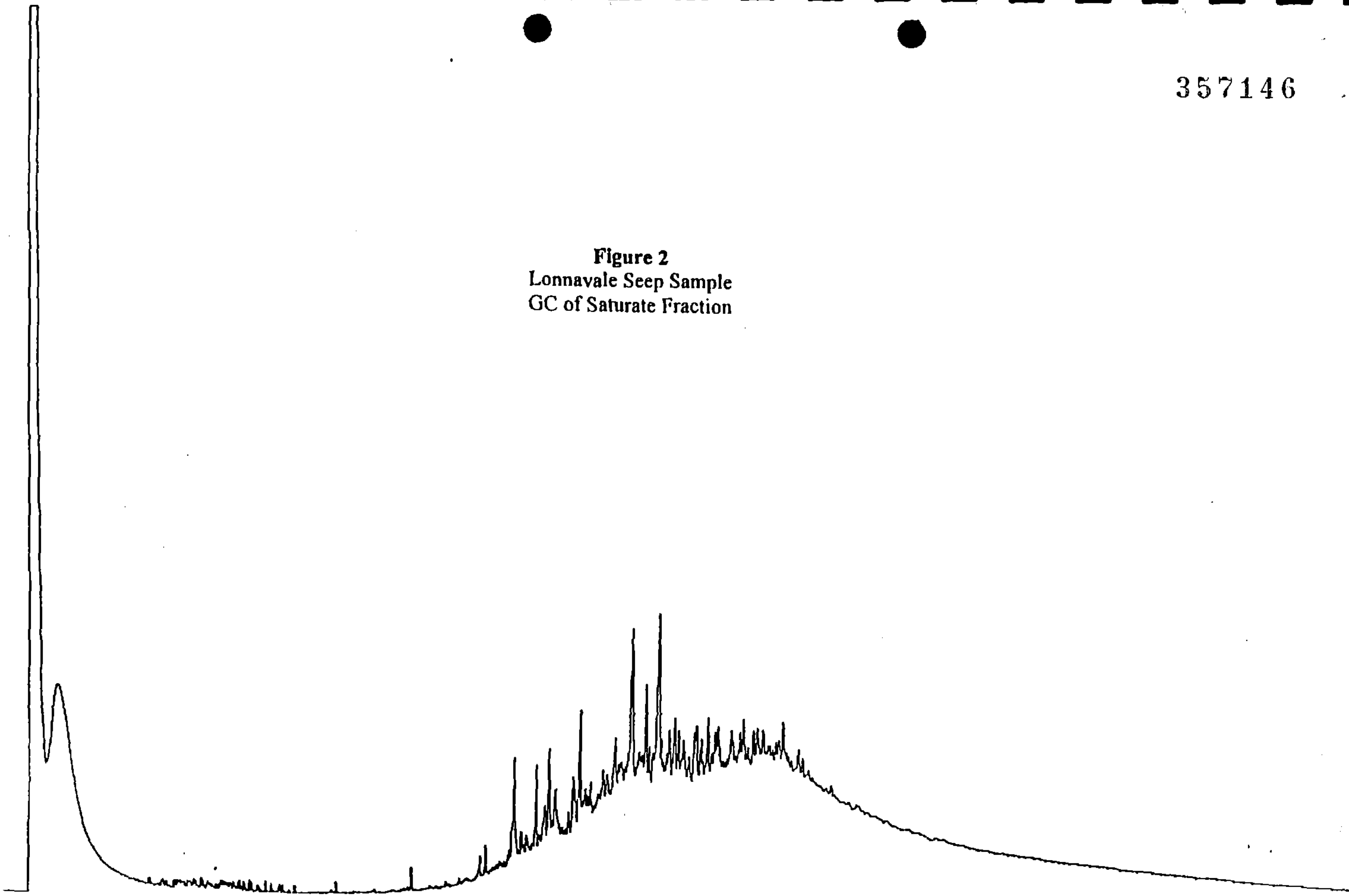

Figure 2
Lonnavale Seep Sample
GC of Saturate Fraction

FIGURE 3

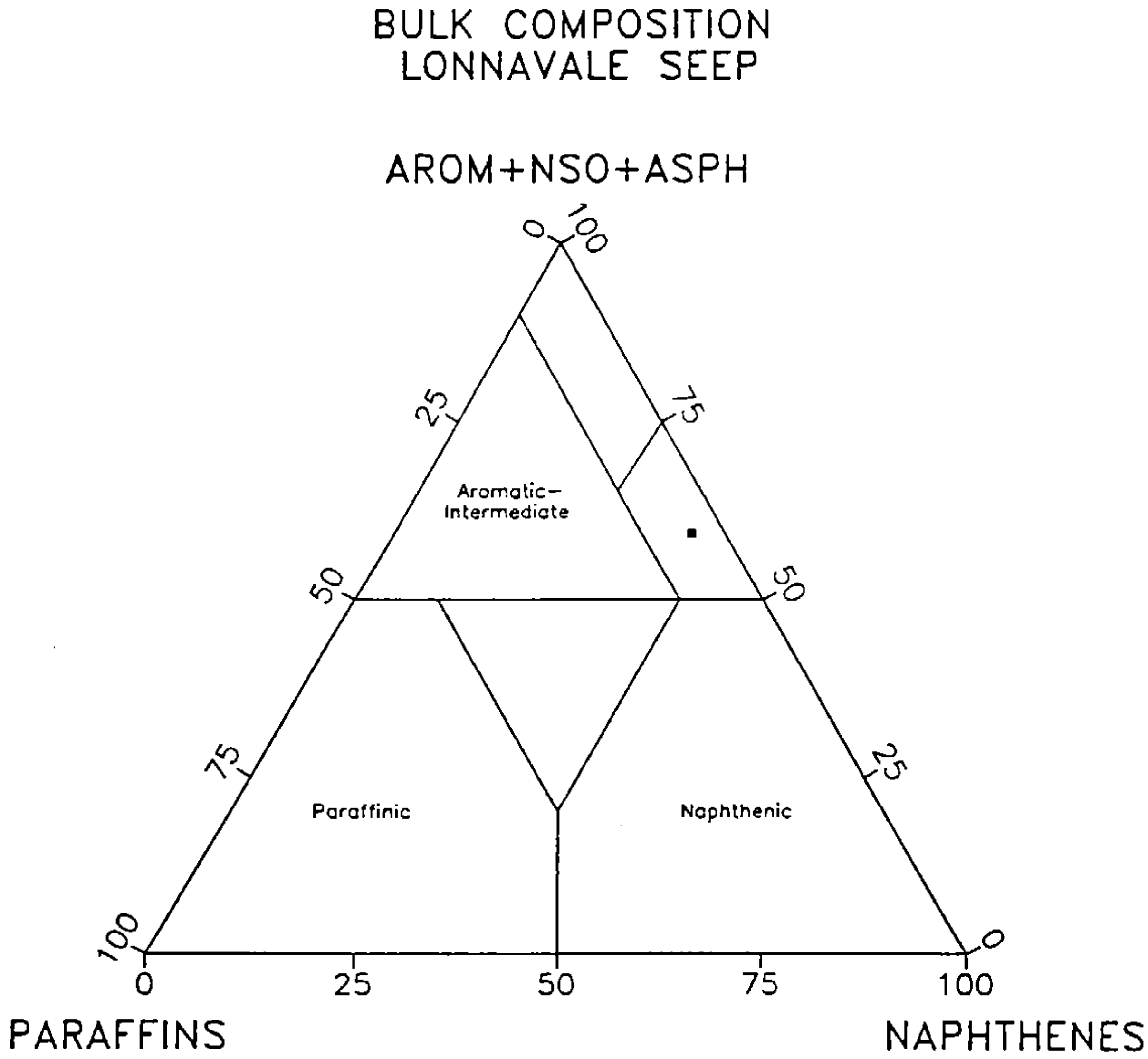
BULK COMPOSITION
LONNAVALE SEEP
AROM+NSO+ASPH
0
100
25
75
Aromatic-
Intermediate
50
50
75
25
Paraffinic
Naphthenic
100
0
0
25
50
75
100
PARAFFINS
NAPHTHENES

FIGURE 4

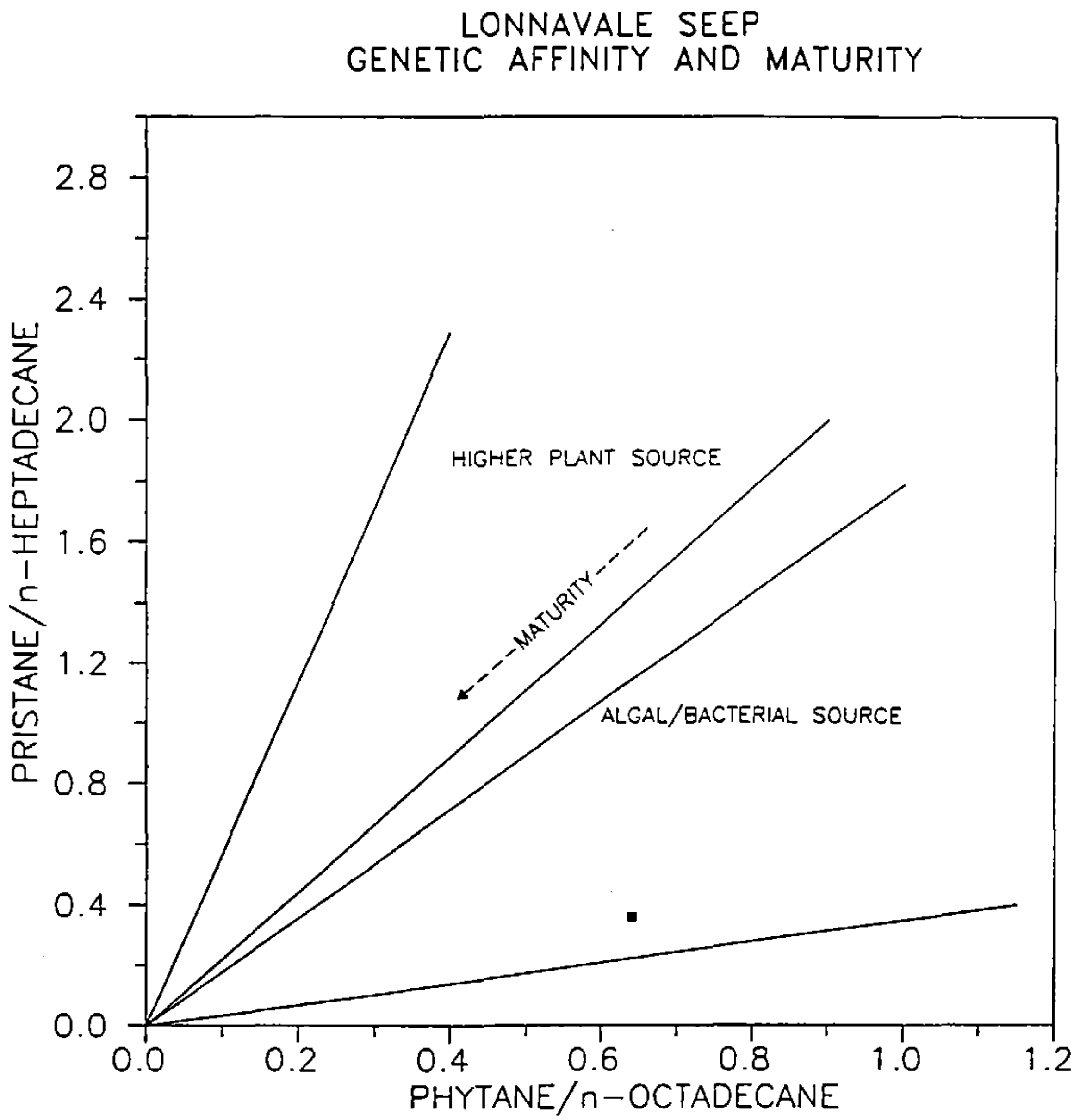
LONNAVALE SEEP
GENETIC AFFINITY AND MATURITY
PRISTANE/n-HEPTADECANE
PHYTANE/n-OCTADECANE
0.0
0.4
0.8
1.2
1.6
2.0
2.4
2.8
0.2
0.6
1.0
HIGHER PLANT SOURCE
MATURITY
ALGAL/BACTERIAL SOURCE

FIGURE 5a

357149

```
File         : C:\HPCHEM\1\DATA\UOFA\4496AROM.D
Operator     : WYTHE
Acquired     : 12 Jan 96  11:16 am using AcqMethod 60MAROM
Instrument :   AMDEL-597
Sample Name: LONAVALE SEEP
Misc Info   :
Vial Number: 1
```

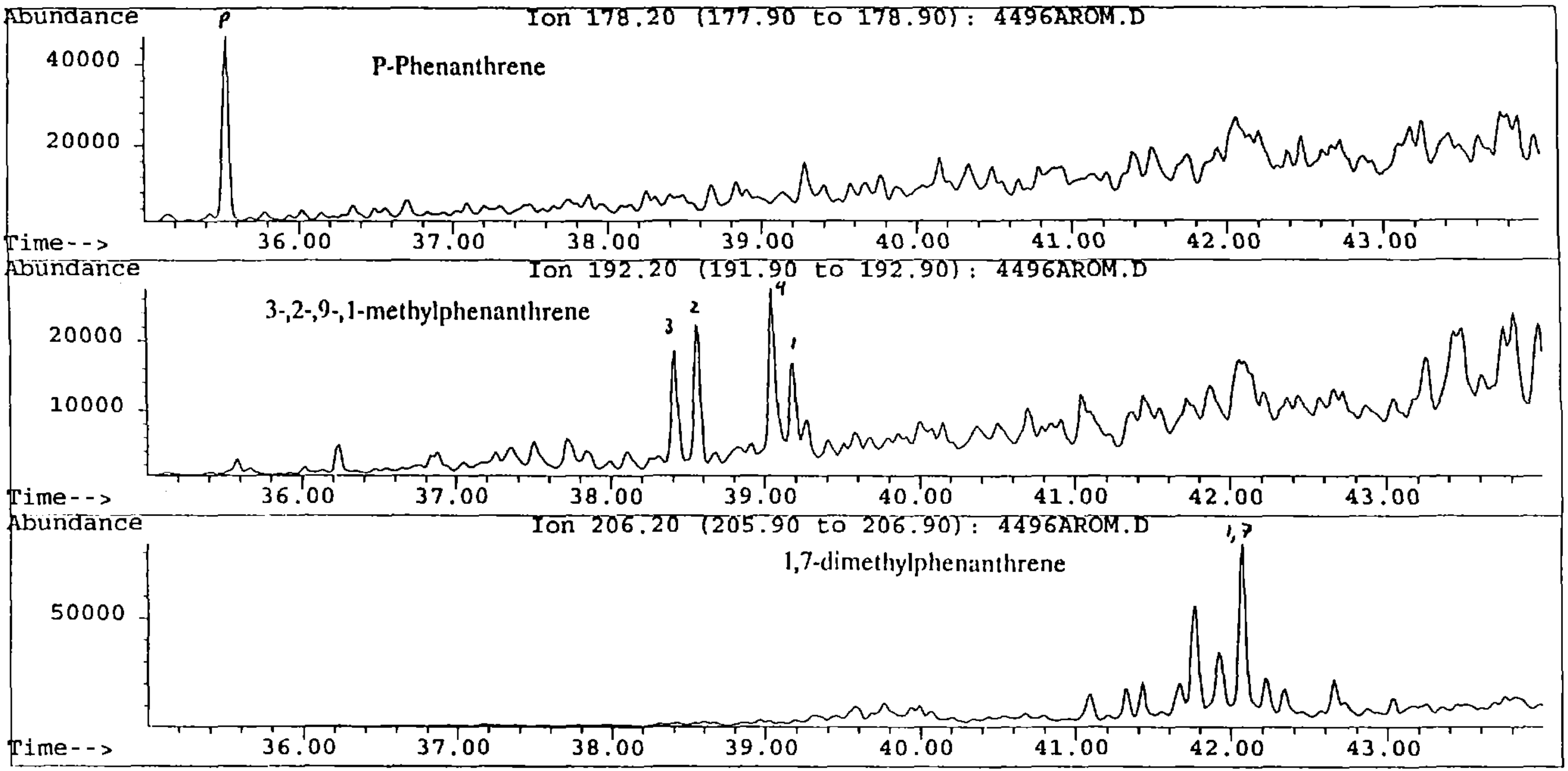

FIGURE 5b

357150

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Instrument :    AMDEL-597
Sample Name: LONAVALE SEEP
Misc Info   :
Vial Number: 1
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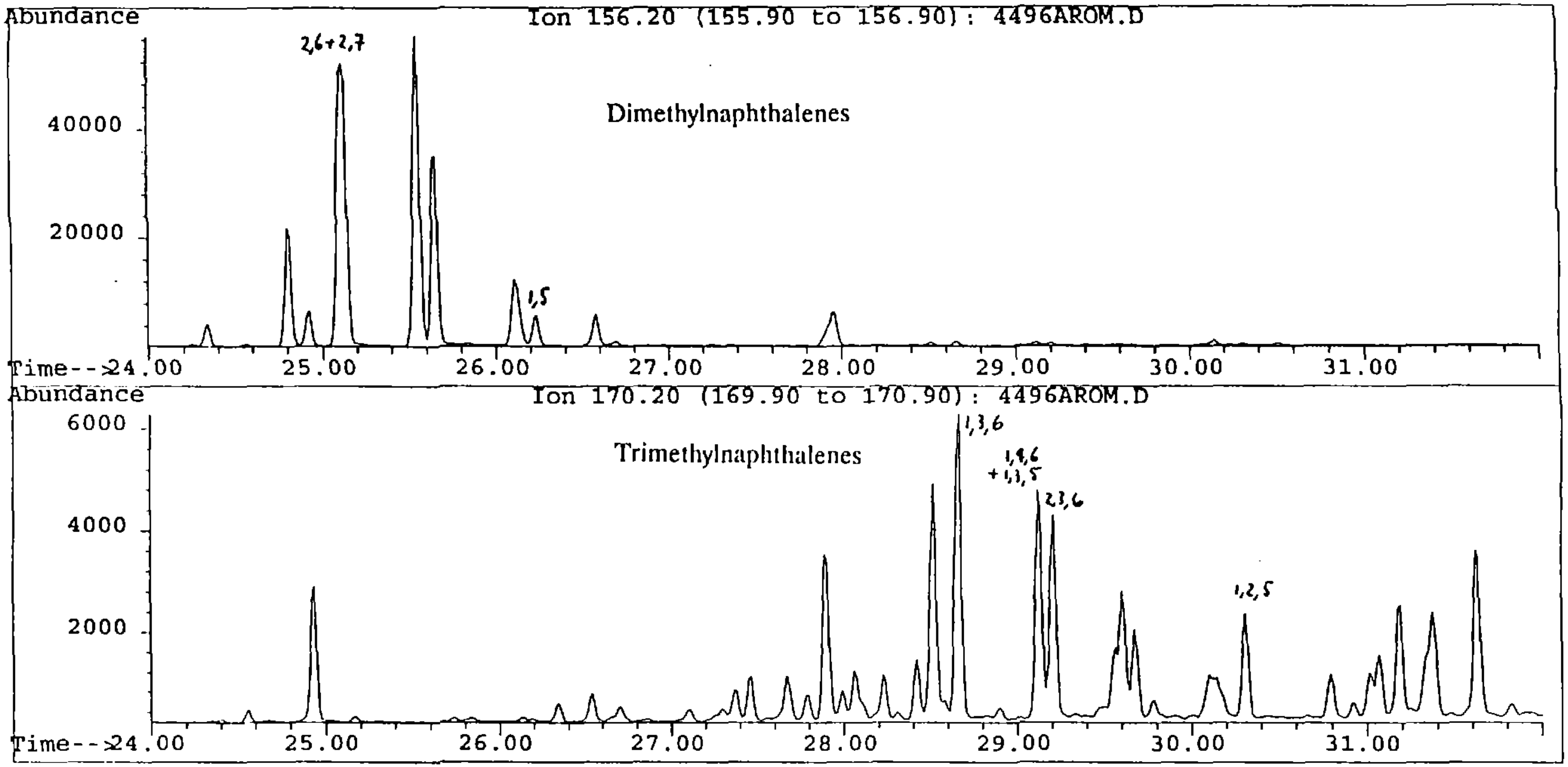


357151

FIGURE 6

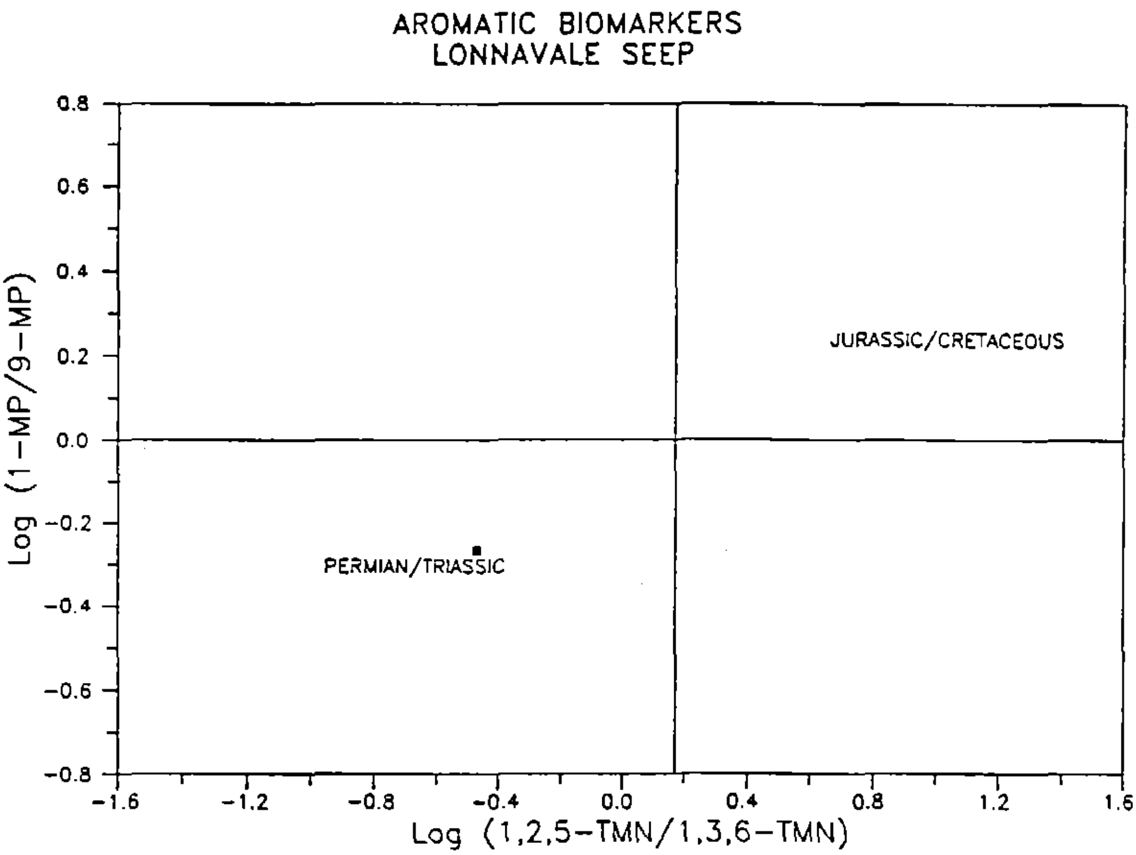


FIGURE 7

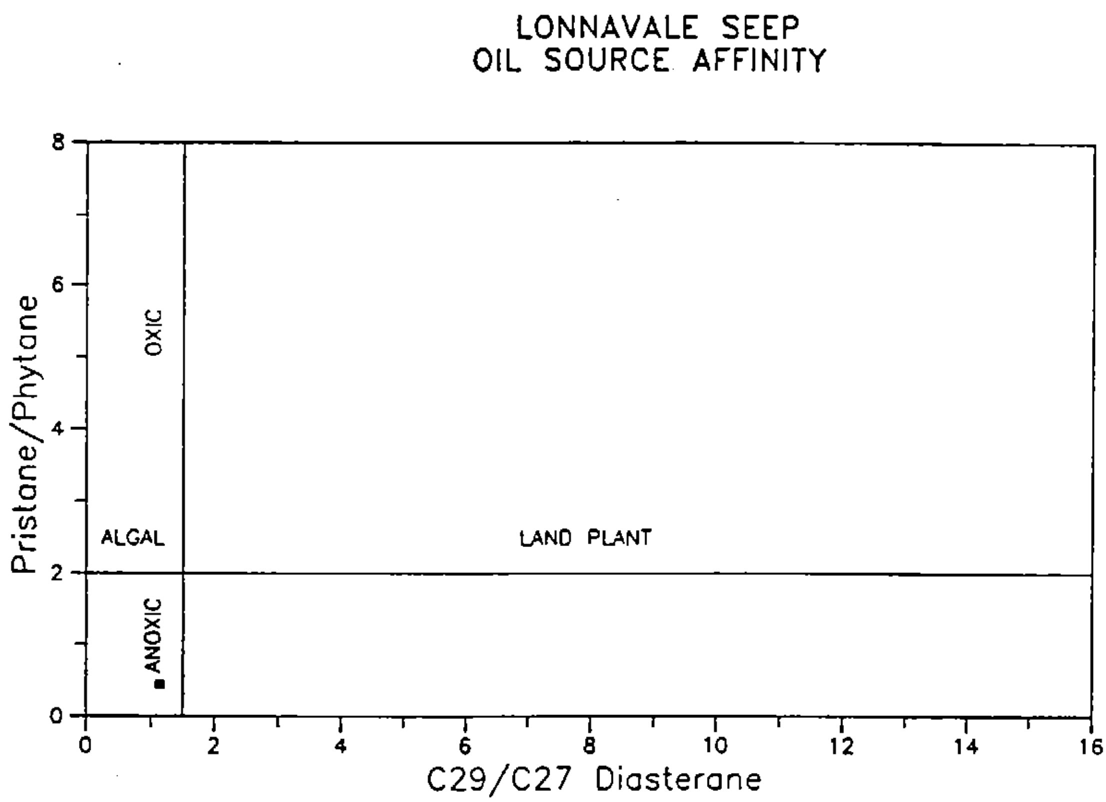

LONNAVALE SEEP
OIL SOURCE AFFINITY
Pristane/Phytane
C29/C27 Diasterane
OXIC
ALGAL
LAND PLANT
ANOXIC
0
2
4
6
8
0
2
4
6
8
10
12
14
16

FIGURE 8

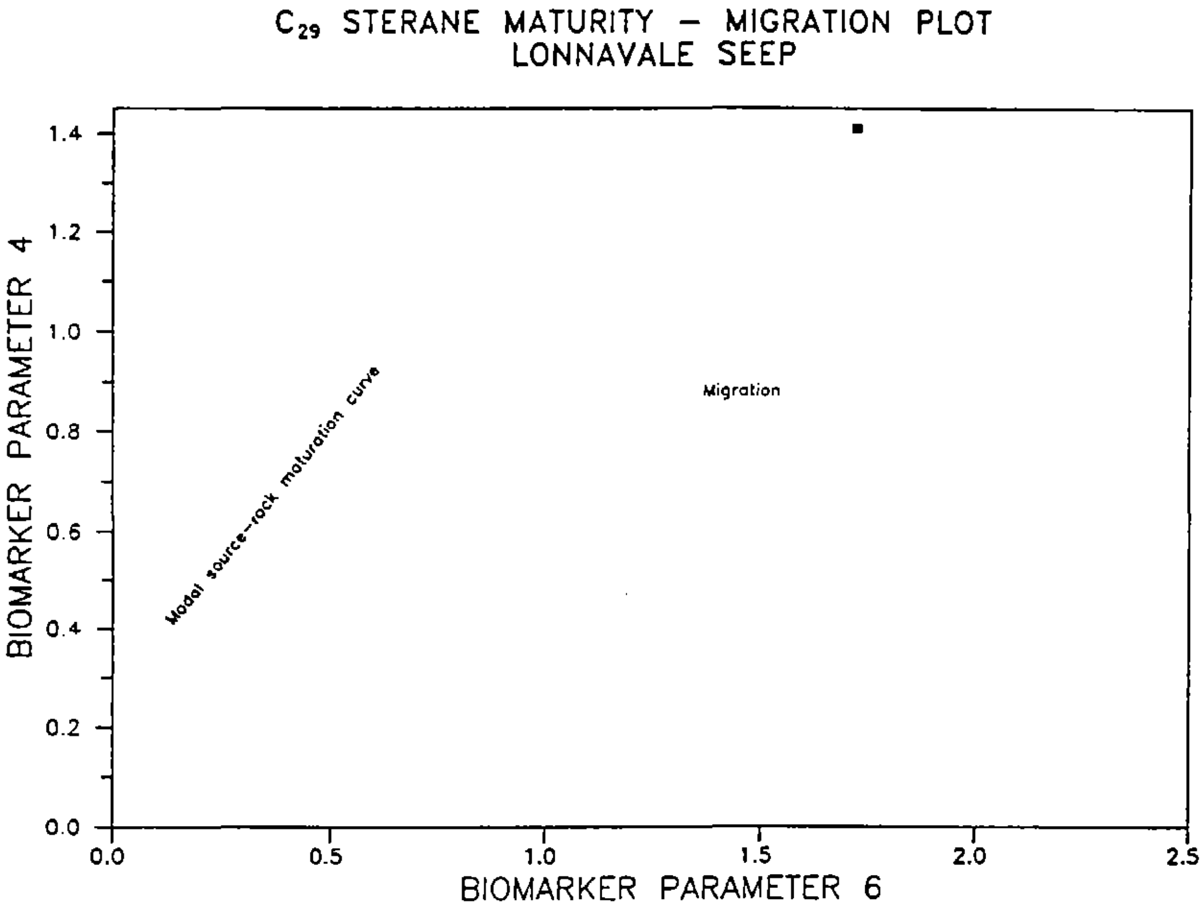
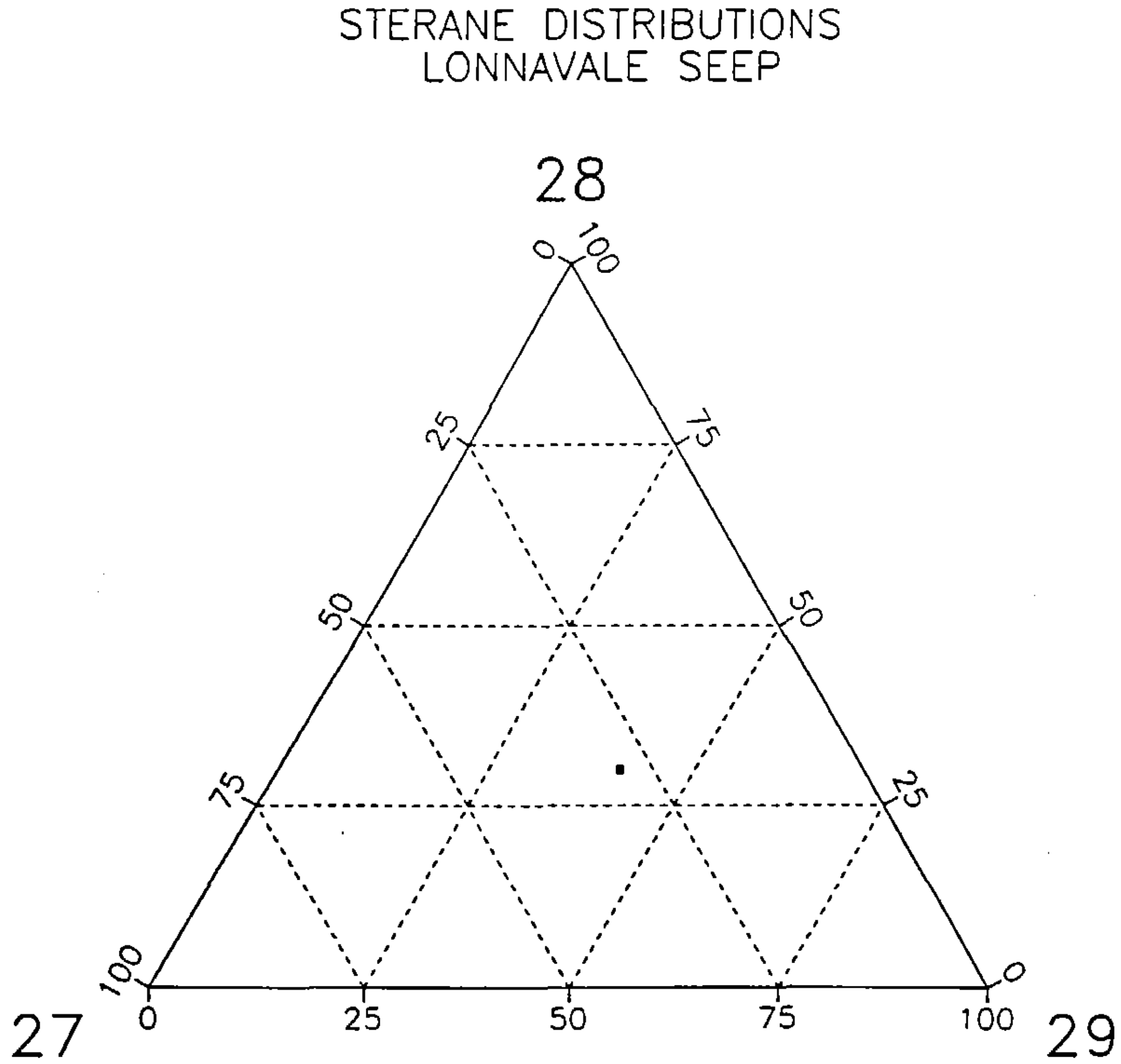

C29 STERANE MATURITY – MIGRATION PLOT
LONNAVALE SEEP
BIOMARKER PARAMETER 4
BIOMARKER PARAMETER 6
Model source-rock maturation curve
Migration
0.0
0.2
0.4
0.6
0.8
1.0
1.2
1.4
0.5
1.5
2.0
2.5

FIGURE 9


STERANE DISTRIBUTIONS
LONNAVALE SEEP
28
27
29
0
100
25
75
50
50
75
25
100
0
0
25
50
75
100

APPENDIX 1

ANALYTICAL PROCEDURES

1. Isolation of Residual Oil

The seep sample was extracted with dichloromethane in a soxhlet apparatus until the solvent was clear. Removal of the solvent by careful rotary evaporation gave the oil (nominal C_{12+} fraction).

2. Liquid Chromatography

Asphaltenes were not precipitated from the condensate prior to liquid chromatography. The samples were separated into hydrocarbons (saturates and aromatics) and polar compounds (resins) by liquid chromatography on activated alumina and silica (sample:adsorbent ratio = 1:100). Saturated hydrocarbons were eluted with petroleum ether, aromatic hydrocarbons with petroleum ether/dichloromethane (50:50) and polar compounds with dichloromethane/methanol (35:65).

3. Gas Chromatography

Whole oils and saturated hydrocarbons (alkanes) were examined by gas chromatography using the following instrumental parameters:

Gas Chromatograph:	Perkin Elmer 8500 operated in the split injection mode
Column:	25 m x 0.3 mm fused silica, SGE QC3/BP1
Detector Temperature:	300°C
Column Temperature:	40°C for 1 minute, then 8° per minute to 300°C and held isothermal at 300°C until all peaks eluted
Quantification:	Relative concentrations of individual hydrocarbons were obtained by measurement of peak areas with a Perkin-Elmer LCI 100 integrator. The areas of peaks responding to aromatic hydrocarbons were multiplied by appropriate response factors

4. Thin Layer Chromatography (TLC)

Aromatic hydrocarbons were isolated from the extracted oil by preparative TLC using Merck GF_{254} silica plates and distilled AR grade n-pentane as eluent. Naphthalene and anthracene were employed as reference standards for the diaromatic and triaromatic hydrocarbons, respectively. These two bands, visualised under UV light, were scraped from the plate and the aromatic hydrocarbons redissolved in dichloromethane.

5. Gas Chromatography-Mass Spectrometry (GC-MS)

GC-MS analysis of the aromatic and naphthenic hydrocarbons was undertaken in the selected ion detection (SID) mode. The instrument and its operating parameters were as follows:

System:	HP 5890 Series II Plus GC coupled to HP 5972 MSD
Column:	60m x 0.25 mm i.d., DB-1 cross-linked methylsilicone phase fused silica, interfaced directly to source of mass spectrometer
Injector:	Splitless 2μL
Carrier Gas:	Helium at a linear velocity of 30cm/minute
Column Temperature:	50°C for 2 minutes then 50-290°C @ 7°/minute
Mass Spectrometer Conditions:	70 eV EI; 9-ion selected ion monitoring, 70 millisec dwell time for each ion

The di- and triaromatic hydrocarbons isolated from the extracted oil by thin layer chromatography were analysed by GC-MS.

The following mass fragmentograms were recorded:

m/z	Compound Type
156	dimethylnaphthalenes
170	trimethylnaphthalenes
178	phenanthrene
192	methylphenanthrene
206	dimethylphenanthrenes

The area of the phenanthrene peak was multiplied by a response factor of 0.667 when calculating the methylphenanthrene index (MPI).

Naphthenes (branched/cyclic alkanes) were isolated from the oil by molecular sieve separation of the saturates fraction.

GC-MS analysis of the naphthenes was undertaken in the multiple ion detection (MID) mode. Instrumental conditions are given below.

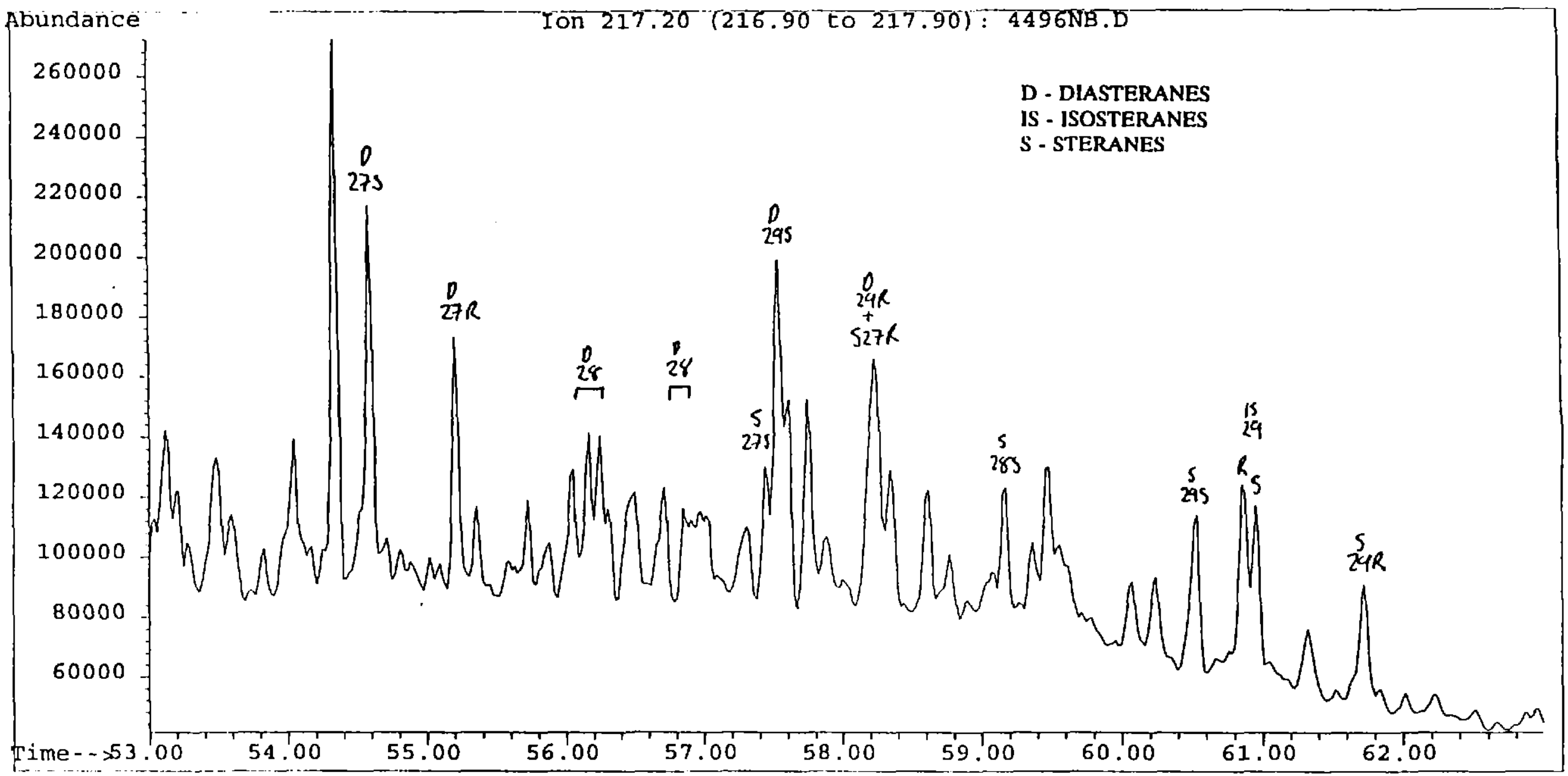
The following mass fragmentograms were recorded:

m/z	Compound Type
83	alkylcyclohexanes
123	drimanes, diterpanes
177	demethylated triterpanes
183	acyclic alkanes (incl isoprenoids, botryococcanes)
191	triterpanes (incl hopanes, moretanes)
205	methyltriterpanes
217	steranes
218	steranes
231	4-methylsteranes
259	diasteranes

APPENDIX 2

GC-MS OF BRANCHED/CYCLIC ALKANES

```
File         : C:\HPCHEM\1\DATA\UOFA\4496NB.D
Operator     : WYTHE
Acquired     : 11 Jan 96   6:57 pm using AcqMethod 60MAMDEL
Instrument   :   AMDEL-597
Sample Name: Lonavale Seep
Misc Info    :
Vial Number: 1
```



357160

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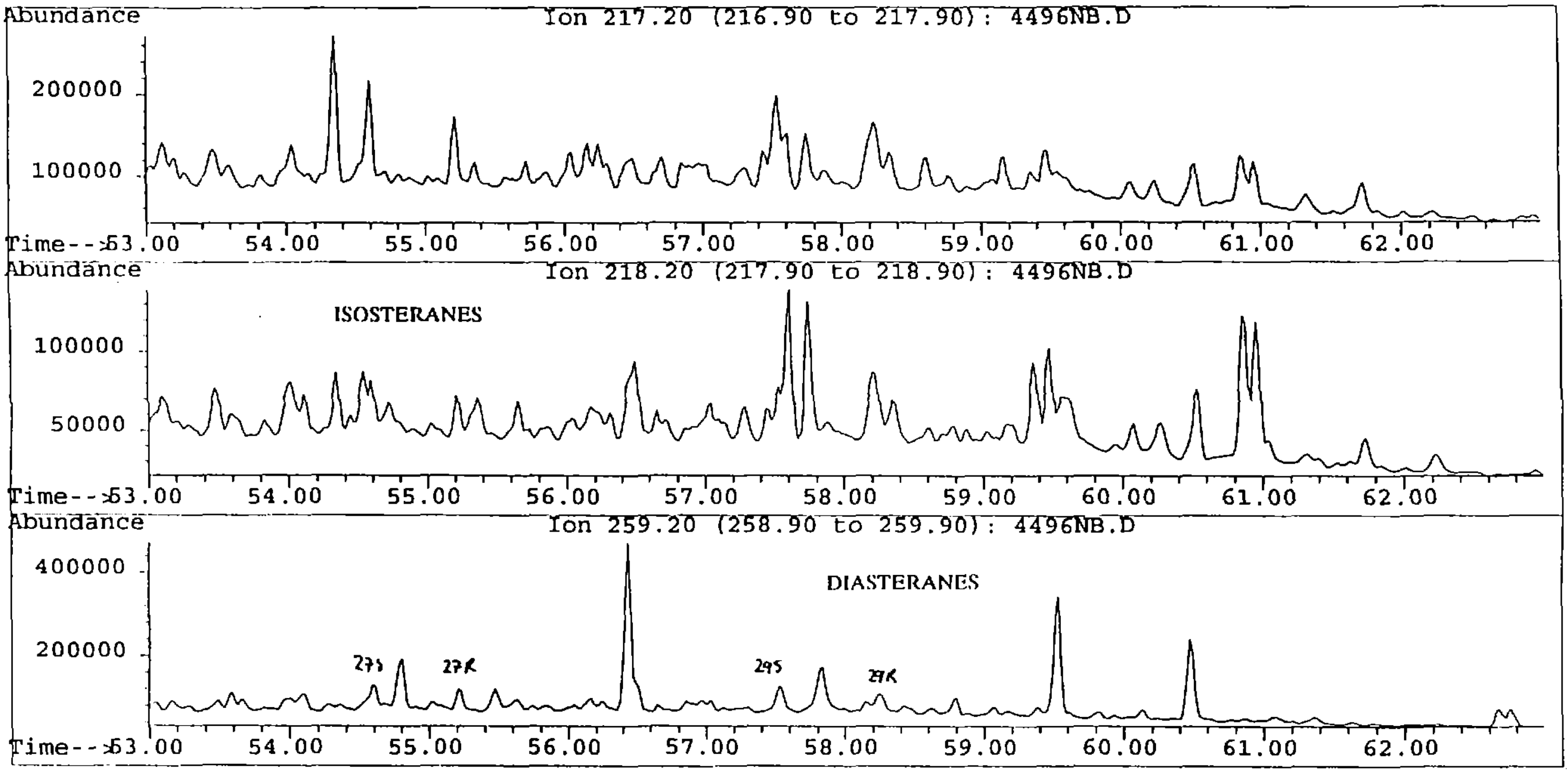
Instrument : AMDEL-597
Sample Name: Lonavale Seep
Misc Info :
Vial Number: 1



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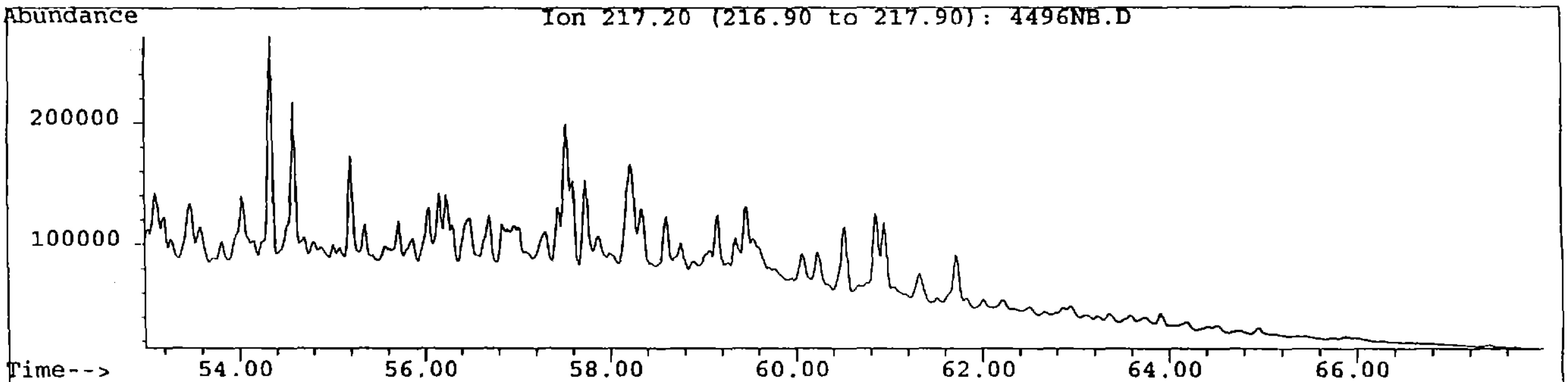
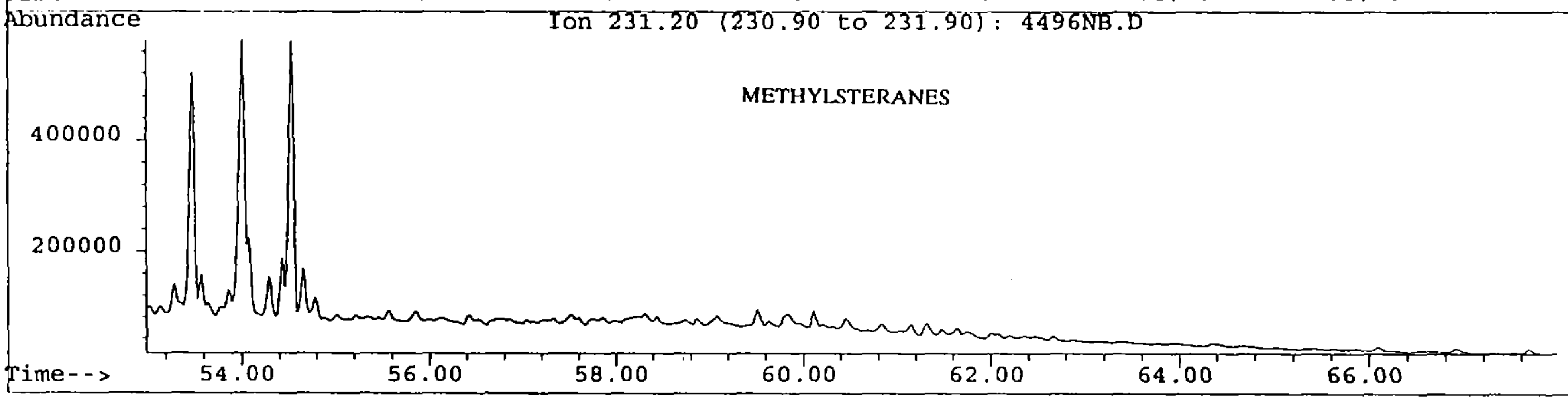
Operator : WYTHE
Acquired : 11 Jan 96 6:57 pm using AcqMethod 60MAMDEL
Instrument : AMDEL-597
Sample Name: Lonavale Seep
Misc Info :
Vial Number: 1





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Instrument : AMDEL-597
Sample Name: Lonavale Seep
Misc Info :
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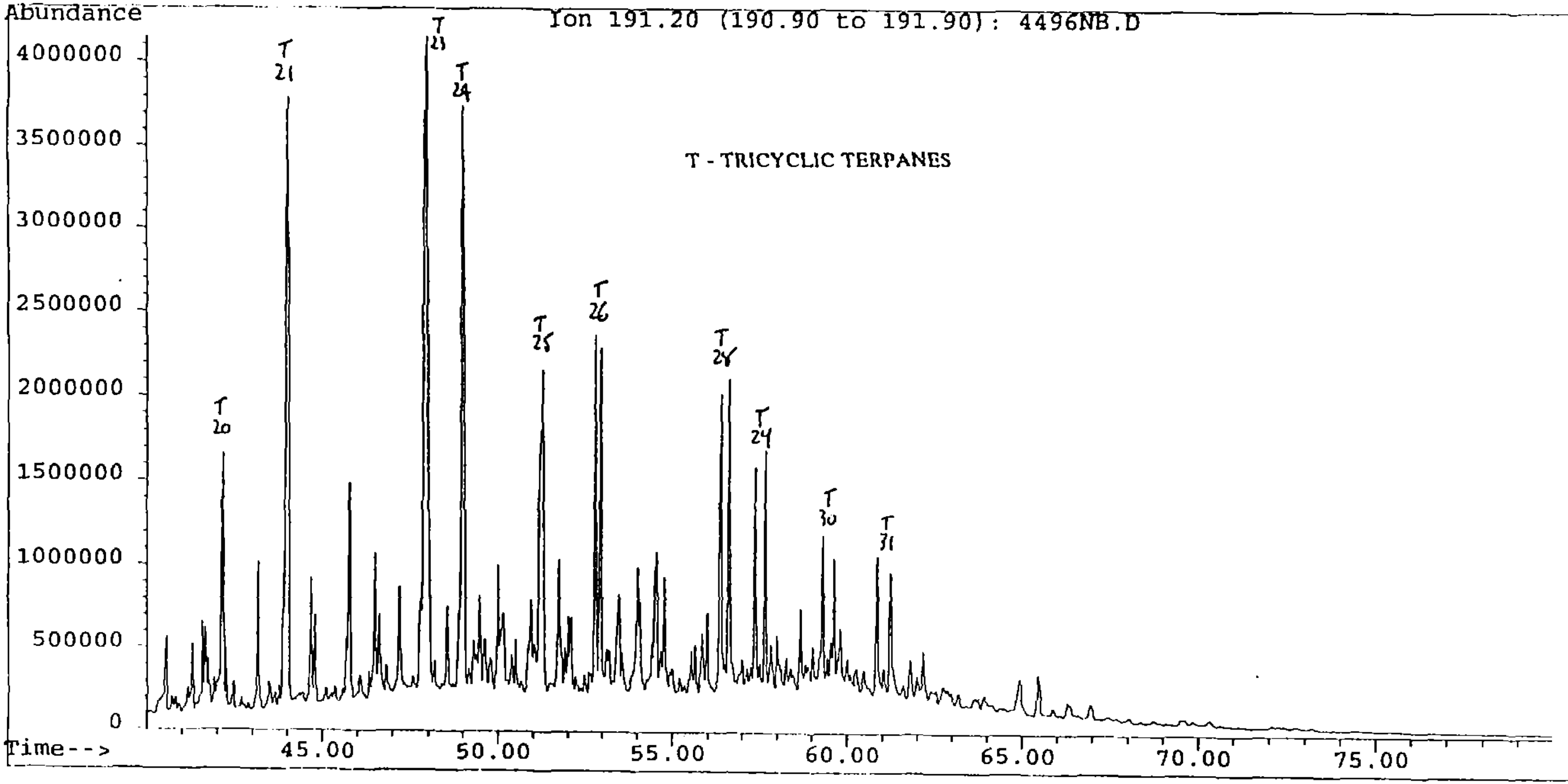

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Operator   : WYTHE
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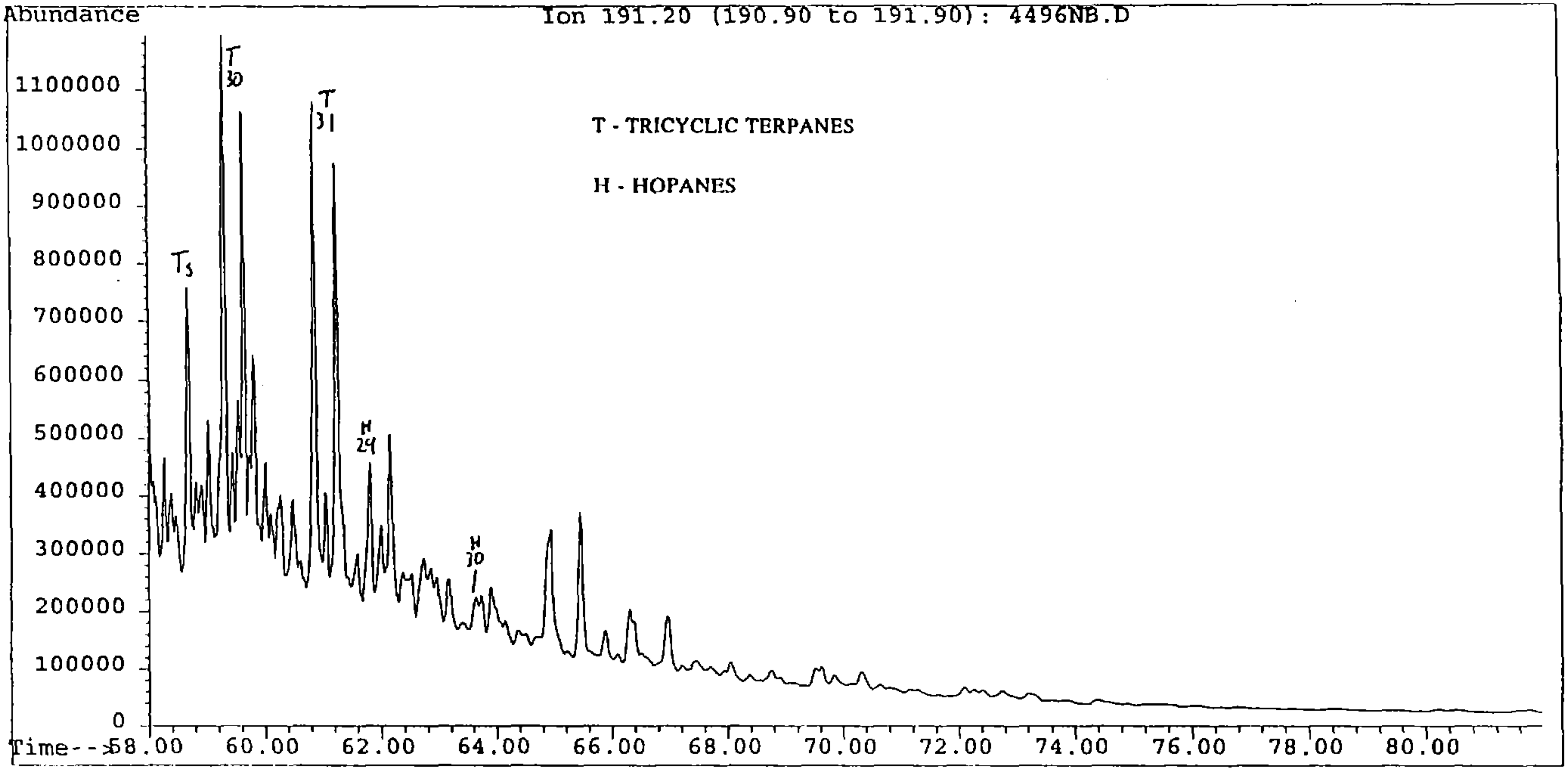
Instrument :   AMDEL-597
Sample Name: Lonavale Seep
Misc Info   :
Vial Number: 1



357164

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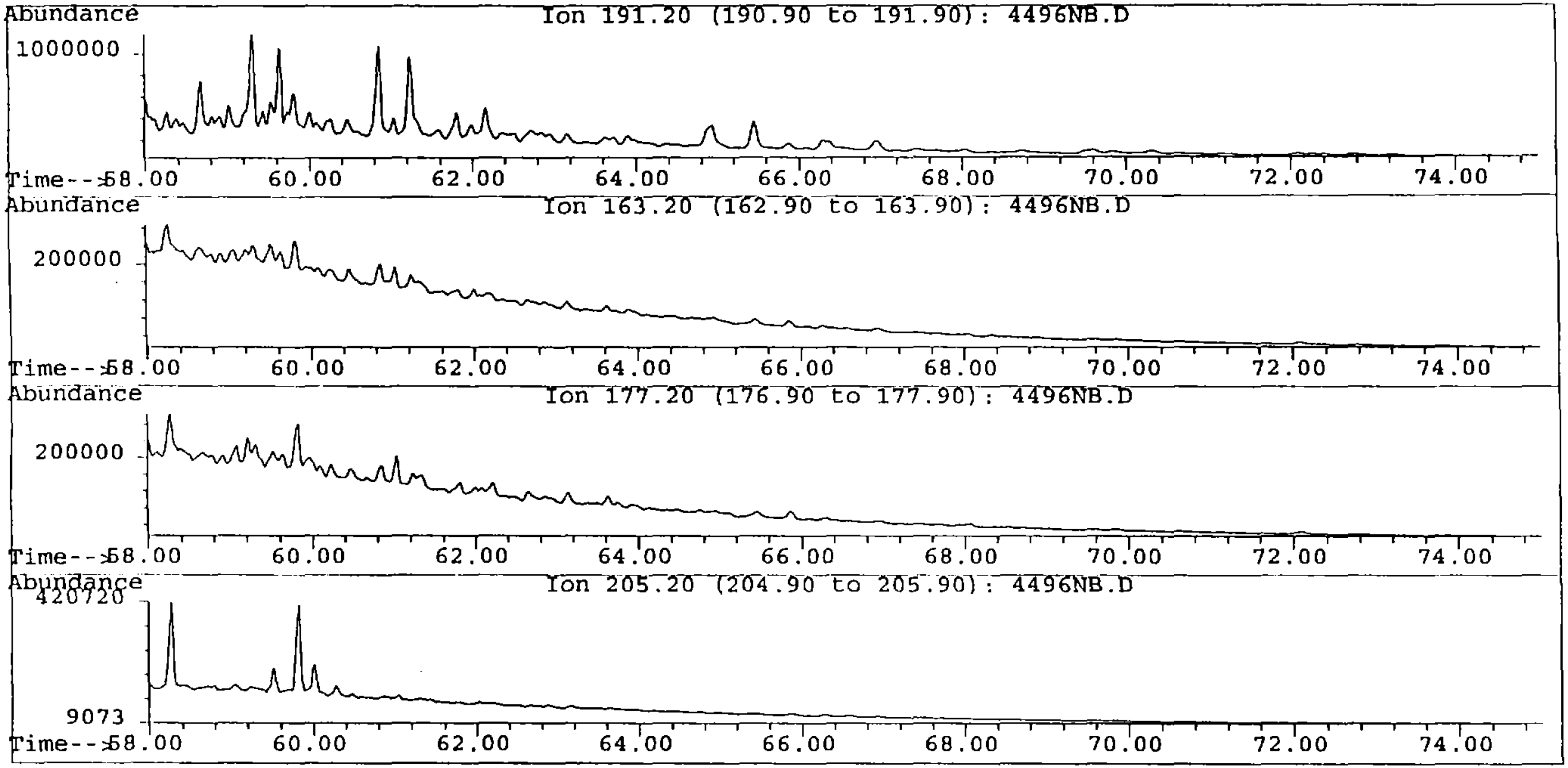
Instrument :   AMDEL-597
Sample Name: Lonavale Seep
Misc Info   :
Vial Number: 1



357165

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Instrument : AMDEL-597
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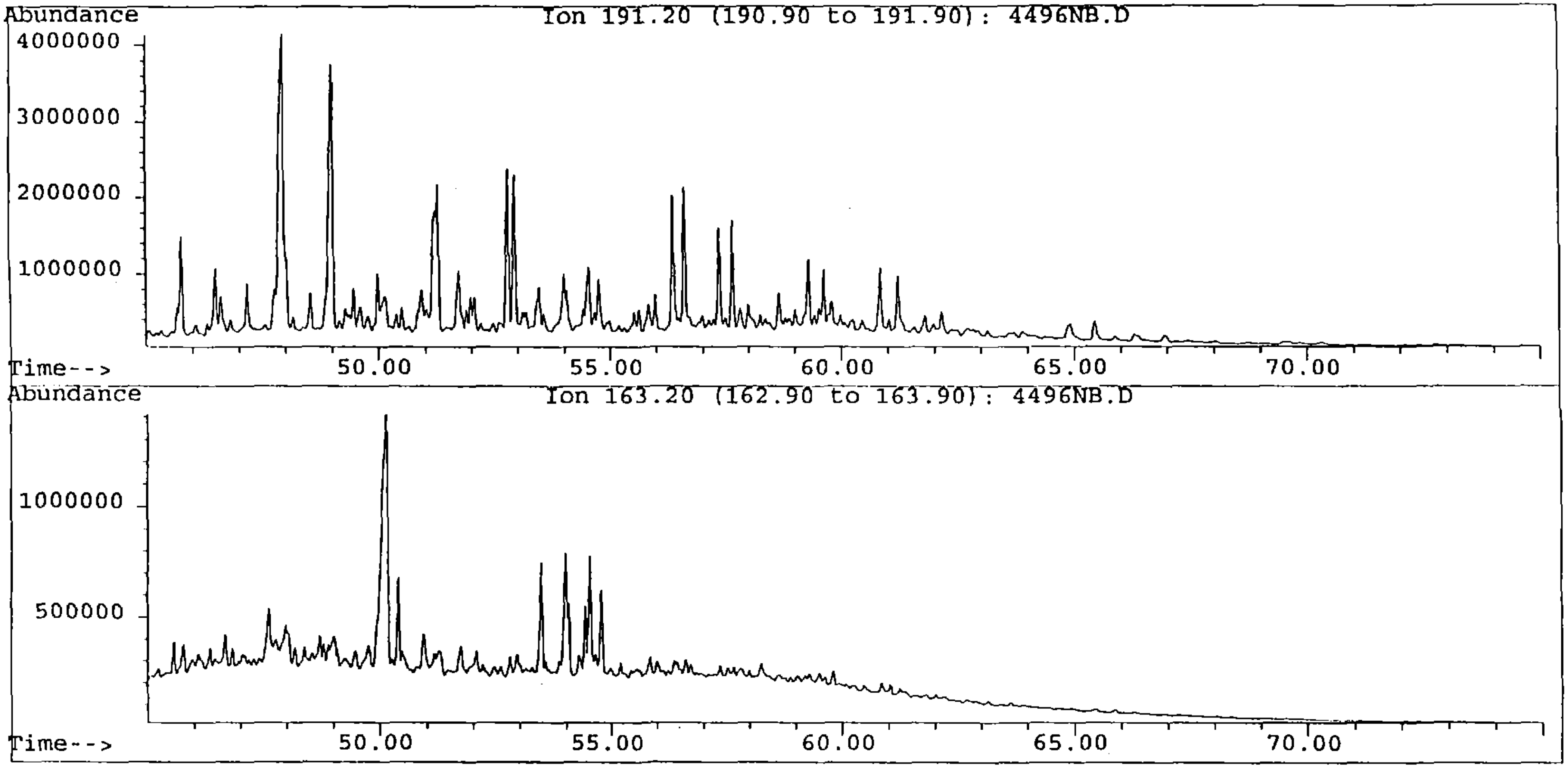
Misc Info :
Vial Number: 1



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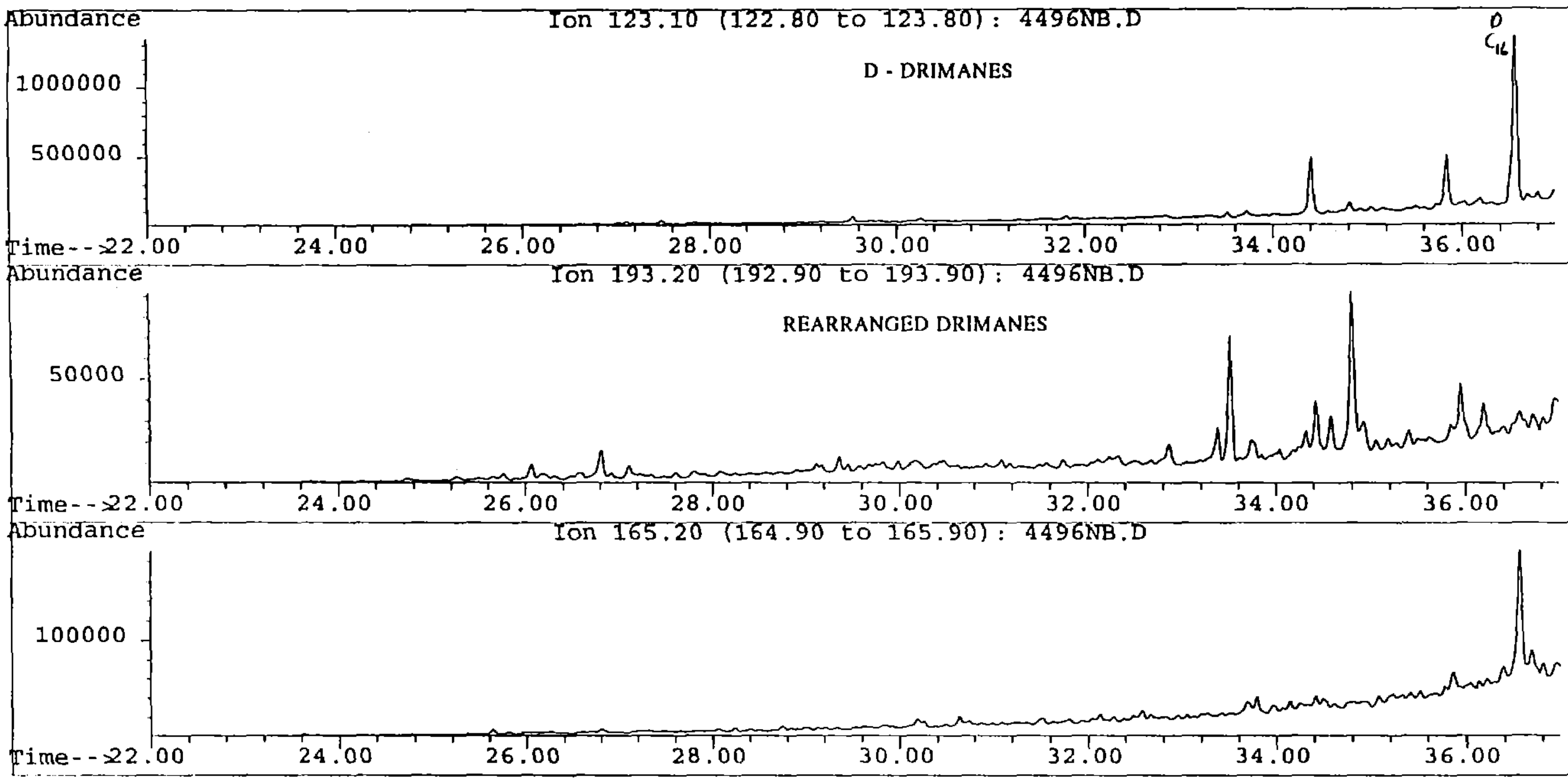
Instrument : AMDEL-597
Sample Name: Lonavale Seep
Misc Info :
Vial Number: 1



357167

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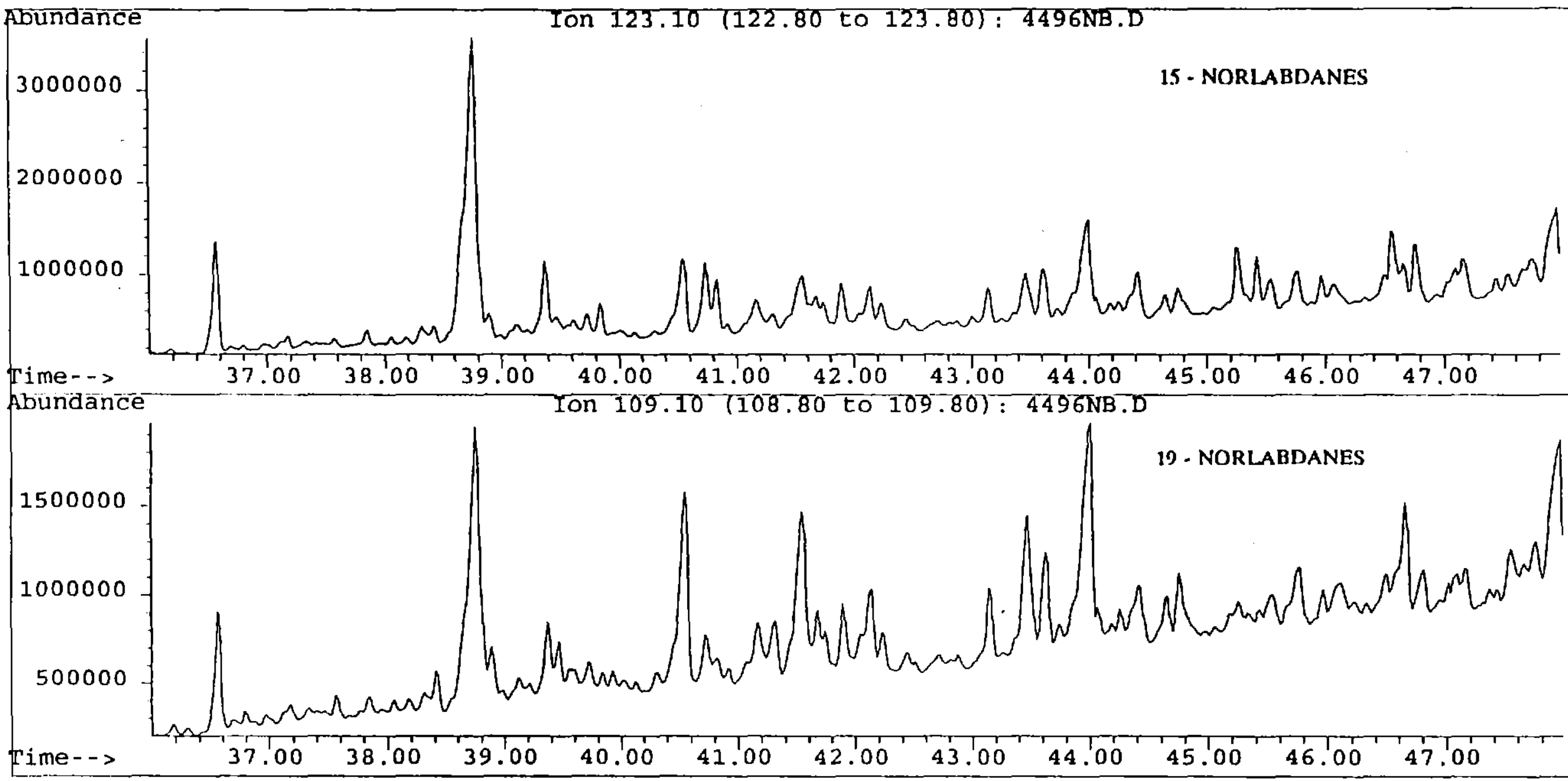
Misc Info :
Vial Number: 1



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File : C:\HPCHEM\1\DATA\UOFA\4496NB.D
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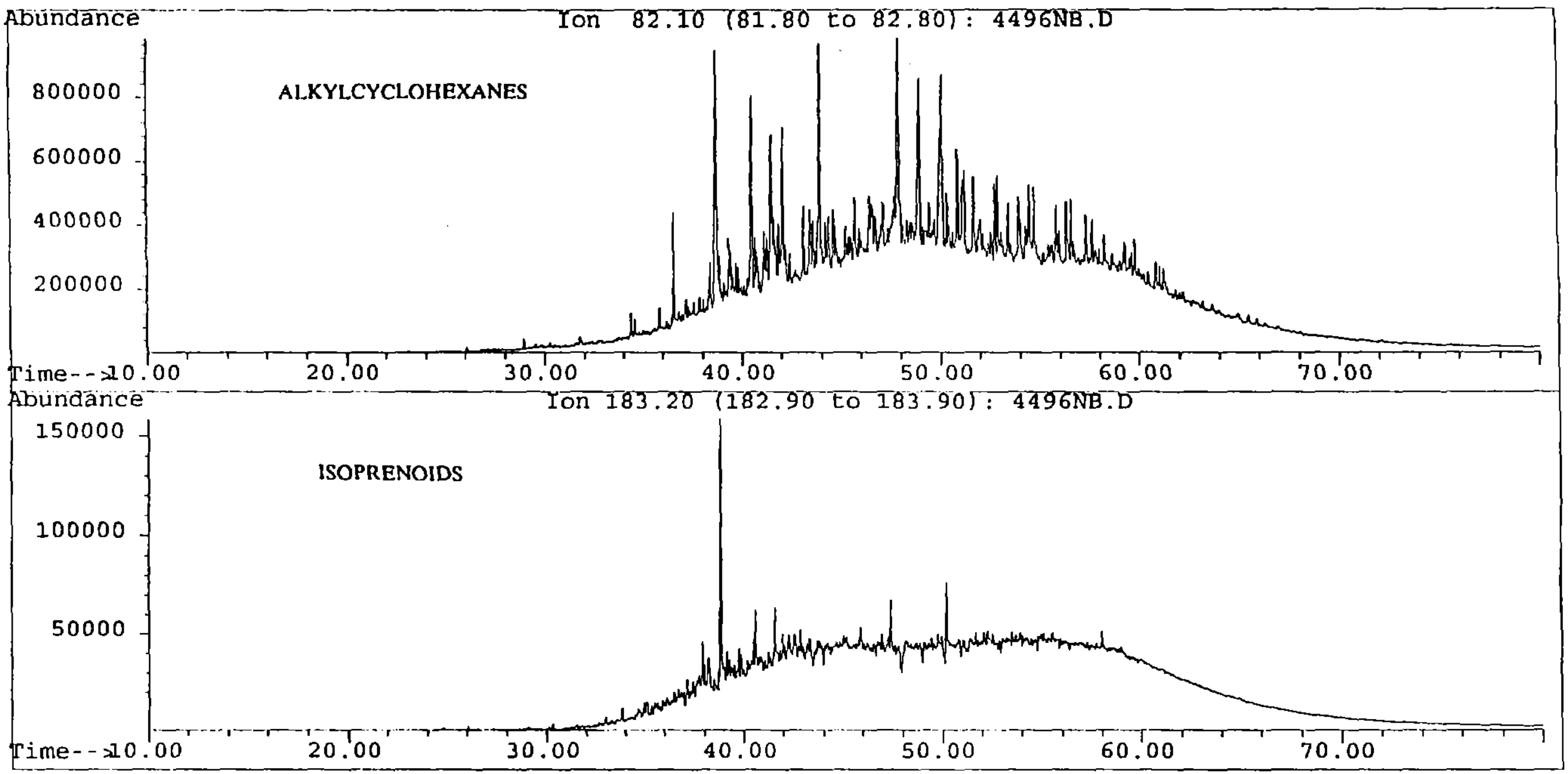
Instrument : AMDEL-597
Sample Name: Lonavale Seep
Misc Info :
Vial Number: 1



357169

Appx 11
357170

357171

Robert S. Young
Consulting Petroleum Geologist

8014 Twining Oaks Lane
Spring, Texas 77379

Office: (713) 370-3623
Fax: (713) 370-3623
Home: (713) 376-3900

March 13, 1996

Dr. Gordon Wise-Chairman
GREAT SOUTHLAND MINERALS PTY. LTD.
24 Jackson Street, Glenorchz,
P. O. Box 101, Glenorchz 7010
Tasmania, Australia

At the request of Great Southland Minerals Pty. Ltd., I have reviewed the geological, geochemical, and geophysical reports made available over several years on the "Potential of Oil & Gas of Tasmania". I have also reviewed the recently completed No. 1 Shittin well drilled to a depth of 1021.4 meters on Bruny Island. The well bottomed in Permian Truro Tillite with an increase of methane gas upon penetrating the tillite. In December, I met with Dr. Clive Burrett, Chief Geologist for Great Southland Minerals; Malcolm Bendal, Director of Great Southland Minerals; Jason Slot, Director of Great Southland Minerals; and David Leaman, Geophyscist with the Geology Department of University of Tasmania. We had extensive discussions on the potential of oil and gas in the basin and also on the recent developments in the geochemical analysis of seep samples, the evaluation of the recently drilled No. 1 Shittin well on Bruny Island, and the recent "TASGO" seismic project onshore Tasmania Basin by Australian Geological Survey Organization (AGSO).

The geochemical analysis from several samples certainly indicate that the source for these many oil seeps could primarily be generated from the Ordovician limestones and the limestones and the Permian source rocks are in or very near the oil window. These rocks, and possibly additional source beds, could exist deeper in the basin.

The methane gas recorded in the Truro Tillite of the No. 1 Shittin well could be interpreted as being in place swamp or lake deposits of the tillite and were released by the coring and drilling. Or, the tillite could be highly fractured with gas seeping in from a deeper ordovician reservoir. Either way, the recording of gas was very important.

Great Southland Minerals Pty. Ltd.
March 13, 1996
Page 2.

The recent "TASGO" seismic lines were shot to test the recording response of shooting over dolerite for half the line and without dolerite for the other half. My observation of the unmigrated T-4 line had good results of energy being recorded on all of the line. I did not get to see the migrated processed line, but I understand it was very successful. This could open up a large area for reflection seismic exploration to define structures or potential traps.

All of this builds a good case for finding commercial oil and gas in the basin, but an extensive seismic program would take a great deal of time and money.

My recommendation would be for a core hole to be located in the deeper part of the basin on what is interpreted as a ridge of structure from magnetics and gravity, with possibly two seismic lines, crossing the well sight, perpendicular to each other and done prior to drilling.

Although the basin has shown potential for source, reservoir and seals, the picking of a location to find commercial reserves is going to be very difficult to impossible without the assistance of reflection seismic. Drilling core holes can also be very expensive and the need for a lot of luck.

Sincerely,

Robert S Young

Robert Young

xc: Dr. Clive Burrett

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POTENTIAL OF OIL AND GAS IN THE TASMANIAN ONSHORE BASIN

Robert S. Young
Consulting Petroleum Geologist
Houston, Texas

INTRODUCTION

There has been an early interest in oil in the Tasmania Basin, since the first sighting of oil seeps in 1880. Shallow wells were drilled in the early 1900's and the maximum depth of any well was about 400 meters. Gas shows were discovered in one well at Port Sorell and oil discovered in small quantities from Bruny Island, but since 1939, there has been little or no activity of serious exploring for oil and gas until recently. Recent drilling at Variety Bay, Bruny Island, had shows of methane gas of over a 200 meter column. The few wells to have penetrated Permian Pre-Parmuner basement have proven dolomitic Precambrian, turbidites or Cambrian volcanics. No hole is deeper than 100 meters.

The areal extent of Tasmania and all its smaller outer islands covers 16.8 million acres. The Tasmanian Basin covers over 5 million acres. These marine and non-marine sediments of upper Paleozoic and lower Mesozoic age are very widespread and are referred to as the Parmeener Super Group (Bank 1973). It is estimated the thickness of the basin is over 2,500 meters. In general, the Tasmanian Basin rests unconformably upon the Ordovician, Cambrian, and Pre-Cambrian rocks. Much of Tasmania consists of exposed Cambrian and Pre-Cambrian in the west and the Ordovician-Devonian turbidites in the northeast, all intruded by Devonian granitoids. The granitoids are inferred to occur at shallow depths beneath the unconformity. There are over 270 seeps discovered, which transect all rock types, strongly suggesting that deep crustal lineaments are still active" (Burrett). Many of the seep samples have been analyzed geochemically and found to be related in oil signatures with the potential source of the Ordovician limestones of the Gordon group and very little with the Tasmanite oil shale or

Quamby mudstones of Permian. It is also presumed that deeper and older formations in the basin could have source potential. The Permian sands make up the greatest potential for reservoirs and are intermixed with coal beds and an oil shale zone. A primary seal to these beds is the overlying Jurassic dolerite that covers nearly 3/4 of the basin. The Ordovician limestones of the Gordon Group are also considered possible reservoirs as paleokarsts, reefal or fractural. Structural features are difficult to define. To date there has been very little refection seismic coverage due to the poor quality of data beneath the blanket of dolerite. The present coverage of gravity and magnetics of the basin, have been used extensively to date and have been able to define regional older structural elements. Most of the younger Permian sediments in the basin will be structurally drapping, fault trapping or stratigraphic, which will be practically impossible to define with only gravity or magnetics.

HYDROCARBON POTENTIAL

The importance in the evaluation of any basin for commercial hydrocarbons are source, reservoirs, seals, and traps.

1. Source

Prolific oil producing basins, when geochemically evaluated are shown to contain at least one adequately mature, deeply buried source rock system. It is often stratigraphically widespread and was deposited in an oxygen-depleted environment. With over 200 hydrocarbon seeps and shows which have been studied geochemically and have identified at least four mature oils, it is very probable there are several possible hydrocarbon sources in the Tasmanian Basin. Geochemical comparisons of seeps shows that the most likely source would be the Ordovician of the Gordon Group Limestones. Ratios of C27: C28: C29 Steranes are identical between seeps of the Bruny Island Johnson well and the Ordovician Gordon Limestone and the predominance of C27 Steranes and the abundant diasteranes in Tasmanian bitumens suggests a widespread algae and clay rich source rock.

Conodonts color indicates that much of the Gordon Limestone, particularly in central and southern Tasmania, is in the oil and gas windows. This limestone is expected to underlay Permian and Triassic sediments in much of Tasmanian Basin.

Other sources include the Permian Quamby Mudstone, "Freshwater Sequence" and Preolenna coal measures. In all three rock units of which the total organic carbon may reach 25%, vitrinite reflectance data and fossil pollen colors show that these source rocks are within the oil window over large areas of the basin.

2. <u>Reservoir</u>

Reservoirs are very easily envisioned in the shallow marine Ordovician Limestones as paleo-karst, reefal, or fractural. Since the Limestones are considered source material, migration would be minimal. Additional potential reservoirs are within the Siluro-Devonian sandstones of the Eldon and Tiger Range Groups and within sandstones of the Permian Bundella Formation, Faulkner Group and Liffey Sandstone of the Lower Parmeener Super Group. Measured porosities in the Faulkner and Liffery are 13% and 12% respectively, while other Permian sandstones in the northern block of EL21/95 have porosities averaging 16% and horizontal permeabilities ranging up to 386 millidarcies.

3. <u>Seals</u>

Evaporites are most efficient seals mainly because they offer very little or no pore space; however, the long-term sealing properties of very fine grained, water-wet porous rocks such as shales are also remarkably efficient in the absence of open fractures. This is due to the displacement pressure barrier effect created by capillary pressure between oil and water in rock pores (Berg 1975, Schowalter 1976). Long-term sealing properties of very fine grained water-wet rocks are demonstrated by the excellant preservation of light oil and gas reserves in some very old sedimentary basins. For instance, shallow Paleozoic oil and gas in Illinois, Michigan and Applachian basins, major reserves in the Palezoic Volga-Ural Basin (USSR) and giant Devonian and Ordovician fields in the southern Algerian Sahara demonstrate the sealing efficiency of very low permeability rocks, provided geologic history following entrapment has remained quiescent. All the above basins feature stable tectonic conditions and a lack of adverse thermal history.

It would be anticipated that the Ordovician Limestone reservoirs would be sealed by additional limestone within the Gordon Group or by the Turo Tillite above the unconformity. Good seals of shale and silts are found throughout the Permian-Triassic sedimentary sequence. The Jurassic dolerite sills also make an excellent cap rock for the Permian-Triassic reservoirs.

4. Traps

Defining traps and structural features within the basin is very difficult to impossible without good reflection seismic records. To date, there has been very little reflection seismic data and most of the data is of poor quality due to the extensive dolorite blanket over a large part of the basinal sediments. Recent seismic work on the TASGO project seems to have improved the quality and depth of recordings through the dolerite, which will greatly assist in defining the structural traps. The present gravity and magnetics, which have been extensively used to date have been able to define regional structural elements of mostly Paleozoics. Structures in the Permian, or younger, are probably going to be faulted, and of low relief. Although I have not reviewed the recent migrated "TASGO" seismic lines T-4 or T-5, I did have the opportunity to see the lines unmigrated and they indicated low relief structural features. Line T-4 was part of an experiment to determine whether sediments within the Tasmanian Basin could be imaged beneath the cover of difficult to penetrate dolerite and to determine the depth of the basin. Previous estimates of the thickness of the carboniferous-Mezozoric basin was 2500± meters and there has been no new reported thickness based on the "TASGO" seismic program.

Except in unusual cases of very long range migration typically encountered on foreland basin plates, most untrapped oil in sedimentary basins originates from synclinal drainage areas that surround the trap itself. Thus, migration distances commonly range in tens rather than hundreds of miles, particularly on strongly structured and/or faulted basins.

RISK

Exploration risk, being defined as the probability of spending exploration funds without economic success, has always been at the heart of the oil business. Geologic risk, which is a part of overall exploration risk, is fueled by uncertainties in subsurface geologic conditions, prior to drilling. It can also be expressed in terms of the probability of simultaneous occurrence of the key factors that determine the habitat of oil and gas in the subsurface.

Successful exploration for producible hydrocarbons in the subsurface depends on satisfying the following probabilities: i) probability of existence of trap (structure x reservoir x seal); ii) probability that the trap has received and physically retained petroleum charge (source x maturation x migration paths x timing); and iii) probability that the entrapped petroleum has been preserved from the effects of thermal or bacterial degradation (temperature x meteoric water ingress).

Since these three probabilities are independent of each other, the overall probability of discovering producible hydrocarbons at a given location is the product (not the sum) of the probabilities of these individual factors, that is, if any one of these three main factors is 0, the overall probability of success is 0, regardless how favorable the other two remaining factors are.

In respect to the Tasmanian Basin. I believe the only probability that may be missing is the probability of trap. Not the probability that there won't be a trap, but how do you locate it? At the present, this makes any drilling program a high risk, and very costly. Hopefully, new and improved parameters in the reflection seismic data will overcome some of this risk.

LAND

Great Southland Minerals Pty. Ltd. holds 100% of exploration leases EL/188 (3500 KM^2; EL9/95 (3700 KM^2), and EL21/95 (6000 KM^2) comprising of a total of 13,200 KM^2 (3.2 million acres) which is located in the Deruent Valley. These leases are granted for six years and expire the year 2001. These exploration licenses cover about 60% of the Tasmanian Basin.

MARKET

Tasmania's primary source of energy has been by hydro-electric. Tasmania is approaching a decision point, in that new sources of energy supply will be required in a relatively near future to entice new industry to the area and to maintain a stable energy base for Tasmania. A commercial discovery of either oil or gas should have a ready market.

Conclusion

Work to date has certainly established a valid exploration play for oil and gas. Although the occurrence of seeps does not guarantee the potential for commercial hydrocarbons, it is encouraging to know that oil is generating in the basin. The recent analysis of the Ordovician and the methane shows in the No. 1 Shittin well lead you to believe that hydrocarbons in commercial quantities could be found in the basin. I believe that the criteria needed to establish hydrocarbons have been met in that source rock, within the oil or gas window, has been

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established. Reservoir rocks are present, seals are in place to trap migration, and if the recent "TASGO" seismic program is successful in penetrating the dolerite to receive good data, then the search for a trap should be made much easier. If it is not possible to use reflection seismic data, then the drilling risk will be considerably higher, but I believe a core hole program to evaluate the basin and explore for hydrocarbons can be designed. The economic factors for the area are very attractive and would sustain the costs of such a program.

March 13, 1996

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96-3942

Hydrocarbon Well Log

COMPANY: GREAT SOUTHLAND MINERALS PTY LTD
WELL: SHITTIM 1B RE-ENTRY
FIELD: EL 1/88 NORTH BRUNY ISLAND
STATE: TASMANIA
TOTAL DEPTH: 1290.8m, 1635.0m
Elev. K.B. 25m ASL
CASING RECORD: 140mm PVC 0m 6m; 88.9mm HQ 0m 181m; 70mm NQ 0m 888m
RIG # 1
CHERYL-LEE RANDALL

FOLD HERE — THE WELL NAME, LOCATION, AND BOREHOLE REFERENCE DATA WERE FURNISHED BY THE CUSTOMER.

LEGEND

ABBREVIATIONS

CRD	CORED	EST	ESTIMATED	NB	NEW BIT	SO&G	SHOW OF OIL AND GAS
CG	CONNECTION GAS	F	FILTRATE, API, CC'S	NR	NO RETURNS	SO&W	SHOW OF OIL AND WATER
CK	FILTER CAKE	F/T	FLOWLINE TEMP	NCB	NEW CORE BIT	SPM	PUMP STROKES
CO	CIRCULATED OUT	G&OCM	GAS AND OIL CUT MUD	PERF	PERFORATED	S/T	SUCTION TEMP
Cl	SALINITY .... PPM CL-	GCM	GAS CUT MUD	PP	PUMP PRESSURE	T.D.	TOTAL DEPTH
DF	DERRICK FLOOR	GCW	GAS CUT WATER	RPM	ROTARY SPEED	TG	TRIP GAS
DST	DRILL-STEM TEST	GL	GROUND LEVEL	RT	ROTARY TABLE	V	VISCOSITY, API SECONDS
DS	DIRECTIONAL SURVEY	KB	KELLY BUSHING	Rm	MUD RESISTIVITY, OHM-METER	W	WEIGHT OF MUD
DC	DEPTH CORRECTION	LAT	LOGGED AFTER TRIP	SO	SHOW OF OIL	WOB	WEIGHT ON BIT

LITHOLOGY

BRECCIA, SANDSTONE, SHALE, LIMESTONE, MARLSTONE, CALCAREOUS, ANHYDRITE, SALT, COAL, BENTONITE, IGNEOUS, TUFF

CONGLOMERATE, SILTSTONE, CLAYSTONE, DOLOMITE, MARLSTONE, DOLOMITIC, GYPSUM, CHERT, SIDERITE, LIMONITE OR HEMATITE, GLACIAL TILL, METAMORPHIC

ACCESSORIES

1 symbol = 10% or 20%
2 symbols = 30% or 40%
3 symbols = 50%

SANDY; SANDSTONE, stringers; SILTY; SILTSTONE, stringers; PEBBLES > 2 mm.; SAND GRAINS > 1 to 2 mm.; ARGILLITE GRAIN; FELDSPAR; BRECCIA, fragment; SILICEOUS; CHERT, light and dark; CHERT, tripolitic; ARGILLACEOUS; SHALE, laminae; CARBONACEOUS FLAKES; COAL, thin beds; CEMENTING BITUMINOUS SUBSTANCE; CALCAREOUS; MARLSTONE, stringers - calc.; LIMESTONE, stringers; DOLOMITIC; MARLSTONE, stringers - dol.; DOLOMITE, stringers

ANHYDRITIC; ANHYDRITE, stringers; GYPSIFEROUS; GYPSUM, stringers; SALT CAST or INFILL; PHOSPHATE PELLETS; FERRUGINOUS GRAINS or PELLETS; FERRUGINOUS; NODULES; TUFFACEOUS

SYMBOLS USED FOR SIGNIFICANT OCCURRENCES (may be less than 10%)

HEAVY, DARK MINERALS; GLAUCONITE; BENTONITE; PYRITE; KAOLIN; PLANT SPORES; PLANT REMAINS; FISH REMAINS; MINERAL CRYSTALS

MISCELLANEOUS

KARST TOPOGRAPHY; NO SAMPLES; CANNOT INTERPRET, cavings etc.; QUESTIONABLE INTERPRETATION

ROCK BUILDERS

F = < 20%; 1 symbol = 20 to 50%; 2 symbols = 50 to 70%; 3 symbols = 70 to 100%

ORGANIC: FORAMINIFERA; CRINOID; PELECYPOD; BIOCLASTIC or FRAGMENTAL; AMPHIPORA; CORAL; STROMATOPOROID; BRYOZOA; BRACHIOPOD; OSTRACOD; CEPHALOPOD; GASTROPOD; SCAPHOPOD; BELEMNITE; ECHINOID; FOSSILS < 20%

ORGANIC or NON ORGANIC: OOLITES; PISOLITE 2mm. or over; PSEUDO OOLITES or PELLETS; INTRACLASTS

FRAMEWORK ALGAE: SKELETAL; OOTOID

NON-FRAMEWORK ALGAE: NON-DESCRIPT; LAMINATED

GAS CURVES LEGEND

Produced Gas — Dashed Curve

Total Gas	— T —
Methane	C_1 — 1 —
Ethane	C_2 — 2 —
Propane	C_3 — 3 —
Iso-Butane & Normal Butane	C_4 — 4 —
Oil Indicator	$\frac{C_3 + C_4}{C_1}$ — 0 —

POROSITY: [x] VISUAL, [ ] INTERPRETED (Trace, Poor, Fair, Good, Excellent)

PENETRATION RATE: [x] min./m, [ ] m/hr.

LITHOLOGY: INTERPRETIVE, LITHO-PERCENT; DEPTH

HYDROCARBON DETECTION & ANALYSIS — DRILLING FLUID | CUTTINGS

TOTAL GAS % BY VOLUME METHANE EQUIVALENT IN AIR (1.0% : 100 UNITS)
OIL INDICATOR RATIO REPORTED WITHOUT UNITS.
CHROMATOGRAPHY % BY VOLUME IN AIR (1.0% : 10000 ppm)

TOTAL SHOW EVALUATION | VISUAL SHOW EVALUATION | INTERPRETIVE LITHOLOGY

REMARKS — LITHOLOGY DESCRIPTION, MUD DATA, TEST RESULTS ETC.