A REAPPRAISAL OF THE REGIONAL HYDROCARBON POTENTIAL OF THE SCOTIAN SHELF

by

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August, 1983

ACKNOWLEDGEMENTS

The author wishes to acknowledge John Wade, Dale Issler and M.S. Barss for supplying data. Special thanks to John Wade for initiating this study and providing enlightening discussions and valuable time to its completion. Finally, appreciation goes to the scientists and technical staff of the Eastern Petroleum Geology section of the Atlantic Geoscience Centre, who provided assistance on numerous occasions.

ABSTRACT

The hydrocarbon potential of the Scotian Shelf has been re-evaluated in light of recent data provided by increased exploration activity and new oil and gas generation models for terrestrial organic matter. Geothermal gradient data, based on corrected downhole temperatures, has been updated and revised. Regionally, patterns on geothermal gradient maps reflect basement topography and the presence or absence of salt at depth. Locally, the primary control is sand/shale ratio and the presence of carbonates. Subsurface fluids have resulted in a geothermal high coincident with the carbonate front at the western end of the Sable Subbasin. Higher primary heat flux from the basement hinge zone may also be a factor.

Patterns of organic matter types and total organic carbon have been investigated and found to be related to age and paleoenvironment. The gas-condensate nature of the hydrocarbons on the shelf is attributed to the terrestrial nature of the organic material. Only late Middle-early Late Jurassic sediments possess enough amorphous material to source liquid hydrocarbons.

A variety of maturation indicators including $\%R_0$, TTI, TAI, cuttings gas analyses and temperature have been calibrated. Absolute values vary with basinal position due to the age of the sediments and subsidence rate. Only the lowermost Cretaceous and older section can be termed fully mature. At high rates of heating, TAI responds more quickly than vitrinite, which may explain the apparent discrepancies between maturation indicators over the Primrose salt diapir.

Oil generation in the Abenaki Subbasin, LaHave Platform, Orpheus Graben and Scotian slope is unlikely. The organic matter is of insufficient quantity and quality to source oil. The LaHave Platform is immature

to basement. Some dry gas may be sourced from shales and coal beds within the Missisauga and/or MicMac Formations of the Abenaki Aubbasin. Due to rapid subsidence and short cooking times, shales on the slope are unlikely to source oil. There is also some question as to the existance of reservoir facies or migration pathways to shallower reservoirs in this area.

In the Sable Island area, potential source rocks have good communication with reservoir facies, however, to the south, the fully mature zone occurs within a thick shale section and migration pathways are restricted.

Oil on the shelf is the consequence of maturation of organic matter which was preferentially preserved under unique environmental conditions. A mechanism must exist whereby the deep, mature shales can be drained. The lack of oil found in seaward wells with communication to potential source beds reflects insufficient maturation and/or deterioration of source rock potential.

A hydrocarbon generating model has been constructed for the Scotian Shelf based on total organic carbon, gas to condensate or oil ratios, observed maturation and known hydrocarbon discoveries. The model applies only to the Scotian Shelf and to terrestrial organic matter.

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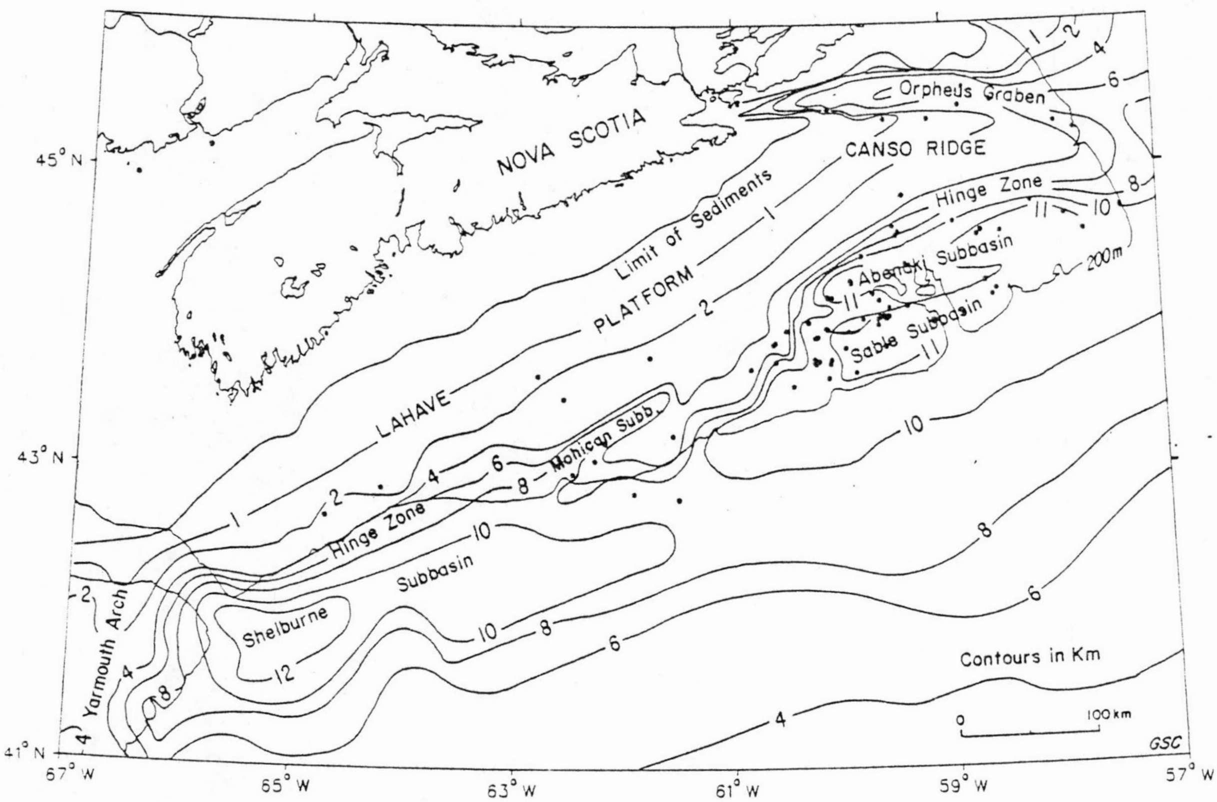
INTRODUCTION

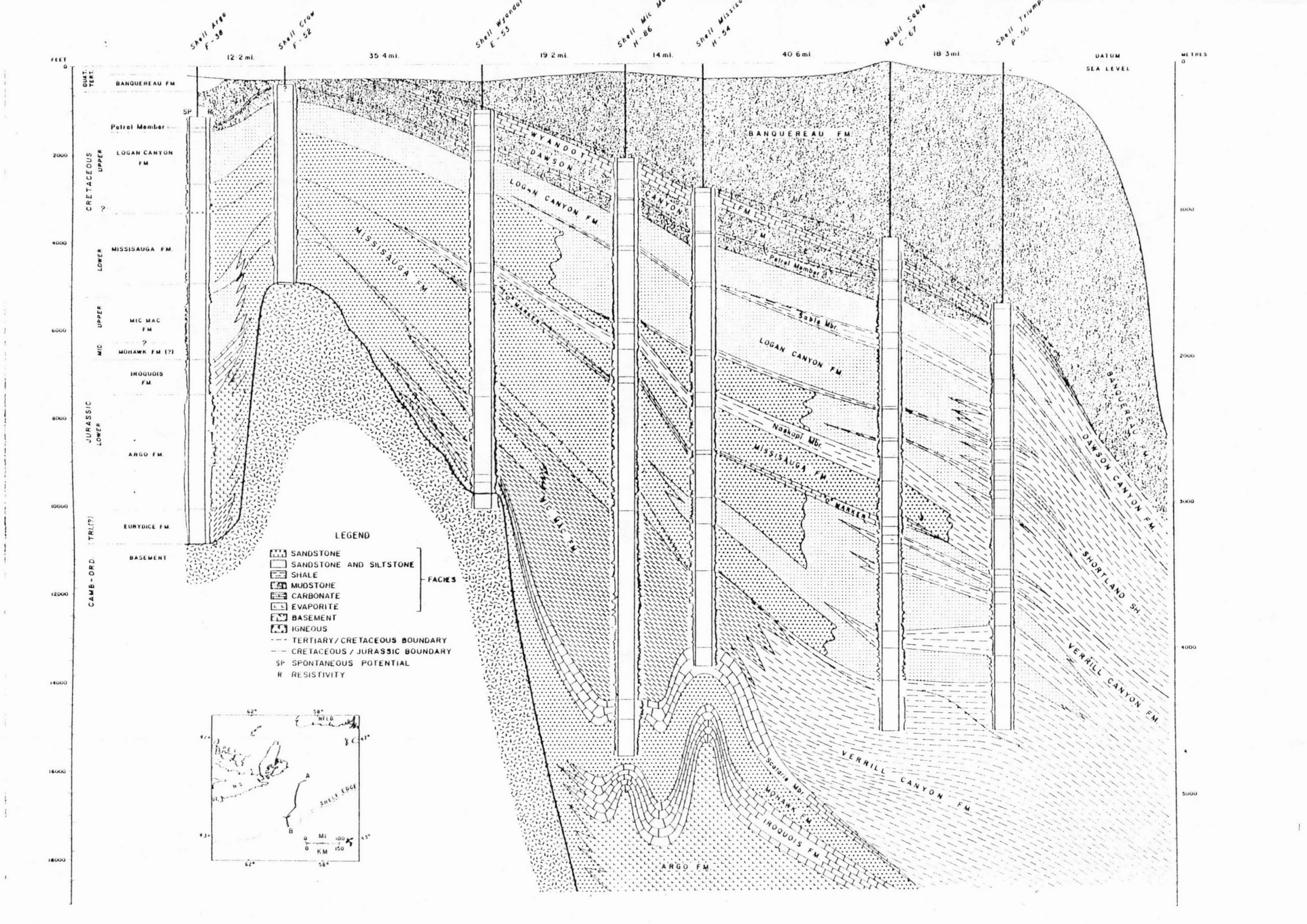
The Scotian Shelf, offshore eastern Canada, has been an active area of deposition during Mesozoic and Cenozoic time resulting in a more or less complete section of clastic, carbonate and evaporitic rocks which represent continental to deep marine environments along a developing passive continental margin. The geologic history of the region indicates the development of the present Atlantic Ocean was initiated in the vicinity of the Scotian Shelf in early-Middle Jurassic time. The geology of the continental margin off Nova Scotia has been studied by McIver (1972), Jansa and Wade (1975), Given (1977) and Eliuk (1978). Figure 1 illustrates the various tectonic elements of the Scotian Shelf. Figures 2 and 3 contain regional strike and dip sections through the shelf.

To date, hydrocarbon accumulations on the Scotian Shelf have been limited primarily to gas, with minor condensate and light oil. Maturation studies by Bujak _et al._ (1977), Purcell _et al._ (1979), Powell (1982) and others have confirmed the existance of an approximately 1500 to 2000m marginally mature section lying above the main zone of hydrocarbon generation. Consequently, only the lowermost Cretaceous and older section (Fig. 5) can be termed fully mature. The marginally mature zone is characterized by the apparent presence of a gas and condensate zone above an oil window. However, this does not conform to the normal hydrocarbon generation sequence of early dry gas, mature oil, overmature condensate and wet gas and finally only dry gas at increasing levels of thermal maturation (Purcell _et al._, 1979). Powell and Snowdon (1979) recognized three families of oils and condensate on the Scotian Shelf. The assignments to different



SEDIMENT THICKNESS AND TECTONIC ELEMENTS – SCOTIAN BASIN

Figure 1



LITHOSTRATIGRAPHIC CROSS SECTION A - B ACROSS SCOTIAN SHELF

Figure 2

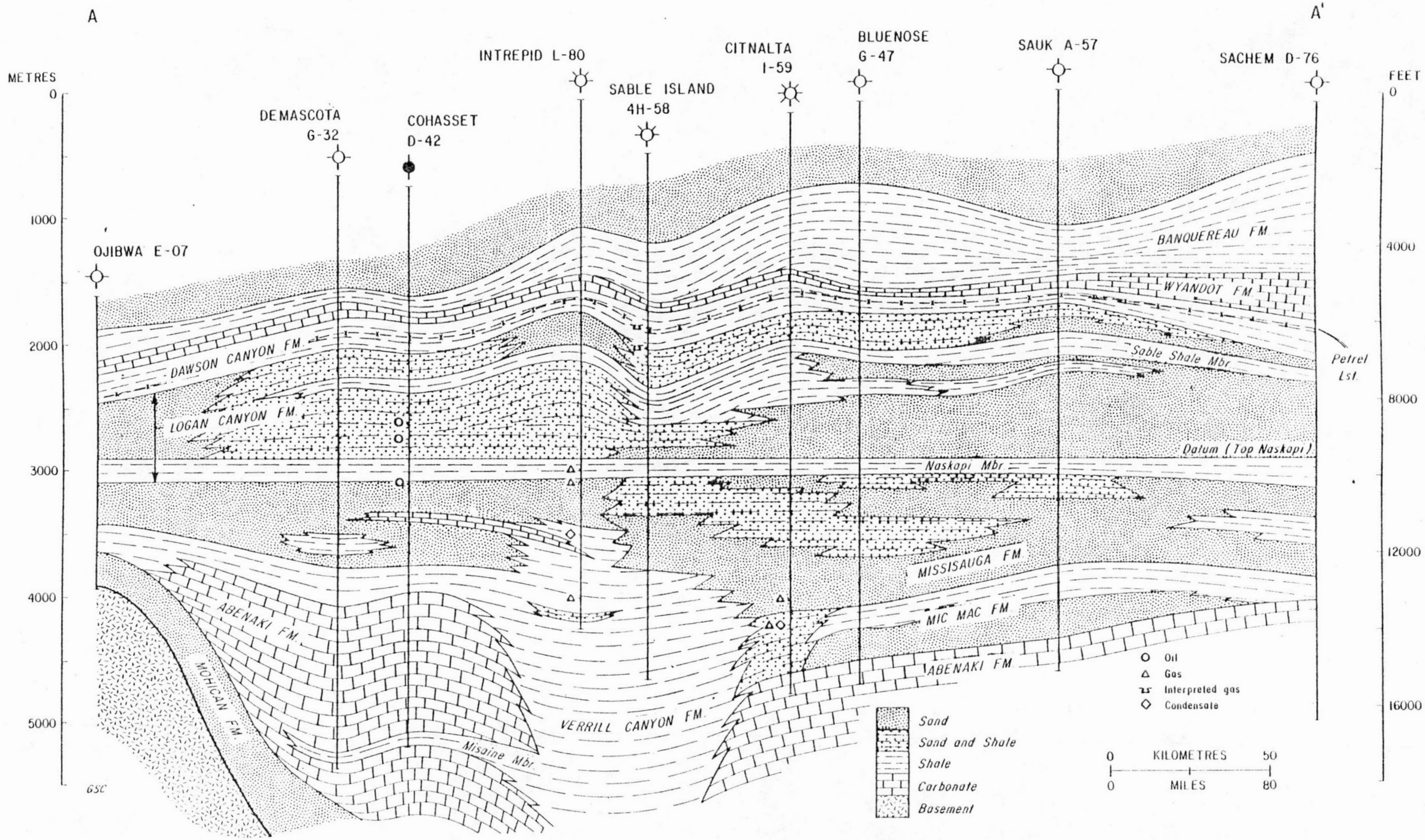
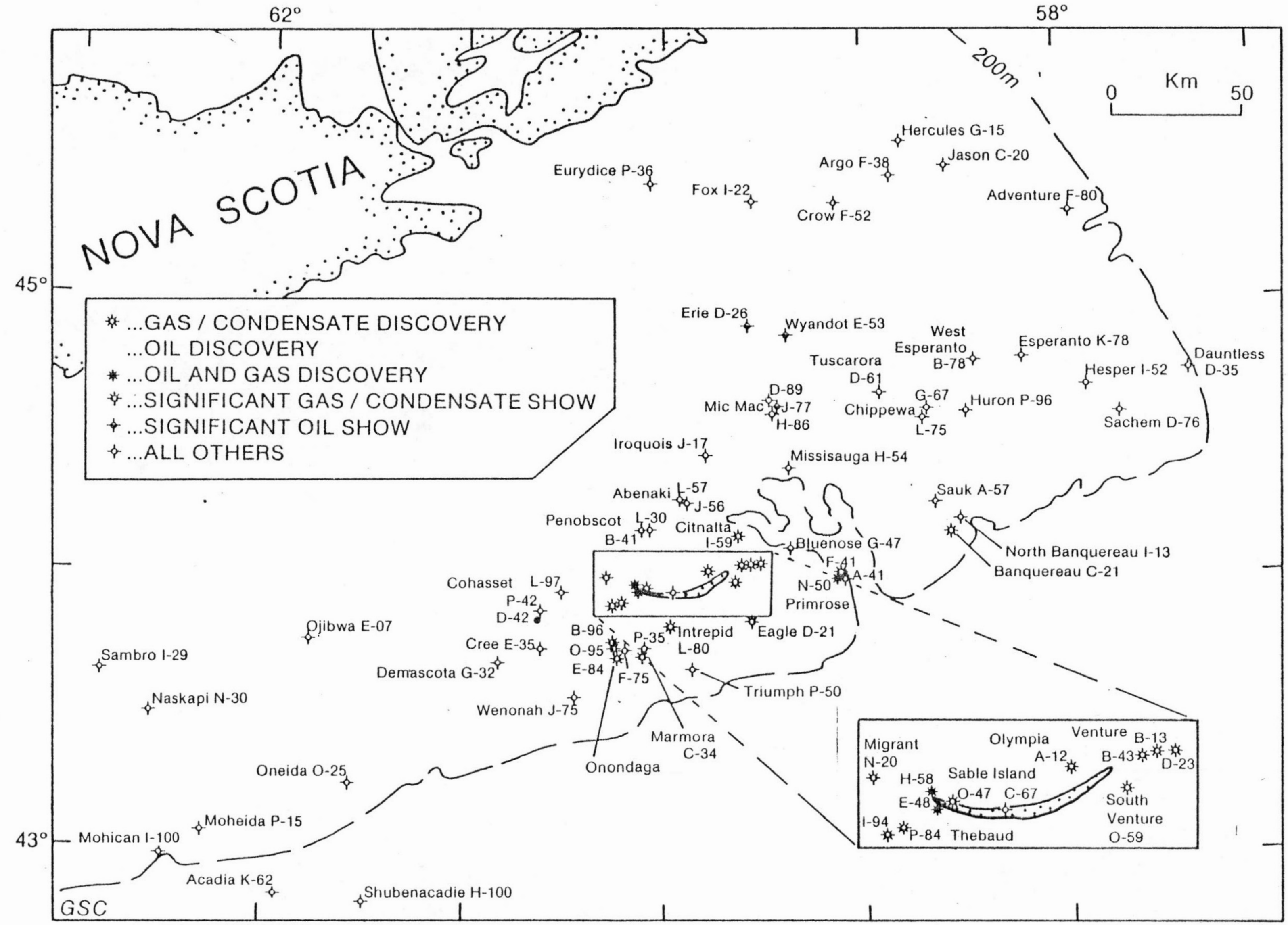


FIG. . STRATIGRAPHIC SECTION - SCOTIAN SHELF

Figure 3



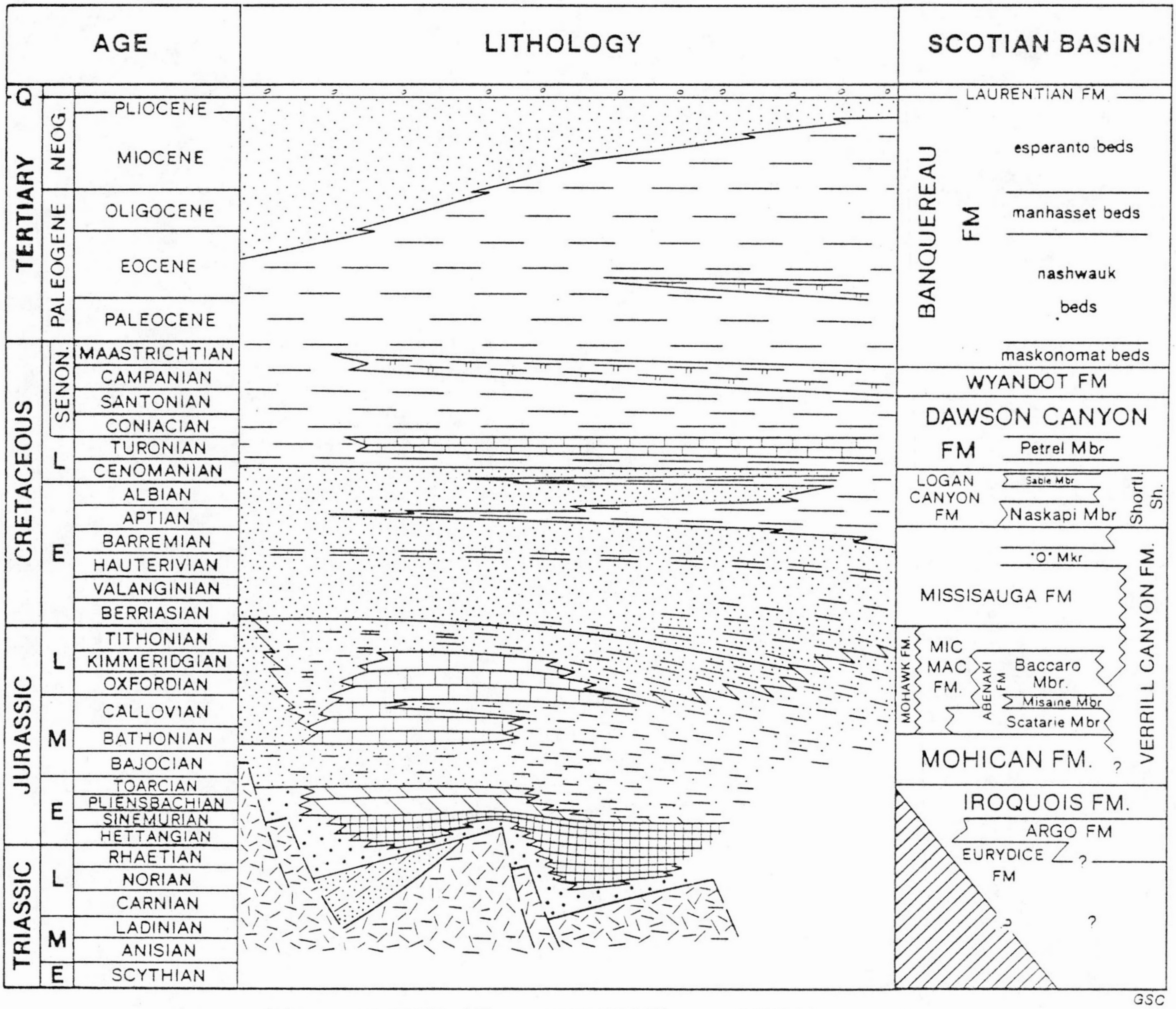
HYDROCARBON OCCURRENCES ON THE SCOTIAN SHELF

Figure 4

categories show an intimate relationship to stratigraphy: that is to the particular formation in which hydrocarbons are reservoired.

The formation of petroleum is principally a thermal maturation process of sedimented organic matter. The exact functional relationship between time, temperature and maturation are not well known (Bostick *et al.*, 1978). The nature of the hydrocarbons generated is primarily a result of the types of organic matter deposited and to a lesser extent, various depositional factors. The predominance of gas and condensate on the Scotian Shelf can be explained by the preponderance of terrestrial organic matter in source rocks within the marginally mature-fully mature zone (Bujak *et al.*, 1977; Purcell *et al.*, 1979). Hydrogen rich components of terrestrial organic matter, such as resinite, are capable of producing significant quantities of liquid hydrocarbons within the marginally mature zone (Powell, 1978; Snowdon, 1980; Snowdon and Powell, 1982). Oil has been discovered in an interpreted case of enhanced maturation of oil prone organic matter in the shallow Upper Cretaceous rocks above the Primrose salt diapir (Rashid and McAlary, 1977). Other oil discoveries on the shelf have been more difficult to explain.

Recent increased activity in exploration on the Scotian Shelf has sparked new interest and provided additional data on the geology and hydrocarbon potential of offshore Nova Scotia. In light of this latest data and recently developed hydrocarbon generation models (Snowdon, 1980; Connan and Cassou, 1980; Snowdon and Powell, 1982; Powell and Snowdon, 1983; Monnier *et al.*, 1983), it has become necessary to re-evaluate the regional hydrocarbon potential. This study investigates the geothermal gradients, maturation profiles and the qualitative and quantitative aspects of potential source rocks in the Scotian Shelf. The project is primarily regional,



GENERALIZED STRATIGRAPHY - SCOTIAN SHELF

Figure 5

however, special areas of interest are covered in detail.

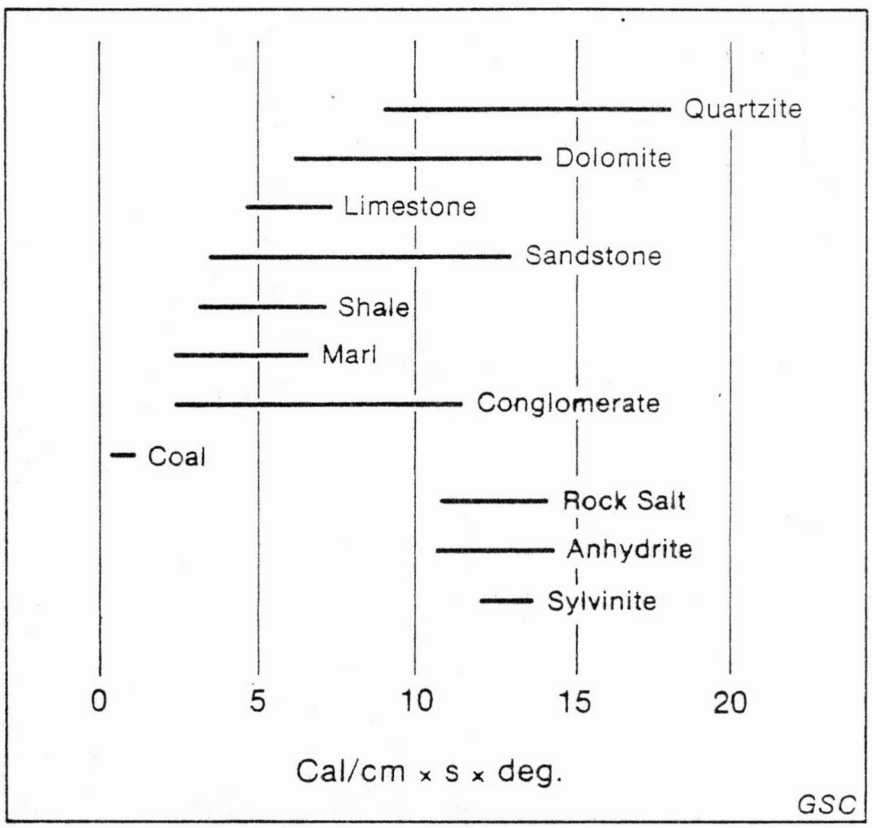
No one paper available from the present literature has considered most of the non-confidential well data relating to the geochemistry, maturation indices and organic matter quantity and types. This study has attempted to compile all of the readily available data on the Scotian Shelf and assimilate it into a comprehensive regional look at the hydrocarbon potential. Data was compiled from the present literature and previously unpublished information on file at the Atlantic Geoscience Centre, Bedford Institute of Oceanography, Dartmouth, Nova Scotia.

I. GEOTHERMAL GRADIENTS ON THE SCOTIAN SHELF

Nearly all geologists and geochemists agree that oil and gas are generated from sedimentary organic matter with increasing temperature as reflected by the geothermal gradient and depth of burial (Philippi, 1965). The geothermal gradient can be important in controlling the types of hydrocarbons generated and their degree of mobility during migration at a given level of maturation. Considering different organic matter types and the time factor, threshold temperatures at various stages of hydrocarbon generation, should vary from basin to basin, except in the case of basins with very high geothermal gradients, where time becomes less important and temperature dominates. In areas of relatively low geothermal gradient, the difference in threshold values may be made up by increasing the time factor. This reflects the fundamental time-temperature relationship to the maturation of organic matter.

The non-linearity of geothermal gradients is well known (Fertl, 1976). Gradients can change through time which may or may not be reflected in maturation profiles. Assuming static heat flux, non-linear gradients can be caused by different thermal conductivities in rocks (Fig. 6), subsurface fluid flow (cooling or heating) and geopressured zones. The non-linearity of geothermal gradients in the upper tens to hundreds of metres of sediment by circulating groundwater is well known, especially in the offshore regions. This particular study and that of Issler (1982), have shown by linearly extrapolating geothermal gradients to the water-sediment interface, the temperature is 10-15°C. Obviously, this is not the actual temperature, but a theoretical temperature based on a linearly extrapolated gradient.

A number of papers have addressed geothermal gradients on the



AVERAGE THERMAL CONDUCTIVITIES OF SELECTED ROCK TYPES
(after Kappelmeyer and Haene, 1974)

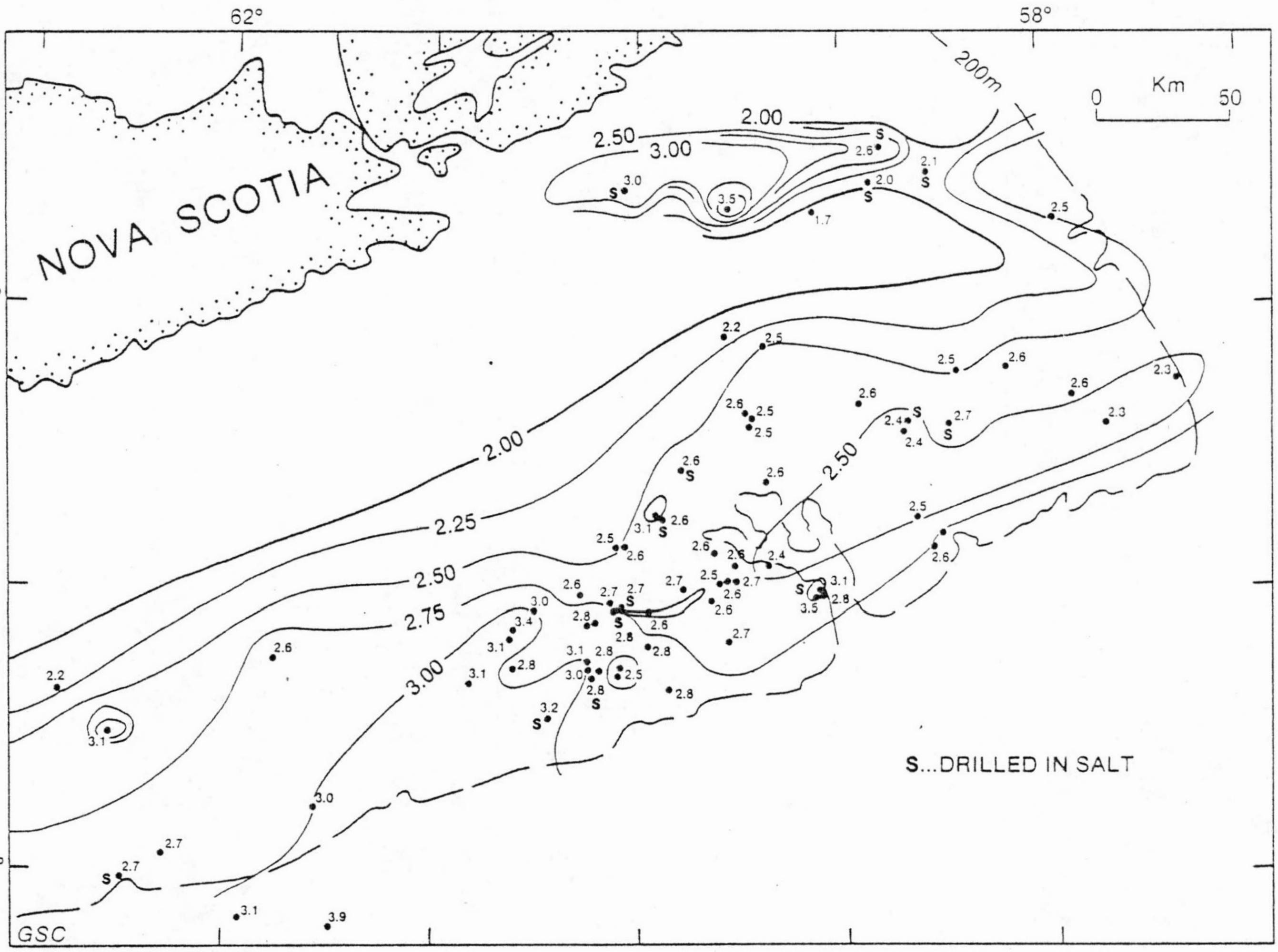
Figure 6

Scotian Shelf (Robbins and Rhodehamel, 1976; Cassou et al., 1977; Purcell et al., 1979) and have suggested average gradients of 2.20°C/100 m and 2.35°C/100 m. However, these values are based on uncorrected well log temperatures and are therefore, under estimates of the true average gradient. Drilling fluids cause thermal cooling of the formation such that temperatures are not representative of the true equilibrium temperature. Bostick et al. (1978) have estimated the uncertainty of isolated temperature readings may be as high as 15-20%. It seems doubtful whether uncorrected temperatures and gradients are useful: except on a gross relative scale.

Issler (1982) and this author have used a theoretical method for correcting temperatures from well logs as discussed by Dowdle and Cobb (1975) and Fertl and Wichmann (1977). Using this method, Issler (1982) calculated an average bottom hole geothermal gradient of 2.66°C/100 m for the Scotian Shelf.

A number of anomalies, particularly low gradients, were noted in Issler's work. On closer examination, it was found that several wells had their bottom hole temperatures measured in salt. Salt has a very high thermal conductivity relative to most other rock types and therefore is not representative of the overlying section. Gradients were recalculated at the deepest temperature measurement above the salt. Using the values of Issler (1982), corrected gradients over salt and additional wells, an average bottom hole geothermal gradient of 2.69°C/100 m was calculated. Gradients ranged from 1.7°C/100 m to 3.51°C/100 m.

Figure 7 is a contour map of geothermal gradients on the Scotian Shelf. The map was contoured with careful consideration of the major tectonic elements of the shelf (Fig. 1). Gradients in this study are quoted to two decimal places. This should not be taken as indicative of accuracy



GEOTHERMAL GRADIENTS° C/100M - SCOTIAN SHELF

Figure 7

TKN/84

to hundredths of a degree, but rather a means of facilitating contouring at 0.25°C/100 m intervals. Temperature values on well logs are normally only quoted to tenths of degrees.

Three main factors affect the patterns seen on geothermal gradient maps (Tissot and Welte, 1978):

1. Differences in primary heat flux
2. Differences in thermal conductivities in the stratigraphic column (a function of mineralogy, pore fluids, porosity and permeability)
3. Subsurface fluid flow.

On the Scotian Shelf it appears that 1 and 3 have only minor or local influence. Figure 7 in general agrees with Issler's (1982) conclusions that areas of thicker sediment accumulations are marked by higher geothermal gradients than sediments overlying shallow basement. The gradients in most of the Sable Subbasin are somewhat higher than in the Abenaki Subbasin. Higher heat flow in the basins is believed due to thick salt accumulations at depth and the overall low conductivity of sediments above the salt. Low gradients are due to the lack of salt and relatively high conductivity sediments above positive basement features (Issler, 1982). Theoretical models of heat flow are discussed by Issler (1982) and will not be dealt with here.

A closer examination of the geothermal gradients and geology on the Scotian Shelf suggests an important lithological control as well as the basement topography and salt distribution effects discussed above. A general increase in geothermal gradient in a seaward direction is apparently parallelled by an increasing shale/sand ratio. Relative volumes of sand and shale in the respective subbasins may account for some of the differences observed in the heat flow. The north part of the Sable Subbasin most affected by the progradation of the Sable Delta over the North Sable High has gradients more similar to those found in the Abenaki Subbasin than those in the shalier southern Sable Subbasin.

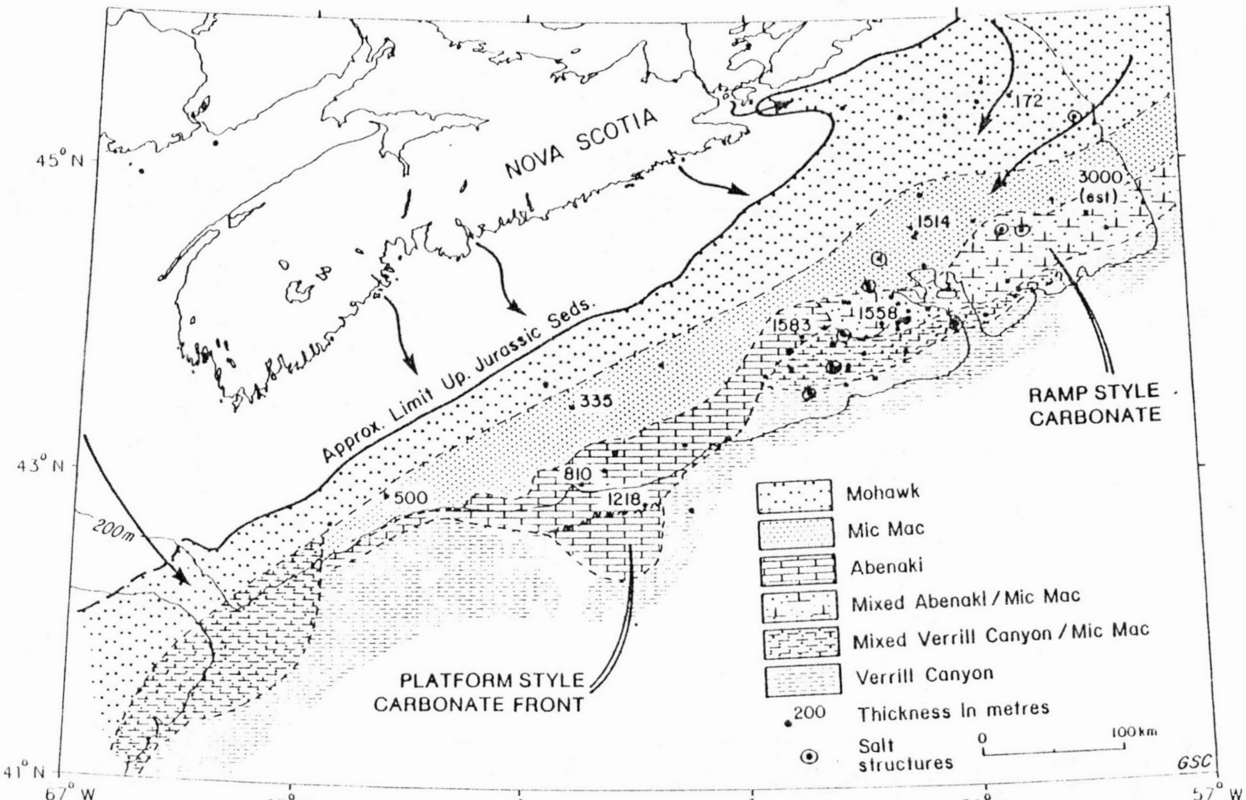
A broad elongate low in the Abenaki Subbasin corresponds to the Upper Jurassic, Baccaro Member of the Abenaki Formation (Fig. 8). The low appears to die out in the vicinity of the North Sable High (Fig. 9). The Baccaro Member carbonates here, reach thicknesses of 1000 m and have very low porosity and permeability (Eliuk, 1978). The Abenaki Formation also contains a significant siliciclastic component. A thick section of Cretaceous sands and shales overlie the carbonates. A decrease in porosity generally increases the thermal conductivity of a rock (Hunt, 1979).

The cumulative evidence above points to a thick section of relatively high conductivity rocks (non-porous limestones and coarse clastics), which have resulted in a broad geothermal low. The fact the geothermal trend follows the carbonate bank suggests the high thermal conductivity of the limestone is the dominant influence over the conductivities of the Cretaceous sand-shale sequence above.

A southwest trending geothermal high exists west of Sable Island. The zone is characterized by gradients exceeding 3.0°C/100 m. The north boundary of the zone is bordered by the carbonate platform and cuts across the platform west of Demascota H-32, continuing out onto the slope. The eastern limit appears to be irregular.

The high gradients can be attributed to one of the following:

1. a predominance of low thermal conductive lithologies
2. subsurface fluid flow
3. deep seated fault structures which may be associated with salt tectonics



FACIES DISTRIBUTION - ABENAKI AND EQUIVALENT FORMATIONS

Figure 8

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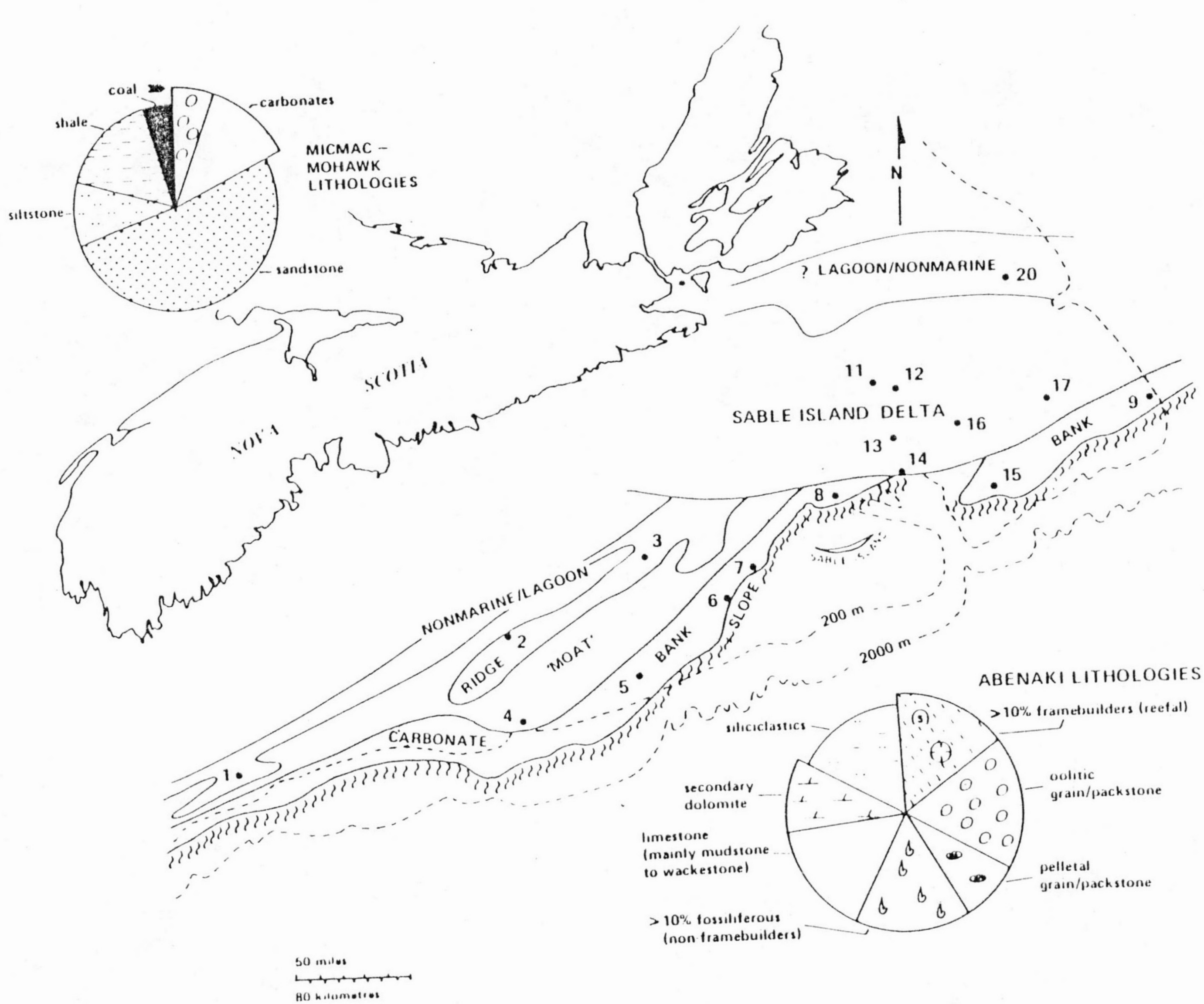

coal
carbonates
shale
MICMAC –
MOHAWK
LITHOLOGIES
siltstone
sandstone
N
? LAGOON/NONMARINE
20
NOVA
SCOTIA
11
12
SABLE ISLAND DELTA
16
17
9
BANK
13
14
15
8
3
7
6
SLOPE
NONMARINE/LAGOON
2
RIDGE
'MOAT'
BANK
5
200 m
2000 m
4
CARBONATE
1
ABENAKI LITHOLOGIES
>10% framebuilders (reefal)
siliciclastics
oolitic
grain/packstone
secondary
dolomite
limestone
(mainly mudstone
to wackestone)
pelletal
grain/packstone
>10% fossiliferous
(non framebuilders)
50 miles
80 kilometres

Figure 9

4. higher primary heat flux, particularly in the basement hinge zone.

On closer examination, the region of high gradients may be restricted to a narrow band which parallels the carbonate front. Faults associated with the carbonate front may have provided local conduits for relatively hot subsurface fluids. Flow may be further enhanced by dolomitized zones such as those intersected in the Acadia K-62, Cohasset L-97 and Demascota H-32 wells. Fluids would be provided by dewatering of shales, seaward of the platform. The distribution of overpressuring will be an important consideration. Whether the fluids can conduct enough heat or have sufficient flux to account for the thermal anomalies is open to speculation. Simple variations in lithological conductivity cannot be used to explain the high gradients seen here. In fact, considering the thick carbonate section in these wells, this area would likely be a geothermal low. There is no evidence for deep seated salt structures or higher primary heat flux; though variations in primary heat flux associated with the basement hinge zone cannot be ruled out. Oneida O-25 does not lie along the carbonate front, but was drilled in a graben structure which may account for the heat anomaly at this well. Alternatively, Oneida O-25 may be connected to the proposed subsurface system, though it does not lie on the front. The proximity of this well to the basement hinge zone may be significant. Cree E-35 was drilled seaward of the carbonate front and is relatively hot compared with the rest of the basin. The heat anomaly at this well is accounted for by a thick shale section in the basin.

It has been observed that wells drilled on the crests of salt diapirs often possess gradients which are greater then regional trends. There appears to be a lithological control on this phenomenon. Gradients measured within dominantly shale sequences above salt structures commonly show elevated temperatures (Onondaga wells and Wenonah J-75). The combined effect of increased heat flux from salt and the blanketing effect of shale results in enhanced gradients. Highly conductive lithologies above salt produce the opposite effect. In wells not drilled over salt diapirs, or drilled on the flanks of salt structures, the enhancement is not seen, as there is relatively moderate heat flux from depth.

Wells drilled in the outer part of the Scotian Shelf have encountered overpressured sands and shales in the Early Cretaceous section (Jansa and Wade, 1975). Abnormal pressures are caused by the inability of fluids to migrate. Abnormal pressures are almost always accompanied by (Fertl, 1976):

1. increase in porosity
2. decrease in the pore water salinity
3. increase in temperature
4. increase in soluble organic matter

Higher temperatures encountered within overpressured zones will result in non-linear geothermal gradients and enhanced maturation. The effect of overpressuring can be clearly seen in the South Venture O-59 and Banquereau C-21 wells (Appendix F). Geothermal gradients of wells measured in the overpressured zone may not be representative of the entire well.

A number of thermal anomalies, such as at Naskapi N-30 are presently being studied using vitrinite reflectance and time-temperature index. The purpose is to determine if the temperature in these wells is sufficient to account for the maturation observed.

II. ORGANIC MATTER ON THE SCOTIAN SHELF

II.1 Organic Matter Types

Organic matter types can be studied and classified by a number of techniques, including geochemistry and petrography. The technique found most practical and used by Bujak *et al.* (1977) for the Scotian Shelf, classifies organic components under transmitted light. Four morphological terms have been used: amorphogen, phyrogen, hylogen and melanogen. These correspond to amorphous, herbaceous, woody and coaly respectively. The relationship between the transmitted light based classifications and other common techniques is illustrated in Figure 10. The data used in this section of the study is from Bujak *et al.* (1977) and unpublished data kindly supplied by M.S. Barss of the Atlantic Geoscience Centre.

Oil and gas are formed by the thermal maturation of organic matter during subsidence. The nature of the hydrocarbons produced is a function of the type of organic matter and the level of maturation attained. Various organic matter types with different kinetics of transformation, possess different threshold temperatures at which they begin to generate hydrocarbons (Tissot and Welte, 1978; Powell, 1982). Using the terms proposed by Bujak *et al.* (1977), oil is most likely to be generated from amorphogen. Phyrogen and hylogen are capable of producing oil at higher levels of maturation, but like melanogen are generally considered gas prone. Maturation commences earlier and proceeds more quickly in amorphous material (Bailey, 1981). Phyrogen and hylogen, though considered gas prone, do not approach the potential for gas or oil produced from amorphogen (Fig. 11).

Optical methods define the source potential of a sediment in a qualitative subjective manner. Powell *et al.* (1982) have noted an apparent lack of correlation between transmitted light petrography and source

	SAPROPELIC			HUMIC	
KEROGEN (by transmitted light)	Algal	Amorphous	Herbaceous	Woody	Coaly (inertinite)
COAL MACERALS (by reflected light)		Liptinite (Exinite)		Vitrinite	Inertinite
	Alginite	Amorphous	Sporinite Cutinite Resinite	Telinite Collinite	Fusinite Micrinite Sclerotinite
KEROGEN (by evolutionary pathway)	Types I,II		Type II	Type III	Type III
H/C	1.7-0.3		1.4-0.3	1.0-0.3	0.45-0.3
O/C	0.1-0.02		0.2-0.02	0.4-0.02	0.3-0.02
ORGANIC SOURCE	Marine and lacustrine		Terrestrial	Terrestrial	Terrestrial and recycled
FOSSIL FUELS	Predominately oil Oil shales, boghead and cannel coals		Oil and gas	Predominately gas Humic coals	No oil, trace of gas

FIGURE 10: Classification of organic matter in sedimentary rocks (from Hunt, 1979).

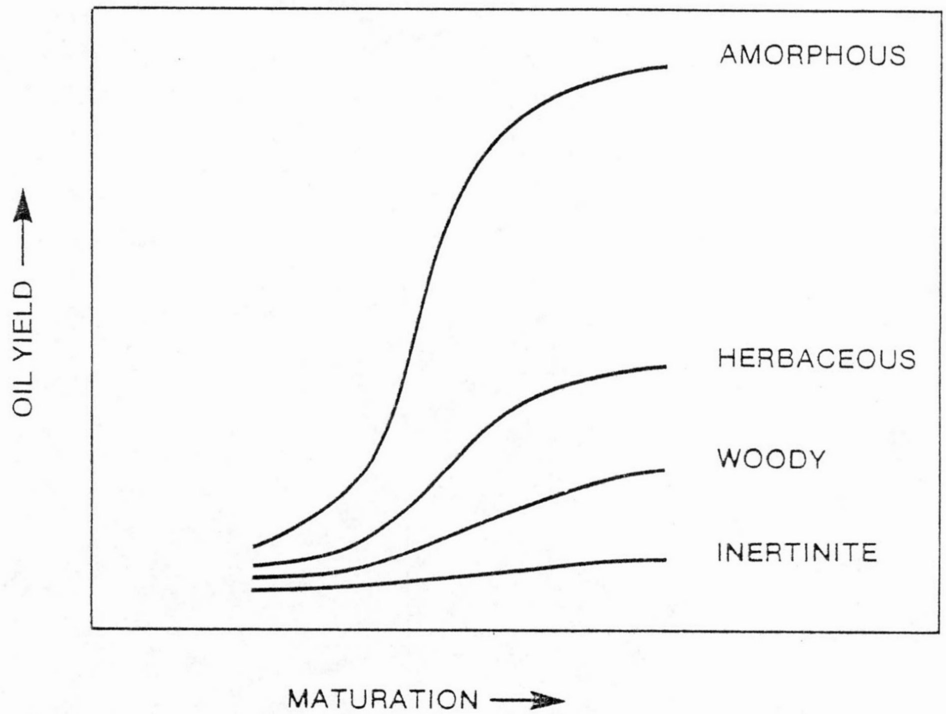


Figure 11

RELATIVE YIELDS FROM DIFFERENT ORGANIC MATTER TYPES
(from Bailey, 1981)

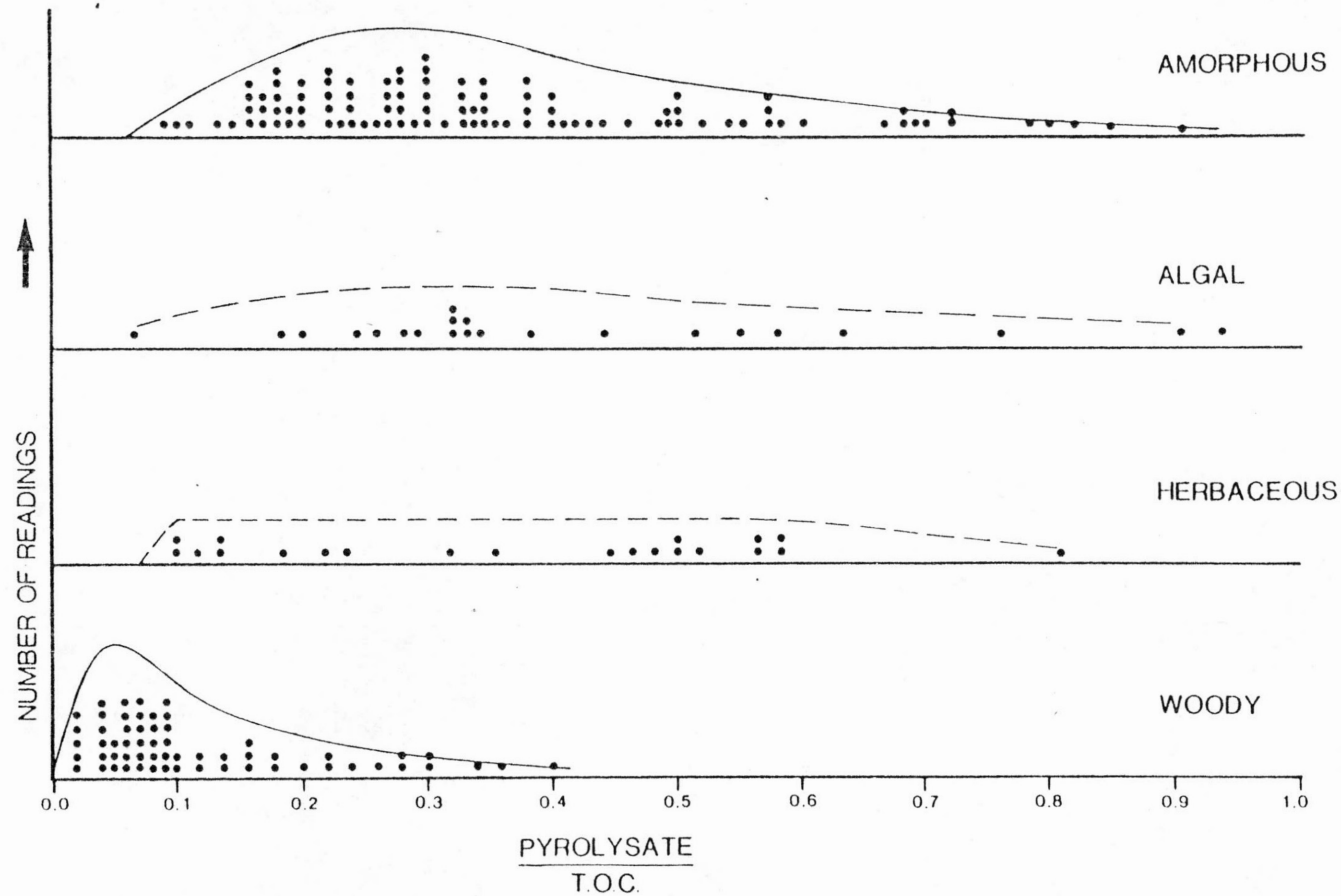
GSC

potential as defined by geochemistry. The primary source of error is a result of the failure to consistantly distinguish between hydrogen rich and hydrogen poor components in amorphous organic matter or degraded herbaceous material. Chemical methods may aid in identifying hydrogen rich organic matter, however, geochemistry suffers from bulk sampling which often fails to detect cavings, contamination and reworking.

Venkatachala (1981) has attempted to resolve the problem of distinguishing variable source potential in amorphous organic material (amorphogen) by developing a detailed classification of amorphous matter using transmitted light microscopy. The respective source potentials and paleoenvironments are defined qualitatively, but have not been calibrated to geochemical parameters. There is also some doubt that each one of the categories in the classification can be recognized consistantly in light of subtle textural and colour variations.

Bailey (1981) has noted the apparent oil proneness of both amorphous algal material and herbaceous organic matter, though both exhibit a considerable range in source richness (Fig. 12). The conversion of organic matter to the amorphous state is of importance primarily in increasing the total yield of hydrocarbons rather than their oil proneness (Bailey, 1981). Although amorphous matter is generally more oil prone, it is not automatically richer than herbaceous organic matter. However, there will be considerable differences in the nature of the hydrocarbons produced. These apparent variations in source quality suggest a continuum of hydrocarbon potential will be displayed by different types of organic matter.

Visual organic matter typing should only be used in a semi-qualitative manner. Visually determined amorphous and herbaceous matter should be considered oil prone only when supporting geochemistry is available or when



AMORPHOUS
ALGAL
HERBACEOUS
WOODY
NUMBER OF READINGS
0.0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1.0
PYROLYSATE
T.O.C.

Figure 12

proven potential source sections can be laterally traced with some degree of confidence. Hylogen and melanogen generally have low potential for oil on the Scotian Shelf.

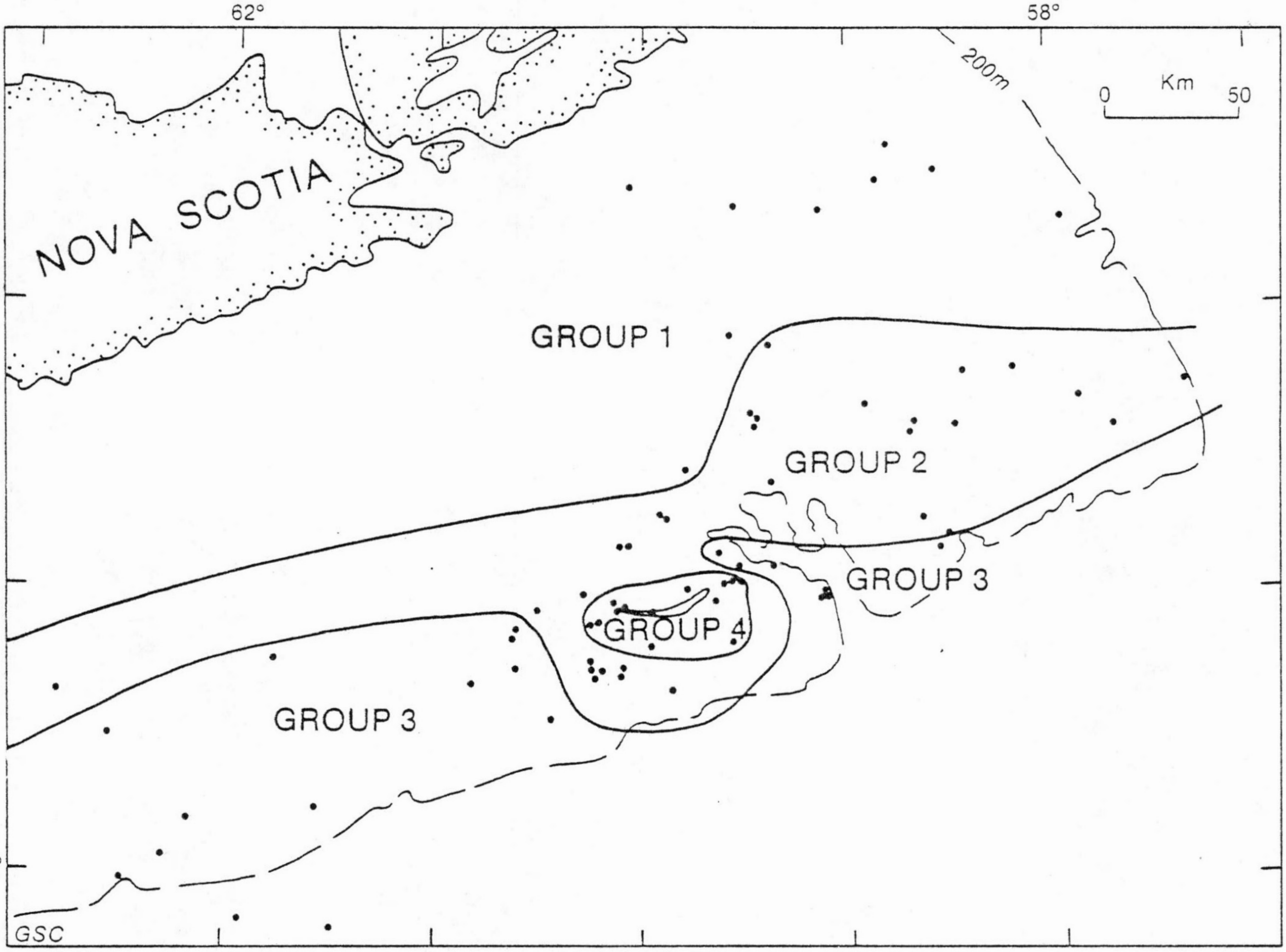
Observation of the distribution profiles (logs) of organic matter types on the Scotian Shelf has determined that there are four major groupings which are controlled by basinal position, depositional environment and age. Figure 13 shows the distribution of the groupings on the shelf. Figure 14 displays the relative organic matter types through time.

Using percentage of amorphogen as the principal criteria for source potential, it is evident basinal position and age of the sediments are important considerations. Depositional environment is critical when investigating relative types of organic matter deposited and their preservation potentials. It often allows the geologist to extrapolate to unexplored areas of the basin. Amorphogen is common in marine strata and generally absent in non-marine environments. Phyrogen is common in most sediments, whereas hylogen and melanogen make up the bulk of organic matter in marginal marine and non-marine environments.

The quantity of organic matter ultimately preserved in sedimentary rocks depends on (Dow, 1977):

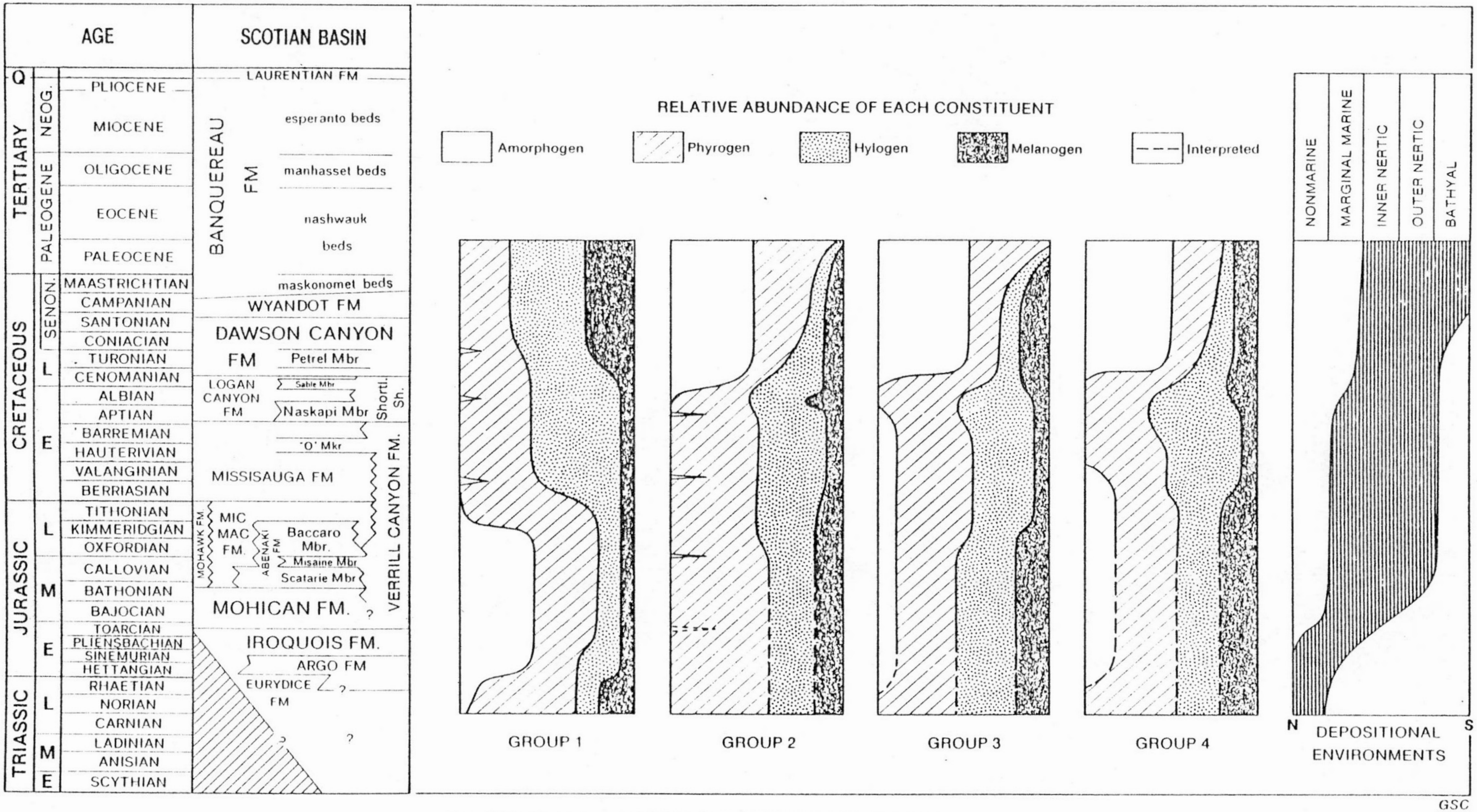
1. sedimentation rate
2. primary organic productivity
3. depositional and post-depositional environment.

Sedimentation rate refers to the dilution factor; and post-depositional environment alludes to reworking of sediments and incorporated organic matter. In environments where the pattern of deposition and erosion is constantly shifting, such as in deltas, the amount of reworked material in sediments may be as much as 90% of the total organic matter, particularly



DISTRIBUTION OF ORGANIC MATTER TYPE - SCOTIAN SHELF

Figure 13



RELATIVE ORGANIC MATTER DISTRIBUTION ON THE SCOTIAN SHELF

Figure 14

at the base of a transgressive sequence (Staplin, 1969). Reworked organic matter may not yield significant quantities of hydrocarbons upon maturation.

II.2 Organic Matter Distribution in Time

The geology discussed in this section is taken exclusively from Jansa and Wade (1975) unless otherwise stated.

Triassic and Early Jurassic sedimentation within the Scotian Shelf was localized in graben structures and was non-marine in character. Consequently, amorphogen is absent or in small quantities and total organic matter is low, hence no source rock potential is indicated. In Early Jurassic time the region was flooded by a shallow epicontinental sea resulting in the deposition of a dominantly evaporitic sequence, the Argo Formation. Amorphogen appears in significant quantities (10-40%) in the Orpheus Graben, but again the total organic matter is very low. The anhydrite and dolomite beds of the overlying Iroquois Formation were deposited in a sabkha, shallow marine environment. Because of the oxic conditions prevalent in this environment, there would be low preservation potential for organic matter. A small amount of amorphogen (10-20%) may be found where marine conditions prevailed. The late Early-early Middle Jurassic time marks the return of continental deposition represented by the Mohican Formation.

The Scotian Shelf from late Middle Jurassic to Kimmeridgian time is marked by a transgressive cycle resulting in the deposition of carbonates and clastics in a shallow sea less than 100-200 m deep. However, distal shale deposition of the Verrill Canyon Formation shows evidence of deeper water. Significant deposition of amorphous type organic matter can be expected. The degree of marine influence, depth of water, the magnitude of a terrestrial component and preservation potential would be expected to change with basinal position.

The Verrill Canyon Formation consists of shales deposited in prodelta, distal shelf and slope environments in water ranging from deep neritic to epibathyal. The lateral relationship of these facies are responsible for the relative percentages of amorphous matter seen between areas 1-4 (Fig. 13). Where the Verrill Canyon Formation is laterally equivalent to the MicMac Formation the shale becomes silty and terrestrial organic matter is dominant. Verrill Canyon shales equivalent to the Abenaki Formation carbonates are often calcareous, with some terrestrial organic matter evident. Evidently, the depocenter of the Sable Subbasin and the area to the southwest were preferential sites of amorphogen accumulation in the Late Jurassic.

A regression in the Late Jurassic-Early Cretaceous resulted in the influx of coarse clastic material which were ultimately deposited within a large deltaic complex (Missisauga Formation). Carbonate deposition persisted to the southwest on the LaHave Platform. Amorphogen within the delta complex is generally less than 10%, except for the occasional shale pulse when amorphogen can constitute more than 25% of the total organic matter. The previously amorphogen rich Sable Subbasin depocenter begins to receive terrigenous material from the delta complex as it progrades across the North Sable High. Verrill Canyon prodelta shales contain a significant quantity of terrestrial material, consequently amorphogen only constitutes 10-20% of the organic matter. Amorphogen froms 10-30% of the organic matter in the vicinity of carbonate deposition at this time.

Rapid regional transgression commencing in the late Early

Cretaceous and lasting into the Tertiary, drowned much of the shelf, resulting in dominantly marine depostion. The relative percentage of amorphogen within the sediments prograded landward as the marine transgression proceeded. By the end of the Cretaceous, organic matter at the shelf edge consisted of greater than 50% amorphogen.

It is clear that sediments which can be considered as oil source rocks are limited to the Late Cretaceous, Late Jurassic and local shale pulses throughout the section. Subsequent discussion in this paper will show much of the Late Cretaceous to be immature and therefore possessing only limited potential. Distal marine shales of the Late Jurassic appear to have the greatest potential for liquid hydrocarbon generation. Sediments dominated by terrestrial organic matter may have potential for some gas and waxy oil, assuming sufficient maturation is present. Early and Middle Jurassic rocks may contain significant amorphogen, but the total organic matter present is low, resulting in a poor rating.

II.3 Quantity of Organic Matter

Total organic carbon (TOC) is a quantitative measurement of the amount of organic matter and the approximate source potential within a sedimentary sequence. A variety of lower limits for TOC have been proposed in the literature (Ronov, 1958; Schrayer and Zarella, 1963; Hedberg et al., 1979). Welte (1965) indicated under certain favourable conditions, 0.5% TOC could be sufficient for the generation of significant quantities of hydrocarbons. However, it is probably unrealistic to preclude any sections below a rigidly established minimum (Snowdon and McCrossan, 1973). Tissot and Welte (1978) point out minimum values are significant because critical levels of hydrocarbons must be generated before expulsion can take place from source rocks. In the overmature stage, where only dry gas is produced, minimum TOC values have little meaning as they merely indicate a residual amount of organic matter.

The generally accepted lower limits for potential source rocks are 0.5% TOC for shales and 0.3% TOC for carbonates. Carbonate rocks generate more hydrocarbons for the same amount of organic matter and therefore possess a lower mimimum than shales (Hunt, 1979). Realistically, minimum values should probably be greater because of the paucicity of reworked organic matter in most rocks. Dow (1978) indicates 0.8-2.0% TOC is the normal range for most acknowledged source beds. Hedberg's et al. (1979) studies indicate sections with significant gas generation have at least 0.4% TOC, but rocks ultimately classed as potential petroleum source beds contain in excess of 1.5% TOC. Organic carbon data should be considered on a relative basis rather than an absolute scale of organic richness.

Measurement of TOC alone is insufficient criteria for identifying potential source beds. At any one time, transported terrestrial material, oxidized aquatic and recycled organic matter can make up the bulk of organic carbon in a sample: up to 4.0% TOC. Obviously, this must be classed as a poor source rock (Demaison and Moore, 1980).

A number of factors determine the preservation potential of organic matter in sedimentary environments (Staplin, 1969; Durand, 1980; Demaison and Moore, 1980).

Biological

1. primary productivity in the water and on land
2. biochemical degradation of organic matter by aerobic and anaerobic microbes and metazoans
   - anaerobic degradation is less efficient and results in a more

lipid rich residue, and a significant fraction consists of the bacterial biomass itself

- rates of anaerobic and aerobic degradation are nearly identical

Physical

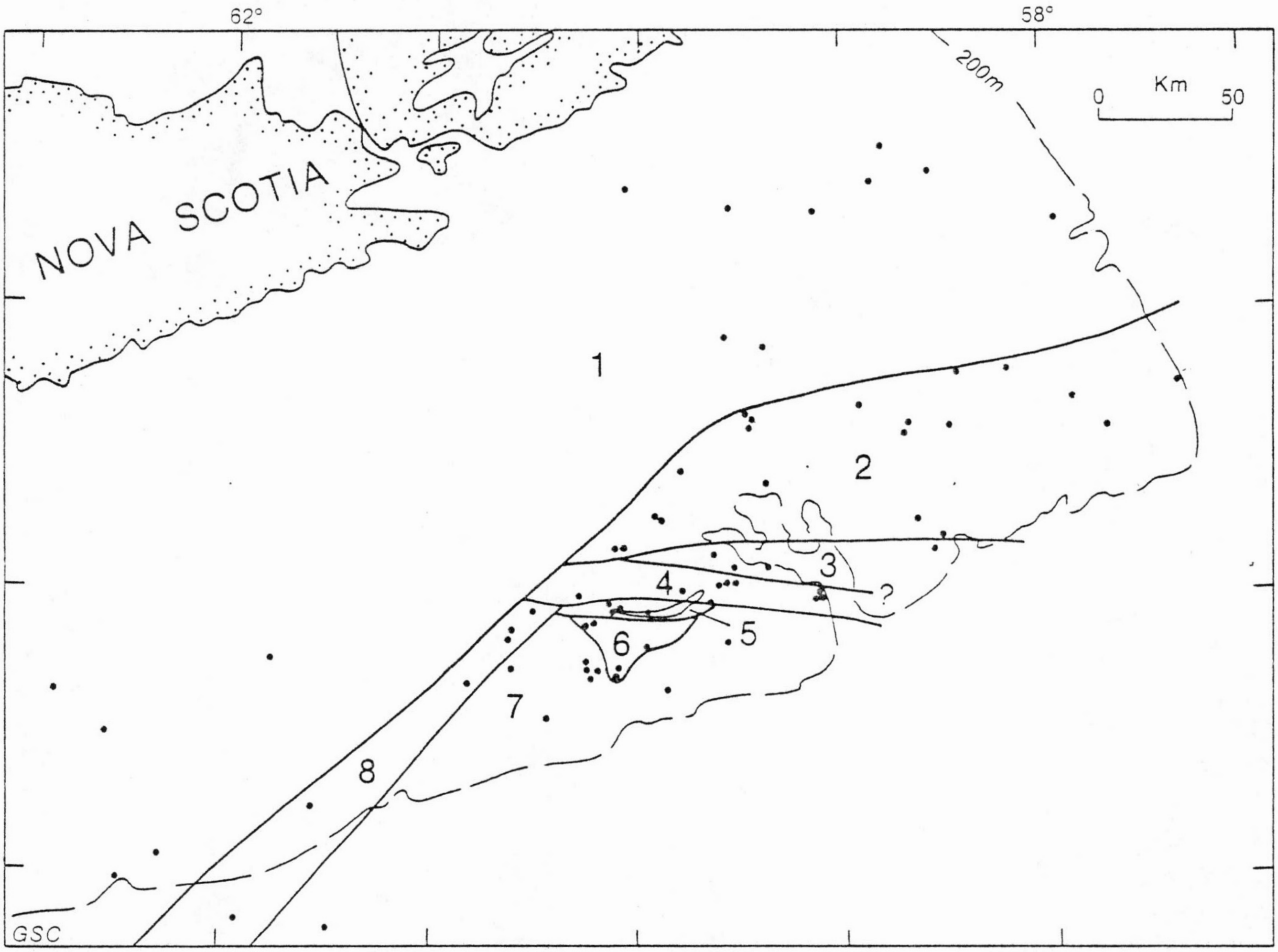
1. modes of transport-chemical transformation, solution, sorting, ingestion and precipitation
2. sediment particle size-refering to the colloidal nature of organic matter and exposure to oxidizing conditions
3. sedimentation rates-the dilution factor

Under the oxic water column, variations in TOC are related to sedimentation rates with little influence of primary productivity, which is compensated for by the number of scavenging and degrading organisms. In the anoxic environment, both sedimentation rates and surface primary productivity cause fluctuations in TOC content (Demaison and Moore, 1980).

Low energy environments and potential areas of anoxia are preferential locations for organic matter accumulation and the development of source beds. These include (Demaison and Moore, 1980; Durand, 1980):

1. depressions in continental shelves and silled basins
2. base of the continental slope
3. deltaic shale beds (up to 4 times more TOC than sandy channels)
4. large anoxic lakes
5. anoxic water layers in the open ocean and in areas of upwelling. Evaluating paleogeography and paleoenvironments can be important when delineating potential petroleum source rocks.

Emperical observation of TOC data for the Scotian Shelf has allowed delineation of several patterns (Fig. 15). Trends in TOC appear to be con-



TRENDS IN TOTAL ORGANIC CARBON - SCOTIAN SHELF

Figure 15

trolled by lithology and depositional environment. In the Sable Subbasin, TOC appears to occur in bands, relative to age. Distribution of TOC in the Abenaki Subbasin appears to be relatively uniform, though this may be more apparent than real due to limited data. Table 1 provides a comparison of TOC between various areas on the shelf.

The variation in TOC trends, in two closely spaced wells, Thebaud I-94 and P-84, help to illustrate the effects of depositional environment and preservation potential. The highly fluctuating TOC in the Lower Cretaceous, Missisauga Formation of Thebaud P-84, results from alternating shale and sand depositional influences. In Thebaud I-94, the lower and uniform TOC in this interval, reflects less organic matter deposited and/or lower preservation potential.

In the data presented, TOC on the Scotian Shelf certainly exceeds the generally accepted minimum and is often greater than 2.0%, especially in the Upper Cretaceous section. Lower Cretaceous, Upper and Middle Jurassic sediments usually range from 0.5-1.5% TOC, but with values greater than 3.0% being not uncommon. Early Jurassic and Triassic sediments are generally less than 0.5% TOC. No organic rich zones have been intersected in the Abenaki Formation (Eliuk, 1978). Some variation in the TOC data in the Abenaki Formation may be accounted for by the tendency of organic carbon to increase with clay content in carbonates (Hunt, 1979).

The Verrill Canyon Formation, identified as a potential source rock by Powell (1982), contains about average total organic carbon for shales. However, these values are lower than many shales identified as rich source rocks (Tissot and Welte, 1978). There is some question as to the relative source potential of Verrill Canyon shales deposited in a deep marine environment and those deposited as prodelta shales. Modern prodelta muds of the

TABLE 1 Distribution of Organic Carbon On the Scotian Shelf

AREA	UPPER CRETACEOUS	LOWER CRETACEOUS	UPPER JURASSIC	MIDDLE JURASSIC	LOWER JURASSIC
Orpheus Graben La Have Plfm	Montagnais I-94 ave. 0.1-0.2% Ojibwa E-7 & Sambro I-29 Logan Cn Fm ave. 1-1.5%, pulses to 3% Jason C-20 4-4.5%	to TD Up Miss 1-1.5% Nask. ave 1.5-2% Sambro 2-10% Low Miss 2-2.5% in Up Miss	Mic Fm ave. .5-.75% one pulse to 3%	Mohn Fm ave .5% one pulse to 2%	Iroq Fm ave .5%
Abenaki Subbasin 2	ave .5-1% occ pulse to 1.75% grad incr with depth	Logan Cn Fm ave 1.5-2% pulses to 3% except Penobscott B-41 ave .5-1%	Miss-Mic Fm Penob B-41 & Mic D-89 ave. .5%, pulses to 1.75% some sect. below .25% Sach D-76 & Sauk A-57, ave 1% pulses to 2.5%	Aben Fm ave 1-2% pulses to 5%?	
SABLE SUBBASIN 3	ave 1-1.5% always >.5% Up Nask ave >1.5% Low Nask ave <.75%	to mid Miss Fm ave 1-1.5% pulses '3% always >.5%	Low Miss/Mic Fm ave >2% very rare <1% rare <1.5%		
SABLE SUBBASIN 4	ave .5-1% pulses to 2% occ <.5% Venture D-23 ave .5-.75%	Low Logan Cn Fm 1-1.5% pulses to 3% rare <.5% Nask ave 1.5%	Miss Fm ave .5-1% pulses to 3% occ <.5%	Mic Fm ave 1-1.5% pulses to 3% always >.5%	
SABLE SUBBASIN 5	Daw Cn Fm >4% decr to base ave <3%	Logan Cn Fm >3% decr in Sable Mem Miss Fm ave 2-3% highly variable over short intervals			

Cont'd

AREA	UPPER CRETACEOUS	LOWER CRETACEOUS	UPPER JURASSIC	MIDDLE JURASSIC	LOWER JURASSIC
SABLE SUBBASIN 6	Daw Cn Fm ave 1-2% decr at base <1%	Logan Cn Fm Up ave 1-1.5% Marmora P-35 >1.5% Low ave 1.5-2%	Miss Fm ave 1-1.5% Variable over short intervals rarely <.5%		
SABLE SUBBASIN 7	Daw Cn-Up Logan Cn Fm ave 3% in Thebaud I-94 ave 1% in Onondaga below Sable Mem ave .75-1% occ <.5%	Low Logan Cn-Nask-Up Miss Fm ave 1-1.5% variable pulses to >3% rarely <.5%	Low Miss-Verrill Cn Fm ave .75-1.25% occ <.5% rarely >1.5%		
SABLE SUBBASIN 8	Wells with a large carbonate section	Up Logan Cn Fm ave 1-1.5% very rarely <.75% Low Logan Cn - Nask ave >2%, very uniform	Low Nask ave .5-.75% occ <.5% pulses to 2% possible analytical problems		

Louisiana Gulf Coast (Dow and Pearson, 1975) and the Amazon Delta (Bezrukov et al., 1977) are systematically less than 1.0% TOC. This appears to be the result of dilution caused by high sedimentation rates. Shales deposited in deep marine environments accumulate slower and possess higher preservation potentials. Verrill Cayon shales of the Middle and Late Jurassic, deposited in deep water may have greater potential for oil than the predominantly prodelta shales of the Early Cretaceous.

No organic rich rocks have been identified within the Orpheus Graben (Eliuk, 1978). Possible source beds in the Mohawk, MicMac and Missisauga Formations include interbedded organic rich shales and perhaps coaly beds within dominantly coarse clastic sequences.

III. MATURATION INDICES ON THE SCOTIAN SHELF

III.1 Time-Temperature Index and Vitrinite Reflectance

Time-temperature index (TTI) and vitrinite reflectance are the primary indices used in this study to evaluate maturation on the Scotian Shelf. Time-temperature index has been calibrated to vitrinite reflectance (Issler, 1982) and found to be related by the function:

$$\log TTI = 6.1841 \log \%R_o + 2.6557$$

Lopatin (1971) originally devised the time-temperature index as a simple, theoretical method of calculating maturation, utilizing burial history curves, temperature profiles and assuming a doubling of reaction rate for every 10°C rise in temperature. Waples (1980) improved the understanding of TTI mechanics and proposed worldwide correlations between TTI and a number of geochemical parameters. Subsequent work by Issler (1982) illustrated the need for calibrating TTI to other maturation indices for separate basins having different burial and temperature histories. A worldwide scale of TTI has little meaning, since TTI must be recalibrated for different basins.

Time-temperature index has been calibrated to vitrinite reflectance measurements due to the qualitative nature of the data. Vitrinite reflectance is somewhat less subjective than most other maturation indicators and more importantly, measurements are independent of kerogen composition. The TTI data used in this chapter is from Issler (1982) and is supplemented by a number of recently completed wells.

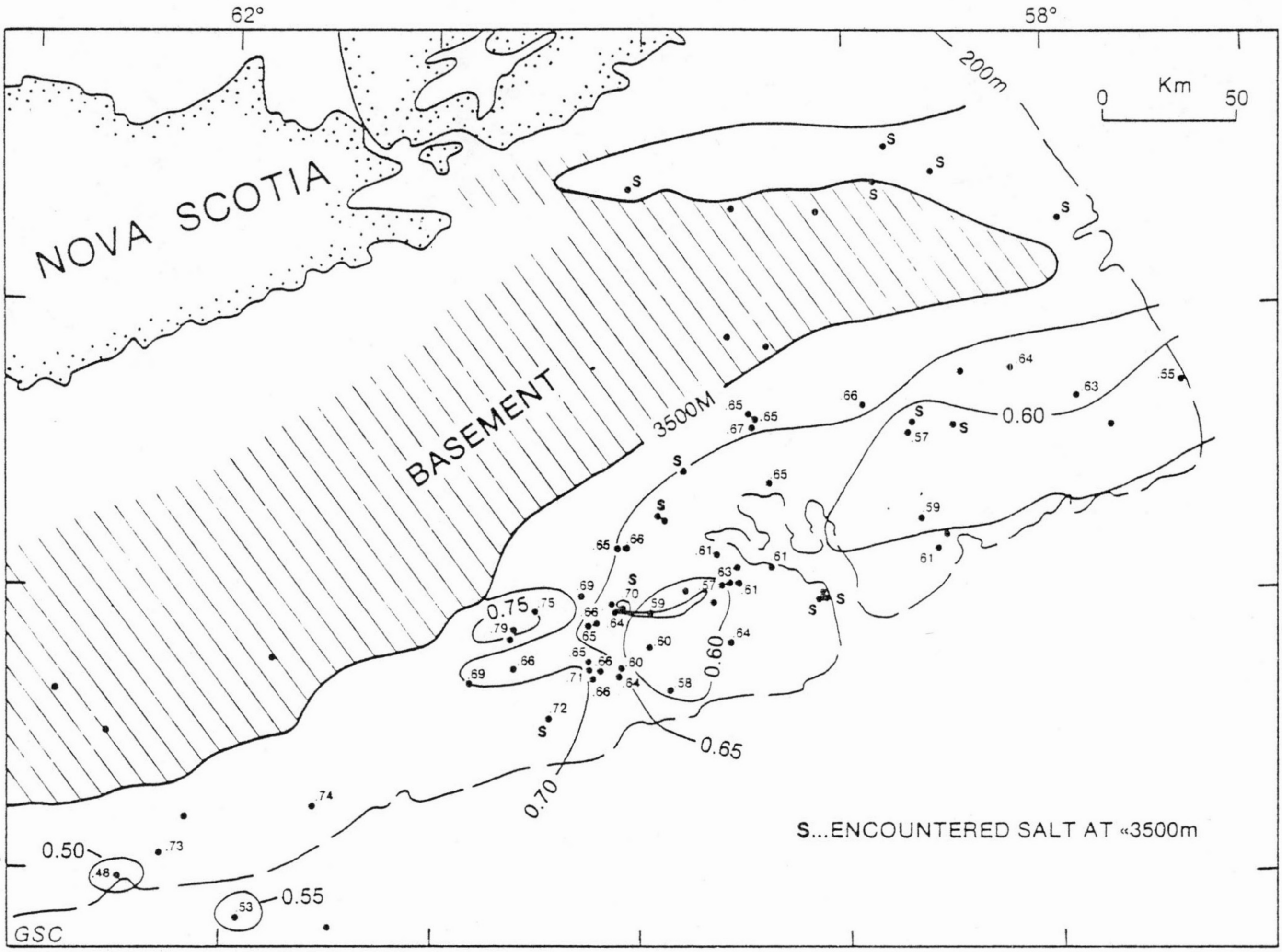
III.2 Maturation Profiles

Present depth of burial on the Scotian Shelf is considered to be maximum, consequently temperatures should be maximum. Maturation is the result of depth of burial (temperature) and duration of heating. Temperature is clearly the dominant factor in the maturation of organic matter. However, the time factor can be important, particularly in areas of low or moderate geothermal gradient. In areas of rapid subsidence, temperatures will be cooler at a given depth than in more stable basins and threshold temperatures will be deeper and higher. Such a phenomenon has resulted in a large vertical separation between accepted threshold values, which take the form of a marginally mature zone, approximately 1500-2000 m thick on the Scotian Shelf. In older or more stable basins, such as the western Canada sedimentary basin, no marginally mature zone exists and threshold temperatures are lower than in actively subsiding basins (Bailey et al., 1974).

The effects of rate of subsidence and geothermal gradient on the Scotian Shelf are shown in Figures 16 and 17. At equivalent depths (e.g. 3500 m) sediments beneath the outer shelf and within the depocenters of the respective subbasins are less mature than those found on the landward margins of the shelf. Sediments on the landward margins are Middle and Upper Jurassic in age. Seaward, the sediments at 3500 m are Early Cretaceous and have not been exposed to elevated temperature regimes as long. Maturation profiles of sediment at equivalent ages (e.g. top Jurassic) presumably reflect subsidence rate and present depth of burial. Seaward, sediments of the same age are more mature, but occur at increasing depths.

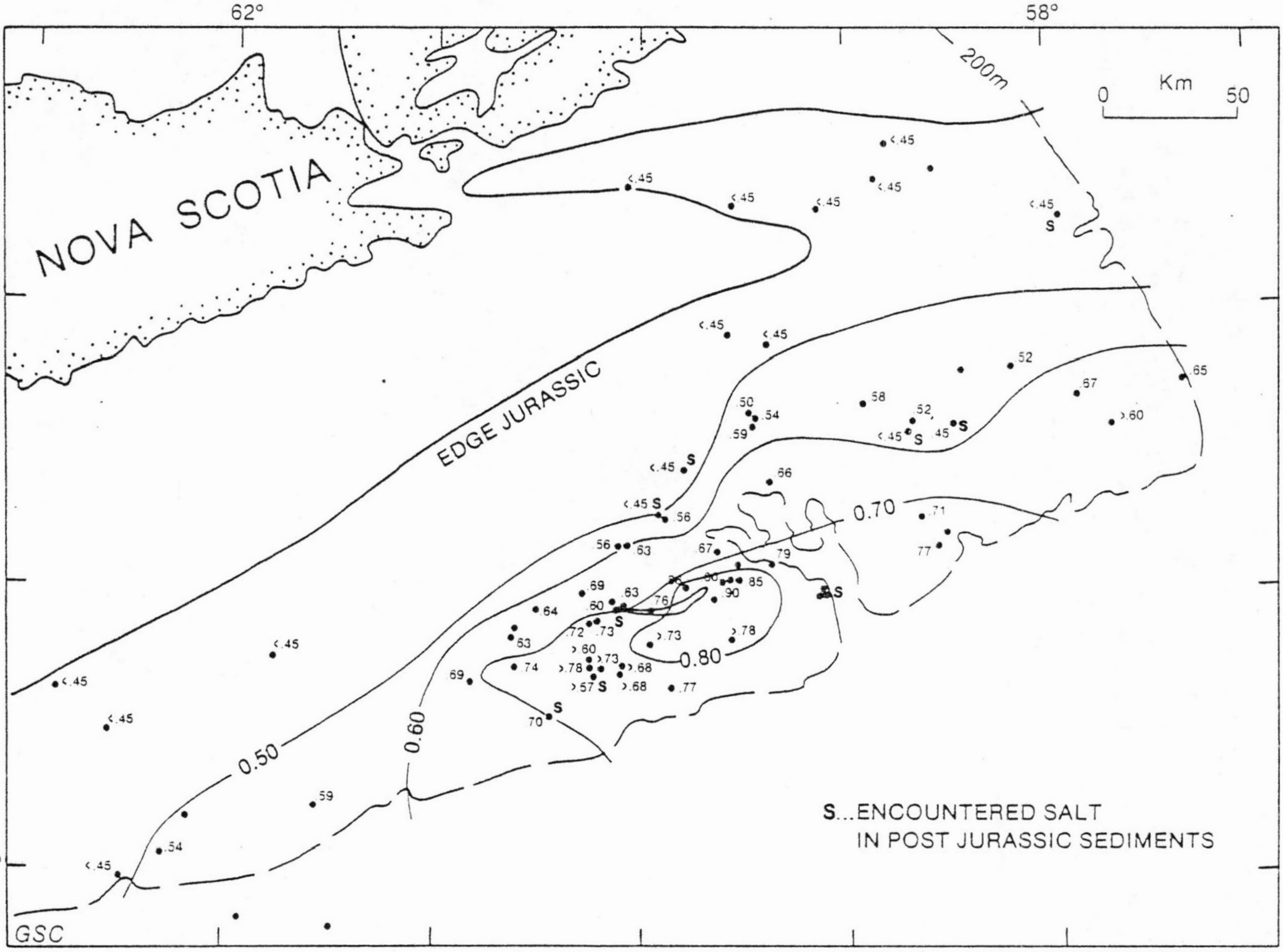
III.3 Threshold Maturation Values

Using geothermal gradient data, Robbins and Rhodehamel (1976) suggested the top of the oil window on the Scotian Shelf to be at 2400 m and the base at about 6080 m. Purcell et al. (1979) proposed the existence of



Ro.% CALCULATED FROM TTI AT 3500M SUBSEA
(LOG TTI =6.1841 LOG Ro. +2.6557)

Figure 16



%Ro. CALCULATED FROM TTI FOR THE TOP OF JURASSIC SEDIMENTS
(LOG TTI=6.1841 LOG Ro+ 2.6557)

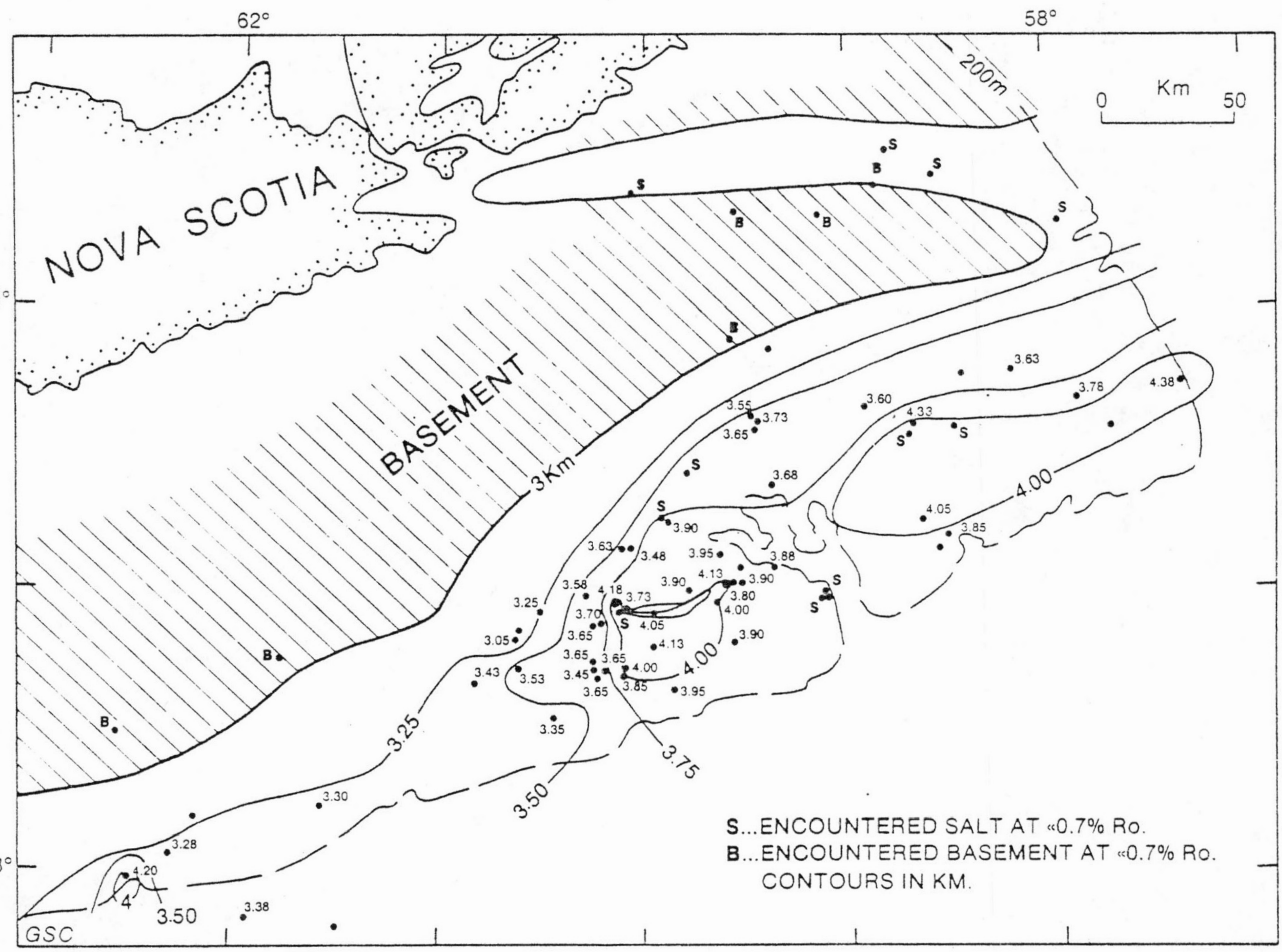
. Figure 17

a marginally mature zone beginning at 2200 m and a fully mature zone commencing at approximately 4200 m. Variations in geothermal gradient and subsidence rate means depths at which maturity is evident can vary within a basin by as much as several hundred metres.

Depth to maturation threshold values on the Scotian Shelf (Fig. 18) are essentially those of Issler (1982), though slightly revised and updated. Vitrinite reflectances of 0.6%R_o and 0.7R_o have been quoted as the level at which Type II and Type III (resinite poor) organic matter become capable of generating significant quantities of liquid hydrocarbons (Powell, 1983). Considering the terrestrial nature of the organic matter, a value of 0.7% R_o was used to construct Figure 18. This figure defines the approximate depth to the fully mature zone on the Scotian Shelf. Some of the depths to calculated R_o values do not correspond to measured vitrinite reflectance. This can be attributed to the combined uncertainty in calculating TTI and in measuring vitrinite reflectance.

Assuming a vitrinite reflectance of 0.7%R_o represents the onset of liquid hydrocarbon generation in terrestrial organic matter, the top of the oil window on the Scotian Shelf occurs at less than 3200 m on the landward margin and at greater than 4000 m in a seaward direction. This difference in depth reflects variations in subsidence rate and the age of the sediments. At the edge of the shelf, sediments at a given maturation level are younger and deeper than sediments higher on the shelf.

Until recently, no wells drilled on the Scotian Shelf had penetrated to the theoretical base of the oil window. A number of recent wells have been drilled to depths exceeding 6000 m, hence some estimate of the limit of hydrocarbon generation can now be attempted. The onset of the dry gas stage occurs at a vitrinite reflectance level of about 1.30% R_o



SUBSEA DEPTH TO CALCULATED Ro. 0.70%

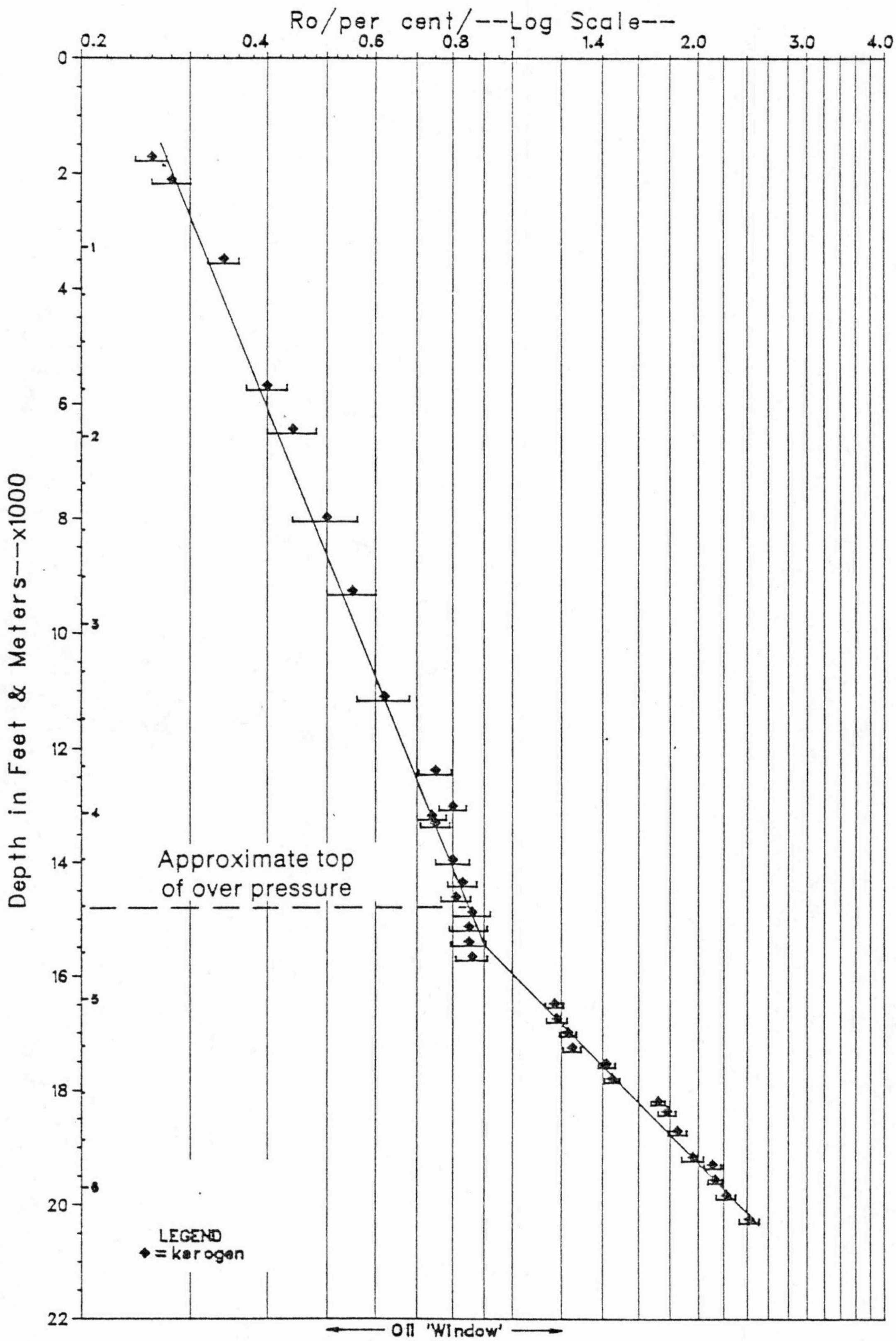
Figure 18

(Powell and Snowdon, 1983). This value appears to be independent of kerogen composition.

In the South Venture O-59 well, a vitrinite reflectance of 1.31% R_o at 6200 m was calculated. A linear geothermal gradient of 2.61°C/ 100 m was used for the calculation, however, the gradient may not be linear due to the bottom of the well being overpressured.

Vitrinite reflectance measurements on South Venture O-59 have recently been completed and a sharp increase in the maturation gradient is evident (Fig. 19). The increase is roughly coincident with the top of the overpressure. Depth difference between top of overpressure and increased maturation gradient may reflect the biases of the sampling interval used and the uncertainty of the reflectance measurements at this depth. The change in maturation gradient can not be explained by an unconformity, as the section is believed to be continuous and conformable. No thermal event has been recognized to account for the greater maturation. There is no evidence of faulting which could result in older, more mature section being drilled. It is unclear whether overpressuring alone can result in the enhanced maturation seen at South Venture O-59. According to theory, an increase in temperature of just 2°C/100 m will amount to 10°C in 500 m, which results in a further doubling of reaction rate. Modest increases in thermal gradient in overpressured zones could significantly affect the level of maturation. More data is required to quantify the effects of overpressuring on maturation and temperatures. However, the narrowing of the oil window is an obvious feature of overpressuring.

The top of the oil window in South Venture O-59 occurs at about 3600 m and the base at approximately 5180 m. These suggest the existence of a 1580 m thick oil window southeast of Sable Island. Using a linear



Maturation Profile South Venture O-59

Figure 19

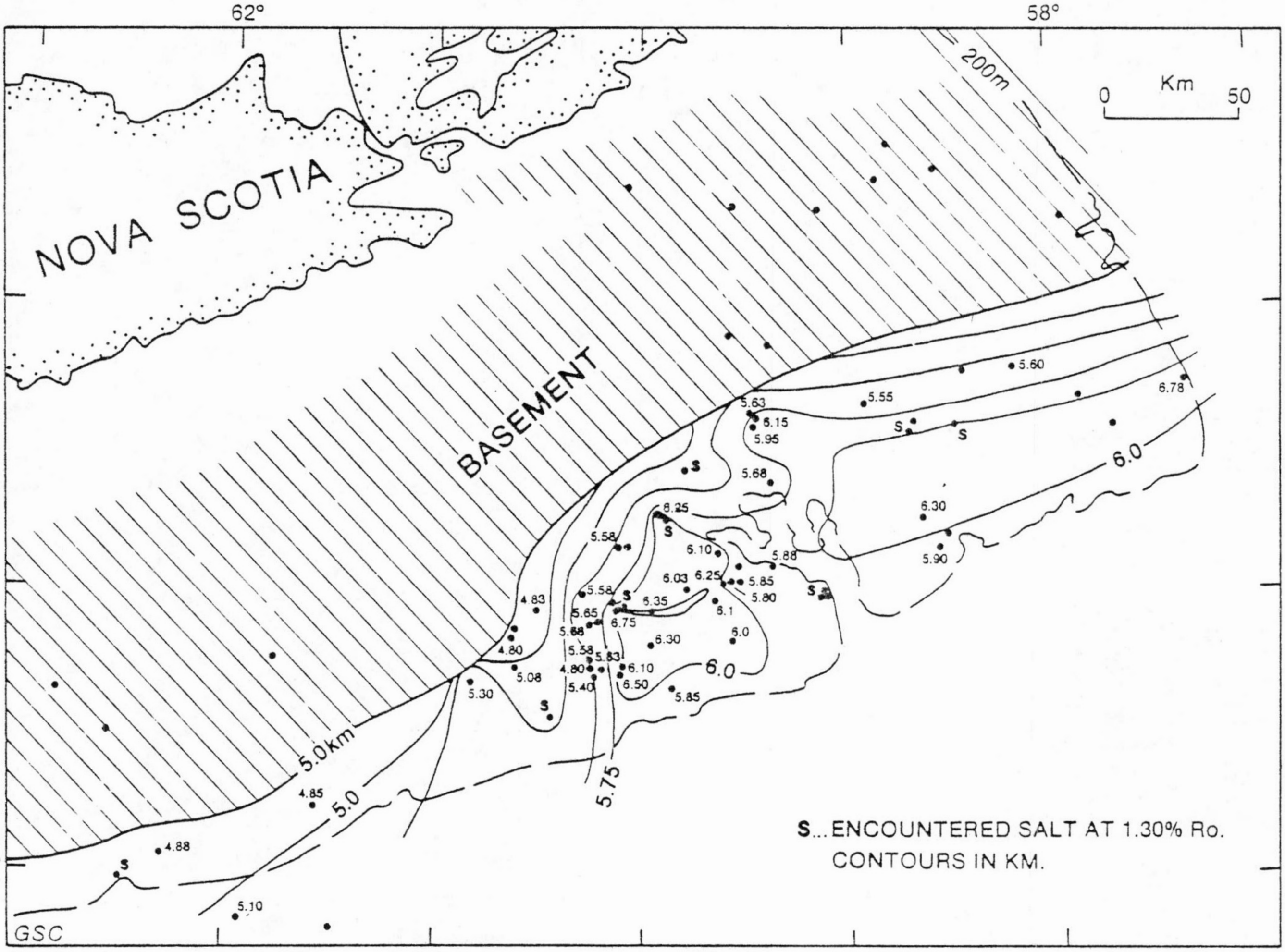
geothermal gradient, the estimated oil window is about 2350 m thick. The oil window will be considerably thicker in wells not drilled in the overpressure zone.

Using Figure 18, calculated thickness of the oil window, and assuming no changes in the maturation gradient, a map of depth to 1.30% R_o was constructed (Fig. 20). This map will require revision when the effects of overpressuring become better known. The base of the oil window defined in Figure 20 can be considered the maximum depth at which liquid hydrocarbons may be generated.

There appears to be some difficulties in calculating TTI above the crests of salt diapirs. Vitrinite reflectance calculated from TTI is commonly lower than what is indicated by measured reflectance and thermal alteration index. In calculating TTI one considers variations in burial history and temperature. Although thermal gradients may have changed over time in a particular basin, it is assumed these changes are proportional between wells and within wells. This enables one to calibrate the scale using present day temperatures and thus predict maturation levels. With salt domes this is clearly not the case. In areas of salt diapirism, temperature changes through time have not been proportional within the basin. Variations due to the age of diapirsm, the amount of heat available to the salt structure and the effectiveness of blanketing by sediments, preclude the development of a systematic relationship between TTI and maturation by other means.

III.4 Timing of Petroleum Generation

One of the applications of Lopatin's method is determining the timing of petroleum generation in relation to trap formation. Resulting



SUBSEA DEPTH TO CALCULATED Ro. 1.30%

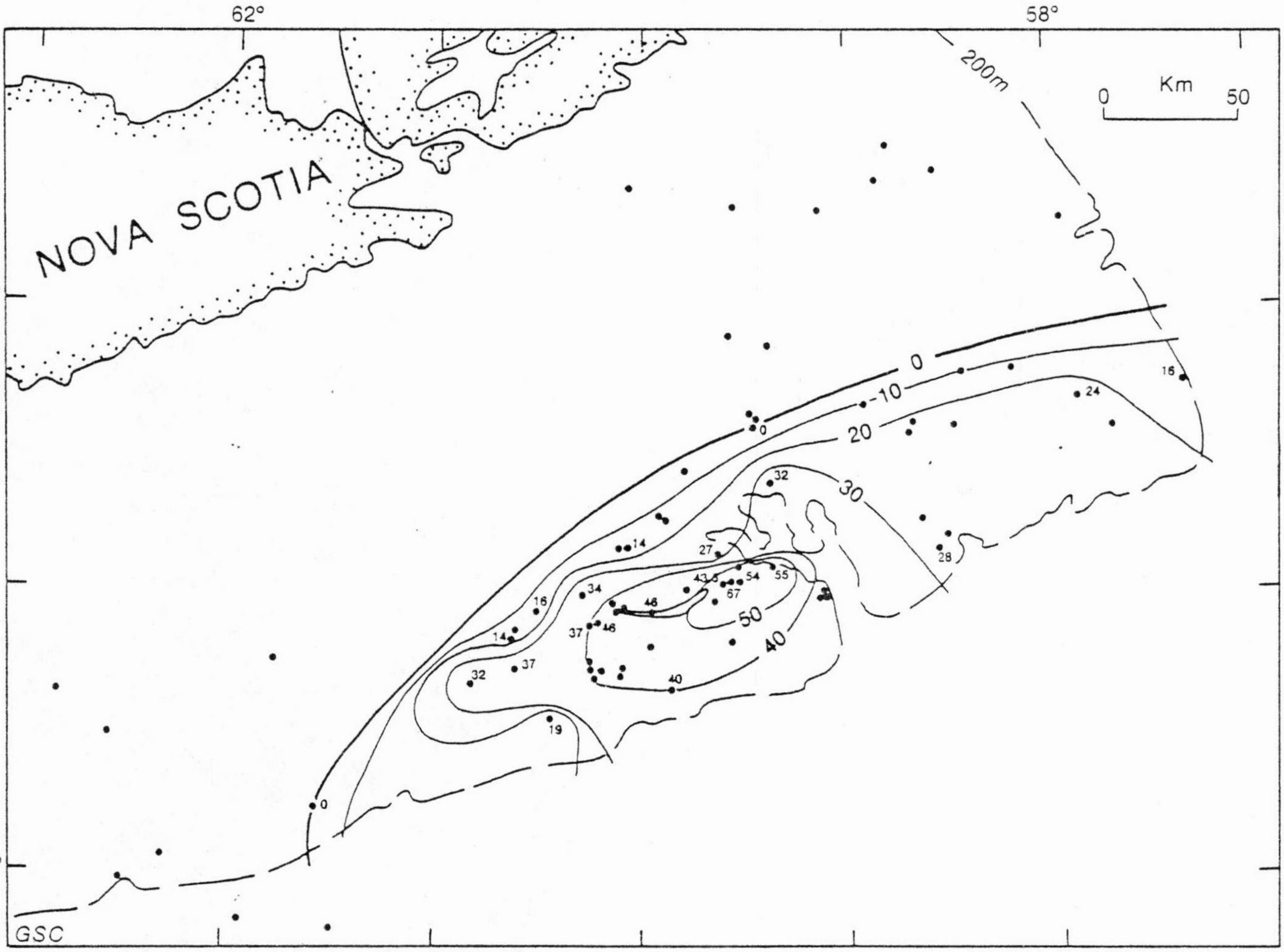
Figure 20

patterns on a contour map of age, strongly reflect subsidence, and to a lesser extent, geothermal gradient (Fig. 21). In Figure 21, the top of the Jurassic was used merely for convenience. This horizon includes the later-ally equivalent MicMac, Lower Missisauga, Abenaki and Verrill Canyon Formations. A vitrinite reflectance of 0.6% R_o was chosen in order to gain more data points. A value of 0.7% R_o would have been more desir-able, however, fewer data points would have made contouring less meaning-ful. Wells drilled over salt domes present special problems in that stratigraphy and subsidence history are often complex and difficult to re-construct. A detailed study of the subsidence and the timing of hydro-carbon generation of a specific potential source rock, such as the Verrill Canyon Formation would be a useful exercise, particularly in terms of the timing of trap developments. Such a study would also help to understand exposure time to heating in relation to hydrocarbon generation on the Scotian Shelf.

III.5 Thermal Alteration Index

Predictable colour changes in organic matter during maturation have been used to define when hydrocarbon generation may be possible. Staplin (1969), refining original work by Gutjahr (1966) and Correia (1969), developed the thermal alteration index (TAI) and successfully applied it to maturation and hydrocarbon occurrences in the western Canada basin. The response of different types of organic matter to maturation has been gra-phically illustrated by Bayliss (1975) in Figure 22. Bujak et al. (1977a,b) used TAI to evaluate maturation and hydrocarbon potential of off-shore eastern Canada.

Determination of TAI has a number of problems, as there is



TIME (MILLION YEARS BEFORE PRESENT) WHEN TOP OF JURASSIC ENTERED Ro 0.60%
(CALCULATED FROM TTI)

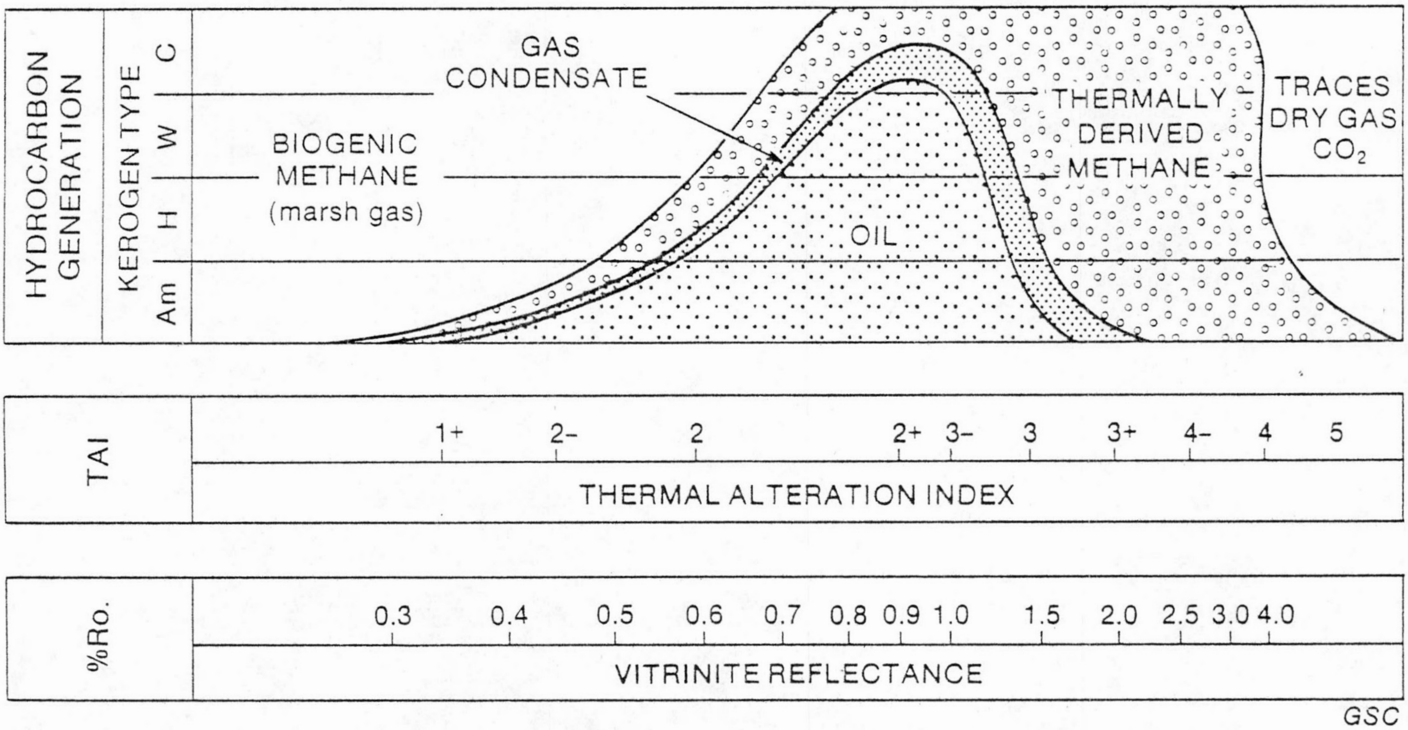
Figure 21

1. subjectivity
2. difficulty of comparing results between operators
3. difficulties in estimating subtle colour changes
4. variations in structure, thickness and colour of different types of organic matter and species variation
5. low geothermal gradients
6. sample quality-cavings, reworked, oxidized and weathered material.

Obviously, TAI measurements require continuous monitoring and calibration with other maturation indicators.

Different types of organic matter will respond to maturation at various rates of transformation, making interpretation to total dispersed organic matter colour difficult. Colour estimations will be more accurate when limited to one type of maceral. Considering the various rates of change in organic matter, TAI will require calibration within different basins of various age sediments and geothermal gradient. In areas of low geothermal gradient, there may be substantial differences in depth between the onset of previously accepted threshold values for maturation. Differences in threshold maturation levels are attributed to differences in activation energy associated with different types of organic matter (Powell and Snowdon, 1983).

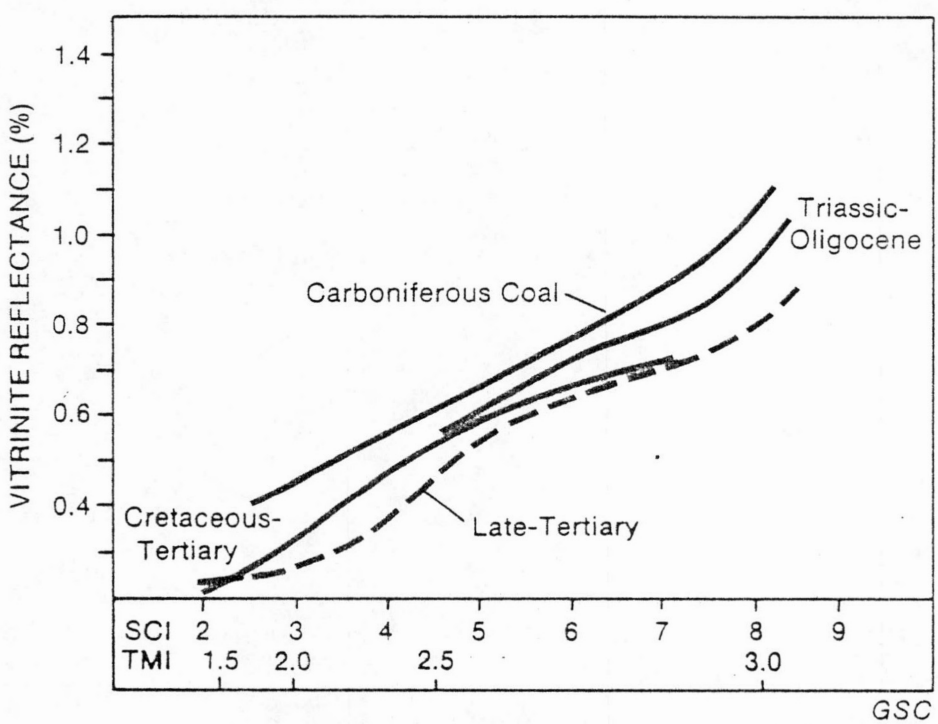
Thompson et al. (1979) have determined that the calibration of spore colouration and TAI to vitrinite reflectance varies with age (Fig. 23). Interpreted in another way, Figure 23 implies that at a higher rate of heating, TAI and spore colouration increase at a faster rate relative to vitrinite reflectance. Alternatively, at equivalent vitrinite reflectance levels, organic matter from the basins of highest geothermal gradient



HYDROCARBON GENERATION MODEL AND CALIBRATION
(after Geo. Chem. Lab. 1975-77, Bayliss 1975)

Figure 22

Figure 23



SPORE COLOUR CALIBRATION AND VITRINITE REFLECTANCE TO AGC
(from Thompson et al., 1979)

relative to age, will have higher TAI values than older, lower gradient basins. The above explanation may partially resolve the apparent lack of correlation between TAI and calculated and measured vitrinite reflectance over the Primrose salt diapir.

Thermal alteration index measurements on the crest of the Primrose salt diapir are as high as 3- to 3 in the N-50 well. Calculated vitrinite reflectance (0.35-0.45) and measured ambient temperatures (60-70°C) are insufficient to account for the maturation expressed by TAI. Paraffin indices indicate the hydrocarbons at Primrose were generated at levels of maturation equivalent to hydrocarbons reservoired in Lower Cretaceous-Upper Jurassic rocks (Fig. 24). This suggests levels of maturation greater than 0.7% R_o. The maturation profile of the crestal well is higher than the flank wells (Issler, pers. comm.) indicating a heat anomaly above the crest.

The salt diapir at Primrose has ceased to grow (Wade, pers. comm.). This implies detachment and isolation of the diapir from the mother salt bed. If the diapir is indeed pinched off at depth, it may be thermally insulated from the basement heat source. This could account for the present day low temperatures measured over the salt. In the past, the temperature would have been higher and possibly of sufficient magnitude to generate hydrocarbons.

The heating above the diapir must have been of relatively short duration, but of sufficient magnitude to alter the organic matter, but not affect vitrinite to the same degree. Duration of heating seems to be important in altering the reflectance of vitrinite at moderate levels of heating. The enhanced rate of heating above the salt due to higher flux and the postulated increased rates of transformation and colouration could

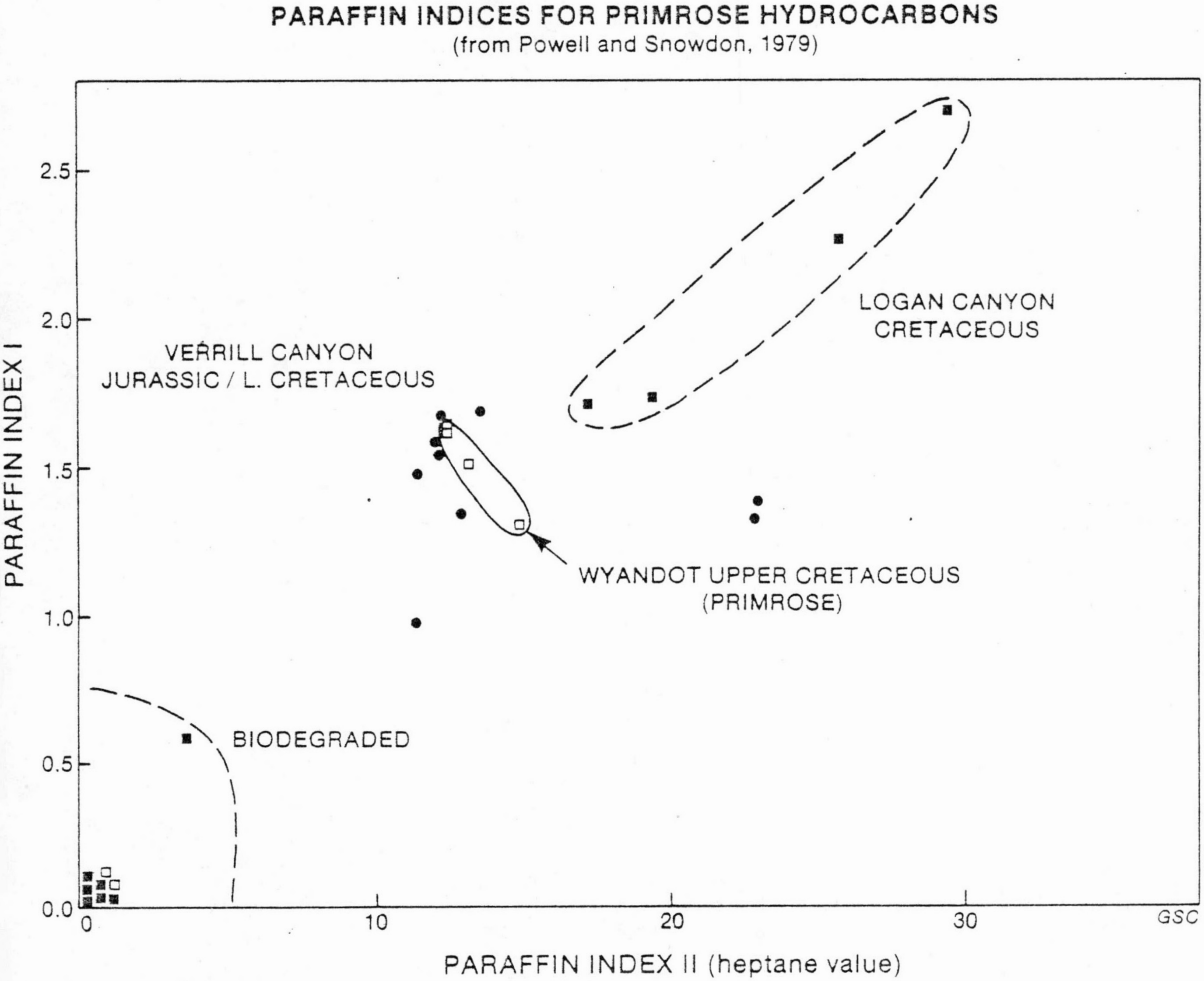

PARAFFIN INDICES FOR PRIMROSE HYDROCARBONS
(from Powell and Snowdon, 1979)
PARAFFIN INDEX I
PARAFFIN INDEX II (heptane value)
0.0
0.5
1.0
1.5
2.0
2.5
0
10
20
30
GSC
LOGAN CANYON
CRETACEOUS
VERRILL CANYON
JURASSIC / L. CRETACEOUS
WYANDOT UPPER CRETACEOUS
(PRIMROSE)
BIODEGRADED

Figure 24

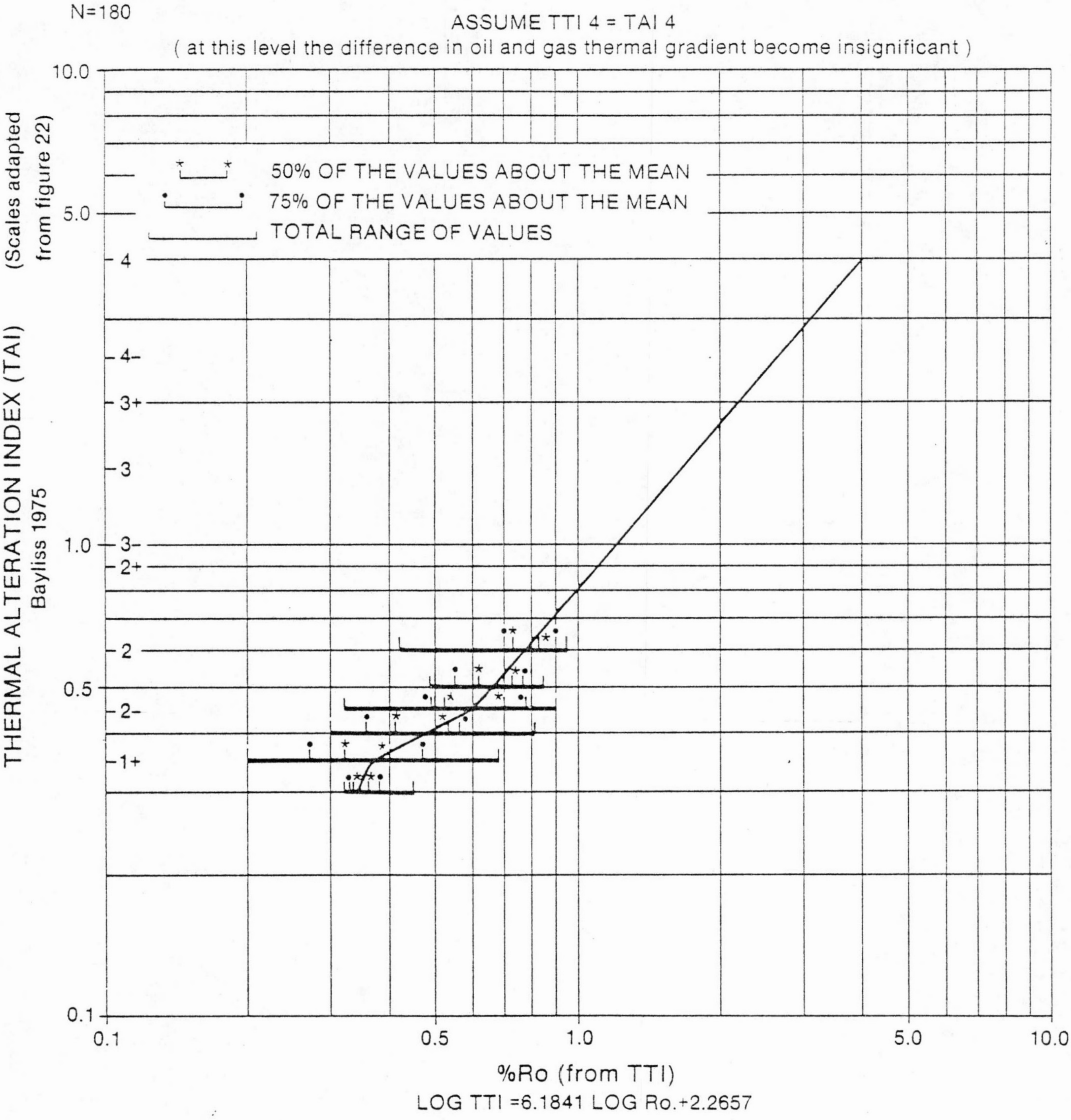
have been sufficient to account for the discrepancies between TAI and vitrinite reflectance. Organic matter type may also play an important role, particularly in lowering the level of maturation required for the onset of liquid hydrocarbon generation.

Thermal alteration index has been calibrated to measured vitrinite reflectance, TTI and wet gas analyses. The latter will be dealt with in a subsequent section. The results are graphically illustrated in Figure 25 and 26. Thermal alteration index data is from Bujak et al. (1977), G.S.C. Open File 714 and previously unpublished data provided by M.S. Barss. The TTI data is from Issler (1982) and updated in this paper. Vitrinite reflectance is from Issler (1982), Powell (1982) and recently completed reflectance data done by the Atlantic Geoscience Centre.

Variations between the two curves in Figures 25 and 26 can be attributed to the problems of measuring R_o and TAI at low levels of maturation and a lack of data for measured vitrinite above the 2- 2 range.

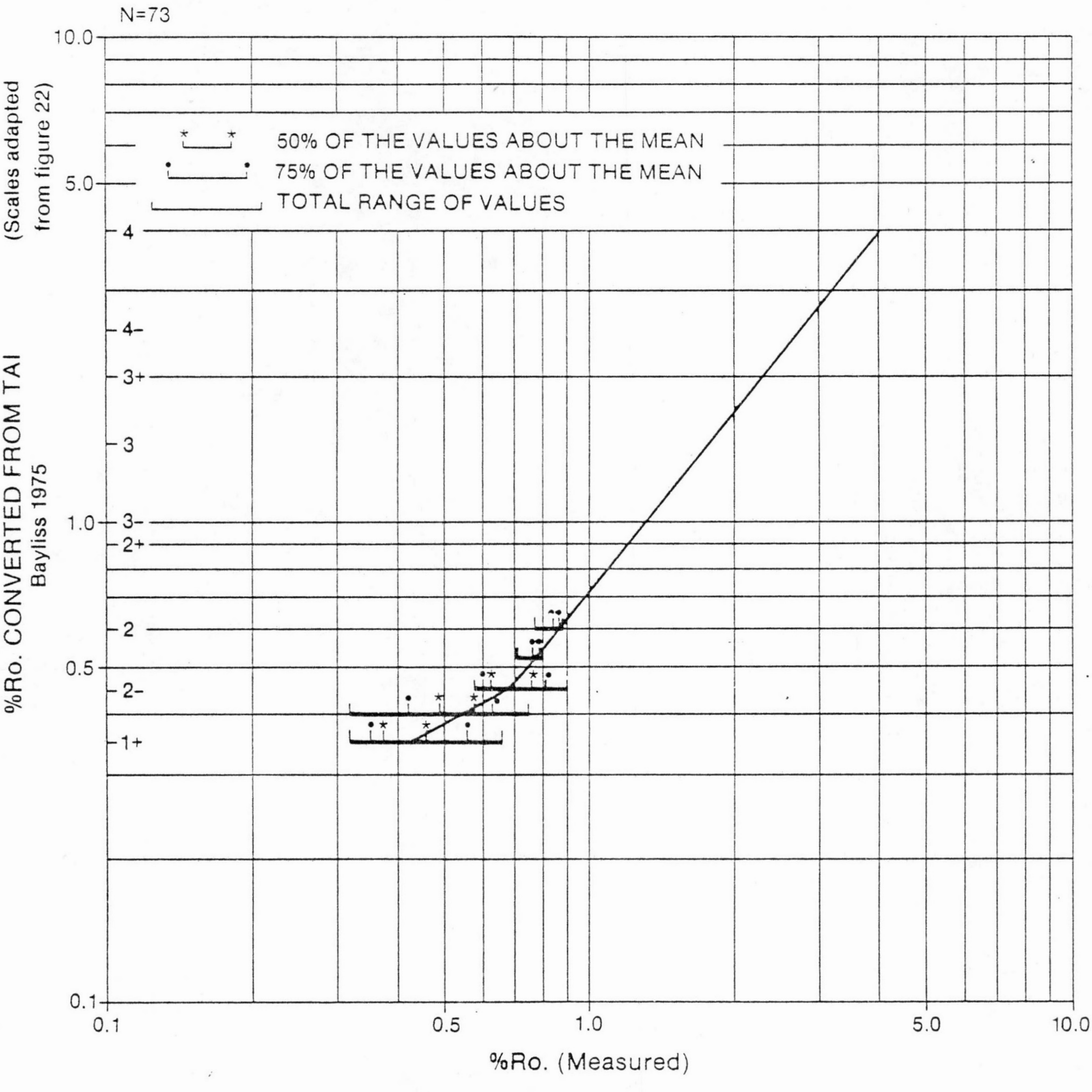
The most interesting aspect of the curves are their shapes. There is a distinct kink at a TAI of 2-, corresponding to a vitrinite reflectance of 0.67 and 0.62 respectively. These reflectances are very close to the threshold values for terrestrial organic matter in the fully mature zone (Powell, 1982). Bujak et al. (1977) stated a TAI of 2- represented a marginally mature facies where 2- to 2 relates to a slightly higher degree of thermal maturation, but not yet fully mature. New data suggests the onset of the fully mature zone commences at a TAI of 2- to 2. The theoretical base of the oil window would occur at a TAI of 3- to 3.

The depressed slope of the lower segment of the curves at a TAI of less than 2- is interesting. It appears the organic matter colouration has been suppressed relative to vitrinite reflectance. The higher TAI



CALIBRATION BETWEEN TAI AND CALCULATED Ro. *GSC*

Figure 25



CALIBRATION BETWEEN TAI AND MEASURED Ro.

GSC

Staplin 1969, Bayliss1975

Figure 26

associated with young, hot basins in relation to cool, older basins has been dis-cussed previously. The low maturity section of the Scotian Shelf can be classed as a relatively young, cool sequence dominated by terrestrial organic matter. The suppression of TAI at and below 2- may be characteristic of this type of basin. The situation at the Primrose diapir would be analagous to a young, hot basin dominated by Type II organic matter, where TAI will exceed the conventional vitrinite reflectance calibration.

III.6 Wet Gas Analysis

As organic matter matures from burial and increasing temperature a variety of hydrocarbons are produced. In the immature zone, the dominant hydrocarbon is undoubtably (biogenic) methane. The top of the marginally mature zone is characterized by the onset of wet gas (C_2-C_4) generation in quantities exceeding 50% of the total gas. Powell (1978) noted the onset of wet gas in the analyses of cuttings, coincided with a reflectance of 0.45% -0.50% R_o in Canadian Arctic basins and subsequently, on the Scotian Shelf (Powell, 1982). In this section, wet gas analysis is calibrated to TTI and TAI in order to define the top of the marginally mature zone (Table 2). Data has been sourced from G.S.C. Open File 714, Purcell et al. (1979 and Powell (1982).

The onset of maturation commences at an average (?) vitrinite reflectance of 0.45% and a TAI of 1+ or 1+ to 2-. Values of reflectance range from 0.28 to 0.53%R_o. Depth to the wet gas line ranges from about 1100 m at Primrose to greater than 2700 m at Onondaga, and averages about 2000 m.

The variations in maturation and depth to the onset of wet gas is a function of geothermal gradient and variable source potential of the

Cuttings Gas Analysis

Well	Subseafloor Depth (m) TAI	50% Wet	75% Wet (Powell, 1982	$\%R_0$ from TTI	Temp. °C
Acadia K-62	NA		2621	0.53	89
Adventure F-80	1+	1051		0.40	46
Bluenose G-47	1+ to 2-	2684		0.48	62
Citnalta I-59	1+ to 2-	2439		0.46	75
Cohasset D-42	1+	1671		0.44	62
Cohasset L-97	NA		1746	0.42	63
Demascota G-32	1+	2016		0.43	63
Intrepid L-80	1+ to 2-	2029		0.42	62
Jason F-20	1+	1701		NA	NA
Marmora C-34	NA	1831		0.37	59
MicMac D-89	NA	2549		0.51	75
Migrant N-20	NA		2410	0.49	76
Moheida P-15	NA		1988	0.44	66
Ojibwa E-07	1+ to 2-	1690		0.43	55
Onondaga B-96	NA	2741		0.53	85
Penobscott B-41	NA		1950	0.41	60
Penobscott L-30	NA		1963	0.45	65
Primrose F-41	1+ to 2-	1105		0.28	42
Sable Island 1H-58	NA	1489		NA	NA
Sable Island 4H-58	1+	2089		0.42	56
Sachem D-76	1+	2335		0.41	62
Sambro I-29	NA	<50%		-	-
Sauk A-57	1+ to 2-	2314		0.43	71
Thebaud I-94	NA		2072	0.42	70
Thebaud P-84	1+ to 2-	1985		0.41	63
Wenonah J-75	NA		1783	0.39	62
Venture D-23	NA		2648	0.49	82
Average					

sediments. Lithology can also have some effect on the concentration of light gases in sediments (Feugére and Gerard, 1970). Cuttings gas data is at best only semi-quantitative (Monnier et al., 1983). Gas may be lost during drilling and this is particularly true for permeable lithologies.

It is not uncommon to find substantial zones of dry gas within the so-called wet gas zone. This reflects poor source potential. Migration and accumulation of methane may be possible and is nearly indistinguishable from indigenous dry gas production, except where abnormal amounts of total gas yield occur in rocks with seemingly little organic matter.

III.7 Threshold Temperatures

The effects of temperature on maturation are well known. Maturation is also a function of the duration of exposure to heating. Considering the time factor, threshold temperatures for various stages of hydrocarbon generation should vary from basin to basin (Table 3).

Oil Window Temperature (C°)	Location	Reference
65-150	World Average	Pusey, 1973
105-?	Tertiary-West Texas	Hood et al. (1975)
68-116	Alberta	Deroo et al. (1977)
65-120 to 135	Paleozoic Rocks	Heroux et al. (1979)

Table 3. Temperature Ranges Within the Oil Window for Various Basins

Threshold temperatures on the Scotian Shelf were determined for wet gas analyses, R_o and TTI. Temperature data is from Issler (1982) and this paper.

The range of temperatures at any given maturation level in Figure 27 is 20°C or ± 10°C maximum about the mean. A number of points show anomalously high maturation levels for the borehole temperature. These wells are drilled on salt diapirs or over shallow basement, where the age of the sediments becomes a factor in maturation.

Temperatures measured at the 50%(?) wet gas line range from 42°C at Primrose to 89°C at Acadia K-62, and average 65°C. Figure 28 correlates $\%R_o$, TTI and TAI and temperature on the Scotian Shelf. These are summarized in Table 4.

The depth to various threshold values will vary with basinal position. In landward and high geothermal gradient wells, the depth to critical values will be less than average, whereas toward the shelf edge, they will be deeper and threshold temperatures may be higher.

III.8 C_{15+} Hydrocarbons

Geochemistry has been used in this study as a qualitative tool to evaluate maturation and organic matter types. These are determined by the nature of the C_{15+} hydrocarbons. The yield of extract from the sediment can be used to assess source potential and maturation. The interpretation of geochemical data appears to be very critical in most immature shale-sand series, owing to the occurrence of discrepancies between the properties of reservoired fluids and those of sediment extract (Connan and Cassou, 1980). In young immature sediments, the hydrocarbons in reservoirs and in related source rocks do not approach distribution equilibrium because primary migration is still occurring (Young and McIver, 1977). The differences tend to be less pronounced when maturation takes place.

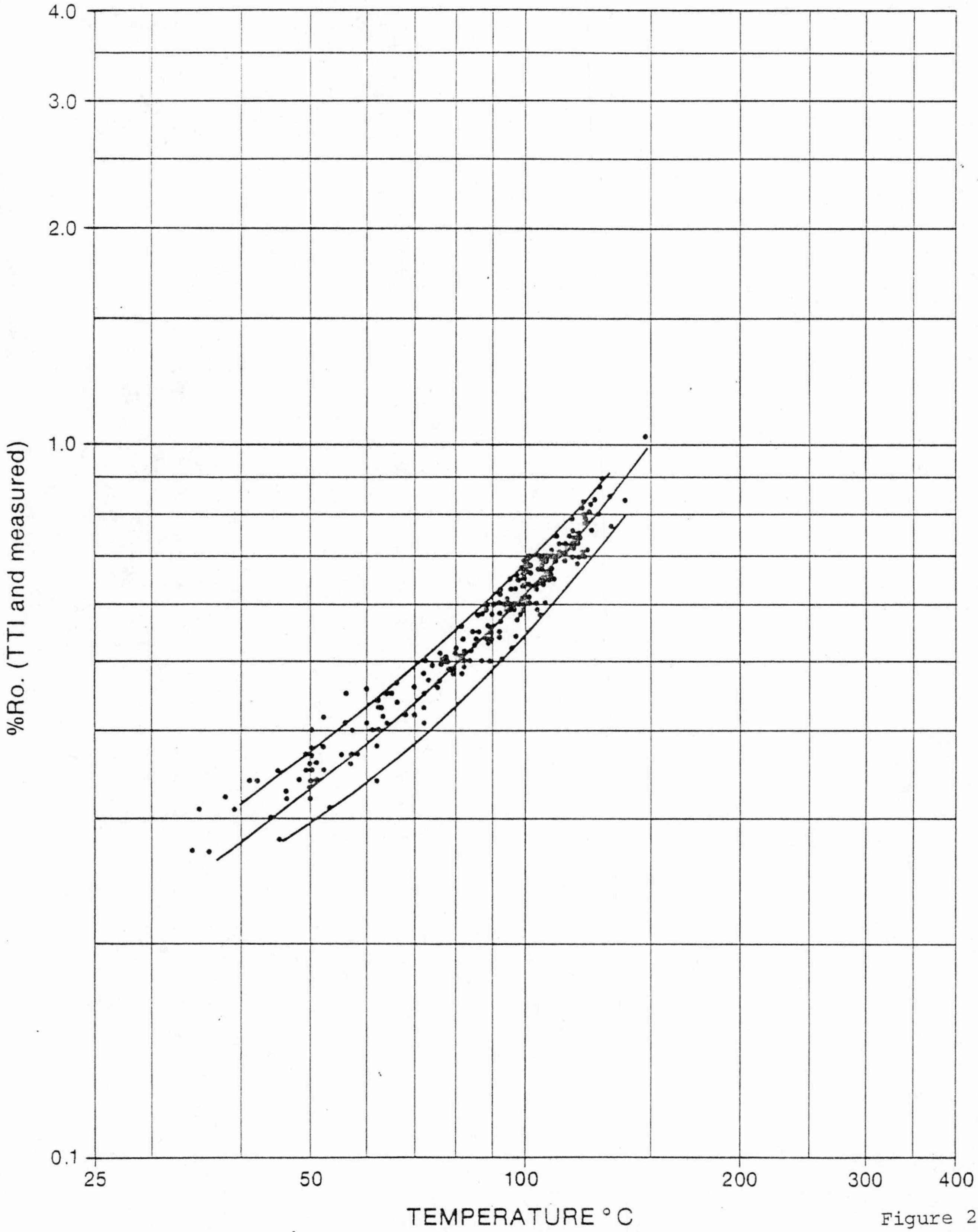
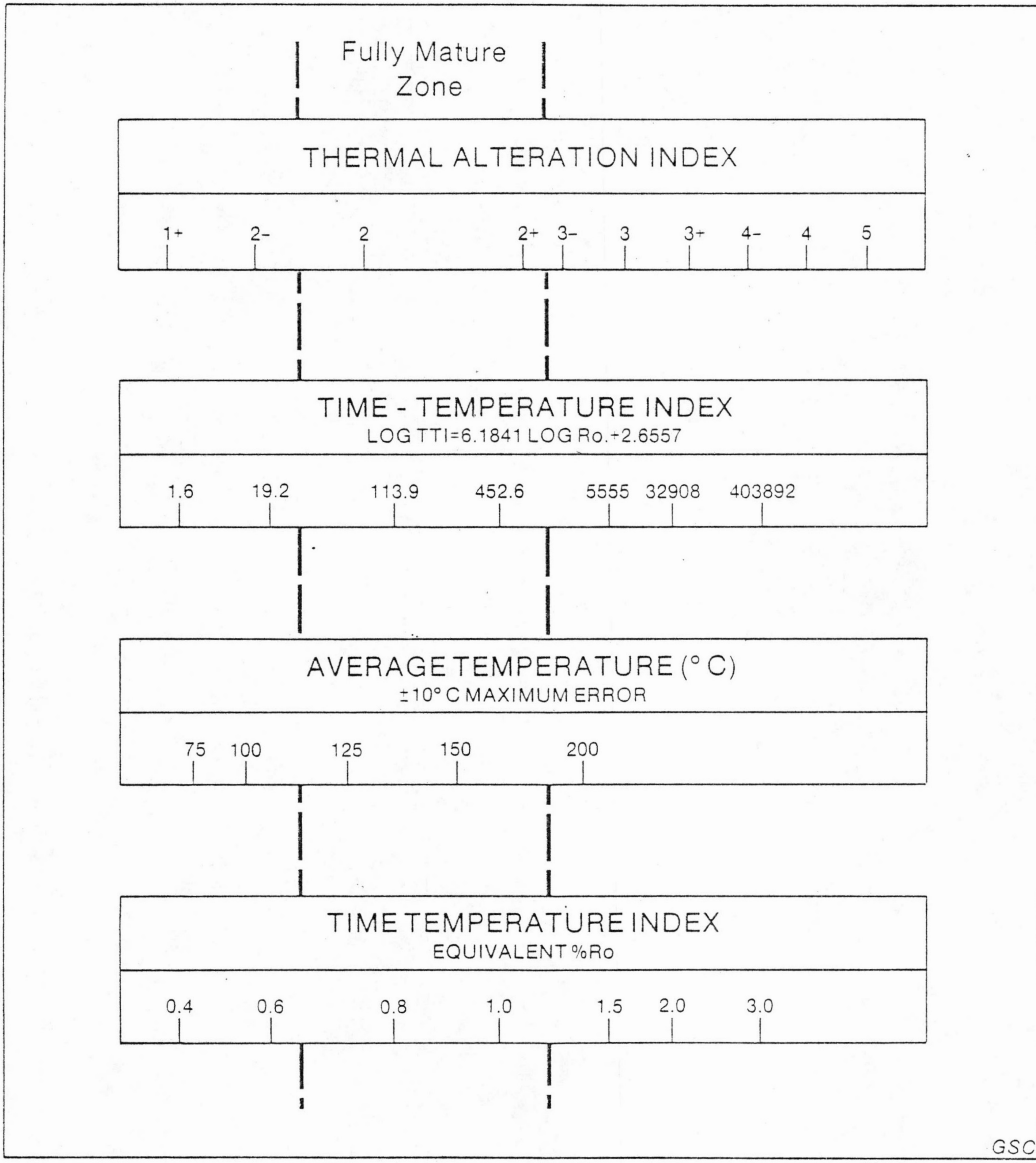


Figure 27

THE RANGE OF VALUES FOR ANY GIVEN LEVEL OF
VITRINITE REFLECTANCE IS APPROXIMATELY 20° C

CALIBRATION BETWEEN TEMPERATURE AND Ro.

GSC



CALIBRATION OF TTI, TAI, TEMPERATURE

Figure 28

TABLE 4 Correlation of $\%R_o$, TTI, TAI and Temperature on the Scotian Shelf

Maturation Stage	Ave. Depth	Range of Depths	$\%R_o$	TAI	TTI	Temperature
	metres	metres				± 10°C maximum
Top Marginally Mature Zone	2230	1250 - 3000	0.45	1+ or 1+ to 2-	3.2	72
Top Fully Mature Zone	3680	2300 - 4375	0.70	2- to 2	50	110
Theoretical Base of Oil Window	5735	4800 - 6775	1.30	3- to 3	2895	180

As maturation proceeds, the value of extract as a percent of organic carbon will increase due to it being rendered more soluble in organic solvents (Robinson and Cook, 1973). This value can be expected to increase with depth until the overmature zone is encountered. This trend is complicated by changing organic matter quality and lithology. The clastic or carbonate character of the rock affects the original amount of organic matter and the efficiency of the conversion to hydrocarbons (Hunt, 1979).

Geochemical data has been used from Purcell _et al._ (1979) and Powell (1982). Table 5 lists the C_{15+} extract chromatogram criteria used to distinguish hydrocarbon generating zones for dominantly terrestrial organic matter.

If the organic matter possesses considerable marine material, the C_{15+} extract will contain n-alkanes of low to medium molecular weight and a bimodal naphthenic hump in the immature-marginally mature zone. Marine type organic matter will yield more C_{15+} extract than terrestrial organic matter at equivalent levels of maturation.

<u>Immature Zone</u>

-odd/even predominance in n-alkanes

-dominance of higher n-alkanes (C_{26}-C_{30})

-high proportion of isoprenoids (pristane, phytane) to n-alkanes

<u>Marginally Mature Zone</u>

-odd/even predominance of higher n-alkanes still evident

-high pristane/phytane and pristane/n-alkane ratios

-lower n-alkanes become more prominant

<u>Fully Mature Zone</u>

-no odd preference remains in n-alkanes and lighter components

-smooth naphthenic hump

-smooth n-alkane distribution

-pristane much less prominant

The failure to generate hydrocarbons with maturation is due to the absence of good quality organic matter and means the immature character of the extract is preserved into the mature zone (Powell, 1982).

Table 5. C_{15+} Extract Criteria for Maturation on the Scotian Shelf

Geochemical analyses suffer from a number of disadvantages, which must be carefully considered when interpreting results. Bulk analysis over relatively large sampling intervals fail to resolve kerogen into its components and recognize stained, reworked and caved material. Drilling fluids, pipe grease and other contaminants can usually be detected because of their characteristic saturate fraction gas chromatograms (Snowdon, 1980). Characteristics derived from the nature of the organic material are not easily distinguishable from those induced by maturation and variable source potential.

Herbaceous organic material may have significant source potential, but sediments with sufficient quantities of this type of matter commonly show no chemical evidence of such potential (Powell et al., 1982 as cited from Snowdon, 1978). Optically, this material will be classed as poor to fair because of the failure to recognize hydrogen rich herbaceous material. Extracts from woody and herbaceous type organic matter can lose a considerable amount of volatile hydrocarbons (C_5-C_{15}) during extraction and fractionation with solvents (Harwood, 1977). This influences the character of the saturate fraction gas chromatogram, the total extract yield and the percentage of hydrocarbons within the total extract. Snowdon (1980) has observed up to 20% extract weight loss. Harwood (1977) estimates average extract weight losses of 5 to 10% for oil prone organic matter in the principal zone of hydrocarbon generation. Consequently, some fair or marginally classed source rocks may in fact possess good potential. These rocks could be capable of generating significant quantities of condensate and gas. Conventional C_{15+} extract data may not be particularly applicable to a potential source rock which generates large amounts of more volatile hydrocarbons (Snowdon, 1980). This may have significant implications when evaluating the hydrocarbon potential of the Scotian Shelf.

IV. HYDROCARBON SOURCE POTENTIAL

IV.1 Maturation and Oil-Gas Generation

In order for a source rock to generate liquid hydrocarbons, it must possess sufficient quantities of the proper type of organic matter at specific levels of maturation. Studies in this area have led to the development of a generalized model of oil and gas generation (Vassoevich et al., 1974; Tissot et al., 1974). The degree of maturation and nature of the organic matter ultimately determines the composition of the hydrocarbons. Threshold temperatures for various stages of generation reflect the type of organic matter and to a lesser extent, the age of the sediments. Organic matter within sediments is a mixture of types, which at any point, certain components might be mature and generating oil, while others are still immature and gas prone or inert.

Tissot et al. (1974) conveniently classified organic matter according to the atomic hydrogen/carbon ratio in the immature stage (Fig. 29). Hydrogen rich organic matter (Type I and II, H/C>1.0) can produce oil at vitrinite reflectance levels of about 0.4%R_o tp 1/30%R_o. Type III (H/C=0.8-1.0) organic matter produces predominantly wet gas and some waxy oil commencing at vitrinite reflectances of 0.7% R_o. At higher levels of maturation (>1.3% R_o), thermal cracking of previously generated liquids becomes important and gas-condensate and dry gas are produced. Type IV (Harwood, 1977) organic matter generates only dry gas upon maturation. An early biogenic gas phase can be generated from all four types of organic matter.

Exploration activity in recent years in Canada's frontier basins has shown the need to revise the hydrocarbon generation model, particularly for terrestrially derived organic matter. Source rock quality of

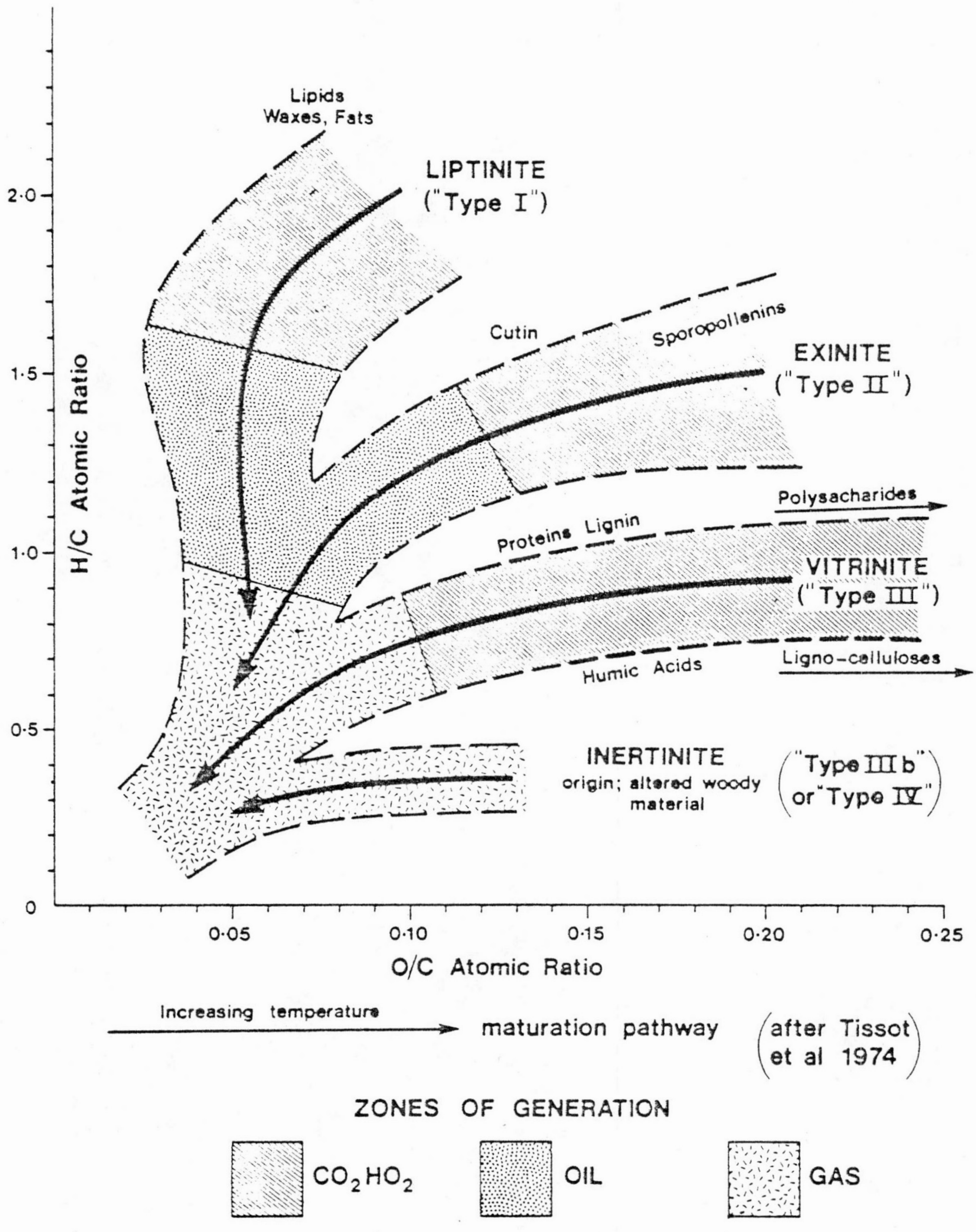

Lipids
Waxes, Fats
LIPTINITE
("Type I")
Cutin
Sporopollenins
EXINITE
("Type II")
Polysacharides
Proteins Lignin
VITRINITE
("Type III")
Humic Acids
Ligno-celluloses
INERTINITE
origin; altered woody material
("Type III b"
or "Type IV")
H/C Atomic Ratio
O/C Atomic Ratio
2·0
1·5
1·0
0·5
0
0·05
0·10
0·15
0·20
0·25
Increasing temperature
maturation pathway
(after Tissot et al 1974)
ZONES OF GENERATION
CO_2HO_2
OIL
GAS

Figure 29a

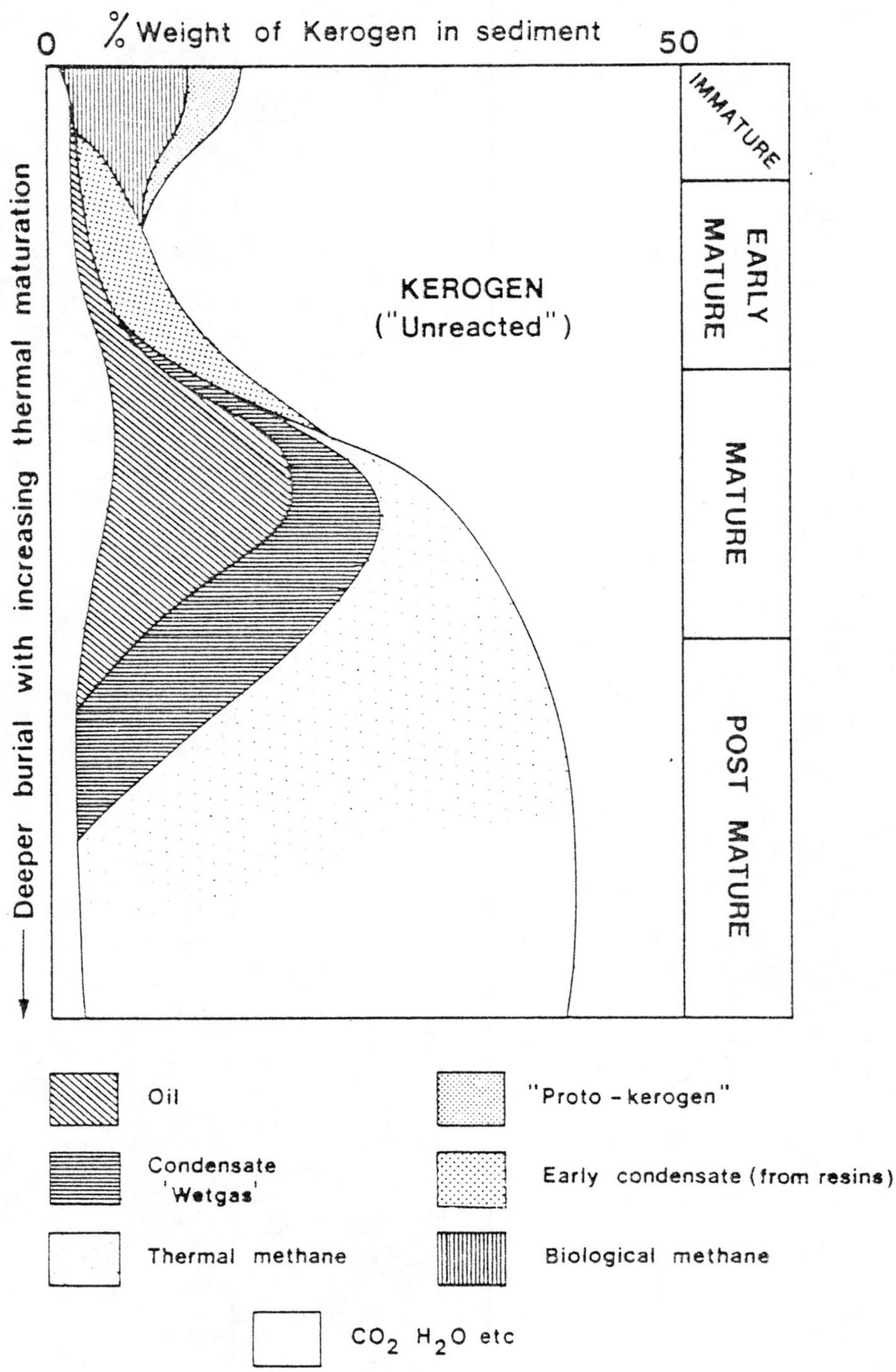

0
% Weight of Kerogen in sediment
50
Deeper burial with increasing thermal maturation
IMMATURE
EARLY MATURE
MATURE
POST MATURE
KEROGEN
("Unreacted")
Oil
"Proto - kerogen"
Condensate 'Wetgas'
Early condensate (from resins)
Thermal methane
Biological methane
CO_2 H_2O etc

Figure 29b

terrestrial organic matter is highly variable and depends on the relative concentration of hydrogen rich (liptinite) and hydrogen deficient (huminite and inertinite) components. Variations in threshold values, combined with low maturation gradients, translates into large depth differences between oil and gas generation for different types of organic matter (Powell and Snowdon, 1983).

Significant generation of liquid hydrocarbons from Type III organic matter begins at vitrinite reflectance 0.7% R_o and peaks at 1.0-1.2% R_o. However, recent work by Snowdon (1980), Connan and Cassou (1980) and Snowdon and Powell (1982) have suggested the existence of an early, immature gas-condensate, light naphthenic oil phase, derived from terrestrial organic matter at a vitrinite reflectance of $<0.6\%R_o$. Recent models have proposed and incorporated resinite as a potential petroleum source for hydrocarbons produced at low levels of maturation. Resinite is readily extracted with solvents and is 100% volatized on mild thermal treatment (Snowdon, 1980). Samples with 10% resinite would be classed as excellent source rocks for generation of liquid hydrocarbons at low levels of maturation (Snowdon and Powell, 1982). The geological parameters controlling the distribution of resinite in sediments is not clear.

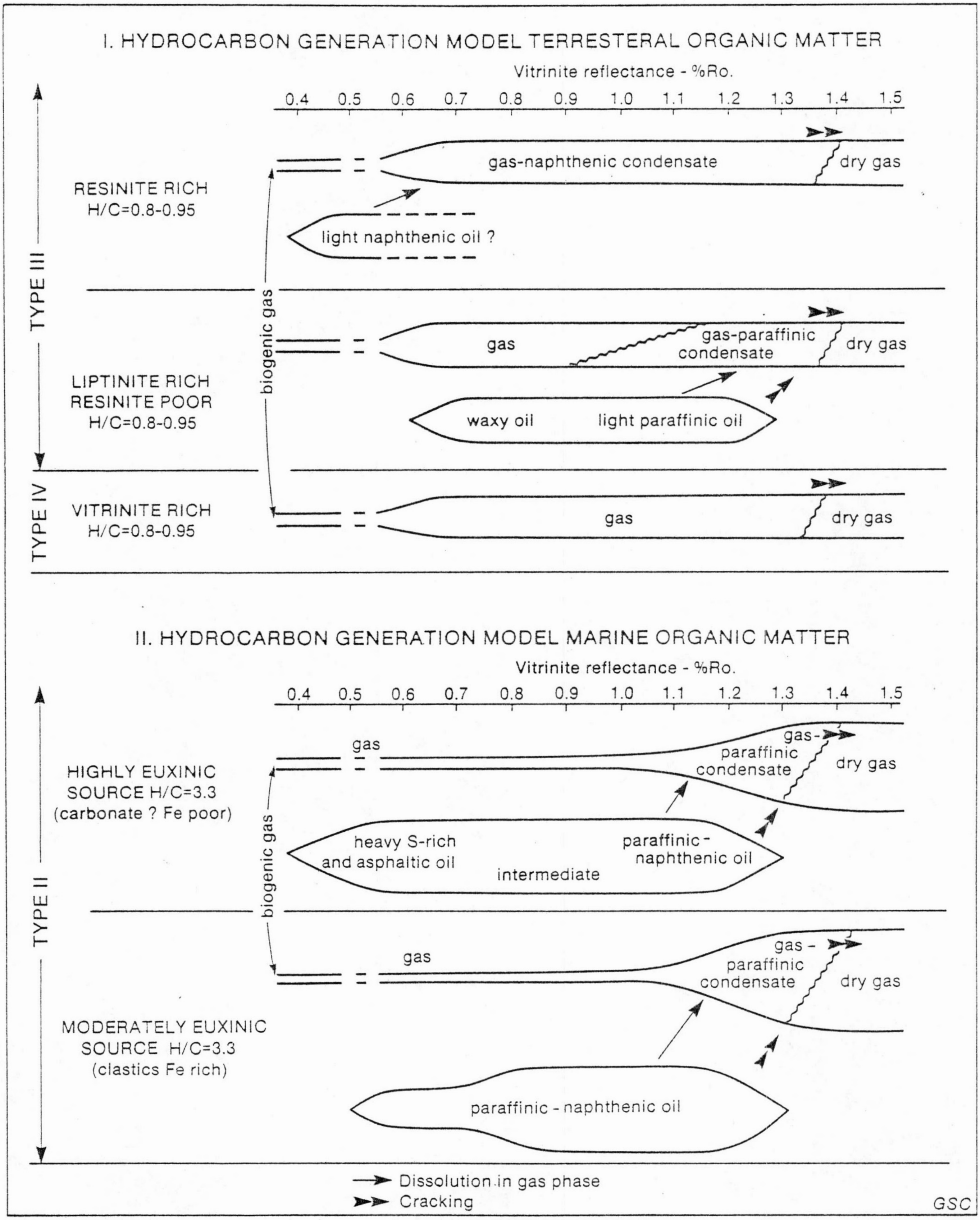
The main phase of gas generation has generally been considered a late stage product at vitrinite reflectance levels exceeding 1.3%. Recent work suggests different organic matter types show significant variations in timing and quantity of gas generation. Monnier et al. (1983) using cuttings gas analysis data from Arctic Canada, demonstrated the principal phase of gas generation for Type III organic matter begins at $0.55\%R_o$ and reaches a maximum at the onset of liquid hydrocarbon generation ($0.7\%R_o$). In Type II organic matter, there is a dramatic increase in gas yield in the late mature and overmature zones as liquid hydrocarbons are cracked. Gas generated from Type III material is three times that generated from Type II organic matter in the mature zone. There may be differences in the timing of gas generation in different basins because of variation within organic matter types and maturation.

Powell and Snowdon (1983) have devised a composite hydrocarbon generation model for Type II and III organic matter, considering both relative gas generation capability and immature light oils and gas-condensate from a resinite source (Fig. 30). Such a model has important implications for the hydrocarbon potential on the Scotian Shelf.

IV.2 Source Rock Criteria

A potential source rock, capable of generating significant accumulations of hydrocarbons, requires sufficient quantities of the proper type of organic matter at adequate levels of thermal maturation. Thus, sediments within the immature zone possess no potential. Within the marginally mature zone, Type II and resinous Type III organic matter may source liquid hydrocarbons. Type III material has some potential for gas. In the fully mature zone, all types of organic matter may source oil and/or gas, however, the nature and quantity of the hydrocarbons depends on the quality and volume of organic material in the sediments. The extrapolation of organic rich, immature rocks to potential source rock may be accomplished through knowledge of regional trends in geothermal gradient, age, and nature of the organic matter in the sediments.

Potential oil source rocks have been defined in terms of the quantity of extractable hydrocarbon in the sediment. The extract data has been normalized to account for the total organic carbon content of the sediment.



COMPOSITE HYDROCARBON GENERATION MODEL FOR TYPE II AND III ORGANIC MATTER
(from Powell and Snowdon, 1983)

Figure 30

Powell (1978) defined hydrocarbon yield as follows:

Extract Yield (mg/gm OC)	Source Potential
<30	poor, oil nil, gas only
30-50	fair, minor oil, gas-condensate
50-80	good
>80	excellent

The proportion of hydrocarbons in the total extract should exceed 40% before being considered.

A qualitative estimate of gas potential may be made by measuring cuttings gas. Hydrocarbon gas generation can occur throughout the sedimentary section (Snowdon, 1980). Estimates of absolute quantities of gas generated are somewhat speculative, in light of the difficulty of analysing cuttings gas and the effects of migration enrichment or loss. Rashid *et al.* (1980) proposed the following limits for gas source rocks:

Total Cuttings Gas	Gas Source Potential
<5000 ppm	poor
5000-10,000 ppm	fair
>10,000 ppm	good

Monnier *et al.* (1983) for Canadian Arctic basins, proposed the following normalized gas source potential criteria:

Cuttings Gas Yield (ppm vol. /% TOC)	Gas Source Potential
<10,000	nil or limited
10,000-25,000	moderate
>25,000	excellent

The above values are unique to the system of analysis and can only be applied to homogeneous shale units. Threshold values may vary from basin to basin due to the degree of compaction of the sediments and variations in organic matter.

The gas source potential classification adopted by Rashid et al. (1980) has been used in this study. Ideally, a qualitative estimation of gas source potential using normalized values to account for the total organic carbon of the sediment would be more suitable, but is not presently available.

Connan and Cassou (1980) have used pristane/n-C_{17} ratios and i-C_4 to n-C_4 ratios to distinguish immature gas-condensates produced at low levels of maturation. Immature condensates are characterized by pristane /n-C_{17} ratios greater than 1.0. Associated gases produced with immature condenstes have i-C_4/n-C_4 ratios greater than 0.8, whereas gases produced with crudes or mature condensates are less than 0.8. Monnier et al. (1983) have used i-C_4/n-C_4 ratio to identify the onset of optimum gas yield in Type III organic matter. A dramatic increase in gas yield at reflectance levels of 0.55 to 0.65 are accompanied by a reduction in the i-C_4/n-C_4 ratio from 1.0 to 0.6. The above quoted values may have some use when interpreting hydrocarbon potential on the Scotian Shelf. However, caution must be used as the relationships are not absolute. The relatively poor knowledge of the relation of condensate and wet gas components to the type of organic matter, reduces the reliability of interpretations (Heroux et al., 1979). The content of adsorbed light gases is also sensititive to the lithology of the sediments (Feugére and Gerard, 1970).

V. REGIONAL EVALUATION OF THE HYDROCARBON SOURCE POTENTIAL

This section of the study uses previously discussed data on maturation and quantity and type of organic matter to re-evaluate the regional hydrocarbon potential of the Scotian Shelf. Recent models for hydrocarbon generation from terrestrial organic matter are carefully considered.

V.1 Abenaki Subbassin

The Abenaki Subbasin has been evaluated primarily on geochemical and maturation considerations of four wells: Penobscott B-41, MicMAc D-89, Sachem D-76 and Sauk A-57. Even though these four wells represent only 20% of the wells drilled in the subbasin, it is believed these are fairly representative of the area. Wells in which no geochemistry was available were considered in terms of maturation and depositional environment, in order to supplement data from the above four wells. Penobscott B-41 lies at the southwest corner of the subbasin, MicMac D-89 covers the north edge, Sauk A-57 the south edge and Sachem D-76 the eastern portion. The northeast edge in the vicinity of Esparanto B-78 is unfortunately not represented. These four wells, though widely spaced, show remarkable similarity in a number of geochemical and maturation parameters and display predictable spatial variation within the subbasin.

To date, hydrocarbons discovered in the Abenaki Subbasin have been limited to local, minor oil and gas shows. No commercial accumulations have been located. The subbasin contains up to 10km of sediment with apparently adequate reservoir characteristics, down hole temperatures and organic matter. However, the terrestrial nature of the organic matter combined with relatively low geothermal gradients has precluded the development of significant hydrocarbon generation in the section drilled.

The fully mature zone within the Abenaki Subbasin is generally encountered within the carbonates of the Abenaki Formation or lower MicMac Formation. The Abenaki carbonates are lean in organic matter and are unlikely to source hydrocarbons. No organic rich layers have been penetrated within the formation (Eliuk, 1978). Reservoir quality rocks, other than local dolomitized zones developed on paleo-highs are rare in the carbonates. Consequently, an evaluation of hydrocarbon potential in the subbasin must be based on the sedimentary section below the Abenaki Formation and lower MicMac.

The geochemical character of sediments in the Early Mesozoic is not well known. The Triassic and lowermost Jurassic, Eurydice and Argo Formations consist of continental red beds and salt and therefore likely have limited source potential for commercial accumulations. The Mohican Formation is a dominantly clastic sequence deposited in an alluvial to coastal plain environment with local, shallow marine incursions (Jansa and Wade, 1975). The organic matter is likely predominantly terrestrial, although local, thin, organically rich shales may be present. The Iroquois Formation is a dolomitic sequence deposited in a coastal sabka and tidal flat environment. The preservation potential of organic matter in this environment is low. Local development of restricted circulation and anoxia may result in thin organic rich layers. In the Abenaki J-56 well, a number of oil and gas shows were encountered within chalky limestones and bituminous shales in the Iroquois Formation. In the deeper parts of the basin, some of the lower Mesozoic sediments may lie within the overmature zone and have potential for dry gas only. This does not preclude liquid hydrocarbon generation at shallower depths of burial and subsequent accumulation and preservation within younger reservoirs.

The top of the marginally mature zone occurs within lower Cretaceous sediments in the Abenaki Subbasin. The sediments above this are immature and have no source rock potential. The marginally mature zone includes sediments of the lowermost Logan Canyon, Missisauga and MicMac Formations; representing continental to inner neritic depositional environments. The organic matter is principally terrestrial and rarely exceeds 2%. Sand-shale ratios are very high. In the western section of the subbasin, organic carbon in the dominantly clastic sequence, averages < 0.5% and is only slightly higher in the eastern portion. Total and wet gas data indicate that the organic matter is lean. Total gas in several narrow horizons exceeds 10,000 ppm, but the gas is invariably less than 25% wet. Generally, oil and gas shows appear to correspond to increases in organic carbon to 1.5% or more. The evidence suggests the hydrocarbons were principally generated insitu within the marginally mature zone, however, the apparent lack of sufficient quantities of quality organic matter precludes the likely discovery of significant accumulations. There may be some potential where the lower MicMac Formation is in the fully mature zone.

Evidently, source rocks are limited to organically enriched shales and coaly beds within the Missisauga and MicMac Formations. Potential source beds are likely local, thin and of limited areal extent, due to the continental nature of the sediments. A large proportion of the organic matter in this environment may be reworked and hydrogen depleted.

In summary, the accumulation of potential economic liquid hydrocarbon deposits in the Abenaki Subbasin is nearly nil. The organic matter is of insufficient quantity and terrestrial in nature within the marginally and fully mature zones. Full maturity is not encountered until the lowermost MicMac or Abenaki Formations. The Abenaki Formation has low potential for generating or reservoiring hydrocarbons. Early and Middle Jurassic sediments, from environmental consideration, also have low potential, though little is known of their geochemical character. Significant quantities of gas may be sourced from these beds or from the shales and coaly beds of the Missisauga and MicMac Formations, however, the organic matter in the four wells analyzed to date is lean and the gas is dominantly methane.

There may be some potential for discovering hydrocarbon filled reservoirs on the periphery of the subbasin if source rocks in basinal facies of the Sable Subbasin, possibly shelf edge or continental slope, possess the necessary migration pathways to reservoirs on the margin.

V.2 LaHave Platform and Canso Ridge

Geochemical data on the sediments in this area of the shelf is limited to organic carbon and cuttings gas analyses of three wells. The main concern in evaluating the source potential of the areas landward of the basement hinge zone is maturation. Total sediment thickness exceeds 2300 m in only one well on the platform, Wyandot E-53. The Oneida O-25 well is located in a down faulted block along the basement hinge zone and though positioned on the platform, sediments in this well are similar to those found in the Sable Subbasin. Therefore, Oneida O-25 will be discussed in the context of the Sable Subbasin.

All but a few wells above the basement hinge zone have any potential for indigenous hydrocarbon, as the sediments are immature to basement. The sedimentary section on the platform is condensed relative to the subbasins, thus at equivalent depths, rocks on the platform are older. The top of the marginally mature zone is 200 to 400 m shallower than in the subbasins.

Lower Cretaceous and Jurassic sedimentation was primarily continental with minor non-marine and shallow marine environments. Paleoenvironmental considerations indicate sediments are dominated by terrestrial organic material except during occasional marine incursions. At the low levels of maturation encountered in these wells, only gas may be generated. Geochemical data indicate organic carbon and total gas is low within these sediments. Organically enriched marine shales have generated oil in very small quantities at the Erie D-26 and Wyandot E-53 wells. This oil has been generated from early Late Jurassic sediments at a vitrinite reflectance of less than 0.60%R_o.

Local graben structures containing thicker sedimentary sections may have some potential for minor oil and gas.

V.3 Orpheus Graben

Organic rich rocks have not been penetrated within wells drilled in the Orpheus Graben (Eliuk, 1978). No significant shows of hydrocarbons have been recorded. Triassic and much of Jurassic time was dominated by continental to marginal marine sedimentation. Part of the section, particularly late Early Jurassic to early Middle Jurassic, is missing due to erosion or non-deposition. The organic matter is apparently sufficient in some sections, however, the material is of terrestrial origin, degraded, and geochemically displays poor gas potential and no oil potential. There is some marine influence in sediments deposited during the Cretaceous, but the section is immature.

V.4 Continental Slope

There is a lack of data on the hydrocarbon potential of the Scotian continental slope, however, a number of aspects deserve discussion.

The two wells drilled on the slope to date are thermal anomalies, having average geothermal gradients exceeding 3.0°C/100 m. The elevated gradients in the Acadia K-62 well appears to be related to the heat anomaly associated with the carbonate front discussed previously. In Shubenacadie H-100, the high gradient is clearly related to overpressured Tertiary and Late Cretaceous shales. Interval gradients greater than 5.0°C/100m have been recorded near the bottom of this well. Calculated maturation indicates a vitrinite reflectance of only 0.41% R_o at a static bottom hole temperature of 104.5°C. The relatively young age of the sediments and short residence time in high temperature regimes has precluded any significant maturation.

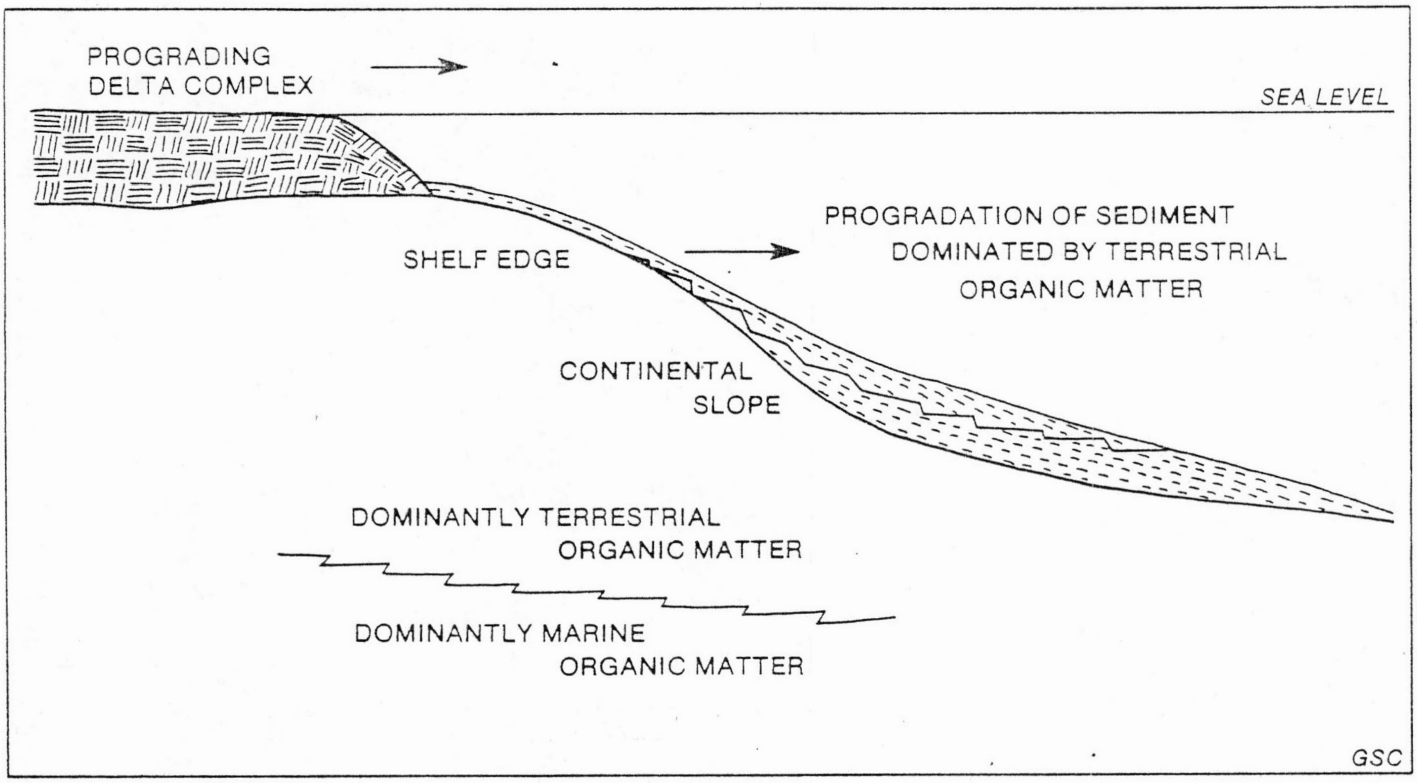
Extract data from Acadia K-62 suggests the organic matter in some intervals has good hydrocarbon producing potential. A lack of significant quantities of organic matter means the section has only limited or poor source potential. The trend of low organic matter and poor source potential of carbonate rocks on the Scotian Shelf, likely continues to carbonate rocks on the continental slope.

Shales as source rocks on the Scotian slope may be empirically evaluated. Primary concerns include the quantity of organic matter present and the relative percentage of marine and terrestrial components. Modern analogues may help to understand the distribution of organic matter in Verrill Canyon shales in relationship to the Sable Delta complex.

Modern prodelta muds of the Louisiana Gulf Coast (Dow and Pearson, 1975) and Amazon River (Bezrukov et al., 1977) delta complexes contain on average, less than 1.0% total organic carbon. These low values result from dilution effects caused by high sedimentation rates, rather than degradation or non-deposition, although these may still be important. The average organic matter content may be low but the overall volume of sediments is large. Logically, a terrestrial component of predelta shales will be greater proximal to the delta front, and decrease basinward. The distance from the delta front at which the accumulation of sufficient quantities of marine organic matter may source liquid hydrocarbons (assuming sufficient maturation) is difficult to assess. It is generally a complex function of paleo-oceanography (primary biological activity, currents, etc.) and preservation potential. Given the progradational nature of a delta complex, the dominantly marine organic matter section transition will be closer to the shelf edge in older sediments, assuming other factors are static (Fig. 31).

Applying the model in Figure 31 to the Scotian Basin, it is tentatively proposed that Middle and perhaps early Late Jurassic, Verrill Canyon Formation shales contain a larger proportion of marine organic material than subsequent prodelta muds. Whether the larger marine component is sufficient to significantly affect the evaluation of source potential is still open to speculation. The point at which marine organic matter accumulation becomes significant may be in water depths beyond present drilling technology. In any event, some of these source rocks may be into the overmature zone, although liquid hydrocarbons could have been generated earlier and released to shallow reservoirs.

An equally important concern is the distribution of reservoir facies on the slope or possible migration pathways to clastic reservoirs on the shelf. A number of seismic reflectors in Jurassic and Cretaceous sedi-



SCHEMATIC CROSS SECTION - SCOTIAN SHELF

Figure 31

ments on the lower slope and rise suggest the presence of turbidites and cherty and/or carbonate horizons (Jansa and Wade, 1975). Eliuk (1978) recognized a number of breaches in the Late Jurassic carbonate bank which presumably acted as conduits for the turbidites. The reservoir quality of these sediments is unknown.

Overpressured shales, combined with elevated temperatures and significant hydrocarbon generation, may provide a situation where fracturing within the shale may result. There can be both generation and entrapment of hydrocarbons within the fractured shale source beds. The Altamont field in the Uinta Basin of Utah is an example of this type of trap (Baker and Lucas, 1972). Obviously, this is a very high risk prospect in frontier areas; its recognition being most difficult.

Migration pathways of potential hydrocarbons from slope shale source rocks to shelf reservoirs are likely restricted to deep seated faults associated with the shelf edge and turbidites, although the latter may be of insufficient extent to have drained large areas of source rock to shallower reservoirs. The Abenaki Formation has very low porosity except in localized dolomitized zones on the paleo shelf edge (Eliuk, 1978). Unless fracturing is adequate, the formation will act as a seal, restricting potential reservoirs to Lower and lower Middle Jurassic sediments. This does not apply to the Sable Subbasin, where the carbonate front lies some distance north of the present day shelf edge.

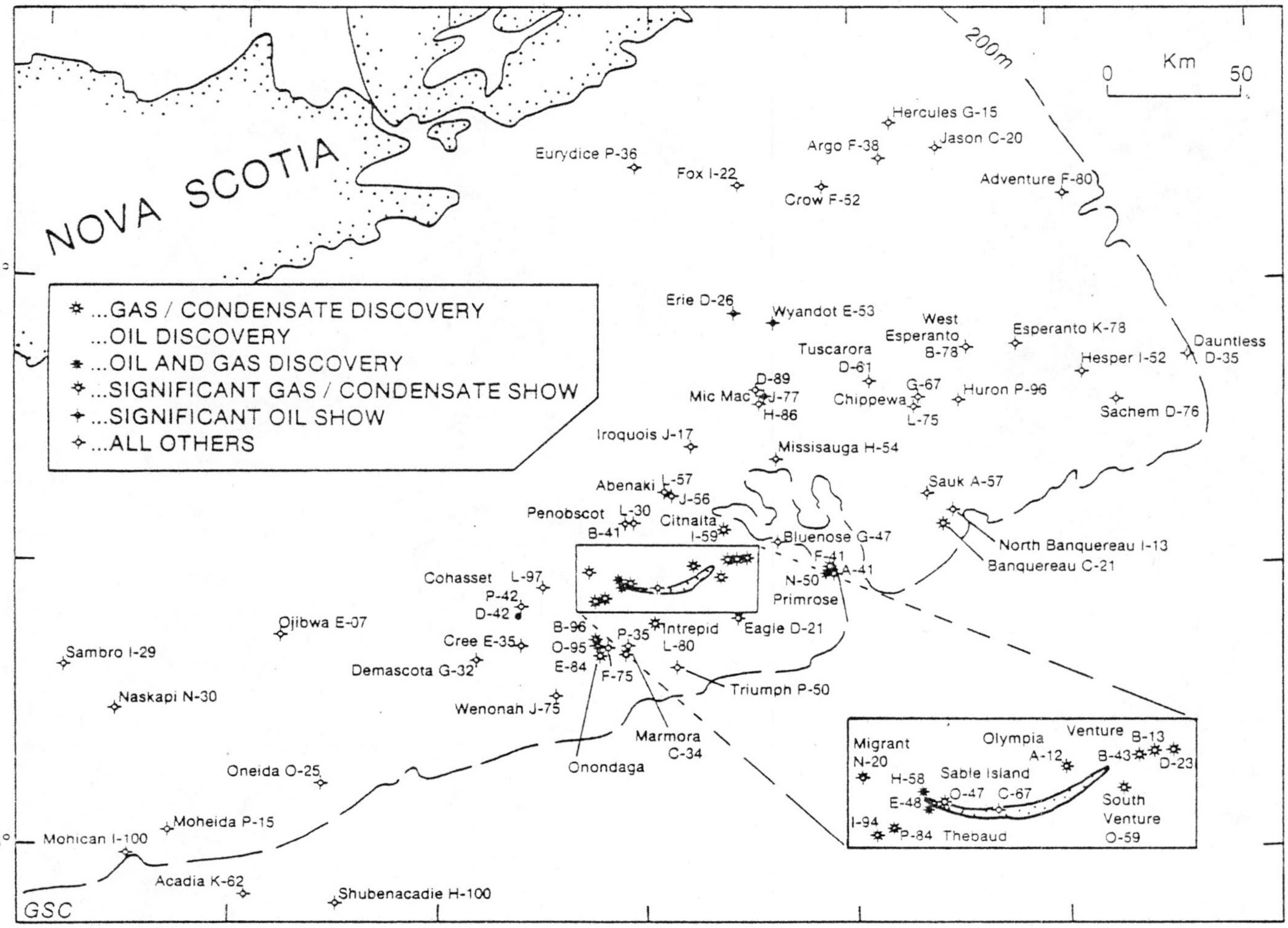
In summary, the hydrocarbon potential of the Scotian Slope must be rated fair to poor. High geothermal gradients aided by shale overpressuring are evident, but rapid subsidence and short cooking time for sediments have resulted in the section being immature to at least the Lower Cretaceous. The amount of organic matter in the sediments is moderate at best and likely contains significant amounts of terrestrial material. The marine organic matter component is unknown. It may or may not be significant. A lack of slope reservoir facies and/or migration pathways to upper slope and shelf reservoirs is suspected. Consequently, plays on the Scotian Slope are considered very high risk.

V.5 Sable Subbasin

A total of 19 wells with substantial geochemical and maturation data were used to evaluate the hydrocarbon potential of the Sable Subbasin. Maturation and paleoenvironmental data from the remaining wells were used to supplement the main data base.

Virtually all the significant hydrocarbon discoveries and notable shows have been found in the Sable Subbasin (Fig. 32). Hydrocarbons are predominantly gas and condensate with minor, local occurrences of light oil. Pristane/phytane ratios indicate oils and condensates were at least in part, derived from terrestrial organic matter (Powell and Snowdon, 1978). Purcell et al. (1979) suggest that in thermally immature basins the presence of a gas-condensate above an oil window may be the norm. The normal sequence of immature dry gas, mature oil and overmature condensate and dry gas is not evident. On the Scotian Shelf, it appears the marginally mature zone is characterized by gas and minor condensate. Gas-condensate and minor light oil have been generated within the oil window. There is little evidence of overmature products being trapped in explored reservoirs. The relative amounts of gas-condensate and light oil produced in the fully mature zone is strictly a function of the quality and quantity of organic matter. Maturation is subordinate to this consideration.

Geothermal gradients, maturation and the quantity of organic carbon



HYDROCARBON OCCURRENCES ON THE SCOTIAN SHELF

Figure 32

in the Sable Subbasin have all been discussed previously and deemed adequate for hydrocarbon generation. Using hydrocarbon yields from extract, a number of trends in relation to maturation, lithology and oil and gas occurrence can be investigated. Oil accumulations will be dealt with in a separate section due to the unique conditions under which oil is found in the Sable Subbasin.

No widely recognized definitive source beds have been cited in the Sable Subbasin. Powell (1982) defined good to excellent source rocks in Verrill Canyon and laterally equivalent Missisauga and MicMac Formation shales within the fully mature zone. The best source rocks are confined to a band extending from Cree E-35, eastward through Venture D-23. Seaward, the oil source potential deteriorates to fair. This either reflects greater source potential for older Verrill Canyon and equivalent shales in the Sable Subbasin area or favourable conditions of deposition, resulting in enhanced preservation of organic matter. Even where extract data indicates oil prone organic matter, the hydrocarbons generated are predominantly gas and condensate. This is attributed to the terrestrial nature of the organic matter. Also, modest amounts of organic carbon in the sediments means insufficient oil can be generated to reach saturation and allow migration.

It may be possible to empirically estimate the minimum values of organic carbon needed for the generation of significant amounts of hydrocarbons in the fully mature zone. Venture D-23 and Migrant N-20 show no hydrocarbon potential in the fully mature zone until particularly rich organic sediments were encountered. In Migrant N-20 this corresponds to a zone averaging greater than 2.0% TOC and reaches a maximum of 4.0% TOC. In Venture D-23 the organically rich zone averages greater than 1.5% TOC and occasionally exceeds 4.0% TOC. Immediately above, in the fully mature zone, organic carbon averages about 0.57% TOC and extract data shows no source potential. Therefore, a value of 1.5% TOC in sediments may be a reasonable minimum for source rocks in the Sable Subbasin. Hydrocarbons may be generated from source rocks with less than 1.5% TOC, but not in commercial quantities required for the offshore.

Previously, a minimum of 0.5% TOC has been considered adequate for potential shale source rocks. However it is reasonable to assume, given the paleoenvironmental considerations of a large delta complex, that a portion of the organic matter incorporated into sediments will be reworked. Similiarly, microbial and chemical oxidation of syngenetic matter in aerobic environments, as exists within a delta complex, results in hydrogen depletion and a reduction in hydrocarbon generating capability. Microbial degradation may take place under limited anoxic conditions, but is generally less efficient than aerobic degradation (Demaison and Moore, 1980).

Gas chromatograms of hydrocarbon extracts frequently display immature characteristics into the fully mature zone (Powell, 1982; Purcell et al., 1979). This reflects variable, often poor, source quality within potential source rocks or cavings. Atomic H/C ratios of kerogens in the marginally mature zone range from 0.73 to 0.88 and suggest some variation in potential (Powell, 1982). Total gas data indicates poor gas source potential.

The effects of lithology and consolidation of sediments on measuring total cuttings gas are well known (Monnier et al., 1983). Low total gas from cuttings may reflect actual low gas source potential or degassing of permeable lithologies during drilling. Useful measurements are rarely attained from sediments other than shaly lithologies, and even then, the data can only be used semi-quantitatively. Even the most favourable results on the Scotian Shelf indicate only fair gas source potential.

The most prolific hydrocarbon discoveries to date on the Scotian Shelf have been in the vicinity of Sable Island. Wells drilled to the south have produced only gas-condensate shows. On closer examination, it appears this distribution can be explained in terms of maturity and facies relationships, although many of the earlier wells did not drill as deep as recent discoveries.

A number of wells, including Cree E-35, Eagle C-21, Marmora P-35 and C-34, Onondaga B-96, Sable C-67, Thebaud I-94, Triumph P-50 and others were drilled to depths near the marginally mature-fully mature threshold. All of the above wells bottomed in the Verrill Canyon Formation. Only limited amounts of hydrocarbons are to be found where the fully mature Verrill Canyon shales are not adjacent to reservoir facies.

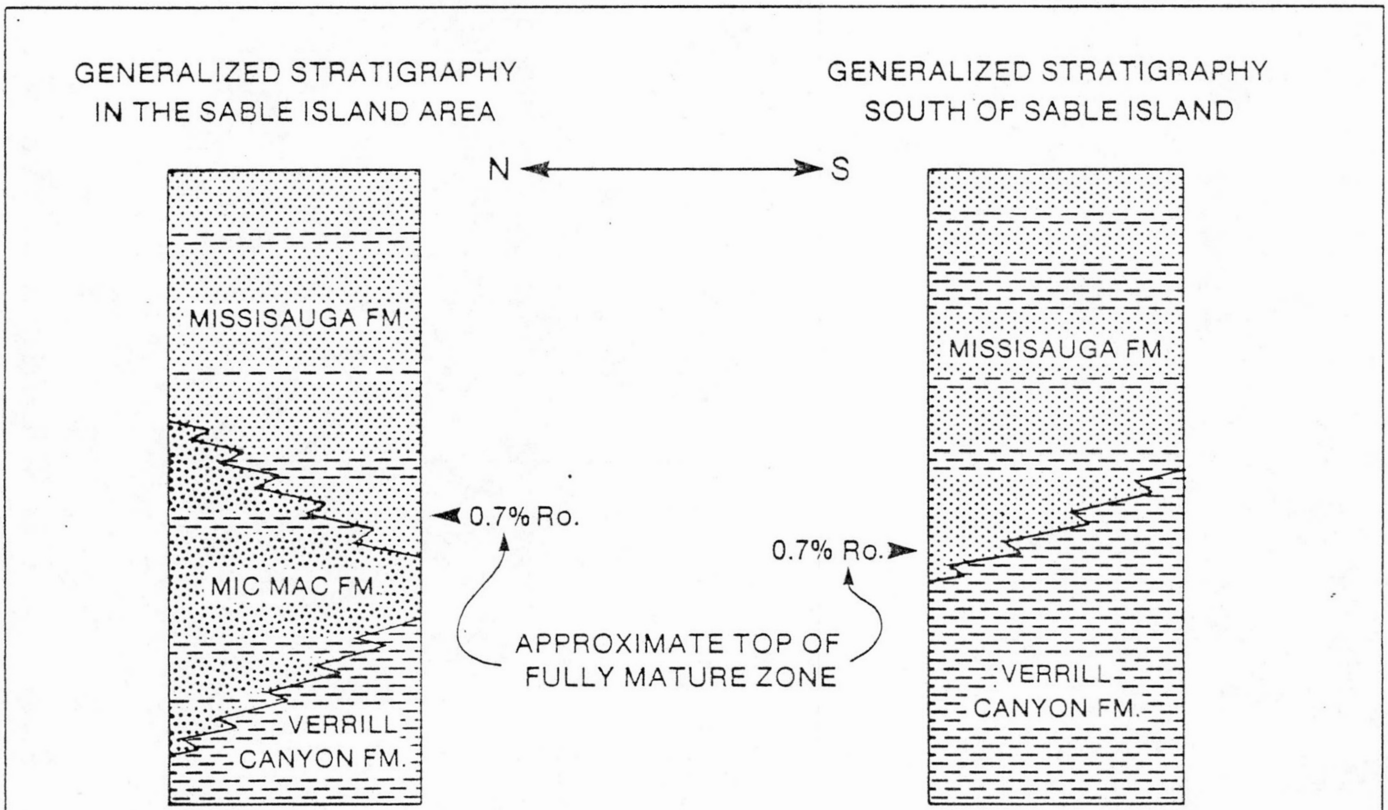
Presumably, the Verrill Canyon Formation does not contain reservoir facies. However, no well has tested regional Verrill Canyon and the presence or absence of some coarse clastics is open to speculation. Given the increased maturation and improved hydrocarbon potential indicated by extract data, there is a high probability of potential reservoirs being filled with liquid hydrocarbons.

Coarse clastics may be transported into the shale basin by turbidites and during regressive cycles. The late Early to early Middle Jurassic was a time of regional uplift and regression (Jansa and Wade, 1975). A second regressive cycle was initiated in post Kimmeridgian time. Recognition of large scale paleochannel features and breaches in the shelf edge carbonate bank may aid in locating turbidite facies. Insufficient maturation at depths where known reservoir facies are found means some mechanism for draining deeper, mature shale source beds must be in operation.

In contrast, in the Sable Island and Venture wells, potential shale source beds interfinger with reservoir facies. The area is a transitional facies between shale and coarse clastic sedimentation. The potential shale source beds are found deeper here, presumably because of the proximity of these wells to the paleodepocentre of the Sable Subbassin. However, the depth to the fully mature zone in this area is also deeper, because of the relatively rapid subsidence. South of the Sable Island area the shale facies encountered in drilling are barely into the fully mature zone and more mature sections cannot be drained due to a lack of good reservoirs (Fig. 33). More deeply buried reservoirs have the best opportunity for large hydrocarbon accumulations. This is limited to the Sable Island area and potential to the south depends on the presence of reservoirs within the deeper Verrill Canyon section.

Due to overpressuring, the base of the oil window in the Sable Island area may be as much as 1000m shallower than projected. Deep Jurassic shales may presently lie in the overmature, dry gas zone. More data is required to precisely define the oil window and the effects of overpressuring on maturation and temperature.

In summary, the Sable Subbasin contains nearly all of the significant discoveries and shows of oil and gas on the Scotian Shelf. The major discoveries occur in a east-west band in the vicinity of Sable Island. Gas with condensate are the principal hydrocarbons due to the terrestrial nature of the organic matter. Oil is rare and appears to be the consequence of maturation of organic matter under unique paleoenvironmental and structural settings.



MATURATION RELATIVE TO STRATIGRAPHY IN THE SABLE SUBBASIN

Figure 33

1/84

The spatial distribution of significant hydrocarbon occurrences is controlled by the depth of the fully mature zone in relation to stratigraphy, and the quality of organic matter. South of the Thebaud wells, Verril Canyon shales show fair oil source potential in the fully mature zone, but have only limited access to reservoir facies. In the Sable Island area, the fully mature zone occurs in potential reservoir clastics well above the top of the Verrill Canyon and shows fair to good oil source potential. The better source potential shown by extract data in wells in the Sable Island area may be more apparent than real. Seaward, wells have not penetrated to sufficient depths, where maturation significantly affects extract yields. Even though extract data indicates some potential for oil, the organic matter is terrestrial in nature and lean. The discovery of significant gas or oil in the southern Sable Subbasin depends on the existence of reservoirs in the Verrill Canyon, or the connection of shale source beds to shallower reservoirs via faults.

Some gas may be sourced from within the marginally mature zone, however, the quantity and quality of the terrestrial organic matter is poor.

V.6 Oil on the Scotian Shelf

Oil in moderate quantities has been found at only three locations on the Scotian Shelf, the West Sable, Cohasset and Primrose structures. In all cases the oil is a local pehnomenon resulting from unique conditions of maturation, organic matter quantity and quality and geological structure.

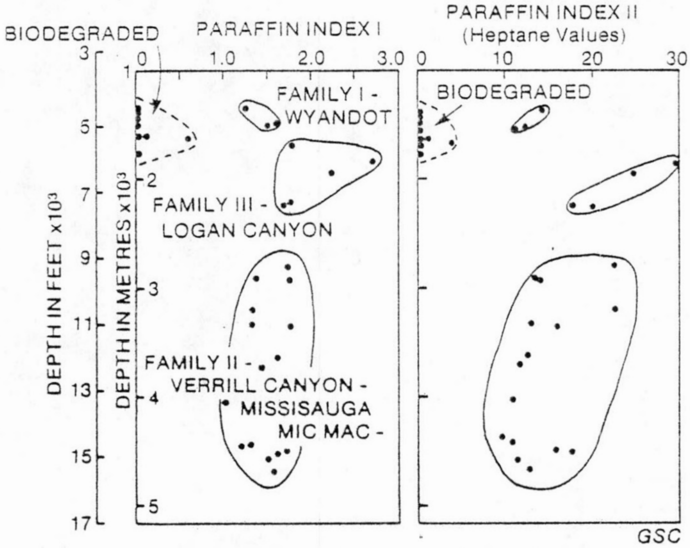
Enhanced maturation of oil prone organic matter at the Primrose structure, attendant with shallow piercement salt diapirsm, has been discussed by Rashid and McAlary (1977). Apparent discrepancies in various maturation indices at Primrose were discussed in an earlier section.

Oil at Cohasset D-42 and the West Sable structure are derived from mature, dominantly terrestrial organic matter. The paraffinic character and high pristane/phytane ratios point to a terrestrial source. Oils in these structures are slightly more, or as mature, as hydrocarbons occurring in older and deeper reservoirs. Powell (1982) using the paraffin indices of Thompson (1979) suggested the oils and condensates at Cohasset and West Sable are more mature than other occurrences (Fig. 34).

Paraffinicity in light hydrocarbon gases is indicative of maturation and frequently, maximum temperature attained, regardless of kerogen type. Paraffin indices are imprecise so that other interpretations are possible (Figs. 35 and 36). Re-interpreting Figure 34 (Fig. 37), it is apparent that the oils at Cohasset and West Sable were generated at levels of maturation equal to, or only slightly higher than other discoveries. From previous discussions, generation of hydrocarbons has occurred within the fully mature zone. There is no evidence of immature oils and condensates being generated on the Scotian Shelf. Consequently, the hydrocarbons at Cohasset and West Sable must have migrated from a deep, fully mature source along faults.

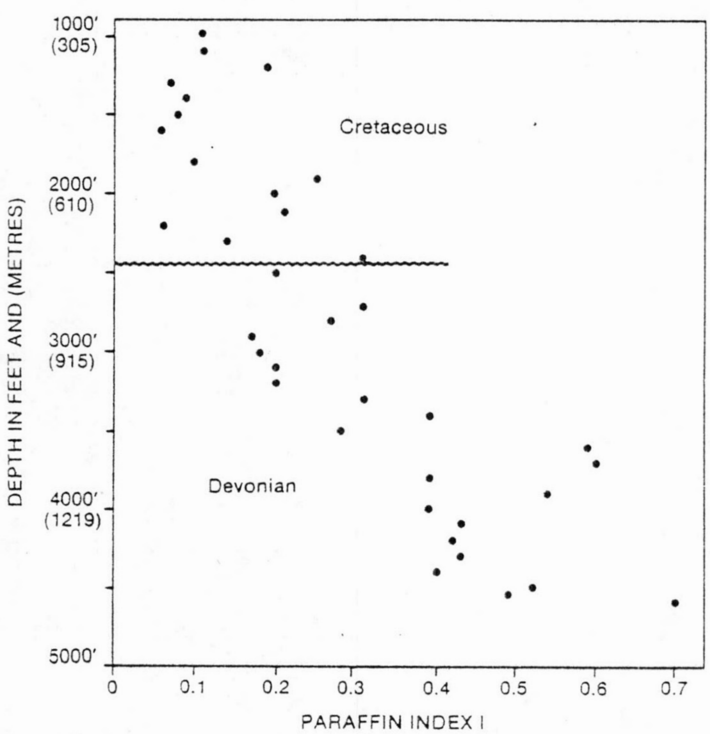
Gas to oil ratios have been used to estimate the relative importance of hydrocarbon generation (Connon and Cassou, 1980). Oils derived from terrestrial organic matter are restricted to the oil window zone and have a GOR of 200-400m^3/m^3 during peak generation. Differences in levels of maturation, organic matter type and migration effects can cause variations in the GOR. Oils at Cohasset are undersaturated with respect to gas, reflecting peak oil generation at depth or migration of gas away from the oil. A similar situation is evident at the West Sable structure where the

Figure 34



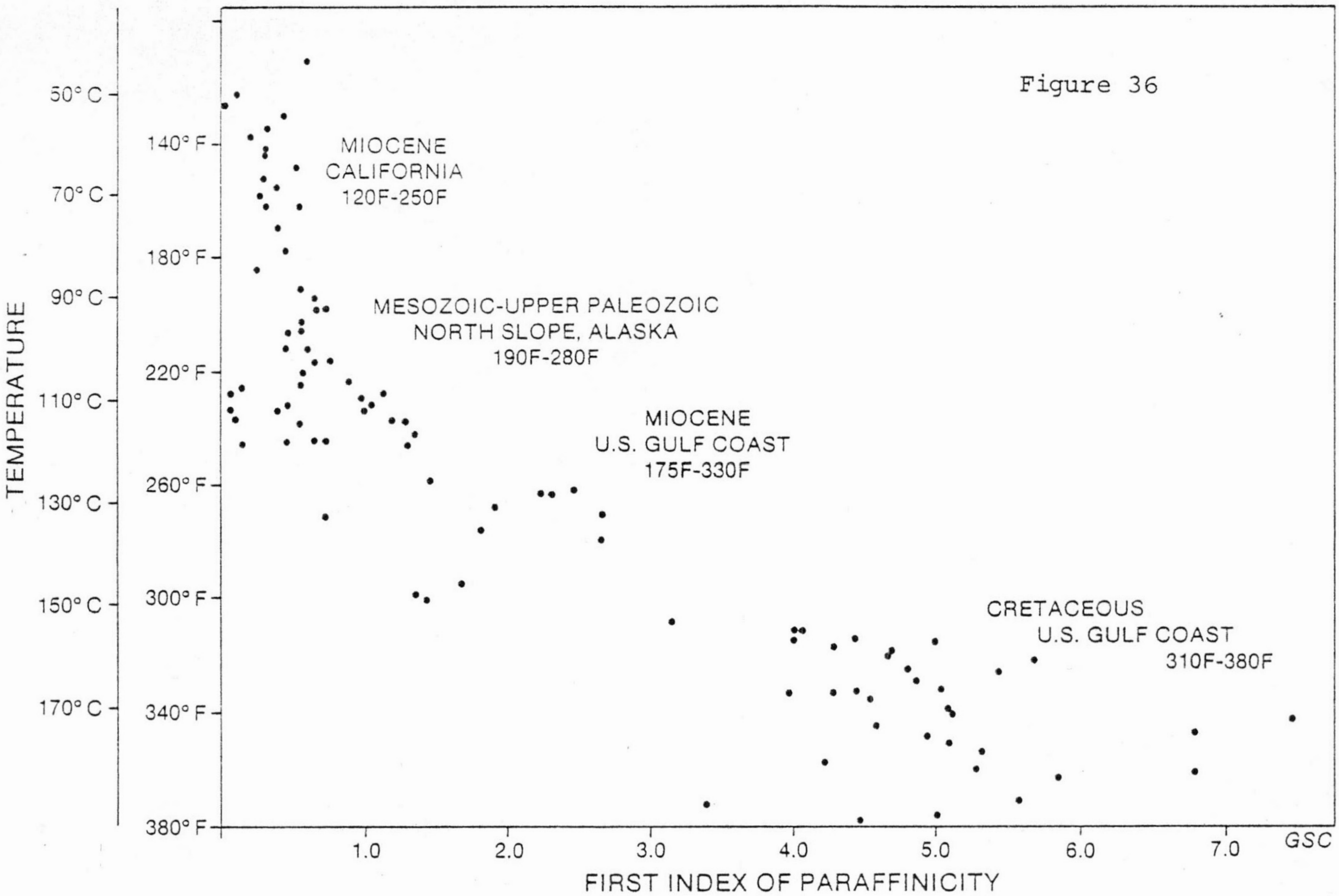
VARIATIONS IN PARAFFIN INDICES AT COHASSET AND WEST SABLE
(from Powell, 1982)

Figure 35



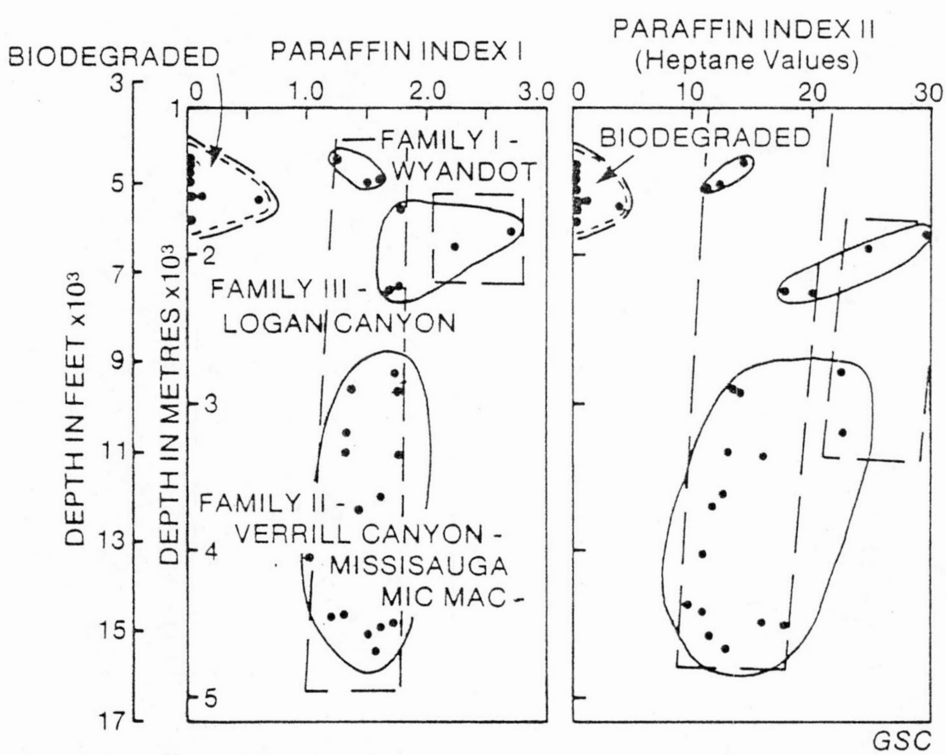
LINEAR ? ASSOCIATION BETWEEN DEPTH AND THE FIRST INDEX OF PARAFFINICITY
(from Thompson, 1979)

GSC



FIRST INDEX OF PARAFFINICITY VERSES MAXIMUM ATTAINED SUBSURFACE TEMPERATURE
(from Thompson, 1979)

Figure 37



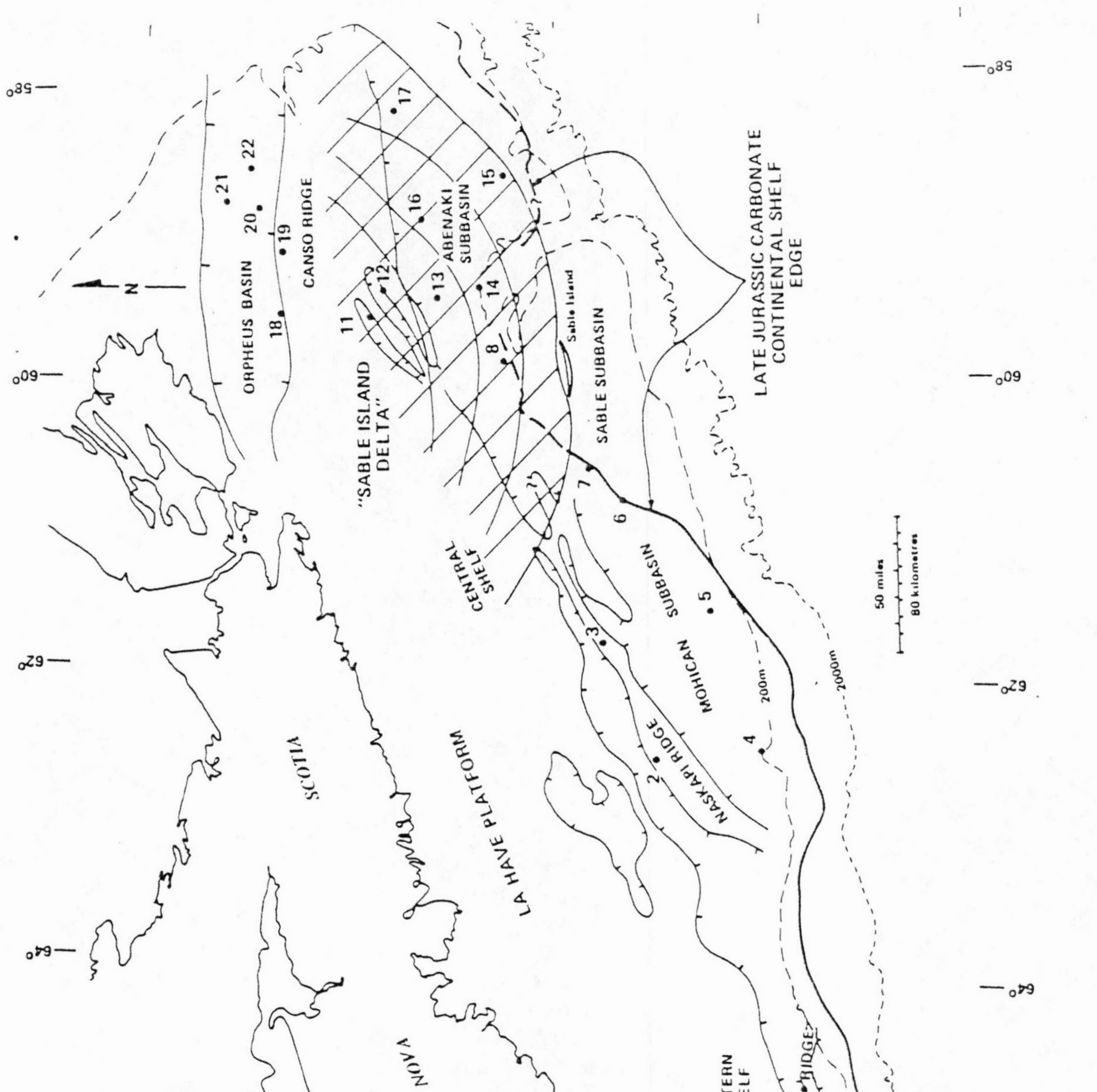
PARAFFIN INDICIES RE-INTERPRETED

GOR ranged from 61-6200 m^3/m^3. By contrast, the gas-condensate ratio in the Venture field ranges from 3000-20,000 m^3/m^3. Gas-condensate ratios of 32,000-300,000 m^3/m^3 have been recorded for hydrocarbons in the marginally mature zone (Connon and Cassou, 1980). Clearly, the oils at Cohasset and West Sable were generated at the peak of liquid hydrocarbon generation for terrestrial organic matter.

The above evidence points to a deep source, dominated by terrestrial organic matter, which has produced oil in the fully mature zone. These conditions exist elsewhere, why then has more oil not been discovered in the Sable Subbasin? The answer may lie in the quality and quantity of terrestrial organic matter in the source rocks. The influence of marine type organic matter may or may not be important. The occurrence of oil on the Scotian Shelf is related to the enhanced preservation of sufficient quantities of terrestrial type organic matter and subsequent maturation at vitrinite reflectance levels of 0.9-1.2% R_o.

The level of maturation has been chosen empirically, on the basis of pristane/phytane ratios, paraffin indices and GOR. Paraffin indices indicate generation of oil at slightly higher levels of maturation than elsewhere on the shelf. Gas to oil ratio estimates the relative importance of generation at a specific level of maturation.

A mechanism for the enhanced preservation of organic matter must be investigated. A low energy environment in moderately deep water, with moderate sedimentation rates; where microbial and chemical oxidation would be minimal, could be sufficient to produce substantial source beds. Evidence exists which suggests such conditions prevailed in the vicinity of the Cohasset and West Sable structures (Figs. 38A and B). The Late Jurassic carbonate front in the western section of the Sable Subbasin has



"SABLE ISLAND DELTA"
ORPHEUS BASIN
CANSO RIDGE
ABENAKI SUBBASIN
Sable Island
SABLE SUBBASIN
LATE JURASSIC CARBONATE CONTINENTAL SHELF EDGE
CENTRAL SHELF
LA HAVE PLATFORM
NOVA SCOTIA
MOHICAN SUBBASIN
NASKAPI RIDGE
WESTERN SHELF
MOHAWK RIDGE
200m
2000m
50 miles
80 kilometres
N
46°
45°
44°
43°
42°
58°
60°
62°
64°
1
2
3
4
5
6
7
8
11
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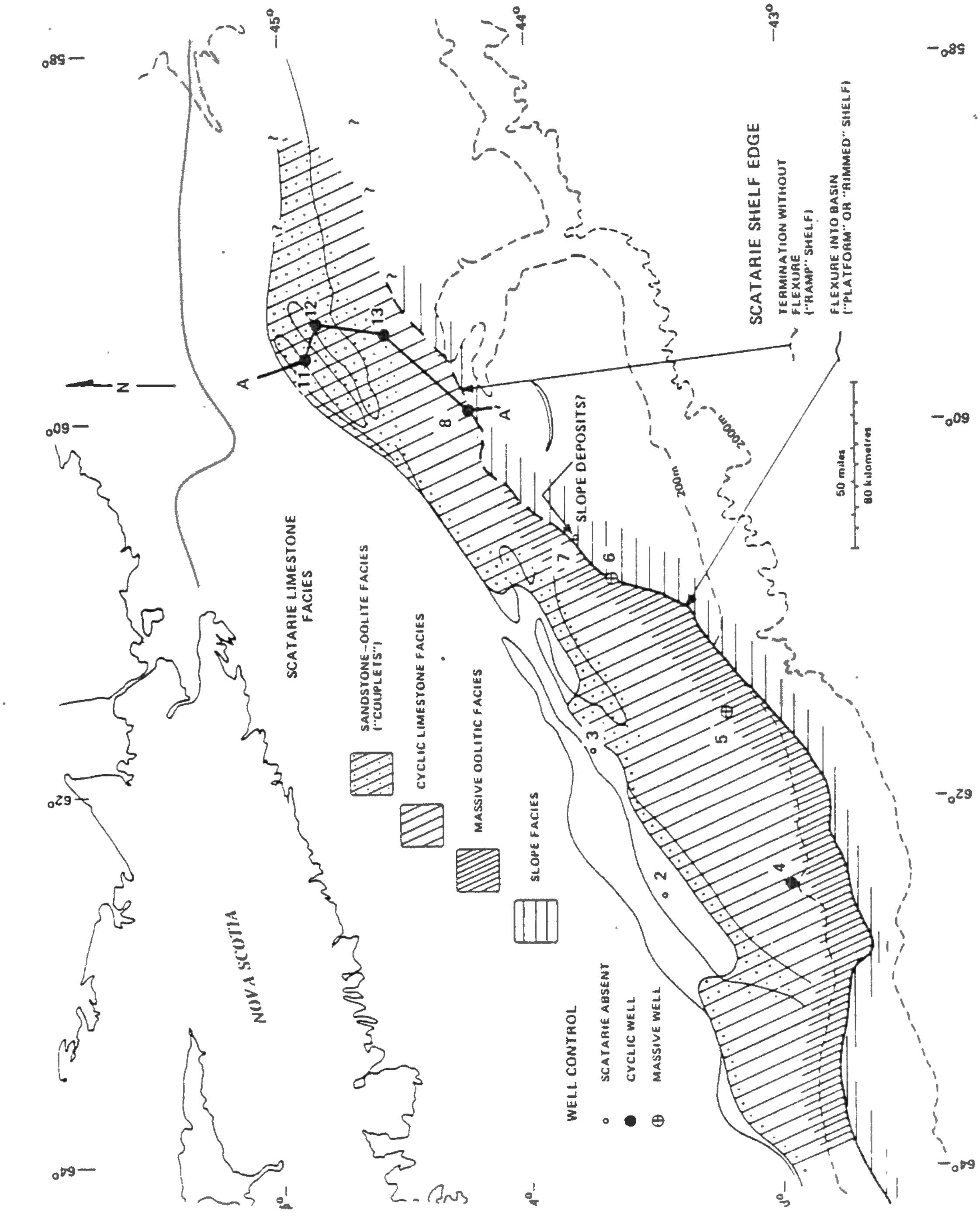
Figure 38a



NOVA SCOTIA
SCATARIE LIMESTONE FACIES
SANDSTONE-OOLITE FACIES ("COUPLETS")
CYCLIC LIMESTONE FACIES
MASSIVE OOLITIC FACIES
SLOPE FACIES
WELL CONTROL
SCATARIE ABSENT
CYCLIC WELL
MASSIVE WELL
SCATARIE SHELF EDGE
TERMINATION WITHOUT FLEXURE ("RAMP" SHELF)
FLEXURE INTO BASIN ("PLATFORM" OR "RIMMED" SHELF)
SLOPE DEPOSITS?
N
A
A'
200m
2000m
50 miles
80 kilometres
45°
44°
43°
58°
60°
62°
64°

Figure 38b

platform profile. Slopes of 20°-30° have been recorded for the flexure in the Sable Island area (Eliuk, 1978). The edge of the platform slopes down to deep water (1.0 km) in less than 3km. Paleoenvironmental studies indicate deep water eastward of the Mohican I-100 well during the Late Jurassic (Jansa and Wade, 1975). Deep water may be indicated in the Sable C-67 well, where a scarcity of microfauna was noted (Jansa and Wade, 1975).

Presumably, organic matter deposited in deep, semi-anoxic environments is subject to less biological and chemical degradation. Deep water Verrill Caynon shale deposition in the vicinity of Cohasset and Sable Island during late Middle and early Late Jurassic time, resulted in local enhanced preservation of terrestrial organic matter and was the likely source for oils at these structures. The presence of oil and condensate together at the West Sable structure suggests some variation in oil source potential. The lack of other oil discoveries in the area attests to the limited distribution of oil prone source rocks at sufficient levels of maturation. Subsequent prodelta Verrill Canyon shales are not likely to source oil due to lower quantities of organic matter (higher sedimentation rates and dilution) and relatively shallow water deposition (higher microbial and chemical degradation). The marine contribution to the organic matter is difficult to assess, but given the paraffinic nature of the hydrocarbons, pristane/phytane ratios and the levels of maturation, it is probably minor.

Differences in the pristane/phytane ratio may reflect variations in the degree of oxidation during the early stages of chlorophyll degradation (Powell and McKirdy, 1973). Variations in pristane/phytane may also reflect differences in maturation, but not to the degree where original source information is destroyed (Didyk et al., 1978). Interestingly, reported pristane/phytane ratios are highest in Cohasset D-42 oils and greater than average in the West Sable structure hydrocarbons (Powell and Snowdon, 1979). Whether this reflects different levels of maturation or degrees of oxidation is uncertain.

One must invoke vertical migration to account for the shallow reservoired hydrocarbons at the Cohasset and West Sable structures. In the case of West Sable wells, migration along faults as the result of salt diapirsm can be proposed. At Cohasset, faults associated with two types of structures may have provided migration pathways. Cohasset D-42 lies on the edge of the carbonate front and a number of growth faults associated with the platform edge are known (Wade, pers. comm.). The Cohasset structure also lies just seaward of a basement hinge zone which could have affected faulting.

In summary, oil in the Sable Subbasin is derived from source rocks containing dominantly terrestrial organic matter. The distribution of the oil prone source rocks are paleoenvironmentally controlled. These source rocks are to be found in Verrill Canyon shales deposited in late Middle to early Late Jurassic time, prior to significant prodelta shale deposition.

The local increase in oil potential is a function of enhanced organic matter preservation in a deep water low oxygen environment with moderate sedimentation rates. A mechanism of draining these deep source shales to shallow reservoirs must exist. Presumably, this is due to insufficient reservoir facies in the Verrill Canyon Formation. The lack of oil found in seaward wells with structural communication to deeper potential source rocks, reflects insufficient maturation or deterioration of source potential.

Oil shows in the Wyandot E-53, Erie D-26, MicMac J-77, Penobscott

L-30 and other wells, appear to be generated from minor lipid rich source rocks in the Missisauga and/or MicMac Formations within the marginally mature zone. However, the organic matter is likely of insufficient quantity to produce significant amounts of liquid hydrocarbons.

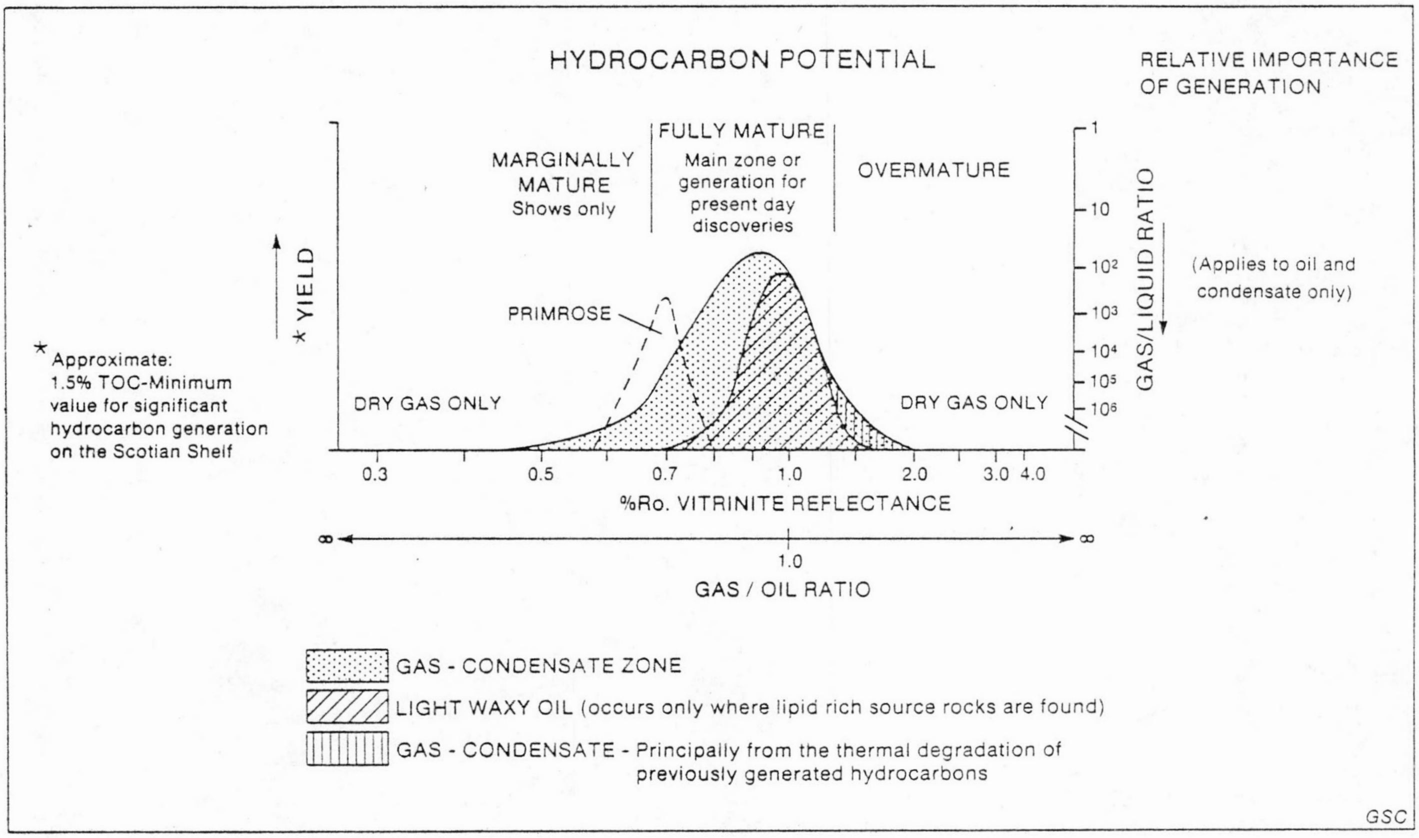
V.7 Hydrocarbon Generation Model

A hydrocarbon generation model has been devised for the Scotian Shelf based on organic matter quantity, quality, maturation and observed hydrocarbon discoveries (Fig. 39). The figure below applies only to hydrocarbons generated from terrestrial organic matter on the Scotian Shelf.

Total organic carbon has been used to estimate the intensity of hydrocarbon generation. In general, a minimum of 1.5% TOC in sediments is required to source substantial hydrocarbons on the Scotian Shelf.

Gas to oil or condensate ratio is a relative measure of the importance of a particular stage of hydrocarbon generation. Actual GOR values at a particular level of maturation vary considerably, due to differences in organic matter type and quality. The following general guidelines for the Scotian Shelf can be employed:

% R_0	Maturation Stage	GOR and GCR m_3/m_3
<0.45	immature	dry gas only
0.45-0.7	marginally mature	>20,000
0.7-1.3	fully mature	5000-20,000
0.9-1.2	peak oil generation	60-6000
1.5	over mature (thermal cracking of oils)	moderate to high
1.5	over mature (no previous oil)	very high



HYDROCARBON MODEL FOR THE SCOTIAN SHELF
(Diagramatic)

Figure 39

Oil generation on the Scotian Shelf is considered a subzone due to the unique conditions under which liquid hydrocarbons occur. Condensate generation is relatively minor within the overmature zone unless it is generated from the thermal cracking of previously generated liquid hydrocarbons. On the Scotian Shelf, the main phase of condensate generation is directly from primary organic matter within the fully mature zone.

CONCLUSIONS

1. The distribution of geothermal gradients on the Scotian Shelf are controlled regionally by basement topography and the distribution of salt. Areas of shallow basement which lack salt, have the lowest gradients. On a local scale, the distribution of gradients is a function of sand/shale ratio or the presence of carbonates. Subsurface fluid flow is proposed as the mechanism for a geothermal high parallelling the fault bounded carbonate front in the Sable Subbasin. However, increased primary heat flux from the basement hinge zone cannot be discounted. A broad geothermal low in the Abenaki Subbasin coincides with the Late Jurassic carbonate bank. The low results from a thick section of highly conductive lithologies of which limestone is most important. Overpressuring may have some effect on temperature and maturation profiles. More research is required to ascertain the magnitude of this phenomenon.

2. The organic matter on the Scotian Shelf is dominated by terrestrial material which is lean and gas prone. Only Late Jurassic and Late Cretaceous sediments contain sufficient amounts of amorphous organic matter to source liquid hydrocarbons. Total organic carbon is average and can reach high values, however, from paleoenvironmental considerations, the organic matter is likely degraded and contains a significant reworked component. Empirical observation suggests a minimum of 1.5% TOC is required for accumulation on the shelf. Organic matter types and TOC display distinct patterns related to the environments of deposition, and geologic time.

3. Vitrinite reflectance, TAI, TTI, cuttings gas analyses and threshold temperatures have been calibrated. Absolute values vary within the basin due to different age sediments and the fact each maturation indicator measures a unique process which proceeds at slightly different rates. The onset of significant hydrocarbon generation commences at a vitrinite reflectance of 0.70%. The depth at which this occurs reflects variations in subsidence rate and age. The hydrocarbons discovered to date, have been generated within the 'oil' window, though the principal products are gas-condensate. There is no evidence to suggest the gas-condensates are an overmature product, reservoired at shallow depths.

4. Recent studies suggest increased rates of transformation and colouration of organic matter at high rates of heating can cause large discrepancies between TAI and other maturation criteria. This may help to explain the apparent lack of correlation between various maturation indices at the Primrose salt diapir. The present day low temperatures are accounted for by invoking detachment and thermal insulation of the diapir from the mother salt and basement heat source. In the past the temperatures would have been much higher and of sufficient magnitude to generate hydrocarbons. Organic matter type may also play an important role.

5. The accumulation of liquid hydrocarbons in the Abenaki Subbasin, LaHave Platform and Orpheus Graben is unlikely. The organic matter is of insufficient quantity and quality to source hydrocarbons. The LaHave Platform is immature to basement and has no indigenous potential. Gas may be sourced from shales and coaly beds of the Missisauga and MicMac Formations in the Abenaki Subbasin, however, the organic matter is lean and the gas is predominantly methane.

6. The hydrocarbon potential of the Scotian Slope is rated poor. Though high geothermal gradients aided by shale overpressuring are evident, rapid subsidence and short cooking time for sediments have resulted in the section being immature to at least the Lower Cretaceous. A lack of slope reservoir facies and migration pathways to upper slope and shelf reservoirs is suspected.

7. The distribution of significant hydrocarbon occurrences is controlled by the depth of the fully mature zone in relation to stratigraphy and the quality of the organic matter. In the Sable Island area, potential source beds have good lateral communication to reservoir facies in the fully mature zone. South of Sable Island, the fully mature zone occurs within the Verrill Canyon Formation and has only limited access to reservoirs. Some gas may be sourced from within the marginally mature zone, however, the organic matter is lean.

8. Oil is rare and is the consequence of maturation of organic matter under unique paleoenvironmental and structural settings. Except at Primrose, the oils are derived from terrestrial organic matter. The local increase in oil potential is a function of enhanced organic matter preservation in a deep water, low oxygen environment with low-moderate sedimentation rates which existed in the late Middle to early Late Jurassic. A mechanism of draining these deep source shales to shallow reservoirs must exist. The lack of oil found in seaward wells with structural communications to deeper potential source rocks reflects insufficient maturation or deterioration of source potential.

RECOMMENDATIONS

1. Continuous monitoring of geothermal gradients and maturation profiles is suggested in order to better understand the geology and hydrocarbon potential of the Scotian Shelf. This report is a formated so that revision and updating are easily accomplished. Data from recently drilling wells may alter some of the conclusions of this study. As well data becomes available, ammendments to this report may be made and contour maps redrawn if required.

2. Investigations of overpressuring and its effects on downhole temperatures and maturation profiles are recommended. Only recently have wells been drilled to depths where overpressuring may affect the evaluation of source potential. Preliminary studies indicate a narrowing of the principal zone of hydrocarbon generation and elevated gradients. A functional relationship between the degree of overpressuring, enhanced maturation and elevated geothermal gradients may exist.

3. A study of potential hydrocarbon generation and suspected trap development using Lopatin's Time-Temperature Index, may provide clues to the distribution of hydrocarbons on the shelf and shape future exploration strategies. These studies were beyond the scope of this research. Detailed geological studies using quality seismic and biostratigraphic control is required.

4. The hydrocarbon source potential south of Sable Island depends on the existence of reservoirs in the Verrill Canyon Formation or structural communication of mature shales to shallow reservoirs. No wells have drilled

regional Verrill Canyon and investigations are warranted. Good source potential is indicated for late Middle early Late Jurassic basinal shales in the Sable Subbasin. There is a high probability of potential reservoirs being filled with hydrocarbons. The difficulty of locating reservoirs in the shale basin are considerable.

5. A continuation of the program for measuring vitrinite reflectance is recommended. Vitrinite reflectance data has been quite valuable in explaining anomalies and discrepancies in maturation data on the Scotian Shelf. Reflectance data will prove to be very useful for studying the effects of overpressuring on the shelf.

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EPGS REPORTS

WELL		PALYNOLOGY (EPGS-PAL)	KEROGEN TYPING & TAI (EPGS-DOM)	STRATIGRAPHY (EPGS-STRAT)	VITRINITE REFLECTANCE (EPGS-DOM)
Acadia	K-62	28-79PA 26-79GLW		1-81LFJ	
Adventure	F-80	8-79JPB	20-77MSB	8-80JAW	
Bluenose	G-47	15-78GLW	18-76MSB	38-79JAW	
Citnalta	I-59	1-79PA	16-77MSB	39-79JAW	
Cohasset	D-42	3-80PA	15-76MSB	40-79JAW	
Cree	E-35	7-78PA	6-77MSB	*	
Demascota		7-79PA	16-76MSB	42-79JAW	7-78MPA
Eagle	D-21		5-77MSB	*	
Intrepid	L-80	85-79PA	23-76MSB	*	
Jason	C-20		1-79MSB	12-80JAW	
Marmora	C-34	19-74FMG	27-76MSB	30-79JAW	
Marmora	P-35			31-79JAW	
MicMac	D-89		9-76MSB	54-79JAW	
Migrant	N-20	89-79PA		45-79JAW	
Ojibwa	E-07	1-77JB	15-77MSB	17-80JAW	
Onondaga	B-96			29-79JAW	
Onondaga	E-84	27-80EHD	17-76MSB	26-79JAW	
Penobscott	B-41			47-79JAW	
Sable Is.	C-67	5-73GLW	6-76MSB	*	
Sable Is.	4H-58		19-77MSB	22-79JAW	5-78MPA
Sable Is.	0-47			18-79JAW	
Sachem	D-76	41-80PA	14-77MSB	64-79JAW	
Sambro	I-29		21-77MSB	19-80JAW	
Sauk	A-57	24-81PA	12-77MSB	65-79JAW	
Thebaud	I-94	17-80PA		20-80JAW	
Thebaud	P-84	17-81EHD	20-78MSB	25-79JAW	
Triumph	P-50	10-77FMG	11-77MSB	34-79JAW	
Venture	D-23	84-79JPG 2-81PA		1-82JAW	6-81PAH/MA

* Offshore Schedule of Wells, Canada Oil and Gas Lands Administration, January, 1983

Other vitrinite reflectance data from Issler, 1982 and Powell, 1982

ADDITIONAL INTERNAL REPORTS

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Report 2. The Depth Related Maturation of Organic Matter in Mobil-Tetco Thebaud P-84, by M.A. Rashid and J.D. Leonard, 1974, 15p.

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APPENDICES

A Bottomhole Geothermal Gradients

B Top of Jurassic-Maturation and Timing of Potential Hydrocarbon Generation

C Top of Middle Jurassic-Maturation and Timing of Potential Hydrocarbon Generation

D Maturation Calculated from TTI at 3500m subsea

E Critical Threshold Values

F Temperature data and Subsidence Curves from Recently Drilled Wells

- Banquereau C-21
- Olympia A-12
- Arcadia J-16
- South Venture O-59
- Venture B-43
- Venture B-13
- West Esperanto B-78
- Shubenacadie H-100/100A

H Well Compilations of geology, biostratigraphy maturation, geochemistry, depositional environment, corrected temperatures, organic matter types and hydrocarbon occurrences.

Bottonhole Geothermal Gradients

(°C/100 m)   * penetrated salt
+ penetrated basement

Well	Gradient
Abenaki J-56	2.55
Abenaki L-57	* 3.13
Acadia K-62	3.13
Adventure F-80	* 2.53
Arcadia J-16	2.55
Argo F-38	*+ 2.05
Banquereau C-21	2.63
Bluenose G-47	2.39
Chippewa G-67	* 2.36
Chippewa L-75	2.41
Citnalta I-59	2.53
Cohasset D-42	3.08
Cohasset L-97	2.96
Cohasset P-42	3.39
Cree E-35	2.81
Crow F-52	+ 1.68
Dauntless D-35	2.26
Demascota G-32	3.07
Eagle C-21	2.69
Erie D-26	+ 2.24
Esperanto K-78	2.55
Eurydice P-36	* 2.96
Fox I-22	+ 3.51
Hercules J-15	* 2.61
Hesper M-52	2.61
Huron P-96	* 2.65
Intrepid L-80	2.76
Iroquois J-17	* 2.55
Jason F-20	* 2.07
Marmora C-34	2.51
Marmora P-35	2.54
MicMac D-89	2.55
MicMac H-86	2.49
MicMac J-77	2.51
Migrant N-20	2.64
Missisauga H-54	2.55
Mohawk B-93	+ 2.58
Moheida P-15	2.74
Mohican I-100	* 2.74
Montagnais I-94	+ 2.81

Naskapi N-30	+	3.06
Ojibwa E-07	+	2.56
Olympia A-12		2.65
Oneida O-25		3.04
Onondaga B-96		2.98
Onondaga O-95	*	2.77
Onondaga F-75		2.76
Onondaga E-84		3.06
Penobscott B-41		2.54
Penobscott L-30		2.59
Primrose A-41		2.84
Primrose F-41	*	3.10
Primrose N-50	*	3.45
Sable Island C-67		2.57
Sable Island E-48	*)	2.70
Sable Island 3H-58	)	-
Sable Island 4H-58	)	2.93
Sable Island O-47	*)	
Sachem D-76		2.30?
Sambro I-29		2.16
Sauk A-57		2.45
South Venture O-59		2.61
Thebaud I-94		2.77
Thebaud P-84		2.75
Tuscarora D-61		2.62
Triumph P-50		2.79
Venture B-13		2.73
Venture B-43		2.52
Venture D-23		2.64
Wenonah J-75	*	3.16
West Espanto		2.50
Wyandot E-53	+	2.47

Top of Jurassic - Maturation and Timing of Potential Generation of Hydrocarbons

Well	Subsea Depth (m)	$\%R_0$ from TTI	Time Before Present When Entering 0.6% R_0
			Millions of Years
Abenaki J-56	3195	0.56	-
Abenaki L-57		TD <0.45	-
Adventure F-80		TD <0.45	-
Argo F-38	1474	<0.45	-
Banquereau C-21	≈4250	≈0.77	?
Bluenose G-47	4442	0.79	55
Chippewa G-67	3220	0.52	-
Chippewa L-75	≈1643	<0.45	-
Citnalta I-59	3856	0.67	27
Cohasset D-42	2855	0.63	14
Cohasset L-97	2972	0.64	16
Cree E-35	3763	0.74	37
Crow F-52		<0.45	-
Dauntless D-35	4196	0.65	16
Demascota G-32	3429	0.69	32
Eagle C-21	≈4500?	>0.78	?
Erie D-26		<0.45	-
Esporanto K-78	2751	0.52	-
Eurydice P-36	≈488	<0.45	-
Fox I-22	≈670	<0.45	-
Hercules G-15	747	<0.45	-
Hesper I-52	≈3717	0.67	24
Huron P-96	≈2558	0.45	-
Intrepid L-80	≈4100?	>0.73	-
Iroquois J-17	1742	<0.45	-
MicMac D-89	2495	0.50	-
MicMac H-86	2928	0.59	-
MicMac J-77	2806	0.54	-
Migrant N-20	3537	0.69	34
Mississauga H-54	3544	0.66	32
Mohawk B-93	1589	<0.45	-
Moheida P-15	2658	0.54	-
Mohican I-100	2665	<0.45	-
Naskapi N-30	1687	<0.45	-
Ojibwa E-07	1790	<0.45	-
Olympia A-12	≈4700	0.86	54
Oneida O-25	2900	0.59	-
Onondaga B-96	>3700	>0.78	-
Onondaga E-84	≈3133	0.57	-
Onondaga F-75	>3800	>0.73	-

Top of Jurassic - Continued

Well	Subsea Depth (m)	%R_0 from TTI	Time Before Present When Entering 0.6% R_0
			Millions of Years
Onondaga O-95	>3225	>0.60	-
Penobscott B-41	≈2993	0.56	-
Penobscott L-30	3311	0.63	14
Primrose N-50	≈1540	<0.45	-
Sable Island C-67	4396	0.76	46
Sable Island E-48	≈2767	0.55	-
Sable Island 4H-58	≈3497	0.60	0
Sable Island O-47	≈3391	0.63	10
Sachem D-76	3844	0.59	-
Sauk A-57	4238	0.71	28
Thebaud I-94	3804	0.72	37
Thebaud P-84	≈3826	0.73	46
Tuscarora D-61	≈3104	0.58	-
Triumph P-50	≈4440	0.77	40
Venture B-13	4546	0.85	54
Venture B-43	4661	0.80	44
Venture D-23	4688	0.90	67
Wenonah J-75	≈3417	0.70	19
Wyandot E-53	1968	<0.45	-

Top of Middle Jurassic - Maturation and Timing of Potential Petroleum Generation

Well	Subsea Depth (m)	$\%R_0$ from TTI	Time (MY) Since Entered 0.6% R_0
			Millions of Years
Abenaki J-56	3906	0.68	37
Acadia K-62	4446	0.75	26
Argo F-38	1800	<0.45	-
Chippewa G-67	≈3295	0.53	-
Citnalta I-59	4420	0.75	52
Cohasset L-97	3532	0.76	52
Cohasset D-42	3830	0.90	68
Crow F-32		<0.45	-
Demascota G-32	4530	1.03	89
Erie D-26	≈1700	<0.45	-
Esporanto K-78	3483	0.64	22
Huron P-96	≈2668	0.52	-
MicMac D-89	3035	0.58	-
MicMac H-86	3632	0.70	44
MicMac J-77	3617	0.68	42
Migrant N-20	4074	0.80	60
Mohawk B-93	1875	<0.45	-
Moheida P-15	3359	0.69	33
Mohican I-100	3307	0.47	-
Naskapi N-30	1986	0.48	-
Ojibwa E-07	2247	0.49	-
Oneida O-25	3671	0.80	58
Onondaga E-84	≈3458	0.64	10
Penobscott B-41	≈3393	0.63	14
Penobscott L-30	4076	0.79	65
Sable Island E-48	≈2842	0.57	-
Sable Island 4H-58	≈3912	0.65	15
Sable Island O-47	≈3641	0.67	26
Sachem D-76	4834	0.70	34
Tuscarora D-61	≈3729	0.71	44
Wenonah J-75	?	>0.72?	?
Wyandot E-53	2584	0.53	

Maturation Calculated from TTI at 3500 m Subsea

$$\log TTI = 6.1841 \log R_0 + 2.6557$$

Well	$\%R_0$	Comments
Abenaki J-56	0.62	
Acadia K-62	0.53	
Banquereau C-21	0.62	
Bluenose G-47	0.61	
Chippewa G-67	0.57	
Citnalta I-59	0.61	
Cohasset D-42	0.79	
Cohasset L-97	0.75	
Cree E-35	0.66	
Dauntless D-35	0.55	
Demascota G-32	0.69	
Eagle C-21	0.64	
Esperanto K-78	0.64	
Intrepid L-80	0.60	
Marmora P-35	0.60	
Marmora C-34	0.64	
MicMac D-89	0.67	
MicMac H-86	0.67	
MicMac J-77	0.65	
Migrant N-20	0.69	
Mississauga H-54	0.65	
Moheida P-15	0.73	
Mohican I-100	0.48	
Olympia A-12	0.60	
Oneida O-25	0.74	
Onondaga B-96	0.71	
Onondaga E-84	0.66	
Onondaga F-75	0.66	
Onondaga O-95	0.65	TD 3283 m
Penobscott B-41	0.65	TD 3414 m
Penobscott L-30	0.66	
Sable Island C-67	0.59	
Sable Island 3H-58	0.71	
Sable Island 4H-58	0.60	
Sable Island O-47	0.64	
Sachem D-76	0.53	
Sauk A-57	0.59	
South Venture O-59	0.60	
Thebaud 1-94	0.65	
Thebaud P-84	0.66	
Tuscarora D-61	0.66	
Triumph P-50	0.58	

Continued

Maturation Calculated from TTI at 3500 m Subsea

$$\log TTI = 6.1841 \log R_0 + 2.6557$$

Well	$\%R_0$	Comments
Venture B-13	0.61	
Venture B-43	0.57	
Venture D-23	0.63	
Wenonah J-75	0.72	

Critical Threshold Values - Depth to

- $0.45\% \ R_0$ - top marginally mature zone
- $0.70\% \ R_0$ - top fully mature zone
- $1.30\% \ R_0$ - base of theoretical liquid hydrocarbon generation zone - calculated by extrapolating vitrinite reflectance on log R_0 - Depth plot

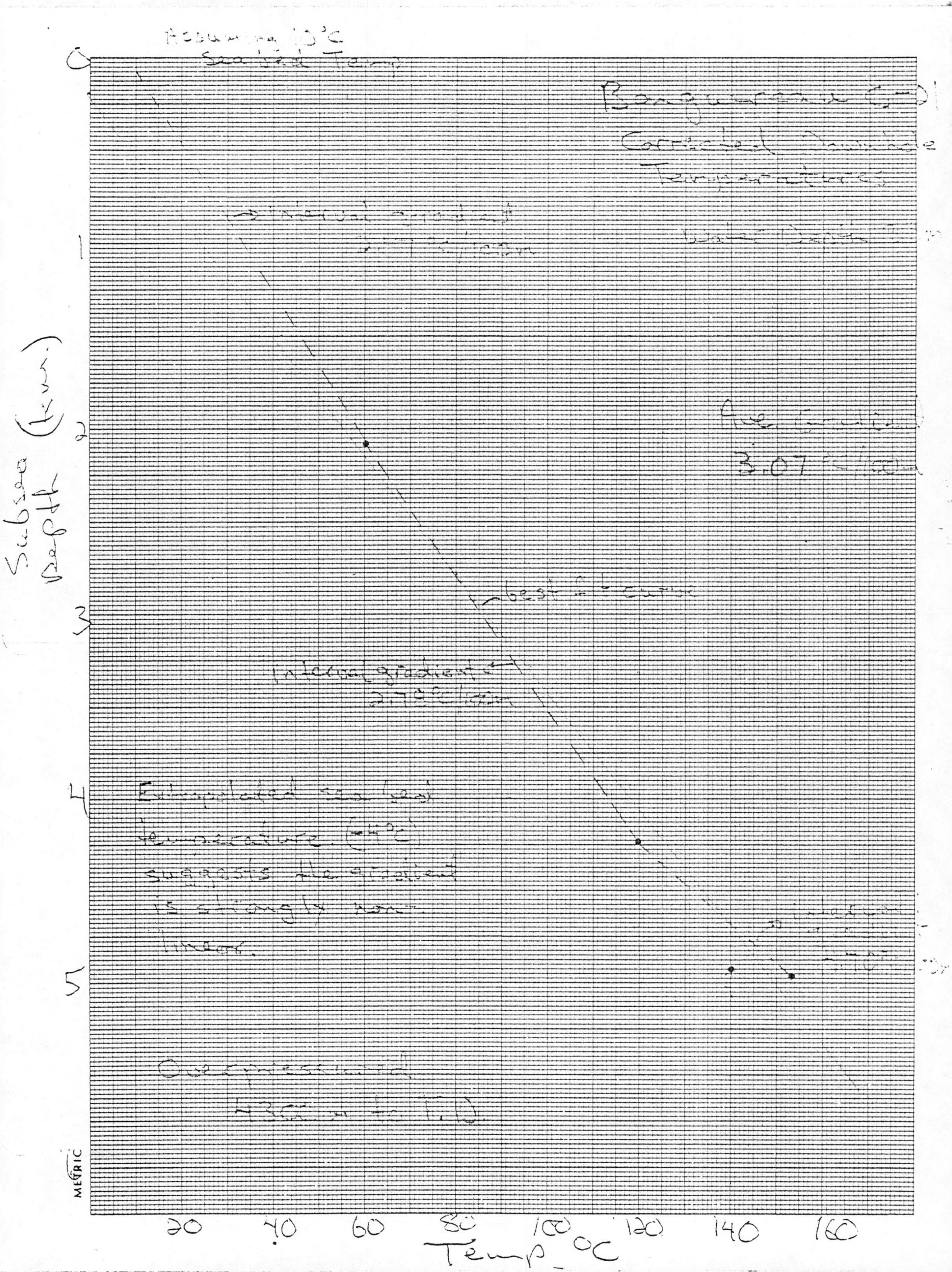
Estimated maximum error of 75 m for a linear maturation gradient

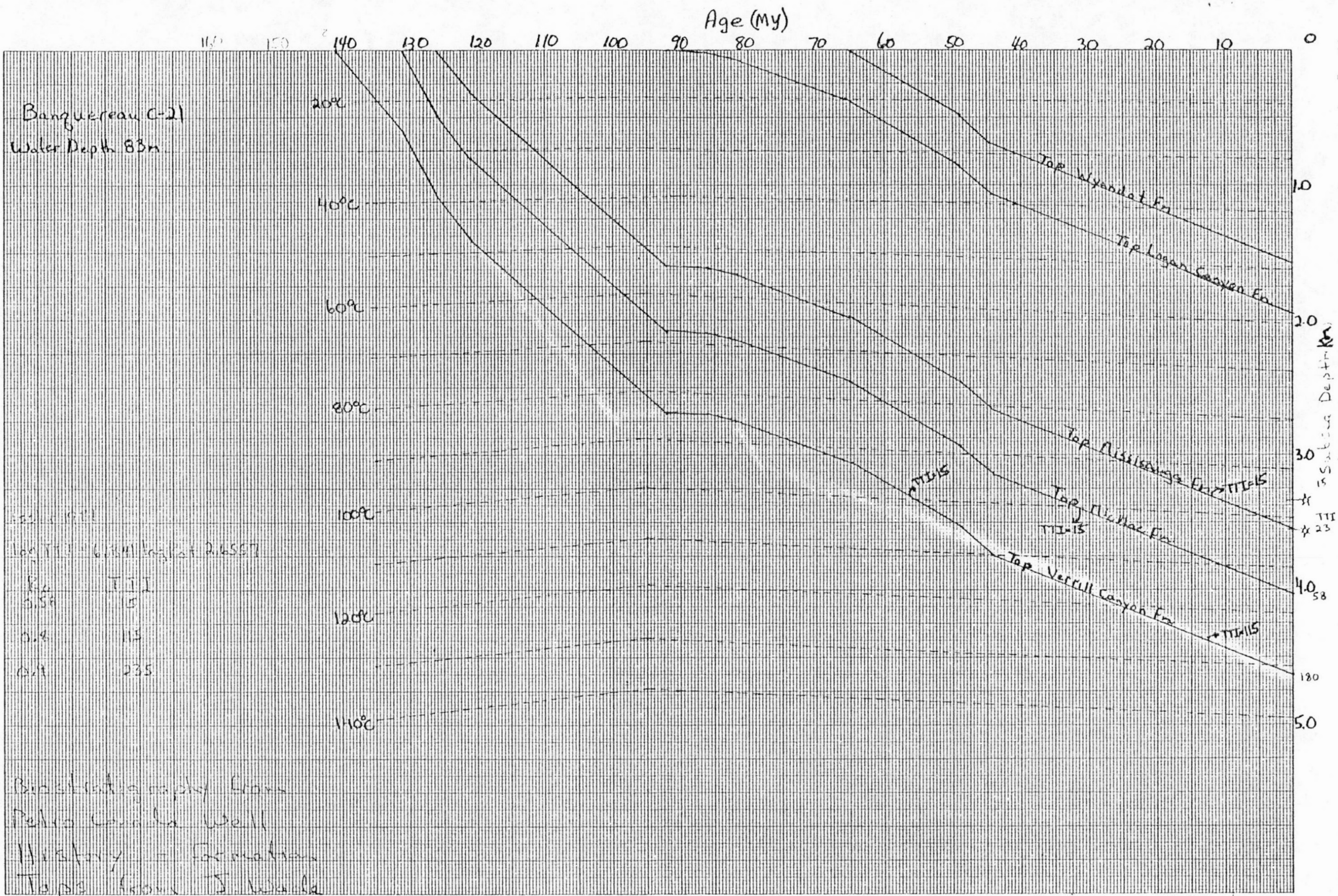
Well	Subsea Depth (m)			Comments
	$0.45\% \ R_0$	$0.7\% \ R_0$	$1.30\% \ R_0$	
Abenaki J-56	2250	3900	6250	
Abenaki L-57	1250	3150	-	Salt 2167 m RT
Acadia K-62	2135	3375	5100	
Argo F-38	2225	4350	-	Basement 3331 m RT
Banquereau C-21	2350	3850	5900	
Bluenose G-47	2500	3875	5875	
Chippewa G-67	2525	4325	-	Salt 3594 m RT
Citnalta I-59	2425	3950	6100	
Cohasset D-42	1750	3050	4800	
Cohasset L-97	2075	3250	4825	
Cree E-35	2400	3525	5075	
Crow F-52	1925	-	-	Basement 1505 m RT
Dauntless D-35	2550	4375	6775	
Demascota G-32	2175	3425	5300	
Eagle C-21	2400	3900	6000	
Esperanto K-78	2225	3625	5600	
Huron P-96	2425	-	-	Salt 2996 m RT
Intrepid L-80	2550	3950	6300	
Iroquois J-17	2100	-	-	Salt 2045 m RT
Marmora C-34	1900	3850	6500	
Marmora P-35	2500	4000	6100	
MicMac D-89	2100	3550	5625	
MicMac H-86	2000	3650	5950	
MicMac J-77	2000	3725	6150	
Migrant N-20	2100	3575	5575	
Mississauga H-54	2225	3675	5675	
Mohawk B-93	1750	-	-	
Moheida P-15	2050	3275	4875	
Mohican I-100	3000	4200	5825	Salt 4366 m RT
Naskapi N-30	1775	2850	-	Basement 2131 m RT
Ojibwa E-07	1800	3000	-	Basement 2305 m RT
Olympia A-12	2375	3900	6025	

Critical Threshold Values - Continued

	Subsea Depth (m)			
Well	0.45% R_0	0.7% R_0	1.30% R_0	Comments
Oneida O-25	2075	3300	4850	
Onondaga B-96	2300	3450	4800	
Onondaga E-84	2375	3650	5400	Salt 3960 m RT
Onondaga F-75	2200	3650	5625	
Onondaga O-95	2300	3650	5575	
Penobscott B-41	2200	3625	5575	
Penobscott L-30	1950	3475	5650	
Primrose F-41	2650	-	-	Salt 1982 m RT
Primrose N-50	1675	2300	-	Salt 1708 m RT
Sable Island C-67	2425	4050	6350	
Sable Island E-48	2150	3475	-	Salt 2986 m RT
Sable Island 4H-58	2325	4175	6750	
Sable Island O-47	2325	3725	5775	Salt 3888 m RT
Sachem 1-29				
Sauk A-57	2475	4050	6300	
South Venture O-59	2500	4000	6100	
Thebaud I-94	2250	3650	5650	
Thebaud P-84	2325	3700	5675	
Triumph P-50	2550	3950	5850	
Tuscarora C-61	2200	3600	5550	
Venture B-13	2500	3900	5850	
Venture B-43	2575	4125	6250	
Venture D-23	2325	3800	5800	
Wenonah 5-75	2200	3350	4975	Salt 3561 m RT

TEMPERATURE DATA AND SUBSIDENCE CURVES FROM RECENTLY DRILLED WELLS


Assuming 10°C Sea Bed Temp
Corrected Downhole Temperatures
Ave. Gradient
3.07
best fit curve
Interval gradient
Extrapolated sea bed temperature (-4°C) suggests the gradient is strongly non-linear.
Subsea Depth (km)
0
1
2
3
4
5
METRIC
20
40
60
80
100
120
140
160
Temp °C


Age (My)
160
150
140
130
120
110
100
90
80
70
60
50
40
30
20
10
0
Banquereau C-21
Water Depth 83m
20°C
40°C
60°C
80°C
100°C
120°C
140°C
Top Wyandot Fm
Top Logan Canyon Fm
Top Missisauga Fm
Top Mic Mac Fm
Top Verrill Canyon Fm
TTI=15
TTI-15
TTI=115
1.0
2.0
3.0
4.0
5.0
Subsea Depth Km
15
TTI
23
58
180

Olympia A-12
Datum Line → Sea Level
Water Depth 39.9 m

Extrapolated Seabed
Temperature 6.91°C

Interval (m)	Thickness Δ Depth (m)	Upper T °C	Lower T °C	ΔT °C	Interval Gradient °C/100m
39.9 - 1482.1	1442.2	7	48	41	2.84
1482.1 - 2984.4	1502.3	48	85	37	2.46
2984.4 - 4714.9	1730.5	85	125	40	2.31
4714.9 - 5250.9	536.0	125	146	21	3.92
5250.9 - 5847.5	596.6	146	156	10	1.68
5847.5 - 6021.9	174.4	156	173	17	9.75
<u>Note</u>					
5250.9 - 6021.9	771.0	146	173	27	3.50
4114.9 - 6021.9	1307.0	125	173	48	3.67

Biostratigraphic control has been extrapolated from Venture D-23 and B-43 for construction of the subsidence curve

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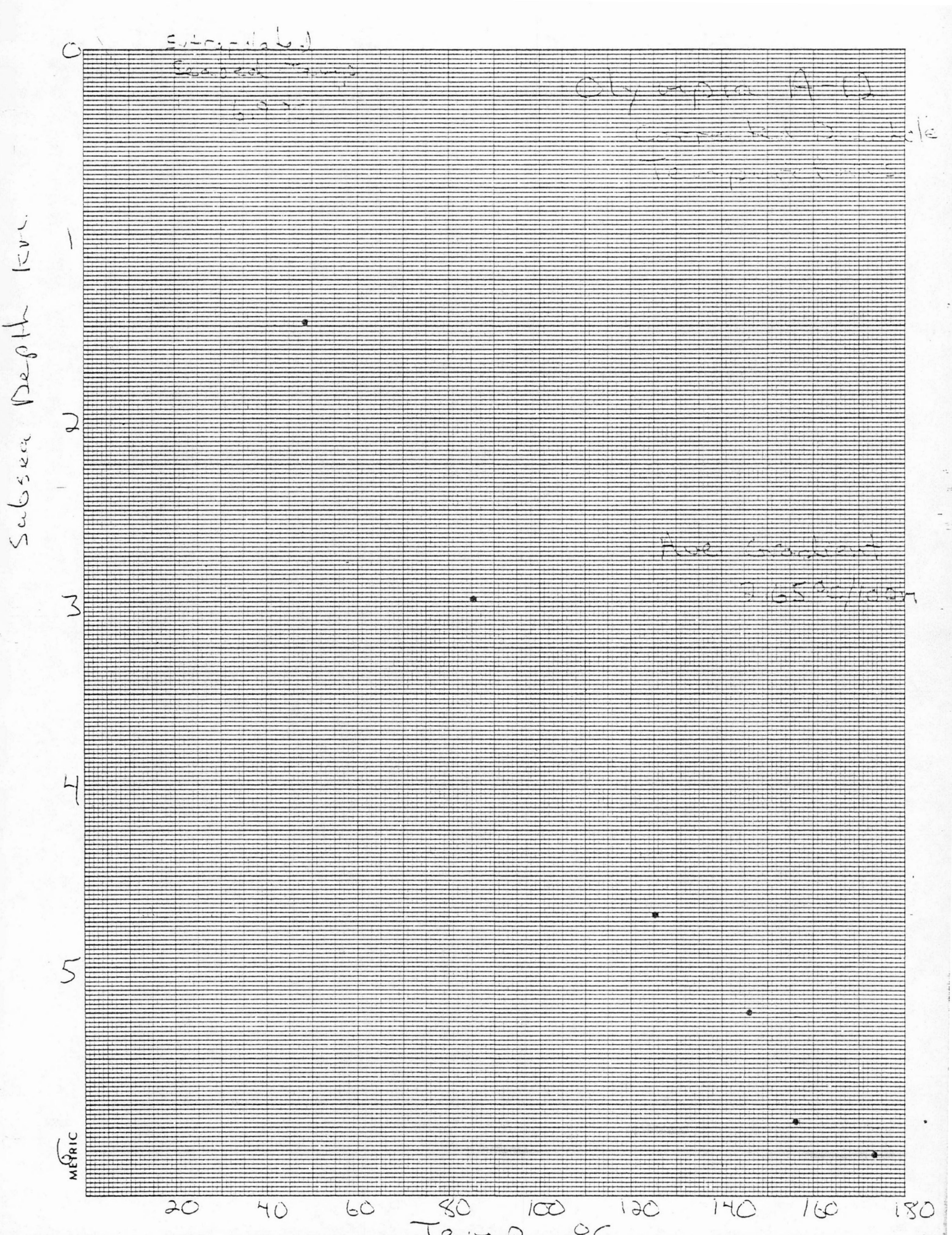
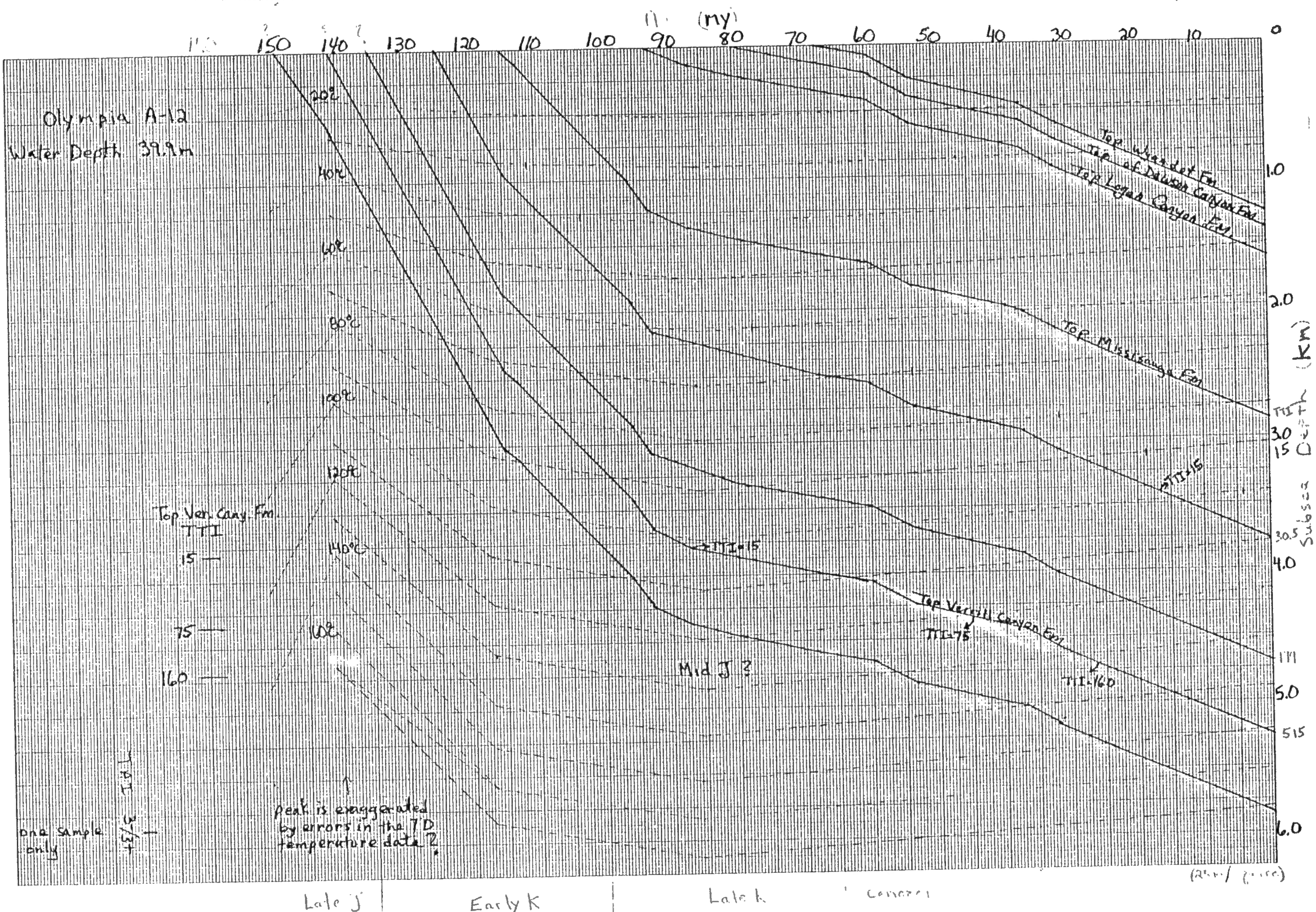
<u>Arcadia J-16</u>

- one temperature reading available
  127.5°C @ 4697 m
  average gradient 2.55°C/100 m.


Olympia A-1
Ave. Gradient
3.65°C/100m
Subsea Depth Km
0
1
2
3
4
5
METRIC
20
40
60
80
100
120
140
160
180
Temp °C



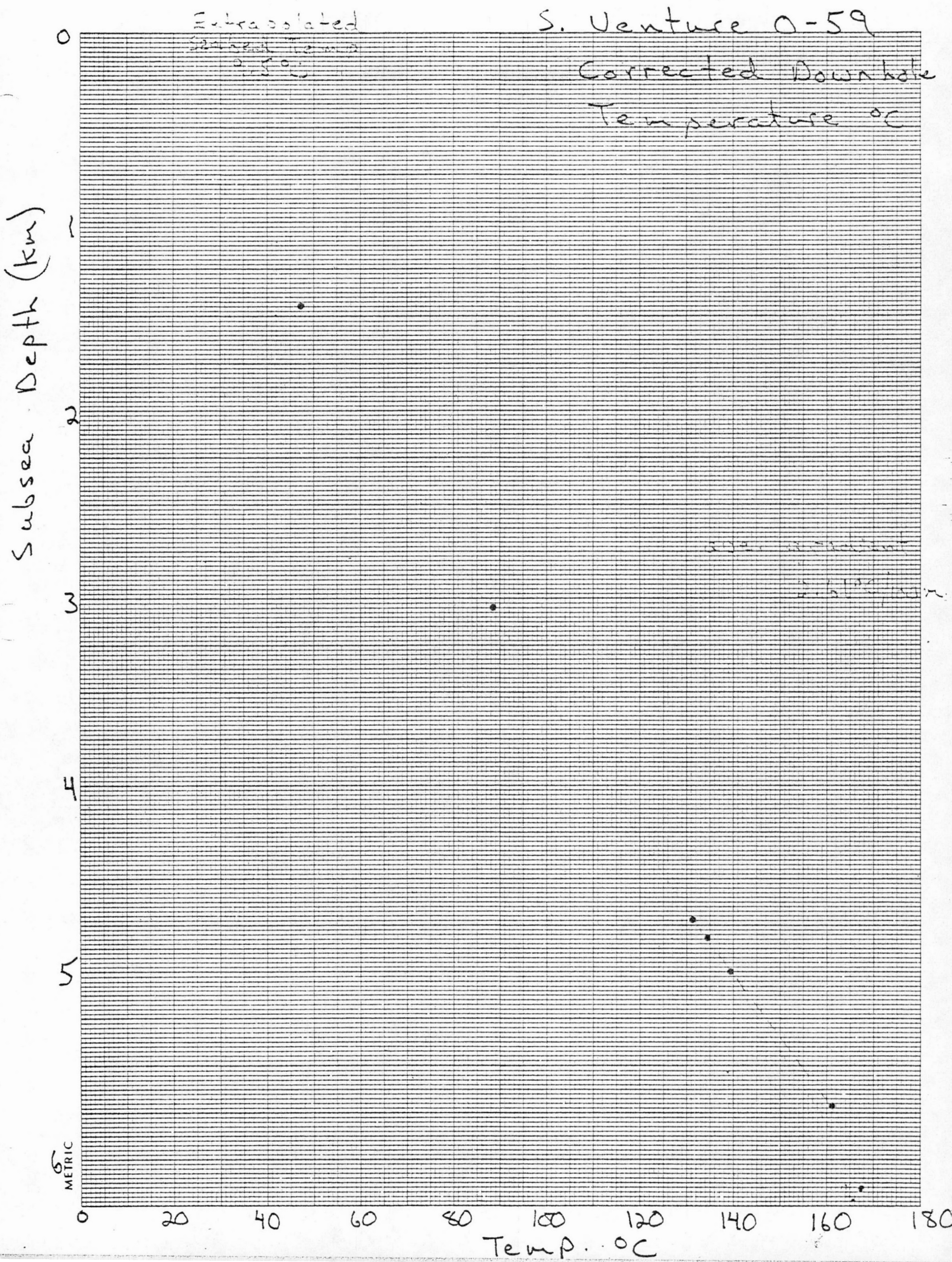
Olympia A-12
Water Depth 39.9m
(my)
150
140
130
120
110
100
90
80
70
60
50
40
30
20
10
0
1.0
2.0
3.0
4.0
5.0
6.0
Subsea Depth (Km)
Top Wyandot Fm
Top of Dawson Canyon Fm
Top Logan Canyon Fm
Top Missisauga Fm
TTI=15
Top Verrill Canyon Fm
TTI=75
TTI=160
Mid J ?
20°C
40°C
60°C
80°C
100°C
120°C
140°C
160°C
Top Ver. Cany. Fm
TTI
15
75
160
TAI 3-/3+
one sample only
peak is exaggerated by errors in the TD temperature data ?
Late J
Early K
Late K

South Venture O-59
Water Depth 24.4 m

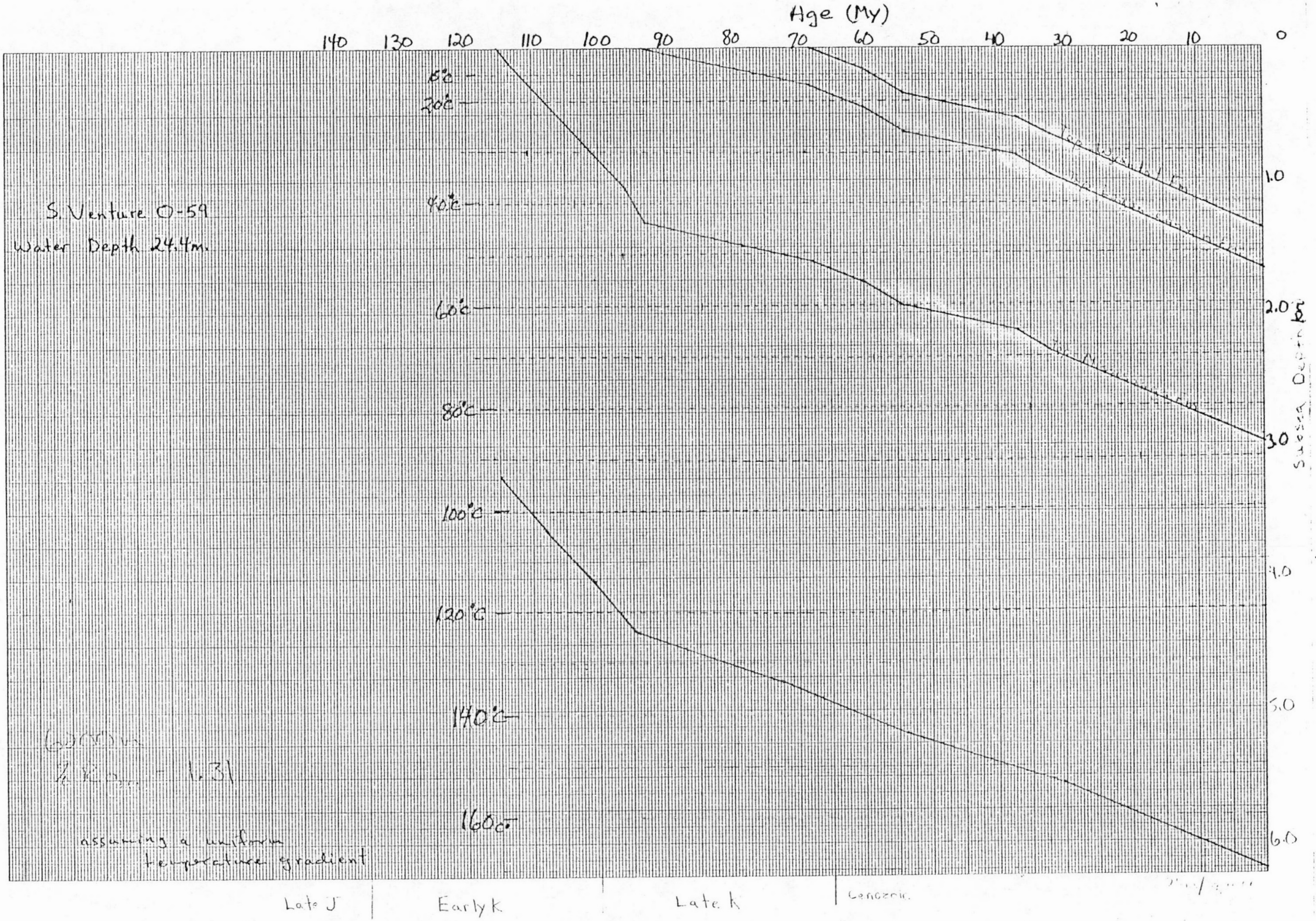
Corrected Temp. Data

Interval m	ΔDepth m	T_1 °C	T_2 °C	ΔT °C	Interval Gradient °C/100 m
24.4 - 1448.7	1424.3	9.5	47	37.5	2.63
1448.7 - 3043	1585.3	47	88	41	2.59
3043 - 4726.6	1686.6	88	131	43	2.55
4726.6 - 4812.9	83.3	131	134	3	3.60
1812.9 - 5002	189.1	134	139	5	2.64
5002 - 5717.8	715.8	139	161	22	3.07
5717.8 - 6136.8	419	161	167	6	1.43

Biostratigraphic control is extrapolated from Venture D-23 and B-43. Some diachronism in formation tops is suspected.



S. Venture O-59
Corrected Downhole
Temperature °C
Extrapolated
Subsea Depth (km)
0
1
2
3
4
5
6
METRIC
0
20
40
60
80
100
120
140
160
180
Temp. °C

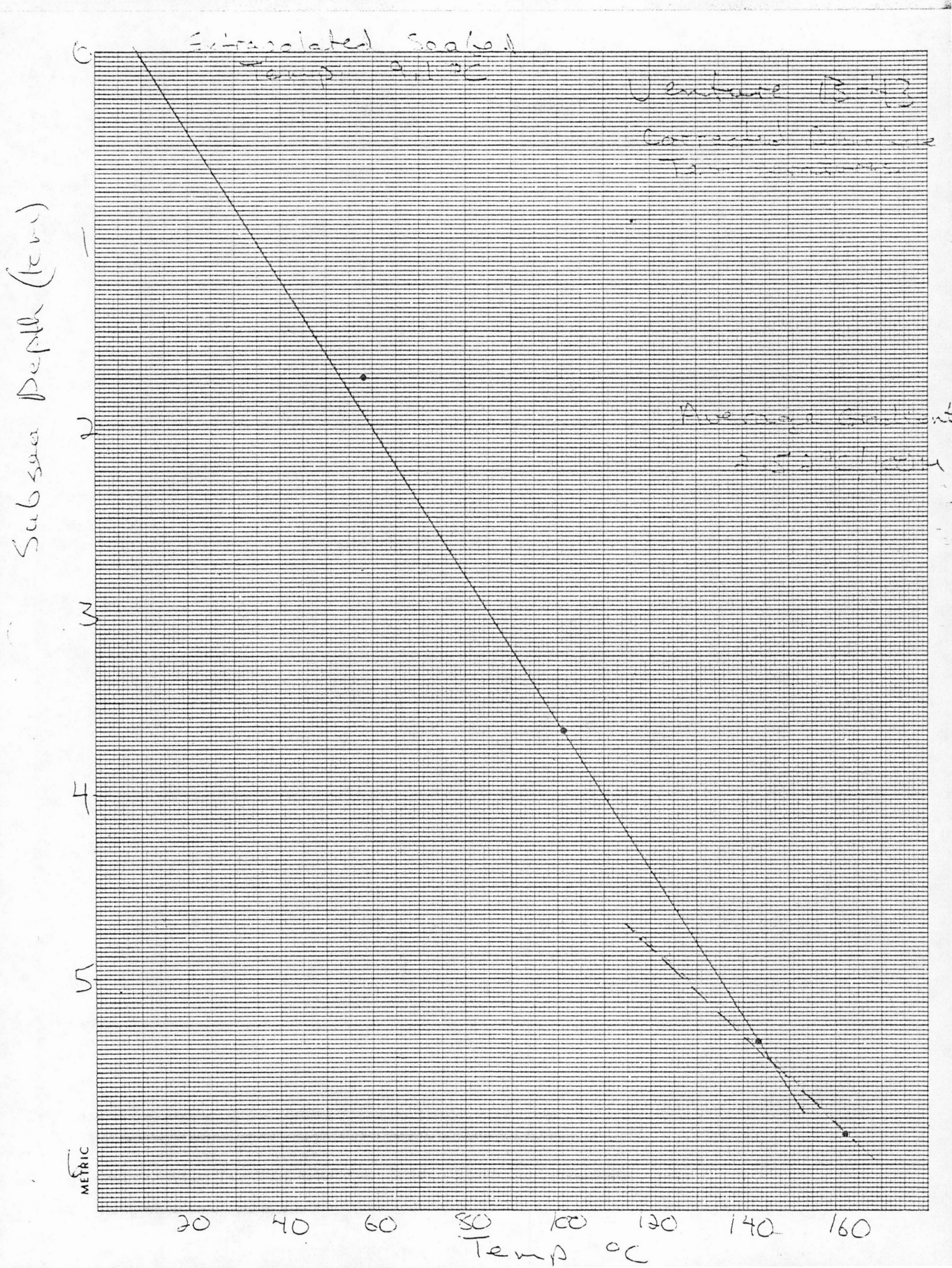

Age (My)
140
130
120
110
100
90
80
70
60
50
40
30
20
10
0
S. Venture O-59
Water Depth 24.4m.
8°C
20°C
40°C
60°C
80°C
100°C
120°C
140°C
160°C
1.0
2.0
3.0
4.0
5.0
6.0
Subsea Depth
assuming a uniform
temperature gradient
Late J
Early K
Late K
Cenozoic

Venture B-43
Depth of Water 20.4 m
Datum Level → Sea level

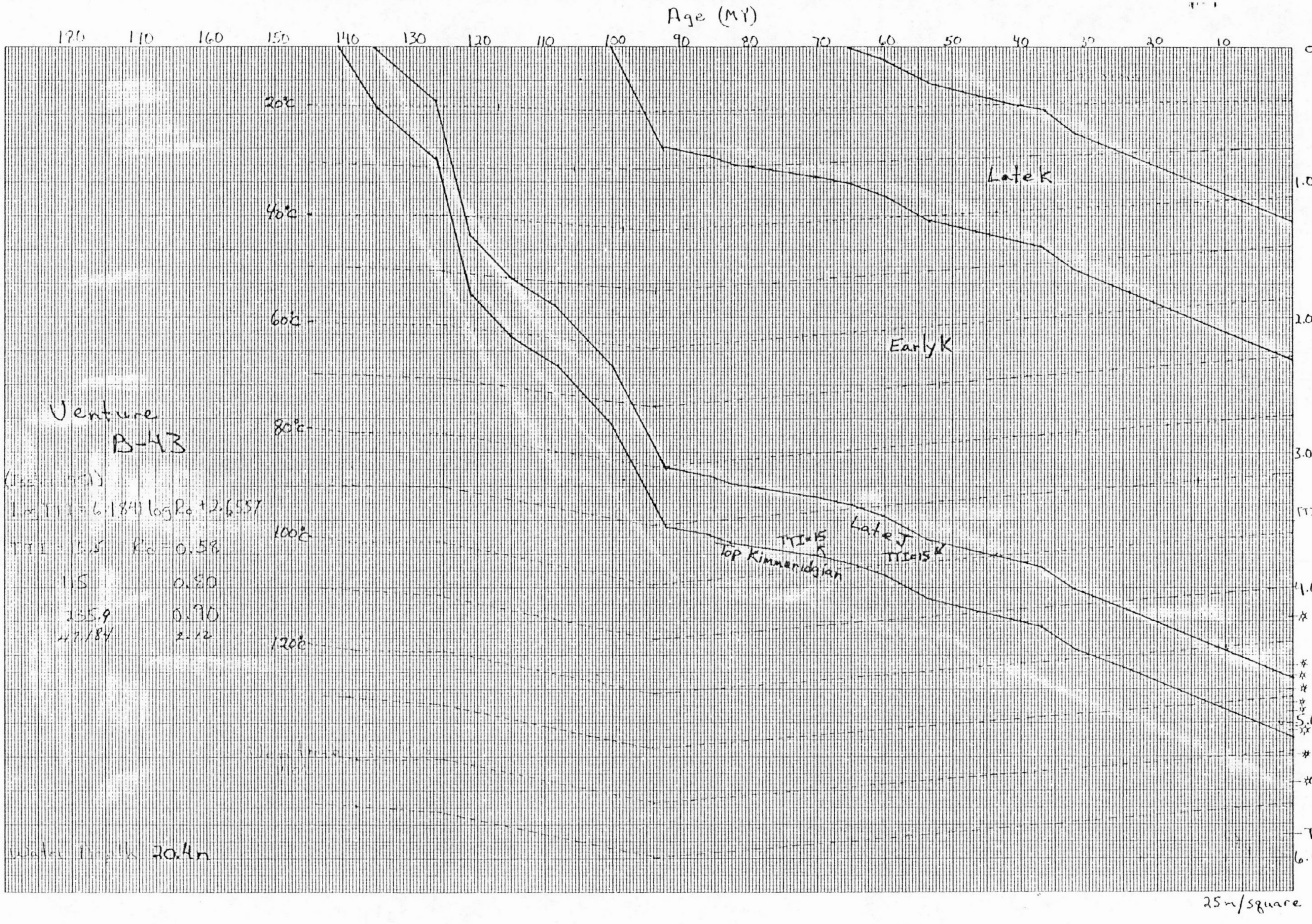
Extrapolated Seabed
Temperature 9.13

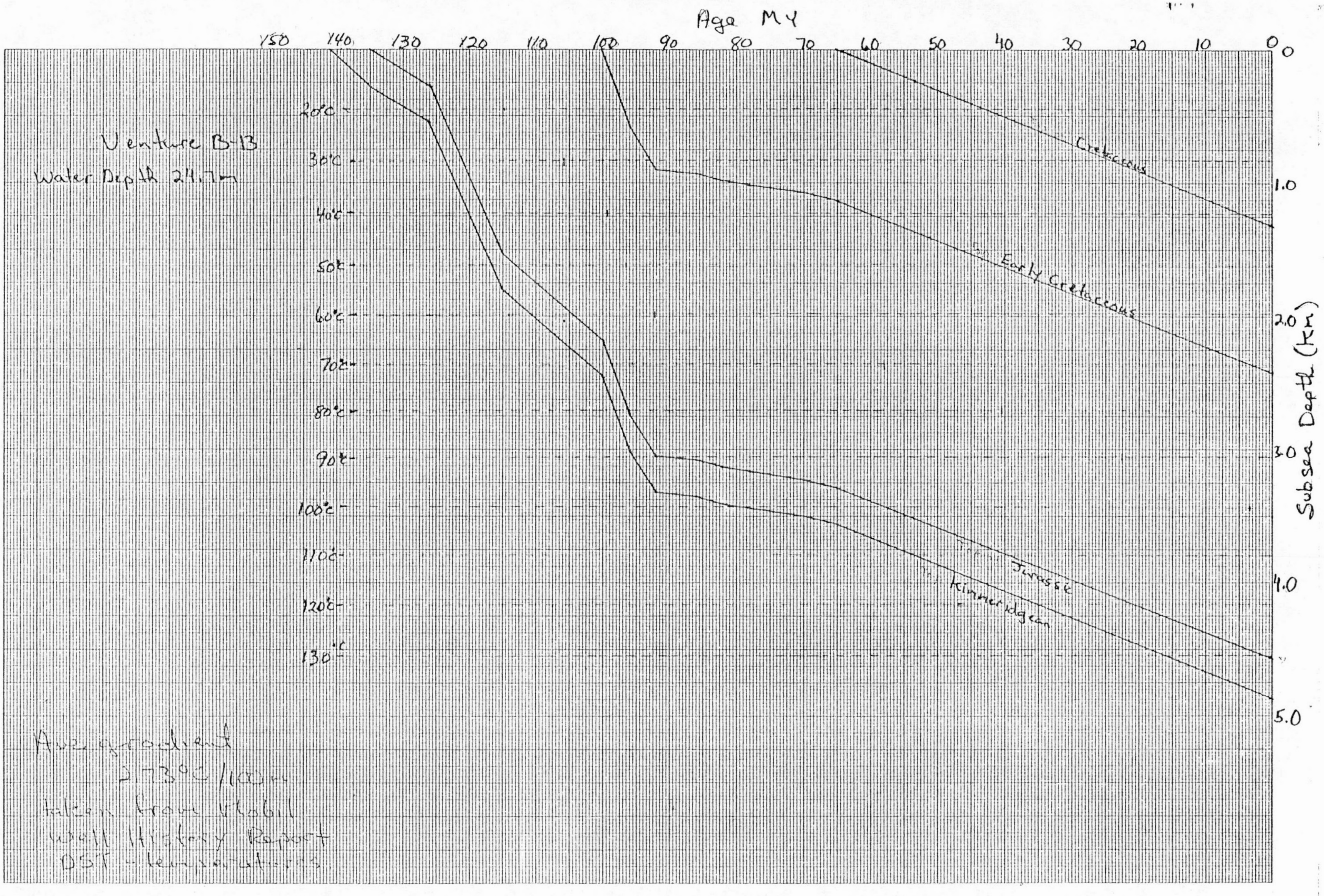
Interval m	ΔDepth m	T_1 °C	T_2 °C	ΔT °C	Interval Gradient °C/100 m
20.4 - 1756	1735.6	9.0	57.5	48.5	2.79
1756 - 3654	1898	57.5	101	43.5	2.29
3654 - 4786.3	1132.3	101	117.5	16.5	1.46
4786.3 - 5339.8	553.5	117.5	143	25.5	4.61
5339.8 - 5837	497.2	143	162	19.0	3.82
Note					
3654 - 5339.8	1685.8	101	143	42	2.49

Biostratigraphy from EPGS 202.



Extrapolated Seabed
Temp 9.1°C
Venture B-13
Corrected Downhole
Temperatures
Average Gradient
Subsea Depth (km)
0
1
2
3
4
5
METRIC
20
40
60
80
100
120
140
160
Temp °C


Age (MY)
170
160
150
140
130
120
110
100
90
80
70
60
50
40
30
20
10
0
1.0
2.0
3.0
4.0
5.0
6.0
Depth of Burial (km)
TTI=15
115
235
TD
25m/square
20°c
40°c
60°c
80°c
100°c
120°c
Late K
Early K
Late J
TTI=15
Top Kimmeridgian
Venture
B-43
TTI=6.1841 log Ro +2.6557
TTI 1.5 Ro 0.58
15 0.80
115 0.90
235.9
47.184 2.12
20.4m


Age MY
150
140
130
120
110
100
90
80
70
60
50
40
30
20
10
0
0
1.0
2.0
3.0
4.0
5.0
Subsea Depth (km)
20°C
30°C
40°C
50°C
60°C
70°C
80°C
90°C
100°C
110°C
120°C
130°C
Cretaceous
Early Cretaceous
Jurassic
Kimmeridgean
Venture B-13
Water Depth 24.7m
Ave gradient
2.73°C/100m
taken from Mobil
Well History Report
DST temperatures

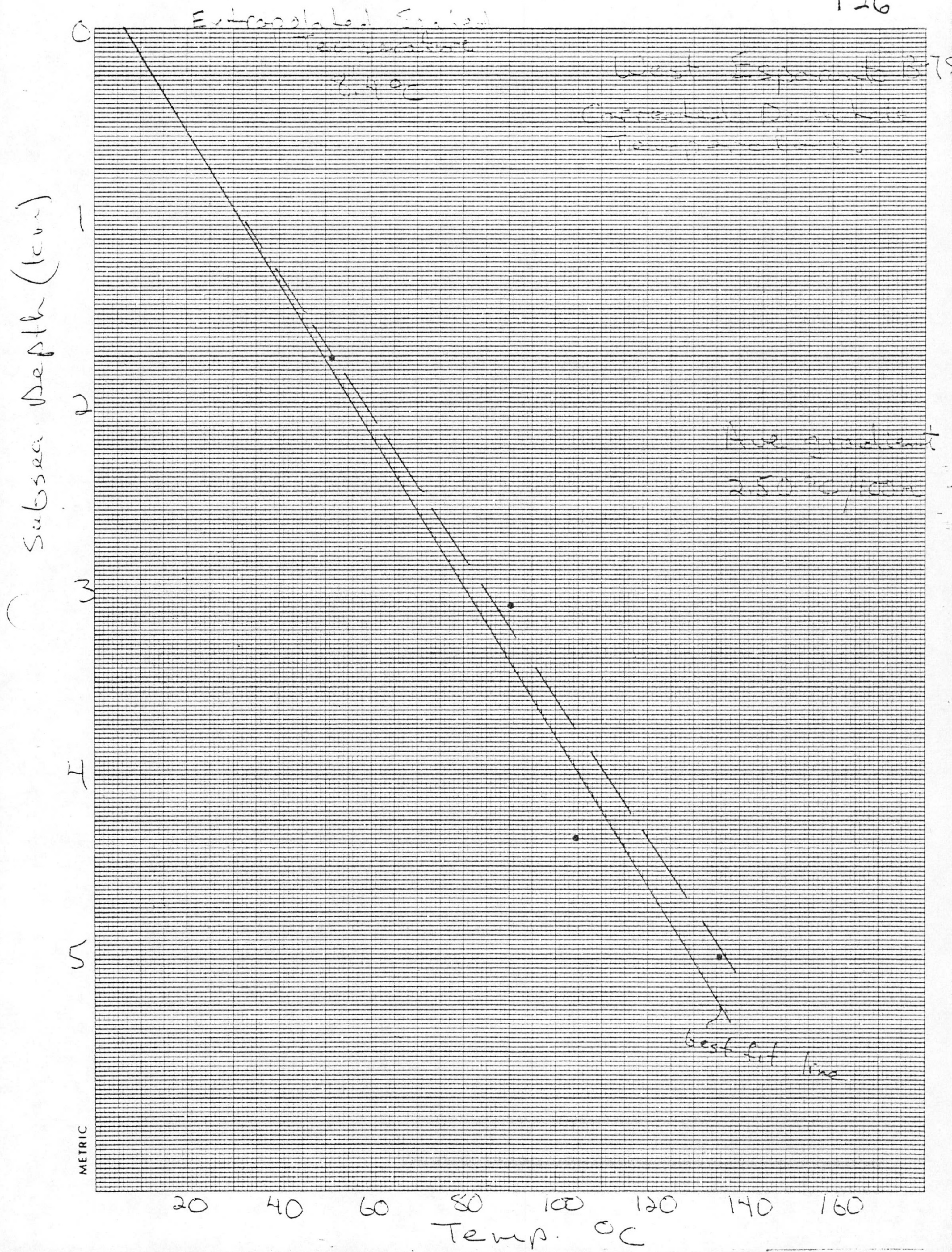
W. Esperanto B-78
Water Depth 92.3 m
Datum Line → Sea level

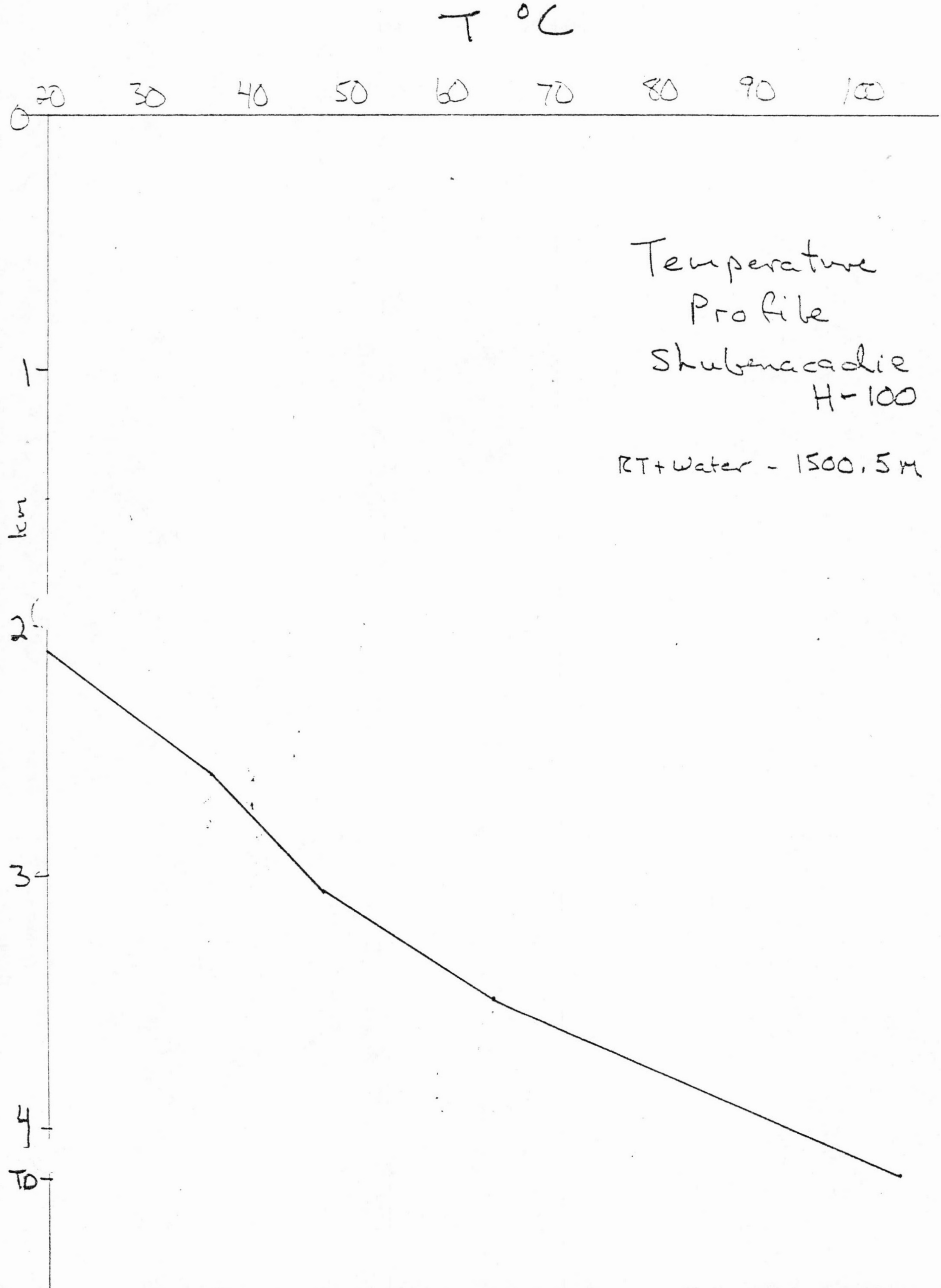
Extrapolated Seabed
Temperature 8.42°C

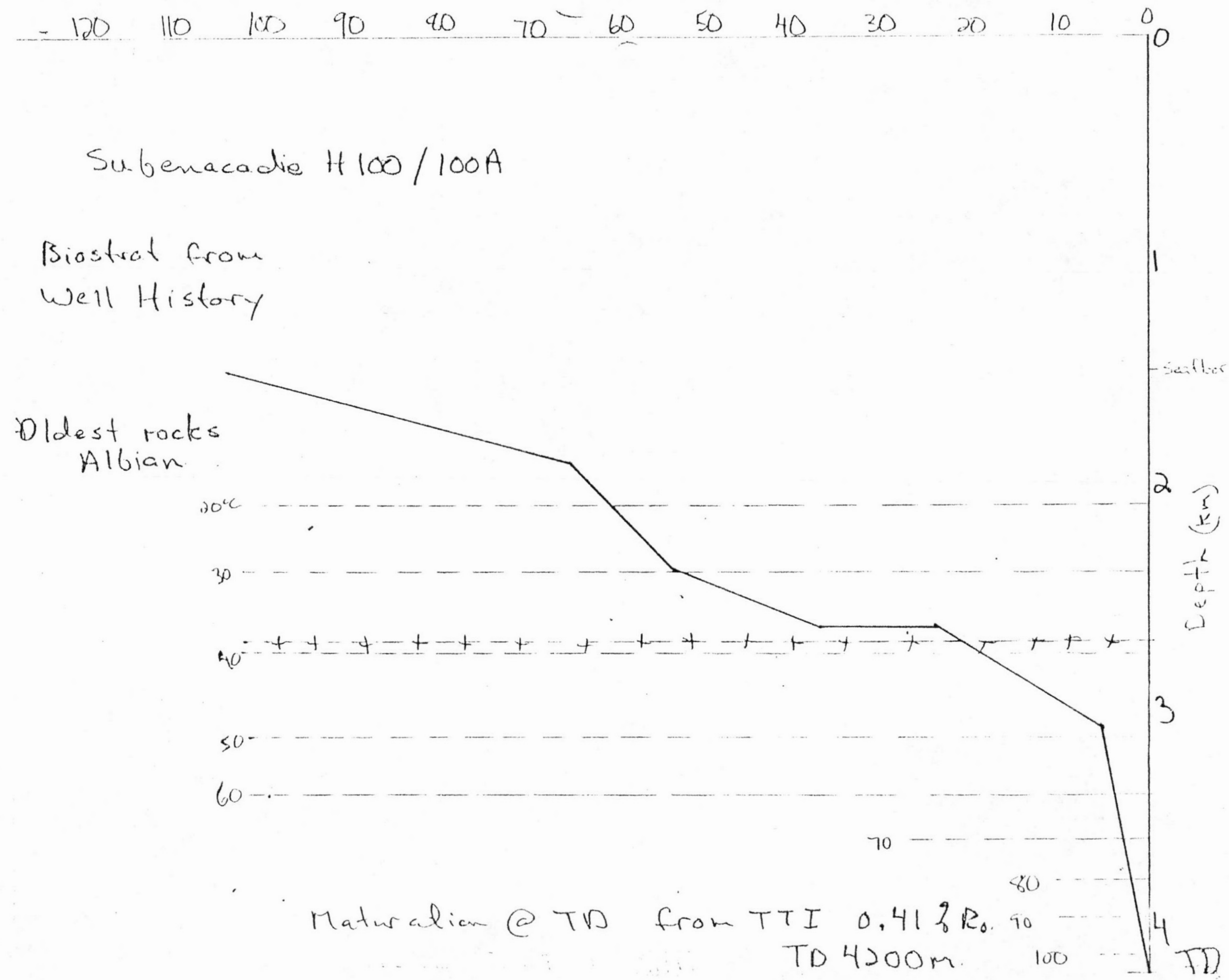
Interval m	ΔDepth m	T_1 °C	T_2 °C	ΔT °C	Interval Gradient °C/100 m
92.3 - 1765.5	1673.2	8.4	51	42.6	2.55
1765.5 - 3097.7	1332.2	51	90	39.0	2.93
3097.7 - 4351.8	1254.1	90	104	14.0	1.12
4351.8 - 4994.2	642.4	104	135	31.0	4.83

No subsidence curve was drawn as the well was still being drilled.

Temperature data only available to 5000 m.


Extrapolated Surface
2.4°C
West Esperanto B-7
Corrected
Ave. gradient
25.0°C/km
best fit line
Subsea Depth (km)
0
1
2
3
4
5
METRIC
20
40
60
80
100
120
140
160
Temp. °C


T °C
20
30
40
50
60
70
80
90
100
0
1
km
2
3
4
TD
Temperature Profile Shubenacadie H-100
RT+Water - 1500.5m

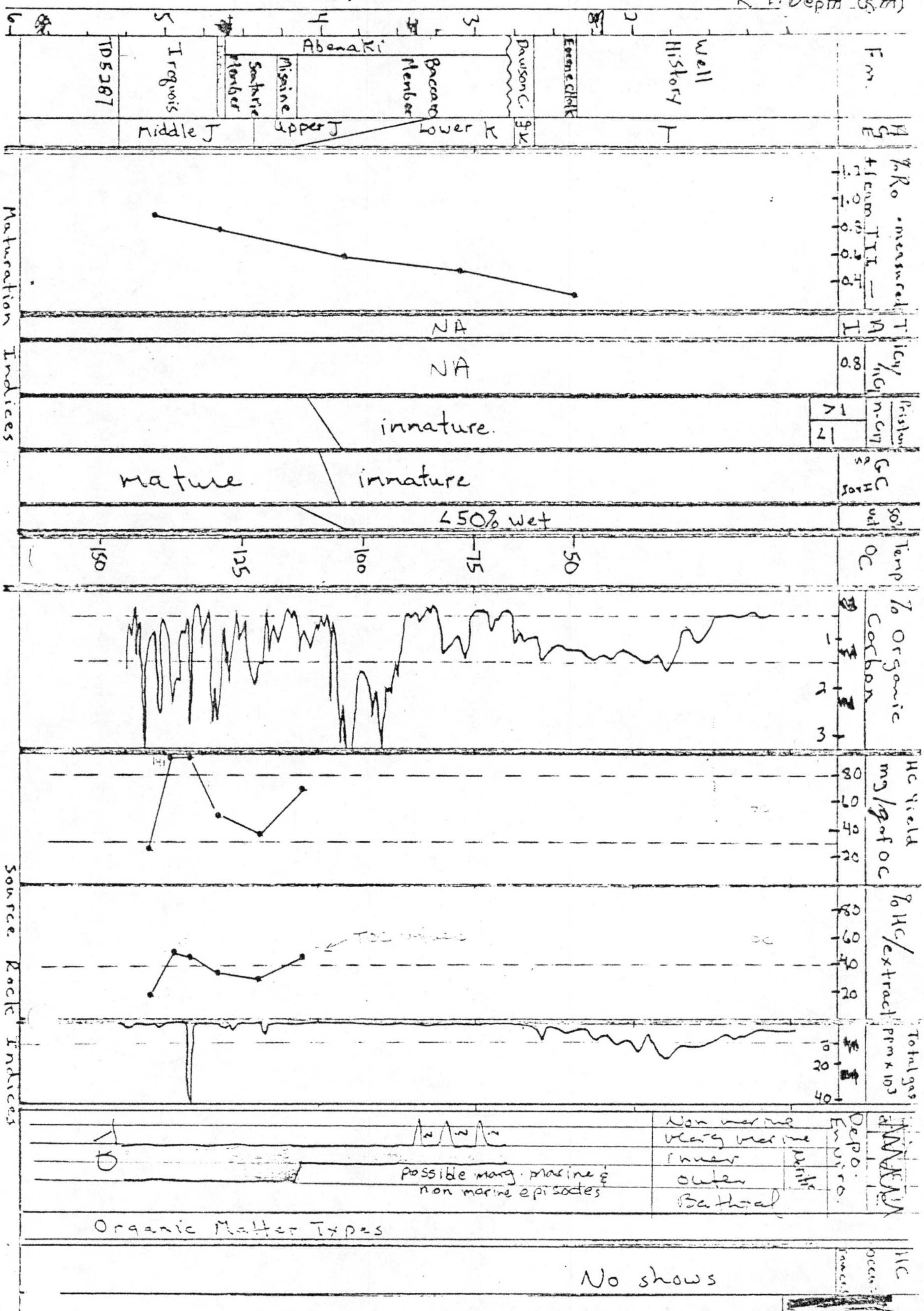


Subenacadie H100/100A
Biostrat from
Well History
Oldest rocks
Albian
120
110
100
90
80
70
60
50
40
30
20
10
0
0
1
seafloor
2
3
4
TD
Depth (km)
20°C
30
40
50
60
70
80
90
100
Maturation @ TD from TTI 0.41 % Ro.
TD 4200m.

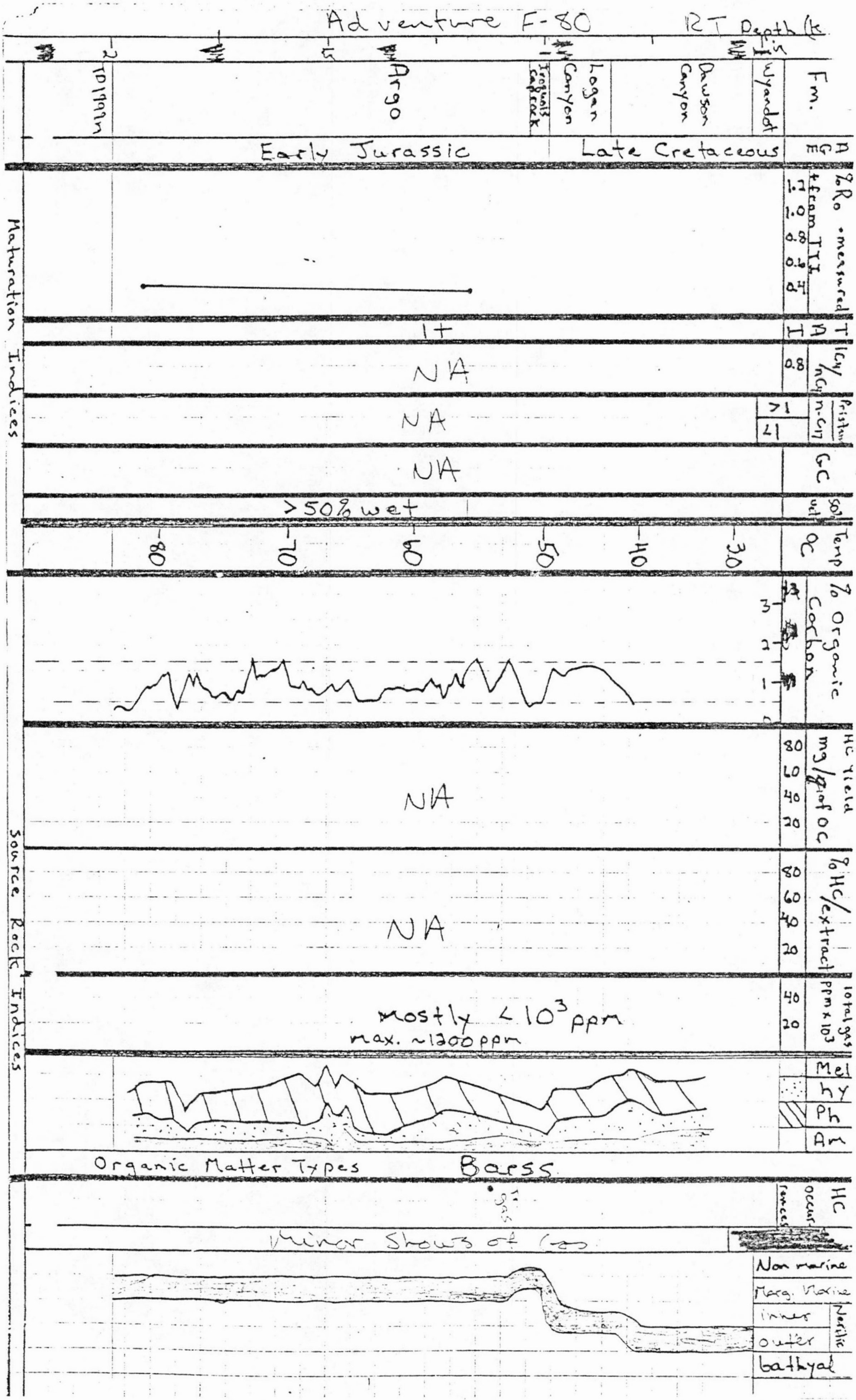
WELL COMPILATIONS

Scales for each compilation vary considerably, due to the variety of sources for data.

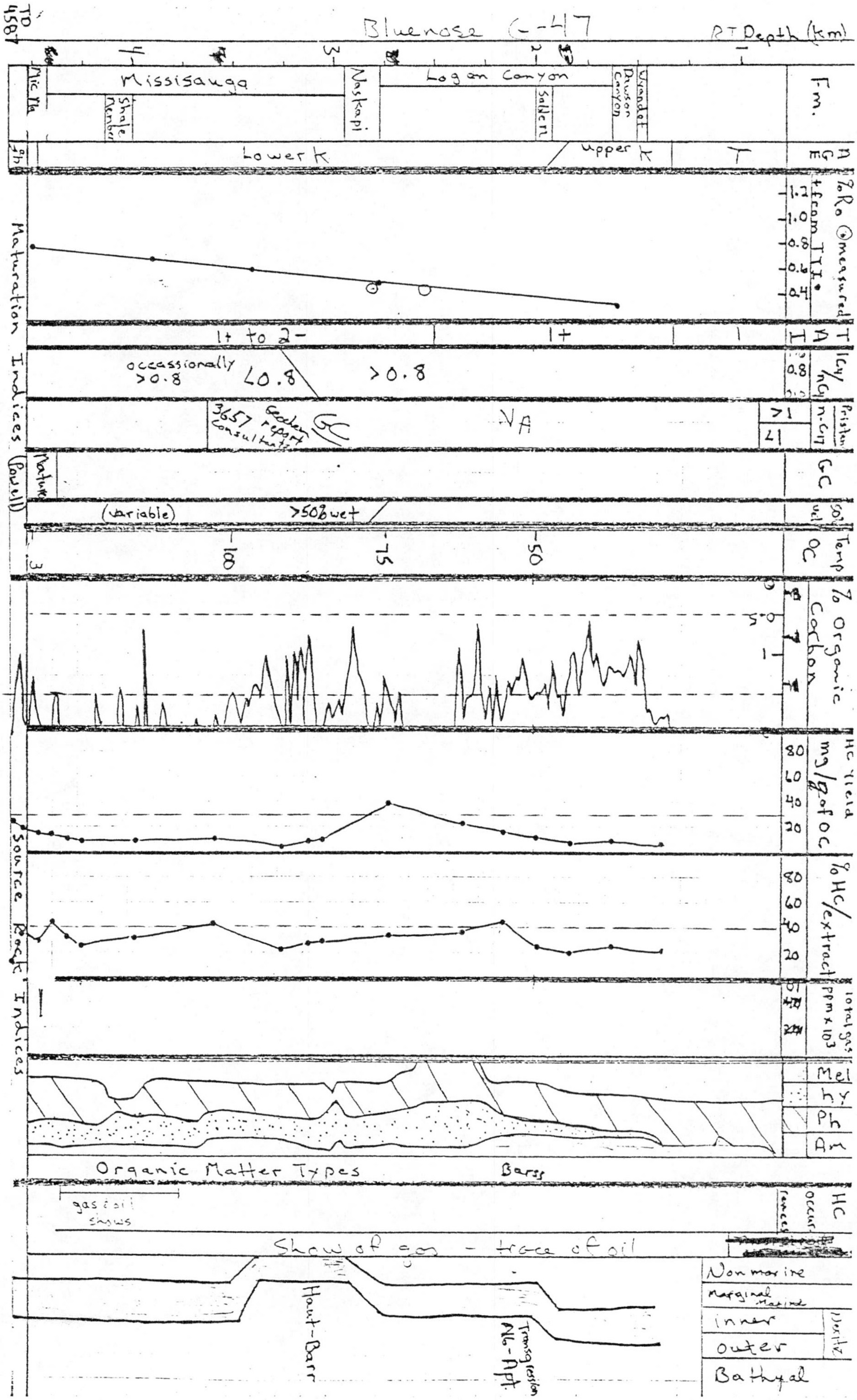
Acadia K-62



TOC data unreliable due to lab errors
Extract data O.K.

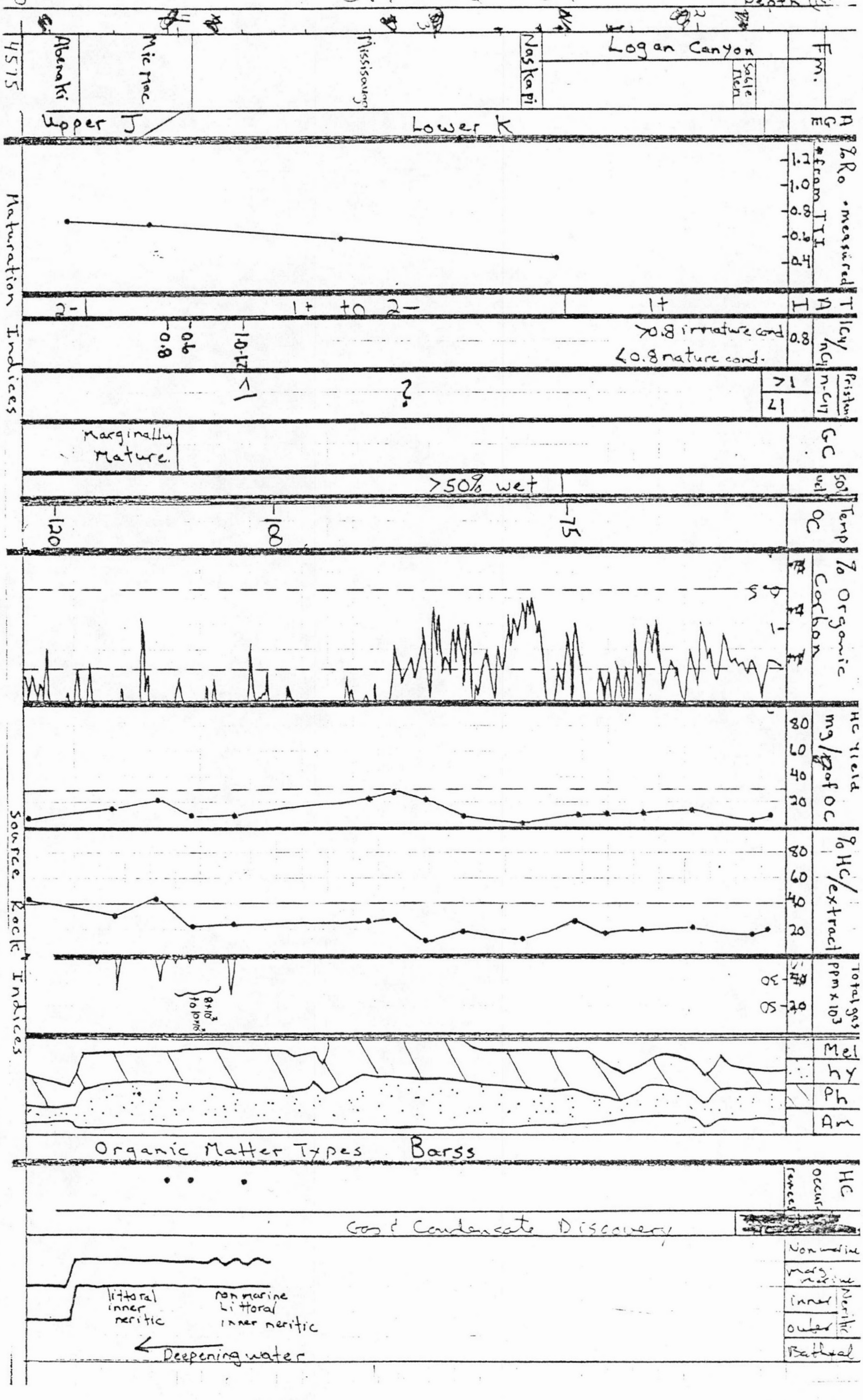


Adventure F-80
RT Depth (k
Fm.
TD1991m
Argo
Iroquois Caprock
Logan Canyon
Dawson Canyon
Wyandot
Early Jurassic
Late Cretaceous
Maturation Indices
%Ro
• measured
† from TAI
1.2
1.0
0.8
0.6
0.4
TAI
1+
NA
0.8
NA
>1
<1
NA
GC
>50% wet
Temp °C
80
70
60
50
40
30
% Organic Carbon
3
2
1
HC Yield mg/g of OC
80
60
40
20
NA
%HC/extract
80
60
40
20
NA
total gas ppm x 10³
40
20
mostly <10³ ppm
max. ~1200 ppm
Source Rock Indices
Mel
hY
Ph
Am
Organic Matter Types
HC occurrence
Minor Shows of Gas
Non marine
Marg. Marine
inner
outer
Neritic
bathyal

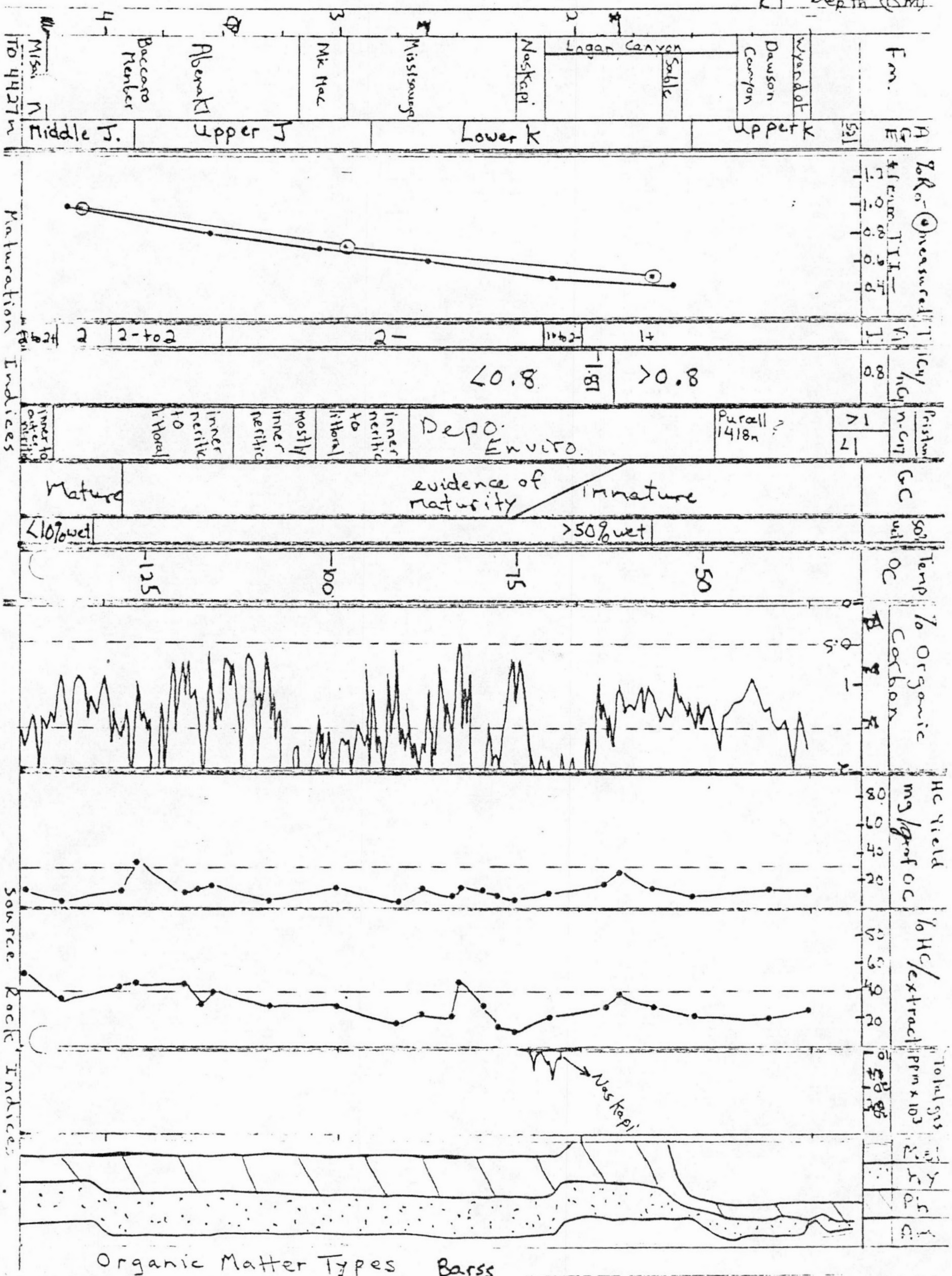


Bluenose G-47
RT Depth (km)
TD 4587
Fm.
Missisauga
Shale Member
Naskapi
Logan Canyon
Sable
Dawson Canyon
Wyandot
Mic Mac
Age
Lower K
Upper K
T
%Ro ⊙ measured • from TAI
Maturation Indices (Powell)
TAI
1+ to 2-
1+
Tl C7 / n C7
occassionally >0.8
<0.8
>0.8
Pristane / n-C17
3657 Geochem report consultants
GC
NA
>1
<1
Nature
GC
% wet
(variable)
>50% wet
Temp °C
100
75
50
% Organic Carbon
HC Yield mg/g of OC
80
60
40
20
Source Rock Indices
% HC/extract
80
60
40
20
Total gas ppm x 10³
Mel
Hy
Ph
Am
Organic Matter Types
Barss
HC occurrences
gas & oil shows
Show of gas - trace of oil
Nonmarine
Marginal Marine
inner
outer
Bathyal
Neritic
Haut-Barr
Transgression Alb-Apt.

Citnalta I-59



Cohasset D-42



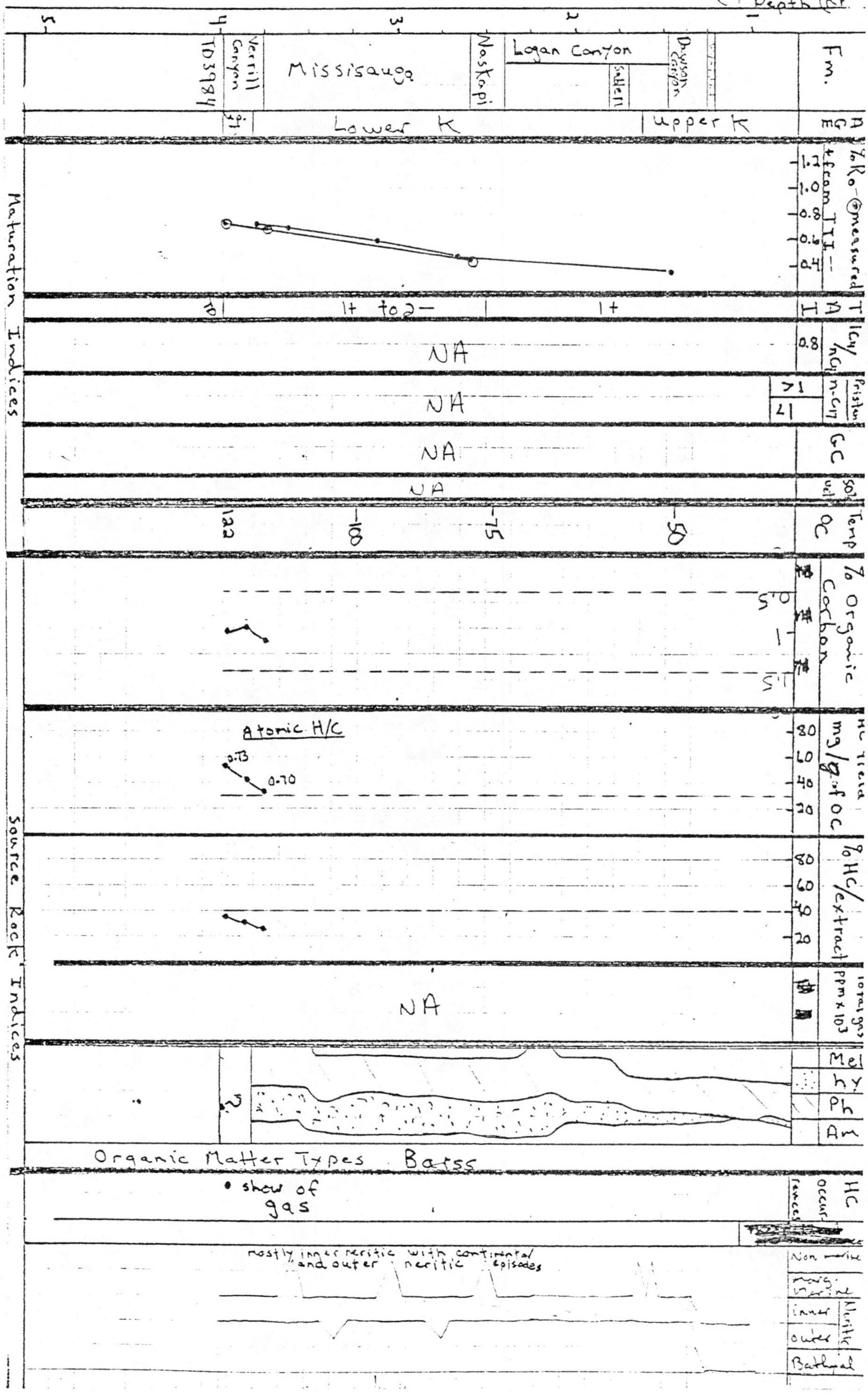
Low GOR <125 CF/bbl

Traces of bitumen in a ss/sh sequence in the Miss. Fm. lower part 2750-2900m

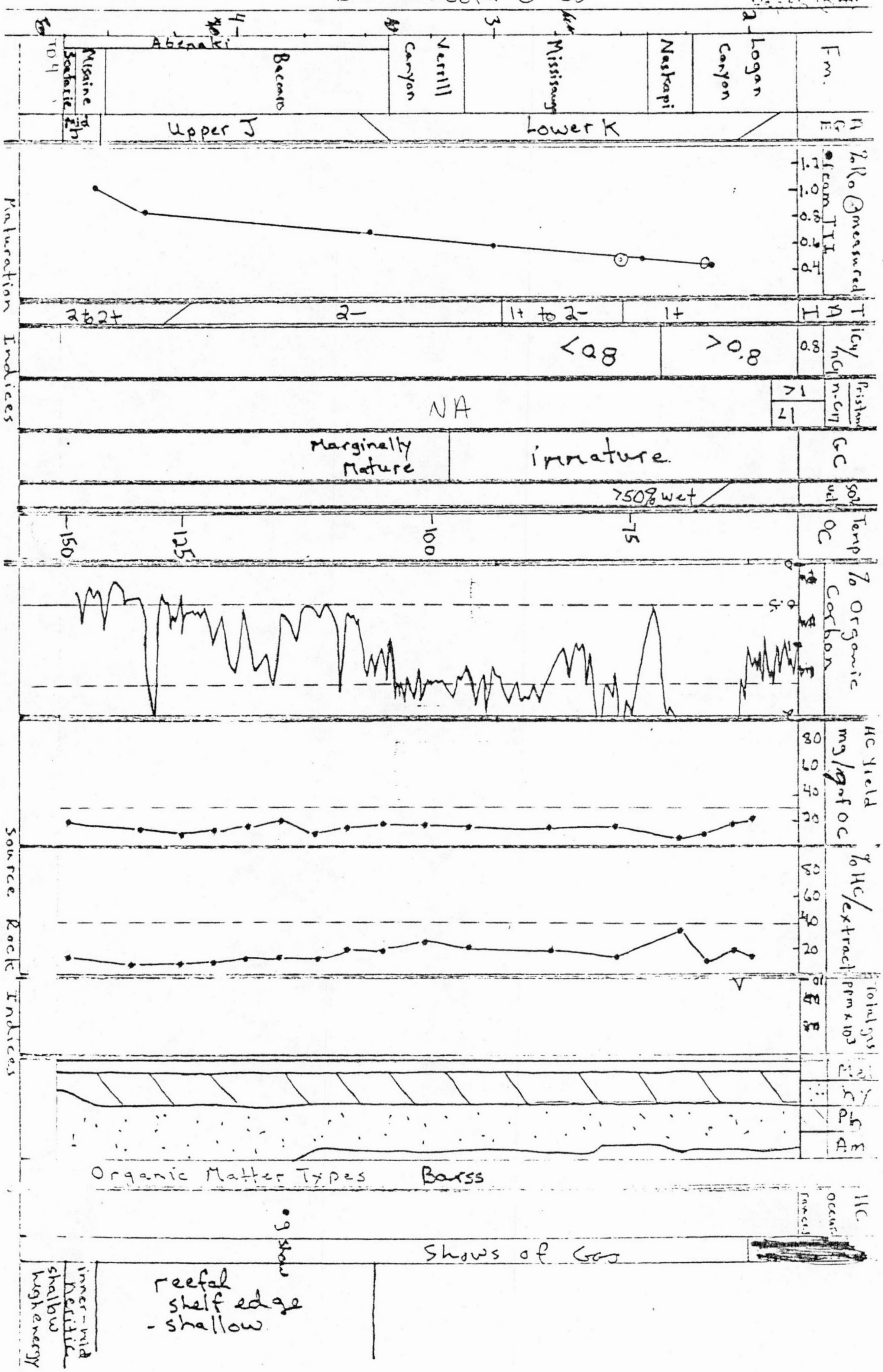
extractable & HC's are comparable to Primrose wells

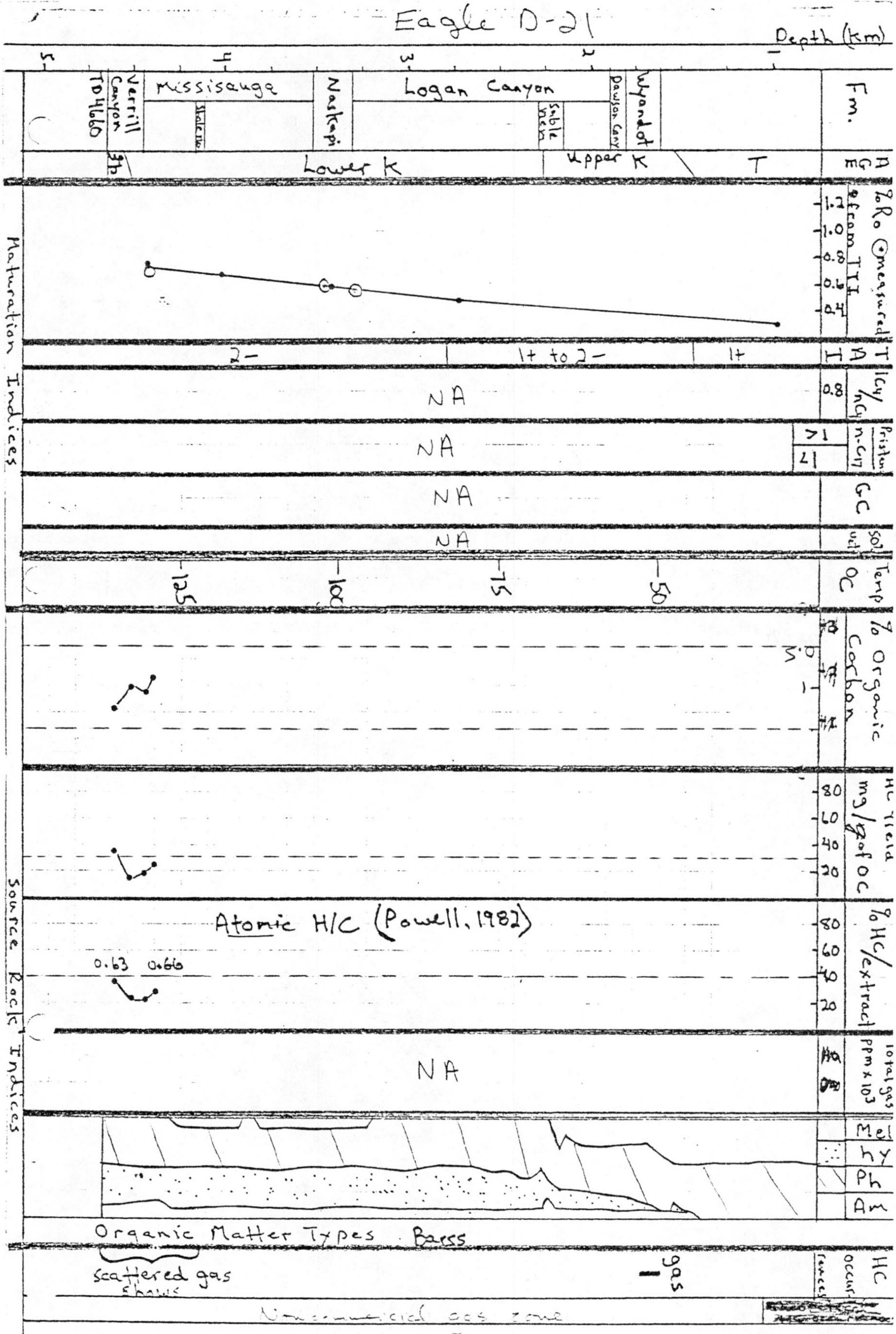
Increase in HC as % extract and decrease in yield in Abenaki due to carbonates - change in OM and efficiency of conversion

Cree E-35

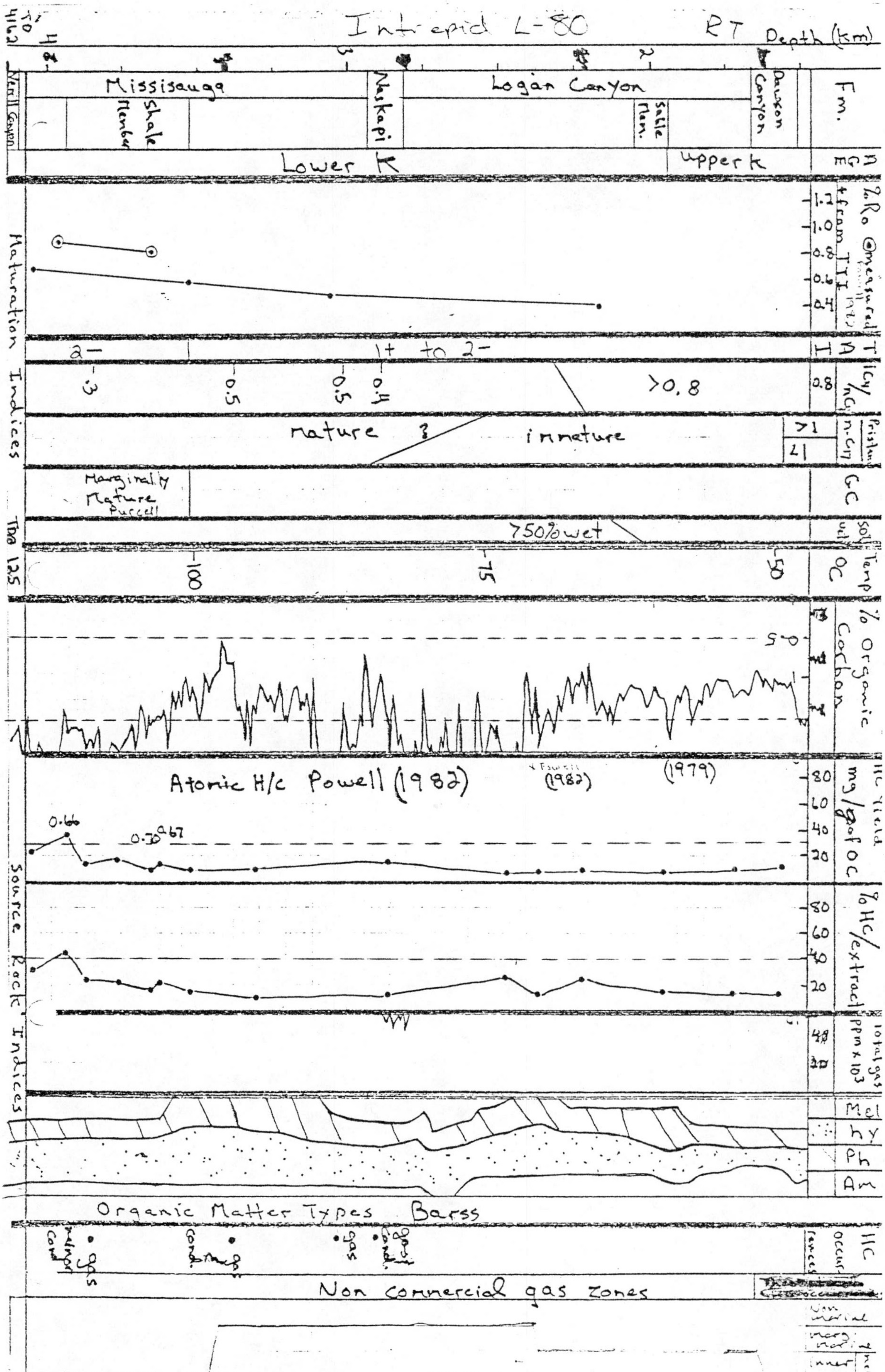

RT Depth (km)
5
4
3
2
1
TD 3984
Verrill Canyon
Missisauga
Naskapi
Logan Canyon
Sable
Dawson Canyon
Fm.
Lower K
Upper K
Age
%Ro - measured
- from TTI -
1.2
1.0
0.8
0.6
0.4
Maturation Indices
10
1+ to 2-
1+
TAI
NA
%nC17
0.8
Pristane/n-C17
>1
<1
NA
GC
NA
NA
122
108
75
50
Temp °C
% Organic Carbon
0.5
1
1.5
Atomic H/C
0.73
0.70
HC Yield mg/g of OC
80
60
40
20
% HC/extract
80
60
40
20
Source Rock Indices
Total gas ppm x 10³
NA
Mel
hy
Ph
Am
Organic Matter Types Batss
• show of gas
HC occurrence
mostly inner neritic with continental and outer neritic episodes
Non marine
marg. marine
inner
outer
Neritic
Bathyal

Demascota G-32



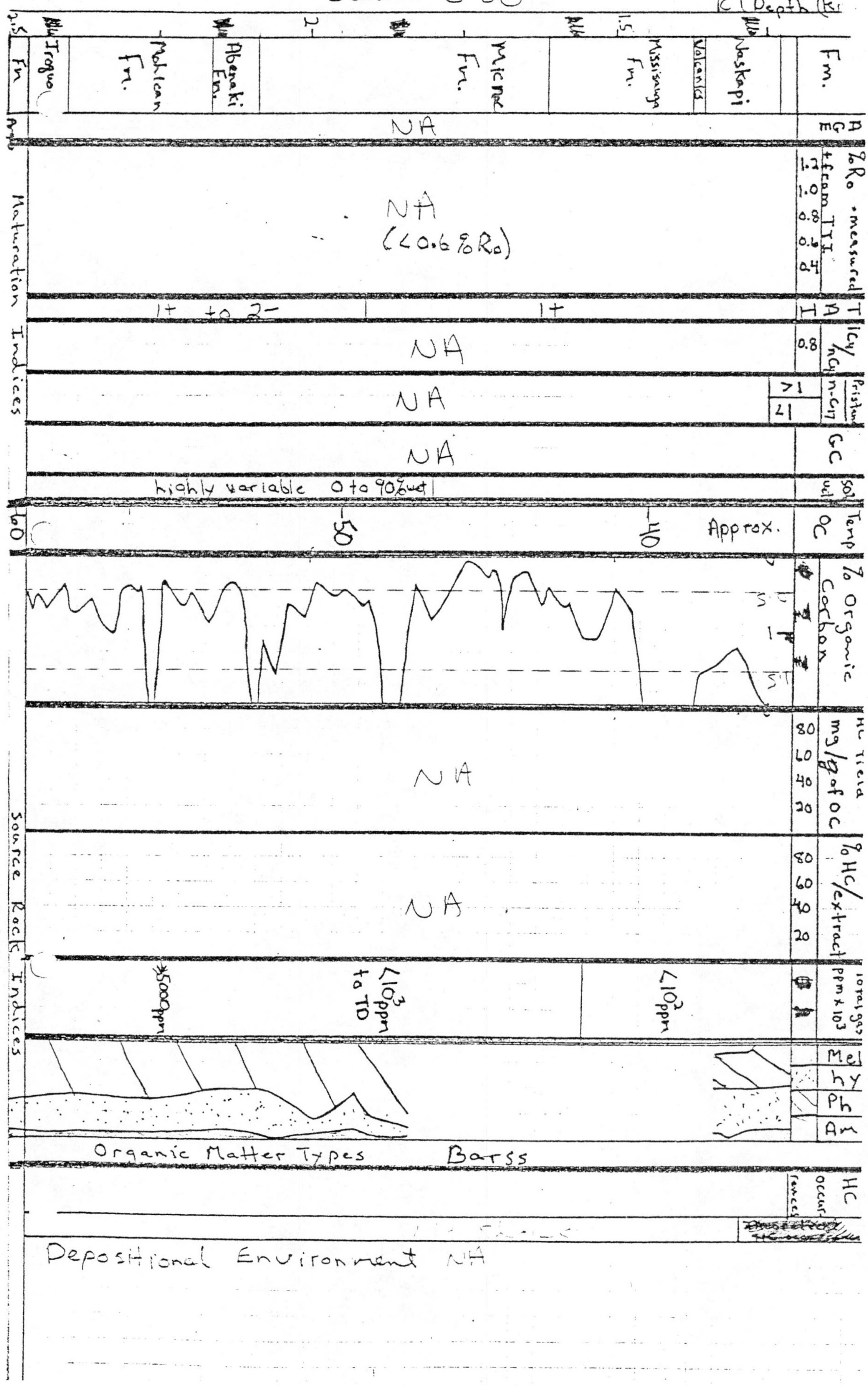


Eagle D-21
Depth (km)
5
4
3
2
1
Fm.
TD 4660
Verrill Canyon
Missisauga
Shale Mb.
Naskapi
Logan Canyon
Sable Mem
Dawson Cany
Wyandot
AGE
Jh
Lower K
Upper K
T
Maturation Indices
%Ro ⊙ measured • from TAI
1.2
1.0
0.8
0.6
0.4
TAI
2-
1+ to 2-
1+
IC/nC
0.8
NA
Pristane/n-C17
>1
<1
NA
GC
NA
sol. ext.
NA
Temp °C
125
100
75
50
% Organic Carbon
0.5
1
Source Rock Indices
HC Yield mg/g of OC
80
60
40
20
% HC/extract
Atomic H/C (Powell, 1982)
0.63
0.66
80
60
40
20
total gas ppm x 10^3
NA
Mel
Hy
Ph
Am
Organic Matter Types
Barss
HC occurrences
scattered gas shows
gas
Non-commercial gas zone

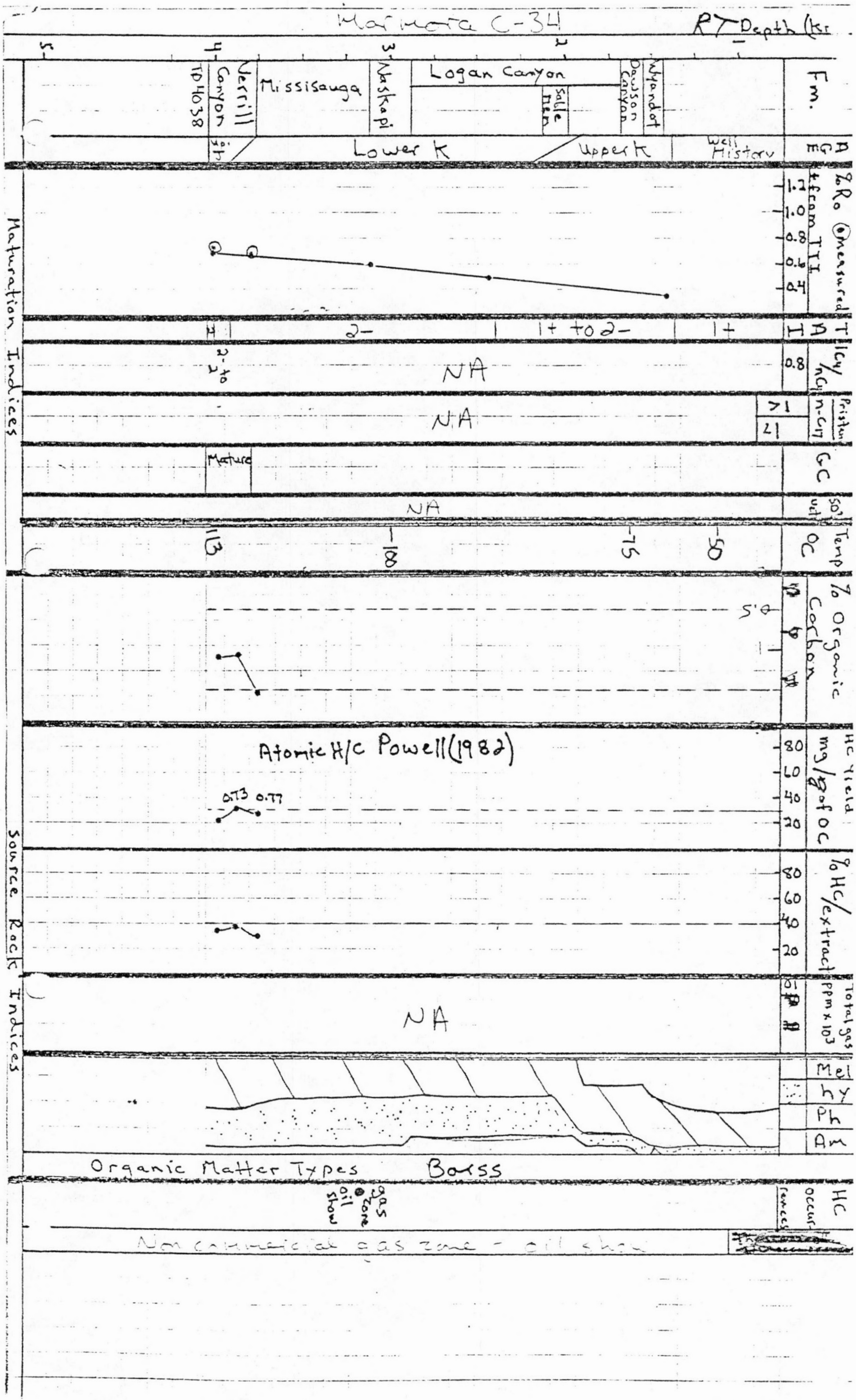


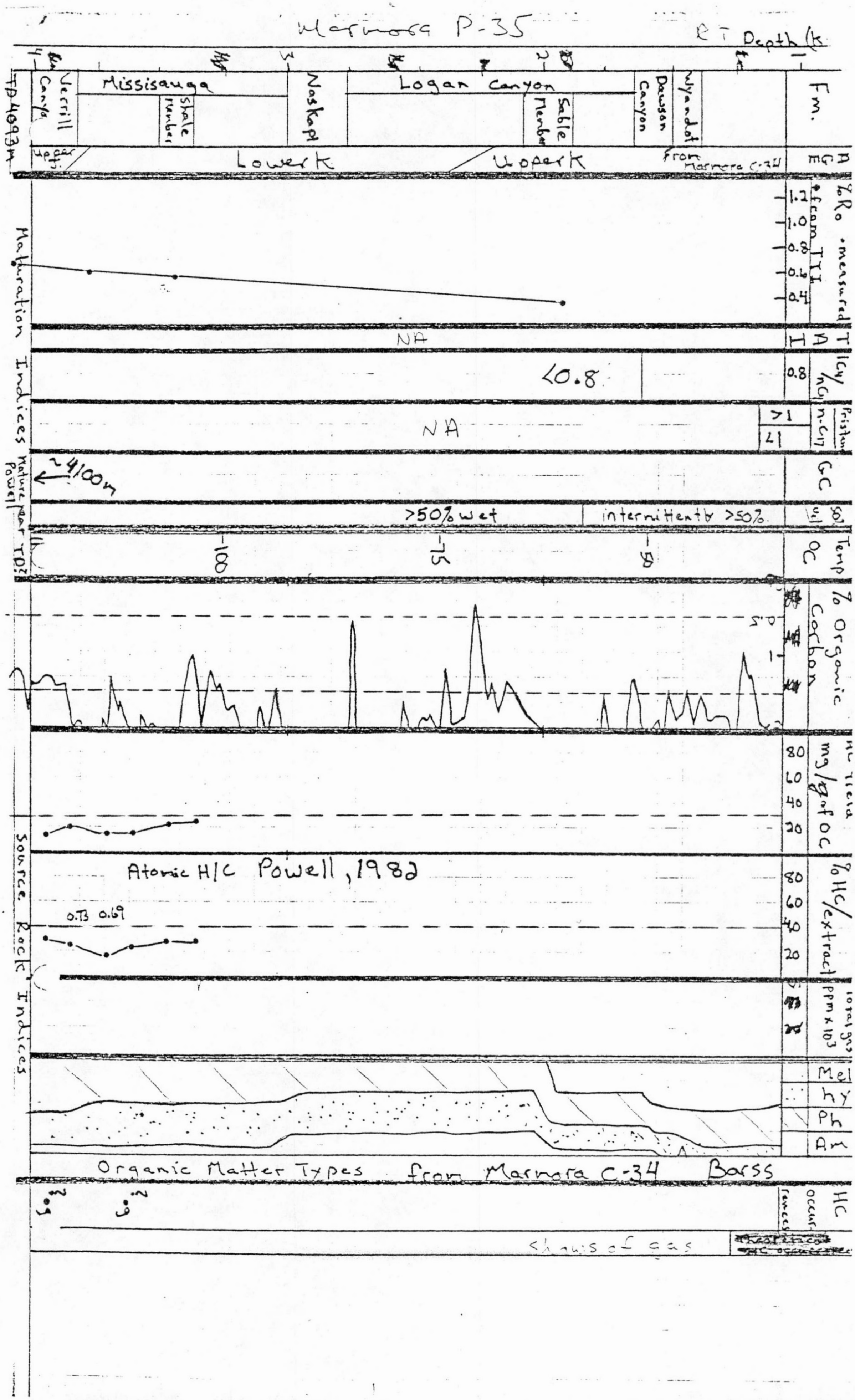
Intrepid L-80
RT Depth (km)
Missisauga
Shale Member
Naskapi
Logan Canyon
Sable Mem.
Dawson Canyon
Fm.
Lower K
Upper K
% Ro
Maturation Indices
2- 1+ to 2-
>0.8
mature ? immature
>1
<1
Marginally Mature Purcell
>50% wet
Temp °C
100
75
50
% Organic Carbon
Atomic H/C Powell (1982)
(1982)
(1979)
HC Yield mg/g of OC
0.66
% HC/extract
Source Rock Indices
total gas ppm x 10³
Mel
hy
Ph
Am
Organic Matter Types Barss
HC occurrences
gas
Cond.
Non commercial gas zones
Non marine
marginal
inner
outer
bathyal

Jason C-20

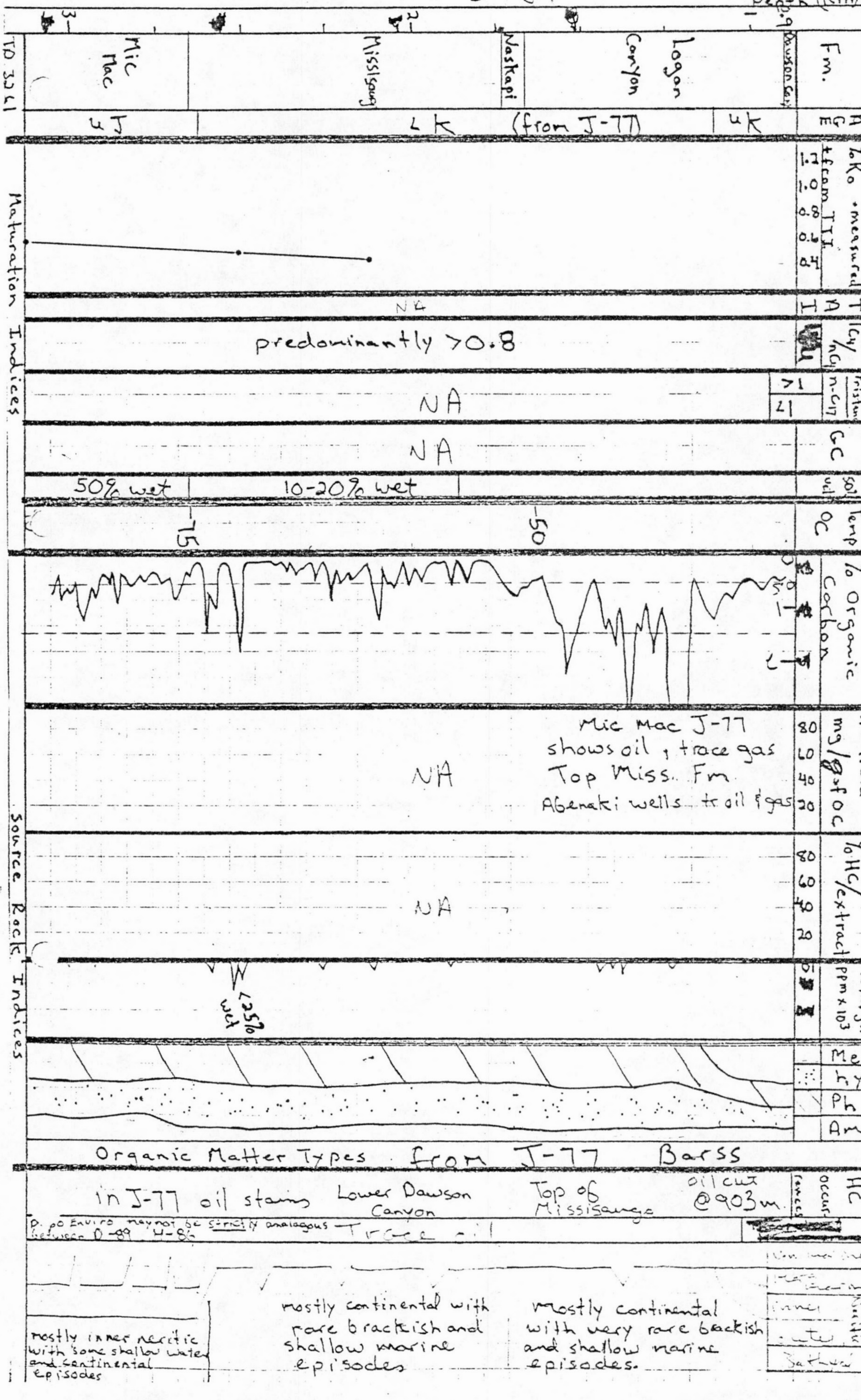


RT Depth (km)
Fm.
Iroquois
Mohican Fm.
Abenaki Fm.
Micmac Fm.
Missisauga Fm.
Volcanics
Naskapi
NA
%Ro • measured † from TAI
1.2
1.0
0.8
0.6
0.4
NA (<0.6 %Ro)
Maturation Indices
TAI
1+ to 2-
1+
iC4/nC4
0.8
NA
Pristane/n-C17
>1
<1
GC
highly variable 0 to 90% wt
Temp °C
60
50
40
Approx.
% Organic Carbon
HC Yield mg/g of OC
80
60
40
20
% HC/extract
Total gas ppm x 10³
5000ppm
<10³ ppm to TD
<10² ppm
Source Rock Indices
Mel
hY
Ph
Am
Organic Matter Types
Barss
HC occurrences
Depositional Environment NA


Marmora C-34
RT Depth (km)
Fm.
TD 4038
Verrill Canyon
Missisauga
Naskapi
Logan Canyon
Sable Shale
Dawson Canyon
Wyandot
Lower K
Upper K
Well History
%Ro (measured / from TAI)
TAI
2-
1+ to 2-
1+
Cy/nC17
0.8
NA
Pristane/n-C17
>1
<1
N.A
GC
Mature
NA
Temp °C
113
88
75
50
% Organic Carbon
Atomic H/C Powell (1982)
HC Yield mg/g of OC
0.73
0.77
80
60
40
20
% HC/extract
Total gas ppm x 10³
NA
Mel
Hy
Ph
Am
Organic Matter Types
Bosss
gas zone
oil show
HC occurrences
Non commercial gas zone - oil show
Maturation Indices
Source Rock Indices

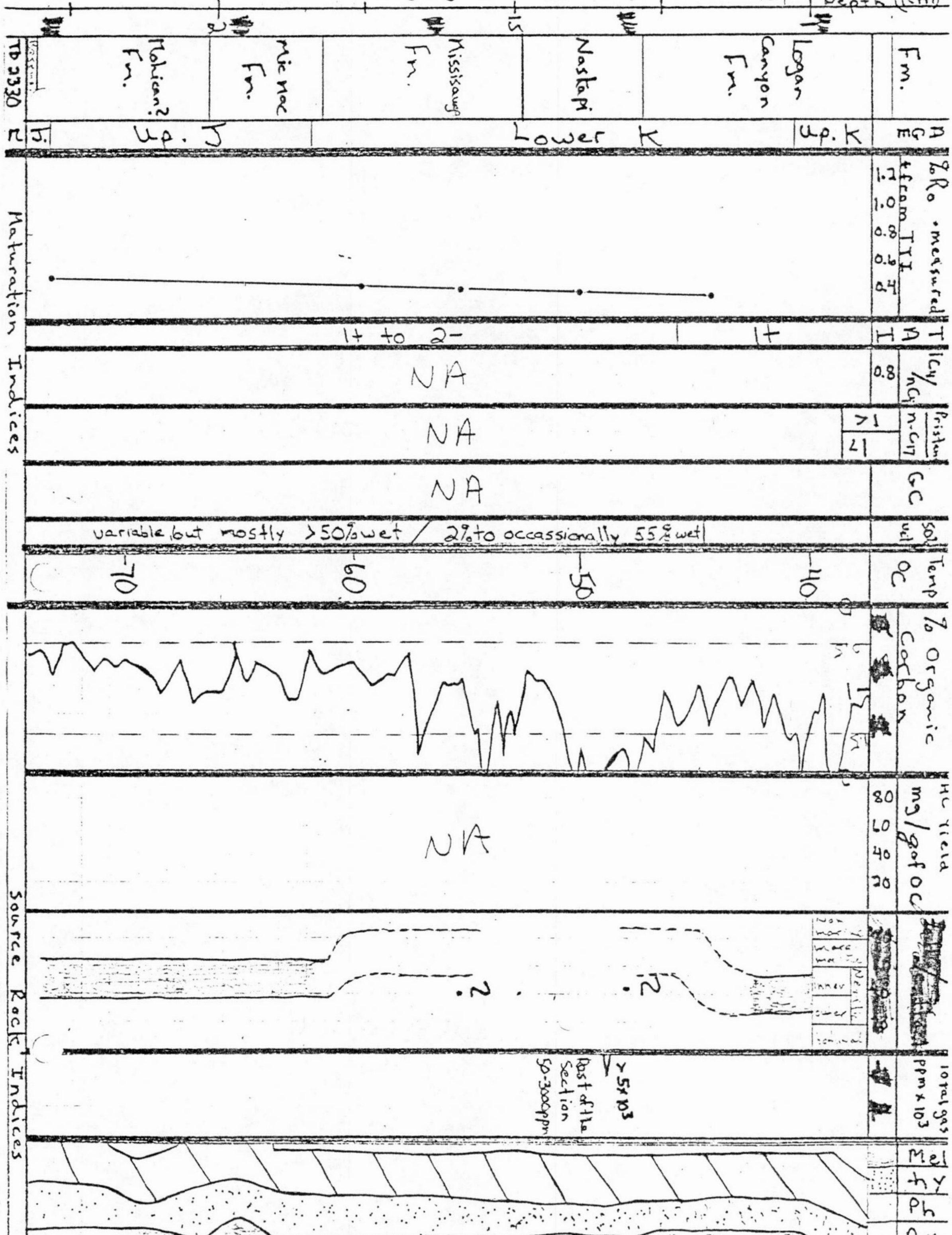

Marmora P-35
RT Depth (k
Fm.
Missisauga
Shale Member
Naskapi
Logan Canyon
Sable Member
Dawson Canyon
Wyandot
Verrill Canyon
TD 4093m
Upper J.
Lower K
Upper K
From Marmora C-34
%Ro •measured *from TTI
1.2
1.0
0.8
0.6
0.4
Maturation Indices
NA
<0.8
0.8
NA
>1
<1
Pristane/n-C17
GC
Mature near TD?
Powell
~4100m
>50% wet
intermittently >50%
Temp °C
100
75
50
% Organic Carbon
0.5
1
HC Yield mg/g of OC
80
60
40
20
Atomic H/C Powell, 1982
0.73 0.69
%HC/extract
80
60
40
20
Source Rock Indices
Total gas ppm x 10³
Mel
Hy
Ph
Am
Organic Matter Types from Marmora C-34 Barss
HC occurrences
shows of gas

Mic mac D-89

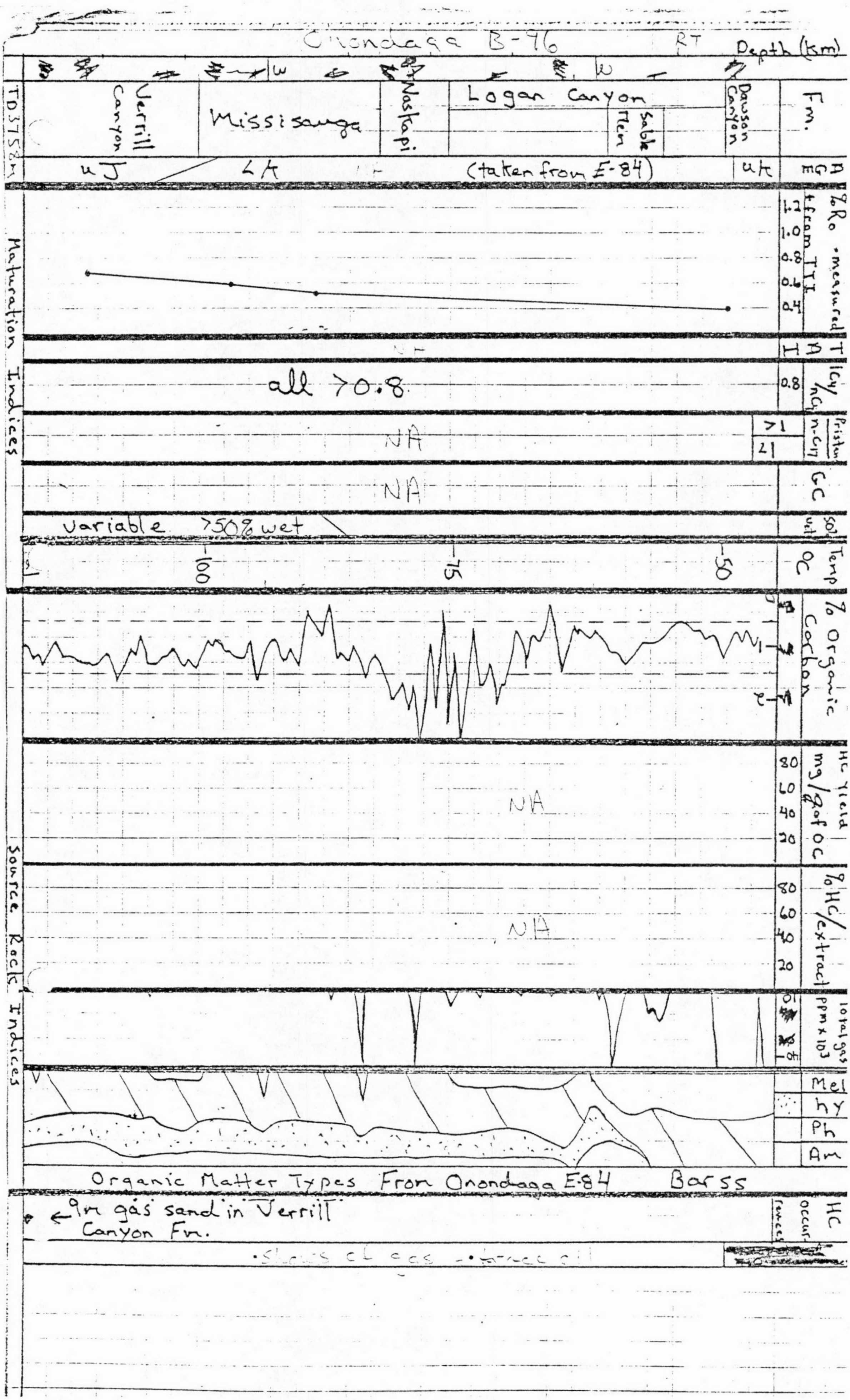


Depth (km)
Fm.
Mic Mac
Missisauga
Naskapi
Canyon
Logan
Dawson Cy
TD 3361
MGA
uJ
LK
(from J-77)
uK
%Ro •measured
+from TTI
Maturation Indices
TAI
NA
predominantly >0.8
>1
<1
NA
GC
NA
50% wet
10-20% wet
Temp °C
75
50
% Organic Carbon
HC Yield mg/g of OC
Mic Mac J-77
shows oil, trace gas
Top Miss. Fm
Abenaki wells tr oil & gas
NA
%HC/extract
NA
Total gas ppm x 10³
<25% wet
Source Rock Indices
Mel
Ph
Am
Organic Matter Types from J-77 Barss
HC occur.
in J-77 oil stains Lower Dawson Canyon
Top of Missisauga
oil cut @903m.
D. po Enviro may not be strictly analogous between D-89 & H-86
Trace oil
mostly inner neritic with some shallow water and continental episodes
mostly continental with rare brackish and shallow marine episodes
mostly continental with very rare brackish and shallow marine episodes.
Inner
Outer
Bathyal

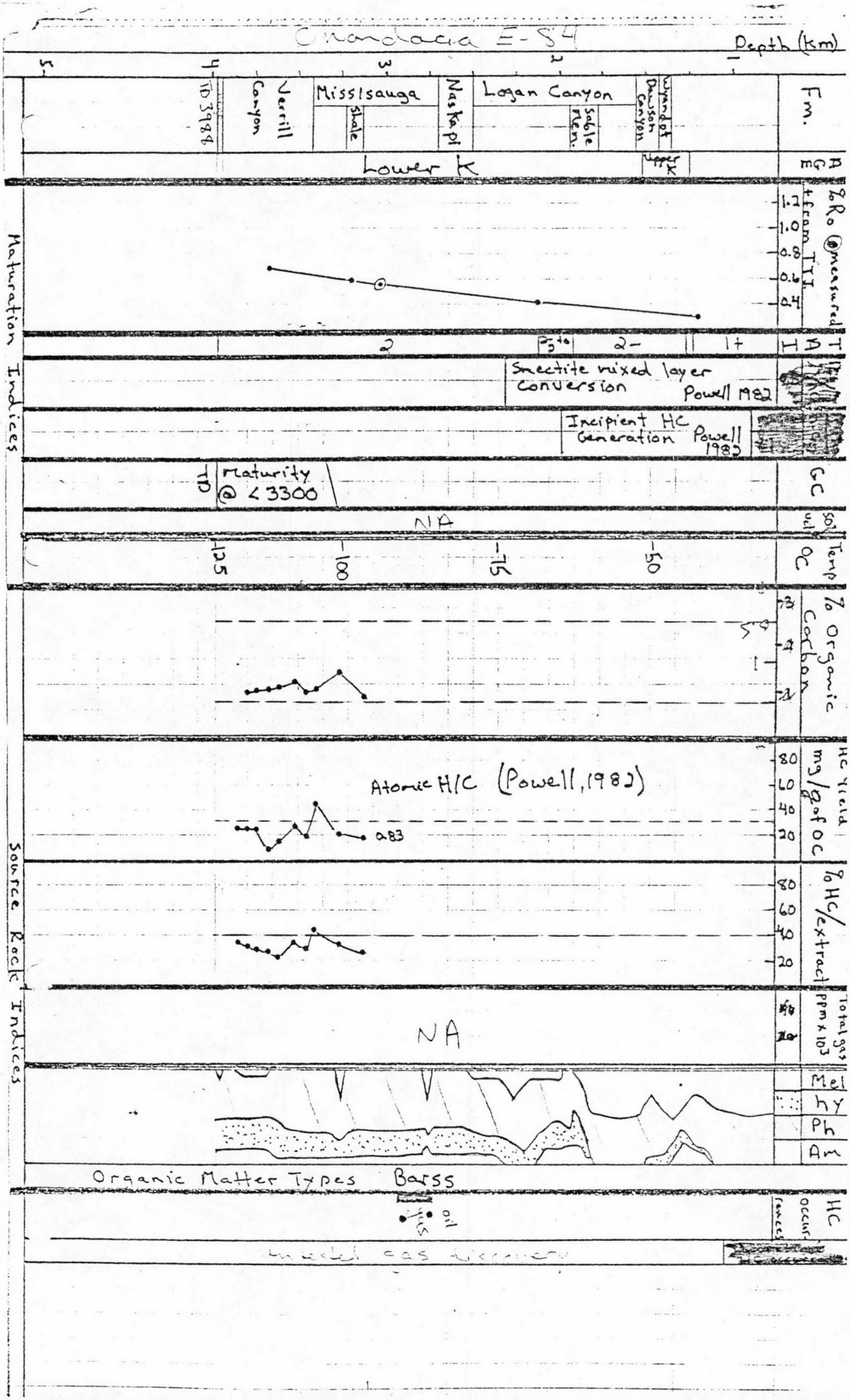
Ojibwa-E-07



Wet gas data indicates wide variation in source potential

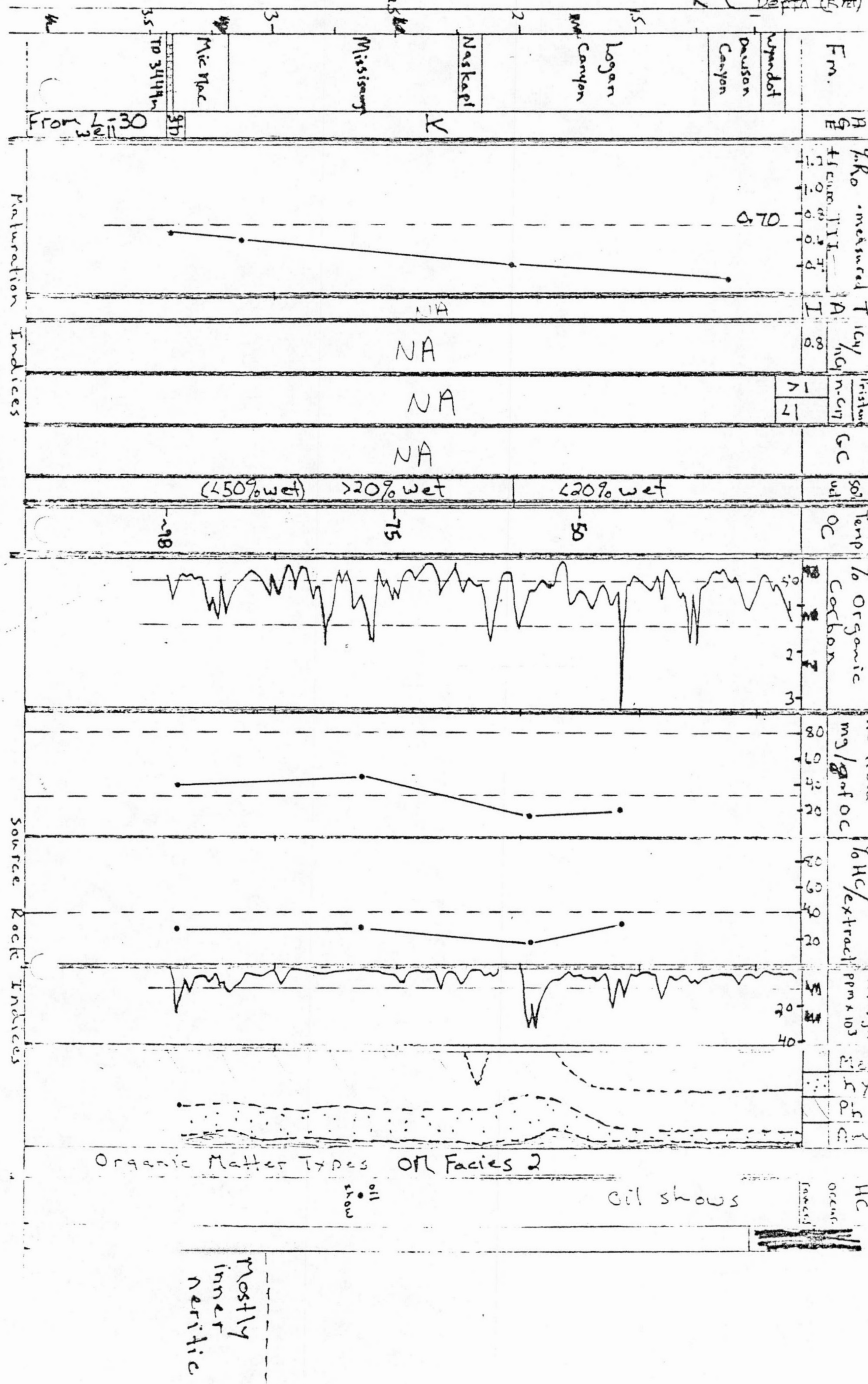


Onondaga B-96
RT
Depth (km)
Verrill Canyon
Missisauga
Naskapi
Logan Canyon
Sable Mem
Dawson Canyon
Fm.
TD3758m
uJ
LK
(taken from E-84)
uK
Maturation Indices
%Ro
• measured
+ from TTI
1.2
1.0
0.8
0.6
0.4
TAI
all >0.8
0.8
C_{27}/nC_{29}
NA
>1
<1
Pristane/n-C17
GC
variable
>50% wet
Sol ext
-100
-75
-50
Temp °C
% Organic Carbon
1
2
Source Rock Indices
NA
80
60
40
20
HC Yield mg/g of OC
%HC/extract
Total gas ppm x 10³
40
Mel
hY
Ph
Am
Organic Matter Types From Onondaga E-84 Bars 55
gas sand in Verrill Canyon Fm.
HC occurrences
• shows of gas
• trace oil

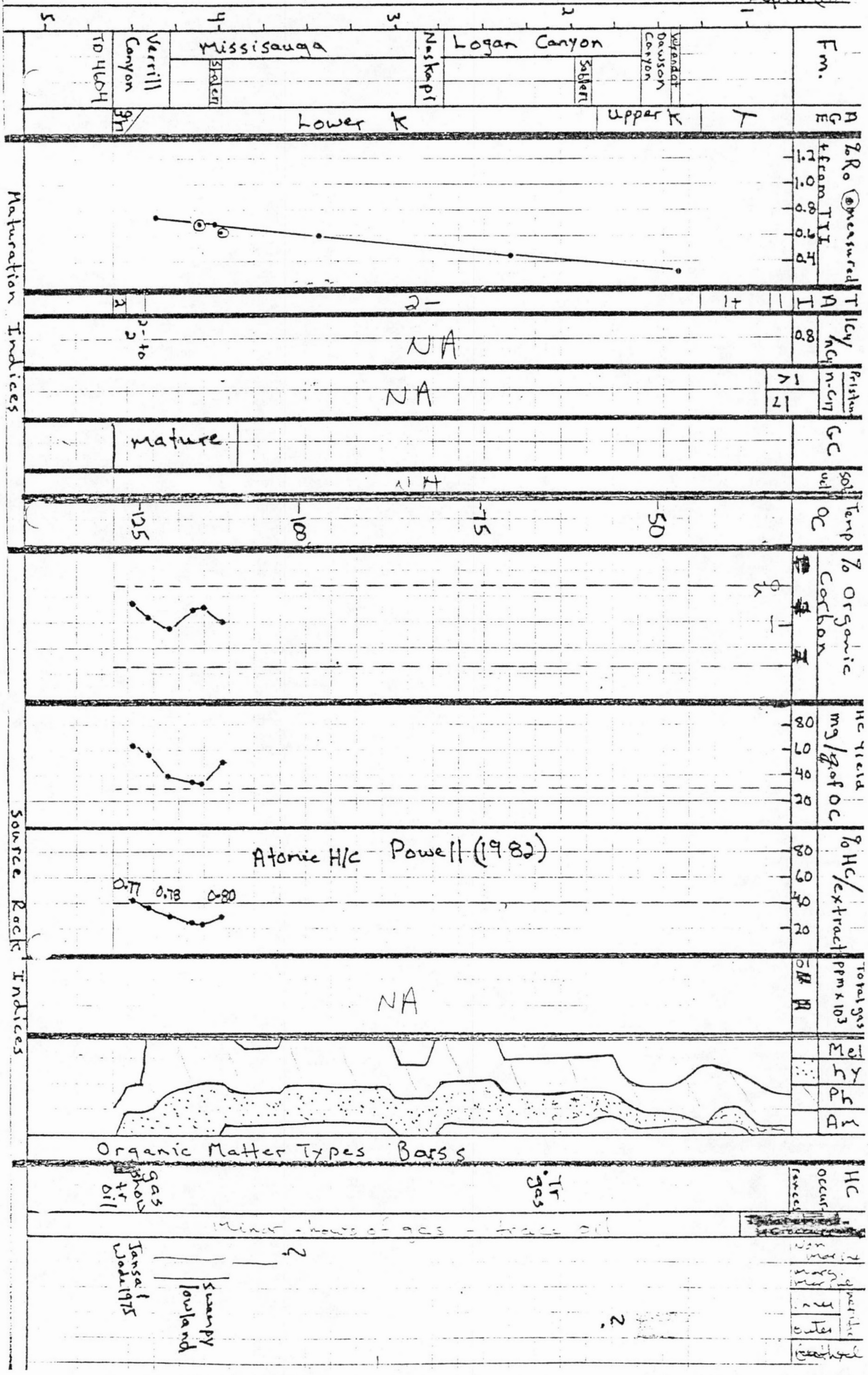


Onondaga E-84
Depth (km)
Fm.
TD 3984
Verrill Canyon
Missisauga
Shale
Naskapi
Logan Canyon
Sable Mem.
Dawson Canyon
Wyandot
Lower K
Upper K
%Ro measured from TAI
Maturation Indices
TAI
Smectite mixed layer conversion Powell 1982
Incipient HC Generation Powell 1982
GC
TD Maturity @ < 3300
NA
Temp °C
% Organic Carbon
HC Yield mg/g of OC
Atomic H/C (Powell, 1982)
% HC/extract
Source Rock Indices
Total gas ppm x 10³
NA
Mel
hy
Ph
Am
Organic Matter Types Barss
HC occurrences
oil

Penobscot B-41

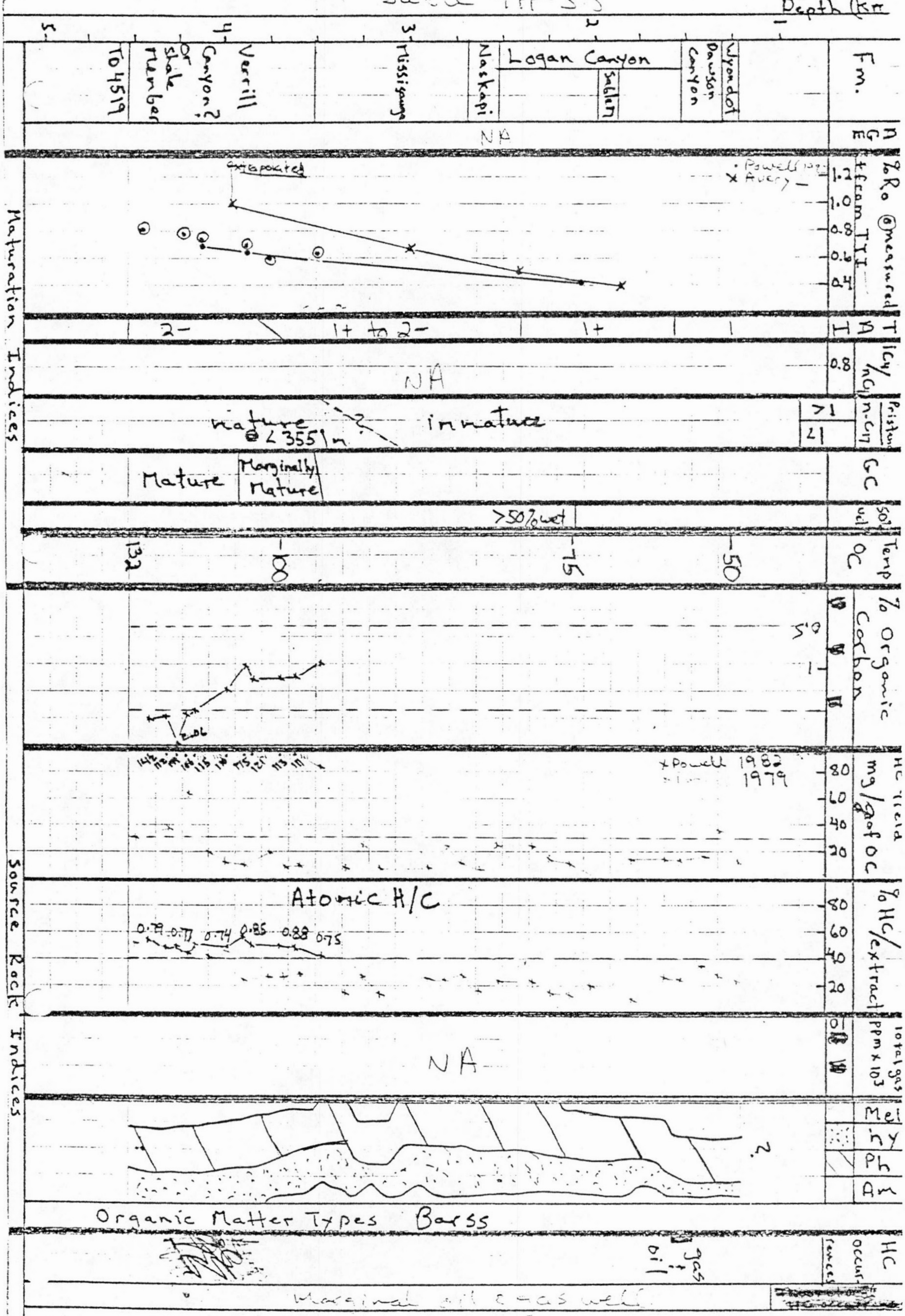


Sable Is C-67



Depth (km)
5
4
3
2
1
Fm.
TD 4604
Verrill Canyon
Missisauga
Naskapi
Logan Canyon
Dawson Canyon
Wyandot
Lower K
Upper K
T
Maturation Indices
%Ro ⊙ measured • from TAI
1.2
1.0
0.8
0.6
0.4
TAI
2-
1+
ICy/nCy
0.8
NA
Pristane/n-C17
>1
<1
NA
GC
mature
Temp °C
125
100
75
50
% Organic Carbon
HC Yield mg/g of OC
80
60
40
20
% HC/extract
80
60
40
20
Atomic H/C Powell (1982)
0.77
0.78
0.80
Source Rock Indices
Total gas ppm x 10³
NA
Mel
hy
Ph
Am
Organic Matter Types Bars
HC occurrences
gas show tr oil
Tr gas
Minor shows of gas - trace oil
Jansa & Wade 1975
swampy lowland

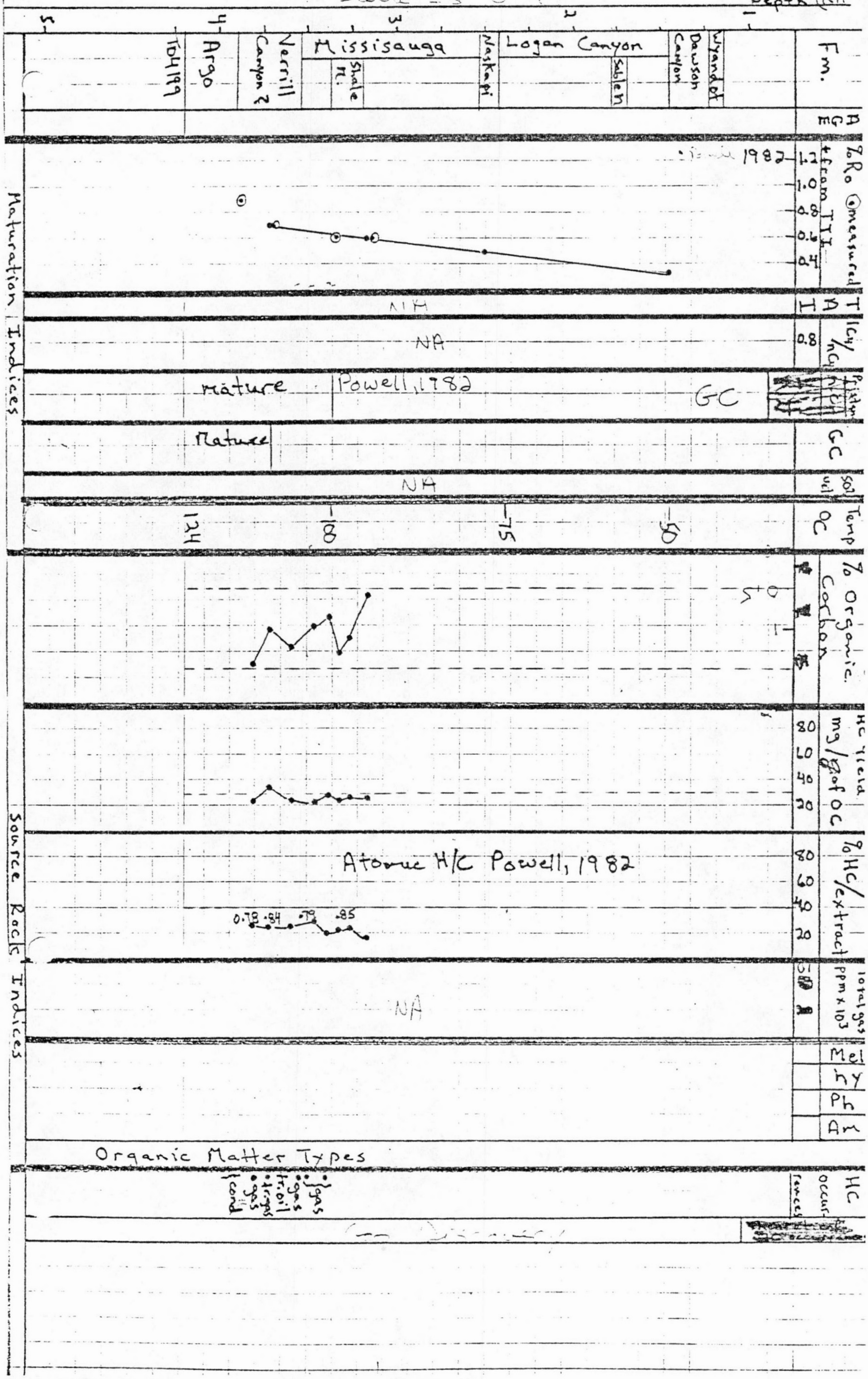
Sable 4H-58

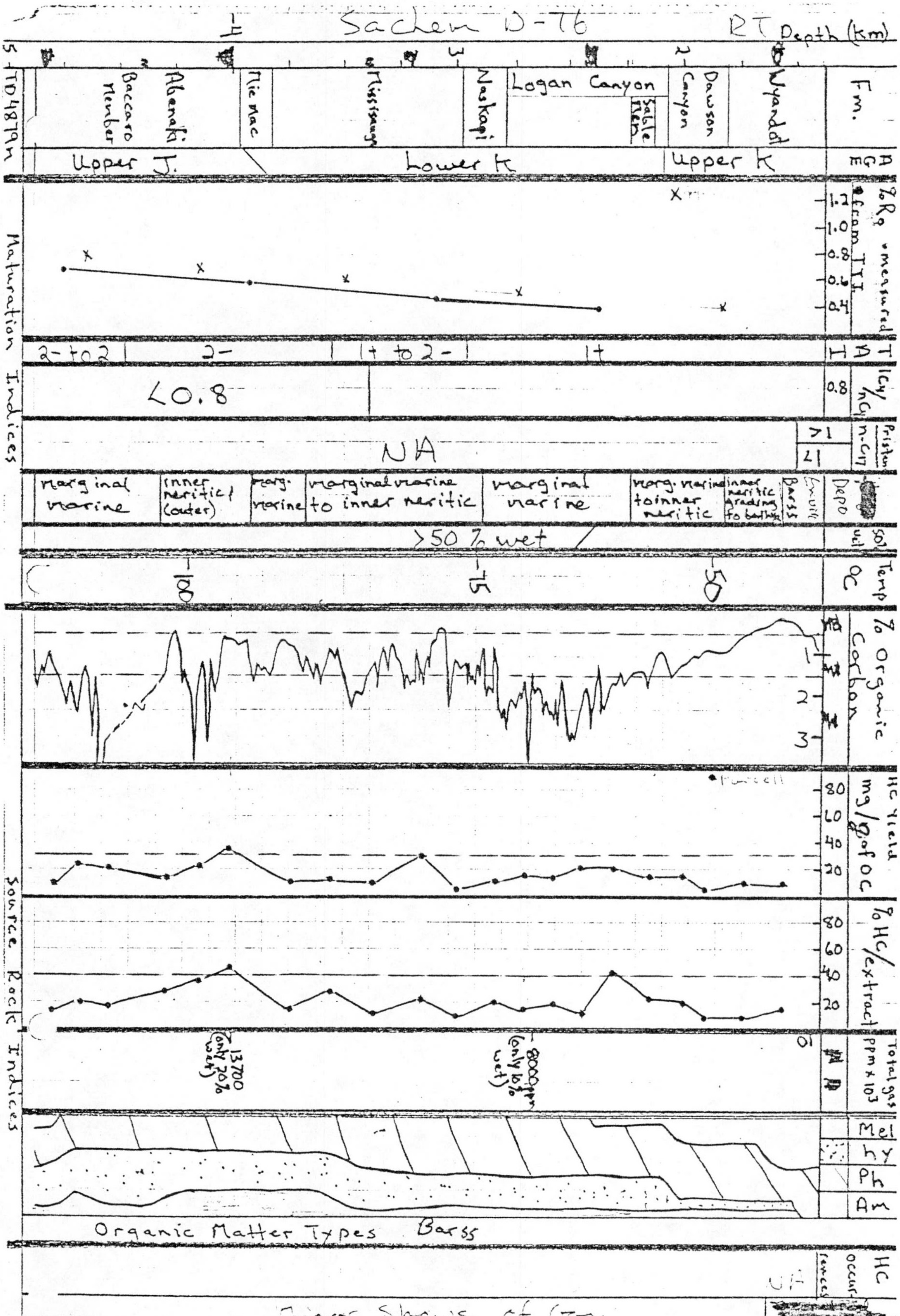


Note deviated hole - measured depths are > actual depths

Drilled on the flank of a salt dome

Sable Is C-47

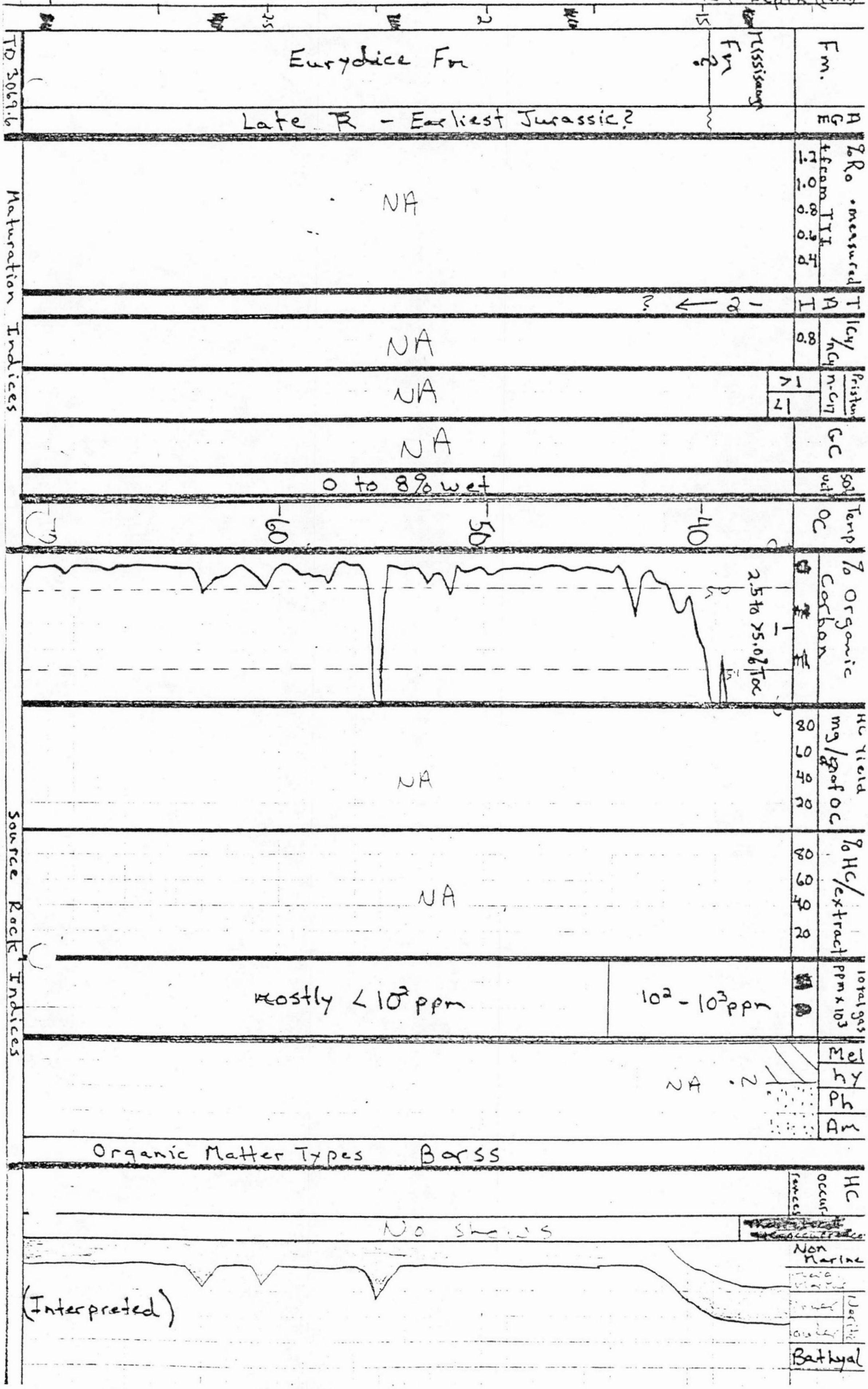

Depth (km
5
4
3
2
1
Fm.
TD4199
Argo
Verrill Canyon ?
Missisauga
Shale Mbr.
Naskapi
Logan Canyon
Sable Mbr.
Dawson Canyon
Wyandot
%Ro ⊙measured +from TTI
1982
1.2
1.0
0.8
0.6
0.4
Maturation Indices
NA
0.8
NA
mature
Powell, 1982
GC
Mature
GC
NA
Temp °C
124
100
75
50
% Organic Carbon
HC Yield mg/g of OC
80
60
40
20
% HC/extract
Atomic H/C Powell, 1982
0.78
.84
.79
.85
80
60
40
20
Source Rock Indices
total gas ppm x 10³
NA
Mel
hY
Ph
Am
Organic Matter Types
HC occurrences



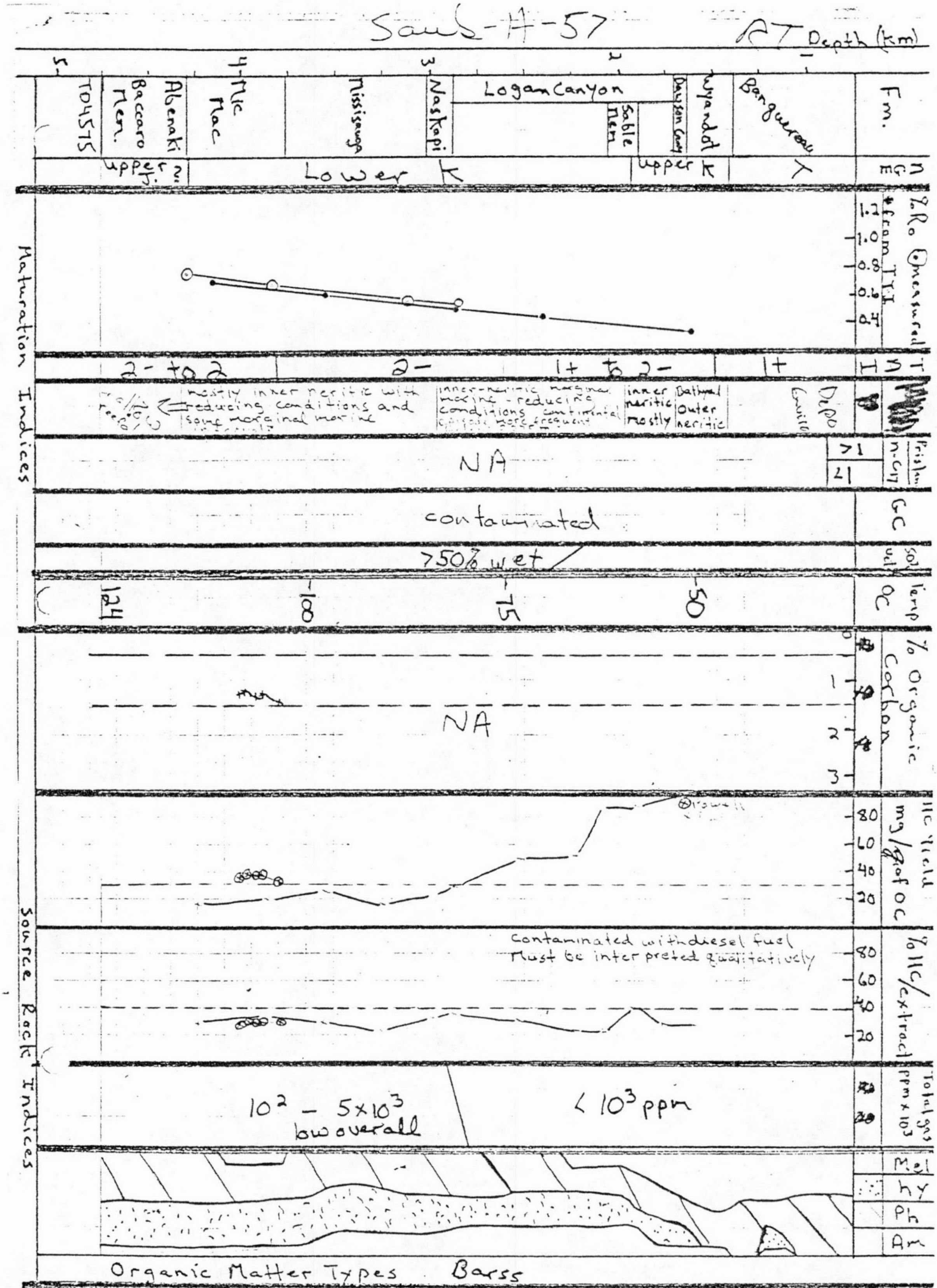
High OC in Abenaki may be due to problems in the lab

- Generally where the total gas > 1000ppm → % wet is < 50%

Sambro I-29

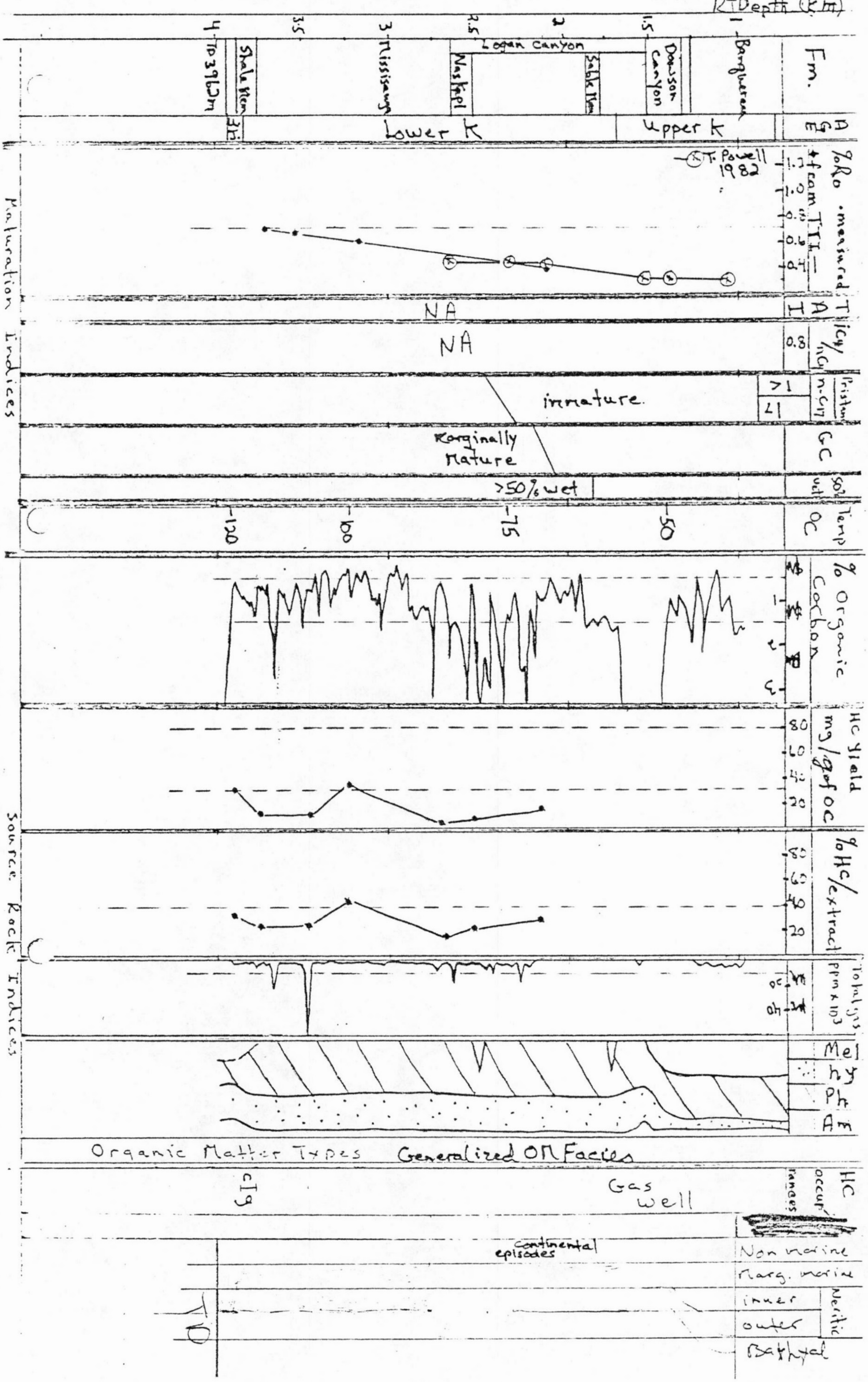


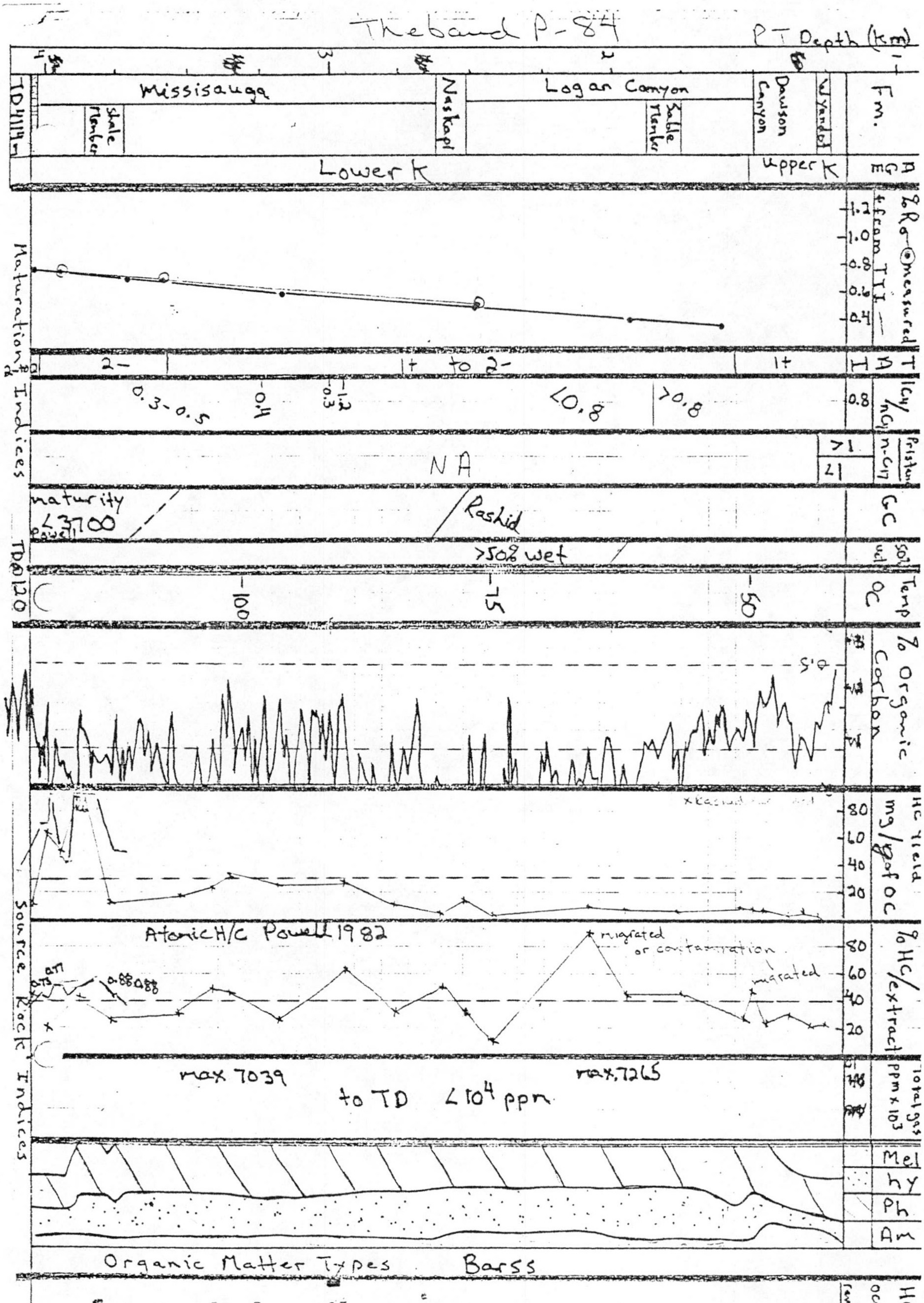
RT Depth (km)
T.D. 3069.6
Eurydice Fm
Mississauga Fm
Fm.
Late R - Earliest Jurassic?
mGA
Maturation Indices
NA
%Ro •measured
t from TII
1.2
1.0
0.8
0.6
0.4
? ← 2 -
TAI
NA
0.8
iC4/nC4
NA
>1
<1
Pristane/n-C17
NA
GC
0 to 8% wet
SOL udi
Terp °C
60
50
40
% Organic Carbon
2.5 to >5.0% TOC
1
Source Rock Indices
NA
80
60
40
20
HC Yield mg/g of OC
NA
80
60
40
20
%HC/extract
mostly <10² ppm
10² - 10³ ppm
total gas ppm x 10³
NA
Mel
hy
Ph
Am
Organic Matter Types Barss
HC occur
No shows
Non Marine
Marine
Bathyal
(Interpreted)



Abundant evidence of reducing conditions

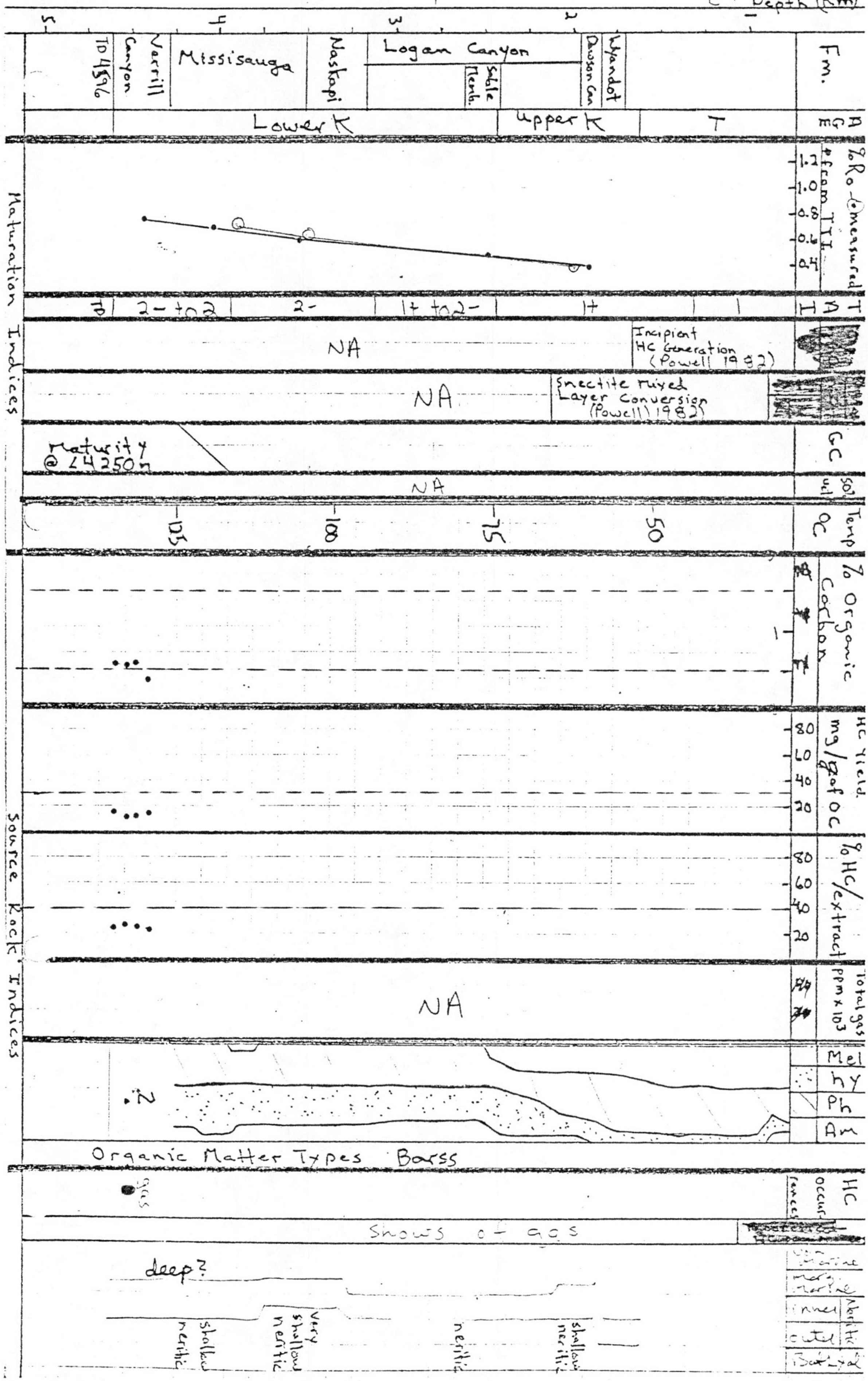
Thebaud I-94


RT Depth (km)
1
1.5
2
2.5
3
3.5
4
Fm.
Banquereau
Dawson Canyon
Logan Canyon
Sable Mem
Naskapi
Missisauga
Shale Mem
TD 3962m
Age
Upper K
Lower K
Maturation Indices
%Ro measured + from TTI
T. Powell 1982
1.2
1.0
0.8
0.6
0.4
TAI
NA
Tmax
NA
0.8
Pristane/n-C17
>1
<1
immature
GC
Marginally Mature
>50% wet
Temp °C
-50
-75
-100
-120
Source Rock Indices
% Organic Carbon
1
2
3
HC Yield mg/g of OC
80
60
40
20
%HC/extract
80
60
40
20
Total gas ppm x 10^3
20
40
Mel
hy
Ph
Am
Organic Matter Types
Generalized OM Facies
HC occurrences
Gas well
continental episodes
Non marine
Marg. marine
inner
outer
Neritic
Bathyal
TD



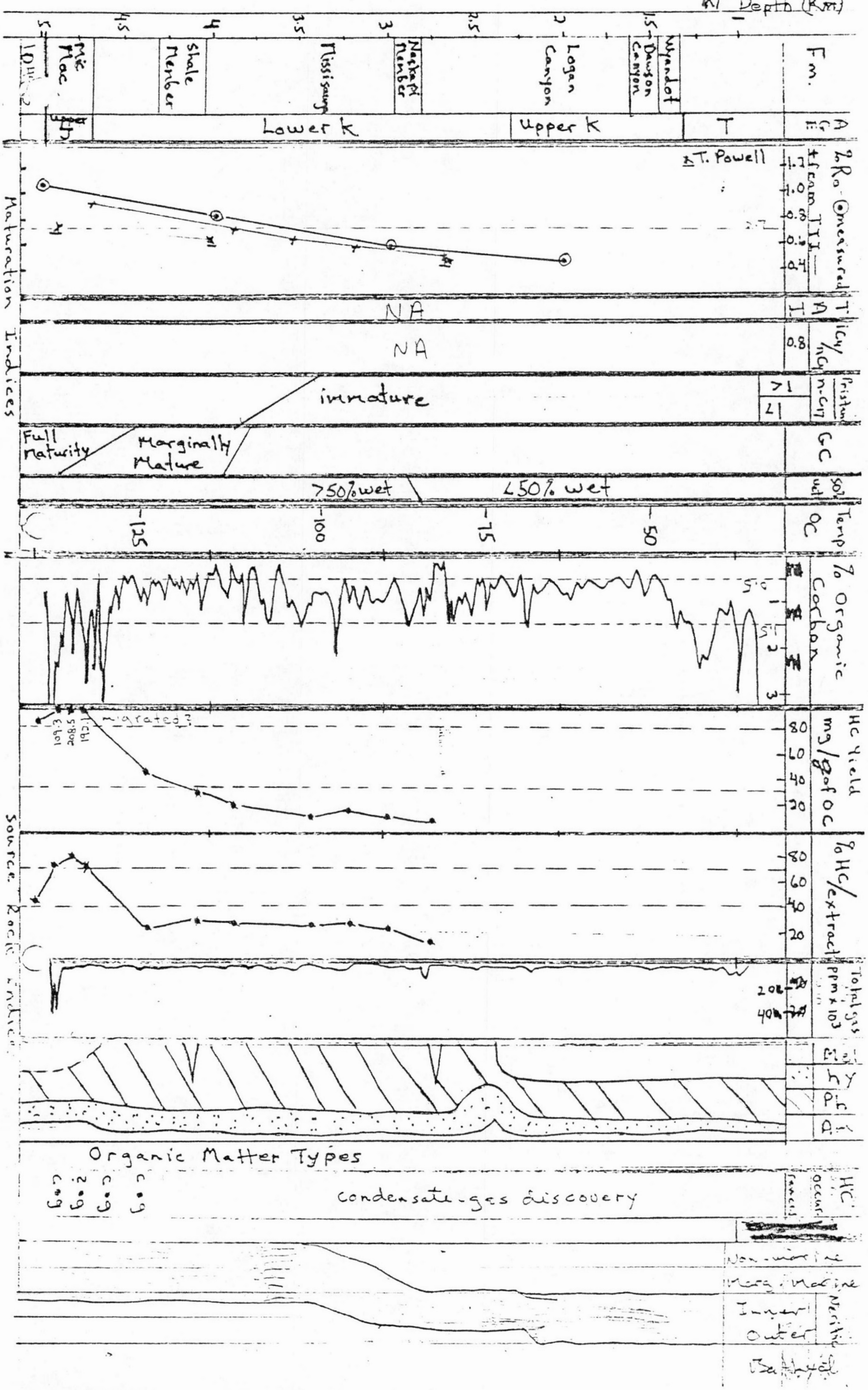
Depo environments may not be strictly analagous between P-84 & I-94 as evidenced in TOC data & Total gas

Triumph P-50



RT Depth (km)
5
4
3
2
1
Fm.
TD 4596
Verrill Canyon
Missisauga
Naskapi
Logan Canyon
Sable Memb.
Dawson Can.
Wyandot
Lower K
Upper K
T
%Ro (measured) (from TTI)
1.2
1.0
0.8
0.6
0.4
Maturation Indices
TAI
2- to 2
2-
1+ to 2-
1+
NA
Incipient HC Generation (Powell 1982)
NA
Smectite mixed Layer Conversion (Powell 1982)
maturity @ ∠4250m
GC
NA
Sol.
Temp °C
125
100
75
50
% Organic Carbon
1
HC Yield mg/g of OC
80
60
40
20
% HC/extract
80
60
40
20
Source Rock Indices
NA
Total gas ppm x 10³
Mel
Hy
Ph
Am
Organic Matter Types Barss
gas
HC occurrences
Shows of gas
deep?
Non-Marine
Marg. Marine
Inner Neritic
Outer Neritic
Bathyal
shallow neritic
very shallow neritic
neritic
shallow neritic

Venture D-23



RT Depth (Km)
5
4.5
4
3.5
3
2.5
2
1.5
1
Fm.
Mic Mac
Shale Member
Missisauga
Naskapi Member
Logan Canyon
Dawson Canyon
Wyandot
Upper J
Lower K
Upper K
T
T. Powell
%Ro measured
+ from TTI
1.2
1.0
0.8
0.6
0.4
Maturation Indices
NA
NA
0.8
immature
Full maturity
Marginally Mature
>1
<1
Pristane/n-C17
GC
>50% wet
<50% wet
50% wet
125
100
75
50
Temp °C
% Organic Carbon
1
2
3
migrated?
HC Yield mg/g of OC
80
60
40
20
% HC/extract
80
60
40
20
Total gas ppm x 10³
20
40
Source Rock Indices
Organic Matter Types
condensate-gas discovery
HC occurrences
Non-marine
Marg. Marine
Inner
Outer
Neritic
Bathyal