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COMPILATION OF RESERVOIR DATA FOR SANDSTONES OF THE DEVONIAN-PERMIAN MARITIMES BASIN, EASTERN CANADA

by

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I. INTRODUCTION

Increased hydrocarbon exploration in Atlantic Canada has sparked recent interest in the economic potential of the Maritimes Basin, which underlies the Gulf of St. Lawrence and onshore portions of all four Atlantic Provinces and Quebec. Late Devonian to Permian sediments in the Maritimes Basin have been the subject of sporadic exploration since the 1850's, with encouraging petroleum shows in some wells (McMahon *et al.*, 1986). A total of 310 petroleum wells (with final depth of more than 500m) have been drilled in the onshore areas of the basin of which 152 wells were drilled in the Stoney Creek Oil and Gas field in New Brunswick. However, only 11 petroleum exploration wells have been drilled to date within the Carboniferous offshore areas of the Maritimes Basin which comprise more than 70% of the total basin area of approximately 150 000 km^2. It is fair to state that the offshore Maritimes Basin geology is inadequately understood and that the region is vastly under-explored.

This compilation of clastic reservoir data is part of a more extensive PERD (Panel of Energy Research and Development) funded project that examines several aspects of the petroleum systems in the Gulf of St. Lawrence Carboniferous. Of the key elements of petroleum systems -- source, reservoir, seal and trap -- it has been generally recognised that for the Carboniferous in the offshore, reservoir risk, i. e., capacity for sustained producibility, is the most poorly understood. This compilation was initiated as part of the process of assessing reservoir risk and is to be the basis of a more detailed diagenetic study of potential reservoirs.

This report summarizes all available public domain data relating to the reservoir potential of Carboniferous and Permian sandstones in the Maritimes Basin. Very little published data exist for other rock types, such as limestone and conglomerates. The list of parameters compiled for this study includes porosity, permeability, grain size, bed thickness, and petrography. The data are available in digital format on the accompanying CD-ROM (Appendix A).

This Open File Report consists of:

- This report which discusses the data collection, handling and a preliminary assessment.
- A database with well data, core data and porosity and permeability data in Microsoft Access and ASCII format.
- A digital map linked to the database to indicate well and outcrop locations in ArcExplorer.

- A correlation diagram of onshore and offshore wells with calculated effective porosities and clay mineralogy information.

Conclusions and results from this study represent a preliminary assessment of reservoir character based on available data. It is evident from this initial assessment that the data are geographically and stratigraphically sparse and that reservoir trends are often difficult to infer. This study identifies a need for further research.

II. REGIONAL SETTING

The area studied in this report encompasses the western portion of the Maritimes basin which includes the central and southern Gulf of St Lawrence, Prince Edward Island and onshore areas of New Brunswick, Nova Scotia and Newfoundland and Quebec (Figure 1). Isolated occurrences of Upper Paleozoic sediments have also been recorded in wells drilled on the eastern Newfoundland, Grand Banks and Labrador shelf areas (Bell and Howie, 1990), these wells are also included in this study. The current extent of the Maritimes Basin represents a structural and erosional remnant of a much bigger area of upper Paleozoic rocks. The sediment fill in the Maritimes Basin has local thicknesses of more than 12 000m, (Sanford and Grant, 1990) east of the Magdalen Islands. Sediment accumulation occurred between the late Devonian to early Permian with a basin fill consisting of nonmarine sediments, conglomerates, sandstones, siltstones, shales, marine carbonates, volcanics, and evaporites (Bell and Howie, 1990). It is estimated that up 4000 m of Carboniferous sediment have been eroded since the late Paleozoic (Ryan and Zentilli, 1993; Hacquebard and Cameron, 1989). This study emphasises Carboniferous and Early Permian rock units.

Most authors agree on the major elements of basin origin and evolution, however some variations exist. Bradley (1982) suggests that the basin evolved as a pull-apart basin between strike-slip faults in Newfoundland and New Brunswick, followed by thermal subsidence. Belt (1968) suggests continental rifting in an east-west strike-slip regime, whereas Fyffe and Barr (1986) suggest a failed rift system along the margin of a late Paleozoic ocean. A more recent explanation by McCutcheon and Robinson (1987) is that the basin formed after the Acadian orogeny by a period of localised rapid subsidence followed by more widespread, less rapid subsidence.

The present topographic configuration and exposures of Carboniferous rocks are largely controlled by the regional fault system (Langdon and Hall, 1994). The Maritimes basin is viewed as a large composite basin with

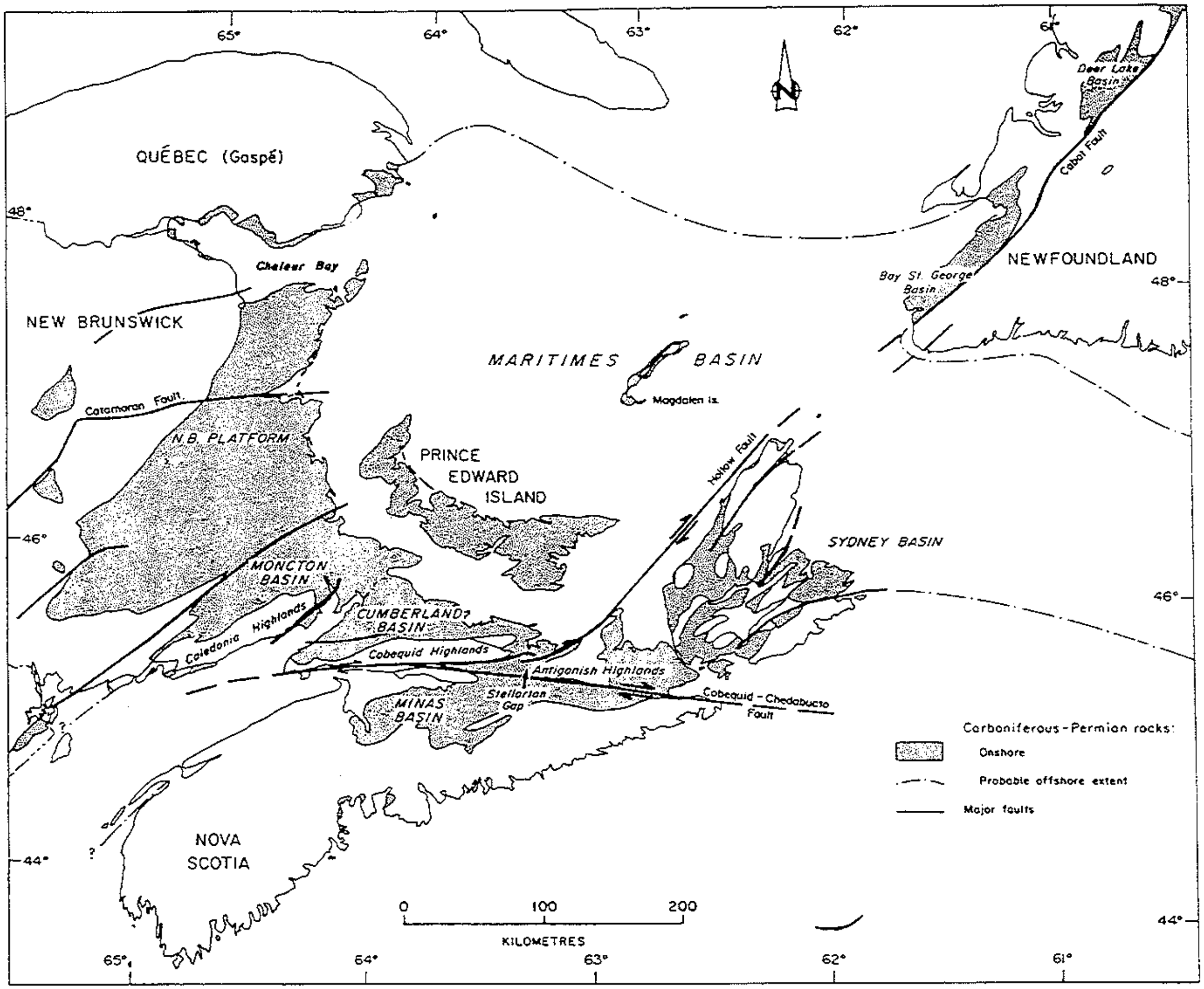


Figure 1: Distribution of Upper Paleozoic rocks and the location of major faults in the Martimes Basin (Gibling et al 1991).

several individual onshore "basins" or "subbasins" separated by these large faults and highland areas (Figure 1). These subbasins have varying shapes and sizes as different authors used the major faults transecting the basin where possible, but defined individual areal limits. (e.g. see Rehill 1996, Sanford and Grant, 1990 and van de Poll *et al.* 1995).

The Upper Paleozoic sediments have experienced four periods of deformation (van de Poll *et al.*, 1995). Horton Group sediments show evidence of pre-Windsor folding, faulting and uplift, and widespread erosion in the Moncton Basin, Mabou Basin and Newfoundland and Gulf of St. Lawrence (van de Poll *et al.*, 1995). Post–depositional salt flowage of the Windsor Group, onshore and offshore, represents a second period of regional deformation (St. Peter, 1987; Rehill, 1996). A third period of deformation resulting in regional uplift and tilting of basement blocks along existing faults occurred during the Middle to Late (?) Permian (Van de Poll, 1970). The final period of deformation involves post Permian subsidence, tilting and normal faulting (Van de Poll *et al.*, 1995).

III. GENERAL STRATIGRAPHY

The present-day understanding of the Maritimes Basin stratigraphy divides it into three general intervals: the alluvial and fluvial clastics of the Horton Group, followed by the marine transgression represented by the Windsor Group and thirdly the thick, largely continental clastic succession of the Mabou, Cumberland and Pictou Groups (Figure 2)

Throughout the late Devonian and early Carboniferous (Tournaisian), Horton sediments consisting of conglomerates, arkosic sandstones, mudstones, oil shales, and minor non-marine evaporites were deposited in fault bounded basins (van de Poll, *et al.,* 1995). Mafic volcanic rocks are interbedded with basal Horton sediments in several areas (Howie and Barss, 1975). The Horton Group rests conformably to unconformably on the Fountain Lake Group (Rehill, 1996), or where the Fountain Lake Group is absent, the Horton Group has an angular unconformity on pre-Acadian metamorphic basement (van de Poll *et al.*, 1995). Marine carbonates, gypsum, anhydrite, and red non-marine clastic rocks, all assigned to the Middle to Late Visean Windsor Group (Giles and Utting, 1999) were deposited in an arid to semi-arid environment with cycles of marine transgression and regression (Schenk, 1969). The Windsor Group is either disconformable or unconformable on uppermost Horton Group rocks (Utting *et al.,* 1989). During the Namurian to Early Permian, thick clastic successions accumulated in the gradually subsiding basin (Langdon and Hall, 1994) represented by the Mabou, Cumberland and Pictou

Maritimes Basin					Sydney Basin
Geochronology			Group	Formation	
	Permian		Unnamed Permian Units		
CARBONIFEROUS	Stephanian		Pictou Group	Naufrage	
				Cable Head	
	Westphalian	D		Green Gables	Unnamed Rock Units
		C		Bradelle	Morien Group
		B			
	Early Westphalian - Namurian		Cumberland Group		
	Namurian - Late Visean		Mabou Group		
	Middle - Late Visean		Windsor Group		
	Tournasian		Horton Group		

Figure 2. Stratigraphic column for the Maritimes and Sydney Basins. Compiled from Giles and Utting (1999).

Groups. The Mabou Group conformably overlies the Windsor and represents a transition from marine to lacustrine to fluvial conditions (Allen, 1998). It consists of grey and red siltstones, shales, interbedded sandstones, and thin carbonate beds. The Cumberland Group conformably to unconformably overlies the Mabou Group and unconformably onlaps older basement rocks (Ryan *et al.,* 1991). The Cumberland Group consists of red and grey fluvial conglomerates, sandstones, and coal measures. (Van de Poll *et al.*, 1995). Bell (1944) described two facies within the Pictou Group: a mainly grey, coal-bearing facies, and a predominantly red facies containing few coal seams. The Pictou Group overlies older Carboniferous sediments or basement rocks with disconformity, angular unconformity, or nonconformity relationships in various parts of the basin (Ryan and Boehner, 1994).

A great variety of stratigraphic nomenclature has evolved over the years, especially within different subbasins. The focus has been mainly on onshore nomenclature, with few applications to the offshore areas (Hacquebard, 1986). Regional correlation of locally named rock units from one subbasin to the other, was done by Bell from 1927 to 1958. Bell (1927) recognised six groups for the Carboniferous consisting of the Horton, Windsor, Canso, Riversdale, Cumberland and the Pictou Groups. These original subdivisions are still widely in use, except for a few revisions; the Mabou Group was introduced by Belt (1964) to replace the Canso and the lower parts of the Riversdale Group. Ryan *et al* (1991) redefined the Pictou/Cumberland boundaries and formally argued for the abandonment of the Riversdale Group of Bell. Rehill (1996) noted the lack of detailed offshore nomenclature and defined a new stratigraphic framework for the offshore areas. He recognised the Horton, Windsor, Mabou, Cumberland and Pictou Groups. He proposed that the Cumberland Group consists of the Brion Island, Bird Rock, Bradelle, Green Gables, Magdalen, and Seacow Formations, while the Pictou Group is composed of the Cable Head and Naufrage Formations.

Giles and Utting (1999) correlated wells drilled in onshore Prince Edward Island and offshore Gulf of St. Lawrence, and used the nomenclature proposed by Rehill (1996) with some revisions. The informal nomenclature used by Giles and Utting (1999) comprises the Horton, Windsor, Mabou, Cumberland and Pictou Groups and unnamed Permian units. Some onshore formation names are successfully applied to the offshore. These include the Shepody Formation (Mabou Group), the Hastings and Pomquet Formations (Mabou Group), and the Port Hood Formation with its members (Cumberland Group). The Pictou Group of Giles and Utting is composed of the Bradelle, Green Gables, Cable Head and Naufrage Formations, and its base is placed at or close to Bell's originally defined base of the Pictou. The data compiled in this study are analysed within the stratigraphic framework of Giles and Utting (1999), (Figure 2).

IV. DATABASE

A comprehensive database (Available on the enclosed CD-ROM as a Microsoft Access 97 database and ASCII delimited files) has been compiled summarizing all available data from wells (petroleum and non-petroleum) drilled in the Maritimes Basin, both onshore and offshore, which reached total depths of 500m or more. An arbitrary depth of 500m was chosen in order to complete the compilation study within a set time-frame. The 621 wells included in this database were compiled and extracted from four main sources. The Nova Scotia Department of Natural Resources (Halifax, N.S) has a library of 21 246 wells, the New Brunswick Department of Natural Resources and Energy (Moncton, N.B.) has compiled data on 689 wells, and data on wells drilled on Prince Edward Island are currently at the Geological Survey of Canada (Atlantic) in Dartmouth, N.S. Additional data for selected wells, including some in Newfoundland, are also available at the Geological Survey of Canada (Atlantic) from the "BASIN" database (Moir, 1999), currently online and available at a fee. No data were available for the province of Quebec. Data on offshore wells drilled in the Gulf of St Lawrence are currently stored at the Canada-Nova Scotia Offshore Petroleum Board in Dartmouth, N.S. Finally, information on offshore wells is also available from the National Energy Board (NEB) located in Calgary, Alberta.

A few boreholes with final depths of less than 500m are included in the database because of indications of hydrocarbon presence or available porosity and permeability data. The database also lists all reservoir data for outcrop reservoir studies and core analysis measurements and calculated effective porosities for the petroleum wells. Some information on petrography and clay mineralogy is also included. Well locations and outcrop locations are plotted on 1:500 000 maps (Keppie, 2000) available for viewing and printing through the freely distributable ArcExplorer software. Details of the database and its contents are described in Appendix A.

V. DATA COMPILATION

Reservoir data were compiled from different sources, but the bulk of the information was obtained from core measurements and from petrophysical analysis. Data from two onshore outcrop reservoir studies are included, as are results from a number of clay mineral analyses.

A. Core Analyses Data

Core analyses included in the data compilation range in age from 1946 to 1998 over which time the analytical procedures changed significantly. Most analyses conducted before 1970 are considered less reliable than those conducted after 1970 (Monahan, Core Laboratories, pers. comm., 1998). In the early days of conventional core analysis, the Retort Method, also known as the Summation of Fluids Technique, was used (Monicard, 1980). In this technique the sample is crushed, and then heated to 650 degrees Celsius and the total volume of oil and water released is measured. A companion sample (assumed to be similar to the crushed sample) is then injected with mercury. The pore volume is calculated by adding the volume of mercury to the volume of oil and water, the porosity is then calculated from the pore volume. Grain density measurements could not be obtained, because the samples were crushed. This technique assumes homogeneity between the two samples and also releases bound water from clay minerals, with the result that the water volume was probably overestimated. Permeability was often measured on a partially cleaned cube or cylindrical sample. As is clear, three different samples were required to calculate porosity and permeability for a specific depth interval.

Recent core analysis methods use a cylindrical plug taken parallel to bedding and the same sample is used for porosity and permeability measurements. The analysis is performed on fully cleaned and dry samples, dried in a gravity oven. Porosity measurements are typically performed using Boyle's law with helium as the gaseous medium, and grain density is also calculated (Monahan, Core Laboratories, pers. comm., 1998). Permeability is measured as horizontal permeability to air.

Efforts were made in this study to identify possibly erroneous data. Questionable data were not used in this study, but are included in the database and flagged as "Questionable". The following criteria were used to distinguish between reliable and questionable data:

- the year in which the core analyses were performed. Analyses performed prior to 1970 were treated with caution.
- absence of grain density measurements on the core analysis reports. This suggests that the Summation of Fluids technique was used.
- core analysis data from Percussion type sidewall cores. It is generally accepted that microfractures are introduced by the sidewall coring process and that porosity measurements are overestimated

with cores collected in this manner. No Rotary type sidewall cores have been cut in the Basin, porosity and permeability data from this type of sidewall core is considered more reliable.

The lower limit of permeability detection is 0.001mD (millidarcy). For the purpose of statistical analysis and presentations, measurement values below the detection limit were arbitrarily assigned a value of 0.0005mD.

B. Analysis of Outcrop Data

The same criteria used for quality control in core analysis were applied to outcrop samples. Two outcrop studies were conducted in the 1970's and samples were analysed by the same company. The method of porosity and permeability measurements is not known, but it is probable that the Summation of Fluids Technique was used for both studies. These data are included in the database, and should be used with caution for several reasons. It is not clear by which criteria samples were selected. For example if only obviously "porous- looking" lithologies were analysed rather than collecting samples randomly, the outcrop data will not accurately reflect the true distribution of reservoir parameters. Also, the influence of aerial exposure on porosity and permeability can be significant, and is discussed in Section VI.

Outcrop locations for the two studies were taken from the original geological maps and were re-plotted on a 1:500 000 scale geological map by Keppie (2000). The outcrop locations may be viewed using software on the enclosed CD-ROM. Re-plotting data at different scales might have introduced some inaccuracies, even though great care was taken to plot locations as accurately as possible. Occasionally original outcrop locations were poorly referenced, resulting in questionable final locations. These are marked as such in the database.

C. Effective Porosities calculated from Wireline Data.

Effective porosities were calculated using publicly available wireline data. Different data vintages together with different methods and corrections posed some challenges. Cases where the method, equations, and corrections were not known were treated as "Questionable" and flagged as such in the database. Quick-look porosity logs generated by well-site service companies are also available. These logs are known by trade name such as SARABAND and CORIBAND. However when compared with the available core analysis data and calculated effective porosities generated for this project, the quick-look logs were found not to be a reliable data source.

i. Corrections to wireline data

Effective porosities were generated for 9 exploration wells in Prince Edward Island and the Gulf of St Lawrence (refer to the correlation chart). Although this study concentrates on Carboniferous rock units, some data were also generated for Permian units and are included in the database. Wireline logs were only available in paper format and these logs were digitised to allow replotting and detailed numerical calculations. Digitised data were then carefully checked against the original paper plots to ensure accuracy. However, it must be noted that random noise is generated by the digitising process. Although difficult to quantify, digitising errors could translate into inaccuracies in the final porosity estimates of perhaps as much as three porosity units.

Once digital data were available, standard borehole geophysical methods described in texts such as Crain (1986) were used to estimate effective porosities using gamma ray, neutron porosity, and density logs. Standard corrections were applied to the wireline data to compensate for changes in borehole diameter, mud density, and temperature (Schlumberger, 1996). Temperature gradients were estimated from bottomhole temperatures, where available.

ii. Apparent Porosity

As the next step, apparent porosity, ϕ_a, was calculated through simultaneous solution of the following equations (Schlumberger, 1989):

$$\phi_n = \phi_a \phi_{nf} + (1 - \phi_a)(x\phi_{nx} + y\,\phi_{ny}), \tag{1}$$

$$\rho_b = \phi_a \rho_f + (1 - \phi_a)(x\rho_{bx} + y\rho_{by}), \tag{2}$$

$$x + y = 1 \tag{3}$$

Equations 1 and 2 model the neutron porosity, ϕ_n and bulk density, ρ_b of a rock saturated with a single fluid. Equation 3 states that the rock matrix is composed only of two minerals in relative proportions x and y. The logging tool response to pure mineral x, pure mineral y, and the pure fluid is indicated by the subscripts x, y, and f respectively. For example, ϕ_{nx} is the neutron porosity that would be measured in pure mineral x, and ρ_{bf} is the bulk density that would be measured in the saturating fluid.

For this study, aquifer units were modeled as a combination of quartz and calcite saturated with slightly saline water. The parameters chosen for Equations 1 and 2 are:

	ϕ_n	ρ_b	Substance
Mineral x	-0.05	2.65	quartz
Mineral y	0.00	2.71	calcite
Fluid	1.00	1.02	water

Given additional data, more complex porosity models involving additional minerals can be formulated. Sonic travel time, for instance, is a function of porosity and could be added to the porosity model. However, in this study, only and ϕ_n and ρ_b measurements were used and, under many typical circumstances, a two-mineral porosity model will yield acceptable results (Schlumberger, 1989).

iii. Effective Porosity

Solution of Equations 1 to 3 yields the apparent porosity, ϕ_a. If the clay mineral content of an aquifer is significant, or if the aquifer is not saturated with water (i.e., gas or hydrocarbons are present), then ϕ_a will not equal the true porosity.

All porosity logs, including ϕ_n and ρ_b, are sensitive to the presence of water bound in clay mineral structures. Thus, when clay mineral content is significant, the apparent porosity, ϕ_a, will be too high. The effective porosity, defined as the porosity available to free fluids, can be estimated as (Schlumberger, 1989):

$$\phi_e = \phi_a (1-V_{cl}), \qquad (4)$$

where V_{cl} is the volumetric proportion of clay minerals within the rock matrix.

Estimation of Vcl can be difficult since no single wireline tool responds directly to clay content. Gamma ray logs are often used because quartz exhibits very low radioactivity (<10 API units) relative to clay (>200 API units) (Schlumberger, 1996). Thus, in quartz-rich sandstones, V_{cl} is calculated as (Crain, 1986):

$$V_{cl} = GR - GR_{ss} / GR_{sh} - GR_{ss} \qquad (5)$$

where GR is the measured gamma ray value at any given depth. The parameters GR_{ss} and GR_{sh} are chosen, after inspection of the data, to be representative gamma ray values within sandstone and shale units respectively.

The presence of feldspars, micas, heavy minerals, or evaporites, will increase the gamma ray signature of a sandstone unit. Under these circumstances, V_{cl} may be overestimated. Independent estimates of clay content are available from combinations of the neutron porosity / bulk density, spontaneous potential, spectral gamma ray, and resistivity logs. In each case, V_{cl} is calculated using an equation similar in form to Equation 5 (consult Crain, 1986 for details). Each approach, though, tends to overestimate V_{cl} under certain conditions. Therefore, V_{cl} is usually assigned the minimum value from all the available estimates over a given interval (Crain, 1986).

In this study, V_{cl} was estimated from the minimum of the gamma ray and neutron porosity / bulk density estimates. Then, ϕ_e was calculated using Equation 4. Core analysis measurements where available, were used to calibrate the ϕ_e estimates. The final results for all the wells should be close to the true porosity given the following conditions:

- hydrocarbons are not present
- minerals such as micas, evaporites, or coal are accounted for or not prevalent
- sand units are reasonably thick (>1 m)
- clay mineral content is reasonably low (<40%)

D. Visual Estimates of Porosity

Visual estimates of porosity were not included in this study, because different individuals make these estimates and the data are highly subjective. Several sources exist with visual porosity estimates, including Canstrat (Canadian Stratigraphic Service Limited) Logs, Well Lithologs, the Carboniferous Drilling Project (Ball et al., 1981), the Shawnee Petroleum outcrop study (Berry, 1973) and Research Projects (Solomon, 1986). These data are publicly available and may be useful in areas where core or wireline data are unavailable.

E. Indirect porosity indicators

Several indirect indications of porosity have also been reported in the literature and well history reports. On Cape Breton Island, Nova Scotia three wells (Inverness 1, Inverness 5 and Inverness 6) were reported to have an influx of water into the well. Influx of water into the boreholes was also a problem on Prince Edward Island and it was reported in the Earnscliffe 202-52, Glencoe, Little Sands and Minimegash wells. The influx of water in all cases was of such an extent that difficulty was encountered in drilling these wells and drilling was subsequently suspended. Although not quantitative (and therefore not included this report), these reports certainly indicate the presence of significant porosity capable of sustained flows.

F. Clay mineralogy data

Bulk clay mineralogy profiles (<2 microns) for selected wells were digitised from the informally published reports by SOQUIP (INRS-Petrole, 1975a, b, c). Various methods for quantitative mineral analysis are in use, and a variety of problems and inconsistencies are likely to exist. These factors will contribute to a discrepancy from 100%, the total clay mineral content typically reported (Brindley, 1980; Fisher and Underwood, 1995). Details on the qualitative and semi-quantitative analyses are often not included in the SOQUIP reports. For Irishtown 1, Green Gables 1, Northumberland Strait F-25, and East Point E-49, the analyses were done with a Philips X-ray diffractometer. CuKα radiation was used with a voltage of 44 kV and a current of 32 mA (milliamps) with 1° slits (INRS-Petrole, 1975c). All the Nova Scotia, Prince Edward Island and offshore Gulf of St. Lawrence wells were analysed by SOQUIP in the 1970's and we have assumed that the same vintage of equipment and procedures were used. No details on the New Brunswick and Newfoundland wells exist. Sampling for the X-ray diffraction (XRD) for the Maritimes Basin was also carried out over large intervals (one sample every 30 to 100m). Due to the limited data on methods used in these studies, together with the large sampling intervals, data quality is difficult to assess and probably lends itself only to general assessment of clay mineralogy trends in the basin.

VI. OUTCROP RESERVOIR STUDIES

Two individual reservoir outcrop studies were conducted in the 1970's. Berry (1973), Berry and Wilson (1973) and Tillement (1973) reported on Shawnee Petroleum Limited's (also known as Tricentrol Oils Limited) reservoir study from 1971-1973 in the vicinity of its licensed petroleum acreage in northern Nova Scotia with a focus on the Horton Group. Felderhof (1975) reported on a more comprehensive study, which included Pennsylvanian, Mississippian and Triassic Formations (this Triassic data is included in the database) in 6 counties in northern Nova Scotia.

Median values from outcrop data were compared with median values of subsurface data to determine the effect of subaerial exposure on the porosity and permeability values. Some authors (Surdam, 1989; McBride 1987) have

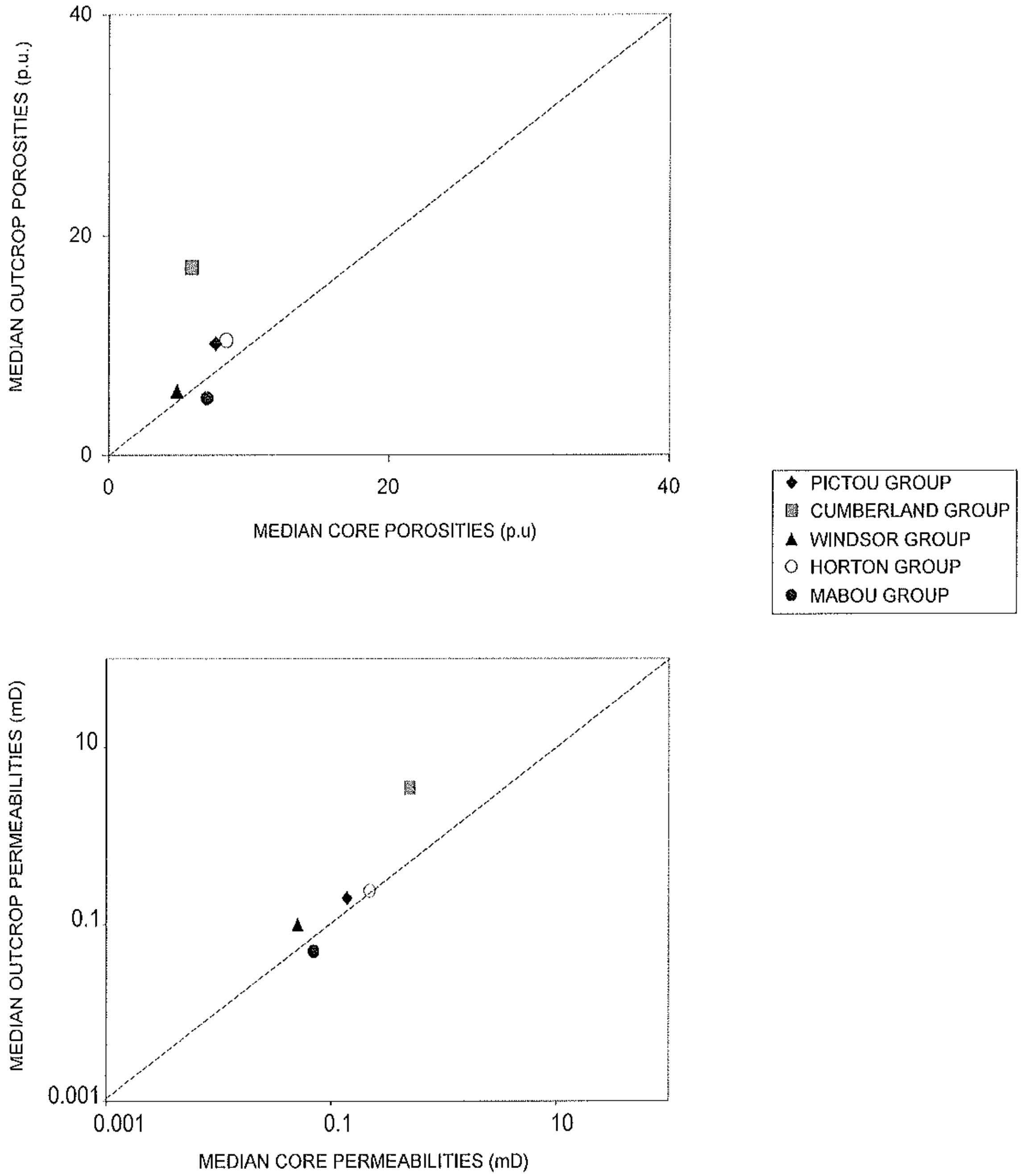


Figure 3: Outcrop median porosity and permeability versus core median porosity and permeability. Note there are only 4 measurements in the Cumberland Group. Porosity in porosity units (p.u.) and permeability in millidarcys (mD).

reported that surface exposure and associated leaching can result in significant porosity increases. Figure 3 shows that the outcrop median porosities and permeabilities are generally higher than median core porosities and permeabilities for the corresponding group. Median outcrop porosities are roughly 7% higher than median core porosities, and as much as 35% higher in the Cumberland Group. Median permeabilities are about 5% higher in outcrop samples, and as much as 14% higher in the Cumberland Group. The Mabou Group is the only exception to this trend and has lower median porosity and permeability in outcrop than in core. However, in all cases, the range of porosity and permeability is significantly greater for outcrop samples than for core samples. Thus, there is reason to suspect that aerial exposure and leaching tends to enhance outcrop porosities and permeabilities relative to those measured in core.

A. Shawnee Petroleum Limited Data (Berry, 1973; Berry and Wilson, 1973 and Tillement, 1973)

The exploration focus of Shawnee Petroleum Ltd. was the Tournaisian-Viséan sedimentary packages adjacent to the Minas Basin, an area near Antigonish, and an area near Inverness on Cape Breton Island and a total of 97 samples of the Horton Group were collected. A visual comparison was made for another 136 samples from the Richmond area, which were not included in this study for reasons mentioned earlier (Section V.D)

The results of this study indicate that measured porosities for the Horton Group range from 0.7 to 39 porosity units (p.u.), with median values of 12.6p.u., whereas permeabilities range from 0.005 to 660 mD (millidarcies) with median values of 0.37mD (Figure 4). It is clear from the plot that the Inverness area generally exhibits the highest porosities and permeabilities, with the Minas and Antigonish areas showing lower values.

Shawnee Petroleum Ltd. concluded that the most prospective reservoir is a sequence of porous sandstone of approximately 150m in thickness, immediately above the grey shales known as the Ainslie Formation in the Antigonish and Inverness areas, and the top of the Horton Bluff Formation in the Minas Basin area. Locally porous limestones and dolomites of the Windsor Group are also considered as potential reservoirs.

B. Felderhof Data (Felderhof, 1975)

Nova Scotia Department of Mines and Energy conducted a study in 1975 in the province of Nova Scotia. Pennsylvanian, Mississippian, and Triassic Formations were sampled and 208 samples were collected in Hants, Kings, Colchester, Cumberland and Antigonish Counties.

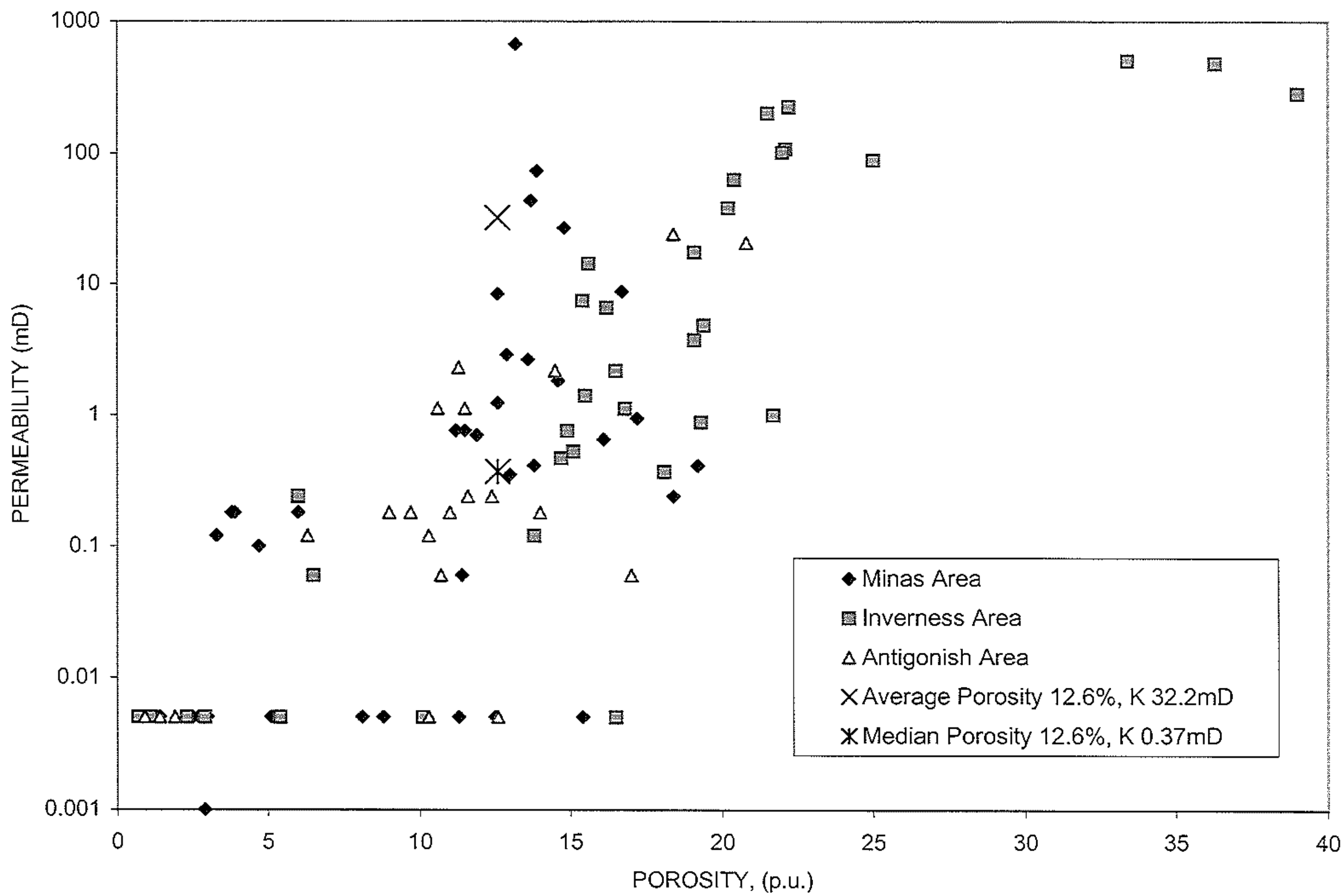


Figure 4. Outcrop porosity and permeability data for the Horton Group, from Berry (1973) for Shawnee Petroleum.

The Felderhof study (Felderhof, 1975) indicates attractive reservoir rocks are present in the Cumberland, Windsor, Horton and Pictou Groups, because of the general high porosity and permeability values (Table 1 and Figs. 5 and 6). The data for the groups are discussed below.

The Cumberland Group exhibits porosities as high as 22.5p.u. (median of 17p.u.) in the Cumberland Area, median porosities of 18.85.u. in the Antigonish Area and median porosities of 9.9p.u. in the Minas Basin Area. The larger grain size (fine-medium grained) and the more rounded (sub-angular to sub-rounded) nature of the grains might contribute to the higher reservoir quality (Felderhof, 1975). The Cumberland Group's reservoir potential seems to be less well developed to the south, which might be explained by the probable lacustrine influence (van de Poll *et al.,* 1995) compared to the predominantly alluvial depositional environment in the Minas Basin Area. Permeability values for the Cumberland Group range as high as 580mD with median values of 54.7mD in the Antigonish Area, 2.67mD in the Cumberland Area and 0.07mD in the Minas Basin Area.

The limestones of the Windsor Group, sampled only in the Minas Basin Area, show porosities of up to 29.6p.u. (median 7.3p.u.), while the maximum permeability measured is 405mD (median 0.005mD). Felderhof noted that the average porosity appears to be higher in the lower members than the upper members of the Windsor Group and that all samples gave off a petroliferous odour from a fresh surface.

Sandstones of the Horton Group reach a maximum of 24.6p.u (median 19.8p.u.) in the Antigonish Area, whereas reservoir quality decreases in the Minas Basin Area (median 9.75p.u.). Conglomerate samples on the other hand show higher porosity development in the Minas Basin Area (median 11.6p.u.) compared to the Antigonish Area (median 6.9p.u.). Permeability values for both the sandstones and the conglomerates are higher in the Antigonish Area (median 2.89 and 9.45mD respectively) than in the Minas Basin Area (median 0.13 and 4.63mD respectively).

Median porosity values for the Pictou Group sandstones range between 10-12p.u. (maximum 23.2 p.u.) and median permeability values range from 0.07 to 0.9mD (maximum 98.5mD) in the Minas Basin and Cumberland Areas, with the reservoir quality slightly better developed in the Cumberland Area. A few conglomerate samples in the Minas Basin Area show a maximum porosity of 12p.u. (median 10.35p.u.) and a maximum permeability of 59.5mD (median 29.88mD).

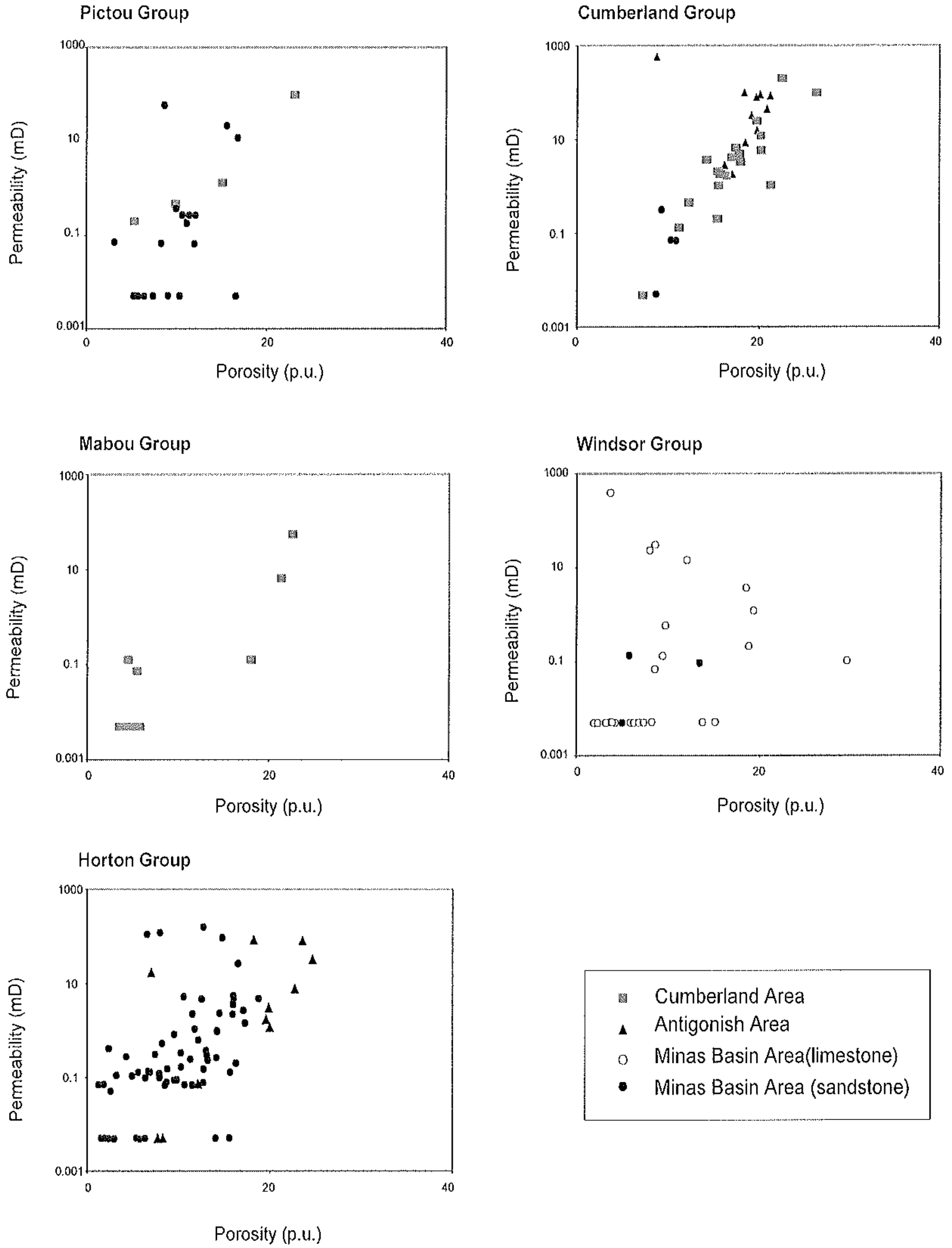


Figure 5: Outcrop porosity and permeability data for the Pictou, Cumberland, Mabou, Windsor and Horton Groups, from Felderhof (1975) data.

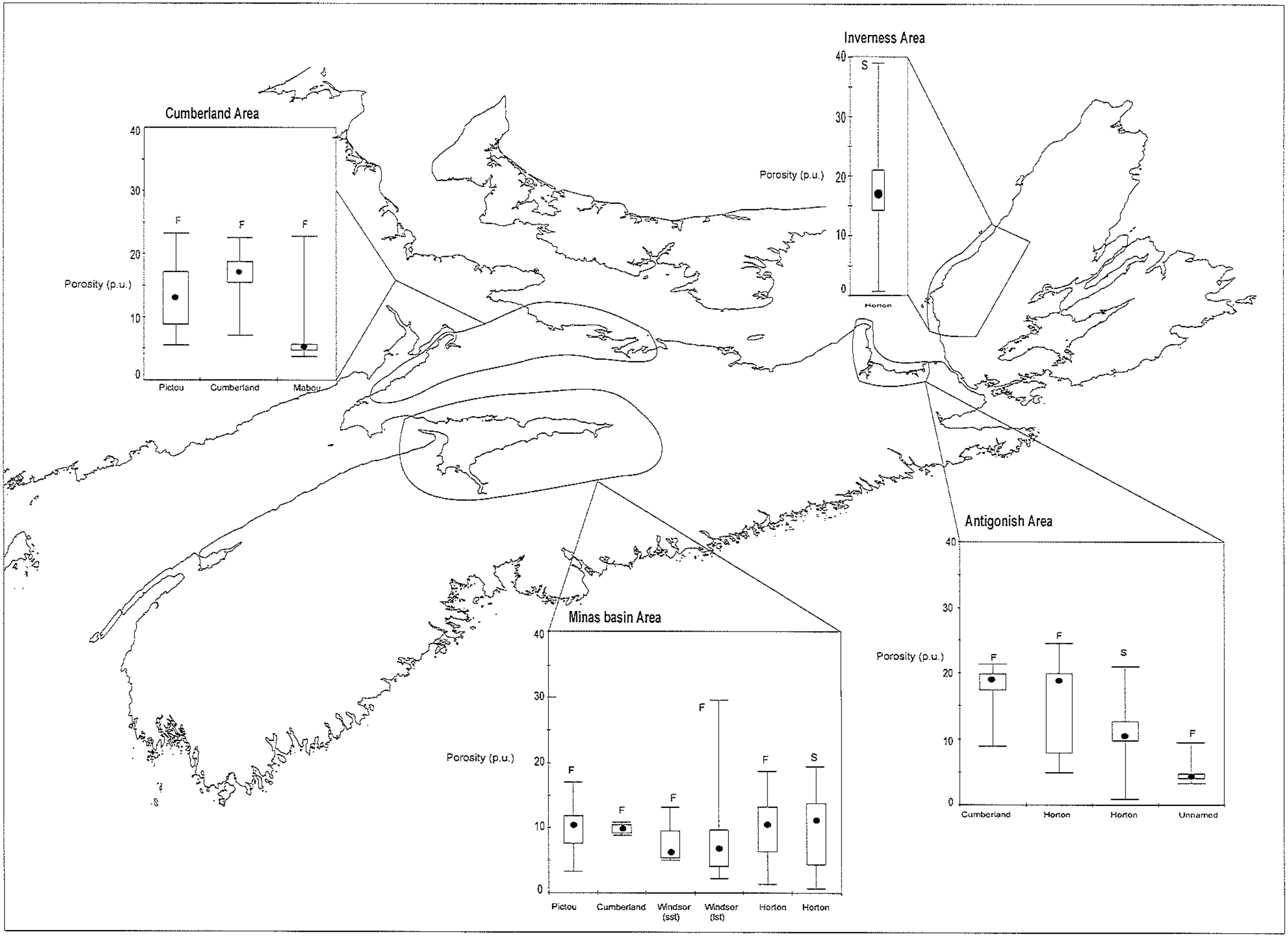


Figure 6. Box and whisker diagrams summarize the porosity data for both outcrop studies in Nova Scotia (F = Felderhof (1975) data, S = Shawnee Petroleum data, Berry (1973)). The whiskers represent the data range and the width of the boxes correspond to the interquartile range, the 25th and 75th percentiles. The median values are shown by the dot within each box.

A few sandstones sampled in the Windsor Group show a maximum of 13.3p.u. porosity (median 5.8p.u.) and 0.13mD permeability (median 0.1mD). Sandstones in the Mabou Group, sampled only in the Cumberland Area show a maximum of 22.7p.u. (median 5.2p.u.) of porosity and a maximum of 53mD (median 0.005mD) of permeability. Unnamed Rock units in the Antigonish Area (sandstone and conglomerate) show maximum porosity values of less than 10p.u. and permeabilities less than 13mD.

C. Summary

Table 1 summarizes the outcrop data obtained from both outcrop studies. Together with Figure 6 it is possible to compare reservoir character of the different groups in different geographical regions. Porosity values from these different groups do seem to follow general trends: the Horton and Cumberland Groups show better reservoir potential in the Antigonish and Inverness Areas, whereas reservoirs of the Pictou Group are best developed in the Cumberland Area. The Windsor and Mabou Groups were only sampled in selected areas and regional comparisons of these two groups are not possible. Direct comparison of the groups from area to area is probably imprecise, as it is often not known whether the same formations were sampled in the different areas.

VII. CORE POROSITIES

All available porosity and permeability measurements from core samples within the Maritimes Basin, for both onshore and offshore wells were compiled in this study (Figure 7). Data for all 24 wells are on the accompanying CD-ROM and are summarised in Table 2. In addition, 202 core samples from the Sydney Coalfield, including 146 samples from the Phalen Colliery and 13 samples from the Prince Colliery, Cape Breton Island were made available to include in this study. These samples representing the Morien Group were analysed as part of a geology and hydrogeology study of the Sydney Coalfield (Gibling *et al.,* 1999). Appendix B lists the core analysis data, plotted as porosity and permeability-plots for each well. Appendix C lists the detailed porosity and permeability-plots for the different groups and formations. Porosity and permeability show a reasonable positive correlation for most of the data. Statistical analyses were performed on the core analysis data for the different groups and where possible, formations and members.

A. Results

Results from the available core analysis data are presented in Figures 8 and 9. The number of datapoints for each group is shown in brackets on Figure 9, and it is important to note the diversity of sample sizes. For

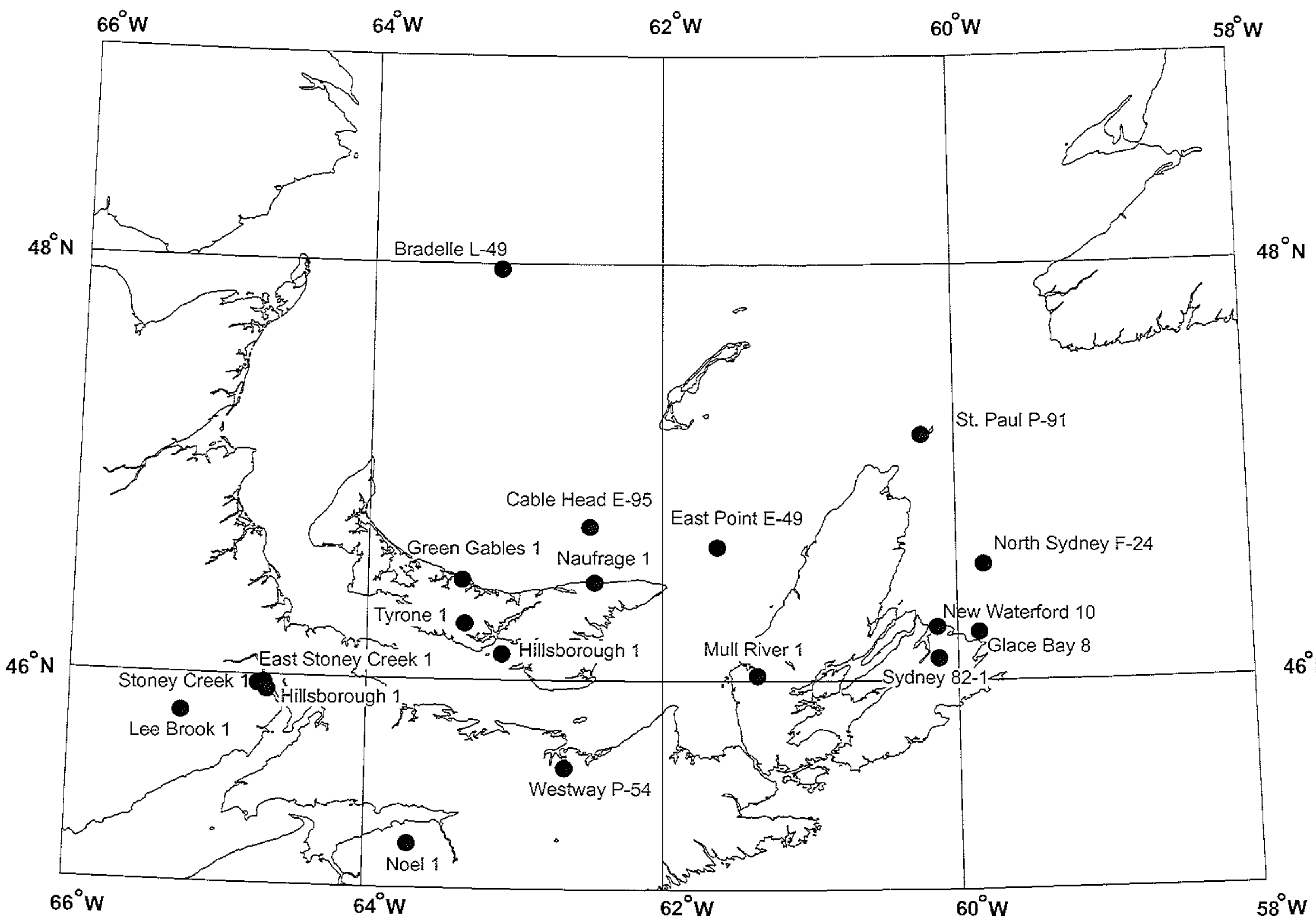


Figure 7. Map showing the locations of wells with core analysis data (Table 2). Wells with questionable core analysis data are not shown. Locations for Port Morien 8, C136, C137,C138 and Glace Bay P-6, all in the Sydney Basin, are not accurately known, and are not plotted.

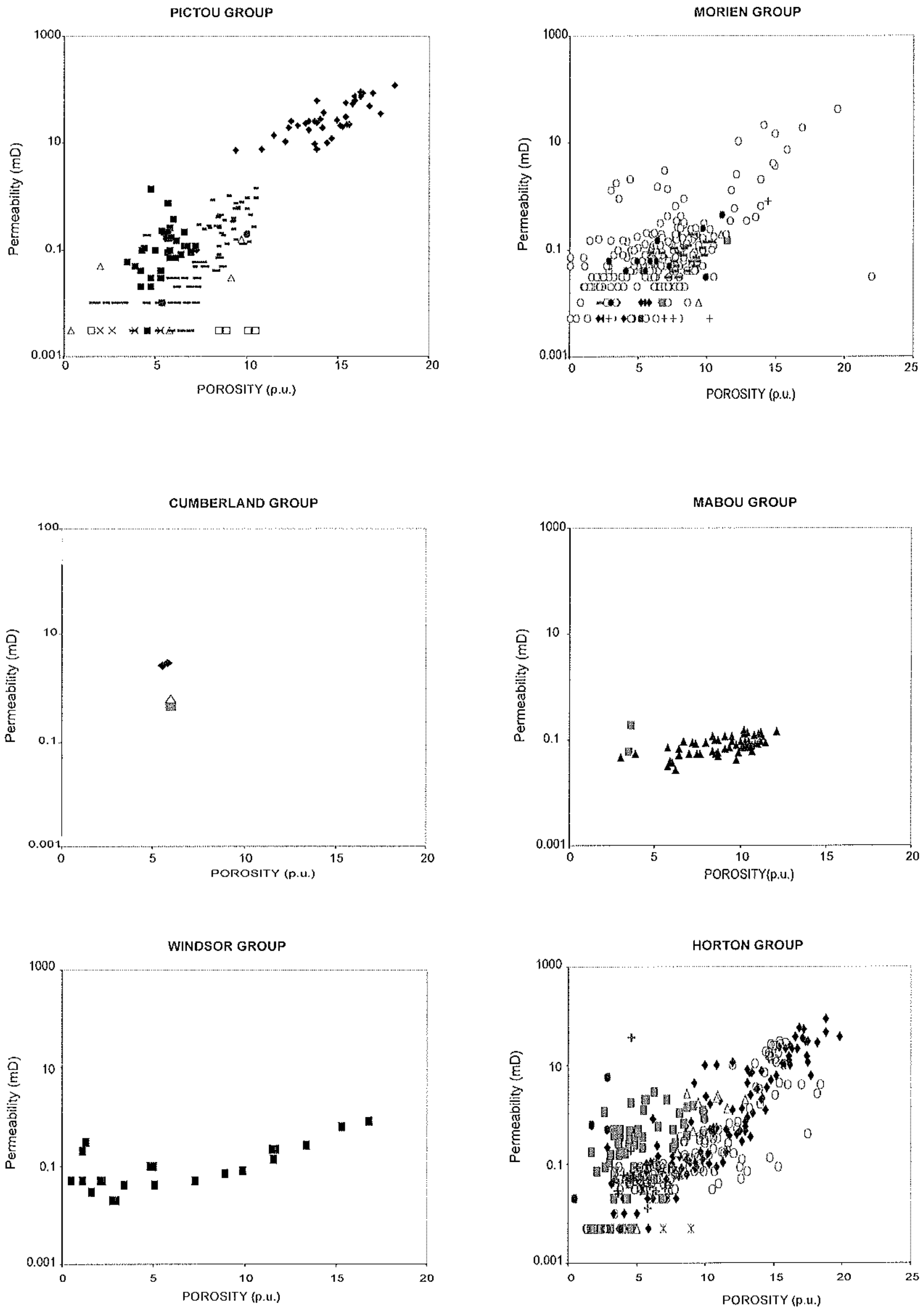


Figure 8: Porosity and Permeability data from cores, shown for different groups. Different symbols represent different wells in each diagram. Appendix C contains page size graphs for each of these groups and has an indication of which wells are represented.

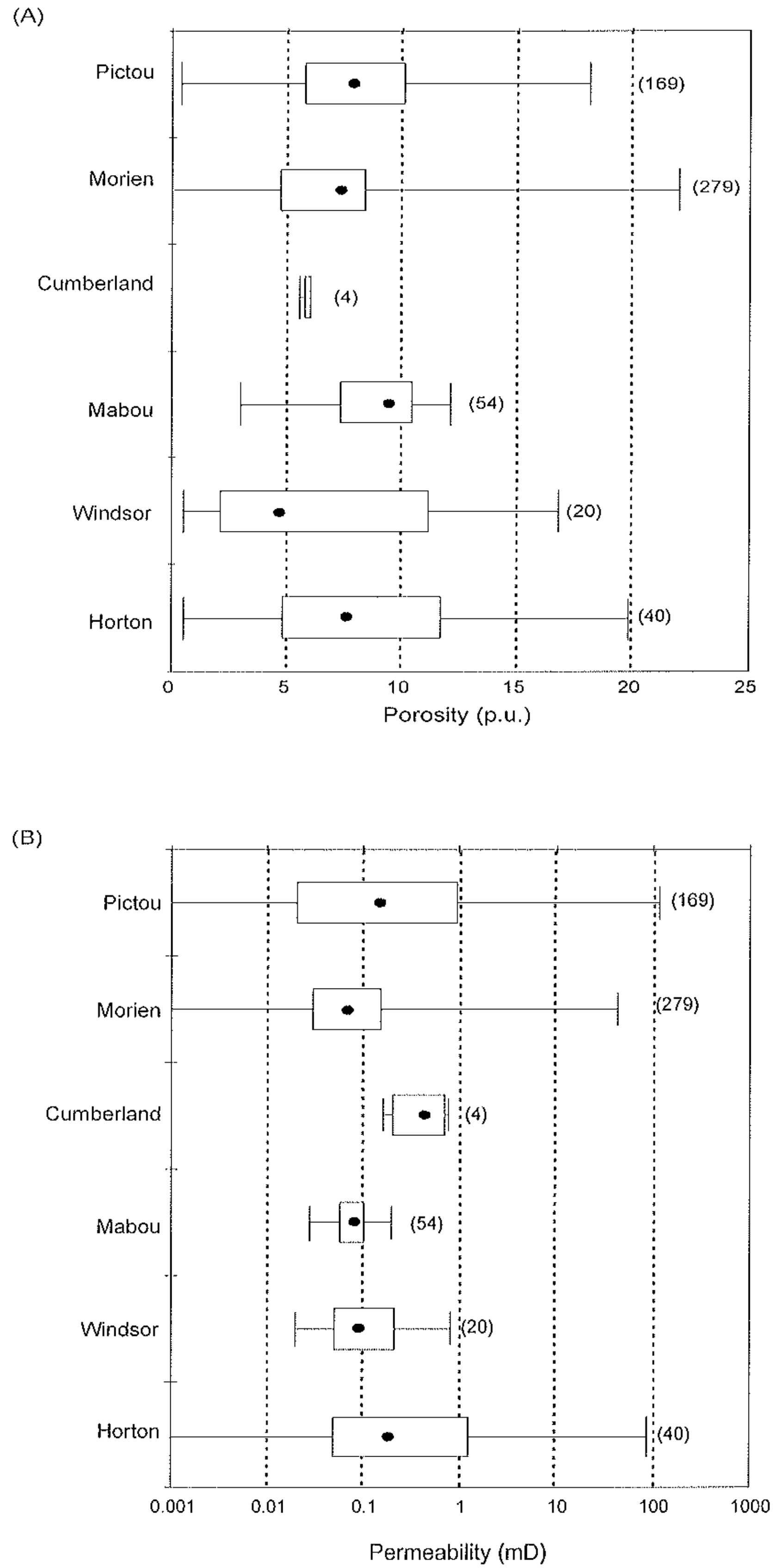


Figure 9: Box and whiskers diagrams summarizing the porosity (A) and permeability (B) data from cores for the different groups. The whiskers represent the data range and the width of the boxes correspond to the interquartile range, the 25th and 75th percentiles. The median values are shown by the dot within each box.

example, the Cumberland Group appears to have a very small range in porosity and permeability, but this may simply reflect the few data points available.

Data from different geographical areas are grouped together in Figure 8 and 9 to get a general impression of porosity development of the different groups in the basin. The coverage of core data does not allow for detailed reservoir characterization on a local scale and, furthermore, it is difficult to compare from well to well because different formations or groups were cored in adjacent wells. Porosity development on a regional scale can be compared only where calculated effective porosities were generated for several wells, as on Prince Edward Island and the adjacent Gulf of St Lawrence. (See section Section VIII).

Statistical analysis of the available core data shows that median porosities for all the groups are less than 10p.u., but it is also clear that the porosity values for specific groups have wide ranges in values. Except for the Cumberland Group, all groups have maximum porosity values of more than 10p.u. The highest porosities measured from core were the Morien Group (22p.u.), the Horton Group (19.8p.u.), Pictou Group (18.1p.u.) and the Windsor Group (16.8p.u.). The maximum porosities measured in the Mabou Group were only 12.1p.u., while the Cumberland Group showed a maximum porosity of only 6p.u. The Cumberland Group has only 4 datapoints and the results possibly do not reflect the true reservoir potential of the Cumberland Group.

The highest median values recorded were in the Mabou Group (9.45p.u.), the Horton and Pictou Groups (7.6p.u.), and the Morien Group (6.9p.u.). The Cumberland Group has a low median value of 5.9p.u. and the Windsor Group shows the lowest median value of 4.9p.u.

Median permeability values for all the groups range from 0.05 to 0.5mD. The highest median permeability was measured in the Cumberland Group (0.5mD). Median permeability for the Horton Group is 0.16mD, while the Pictou Group shows median values of 0.14mD. The Windsor, Mabou and Morien Groups all show similar permeability values of less than 0.1mD.

It is possible to consider the data for the Horton Group, Morien Group and the Pictou Group in a formational context.

i. Horton Group

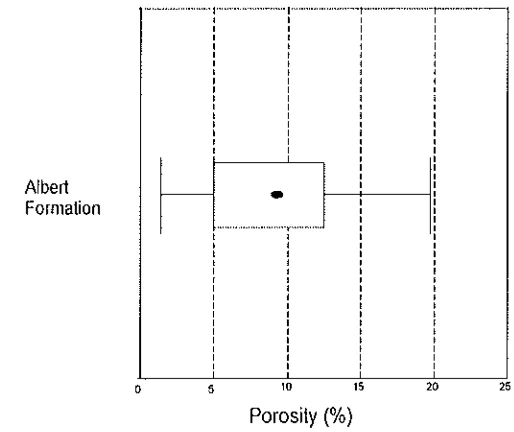
Within the Horton Group dataset it is possible to compare the Albert Formation and the Craignish Formation, although only 5 measurements are available for the latter formation. Porosity values for the Craignish Formation range from 0.5 to 3.9p.u. (median 2.9p.u.) and the permeability values range from 0 to 5.79mD (median 0.5mD). Data for the Albert Formation are available from 4 wells in New Brunswick and are summarised in Figure 10. The median porosity for the Albert Formation is 8.5p.u. (range 1.3-19.8p.u.) and the median permeability is 0.225mD (range 0.005-85.7mD).

ii Morien Group

Two sets of data for the Morien Group exist. The first set of data is from boreholes listed in Table 2 (including boreholes C-136, C-137, C-138 which were drilled from the surface prior to mining, no further details are available on these wells in the database). The second set of data is from the South Bar and Sydney Mines Formations from the Prince and Phalen Mines of the Sydney Coalfield. Data combined from all sources for the South Bar and Sydney Mines Formations are summarised in Figure 11. Median porosity and permeability values for both formations are similar, whereas the range is greater in the Sydney Mines Formation. Median porosity for the South Bar Formation is 7.9p.u. (range 1.9-11.1p.u.) and the median porosity for the Sydney Mines Formation is 6.8p.u. (range 0.5-22p.u.). Permeability values for the South Bar Formation range from 0.01 to 0.46mD (median 0.06mD) and for the Sydney Mines Formation 0-42.5mD (median 0.1mD). The higher range of values in the Sydney Mines Formation is from the more porous and shallower Prince Mine sandstones. These higher values are attributed to calcite cement dissolution (Gibling *et al.*, 1999) on a local scale, probably due to its close proximity to the Mountain fault (Gibling *et al.*, 1999).

iii. Pictou Group

Figure 12 illustrates the statistical summary of the formations of the Pictou Group. Porosity values for the Bradelle and Cable Head Formations are similar, with maximum porosities around 10p.u. (median 5.8p.u.). Maximum permeability values for the Bradelle Formation (1.41mD) are higher than the Cable Head Formation (0.16mD), whereas the median permeability values for both formations are 0.03mD. The Green Gables Formation shows porosity values ranging up to 18.1p.u. (median 10.1p.u.) and permeabilities as high as 116mD (median 0.91mD). The Naufrage Formation has only one porosity datapoint of 19.1p.u. and permeability of 196mD. This single data point falls within the same range of values obtained from calculated effective porosities, which are presented under a subsequent heading.



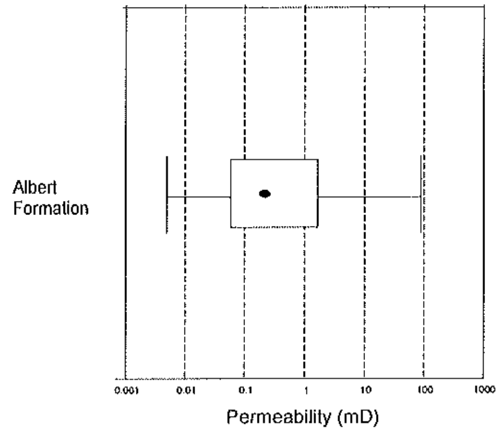
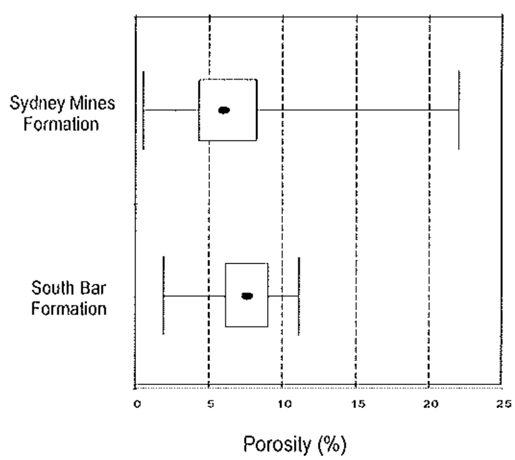


Figure 10. Box and whisker diagrams summarizing the porosity (left) and permeability (right) data from cores for the Albert Formation, Horton Group.



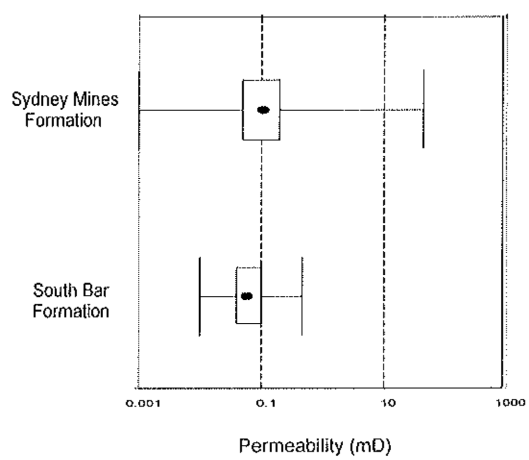
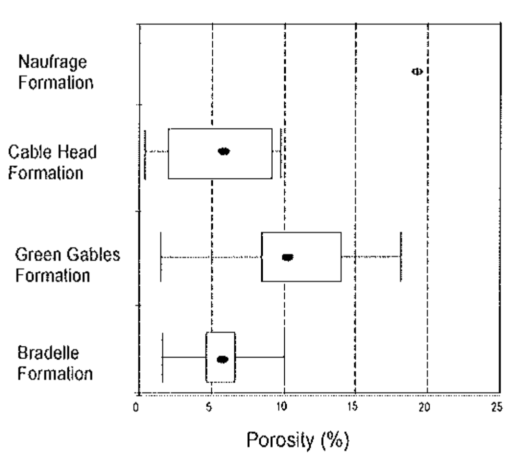


Figure 11. Box and whisker diagrams summarizing the porosity (left) and permeability (right) data from cores for the Sydney Mines and South Bar Formations, Morien Group.



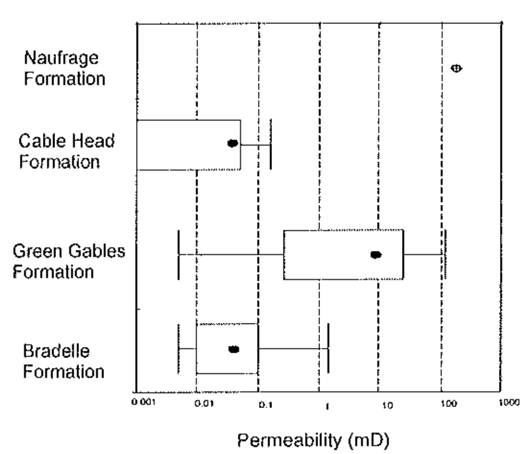


Figure 12. Box and whisker diagrams summarizing the porosity (left) and permeability (right) data from cores for the formations in the Pictou Group. Note that only one measurement is available for the Naufrage Formation.

VIII. CALCULATED EFFECTIVE POROSITIES

Existing porosity data calculated from geophysical logs were available for several wells in the basin and new data were generated for 9 wells in the Gulf of St Lawrence and Prince Edward Island. Existing SARABAND data were available for North Sydney P-05 and MacLeod Brook 1 and CORIBAND data for EMERILLON C-56, but as mentioned earlier, these data were not considered reliable. Calculated effective porosity data for the Morien Group are also available for shallow (<500m) coal exploration wells. Refer to Gibling *et al* (1999) for the results from Glace Bay P-1 to P-6. New data were generated for Tyrone 1, Bradelle L-49, Cable Head E-95, Naufrage 1, Beaton Point F-70, East Point E-47 and St Paul P-91, North Sydney F-24 and North Sydney P-05. Table 3 summarizes the available data and Figure 13 shows the locations of these wells. SARABAND data are listed in the database with no corrections applied for clay content etc. and the newly generated data are listed in an edited format.

A. Results

Statistical analyses were performed on all the calculated effective porosities and are presented in Table 4. The median porosity value for the Horton Group is 2p.u. (maximum 16p.u.). The Windsor Group shows poor porosity development from the available data, with median porosities of 2-3p.u. and maximum values of 11p.u. The Mabou Group shows median porosities of 3 to 11p.u. with a maximum value recorded in Bradelle L-49 of 29p.u. Calculated porosity data for the Cumberland Group are sparse, and range from 7-10p.u., median 8-9p.u.

Calculated effective porosities for the Pictou Group are available from 6 wells (Figure 14). Median values for the Bradelle Formation range from 6-11p.u., with the exception of Bradelle L-49 with a median of 17p.u. and a maximum of 30p.u. The Green Gables Formation has median porosities ranging from 5-8p.u., with the exception of Beaton Point F-70 with a median porosity of 15p.u. and a maximum of 19p.u. The Cable Head Formation, which has proven to be an effective reservoir in the East Point E-49 gas discovery well (Hudson Bay Oil and Gas Company Limited, 1974), shows median porosities of 8-11p.u. (maximum 24p.u.) in four surrounding wells. The closest well to the gas discovery, East Point E-47, shows a median of 8p.u. (maximum 12p.u.). The Naufrage Formation shows median values within a small range, 12-14p.u. with a maximum of 30p.u. recorded in East Point E-47. Median values for the Unnamed Permian sandstones range from 13-17p.u., with a maximum value of 26p.u. in Beaton Point F-70. These Permian sandstones show good reservoir potential, but unfortunately have no present seal as they are at the seafloor in the Gulf of St. Lawrence.

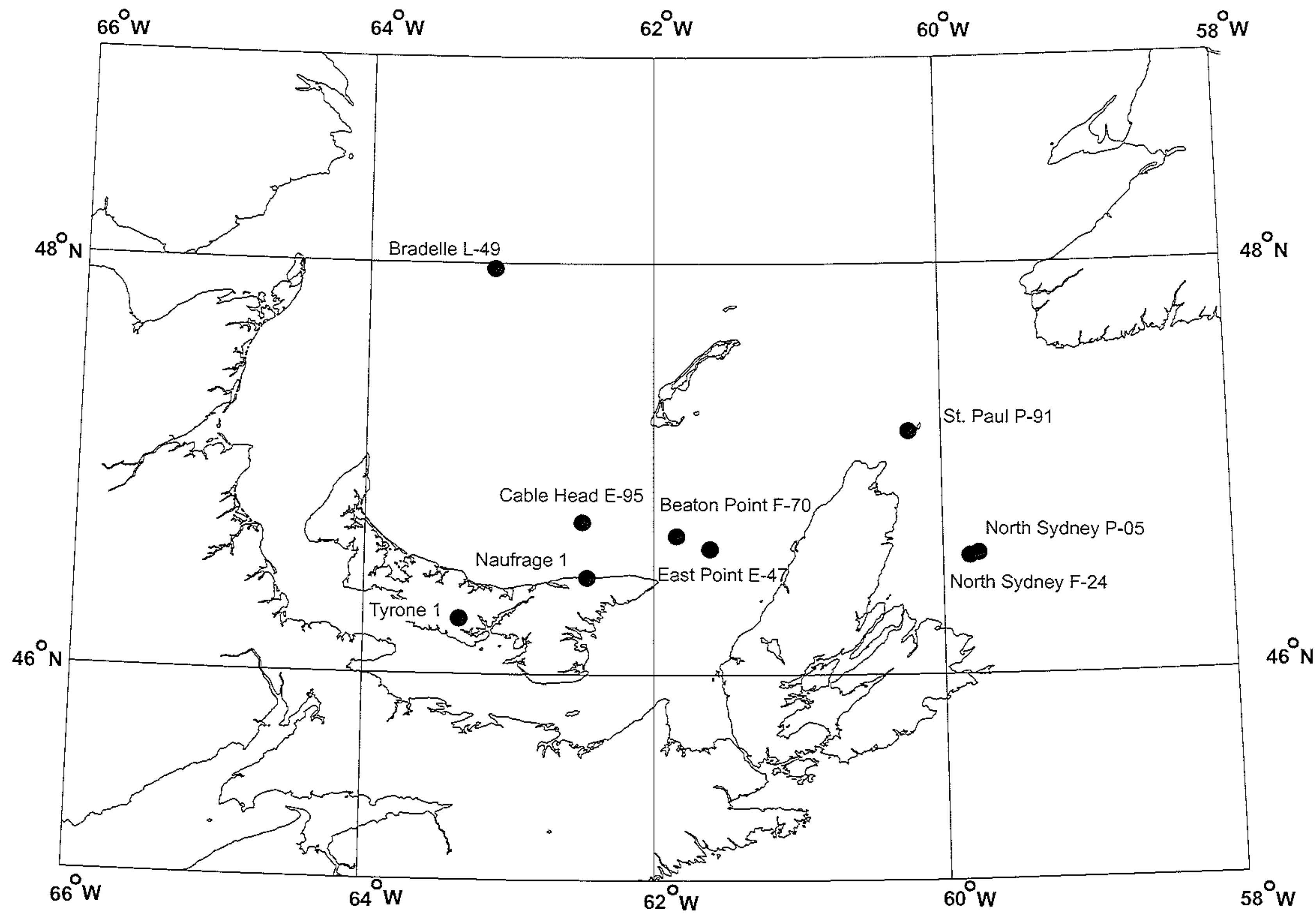


Figure 13. Map showing the locations of wells with calculated effective porosity data. Wells with questionable calculated porosities are not shown. The Glace Bay P-1 to P-6 wells also have available data, but are not included in the database, and therefore not plotted.

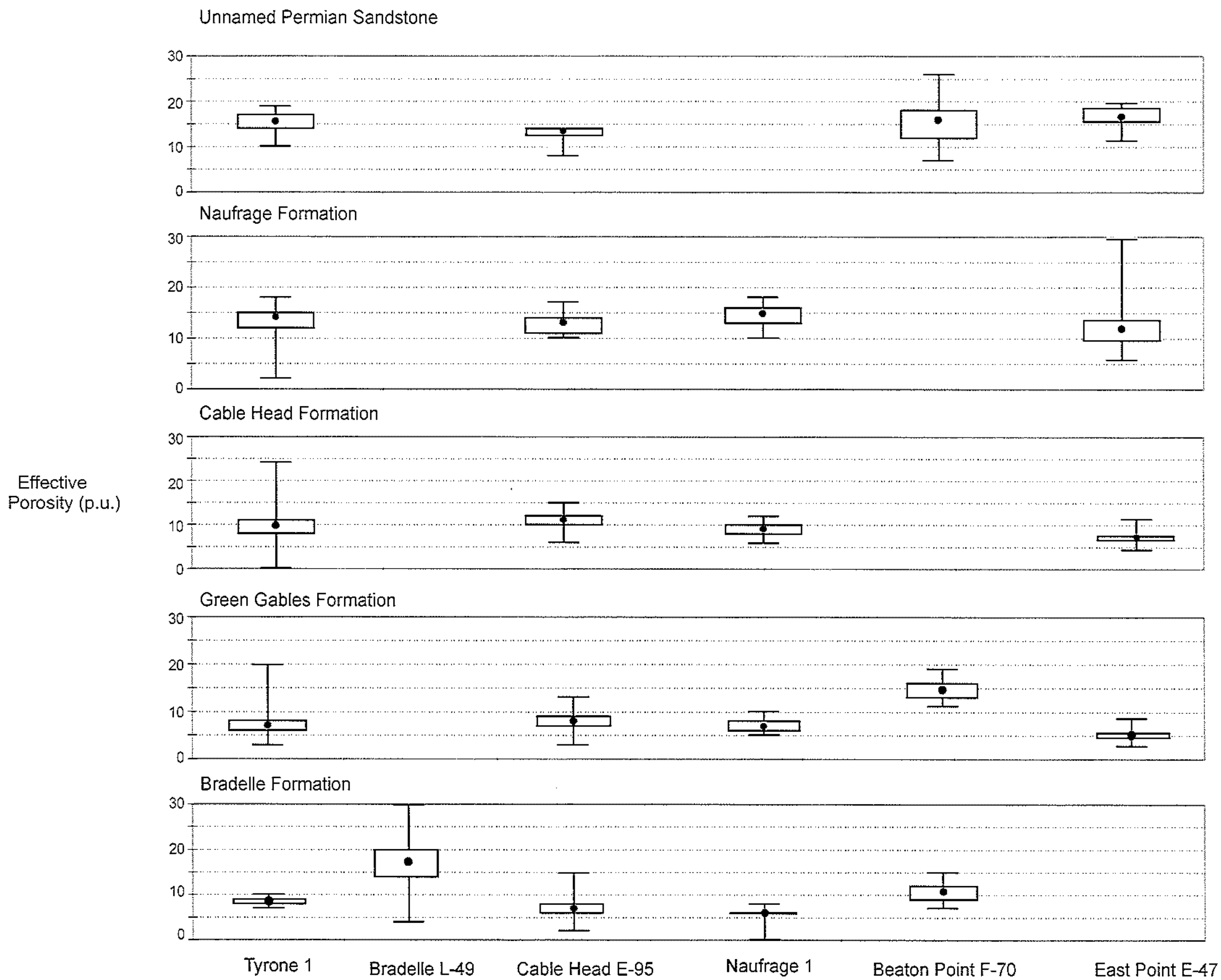


Figure 14. Box and whisker diagrams summarizing the calculated effective porosities for the formations of the Pictou Group. Intervals with >40% clay volume are excluded.

Calculated porosity data for the Sydney Basin, available from North Sydney P-05 and North Sydney F-24, show similar reservoir quality, with the North-Sydney F-24 well showing slightly higher median values. Median values for both wells range from 7.9-10.2p.u., except for the unnamed conglomerates at the base of North Sydney P-05 (median 4.7p.u.). A maximum porosity of 15.8p.u was calculated in North Sydney P-05 in the South Bar Formation.

B. Porosity trends with depth.

Figure 15 illustrates the porosity trends with depth for the Pictou Group with the Green Gables Formation as datum. All wells show a general decreasing trend with depth and it appears that most wells show porosities of less than 10p.u. at depths greater than the datum. There are however a few exceptions. The Beaton Point F-70 well show a decreasing trend with depth but the porosity values are all higher than the other wells plotted on the graph. Possibly, the presence of underlying salt in this area might have influenced the porosity development in this well. In Miocene sediments of the Black Bayou Field, secondary porosity has been created by acidic pore fluids associated with the Black Bayou Field salt dome (Leger 1998).

Tyrone 1 also shows porosity values that do not follow the trend; higher porosity values are present at approximately 1300m below the datum. Possible secondary porosity development is also present in the Cable Head E-95 well at approximately 1700m below the datum.

The Bradelle L-49 location shows the best overall reservoir quality from all the available data. In Figure 16, (Bradelle Formation and the Mabou Group) porosities are generally higher than all other data presented in this report. Although there is a general decreasing trend with depth, occasional higher porosity streaks of up to 30p.u. are present. The abundance of coal over the interval from 1700 – 2010m may cause spuriously high porosities, although care was taken to edit intervals with discreet coal intervals. Formations shallower than the Bradelle Formation in this location can be expected to have similar or even higher porosity values, although poor log quality in the upper parts made porosity calculations impossible.

Porosity values in the St Paul P-91 well are generally very low and only a slight decrease in porosity trends with depth can be observed in Figure 17 (Mabou, Windsor, Horton Groups). A few streaks of higher porosity values are present but reach a maximum value of only 16p.u. St Paul P-91 shows the lowest overall reservoir potential of all the wells for which effective porosities were calculated. Existing petrographic data for sandstones in this well

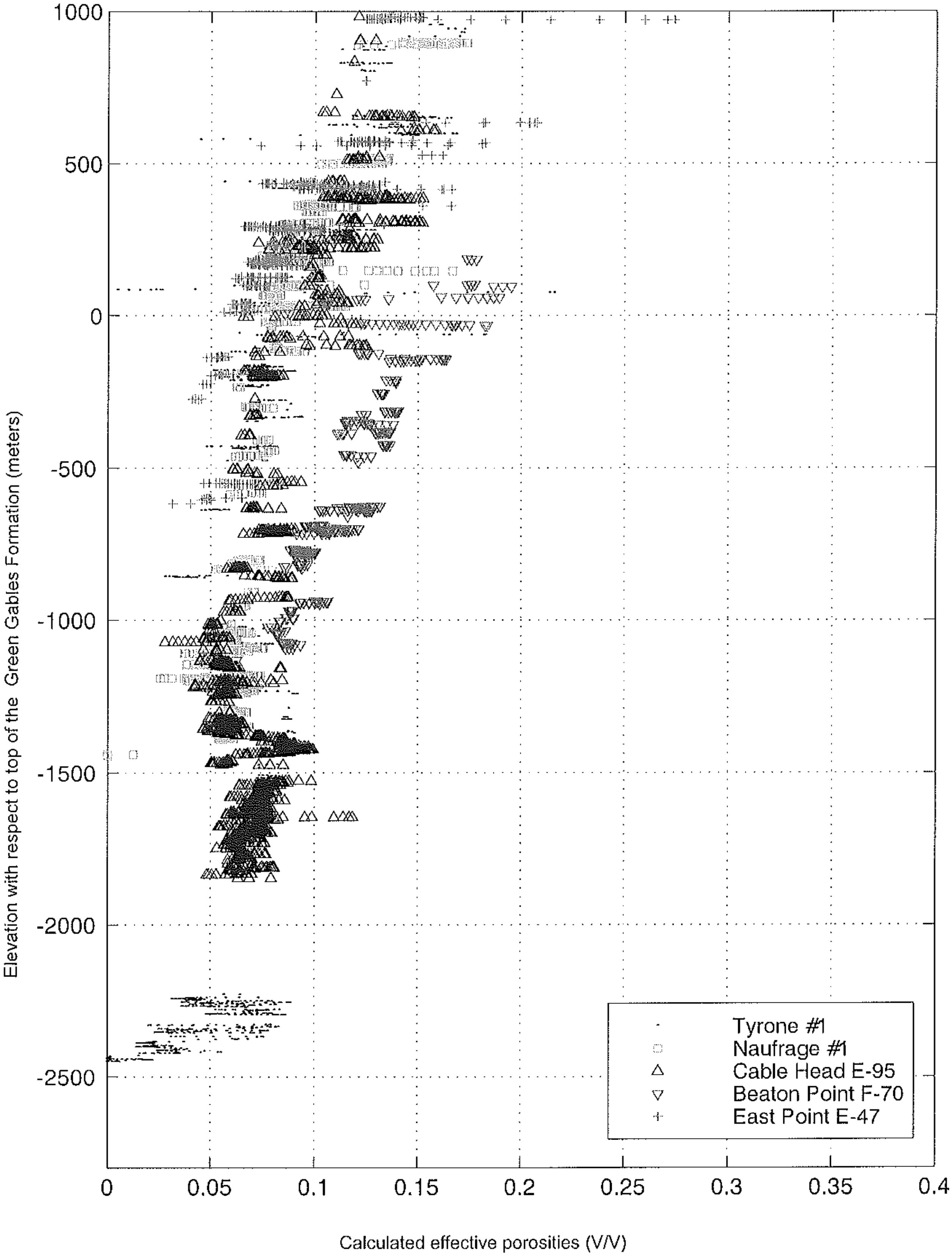


Figure 15. Calculated effective porosites for the Pictou Group plotted against depth with respect to the Green Gables Formation. Coal beds and intervals where the clay volume exceeds 40% are not plotted. Data smoothed using a 0.5 meter Savitzky-Golay smoothing filter (Press et. al, 1995).

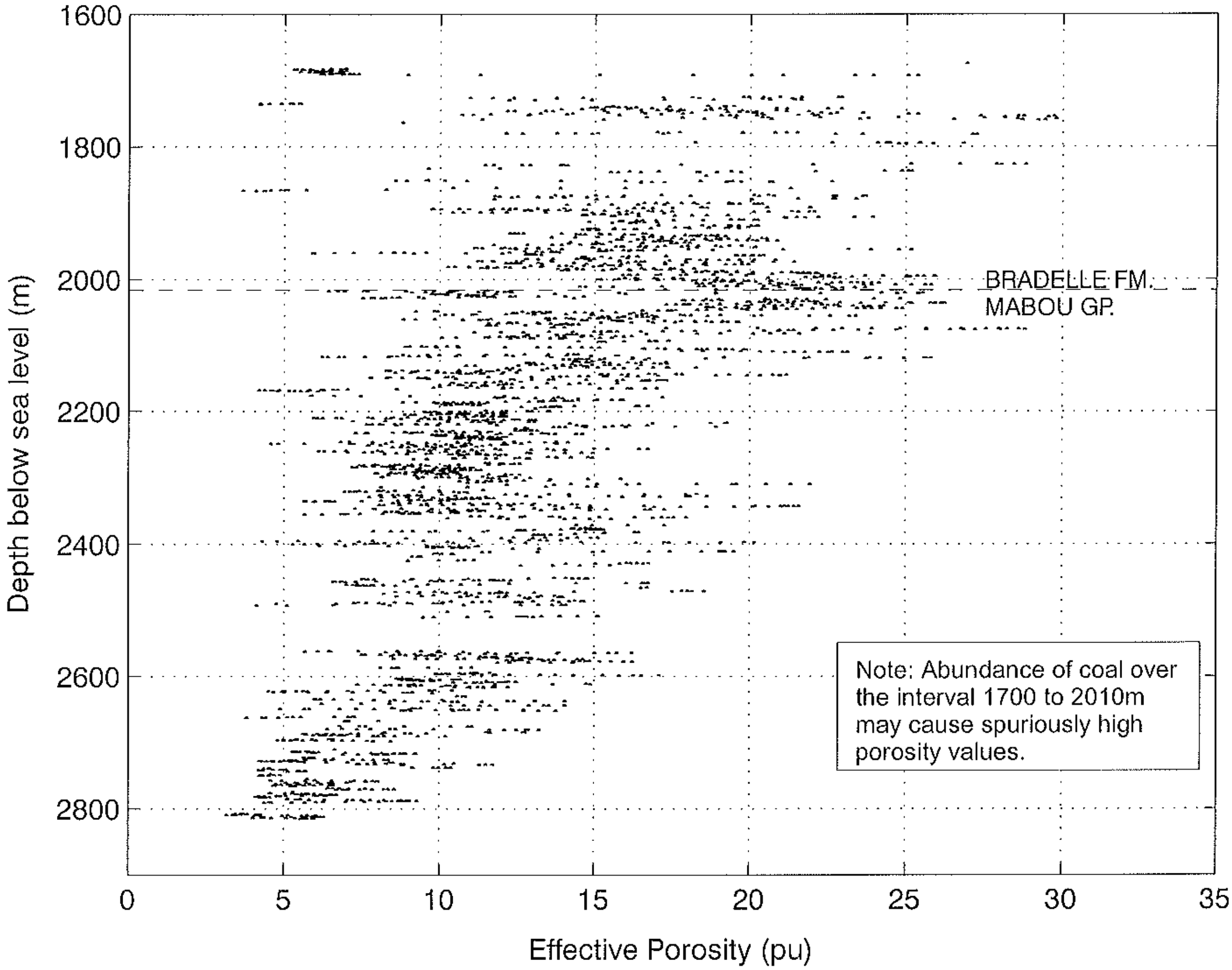


Figure 16. Calculated effective porosity data for the Bradelle L-49 well versus depth below sea level.

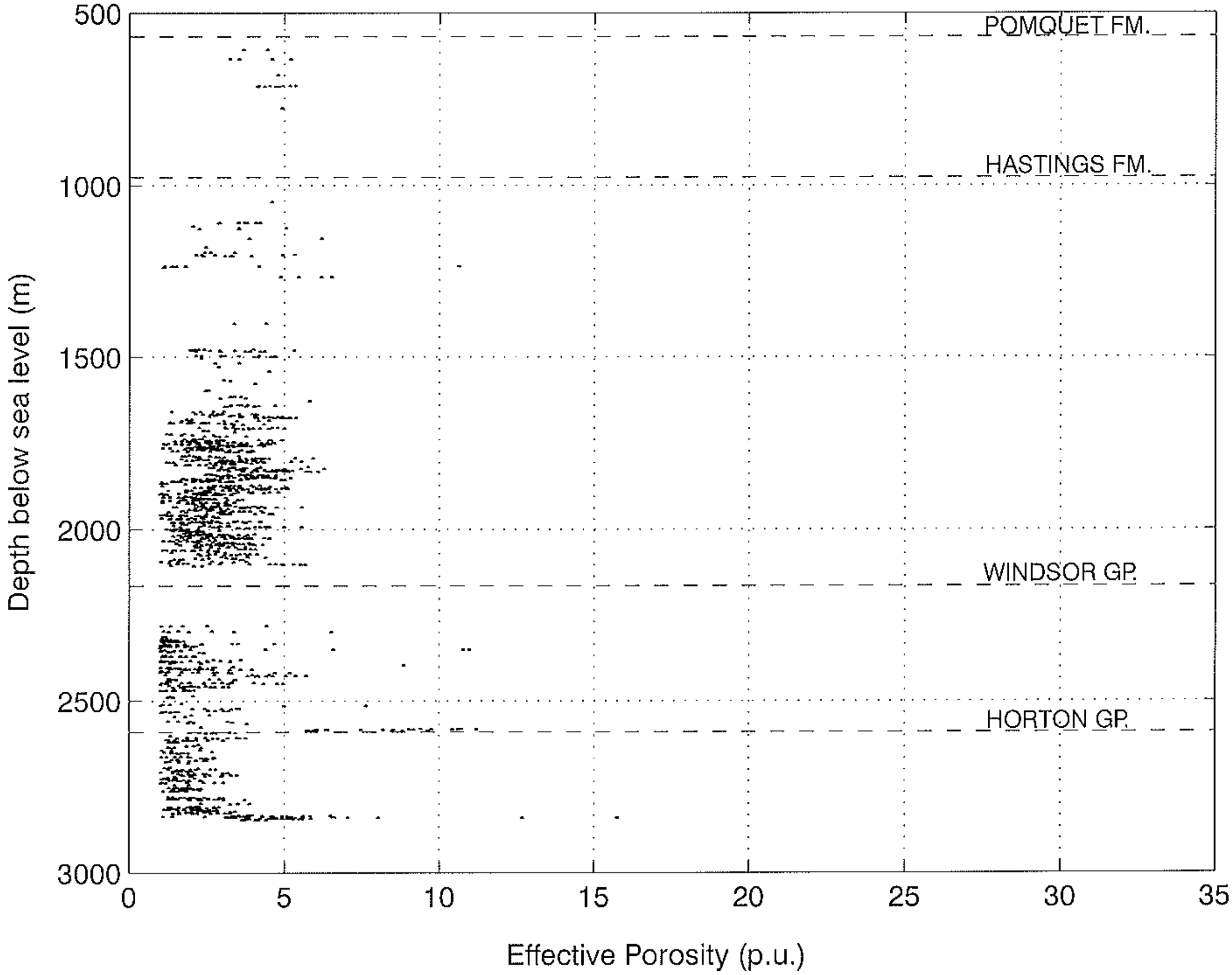


Figure 17.Calculated effective porosity for the St Paul P-91 well versus depth below sea level.

indicate that visible porosities approaching 15p.u. are developed in the well-sorted fine-grained sandstones of the Mabou Group. These higher porosities are due to ferroan calcite decementation, whereas higher porosities elsewhere are attributed to calcite decementation and leaching of labile framework grains (Rodrigue and Meloche, 1984). In the rest of the well, much of the secondary porosity developed through calcite decementation is occluded by late pervasive fibrous pore-filling and grain-replacive authigenic chlorite. Pore filling agents include authigenic calcite, chlorite, quartz, dolomite and illite in decreasing volumetric order. Poor textural sorting also reduces primary porosity in the deeper parts of the well (Rodrigue and Meloche 1984).

Data from two wells (North Sydney P-05 and North Sydney F-24) in the Sydney Basin are shown in Figure 18 and are plotted with the top of the Morien Group as datum. Porosity trends for both wells are very similar and no significant decrease with depth can be observed. As Table 4 shows, this corresponds to median values of 7.9-10.2p.u. for both wells.

Significant increases in porosity can be associated with unconformities (Surdam, 1989) due to extended periods of surface exposure. The only location in the study area where this is evident is in Bradelle L-49, immediately above and below the Westphalian unconformity (Figure 16 at approximately 2000m) where porosities of up to 30p.u. are developed.

All available porosity data (calculated effective porosities and porosities from core analysis) as compiled in this study, are presented against depth in Figure 19. It is evident from the present dataset that porosities of more than 10p.u. have not been intersected at depths of greater than 2780m.

IX. GRAIN SIZE DISTRIBUTION AND SAND THICKNESSES.

Grain size distribution and sandstone thicknesses are two other important factors in reservoir assessment. Statistical analysis for the Pictou Group was undertaken for the following petroleum exploration wells: Bradelle L-49, Cable Head E-95, Beaton Point F-70, East Point E-47 and East Point E-49. These selected wells had available cuttings information over the Pictou Group and the raw data were extracted from digital Canstrat logs, purchased by the Geological Survey of Canada (Atlantic) from Canadian Stratigraphic Services Ltd. in Calgary, Alberta.

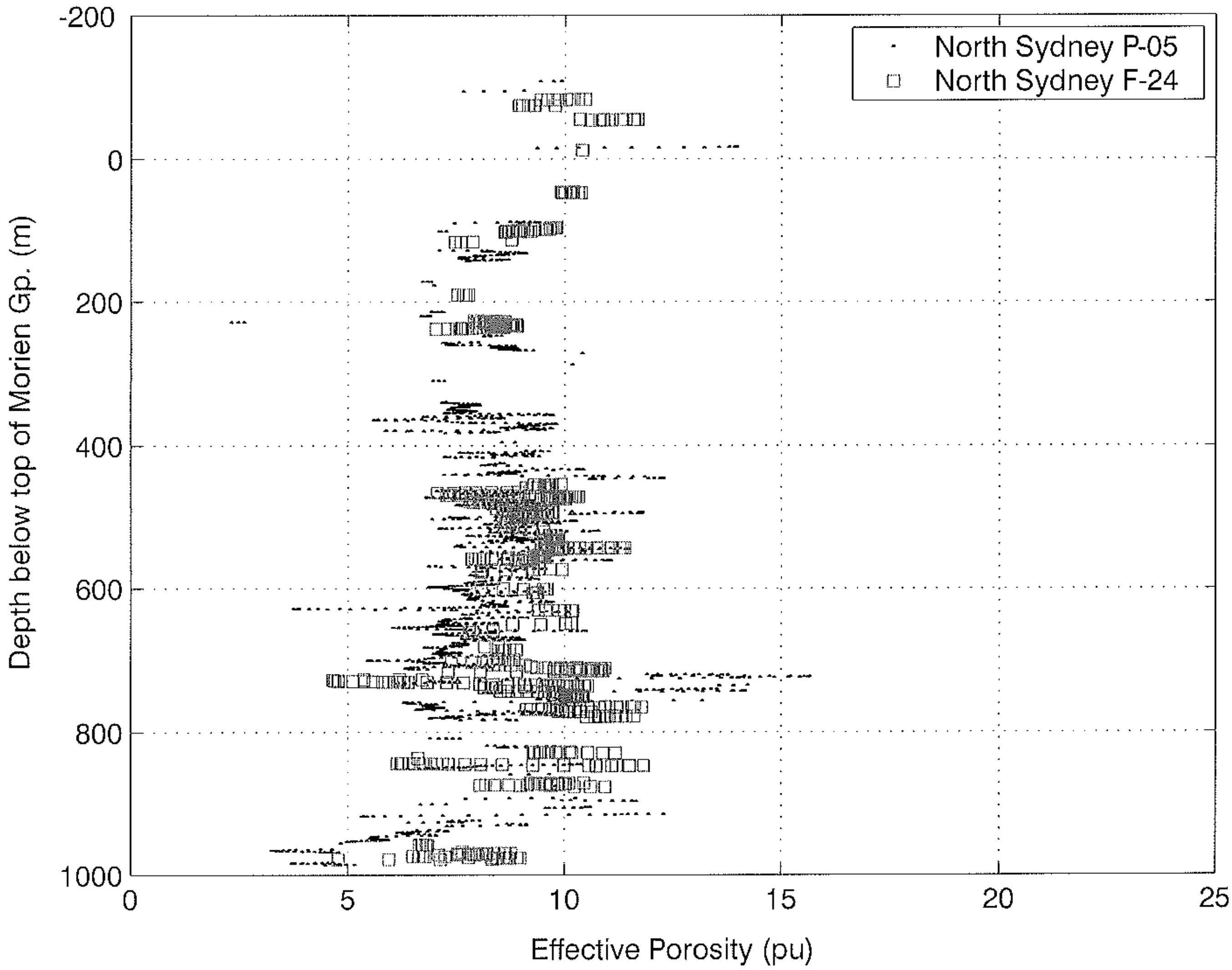


Figure 18. Calculated effective porosity data for the North Sydney P-05 and North Sydney F-24 wells plotted with the top of the Morien Group as datum.

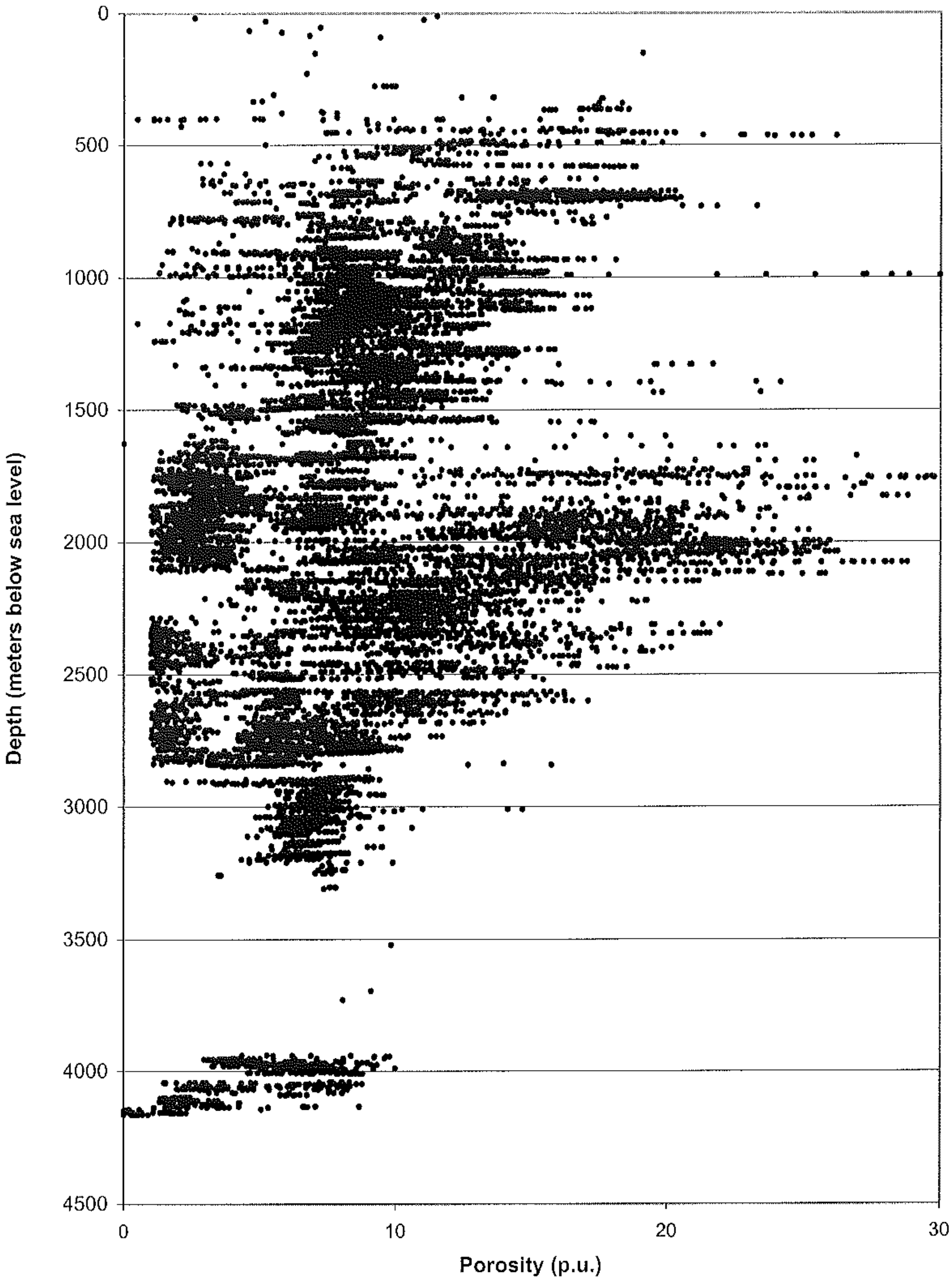


Figure 19. All available calculated effective porosites and core analysis data from this study plotted against depth below sealevel.

A. Grain size

Figure 20 shows the statistical summary of the grain size distribution for the above mentioned wells. Median grain size values for the Naufrage Formation are generally fine, although they can increase to medium as is seen in Cable Head E-95 and the East Point wells.

In the Cable Head Formation median grain size values are fine (0.250mm) for all the wells with the exception of East Point E-49 that shows a higher median grain size between fine and medium (0.500mm) grained. The gas discovery of 150 000m^3 per day in this well was in the upper part of this formation. Porosity measurements are not available for this formation, but it is possible that the coarser grain size in this location made a contribution to the reservoir quality. East Point E-47, which is only 4km to the south of East Point E-49 has a median grain size of fine and a median calculated effective porosity of 8p.u.

Median grain size values for the Green Gables Formation are fine grained for all of the wells. East Point E-49 shows a bigger range of grain size up to medium and also shows that the interquartile range is bigger suggesting that most of the East Point E-49 sandstones are more poorly sorted than in the surrounding wells.
Grain sizes seem to be more varied within the Bradelle Formation, with East Point E-49 showing the highest median of between fine to medium. Interestingly, the smallest median grain size of very fine (0.125mm) to fine corresponds with the highest median calculated effective porosity (17p.u.) in the basin. At this location there appears to be a negative correlation between the grain size and the reservoir quality.

B. Sand thicknesses

The thickness of the sandstone units in these wells is summarized in Figure 21. Sandstone units in the Naufrage Formation show median thicknesses of less than 10m in all wells. Individual sand units of thicknesses greater than 10 meters are developed in Cable Head E-95 (almost 20m thick), East Point E-49 (>10m) and in East Point E-47 a maximum thickness of more than 30 meters were recorded.

Median thicknesses for the Cable Head Formation are generally less than 10 meters, except for the Bradelle L-49 well where the median thickness is 17 meters. Cable Head E-95 and the two East Point wells again show maximum thicknesses of more than 10 meters.

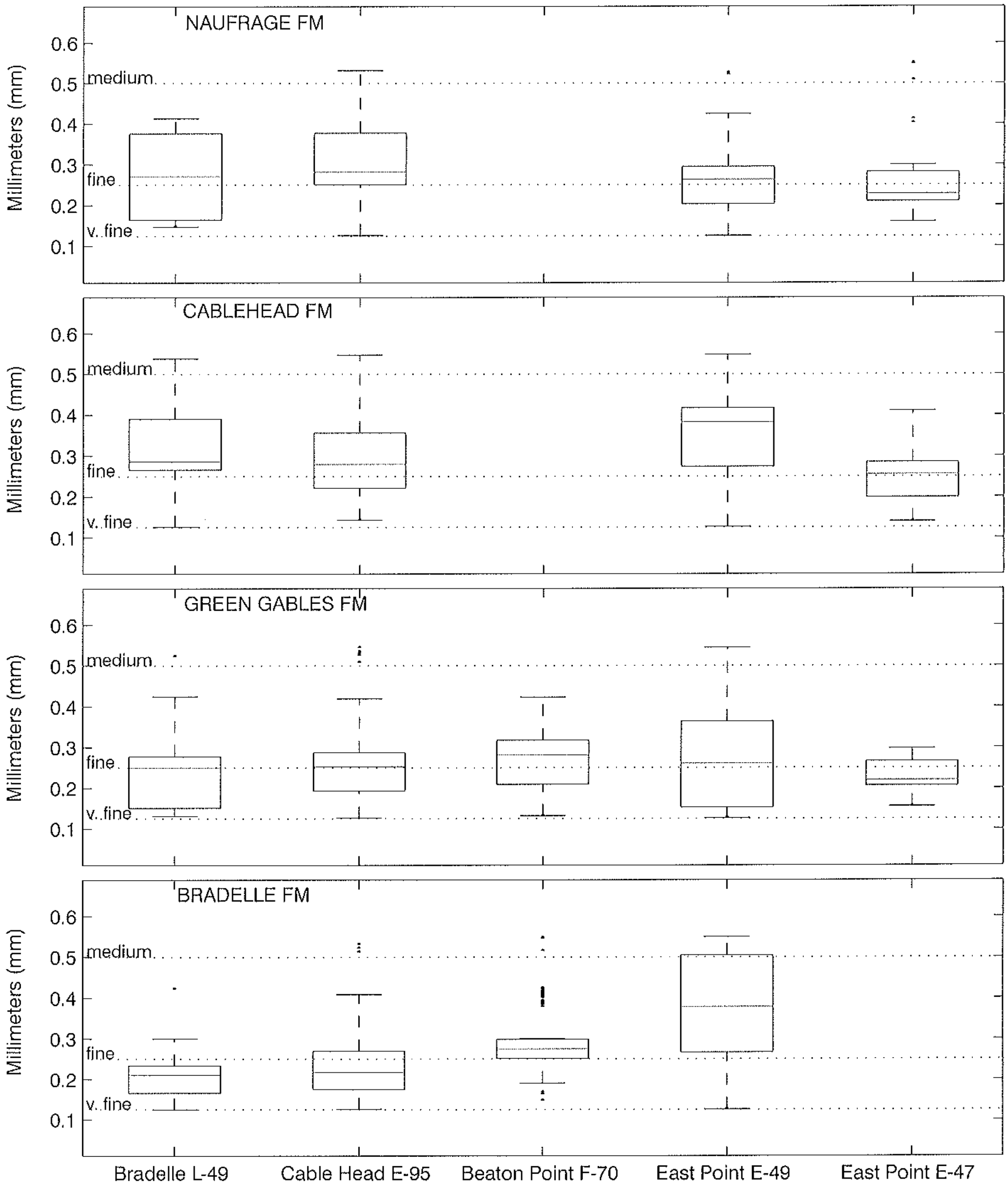


Figure 20. Box and whiskers diagrams summarizing the grain size distribution for the Pictou Group for several wells. The median is indicated by the horizontal line in each box and the dots which plot outside the boxes, are outliers. The outliers are datapoints which are 1.5 time that of the interquartile range.

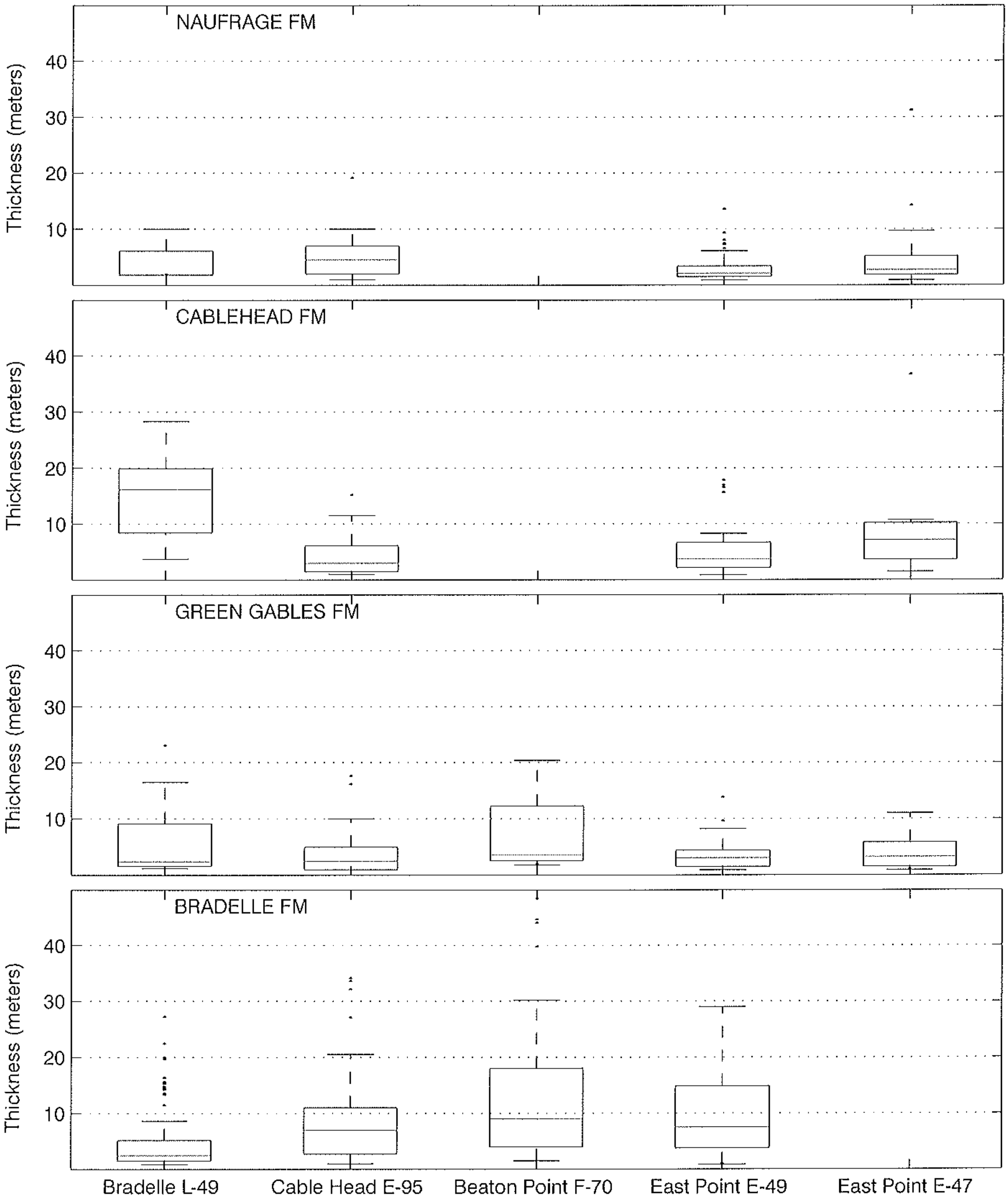


Figure 21. Box and whiskers diagrams summarizing the sand unit thicknesses for the Pictou Group for several wells. The median is indicated by the horizontal line in each box and the dots which plot outside the boxes, are outliers. The outliers are datapoints which are 1.5 time that of the interquartile range.

Median sandstone thicknesses are generally less than 10 meters in the Green Gables Formation. In most wells maximum thicknesses are generally more than 10 meters; in Bradelle L-49 and Beaton Point F-70 the sand units are more than 20 meters thick.

The thickest sandstone units are developed in the Bradelle Formation, although median values are generally less than 10 meters, maximum values of more than 20 meters thick are present in all wells. In Cable Head E-95 the maximum thickness is more than 30 meters and more than 40 meters in Beaton Point F-70.

X. CLAY MINERALOGY

Authigenic minerals reflect their chemical environment (fluid phase) as well as the physical environment (temperature and pressure) and are the key to predicting reservoir quality because they reduce permeability and occlude porosity (MacDonald and Surdam, 1984). Clay mineral diagenesis is also important in reconstructing the temperature history of petroleum basins and plays an important role at the production stage of hydrocarbon reservoirs (Moore and Reynolds, 1997).

Four species of authigenic clay minerals occur in the Carboniferous sandstones in the Maritime Basin, including illite (50-80%), chlorite (10-25%), mixed-layer clays (5-25%), kaolinite (trace –15%) and smectite (trace-10%) in the <2μm fraction. Clay mineralogy data for Irishtown 1, East Point E-49, Green Gables 1, Naufrage 1, Bradelle L-49 and North Sydney P-05 are presented on the correlation chart. Clay mineralogy curves are also available for Northumberland Strait F-25 and Brion Island 1 in the database. The original data for Noel 1 are of poor quality, and a reproduction of the original is not possible. Refer to Rodrigue and Meloche (1984) for complete details on the clay mineralogy of St Paul P-91 and refer to Solomon (1986) for complete details on boreholes BSG 1 and FB2-76.

Raw, uninterpreted X-ray diffraction data are also available for Albert Mines 1A, Boudreau 1, St. Joseph 2, Rosevale 1 and Dover 57, but are not included in the database. Most wells contain most or all of the clay species with illite usually the dominant variety. Illite and chlorite are present in all the wells from the Permian Sands to the Horton Group. Kaolinite is present from the Naufrage Formation to the Horton Group and mixed-layer clays are present from the Permian sandstones to the Horton Group. Interestingly, no kaolinite is present in the Cumberland Group (intersected by Green Gables 1 and East Point E-49).

Clay minerals can affect permeability and porosity in different ways. The greatest reduction in porosity and permeability is caused by the bridging across pores by clay mineral "books" or fibers (North, 1985). Authigenic illite often causes this reduction, although chlorite and smectite may also bridge pores. The absolute size of pores can also be reduced by clay minerals lining the pore walls. The most common mineral in this category is chlorite, and illite causes the same effect occasionally. However, it has also been recorded that grain-coating authigenic chlorite can preserve intergranular porosity in deeply buried sandstone reservoirs, by inhibiting quartz cementation (Ehrenberg, 1993). Discreet clay particles, most commonly kaolinite, within pores can seriously interfere with pore-throats and affect permeability. For example, the Albert Formation in the Stoney Creek Oil and Gas field rarely contains kaolinite (Chowdhury and Noble, 1992) and is the only known hydrocarbon producing reservoir in the Maritimes Basin. It is also reported that no kaolinite is present in Northumberland Strait F-25 (IRNS-Petrole, 1975c), but no porosity data are available to assess its effect on the reservoir. In Carboniferous sandstones in Northern Ireland pore filling kaolinite has reduced the porosity, but the kaolinite is recorded to still exhibit an effective microporosity (Wang, 1992).

The accompanying correlation chart displays calculated effective porosities and clay mineral assemblages for 11 wells in the Maritimes Basin. This chart's aim is to determine the effect that authigenic clay minerals have on the reservoir quality.

Clay mineralogy data and calculated effective porosities are available for Naufrage 1, Bradelle L-49, North-Sydney P-05 and St. Paul P-91 (no clay mineralogy curve is available for St. Paul P-91). In the Bradelle L-49 well, the high median porosity of 17p.u. seems to correspond with a clay mineralogy suite of illite, kaolinite, chlorite and minor mixed-layer clays and undetermined clay minerals (in decreasing order). The absence of chlorite near the base of the Bradelle Formation and the upper Mabou Group might play a role in the reservoir quality at this location. In Naufrage 1, the clay mineral assemblage consists of illite, chlorite, kaolinite and mixed-layer clays (in decreasing order). The proportions of these clays stay fairly constant throughout the well, except for a slight decrease in the kaolinite and mixed layer clays towards the deepest part of the well. Median porosities decrease from 14p.u. (Naufrage Formation), to 9p.u. (Cable Head E-95), to 7p.u. and 6p.u. for the Green Gables and Bradelle Formations respectively. The clay mineralogy does not seem to have a significant relationship with the porosity trends in this well, and the decrease might as logically be attributed to compaction with depth. Median porosities in North Sydney P-05 are fairly constant in the well and do not seem to be influenced by the abrupt change in the clay mineralogy from approximately 1160 – 1360m.

Clay minerals can also be used for stratigraphic markers and environmental indicators (Moore and Reynolds, 1997). In the Maritimes Basin unconformities and formation boundaries are highlighted by changes in clay mineral assemblages. In Irishtown 1, the Westphalian unconformity is marked by the disappearance of kaolinite at this depth. In East Point E-49 the chlorite fraction appears to increase slightly immediately below the Westphalian unconformity. The appearance of kaolinite and mixed-layer clays seems to coincide with the Westphalian unconformity in the North-Sydney P-05 well. Clay mineralogy stays fairly constant at the Westphalian unconformity in the Green Gables 1 well. Formation boundaries also show changes in the clay mineralogy proportions and the relative proportions of kaolinite seem to play an important role. The top of the Green Gables Formation seems to coincide with an increase in kaolinite in the Green Gables 1 and East Point E-49 wells. The top of the Bradelle Formation coincides with the re-appearance of kaolinite in these two wells. The clay mineralogy does not show significant changes at other formation boundaries on the chart and it is also notable that changes in the clay mineralogy can occur within a single formation as presently defined.

In St Paul P-91, the clay mineralogy data are not available as relative percentages and the format therefore does not allow for the same presentation as the other wells on the correlation chart. However it is reported that chlorite is more abundant than illite in this well (Rodrigue and Meloche, 1984). The presence of pore-filling authigenic chlorite and minor illite accounts for most of the porosity reduction in this well. These relative proportions do not correspond to the relative proportions that are recorded in the other five wells, e.i. illite usually is the dominant clay variety. Temperatures of at least 200 degrees Celsius (Rodrigue and Meloche, 1984) are necessary to transform illite/smectite to illite/chlorite. The local paleothermal gradient was calculated to be 44.4 degrees C/km, characteristic of active tectonic regimes (Rodrigue and Meloche, 1984).

XI. INTERNATIONAL ANALOGUES

Carboniferous to early Permian reservoirs elsewhere in the world are prolific producers and show reservoir qualities similar to the Maritimes Basin.

The sandstones of the Upper Rotliegendes (Permian) form the most important gas reservoir rock in the Southern Permian Basin of the North Sea. They contain 4.1 x 10^{12} m^3 of proven recoverable reserves of which 2.4 x 10^{12} m^3 are in the giant Groningen gas field in the Netherlands sector of the North Sea (Ziegler , in Glennie 1984). These red beds were deposited under arid continental conditions with two main facies characteristically developed -

aeolian and fluvial sediments in the southern part of the basin and a clayey lacustrine facies deposited in the northern and central part of the basin (Woodland, 1975). The fluvial sandstones form locally good reservoirs such as the Slochteren sandstone in the Groningen Gas Field. Good fluvial reservoirs are also present in the small Rough field, offshore Yorkshire. Apart from these fields the fluvial sandstones are commonly well cemented. Porosities for the fluvial facies range from 10p.u. to 25p.u. and permeabilities range from 0.1 to 1000mD (Glennie, 1984). In the Leman Gas Field, also in the South Basin, the water-laid facies have porosities ranging from 8-15p.u. and permeabilities from 0.1-100mD. (Woodland, 1975).

The presence of red beds might have significant implications in the search for secondary porosity enhancement in the Maritimes Basin. Gas reservoirs are present in the Westphalian C red beds in the southern North Sea. These red sandstones contain a higher proportion of sandstone and have better reservoir characteristics than sandstones of the underlying Coal Measures (Besley *et al.,* 1993). The same secondary porosity enhancement is seen in the red Carboniferous sandstones in Northern Ireland. (Wang, 1992). Wang concluded that all reddened Carboniferous strata across the United Kingdom are potential oil and gas reservoirs as these sandstones might have high secondary porosity.

The world's richest Paleozoic petroleum province is in the American Mid-Continent and the Permian Basin of West Texas with reserves of nearly 7 Gt of oil and 6.5 Tm^3 of gas. The Mid-Continent covers nearly one million km^2 and contains six Paleozoic basins for which Carboniferous and Permian sediments make up the bulk of the sediment fill. (Perrodon, 1983). Data from 1978 suggest that 19.4 BBO and 119 TCF of non-associated gas have been discovered in the Mid-Continent of which approximately 8.8 BBO and about 31.9 TCF of non-associated gas have been found in the Pennsylvanian reservoirs (Rascoe and Alder, 1983). The depositional environments for most of the sandstones range from fluvial-deltaic to shallow marine. The Pennsylvanian System is characterized by transgressive-regressive cycles that periodically inundated the Mid-Continent with marine environments, unlike the predominantly terrestrial environment that existed in the Maritimes for most of the Upper Carboniferous, except for the marine incursion in Windsor times. Porosity and permeability data from the mid-continent are generally from the fluvial-deltaic sandstones.

Data from the Eastern Mid-Continent's Black Warrior Basin suggest that deltaic and distributary channel sandstones of the Upper Mississippian Parkwood Formation exhibit porosities of 5p.u. to 20p.u. and permeabilities of 0.1 to 250mD. (Ryder, in Gautier et. al, 1996). These sandstones produce 85p.u. (1 TCFG) and

95p.u. (10 MMBO) of the gas and oil respectively in this basin. The Pennsylvanian Pottsville Formation, which produce 7p.u. of the gas and 0.5p.u. of the oil in the basin, has porosities of 1.2 to 14.7p.u.

Desmoinesian fluvial-deltaic sandstones from the Arkoma Basin, Southern Mid-Continent have porosities ranging from 10 to 18p.u. and permeabilities from 6 to as high as 850mD. (Brown and Parham, 1983 in Gautier et. al, 1996). These sandstones have produced 3,360 BCFG of gas up to 1992. Morrowan sandstones in the Anadarka Basin have origins that are interpreted as valley fill, deltaic, beach and offshore bar, and exhibit porosities of 6-26p.u. (median 13p.u.) and permeabilities from 1 to 600mD (median 20mD). The largest gas accumulation associated with the Morrowan sandstones is at the Watonga-Chickasha Trend with an estimated ultimate recovery of 4.3 TCFG and the largest oil accumulation is at Postle Field (120 MMBO).

XII. SUMMARY AND CONCLUDING REMARKS

This compilation of reservoir data summarises different aspects of the reservoirs in the Maritimes Basin. The most notable observation is that the data are sparse and the reservoir quality as outlined by this report may change considerably as more data becomes available. The basin is relatively unexplored and huge areas offshore are still untested.

Median porosities obtained from geophysical logs show that the Unnamed Permian Sands and the Naufrage Formation exhibit the best overall porosity with median values between 12 and 17p.u. The Bradelle Formation in Bradelle L-49 also exhibits good reservoir potential with a median porosity of 17p.u. This formation, and the Naufrage Formation in East Point E-47, show the highest recorded porosities of 30p.u. Most of the sandstone reservoirs in the basin have median porosities of less than 10p.u. The exceptions to this trend, as seen in several wells (Bradelle L-49, Beaton Point F-70, Tyrone 1 and Cable Head E-95), are encouraging and indicate that reservoir quality in the basin can be enhanced by the development of secondary porosity at depth. Limited permeability data exist for the reservoirs and indicate that median permeabilities for all sandstone units range from 0.06 to 0.5mD. The highest permeability was recorded in the Pictou Group (116mD).

Sandstone units of considerable thickness are present in several formations. The thickest sandstone development is in the Bradelle Formation in which multistorey sandstone bodies can reach thicknesses of more than 40m. The median sandstone thickness is generally less than 10m, with the exception of the Cable Head Formation in the

Bradelle L-49 well (median 17m). The grain size distribution for the sandstones generally ranges from very fine to medium, with the median grain size about 0.250mm (fine). Between wells, there are significant variations in grain size distribution within a given formation, especially in the Bradelle Formation, suggesting a degree of variability in the depositional processes within various portions of the basin.

Illite, chlorite, kaolinite and mixed-layer clays typically make up the clay mineralogy suite in the Maritimes Basin. The presence and distribution of these clays in different wells highlight unconformities and formation boundaries, although their effect on reservoir quality is not yet fully understood. The nature and character of the clays need to be studied in order to understand their influence on the reservoir quality in the basin; identification of grain-coating chlorite, for example, will determine whether its presence has a positive or negative influence on the reservoir quality.

This data compilation has also highlighted the spatial and temporal coverage of reservoir data in the Maritimes Basin. Existing data and newly generated data for this project indicate that the Pictou and Morien Groups have extensive data coverage and the data represented in this report are probably a true indication of the reservoir properties of these two groups. The Cumberland, Mabou, Windsor and Horton Groups, on the other hand, show very limited data coverage. Further work in the basin should include the acquisition of new data for these groups. Data coverage for the Horton Group is mainly concentrated in the Moncton subbasin, with relatively little data outside that basin. The Horton Group hosts the only producing oil and gas field in the Maritimes and its development in other parts of the basin should be examined. Also, no detailed petrographic work (except for the Albert Formation of the Horton Group and the Morien Group in the Sydney Basin) has been performed on the sandstones of the Maritimes Basin. A diagenesis study on the sandstones will provide insight on several aspects of the reservoir evolution of the basin, including the nature and character of the clay minerals and their effects on reservoir quality.

When comparing the reservoir quality of the sandstone reservoirs in the Maritimes Basin with that of international producing reservoirs, it is encouraging that reservoirs with similar poroperm attributes are prolific producers.

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APPENDIX A

Details on the Carboniferous Database and digital map and CD-ROM.

APPENDIX A:

The Carboniferous database consists of various types of data that were compiled as part of the reservoir compilation. The data are available on a CD-ROM as a Microsoft Access 97 for Windows database, and are also available in ASCII format for viewing in other software packages. Digital maps, with well and outcrop locations can be viewed and printed with the freely distributable ArcExplorer software. ArcExplorer is a browsing tool with interaction with parts of the database. The basemap used for this project is the 1:500 000 geology map by Keppie (1999). This digital basemap does not cover the entire study area, therefore some wells plot outside the map area.

Microsoft Access Database

All the data are presented in forms, tables, queries and reports. A summary of the different tables, their fields and relationships between tables are shown on the relationship diagram in this appendix. (Figure A.1). Selected queries have been created, using the relational features between the tables, although the user can perform various other data requests.

A total of 621 wells are included in the database, consisting of petroleum and non-petroleum wells drilled in the Carboniferous sediments of the Maritimes Basin. Data pertaining to wells are listed in tblWells. Information about cores cut in the basin with available core analysis data is available in tblCores and tblCore Analysis. Calculated porosity data obtained from wireline logs are listed in tblLog Porosities. TblOutcrop lists all the details of the two outcrop reservoir studies. Compiled petrographic work from several sources is included in tblPetrography. A table called tblTests lists all tests and analysis performed on the well or samples obtained from the well; for example Drillstem Tests (DST), Repeat Formation Test (RFT) and geochemical analysis etc.

Several queries are also included, they are Petroleum wells and Non-Petroleum wells extracted from the original data. Complete references, pertaining to the data presented in the tables are listed in tblCitations (a look-up table). A diagram showing the relationship features of the database is also available in "Reports" in the database.

Microsoft Access 97 software is not included.

Figure A 1.
Relationships for Carbonif

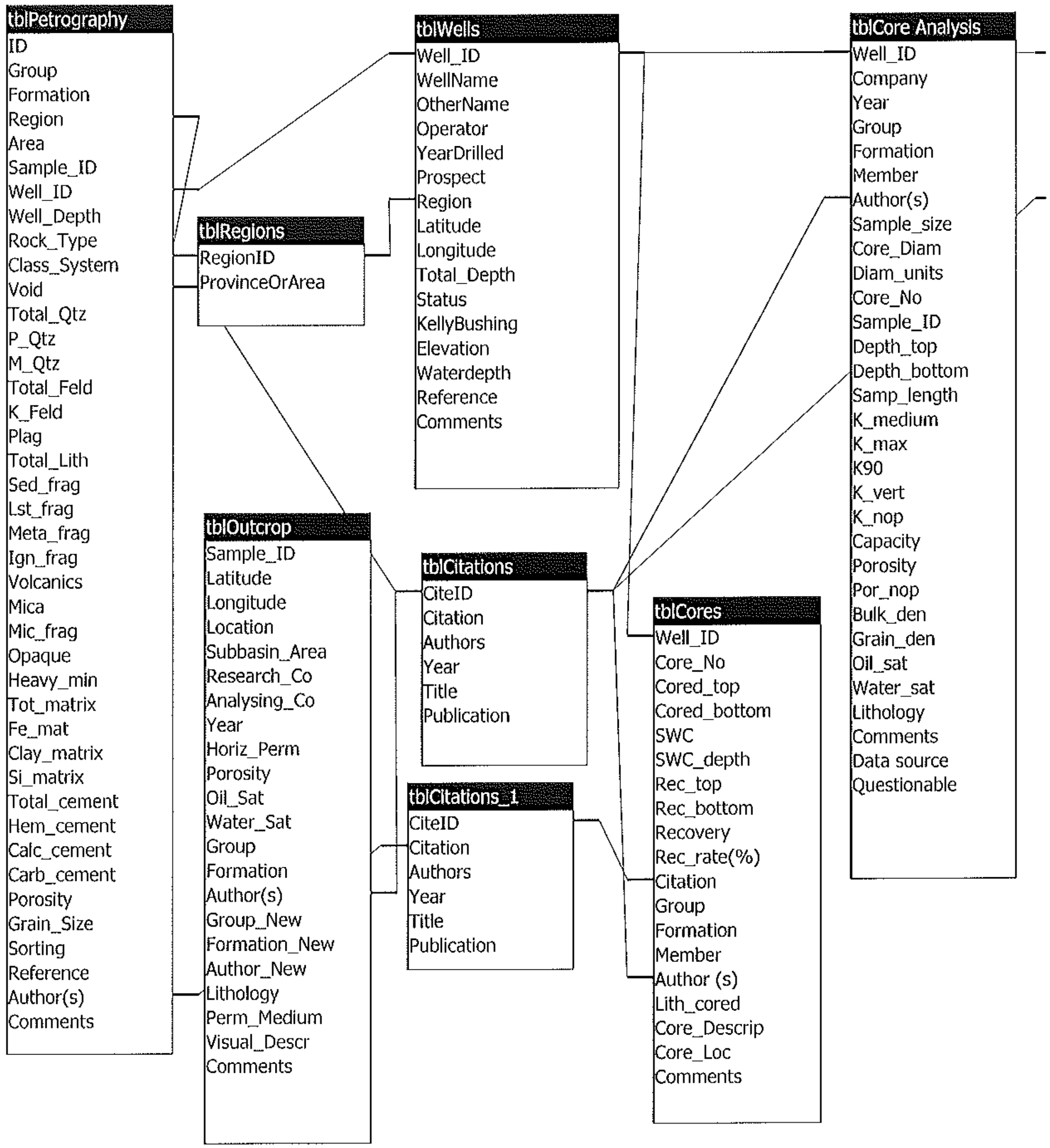

Figure A 1. Relationships for Carboniferous data base

ArcExplorer

ArcExplorer 1.1 is a geographic data explorer freely distributed by Environmental Systems Research Institute also known as ESRI Ltd. (http://www.esri.com/software/arcexplorer/index.html). ArcExplorer will allow you to view, explore and print well and outcrop locations for the Maritimes Basin. This browsing tool is also linked to the parts of the database mentioned above and will therefore show relevant data for each well and simple queries can be built. The ArcExpl.txt and ArcExpl.htm files on the CD-ROM give complete details on how to use ArcExplorer. Additional information can be obtained from the User's Manual.

Clay mineralogy curves.

Clay mineralogy curves as presented on the correlation chart, are available on the CD-ROM as Adobe Acrobat files (.pdf format).

CD-ROM Contents:

Readme.txt		Lists complete CD-ROM contents.
Database	Readmedb.txt	Read me file for database, with general information.
	Carbonif.mdb	Microsoft Access 97 Database for the Carboniferous.
	QPetrol.asc	Petroleum wells (ASCII format)
	QNonPetr.asc	Non-Petroleum wells (ASCII)
	tblWells.asc	General well information (ASCII)
	tblTests.asc	Well tests (ASCII)
	tblReg.asc	Regions and Provinces (ASCII)
	tblPetr.asc	Petrography data (SCII)
	tblOut.asc	Outcrop reservoir data (ASCII)
	TblLogP.asc	Calculated effective porosities from logs (ASCII)
	tblCores.asc	General core information (ASCII)
	tblAnaly.asc	Reservoir data from core analysis (ASCII)
	tblCita.asc	Lists citations (ASCII)
	Abbrev.asc	Lithological descriptions for abbreviations(ASCII)
Map	Readmeex.txt	Text file on how to use arcexplorer
	Readmeex.htm	Html file on how to use arcexplorer
	*.gif	Corel Photopaint images used in html file
	aeclient.exe	ArcExplorer V1.1 with Licence Agreement and Users Manual.
	ofptp.aep	Digital map, arcexplorer project file.
	*.dbf, *.shp, *.shx	Supporting files for ArcExplorer
	/info	Info subdirectory

	/major_anno	Major annotation subdirectory
	/minor_anno	Minor annotation subdirectory
	/outcrop_anno	Outcrop annotation subdirectory
	/well_anno	Well annotation subdirectory
Clay	Readmecl.txt	Text file with general information
	Bradelle.pdf	Bradelle L-49 clay curve in Adobe format
	Naufrage.pdf	Naufrage 1 clay curve
	GGables1.pdf	Green Gables 1 clay curve
	EastP49.pdf	East Point E-49 clay curve
	NSydP05.pdf	North Sydney P-05 clay curve
	Irishtow.pdf	Irishtown 1 clay curve
	Northum.pdf	Northumberland Strait F-25 clay curve
	BrionIs.pdf	Brion Island 1 clay curve

APPENDIX B

Porosity and permeability plots for each well.
(Core analysis data).

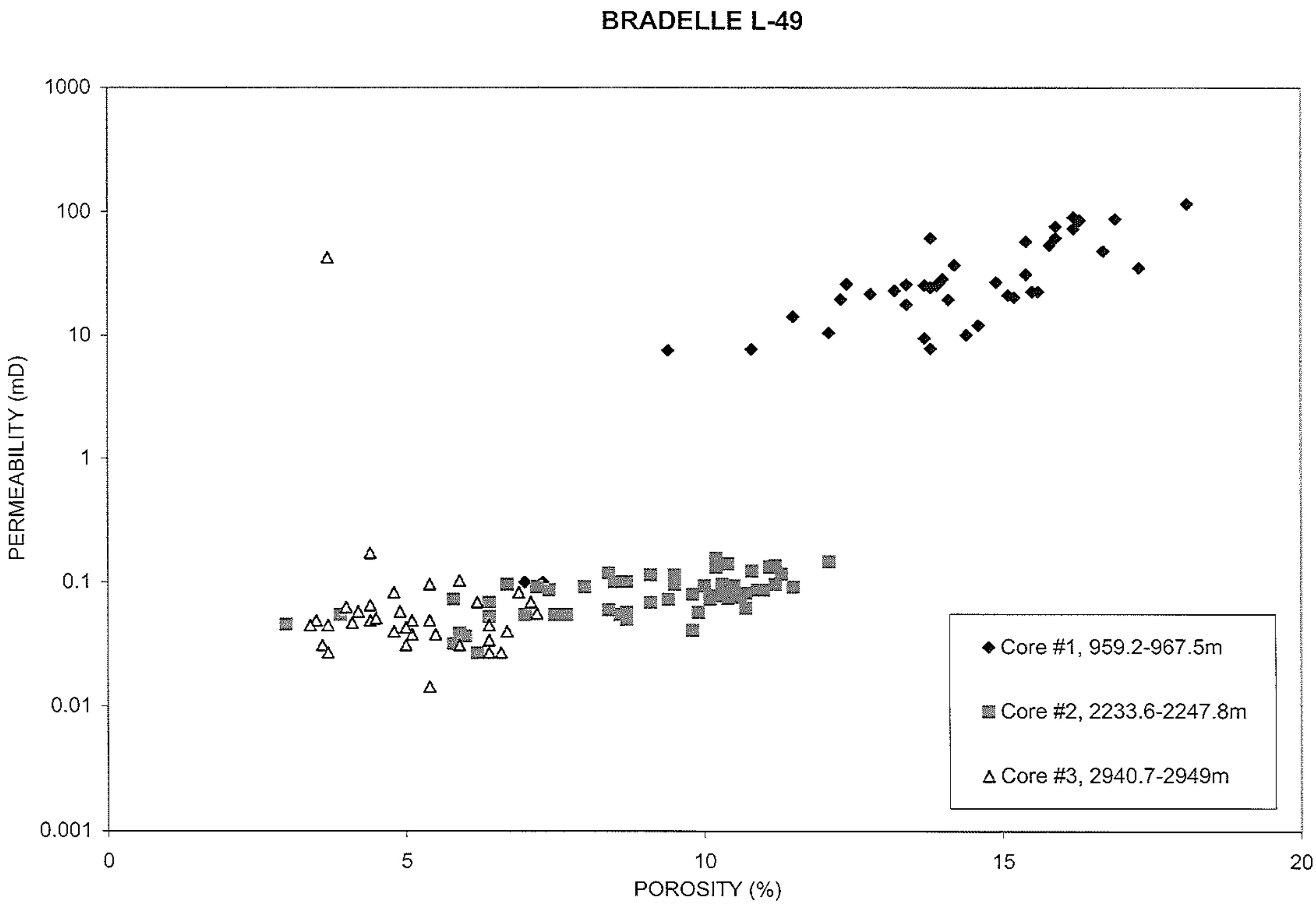

Figure B.1. Core analysis data for Bradelle L-49.

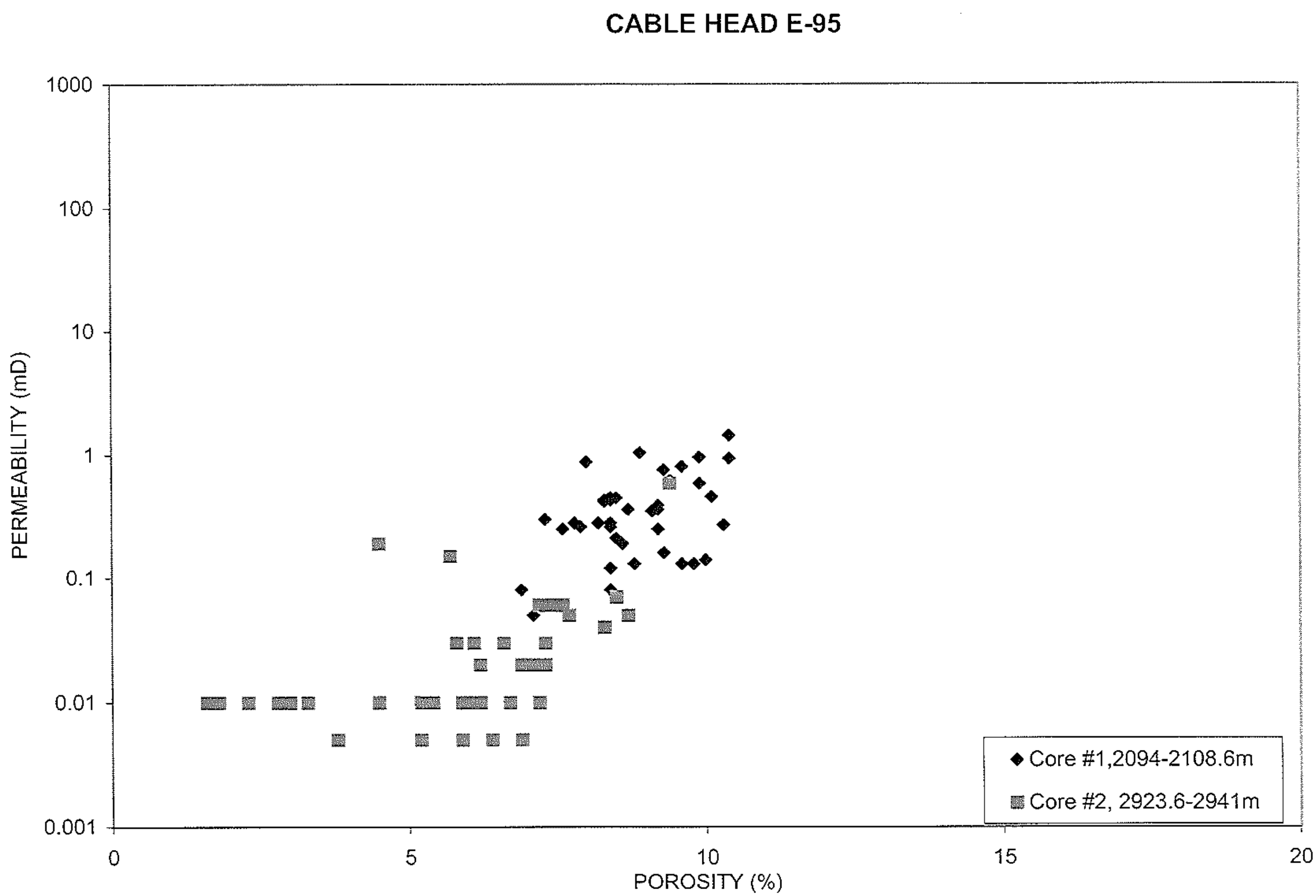

Figure B.2. Core analysis data for Cable Head E-95.

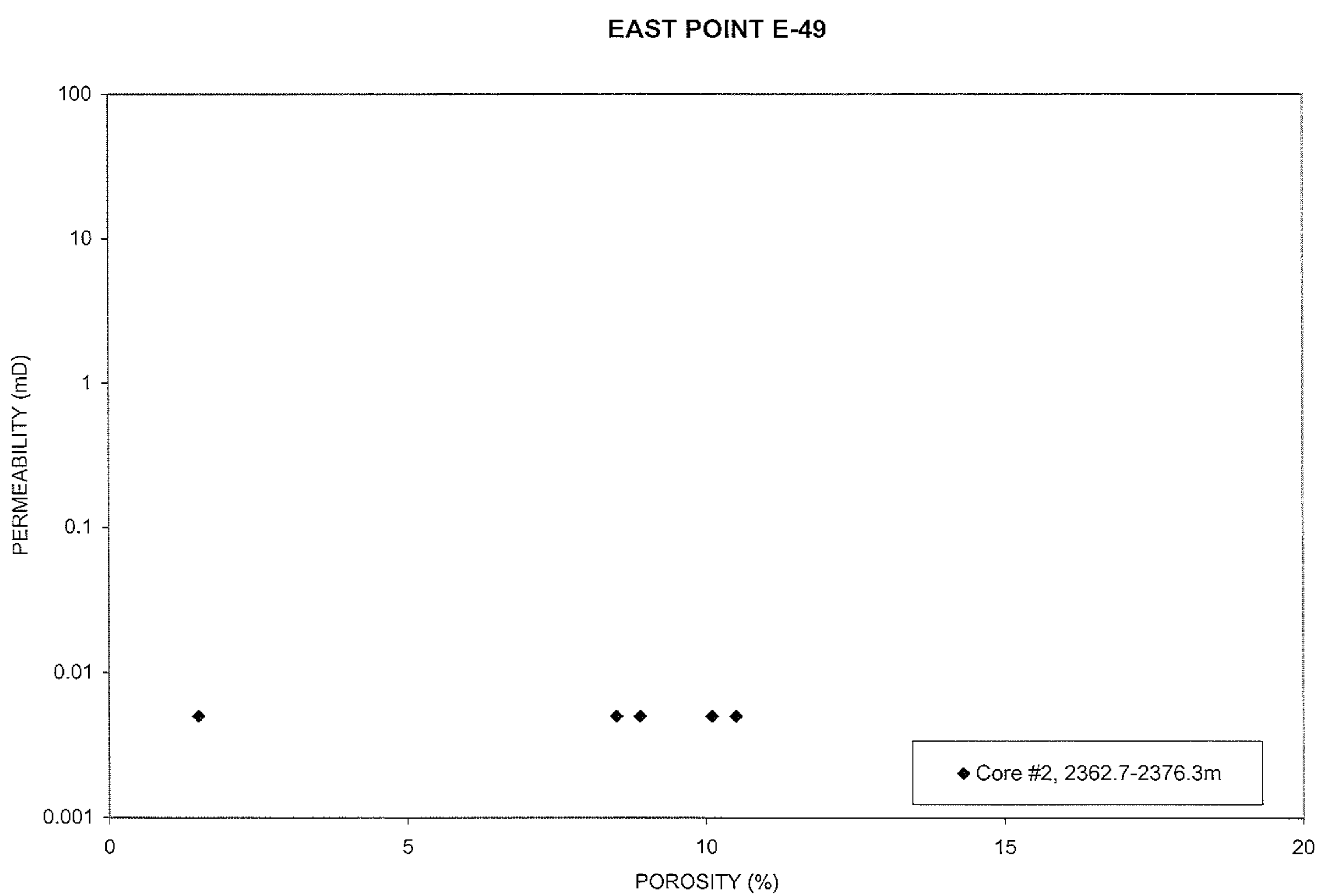

Figure B.3. Core analysis data for East Point E-49.

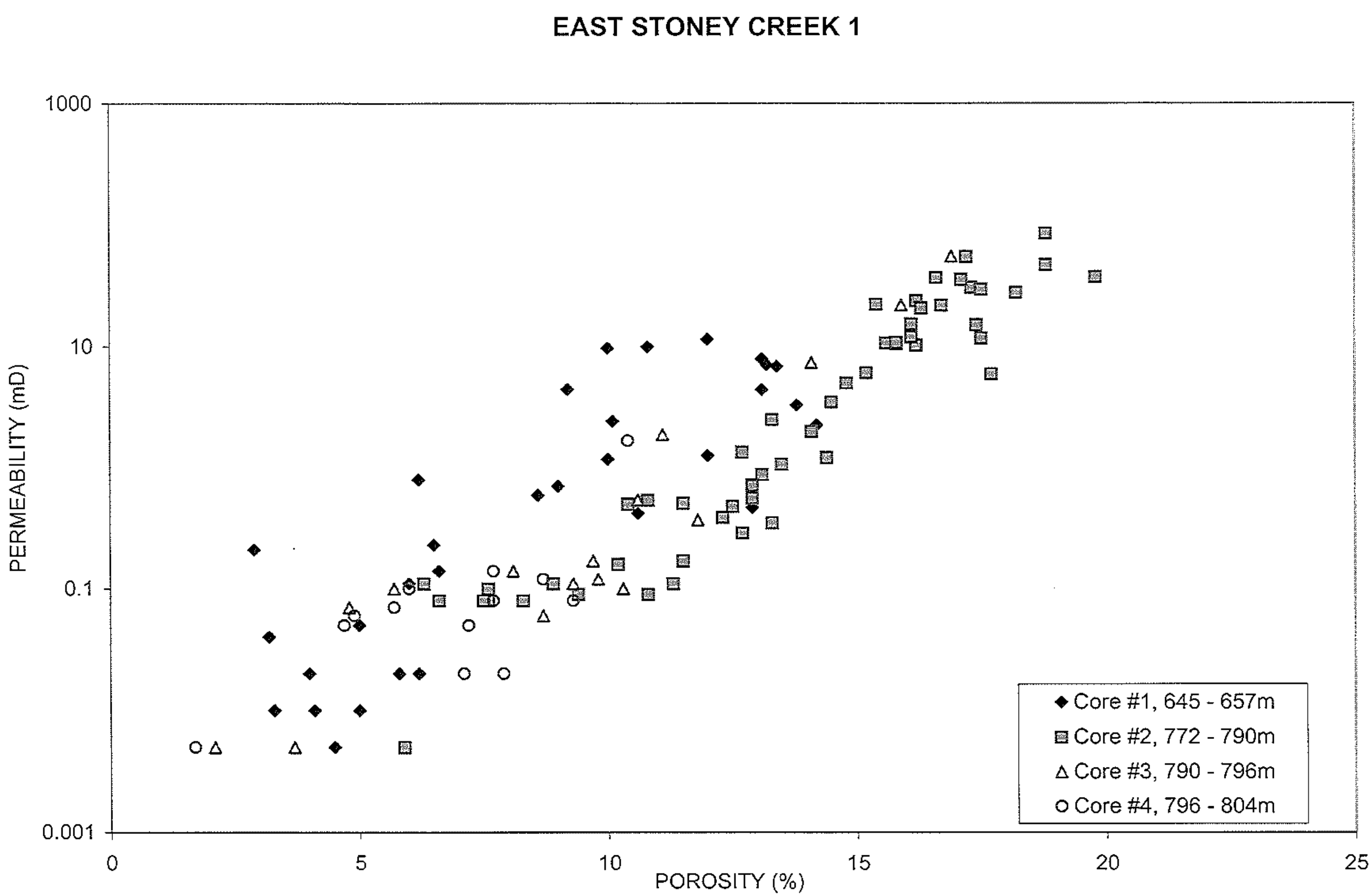

Figure B.4. Core analysis data for East Stoney Creek 1.

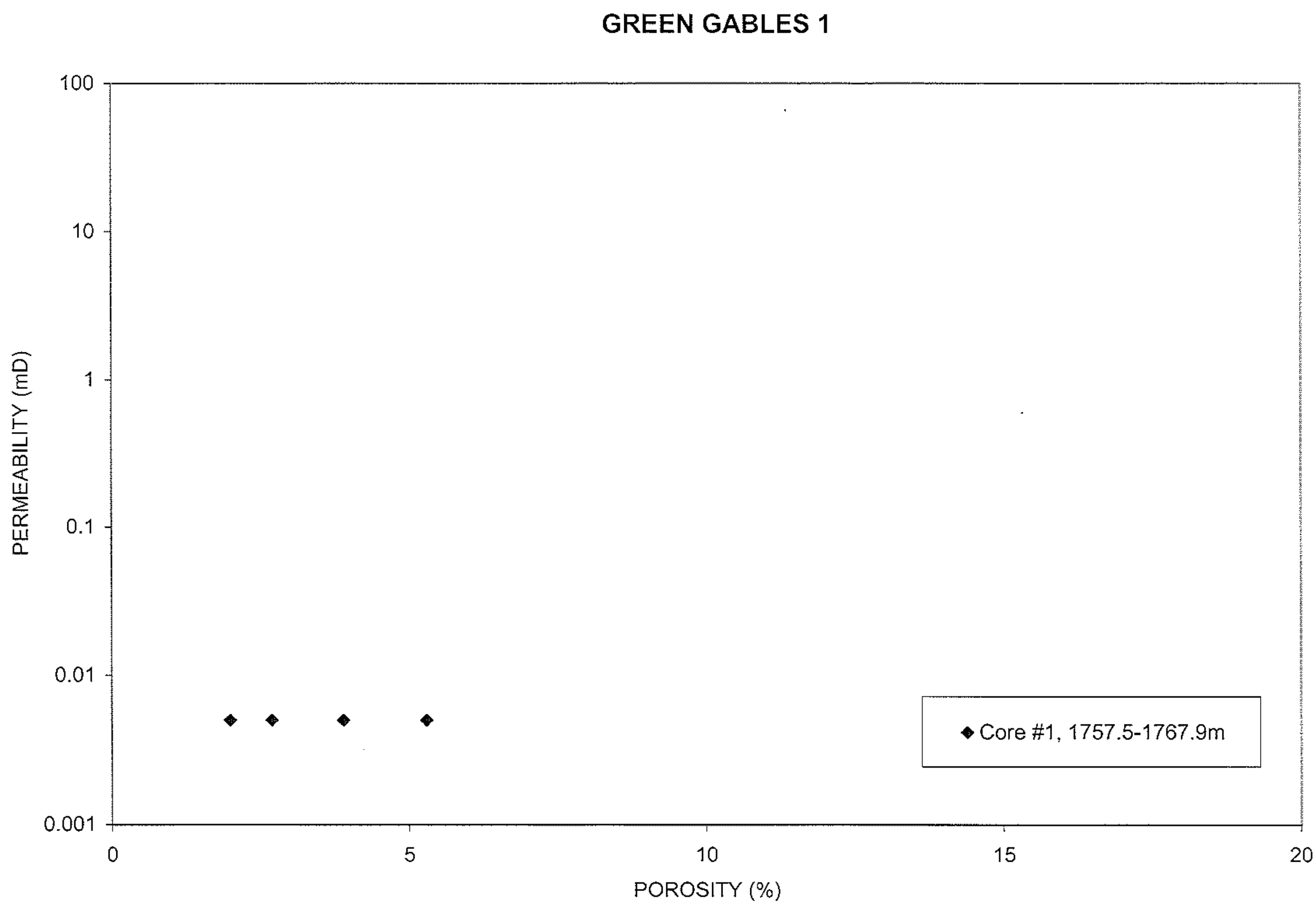

Figure B.5. Core analysis data for Green Gables 1.

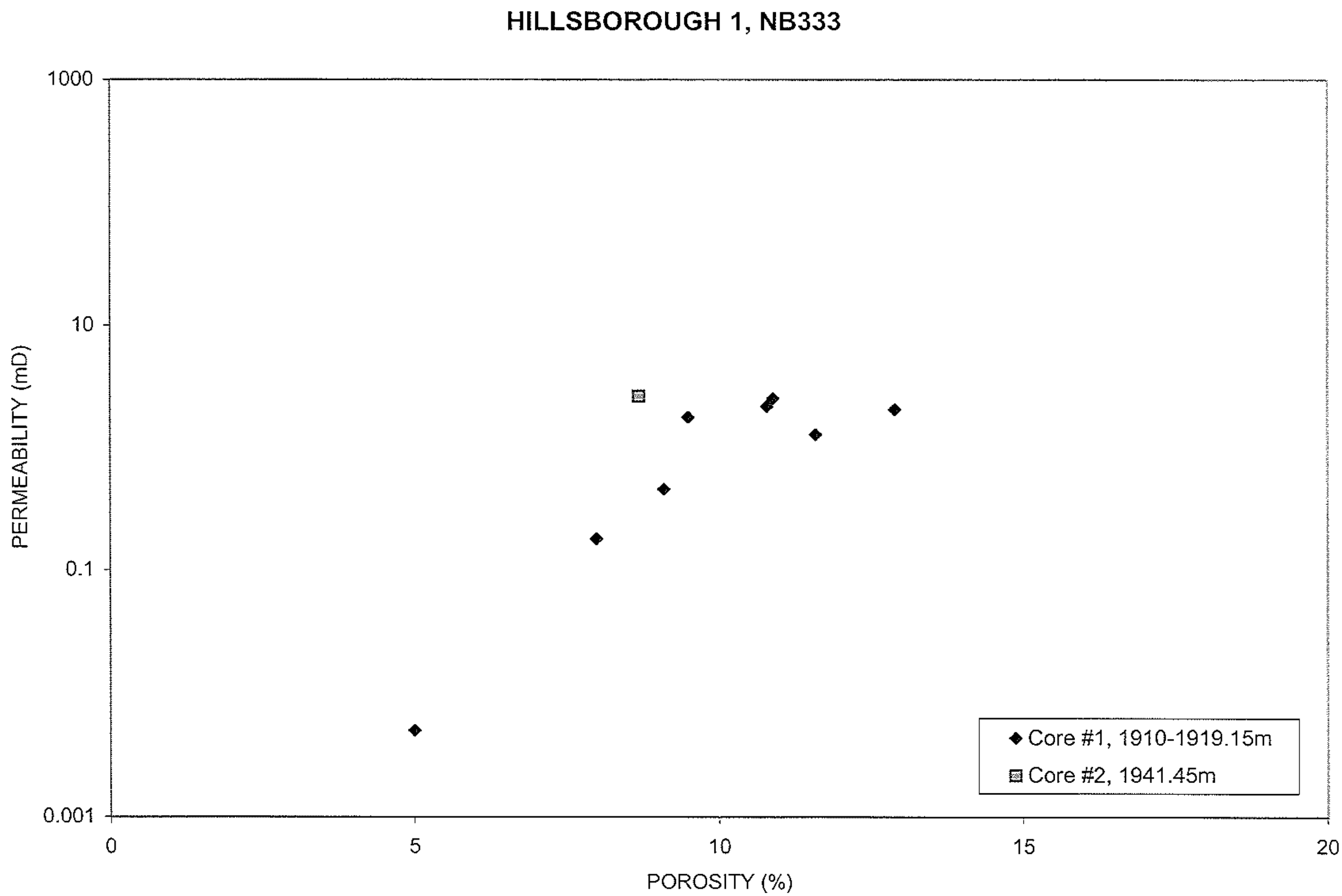

Figure B.6. Core analysis data for Hillsborough 1, New Brunswick.

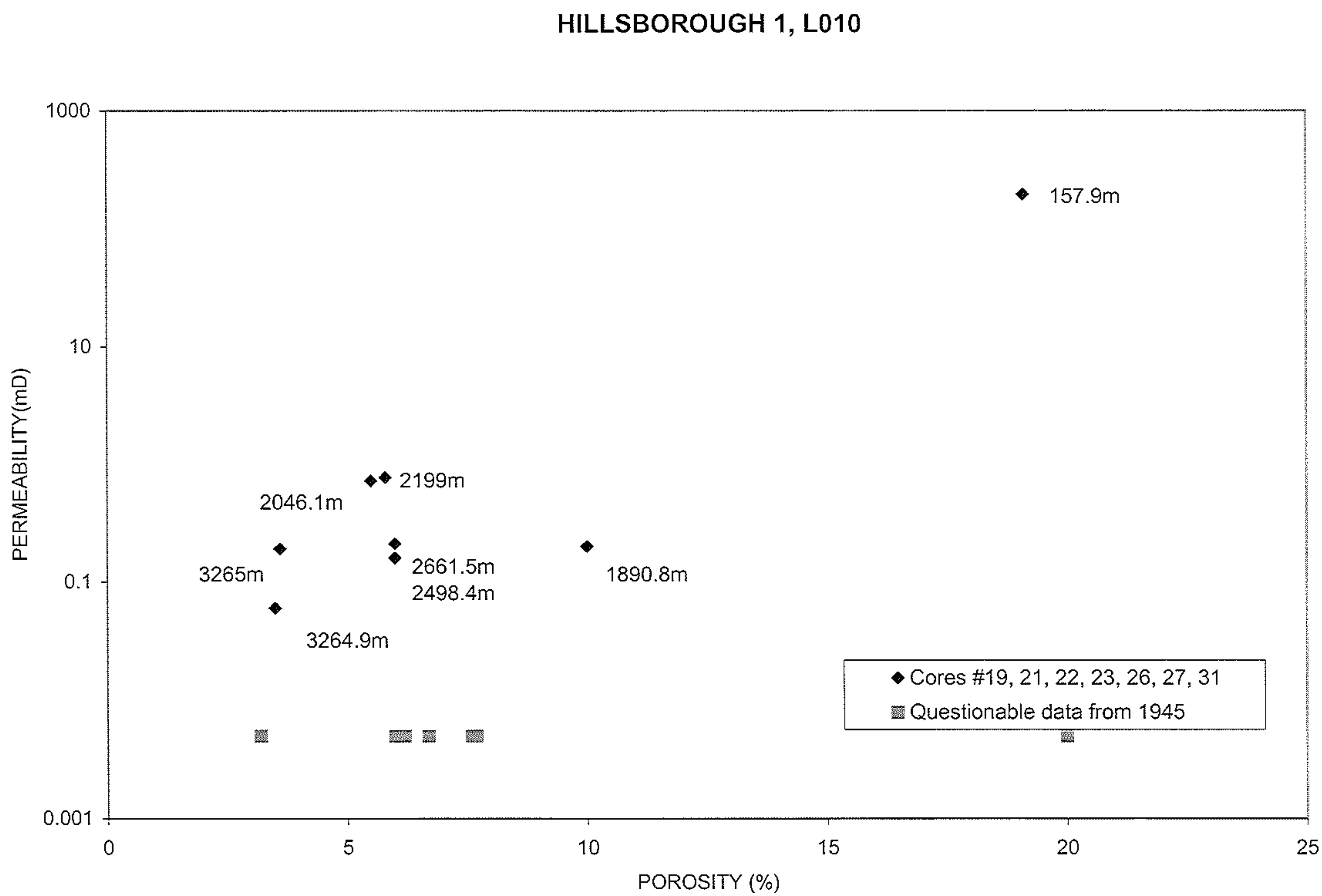

Figure B.7. Core analysis data for Hillsborough 1 (Prince Edward Island).

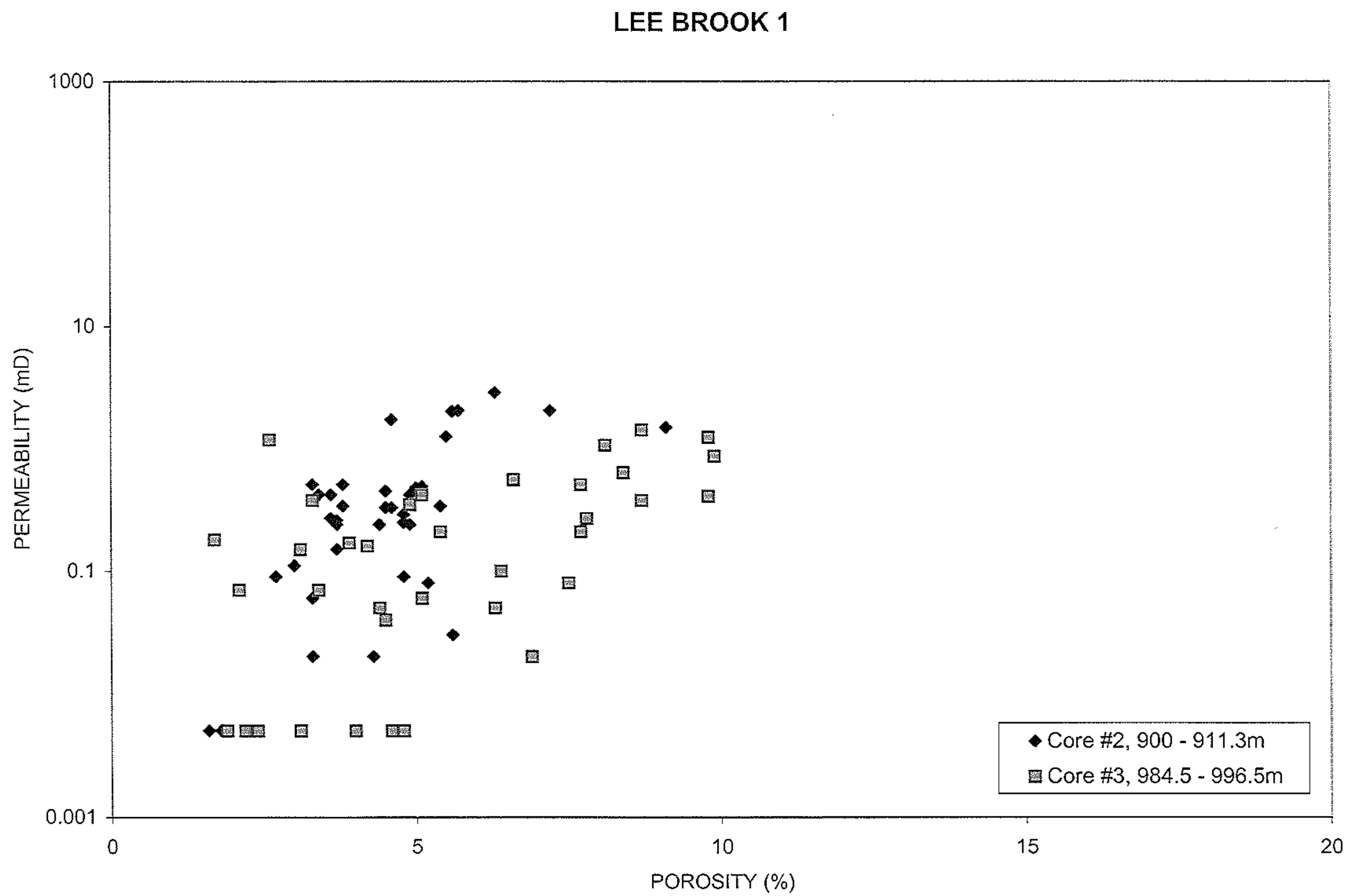

Figure B.8. Core analysis data for Lee Brook 1.

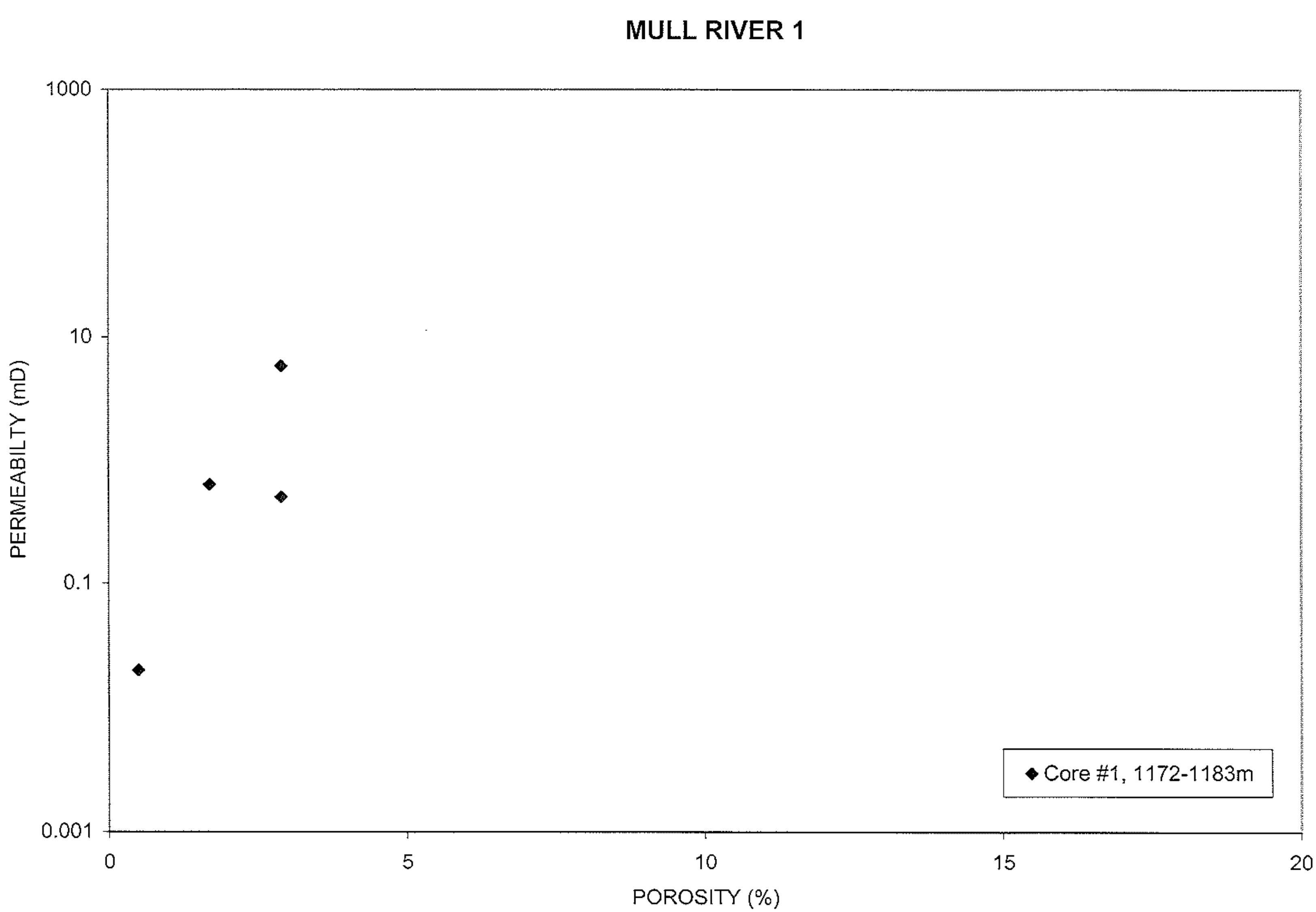

Figure B.9. Core analysis data for Mull River 1.

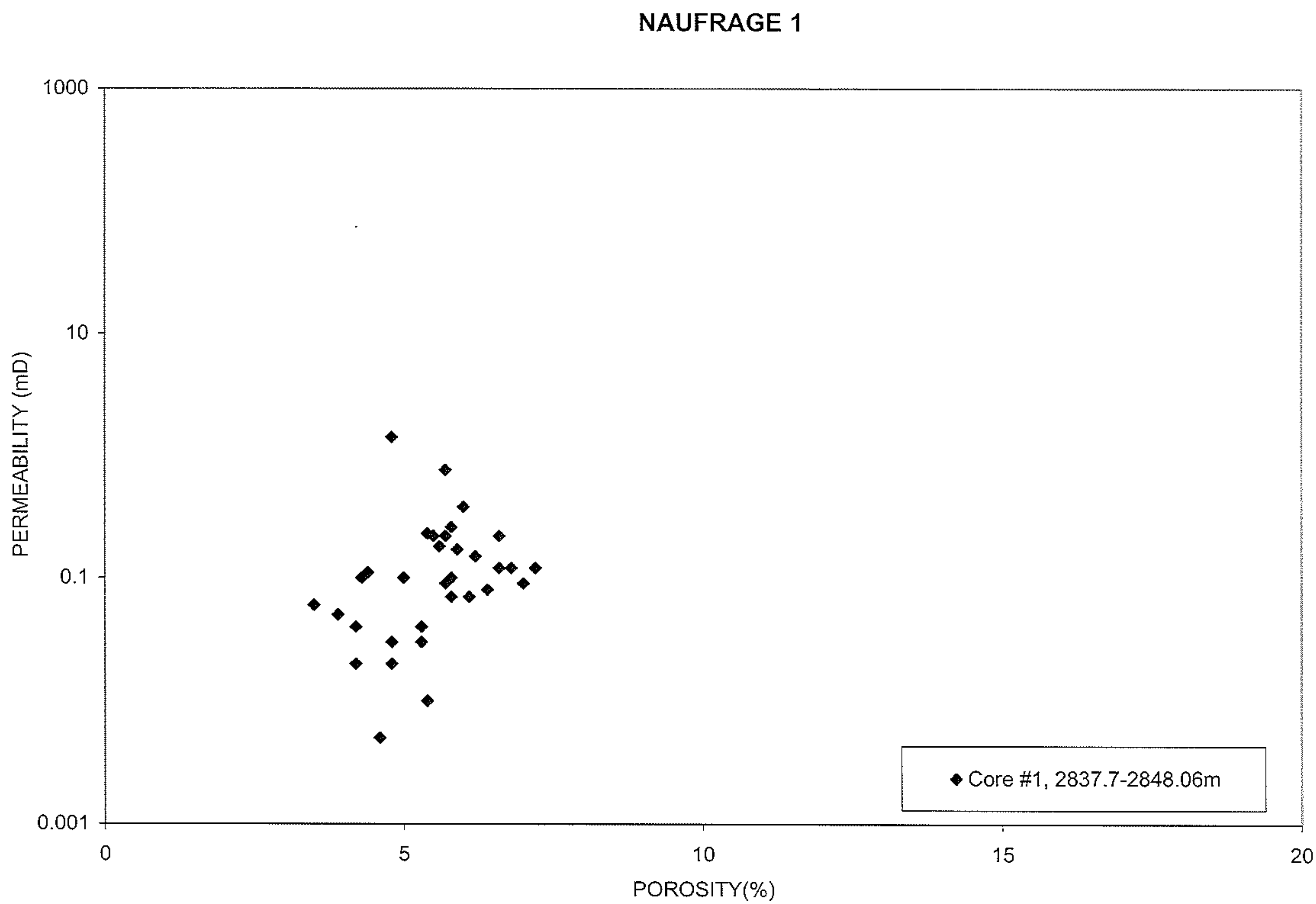

Figure B.10. Core analysis data for Naufrage 1.

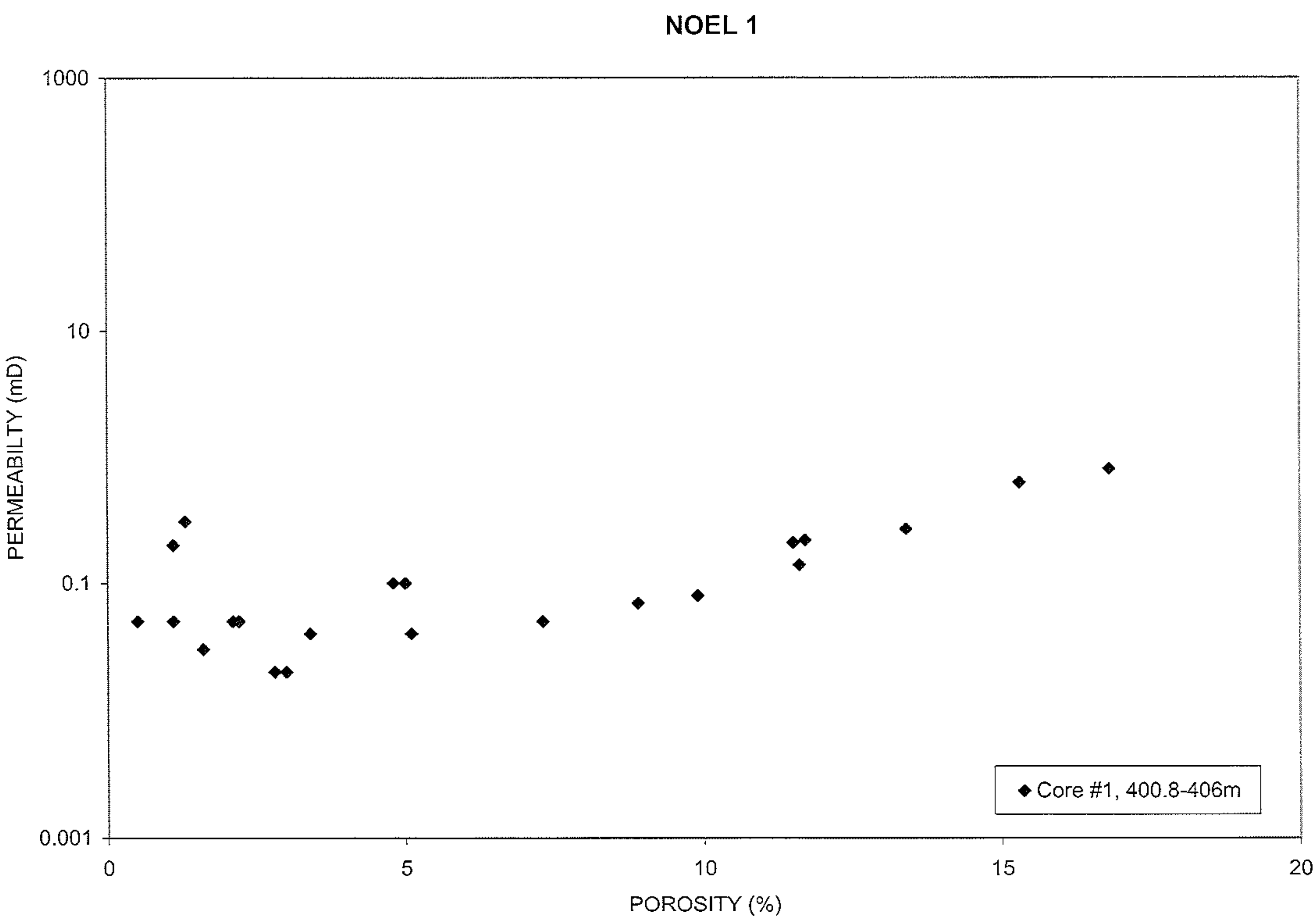

Figure B.11. Core analysis data Noel 1.

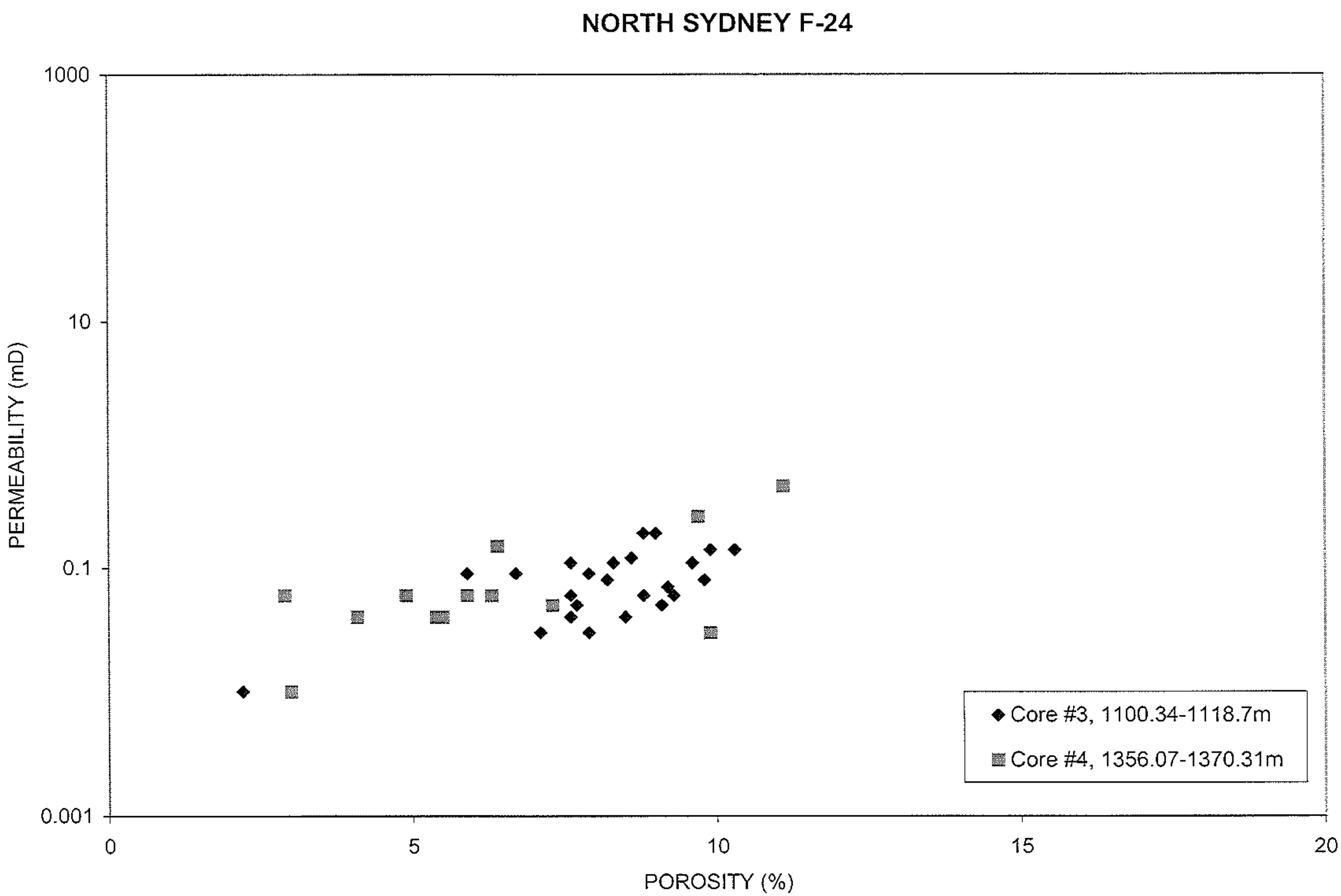

Figure B.12. Core analysis data for North Sydney F-24.

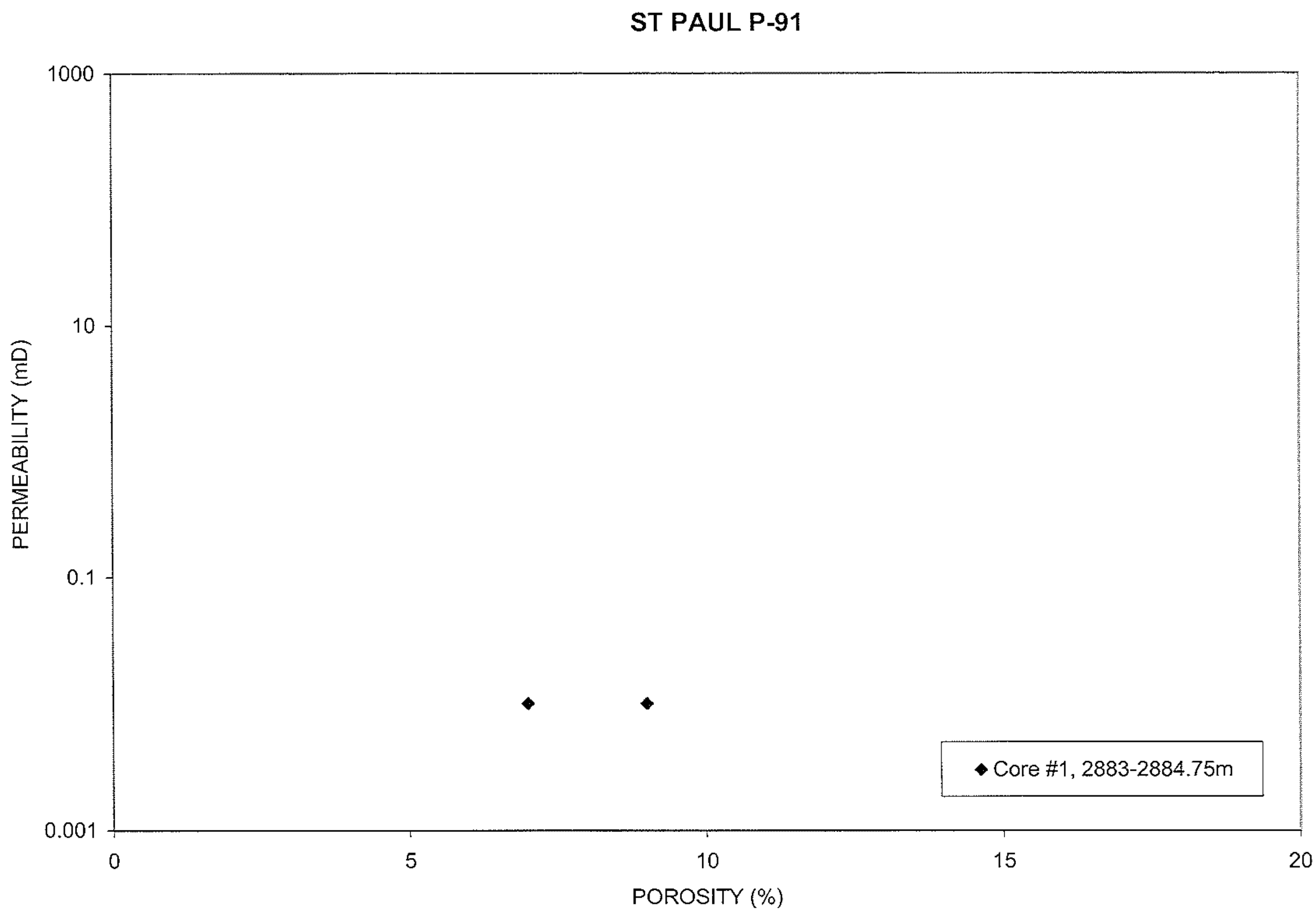

Figure B.13. Core analysis data for St Paul P-91.

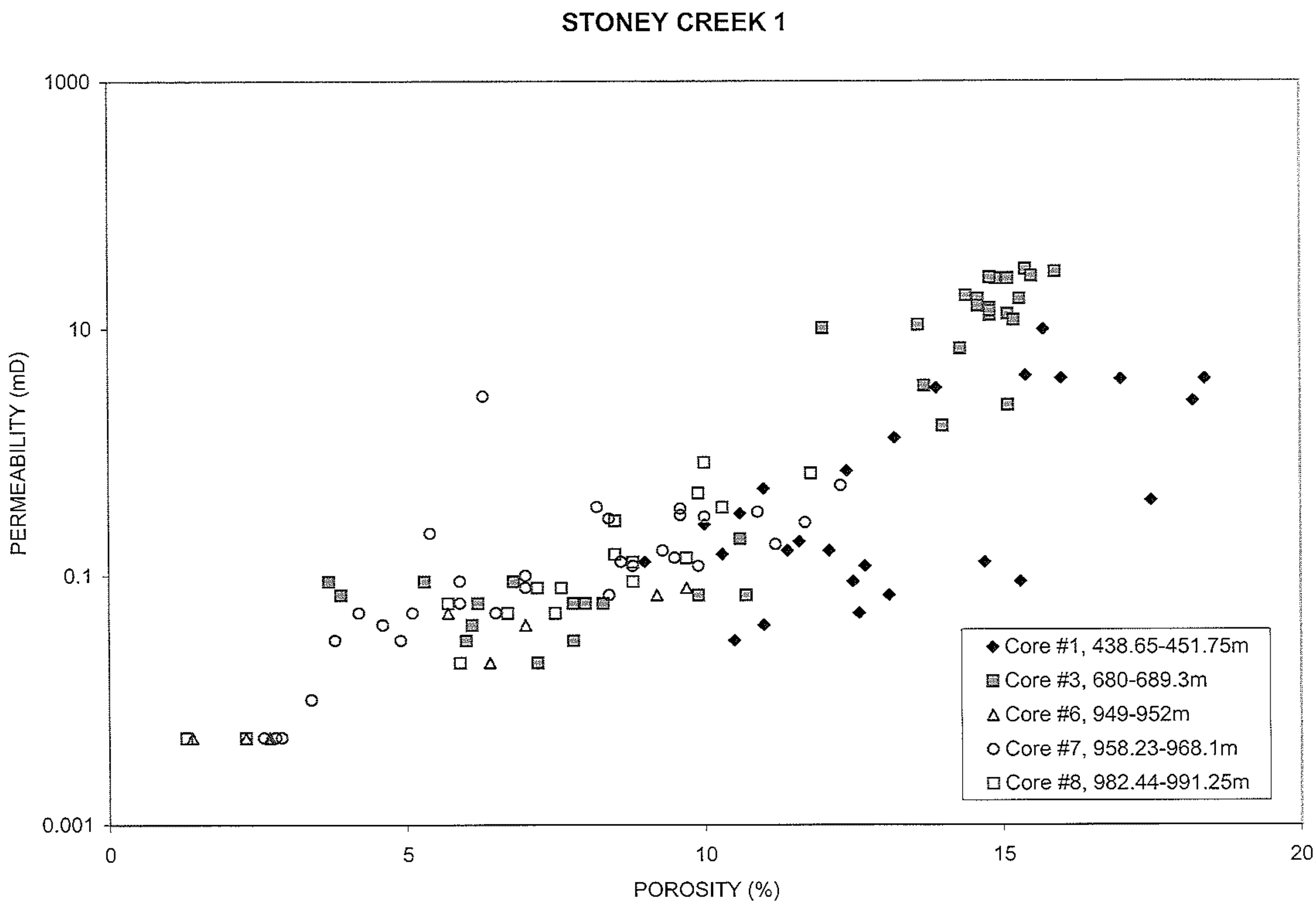

Figure B.14. Core analysis data for Stoney Creek 1.

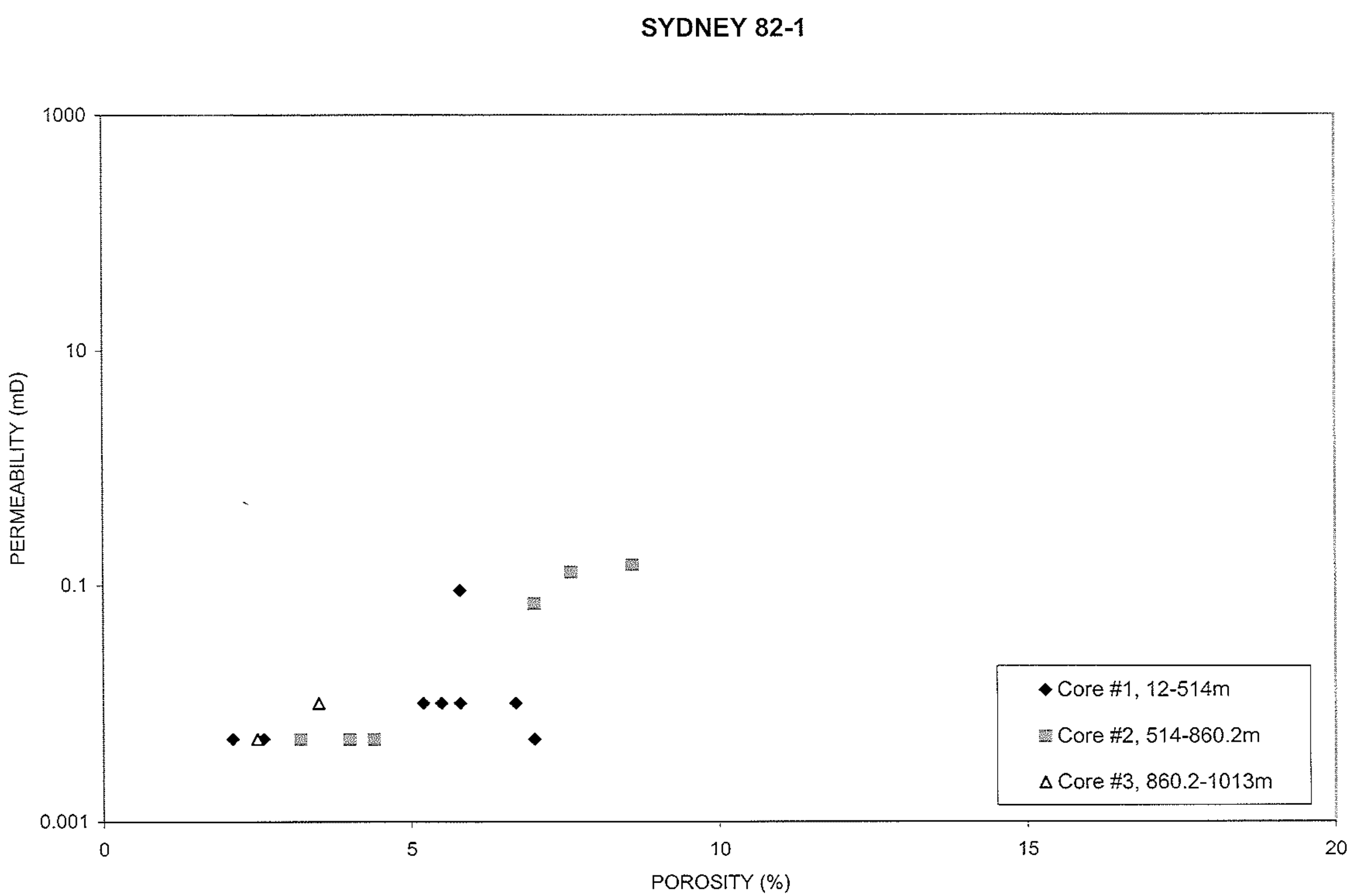

Figure B.15. Core analysis data for Sydney 82-1.

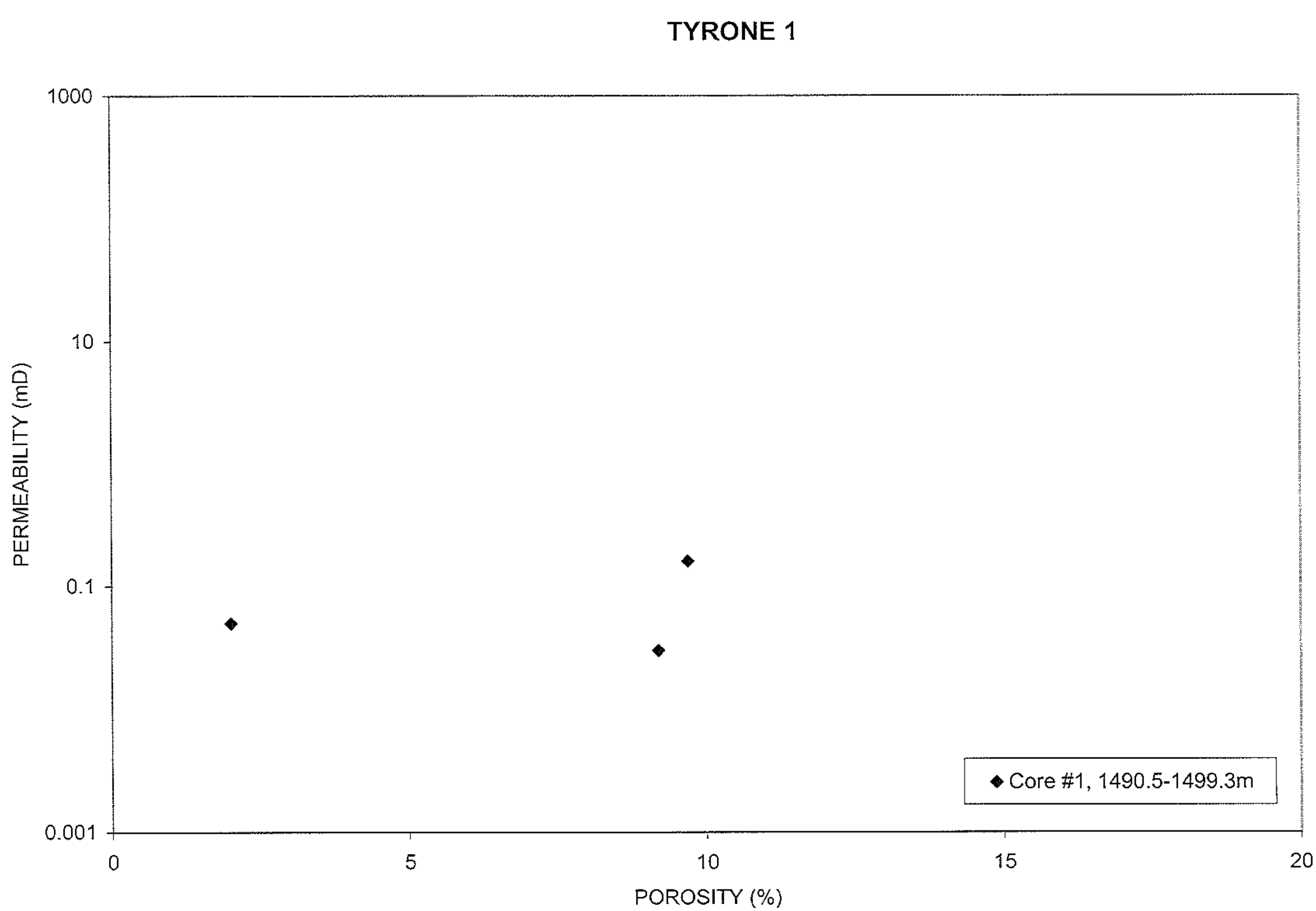

Figure B.16. Core analysis data for Tyrone 1.

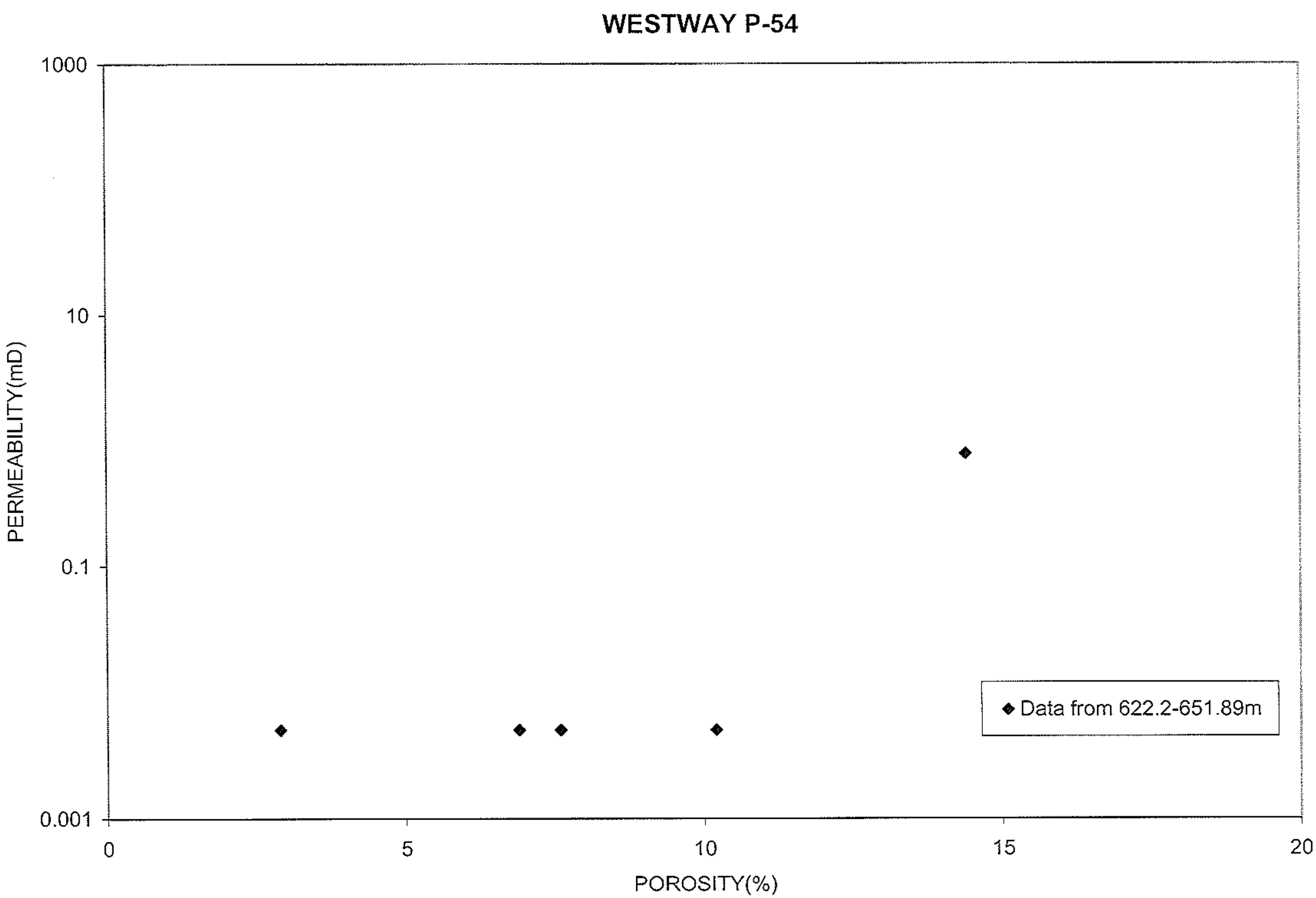

Figure B.17. Core analysis data for Westway P-54.

APPENDIX C

Porosity and permeability plots for the different groups and formations.
(Core analysis data).

Table 4. Summary of the statistical analysis performed on calculated effective porosity data(p.u.).

HORTON GROUP	Horton	
	Range	Median
St. Paul P-91	1-16.	2

WINDSOR GROUP	Windsor		Middle Windsor		Upper Windsor	
	Range	Median	Range	Median	Range	Median
Tyrone 1			0-2	0	0-9	3
St. Paul P-91	1-11	2				

MABOU GROUP	Mabou		Pomquet Formation	
	Range	Median	Range	Median
Bradelle L-49	3-29	11		
St. Paul P-91	1-11	3		
Tyrone 1			1-10	6

CUMBERLAND GROUP	Port Hood Formation			
	Colindale Member		Margaree Member	
	Range	Median	Range	Median
Tyrone 1	7-10	8	8-10	9

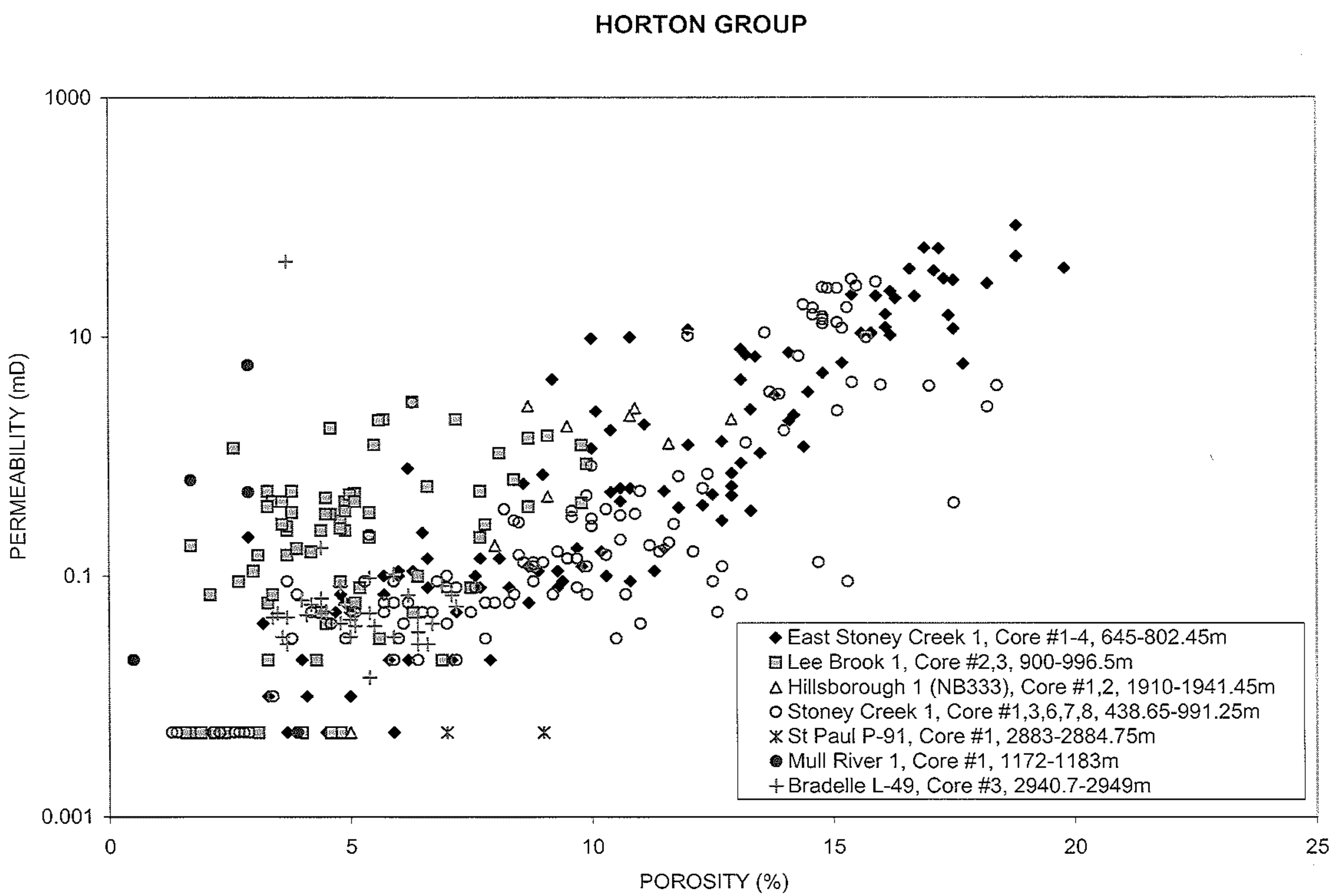

Figure C.1. Core analysis data for the Horton Group (all data).

HORTON GROUP

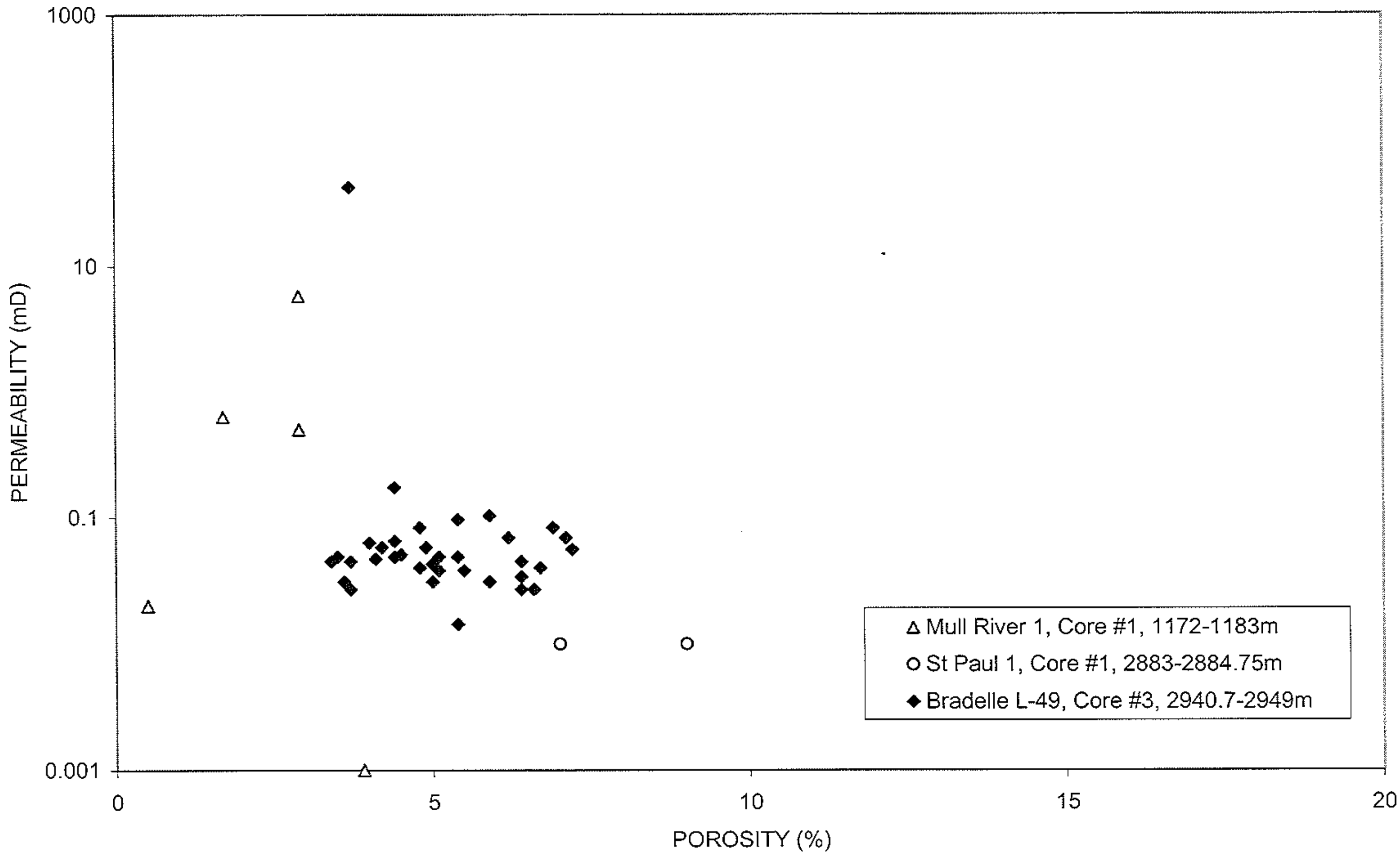

Figure C.2. Core analysis data for the Horton Group and equivalent strata (excluding the Albert Formation).

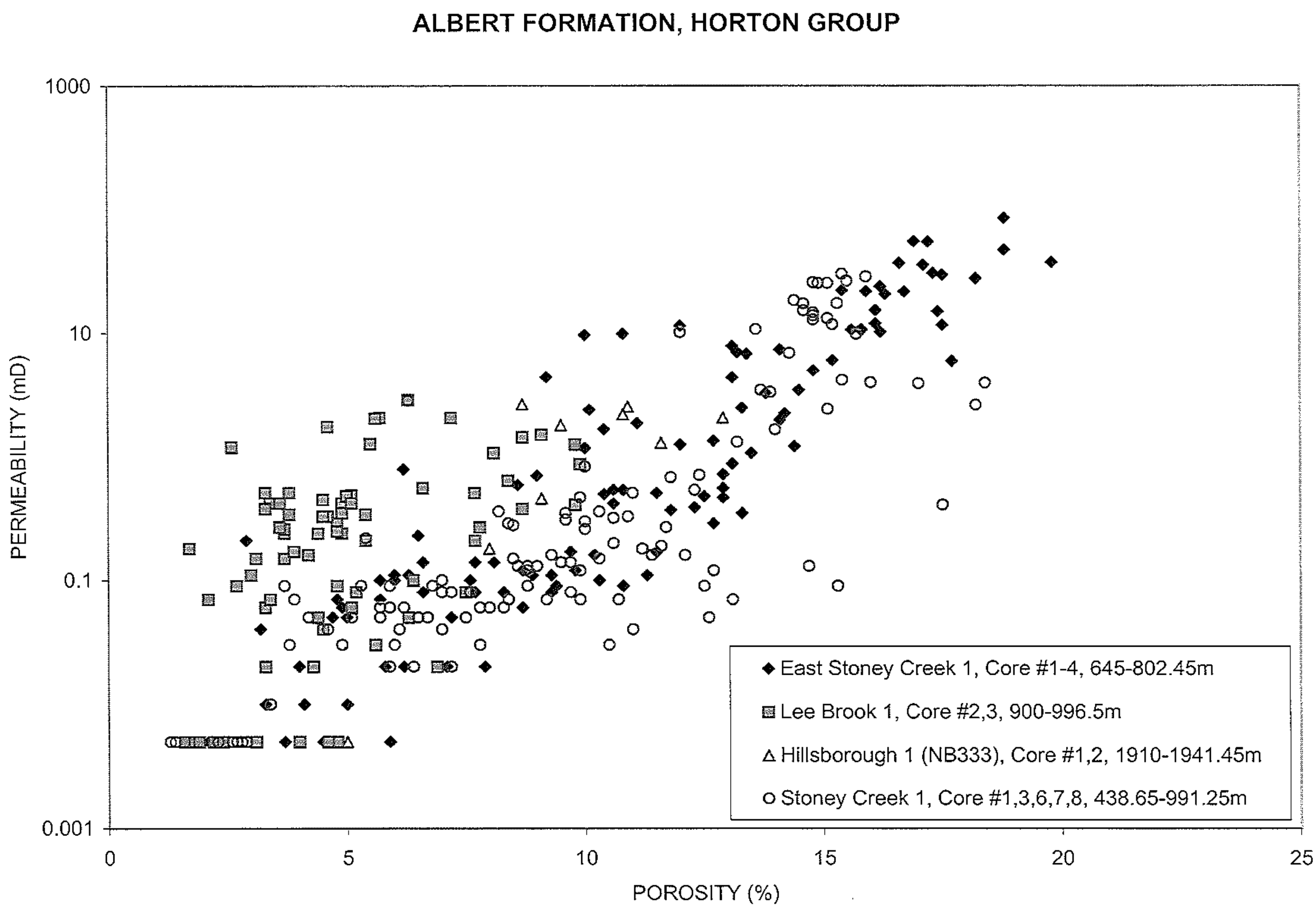

Figure C.3. Core analysis data for the Albert Formation, Horton Group

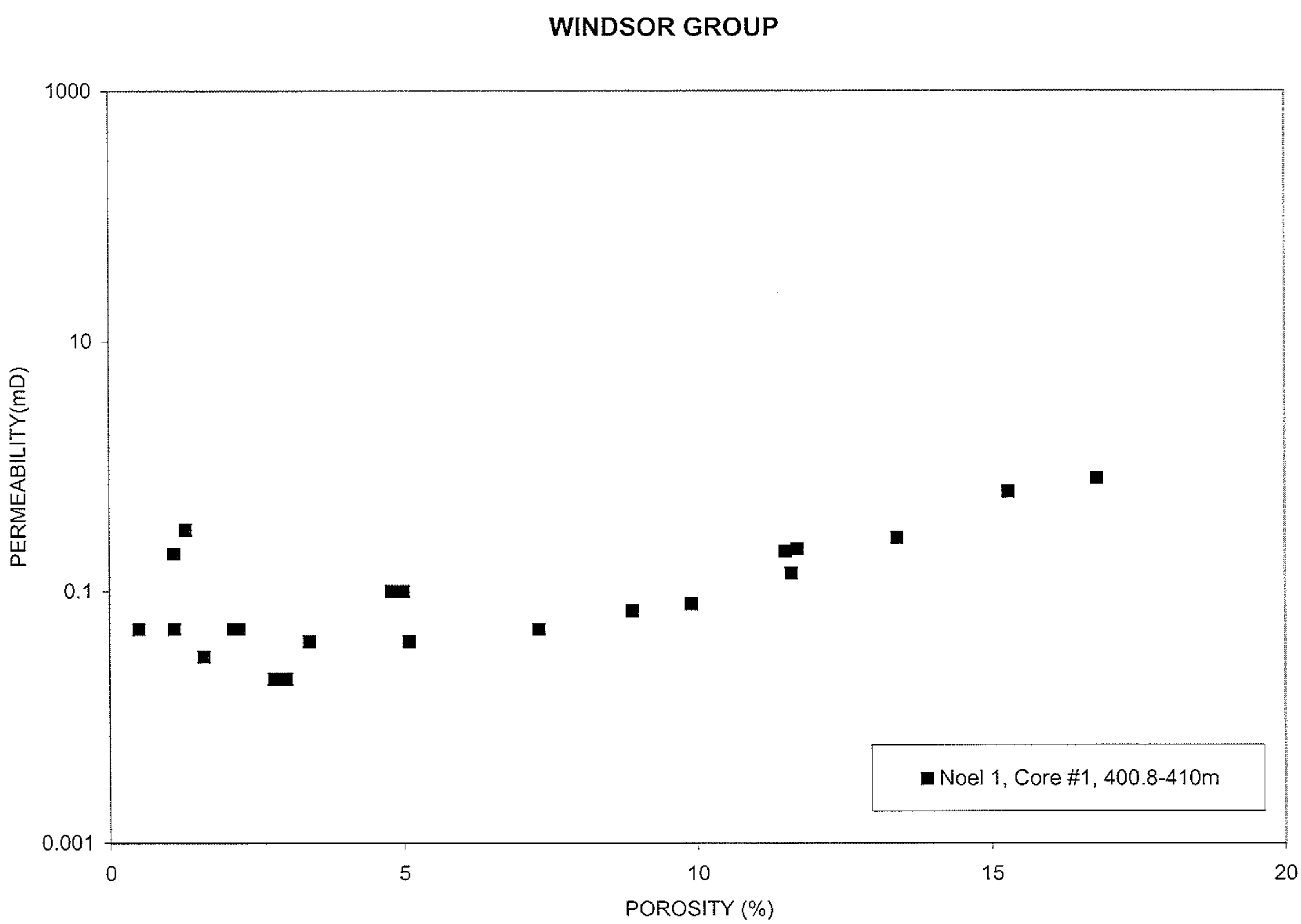

Figure C.4. Core analysis data for the Windsor Group.

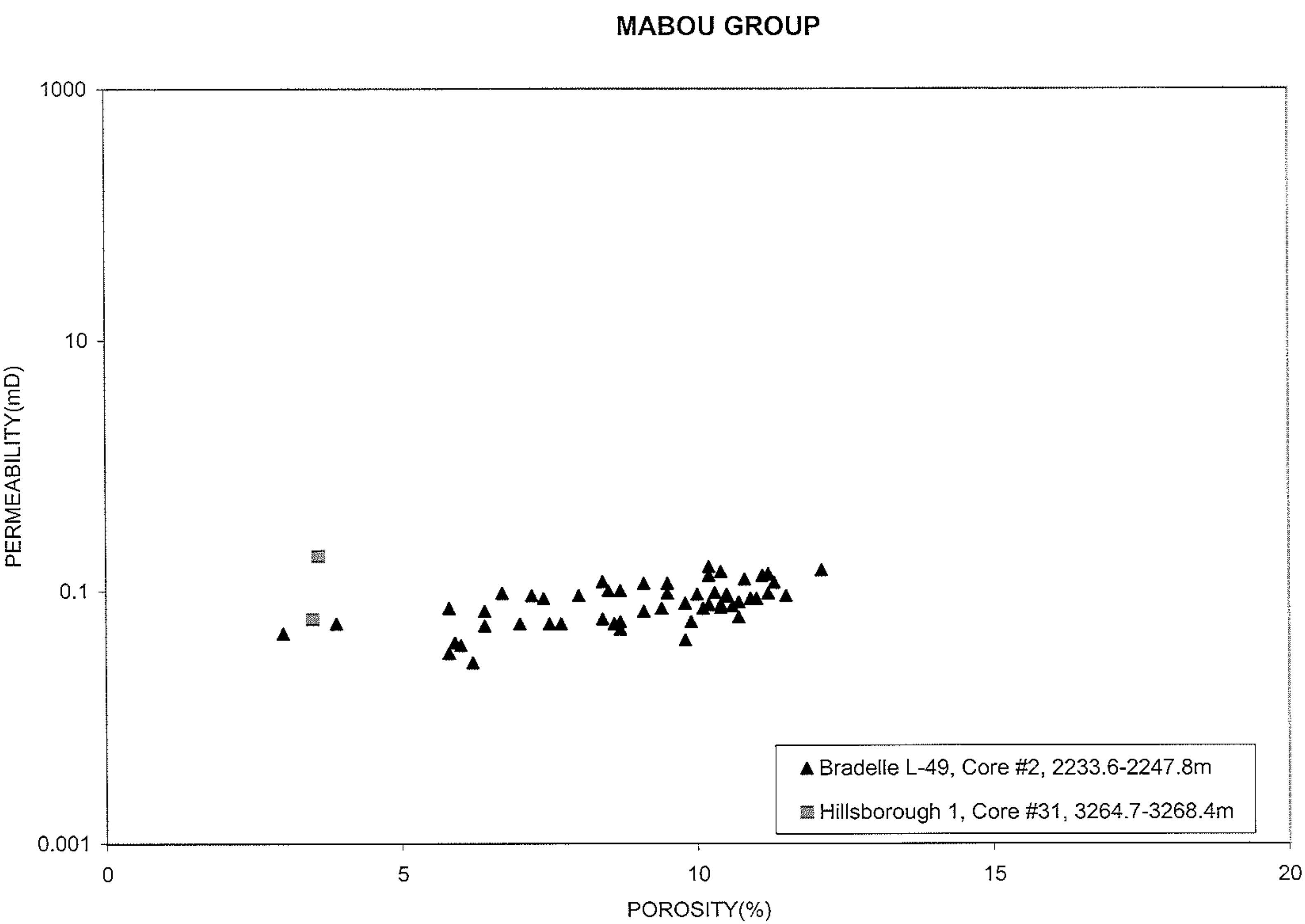

Figure C.5. Core analysis data for the Mabou Group.

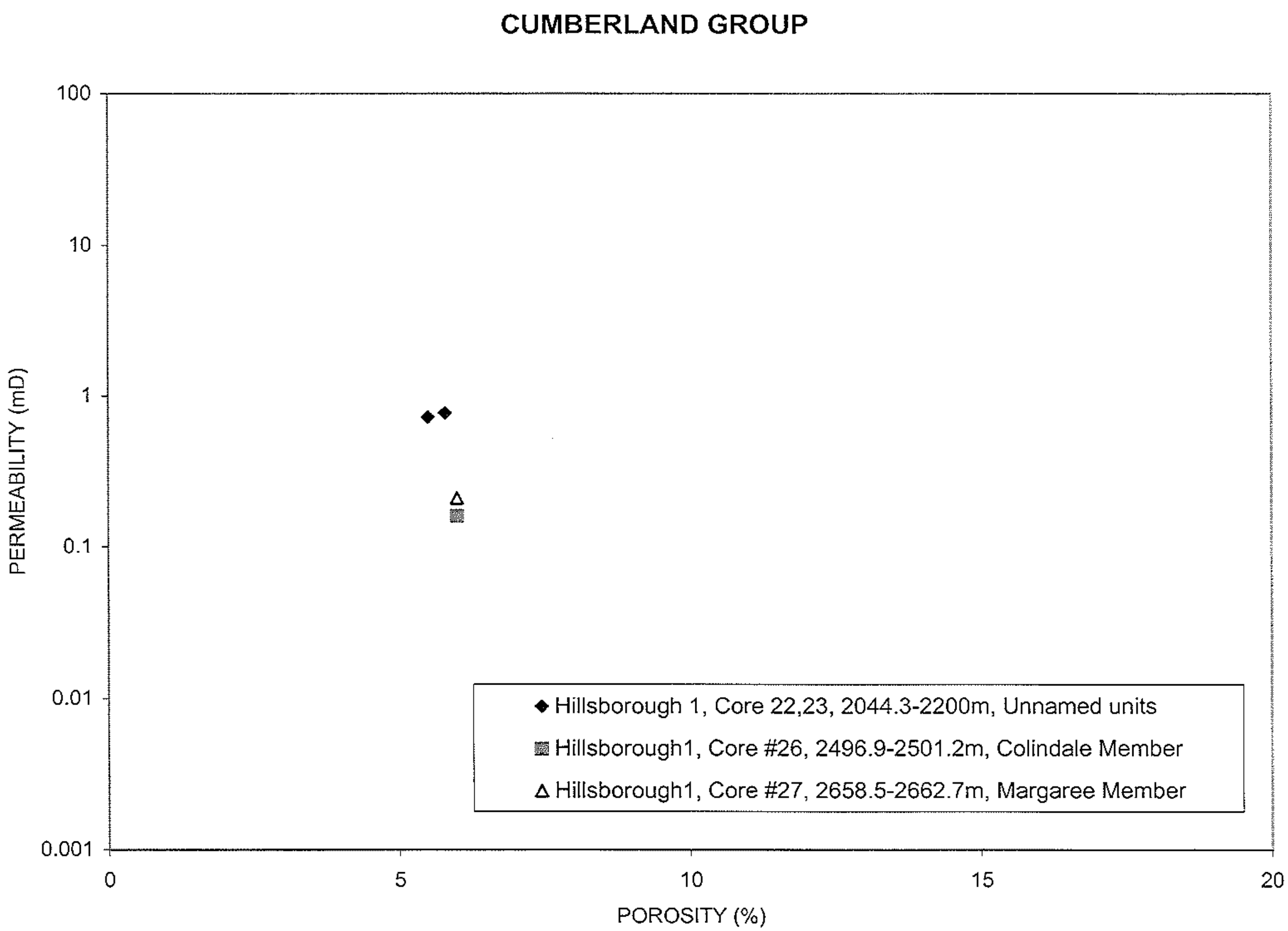

Figure C.6. Core analysis data for the Cumberland Group.

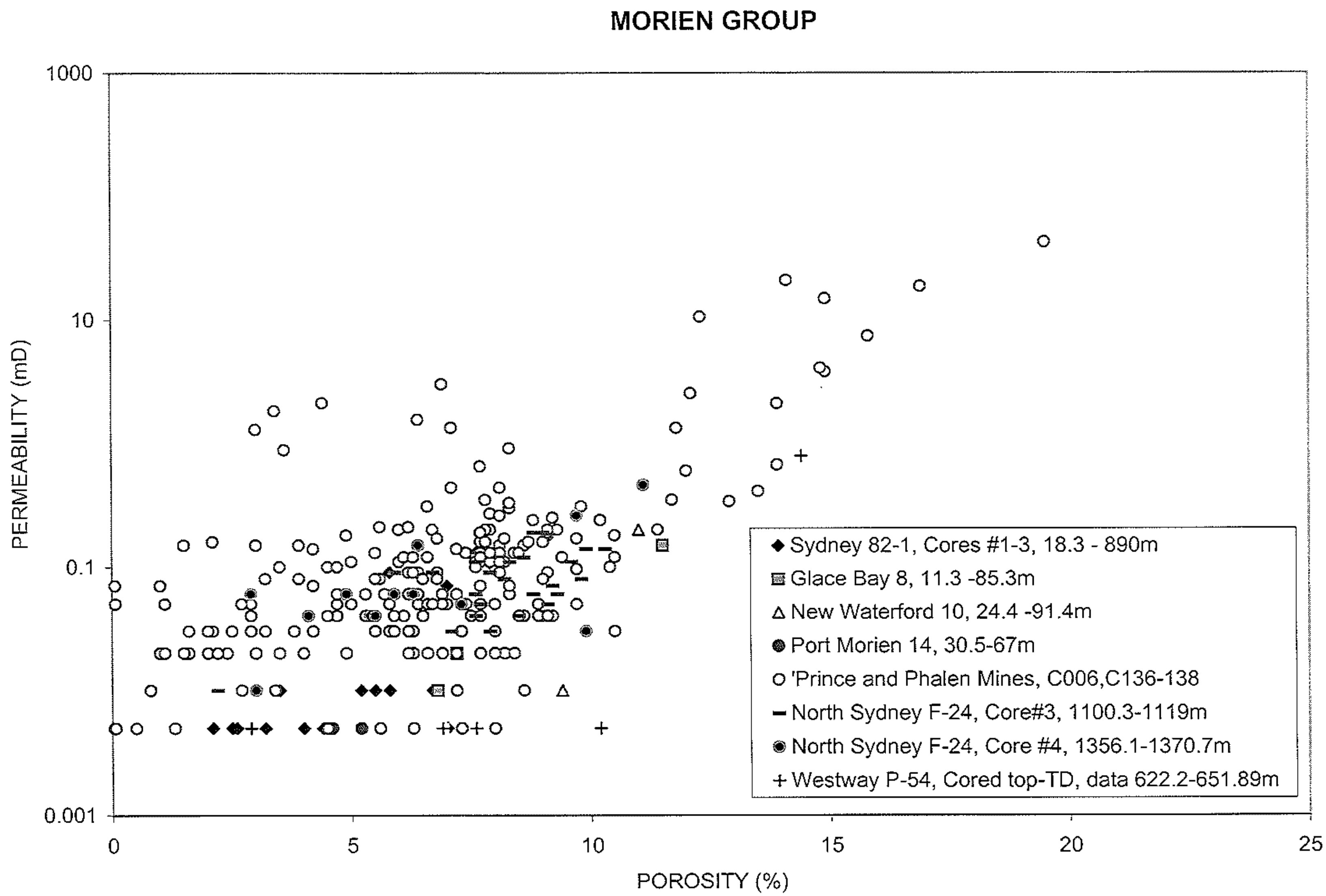

Figure C.7. Core analysis data for the Morien Group.

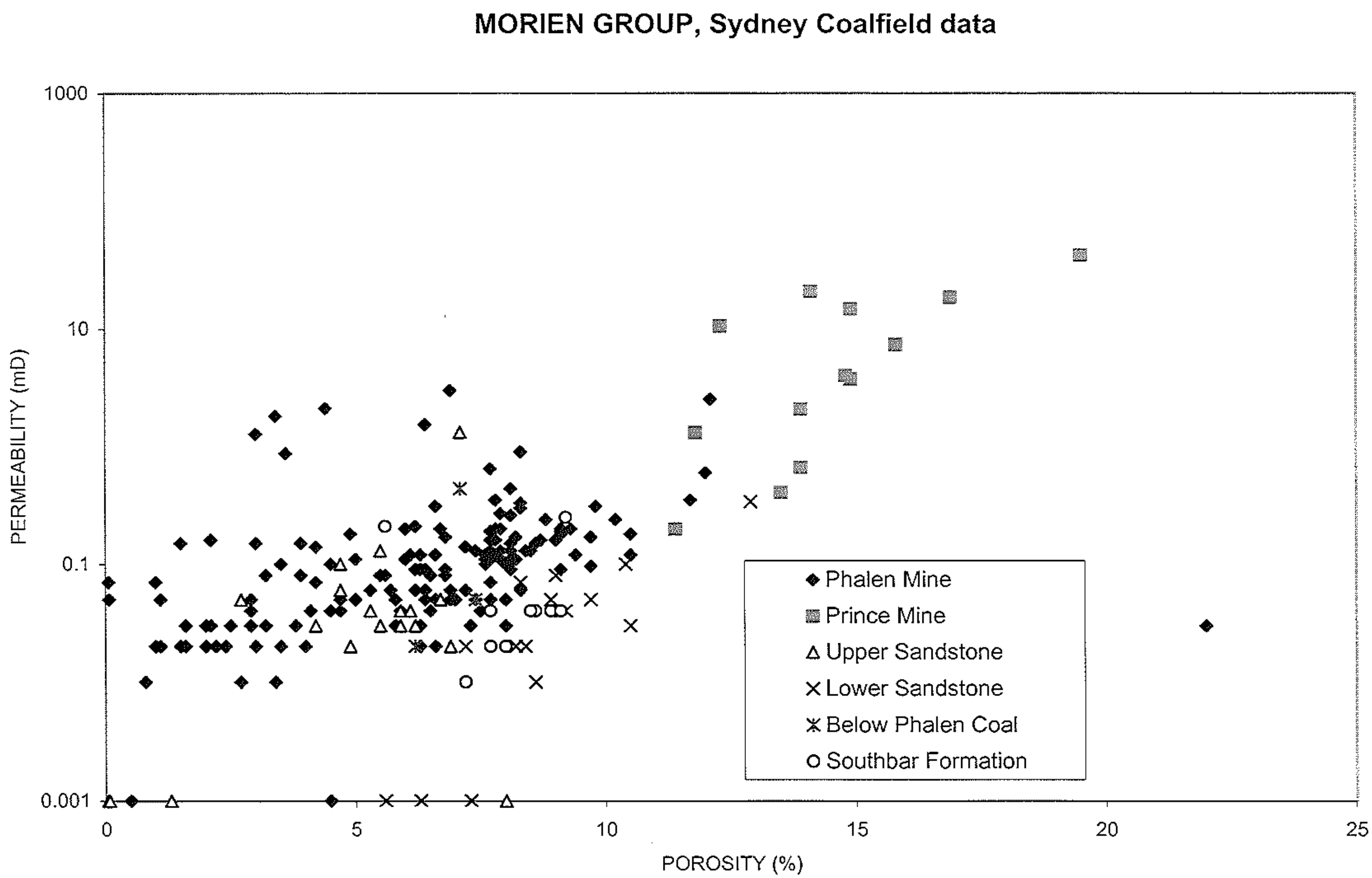

Figure C.8. Data from the Prince and Phalen Mines represent the Sydney Mines Formation, whereas data for the C-Series boreholes are from different stratigraphic levels and were identified according to whether they represent the "Upper Sandstone" (between Backpit- and Harbour Seam levels), the "Lower Sandstone" (between Phalen Backpit Seam levels) or sandstones below the Phalen Seam in the Sydney Mines and South Bar Formations.

SOUTH BAR AND SYDNEY MINES FORMATION, MORIEN GROUP

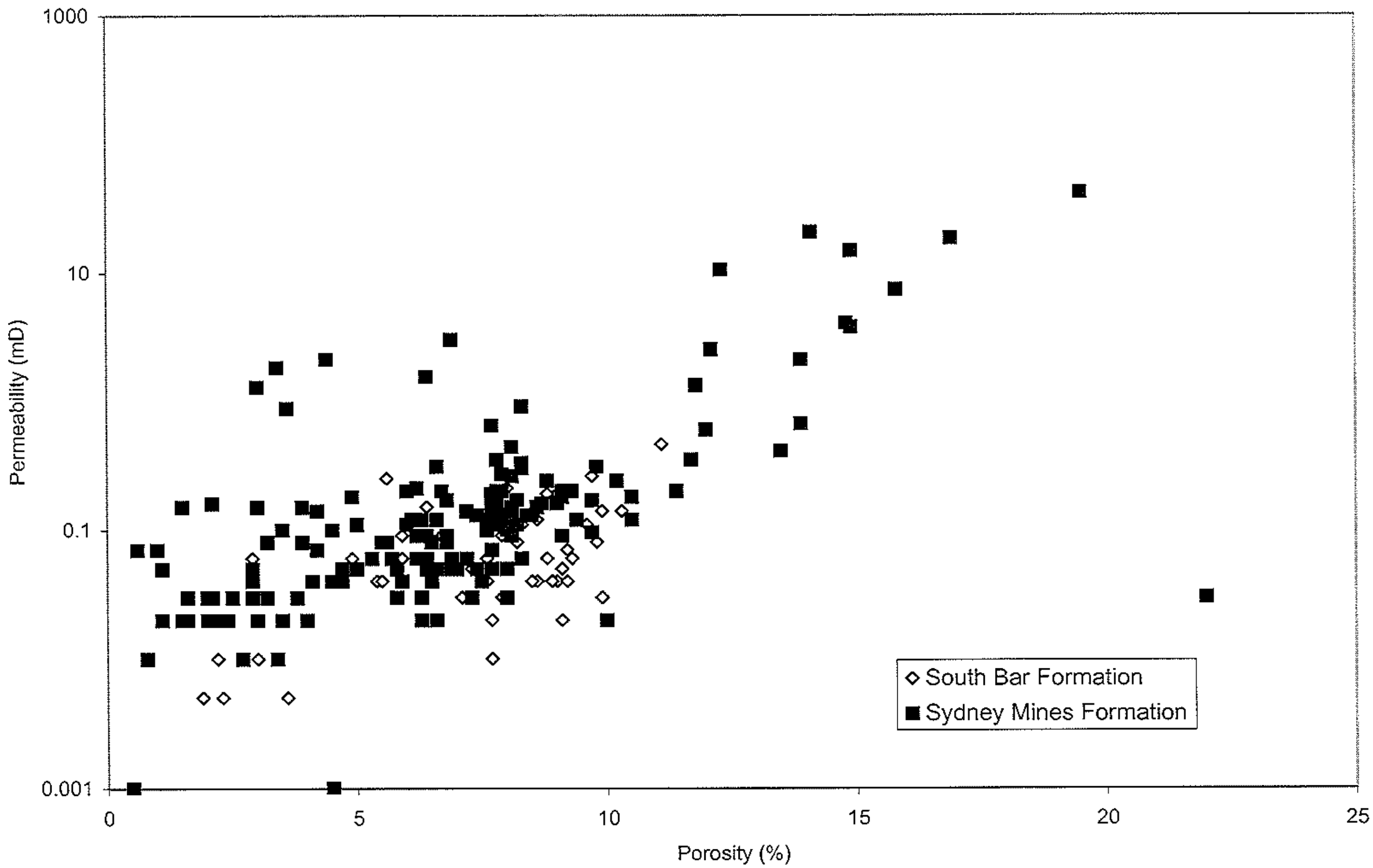

Figure C.9. Porosity and Permeability data for the South Bar Formation (C-Series boreholes, North Sydney F-24) and the Sydney Mines Formation (Prince and Phalen Mines).

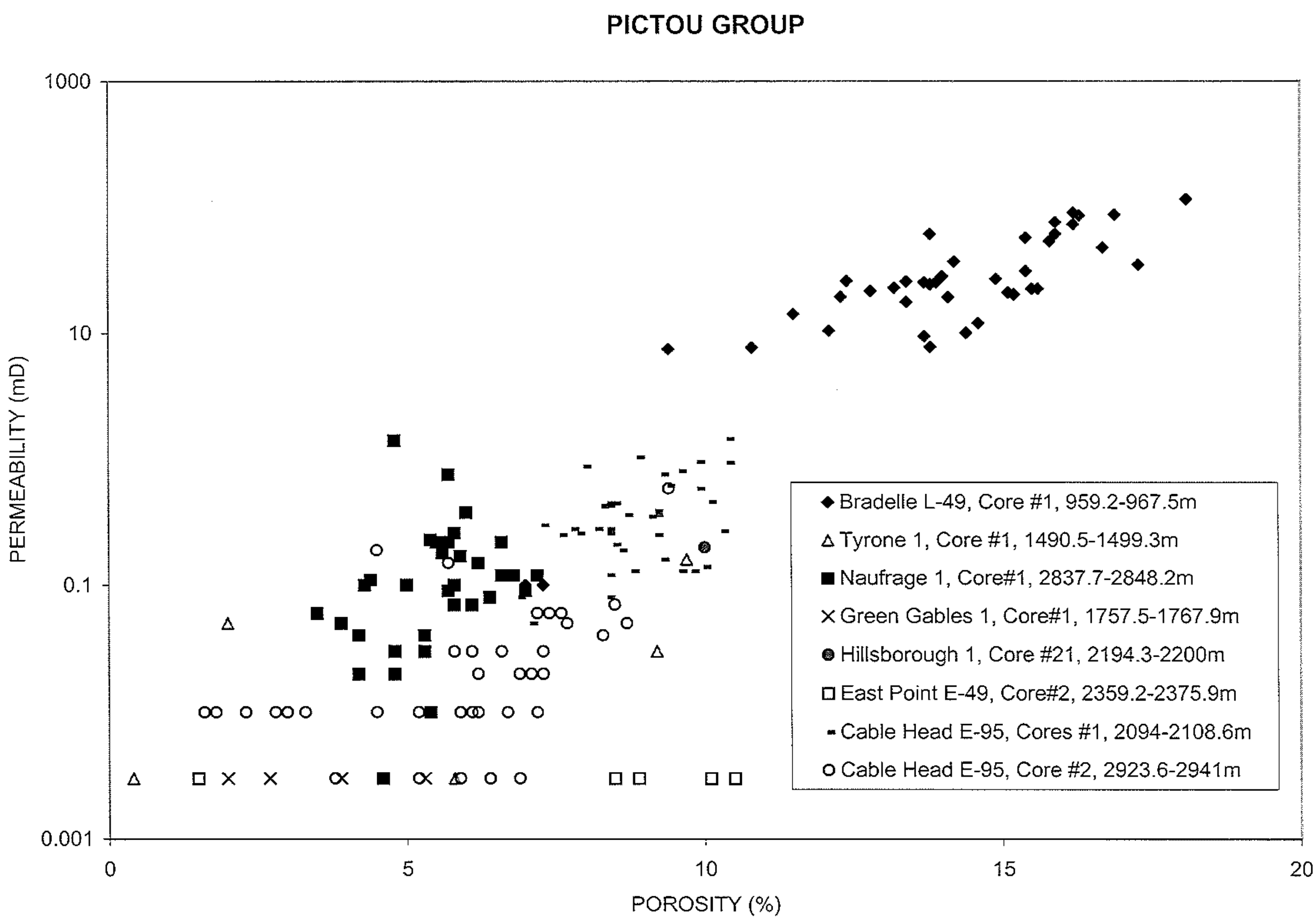

Figure C.10. Core analysis data for the Pictou Group.

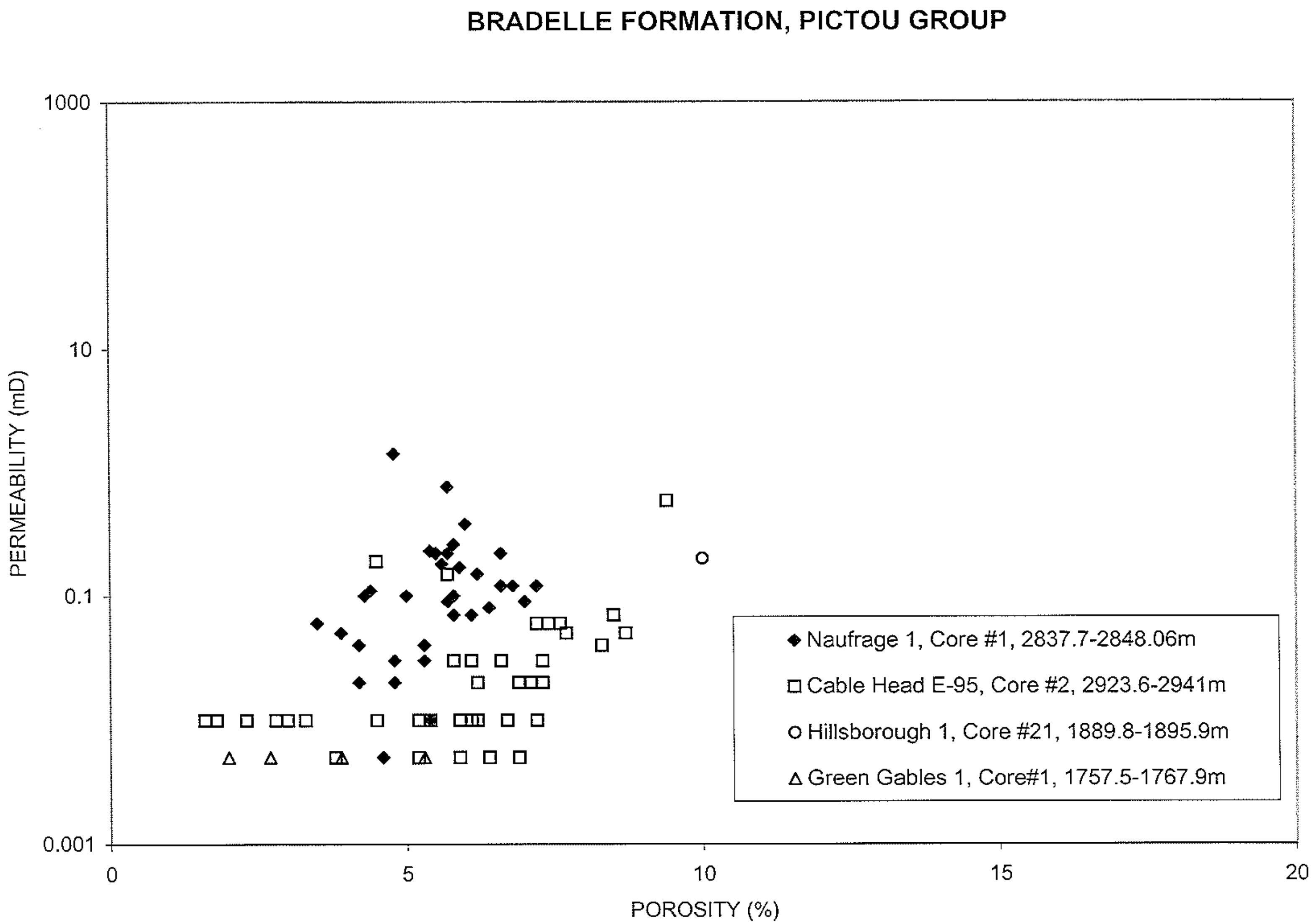

Figure C.11. Core analysis data for the Bradelle Formation, Pictou Group.

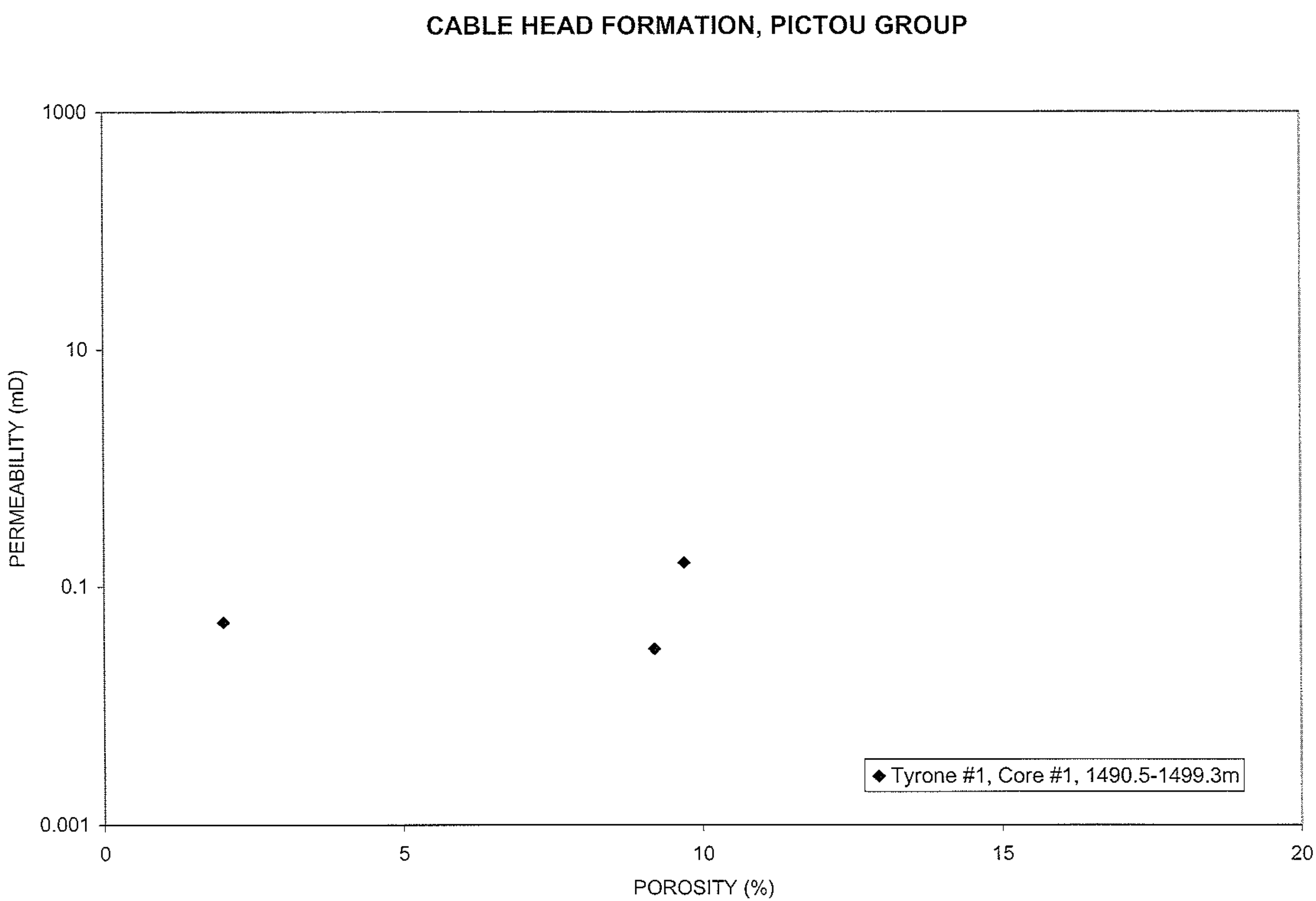

Figure C.12. Core analysis data for the Cable Head Formation, Pictou Group.

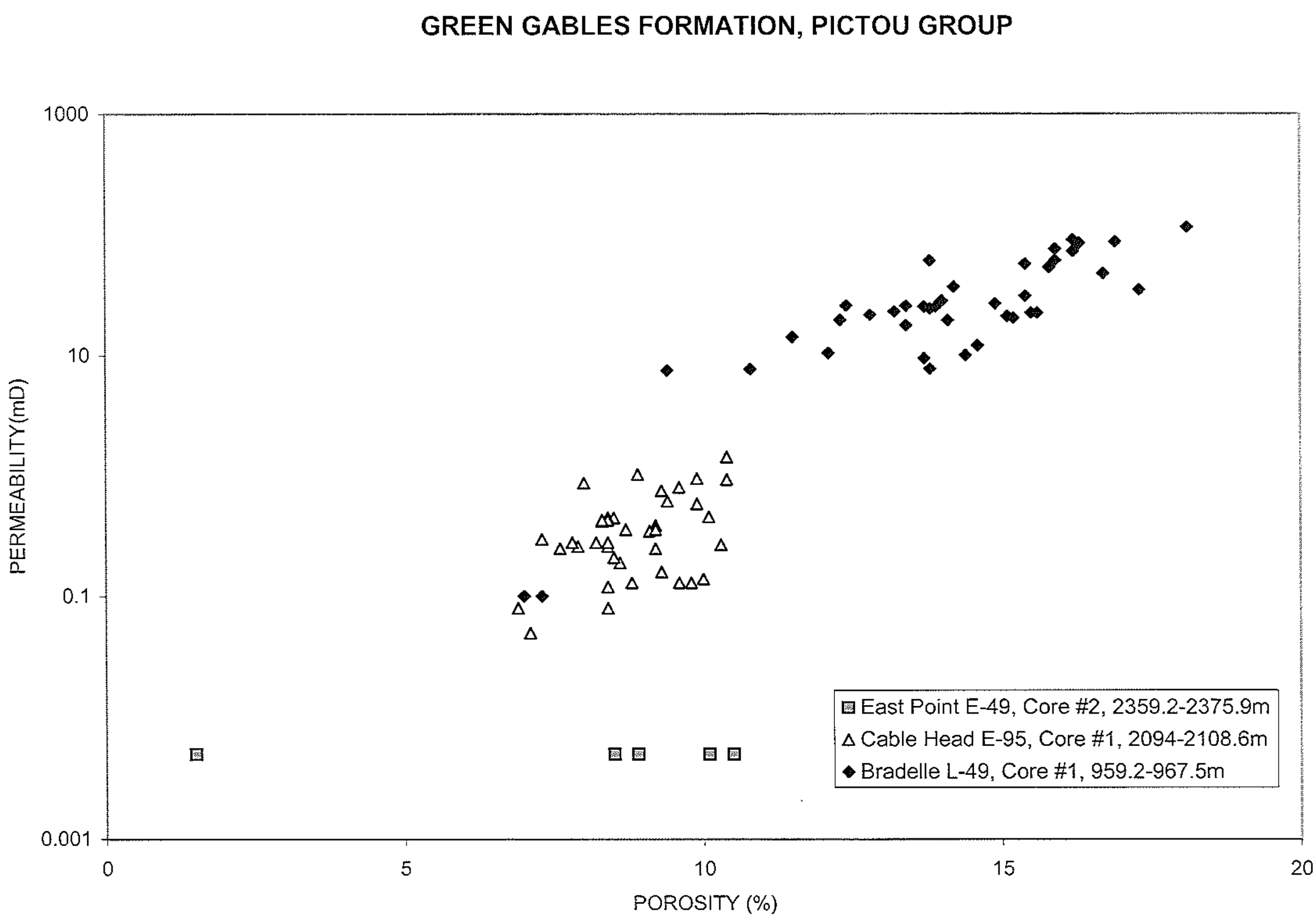

Figure C.13. Core analysis data for the Green Gables Formation, Pictou Group.

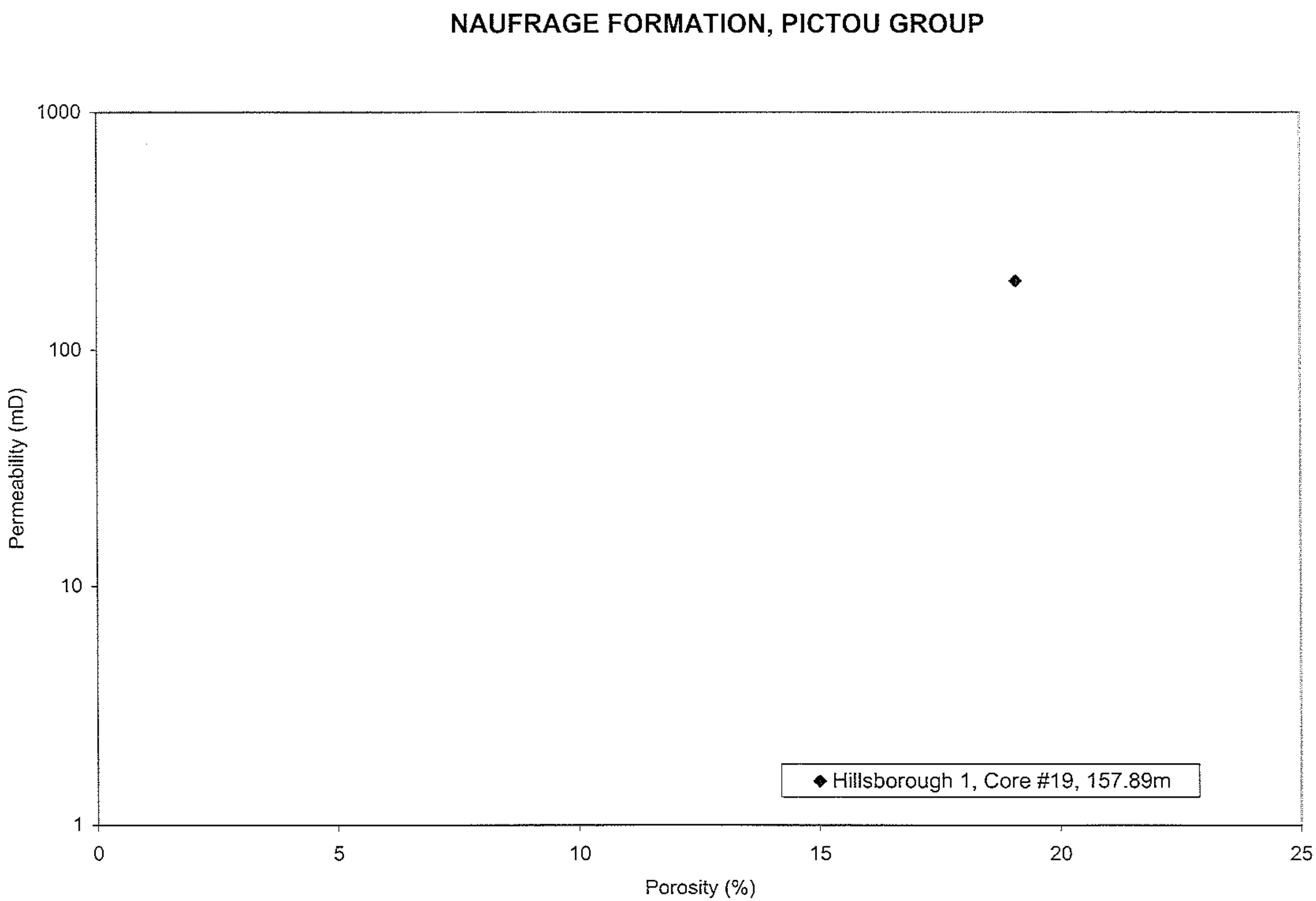

Figure C.14. Core Analysis data for the Naufrage Formation, Pictou Group.

LIST OF TABLES

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Table 4	Summary of the statistical analysis performed on calculated effective porosity data.

GROUP	AREA	DATAPOINTS	STUDY	RANGE	MEDIAN
HORTON	Antigonish	9	Felderhof	8.2 - 24.6p.u. 0.005 - 77mD	19.8p.u. 2.89mD
		4(conglomerate)	Felderhof	4.9-7.9p.u. 0.005-60.5mD	6.9p.u. 9.45mD
	Antigonish	19	Shawnee	0.9 - 20.8p.u. 0.005 - 24.2mD	11p.u. 0.18mD
	Minas	56	Felderhof	1.3 - 18.7p.u. 0.005-94.5mD	9.75p.u. 0.13mD
		9(conglomerate)	Felderhof	5.6-16p.u. 0.13-156mD	11.6p.u. 4.63mD
	Minas	37	Shawnee	0.7 - 19.2p.u. 0.005 - 666mD	11.5p.u. 0.18mD
	Inverness	33	Shawnee	0.7 - 39p.u. 0.005 - 505mD	16.5p.u. 1.41mD
WINDSOR	Minas	29(limestone)	Felderhof	2.1-29.6p.u. 0.005 - 405mD	7.3p.u. 0.005mD
		3	Felderhof	5-13.3p.u. 0.005-0.13mD	5.8p.u. 0.1mD
MABOU	Cumberland	19	Felderhof	3.7-22.7p.u. 0.005-53mD	5.2p.u. 0.005mD
CUMBERLAND	Antigonish	11	Felderhof	8.8-21.2p.u. 1.8-580mD	18.85p.u. 54.7mD
	Cumberland	18	Felderhof	7-22.5p.u. 0.005-193mD	17p.u. 2.67mD
		1(conglomerate)	Felderhof	12.3p.u. 0.45mD	
	Minas	4	Felderhof	8.8-10.8p.u. 0.005-0.32mD	9.9p.u. 0.07mD
PICTOU	Cumberland	4	Felderhof	5.5 - 23.2p.u. 0.2-98.5mD	12.5p.u. 0.9mD
	Minas	16	Felderhof	3.2-16.9p.u. 0.005-21.3mD	10.2p.u. 0.07mD
		2(conglomerate)	Felderhof	8.7-12p.u. 0.26-59.5mD	10.35p.u. 29.88mD
UNNAMED UNIT	Antigonish	2	Felderhof	3.9-9.4p.u. 0.005-0.07mD	6.65p.u. 0.04md
		10(conglomerate)	Felderhof	3.3-5.8p.u. 0.005-13mD	4.4p.u. 0.165mD

Table 1. Statistical summary of the outcrop data in the Maritimes Basin. All samples are sandstone unless otherwise indicated.

Table 2. Summary of the available core analysis data in the Maritimes Basin, the year of the analysis and the formation. More details on cores are in the database.

Well ID	Wellname	Area	Cores Analysed	Year	Group Analysed	Formation Analysed	Data quality
NB328	Berryton 1	New Brunswick	not known	1959	not known	not known	Questionable
D110	Bradelle L-49	Gulf of St Lawrence	#1	1973	Pictou	Green Gables	
			#2	1973	Mabou		
			#3	1973	Horton		
D230	Cable Head E-95	Gulf of St Lawrence	#1	1983	Pictou	Green Gables	
			#2	1983	Pictou	Bradelle	
D014	East Point E-49	Gulf of St Lawrence	#2	197X?	Pictou	Green Gables	
NB332	East Stoney Creek 1	New Brunswick	#1	1985	Horton	Albert	
			#2	1985	Horton	Albert	
			#3	1985	Horton	Albert	
			#4	1985	Horton	Albert	
13620	Glace Bay 8	Cape Breton Island	not known	1984	Morien		
C006	Glace Bay P-6	Cape Breton Island	not known	1979	Morien		
L001	Green Gables 1	Prince Edward Island	#1	1972	Pictou	Bradelle	
NB333	Hillsborough 1	New Brunswick	#1	1985	Horton	Albert	
			#2	1985	Horton	Albert	
L010	Hillsborough 1	Prince Edward Island	#19	1998	Pictou	Naufrage	Data for 1945 questionable
			#20	1945	Pictou	Green Gables	
			#21	1945, 1998	Pictou	Bradelle	
			#22	1945, 1998	Cumberland	Unnamed Red Beds	
			#23	1945, 1998	Cumberland	Unnamed Red Beds	
			#24	1945	Cumberland	Port Hood (Colindale Member)	
			#25	1945	Cumberland	Port Hood (Colindale Member)	
			#26	1945, 1998	Cumberland	Port Hood (Colindale Member)	
			#27	1945, 1998	Cumberland	Port Hood (Margaree Member)	
			#28	1945	Cumberland	Port Hood (Margaree Member)	
			#29	1945	Cumberland	Port Hood (Margaree Member)	
			#30	1945	Cumberland	Port Hood (Margaree Member)	
			#31	1945, 1998	Mabou	Pomquet	
			#32	1945	Mabou	Pomquet	
			#33	1945	Mabou	Pomquet	
			#34	1945	Mabou	Pomquet	
			#35	1945	Mabou	Pomquet	
			#36	1945	Mabou, U Windsor	Pomquet	

Table 2 (continued). Summary of the available core analysis data in the Maritimes Basin, the year of the analysis and the formation. More details on cores are in the database.

Well ID	Wellname	Area	Cores Analysed	Year	Group Analysed	Formation Analysed	Data quality
NB147	Lee Brook 1	New Brunswick	#2	1986	Horton	Albert	
			#3	1986	Horton	Albert	
L014	Mull River 1	Nova Scotia	#1	1988	Horton	Craignish	
D150	Naufrage 1	Prince Edward Island	#1	1975	Pictou	Bradelle	
2468	New Waterford 10	Cape Breton Island	not known	1984	Morien		
D155	Noel 1	Nova Scotia	#1	1975	Windsor (?)		
D163	North Sydney F-24	Gulf of St Lawrence	#3	not known	Morien	Southbar	
			#4	not known	Morien	Southbar	
11600	Port Morien 8	Cape Breton Island	not known	1984	Morien		
NB335	St Joseph 1	New Brunswick	#1	1967	Horton	Albert	Questionable
D235	St Paul P-91	Gulf of St Lawrence	#1	1983	Horton		
NB331	Stoney Creek 1	New Brunswick	#1	1985	Horton	Albert	
			#3	1985	Horton	Albert	
			#6	1985	Horton	Albert	
			#7	1985	Horton	Albert	
			#8	1985	Horton	Albert	
NB307	Stoney Creek 168	New Brunswick	#3	1966	Horton	Albert	Questionable
			#4	1966	Horton	Albert	Questionable
			#5	1966	Horton	Albert	Questionable
			#6	1966	Horton	Albert	Questionable
20826	Sydney 82-1	Cape Breton Island	#1	1984	Morien		
			#2	1984	Morien		
			#3	1984	Morien		
D143	Tyrone 1	Prince Edward Island	#1	1975	Pictou	Cable Head	
785	Wallace Station 1	Nova Scotia	#2	1973	Horton		Questionable
			#3	1973	Horton		Questionable
3922	Westway P-54	Nova Scotia	not known	1983	Morien		
C136-138		Cape Breton Island	not known	1989	Morien		

Table 3. Summary of available reservoir data calculated from geophysical logs.

Well ID	Wellname	Area	Year of calculation	Interval (m)	Group	Data quality
D189	Beaton Point F-70	Gulf of St. Lawrence	1999	351.8-1709.8	Pictou	
D110	Bradelle L-49	Gulf of St. Lawrence	1999	1705.81-2846.37	Pictou, Mabou	
D037	Brion Island 1	Gulf of St. Lawrence	1973	410-2675.6	Pictou, Mabou, Windsor	Questionable
D230	Cable Head E-95	Gulf of St. Lawrence	1999	347.8-3227	Pictou	
D188	East Point E-47	Gulf of St. Lawrence	1999	700-2607	Pictou	
D014	East Point E-49	Gulf of St. Lawrence	1972	353.6-2853	Pictou	Questionable
D115	Emerillon C-56	Grand Banks	1974	3118-3277	Windsor	Questionable
D078	Gannet O-54	Grand Banks	1974	2353-2872.8	Horton	Questionable
L001	Green Gables 1	Prince Edward Island	1974	1228.7-2367.4	Pictou, Cumberland	Questionable
D038	Hermine E-94	Grand Banks	1974	1663.6-2240	Carboniferous Red Beds	Questionable
NB038	MacLeod Brook 1	New Brunswick	1975	117-2058.6	Horton	Questionable
D150	Naufrage 1	Prince Edward Island	1999	762.91-3104.54	Pictou	
D163	North Sydney F-24	Gulf of St. Lawrence	1999	559-1621.54	Unnamed Rock Units, Morien	
D134	North Sydney P-05	Gulf of St. Lawrence	1974	910-2069	Unnamed Rock Units, Morien	
			1999	277.4-1622.45	Unnamed Rock Units, Morien	Questionable
D235	St Paul P-91	Gulf of St. Lawrence	1999	634.6-2855	Mabou, Windsor, Horton	
D143	Tyrone 1	Prince Edward Island	1999	631.85-4169.36	Pictou, Cumberland, Mabou, Windsor	