Post-Drilling Analysis of the North Falkland Basin - Part 2: The Petroleum System and Future Prospects

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Six wells were drilled in the North Falkland Basin in 1998. Five of these wells recorded oil shows, and up to 32% gas was also recorded in mud returns to the rig floor. However, none of the wells encountered commercially viable petroleum accumulations.
The syn-rift and early post-rift intervals contain thick, lacustrine claystones with oil source potential as indicated by TOC values up to 7.5% and rock-eval pyrolysis values of expelled hydrocarbons (S2) of up to 102 Kg of oil per tonne of rock. These source rocks were immature or only marginally mature in five of the wells, but attained maturity in one. Modelling suggests that the main source interval may well be within the peak oil generation window in deeper, undrilled parts of the basin. Calculations of the amount of oil expelled range up to 60 billion barrels.
Most of the wells tested a closely related set of plays in large structures associated with a sandstone interval near the top of the late syn-rift to early post-rift source rock succession. Post-drilling geological modelling of the basin suggests that oil is unlikely to have migrated into this sandstone play at the localities tested, and that the wells consequently failed largely due to a lack of charge. However, the play maintains exploration potential elsewhere. Other plays, particularly those stratigraphically associated with the base rather than the top of the source rock, may have a higher chance of exploration success.

INTRODUCTION

Several attempts were made before drilling to predict the nature of the North Falkland Basin's infill and its petroleum potential (Richards et al., 1996 a and b; Richards and Fannin, 1997; Thomson and Underhill, 1999; Bransden et al., 1999; Lawrence et al., 1999). Part 1 of this paper summaries the new tectono-stratigraphic model developed for the basin using all existing well and seismic data from the region. Here, Part 2 summarises the petroleum-related results of the six exploration wells drilled in the North Falkland Basin in the period April to November, 1998.

The oldest Mesozoic sediments in the North Falkland Basin are Jurassic to Valanginian, early and late syn-rift successions of predominantly fluvio-lacustrine origin. The succeeding, post-rift, thermal sag phase of the basin's evolution can be separated into five phases: a transitional unit characterised by lacustrine sedimentation; an early post-rift unit also characterised by lacustrine sedimentation, but with evidence of deltaic deposition from the north, west and east margins of the basin; a middle post-rift phase characterised by the re-establishment of fluvial conditions; a late post-rift phase characterised by a transition from marginal-marine/fluvial up to more open-marine conditions; and a post-uplift sag phase recording open-marine conditions.

This study presents a summary of the results of the principal investigations into the nature of the petroleum system of the North Falkland Basin. A detailed break-down of the proprietary analyses conducted for each well is beyond the scope of this paper, and accordingly, only a summary of the salient features of the petroleum system are recorded here.

MATERIALS AND METHODS

Geochemical analyses were conducted by each operating company (using several different laboratories), in order to determine the nature and maturity of the source rocks. Measurements were made of TOC (carbon content), and of RO value (vitrinite reflectance) as an indicator of maturity. Rock-Eval pyrolysis studies were conducted on samples from every well, in order to determine the presence of free-hydrocarbons (S1), the hydrocarbon-generating potential of the rock (S2), the amount of carbon dioxide evolved during pyrolysis (S3), the maximum rate of S2 hydrocarbon evolution (Tmax), the Hydrogen Index (HI), the Oxygen Index (OI), and the Production Index (PI). Oils recovered at surface while drilling, as well as samples centrifugally-spun from cores were also analysed in order to compare their isotope geochemistry with the analysed source rocks. Basin subsidence modelling was also conducted independently by each company and by the authors, using a variety of heat-flow models. Porosity and permeability measurements and petrological determinations from conventional and side-wall cores were integrated with petrophysical log readings in order to calculate water saturations (Sw), log porosities, etc.

SOURCE ROCKS IN THE NORTH FALKLAND BASIN

Extensive analyses have been conducted on all claystones in all six wells. A complete review and listing of all the geochemical data available is beyond the scope of this paper, but a summary of the Total Organic Carbon (TOC), oil-yield potential (Rock-Eval S2) and vitrinite reflectance (VR) values recorded in the six wells is presented graphically in Figs. 1, 2 and 3. A summary of the ranges of key source rock data from all six wells is also presented in Table 1. Although source rock data were collected and analysed from all wells in the basin, the source rock evaluation is probably most effectively illustrated by preferentially considering the nature of the claystone-rich intervals in Wells 14/5-1A and 14/10-1, which were drilled in a basinal setting within the Eastern Depocentre (see Figs. 1 and 2 in Part 1). The nature of the source rocks in the syn-rift to early post-rift intervals is discussed below.

Source rocks in the early syn-rift sequence (?mid Jurassic to ?Tithonian)

Average TOC values for this unit in Well 14/5-1A were 0.76%, but they range up to 1.6%. Although there are lacustrine elements to this succession, it contains more fluviatile sediments than the overlying, claystone dominated units, and the depositional setting may have been relatively unfavourable for source rock preservation. However, post-mature, Type II source rocks are present below 4,150m in Shell well 14/5-1A. Vitrinite reflectance studies suggest that the transition from wet gas/condensate to dry gas occurs at around 3,762m in Well 14/5-1A, while significant high levels of gas (up to 32%) are recorded from this unit below 4,000 m.

	Early Syn-Rift	**Late Syn-Rift**	**Early Post-Rift and Trans. Unit**
Kerogen type	II	II	I
TOC (%)	0.2-1.6	0.3 - 6	0.1 - 8.7
S1 (kg HC/tonne rock)	0.06 - 6.1	0.6 - 8.3	0.8 - 11.1
S2 (kg HC/tonne rock)	0.06 - 32	0.4 - 77	7.7 - 102.6
S3 (kg HC/tonne rock)	0.3 - 4	0.1 - 3.2	0.08 - 4.8
HI (S2x100/TOC)	12 - 390	235 - 719	650 - 1,095
OI (S3x100/TOC)	25 - 680	9 - 286	11 - 160
PI (S1/S1+S2)	0.04 - 0.62	0.01 - 0.65	0.04 - 0.49
T max (deg C)	320 - 516	368 - 450	62 - 451
Thickness (m)	> 1,000	up to 930	up to 600

Table 1. Ranges of source rock values (based partly on Rock-Eval pyrolysis) in all six wells.

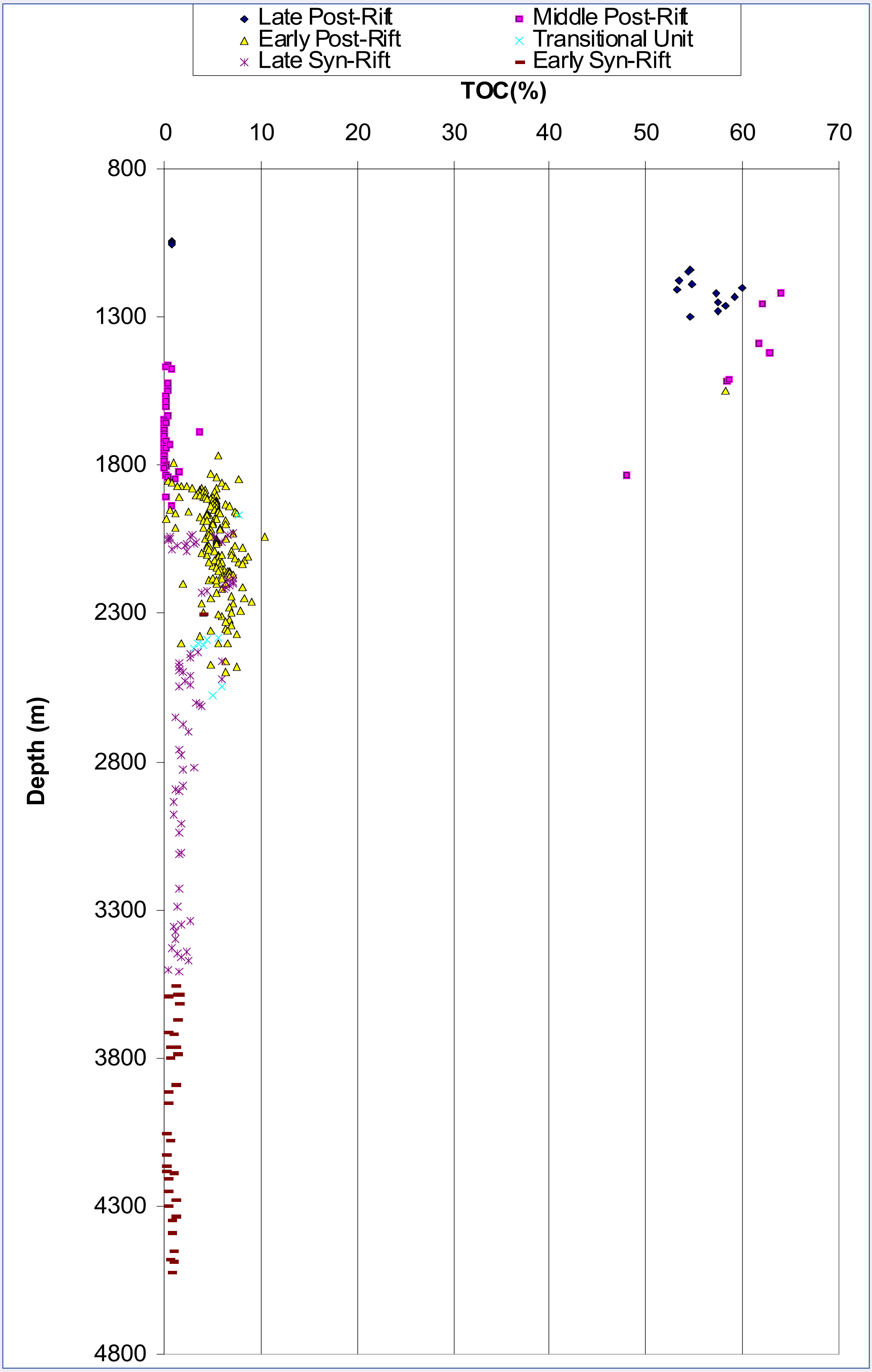

Fig. 1. Plot of TOC content (%) against depth (metres below KB) for all six wells.

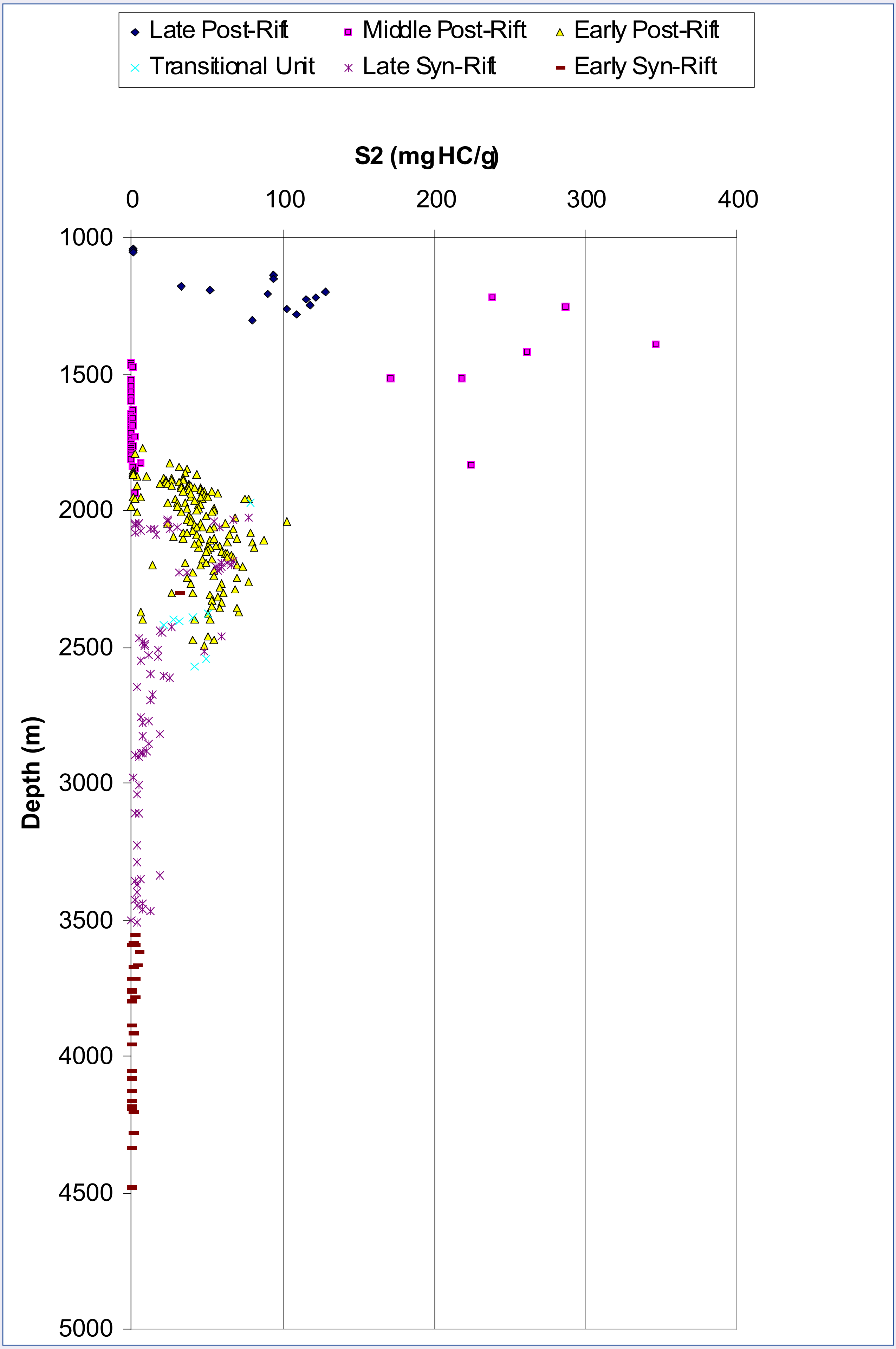

Fig. 2. Plot of S2 values (oil yield in kg HC per tonne of rock) against depth (metres below KB) for all six wells.

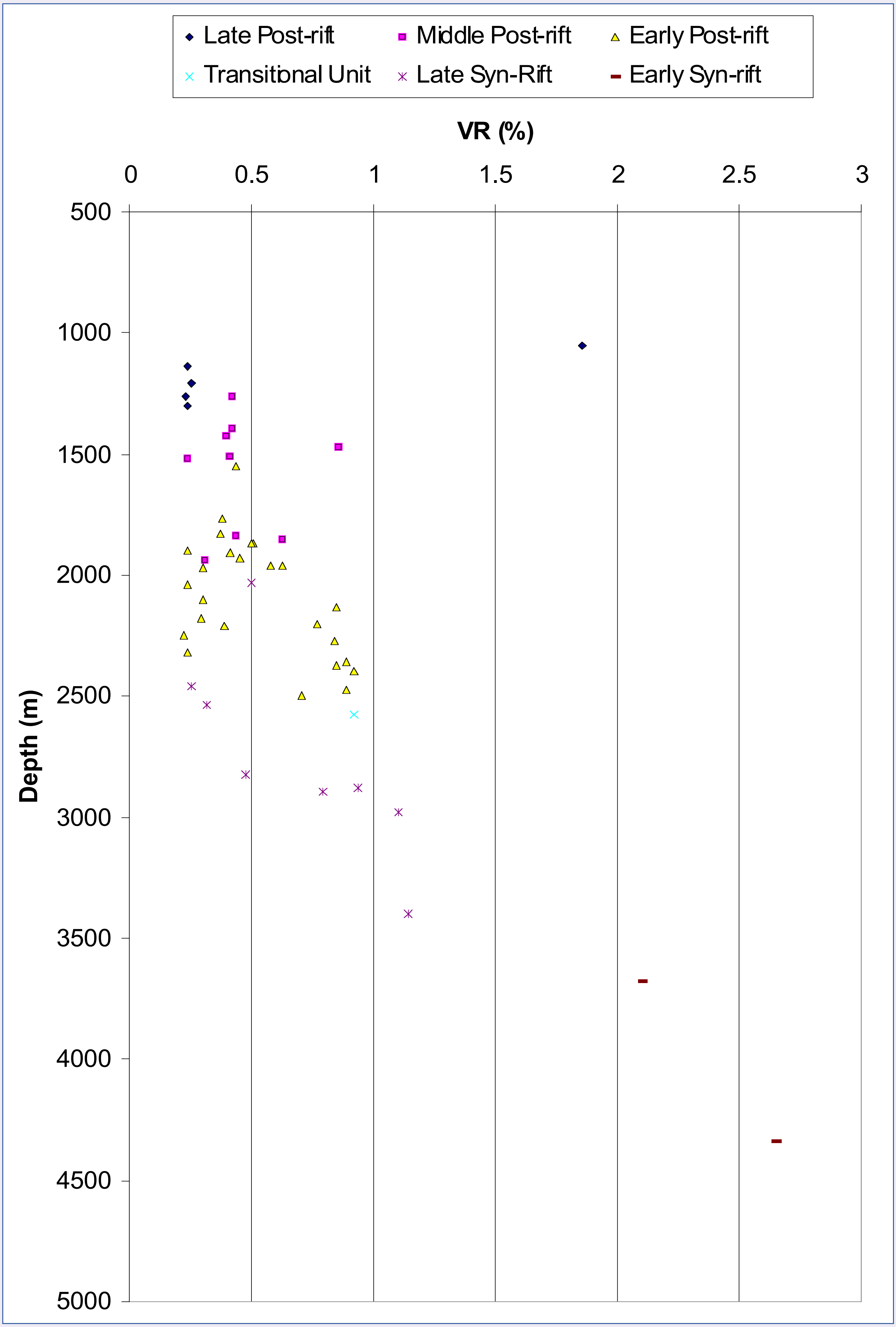

Fig. 3. Plot of VR values (%) against depth (metres below KB) for all six wells.

Outcrops of Upper Permian source rocks in the Southern Junggar Basin:
average source values (data from Carroll et al., 1992)

Thickness	=	800m
Av TOC	=	4.1%
Av S2	=	26.2 kg HC/tonne of rock

North Falkland Basin average source rock values
(for the late syn-rift to early post-rift units combined)

Thickness	=	Approx 1,150m
Av TOC	=	4.5%
Av S2	=	42 kg HC/tonne of rock

Table 2. Comparison of source rock characteristics for the North Falkland Basin and the Jungarr Basin of China.

Source rocks in the late syn-rift sequence (Tithonian to Berriasian)

In Wells 14/5-1A and 14/10-1, the late syn-rift sequence is characterised by marginal, highly mature, predominantly Type II source rocks. The unit has average TOC values of 1.6%, although values range up to 7.5% in one of the other wells. Average values for the oil-yield (Rock-Eval S2) in well 14/5-1A are 5.6 kg HC/tonne, but with values as high as 77 kg HC/tonne recorded from one sample (Table 1). Vitrinite reflectance values of 0.9% have been measured for the claystones at 3,000m below KB in Well 14/10-1, and such values would place the claystone-dominated sediments comprising the sequence penetrated at the very base of this well within the zone of peak oil generation.

Basin	Age of source rock	Kerogen type	Av SPI value
Junggar	Late Permian	I	65
North Falkland	All source interval	I/II	62.5
North Falkland	Early post-rift only	I	49.2
Lower Congo	Early Cretaceous	I	46
Santa Barbara	Miocene	II	39
San Joaquin	Miocene	II	38
Central Sumatra	Eoc-Oligocene	I	34
E Venezuela	M-Late Cretaceous	II	27
North Falkland	L. syn-rift & Trans Unit only	I/II	21.5
Mid Magdalena	M-Late Cretaceous	II	16
North Sea	Late Jurassic	II	15

Table 3. Comparative SPI values for source rocks worldwide, illustrating the extraordinary richness of the north falkland basin source. Data from other basins from Demaison and Huizinga (1991)

Source rocks in the syn to post-rift transition (Berriasian to Valanginian) and the early post-rift sequence (Valanginian to early Aptian)

These claystone-dominated units are here treated together because they form the main lacustrine source rock interval of the North Falkland Basin. The TOC content of the claystones generally increases downwards through this interval. TOC values reach 7.5% near the base of the units in Well 14/5-1A. The downwards increase in TOC values throughout this interval corresponds to a downwards decrease in sonic log velocity values recorded in all wells (see Fig. 2 in Part 1). The downwards increase in TOC values is mirrored by a general downwards increase in potential oil-yield (Rock-Eval S2) values, from 3 kg HC/tonne at the top, to over 69 kg HC/tonne in places in Well 14/10-1. However, S2 values of over 100 kg HC/tonne have been recorded from one sample in well 14/24-1 (Table 1).

The organic matter in this claystone dominated interval is predominantly Type I kerogens, comprised mainly of alginite or lamalginite. Minor amounts of organic matter derived from terrestrial plants are also present. The algae are composed primarily of small unicellular types, with some larger Botryococcus, and indicate deposition in a lacustrine environment. Bottom conditions in the lake were probably oxygenated during the latter stages of deposition of the early-post rift interval, when the late stages of deposition of the major, southwards prograding Early Cretaceous axial delta (see Part 1) possibly contributed to the frequent overturning of the water column. However, the sudden downwards increase in well preserved algal matter below the foresets of the younger portion of delta (that is, below about 2,050m in Well 14/5-1A) indicates a downward change to more restricted, anaerobic conditions. The transitional unit at the base of the claystone interval was probably deposited under slightly more oxygenated conditions than the overlying unit (see Part 1).

Comparisons with source rocks in other basins

The greyish brown lacustrine source rocks developed within the late syn-rift to early post-rift sections are lithologically similar to the Upper Permian lacustrine source rocks of the southern Junggar Basin of NW China. Carroll et al. (1992) described these rocks as ranking amongst the richest petroleum source rocks in the world, with TOC values up to 34% and Rock-Eval pyrolysis yields (S2) of up to 200 kg HC/ tonne of rock. Whilst these maximum values are significantly higher than those recorded in the North Falkland Basin, the average values for both source rock intervals are much closer (Table 2).

Source Potential Index (SPI) values (Demaison and Huizinga, 1991) can be calculated for any potential source rock using the calculation:

$$SPI = h(S1 + S2)r/1000$$

where:

h = thickness of source rock interval
S1 = average value of Rock-Eval S1 (the presence of free hydrocarbons in the rock)
S2 = average value of Rock-Eval S2
(the amount of hydrocarbons formed by breakdown of the kerogen)
r = density of the source rock

Calculations of SPI for the North Falkland Basin lacustrine sequences vary according to the units studied. The average SPI for the entire source rock interval, spanning the syn-rift through early post-rift successions is 62.5 (based on a conservative estimate of total source rock thickness of 2,205 m, an average S1 value of 2.14, an average S2 value of 10.19 and a density of 2.3), making it the second richest source rock known in the world. The SPI value for the Valanginian to early Aptian, early post-rift unit only (the interval with the highest TOC values) is calculated at 49.2 (based on a conservative thickness of 485 m, an average S1 value of 3.7, an average S2 value of 40.4 and a density of 2.3). The SPI for the late syn-rift (Tithonian to Berriasian) and the rift to post-rift transitional unit (Berriasian to Valanginian) is 21.5 (based on a conservative thickness estimate of 820 m, an average S1 value of 4.56, an average S2 value of 6.83 and a density of 2.3): this interval does not contain as much organic carbon as the younger sequences. The stratigraphically lower units are probably within the main oil generation window, and they are therefore probably the units that are best suited to comparison with oil producing basins of the world. Based on SPI values, the late syn-rift and transitional units constitute the seventh best source rock (excluding the younger, less mature units in the North Falkland Basin) so far discovered anywhere (Table 3).

The early post-rift and Transitional Unit claystones that form the primary source rock interval of the North Falkland Basin are located in a tectono-stratigraphic setting similar to the Aptian ?marine early sag succession within the Colorado Basin, offshore from Buenos Aires Province in Argentina (see Bushnell et al., 1997). They described the undrilled unit in the Colorado Basin as potentially the most promising source rock succession in the basin. Like the early post-rift source rock of the North Falkland Basin, it is characterised on seismic sections by a package of high amplitude reflectors (see Part 1 of this paper). However, the Colorado Basin example is developed presently at greater than 5,000 m below sea level, and is therefore below the oil generation window (Bushnell et al., 1997).

The main source rock in the nearby Malvinas Basin is the Barremian to Aptian, Lower Inoceramus Formation, described by Galeazzi (1998) as a regressive wedge deposited in an anoxix-marine setting. This source rock contains type II and III kerogens, and is more comparable to the Cretaceous anoxic-marine claystones described by Jacquin and Graciansky (1988) from the DSDP drill sites on the Maurice Ewing Bank to the East of the Falkland Islands, than to the lacustrine source rocks of the North Falkland Basin.

Timing of oil generation

Modelling the timing of oil generation is imprecise, as it is difficult to define exactly when the peak heat-flow was reached in the basin: it may have been either from about 150 to 125 ma (during Jurassic to Valanginian rifting), or around 90 ma (during the post-rift phase), when the crustal temperature in the region may have increased due to opening of the South Atlantic. A regional unconformity has been recognised in the Turonian at about 90 ma (see Part 1). The unconformity presumably represents a phase of regional uplift and crustal thinning, and could therefore be associated with increased heat-flow at that time.

A number of basin subsidence models with varying heat-flows have been calculated for the basin, but a model based on a peak heat-flow of around 80 mW/m2 at 90 ma (Fig. 4) closely matches the observed VR, temperature and geochemical data, and indicates that oil generation took place from the early post-rift source rock during the late Cretaceous, between 70 and 100 ma (Fig. 5). This model suggests that at a depth of around 3,000m below sea level, over 50% of the organic material will have been converted to oil. Subsidence modelling based on an earlier heat-flow peak (around 125ma) produces peak oil generation around present day, but suggests that there would be only about 2% conversion of organic matter, which is not consistent with the maturation analyses carried out on the source rocks themselves. A third subsidence model, with a heat-flow peak at around 112 ma, but with an estimated depth to source rock interval at 3,400m below sea level (which it may be in deeper, undrilled parts of the basin), predicts about 35% organic matter conversion to oil, but with maximum expulsion in the Aptian.

Subsidence modelling of the (relatively lean) deeper potential source rocks of mid Jurassic to Berriasian age within the early and late syn-rift successions suggests that they are currently post-mature, but have possibly been a (marginal) source, mostly for gas. They probably reached peak generation in the early Cretaceous, with most of the hydrocarbons expelled by about 90 ma (in the Cenomanian to Turonian).

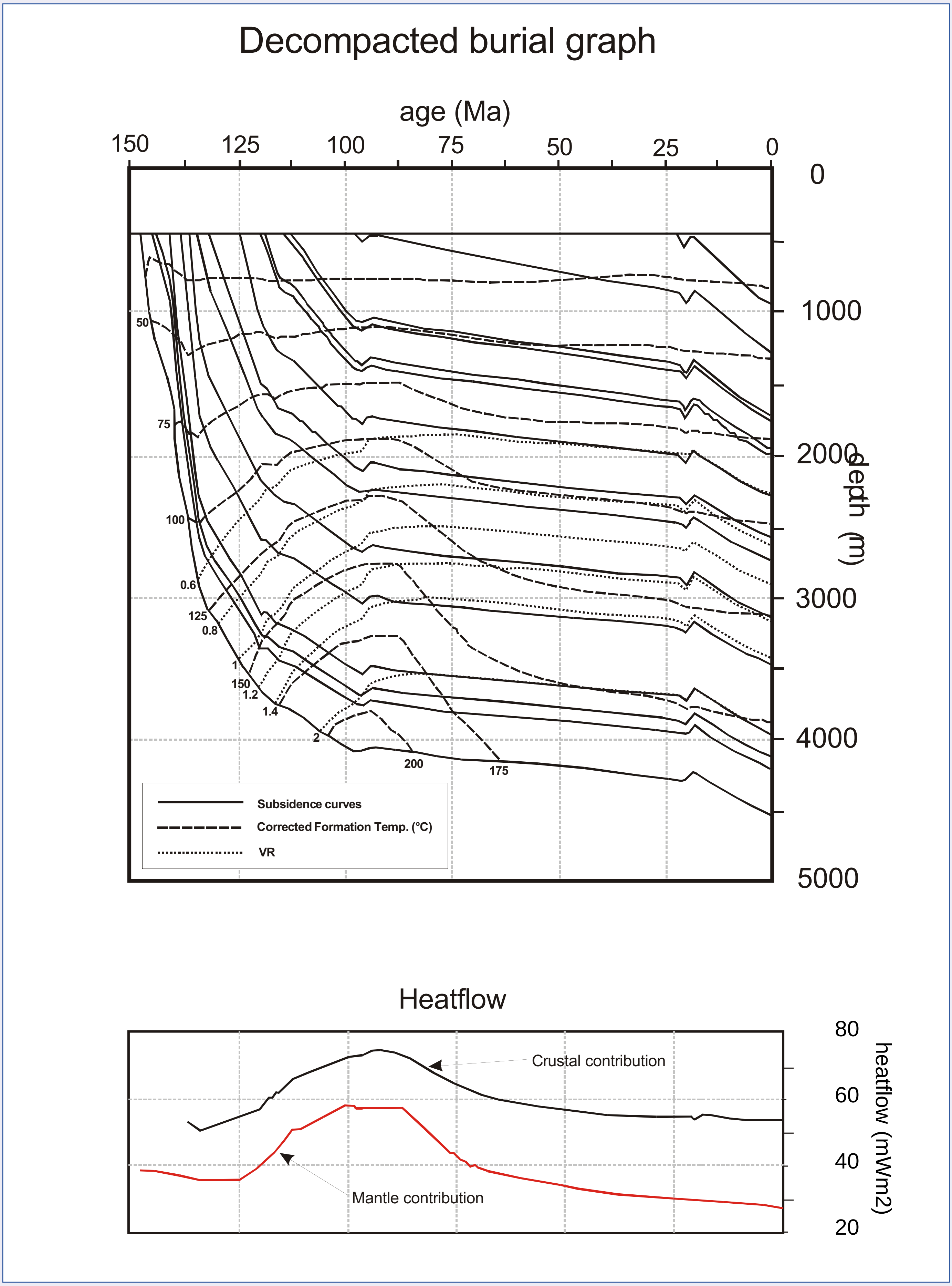

Fig. 4. The subsidence curves and heat-flow scenario that best fits the vitrinite reflectance, calculated and observed formation temperatures, used to model the evolution of source rocks in the North Falkland Basin.

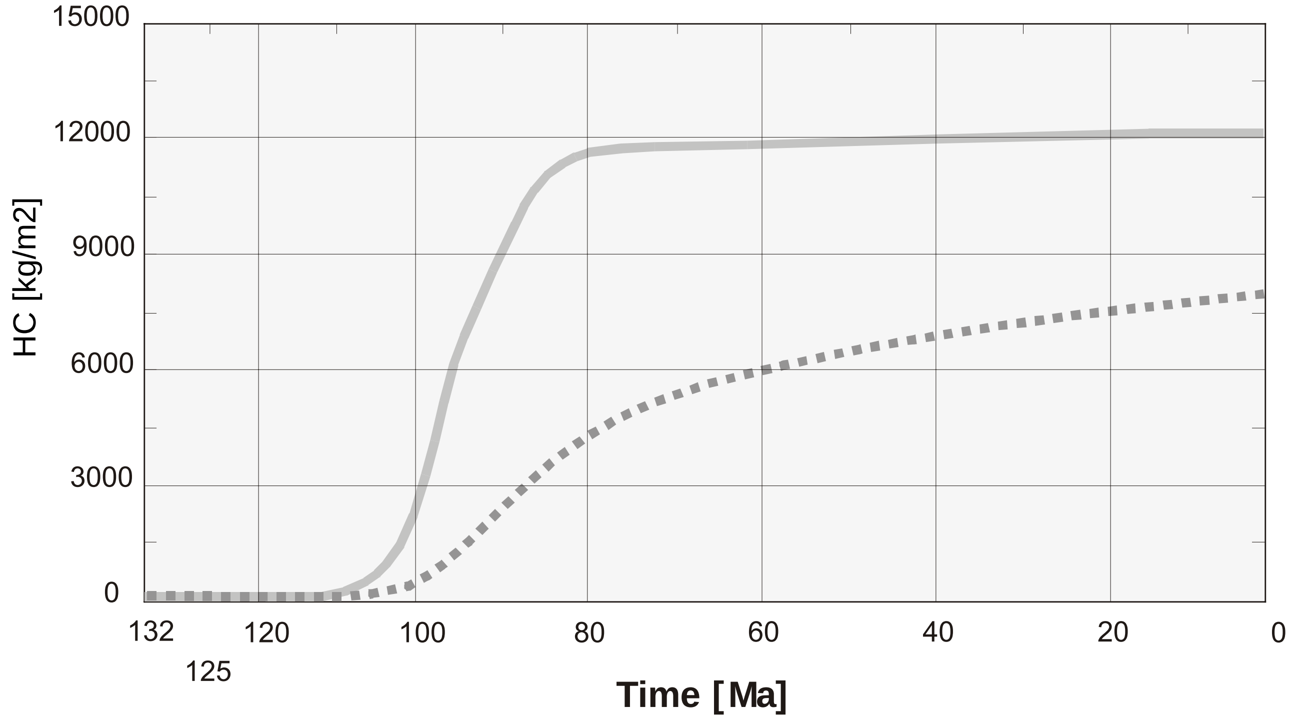

Fig. 5. Modelled generation (solid line) and expulsion (dashed line) of oil from the base of the main source rock interval (the early post rift lacustrine claystone). The oil generation/expulsion scale on the y axis assumes 400 metres of mature source rock.

SHOWS AND HYDROCARBON TYPES

Oil or oil and gas shows were encountered in five of the six wells, but the only hydrocarbons that flowed to surface were waxy oils (27∞ API) from Well 14/10-1. The shows were recorded from reservoir rocks at various levels, and also while drilling through the late syn-rift to early post-rift source rock interval, apparently seeping directly from the source. The characteristics of these oil samples are summarised in Table 4.

In summary, oils within the middle post-rift sandstones in Well 14/9-1, and those recovered from the late syn-rift succession in Well 14/10-1, were derived from the lowermost part of the early post-rift lacustrine, Type I source rock. By contrast, shows in the middle post-rift sandstones in Well 14/5-1A are from a different, Type II source rock, characteristic of the late syn-rift succession. The oil recovered from near the base of Well 14/10-1 was probably expelled downwards from the early post-rift succession, whereas the oil spun from the middle post-rift core in Amerada’s well appears to have migrated vertically and laterally for at least six kilometres, from a deeper kitchen area, as have the oil shows recorded from the middle post-rift sandstones in Well 14/5-1A. The vertical migration pathway appears to have been less efficient than the downwards migration pathway, as evidenced by the contrast between live oil recovery from horizons below the main source interval and the finding only of shows above the main source interval (see below for further discussion of migration pathways).

Well Number	Sample depth	Oil sample characteristics	Tectono-strat unit
14/5-1A	1,728 m	Biodegraded, but of mature character. Corresponding Type II source rock contained predominantly structureless organic matter; similar to that in a side-wall core sample analysed from 2,677m below rig floor (within the uppermost parts of the late syn-rift sequence).	Middle post-rift
14/5-1A	1,948 m	Biomarkers exhibit a high degree of maturity, and show the oil is derived from the early post-rift, Type I source rock	Early post-rift
14/5-1A	1,950 m	The sample is immature as indicated by presence of the thermally unstable compound C27-22,29,30-trisnor-17b(H)-hopane, the concentration of which reaches zero at the earliest oil window. The differences between this and the sample from 1,948 m may be due to the fact that part of the organic matter in this interval represents indigenous, immature material, whereas another part is derived from migration of low mature material.	Early post-rift
14/10-1	?3,000 m	Oil (API 27.1) was collected at surface during terminal logging. The complete sterane isomerisation observed indicates that this oil has been expelled from a mature source rock. This source rock contained structureless organic matter with a significant algal component, and is equivalent to the Type I lacustrine claystones found in the the early post-rift source rock interval in Well 14/5-1A. However, the source rock interval from which this recovered oil was derived was apparently more mature than the early post-rift source rocks analysed from well 14/5-1A.	Late syn-rift
14/9-1	1,830 m	Oil was centrifugally spun from a core sample. This oil has an early mature, highly paraffinic composition, and has been derived from a Type I lacustrine source rock. The oil is Carbon isotope depleted, and is similar in nature to the Valanginian to Barremian source rocks comprising the lowermost part of the early post-rift succession recorded in Well 14/5-1A. The oil is also isotopically similar to the oil recovered at surface in Well 14/10-1.	Middle post-rift
14/24-1	1,790 m	Post-well geochemical analyses indicate that a sandstone from near the base of the middle post-rift sequence contained traces of hydrocarbons that were not detected during drilling, presumably due to their very low concentration (although dull gold to yellow fluorescence was noted while drilling through the underlying source rocks). These hydrocarbons are characterised by normal alkanes with a mature configuration, and do not resemble the indigenous hydrocarbons detected in the immediately underlying claystones. They probably represent migrated hydrocarbons originating from a deeper, mature zone of the underlying Type I claystones.	Middle post-rift

Table 4. Summary of oil sample characteristics from Wells 14/5-1A, 14/10-1, 14/9-1 and 14/24-1

Description of gas shows

Gas shows observed during drilling ranged from part of one percent, to in excess of 32% in the early syn-rift sequence in Well 14/5-1A (from some of the thin sandstones recorded within a unit containing about 120 m of net sandstone; see Part 1). Gas types were often confined to C1, sometimes with minor amounts of C2 and C3, although high levels of C2 to C5 were recorded at times. Gas shows in the stratigraphically higher sandstones are generally less voluminous, with, for example, up to 2,900 ppm C1 and only traces of C2 recorded from the middle post-rift sandstones in Well 14/9-2. Gas shows directly from syn-rift and early post-rift lacustrine claystones are up to 12.06% (in Well 14/10-1), with a complete range of C1 through C5 gases recorded.

RESERVOIR ROCKS IN THE NORTH FALKLAND BASIN

All six exploration wells encountered potential reservoir rocks, ranging in age from Late Jurassic to Late Cretaceous. Lower Cretaceous potential reservoirs were most commonly encountered, particularly within the early and middle post-rift units. The lithology of these intervals were described in Part 1.

Early and late syn-rift potential reservoir rocks (mid Jurassic to Berriasian)

Several clastic reservoir intervals were encountered in these units in Well 14/5-1A. One sand-dominated, early syn-rift interval, has a net reservoir thickness of nearly 40m, with porosities of 4.4 to 7.5%; a second early syn-rift interval has a net thickness of over 10 m but porosities of up to only 4.6%; a third reservoir interval, which spans the boundary of the early and late syn-rift sequences in Well 14/5-1A, has net a thickness of 74m, and porosities of up to 9.0%. The thickest late syn-rift reservoir interval in Well 14/5-1A has a net thickness of 125m, with porosities ranging from 27.8 to 30.4%, and Sw values as low as 51%. Although these net sand values are relatively high, the sandstones themselves are thinnly bedded. Well 14/10-1 also encountered two thin, late syn-rift reservoirs. The lower of these had a net thickness of 1.2 m; the upper had a net thickness of 2.4 m. Both of these sandstones had log-derived Sw values as low as 36%. Well 14/9-1 also encountered potential reservoir within the late syn-rift sequence, with porosities of up to 30% and water saturations as low as 70%, but sampling using a wireline formation tester was unsuccessful, suggesting that the sandstones were tight.

Early post-rift reservoir rocks (Valanginian to early Aptian)

Early post-rift sandstones were encountered only in Well 14/5-1A, where they form part of the axial, southerly prograding delta deposits in the Eastern Depocentre. A sandstone-dominated interval identified within the delta foresets contained 38m of net sandstone reservoir, with up to 28% porosity and 974 mD permeability, but 89% water saturation.

Middle post-rift reservoir rocks (Aptian to Albian)

Middle post-rift reservoir sandstones were deposited in transgressive and fluvio-lacustrine settings, following the cessation of lacustrine depostition. Therefore, these reservoir rocks lie immediately above the main source interval. They are present in all of the wells. In Well 14/5-1A, the sandstones have a net thickness of nearly 23m, with a net to gross ratio of 0.56 and a porosity range of 19.6 to 25.4%. Furthermore, 79 m of net sandstone in this interval were encountered in Well 14/10-1, while over 133 m of net sandstone were found in Well 14/24-1.

These sandstones constituted a prime exploration target in four of the wells, and an important secondary target in the other two. However, the relatively low permeabilities and high water saturations, together with the common occurrence of pore-throat-blocking kaolinite cements, has reduced their reservoir quality. Furthermore, their effectiveness as a trap for hydrcarbons migrating from the underlying source rock interval may be limited by the sealing nature of the uppermost parts of the claystone interval, which may have acted as a barrier to vertical fluid migration (see discussions below of migration routes and seals).

Summary of reservoir characteristics

Some significant sandstone intervals have been encountered. For example, Well 14/5-1A encountered a total of 390 m of net reservoir (deltaic and fluvial sandstones) with an average porosity of 13%; while Well 14/10-1 had a total of 84 m of net sandstones, with porosities averaging 27.5%.

TRAPS, SEALS AND MIGRATION ROUTES

Traps

A number of different trap styles were tested by the six wells drilled in the North Falkland Basin. Four of the wells tested four-way dip closures with reservoirs in the middle post-rift succession. Well 14/9-1 was designed to test early and late syn-rift sandstones within a tilted fault block forming part of the Intra-Graben High, in addition to the four-way drape at the top of the early post-rift level. Well 14/9-2 was designed to test a syn-rift closed high on the eastern flank of the Intra-Graben High. Well 14/13-1 was designed to test a similar structure within the Western Depocentre (the so-called Minke High). Wells 14/5-1A and 14/10-1tested four-way dip closures within the early post-rift sequence, in addition to the middle post-rift drapes.

Seals and Migration routes

An understanding of migration pathways and seals may provide the key to predicting the presence of hydrocarbon accumulations in the North Falkland Basin. The most effective top seal is probably provided by the early post-rift source rock itself, just as the Kimmeridge Clay Formation acts as both source and regional seal in the central and northern North Sea. The uppermost 600 m or so of the early post-rift claystone interval is above the oil generation window in the central parts of the Eastern Depocentre. Headspace gas analyses suggest that there has been no vertical migration of gas through this claystone, pointing to its viability as an effective seal.

The main source rock interval (the Valanginian to early Aptian, early post-rift sequence) is represented on seismic sections by a Low Velocity Zone (LVZ), and before drilling this was thought to represent an overpressured zone. However, no overpressures were recorded in the basin during drilling, and the LVZ represents an extremely organic rich interval with low density: the low density values, and a downwards decrease in density with depth is concommitent with a downwards increase in TOC values in each well (Fig. 1), and also with a downwards increase in Rock-Eval S2 values (Fig. 2) which represent a downwards increase in hydrocarbon expulsion.

Since the claystones are not overpressured, the fluid-flow system beneath the claystones is not confined, and hydrocarbons are therefore more likely to have migrated laterally down-section, along migration channels provided by sandstones within or just below the claystones. This type of migration would tend to favour the accumulation of oil either near the basin margin in marginally-attached fans, in tilted fault blocks stratigraphically beneath the claystone blanket, or in syn-rift reservoirs along features such as the Intra-Graben High. Thus, it is possible that the syn-rift succession penetrated in Well 14/9-1, which was found to have poor reservoir qualities at this location, may be a viable target at other sites along the Intra-Graben High. Some younger, middle post-rift targets may also be viable if they are near to faults which breach the early post-rift claystone seal.

Analyses of the oils recovered at the surface and observed as shows tend to confirm the hypothesis of preferential downwards migration. Only oil shows were observed in apparently under-charged sandstones above the main early post-rift source interval, whereas live oil was recovered from beneath the early post-rift source rock in Well 14/10-1.

An unconfined migration system could mean that relatively long-distance, lateral migration into syn-rift sandstones within the Western Depocentre is a possibility. If so, then structures such as the Minke High, drilled by Well 14/13-1, could contain oil where they comprise syn-rift sedimentary rocks rather than basement. Because Well 14/13-1 did not penetrate beneath the base of the claystone, it is not known whether syn-rift sandstones are present within that structure or down-flank to the east of the well location.

In summary, it seems probable that the main source rock interval provides an efficient vertical barrier to migration, and possibly explains why only small amounts of oil were able to migrate from the mature, basal parts of the source rock interval up into the middle post-rift transgressive and fluvial sandstones penetrated in all six wells. However, vertical migration into the middle post-rift sandstones might be possible where traps lie close to penetrative faults which provide a migration pathway down into the main kitchen area in the Eastern Depocentre, particularly adjacent to the basin margins. Lateral migration, beneath the claystones, and then into sub-source rock tiled fault blocks, fans attached to the eastern margin, or syn-rift sandstones in places along the Intra-Grabenal-High, is possibly the most efficient migration pathway in the basin. Large volumes of oil have possibly been generated in the basin, but there are only relatively minor shows in post-rift traps, whilst syn-rift traps have not been adequately tested.

FUTURE PLAYS AND PROSPECTS

A variety of play types were planned to be targeted by the 1998 drilling campaign, but post-well analyses indicate that only three play types were actually partially tested. These tested plays were the early post-rift deltas, the middle post-rift transgressive and fluvial sandstones, and the syn-rift succession in the core of the Intra-Graben High. There are more untested than partially-tested plays remaining in the basin: a small selection of both are reviewed below.

Partially tested plays

Syn-rift sandstones on the crests of tilted fault blocks

Only Well 14/9-1 tested this play within closure on the crest of the Intra-Graben High. The mid Jurassic to Berriasian sandstones encountered on the Intra-Graben High had reasonable reservoir properties, particularly within the Tithonian to Berriasian, late syn-rift unit: log-derived porosities up to 30% and Sw values as low as 70% were recorded. Although permeabilities appear to be poor at the 14/9-1 location, the prospectivity of the syn-rift succession cannot be ruled out elsewhere.

Two thin sandstone beds (3 and 5 m thick) were also penetrated in the late syn-rift sequence by Well 14/10-1, in a palaeo-lake centre setting. It is thought that these two sandstones were not within closure at the level they were encountered, and therefore were not fully oil charged. However, both the sandstones had oil shows, and porosities of about 19%, with Sw values of about 36%. These reservoir characteristics indicate that the syn-rift succession may have considerable reservoir potential. The play has been only partially tested, and may merit further drilling at other locations, particularly on the eastern flank of the Intra-Graben High. The syn-rift succession should not be taken to represent economic basement in the region without considerable further drilling data being acquired.

Middle post-rift transgressive and fluvial sandstones

All six wells encountered reservoir quality sandstones within the Aptian to Albian middle post-rift unit that directly overlies the main source rock succession, and five of them had oil shows. The play has been only partially tested, and may merit further exploration, particularly if viable migration pathways can be mapped at some localities. For example, there are several relatively shallow closures along the crest of the Intra-Grabenal-High. These closures may also be located immediately adjacent to a fault which breaches the early post-rift seal, and which provides a direct migration pathway from the kitchen area in the middle of the Eastern Depocentre.

Early post-rift axial delta play and associated basin floor sandstones

Only Well 14/5-1A addressed the Valanginian to early Aptian, early post-rift axial delta play. Thick sandstones are likely to occur at delta top and delta front level to the north of the 14/5-1A well location, although there is very little seismic data in that area of the delta at present. Furthermore, some possible channel features have been imaged cut into the front of the delta in the Eastern Depocentre. These channels themselves have significant potential, especially since they are encased in source rocks which may provide a straight forward migration pathway and therefore relatively easy charge. They may also have carried sand further out into the lacustrine basin, into presently undrilled acreage which is only sparsely covered by seismic data.

Untested plays

Fan sandstones along the eastern margin of the Eastern Depocentre

Jurassic to earliest Cretaceous fan sandstones, deposited during the syn-rift phase, may be developed along the margins of the basin in situations analagous to the Brae complex in the South Viking Graben. Such sandstones would be stratigraphically sub-jacent to the mature, basal part of the source rock, and would therefore be likely to be charged with hydrocarbons. Fan-like bodies have been mapped in places along the margin, but are difficult to identify on presently existing seismic data.

Laterally-derived delta sandstones along both basin margins

Early Cretaceous deltaic bodies that prograded into the basin from marginal areas during the early post-rift phase may be sand-rich, and may also be closer to migration pathways, particularly those associated with the basin margin faults. They may therefore be more to likely to have been charged with hydrocarbons than sandstones within the axial delta. It is difficult to identify their distribution with any certainty using existing seismic data, but they may be significantly more extensive than their presently known distribution.

Basin margin sandstones developed during overstepping of the eastern rift shoulder

Shoreline and/or transgressive sandstones of Aptian to Albian age may have been deposited along the margins of the basin during the initial overstepping of the flanks in the middle post-rift phase. Although such sandstones would be stratigraphically above the main mature part of the source rock succession, they might have been charged by fluid flow vertically up basin margin faults.

Closed high plays in acreage to the south of drilled areas

Mapping of the 2D seismic data acquired by Desire Petroleum during 1998 in the southern part of the North Falkland Basin is not yet completed, but early work points to the presence of numerous closed highs in several discrete, deep sub-basins that extend to at least four seconds of two-way travel time (TWT). No definitive correlations have yet been established with the drilled areas to the north, although it seems likely that the deeper parts of the section equate with the early syn-rift sediments penetrated in the Shell well 14/5-1A. These sediments were the source of gas in that well, although are capable of generating oil where less deeply buried.

DISCUSSION

Good quality source rocks, reservoirs, seals and traps have all been identified in the North Falkland Basin. Although oil was recovered at surface in small quantities, the structures and primary reservoir targets drilled by the six wells did not contain commercially viable accumulations of hydrocarbons. However, all of the elements of a working petroleum system are present in the basin, suggesting that further drilling, planned using information such as that derived from this post-well analysis, could lead to better commercial results.

The present day geothermal gradient for the basin has been established as approximately 44oC/km. Calculations of the probable depth of burial required at the present day geothermal gradient to place oil-prone claystones within the oil generation window indicate that the early generation of oil starts at around 2,700m below sea level, and that peak generation will occur in source rocks buried to greater than 3,000m below sea level.

The main oil-prone source rock intervals are provided by early post-rift lacustrine claystones of Valanginian to early Aptian age, although there is also some source potential in the deeper, older units. The Valanginian to early Aptian (early post-rift) claystones have not yet been penetrated in a setting deeper than the 3,000m peak oil generation threshold. However they, as well as older source rocks, are more deeply buried in undrilled parts of the basin. Fig. 6 is a depth map on the top of the late syn-rift unit, and indicates the area in which the lower parts of the potential source rocks are buried to greater than 2,700m, the probable depth of onset of oil generation.

There is probably sufficient thickness of source rock in the basin, buried to depths in excess of 3,000m below sea level, to generate significant amounts of oil. One of the more optimistic calculations of the amount of oil in the basin suggests that up to 60 billion barrels have been generated. This figure is based on the source rock pyrolysis data obtained from the wells (Fig. 2), and assumes a 400m thick mature interval at the base of the source succession (as shown by Well 14/10-1) extending over an area of 40 km by 40 km. However, even when the calculations are based on much more conservative figures for the thickness and extent of the mature source and the richness and generative potential of the kerogens, significant amounts of expulsion are also calculated. For example, a 200m thick mature zone, over an area of 35km by 12km, may have expelled over 11.5 billion barrels of oil, even at oil yields of 8 kg HC/tonne, which are towards the low end of those observed by Rock-Eval pyrolysis for this basin. Similarly, when the area of potentially mature source rocks is reduced, to just 180 km2 (ie, 30km by 6km), and a very low potential oil-yield of only 2 kg HC/tonne of rock is used in the calculation, over 1.2 billion barrels of oil are likely to have been generated.

Kinetic analyses of the early post-rift claystones were conducted for Shell (by a commercial laboratory) on samples from Well 14/5-1A. Using this method, the timing of organic matter (kerogen) decomposition into hydrocarbons is assessed using a non-isothermal, open laboratory pyrolysis technique applied at selected heating rates, with a mathematical optimisation, to derive the kerogen decomposition kinetics. Presentation of the full particulars of the analyses is beyond the scope of this paper, but in summary, indicate that a sample from 2,100m (within the uppermost parts of the early post-rift sequence) achieves the onset of oil generation at a VR value of 0.74%, and peak generation at a VR of 0.86%, while a sample from 2,478m (within the lowermost part of the early post-rift sequence) achieves oil generation onset at a VR of 0.76% and peak generation at a VR of 0.9%. These VR values are slightly higher than the generally accepted value of 0.7% required for the onset of oil generation in other basins, and may reflect the higher heat levels/greater depth of burial required to generate oil from Type I kerogens than from source rocks characterised by mixed assemblages.

The extrapolated VR measurements in Well 14/5-1A suggest that the most prolific oil-prone interval (from 2,000m to 2,550m, the early post-rift interval) is still immature, whilst the less rich basal part of the interval (2,550m to 2,615m, the transitional phase of basin evolution) is just

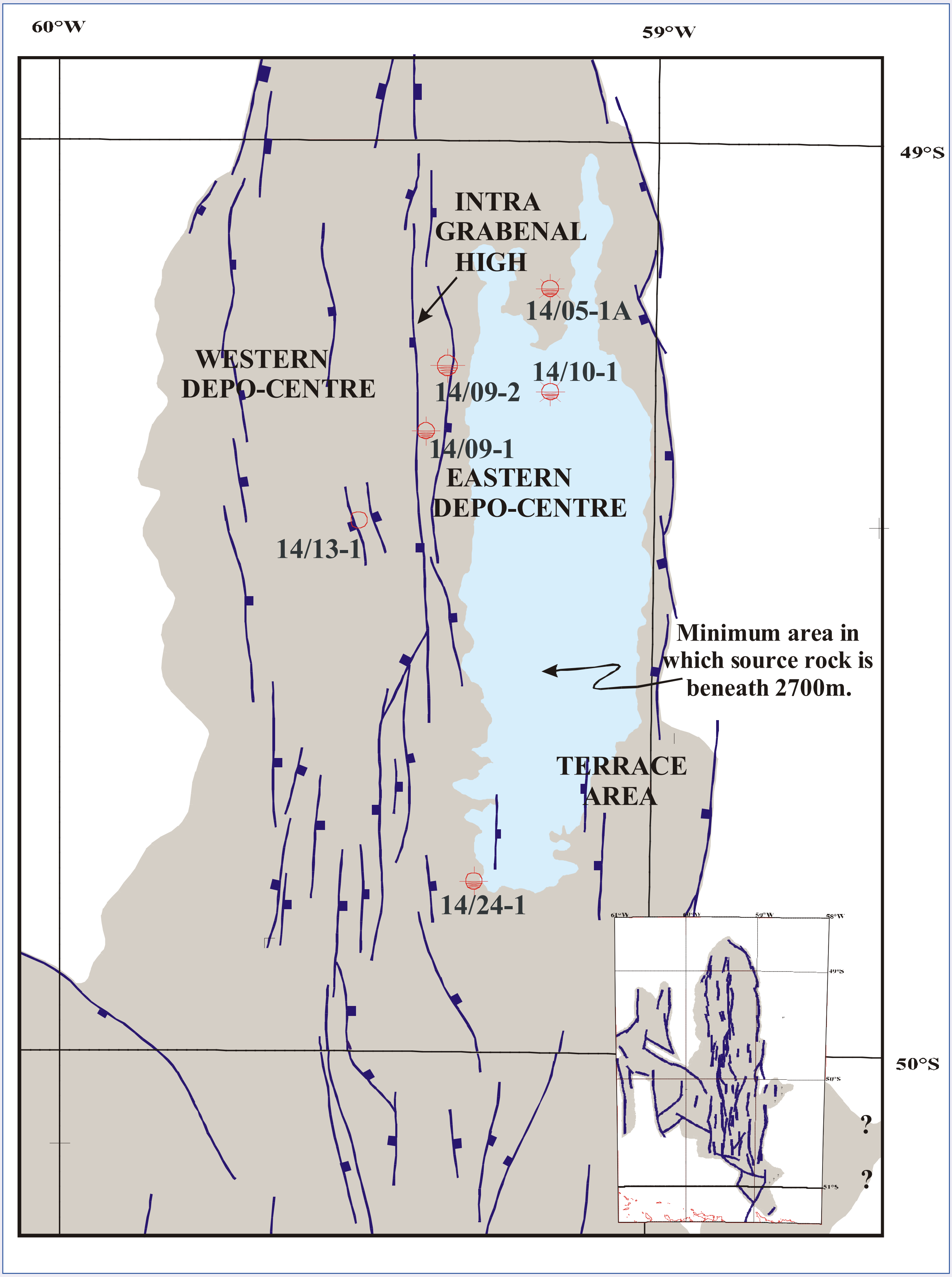

Fig. 6. Map of the base of the syn- to post-rift transitional unit (based on depth converted interpretation of all seismic data in the basin), highlighting the minimum area in which the source rocks are buried deeper than the 2,700 metre threshold needed for commercial oil generation.

entering the oil window, and is presently generating minor quantities of waxy crude oil. However, results from Well 14/10-1 indicate that the syn to post-rift transitional succession of the claystone dominated interval at this locality is within the zone of peak oil generation, with VR values of 0.9% recorded.

The six wells were drilled in quick succession, using a single rig, on pre-planned locations that had been site-surveyed several months earlier. Although some scope for testing different play types had been built into the exploration programme by all the drilling companies, each had picked the largest, most easily defined structure to test in their own acreage. These structures all relied on a primary reservoir being located in early or middle post-rift sandstones situated within or above the early post-rift sequence that was correctly predicted to be the main source interval in the basin. Because the wells were drilled back to back, with little time available to analyse the information obtained from previous wells, there was only very limited opportunity for the companies to refocus wells to target different play concepts. Consequently, all six wells were focused primarily on targeting sandstones that lie on probably the least effective migration pathway in the basin, and all found under-charged reservoirs.

High quality reservoirs may yet be found in other parts of the basin, on more viable migration routes. Such locations might lie particularly along the eastern flank, and in other locations beneath the main source rock succession, as well as in various delta settings (perhaps to the north of Well 14/5-1A), and in delta front channels and associated fans further south. Modern lakes in the East African Rift Valley provide a reasonable analogue which may aid exploration in the North Falkland Basin lake system. Johnson and Ng'ang'a (1990) described several sandstone depositional environments from Lake Malawi which could provide analogues for as yet undetected reservoirs in the North Falkland Basin. They noted that the sedimentary architecture of the lake is complex, but includes the deposition of coarse-grained clastic material both in river deltas and along border faults. Coarse-grained aprons or fans of sediment, attached to the eastern border faults of Lake Malawi, extend several kilometres into the lake, while large river deltas feed into the lake from the higher rainfall areas to the north. These deltas have well-developed channel systems that funnel turbidity currents into the deep, offshore basin. Nearshore sands extend to water depths of about 100 m in most parts of Lake Malawi, indicating the great depths to which surface waves can influence sedimentation in large lakes (Johnson and Ng'ang'a, 1990). These authors also noted that Lake Malawi's nearshore sands are texturally and mineralogically immature because of the short transport distances from the source areas on the rift margins. However, the beach sands are likely to be the best sorted of the various sandy facies present, because winnowing by waves is a very effective sorting mechanism in very shallow waters.

The North Rukuru and Ruhuhu river deltas that feed sediment into the northern part of Lake Malawi are collectively about half of the size of the delta (within the early post-rift sequence) in the North Falkland Basin (see Part 1). The upper section of the North Rukuru fan extends about 25 km into the basin, and shows evidence of several incised turbidite channels (Johnson and Ng'ang'a, 1990) similar to those observed on 3D seismic cutting the front of the axial North Falkland Basin delta. The Ruhuhu delta is different in that its surface is transected by several deep distributary channels, floored by gravel, that radiate from the river mouth (Johnson and Ng'ang'a, 1990). Gravity cores from both these deltas contain numerous sandy turbidites and debris flows (Johnson and Ng'ang'a, 1990). Although Johnson and Ng'ang'a (1990) were unable to sample more than the topmost parts of the Lake Malawi deltas and marginal fans due to the limitations of their coring equipment, seismic data presented by Scholz and Rosendahl (1988) suggest that some of the sand units may be up to 1,000 m thick.

Cohen (1990) reviewed the setting of depositional systems in Lake Tanganyika which may provode modern analogues for stratigraphic traps in the North Falkland Basin. The most obvious of these are axial deltas, although Cohen (1990) noted that platform deltas (such as the Malagarasi River delta, possibly analagous to the Easterly and Westerly-derived deltas of the North Falkland Basin - see Part 1) may have more advantageous source-reservoir-seal geometries.

CONCLUSIONS

A very rich source rock has been encountered in the North Falkland Basin, capable of generating up to 102 kg HC/ton of rock. Although much of the vertical thickness of the source rock is immature, it is capable of generating hydrocarbons below about 2,700m, and reaches the peak of oil generation at a depth of about 3,000m. Estimates of the volume of source rock that lie within the oil-mature window range from 36 x 109 m3 to 400 x 109 m3, depending on the seismic horizon mapped. It is estimated that up to 60 billion barrels of oil may have been expelled in the basin.

Some thick (approximately 100 metre) sandstones have been encountered above the main source rock interval, with porosities ranging up to about 30%. Well 14/5-1A had a total of about 390 metres of net sandstone throughout the syn- to post-rift interval, indicating that there are significant sandstone bodies within the basin. Very few thick sandstones with good reservoir properties have yet been encountered in the syn-rift succession beneath the main source rock interval, but few of the wells have penetrated this section.

The absence of overpressures within the basin suggests that any expelled oils may have migrated laterally, and they may therefore be trapped preferentially in syn-rift reservoirs developed beneath and lateral to the main source rock interval. Reservoirs of this age have been encountered within structural closure only in Well 14/9-1, where they had good porosities but presumed poor permeabilities (based on failed wireline formation tests). Several structures that contain syn-rift sedimentary rocks have been mapped, and these may provide adequate exploration targets for future drilling. However, most play-concept mapping to date has concentrated on early to mid post-rift reservoirs and associated targets, and little information has been gathered about syn-rift plays.

The six wells drilled so far in the basin targeted, as the main play, a middle post-rift sandstone lying immediately above the main source rock interval. This source rock is immature in its upper parts, and acts as an effective seal over much of the basin, being breached by faults only at the basin margins. Consequently, hydrocarbon charge into the middle post-rift sandstones was low where they were tested by the six wells.

The optimum plays that should be tested by future wells, given the probable sealing nature of the thick source rock interval, are sub-source sandstones in both stratigraphic traps and tilted fault blocks. These may be difficult to locate on the present seismic data, which was acquired and processed primarily with the intention of exploring the younger, shallower parts of the basin.

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