Tar-Mat Samples as Timing Indicators of Episodic Fill-and-Spill Oil Migration History in an Albian Channel-Splay Complex from the Outeniqua(!) Petroleum System, South Africa*

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Abstract

Biomarker analyses of a series of oil and tar-bearing sandstone samples from an Albian shelf-margin channel-splay complex in the Bredasdorp Basin and source rock samples from the immediately subjacent Aptian deep marine shales show a time-related sequence of fill-and-spill along the channel. Optical and pyrolysis analyses from many samples of the source rock both locally and regionally show a maturation history that fits the known multiple-event basin heat flow and is similar to the calculated oil maturities.

As oil was generated from the kerogen, the shale porosity gradually became charged with oil but this oil was only actively expelled from the shale once the threshold oil saturation was exceeded; this threshold oil volume can be estimated from the available source rock analyses. Comparing the known rates of maturation with the calculated oil saturation potential of the shale suggests a punctuated oil expulsion and migration history that broadly matches the fill increments evident from multiple tar-mats in the field.

This compelling synchroneity suggests a complete ‘source-to-reservoir fill’ sequence passing into and through the channel system in which tarmats represent previous oil fills and live oil represents the latest fill(s). The volume of oil shown to be lost from the studied reservoir before the present fill is probably of similar volume to that currently trapped, namely a few tens of MMbbl, constituting an updip target for future drilling.

Regional Geology

The Bredasdorp Basin is the westernmost of a series of five basins located on the southern tip of Africa, offshore South Africa, all formed during the Mesozoic pull-apart of Africa and South America (Figure 1). Only the early post-rift strata, namely post-Hauterivian, are discussed here as they host both the source and reservoir rocks (Figure 2).

Shortly after the Barremian opening of the basin the Aptian regional anoxic event occurred. This is believed to result from the colonisation of previously exposed land surface and higher than normal atmospheric and oceanic temperatures, allowing for massive organic growth and the ensuing deep basin anoxia. The anoxia resulted in regional deposition of Type 2 organic matter away from the newly transgressed shelf areas; a good example is seen at the DSDP361 location SW of Cape Town. It is this regionally extensive shale that is the source of almost all the oil discovered to date off South Africa. Closely following this event, a period of regional uplift and landward erosion occurred culminating in mid-Albian sandstone deposition in basins around South Africa, particularly the Bredasdorp Basin. These locally extensive marine sandstones take the form of stacked anastomosing channel and fan lobe deposition off the palaeo-shelf into the central part of the basin. They are the main oil productive interval in the basin.

Hotspots

Apart from expected thermal decay effects consequent on the pull-apart events, an unusual feature of Southern African geology is that it has been affected by heating and uplift due to hotspot transits in two separate periods. The first, and more important, is marked by the Bouvet (Shona) hotspot, reported by Duncan (1981) to have transited the Bredasdorp Basin at ~ 65-55Ma (Figure 3) bringing extensive intrusions of calc-alkaline igneous rocks to the easternmost and westernmost Bredasdorp Basin over that period. Although the area of discussion lies between the two igneous centres, the heating effects of the Bouvet/Shona hotspot are widespread due to the underpinning of the basin by the hotspot head, so the whole basin was affected. The second hotspot event is that currently building under southern Africa, the so-called African Superswell of Nyblade and Robinson (1994). This hotspot seems to have initiated at ~10Ma and is still growing. Physical effects of this can be seen in the recently elevated hinterland of southern Africa and regional erosion along the coastline during the last ~10Ma.

Thermal Maturation

Optical and pyrolysis maturity data from ~4000 Vitrinite Reflectance samples from 99 wells and ~22000 Rock-Eval samples from 143 wells in the basin were used to construct the heat flow model using the Basinmod Easy Ro% method. Increases in heat flow expected from such thermal events based on global sources of data were applied to the model in order to match calculated with measured Ro%

(Figure 4). These data are dealt with in detail in Davies (1997) and are not addressed further here other than to reiterate the conclusions, namely that modelling based on these features confirm the timing and likely reflectance levels of expelled oil.

The Bredasdorp Basin hosts significant volumes of hydrocarbons, to date some 3Tcf and 100MMbbl recoverable gas, condensate and oil have been discovered and are in production. Much of the oil and gas was generated by the Aptian source although an earlier wet gas prone source in the Barremian strata seems to be responsible for regional gas-condensate generation, some of which is seen in the deeper wells in the study area.

In this paper, discussion centres on the low sulphur, ~38deg API Aptian oil with wet gas and the Barremian gas-condensate that are found reservoired in a continuous sequence of stacked channel sandstones between the E-CR and E-CB structures in the south-eastern part of the Bredasdorp Basin (Figure 1). More specifically it focuses on the genesis of the unusual intersections of Albian reservoir sandstones which contain multiple millimetre-to-centimetre-thick ‘wavy’ tar-mats (so-called as they comprise up to 74% asphalt and barely 1% saturates) and deep residual oils. These are considered to have been deposited at multiple OWC’s, either by compositional segregation or bacterial activity

This paper addresses the generation and punctuated expulsion of oil from the Aptian source shales, the reservoiring of that oil in the superjacent Albian sandstones and the evidence for the continuation of the migration conduit over the past ~60Ma. The available optical, pyrolysis, GC and GC-MS data all confirm the oil and tar were generated from the same source but at different maturity levels, therefore at different times (Davies, 1997). One such correlation is used herein.

Punctuated Oil Expulsion

Detailed pyrolysis evaluation (using industry-standard Rock-Eval and Leco instruments) has shown the Aptian source rock to be able to generate and expel some 12kg HC/tonne rock across its ~100m thickness, a large part of which is likely to be oil. It is often assumed that since generation is continuous as maturation increases, then expulsion must also be continuous. Yet there is a body of evidence suggesting expulsion is punctuated, occurring only when internal pressures in the shale from expanding volumes of generated oil cause microfractures resulting in oil being expelled to relieve pressure. Thus one would expect that samples from the edges of shales should be depleted in free oil compared to samples from the centres of shales - available data do indeed confirm this supposition.

Further, since the composition of oil is a function of the organic matter and the maturity level, then oil expelled at different times, and at different maturity levels, should differ chemically; this aspect is routinely used to demonstrate the maturity of expelled oil. Such information is also available and does indeed confirm the range of maturity levels expected for the samples.

The data show that at least 4 pulses of oil and gas, and maybe more, have been expelled from the Aptian source shales, each pulse of ~1-2kg/tonne rock. This totals barely 60% of the total expulsion expected (~12kg/tonne) but the lack of shallow and deep basin wells precludes demonstration of the full range of these effects.

Oil Maturity

GC and GC-MS analyses of movable oils, tars and residual oils in the area have been analysed to determine their biomarker correlation and maturity information. Critical parameters calculated from these analyses are captured in Table 1.

Methods commonly used to distinguish between compounds generated at different maturity levels rely on use of many parameters to avoid over-reliance on a single parameter. In this case multiple such biomarker ratios are used, specifically Tricyclic and Pentacyclic terpanes, Steranes and Diasteranes, and Aromatics. One example being the ternary plot of C27-29 $\alpha\alpha$Steranes (Figure 5) which shows the maturity levels of tar, residual oils, oils and condensates in the area.

Evaluation of filling sequence

Yet the distribution of these low-to-high maturity shows does not follow a consistent pattern in the reservoirs, the least mature oil residues being juxtaposed by the highest mature oil with even deeper oil residues, suggesting filling was discontinuous. The data also show a high maturity contribution from the Barremian gas-condensate prone source rock as well.

The simplest explanation is that there were periods of early fill which formed a much larger oil reservoir than that seen today, of which all trace has been lost except for the tars and deep residual oils. Presumably that oil was lost through updip migration and the reservoir has refilled much later with higher maturity oil and late gas-condensate.

Proposed Paragenetic Chronology

If the oil maturity levels are compared to burial depths, the following sequence of events can be determined in which early oil fill episodes represent generation during the hotspot transit. Latest fill episodes reflect oil considered to have been generated as the African Superswell developed.

Placing these maturity levels in a paragenetic form (Figure 6) shows that this progression is related to the time of expulsion and would fit with the following sequence of events:

1. Reservoiring of the first pulse of expelled low Maturity oil (at R_o ~0.7%) at ~60Ma during the early hot spot transit.
2. Conversion of some of this to tar at the base of the column, either by bacterial action at the oil-water interface or by formation of a compositional gradient.
3. Reservoiring of the next pulse of migrating oil below the early pulse, because of the baffle caused by the tar mat. Formation of a second tar mat as above at the oil-water interface.
4. Repeat reservoiring as above 1-2 more times, probably all during the latter parts of the hotspot transit with tar mats formed as seen and oil shows near the base of the oil charge, perhaps from compositional gradient effects.
5. Tilting of the basin during thermal decay after the hotspot transit allowing the oil to escape but the tar mats and residual oils to remain.
6. Refill of 1-2 episodes of oil expulsion during the African Superswell at ~10Ma and admixture with gas-condensate from the deeper Barremian source.

Conclusions

A good match between the maturity levels of tar and oil samples recorded by the vitrinite reflectance data and the EasyRo% calculated maturities, suggest a complex heat flow model that largely matches known regional geology. The study also assesses the volumes of oil generated and expelled from source rocks over time which can be compared to those currently and formerly reservoired. As a result, the above chronology reasonably predicts the presence of analysed low maturity tar mats and residual oils structurally both above and below the present high maturity oil charge.

Equally important is the evidence that volumes of oil have been lost from the trap during the late hotspot transit, and that these volumes are far larger than the current E-CB oil charge. This points the way to exploration updip onto the Agulhas Arch for 10’s MMbbl to perhaps 100MMbbl of medium gravity crude, a large new target for exploration driven by a proper geochemical understanding of the area. Small volumes of oil have been found in wells updip to the SW but so far not enough to account for the apparent palaeo-charge in the E-CB structure.

It is considered highly likely that such punctuated oil expulsion is more the norm than the supposed continuous expulsion suggested by Basinmod and other 1D modelling tools. It is expected that more examples of early and late oil being reservoired together may be expected to be reported on in the near future.

The modelling work also shows that the starting point for any such evaluation is a proper and correct understanding and modelling of regional heating events. It is not enough to merely assume that all heating is burial-related. All geological events must be considered as possible causes of maturation change. Where the simple burial model does not match the available maturation data should be a cause for concern to the prudent geoscientist - any differential between reality and the model tells a story that is ignored at ones peril.

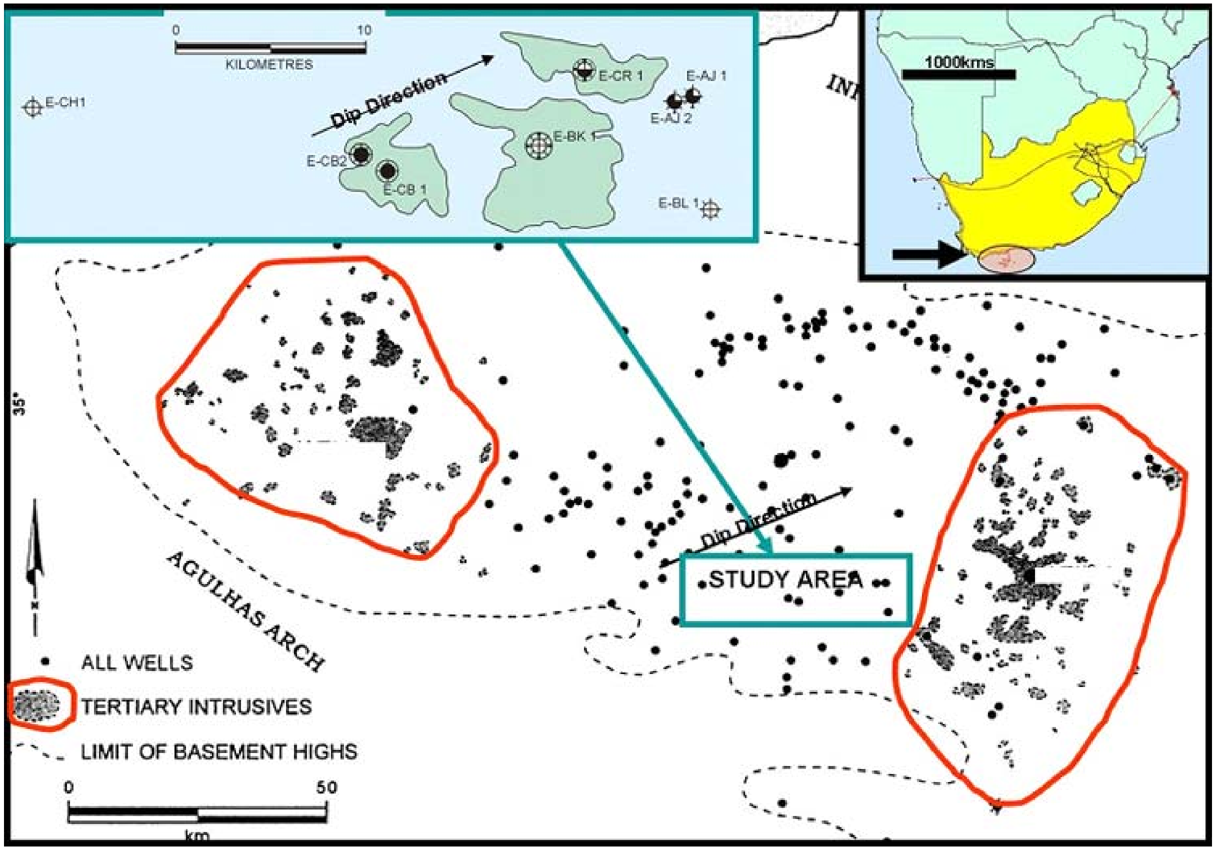

Figure 1. Locality map showing igneous areas and study area.

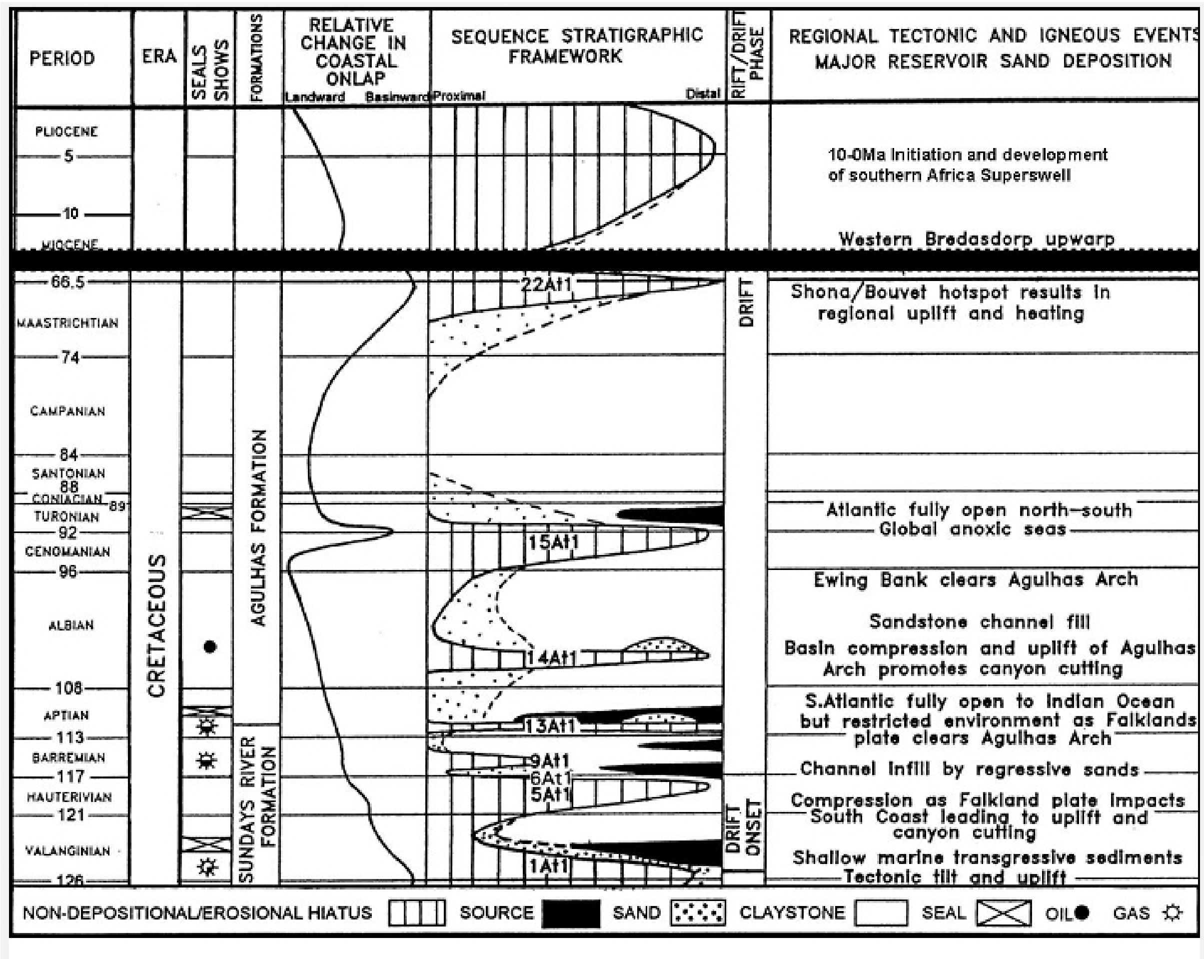

Figure 2. Chronostratigraphic chart showing Aptian and Albian source and reservoir rocks.

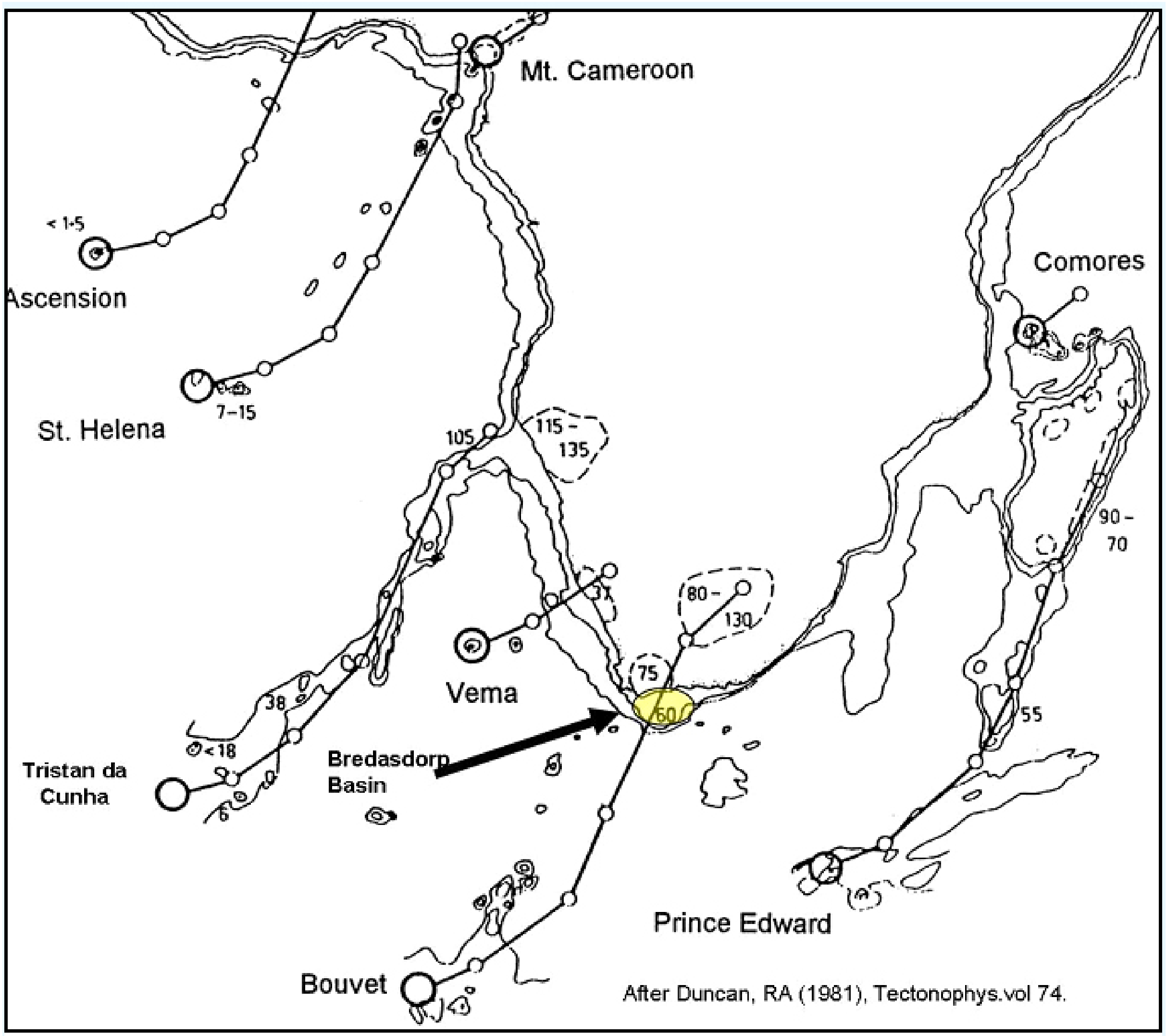

Figure 3. Map of regional hotspots that transit southern Africa during Mesozoic-Tertiary.

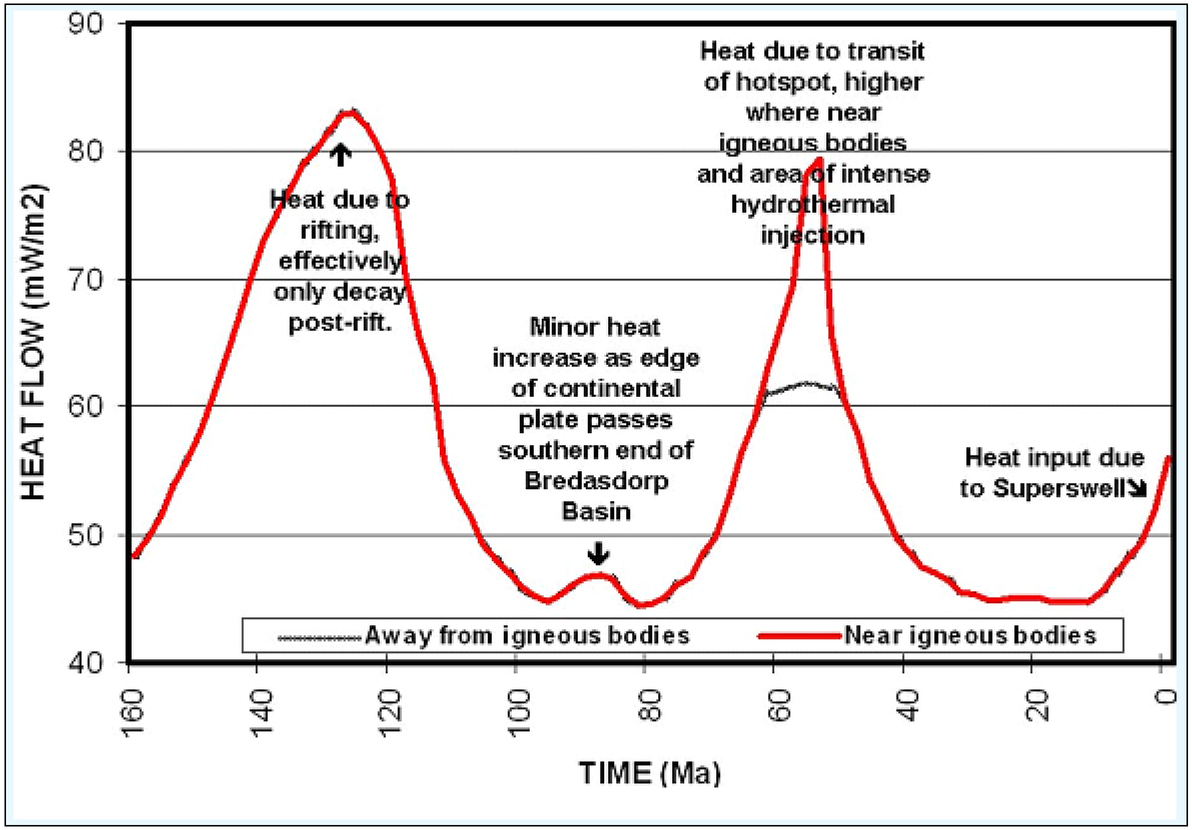

Figure 4. Heat flow model of Bredasdorp Basin which matches geology and maturity data.

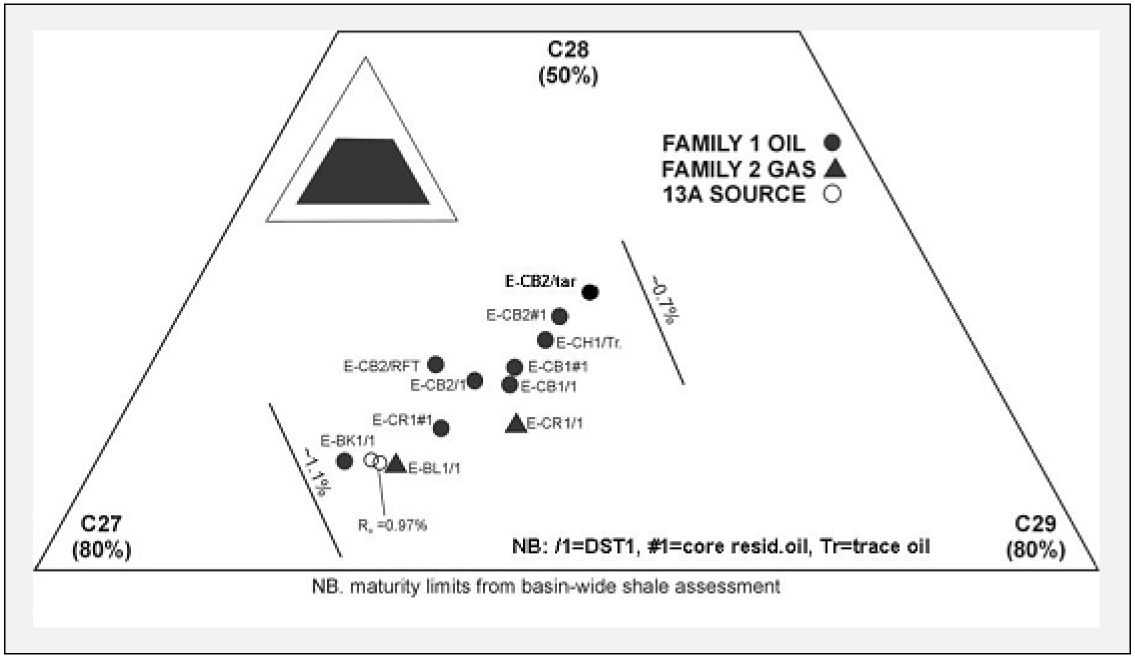

Figure 5. Ternary plot of C27-29ααSteranes showing maturity-related variability.

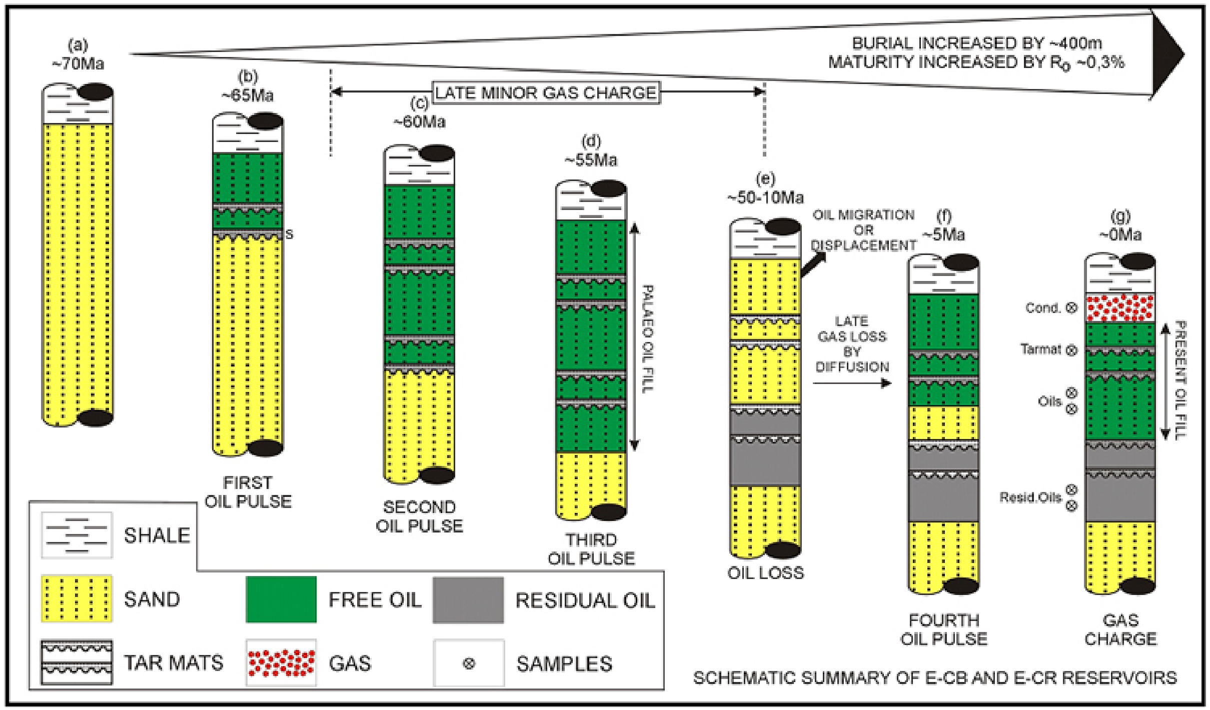

Figure 6. Paragenetic evolution of proven oil charge, empty and recharge over the past ~60Ma.

Sample				Hydrocarbon			Steranes				Terpanes			Aromatics	
						Ro%	$\alpha\alpha$			S/S+R	$\beta\alpha$S/nHop	nHop/D	Tri/D	DMDBT	TMN
Well	**Depth**	**Family**	**Age**	**Spl.**	**HC**	St+Terp	**C27**	**C28**	**C29**	**C29**	C27(m/z177)	**C29**	**C23/C30**	**C/E**	**125/136**
E-BK1	2643m	2	14A	DST1	Cond.	1.02%	55%	19%	26%	0.63	7.32	1.37	3.5	0.95	-0.68
E-BL1	2931m	2	13B?	DST1	Cond.	1.03%	52%	18%	30%	0.57	2.27	0.98	6.3	1.90	-0.59
E-CB1	2522m	1	14A	DST1	Oil	0.86%	43%	23%	34%	0.59	1.15	1.36	0.67	0.88	-0.35
E-CB1	2525m	1	14A	Core1	Resid oil	0.80%	41%	25%	34%	0.53	1.52	3.18	0.53	0.73	-0.36
E-CB1	2805m	1	13A	RC	Shale	0.96%	54%	18%	28%	0.61	4.24	0.68	0.81	0.65	-0.74
E-CB1	2835m	1	13A	RC	Shale	0.99%	53%	17%	30%	0.58	5.09	0.50	1.31	0.74	-0.69
E-CB2	2508m	2	14A	RFT	Cond.	0.93%	46%	24%	30%	0.61	3.36	2.09	2.10	0.87	-0.68
E-CB2	2510.4m	1	14A	Core1	Tarmat	0.76%	34%	31%	35%	0.50	0.62	2.24	0.59	0.76	-0.28
E-CB2	2520m	1	14A	DST1	Oil	0.89%	44%	24%	32%	0.53	2.59	1.26	1.11	0.85	-0.62
E-CB2	2522.5m	1	14A	Core1	Resid.oil	0.78%	36%	29%	35%	0.57	0.77	7.46	0.11	0.83	-0.65
E-CH1	2256m	1	14A?	RC	Resid.oil	0.75%	35%	28%	37%	0.51	0.87	2.63	0.12	0.48	0.37
E-CR1	2679m	2	14A	DST1	Cond.	0.96%	41%	22%	37%	0.46?	3.15	1.05	4.0	1.00	-0.33
E-CR1	2681.7m	1	14A	Core1	Oil	0.95%	46%	21%	33%	0.58	3.38	1.02	1.89	1.03	-0.99

nHop=norhopane, Tri=tricyclicterpane, D=Diahopane, DMDBT=dimethyldibenzothiophene, TMN=trimethylnaphthalene, C/E=2,2(?)/2,4DMDBT.

Table 1. Relevant sample, analytical data and biomarker ratios.

References

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