Petroleum geology of South Australia
Vol. 2: Eromanga Basin

CHAPTER 8 Source rock distribution and hydrocarbon geochemistry

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TABLE

INTRODUCTION

Numerous commercial and non-commercial hydrocarbon discoveries have been made in the Eromanga Basin. One question which continues to perplex explorers is whether these hydrocarbons are indigenous or have migrated from kitchens in the underlying Permo-Triassic Cooper Basin. Over the last three decades, explorationists have come to the realisation that oil-prone and effective source rocks are developed within the Eromanga Basin itself. Some oil and gas has almost certainly migrated from the Cooper Basin and has been trapped in the overlying Eromanga sequence. However, geochemical evidence suggests that a large proportion of the Eromanga crudes are indigenous and are derived from source beds in the Eromanga Basin. The most prolific source rock horizons are the Poolowanna, Birkhead and Murta formations. This chapter reviews the source rock distribution and hydrocarbon geochemistry of the Eromanga Basin. Its aims are twofold: to collate the large body of Rock-Eval pyrolysis and vitrinite reflectance data on the South Australian sector of the Eromanga Basin, with a view to identifying potential and probable hydrocarbon source rocks; and to briefly summarise the biomarker geochemistry database for oils and source rocks and, where possible, to establish genetic relationships between potential source rocks and hydrocarbon accumulations.

To facilitate discussion of the large volume of data, we have chosen to present the South Australian database in two parts: data on the basin east of the Birdsville Track Ridge (i.e. the Eromanga Basin immediately overlying the Cooper Basin and adjacent areas) which we refer to as the ‘eastern’ sector; and the Eromanga Basin west of the Birdsville Track Ridge, which we describe as the ‘western’ sector. For the purposes of this chapter, the western Eromanga Basin includes the Jurassic and Cretaceous strata overlying the Pedirka and Simpson Basins. These data are compiled mostly from Amdel, Analabs, and University of Adelaide reports, or from respective well completion reports. Data from the western Eromanga Basin in the Eringa Trough area and from the Pandieburra 1, Poonarunna 1 and Putamurdie 1 wells west of the Birdsville Track Ridge are presented in Table 8.1.

POOLOWANNA FORMATION

Western sector

The fluviolacustrine Poolowanna Formation is the basal unit of the Eromanga Basin and is its first important potential source rock. Rock-Eval data for the western sector are plotted in Figure 8.1. As the samples analysed are predominantly coals and carbonaceous shales or siltstones, source richness is generally very high. For example, for the Poolowanna 1, 2 and 3 wells in the Poolowanna Trough, total organic carbon (TOC) ranges from 5.1 to 42.1%. Potential yield ($S_1 + S_2$) ranges from 11 to 160 kg hydrocarbons per tonne, indicating good to excellent source richness.

Kerogen composition for the Poolowanna samples ranges from Type III (gas-prone) to Type II (oil-prone). Although there is considerable variability, a total of five samples out of the 35 analysed have hydrogen indices (HI) >300 (Fig. 8.1). These samples are from Koonchera 1, Poolowanna 1 and Poolowanna 2 and have good oil-generative potential. Organic petrography shows that in the Poolowanna area liptinite ≥ vitrinite > inertinite. Elevated HI values (i.e. Type II kerogen) occur when the coals and shaley coals are resinite-enriched (Kagya et al., 1996).

As indicated by measured vitrinite reflectance (R_o) and maturities estimated from T_{max}, the maturity of the Poolowanna Formation in the Poolowanna Trough reaches about 0.9% R_o which corresponds to peak hydrocarbon generation for Type II organic matter. However, where it is intersected by Koonchera 1 in the Birdsville Track area, or by Glen Joyce 1 and Miandana 1 in the Pedirka Basin, the Poolowanna Formation is only marginally mature for liquid hydrocarbon generation (0.5–0.6% R_o).

Table 8.1 Rock-Eval pyrolysis data from the western Eromanga Basin

Well	**Depth** (m)	**TOC** (%)	**Genetic potential** ($S_1 + S_2$)	**Hydrogen index**	**Oxygen index**
Birkhead equivalent					
Cur 3	251.6	34.3	135.08	359	38
	251.9	39	168.29	388	36
	259.5	47.2	279.41	542	37
Cur 5	209.2	52.9	49.41	87	47
	210.1	50.5	175.72	312	39
	249.4	58.7	248.59	368	46
Pandieburra 1	1567.4	1.01	1.66	158	51
	1753.3	0.84	1.43	165	91
Poonarunna 1	1583.2	9.34	43.15	417	11
	1587.8	3.56	21.07	553	13
	1601.3	1.72	5.12	277	19
	1602	1.61	4.94	288	39
	1621.1	1.96	11.03	509	26
	1622.8	1.96	8.31	378	21
	1625	9.19	40.89	398	9
	1625.4	8.88	37.88	367	5
	1627.1	19.7	97.64	438	7
Putamurdie 1	1456.6	5.98	24.45	391	8
	1458.5	1.11	3.44	297	30
	1458.6	1.74	6.35	354	31
Namur Sandstone					
Poonarunna 1	1519.7	6.04	27.97	437	8
	1522.4	2.86	12.28	397	9
	1524.3	1.44	8.03	538	22
	1529.6	0.77	2.03	255	37
	1529.8	1.03	2.7	251	13

Eastern sector

Rock-Eval data from 44 wells (88 samples) in the Cooper region are plotted in Figure 8.2. As expected for such a large database, source richness and quality are highly variable. However, some of the best source rocks are developed at Kobari 1, Leleptian 1, Toolachee East 2, Tantanna 1 and Titan 1. When considering data from only these wells source quality ranges from fair to very good. Eight of the samples from these wells, and 10 samples from other wells, have HI values greater than 250 indicating good (Type II/III kerogen) to very good oil source potential (Type II kerogen).

The organic petrography of the Poolowanna facies in the Sturt–Tantanna area south of the Patchawarra Trough is similar to that described for the Poolowanna Trough, except that in many samples inertinite is dominant over vitrinite suggesting a greater variety of sub-oxic to oxic terrestrial depositional environments (M. Kagya, University of Adelaide, pers. comm., 1996). In some samples *Botryococcus*-type telalginite is relatively abundant, and is occasionally associated with framboidal pyrite, signifying local anoxic lacustrine conditions (Kagya and McKirdy, 1996).

The Poolowanna facies has attained only marginal maturity (0.5–0.6% R_O) in the Sturt–Tantanna area, but is of slightly higher maturity (0.6–0.7% R_O) in the Leleptian and Toolachee East areas.

HUTTON SANDSTONE

Source rock data for the Hutton Sandstone in the western and eastern sectors are presented in Figures 8.3 and 8.4, respectively. Note that data from the western sector are sparse. Despite low shale/sand ratios, some thin source beds were encountered at 1359.7 and 1362.8 m in Mulapula 1 (TOC = 1.6 and 2.3%; HI = 220 and 273; Ro ≈ 0.5%). These are immature and moderately oil prone. More data are available from the eastern sector where it appears that an immature, moderately oil-prone source facies (Type II/III kerogen) is developed at Murteree 2 on the Murteree Ridge (TOC = 1.2–3.4%; HI = 229–336; R_o ≈ 0.5%). A single sample at Merrimelia 18 also displays good oil source potential (TOC = 16.8%; HI = 284) and is initially mature (R_o ≈ 0.65–0.7%). The source quality of some moderately oil-prone shales at Munkarie 4 and Tirrawarra West 1 (amongst other localities) is diluted by inferior Type III kerogen in other samples from the same Hutton section.

BIRKHEAD FORMATION

Western sector

The Birkhead Formation of the western Eromanga Basin is the second important unit for hydrocarbon generation. The Rock-Eval plot of Figure 8.5 summarises these data. Source richness parameters are highly variable in the Birkhead Formation. For example, in Pandieburra 1, Poonarunna 1 and Putamurdie 1, where core was selectively sampled for dark argillaceous lithologies, source richness is generally high but ranges from fair to excellent (TOC = 0.84–19.7%; S_1+S_2 = 1–98 kg hydrocarbons per tonne). TOC values and potential yields are even higher in the Algebuckina Sandstone (the Birkhead equivalent) at Cur 3 and Cur 5 (TOC = 34.3–58.7%; S1 + S2 = 49–279 kg hydrocarbons per tonne). Twenty-nine of the 31 samples from Cur 3, Cur 5, Mulapula 1, Poonarunna 1 and Putamurdie 1 display good to excellent source quality (HI = 199–553). The spatial distribution of these wells implies that high quality (Type II) source rocks are developed over wide areas of the western Eromanga Basin. Even samples with lesser generative-potential (i.e. those where HI <200) are notably better than the least oil-prone samples in other Eromanga formations.

T_{max} values between 435 and 444°C for the Birkhead at Poonarunna 1 and Putamurdie 1 suggest that its level of maturity is between 0.65 and 0.85% R_o. This is in conflict with directly measured vitrinite reflectance which indicates a maturity of <0.6% R_o. Michaelsen and McKirdy (1996) reported suppression of directly measured R_o at these localities. Petrographic observations suggest that such suppression is the result of natural impregnation of vitrinite by plant resins and essential oils. Thus R_o values closer to 0.80–0.85% are the preferred maturity estimates. Since Type II kerogen enters the oil window ahead of Type III kerogen (Type II at ≈ 0.5% R_o; Type III at ≈ 0.7% R_o), it is highly likely that the Birkhead sequence intersected at Poonarunna 1 and Putamurdie 1 is presently an effective source rock. Moreover, a maturity of around 0.80 to 0.85% R_o suggests the Birkhead Formation at these localities may be approaching the peak of oil generation.

The Birkhead equivalent of the Algebuckina Sandstone at Cur 3 and Cur 5 on the western margin of the Eringa Trough also contains high quality source facies (Type II/III and Type II kerogen) although at a lower thermal maturity (0.41–0.45% R_o: Staples et al., 1995). The best quality samples from the Cur wells are telovitrinite-rich coals which contain abundant resinite and fluorinite (plant oils). Gas chromatography–mass spectrometry (GC–MS) of their saturated hydrocarbons demonstrates that the same samples have an enriched microbial biomarker signature (Alexander et al., 1996). In Cook’s (1986) opinion, hydrocarbon generation from resinite can commence as early as 0.40 to 0.45% R_o. Powell (1985) also put forward a hydrocarbon generation model wherein resinite-enriched and bacterially-modified source rocks (comprising predominantly vitrinite and inertinite) can begin generating hydrocarbons at 0.45% R_o. Therefore, it is conceivable that the Birkhead equivalent in this area has entered the oil window, especially towards the centre of the Eringa Trough where maturity levels are expected to be higher.

Eastern sector

Figure 8.6 summarises the HI and T_{max} data for 115 samples from 31 well localities. Although much of the Birkhead Formation appears favourable for liquid hydrocarbon generation, its source potential is clearly less than in the western Eromanga Basin. Of the 134 samples analysed, only 18 (or 13%) have HI values of 300 or greater (i.e. Type II/III or II kerogen). This compares to 52% of samples analysed (23 out of 44) in the western sector. High quality source facies are developed at Cuttapirrie 1, Lake Macmillan 1, Snake Hole 1, Tirrawarra North 1, Tirrawarra West 1 and Wancoocha 4. One sample from Snake Hole 1 has an exceptionally high HI of 568 and represents very oil-prone Type II kerogen. Although these localities contain reasonably high quality source material (Type II/III kerogen), many of the coals and shales are diluted with equal amounts of inferior Type III kerogen.

ADORI SANDSTONE

In both the western and eastern sectors of the Eromanga Basin, the Adori Sandstone is a poor source for liquid hydrocarbons. Only one cuttings sample (2048.3–2057.4 m) from Tindilpie 2 has any noteworthy source potential (TOC = 3.7%; HI = 449; Type II kerogen; $R_o \approx 0.6\%$). Cross-plots of Rock-Eval data for the Adori Sandstone are provided in Figures 8.7 and 8.8.

WESTBOURNE FORMATION

The Westbourne Formation, which is restricted to the eastern sector of the Eromanga Basin in South Australia, has poor source potential for liquid hydrocarbons (Fig. 8.9). Most of the 27 rock samples from 12 wells analysed by Rock-Eval pyrolysis plot beneath the Type III kerogen evolution curve, indicating very poor oil potential. Based on one cuttings sample (2020.8–2039.1 m) from Leleptian 1 (TOC = 0.77%; HI = 210; $R_o \approx 0.55\%$), the Westbourne Formation at best exhibits only minor development of a moderately oil-prone source facies.

NAMUR SANDSTONE

Rock-Eval pyrolysis data for the Namur Sandstone in the western and eastern sectors of the South Australian Eromanga Basin are presented in Figures 8.8 and 8.10, respectively. In the western sector, based on only 8 shale samples from Mulapula 1 and Poonarunna 1, the Namur Sandstone contains, on average, excellent quality Type II/III and oil-prone Type II kerogen. If one excludes an atypically poor sample from Poonarunna 1 (1523.7 m; TOC = 0.36%; HI = 22), the sample suite from Mulapula 1 and Poonarunna 1 displays fair to excellent source richness (TOC = 0.8–6.0%; $S_1 + S_2$ = 7–28 kg hydrocarbons per tonne) and good to excellent source quality (HI range = 251–548; average = 391). Dispersed organic matter (DOM) in these oil-prone samples is dominated by vitrinite with subordinate liptinite, and only minor inertinite (Michaelsen and McKirdy, 1996). However, in the exceptionally oil-prone samples with HI above 500, liptinite is the dominant maceral group. The liptinites in all samples are chiefly sporinite and sporinite-derived liptodetrinite. Measured vitrinite reflectances suggest a maturity between 0.4 and 0.5% R_o, at variance with T_{max} data which indicate a significantly higher maturity (0.65–0.80% R_o). The T_{max}-derived maturity estimates are probably more realistic, since it is evident from petrographic observations that R_o suppression has lowered the measured reflectance values.

Thin shale intervals of the Namur Sandstone in the eastern sector appear to have potential only for gas generation. HI values are at best around 200, but most samples plot below the Type II evolution pathway, suggesting the presence of Type III (gas-prone) or Type IV (inert) kerogen.

MCKINLAY MEMBER

Where developed at the base of the Murta Formation, shaley facies of the McKinlay Member appear to have generally poor source potential. Ten of the 13 samples analysed by Rock-Eval pyrolysis plot around or below the Type III evolution curve (Fig. 8.11) which is typical of gas-prone organic matter. Only three samples from Buckinna 1 have any liquids-generating capacity. However, this potential has been significantly downgraded by dilution with poorer quality Type III/IV source material.

MURTA FORMATION

The lacustrine Murta Formation is stratigraphically the highest unit of importance for hydrocarbon generation. Its hydrocarbon geochemistry was studied in detail by Michaelsen and McKirdy (1989) and Powell et al. (1989) who concluded it had potential to generate light paraffinic crude oils, even at maturity levels as low as 0.50–0.55% R_O. Rock-Eval data on 136 samples from 37 wells are summarised in Figure 8.12. The data fall into three broad groupings, as follows:

- Thirty-three core samples analysed from the Biala 1, Buckinna 1, Limestone Creek 6 and McKinlay 2 wells on the Murteree Ridge have by far the best source potential. Here TOC values in the range 0.8 to 2.6% and potential hydrocarbon yields of 3–12 kg per tonne indicate fair to good source richness. HI values between 175 and 541 are characteristic of Type II/III (oil/gas prone) to Type II (oil prone) organic matter. Optical microscopy reveals that the main macerals present are inertinite (40–80% of DOM) and liptinite (15–60% of DOM). Vitrinite is a minor component of the maceral assemblage. Many of the Murteree Ridge samples contain high concentrations of *Botryococcus*-type telalginite, and a positive correlation has been observed between telalginite and elevated HI, especially at Limestone Creek 6, where two samples containing 25% and 26% telalginite (as a percentage of total DOM) possess HI values of 351 and 541, respectively. Intense autofluorescence of the liptinite fraction in the Murteree Ridge samples suggests it has been little altered by oxidation, probably because of relatively rapid burial.
- Data from 15 core samples at Moomba 18 in the Nappamerri Trough form a second discrete cluster of points in Figure 8.12. For all but one sample, TOC values range between 0.6 and 2.1% and genetic potentials are between 1 to 6 kg hydrocarbons per tonne. All but two of the 15 samples analysed have HI values between 125 and 200, and therefore contain essentially gas-prone Type III kerogen. Although the maceral composition of the Moomba 18 samples is broadly similar to that of the samples from the Murteree Ridge, muted fluorescence of the liptinite fraction hints that the organic matter was subjected to enough oxidation prior to burial to result in significant loss of oil generating potential.
- The bulk of the remaining 88 samples from 32 wells have HI values <200 and represent Type III to Type IV kerogen. It is possible that many of these samples have diminished source potential because they comprise cuttings which may have contained mixtures of sandy and argillaceous lithologies. However, it is clear that the Murta Formation has poor source potential outside the Murteree Ridge, although oil-prone facies are developed in the Queensland sector (cf. Michaelsen and McKirdy, 1989; Powell et al., 1989).

The maturity of the Murta along the Murteree Horst (0.55–0.60% R_O) places it at the incipient stage of hydrocarbon generation for conventional terrestrial organic matter. Powell et al. (1989) provided biomarker evidence that the best Murta source facies contains abundant alkanes derived from bacterial precursors. Bacterial organic matter is more labile than woody (terrestrial) material. Therefore, it is likely that the shales and siltstones of the Murta Formation along, and immediately adjacent to, the Murteree Ridge have been effective source rocks, given their current level of maturity. Powell et al. (1989) demonstrated that Rock-Eval pyrolysis of powdered whole rock samples provide an unduly pessimistic assessment of source quality in organically lean (i.e. TOC <2%) units like the Murta Formation, due to the absorption of hydrocarbons by the mineral matrix. Experiments on demineralised samples (kerogens) from Limestone Creek 6 and Biala 1 by Powell et al. (1989) revealed that even the Murta shales from the Murteree Ridge have significantly better source potential than conventional Rock-Eval indicates. Finally, the intercalation of these thin oil-prone source facies with reservoir quality sandstones has provided a highly efficient mechanism for the drainage of hydrocarbons into carrier and reservoir lithologies.

CADNA-OWIE FORMATION

Figures 8.13 and 8.14 summarise Rock-Eval data for the Cadna-owie Formation. In the western sector, only one sample from Mulapula 1 stands out as having any oil-source potential. Although this sample is organically lean (TOC = 0.26%), it exhibits fair to good source quality (HI = 280; Type II/III kerogen). The remaining samples have very poor source potential for liquid hydrocarbons. In the eastern sector, a similarly pessimistic picture emerges, except perhaps for samples from Buckinna 1, McLeod 1 and Nulla 1 (HI = 180–250).

BULLDOG SHALE

Western sector

Available data for the Bulldog Shale in the area west of the Birdsville Track Ridge come entirely from Toodla 1. Core samples from this drillhole were studied extensively by McKirdy et al. (1986). TOC values are in the range 0.8–1.9% and potential yields <1 kg hydrocarbons per tonne. Figure 8.15 demonstrates that the Bulldog Shale contains inert (Type IV) kerogen with no liquid hydrocarbon-generative potential. McKirdy et al. (1986) reported that the maceral assemblage is dominated by inertinite, although a minority of samples studied contain mostly liptinite (chiefly phytoplankton and sporinite). Vitrinite is only a minor component in all samples. Suppressed fluorescence of the liptinitic fraction is evidence of partial oxidation and loss of hydrocarbon potential. The thermal immaturity of the Toodla 1 samples is evident from their low T_{max} values (423–436°C) which equate to measured vitrinite reflectances of <0.4% R_o.

Eastern sector

The Bulldog Shale in the eastern sector exhibits similarly poor oil source potential (Fig. 8.16). Notable exceptions are three samples from Buckinna 1 on the Murteree Ridge which have TOC values of 1.2–1.7% and HI values of 224–248. These samples contain Type II/III kerogen with a modest liquids-generating potential. Petrographic examination of cuttings and sidewall cores in Strzelecki 3 by McKirdy et al. (1986) confirmed that the Bulldog Shale contains an abundance of inertinite and subordinate vitrinite and liptinite. The present low maturity of the Bulldog Shale at such localities (< 0.45% R_o) precludes hydrocarbon generation. What appear to be unduly high T_{max} values for the Buckinna samples may be a function of organic matter type and so may not accurately represent the true thermal maturity (cf. McKirdy et al., 1986).

HYDROCARBON GEOCHEMISTRY

Considerable efforts have been made to establish robust correlations between reservoired oils and potential source rocks within the Cooper–Eromanga petroleum system. This problem has been tackled using three different approaches.

Aromatic hydrocarbons can be useful in determining the maturity of an oil at the time of its expulsion from the source rock. Michaelsen and McKirdy (1989), Powell et al. (1989) and Tupper and Burckhardt (1990) used calculated vitrinite reflectance (R_c) derived from the methylphenanthrene index (MPI) to type a large number of oils for comparison with the maturity of potential source rocks. These studies reveal that most Murta–Namur oils migrated from their source rocks at the very threshhold of the conventional oil window (R_c = 0.54–0.61%). Murta oils with low R_c values include those along the Murteree Ridge (e.g. Biala, Limestone Creek and McKinlay) and at Dullingari. Among the few exceptions are Murta crudes at Merrimelia for which higher source maturities are indicated (R_c = 0.73–0.84%). Oils in Jurassic reservoirs generally have MPI values that indicate they were expelled from their respective source rocks at somewhat higher maturity levels (R_c = 0.64–1.04%). This is in broad agreement with present maturation levels of the Birkhead Formation. Calculated vitrinite reflectance values of the Murta and Jurassic oils differentiate them from many Cooper Basin oils which underwent primary migration between 0.95 and 1.10% R_o. The values of other maturity parameters based on saturated hydrocarbon biomarkers (e.g. C_{29} sterane 20S/20R and C_{30} moretane/hopane) are consistent with the inferred thermal immaturity of the Murta and Jurassic-hosted crudes (cf. Michaelsen and McKirdy, 1989).

Alexander et al. (1988) employed aromatic biomarkers derived from the conifer family Araucariaceae to differentiate between oils sourced from Permian and Jurassic kitchens in the Cooper–Eromanga Basins. Araucariaceae did not become important members of the plant kingdom until the Early–Middle Jurassic, and therefore their biomarkers should be abundant in rocks and oils of the Eromanga Basin. Conversely, the relative abundance of the araucariacean biomarkers can be expected to be low in Cooper Basin source rocks and their derived oils. Figure 8.17 plots log 1,2,5-trimethylnaphthalene/1,3,6-trimethylnaphthalene against log 1-methylphenanthrene/9-methylphenanthrene for a selection of oils and source rocks in the western Cooper region. The following can be inferred from these data:

- Permian sediments have low concentrations of 1-methylphenanthrene (an araucariacean biomarker) relative to 9-methylphenanthrene when compared to Jurassic and Cretaceous sediments. However, the ratio of 1,2,5-trimethylnaphthalene (another araucariacean biomarker) to 1,3,6-trimethylnaphthalene alone is insufficient to discriminate between Permian and Jurassic rocks.
- Permian and Jurassic-reservoired oils can be distinguished on the basis of their 1,2,5-trimethylnaphthalene/1,3,6-trimethylnaphthalene and 1-methylphenanthrene/9-methylphenanthrene ratios. Both parameters are markedly higher in oils from Jurassic reservoirs. Based on this premise, the following oils can be assigned a Cretaceous or Jurassic source affinity: Bookabourdie 1, Callabonna 1, Charo 1 (all Birkhead reservoirs), Cuttapirrie 1 (basal Jurassic reservoir), Gidgealpa 20 (Namur and Birkhead reservoirs), Kenny 1 (Birkhead), Merrimelia 9 (Birkhead), Merrimelia 15 (Murta) Moolion 1 (Poolowanna), Mulapula 1 (Namur), Strzelecki 19 (Namur and Birkhead) and Wancoocha 2 (Murta, Birkhead and Hutton; cf. Michaelsen et al., 1995). Its aromatic biomarker distribution and low maturity (R_C = 0.61%) also suggest an intra-Poolowanna source for the Poolowanna 1 oil.

Other biomarker studies have utilised saturated hydrocarbons to distinguish between Cooper and Eromanga-sourced oils. Jenkins (1989) attempted to assign source affinity on the basis of differences in the concentration of the demethylated hopanes, 25,28,30-trisnorhopane (25,28,30-TNH) and 28,30-bisnorhopane (28,30-BNH). Both 25,28,30-TNH and 28,30-BNH are biomarkers for anaerobic bacteria. Jenkins concluded that 25,28,30-TNH was restricted to rocks of Jurassic age or younger, and their genetically related crude oils. However, we disagree with this premise because 25,28,30-TNH (± 25,28,30-trisnormoretane) occurs in high abundance in Triassic shales of the Mungaroo Formation, Northern Carnarvon Basin, Western Australia (B.H. Michaelsen, University of Adelaide, unpub. data; Noble et al., 1985; Peters and Moldowan, 1993). Nevertheless, we agree with Jenkins (1989) to the extent that 25,28,30-TNH is virtually absent from the geological record during the Palaeozoic. Thus, the presence or absence of 25,28,30-TNH may be indicative, but not necessarily definitive, of source affinity in the case of oils from the Cooper and Eromanga Basins.

Until recently very little biomarker information was available for oils and rock extracts from the western sector of the study area. Alexander et al. (1996) used the ratios 28,30-BNH/17α-hopane and retene/phenanthrene to geochemically characterise Permian coals and Jurassic coals in the Eringa Trough. Figure 8.18 summarises their data on logarithmic axes. All Permian samples (n = 7) have retene/phenanthrene ratios lower than those of the Jurassic samples (n = 3). Concentrations of the demethylated hopane 28,30-bisnorhopane are consistently higher, relative to 17α-hopane, in Permian rocks (Purni, Crown Point formations) than they are in the Jurassic (Birkhead Formation) samples. High concentrations of 28,30-bisnorhopane are indicative of rocks deposited under suboxic and anoxic conditions (especially the latter: cf. Peters and Moldowan, 1993). There is no obvious reason why the concentration of 28,30-BNH in Permian coals should be higher than in Jurassic coals. Nevertheless, it appears that the observed variation in 28,30-BNH content can be readily exploited in oil-source rock correlation studies. This finding presents explorers of the western Eromanga Basin with another means of distinguishing Permian and Jurassic hydrocarbons.

Future oil discoveries with elevated 28,30-bisnorhopane/17α-hopane ratios are likely to be sourced from the Permian, whereas those with low 28,30-bisnorhopane contents could be expulsion products of Jurassic source rocks.

CONCLUSION

Ranked in order of decreasing potential as measured by Rock-Eval pyrolysis, the best source rocks in the western Eromanga Basin are the coals and carbonaceous shales of the Birkhead Formation, followed by the organic-rich shales and siltstones of the Murta Formation, and the highly carbonaceous shales of the Poolowanna Formation. These units display a wide range of source richness and quality, but all contain varying quantities of Type II/III (oil/gas-prone) and Type II (oil-prone) organic matter. Other units have negligible source potential. The calculated vitrinite reflectance of most Eromanga oils indicates they were expelled from their source rocks at maturation levels which closely match the present-day maturities of the adjacent intra-Eromanga source rocks.

The aromatic hydrocarbon geochemistry of oils from Jurassic reservoirs in the Eromanga Basin, where it overlies the southern Cooper Basin, closely resembles that of potential Jurassic source rocks. Likewise, the chemistry of the Permian oils matches that of potential source rocks in the Cooper Basin. These findings suggest that migration from Permian source kitchens into the superjacent Eromanga sequence has not occurred to any appreciable extent in the southern Cooper Basin region. Therefore, many of the oils which are reservoired in the Eromanga Basin have been generated in situ, and have not migrated from deeper source rocks in the Cooper Basin.

FIGURES

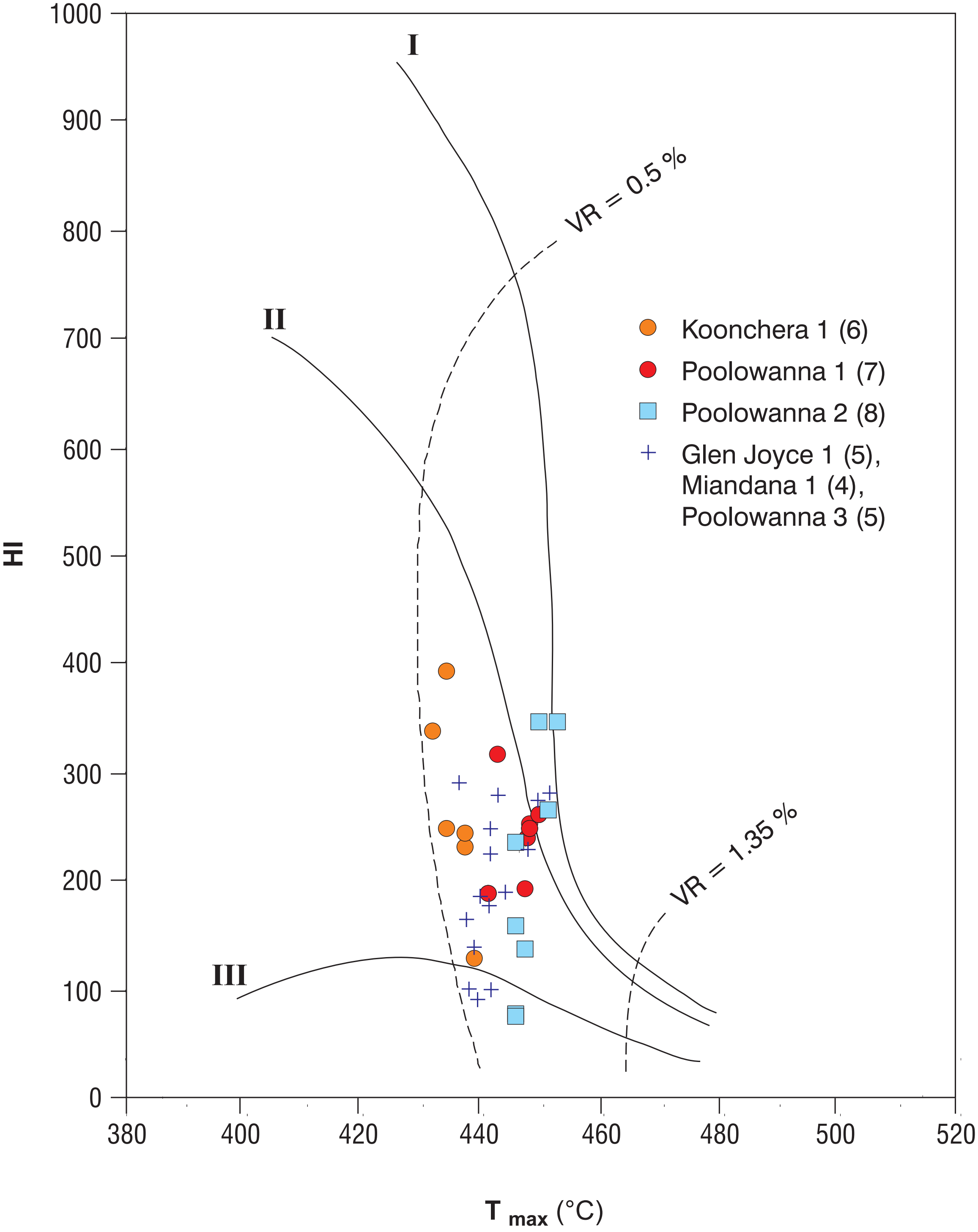

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Figure 8.1 HI versus T_{max} plot, Poolowanna Formation, Eromanga Basin, South Australia (western sector).

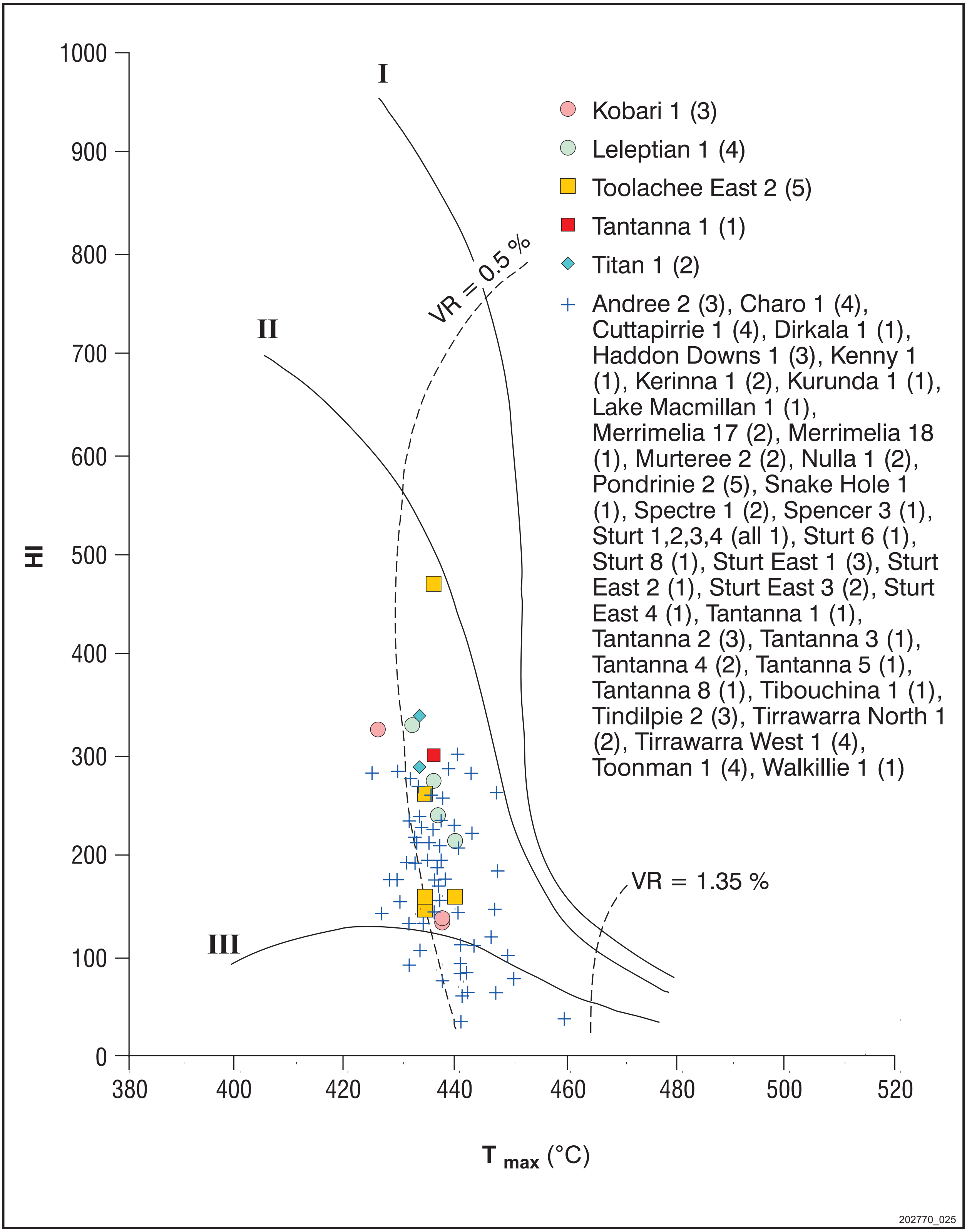

Figure 8.2 HI versus T$_{max}$ plot, Poolowanna facies, Eromanga Basin, South Australia (eastern sector).

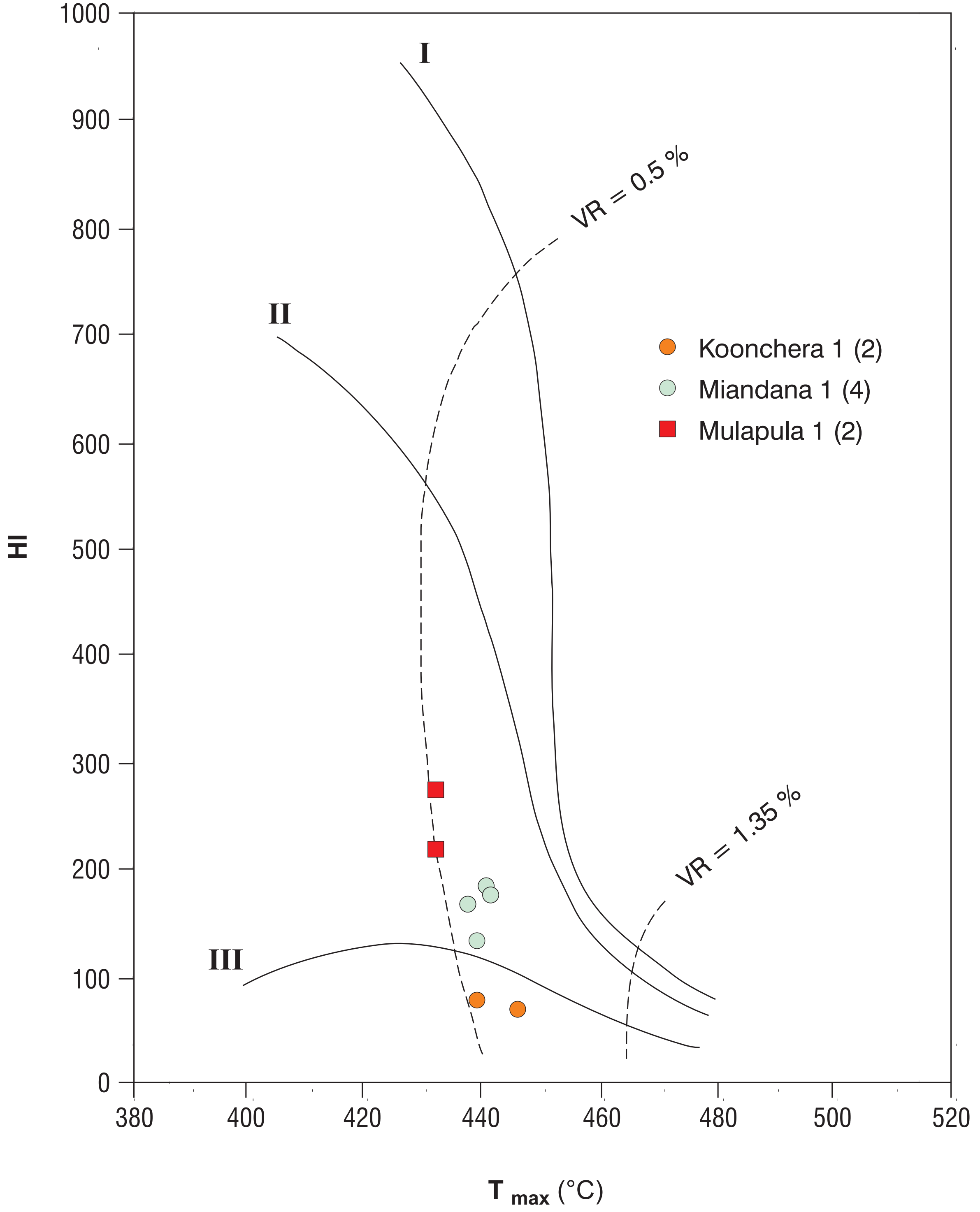

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Figure 8.3 HI versus T_{max} plot, Hutton Sandstone, Eromanga Basin, South Australia (western sector).

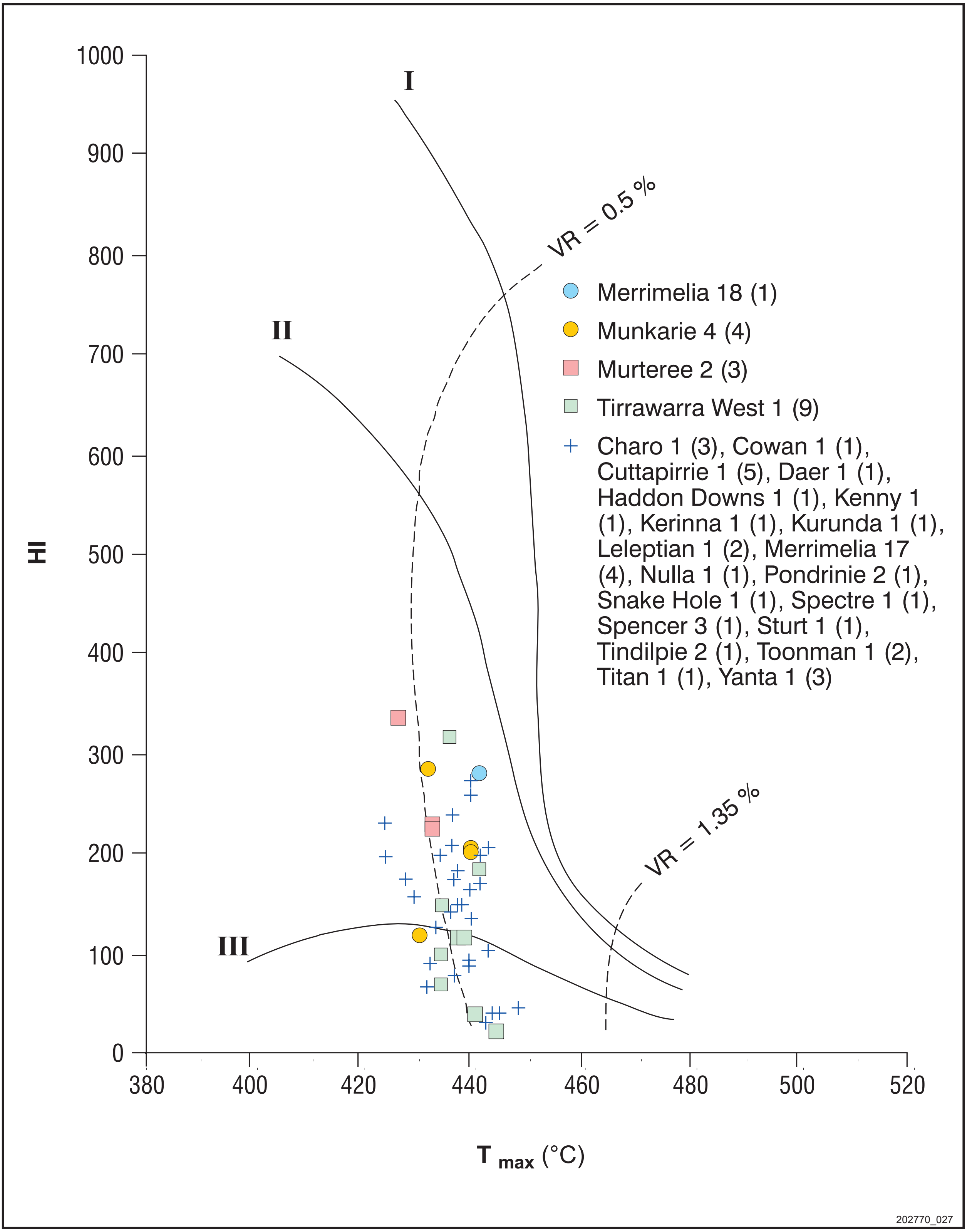

Figure 8.4 HI versus T_{max} plot, Hutton Sandstone, Eromanga Basin, South Australia (eastern sector).

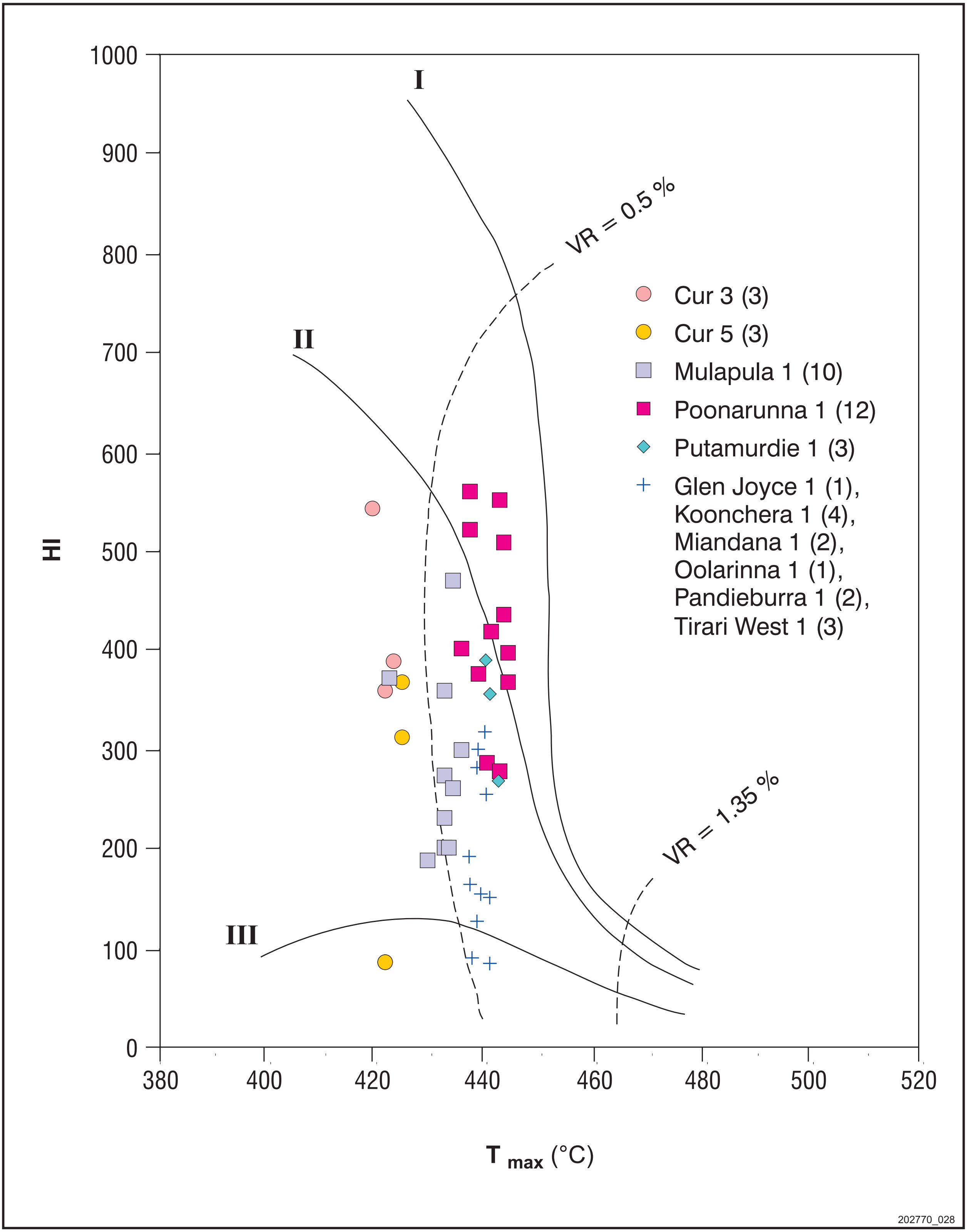

Figure 8.5 HI versus T_{max} plot, Birkhead Formation, Eromanga Basin, South Australia (western sector).

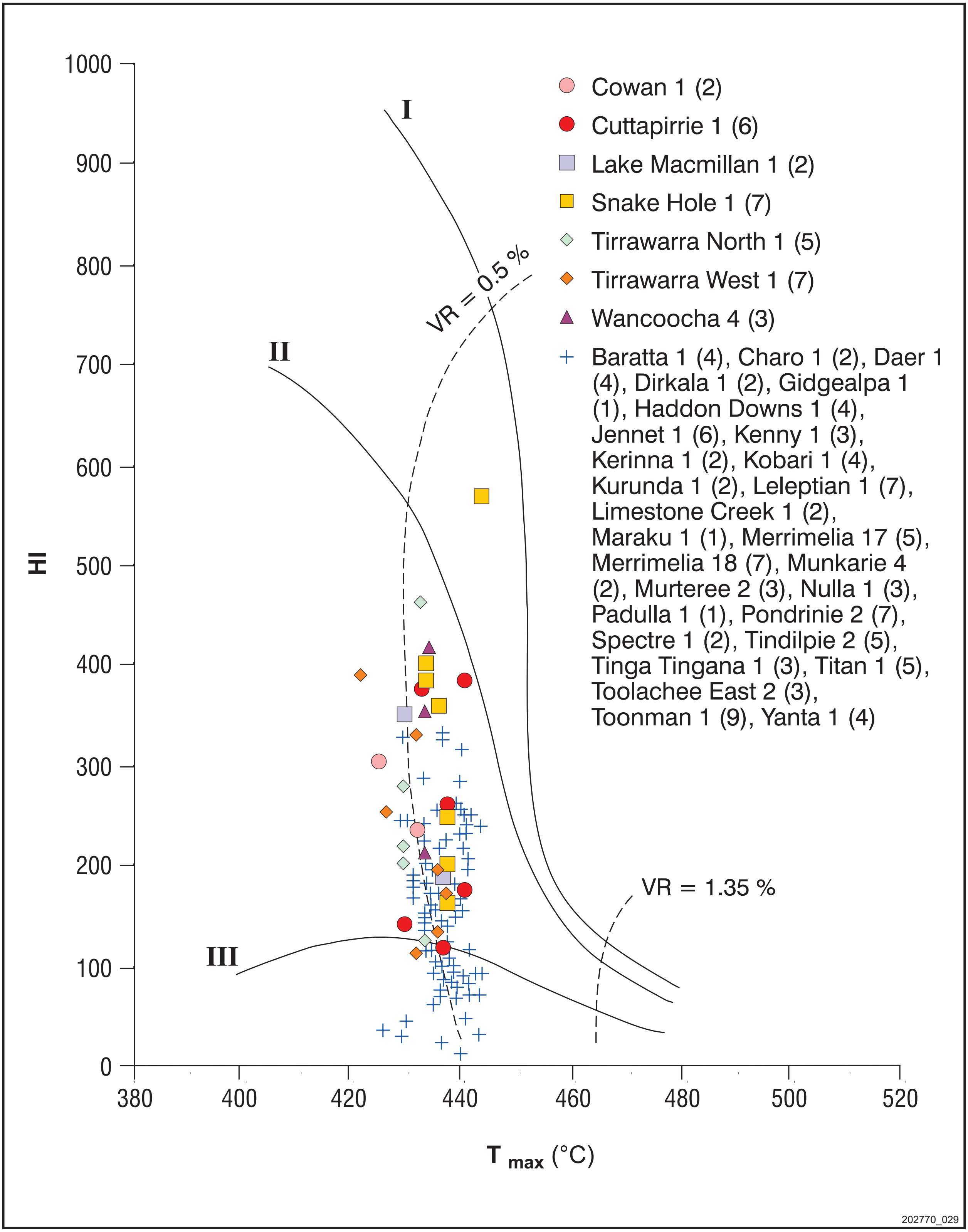

Figure 8.6 HI versus T_{max} plot, Birkhead Formation, Eromanga Basin, South Australia (eastern sector).

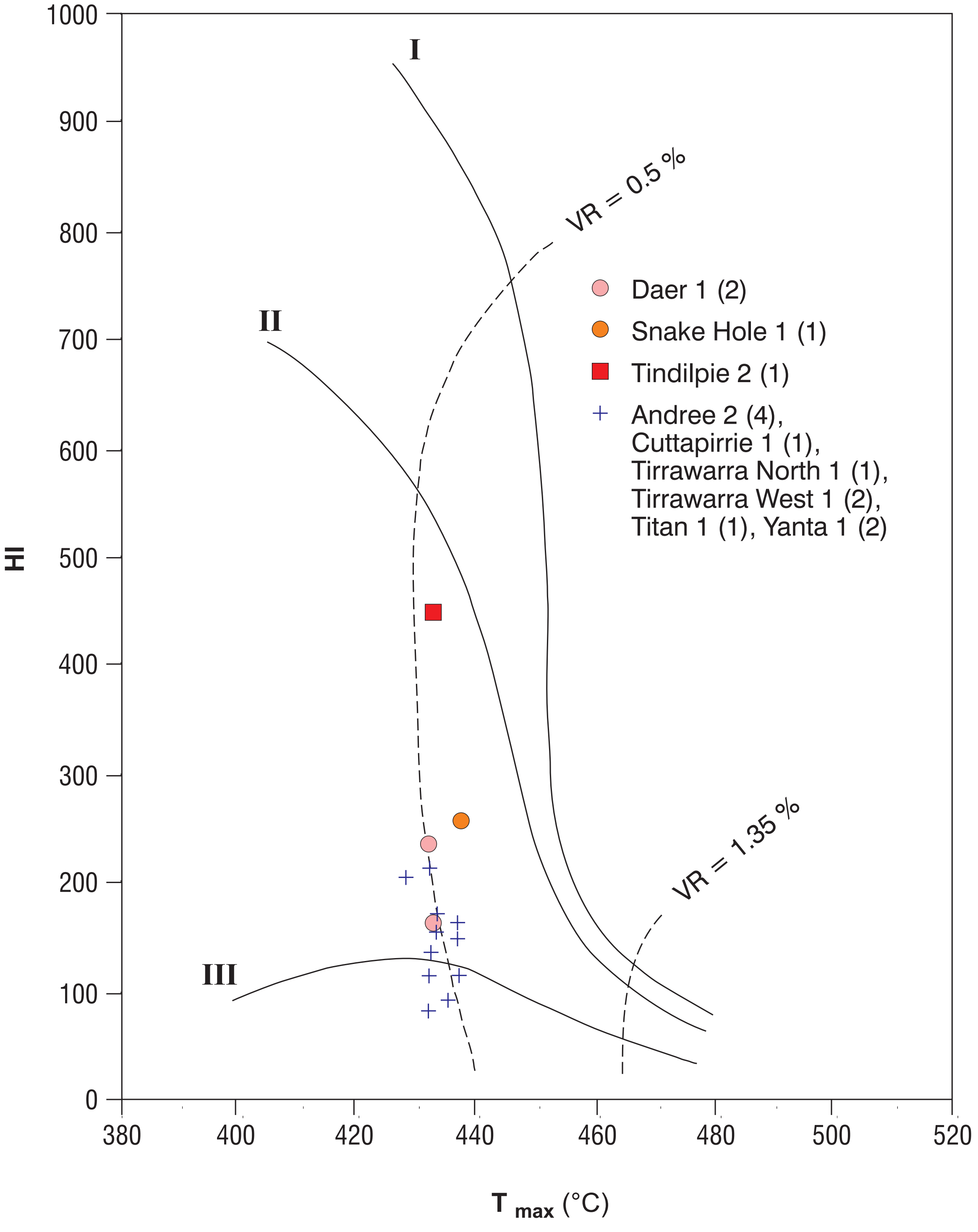

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Figure 8.7 HI versus T_{max} plot, Adori Sandstone, Eromanga Basin, South Australia (eastern sector).

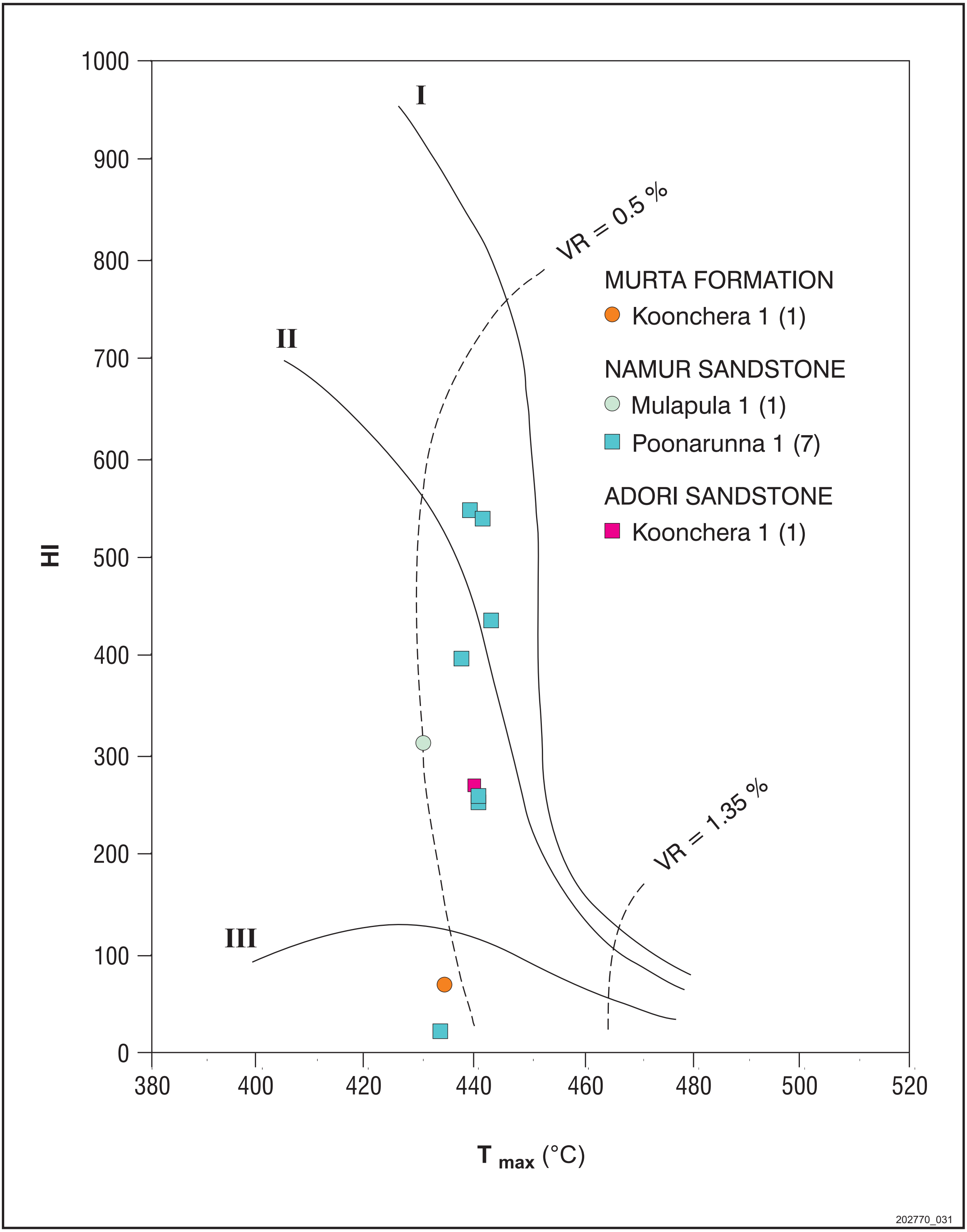

Figure 8.8 HI versus T_{max} plot, Murta Formation, Namur Sandstone and Adori Sandstone, Eromanga Basin, South Australia (eastern sector).

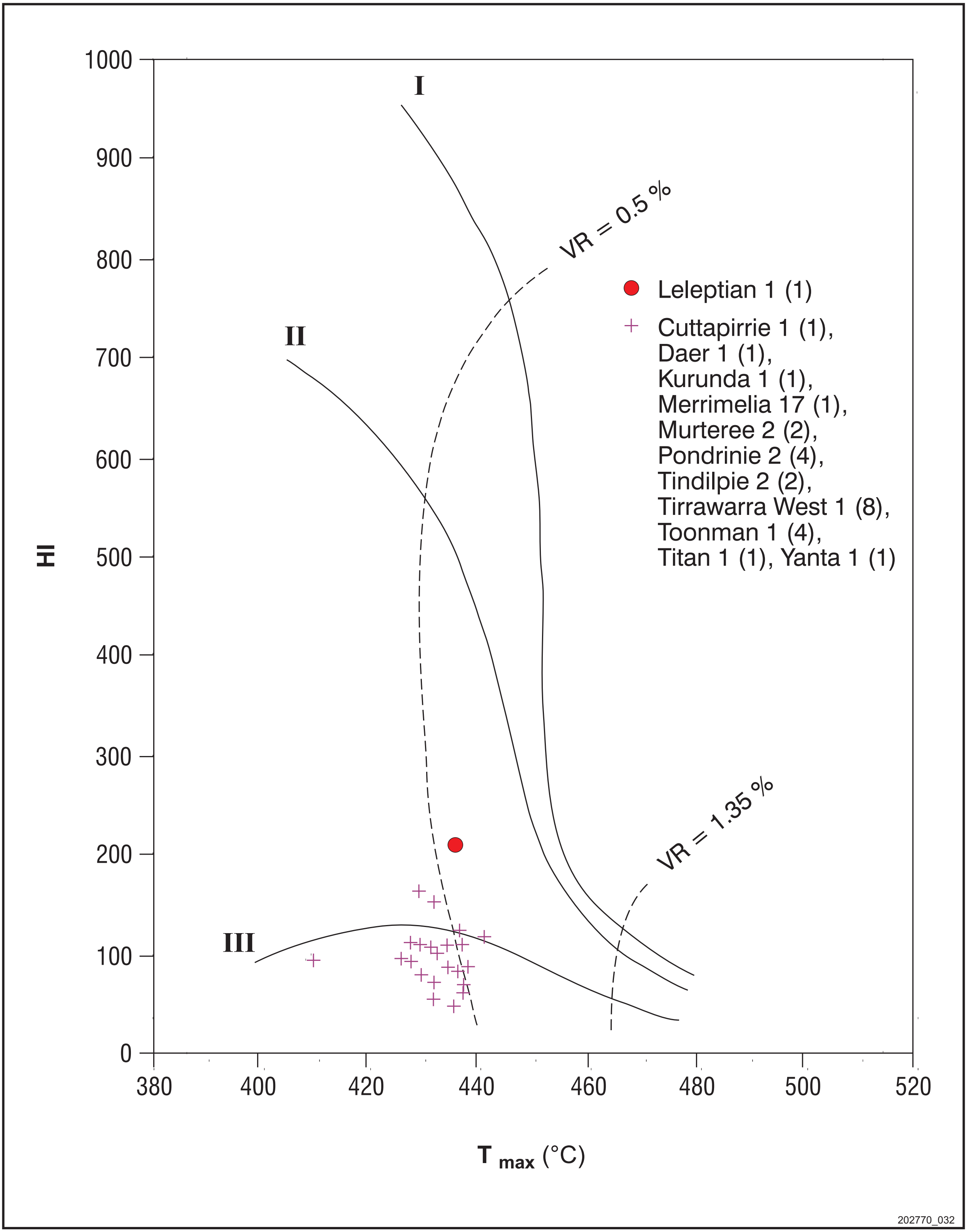

Figure 8.9 HI versus T_{max} plot, Westbourne Formation, Eromanga Basin, South Australia (eastern sector).

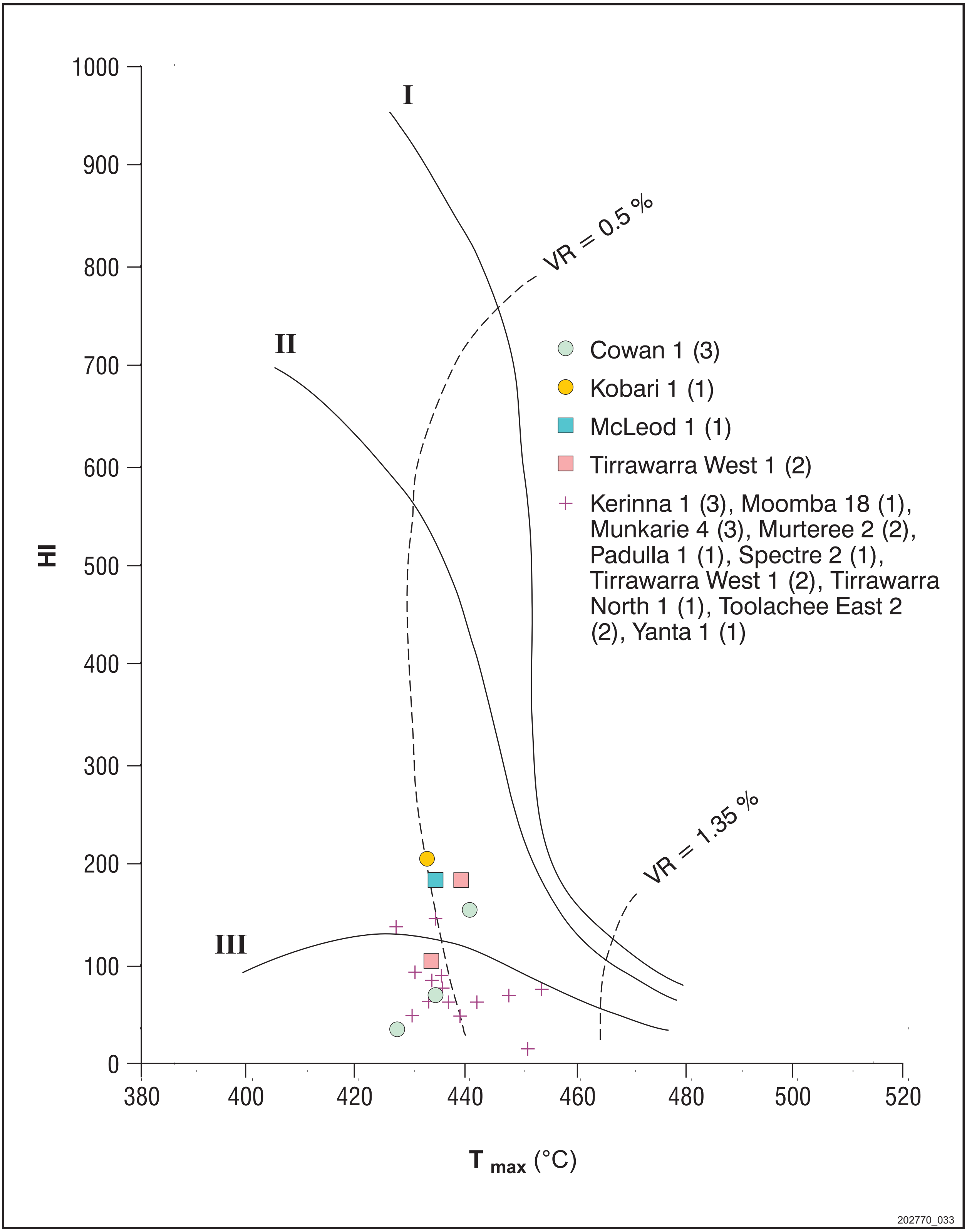

Figure 8.10 HI versus T_{max} plot, Namur Sandstone, Eromanga Basin, South Australia (eastern sector).

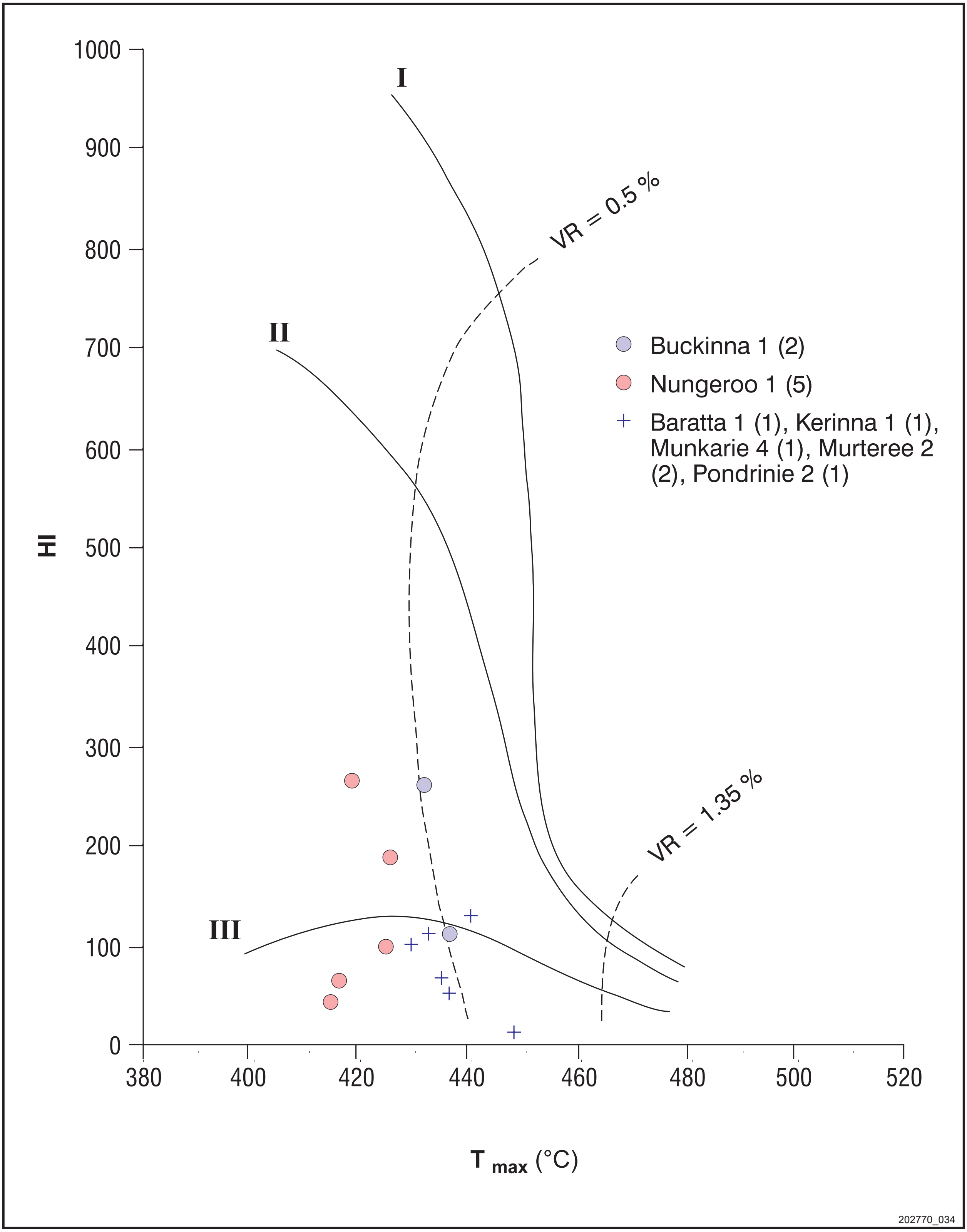

Figure 8.11 HI versus T_{max} plot, McKinlay Member, Eromanga Basin, South Australia (eastern sector).

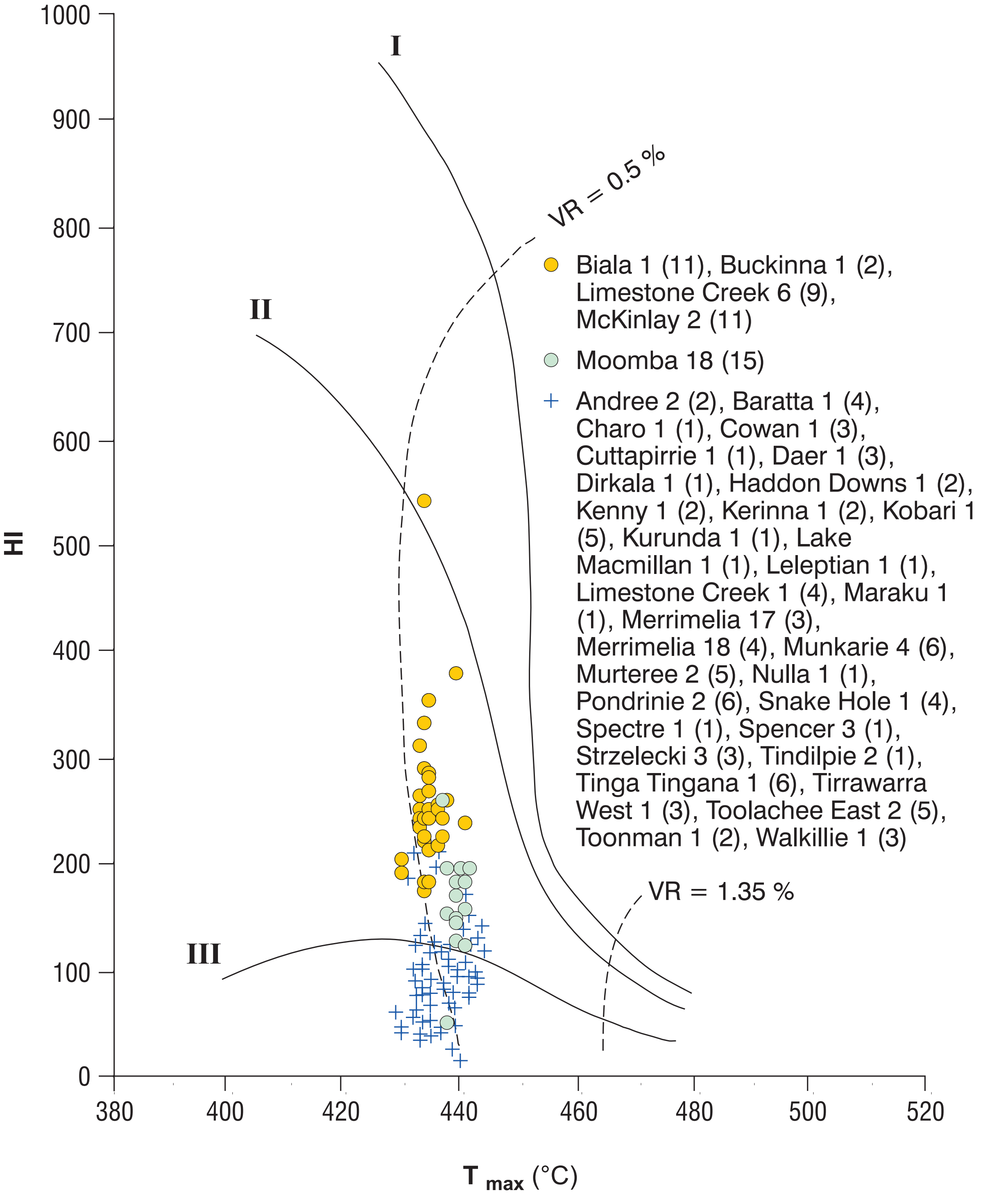

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Figure 8.12 HI versus T_{max} plot, Murta Formation, Eromanga Basin, South Australia (eastern sector).

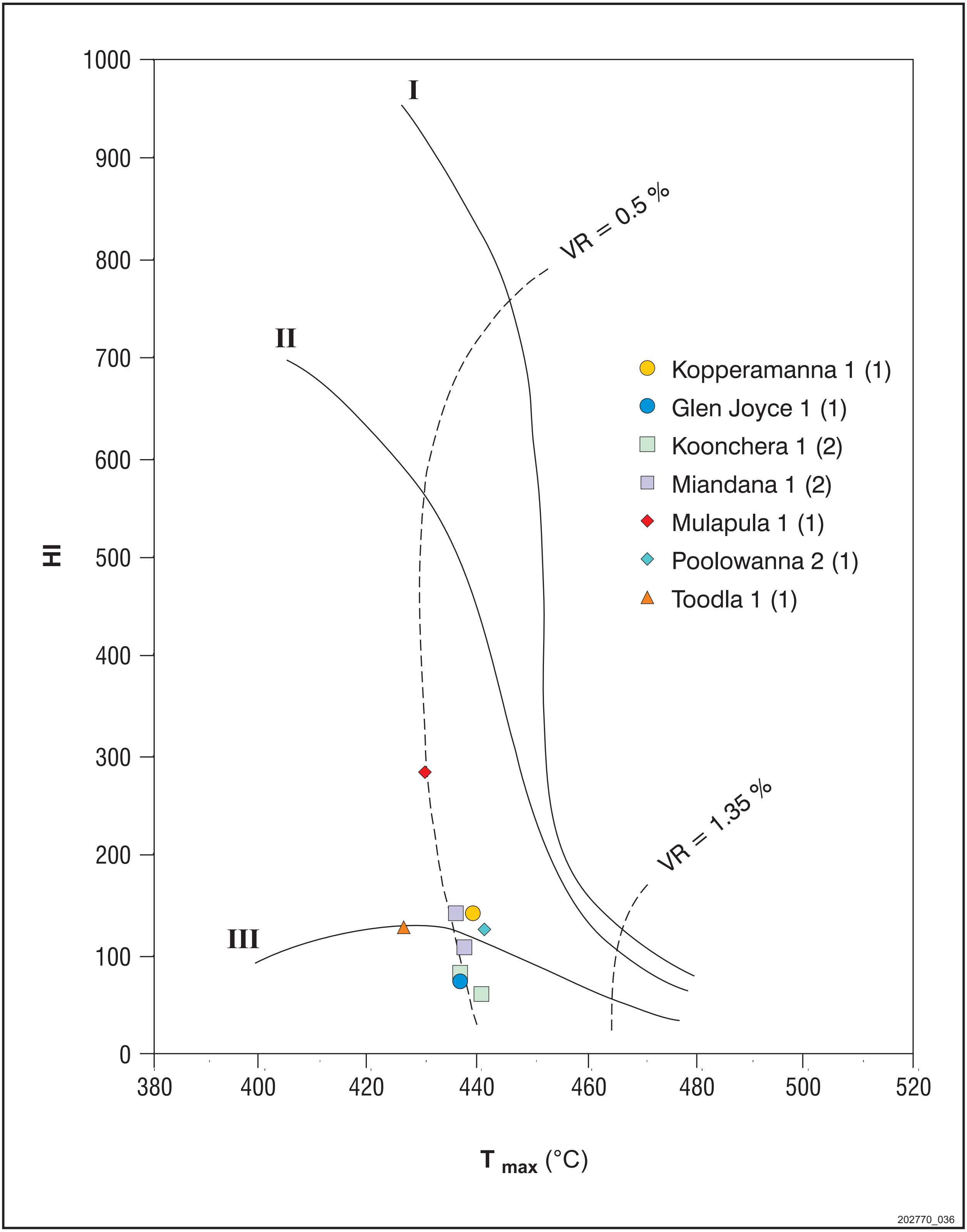

Figure 8.13 HI versus T_{max} plot, Cadna-owie Formation, Eromanga Basin, South Australia (western sector).

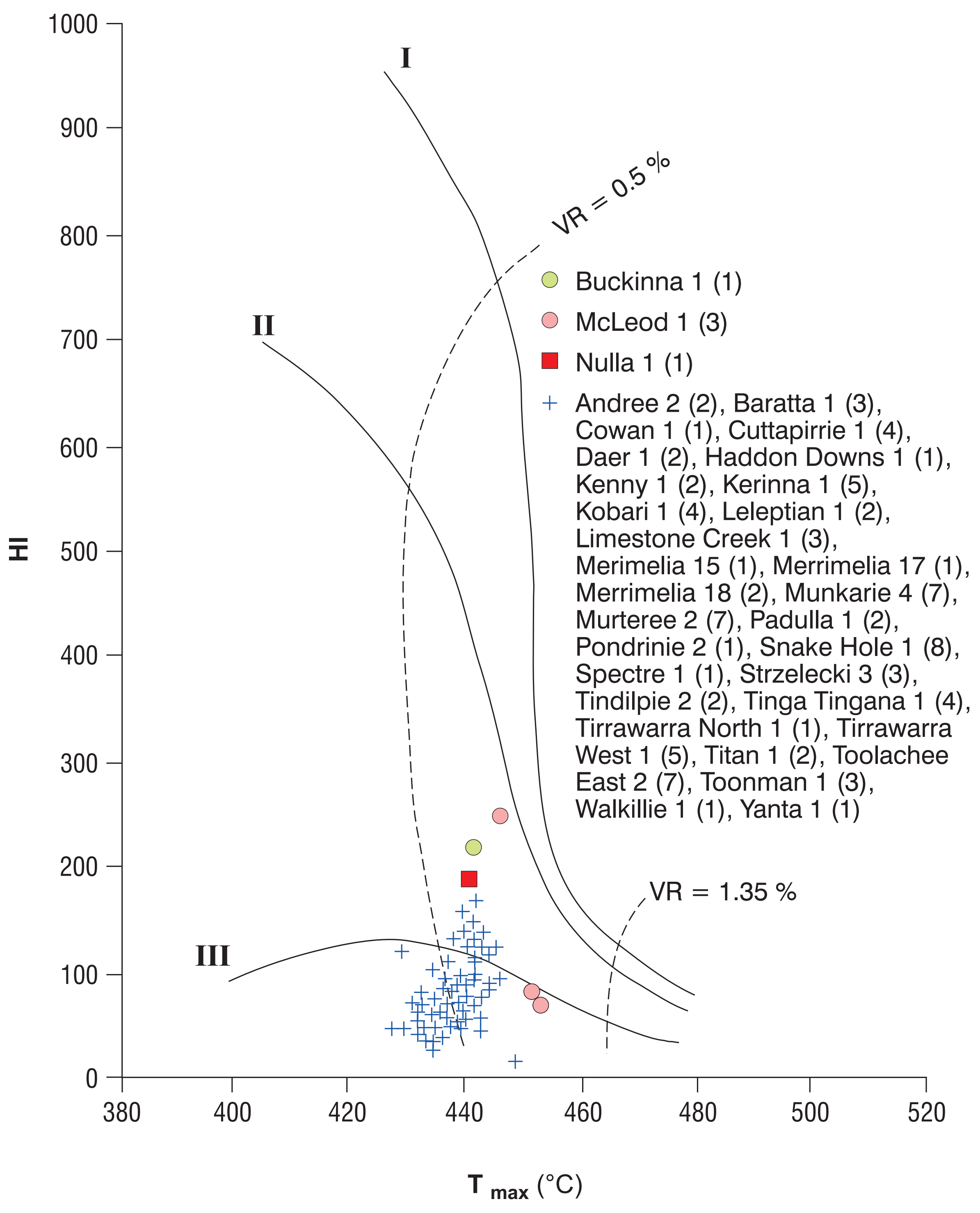

Figure 8.14 HI versus T_{max} plot, Cadna-owie Formation, Eromanga Basin, South Australia (eastern sector).

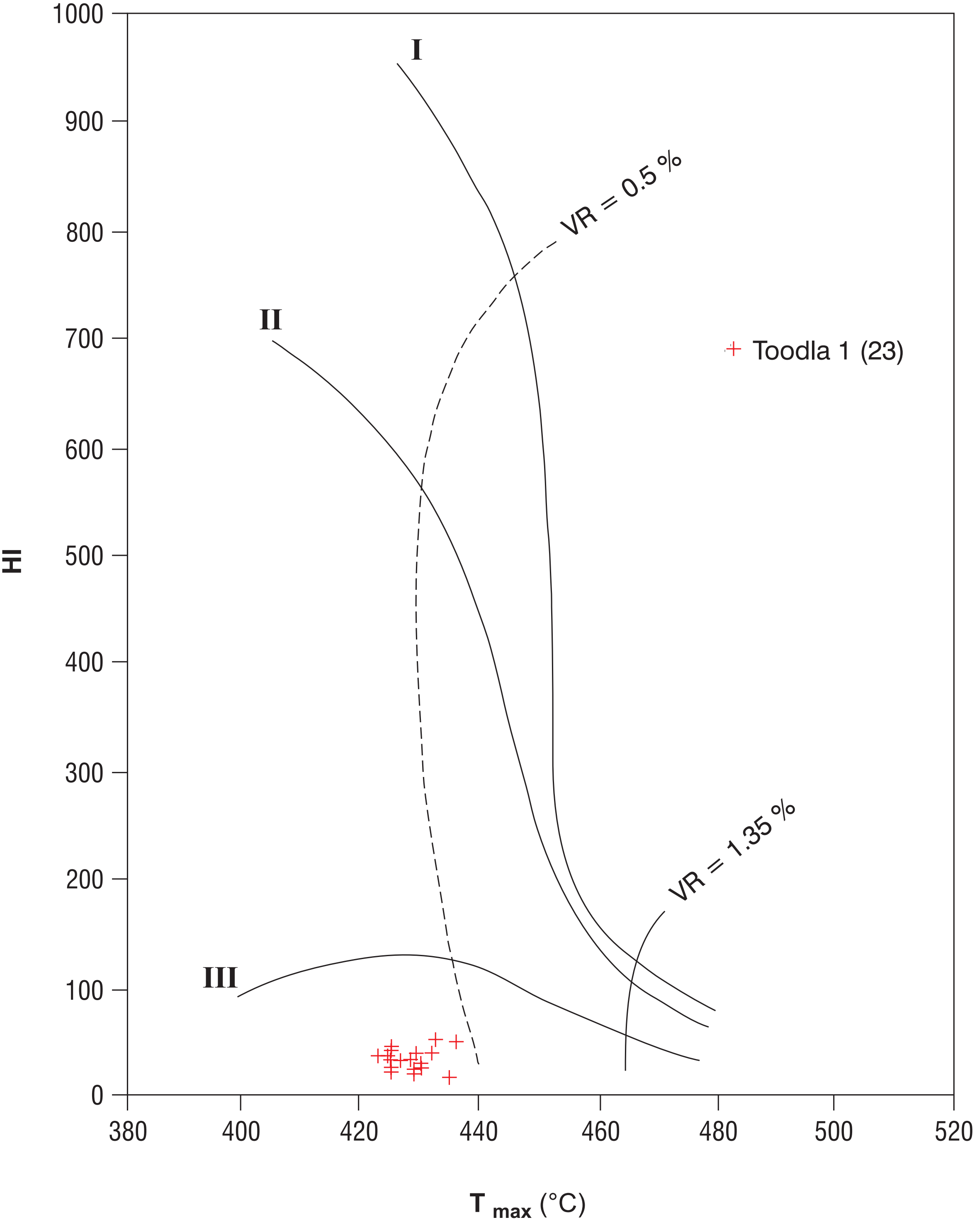

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Figure 8.15 HI versus T_{max} plot, Bulldog Shale, Eromanga Basin, South Australia (western sector).

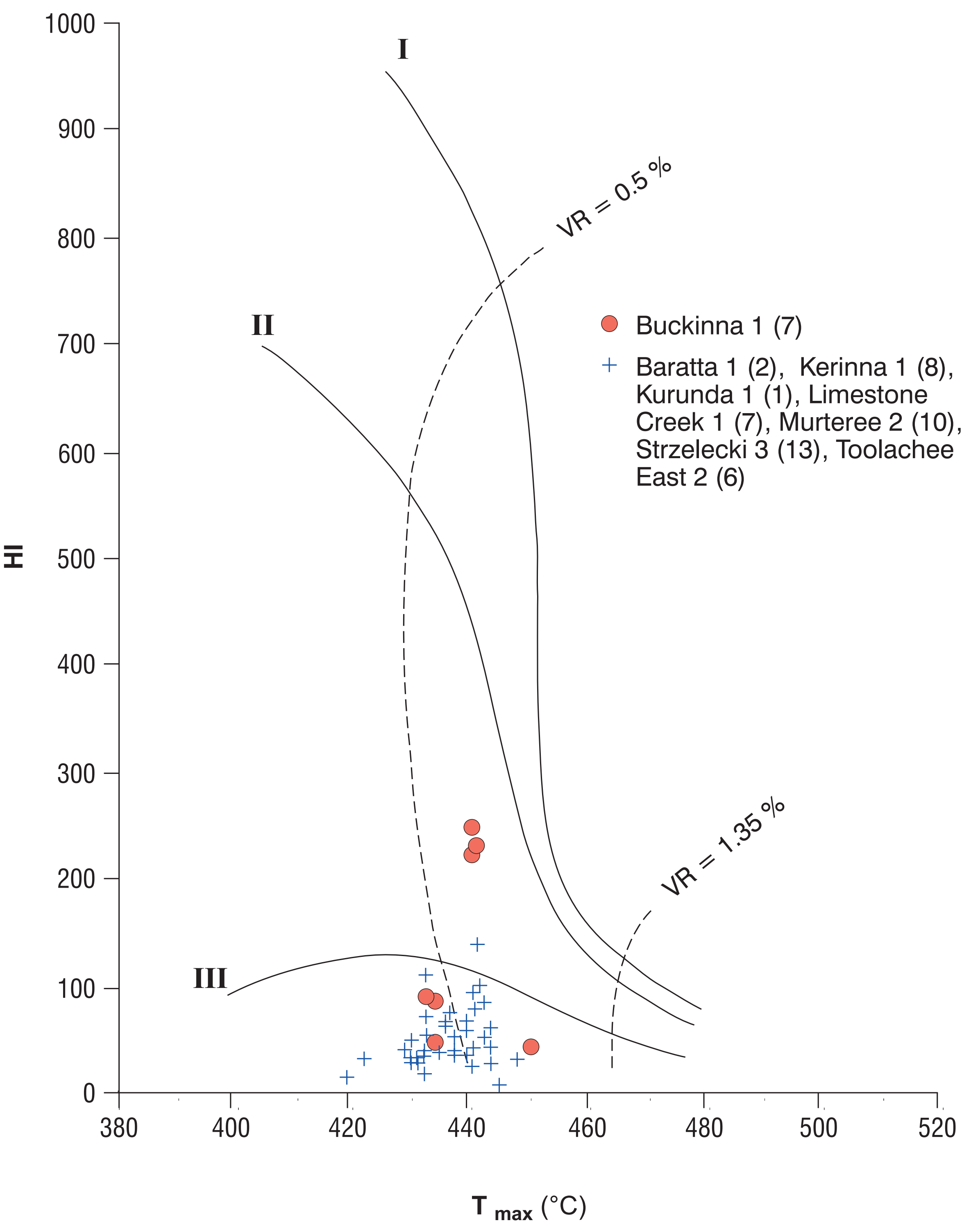

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Figure 8.16 HI versus T_{max} plot, Bulldog Shale, Eromanga Basin, South Australia (eastern sector).

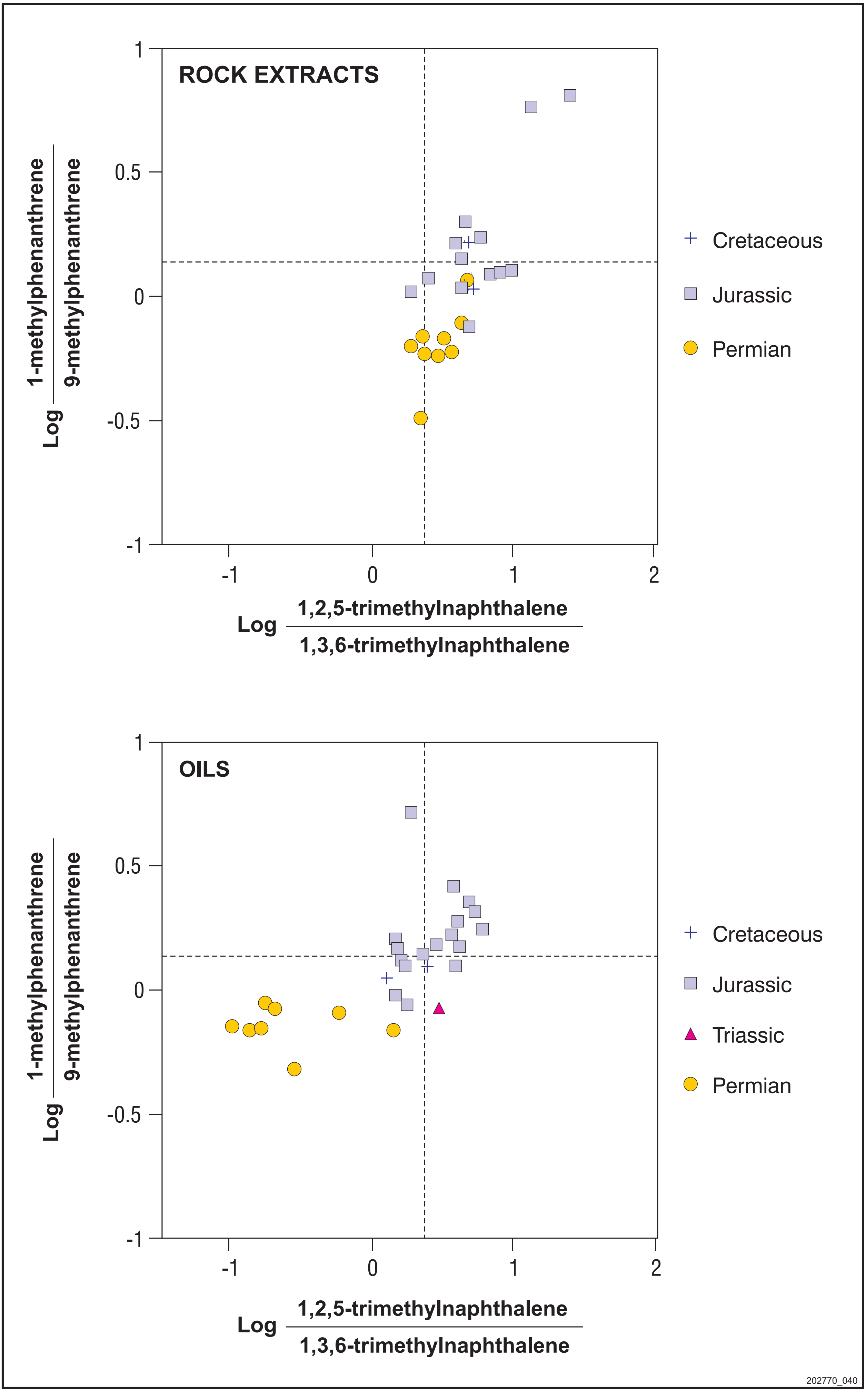

Figure 8.17 Plot of log 1,2,5-Trimethylnaphthalene/1,3,6-trimethylnaphthalene versus log 1-Methylphenanthrene/9-methylphenanthrene for rock extracts and oils from the western Cooper region.

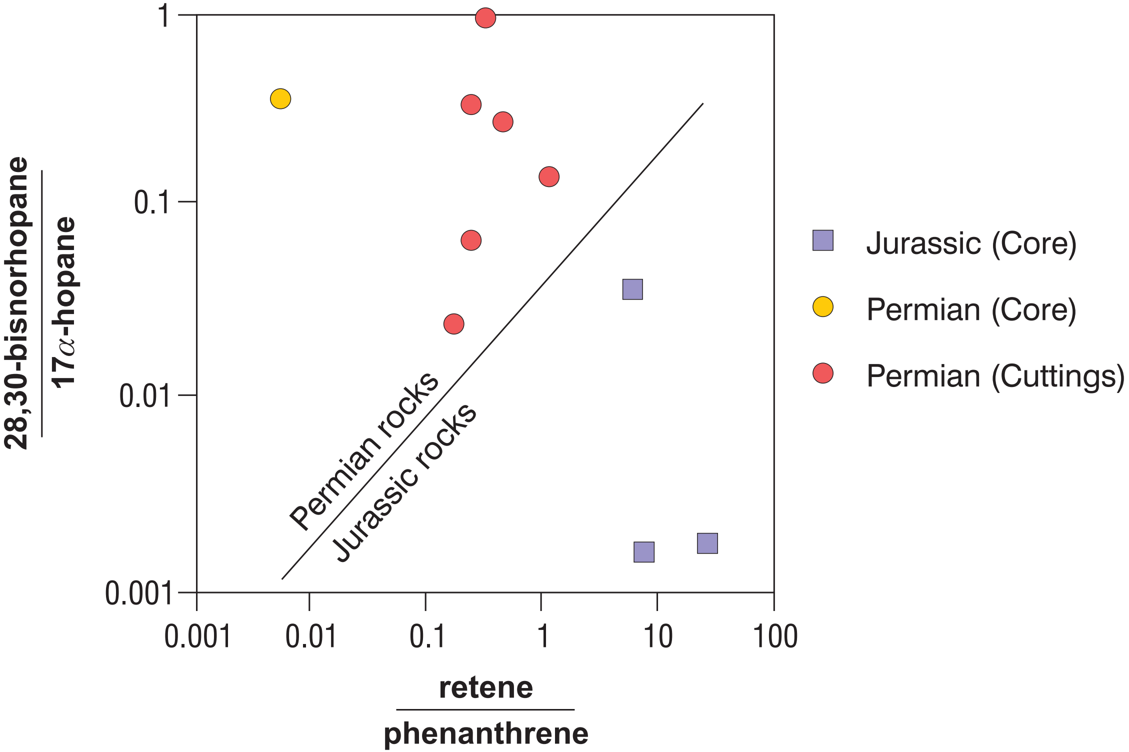

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Figure 8.18 Plot on logarithmic axes of retene/phenanthrene versus 28,30-bisnorhopane/17α-hopane for Permian (Crown Point and Purni Formations) and Jurassic (Birkhead equivalent of Algebuckina Sandstone) rock extracts, Eringa Trough (after Alexander et al., 1996).