

Petroleum Systems of the Perth Basin, Western Australia*

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Abstract

Emerging shale plays, with encouraging results at Woodada Deep 1 and Arrowsmith 2, and a new Permian gas-play at Senecio 3 have revived exploration in the Perth Basin. Locally significant petroleum production (55,769 barrels of liquid and 9.45 million cubic feet of gas in 2013) also point to significant tight sand and shale petroleum potential in the Perth Basin. High-quality source rocks with over 2% TOC and 5 mg/g potential yields are present across the basin with Permian coal and shale predominantly gas-prone, Triassic shale oil-prone, Jurassic coal and shale both gas- and oil-prone, and Cretaceous shale oil-prone. Correlations between oil and source rock show that Whicher Range oil has a Permian source; Dongara, Erregulla, Mount Horner, and Yardarino oil are derived from Triassic source rocks; and oil from Walyering and Gage Roads wells are from Jurassic and Cretaceous sources, respectively. Petroleum system modelling of Arranoo South 1, Cataby 1, West Erregulla 1, and Whicher Range 1 indicates major Permian–Jurassic subsidence and burial in the onshore Perth Basin. Apatite fission-track data indicate regional palaeothermal events during the Cretaceous (135–56 Ma) and Tertiary (30–0 Ma), which vary locally and Cretaceous event extend up to Permian. Consequently, there are significant variations in the timing of petroleum generation across the basin. Initial estimates by US Energy Information Administration indicate tight-sand/shale oil and gas resources in Permian shales of up to 25 trillion cubic feet (Tcf) gas, and in Triassic shales up to 8 trillion cubic feet (Tcf) gas and 500 million barrels oil/condensate. Shale oil and gas exploration is at a very early stage, and more work is needed to verify these estimates as well as to include estimates for the Jurassic. By comparison, the Cretaceous is relatively thin onshore and so is unlikely to contain significant hydrocarbons.

Introduction

The Perth Basin forms a north–south elongate rift trough along the west coast of Australia. There are two main depocentres in the onshore portion, the northern Dandaragan Trough and the southern Bunbury Trough, which are separated by the middle Mandurah Terrace. The Dandaragan Trough is a major depocentre up to 12 km thick. The basin contains mainly continental clastic rocks of Permian and younger age, deposited in a rift system that culminated with the breakup of Gondwana in the Early Cretaceous. Two major tectonic phases are recognized: Permian extension in a southwesterly direction, and Early Cretaceous transtension to the northwest during breakup.

Petroleum exploration started in the early 1950s and since then over 309 onshore and 52 offshore wells has been drilled. As a result, about 20 commercial oil and gas fields and numerous other significant discoveries within tight sand have been discovered (Figure 1 and Figure 2). The basin is producing oil and gas from conventional reservoirs; it produced over 1,155 barrels of oil, 104,324 barrels of condensate, and 7.335 billion cubic feet of gas in 2014, which is locally significant and indicating gas-condensate rich resources.

Petroleum resource estimates indicate tight-sand/shale gas and oil within the Permian Carynginia Formation is up to 25 trillion cubic feet (Tcf) gas, and within the Latest Permian–Triassic Kockatea shales is up to 8 trillion cubic feet (Tcf) gas with 500 million barrels oil/condensate (Kuuskraa et al., 2013). Shale plays have been developed primarily in the US. Over the last 30 years, the US has enjoyed vast increases in production, with drilling of over 102 000 successful production wells.

This has triggered searches for the richest petroleum- shale-plays in the Perth Basin with encouraging results at Woodada Deep 1 and Arrowsmith 2, and a new Permian gas-play at Senecio 3 (Waitsia discovery). The oil recovery from the Kockatea Shale in Arrowsmith 2 was the first proven shale-oil play in the Perth Basin. Shale oil and gas exploration is at a very early stage, and more work is needed to verify these estimates as well as to include estimates for the Jurassic source rocks. By comparison, the Perth Basin has relatively few shale-play wells in the last few years in comparison with thousands of wells in the US.

Currently, the Permian Carynginia and Latest Permian–Triassic Kockatea Shale is a focus for exploration and research to evaluate its tight-petroleum potential. For these shaly formations, Middleton (2015) discussed maturity within the northern Perth Basin; Cooper et al. (2015) used a mass-balance approach through basin modelling to estimate tight-petroleum resources; Rasouli and Rezaee (2014) provided research results on mechanical properties of these shales, and Core Laboratories (2013) evaluated shale source-reservoir systems based on core analyses from six wells in the northern Perth Basin. Ghorri (2013) discussed emerging unconventional shale plays in Western Australia.

Petroleum Systems

Petroleum geochemistry, organic petrology, apatite fission track analysis (AFTA), heat-flow data, subsurface temperatures, and other exploration data from the onshore Perth Basin are used to evaluate petroleum systems. Source-rock and crude oil analytical data are used to identify and characterize conventional and source-rock reservoir petroleum systems. In these reservoirs, there is a porosity continuum from a pore-throat size greater than 2 μm in conventional reservoirs, to 2–0.03 μm in tight-gas sandstone, and 0.1–0.005 μm in shale (Nelson, 2009). In tight-reservoir systems, trapping mechanisms are typically subtle and can cover large basinal areas (Curtis, 2002; Law and Curtis, 2002), and the timing of charge versus trap formation is not as critical as it is in conventional reservoir systems.

Source rocks form the richest petroleum shale-plays, because they retain a vast quantity of petroleum even after expelling significant petroleum to conventional reservoirs. These are texturally and mineralogically heterogeneous, so that apparently similar-looking shales often have different source-rock characteristics (Durham, 2010; Aplin and Macquaker, 2011). The geochemical, geomechanical, and petrophysical properties of source rocks determine the potential difficulty of unlocking petroleum retained in the source rock. Unlocking to commercialize shale petroleum is mostly accomplished by horizontal drilling and hydraulic fracturing (Jacobi et al., 2008; Jacobi et al., 2009).

Good quality shale-gas resources depend on adequate source-rock thicknesses of net pay (>100 m), adequate porosity (>2%), high reservoir pressure (ideally overpressured), high thermal maturity (>1.5% Ro), high organic richness (>2% TOC), low in clay (<50%), high in brittle minerals (quartz, carbonates, feldspars), and favourable in situ stress. These shale-play properties and their petroleum richness vary from basin to basin as well as within a basin.

Source Rock Parameters

The source-rock characterization generally used by the petroleum industry (Baskin, 1997; Dembicki Jr., 2009) was applied for this study, albeit with some modifications as discussed below. The petroleum-generating capacity of a source rock depends on four factors: organic richness (amount of kerogen), organic facies (type of kerogen), organic maturity (kerogen to petroleum transformation ratio), and expulsion efficiency. Organic richness is measured by TOC content. Source-rock samples with TOC content >0.5% are classified as of fair organic richness, between 1% and 2% as good, between 2% and 4% as very good, and over 4% as excellent.

Thermal and pyrolysate yield of organic compounds from Rock-Eval pyrolysis is expressed as S_1+S_2 or potential yield, which quantifies the hydrocarbon-generating capacity of rocks. S_1 represents existing indigenous or migrated hydrocarbons in a rock and is approximately equivalent to the extractable organic matter (bitumen). S_2 represents the organic compounds generated from kerogens during pyrolysis. S_1 and S_2 are both measured as milligrams in a gram of rock (mg/g rock). Samples with potential pyrolysate yield (S_2) of 2–5 mg/g rock are classified as fair, those with 5–10 mg/g rock as good, those with 10–20 mg/g rock as very good, and those over 20 mg/g rock as excellent.

Source-rock facies classification of the kerogen type is determined using a cross plot of TOC versus the Hydrogen Index (HI). The HI from Rock-Eval corresponds to the quantity of hydrocarbon compounds (HC) that can be pyrolyzed relative to the total organic carbon (mg HC/g TOC). Source rocks with HI values less than 150 are classified as gas generating, while those with HI values over 150 are classified as oil and gas generating. Source-rock maturity level is determined using a cross plot of T_{max} and the Production Index (PI). T_{max} provides an indication of source-rock maturity but can be affected by organic facies type. T_{max} less than 435°C is classified as immature, between 435°C and 460°C as oil generating, between 460°C and 470°C as wet-gas generating, and over 470°C as dry-gas generating.

Vitrinite reflectance (VR) data and T_{max} from Rock-Eval indicate thermal maturity; AFTA indicates maximum paleotemperatures and their timing, whereas present-day temperatures are estimated from recorded temperatures in petroleum wells. Finally, organic maturity and timing of oil and gas generation from source rocks can be estimated from basin modelling. No direct method is available to measure expulsion efficiency, although a mass balance approach can be used to estimate petroleum expulsion efficiency (PEE) using Rock-Eval parameters (Coolles et al., 1986; Powell and Boreham, 1991).

Source Rock

Source rocks of the Perth Basin are identified from analytical data available for about 4000 samples (Figure 3). TOC and Rock-Eval pyrolysis data (Figure 3a) are used to discriminate between source- and non source-rock samples (Espitalié et al., 1985; Peters, 1986; Bordenave et al., 1993). Those samples with <0.5% TOC and <2 mg HC/g rock pyrolysate yield (S_2) are discriminated as non source-rock samples (Figure 3b

and 3c), and excluded from further interpretation. For source-rock samples, a cross plot of T_{\max} versus PI is used to further discriminate between oil and gas shows or contaminated samples and source-rock samples (Figure 3d). T_{\max} represents the analysis temperature ($^{\circ}\text{C}$) at maximum hydrocarbon generation during the S_2 cycle. PI represents kerogen conversion indices ($S_1 / (S_1 + S_2)$); its value increases with hydrocarbon generation as a function of increasing maturity. Higher than normal values (0.4) are observed in migrated or accumulated hydrocarbons, non source-rock, or contaminated samples, whereas lower than normal (0.1) values are due to the expulsion of hydrocarbons from the source rock. Parameters for source-rock richness, facies, and maturity discussed above are used to characterize petroleum source rocks (Espitalié et al., 1985; Peters, 1986; Bordenave et al., 1993). The petroleum-generating potential of the Permian, Triassic, Jurassic, and Cretaceous source rocks are summarized in Figure 4.

Crude Oil

GeoMark Research and the Australian Geological Survey Organisation (now Geoscience Australia) analysed 13 oil samples from the Perth Basin for their physical, chemical, biomarker, and isotopic characteristics (GeoMark and AGSO, 1996). These oil characteristics were used to describe the organic type, depositional environment, and mineralogy of the source rocks. GeoMark and AGSO (1996) used chemometric analysis to identify different oil families by removing noise from the large, regional database (Peters et al., 2005) and statistically analysed a multivariate dataset. This enabled GeoMark and AGSO (1996) to recognize four genetically related oil families based on principal component analysis (PCA) techniques (Figure 5). These oil families were sourced from the Permian, Triassic, Jurassic, and Cretaceous source rocks, which are part of the Gondwanan and Austral Superpetroleum Systems (Bradshaw et al., 1994; GeoMark Resource and AGSO, 1996).

Gas-prone source beds within the Permian Carynginia Formation with organic richness up to 11% TOC, and Latest Permian–Triassic Kockatea Shale with TOC over 2% are part of the Gondwanan Superpetroleum System; whereas oil- and gas-prone source beds with TOC up to 27% within the fluvial-lacustrine shale facies of the Jurassic Cattamarra Coal Measures and Yarragadee Formation with TOC up to 2% are part of the Austral Superpetroleum System (Figure 2 and Figure 5). These source rocks have been correlated with conventional reservoir oil accumulations (Figure 5), and are potential petroleum shale-plays within the onshore Perth Basin. The source rocks of the Gondwanan Superpetroleum System are currently under exploration for shale-plays. Source beds within the Permian, Triassic, and Jurassic have a wide distribution and extend offshore Perth Basin (Thomas, 1984; Thomas and Barber, 1994; Crostella and Backhouse, 2001; Grosjean et al., 2012).

Petroleum System Modelling

BasinMod 2014 software (Platte River Associates) is used to model maturation and petroleum-generation history of West Erregulla 1 from the northern Perth Basin and Whicher Range 1 from the southern Perth Basin. These modeled reconstructions were constrained using present-day temperatures and heat flows, and AFTA paleothermal events. Chopra and Holgate (2007), Hot Dry Rocks Pty Ltd (2008), and Ghorri (2009) provide information on present-day temperatures (in most wells) and heat flows (162 wells).

AFTA constrains paleotemperatures and the time of cooling from peak temperatures. Fission-track ages are largely a function of track annealing in response to an increase in temperature of between about 50°C and 120°C , and track length reflects the style of cooling. Vitrinite

reflectance (VR) data are used to constrain the range of paleotemperatures, since apatite fission tracks are totally annealed above approximately 110°C. This temperature corresponds to a vitrinite reflectance range of 0.7–0.9%.

AFTA data is available for 15 samples, five each from Arranoo South 1, Cataby 1, and West Erregulla 1 (Gibson et al., 1997). These samples are from the Permian Carynginia Formation, Latest Permian–Triassic Kockatea Shale, Jurassic Eneabba Formation, Cattamarra Coal Measure, and Yarragadee Formation. Measurements of 26 AFTA time constraints indicate two major regional episodes of heating and cooling (burial and erosion); the first occurred between 135–65 Ma (Cretaceous), and the second between 30–0 Ma (Tertiary; [Figure 6](#)).

In the modelling, transient heat flow was applied in order to link the thermal history with tectonically induced heat changes. This provides a direct interpretation in terms of the physical processes involved in basin formation (Gallagher and Morrow, 1998). BasinMod fluid-flow parameters are applied for estimating compaction, pressure, and reduction in porosity and permeability. Predicted maturity and oil windows are based on the Lawrence Livermore National Laboratory vitrinite and kerogen kinetics used by BasinMod.

The burial history was reconstructed from the rock-unit thicknesses and lithologies interpreted in modelling wells, as well as events that occurred during times represented by unconformities. Then, the thermal history was reconstructed by adjusting thermal conductivities and heat flow to constrain the maturity model against measured corrected bottom-hole temperatures (BHT), % Ro, T_{max} , and AFTA to constrain present and paleo-temperatures. Finally, kinetic modelling and reconstruction of petroleum generation, as a function of geothermal history and the type and amount of kerogen, was used to estimate the time of petroleum generation. The depth of the oil window is believed to be equivalent to the burial depths necessary to convert 10–90% of the available kerogen to petroleum. Based on the geochemical data, the Permian and Jurassic source rocks are assumed to contain mostly type III kerogen. The Triassic and Cretaceous source rocks are assumed to contain mostly type II kerogen.

This study includes 1D modelling, which is generally referred to as maturity modelling, whereas multidimensional (2D) modelling is generally referred to as fluid-flow modelling. Most of the geological framework used in 1D maturity modelling is also used in 2D fluid-flow modelling, with the kinetics of hydrocarbon generation and expulsion model. The thermal regimes used in 1D and 2D models are the same except for lateral heat transfer by convection or diffraction (Waples, 1998).

West Erregulla 1

The West Erregulla 1 exploration well was drilled by Barrack Energy Ltd to a total depth of 4065.5 m in 1990. It is located within the Allanook High, northern Perth Basin and was drilled to test the structure within Early Jurassic and Late Permian rocks. It is updip from the Erregulla 1 (1966) and Erregulla 2 (1980). North Erregulla 1 is located 16 km north-northwest of Erregulla 1 and 2. In Erregulla 1 oil was recovered from the Eneabba Formation, and in North Erregulla 1, drill Stem test 1 and 2 recovered 20 gallons (91 litres) of 38° API oil from the upper part of the Latest Permian to Early Triassic Kockatea Shale, and 8 gallons (36 litres) at the top of the Permian section, respectively (Thornton, 1990; Crostella, 1995).

Source-rock analyses are available from Erregulla 1 and North Erregulla 1, whereas AFTA data are available from West Erregulla 1 (Figure 6). Petroleum-generation modelling for the Erregulla Area is based on preserved stratigraphic thicknesses, geochemistry, organic petrography, and AFTA data are available from Erregulla area wells. Modelling indicates that petroleum generation–migration–accumulation took place during the Cretaceous paleothermal event (Figure 7 and Figure 8), which is used as an example for the northern Perth Basin.

Whicher Range 1

The Whicher Range I exploration well was drilled by Union Oil Development Corporation to a total depth of 4653 m in 1968. It is located in the Bunbary Trough, southern Perth Basin. The well was drilled on a well-defined dome closure with approximately 274 m of closure near the top of the Permian, to test the Jurassic–Permian section. Drill Stem Tests (DST) were run for the interval 3949.6–4027.4 m and recovered up to 1.93 MMCFD of gas and a gas discovery was declared (Union Oil Development Corporation, 1968). Four more wells were drilled to appraise the Whicher Range tight-sand gas field and detailed research is reported by Western Australian Energy Research Alliance (2012).

Source-rock analyses are available from the Willespie Formation, Cattamarra Coal Measures, and Yarragadee Formation, which indicate high-quality gas-prone source rocks but not gas matured at Whicher Range 1 location. For this well, AFTA data is not available; thus, the petroleum-generation modelling for the Whicher Range Area is based on preserved stratigraphic thicknesses, geochemistry, and organic petrography data. Modelling indicates that petroleum generation–migration–accumulation took place during the Jurassic (Figure 9 and Figure 10) which is used as an example for the southern Perth Basin.

Conclusions

Emerging shale plays are estimated to produce over 33 trillion cubic feet of gas and 500 million barrels of oil, which is expected to compensate decreasing production from conventional reservoirs. Initial results obtained at Woodada Deep 1, Arrowsmith 2 where oil recovery from the Latest Permian–Kockatea Shale and a new Permian gas-play at Senecio 3 (Waitsia discovery) has revived exploration in the Perth Basin. Whicher Range oil has a Permian source; Dongara, Erregulla, Mount Horner, and Yardarino oil are derived from Triassic source rocks; and oil from Walyering and Gage Roads wells are from Jurassic and Cretaceous sources, respectively.

Petroleum system modelling of West Erregulla 1 and Whicher Range 1 indicates major Permian–Jurassic subsidence and burial in the onshore Perth Basin. AFTA data indicate regional paleothermal events during the Cretaceous (135–56 Ma) and Tertiary (30–0 Ma) which vary locally, and a Cretaceous event extending up to the Permian. Consequently, there are significant variations in the timing of petroleum generation across the basin.

Currently, the Permian Carynginia and Latest Permian–Triassic Kockatea Shale are the focus of exploration and research for their tight-petroleum potential. These studies indicate that emerging tight-petroleum resources of the Perth Basin are viable petroleum plays of significant quantity with favourable geology. While the US produces shale-plays from thousands of wells backed by over 30 years of research, the Perth Basin geological and technological studies of these resources are at an early stage as only few wells have been drilled.

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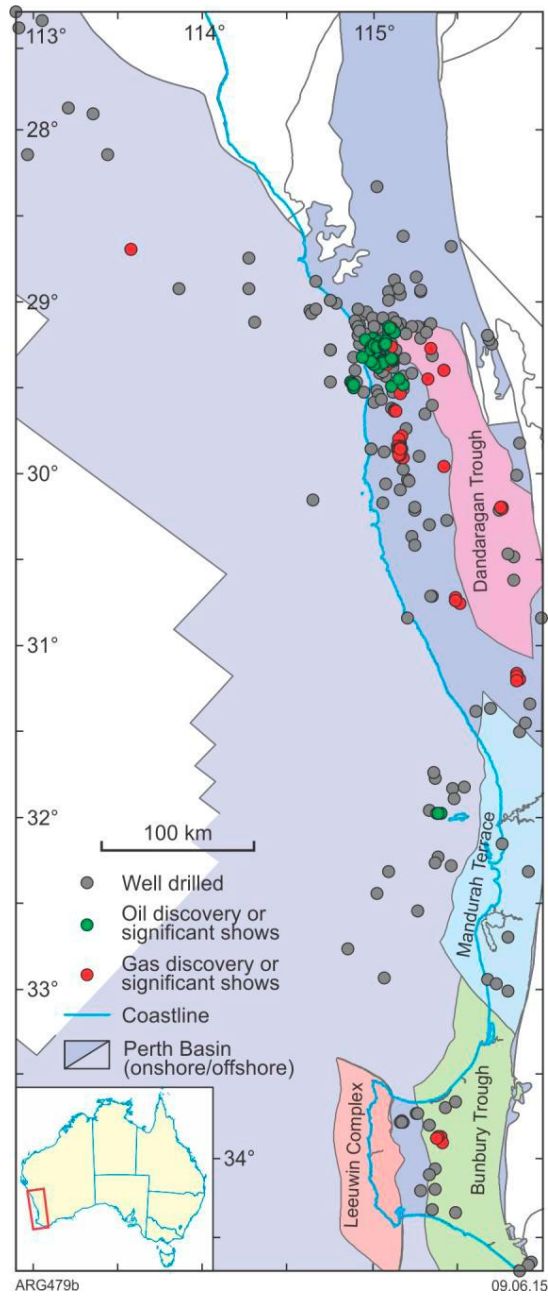


Figure 1. Perth Basin map showing tectonic units, exploration wells, and petroleum discoveries.

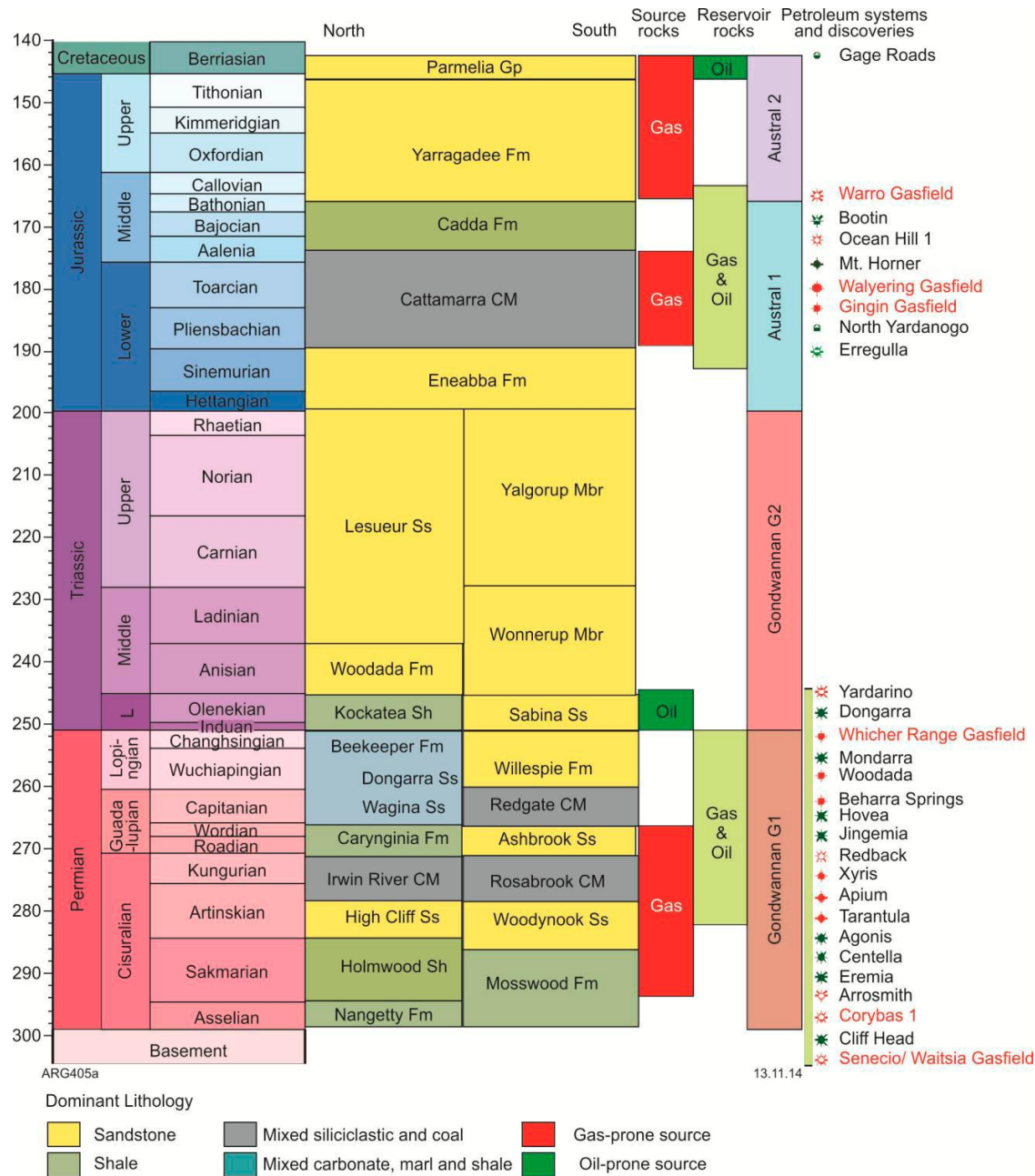


Figure 2. Time-stratigraphy of the Perth Basin showing petroleum source rocks, reservoirs, and systems.

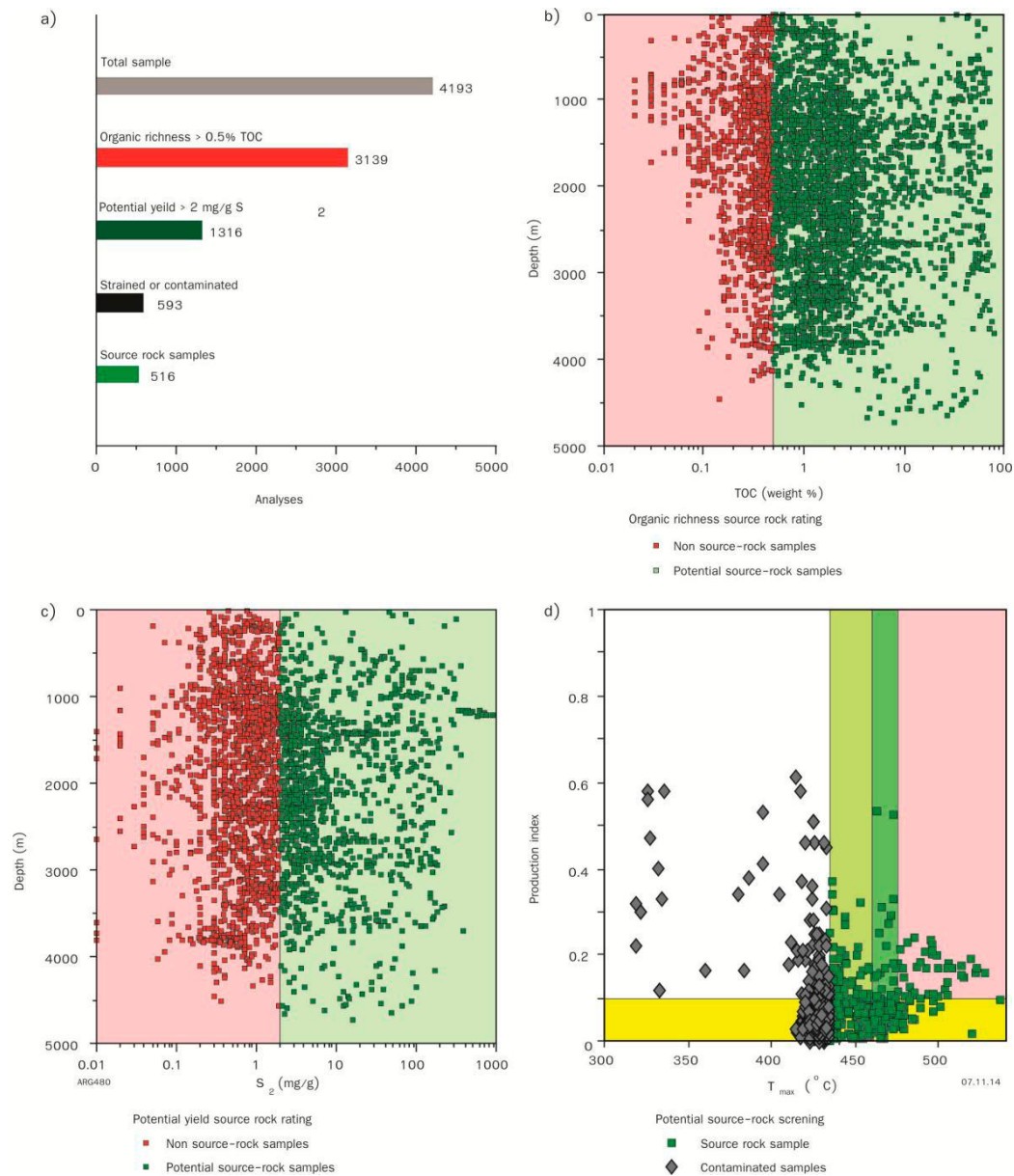


Figure 3. Petroleum source rock evaluation data: a) number of analysis; b) differentiating between non-source and source rock samples based on organic-richness; c) differentiating between non-source and source rock samples based on Rock-Eval potential yield; d) differentiating between non-contaminated and contaminated source rock samples based on Rock-Eval maturity parameters.

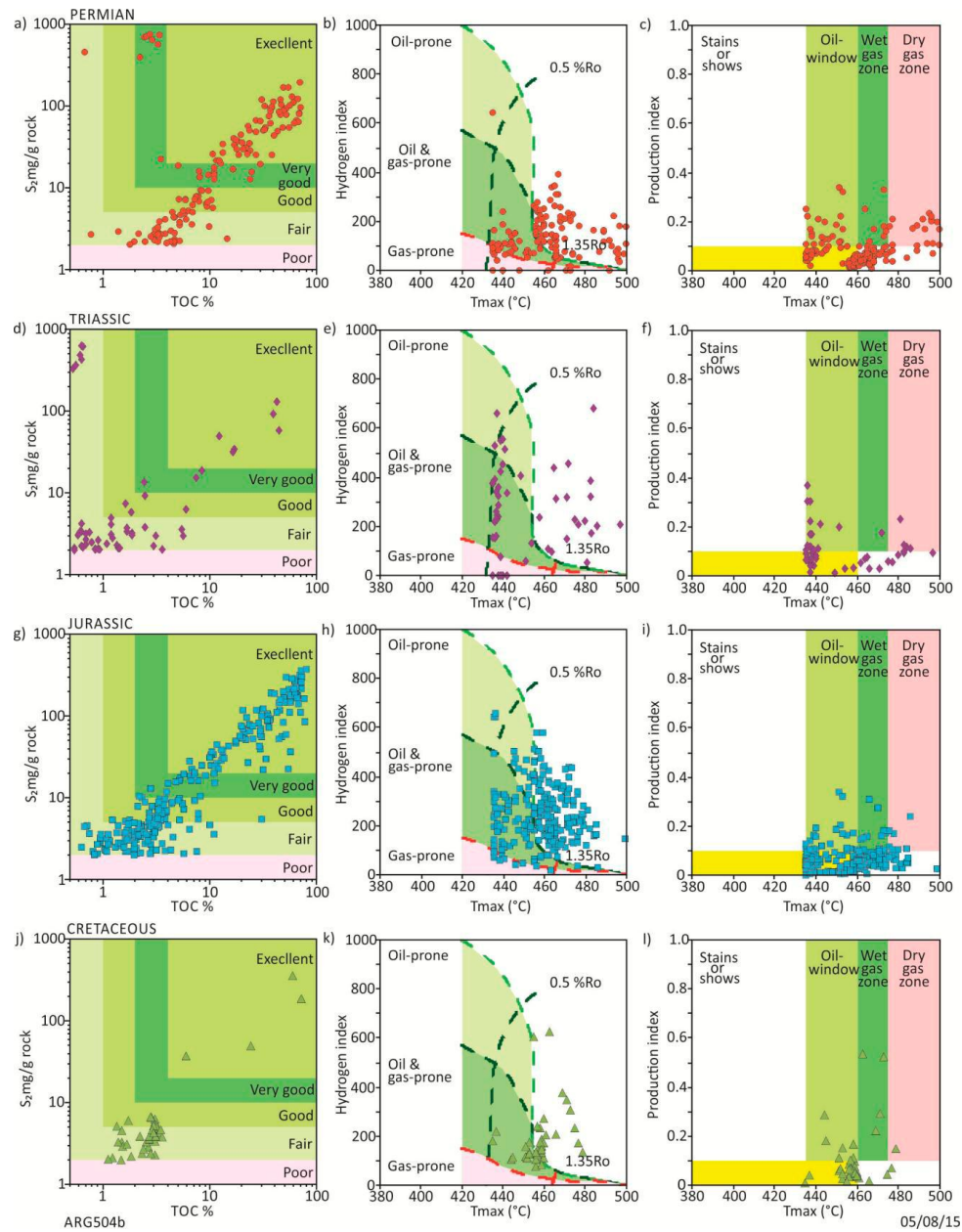


Figure 4. Characterization of source rock generating potential, kerogen type, and thermal maturity based on Rock-Eval parameters: a–c) Permian; d–f) Triassic; g–i) Jurassic; j–l) Cretaceous.

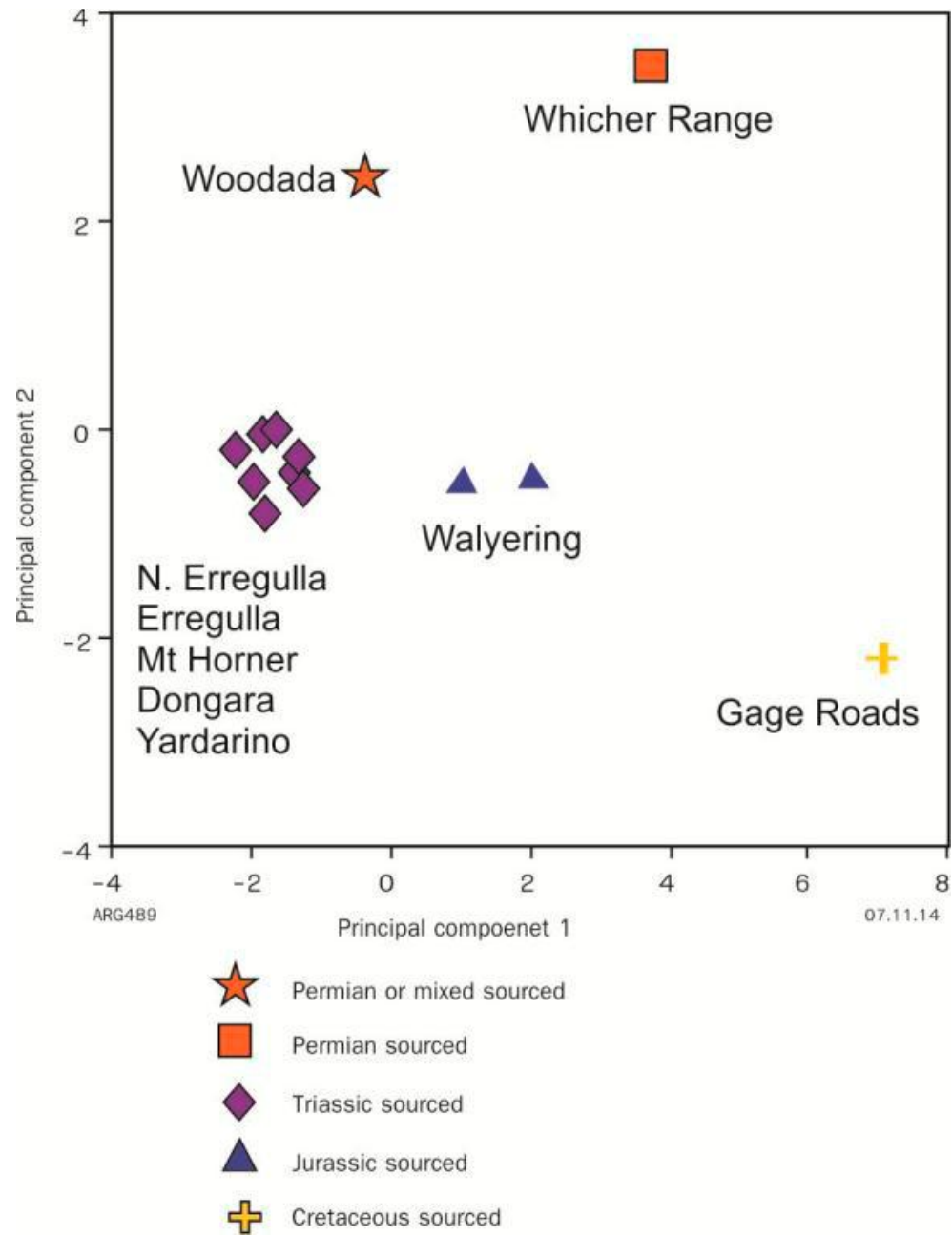


Figure 5. Chemometric characterization of 13 crude oils, analysed by GeoMark and AGSO (1996).

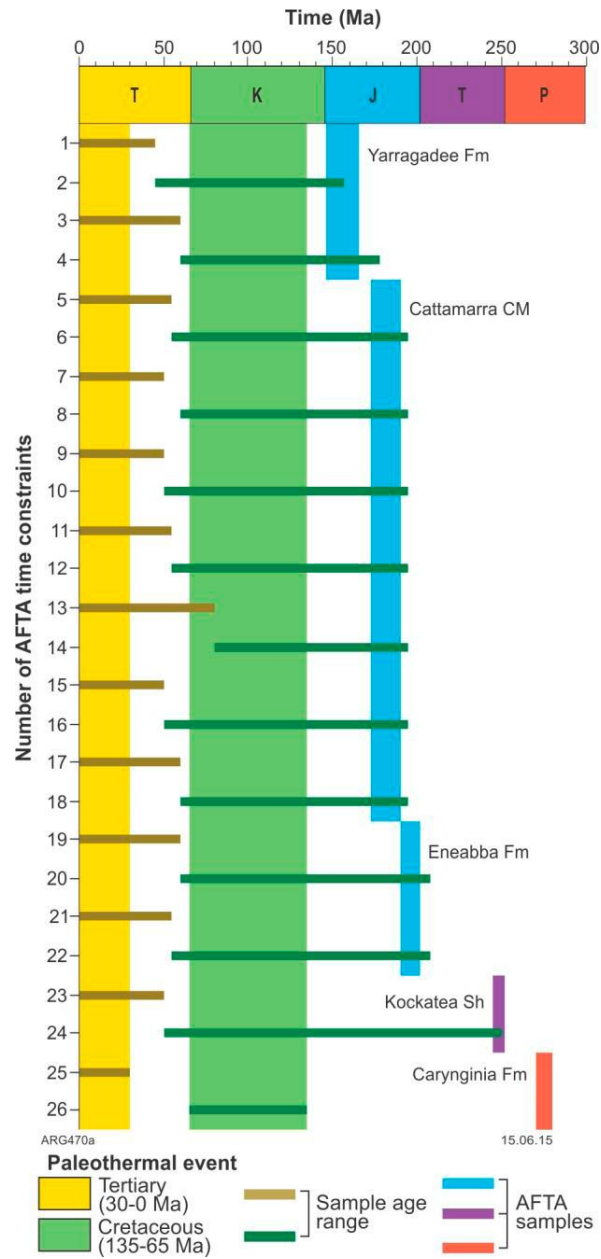


Figure 6. AFTA[®] regional paleothermal events of the Perth Basin identified from analysis of 26 samples representing Permian to Jurassic rocks from three wells.

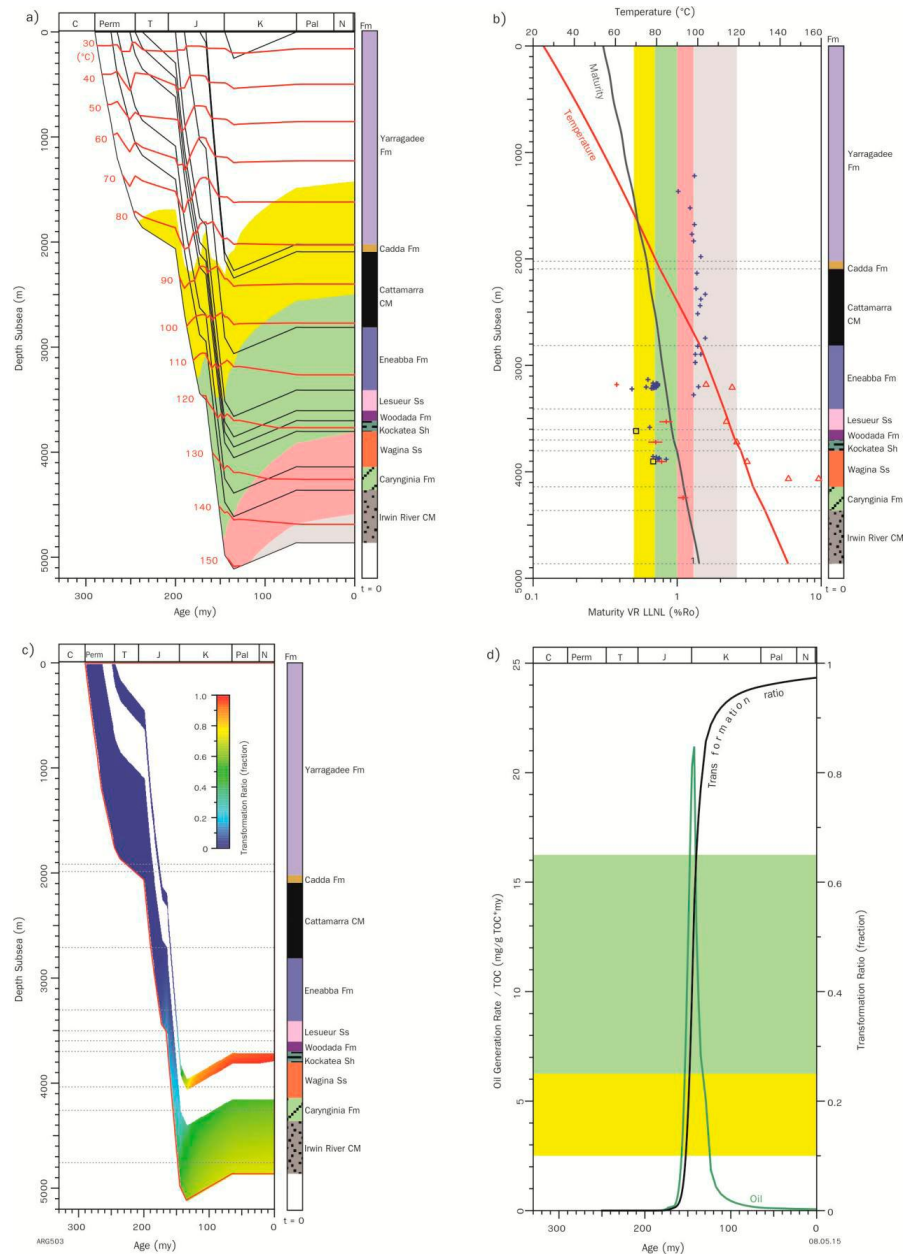


Figure 7. Petroleum system modelling of Erregulla area northern Perth Basin: a) burial history; b) maturity calibration c) kerogen transformation versus depth; d) kerogen transformation and oil generation rate versus time.

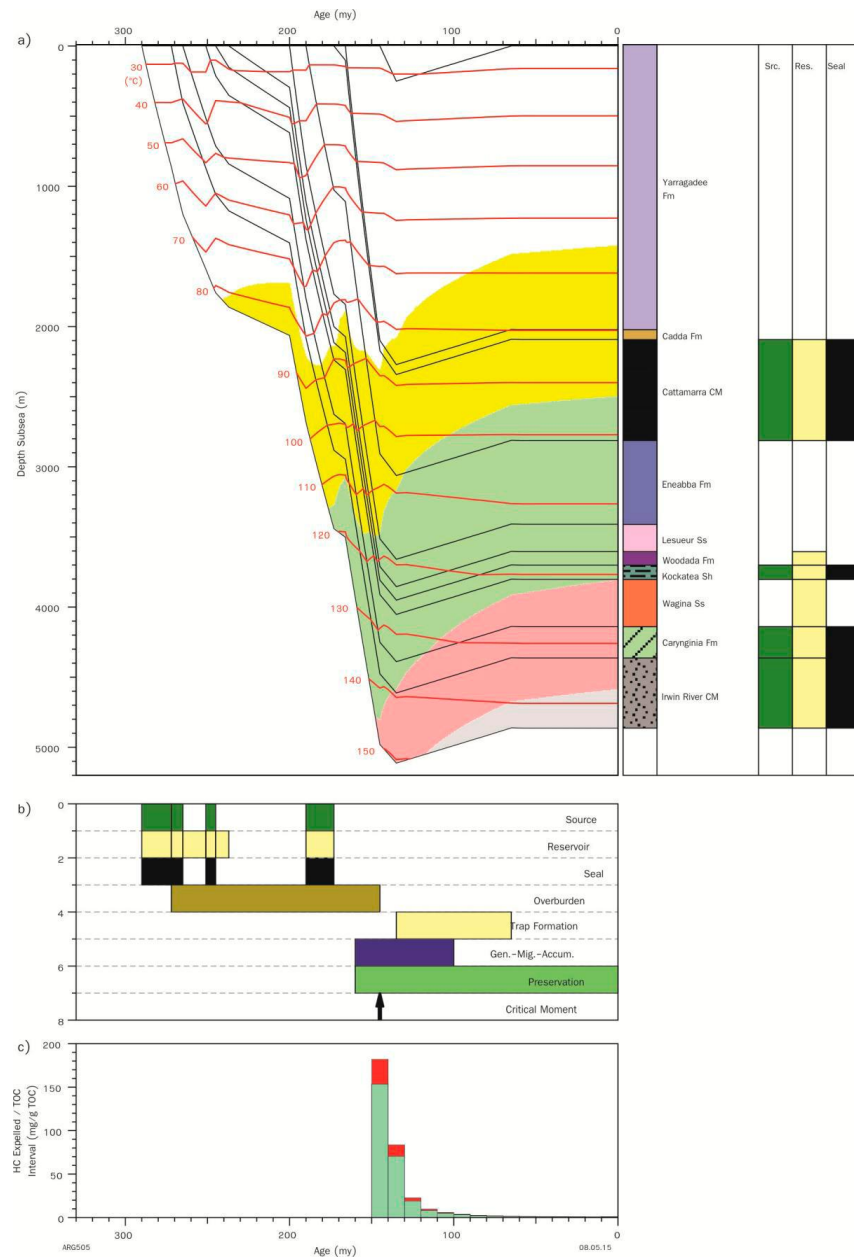


Figure 8. Petroleum system modelling of Erregulla area northern Perth Basin: a) burial history; b) petroleum system elements and timing; c) hydrocarbon expulsion timing from the Latest Permian–Triassic Kockatea Shale source-beds.

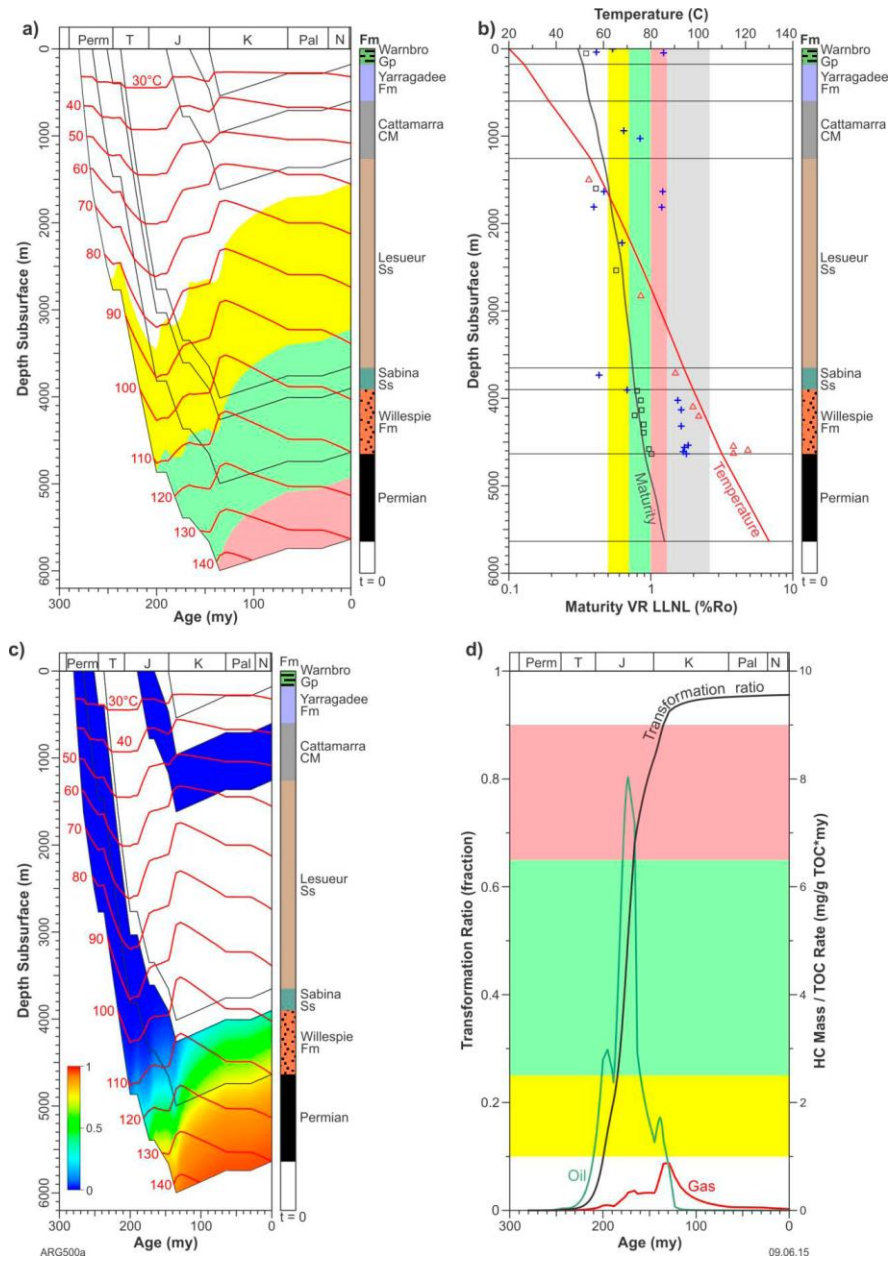


Figure 9. Petroleum system modelling of Whicher Range area southern Perth Basin: a) burial history; b) maturity calibration c) kerogen transformation versus depth; d) kerogen transformation, oil, and gas generation rate versus time.

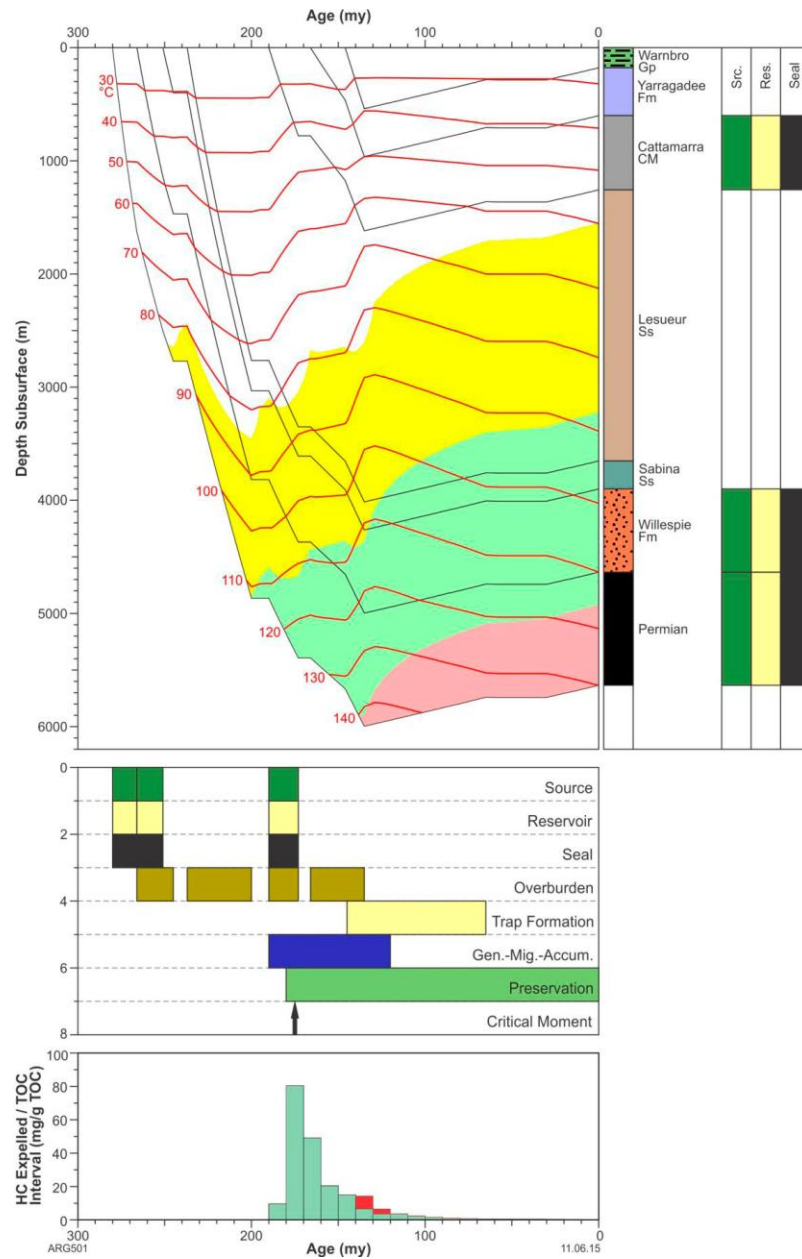


Figure 10. Petroleum system modelling of Whicher Range area southern Perth Basin: a) burial history; b) petroleum system elements and timing; c) hydrocarbon expulsion timing from the Permian source-beds.