Mineralogical modelling and petrophysical parameters in Permian gas shales from the Roseneath and Murteree formations, Cooper Basin, Australia

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Abstract

Gas volumes for gas shale reservoirs are generally estimated through a combination of geochemical analysis and complex log interpretation techniques. Here geochemical data including TOC (Total Organic Carbon) and results from pyrolysis-based on core and cuttings are integrated with log derived TOC and other petrophysical outputs to calculate the volume of kerogen (for adsorbed gas), kerogen and clay-free porosity, and best estimates of volume of clay (VCL) and water saturation (S_w). The samples and logs come from the Cooper basin, Australia, where the Roseneath and Muteree fomarions are currently of interest for shale gas potential. This study developed a framework to assist in the selection of a proper mineralogical model. The framework involved grouping of similar minerals into a single mineral category to make a simple mineralogical model because of shortcomings of the stochastic petrophysical techniques, which cannot solve for more minerals than the input curves (only a handful of logs were available for all the wells). The same mineralogical model was used for other wells in the study area where there was no XRD and core data available. Total Organic Content is the basis for the absorbed gas and provides means to correct the total porosity for kerogen and clay. Hence, TOC was estimated cautiously. The log-derived TOC profiles exhibit the best fit to core data in the Murteree Shale as compare to Roseneath Shale where both the resistivity and the sonic logs depict the best overlay. When a proper core calibrated mineral model is chosen that fits well with the XRD mineral proportions, then the porosity fits well with the core derived porosity. After achieving a good correlation between the log-derived mineral constituents and XRD mineral constituents, the user only

requires additional conductivity estimates from the Waxman and Smits techniques to solve for gas volume in a gas shale reservoir. The input parameters of the wells having a full log and core data were noted and used consistently in the other wells from the Cooper Basin, which had often either only short core sections available or core data missing. Murteree Shale exhibits excellent potential in and around Nappameri, Patchawarra and Tenappera Troughs but the poor potential in Allunga trough, where Roseneath Shale shows moderate potential in these troughs. The petrophysical interpretation shows that Murteree Shale has the potential to produce commercial quantities of hydrocarbon economically because of significant volume of kerogen (for adsorbed gas), good porosity, significant amount of brittle minerals and producible hydrocarbon.

Key words: Shale gas, Roseneath, Murteree, Petrophysical, Mineral model, TOC, XRD.

Introduction:

Unconventional hydrocarbon exploration has become an important component of the industry as traditional hydrocarbon reservoirs are rapidly depleting and becoming scarce. Prior to the shale gas revolution over the last decade, shales containing commercial hydrocarbon accumulations (acting as source, seal and reservoir) were typically ignored during log processing, and work instead focused solely on using shale intervals for correction of porosity and resistivity logs for clay effects. Since then, the arrival of new technology, such as hydraulic fracturing, geochemical logging and complex petrophysical modelling, has encouraged greater interest in the exploitation of these reservoirs. This study focuses on the lacustrine Permian Murteree and Roseneath shales which represent two of the most prospective shale gas plays in the Cooper Basin, Australia. Both shales were investigated for gas volumes by employing unconventional petrophysical techniques through combining different parameters acquired by geochemical analysis, log interpretation and core studies.

The late Paleozoic-early Mesozoic Cooper Basin of northern South Australia and south-western Queensland has been extensively explored and exploited for conventional hydrocarbons for the past 40 years; however, in the past few years its potential for shale gas has also started to attract attention. In particular, encouraging results from recently drilled

wells in the Moomba field have led to significant interest and further exploration throughout the basin [29] .

However, the typical suite of petrophysical log investigations carried out in previous decades focused on conventional sandstone and carbonate reservoir characterization and was largely limited to gamma ray, resistivity, neutron-density, and sonic log investigations with limited formation tests and rotary sidewall coring [43]. Fortunately a small number of cores were taken from one of the most prospective intervals in the basin for shale gas, the lacustrine Roseneath and Murteree Shales, and archived at the South Australia core storage facility by the (DIMITRE) Department for Manufacturing, Innovation, Trade, Resources and Energy by the Government of South Australia [10].

The DIMITRE cores from the Murteree and Roseneath shales intervals, in combination with existing wireline logs, were investigated in this study in order to evaluate the potential for lacustrine shale gas reservoirs in the Cooper Basin (Fig. 1). Here we present the results of our petrophysical investigation of the Murteree and Roseneath shales by integrating the following analyses: Total Organic Carbon content (TOC), vitrinite reflectance (VR), Rock-Eval pyrolysis, maceral analysis, powder x-ray diffraction (XRD), porosity (measured on crushed samples), permeability, grain density and water saturation (S_w). The primary goals of this study are: 1) to determine the organic content, mineral content, porosity and permeability of the Roseneath, Epsilon and Murteree shales; 2) to use the data to make a model which conforms with the regional geological model to establish the shale gas potential of the basin; 3) to develop methodology that can be applied to other wells in the basin, including legacy wells that contain very limited log data, and that provides for the evaluation of shales in a reasonable time frame to accurately predict mineralogy, kerogen content, grain density, porosity and gas saturation.

Background:

Two types of reservoirs are classically described in petrophysical studies, which include those that correspond to the unimodal pore system assumptions of Archie [1] and those that do not (i.e., non-Archie conventional reservoirs and most unconventional

reservoirs) [51–52]. The first category has been thoroughly explored, whereas the second type now constitutes most common new exploration targets.

Archie reservoir rocks are those have unimodal pore systems, with hydrophilic pore surfaces and that conduct by only a single mechanism (pore water) and are both homogeneous and isotropic [25] . In contrast, reservoirs with fresh waters, significant shale content, conductive minerals, oil, water and a multi-modal pore systems constitute non-Archie conventional reservoirs [25]**.** Contrary to Bust [5] in 2011, this study considers high capillary reservoirs to also come under domain of conventional Archie reservoirs, whereas reservoirs with a significant volume of conductive minerals are best classified as non-Archie reservoirs or unconventional reservoirs. Unconventional reservoirs include coal-seam reservoirs and shale gas reservoirs, which contradict the assumptions made by Archie [1] (1942). Therefore, techniques used to evaluate shale gas should be separate from conventional reservoir characterization techniques, and must take into account grain size, variable pore character, clay volume, kerogen, and clay surface conductivity.

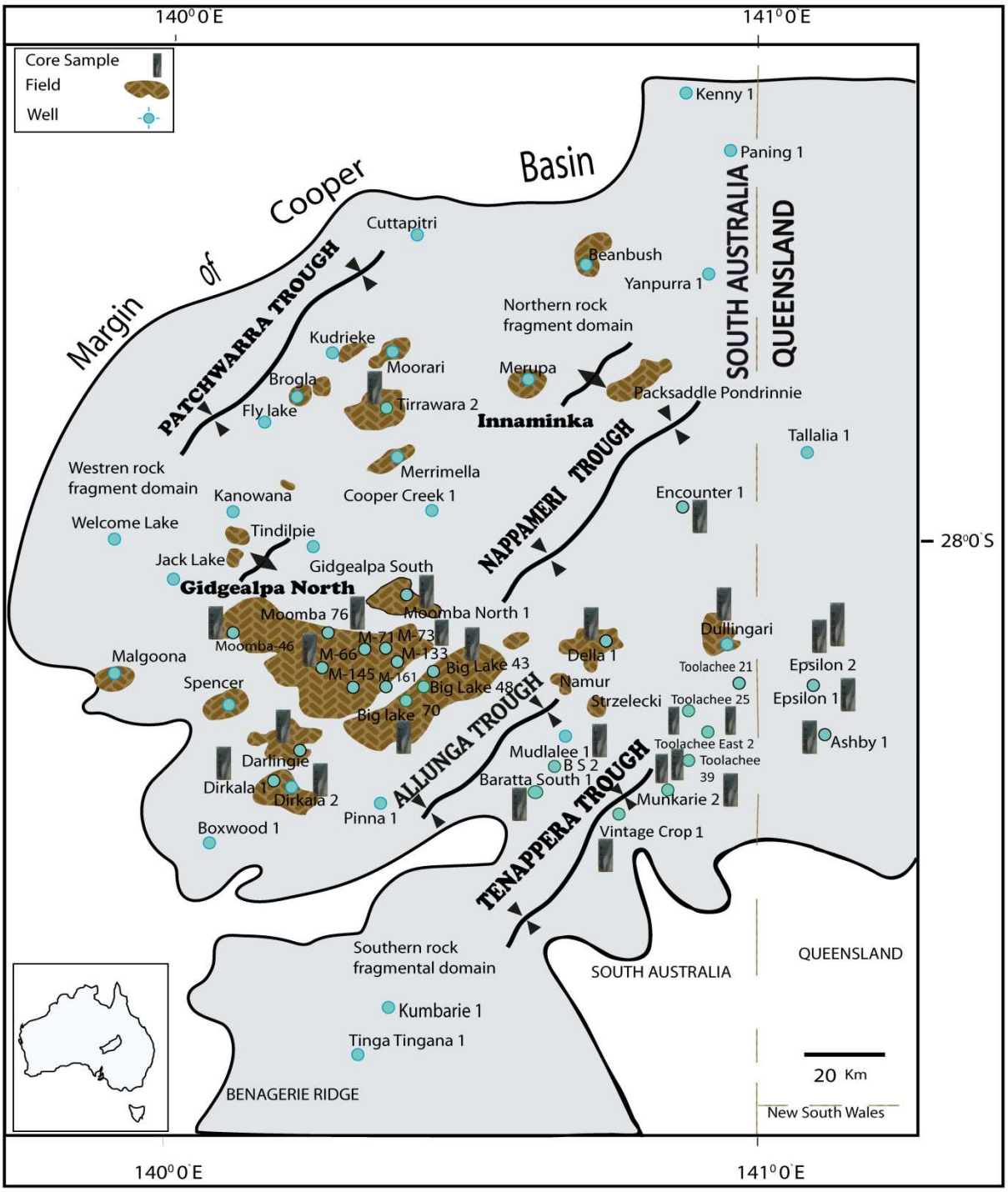


Figure 1: Map of the study area in the Cooper Basin, Australia (modified after Chaney et al., 1997) [7] . Blue dots show the location of wells in the basin. Black columns next to wells represent Roseneath and Murteree cores from which samples were collected in this study and used to produce petrophysical models.

Geological setting of the Cooper Basin

The Cooper Basin is an intracratonic rift basin of Permian to Triassic age that extends from the northeastern corner of South Australia into southwestern Queensland [24] (Fig. 1). The basin covers an area of approximately 130,000 km^2, of which ~35000 km^2 are in NE South Australia. Three major troughs in the basin, known as the Patchawarra, Nappamerri, and Tenappera troughs are separated by the Gidgealpa, Merrimelia, Innaminka and Murteree structural highs/ridges, which are associated with the reactivation of NW trending thrust faults in the underlying Warburton Basin [50] (Figs. 1-2). These three troughs preserve up to 2500 m of Carboniferous to Triassic sedimentary fill, which is dominated by thick non-marine depositional successions of the Late Permian Gidgealpa Group and the Upper Permian to Middle Triassic Nappamerri Group [34] (Fig. 2). Underneath the Cooper Basin are Precambrian to Ordovician sedimentary rocks of the Warburton Basin and intrusive Devonian granitoids [24]. The main tectonic sequence separating the Cooper from the underlying Warburton basin is interpreted to be the Devonian- Carboniferous Alice Springs orogeny. Overlying and extending beyond the Cooper Basin are Jurassic-Cretaceous cover sequences of the Eromanga Basin (~1300 m), which form part of the Great Artesian Basin of eastern Australia [37].

The basal unit in the Cooper Basin is the Merrimelia Formation, which is considered the economic basement for hydrocarbon exploration [48–49] (Fig. 2). The Merrimelia Formation is late Carboniferous to Early Permian in age, based on palynological zonation [36] and consists of conglomerate, sandstone and shale deposited in glacial paleoenvironments. A variety of depositional settings are inferred, including glacial valleys, braid plains and lakes, which resulted in complex facies relationships and irregular thicknesses [48].

Overlying the Merrimelia Formation is the Tirrawarra Sandstone, which is characterized by thick, multi-story channel sandstones with distinctive quartz arenite compositions [40–41] (Fig. 2). The Patchawarra Formation overlies this unit and is the thickest unit in the Cooper Basin, although it shows great lateral thickness variation [16]. It is thickest in the Nappamerri and Patchawarra troughs and thins by onlap and truncation onto the crests of major structures and at the basin margins [2]. The Patchwarra Formation represents an interbedded succession of minor channel lag conglomerates and massive, cross-bedded sandstones of fluvial origin, along with laminated siltstones, shales and coals that formed in

abandoned channels, back swamps and shallow lakes and peat mires. The overlying Murteree, Epsilon, Roseneath and Daralingie formations record alternating lacustrine and lower delta plain environments, consisting mainly of interbedded fluvial-deltaic sandstones, shales, siltstones and coals [14]

The Murteree Shale was defined by Gatehouse [16] as the series of shales overlain by the Epsilon Formation and underlain by the Patchawarra Formation (Fig. 2). This unit consists of black to dark grey to brown argillaceous siltstone and fine grained sandstone, which is sandier in the southern Cooper Basin. Fine-grained pyrite and muscovite are both characteristic of the Murteree Shale and significantly, carbonaceous siltstone is also present. The type section lies between 1922.9 – 1970.8 m in the Murteree-1 well. The Murteree Shale is widespread within the Cooper Basin in both South Australia and Queensland. It is relatively uniform in thickness, averaging ~50m and reaching a maximum thickness of 86 m in the Nappameri Trough, thinning to the north, and having a maximum thickness of 35 m in the Patchawarra Trough. It is absent over the crestal ridges [3]. The Murteree Shale is Early Permian [36]. A relatively deep lacustrine depositional environment has been interpreted for the formation, in part based on the rarity of wave ripples and other evidence of storm reworking as would be expected for a more shallow lake system [16].

The Roseneath Shale was defined by Gatehouse [12] as a suite of shales and minor siltstones that conformably overlie the Epsilon Formation (Fig.2). The unit was originally included as one of three units in the Moomba Formation by Kapel [22]. Gatehouse [12] raised it to formation status. The type section lies between 1956.8 – 2024.5 m in the Roseneath-1 well [12] .The Roseneath Shale is composed of light to dark brown-grey or olive-grey siltstones, mudstones with minor fine-grained pyrite and pale brown sandstone interbeds. It occurs across the central Cooper Basin but has been eroded from the Dunoon and Murteree Ridges and crestal areas of other ridges during late Early Permian uplift. The Roseneath Shale is not as extensive as the Murteree Shale. It conformably overlies and intertongues with the Epsilon Formation and is overlain by and also intertongues with the Daralingie Formation. Where the Darlingie Formation has been removed by erosion, the Roseneath Shale is unconformably overlain by the Toolaches Formation. The Roseneath Shale reaches a maximum thickness of 105 m in the Strathmount-1 well and thickens into the Nappamerri and Tenappera Troughs

[3] . It is considered to be Early Permian in age [36]. A lacustrine environment of deposition, similar to that of the Murteree Shale, is inferred for the Roseneath Shale [39–40]. Variations between massive to finely laminated, with minor wavy lamination and wave ripples, suggest possible storm reworking and loading features, flame structures and slump folds indicate slope instability, both of which suggest a slightly shallower lake-floor depocenter than for the Murteree Shale [39–40].

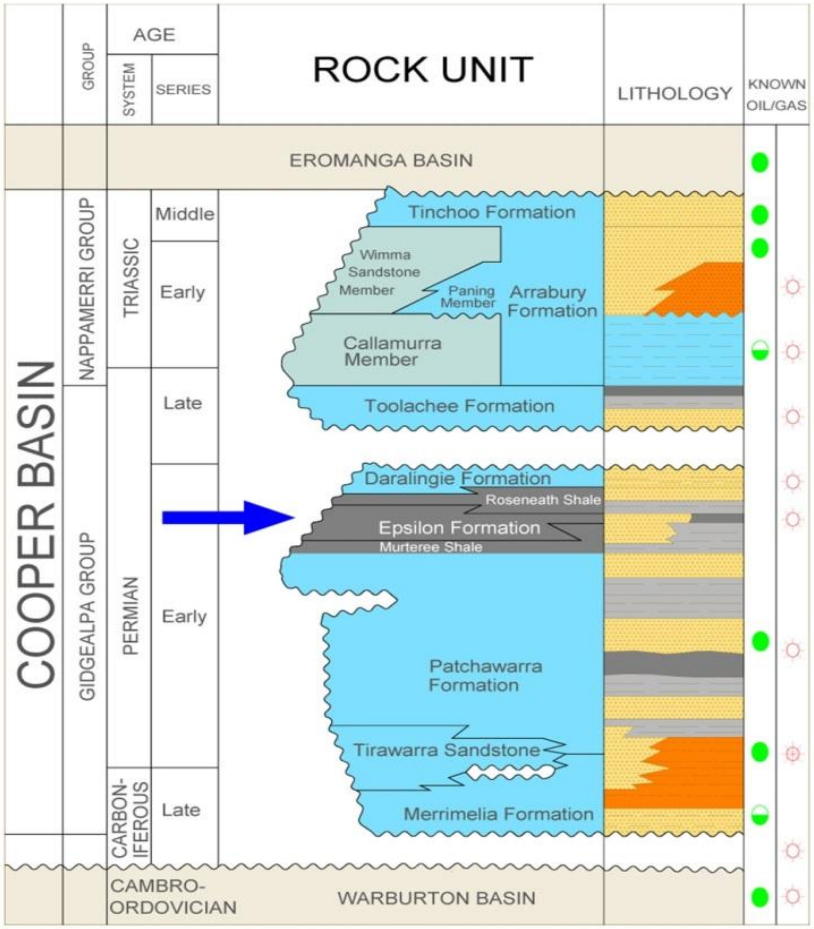


Figure 2: Stratigraphy of the Cooper Basin [35]. Arrow shows the study interval that includes the Roseneath and Murteree shales.

Methodology:

In this study, analyses were performed on a variety of logs, chip cuttings and cores, principally for evaluation of shale gas reservoirs. Modelling mineralogical composition from geochemical logs requires the selection of a proper mineral model. The mineral model was built in the Senergy Interactive Petrophysics (IP) Mineral Solver module by integrating all

regional sedimentological, petrographic, SEM (Scanning electronic microscope) and X-ray diffraction data (XRD) from core and chip cutting samples.

Petrophysical properties investigated include: shale porosity, permeability, water saturation, TOC, mineral composition, CEC and geochemistry. Methods for evaluating shale gas potential in existing conventional reservoirs are shown in Table 1 and compared to those methods used herein to study unconventional reservoirs in the Cooper Basin. Evaluation has been divided into four parts, TOC determination, mineral modelling, quantification of porosity, and estimation of water saturation. Table 1 shows how information was obtained from core and log data.

Samples were analysed by XRD (X-Ray Diffraction), petrographic microscopy, ICP-MS (Inductivity Coupled Plasma Mass Spectrometer) and SEM (Scanning Electronic Microscopy) to characterise mineral composition, fabric and structure. XRD analysis was performed on core samples to get quantitative results for mineralogical content. The sample material was micronized and pressed into pellets for X-ray diffraction analysis (XRD). X-ray diffraction is conducted between 3 and $70^0 2\Theta$ using Bruker® D4 Endeavour X-ray diffraction instrument with Lynx-Eye detector. The instrument is run at 40 V and 30 mA and features a fixed divergence slit geometry (0.5^0), an anti-scatter slit with both primary and secondary Soller slits at 4^0. The results of the x-ray diffraction analyses are analysed using PDF-4 minerals database 2013 (peak identification) and then quantified using Jade 9 software.

TOC analyses were conducted at Trican Alberta Calgary laboratory and supplemented with the log derived TOC, which together provide consistent values of TOC from top to bottom of the formation giving preliminary areas of interest. A threshold of 1.5% TOC was taken for shale to be considered as the prospective zone based on productive shale gas reservoir values (e.g., from the Barnett, Marcellus and Eagle ford gas shales in the USA), which range in TOC from 1.5 to 8 % [21].

The second phase of this study was to calculate the mineral constituents of the formation under consideration. Core XRD data were obtained and the desired minerals were modelled using the Multiple Mineral Model programme by Interactive Senergy Petrophysics (IP). The mineral volumes were input in weight percent and the software requires volume

percentage, so the mineral volumes were first transformed from weight percent to wet volume percent (by equation, Wet volume percent = (Dry Weight %) * (1- Porosity) * (Rock Grain Density)/(Mineral Grain Density) using rock grain density and porosity from the routine core analysis. As porosity plays an important part in the conversion, core porosity was used in order to mitigate the severe porosity issues related to kerogen effects. This was done by using the mineral solver processing utility in the software package, which converts weight percent into volume percent using the equation above. After several iterations, the exact mineral end points were determined, which then allowed us to correlate the log calculated mineral volumes with the XRD driven mineral volumes.

Quantification of porosity was done in several steps. First TOC was converted into kerogen and then the porosity was calculated using the density log and core-derived grain density. The porosity output was corrected by adjusting for the kerogen effects. Porosity was then calibrated using the porosity results from the multiple mineral modelling. Wherever there was a reasonable match between the mineral and fluid volumes with the core derived mineral and fluid volumes, there was also a good match between the core and multiple minerals derived porosity. Where there was no grain density data from core analysis, the grain density was obtained by combining the density and TOC data.

Water saturation was calculated with the standard shaly sand equations, including the Dual water equation [8], Waxman Smit's equation [45] and Juhasz's equation [20]. Once a reasonable match between the core and log derived outputs was found, these parameters were extended to the non-key wells. Some of the non-key wells had some chip cutting data, for which the match was nearly perfect. This method is more reliable for the development of a localised petrophysical shale-gas model.

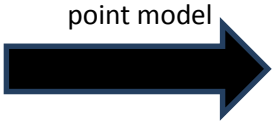
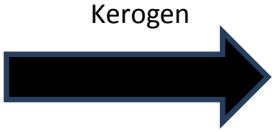
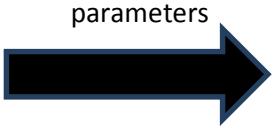
Key well		Non- key wells
TOC Determination Core-TOC measurement (Rock-Eval Pyrolysis/ TOC) Log standard logs (density, spectral GR, resistivity, sonic). Log-standard logs (density, spectral, GR, resistivity, sonic)	Log VS TOC relationship 	**TOC Determination** Log- standard logs (density, spectral GR, resistivity, sonic).
Mineral Modelling Core –XRD, SEM, SPECTRA, Log-Spectral gamma.	Mineral end-point model 	**Mineral Modelling** Log-Standard logs for multi minerals analysis (density, neutron, PEF, GR).
Qualification of Porosity Core – GRI data, grain density Log- mineral model (grain density), density, sonic.	Estimation Kerogen 	**Qualification of Porosity** Log- Standard logs (density)
Evaluation of Water Saturation Core- GRI data, water salinity Log- Standard logs (density, resistivity).	Shaly sand parameters 	**Evaluation of Water Saturation** Log- Standard logs (density, resistivity).

Table. 1: Methods for Petrophysical analysis, modified after Bust [5]

Petrophysical Modelling

Petrophysical modelling was conducted for key wells in this study (Table 1) using the following input parameters: routine core analysis (RCAL), gamma ray (GR) log, scanning electronic microscope (SEM), X-ray diffraction (XRD), geochemical and petrographic analysis performed on core and cutting data for resolving the total gas content calculations by integrating the core, geochemical and petrographic analysis to the electric and radioactive logs. In developing our models, a number of key assumptions, conditions and potential issues were encountered. For instance, shales tend to show very high GR and in reducing environments the presence of elevated GR log readings due to high uranium content make it hard to identify clays by the GR log. Another issue pertains to the multiple mineral model clay

volume calculations (referred to as VCL), which are dependent upon the integrated response of all the input curves. Hence, the number of input curves greatly affects the quality of the model.

Another common issue pertains to when the reservoir produces significant quantities of free gas, which causes the reservoir to have lower pressure and hence, the sorbed gas can become liberated from the kerogen surface and this effects calculation of gas volume, which is used in the model. One final issue that must be considered is the potential for the Archie equation to yield erroneously high Saturation of water (S_w) results. This is because the inorganic part of the rock consists of free gas and entrapped water mainly due to capillarity in the smallest pores which are non-producible in nature and clays present in shales may lead to greater conductivity in the reservoir and hence affect the model. Finally, the porosity may be elevated in the inorganic, brittle portions of the shale and in the kerogen, although the individual pore sizes will be micro- to nano-scale [15].

Mineral Modelling Methods

Evaluation of shale gas formation requires a consistent volume of minerals present in the formation. This can be achieved by integration of the XRD, wireline logs and geochemical data [5]. This further supports the idea of having XRD and geochemical analysis, because normal mineral identification by wireline log methods does not work due the presence of clay, kerogen and small grains. The application of multiple mineral petrophysical models provide the best solution for the evaluation of challenging shale gas reservoirs because they provide results that can be fine-tuned by adjusting the input parameters to get a good match between the core and log data. Differences in interpretation may arise due to the differences in the mineral model definition (mineral endpoint) and assumptions regarding the tool physics of the logs used [38]. The mineral endpoint is a value of a specific mineral for a specific log (e.g., 2.71 is the endpoint of calcite for the density log). For each mineral and equation, there is an endpoint parameter, which is the result of the equation if the rock is composed 100% of that mineral. The mineral model is then put into the mineral solver application of a petrophysical package such as the one used here by IP (or other comparable packages like Elan and Satmin), which takes all logs and the petrophysical and mineral models into account and computes answers in the form of VCL, porosity, S_w and mineral constituents for the entire interval being

investigated. It also recreates the input tool readings from the results. Hence, this approach provides a means to check whether the mineral model and petrophysical model are valid.

In general, shale units in most studies consist of only about 10 essential minerals, including quartz, feldspar, carbonates, titanium-oxides and clay minerals. Since only four to seven independent petrophysical log measurements were commonly available in this study for most wells, the constituents have to be grouped for constructing mineral models. The mineral-solver utility in IP cannot determine more minerals than the number of input curves used. Two different approaches were used to make two different models in this study. In wells with all conventional log suits available, mineral volumes for quartz, carbonate and feldspar illite/mica, muscovite, kerogen were calculated separately. In some cases the proportion of carbonates and feldspars were nominal so they were put in the quartz category for simplifying the model and where the brittle mineral volumes were nominal (for minerals other than quartz), they were included with quartz and kerogen (Figs 4–6). In wells having limited log data, the minerals quartz, calcite, feldspar and titanium oxides have been combined as quartz while clay minerals (illite, muscovite and chlorite) have been lumped as clay. Kerogen was solved for alone because of the huge effect it has on porosity. Validation of the mineral model was achieved through the direct comparison of mineral compositions obtained by XRD analysis of the core (Tables 2–3). The core-to-log match was achieved by refining the mineral endpoints and other input parameters, as well as by adjusting the model specifications. The versatility provided by the multiple mineral models to compare the input curves to output curves is also very helpful in determining where the model was incorrect. The mineralogical evaluation of wells with limited data available was conducted using the output parameters of key wells having complete data [5].

Table 2: General characteristics and minerals observed by XRD and TOC analysis of the Roseneath Shale from Well Encounter-01.

Encounter 1 Mineral Composition in wt-%										
Depth (m)	Quartz	Feldspars	Fe-carbonates	Ti-Oxides		Clay minerals			TOC %	Total Clays
		Albite	Siderite	Rutile	Anatase	Mica/ Illite	Kaolinite	Chlorite		
	40.6	1.0	2.2	0.1	0.7	42.1	13.4		4.08	55.5
3106.44	43.7	1.1	6.4	0.1	0.6	32.4	15.9		2.45	48.3
3266.60	26.5	0.3	11.6	0.1	0.4	47.0	9.4	4.8	3.26	61.2
3268.60	25.8	0.5	20.0	0.1	0.2	43.9	5.9	3.8	2.31	53.6
3269.60	31.0	0.6	9.7	0.1	0.4	43.2	9.9	5.1	3.01	58.2
3272.20	33.7	0.4	6.3	0.1	0.6	45.4	8.7	4.8	2.28	58.9
3274.20	34.3	1.0	9.0	0.1	0.6	38.2	12.1	4.9	3.80	55.2
3276.80	34.1	0.8	7.2	0.1	0.7	41.2	11.3	4.8	3.19	57.3
3278.60	33.1	0.4	6.1	0.1	0.4	42.7	12.6	4.7	3.17	60.0
3279.63	22.0	0.1	46.5	0.1	0.3	21.5	7.3	2.4	2.94	31.2
3281.20	35.2	1.1	7.8	0.1	0.7	39.2	11.5	4.5	3.16	55.2
3282.32	36.8	0.5	7.8	0.1	1.0	36.9	10.7	5.2	2.59	52.8
3282.38	34.8	1.1	9.8	0.1	1.0	36.6	11.4	5.4	3.45	53.4
3282.43	36.9	1.2	7.2	0.1	1.0	36.5	12.5	4.6	3.26	53.6
3282.47	43.9	1.7	9.9	0.1	1.4	24.6	13.1	5.6	3.30	43.3
3282.55	39.6	1.1	9.4	0.1	1.0	30.5	14.4	4.1	2.70	49.0
3282.55	37.0	0.8	9.5	0.1	0.9	34.2	13.3	4.2		51.7
3283.50	28.5		14.6	0.1	0.3	41.4	10.9	4.3	3.93	56.6
3283.69	36.2	1.0	16.1	0.1	0.9	30.4	11.1	4.4	2.61	45.9
3286.40	24.4		11.9	0.1	0.1	18.9	11.0	3.7	3.73	33.6
3287.30	37.9	0.4	3.8	0.1	0.7	42.2	10.0	5.0	3.48	57.2
3289.60	29.1	0.1	10.4	0.1	0.4	47.7	8.8	3.6	3.13	60.1
3290.50	36.1	0.7	5.9	0.1	0.7	41.6	10.3	4.7	2.91	56.6
3293.10	32.4	0.4	5.5	0.1	0.8	42.6	14.1	4.3	4.88	61.0
3295.50	33.4	0.4	8.4	0.1	0.9	40.4	11.8	4.8	4.04	57.0
3380.90	42.5	0.9	3.5	0.1	0.4	41.6	11.0		2.83	52.6

Total organic carbon (TOC)

The ΔlogR methodology of [27] was used to determine Total Organic Carbon (TOC) based on the apparent separation between the resistivity and porosity log (ΔlogR) when properly scaled. A maturity factor is necessary, which was taken from the cross-plot where vitrinite reflectance (VR) was available. Total Organic Content (TOC) can be determined from Passey's overlay only when there are some lean and water-saturated rocks where both the curves overlie each other, because both respond to variation to formation porosity and the scale can be set accordingly (Figs. 3–4).

Table 3*:* General characteristics and minerals observed by XRD and TOC analysis of the Murteree Shale in Well Dirkala-02.

Depth (m)	Quartz	Feldspars	Fe-carbonates	Ti-Oxides		Mica/clay minerals			TOC%
		Albite	Siderite*	Rutile	Anatase	Muscovite	Illite 2M2	Kaolinite	
1892.91	42.7	0.7	5.4	0.1	0.7	27.8	9.5	13.3	2.0
1893.06	40.1	1.2	11.7	0.1	0.6	15.6	18.3	12.5	1.8
1893.11	40.9	0.9	11.2	0.1	0.5	25.2	9.0	12.3	2.5
1893.65	31.4	0.4	28.6	0.1	0.1	22.3	8.3	8.9	2.0
1893.65	27.4	0.1	31.0	0.1	0.1	31.2	0.1	10.4	1.0
1893.65	38.9	0.8	4.4	0.1	0.5	38.6	4.5	12.3	1.0
1893.70	40.9	0.9	9.2	0.1	0.5	22.3	13.4	12.8	4.5
1894.25	30.4	0.1	18.5	0.1	0.1	40.4	1.4	9.4	2.0
1896.08	58.0	1.1	4.4	0.1	0.7	12.8	8.3	14.8	2.5
1896.10	46.2	0.9	1.9	0.1	0.8	27.2	9.0	14.0	1.5
896.24	45.6	0.9	1.0	0.1	0.6	25.7	13.2	13.1	2.5
1896.29	41.0	1.1	1.5	0.1	0.6	25.6	18.7	11.4	2.0
1896.45	46.8	1.3	3.0	0.1	1.2	23.8	7.8	16.0	3.0
1892.88	48.3	0.9	3.7	0.1	0.6	25.2	8.9	12.4	4.0

Conventional reservoir rocks can be eliminated from the analysis by the log character of GR and other data, such as lithology from mud log and well samples.

The Total Organic Content (TOC) was calculated based on the ΔlogR separation expressed as logarithmic resistivity cycles and thermal maturity expressed as LOM (level of organic maturity) by using the following empirical equations [27] :

ΔlogR = LOG (LLD /RESDB) +0.02*(DT-DTB)

TOC = 100* ΔlogR * 10^ (0.297-0.1688*LOM)

Where Laterlog deep measurement (LLD) is resistivity measured in ohm-m by the logging tool, DT is the measured transit time in µsec/ft. RESDB (Resistivity baseline) is the resistivity corresponding to the DTB (sonic baseline) value when the curves are base lined in non-source, clay rich rocks. Level of maturity (LOM) can be taken from the cross-plot (Figure 3). RESB = 10 ohm.m, LOM =11 and DTB = 65 µsec/ft were used in all the wells analysed.

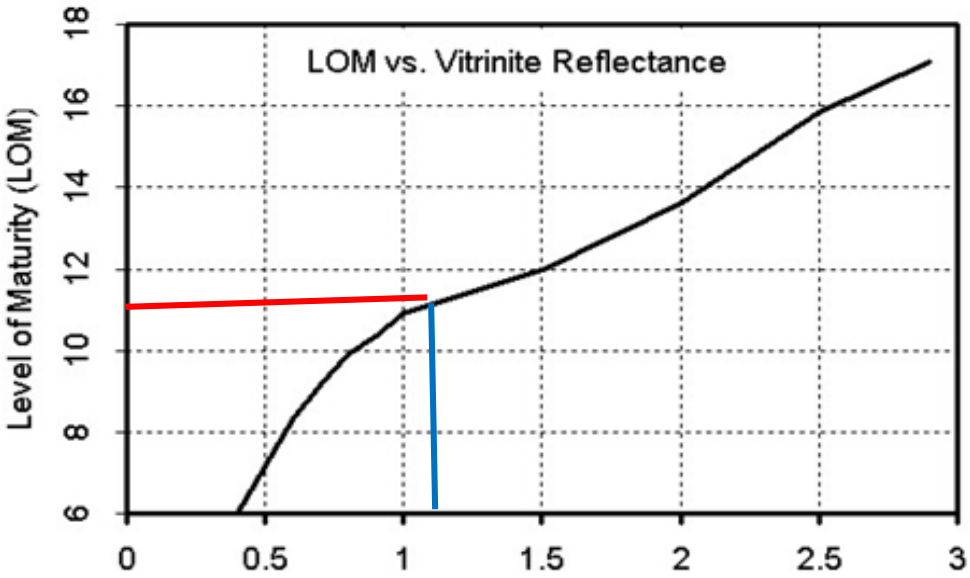


Figure 3: Example of using graphic approach for finding Level of maturity (LOM) from vitrinite reflectance (VR) data. Higher LOM reduces calculated TOC [9].

The best means to check the validity of TOC determined from the ΔlogR technique is to check with TOC analysed on borehole cuttings because both of them represent an average interval, although the cuttings interval is usually slightly greater than the approximate resolution of the ΔlogR values for one metre intervals. Therefore, in heterogeneous shale gas reservoirs the TOC determined by the ΔlogR technique should be validated against cutting analysed TOC rather than core derived TOC [23] . The log derived TOC profiles exhibit the best fit to cutting and core data in both the Murteree and Roseneath shales, where both the resistivity and the sonic logs depict the best overlay. These parameters were noted and used consistently in all the wells having less complete data sets.

One of the biggest potential drawbacks of this approach is the assumption that no other rock constituent influences both the logs used other than kerogen. For example, significant amounts of pyrite can mask the resistivity profile and can exhibit lower resistivity in organic rich rocks, which can bypass the actual organic-rich rocks [28]. Since no volume of pyrite was indicated in the XRD data, Passey's approach can be used to get meaningful TOC volumes.

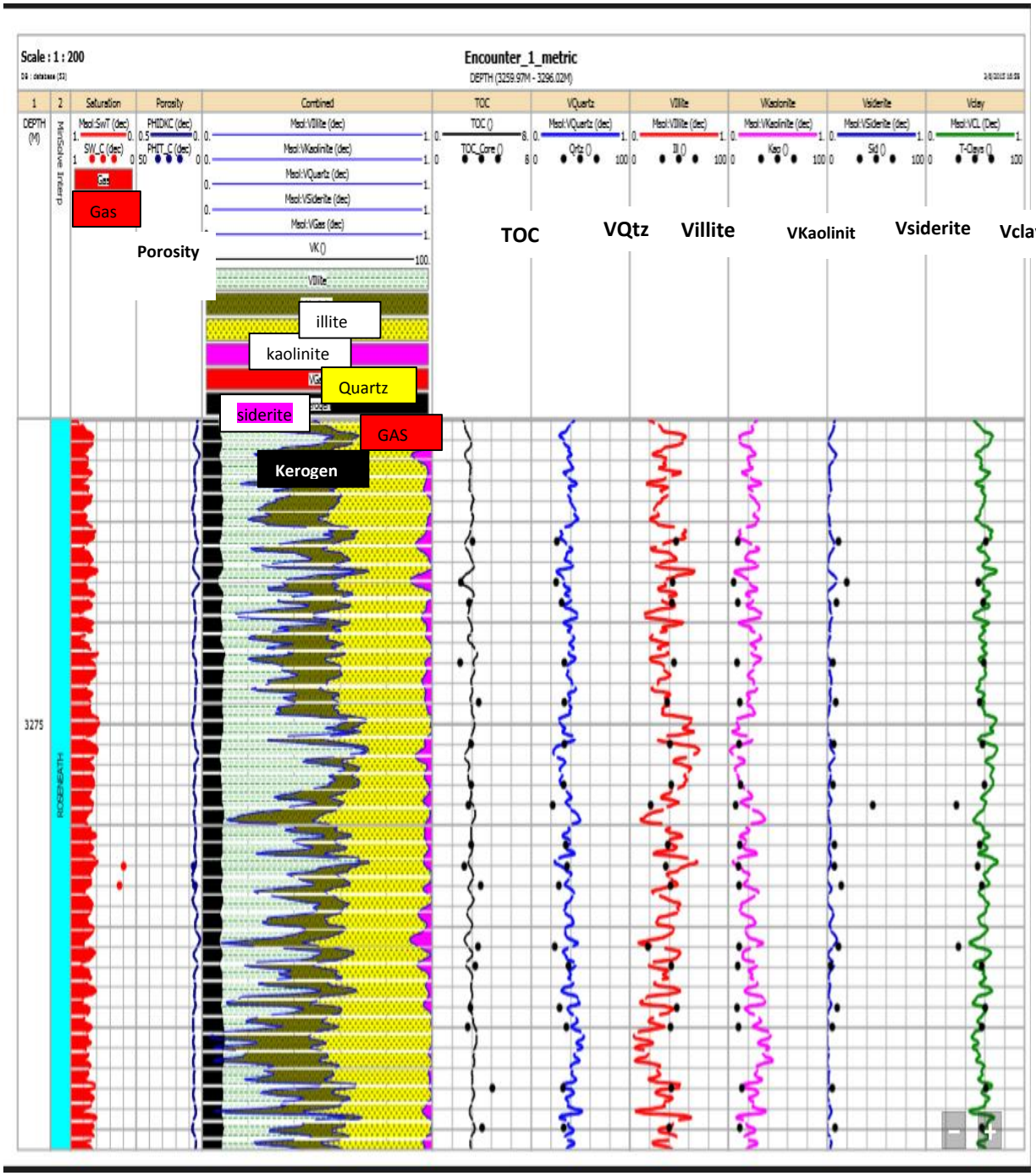


Figure 4: The mineral model for the Roseneath Shale in Encounter-1 Well. Note that kerogen and all minerals present are segregated on the basis of conventional logs in the second left hand track. A good match between the log derived and core derived parameters was obtained due to a selection of appropriate selection of the mineral model. The black dots XRD data to get a close match as good as this. They also match quite well. The left edge of red shading on porosity track is gas volume.

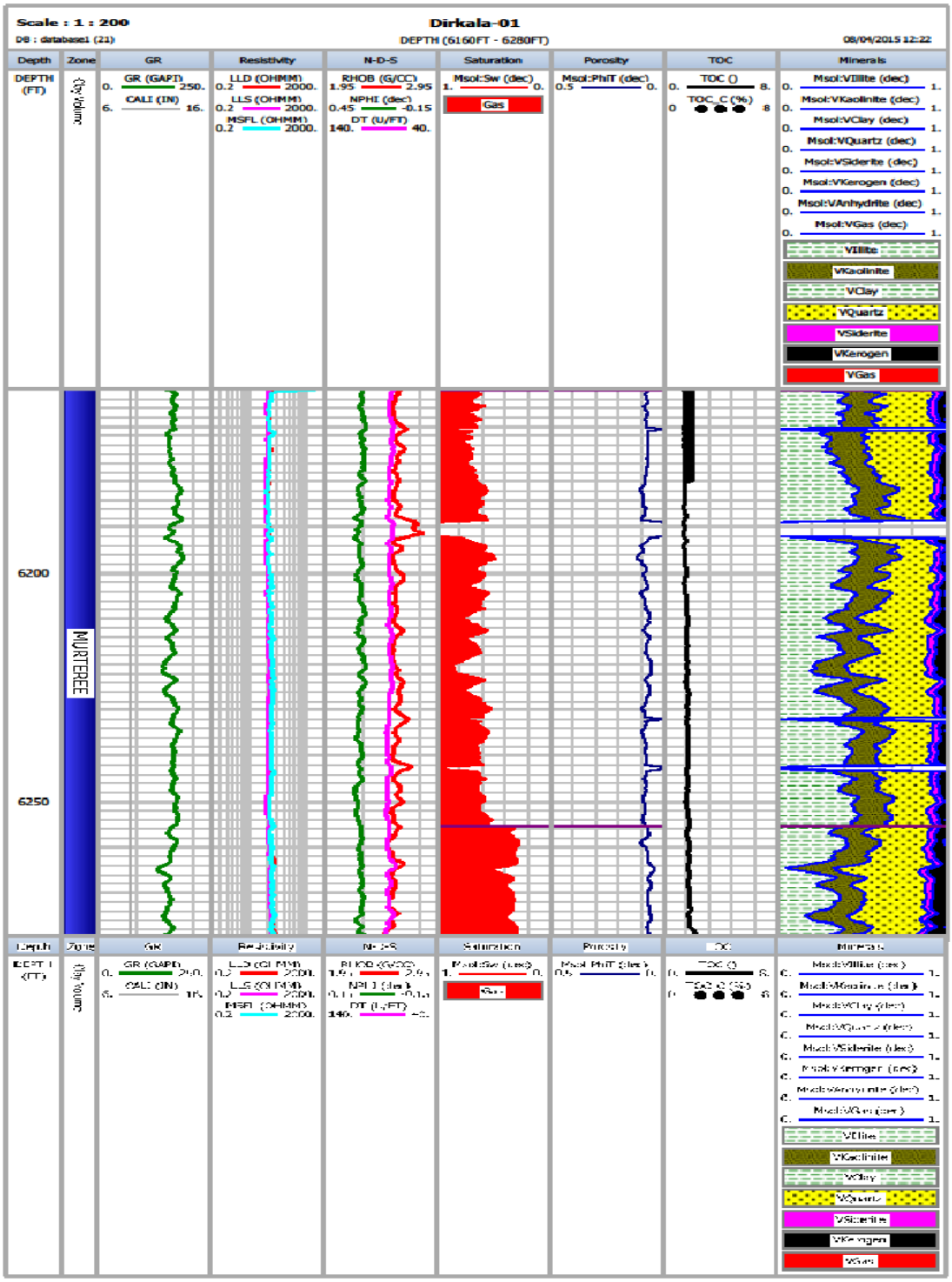


Figure 5: Mineral model for the Murteree Shale in the Dirkala-01 well. Note that Kerogen, siderite and clay minerals were nominal, they are grouped with quartz in first right hand track. No core data were present for this well so the output parameters of Dirkala-02 were used as input for this well.

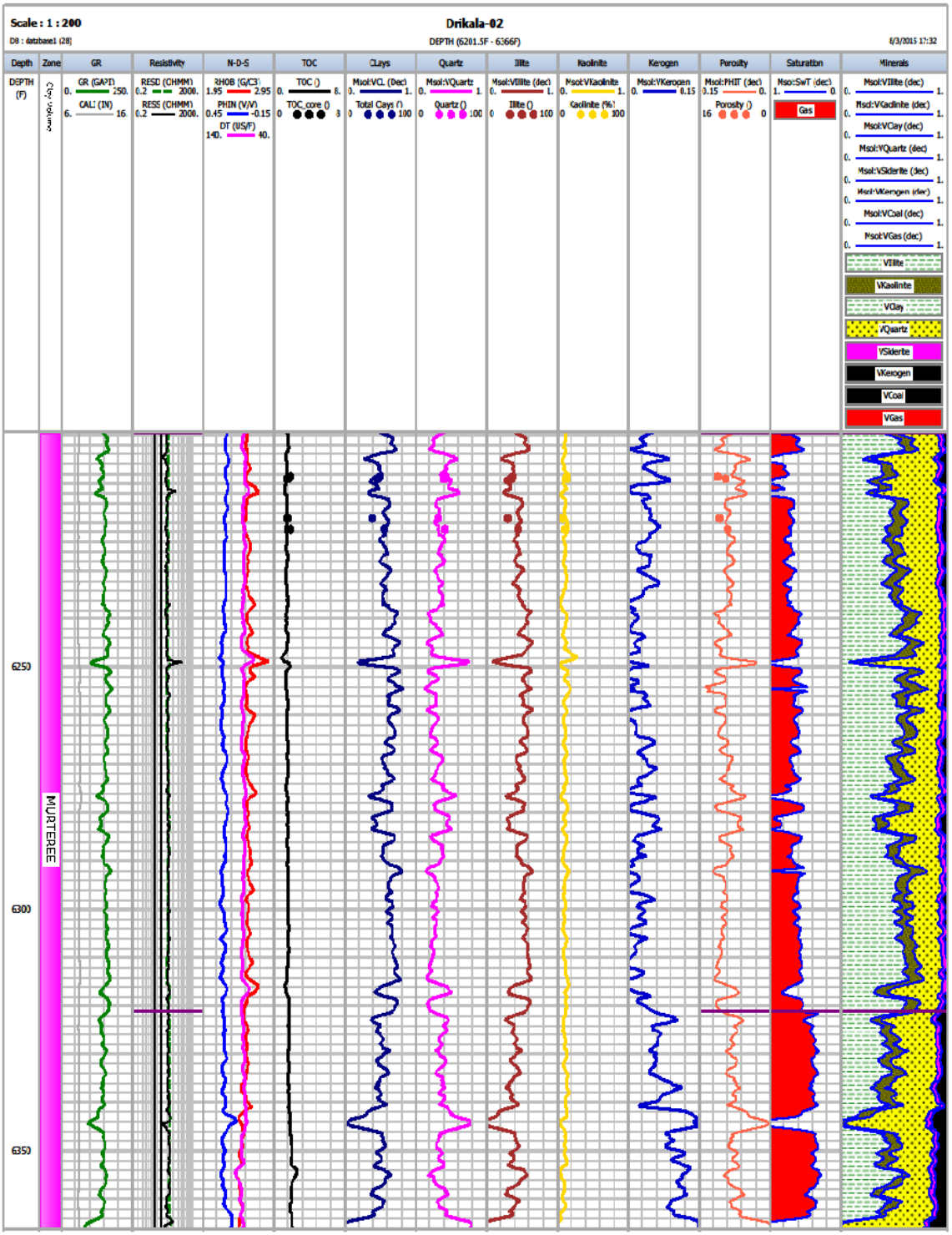


Figure 6: Mineralogy model for the Murteree Shale in the Dirkala-02 well, demonstrating an example of Kerogen, siderite and clay minerals were nominal, they are grouped with quartz in first right-hand track. The black dots TOC from cores match well with log derived TOC. The dark blue (volume of clays), Pink (quartz), brown (illite), yellow (kaolinite) blue (kerogen) and orange (porosity) dots show XRD core data to get a close match with log derived data.

Input Parameters

Analysis of the petrophysical properties of the Roseneath and Murteree shales were used to evaluate the shale gas potential of these two prospective units in the Cooper Basin. Critical input parameters, including shale porosity, permeability, water saturation, TOC, mineral composition, CEC and geochemistry, were all investigated in this study and these data are presented in (Tables 4–5). This paper focuses on describing the complex methodology and input parameters developed in order to model the petrophysical properties of the Roseneath and Murteree shales, however only a fraction of the analytical data and modelling results are discussed herein. However, all results and a suite of models salient to this methodological investigation are presented, both within the body of the paper.

Volume of Kerogen

Kerogen is typically characterized as having a low bulk density, high hydrogen index, high resistivity and delayed sonic transit time [15]. Although kerogen has distinctive log response, it is difficult to differentiate it solely on the basis of wireline logs because some conductive and dense minerals may alter the overall log response and it is hard to identify what is influencing the log signals unless proper a mineral model is designed. Conventional porosity estimation methods may lead to erroneously high porosity without accounting of the kerogen. In the petrophysical assessment of any shale gas reservoir, the estimation of the volume of kerogen (VK) is the key to getting good estimates of adsorbed gas content and porosity with reasonable accuracy. If TOC can be estimated, the volume of kerogen can be established by using the formula below [15] .

VK = TOC * RHOB/ RHOK

Where

VK = volume of Kerogen

TOC = Total Organic Content

RHOB = Bulk Density

RHOK = Density of Kerogen

Volume percent to volume fraction

VKF = VK/100 Where VKF = Volume of Kerogen Fraction

It is also necessary to ascertain kerogen density, which is challenging to establish, and the rock density [15]. Kerogen density is assumed to be 1.0 g/cc [17]. Following the procedures outlined above, VK was calculated and used in for petrophysical modelling of the Roseneath and Murteree shales (Figs 4–6). These results and additional modelling results are presented in Tables 2–5.

Scanning Electronic Microscope (SEM) analysis of the Roseneath and Murteree shales

The Roseneath and Murteree shales are very heterogeneous formations. Clay rich intervals with coal interbeds can easily be identified by visual inspection of the core. XRD analysis demonstrates that both shales primarily contain clay minerals; kaolinite, illite, muscovite and quartz (Tables 2–3). The shales are composed mainly of clay, authigenic quartz, siderite and kerogen. SEM section images show that organic matter is present and aligned parallel to bedding planes accounting for the TOC (as determined from logs and core) (Figs. 4–6). SEM of Roseneath and Murteree shales provide much needed visual evidence to understand how the porosity and fractures are distributed at the micro-scale. The foliated rock fabric is due to abundant quartz and clay with porous kerogen and siderite minerals. (Figs. 7–8).

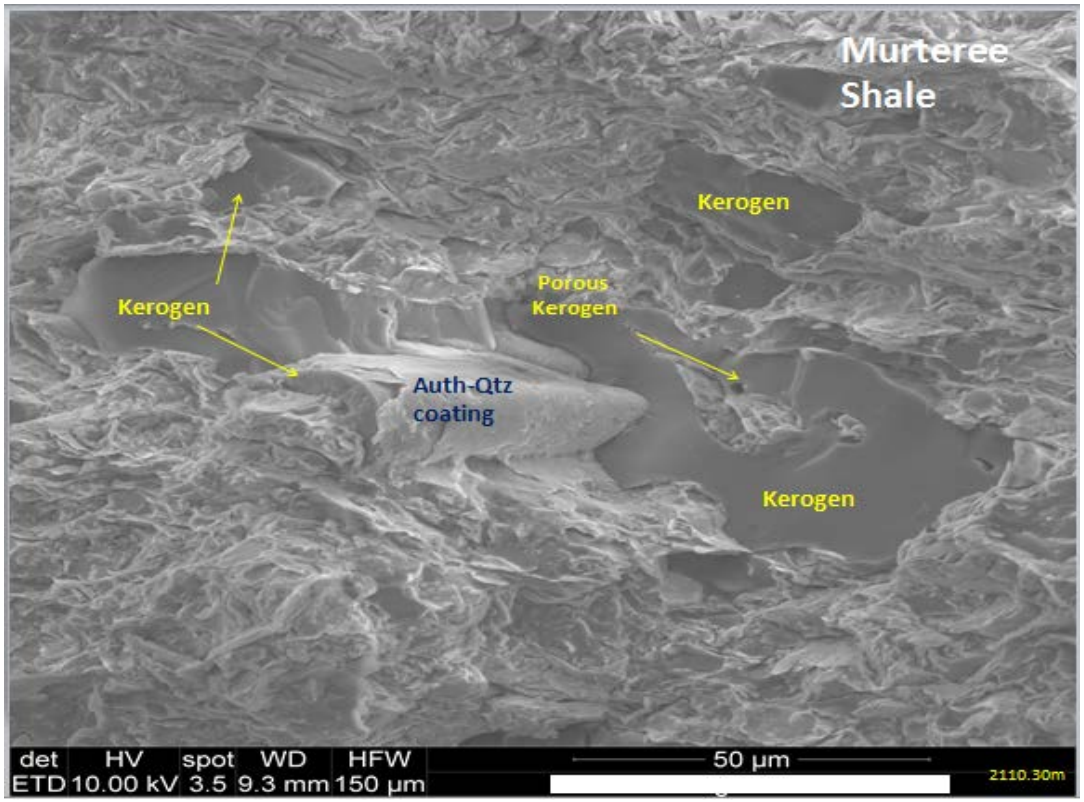
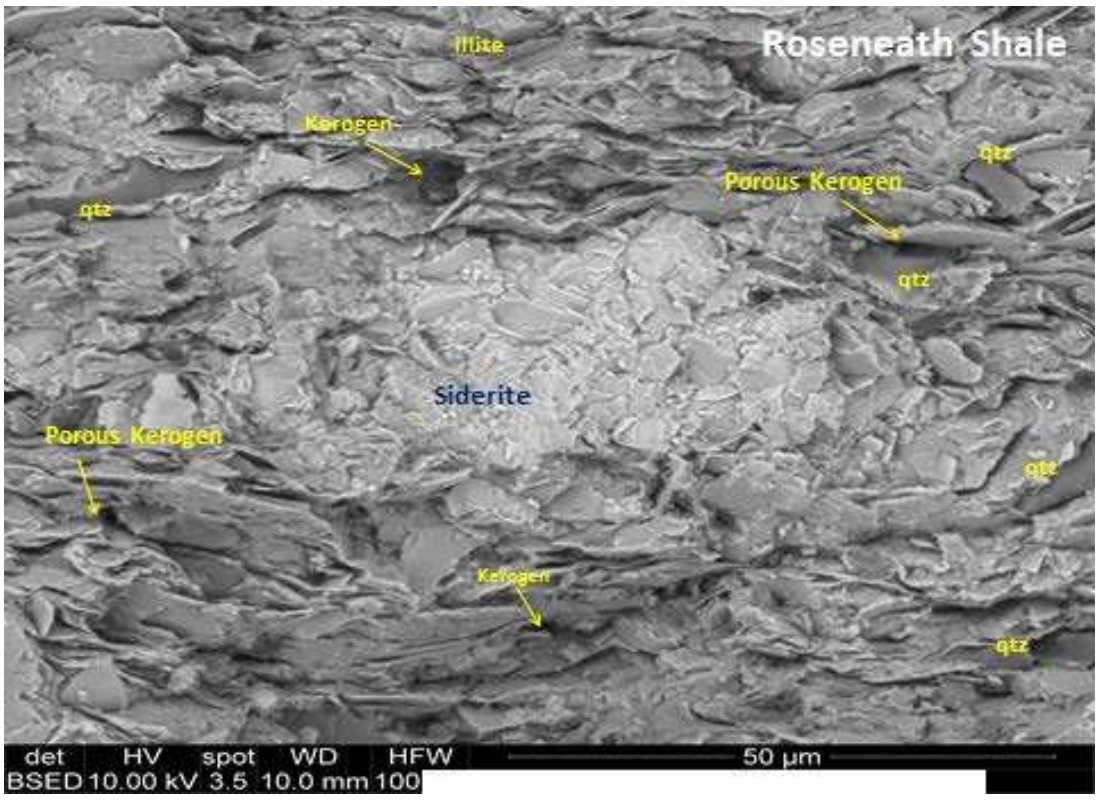


Figure 7: Kerogen embedded in a clay-rich matrix with abundant porosity in the Murteree Shale in the Dirkala-2 well. Porosity ranges from 10-50 nm to ~ 2 µm. The kerogen is located in the interstitial spaces of the authigenic quartz coating.



Results and Discussion

The conceptual rock model suggests that the source rock consists of inorganic detritus and kerogen for both the Murteree and Roseneath shales. However, this study illustrates that shales that are similar in appearance to each other actually show a lot of lithological variation, even if the grain size is fairly consistent and limited to silt and clay size particles. Murteree and Roseneath shales have quartz-rich 40 -50% volume Dirkala-1, Dirkala-2, Encounter-1, Moomba-73 and Toolache North wells, while in the Baratta-1 and Baratta South-1 wells have clay rich with 20-25% brittle minerals. The higher percentages of brittle minerals positively impact the use of hydraulic fracturing in sweat spots.

Conceptually, TOC quantification requires caution because the preliminary assessment of any shale relies on TOC. Lower percentages of TOC do not necessarily imply an immature source rock; rather this depends upon the amount of organic content present and amount of organic matter converted to hydrocarbons. Original TOC can be constructed with the help of Rock-Eval pyrolysis and vitrinite analysis, which helps to determine actual maturation of the source rock. Higher TOC values have a positive impact because gas can be sorbed onto organic matter. TOC can be transformed into kerogen volume by the relationship specified above. Pyrolysis, VR and maceral analysis should always be done along with TOC to differentiate between the dead and live carbons and amount of kerogen left, the type of kerogen (used to determine hydrocarbon yield), amount of free hydrocarbons and source potential remaining. VR analysis additionally helps to find the hydrocarbon window and hence the yield of hydrocarbons.

Porosity remains the most important element of any petrophysical analyses because it provides an indication of volume percent of space present for the occurrence of hydrocarbons. When porosity is nominal then most of the log response comes from the rock itself. The density log has traditionally provided the most reliable means of porosity quantification, but in shales, unless the grain density is known, the quantification of porosity is very difficult due to different shales consisting of different types of clay and brittle minerals. Contrary to shales, in carbonate and clastic rocks one can choose default grain density based on reference charts. Because many wells in this study did not have density logs, an alternative approach was developed. When the density log was present, it was used to quantify the

porosity and then tied with the core derived crushed porosities and then multiple mineral analysis was carried out with the minerals given in the XRD analysis. This method requires several iterations by tweaking the input parameters until the desired match is achieved between the output curves and the core data.

As observed by many authors, multiple mineral models provide the best solution in complex shale gas reservoirs, because they provide pragmatic solutions which can be tied with core data easily [38] . The facility given by the multiple mineral models to match the input and output curves provides a means to check the reliability of the model. A true mineral model helps to get the result with reasonable accuracy as given above in the mineral model section. Water saturation gives the sweet spots for fracking so it is very important to quantify it with accuracy. No silt rock saturation model is present in literature, so it was estimated through the classical shaly sand equations. Waxman & Smit's [45] model has been providing the scientifically most correct model for years now. A CEC derived from core is very important in order to check whether the formation behaves like Archie or shaly sand. In the absence, we can estimate Qv by back calculating the Waxman and Smit's equation in 100% water zone.

Formation water resistivity (R_w) was computed by a combination of SP, apparent water resistivity calculated from logs and Picket cross-plots. A minimum value of R_w for both the formations was used because the determinations of the shale-gas potential of the Roseneath and Murteree formations are at the initial phase. An optimistic approach was followed to begin with since the projects are large scale. Generally, in the Permian shale wells in this study area R_w corresponds to a water salinity of 6000-8000 ppm NaCl. It also corresponds to the regional R_w from analyses of water from drill stem tests that are published in the completion reports of Ashbay-1, Dirkala-1, 2, Encounter-1.

SEM study show clays, quartz, carbonate, and kerogen, with subordinate accessory minerals of feldspar, siderite, etc. (Figs. 6–7) in both Roseneath and Murteree shales. The most abundant type of organic matter found in both shales is kerogen. The visible porosity in Roseneath and Murteree shales is rare and comprises matrix-hosted micro porosity. Visible porosity (1 to 2%) from SEM and optical microscopy is most commonly patches and isolated pinpoints in the matrix. Siderite cement as irregularly shaped, which are surrounded by quartz and porous kerogen. Dolomitization increases the porosity in over-mature Roseneath and

Murteree shales. The implication of siderite is not favourable for the density tool in oil and gas industry. Siderite affects the density tool leading to incorrect porosity [13].

The reservoir characteristics interms of porosity, saturation of water, the volume of clay, TOC, permeability. The petrophysical summaries are represented of the average properties of gross shale interval for the Roseneath and Murteree. Key information has been tabulated in Tables 4–5.

Table 4: Murteree Shale Shows key information of porosity, VCL, TOC, S_w and permeability**.**

Well name	Avg Phi	Avg S_w	Avg VCL	Avg TOC	Permeability
Dirkala-1	10.2	60	52.1	1.6	3.5 * 10-5
Barata-2	3.5	85	70	1.1	-
Ashbay-1	3.6	65	41	1.4	5.1 * 10-5
Moomba-73	8	51	50	4.1	4.1 * 10-5
Toolache-N-1	4.8	50	54	3.3	-
Moomba-66	4.4	62	49	3.3	3.5 * 10-5
Toolache-39	6	79	50	2.5	-
Big Lake-70	3.2	-	75	-	4.14 *10-6
Della-1	4.1	55	55	2.1	-
Dirkala-2	10	48	48	1.6	3.8 * 10-5
Encounter-1	6	55	57	2.2	1.92 * 10-5

Table 5: Roseneath Shale Shows key information of porosity, VCL, TOC, S_w and permeability.

Well name	Avg Phi	Avg S_w	Avg VCL	Avg TOC	Permeability
Dirkala-1	2	100	50	1.5	$5.5 * 10^{-5}$
Baratta-2	4	90	75	1	-
Ashbay-1	4	76	48	1.5	-
Moomba-73	2	63	47	4	$5.1 * 10^{-5}$
Toolache-N-1	5	70	53	2.6	-
Moomba-66	4	60	50	3	$6 * 10^{-5}$
Toolache-39	5	90	55	1.8	-
Big Lake-70	3.5	-	80	-	$4.5 *10^{-6}$
Della-1	1.5	95	58	0.9	-
Dirkala-2	3	90	60	1	$3 * 10^{-5}$
Encounter-1	4.5	60	60	3.5	$1.5 * 10^{-5}$

Conclusions:

- The multiple mineral analysis in this study yielded better results compared to deterministic petrophysical analysis which cannot resolve rocks containing more than four minerals) when the lithology is complex and gave a good fit to the regional model when data is very limited. Total organic content (TOC) can be estimated easily with the Passey method if there are no conductive minerals. In case of conductive minerals in the formation extreme caution is recommended.
- Core/cutting derived TOC is required to tie the log calculated TOC to attain accurate TOC results from top to bottom of a formation. Log-derived TOC is merely an estimation which needs to be compared/tied to a more authentic laboratory driven TOC. A vitrinite reflectance (VR) value is necessary to get the level of maturity (LOM), which is needed as a supplement in the estimation of TOC.
- The most common concretion siderite is present in Roseneath and Murteree shales. This siderite cement occurs as in irregularly shaped and gives cycle skipping, which are badly effect in the density log that may be lost in general variation due to varying porosity.
- A mineral model can produce the desired results (mineral constituents, porosity, volume of clay, volume of kerogen, saturation of water) in underexplored areas. The log derived output (mineral constituents, porosity, volume of clay, volume of kerogen, saturation of water) needs to be first calibrated with a more reliable core.
- On the basis of porosity, permeability, TOC, S_w, mineral model and petrophysical model outcome, the Murteree Shale exhibits better potential basin wide than the Roseneath Shale, which looks prospective in and near Encounter-01 well area.

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Nomenclature

API American Petroleum Institute units.

CEC Cation exchange capacity

DT Sonic log interval transit time (micro sec/ft)

DTB Sonic baseline

DMITRE Department for Manufacturing Innovation, Trade, Resources and Energy.

ECS Elemental capture spectroscopy

Elan Petrophysics software

GR Gamma ray log (API units).

ICPMS Inductively coupled plasma mass spectrometry

IP Interactive Petrophysics software

LLD Laterolog deep

LOM Level of Maturity

md Millidarcy, unit of permeability (100-1 darcy)

PEF Photoelectric factor

PESA Petroleum Exploration Society of Australia

PHID Density Porosity

PHIDKC Density porosity corrected to kerogen content

PHIDK Density porosity of Kerogen

Qv Pore volume concentration of clay exchange cations (meq/mL).

PIRSA Primary Industries and Resources South Australia

RhoM Matrix density

RHOB Bulk density from the density log

RhoF Fluid density

RWb Dual water equation

Satmin Petrophysical software

S_w Water Saturation

SCAL Special Core Analysis

RI Resistivity index Rt/ R0.

Rsh Resistivity of shale

R0 Resistivity of fully brine saturated sample.

Rwb Dual water equation

Rt Resistivity of partially saturated sample or formation.

SEM Scanning electronic microscope

TOC Total organic carbon

VKF Volume of Kerogen in fraction

VR Vitrinite reflectance

Vsh Volume of shale derived from GR log (fraction)

VCL Volume of clay

VK Volume of kerogen

XRD X-ray diffraction

ϕT Total porosity