CHAPTER 2

DATABASE AND METHODOLOGY

2.1 Database

The study is focused on the interpretation of well-log parameters and selected core samples of potential reservoir zone. Available data comprise conventional Laterlogs and Porosity logs, deviation survey data, ten selected intervals of core samples of a well and associated 3D-seismic section through each well. These comprehensive data were supported by PTT Exploration and Production Public Company Limited, Bangkok, Thailand.

Geological completion well reports for four wells, petrologic core analysis report and related documents are referenced in this study. The logging parameters for the wells are listed in Table 2.1.

Table 2.1. Available log parameters with wells in study area.

Well	Log parameters	Interval mMD	Remark
A	RESDE, LLS, MSFL, GRE, DTCE, RHOBE, NPHIE, CALIE	1000 – 1460	
B-West	RESDE, LLS, GRE, DTCE, RHOBE, NPHIE, CALIE	800 - 1350	not applicable RHOBE, NPHIE
B	RESDE, LLD, LLS, MSFL, GRE, DTCE, RHOBE, NPHIE	945 - 1590	absent CALIE
C	RESDE, LLD, LLS, MSFL, GRE, DTCE, RHOBE, NPHIE, CALIE	1200 - 1595	

The logs were taken inside 8.5 inch open-hole. Log parameters were recorded with LAS format. The resistivity properties of mud and mud filtrations, and associated header parameters with bottom hole temperatures are absent for these wells. Well B, at the depth interval between 1442m and 1458m has no resistivity parameters. Density and Neutron logs are not reliable for formation evaluation in well B-West. Except well B, three wells were deviated. Interactive Petrophysics Software (IP version 3.4) was used to interpret the formation evaluation in this study.

Ten selected intervals with core samples from well B were examined. These samples were prepared as thin sections for petrography and Scanning Electron Microscope (SEM) studying. Thin sections were made at the Department of Geological Sciences, Faculty of Science, Chiang Mai University. SEM analyses were accomplished in Electron Microscopy Research and Service Centre (EMRSc), Faculty of Science, Chiang Mai University.

Total twelve 3D seismic sections were collected as soft-copies. These sections are seven cross lines and five inlines.

2.2 Methodology and Studying Procedure

The prediction of reservoir properties and their distributions are the most critical aspects for reservoir characterization. Combination of well log analysis and petrographic study of core samples are efficient to estimate reservoir properties of potential zones.

The studying procedure is described in Figure 2.1.

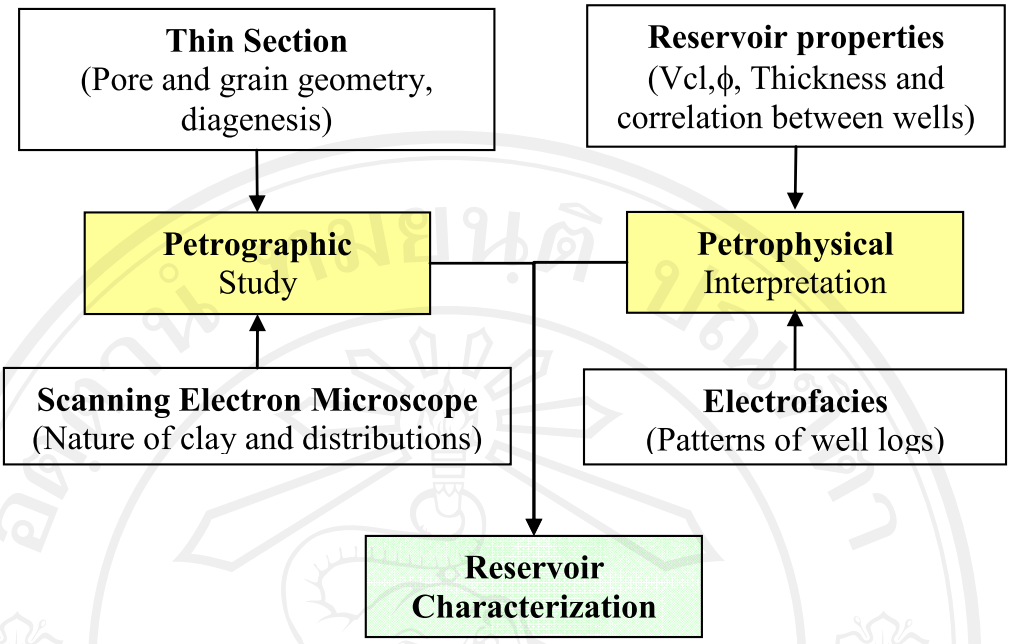

Figure 2.1 Studying procedures.

2.3 Petrophysical Interpretation

The objective of this section is to evaluate reservoir properties such as porosity, volume of shale and saturation of water by using gamma ray, resistivity, caliper, sonic, neutron and density logs. Some logs are principally necessary for the correction of the environmental factors of borehole. There are the base line shift to Spontaneous potential (Sp), matching depths to all log parameters, and environmental correction and transformation to gamma ray, density, resistivity and neutron. These could be completed if background processing data are available. For example, the gamma ray and density logs are corrected with hole caliper and mud weight. The resistivity and neutron logs are transformed to true resistivity and sandstone-matrix neutron. Figure 2.2 presents the generalized well logs preparation and fundamental corrections.

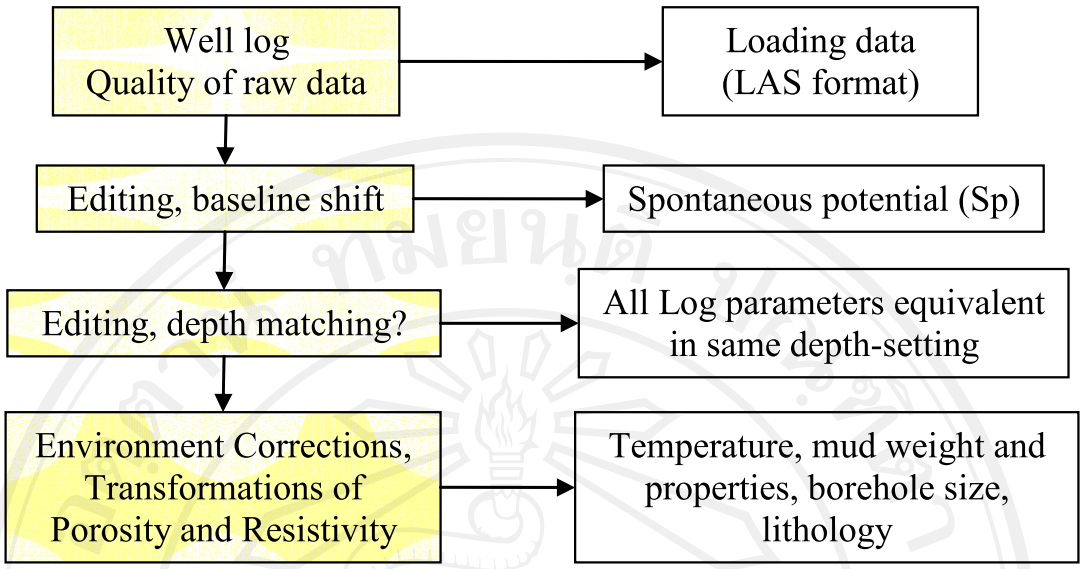

Figure 2.2. Generalized well logs preparing and fundamental corrections.

After correcting log parameters, wells correlation were made based on gamma ray and sonic logs. The well log interpretation consists of qualitative and quantitative analyses. Qualitative analysis comprises determination of porous zone, shale base line comparing with sand, water bearing formation with hydrocarbon content and oil water contact. Quantitative analysis includes estimating the temperature gradient, shale/clay volume, porosity, and saturation of formation water.

Although there are various models in log interpretation, only available models and procedures will be presented based on available well log parameters. The generalized process of reservoir zone interpretation an evaluation is shown in Figure 2.3.

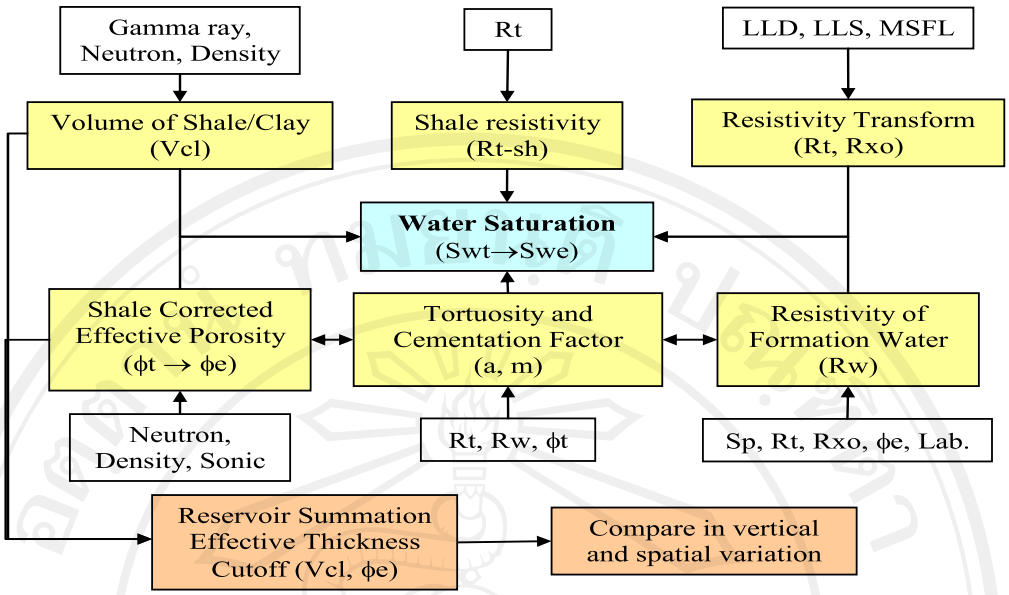

Figure 2.3 Flow chat of formation evaluation.

2.3.1 Volume of Shale Models (Vsh)

The content of shale/clay is significant in the estimation of the capacity of hydrocarbons and production performance. Not only the types of clay but also their distributions in reservoir affects gamma ray, neutron and density logs are used to generate volume of shale (Figure 2.4).

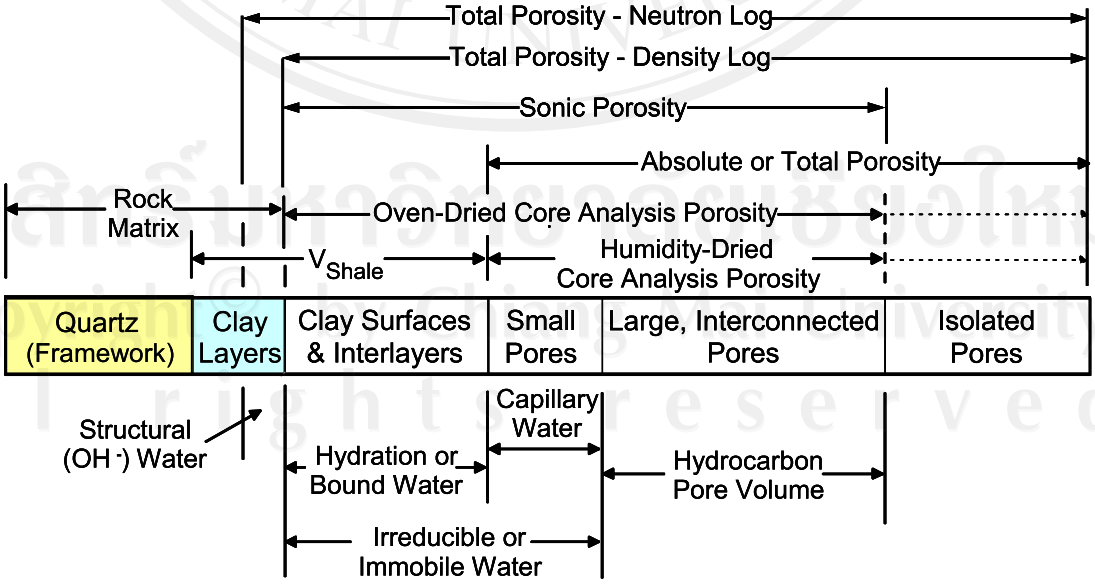

Figure 2.4 Volume of shale/clay and porosity models (Eslinger and Pevear, 1988).

- **Volume of Shale based on Gamma ray (Dresser Atlas, 1979)**

The gamma ray (°API) is a measurement of the natural radioactivity of the formation, normally reflects the shale content of the formation because the radioactive elements tend to concentrate in clay and shale (Schlumberger, 1989). Gamma ray logs are normally used in estimating volume of shale and lithology identification (sand and shale), formation correlation, detection of permeable or non-permeable beds and to harmonize between open hole and cased hole.

There are limitation in the calculation of volume of shale in bad holes (large hole by caving) and potassium-rich feldspar in sandstone reservoirs. The following formulae are usually applied.

$$I_{GR} = \frac{GR_{\log} - GR_{\min}}{GR_{\max} - GR_{\min}}, \qquad \text{Liner formula of Volume of shale}$$

where for linear response, Volume of shale, $V_{sh} = I_{GR}$

$$V_{sh} = 0.33\left[2^{(2\times I_{GR})} - 1.0\right] \qquad \text{Larionov (1969) for older rocks}$$

$$V_{sh} = 0.083\left[2^{(3.7\times I_{GR})} - 1.0\right] \qquad \text{Larionov (1969) for younger rocks}$$

$$V_{sh} = \frac{I_{GR}}{3 - 2\times I_{GR}} \qquad \text{Steiber (1970)}$$

$$V_{clGr} = 1.7 - \sqrt{3.38 + \left(I_{GR} + 0.7\right)^2} \qquad \text{Clavier formula}$$

Curved method: $V_{sh} = I_{GR}$

For $V_{sh} < 0.55$ $\qquad V_{sh} = 0.0006078 \times \left(100 \times I_{GR}\right)^{158527}$

For $0.73 < V_{sh} > 0.55$ $\qquad V_{sh} = 2.1212 \times I_{GR} - 0.81667$

For $1 < V_{sh} > 0.73$ $\qquad V_{sh} = I_{GR}$

where GR_{log}= Gamma ray reading of formation (API°)

GR_{min}= minimum Gamma ray in clean sand or carbonate (API°)

GR_{max}= maximum Gamma ray in shale unit (API°).

Significant contrasts of these methods are recognizable in shaly sand reservoirs (Figure 2.5). Linear method produces the maximum volume of shale while Larionov (1969) for younger rock method shows the minimum result.

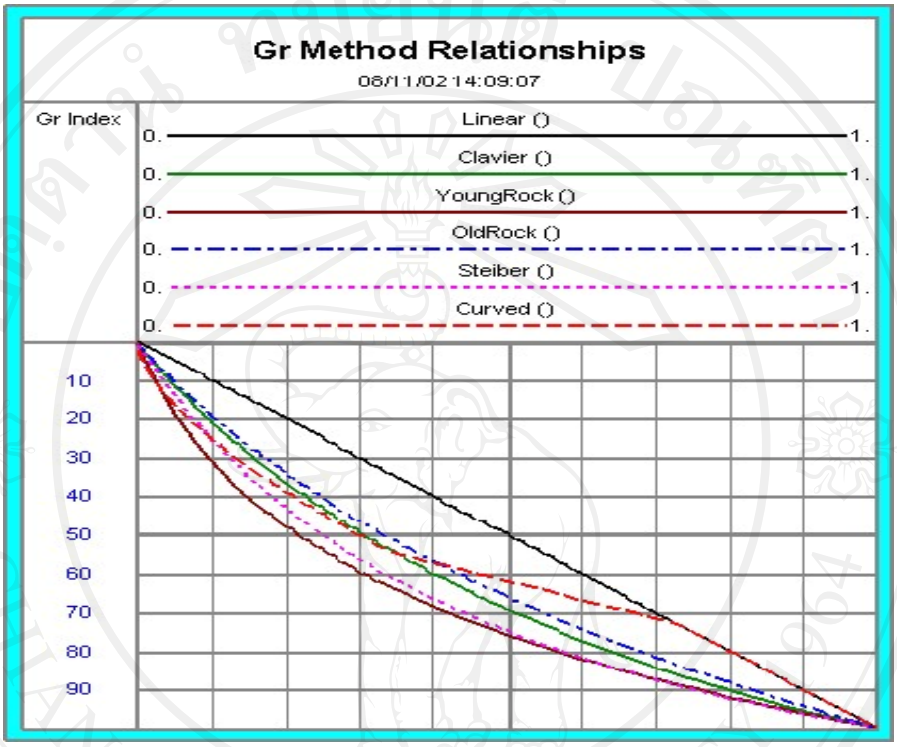

Figure 2.5 Gamma ray method for estimation of volume of shale/clay (Interactive Petrophysics™ (IP), version 3.4).

- **Volume of Shale based on Neutron-Density**

Neutron measures the hydrogen ion concentration in a formation. Where pores are filled with gas rather than oil or water, neutron porosity is lower because of less concentration of hydrogen in gas than that in oil or water. The density log measures electron density of a formation. Electron density can be related to bulk density (ρ_b) of a formation. It depends on the density of the rock matrix material, the formation porosity, and the density of the fluids filling the pores.

The present of shale is significantly realized in shale formation and shaly reservoir by the result of increasing Neutron porosity over Density porosity. Neutron-Density method is limited for gas saturated zones. Porosity determination in gas zones may be high because if there is residual gas nears the borehole. For that reason, volume of clay (V_{cl}) should not be determined by using the neutron-density log in gas saturated reservoirs.

$$V_{sh} = (\phi_n - \phi_d)/(\phi_{nsh} - \phi_{dsh})$$

$$\phi_d = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f} \quad \text{and} \quad \phi_{dsh} = \frac{\rho_{ma} - \rho_{sh}}{\rho_{ma} - \rho_f}$$

where ϕ_n = Neutron porosity in shaly sand without shale correction (v/v)

ϕ_d = Density porosity in shaly sand without shale correction (v/v)

ϕ_{nsh} = Neutron porosity in adjacent shale (v/v)

ϕ_{dsh} = Density porosity in adjacent shale (v/v)

ρ_{ma} = Matrix density (gm/cc)

ρ_b = Formation bulk density (gm/cc)

ρ_{sh} = Adjacent shale density (gm/cc)

ρ_f = Fluid density (gm/cc), (1.1 for salty mud, 1.0 used in fresh mud).

2.3.2 Porosity Models (ϕ)

While there are more than one model to determine the porosity, the following methods are adopted based on the nature of available data. Density, Neutron and Sonic logs are primary tools to measure total porosity (ϕ_t) and effective porosity (ϕ_e) of a formation (Figure 2.4).

- **Sonic Porosity (ϕ_s)**

Sonic tools measure interval transit time (Δt) of a compressional sound wave traveling through one foot of formation (μsec/feet or μsec/meter) and can only be calculated for primary porosity. The sonic log records matrix porosity rather than vuggy or secondary porosity attributed to fractures. Thus, sonic porosities in carbonate rocks with vugs or fractures will be low.

$$\phi_s = \frac{\Delta t_{\log} - \Delta t_{ma}}{\Delta t_f - \Delta t_{ma}},$$ Wyllie (1958) (ϕ_s with uncorrected shale)

$$\phi_s = \frac{\Delta t_{\log} - \Delta t_{ma}}{\Delta t_f - \Delta t_{ma}} \times {}^{1}\!/_{C_p},\ C_p = \frac{\Delta t_{\log} \times C}{100},$$ (ϕ_s for unconsolidated sands)

C has a range of 0.625 to 0.7 (0.67 is more appropriate). In the case of a gas-saturated reservoir rock, C is 0.6.

$$\phi_s = \frac{5}{8}.\frac{\Delta t_{\log} - \Delta t_{ma}}{\Delta t_{\log}},$$ Raymer–Hunt Equation

where ϕ_s = Sonic porosity (fraction or percentage)

$\Delta t_{\log}$ = interval transit time of formation

Δt_{ma} = interval transit time of matrix

Δt_f = interval transit time of fluid.

Typical values:

Sandstone:	Δt_{ma}	= 55 μsec/ft (182 μsec/m)
Limestone:	Δt_{ma}	= 47 μsec/ft (156 μsec/m)
Dolomite:	Δt_{ma}	= 43.5 μsec/ft (143 μsec/m)
Anhydrite:	Δt_{ma}	= 50 μsec/ft (164 μsec/m)
Fresh water:	Δt_f	= 189μs/ft (620 μs/m)
Salty water:	Δt_f	= 185 μs/ft (607 μs/m)

- **Sonic Effective Porosity (ϕ_e) (Dresser Atlas, 1979)**

$$\phi_e = \frac{\Delta t_{\log} - \Delta t_{ma}}{\Delta t_f - \Delta t_{ma}} \times \frac{100}{\Delta t_{sh}} - V_{cl}\left(\frac{\Delta t_{sh} - \Delta t_{ma}}{\Delta t_f - \Delta t_{ma}}\right)$$

Δt reading can be too high for a porosity calculation due to the bound water in the shale. Residual gas causes Δt log reading to be too high also when the formation is uncompacted (usually at depths shallower than 1000 m). In compacted sands, the wave will travel from one sand grain to another and the gas effect will be reduced. Therefore, sonic porosity when corrected with density of hydrocarbon or fluid is generally assumed as $\phi = \phi_{sonic} \times 0.7$ for gas and $\phi = \phi_{sonic} \times 0.9$ for oil.

- **Density Effective Porosity (ϕ_d) with corrected shale (Dresser Atlas, 1979)**

$$\phi_d = \left(\frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f}\right) - V_{sh}\left(\frac{\rho_{ma} - \rho_{sh}}{\rho_{ma} - \rho_f}\right)$$

- **Neutron-Density Porosity (ϕ_{nd})**

$$\phi_{nd} = \sqrt{\frac{\phi_n^2 + \phi_d^2}{2}}$$ for gas bearing zone without correction for shale.

$$\phi_{nd} = \frac{\phi_n + \phi_d}{2}$$ for oil bearing zone without correction for shale.

$$\phi_d = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f}$$ Density porosity without correction for shale.

- **Neutron-Density Porosity (ϕ_e) (Dewan, 1983)**

$$\phi_{nc} = \phi_n - (V_{cl} \times \phi_{nsh}) \quad \text{and} \quad \phi_{dc} = \phi_d - (V_{cl} \times \phi_{dsh})$$

$$\phi_e = (\phi_{nc} \times \phi_{dc})/2 \quad \text{for oil} \qquad \phi_e = \left[\left(\phi_{nc}{}^2 \times \phi_{dc}{}^2\right)/2\right]^{1/2} \quad \text{for gas}$$

where ϕ_e = effective porosity (neutron and density logs corrected for clay)

ϕ_n, ϕ_d = neutron and density porosities of shaly formation

ϕ_{nc}, ϕ_{dc} = neutron and density porosities corrected for clay

ϕ_{nsh}, ϕ_{dsh} = neutron and density porosities of shale.

- **Neutron-Density Porosity (ϕ_{nd}) (Schlumberger, 1975)**

$$\phi_{n.corr} = \phi_n - \left(\left(\frac{\phi_{n.clay}}{0.45} \right) \times 0.30 \times V_{sh} \right)$$, Neutron porosity corrected for shale

$$\phi_{d.corr} = \phi_d - \left(\left(\frac{\phi_{d.clay}}{0.45} \right) \times 0.13 \times V_{sh} \right)$$, Density porosity corrected for shale

$$\phi_{nd} = \sqrt{\frac{(\phi_{n.corr})^2 + (\phi_{d.corr})^2}{2}}$$, neutron-density porosity corrected for shale

$$\phi_{d.clay} = \frac{\rho_{ma} - \rho_{clay}}{\rho_{ma} - \rho_f}$$, density porosity in adjacent clay

where $\phi_{n.clay}, \phi_{d.caly}$ = neutron and density porosities of adjacent shale

ϕ_n, ϕ_d = neutron and density porosities uncorrected for shale

ρ_{clay} = density of adjacent clay/shale.

Density porosity increases with the decrease of neutron porosity in a gas-bearing zone. That is called gas-effect (Schlumberger, 1989). Gas in the pores causes the density log to record too high a porosity (i.e. gas is lighter than oil or water), and causes the neutron log to record too low a porosity (i.e. gas has a lower concentration of hydrogen atoms than oil or water).

2.3.3 Formation water resistivity (Rw), mud filtrated resistivity (Rmf), Cementation factor (m) and Moveable Hydrocarbon Index (MHI)

The resistivity of formation water (Rw) is fundamentally important in distinguishing between potential reservoir and non-potential reservoir. The parameter, Rw, is determined by using well log data such as spontaneous potential (Sp), apparent water resistivity (Rwa), resistivity ratio method, Pickett Crossplot, direct measurement of water samples in laboratory, and regional resistivity catalogue. Only Pickett crossplot method is available with existing log parameters to develop "Rw" and "m".

- **Pickett Crossplot Method**

Pickett (1963, 1966) observed that true resistivity (Rt) is a function of porosity (ϕ), water saturation (Sw), and cementation exponent (m). The method is not only key to estimation of water saturation (Sw) and it could be used to determine "Rw", cementation factor (m), and matrix parameters for sonic and density logs (Δt_{ma}, ρ_{ma}).

The application is based on graphical solution of Archie's saturation equation and it generates the formula

$$\log(R_t) = \log(a \times R_w) - m.\log(\phi) - n\log S_w.$$

At water bearing zone, Sw=100% and assumed a=1, the equation becomes

$$\log(R_t) = \log(a \times R_w) - m.\log(\phi).$$

The equation is linear ($y = b + mx$).

It could be proved by plotting formation resistivity on the y-axis against porosity (ϕ) on the x-axis with the logarithmic scale (Figure 2.6).

Resistivity of the formation water (Rw) is a function of salinity and temperature, and it can be measured using produced waters and estimated from water-saturated intervals using cross plot of porosity and resistivity extrapolated to 100% porosity (Pickett, 1966).

The saturation exponent "n" value can be measured in the laboratory and it is normally assumed to be "2" based on wettability. The cementation factor or lithology exponent is related to rock fabrics and porosity. The "m" values vary in ranges of 1.8 to 4 for carbonate rocks and less than 2 in the presence of fractures and vuggy pore types (Meyers, 1991; Wang and Lucia, 1993).

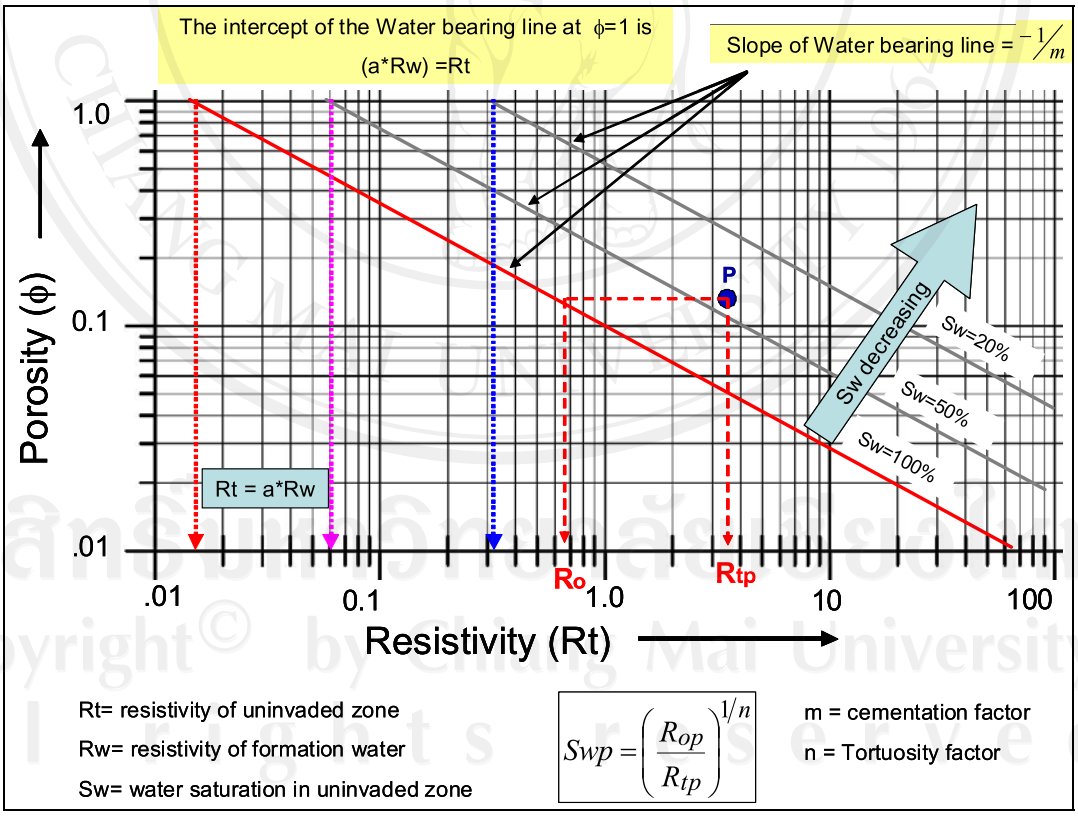

Figure 2.6 Pickett Crossplot, Resistivity (Rt) against Porosity (ϕ) on log-log scale.

- **Resistivity Ratio Method**

The method is based on the division of Archie's uninvaded zone water saturation (Sw) and flushed zone water saturation (Sxo). The apparent water resistivity value can be identified from water bearing zone. It then can be used to estimate moveable hydrocarbon index MHI (S_w/S_{xo}).

$$\frac{S_w}{S_{xo}} = \left(\frac{R_{xo}/R_t}{R_{mf}/R_w} \right)^{\frac{1}{2}}$$

In 100% water saturated zone $S_w = S_{xo}$, and the equation becomes

$$R_w = \frac{R_{mf} \times R_{xo}}{R_t} \qquad \text{and} \qquad R_{mf} = \frac{R_w \times R_t}{R_{xo}}$$

Whereas the ratio S_w/S_{xo} is equal to or greater than 1.0 indicating that the hydrocarbons were not moved during invasion regardless of whether or not there is hydrocarbon in the formation. The result of S_w/S_{xo} is less than 0.7 for sandstone or less than 0.6 for carbonate rocks where moveable hydrocarbons are indicated (Schlumberger, 1975). The resistivity values vary with temperatures and the formation temperature gradient can be assumed by using linear regression equation.

$$G = \frac{T_1 - T_{surface}}{D1}$$ Geothermal gradient (°C/100m)

$$T_2 = (depth \times G) + T_{surface}$$ Temperature at desired depth (°C)

$$R_2 = R_1 \left[\frac{T_1 + 21.5}{T_2 + 21.5} \right]$$ Resistivity at desired depth (ohm-m)

where D1= the depth measured temperature (meter)

T_1 = Measured temperature at depth D1 (°C)

T_2 = Temperature at depth D2 (°C)

$T_{formation}$ = Measured temperature at depth, °C (BHT)

$T_{surface}$ = Surface temperature climate zone, (°C)

R_1 = Measured resistivity (ohm-m)

R_2 = Resistivity at studying depth (ohm-m).

2.3.4 Archie Water Saturation Model (Archie, 1941)

Archie (1941) initially introduced the water saturation model. The model becomes the fundamental relationship between resistivity, porosity and associated factors used to estimate saturation of water volume in the rock. Resistivity of formation is increased (Rt > Rw) proportionally with the amount of hydrocarbon present.

$S_w = \left(F \times \frac{R_w}{R_t} \right)^{1/n}$ Water saturation valid for clean reservoir, $F = \frac{a}{\phi^m}$

where S_w = the fraction of pore volume filled with water

R_w, R_t = Resistivity of formation water and uninvaded zone formation

a = Tortuosity or porosity factor (varying around “1”)

m = Cementation factor (dimensionless)

n= Saturation exponent (dimensionless)

ϕ= Porosity (fraction).

Most recognized coefficients and exponents used to calculate formation factor (F) are recorded by Asquith (1990).

$F = 1/\phi^2$ for carbonate rocks

$F = 0.81/\phi^2$ Humble formula for consolidated sandstone

$F = 0.62/\phi^{2.15}$ Humble formula for unconsolidated sand (Tertiary)

$F = 1.45/\phi^{1.54}$ for average sand (after Carothers, 1958)

$F = 1.65/\phi^{1.33}$ for shaly sand (after Carothers, 1958)

$F = 1.45/\phi^{1.7}$ for calcareous sand (after Carothers, 1958)

$F = 0.85/\phi^{2.14}$ for carbonate sand (after Carothers, 1958)

$F = 1/\phi^{(2.05-\phi)}$ for calcareous sand (after Sethi, 1979)

The tortuosity factor “a”, generally, is not a strong influence on water saturation. The commonly used value “1” was a standard in this study. The cementation exponent (m) is the important influence in Archie’s formula due to the exponent of the porosity. The value “m” by Humble formula, is practically applied in hydrocarbon bearing formations. The Pickett crossplot is typically acceptable to evaluate the “m” for specified potential reservoirs.

2.3.5 Shaly Sand and Dual Water Models

A reservoir with the presence of shale/clay complicates the evaluation of reservoir characteristics. The presence of shale/clay degrades to reservoir qualities, porosity and permeability. They reduce the storage capacity of reservoir and discourage flowing hydrocarbon. Moreover, a fair amount of clay distributed in reservoir could affect the entrapment of interstitial water and produce water free hydrocarbon only (Figure 2.7). They also significantly affect petrophysical logs resulting in low resistivity, high gamma ray, and generally too high reading in porosity logs (sonic, neutron and density). The most common problems in reservoir caused by the presence of clay are mentioned in Table 2.2.

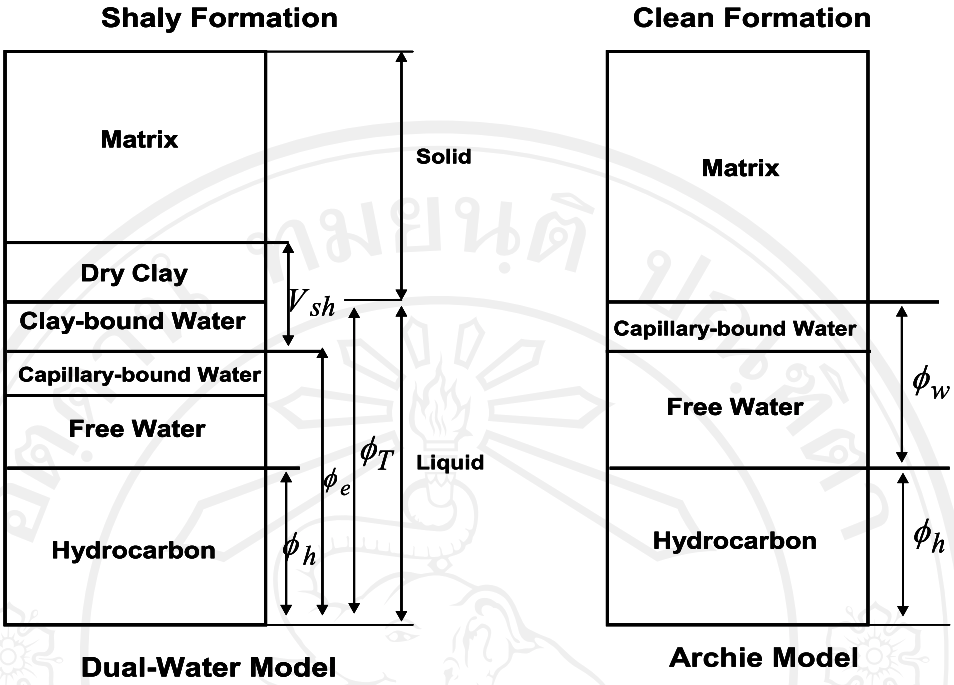

Figure 2.7 Comparison of Shaly Formation-Dual Water Model and Clean Formation-Archie Model.

Table 2.2 Group of clay mineral and major problems cause their presence in reservoirs (after Ali, 1981).

GROUP	COMPOSITION	MAJOR RESERVOIR PROBLEMS
Kaolinite	$Al_4[Si_4O_{10}](OH)_8$	Migration of fines
Smectite (Montmorillonite)	$(1/2\ Ca,Na)_{0.7}(AL,Mg,Fe)_4$ $[(Si,Al)_8O_{20}](OH)_4.nH_2O$	Water sensitivity Microporosity
Illite	$K1\text{-}1.5Al4[Si_{7\text{-}6.5}Al_{1\text{-}1.5}O_{20}](OH)_4$	Microporosity Migration of fines
Chlorite	$(Mg,Fe,Al)_{12}[(Si,Al)_8O_{20}](OH)_{16}$	Acid sensitivity
Mixed-Layer Clay Minerals		Water sensitivity Microporosity Acid sensitivity

According to the crystal structures of clay minerals, three types of their distribution in reservoirs can be defined in Figure 2.8.

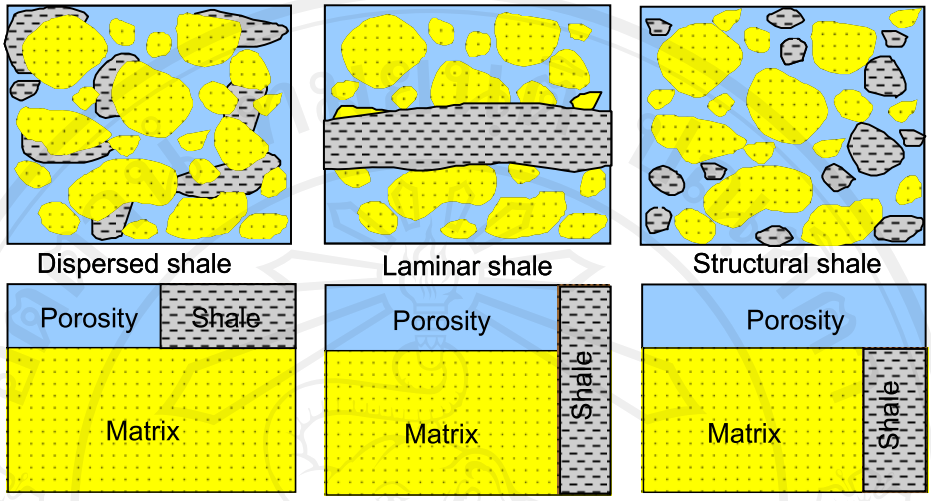

Figure 2.8 Distributions of shale in a reservoir on their influences on porosity (Serra, 1984).

i. Laminated Shale (detrital clay): The laminar shale does not extremely change the porosity or permeability of the sand bands.

ii. Structural Shale (detrital clay): Detrital grains of clay are scattered along with sand grains and they are forming as grains or nodules in the formation matrix.

iii. Dispersed Clay (authigenic clay): The clays are dispersed in the pore space of sand and replaces fluid volume and typically reduce the porosity and permeability of the formation.

Archie's equation is valid in clean reservoirs only. Based on this model, a number of saturation models are developed and modified regarding depositional environments especially in the presence of shale/clay in reservoirs. Within numbers of shaly sand models for effective water saturation (Swe), the dependable models on available data will be described subsequently.

- **Simandoux (1963)**

$$Sw = \left[\frac{0.4 \times Rw}{\phi^2}\right] \times \left[\sqrt{\left[\frac{Vsh}{Rsh}\right]^2 + \frac{5 \times \phi^2}{Rt \times Rw}} - \frac{Vsh}{Rsh}\right]$$

The Vcl does not represent the completed volume of shale in this equation.

- **Modified Simandox (Bardon and Pied, 1969)**

$$Sw = \left[\frac{0.4 \times Rw}{\phi^2}\right] \times \left[\sqrt{\left[\frac{Vsh}{Rsh}\right]^2 + \frac{5 \times \phi^2}{Rt \times Rw}} - \frac{Vsh}{Rsh}\right] - \left[1 - V_{sh}\right]$$

- **Indonesia Equation (Poupon-Leveaux, 1971)**

This equation was used for fresh formation waters and high saline water content in reservoirs.

$$S_{we}^{n/2} = \left[\frac{\sqrt{\frac{1}{R_t}}}{\left[\frac{V_{cl}^{(1-V_{cl}/2)}}{\sqrt{R_{cl}}} + \frac{\sqrt{\phi_e^m}}{\sqrt{a.R_w}}\right]}\right]$$

- **Dual Water Model (Tepper, 1989)**

$$S_{we} = (S_{wt} - S_b)/(1 - S_b)$$

$$S_{wt} = \left\{-S_b(R_w/R_b - 1.0) + \left\{[S_b(R_w/R_b - 1.0)]^2 + 4\left(R_w/\phi_t^2 R_t\right)\right\}^{0.5}\right\}/2$$

$$S_b = V_{cl} \times \left[(R_w/R_t)^{0.5}/\phi_t\right]^{0.5}$$

$$R_b = R_{sh} \times \phi_{tsh}^2$$

$$\phi_{tsh} = \delta.\phi_{dsh} + (1 - \delta).\phi_{nsh}$$

δ= 0.5 to 1.0 depends on hydrocarbon density (≥0.7 for oil & ≤0.7 for gas)

$$\phi_{dsh} = \left(\frac{\rho_{ma} - \rho_{sh}}{\rho_{ma} - \rho_{f}} \right)$$

where

R_{cl}, R_{sh}, R_t, R_w = Resistivity of clay, shale, uninvaded zone and formation water (ohm-m)

ϕ_e = effective porosity (fraction or percentage)

ϕ_{nsh} = Neutron porosity of adjacent shales (fraction or percentage)

a = Tortuosity or porosity factor (varying around "1")

m = Cementation factor (dimensionless)

n= Saturation exponent (dimensionless).

2.3.6 Reservoir Summation

The summation of reservoir properties are identified mainly on the nature of gamma ray, effective porosity and saturation capacities for potential reservoir zones. Effective porosity, volume of shale/clay, and water saturation are applied as cut-off criteria to verify 'Net Pay' with 'Net Reservoir' zones. The cut-off values are concluded within level of limitations with vertical characteristics and distribution of reservoir properties. The specific cutoff level can be determined on different qualities of individual reservoir zones.

2.4. Electrofacies Analysis

Facies are the assemblages of particular characters of a sedimentary unit (Middleton, 1973). The sedimentary units which are defined and characterized from wireline logs are known as electrofacies. Wireline logs are reliable data sources in the

study sedimentological and depositional environment of reservoir and non-reservoir rocks. Electrofacies, for that reason, could be defined at wellbore scale.

Based on the shapes of log curves, grouping with their significant features, particular facies can be classified. The method could be used to interpret the depositional environment in vertically and spatially by correlation of wells in an area where no core data exist. The principal log responses are fundamentally classified in shapes of the bell, the funnel and the cylinder (Figure 2.8). These shapes can be recognized in gamma ray logs because gamma ray logs are the most sensitive. Its patterns are dependent on the variation of shale, clay contents and of grain size.

The generalized annotations of electrofacies are baselines, trends, shapes, abrupt breaks, and anomalies of log patterns. A baseline is a vertically constant log value that is of lithologic and stratigraphic significance. A trend shows the increasing or decreasing of thickness, depositional cycles or sequence alternatively. The log shapes vary with depositional environments. Abrupt break features are important in defining changes of lithology, structural break, depositional hiatus (unconformity), and diagenetic events (erosion, flooding). Anomalies are unusual features such as high spikes of gamma ray, resistivity and densities within a few ranges of depth.

Each facies possesses with individual characteristics of sedimentary structures, texture and fabric (grain size, sorting, roundness, packing and orientation). The groups of facies with distinct petrophysical characteristics are reflect their major primary composition and diagenetic processes. Therefore, the combination of electrofacies could represent a part of a sedimentary environment.

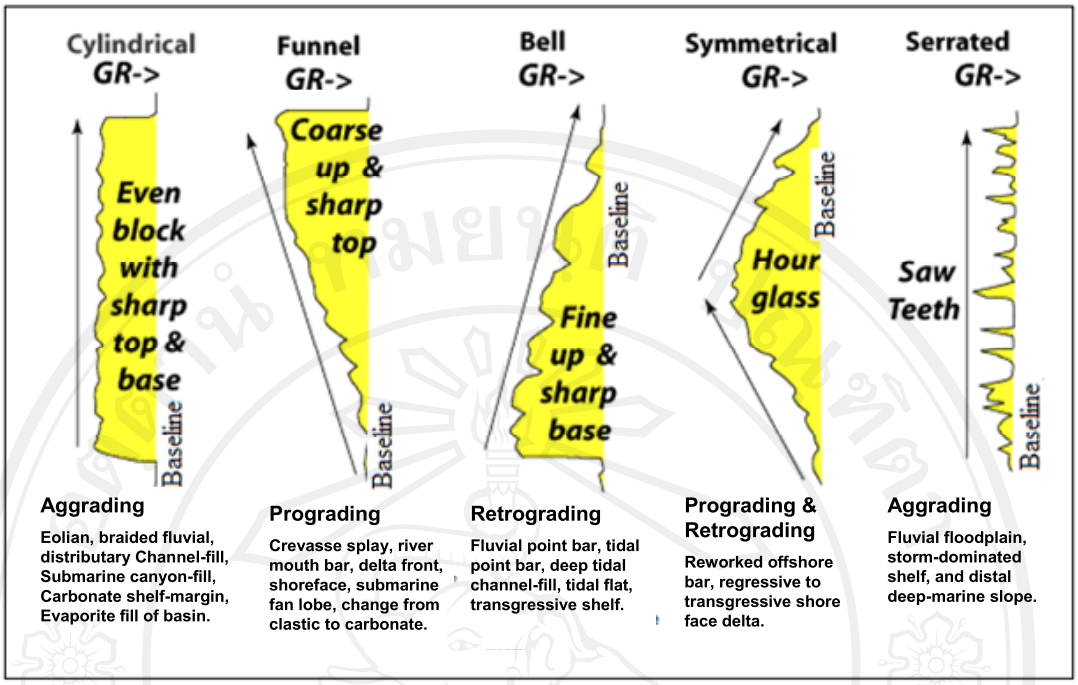

Figure 2.9 General gamma ray responses to variations in grain size (modified after Rider, 1996).

2.5. Petrographic Study

Ten selected core samples were collected from well B. The study of core samples in thin sections and under scanning electron microscope (SEM) are required to observe reservoir qualities through as the origin of depositional environment and diagenesis processes. Petrographic study, the identification of rocks, is visual estimation of grain size, sorting, and mineral abundances, fabric, rock classification and porosity varieties. The investigated results of petrographic analysis are also calibrated with formation evaluation. Additional identifications are carried out in other wells with no core data for reservoir correlation.

The interpretation of thin section images is basically a qualitative description of reservoir qualities. The samples are observed under the microscope to consider

depositional origin and diagenetic events. Diagenetic processes imply physical, chemical and biological environment the reservoirs went through. Alteration and diagenesis change the textures of compaction, cementation, replacement, recrystallization and dissolution (Boggs, 1992).

Scanning electron microscopy (SEM) used a ray of medium-energy electrons to scan the surface of a sample. The method is the only direct investigation in details of the pore space morphology and liquid films within pore network and pore-throats. It is also effective in the study of mineral composition, type and distribution of clays between the pore spaces. For these reasons, the petrographic analysis provides a better understand on depositional environment and rock physical properties at microscopic scale.