



## E01 • Tool handling

### E01.1 • Density

The density measurement is in most situations a major input of the rate calculation. It may be the result of a measurement possibly followed by some post-processing. It may also be a pseudo-density channel, calculated by taking the derivative of a pressure channel with respect to depth.

Except with a nuclear density tool, the value of a density channel is not the actual mixture fluid density but a function of the density, the deviation, the fluid velocity and viscosity, etc. It is therefore critical to define the tool accurately so that Emeraude can simulate the measurement in a consistent fashion. The following types are distinguished:

#### Pseudo-density channel

The nature of the channel is known internally by Emeraude and no user input is required. When simulating a pseudo-density value, Emeraude will:

- multiply the actual density by  $\cos(\text{deviation})$
- Compute and add tool frictions

#### Tool density channel

The channel characteristics MUST be defined properly in the Tool Info dialog. Emeraude distinguishes 6 different situations, as shown below. The second table column shows what settings should be selected for those tools in the Survey Tool info dialog:

Tool / channel info	Apply deviation correction
Gradio / corrected for deviation	None
Schlumberger PTS / not corrected for deviation	Schlumberger PTS
Sondex FDP / not corrected for deviation	Sondex FDP
Gradio / not corrected (not PTS or FDP)	/cos(deviation)
Nuclear density	None
Pressure derived density **	/cos(deviation) ; [dP/dZ]

\*\* When a pressure derivative is calculated inside Emeraude the choice will be internally set to this correction. The dPdZ channel will not even appear in Tool Infos.

For all gradios the internal correction removes pipe and tool frictions, except for the “Pressure derived density” for which tool frictions are ignored.



## E01.2 • Capacitance

There are two ways to calibrate Capacitance tools: Yw vs Normalized resp or Diel vs cps:

### Yw vs Normalized resp

The calibration is defined by a table of water holdup (Yw) versus normalized tool response, and the in-situ responses for 100% Water and 100% Hydrocarbon:

- $Yw = f(\text{Normalized response})$
- $Resp(100\%H_2O)$ , and  $Resp(100\%HC)$

Using the calibration data, the water holdup Yw is obtained from any log value Resp as:

- $Yw = f(\text{Normalized response})$  where
- $\text{Normalized response} = [ Resp(100\%HC) - Resp ] / [ Resp(100\%HC) - Resp(100\%H_2O) ]$

Linear interpolation is used to estimate the result.

The calibration chart obtained in a flow loop is unique to the particular tool or tool type. When no chart is available a default chart can be selected in the Tool info dialog for the followings:

- Sondex (CAPI)
- Atlas (FCAP)
- Schlumberger (HUM)

When entered manually, the table X-values must be in increasing order. The in-situ tool readings as read from the log (ideally in a shut-in survey) are entered in the lower part of the dialog.

### Diel vs. cps

In this mode, the calibration is defined by a table of dielectric values versus tool response, and the in-situ dielectric readings in 100% Water and 100% Hydrocarbon:

- $Diel = f(Resp)$
- $Diel(100\%H_2O)$ , and  $Diel(100\%HC)$

Using the calibration data, the water holdup Yw is obtained by first interpolating the table to find the dielectric value Diel corresponding to Resp. Then:

- $Yw = [ Diel - Diel(100\%HC) ] / [ Diel(100\%H_2O) - Diel(100\%HC) ]$

Interpolation in the table may be linear or semi-log.

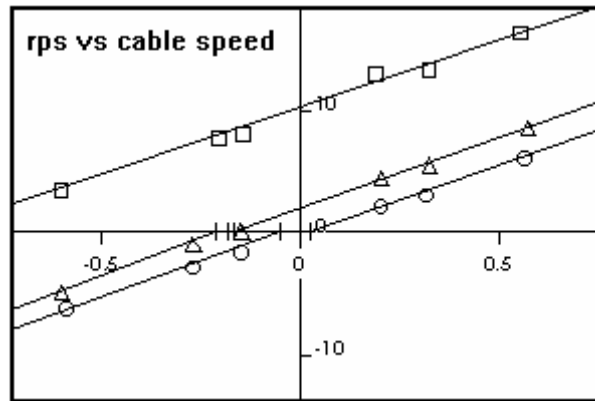
When entered manually, the table X-values must be in increasing order. The in-situ tool readings as read from the log (ideally in a shut-in survey) are entered in the lower part of the dialog.

The “View Plot” option displays the chart graphically. Selecting “View Plot” will give an indication of the most appropriate scale (linear or semi-log).



### E01.3 • Spinner Calibration

In the spinner calibration plot, the flowmeter response and the cable speed are averaged for each pass and each zone and plotted against each other for each pass in each of the selected calibration zones.



The above plot considers 3 zones, 3 Up and Down passes. The cable speed is considered positive for Down passes, the spinner rotation is counted positive when logging down in a producer. We distinguish the positive lines, corresponding to positive rps, and negative lines, corresponding to negative rps. Each line is defined by a **slope** and **intercept** value:

$$\text{Line}(+) : \text{rps} = \text{slope}(+) \times [\text{cs} - \text{Intercept}(+)]$$

$$\text{Line}(-) : \text{rps} = \text{slope}(-) \times [\text{cs} - \text{Intercept}(-)]$$

For each zone and each direction, the spinner will not rotate until the apparent velocity reaches a certain **threshold** value. Due to the blade geometry, the fluid velocity required to initiate the rotation may not be the same for negative and positive fluid velocities, and there are two distinct threshold values: **threshold(+)** and **threshold(-)**.

If the spinner is well centralized and there is a calibration zone with static fluid, the threshold values can be set from the lines intercepts on this zone. For other zones, Ideally, the slopes should be exactly the same as for the no-flow case, and the intercepts shifted by an amount equal to the opposite of the fluid velocity. So the ideal case for all zones would give:

$$\text{Intercept}(+) - \text{Intercept}(-) = \text{Threshold}(+) - \text{Threshold}(-) \quad [1]$$

For several reasons (lack of centralization, viscosity change, etc) this situation may not occur in practice. Two calibration methods are available in Emeraude.



### Mode 1: Unique value of (+) and (-) thresholds for all zones

The apparent velocity for a point on a positive line is calculated based on the slope of that line and the common positive threshold. The apparent velocity for a point on a negative line is calculated based on the slope of that line and the common negative threshold.

For a given calibration zone, as the relation [1] above does not hold, this mode typically produces different  $V_{app}$  values for positive and negative lines. In the calculation of the  $V_{app}$  channel, these values are averaged with user-defined weighting.

On the calibration plot, the apparent velocity for each line is indicated by an arrow, pointing down for the Line(+), and up for the Line(-)  $V_{app}$ .

This mode has no restriction on the intercept positions with respect to each other.

### Mode 2: Distinct thresholds but unique ratio: $\text{threshold}(-)/[\text{Intercept}(-) - \text{Intercept}(+)]$

This ratio is equal by default to  $7/12 = 0.583$  but can be set from the value on a no-flow zone.

The apparent velocity for a point on given line is calculated based on the slope and the threshold of that line.

This mode requires that for any zone with 2 intercepts defined:  $\text{Intercept}(-) < \text{Intercept}(+)$

## E01.4 • Multiple Probe Tools

Emeraude includes dedicated options for tools having multiple probe distributed on one or several circumferences. These options apply to the Schlumberger DEFT, GHOST, the dual DEFT situation, as well as the Sondex CAT tool. For the CAT, it is assumed that the supplied probe data must be normalized readings, between 0, corresponding to gas, and 1 corresponding to water. Furthermore, the normalization which will have been done beforehand should have been made in such a way that the oil point has a fixed value between 0 and 1.

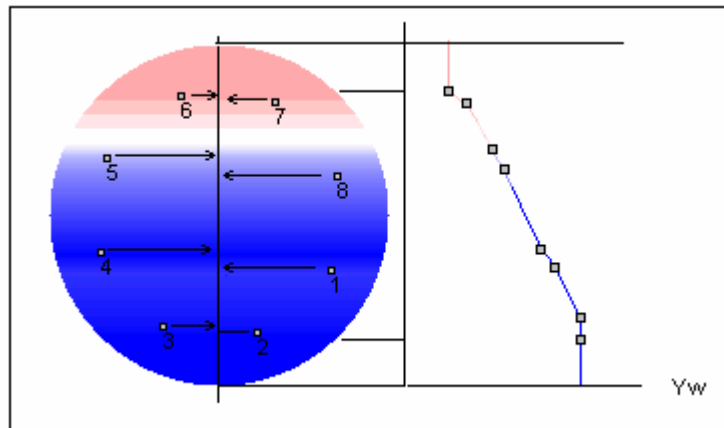
When a MPT is present in the survey, you will be able to generate corresponding reference channels directly from the Interpretation Infos/New dialog (see section D09.4). How to get reference channels lies on the ability to calculate for each pass, a representative average holdup. The following options are offered:

#### Simple average (all tools)

When simple average is selected the average holdup(s) for a given pass is (are) defined as an arithmetic average of the holdup(s) at the active probes.

#### Stratified average (all tools except the built-in CAT tool for which a dedicated processing exists - see below)

A projection of the probe readings is done on the vertical axis. A linear interpolation is used on this axis up to the top and bottom values. Outside, the last value is extrapolated.



At every depth the average holdup is calculated based on the cross-section map. The simple stratified average option requires the definition of the tool geometric dimensions,  $L_p/L_a$ ,  $ID_{max}$ , and the internal diameter. The internal diameter is read in the pass, if found, or else in the General Well Data.

#### Sondex stratified average (CAT only)

With segregated flow, a simple average will not give a realistic holdup value. For the CAT, Emeraude connects to a tailored processing developed by Sondex.



For tools other than the CAT you should use the average holdup provided by the Service Company when segregated flow is encountered if this curve includes specific corrections taking into account the flow geometry.





## E02 • PVT

An Emeraude interpretation relies on the definition of a PVT model describing the nature of the flowing mixture, and giving the associated PVT properties as a function of T and P. Each property is represented by a user selected Black-Oil correlation, possibly constrained to match some entered measurements. The flowing mixture is defined as a hydrocarbon model with or without water:

For hydrocarbons involving potentially 2 phases, the PVT model does not pre-suppose the existence/presence of a given phase at downhole conditions. This is delayed until the actual rate calculations.

The calculation engine invokes the PVT model dynamically when PVT properties are required, which makes the PVT model an independent and self-contained component of the interpretation. In the data browser, a PVT node appears inside an interpretation (once the PVT model has been defined). This node can be copied from one interpretation to another using drag and drop in the data browser. It can be saved to a file, and loaded from a file.

### E02.1 • Gas PVT

The available correlations for the gas phase are:

Z factor	$\mu_g$	$\rho_g$
Dranchuk	Lee et al.	Katz
Beggs and Brill	Carr et al.	
Hall-Yarborough		



## E02.2 • Oil PVT

The available oil phase correlations are:

Rs, Pb	Bo	$\mu_o$	Co
Lasater	Standing	Beggs & Robinson	Vasquez & Beggs
Standing	Vasquez & Beggs	Beal	Petrosky & Farshad
Vasquez & Beggs	Glaso	Glaso (dead oil)	
Glaso volatile	Petrosky & Farshad		
Lasater-Standing			
Petrosky & Farshad			

## E02.3 • Water PVT

The water phase correlations are:

Bw	Cw	Muw
Gould	Dodson and Standing	Van-Wingen + Frick
McCain	Osif	

A working subset as well as the default for each property can be defined in the Interpretation Settings option. It is possible to constrain the followings with entered match points: Rsw, Cw, Bw,  $\mu_w$ ,  $\rho_w$

## E02.4 • Condensate PVT

The Black-Oil condensate model available in Emeraude uses a parabolic relation for the dissolved condensate as a function of pressure. The relation is set from tank and separator conditions. The required input parameters are:

- Tank gas gravity
- Tank GOR
- Separator gas gravity
- Separator GOR
- Separator P and T
- Dewpoint P and T
- Liquid Gravity
- Sour gas content

The condensate model is based on a special correlation for the vaporized condensate. This correlation is initialized from the knowledge of the dew point conditions, the separator, and the tank conditions. The tank values can be calculated automatically using the method after D.K. Gold, W.D. McCain Jr & J.W. Jennings described in their paper “An improved method for the Determination of the Reservoir-Gas Specific Gravity for Retrograde Gases”, Journal of Petroleum Technology, July 1989.





## E03 • Rate calculations

### E03.1 • Frictions/Acceleration

When dealing with a density channel coming from a differential pressure tool (or with a pseudo-density channel), it is necessary that the simulation reproduces the different terms involved in the measurement. The pressure gradient can be decomposed in three terms: hydrostatic head, friction gradient, and acceleration gradient:

$$\frac{dP}{dZ} = \left[ \frac{dP}{dZ} \right]_{hydrostatic} + \left[ \frac{dP}{dZ} \right]_{friction} + \left[ \frac{dP}{dZ} \right]_{acceleration}$$

#### Hydrostatic head

The hydrostatic head component is calculated from the mixture density  $\rho_m$ , which is based on the PVT as well as the calculated phase holdups:

$$\left[ \frac{dP}{dZ} \right]_{hydrostatic} = \rho_m g \cos(\theta)$$

#### Acceleration

The acceleration component is neglected except in the case of single phase gas or mist flow of a liquid-gas mixture. In those cases, the gradient is calculated as a correction of the total gradient, involving the mach numbers of the phases, as described by Duns and Ross.

#### Frictions

Friction calculations include the determination of the friction gradients along the pipe as well as along the tool (the latter term is ignored when a pressure derived density is used). All friction terms are estimated using a Moody type friction factor and are of the general form:

$$\left[ \frac{dP}{dZ} \right]_{friction} = \frac{f \rho V^2}{2D}$$

When it must be calculated, friction along the tool requires the knowledge of the tool velocity as the considered velocity  $V$ , above, is the relative velocity between the tool and the fluid. This cable velocity is normally copied inside the interpretation when the density channel is defined. In the case where the reference density is defined as an average, the corresponding average cable speed is used. This is not



rigorous as the frictions are obviously not a linear function of the tool velocity, but it is assumed that there is a local linearity. Note that if you manually drop a gradio channel inside an interpretation, no cable speed is automatically copied and in that case the tool velocity is taken as 0.

### E03.1.1 • Detailed friction equations

The general expression of the friction gradient is :

$$\frac{dP}{dZ} = \frac{f_p V^2}{8} \times \frac{S}{A}$$

where:

$f$  is the Moody friction factor, function of the appropriate Reynolds number and roughness

$S$  is the surface in contact with the fluid,  $A$  is the area opened to flow

$\rho$  is the density

$V$  is the speed of the fluid relative to the considered surface.

The density appearing in the above equations depends on the flow regime. For instance in annular flow, a liquid film is in contact with the pipe and only the liquid density is considered.

#### Friction along the pipe

The velocity to be considered is:

$$V_p = \frac{V_f \cdot D^2}{D^2 - d^2}$$

$V_f$  is the fluid velocity

$D$  is the pipe I.D.

$d$  is the tool O.D.

The equivalent diameter as well as the Reynolds are:

$$D_e = (D - d) ; Re = \frac{\rho \cdot V_p^2 \cdot D_e}{\mu}$$

The friction factor in this case is noted  $f_p$ , and is a function of the relative roughness  $rt$  :  $f_p = f_p(Re, rt)$

The ratio  $S/A$  is defined as :

$$\frac{S}{A} = \frac{\pi D}{\pi \left( \frac{D^2 - d^2}{4} \right)} = \frac{4 \cdot D}{D^2 - d^2}$$

Finally, the pipe friction component is written:

$$\boxed{\frac{dP}{dZ}_{\text{pipe}} = \frac{f_p \rho V_p^2}{2} \times \frac{D}{(D^2 - d^2)}}$$



### Tool friction component

The velocity to be considered is:

$$V_t = \frac{V_f \cdot D^2}{D^2 - d^2} - V_{\text{cable}}$$

$V_f$  is the fluid velocity

$D$  is the pipe I.D.

$d$  is the tool O.D.

$V_{\text{cable}}$  is the tool velocity. Note that this assumes a consistent sign convention between the fluid velocity and the cable speed.

The equivalent diameter for the Reynolds number is the same as before:  $D_e = (D - d)$

and  $Re$  is given by 
$$Re = \frac{\rho \cdot V_t^2 \cdot D_e}{\mu}$$

The friction factor in this case is noted  $f_p$  and no roughness is considered.  $f_t = f_t(Re, 0)$ .

The ratio  $S/A$  is defined as :

$$\frac{S}{A} = \frac{\pi d}{\pi \left( \frac{D^2 - d^2}{4} \right)} = \frac{4 \cdot d}{D^2 - d^2}$$

Finally, the tool friction component is written:

$$\frac{dP}{dZ_{\text{tool}}} = \frac{f_t \rho V_t^2}{2} \times \frac{d}{(D^2 - d^2)}$$

### Total friction term and Emeraude results

The total friction gradient is the sum of the two terms derived above :

$$\frac{dP}{dZ_{\text{friction}}} = \frac{dP}{dZ_{\text{pipe}}} + \frac{dP}{dZ_{\text{tool}}} = \frac{f_p \rho V_p^2}{2} \times \frac{D}{(D^2 - d^2)} + \frac{f_t \rho V_t^2}{2} \times \frac{d}{(D^2 - d^2)}$$

In the Zone Rate Gradio page, Emeraude gives values referring to «Pipe friction» and «Tool friction». Their sum is the same as the sum of the two gradients above but their definition is different :

Pipe friction, as reported by Emeraude : the friction gradient if the tool was not present. This is calculated with  $D$  as the hydraulic diameter, the velocity being the actual fluid velocity  $V_f$ .

Tool friction, as reported by Emeraude : the additional gradient to the above term, due to the tool presence.

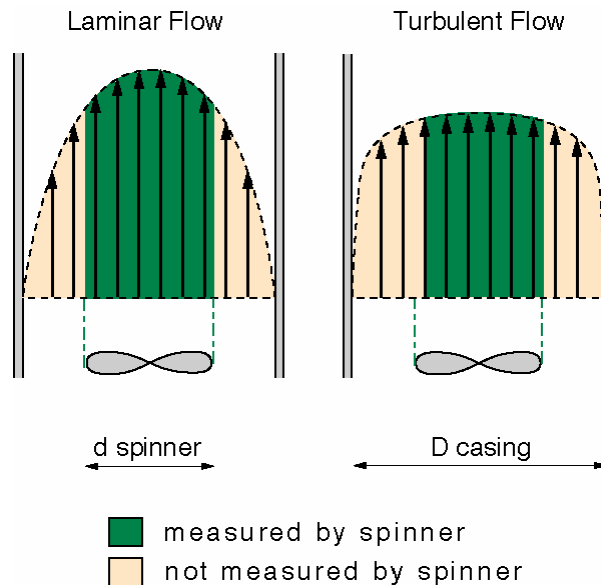
This is calculated as:

$$\frac{dP}{dZ}_{\text{friction}} - \frac{dP}{dZ}_{\text{friction without tool}}$$



## E03.2 • Vapp / Vm relation

The velocity of the fluid inside a pipe cross section is not uniform but follows a defined profile as shown on the figure below. The spinner calibration gives an apparent velocity  $V_{app}$ , which, if the spinner is well centralized, is a measure of the maximum velocity. What is needed for rate calculation is the average velocity  $V_m$ .



### Vpcf: Velocity Profile Correction Factor

The relation between  $V_{app}$  and  $V_m$  is influenced by the type of flow. It can be expressed by introducing a correction factor noted  $V_{pcf}$  (Velocity Profile Correction Factor) such that:

$$V_m = V_{pcf} \times V_{app}$$

Assuming a centralised spinner and a symmetrical flow profile around the pipe central axis,  $V_{pcf}$  can be correlated with the Reynolds number and the ratio between the spinner blade, and pipe diameter.

$$V_m = V_{pcf}(\rho, V_m, \dots) \times V_{app}$$

A value of 0.83 is assumed by default but a better estimate can be obtained by solving the above equation. The solution can only be obtained iteratively as  $V_m$  is an argument of  $V_{pcf}$ . When a gradiometer is used the density  $\rho$  is also dependent on  $V_m$  (through frictions). Emeraude solves this equation by using a non-linear regression scheme in order to minimize the function:

$$E(V_m) = [V_m / V_{pcf}(\rho, V_m, \mu, \dots) - V_{app}]^2$$

A value of 0.83 is assumed by default but a better estimate can be obtained by solving the above equation. In the conventional approach, the solution is obtained iteratively as  $V_m$  is an argument of  $V_{pcf}$ . In Emeraude, since we rely on the non-linear regression for inversion we need to simulate  $V_{app}$  from assumed rate values:



$$V_{app} = \frac{V_m}{V_{pcf}}$$

In a single phase case this is done directly. In multiphase, the determination of the Reynolds number requires the prior determination of the mixture density and viscosity, based on holdup calculation. To the apparent velocity corresponds the following residual term in the non-linear regression:

$$E = \left[ \frac{V_m}{V_{pcf}} - V_{app}^* \right]^2$$

Where  $V_{app}^*$  is the measured apparent velocity.

In single phase, this residual alone constitutes the complete function to be minimized. In multiphase, it is one residual among for others for the additional tools.

### Vpcf multiplier

The correlation for  $V_{pcf}$  is based on assumptions that may not be valid in practice. An error in the correction factor leads to an error in the mixture velocity, and hence total downhole rates. An additional parameter is introduced that represents the potential error and allows for an adjustment of the model. This factor noted “ $V_{pcf\_Mult}$ ” below modifies the relation above to:

$$V_m = V_{pcf\_mult} \times V_{pcf}(\rho, V_m, \dots) \times V_{app}$$

By default the value of the multiplier is 1. A different value can be determined when surface rates are available. The same value is then applied at all depths.

## E03.3 • Single-phase interpretation

In single-phase interpretation the sole unknown is  $V_m$  the mixture velocity. One input needs to be a velocity or the temperature. The velocity input may be a spinner  $V_{app}$ , a direct mixture velocity.

$r^*$

If a density channel is available in the interpretation, the density used in the calculation of  $V_{pcf}$  is read from this channel (and necessary corrections are applied). Otherwise, if temperature and pressure channels are present, the density is calculated from the PVT model.

$m$

When T and P channels are available, the default viscosity is computed from the PVT model. Otherwise it must be supplied by the user.

When all inputs are defined  $V_m$  is obtained using non-linear regression to minimize the function:



$$E = \left[ \frac{V_m}{V_{pcf}} - V_{app}^* \right]^2$$

At each iteration, the density  $\rho$  is estimated from the input value  $\rho^*$  correcting for frictions and deviation if necessary.

### E03.4 • Matching surface conditions – Single-phase case

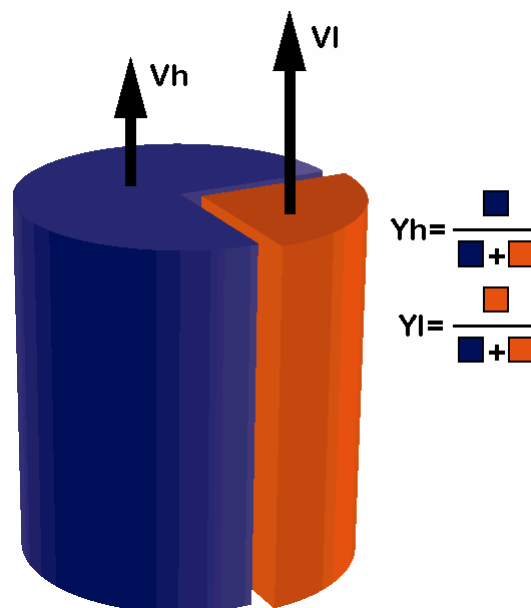
Matching surface rates involves the determination of the  $V_{pcf}$  multiplier coefficient, thereby changing the model predicting the  $V_{app}$  /  $V_m$  relation. This is made for the top calculation zone (i.e. above the top producing interval) and must be followed by a re-calculation of any prior rate result:

- Zonal calculation:  $V_m$  must be recalculated for all zones. Done automatically when selecting the “Match S.C.” option.
- Logs: All existing rates must be recalculated and the change in  $V_{pcf}$  affects the calculation at any depth.  
On the top calculation zone, the estimate of the  $V_{pcf}$  multiplier is done as follows:
  - Set “ $V_{pcf\_Mult}$ ” = 1, and seek the best estimate of  $V_m$  from supplied input.
  - Compute  $V_{mSC}$ , expected downhole mixture velocity. In single phase  $V_{mSC} = QSC \times B$  where  $B$  is the formation volume factor estimated for the  $T$  and  $P$  values of the zone.
  - $V_{pcf\_Mult} = V_{mSC} / V_m$

### E03.5 • Multiphase Interpretation – Theory

We consider first a situation with 2 phases, a light phase represented by the “l” subscript, and a heavy phase represented by “h”. The results are extended to 3 phases at the end of the section.

The figure below gives a hypothetical view of a pipe cross-section where the phases would be perfectly separated.





### Holdups, $Y_h$ and $Y_l$

Holdups are defined as the volume fraction that a phase occupies in the pipe section. They satisfy the relation:

$$Y_h + Y_l = 1$$

### Average velocities, $V_h$ and $V_l$

The actual velocity of a given phase:

$$V_h = \frac{Q_h}{A \times Y_h} ; \quad V_l = \frac{Q_l}{A \times Y_l}$$

where  $A$  is the pipe cross sectional area.

### **E03.5.1 • Case of Equal average velocities**

The assumption is made to introduce some graphical representations and notations, and is by no means a required assumption in Emeraude. This assumption leads to:

$$\frac{Q_h}{Q_l} = \frac{Y_h}{Y_l}$$

From the spinner measurement, we can estimate the total mixture rate at any depth  $q_m$  and impose the condition:

$$Q_h + Q_l = Q_m$$

In this case solving for the individual rates is straightforward if we can measure one of the phase holdups. The holdup may be measured directly or assumed from a mixture density measurement if we know the individual phase density:

$$Y_h = \frac{\rho - \rho_l}{\rho_h - \rho_l}$$

### Superficial velocities

The superficial velocities are introduced in order to simplify the subsequent discussion; they are defined as the rate of a given phase divided by the pipe cross section:

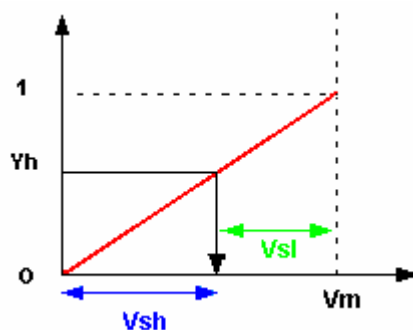
$$V_{sh} = \frac{Q_h}{A} ; \quad V_{sl} = \frac{Q_l}{A}$$

They satisfy the relation:  $V_{sh} + V_{sl} = V_m$ , where  $V_m$  is the average mixture velocity

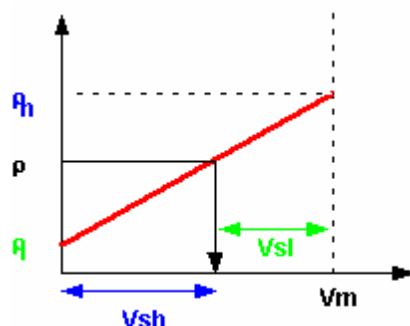
The average velocities can be expressed in terms of the superficial velocities:

$$V_h = \frac{V_{sh}}{Y_h} ; \quad V_l = \frac{V_{sl}}{Y_l}$$

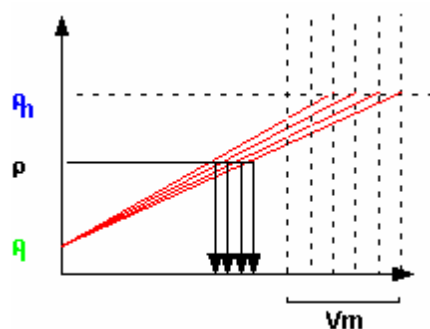
The problem described by the above equations is represented graphically when a solution is sought from a holdup value  $Y_h$ :



The X-axis gives the heavy phase superficial velocity, ranging from 0 to  $V_m$ . The complement between  $V_{sh}$  and  $V_m$  is by definition  $V_{sl}$ , superficial velocity of the light phase. The proportionality relation between holdups and rates is a straight line, plotted in red. From the measured holdup, the solution  $V_{sh}$  and  $V_{sl}$  are found by intercepting the red line. The same plot can be made when applied to a density measurement:



The plot is drawn assuming that the mixture velocity is known, and fixed. The actual calculation scheme used by Emeraude does not required  $V_m$  to be fixed but integrates its determination in a non-linear regression loop. For illustration purposes only, the plot below shows how the plot, and hence the relation changes with  $V_m$ .







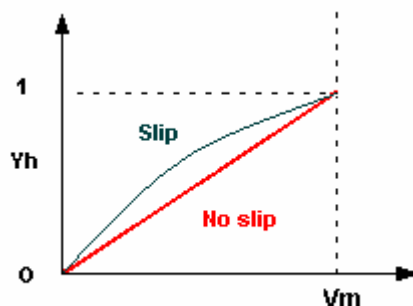
### E03.5.2 • Unequal average velocities

#### Slippage velocity, $V_s$

The slippage velocity is defined as the difference between the average velocities:

$$V_s = V_l - V_h$$

A non zero slippage means that the light phase is travelling faster than the heavy phase. For a given rate ratio, the volume ratio of the light phase will be less than in the no slip situation. Conversely, the heavy phase holdup will be bigger. The relation between superficial velocities and heavy phase holdup (or mixture density) becomes non linear:



A similar change would apply to the density plot. As before, we can find a solution to the problem provided that we have a way of calculating  $V_m$ , and  $Y_h$ . The determination of  $Y_h$  is made using two-phase flow correlation's which either correlate directly  $Y_h$  or alternatively  $V_s$ . When  $V_s$  is predicted,  $Y_h$  can be estimated from the equation:

$$Y_h^2 \times V_s + Y_h \times (V_m - V_s) - V_{sh} = 0$$

This equation admits one, and only one root in  $[0,1]$  for any value of  $V_s$ .

*Note: Certain flow correlation's predict  $V_s$  as a function of  $Y_h$ . This renders the solution to the above equation iterative.*

### E03.5.3 • 3-phase flow

Use of the 2-phase flow models is extended to this situation by considering that one of the phases contains in fact 2 components. Within this mixed phase, the simplest assumption is to consider that there is no slippage between the two components. This assumption is made by some models in Emeraude but not all of them (see C3.6 below). The "3-Phase L-G" model applies the above equation twice: once in the liquid phase, between oil and water, and once between the liquid phase and the gas. An additional parameter is introduced in order to represent the split of the mixed phase rate into the two components:

- Mixed phase is oil+water:

Introduce **fo**, fraction of the oil rate to the liquid phase rate. If the model assumes no slippage between the oil and water (Liquid-Gas) then **fo** is also a volumetric ratio.

- Mixed phase is oil+gas:

Introduce **fg**, fraction of the gas rate to the hydrocarbon phase rate. The only situation where this is used is the Water-Hydrocarbon model which assumes no slippage within the hydrocarbon phase. Therefore **fg** is also the volumetric ratio in this case.



## Slippage modifications

The 2-phase flow correlation's can be reduced to one equation predicting  $V_s$  as a function of the superficial velocities (and other known properties):

$$V_s = V_s(V_{sh}, V_{sl}, \rho_h, \rho_l, \mu_h, \mu_l)$$

For the flow correlation's concerned with Liquid-Gas flows, different flow regimes are distinguished leading to a set of such equations. In Emeraude, this relation is modified by the introduction of two additional parameters:

$$V_s = \max[V_m \times C_2, C_1 \times V_s(V_{sh}, V_{sl}, \rho_h, \rho_l, \mu_h, \mu_l)]$$

$C_1$  is a multiplier applied to the original slip correlation. It is originally equal to 1 but can be modified to match the surface conditions (see Surface Conditions). There is one slip multiplier for each correlation.

$C_2$  defines the maximum limit for the ratio  $V_s/V_m$ . By default this limit is undefined.

## E03.6 • Two-phase flow models

There are 4 flow models in Emeraude (in addition to the single-phase model):

### Liquid-Gas

The liquid phase can comprise oil, water, or a mixture of both. There is no slippage between oil and water. In 3-phase, the fraction of oil in the Liquid phase, **fo** is introduced. The initial **fo** value is based on the entered surface WOR. If the necessary measurements are available **fo** is determined by the non-linear regression. In this case a green light will appear in front of the **fo** button in the Zone Rate dialog.

### Water-Hydrocarbons (G)

Liquid-Gas situation where the heavy phase is water and the light phase is mainly gas possibly with some oil (or condensate). There is no slippage between the oil and gas phases. If this model is used in 3-phase, the ratio of gas in the hydrocarbon phase, **fg**, is introduced. This value is fixed from the PVT CGR ratio.

### Water-Hydrocarbons (L)

Liquid-Liquid situation where the heavy phase is water and the light phase is oil possibly with evolved gas. There is no slippage between the oil and gas phases. If this model is used in 3-phase, the ratio of gas in the hydrocarbon phase, **fg**, is introduced. This value is fixed from the PVT Rs ratio.



### 3-Phase L-G

This is the combination of a Liquid-Gas and Water-Oil models. There is slippage between the oil and water phases within the Liquid phase. There is also slippage between the gas and the mixed liquid. The oil fraction **fo** represents the ratio of the oil rate to the liquid rate. This model is only offered when there are enough measurements for **fo** to be a variable.

The following correlation's are available in Emeraude:

Liquid-Gas	Liquid-Liquid
Duns and Ross	Nicolas
Aziz and Govier	Choquette*
Beggs and Brill	ABB-Deviated
Artep	Nicolas*
Duckler*	Constant slippage
Hagedorn-Brown	
Petalas & Aziz	
Constant slippage	

One can use the Interpretation option of the Settings panel to disable some correlation or re-define the default correlation for each model. The deviation correction on the slippage predicted by the models with a “\*” can be selected in the same dialog.

### E03.7 • Multiphase interpretation – Calculation scheme

This section describes the steps involved in the simulation of all potential measurements, assuming a value for the rates. This calculation is done at every iteration of the non-linear regression that solves for the rates.

#### “Water-Hydrocarbons (G)” and “ Water-Hydrocarbons (L)”

Parameters: Vsh, Vsl, and fg

Variables:

- Vsh and Vsl

fg is not a variable but is fixed from PVT. Since no slippage is assumed between the oil and gas phases in this case, fg gives the rate fraction as well as volume fraction here.

Calculation steps:

1. Mixture velocity:  

$$V_m = V_{sh} + V_{sl}$$
2. Get flow regime (not for the Liquid-Liquid case where bubble flow is assumed).



3. Calculate the overall PVT properties of the light phase:

$$\rho_l = [f_g \times \rho_g + (1 - f_g) \times \rho_o]$$

$$\mu_l = [f_g \times \mu_g + (1 - f_g) \times \mu_o]$$

4. Calculate the heavy phase holdup and the slippage velocity from the selected correlation:

$$Y_h = Y_h(V_{sh}, V_{sl}, \rho_h, \rho_l, \mu_h, \mu_l, \dots) \quad ; \quad V_s = V_s(V_{sh}, V_{sl}, \rho_h, \rho_l, \mu_h, \mu_l, \dots)$$

5. Get all holdups:

$$Y_w = Y_h \quad ; \quad Y_o = (1 - f_g) \times (1 - Y_w) \quad ; \quad Y_g = f_g \times (1 - Y_w)$$

6. Get all average velocities:

$$V_w = \frac{V_{sh}}{Y_w} \quad ; \quad V_o = \frac{V_{sl} \times (1 - f_g)}{Y_o} \quad ; \quad V_g = \frac{V_{sl} \times f_g}{Y_g}$$

If a spinner is used, steps to get Vapp

1. Mixture density:

$$\rho_m = \rho_w \times Y_w + \rho_o \times Y_o + \rho_g \times Y_g$$

2. Mixture viscosity:

$$\mu_m = \mu_w \times Y_w + \mu_o \times Y_o + \mu_g \times Y_g$$

3. Velocity profile correction factor:

$$V_{pcf} = V_{pcf}(V_m, \rho_m, \mu_m)$$

4. Apparent velocity:

$$V_{app} = \frac{V_m}{V_{pcf}}$$

If a gradiometer or a pressure derived density is used

If a density measurement is available, simulate that measurement by accounting for frictions as required. Also reproduce how the deviation is handled by the tool output (corrected, not corrected).

**“Liquid-Gas” and “3-Phase L-G” models**

Parameters: Vsh, Vsl, and fo

Variables:

- Vsh and Vsl
- fo, variable only in a 3-phase situation with enough measurements.

Calculation steps:

1. Mixture velocity:

$$V_m = V_{sh} + V_{sl}$$

2. Determine the volumetric fraction of oil in the liquid phase noted **fyo**:

No slippage between oil and water (Liquid-Gas model):  $f_{yo} = f_o$

If the model assumes slippage between oil and water, the steps 1-4 of the procedure **A** above are executed with the input (superscript A designates parameters of procedure A):

$$V_{sh}^A = V_{sh} \times (1 - f_o) \quad ; \quad V_{sl}^A = V_{sl} \times f_o \quad ; \quad f_g^A = 0$$



Then  $f_{yo}$  can be obtained as:  $f_{yo} = Y_o^A$

- Get overall liquid phase properties required for further calculations

$$\rho_h = [f_{yo} \times \rho_o + (1 - f_{yo}) \times \rho_w]$$

$$\mu_h = [f_{yo} \times \mu_o + (1 - f_{yo}) \times \mu_w]$$

- The heavy phase holdup and the slippage velocity (between gas and liquid) are calculated:

$$Y_h = Y_h(V_{sh}, V_{sl}, \rho_h, \rho_l, \mu_h, \mu_l \dots) \quad ; \quad V_s = V_s(V_{sh}, V_{sl}, \rho_h, \rho_l, \mu_h, \mu_l \dots)$$

- Get all holdups:

$$Y_w = Y_h \times (1 - f_{yo}) \quad ; \quad Y_o = Y_h \times f_{yo} \quad ; \quad Y_g = Y_l$$

- Get all average velocities:

$$V_w = \frac{V_{sh} \times (1 - f_o)}{Y_w} \quad ; \quad V_o = \frac{V_{sh} \times f_o}{Y_o} \quad ; \quad V_g = \frac{V_{sl}}{Y_g}$$

If a spinner is used, steps to get  $V_{app}$

- Mixture density:

$$\rho_m = \rho_w \times Y_w + \rho_o \times Y_o + \rho_g \times Y_g$$

- Mixture viscosity:

$$\mu_m = \mu_w \times Y_w + \mu_o \times Y_o + \mu_g \times Y_g$$

- Velocity profile correction factor:

$$V_{pcf} = V_{pcf}(V_m, \rho_m, \mu_m)$$

- Predicted apparent velocity

$$V_{app} = \frac{V_m}{V_{pcf}}$$

If a gradiometer or a pressure derived density is used

If a density measurement is available, simulate that measurement by accounting for frictions as required. Also reproduce how the deviation is handled by the tool output (corrected, not corrected).

## E03.8 • Surface Conditions

Matching the surface rates involves the determination of two multipliers (or three with the 3Phase L-G model), one for the model predicting  $V_{pcf}$ , one for the slip model(s). As the model is modified the change is global and any prior calculation is invalid:

- Zonal calculation: All zones must be re-calculated. Done automatically when selecting the "Match S.C." option.

- Logs: All existing rates must be recalculated

A slip multiplier pertains to a particular correlation, and in practice is calculated for the correlation used on the top calculation zone. The calculation proceeds as follows:

- Top zone: Set  $V_{pcf\_Mult} = 1$ , and  $V_{slip\_Mult} = 1$ ; Seek the best estimate of  $V_{sh}$ ,  $V_{sl}$  (possibly  $f_o$ ) from supplied input.

- Compute  $V_{mSC}$ , and  $V_{shSC}$  mixture and heavy phase superficial mixture velocities expected from the surface rates.

- $V_{pcf\_Mult} = V_{mSC}/V_m$



- Vslip\_Mult obtained by non-linear regression so that  $V_{sh} = V_{shSC}$

### E03.9 • Apparent DownFlow

“Apparent Downflow” can occur in deviated wells with a high heavy phase holdup. For instance in a deviated well with a high water holdup, the water may be dragged upwards by the oil flowing up - on the high side of the pipe - , and fall back -on the low side of the pipe- if there is not enough energy to lift it. This circulation of water may be “seen” by the spinner as only downward flow when it is in fact due to an upward oil flow. Deciding that the flow is up when the spinners says it is down, can be done if additional information is available (zone pressure, temperature, etc).

When this “Apparent DownFlow” situation has been recognized, a specific option in the Zone Rate dialog can be used for quantitative interpretation. The option is available in both Liquid-Liquid and Liquid-Gas cases.

In this option, the superficial velocity of the light phase  $V_{sl}$  is assumed to be a function of the slip velocity,  $V_s$  and the Holdup:

$$V_{sl} = C \times V_s \times (1 - Y_h) \quad \text{where } C \text{ is a constant}$$

The spinner measurement is disregarded and the superficial velocity of the heavy phase is set to 0.

#### Correlation

When the “Apparent Downflow” option is selected, the slip correlation for the zone is automatically set to:

- Liquid-Gas: the bubble flow correlation of the Duckler model
- Liquid-Liquid: the “Deviated” correlation

#### Calculation Scheme

The scheme is again a non-linear regression with a unique variable,  $V_{sl}$  and a unique match point  $\rho$  the measured tool density (or  $Y_w$  a measured water holdup)

Each iteration step assumes a value of  $V_{sl}$ . With the relation above and the equation relating  $V_s$  and  $Y_h$  introduced in Multiphase Interpretation - Theory, it is possible to solve for  $Y_h$  and  $V_s$ . Once we have  $Y_h$  we can predict the density tool response, or water holdup.

*The Apparent Downflow option is not offered with the “3-Phase L-G” model.*

### E03.10 • Multiphase interpretation - Problems and solution

The potential measurements are divided into 3 categories:

1. Velocity:  $V_{app}$ ,  $V_w$ ,  $V_o$ ,  $V_g$ ,  $Q_w$ ,  $Q_o$ ,  $Q_g$
2. Holdup:  $Y_w$ ,  $Y_o$ ,  $Y_g$ ,  $\rho$
3. Temperature

*Required measurements in the array below must be relevant for the defined PVT.*



PVT	Flow model	Variable	Required Measurements
Single phase	Single phase	Vm	1 velocity (or temperature)
Oil-Gas	Single phase	Vm	1 velocity (or temperature)
	Liquid-Gas	Vsh, Vsl	2 including 1 velocity (or temperature)
Water-Gas	Liquid-Gas	Vsh, Vsl	2 including 1 velocity (or temperature)
Gas – Condensate	Single phase	Vm	1 velocity (or temperature)
	Liquid-Gas	Vsh, Vsl	2 including 1 velocity (or temperature)
Water-Oil-Gas	Liquid-Gas	Vsh, Vsl (fo fixed)	2 including 1 velocity (or temperature)
		Vsh, Vsl, fo	3 including 1 velocity (or temperature)
	Water-Hydrocarbons (L)	Vsh, Vsl	2 including 1 velocity (or temperature)
	3-Phase L-G	Vsh, Vsl, fo	3 including 1 velocity (or temperature)
Water-Gas-Condensate	Water-Hydrocarbons (G)	Vsh, Vsl	2 including 1 velocity (or temperature)

When a constant slippage model is used, and if enough measurements are available, the slippage velocity is taken as a variable.

The constant slippage model normally uses a slippage value entered by the user. In a situation where enough measurements are available, Emeraude will include the slippage value among the non-linear regression variables.

For instance, in a 2 phase Water-Oil situation, with measurements of  $V_{app}$ ,  $V_w$ ,  $\rho$ , there are enough data to calculate the slippage. In such a situation, if the constant slippage model is selected and Improve is executed, the slippage is updated and a green light will appear next to it, to indicate that it became a variable of the regression:







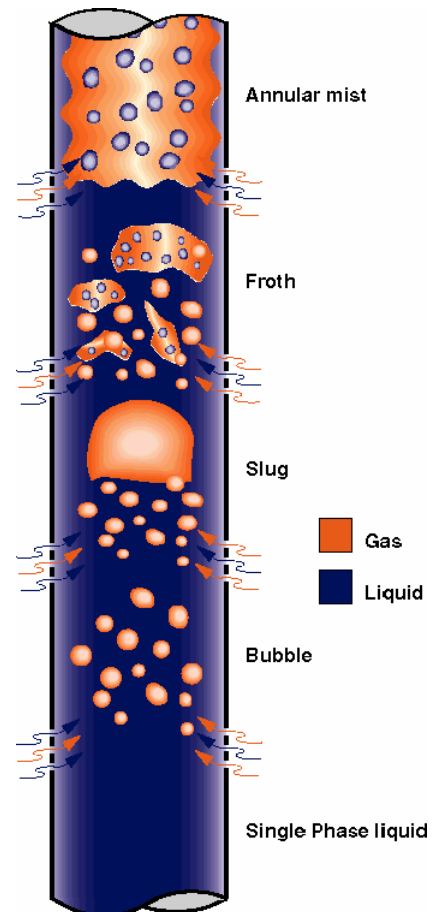
## E04 • Flow models

### E04.1 • Flow regimes

Most Liquid-Gas models consider the flow regimes described by the figure opposite. In horizontal or near horizontal flow, stratified flow regimes may also be considered (e.g. Beggs & Brill, Petalas & Aziz).

Liquid-Gas models provide a mean of calculating a flow, and for each flow regime, a slip or holdup correlation. In mist flow, the slippage is 0 in all cases.

In Liquid-Liquid situations, only bubble flow is considered.



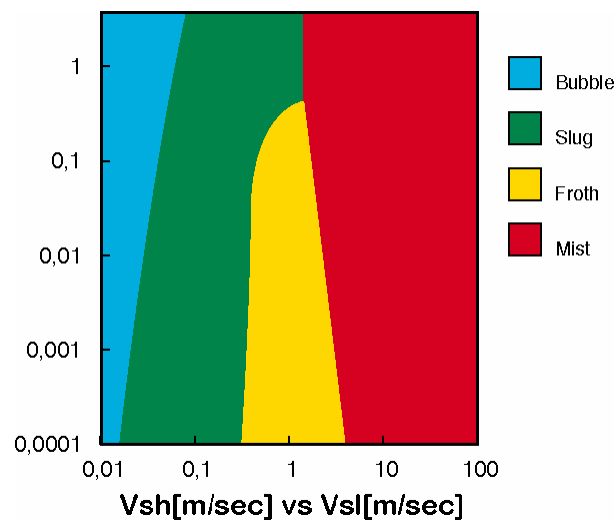
### E04.2 • Aziz and Govier

Reference: Aziz K., Govier G., and Fogarasi, M., J., "Pressure Drop in Wells Producing Oil and Gas", Can. Pet. Tech. (July-Sept 1972), 38-48.

Mechanistic model for Liquid-gas flows.

Only vertical flow is considered by the model.

Determination of the flow regimes is made using a single flow map plotted in terms of modified superficial velocities  $Y.V_{sh}$  vs  $X.V_{sl}$ , where  $X$  and  $Y$  are functions of the densities and interfacial tensions. An equivalent in terms of superficial velocities (for a particular value of the other parameters) is given below:

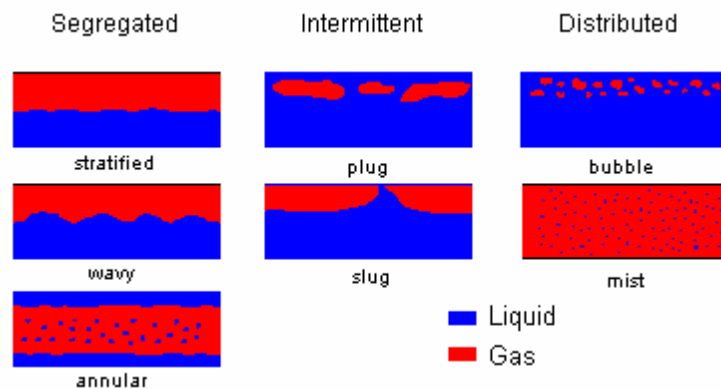


When calculations are made using a differential pressure density tool, the pipe friction is estimated using the method described in the above reference, except in mist flow, where the calculation is done according to Duns and Ross.

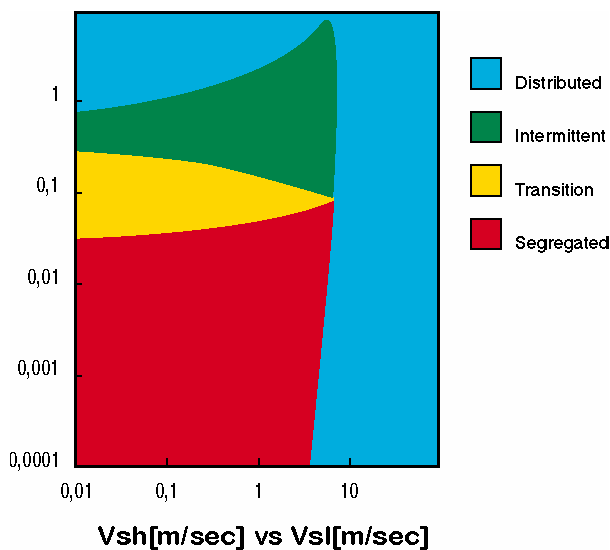
### E04.3 • Beggs and Brill

Reference: Beggs H., Brill J., "A Study of Two-Phase Flow in Inclined Pipes", JPT (May 1973), 607-617.

Model based on experiments with air-water flow for various pipe inclinations. The model distinguishes the flow regimes below:



Beggs and Brill present a unique flow map in terms of Froude number vs. Input liquid content. An equivalent in terms of  $V_{sh}$  vs.  $V_{sl}$  for a particular condition is shown below.



When calculations are made using a differential pressure density tool, the pipe friction is estimated using the method described in the above reference.

#### E04.4 • Artep

Reference: Ferschneider G., Ozon P.M., Duchet-Suchaux P.: “Models for Multiphase Flow in Oil Wells”, Offshore Multiphase Production Conference, London, 14-15 Sept 1988.

Model for Liquid-Gas flow coupling a mechanistic derivation with a physical basis provided by experiments. The experiments were conducted in a flow loop at deviation between 0 and 90 degrees.

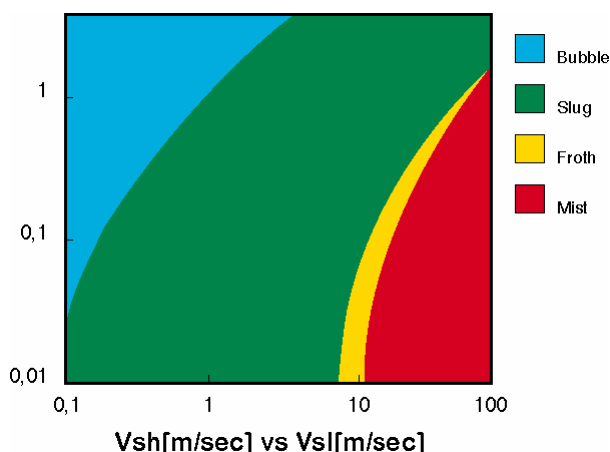
The correlation does not handle a deviation of 90°.

#### E04.5 • Duns and Ross

Reference: Duns H., and Ross N., “Vertical Flow of Gas and Liquid Mixtures in Wells”, Proceedings of the Sixth World Petroleum Congress, Frankfurt (1963), Vol. 10, p 694.

Only vertical upward flow is considered by the model.

Experimental model derived from laboratory data for vertical Liquid-Gas flow and based on a unique flow map plotted as Liquid velocity number vs Gas velocity numbers. These numbers are functions of superficial velocities, liquid density and interfacial tension. An equivalent in terms of Vsh, and Vsl for particular value of the other parameters is shown on the following page:



When calculations are made using a differential pressure density tool, the pipe friction is estimated using the method described in the above reference.

#### E04.6 • Hagedorn and Brown

Reference: Hagedorn, A.R., & Brown, K.E., 'Experimental Study of Pressure Gradients Occurring During Continuous Two-Phase Flow in Small Diameter Vertical Conduits', JPT (April 1965), Vol. 17, p. 475.

Experimental model for Liquid-Gas flow. Experiment realised in a 1,500 ft vertical well. Tubing I.D: 1 in, 1 ¼ in, 1 ½ in.

Only vertical upward flow is considered by the model.

No flowmap. Single Holdup correlation provided for all conditions.

When calculations are made using a differential pressure density tool, the pipe friction is estimated using the method described in the above reference.

#### E04.7 • Dukler

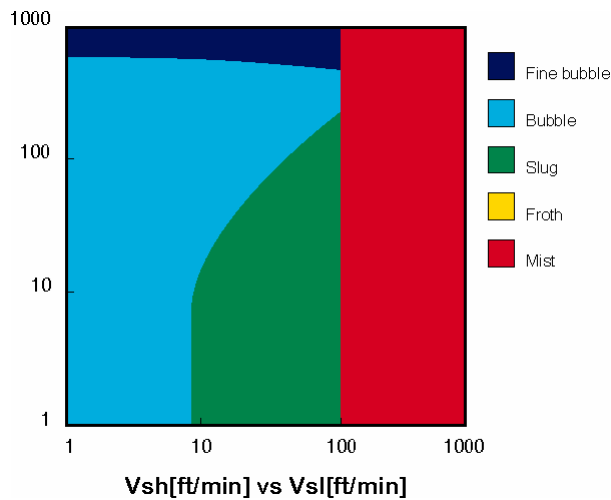
Reference: Taitel, Y., Dukler, A.E., and Barnea, D., "Modelling Flow Pattern Transitions for Steady Upward Gas-Liquid Flow in Vertical Tubes", AIChE J. (1980) 26, 345-354.

Mechanistic approach for the flow map determination.

Only vertical flow is considered by the flowmap. Slip deviation correction is however applied in bubble flow (see below).



Unlike other models where a unique flowmap can be presented by using some parameter groups, this model always requires calculation of a specific flowmap in each situation. An example is shown below.



Slug flow: The slippage correlation is given in the above reference.

Bubble flow: Slippage is based on (in ft/min)

$$V_s = 60 \times \text{SqRoot}(0.95 - (1 - Y_h) \cdot (1 - Y_h)) + 1.50$$

Pipe deviation: Taken into account by correcting the slippage velocity with a factor defined in the Interpretation Settings dialog as either linear for all angles:

$$V_s = V_s \times (1 + 0.04 \times \text{dev}) \text{ where dev is the deviation in degrees}$$

Or identical to the above until 45° and decreasing above this value (Ding et al.)

The default setting is the linear correction.

*Note that changing the correction mode in the Interpretation Settings will potentially affect all existing interpretations using the Dukler correlation. It is left to the user to update calculations for zones/logs that are affected by the change.*

When calculations are made using a differential pressure density tool, the pipe friction is estimated using the same method as for Aziz & Govier in slug and bubble flows, and that of Duns and Ross in mist flow.

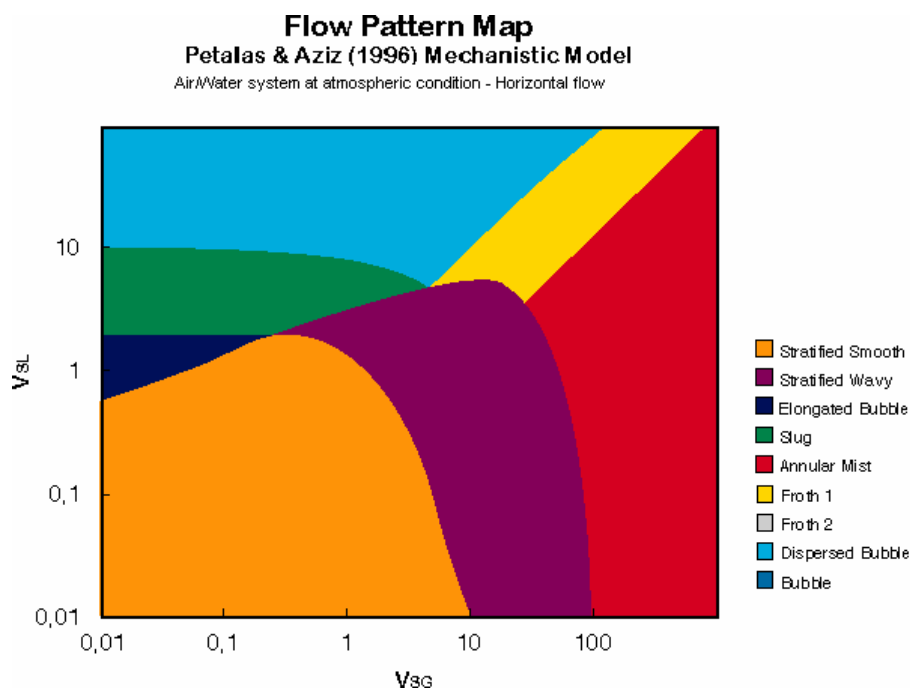


## E04.8 • Petalas & Aziz

**Acknowledgements:** Integration of this model in Emeraude was made possible through the support of the Reservoir Simulation Industrial Affiliates Program at Stanford University (SUPRI-B and SUPRI-HW).

**Reference:** Petalas N., and Aziz, K., "Development and Testing of a New Mechanistic Model for Multiphase Flow in Pipes ", ASME Fluids Engineering Division Second International Symposium on Numerical Methods for Multiphase Flows, San Diego, Cal., July 7-11, 1996.

Mechanistic model for all pipe inclinations, geometries, and fluid properties. Empirical correlations involved in the model were developed based on the Multiphase Flow Database of Stanford University gathering 20,000 laboratory measurements and 1800 measurements from actual wells.



The model distinguishes the following regimes:

- Elongated bubbles
- Bubble
- Stratified smooth
- Stratified wavy
- Slug
- Annular-Mist
- Dispersed bubble
- Froth (transition between dispersed bubble and annular-mist).
- Froth II (transition between slug flow and annular-mist).

Stratified flow regimes are restricted to horizontal flow.



When displaying the flowmap, each point involves the actual calculation of all the gradient terms. This renders the flowmap display a lot slower than for other models, hence the default number of points equal to 10. When more resolution is required, it is advised not to increase the “Number of points” but instead to zoom-in on the region of interest.

## E04.9 • Nicolas, Choquette, ABB-Deviated, Constant slippage

Nicolas, Choquette, and “ABB-deviated” are experimental correlations for Liquid-Liquid bubble flow. They all related the slippage velocity to the bubble rise velocity in a static column.

### Nicolas

Reference: Nicolas, Y., and Witterholt E.J.: “Measurements of Multiphase Fluid Flow”, paper SPE 4023, 47<sup>th</sup> Annual SPE Fall Meeting, San Antonio, Texas, October 1972.

#### Slip deviation correction in Emeraude:

Pipe deviation is taken into account by correcting the slippage velocity with a factor defined in the Interpretation Settings dialog as either linear for all angles:

$$V_s = V_s \times (1 + 0.04 \times \text{dev}) \text{ where dev is the deviation in degrees}$$

Or identical to the above until 45° and decreasing above this value (Ding et al.)

*Note that changing the correction mode in the Interpretation Settings will potentially affect all existing interpretations using the Nicolas correlation. It is left to the user to update calculations for zones/logs that are affected by the change.*

### Choquette

Reference: Choquette, Stanford University M.S. Thesis.

This is a conventional slip velocity model in Water-Oil flow, represented as a chart giving the slippage versus the density difference for several values of water holdup .

#### Slip deviation correction in Emeraude:

Pipe deviation is taken into account by correcting the slippage velocity with a factor defined in the Interpretation Settings dialog as either linear for all angles:

$$V_s = V_s \times (1 + 0.04 \times \text{dev}) \text{ where dev is the deviation in degrees}$$



Or identical to the above until 45° and decreasing above this value (Ding et al.)

*Note that changing the correction mode in the Interpretation Settings will potentially affect all existing interpretations using the Choquette correlation. It is left to the user to update calculations for zones/logs that are affected by the change.*

### **ABB – Deviated**

Variation of the Choquette correlation specifically derived from deviated wells data. Recommended for Liquid-Liquid calculations in deviated wells.

### **Constant slippage**

The slippage value is entered manually on each zone.

When calculations are made using a differential pressure density tool, the pipe friction for all the above models is estimated using a Moody friction factor based for an Reynolds number representative of the mixture.



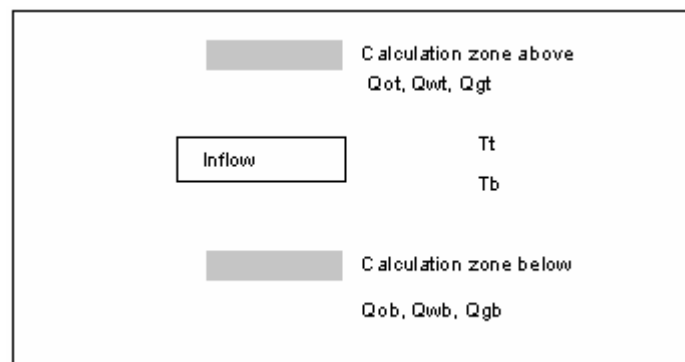


## E05 • Temperature Modelling

Two distinct models are used, whether the simulation is made within, or outside inflow zones:

### Within inflow zones

The temperature is calculated from enthalpy balance.



The enthalpy of the fluid at the bottom of the inflow zone is calculated as:

$$H_b = (Q_{ob} \times C_{po} \times \rho_o + Q_{wb} \times C_{pw} \times \rho_w + Q_{gb} \times C_{pg} \times \rho_g) \times T_b$$

$T_b$ , the bottom temperature, is read directly from the reference temperature log. The  $C_p$ 's are the heat capacities of the various fluids, defined in the PVT model.

The enthalpy at the top of the inflow zone is given by:

$$H_t = (Q_{ot} \times C_{po} \times \rho_o + Q_{wt} \times C_{pw} \times \rho_w + Q_{gt} \times C_{pg} \times \rho_g) \times T_t$$

It is assumed that the geothermal temperature profile is given. The incoming fluids are supposed to enter at a temperature equal to the geothermal temperature at the mid-point of the inflow zone,  $T_{geo}$ . For the gas, the entry temperature is corrected for Joule-Thomson.



## Joule-Thomson

For the gas, an isenthalpic process is assumed, leading to:

$$T_{\text{gas}} = T_{\text{geo}} + \frac{R \times T^2}{M \times C_p} \times \frac{dZ}{dT} \times \frac{\Delta P}{P}$$

Enthalpy balance between the top and bottom of the inflow zone gives:

$$H_t = H_b + \left( \Delta Q_{ob} \times C_{po} \times \rho_o + \Delta Q_{wb} \times C_{pw} \times \rho_w \right) \times T_{\text{geo}} + \Delta Q_{gb} \times C_{pg} \times \rho_g \times T_{\text{gas}}$$

Therefore:

$$T_t = \frac{H_b + \left( \Delta Q_{ob} \times C_{po} \times \rho_o + \Delta Q_{wb} \times C_{pw} \times \rho_w \right) \times T_{\text{geo}} + \Delta Q_{gb} \times C_{pg} \times \rho_g \times T_{\text{gas}}}{\left( Q_{ot} \times C_{po} \times \rho_o + Q_{wt} \times C_{pw} \times \rho_w + Q_{gt} \times C_{pg} \times \rho_g \right)}$$

*Note that this equation does hold only if all the contributions are positive. Extensions are made in other situations.*

## Between inflow zones

With Reference to the SPE Reprint Series No 19, and more specifically the paper “Use of Temperature Log For Determining Flow Rates in Producing Wells”, by Curtis & Witterholt, the temperature above a fluid entry zone is given by:

$$T_f(z, t) = T_{\text{Ge}} - g_G \times z + g_G \times A + \left( T_{\text{fe}} - T_{\text{Ge}} - g_G \times A \right) \times e^{\frac{-z}{A}}$$

*This equation was introduced by Ramey.*

$T_f$  = wellbore temperature

$T_{\text{Ge}}$  = geothermal temperature at depth of fluid entry

$g_G$  = geothermal gradient

$z$  = distance from fluid entry measured upwards

$T_{\text{fe}}$  = wellbore temperature at depth of fluid entry

$A$  = relaxation distance

Under certain assumptions, the relaxation distance  $A$  can be expressed as:



$$A = q \times \rho_f \times C_{pf} \frac{f(t)}{2 \times \pi \times k_h}$$

In Emeraude, the user is asked to input a “Heat loss coefficient” equal to the inverse of  $\frac{A}{q \times \rho_f \times C_{pf}}$ .

This is assumed a constant throughout the log.

The heat loss coefficient can be expressed using the formation heat conductivity, and diffusivity. The time function is given by Ramey and could be calculated knowing the production time. However, this coefficient can also be calculated directly from the log if the surface rates are known. It was decided to use this approach instead. This calculation is done automatically when reaching Zone Rates the first time. Also, the Heat loss coefficient can be included when matching surface conditions in the regression.





## E06 • Selective Inflow Performance

### E06.1 • Introduction

Selective inflow performance (SIP) provides a mean of establishing the IPR for each rate producing layer. The well is flowed at several different stabilized surface rates and for each rate, a production log is run across the entire producing interval to record simultaneous profiles of downhole flow rates and flowing pressure. Measured in-situ rates can be converted to surface conditions using PVT data. The SIP theory is only valid for single phase flow and usage of the SIP option is not recommended in case of multiphase flow.

The SIP option is enabled when:

- There are at least two interpretations (in two different surveys)
- Schematic logs exist for those interpretations
- The reservoir zones (green) have been defined in the Document panel.

A typical SIP diagram is shown in Fig 6.1.

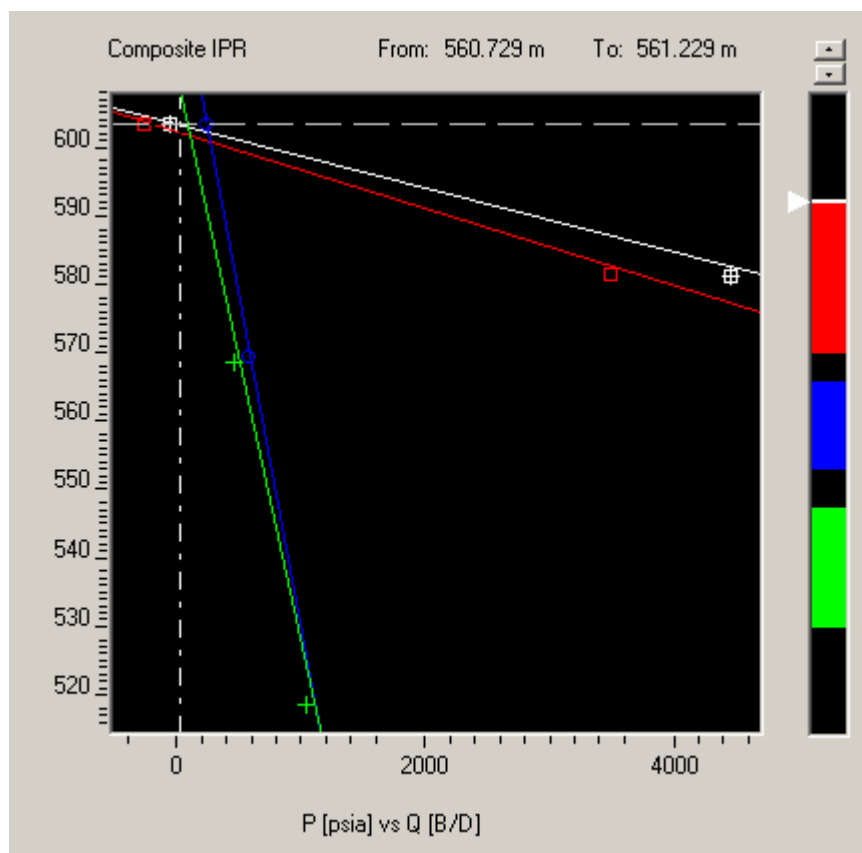


Fig 6.1



To each reservoir zone corresponds for each survey/interpretation a couple [rate, pressure] used in the SIP calculation. For the pressure, the interpretation reference channel is interpolated at the top of the zone. For the rate, the value used in the SIP is the contribution. It is calculated for a given reservoir zone as the difference between:

- values interpolated on the schematic logs at the top of that zone
- values interpolated on the schematic logs at the bottom of that same zone

## E06.2 • IPR Type

The user can decide to fit the data with different types of IPR equations: Straight line, C&n, and LIT relations. In the case of a gas well, the pseudo pressure  $m(p)$  can be used instead of the pressure  $p$  to estimate the gas potential. All the results are summarized in the results grid dialog accessible from the 'show results' button.

### Straight line or Darcy's law

$$q_o = PI \times (\bar{p} - p)$$

with  $\bar{p}$ , is the calculated average pressure  
 $PI$ , the productivity index

This option requires at least two valid data points and accept negative rates for the regression (typically for shut-in surveys with cross flow or for injection wells).

For this option only, the user can interactively re-define the straight line with the mouse (slope and intercept). The results are updated automatically. See section E6.2.1.

### LIT or Jones (A & B)

$$\bar{p}^2 - p^2 = A \times q + B \times q^2$$

with  $\bar{p}$ , the calculated average pressure  
 $A$ , the turbulence term, must be  $\geq 0$   
 $B$ , the Darcy flow term, must be  $\geq 0$

This option requires at least two valid data points and negative rates are disregarded for the regression.

**Fetkovitch or C&N**

$$q = C \times \left( \bar{p}^2 - p^2 \right)^N$$

with  $\bar{p}$ , the calculated average pressure  
 C, coefficient dependent on fluid properties, must be  $\geq 0$   
 N, exponent, must be between 0.5 and 1

In this case, the user can fix a value for the N exponent.

This option requires at least two valid data points; negative rates are disregarded for the regression.

**E06.3 • Pseudo Pressure  $m(p)$** 

The equations used in the IPR analysis assume constant fluid characteristics (compressibility, viscosity, formation volume factor). In gas well this is seldom the case and the real gas potential or pseudo pressure  $m(p)$  must be used instead.

Pseudo pressure is given as:

$$m(p) = \int_{p_0}^p \frac{p dp}{m z}$$

with  $p_0$ , the atmospheric pressure = 14.7 psia  
 $m$ , the fluid viscosity  
 z, the gas compressibility factor

The calculation of  $z(p,t)$  and  $m(p,t)$  uses the pressure and temperature reference channels of the considered interpretation and the associated PVT module.

When calculating the IPR data points, Emeraude will build a table relating the pseudo pressure to the corresponding pressure. This table is used to extract the average pressure  $\bar{p}$  from the calculated average pseudo pressure  $m(\bar{p})$ .



## E06.4 • Datum correction

The default is to generate the SIP without pressure correction to a common datum. However the user can select this option defining the following parameters: reference depth + reference(s) channel(s) (pressure and temperature if pseudo pressure is used); by checking the check box called 'correct at depth', the computed correction is applied to the data point and IPR lines.

This option is used to correct for the hydrostatic gradient of the well bore fluid column, so that pressure potentials from layers at different depth can be compared to an arbitrary common datum. It can be used to highlight cross flow between layers. Note that the average pressure of each of the layer remains the same and results will not be affected by these corrections.

In order to correct for the hydrostatic gradient, a reference pressure channel, preferably the shut-in pressure, must be available.

The shift will then be calculated as follow:

$$\Delta p_{IPR} = p_{ref(shut-in)} @ datum\ depth - p_{ref(shut-in)} @ IPR\ depth$$

The IPR depth is taken as the top of the IPR zone.

All the potential within the same IPR will be shifted by the same amount  $\Delta p_{IPR}$ .

If the pseudo pressure potential is used, then the user must also supply a reference temperature channel to compute the  $\Delta(m(p))_{IPR}$ .

## E6.5 • Phase Selection

Although the SIP theory only applies to single phase flow, the user can restrict the IPR's computations to a particular phase; only contribution of the selected phase will be taken into account. The default is set to the phase with the most important total contribution in each survey (the condition must be consistent between all surveys); the mixture option is chosen otherwise.

This facility has been implemented so that the user can withdraw the minor contribution of marginal phases showing in the rate schematic log (typically bottom zone water production in an oil or gas well).





## E07 • Pulsed Neutron Logging

### E07.1 • Basic principle of the Pulsed Neutron Logging (PNL) measurement.

The PNL measurement involves bombarding the formation with a high density flux of fast, high energy neutrons. Whenever any of these neutrons interacts with heavy formation atoms, it bounces back without much loss in energy. Whenever the interaction is with a light atom like hydrogen, however, there is a significant energy loss at each interaction. This means that the neutrons will gradually lose energy until they reach 'thermal' velocities, at which they are likely to be 'captured' by elements having the appropriate 'capture cross-section' (parameter  $\Sigma$  in PNL log analysis). Thermal neutron capture is accompanied by emission of gamma rays, and the PNL measurement is a measurement of the decay of the population of capture gamma rays as a function of time, in the region investigated by PNL tools (typically, 8 to 10 inches of depth from the borehole wall).

The capture gamma ray 'decay time',  $\tau$ , is modelled differently with different PNL tools. The ultimate objective is to derive the most accurate  $\tau$  possible.  $\tau$  is related to the formation capture cross-section,  $\Sigma$ , by the equation:

$$\tau \text{ (msec)} = 4.545 / \Sigma \text{ (c.u.)}$$

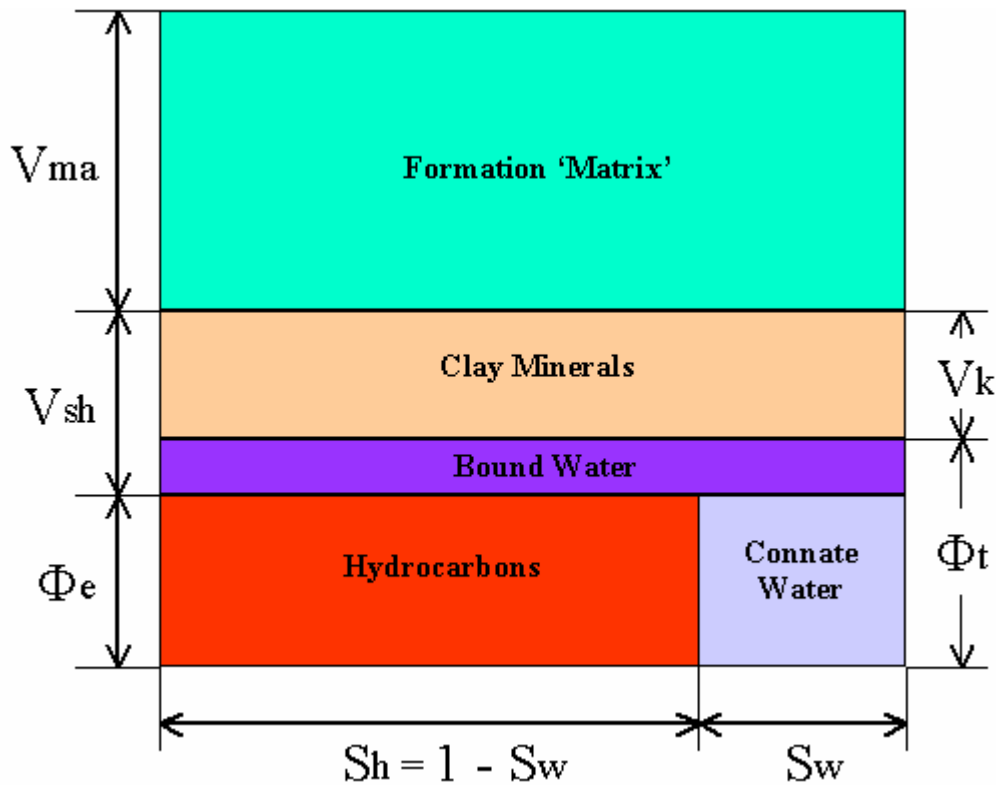
The main objective of PNL logging resides in the determination of the water saturation in the formation,  $S_w$ .  $S_w$  is determined at the initial stage by open hole logging, but it changes continuously during the production stage because of the removal of oil and its replacement in the porous system by water, mostly by encroachment from the aquifer. It is important to monitor these changes in saturation along the producing life of oil and gas reservoirs, because such changes govern the economics of the reservoir.

The interpretation principle of PNL logging rests essentially on the fact that chlorine (Cl) has a high capture cross-section, compared to other elements like Si, Ca, C, O, H, and possibly others, which are relatively more abundant than Cl in the bulk volume. Hence a measurement of the formation capture cross-section will be directly related to the bulk volume of chlorine in the formation, which in turn is related to the water saturation (because the salinity of the water results from its dissolved chlorine content). This is of course contingent to the water salinity being not only known, but also high enough to provide an appropriate resolution to the measurement. A typical requirement is that the formation water salinity must be (barring exceptions) in the range of 30000 ppm Cl or higher, for the PNL measurement to be worthwhile in practical field engineering applications.

Until the early 1990's, traditional PNL logging was carried out with tools designed solely around the thermal neutron capture physics. Because of the manifold petrophysical applications of neutron logging, modern tools are no longer limited to capture logging, but also address neutron slowing-down applications (porosity determination and gas identification), inelastic interaction applications (lithology and saturation determination), oxygen activation (for production logging), and other applications.



## E07.2 • Volumetrics and definition of parameters.



The above figure describes the partitioning of the total formation volume into its basic constituents as follows:

- $V_{ma}$  is the volume of non-clayey solids (e.g. quartz, limestone etc...), often called 'matrix'. Silt (fine particles of sand-type mineralogy) is usually included into the 'matrix' fraction, but appropriate 'shaly sand' models can differentiate between the silt and the rock fractions.
- $V_{sh}$  is the volume of shale, itself made up of clay minerals ( $V_k$ ) and 'bound water'.
- $\Phi_e$  is the effective (or interconnected) porosity.  $\Phi_e$  is made up of the 'free' water fraction,  $S_w$ , and the hydrocarbon fraction,  $S_h$ . The total porosity  $\Phi_t$  is the sum of the effective porosity and of the bound water fraction.

All these volumes are commonly expressed in percentages (e.g.  $\Phi_e$  is 25%), but whenever they are considered as parameters into equations, they must be entered in decimal fractions.

The measurement of the formation capture cross-section, called  $\Sigma_f$ , is a linear measurement. This means that each constituent of the formation bulk volume contributes to  $\Sigma_f$  in proportion to its volumetric fraction, and to its specific capture cross-section.

For example, in the most simple models, the bulk volume would be made up of fluid (fraction  $\Phi_e$ ) and matrix (fraction  $1 - \Phi_e$ ). The formation  $\Sigma$ ,  $\Sigma_f$ , would then be



$$\Sigma f = \Phi e * \Sigma fl + (1 - \Phi e) * \Sigma ma \quad (\text{Eq. 1})$$

in which

$\Sigma f$  is the formation  $\Sigma$  measured by the tool,  
 $\Sigma fl$  is the fluid capture cross-section,  
 $\Sigma ma$  is the matrix capture cross-section;

## E07.2 • Clean formation interpretation

In this model the shale fraction is assumed to be zero. (Eq. 1) applies, and the fluid  $\Sigma fl$  is itself a proportion of the water ( $\Sigma w$ ) and of the hydrocarbon ( $\Sigma h$ ), in weights equal to their volumetric fractions, which are  $S_w$  and  $S_h = 1 - S_w$  respectively. Hence:

$$\Sigma fl = S_w * \Sigma w + (1 - S_w) * \Sigma h. \quad (\text{Eq. 2})$$

Combining (Eq. 1) and (Eq. 2) together:

$$\Sigma f = \Phi e * S_w * \Sigma w + \Phi e * (1 - S_w) * \Sigma h + (1 - \Phi e) * \Sigma ma \quad (\text{Eq. 3})$$

If  $\Phi e$  is known (OH logging), and if  $\Sigma h$  and  $\Sigma w$  can be determined or assumed, the measurement of  $\Sigma f$  yields the value of  $S_w$  at any depth in the well, by

$$S_w = [(\Sigma f - \Sigma ma) - \Phi e * (\Sigma h - \Sigma ma)] / [\Phi e * (\Sigma w - \Sigma h)] \quad (\text{Eq. 3a})$$

It is obvious from (Eq. 3a) that the resolution of the measurement will depend on the difference between  $\Sigma w$  and  $\Sigma h$ , which will be the greater the higher the formation water salinity. As an example,  $\Sigma h$  will be in the about 21 for oil reservoirs, and  $\Sigma w$  will range between 21 for fresh waters (no salts) to some 120 for salt-saturated waters (250000 ppm Cl). At 30000 ppm Cl,  $\Sigma w$  equals about 30.

## E07.3 • 'Single Water' shaly reservoir interpretation

Most reservoirs are 'shaly', that is includes a - sometimes large - fraction of shale in the bulk volume. In traditional petrophysical interpretation this fraction, called  $V_{sh}$ , can be determined using a number of available shale indicators, which are measurements that are affected to some extent by the presence of shale. Such are, among others, the SP (Spontaneous Potential), the natural radioactivity (so-called 'Gamma Ray'), the formation resistivity, and most of the porosity logging measurements. For example, in the case of the Gamma Ray, which is one of the most common used indicators, an estimation of  $V_{sh}$  would be given by:

$$V_{shGR} = I_{RA}^N \quad \text{with} \quad I_{RA} = (GR_{log} - GR_{clean}) / (GR_{sh} - GR_{clean}) \quad (\text{Eq. 4})$$

$GR_{log}$  being the Gamma Ray reading at the depth of interpretation,

$GR_{clean}$  being the Gamma Ray reading in a clean formation ( $V_{sh} = 0$ ),



GRsh being the Gamma Ray reading in a shale formation ( $V_{sh} = 1$ ),  
 N being an empirical exponent determined locally,  
 $I_{RA}$  being the Radioactive Index.

The following correlations can be used as an alternative to the above estimation :

**Clavier, et al :** 
$$V_{sh} = 1.7 - \sqrt{3.38 - (I_{RA} + 0.7)^2} \quad (\text{Clavier})$$

**Stieber :**

*South Lousiana Miocene and Pliocene :* 
$$V_{sh} = I_{RA} / (3.0 - 2.0 \times I_{RA}) \quad (\text{Stieber 1})$$

*Variations :* 
$$V_{sh} = I_{RA} / (2.0 - I_{RA}) \quad (\text{Stieber 2})$$

$$V_{sh} = I_{RA} / (4.0 - 3.0 \times I_{RA}) \quad (\text{Stieber 3})$$

**Larionov:**

*“Older” rocks:* 
$$V_{sh} = 0.33 \times (2^{2 \times I_{RA}} - 1.0) \quad (\text{Larionov 1})$$

*“Tertiary” rocks:* 
$$V_{sh} = 0.0083 \times (2^{3.7 \times I_{RA}} - 1.0) \quad (\text{Larionov 2})$$

In petrophysical analysis, the logic for the determination of  $V_{sh}$  at any depth involves calculating the values  $V_{shXX}$  determined by all the available ‘XX’ indicators, and picking the minimum of all of them as the best estimate of  $V_{sh}$  at that depth.

In a shaly formations the measured formation  $\Sigma$ ,  $\Sigma_f$ , will include a shale term in addition to the fluid and matrix terms. Thus, if we write from (Eq. 3):

$$\Sigma_{clean} = \Phi_e * S_w * \Sigma_w + \Phi_e * (1 - S_w) * \Sigma_h + (1 - \Phi_e) * \Sigma_{ma} \quad (\text{Eq. 5})$$

then:

$$\Sigma_f = V_{sh} * \Sigma_{sh} + (1 - V_{sh}) * \Sigma_{clean} \quad (\text{Eq. 6})$$

$\Sigma_{clean}$  being the  $\Sigma$  of the non-shale fraction of the formation,  
 $V_{sh}$  being the bulk volume of shale,  
 $\Sigma_{sh}$  being the  $\Sigma$  of shale beds ( $V_{sh} = 1$ ).

By eliminating  $\Sigma_{clean}$  between (Eq. 5) and (Eq. 6),  $S_w$  can be calculated at any depth if, on top of the previously described parameters,  $V_{sh}$  can be calculated at that depth and if  $\Sigma_{sh}$  can be picked from shoulder shale beds.



## E07.4 • ‘Dual Water’ shaly reservoir interpretation

A proven sophistication to the Single Water shaly reservoir model involves that the particles of clay minerals are surrounded by bound water. Bound water consists of molecules of water that are tied to the surface of the clay particles by electrostatic forces. These forces easily overcome drag forces such as created by pressure differentials during the production stage of the reservoir, in such a way that the bound water will not be produced and therefore poses no threat to the production engineers. But because of its salinity, the bound water will affect logging measurements (amongst which PNL logs). Hence it is important to differentiate the bound water from the connate, free water, which is a difficult task owing to the different properties of the two types of water. The need to cope with this situation has made necessary the development of the so-called Dual Water model, and the adaptation of PNL logging to the requirements of this model.

### Preliminary definitions

Referring to the partitioning of the bulk volume, we define the total porosity  $\Phi_t$ :

$$\Phi_t = \Phi_e + V_{wb} \quad (\text{Eq. 7})$$

$V_{wb}$  being the bulk volume of bound water.

Also:

$$V_{sh} = V_k + V_{wb} \quad (\text{Eq. 8})$$

$V_k$  being the bulk volume of dry clay minerals.

The saturation of the bound water is termed  $S_{wb}$ , such as:

$$S_{wb} = V_{wb} / \Phi_t \quad (\text{Eq. 9})$$

and the free water saturation,  $S_w$ , is such as:

$$S_w = V_{wf} / \Phi_t \quad (\text{Eq. 10})$$

$V_{wf}$  being the bulk volume of free water.

The total water saturation  $S_{wt}$  is defined as:

$$S_{wt} = (V_{wf} + V_{wb}) / \Phi_t = S_w + S_{wb} \quad (\text{Eq. 11})$$

and by combining (Eq. 7), (Eq. 9), (Eq. 10) and (Eq. 11), one can show that:

$$S_w = V_{wf} / \Phi_e = (S_{wt} - S_{wb}) / (1 - S_{wb}) \quad (\text{Eq. 12})$$



## Determination of Swb

Swb is determined by petrophysical analysis using Swb indicators, pretty much in the same way Vsh is determined by shale indicators in the Single Water model, with the difference that the presence of two types of water in the formation is taken into the formulation of the derivation of Swb from the corresponding measurements.

In particular, the Gamma Ray, which is of specific interest in cased hole applications such as PNL logging, affords a determination of Swb using the formula

$$SwbGR = [(GRlog - GRw) / (GRwb - GRw)]^{**M} \quad (Eq. 13)$$

This formulation has the same shape as (Eq. 4). However, here, the selection of parameters is different,

GRlog            being the Gamma Ray reading at the depth of interpretation,

GRw             being the Gamma Ray reading in a 100% free water zone (typically, reservoir),

GRwb            being the Gamma Ray reading in a 100% bound water zone (typically, shale),

M                being an empirical exponent derived locally.

Because of the similarity between the Swb and Vsh derivations from the Gamma Ray, it has been suggested to use  $Swb = Vsh$  as a first approximation (and this option is proposed in Emeraude). It should be noted, however, that making this assumption is equivalent to assuming that the proportions of dry clay and bound water in the shales are the same as the proportions of total solids (dry clay + matrix) and total liquids in the bulk volume. In other words, the 'porosity' of the shales would equal the porosity of the formation. This in theory has no reason for being true, but nevertheless the tradition persists.

A good solution for PNL logging consists in using a Swb computation previously performed on the set of open hole logs by using a suitable Dual Water shaly reservoir model.

## Determination of the saturation

In the Dual Water model, the response equation of PNL logs simplifies when the porosity and saturation are taken as  $\Phi_t$  and  $Sw_t$ , not as  $\Phi_e$  and  $Sw$ .  $\Phi_e$  and  $\Phi_t$  are related by (Eq. 7), which, given that

$$Sw = V_{wf} / \Phi_e \quad (Eq. 13a)$$

yields, after combining with (Eq. 9):

$$\Phi_e = \Phi_t * (1 - Sw_b) \quad (Eq. 14)$$

Now the PNL response equation can be written as:

$$\Sigma f = V_{ma} * \Sigma ma + V_{wf} * \Sigma wf + V_{wb} * \Sigma wb + V_h * \Sigma h + V_k * \Sigma k \quad (Eq. 15)$$

$V_{ma}$             being the bulk volume of matrix,



$V_h$	being the bulk volume of hydrocarbons,
$\Sigma_{wf}$	being the $\Sigma$ of the free water,
$\Sigma_{wb}$	being the $\Sigma$ of the bound water,
$\Sigma_k$	being the $\Sigma$ of the dry clay minerals.

Now

$$V_{ma} = 1 - \Phi_t - V_k \quad (\text{Eq. 16})$$

and one makes the assumption that  $\Sigma_k = \Sigma_{ma}$ . This assumption is valid whenever the shales are primarily composed of silts and very small rock fragments, and also holds true whenever clay fractions are small in the bulk volume. Under this assumption, (Eq. 15) simplifies to

$$\Sigma_f = (1 - \Phi_t) * \Sigma_{ma} + V_{wf} * \Sigma_{wf} + V_{wb} * \Sigma_{wb} + V_h * \Sigma_h \quad (\text{Eq. 15})$$

Further from (Eq. 11)

$$V_{wf} = \Phi_t * (S_{wt} - S_{wb}) \quad (\text{Eq. 16})$$

and again from (Eq. 11)

$$V_h = \Phi_t - V_{wf} - V_{wb} = \Phi_t * (1 - S_{wt}) \quad (\text{Eq. 17})$$

So that (Eq. 15) becomes

$$\Sigma_f = (1 - \Phi_t) * \Sigma_{ma} + \Phi_t * (S_{wt} - S_{wb}) * \Sigma_{wf} + \Phi_t * S_{wb} * \Sigma_{wb} + \Phi_t * (1 - S_{wt}) * \Sigma_h \quad (\text{Eq. 17a})$$

or, rearranging:

$$\Sigma_f = \Sigma_{ma} + \Phi_t * [(\Sigma_h - \Sigma_{ma}) + S_{wt} * (\Sigma_{wf} - \Sigma_h) - S_{wb} * (\Sigma_{wf} - \Sigma_{wb})] \quad (\text{Eq. 18})$$

In (Eq. 18)  $\Phi_t$  is derived from  $\Phi_e$  and  $S_{wb}$  through (Eq. 14);  $\Sigma_{wf}$  and  $\Sigma_{wb}$  are derived from the PNL log, so that  $S_{wt}$  can be calculated if one has previously determined parameters  $\Sigma_{ma}$  and  $\Sigma_h$ .

$S_w$ , which is the objective of the interpretation, is eventually derived from  $S_{wt}$  and  $S_{wb}$  through (Eq. 12).

It can be seen that  $V_{sh}$  has no direct input in the calculation of  $S_w$  in the Dual Water model, which rather relies on an accurate determination of  $S_{wb}$ .

It can also be seen that (Eq. 18) reduces into (Eq. 3) in clean formation cases in which  $S_{wb} = 0$ ,  $\Phi_t = \Phi_e$  and  $S_{wt} = S_w$ .



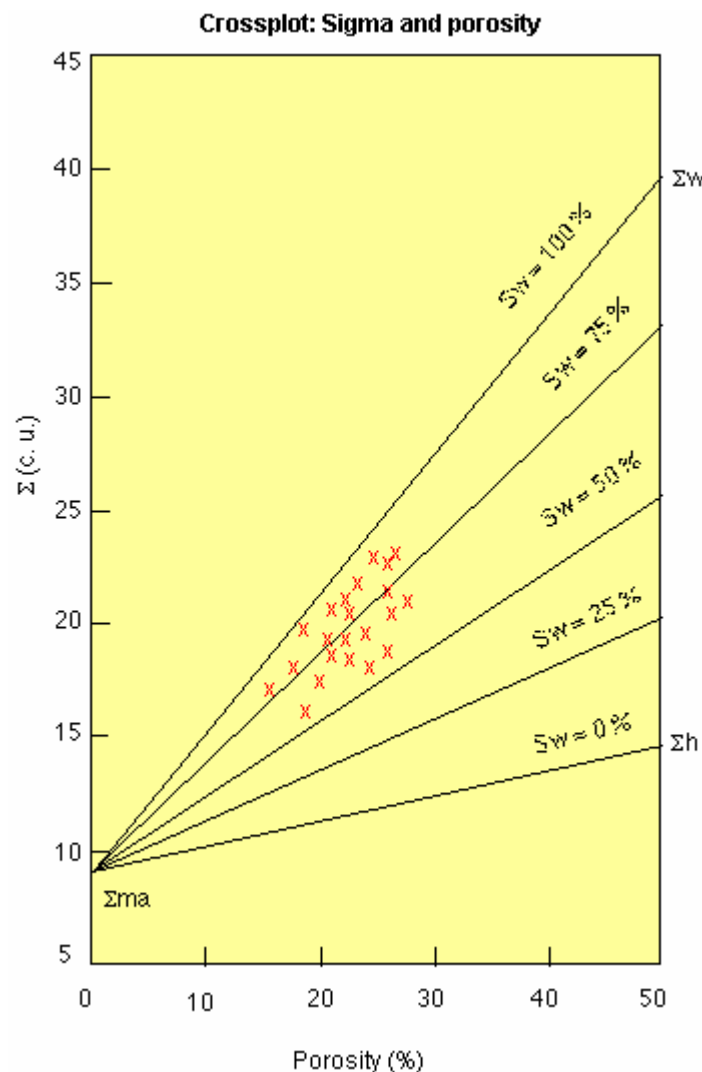
## E07.5 • Use of crossplots

Like in all petrophysical analyses, in PNL log interpretation crossplots can be used in three ways:

- To help in the determination of zoned parameters,
- To solve graphically for the interpretation target outputs such as  $S_w$ ,
- To quality control the results.

### S - Porosity crossplot

In clean formations and when using a Single Water shaly model (once the shale correction on  $\Sigma$  has been performed), this crossplot will help tie down the values of  $\Sigma_{ma}$  and  $\Sigma_w$  if a zone with 100% water saturation is available. It will also be used to graphically determine  $S_w$  for any data point once the shale correction has been performed. In Emeraude, the input porosity needs to be an effective porosity, extracted for example from the interpretation of openhole logs.



The shale correction is calculated as:





$$\Sigma_{fcorr} = \Sigma_f - V_{sh} * (\Sigma_{sh} - \Sigma_{ma}) \quad (\text{Eq. 18})$$

### S - Neutron Porosity crossplot

In some cases and especially on old wells in which PNL log data is the only petrophysical data available, the only porosity values come from the so-called PNL ratio porosity. That porosity can be converted into an effective porosity by correcting for shaliness, by applying the equation:

$$\Phi_{corr} = \Phi_r - V_{sh} * \Phi_{sh} \quad (\text{Eq. 19})$$

$\Phi_r$  being the 'ratio porosity' from the PNL log,  
 $\Phi_{sh}$  being the 'ratio porosity' reading in shale beds ( $V_{sh} = 1$ ).

### Seq - Feq crossplot

This crossplot is used to determine  $\Sigma_w$  and  $\Sigma_{ma}$  when the saturation is available from an external source (for example, from the open hole logs).

The PNL saturation equation in a clean formation has been written as:

$$\Sigma_f = \Phi_e * S_w * \Sigma_w + \Phi_e * (1 - S_w) * \Sigma_h + (1 - \Phi_e) * \Sigma_{ma} \quad (\text{Eq. 3})$$

It can also be written as:

$$\Sigma_{eq} = (1 - \Phi_{eq}) * \Sigma_{ma} + \Phi_{eq} * \Sigma_w \quad (\text{Eq. 20})$$

if we define

$$\Sigma_{eq} = [\Sigma_f - (1 - S_w) * \Phi_e * \Sigma_h] / [1 - \Phi_e * (1 - S_w)] \quad (\text{Eq. 21})$$

and

$$\Phi_{eq} = (\Phi_e * S_w) / [1 - \Phi_e * (1 - S_w)] \quad (\text{Eq. 22})$$

In the  $\Sigma_{eq} - \Phi_{eq}$  crossplot the influence of hydrocarbons has been eliminated, so that the data points should lie on a straight line joining the matrix point and the fluid point. This helps in the determination of  $\Sigma_{ma}$  and  $\Sigma_w$ , provided there is a sufficient spread in the values of  $\Sigma_f$  of all the data points.

Of course this presupposes that the saturation has not changed since the initial values which serve as a reference for the calculation of  $\Sigma_{eq}$  and of  $\Phi_{eq}$ . Any further change in saturation will distort the crossplot, which however may still be useable in sections in which the saturation has not changed.



### Sma - Vma crossplot

Here again, this crossplot is used to determine  $\Sigma_{ma}$  when the saturation is available from an external source, for example from the open hole logs. The method involves calculating  $\Sigma_{ma}$  from the set of (Eq. 5) and (Eq. 6), as:

$$\Sigma_{ma} \text{ (calculated)} = [\Sigma_f - V_{sh} * \Sigma_{sh} - \Phi_e * (S_w * \Sigma_w + (1 - S_w) * \Sigma_h)] / V_{ma} \quad (\text{Eq. 23})$$

With

$$V_{ma} = 1 - \Phi_e - V_{sh} \quad (\text{Eq. 24})$$

The  $\Sigma_{ma}$  (calculated) -  $V_{ma}$  crossplot will then show a trend of data points funnelling towards the value of  $\Sigma_{ma}$  at high values of  $V_{ma}$  (for which  $\Phi_e = V_{sh} = 0$ ), where the log values approximate  $\Sigma_{ma}$ .

### Swa - Swb crossplot

This crossplot provides a graphical solution to the determination of the water saturation when using a Dual Water model.

First,  $S_{wb}$  is calculated by means of bound water indicators as described above. Then,  $\Sigma_{wa}$  is calculated assuming that the formation is shale-free ( $S_{wb} = 0$ ) and water-bearing ( $S_{wt} = 1$ ), as

$$\Sigma_{wa} = [\Sigma_f - \Sigma_{ma} (1 - \Phi_e)] / \Phi_e \quad (\text{Eq. 25})$$

On the  $\Sigma_{wa}$  -  $S_{wb}$  crossplot three remarkable points are located: the 'free water' point and the 'hydrocarbon' point on the  $\Sigma_{wa}$  axis ( $S_{wb} = 0$ ) with their respective  $\Sigma_{wf}$  and  $\Sigma_h$  values, and the 'bound water' point (value  $\Sigma_{wb}$  with  $S_{wb} = 1$ ).  $\Sigma_{wb}$  is obtained from the PNL log in shale intervals using (Eq. 25), in which it is recalled that  $\Phi_e$  is the effective porosity (not an uncorrected Neutron porosity).

The distance between the free water and hydrocarbon points is linearly divided into constant  $S_{wt}$  (total water saturation) lines drawn parallel to a line connecting the free water and bound water points. Thus  $S_{wt}$  is determined graphically, and  $S_w$  is finally calculated using (Eq. 12):

$$S_w = (S_{wt} - S_{wb}) / (1 - S_{wb}) \quad (\text{Eq. 12})$$

## E07.5 • Time-Lapse interpretation

PNL logs are often run at repeated time intervals ('time-lapse') to check for hydrocarbon depletion and encroachment of water. The use of time-lapse PNL logs has the advantage that many of the parameters that are needed to derive the water saturation, keep an assumed constant value. Such are  $\Sigma_{ma}$ ,  $\Sigma_h$ , and if there is no replacement of fluid by injection water,  $\Sigma_w$ .

When the above conditions are met, and also assuming that the effective porosity  $\Phi_e$  remains constant, the change in saturation in a reservoir can be directly inferred from the change in  $\Sigma$  values from an early run (run1) to a later run (run2), as follows:



$$Sw2 - Sw1 = (\Sigma f2 - \Sigma f1) / [\Phi_e * (\Sigma w - \Sigma h)] \quad (\text{Eq. 26})$$

Particular cases in which the formation lithology varies from time step 1 to time step 2 (for example because of production of fines, or following an acid treatment), or in which the water salinity changes (for example due to encroachment from a water injection system) are more complex and need specific modeling.

Changes in saturation are best visualised by calculating the Bulk Volume of Water (BVW) for each run of the PNL log, and by plotting BVW1, BVW2, ... BVWn on the same User View representing the total pore space. BVW is defined as the product of the porosity by the water saturation:

$$BVWn = \Phi_e * S_{wn} \quad (\text{Eq. 27})$$

In Emeraude, the 'Pore Volume Analysis' (PVA) automatic view presents the stacked successive BVW curves with an appropriate color coding, allowing the user to visualize the extent to which hydrocarbons in the reservoir are gradually being replaced by water. The time-lapse technique also applies to such operations as 'Log-Inject-Log' and 'Acid Effect'. In the Log-Inject-Log technique,  $\Sigma w$  is deliberately modified (e.g. by injection of high capture cross-section fluids such as salt-saturated or borated waters) to provide a higher than natural resolution in order to derive saturations (for example, residual oil saturation) with a better precision. In the Acid Effect technique, the target objective is rather the change in porosity resulting for example from dissolution of fines by the acid.

### Gas saturation monitoring

Due to its lower capture cross-section than the oil  $\Sigma$  (typically,  $\Sigma_{\text{Gas}}$  could be between 0 and possibly 15 at reservoir conditions), gas detection and saturation monitoring presents an excellent case of application of PNL logs. Methods will involve modifying the value of  $\Sigma h$  to reflect the expected change of fluid type in the reservoir as depletion proceeds, for example as the decrease in reservoir pressure draws gas from solution in the oil below the bubble point.

