Porosity Logs
General

- Type of porosity logs
  - Sonic log
  - Density log
  - Neutron log
- None of these logs measure porosity directly
- The density and neutron logs are nuclear measurements
- The sonic log use acoustic measurements
- A combination of these logs gives good indications for lithology and more accurate estimates of porosity
Sonic log
General Sonic

- A log that measures interval transit time ($\Delta t$) of a compressional sound wave travelling through the formation along the axis of the borehole.
- The acoustic pulse from a transmitter is detected at two or more receivers. The time of the first detection of the transmitted pulse at each receiver is processed to produce $\Delta t$.
- The $\Delta t$ is the transit time of the wave front over one foot of formation and is the reciprocal of the velocity.
- Interval transit time is both dependent on lithology and porosity.
- Sonic log is usually displayed in track 2 or 3.
- Units: $\mu$sec/ft, $\mu$sec/m.
- Mnemonics: DT, AC.
- Symbol: $\phi$. 
• Interpretation goals:
  – Porosity
  – Lithology identification (with Density and/or Neutron)
  – Synthetic seismograms (with Density)
  – Formation mechanical properties (with Density)
  – Detection of abnormal formation pressure
  – Permeability identification (from waveform)
  – Cement bond quality
Sonic Porosity

Formula

- From the Sonic log, a sonic derived porosity log (SPHI) may be derived:
  - Wyllie Time-average
    \[ \phi_s = \frac{\Delta t_{\text{log}} - \Delta t_{\text{matrix}}}{\Delta t_f - \Delta t_{\text{matrix}}} \]
  - Raymer-Hunt-Gardner
    \[ \phi_s = \frac{5}{8} \times \left( \frac{\Delta t_{\text{mg}} - \Delta t_{\text{matrix}}}{\Delta t_{\text{mg}}} \right) \]
  - For unconsolidated formations
    \[ \phi_s = \left( \frac{\Delta t_{\text{log}} - \Delta t_{\text{matrix}}}{\Delta t_f - \Delta t_{\text{matrix}}} \right) \times \frac{1}{C_p} \text{, with } C_p = \frac{\Delta t_{\text{sh}} \times C}{100} \]
- This requires a formation matrix transit time to be known
- SPHI Units: percent, fraction
- \( C_p = \) Compaction factor
- \( C = \) constant, normally 1.0

- Hydrocarbon effects:
  - The \( D_t \) is increased due to HC therefore:
    - \( \phi = \phi_s \times 0.7 \) (gas)
    - \( \phi = \phi_s \times 0.9 \) (oil)
Sonic Porosity
Charts

These charts (Fig. 1) present sonic log interpretation time, pore pressure, and porosity in various layers. The blue line represents the sonic log for the selected layer. When using the sonic log to determine the porosity, one must understand the relationship between the sonic log and the observed porosity. By consulting the charts, one can determine the porosity accurately.

For more information, see References 16, 17, and 18.
Sonic Porosity

<table>
<thead>
<tr>
<th></th>
<th>$V_{ma}$ (ft/sec)</th>
<th>$V_{ma}$ (m/s)</th>
<th>$\Delta t_{ma}$ (μs/ft)</th>
<th>$\Delta t_{ma}$ (μs/m)</th>
<th>$\Delta t_{ma}$ (μs/ft) commonly used</th>
<th>$\Delta t_{ma}$ (μs/m) commonly used</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sandstone</td>
<td>18 – 19.5</td>
<td>5.5 – 5.95</td>
<td>55.5 - 51</td>
<td>182 – 167</td>
<td>55.5 or 51</td>
<td>182 or 167</td>
</tr>
<tr>
<td>Limestone</td>
<td>21 – 23</td>
<td>6.4 – 7.0</td>
<td>47.6 – 43.5</td>
<td>156 – 143</td>
<td>47.5</td>
<td>156</td>
</tr>
<tr>
<td>Dolomite</td>
<td>23</td>
<td>7.0</td>
<td>43.5</td>
<td>143</td>
<td>43.5</td>
<td>143</td>
</tr>
<tr>
<td>Anhydrite</td>
<td>20</td>
<td>6.1</td>
<td>50</td>
<td>164</td>
<td>50</td>
<td>164</td>
</tr>
<tr>
<td>Salt</td>
<td>15</td>
<td>4.575</td>
<td>66.7</td>
<td>219</td>
<td>67</td>
<td>220</td>
</tr>
<tr>
<td>Freshwater mud filtrate</td>
<td>5.28</td>
<td>1.610</td>
<td>189</td>
<td>620</td>
<td>189</td>
<td>620</td>
</tr>
<tr>
<td>Saltwater mud filtrate</td>
<td>5.40</td>
<td>1.649</td>
<td>185</td>
<td>607</td>
<td>185</td>
<td>607</td>
</tr>
<tr>
<td>Gas</td>
<td>1.08</td>
<td>0.33</td>
<td>920</td>
<td>3018</td>
<td>920</td>
<td>3018</td>
</tr>
<tr>
<td>Oil</td>
<td>4.35</td>
<td>1.32</td>
<td>230</td>
<td>755</td>
<td>230</td>
<td>755</td>
</tr>
<tr>
<td>Casing (iron)</td>
<td>17.5</td>
<td>5.33</td>
<td>57</td>
<td>187</td>
<td>57</td>
<td>187</td>
</tr>
</tbody>
</table>
Sonic Secondary Effects

• Environmental effects:
  – Enlarged borehole, formation fractures, gas in the borehole or formation, or improper centralization can produce signal attenuation resulting in "cycle skipping" or DT spikes to higher values
  – Improper centralization, lack of standoff, or excessive logging speed can result in "road noise", or DT spikes to either higher or lower values

• Interpretation effects:
  – Lithology: porosity calculated from sonic depends on the choice of matrix transit time, which varies with lithology
  – Porosity calculations for uncompacted formations may yield porosity values higher than the actual values when using the Wyllie equation. Use instead the Raymer-Hunt-Gardner equation or correct for decompaction
  – Porosity calculated in gas bearing zones will be slightly higher than the actual values because the traveltime in gas is higher than in water
Density Log
General Density

- Gamma rays emitted from a chemical source (Ce$^{137}$, Co$^{60}$) interact with electrons of the elements in the formation.
- Two detectors count the number of returning gamma rays which are related to formation electron density.
- For most earth materials, electron density is related to formation density through a constant.
- Returning gamma rays are measured at two different energy levels:
  - High energy gamma rays (Compton scattering) determine bulk density and therefore porosity.
  - Low energy gamma rays (due to photoelectric effect) are used to determine formation lithology.
- Low energy gamma rays are related to the lithology and show little dependence on porosity and fluid type.
- Symbol for density: $\rho$ (rho)
General

Density

• Bulk Density:
  – Units: g/cm³, kg/m³
  – Mnemonics: RHOB, DEN, (ZDEN)
• Density Porosity:
  – Units: %, v/v decimal
  – Mnemonics: DPHI, PHID, DPOR
• Density Correction:
  – Units: g/cm³, kg/m³
  – Mnemonics: DRHO
• Photoelectric effect:
  – Units: b/e (barns per electron)†
  – Mnemonics: PE, Pe, PEF

†A barn is a unit of area, abbreviated mostly as “bn” or “b”, equal to 10⁻²⁸ m². Although not an official SI unit, it is widely used by nuclear physicists, since it is convenient for expressing the cross sectional area of nuclei and nuclear reactions. A barn is approximately equal to the area of a uranium nucleus
General Density

- Interpretation goals
  - Porosity
  - Lithology identification (from PEF and/or with Sonic and/or Neutron)
  - Gas indication (with Neutron)
  - Synthetic seismograms (with Sonic)
  - Formation mechanical properties (with Sonic)
  - Clay content (shaliness) (with Neutron)
Density Porosity

Formula

- Formation bulk density ($\rho_b$) is a function of matrix density ($\rho_{ma}$), porosity and formation fluid density ($\rho_f$).
- Density porosity is defined as:

\[
\phi_{den} = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f}
\]

- The matrix density and the fluid density need to be known.
Density Porosity Chart

Risk analysis, $p_0$, is accorded with the EEC-Correlated Formation Density by $D_0$-Density Log. It is converted to porosity with this chart. To use, enter log density, converted for formation from log density to the appropriate current rock type and multiply porosity by the appropriate bulk density $p_0$, such as to estimate $p_0$ (ratio of density of the formation to density of the formation closely surrounding the borehole—usually sandstone).

Example:
$p_0 = 2.3$ g/cm³ in Jurassic Shale
$p_0 = 2.7$ (porosity)
$p_0 = 1.1$ (g/cm³ sand)
Therefore, $\phi = 25\%$.
# Density Porosity

<table>
<thead>
<tr>
<th></th>
<th>Matrix density (g/cm³)</th>
<th>Fluid density (g/cm³)</th>
<th>PEF (b/e)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sandstone</td>
<td>2.65</td>
<td></td>
<td>1.81</td>
</tr>
<tr>
<td>Limestone</td>
<td>2.71</td>
<td></td>
<td>5.08</td>
</tr>
<tr>
<td>Dolomite</td>
<td>2.87</td>
<td></td>
<td>3.14</td>
</tr>
<tr>
<td>Anhydrite</td>
<td>2.98</td>
<td></td>
<td>5.05</td>
</tr>
<tr>
<td>Halite</td>
<td>2.04</td>
<td></td>
<td>4.65</td>
</tr>
<tr>
<td>Coal</td>
<td>~1.2</td>
<td></td>
<td>0.2</td>
</tr>
<tr>
<td>Barite</td>
<td>4.09</td>
<td></td>
<td>267</td>
</tr>
<tr>
<td>Gas</td>
<td></td>
<td>0.2</td>
<td>0.95</td>
</tr>
<tr>
<td>Oil</td>
<td></td>
<td>~0.85</td>
<td>0.12</td>
</tr>
<tr>
<td>Water</td>
<td></td>
<td>1.0 – 1.2</td>
<td>0.36 – 1.1</td>
</tr>
</tbody>
</table>
Density
Secondary Effects

- **Environmental effects:**
  - Enlarged borehole: $\text{RHOB} < \text{Fm. Bulk Density (DPHI} > \text{PHI}_{\text{actual}})$
  - Rough borehole: $\text{RHOB} < \text{Fm. Bulk Density (DPHI} > \text{PHI}_{\text{actual}})$. This is due to the sensor pad losing contact with the borehole wall. Other indications for a rough borehole will be highly variable Caliper curve, and a high-valued density correction (DRHO)
  - Barite muds: $\text{RHOB} > \text{Fm. Bulk Density (DPHI} < \text{PHI}_{\text{actual}})$ and $\text{PEF} > \text{PEF}_{\text{actual}}$

- **Interpretation effects:**
  - Lithology: porosity calculated from density depends on the choice of matrix density, which varies with lithology (DPHI might be negative)
  - Fluid content: porosity calculated from density depends on the choice of fluid density, which varies with fluid type and salinity. In routine calculations, zone of investigations is assumed to be 100% filled with mud filtrate
  - Hydrocarbons: Presence of gas (light HC) in the pore space causes DPHI to be more than the actual porosity. In Density-Neutron combinations, this causes a ”cross-over”, where the NPHI values are less than the DPHI values
  - In all three cases above, the RHOB value from the tool is correct, but the calculated DPHI is erroneous
Neutron Log
General Neutron

- Neutron logs measure the hydrogen content in a formation. In clean, shale-free formations, where the porosity is filled with water or oil, the neutron log measures liquid-filled porosity ($\phi_N$, PHIN, NPHI).
- Neutrons are emitted from a chemical source (americium – beryllium mixture). At collision with nuclei in the formation, the neutrons lose energy. With enough collisions, the neutron is absorbed and a gamma ray is emitted.
- Since a neutron is slightly heavier than a proton, the element which closely approximates the mass of a neutron is hydrogen. In neutron-hydrogen collisions, the average energy transferred to the hydrogen nucleus is about $\frac{1}{2}$ that of the energy originally contained in the neutron. Whereas, if the scattering nucleus was oxygen (mass 16 amu) the neutron would retain 77% of its energy.
- Materials with large hydrogen content like water or hydrocarbons become very important for slowing down neutrons. Since hydrogen in a porous formation is concentrated in the fluid-filled pores, energy loss can be related to the formation’s porosity.
General

Neutron

- Neutron curves commonly displayed in track 2 or 3
- Displayed as Neutron Porosity (NPHI, PHIN, NPOR)
- Units: porosity units (p.u.) (calibrated with a standard, different for all tools), v/v decimal, fraction or %
- Neutron logs are not calibrated in basic physical units. Therefore, specific logs need to be interpreted with specific charts


General Neutron

- Interpretation goals:
  - Porosity (displayed directly on the log)
  - Lithology identification (with Sonic and Density)
  - Gas indication (with Density)
  - Clay content, shaliness (with Density)
  - Correlation, especially in cased holes
Neutron Porosity
Secondary Effects

• Environmental effects:
  - Enlarged borehole: $\text{NPHI} > \text{PHI}_{\text{actual}}$
  - Mudcake: $\text{NPHI} < \text{PHI}_{\text{actual}}$
  - Borehole salinity: $\text{NPHI} < \text{PHI}_{\text{actual}}$
  - Formation salinity: $\text{NPHI} > \text{PHI}_{\text{actual}}$
  - Mud weight: $\text{NPHI} < \text{PHI}_{\text{actual}}$
  - Pressure: $\text{NPHI} > \text{PHI}_{\text{actual}}$
  - Temperature: $\text{NPHI} < \text{PHI}_{\text{actual}}$

Pressure and temperature have the greatest effect. Neutron less affected by rough borehole

• Interpretation effects:
  - Shaliness: $\text{NPHI} > \text{PHI}_{\text{actual}}$ in shaly zones
  - Gas: $\text{NPHI} < \text{PHI}_{\text{actual}}$ in gassy zones.
  - Lithology: In genera, for logs recorded in limestone porosity units, if the actual lithology is sandstone, the log porosity is less than the actual porosity. If the actual lithology is dolomite, the log porosity is greater than the actual porosity
Porosity determination

Given $t_{ma}$, $\rho_{ma}$ or $\phi_{ma}$, correct total porosities can be calculated from the appropriate logs, in water-filled formations and with no secondary porosity* present.

* The porosity created through alteration of rock, commonly by processes such as dolomitization, dissolution and fracturing.
But…

- Matrix lithology often unknown
- Complex mineralogical composition
- Presence of other pore fluids than water
- Even geometry of pore structures affect the tools

So, we need additional information

- Fortunately, sonic, density and neutron logs respond different on
  - Matrix minerals
  - Pore fluids
  - Geometry of pore structure

- Combination of logs may unravel complex matrix and fluid mixtures and thereby provide a more accurate determination of porosity

- A.o. crossplots are a convenient way to demonstrate how various combinations of logs respond to lithology and porosity
Introduction

Porosity combinations

- When using a single porosity measurement, lithology must be specified, through the choice of a matrix value, for the correct porosity to be calculated
- When using two or more measurements, lithology may be predicted (along with porosity), but with some ambiguity
- Measurement preferences (in order of choice):
  - Two measurements:
    - Neutron and Density
    - Neutron and Sonic
    - Spectral density (bulk density and Pe)
    - Density and Sonic
  - Three measurements:
    - Neutron and spectral density
    - Neutron; Density, and Sonic
      - MID (Matrix Identifications) Plots
      - M-N Plots
# Quick-look ($\phi_N$ & $\phi_D$)

<table>
<thead>
<tr>
<th>Lithology</th>
<th>$\phi_N$ and $\phi_D$</th>
<th>Pe</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sandstone</td>
<td>Neutron-Density crossover ($\phi_N &gt; \phi_D$) of 6 to 8 porosity units</td>
<td>&lt;2</td>
</tr>
<tr>
<td>Limestone</td>
<td>Neutron and density curves overlay ($\phi_N \approx \phi_D$)</td>
<td>~5</td>
</tr>
<tr>
<td>Dolomite</td>
<td>Neutron-density separation ($\phi_N &lt; \phi_D$) of 12 to 14 porosity units</td>
<td>~3</td>
</tr>
<tr>
<td>Anhydrite</td>
<td>Neutron porosity is greater than density porosity ($\phi_N &gt; \phi_D$) by 14 porosity units; $\phi_N \approx 0$</td>
<td>~5</td>
</tr>
<tr>
<td>Salt</td>
<td>Neutron porosity is slightly less than zero. Density porosity is 40 porosity units (0.40) or more. Watch for washed out hole (high Caliper) and bad density data</td>
<td>4.7</td>
</tr>
</tbody>
</table>

**Note:** Both $\phi_N$ and $\phi_D$ should be calculated with respect to limestone. $\phi_N$ is recorded on limestone matrix and $\phi_D$ is calculated with a $\rho_{ma}$ of 2.71 g/cm$^3$ or scaled to approx. the Neutron porosity scale.
Neutron-Density: Special Case

- Gas detection:
  - Density porosity is too high
  - Neutron porosity is too low
  - Neutron porosity < Density porosity
  - Cross-over
  - Be aware, cross-overs may also be caused by lithological differences as an affect of the scaling

Porosity of a gas-bearing formation

\[
\phi_{ND} = \sqrt{\frac{\phi_N^2 + \phi_D^2}{2}} \approx \frac{1}{3} \times \phi_N + \frac{2}{3} \times \phi_D
\]
Neutron-Density crossplot

**Advantage:**
- Given two possible lithology pair solutions, the porosity remains relatively invariant between the solutions.
- The combination of neutron and density is the most common of all porosity tool pairs.

**Disadvantage:**
- In rough holes or in heavy drilling muds, the density data might be invalid.
Sonic-Density crossplot

- **Advantage:**
  - Potential reservoirs plot along the closely spaced lithology lines, while shales tend to fall toward the lower right of the plot.
  - Quite useful for determining some evaporite minerals.

- **Disadvantage:**
  - The choice of the lithology pair has a significant effect on the estimation of the porosity.
  - The lithology lines are closely spaced, so any uncertainty in the measurements produces large changes in lithology and porosity estimates.
Sonic-Neutron crossplot

- **Advantage:**
  - Given two possible lithology pair solutions, the porosity remains relatively invariant between the solutions
  - The sonic is less sensitive to rough holes than the density

- **Disadvantage:**
  - The combination of sonic and neutron data is not common
Density-Photoelectric crossplot

- **Advantage:**
  - Both measurements are made with the same logging tool; both will be available in newer wells

- **Disadvantage:**
  - The choice of the lithology pair has a significant effect on the estimation of the porosity
  - In rough holes or in heavy drilling mud the data may be invalid
  - The Pe will not be present in wells logged before 1978
M-N Lithology plots

- Three-measurement lithology technique
- Combination of the three porosity measurements
- Single mineralogy
- Binary mixtures
- Ternary mixtures

\[ M = \frac{\Delta t_n - \Delta t}{\rho_b - \rho_n} \times 0.01 \text{ or } 0.003 \]

\[ N = \frac{\phi_{nf} - \phi_N}{\rho_b - \rho_n} \]

Terms:
- \( M \): English
- \( N \): Metric
- \( \Delta t \): from log
- \( \Delta t_n \): formation fluid
- \( \rho_b \): from log
- \( \rho_n \): formation fluid
- \( \phi_N \): from log
- \( \phi_{nf} \): fluid, usually 1.0
Lithology and Porosity

• Result:
  – Approximate idea of Lithology
  – Value for the Total Porosity

• But…
  – We want a value for the Effective Porosity

\[ \phi_e = \phi_t \times (1 - V_{sh}) \]
Volume of shale

- The volume of shale in a sand is used in the evaluation of shaly sand reservoirs.

- It can be calculated by
  - Spontaneous Potential
  - Gamma Ray
$V_{sh} \text{ by SP}$

\[
V_{sh} = 1.0 - \frac{PSP}{SSP}
\]

or

\[
V_{sh} = \frac{PSP - SSP}{SP_{shale} - SSP}
\]

- With
  - PSP, Pseudostatic Spontaneous Potential (max. SP of shaly formation)
  - SSP, Static Spontaneous Potential of a nearby thick clean sand
  - $SP_{shale}$, value of SP in shale, usually assumed to be zero
PSP definition

- pseudostatic spontaneous potential
  1. n. [Formation Evaluation]
  The ideal spontaneous potential (SP) that would be observed opposite a shaly, permeable bed if the SP currents were prevented from flowing. In the middle of a thick, permeable bed whose resistivity is not too high, the SP reads close to the pseudostatic spontaneous potential (PSP). In other conditions, however, the SP may be significantly less than the PSP. The PSP ignores other potential sources and assumes that a surrounding shale is a perfect cationic membrane. The ratio of the PSP to the static spontaneous potential is known as the SP reduction factor, alpha. Alpha is less than 1 and is a function of the shaliness, or cation-exchange capacity, within the sand. The higher this cation-exchange capacity, the larger the internal membrane potential. The latter has the opposite polarity to the liquid-junction potential and reduces the SP.

The PSP, and alpha, are reduced when hydrocarbons are introduced into shaly sands, because the cation-exchange capacity in the sands is forced into a smaller conductive pore volume and therefore has a larger relative effect.

Conclusion: PSP is difficult to determine
\[ V_{\text{sh}} \text{ by GR} \]

**Gamma Ray Index**

\[ I_{GR} = \frac{GR_{\text{log}} - GR_{\text{min}}}{GR_{\text{max}} - GR_{\text{min}}} \]

- \( I_{GR} \) = Gamma Ray index
- \( GR_{\text{log}} \) = GR reading from the log
- \( GR_{\text{min}} \) = minimum GR
- \( GR_{\text{max}} \) = maximum GR

\[ V_{\text{shale}} = I_{GR}, \quad \text{Linear response, 1st order estimate} \]

\[ V_{\text{shale}} = 0.08(2^{3.7\cdot I_{GR}} - 1), \quad \text{Larionov (1969), Tertiary rocks} \]

\[ V_{\text{shale}} = \frac{I_{GR}}{3 - 2 \cdot I_{GR}}, \quad \text{Steiber (1970)} \]

\[ V_{\text{shale}} = 1.7 - \left[3.38 - (I_{GR} - 0.7)^2\right]^{\frac{1}{2}}, \quad \text{Clavier (1971)} \]

\[ V_{\text{shale}} = 0.33 \times (2^{2\cdot I_{GR}} - 1), \quad \text{Larionov (1969), for older rocks} \]