Understanding STOIIP

This is the STOIIP Equation: **S**tock **T**ank **O**il **I**nitially **I**n **P**lace. We could also consider GIIP for gas or HCIIP to represent generic hydrocarbon. This is an important equation because it tells us what our focus should be. We need to get the best possible measurements or estimates of each of the parameters in this equation to make reliable volumetric estimates of STOIIP.

$$\text{STOIIP} = (\text{BRV} * \text{N:G} * \text{Ø} * S_o * \text{RF} * 1/\text{FVF}\ ) * \text{RF}$$

But how do we remember this equation? The best way is to visualise it as an image, which also helps us understand the relationships between the parameters, the nomenclature that we must consistently use and the methods we could employ to determine these parameters and the workflow.

Workflow: Note the order that we determine the parameters below:

- **BRV:** First we establish the bulk rock volume from seismic mapping. The lowest closing contour should define the spill point
- **N:G:** Once we have the BRV, we need to determine the lithological make-up of the BRV from cores and lithological logs if we have wells, or analogues and depositional models if we do not. The logs we would use are typically gamma-ray, and neutron-density.
- **Ø – Porosity**: Once we have a handle on the lithologies we need to define the porosity. Given that lithology and porosity are closely linked, this tends to be an integrated / iterative process. The main porosity logs would the neutron, density and sonic logs. If we have no wells available for the prospect, we must defer to analogues and predictive models.
- **S_0 – Oil Saturation:** Once the pore volume is established, we can turn our attention to the fluid saturations which are ideally determined from cores and logs. If no wells have been drilled, we again turn to analogues and models.

Direct Well Measurements: Ideally the parameters we need should be measured directly from cores or logs. But this is not possible in undrilled prospects. Where no wells have been drilled we must refer to analogues and models.

Analogues and Models: A model should ideally be based on data from nearby wells, from the same petroleum system, in the same basin setting. If this is not possible we have to calibrate our models from data in other systems, which may not be so reliable and bring greater uncertainty.

Core analysis
Resistivity logs
Saturation Models

Core analysis
Porosity logs
Porosity Models

Core analysis
Lithology logs
Depositional Models

STOCK TANK

Atmospheric pressure of 14.696 psi, temperature of 60°F (16°C)

FVF - Formation Volume Factor: B_o and B_g

The hydrocarbon volume change from the reservoir to the stock tank.
Depends on:

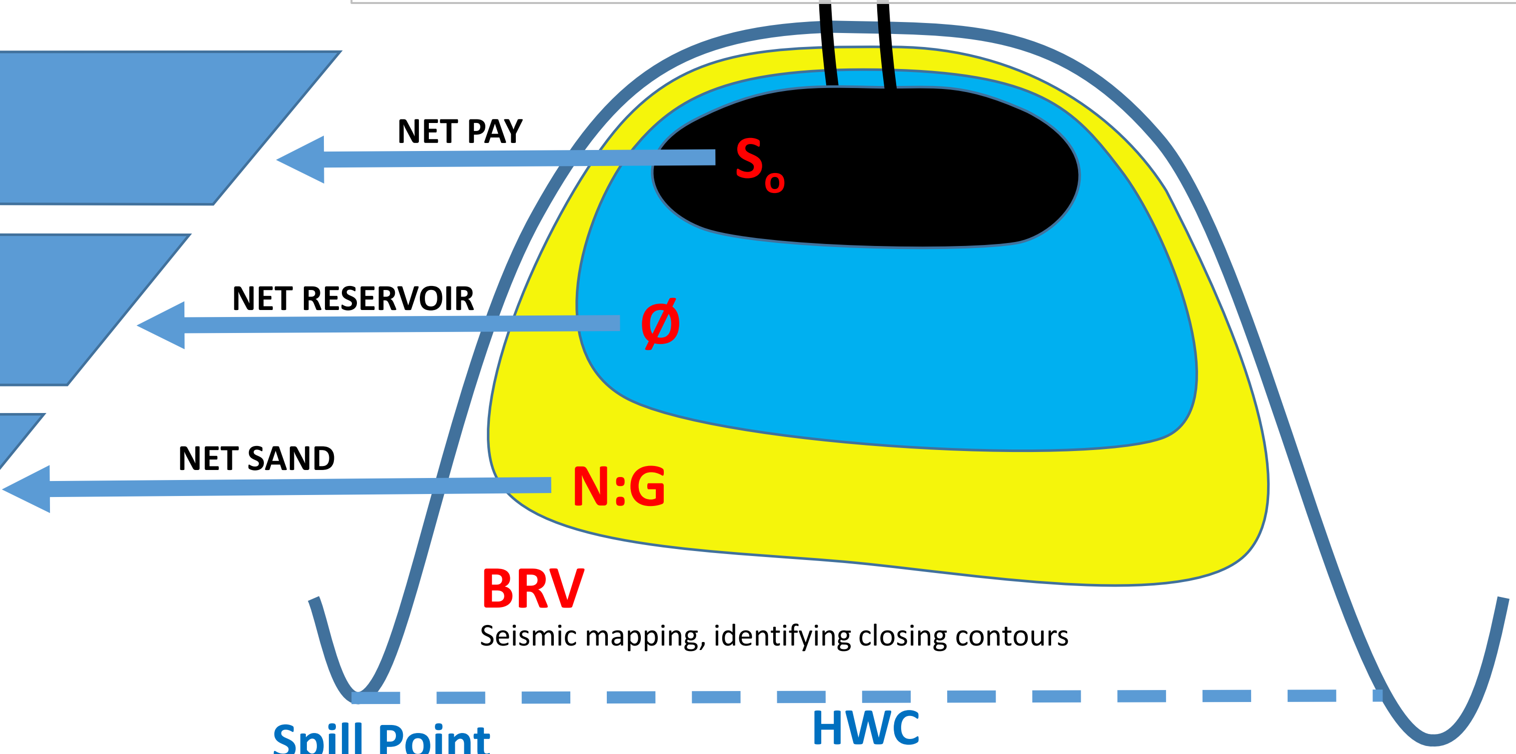
- Fluid composition (API gravity, Gas-Oil-Ratio -GOR)
- Changes in Pressure and Temperature between reservoir and stock tank

B_0 for oil, B_g for gas. Typical Bo: high GOR oil 1.4, low GOR oil 1.2, bitumen 1.05

RF - Recovery Factor

The volume of hydrocarbon that we can actually get out of the reservoir. Typically around 30-35% for oil and around 70% for gas.
Depends on:

- Rock flow properties (Ø, Kh)
- Hydrocarbon type (gas, light oil, heavy oil)
- Fluid-rock interaction (wettability, capillary pressure)
- Sandbody connectivity
- Drive Mechanism



BRV

Seismic mapping, identifying closing contours

Spill Point

Identified by mapping the lowest closing contour of the trapping structure using seismic

HWC

Hydrocarbon / Water Contact.
Could also be Oil Water Contact (OWC) or Gas Water Contact (GWC).

Conversion Factors

from	to	X by
ft	m	0.3048
m	ft	3.281
in	mm	25.4
mile	km	1.609
acre	ha	0.4047
ha	acre	2.471
Sq mi	ha	259
Sq mi	km^2	2.59
Sq mi	acre	640
bbl	m3	0.1590
m3	bbl	6.2898
scf	m^3	0.02832
m3	scf	35.31
Boe (1)	Btu	ca. 5.80 x 10^6
scf	Btu	ca. 1050
scf	boe	ca. 1.79 x10^{-4}
boe	scf	ca. 5600 (2)
lb	kg	0.4536
Pa	Nm2	1
bar	kPa	100
psi	kPa	6.895
atm	kPa	101.3
Torr	kPa	0.1333

1. Barrel of Oil Equivalent (boe) is a measure of energy, not volume. However, it is used as pseudo-volume comparator when comparing oils of different gravities, or oil and gas. There are no standard conversion factors.
2. Some sources suggest 6000.

Author: Greg Samways; Date: 05/12/2016; Version: 1.0