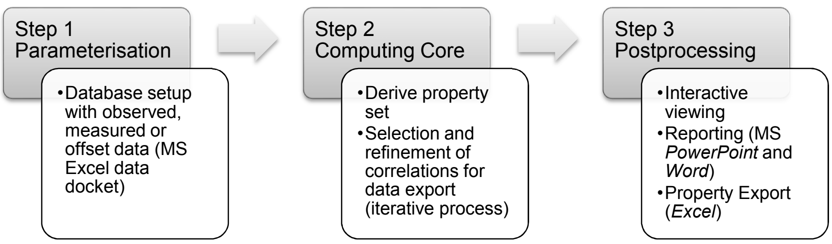
Reservoir – Fluid System©

Data Room Services and Solutions by Kostro&Friedel Pte. Ltd. (K&F)

K&F offers a range of data room and asset evaluation centric services and solutions as part of a techno-commercial advisory for the oil and gas industry. The proprietary Reservoir – Fluid System© allows to assess rock and fluid properties including benchmarking from minimum available data and time requirements.

Determining reasonably accurate fluid and reservoir properties is crucial for a wide range of technical, due-diligence related asset evaluation tasks. It influences the quality as well as the time requirements for volumetric and productivity related assessments. In a typical data room environment, fast turnaround time can provide a major competitive advantage towards a successful bid. Moreover, improving the level of understanding of an asset and certainty of the underlying assumptions will ultimately raise the level of confidence in the outcome of the valuation process.

The Reservoir – Fluid System© comprises an extensive library of state of the art correlations and empirical methods. The correlations cover a wide range of fluid, rock and multi-phase flow properties including applicability screening of EOR methods and benchmarking of the fluid system. The oil phase correlations implemented cover a wide geographical range. The library is regularly updated and can be customised to any client specific requirement.



Reservoir – Fluid System©: A simple 3 step process, **Figure A**

The Reservoir – Fluid System© uses a simple three step process to generate a range of deliverables, as shown in the figure above. The first stage parametrises a simple data docket, requiring only a minimum of measured, observed or assumed parameters that can be typically found in data rooms. Available offset data can be taken into account for additional calibration and quality control. The data is then processed and evaluated in a second stage. In-bedded in a modern software environment, it features sophisticated post-processing capabilities including automated report generation in the third stage.
The post-processor currently consists of more than 50 diagnostic plots.

The efficiency gains are significant compared to traditional methods such as compositional modelling or spreadsheet based correlation systems, enabling a wide range of potential cost-efficient applications. Determining fluid and rock properties, including quality assurance on available data or interpretation, is crucial for asset evaluation and due-diligence workflows. However, the Reservoir – Fluid System© can also be applied for reservoir studies, in particular where insufficient data is available to conduct detailed compositional PVT analysis. Furthermore, it can be recommended for concept screening or development studies of prospects and discoveries, where fast delivery and some degree of uncertainty management take priority.

Functionality

The software identifies the main characteristics of the reservoir – fluid system, invoking a system of correlations and empirical methods for the analysis. It covers a wide range of physical properties and aims to directly translate properties to reservoir characteristics. The following overview lists the main properties together with the number of available fluid correlations (noted in brackets). The properties are typically derived as function of pressure covering the entire pressure range as well for standard conditions.

Reservoir System features reservoir temperature, pressure as well as gradients. The hydrocarbon types are classified by gravity, Heptanes plus (C7+) Fraction, conventional screening tables as well as benchmarking charts. The step is conducted both for liquid as well as gaseous hydrocarbons. Expected reservoir fluid viscosity ratios are derived alongside the total formation volume factor for potential material balance assessment.

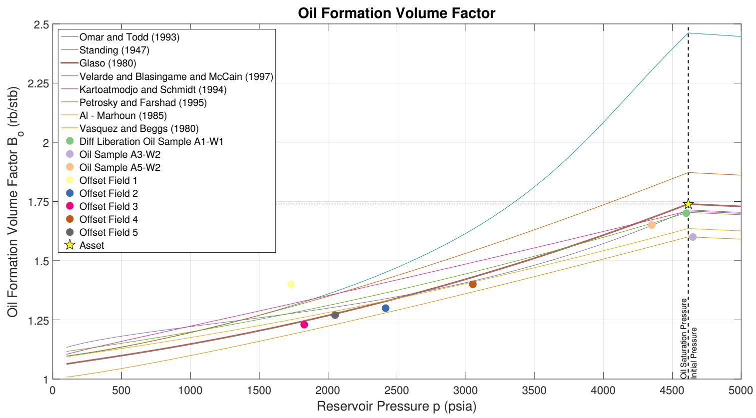
Oil Properties analyses relevant fluid chemistry and composition related parameters, e.g., molecular weight (5), boiling point (6), the Watson Characterisation Factor (3) as well as Heptanes plus (C7+) related assessments. It furthermore supports the conversion of field production data into PVT data, e.g., in estimating the initial solution gas — oil ratio from separator production data. Furthermore it captures all relevant oil phase properties, i.e., oil saturation bubblepoint pressure (12), solution gas – oil ratio (12), saturated and undersaturated compressibility (15), density, formation volume factor (10), and deadoil, saturated and undersaturated viscosity (18). It has specialised correlations for heavy and extra-heavy oil.

Gas Properties assessment includes a wide range of correlations for pseudo-critical property calculation (6). It includes the calculation of calorific value, real gas compressibility factor (6), gas compressibility (6), gas density (6), the gas pressure gradient (6), formation volume and expansion factor (6), viscosity (5), amount of vaporised oil in the gas phase (3) and dewpoint pressure (2), real gas potential, water vapour content in gas (3) and the gas hydrate formation pressure (6).

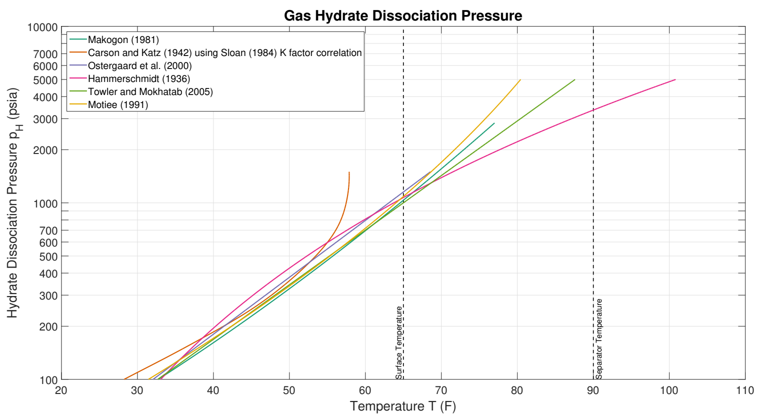
Hydrocarbon Classification

	Asset	Extra Heavy Oils and Tars	Heavy Oils	Black Oils	Volatile Oils	Gas Condensates	Wet Gases	Dry Gases
Initial producing GLR (scf/stb)	1200	0 - 50	50 - 200	200 - 1,900	1,500 - 3,200	3,200 - 15,000	>15,000	>100,000
Stock tank API gravity	44	5 - 10	10 - 22	15 - 45	42 - 55	45 - 60	Up to 70	Up to 70
Stock tank oil color		Black	Black	Brown to light green	Greenish to orange	Orange to clear	Clear	Clear
Phase change in reservoir		Bubblepoint	Bubblepoint	Bubblepoint	Bubblepoint	Dewpoint	None	None
Initial molecular weight	169	210+	170 +	70 - 210	40 - 70	23 - 40	<23	<23
C7+ fraction (mol%)	38	>50	>50	18 - 50	12.9 - 26.5	4 - 12.9	.5 - 4.0	<0.5
Typical reservoir temperature (F)	225	60 - 100	100 - 200	150 - 300	150 - 300	150 - 300	150 - 300	150 - 300
Typical saturation pressure (psia)	4616	0 - 100	0 - 500	300 - 5,000	3,000 - 7,000	1,500 - 9,000	-	-
Initial FVF (rb/stb)	1.74	1.0	1.0 - 1.1	1.1 - 1.5	1.5 - 3.0	3.0 - 20.0	20+	20+

Liquid hydrocarbon classification summary, *Screening Example*, **Figure B**



Oil formation volume factor, *Screening Example*, **Figure C**



Gas hydrate formation pressure, *Screening Example*, **Figure D**

Water Properties assessment includes an estimation of water pressure gradient as function of salinity, maximum solubility of salt, compressibility (6), density (4), formation volume factor (4), viscosity (5) and gas solubility in water (2).

Rock Properties are assessed regarding rock compressibility (10), non-Darcy flow coefficient and stress-dependent permeability parameters. In addition, it includes multiphase flow functions (5) for oil – water and oil – gas flow.

EOR Screening comprises a quick screening of the reservoir – fluid system with respect to applicable methods of improved or enhanced oil recovery (IOR/EOR). This includes an estimation of minimum miscibility pressure (MMP) for the oil phase under prevailing reservoir conditions for Nitrogen N_2 (4) and CO_2 (5).

Most appropriate correlations are selected based on available measured and offset data, geographic region and the expected behaviour. The resulting oil, gas, water and rock properties as function of pressure under reservoir and standard conditions can directly be used for volumetric assessment, evaluation of observed production behaviour or predictive assessment such as material balance.

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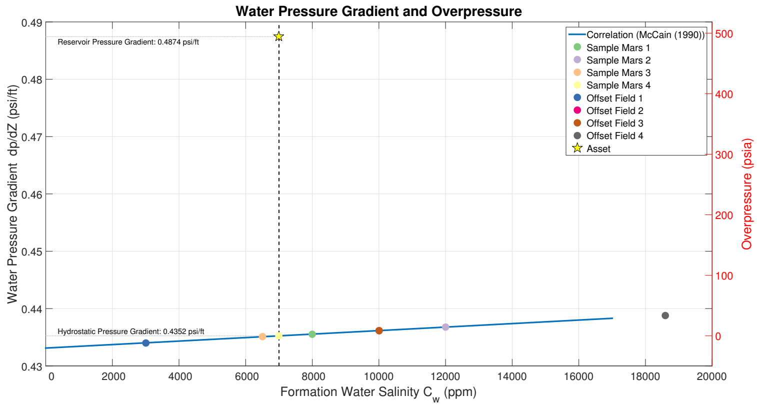
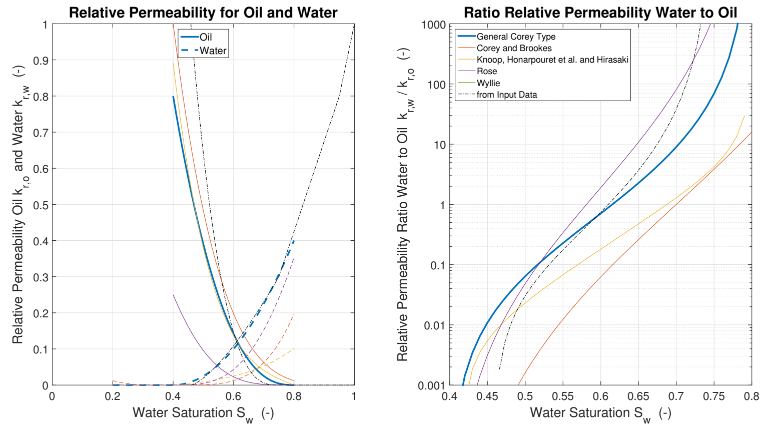
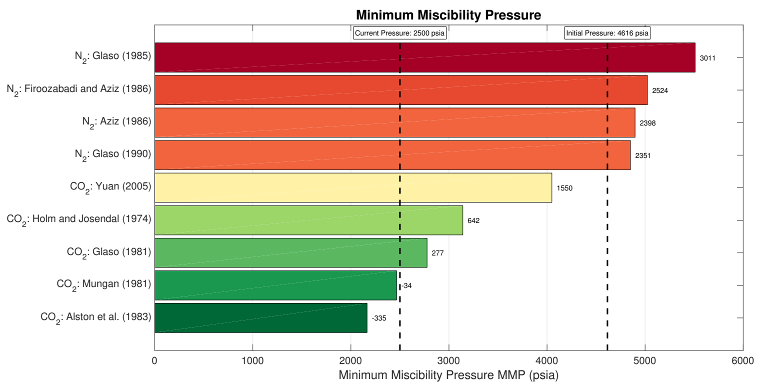


Water pressure gradient, *Screening Example*, **Figure E**



Water – oil relative permeabilities, *Screening Example*, **Figure F**



Minimum miscibility pressure, *Screening Example*, **Figure G**

Key IOR / EOR Screening Criteria

	Asset	Nitrogen and Flue Gas	Hydrocarbon	Carbon Dioxide	Immiscible Gases	Miscible/Polymer, ASP and Alkaline	Polymer Flooding	Combustion	Steam
Stock tank API gravity	44	>35 Average 48	>23 Average 41	>22 Average 36	>12	>20 Average 35	15 - 40	>10 Average 16	8 - 13.5 Average 13.5
Live oil viscosity (cP)	0.20	<0.4 Average 0.2	<3 Average 0.5	<10 Average 0.2	<600	<35 Average 13	10 - 150	<5,000 Average 1,200	<200,000 Average 4,700
Composition		High % C1-C7	High % C2-C7	High % C5-C12	Not critical	Light, intermediate	Not critical	Some asphaltenic components	Not critical
Oil saturation (PV fraction)	0.60	>0.40 Average 0.75	>0.30 Average 0.80	>0.20 Average 0.55	>0.35 Average 0.70	>0.35 Average 0.53	>0.70 Average 0.80	>0.50 Average 0.72	>0.40 Average 0.66
Formation type		Sandstone or Carbonate	Sandstone or Carbonate	Sandstone or Carbonate	Not critical	Sandstone preferred	Sandstone preferred	High porosity sandstone	High porosity sandstone
Net thickness (ft)		Thin unless dipping	Thin unless dipping	Wide range	Not critical if dipping	Not critical	Not critical	>10 ft	>20 ft
Average permeability (mD)	100	Not critical	Not critical	Not critical	Not critical	>10 Average 450	>10 Average 800	>50 mD	>200 mD
Depth (ft)	9470	>6,000	>4,000	>2,500	>1,800	<9,000 Average 3,250	<9,000	<11,500 Average 3,000	<4,500
Temperature (F)	225	Not critical	Not critical	Not critical	Not critical	<200	<200	>100	Not critical

EOR general criteria, *Screening Example*, **Figure H**