The Ara Stringer Play in the South Oman Salt Basin contains sour oil and gas fields reservoired in carbonate slabs encased within salt. Hydrocarbons occur in a depth range of 2.5 km to 5.5 km with reservoir pressures ranging from hydrostatic (10-11 kPa/m) to near-lithostatic (22 kPa/m) gradients. Similarly, in-situ hydrocarbon fluid densities vary widely, from 3 kPa/m to 8 kPa/m. Such variability in reservoir pressure and fluid density present a challenge for the design of safe and cost-effective drilling and completion strategies. Of particular concern is the combination of dry gas and high overpressure, which could lead to wellhead pressures of up to 100 MPa (14,500 psi) at 5km. To address this uncertainty we have completed an integration of reservoir pressure data, seismic data, fluid PVT data and geochemical data to allow the construction of a model for the risking of likely pressure regime and hydrocarbon fluid types pre-drill.

Previous work has shown that stringers which have pore pressures close to a hydrostatic gradient today, should have been highly overpressured prior to a “deflation” event in the geologic past. Our observations on the hydrocarbon fluid characteristics support a scenario in which gas-condensate accumulations have originated from a palaeo oil phase within overpressured reservoirs. These oil accumulations were subsequently depressurised to allow separation and segregation of a gas phase.

In the event that a “deflated” stringer is re-pressurised due to further burial, the saturation pressure of the mixture will be exceeded once again and the two-phase accumulation will revert back to a single phase oil column. Therefore highly overpressured gas reservoirs are only expected when the oil and gas phases are physically isolated prior to re-burial. Structural separation of the oil and gas legs of a palaeo-accumulation in the Ara Stringer Play has been observed.

The consequence of a phase separation / segregation model of gas occurrence is that the density of the segregated gas-condensate fluid is dependent upon the reservoir pressure (depth) at the time of deflation to hydrostatic conditions. There is, therefore, a strong depth dependency to the predicted fluid character, with in-situ density increasing with depth. This knowledge can be used to optimise engineering decisions, rather than relying on the “worst-case scenario” of lowest density fluid properties and highest reservoir pressures observed within the play.
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