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Monitoring Reservoir Alteration by Thermochemical Sulfate Reduction (TSR): H₂S Formation and Sequestration Mechanisms Revealed - A Case Study from the Western Canadian Sedimentary Basin (WCSB)

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The distribution of non-hydrocarbon gases (H₂S, CO₂) in hydrocarbon reservoirs is controlled mainly by thermochemical sulphate reduction (TSR) and organic matter cracking of organic sulfur compounds (OSC) in high temperature reservoirs versus bacterial sulfate reduction (BSR) in low-temperature reservoirs. In the TSR reaction aqueous sulphate, most probably in the form of MgSO₄ contact ion pairs or HSO₄⁻, is the main electron acceptor which oxidizes hydrocarbons to yield H₂S, CO₂ and H₂O (Ma et al., 2008).

Of particular importance in risking H₂S formation are: 1) the use of diagnostic tools to identify the H₂S source, 2) the lateral and vertical subsurface distribution, and 3) the degree of H₂S forming process at various subsurface conditions. Our aim in this study is to better quantify how much H₂S has been formed, what the key drivers are and what the potential impact on fluid and reservoir properties may be. In order to do this, a robust understanding of the effects H₂S formation has on reservoir properties at the pore and field scale are vital to assessing the regional geological integration at the field and/or basin scale. The integration of these data into the geological evolution of a given setting, along with learnings from adjacent sour gas fields, are essential elements for determining the proportions of in-situ versus migrated H₂S. The distribution of non-hydrocarbon gases (i.e. H₂S, CO₂) in sour gas assets, as well as subsequent by-products of TSR reactions (e.g. solid bitumen formation, mineral precipitation, HC compositional alterations), are critical factors in the future enhancement of production.

In this paper we present the main elements of a diagnostic workflow that we have developed to identify and quantify the subsurface distribution of H₂S, its origin and its impact on reservoir quality in time and space. Rock-Fluid/Gas interactions represent the core of processes that we attempt to quantify using an integrated approach combining expertise from various disciplines in geochemistry, basin modeling and carbonate petrography.

Mississippian tight carbonate/dry gas reservoirs in the Western Canadian Foothills region have undergone an extreme burial-uplift history with reservoir temperatures exceeding 200°C. They represent excellent study areas and test cases as many of them contain H₂S in various amounts ranging from 5 to >90 Mol%. H₂S contents can vary significantly on both the reservoir scale and basin scale. Such variation in H₂S can create large uncertainties in the placement of new wells if TSR processes are not identified and simulated properly. We have selected one reservoir to apply

a broad range of geochemical, petrographical and spectroscopic technologies to identify and quantify the effects of H₂S forming processes on the subsurface distribution of H₂S, distinguish between migrated and in-situ formed H₂S, its impact on reservoir rock properties and its formation in time and space. Special emphasis in this study has been placed on stable isotope analysis of matrix minerals, solid bitumen characterization in terms of sulphur speciation, its extent which negatively impacts on the porosity distribution in the reservoir, and detailed gas compositional analysis from fluid inclusions. This integrated workflow is used to sweetspot sour gas reservoirs in TSR-prone areas.

References

Ma et al. (2008): Theoretical study on the reactivity of sulfate species with hydrocarbons. - *Geochimica et Cosmochimica Acta* 72, 4565-4576.