Impact of Liquid Volume Fraction on Accurate Measurement of Hydrogen Sulfide in Natural Gas Systems

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Abstract:

Accurate measurement of hydrogen sulfide (H_2S) in natural gas is critical for safety, compliance, and operational performance. Now that liquid detection systems such as LineVu are detecting the presence of liquid carryover in natural gas streams at considerably higher levels than expected, this paper examines the partitioning behavior of H_2S between gas and liquid phases in the presence of condensate using Henry's Law. A quantitative model is developed to show how increasing liquid volume fraction (LVF) leads to significant underreporting of gas-phase H_2S, potentially misleading gas quality assessments. The model is for illustrative purposes and is validated through real-world operating conditions and supported by thermodynamic data.

1. Introduction

Hydrogen sulfide (H_2S) is a toxic, corrosive, and regulated component of natural gas. Monitoring its concentration with precision is vital for meeting pipeline specifications and environmental standards. H_2S-specific analyzers are commonly used for this purpose. However, these instruments are gas phase measurements and assume that the gas is dry. When liquids are present in the pipeline, H_2S can partition into the liquid phase, leading to erroneous gas-phase measurements.

This paper explores the effect of condensate on H_2S partitioning, quantifies the error introduced in H_2S readings, and offers guidance on how to mitigate this problem. It is acknowledged that ideal gas law may not apply to natural gas calculations. For the purposes of this paper the differences caused by the compressibility factor of natural gas are minimal and so have been ignored as the example calculations are for illustrative purposes only.

2. Theoretical Background

Henry's Law describes the equilibrium between gas and liquid phases for a dissolvable gas:

$$C = k_H P$$

Where:

C = Concentration of gas in the liquid phase (mol/L)

k_H = Henry's Law constant (mol/L·atm)

P = Partial pressure of the gas (atm)

H_2S is highly soluble in water and moderately soluble in hydrocarbon liquids. The Henry's Law constant for H_2S in water at 25°C (77°F) is approximately 0.087 mol/(L·atm)[1]. In hydrocarbon condensates, the value is typically estimated between 1.0 to 3.0 mol/(L·atm), depending on composition and temperature[2]

3. Methodology

To model the impact of LVF on gas-phase H_2S readings, we consider a standard case:

Total H_2S: 5 ppm (mole fraction)

Pressure: 1000 psi (68.95 atm)

Temperature: 25°C (298 K)

LVF: 0% to 1% (0 to 0.01 L of liquid per liter of gas)

Using ideal gas behavior, the total moles of gas and H_2S per liter are calculated. Partitioning is then modeled using Henry's Law, assuming equilibrium between gas and liquid.

4. Results and Discussion

The calculations show that even a 0.1% LVF results in approximately 1.6% underreporting of H_2S concentration. At 0.5% LVF, this error increases to more than 7%. This is significant, especially near threshold limits for pipeline specification (e.g., 2 ppm for transmission).

An Excel tool has been developed (see Appendix) to allow operators to input local conditions and quantify the potential measurement error based on LVF.

Key Observations: - Higher pressure increases the partial pressure of H_2S, increasing partitioning into liquid - Higher LVF results in a larger sink for soluble gas species - Under-reporting is systematic and repeatable, making it predictable but dangerous

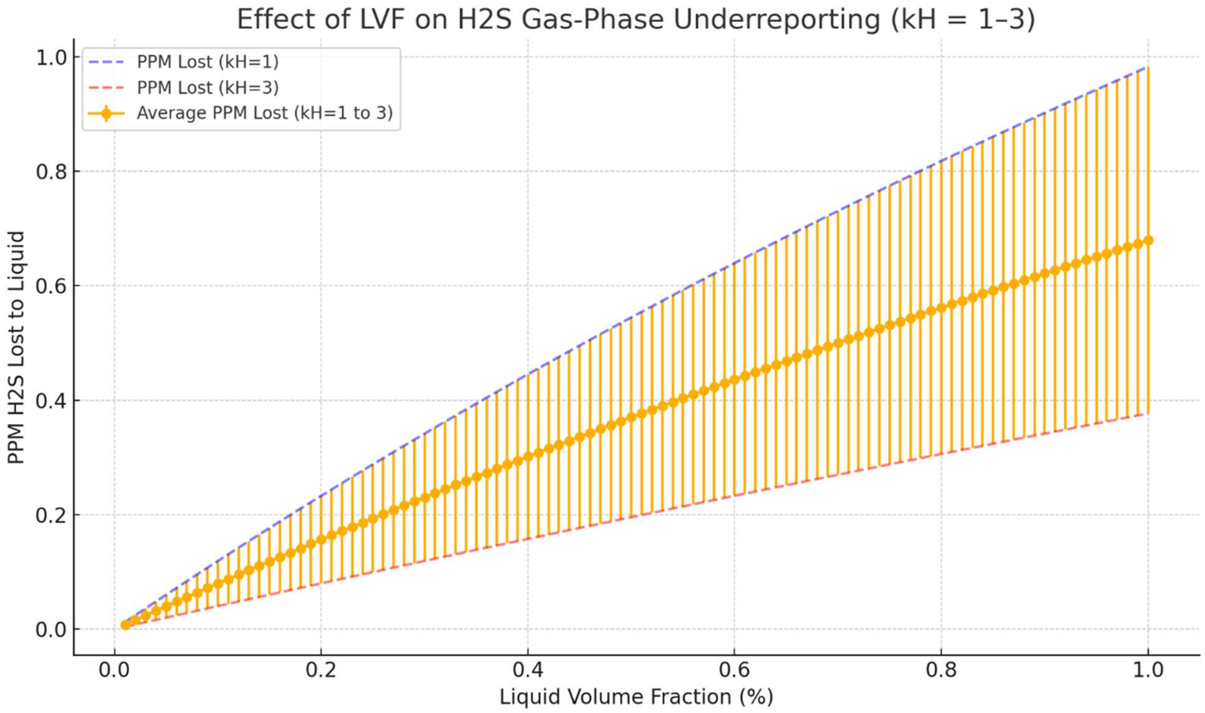

Figure 1. Example under reading of 5 PPM H_2S in the presence of low levels of condensate in gas pipelines

5. Practical Implications - Compliance Risk

Gas reported as compliant may exceed H_2S thresholds after phase separation.

Corrosion Risk: Underestimating H_2S can lead to under-injection of scavengers and corrosion inhibitors

Measurement Inaccuracy: This effect undermines the reliability of all H_2S measurement systems as it is a physical effect locking H_2S up in liquids that may be either in a mist flow or stratified flow. In all gas analysis systems at custody transfer points, these liquids are either:

a) Avoided, in the case of stratified flow, by sampling according to API 14.1[5] using a sample probe to sample from the middle of the pipeline or;

b) Removed by a coalescing or membrane filter before the gas phase sample arrives at the gas analyzer.

c) The uncertainty budget for H_2S analysis should include the baseline accuracy of the measurement systems, errors introduced by temperature and pressure changes in the sample system and, unless a pipeline liquid detection system is installed, the possibility of unknown liquids being present in the gas stream should be included in the uncertainty statement (accuracy) for the analysis. This is because pipeline liquid detection systems such as LineVu have demonstrated that calculated and measured hydrocarbon dewpoint systems do not guarantee that liquid hydrocarbons are not present in the pipeline.

Mitigation Strategies: Liquid Carryover is considered a fault condition. It affects the accuracy of flow measurement, gas analysis systems and increases the risk of corrosion, compressor trips and compressor failures. Introducing a liquid Carryover detection system (e.g., optical or visual monitoring) upstream of analyzers, alerts operators to this fault condition.

6. Conclusion

The presence of even small volumes of liquid in a natural gas stream introduces a measurable and significant bias in gas-phase H_2S concentration readings. This is governed by well-understood thermodynamics, notably Henry's Law. Operators and measurement engineers must consider LVF as a critical factor in gas quality assurance.

7. References

1: Sander, R. (2015). "Compilation of Henry's Law Constants".
2: Atmospheric Chemistry and Physics. - Gmehling, J., Rasmussen, P., et al. (1994). "Vapor-Liquid Equilibrium by UNIFAC Group Contribution".
3: Industrial & Engineering Chemistry Research. - NIST Chemistry WebBook. (*https://webbook.nist.gov?utm_source=chatgpt.com*)
4: GPA Midstream Standard 2261: Gas Analysis and Reporting Guidelines (2023 Edition)
5: API 14.1

8. Appendix

A downloadable Excel tool accompanies this paper, allowing users to simulate partitioning effects for custom input parameters (H_2S ppm, pressure, temperature, LVF, and kH).

[Tool: H2S_Partitioning_InputTool.xlsx]