

## Caerus Flow Line Failure Puckett H2 41B-2

Two samples from the Puckett H2 41B-2 well were received November 1<sup>st</sup>, 2017, an eighteen-inch section of flow line and the stem and seat from the well. A six-inch section of the damaged flowline with the through-wall hole was cut out and split., **Photo #1**. **Photo # 2** shows the stem and seat.



Photo # 1. Cut and split section of flowline with failure, exterior view



Photo # 2. Stem and seat from the well

Both the flowline and stem and seat were damaged from corrosion. **Photo # 3** shows the interior view of the flowline sample. There was heavy corrosion on both halves and a through-wall hole on the upper half. The upper half in the photo was more heavily corroded than the lower half. The upper half in the photo with the through-wall hole was oriented on the bottom of the line. Photo #s 4 and 5 are close-up views of the top section in the photo.



Photo # 3. Cut and split flowline with through-wall hole (upper half)



Photo # 4. Close-up of top section, heavily pitted with through-wall hole



Photo # 5. Through-wall hole noted with red arrow





Photo # 6. Lower section of flowline cut-out with light pitting

The corrosion, especially that shown in **Photo #s 4 and 5** is most likely due to CO<sub>2</sub> acid gas. The orientation of the through-wall hole was at the 6 o'clock position. Pooling of water in this hemisphere likely contributed to the heavier corrosion. This hemisphere had a hard iron carbonate corrosion product deposit consistent with CO<sub>2</sub> corrosion.

**Photo #s 7 and 8** are views of the stem and seat respectively. The corrosion damage on the stem and seat is most likely from CO<sub>2</sub> corrosion.



Photo # 7. Corrosion damage on the stem



Photo # 8. Corrosion damage on the seat



Puckett H2 41B-2 first produced in 2015. It is a plunger well that produced on average 800 mcf/d gas, 1 bbl oil / d, and 17 bbls water / d. The gas from this well is quite high in CO<sub>2</sub>, about 4 %. At a wellhead pressure of 234 psi, the CO<sub>2</sub> partial pressure would be 9.4 psi. This is considered to be in the "corrosion possible" range for pipelines.

The well is being treated with the combination corrosion scale inhibitor WCW7016 @ 4 q.p.d. and should be switched to CRW9218, a straight corrosion inhibitor. It is not known when the corrosion damage was done. The switch to CRW9218 should be sufficient to prevent and or greatly slow additional corrosion damage from CO<sub>2</sub>.

### **Recommendations**

- Maintain consistent treatment with CRW9218 corrosion inhibitor, starting at a concentration of at least 200 ppm based upon water production or a minimum of 2 quarts per day.
- Install a wellhead and or flowline coupon to monitor corrosion rates.

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