YESO BEST PRACTICES

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ABSTRACT

COG Resources has drilled and completed over 1,500 commingled Yeso wells in Southeast New Mexico since early 2006. Over the past six years, COG Resources and Catalyst Oilfield Services have coordinated with one another and developed strategies to address producing conditions and known fluid incompatibility. These strategies have the potential to benefit other operators producing in multiple horizons where fluid compatibility is an issue.

INTRODUCTION

COG Resources is an exploration and development company located in the Permian Basin, headquartered in Midland, TX. In an effort the maximize profits, maintain equipment, and minimize well interventions, COG Resources has partnered with industry professionals such as Catalyst Oilfield Services. Trial and error, coupled with years of experience have generated best practices for scale control in incompatible fluids. This paper will discuss Yeso produced water problems and tendencies, the evolution of scale and corrosion control, and overcoming hurdles for optimal chemistry.

Most of COG Resources' New Mexico Shelf operations are comprised in the northwestern portion of the Delaware Basin. Figure 1 illustrates the location of the New Mexico Shelf area. During 2011 this region represented COG's most significant concentration of assets. The acreage covers parts of Eddy and Lea counties. COG's activities in the New Mexico Shelf are primarily focused in the vertical Yeso play, where COG has been developing the asset since 2006. The Yeso play consists primarily of four distinct formations: Paddock, Blinebry, Tubb, and Drinkard. Figure 2 illustrates a Stratigraphic Map of the New Mexico Shelf. COG generally produces from the Paddock or Blinebry intervals or downhole commingling the two intervals, with the the Paddock having one producing interval and the Blinebry having up to three producing intervals. The producing intervals range from approximately 4,000' to 7,500'. 30-day initial production rates are approximately 90-140 BOEPD and 500-700 BWPD. In 2013, COG Resources celebrated the drilling of its 1,500th Yeso well.

COG Resources is faced with the typical operational problems which many exploration and development companies may face. The challenge of producing from a reservoir which is a solution gas drive and pressure depleted. The Yeso is typical of many reservoirs in the Permian Basin: a low pressure, low permeable reservoir with a high concentration of wells. A particularly interesting challenge is dealing with cross-flow from independent producing intervals. Waters from different producing intervals are not always compatible. Adding complexity to a difficult situation; one zone can often take or thief fluid from the other. A solution COG has adopted is setting the intake as close to plug back total depth as possible. The benefit is a lower intake pressure allowing higher inflow from both formations and minimizing differential pressure due to cross-flow. Experience has shown keeping a commingled well at or near pumped off conditions can help prevent cross-flow issues. Cross-flow between incompatible fluids such as waters from the Blinebry and Paddock are managed better in production tubulars rather than out in the formation. It is considerably more difficult to prevent scale precipitation out in the formation. As an aside, the Yeso doesn't typically face gas interference issues unless pumping above the perforations.

In a conventional non-commingled well the fluid level decreases over time and eventually becomes static. Fluid level characteristics in non-commingled wells are more predictable than in commingled wells. In a commingled well, one zone may not produce due the high bottom-hole pressure of another interval. As the other zone in the well produces over time, as pressure begins to decrease, there can be an influx of fluid from both zones causing inconsistent inflow conditions. This creates conditions difficult to monitor and adjust. The use of SCADA monitoring and POC's (pump-off controllers) are both industry recognized innovations. However, early in COG's infancy these ground breaking technologies where not being employed as frequently as they are now.

Sand, both from the formation and fracture stimulation efforts present production and mechanical hurdles. Pump changes within the first 90 days of well completion became very common. Limiting interventions would obviously be ideal and help to drive down a company's failure rate. There are a number of practices COG adopted to prolong the run life of the down hole pump. Installing looser fitted Pressure Actuated Plungers or PAPs allows solid particles a place to escape. The PAP expands on the up-stroke and wipes the barrel clean from debris while moving fluid up through the tubing. On the down-stroke the PAP collapses allowing sand and other solids a place to escape, thus preventing rod buckling. COG also uses different bottom-hole tools designed to divert sand away from the pump such as sand screens or Cavin's Desander. The goal being to keep sand out of the barrel, away from the plunger, extending the time a pump is producing down hole.

Materials utilized also contributed to short pump run times. Initially, COG was using pumps constructed with chrome steel barrels and steel plungers. Working in conjunction with our pump companies, many different material combinations where experimented with in order to determine a best fit candidate for the Yeso formation. COG determined a brass nicarb barrel and a stainless steel plunger is the best material combination to optimize beam pumping operations in the Yeso.

In a field consisting of vertical wells and horizontal wells, it may be intuitive to say the horizontal wells face more down-hole challenges than the vertical. The introduction of inclination into a well bore presents addition rod on tubing wear. To address this issue, COG began to maintain a higher fluid level, compared to a vertical well, providing less potential for fluid pound and maintaining the integrity of the pump. Essentially, COG is not pumping off the deviated wells to prevent a server fluid pound scenario and to minimize damages.

The Yeso is not immune to common failures which have become routine in the oil field. Failures such as rod parts, holes in tubing, polish rod breaks and "no pump action" are ordinary. Initially, COG's strategy for dealing with failures was not very detailed. COG would implement repairs for repeat failure wells with minimal planning. As optimization became more of a focus, so did the care and attention given to each well failure. COG adopted an extensive pre-pull process to ensure repairs are not done haphazardly. Operations engineers seek input from pumpers, fluid techs, foremen, superintendents, and artificial lift specialists, making an effort to consider all aspects contributing to the failure. If a well fails twice within a one year period, COG defines it as a multi-failure well. COG has monthly Optimization Meetings in which the chemical companies, pump companies, and COG operations personnel meet to discuss possible solutions that could prolong run life. These meetings utilize vendor partners to troubleshoot, identify, and minimize repeat pulls to everyone's mutual benefit.
A significant issue COG Resources faced was short runs on ESP's due to high motor temperatures and or scale. In an effort to maximize run life and minimize ESP interventions, COG met with vendor partner such as Catalyst Chemical to seek out possible solutions. Initially, COG sought to remedy the situation experimenting with different run times and add SCADA technology. Eventually, chemical treatments where added to reduce scale build up. A reduction in scale allows down-hole equipment to work without added hindrance which helps to reduce temperature. COG tried many chemical iterations, determining that a capillary string ultimately worked best. Delivering the chemical down-hole, applying chemical directly to the desired areas, avoiding dispersion, provided the best outcome.

For years, the Yeso play involved completions in generally only one of the intervals (could be Paddock or Blinebry). Starting in 2007, COG Resources started evaluating multiple interval completions by adding either Paddock or Blinebry to an existing wellbore and completing all intervals together on initial drilling and completing of new wells. Within months, gypsum scale was observed on many of the commingled wells. Due to the increased production from the commingled wellbores, COG wanted to produce both zones initially in existing wellbores, but eventually as dual completions.

Since scale was not typically observed in single zone completions in the Yeso, it was suspected the commingled zone completions created an incompatible fluid condition. Historical water analysis from the field allowed COG and Catalyst to characterize typical Blinebry and Paddock waters. After initial review, it became apparent that there was the potential for gypsum scale due to generally high calcium/low sulfate in the Blinebry formation and high sulfate/low calcium in the Paddock formation.

WATER CHEMISTRY

Water analyses have been performed on most of the wells listed in the Figure 3 & 4 either before the re-completion, after the re-completion or both. In general, the Blinebry formation has high calcium (ave – 19,110; range 8,731 – 41,647) ion and low sulfate (ave – 896; range 164 – 2,550) ion concentrations while the Paddock formation has low calcium (ave – 4,208; range 1,286 – 9,326) ion and high sulfate (ave – 3,072; range 800 – 4,500) ion concentrations.

Figures 3 & 4 illustrate examples of Blinebry and Paddock waters respectively. The Blinebry formation generally has higher scaling tendencies especially from gypsum scale. In the right combination, Blinebry and Paddock waters can have severe incompatibility. Figure 5 illustrates the mixing table for the JC #4 (7/13/06 – Paddock only) and the Harvard #7 (1/11/07 – Blinebry only): Under a worst case scenario of 80% Paddock and 20% Blinebry (indicated by the ARROW in Figure 5), the water analysis predicted a potential for 1,207# of gypsum per 1,000 barrels of water. Since gypsum is acid insoluble and costly to remove with chemical converter, a plan was needed to proactively identify and treat all commingled wells. Preventing scale from forming in the wellbore due to the commingling of the Paddock and Blinebry formations became a high priority.

After reviewing the water analysis for commingled wells, there were several trends that became apparent. Not all wells showed super saturation (potential) for gypsum even though the wells had commingled fluids. This could be explained by variable inflow from each formation at the time when the fluids were captured, or scale had already precipitated in the wellbore, and or the general variability of the formation waters for each zone/well. Of the wells that showed gypsum potential (supersaturated

fluids), scale was observed in the well during routine well pulls. Scale was still observed in 20% of the wells that did not show a positive gypsum scale potential.

When gypsum was observed on the well pulls due to the incompatible fluids, the damage was generally significant. Gypsum scale formed in the pump and inside the tubing. Failure costs ranged from $30,000 to $100,000 depending upon the extent of the scale precipitation. Scale was rarely observed on the outside of the tubing or in the wellbore. It was presumed that it took a little time for the mixing of the incompatible fluids to precipitate scale.

After extensive laboratory testing, a phosphonate scale inhibitor was developed to be used on the wells in a continuous injection application. The treatment was initially only started on wells that demonstrated scale precipitation during well intervention operations. Additionally, solid scale inhibitor was added to the fracture stimulation fluids for optimal protection during the frac job. As much as 3,000# of solid scale inhibitor was added to each frac job.

By mid to late 2007, additional wells started exhibiting gypsum scale deposition. COG and Catalyst started continuous injection of the previously selected scale inhibitor on all of the wells that did not have solid scale inhibitor in their initial frac jobs, and that had commingled zones (Blinebry and Paddock).

By early 2008, wells that were commingled and had solid scale inhibitor in the frac jobs (but no continuous injection of scale inhibitor) started exhibiting gypsum scale. This was despite “acceptable” scale residual levels of solid scale inhibitor. It was later determined that the incompatible fluids generally required much higher levels of scale inhibitor than what could be provided with solid scale inhibitor applications. Wells with the solid scale inhibitor treatments were added to the continuous injection program.

By mid-2008, it became apparent that the continuous injection applications of scale inhibitor had a very high success ratio for controlling scale. There were incidences where scale formed in the early life of the well, but it became apparent that the treatment rates were too low (due to initial high production rates of the wells) or when wells started producing before scale inhibitor was started. Once policies were put into place that required initial scale inhibitor installations to be started before a well is put on initial production and the injection rate was started at “worst case” initial production rates, the scale failures on new wells became rare.

By 2009, all solid scale inhibitor was removed from the frac designs. To control scale during the initial flowing conditions, liquid scale inhibitor was added to the frac jobs. However the initial continuous injection application was still the primary control mechanism for scale control.

From 2009 to 2011, the treatment rates were optimized with scale related failures accounting for less than 1% of the overall failures in the Yeso area. The next step was to develop a combination product that combined the corrosion control with the scale control program to optimize costs and reduce truck treatments.

Extensive lab testing was required to utilize the scale inhibitor that already had proven itself to be successful in controlling the gypsum scale in a combination scale/corrosion inhibitor. The primary concerns were to provide a product that maintained its calcium tolerance while providing the same scale protection and corrosion protection. The primary issue for corrosion control was based upon acid gases from CO2 and H2S. The H2S levels varied considerably with some wells that had H2S levels of 2-5% H2S (20,000 – 50,000 ppm). After the lab testing was performed, a combination product was developed that was field tested.

Initial field testing confirmed the scale and corrosion control. As the field was switched from the continuous scale control and batch corrosion truck treatments to continuous injection of the combination product, it became apparent that the new product provided additional benefits from solids control (sand, FeS, etc). Pumping conditions (sticking pumps, high friction) could be correlated to problems with the continuous chemical injection.

CONCLUSION

Today COG's scale related failures are extremely rare and the overall failure trend is low. This is attributed to continuous injection of combination scale/corrosion inhibitor and best practices for installing, monitoring and maintaining the continuous injection equipment. Figure 6 illustrates COG's failure rate from 2006 when the asset was beginning to be developed, through the peak in 2010 when the chemical plan was being implemented, to its current 2014 levels.

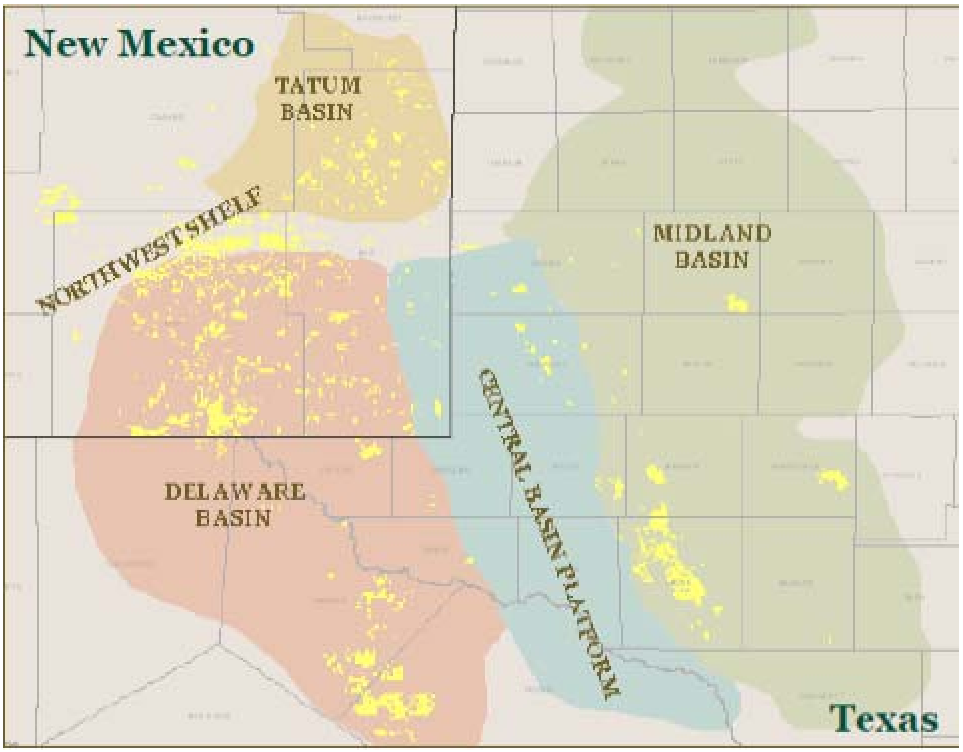

Figure 1 - Basin Map

Platform - Shelf					
System	**Period**	**Series**	**Formation**	**Dominant Lithologhy**	**Average Thickness**
Permian	Guadalaupe	White Horse	Tansill	Limestone	125'
			Yates	Sandstone	250'
			7 Rivers	Dolo/Anhydrite	650'
			Queen	SS/Dolo	150'
			Grayburg	SS/Dolo	325'
		Ward	San Andres	Dolo/LS	1560'
			Glorieta	Sandstone	140'
	Leonard	Yeso	Paddock	Dolo/LS	240'
			Blinebry	Clearfork SS	670'
			Tubb	Dolo/SS	140'
			Drinkard	Dolomite	330'
		Abo		Shale/SS	550'

Figure 2 - New Mexico Shelf: Stratigraphic Map

Lease	Location	Date	Formation	TDS	SO4	Ca	Calcite SI	Calcite Amt	Gypsum SI	Gypsum Amt
CONTINENTAL A STATE	11	10/18/06	Blinebry	185158	900	10532	0.68	9.67	-0.13	0
CONTINENTAL A STATE	12	11/16/06	Blinebry	178033	1800	10130	0.45	10.91	0.15	281.71
CONTINENTAL A STATE	3	9/7/06	Blinebry	202889	660	17929	0.98	10.09	-0.1	0
ELECTRA FED.	7	10/13/06	Blinebry	215013	650	21065	0.96	7.98	-0.05	0
ELECTRA FED.	9	1/11/07	Blinebry	123518	1680	8731	0.62	7.46	0.1	193.53
HARPER STATE	5	9/7/06	Blinebry	216449	360	22673	0.99	7.97	-0.28	0
HARVARD	5	7/27/06	Blinebry	231512	290	28864	0.83	3.65	-0.3	0
HARVARD	5	9/7/06	Blinebry	233416	300	29828	0.68	1.68	-0.28	0
HARVARD	6	1/11/07	Blinebry	229970	340	27650	0.17	0.56	-0.25	0
HARVARD	7	1/11/07	Blinebry	244706	320	29845	0.38	2.22	-0.24	0
HOUMA	2	1/11/07	Blinebry	198009	750	19127	0.49	7.24	-0.02	0
MCINTYRE A	19	1/11/07	Blinebry	140054	1000	8474	0.63	7.34	-0.15	0
MESQUITE STATE	18	10/18/06	Blinebry	221090	700	17366	0.71	8.5	-0.08	0
MESQUITE STATE	19	9/7/06	Blinebry	174990	1000	14070	0.99	14.79	0.01	6.8
MESQUITE STATE	19	10/18/06	Blinebry	195227	850	16804	0.98	15.09	-0.01	0
STATE S-19	23	11/16/06	Blinebry	198147	800	19457	0.5	7.24	0.01	9.26
STATE S-19	26	11/16/06	Blinebry	170969	2550	9085	0.89	15.14	0.26	617.07
STATE S-19	28	11/16/06	Blinebry	196382	1900	9809	0.3	4.64	0.16	310.27
TEXACO BE	7	5/4/06	Blinebry	264942	164	41647	0.58	0.54	-0.42	0

Figure 3 - Blinebry Water

Lease	Location	Date	Formation	TDS	SO4	Ca	Calcite SI	Calcite Amt	Gypsum SI	Gypsum Amt
BC FEDERAL	10	10/12/06	Paddock	191742	2300	4824	0.66	9.03	-0.02	0
JC FEDERAL	4	7/13/06	Paddock	58006	4500	1286	0.89	134.71	-0.05	0
JC FEDERAL	4	10/18/06	Paddock	193513	800	9326	0.68	7.56	-0.23	0
JENKINS B FED.	7	7/14/06	Paddock	175253	3915	2010	0.15	1.48	-0.14	0

Figure 4 - Paddock Water

		Calcite $CaCO_3$		Gypsum $CaSO_4 \cdot 2H_2O$	
Paddock - JC 4	Blinebry - Harvard 7	Index	Amount	Index	Amount
0%	100%	0.38	2	-0.24	
1%	99%	0.45	3	-0.20	
2%	98%	0.50	4	-0.15	
3%	97%	0.55	5	-0.12	
5%	95%	0.64	8	-0.05	
10%	90%	0.80	15	0.07	56
15%	85%	0.91	24	0.16	149
20%	80%	1.00	33	0.22	243
25%	75%	1.07	43	0.27	337
30%	70%	1.13	54	0.32	432
40%	60%	1.22	76	0.38	620
50%	50%	1.28	99	0.41	806
60%	40%	1.32	122	0.43	980
70%	30%	1.34	145	0.43	1,129
75%	25%	1.34	156	0.42	1,182
80%	20%	1.33	166	0.40	1,207
85%	15%	1.30	173	0.36	1,180
90%	10%	1.24	177	0.30	1,048
95%	5%	1.14	170	0.20	685
97%	3%	1.06	162	0.13	424
98%	2%	1.02	156	0.08	260
99%	1%	0.96	147	0.02	71
100%	0%	0.89	135	-0.05	

Figure 5 - Mixing table for the JC #4 and Harvard #7

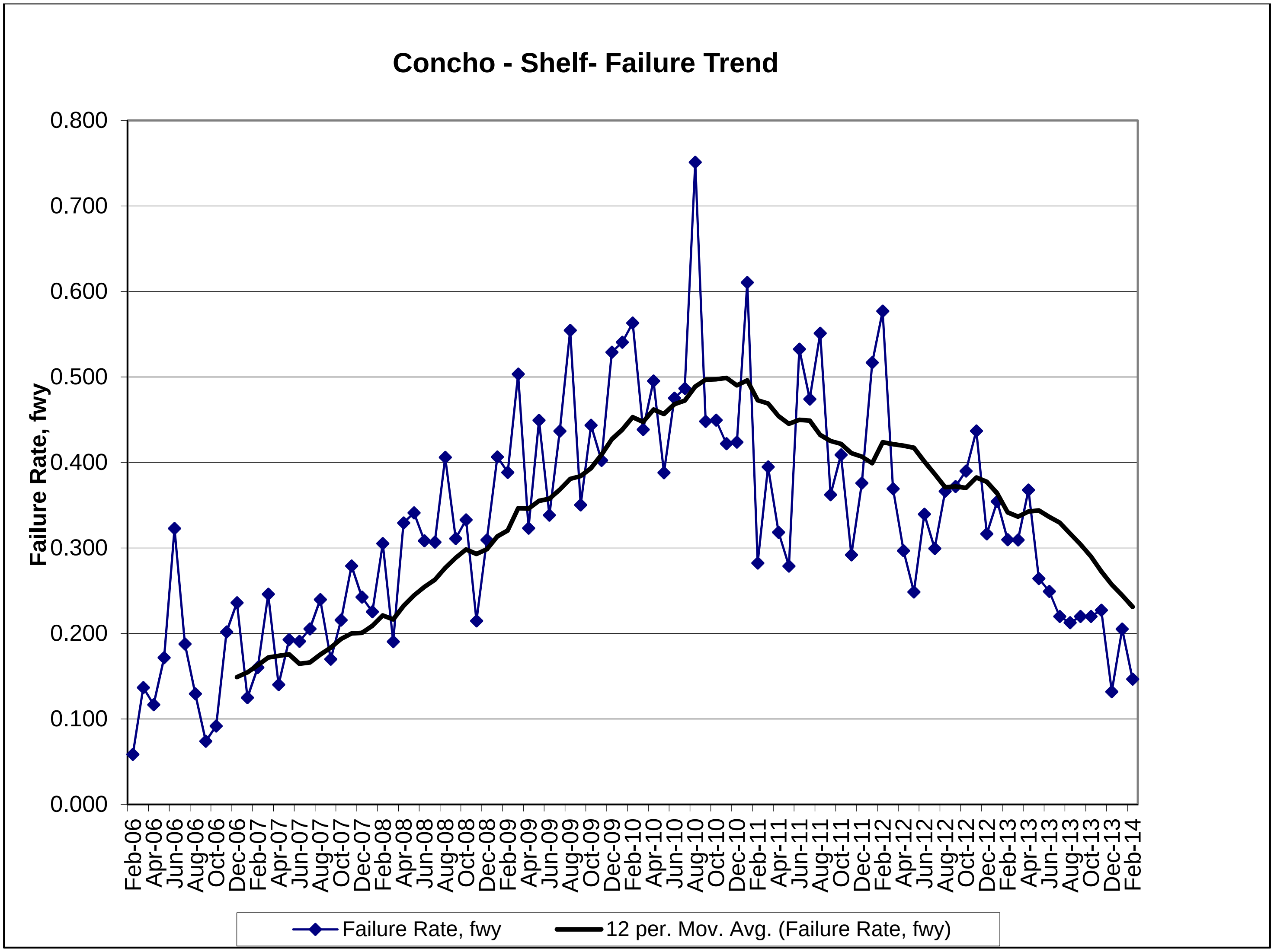

Figure 6 - COG failure rate 2006-2014