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Optimized Commingle Method for Successful Cost Effective Sand Consolidation Treatment

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Abstract. Limited production due to maintaining safe drawdown is an inevitable consequence of single target sand consolidation treatment. One of the methods to improve production is by adding a reservoir target to be produced commingle. Sand consolidation quality need to be maintained, meanwhile jobs efficiency still highly demanded.

There are 3 types of commingle treatment strategy. First method was bottom up strategy, it was performed by treating single zone while isolating others. It was performed either by temporary plug isolation or straddle packer. Second method was nitrified treatment; it was performed by mixing sand consolidation treatment with nitrogen in order to boost injection velocity. Third method was currently developed by optimizing single run – single isolation to perform commingle treatment. In this method, the fluid distribution will be calculated by the reservoir actual injectivity parameter for each targeted reservoir.

The first method was performed on well X with total duration of 20 days with Instantaneous gain of 5.3 MMscfd and well is producing for 11 months until it died. Job cost and operation duration for Well X was approximately double compared to single treatment. The second method was performed on well Y, Gas rate of 1.46 MMscfd is achieved during clean up. Well was producing for total of 30 days after that well was choked up to achieved a higher gas rate but sand burst occurred and well died. The third method was performed on Well A and Well B. The treatment design showed that the bigger the reservoir's physical parameter, the more the volume needed for the reservoir. The injectivity test was performed for both wells, actual reservoir's physical parameter values were known. Thus, it changed the treatment volume and fluid penetration by the previous design. Post-treatment production rate could achieve 4.2 MMscfd for well A and 2.344 MMscfd for well B. Both wells produced without sand. In addition to successful treatment, commingle method can also save operation costs by 40% compared to single treatment.

This paper showed that Correct measurement of fluid distribution determines the successful sand consolidation result, proven by comparison of Well A and Well B to Well Y. Production increment and acceleration are also achieved compared to bottom-up perforation strategy. Commingle treatment method opens possibility to produce marginal reserve by reducing operational cost and shorten production period; hence, the well maintenance cost could be minimized during well's lifetime.

Keyword: Sand Consolidation, Commingle Treatment, Fluid Distribution

1 Introduction

Sand consolidation method is initially designed for targeting single short perforation interval. Initially, sand consolidation treated reservoir is produced in single mode. After reservoir has died, it will be isolated mechanically then move to next layer for another sand consolidation treatment. However, due to high demand to increase the production, sand consolidation treatment is challenged beyond its conservative limits.

One of the challenge is commingle production from sand consolidation reservoirs. However, multi-layer sand consolidation has risk for non-uniform distribution. Hence, it has higher risk for sand consolidation failure (Hower, 1961).

Several strategies available on literatures to mitigate failure and maintain sand consolidation quality. Mechanical isolation, either bottom up isolation or straddle packer, is a mitigation to control sand consolidation penetration (Gunningham, 1996). Another method to allow commingle sand consolidation treatment is by treatment nitrification (Riyanto, 2016; Villesca, 2011). This method allows further treatment injection due to its gaseous properties.

One of the method to justify the quality of commingle sand consolidation is by measurement of treatment distribution. The most recent development of this measurement is by using distributed temperature-monitoring sytem through fiber optic sensing (Villesca, 2011). However, the unit availability concern and marginal economical condition restricted the feasibility to perform the distribution measurement.

The author presents an indirect distribution measurement in order to justify the sand consolidation quality. Moreover, the optimized utilization of single isolation packer instead of straddle packer gives additional advantage in cost optimization.

2 Methodology

This section will explain the portfolio to perform commingle treatment. The most conventional method is to perform treatment individually and produce both reservoir target in commingle. Optimization is generally implemented by reduce number of run while targeting multiple reservoir.

In order to provide same individual isolation advantage, straddle packer was an available option in industry (Scott, 2001). However, it is a challenging operation to deploy straddle packer due to sea swelling condition in typical delta unit and environment. Another method proposed for optimization are nitrified or foamed treatment and optimized single isolation packer that is described in the next section.

A new method was proposed to utilize single run – single isolation to perform commingle treatment. In this method, the fluid distribution will be calculated by the reservoir actual injectivity parameter for each targeted reservoir.

2.1 Bottom up strategy

Bottom up strategy is the base method for well with more than one targeted reservoir. The method is divided into several steps, which are:

1. Perforate lower zone
2. Sand consolidation treatment upper zone by CT with isolation packer
3. Perforate upper zone
4. Set retrievable bridge plug between upper and lower zone
5. Sand consolidation treatment upper zone by CT with isolation packer
6. Retrieve plug between upper and lower zone
7. Clean up well and production test

The benefit from bottom up strategy is controlled sand consolidation penetration. Each reservoir with high or low permeability profile will receive same treatment penetration.

However, this method takes longer operation duration, equal to twice normal single sand consolidation operation. It also directly correlates with twice larger operation cost compared to single one. Moreover, single isolation treatment exposes resin contact to temporary isolation plug. There is a risk for not able to retrieve the temporary plug. Mitigation to mill out the plug must be considered prior operation.

2.2 Nitrified treatment

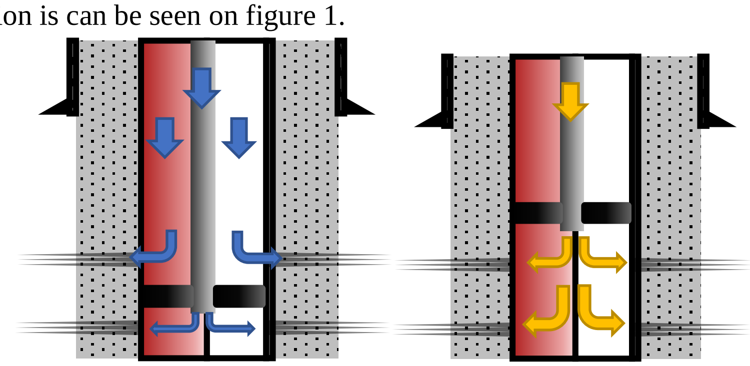
The purpose of nitrified treatment is to boost velocity, in order to satisfy minimum penetration of least permeable reservoir. This method is used whether targeting long interval (Riyanto, 2016) or multiple perforation (Villesca, 2011).

Nitrified treatment was expected to push further in least permeable reservoir compared to sand consolidation in liquid phase. Nitrified treatment also utilized less liquid volume compared to liquid phase.

However, actual penetration value of least permeable reservoir is remaining unknown due to actual permeability of each reservoir was never measured individually. Therefore, there is still high risk of sand consolidation failure due to inequality treatment distribution.

2.3 Optimized Method: Single Run – Single Isolation Packer

A method is developed in order to perform commingle treatment with only single run and single isolation packer. The illustration is can be seen on figure 1.



(a) (b)

Figure 1. (a) Single Isolation Packer Method Schematic for Injectivity Test and (b) for main treatment

In order to achieve a successful operation, actual value of permeability must be known so that the penetration and chemical volume for each targeted reservoir can be calculated. Penetration can be relied on injectivity data instead of actually measured. Actual value of permeability was measured by injectivity test as per described on the next section.

2.3.1 Injectivity Calculation

Optimum strategy for commingle sand consolidation treatment is required to achieved good production results. The first step in order to fulfil that goal is performing injectivity test. Injectivity test is a procedure to establish the correlation between pressure and rate at which fluids can be pumped into the targeted zone without fracturing the formation. The purpose of injectivity test is to obtain information about the reservoir characteristics that can be estimated from the pressure response achieved during the test. The final goal for doing injectivity test for sand consolidation treatment is to estimating maximum bottom hole pressure and measuring the fluid distribution. Darcy's law for radial flow is applied to find the correlation between pressure, flowrate, and permeability of the reservoir. The equation can be written as:

$$\frac{Q}{\Delta P} = \frac{2\pi kh}{\mu\left[\ln\frac{r_e}{r_w} - \frac{3}{4} + S\right]} \tag{1}$$

$$\Delta P = P_r - P_{wf} = Q \times \frac{\mu\left[\ln\frac{r_e}{r_w} - \frac{3}{4} + S\right]}{2\pi kh} \tag{2}$$

Injectivity test operation is performed by single run coil tubing with isolation packer set between 2 reservoir perforation. Lower reservoir is tested through coil tubing string and upper reservoir is tested through annulus tubing and coil tubing. During injectivity test, the pressure loss is occurred across the coil tubing as well as annulus tubing-coil tubing. Several parameters are calculated in order to obtain the total pressure loss. All equations are divided into 2 types based on the different flow area for doing the injectivity test.

Reynolds number is a dimensionless parameter that is useful in characterizing the degree of turbulence in the flow regime and is needed to determine the friction factor. For flow inside CT, Reynold number can be calculated by:

$$Re = \frac{\rho v D_{CT}}{\mu} \tag{3}$$

While Reynold number for flow via annulus tubing-coil tubing can be calculated by:

$$Re = \frac{\rho v (D_{tubing} - OD_{CT})}{\mu} \tag{4}$$

Pipe friction factor coefficient is a dimensionless number. The friction factor for laminar flow condition is a function of Reynolds number only.

$$f = \frac{64}{Re} \tag{5}$$

Colbrook equation for turbulent flow is used to determine the pipe friction factor. The equation is not only a function of Reynolds number but also with function of the characteristics of the pipe wall.

$$\frac{1}{\sqrt{f}} = -2\log\left(\frac{\varepsilon/D}{3.7} + \frac{2.51}{Re\sqrt{f}}\right) \tag{6}$$

With the value of friction factor, the pressure loss across coil tubing can be calculated by:

$$\Delta P = f \times \frac{L}{D_{CT}} \times \frac{\rho}{2} \times v^2 \tag{7}$$

And pressure loss across annulus tubing-coil tubing can be calculated by:

$$\Delta P = f \times \frac{L}{(D_{tubing} - OD_{CT})} \times \frac{\rho}{2} \times v^2 \tag{8}$$

After the pressure loss is estimated by calculation, bottom hole pressure for each targeted reservoir can be estimated by:

$$BHP = Pump\ pressure + Hydrostatic\ pressure - friction\ loss \tag{9}$$

2.3.2 Distribution calculation

After the estimated permeability and bottom hole pressure value obtained, the chemical distribution by penetration and volume can be calculated. Prior starting main treatment, isolation packer was unset from initial position between upper and lower zone then picked up to above upper and lower zone as per figure 1(b). The distribution of chemical that pumped into each reservoir can be seen by the workflow as described on figure 2.

By knowing actual permeability of upper and lower reservoir, total rate of injection of upper and lower reservoir could be calculated. Friction pressure were calculated as per applied pumping rate on surface. Therefore, bottomhole pressure of upper and lower reservoir were known. Those bottomhole pressure were correlated with each injection rate of upper and lower zone as per equation 2. After rate distribution were known, penetration of treatment can be calculated as geometry of an annulus between openhole and chemical penetration with its remaining space of reservoir porosity.

$$Volume = Porosity \times Perforation\ interval \times (Penetration\ area - Openhole\ area) \tag{10}$$

Minimum penetration of least permeable reservoir must satisfy minimum 30 to 50 gal per foot perforation (Hower, 1961). A certain margin was given to initial design in order to compensate non uniform penetration deviation.

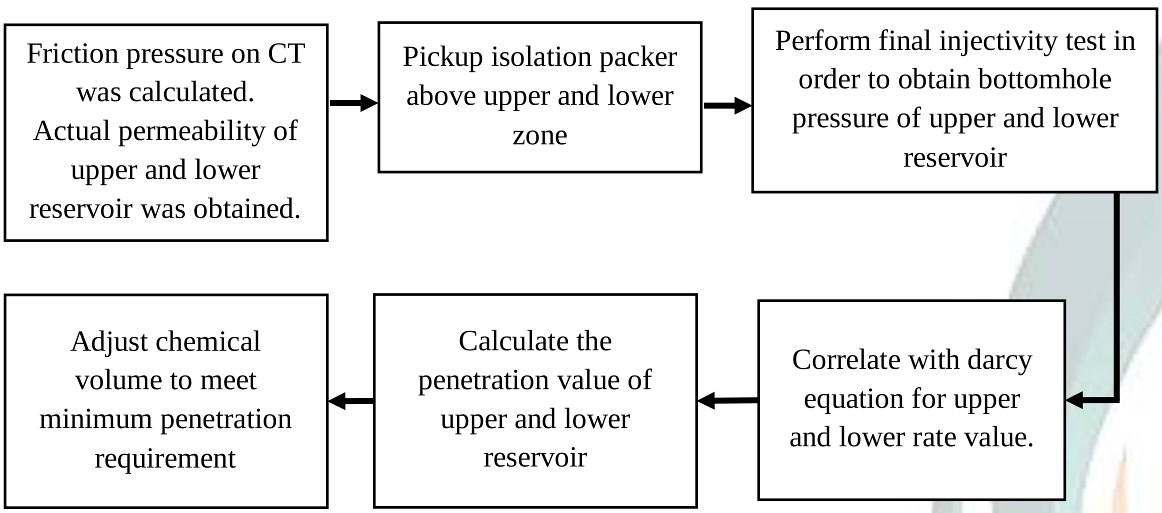


Figure 2. Distribution Calculation Flowchart

3 Result and Discussion

3.1 Bottom up strategy

As the description above for bottom up strategy steps, bottom up strategy method was performed in well X with 2 different targeted reservoirs, X1 on 2462.5 - 2464 mBRT and X2 on 2480.0 - 2481.5 mBRT. Well diagram can be seen in appendix. The treatment was performed for total of 2 times pumping for each reservoir and take total of 20 days of treatment. Instantaneous gain of 5.3 MMscfd is achieved and well is producing for 11 months until it died. No major issues with the implementation of bottom up sand consolidation strategy compared to commingle treatment. However, the job cost and operation duration was approximately double compared to single treatment.

3.2 Nitrified treatment

The purpose of nitrified treatment is to boost velocity, in order to satisfy minimum penetration of least permeable reservoir. However, actual penetration value of least permeable reservoir is remaining unknown if fluid distribution is not measured. Trial of nitrified treatment was performed on Well Y. Well diagram can be seen in appendix. Well Y has 2 targeted reservoirs. Res. Y1 on 1014.5 -1016 mBRT with estimated permeability value of 1357 mD and res. Y2 on 1025.5-1026.5 with estimated permeability value of 370 mD. The treatment distribution is not calculated for each reservoir by permeability value. The reason is due to no isolation behind the tubing between upper and lower target. Penetration length design for each reservoir is equally the same with length of 3.5 ft. Injectivity test is also performed differently by bullheading method using nitrified KCl brine. The result showed that the actual value of permeability for both reservoirs were assumed the same with value of 360 mD. Gas rate of 1.46 MMscfd is achieved during clean up. Well was producing for total of 30 days after that well was choked up to achieved a higher gas rate but sand burst occurred and well died.

3.3 Optimized Method Result

This method was successfully applied on 2 wells. It was not surprised the actual permeability and distribution was different compared to initial data. The operation detail was explained as per following:

Well A

There are 2 targeted reservoirs for well A. Well diagram can be seen in appendix. Reservoir A1 on 1993-1994.5 mBRT had estimated permeability of 263.5 mD and reservoir A2 on 2014-2016 mBRT had estimated permeability value of 227 mD. By calculation and design for commingle treatment, reservoir A1 will get 3.61 ft of penetration length and reservoir A2 will get 3.49 ft of penetration length.

Injectivity test for res. A1 was performed through annulus tubing-coil tubing meanwhile res. A2 was performed through coil tubing. the results showed that the actual permeability value for res. A1 is equal to 191 mD and res. A2 equal to 190 mD. The actual value of permeability for both reservoirs were quite similar to the estimated permeability value. The penetration length for both reservoirs were adjusted to its actual value of the permeability. By the actual reservoir permeability, penetration length for res. A1 is equal

to 3.45 ft penetration length and res. A2 is equal to 3.62 ft. The penetration evolution based on estimated permeability value and after injectivity test was performed can be seen on figure 3.

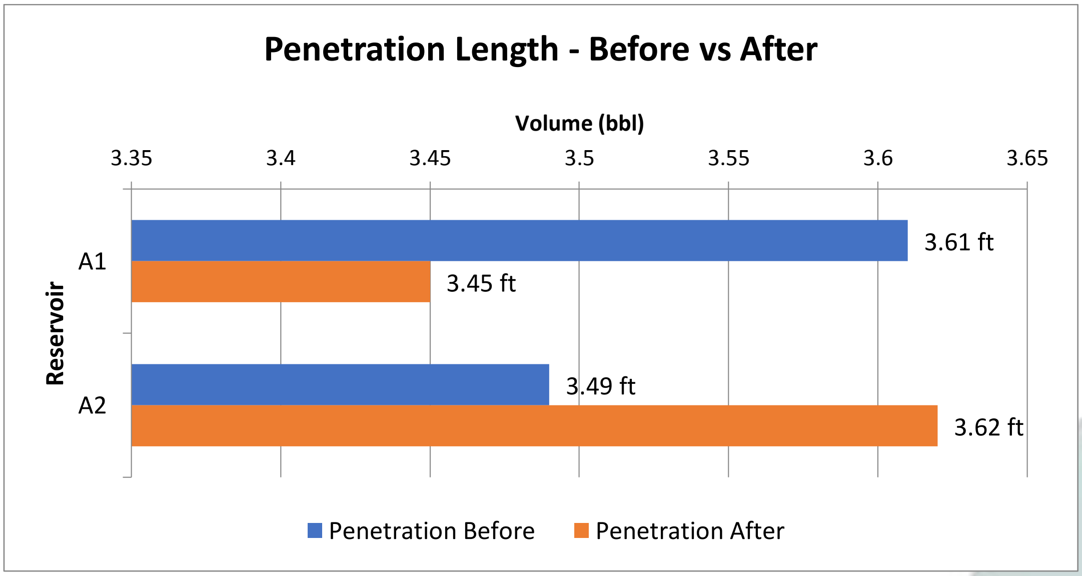


Figure 3. Well A – Penetration Length Evolution Before and After Injectivity Test

Post-treatment production rate could achieve 4.2 MMscfd for well A and produced without sand as per shown on figure 4.

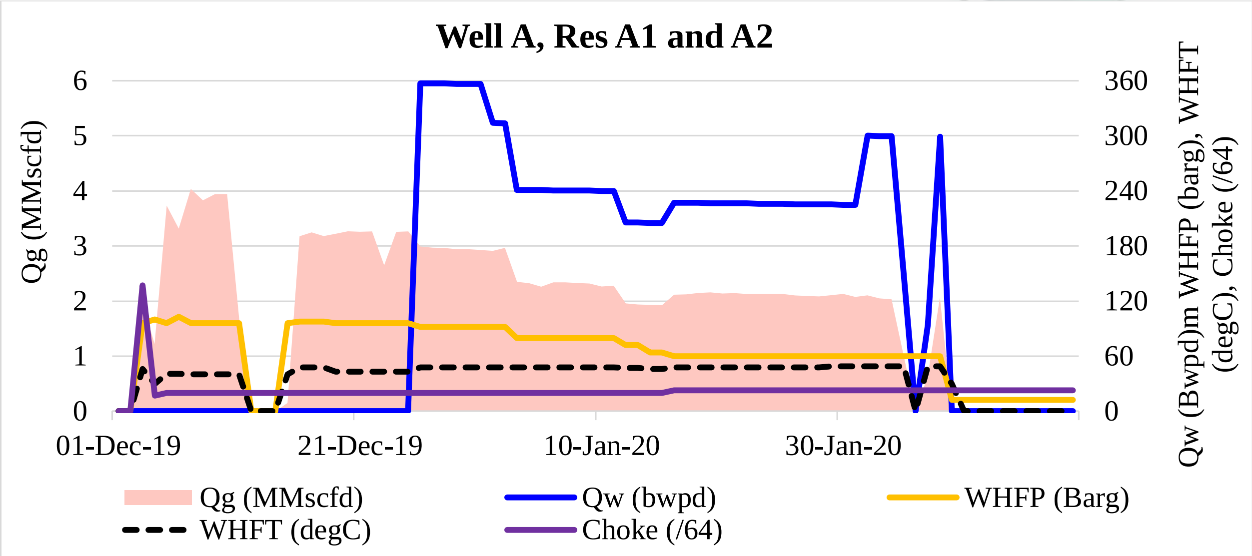


Figure 4. Well A Production Result

Well B

Well B has 2 targeted reservoirs (see well diagram for appendix), which are res. B1 on 907.7-908.7 mBRT with estimated permeability of 1817 mD and res. B2 on 938.7-939.7 mBRT with estimated permeability value of 1263 mD. By calculation and design for commingle treatment, res. B1 will get 5.37 ft of penetration length and res. B2 will get 3.0 ft of penetration length.

Injectivity test for res. B1 was performed through annulus tubing-coil tubing meanwhile res. B2 was performed through coil tubing. the results showed that the actual permeability value for res. B1 is equal to 1230 mD and res. B2 equal to 2500 mD. The actual value of permeability for both reservoirs were quite similar compared to initial permeability value. Therefore, penetration length for both reservoirs were slightly reduced to avoid excessive utilization of chemical. By the actual reservoir permeability, penetration length for res. B1 is equal to 3.0 ft penetration length and res. B2 is equal to 3.49 ft. The penetration evolution based on estimated permeability value and after injectivity test was performed can be seen on figure 5.

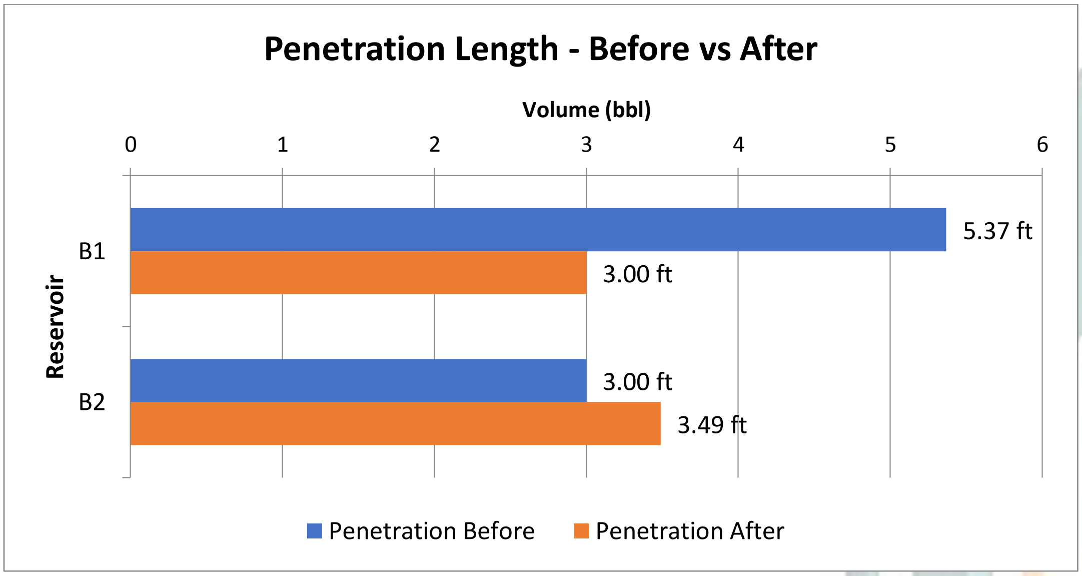


Figure 5 Well B – Penetration Length Evolution Before and After Injectivity Test with Volume adjustment.

Post-treatment production rate could achieve 2.344 MMscfd and produced without sand as per shown on figure 6.

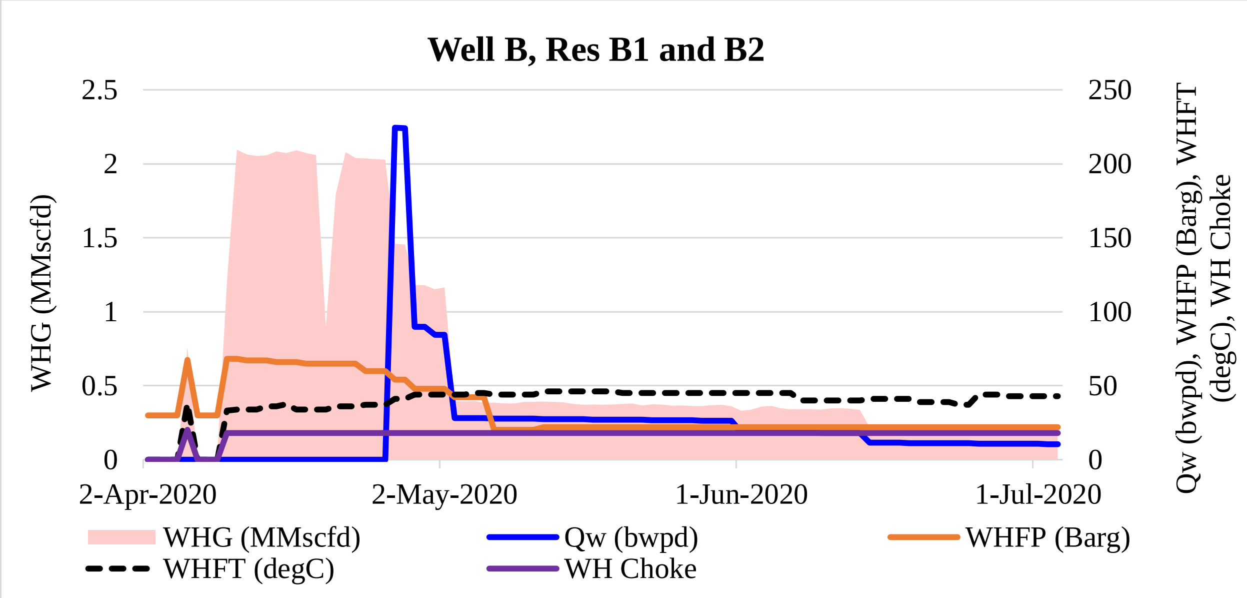


Figure 6. Well B Production Result

Cost of this optimized method is 40% less than bottom up strategy which applied on well X. Single run commingle method nearly had the same cost with single treatment. Additional cost for commingle treatment by bottom up method compared with single treatment is came from additional chemical volume that pumped into two targeted reservoirs instead of one reservoir.

4 Conclusion

Conclusions from 3 different commingle methods as described earlier are:

1. Bottom up strategy is successfully proven maintaining sand consolidation quality. However, operation cost and period also twice as much as single treatment. This method is acceptable if economically justified, but not feasible for marginal reservoirs.
2. Nitrified treatment is successfully implemented in low gas production rate. In order to challenge the envelope, actual penetration measurement need to be performed.
3. Single run isolation packer is successfully optimized for measuring upper and lower reservoir injectivity, hence penetration of treatment can be calculated through actual permeability data. Therefore, penetration can be relied on injectivity data instead of actually measured. This method has been successfully implemented in order to achieve good sand consolidation result.

Nomenclature

Q = flow rate at surface, stb/d
P_r = Reservoir pressure, psia
P_{wf}= flowing bottom hole pressure, psia
k = matrix permeability, md
r_e = external drainage radius, ft
r_w = wellbore radius, ft
S = skin factor, dimensionless
h = net formation thickness, ft
Re = Reynold Number
f = pipe friction factor coefficient
ε = pipe roughness, ft
D_{CT} = inside diameter of coil tubing, ft
OD_{CT} = outside diameter of coil tubing, ft
D_{tubing} = inside diameter of tubing, ft
L = length of pipe, ft
ρ = density, lb/ft^3
v = flow velocity, ft/s
Δp = pressure drop, psia

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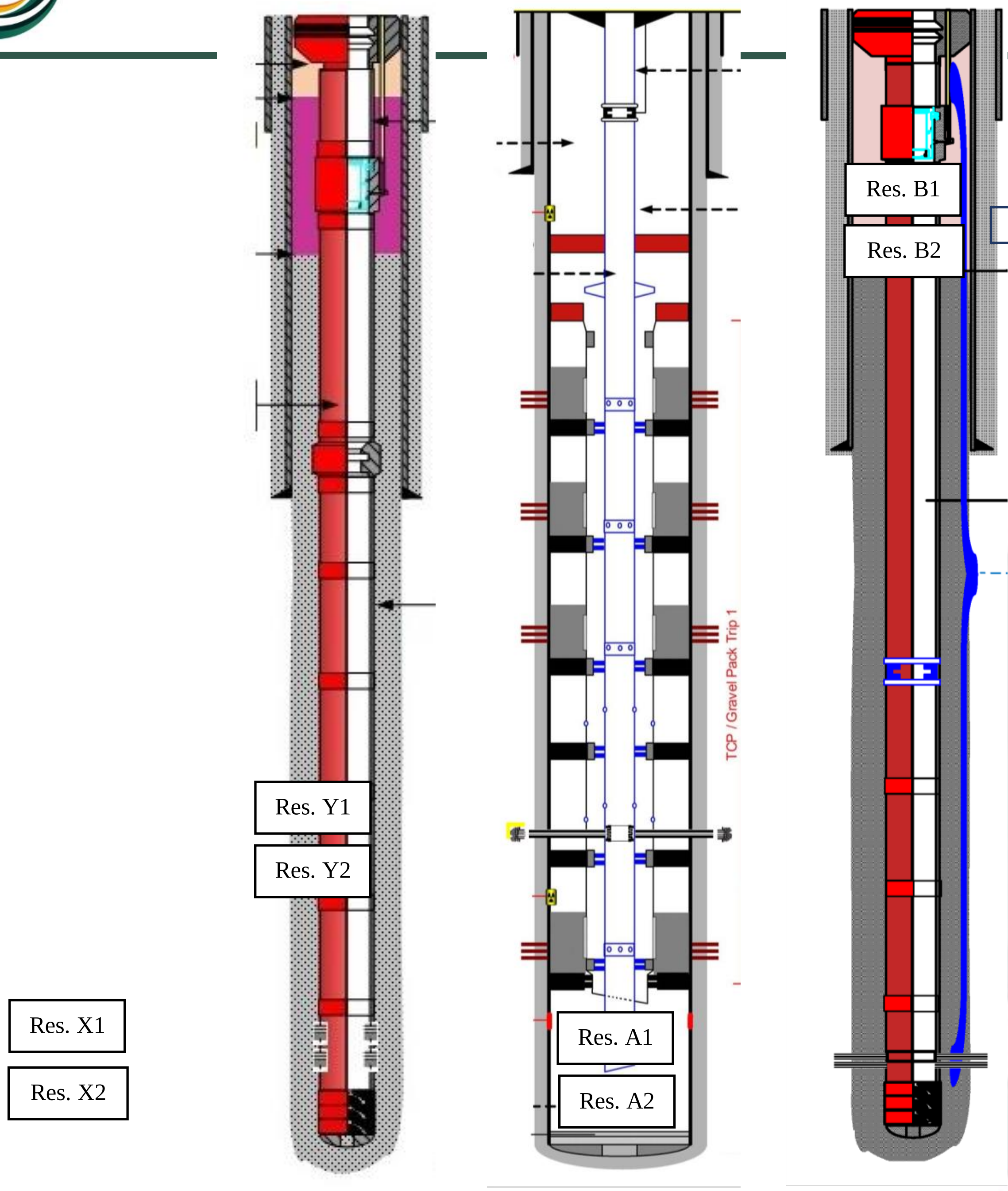
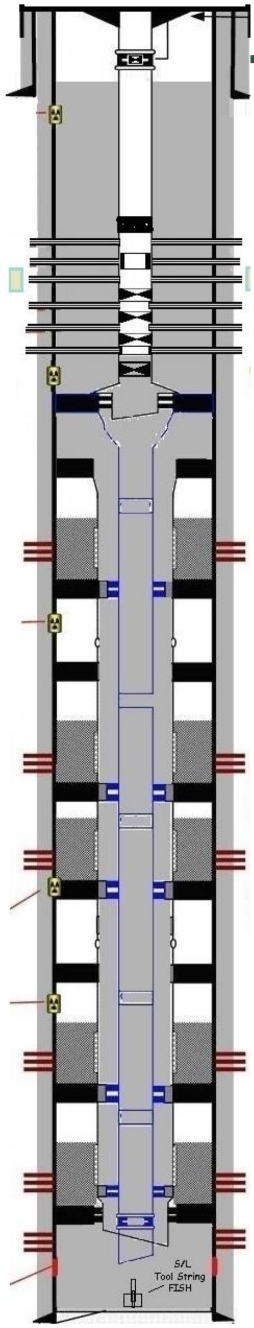
Appendix – Well Diagram


Res. Y1
Res. Y2
Res. X1
Res. X2
TCP / Gravel Pack Trip 1
Res. A1
Res. A2
Res. B1
Res. B2



(a) Well X **(b) Well Y** **(c) Well A** **(d) Well B**