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# Lessons Learned to Avoid Formation Damage Development During Waste Slurry Injection Operations

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**Abstract**

*The injection of oil and gas wastes produced during the exploration and production phases have been proven to be an effective technique towards achieving zero discharge. However, several challenges are associated with the injection of slurry into an underground formation. The most common challenge during waste slurry injection (WSI) is the loss of well injectivity and pre mature formation damage due to a poor engineering and operational design.*

*For the WSI operation, near wellbore formation damage is one of the major risk and is created by the injected solids. The real time injection monitoring of the ongoing operations is important to make amends to the injection procedure in order to avoid the formation damage and ensure the well longevity.*

*Three different case studies are presented to highlight the operational mistakes that caused a significant formation damage in injectors in Eagle Ford, Haynesville, and Permian Basin shale plays of Texas, United States. Certain guidelines depending on the monitoring results are provided like modifying the slurry rheology, injection pressure, injection strategy etc. that are helpful in maintaining the injectivity. The presented case studies show that the wells with good monitoring program maintained its injectivity during its operation compared to the other wells that lost its injectivity sooner. The paper discusses the importance of injection monitoring and steps necessary to maintain the injectivity and perform a healthy WSI operation.*

## Introduction

The oil and gas waste generated during the course of the exploration and production activity are effectively disposed in an environment friendly manner by using Waste Slurry Injection (WSI) technique [1]. The injectate is a mixture of carrying phase (mixing water, flow backs, tank bottoms, produced water etc.) and waste solids (drilling mud and drill cuttings). WSI is conducted at pressure higher than the formation fracture pressure into hydraulically formed cracks and fractures [2]. In case of water flooding and saltwater disposal, the injection operations can be conducted at pressures below formation fracture pressure into naturally occurred cracks and vugs or into salt caverns [3].

The main concern during WSI operations is the containment of the injected wastes within the targeted formation. Injectate's containment is ensured by selecting the candidate formation that has an overlaying layer with high stress to prevent vertical migration of the created fracture [4]. Unlike the saltwater injection operations conducted under either matrix or fracture flow regimes, the WSI operations can only be conducted under fractured flow regime [5]. A detailed geomechanical and stress analysis along the well depth is done prior to drilling activity to confirm the well location and well path followed by selection of the injection formation and its perforation depth. Several parameters like formation stress, geomechanical properties (Young's modulus, Poisson's ratio, bulk modulus etc.) and petrophysical properties (porosity and permeability) are necessary to ensure the containment of the injected slurry [6]. Geomechanical models are Geomechanical models are followed by fracture simulation to validate the selected injection formation, containment of injected slurry within the formation and to estimate formation capacity.

The well injectivity, unlike slurry containment cannot be estimated in advance due to the lack of any appropriate models predicting real time changes in the formation properties, so it requires a thorough monitoring and detailed analysis. For water injection, the quality of water is a key factor that affects the well injectivity. Disposal water with high suspended solid content or scale formation tendency can compromise the effective injectivity of even high-quality sandstone or limestone formations [7]. The suspended solids in the injected stream can block the open pores and damage the formation permeability when the injection operations lack an appropriate engineering design. The size of the solid particles controls the damage location as the filter cake formation can be either internal (inside the formation pores) or external (on the formation face) [8]. The most critical factor determining filter cake formation within porous medium is the ratio of the solid particle size to the pore throat size [9]. Large ratio indicates small throat size for a particle to pass through. Through several experiments Thakur and Satter concluded that suspended solids with size larger than 1/3 of the pore throat will build external filter cake and the particle size between 1/7 and 1/3 will form internal filter cake (Figure 1), and both will negatively affect the formation leakoff rate [10].

During WSI, the solids are pre-processed by grinding and screening, to prepare the slurry of appropriate density and are injected into the pre-selected formation by creating a hydraulic fracture. The injection activity takes place in cycles, to dissipate the excess pressure built up around the wellbore and to allow the created fracture to close. The main concern here is the formation of filter cake at fracture face leading to slow leakoff rate and ultimately loss in the injectivity. Formation damage and injectivity loss can be predicted by monitoring an injection activity, it is of utmost importance to handle both in an effective way to extend the well life.

In this paper, three case studies are presented and discussed, each targeting different geographic locations. The injectivity of various injection wells in Eagle Ford, Haynesville and Permian basin of Texas, United States are analyzed and compared with the wells in the same geographic and geologic location. In order to maintain the privacy of the wells in study, the monitored wells are referred as "study well" and the injectors used for comparison are referred as "reference wells". This study shows how regular monitoring and detailed technical analysis after each injection batch ensures the longevity of injection wells. Also, an effective communication between the data analyst and field operator improves the well life, as the field operator can make necessary changes to the injection strategy and/or slurry rheology based on the monitoring results obtained by the data analyst.

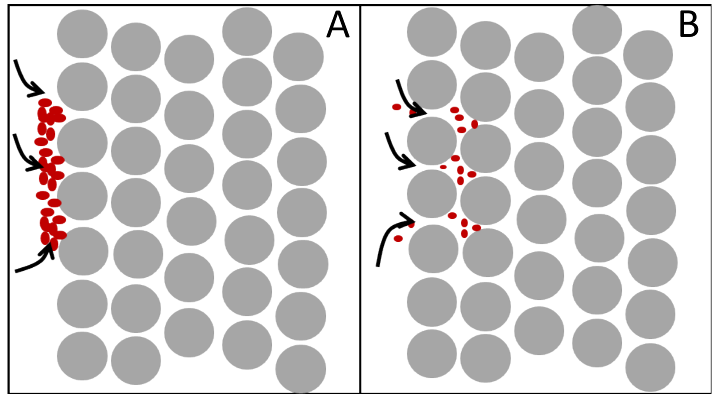


**Figure 1:** Formation damage due to the presence of solid particles (A) External filter cake and (B) Internal filter cake

## Case Study

For each study well the initial fracture pressure was calculated by performing a Step-Rate Test (SRT). The tests were performed using solid free water and was injected at different flowrates and allowing the rate to stabilize at each step. The pressure required to breakdown the formation during the injection operations should be estimated from the SRT, however, if this pressure is not determined from the injection test it can be calculated using the diffusivity equation 1 [11].

$$(P_i - P_{bh}) = \left(\frac{162.6QB\mu}{kh}\right)\left[log\left(\frac{kt}{\emptyset\mu c_t r_w^2}\right) - 3.23 + 0.87s\right] \qquad 1$$

The injection activity of the "study wells" were monitored on real time basis. The pressure and rate data were monitored by both the crew at the injection site and the data analyst using a commercial monitoring application @ssure. The monitoring of data by two different teams provides confidence regarding the data and desired well behavior in general. The description of the study wells and the reference wells are divided into different cases based on the location.

## Case 1: Eagle Ford Shale

The wells studied in the Eagle Ford region had similar geological sequence and were permitted for injection at similar depth. The Gamma Ray (GR) log comparison (Figure 2) was performed to confirm the similarity in the lithology at both locations. The lithology of the injection formation mainly consists of thick composed layer of sandstone and embedded shale layers at regular intervals [12]. The sandstone formation is the targeted injection zone and the shale formation acts as a containment zone. Within the interbedded sand layers, the study well targeted the bottommost sand layer while reference wells targeted topmost sandstone layer. The average porosity of the sandstone layers within the formation was 13 -20% along with a decent permeability [13]. The injection operation was conducted through 4½ inch tubing.

The study well has been fully functional and operating for more than four years. It injects all sorts of oil and gas wastes including drill cuttings, drilling muds, produced water, tank bottoms, fracture flowback etc. At the same time, the reference wells A# 1 and B# 1 were injecting less damaging oil and gas waste and with low concentration (~2% - 5%) solid wastes was injected. However, the injection pressure increased linearly within couple of months of injection activity due to extensive formation damage and loss in injectivity in these wells which led to pre-mature shut down as shown in Figure 3. The study well on the other hand has maintained its injectivity due to detailed monitoring and data analysis.

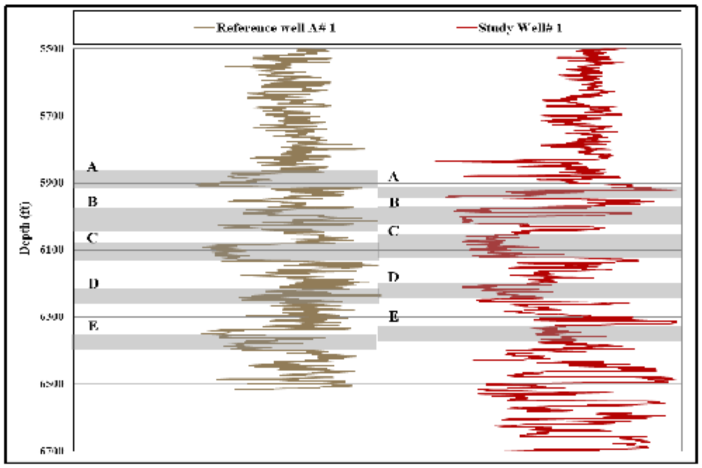


**Figure 2:** GR Log comparison between Reference Well and the Study Well (Eagle Ford)

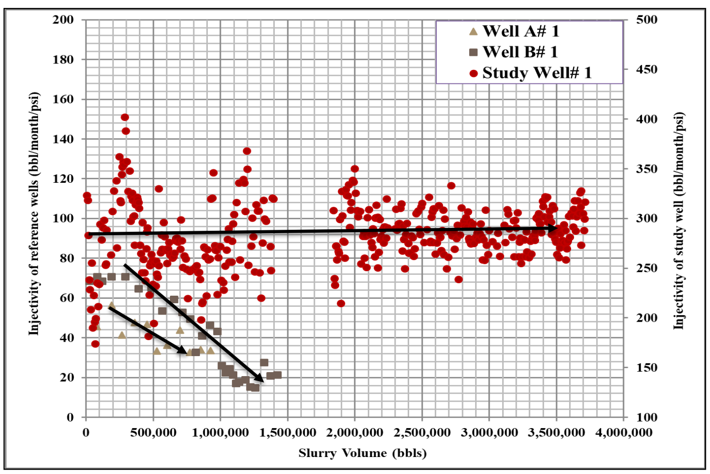


**Figure 3:** Injectivity comparison between reference wells and study well (Eagle Ford)

## Case 2: Haynesville Shale

In the Haynesville Shale, the study well# 2 and the reference wells A# 2, B# 2, and C# 2 are injecting into the same formation. The injection formation in the area has various transgressive and regressive lithology. It varies from shale and limestone to siltstone and sandstone, the perforated interval for the study injection wells is a limestone formation. Based on the study conducted by the Nehring Associates, the average porosity of the formation is 17.5% and the average permeability is about 159 mD [14]. The similarity in the lithology between study well and reference wells is observed in the similarity of the GR trend in Figure 4.

The injection in both the study well# 2 and the reference well A# 2 is conducted through 4½ inch tubing. For the reference wells, most of the injection batches were mainly comprised of saltwater and fracture flow back through the well life unlike the study well. The study well is injecting slurry that contains more than 10% solids. The injection pressure history for well A# 2 shows cycle of increased pressure (Stage 1) followed by decrease (Stage 2) followed by another increase (Stage 3) while the injection pressure in wells B# 2 and C# 2 increased consistently. The pressure behavior in well A# 2 indicates the formation of filter cake around wellbore during Stage 1 had propagated away from wellbore allowing the injection pressure to decline. The average injection pressure for study well# 2 is almost constant, thus the injectivity was maintained throughout the course of injection operation as shown in Figure 5. Although the study well# 2 has injected low volume compared to the reference wells, the injectivity for study well# 2 was always higher than the reference wells even with more than 10% solids compared to almost 0% solids in reference wells.

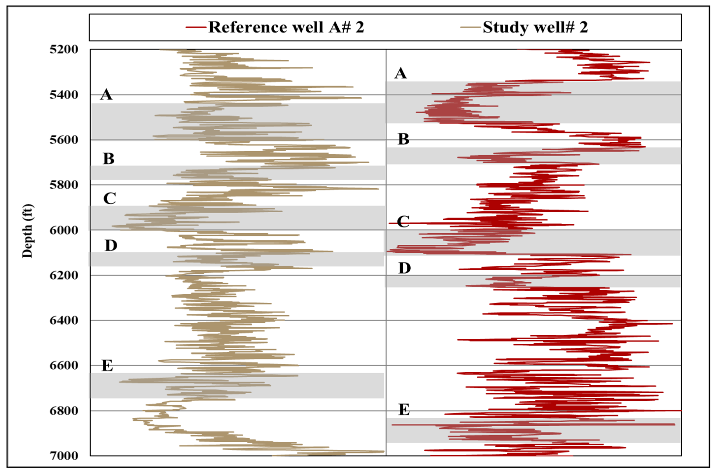


**Figure 4:** GR Log comparison between Reference Well and the Study Well (Haynesville)

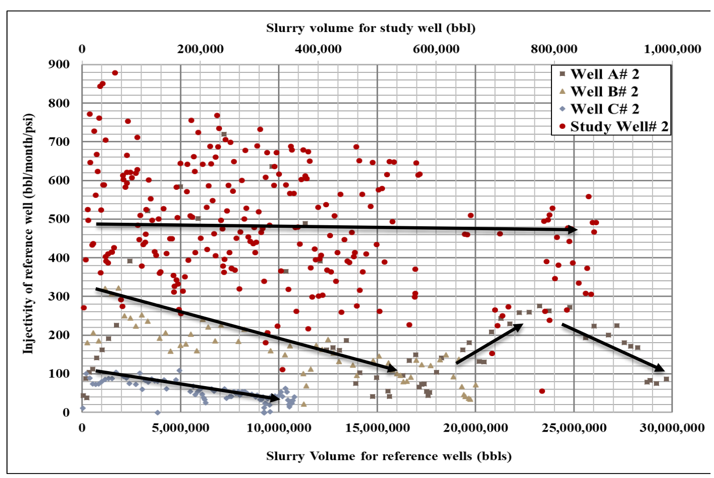


**Figure 5:** Injectivity comparison between reference wells and study well (Haynesville)

## Case 3: Permian Basin

The wells studied in the Permian basin are having the same lithological column as shown in Figure 6 by Gamma Ray comparison. The injection formation in the area has majority of carbonate formation with layers of sandstone [15]. For the study well# 3 the lowermost sandstone layer is perforated, while for well A# 3 and C# 3 topmost layer and for well B# 3 middle layer is perforated. Similar to the other case studies, the injection slurry for the study well 3 is composed of ~15% solids. Reference wells A# 3 and C# 3 are permitted to strictly inject saltwater whereas well B# 3 is permitted to inject all sorts of oil and gas waste. Also, the injection is carried through 4½ - inch tubing for the study well# 3 and the reference wells A# 3 and B# 3, while for well C# 3 via 2 7/8-inch tubing were higher pressure loss due to friction is expected.

The injection pressure history of the reference wells shows a continuous increase in the injection pressure as more fluid was injected. Similar to the wells B# 2 and C# 2 the increased pressure is an indication of the filter cake formation near the wellbore which affects the fluid leakoff rate.

Figure 7 shows the injectivity behavior for both the study well# 3 and the reference wells A# 3, B# 3, and C# 3. It is observed that the injectivity for the study well was steady throughout the injection operations. The slight drop in the injectivity was due to the drop-in injection rate to accommodate the pump capacity. Similar to study wells #1 and #2, study well# 3 could maintain its injectivity due to the continuous monitoring and data analysis, which enable on time correction and adjustment to the injection strategy.

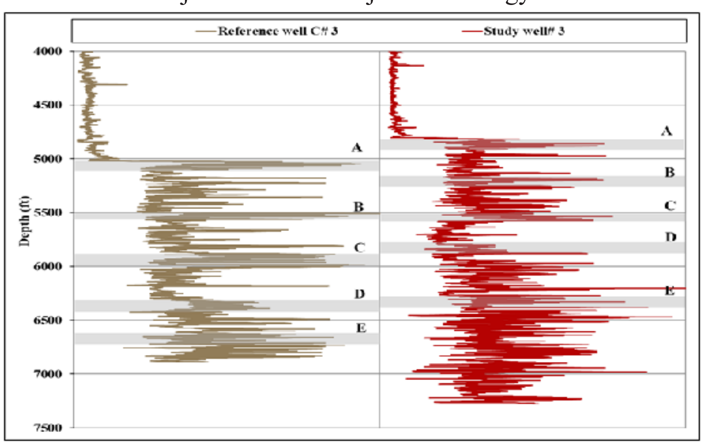


**Figure 6:** GR Log comparison between Reference Well and the Study Well (Permian Basin)

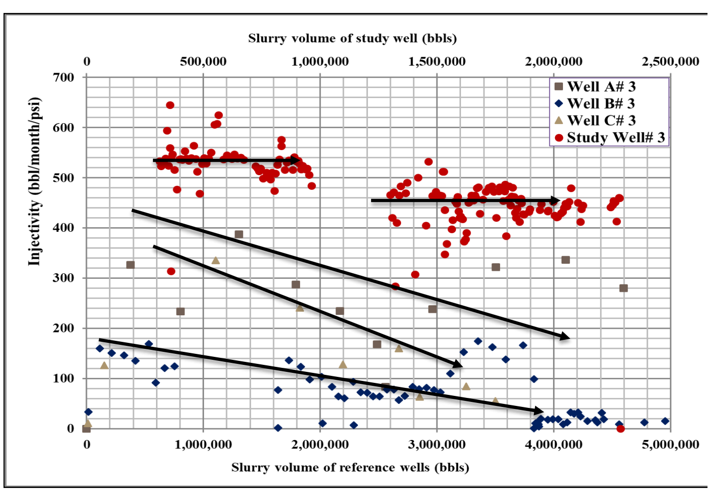


**Figure 7:** Injectivity comparison between reference wells and study well (Permian Basin)

## Discussion

WSI operations was introduced in 1980’s and the recording of the injection data was very unlikely, it was only after certain failed projects, the need for obtaining and monitoring rigorous data became imperative [16, 17]. The reference wells in each case studies collected the pressure and rate data as per permit requirement, but the data were never analyzed. In contrast the study wells had the pressure and rate data recorded, monitored and analyzed. The monitoring of the injection data captures pressure anomalies, while analyzing the shut-in data enables a detailed track of formation property. The changes to the formation properties is used to make necessary amendments to the injection strategy and slurry properties, which ultimately extend the well life.

A typical matrix injection (usually used in case of saltwater, filtered water disposal, water flooding etc.) operation with the injection fluids flowing through the formation pores and pushing the formation brine away from the wellbore is shown in Figure 8. The scenario described here shows the behavior of injection rate when suspended solids do not block the pores as they are relatively smaller than the formation pore size.

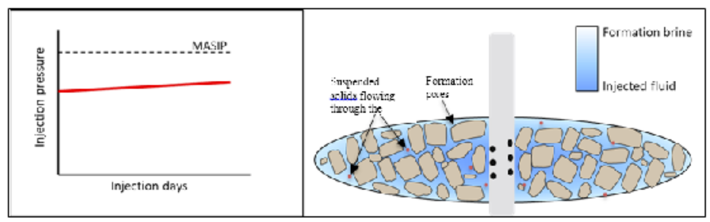


**Figure 8:** Injection rate behavior with no formation damage

However, for the slurry injection case with injectate having high solid concentration, are prone to formation damage as shown in Figure 9 due to the presence of solids that block the formation pores. This behavior leads to a rise in injection pressure immediately and once the injection pressure reaches its MASIP, the injection operation cannot be continued. Thus, the formation capacity of the injection formation is not fully utilized.

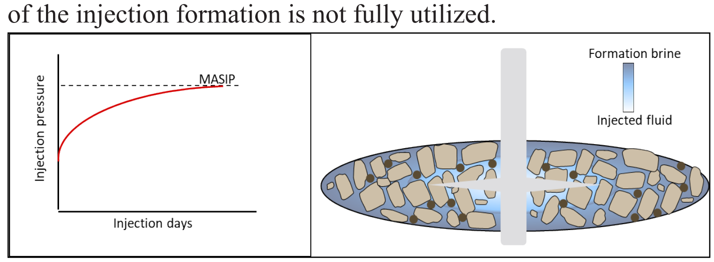


**Figure 9:** Injection rate behavior with formation damage

The injection operation in reference wells A# 1 and B# 1 was performed under fractured flow regime at an average injection rate of 8 bpm and 10 bpm, respectively. The recorded pressure and rate history show a consistent rise in the injection pressure and thus the calculated injectivity declined consistently. The detailed analysis of the injection history and slurry rheology concluded that the loss in the injectivity was mainly because of short injection batches and the use of unfiltered water for the post flush. The solids do not travel farther from the formation due to the low injection volume and the presence of suspended solids in the post flush increases the risk of near wellbore filter cake formation. This issue can be handled by injecting large slurry batches followed by a decent post flush using filtered water, the post flush pushes the injected slurry away from the wellbore and maintains the porosity and permeability in the near wellbore region

For wells B# 2 and C# 2 the injection batches mainly comprised of low solid content water (2% - 5%). The well behavior throughout its injection life was almost similar to the wells A# 1 and B# 1 with a consistent injectivity decline due to poor monitoring and no pressure analysis. Unlike wells B# 2 and C# 2, well A# 2 injected longer batches and was permitted to inject saltwater only. The injectivity history shows a drop (stage 1) followed by a rise (stage 2) and a drop (stage 3) again. The injection pressure gradient calculated from the pressure history was 0.78 psi/ft compared to the minimum horizontal stress gradient of 0.82 psi/ft, which indicate the matrix flow regime during injection in stage 1. The unfiltered water in the injection operation, has TSS that creates internal filter cake gradually and plug the formation near wellbore. The injection pressure kept increasing due to the filter cake formed in stage 1, and eventually increased to 0.85 psi/ft which was above the minimum horizontal stress gradient and according to [5] the hydraulic fractures are created when the pressure at the formation face exceeds the local in-situ stress (i.e. minimum horizontal stress). Thus, with increased permeability, the solids propagated away from the wellbore toward the fracture tips. Thus, the average injection pressure started to drop leading to a rise in injectivity during stage 2. Stage 3 i.e. decline in injectivity was soon observed after couple of months of injection activity similar to Stage 1.

In case study 3, the reference wells (well A# 3 and well C# 3) were permitted to inject saltwater only, However, they suffered a declining injectivity trend due to lower injection flow rate. Based on the permitted injection pressure, the injection can be performed under fractured flow regime, but the flowrate used by the operator (9 bpm) was not sufficient. The flowrate necessary to inject under fractured regime was calculated using Darcy's law [18] and was found to be 12 bpm (equation 2). At low injection flow rate, the suspended solids do not propagate away from the wellbore, which decreases the near well formation permeability. Well B# 3 which is permitted to inject all kind of oil and gas waste had a consistent injectivity decline similar to wells B# 2 and C# 2.

$$q = \frac{Kh}{141.2\mu\beta}\frac{\Delta P}{ln\frac{re}{rw}} \qquad 2$$

## Methods to Predict and Avoid Formation Damage

As mentioned earlier, the monitoring of the injection and shut-in pressure data is necessary for improving the well life. The abnormal pressure response during the injection and the shut-in phases can be captured by in-depth pressure analyses, which enables early capturing of any injection issues. If the pressure anomaly is not identified at right time it can lead to a well failure [17]. For all the study wells the pressure and rate data during injection and shut-in are recorded and monitored on regular basis. The formation injectivity history describes the formation behavior with respect to each injection batch, higher injectivity indicates lesser formation damage associated with formation of filter cake. The injectivity is calculated using equation 3 assuming that the fluid flow occurs in a steady- state, single phase and under radial flow regime [19].

$$II = \frac{Q}{(P_{bh} - P_r)} = \frac{K_w h}{141.2\mu\beta\left(ln\frac{r_e}{r_w} + S\right)} \qquad 3$$

The formation injectivity is a function of the injection pressure and the flowrate. The change in the injectivity is an indication of change in formation properties. Since the increase in the injection pressure is a gradual process depending on the formation of filter cake near the wellbore, each injection batch must be thoroughly analyzed and recorded to understand the related changes in the formation properties. Showed that the formation of filter cake slows down the fluid leak off rate and thus increases the injection pressure [20]. A proper monitoring of the injection batches determines the buildup of filter cake and the related rise in formation stress.

The pressure analysis of the shut-in data for each of the Study wells after each injection batch created a history of the formation and fracture properties. The log-log diagnostic plot approach was used to interpret the injection data by plotting the pressure derivative with respect to the logarithm of superposition time. The slopes on the log-log plot identify different flow regime which ultimately are used in calculating the formation properties. The radial flow is used to predict the formation permeability (equation 4) while the linear and bi-linear flow is used to estimate the fracture half-length (equation 5) and fracture width respectively [21, 22].

$$K = \frac{70.6Q\beta\mu}{m'h} \qquad 4$$

where m' is the logarithmic derivative on log-log derivative

$$X_f = \left(\frac{4.064\Delta Q\beta}{m_{lf}h}\right)\left(\frac{\mu}{\varphi C_t K}\right)^{0.5} \qquad 5$$

where

$$m_{lf} = {2\Delta p'}/{\sqrt{\Delta t}} \qquad 6$$

The calculated formation and fracture properties predicts the formation of internal filter cake during the course of injection activity. The change in permeability overtime can be explained by gradual formation of filter cake. Also, a continuous increase in the fracture length indicates the formation of filter cake. Since the fracture length co-relates with permeability a consistent increase in fracture length indicates permeability decline and ultimately filter cake formation as shown in equation 5.

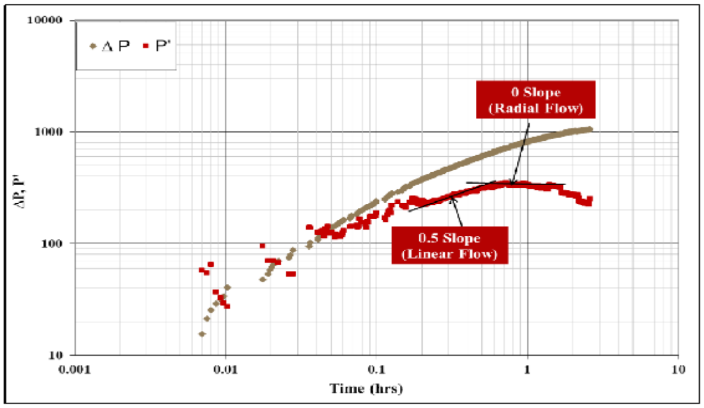


**Figure 10:** shows the shut-in pressure analysis for an injection batch for study well# 1.

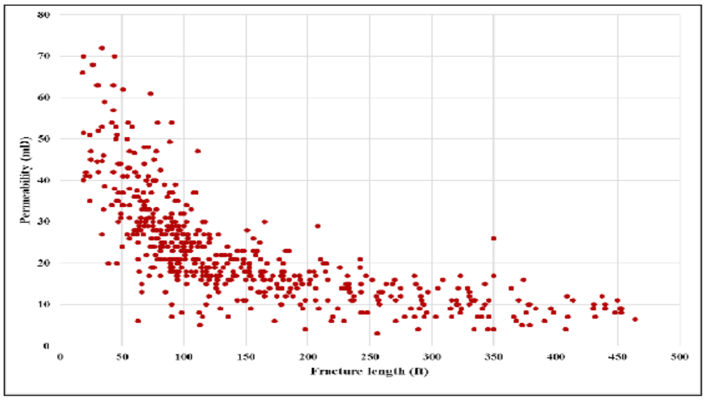


**Figure 11:** shows the relation of permeability with respect the fracture length and the exponential decline in the curve indicates the formation damage.

The formation of internal cake continues until the formation is plugged and it remains plugged until the injection pressure reaches a critical value and exceeds the pressure necessary to propagate the fracture. The pumping pressure drops thereafter, and the injection rate increases due to clean fracture surface exposed due to the fracture propagation [23]. Due to the presence of suspended solids in the slurry, formation damage is inevitable but through detailed shut-in analysis the process can be delayed and well life can be extended.

For fractured injection, the injection slurry must be pumped at the highest allowed rate as concluded by [24, 25]. At low injection rate, the fluid leaks off quickly and solids settle closer to the wellbore creating a short fracture, while at higher rate the fracture length is relatively longer, and solids are displaced far from the wellbore. The trapped solids in the fracture due to low injection rate may lead to fracture tip screen out (TSO). The TSO restricts the pressure communication with the fracture tip and prevents fracture from propagating, while increasing the fracture width. Short fracture length and increased fracture width accumulates more solids closer to the wellbore increasing the risks of formation damage.

## Conclusions

The study of comparison of various non monitored injection wells with respect to the monitored injection wells at different locations across the state of Texas has led to following conclusions,

1. Lack of proper pressure analysis after each injection batch raises the risks of formation damage and may lead to permanent plugged well.
2. A correct flowrate and injection pressure are necessary to laterally propagate solids farther away from the wellbore and into the formation for a successful WSI operation.
3. It is important to have a post flush with filtered water as the unfiltered/untreated water will suspend the solids, which when settled near the wellbore will accelerate the filter cake formation and lead to pre-mature plugging.
4. Formation damage while performing WSI is inevitable, but in order to extend the well life and procrastinate the filter cake formation, the field operators must make necessary changes to the injection strategy, pressure, rate, slurry properties etc. as suggested by the data analyst after performing shut-in data analysis for each injection batch.

5. The above described case studies are summarized in Table 1

| Case Study# / Region | Case study# 1 Eagle ford, South Texas | Case study# 2 Haynesville, East Texas | Case study# 3 Permian Basin, West Texas |
|---|---|---|---|
| Formation lithology | Sandstone with embedded shale layers | Transgressive lithology with shale and limestone to siltstone and sandstone | Majority of carbonate with layers of sandstone |
| Injection waste | A#1 and B#1 injecting oil and gas with low solid concentration | A#2, B#2 and C#2 injecting saltwater and fracture flow back | A# 3 and B# 3 – saltwater and fracture flowback water C# 3 all sort of oil and gas waste |
| Well behavior | Decreased injectivity from almost the beginning of injection operation | A# 2 cycles of up and down in injectivity B# 2 and C# 2 injection pressure increased consistently | Consistent increase in the injection pressure |
| Reason | Smaller batches followed by post flush with unfiltered water | Presence of suspended solid forming filter cake within formation pores | Injection at lower flowrate |
| Suggested treatment | Inject longer batches and make sure to use filtered or treated water for post flush to push the solids away from wellbore | Conduct the injection at maximum possible rate and use filtered water to remove the suspended solids | Increase the flowrate necessary to inject under fracture flow and improve the leak off rate. |

## Nomenclature

| | |
|---|---|
| Pbh | Bottomhole pressure |
| Pi | Initial reservoir pressure |
| Q | Flowrate |
| β | Fluid formation volume factor |
| µ | Fluid viscosity |
| φ | Formation porosity |
| K | Formation permeability |
| h | Formation thickness |
| Ct | Total compressibility |
| rw | Wellbore radius |
| re | Drainage radius |
| S | Skin factor |
| ri | Drainage radius |
| Fcd | Fracture conductivity |
| Xf | Fracture length |
| Wf | Fracture width |
| ΔP | Pressure difference (Pi – Pbh) |

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