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Novel Fluids for Productivity Enhancement in Tight Gas Formations

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ABSTRACT

Natural gas is increasingly becoming the fuel of choice due to its cleaner burning properties. In the continental United States and many parts of the world large volumes of natural gas are available in very difficult to produce formations such as shales, tight sands, coalbeds and hydrates. Our research program aims to address key issues to enable recovery from these resources through improved completions and stimulation fluids.

Due to the low permeability of the unconventional formations fracture stimulation is most commonly used to recover more gas. Fracture treatments are frequently performed with polymeric fluids and the impact of the invasion of these fluids is to depress the productivity of the gas well. Invasion of aqueous fracturing fluids during stimulation operations can reduce the relative permeability to gas resulting in a "block". The invaded fracturing fluid establishes a region of high saturation in the rock formation near the fracture, and can significantly reduce the relative permeability and hence the productivity of the well.

We propose to develop novel fluids for remediation and fracturing by better understanding the impact of fluid properties on the performance of flowback of gas in tight gas wells. The results of this study will enable better selection of treatment fluids to remediate non-performing tight gas wells and also strategies for fluid additives selection in fracturing fluids for future applications.

SIGNATURE PAGE

Dated this ____13____ day of ____March____, 2012

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NOVEL FLUIDS FOR PRODUCTIVITY ENHANCEMENT IN TIGHT GAS FORMATIONS

1.0 Introduction

The impairment of production from fractured tight gas wells, due to liquid blocking, can be remediated using novel fluid treatments such as solvent/gas injection processes. In December 2007, a proposal to test the effectiveness of dry gas injection into a liquid blocked fractured well was made to the Research Partnership to Secure Energy for America (RPSEA) both in a laboratory environment as well as in field conditions.

The laboratory and the field tests were divided into a total of seven tasks which were to be completed over a period of 3 years starting from the month of September 2008 to September 2011. In addition to the specific tasks, a project management plan was also drafted to accomplish technology assessment, development and transfer to the larger audience of energy professionals.

In this report, the progress made and the milestones achieved during the project duration to date is provided. The specific technical tasks completed and the outcomes are discussed. A discussion of the field test, and the potential outcomes of the field test, is also provided. The report consists of the following sections: project management plan and schedule of deliverables, technical tasks and outcomes, discussion of results and outcomes of the project, conclusions and future work.

2.0 Project Management Plan and Schedule of Tasks

At the commencement of the project, a management plan was prepared to identify all the tasks associated with project as per the original proposal approved by RPSEA. This section describes the management plan. In the subsequent paragraphs, the specific tasks proposed as part of the study are described and the results of the task are presented. In total seven tasks were proposed out of which six tasks are complete. The seventh and final task was not completed because the lab results were inconclusive in terms of efficacy of the methodology. Towards the end of this section the schedule of completion of the tasks is described in the form of a Gantt chart.

The overall goal of the project is to identify a remediation fluid designed to improve liquid blocked gas wells that have been subjected to fracture stimulation. Both laboratory investigation and field application components are included in the proposal to validate the applicability of the proposed technique. We aim to study the effect of gas and solvent injection on the improvement of production from tight gas reservoirs. The results of this study will also help to identify improved composition of fracturing fluids suitable for fracturing in tight formations. We propose to conduct lab experiments to:

1. Investigate the impact of injection of dry gas on the rate of recovery of gas flow rate during gas flowback in laboratory and field samples invaded by fracturing fluids.

2. Determine the effect of injection of solvent such as methanol on the rate of recovery of gas flow rate during gas flowback in liquid blocked laboratory samples.

If successful the technique can potentially improve the productivity of underperforming wells. The following paragraphs discuss the tasks planned for the successful execution of the project in a timely manner. Each paragraph below starts with a description of the task its objectives, and its role in the overall research program.

2.1 Technology Status Assessment (Task 2)

A detailed review of current technology status is to be presented within the first 30 days of the contract award. The main objective of this task is to describe existing technologies and delineate the positives and the negatives of each technology used in the removal of liquid blocks to remediate and enhance productivity of underperforming gas wells in tight formations.

Task 2: Technology Status Assessment	
Planned Expenditures	None
Major Milestones	Review of current status
Key/Decisive Milestone	None

2.2 Technology Transfer Agreement (Task 3)

This task is to establish a system to develop and transfer technology to its end user. The main sub-tasks in this category are:

1. Awardee will make a minimum of two presentations in local professional organization meetings; one each in mid-continent and rocky mountain areas.
2. Awardee will submit at least one paper for consideration for presentation at an SPE Annual Meeting.
3. Awardee will coordinate with RPSEA to make a minimum of one presentation at a program level technology transfer activity. Forty percent (40%) of the total technology transfer budget should be set aside for participation and support of program level activities as directed by RPSEA.
4. Awardee will prepare papers for publication.
5. Awardee will build and maintain a web site with information about the project and updates as appropriate.

Subtasks 1 through 4 are tasks which will be performed in due course of the project as an when the results and increased knowledge become available. Task 4, development of website, will be made concurrently with the start of the project and the first webpage, containing information on the project will be made available before the end of the year. The main information to be included in the webpage are details of the research plans and preliminary results of task 4.

Task 3: Technology Transfer Plan	
Planned Expenditures	-$1000 travel cost to present in rocky mountain region conference in year three -No dollar amount envisaged for website development and maintenance
Major Milestones	Presentation at the SPE mid-continental section locally in Tulsa and at a regional conference in Rocky Mountain area in year three Paper presentation at SPE Annual conference meeting in year three
Key/Decisive Milestone	This task occurs towards the end of the research program and therefore the completion of technology transfer as per RPSEA directions will be key to completion of the task

2.3 Lab Studies - Effect of Gas Injection (Task 4)

In this experimental study, dry cores will be subjected to invasion by typical aqueous fracturing liquids. The most used fracturing fluids in the Merna field are gel based fracturing fluids. For the purpose of this study, only gel based fracturing fluids will be used. Also, no breakers will be used to reflect the hypothesized conditions in the field, namely, unbroken gel. This will be followed by dry Nitrogen gas injection to simulate the treatment procedure. Then Nitrogen, saturated with water to 100% relative humidity, will be used for conducting the gas flowback experiments to simulate production.

Experimental data collected will include flow rate of gas and the saturation of liquid in the core with time by observation of effluent fluids. The results of the experiments will be used to confirm the value of dry gas injection as a method to increase evaporation rates and reduce invaded fluid saturations quickly. We plan to conduct all the experiments with Berea sandstone cores which will be procured from local vendors.

Task 4: Gas Injection Studies (Duration 10 months)	
Planned Expenditures	-$20000 cost to purchase instruments, equipment and supplies
Major Milestones	1) Student hiring 2) Purchase of instruments, equipment and supplies 3) Setting up of core holder, instruments and gas flow systems 4) Setting up data acquisition system 5) Procurement of sample fracturing fluids from vendor-preferably from fracturing fluid suppliers

	to Merna field jobs 6) Experimentation as described in proposal
Key/Decisive Milestone	Subtask 6

2.4 Lab Studies - Effect of Solvent Injection (Task 5.0)

Additives such as methanol/isopropyl alcohol can result in an improvement in the production of gas from reservoirs by enhancing the rate of evaporation and also by changing the wettability to expel wetting liquids. In this experimental study, dry cores will be subjected to invasion by typical aqueous fracturing liquids. The most used fracturing fluids in the Merna field are gel based fracturing fluids. For the purpose of this study, only gel based fracturing fluids will be used. Also, no breakers will be used to reflect the hypothesized conditions in the field, namely, unbroken gel. This will be followed by solvent (alcohol) injection cycle and then gas flow back. Nitrogen, saturated with water to 100% relative humidity, will be used for conducting the gas flowback experiments.

Experiments that combine both cycles, of dry gas injection and solvent injection will be performed in sequence. Two sequences will be investigated: 1) dry gas injection followed by alcohol injection and subsequently flowback; 2) a reverse, with alcohol injection, followed by dry gas injection and finally flowback. The experimental parameters measured will be similar to that in the gas injection case and the results can be used to ascertain the effect of methanol addition and the treatment cycle.

Task 5: Solvent/Gas Injection Studies: Duration 12 months	
Planned Expenditures	-$500 cost to purchase the following: 1) Isopropyl alcohol 2) Nitrogen/Air supply
Major Milestones	1) Purchase of supplies 2) Setting up of core holder, instruments and gas flow systems 3) Setting up data acquisition system to successfully acquire flow rate and other parameters 4) Procurement of sample fracturing fluids from vendor-preferably from fracturing fluid suppliers to Merna field jobs 5) Experimentation as described in proposal
Key/Decisive Milestone	Subtask 4 and 5

2.5 Modeling of Dry Gas and Solvent Injection (Task 6.0)

This section of the study is mainly aimed at determination of the volume of nitrogen gas and the volume of alcohol that will be used in the subsequent field testing. The experimental results will be the determining factor in deciding if the next task is viable and, if so, which strategy is optimum. For this purpose a modeling study will be carried out to understand the role of both dry gas injection and solvent injection on the gas flowback rates. It is expected that the injection of dry gas will produce drying fronts that will propagate through the rock core. When a solvent is injected through the core a miscible displacement takes place. There are two regimes that will be considered for modeling during fluid injection and gas flowback: 1) displacement regime; 2) evaporation regime. A model for displacement, including relative permeability and capillary pressure effects, and for evaporation will be developed from conservation equations for components of gas and liquid phases. Consequently the evaporation regime model will be developed independent of displacement regime. The following assumptions will be made:

a. 4 components: water; nitrogen; alcohol; and fracturing liquid;
b. 2 phases: liquid and gas;
c. Local thermodynamic equilibrium.
d. surfactant will not be considered as a component and study of its effect on results will solely be experimental

The following assumptions will be made about the mass fractions in each phase:

a. Mass fraction of water and methanol in gas phase is greater than zero;
b. Mass fraction of fracturing liquid in gas is zero;
c. Mass fraction of nitrogen in liquid phase is zero;
d. Mass fraction of methanol, water in liquid phase is greater than zero.

The development of conservation equations for gas injection in laboratory core will be similar to that described in reference 1 and that for the field will be similar to that developed in reference 3. The conservation equations will be solved using either numerical or analytical methods. The result of this effort will be a model to predict the residual liquid saturation when a dry gas and methanol are injected, respectively, and humidified nitrogen gas is flowed back. The model will be used to compute the rate of evaporation of volatile components from fracturing fluids and the residual fracturing fluid saturations in the near fracture region. Reservoir parameters such as height of reservoir and completions information will be obtained with the help of company personnel.

Task 6: Modeling Studies: 24 months	
Planned Expenditures	-$3500 cost to purchase the following computer hardware and software: 1) Dell workstation 2) Monitor
Major Milestones	Development of 1) conservation equations for each component for formation linear flow condition and boundary conditions 2) Numerical solution of the equations 3) Prediction of field nitrogen and methanol

	consumption
Key/Decisive Milestone	Subtask 3

2.6 Field Testing of Solvent/Gas Injection (Task 7.0)

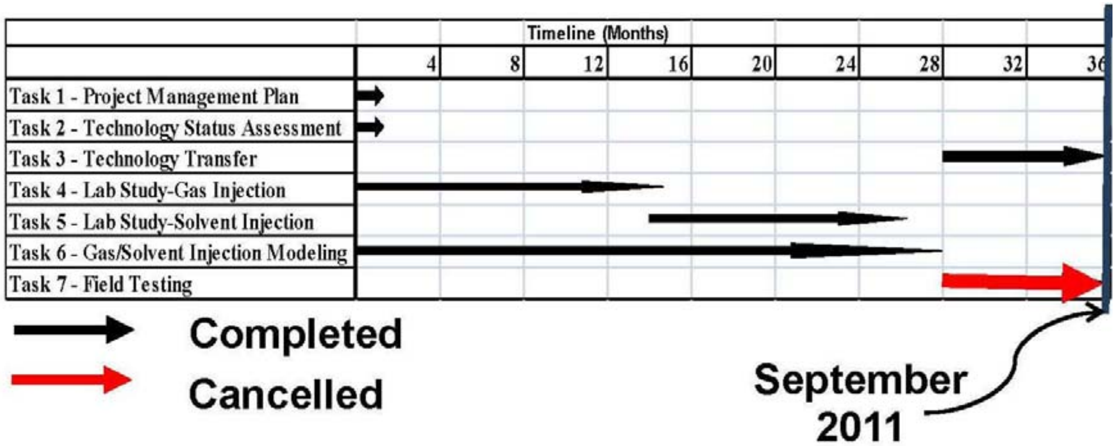
We expect the laboratory experiments to provide quantitative information on the rate of cleanup of the fracturing liquids under different treatment procedures. We will also understand the viability of the method. The choice of the optimum treatment procedure will depend on the findings of the results in the laboratory. The rate of cleanup in the field could be predicted with the help of model and hence the volume of gas injection and solvent injection could be obtained from fractured well model. The field treatment design will follow the modeling of gas and solvent injection process described in Task 6.

Based on the laboratory injection studies of the solvent/surfactant mixture, and subsequent modeling, the field requirements can be computed. Once the field treatment volumes of chemicals are identified, the operation in the field can be performed with the coordination of the company staff.

Task 7: Field Testing	
Planned Expenditures	\$175,244, Refer to Williams supporting letter for details
Major Milestones	1) Calculated volumes of gas and methanol to be consumed from modeling 2) Collection of data, cores 3) Procurement of supplies 4) Well treatment
Key/Decisive Milestone	Well treatment and observation of well performance

2.7 Schedule of Tasks and Completion

In the Gantt chart below the schedule of completion of tasks is shown along with the tasks that are completed and those that are cancelled.



The proposed tasks as part of the PI's laboratory investigation are now complete. The seventh and final task is cancelled due to ambiguous results from the previous tasks.

3.0 Discussion of Results of the Technical Study

The technical study conducted in laboratory resulted in the publication of two papers and one thesis. They are:

- Le, D., Dabholkar, D., Mahadevan, J., "Removal of Fracturing Gel: A Laboratory and Modeling Investigation Accounting for Viscous Fingering Channels," accepted for publication, with moderate revisions, in the Journal of Petroleum Science and Engineering, Elsevier Publications, Amsterdam, Netherlands, 2011.
- Le, D., Hoang, H., and Mahadevan, J., "Clean-up of Water Blocks in Gas Wells by Capillary Suction and Evaporation," paper SPE-119585-PP accepted for publication in the SPE Journal with minor revisions.
- Duc Le (MS Thesis, Committee Chair, 2011, "Impairment Mechanisms in Tight Gas Wells: An Experimental and Modeling Investigation").
- A Method of Treating a Fractured Well - Patent, Sponsored by University of Tulsa, Applied on April 21 2011, Pending with United States Patent Office.

In the following paragraphs, a summary of the results of the technical study is presented.

3.1 Formation Damage in Hydraulically Fractured Gas Wells

Production from tight gas formations is uneconomical without hydraulic fracturing which parts the subsurface reservoir rock to increase exposure of the rock's cross-sectional area. Hydraulic fracturing operation is performed to serve one or more of the following reasons (Economides and Nolte 2000): to bypass near-wellbore damage and return a well to its "natural" productivity, to extend a conductive path deep into a formation and thus increase productivity beyond the natural level, and to alter fluid flow in the formation. In most cases of hydraulic fracturing (Gidley, *et al.* 1989), fracturing fluid is mixed with proppant and then injected into the rock at high pressure. Many types of fracturing fluids are available, of which the most common ones are water-based polymer, gelled alcohol and gelled CO_2. The liquid gel possesses a high viscosity and therefore can carry proppants to large distances within the fracture. After the fluids are pumped, the gel chemically breaks down to become less viscous and flows back out of the well, leaving a highly permeable fracture to facilitate gas flow.

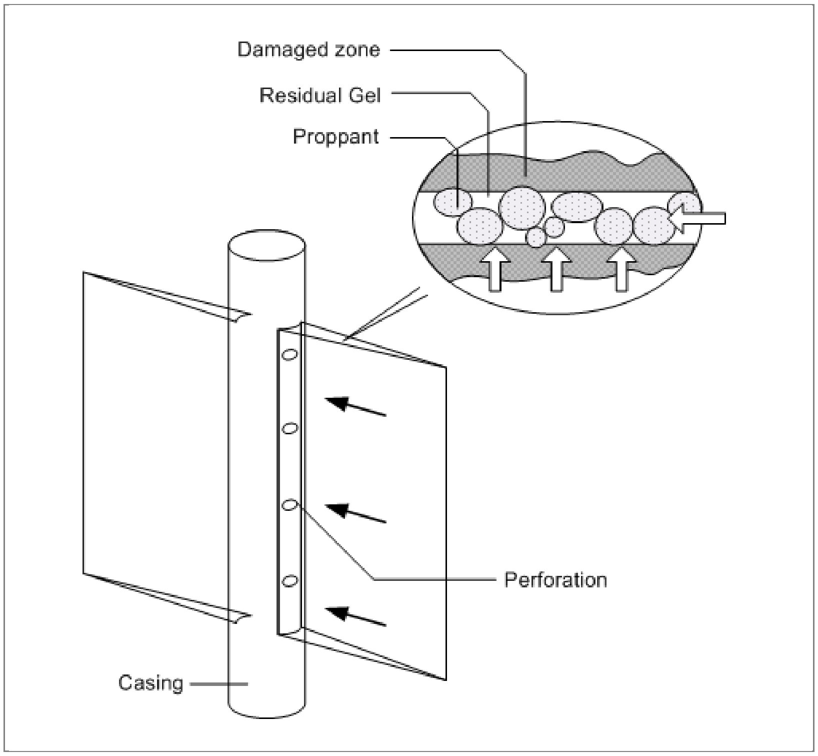


Figure 1: Hydraulic fracturing schematic

The well performance in a gas well is given by the following equation (Chaudhry, 2003):

$$J = \frac{q}{m(\overline{p}) - m(p_{wf})} = \frac{703\times10^{-6}kh}{T\left[\ln(r_e/r_w) - 0.75 + s\right]} \tag{1}$$

where J is the productivity index, which is defined as the ratio of the flowrate to the pseudo-pressure drawdown, q is the flowrate (Mscf/D), $\overline{p}, p_{wf}$ is the average reservoir pressure and wellbore pressure, respectively (psi), $m(p) = \int_0^p \frac{p}{\mu_g z} dp$ is the pseudo-pressure corresponding to a pressure p, μ_g is the gas viscosity (cp), z is the compressibility factor, k is the permeability (md), h is the pay thickness (ft), T is the reservoir pressure (^oR), r_e, r_w are the reservoir and wellbore radius, respectively (ft), and s is the skin factor.

In an ideal fracturing operation, after the completion of injection and flowback of gas, the well is left with negative skin ($s < 0$) and higher productivity compared to pre-treatment well performance. In reality, many factors may affect the fracturing effectiveness, which leads to less than desirable post-treatment performance. During fracturing operation, the injected fracturing fluid may leak off into the formation and thus reduce the gas relative permeability to gas in the invaded zone. This is commonly referred to as the fracture face skin effect (Figure 2). Fracturing fluid can also reduce conductivity in the fracture near the wellbore, which is described as fracture choke skin (Figure 3) (Economides and Nolte, 2000). In some cases, the fracture will be able to clean itself from these impairments as the gas flows through the reservoir rock matrix and in the fracture and begins to remove the blocking fluids. After fluid injection stops and gas production begins, the fluid saturation in the near fracture region changes due to displacement and evaporation (Mahadevan, *et al.,* 2006, 2007a, 2007b). This in turn slowly increases the gas relative permeability in the invaded zone. However, if the injected fracturing fluid does not clean up fast enough, it may adversely affect gas flow rate for a long period of time. A complete water block to gas flow can even occur in the most extreme cases. In some other cases, the fracturing fluid may permanently reduce the formation permeability in the invaded zone through means such as clay swelling, solid precipitation (e.g. salt drop-out), proppant crushing or fine migration. This happens if the fracturing fluids are not chosen carefully to be compatible with the formation rock (Holditch, 1979).

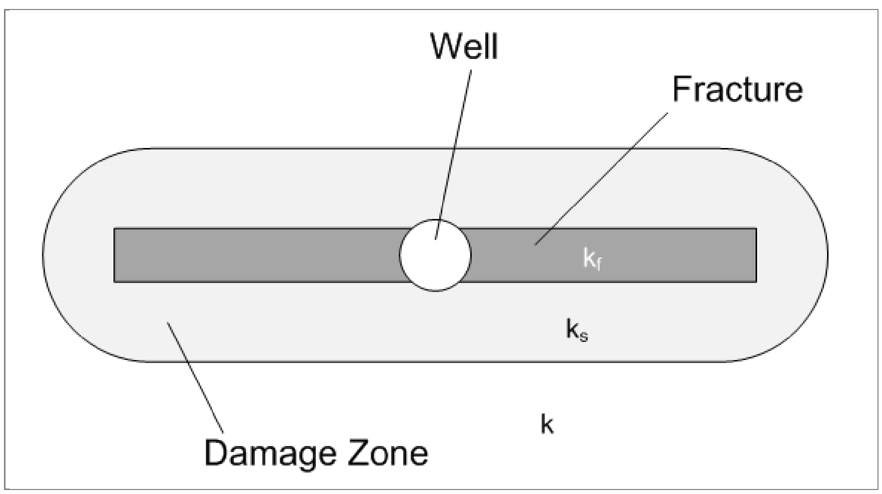


Figure 2: Fracture face skin effect

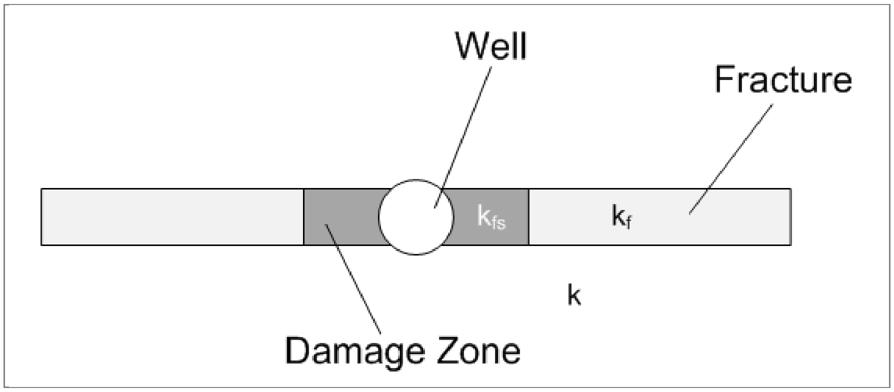


Figure 3: Fracture choke skin effect

In the following sections, the impact of liquid blocking on flow through the fracture, or choke skin, is discussed. The main aim of the proposed study is to develop a better understanding of the application of the dry gas injection/solvent treatment as a methodology to remediate formation damage in fracture to increase recovery.

3.2 Impact of Gelled Fluids on Fracture Flow

Hydraulic fracturing uses high viscosity liquid gel to carry proppants to large distances within the fracture. In some cases, the injected fracturing fluid may be trapped in the fracture or in the near fracture region if the fracturing liquid is either improperly prepared or due to malfunction of the design of breaker system. The breakers are used to break the polymer gel and reduce the viscosity during well flow-back. Holditch and Tschirhart (2005) report that on average only 35% of the polymer pumped into the well is recovered during flow-back following fracture treatments. They also observe that the breaker is unable to break polymer chains in cross-linked fluids unless the fluid viscosity is reduced to 3cp or less. Additionally, during injection, leak-off of the aqueous fracturing liquid can cause a concentration of the gel in the form of filter cake within the fracture which can lead to reduced fracture conductivity (Ayoub, *et al.,* 2006). This aspect is again discussed later in this section.

When the fracture conductivity or the near fracture reservoir permeability is reduced, the fracture choke skin and fracture face skin increases (Cinco-Ley and Samaniego, 1981). This can lead to a reduction in the productivity of the gas well. It is reported that the fracture face skin may not be an important parameter that affects the gas production (Economides and Nolte 1989). This is primarily due to the fact that the very large cross-sectional area created by the fracture offsets small reduction in the permeability of the fracture face. A study by Adegbola, *et al.* (2002) on the impact of leak-off and the consequent fracture face skin on production rate shows that low permeability rock, with a small leak-off depth is not very significant. The reduction of near fracture permeability to 10% of the original value did not change the gas rate significantly after 1 day of production. However, liquid blocks, which cause fracture face skin, can completely shut-off gas flow if the liquid saturations are high (Ward and Morrow, 1987). Assuming that the liquid saturations are low, the fracture choke skin (which occurs due to reduced fracture conductivity) may be an influential factor in determining the well productivity.

During gas flow-back, removal of the trapped liquids from formation takes place in two stages (Kamath, *et al*., 2003; Mahadevan, *et al.,* 2006). The first stage is a displacement process where the trapped liquid is removed by means of viscous removal. The second stage which follows the viscous removal is a long period of expansion driven evaporation process.

Most attempts to clean the fracturing fluid block focus on improving the effectiveness of the displacement process. Penny, *et al*. (1983) examine the roles of capillary pressure, wettability, and relative permeability, all of which control recovery during displacement. They propose the use of surfactants to alter the contact angle of the invaded reservoir rock and the proppant to a nonwet state, leading to near zero capillary pressure. In a later study, Penny, *et al*. (2005, 2006) suggest using microemulsion additives to reduce the capillary end effect associated with low permeability reservoirs. Paktinat, *et al*. (2005) compare the effectiveness of several surfactants in increasing water recovery, including ethoxylated linear alcohol, nonyl phenol ethoxylate and a microemulsion system. Experimental results reported in these studies show that microemulsion is more effective than common surfactants in post-frac treatment. It is not clear, however, whether these methods are effective in the treatment of gel damage and if so the mechanisms by which the methods become effective.

Filter cake forms in the fracture during a hydraulic fracturing process using gel based fluids due to leak off. The filter cake consists of concentrated polymer which generally possesses a very high viscosity compared to the gelled fracturing fluid. Thus removal of filter cake, from the fracture, requires greater amount of displacement pressure and may not be accomplished easily during flow-back of a well under low pressure condition. Studies by Ayoub, *et al*. (2006) on the removal of filter cake by chemical methods shows that adding encapsulated chemical breakers can reduce the viscosity of the filter cake by breaking the bonds of the polymer. The reduction in viscosity then leads to a more effective viscous displacement of the residual fluid from the fracture and the fracture face. This reduction in viscosity also leads to a reduction in the flow initiation gradient which is the minimum pressure gradient across the filter cake that is needed to create a gas flow.

Experimental work reported by Marpaung, *et al.* (2008), on removal of gel by viscous displacement, shows clean-up efficiency of fracture pack is high if gas flow rates are high and the filter cake gel concentration is low. The maximum filter cake gel concentration the study considers is 480 lb/gal which is approximately 57.5 gm/liter. Assuming no volume change in mixing, this indicates that the mass fraction of water in the gel phase is approximately 0.94. This level of water in gel does not impact the phase behaviors and the vapor pressure of water. Although the filter cake is concentrated it still contains a substantial quantity of water which is trapped in the polymeric gel phase. The removal of this water from the gel phase can reduce the gel saturation by a reduction in the gel volume.

Solvents such as methanol are useful both as a carrier fracturing fluid and as a treatment fluid. McLeod and Coulter (1966) summarize the use of alcohol in various gas well stimulation activities, including waterblock removal, matrix acidizing and hydraulic fracturing. According to the authors, alcohol helps remove waterblock in gas wells by reducing surface tension of the liquid phase and increasing the water evaporation rate. Depending on the nature of the block, alcohol can be introduced into gas wells by gas misting, alcohol imbibition, alcohol breakdown, or slug injection. Alcohol can also be used as an additive during acidizing or fracturing to achieve better clean-up after the operation is completed. Alcohol when used as a fracturing fluid is shown to result in better clean-up and increased gas productivity (Antoci, *et al.,* 2001). The main reason for improved clean-up is the lower viscosity and higher volatility of alcohol as compared to that of water. Lower viscosity enables better displacement of the cross-linked methanol and higher volatility leads to faster evaporation.

When dry gas is injected the residual liquid is evaporated by both the formation of a drying front (Zuluaga and Lake, 2008; Mahadevan, *et al.,* 2006) and due to compressibility driven drying (Mahadevan, *et al.,* 2006). The formation of drying front and its spreading affects the measured flowrates. Dry gas injection can substantially increase the rate of evaporation due to the inherent nature of the drying process which is mainly controlled by the gas flowrates. Most previous studies have focused on the evaporation of water from rock cores. A study focusing on gel evaporation may however have a greater appeal for the application considered in this study.

In this study we investigate the effectiveness of dry gas injection and solvent treatment as a method to improve the production from laboratory scale proppant packs affected by gel damage problem. Results from this study may also be applied to waterblock remediation. In order to study the clean-up of gel damage in laboratory we construct small scale models of fractured rock filled with proppant that keeps the fracture open. Dry gas is then injected into the fracture pack to study the clean-up of gel trapped within the porous fracture. After dry gas treatment wet gas is flowed back in a process similar to when the method is applied to field conditions. The gas flowrate recovery is monitored during both dry and wet gas flow conditions. The ultimate effective gas permeability achieved, after the treatment process, is used as an indicator of the treatment effectiveness.

The effect of addition of alcohol on the clean-up and the recovery of gas flowrate is also studied. The gel residue in the fracture pack is treated with an alcohol flow. At the end of treatment, wet gas flow is introduced and the flowrate is monitored to measure the effectiveness of treatment. The results of these experiments are reported in the section following that of the dry gas treatment.

Subsequently, a combination treatment, where alcohol is injected and allowed to remain and then followed by a dry gas treatment, is conducted. The result of this procedure is described in the penultimate section. Finally a small discussion section is devoted to the analysis of the effects of viscous fingering and drying from porous media. In the sections below we discuss the experimental methods followed by a description of the laboratory procedure. Subsequently, the results from experiments and the applications to field improvement of gas flowrates are discussed.

3.3 Experimental Method

3.3.1 Sandpack Preparation

A metal shell is created by wrapping aluminum shim stock around a solid cylinder. The diameter and length of metal cylinder is 1.0 inch and 3.0 inches, respectively. The metal shell is then closed at one end with a sand screen supported by a perforated end piece. The sand screen helps to retain and prevent the sand from flowing along with the injected fluids during experiment. The metal shell is then completely filled with 16/40 (0.422 – 1.20 mm) mesh size sand and packed by continuous vibration. Subsequently the shell is closed with another end piece lined with a sand screen and the entire assembly is securely fastened by using adhesive tape.

3.3.2 Fracture-pack Preparation

In order to create a fracture-pack, tight gas sandstone rock (taken from Inexco A.1 Wasp well in Merna field) of 2.2 inch long and 1.0 inch diameter is cut longitudinally to create equally sized rock halves. A portion of the face of the rock is further removed to reduce the thickness of the rock half. The two halves are then assembled in the metal shell, prepared using procedure described in the previous section for sandpacks. The space between the two halves is then filled with sand of 16/40 (0.422 – 1.20 mm) mesh size completely and packed. The width of this fracture-pack is approximately 3.8 mm. Figure 4 shows the picture of the assembly and the fracture-packs.

Figure 4: Fracture-pack assembly

3.3.3 Dry Gas Treatment

Dry gas treatment method is used to improve gas flowrate recovery. Dry sandpack/fracture-pack is first subjected to invasion by gel fracturing liquid, the preparation of which is described in the next section. The invaded gel is then subjected to wet gas flow-back. This step mimics the gas flow-back from the well subsequent to fracturing operation. The clean-up process during this flow-back is mainly due to viscous displacement. The displacement process ends when no more gel is visually observed at the outlet end. When dry gas is injected, the water content of the gel is mainly removed by evaporation.

3.3.4 Solvent Treatment

Solvent treatment is used to improve gas flowrate recovery from gel damaged fracture-pack. Fracture-pack is initially subjected to fracturing fluid invasion followed by wet gas flow-back which displaces the trapped gel. Two different solvent treatment methods are followed to improve gas flowrate recovery from the fracture-pack. First is a solvent flow treatment immediately following the gas flow-back and gel displacement. Second is a solvent soak treatment in combination with dry gas treatment after the gas flow-back.

3.3.5 Fluids Used

A borate cross-linked guar polymer is used as the fracture fluid. The gel is prepared by slowly adding 3.0 grams of WG-35 Guar Polymer (obtained from Halliburton) to 1 liter of water and stirring at moderate speed for 30mins. Finally, 1.75 ml BC-140 cross-linker (obtained from Halliburton) is added to the solution, making the solution crosslink immediately.

Air saturated with water is used to displace the gel in the sandpack/fracture-pack. Wet gas helps minimize the evaporation effect during displacement. Dry air is used to evaporate the water content of the gel. Laboratory-grade isopropyl alcohol of 99.8% purity is used in experiments performed for evaluating the effect of solvents.

3.4 Experimental Procedure

The sandpack is placed inside a Hassler type triaxial core holder and a confining pressure of 1000 psia is applied using compressed nitrogen. The tri-axial confinement prevents the sand from flowing under both axial and radial pressure. The sandpack is evacuated and fracturing gel is flowed through the sandpack at 10 cc/min for 10 minutes. A gravimetric analysis is made to obtain the initial weight gained by the sandpack after injection. The gravimetric analysis is performed after the core is taken out of the core holder.

A certain inlet pressure is necessary to initiate gas flow through the sandpack which is completely saturated with fracturing gel. This pressure may also be termed as the flow initiation pressure. A previous study by Ayoub, *et al.* (2006) shows that the flow initiation pressure is determined by the viscosity of the fracturing liquid and the permeability of the sandpack. In this study, the flow initiation pressure for the sandpack is determined by conducting an experimental sensitivity study with increasing pressure drops upwards from atmospheric pressure. The results show that the gas flow in sandpack is initiated after an inlet pressure of 80 psia is achieved (Figure 5).

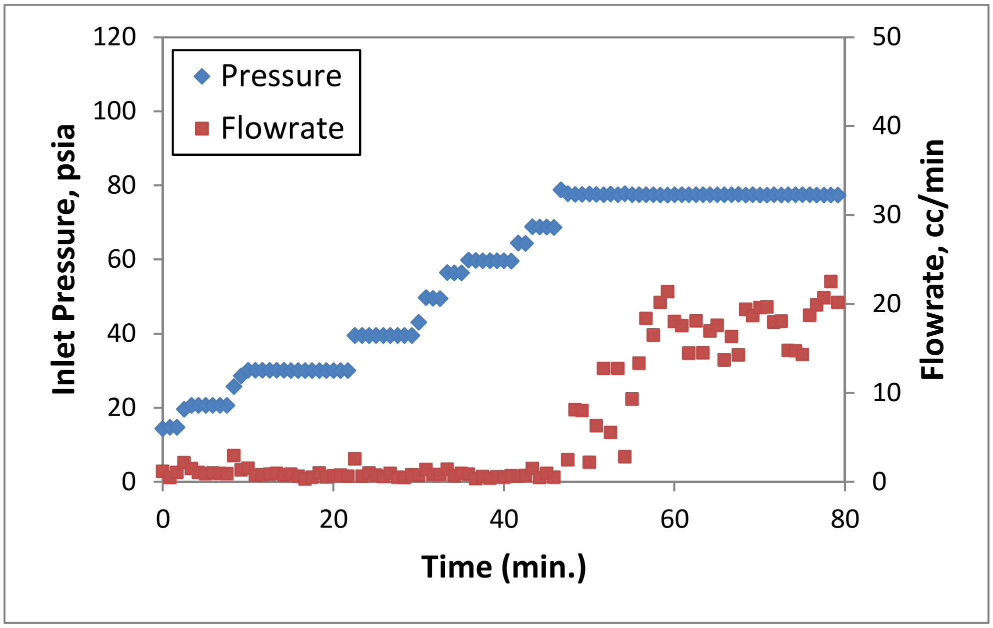


Figure 5: Determination of Flow Initiation Pressure in Sandpack

After gravimetric analysis, the sandpack is placed back in the core holder to conduct gas displacement process and is subjected to the same confining pressure as before. Compressed instrument air, humidified by passing through a column of water, is injected into the sandpack at an inlet pressure of 80 psia with atmospheric pressure at the outlet. The displaced gel, from the sandpack, is collected at the outlet. The gas injection is continued until no more fracturing liquid is collected at the outlet end. A gravimetric analysis of the displaced liquid is conducted to determine the gel saturation at the end of displacement. Data acquisition system (National Instruments cFP-1804 with LabView) connected to a work-station is used to continuously record flowrates measured using a digital mass flow meter (Aalborg GFM17).

Subsequent to the displacement step, residual gel saturation is achieved, and no more gel can be removed. This condition is similar to that observed in the field where there is no more fracturing gel recovery after a certain time during well flow-back. The gas flowrates achieved after the displacement step is low (3-5%) due to the low relative permeability of gas. The wet gas flow-back is similar to the field condition, where the gas produced is generally completely humidified due to contact with reservoir brine.

Dry gas is injected into the sandpack at 25 psia inlet pressure, subsequently, to initiate the evaporation process and to reduce the water content of the trapped gel. The gas flowrates at the outlet end are continuously monitored using a mass flowmeter which is connected to the National Instruments data acquisition system. The dry gas injection process is complete when all the gel is completely dried and no more improvement in gas flowrate is observed. The dry gas treatment process on fracture-pack is performed using the same procedure as that of sandpack.

Solvent treatment is applied either prior to the dry gas injection or at the end. In this study, Isopropyl Alcohol is used as a solvent. Approximately 15 pore volumes (80 mL) of solvent are flowed through the fracture-pack after the end of displacement. A soak period of 3 hours is provided to enable better dissolution of the gel before dry gas treatment.

The above treatment processes are carried out using the equipment setup as shown in Figure 6.

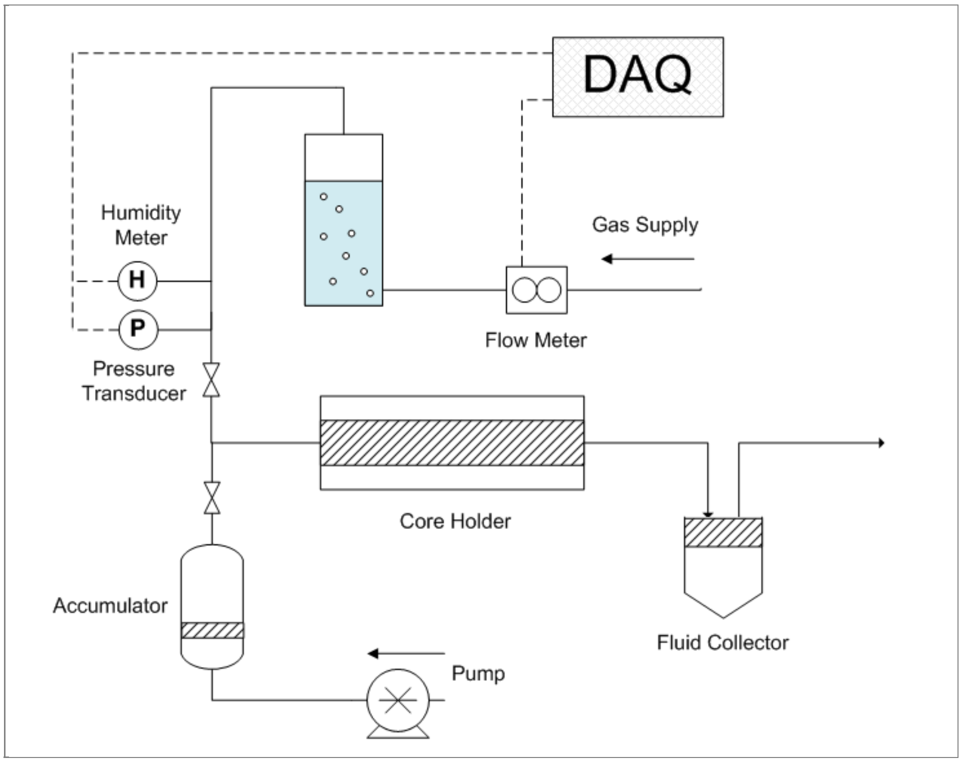


Figure 6: Schematic of experimental setup for measuring gas flow recovery from gel damaged fracture-pack and sandpack

3.5 Results and Discussion

3.5.1 Gel Clean-up by Dry Gas Treatment in Sandpacks

When dry gas is injected, the water content of gel is gradually removed due to the partitioning of water between gas and gel phase. Water is evaporated at greater rates near the inlet end due to the lack of water in the injected gas. The gas becomes saturated with water on contact with the gel phase as the mass transfer rates are expected to be sufficiently fast to establish complete phase equilibrium across the entire pore space. The drying rate of gel in the sandpack therefore depends mainly on the gas convection rates and to some extent on the expansion driven drying. Viscous fingering, whose effects are discussed in a later section, however, can introduce complexities and thus cause a deviation from the above drying process.

When wet gas is flowed through the sandpack, to mimic gas well flow-back after a hydraulic fracturing treatment, only a portion of the gel is displaced and hence the flowrate of gas recovers only to a small extent. Figure 7 shows the recovery of gas flowrate during displacement of gel from a sandpack. The gas flowrate is essentially zero at the beginning of the displacement and for up to an hour. This is because the gel saturation is 100% initially and the displacement of the gel is slow due to the high viscosity of the gel. At the end of displacement, when no more gel is observed at the outlet end, a gravimetric analysis is performed to determine the residual gel saturation. It is observed that about 80% of the initial gel is still trapped in the sandpack at the end of displacement.

Subsequent to the gel removal by displacement, dry gas is injected to evaporate or desiccate the trapped gel. Figure 8 shows the improvement of gas relative permeability during the evaporation process. The effective gas relative permeability increases gradually from a value of ~0.05, initially, to approximately 0.29 at the end of evaporation process. The gas relative permeability at early times during the dry gas injection is lower than that at the end of displacement. This is due to the fact that the sandpack is taken out of the core holder for weight measurement after displacement finished. This may disturb the flow channels inside the sandpack and some channels may close due to yield stress, which reduces the gas relative permeability when the experiment is resumed. Due to the evaporation process, the sandpack is completely dry after about 20 hours. A gravimetric analysis confirms that the weight of gel in sandpack after the dry gas injection is close to zero.

The gas flowrate at the end of the dry gas treatment is much higher than that at the end of displacement by gas flow-back. Thus the viscous displacement process alone leads to a poor recovery as compared to the dry gas treatment process. The gas relative permeability does not, however, recover beyond 29% even if the sandpack is completely dry. This is probably so because the evaporated polymer organizes itself in the pore space in such a way that the pore throats are plugged with the deposited polymer which reduces the overall permeability of the sandpack. This improvement is not significant. Field rates based on this improvement will still be uneconomical.

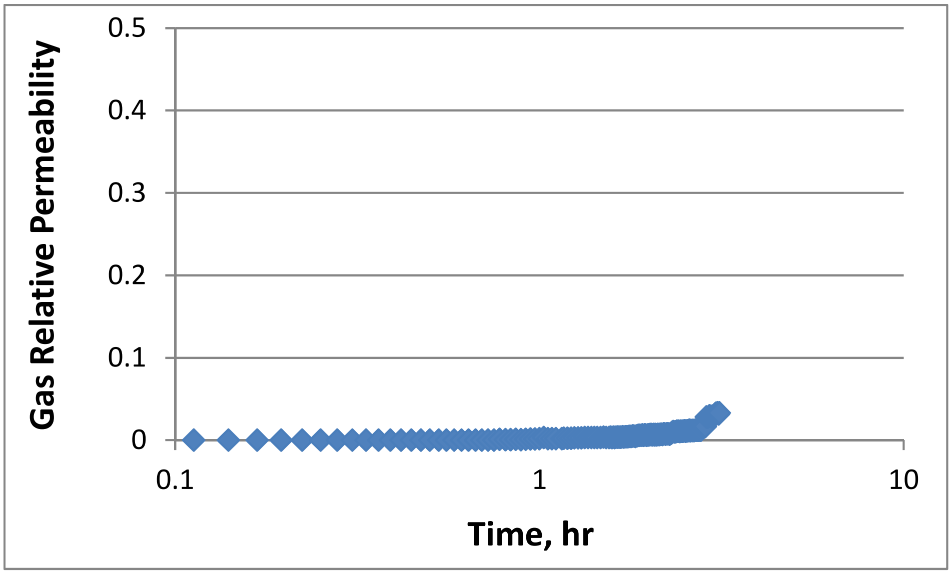


Figure 7: Recovery of effective gas relative permeability in sand pack during displacement at flow initiation pressure of 80 psia at the inlet and 14.7 psia at the outlet.

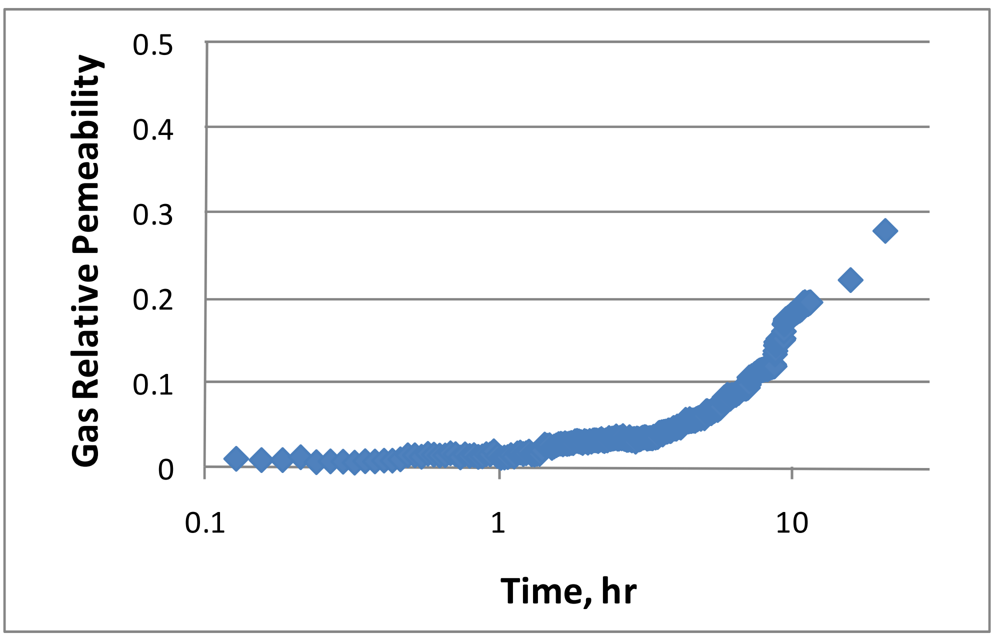


Figure 8: Recovery of effective gas relative permeability in sandpack during dry gas treatment after displacement at a pressure drop of 10 psi (25 psia inlet and 14.7 psia outlet)

3.5.2 Gel Clean-up in Fracture-pack

When dry gas is injected into a fracture-pack, the evaporation process takes place in a similar way to that of the evaporation by dry gas in a sandpack. Figure 9 shows the gas relative permeability recovery with time during displacement by gas flow-back in a fracture-pack. The gas flowrate recovers to about 5% of the original gas flowrate at the end of displacement while approximately 70% of the gel still remains trapped in the fracture-pack.

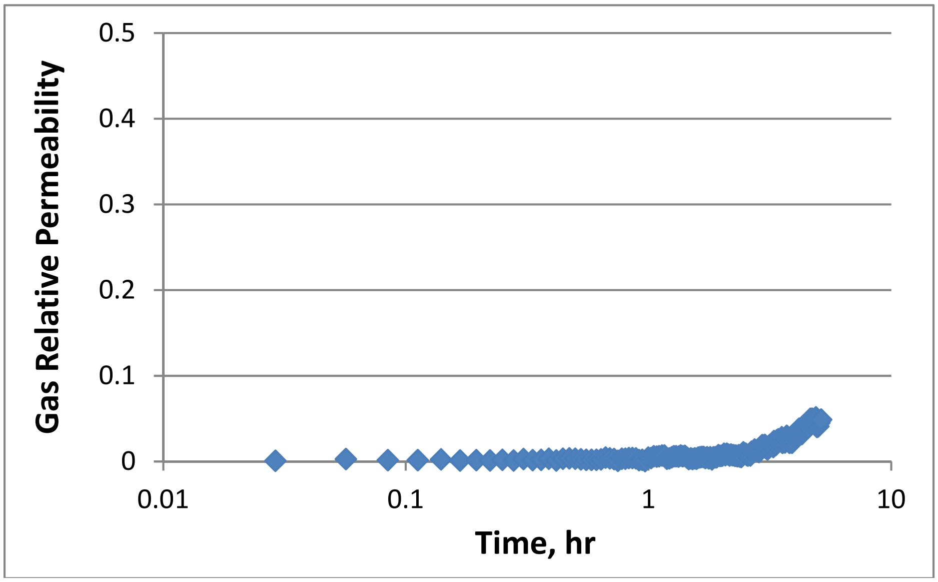


Figure 9: Recovery of effective gas relative permeability in fracture-pack during displacement at flow initiation pressure of 80 psia at the inlet and 14.7 psia at the outlet.

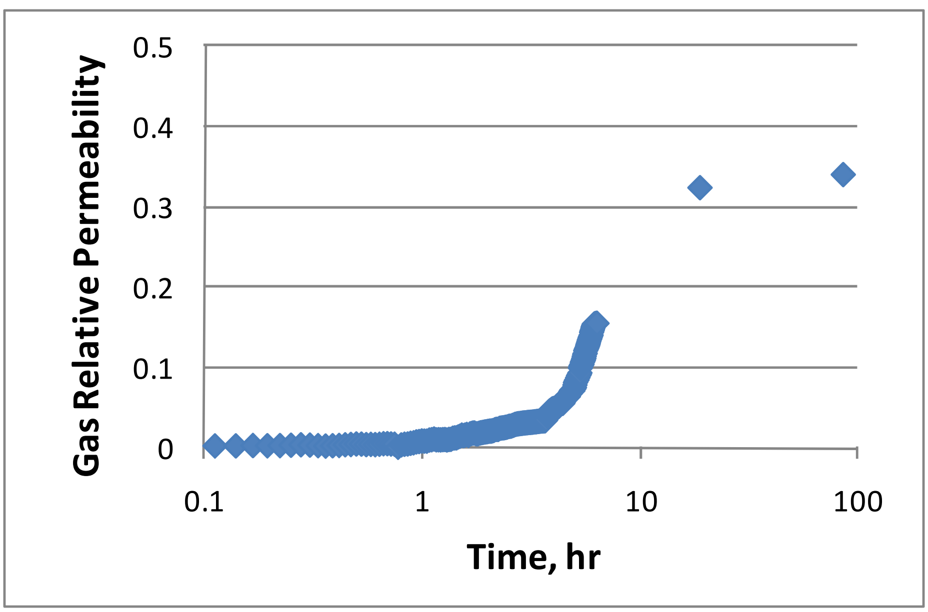


Figure 10: Recovery of effective gas relative permeability in fracture-pack during dry gas treatment after displacement at a pressure drop of 10 psi (25 psia inlet and 14.7 psia outlet)

Figure 10 shows the improvement in gas relative permeability when the fracture-pack is further subjected to dry gas treatment. The effective gas relative permeability reaches

32% before the rates achieve a plateau. Thus the dry gas treatment is effective in reducing the liquid gel saturation while improving gas recovery; however, this improvement is not significant enough to increase field production substantially. It should be noted that the fracture pack was taken out of the core holder after displacement. The figure shows the flowrate evolution after the fracture pack was replaced to conduct the evaporation experiment. The early times show a much smaller effective gas relative permeability compared to that at the end of displacement. This could be mainly due to the lower pressure drop (10 psi) during the evaporation period as compared to the displacement (65 psi) period.

3.5.3 Effect of Solvent Treatment with No Soak

Subsequent to displacement by gas flow-back, 15 pore volumes of isopropyl alcohol are injected into the fracture to treat the residual gel. The fracture-pack is then immediately subjected to wet gas flow-back. Figure 11 shows the improvement of the effective gas relative permeability with time during gas flow-back. The improvement is compared with a case when the gas flow-back is continued without any solvent treatment. The trends readily show that when the residual gel is treated with alcohol the rate of improvement and the ultimate gas relative permeability are slightly higher. When alcohol treatment is used, the improvement of gas relative permeability in the first 20 hours is significant. Subsequently the improvement is gradual. The most likely cause of this variation is that the alcohol is more volatile and is easily evaporated during wet gas flow back as the wet gas contains no alcohol concentration initially. Subsequently the residual gel continues to evaporate due to compressibility driven drying (Mahadevan, *et al.,* 2006), which is considerably slower. When there is no alcohol treatment, only compressibility driven drying takes place and improvement due to gel saturation reduction is much more gradual.

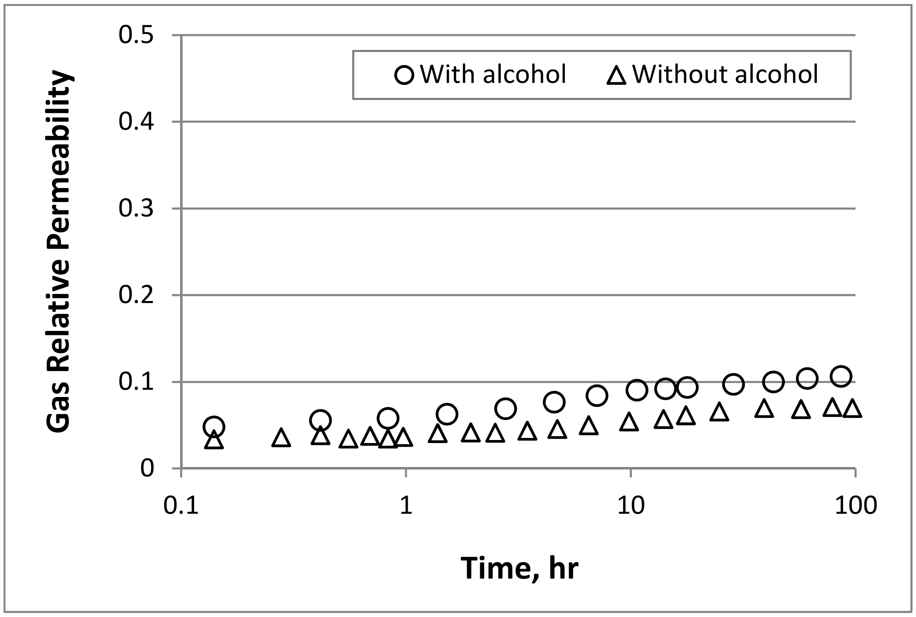


Figure 11: Effect of solvent treatment on gas relative permeability in fracture-pack during wet gas flow-back at 10 psi pressure drop.

The ultimate gas flowrate achieved after the alcohol treatment is 11% of the original undamaged rate, which is lower than that achieved with a dry gas treatment (34%). While multiple treatments of alcohol may be able to increase the end point gas relative permeability or improve the ultimate gas flowrate achievable, the use of alcohol alone is not as effective as a dry gas treatment.

3.5.4 Solvent Soak/Dry Gas Combination Treatment

When both dry gas and solvent treatment are used, the resulting clean-up and improvement in the gas flowrate is expected to be greater. Two different treatment processes are considered in this study. In the first case dry gas treatment is conducted after an alcohol injection and soak period. In the second case dry gas treatment is followed by an alcohol treatment.

Approximately 15 pore volumes of alcohol are injected into the fracture-pack after displacement and allowed to remain in the fracture-pack for approximately 3 hours to allow enough time for the gel to dissolve in alcohol. Subsequently dry gas is injected to completely evaporate the alcohol and water trapped in the fracture-pack. The improvement in relative permeability during dry gas treatment is shown in Figure 12. The figure also shows the improvement during a similar dry gas injection without any alcohol treatment. The trends observed in the figure clearly show a greater and faster improvement in the gas flowrate in the case of alcohol treated fracture-pack as compared to that when there is no alcohol treatment. When treated with alcohol it takes less than an hour to achieve 15% of the undamaged gas flowrate compared to 6.5 hours when not treated with alcohol. The ultimate gas effective relative permeability achieved is also high at 43%. It is possible that the higher volatility of alcohol combined with the phase behavior of gel causes faster and greater recovery of gas rates. We are still not able to restore the original gas rate prior to gel treatment.

In order to investigate the effect of addition of isopropyl alcohol (IPA) to gel, we performed an experiment ex-situ of the porous sandpack/fracture-pack. The experiment was timed to evaluate the gel's water content when it is simply exposed to IPA. 10 grams of the gel was immersed and soaked in 100 ml of IPA for 3 hours which is an identical soak time compared to the alcohol treatment experiment on the sandpack. Visual observation of the gel immersed in the alcohol showed that the gel shrank and only a skeleton structure of a white colored substance (most likely the polymer and the cross-linker that were added to create the gel) remained along with some entrapped water. The entire mixture was filtered using a type 1 Whatman filter paper in a Buchner funnel. The residue exactly corresponded to the weight of polymer and cross-linker used in making the gel. Thus the IPA addition results in complete removal of water from the gel matrix which perhaps represents the ultimate equilibrium phase behavior of the gel alcohol system. The reduction of gel size/weight due to removal of water content can lead to reduction of gel saturation and hence allow greater gas flow.

When dry gas treatment alone is used the ultimate gas rate is a maximum of 34% of the original undamaged fracture-pack. This is evidently lower than that of the case when alcohol treatment/soak precedes the dry gas injection.

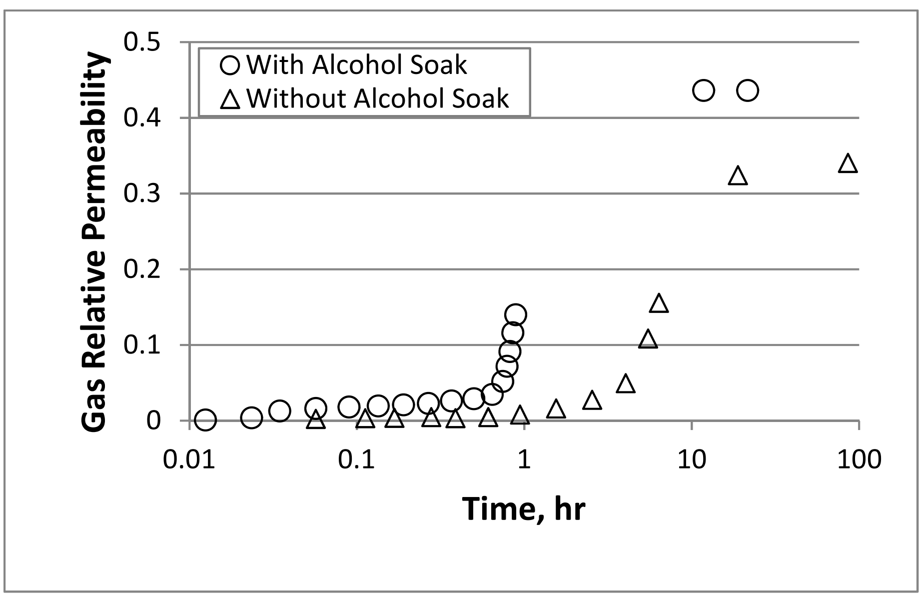


Figure 12: Effect of solvent treatment/soak on gas relative permeability in fracture-pack during dry gas injection

Injection of alcohol after a dry gas treatment, when the residual gel is completely dried, does not produce any significant impact on the recovered flowrate. This may be due to the non-dissolution of dried polymer gel by the alcohol.

3.5.5 *Discussion on Gel Drying*

Drying of liquids from porous media due to gas flow depends on the distribution of the liquid within the medium. When the viscosity of the liquid is small capillary effects can redistribute the volatile liquid and enhance drying rate (Mahadevan 2006). However, in the gels, the viscosity is generally high and hence the gels are not mobile. Thus gel is poorly distributed within a porous medium and is also affected by viscous fingering. The drying rate of gel, in the presence of complex viscous fingering and other mass transfer limitations is not well understood. This area is a candidate for future investigations as such compositional effects in the presence of unfavorable mobility displacements has wider applications than considered in this study. This is probably the reason that the recovery of gas relative permeability is not as high as anticipated.

3.6 Model Comparison to Experimental Data

To account for viscous fingering effect, we assume that the sandpack/fracture-pack consists of multiple channels. Each channel is considered a separate system with different gel saturation at the end of displacement regime. In each channel, it is assumed that the gas flow is one dimensional and a drying front develops due to dry gas injection. Therefore, a one-dimensional model for evaporation due to dry gas injection, developed in a recent study (Mahadevan, *et al*. 2006), is used to calculate the saturation of the gel phase in the each channel. The resulting saturation profiles may be used to calculate the effective gas relative permeability (for one channel) using the following equation:

$$k_{rg,eff} = \frac{L}{\int_0^L \frac{dx}{k_{rg,local}}}, \tag{2}$$

where $k_{rg,local}$ is obtained using a Corey type model with local gel phase saturation.

The overall effective gas relative permeability for sandpack/fracture-pack is simply the average of the effective gas relative permeability in each channel:

$$k_{rg,overall} = \frac{\sum_{i=1}^{n} k_{rg,eff,i} A_i}{\sum_{i=1}^{n} A_i}, \tag{3}$$

where n is the number of fingering channels and A_i is the cross-sectional area of finger i

The model assumes the following:

- 1D (linear, homogeneous) system.
- Temperature variation caused by Joule-Thompson cooling is negligible
- Phase behavior is described by Raoult's Law (this assumption may be acceptable if polymer concentration in gel is low enough or gel saturation is high)
- The gas obeys ideal gas law
- Local thermodynamic equilibrium exists.
- Mass transfer is dominated by convection
- Liquid flow is negligible (absence of capillary effects) during evaporation.

The saturation profile with the presence of a drying front then displays the following features: a time decreasing flat profile ahead of the drying front, an inlet saturation that decreases in time, the disconnection of the liquid (zero liquid saturation) at the inlet, and the onset of a moving front, with two boundaries located at x_r and x_f moving in time. Figure 13 shows the schematic of the gel saturation profile.

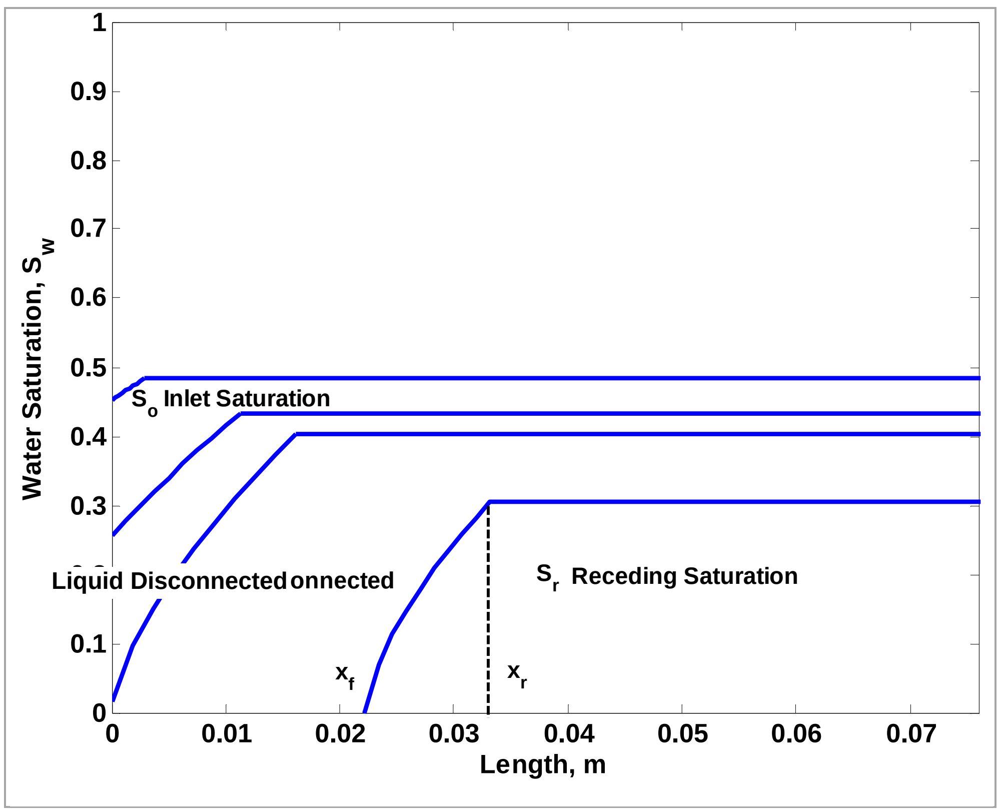


Fig. 13 – Gel saturation profile schematic during a dry gas injection process (Mahadevan, et al., 2006)

In the initial stage, the liquid phase is connected to the inlet. Later, the phase disconnects and a moving drying front propagates into the porous medium. The receding saturation decreases due to evaporation by gas expansion. In the presence of gel, instead of water, because the gel is very viscous, it is assumed that $x_f \approx x_r$ (i.e. the drying front is sharp) and the drying front is immediately disconnected from the inlet once dry gas injection starts.

The following equations describe the change of S_r and x_r with time:

$$(1-x_r)\frac{1}{\varepsilon}\frac{dS_r}{dt_D} = -u_D(1)+u_D(x_r) \ , \tag{4}$$

and

$$S_r\frac{1}{\varepsilon}\frac{dx_r}{dt_D} = u_D(x_r)\,. \tag{5}$$

Solving Equations 4 and 5 allows us to obtain the gel saturation profile at any time during dry gas injection. Once the saturation profile is obtained, the local gas permeability for each grid block can be easily calculated using the gas relative permeability curve that we have determined experimentally. The effective gas relative permeability is obtained by taking the pore volume average over the entire length of the core.

To run the simulation, we assume the sandpack/fracture-pack consists of 10 separate fingering channels. The initial gel saturation in each channel is adjusted to obtain a match between model and experimental results. The weighted average of the gel saturation in all channels, however, is constrained to be equal to the residual gel saturation observed in experiments. Figures 14 and 15 show the comparison of experimental results with the mathematical model prediction of gas relative permeability for both sandpack and fracture-pack.

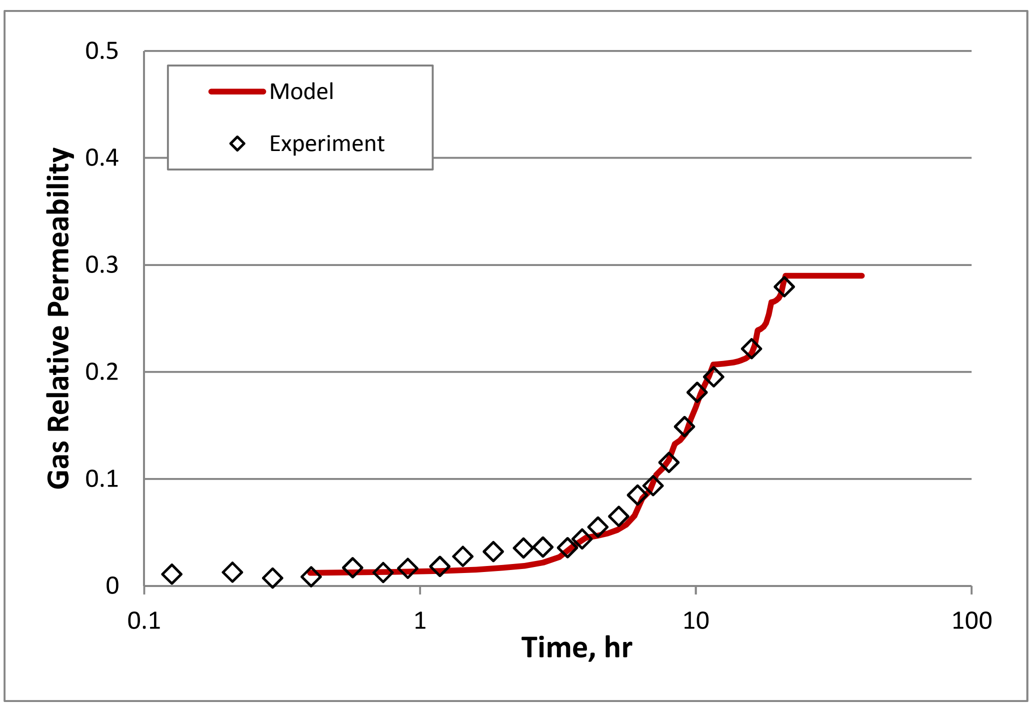


Figure 14: Gas relative permeability in sand pack during evaporation

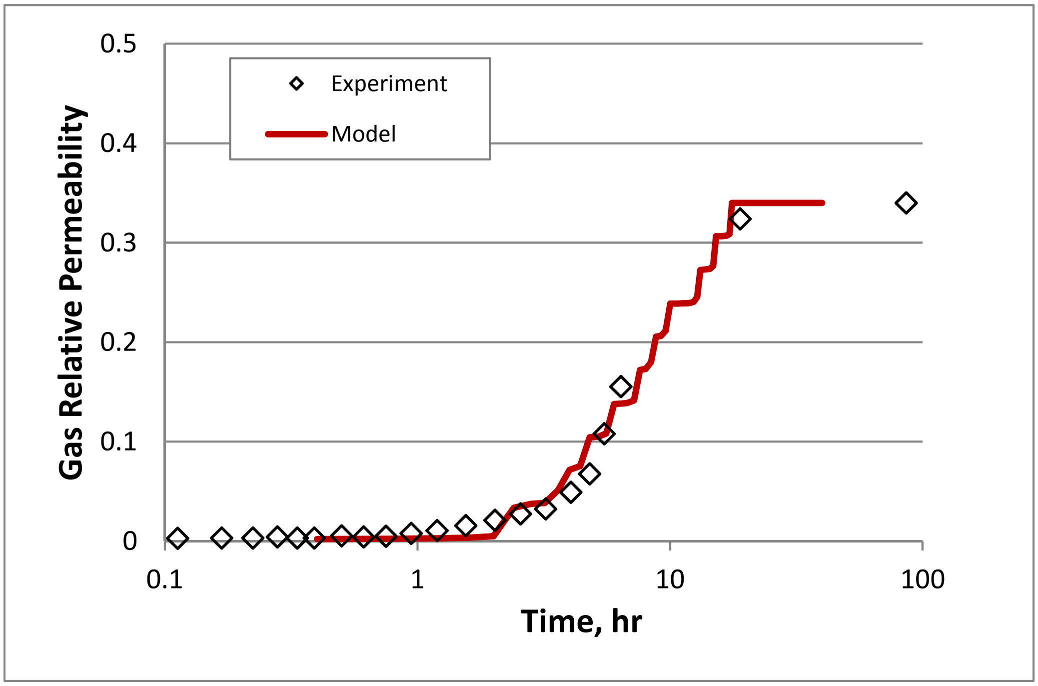


Figure 15: Gas relative permeability in fracture-pack during evaporation

The above figures show reasonable comparison between model and experimental results. When a channel is completely dried out, it does not contribute to the improvement of the overall gas effective permeability anymore. This explains the steps profile in the model results. When the number of channels is increased, we can expect a smoother profile, which is closer to what happen in reality.

The model proposed is quite simple and can result in non-unique solutions. Alternate solutions, which show significant remaining gel, are possible.

4.0 Field Implementation

Originally, the seventh and final task was expected to be field implementation of alcohol injection followed by dry gas injection in a gas well. However, when we carefully examined the potential results under the best case scenario, we concluded that field implementation is going to be a failure.

As part of the preparation, Williams conducted a long-term well test in summer 2010. A downhole pressure gauge was used to collect the data at a cost of $115,168. Figure 16 shows the results from the well test. The well was shut in over a period of two months.

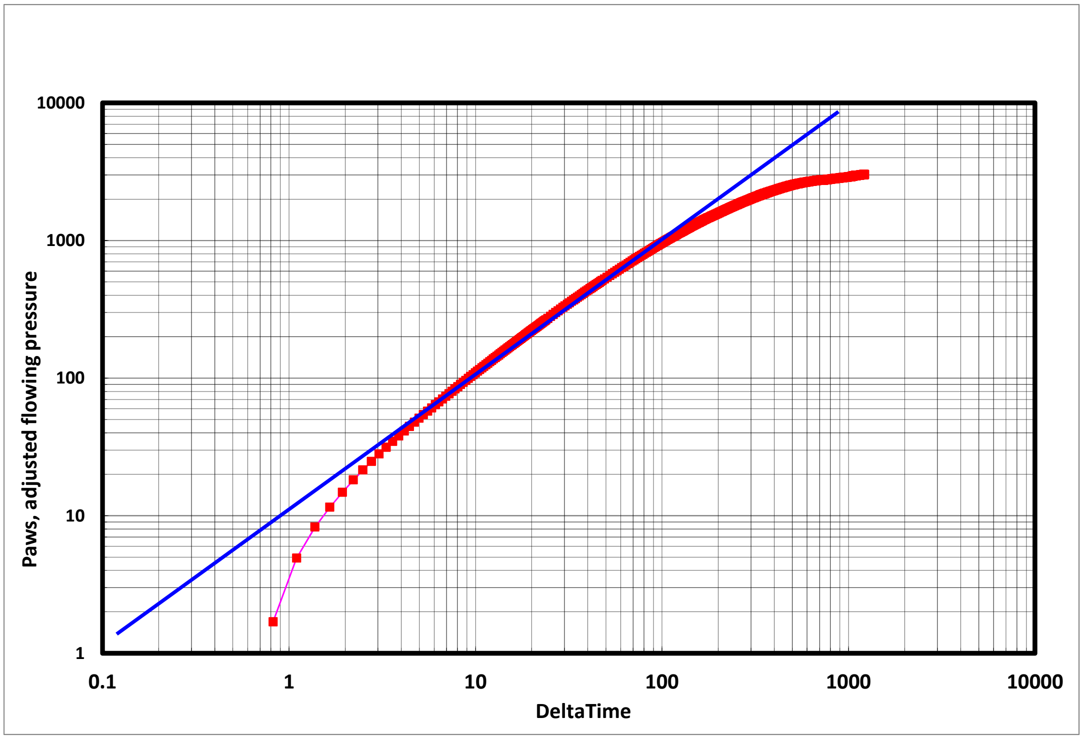


Figure 16: Build-up test on Miller Federal 7-4

As shown, the build-up test is largely dominated by the wellbore storage effect. An attempt to analyze the data beyond storage failed due to non-unique solutions for a fractured well. However, the results indicated a small skin with low fracture conductivity.

The well currently produces 63 MSCFD. The operating costs per month are $13,040. If we assume a current gas price of $2.50/MSCF, and further assume that treating the well will improve the performance four-fold (an optimistic scenario), it will take more than four years to recover the cost of treatment, which is estimated to be $103,503. The most likely scenario is an expected improvement in well production of 25 to 50%. This increment does not justify the cost of treatment under current gas pricing. As a result, we decided not to conduct the field test.

5.0 Conclusions

1. Experiments on sandpacks and fracture-packs show that dry gas treatment leads to clean-up of gel damage by removing the water content of the gel through evaporation process, thus reducing gel saturation.
2. The improvement in ultimate gas flowrate during flow-back in sandpacks and fracture-packs due to dry gas treatment is several times higher than that obtained by the viscous displacement method alone.
3. Alcohol treatment of the damaged fracture-pack results in a marginal improvement in the gas flowrate during flow-back. However, when the alcohol treatment is combined with a dry gas treatment, gas flowrate recovers faster and to greater values compared to dry gas

treatment alone. Possible dissolution of the gel in alcohol, combined with the low interfacial tension and high volatility of alcohol may explain this observation.

4. Experiments on the phase behavior of air-gel system shows that the vapor pressure of water in the gas phase is not affected until very high mass fraction of polymer is achieved. It is unlikely that such high mass fraction can be achieved in the field.
5. Isopropyl alcohol-gel phase behavior experiment shows a complete redistribution of water into alcohol from the gel phase resulting in only polymer structure residue. This shows that alcohol treatment has the potential to remove gel damage by removal of water.
6. A model based on drying front propagation is able to predict gas flowrate recovery during dry gas treatment and the predictions compare well with experimental observations. The model is based on some simplifying assumptions. Alternate models can be developed that may result in different residual amounts of gel. The model may be scaled up to reservoir conditions in order to make quantitative predictions for field applications of dry gas treatment.

6.0 Future Work

1. In a fractured well, gas movement actually goes through different flow periods, from fracture linear flow, formation linear flow to transition flow, elliptical flow and finally pseudo-radial flow. We can potentially develop a more complex simulator to handle these flow periods. The grid sizes near the fracture region need to be very small to accurately calculate the capillary end effects and the gas flowrates. This will require the use of finite element modeling with local grid refinement and/or unstructured grid.
2. The severe of the gel damage problem depends on the type of gels and the extent of leak-off. This, in turn, depends on the gel characteristics and the polymer concentration (Ribeiro and Sharma, 2011). Future work can look into this matter to accurately determine the fracture face skin.
3. A 3-D flow simulator of flow in fracture can be coupled with gel drying model to realistically predict flowrate recovery in fractured well.

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