Fracture Height Containment in the Stimulation of Oriskany Formation

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The Oriskany sandstone formation has been a prolific producer of natural gas in the Appalachian basin since 1930s. Lot of production wells have been converted to gas storage wells for the ease of operation. Natural gas storage industry is a vital part of North American energy driven economy because of the fluctuation in seasonal demand and in maintaining the reliability of supply needed to meet the demands of the consumer. However, the storage wells suffer from an annual deliverability loss of 5% owing to the various damage mechanisms. A lot of work pertaining to the issue of identification of damage mechanisms and subsequent development of stimulation technology in order to mitigate the damage and restore the wells deliverability have been done in a joint effort between The Gas Research Institute, Department of Energy, American Gas Association and the various other operator companies involved in the storage industry. Operators mostly rely on traditional methods such as blowing, washing, reperforating, acidizing, infill drilling to restore wells deliverability. These traditional methods do provide short term benefits, but the longevity is not sustained and the overall situation remains same. Hydraulic fracturing is not preferred in terms of legitimate concerns over excessive vertical height growth, long fracture fluid cleanup times, lack of expertise and cost. This research study was carried out to understand the various damage mechanisms affecting the Oriskany wells, with a focus on gas storage wells. We then developed a dataset of reservoir properties, rock properties and fracture treatment data for Oriskany based on a complete literature review and calculations from a sonic log. Parametrical studies were carried out to investigate the effect of type of fracture fluids, injection rate, types of proppant, treatment volume, reservoir pressure and treatment schedule on fracture geometries in the Oriskany formation. Based on the results, we developed new stimulation methods that lead to increased well deliverability, fracture height containment, and higher average fracture conductivity. This new understanding and knowledge help in practicing engineers design better treatments in stimulating Oriskany wells. [DOI: 10.1115/1.4023169]

Keywords: fracture height containment, Oriskany sand formation, gas storage wells

Introduction

Underground gas storage reservoirs are used worldwide to store produced natural gas during the periods of low demand and for use during the periods of high demand [1]. Underground gas storage is an efficient way to balance the discrepancies between demand and supply. Effective use of underground gas storage requires delivery and permanent containment of a certain level of gas as base or cushion gas. The base gas maintains the pressure required for deliverability at the minimum acceptable flow rate.

Gas deliverability from an underground gas storage facility requires the preinjection of desired level of working gas. The rate at which an underground gas storage facility can accept gas on injection and deliver gas on withdrawal is normally dependent on the characteristics of both underground reservoir and surface facilities. These reservoirs are often depleted oil and gas reservoirs which have been converted to storage for the ease of operation and to better utilize the already existing facilities.

As depleted reservoirs are formations that have already been tapped of their recoverable reserves, this leaves an underground formation geologically capable of holding natural gas. Also as the inventory in terms of production and surface equipment already exists, costs are minimized when depleted reservoirs are converted to gas storage facility. Factors governing whether or not depleted reservoirs will be suitable for gas storage are both geographic and geologic.

Geographically depleted reservoirs should be relatively close to the consuming regions, transportation facilities, and distribution network. Geologically depleted reservoirs should have high permeability and porosity. The porosity determines the amount of gas that can be stored, whereas the permeability determines the rate at which the gas flows in the formation which in turn determines the rate at which gas can be injected or withdrawn from the formation. Proper selection of gas storage reservoir is important to allow safe and economic operation of the project on a long time basis. Studies have shown that with time, the repeated high-pressure injection and withdrawal of gas progressively damages gas storage wells by filling the pore spaces with inorganic precipitates, hydrocarbons, organic residues, production chemicals, bacterial fouling, emulsions, water blockages and naturally occurring particulates [2].

As a result of formation damage individual U.S. gas wells are prone to deliverability losses at the rate of 5% annually [3]. Hence over a period of 10 years losses can amount to 50% which further increases the operating costs and serves as a huge loss considering today's energy prone economy. Most of the times the damage is in and around the wellbore hence we need short, wide high conductivity fractures rather than massive hydraulic fracturing. A significant amount of money is expended without a clear knowledge of the damage being addressed. Second, even though storage operators may understand the different damage mechanisms, they have no diagnostic approach to determine which mechanism is responsible for damage in a particular case [4].

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Storage operating companies have tried and tested various techniques to maintain and enhance deliverability. Amongst the various stimulation technologies, hydraulic fracturing remains one of the most cost-effective means of accomplishing deliverability enhancement although valid concerns such as fracture height growth outside the zone of interest, expected cost or lack of experience and long fracture fluid clean up times need to be addressed accordingly. Also hydraulic fracturing if and when executed can effectively stimulate the well and restore deliverability irrespective of any kind of damage the well might be suffering from. This in turn with the longevity of the treatment makes it the best alternative to mitigate and surpass damage in gas storage wells.

Lot of work on the testing and subsequent development of new and novel fracture stimulation technologies had been carried out as part of a joint effort between the U.S. Department of Energy and Gas Research Institute Research & Development program that began in 1994. The technologies included tip-screen out fracturing, hydraulic fracturing with liquid CO_2 and proppant, extreme overbalance fracturing, and high-energy gas fracturing. Based on the results derived from the project, conclusions were drawn concerning the applicability and utility of these technologies, storage well damage conditions, remediation candidate selection and future technology needs [3].

Also not to mention the fact that storage operators mostly rely on traditional methods for deliverability maintenance such as blowing the wells, surging, swabbing, coil tubing cleanouts, reperforating and acidizing accounting for 80% of all storage well remediation which in turn provides limited short term results but the overall scenario remains the same. Apart from the exception of acidizing none will improve the well to a stimulated condition for a sustained period of time [3].

In this research after understanding the damage mechanisms, we will develop suitable fracturing technologies in order to mitigate and bypass the near wellbore damage and subsequently restore and increase the wells deliverability. Also through this research I will address the legitimate concerns of the storage operators in terms of fracture height growth out of the zone.

Damage Mechanism in Oriskany Gas Storage Wells

One of the foremost considerations before applying any type of deliverability enhancement technique is to understand the types of damage that has to be removed. A clear understanding of the damage mechanism is necessary in order to fully utilize the benefits of various stimulation technologies. Otherwise, ineffective methods might be chosen and lead to waste of investment or even overall treatment failure. Gas storage well damage is confined to near wellbore with the depth being a few inches hence surpassing the near wellbore damage would definitely lead to increase in deliverability of gas storage wells [5]. Damage mechanisms in gas storage wells are summarized as follows.

(1) Bacteria Fouling—Stagnant water and low flow conditions as encountered in the bottom of the wellbore are ideal for bacterial growth. Also even small amounts of oil and grease provide nutrients for growth. The above mentioned problem is further strengthened by a case study conducted in an Oriskany storage field. The wells were watered with fresh water in order to wash away the plugging material. It was allowed to stand for 24 h after which a bailer sample was procured and tested. Every sample contained general bacteria population especially sulfate reducing bacteria and almost all samples indicated iron oxide, iron sulfide or hydrogen sulfide of significant quantities, however, byproducts of biological growth attributed greatly to the plugging incurred in well [6].

The results of the treating program are as follows:

- All samples contained general bacteria population. Water samples used to treat the wells also showed signs of microorganisms. Plugging can be greatly attributed to byproducts of biological growth such as bacteria slime and iron sulfide.
- High iron content supports the reaction with hydrogen sulfide to form iron sulfide which was further confirmed by sidewall cores. It showed definite plugging with iron sulfide. It is also indicative of the presence of sulfate reducing bacteria which reduces sulfates to sulfides.
- Low *p*H indicated acidity in samples, corrosive atmosphere and also the surface tension of the water sample procured was extremely high, which could definitely lead to the problem of water blockage.

As can be seen from above bacteria plugging and water blockage were identified as the major causes for the reduction in flow rate. The treatment program developed included a solution of alcohol, bactericide and fresh water. Water was used as a carrier fluid for the alcohol and bacteria and also to penetrate deeper into the formation, whereas alcohol and bactericide were added to reduce the surface tension and eliminate the growth of bacteria, respectively. Results showed significant increase in accordance with the open flow potential of wells and hence increase in deliverability.

(2) Inorganic Precipitates and Scaling—Precipitated compounds include compounds such as iron oxide, iron carbonate, iron sulfides, salts such as sodium chloride, calcium chloride and barium sulfates to name a few. The presence of inorganic precipitates is undoubtedly influenced by the following:

- type and quantity of fluids injected and withdrawn from the formation
- operating procedures
- presence of bacteria
- reservoir characteristics such as temperature and pressure

Examining the source of damage can provide a keen insight into the amount of scales that can exist downhole. Downhole samples or sidewall core samples should be obtained to quantify the amount and type of scale. Scales basically refer to the precipitation of compounds such as calcium carbonate, iron carbonate, iron oxides, and iron sulfides to name a few.

- Carbonate scales—Occurs as the *p*H increases in the presence of carbonate or bicarbonate ions and metal ions such as calcium, magnesium and iron. The origin of calcium and magnesium can be the formation brines, whereas origin of iron can be traced back to either formation brine, but a more likely source is the casing or tubing. Many waters naturally contain carbonates or bicarbonates, but in gas storage wells, the source of carbonate is probably the CO_2 in the injected gas [5]. Guidelines governing the CO_2 content of injected gas might vary, but it does not take much CO_2 in the gas to produce huge amounts of carbonate scales over the years.
- Sulfide scales—Source is probably the formation. H_2S (hydrogen sulfide) can react with iron to precipitate iron sulfide. Also if H_2S reacts with oxygen, elemental sulfur could also precipitate out.

(3) Production chemicals and hydrocarbon deposits—Hydrocarbon oils, ester compounds, compressor oils, bactericides, and corrosion inhibitors are all part of the production chemicals/organic residues found in the samples collected and are generally identified as a dark layer along the wellbore face or as substances lining/plugging the pore throats. Also the production chemicals are filtered out near the wellbore plugging the pore throats, which further reduce the permeability. Seepage of compressor oil, lube oil, and grease has been identified as a universal problem which not only reduces permeability but also serves as nutrients for bacteria growth.

(4) Drilling and injection particulate plugging—Drilling leads to deposition of mud cake and filtration of drilling fluids into the formation which can impair permeability by

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plugging the pore throats and by reducing the effective permeability to gas.

(5) Mechanical obstruction—Mechanical obstructions include inefficient connectivity between wellbore and formation and any tools lost downhole and not recovered during fishing operations. Proper cement job should be carried out in order to prevent the well from sloughing. Oriskany is believed to be a well sorted sandstone without much unconsolidation.

(6) Relative permeability effects and water blockage—Water blocking is caused by the capillary forces present in porous rock and the high mobility ratio of gas and water [7,8]. Gas rapidly breaks through the water remaining around the wellbore when the well is put back on production following a stimulation treatment. The low viscosity gas forces some of the water out but after the gas breaks through, a higher water saturation is left around the wellbore. This higher water saturation reduces the effective permeability to gas. Severity of water blocking increases in low permeability formations where capillary pressures are high. In gas storage wells, dry cycling of natural gas in and out of the wellbore upteem number of times reduces the near wellbore to very low residual water saturation, hence any aqueous fluid introduced will definitely increase the residual saturation. This would decrease the relative permeability to gas and in turn reduce deliverability. Water blocking is also severe when combined with other forms of damage, either mechanical plugging such as mud filtrate invasion, cement filtrate invasion, scaling and organic precipitation.

Use of alcohol in stimulation treatments aids in removal of water blockages. The advantages associated are as follows:

- Better and rapid clean-up due to volatile nature of alcohol.
- Reduces the surface tension which further reduces the capillary pressure and aids in better and rapid clean up.
- Ease of availability and low in cost as compared to surfactants, also can penetrate deeper into the formation as compared to surfactants which have a tendency to get adsorbed on the clay surface.

(7) Excessive sand production in unconsolidated formation.

(8) Wellbore condition—According to the American gas association database 70% of the active gas storage reservoirs are 25 to 100 years old. This means that they may contain wellbores of similar ages and hence ample opportunities for corrosion products, geochemical precipitates, microbial byproducts, fluid, etc., to accumulate in these wellbores. No stimulation technique will be effective if it never reaches the formation, spends or reacts with wellbore fill, precipitates [5].

Pickling (removal of iron scales from tubing/casing) is also considered a good practice for wells that have not been treated in many years; circulation of fluids removes some soluble salt minerals and other debris. It also helps in elimination of large source of iron which prevents formation of iron related precipitates later on if and when the well is subjected to treatment.

(9) Stimulation fluid effects—Fluids introduced from workover and stimulation/remediation may also be a source of fluid which may be retained by the formation. This can occur when the portion of the formation that accepts the injected gas is undersaturated with water. This undersaturation leads to the inability of aqueous stimulation fluids, including spent acids, to be recovered [5]. Moreover, the most likely reason for fluid being retained in the formation is lack of reservoir pressure. Most of the stimulation/remedial treatments are carried out after the withdrawal season. The reservoir pressure is lowest during this period of time and hence effective fluid cleanup is not possible.

Damage Mechanism in Oriskany Producing Wells

The Oriskany formation has been a prolific producer of natural gas in the Appalachian basin since the early 1930's [9]. Identification, detection, and quick resolution of both downhole and surface production problems are necessary for maintaining efficient field operations [9]. The prominent damage mechanisms in Oriskany producing wells are as follows:

(1) hydrate formation
(2) salt blockages
(3) liquid loading
(4) excessive brine production

To bypass the near wellbore damage, several new and novel fracturing technologies have been proposed and tested at different test sites in USA by a joint effort between DOE and GRI in the year 1998. These new technologies include hydraulic fracturing by using:

(1) water
(2) crosslink gels
(3) energized fluids (foamed acid treatments)
(4) liquid CO_2 fracturing with proppant
(5) Extreme overbalance technique
(6) tip screen out fracturing
(7) high energy gas fracturing
(8) propellant fracturing
(9) gelled liquefied LPG fracturing

All the above mentioned methods have their own advantages and disadvantages hence comparisons as such cannot be made and also we may have to use them in tandem in order to reap maximum benefits. Lot of these methods are new to the industry hence it is imperative to investigate each method in detail and evaluate the applicability of each in the Oriskany formation by analyzing past treatments, production data, pressure transient analysis and well logging.

Vertical Height Growth of Hydraulic Fractures

Fracture height growth has been recognized as one of the critical factors that can determine the success or failure of a hydraulic fracturing treatment. Unwanted fracture height growth into the upper and lower barriers can have detrimental effects in terms of unwanted gas and or water production. It also reduces the overall effectiveness of the stimulation treatment in terms of the designed fracture conductivity and subsequently the overall gain in deliverability. In context to the above statement containment of hydraulic fractures in gas storage wells is of prime importance as unwanted fracture height growth can lead to loss of gas and subsequently loss in deliverability. The prominent factors affecting the vertical fracture height growth is as follows:

(1) In situ stress—In situ stress difference between the pay zone and the bounding layers is the most important factor controlling vertical height growth. The above statement has been verified by various theoretical, laboratory and field data. Layers of greater in situ stress act as a barrier because of the increase in fracturing pressure required to continue fracture propagation in that particular layer. Effectiveness of the barrier would depend on the difference in the stress contrast that is greater the stress contrast more efficient would be the fracture containment and vice versa. Variations in in situ stress are dependent on a number of factors including the elastic properties of the layers, pore fluid pressures, tectonic boundary stresses, and thermal stresses. The relative difference in the magnitude of horizontal stresses in different layers is a function of different elastic properties.

(2) Young's modulus—Although the variation in in situ stress is the dominant factor controlling fracture height growth the effect of Young's modulus cannot be negated. Young's modulus becomes the dominant factor when the net treating pressure is comparable to the in situ stress contrast. Both types of modulus contrast that is lower modulus outer

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Table 1 Summary of various zones under consideration

Marker A & Stafford
Upper Marcellus
Lower Marcellus
Basal
Onondaga limestone
Oriskany sandstone
Helderberg limestone

layers and higher modulus outer layers and can hinder fracture growth. A higher modulus outer layer hinders fracture growth when a fracture is approaching the interface whereas lower modulus outer layer hinders fracture growth when the fracture is inside the layer. Also although neither situation can stop fracture growth completely, the hindering process of both can contribute to fracture height containment [10]. That is when a fracture approaches a high modulus layer from a lower modulus layer the stress intensity fracture decreases, it approaches zero as the tip of fracture gets closer to the interface, making it harder for the fracture to propagate [11]. On the other hand, when a fracture approaches a lower modulus layer from a high modulus layer, the stress intensity factor increases drastically. Hence, lower modulus outer layer promotes fracture growth toward it. However, once inside the fracture the stress intensity factor decreases and further growth is arrested [10]. Another reason can be that in layered formations fracture width depends not only on modulus of the pay zone but is also influenced by modulus in the outer layers. Fracture width is larger for the above mentioned case which means that there is less resistance to fluid flow, fluid pressure is lower hence the fracture is more contained under the same stress contrast. Similar reason can be formulated for the opposite case in which lower modulus middle layer is surmounted by higher modulus layers [10].

(3) Stress intensity factor—Stresses around the tip of a crack are singular with $r^{-0.5}$, where r is the distance from the wellbore to the crack tip [12]. The strength of the singularity is measured by the means of the stress intensity factor. The value of the stress intensity factor depends on the fracture geometry and on the load applied. Fracture propagates if the stress intensity factor reaches a critical value K_{IC}, which is assumed to be a material property called as either the stress intensity factor or fracture toughness. In the absence of Young's modulus and in situ stress contrast fracture toughness can affect height growth [10]. That is higher fracture toughness in the outer layer can restrict height growth and vice versa. Also since the variation in toughness values of sedimentary rocks measured in laboratory is small the effect of fracture toughness is negligible except for cases where stress contrast is minimal.

(4) Shear slippage—Fracture sliding at the interface due to low shear strength can definitely lead to height containment. Although these cases are likely to occur at shallow depths due to less overburden stress and smaller frictional forces at the interface [13]. In the above mentioned case, the fracture will completely stop at the boundary. Sliding occurs wherever fracture encounters a weak interface, such as a weak natural fracture within the same formation. Basically the shear strength of the interface is sufficiently weak relative to the tensile strength and the minimum compressive stress of the bounding layers [14]. This type of fracture containment is usually very local and bounded by the size of the plane of weakness. At greater depth however high frictional resistance caused by the overburden load will prevent interface slippage, so this crack arrest mechanism will not be operative [12]. The depth to which interface slippage occurs depends both upon the frictional pressure and to some extent on the rock properties.

(5) Permeability—Fracture growth can be restricted if the upper and lower barriers have higher permeability in comparison to the pay zone. Higher permeability in the upper and lower cap rocks would lead to an increase in fluid leakoff. The increase in fluid leakoff allows the proppant slurry to bridge at the top and bottom of the fracture inhibiting further fracture growth along these tips. The objective is to arrest the growth of either the upper or lower tip or both the tips of fracture by the bridging action of proppant laden slurry.

Reservoir, Fluid, and Rock Properties

In this section, we will describe the reservoir properties, associated fluid properties and subsequently the calculations of the average rock properties of various zones under consideration in Table 1. The rock properties have been calculated from a sonic log given to us by an operator in Pennsylvania. Due to lack of available data regarding Helderberg limestone which is below the Oriskany, we have made reasonable estimations as shown in Table 2. The reservoir properties under consideration can be verified as in Table 3. The original and more detailed data could be found in the thesis written by Vatsa in 2011 [15].

The average rock properties of the various zones under consideration in our model have been calculated using the thickness weighted averaging technique. The formula used for calculating the average properties is

$$\sum_{i=1}^{n}(k_i \times h_i) \Big/ \sum_{i=1}^{n} h_i \tag{1}$$

Here k_i refers to the rock properties of the different zones, whereas h_i refers to the thickness of the zones, respectively. Each interval has been divided into smaller number of zones and the average properties are calculated according to the formula mentioned above. The different proppants and fluids used in fracture simulation runs can be found in Tables 4 and 5, respectively.

Table 2 Average rock properties

Rock properties/ formations	Depth (ft)	Vertical in situ stress (psi)	Poisson's ratio (ν)	Young's modulus (E) (psi)	Bulk modulus (K) (psi)	Shear modulus (G) (psi)
Marker A & Stafford	5200–5347	3454	0.251	$4.85 \times 10^{+06}$	$3.23 \times 10^{+06}$	$1.94 \times 10^{+06}$
Upper Marcellus	5347–5384	3352	0.223	$3.66 \times 10^{+06}$	$2.25 \times 10^{+06}$	$1.49 \times 10^{+06}$
Lower Marcellus	5384–5446	3375	0.212	$3.74 \times 10^{+06}$	$2.12 \times 10^{+06}$	$1.55 \times 10^{+06}$
Basal	5446–5469	3451	0.217	$4.08 \times 10^{+06}$	$2.32 \times 10^{+06}$	$1.69 \times 10^{+06}$
Onondaga limestone	5469–5495	3792	0.276	$6.96 \times 10^{+06}$	$5.01 \times 10^{+06}$	$2.75 \times 10^{+06}$
Oriskany sandstone	5495–5586	3497	0.218	$1.16 \times 10^{+07}$	$6.72 \times 10^{+06}$	$4.79 \times 10^{+06}$
Helderberg limestone	5586–5636	3997	0.28	$7.00 \times 10^{+06}$	$5.25 \times 10^{+06}$	$2.8 \times 10^{+06}$

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Table 3 Reservoir properties

Reservoir properties	Permeability (md)	Water of saturation (S_w) (%)	Porosity (%)	Thickness (ft)
Marker A & Stafford	0.0001	20	3	147
Upper Marcellus	0.0001	20	3	37
Lower Marcellus	0.0001	20	3	62
Basal	0.0001	20	3	23
Onondaga limestone	0.01	10	4	26
Oriskany sandstone	10	30	8	91
Helderberg limestone	0.001	10	4	50

Table 4 Proppant pack conductivity for different proppants

Proppant type	Proppant pack conductivity (md-ft)
20–40 Mesh super HS curable sand proppant	2266.26
20–40 Mesh Ottawa sand proppant	1045.97
20–40 Mesh Jordan sand proppant	1260.56
20–40 Mesh Arizona sand proppant	1769.40
20–40 Mesh Carbo Prop ceramic proppant	1506.06
20–40 Mesh Carbo Lite ceramic proppant	2292.72
20–40 Mesh carbon HSP ceramic proppant	1526.62
40–70 Mesh Inter Prop ceramic proppant	1807.32
40–70 Mesh Ottawa sand proppant	307.28
40–70 Mesh Jordan sand proppant	482.02
40–70 Mesh Arizona sand proppant	399.01
40–70 Mesh Carbo Prop ceramic proppant	676.12
100 Mesh sand proppant	144.12

Table 5 Different fluids used in the model

Slick water
Binary foam fluid
Hydrochloric acid (HCL)
Linear gel 10 lbm per M gallon
Linear gel 30 lbm per M gallon
Linear gel 40 lbm per M gallon
Linear gel 60 lbm per M gallon
Crosslink gel 40 lbm per M gallon
Crosslink gel 60 lbm per M gallon

Model Description

Palmer and Luiskutty critically reviewed the assumptions that differ in all the models. The comparisons provided an encouraging steps toward normalizing and understanding these hydraulic fracture models [16–18]. I chose to use fracture design software [19] to carry out parametric studies. The model used for designing hydraulic fractures is 3D Tip Dominated. We know that stresses at the tip of a crack are singular in nature with $r^{-0.5}$, where r is the distance to the crack tip. The strength of this singularity is measured by the means of stress intensity factor (K).

$$K = \lim_{r-0}(2\pi r)\hat{}\left(\frac{1}{2}\right)\sigma \tag{2}$$

where **σ** is the tensile stress ahead of the crack tip. The value of the stress intensity factor depends on the shape of the fracture and the load applied. Fracture initiation mechanisms depend on several factors such as the rate of loading, stress induced and the presence of heterogeneity [20]. The fracture propagates when the stress intensity factor reaches a critical value that is the fracture toughness of the material Kc which is a material property. 3D Tip Dominated model incorporates the various tip mechanisms proposed to play a role in fracture propagation. The various tip mechanisms proposed are as follows:

- Fluid Lag region—A fluid lag region has been considered as the primary tip mechanism and has been a subject of interest in development of two- and three-dimensional hydraulic fracture models. The most sophisticated models predict the size of the fluid lag region and the pressure distribution in the fracture [21]. These models formulate a uniform pressure drop in the main body of the fracture and a rapid pressure drop near the fracture tip. This assumption was valid for viscous fluid [22]. Also they state that the fracture geometry can vary significantly after shut in. These models when compared with field data often simulate too high net pressures for early injection times and too low net pressures for poorly contained fractures at late times [21]. Any efforts required to match the field net pressure for a developed hydraulic fracture requires excessive increase or overestimation of the size of the fluid lag region.
- Tip dilatancy—Inelastic rock behavior near the tip of the fracture has been proposed to be one of the possible mechanisms to explain why fluid lag behavior fails to simulate the observed net pressures in the field [21]. As known stresses ahead of the crack tip are supposed to be high, hence the rock may deform plastically causing rock dilatancy [20]. Rock dilation basically refers to permanent deformation registered in rocks subjected to nonuniform stresses. This basically results in reduction in fracture opening which further increases the resistance to fluid flow and subsequent build up of net pressure in the main body of fracture. The above hypothesis has been successfully applied in the field to model the net pressure increase by adjusting the parameters which control the overall pressure profile and reduction of near tip fracture opening due to dilatancy [21].
- Continuum damage mechanics—The idea of continuum damage mechanics has also been developed to better understand the inelastic rock behavior near the fracture tip. The model basically uses two parameters: a damage parameter C, and a scale parameter, l. For vertically contained fractures, the fracture model can be calibrated easily to match the net pressure by using the parameter Cl 2, which is used directly. The scale parameter can be related to the apparent fracture toughness. It also states that for smaller fracture lengths the driving force is stress intensity square whereas for longer fracture lengths the driving force is reduced by a factor which is measured by the continuum damage mechanics scale [23].
- Apparent fracture toughness—The presence of various dissipative forces such as microcracking, bridging, fragmentation, viscous fluid flow, and internal friction at the fracture tip is considered to be a primary cause for variation in observed value of measured fracture toughness. According to classical hydraulic fracture theory crack advances in a perfectly elastic solid if the driving force is equal to or greater than the specific surface energy. However, there exists a zone adjacent to the fracture tip where various micromechanical processes take place preceding and accompanying the crack advance. This

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leads to creation of what we call as a process zone. This zone makes the crack advance difficult due to increase in fracture toughness. Hence according to the above discussion we can justify the use of fracture toughness as a calibration parameter to reduce the discrepancies between modeled and observed net pressures in the field. The calibration of the models accounts for increase in net pressure at the fracture tip whereas makes the pressure profile in the main body of the fracture more uniform. Field results have also indicated that the apparent fracture toughness values are a magnitude greater than the ones calculated via laboratory measurements [21].

The software allows us to design fractures based on the respective reservoir, rock and fluid properties, the treatment schedule in terms of the fluid and proppants required for the stimulation treatment. The reservoir rock and fluid property basically comprise of the Young's modulus (E), in situ stress, fracture toughness, Poisson's ratio (ν), permeability, reservoir pressure, porosity, water of saturation (S_w). Once done with the input of all the data required, we go ahead and run the model and can visualize the fracture propagation with respect to the treatment schedule entered. Our main criterion is to control the vertical height growth hence we will design treatments based on containment of the fracture inside the Oriskany and maximize the fracture conductivity accordingly.

Results and Discussions

In this research, we studied various factors affecting the hydraulic fracture propagation and inturn which can directly contribute to vertical height containment of the fracture. The factors studied are as follows:

(1) effect of fracture fluid type
(2) effect of injection rate
(3) effect of proppant type
(4) effect of fracture fluid volume
(5) effect of reservoir pore pressure
(6) effect of treatment schedule

We conducted parametric studies on the various factors influencing hydraulic fracture propagation as discussed above. The effect of various factors on fracture propagation will be discussed in detail from here on.

Effect of Fracture Fluid Type on Fracture Propagation. Dry cycling of gas in and out of the wellbore reduces the near wellbore to very low residual water saturation. Hence introduction of aqueous fluids itself can be problematic because it increases the water saturation and, further reduces the relative permeability to gas. Also the well might take a long time to clean up, which sometimes might offset the benefit of stimulation treatment in the first place.

Considering the factors discussed above it becomes all the more important to choose fracture fluids which tend to minimize these effects and subsequently maximize the fracture conductivity. A total of nine different fracture fluids were chosen as part of our research to conduct parametric studies on the effect of fracture fluids on hydraulic fracture propagation.

The treatments are analyzed with respect to the length, height and conductivities generated after running the model. Fracture lengths and height obtained from different fluid simulation runs are inconsequential in determining the best fluids for treatment. Their values are somewhat similar in range. Hence fracture conductivity has been considered to zero down on best possible combinations of fracture fluids. Figure 1 shows the variation of average fracture conductivity (md-feet) with respect to different fracture fluids.

From Fig. 1, we can see that the maximum average conductivity is given by binary foam fluid. We use Binary 30–70 that is 70% Binary BJ services foam with 30 lbm/1000 gal gel. Slick water and acids are not considered due to low average conductivity and also keeping in mind the reintroduction of the aqueous phase. Amongst all the linear gels 40 lbm/1000 gal has been chosen over 60 lbm/1000 gal although the average conductivity is slightly greater for the latter. Keeping in mind the cost and also minimizing the gel residue once the treatment is done we decided to go forward with linear gel 40 lbm/1000 gal. Crosslinked gel 40 lbm/1000 gal has been chosen over 50 lbm/1000 gal owing to the same reasons as mentioned for linear gels.

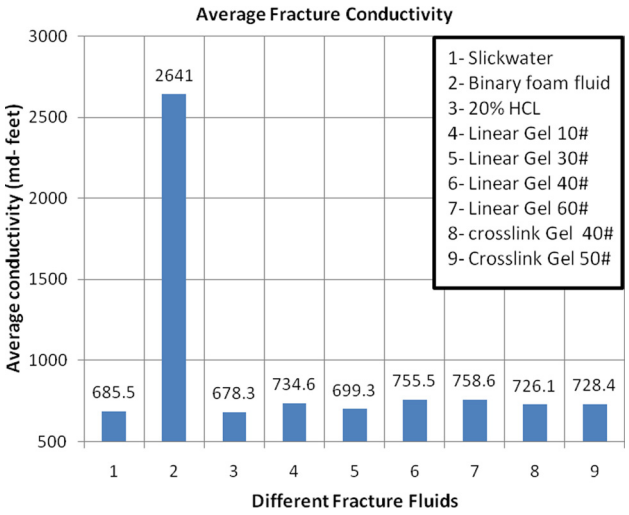

Fig. 1 Average fracture conductivity for different fracture fluids at constat injection rate of 10 bpm

Binary foam fluid gives us the maximum average fracture conductivity as we can pump more of the designed fluid volume as compared to the rest of the fracture fluids. Also the width created is larger almost three times as compared with the other two fluids. Although if the size of the treatment is same the fracture conductivities obtained for the three fluids under consideration is the same. As we are able to pump more of the design fluid volume for binary foam fluid we obtain conductivities greater than as compared to the rest of the fracture fluids under consideration. The design fluid volume for all the treatments is 17,500 gal, respectively.

Effect of Injection Rate on Hydraulic Fracture Propagation. We tried different injection rates in order to come up with the best possible treatment. We used injection rates of 10 barrels per minute (BPM), 20 BPM, 40 BPM, 60 BPM, and 100 BPM. The simulation model results indicate that the fractures are contained in the pay zone only for 10 BPM injection rate. Hence, we decided to move forward with the injection rate of 10 BPM, which is practical and was often done in the stimulation of Oriskany storage wells. From Fig. 2, we can see the variation in vertical fracture height with respect to different fracture fluids at a constant injection rate of 10 BPM. As can be seen clearly from the graph the fractures are contained in the pay zone which is 91-ft thick. For the various other injection rates, the fracture is not contained inside the pay zone, hence it becomes inconsequential to analyze their simulation results.

Effect of Proppant on Hydraulic Fracture Propagation. We tried several different proppant types in order to come up with the one which provides maximum average conductivity. The various different proppant types and their respective proppant pack conductivities can be verified from Table 5. The maximum average conductivity was obtained by using a combination of Carbo Prop 40–70 ceramic proppant and Carbo Lite 20–40 ceramic proppant. Hence, we decided to move forward with the above mentioned proppant combination. From Fig. 3, we can see the effect of

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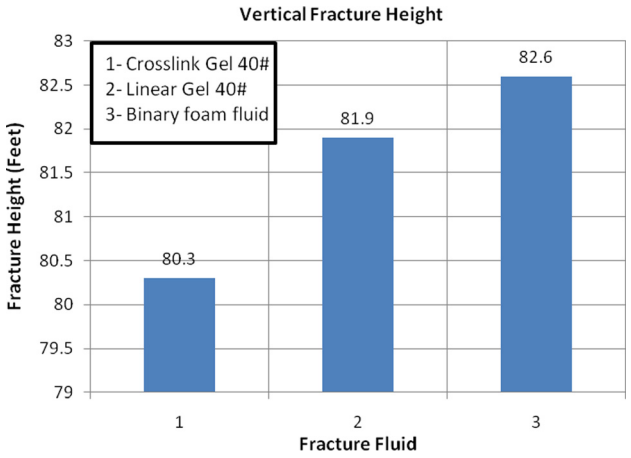

Fig. 2 Average fracture height for different fracture fluids at constat injection rate of 10 bpm

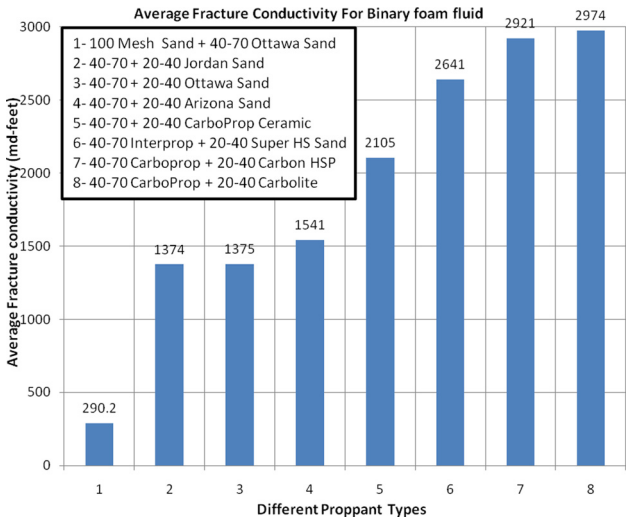

Fig. 3 Effect of proppant on fracture conductivity for binary foam fluid

different proppants on average fracture conductivity for binary foam fluid. As can be seen from the figure the maximum conductivity is obtained for the combination of Carbo Prop 40–70 and Carbolite 20–40 ceramic proppant. Similar results are replicated for linear gel 40 lbm/1000 gal and crosslinked gel 40 lbm/1000 gal. Figures 4 and 5 show the effect of proppant types on average fracture conductivities of linear gel 40 lbm/1000 gal and crosslinked gel 40 lbm/gal. Hence combination of Carbo Prop 40–70 and Carbolite 20–40 ceramic proppant was chosen as the best proppant combination.

Effect of Injection Volumes on Hydraulic Fracture Propagation. For the parametric study based on different fracture fluid volumes, we tried different injection volumes in order to come up with best possible treatment in terms of the maximum average fracture conductivity obtained. The various designed fluid volumes were 10,000 gal, 17,500 gal, 23,000 gal, 30,000 gal, 34,000 gal, and 40,000 gal. 17,500 gal have been used as our base case on which we have studied the effect of various different parameters mentioned above. The simulation results reveal that the designed volume of 30,000 gal is best suited for fracture fluids linear gel 40 lbm/1000 gal and binary foam fluid 30–70. For the case

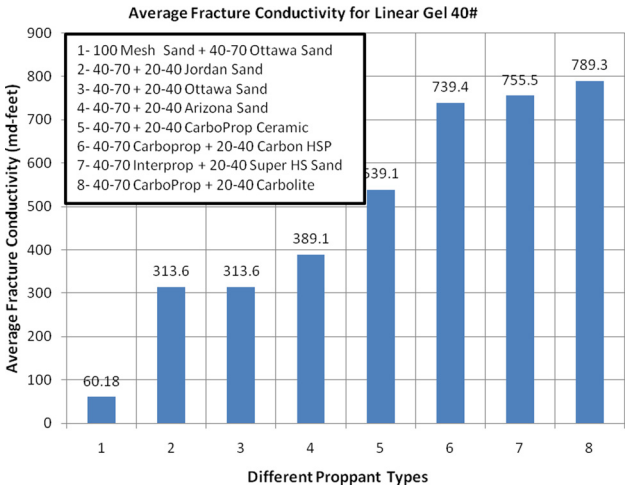

Fig. 4 Effect of proppant on fracture conductivity for linear gel of 40 lbm/1000 gal

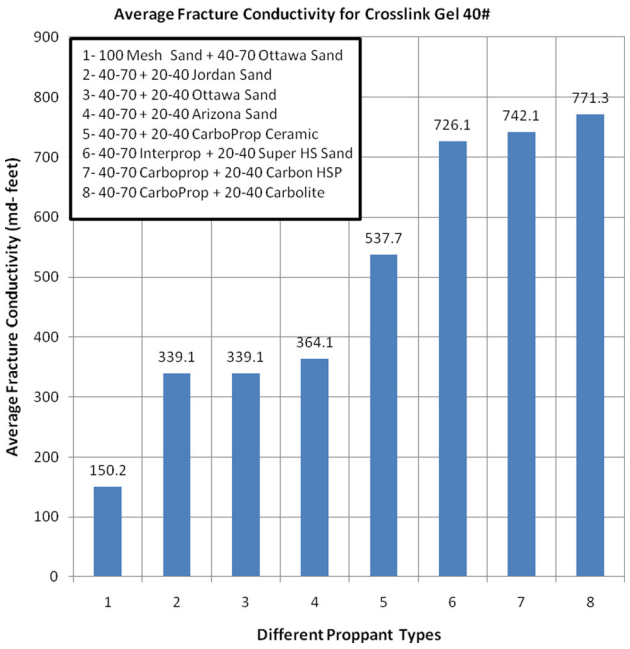

Fig. 5 Effect of proppant on fracture conductivity for crosslinked gel of 40 lbm/1000 gal

of crosslinked gel 40 lbm/1000 gal, the base case of 17,500 gal is best.

As per Fig. 6, we can see the variation in fracture conductivity with respect to design fluid volume for binary foam fluid (Fig. 7). The maximum average conductivity is given by total design fluid volume of 34,000 gal, but the fracture is not contained within the pay zone. Also average fracture conductivity is greatest as we are able to pump all of the designed fluid volume of 34,000 gal. Hence discussing the results will not serve any purpose. Similar is the case for total designed fluid volume of 40,000 gal. Therefore keeping in mind that the fracture should be contained within the pay zone we decided to go forward with the designed fluid volume of 30,000 gal. Similar is the case for linear gel 40 lbm/gal.

From Fig. 8, the average conductivities obtained with 34,000 and 40,000 designed fluid volumes are inconsequential as the respective fractures are not contained within the pay zone. Also designed fluid volume of 34,000 gal gives the maximum average fracture conductivity as we are able to pump the full amount of fluid volume. Hence, we decided to go forward with total designed

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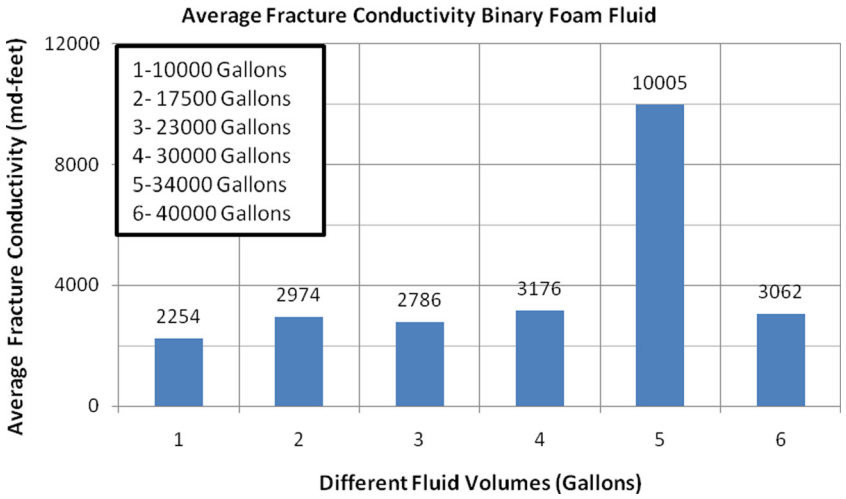

Fig. 6 Effect of treatment volume on fracture conductivity for binary foam fluid

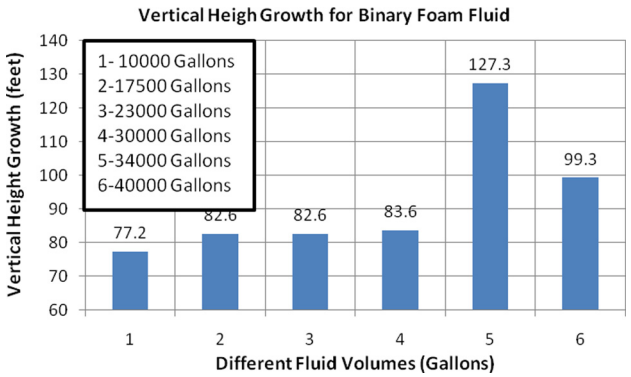

Fig. 7 Effect of treatment volume on vertical fracture height for binary foam fluid

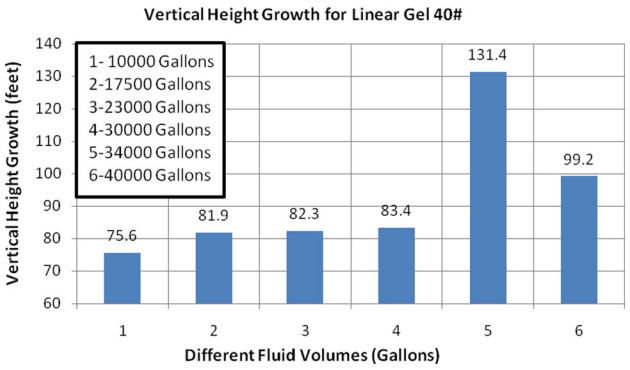

Fig. 9 Effect of treatment volume on vertical fracture height for linear gel of 40 lbm/1000 gal

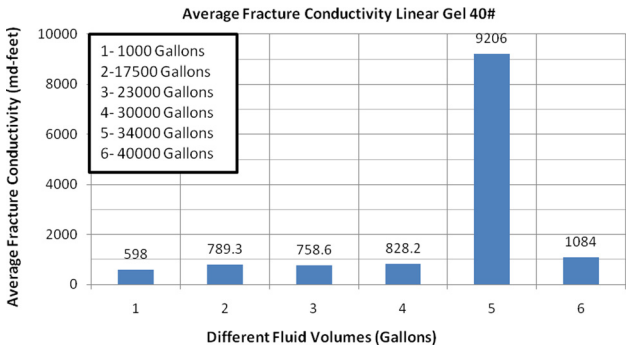

Fig. 8 Effect of treatment volume on fracture conductivity for linear gel of 40 lbm/1000 gal

volume of 30,000 gal for linear gel 40 lbm/1000 gal as it gives the maximum average conductivity (Fig 9).

From Figs. 10 and 11, we can see the variation of average fracture conductivity for crosslinked gel 40 lbm/1000 gal gel. The results are completely different from the rest of the two selected fracture fluids. For all the total design fluid volumes except 10,000 gal and 17,500 gal, none of the fractures are contained in the pay zone. Hence from the two choices that we are left with we decided to go along with the base case of 17,500 gal as the optimum total designed fluid volume as it gives the maximum average fracture conductivity.

Effect of Reservoir Pressure on Hydraulic Fracture Propagation. Reservoir pressure can play an effective role in hydraulic fracturing of gas storage wells. That is it can provide better vertical containment due to the contrast between the in situ stresses between the pay zone and the upper and lower caprocks. Reservoir pressure is at its lowest during the end of withdrawal season.

Hence it definitely makes sense to perform fracture treatments at the end of the withdrawal season when the reservoir pressure is at its lowest. This basically means that during low reservoir pressure the corresponding in situ stress in the pay zone is reduced which creates a contrast between the stresses present above and below the pay zone and leads to better vertical height containment.

This clearly reinstates the proven fact that in situ stress is the prominent factor in controlling vertical height growth of fractures. Also the fracture conductivities obtained are better due to reduction in in situ stress. Therefore, we should fracture at the end of the withdrawal season.

From Fig. 12, we can see the variation in conductivity for the three best fracture fluids with respect to different reservoir pressure. The maximum average fracture conductivity is obtained

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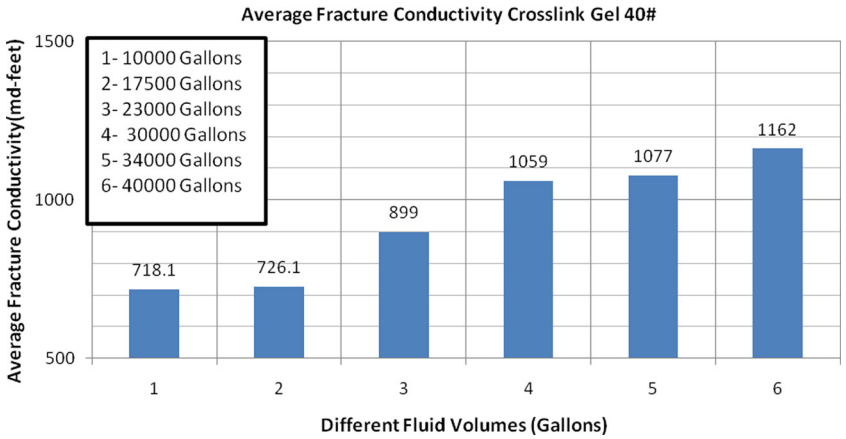

Fig. 10 Effect of treatment volume on fracture conductivity for crosslinked gel of 40 lbm/1000 gal

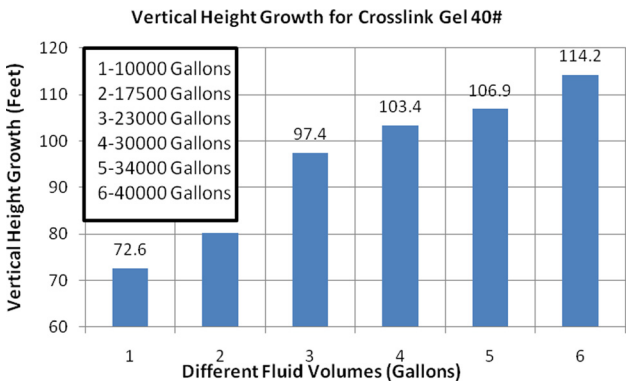

Fig. 11 Effect of treatment volume on vertical fracture height for crosslinked gel of 40 lbm/1000 gal

when the in situ stress is lower that is when the reservoir pressure is at its lowest. Hence according to the above results we should undergo treatment at the end of the withdrawal season, when the reservoir pressure is at its lowest. From Fig. 13, we can see the vertical height growth is curtailed when the reservoir is fractured at the end of the withdrawal season, when the reservoir pressure is at the lowest. The reason for this is the same as discussed above that is the contrast in in situ stress increases when wells are fractured at the end of the withdrawal season. Hence, this leads to better containment of fracture within the pay zone. From Fig. 14, we can see the variation in fracture length for the selected fluids with respect to the reservoir pressure.

Effect of Treatment Schedule on Hydraulic Fracture Propagation. For the parametric study based on different treatment schedules that is different proppant concentrations we considered three different scenarios. The given scenarios can be verified as in Table 6. Treatment Schedule 1 is considered to be our base case, whereas the other two schedules have been included to study the effect of treatment schedule on hydraulic fracture propagation.

From Fig. 15, we can see average fracture conductivity increases for binary foam fluid if we increase the proppant concentration gradually. That is low concentration during the initial stages and increasing it gradually during the later stages. Increasing the proppant concentration gradually leads to better proppant transport. The maximum average fracture conductivity is obtained with the Treatment Schedule 3. Hence, we decided to move forward with the proppant concentrations used in Treatment Schedule 3. Similar results are replicated for the other two fracture fluids in Figs. 16 and 17, respectively.

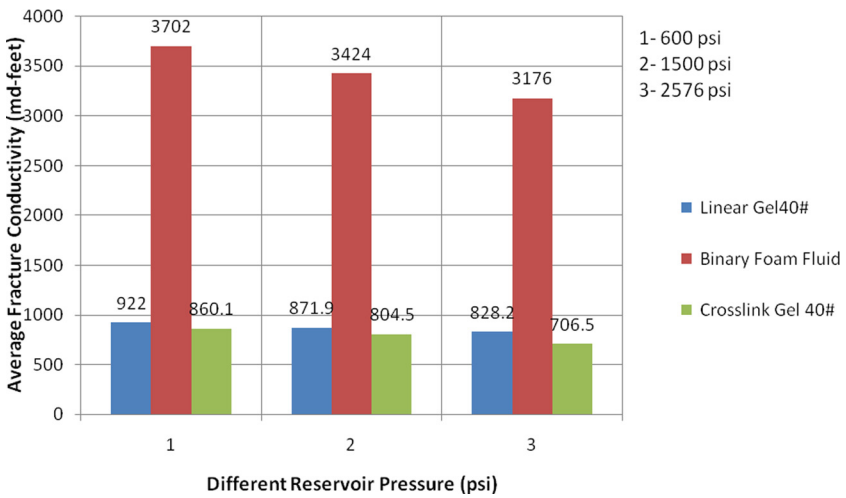

Fig. 12 Effect of reservoir pressure on fracture conductivity in Oriskany wells

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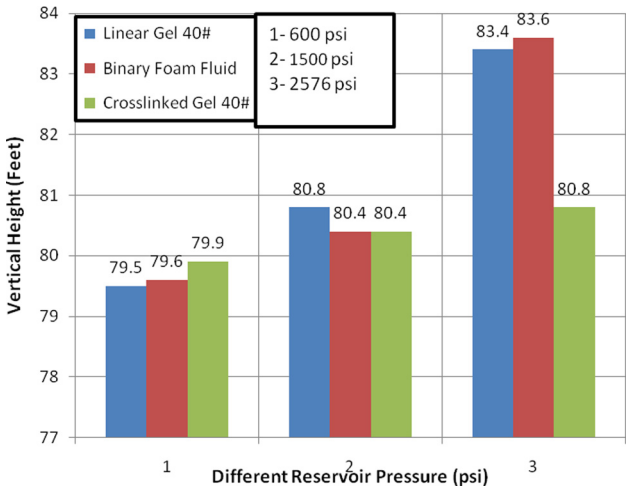

Fig. 13 Effect of reservoir pressure on fracture height in Oriskany wells

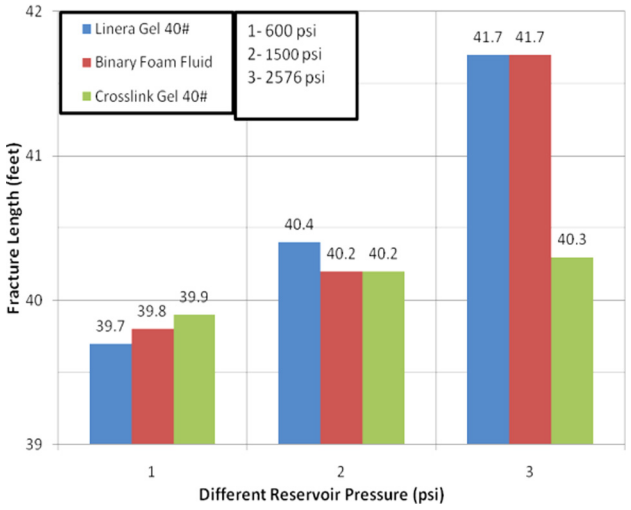

Fig. 14 Effect of reservoir pressure on fracture length in Oriskany wells

Summary

We conducted parametric studies to quantify the effect of individual factors which can impact hydraulic fracture propagation in Oriskany gas wells. In the end, we came up with three best fracture treatments for Oriskany production and gas storage wells as described in Tables 7–9, respectively.

The only difference between the Oriskany production and gas storage wells is in terms of the reservoir pressure and in situ stress. The producing Oriskany wells have been assigned a closure stress of 3497 psi, whereas the reservoir pressure is assigned as 2576 psi based on the calculations as in Table 2. The permeabilities are

Table 6 Different treatment schedules included in the parametric study

Treatment Schedule 1	Treatment Schedule 2	Treatment Schedule 3
0.5 ppg	0.5 ppg	1.0 ppg
2.0 ppg	1.0 ppg	1.5 ppg
2.5 ppg	1.5 ppg	2.0 ppg
3.0 ppg	2.0 ppg	2.5 ppg

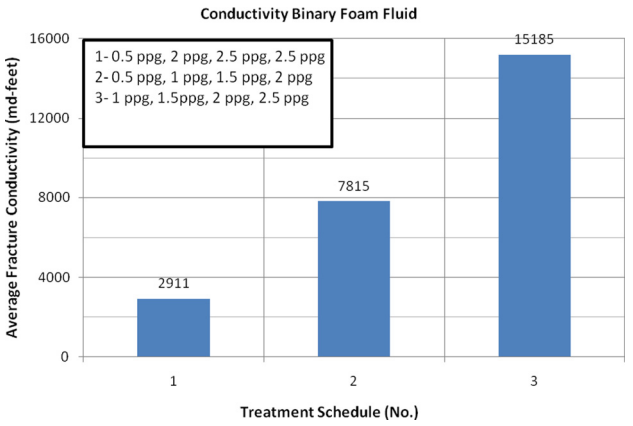

Fig. 15 Effect of treatment schedule on fracture conductivity for binary foam fluid

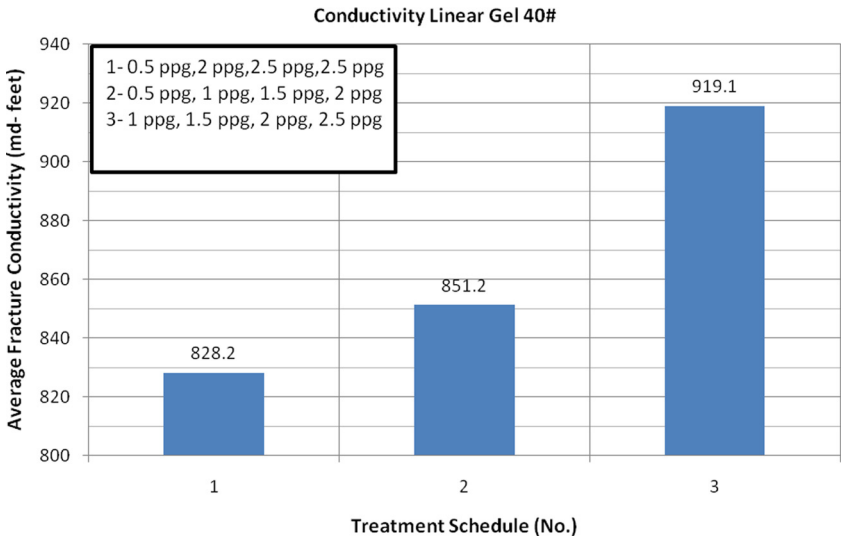

Fig. 16 Effect of treatment schedule on fracture conductivity for linear gel of 40 lbm/1000 gal

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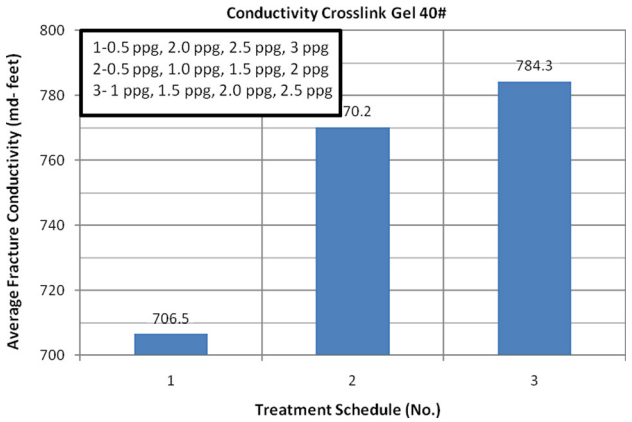

Fig. 17 Effect of treatment schedule on fracture conductivity for crosslinked gel of 40 lbm/1000 gal

assumed to be 10 md. For Oriskany gas storage wells, the reservoir pressure at the end of the withdrawal season is assumed to be 600 psi. Thus based on this we recalculated the in situ stress of Oriskany as 1995 psi. Permeabilities are same as that of producing wells that is 10 md.

For the case of Oriskany production wells undergoing treatment using binary foam fluid the treatment schedule obtained is similar to the one for linear gel 40 lbm/1000 gal. The main difference between the two is that the fluid design volume of 30,000 gal is pumped completely inside the payzone. Whereas in the case of linear gel 40 lbm/1000 gal we are able to pump only 17,000 gal out of the total designed 30,000 gal. Therefore as one would expect the average fracture conductivity obtained for treatment with binary foam fluids is the highest amongst all with a value of 15185 md-ft. However, the conductivity obtained from binary foam fluid was the same as crosslinked gel 40 lbm/1000 gal if the size of treatment was the same. Binary foam fluid provided such a high conductivity, which is unrealistic to us, because of the limitation of the model in simulating the leakoff behavior of binary foam fluid, crosslinked gel 40lbm/1000 gal and linear gel 40 lbm/1000 gal. Therefore, amongst all the fluids chosen to undergo fracturing binary foam fluid 30–70 gives us the maximum average conductivity. From this treatment design, we obtained a fracture half length of 34.6 ft and vertical fracture height of 69.2 ft. Similar results are obtained for Oriskany gas storage wells with the average fracture conductivity value being 18654 md-ft. From this treatment design, we obtained fracture half length of 33.9 ft and vertical fracture height of 67.9 ft.

For the case of Oriskany production wells undergoing treatment using linear gel 40 lbm/1000 gal the designed fluid volume of 30,000 gal gives the maximum fracture conductivity. Also as the viscosity of linear gel is lower than the corresponding crosslinked gel, we can pump more fracture fluid at the same injection rate. The proppants pumped are slightly more in concentration when compared with the case for crosslinked fluids. From this treatment design, we obtained an average fracture conductivity of 919.1md-ft, fracture half length of 34.6 ft and vertical fracture height of 69.2 ft. Similar results are obtained for Oriskany gas storage wells with the conductivity being 1136 md-ft. From this treatment design, we obtained a fracture half length of 33.9 ft and vertical fracture height of 67.9 ft.

Table 7 Final treatment schedule for crosslink gel 40#

Stage type	Flow rate (BPM)	Prop conc (ppg)	Clean vol (gal)	Fluid type	Proppant type
Main frac pad	10	0	3000	LINEAR_40_GW-32	
Main frac slurry	10	1	2000	40#	CarboProp 40/70
Main frac slurry	10	1.5	2000	40#	CarboLite 20/40
Main frac slurry	10	2	3000	40#	CarboLite 20/40
Main frac slurry	10	2.5	6000	40#	CarboLite 20/40
Main frac flush	10	0	1500	Fresh water	
Shut-in	0	0	0	Shut-in	

Table 8 Final treatment schedule for linear gel 40#

Stage type	Flow rate (BPM)	Prop conc (ppg)	Clean vol (gal)	Fluid type	Proppant type
Main frac pad	10	0	3500	Fresh water	
Main frac slurry	10	1	5000	LINEAR_40_GW-32	CarboProp 40/70
Main frac slurry	10	1.5	4500	LINEAR_40_GW-32	CarboLite 20/40
Main frac slurry	10	2	5000	LINEAR_40_GW-32	CarboLite 20/40
Main frac slurry	10	2.5	8000	LINEAR_40_GW-32	CarboLite 20/40
Main frac flush	10	0	4000	Fresh water	
Shut-in	0	0	0	Shut-in	

Table 9 Final treatment schedule for binary foam fluid

Stage type	Flow rate (BPM)	Prop conc (ppg)	Clean vol (gal)	Fluid type	Proppant type
Main frac pad	10	0	3500	Fresh Water	
Main frac slurry	10	1	5000	LINEAR_40_GW-32	CarboProp 40/70
Main frac slurry	10	1.5	4500	BINARY_30_70	CarboLite 20/40
Main frac slurry	10	2	5000	BINARY_30_70	CarboLite 20/40
Main frac slurry	10	2.5	8000	BINARY_30_70	CarboLite 20/40
Main frac flush	10	0	4000	Fresh water	
Shut-in	0	0	0	Shut-in	

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For the case of Oriskany production wells undergoing treatment using crosslinked gel 40 lbm/1000 gal the designed fluid volume of 17,500 gal gives the maximum fracture conductivity. From this treatment design, we obtained an average fracture conductivity of 784.3 md-ft, fracture half length of 37.6 ft, and vertical fracture height of 75.3 ft. Similar results are obtained for Oriskany gas storage wells. From this treatment design, we obtained an average fracture conductivity of 887.6.1md-ft, fracture half length of 36.8 ft, and vertical fracture height of 76.7 ft.

The main conclusions are summarized as follows:

- Six best stimulation methods have been developed for Oriskany production and storage wells as shown in Tables 7–9, to effectively control fracture height growth and to optimize fracture conductivity.
- Parametric study concerning the use of different fracture fluids for hydraulic fracturing showed that three fluids linear gel 40 lbm/1000 gal, crosslinked gel 40 lbm/1000 gal and binary foam fluid 30–70 provide the best average fracture conductivities. Also they tend to minimize the aqueous content inside the formation which if high can actually offset the benefits of stimulation due to long fracture fluid cleanup times.
- Parametric study concerning the injection rate showed that injection rate should be kept constant at 10 BPM for all the stages in a treatment schedule in order to contain the created hydraulic fracture inside the Oriskany and prevent further growth into the surrounding layers.
- Parametric study concerning the effect of proppants on the created hydraulic fractured confirmed that a combination of CarboProp 40–70 and CarboLite 20–40 ceramic proppant should be used in order to attain maximum fracture conductivities and inturn maximize the deliverability.
- Parametric studies on the effect of different treatment volumes showed that the maximum average fracture conductivity is attained when the designed fluid volume for linear gel 40 lbm/1000 gal and binary foam fluid 30–70 is 30,000 gal, whereas for crosslinked fluid 40 lbm/1000 gal, it is 17,500 gal. The difference in optimum values can be explained in terms of the viscosity of the fluids. As crosslinked fluids are more viscous, pumping in more volumes can lead to vertical height growth out of the zone. Also the difference in different designed fluid volumes for different fracture fluids can be explained in terms of the limitation of the model to simulate the leakoff behavior for binary foam fluid, linear gel 40 lbm/1000 gal and crosslinked gel 40 lbm/1000 gal.
- Parametric studies concerning the effect of reservoir pressure provides us with a very interesting fact. It shows that if for gas storage wells treatments are carried out at the end of the withdrawal season, that is when the reservoir pressure is at its lowest, the created fractures have better fracture conductivities due to reduction in corresponding in situ stress. Also it leads to better vertical height containment due to increase in in situ stress contrast between the Oriskany and the upper and lower layers. Hence keeping in mind the concerns of gas storage operators in terms of unwanted height growth we should undergo treatment at the end of the withdrawal season.
- Last but not the least parametric studies conducted concerning the effect of treatment schedule on hydraulic fracturing clearly indicates that the proppant concentration should be increased gradually from low concentrations during the initial stages of treatment schedule to gradually higher during the later stages. Increasing the proppant concentration gradually leads to better proppant transport.

Future work should involve better understanding of all the factors mentioned above and development of a diagnostic methodology for identification of damages.

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