Investigating Hydraulic Communication Between Wells During Hydraulic Fracturing Treatments
in the Piceance Basin, Colorado, USA

By
Alexis Ahlert
Department of Geological Sciences, University of Colorado Boulder

April 7, 2019

Thesis Advisor:
Shemin Ge, Department of Geological Sciences

Defense Committee:
Shemin Ge, Department of Geological Sciences
Roseanna Neupauer, Civil, Environmental, and Architectural Engineering
Brian Hynek, Department of Geological Sciences

Abstract

Oil and gas wells in Colorado had a circular spacing regulation that required wells to be spaced 745 ft (227 m) in diameter apart. Some oil and gas wells in the Piceance Basin experience hydraulic communication, which is when the hydraulic fracturing of one well damages the production of a neighboring well. During hydraulic communication, formation water enters the producing borehole at the front of the pressure wave and must be removed before the well is brought back into production. Several wells that have experienced communication have come back on line, but months later, have not recovered their original production rates. It is known that when communication occurs in this scenario there is an increase in the casing pressure of the pumping well of 400 psi (280 meters of head). During hydraulic communication, the bedrock formation experiences long term damage. To test this hypothesis, MODFLOW is utilized to model a generalized two-well system in which a producing well and hydraulic fracturing well are approximately one mile (1,610 m) apart. Modeling is conducted to test how geologic heterogeneity in aquifer conductivity and specific storage, and engineering parameters including well spacing and hydraulic fracturing injection rates affect the change in hydraulic head between the injection well and the pumping well. By changing these parameters in a sensitivity analysis, it is possible to determine which have the greatest effect on hydraulic communication.

Overall, the systems with lower hydraulic conductivity, higher specific storage, and increased well spacing have a decreased probability of well-to-well communication in the Piceance Basin. Hydraulic communication in the Basin is due to geologic heterogeneity of the area. However, for impacted wells, hydraulic communication can cause both unexpected short-term expenses and permanent economic loss. It is therefore critical to understand the appropriate geological parameters for communication minimization, despite a fairly limited number of occurrences thus far. Additionally, a better understanding of hydraulic communication between wells will provide new knowledge for Colorado regulators to reevaluate their current spacing regulations.

Introduction

When low-permeability hydrogeological systems are perturbed such as hydraulic fracturing, it is commonly assumed that fluid flow processes are limited to the vicinity of external perturbations. Yet oil and gas well data has shown that these perturbed fluid flow processes can involve a larger area than expected. These changes in fluid dynamics can be seen in the Piceance Basin where oil and gas industries hydraulically fracture the Williams Fork Sandstone Formation. Hydraulic fracturing commonly involves injecting water, sand, and other chemicals under high pressure into a bedrock formation (Cooley and Donnelly 2012), to create a network of fractures to artificially increase the formation hydraulic conductivity. Such an increase in hydraulic conductivity may also impact pressure gradients and production in nearby wells. For example, hydraulic fracturing of one well could affect or reduce the production of a

neighboring well. This phenomenon, referred to as hydraulic communication, has been observed in the Piceance Basin.

At the initiation of this study, wells in the Piceance Basin had a circular well spacing regulation that requires them to be spaced 745 ft (227 m) in diameter apart, due to the geology of the area. However, hydraulic communication between hydraulic fracturing wells has been seen in in approximately 14-28% of wells in the Basin (COGCC 2018). This communication causes the impacted well to experience a major drop in production of natural gas because of excess of water entering the wellbore. Hydraulic communication between wells can cause permanent economic loss and unexpected short term expenses to an oil and gas company. In such cases, if the formation in which the pressure is being transferred is predominantly water saturated then wells may produce an excess volume of water.

The goal of this study is to model pressure gradients between one hydraulic fracturing well and one gas production well in the Piceance Basin in order to determine whether the most important parameter for well-to-well communication is geological or engineered. All data regarding drilling and completion parameters and regulatory decisions were collected from COGCC hearing files, scout cards, drilling and completion reports, and public presentations unless otherwise specified.

Background

Piceance Basin Geology

The Piceance Basin is a part of the larger Uinta-Piceance Province, which is located in eastern Utah and western Colorado (Norton & Groat 2003). This study focused on the part of the Piceance that is located in western Colorado (Figure 1), where hydraulic communication has occurred.

Figure 1. Approximate location of the Piceance Basin in Colorado. Created with GIS (QGIS 2009).

As seen in Figure 2, production wells in the Piceance Basin are usually drilled vertically through layers of sandstone (Wasatch, Ohio Creek, and the upper Williams Fork Formations) and mudstone (lower Williams Fork Formation), and terminate beneath a number of laterally extensive coal beds (Cameo Coal). The Williams Fork Formation is the thickest formation in the Basin and it contains the Cameo coal layer at its base (Hettinger & Kirschbaum 2002). Patterson et. al (2003) suggested that the top of the Williams Fork Formation is sandstone rich and runs to a depth of 1000 ft [305 meters]. The middle part of the Williams Fork consists mostly of mudstones and is around 660 ft [201 meters] thick (Patterson et. al. 2003). The Williams Fork sandstones and mudstones were deposited in a coastal plain setting that had meandering streams, swamps, and floodplains (Johnson, 1989). The lowest portion of the Williams Fork contains the Cameo Coal, which was deposited in a coastal plain swamp (Patterson et al. 2003). The coal layer ranges in thickness from 140 ft [43 meters] to 1,400 ft [427 meters] (Hettinger and Kirschbaum 2002). The Rollins Sandstone lies below the Williams Fork Formation. The Rollins Sandstone is around 200 ft [61 meters] thick and is a very fine-grained to coarse-grained sandstone (Hettinger and Kirschbaum 2002). This sandstone accumulated in a regressive shallow marine environment (Johnson 1989). All of the formations within this area have a very low permeability (Cumella and Ostby 2003). Due to folding, which has caused some minor faulting, the coal zone has experienced stress which has caused its permeability to increase (Cumella and

Ostby 2003). The full stratigraphy and a conceptual cross section can be seen in Figure 2. Hydraulic fracturing wells in the Piceance specifically target lenticular channels sands that are located within the Williams Fork Formation.

Figure 2: Conceptual cross-section and stratigraphic column of study region. The red color represents pore pressure transfer. The Cameo Coal layer is highlighted blue on the stratigraphic column to represent the modeled formation. The grey channels are the lenticular channel sands, which are targeted specifically for gas.

The Rollins sandstone was deposited along the shore of the Western Interior Seaway during the late Cretaceous (Cole and Cumella 2003). As the Western Interior seaway began to retreat, it left a coastal plain setting that formed the Cameo Coal layer (Patterson et al. 2003). Then at the beginning of the Laramide orogeny, mountains uplifted farther east and meandering streams cut through Colorado (Cumella and Ostby 2003). These rivers cut through layers of mudstone and deposited sediment to form the current lenticular channel sands in the Piceance Basin (Cumella and Ostby 2003). The Piceance Basin consists of a geologically downwarped region that is surrounded by uplifted regions. The downwarped region is filled with eroded sediments that have been compacted to form sedimentary rock. Rocks as old as Precambrian are found within the basin and range in age from 950 million to 1.8 billion years old (MacLachlan 1987). The structure of this Basin was formed during the Laramide orogeny, which was a time of mountain building processes that involved thrusting, faulting, and folding of rocks. The Piceance was an area of subsidence while areas surrounding the Basin were areas of uplift (MacLachlan 1987). Within the central part of Piceance Basin, fractures dominantly have a west-northwest and east-southeast subsurface strike (Lorenz 2003). In the Western portion of the Basin fractures typically strike east-west (Lorenz 2003).

Engineering and Development

In the Piceance Basin, most production wells are slightly deviated vertical boreholes with perforated liners spanning the Williams Fork and Cameo Coal Formations. For oil and gas wells in the Basin, a circular spacing regulation existed at the initiation of this study (before December 2018) that required wells to be spaced 745 ft (227 m) in diameter apart. This spacing assumed a drainage area of 10 total acres. This close well spacing in the Piceance is due to the isolated nature of the target Williams Fork channel sand bodies (Spielman et al. 2016); historically wells drilled on larger (greater than 128 acres) spacing have assumed lateral connectivity of sand bodies and complete drainage therein, unless production data demonstrates otherwise after initial drilling (Junkin et al. 1992). Since these wells cannot drain more than the individual channel sands they penetrate in the Williams Fork, it is unlikely that hydraulic communication occurs in this interval. Instead, the highest potential for lateral connection is within the Cameo Coal layer.

Hydraulic communication between wells is when the hydraulic fracturing of one well damages the production of a neighboring well (Kumar et al. 2018). When communication occurs, the impacted well produces more formation water and less gas/oil. In severe cases, these wells must be shut in to cease production, and a workover rig contracted to pump out the wellbore before production can resume (Jacobs 2017). Many wells that have been “hit” come back on line after such recovery treatment, but it may take months to years to reach original levels of production. In one Piceance Basin example, a post-communication, empirically fitted power function representing the line of best fit for the production curve recovers the same slope as the pre-communication line of best fit; however, the intercept is lower for the post-communication line, indicating a loss of production (Figure 3). The gas production, shown in the solid red line, came from the COGCC public database.

Figure 3. Gas production versus the time of production from one impacted well. The solid red line is gas production data. The dashed line, labeled gas produced after communication, is the estimated gas produced from the impacted well after hydraulic communication occurs. The dotted line, labeled gas produced before communication, is the estimated gas produced from a well that does not experience communication. The red line shows the time of hydraulic communication.

Hydraulic communication has also been seen in Ohio (Kozłowska, et al. 2017), Oklahoma (Thompson 2017), Texas (Morales et.al. 2016), Germany (Kessels and Kuck 1995), and Argentina (Rimedio et al. 2015). In each of these studies, well-to-well communication occurs when there were connected fracture networks. Kessels and Kuck (1995) found that the mean fracture aperture for a situation of communication was around 5-7 μm . Thompson (2017) found that it was possible to simulate hydraulic communication by altering fracture aperture and connectivity. Each of these studies reports that for hydraulic communication to occur there must be geologic heterogeneity in the subsurface, either major faults or networks of fractures.

In this study, injection and production data from two incidents involving two pairs of wells inform a generic two-well groundwater model. Each well pair included a borehole that was hydraulically fractured and a neighboring borehole that experienced a decrease in production during hydraulic fracturing in the other well. Several model scenarios introduce similar heterogeneity that deemed necessary for communication by previous studies (Kessels and Kuck 1995). Additional modeled scenarios were designed to test Piceance Basin-specific factors.

In the Piceance Basin, past hydraulic fracturing consisted of a mixture of water and gel fracturing fluid. Changes in economics have made it more viable for well operators to use just water to treat hydraulic fracturing wells. However, this has led to an increase in the amount of water used during treatment. It also has led to an increase in the injection rate during a hydraulic fracturing treatment. Because hydraulic communication can cause both unexpected short-term expenses and permanent economic loss, it is critical to understand both the appropriate geological and engineering parameters for communication minimization. Additionally, a better understanding of hydraulic communication between wells will provide new knowledge for Colorado regulators to reevaluate their current spacing regulations, similarly to the changes they made in December 2018. Figure 4 depicts past and present spacing regulations for the Basin.

Total Area:
10-Acres (425,600 ft²)

Figure 4: Map view of spacing regulations in the Piceance Basin. A depicts the original circular spacing unit before it was changed in December 2018. B shows the new elliptical spacing regulation after December 2018. The total area for both A and B is 425,600 ft². The black dot in the middle of both A and B represents the well location.

These changes forced operators to space wells 425,600 ft² (39540 m²) apart in a non-circular, but elliptical shape, per COGCC Order 1-229. This accounted for the anisotropic nature of the basin, which means the drainage area of typical wells is not circular but elliptical. This change in the

well spacing order shows that it was seen that hydraulic fracturing propagations affected a much larger area than the original spacing order considered (COGCC 2018).

Methods

Quantifying “Hydraulic Communication”

When a production well experiences hydraulic communication, there is likely an increase in the casing pressure, which represents the fluid pressure in annular space between well segments. In one well in the Piceance Basin this casing pressure increase was equivalent to roughly 400 psi (280 meters of head; COGCC Personal Comm.) This change in pressure can be related to the change in hydraulic head that are part of modeled results.

Pore Pressure Model

This study uses a generic 3D pore pressure model built in MODFLOW-2005 to model pore pressure change caused by hydraulic fracturing treatment (Harbaugh 2005). The model simulates pressure diffusion between two wells: one actively injecting fluid, and the other either pumping or shut in. The Theis solution (1935) was used to constrain the model domain, in combination with realistic geometries recovered from publicly available Piceance Basin data. By using the Theis solution (1935) it was possible to find the distance from the injection well at which the change in hydraulic head went to zero. This distance was then used to constrain the model domain. The 3D model is 160 m thick and has a 30 km by 30 km variably discretized lateral extent (Figure 5).

Figure 5: plan view of the Model domain from MODFLOW-2005 (Harbaugh 2005). The blue triangle represents the pumping well and the blue circle represents the injection well.

The 160 m thickness represents the vertical extent of the Cameo Coal, which is laterally extensive (Cumella and Ostby 2003). The Cameo Coal layer is the only probable formation where wells can laterally communicate. The total Cameo thickness of 160 meters was vertically discretized into 20 layers, each 8 meters thick. The model used a General Head Boundary, which is a boundary that increases the drainage area to 15 km outside of the model domain and forces the change in hydraulic head to decrease linearly to 0 meters.

Two wells spaced a distance 1600 meters apart (~1 mile) were positioned in the center of the model domain, one hydraulic fracturing well over the thickness of 156 m (512 ft), which is nearly equivalent to the entire thickness of the cameo coal interval) and one production well over the top 132 m (433 ft) of Cameo Coal. Hydraulic parameters, like specific storage (S_s) and hydraulic conductivity (K), for this injection interval vary over three orders of magnitude (Table 1). Baseline values were gleaned directly from literature, while model values assumed a three orders of magnitude increase in K . This increase in K is intended to simulate both the breaking of rock during hydraulic fracturing treatment or naturally open faults and fractures in the subsurface (Rubin et al. 2019).

Injection into the model was designed to simulate a single stage from a typical hydraulic fracturing treatment in the Piceance Basin, followed by several hours of non-injection time over which pressure is monitored. The model run time is 24 hours. Utilizing the COGCC public

databases, an injection volume was calculated from a ten stage hydraulic fracturing treatment, to constrain the injection rates for the modeled single stage. It was assumed that an equal volume of water was injected in each of the ten stages.

Hydraulic fracturing treatments typically involve a several-hour period of high rate injection followed by flow back and equipment reset, during which time no fluid is injected. Given the total volume of 24670 m³ (ft) injected over ten days into the well selected from the COGCC database, the average daily volume was 2467 m³ (ft) or 0.285 m³/s. Instead of simulating a full hydraulic fracturing treatment with multiple injection periods for this well, this model simulates one 2.4 hour period of injection (end of injection) followed by monitoring for the remainder of the 24 hours (end of day).

Table 1
Hydraulic conductivity values for Cameo Coal (Papadopoulos 2008)

	high	mid	low
$K_{\text{literature}}$ (m/s)	2.08×10^{-6}	4.77×10^{-8}	5.65×10^{-10}
K_{model} (m/s)	2.08×10^{-3}	4.77×10^{-5}	5.65×10^{-7}

Table 2
Specific Storage values for Cameo Coal (Papadopoulos 2008)

	high	low
S_s (m ⁻¹)	6.25×10^{-7}	3.13×10^{-8}

Five model parameter scenarios were considered to test what parameters had the largest effect on communication. The five models were (1) isotropic and homogeneous with only an injection well; (2) isotropic and homogeneous with both a pumping and injection well; (3) a one mile fracture network with an injection well only; (4) a two mile fracture network with an injection well only; and (5) a one mile fracture network with decreased injection rates. In the homogeneous and isotropic models, with no pumping well (1), the injection well had an injection rate of 0.285 m³/s over the time of injection and the hydraulic conductivity and specific storage were varied between the high and low ranges. In the homogeneous and isotropic models with a pumping well (2), hydraulic conductivity and specific storage were again varied and the pumping

well had a pumping rate of $6.72 \times 10^{-3} \text{ m}^3/\text{s}$. The pumping rate was found for the pumping well by using the ideal gas law (Figure 6), with some major simplifying assumptions.

Figure 6: The Ideal Gas Law Calculation. The grey line represents an oil and gas well and the black line shows a linear increase in temperature with depth. By finding the pressure and temperature, it was possible to solve for the volume of gas produced at the top of the Williams Fork and the top of the Rollins. A fracture gradient is a parameter that determines the pressure needed to fracture a formation (Zhang and Yin 2008) and these gradients come from the COGCC public database.

Figure 6 shows how the volumes of gas produced at the top of the Williams Fork and Rollins were calculated. These volumes were then averaged to find the pumping rate of the pumping well. It was assumed that the downhole temperature followed a linear increase with depth. Also, that the production well was a single phase system with the gas production equaling the water production.

Coal contains systematic fractures called cleats that usually occur in two directions (Laubach et al. 1997). Face cleats are through-going fractures that formed first, and butt cleats are the fractures that end at intersections of the face cleats (Laubach et al. 1997). Lateral

anisotropy was introduced into the homogeneous and isotropic models by changing the lateral hydraulic conductivity (K_y) so that it was equal to the horizontal hydraulic conductivity (K_x) divided by 1.84, which is a reasonable estimate of the butt to face cleat permeability (k_{face}/k_{butt}) ratio for coal cleats in the subsurface (Pan and Connell 2012).

Fracture networks were added to the homogeneous and isotropic model to test how major geologic heterogeneity affected pore pressure diffusion. These fractures were added with consideration of the general stress field of the Piceance Basin. A one-mile long fracture network was added by setting a 10 meter wide area in the east west direction, between the wells, to have a higher hydraulic conductivity than that in rest of the model domain. This fracture network represented a very permeable pathway. The model domain had a hydraulic conductivity value of 5.65×10^{-10} m/s. The hydraulic conductivity of the fracture network was equal to either mid or high range conductivity increased by 3 orders of magnitude from literature. The specific storage was varied from $S_{S(high)}$ to $S_{S(low)}$ to test the full range of specific storage. To test the sensitivity of the fracture network's hydraulic conductivity on model results, the conductivity value was increased by three orders of magnitude, while the model domain's hydraulic conductivity remained the same. Then the fracture network and the distance between the wells was increased to two miles long. The two-mile scenarios had the same varying hydraulic conductivity and specific storage values as the one-mile scenarios.

Within the one-mile fracture network models, the injection rate was decreased to see the effect on pore pressure diffusion in the system. The hydraulic conductivity and the specific storage values from the one-mile fracture run that was most likely to cause hydraulic communication was used. These hydraulic properties were chosen to see if decreasing the injection rate decreased the likelihood of hydraulic communication. In these scenarios, the hydraulic parameters were equal to the high specific storage and hydraulic conductivity values. With these hydraulic conductivity and specific storage values, the model was rerun, but the injection rate was decreased to a mid value of $0.193 \text{ m}^3/\text{s}$ and a low value of $0.102 \text{ m}^3/\text{s}$. The rate $0.102 \text{ m}^3/\text{s}$ is close to past treatment rates that used both water and addition chemical additives, such as gel stabilizers.

The result of these modeled scenarios is an array of hydraulic head values for every cell at every time period within the model domain. To relate these results to the casing pressure threshold of hydraulic communication, the change in hydraulic head was examined at three points between the injection well and the pumping well: (1) at 25% of the distance from the injector, (2) at 50% of the distance from the injector, and (3) immediately adjacent to the pumping well. If the change in hydraulic head exceeds 280 meters at any of these points, the scenario caused enough pressure diffusion to experience hydraulic communication. The change in hydraulic head in each of model scenarios is directly compared to the actual increase in casing pressure that was measured at the impacted well.

Results

The calculated change in hydraulic heads from the five model scenarios are presented in Table 3. Positive values indicate an increase in the hydraulic head, and negative values indicate a drawdown, or decrease, in the hydraulic head. The change in hydraulic head was examined at three locations: adjacent to the pumping well; 25% of the distance from the injecting well; and 50% of the distance from the injecting well. The homogeneous and isotropic models did not exceed the threshold change in hydraulic head of 280 m. The change in hydraulic head was found at the end of injection (at the end of 2.4 hours of high injection rate) for the homogeneous and isotropic models with no pumping well ranged from 4.10×10^{-10} m to 243.7 m. At the end of the day (end of the 24-hour model time), the change in hydraulic head ranged from 7.60×10^{-3} m to 26.0 m. For the homogeneous and isotropic models with a pumping well, at the end of injection, the change of hydraulic head ranged from -27.1 m to 6.68 m. At the end of the day, the change in hydraulic head ranged from -44.2 m to 15.4 m.

Several of the fracture network models exceeded the threshold change in hydraulic head. The range of values for change in hydraulic head for the one-mile fracture network scenarios, at the end of injection, was 504 m to 10870 m. Figure 7 shows the change in hydraulic head as distance from the injecting well increases. Closer to the pumping well, the change in the hydraulic head decreases as the distance from the injection well is increased.

Figure 7: Change in hydraulic head with distance at the end of injection. The hotter colors represent larger hydraulic head values and the cooler colors represent smaller hydraulic head values. The three measuring points are depicted by a, b, and c. The black lines represent the pumping well and the injection well. The white line depicts the change in hydraulic head with distance from the injection well. 0.25L represents the change in hydraulic head measured 25% of the distance from the injector well. 0.50L represents the change in hydraulic head measured 50% of the distance from the injector well. $L - \delta L$ represents the change in hydraulic head measured adjacent to the pumping well.

At the end of day, the change in hydraulic head at the three measuring points ranged from 416 m to 2120 m. For the two-mile fracture network scenarios, at the end of injection, the change in hydraulic head ranged from 12.5 m to 6240 m. At the end of the day, the change in hydraulic head ranged from 181 m to 1073 m. When decreasing the injection rate to $0.193 \text{ m}^3/\text{s}$ the change in hydraulic head ranged from 869 m to 896 m at the end of injection. With the same injection rate at the end of the day, the change in hydraulic head was 285 m at every measuring point. With an injection rate of $0.102 \text{ m}^3/\text{s}$ the change in hydraulic head ranged from 457 m to 471 m at the end of injection. At the end of the day, with an injection rate of $0.102 \text{ m}^3/\text{s}$, the change in hydraulic head was 150 m at every measuring point. The excess volume of water calculated from the production curve is estimated to be $\sim 145 \text{ m}^3$. It is possible to compare this excess volume solved from the production curve to the volumes calculated from the model scenarios. Diffusivity is defined as the hydraulic conductivity divided by the specific storage (Freeze and Cherry 1979). Figure 8 compares diffusivity and change in hydraulic head. The horizontal axis of these figures is in terms of diffusivity.

Figure 8: Change in hydraulic head versus diffusivity from the model scenarios at end of injection. Diffusivity is equal to hydraulic conductivity divided by specific storage. A shows the change in hydraulic head for the one-mile and two-mile fracture network scenarios. B shows the change in hydraulic head for homogeneous and isotropic scenarios. Pink indicates the change in head at the end of injection and grey indicates the change in head at the end of the day. The solid black line is the threshold pressure, which was calculated to be 280 m.

None of the homogeneous and isotropic model scenarios, at the end of injection and at the end of the day, exceeded the threshold pressure change of 280 m. Most of the network of fractures scenarios did exceed the threshold pressure. The fractures scenarios that did not exceed the threshold pressure were the two-mile network of fractures scenarios that had the higher specific storage value.

Table 3
Change in Hydraulic Head for Model Results

		End of Injection			End of Day		
	K and S _s	Change In Hydraulic Head At 25% Of The Distance From The Injection Well (m)	Change In Hydraulic Head At 50% Of The Distance From The Injection Well (m)	Change In Hydraulic Head Adjacent To Pumping Well (m)	Change In Hydraulic Head At 25% Of The Distance From The Injection Well (m)	Change In Hydraulic Head At 50% Of The Distance From The Injection Well (m)	Change In Hydraulic Head Adjacent To Pumping Well (m)
Homogenous and isotropic model with no pumping well	High K / High S _s	0.404	0.311	0.218	7.60x10 ⁻³	7.60x10 ⁻³	7.60x10 ⁻³
	High K / Low S _s	-	-	-	-	-	-
	Mid K / High S _s	6.72	3.06	0.686	0.315	0.308	0.285
	Mid K / Low S _s	15.46	11.3	7.28	0.151	0.151	0.151
	Low K / High S _s	0.467	7.41x10 ⁻⁷	4.10x10 ⁻¹⁰	15.5	2.87	4.10x10 ⁻³
	Low K / Low S _s	243.7	50.9	1.20	26.0	23.9	17.1
Homogenous and isotropic model with pumping well	High K / High S _s	0.401	0.304	0.19	-8.0x10 ⁻³	-9.3x10 ⁻³	-0.03
	High K / Low S _s	0.498	0.4	0.286	-8.4x10 ⁻³	-9.7x10 ⁻³	-3.1x10 ⁻²
	Mid K / High S _s	6.68	2.99	-0.299	0.149	8.7x10 ⁻²	-0.844
	Mid K / Low S _s	15.3	11	6.34	-0.204	-0.261	-1.18
	Low K / High S _s	0.467	4.39	-27.1	15.4	2.62	-44.2
	Low K / Low S _s	-	-	-	-	-	-
1 mile Fracture Network	High K / High S _s	1320	1301	1280	420	420	420
	High K / Low S _s	10200	10200	10200	2120	2120	2120
	Mid K / High S _s	1850	1055	504	423	420	416
	Mid K / Low S _s	10870	9950	9230	2120	2120	2120
2 mile Fracture Network	High K / High S _s	676	633	597	208	208	208
	High K / Low S _s	5080	4970	5005	1071	1071	1071
	Mid K / High S _s	1006	255	12.5	228	207	181
	Mid K / Low S _s	6240	4600	3320	1073	1070	1064
Injection Rate of 0.193 m ³ /s	High K / High S _s	896	881	869	285	285	285
Injection Rate of 0.102 m ³ /s	High K / High S _s	471	463	457	150	150	150

Notes: The dashes in this table show model scenarios that failed to converge. The bolded numbers represent scenarios that did experience communication.

Excess Volume of Water

The goal of this section was to better understand how much excess water is produced when communication impacts a well. When a well is impacted by hydraulic communication, there is an unexpected increase in the water produced. This means that there is an excess amount of water that would have not been produced if a well was not impacted. Figure 9 shows an example water production curve for a well impacted by hydraulic communication. The two black dashed curves are empirically fitted power functions that represent the water produced when a well experiences no communication and the water produced with communication.

Figure 9: Water production versus the time of production for one well that was impacted by communication. The solid blue line is water production data gleaned from COGCC public data.

The dashed blue lines are estimates of the missing data from the water production data. The small black dashed line, labeled water produced after communication, is the estimated water produced from the impacted well after hydraulic communication occurs. The large black dashed line, labeled water produced before communication, is the estimated water produced from a well that does not experience communication. The red line shows the time of hydraulic communication.

To calculate the excess volume of water produced during the well's production time, an integral was calculated that measured the area between the two black curves. The integral measured the difference between the water produced from the well that did not have communication. This integral was calculated from the time of the hit to the time that the two black curves were equal to one another (Eq. 1).

$$V_{excess} = \int_{t=325 \text{ days}}^{t=721 \text{ days}} (\text{Volume of Water Produced}_{After} - \text{Volume of Water Produced}_{Before}) dt \quad (1)$$

By measuring this discrepancy in water produced, the excess volume of water produced due to communication was calculated. During communication there is an excess volume of water produced of $\sim 145 \text{ m}^3$.

Particle Tracker

A particle tracker was conducted to determine whether the excess water entering the production well was formation fluid or hydraulic fracturing fluid. Formation water is water that occurs naturally within the pores of a rock (Schlumberger 2018), and its dominance in an impacted well would thus imply limited to no advection of treatment fluid between wells. MODPATH is a program that works in conjunction with MODFLOW to model three-dimensional flow paths from groundwater flow simulations (Pollock 2012). MODPATH was used to track the movement of treatment fluid from the injection well over the model run time. It was used within the one-mile fracture network scenario, since some of these runs did experience communication. To track the movement of treatment fluid, MODPATH was specified to release particles within the injection well at the beginning of the 24-hour simulation. These particles were tracked from the beginning of the simulation to the end of the simulation. The results showed that no treatment fluid entered the pumping well and that the treatment fluid from the injection well only moved approximately ten meters away from the well during the entire 24-hour modeled period.

Discussion

By comparing the change in hydraulic head at each of the measuring points to the increase in casing pressure, it is possible to see that communication did occur in some of the model scenarios.

Homogeneous, Isotropic Models

The results of the homogenous, isotropic models indicate that no communication occurred between wells in both the non-pumping and pumping scenarios. Since the change in hydraulic head in these scenarios did not exceed 280 m of head change, no communication occurred. Results in Tables 3 and 4 indicate that decreasing the specific storage led to an increase in the change in hydraulic head at each of the measuring points that were at (1) 25% of the distance from the injector, (2) at 50% of the distance from the injector, and (3) immediately adjacent to the pumping well. By decreasing the hydraulic conductivity and decreasing the specific storage, larger changes in hydraulic head is modeled between the well pair. Adding a pumping well to the system is more consistent with the observed situation that occurred between these wells. These results show that if the pumping well is a quarter mile away from the injecting

well, no communication will occur in the pumping well. In the homogeneous, isotropic models there is no situation where the pumping well experiences communication.

Network of Fractures

When introducing a network of fractures into the system, the model results show that all of the one-mile fracture network scenarios did experience hydraulic communication. The scenarios with low specific storage had the largest changes of hydraulic head at each of the measuring points. At the end of the day, all of the fracture network scenarios experienced communication. The results show that all scenarios communicate, but certain scenarios had larger changes in hydraulic head. These larger changes in hydraulic head are most strongly linked to lower specific storage and higher hydraulic conductivity values. The scenario that had the largest change in hydraulic head was the mid-range hydraulic conductivity and the low specific storage. These results prove that when adding a permeable conduit, like a fracture network, hydraulic communication could occur up to a mile away from the injecting well.

In the two-mile fracture network scenarios almost all measurement points did exceed the change in hydraulic head threshold of 280 m. For the mid-range conductivity and high specific storage scenario, the modeled change in hydraulic head adjacent to the pumping well and 50% away from the injection well did not exceed the threshold. All other scenarios within the two-mile fracture network did experience communication at the end of injection. At the end of the day, only two of the four scenarios experienced communication. The two scenarios that experienced communication had low specific storage. The scenarios that did not experience communication had high specific storage. Similar to the one-mile fracture networks, decreasing the specific storage increases the likelihood of communication between two wells. The largest modeled change in hydraulic head in the two-mile fracture network scenarios occurred when the hydrogeologic properties were set to the lower hydraulic conductivity value and low specific storage value. Scenarios with lower specific storage values are more likely to have hydraulic communication occur between a pair of wells. The two-mile network of fractures results found that communication can occur up to two miles away from the injection well.

When decreasing the injection rate of the injection well, hydraulic communication still occurred at all of the measuring points at the end of injection. At the end of the day, the decreased injection scenarios did not experience communication. Past hydraulic fracturing treatment techniques used both water and chemical additives. This type of treatment, using both water and chemicals, usually has lower injection rates (e.g. $0.103 \text{ m}^3/\text{s}$). In recent years, it has become more economical to treat hydraulic fracturing wells only using water. This change requires larger volumes of water to complete treatment and higher injection rates than were previously used. By decreasing the rate of injection in the injecting well, the modeled change in hydraulic head at all three measurement points also decreases. The change in hydraulic head does not decrease enough though to stop communication from occurring in the one-mile fracture network scenarios. This means that the change in hydraulic head calculated at each of the measuring points, even with a decreased injection rate, still exceeds the threshold pressure for

hydraulic communication. Injection rates help decrease the pore pressure transferred between the well system, but to decrease the likelihood of communication in the Basin, injection rates would have to be decreased even lower than 0.102 m³/s. The modeled results show that there is a correlation between injection rate and hydraulic communication.

Significance / Big Picture

For hydraulic communication to occur, there must be geologic heterogeneity within the subsurface. All of the modeled scenarios with homogeneous and isotropic media did not experience communication, but when a permeable pathway was added in the system, communication did occur. In the fracture network models hydrogeologic parameters play a large role in whether hydraulic communication occurs between a pair of wells. Lower specific storage values increase the likelihood of communication in the fracture network scenarios. These results have large implications for wells experiencing hydraulic communication, since geologic heterogeneity must exist within the subsurface. Geologic heterogeneity plays the largest role in determining whether communication will occur between well pairs in all modeled scenarios. At distances greater than one-mile between the wells, it was found that the hydraulic conductivity and the specific storage of the system also has an effect on determining whether communication will occur. The hydrologic parameters of the formation being targeted by oil and gas production should be studied, since there is a relationship between hydrogeologic parameters and hydraulic communication. Changing spacing regulations is an effective way to reduce communication, because in this case it capitalizes on the heterogeneity of the subsurface and the hydrogeology being targeted by oil and gas wells.

During hydraulic communication there is an excess volume of water produced (Figure 9). It was calculated that an excess of ~145 m³ of water was produced over a year after communication occurred. Due to this volume being produced over a long time frame it cannot be directly compared to the model results, since the total model run time is 24 hours. It can be assumed that the formation experiences long term damage. This damage can be seen when looking at how much gas is lost (Figure 3) and the water that is gained (Figure 9) after communication impacts a well. Since the changes in hydraulic head are large enough to cause communication, it can be said that formation damage must occur quickly. This damage continues to affect the rock up to a year after communication occurs, which means that this large change in hydraulic head has a lasting effect on the formation. In order to relate the excess volume of water produced to the time of communication, studies should be conducted that focus on creating groundwater models that extend for longer time frames.

Conclusion

Hydraulic communication in the Piceance Basin is dependent upon geologic heterogeneity within the subsurface. Along with geologic heterogeneity, hydrogeologic

parameters play a role in whether communication occurs between well pairs. By introducing geologic heterogeneity into the system, the pore pressure (change in hydraulic head) between the wells increases (Figure 8). While hydraulic communication is not a pervasive problem since only a small percentage of wells in the Basin experience it, it is still important to understand what parameters play a role in affecting it. By having an understanding of the parameters that play a role on communication, regulatory agencies in the future will be better equipped to enforce spacing orders that mitigate communication from occurring in the Piceance Basin. Operators whose wells experience communication can have permanent economic loss and higher short-term expenses. To reduce the occurrence of communication, there needs to be a better understanding of the geologic heterogeneity of the Basin. Changing well spacing is a viable option for decreasing communication, which requires an understanding of the geologic heterogeneity of the area, otherwise, hydraulic communication could continue to occur. Operators should also have a better understanding of the hydrogeologic properties of the Basin, since the hydraulic conductivity and specific storage play a role in determining whether communication occurs. In the future, studies should be conducted to better understand how the excess volume of water produced relates to the long-term effects of communication.

References

- Cole, R., and S. Cumella. 2003. Stratigraphic Architecture and Reservoir Characteristics of the Mesaverde Group, Southern Piceance Basin, Colorado. *Piceance Basin 2003 Guidebook*, 385–442.
- Colorado Oil and Gas Conservation Commission. April, 2018. Piceance Basin: Basin Wide Order for Asymmetric Setbacks.
- Colorado Oil and Gas Conservation Commission. December, 2018. Piceance Basin: Well Spacing and Setback Review.
- Cooley, H., K. Donnelly, N. Ross, and P. Luu. 2012. Hydraulic fracturing and water resources: separating the frack from the fiction. *Pacific Institute, Oakland*.
- Cumella, S. P., and D. B. Ostby. 2003. Geology of the Basin-Centered Gas Accumulation, Piceance Basin, Colorado, 171–193.
- Freeze, R. A., and J. A. Cherry. 1979. Groundwater: Englewood Cliffs. *New Jersey*.
- Harbaugh, A.W. 2005. MODFLOW-2005, the U.S. Geological Survey modular ground-water model -- the Ground-Water Flow Process: U.S. Geological Survey Techniques and Methods 6-A16.
- Hettinger, R. D., and M. A. Kirschbaum. 2002. Stratigraphy of the Upper Cretaceous Mancos Shale (Upper Part) and Mesaverde Group in the Southern Part of the Uinta and Piceance Basins, Utah and Colorado, 1–24.
- Jacobs, T. 2017. Oil and gas producers find frac hits in shale wells a major challenge. *Journal of Petroleum Technology* 69, no. 04: 29-34.
- Johnson, R. C. 1989. Geologic History and Hydrocarbon Potential of Late Cretaceous-Age, Low-Permeability Reservoirs, Piceance Basin, Western Colorado. *USGS Bulletin 1787-E*, 51.
- Junkin, J. E., M. A. Sippel, R. E. Collins, and M. E. Lord. "Well performance evidence for compartmented geometry of oil and gas reservoirs." In *SPE Rocky Mountain Regional Meeting*. Society of Petroleum Engineers, 1992.
- Kessels, W., and J. Kück. 1995. Hydraulic Communication in Crystalline Rock Between the Two Boreholes of the Continental Deep Drilling Project in Germany. *International Journal of Rock Mechanics and Mining Sciences & Geomechanics Abstracts* 32 (I): 37–47.

- Koz, M., M. R. Brudzinski, P. Friberg, R. J. Skoumal, N. D. Baxter, and B. S. Currie. 2017. Maturity of Nearby Faults Influences Seismic Hazard from Hydraulic Fracturing, 1–10.
- Kumar, A., P. Seth, K. Shrivastava, R. Manchanda, and M. M. Sharma. 2018. Well Interference Diagnosis through Integrated Analysis of Tracer and Pressure Interference Tests. Unconventional Resources Technology Conference (URTEC).
- Laubach, S. E., R. A. Marrett, R.A., J.E. Olson, A. R. Scott. 1998. Characteristics and Origins of Coal Cleat : A Review. *International Journal of Coal Geology*, no. 35: 175–207.
- Lorenz, J. C. 2003. Fracture systems in the Piceance Basin: Overview and comparison with fractures in the San Juan and Green River basins.
- MacLachlan, M. E. 1987. General geology of the Piceance Basin. *Oil shale, water resources, and valuable minerals of the Piceance basin, Colorado--the challenge and choices of development: USGS Professional Paper 1310*: 7-15.
- Morales, A., K. Zhang, K. Gakhar, M. M. Porcu, D. Lee, D. Shan, R. Malpani, D. Sobernheim, and A. Acock. 2016. Advanced Modeling of Interwell Fracturing Interference : An Eagle Ford Shale Oil Study - Refracturing. *Society of Petroleum Engineers Journal* 21: 1–19.
- Norton, G., and C. Groat. 2003. Chapter 2: The Uinta-Piceance Province— Undiscovered Oil and Gas Resources. *U.S. Geological Survey Digital Data Series DDS-69-B*, 25pp.
- Pan, Z., and L. D. Connell. 2012. International Journal of Coal Geology Modelling Permeability for Coal Reservoirs : A Review of Analytical Models and Testing Data. *International Journal of Coal Geology* 92: 1–44.
- Papadopoulos, S.S. & Associates. 2008. Coalbed Methane Stream Depletion Assessment Study - Raton Basin, Colorado, 1–189.
- Patterson, P. E., K. Kronmueller, and T. D. Davies. 2003. Sequence Stratigraphy of the Mesaverde Group and Ohio Creek Conglomerate, Northern Piceance Basin, Colorado. *Piceance Basin 2003 Guidebook*, 115–28.
- Pollock, D.W. 2012. User guide for MODPATH version 6—A particle-tracking model for MODFLOW. *U.S. Geological Survey Techniques and Methods*, p. 58.
- QGIS Development Team. QGIS Geographic Information System. 2009. Accessed October 2, 2018. <http://qgis.osgeo.org>.
- Rimedio*, M., L. Monti, J. Quiroga, C. Shannon, A. Lerza, and M. Roberts. 2015. Interference Behavior Analysis in Vaca Muerta Shale Oil Development, Loma Campana Field, Argentina. *In Unconventional Resources Technology Conference, San Antonio, Texas, 20-*

22 July 2015, pp. 2157-2169. Society of Exploration Geophysicists, American Association of Petroleum Geologists, Society of Petroleum Engineers.

Rubin, C., M. Zamirian, A. Takbiri-borujeni, and M. Gu. 2019. Investigation of Gas Slippage effect and Matrix Compaction effect on Shale Gas Production Evaluation and Hydraulic Fracturing Design Based on Experiment and Reservoir Simulation. *Fuel* 241: 12–24. <https://doi.org/10.1016/j.fuel.2018.12.015>.

Spielman, A., L. Wolk, and A. L. Ager. 2016. Record of Proceedings COGCC.

Theis, C. V. 1935. The relation between the lowering of the piezometric surface and the rate and duration of discharge of a well using ground-water storage. *Eos, Transactions American Geophysical Union* 16, no. 2: 519-524.

Thompson, L. G. 2018. Modeling the Effects of Fracture Interference Using a Spectral Gas Reservoir Simulator. *Journal of Petroleum Science and Engineering* 160 (September 2017): 474–82.

Zhang, J., and S. X. Yin. 2017. Fracture Gradient Prediction: An Overview and an Improved Method. *Petroleum Science* 14 (2): 1–11. <https://doi.org/10.1007/s12182-017-0182-1>.