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Key Points:

- Existing wells may intersect hydraulically stimulated fractures
- Data from existing wells are used to develop probability distributions
- Spatial probability distributions provide insights into gas extraction

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Potential of hydraulically induced fractures to communicate with existing wellbores

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Abstract The probability that new hydraulically fractured wells drilled within the area of New York underlain by the Marcellus Shale will intersect an existing wellbore is calculated using a statistical model, which incorporates: the depth of a new fracturing well, the vertical growth of induced fractures, and the depths and locations of existing nearby wells. The model first calculates the probability of encountering an existing well in plan view and combines this with the probability of an existing well-being at sufficient depth to intersect the fractured region. Average probability estimates for the entire region of New York underlain by the Marcellus Shale range from 0.00% to 3.45% based upon the input parameters used. The largest contributing parameter on the probability value calculated is the nearby density of wells meaning that due diligence by oil and gas companies during construction in identifying all nearby wells will have the greatest effect in reducing the probability of interwellbore communication.

1. Introduction

A large part of southern New York State is underlain by the Marcellus Shale. The depth varies spatially, ranging from 3000 to 6000 ft below the surface, where gas is readily present. The large distance through overlying rock formations to shallow aquifers makes fluid migration unlikely without the presence of discontinuities to provide pathways through the rock [*Leff*, 2011; *Flewelling et al*., 2013]. Unplugged existing wells or existing wells with compromised casings/cement as well as natural fractures and compromised producing wells all provide potential pathways from depth [*Harrison*, 1983; *Nordbotten et al*., 2004, 2005; *Dusseault and Jackson*, 2014]. Existing boreholes, both producing and nonproducing that are either unplugged or have had their casings compromised in some way, provide the most likely pathway for fluid migration by providing a continuous conduit from depth [*Harrison*, 1985]. Upward propagation through natural fractures, on the other hand, is deemed impossible by *Engelder et al*. [2014]. The presence of large capillary forces and low water saturations that exist in the Marcellus Shale serve to trap fracing fluid and brine within the shale matrix. For the purposes of this study, we consider only the potential of preexisting wells in combination with the induced fracture network to permit migration.

Migration in this case can refer to the migration of any fluid (gas, brine, or fracturing fluid). While it may be possible for liquids to migrate upward, the conditions required to reach shallow aquifers or the surface seem unlikely to occur. *Flewelling and Sharma* [2014] provide a good analysis of the conditions necessary to mobilize fracturing fluid or brine. Gases are therefore the most likely fluid to migrate because gas requires much less pressure to mobilize due to its buoyancy.

Modeling was conducted by *Reagan et al*. [2015] to examine the short-term transport of fluids from a single hydraulic fracturing well through various pathways. Their pathways included fractures extending to the surface or intersecting natural fractures (F-cases) as well as fractures intersecting existing wells or the fracturing well (W-cases). The study makes it clear that the probability of each scenario was not addressed, merely the resulting quantity of fluid delivered to the shallow water resource. They found that W-cases transport larger amounts of methane to aquifers than F-cases. In addition, both cases are highly dependent on the production regime within the tight gas reservoir (producing wells limit the amount of gas available for transport). Furthermore, the amount of gas available for migration is limited by slow recharge from the source rock, meaning that the amount initially available for migration is constrained to the volume of gas stored within the fractured portion of the reservoir.

Data on New York State wells and microseismic data collected from Marcellus fracturing jobs within Ohio, Pennsylvania, and West Virginia are used herein to develop a statistical model to better understand the risk

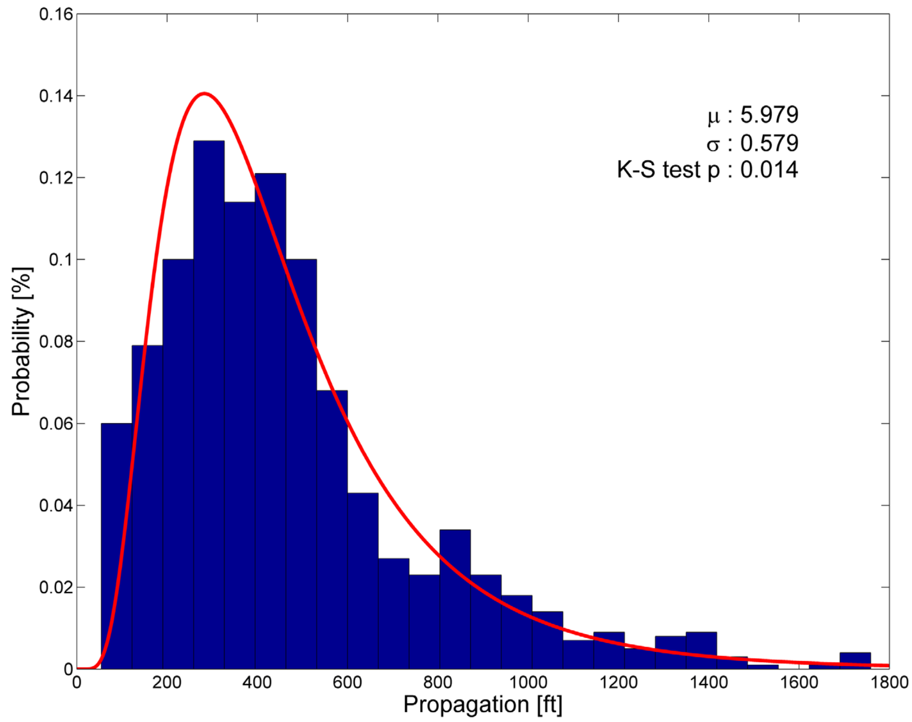

Figure 1. Marcellus-shale-induced fracture heights with fit lognormal distribution.

of communication from hydraulic fracturing associated with all existing boreholes and wells reported in the New York Department of Environmental Conservation (NYDEC) downloadable well database. Since the integrity of the wells and borings are not considered in this paper, the results found do not represent the actual risk associated with hydraulic fracturing by means of communication with existing wellbores, but instead place an upper bound on that estimation.

1.1. Fracture Propagation

Induced upward fracture growth for hydraulically fractured wells in the Marcellus region was estimated from microseismic data collected for over 1000 fracture stages by *Fisher and Warpinski* [2012] and digitized by *Davies et al*. [2012]. Microseismic monitoring is commonly used during hydraulic fracturing to estimate the extent of fracture growth by detecting shear waves produced during the fracturing process. Shear waves are generated during the tensile opening of fractures when fluid pressure exceeds the minimum principle stress of the rock, in this case, the fracture is dilated normal to the fracture surface. Shear waves are also generated by shear slipping in which the motion is parallel to the fractures. Finally, shear waves can be generated by the contraction of the rock or fracture [*Busetti et al*., 2014]. Perturbations in the stress field of the surrounding rock can be caused by poroelastic coupling of tensile and shear fractures causing microseisms to be detected beyond the fractured region [*Warpinski*, 2009]. Microseisms provide an estimate of the extent of fracture propagation and volume of fractures due to hydraulic fracturing, but may overestimate the maximum growth of fractures [*Warpinski et al*., 2004]. This data set, therefore, provides a maximum estimate for fracture propagation distances that we use to create a probability distribution of the maximum vertical extent of fractures based on a log transformation of the propagation heights in feet and a fit lognormal distribution. The parameters that were extracted from this data provide fitting parameters of $\mu = 5.979$ ln(ft) and $\sigma = 0.579$ with a Kolmogorov-Smirnov goodness of fit resulting in a p value of 0.014 (Figure 1). The parameters μ and σ are fitting parameters defined by equation (1), where m is the mean of the untransformed data and v is the variance of the untransformed data.

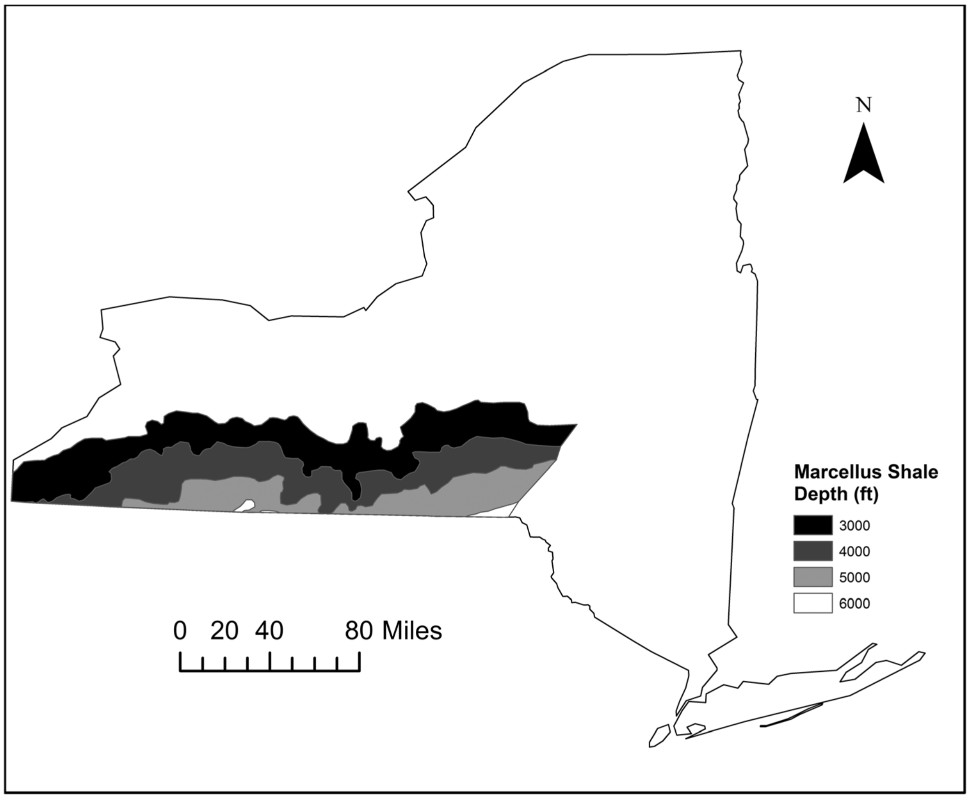

Figure 2. Depth (feet) to shale gas formations in New York.

$$\mu = \ln\left(\frac{m}{\sqrt{1+\frac{v}{m^2}}}\right), \sigma = \sqrt{\ln\left(1+\frac{v}{m^2}\right)} \tag{1}$$

The envelope of induced fractures provides a region of higher permeability in which fluid movement is possible.

1.2. Energy Production in New York State

Energy extraction has been occurring in New York since the mid-1800s. The Marcellus in particular has been produced since 1880, the depth of the bottom of the Marcellus Shale are shown in Figure 2 [*Leff*, 2011]. However, the discovery of easily accessible conventional reservoirs within New York led to a decrease in Marcellus production wells until recent directional drilling and slick water technologies made unconventional reservoirs more accessible. The locations, uses, dates of installation, and depths of energy wells have been recorded by New York since 1900. The density of wells across New York is shown in Figure 3, with darker colors representing higher densities. The outline of the Marcellus Shale's producible area is outlined for reference. Many of the wells included in the NYDEC downloadable well database targeted conventional oil and gas producing formations other than the Marcellus. Table 1 shows formations located in southern New York that have been targeted for energy extraction at some point since the mid-1800s. The last column shows the relative depth with respect to the Marcellus Shale, which is the bottom unit of the Hamilton Group in this region.

The state of New York estimates that around 70,000 wells have been drilled since the 1800s; of those, a database of 41,000 wells exists. Of these 41,000 wells, 29,000 are located in the same region that is underlain by the Marcellus Shale, with well depths ranging from a few hundred feet to upward of 10,000 ft. The number of reported wells increased significantly in the late 1960s from a rate of about 100 wells per year to upward of 800 per year, while the production of oil and natural gas dropped, as shown by the historical production rates in Figure 4. This suggests that many of the unaccounted for wells were constructed before

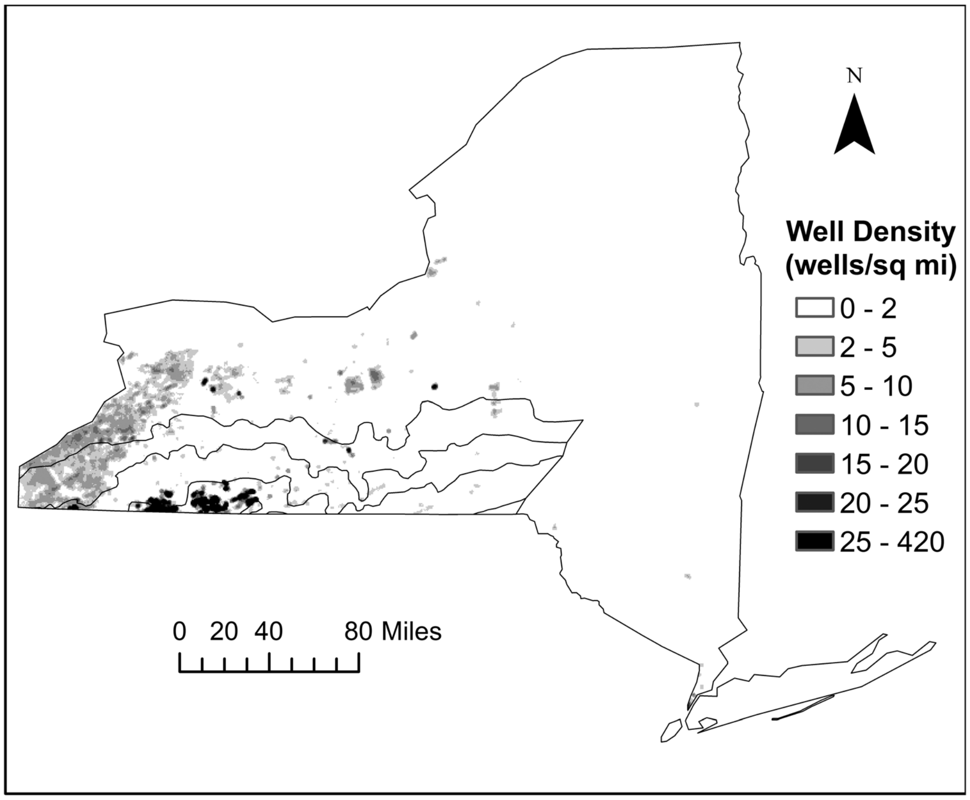

Figure 3. Density of existing wells located within New York, the Marcellus Shale is outlined for reference.

the 1960s. The large number of unaccounted for wells necessitates a probabilistic approach to dealing with the locations and depths of existing wells.

2. Methods

The large number of unaccounted for wells within New York State means that determining exactly where new hydraulic fracturing (HF) wells will intersect existing wells is not possible and necessitates a probabilistic approach to existing well locations and depths. This requires several assumptions to be made with regards to existing wells and fracture propagation:

1. The existing wells in our database are a representative subset of all existing wells, known and unknown.
2. The depth of existing wells that are close to one another come from the same distributions, i.e., wells in an area tend to target the same formation or set of formations.
3. Existing wells within the data set are vertical; the inclusion of horizontal wells within the data set would provide a greater opportunity for intersection with hydraulic fractures.
4. Fractures growth is not impacted by nearby wells or existing fractures, i.e., fractures will not bend toward nearby discontinuities to

Table 1. Hydrocarbon Producing Formations and Groups in Southwestern New York [*Alpha Environmental Consultants Inc.*, 2009]

Formation	Type	Production	Above/Below Marcellus
Canadaway Group	Sandstone and Shale	Gas/Oil	Above
Hamilton Group	Sandstone and Shale	Gas	At/Above
Onondaga	Limestone	Gas/Oil	Below
Helderberg Group	Limestone	Gas	Below
Clinton Group	Shale	Gas	Below
Medina Group	Sandstone	Gas	Below
Queenston	Sandstone and Shale	Gas	Below
Trenton-Black River	Limestone	Gas	Below

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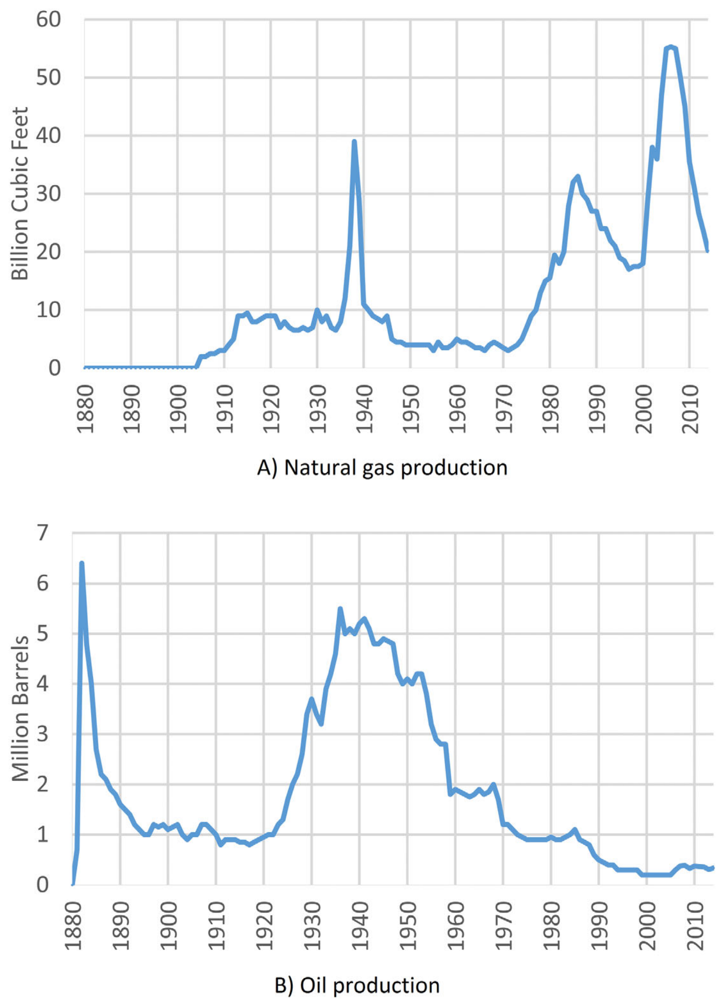

Figure 4. New York historical gas and oil production 1880–2014.

increase the volume of the fractured region.

The first two assumptions mean that to calculate the probability in a spatial sense, the region must be subdivided so that distributions of well depths can be determined on an appropriate scale. The third assumption allows for the probability calculation to be simplified to point intersections rather than point and line intersections. Finally, the fourth assumption eliminates the need for fracture growth modeling from the statistical model.

The probability calculation is evaluated for each subdivided region or representative area (RA). For the purposes of this analysis, RAs are located in a uniform pattern consisting of one RA centered every mile in both the x and y directions. One mile is used to provide significant overlap of each RA so that probability values transition smoothly across the region. A more efficient way to discretize may be adaptive spacing based on the size of neighboring RAs. This has the benefit of reducing the number of RAs needed for the analysis, but the calculated probabilities do not transition as smoothly across RAs. For the purposes of this analysis, using more RAs did not slow down the model enough to warrant an adaptive spacing approach. However, analysis over larger regions would benefit from either adaptive spacing or from a coarser uniform discretization.

Representative areas are used to determine the probability of induced hydraulic fractures encountering an existing well. Assigned to each RA are the n existing wells from the NYDEC downloadable well database that are closest to the center of the RA. We will consider these n wells as being within the RA. For the purposes of this study, we investigated cases in which n equals 20 wells up to n equals 120 wells. In addition to knowing the wells within each RA, the radius necessary to contain these n wells, r_{RA}, is needed to determine the density of wells in the region. Equation (2) defines r_{RA},

$$r_{RA} = \frac{d_n + d_{n+1}}{2}, \tag{2}$$

where d_n is the distance from the center of the RA to existing well n and d_{n+1} is the distance to existing well $n+1$. This formulation of the radius of contained wells is chosen so that included wells are not on the boundary of the RA and the area is not biased toward existing well n or existing well $n+1$.

To simplify the probability calculation further, the probability will be determined in two separate parts and then those parts will be multiplied to get the full three-dimensional probability of a new HF well encountering existing wells. The first part is calculating the horizontal probability of encounter or the probability of an

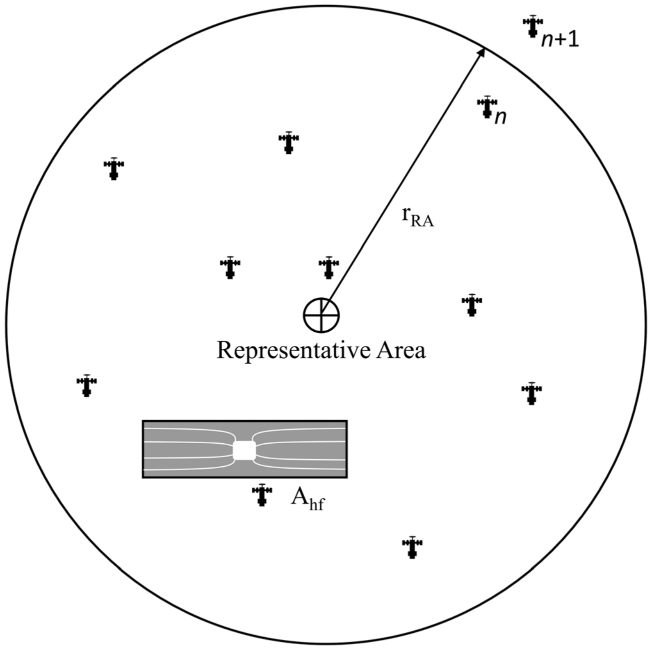

Figure 5. Calculation point with corresponding radius containing the nearest n wells. Hydraulic fracturing area of influence is shown in gray in the lower left of the containing circle.

existing well-being within the plan view footprint of an HF well. The second part is calculating the probability that wells within the RA are at sufficient depth to intersect the fractured region around the HF well. The total probability will then be calculated by multiplying the horizontal and vertical probabilities.

2.1. Horizontal Probability of Encounter

The probability that a new HF well placed randomly within the RA horizontally intersects an existing well is dependent on the area of the RA (A_{RA}), the number of existing wells in the RA (n), and the anticipated *x-y* area of influence of the HF wells (A_{hf}). In this case, A_{hf} is defined as the *x-y* area that is underlain with induced hydraulic fractures. Figure 5 shows an example representative area containing n wells and an HF well. The *x-y* HF area of influence is the gray area in the lower left quadrant of the RA, but it can be located anywhere within the circle and oriented in any direction since the probability of encountering the fractured region is calculated for the entire RA. Typically, new HF wells are located perpendicular to natural fractures or parallel to the minimum principle stress in the *x-y* plane [*Engelder et al*., 2009]. However, due to the large number of unidentified existing wells, the location of existing wells within an RA is random as well. This means that the orientation of the HF well does not enter into the probability equation, only its area (see equations (3) and (4)). Note that this is for new, yet to be located HF wells in the region of interest.

The probability of a single existing well intersecting A_{hf} is simply a ratio of the two areas, A_{hf} and A_{RA}, given as P_{h1} in equation (3).

$$P_{h1} = \frac{A_{hf}}{A_{RA}} \tag{3}$$

More than one well exists in the containing circle, defined by n, so the probability of encountering at least one well is given in equation (4) as P_h.

$$P_h = 1 - \left[(1 - P_{h1})^n \right] \tag{4}$$

The bracketed terms represent the probability of the hydraulically fractured region intersecting none of the n existing wells in the RA. The probability of one or more wells intersecting the fractured region is therefore the converse of the bracketed terms. The next step is to determine the probability of the existing wells vertically encountering the fractured region.

2.2. Vertical Probability of Encounter

Vertical intersection of an existing well with the fractured region is determined by combining the depth to the horizontal segment of the HF well with probability distributions for regional well depths and upward fracture growth. The depth to the horizontal segment of the HF well is taken as a single value based on the depth of the Marcellus Shale at the center of the RA. Probability distributions are fit to the depth of wells for the n wells within each RA, while the probability of fracture height is represented by the fit lognormal distribution for the whole of the Marcellus Shale.

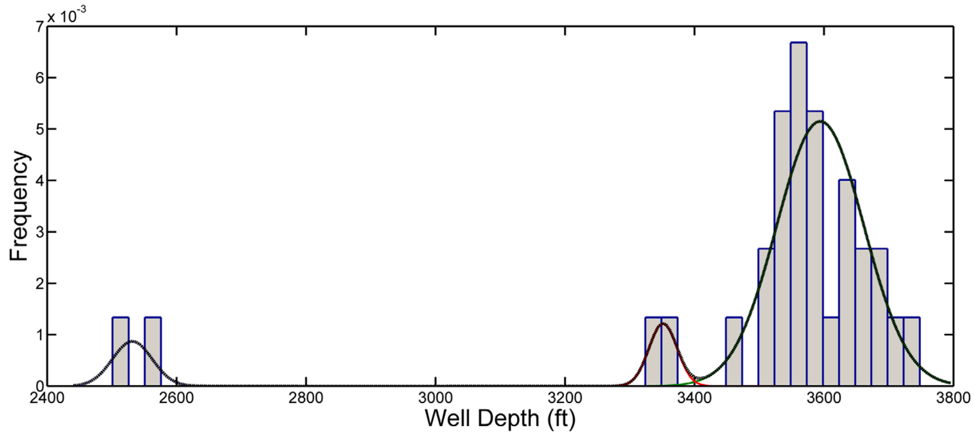

Figure 6. Fit probability density function of GMM Distribution using three Gaussians normalized by the number of wells.

A Gaussian mixture model (GMM), given by equation (5), is used to fit depth data, where μ_j are the means associated with each Gaussian, σ_j^2 are the variances, and π_j are the weights (which sum to one). A GMM allows for multipeaked data to be fit. This makes it ideal for fitting the depth of existing wells that have targeted multiple formations in the same regions over the history of oil and gas drilling in New York. An example distribution is shown in Figure 6, in which three Gaussians are fit to 60 well depths.

$$p(y \mid \mu_1, \ldots, \mu_k, \sigma_1^2, \ldots, \sigma_k^2, \pi_1, \ldots, \pi_k) = \sum_{j=1}^{k} \pi_j N(\mu_j, \sigma_j^2) \tag{5}$$

GMM fitting is done using the EM algorithm, which uses maximum likelihood estimates of the GMM parameters given the desired number of Gaussians, k [*McLachlan and Peel*, 2000; *Dempster et al*., 1977]. The Matlab function gmdistriubtion.fit is used to accomplish this task for values of k ranging from 1 to 20. The value of k to be used is calculated with the Akaike information criterion (AIC). The AIC identifies the simplest model that fits the data presented by rewarding the maximum likelihood calculated for a given number of independent parameters, k, while penalizing large values of k used in the GMM [*Akaike*, 1974]. Using the GMM with a k that produces the lowest AIC ensures that the best fit for the data is used without overfitting.

The probability that an existing well will be at or below the fractured region is calculated first with the convolution of the fracture propagation distribution and the well depth distribution and then a cross correlation of the horizontal segment depth of the HF well and the result of the convolution integral [*Casella and Berger*, 2002]. Equation (6) provides G which is the random variable for the distance between the base of the well and the top of the fractured zone given the random variables for the depth of the horizontal portion of the fracturing well, S, the fracture propagation height, F, and the depth of existing wells, D. The probability of the fractured region vertically encountering an existing well is $P(G \leq 0)$ or the integral of equation (6) from $-\infty$ to 0.

$$G = S - [F + D] \tag{6}$$

The convolution integral, equation (7), is used to sum two independent random variables, $Z = F + D$, and is applied to the bracketed terms in equation (6).

$$p_Z(z) = \frac{d}{dz} P_Z(z) = \int_{-\infty}^{\infty} p_F(f)\, p_D(z-f)\, df \tag{7}$$

Similarly, the cross-correlation integral is used to find the difference of two independent random variables, $G = S - Z$, given in equation (8).

$$p_G(g) = \frac{d}{dg} P_G(g) = \int_{-\infty}^{\infty} p_Z(z)\, p_S(g+z)\, dz \tag{8}$$

Using arithmetic on probability distributions in this manner is similar to the distributions generated from load and resistance factor design (LRFD) in structural mechanics. The integral of the resistance minus the load in LRFD from $-\infty$ to 0 provides the probability of a load exceeding a material's resistance. Similarly, integrating p(g) from $-\infty$ to 0 in equation (8) provides the probability that a well will exceed the depth of the fractured region.

2.3. Total Probability of Encounter

The two previous subsections have provided the probability of a new horizontal hydraulically fractured well encountering an existing well in the horizontal plane only and the vertical plane only. The total probability in three dimensions, P_{int}, is the multiplication of $P(G \leq 0)$ and P_h, shown in equation (9).

$$P_{\text{int}} = P(G \leq 0) \times P_h \tag{9}$$

It is important to note that P_{int} is not sufficient to establish the risk of communication to the surface or shallow aquifers because it does not incorporate the probability that an existing well provides a pathway for fluids to migrate upward in, rather it is a necessary condition.

3. Sensitivity Analysis

The above analytical approach has been applied to the New York State well data set. Since there are four user supplied parameters that can influence the final result, we examine the importance of each via a sensitivity analysis. The four input parameters are:

1. The area of influence of each hydraulic fracturing job (A_{hf}) which we allow to range from 1500 to 1,600,000 ft^2.
2. The number of wells included for each calculation point (n) which ranges from 20 wells to 120 wells.
3. The inclusion of vertical fracture growth (F) to the model.
4. The depth at which the horizontal segment of the fracturing well is located, where fracture growth is initiated (S).

Values for A_{hf} were chosen based on typical well sizes and assumed fracture growth and orientation. Horizontal wells within the Marcellus region typically have lateral lengths between 2000 and 4000 ft and a well pad can support multiple wells (between six and eight). A_{hf} is therefore allowed to range from 1500 to 1,600,000 ft^2. The upper value of 1.6 million ft^2 is used as an upper bound and assumes that fractures are complex and create permeable zones around the well that extend 400 ft in either horizontal direction perpendicular to eight wells, for one eighth of each of their 4000 ft length. The lower bound of 1500 ft^2 assumes that fractures are not complex and instead have a width of 0.25 in. extending 400 ft in either horizontal direction perpendicular to six horizontal wells. The wells each extend 3000 ft and have a single fracture every 200 ft along the length.

The measure selected to assess the sensitivity of each parameter was the average probability of encountering an existing well with the installation of a new HF well across the entire region considered (the Marcellus Shale within New York). The average of the resultant probability (P_{int}) across all representative areas provides a metric to easily compare each model configuration.

The model was run using ten values of A_{hf}, eight values of n, and three strategies for the HF well depth within the shale. To test the impact of fracture growth, the model was also run with and without fractures. Taking all combinations of these parameters yields 320 different parameter configurations.

Figure 7 shows the average probability across A_{hf} holding n constant at 60 wells (top) and the average probability across n holding A_{hf} constant at 12,000 ft^2 (bottom). This provides insight into the sensitivity of each parameter, which can be examined in more detail by looking back at the equations that form the probability estimate. Increasing A_{hf} increases P_{h1} in equation (3), which in turn increases P_h in equation (4). The impact of adjusting n is more difficult to assess through evaluating the equations, because n plays a role in the horizontal probability of encountering an existing well through equations (3) and (4). An increase of n causes P_h to increase, but decreases P_{h1} by making A_{RA} larger. The direct impact of these changes is difficult to assess analytically since the rate at which A_{RA} changes with n is different for each calculation point. Additionally, increasing n increases the number of wells that contribute to D, which may cause the vertical

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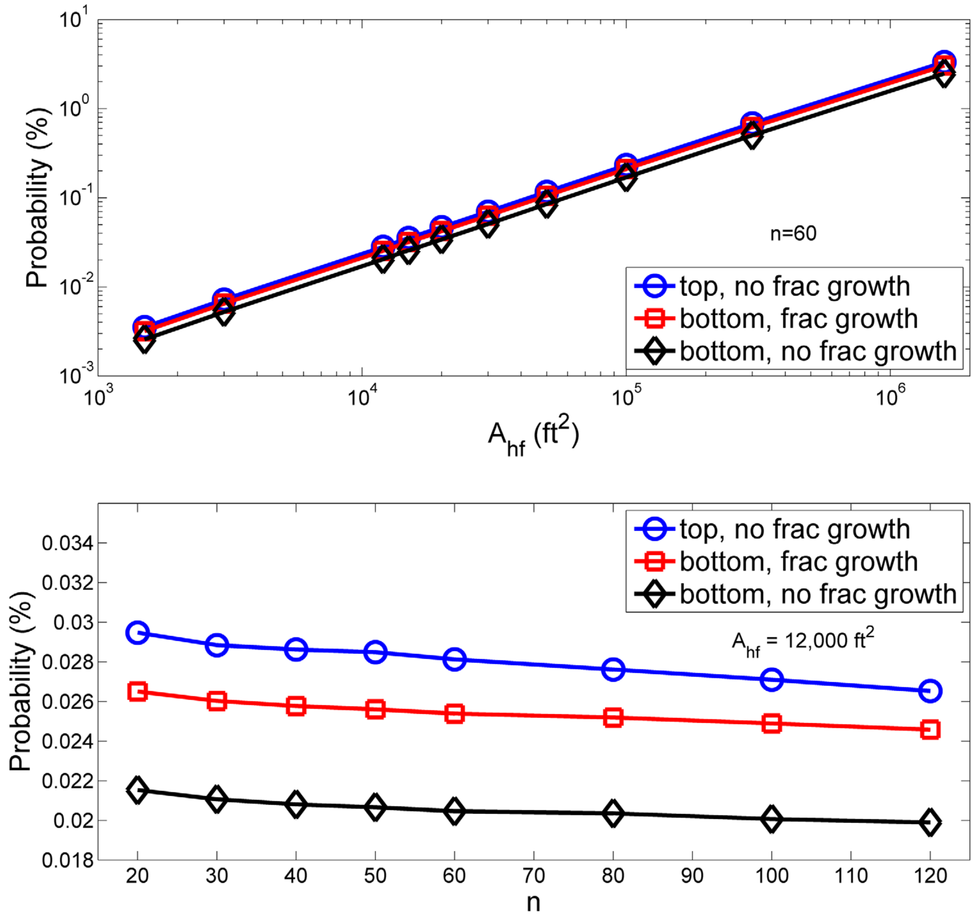

Figure 7. (top) Average probability of model configurations holding n constant at 60 wells, and (bottom) the average probability of model configurations holding A_{hf} constant at 12,000 ft^2. The three lines refer to where fractures were initiated from, the top or bottom of the target formation, and whether upward fracture growth was included.

probability of encounter to shift slightly. It is found that increasing the number of wells used for each calculation point does little to the average probability when compared to the other parameters. The difference between using $n = 20$ wells and $n = 120$ wells is very small, at most increasing the average probability by 0.27%. The sensitivity of n becomes more apparent when looking at discrete calculation points rather than the average probability of all calculation points.

To assess the importance of the fracture propagation, three scenarios were run, (1) when vertical fracture propagation was not included and the depth to the horizontal fracturing well was set to the base depth of shale in the region, (2) when vertical fracture propagation was not included and the depth to the horizontal fracturing well was set to the top depth of the shale in the region, and (3) the depth to the horizontal fracturing well was set to the base depth of shale in the region and fracture propagation was included (this represents a more realistic and conservative scenario in which wells are drilled so that they are near the bottom of the target formation). The use of F predictably increases the average probability values over not using F, but interestingly setting S to the top depth of the Marcellus Shale without any fracture propagation produces the highest average probability values. This means that the fractures are rarely propagating to formations above the Marcellus Shale based on the statistical distribution of fracture heights from Figure 1. Disregarding fracture propagation and setting S to either the top or bottom of the shale therefore provides a reasonable upper and lower bound on the average probability. Fractures do propagate and we will therefore accept that setting S to the bottom of the Marcellus Shale and allowing upward fracture propagation to occur provides a reasonable estimation of the probability of a hydraulic fracturing job encountering an existing well. Disregarding fracture propagation will effectively eliminate some existing wells that are above the target formation, but still close enough to have a nonzero probability of intersecting hydraulic fractures.

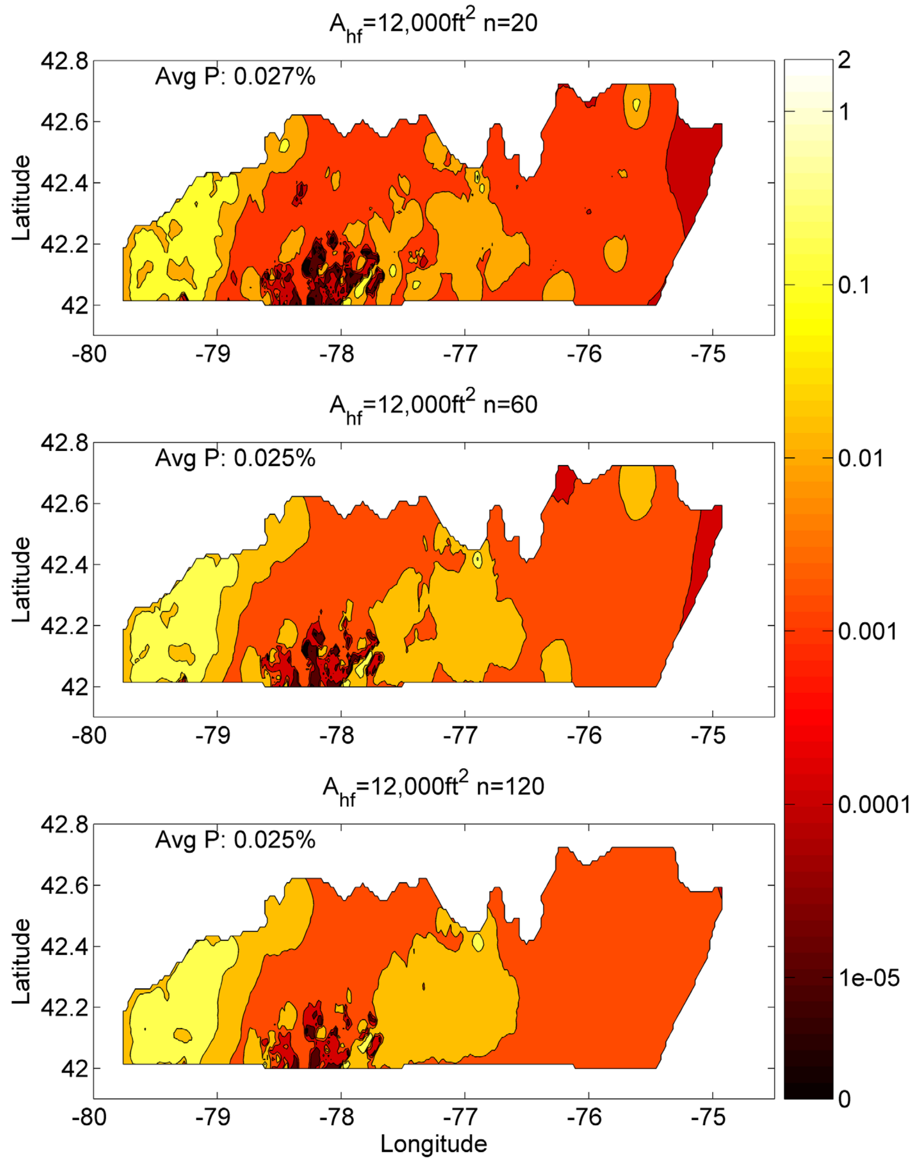

Figure 8. Percent probability of encountering an existing well with a new horizontal hydraulic fracturing job in New York State underlain by the Marcellus Shale. HF area of influence is 12,000 ft^2 and the number of wells in each calculation point is 20, 60, and 120, respectively. Contours are delineated at the color bar labels.

This means that the probability of individual RAs may be smaller when disregarding fracture propagation. Consider the scenario where an RA contains existing wells that are all above the target formation, but still close enough to be within the region where fractures may grow to. Disregarding fracture growth and setting the S to the top of the target formation will produce a probability for that RA of 0. However, setting S to the bottom of the target formation and allowing fracture propagation will yield a nonzero probability since those wells are deep enough to intersect some of the longer hydraulic fractures. This will vary based on the thickness of the target formation, making the use of fracture propagation important when looking at the probability results spatially, while the average probability provides an easy way to compare different parameters in a global sense.

The nonaveraged data must be examined to take into consideration spatial variability in P_{int} so that regions of higher and lower probability can be identified. Figure 8 is a representation of the probability of encountering an existing well at all 8873 RAs for A_{hf} set to 12,000 ft^2 and n set to 20, 60, and 120 wells. In all cases, the HF well is placed at the base of the Marcellus Shale and fractures growth is included. The western region is an

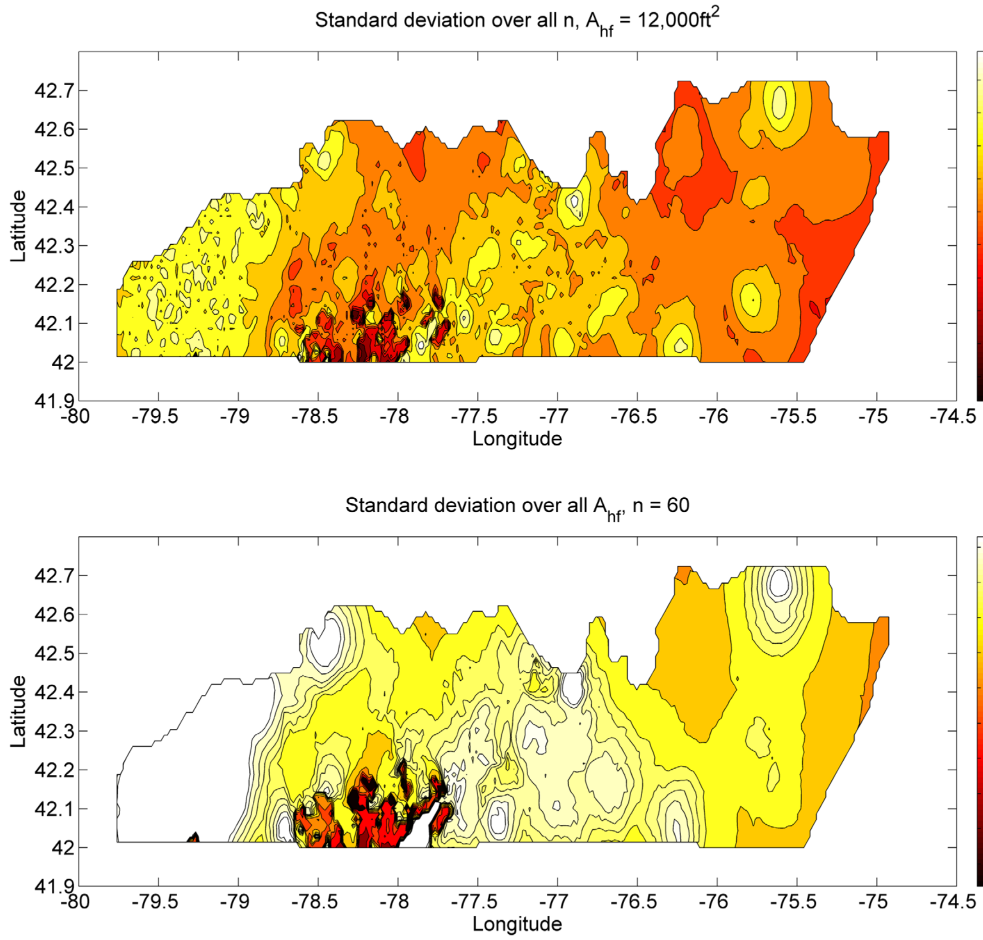

Figure 9. Percent probability standard deviation over a single parameter, A_{hf} or n, while keeping the other constant for the Marcellus region of New York. Contours are delineated at the color bar labels.

area containing the highest density of existing wells that reach a depth that is equal to or greater than the base depth of the Marcellus Shale. This high density of deep wells produces a region in which the probability of encountering an existing well is comparably high across all parameters. This region, however, contains less thermally mature gas making it less likely to be targeted by hydraulic fracturing companies as evident by the pattern of drilling just across the state line in Pennsylvania. The eastern region of the Marcellus Shale within New York is the most likely area to be targeted for hydraulic fracturing based on the trend of well placements occurring across the border in Pennsylvania (PA DEP, unpublished data, 2015, www.depgis.state.pa.us/PaOilAndGasMapping/). At the point scale, the impact of increasing *n* can be seen as smoothing the probability across neighboring RAs. This is because RAs will share a greater number of existing wells with their neighbors. The effect is most evident in the blurring of the western region of the Marcellus Shale in Figure 8. To more closely analyze the impact of changing parameters, the standard deviation was calculated for A_{hf} and *n*.

The standard deviation of the probability results over a single parameter allow for areas of higher variability to be identified. Figure 9 shows the standard deviation of the probabilities for all values of *n* with A_{hf} held constant at 12,000 ft^2 in the top plot and the standard deviation of the probabilities for all values of A_{hf} with *n* held constant at 60 wells in the bottom plot. From these figures, the increased variability associated with changing the hydraulic fracturing area of influence is apparent, with some areas having a standard deviation of as much as 13%. However, the number of points with a standard deviation exceeding 5% is 573 calculation points or 6.5% of the calculation points

The standard deviation associated with changing the number of wells used for each representative area has a much smaller maximum than varying A_{hf}, with a maximum standard deviation of 0.85%. Hot spots in standard deviation for varying n are the results of the smoothing seen in Figure 8. Too many wells in the same region create a regional average that washes out high local probabilities seen when a smaller n is used. This can be seen most evidently in the north-central region of the Marcellus Shale in Figure 8, where the white area fades as the number of wells used per calculation point is increased. Higher standard deviations for varying A_{hf} are primarily due to the regional well density of an area because of the role that A_{hf} plays in equations (3) and (4).

4. Results

The model indicates that the upward fracture growth has very little impact on the probabilities calculated when compared to the plan view area that a new HF well takes up. Furthermore, the probability of encountering an existing well is on average lower for wells that have fractures initiated from the base of the target formation than those cases tested in which wells were not vertically fractured and placed at the top of the target formation. This indicates that fractures growing out of the target formation do not increase the average probability more than setting S to the top of the formation with no fracture growth. Comparing each RA individually shows that 2282 out of 8873 RAs (25.7%) have probabilities that are lower by at least 0.01% when S is set to the top without fracture growth compared to the bottom with fracture growth. The use of fracture growth is important to the results of individual RAs, while not producing values that are much above those probabilities calculated using the top of the target formation. We find that only one RA had a probability value that was more than 0.8% lower (the difference was 2.53%) when S was set to the top of the target formation rather than the bottom with fracture growth.

5. Discussion

The number of actual well encounters is difficult to determine since not all encounters will result in communication; however, records on interwellbore communication are reported. Interwellbore communication has been documented in Alberta by the regulatory agency Energy Resources Conservation Board, now Alberta Energy Regulator. Reported interwellbore communication has occurred 20 times from 2009 to 2012 in Alberta where multistage fracturing wells connected to existing wells [*Kim*, 2012]. Of these 20 incidents, 55% resulted in no long-term adverse effects on production and communication was within the same formation. The maximum distance of communication was 2400 m, the closest was 30 m, and the median was 250 m. During the same time period, 5041 multistage fracturing wells were constructed. This leads to a known interwellbore communication rate of 0.4%. In addition, 95% of those incidents were horizontal to horizontal well communication. That means that the probability of encountering a vertical well was 0.02% of monitored wells in Alberta. All impacted wells were active at the time of communication, where monitoring would likely be focused. Abandoned wells are not instrumented to determine if interwellbore communication has occurred in those instances where there is no impact at the surface.

A 2010 report by BC Oil and Gas Commission states that as of 2010, 18 fracture communication incidents had occurred in British Columbia [*BC Oil and Gas Commission*, 2010]. The report states that these incidents primarily involved horizontal to horizontal communication and ranged in distances from 50 to 715 m. These reports led to the recommendation that operators cooperate through notifications and monitoring of all drilling and completion operations where fracturing takes place within 1000 m of existing wellbores.

One specific incident in Alberta led to hydraulic fracturing and formation fluids being released at the surface of a nearby horizontal producing oil well [*Energy Resources Conservation Board*, 2012]. The wells were 129 m apart at the closest point and were both targeting the same formation. The communication was deemed to be a result of not maintaining the company's protocol of spacing wells a minimum of 135 m apart. The number of cases in Alberta and British Columbia shed light on the reality of interwellbore communication even with well documented existing wells and surveys conducted by operators.

This study has found that certain regions of New York underlain by the Marcellus Shale have probabilities on the order of 1–2% of encountering existing wells, while the vast majority of regions have much lower probabilities. The average probability for this entire area is found to be around 0.025% when A_{hf} is 12,000 ft^2. An area of 12,000 ft^2 represents a cluster of ten 0.25 in. fractures extending approximately 250 ft in plan view in both directions every 200 ft from a horizontal well that is approximately 4000 ft long for a pad containing six horizontal wells. Due diligence on the part of oil and gas well operators is the largest factor in reducing the probability of new hydraulic fracturing wells encountering an existing well. Surveys of existing wells, their depths, and closure status will reduce the probability that new wells encounter exiting wells. This study therefore provides insights into areas where more care should be taken if new horizontal hydraulic fracturing wells were to be constructed in the Marcellus Shale in New York.

6. Conclusion

Encountering an existing well does not guarantee that a wellbore is capable of providing a pathway to the surface. Potential pathways include: cracks between cement and surrounding rock formations, spaces between the cement and well casing, voids created by well casing corrosion, and pathways through the interior of the well itself. Pathway development is dependent on whether a wellbore has failed, and failure is dependent on the quality of construction, lifetime monitoring, and the care taken during shut-in [*Wojtanowicz*, 2008; *Bachu and Watson*, 2009; *Watson and Bachu*, 2009]. The probability of encountering a well is the first step in assessing the risk of a hydraulically fractured well communicating with shallow aquifers, and places an upper bound on that risk. Further work on assessing the probability of an encountered well providing a pathway needs to be done to determine the risk that fracturing poses to shallow aquifers.

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