Impact of Diversion on Acid Fracturing of Laminated Carbonate Formations: A Modeling Perspective

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ABSTRACT: Acid-fracturing treatment schedules usually contain diversion stages either to reduce fluid loss or equally stimulate pay zones. Near-wellbore diversion employs solid or mechanical diverters to direct acid to less-stimulated zones. This study focuses on the impact of near-wellbore diversion on the acid fracturing of calcite/dolomite laminated formations. The study was performed using an integrated acid fracture and productivity model. Simulations showed that when acid preferentially etches more reactive lamina, channels with infinite conductivity can be achieved. Nevertheless, deploying diverters to equally stimulate pay zones can result in less conductive but equally stimulated zones. The productivity model showed that the preferential etching that naturally occurs when injecting acid results in better well performance, if a continuous pay zone is assumed. This study also shows that the optimum acid fracture design conditions in laminated formations are similar to those of calcite-dominated formations.

INTRODUCTION

Acid fracture is a common well stimulation method that is applied specifically to carbonate formations to enhance productivity. Acid etches the fracture walls in nonuniform patterns, causing the fracture to prop itself open and eliminating the need for proppant. The acid fracture roughness is larger near the wellbore as compared with far-field based on large block triaxial experiments.1 A treatment schedule consists of different stages that are usually repeated in three or four cycles. Commonly, each cycle consists of a concentrated hydrochloric acid (HCl) stage and diverter. The treatment begins with a viscous nonreactive fluid to open the fracture and ends with a flush to push the acid from the tubular near-wellbore region.

Acid fracture is usually compared to matrix acidizing, which is a similar stimulation method but performed below the fracture extension pressure. Matrix acidizing is frequently performed for damage removal or productivity enhancement through wormhole generation. Choosing whether acid fracture or matrix acidizing is the most suitable stimulation method can be tricky. Pallarini Schwalbert et al.2 showed that acid fracture results in better productivity than does matrix acidizing when the reservoir permeability is lower than 1.0 md, providing a methodology for estimating the cutoff permeability at which matrix acidizing is the preferred stimulation method. This methodology is based on information about the formation depth, rock type and strength, and treatment volume. Acid fracturing can be a less favorable option in weakly contained pay zones surrounded by water aquifers or gas caps.

A propped fracture is an alternative stimulation technique wherein acid is replaced with proppant slurry. Abbas et al.3 and Suleimenova et al.4 showed that a propped fracture is better at sustaining conductivity at higher closure stresses. Nevertheless, acid fracturing is a cheaper option that does not suffer from screenout complications. Acid fracture is usually preferred in shallow heterogeneous formations where conductivity can be created and sustained. Also, it is preferred in naturally fractured formations, especially if proppant screenout is a common operational challenge.

Acid fracture productivity depends on the resulting conductivity and penetration length. These two parameters can be optimized through a well-designed acid fracture job. Several models were developed to simulate acid reaction in a fractured well; some are three-dimensional (3D) models.5 Nevertheless, limited research has pursued optimizing acid fracture design parameters. Sevougian et al.6 provided an analytical formula for estimating the optimum conductivity and penetration length, based on Nierode and Kruk’s7 conductivity model and Raymond and Binder’s8 productivity equation. These researchers concluded that a Peclet number of 4 should be targeted to create uniform conductivity. Ravikumar et al.9 applied the concept of unified fracture design (UFD) to optimize acid fracture design. Recently, Aljawad et al.10 showed...
that the optimum acid fracture design depends on reservoir permeability, depth, rock mineralogy and strength, and acid treatment volume. For instance, a lower injection rate is usually required in high rather than low permeability formations. The optimum design is not unique and can be achieved through different combinations of design conditions. Increasing the acid treatment volume results in a higher optimum acid injection rate. Also, dolomite rocks with lower levels of reactivity have much lower optimum injection rates than calcite rocks.

Diversion operations have been introduced in acid fracturing to optimize the design. Diverters can be mechanical (e.g., coil tubing) or chemical; they are also categorized as solid or liquid. Conventional diversion is applied to reduce the fluid loss rate to enhance acid penetration and keep the fracture open during operation. Recently, diversion has been applied to equally stimulate laminated pay zones and perforation clusters in multistage hydraulic fracturing. Although diversion is heavily applied in acid fracturing operations, it was rarely considered at the boundary of the domain. Modeling acid transport can achieve better accuracy when coupled with a heat transfer model because acid reactivity is temperature-sensitive, especially in dolomite rocks. The heat transfer model is described as

$$ \rho \frac{\partial T}{\partial t} + \nabla \cdot (\rho uT) = \nabla \cdot (k \nabla T) $$

where $\rho$ is the fluid density, $T$ is the temperature, $k$ is the fluid’s thermal conductivity, and $\rho_c$ is the fluid’s heat capacity. The first term in eq 2 represents the heat accumulation, the second is the heat convection, and the third is the heat conduction. In the present research, the heat of reaction and reservoir heat flux were considered at the boundary of the domain.

The productivity model consists of a reservoir simulator that simulates fluid flow in a fractured wellbore. This is done by solving the diffusivity equation, presented as

$$ \nabla \cdot (k \nabla p) = \phi \mu c \frac{\partial p}{\partial t} $$

where $k$ is the permeability tensor, $p$ is the pressure, $\phi$ is the reservoir porosity, $\mu$ is the reservoir fluid viscosity, and $c$ is the reservoir’s total compressibility. The fracture permeability distribution along the fracture surface is imported from the acid fracture model. The diffusivity equation is then solved ultimately to obtain the dimensionless pseudo steady state productivity index. The higher the productivity index, the better the acid fracture treatment for a given treatment volume. The dimensionless productivity index used in this study is defined as

$$ I_D = \frac{q}{\Delta p_{\text{reservoir}}} = \frac{B \mu}{2 \pi k_h h} f $$

where $I_D$ is the dimensionless productivity index, $q$ is the production rate, $\Delta p_{\text{reservoir}}$ is the reservoir drawdown, $B$ is the

![Figure 1. Integrated acid fracture and productivity model flow chart.](image-url)

The model presented by Aljawad et al. was used to produce acid fracture model results and productivity enhancement in a layered formation. The detailed mathematical formulations can be found in the above-mentioned research; a brief description of the model is introduced in this study. The model consists of integrated acid fracture and reservoir productivity models, as shown in Figure 1.

The acid fracture model consists of a fracture propagation model that considers multiple fluid injections and a layered formation. The fracture propagation model was integrated with acid and heat transfer models (see the blue dashed rectangle in Figure 1). The acid transfer model is used to find the distribution of acid concentration inside a fracture during propagation. The acid model can be mathematically described as

$$ \frac{\partial C_A}{\partial t} + \nabla \cdot (u C_A) = \nabla \cdot (D_A \nabla C_A) $$

where $C_A$ is the acid concentration, $D_A$ is the effective acid diffusion coefficient, the vector $u$ is the velocity, and $t$ is the time. The first term in eq 1 represents acid accumulation, the second is acid convection, and the third is acid diffusion. The acid/rock reaction occurs at the boundary of the domain and in the present research was handled as a boundary condition. Modeling acid transport can achieve better accuracy when coupled with a heat transfer model because acid reactivity is temperature-sensitive, especially in dolomite rocks.
formation volume factor of the fluid produced, \( \mu \) is the produced fluid’s viscosity, \( k_h \) is the effective horizontal permeability, \( h \) is the net pay (i.e., permeable formation thickness), and \( J \) is the productivity index (\( q/\Delta p_{\text{reservoir}} \)).

**MODEL VALIDATION**

The model was used to study the impact of acid fracturing a laminated calcite/dolomite formation. To validate the model, it was compared to an acid fracture job performed on a laminated formation. Rahim et al.\(^{15}\) provided a temperature profile after an acid-fracturing job in a Middle Eastern laminated formation. They showed the lithology distribution where a calcite layer existed in the middle of a dolomite pay zone. The model was used to match the impacts of different types of mineralogy to the temperature profile. It was assumed that a fracture was created in the entire pay zone. Nevertheless, most of the acid volume reacted in the calcite layer according to the cool anomaly. Although the field data were not available, the temperature behavior in the laminated formation was reproduced by the model. This indicates that the model was able to capture the impact of acid fracture in calcite/dolomite laminated formations. Aljawad provided the detailed validation and match of the model.\(^{17}\)

**RESULTS AND DISCUSSION**

This section discusses the importance of diversion in laminated formations, from the perspective of productivity. It also describes design parameters that can help to create an equal acid distribution. Finally, acid-fracturing design optimization in laminated formations is discussed.

The model assumed a vertical wellbore drilled through a calcite/dolomite laminated pay zone. The pay zone was assumed to be continuous and not separated by shale or nonproductive layers. A gelled acid was simulated, which is commonly used in acid-fracturing operations. It was assumed that the pay zone was made of dolomite, with a thin streak of calcite in the middle acting as a thief zone. It was also assumed that the acid was injected into an open-hole section. The properties of the reservoir, wellbore, and fracture fluids are shown in Tables 1–4.

**Productivity and Acid Placement.** Hydrochloric (HCl) acid reacts faster with calcite than dolomite at low to moderate reservoir temperatures. This causes the acid to preferentially react with calcite layers, causing understimulation of the dolomite layers. Moreover, the dissolving power of HCl with calcite is larger than with dolomite, resulting in a higher dissolution volume, even at a similar reaction rate. Other reasons for the differential etching would be the differences in layers’ permeabilities and geomechanical properties. It was assumed in the present research that the formation analyzed was made of dolomite, with a thin layer of calcite in the middle. The analysis below utilized only the productivity model, in which various dissolution scenarios were assumed. For the sake of simplicity, it was also assumed that the acid etching linearly decreased across the fracture’s 400 ft half-length. This was to show if a uniform etching across the pay zone was desirable from a productivity perspective.

In this section, a 20 wt % acid was assumed to create the dissolution across the fracture length and height. It was also assumed that the fracture height was 100 ft, which was equal to the pay zone’s thickness. Three cases were applied, with the first representing a uniform acid distribution across the pay zone; the second, a moderate acid preferential to the calcite layer, and the third, a case in which the thin calcite layer acted as a thief zone. Figure 2 shows the acid-fractured well productivity levels of the

### Table 1. Input Data for the Simulations

| input data | SI unit | field unit |
|------------|---------|------------|
| wellbore radius, \( r_w \) | 0.104 m | 0.34 ft |
| inner casing radius, \( r_1 \) | 0.0628 m | 2.475 in. |
| outer casing radius, \( r_2 \) | 0.0699 m | 2.75 in. |
| overall heat transfer coefficient, \( U_l \) | 0.8 kJ/(s-m\(^2\)-°C) | 0.039 Btu/(h-ft\(^2\)-°F) |
| ambient temperature, \( T_{\text{amb}} \) | 25 °C | 77 °F |
| reservoir pressure, \( P_r \) | 2.0684 × 10\(^7\) Pa | 3000 psi |
| bottomhole pressure, \( P_w \) | 1.0342 × 10\(^7\) Pa | 1500 psi |
| formation fluid density, \( \rho_f \) | 850 kg/m\(^3\) | 54 lbm/ft\(^3\) |
| reservoir length, \( L_x \) | 500 m | 3280 ft |
| reservoir width, \( L_y \) | 500 m | 3280 ft |
| formation fluid viscosity, \( \mu_f \) | 0.0008 kg/(m-s) | 0.8 cp |
| formation volume factor, \( B \) | 1.3 volume at reservoir conditions/volume at standard conditions |
| total compressibility, \( c_i \) | 2.26 × 10\(^{-9}\) Pa\(^{-1}\) | 1.56 × 10\(^{-5}\) psi\(^{-1}\) |
| reservoir temperature, \( T_R \) | 100 °C | 212 °F |
| formation rock density, \( \rho_{\text{f,ro}} \) | 2700 kg/m\(^3\) | 168.5 lbm/ft\(^3\) |
| formation specific heat capacity, \( c_{\text{f,ro}} \) | 0.879 kJ/(kg °C) | 0.2099 Btu/(lb °F) |
| formation thermal conductivity, \( k_{\text{f,ro}} \) | 1.57 × 10\(^{-3}\) kJ/(s-m °C) | 0.907 Btu/(h-ft °F) |

### Table 2. Layer Input Data for the Simulations

| layer number | top of layer (ft) | layer thickness (ft) | stress (psi) | perforation | minerology |
|--------------|------------------|---------------------|--------------|-------------|------------|
| 1            | 0                | 7900                | 6000         | no          | nonreactive |
| 2            | 7900             | 100                 | 6000         | no          | nonreactive |
| 3            | 8000             | 40                  | 4000         | yes         | dolomite   |
| 4            | 8040             | 20                  | 4000         | yes         | calcite    |
| 5            | 8060             | 40                  | 4000         | yes         | dolomite   |
| 6            | 8100             | 100                 | 6000         | no          | nonreactive |
| 7            | 8200             | 500                 | 6000         | no          | nonreactive |

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Table 3. Reaction Kinetics Constants for the Reaction between HCl–Calcite/HCl–Dolomite and Heat of Reaction

| mineral       | n_r | k_r | ΔAF (K) | ΔH_r (kJ/mol HCl) |
|---------------|-----|-----|---------|-------------------|
| calcite       | 0.63| $\frac{6.52 \times 10^4 T}{1 - 1.92 \times 10^{-3} T}$ | $7.55 \times 10^3$ | 7.5               |
| dolomite      |     | $4.48 \times 10^3$ | $7.9 \times 10^3$ | 6.9               |

Table 4. Properties of the Acid Systems

| acid          | T (°F) | n  | K (lb/ft²·s) | D_A (cm²/s) | references         |
|---------------|--------|----|--------------|-------------|--------------------|
| straight      | 84     | 1  | 0.00002      | 1.00 $\times 10^{-4}$ | Roberts and Guin     |
| ret. gelled   | 84     | 0.55 | 0.0082      | 8.00 $\times 10^{-6}$ | De Rozieres         |
| emulsified    | 83     | 0.675 | 0.0066      | 2.66 $\times 10^{-8}$ | De Rozieres         |

Figure 2. Acid fracture productivity performances in different dissolution scenarios and isotropic reservoir permeabilities.

Figure 3. Acid fracture productivity performances in different dissolution scenarios and anisotropic reservoir permeabilities.

Figure 4. Acid fracture productivity performances in different dissolution scenarios and reservoir permeabilities, assuming the thin permeable layer is surrounded by impermeable layers.

three scenarios at different isotropic reservoir permeabilities. The blue curve represents the case in which the near-wellbore diversion is effective, resulting in a similar acid volume per foot for each layer. The red and yellow curves illustrate the other two scenarios, where the acid is not being diverted. The results show that the preferential etching in the calcite layer is favorable in terms of productivity when the reservoir permeability is higher than 0.1 md. This is because creating high conductivity is more favorable than creating a large fracture in moderate reservoir permeability. It is of note that the equal stimulation of the pay zone did not show a significant advantage, even at a low reservoir permeability (see Figure 2). This outcome can be explained by the fact that fracture conductivity is related to the cube of the rock’s etched width.7,21 Hence, acid concentrated in a thin layer results in an infinite conductivity fracture, producing a much higher overall average fracture conductivity as compared with the case of uniform acid distribution. For instance, viscous fingering is a technique applied in acid fracturing to create narrow channels with high conductivity. A similar scenario naturally occurs when a more reactive thin zone exists. Different acid volumes were simulated, and the same conclusion was drawn. The smaller the acid treatment volume, the higher is the range of permeability at which preferential etching is favorable. A similar exercise was performed assuming thicker (40 ft) and thinner (10 ft) calcite layers, and similar results were observed.

Figure 3 shows the productivity outcomes when the formation is anisotropic. The x-axis shows the horizontal reservoir permeabilities while the vertical ones were assumed to be 10 times smaller ($k_h/k_v = 10$). In that case, the uniform acid distribution gave roughly 10% higher productivity when the reservoir permeability was less than 0.1 md. Nevertheless, differential etching gave significantly higher productivity at higher reservoir permeabilities. Figure 4 illustrates the case when the middle layer (20 ft) is assumed to be permeable. Notice that the x-axis represents the permeabilities of the permeable layer. That layer is bounded by 100 times lower permeabilities of layers, wherein each layer is 40 ft thick. The figure shows that the differential etching gave better productivity at all studied reservoir permeabilities. Moreover, the productivity of that case was higher than that in previous cases of similar layer permeabilities (comparing Figure 4 to Figures 2 and 3). Although the differential etching resulted in better productivity, this does not mean that this will result in better sweep efficiency.
when the reservoir is water flooded. Notice that the fracture half-length was assumed to be 400 ft for all cases as the acid fracture model was decoupled in this section.

**Design Parameters and Acid Zonal Distribution.** The previous section assumed different acid distributions to assess the importance of near-wellbore diversion. In this section, the acid distribution was simulated using the acid fracture model. The model did not simulate near-wellbore solid diverters; however, sensitivity analyses of the impacts of different design parameters on acid distribution were conducted. It was assumed that the pay zone consisted of 20 ft of calcite placed in the middle of two 40 ft dolomite layers. The simulated acid was 15 wt % of 1200 bbl HCl injected into an open-hole section. For simplicity, the fracture height was assumed to be constant and equal to the pay zone thickness.

**Acid Type.** In all cases, the simulations of acid injection ran for 30 min at a 40 bpm injection rate and the acid temperature at sandface was 77 °F. Different acid types showed different reactivity behaviors. Straight HCl is very reactive and does not reach long distances inside a fracture, especially compared with the more retarded gelled, foamed, or emulsified HCl acids. This impacts the way the acid is distributed among layers with different levels of reactivity. Straight acid was simulated as shown in Figure 5, where most of the reactions occurred in the calcite formation (the middle layer in Figure 5a) and near the wellbore. Figure 5b shows a 1D etched-width profile in the middle of the calcite and dolomite sections. One observation was that dolomite had a bell-curved etched-width profile, while the calcite had maximum etching near the wellbore, a phenomenon studied previously by Ben Naceur and Economides and Aljawad et al. The magnitude difference in dissolution between the calcite and dolomite layers was significant. Figure 6 shows the etched-width profile when using the more retarded gelled acid. It can be observed that the gelled acid traveled a longer distance than did the straight acid. Also, the etched-width magnitude difference between the different layers was lower. Similarly, Figure 7 shows the etched-width profile of an emulsified acid where the difference in the etched-width profile

![Figure 5. Etched-width profiles (1D and 2D) of a laminated formation, considering a straight acid injection.](image)

![Figure 6. Etched-width profiles (1D and 2D) of a laminated formation, considering a gelled acid injection.](image)

![Figure 7. Etched-width profiles (1D and 2D) of a laminated formation, considering an emulsified acid injection.](image)
was negligible as compared with previous cases. It is observed that the total fracture surface dissolution by emulsified acid was lower than that of the gelled acid. Emulsified acid is two orders of magnitude less reactive, and hence a large volume of live acid will be lost to the formation creating wormholes instead of etching the fracture surface. Notice that the scale used for the 2D etched-width figures was different to make etching visualization possible. Using more retard acid resulted in a lower difference in etched width between the calcite and dolomite rocks. Hence, retarded acid systems can act as near-wellbore diverters, providing better acid zonal distribution.

**Injection Rate.** Significant differences in acid fracture outcomes arise from different injection rates. Usually, higher injection rates correspond to larger fracture sizes and better acid distributions. Figure 8 shows the etched-with profile when the acid injection of gelled acid was reduced from 40 bpm (see Figure 6) to 10 bpm for the same treatment volume. This resulted in a larger dissolution near the wellbore for both the calcite and dolomite layers, as compared with the higher injection rate case. The magnitude of difference of the calcite and dolomite etched widths was also larger in the lower injection rate scenario. The higher injection rate resulted in better acid distribution across different formation layers.

**Acid Temperature.** The temperature at which an acid encounters a formation has a significant impact on reactivity. Dolomite is more sensitive to temperature, and the reaction at low temperatures is described as reaction rate limited. At high temperatures, however, the reaction is described as diffusion limited. The reaction rate between HCl and calcite can be described as diffusion limited, even at low temperatures. Figure 9 shows the etched-with profile of a gelled acid that encountered the formation at 122 °F. This resulted in the most uniform etched-width profile between the calcite and dolomite layers. This can be compared to the case in Figure 6 where the gelled acid temperature was 77 °F, resulting in a larger difference in dissolution magnitude between the layers. The higher the reservoir and injected acid temperatures, the less the reactivity difference between the calcite and dolomite rocks.

Figure 10 shows the fluid temperature profiles along the fracture length and height of the two different acid temperatures.
cases. As the figure shows, the acid temperature kept increasing while penetrating the fracture, until reaching the reservoir temperature. Injecting at a higher temperature resulted in a significantly higher fracture temperature, increasing the reactivity in the dolomite section. This prevented the preferential etching that would otherwise be created in the calcite layer.

Optimum Design Conditions. In this section, the design conditions (e.g., acid type, injection rate, pad volume) that maximize productivity are studied. An analysis of this sort can be complex because it depends on the rock type and strength, reservoir permeability and depth, and acid treatment volume. The heterogeneity of carbonate formations and existence of natural fractures can further complicate the problem. This portion of the research tested the optimum design conditions at different reservoir permeabilities and acid treatment volumes, offering a comparison of the optimum design conditions when the formation was made of pure calcite, pure dolomite, and a laminated formation. The data from Tables 1–4 were also used in this section.

Tight Formation (0.01 md). Both straight and retarded acids (gelled) were simulated for this study. In Figure 11, a productivity map was generated based on the injection rate and amount of pad. The amount of pad is shown as a fraction, according to the equation below

\[ N_{pad} = \frac{\text{pad volume}}{\text{acid volume}} \] (6)

where \( N_{pad} \) is the pad number. Here, pad is any viscous nonreactive fluid injected either to initiate the fracture or reduce fluid loss during different injection cycles. First, the optimum design conditions for pure calcite and dolomite rocks are shown

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Figure 11. Dimensionless productivity map of acid fracture in a calcite formation at different injection rates and pad volumes in the case of low permeability.

Figure 12. Dimensionless productivity map of acid fracture in a dolomite formation at different injection rates and pad volumes in the case of low permeability.

Figure 13. Dimensionless productivity map of acid fracture in a laminated formation at different injection rates and pad volumes in the case of low permeability.
and then compared with those of the laminated formation. Figure 11 indicates that the optimum design conditions for both the straight and retarded acid injected into the calcite rock were achieved at the maximum injection rate and pad volume. Straight acid could not achieve the same magnitude of productivity that was attained with the retarded acid because long acid penetration should be pursued in tight formations; this target could not be accomplished with straight acid.

The optimum design conditions for tight dolomite were similar to those of calcite, as shown in Figure 12. The maximum injection rate and pad volume also needed to be targeted for both acids. The straight and retarded acids achieved similar levels of productivity because the diffusion of the acid did not control the acid/rock reactivity at moderate to low dolomite temperatures (i.e., reaction rate limited). Also, the maximum productivity of the dolomite (i.e., 0.66) was lower than that of calcite (i.e., 0.76) because a lower rock volume is dissolved when acid fracturing a dolomite formation, resulting in overall lower conductivity.

Since the optimum design conditions were the same for pure calcite and dolomite, the optimum design conditions in a laminated calcite/dolomite formation should also have been similar. As expected, the optimum design conditions were achieved at the maximum injection rate and pad volume (see Figure 13). Interestingly, straight acid could not achieve maximum productivity. The maximum productivity achieved simulating gelled acid was 0.76, which perfectly matched the results from the pure calcite case. The existence of a thin calcite layer (20 ft) resulted in a channel with infinite conductivity, an outcome that could not be achieved in pure dolomite formation. This makes the overall conductivity of the laminated formation within the same order of magnitude as pure calcite. Hence, high productivity similar to pure calcite was achieved.

**Moderate Formation Permeability (10 md).** Fracture design in moderate permeability formations favors the creation of high conductivity fractures, even at the expense of fracture length. It also favors creating an infinite conductivity channel in the thin calcite layer over equally stimulating the pay zone. Similar to the analysis above, a calcite-dominant formation was investigated first. Figure 14 illustrates that the maximum productivity was achieved in a wide range of design conditions. Importantly, the pad was not needed to maximize productivity. From a statistical perspective, a narrow range of optimum injection rates was realized when the design considered a large amount of pad fluid (see Figure 14b). Nevertheless, the minimum amount of pad that can keep the fracture open should be used. Straight acid was also able to achieve the optimum design but at much higher injection rates. A safe window would be injecting at 30 bpm or higher for straight acid and 10 bpm for retarded acid.

The maximum productivity achieved in the dolomite was slightly lower, as shown in Figure 15. It is of note that the optimum design conditions occurred at a much narrower injection rate. Hence, from a statistical point of view, achieving the optimum design in a dolomite-dominated formation is more challenging. This could be the reason why acid fracture in dolomite rocks is not always successful. Similar to the calcite case, pad was not needed to increase productivity. The optimum conditions were achieved between 15 and 25 bpm for the straight acid and between 5 and 20 bpm for the retarded acid. A low injection rate was needed to improve conductivity near the

![Figure 14](https://dx.doi.org/10.1021/acsomega.0c00178)

**Figure 14.** Dimensionless productivity map of acid fracture in a calcite formation at different injection rates and pad volumes in the case of relatively high permeability.

![Figure 15](https://dx.doi.org/10.1021/acsomega.0c00178)

**Figure 15.** Dimensionless productivity map of acid fracture in a dolomite formation at different injection rates and pad volumes in the case of relatively high permeability.
wellbore, which is desirable in moderate permeability formations.

The existence of a thin calcite layer made the optimum design condition of the laminated formation similar to that of the calcite-dominated formation, although the formation was comprised of 80% dolomite. The optimum design conditions occurred in a wide range of injection rates. The existence of calcite lamina enhanced the possibility of achieving the optimum design, as compared with what would have occurred with pure dolomite. It is of note that the productivity map in Figure 16 follows a similar trend to what is illustrated in Figure 14.

Treatment Volume. A large treatment volume of 1800 bbl of acid was simulated in this case. The optimum design conditions for low permeability were similar to the outcomes outlined above, where the maximum injection rate and pad volumes needed to be targeted. For the case of relative high permeability, the range of optimum injection rates increased, especially in the dolomite scenario. In general, increasing the treatment volume resulted in larger optimum injection rates, as longer acid penetration should be targeted.

■ CONCLUSIONS
The study provided insight on acid-fracturing design enhancement of a laminated (calcite/dolomite) carbonate formation. Applying near-wellbore diverters to equally stimulate the pay zone is not desirable from a well productivity perspective. It, however, gives a slight productivity advantage in tight anisotropic formations. The uneven acid distribution due to the existence of more reactive or high-permeability lamina enhances the acid-fractured well productivity. The impact is more significant in moderate to relatively high permeability formations. Therefore, an engineer should study the economical outcome of near-wellbore diversion more carefully before field deployment.

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■ NOMENCLATURE

- B: formation volume factor, dimensionless
- C: formation volume factor, dimensionless
- Cₐ: acid concentration (mass fraction), kg HCl/kg solution
- cₚ: fluid heat capacity, ML·T⁻¹·°C⁻¹, Btu/(ft³·°F) [kJ/(m³·°C)]
- cᵣ: reservoir total compressibility, 1/(M·L²), 1/psia [1/Pa]
- J: productivity index, M³·L⁻¹·t⁻¹, bbl/day/psia
- J₀: dimensionless productivity index, dimensionless
- h: net pay, L, ft [m]
- k: permeability tensor, L², md [m²]
- k_long: effective horizontal permeability, L², md [m²]
- q: production (or injection) rate, L³/t, bbl/min [m³/s]
- N_pad: pad number, dimensionless
- p: pressure, M·L⁻¹, psia [Pa]
- t: time, t, day [second]
- T: temperature, T, °F [°C]
- u: velocity vector, L/t, ft/min [m/s]
- wₖ: fracture conductivity, L⁻¹, md·ft [m³]
- α: Nierode–Kruk correlation’s constant, L³, md·ft [m³]
- β: Nierode–Kruk correlation’s constant, L²·M, psia⁻¹ [Pa⁻¹]
- Δp_reserve: reservoir drawdown, M/L², psia [Pa]
- μ: viscosity, M/Lt, cp
- φ: porosity, dimensionless
- κ: thermal conductivity, ML·T⁻¹·°C⁻¹, Btu/(ft·°F) [kJ/(m·°C)]

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