

**DEVELOPING A TIGHT GAS SAND ADVISOR FOR COMPLETION AND
STIMULATION IN TIGHT GAS RESERVOIRS WORLDWIDE**

A Thesis

by

KIRILL BOGATCHEV

Submitted to the Office of Graduate Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

December 2007

Major Subject: Petroleum Engineering

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ABSTRACT

Developing a Tight Gas Sand Advisor for Completion and Stimulation in Tight Gas Reservoirs Worldwide. (December 2007)

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Chair of Advisory Committee: Dr. Stephen A. Holditch

As the demand for energy worldwide increases, the oil and gas industry will need to increase recovery from unconventional gas reservoirs (UGR). UGRs include Tight Gas Sand (TGS), coalbed methane and gas shales. To economically produce UGRs, one must have adequate product price and one must use the most current technology. TGS reservoirs require stimulation as a part of the completion, so improvement of completion practices is very important. We did a thorough literature review to extract knowledge and experience about completion and stimulation technologies used in TGS reservoirs. We developed the principal design and two modules of a computer program called Tight Gas Sand Advisor (TGS Advisor), which can be used to assist engineers in making decisions while completing and stimulating TGS reservoirs. The modules include Perforation Selection and Proppant Selection. Based on input well/reservoir parameters these subroutines provide unambiguous recommendations concerning which perforation strategy(s) and what proppant(s) are applicable for a given well. The most crucial parameters from completion best-practices analyses and consultations with experts are built into TGS Advisor's logic, which mimics human expert's decision-making process. TGS Advisor's recommended procedures for successful completions will facilitate TGS development and improve economical performance of TGS reservoirs.

DEDICATION

This thesis is dedicated to my family and Yana Muzafina because of their support, belief and care.

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1. INTRODUCTION

Tight Gas Sand Reservoirs

Unconventional gas reservoirs (UGR), including tight gas sands (TGS), coalbed methane, and gas shale formations, account for 40% of total U.S. gas production¹ and they are expected to surpass U.S. onshore conventional reservoirs in 2009.² TGSs contribute 76% to the total gas production from the UGRs.¹ Moreover, in 2005 the U.S. Energy Information Administration estimated that TGSs could account for up to 35% of the U.S. recoverable gas resources.³ TGSs is a critical hydrocarbon source to meet raising energy demand and its role as an energy source is constantly increasing.

The U.S. government has defined a TGS as a gas reservoir with an expected permeability of 0.1 md or less. TGSs are considered as unconventional resources, because the economic exploitation of TGSs is not feasible without advanced technologies and sophisticated stimulation treatments. Overall, the finding and development costs of TGSs are usually higher than for conventional reservoirs, and reserves per well are lower; thus, the economic risk is usually higher for development of TGSs than for conventional gas fields. Consequently, to improve the economics of developing TGSs, the industry needs to use the best technologies to both reduce costs and improve recovery per completion.

The U.S.A. was the first country to begin development of TGSs in the 1970s. Since then the U.S.A. has been being a world leader in development of TGSs. Most of world's experience and knowledge about TGSs and technologies applied to those reservoirs have been created and accumulated in North America. In spite of the plethora of information about TGSs that has been documented in the publicly available petroleum literature in the USA, this knowledge is neither easily accessible nor has been systematically

This thesis follows the style of *SPE Drilling and Completion Journal*.

analyzed in public documents. Improved data collection and analysis including best-practices is one of the industry's most important technology challenge.⁴

Because of complexities, high risks and uncertainties associated with UGRs, profitable development of a TGS reservoir requires experts to be involved in the most critical development stages. The application of optimal completion and stimulation technologies is usually the most critical stage in determining the success of the development of a TGS reservoir. In the past 5-10 years, the number of unconventional wells being drilled worldwide has increased considerably. At the same time, the number of TGS experts is increasing but many other experts are retiring or nearing retirement age. Thus, more and more young inexperienced engineers are making critical decisions for completion and stimulation of wells in TGSs without optimal guidance and supervision.

This research project presents a method to capture expertise existing in the public domain. Also, the project collects experts' knowledge and makes it available for practical use. Finally, the expertise and knowledge are combined in computer programs to assist engineers to make decisions when completing and stimulating TGSs world-wide.

Objectives

The main objective of this research project was to build subroutines that can be included into a computer program that will provide recommended best-practices on how to drill and complete TGS reservoirs. To help define the problem, I located and read papers concerning completion and stimulation technologies used in TGSs. One of the assumptions in this work was that the information in published papers represents “best-practices” at the time the papers were published. We assume each author of each paper genuinely published completion and stimulation processes that were the best solutions for specific conditions. We realize this assumption may not always be true, but we decided to use the literature to define best-practices in North American basins. We then examined patterns and correlations between best-practices and reservoir parameters using collected information about best-practices. We also interviewed industry experts to understand their decision-making process as they decide how to complete and stimulate TGSs. Finally, we identified the workflow concerning how to capture patterns from best-practices and experts’ decision logic and developed several subroutines which process input well/reservoir data and give recommendations on how to complete/stimulate a specific TGS well. This project included building subroutines concerning perforating and proppant selection. This work will be combined with others to develop a computer program called “TGS Advisor”, to assist engineers working in the development of TGSs worldwide.

2. LITERATURE REVIEW

Data Analysis Approaches

In this research, we are using published data and information to solve problems associated with well completions in TGSs. In the literature, several authors have proposed various methods to mine and use published data to solve problems. Mohaghegh proposed a two-level data-mining process.⁵ Level one is descriptive data-mining; that is an explanatory process, attempting to find high-impact parameters (HIP) mostly determining well performance. Second, this process searches for patterns existing between treatment parameters (stimulation fluid type, amount of proppant, injection pressure, etc.) and well-reservoir characteristics (saturation, depth, pressure, stresses, etc.) on one side and subsequent well performance on the other. Level two is a predictive process that is a consequent step, trying to make recommendations and forecasts based on the trends derived in the descriptive stage. Aminian and Yos graphed different well and reservoir parameters as a function of coordinates in the 3-dimensional map.⁶ A general correlation was believed to exist among those parameters, but the actual difference was explained by using different stimulation techniques. As such, they were able to identify “sweet spots” and recompletion candidates by looking onto graphical output. In 2000 Mohaghegh, Revees and Hill used more sophisticated techniques to identify candidates for restimulation.⁷ They trained an artificial neural network (ANN) to predict well response depending on input controllable stimulation parameters: a generic algorithm was then used to identify the most optimal combination of input parameters based on the ANN outcome. If an optimal combination of treatment design characteristics was not used and well did not perform at the maximum level predicted by ANN, it was a good restimulation candidate.

Later Mohaghegh *et al.* used various other algorithms (including but not limited to Forward Selection and Backward Elimination, and Hard Clustering, Fuzzy Clustering) to

identify HIPs and an optimal combination of these parameters to achieve the best possible stimulation treatment.⁸ The optimization process was started for a single well and subsequently covered the entire field to derive an optimal standard stimulation design for all of the wells in the field. In another study, Mohaghegh *et al.* started their optimization process at the field level and then focused on a single well.⁹ Fuzzy logic, ANN, combinatorial analysis, and Monte Carlo simulation were all used to determine the most applicable stimulation fluid type. Ederhard *et al.* used a 3-dimensional 3-phase reservoir simulator, statistical analysis and ANN to evaluate hydraulic fracturing treatments and identify HIPs.¹⁰ **Table 1** shows results of a sensitivity study; it was performed by varying only one parameter while keeping the rest of the parameters constant. Varying operators and number of stages have not influenced the cumulative production. However, cumulative production can be significantly affected by varying pad and proppant volumes. Thus, pad and proppant volumes had the most impact on post-treatment production at the investigated field.

| TABLE 1 – IMPACT OF VARIOUS CONTROLABLE STIMULATION PARAMETERS ONTO POST-STIMULATION PRODUCTION¹⁰ | | | | | | | | |
|---|-----------|-----------|------------|-----------|---------------|-----------|-----------------|------------|
| Variable | Operator | | % Pad | | No. of stages | | Proppant volume | |
| Variance | 1 | 2 | 80% | 120% | 5 | 10 | 80% | 120% |
| Total production, Mcf | 8,076,967 | 9,119,581 | 12,396,771 | 7,229,925 | 9,676,123 | 7,690,146 | 7,585,713 | 11,508,505 |
| % Deviation | -0.16 | -0.05 | 30.00 | -24.00 | 0.01 | -0.20 | -21.00 | 20.00 |

The disadvantage of the methods above is that they require an extensive high quality data set to run an optimization model. It is very difficult to obtain the type of data required to run an expert system or ANNs from published papers.

Popa *et al.* proposed a method to evaluate the quality of a data set.¹¹ First, parameters are ranked by fuzzy curve analysis, then fuzzy c-mean groups the data by its quality and ANN is trained to compare actual data records and simulated ones. Good data sets had little difference between ANN predicted values and actual data points. In 2003 Mohaghegh created not only a data mining tool, but he proposed to incorporate a data-driven model and expert knowledge into a comprehensive data-mining process.⁵ A combination of ANN and generic algorithms was used to identify and fix contaminated and erroneous data. Principal component analysis, fuzzy curves, and fuzzy combinatorial analysis revealed relationships between parameters. Finally, fuzzy logic system derived from experts' knowledge was used to predict a stimulation results and to optimize input adjustable stimulation parameters.

All the methods described above were built using sophisticated, statistical analysis of data collected during completion, stimulation and production of TGS wells. All of the analysis methods require large data sets and their optimization applicability is limited to the area where the data were collected. Initially we built a relational database where we tried to capture all reservoir and stimulation parameters to perform a statistical analysis to determine best-practices and HIPs from published papers for a specific North American basin. However, we soon realized that the data in the public domain did not contain the detailed information we needed to do a data-driven analysis. Instead, we decided to use published case histories where new and existing technologies were used successfully to complete and stimulate TGSs to develop a decision-making process. We assume authors published details about technologies that worked out successfully. We also used results from authors who did perform more detailed statistical analysis of valid data sets. We propose to develop a methodology that is based on solid engineering logic as found in the literature, so it will give more widely applicable, but less detailed recommendations.

Xiong, Rahim and Holditch studied the petroleum literature and interviewed experts to determine the HIPs for well stimulation.¹² Based on their findings, they developed an expert system, Stimex, which is able to propose optimal detailed treatment design based on input data. They found that a fuzzy logic system can be a suitable approach to capture the complexity of relations between the stimulation, reservoir parameters and subsequent well response.¹³⁻¹⁵

We have used a similar approach to identify HIPs using public domain and expert's opinions. Also, we have adopted some of the HIPs and relations among them published by Holditch, Rahim and Xiong.¹² We have then built several decision charts that offer a process for reflecting the most suitable completion/stimulation alternative techniques for given well/reservoir parameters.

Perforating

A typical well design includes running production casing, then filling the annular space between formation and the casing with cement to stabilize the casing and for better well production management. After the casing is set and cemented, the well must be perforated to establish communication between the formation and the well. **Fig. 1** shows a typical well completion. When deciding how to perforate, one must consider factors involved with flowing gas from the formation and how the well is going to be stimulated. TGS wells have to be hydraulically fractured to achieve economic flow rates. So, for a TGS well, the most important consideration is how the well will be stimulated. One has to consider the number of stages, the number of layers, the injection rate, the type of fluid, as well as many other parameters. The perforation characteristics influencing the success of the hydraulic fracturing are perforation phasing, perforation shot density and perforation interval.

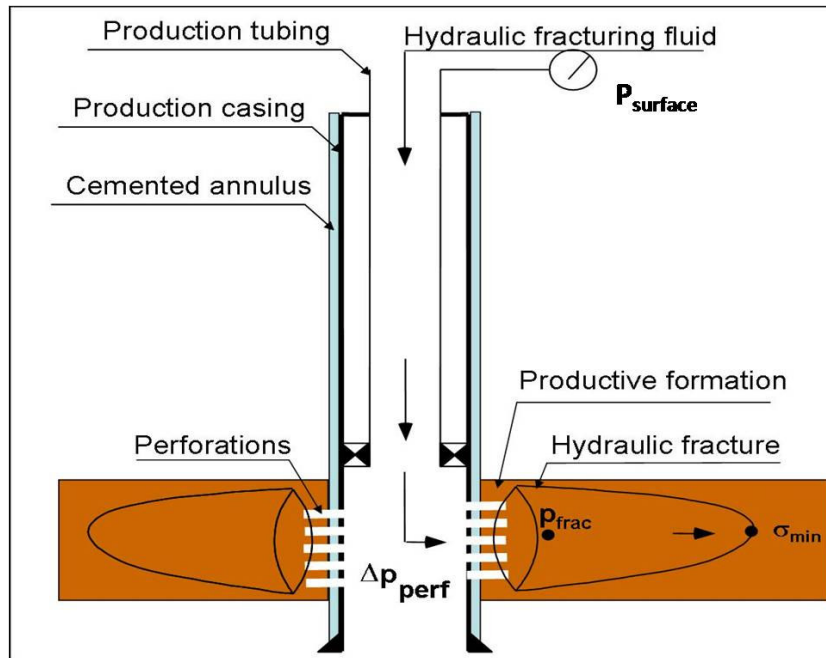


Fig. 1 – A schematic of a typical well completion.

An ideal perforation for fracture initiation should have minimal pressure drop across perforation (perforation friction pressure), initiate only a single fracture (bi-wing), and generate a fracture with minimal tortuosity (turning from the initiated fracture into the preferred fracture plane – **Fig. 2**) at an achievable fracture initiation pressure. Perforation friction pressure, pressure drop due to tortuosity, and pressure drop in the fracture itself can be a considerable portion of total injection pressure. Eq. 1 shows the relationship among the surface pressure, the minimum stress, the friction pressure, the pressure drop across perforation and near wellbore, and the hydrostatic pressure:

$$P_{surface} = P_{net} + \sigma_{min} + P_{fr,tub} + \Delta P_{perf} - P_h + P_{tort} \dots \dots \dots (1)$$

where:

$P_{surface}$ – surface treatment pressure, psi

P_{net} – pressure inside the fracture, psi

σ_{min} – minimum horizontal stress, psi

$P_{fr.tub}$ – pressure drop because of friction in the tubing, psi

ΔP_{perf} – pressure drop across the perforations, psi

P_h – hydrostatic pressure, psi

P_{tort} – pressure due to tortuosity, psi

Even if multiple fractures link up to a single fracture near the wellbore (Case A at **Fig. 3**), the near wellbore pressure drop through the multiple fractures increases by the square root of the number of fractures.¹⁶ Sometime multiple fractures do not link up, but propagate simultaneously and compete for fracture fluid (Case B at Fig. 3).¹⁷ Thus, multiple fractures, that cause near wellbore tortuosity and increase in pumping pressure can significantly increase treatment costs and increase the difficulty in pumping the job away. Furthermore, high near wellbore tortuosity may cause proppant bridging in the more narrow channels and early screenout, because of reduced width of each of the channels. Because of large fluid leakoff and nonoptimal proppant placement in multiple fractures, the formation may not be adequately stimulated (optimal fracture length and height are not achieved) and early screenout is likely. Moreover, a hydraulic fracture should be initiated in the perforation, because otherwise (**Fig. 4**) it will cause significant increase in perforation friction pressure.¹⁸

Sand slugs (low concentration 100 mesh sand) during the pad can be used to further remediate the negative effects of perforation friction pressure and near wellbore tortuosity.¹⁹⁻²¹

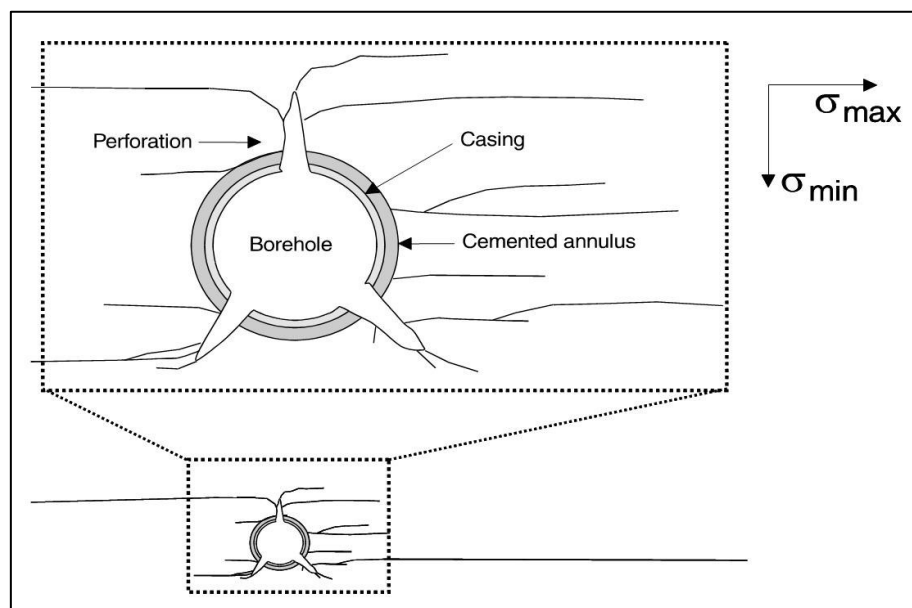


Fig. 2 – Nonoptimal perforation causes fracture tortuosity (Wright *et al.*²²).

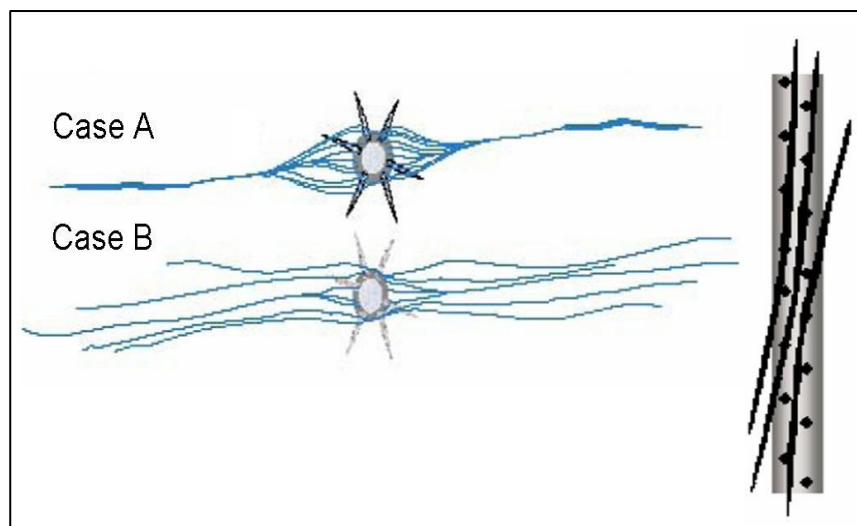


Fig. 3 – Multiple fractures can be created in the case of a nonoptimal perforation design (Patino *et al.*²³).

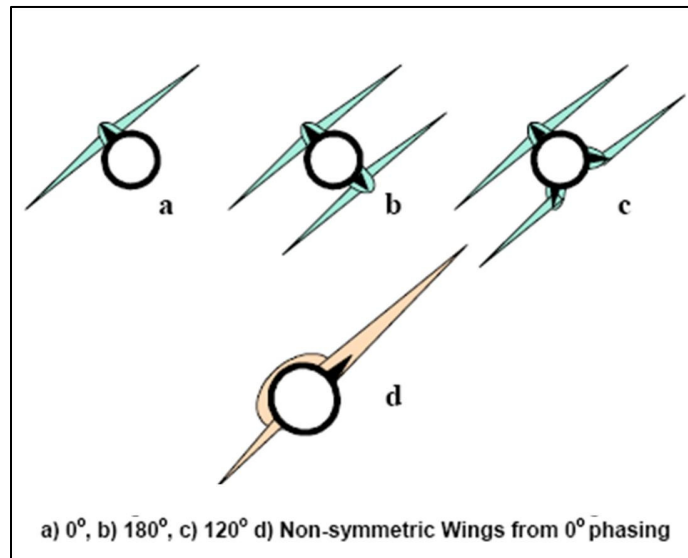


Fig. 4 – For a better stimulation result, a hydraulic fracture should be initiated in perforation (Manrique, Bjornen, Ehlig-Economides²⁴).

Ramirez *et al.*²⁵ suggested that for a production test in high a pressure/high temperature exploration TGS wells, propellant-assisted perforating could be an attractive alternative to hydraulic fracturing. Propellant is defined as an oxidizer material that deflagrates as opposed to an explosive that detonates. As the perforating gun is detonated, the shaped charges penetrate through the scallops, causing the propellant sleeve to fracture into many small pieces. Propellant burns and the generated gas-pressure pulse is generally sufficiently high enough to overcome in-situ stress to create and extent short fractures into the formation.

Perforation Phasing

Typical perforation phasing (an angle between shots) used in the industry is 0° , 60° , 90° , 120° , and 180° . Though, 0° perforation may not allow generation of two active fracture wings because it might be perpendicular to the preferred fracture plane (Fig. 4a).²⁴ Zero degree perforation has to be done through small diameter casing or tubing, e.g. in geopressured wells, 0° phasing is the optimal solution. Since no well is perfectly vertical, a perforation gun always lays on the lower side of the casing (**Fig. 5**). Perforation performance is a function of clearance, the distance from the gun to casing along the axis of perforation shots.²³ So, for the best result, a perforation gun should be centralized in the hole to equalize the clearance of all phases.

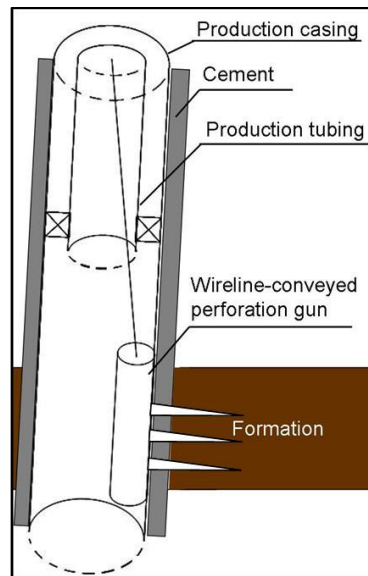


Fig. 5 - A perforation gun always lies on the lower side of the casing in nonvertical wells.

However, centralization tools can not be used on a through-tubing gun. Thus, for perforation through tubing, 0° phased gun is used. A perforation gun is held against the wall of the casing by means of magnetic or mechanical eccentric devices.

For successful hydraulic fracturing treatments, the perforations should be oriented within 30° of the preferred fracture plane.²⁶ 60° phasing guarantees that some of the perforation shots will be within the 30° angle of the preferred fracture plane. In the worst scenario the closest perforation shots of the 90° and 120° phased perforation can be deviated 45° and 60° respectively from the preferred fracture plane, what are unacceptable angles for the successful stimulation treatments. That is why, in this study we consider neither 90° nor 120° phased perforation. However, there are cases when 180° phased perforations should be used instead of 60°. 180° phased perforation can be oriented and nonoriented. Oriented perforations are usually aligned with maximum horizontal stress direction. If the perforations are aligned with the preferred fracture plane then the near wellbore tortuosity should be negligible and the wellbore should be optimally connected to the fracture. However, oriented 180° phased perforating is more expensive and requires more sophisticated tools than nonoriented. Moreover, the advantages of oriented perforating are diminished if an angle 30° or less between preferred fracture plane and perforation is not achieved.²⁶

For oil wells, optimal phasing is usually 60° or 90°. However, Tang, Pan and Wang showed that for gas wells optimal phasing depends on permeability anisotropy in a vertical plane (k_v/k_h).²⁶ They found that the productivity ratio decreases when k_v/k_h decreases (anisotropy increases). The effect of anisotropy is most severe at phasing 180° and least severe at phasing 60°. However, for hydraulically fractured wells, when the fracture penetrates formation from top to bottom, the effect of anisotropy in the vertical plane is negligible.

Patino *et al.* showed that for formations with uniform horizontal stress distribution, minimum perforation friction and near wellbore tortuosity can be achieved with 60° charge-to-charge phasing.²³ In formations where horizontal stress contrast exists, 60° phasing may result in too many perforations for an effective hydraulic fracturing stimulation, so 180° phasing is preferred. However, most experts we interviewed disagree with this statement. Moreover, Behrmann and Nolte found that a large horizontal stress contrast favors 60° phased perforation to facilitate fracture alignment with the preferred fracture plane.²⁷ The opposite is true for a low horizontal stress contrast, where 180° phasing is preferable, because it will minimize risk of creation of multiple fractures. Ideally, in this case perforation should be oriented towards maximum horizontal stress. However, even nonoriented 180° phased perforation is superior to 60° phased one in formation with low horizontal stress contrast, because it will favor generation of only one bi-wing fracture, which will eventually align with the preferred fracture plane (**Fig. 6**). So, we accept conclusions by Behrmann and Nolte.²⁷

For weak formations, Behrman and Nolte recommended 180° phased perforation (ideally aligned with the preferred fracture plane) to eliminate any nonessential perforations that can produce formation sand.²⁷

Meanwhile, formations with high Young's modulus should be perforated with oriented 180° phasing to expel multiple fractures and early screenout. Yet, Behrmann and Nolte suggested that if a 180° phased perforation can not be oriented within 30° of the preferred fracture plane in hard-rock formations, then the use of 60° phased gun is recommended for a good fracture connection.²⁷

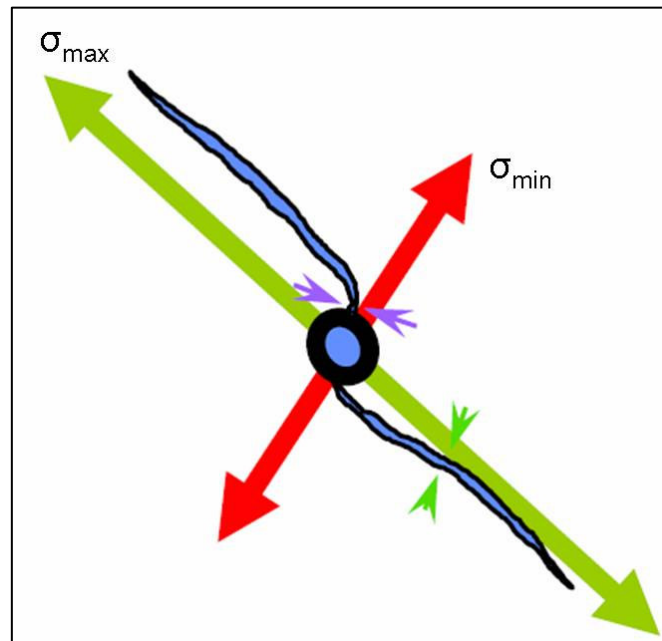


Fig. 6 – In case of a nonoriented 180° phased perforation, a fracture aligns with maximum horizontal stress as it propagates from the wellbore (Patino *et al.*²³).

Information about the existence of a natural fracture network is crucial for an optimal perforation design. If possible, the direction of the induced hydraulic fracture should be normal to the direction of natural fractures to provide high intersection rate.²⁸ Thus, to avoid creation of multiple fractures, excessive fluid leakoff and pressure drop, oriented 180° phased perforation should be used in naturally fractured TGS reservoirs.

Perforation Interval

Perforation strategy might be either blanket perforating (perforation of an entire payzone) or selective perforation (perforation of only a certain interval). Point-source

perforating is a type of selective perforation when only very short interval (1-3 ft) is perforated. The limited-entry approach is a peculiar perforation strategy used to simultaneously stimulate multilayer payzones. Limited-entry strategy means choosing the perforation diameter and the number of perforations in every zone to create a certain pressure differential across the perforations, so that anticipated injection flow rate produces sufficient flow rate and fracture net pressure through each perforation to adequately stimulate every zone.

Caron *et al.* showed that multiple perforation intervals within one payzone are detrimental to the fracture treatment efficiency, because of the creation of multiple fractures.²⁹ However, there are cases when multiple perforation intervals are the only applicable perforation strategy. Manrique, Bjornen and Ehlig-Economides showed that perforation strategy has to consider stress distribution within the payzone.²⁴ Since different stress profiles may be present (**Fig. 7**) different perforation/fracturing approaches may be applicable. We can describe the four situations in Fig. 7 as follows:

- a) Corresponds to a linear stress behavior - any fracture treatment will tend to grow upward. A point-source approach placed at the bottom of the zone may be applicable.²⁴ However, point-source perforating should not be used in thick intervals (gross thickness > 150 ft) and when number of layers is greater than 3;²⁹
- b) In the case of a depleted zone, the treatment will tend to grow into the depleted zone - it will act as a sump for any fracture treatment. Point-source perforation at the bottom of payzone may be an alternative.²⁴ Also, it may be best to perforate the low pressure, low stress interval if it is going to take all or most of the fracturing fluid anyway, and try to propagate a fracture to the high stress zones;
- c) Competent stress barriers will favor treatment containment provided that enough stress contrast is present between low and high stresses – point-source or blanket perforation within the interval may be used;²⁴

- d) Variable stress profile; intercalated high and low stress zones - a selective perforation approach may follow.²⁴ It is usually best to perforate and initiate the fracture in the lower stress intervals and try to grow the fracture into the high stress intervals.

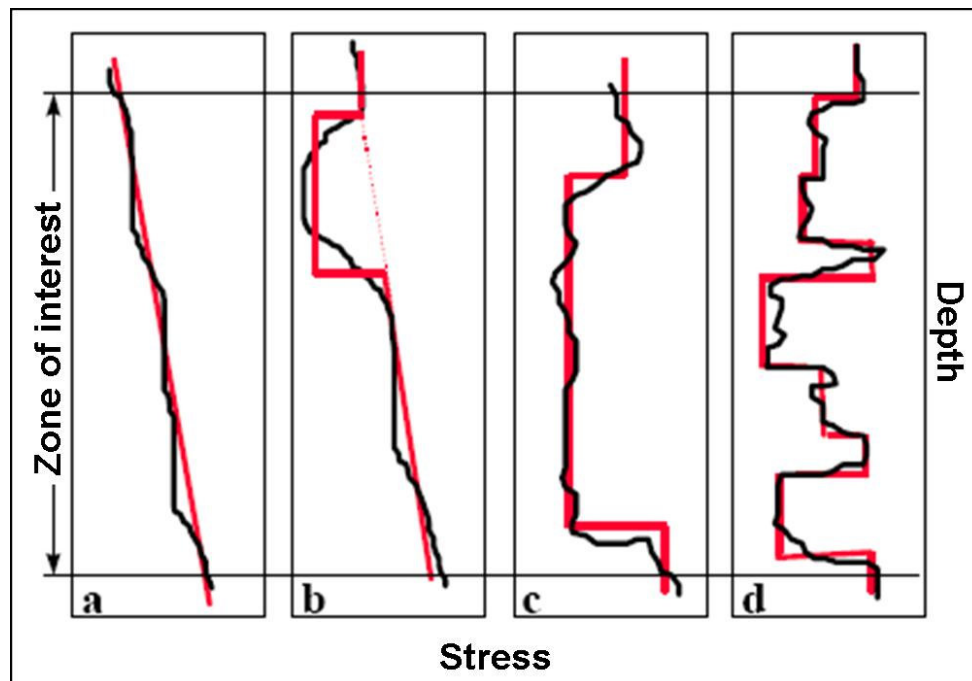


Fig. 7 – Potential stress distribution within different zones of interest (Manrique, Bjornen and Ehlig-Economides²⁴).

Behrmann and Nolte recommended that even when the perforated portion of the well is nominally aligned with the preferred fracture plane, consideration should be given to limiting the perforated interval length, particularly for relatively thick sections that most likely will be covered by the propped fracture.²⁷ Another consideration for limiting the perforated section near the center of a zone is to assist vertical confinement of a tip

screenout treatment. Also, a limited perforation section (20 ft or less) should be implemented in weak formations where sand production problems are likely to occur.

In naturally fractured reservoirs, the perforation interval should not be chosen based solely on the analysis of the net-pay; instead, perforations should be placed at a location so most of the net gas pay is stimulated.³⁰ It is recommended to reduce perforation interval to about 6-20 ft.³¹⁻³³ If the number of natural fractures varies along the wellbore, Weijers *et al.* recommended to place perforations in the highly naturally fractured areas to improve production response.³¹

Lestz *et al.* wrote a paper about perforation considerations if stimulation treatment follows the perforation. They suggested the perforation interval should be:

- a) limited to small intervals to minimize multiple fractures;
- b) positioned to take an advantage of proppant bridging; positioned in the lower-permeability, higher-stressed rocks to ensure that they are better stimulated;
- c) limited to reduce proppant flowback;
- d) positioned at the bottom of the payzone, leaving alternatives to recomplete or restimulate additional pay up hole.³⁴

Work presented by El Rabaa showed that in deviated wells with perforation intervals greater than four times of the wellbore diameter, unwanted multiple fractures begin to form.³⁵ Then, McDaniel, Willett and Underwood confirmed that for highly deviated and horizontal wells, limited-entry fracturing and point-source perforation of only a very small section of the wellbore (1-3 ft) are optimal approaches to reduce potential of tortuosity and multiple fractures (**Fig. 8**).³⁶ These conclusions are also applicable for vertical wells in dipping reservoirs.²⁴

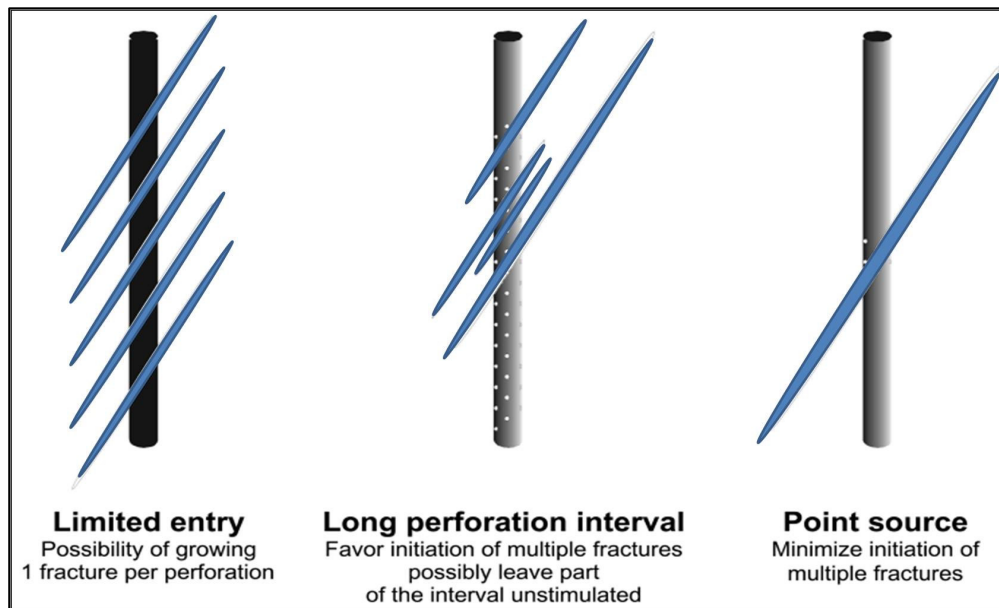


Fig. 8 – Different perforation strategies can lead to different fracture geometry (Lestz *et al.*³⁴).

Perforation Shot Density

For wells that do not require fracture stimulation, Bell discovered that shot density equal to 4 shots/ft (SPF) is usually enough to provide desirably low values of perforation pressure drop.³⁷ Then Todd and Bradley identified a point of diminishing returns, where additional perforations do not significantly increase well capacity, at shot density above 8 SPF. Four to 8 SPF would give optimal well performance at a minimum cost in wells that do not need to be fracture treated.³⁸

For wells which are to be hydraulically fractured we have to take into consideration some other parameters while deciding on shot density. There will be a pressure drop

across the perforation during a hydraulic fracturing treatment. The perforation friction pressure drop can be computed using Eq. 2:³⁹

$$\Delta P_{Perf} = 0.2369 \cdot \rho \cdot \left(\frac{Q}{C \cdot N_{perf} \cdot D_{perf}^2} \right)^2 \dots\dots\dots(2)$$

where:

ΔP_{Perf} – pressure drop across the perforations, psi

ρ – density of the fracturing fluid, lbm/gal

Q – fracturing fluid flow rate, bpm

N_{perf} – number of perforations

D_{perf} – perforation diameter, in.

C – discharge coefficient

The perforation friction pressure drop is a function of the total injection rate divided by the number of perforations. Thus, to minimize the perforation friction pressure drop, one could maximize the number of perforations. However, if too many perforations are shot, one can have problems with proppant dropping out in the wellbore because of low velocities per perforation and/or multiple fractures causing near wellbore tortuosity and high near wellbore pressure drops. Thus, when deciding on the number of perforations needed, the design engineer must balance the need to minimize perforation friction by shooting more holes, with the need to minimize proppant drop-out in the wellbore, near wellbore tortuosity, and multiple fractures by shooting fewer holes.

One expert has provided his rule-of-thumb on how to decide on the number of perforations required for a TGS well to be fracture treated. The Holditch rule-of-thumb is that the injection rate for a normal treatment should be between 0.25 and 0.5 bbl/min/perforation.⁴⁰ For limited-entry fracturing, however, fewer perforations are used; thus, the injection rate should be between 1 and 2 bbl/min/perforation. Perforation shots

for limited-entry fracturing are usually distributed throughout the interval(s) in the zones of higher porosity and permeability.

If one assumes that only those perforations closest to the preferred fracture plane initiate a fracture, then the shot density of the 60° phased gun must be 3 times that of a 180° phased gun to achieve the same number of holes directly linked to the fracture.²⁰

Propping Agents

Proppant

Propping agents (proppants) are small spherical solid particles that are used in hydraulic fracturing to keep the created fracture open after the hydraulic fracturing treatment is completed. Proppant is transported into the fracture using a viscous fluid to keep open the fracture and carry the proppant. When pumping stops and pressure inside the fracture decreases due to fluid leakoff into formation, the formation closes on the proppant.⁴¹ To maintain a conductive flow path in the fracture, the proppant has to satisfy several major requirements. First, the proppant has to have minimum crushing due to the formation closure stress, which is defined as a minimum horizontal stress minus wellbore flowing pressure. Second, the proppant has to maintain the desired conductivity at formation closure stress and temperature to achieve desired hydrocarbon deliverability to the wellbore. Moreover, the proppant must be small enough to get through perforations and flow down the dynamic fracture width without bridging.⁴² Also, the proppant has to stay suspended in the fracturing fluid during pumping and not settle until the fracture closes. Importantly, the proppant has to stay in the fracture and not flow back with the broken fracture fluid or natural gas. Proppant flowback is not desirable because, first, a fracture without proppant will close and the fracture will not be effective. Second, the proppant

in the hydrocarbon stream can erode surface equipment reducing equipment life and creating a potential dangerous situation.⁴¹

Proppants can be natural (sand) or synthetic. Sand can be used in formations with low and moderate closure stress.⁴³ A variety of synthetic proppants covers all closure stress and temperature ranges that are normally encountered in oil and gas wells. **Table 2** shows typical properties of various proppant types. There are two major types of synthetic proppant: intermediate strength proppant (ceramics) and high strength proppant (bauxite). However, intermediate and high strength proppants have specific gravities much greater than sand, so viscous fluid is required to transport these proppant types deeply into the fracture. A new propping agent, porous ceramic, is an intermediate strength proppant but with specific gravity lower than regular ceramics, so less viscous hydraulic fracturing fluid can be used.⁴⁴

Some of the properties of propping agents can be enhanced by coating proppants with resin. Resin coated proppant (RCP) has improved strength characteristics, and does not tend to flow back into the well during production because at formation temperature and closure stress the resin becomes tacky and proppant grains adhere to each other. However, the applicability of RCP is limited by temperature and closure stress required for the adhesive process to work. Various catalysts can be used to decrease the minimum required temperature and stress for the resin to set properly. However, it has been shown that some hydraulic fractures do not completely close during the first 24 hours after the fracture treatment especially in case of the low-permeability formations.⁴⁵ The chemical compatibility of RCP with all hydraulic fracturing fluids and additives should be checked before the treatment. Placement of RCP during the tail-in stage of the hydraulic fracturing treatment is a common technique to prevent proppant flowback at a minimum cost; however, it does not guarantee success, because the RCP may not end up at the desired location and fill all perforations.⁴⁴ RCP may not be effective when wells with multiple or large perforated intervals are treated.⁴¹ RCP loses its ability to form

consolidations with adequate strengths after being exposed to extended pump times in water-based fracturing fluids and high temperatures.⁴⁴

| TABLE 2 - TYPICAL PROPPANT PROPERTIES | | | | | |
|---|------------|----------------------------|-----------------------------------|--------------------------------|------------------------|
| Proppant type | Sand | Precured Resin Coated Sand | Partially Cured Resin Coated Sand | Intermediate Strength Proppant | High Strength Proppant |
| Manufacturer | Santrol | Santrol | Santrol | Carbo Ceramics | Saint-Gobain Proppants |
| Trade name | Frac Sands | THS | MagnaProp G2 | CarboEconoprop | Ultraprop |
| Price, \$/lbm | 0.50 | 2.17 | 4.42 | 2.05 | 2.93 |
| Specific gravity | 2.65 | 2.45 | 2.63 | 2.70 | 3.50 |
| Minimum required closure stress, psi | 0 | 6000 | 6000 | 0 | 0 |
| Maximum allowable closure stress, psi | 8000 | 10000 | 12000 | 10000 | 14000 |
| Minimum required temperature, °F | 0 | 70 | 140 | 0 | 0 |
| Maximum allowable temperature, °F | 500 | 600 | 600 | 500 | 500 |
| API mesh size | 20/40 | 20/40 | 20/40 | 20/40 | 20/40 |
| Test concentration, lbm/ft ² | 2 | 2 | 20 | 2 | 2 |
| Test temperature, °F | 150 | 250 | 250 | 250 | 300 |
| Conductivity at 2000 psi closure stress, md-ft | 4820 | 0 | 0 | 6300 | 8535 |
| Conductivity at 4000 psi closure stress, md-ft | 3190 | 0 | 0 | 5500 | 6640 |
| Conductivity at 6000 psi closure stress, md-ft | 1618 | 3011 | 4436 | 4100 | 5649 |
| Conductivity at 8000 psi closure stress, md-ft | 721 | 1753 | 3650 | 2500 | 4552 |
| Conductivity at 10000 psi closure stress, md-ft | 312 | 995 | 2740 | 1300 | 3469 |
| Conductivity at 12000 psi closure stress, md-ft | 0 | 0 | 1437 | 0 | 2348 |
| Conductivity at 14000 psi closure stress, md-ft | 0 | 0 | 0 | 0 | 1727 |

Two types of RCP are common for the industry: precoated RCP and curable RCP.

Precoated RCP is coated with resin and cured before hand and then delivered to the location. However, precoated RCP requires high temperature and stress as well as time to consolidate down hole. Curable RCP usually consist of a tempered core surrounded

by an outer layer of uncured resin. Prior to curing, the resin softens and flows when heated, particularly when subject to confining stress. This softening process melds adjacent RCP particles together as resin forms bridges at grain-to-grain contact points (**Fig. 9**). Usually, curable RCP requires less time, lower temperature and closure stress for effective consolidation.

Rickards *et al.* recently described a technology for manufacturing lightweight proppant (LWP) by treating wall nut hulls and porous ceramics with resin.⁴⁶ Resin coated wall nut hulls withstand closure stress up to 6,000 psi and have density less than water. Another technique to manufacture LWP is coated porous ceramics with resin. The strength of resin coated porous ceramics is within the range of intermediate strength proppant, but its density is about 30% less than regular ceramics, because, external pore space is isolated by resin.⁴⁷ So, besides conventional hydraulic fracturing, LWP might be used in water fracturing and in fracturing with very low viscosity fluid.

Proppant Flowback Control Additives

Using downhole screens to prevent proppant flowback in high permeability unconsolidated formations is a commonly applied and successful technology. However, if not designed properly, screens can become plugged with formation fines and the flow of oil and gas will be reduced. In general, screens are not used to prevent proppant flowback in hydraulically fractured wells. One solution, as discussed above, is to use RCP to reduce proppant flowback. Another method, using fibrous bundles mixed with

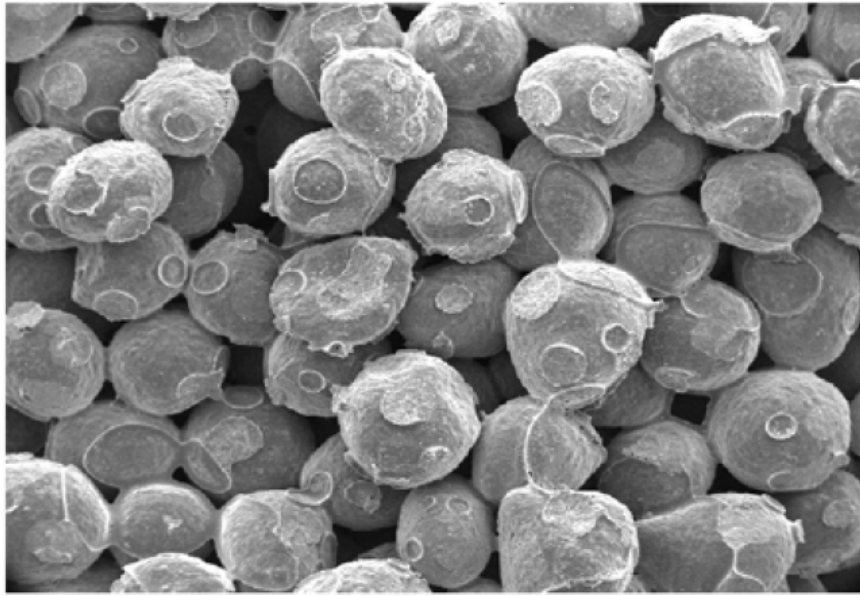


Fig. 9 – Resin material adheres to the proppant at grain-to-grain contact points (Nguen, P.D., Weaver, J.D⁴⁴).

the proppant, has been proposed as an alternative to RCP for proppant flowback control. The main functions of the fibrous strands are to induce bridging at the perforations and allow solids free fluid to flow through the proppant pack. However, the permeability of a proppant pack is reduced when a fibrous material is used.⁴⁶

A surface modification agent (SMA) has also been used to minimize proppant flowback problems. SMA is a water and oil-insoluble resinous material that does not harden or cure under reservoir conditions. This liquid additive is applied during a fracture treatment, easily coating the proppant and making the grains very tacky.⁴⁷ SMA is designed for low temperature wells; it is applicable for low closure stress and does not require any shut-in time before flowback.⁴⁸

Krismartopo *et al.* described an application of a liquid resin system (LRS) to remediate proppant flowback after hydraulic fracturing.⁴⁹ Dry proppant is directly coated with the

LRS before being blended with fracturing fluid. LRS adheres to the proppant surface and makes it tacky, which promotes grain-to-grain contact, and remains as a liquid until it is fully cured downhole. A variety of LRS products was specially formulated to accommodate all temperature ranges: a low-temperature, two-component, epoxy system (70° F - 225° F); a high-temperature, two-component, epoxy system (200° F - 350° F); a high-temperature, one-component, furan system (300° F - 550° F).

Recently, new technology (using an old idea) was introduced to the market: deformable isometric particles (DIP).⁴⁹ The product is made by binding silica flour with a resin matrix to form a conglomerate. It is insoluble in water and oil and unaffected by HCl and HF up to 400° F. It is 1.5-2 times lighter sand. Various sizes of DIPs are available, but the size of DIPs always should be slightly larger than proppant, to compensate for inter-particle embedment. DIPs deform or dimple to mechanically connect themselves with the adjacent proppant grains (**Fig. 10**), which embed themselves slightly into the surface of the DIPs, consolidating the pack.⁵⁰ Also because their slight deformability, DIPs act to redistribute load in the confined proppant pack, strengthening the pack. DIPs require to be surrounded by proppant grains, concentration of 10-15% by weight of proppant is effective to increase sand pack drag resistance. A certain minimum closure stress has to exist for consolidation. Medium stress DIPs can be used in wells with closure stress up to 6,200 psi. High stress DIPs have a needle like shape (**Fig. 11**). These elongated particles are sized about 1 mm in diameter by 7 mm in length. This increases the number of individual proppant grains stabilized by each DIP while decreasing the number of high stress DIPs needed to control proppant flowback. These new high stress DIPs have an optimal ratio of 9:1 proppant to deformable particle when uniformly mixed into the pack. High strength DIPs are able to withstand closure stress up to 10,000 psi. Thus, DIP/sand mixtures can offer an attractive alternative to higher-strength ceramics proppant and DIP/ceramics is an attractive alternative to sintered bauxite.⁵¹



Fig. 10 – Low and medium strength deformable isometric particles.⁵²

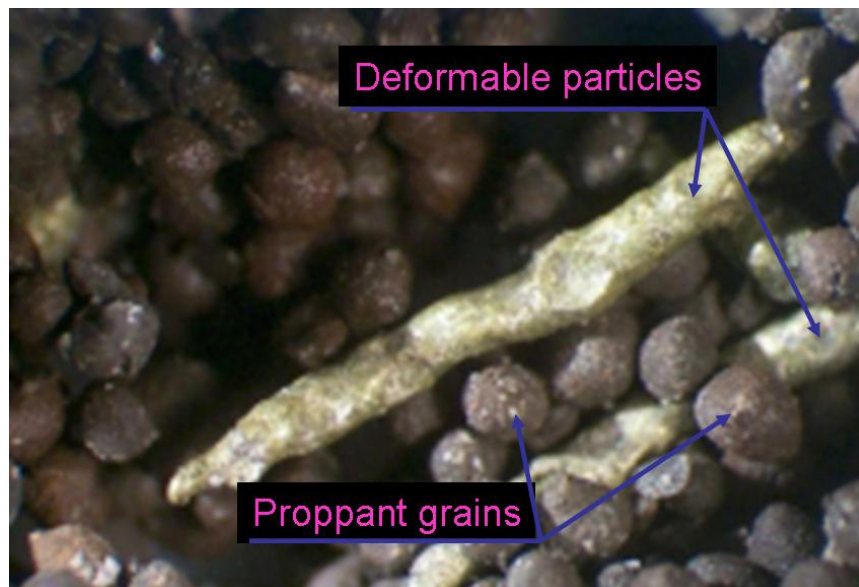


Fig. 11 – High strength deformable isometric particles have a needle shape.⁵²

3. METHODOLOGY

Tight Gas Sand Advisor

The main objective of this project was to define best-practices for the drilling, completion and stimulation for the TGS reservoirs. Our first approach was to download papers, and try to create a relational database containing best-practices. Then using the relational database, one could search for best-practices using whatever reservoir information that was available for a given situation. However, it soon became clear that there were too many possible scenarios and too little data in the literature for the database approach to be successful.

To achieve our goals, we decided to use a decision chart approach and fuzzy logic models when applicable, to help define best-practices in the drilling, completion and stimulation of a TGS reservoirs. In this thesis, I will describe the work done to develop a methodology to determine best-practices when perforating a TGS and when choosing a propping agent.

To place all the decision making steps in a logical order, we had to develop a workflow on how all decisions are made concerning the drilling, completion and stimulation of a well in TGS reservoir. The workflow diagram we have developed is shown in **Fig. 12**. Every independent level in Fig. 12 requires making a critical decision that affects all levels below it. The well development decision chart we have generated has four major parts:

- drilling;
- completion;
- stimulation;
- production.

Our workflow diagram shows that both the completion and production considerations influence the required diameter of production casing. An iteration process should be used if conflicting values for optimal casing diameter were generated by completion and production considerations. When the production casing diameter satisfies completion and production purposes, the stimulation design is initiated. For a stimulation treatment, we need a certain minimum casing diameter, so we can pump viscous fracture fluid at high injection rates. As such, the iteration processes are required to determine “the best” way to complete, stimulate and produce a TGS well. The last stage of the well design is a drilling design.

Using all available information about a well and a reservoir (input data), an engineer should be able to determine the volume of the total gas-in-place per layer and which layers can be produced economically. Then the layers can be grouped for stimulation purposes depending on layer thickness, distance between the layers, strength of barriers between the layers, and other variables such as the in-situ stress profile. Based on the grouping level outcome, an engineer must make the decision on how to complete the well. At this point an engineer should bear in mind that the completion should simultaneously fit stimulation and production purposes if at all possible. That is why two processes are initiated: completion design for stimulation and completion design for production. Then, the outcomes of both designs are compared to make sure all requirements are satisfied. An optimization process is started when completion for production and for stimulation are not compatible.

The first step in the completion design for stimulation is to determine the minimum required number of hydraulic fracturing stages to assure that every producible layer is adequately stimulated. Next, the applicable completion type (open-hole completion, cemented casing/liner, slotted liner) is selected for the treatment. If there are going to be more than one hydraulic fracturing stage, a decision must be made on how to divert the hydraulic fracturing stages. The next level is to determine a perforation technique. The

diversion method and the perforation technique dictate the minimum production casing diameter, d_1 . Also, production casing diameter, d_2 , comes from predicted gas and water flow rates. When production tubing is installed, the production casing must be large enough to accommodate the tubing, any possible artificial lift tools and leave enough room to perform workover later in the live of the well.

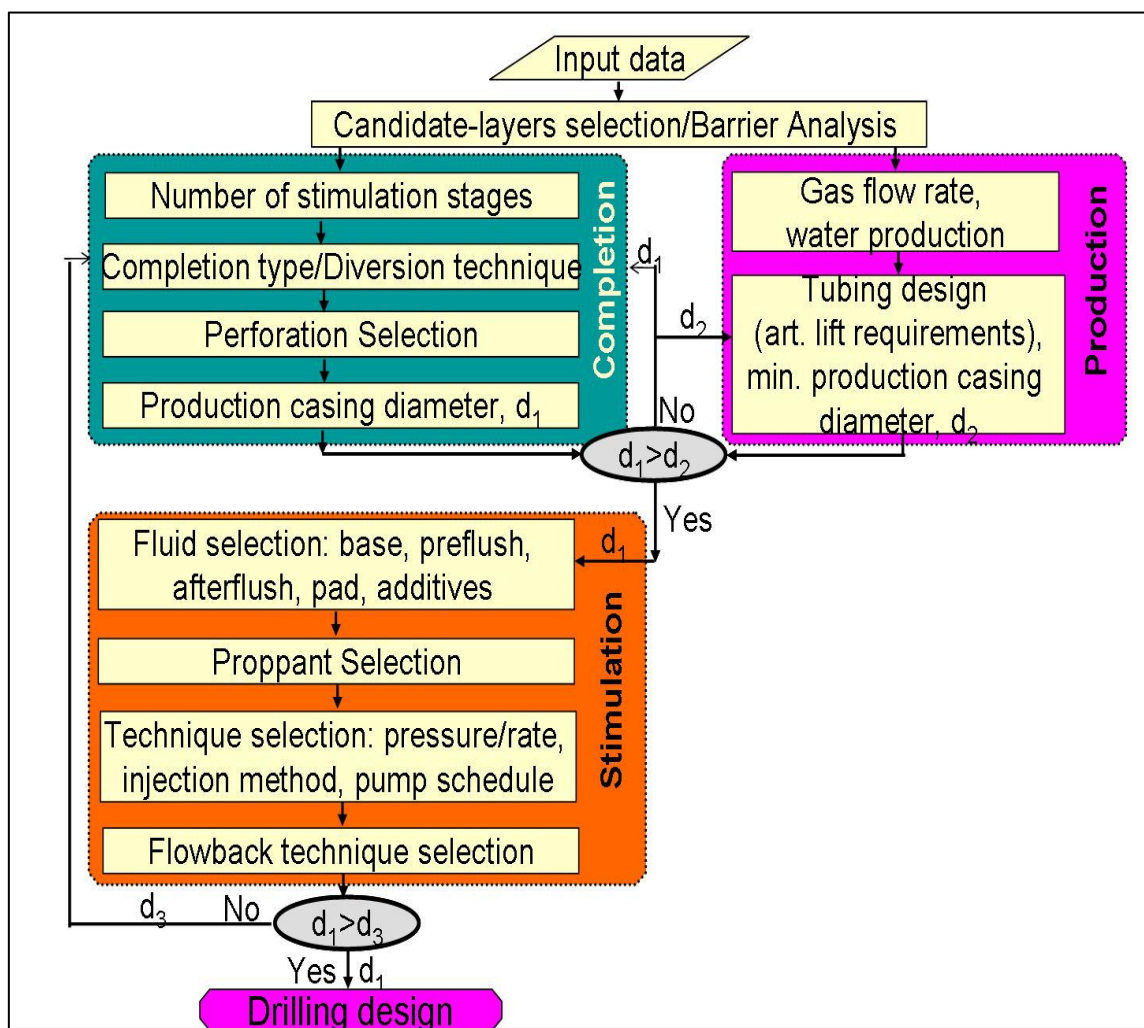


Fig. 12 – Major decision points in completion and stimulation of TGSs.

In tubingless completions, production casing should be big enough to allow adequate injection rates during stimulation, but small enough to maintain minimum gas velocity to lift water to the surface. Thus, if the diameter of the production casing required for the selected diversion technique is greater than for production purposes, an iteration process is initiated to determine the optimal casing diameter, that satisfies both the stimulation and production requirements.

The stimulation design is started after the optimal casing diameter has been determined. Stimulation design includes: fluid selection (base fluid, pad, flush, additives, etc.), proppant selection, injection technique selection (injection method, pump schedule, injection pressure and rate, etc.), and flowback technique selection. If the production casing diameter satisfies the treatment requirements, one can proceed to the drilling design. If the production casing diameter is too small to achieve the required stimulation flow rate and pressure, the iteration process is carried out again until all requirements are satisfied.

The computer program, called TGS Advisor, has a modular architecture. Every module is a stand-alone subroutine accommodating one decision level. In this work I have developed modules for perforation design and proppant selection. Other members of the research team are working on: 1) candidate-layer selection/barrier analysis; 2) number of stimulation stages; 3) technique selection modules; 4) completion type/diversion technique; 5) tubing design for production purposes. Raj Malpani developed a base fluid selection module.⁵³ All of these models will be incorporated into TGS Advisor.

The first step in my work was to explore the petroleum literature and to determine the most important parameters for perforation design and proppant selection. I also looked for best-practices to discover correlations between reservoir properties and best applicable technologies. When possible, we summarized our results graphically, trying to capture the thought process of a subject matter expert making a decision. We sent our

decision charts to experts and ask for their advice and suggestions. Then we programmed subroutines to automate the decision processes. The subroutines consider input well and reservoir parameters and give recommendations based on the decision charts and fuzzy logic models that were developed in this research. Programming was done in Visual Basic for Applications (VBA).

Perforation Selection

We assume almost every TGS well will be fracture treated upon initiated completion and before production. Therefore, the perforation scheme should be designed to optimize the hydraulic fracturing treatment. We identified three major perforating parameters influencing the outcome of a hydraulic fracture treatment: perforation phasing, perforation interval and perforation shot density. **Fig. 13** shows the perforation module with input parameters and output recommendations. The computer code for the perforation design module is available in Appendix A.

Perforation Phasing

In this research project, we distinguish only 0° , 60° , and 180° phased perforation. 180° phased perforation is either oriented or nonoriented. From the literature review and consultation with experts, we discovered that the following reservoir characteristics favor 60° phased perforation:

- absence of natural fractures;
- absence of formation sand production;
- a low Young's modulus; or

- a high horizontal stress contrast exists.

180° phased perforation should be used when a reservoir:

- is naturally fractured;
- has high Young's modulus;
- has a low horizontal stress contrast; or
- the formation is unconsolidated.

In the case of high formation's Young's modulus, oriented 180° phased perforation is preferred. Though we were not able to accommodate all of the above conclusions in a single decision chart, we included only the most influential parameters (**Fig. 14**).

Moreover, these complicated relationships and fuzzy definitions can not easily be programmed using "IF-THEN" expert system methodology, so we used a combination of fuzzy logic approach and expert system method to capture the complexity of perforation phasing decision.

For each parameter, we defined two membership functions: one for 60° phasing and the other one for 180°. The membership functions are in the range between null and unity and show how much independent influence each particular parameter has onto the outcome.

| Input data | |
|--|------------|
| Exploration well | yes |
| Formation sand production | no |
| Horizontal stress contrast | moderate |
| Youngs modulus | 5.5 MMpsi |
| Naturally fractured | low |
| Layer/Barrier stress contrast | high |
| Perforation diameter | 0.32 in. |
| Injection rate | 23 bbl/min |
| Pay zone thickness | 149 ft |
| Net-pay thickness | 60 ft |
| Number of separate fractures | 1 |
| Well position relative to bed boundaries | Normal |
| Possible to centralize perforation gun in the well | yes |

CLICK TO
DETERMINE
PERFORATION INTERVAL
AND PHASING

CLICK TO
DETERMINE
PERFORATION SHOT
DENSITY

OUTPUT

| Perforation interval: | | | |
|-----------------------|---|--------------------------------|----|
| Option 1 | Perforate most porous zone(s) within the layer(s) | Length of perf. Interval 1, ft | 20 |
| Option 2 | | Length of perf. Interval 2, ft | |

| Phasing recommendations: | Recommendations | Confidence level (0...1) | Options within recommendations |
|--------------------------|---|--------------------------|--------------------------------|
| 0° phasing perforation | No | n/a | |
| 60° phasing perforation | Yes | 0.5170 | |
| 180° phasing perforation | No | 0.7244 | |
| Alternatives | Proppelant assisted perforation w/o HF, put on production immediately after perforation | | |

| Shot Density: | |
|-----------------------|-----|
| Min shot density, spf | 6.1 |
| Max shot density, spf | 8.0 |

You may change length of the perforated interval and rerun Shot Density subroutine.

Fig. 13 – The perforation design module of TGS Advisor.

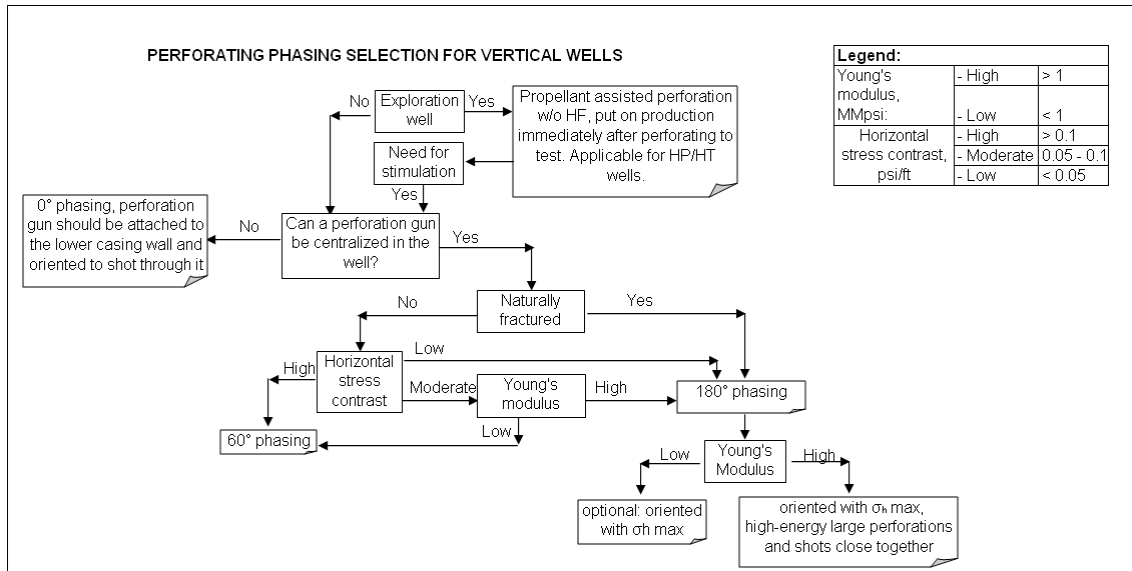


Fig. 14 – Phasing preference depends on Young’s modulus, existence of natural fractures, and a horizontal stress contrast.

Since Young’s modulus has a discrete value, its membership functions are continuous (**Fig. 15**). Membership functions for Young’s modulus (E) are as follows:

$$F_{180}(E) = \begin{cases} 0.1 \cdot E & (E < 5 \text{ MMpsi}) \dots\dots\dots(3a) \\ \frac{1}{1 + 1.6^{5-E}} & (E \geq 5 \text{ MMpsi}) \dots\dots\dots(3b) \end{cases}$$

$$F_{60}(E) = \begin{cases} 1 - e^{\frac{E-5.8}{1.5}} & (E < 5 \text{ MMpsi}) \dots\dots\dots(4a) \\ \frac{0.7}{0.7 + 4^{E-5}} & (E \geq 5 \text{ MMpsi}) \dots\dots\dots(4b) \end{cases}$$

Membership functions for all other parameters are step-functions, because these parameters are either not directly measurable or unknown and that is why they have fuzzy values.

The membership functions for natural fractures:

$$F_{180}(NF) = \begin{cases} 0 & \text{(very few natural fractures).....(5a)} \\ 0.5 & \text{(moderately naturally fractured).....(5b)} \\ 1 & \text{(highly naturally fractured).....(5c)} \end{cases}$$

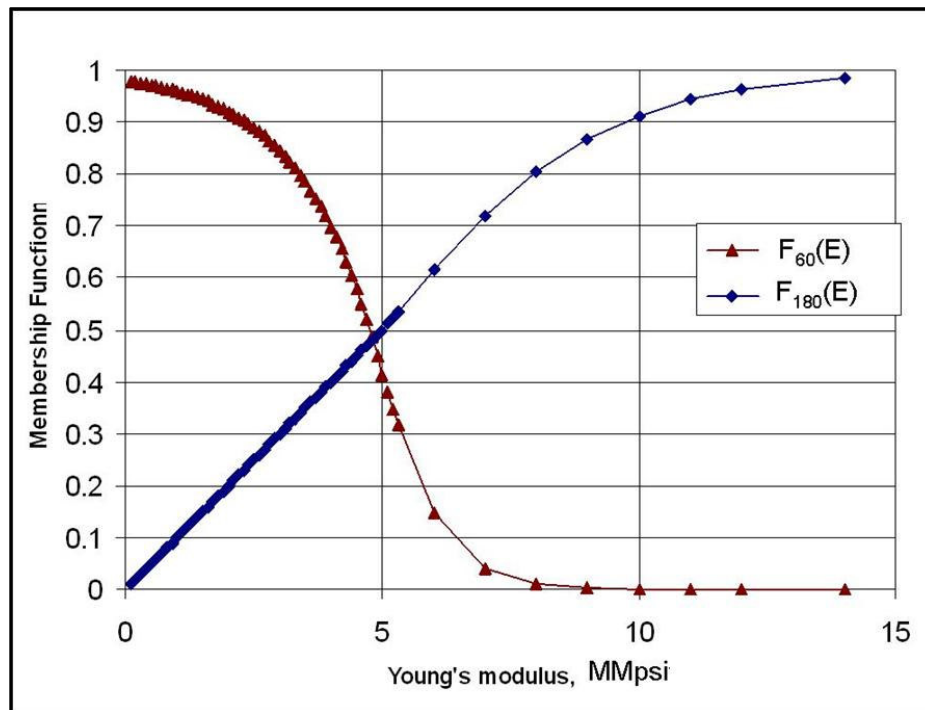


Fig. 15 – The membership functions for Young's modulus.

$$F_{60}(NF) = \begin{cases} 0.8 & \text{(very few natural fractures).....(6a)} \\ 0.5 & \text{(moderately naturally fractured).....(6b)} \\ 0 & \text{(highly naturally fractured).....(6c)} \end{cases}$$

The membership functions for formation sand production (fines migration):

$$F_{180}(SP) = \begin{cases} 1 & \text{(sand production is considerable).....(7a)} \\ 0 & \text{(no sand production).....(7b)} \end{cases}$$

$$F_{60}(NF) = \begin{cases} 0.5 & \text{(no sand production).....(8a)} \\ 0 & \text{(sand production is considerable).....(8b)} \end{cases}$$

The membership functions for horizontal stress contrast ($\sigma_{Hmin}/\sigma_{Hmax}$)

$$F_{180}(HC) = \begin{cases} 1 & \text{(low horizontal stress contrast).....(9a)} \\ 0.4 & \text{(moderate horizontal stress contrast).....(9b)} \\ 0 & \text{(high horizontal stress contrast).....(9c)} \end{cases}$$

$$F_{60}(HC) = \begin{cases} 0 & \text{(low horizontal stress contrast).....(10a)} \\ 0.5 & \text{(moderate horizontal stress contrast).....(10b)} \\ 0.8 & \text{(high horizontal stress contrast).....(10c)} \end{cases}$$

The impact of every parameter as a part of a data set onto the final recommendation is weighted as shown in **Table 3**. Values of membership functions for 60° and 180° phased perforations multiplied by the weighting factors are added up in perforation phasing indexes:

The perforation phasing index for 180° phased perforation:

$$I_{180} = F_{180}(E) \cdot W_E + F_{180}(NF) \cdot W_{NF} + F_{180}(SP) \cdot W_{SP} + F_{180}(HC) \cdot W_{HC} \dots\dots\dots(11)$$

The perforation phasing index for 60° phased perforation:

$$I_{60} = F_{60}(E) \cdot W_E + F_{60}(NF) \cdot W_{NF} + F_{60}(SP) \cdot W_{SP} + F_{60}(HC) \cdot W_{HC} \dots\dots\dots(12)$$

| TABLE 3 – WEIGHTING FACTORS FOR PHASING SELECTION | |
|---|--------|
| W_E (Young's modulus) | 0.2875 |
| W_{NF} (Natural fractures) | 0.2875 |
| W_{SP} (Formation sand production) | 0.1375 |
| W_{HC} (Horizontal stress contrast) | 0.2875 |
| $\sum W_i$ (Sum) | 1 |

A recommendation concerning which perforation phasing to choose is derived from the comparison of the perforation phasing indexes. The perforation phasing indexes are called confidence levels in the subroutine's outcome. It is a number between null and unity used in the subroutine reflecting the degree of confidence in the recommendations. If 180° phased perforation is recommended and 180° membership function of Young's modulus is equal or greater than 0.5, perforation should be oriented with maximum horizontal stress (**Fig. 16a**). If it is an exploration well, an alternative option is to use propellant assisted perforation instead of hydraulic fracturing (Fig. 16b). Another special case we consider is for a high pressured, deep well where the casing is going to be perforated through tubing using a small diameter, retrievable tubing gun. For this case, the gun should be loaded with 0° degree phasing (Fig. 16c) and should be magnetically or mechanically decentralized.

| Phasing recommendations: | Recommendations | Confidence level (0...1) | Options within recommendations |
|--------------------------|-----------------|--------------------------|--|
| 0° phasing perforation | No | n/a | |
| 60° phasing perforation | No | 0.2246 | |
| 180° phasing perforation | Yes | 0.6092 | Perforation oriented with maximum horizontal stress, |
| Alternatives | | | |

a

| Phasing recommendations: | Recommendations | Confidence level (0...1) | Options within recommendations |
|--------------------------|--|--------------------------|--------------------------------|
| 0° phasing perforation | No | n/a | |
| 60° phasing perforation | Yes | 0.4746 | |
| 180° phasing perforation | No | 0.4025 | |
| Alternatives | Proppellant assisted perforation w/o HF, put on production immediately after perforation | | |

b

| Phasing recommendations: | Recommendations | Confidence level (0...1) | Options within recommendations |
|--------------------------|-----------------|--------------------------|--------------------------------|
| 0° phasing perforation | Yes | n/a | |
| 60° phasing perforation | No | 1.0000 | |
| 180° phasing perforation | No | 1.0000 | |

c

Fig. 16 –TGS Advisor generates specific recommendations based on the analysis of the input data.

Perforation Interval

The perforation interval length for a one-stage hydraulic fracturing depends on payzone thickness (gross thickness) (**Fig. 17a**). In multilayer payzones, where shales are not strong barriers, one hydraulic fracture may cover the entire thickness of the payzone including shales, so only one layer can be perforated (Fig. 17b). If all layers are perforated, several fractures may be created that might interfere with each other. So, usually the layer with the highest sum of porosity-thickness and permeability-thickness products is perforated. However, if shales are thick and/or have much higher Young's modulus than sands, they might confine fracture height growth (Fig. 17c). In this case

perforation should cover every layer of interest, so several separated fractures are generated simultaneously during hydraulic fracturing.

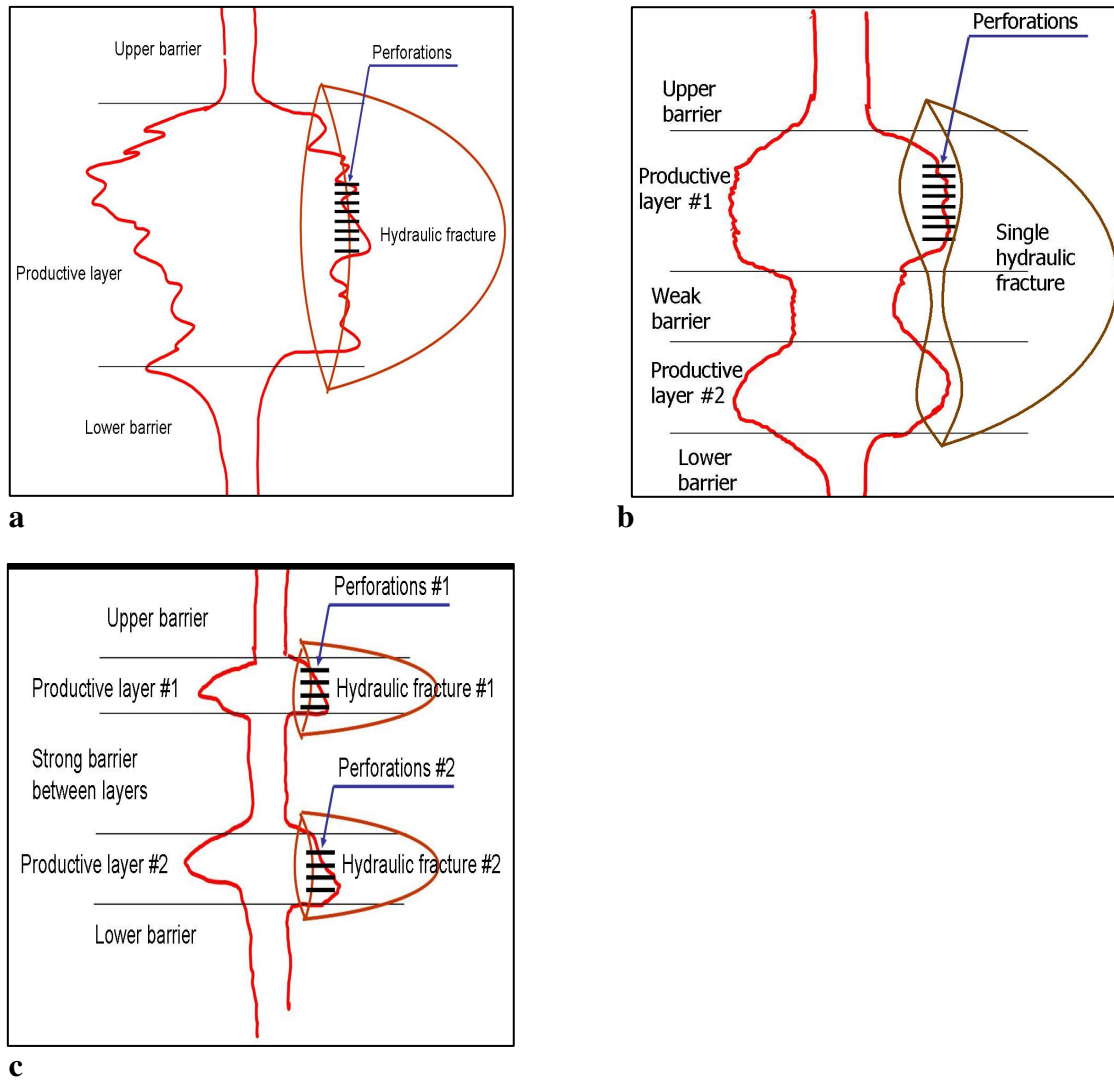


Fig. 17 – The length of the perforation interval depends on the number of separate fractures and payzone thickness.

Thus, perforation interval also depends on the number of desired separate fractures, if several productive layers exist.

Fig. 18 is a two dimensional chart explaining dependence of the perforation interval length on the number of separate fractures and the length of the payzone. Payzone thickness is divided into three categories: thin payzone (< 50 ft), moderate thickness (50 – 150 ft), and thick payzone (> 150 ft). If a payzone is thin and only one fracture is expected, the entire interval should be perforated (Fig. 18a). However, if at least two separate fractures are needed for stimulation of multiple layers, every productive layer within the payzone should be perforated completely to assure all layer of interest are stimulated (Fig. 18b). For a single fracture in a moderately thick payzone only the most porous zone should be perforated to prevent multiple fractures caused by a long perforated interval (Fig. 18c). Since generally there is a correlation between porosity and permeability, the most porous zone should be the most permeable one. For old recompleted wells the zone with the lowest pressure should be perforated, because it is usually a partially depleted zone and it will have the lowest in-situ stress.

Up to three fractures in a moderately thick payzone require perforation of the most porous zone in every productive layer or point-source perforation of every layer (Fig. 18d). Point-source perforation is a preferred technique, when the well is not normal to formation bed boundaries (deviated well or vertical well in a dipping reservoir). Moreover, if there is a low or moderate stress contrast between a barrier and sand, point-source perforation should be used to minimize uncontrolled upward/downward growth of the fracture (**Fig. 19**) and to minimize the creation of multiple fractures. A barrier/sand stress contrast is considered low when a difference between barrier's and sand's horizontal stresses is less than 0.05 psi/ft; a moderate contrast – stress difference is between 0.05 and 0.1 psi/ft; a high contrast – stress difference is greater 0.1 psi/ft.

| Payzone thickness | Thick | Limited-entry f | | |
|-------------------------------------|----------|--|---|--|
| | Moderate | Perforate most porous zone c | Perforate most porous zone in each layer. Point-source perforation. d | Perforate zones with major gas-inplace or use limited-entry technique. e |
| | Thin | Perforate entire interval a | Perforate entire interval in each layer b | |
| | | 1 | 2-3 | 3+ |
| Number of separate fractures | | | | |

Fig. 18 – Selection of the perforation interval for a vertical well.

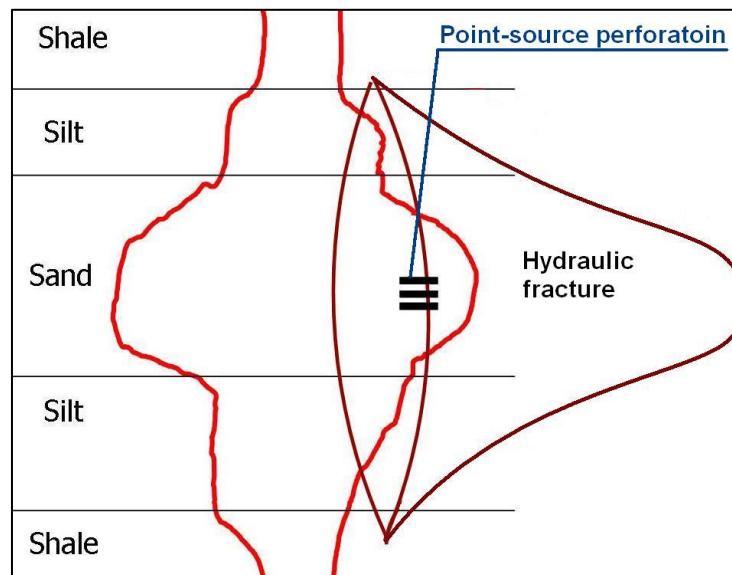


Fig. 19 – Low horizontal stress contrast favors a point-source perforation approach.

A moderately thick payzone with four or more fractures requires perforation of only layers with major gas-in-place to assure that stimulation fluid and proppant are not wasted in low-productive uneconomic horizons; also, the limited-entry technique should be used in this case (Fig. 18e). The limited-entry technique can also be applied in thick payzones regardless of the number of the separate fractures (Fig. 18f), but there is always the risk of creating multiple fractures in thick intervals.

If a formation is naturally fractured, we recommend a limit perforation interval to 6 ft per separate fracture to avoid excessive fluid leak off and the possibility of creating multiple fractures. Also the interval with highest degree of natural fractures should be perforated. We assume it is the most porous interval, so we recommend to perforate the most porous interval.

Perforation Shot Density

A review of the literature and interviews with experts showed that the main concern about perforation shot density in TGS wells is its impact onto proppant settling in the well during the hydraulic fracture treatment. The velocity of fluid entering the perforations depends on total cross section of all shots where the fracture is initiated. We assume that the perforation diameter and the total fluid injection flow rate are known, so the fluid velocity becomes only a function of the number of perforations. If there are too many perforation shots, the fluid velocity can drop below the proppant settling velocity. If this happens, the proppant may settle in the wellbore. If the proppant fills the wellbore, it can lead to a screenout. On the other hand, if the shot density is too low, it will cause the perforation friction pressure to be too high. Because of complexity and inaccuracy of fluid velocity calculations near perforations, we have applied a rule-of-thumb to compute perforation shot density. The injection rate in every perforation should

be between 0.25 and 0.5 bbl/min for conventional hydraulic fracturing. Perforations for limited-entry hydraulic fracturing are designed to create a considerable pressure drop across the perforations, so all productive zones get enough treatment fluid and are adequately stimulated. So, we suggest that for limited-entry fracturing average injection rate across each perforation should be between 1 and 2 bbl/min. Also, we set maximum allowable perforation density to 12 SPF, because of casing integrity limitations. Assuming that a hydraulic fracture is propagated only in perforation shots closest to the preferred fracture plane, shot density for 60° phasing should be 3 times of shot density for 180° phasing (**Fig. 20**) and 6 times of shot density for 0° phasing. So, prior shot density calculations we have to determine perforation phasing and length of the perforated interval.

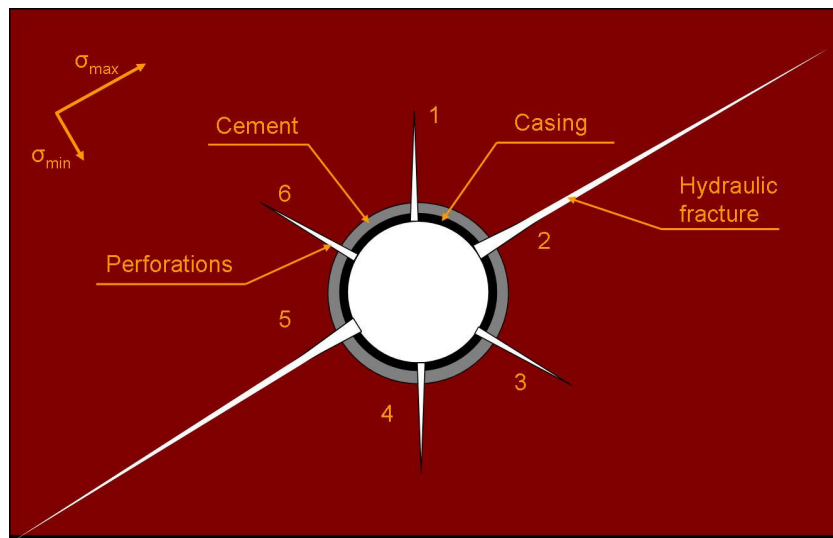


Fig. 20 – In case of a 60° phased perforation, only perforations closest to the preferred fracture plane (perforations # 2 and 5) take treatment fluid.

Propping Agent Selection

We improved and updated the workflow to select the proppant developed by Xiong (**Fig. 21**).⁵⁴ Cinco-Ley and Samaniego generated type curves to describe flow in a reservoir containing a well with a finite-conductivity fracture.⁵⁵ They used a correlating parameter called the dimensionless fracture conductivity, Cr , to correlate dimensionless pressure with dimensionless time. It was pointed out that when the value of $Cr \geq 100$, the Cinco-Ley solution was identical to the infinite conductivity solution generated earlier by Ramey, Gringarten, Raghavan.⁵⁶

Gidley *et al.* later pointed out that a good design goal for determining the fracture conductivity in a particular well was a value of $Cr \approx 10$.⁴³ The equation is as follows:

$$Cr = \frac{wk_f}{\pi \cdot k \cdot L_f} \dots\dots\dots(13)$$

where:

wk_f – desired fracture conductivity, md-ft

$\pi = 3.14$

L_f – optimal fracture half-length, ft

C_r – dimensionless conductivity factor

k – formation permeability, md

If we solve Eq. 13 for the needed fracture conductivity, we get:

$$wk_f = \pi \cdot L_f \cdot C_r \cdot k \dots\dots\dots(14)$$

Thus, Cr becomes an input parameter, set by the user. For Cr of 10 or more, the fracture is considered to have minimal pressure drop down the fracture. Assuming no damage to the fracture from gel residue or formation fines, we can design a fracture treatment to achieve a conductivity of wk_f from Eq. 14. However, based on experience, the fracture

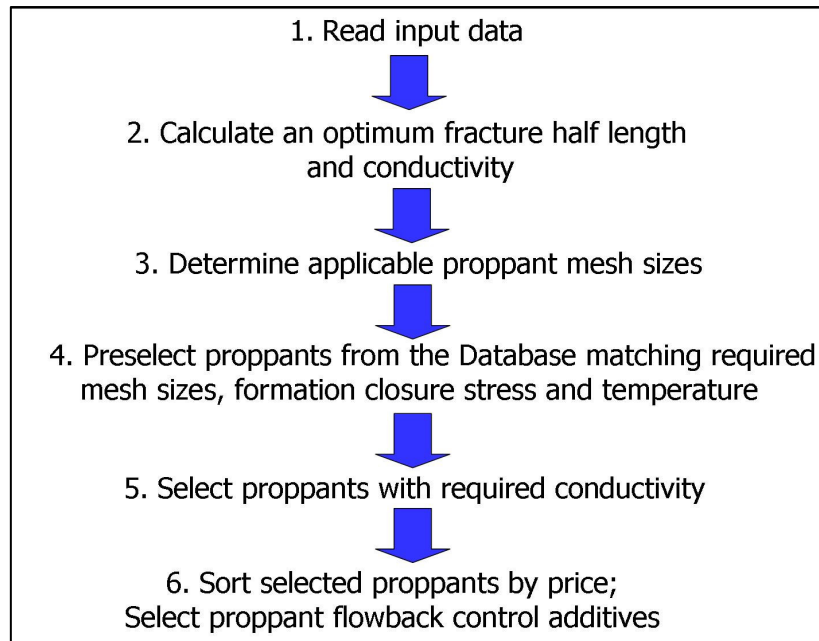


Fig. 21 – Proppant selection workflow.

can be damaged for a number of reasons. That is why we included a variable dimensionless damage factor, Dr , into Eq. 14:

$$wk_f = \pi \cdot L_f \cdot C_r \cdot k \cdot Dr \dots \dots \dots (15)$$

A damage factor is a dimensionless empirical value capturing all potential damage to fracture conductivity: proppant embedment, proppant crushing due to formation closure stress and temperature, etc.⁵⁴ If we use a damage factor of, say, 5, then we will need to actually achieve 5 times higher wk_f initially to obtain optimal conductivity. We used linear interpolation to obtain an exact value of the damage factor:

$$D_r = \begin{cases} 2 \text{ to } 5 & (\text{formation closure stress} \leq 6,000 \text{ psi}) \\ 5 \text{ to } 10 & (6,000 \text{ psi} < \text{formation closure stress} \leq 10,000 \text{ psi}) \\ 10 & (\text{formation closure stress} > 10,000 \text{ psi, or formation depth} > 10,000 \text{ ft, or formation temperature} > 275 \text{ }^\circ\text{F}) \end{cases}$$

For gas reservoirs, Gidley *et al.*⁴³ determined that an optimal fracture half-length is correlated to the permeability and well drainage area. They found that the ration of optimal fracture half-length to drainage radius should be 0.7 for low permeability reservoirs, 0.4 for medium permeability reservoirs, and 0.2 for high permeability reservoirs. We defined low permeability as a permeability lower than 1 md, moderate is between 1 md and 1 Darcy, while high permeability is greater than 1 Darcy. Using above relationships, I generated several graphs representing dependence of optimal fracture half-length on reservoir permeability and well drainage area (**Fig. 22**). Eq. 16 expresses a general equation used to generate graphs on Fig. 22:

$$L_f = a \cdot \ln(k) + b \dots \dots \dots (16)$$

where:

L_f – optimal fracture half-length, ft

k – formation permeability, md

a, b – correlation coefficients depending on the well drainage area

I correlated coefficients a and b to well drainage area using Eq. 17a and Eq. 17b, respectively:

$$a = -0.1818 \cdot A - 24.6220 \dots \dots \dots (17a)$$

$$b = 231.23 \cdot \ln(A) - 615.37 \dots \dots \dots (17b)$$

where:

a, b – correlation coefficients

A – well drainage area, acres

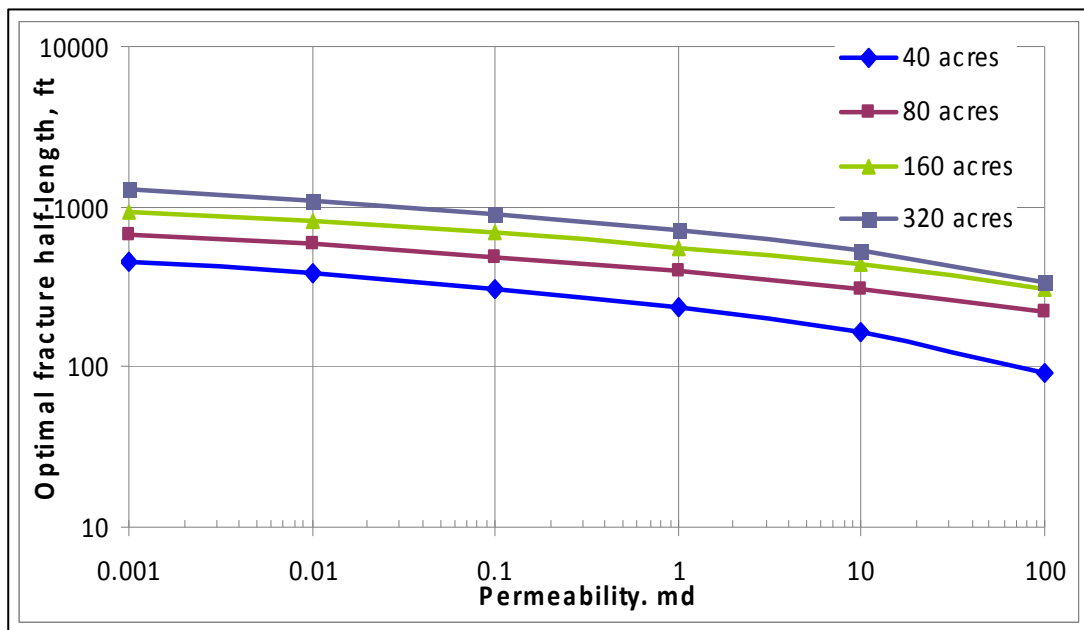


Fig. 22 – Optimal fracture half-length is a function of formation permeability and well drainage area.

From the petroleum literature and best-practices, we concluded that if formation temperature is greater 275 °F, or formation closure stress is greater 8,000 psi, or well depth is greater 10,000 ft,⁵¹ or a formation produces sand (an unconsolidated formation), then proppant API mesh size should be 20/40 or smaller. Moreover, the maximum proppant diameter should be at least 6 times of perforation diameter and 3 times of dynamic fracture width.⁴²

The very first requirement for the proppant during the selection process is that the proppant has to be able to withstand formation closure stress and temperature. **Fig. 23** summarizes our findings about the applicability of various proppant types and additives depending on the formation closure stress and temperature. Even though, this chart is somewhat general, it captures the maximum range of applicability of certain proppant types. Though different proppant manufacturers may include their products into the same proppant type, e.g. intermediate strength ceramics, the proppants' working pressures and temperatures can vary significantly. That is why, instead of proposing recommendations concerning what proppant type is suitable for the given formation closure stress and temperature, we should compare particular proppant working limits specified by a manufacturer with the formation parameters.

Proppant conductivity is a function of formation closure stress, proppant concentration, and proppant mesh size. In laboratory tests, if salt water is filtrated through the proppant to measure proppant conductivity, proppant conductivity decreases with increasing temperature; while if gas is a filtrate, proppant conductivity is irrelevant to the temperature. The explanation of this phenomenon is that water dissolves silica which is a component of every proppant and dissolubility of silica in water increases with increasing temperature. Since formation water usually is already saturated with silica, should not affect proppant conductivity, so formation temperature does not influence proppant conductivity. Usually proppant manufactures provide conductivity data for various temperatures and concentrations. We created a proppant database containing proppant conductivity at different conditions, price, specific gravity and other parameters (**Fig. 24**). Currently, the database contains data about 80-90% of proppants available at the stimulation market. Moreover, a user can easily modify, update and/or customize the data, such as proppant price, specifically for his or her situation.

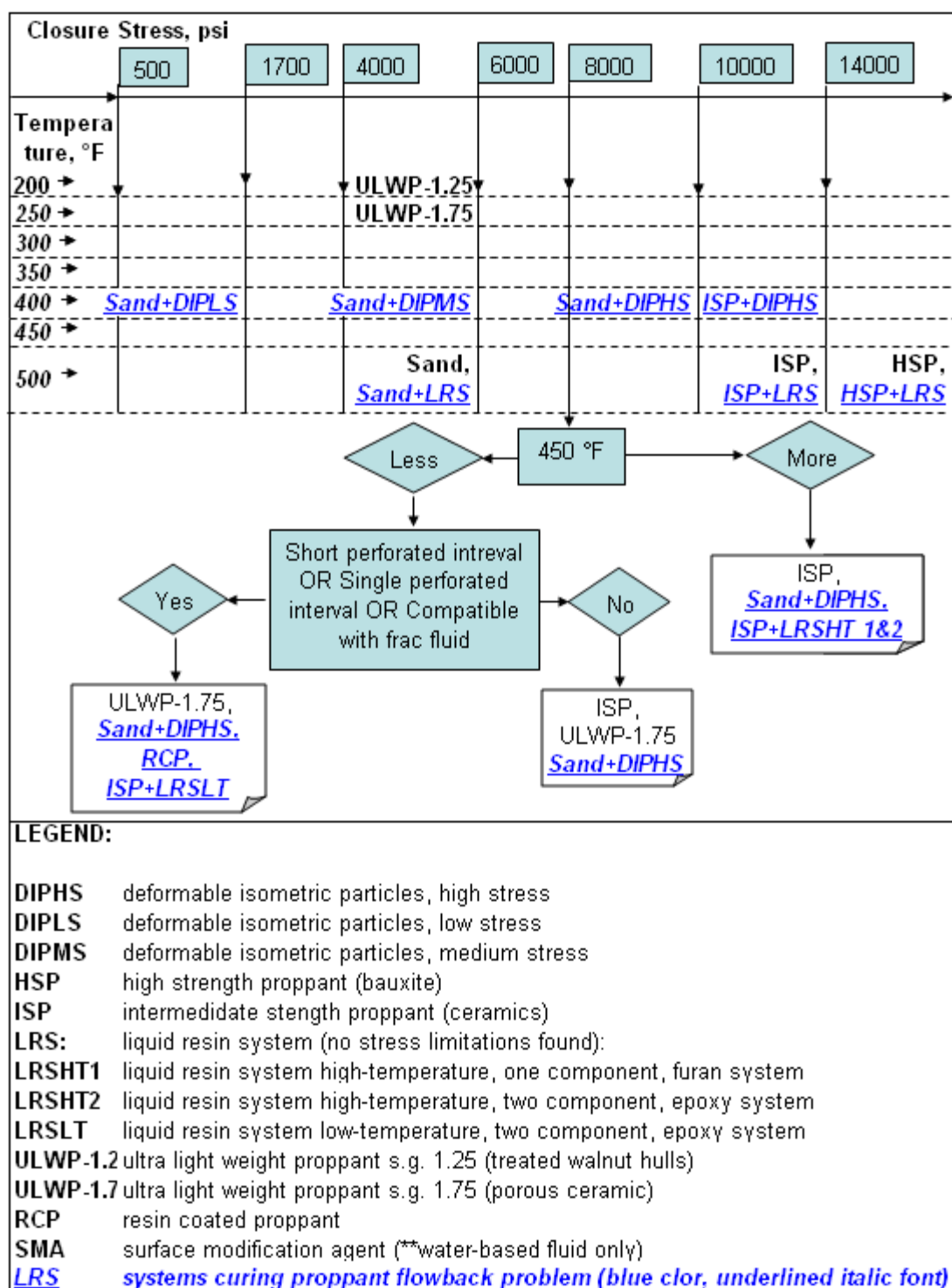


Fig. 23 – Applicability of proppants and proppant flowback control additives as a function of formation closure stress and temperature.

| | | | |
|---------------------------------|-----------------------------------|--|---|
| TRADENAME | Atlas CRC Premium | MIN REQUIRED CLOSURE STRESS, psi | 4000 |
| MANUFACTURER | Atlas Resin Proppants | MAX ALLOWABLE CLOSURE STRESS, psi | 10000 |
| TYPE | Curable Resin Coated Sand | MIN REQUIRED FORMATION TEMPERATURE, F | 0 |
| SPECIFIC GRAVITY | 2.5 | MAX ALLOWABLE FORMATION TEMPERATURE, F | 500 |
| BOOK PRICE, \$/lbm | 2.17 | DESCRIPTION | Minimum temperature is not specified by the manufacturer. Manufacturer recommends to use the proppant up to 1 |
| DISCOUNT, % | 75 | | |
| PERM | | | |
| MESH SIZE | CONCENTRATION, lb/ft ² | TEMPERATURE, F | |
| 20/40 | 2 | 250 | |
| CONDUCTIVITY @ 2000 psi, md-ft | | 0 | ADD CONDUCTIVITY DATA |
| CONDUCTIVITY @ 4000 psi, md-ft | | 3200 | |
| CONDUCTIVITY @ 6000 psi, md-ft | | 2700 | DELETE CONDUCTIVITY DATA |
| CONDUCTIVITY @ 8000 psi, md-ft | | 1700 | |
| CONDUCTIVITY @ 10000 psi, md-ft | | 840 | |
| CONDUCTIVITY @ 12000 psi, md-ft | | 0 | |
| CONDUCTIVITY @ 14000 psi, md-ft | | 0 | |
| Record: 1 of 1 | | | |

Fig. 24 – The proppant database.

Searching through the proppant database, the subroutine preselects proppants matching required closure stress and mesh size. Then for the preselected proppants the subroutine looks for a conductivity data set that satisfies required proppant concentration. The actual proppant conductivity is calculated using a linear interpolation technique.

Proppants whose conductivity is equal to or greater than the desired fracture conductivity are sorted by their prices and displayed in the output file (**Fig. 25**).

However, most of the time proppant manufacturers do not provide conductivity data for all possible temperatures and proppant concentrations. Since there are no general correlations between proppant conductivity and concentration, only proppants that have conductivity data for concentrations lower than the input concentration are considered.

| OUTPUT | | | | | | | |
|--|------------------------|------------------------------|--------------------|--------------------|-------------|----------------------|--------------------------------|
| Optimum fracture half-length, ft | 936 | | | | | | |
| Fracture conductivity, md-ft | 1646 | Proppant perm, Darcy | 50 | | | | |
| Proppants | Manufacturer | Proppant conductivity, md-ft | Proppant mesh size | Book Price, \$/lbm | Discount, % | Actual Price, \$/lbm | Proppant type |
| Interprop | Saint-Gobain Proppants | 1785 | 30/50 | 2.91 | 75 | 0.728 | Intermediate Strength Proppant |
| Interprop | Saint-Gobain Proppants | 1785 | 30/50 | 2.91 | 75 | 0.728 | Intermediate Strength Proppant |
| Ultraprop | Saint-Gobain Proppants | 4771 | 20/40 | 2.93 | 75 | 0.733 | High Strength Proppant |
| SinterBall Bauxite | Sintex | 2269 | 30/50 | 3.71 | 75 | 0.928 | High Strength Proppant |
| Sintered Bauxite | Saint-Gobain Proppants | 4318 | 20/40 | 3.71 | 75 | 0.928 | High Strength Proppant |
| SinterBall Bauxite | Sintex | 4645 | 20/40 | 3.71 | 75 | 0.928 | High Strength Proppant |
| Sintered Bauxite | Saint-Gobain Proppants | 7625 | 16/30 | 3.71 | 75 | 0.928 | High Strength Proppant |
| SinterBall Bauxite | Sintex | 7793 | 16/30 | 3.71 | 75 | 0.928 | High Strength Proppant |
| Proppants are applicable for the reservoir temperature and closure stress, but conductivity is not specified by the manufacturer | | | | | | | |
| LiteProp 175 | BJ Services | ??? | See the data | 0.00 | 75 | 0.000 | Resin Coated Ceramics |
| Frac Sands | Santrol | ??? | See the data | 0.50 | 75 | 0.125 | Sand |
| Frac Sands | Santrol | ??? | See the data | 0.50 | 75 | 0.125 | Sand |
| Frac Sands | Santrol | ??? | See the data | 0.5 | 75 | 0.125 | Sand |
| Atlas PRC | Atlas Resin Proppants | ??? | See the data | 1.66 | 75 | 0.415 | Precured Resin Coated Sand |

Fig. 25 – Recommended proppants are sorted by price in the TGS Advisor output.

Proppant conductivity decreases with increasing concentration. Thus, in the case where the input concentration is much smaller than the tested concentration, the proppant conductivity will be underestimated. However, this conservative approach gives reliable conductivity estimations. If a particular proppant does not have conductivity data for the desired concentration, but the formation temperature and closure stress are within proppant's working limits, this proppant is offset to the bottom of the output and the comment about its unknown conductivity is made (Fig. 25).

For formations where proppant flowback can be an issue, specific additives can be considered to help minimize proppant flowback into the wellbore. We found papers on the several additives that are being used in the industry (**Table 4**). The subroutine compares applicability limits of the additives with the input reservoir data, if an additive

satisfies formation conditions, the additives is selected and shown in the additives output file. The programming code for the TGS Advisor's proppant selection module could be found in Appendix B.

| TABLE 4 - PROPPANT FLOWBACK CONTROL ADDITIVES | | | | | |
|---|---------------------|---------------------|-------------------------|-------------------------|--|
| Flowback Control Additives | Min Temperature, °F | Max Temperature, °F | Min Closure Stress, psi | Max Closure Stress, psi | Name |
| SMA | 0 | 200 | n/a | n/a | Surface Modification Agent (water-based fluid only) (Halliburton) |
| LRSHT1 | 300 | 550 | n/a | n/a | Liquid Resin System High-Temperature, one component (furan system) (Halliburton) |
| LRSHT2 | 200 | 350 | n/a | n/a | Liquid Resin System High-Temperature, two component (epoxy system) (Halliburton) |
| LRSLT | 70 | 225 | n/a | n/a | Liquid Resin System Low-Temperature, two component (epoxy system) (Halliburton) |
| DIPLS | 0 | 200 | 250 | 1750 | Deformable Isometric Particles, low strength (BJ Services) |
| DIPMS | 0 | 275 | 1500 | 7000 | Deformable Isometric Particles, medium strength (BJ Services) |
| DIPHS | 0 | 400 | 6000 | 12000 | Deformable Isometric Particles, high strength (BJ Services) |

4. RESULTS AND DISCUSSION

To test our decision charts and fuzzy logic models, we used case histories from the petroleum literature. We searched the petroleum literature to identify case histories representing the best completion and stimulation practices in TGS wells. We used well and reservoir data from these case histories as the input for TGS Advisor to evaluate our methodology and validate our results. We compared the actual completion and stimulation solutions that were described in the case histories with recommendations given by our TGS Advisor subroutines. If the actual best-practice from the case histories was within the subroutine's recommended options, we concluded that our methodology was valid and applicable. If the best-practice did not match any subroutines' recommendations, we tried to identify reasons for the mismatch. The reasons might be: 1) the best-practice was obsolete; 2) the completion/stimulation decision was derived specifically for a given well, capturing other parameters such as costs, logistics, or regulations, that we are yet considered in TGS Advisor; 3) TGS Advisor's subroutine did not include all critical parameters during decision making; 4) TGS Advisor's fuzzy definitions were not correct; 5) TGS Advisor's weighting factors of high-impact parameters needed to be adjusted. To keep our TGS Advisor subroutines as general as possible and up-to-date, we did not modify the subroutines in case of the first or the second mismatch reasons. However, we altered the subroutines' parameters if there were no evidence that a best-practice was obsolete or specific to a given well. After this iteration process, we have achieved a reasonable agreement between TGS Advisor outcomes and the actual best-practices, as documented in the petroleum literature.

Perforation Selection Module

Perforation Interval

We identified four options for selecting the perforation interval depending on reservoir properties:

- 1) perforate an entire interval(s);
- 2) perforate the most porous zone(s) (20 ft long in each layer by default for not naturally fractured reservoirs and 6 ft for naturally fractured reservoirs);
- 3) use limited-entry technique; or
- 4) use point-source perforation (5 ft long in each layer by default).

In the petroleum literature, we found a complete set of required data for over a dozen wells which we believe represent best-practices (**Table 5**). Wells 1-6 have a net-pay greater than 50 ft, which is distributed through a moderately thick payzone (50 - 150 ft), so TGS Advisor recommended to perforate the most porous zone(s). These recommendations are in agreement with the actual situation as documented in the case histories. In all of these wells, the perforated interval was limited and never covered the entire net-pay thickness. Without log data, it is impossible to determine the thickness of the most porous zone, so we set it to 20 ft by default. Wells 1-4 have perforated intervals within 25 ft long. There are 3 productive layers with the total thickness greater 50 ft in Well 5. That is why, TGS Advisor recommended to perforate a most porous zone in every layer, so total length of perforated interval became 60 ft. However, the operator of the well shortened the length of the perforated interval to 38 ft. The operator of Well 6 choose to perforate 36 ft out of 60 ft net-pay. Even though in Well 6 a default value of the length of the most porous zone is too short, I can conclude that our default value for the most porous zone is reasonable and the decision to limit perforation interval to the most porous zone only is valid. However, the actual length of the perforated interval should be determined using the length of the most porous zone(s) from logs. Wells 7 and

8 are naturally fractured, so TGS Advisor recommended to limit the perforated interval to 6 ft per separate fracture, that is exactly what was done by the operators. The net-pay thicknesses of Wells 9 and 10 are within the 50 ft range, while the payzone is less than 150 ft. Thus, TGS Advisor recommended perforating the entire net-pay thickness. The operators of the wells made the same decision.

In Wells 11-13, the operators used a limited-entry technique to stimulate several zones distributed through a very long payzone simultaneously. Since the length of the payzones in these wells was greater than 150 ft, TGS Advisor recommended to use the limited-entry technique and to distribute perforation shots throughout the entire net-pay to assure that every zone is stimulated. Obviously, this recommendation is valid.

The operator of Well 14 proved that a point-source perforation approach is the best-practice for a given field. TGS Advisor's logic says that main reason to use the point-source approach at that well is a low stress contrast between the sand and the barriers. Since the reservoir satisfies point-source technique limitations (the payzone is less than 150 ft, the net-pay is greater than 50 ft, and the number of intervals is less than 3), point-source perforation was recommended by the TGS Advisor. The actual length of the perforated interval is 5 ft which is equal to Advisor's default value for point-source perforation.

| TABLE 5 - VALIDATION OF THE PERFORATION INTERVAL SELECTION SUBROUTINE | | | | | | | | | | | | | | |
|---|-------------|--------------------|----------------|---------------|------------------------|-----------------------|---|-------------|--------------------------------|---|---------|------------------|------------------------|-------------------|
| # | SPE Paper # | Basin | Formation | Well | Pay-zone thickness, ft | Net-pay thickness, ft | Total length of perforated interval, ft | | Number of perforated intervals | Sand/Shale closure stress contrast gradient, psi/ft | TVD, ft | Permeability, md | Young's modulus, MMpsi | Natural fractures |
| | | | | | | | Actual | Recommended | | | | | | |
| Most Porous Zone | | | | | | | | | | | | | | |
| 1 | 36471 | W.Texas | Wolfcamp | Mitchell 5B#6 | 90 | 70 | 20 | 20 | 1 | 0.03 | 7950 | 0.01 | 5.0 | low |
| 2 | 39951 | S.Texas | Vicksburg | B | 149 | 60 | 25 | 20 | 1 | moderate | 10000 | 0.10 | 3.5 | low |
| 3 | 36471 | W.Texas | Wolfcamp | Mitchell 5a#8 | 80 | 79 | 20 | 20 | 1 | 0.11 | 7950 | 0.01 | 5.0 | low |
| 4 | 94002 | S.Texas | Vicksburg | 1 | 149 | 70 | 26 | 20 | 1 | moderate | 9310 | 0.10 | 3.3 | low |
| 5 | 36471 | W.Texas | Wolfcamp | Mitchell 11#6 | 90 | 81 | 38 | 60 | 3 | 0.1 | 9800 | 0.01 | 5.0 | low |
| 6 | 36471 | W.Texas | Wolfcamp | Mitchell 6#5 | 80 | 60 | 36 | 20 | 1 | 0.1 | 7700 | 0.01 | 5.0 | low |
| 7 | 107827 | Neuduen, Argentina | Cupen Mahida | 1 | 150 | 130 | 6 | 6 | 1 | moderate | 11000 | 0.10 | 2.5 | high |
| 8 | 77678 | Japan | Minami-Nagaoka | MHF#1 -1 | 150 | 120 | 12 | 12 | 2 | moderate | 14000 | 0.10 | 4.9 | moderate |
| Entire Interval | | | | | | | | | | | | | | |
| 9 | 36471 | W.Texas | Wolfcamp | Mitchell 5B#7 | 100 | 46 | 46 | 46 | 2 | 0.12 | 7850 | 0.01 | 5.0 | low |
| 10 | 11600 | S.Texas | Wilcox Lobo | 1 | 149 | 50 | 50 | 50 | 1 | moderate | 10000 | 0.10 | 2.5 | low |
| Limited-Entry | | | | | | | | | | | | | | |
| 11 | 95337 | Permian | Canyon | A | 1000 | 909 | 909 | 909 | 6 | 0.15 | 5834 | 0.01 | 5.5 | low |
| 12 | 95337 | Permian | Canyon | B | 1000 | 722 | 722 | 722 | 7 | 0.15 | 5929 | 0.01 | 5.5 | low |
| 13 | 53923 | Texas | Mesaverde | | 400 | 100 | 100 | 100 | 2 | moderate | 5500 | 1.00 | | low |
| Point-Source | | | | | | | | | | | | | | |
| 14 | 76812 | S.Texas | Wilcox Lobo | B | 140 | 96 | 5 | 5 | 1 | low | 7800 | 0.1 | 2.5 | low |

Perforation Shot Density

TGS Advisor's logic considers that a major parameter influencing perforation shot density is the fluid flow rate through perforations that should prevent proppant settling in the wellbore. Moreover, we have concluded that only perforation shots that are the closest to the preferred fracture plane take fracturing fluid, so shot density for 60° phasing should be three times of shot density for 180° phased perforation and six times of the shot density for zero degree (0°) phased perforation. All following shot density calculations are done for 180° phased perforation.

For conventional hydraulic fracturing, a rule-of-thumb that we have applied is that the fluid injection rate should be between 0.25 and 0.5 bbl/min per perforation. Even though, not all industry experts may agree completely with this approach, we have chosen to use these guidelines to develop our expert advisor. Thus, the output will be a range of holes where the minimum shot density is calculated using the flow rate 0.5 bbl/min per perforation and maximum shot density is calculated using 0.25 bbl/min per perforation. **Table 6** presents data for 10 wells. We input these data into TGS Advisor to compare its recommendations and the actual shot density. For Wells 1-6, the actual perforation shot density is between the recommended minimum and maximum values. Though, for Wells 7-10, the recommended minimum shot density is greater than the actual one, it is reasonable close. Thus, we have concluded that TGS Advisor's shot density determination subroutine is generally applicable.

We also made an assumption that if a limited-entry technique is used, the minimum flow rate through every perforation shot should be 1 bbl/min and the maximum should be 2 bbl/min. Field data and TGS Advisor's output (**Table 7**) are in reasonable agreement. The recommended number of shots perfectly matches the actual situation for the Wells 1-9. For Wells 1-7, the number of shots is very close to the predicted minimum number of shots which reflects flow rate of 2 bbl/min per perforation, which gives a very high

pressure drop across perforations. Moreover, for the Wells 10-15, the predicted minimum shot density is even higher than what actually occurred. So, we can conclude that operators generally prefer minimum shot density to achieve maximum pressure drop for better stimulation control.

| TABLE 6 – VALIDATION OF THE SHOT DENSITY SUBROUTINE FOR CONVENTIONAL HYDRAULIC FRACTURING | | | | | | | | | | | | | | |
|---|-------------|---------|----------------|---------------|-------------------------------|-------------------|-------------|------|------------------------|--------------------------------|---------------------------|--------------------------|---------|------------------|
| # | SPE Paper # | Basin | Formation | Well | Total perforated interval, ft | Shot density, SPF | | | Perforation phasing, ° | Number of perforated intervals | Perforation diameter, in. | Average slurry rate, bpm | TVD, ft | Permeability, md |
| | | | | | | Actual | Recommended | | | | | | | |
| | | | | | | | Min | Max | | | | | | |
| 1 | 36471 | W.Texas | Wolfcamp | Mitchell 11#6 | 38 | 2.0 | 1.8 | 3.6 | 90 | 3 | 0.38 | 35 | 9800 | 0.01 |
| 2 | 39951 | S.Texas | Vicksburg | B | 25 | 4.0 | 3.3 | 6.6 | 60 | 1 | 0.25 | 18 | 10000 | 0.10 |
| 3 | 11600 | S.Texas | Wilcox Lobo | 1 | 50 | 1.0 | 1.0 | 2.0 | 60 | | 0.25 | 20 | 10000 | 0.10 |
| 4 | 94002 | S.Texas | Vicksburg | 1 | 26 | 2.0 | 1.5 | 3.0 | 60 | | 0.25 | 20 | 9310 | 0.10 |
| 5 | 76812 | S.Texas | Wilcox Lobo | B | 5 | 8.0 | 8.0 | 12.0 | 60 | | 0.32 | 23 | 7800 | 0.10 |
| 6 | 36471 | W.Texas | Wolfcamp | Mitchell 6#5 | 36 | 2.0 | 1.6 | 3.3 | 90 | 1 | 0.38 | 30 | 7700 | 0.01 |
| 7 | 77678 | Japan | Minami-Nagaoka | MHF#1-1 | 12 | 6.0 | 10.0 | 12.0 | 60 | 1 | 0.26 | 15 | 1400 | 0.10 |
| 8 | 36471 | W.Texas | Wolfcamp | Mitchell 5B#6 | 20 | 2.0 | 3.0 | 6.0 | 90 | 2 | 0.43 | 30 | 7950 | 0.01 |
| 9 | 36471 | W.Texas | Wolfcamp | Mitchell 5B#7 | 46 | 1.0 | 1.3 | 2.6 | 90 | 2 | 0.43 | 30 | 7850 | 0.01 |
| 10 | 36471 | W.Texas | Wolfcamp | Mitchell 5a#8 | 20 | 2.0 | 3.5 | 7.0 | 90 | 1 | 0.43 | 35 | 7950 | 0.01 |

| TABLE 7 – VALIDATION OF THE SHOT DENSITY SUBROUTINE FOR LIMITED-ENTRY HYDRAULIC FRACTURING | | | | | | | | | | | | | |
|--|-------------|---------|-----------|---------|-------------------------------|-----------------|-------------|-----|------------------------|--------------------------------|---------------------------|--------------------------|------------------|
| # | SPE Paper # | Basin | Formation | Well | Total perforated interval, ft | Number of shots | | | Perforation phasing, ° | Number of perforated intervals | Perforation diameter, in. | Average slurry rate, bpm | Permeability, md |
| | | | | | | Actual | Recommended | | | | | | |
| | | | | | | | Min | Max | | | | | |
| 1 | 95337 | Permian | Canyon | A-zone3 | 115 | 24 | 23 | 46 | 60 | 1 | 0.32 | 48 | 0.01 |
| 2 | 95337 | Permian | Canyon | A-zone4 | 91 | 24 | 24 | 48 | 60 | 1 | 0.32 | 49 | 0.01 |
| 3 | 95337 | Permian | Canyon | B-zone4 | 126 | 28 | 25 | 49 | 60 | 1 | 0.32 | 49 | 0.01 |
| 4 | 95337 | Permian | Canyon | B-zone5 | 140 | 24 | 24 | 48 | 60 | 1 | 0.32 | 48 | 0.01 |
| 5 | 95337 | Permian | Canyon | B-zone6 | 104 | 18 | 19 | 37 | 60 | 1 | 0.32 | 38 | 0.01 |
| 6 | 53923 | Texas | Mesaverde | | 100 | 25 | 22 | 45 | 60 | 2 | 0.32 | 45 | 1.00 |
| 7 | 95337 | Permian | Canyon | A | 723 | 101 | 72 | 145 | 60 | 6 | 0.32 | 46 | 0.01 |
| 8 | 95337 | Permian | Canyon | B-zone2 | 30 | 13 | 8 | 15 | 60 | 1 | 0.32 | 16 | 0.01 |
| 9 | 95337 | Permian | Canyon | A-zone2 | 174 | 30 | 16 | 33 | 60 | 1 | 0.32 | 33 | 0.01 |
| 10 | 95337 | Permian | Canyon | B-zone3 | 122 | 17 | 22 | 44 | 60 | 1 | 0.32 | 45 | 0.01 |
| 11 | 95337 | Permian | Canyon | B-zone1 | 84 | 13 | 19 | 39 | 60 | 1 | 0.32 | 38 | 0.01 |
| 12 | 95337 | Permian | Canyon | A-zone6 | 271 | 16 | 24 | 49 | 60 | 1 | 0.32 | 51 | 0.01 |
| 13 | 95337 | Permian | Canyon | A-zone1 | 130 | 14 | 22 | 46 | 60 | 1 | 0.32 | 46 | 0.01 |
| 14 | 95337 | Permian | Canyon | B-zone7 | 116 | 13 | 26 | 51 | 60 | 1 | 0.32 | 52 | 0.01 |
| 15 | 95337 | Permian | Canyon | A-zone5 | 128 | 14 | 36 | 46 | 60 | 1 | 0.32 | 47 | 0.01 |

Perforation Phasing

After a thorough literature search and consultations with experts, we decided to distinguish between 0° perforation phasing (for perforation through small diameter tubing or casing), 60° phasing and 180° phasing. The first seven wells in **Table 8** were perforated with 60° phasing. We used the fuzzy logic model described in the Methodology section to evaluate the well data in Table 8. We calculated the fuzzy logic index for 180° phasing (I_{180}) and the fuzzy logic index for 60° phasing (I_{60}) using Eqs. 11 and 12. The perforation scheme recommended by TGS Advisor will be the one with the largest value of the fuzzy logic index. For Wells 1-7, TGS Advisor subroutine recommends 60° phasing, the same phasing was selected by the operators of the wells.

90° phasing was used in Wells 8-12. Early on, 90° phasing was commonly used because it was more convenient to load a perforation gun for 90° phasing than for 60° . Even though, the perforation index of 60° phasing is larger than for 180° phasing for Wells 8-12, there is only 0.07 difference between the 60° and 180° phasing indexes. It means that 60° phasing has very little advantage above 180° phasing, so 90° phasing could be considered a compromise phasing for this marginal combination of the reservoir properties. Wells 13-14 were perforated with 120° phasing. Based on TGS Advisor recommendations, we believe that 60° phasing would be more suitable for the given reservoir conditions. Well 15 was perforated using 180° phasing by the operator. Since the well is naturally fractured and has high Young's modulus, TGS Advisor recommended 180° phasing as well.

TABLE 8 – VALIDATION OF THE PERFORATION PHASING SELECTION SUBROUTINE

| # | SPE Paper # | Basin | Formation | Well | Perforation phasing, ° | | | TVD, ft | Perm, md | Young's modulus, MMpsi | Natural fractures | Formation sand production | Horizontal stress contrast |
|----|-------------|----------------|-------------------|----------------|------------------------|-------------|---------|---------|----------|------------------------|-------------------|---------------------------|----------------------------|
| | | | | | Actual | Recommended | | | | | | | |
| | | | | | | I(60°) | I(180°) | | | | | | |
| 1 | 94002 | S. Texas | Vicksburg | 1 | 60 | 0.67 | 0.20 | 9310 | 0.100 | 3.3 | low | no | moderate |
| 2 | 95337 | Permian | Canyon | A | 60 | 0.51 | 0.27 | 5834 | 0.010 | 5.5 | low | no | moderate |
| 3 | 95337 | Permian | Canyon | B | 60 | 0.51 | 0.27 | 5930 | 0.010 | 5.5 | low | no | moderate |
| 4 | 39951 | S. Texas | Vicksburg | B | 60 | 0.58 | 0.35 | 9900 | 0.010 | 3.5 | low | no | moderate |
| 5 | 76812 | S. Texas | Wilcox Lobo | B | 60 | 0.61 | 0.33 | 7800 | 0.010 | 2.5 | low | no | moderate |
| 6 | 50610 | Illizi Algeria | Tin Fouye | 1 | 60 | 0.56 | 0.26 | 4500 | 10.000 | 5.0 | low | no | moderate |
| 7 | 77678 | Japan | Minami-Nagaoka | MHF#1-1 | 60 | 0.49 | 0.40 | 14000 | 0.100 | 5.0 | moderate | no | moderate |
| 8 | 36471 | W. Texas | Wolfcamp | Mitchell 6#5 | 90 | 0.47 | 0.40 | 7700 | 0.010 | 5.0 | moderate | no | moderate |
| 9 | 36471 | W. Texas | Wolfcamp | Mitchell 5B#6 | 90 | 0.47 | 0.40 | 7950 | 0.010 | 5.0 | moderate | no | moderate |
| 10 | 36471 | W. Texas | Wolfcamp | Mitchell 5B#7 | 90 | 0.47 | 0.40 | 7850 | 0.010 | 5.0 | moderate | no | moderate |
| 11 | 36471 | W. Texas | Wolfcamp | Mitchell 5a#8 | 90 | 0.47 | 0.40 | 7950 | 0.010 | 5.0 | moderate | no | moderate |
| 12 | 36471 | W. Texas | Wolfcamp | Mitchell 11#6 | 90 | 0.47 | 0.40 | 9800 | 0.010 | 5.0 | moderate | no | moderate |
| 13 | 36735 | Permian | Canyon | Henderson 32-9 | 120 | 0.51 | 0.27 | 6400 | 0.010 | 5.5 | low | no | moderate |
| 14 | 36735 | Permian | Canyon | Couch #7 | 120 | 0.51 | 0.27 | 6500 | 0.010 | 5.5 | low | no | moderate |
| 15 | 21495 | E. Texas | Upper Travis Peak | SFE #2 | 180 | 0.35 | 0.47 | 8300 | 0.006 | 7.0 | moderate | no | moderate |

Proppant Selection Module

To select a propping agent for a hydraulic fracture treatment, one has to identify the desired fracture half-length and subsequently fracture conductivity. Using a correlation between the optimal fracture half-length on one side and reservoir permeability and well drainage area on the other, I calculated the desired fracture half-length for 14 wells in **Table 9**. I used 80 acres spacing by default because it is a very common spacing for low permeability gas reservoirs. For gas reservoirs, optimal fracture half-length is increasing with decreasing reservoir permeability. Recommended fracture half-length is within 4% of the half-length which was calculated by the operators for Wells 1-7. However, optimal fracture half-length is not always achievable because of equipment limitations, economic constraints, and other factors. That is why recommended half-length fluctuates from what was predicted by the operators of Wells 8-14.

To validate proppant selection subroutine of TGS Advisor we input data from published reports into the subroutine and compared the proppant which actually was used in real wells with subroutine's recommendations (**Table 10**). All calculations were done for proppant concentration 2 lbm/ft² and various dimensionless fracture conductivity factors (Cr), a default value is 10. A value of $Cr \geq 10$ means there is very little pressure drop down the fracture. As such, the gas flow rates will be controlled by the fracture length and formation permeability. The fracture conductivity is large enough so the fracture is not restricting the gas flow rate.

The actual proppant used for the hydraulic fracturing in Wells 1-13 was within the first two proppants recommended by TGS Advisor's proppant selection module; a default value of Cr was used. I reduced the value of Cr for Wells 14-22. For these values of Cr , there will be some pressure drop down the fracture, which will restrict the early time flow rates. However, over the life of the wells, the ultimate recovery will be dictated by

the formation permeability, and the fracture length. Thus, actual used proppant was again within top two options given by TGS Advisor for Wells 14-22.

Bauxite was used as a propping agent in Wells 23-25. Since TGS Advisor identified that cheaper proppants with lower conductivity for those wells; we concluded that the operators of the wells tried to achieve very high conductivity fractures. That is why I increased the value of dimensionless conductivity factor. Finally, bauxite was fourth in the list of proppant recommended by TGS Advisor. Also, we found that the recommended API mesh sizes perfectly match API mesh sizes which were actually selected by the operators for all wells in Table 10 except Well 21 (Table 10). Thus, we are confident in the validity of TGS Advisor's approach for proppant type and API mesh recommendations.

| TABLE 9 – COMPARISON OF CALCULATED OPTIMAL FRACTURE HALF-LENGTH WITH FIELD DATA | | | | | | | | |
|---|-------------|----------|--------------|----------------|------------------|----------------------------------|-------------|--------------|
| # | SPE Paper # | Basin | Formation | Well | Permeability, md | Desired fracture half-length, ft | | Deviation, % |
| | | | | | | Actual | Recommended | |
| 1 | 67299 | S. Texas | Vicksburg | #1 | 0.090 | 500 | 492 | 2 |
| 2 | 67299 | S.Texas | Frio | #B | 0.800 | 400 | 407 | 2 |
| 3 | 36471 | W. Texas | Wolfcamp | Mitchell 6#5 | 0.010 | 600 | 578 | 4 |
| 4 | 36471 | W. Texas | Wolfcamp | Mitchell 5B#6 | 0.010 | 600 | 578 | 4 |
| 5 | 36471 | W.Texas | Wolfcamp | Mitchell 5B#7 | 0.010 | 600 | 578 | 4 |
| 6 | 36471 | W. Texas | Wolfcamp | Mitchell 5a#8 | 0.010 | 600 | 578 | 4 |
| 7 | 36471 | W. Texas | Wolfcamp | Mitchell 11#6 | 0.010 | 600 | 578 | 4 |
| 8 | 67299 | S. Texas | Frio | #A | 0.150 | 400 | 472 | 18 |
| 9 | 11600 | S. Texas | Wilcox Lobo | 1 | 0.100 | 750 | 488 | 35 |
| 10 | 30532 | Germany | Rotliegendes | Soehlingen Z10 | 0.010 | 350 | 578 | 65 |
| 11 | 35196 | Permian | Penn | McDonald 15-10 | 0.023 | 240 | 546 | 128 |
| 12 | 36735 | Permian | Canyon | Couch #7 | 0.010 | 200 | 578 | 189 |
| 13 | 36735 | Permian | Canyon | Henderson 32-9 | 0.010 | 200 | 578 | 189 |
| 14 | 35196 | Permian | Canyon | Henderson 6-2 | 0.054 | 170 | 512 | 201 |

| TABLE 10 – VALIDATION OF THE PROPPANT SELECTION SUBROUTINE | | | | | | | | | | | | | | |
|--|-------------|-------------|----------------------|----------------|--------------------|-------------|----|--------------------------------------|-----------------------------|---------------|-------------|-----------|------------------|---------------------------|
| # | SPE Paper # | Basin | Formation | Well | Proppant type | | Cr | Sand closure stress gradient, psi/ft | Proppant concentration, psf | API Mesh size | | Depth, ft | Permeability, md | Reservoir temperature, °F |
| | | | | | Actual | Recommended | | | | Actual | Recommended | | | |
| 1 | 30532 | Germany | Rotliegendes | Soehlingen Z10 | ISP, RCISP | 1 | 10 | 0.64 | 4.00 | 20/40 | 20/40 | 15687 | 0.010 | 200 |
| 2 | 36735 | Permian | Canyon | Couch #7 | Sand | 1 | 10 | 0.83 | 0.50 | 20/40 | 20/40 | 6500 | 0.010 | 170 |
| 3 | 36735 | Permian | Canyon | Henderson 32-9 | Sand | 1 | 10 | 0.83 | 0.50 | 20/40 | 20/40 | 6400 | 0.010 | 170 |
| 4 | 35196 | Permian | Canyon | Henderson 6-2 | Sand | 1 | 10 | 0.67 | 0.50 | 20/40 | 20/40 | 6260 | 0.054 | 170 |
| 5 | 35196 | Permian | Penn | McDonald 15-10 | Sand | 1 | 10 | 0.73 | 0.70 | 20/40 | 20/40 | 3608 | 0.023 | 180 |
| 6 | 36471 | W.Texas | Wolfcamp | Mitchell 6#5 | Sand, precured RCS | 1 | 10 | 0.71 | 2.20 | 20/40 | 20/40 | 7700 | 0.010 | 200 |
| 7 | 36471 | W.Texas | Wolfcamp | Mitchell 5B#6 | Sand, precured RCS | 1 | 10 | 0.78 | 2.70 | 20/40 | 20/40 | 7950 | 0.010 | 200 |
| 8 | 36471 | W.Texas | Wolfcamp | Mitchell 5B#7 | Sand, precured RCS | 1 | 10 | 0.74 | 1.20 | 20/40 | 20/40 | 7850 | 0.010 | 200 |
| 9 | 36471 | W.Texas | Wolfcamp | Mitchell 5a#8 | Sand, precured RCS | 1 | 10 | 0.70 | 1.10 | 20/40 | 20/40 | 7950 | 0.010 | 200 |
| 10 | 36471 | W.Texas | Wolfcamp | Mitchell 11#6 | Sand, precured RCS | 1 | 10 | 0.82 | 0.40 | 20/40 | 20/40 | 9800 | 0.010 | 200 |
| 11 | 103591 | W.Texas | Canyon | 1 | RCS | 2 | 10 | 0.87 | 2.00 | 20/40 | 20/40 | 5499 | 0.073 | 170 |
| 12 | 103591 | S.Texas | Frio | 2 | RCS | 2 | 10 | 0.63 | 2.00 | 20/40 | 20/40 | 9363 | 0.018 | 200 |
| 13 | 67299 | Green River | Frontier, Bear River | 167 | LWP | 2 | 10 | 0.73 | 0.65 | 20/40 | 20/40 | 7500 | 0.050 | 150 |
| 14 | 67299 | S.Texas | Vicksburg | #1 | LWP | 1 | 8 | 0.77 | 1.80 | 20/40 | 20/40 | 9350 | 0.090 | 265 |
| 15 | 76812 | S.Texas | Wilcox Lobo | A | RCS | 1 | 5 | 0.71 | 2.00 | 16/30 | 16/30 | 7800 | 0.100 | 250 |
| 16 | 76812 | S. Texas | Wilcox Lobo | B | RCS | 1 | 5 | 0.71 | 2.00 | 16/30 | 16/30 | 7800 | 0.100 | 250 |
| 17 | 11600 | S.Texas | Wilcox Lobo | 1 | Sand | 1 | 1 | 0.71 | 2.00 | 20/40 | 20/40 | 10000 | 0.100 | 250 |
| 18 | 67299 | S.Texas | Frio | #A | LWP | 2 | 1 | 0.74 | 2.00 | 20/40 | 20/40 | 9000 | 0.150 | 250 |
| 19 | 67299 | S.Texas | Frio | #B | RCS | 2 | 1 | 0.74 | 2.00 | 20/40 | 20/40 | 9000 | 0.800 | 250 |

| TABLE 10 – CONTINUED | | | | | | | | | | | | | | |
|----------------------|-------------|---------|-----------|----------|---------------|-------------|----|--------------------------------------|-----------------------------|---------------|-------------|-----------|------------------|---------------------------|
| # | SPE Paper # | Basin | Formation | Well | Proppant type | | Cr | Sand closure stress gradient, psi/ft | Proppant concentration, psf | API Mesh size | | Depth, ft | Permeability, md | Reservoir temperature, °F |
| | | | | | Actual | Recommended | | | | Actual | Recommended | | | |
| 20 | 27722 | S.Texas | Vicksburg | Slick#73 | RCS | 4 | 1 | 0.80 | 2.00 | 20/40 | 20/40 | 10000 | 0.100 | 300 |
| 21 | 94002 | S.Texas | Vicksburg | 1 | RCS | 3 | 1 | 0.78 | 2.00 | 16/30 | 20/40 | 9310 | 0.100 | 300 |
| 22 | 39951 | S.Texas | Vicksburg | B | RCS | 4 | 1 | 0.80 | 2.00 | 20/40 | 20/40 | 10000 | 0.100 | 320 |
| 23 | 99720 | S.Texas | Vicksburg | A | Bauxite | 4 | 20 | 0.80 | 2.00 | 20/40 | 20/40 | 10000 | 0.005 | 300 |
| 24 | 82241 | S.Texas | Vicksburg | SMA_1 | Bauxite | 4 | 35 | 0.80 | 2.00 | 16/30 | 20/40 | 9500 | 0.008 | 340 |
| 25 | 82241 | S.Texas | Vicksburg | Norm_1 | Bauxite | 4 | 35 | 0.80 | 2.00 | 16/30 | 20/40 | 9500 | 0.003 | 340 |

5. CONCLUSIONS

The results of this research project have led to the following conclusions:

- In perforation for stimulation, perforation phasing should be 0° , 60° , or 180° , and the length of perforation interval as well as perforation shot density should be limited to a certain optimal value.
- Applicability of every proppant should be evaluated individually, rather than as a part of the particular proppant type.
- A combination of a fuzzy logic approach and an “IF-THEN” expert system methodology is an excellent way to program practical knowledge derived from critically evaluated publicly available data and information coupled with opinions from subject-matter experts. TGS Advisor can be developed into a permanent, practical, applicable depository of industry knowledge and experience.
- TGS Advisor produces consistent recommendations that should assist decision making while developing TGS reservoirs, as well as to facilitate development and improve the economics of developing TGS reservoirs.
- Using TGS Advisor to capture the most important completion and stimulation parameters will be extremely useful for new frontier TGS developments and exploration wells, especially when an operator does not have much experience in such matters. The TGS Advisor’s recommendations used at the initial development stage can be further modified and improved while an operator gains more information and experience about a particular field.
- Young engineers can derive benefits from using TGS Advisor, while they make completion/stimulation decisions. First, TGS Advisor prevents inexperienced engineers from making unreasonable decisions and focuses them on a few potentially applicable solutions. Second, TGS Advisor can be used as a training tool to decipher to engineers experience collected about technologies and techniques used in TGS development.
- Recommendations generated by TGS Advisor can be applied in TGS reservoirs worldwide.

NOMENCLATURE

| | |
|-------------------|---|
| a | – correlation coefficient |
| b | – correlation coefficient |
| k | – formation permeability, md |
| k_h | – horizontal formation permeability, md |
| k_v | – vertical formation permeability, md |
| A | – drainage area, acres |
| Cr | – dimensionless fracture conductivity factor |
| Dr | – damage factor |
| E | – Young's modulus |
| $F_{180}(E)$ | – 180° phasing membership function for Young's modulus |
| $F_{180}(HC)$ | – 180° phasing membership function for horizontal stress contrast |
| $F_{180}(NF)$ | – 180° phasing membership function for natural fractures |
| $F_{180}(SP)$ | – 180° phasing membership function for sand production |
| $F_{60}(E)$ | – 60° phasing membership function for Young's modulus |
| $F_{60}(HC)$ | – 60° phasing membership function for Young's modulus |
| $F_{60}(NF)$ | – 60° phasing membership function for Young's modulus |
| $F_{60}(SP)$ | – 60° phasing membership function for Young's modulus |
| I_{180} | – perforation phasing index for 180° phasing |
| I_{60} | – perforation phasing index for 60° phasing |
| L_f | – optimal fracture half-length, ft |
| N_{perf} | – number of perforations |
| $P_{fr.tub}$ | – pressure drop because of friction in the tubing, psi |
| P_h | – hydrostatic pressure, psi |
| P_{net} | – pressure inside the fracture, psi |
| $P_{surface}$ | – surface treatment pressure, psi |
| P_{tort} | – pressure due to tortuosity, psi |
| Q | – fracturing fluid flow rate, bpm |
| W_E | – weighting factor for Young's modulus |
| W_{HC} | – weighting factor for horizontal stress contrast |
| W_{NF} | – weighting factor for natural fractures |
| W_{SP} | – weighting factor for sand production |
| ΔP_{Perf} | – pressure drop across the perforations, psi |
| μ | – formation fluid viscosity, cP |
| ρ | – density of the fracturing fluid, lbm/gal |

| | |
|----------------|----------------------------------|
| σ_{min} | – minimum horizontal stress, psi |
| ANN | – Artificial Neural Network |
| DIP | – Deformable Isometric Particles |
| HIP | – High-impact Parameters |
| LRS | – Liquid Resin System |
| LWP | – Lightweight Proppant |
| RCP | – Resin Coated Proppant |
| SMA | – Surface Modification Agent |
| SPF | – shots/ft |
| TGS | – Tight Gas Sand |
| TGS Advisor | – Tight Gas Sand Advisor |
| UGR | – Unconventional Gas Reservoir |
| VBA | – Visual Basic for Applications |

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APPENDIX A

SOURCE CODE OF THE PERFORATION SELECTION SUBROUTINE

```

Option Explicit
Public Youngs_modulus, Cell_60_Row, Cell_60_Col, _
Perf_D, Inj_Rate, Payzone_Thickness, Hor_Str_Contr, Layer_Bar_Stress_Contr,
Num_of_Fr, Netpay_Thickness, Well_Form_Angle As Integer
Public Exploration_well, Naturally_fractured, Sand_Prod, Perf_Gun_Cent As Boolean
Public Output_60, Interval_Output, Error As String

Sub Main()
Cell_60_Row = 28
Cell_60_Col = 1
Call Refresh_Screen
Call DataInput
Call Interval
Call Phasing

Veryend:
End Sub

Sub DataInput()
Dim name As String
Dim indr, indc As Integer
Dim value
indr = 0

Do
    indc = 1
    indr = indr + 1
    Worksheets("InputData").Cells(indr, indc).Select
    name = Cells(indr, indc)
    Selection.Font.ColorIndex = 5
    value = ActiveCell.Offset(0, 1).Range("A1").value

    If (name = "Exploration well") Then Call TrueFalse(value, Exploration_well)
    If (name = "Youngs modulus") Then Youngs_modulus = value
    If (name = "Naturally fractured") Then Naturally_fractured = value
    If (name = "Pay zone thickness") Then Payzone_Thickness = value
    If (name = "Net-pay thickness") Then Netpay_Thickness = value
    If (name = "Number of separate fractures") Then Num_of_Fr = value
    If (name = "Formation sand production") Then Call TrueFalse(value, Sand_Prod)

```

```

    If (name = "Horizontal stress contrast") Then Hor_Str_Contr = value
    If (name = "Layer/Barrier stress contrast") Then Layer_Bar_Stress_Cont = value
    If (name = "Well position relative to bed boundaries") Then Well_Form_Angle =
value
    If (name = "Possible to centralize perforatoin gun in the well") Then Call
TrueFalse(value, Perf_Gun_Cent)

```

```

    Loop Until indr = 20
    If Payzone_Thickness = Netpay_Thickness And Num_of_Fr <> 1 Then
        Error = MsgBox("Netpay thickness is equal to Payzone thickness; so only one layer is
viable.", vbOK)
    End If

```

```

    If Payzone_Thickness < Netpay_Thickness Then Error = MsgBox("Payzone thickness
can not be lower than Netpay thickness.", vbOK)

```

```

End Sub

```

```

Sub Refresh_Screen()
    Sheets("InputData").Select
    Range(Cells(1, 1), Cells(Cell_60_Row - 8, 1)).ClearFormats
    Cells(Cell_60_Row - 5, Cell_60_Col + 7).ClearContents
    Cells(Cell_60_Row - 5, Cell_60_Col + 6).ClearContents
    Cells(Cell_60_Row - 4, Cell_60_Col + 7).ClearContents
    Cells(Cell_60_Row - 4, Cell_60_Col + 6).ClearContents
    Cells(Cell_60_Row - 4, Cell_60_Col + 1).ClearContents
    Cells(Cell_60_Row - 5, Cell_60_Col + 6).Select

```

```

    End Sub
Sub TrueFalse(x1 As Variant, x2)

```

```

Dim TrF As Boolean

```

```

If x1 = 1 Then
    TrF = True
Else: TrF = False
End If

```

```

x2 = TrF

```

```

End Sub

```

```

Sub Interval()
    Dim Interval_Output_2, Int_Length_1, Int_Length_2, Int_Length_1_Com,
Int_Length_2_Com
    Int_Length_1 = Netpay_Thickness
    Int_Length_2 = ""

```

```

Int_Length_1_Com = ""
Int_Length_2_Com = ""
Interval_Output = "Perforate entire layer(s)"

If Payzone_Thickness > 50 And Payzone_Thickness < 150 Then

    If Netpay_Thickness > 50 Then

        Interval_Output = "Perforate most porous zone(s) within the layer(s)"
        Int_Length_1 = 20 * Num_of_Fr

        If Num_of_Fr <= 3 Then

            If Layer_Bar_Stress_Cont = 1 Or Well_Form_Angle = 3 Or
(Layer_Bar_Stress_Cont = 2 And Well_Form_Angle = 2) Then
                Interval_Output_2 = "Point-Source Perforation Technique"
                Int_Length_2 = 5 * Num_of_Fr
                Int_Length_2_Com = "Default value"
            End If

        End If

        If Num_of_Fr >= 4 Then
            Interval_Output = "Perforate zones with major gas-in-place"
            Int_Length_1 = Netpay_Thickness
            Int_Length_1_Com = "Maximum possible value"

            Interval_Output_2 = "Limited Entry Technique"
            Int_Length_2 = Netpay_Thickness
        End If

    End If
End If

If Payzone_Thickness >= 150 Then
    Interval_Output = "Limited Entry Technique"
    Int_Length_1 = Netpay_Thickness
End If

If Sand_Prod = True And Payzone_Thickness < 150 And Int_Length_1 > 20 *
Num_of_Fr Then
    Int_Length_1 = 20 * Num_of_Fr
    Int_Length_1_Com = "Because of fines migration perforated interval in each layer
should be limited to 20 ft"
End If

```


If Int_Length_1 > Netpay_Thickness Then

 Int_Length_1 = Netpay_Thickness

 Int_Length_1_Com = ""

End If

If Naturally_fractured = 3 Then

 Int_Length_1 = 6 * Num_of_Fr

 Int_Length_1_Com = "Becuase of the reservoir is naturally fractured perforation interval in each layer should be limited to 6 ft"

End If

If Naturally_fractured = 2 Then

 Int_Length_2 = 6 * Num_of_Fr

 Interval_Output_2 = "Perforate most porous zone(s) within the layer(s)"

 Int_Length_2_Com = "Becuase of the reservoir is naturally fractured perforation interval in each layer should be limited to 6 ft"

End If

Cells(Cell_60_Row - 5, Cell_60_Col + 1).value = Interval_Output

Cells(Cell_60_Row - 4, Cell_60_Col + 1).value = Interval_Output_2

Cells(Cell_60_Row - 5, Cell_60_Col + 6).value = Int_Length_1

Cells(Cell_60_Row - 4, Cell_60_Col + 6).value = Int_Length_2

Cells(Cell_60_Row - 5, Cell_60_Col + 7).value = Int_Length_1_Com

Cells(Cell_60_Row - 4, Cell_60_Col + 7).value = Int_Length_2_Com

End Sub

Sub Phasing()

Dim WF_NF, WF_YM, f_NF_180, f_NF_60, f_YM_180, f_YM_60, f_180, f_60,

Output_180, Output2, f_SP_180, _

f_HS_60, f_HS_180, WF_SP, WF_HS, f_SP_60, Opt, Output_0

WF_NF = 0.2875

WF_YM = 0.2875

WF_SP = 0.1375

WF_HS = 0.2875

f_NF_180 = 0

f_NF_60 = 0.8

f_YM_180 = 0

f_YM_60 = 0

f_180 = 0

f_60 = 0

f_SP_180 = 0

f_SP_60 = 0.5

f_HS_180 = 1

f_HS_60 = 0

Output_0 = "No"

If Exploration_well = True Then Output2 = "Proppellant assisted perforation w/o HF, put on production immediately after perforation"

If Perf_Gun_Cent = False Then

Output_0 = "Yes"

Output_60 = "No"

Output_180 = "No"

f_60 = 1

f_180 = 1

GoTo ZeroPh

End If

If Naturally_fractured = 2 Then

f_NF_180 = 0.5

f_NF_60 = 0.5

End If

If Naturally_fractured = 3 Then

f_NF_180 = 1

f_NF_60 = 0

End If

If Youngs_modulus >= 5 Then

f_YM_180 = $1 / (1 + 1.6^{(-\text{Youngs_modulus} + 5)})$

f_YM_60 = $0.7 / (0.7 + 4^{(\text{Youngs_modulus} - 5)})$

Else

f_YM_180 = $0.1 * \text{Youngs_modulus}$

f_YM_60 = $1 - \text{Exp}((\text{Youngs_modulus} - 5.8) / 1.5)$

End If

If Sand_Prod = True Then

f_SP_180 = 1

f_SP_60 = 0

End If

If Hor_Str_Contr = 2 Then

f_HS_180 = 0.4

f_HS_60 = 0.5

End If

If Hor_Str_Contr = 3 Then

f_HS_180 = 0

f_HS_60 = 0.8

End If

```

f_180 = f_NF_180 * WF_NF + f_YM_180 * WF_YM + f_SP_180 * WF_SP +
f_HS_180 * WF_HS
f_60 = f_NF_60 * WF_NF + f_YM_60 * WF_YM + f_SP_60 * WF_SP + f_HS_60 *
WF_HS

```

```

If f_180 <= f_60 Then
Output_60 = "Yes"
Output_180 = "No"

```

```

Else
Output_60 = "No"
Output_180 = "Yes"

```

```

    If f_YM_180 < 0.5 Then
    Opt = "Optional: perforation oriented with maximum horisonatal stress"
    Else
    Opt = "Perforation oriented with maximum horizontal stress, high-energy large
perforation, shots close together"
    End If
End If

```

```

ZeroPh:
Cells(Cell_60_Row - 1, Cell_60_Col + 1).value = Output_0
Cells(Cell_60_Row, Cell_60_Col + 1).value = Output_60
Cells(Cell_60_Row + 1, Cell_60_Col + 3).value = Opt
Cells(Cell_60_Row + 1, Cell_60_Col + 1).value = Output_180
Cells(Cell_60_Row + 2, Cell_60_Col + 1).value = Output2
Cells(Cell_60_Row, Cell_60_Col + 2).value = f_60
Cells(Cell_60_Row + 1, Cell_60_Col + 2).value = f_180

```

```

End Sub

```

```

Sub Shot_Density()
Dim Rate_per_Perf_Min, Rate_per_Perf_Max, Ph_Ef, Shot_Density_Min,
Shot_Density_Max, Interval, Response, Response2, Response3, Response4, Technique, _
indc, indr, name, value, Opt_Row

```

```

Cell_60_Row = 28
Cell_60_Col = 1
Interval = Cells(Cell_60_Row - 5, Cell_60_Col + 6).value
Technique = Cells(Cell_60_Row - 5, Cell_60_Col + 1).value
Rate_per_Perf_Min = 0.25
Rate_per_Perf_Max = 0.5

```

```

Do

```

```

    indc = 1
    indr = indr + 1
    Worksheets("InputData").Cells(indr, indc).Select
    name = Cells(indr, indc)
    Selection.Font.ColorIndex = 5
    value = ActiveCell.Offset(0, 1).Range("A1").value
    If (name = "Perforation diameter") Then Perf_D = value
    If (name = "Injection rate") Then Inj_Rate = value
Loop Until indr = 20

```

If Cells(Cell_60_Row - 4, Cell_60_Col + 1).value = "" Then GoTo Option1_2:

Response4 = MsgBox("If you prefer to use Option 1 from Perforation Interval Output click 'Yes'. Click 'No' to use Option 2", vbYesNo)

```

    If Response4 = 6 Then
        Technique = Cells(Cell_60_Row - 5, Cell_60_Col + 2)
        Interval = Cells(Cell_60_Row - 5, Cell_60_Col + 6)
        Opt_Row = Cell_60_Row - 5
    Else
        Technique = Cells(Cell_60_Row - 4, Cell_60_Col + 2)
        Interval = Cells(Cell_60_Row - 4, Cell_60_Col + 6)
        Opt_Row = Cell_60_Row - 4
    End If

```

Option1_2:

```

If Technique = "Limited Entry Technique" Then
    Rate_per_Perf_Min = 1
    Rate_per_Perf_Max = 2
End If

```

```

Ph_Ef = 1
If Cells(Cell_60_Row, Cell_60_Col + 1).value = "Yes" Then Ph_Ef = 3
If Cells(Cell_60_Row - 1, Cell_60_Col + 1).value = "Yes" Then Ph_Ef = 0.5

```

```

Shot_Density_Min = Inj_Rate / Rate_per_Perf_Max / Perf_D ^ 2 * 0.09 * Ph_Ef /
Interval
Shot_Density_Max = Inj_Rate / Rate_per_Perf_Min / Perf_D ^ 2 * 0.09 * Ph_Ef /
Interval

```

```

If Shot_Density_Min > 12 Then Shot_Density_Min = 12
If Shot_Density_Max > 12 Then Shot_Density_Max = 12

```

Cells(Cell_60_Row + 5, Cell_60_Col + 1).value = Shot_Density_Min

```
Cells(Cell_60_Row + 6, Cell_60_Col + 1).value = Shot_Density_Max
```

```
End Sub
```

APPENDIX B

SOURCE CODE OF THE PROPPANT SELECTION SUBROUTINE

```

Option Explicit
Public BHT, Form_Closure_Stress, Length, Length_Ad, Form_Perm, Gas_Visc,
Cond_Factor, Xf, Prop_Surf_Conc, _
Depth, indc, indr, Prop_Slurry_Conc, row, Length_Name, Length_Perm_Data,
Length_Prop_Size, Output_Row, _
Output_Col, Length_Pre_Prop_Size, Num_of_Prop, Num_of_Prop_Ukn_Con As
Integer

Public Perf_D, Dyn_Fr_Width, wkf As Double

Public name, Prop_Name, dbFilename, Comments As String

Public Selected_Additive(1 To 100), Additive(1 To 100), Ad_Temp_Min(1 To 100),
Ad_Temp_Max(1 To 100), _
Prop_Size(1 To 50), Ad_Stress_Min(1 To 100), Ad_Stress_Max(1 To 100), Ad_Desc(1
To 100), Prop_Diam(1 To 50), _
Prop_Cond(1 To 200) As Variant

Public a, b, c, d, e, f, g, h, i, j, k, l, m, o, p, value, DB_data(), Perm_Data() As Variant

Public Length_Interval_Long, Number_Intervals_Single, Proppant_Flowback,
Fines_Mig As Boolean

Sub Main()
'Row and Column indexes of the cell where the first output is to be printed
Output_Row = 31
Output_Col = 1

Call Refresh_Screen
Call DataInput
Call Calculation
End Sub

Sub DataInput()

indr = 0

Do
    indc = 1
    indr = indr + 1

```

```
Worksheets("InputData").Cells(indr, indc).Select
name = Cells(indr, indc)
Selection.Font.ColorIndex = 5
value = ActiveCell.Offset(0, 1).Range("A1").value
```

```
If (name = "END") Then Exit Do
```

```
If name = "Length of Perforated Interval" Then
```

```
    If value <= 2 Then
```

```
        Length_Interval_Long = False
```

```
    Else: Length_Interval_Long = True
```

```
    End If
```

```
End If
```

```
If (name = "Formation Depth") Then Depth = value
```

```
If (name = "Bottomhole temperature") Then BHT = value
```

```
If (name = "Number of Perforated Intervals") Then Call TrueFalse(value,  
Number_Intervals_Single)
```

```
    If (name = "Proppant Flowback Problem") Then Call TrueFalse(value,  
Proppant_Flowback)
```

```
    If (name = "Formation Permeability") Then Form_Perm = value
```

```
    If (name = "Gas Viscosity") Then Gas_Visc = value
```

```
    If (name = "Desired Dimensionless Conductivity") Then Cond_Factor = value
```

```
    If (name = "Dynamic Fracture Width") Then Dyn_Fr_Width = value
```

```
'Proppant concentration
```

```
    If (name = "1") Then
```

```
        Prop_Slurry_Conc = value
```

```
        Prop_Surf_Conc = Prop_Slurry_Conc * Dyn_Fr_Width * 0.623
```

```
    End If
```

```
    If (name = "2") Then
```

```
        Prop_Surf_Conc = value
```

```
        Prop_Slurry_Conc = Prop_Surf_Conc / Dyn_Fr_Width / 0.623
```

```
    End If
```

```
'Formation closure stress
```

```
    If (name = "3") Then
```

```
        Form_Closure_Stress = value
```

```
    End If
```

```
    If (name = "4") Then
```

```
        Form_Closure_Stress = value * Depth
```

```
    End If
```

```
If (name = "Perforation Diameter") Then Perf_D = value
```

```
If (name = "Formation Fines Migration") Then Call TrueFalse(value, Fines_Mig)
```

Loop Until name = "End of Input Data"

indc = 10

indr = 1

Do

Worksheets("InputData").Cells(indr, indc).Select

name = Cells(indr, indc)

Selection.Font.ColorIndex = 5

'Read additives' data

If (name = "Flowback Control Additives") Then

p = 0

Do

p = p + 1

Additive(p) = Cells(p + indr, indc).value

Ad_Temp_Min(p) = Cells(p + indr, indc + 1).value

Ad_Temp_Max(p) = Cells(p + indr, indc + 2).value

Ad_Stress_Min(p) = Cells(p + indr, indc + 3).value

Ad_Stress_Max(p) = Cells(p + indr, indc + 4).value

Ad_Desc(p) = Cells(p + indr, indc + 5).value

Loop Until Additive(p) = ""

Length_Ad = p

End If

indr = indr + 1

Loop Until name = ""

'Identify appropriate proppant mesh sizes

If Form_Closure_Stress >= 8000 Or BHT >= 275 Or Depth >= 10000 Or Fines_Mig = True Then

'Diameters are maximum for the mesh size; [microns x conv.factor]=inch

Prop_Size(1) = "20/40"

Prop_Diam(1) = 850 * 0.0000394

Prop_Size(2) = "30/50"

Prop_Diam(2) = 600 * 0.0000394

Prop_Size(3) = "30/60"

Prop_Diam(3) = 595 * 0.0000394

Prop_Size(4) = "40/60"


```

Prop_Diam(4) = 425 * 0.0000394
Prop_Size(5) = "40/70"
Prop_Diam(5) = 425 * 0.0000394
Length_Pre_Prop_Size = 5

Else
Prop_Size(1) = "8/12"
Prop_Diam(1) = 2380 * 0.0000394
Prop_Size(2) = "8/16"
Prop_Diam(2) = 2380 * 0.0000394
Prop_Size(3) = "12/18"
Prop_Diam(3) = 1680 * 0.0000394
Prop_Size(4) = "12/20"
Prop_Diam(4) = 1700 * 0.0000394
Prop_Size(5) = "14/20"
Prop_Diam(5) = 1410 * 0.0000394
Prop_Size(6) = "14/30"
Prop_Diam(6) = 1410 * 0.0000394
Prop_Size(7) = "16/20"
Prop_Diam(7) = 1180 * 0.0000394
Prop_Size(8) = "16/30"
Prop_Diam(8) = 1180 * 0.0000394
Prop_Size(9) = "20/40"
Prop_Diam(9) = 850 * 0.0000394
Prop_Size(10) = "30/50"
Prop_Diam(10) = 600 * 0.0000394
Prop_Size(11) = "30/60"
Prop_Diam(11) = 595 * 0.0000394
Prop_Size(12) = "40/60"
Prop_Diam(12) = 425 * 0.0000394
Prop_Size(13) = "40/70"
Prop_Diam(13) = 425 * 0.0000394
Length_Pre_Prop_Size = 13
End If

End Sub

```

```

Function ScanBlank(x As String) As String
Dim i As Integer, j As Integer
Dim c As String
i = 1
c = x
For i = 1 To Len(c)
If Left(c, 1) = " " Then
c = Mid(c, 2)
Else

```

```

For j = 1 To Len(c)
    If Right(c, 1) = " " Then
        c = Mid(c, 1, Len(c) - 1)
    Else
        ScanBlank = c
        Exit Function
    End If
Next
End If
Next
ScanBlank = ""
End Function
Sub Refresh_Screen()
    'Clear old results
    Sheets("InputData").Select
    Range(Cells(1, 1), Cells(1, Output_Row - 5)).ClearFormats
    Range(Cells(1, 10), Cells(Output_Row - 5, 10)).ClearFormats
    Sheets("InputData").Range("A1:BS1").ClearFormats
    Sheets("InputData").Range(Cells(Output_Row, Output_Col), Cells(Output_Row + 100,
Output_Col + 50)).ClearContents ' Clears main proppant output table
    Sheets("InputData").Range(Cells(Output_Row, Output_Col + 12), Cells(Output_Row +
10, Output_Col + 18)).ClearContents 'Clears additives table

    Range(Cells(Output_Row, Output_Col), Cells(Output_Row + 70, Output_Col +
10)).Select
    Selection.Borders(xlDiagonalDown).LineStyle = xlNone
    Selection.Borders(xlDiagonalUp).LineStyle = xlNone
    With Selection.Borders(xlEdgeLeft)
        .LineStyle = xlContinuous
        .Weight = xlThin
        .ColorIndex = xlAutomatic
    End With
    With Selection.Borders(xlEdgeTop)
        .LineStyle = xlContinuous
        .Weight = xlThin
        .ColorIndex = xlAutomatic
    End With
    With Selection.Borders(xlEdgeBottom)
        .LineStyle = xlContinuous
        .Weight = xlThin
        .ColorIndex = xlAutomatic
    End With
    With Selection.Borders(xlEdgeRight)
        .LineStyle = xlContinuous
        .Weight = xlThin

```

```

        .ColorIndex = xlAutomatic
    End With
    With Selection.Borders(xlInsideVertical)
        .LineStyle = xlContinuous
        .Weight = xlThin
        .ColorIndex = xlAutomatic
    End With
    With Selection.Borders(xlInsideHorizontal)
        .LineStyle = xlContinuous
        .Weight = xlThin
        .ColorIndex = xlAutomatic
    End With
    Selection.Interior.ColorIndex = 44

End Sub
Sub TrueFalse(x1 As Variant, x2)

Dim TrF As Boolean

If x1 = 1 Then
    TrF = True
Else: TrF = False
End If
x2 = TrF
End Sub

Sub Calculation()
Dim tc, tc1, Min_m, Min_Temp_Coef, Xf_Coef_a, Xf_Coef_b
Dim Temp_Coef(1 To 100) As Double

Dim Damage_Factor As Double
Dim Comment1, Comment2, Comment3 As String

Num_of_Prop = 0
Num_of_Prop_Ukn_Con = 0
'Check if perforation diameter and dynamic fracture width are capable to accomodate
selested proppant mesh sizes

' Optimum fracture half length
Xf_Coef_a = -0.1818 * Dr_Area - 24.62
Xf_Coef_b = 231.23 * Log(Dr_Area) - 615.37
Xf = Xf_Coef_a * Log(Form_Perm) + Xf_Coef_b

```

'Damage factor

If Form_Closure_Stress < 6000 Then Damage_Factor = Form_Closure_Stress / 2000 + 2

If Form_Closure_Stress >= 6000 Then

 If BHT >= 275 Or Depth >= 10000 Then

 Damage_Factor = 10

 Else: Damage_Factor = Form_Closure_Stress * 5 / 4000 - 2.5

 End If

End If

'Optimum fracture conductivity

wkf = 3.14 * Xf * Cond_Factor * Form_Perm * Damage_Factor

Cells(Output_Row - 5, Output_Col + 1).value = Xf

Cells(Output_Row - 4, Output_Col + 1).value = wkf

i = 0

Length_Prop_Size = 0

For p = 1 To Length_Pre_Prop_Size

 If (3 * Prop_Diam(p) <= Dyn_Fr_Width) And (6 * Prop_Diam(p) <= Perf_D) Then

 i = i + 1

 Prop_Size(i) = Prop_Size(p)

 Prop_Diam(i) = Prop_Diam(p)

 Length_Prop_Size = i

 End If

Next p

If Length_Prop_Size = 0 Then

 Cells(Output_Row, Output_Col).value = "Perforation diameter and/or dynamic fracture width are too small for available proppant mesh sizes"

 GoTo TheEnd

End If

'Select particular proppant and proppant size

'Extract data for proppants from the database

ChDir ThisWorkbook.Path

dbFilename = ThisWorkbook.Path & "\Proppant_DB.mdb"

'Identifiy reference closure stress

Dim Test_Stress

e = 4

Test_Stress = 2000

c = 1

```

While (Test_Stress - Form_Closure_Stress) < 0
  e = e + 1
  Test_Stress = Test_Stress + 2000
  If Test_Stress > 14000 Then
    Cells(Output_Row, Output_Col).value = "Manufacturers do not provide proppant
conductivity data at closure stress above 14000 psi"
    Call StressAbove14000
    GoTo 13
  End If
Wend

```

```

Call DB_select(dbFilename, "General")

```

```

'Extract additional data from the DB for particular proppant
For a = 1 To Length_Name ' Loop for Proppant names

```

```

  If BHT < DB_data(9, a) Or BHT > DB_data(10, a) Or Form_Closure_Stress <
DB_data(8, a) Or Form_Closure_Stress > DB_data(11, a) Then GoTo 9

```

```

  Prop_Name = DB_data(2, a)
  Call DB_select_Perm(dbFilename, "CONDUCTIVITY")

```

```

  For h = 1 To Length_Prop_Size 'Loop for required proppant mesh

```

```

    For b = 1 To Length_Perm_Data ' Loop to find required mesh size within all
recorded datapoints for particular proppant

```

```

      j = b ' beginning of the interval
      If Perm_Data(1, b) <> Prop_Size(h) Then GoTo 10

```

```

      'Identify interval of the dataset with required mesh size

```

```

      While Perm_Data(1, b) = Prop_Size(h)
        If b = Length_Perm_Data Then GoTo 11
        b = b + 1 'end of the interval
      Wend

```

```

      b = b - 1

```

```

11:

```

```

  'Find FIRST data records for an appropriate proppant concentration for every
considered mesh size

```

```

  While (Perm_Data(2, j) - Prop_Surf_Conc) < 0
    If j = b Then
      Call OutofData(" proppant concentration.")
      GoTo 10
    End If
    j = j + 1
  Wend

```

```

'Identify interval of the dataset with required concentration
If j = b Then ' it there is only one data point for this concentration
    m = b
    GoTo 12
Else
    m = j 'm - first datapoint with the required concentration
End If

```

```

'Length of the interval with the required concentration
While Perm_Data(2, j) = Perm_Data(2, j + 1)
    j = j + 1
    If j = b Then GoTo 15
Wend

```

15:

```

'Find data records with the closest temperature
tc1 = m
If tc1 < j Then

    For tc = m To j
        Temp_Coef(tc) = Abs((BHT - Perm_Data(3, tc)) / BHT)

    Next tc

    Min_Temp_Coef = Temp_Coef(tc1)

    For tc = tc1 To j
        If Min_Temp_Coef < Temp_Coef(tc + 1) Then
            Else
                Min_Temp_Coef = Temp_Coef(tc + 1)
                Min_m = tc + 1
            End If
        Next tc
    m = Min_m
End If

```

12:

```

'Linear interpolation for proppant conductivity depending on formation closure
stress
If Form_Closure_Stress <= 2000 Then
    Prop_Cond(m) = 0.58 * (Test_Stress - Form_Closure_Stress) +
Perm_Data(e, m)
Else
    Prop_Cond(m) = Perm_Data(e - 1, m) + (Perm_Data(e, m) - Perm_Data(e -
1, m)) / 2000 * (Form_Closure_Stress - Test_Stress + 2000)
End If
'Compare fracture and proppant conductivities and perforation diameters
If Prop_Cond(m) > wkf Then

```

```

Cells(Output_Row + c, Output_Col).value = Perm_Data(11, m) 'Proppant
name
Cells(Output_Row + c, Output_Col + 1).value = DB_data(1, a)
'Manufacturer
Cells(Output_Row + c, Output_Col + 2).value = Prop_Cond(m)
Cells(Output_Row + c, Output_Col + 3).value = Perm_Data(1, m) 'Mesh
Size
Cells(Output_Row + c, Output_Col + 4).value = DB_data(3, a) 'Price
Cells(Output_Row + c, Output_Col + 5).value = DB_data(7, a) 'Discount
Cells(Output_Row + c, Output_Col + 6).value = DB_data(3, a) * (1 -
DB_data(7, a) / 100)
Cells(Output_Row + c, Output_Col + 7).value = DB_data(5, a) 'Proppant
type
Cells(Output_Row + c, Output_Col + 8).value = DB_data(4, a)
'Description
Cells(Output_Row + c, Output_Col + 10).value = DB_data(6, a) 'Specific
Gravity

If DB_data(5, a) = "Partially Cured Resin Coated Sand" Or DB_data(5, a)
= "Partially Cured Resin Coated Ceramics" Or DB_data(5, a) = "Precured Resin Coated
Sand" Or DB_data(5, a) = "Curable Resin Coated Sand" Or DB_data(5, a) = "Resin
Coated Ceramics" Or DB_data(5, a) = "Resin Coated Bauxite" Then
If Proppant_Flowback = True Then
Comment1 = "Resin Coated Proppant: Check compatibility with frac
fluid."
If Length_Interval_Long = True Or Number_Intervals_Single = False
Then Comment2 = "Resin Coated Proppant may not be effective when long or multiple
perforated interval are treated."
End If
Cells(Output_Row + c, Output_Col + 9).value = Comment1 +
Comment2
End If

Num_of_Prop = Num_of_Prop + 1
c = c + 1
'End If
End If
10:
Next b
Next h
9:
Next a
13:

```

If c = 1 Then Cells(Output_Row, Output_Col).value = "None of the proppants have required conductivity and/or suitable for these temperature and/or closure stress"

Call Price_Sort(Output_Row, Output_Col, Output_Col + 10, Num_of_Prop)

TheEnd:

'Select proppant flowback control additives if necessary

If Proppant_Flowback = True Then

o = 0

For p = 1 To Length_Ad

If BHT < Ad_Temp_Max(p) And BHT >= Ad_Temp_Min(p) Then

If Ad_Stress_Min(p) = "n/a" And Ad_Stress_Max(p) = "n/a" Then

o = o + 1

Selected_Additive(o) = Additive(p)

Cells(Output_Row - 1 + o, Output_Col + 12).value = Selected_Additive(o)

Cells(Output_Row - 1 + o, Output_Col + 12).value = Ad_Desc(p)

Else

If Ad_Stress_Min(p) < Form_Closure_Stress And Form_Closure_Stress < Ad_Stress_Max(p) Then

If Additive(p) = "DIPLS" Or Additive(p) = "DIPMS" Or Additive(p) = "DIPHS" Then

If Perf_D >= 0.25 Then

o = o + 1

Selected_Additive(o) = Additive(p)

Cells(Output_Row - 1 + o, Output_Col + 12).value =

Selected_Additive(o)

Cells(Output_Row - 1 + o, Output_Col + 12).value = Ad_Desc(p)

End If

Else

o = o + 1

Selected_Additive(o) = Additive(p)

Cells(Output_Row - 1 + o, Output_Col + 12).value =

Selected_Additive(o)

Cells(Output_Row - 1 + o, Output_Col + 12).value = Ad_Desc(p)

End If

End If

End If

End If

Next p

End If

End Sub


```
'For closure stress above 14000 psi
Sub StressAbove14000()
Dim a1, b1, h1
Call DB_select(dbFilename, "General")
```

```
For a1 = 1 To Length_Name
```

```
    If DB_data(8, a1) <= Form_Closure_Stress And DB_data(8, a1) >= 14000 Then
        Prop_Name = DB_data(2, a1)
        Call DB_select_Perm(dbFilename, "PERM")
        For h1 = 1 To Length_Prop_Size 'Loop for required mesh sizes
```

```
            For b1 = 1 To Length_Perm_Data ' Loop to find required mesh size within
all recorded datapoints for particular proppant
```

```
                If Perm_Data(1, b1) <> Prop_Size(h1) Then GoTo 9
```

```
8:
```

```
        'If Perf_D > Perf_D_Min(g) Then
            Cells(Output_Row + c, Output_Col).value = Perm_Data(11, b1)
'Proppant name
            Cells(Output_Row + c, Output_Col + 1).value = DB_data(1, a1)
'Manufacturer
            Cells(Output_Row + c, Output_Col + 2).value = "Unknown"
            Cells(Output_Row + c, Output_Col + 3).value = Perm_Data(1, b1) '
Mesh size
            Cells(Output_Row + c, Output_Col + 4).value = DB_data(3, a1) 'Price
            Cells(Output_Row + c, Output_Col + 5).value = DB_data(7, a1)
'Discount
            Cells(Output_Row + c, Output_Col + 6).value = DB_data(3, a1) * (1 -
DB_data(7, a1) / 100)
            Cells(Output_Row + c, Output_Col + 7).value = DB_data(5, a1)
'Proppant type
            Cells(Output_Row + c, Output_Col + 8).value = DB_data(4, a1)
'Description
            Cells(Output_Row + c, Output_Col + 10).value = DB_data(6, a)
'Specific Gravity
            Comment3 = "Although the conductivity data is not available for this
closure stress, the manufacturer suggests to use this proppant at closure stress above
14000 psi."
```

```
                If DB_data(5, a1) = "Partially Cured Resin Coated Sand" Or
DB_data(5, a1) = "Partially Cured Resin Coated Ceramics" Or DB_data(5, a1) =
```

```
"Precured Resin Coated Sand" Or DB_data(5, a1) = "Curable Resin Coated Sand" Or
DB_data(5, a1) = "Resin Coated Ceramics" Or DB_data(5, a1) = "Resin Coated Bauxite"
Then
```

```
    If Proppant_Flowback = True Then
        Comment1 = "Resin Coated Proppant: Check compatibility with
frac fluid."
```

```
        If Length_Interval_Long = True Or Number_Intervals_Single =
False Then Comment2 = "Resin Coated Proppant may not be effective when long or
multiple perforated interval are treated."
```

```
        End If
        Cells(Output_Row + c, Output_Col + 9).value = Comment3 +
Comment1 + Comment2
        End If
        c = c + 1
```

```
9:
```

```
    Next b1
    Next h1
    End If
    Next a1
End Sub
```

'Sub need when formation temperature and closure stress are within proppant's working conditions, but manufacturer did not provide the conductivity data.

```
Sub OutofData(Comments As String)
```

```
Cells(Output_Row + c, Output_Col).value = DB_data(2, a) 'Proppant name
Cells(Output_Row + c, Output_Col + 1).value = DB_data(1, a) 'Manufacturer
Cells(Output_Row + c, Output_Col + 2).value = "???"
Cells(Output_Row + c, Output_Col + 3).value = "See the database" 'Mesh size
Cells(Output_Row + c, Output_Col + 4).value = DB_data(3, a) 'Price
Cells(Output_Row + c, Output_Col + 5).value = DB_data(7, a) 'Discount
Cells(Output_Row + c, Output_Col + 6).value = DB_data(3, a) * (1 - DB_data(7, a) /
100)
Cells(Output_Row + c, Output_Col + 7).value = DB_data(5, a) 'Proppant type
Cells(Output_Row + c, Output_Col + 8).value = DB_data(4, a) 'Description
Cells(Output_Row + c, Output_Col + 9).value = "The proppant is suitable for the well
temperature and closure stress; however, the manufacturer does not provide conductivity
data for this" + Comments
Cells(Output_Row + c, Output_Col + 10).value = DB_data(6, a) 'Specific Gravity
c = c + 1
Num_of_Prop_Ukn_Con = Num_of_Prop_Ukn_Con + 1
```

```
End Sub
```

```

Private adoconnection As ADODB.Connection

Sub DB_select(ByVal dbFilename As String, ByVal TabName As String)
Dim thesql As String
Dim adorecordset As ADODB.Recordset
Dim col As Integer
Call DB_open(dbFilename) ' open the database
On Error GoTo Err

' reading particular table in the database
Set adorecordset = New ADODB.Recordset
'thesql = "SELECT * FROM Proppant_DB.General WHERE (TYPE = '" &
Selected_Prop_Type & "')"
thesql = "SELECT * FROM Proppant_DB.General"
adorecordset.Open (thesql), adoconnection '.adOpenStatic, adLockReadOnly

' All the data are stored inside DB_Data variable
ReDim DB_data(1 To adorecordset.Fields.Count, 0 To 1)

For col = 1 To adorecordset.Fields.Count
    row = 0
    DB_data(col, row) = adorecordset.Fields(col - 1).name
    If Not adorecordset.BOF Then adorecordset.MoveFirst
    Do While Not adorecordset.EOF
        row = row + 1
        If col = 1 Then ReDim Preserve DB_data(1 To adorecordset.Fields.Count, 0 To
row)
        If Len(adorecordset.Fields(col - 1)) > 0 Then DB_data(col, row) =
adorecordset.Fields(col - 1)
        adorecordset.MoveNext
    Loop
Next col
Length_Name = row
adorecordset.Close

Set adorecordset = Nothing

Exit Sub
Err:
MsgBox Err.Description
adorecordset.Close

Set adorecordset = Nothing
End Sub

Sub DB_select_Perm(ByVal dbFilename As String, ByVal TabName As String)

```

```

Dim thesql_Perm As String
Dim adorecordset1 As ADODB.Recordset
Dim col As Integer

On Error GoTo Err

'Call DB_open(dbFilename) ' open the database

' reading particular table in the database
Set adorecordset1 = New ADODB.Recordset

thesql_Perm = "SELECT * FROM Proppant_DB.CONDUCTIVITY WHERE
(TRADENAME = '' & Prop_Name & '')"
adorecordset1.Open (thesql_Perm), adoconnection

' All the data are stored inside DB_Data variable
ReDim Perm_Data(1 To adorecordset1.Fields.Count, 0 To 1)

For col = 1 To adorecordset1.Fields.Count
    row = 0
    Perm_Data(col, row) = adorecordset1.Fields(col - 1).name
    If Not adorecordset1.BOF Then adorecordset1.MoveFirst
    Do While Not adorecordset1.EOF
        row = row + 1
        If col = 1 Then ReDim Preserve Perm_Data(1 To adorecordset1.Fields.Count, 0 To
row)
        If Len(adorecordset1.Fields(col - 1)) > 0 Then Perm_Data(col, row) =
adorecordset1.Fields(col - 1)
        adorecordset1.MoveNext
    Loop
Next col
Length_Perm_Data = row
adorecordset1.Close

Set adorecordset1 = Nothing

Exit Sub
Err:
MsgBox Err.Description
adorecordset1.Close

Set adorecordset1 = Nothing
End Sub

Public Sub DB_ins_del_upd(ByVal thesql As String)

```

```
On Error GoTo Err
adoconnection.Execute thesql
Exit Sub
Err:
MsgBox Err.Description
End Sub
```

```
Public Sub DB_open(ByVal DBfile As String)
Dim connectstring As String
```

```
On Error GoTo Err
Set adoconnection = New ADODB.Connection
```

```
connectstring = "Provider=Microsoft.Jet.OLEDB.4.0;" _
& "Data Source=" & DBfile
```

```
adoconnection.Open connectstring
```

```
Exit Sub
Err:
MsgBox Err.Description
Call DB_close
End Sub
```

```
Public Sub DB_close()
On Error Resume Next
If adoconnection.State = adStateOpen Then
adoconnection.Close
Set adoconnection = Nothing
End If
End Sub
```

VITA

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This thesis was typed by the author.