We are IntechOpen, the world's leading publisher of Open Access books Built by scientists, for scientists

6,100
Open access books available

149,000
International authors and editors

185M
Downloads

Our authors are among the

154
Countries delivered to

TOP 1%
most cited scientists

12.2%
Contributors from top 500 universities

CLARIVATE ANALYTICS
BOOK CITATION INDEX
INDEXED

WEB OF SCIENCE™

Selection of our books indexed in the Book Citation Index
in Web of Science™ Core Collection (BKCI)

Interested in publishing with us?
Contact book.department@intechopen.com

Numbers displayed above are based on latest data collected.
For more information visit www.intechopen.com

Do Perforated Completions Have Value for Engineered Geothermal Systems

Walter Glauser, John McLennan and Ian Walton

Additional information is available at the end of the chapter

Abstract

Engineered or enhanced geothermal systems (EGS) differ from conventional hydrothermal reservoirs in that supplementary hydraulic stimulation is required to create surface area needed for heat exchange, and to allow adequate fluid production. Historically, geothermal wells have been straight hole or inclined and usually employ barefoot completions. If horizontal drilling and hydraulic fracturing experience, refined to some extent with recent shale gas and shale oil stimulation campaigns, can be adapted for geothermal applications, it may be possible to improve the chances for successful EGS. One central issue for vertical, inclined, extended reach or horizontally drilled wells is whether there is merit in landing and cementing casing. This would allow discrete zones to be fractured, isolate thief zones or low temperature zones, allow future remediation and facilitate generation of multiple fracture systems.

Most experienced geothermal operators balk at perforated and cemented completions. The arguments can be legitimate. There are supplementary costs associated with this completion, and the temperatures can make cementing and perforating challenging. Plugging of existing fracture systems from casing and cement is also proposed as a problem – which is easily overcome by the supplementary stimulation required. On the other hand, simple calculations suggest that proximal and interconnected fracture systems, natural or otherwise, are required for economic viability in all but the hottest scenarios. To effectively develop multiple fracture systems, wellbore isolation seems to be a natural requirement. One legitimate method to accomplish this is diversion, but the question remains as to how many intersected fractures can be stimulated. Another option is cementing and perforating. A comparative and realistic analysis is done to assess the impact of perforation skin, tortuosity associated with shear

fractures intersecting the wellbore and relative economics associated with perforating and cementing geothermal wells.

Keywords: geothermal, perforations, openhole, multiple fractures

1. Introduction

Engineered or enhanced geothermal systems (EGS) differ from conventional hydrothermal reservoirs in that supplementary hydraulic stimulation is required to create surface area needed for heat exchange, and to allow adequate fluid production. Historically, geothermal wells have been straight hole or inclined and usually employ barefoot completions. If horizontal drilling and hydraulic fracturing experience, refined to some extent with recent shale gas and shale oil stimulation campaigns, can be adapted for geothermal applications, it may be possible to improve the chances for successful EGS. One central issue, for horizontal, inclined, extended reach, or horizontally drilled wells, is whether there is merit in landing and cementing casing to allow discrete zones to be fractured, to isolate thief zones or low temperature zones, to allow future remediation and to facilitate generation of multiple fracture systems.

Most experienced geothermal operators balk at cased, cemented and perforated completions. The arguments can be legitimate. There are supplementary costs associated with this completion and the temperatures can make cementing and perforating challenging. Plugging of existing fracture systems during cementing is also proposed as a problem – which is easily overcome by the supplementary stimulation required. On the other hand, simple calculations suggest that proximal and interconnected fracture systems, natural or otherwise, are required for economic viability in all but the hottest scenarios. To effectively develop multiple fracture systems wellbore isolation seems to be a natural requirement. One legitimate possibility is diversion. The question remains how many intersected fractures can be stimulated? Another option is cementing and perforating. In this paper we undertake a comparative and realistic analysis to assess the impact of perforation skin, tortuosity associated with shear fractures intersecting the wellbore and relative economics associated with perforating and cementing geothermal wells.

2. Requirements for a Successful Geothermal Well (EGS)

Simple calculations suggest that proximal and interconnected fracture systems, natural or otherwise, are required for economic viability in all but the hottest geothermal scenarios. Currently, geothermally derived power is associated with "natural" hydrothermal systems. These are reasonably permeable and have equilibrated fluid circulation systems, with heat delivered by deep convection. They are characteristically naturally fractured and/or faulted, at least to some extent. Stimulation of fractured wells to enhance fracture conductivity is an opportunity for engineering massively stimulated systems – engi-

neered geothermal prospects – using hydraulic fracturing. Pritchett, 2012 [1], cautions that the practicality of these scenarios depends on fractures that are conductive enough to support the required high geothermal flow rates. "Performance will be significantly impaired if the average fracture separation is greater than 50 meters or so. … The creation of such extensive and pervasive artificial fracture networks at costs that will prove acceptable … is the fundamental challenge for EGS. … New stimulation paradigms may be required." These fractures need to be close enough together and appropriately oriented to encourage heat sweep and thermal energy recovery.

Following Pritchett's logic, for a very specialized generic reservoir analysis, assume 100 kg/s are required for an economic system. To adequately delay thermal breakthrough (on the order of 30 years), required fracture spacing varies from 20 to 70 m.The time to breakthrough decreases as the fracture spacing becomes larger. Wu et al., 2012 [59] demonstrate fracture spacing issues numerically.

What non-specialists don't always realize is the throughput that is required to ensure an economic geothermal prospect. If there is a single producer, the criterion for economic throughput is colloquially expressed as 100 kg/s by some; 2000 gal/minute by others. In any case, at 200°C this is between 62,000 and 69,000 BWPD at the sand face. To accommodate such high rates with nominal friction, large diameter casing is conventionally used with large diameter barefoot sections. This philosophy may be acceptable in conventional systems. If EGS is planned, large contact between one or more fractures and the wellbore is essential. Without effective diversion, multiple fracturing in an open hole is extremely difficult. Extended fracture contact with the well and/or multiple fracture intersections seem to be essential for EGS. This brings up the contentious topic of whether cased and perforated completions would be acceptable in geothermal environments.

3. Cemented versus barefoot completions

Even barefoot completions are cased and cemented over a substantial portion of their length. For example, deep geothermal wells in Australia have the casing set below 4000 m or so and are open hole below that for a length of 500 m. Similar situations exist at Raft River in the United States. Nevertheless, cemented completions across thermally-productive zones will allow isolation and multiple zones can be stimulated. For example, the advantages of a cemented completion include:

- **Potential for isolating fluid thief zones.** If low-pressure, shallow thief zones are present, crossflow can be avoided by casing across those zones.

- **Potential for isolating zones that bring in low temperature fluid.** There are many anecdotal examples of cooler fluids entering the wellbore uphole in uncased environments, jeopardizing overall economics. Even if these zones have been perforated, the possibility for plugging, while always difficult, is improved by squeezing perforations rather than an openhole section.

- **Potential for tactical perforating to initiate multiple fractures in a single wellbore.** This is potentially a huge advantage. In openhole, without diversion, fracture initiation will seek out major discontinuities and ultimately only a restricted number of these will develop. Isolation of individual zones can ensure at least local initiation of multiple fractures. Pre-existing fractures may be preferentially treated. Gale, 2008, [2] argued that natural fractures (healed) in certain shales opened at approximately 60% of the stress level needed to fracture the virgin formation. While this offers some potential to override the in-situ stress field, depending on the orientation of the fractures, there may be a greater chance of short-circuiting and minimizing new development of fracture surface area for heat exchange. Casing and selective perforating can avoid or incorporate pre-existing fractures at the operator's discretion.

- **Standard isolation benefits from an environmental perspective.** A primary goal of cemented casing is to provide another hydraulic barrier. In most cases this is not a consideration since standard casing programs should have been implemented above the openhole sections.

- **Workover is legitimately possible.** This would seem to be a substantial advantage. Envisioning a dynamically changing reservoir, profile modification in the future could be desirable.

- **Hole integrity is increased.** This will possibly become more of an issue if sedimentary basins start to be routinely exploited.

- **Wider fractures and inhibited scaling?** Consider the restricted exit through perforations into a wellbore as fluid is produced. It will be demonstrated that these flow restrictions will be relatively small. However, they will still facilitate a back pressure in the formation adjacent to the perforations. One might anticipate that most of this pressure is lost very close to the perforations. The back pressure may inhibit scaling and may even lead to slightly wider fractures near the perforations. Perforation skin may be high but choke skin might actually be reduced.

- **Ability to Pump Proppant?** Proppant placement may or may not be more effective through isolated perforated completions. Wider fractures may exist facilitating slurry entry. Also, if discrete zones are isolated, focused injection through perforations may cause more tension and/or shearing and may actually promote self-propping. This is only an hypothesis.

- **More Contact Area?** For wellbores inclined at a significant angle to productive fractures in openhole the contact area between the wellbore and the fracture may be small. Cased, cemented and perforated completions may actually alleviate some contact related pressure losses. For example, Mukherjee and Economides, 1991, [3] considered skin that would develop because of inadequate contact between a vertical transverse fracture and a horizontal well. They expressed this choking effect as:

$$\Delta p_s = \frac{Q\mu}{2\pi kh}\left\{\frac{kh}{k_f w_f}\left[\ln\left(\frac{h}{2r_w}\right)-\frac{\pi}{2}\right]\right\}$$

$$s_c = \frac{kh}{k_f w_f}\left[\ln\left(\frac{h}{2r_w}\right)-\frac{\pi}{2}\right]$$

(1)

where:

Δp_s pressure drop due to finite wellbore contact

Q volumetric flow rate

μ dynamic viscosity

k formation permeability

h fracture height

k_f fracture permeability

w_f fracture width

s_c choke skin for radial convergent fracture flow.

In low permeability, fractured formations, this conventional vision of choking skin gives very small values and suggests small pressure drops. In reality, tortuous, near-wellbore interconnection between perforations and the wellbore can lead to pressure losses commonly expressed as skin. Some estimations are provided later.

However, there are challenges with cased and cemented geothermal completions. These include:

• **Cost.** Cased and cemented completions certainly require additional tangible capital expenditure. One would anticipate that the potential for workover and the ability to generate multiple fractures will override this, as is the case in any cased wellbore.

• **Placement Issues.** Geothermal wells present difficult completion environments. These can be made even worse (as with cost) because of the large diameter casing that is conventionally called out to accommodate pumping equipment. There may be situations when multiple, smaller diameter wells are more economic than single large bore wells.

• **Temperature Issues.** Perforating gun performance will need to be considered when temperatures become extremely high, in which case abrasive jet slotting may be preferable.

• **Cementing Natural Fractures.** Plugging of existing fracture systems during cementing is also proposed as a problem – which is easily overcome by the supplementary stimulation required.

• **Casing Integrity.** Corrosion, erosion and erosion corrosion could be long-term issues, particularly in high salinity or anomalous pH reservoirs. Operators must decide whether

the benefits of casing, cementing and perforating in the short-term override the costs of degradation with time, and whether these completions jeopardize well or system productivity and economics.

- **Pressure Losses.** For commercial purposes, single well rates are high. It is often argued that pressure losses will be too extreme. Simple calculations to follow explore some of these mechanisms, and suggest that this may or may not be the case.

Pending successful isolation (casing and cementing), it is still necessary to complete the well. What are the methods for carrying this out? Perforating is the first logical choice. Abrasive jetting is also a possibility and may in fact ultimately turn out to be preferable. Alternatively, diversion is advocated as a methodology for isolation in openhole – and there is good logic for this, if the diverter can tolerate incremental pressures between fracturing events. Diversion could be considered in open or cased hole scenarios to maximize fracture contacts with the wellbore.

4. Using diversion in openhole situations

To effectively develop multiple fracture systems, wellbore isolation seems to be a natural requirement. One legitimate possibility is diversion. This technology is decades old. For example, Spencer, 1970, [4] stated that "For many years solid materials have been used down hole as temporary barriers for diverting injected fluids. A typical operation involves adding the solids to a carrier fluid which is then pumped down hole. This solid laden fluid will be pumped into existing fractures and fissures. As the solids lodge and wedge in the openings and cracks within the formation, they reduce the flow … As the flow decreases due to the action of additional solids blocking the fluid path, the pressure continues to rise until another region of the formation fractures and provides a different path for the fluid to follow." Waters et al., 2009, [5] document more recent use in openhole hydraulic fracturing for shale production. Stalker et al., 2009, [6] show rudimentary calculations of the pressures that could be anticipated. Geothermal applications have been described by Petty, 2012 [7].

5. How to develop multiple fracture systems

Suppose that diversion is not appropriate in a particular openhole scenario. Possibly there are not enough pre-existing discontinuities intersecting the wellbore. This could mean that the pressure increments between diversions in an open hole would be so large that previously diverted zones would start to take fluid. Possibly there are pre-existing fractures that need to be avoided, and so on … If this is the case, a cased and cemented completion could be a rationale decision. Presuming that adequate pumping capacity can be installed, the primary concern has been "How much fluid can be economically delivered through a perforated completion during production?". Whether it is in the geothermal domain or the oil and gas domain, this is a relevant question.

In a perforated completion, and to some extent openhole, stimulation effectiveness and the economics for producing adequate mass flow rates are influenced by near-wellbore completion characteristics. During stimulation, the goal is to transmit pressure to the tip of the fractures that are being created or inflated. Near-wellbore pressure drop requires additional horsepower with accompanying cost for the stimulation. Similarly, during production, the goal is to minimize frictional losses – in the fractures and especially where the fractures intersect the wellbore, near and through the perforated completion. In either case it is necessary to minimize near-wellbore pressure losses.

6. Perforation skin — Pressure loss during injection

A substantial amount of work has been done to understand pressure drop that occurs through perforations. One facet of this research has been to evaluate the pressure loss in a complicated perforation connection from the wellbore to the formation during injection. Eftaxiopoulos and Atkinson, 1996, [8] provided an elegant mathematical approximation. This built on earlier work by Yew and Li, 1988, [9] as well as Yew et al., 1989 [10]. These latter authors applied three-dimensional elasticity to assess hydraulic fracture growth from inclined wells. This is a situation that does promote complicated interconnection with the main hydraulic fracture and where a perforated completion may offer significant advantages over open hole. Initiation, propagation and linkage of fractures formed from individual perforations were considered. Yew et al., 1993, [11] continued these evaluations. A landmark practical presentation of these concepts was provided by Weng et al., 1993 [12].

In 1991, Behrmann and Elbel [13] carried out laboratory block testing to study the complex interconnection of multiple fractures growing from perforations. These authors suggested the strong potential role of a microannular fracture link. "In both cases, despite ideal laboratory conditions, clean wellbore and casing, and short cement interval, the wellbore annulus is pressurized during any pumping treatment. Therefore, in the absence of any optimally oriented defects (perforations), fractures will initiate as though the completion were openhole. Fracturing pressure will obviously be higher than in open hole, but initiation sites and extension geometry will be the same. Thus, it is theoretically possible to have different fracture-initiation sites with identical perforation orientations if two wells have substantially different wellbore damage."

In 1995, Romero et al. [14] presented numerical evaluations related to near-wellbore injection pressure losses attributed to communication (perforations), fractures (turning and twisting) and multiple fractures. Their interest was in mitigating high treatment pressure and unanticipated screenouts. They allocated a near-wellbore pressure loss to the sum of these three effects – perforation pressure drop, turning/twisting or tortuosity and perforation misalignment. For the perforations themselves, they considered the perforation tunnels as orifices. That relationship is (see Crump and Conway, 1988, [15], Lord et al., 1994, [16] Shah et al., 1996 [17]):

$$\Delta p_{perforations} = 0.2369 \frac{Q^2 \rho}{N_p^2 d^4 C_d^2} \tag{2}$$

where:

Q total flow rate, BLPD

ϱ fluid density, lbm/gal

N_p number of contributing perforations

d perforation nominal diameter, inch

C_d orifice discharge coefficient

Depending on the upstream Reynolds' number and the roundness of the edges, the discharge coefficient can range from less than 0.5 to approximately 1. It has been empirically expressed as (El Rabba et al., 1997 and 1999 [18]):

$$C_d = \left(1 - e^{-\frac{2.2d}{\mu^{0.1}}} \right)^{0.4} \tag{3}$$

where:

d perforation diameter through the casing, inch

μ apparent viscosity, cP

The pressure drop due to fracture turning was also approximated, as was microannular flow. Romero et al. [14] stated that, "If the fluid exits the well through the perforation, it must traverse the microannulus and pass the restriction area before, entering the main body of the fracture. A geometry effect occurs in which the rock moves away from the cement resulting in a channel around the annulus with a width of [$w^2/16r_w$] at the fracture entrance, where w is the fracture width, and rw the wellbore radius. In addition, an elastic response (Poisson's effect) occurs in which the fracture opening results in a movement of the rock towards the wellbore." This results in a pinch point during injection – a similar restriction with opposing geometry (but widest where the pressure is highest) is anticipated during production. Gulrajani and Romero, 1996, [19] acknowledged the importance of diagnostic measurements with rate changes to determine near-wellbore losses during injection, where the pressure losses associated with near-wellbore effects could be approximated by the injection rate to a suitable power. If there are insufficient perforations, the pressure loss varies with the rate squared. If tortuosity dominates, the pressure loss varies with the square root of the rate. Similar considerations have been published by Manrique et al., 1997, [20] and by Behrmann and Nolte, 1998, [21] who discussed fracture contact with deviated wellbores. Communicating with a fracture intersecting the hole at an oblique angle may actually be an advantage for a cased hole scenario. In

openhole, the contact area is explicitly defined. In cased hole, injection restrictions through individual perforations may force a larger contact area along the wellbore with linked fractures evolving from perforations, feeding into the pre-existing fracture at some small distance from the well. See also Massaras et al., 2007 [22].

These considerations of pinch points are appealing, but may not work equally well during production, with the pressure gradient into the wellbore.

7. Perforation skin — Pressure loss during production

At the other end of the spectrum are production-related publications which have either assumed a high permeability formation without hydraulic fractures, or have agglomerated complicated near wellbore effects into a choke skin. Karakas and Tariq, 1991, [23] provide a summary of these effects. Since these tend not to reveal a great deal of information about specific losses in the near-wellbore area other than an overall skin, they are only summarized here (refer to Appendix I).

8. Relative order of magnitude calculations — Pressure losses

A comparative analysis is done to assess the magnitude of perforation friction losses. Tortuosity associated with shear fractures intersecting the wellbore can be included using methods proposed by Weng, 1993, [12] and Haney et al., 1995, [57] with the assumption that they work for production in the same fashion that they do for hydraulic fracturing. The simplest possible representation of near-wellbore pressure loss, ignoring tortuosity, is that the pressure drop is strictly due to orifice losses using calculations that can be readily inferred from Bernoulli's equation along with a discharge coefficient, C_d. Consider a hypothetical case:

TD to reservoir top 2000 m

Reservoir net thickness 500 m

Net to gross 1

Perforated reservoir thickness up to 500 m

Inclination 0°

Average reservoir temperature 200°C

required mass flow rate per well 100 kg/sec

Required volumetric flow rate 62,000± BWPD (sand face)

Average bottomhole fluid density[1], 877.6 kg/m^3

Average viscosity 0.14 cP

Perforation casing diameter.0127,.0254 m

Perforation phasing 60°[2]

Formation pressure gradient 10.18 kPa/m or 0.45 psi/ft

Wellbore inclination vertical

Hydraulic fracture width 2 mm

Drilled hole diameter in reservoir 0.254 m, 10 inch

$$\Delta p_{perforations} = \frac{1}{2} \frac{16}{\pi^2} \frac{Q^2 \rho}{N_p^2 d^4 C_d^2} \qquad C_d = \left(1 - e^{-\frac{2.2D}{\mu^{0.1}}}\right)^{0.4}$$

(4)

$$\Delta p_{perforations} = \frac{8}{\pi^2} \frac{\left(\pi \frac{d^2}{4}\right)^2 v^2 \rho}{N_p^2 d^4 C_d^2} = \frac{v^2 \rho}{2N_p^2 C_d^2}$$

For economic viability, it has been suggested that a minimum of 100 kg/s of water needs to be generated (at this reservoir temperature).[3] This is 0.114 m3/s (~60,000 BWPD) downhole. Friction in the tubulars is considered to be second order at this point – and similar for cased and openhole completions.

It has been argued that the casing, cement and perforating a geothermal well would result in poor production, due to restrictive flow. There is also concern that the pressure drop associated with the perforations would be much too large or severe. To investigate the nature of orifice losses near the wellbore, a simple theoretical model was developed to compare pressure drop between an openhole and cased/perforated wellbores. To start the assessment, the flow regime was assessed to confirm that both completion types are in turbulent flow.

The generic data above were used, assuming a vertical wellbore with a longitudinal fracture 2 mm wide for both completion methods (openhole or cased, cemented, and perforated). Later the consequences of multiple interconnected fractures associated with fracturing through perforations are considered. Although it could be argued that fracture width close to the wellbore would likely be significantly greater for a cased hole, the analysis is too sensitive to width to modify it arbitrarily.

---

1 The generic geothermal fluid properties were based on the composition of water from Roosevelt Hot Springs, Utah (Capuano and Cole, 1981), which is a 1% NaCl solution.Ershaghi et al., 1983, [24] measured viscosity for a 1% NaCl brine at 200° C to be 0.139 cP, which is almost exactly the same value given by the NIST thermodynamic tables for pure water under downhole pressure.In addition, the density of water is 878.31 kg/m3 at this pressure.

2 For 60° phasing and 6 shots per foot, there would be 2 perforations at 180° most likely to communicate – other shots may have a complicated interconnectivity, but this assumption is conservative.

3 J. Moore, personal communication, 2012.

To determine conditions for laminar flow, Re ≤ 2,000, for an openhole longitudinal fracture, hydraulic radius was used to approximate the fracture as a slot-like wellbore intersection:

$$\text{Re} = \frac{4HR\rho V}{\mu} \quad HR = \frac{hw}{2(h+w)} \tag{5}$$

where:

HR hydraulic radius

h fracture height intersecting the vertical wellbore

w nominal and vertically constant fracture width at wellbore

ρ fluid density

V fluid velocity in the fracture at the wellbore

μ dynamic viscosity

The maximum velocity of fluid through the fracture will be based on one half of the total flow rate presuming a symmetrical, bi-winged fracture, and the cross sectional area of the fracture on that side. After some rudimentary manipulation it is found that:

$$\text{Re} = \frac{\rho Q}{\mu(h+w)} \tag{6}$$

To maintain laminar flow, the fracture contact length, h, along the wellbore can be estimated as:

$$h = \frac{\rho Q}{\mu \text{Re}} - w = \frac{877.6 \, \frac{kg}{m^3} \times 0.1104 \, \frac{m^3}{s}}{2000 \times 1.4 \times 10^{-4} \, Pa \cdot s} - 0.002 \, m = 346 \, m \tag{7}$$

The fracture height would need to be about 346 m (with connection along the wellbore) to avoid going into turbulent flow for an openhole completion. While not strictly speaking impossible in a 500 m reservoir, it may prove difficult to accommodate this much longitudinal wellbore contact openhole. Additionally, this gives us a maximum velocity under 0.08 m/s for laminar flow.

To assess the flow regime for production of a geothermal reservoir through a cased, cemented and perforated completion, first consider the concept of effective perforations. Assume that only perforations within less than 30° of the preferred fracture plane are expected to significantly contribute to fracturing/flow (Behrmann and Elbel, 1991 [13]). It may be assumed that these same perforations will also contribute the vast majority of production flow, due to their connectivity to the fracture(s). For simplicity, the model developed here assumes that effective

perforations are fully open for flow, and are perfectly aligned with the preferred fracture plane. The model therefore fails to account for tortuosity or proppant packing in order to compare the best case scenario for using perforations with that of an openhole fractured completion. Order of magnitude calculations for those effects are presented later.

Maximum laminar velocity was determined through perforations with 60° phasing, 12 spf (39.37 spm) and 1.27 cm casing-hole diameters. This phasing guarantees that 1/3 of the perforations will be within 30° or less of the preferred fracture plane. While a more detailed study would need to take place to determine the pressure drop due to misalignment of the perforations (reorientation and/or microannulus flow), for now it is assumed that the best oriented perforations are perfectly aligned with the fractures. As discussed earlier, it is also assumed that the aligned perforations accept virtually all flow. The maximum velocity for laminar conditions would be approximately 0.0251 m/s. The number of perforations for laminar flow with this velocity is too large to be feasible. Perforation flow would theoretically be turbulent (based on the Reynolds' number). The length over which this occurs is very small however and the losses through the perforation tunnel itself – if it is clear of debris – are proposed to be small – calculations demonstrating this will follow.

The next logical step is to consider turbulent flow. For either completion case, flow up the wellbore will likely be turbulent above the reservoir.[4] The openhole scenario suggests that a continuous fracture height with laminar flow could fit vertically within this reservoir. While possible, it isn't probable that this will be the case (over 346 m). Alternatively the perforations will almost certainly see nonlaminar effects. Depending on the fracture height, turbulent flow will also exist within the fracture, but may not fully develop in the short interval of the perforations.

A correlation often adopted in chemical engineering piping design (Towler and Sinnott, 2012 [55]) was used as a measuring stick for the maximum allowable fluid velocity (to avoid erosion and to carry any entrained solids; the latter is likely not relevant for geothermal applications). A common rule of thumb for sizing pipes for liquid flow is to impose a velocity of 3 m/s. Realistically, this may be extremely conservative if the flow is single phase and solids-free. Nevertheless, for purposes of illustration, this limit is adopted - the maximum velocity through the perforations was set at 2.5 m/s (this conservatively low velocity can account for situations where two-phase flow may unexpectedly occur). Compared to perforation requirements for laminar flow, using this design velocity vastly reduces the number of perforations required to make up the total flow rate (62,000 BWPD). Assuming 60° phasing, and 6 spf, the required perforated height restrict velocity to 2.5 m/s would be ~160 m. This is still a substantial number of perforations and relaxing the critical velocity restriction would seem to make sense.

9. Modeling pressure drop due to perforations in a fractured reservoir

To confirm these initial predictions, a more fundamental approach was implemented to predict the near-wellbore pressure drop – following Huang and Ayoub, 2007 [56]. The problem of

---

4 Flow up a 10-inch (0.254 m) ID pipe will be turbulent at this rate (Re = 3.61 × 106).

pressure drop can be broken up into three parts: pressure drop from the contraction between the fracture and the perforation, pressure drop from friction within the perforation itself and pressure drop from the expansion between the perforation to the wellbore. These are shown schematically in Figure 1, representing flow regimes going from a fracture, through the perforations, into the wellbore.

$$\Delta p_{perf} = \Delta p_{sc} + \Delta p_f + \Delta p_{se} \tag{8}$$

where:

Δp_{sc} pressure drop from sudden contraction/expansion between fracture and perforation tunnel

Δp_f pressure drop due to friction in the perforation tunnel

Δp_{se} pressure drop due to sudden expansion between perforation tunnel and wellbore
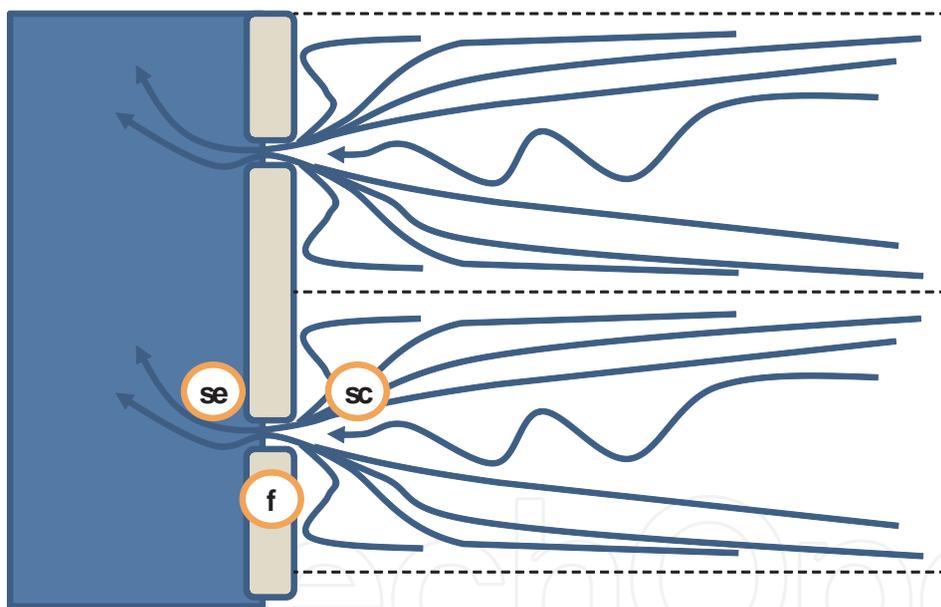

Figure 1. Proposed flow regime near the wellbore through effective perforations.

For 12 spf (39.37 spm) at 60° phasing, parallel effective perforations are spaced 15.24 cm apart. For this system, transition from the fracture "cells" to the perforation is equivalent to going from a 15.24 cm x 0.20 cm slit to a 1.27 cm pipe. One could therefore account for the first phase of pressure loss as the result of sudden contraction. Using conventional fluid mechanics principles, the minor loss in a sudden contraction similar to this are again estimated to be negligible (0.92 kPa, 0.13 psi). The friction loss through each perforation tunnel, Δp_f, is
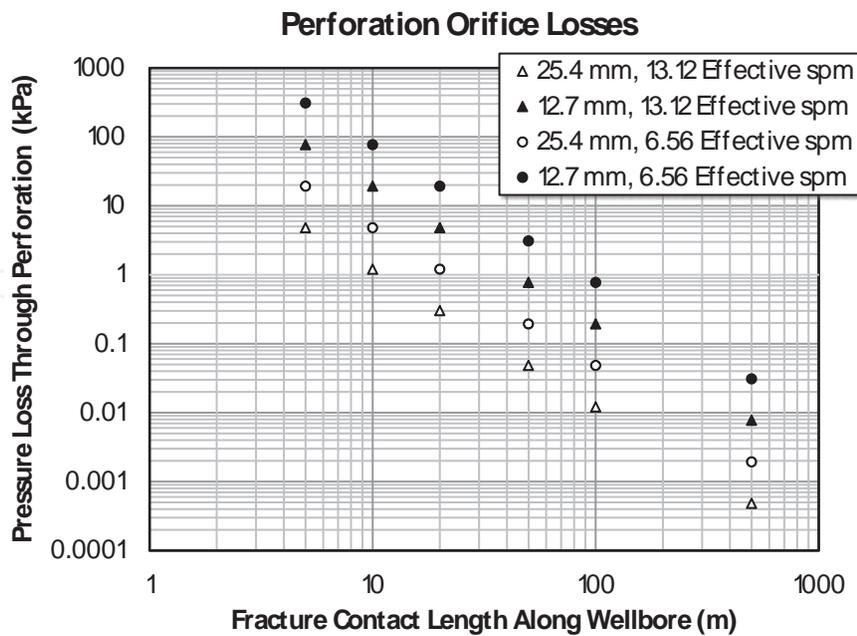
Perforation Orifice Losses

Figure 2. Total pressure loss through perforations for 60,000 BWPD (0.11 m³/sec). The legend shows the nominal per-foration diameter through the casing and the number of shots per meter connecting with the fracture. The abscissa is the actual contact length of the fracture along the wellbore. For practical lengths and open perforations, this type of loss is inconsequential.

estimated using the formulae for an orifice shown previously. The actual value for the discharge coefficient is uncertain because conventionally some of that is embodied in the entrance and exit losses being calculated separately. To be conservative, it will be calculated in the same fashion as above, shown by Crump and Conway [8] in 1988. For the generic situation chosen, a pressure drop of 3.48 kPa, ~0.5 psi is estimated. Finally, for the sudden expansion into the wellbore, the minor loss, Δp_{se}, is estimated as 2.73 kPa (0.4 psi). The sum is again a remarkably small loss. Figure 2 demonstrates this.

While more complex models may need to be developed to account for tortuosity and packing perforations, this simple model suggests that the pressure drop difference between perforated completions and openhole will be small. For practical lengths and open perforations, this type of loss is inconsequential. However, other losses have to be considered ….

From experience in fracturing, there is evidence for near wellbore flow impedance. Simple calculations suggest that it is not strictly due to the perforations themselves. It seems that the real issue then remains choking skin associated with near-wellbore fracture turning and twisting and interlinking. The best discussion of this is Weng, 1993, [12] who proposed approximations of frictional losses during injection. If it is assumed that reciprocal losses might be approximated during production, some gross approximations are possible. First, fracture turning[5] is probably not a significant issue. Weng [12], in discussing fracture turning states

---

5 Weng [12]delineated the turning stage as being related to fracture growth with tip rotation in a plane collinear with the wellbore.

"Since the width reduction [due to turning] takes place only on a small portion of the fracture, the friction loss, i.e., the incremental pressure above the pressure for a straight fracture, is small unless the perforation angle is off the preferred direction by a large angle." The situation during production is more complicated since the width will be smaller than during fracturing because of the direction of the pressure gradient.

Of more interest is twisting. When the fracture half-length becomes large enough, a twisting component can result as the fracture evolves to realign with the far-field stresses. For the twisting component, Weng incorporated a local increase in the closure stress:

$$\sigma_c = \sigma_{HMIN} + \left(\sigma_{HMAX} - \sigma_{HMIN}\right)\sin^2 \alpha' \tag{9}$$

where:

α azimuth angle from the horizontal minimum stress direction (well is projected into a horizontal plane)

α' 90° - α

This local stress increase is superimposed on local stress concentrations and causes a near-wellbore width reduction during injection or production. As can be seen in Figure 7 in Weng's [12] paper, most of this loss can be eliminated by appropriate drilling direction, to keep α' small. Turning then does not appear to be too substantial of a pressure loss mechanism.

The twisting component is more significant. Additional frictional losses may result from the specific connectivity of starter fractures near the wellbore; specifically, how do fractures that initiate at an angle to the wellbore (normal to the smallest local principal stress) propagate, twist and align (or not) to direct injection fluid to or to collect production fluid from a more dominant master fracture. For simplicity, assume one dominant master fracture surviving a short distance radially from the wellbore. Fractures from the perforations reorient and/or link to connect with this main fracture. The multiply fractured region connects the master fracture to the perforations and the wellbore. If the wellbore orientation falls outside of a specified range, these starter fractures do not link up (they grow independently until fracture friction causes only one to survive. Production will be through discrete fractures. An extensive, multiply fractured zone was proposed by Weng [12] as being capable of causing a significant frictional zone. This becomes quite a complicated consideration during production – are multiple, nonlinked fractures at the wellbore an impediment (friction, propensity for width reduction) or an advantage (wider pressurized fractures)?

With twisting and interacting fractures, only approximate calculations are attempted – just to assess the relative order of magnitude of the frictional loss that might be anticipated. Adapting Weng's equation 18 [12] for flow through a multiplicity of near-wellbore fractures for a Newtonian fluid (parallel plate flow):

$$\Delta p_{mf} = \frac{12\mu q}{h}\frac{L_m}{\overline{w}^3} \tag{10}$$

where:

Δp_{mf} pressure loss for flow through the multiply fractured region

h unit height

m dynamic viscosity

q volumetric flow rate in each fracture per unit height

L_m half-length of multiply fractured zone
$\overline{w}$ average aperture for each connecting fracture

Apply this relationship to estimate the pressure drop. On a meter by meter basis it is possible to assume that the fracture width would be the width of an openhole fracture (assume 2 mm constant along the wellbore length) divided by the number of effective perforations;[6] similarly for the flow rate per fracture. For 60° phasing and 6 spf, one can envision something over six effective perforations per meter, giving an effective width of 0.33 mm (as opposed to 2 mm for an openhole bi-winged fracture). Assuming a velocity of 2.5 m/s through each perforation, the required perforated wellbore length (net perforated length) would be 160 m (see earlier) and the total inflow per meter would need to be 6.9×10^{-4} m^3/s/m. The greater the half-length of the zone of multiple fractures (distance away from wellbore), Lm, the greater the pressure losses. Assume 5 m (Weng [12] found a typical transition at about 15 ft. in some of his calculations), the pressure loss can be estimated as 27 kPa (4 psi). The key variables are of course the number of effective perforations per unit length (phasing and spm) and the length over which linkage would occur. The presumption is that the length required for linkage can be reduced when the stimulation is carried out by breaking down all perforations, drilling at acceptable angles, and initiating at low rate. The troublesome aspect of this logic here is that more perforations give a higher pressure drop – so the ideal situation would be to use fewer, which is counter-intuitive and would increase the perforation tunnel losses. Figure 3 shows order of magnitude pressure losses for first order approximations of losses through the perforation tunnels themselves (see Figure 2) and from the friction estimated in the multiply fractured region.

10. Relative order of magnitude calculations — Supplemental power

Using the hypothetical pressure losses that might occur for the generic scenario being considered, presuming a certain number of effective perforations (broken down, and closely enough aligned with the local minimum principal stress[7]), additional pumping requirements (above

---

6 In fact, this is approximate. For multiple, closely spaced fractures the width of the fractures is generally reduced. This was proposed by Nolte ,1997, [60] and Jeffrey et al., 1997 [62]. Germanovich et al., 1997, showed the complexity of the interaction with internal fractures being preferentially closed by encompassing external fractures.

openhole requirements) are estimated. This depends strongly on the number of effective perforations. The number of effective perforations is strictly governed by gun characteristics, especially phasing and density as well as in-situ conditions. It appears that for typical perforation diameters the casing hole perforation diameter is a secondary parameter – unless it becomes extremely small.

Using the same generic reservoir, the power requirements for lifting and to overcome the estimated pressure losses in the perforations and the multiply fractured region are shown in Figure 4, using additional assumptions shown below.

h_{set} setting depth for pump -- 500 m TVD

$h_{reservoir}$ nominal depth to midpoint of producing fracture(s) -- 2,000 m TVD

h_f length fracture communicates with wellbore -- 10, 20, 50, 100, 500 m
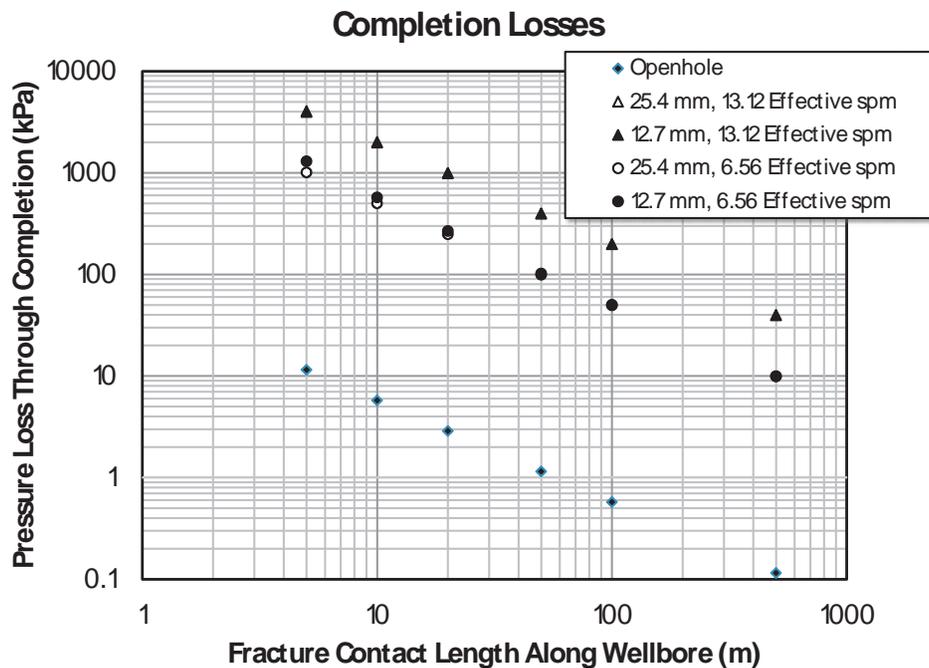
η pump efficiency (dimensionless) … 0.50 was used

Figure 3. Total pressure loss through perforations and near-wellbore region for 60,000 BWPD (0.11 m³/sec) – Completion Losses. The legend shows the nominal perforation diameter through the casing and the number of shots per meter connecting with the fracture. The abscissa is the actual contact length of the fracture along the wellbore. For practical lengths and open perforations, this type of loss is inconsequential.

This might be considered in terms of incremental cost. Figure 5 shows that with enough connectivity these costs could be manageable. An overall economics evaluation would be required.

---

7 Sometimes referred to as a secondary minimum principal stress. This strictly indicates the minimum principal stress at the borehole wall, not necessarily aligned with the far-field minimum principal stress.

11. Erosion of perforations

Figure 6 shows velocities through individual perforations in the generic geothermal system being considered. While the erosive capabilities of clean fluids are not always certain, two-phase and solids-entrained fluids will have significant erosive potential. In conservative engineering applications, Simpson, 1968, [58] argued for velocities between 2.5 and 3 m/s. Considering that time-dependent enlargement of the perforations will stabilize the erosive potential and that the most important role of the perforations is before the well is in use (e.g., to promote multiple hydraulic fracturing) erosion is probably a benefit – reducing the pressure drop.
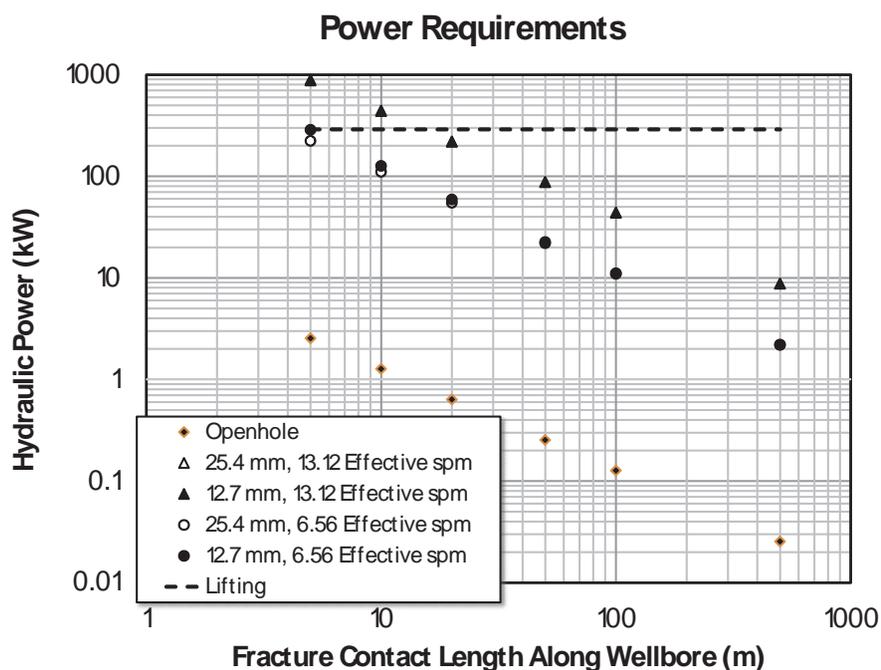
Power Requirements

Figure 4. Power requirements to lift 60,000 BWPD (0.11 m³/sec) and to accommodate the required pressure drop through the perforations for a 50 percent efficiency. The legend shows the nominal perforation diameter through the casing and the number of shots per meter connecting with the fracture. The abscissa is the actual contact length of the fracture along the wellbore.

12. Summary

There are supplementary costs associated with casing, cementing and perforating geothermal production and injection wells that are to be hydraulically fractured. There are also operational costs related to overcoming near-wellbore losses as well as minor losses through perforation tunnels themselves. However, the advantages of ensuring extended contact along the wellbore with perforated completions could be substantial. At the very least, assertions that cased and

perforated completions cannot accommodate the volumes required for economical geothermal production should be carefully reconsidered. The key findings:

1. Pressure losses through perforation tunnels per se are theoretically small. More perforations and larger shots reduce this component further.

2. Twisting and to a lesser extent turning of fractures initiating from perforations can cause greater pressure losses. Smaller densities can reduce this friction if the alignment of the wellbore falls within acceptable limits.

3. It seems that perforated completions for geothermal wells can be designed to minimize near-wellbore losses and improve economics. The calculations done to support this only have a relative order of magnitude reliability and further numerical and empirical evaluation is necessary to generalize this observation.
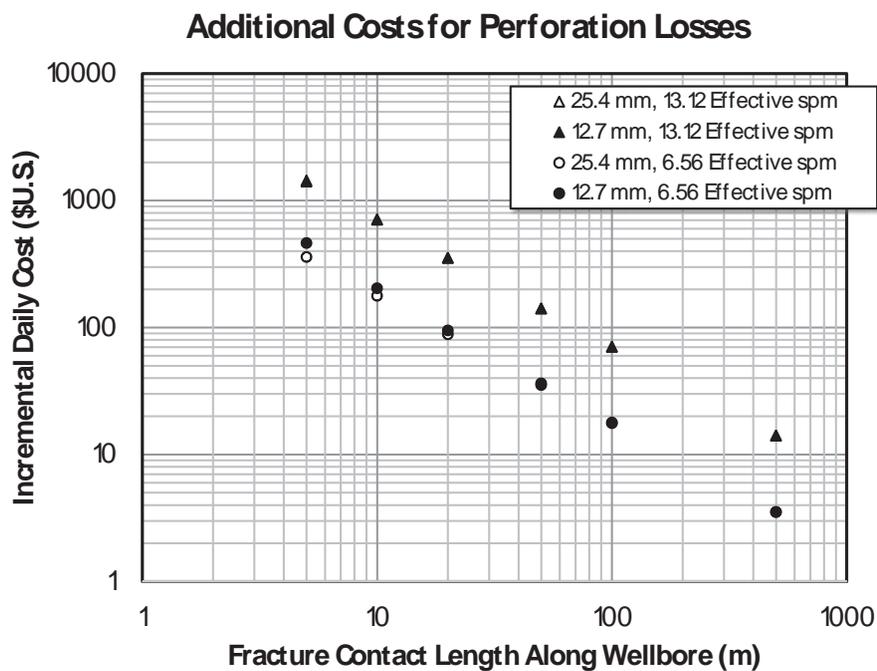

Figure 5. Incremental daily cost estimate for pressure losses through the perforations.

Appendix I — Pressure losses during production (Literature survey)

The most cited work for perforation pressure losses is usually Karakas and Tariq, 1991 [23], Although their skin values were designed for permeable formations, the methodology is useful for thinking about pressure losses that might be incurred. They incorporated additive skin components that accounted for vertical and horizontal convergence and phasing. Inclination mechanical skin can also be considered. Presume that the perforation skin for a vertical well can be represented as:
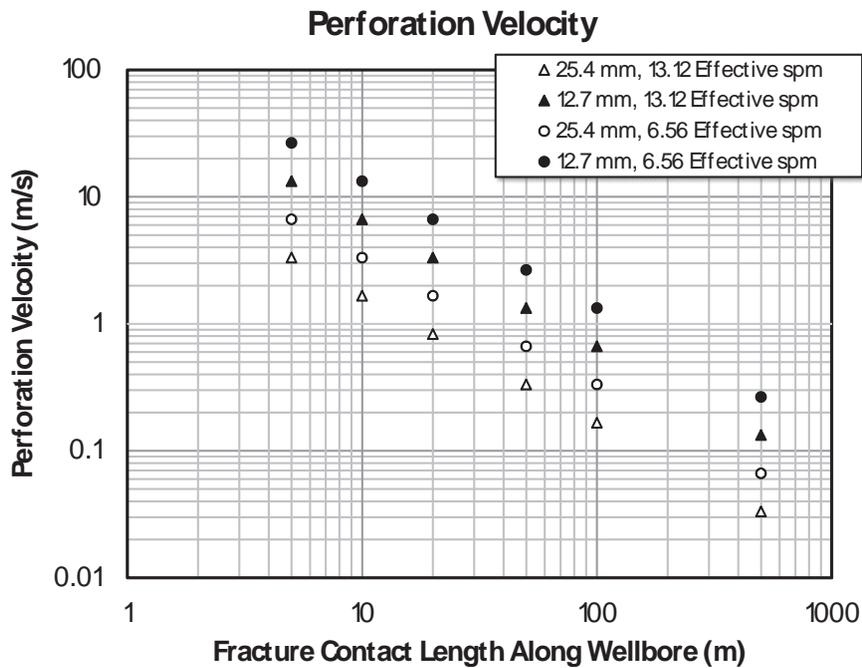
Figure 6. For practical perforated lengths, single phase erosion will not be likely. Even if erosion does occur it should only reduce the velocities and the pressure loss in the perforations.

$$s_p = s_H + s_V + s_{wb} \tag{11}$$

where:

s_p perforation skin, dimensionless

s_H skin due to horizontal convergence, dimensionless

s_V skin due to vertical flow convergence, dimensionless

s_{wb} wellbore skin, dimensionless

The wellbore skin accounts for perforation phasing. Karakas and Tariq, 1991, [23] suggested that it is quite small for phasing less than 120°. Its direct application here (for fracture flow only) may partially account for microannular restrictions although this was not the original intent. Consider a dimensionless radius (r_{wD}) and the wellbore skin (swb):

$$r_{wD} = \frac{r_w}{r_w + L_{perf}} \quad s_{wb} = c_1 e^{c_2 r_{wD}} \tag{12}$$

These coefficients were tabulated by Karakas and Tariq [23] from their numerical work. As an example, suppose, the wellbore radius is rw = 0.5 ft., the perforation length, L_{perf} = 1.0 ft., the perforation radius, r_{perf} = 0.5 inches and that the vertical and horizontal permeability, k_V and

k_H, are equal and the density is 6 spf (giving the space between the perforations, h, as 0.2 ft. For 60° phasing we have $c_1 = 3 \times 10^{-4}$, $c_2 = 7.509$, $r_{wD} = 0.333$ and the skin as 3.67×10^{-3}. Since there is no horizontal permeability to speak of one can chose to ignore the horizontal convergence for a vertical fracture aligning with a vertical wellbore. Alternatively, the vertical convergence concept can be ignored for a transverse fracture intersecting a vertical well and axisymmetric convergent flow is required. Similar simplifications are possible for horizontal wells. For these two cases (vertical well):

$$h_D = \frac{h_{perf}}{L_{perf}}, r_{pD} = \frac{r_{perf}}{2h_{perf}}, a = a_1 \log_{10} r_{pD} + a_2, b = b_1 r_{pD} + b_2$$

$$\text{Longitudinal Fracture} \rightarrow s_H = 0, s_V = 10^a h_D^{b-1} r_D^b$$

$$\text{Transverse Fracture} \rightarrow s_V = 0, s_H = \ln\left(\frac{r_w}{\alpha_\theta\left(r_w + L_{perf}\right)}\right) = \ln\left(\frac{r_{wD}}{\alpha_\theta}\right)$$

(13)

For the example being considered we find $a_1 =$, $a_2 =$, $a =$, $b_1 =$, $b_2 =$, $b = \alpha\theta = 0.813$, giving:

$$h_D = 0.2, r_{pD} = \frac{r_{perf}}{2h_{perf}}, a = a_1 \log_{10} r_{pD} + a_2, b = b_1 r_{pD} + b_2$$

$$\text{Longitudinal Fracture} \rightarrow s_H = 0, s_V = 10^a h_D^{b-1} r_{pD}^b = 0.45$$

$$\text{Transverse Fracture} \rightarrow s_V = 0, s_H = \ln\left(\frac{r_w}{\alpha_\theta\left(r_w + L_{perf}\right)}\right) = \ln\left(\frac{r_{wD}}{\alpha_\theta}\right) = -0.89$$

(14)

If the pressure drop to anticipate under steady state conditions is:

$$\Delta p_s = \frac{Q\mu}{2\pi kh} s_p$$

(15)

the pressure drop for a longitudinal fracture is negligible for a highly conductive fracture. Transverse fracturing may even give a negative skin although the simplifications adopted may not be appropriate. In either case, skin is small.

Kabir and Salmachi, 2009, [25] described relationships for perforation skin calculation during injection, using well-known relationships; extending concepts from Karakas and Tariq, 1991 [23], representing the skin as a superposed combination of convergence to the perforations (but presuming flow from the matrix, whereas the considerations here are fracture-flow dominated, damage (the analog here could be choking or micro-annular pressure drop) and crushing (perforation infill and poor fracture connectivity could be relevant.

Saleh and Stewart, 1996, [26] elaborated on the Karakas and Tariq [23] considerations for pressure loss and added an additional complexity that is relevant for geothermal as well as shale gas/oil production – a second phase. The conventional production pressure drop allocations are represented by van Everdingen and Hurst's skin and Hawkins's representation:

$$s = \frac{2\pi \Delta p_s k h}{Q\mu} = \left(\frac{k_s}{k} - 1\right)\ln\left(\frac{r_s}{r_w}\right) \qquad (16)$$

where:

Δp_s incremental pressure drop occurring in the

wellbore region due to a changed permeability – this could be considered to be reduced aperture or reduced relative permeability or twisting of the fracture, etc.

k virgin permeability

k_s damaged permeability

h reservoir thickness

Q volumetric flow rate

μ dynamic viscosity of flowing fluid

r_w wellbore radius

r_s damaged radius

Before low permeability (shale gas and shale liquids) was popular, Tariq et al., 1989, [27] considered production from naturally fractured reservoirs in low matrix permeability environments. "The sharp discontinuities in porosity and permeability created by fractures have a significant impact on the overall fluid flow in the reservoir. Fractures allow rapid conduction of fluids with very little pressure drop because their resistance to fluid flow is much lower than that of the matrix rock. Very high flow rates (30,000 to 50,000 B/D … have been obtained from fractured reservoir wells under a limited pressure drop." They further stated: "In the past, many naturally fractured reservoirs were completed openhole (barefoot). Perforated completions have now become more popular for naturally fractured reservoirs as a result of improvements in drilling technology and in fracture detection techniques. The concern in the perforated completion, however, is the small area open to flow. The productivity of a perforated completion in naturally fractured reservoirs is totally dependent on the hydraulic communication between the perforations and the fracture network. This commu‐nication, in turn, is dependent on such factors as fracture interval (or fracture density), fracture orientation, number of joint sets, shot density, and perforation length."

Part of the concern near the wellbore is the choking type of skin [3, 28, 29, 30], where losses due to damage and convergence are isolated in the plane (or within the confines) of a fracture. The effects can be further normalized by looking at various forms of the productivity ratio or

flow efficiency – normalized with respect to ideal (cased but no mechanical losses; or undamaged openhole...) situations.

Lian et al., 2000, [31] describe numerical modeling of perforated completions for fractures. Yildiz, 2006, [32] described methods of approximating a composite skin, as did Furui et al., 2008 [33]. Ehlig-Economides et al., 2008, [34] provided a rationale analysis, presuming flow through perforations directly connected to the hydraulic fracture (this may be impacted by wellbore and perforation deviation from principal stress directions). A halo effect was also considered wherein angularly offset perforations would still be connected along this length. This was acceptable in the high permeability formations that those authors were considering but seems unrealistic in most EGS scenarios.

Zhang et al., 2009, [35] expanded on the work of Ehlig-Economides et al., 2008, [34]. They introduced a model hypothesizing that only perforations between the far-field hydraulic fracture plane and the wellbore actually connect flow through the fracture and the well, for fracpacks. For deviated wells the number of perforations can drop substantially unless multiple injections are carried out on isolated zones. The problem may be more severe in openhole – with the fracture quickly deviating from where it discretely intersects the wellbore and possibly minimizing contact length along the well. Considering only the connected perforations (fracture(s) physically in contact with the wellbore), the pressure drop can be considered as:

$$\Delta p_{perf} = \frac{888 L_g \mu B}{k_p A_p N_c} q_{f,total} \tag{17}$$

where:

Δp_{perf} pressure drop through the perforations, psi

L_g length of the propped perforation tunnel, ft

μ dynamic viscosity, cP

B water formation volume factor, res bbl/STbbl

$q_{f,total}$ bottomhole total flow rate, BLPD

k_p absolute permeability of packed perforation, md

A_p cross-sectional area (nominal) of individual perforation, ft^2

N_c number of connected perforations

This relationship came from Welling, 1998, [36] simply calculating the pressure drop for liquid flow through a sand-packed perforation, as follows:

$$P_{wfs} - P_{wf} = cQ + dQ^2$$

$$c = 888 \frac{L_{gr}\mu B_w}{k_{gr}AN} \text{ and } d = 9.08 \times 10^{-13} \frac{\beta_{gr}L_{gr}\rho B_w^2}{A^2 N^2} \text{ and } \beta_{gr-oil} = \frac{6.5 \times 10^4}{k^{0.996}} \tag{18}$$

It is not really relevant because this analysis assumes that the fracture perforations are not infilled with any material. However, propped fractures may require consideration of this additional skin. It is known that near-wellbore fracture geometry is likely more complicated and that more than orifice frictional losses or packed perforation losses are involved. Fracture width reduction near the wellbore can result from twisting and turning with associated shear or partial departures from the direction of perforating, through a microannulus and then in the direction of the maximum normal stress. Cherny et al., 2009, [37] considered (in two-dimensions) the consequences of micro-annular losses. A relevant question is how they are represented during production. It might be anticipated that pressure drops are even larger because of the different sign of the pressure gradient from the wellbore into the fracture during injection – as opposed to during production. Fallahzadeh and Rasouli, 2012, [38] considered some aspects of stress conditions around cased and cemented wellbores impacting perforation performance. Other references relevant to pressure losses during hydraulic fracturing include Ceccarelli et., 2010, [39] as well as Fallahzadeh et al., 2010 [40].

Jackson and Rai, 2012, [41] have come closest to proposing methodologies for discriminating various types of apparent skin in shale gas plays – including low conductivity fractures (manifested by a ¼ slope), poor connection to the wellbore (choke skin and near fracture face damage), relative permeability effects, fracture skin and casing connections; using the apparent skin intercept concept. They reiterated concepts for poorly connected factors strictly using standard choking analogs [see for example Cinco-Ley and Samaniego, 1981 [29]. This certainly has an effect but also needs to consider tortuosity and perforation damage. The choking skin, s_{ch}, has been considered to be:

$$s_{ch} = \frac{\pi x_s k}{w_s k_{fs}} \tag{19}$$

where:

x_s damage length, ft

w_s width of the fracture over the damaged length, ft

k fracture permeability, md

k_{fs} damaged permeability in the fracture, md

The convergent skin macroscopically exists for a fracture that is transverse to the wellbore. It is further increased by convergent flow of some additional complexity into individual

perforations. Jackson and Rai [41] suggested, where the subscripts 1 and 2 indicate some fine near wellbore distances:

$$q = -\frac{2\pi k_f \left(p_2 - p_1\right)}{\mu \ln\left(\dfrac{r_2}{r_1}\right)} \tag{20}$$

"The near-perforation damage influences the positive y-intercept significantly more than poor fracture conductivity for the entire length of the fracture." This finding implies how important the near wellbore regime is.

Recently, there have been numerous publications to determine near-wellbore skin from productive fractures. Many of these have been diagnostic methods. That in itself is valuable by providing a method for discerning how large these pressure drops in the near-wellbore region can be. Nobakht and Mattar, 2012, described a method for correcting for the apparent skin effect that has been attributed to flow convergence in a horizontal well and/or finite conductivity of the fractures – as well as a number of other mechanisms such as two phase flow. Inappropriate consideration of skin can cause linear flow with skin to appear as transient radial flow with boundaries. This can be overcome by using a square root of time plot (the time can be a superposed square root) and taking a linear relationship as:

$$\frac{p_i - p_{wf}}{q} = m\sqrt{t} + b' \tag{21}$$

This can also be expressed for a gas by using pseudopressure. It can be rewritten as (pm is referred to as a modified normalized pressure):

$$p_m = \frac{p_i - p_{wf}}{q} - b' = m\sqrt{t} \tag{22}$$

Most reservoir simulations don't discriminate the near-wellbore specifics in any sort of detail (Xie et al., 2012 [43]). Clarkson et al., 2012, [44] do describe dynamic skin effects. They use a time-dependent intercept, b'(t), to give a time-dependent s'(t). This dynamic skin was associated with depletion- and fluid-damage-related fracture conductivity changes, convergent flow, non-Darcy flow and fracture face skin.

Bello and Wattenbarger, 2010, [45] pointed out that in many multiply-hydraulically-fractured horizontal wells, skin is observed in a characteristic fourth production region (transient drainage from the matrix). They incorporated a convergence skin, s_c.

$$s_c = \frac{k_f x_e \left[m(p_i) - m(p_{wf}) \right]}{1422 q_g T} = -\ln\left[\frac{\pi r_w}{h} \left(1 + \sqrt{\frac{k_V}{k_H}} \right) \sin\left(\frac{\pi d_z}{h} \right) \right] \tag{23}$$

where:

k_f bulk fracture permeability for dual porosity model md

k_V vertical permeability

k_H horizontal permeability

h net reservoir thickness, feet

m(p) pseudopressure – gas, psi^2/cP

p_i initial reservoir pressure, psi

p_{wf} wellbore flowing pressure, psi

q_g gas rate, MscfD

r_w wellbore radius, ft

d_z well position in reservoir

Rationalizing the permeability ratio for fracture flow in a geothermal well makes applying this difficult. The same problem exists for using the basic Karakas and Tariq [23] relationships.

Al-Ahmadi, et al. 2010, [46] observed that while transient linear flow is common in tight gas reservoirs, in shale gas wells, it is accompanied by a significant skin effect – not commonly seen in tight gas wells. They accounted for this with a modified linear flow relationship. For early time, Bello, 2009, [47] and Bello and Wattenbarger, 2009 [48], 2010 [45, 49] treated this as a constant skin effect. For a shale gas reservoir, they indicated:

$$\frac{\left| m(p_i) - m(p_{wf}) \right|}{q_g} = \tilde{m}_4 \sqrt{t} + \frac{Int_4}{1 + \frac{0.45 \tilde{m}_4 \sqrt{t}}{Int_4}} \tag{24}$$

where:

m(p) pseudopressure – gas, psi^2/cP

pi initial reservoir pressure, psi

p_{wf} wellbore flowing pressure, psi

q_g gas rate, MscfD
$\tilde{m}_4$ slope of line matching linear flow data and passing through origin on √time plot

t time, days

Int4 intercept of field data on [m(pi-m(p_{wf})/q_g vs. $\sqrt{t}$, psi^2/cP/MscfD

The message is that there are near-wellbore skins that have been diagnosed using pressure transient analyses on production data from tight formations. Near-wellbore pressure losses could be a dominant mechanism. Anderson et al., 2010, [50] recognized a significant skin effect from pressure loss due to finite conductivity in the fracture system, even if there is no mechanical skin damage at the wellbore. If a square root of time plot is used, the apparent skin (gas) can be inferred from a y-intercept, b, that represents a constant pressure loss.

$$s' = \frac{kh}{1417T} b \qquad (25)$$

where:

T reservoir temperature, °R

k absolute permeability, md

s' apparent skin, dimensionless

h net reservoir thickness, feet

b intercept of square root time plot, psi^2/cP/MscfD

Other similar references include Bahrmai et al., 2011 [50], Sun et al., 2011 [51], Byrne et al., 2011 [52] and Li et al., 2012 [53].

Author details

Walter Glauser[1], John McLennan[1] and Ian Walton[2]

1 Department of Chemical Engineering, U. of Utah, Salt Lake City, USA

2 Energy & Geoscience Institute, U. of Utah, Salt Lake City, USA

References

[1] Pritchett, J. The role of reservoir stimulation in the future of the geothermal power industry. In: Reservoir stimulation current understanding and practice, and the path forward, GRC 2012 Annual Pre-Meeting Workshop, September 2012, Reno, Nevada; (2012). , 28-29.

[2] Gale, J. F. Natural fractures in Shales: Origins, characteristics and relevance for hydraulic fracture treatments. Search and Discovery Article #40338, adapted from oral presentation at AAPG Annual Convention..San Antonio, TX, April (2008). posted October 30, 2008)., 20-23.

[3] Mukherjee, H, & Economides, M. J. A parametric comparison of horizontal and vertical well performance. In: SPE Formation Evaluation. June (1991).

[4] Spencer, A. New diverting agents from applied research. SPE 2828, AIME.

[5] Waters, G, Ramakrishnan, H, Daniels, J, Bentley, D, Belhadi, J, & Sparkman, D. Utilization of real time microseismic monitoring and hydraulic fracture diversion technology in the completion of Barnett Shale horizontal wells. OTC 20268, OTC, Houston, TX May (2009). , 4-7.

[6] Stalker, R, Graham, G. M, & Oluyemi, G. Modelling staged diversion treatments and chemical placement in the presence of near-wellbore fractures. SPE 121683, Intl. Symp. on Oilfield Chemistry, The Woodlands, TX, April (2009). , 20-22.

[7] Petty, S. Stimulation methods in geothermal and oil and gas, reservoir stimulation: In: Current Understanding and Practice, and the Path Forward, GRC Annual Pre-Meeting Workshop, September (2012). , 28-29.

[8] Eftaxiopoulos, D. A, & Atkinson, C. Hydraulic fracture propagation from a cased, cemented and inclined wellbore. In: Aurertin, Hassani and Mitri, (eds.) Rock Mechanics. Rotterdam, The Netherlands: Balkema, (1996).

[9] Yew, C. H, & Li, Y. Fracturing of a deviated well. In: SPE Production Engineering (1987).

[10] Yew, C. H, Schmidt, J. H, & Yi, L. On fracture design of deviated wells. SPE 19722, SPE ATCE, October (1989). , 8-11.

[11] Yew, C. H, Mear, M. E, Chang, C. C, & Zhang, X. C. On perforating and fracturing of deviated wellbores. In: SPE ATCE, SPE 26514, October (1993). Houston, Texas.

[12] Weng, X. Fracture initiation and propagation from deviated wellbores. SPE 26597, SPE ATCE, Houston, October (1993). , 3-6.

[13] Behrmann, L. A, & Elbel, J. L. Effect of perforations on fracture initiation. In: JPT, May (1991).

[14] Romero, J, Mack, M. G, & Elbel, J. L. Theoretical model and numerical investigation of near-wellbore effects in hydraulic fracturing. SPE 30506, ATCE, Dallas, TX, October (1995). , 22-25.

[15] Crump, J, & Conway, M. Effects of perforation-entry friction on bottomhole treating analysis. In: JPT, August (1988).

[16] Lord, D. L, Shah, S. N, & Rein, R. G. Lawson III, J.T. Study of perforation friction pressure employing a large-scale fracture "simulator." SPE 28508, (1994).

[17] Shah, S. N, et al. New correlations for perforation pressure loss. In: GRI Technical Summary, GRI-96/0208, (1996).

[18] El-Rabba, A. M, Shah, S. N, & Lord, D. L. New perforation pressure-loss correlations for limited-entry fracturing treatments. SPE 54533 (1997), SPE Prod & Facilities, 14, (1), February (1999).

[19] Gulrajani, S. N, & Romero, J. Evaluation and modification of fracture treatments showing near-wellbore effects. SPE 36901, Eur. Petl. Conf., Milan, Italy, October (1996). , 22-24.

[20] Manrique, J. F, Bjornen, K, & Ehlig-economides, C. Systematic methodology for effective perforation and fracturing strategies. SPE 38630, ATCE, San Antonio, TX, October (1997). , 5-8.

[21] Behrmann, L. A, & Nolte, K. G. Perforating requirements for fracture stimulations. SPE 39453, Intl. Symp. on Formation Damage Control, Lafayette, LA, February (1998). , 18-19.

[22] Massaras, L. E, Dragomir, A, & Chiriac, D. Enhanced fracture entry friction analysis of the rate step-down test. SPE 106058, Hydraulic Fracturing Technology Conference, College Station, Texas, January (2007). , 29-31.

[23] Karakas, M, & Tariq, S. M. Semianalytical productivity models for perforated completions. SPEPE, SPE 18247, February (1991).

[24] Ershaghi, I, Abdassah, D, Bonadkdar, M. R, & Ahmad, S. Estimation of geothermal brine viscosity. In: J. Pet. Tech. March (1983). , 621-628.

[25] Kabir, A. H, & Salmachi, A. An improved method for total mechanical skin calculation for perforated completions. SPE 121233, SPE EUROPEC/EAGE Annual Conf. Exhib., Amsterdam, The Netherlands, June (2009). , 8-11.

[26] Saleh, A. M, & Stewart, G. New approach towards understanding of near well bore behaviour of perforated completions. SPE 36866, European Petl. Conf., Milan, Italy, October (1996). , 22-24.

[27] Tariq, S. M, Ichara, M. J, & Ayestaran, L. Performance of perforated completions in the presence of anisotropy, laminations, or natural fractures. SPEPE, November (1989).

[28] Cinco-ley, H, & Samaniego-v, F. Effect of wellbore storage and damage on the transient pressure behavior of vertically fractured wells. SPE Annual Fall Technical Conference and Exhibition. Denver, Colorado (1977).

[29] Cinco-ley, H, & Samaniego-v, F. Transient pressure analysis: finite conductivity fracture case versus damaged fracture case. SPE ATCE, SPE October, 1981, San Antonio, Texas (1981). , 10179, 5-7.

[30] Mukherjee, H. Fractured well performance: key to fracture treatment success. SPE 50976 and JPT, March (1999).

[31] Lian, Z, Meng, Y, & Tong, M. A new method of numerical simulation for perforation completion of fracture formation. SPE 64512, Asia Pacific Oil and Gas Conf. and Exhib., Brisbane, Australia, October (2000). , 16-18.

[32] Yildiz, T. Assessment of total skin factor in perforated wells. SPE 82249, SPEREE, February (2006).

[33] Furui, K, Zhu, D, & Hill, A. D. A new skin-factor model for perforated horizontal wells. In: SPE Drilling & Completion, 23, (3): September (2008). , 205-215.

[34] Ehlig-economides, C. A, Tosic, S, & Economides, M. J. Foolproof completions for high-rate production wells. SPE 111455, Intl. Symp. on Formation Damage Control, Lafayette, LA, February (2008). , 13-15.

[35] Zhang, Y, Marongiu-porcu, M, Ehlig-economides, C. A, Tosic, S, & Economides, M. J. Comprehensive model for flow behavior of high performance fracture completions. SPE 124431, SPE ATCE, New Orleans, LA, October (2009). , 4-7.

[36] Welling, R. W. F. Conventional high rate well completions: limitations of frac&pack, high rate water pack and open hole gravel pack completions. SPE 39475, SPE Intl. Symp. And Exhib. on Formation Damage Control, Lafayette, LA, February (1998). , 18-19.

[37] Cherny, S. G, Lapin, V. N, Alekseenko, O. P, & Medvedev, O. O. D modeling of hydraulic fracture initiating at a wellbore with or without microannulus. SPE 119352, SPE Hydraulic Fracturing Tech. Conf., The Woodlands, TX January (2009). , 19-21.

[38] Fallahzadeh, S. H, & Rasouli, V. The impact of cement sheath mechanical properties on near wellbore hydraulic fracture initiation. Rock Engineering and Technology for Sustainable Underground Construction, EUROCK ISRM Intl. Symp., Stockholm, Sweden, 28-30 May (2012). , 2012.

[39] Ceccarelli, R. L, Pace, G, Casero, A, Ciuca, A, & Tambini, M. Perforating for fracturing:theory vs. field experiences. SPE 128270, SPE Intl. Symp. And Exhib. on Formation Damage Control, Lafayette, LA, February (2010). , 10-12.

[40] Fallahzadeh, S. H, Shadizadeh, S. R, & Pourafshary, P. Dealing with the challenges of hydraulic fracture initiation in deviated-cased perforated boreholes. SPE 132797, Trinidad and Tobago Energy Resources Conf., Port of Spain, Trinidad, June (2010). , 27-30.

[41] Jackson, G, & Rai, R. The impact of completion related pressure losses on productivity in shale gas wells. SPE 162213, Abu Dhabi International Petroleum Exhib. & Conf., Abu Dhabi, UAE, November (2012). , 11-14.

[42] Nobakht, M, & Mattar, L. Analyzing production data from unconventional gas reservoirs with linear flow and apparent skin. In: JCPT and SPE 137454, Canadian Unconventional Resources and International Petroleum Conference, Calgary, AB, October, (2010). , 19-21.

[43] Xie, X. MacGlashan, J.D., Holzhauser, S.P., Knott, G.M. Completion influence on Haynesville shale gas well performance. SPE 159823, SPE Hydrocarbon Economics and Evaluation Symp., Calgary, AB, September (2012). , 24-25.

[44] Clarkson, C. R, Qanbari, F, Nobakht, M, & Heffner, L. Incorporating geomechanical and dynamic hydraulic fracture property changes into rate-transient analysis: example from the Haynesville shale. SPE 162526, SPE Canadian Unconventional Resources Conf., Calgary, AB, 30 October-1 November (2012).

[45] Bello, R. O, & Wattenbarger, R. A. Multi-stage hydraulically fractured shale gas rate transient analysis. SPE 126754, SPE North Africa Tech. Conf. Exhib., Cairo, Egypt, February (2010). , 14-17.

[46] Al-ahmadi, H. A, Almarzooq, A. M, & Wattenbarger, R. A. Application of linear flow analysis to shale gas wells- field cases. SPE 130370, SPE Unconventional Gas Conf., Pittsburgh, PA, February (2010). , 23-25.

[47] Bello, R. O. Rate transient analysis in shale gas reservoirs with transient linear behavior. PhD thesis. Texas A&M University, College Station, Texas; May (2009).

[48] Bello, R. O, & Wattenbarger, R. A. Modelling and analysis of shale gas production with a skin effect. In: Can. Intl. Petrl. Conf., Paper 2009-082, 16-18 June (2009). Calgary, Canada.

[49] Bello, R. O, & Wattenbarger, R. A. Modelling and analysis of shale gas production with a skin effect. In: JCPT, 49(12), December (2010).

[50] Anderson, D. M, Nobakht, M, Moghadam, S, & Mattar, L. Analysis of production data from fractured shale gas wells. SPE 131787, SPE Unconventional Gas Conf., Pittsburgh, PA, February (2010). , 23-25.

[51] Bahrami, H, Rezaee, R, Ostojic, J, Nazhat, D, & Clennell, B. Evaluation of damage mechanisms and skin factor in tight gas reservoirs. SPE 142284, SPE European Formation Damage Conf., Noordwijk, The Netherlands, June (2011). , 7-10.

[52] Sun, D, Li, B, Gladkikh, M, Satti, R, & Evans, R. Comparison of skin factors for perforated completions calculated with computational fluid dynamics software and a semi-analytical model. SPE 143663, SPE European Formation Damage Conf., Noordwijk, The Netherlands, June (2011). , 7-10.

[53] Byrne, M, Jimenez, M. A, & Salimi, S. Modelling the near wellbore and formation damage- a comprehensive review of current and future options. SPE 144096, SPE European Formation Damage Conf., Noordwijk, The Netherlands, June (2011). , 7-10.

[54] Li, B, Sun, D, & Satti, R. Statistical analysis of significant factors affecting perforation flow at well scale. SPE 150122, SPE Intl. Symp. And Exhib. on Formation Damage Control, Lafayette, LA, February (2012). , 15-17.

[55] Towler, G, & Sinnott, R. K. Chemical engineering design: principles, practice and economics of plant and process design. Elsevier; (2012).

[56] Huang, H, & Ayoub, J. A. Modeling non-Darcy flow and perforation convergence for vertically fractured wells. In: European Formation Damage Conference, SPE 107853, Scheveningen, The Netherlands, 30 May-1 June (2007).

[57] Hainey, B. W, Weng, X, & Stoisits, R. F. Mitigation of multiple fractures from deviated wellbores. SPE 30482, SPE ATCE, Dallas, TX, October (1995). , 22-25.

[58] Simpson, L. L. (1968). Sizing piping for process plants. In: Chem. Eng., NY, (June 17th), , 1923.

[59] Wu, B, Bunger, A, Zhang, X, & Jeffrey, R. G. Modeling Heat Extraction by Fluid Circulation through an Array of Conductive Fractures Australian Geothermal Energy Conference Nov. (2012). Sydney, 14-16.

[60] Nolte, K. G. Discussion of influence of geologic discontinuities on hydraulic fracture propagation, JPT, August (1987).

[61] Germanovich, L. N, Ring, L. M, Astakhov, D. K, Shlyapobersky, J, & Meyerhofer, M. J. Hydraulic fracture with multiple segments II. Modeling. Int. J. Rock Mech. & Min. Sci. Paper (1997). Elsevier Science Ltd., 34(098), 3-4.

[62] Jeffrey, R. G, Vandamme, L, & Roegiers, J-C. Mechanical interactions in branched or subparallel hydraulic fractures. SPE 16422, Low Permeability Reservoirs Symposium, Denver, CO, May (1997). , 18-19.