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Тема работы
Особенности проведения мини-гидроразрыва пласта на нефтяном месторождении М (ХМАО)

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ВВЕДЕНИЕ

Нефтяная промышленность является одной из важнейших составляющих российской экономики, которая непосредственно влияет на формирование бюджета страны и её экспорт.

Самой острой проблемой на сегодняшний деньявляется состояние ресурсной базы нефтегазового комплекса. Нефтяные ресурсы постепенно истощаются, большое количество месторождений находятся на заключительной стадии разработки и имеют высокий процент обводненности, поэтому самой основной и первоочередной задачей является поиск и ввод в эксплуатацию молодых и перспективных месторождений, одиним из которых является месторождением М.

Месторождение характеризуется сложным строением продуктивных горизонтов. Промышленный интерес представляют пласты АС10, АС11, АС12. Коллектора горизонтов АС10 и АС11 относятся к средне и низкопродуктивным, а АС12 к аномально низкопродуктивным. Эксплуатацию пласта АС12 необходимо выделить в отдельную проблему разработки, поскольку пласт АС12 к томуже является самым значительным по запасам из всех пластов. Эта характеристика указывает на невозможность разработки месторождения без активного воздействия на его продуктивные пласты .

Одним из направлений решения этой проблемы является осуществление мероприятия по интенсификации добычи нефти методом гидроразрыва пласта. Именно поэтому проведение мини-ГРП и использование полученных данных позволит выявить возможные геологические риски и осложнения в процессе проведения основного ГРП.

В данной выпускной квалификационной работе поставлена цель – изучение результатов диагностических закачек, проводимых на месторождении М, и определение возможных геологических рисков и осложнений в предстоящем процессе размещения проппанта.

В связи с этим задачами работы являются:

1) Изучение геолого-физических свойств продуктивных пластов и пластовых флюидов;
2) Изучение методики проектирования гидроразрыва пласта;
3) Выявление возможных геологических рисков и осложнений при проведении ГРП;
4) Выполнение сравнительного анализа методов определения точки закрытия пласта после проведения мини-ГРП;
5) Разработка рекомендаций по составлению графика закачки проппанта.

Защищаемые положения:

1) Выбор метода Нолти (G) как наиболее точной методикидля определения точки закрытия пласта;
2) Составление рекомендаций по программе закачки проппанта согласно технологическим параметрам, полученным в результатепроведения мини-ГРП.

АННОТАЦИЯ

Объектом исследования является изучение особенностей проведения мини-гидроразрыва пласта на нефтяном месторождении М (ХМАО).

Целью данной выпускной квалификационной работы является изучение результатов диагностических закачек, проводимых на месторождении М. Выявление возможных геологических рисков и осложнений в предстоящем процессе размещения проппанта.

В первом разделе выпускной квалификационной работы представлена общая информацияо географическом и административном положении и природно-климатических условиях месторождения М, крупных ближайших населенных пунктах. Также рассматриваютсяосновные особенности тектонического строения продуктивных пластов и краткая стратиграфическая характеристика разреза. Дается описание промышленной нефтеносности месторождения, свойств и составов пластовых флюидов. Приводятся информация о запасах углеводородов и сводная геолого-физическая характеристика продуктивных пластов.

Во втором разделе дана подробная характеристика фонда скважин по каждому продуктивному пласту и месторождению в целом, описано общее количество нагнетательных и добывающих скважин, дана характеристика текущего состояния разработки. Также сделаны выводы о темпах освоения месторождения.

В третьем разделе представлена методика проектирования гидроразрыва пласта. Описаны необходимые диагностические тесты и испытания перед проведением основной операции ГРП. Также приведен анализ и классификация причин преждевременных остановок закачки при проведении гидравлического разрыва пласта.

В четвертом разделе представлен анализ мини-ГРП при составлении дизайна ГРП. Проведен сравнительный анализ методов определения точки закрытия пласта. Вынесены рекомендации по составлению программы закачки проппанта и составлен график закачки проппанта.

В пятом разделе произведен расчет с целью определения дополнительных экономических затрат на проведение мини-ГРП. Произведен расчет стоимость транспортировки оборудования, расчет заработной платы, расчет затрат на амортизацию оборудования и затрат на материалы, необходимые для проведения мини-ГРП.

В шестом разделерассмотрена тема социальной ответственности при проведении гидроразрыва пласта на месторождении М. Рассмотрены мероприятий по защите персонала от воздействиявредных и опасных факторов. Проанализированы возможные вредные и опасные факторы на производстве в соответствии с нормативными документами с описанием источников данных факторов. Выявленывозможные чрезвычайные ситуации на объекте и способы по их предотвращению. Также проведен анализ влияния операции на окружающую среду с обоснованием мероприятий по ее защите.

MINIFRACS

The most important test on location before the main treatment isknown as a "minifrac," or a fracture calibration test. The minifrac isa pump-in/shut-in test that employs full-scale pump rates and relativelylarge fluid volumes, on the order of thousands of gallons. Information gathered from a minifrac includes the closure pressure,p_c, netpressure, entry conditions (perforation and near-wellbore friction), andpossibly evidence of fracture height containment. The falloff portionof the pressure curve is used to obtain the leakoff coefficient fora given fracture geometry. Figure1 illustrates the strategic locations on a typical pressure response curve registered during the calibration activities.

A minifrac design should be performed along with the initial treatment design. The design goal for the minifrac is to be as representative as possible of the main treatment. To achieve this objective,sufficient geometry should be created to reflect the fracture geometryof the main treatment and to obtain an observable closure pressurefrom the pressure decline curve. The most representative minifracwould have an injection rate and fluid volume equal to the main treatment, but this is often not practical. In reality, several conflictingdesign criteria must be balanced, including minifrac volume, created

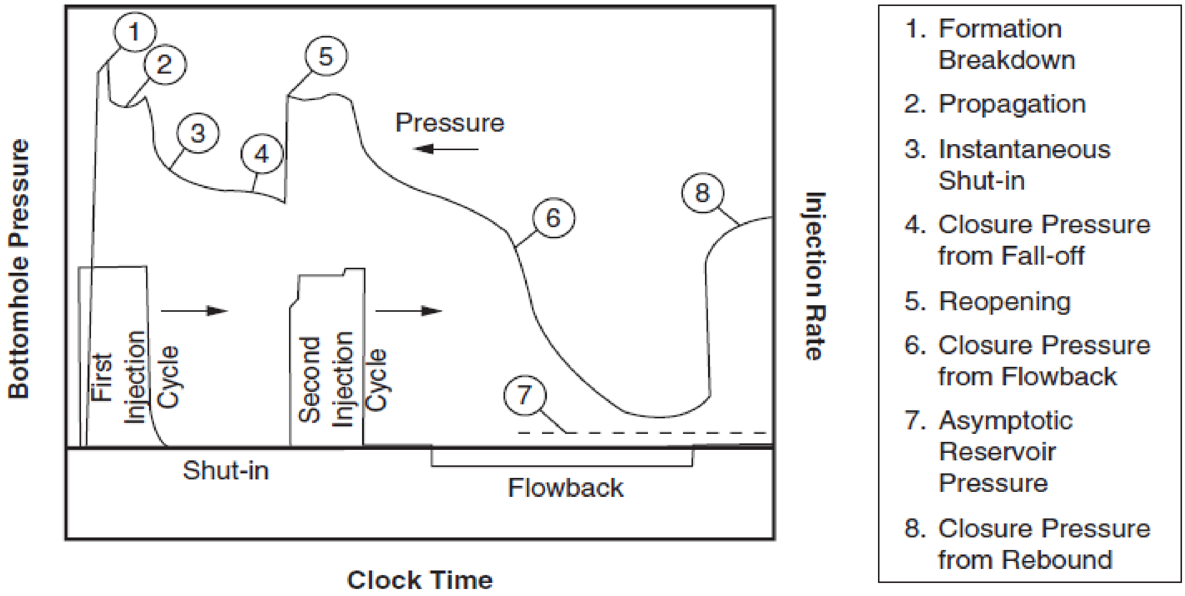

Figure 1 Key elements on minfrac pressure response curve

fracture geometry, damage to the formation, a reasonable closure time,and the cost of materials and personnel.

Fracture closure is typically determined from one or more constructions of the pressure decline curve while taking into considerationany available prior knowledge (e.g., that obtained from microfractests).

The origin and use of these various plots is sometimes more intuitive than theoretical, which can lead to spurious results. The theoretical basis and limitations of pressure decline analysis must beunderstood in the context of individual applications. An added complication is that temperature and compressibility effects may causepressure deviations. In this case, temperature-corrected decline curvescan be generated to permit the normal interpretations of the differentplot types.

The original concept of pressure decline analysis is based on theobservation that the rate of pressure decline during the closure process contains useful information on the intensity of the leakoffprocess. This stands incontrast to the pumping period, when the pressure is affected by manyother factors.

If we assume that the fracture area has evolved with a constantexponent α and remains constant after the pumps are stopped, at time$(t_e + \Delta t)$ the volume of the fracture is given by

$$V_{t_e+\Delta t} = V_i - 2A_e S_p - 2A_e g(\Delta t_D, \alpha)\, C_L \sqrt{t_e} \tag{1}$$

where the dimensionless delta time is defined as

$$\Delta t_D = \Delta t / t_e \tag{2}$$

and the two-variable function $g(\Delta t_D,a)$ can be obtained by integration.

$$g(\Delta t_D, \alpha) = \frac{4\alpha\sqrt{\Delta t_D} + 2\sqrt{1+\Delta t_D} \times F\left[\frac{1}{2}, \alpha; 1+\alpha; (1+\Delta t_D)^{-1}\right]}{1+2\alpha} \tag{3}$$

The function$F[a, b; c; z]$ is the "Hypergeometric function" available in the form of tables or computing algorithms.

Dividing Equation 1 by the area, the fracture width at time Δtafter the end of pumping is given by

$$\overline{w}_{t_e+\Delta t} = \frac{V_i}{A_e} - 2S_p - 2C_L\sqrt{t_e}\,g(\Delta t_D, \alpha) \tag{4}$$

The decrease of average width cannot be observed directly, butthe net pressure during closure is already directly proportional to theaverage width according to

$$p_{net} = S_f \overline{w} \tag{5}$$

simply because the formation is described by linear elasticity theory. The coefficient $S_f$is the *fracture stiffness*, expressedin Pa/m. Its inverse, $1/S_f$, is called the *fracture compliance*. For the basic fracture geometries, expressions of the fracture stiffnessare given in Table 1

Table 1. Leakoff coefficient and No-Spurt Fracture Extent for Various Fracture Geometries

	PKN	KGD	Radial
S_f	$\frac{2E'}{\pi h_f}$	$\frac{E'}{\pi x_f}$	$\frac{3\pi E'}{16R_f}$
α	4/5	2/3	8/9

The combination of Equations 4 and 5 yields the following

$$p = \left(p_C + \frac{S_f V_i}{A_e} - 2S_f S_p\right) - \left(2S_f C_L\sqrt{t_e}\right) \times g(\Delta t_D, \alpha) \tag{6}$$

Equation 6 shows that the pressure falloff in the shut-in periodwill follow a straight line trend,

$$p = b_N - m_N \times g(\Delta t_D, \alpha) \tag{7}$$

if plotted against the g-function.The slope of the straight line,m_N ,is related to the unknown leakoff coefficient by

$$C_L = \frac{-m_N}{2\sqrt{t_e}\,s_f} \tag{8}$$

Substituting the relevant expression for fracture stiffness, theleakoff coefficient can be estimated as given in Table 2. This tableshows that the estimated leakoff coefficient for the PKN geometry doesnot depend on unknown quantities because the pumping time, fracture height, and plain strain modulus are assumed to be known. Forthe other two geometries considered, the procedure results in an estimate of the leakoff coefficient that is strongly dependent on the fracture extent (xf orR_f).

From Equation 6 we see that the effect of the spurt loss is concentrated in the intercept of the straight line with the g = 0 axis:

$$S_p = \frac{V_i}{2A_e} - \frac{b_N - p_C}{2S_f} \tag{9}$$

Table 2. Leakoff Coefficient and No-Spurt Fracture Extent for Various Fracture Geometries

	PKN	KGD	Radial
Leakoff coefficient C_L	$\frac{\pi h_f}{4\sqrt{t_e E'}}(-m_N)$	$\frac{\pi x_f}{2\sqrt{t_e E'}}(-m_N)$	$\frac{8R_f}{3\pi\sqrt{t_e E'}}(-m_N)$
Fracture Extent	$x_f = \frac{2E'V_i}{\pi h_f^{\ 2}(b_N - p_C)}$	$x_f = \sqrt{\frac{E'V_i}{\pi h_f (b_N - p_C)}}$	$R_f = 3\sqrt{\frac{3E'V_i}{8(b_N - p_C)}}$

As suggested by Shlyapobersky, Equation 9 can be usedto obtain the unknown fracture extent if we assume there is no spurtloss. The second row of Table 2 shows the estimated fractureextent for the three basic models. The no-spurt-loss assumption results in an estimated fracture length for the PKN geometry, butthis value is not used to obtain the leakoff coefficient. For the KGDand radial models, fracture extent is calculated first and then used tointerpret the slope (i.e., to determine C_L). Once the fracture extent andthe leakoff coefficient are known, the lost width at the end of pumping can be easily obtained from

$$w_{Le} = 2g_0(\alpha)C_L\sqrt{t_e} \tag{10}$$

The fracture width is

$$\overline{w}_e = \frac{V_i}{x_f h_f} - w_{Le} \tag{11}$$

for the two rectangular models

$$\overline{w}_e = \frac{V_i}{R_f^2 \pi / 2} - w_{Le} \tag{12}$$

for the radial model.

Often the fluid efficiency is also determined:

$$\eta_e = \frac{\overline{w}_e}{\overline{w}_e + w_{Le}} \tag{13}$$

The fracture extent and the efficiency are *state variables,* which is to say that they will have different values in the minifrac and main treatment. Only the leakoff coefficient is a *model parameter* that can be transferred from the minifrac to main treatment, buteven then some caution is needed in its interpretation. The bulk leakoffcoefficient determined from the above method is "apparent" withrespect to the fracture area. If we have information on the permeableheight,h_p, and it indicates that only part of the fracture area fallsinto the permeable layer, the apparent leakoff coefficient should beconverted into a "true" value that corresponds to the permeable areaonly.

While adequate for many low permeability treatments, the outlinedprocedure might be misleading for higher permeability reservoirs. Theconventional minifrac interpretation determines a single effective fluidloss coefficient, which usually slightly overestimates the fluid losswhen extrapolated to the full job volume (Figure 2).

This overestimation typically provides an extra factor of safety inlow permeability formations to prevent a screenout. However, thissame technique applied in high permeability, or when the differentialpressure between the fracture and the formation is high, can significantly overestimate the fluid loss for wall-building fluids (Figure 3).

Overestimating fluid leakoff can be highly detrimental when theobjective is to achieve a carefully timed tip screenout. Inthiscase,

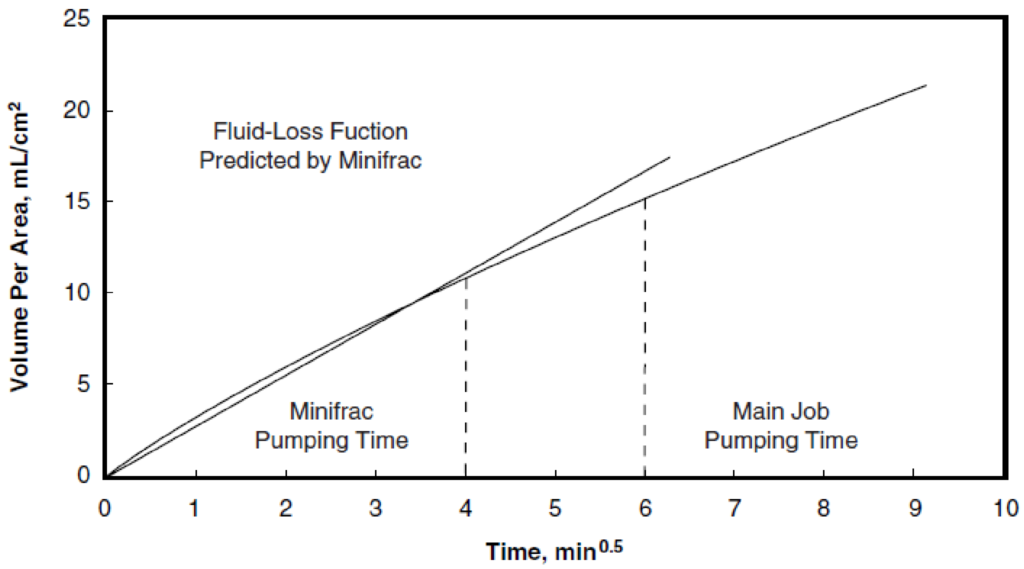

Figure 2. Fluid leakoff extrapolated to full job volume, low permeability

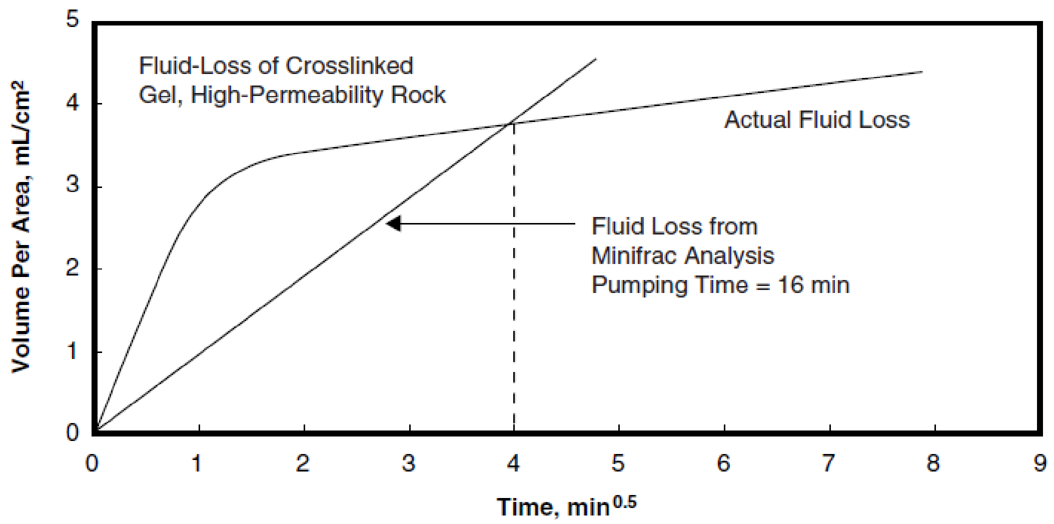

Figure 3 Overestimation of fluid leakoff extrapolated to full job volume, high permeability

modeling both the spurt loss and the combined fluid loss coefficientby performing a net pressure match in a 3D simulator is an alternative toclassical falloff analysis. This approach is illustrated in Figure 4.

The incorporation of more than one leakoff parameter(and other adjustable variables) increases the *degrees of freedom.*

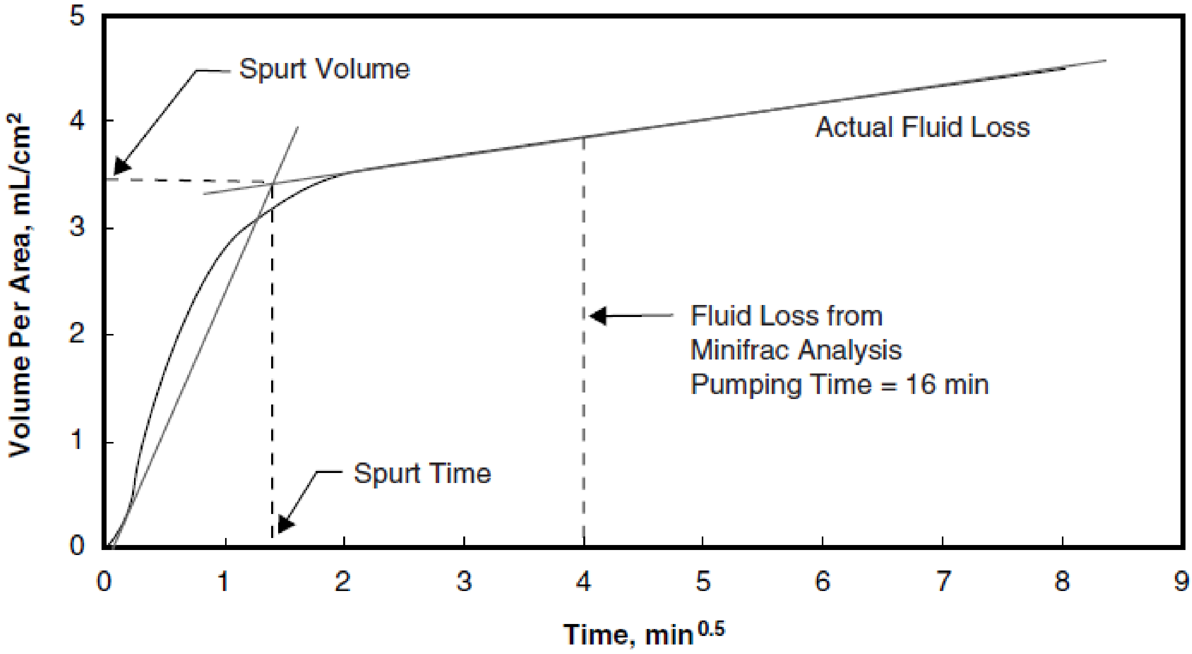

Figure 4 Leakoff estimate on a net-pressure match in a 3D simulator

While a better match of the observed pressure can usually be achieved,the solution often becomes *non-unique*.

PROPPANT SCHEDULE

Given the total pumping time and slurry volume, a stepwise pumpschedule (more specifically, a proppant addition schedule, or just*proppant schedule)* is still needed that will yield the designed, proppedfracture geometry.

Fluid injected at the beginning of the job without proppant iscalled the "pad." It initiates and opens up the fracture. Typically, 30to 60 percent of the fluid pumped during a treatment leaks off intothe formation while pumping; the pad provides much of this necessary extra fluid. The pad also generates sufficient fracture length andwidth to allow proppant placement. Too little pad results in premature bridging of proppant and shorter-that-desired fracture lengths. Toomuch pad results in excessive fracture height growth and created fracture length. For a fixed slurry volume, excessive pad may result ina final propped length that is considerably shorter than the created(desired) fracture length. Even if the fluid loss were zero, a minimumpad volume would be required to open sufficient fracture width toadmit proppant. Generally, a fracture width equal to three times theproppant diameter is felt to be necessary to avoid bridging.

After the specified pad is pumped, the proppant concentration ofthe injected slurry is ramped up step-by-step until a maximum valueis reached at end of the treatment.

Figure 5 conceptually illustrates the proppant distribution in thefracture after the first proppant-carrying stage. Most fluid loss occursin the pad, near the fracture tip. However, some fluid loss occurs alongthe fracture, and in fact, fluid loss acts to dehydrate the proppant-ladenstages. Figure 6 shows the concentration of the initial proppant stageclimbing from 1 up to 3 lb_m of proppant per gallon of fluid (ppg) as

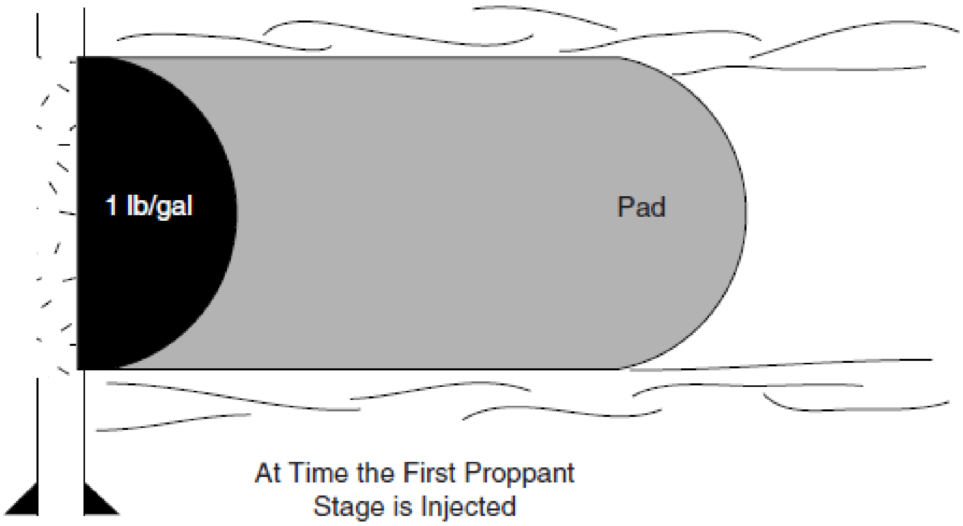

Figure 5 Beginning of proppant distribution during pumping

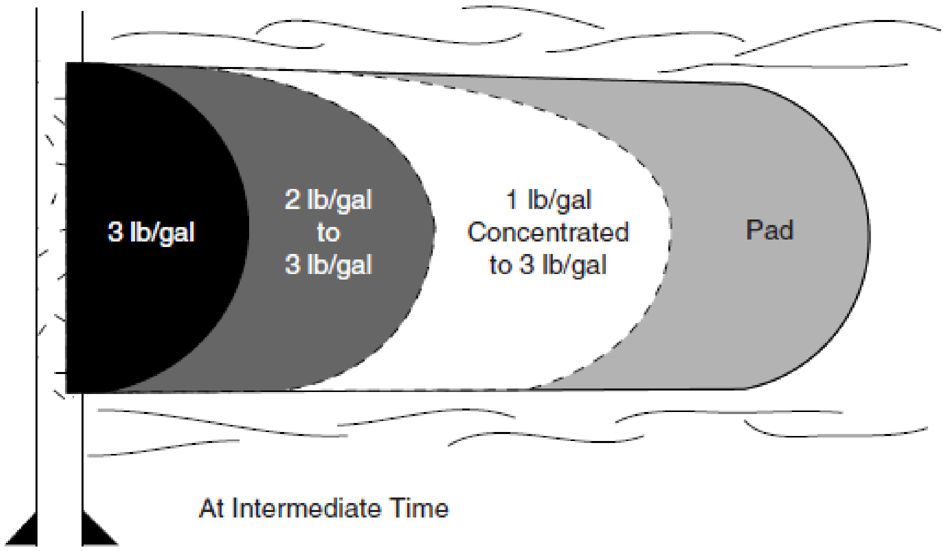

Figure 6 Evolution of slurry proppant distribution during pumping

the treatment progresses. Later stages are pumped at higher initialproppant concentrations because they suffer less fluid leakoff (i.e.,shorter exposure time and reduced leakoff rates near the well).

Figure 7 completes the ideal sequence in which the pad isdepleted just as pumping ends and the first proppant stage has concentrated to a final designed value of 5 ppg. The second proppant stagehas undergone less dehydration, but also has concentrated to the same

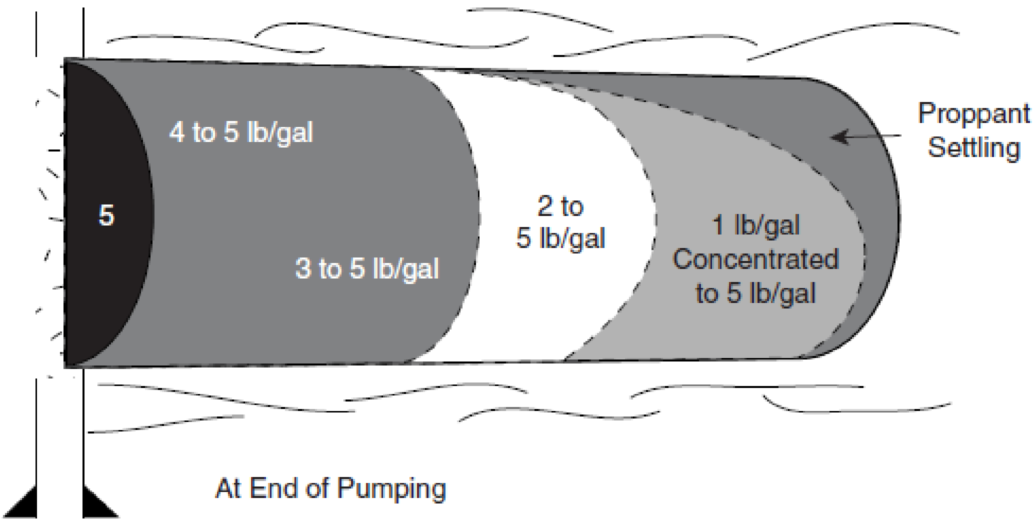

Figure 7 Proppant concentration in the injected slurry

final value. If done properly, the entire fracture is filled with a *uniform proppant concentration* at the end of the treatment.

If proppant bridges in the fracture prematurely during pumping, asituation known as a "screen-out," the treating pressure will rise rapidly to the technical limit of the equipment. In this case, pumping mustcease immediately (both for the safety of personnel on location andto avoid damaging the equipment), effectively truncating the treatmentbefore the full proppant volume has been placed. Making things worse,the treatment string is often left filled with sand, which then requiresincremental rig time and expense to clean out.

TSO designs for highly permeable and soft formations are specifically *intended* to screen out. In this case, it is often possible tocontinue pumping and inflate the fracture width without exceeding thepressure limits of the equipment because these formations tend to behighly compliant.

One additional parameter must be specified:c_e, the maximumproppant concentration of the injected slurry at the end of pumping.The physical capabilities of the fracturing equipment being used provides one limit to the maximum proppant concentration, but rarelyshould this be specified as the value forc_e. Ideally, the proppant schedule should be designed to result in a uniform proppant concentration in the fracture at the end of pumping, with the value of the concentration equal toc_e. Therefore, the proppant concentration,c_e, at the end of pumping should be determined from material balance:

$$M = \eta_e c_e V_i \tag{14}$$

where $V_i$is the volume of slurry injected in one wing, n_e is the fluidefficiency (or more accurately, slurry efficiency), and M is the massof injected proppant (one wing).

The schedule is derived from the requirement that (1) the whole length created should be propped; (2) atthe end of pumping, the proppant distribution in the fracture shouldbe uniform; and (3) the proppant schedule should be of the form of adelayed power law with the exponent, £, and fraction of pad beingequal. More complex proppant scheduling calculationsattempt to account for the movement of the proppant both in the lateral and the vertical directions; variations of the viscosity of the slurrywith time and location (due to temperature, shear rate and changes insolid content); width requirements for free proppant movement; andother phenomena.

TSO DESIGN

It is the tip screenout or TSO design which clearly differentiates highpermeability fracturing from conventional massive hydraulic fracturing. While HPF introduces other identifiable differences (e.g., higher permeability, softer rock, smaller proppant volumes, and so on), it isthe tip screenout that makes these fracturing treatments unique. Conventional fracture treatments are designed to propagate laterally andachieve TSO at the end of pumping. In high permeability fracturing,pumping continues beyond the TSO to a second stage of fracture widthinflation and packing. It is this two-stage treatment that gives rise tothe vernacular of*frac& pack.*

Early TSO designs commonly called for 50 percent pad (similarto conventional fracturing) and proppant schedules that ramped-up aggressively; then it became increasingly common to reducethe pad to 10 to 15 percent of the treatment and extend the 0.5 to2 lb_m/gal stages (which combined may constitute 50 percent of thetotal slurry volume, for example). Notionally, this was intended to"create width" for the higher concentration proppant addition.

After the TSO is triggered, injection of additional slurry onlyserves to inflate the width of the fracture. Thus, it is important toschedule the proppant such that the critical dry-to-wet width ratio isreached at the same time (pumping time) that the *created* fracturelength matches the *optimum* fracture length. With the TSO design,practically any width can be achieved —at least in principle. In addition, the first part of any TSO design very much resembles a traditional design, only the target length is reached in a relatively shorttime, and the dry-to-wet width ratio must reach its critical value during this first part of the treatment.

There is no clear procedure to predict if TSO width inflationwill be possible in a given formation, though rock mechanics laboratoryinvestigations can suggest the answer. The formation needs to be "softenough"; in other words, the elasticity modulus cannot be too high.On the other hand, soft formations are often unconsolidated, lackingsignificant cohesion between the formation grain particles. The maintechnical limitation to keep in mind is the net pressure, which increasesduring width inflation. The design engineer should be prepared to departfrom the theoretical optimum placement if necessary to keep the fracturetreating pressure below critical limits imposed by the equipment.

Another consideration in TSO design is that the created fracturemust bypass the assumed damaged region near the wellbore. As such,the design should specify a minimum target length, even if the theoretical optimum calls for a shorter fracture. Often the minimum length ison the order of 50 ft, while the nature of the damage and the lengthof the perforated interval may dictate other values.

PUMPING A TSO TREATMENT

Most treatments are pumped using a gravel pack service toolin the "circulate" position with the annulus valve closed at thesurface. This allows for live annulus monitoring of bottomholepressure (annulus pressure + annulus hydrostatic head) and realtime monitoring of the progress of the treatment.

When there is no evidence of the planned TSO on the real-timepressure record, the late treatment stages can be pumped at areduced rate to effect a tip screenout. Obviously, this requiresreliable bottomhole pressure data and direct communication bythe frac unit operator.

Near the end of the treatment, the pump rate is slowed to gravelpacking rates and the annulus valve is opened to begin circulating a gravel pack. The reduced pump rate is maintained untiltubing pressure reaches an upper limit, signaling that the screen-casing annulus is packed.

Because very high proppant concentrations are employed, thesand-laden slurry used to pack the screen-casing annulus mustbe displaced from surface with clean gel, well before the endof pumping. Thus, proppant addition and slurry volumes mustbe metered carefully to ensure there is sufficient proppant leftin the tubing to place the gravel pack (i.e., to avoid over-displacing proppant into the fracture).

Conversely, if an HPF treatment sands out prematurely (i.e.,with proppant in the tubing), the service tool can be moved intothe "reverse" position and the excess proppant circulated out.

Movement of the service tool from the squeeze/circulating position to the reverse position can create a sharp instantaneousdrawdown effect and should be done carefully to avoid swabbing unstabilized formation material into the perforation tunnels and annulus.

PRE-TREATMENT DIAGNOSTIC TESTS FOR HPF

There are several features unique to high permeability fracturing whichmake pre-treatment diagnostic tests and well-specific design strategieshighly desirable if not essential: fracture design in soft formations isvery sensitive to leakoff and net pressure; the controlled nature of thesequential tip screenout/fracture inflation and packing/gravel packingprocess demands relatively precise execution strategies; and the treatments are very small and typically "one-shot" opportunities. Further-more, methods used in hard-rock fracturing to determine criticalfracture parameters *a priori* (e.g., geologic models, log and core data,or Poisson ratio computational models based on poroelasticity) are oflimited value or not yet adapted to the unconsolidated, soft, high permeability formations.

There are two tests (with variations) that form the current basisof pre-treatment testing in high permeability formations: step-rate tests andminifrac tests.

STEP-RATE TESTS

The step-rate test (SRT), as implied by the name, involves injectingclean gel at several stabilized rates, beginning at matrix rates andprogressing to rates above fracture extension pressure. In a high permeability environment, a test may be conducted at rate steps of 0.5,1, 2, 4, 8, 10, and 12 barrels per minute, and then at the maximumattainable rate. The injection is held steady at each rate step for auniform time interval (typically 2 or 3 minutes at each step).

In principle, the test is intended to identify the fracture extensionpressure and rate. The stabilized pressure (ideally bottomhole pressure)at each step is classically plotted on a Cartesian graph versus injection rate. Two straight lines are drawn, one through those points thatare obviously *below* the fracture extension pressure (dramatic increasein bottomhole pressure with increasing rate), and a second throughthose points that are clearly *above* the fracture extension pressure(minimal increase in pressure with increasing rate). The point at whichthe two lines intersect is interpreted as the fracture extension pressure.The dashed lines on Figure 8 illustrate this classic approach.

While the conventional SRT is operationally simple and inexpensive, it is not necessarily accurate. A Cartesian plot of bottomholepressure versus injection rate, in fact, does not generally form astraight line for radial flow in an unfractured well. Simple pressuretransient analysis of SRT data using desuperposition techniques showsthat with no fracturing the pressure versus rate curve should exhibitupward concavity. Thus, the departure of the real data from idealbehavior may occur at a pressure and rate well below that indicated bythe classic intersection of the straight lines.

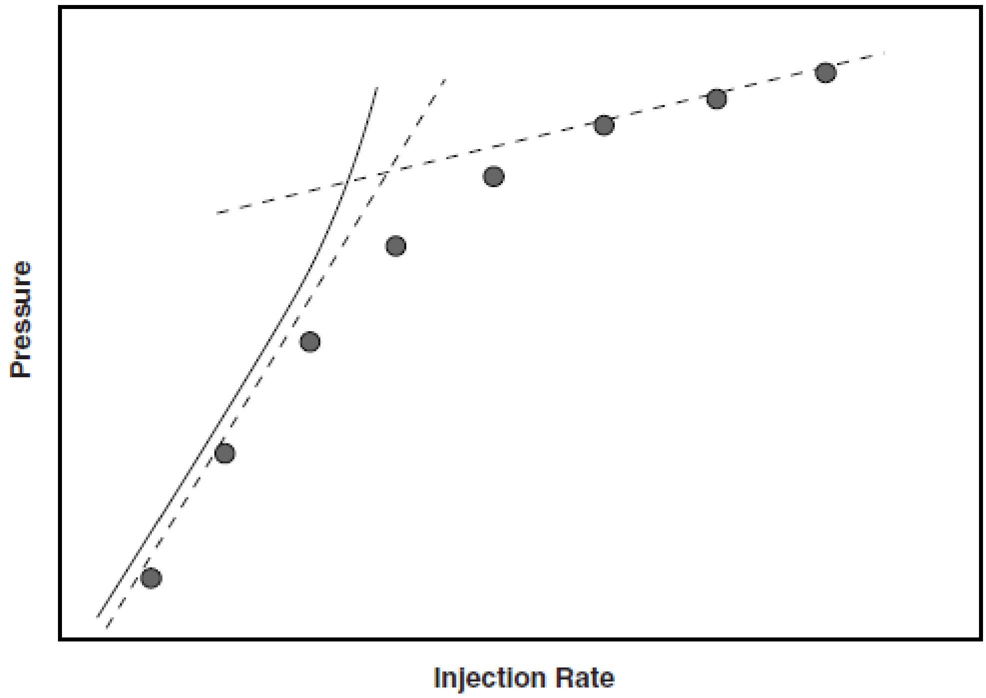

Figure 8 Ideal SRT – radial flow with no fracturing

Given the relatively crude objectives ofthe SRT in high permeability fracturing, the conventional test procedure and analysis may be sufficient.

The classic test does provide an indication of several things:

- Upper limit for fracture closure pressure (useful in analysis ofminifrac pressure falloff data).
- Surface treating pressure that must be sustained during fracturing (or whether sustained fracturing is even possible with agiven fluid).
- Reduced rates that will ensure no additional fracture extensionand packing of the fracture and near-wellbore with proppant(aided by fluid leakoff).
- Perforation and/or near wellbore friction, which is seldom aproblem in soft formations with large perforations and high shotdensities.
- Casing pressure that can be expected if the treatment is pumpedwith the service tool in the circulating position.

A step-down option to the normal SRT is sometimes used specificallyto identify near-wellbore restrictions (tortuosity or perforation friction).This test is done immediately following a minifrac or other pump-instage. By observing bottomhole pressure variations with decreasingrate, near-wellbore restrictions can be immediately detected (i.e.,bottomhole pressures that change only gradually as injection rate isreduced sharply in steps is indicative of *no restriction).*

MINIFRACS

Following the SRT, a minifrac should be performed to tailor the HPFtreatment with well-specific information. This is the critical diagnostic test. The minifrac analysis and treatment design modifications cantypically be done on-site in less than an hour.

Concurrent with the rise of HPF, minifrac tests, and especially theuse of bottomhole pressure information, have become much morecommon. Otherwise, the classic minifrac procedure and primary outputs as described in the preceding section (i.e., determination of fracture closure pressure and a bulk leakoff coefficient) are widely appliedto HPF, this in spite of some rather obvious shortcomings. The selection of closure pressure, a difficult enough task in hardrock fracturing, can be arbitrary or nearly impossible in high permeability, high-fluid-loss formations. In some cases, the duration of the closure period is so limited (one minute or less) that the pressure signalis masked by transient phenomena. Deviated wellbores and laminatedformations, multiplefracture closures, and other complex features are often evident duringthe pressure falloff. The softness of these formations (i.e., low elasticmodulus) means very subtle fracture closure signatures on the pressure decline curve. Flowbacks are not used to accent closure featuresbecause of the high leakoff and concerns with production of uncon-solidated formation sand.

The shortcomings of classic minifrac analysis are further exposedwhen used (commonly) to select a single effective fluid loss coefficient for the treatment. As described above, in low permeability formations this approach results in a slight overestimation of fluid lossand actually provides a factor of safety to prevent screenout. In highpermeability formations, the classic approach can dramatically underestimate spurt loss (zero spurt loss assumption) and overestimatetotal fluid loss. This uncertainty in leakoff behavior makes the controlled timing of a tip screenout very difficult. Entirely new procedures based on sound fundamentals of leakoff in HPF are ultimately needed. The traditional practice of accounting for leakoff with a bulk leakoff coefficient is simply not sufficientfor this application.

ЗАКЛЮЧЕНИЕ

В результате проведенных исследований, было выявлено, что наиболее достоверным из используемых методов анализа КПД является производная Нолти (G). Она позволяет наиболее точно определить точку закрытия. Метод анализа квадратного корня времени также является широко используемым на практике способом интерпретации падения давления для многих инженеров. Ноон менее обоснован с математическое точки зрения в отличие от функцииG.

Изучены основные геологические, технические и технологические риски и осложнения в предстоящем процессе закачки проппанта. Показано, что полностью исключить риск преждевременной остановки закачки при проведении ГРП невозможно, поскольку существуют неопределенность, связанная с геологическим строением и механическими свойствами пласта, состоянием обсадной колонны и поведением жидкости ГРП, а также риски, обусловленные выходом из строя оборудования. Выяснено, что наиболее частыми причинами преждевременных остановок являются незапланированный рост трещины по высоте и сложнообъяснимые преждевременные остановки.

Также была проанализирована калибровка модели дизайна трещины на реальные параметры пласта,вынесены рекомендации по составлению программы закачки проппанта и составлен график закачки проппанта, в результате чего исходный дизайн был изменен дляполучения планируемых результатов обработки пласта с целью достижения эффективной проводимости трещины и создания условий максимальной выработки запасов.

В результате проведенных технологических и экономических расчетов определили:

1) Конечную концентрацию проппанта в интервале перфорации необходимо увеличить с 1000 кг/м3 до 1200 кг/м3. Расход на основном ГРП необходимо увеличить с 3,6 м3/мин до 4,2 м3/мин.
2) Исходя из того, что проведение основного ГРП без диагностической закачки подразумевает наличие больших рисков на успешное проведение ГРП, которые характеризуется не только безрезультатным использование материалов, а также увеличением обводненности и уменьшением дебита нефти, целесообразным будет осуществление дополнительных затрат для проведения мини-ГРП в размере 424 000 рублей с целью максимально минимизировать риски.