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Integrating Solid Expandables, Swellables, and Hydra Jet Perforating for Optimized Multizone Fractured Wellbores

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Abstract

Growing energy demand is leading the industry to re-evaluate resources found in challenging conditions such as unconventional formations. Cost-effective development of these resources depends upon strategic application of advancing production solution technologies. To enhance production and improve recovery processes, more efficient perforating and fracturing methods have evolved along with advancements in wellbore production hardware via use of solid expandable tubulars or combinations of solid expandable and conventional tubulars.

Expandable technology applied as a completion/production string provides an optimized or customized wellbore that can facilitate increased fracturing rates, resulting in improved conductivity and enhanced hydrocarbon production. A fully expandable or combination system with standard casing can provide an integral component in either new wells or re-entry wells where low-permeability reservoirs, such as those characteristic of unconventional formations, require isolation and separation for pinpoint hydraulic fracturing.

Although successful stimulation is routinely attained from hydraulic fracturing, ancillary downhole tools, such as conventional completion equipment, often compromise results by restricting flow and affecting pressure performance. Solid expandable swellable systems can optimize the fracturing parameters by maintaining larger diameters and providing positive seals for selective multi-zone isolation purposes. These production systems consist of expanded sealing sections in combination with expandable or conventional intermediate tubulars utilizing premium connections thereby providing a superior completion solution for mechanical diversion.

Right-sizing the wellbore to the reservoir can provide operators significant cost savings, even more so during these economic times. Utilizing larger diameter expandables in the horizontal wellbore allows operators to first optimize the fracture program to the potential of the reservoir then develop the well program to accommodate the fracturing rates and volumes as well as the surface pumping facilities. This can result in slimmer surface and intermediate sections at much lower cost without compromising the overall stimulation completion program nor planned production and recovery.

This paper will discuss the integration of expandable systems with other technologies and cite case histories to illustrate the effectiveness of solid expandable systems in enhanced production and fracturing applications.

Introduction

A large percentage of the world's future energy demands will be fulfilled by unconventional natural gases that include tight gas, coalbed methane (CBM), shale gas, deep earth gas, geo-pressured gas, and methane hydrates. Unconventional gas reservoirs require the formation to be fractured by hydraulic means to improve the formation productivity by providing a conductive path and joining the existing fractures and cleats in the reservoir (Zahid 2007). Ultimate recoverable unconventional gas resources in the U.S. are estimated to be about 750 Tcf of which 170 Tcf are in coalbeds, 480 Tcf are in tight gas sand and 100 Tcf are in shale (Stark 2007).

The major unconventional gas reservoir types include tight reservoirs, CBM, shale's and hydrates. To some degree, there has always been production from unconventional reservoirs in virtually all North American basins in the United States such as Rocky Mountains, South and East Texas, north Louisiana, Mid continent, Appalachia, Jonah/Pinedale, Natural Buttes, Wilcox Lobo, Cotton Valley/Travis Peak, and Clinton/Medina. (Arukhe 2009)

Estimates of shale gas in the US range from 500 to 1,000 Tcf, while the Gas Technology Institute calculates ~780 Tcf. The US Energy Information Administration estimates that US shale's contain 55.42 Tcf in recoverable gas. Shale plays with potential occur across the United States from southern California through the Rocky Mountains, across the Midwest into the Michigan, Illinois, and Appalachian basins in the east and as far south as the Black Warrior Basin in Alabama. (Lyle 2007)

Solid expandable technology in production applications has been used extensively to address isolation challenges in cased-hole and openhole scenarios. Generally, an elastomeric compound is bonded to the outside diameter (OD) of the pipe to provide effective isolation. When the pipe is expanded to contact the wellbore inside diameter (ID), the elastomer is compressed between the formation and/or base casing and the expandable pipe, providing a high pressure seal and an anchor to resist axial loads. Solid expandable systems in production applications typically repair or reinforce existing casing and isolate sections such as perforated intervals and/or leaking connections. Anchor or flex hanger joints (expandable sections) are placed at the top and the bottom of the liner to isolate these intervals. Additional anchor or flex hangers can be placed anywhere along the liner to address otherrequirements. By accommodating multiple anchor hangers, several zones can be isolated with one liner. The compound used for the elastomer bands on the anchor hanger joints depend on downhole temperature and fluid compatibility. Elastomer bands of different thicknesses can be used on the same liner to seal in a variety of IDs or range of casing weights.

For unconventional formations (low permeability), solid expandable systems combined with swellable technology and advanced perforating and fracturing techniques provide an integrated solution with greater benefits than alternative solutions. Expandable technology product diversity and design flexibility can provide and/or allows the means to configure a variety of different wellbore solutions to a broad variation of wellplans. The uncertainty of the current market necessitates the need to operate more efficiently. Increasing completion efficiency directly affects project economics and profits especially in a time of fluctuating commodity prices. One means of maximizing the completion efficiency is to decrease the time required to drill and complete the well. Additionally, coiled tubing deployed fracturing service (CTDFS) has proven to decrease cycle time without sacrificing valuable production out of the well. By eliminating operations such as perforating with wireline or coil and milling out bridge plugs, CTDFS has decreased the cycle time by as much as a factor of 10. Equipment and personnel become less available when the demand for services increases. By applying CTDFS to the completions schedule of a well, operators and service companies can maximize the use of their assets. The efficiency of CTDFS allows wells to be perforated, fractured, and cleaned out in a few days compared to typically several weeks required with conventional methods. (Peak 2007)

Solid expandable technology plays a significant role in providing solutions in all types of production and completion applications. The general evolvement of completion techniques provide the means to carry out discrete multi-stage fracturing programs over long horizontal wellbores to create more connectivity. The newer solutions now allow for better project economics by separating the drilling, casing, and completion aspects of the project from the fracturing operations thereby gaining project efficiencies by not tying up the rig for all operations.

Unconventional Formations

Operators are attracted to unconventional resource plays because their location and extent often are known; they offer long life production; development and production of these reservoirs are conducive to assembly line methods; and they offer good upside potential to boost recoveries through new technologies. Technology benefits can accrue across the supply chain – including enhanced seismic, drilling and completion technologies, upgrading and operating efficiencies. Moreover, many large unconventional resources are close to established infrastructure and to large markets in North America, Europe and Asia. Global in place coalbed methane resources are widespread and are estimated to have 4,800 Tcf to 6,500 Tcf gas in place. Little information is available to make reliable estimates of global in place resources for tight sands and shale's but U.S. in place tight sand resources are estimated to be as high as 10,000 Tcf so global resources should be larger. Similar in place resource eventually may be identified for global organic rich gas shale's. The shift in emphasis from conventional reservoirs to unconventional reservoirs in North America has been positive for the gas industry. New technologies, such as multilateral and pinnate horizontal wells and multi-staged fracs, have enabled economic production from many tight formations in mature and all but dormant basins (Stark 2007).

At present, the rapidly growing energy demand worldwide and the higher depletion rates of existing reserves as compared to their discoveries are a major cause of gap between supply and demand. This situation of increasing gap between demand and supply has promoted the world to explore and develop unconventional resources of gas. However, the technological advancements, long-term potential, environmental benefits and attractive gas prices bring unconventional gas resources more rather than oil into the forefront of our energy future. At the moment the world is witnessing an increasing demand of gas and thus unconventional gas resources development has the focus of increased attention. In the future, a significant percentage of the world's energy demands (especially North America) will be satisfied by the natural gas. (Zahid 2007)

To produce these resources (gases) economically and efficiently, well stimulation plays a major role in achieving the optimal target production from these reservoirs. Unconventional gas resources require the formation to be fractured by hydraulic means to improve the formation productivity by providing a conductive path and joining the existing fractures and cleats in the reservoir. (Zahid 2007)

Globalization of gas supply and demand has launched tight gas as an increasing source of energy. A recent gas presentation sourced Wood Mackenzie as stating that in 2003 17% of gas was tight gas and 73% was conventional. In 2003 shale accounted for 2% and the remaining 8% was coalbed methane (CBM). They projected that in 2010 the portion of gas that was tight gas would increase to 26%, whereas conventional gas would decrease to 58%. Shale would only increase to 3% of the volume and CBM would increase to 13%. With the increased percentage of gas being tight gas, it has become more challenging to produce, especially as production moves to more remote areas and deeper or more difficult well paths. (Aly 2009)

Expandable Completions

For unconventional gas plays, many operators use multi-zone isolation completion systems for selective and pinpoint fracturing. Some conventional completion systems utilize incrementally-sized frac sleeves or mechanically shifted sliding sleeves to enable selective fracturing. Other systems consist of tubing with mechanically shifted sliding sleeves that are cemented in place provide pinpoint fracturing. Stimulating a horizontal or multi-zone vertical well to properly distribute and optimize the induced fractures is dependent on interpretation of log data, possible well modeling, and the formation's natural fracture structure. Smaller discrete multi-position controlled stimulated zones provide a higher capacity producing well than that of a larger single stimulation over the entire length of the wellbore where there is no interval isolation or mechanical diversion.

Traditionally, producing gas or oil from tight formations required investment in costly pumping equipment and other conventional operations including multiple trips downhole, and repeated cementing, plugging, perforating, and fracturing. Unconventional reservoirs require more effective completion and production strategies to make their development economical. New techniques and technologies have led to systems that create multiple transverse or longitudinal fractures in horizontal wells that are completed in unconventional formations. Coupled with advanced reservoir management strategies, multi-zone isolation fracturing systems are at the core of a process which improves field economics by decreasing rig time, reducing time and cost for hydraulic fracturing services, accelerating production, and improving reservoir drainage.

For example, completions have evolved from multi-step operations that use a perf and frac program followed by setting a drillable plug or retrievable. This process is time consuming and requires using the drilling rig for the duration of the project as each section of the wellbore would necessitate multiple steps, trips, and operations be performed separately and repeatedly from the toe to the heel or from the bottom of the well up. More recently, one trip multi-isolation completions have been used where conventional tubulars and conventional or slightly modified production packers provide the isolation for each zone or section to be fractured. Additionally, either mechanically shifted sliding sleeves or incrementally sized frac sleeves actuated by dropped balls provide the means to communicate the fracture to the reservoir with a conventional liner hanger packer and polished bore receptacle (PBR) to tie back the whole completion to the previous casing string. These solutions are typically referred to as a selective fracturing process because fracturing occurs somewhere along the wellbore within the specific zone/section. Cemented conventional tubulars and mechanical shifted sliding sleeves have also been used to attain pinpoint fracturing.

An expandable system with swellable elastomers offers a single-trip, multi-stage, multi-zone completion in conjunction with perf/jet perforating/fracturing as a cost-effective technique that provides openhole isolation between zones, zone lobes, fault lines, poor permeability sections, or questionable water saturation sections and delivers fracture fluid to specific ideal sections of the wellbore. Single-trip, multi-stage, isolation completions (utilizing expandables) offer the means to divert the fracture where desired to maximize effectiveness. At each stage of the perf/jet perforating/fracturing process, the lateral is exposed while the lower section is temporarily isolated, providing greater control, thereby eliminating the possibility of divergence and giving the operator a greater chance of fracturing the entire length of the lateral **(Figure 1)**.

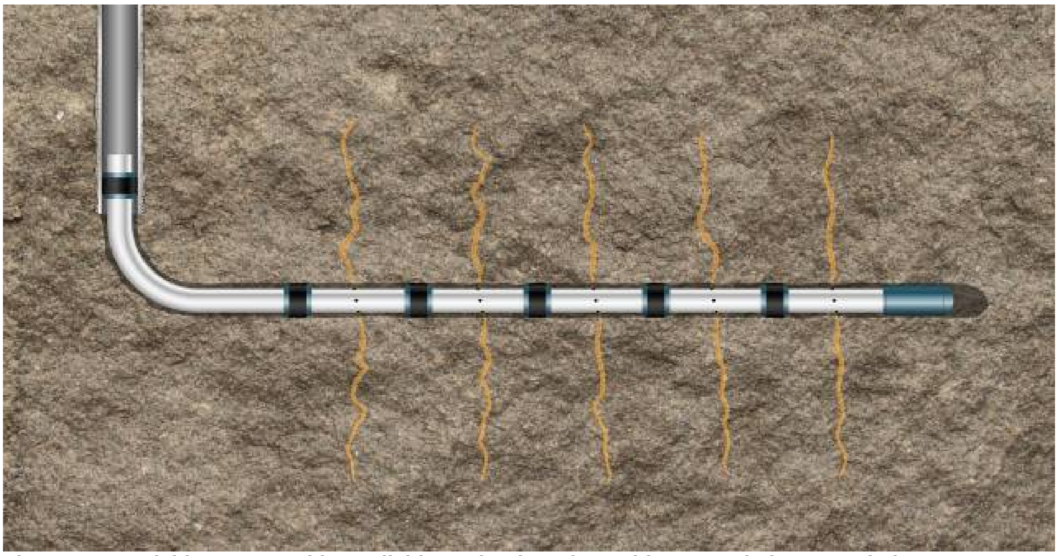

Fig. 1 – Expandable System with Swellable Technology for Multi-zone Isolation Completion

As part of the expandable completion, swellable isolation anchors with swellables provide positive isolation for each interval or zone of interest. A swellable anchor (member, packer, etc.) develops dynamic swelling pressure in an osmosis or diffusion process through the absorption of oil, water, or some liquid composition into the sealing element. Setting is typically initiated by the natural or artificial introduction of oil or water but other wellbore fluids can possibly be used (such as diesel, distillate, etc.). Subsequently, no rig or operational time is associated with the setting process. The swellable device is manufactured and bonded directly onto any size base pipe or expandable pipe. Differential pressure ratings are dependent on initial rubber thickness—the relation of the rubber OD to the openhole ID it expands to and/or the number of bands (or length of bands) along the length of the joint. The full limits of differential pressures for any application can be modeled using vendor's software programs. Several factors determine appropriate design of the swellable elastomers and it is good practice that appropriate downhole parameters be supplied by the operator prior to field installation. By design, swellable elastomers on an expanded liner have minimal elastomer thickness and create a seal (designed compression for fully expanded system) immediately upon expansion of the liner against the borehole. This enables stimulations treatments to begin immediately as opposed to waiting days for swelling to occur in conventional liner installations. Once the expandable production liner is in place, the rig can demobilize and move to next well location. Pumping and coil tubing equipment can be mobilized and perf/jet perforating/fracturing operations can be kicked off.

This solid expandable production conduit combined with swellable elastomer technology and coil tubing perforating and fracturing techniques provide the following important benefits over alternative completion options for wells that require hydraulic fracturing **(Figure 2)**:

- Enhanced management and control during execution of the hydraulic fracturing operation with coil tubing in place during frac operations and the ability to reverse circulate excess proppant in case of an early screenout. These benefits allow for "real-time" decision making based on the actual downhole field conditions that enable the maximum possible amount of proppant to be injected into desired zone, resulting in the most effective fracture treatment.
- Unlimited number of zones or sections to be fractured because no sliding sleeves or incrementally-sized balls are required. Expandables overcomes the mechanical complexity of conventional completions
- Pinpoint fracturing versus selective fracturing. More control of fracture initiation point.
- Supports optimum remedial intervention providing means for future control of water or problem zones and for easily supports re-entry for refract programs.
- Large expanded wellbore ID:
    - Enables use of larger CT strings and perf/jet perf assembly allowing longer and more optimized nozzles which yield better defined jetted perforations and a higher probability of pinpoint fracture initiation at the perforation.
    - Optimized flow regimes – both within the CT and the annulus – improves hydraulics. This enables larger frac volumes, higher pump rates, and higher probability of maximum fracture connectivity near the wellbore.
    - Less surface horsepower, lower pressure-rated surface facilities and lines are required.
- Improved overall efficiency and reduced non-productive time. Rig utilization is independent of treating operations.
- Enhanced swellable seal compression and sealing performance with shorter "swelling time" as opposed to conventional API tubulars. Positive seal and isolation points along the length of the section of the wellbore with high differential pressure capability.
- Expandable wellbores are customized for well construction/stimulation/production program needs
    - To address a range of build rates
    - To address a range of depths and horizontal section lengths
    - To address a range of treatment rates, volumes and pressures which optimize horsepower requirements
    - To provide an optimum wellbore in the reservoir and/or a slimmer and more cost-effective casing program

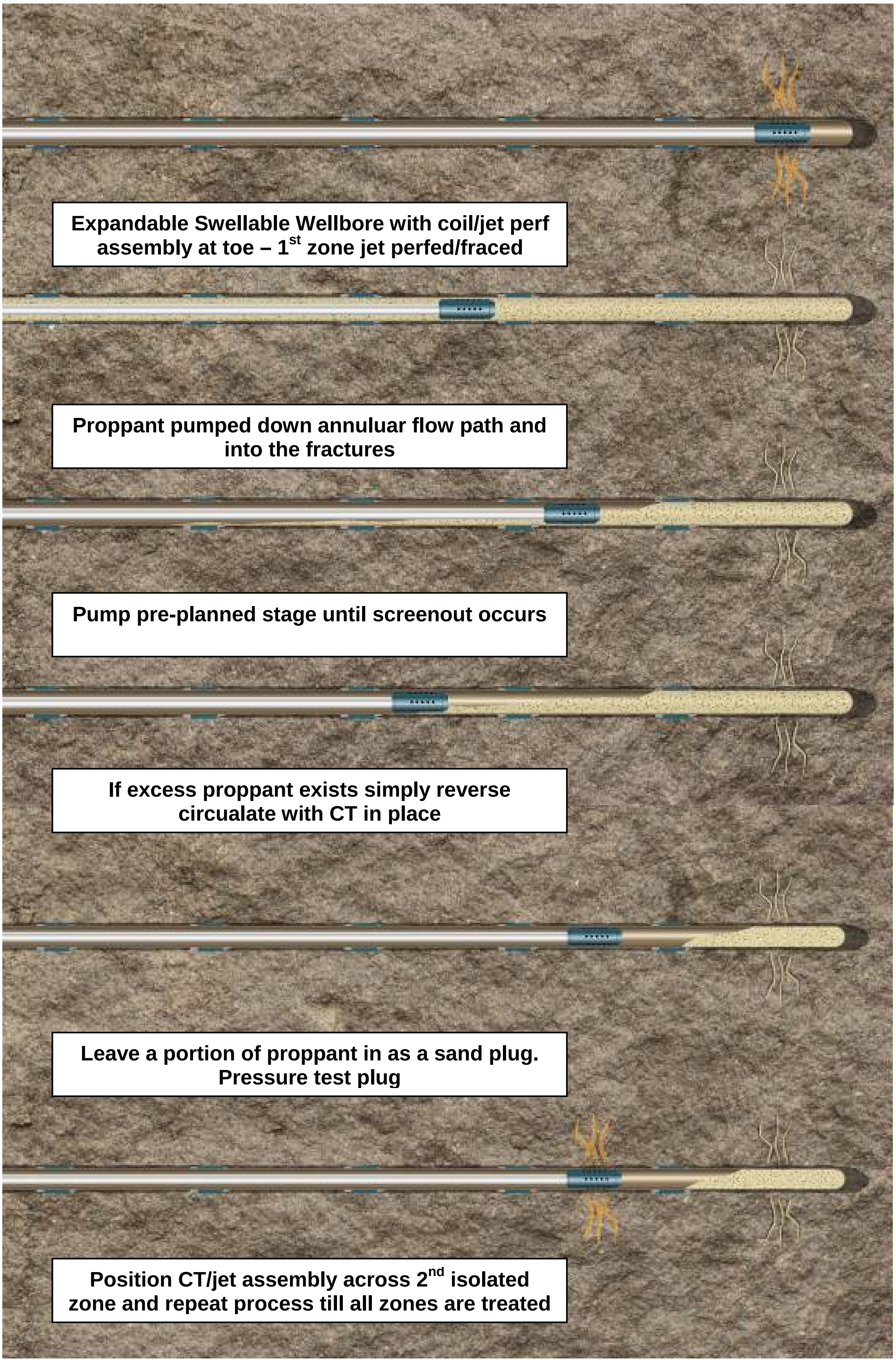

Fig. 2 – Expandable Swellable Perforating/Fracturing Process

Perforating/Hydraulic Fracturing Process

General

Prior to selective fracturing where various methods of isolation are used, operators simply scheduled large-scale, single multi-staged fracs to be pumped into long horizontal sections. This method typically resulted in the frac fluids/materials migrating to the areas of least resistance, which resulted in reduced production along the untreated section of the wellbore. With the advent of isolation perf and frac techniques, the operation progressed to selective fracturing. Some common completion systems for cased-hole applications require multiple trips into the wellbore to repeatedly perforate, fracture, and isolate each section or interval in a bottom-up fashion. Typical isolation solutions may use bridge plugs, straddle packers, chemical or mechanical diverters, external casing packers, or modified production packers combined with a multi-trip conventional perf and frac operations. Although these systems have been workable alternatives for multi-zone isolation systems, most require multiple trips in and out of the wellbore and simultaneous rig and pumping operations that add cost to the overall project. More recent multi-zone isolation completion systems such as a solid expandable swellable solution combined with perf/jet perforating and fracturing methods require only a single trip to install the expandable swellable production conduit and a single trip to carry out all the perforating, fracturing, and cleanout operations as well as production kickoff, if required. After the well is drilled and the solid expandable liner installed, the rig is moved to the next pad to continue optimum asset utilization.

Once pumping operations are scheduled, equipment is mobilized and perf/jet perforating and fracturing operations are carried out. Fracturing methods that focus on treating intervals individually can result in many hours of non-productive time (NPT) mainly as a result of discrete process steps that require trips in and out of the well between treatments while pumping equipment resources remain idle or are required to leave and return to the well site. These discrete steps include trips for perforating, setting or moving tools such as bridge plugs, and wellbore cleanouts. (East 2008)

In recent years, between 40 to 50% of wells in North America were fracture stimulated as an initial part of their completion program, many with multiple stimulation stages. Russia and China represent the highest concentration of hydraulic fracturing activity outside North America. Excluding these three areas, it is likely that less than 10-15% of the wells completed currently use hydraulic fracturing. The relevance of this information is to illustrate that most of these latter wells will be perforated for production, not for fracture stimulation. (Pongratz 2007)

Jet Perforating

The hydrajetting of perforations (rather than using conventional explosive-charge perforating) results in effective communication paths, which are very “frac friendly”. In many cases, when fracturing through hydrajetted perforations, it will reduce (if not completely remove) the commonly observed extreme pressure spike at formation breakdown at the start of the fracturing treatment, making it hard to find on the pressure record. Additionally, near-wellbore tortuosity problems that often occur in hard formations will rarely be present when fracturing through hydrajetted perforations (Surjaatmada 1994).

Hydrajetting is basically flow through an (elongated) orifice. In hydrajetting, high-pressure fluid is pumped through a jet nozzle; converting the pressure energy to velocity (kinetic energy). In jetting, the most important task is to maintain the fluid concentrated following a straight line. Flaring the jet stream must be minimized. The length of a jet must be short or very long—short to equal the distance to the vena contracta or of adequate length such that the jet streams are already “controlled” by the walls of the nozzle before the jet streams exit. A short jet nozzle is very difficult for field applications, as the distance to the vena contracta varies with fluid densities, velocities, viscosities, etc.; and hence very hard to predict. Fluid parameters are not constant and abrasive wear alters the geometry. A long jet nozzle would be much more controllable and would reduce flaring of the jet stream. (McDaniel 2008)

Perforations formed by hydrajetting can achieve perforation tunnels that provide a higher probability of hydraulic fracture initiation within the tunnel. Even when the perf tunnel is not closely aligned with the preferred fracture plane (PFP) it will still be the likely point of initiation and initiation will be more likely than with shape-charge perforating. However, this still does not guarantee that fracture initiation will always be achieved since well construction limits the pressure that can be delivered into a perforation. Hydrajet perforating cannot change nature; it can only allow the most communication possible with the rock. Hydrajet perforating at multiple locations that are distant enhance the probability that the perforated intervals are not feeding fluid to the same fracture planes. Concentrated fluid entry into a single hydraulic fracture plane requires lower injection rates to achieve geometry growth and higher concentrations of proppant will be easily accepted by the fracture. As the industry has increased the use of hydrajet perforating before fracture stimulation, one of the most common field observations is the ability to place higher proppant concentrations than similar wells using shape-charge perforating. The particular well completion involved dictates the maximum jetting tool OD than can be used. The smallest tubular size to be entered may be the limit or a restriction such as a landing nipple or a packer ID may be the determining factor. Reduced tool OD may result in the sacrifice of nozzle length. As maximum flow rate possible decreases, the allowable number of nozzles and/or nozzle ID reduces. These two are to some degree interchangeable variables. In practice, the location of nozzles around the tool body is a variable that may affect the choice of jet nozzle number and ID. As a nozzle ID decreases, for any given delta pressure there is less energy delivered per unit time. If nozzle ID is decreased and delta pressure cannot be increased, the rate of erosion will be lower. (McDaniel 2008)

Fracturing

Effective stimulation (particularly hydraulic fracturing) is a key for the development of tight gas, coalbed methane and shale gas resources. Since these reservoirs have low permeability, to make them flow and have a best possible early production rate as well as the highest ultimate recovery, stimulation by fracturing of the reservoir hydraulically or by other means is necessary. Each stimulation technique is intended to provide a net increase in the productivity index, which can be used to either increase the production rate or to decrease the drawdown pressure differential. In most of the cases hydraulic fracturing is employed and the productivity of the well is increased by creating a highly conductive path so that gas can flow more easily. The conductivity is maintained by propping with sand to hold the fracture faces apart. Typically, the fluid is innocuous and contains sand or some other permeable material. Because of some unique properties, the fluid systems and additives used for fracturing stimulation in conventional wells are not suitable for these resources. Thus, good understanding of the reservoir is mandatory before adopting any stimulation technique. (Zahid 2007)

Trillions of cubic feet of natural gas lie in tight gas reservoirs that 20 years ago were considered uneconomical to produce. Interest in these tight gas fields has increased substantially as new stimulation technology and market prices improve the economics of coaxing gas out of the these unconventional formations. CT fracture stimulation achieves excellent production results in previously by-passed laminated tight gas formations. By efficiently targeting specific gas-bearing layers with optimal stimulation treatments, the technique maximizes hydrocarbon production while minimizing the water production associated with traditional stimulation techniques. The service uses CT to convey and operate a sand-jetting tool, which cuts three perforations (120° phasing) in about ten minutes after the sand reaches the tool ports. Sand jetting is performed by operating at less than fracturing pressure to create clean, large holes with no debris in the perforation tunnel. Jetted perforation tunnels have less damage than conventional shape-charge perforations, have low near-wellbore pressure loss, and tend to initiate simple hydraulic fractures. This is particularly important in gas wells because simple fractures minimize tortuosity, a key factor both in ensuring proppant transport into the fracture and in producing gas through the newly created channel. To achieve frac pressures and rates, the frac is pumped down the casing/CT annulus. At the end of the fracture stimulation, a sand slug is pumped to isolate the zone from the next treatment. The next zone can begin immediately after CT confirms the integrity of the plug by "tagging" and performing a pressure test. Unlike limited-entry techniques, the jetted technology enables targeted stimulation of multiple producing zones. Most plug-and-perf operations can treat just two zones per day, but well-coordinated jetted operations can treat as many as four to five zones per day. In addition, the technique can complete many zones quickly, and cleaning out sand plugs is faster than drilling out multiple bridge plugs, thus accelerating time to sales. (Tullier 2007)

Hydraulic fracturing of the horizontal shale gas wells is performed in stages. Lateral lengths in typical shale gas development wells are from 1,000 feet to more than 5,000 feet in length. Because of the length of exposed wellbore, it is usually not possible to maintain a downhole pressure sufficient to stimulate the entire length of a lateral in a single stimulation event. As such, hydraulic fracture treatments of shale gas wells are performed by isolating portions of the lateral and performing multiple treatments to stimulate the entire length of the lateral portion of the well. Each fracture stage is performed within an isolated interval (for example, a 500 ft interval) within which a cluster of perforations is created using a perforating tool. Perforations allow fluids to flow through the casing to the formation during the fracture treatment and also allow gas to flow into the wellbore during the production phase of operations. In order to isolate each fracture stage of a fracture treatment, a packer is used to isolate each fracturing interval. (Arthur 2009)

The initiation of a fracture in a conventional treatment requires pressuring up the entire wellbore, and quite often, severely damaged perforation tunnels will increase the real life fracture initiation pressure well beyond the pressure that would be required in a nondamaged or even moderately damaged condition. However, when hydrajetting continues after the casing has been penetrated a clean non-damaged tunnel is eroded within a few minutes. Some of the jetting energy is converted into fluid pressure, which is additive to the system pressure out in the wellbore. If jetting continues as the wellbore pressure is increased when formation breakdown is desired, the actual pressure inside this tunnel will be hundreds of psi above the wellbore pressure to assist fracture initiation from the tunnel itself. This would rarely happen in conventional perforations in hard to very low perm reservoirs (Pongratz 2007)

The design process, including selection of proppants and fluids, pumping schedule, injected proppant concentrations, total job size, pump rate, and other parameters requires an idea of the desired outcome of the job: required fracture length, possible pack concentration and clean-up time. Critical measurements from testing the actual cores has allowed to sift through the chaff to find those "gems" in hydraulic fracturing that materially improve the completion efficiency in tight gas reservoirs. (Arukhe 2009)

Develop the Wellbore to Match the Reservoir Potential – "Rightsizing"

Solid expandable technology provides the means to establish the largest possible reservoir wellbore to support any type of perforating/fracturing technique without sacrificing maximum stimulation programs, production pathway or future re-entry requirements. The real value added is from the overall wellbore construction. By designing the well with expandables in the horizontal section, the entire drilling/casing program can be re-configured ("rightsized") and substantially reduce CAPEX. As an example, many horizontal multi-zone isolation wellbores designed in tight permeable formations consist of a 9-5/8" surface string, followed by a 7" intermediate string (usually installed through the build) followed by a 6-1/8" or 6-1/4" openhole (OH) horizontal section. The conventional non-expandable completion often consists of a 4-1/2" liner with a liner hanger packer tied back to the 7" intermediate string with a series of modified production packers and frac sleeves. Conversely a typical expandable wellbore would involve utilizing a 5-1/2" x 7" solid expandable liner with a finished ID of 5.5" - far greater than a 3.75" ID through the 4-1/2" liner.

Additionally, the same application could have a 4-7/8" openhole with a 4-1/4" x 5-1/2" expandable installed in the horizontal section providing a 4.210" ID. The expandable option still provides a greater ID than a conventional 4-1/2" liner and an equivalent or greater ID than a 5" liner. This provides the means to build the wellbore with a 7" surface casing string and a 5-1/2" intermediate string followed by the 4-7/8" openhole which accommodates the expandable. Slimming the well profile produces a higher rate of penetration thereby reducing rig days and saving overall project costs. Moreover, smaller casing strings, less drilling fluids, and less cement add additional cost savings while minimizing the environmental impact. The maximized and customized expandable wellbore will still provide greater flow areas to accommodate large coil strings, larger diameter perforating/fracturing assemblies, and high frac rates and volumes all optimizing the stimulation program while minimizing the surface treating facilities. **(Figure 3)**

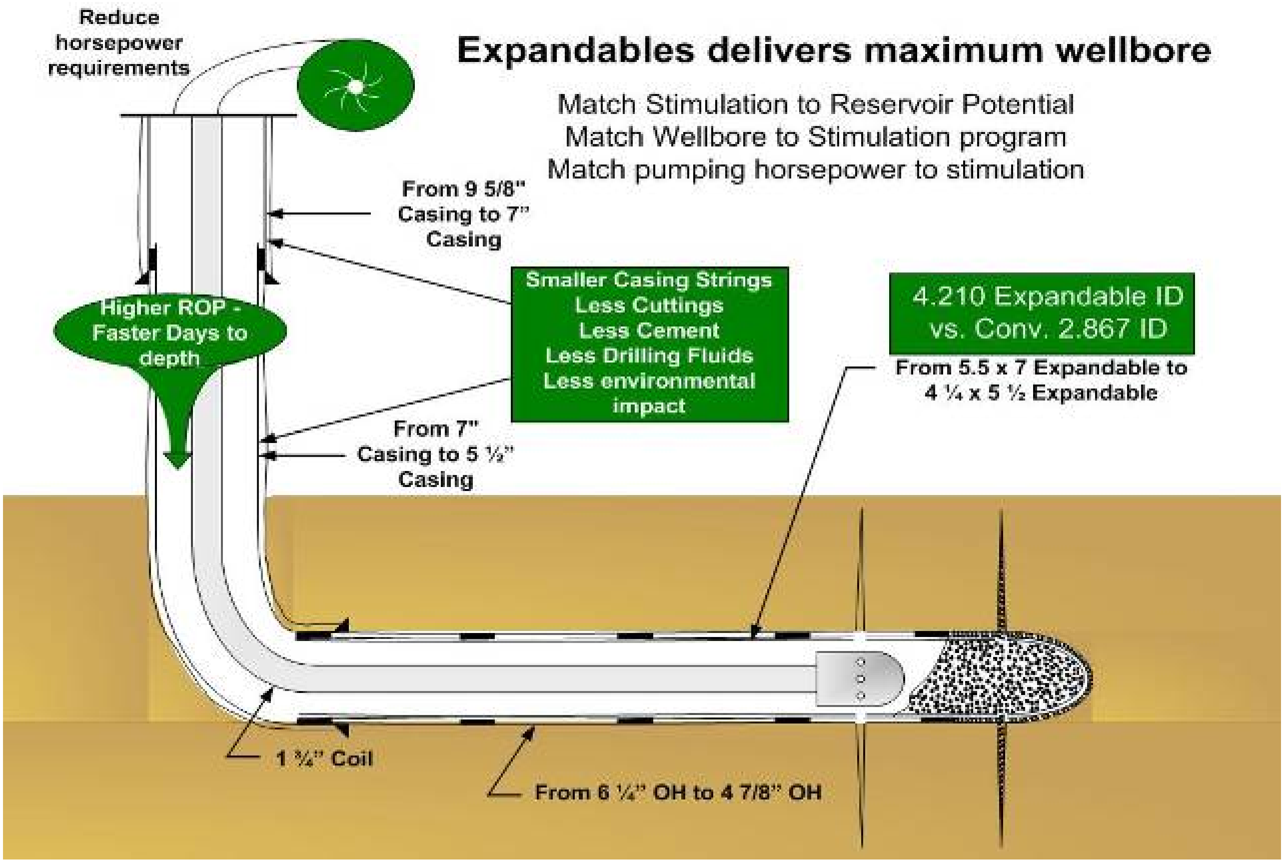

Fig. 3 – Expandable Wellbores allows one to re-configure the complete well program creating new value

Case History

Through 2007-2008 a North American operator planned and developed a total of 4 vertical/directional drills and 3 vertical recompletions. Operational and performance limitations were encountered such as frac placement failure (not placing fracs as programmed) 40% of the time and vertical well performance that was inconsistent and ultimately uneconomical. Re-evaluation of the development program led to the following conclusions:

- Drill and complete a horizontal wellbore to accommodate a multi-zone fracturing completion
- Need to grow fracs vertically throughout pay
- Desire to execute fracs at reasonable costs
- Determination of optimal size, spacing, and type of production completion
- Utilize recent technology developments that have enabled efficient stimulation of multiple zones in horizontal wells

The operator considered and evaluated a number of completion options taking into account drilling and completion impact, the cost and risk of the different options and, most importantly, options providing the most flexiblity to adjust plans as the program progressed. This flexibility was needed to evaluate a variety of frac materials and programs to gain an understanding of the performance of each. High rate slick water fracs, conventional gelled water and hybrid alternating gelled and non gelled fluids were utilized and evaluated. In addition, they desired the largest possible wellbore to reduce friction during treating to minimize surface pressure equipment and lines (reduced horsepower equates to significant savings).

Through a risk analysis the following were some of the parameters considered:

- Hole Profile and Condition – This affects zonal isolation. The success of certain systems is more dependent than others on hole condition. Most significantly, frac isolation for the packer systems is dependent to varying degrees upon an effective packer seal against the borehole.
- Downhole Mechanical Systems – Oil tool complexity (higher for packer and sliding sleeve type devices) affects the reliability of each system. Failures with complex downhole systems will result in high refracturing costs, lost opportunity for refracturing and possible formation damage if complex fishing operations result. Systems that rely on permanently deployed downhole mechanical devices will rate higher in this category.
- Surface Mechanical Systems – Systems relying on CTU or with complicated hydraulic fracturing techniques which rely on precise timing or coordination of multiple services will rate higher in a risk analysis because of reliability issues. However, system failures in this area are generally lower risk because the more complex components of these systems are on the surface.
- Frac Placement – Some options will increase the risks against effective frac placement. Control over frac initiation point, opportunities for on-the-fly frac design adjustment, and reperforation will increase the chance of success. Coiled tubing methods enable screened-out frac treatments to be circulated out and reperforation with equipment already in the well. Casing fracs are much more restrictive in these areas.

First Well

The first well casing construction consisted of a 9-5/8" surface string, a 7" intermediate string through the build followed by a 6-1/8" openhole horizontal. The expandable assembly consisted of 71 joints of EX-80 expandable casing with multiple isolation anchor hangers (utilizing swellable technology) in the openhole and conventional elastomers on the anchor hangers in the tie-back section. A four stage/interval frac program was performed utilizing a variety of frac fluids. Micro-seismic monitoring indicated all four fracs were hydraulically isolated by the swellable anchor hanger sections.

Well Results

- Liner expanded as expected and without incident
- Liner pressure tested as expected, held pressures up to 5800 psi during stimulation operations
- No liner-related issues with any coil tubing operations
- Micro-seismic indicated all swellable anchor hanger sections maintained integrity during fracs and provided hydraulic isolation

Lessons Learned

- Doglegs in horizontal section increased hole drag
  - slowed down drilling rate of penetration
  - liner landed short of TD (230 ft.)
- PDC bit run in horizontal section lead to lost time back-reaming as well as reaming the hole on final cleanout trip
- Lubricant used to reduce torque and drag while drilling horizontal section may have caused premature swelling of seals
- Difficulties dropping landing dart due to differences in fluid hydrostatics and working height on rig floor

Second Well

The second well casing construction consisted of a 9-5/8" surface string, a 7" intermediate string through the build followed by a 6-1/8" openhole horizontal. The expandable assembly consisted of 63 joints of EX-80 expandable casing with multiple isolation anchor hangers (utilizing swellable elastomers) in the openhole and conventional elastomers on the anchor hangers in the tie-back section. A five stage/interval frac program was performed utilizing a hybrid gelled frac fluid. Micro-seismic monitoring indicated all five fracs were hydraulically isolated by the swellable packers.

Well Results

- Achieved almost all objectives:
  - Designed repeatable drilling and completion program
  - Placed fracs in the reservoir where desired without screening them out
  - Gained wellbore design flexibility to adapt the completion on the fly
  - Created economically producing wells

Future Considerations

- Re-examine wellbore construction in light of learning’s from 2008 wells
  - Frac design: pump rates and sand/fluid volumes needed to achieve the same production results
  - Frac placement: moving towards a different lower cost design

- Improve drilling program for horizontal leg
- Tweak liner installation procedure

Conclusion

Expandable technology provides a maximized wellbore that reduces surface treating pressure while allowing high pump rates and volumes. Several expandable systems were installed in horizontal multi-zone isolation wellbores and estimated production rates were met. Lesson learned prove that expandable solutions can be customized to meet most any type of well program. These systems:

- provide an optimized wellbore in the reservoir,
- slim the overall casing program,
- pass through various build rates,
- reach TD (tubing depth) of extended horizontals,
- minimize horsepower requirements for a given treatment program,
- and many other benefits as previously noted.

Solid expandable systems are commonly used and integrated with many other conventional and advanced completion or workover production solutions. Combined with technologies such as conventional completions (such as tie-back or polished-bore receptacles, stingers, latches, plugs, etc.) and intelligent completions, multi-laterals, swellables, perforating and fracturing techniques, coil tubing, etc. Expandables will continue to evolve to address ever-changing technical challenges providing operators new and more cost effective and problem-solving alternatives.

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