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Innovative Completion Technology Enhances Production Assurance in Alaskan North Slope Viscous Oil Developments

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Abstract

In the challenging North Slope operating environment, use of innovative production equipment has provided solutions to zonal isolation and packer integrity problems in viscous oil reservoirs. Operators have employed new tools and technology utilizing expandable rubber materials to manage annular fluid flow, control solids/shale production, and achieve zonal isolation in wells where high costs, shallow depths, and long step-outs create unique completion challenges. The new technology is allowing once bypassed zones to be added to existing developments, and making future developments more economically viable.

The new design approach involves installing swelling rubber packer (SRP) technology as part of the completion. This technology is based on specially designed swelling properties of rubber in crude or mineral oil based mud (MOBM) to expand and seal the annulus.

The paper describes one operator's use of as many as 17 devices in a tri-lateral horizontal undulating well to manage annular flow and minimize shale/solids production. The successful application of this technology has allowed shale interbedding to be effectively isolated behind blank pipe, thus allowing an additional zone to be added to the existing development. To date the technology has been applied to eleven wells, improving production assurance.

Another major operator on the North Slope has used the technology to isolate potentially conductive fault crossings along the lateral and inadvertent zonal crossings while kicking off from the parent bore. Multiple packers have been run in single laterals to achieve the desired isolation without noticeable effects on liner running drag. Recent density caliper data shows significantly more washout than previously envisioned, increasing the desire to manage annular flow.

Development and application of this SRP technology is detailed in the paper, including documentation of improved efficiencies as a result of its use. The paper will also discuss field operations, installation, and unique considerations associated with design and installation in viscous oil environments.

Introduction

On the North Slope of Alaska, it has been estimated that between 20-25 billion barrels OOIP of viscous oil are contained within shallow, regionally extensive sands. [1,2,3,4,5,6] **(Figure 1)** To date, development of these viscous oil sands has been deferred in favor of the warmer, less viscous oil that lies below. The presence of the highly viscous oil in the shallow sands results from oil biodegradation and low reservoir temperatures due to the extreme northern latitude, the presence of 1,800 feet of permafrost, and its relatively shallow burial depth.

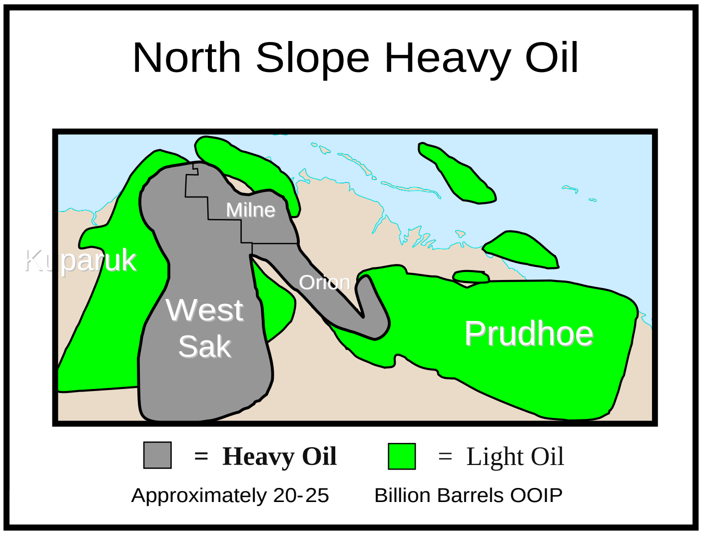

Figure 1: North Slope Heavy Oil Reserve Base

The North Slope Viscous Oil Reservoirs are located in the West Sak (WS) and Schrader Bluff (SB) Sandstone formations. Both formations will be discussed in this paper and have similar reservoir characteristics. These reservoirs are located above the light oil Kuparuk and Ivishak reservoirs as seen in **Figure 2**.

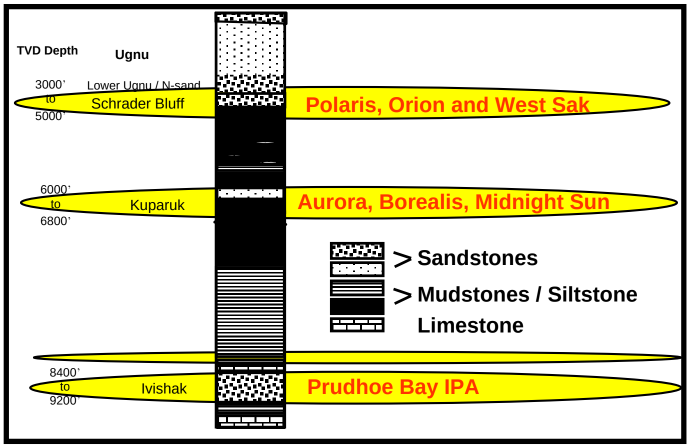

Figure 2: North Slope Geological Cross Section

Geologic Discussion and Development History

The WS / SB sands are unconsolidated very fine to fine grained, single and amalgamated sandstone/siltstone beds. The reservoirs consist of vertically stacked sand intervals separated by muddy siltstone intervals as seen from **Figure 3**. There are regional differences in reservoir layering moving from east to west, with the most notable changes being the number and depths of the individual sand intervals. The reservoirs are located at depths between 3,000 – 5,000 feet TVD, with depths increasing towards the east. The viscosities of the oils within these reservoirs range from 10 to 3,000 cp at reservoir conditions. The API gravities of the same oils are between 13° and 24°.[7,8]

The high viscosity crude in combination with unconsolidated reservoir rock has resulted in a tendency of the reservoir to produce solids.[6] As a result, conventional wells with downhole sand exclusion became the development strategy of choice for the majority of the pilot projects and early development as viscous oil production was being optimized. However, in an effort to maintain higher production rates improve economics, the completion philosophy has shifted to surface sand management and the wells are now completed with “Big slot” slotted liners without sand exclusion.(6) This change in completion strategy in combination with horizontal multi-lateral technology and improved drilling fluids has increased the WS/SB production dramatically. Initially, production rates of 100-200 barrels of oil per day (BOPD) were achieved from vertical fracced wells, and now horizontal, multilateral wells deliver rates over 5,000 BOPD.[9]

Above the WS / SB sand sequence, the colder, more viscous oil in the Lower Ugnu / N-sand sequence is now being completed and produced with horizontal laterals and downhole sand exclusion. These sands are slightly higher on structure and more unconsolidated than the WS / SB reservoir and consequently have different challenges to overcome to successfully and economically develop the resource. One case study in this paper discusses recent development strategies employed to develop the Ugnu / N-sands in conjunction with the SB sands.

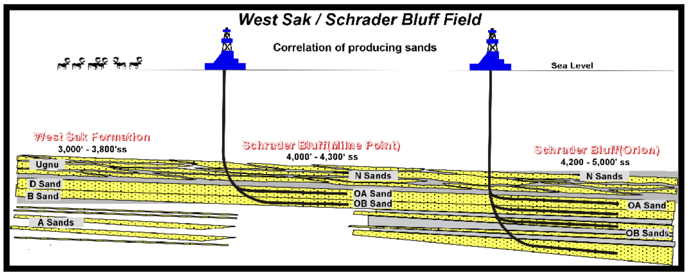

Figure 3: Regional Viscous Geologic View

Swelling Rubber Packer Technology & History

Hydrocarbon swelling rubber packer (SRP) technology was first introduced in the Norsk Hydro, Grane heavy oil field in the Norwegian sector of the North Sea in 2001. Through extensive development efforts, SRP technology was designed for different conditions and applications ranging from low temperature, heavy oil applications as discussed in this paper, to high temperature gas conditions.[10,11,12]

The application of this technology provides downhole zonal isolation while alleviating many of the shortcomings and difficulties associated with cement placement and other annular isolation devices. The SRP relies on the expansion properties of a bonded elastomer to provide an annular seal when the rubber is exposed to hydrocarbons. The unique aspect of SRP technology is that it has no moving parts and requires no service tools or surface operations to be activated or installed. The technology's efficiency allows operators to reduce installation complexities and significantly cut costs for rig time and materials.[12]

Construction and Swelling Design

SRP technology consists of a standard oilfield grade tubular with layered rubber bonded along the length of the tubular. The rubber element swells through the absorption of hydrocarbons, resulting in an annular seal. The source of these hydrocarbons can either be from the reservoir, the drilling fluid or a specially formulated spotted fluid.

The swelling is controlled by a thermodynamic absorption process. When the thermodynamic properties of the rubber and hydrocarbons are close to each other, the attraction between the molecules causes the molecular structure to stretch, allowing oil to enter the structure. The swelling can cause a change of several hundred percent in the rubber volume when the packer is unconfined.

Although the packer will not swell in pure water, tests and field applications have shown the packer will swell in water cuts where only traces of hydrocarbon are present.

The swelling process is time-dependent and is primarily controlled by the viscosity and temperature of the hydrocarbon being absorbed. Swelling is homogenous along the element length, and the hydrocarbon does not degrade the rubber structure. The hydrocarbon alters the mechanical properties, reducing the hardness, tensile strength and Young's

Modulus. The change in mechanical properties is a function of the volume change in the rubber element.

Positive swelling pressure is developed which exceeds the surrounding pressure by a few psi. This swelling pressure is very different from the sealing pressure of the packer. The sealing pressure is the maximum estimated pressure differential across the element. The sealing ability depends on the absolute swelling (hole size versus packer dimensions), not the swelling fluid.

Packer Types

Different SRP configurations and sizes can be employed depending on the downhole conditions and the drilling fluid. SRPs are designed with two standard configurations: stand alone subs and slip-on sleeves. Industry standard lengths for the stand alone sub element length range from 10 – 20-ft and the slip-on sleeve elements are normally 12-in. long. However, the stand alone subs and slip-on sleeves can be manufactured to meet the needs of the specific application.

SRPs must also consider deployment fluid in their design since hydrocarbon activates swelling. As such deployment in water based muds require little special running design features. For deployment in an oil-based mud system a packer with a multi-layered construction normally is used to delay the onset of swelling while the packer is deployed into the well. **(Figure 4)**

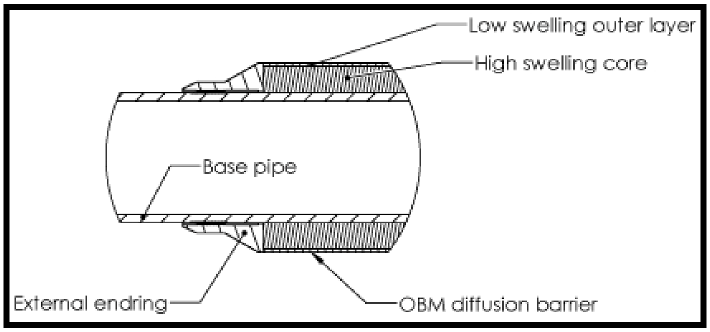

Figure 4. Swelling packer design

The packer consists of a high swelling inner core surrounded by a low swelling outer layer and a diffusion barrier. The outer two layers typically delay the onset of swelling by 72 hours, but this property can be tailored to the application. With Alaska's low temperature viscous oil (70° – 90°F), testing showed the diffusion layer was unnecessary and thus it was eliminated from the design even though OBM was the deployment fluid.

Design, Simulation, Testing, and Deployment

The application and design of an SRP is based on three key variables: the open hole size, required minimum differential pressure across the packer, and the time to seal.

Extensive testing on the expansion properties of the elastomer has led to the development of simulators which can predict the expansion ratio, differential pressure capability and time to seal for a given base pipe and outer element diameter. These simulators are used to design and size a packer for a given application and are key to proper design. The final hole size must be considered carefully in the design phase to ensure the SRP is sized correctly to fill the annular space and sustain the required differential pressure. These simulators are extremely important in a cool, viscous oil environment because of the slower swelling times when compared to lighter crude or mineral oil based mud (MOBM). Laboratory and SRP coupon testing was performed for the viscous oil reserves described in this paper in order to determine the expected expansion times for its unique condition and to ensure simulation results matched laboratory measurements. By placing pieces of rubber into wellbore fluids and comparing against known swelling rates for packers, the predicted expansion rates were determined for the drilling fluids to be used in each of the cases. The tests determined the OBM sleeve was not necessary, and the time required for the packers to expand completely to the open hole diameter was less than the time needed for the well to be put on production, *i.e.*, the period when the MOBM was still in the wellbore.

Since the packer has no moving parts and requires no surface or downhole activation, deployment is very straightforward. The packer is simply made up as part of the completion or casing string and deployed with the assembly in a single trip.

Swelling for Alaskan North Slope Viscous Oil

The amount of time required for the SRP to seal within the annulus is dependent on the following parameters:

- Viscosity of the hydrocarbon fluid (thus also temperature)
- Completion fluid (water based mud (WBM), MOBM or spotted fluid), WBM or OBM packer design
- Gap between original packer OD and hole ID
- Running time

Viscosity of the hydrocarbon fluid

As discussed previously, the viscosity of the hydrocarbon fluid is the driving mechanism of the rubber element diameter expansion timing. Downhole temperature changes result in fluid viscosity changes, and therefore will ultimately effect the expansion times.

Figure 5 illustrates the viscosity effects on the swelling curves. Exposure to a viscous crude will result in a slow swelling time. If a faster swelling is desirable, the packer should be set in a spotted fluid (such as diesel, base oil or MOBM) which has a lower hydrocarbon viscosity than the reservoir fluids.

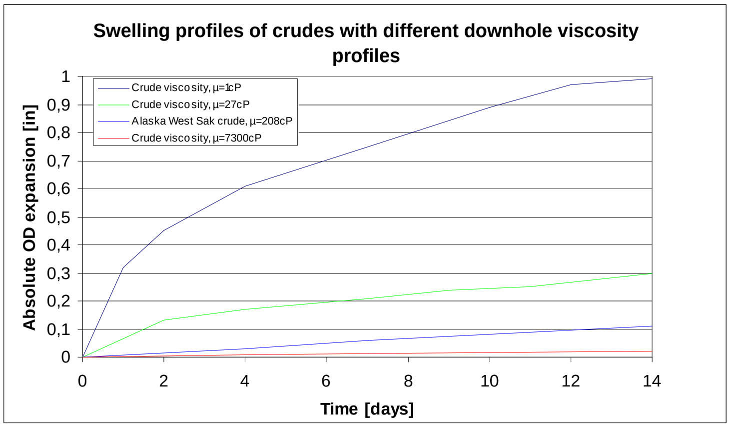

Figure 5. Viscosity Effects on Swelling Curves

Table 1 illustrates the differences in equivalent sealing times of a 5.5-in x 8.2-in SRP within an 8.5-in hole, when immersed in various fluid viscosities.

5.5-in x 8.2-in SRP 8.5-in hole	Time to seal			
Viscosity, µ	1cP	27cP	208cP	7300cP
Time in days to expand 0.3-in	1 day	15 days	111 days	3,903 Days

Table 1. Equivalent Sealing Times

Figure 6 is a graph showing the variation of Alaskan crudes to the MOBM used to drill the wells. The SRP reaches sealing OD within 7 days when submersed in the MOBM, whereas it takes 111 days to seal in the crude. Thus, immersion in the MOBM is recommended to ensure minimal swelling times and to decrease the risk of annular washout around the packer during initial production.

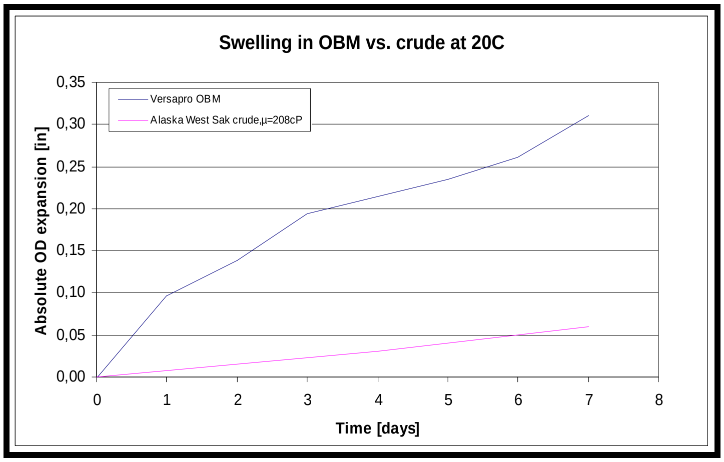

Figure 6. Swelling profiles for a WBM SRP in oil based mud compared to heavy Alaska West Sak crude.

The packer length has no influence on the timing to seal, but it has importance regarding the differential pressure capability.

For fastest possible seal, the gap between the packer OD and the hole ID should be minimized, especially in heavy viscous fluid reservoirs. A large OD packer will help ensure a high differential pressure seal is achieved prior to the wellbore being invaded with viscous crude during initial production. Large OD packers will also assure a better seal within wellbore washout intervals.

Completion fluid (WBM or OBM)

The SRP will swell only when there is access to hydrocarbons. The expansion velocity of the SRP rubber when exposed to MOBM is dependent on:

- the viscosity of the base oil for the oil based mud
- the low swelling rubber thickness
- the OBM diffusion barrier type and thickness

It is possible to run a WBM packer in an oil based mud, but it is important to know the exact swelling parameters to be sure the packer OD will not increase significantly while being run in the hole. The SRP simulator gives a predictable expansion time for a given hydrocarbon. As noted before, with Alaska's low temperature viscous oil (70° – 90°F), testing showed the OBM layer was unnecessary and was eliminated from the design even though OBM was the deployment fluid.

Alaska Schrader Bluff Operations

BP Case Study #1 & #2:

The current Orion / Polaris developments target between 3 and 5 laterally extensive sands (**Figure 3)** with horizontal multilateral producers utilizing TAML (Technological Advancement of Multilaterals) level 3 junction systems and 4-½" slotted liner completions (6-¾-in hole size). Each ML well exposes 15,000 – 27,000-ft of reservoir, with an average lateral length of 4,000 – 7,300-ft. Mineral oil based mud (MOBM) has become the drilling fluid of choice along with displacements to solids free MOBM prior to the completion of each lateral. Liners are run after pulling the whipstock via a bent joint; consequently anything run in conjunction with the liners has to be configured so as to not hang up in the window while running.

SRP configuration, hydrocarbon / MOBM swell testing, and several viable utilization strategies were developed and assessed to ensure all necessary issues were covered prior to installation. The SRP OD (6.3-in. – 6.4-in.) was based on the bit size plus expected washout, with the goal being to minimize running difficulties and maximize the differential pressure rating (planned for 1,000 psi) across the element when fully swelled. The SRP element length of 10-ft was decided based on minimizing assembly stiffness while ensuring adequate length to reduce the risk of failure across the element.

Packer configuration was a critical design due to the absence of whipstocks when running the production liners, as mentioned previously. Modified end rings were developed and installed on each end of the element to prevent snagging on the sharp window edges and on ledges throughout the horizontal lateral. In addition, 2-ft pup joints with centralizers are bucked onto either side of the SRP sub to aid in centralization through the window and throughout the remainder of the horizontal lateral while running. Reservoir temperature and MOBM rheologies did not equate to efficient swell times; this coupled with relatively short running times, allowed for the exclusion of the diffusion layer typically needed to slow swelling throughout installation.

Sand interval thicknesses range from 10 – 35-ft with permeability sweet spots ranging from 5 – 15-ft. It is fairly common when drilling the horizontal laterals to cross unforeseen faults, either below seismic resolution or shadowed by other faults along the laterals. These faults can range from 5 – 50-ft of throw and can result in involuntary drilling out of zone into the overlying or underlying sand intervals which can result in along-the-lateral commingling during well production. The reservoir heterogeneity tends to significantly complicate lateral contribution expectations and reservoir management strategies. Thus, this form of commingling is undesirable from a reservoir management perspective due to the variability in rock quality, oil quality, and expected water breakthrough potential along and between individual laterals. Thus, when drilling out of zone occurs in conjunction with significant variations in rock quality and oil quality, SRPs and blank liner are utilized to isolate the interval from the reminder of the lateral (**Figure 7**).

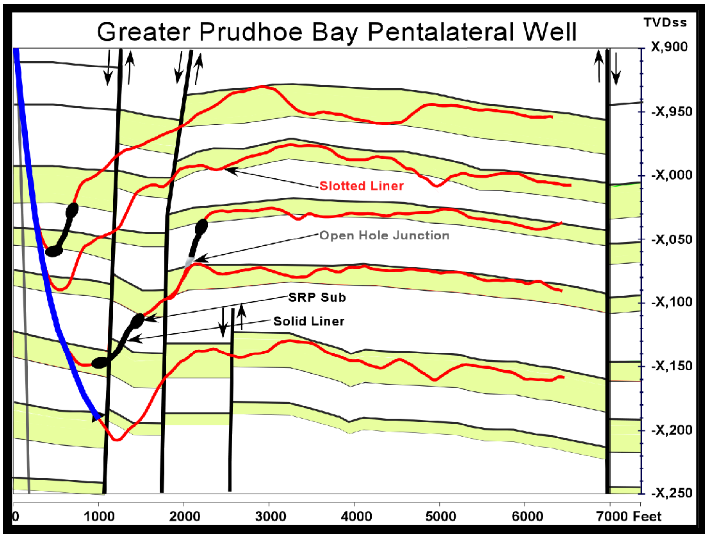

Figure 7. Interval Isolation using SRP and blank liner

Because the individual laterals are most often drilled within the same vertical plane, stratigraphic and structural insights are transferred from the lower to upper laterals, aiding in trajectory planning for optimal placement of the packers.

One well within the Polaris development employed five SRP subs: four to isolate fault crossings within two laterals and one to isolate an open hole junction on another lateral (**Figure 7**). Liner and junction installation problems on one lateral necessitated the removal of the liner containing two packers that had been run outside the casing window. The SRPs were run to 6,400 ft within the mainbore casing and 1,500 ft outside the window in the inverted horizontal hole prior to being reciprocated for 7 hours while attempting to get the liner and junction installed. The liner and packers were pulled out of the open hole and the junction equipment on top of the liner assembly was changed out. The assembly was then rerun back out through the window and again was not able to be installed. The decision was finally made to pull the liner and SRPs out of the hole after being immersed in the MOBM for 48 hours. The packers came out of the hole visibly undamaged after being run in and out of the hole and through the unprotected window twice; however the SRPs swelled from a nominal OD of 6.4-in to 6.52-in**.**

Table 2 shows the progression of the circumferential OD measurements that were taken on the SRP subs after being pulled out of the hole.

Table 2. Circumferential OD Measurements after POOH

Detailed SRP Sub Dimensional Data		
SRP Measurement Interval	**SRP #1**	**SRP #2**
1 ft	6.5-in	6.52-in
2 ft	6.53-in	6.52-in
3 ft	6.52-in	6.52-in
4 ft	6.50-in	6.52-in
5 ft	6.52-in	6.52-in
6 ft	6.52-in	6.50-in
7 ft	6.52-in	6.52-in
8 ft	6.50-in	6.52-in
9 ft	6.50-in	6.50-in

The measurements were taken every foot down the element to show potential anomalies in swelling distribution along the element. The data clearly illustrates a very even swelling distribution along the SRP element, as well as the striking similarity in overall OD between the two SRP subs. Furthermore, the swelling rate seen on these packers is within 5% of the empirical swelling rates derived from the simulators (**Figure 6**)

Once the SRPs are immersed in a hydrocarbon, removed and then reimmersed, the swelling speed increases. Since swelling causes relocation of the rubber molecules, the second deformation requires less force than the initial swelling, much as a balloon is easier to inflate a second time. Based on the swelling that had occurred and the critical nature of the installation, rerunning the packers was deemed too risky and two new packers were picked up and run without incident after conducting remedial work on the casing window area**. Figure 8** shows the configuration and condition of the stand alone SRP subs after removal from the well.

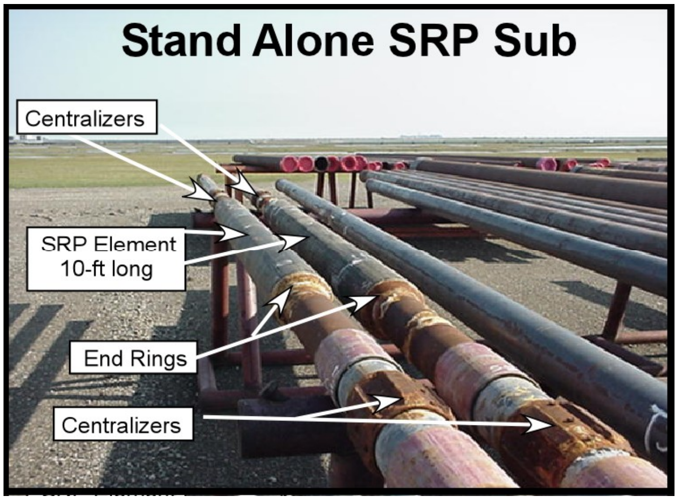

Figure 8. Stand Alone SRP after POOH

Recorded density caliper data was acquired within the 6-¾-in laterals on this well and showed an average hole size of 7-½-in with IDs in excess of 8-in over some intervals. This hole size is bigger than expected and will require careful analysis of hole size across an interval prior to SRP installation. Further understanding of the differences in hole size between the sand and siltstones will be imperative to a successful application of the SRP technology. A comprehensive liner running drag analysis program was conducted during the running of the liners, with no visible differences in friction factors or trends associated with the addition of the SRPs to the liner assemblies.

Another horizontal multilateral well within the Orion development was intentionally drilled downstructure toward the aquifer in order to optimize the development pattern within the polygon. The risk of water breakthrough from the aquifer at the toe of each lateral was considered relatively high, and if breakthrough occurred, would eliminate oil production from the uphole lateral sections due to the fluid mobility differences. Thus, two SRPs were run per lateral, strategically placed half-way and two-thirds down the lateral, to allow future through tubing lateral segregation or lateral segment isolation (**Figure 9)**.

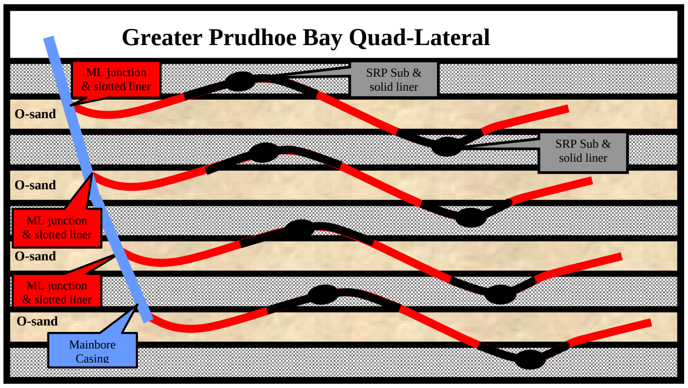

Figure 9. Strategic positioning of SRPs

These SRPs were also run through unprotected windows and out to depths as far as 11,170 ft MD (3,500 ft in horizontal open hole). The packers were intentionally placed within planned shale exit points along the lateral to further increase the likelihood of slowing the imminent migration of water along the lateral throughout the life of the well. Four joints of blank pipe were run on either side of the packer to isolate the shale and provide adequate space to position inflatable packers on coil tubing. Drag data was acquired for all liners run on this well and compared to drag data acquired on past wells where no SRPs were run. The data shows negligible effects on friction factors or slack-off weight. The SRP stand alone subs do weigh more then a standard liner but do not appear to add any significant difficulty to liner installation in these shallow ERD wells.

BP Case Study #3

The Milne Point O-sand sequence (**Figure 3)** has been being developed for several years via TAML level 3 horizontal dual lateral wells with great success, employing only slotted liners as the lateral completion of choice; resulting in manageable levels of sand production which have been handled at surface. It was not until recently that a push to develop the more unconsolidated N-sand section lying just above the O-sand sequence became a reality. It was realized early on that the economic development of the N-sands was conditional upon adequate sand control. Thus, commingled development of the N- and O-sand reservoirs within one well would not be possible without the proper well design.

Several well designs have been used to achieve the necessary downhole sand control to enable the addition of an N-sand lateral to an O-sand ML well. The major factor that determines the well design is the thickness of the sealing siltstone which lies above the N-sand target (**Figure 10**).

The N-sand sequence is similar to the underlying O-sands in that each interval is separated by an overlying and underlying siltstone interval. The sands above the N-sand siltstone are often wet; thus isolation of the N-sand lateral from the overlying wet sands is essential to prevent potential water production.

If the siltstone above the interval is too thin to set a junction and stand alone SRP with sufficient separation from the overlying and underlying sands, then an inverted well design is required **(Figure 10)**

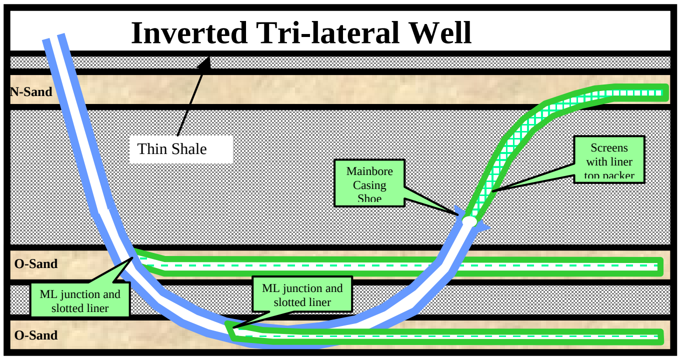

Figure 10. Inverted well design required by formation specifics

The inverted well design makes it difficult to plan the landing points, is difficult to drill and does not accommodate efficient reserves access. In the inverted well configuration, the N-sand lateral, being in most cases bound on all sides by faulting and/or nearby wells, is often considerably shorter than desired, with the lateral landing point up to 1,000 feet from the mainbore.

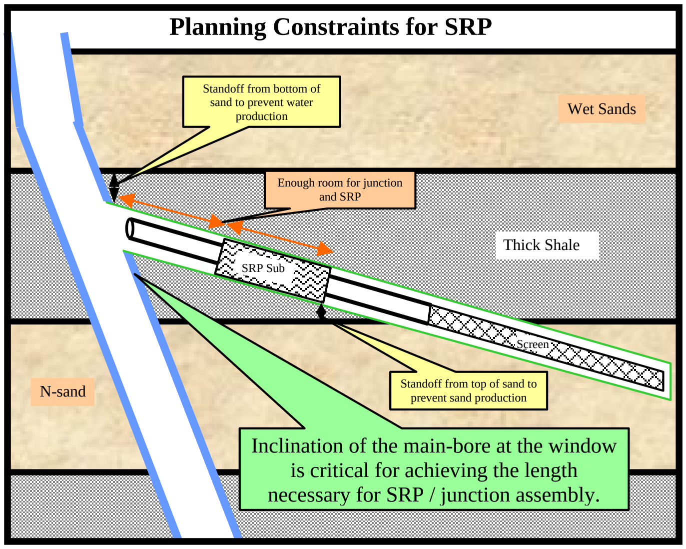

Figure 11. Determination of well design based on formation

A more efficient N-sand lateral well design can be achieved in areas where the siltstone overlying the N-sand is thick enough to allow a junction and SRP sub to be set with confidence. In these areas, the SRPs provide the necessary isolation from the overlying wet sands to prevent water or sand production from behind the SRP sub. **(Figure 11**)

The ability to change the well design in conjunction with the SRP sub utilization has resulted in longer N-sand lateral lengths, less tortuous trajectories, cheaper well costs; better future remediation options, and an overall superior N-sand development strategy. To date, three wells have been drilled using this design, all of which are producing as per the forecasts, with sand production falling within planned quantities and grainsize distribution.

Alaska West Sak Operations

Initial Proof of Concept and COP Case Study #1

The West Sak reservoir has three primary sandstone targets- the D, B, and A intervals. The upper two zones are accessed by long horizontal slotted liner completions, but the lower zone is separated by a shale layers and no single pay section can justify the cost of a lateral. A horizontal undulating well was drilled in the lower zone in June, 2003, and was completed with a preperforated liner without shale isolation. Production, however, could not be maintained in the well, because wellbore solids collapsed and blocked off flow in the liner on multiple occasions.

The next well in which the lower zone was drilled was in June, 2004. This well was drilled and completed with the application of twelve slip-on SRPs on blank liner across shale zones in order to isolate the water sensitive shales from inside the slotted liner (**Figure 12).** This was the first application of the slip-on SRP technology on the North Slope. The liner with SRPs was successfully run in the hole without incident or operational trouble time.

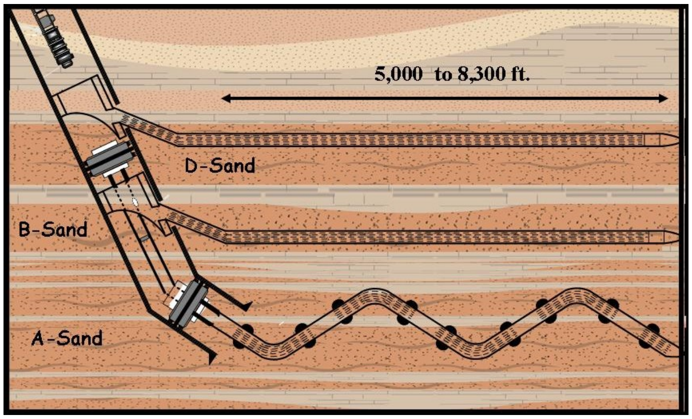

Figure 12. SRPs on blank liner across shale zones

The zone drilled in this well and now being developed in subsequent wells contains approximately 20 feet of net pay separated one or two shale layers. The geologic structure has been described by either

(1) two ten-foot sand packages with one ten- foot shale between, or

(2) three thinner sand packages with two shale layers separating the sand lobes depending on the well.

To date, all eleven subsequent wells have utilized SRP technology. More importantly each tri-lateral well, including this first installation with isolation of the shale layers in the lower zone, has maintained contribution from the lower zone as shown through production logs and geochemical fingerprinting.

COP Case Study #2- 1E-168

As mentioned previously, West Sak has three major sand packages. By keeping the shales isolated, the lower package becomes a desirable target when the 20-foot sand package is completed with an undulating well design.

In one particular well (1E-168), 17 slip-on SRPs were run in the lower undulating lateral (**Figure 13**). Of these, 14 of the packers were needed due to the planned isolation of shales in the undulating well design, while deviations out of the target sands accounted for three additional packers, one of which isolated a shale section at the heel of the well.

In well 1E-168, 6.3-in. OD SRPs were run on a 4.5-in. liner inside a 6.75-in. drilled wellbore.

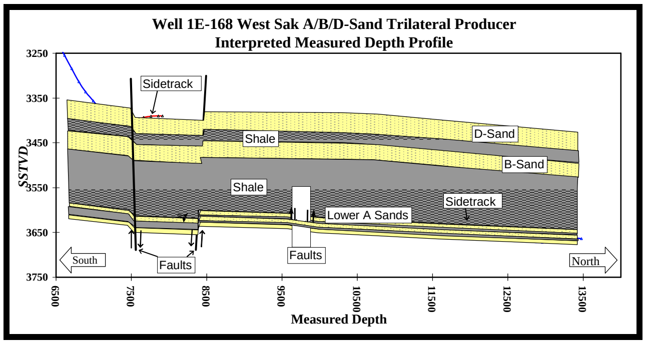

Figure 13. Multiple SRPs used for isolation on undulating lateral

The undulating nature of these wells, relatively high rates of penetration (~250 feet/hour in good sand), and the logging tool location 30 to 60 feet behind the bit result in occasional excursions out of zone in a number of wells, including this one. Often, if the well can be steered back into pay in less than 500 feet, the wells are merely undulated back into the pay section to avoid time-consuming sidetracking (as was done from 9650 to 9950 ft MD when multiple faults were crossed). Utilizing SRP for production assurance knowing our shale sections are isolated allows for this reduced sidetracking requirement to be possible.

Correctional geosteering could not have steered the wellbore back into zone within 500 feet in a later excursion in the lower lateral of 1E-168 when the bit drilled out of zone, requiring an open hole sidetrack at 11,725 ft MD. Unless a sand section is penetrated in the excursion, open hole sidetracks are not isolated by SRPs, because the low permeability of the shale limits the inflow to the extent that SRPs are not needed for isolation.

After the lower lateral liner was landed with a liner top packer and hanger, the B-lateral window was milled off a whipstock. The milling operation went as planned and the lateral was drilled to a depth of 11,927 ft MD. The entire lateral was in zone except for a 155-ft excursion from 10,678 ft to 10,833 ft MD, where two SRPs were run to isolate a shale section. Both slip-on SRPs exited the window (without a whipstock) without incident on this well and production has been maintained indicating that shale/silt isolation is successful.

The D-lateral was milled out of the 7-⅝-in. casing using a whipstock also. The well was steered out of zone ~250-ft from the window, and was low-side, open hole sidetracked at 7,431-ft MD. The liner was run to a TD of 11,937-ft, and no SRPs were run in the upper lateral.

Overall, 1E-168 had 19 SRPs to isolate shale sections from the slotted liner. There did not appear to be an increase in drag running the SRPs on the slotted and blank liner, despite the relatively small clearance between packer OD and wellbore ID. (Every joint in the WS liners run to date has a floating centralizer.) Drag modeling for the lower lateral run with 17 packers did not account for any drag increase from the packers, but still matched expected friction factor values established through numerous liner runs without SRP technology, **(Figure 14)**.

Well 1E-168 has maintained production from all three laterals during initial production, which is the best indication that the SRPs are holding.

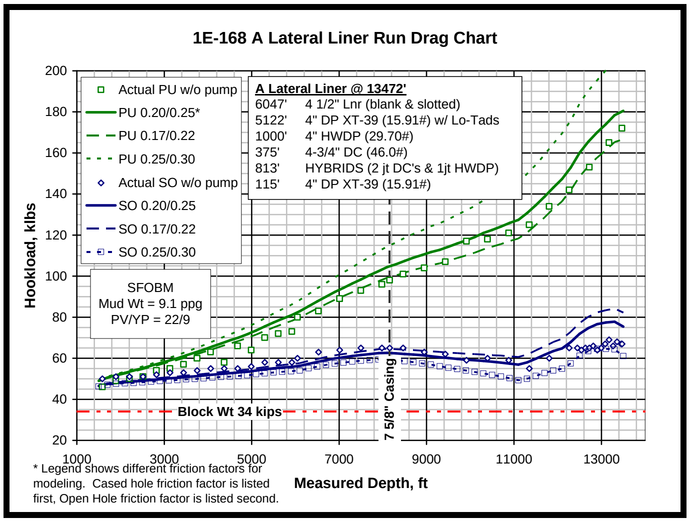

Figure 14. Drag for Lower "A" Lateral on 1E-168

COP Case Study # 3- 1E-105

The 1E-105 well was planned as a horizontal, tri-lateral injector targeting the West Sak A, B, and D Sands. This well has a 9-⅝-in. intermediate casing and 8.5-in. laterals. In this well, 8.1-in. slip-on SRPs were run on a 5.5-in. liner inside the 8.5-in. drilled horizontal wellbore. The schematic for 1E-105 can be seen in **Figure 15.**

The intermediate casing was run without incident, and casing was cemented with full returns throughout the job. The casing shoe was drilled out at 8,920-ft and the A Sand was drilled to 13,539-ft. The A-Sand liner was run to 13,519-ft using slip-on 15 SRPs without incident.

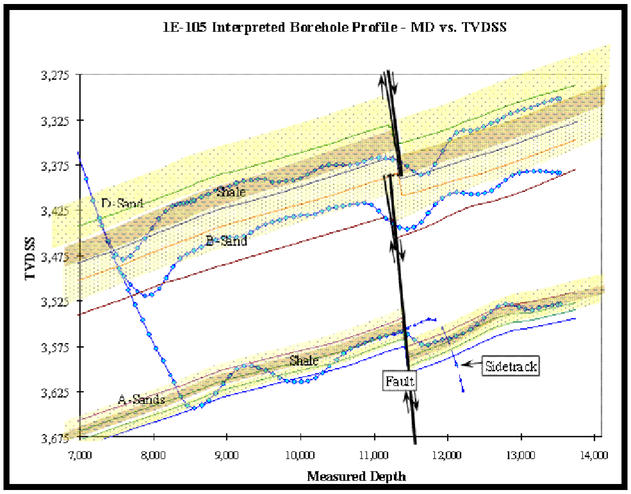

Figure 15. Schematic of horizontal tri-lateral injector well

The window was milled for the B lateral from 7,524-ft to 7,540-ft. Shortly after milling the window, a concretion was drilled, which altered the trajectory of the well deeper than planned immediately outside the casing. Besides changing trajectory, the concretion also slowed down drilling with the window milling assembly due to the hard properties of the rock. A caliper log showed the hole section immediately outside the window was washed out to approximately 9-10-in. for the first 10 feet outside the casing window. The well ended up dipping out of zone before the trajectory could be corrected. The rest of the B lateral was drilled to 13,529-ft as planned.

During the running of the liner in this well, a number of centralizers and at least one SRP were torn off of the liner and deposited into the mainbore of the multi-lateral. This equipment was later captured with a mill and junk basket in the main bore. The exact cause of the equipment being torn off the liner is not known, but was likely a combination of several factors. Theories include the stiffer 5-½-in. liner applying more force to the liner jewelry than previous 4-½-in. liners, the washout immediately outside the window not providing formation support of the liner and the tortuous near-casing downward path "bounced-off" the concretion just outside the window. At this point our conclusion is that the combination of these items all contributed to the "peeling off" of the completion equipment until enough liner standoff was generated but pipe in the lateral. The liner did make it to bottom, but clearly, care needs to be taken when running out of a window when non-standard conditions indicate that the near window region could be problematic. Future wells with these factors or perceived problems have utilized a whipstock to run the lateral to ensure near window stand-off of completion equipment.

No SRPs were run on the upper "D" lateral, and the rest of the completion was executed without incident.

Conclusions

SRPs have been deployed in a variety of applications worldwide, and are proving to be a viable technology to enhance wellbore completions. In many cases the zonal isolation provided by the SRPs has successfully replaced cement and liner washpipe operational requirements, without the challenges associated cement placement and washpipe running in more complex, extended reach, multi-lateral environments.

At West Sak, SRP technology has allowed for a cost effective way to efficiently develop a previously bypassed formation. Throughout North Slope viscous oil developments, solids/shale production has been minimized through the use of slip-on SRPs such that flow has been maintained where previous non-isolated shale completions had to be cleaned out multiple times to reinitiate production or where wells were shut-in due to shale plugging that could not be remedied. In terms of operation, no noticeable torque and drag losses were experienced, even with upwards of 17 SRP slip-on sleeves on a long liner.

At the Orion development, SRP technology is being used for multiple strategies, with both short term and long term impacts over the life of the well. Initially the SRPs will help to minimize silt production across intervals where deviations occur from the sand and will also help to reduce along-the-lateral commingling which could significantly complicate the understanding of individual lateral contribution.

Lastly, the SRPs are meant to be an upfront proactive addition to aid in future remediation operations required to reduce the severity of water breakthrough via waterflood or the aquifer. As discussed throughout the paper, these reservoirs are very complex to develop, often resulting in unforeseen situations encountered while drilling; requiring greater flexibility and contingency options within the completion. SRPs have helped to enhance these complex wellbore completions and allow the much needed flexibility without significant operational impacts associated with their inclusion.

Density caliper data will continue to be utilized to further substantiate the understanding of hole size differences between the sands and confining siltstones. Strategies based on these findings will continue to be developed to ensure the best possible success of the SRP for a given application.

At the Milne Point development, SRPs have been utilized to help compliment and simplify significant well design changes in an effort to incorporate the N-sands into an already successful O-sand development. The addition of the SRP within the wellbore completion has achieved the required sand production isolation to allow the economic incorporation of an N-sand lateral into an O-sand ML well. The utilization of the TAML level 3 ML junction and SRP within the N-sand lateral is still contingent on the necessary reservoir configuration as discussed within the paper. However, when reservoir conditions allow, this design change has resulted in longer N-sand lateral lengths, less tortuous trajectories, cheaper well costs, better future remediation options, and an overall superior N-sand development strategy.

Finally, it should be noted that when SRPs are used, care is required running out windows, especially if there is a washout, tortuous path or poor centralization due to a combination of these factors while exiting the milled window. As such use of a caliper calculator in the logging while drilling (LWD) and measurement while drilling (MWD) strings is desirable.

Swelling rubber packer technology is seen as a key new enabling technology reducing total well construction costs by eliminating extra material and operational expenses, as well as reducing the complexity and non-productive time associated with completion wash pipe operations.

However more importantly, further use of SRP technology not only eliminates the material and operational costs, but significantly changes the risk profile of operations. With simpler and more effective zonal isolation solutions, operators are able to take on more challenging and higher risk programs to recover marginal reserves.

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Nomenclature

API = American Petroleum Institute
Bbls = barrels
BP = British Petroleum
COP = ConocoPhillips
F = Fahrenheit
Ft = feet
KRU = Kuparuk River Unit
ML = Multi-lateral
MOBM = Mineral Oil Based Mud
MPU = Milne Point Unit
OBM = Oil Based Mud
OOIP = Original Oil In Place
SB = Schrader Bluff
SPE = Society of Petroleum Engineers
SRP = Swelling Rubber Packer
TVD = true vertical depth, ft
WS = West Sak
WBM = Water Based Mud