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ANTISCALANT INJECTION TRIAL AT KAWERAU GEOTHERMAL FIELD, NEW ZEALAND.

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ABSTRACT

Scale formation is one of the main problems associated with the exploitation of water-dominated Geothermal fields. The deposition of calcium carbonate scale is a severe operational problem in the Kawerau field in New Zealand, necessitating annual workovers to cleanout the calcite in the casings. Investigations into alternative methods of scale control were conducted. The most promising appeared to be the use of scale inhibitors injected down hole via capillary tubing to a depth below the flash point. Laboratory tests were conducted to find an inhibitor that would not degrade at the high temperatures encountered in the Kawerau field. Upon selection of a suitable chemical a field trial followed. Teething problems with the surface injection system has resulted in well rundown, however at time of writing the run down was 35% of that expected with no injection of inhibitor.

INTRODUCTION

The Kawerau geothermal field is located towards the north eastern end of the Taupo Volcanic Zone in the North Island of New Zealand. (Fig 1)

In 1952 the field was chosen as the site for a pulp and paper mill by the Tasman Pulp and Paper Company. Since 1952 thirty one wells have been drilled within the field, five of which are currently used to supply 270 tonnes/hour of geothermal steam for direct and indirect process use and electricity generation in the mill.

The formation of calcium carbonate scale on the walls of the casing in these production wells causes flow restrictions and a subsequent reduction in well output. The deposition of this scale is rapid whenever the producing fluid loses CO_2 gas, which allows the fluid to become supersaturated in calcium carbonate which subsequently precipitates from solution.

Previously the scale has been removed mechanically using a drilling rig. To maintain an acceptable level of supply of steam to the mill, the wells require working over every 1 - 2 years.

Alternative more economical methods of scale control were investigated. Mitigation via continuous downhole injection of scale inhibitor into the producing well fluids upstream of the deposition zone offered the greatest potential.

The use of organic phosphonates as CO_2 inhibitors in oil/gas wells and low temperature (<200 deg C) geothermal wells in the Cesano and Latera fields of Italy have been well documented. However, research carried out by the Italian Electricity Board (ENEL) in the Cesano and Latera fields has shown that organic phosphonates degrade rapidly at temperatures above 210 deg C.

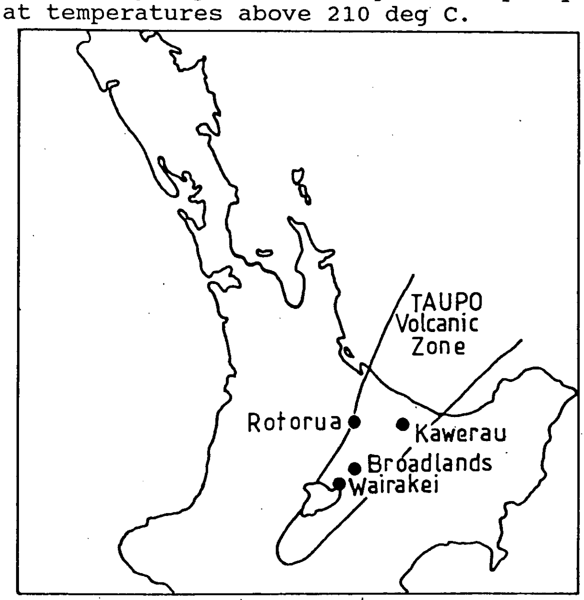


Fig 1 Kawerau Locality Map

It appears no work on calcium carbonate scale inhibitors at elevated temperatures (>270 deg C) has been reported previously.

LABORATORY TESTS

Scale inhibitors mostly act through adsorption on the forming micro crystalline scale nuclei thus preventing their growth to full fledged scale crystals and subsequent deposition.

Threshold effect chemicals acting in sub-stoichiometric concentrations can be most effective in other less challenging environments. Dosage level of a well tailored scale inhibitor is normally in the range of one to ten parts per million. The chemical must be introduced to the system before the point of initial scale formation. Chemicals of this type only work effectively from solution.

With the thermal stability limitations and corrosive nature of phosphonate based inhibitors it was decided to restrict the search for suitable products to organic polymer types.

Extensive laboratory tests were conducted by Exxon Chemicals in Houston with various inhibitors under static conditions at expected downhole temperature and pressure.

To test the product's heat stability all formulations were first made up to standard activities then placed in aging cells, pressurised to 3450 kpa with Nitrogen then heated to 290^{o}C and subsequently held at that temperature for one and a half hours.
The cells were then cooled and the contents removed and observed for precipitation and turbidity.

Stable formulations were then tested using the NACE Calcium Carbonate method TM-03-74.

Inhibitor effectiveness was evaluated through comparison of test performance of samples taken before and after heat stability screening. The aim of the program was to find a formulation that would not only remain physically stable under typical Kawerau downhole conditions but that would also retain all of its performance capabilities.

Three effective products were eventually identified. SURFLO RD3056 was finally selected as being the most cost effective offering 100% inhibition of calcium carbonate at 30 ppm dose rate.

The NACE test is a screening procedure designed to measure the ability of inhibitors to prevent the precipitation of calcium carbonate from solution. The test utilises a synthetic brine with extremely high scaling drive. The actual calcium ion content of the final mixed brine is approximately 1650 ppm. Analysis of the Kawerau produced water indicated that, although significant, the actual scaling drive of the water was quite low, therefore it was predicted that in field conditions somewhat less than 30 ppm would be required to inhibit downhole scaling. An upper limit of 5 ppm was set for economical viability.

Once a product had been selected further work was required prior to trial.

Sperry Sun in Houston conducted dynamic trials on the chemical. The tests were performed by injecting various inhibitor solutions through 30 metres of coiled tubing at elevated temperatures. Sperry Sun monitored for viscosity changes and pumpability. No adverse tendencies were noted.

Exxon Chemicals in Houston carried out corrosion studies to determine whether at elevated temperature and pressure the capillary transmission string would be corroded by the inhibitor solution. Incoloy 825 and SS316L alloy capillary tubing samples cut from Sperry Sun standard rolls were placed in HPHT test cells which were subsequently charged with a 10% solution of SURFLO H3056 in deionized water. The cells were pressurised with 2000 psi of Nitrogen then placed in a thermostatically controlled oven where the temperature was maintained at 290^{o}C for 90 hours. Following this exposure the tubing samples were cleaned and inspected, the corrosion rate was then determined from weight loss measurements.

Incoloy 825 was finally recommended due to its resistance to both aerated inhibitor solution (0.30 mpy, 0.008 mm/yr) and pitting with possible chloride stress cracking from external oxygen free annular fluids.

Finally the environmental impact of the product had to be assessed. Exxon commissioned an independent analytical laboratory in the USA to carry out aquatic toxicology testing. The results confirmed that the inhibitor had very low toxicity values and would have no impact on the environment at the envisaged treating rates.

WELL SELECTION

Well KA35 was chosen for the trial as the calcite deposition is mainly in the production casing. The well has excellent permeability with the main feed zone at 963m. Feed zone temperature is 260°C. Smaller feed zones are at 995m (266°C) and at 1025m (259°C). The inhibitor is able to be injected below the deposition zone and thus full mixing of the inhibitor with the production fluids is guaranteed.

KA35 was drilled in March 1985 to a depth of 1095m. It is cased with 9 5/8" casing to 795m and has a 7 5/8" slotted liner which sits on the bottom of the hole with the top of the liner at 763m. The well has been cleaned out four times since it has been on production, in March 1986, April 1987, May 1988 and in April 1989. Deposition was located between approximately 580m and the top of the liner at 765m. (Fig 2). The liner inspections gave no indications of any deposition on either the inside or outside wall of the liner, however some minor deposition was located in the slots during the 1988 inspection.

COMPLETION DESIGN

Two options were considered for injecting the antiscalant. The first was to run a liner with the tubing attached to the outside and entering the liner at the shoe through a side pocket mandrel. Unfortunately this necessitated producing the well through the smaller diameter liner which would have an adverse affect on the well output.

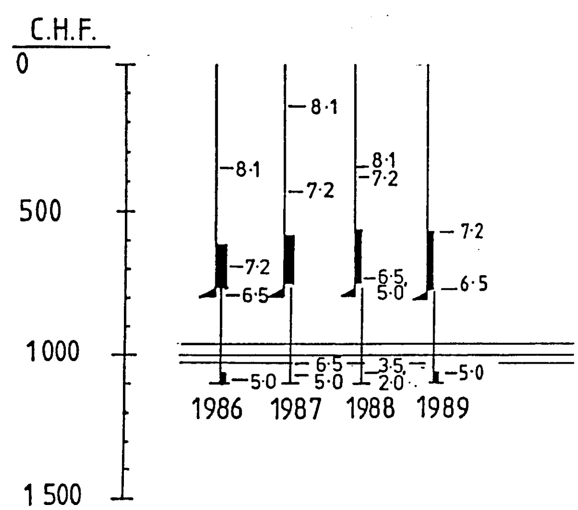


Fig 2 KA35 Calcite deposition and go devil depths prior to cleanouts.

The other option and the one finally selected was to inject the inhibitor through 1/4" capillary tubing held in place by a weighted injection head attached to the bottom of the tubing. (Fig 3). The injection head had to be of sufficient weight to keep the tubing in tension under flowing conditions. The tubing/injection head is suspended from the wellhead using a tubing clamp to prevent slippage down hole and is sealed with a metal to metal fitting where it passes out of the wellhead.

The injection head assembly was made from C-276 alloy for the tubing socket and monel for the non-return valve. The sinker bar was made from carbon steel and measures 6 metres long, 75mm in diameter and weighs 204 kg (450 pounds). The tubing is attached to the injection head using back to back swaglok fittings housed in a specially designed sub for extra strength. The injection head also contains a non-return valve with a pressure setting designed to prevent the chemical boiling in the tubing and to maintain a positive pump pressure on surface. (Fig 4). The NRV pressure setting is determined by bottom hole pressure, chemical density and viscosity.

The surface system (Fig 5) consists of two pneumatic variable stroke Williams pumps (one as a standby). The suction end of the pumps is connected to the chemical supply tanks and the discharge end is connected directly to the downhole tubing, with surface NRV at the pumps and again down stream of the injection pressure monitor. A safety release valve is down stream of the pumps and tied back into the supply line to prevent over pressuring of the capillary while unattended. Injection pressure is recorded on a 7 day chart recorder to monitor both injection rate and record any pressure increase that would mean a restriction or blockage in the capillary.

INSTALLATION

The installation of the injection system was timed to coincide with a drilling workover. This ensured the well was clear of calcite prior to the trial commencing and the well was quenched and off pressure allowing the installation to proceed with the well in an open state and thus eliminating the need for a lubricator.

The tubing was fed through the wellhead support flange and cap and made up onto the injection assembly. The tubing was

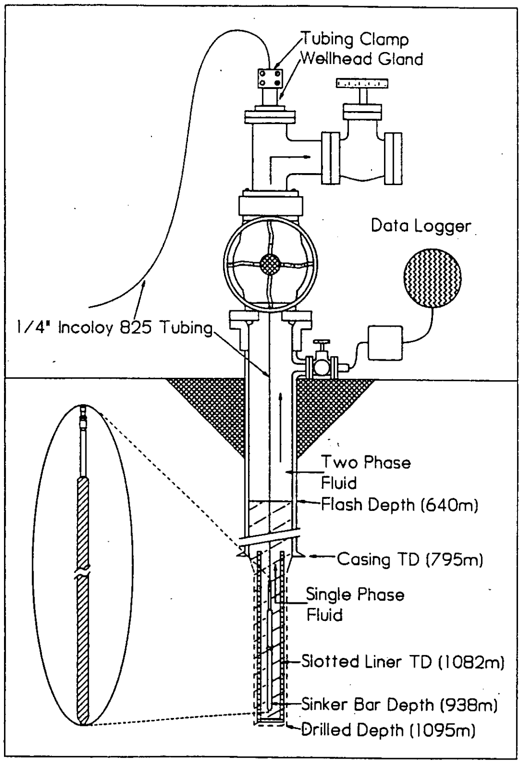


Figure 3. KA-35 Completion Profile

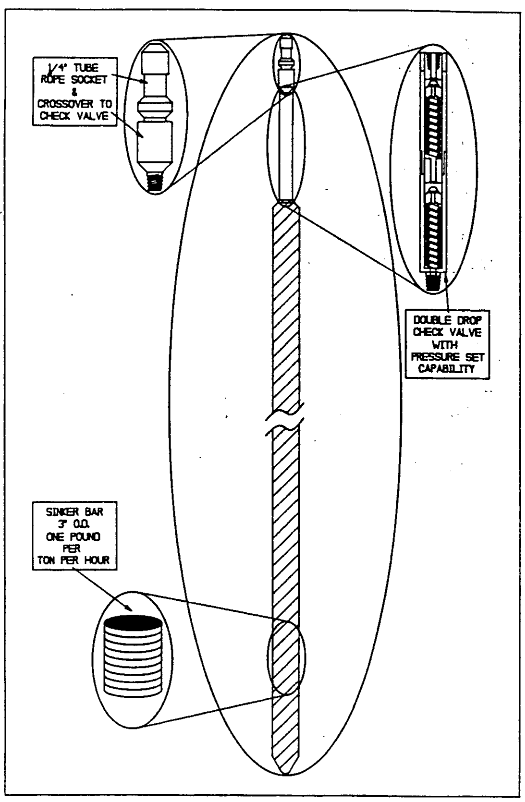


Figure 4. Sperry-Sun Injection Ass'y Non-Return Valve & Sinker Bar

then run over two 18" sheaths, the bottom one attached to the wellhead and the other was suspended directly above the wellhead using a crane. The assembly and tubing was then lowered slowly into the well using a mechanical winch. The tubing was to be lowered to 1000m, however the injection assembly held up at 938m. Rather than risk placing excessive stress on the tubing to pull the assembly free from the obstruction it was decided to leave it in its present position.

A 15% solution of chemical was prepared and injection began at an injection rate of 20 litres/hour. This gave a dose rate of 5ppm and a residence time in the tubing of 16.5 minutes.

Wellhead pressure, separator outlet pressure, steam and water flows were monitored to check well performance. Hourly averages were recorded by a data logger at the site office.

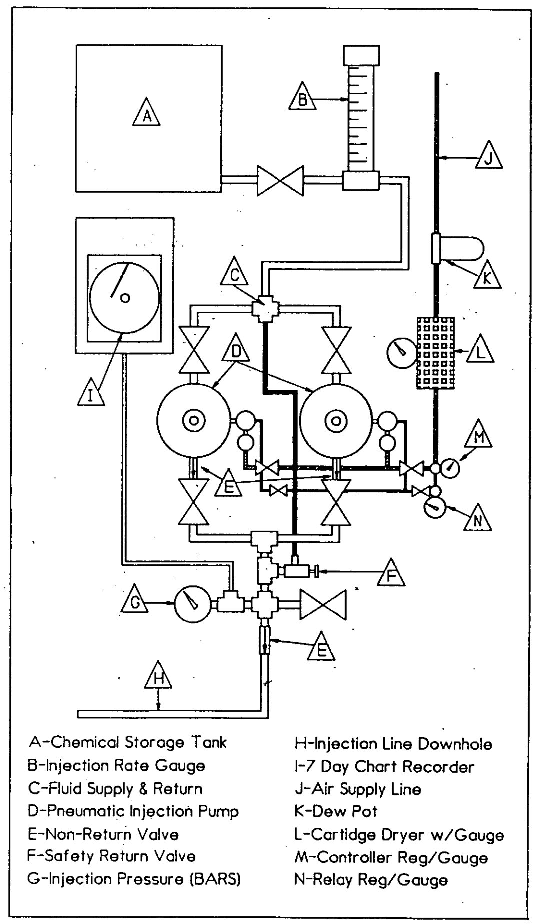


Figure 5. Injection Pump Ass'y

PROBLEMS ENCOUNTERED

As to be expected during a trial of this duration there were several instances of surface chemical dosing system failure. Compressor breakdowns, land slips, mechanical tubing damage and general operator error all contributed to a total of 13 days loss of injection in the first 10 months of treatment.

There was initial confusion over selection of dosing pump pressure seals. The manufacturers recommendations proved inadequate for this application and pressure seal failure resulted. The recommended input air pressure was initially set too high for the output chemical pressure. This caused excessive piston velocity and momentum with consequential seal damage.

MODIFICATIONS TO FUTURE DESIGN

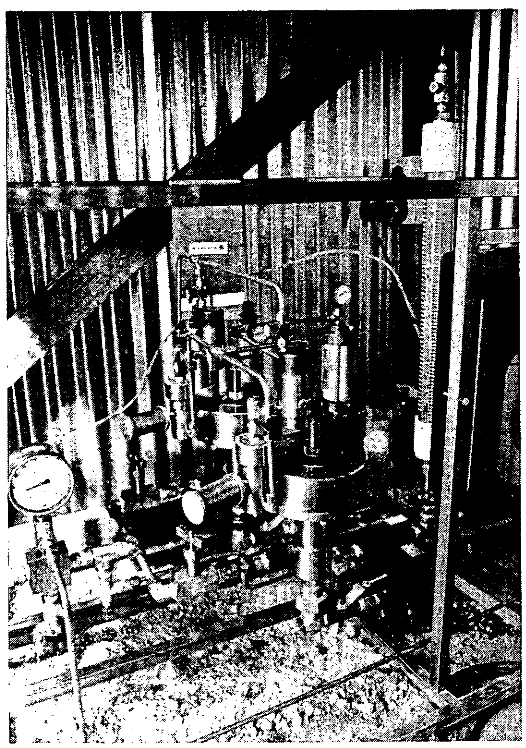
Experience gained during the course of the trial leads to consideration of possible improvements to future designs.

An in-line filter installed downstream of the chemical injection pump would ensure that particulate matter from injection system component failure would be prevented from entering the fine bore capillary tubing.

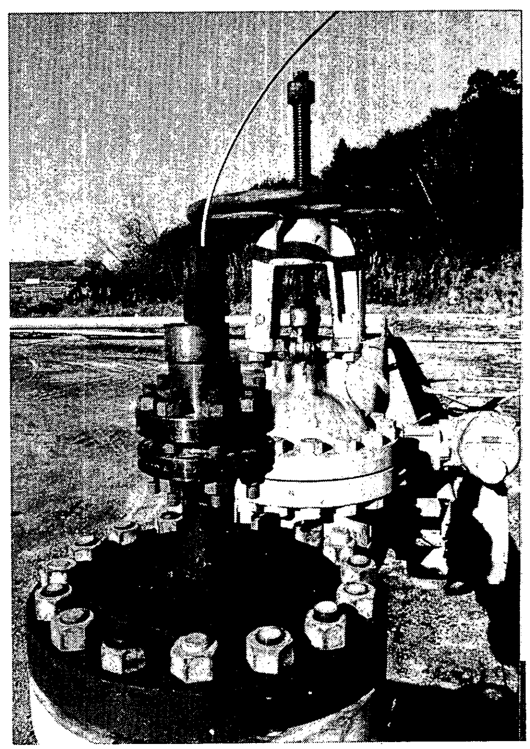
Replacement of the pressure seals on the injection pumps with a more appropriate material to give a greater tolerance to pump pressure variation would be beneficial.

Removal of possible sacrificial action between components of the injection head assembly would be prudent. Research has shown that the Nickel-Chrome-Molybdenum alloy C276 is virtually immune from corrosion in aerated and non-aerated geothermal environments.

To allow easier make up and modification of sinker bar weight it could be sectionalised down to one metre lengths. The individual sections would be bored through down the centreline allowing chemical discharge from the bottom of the completed assembly.



Surface Injection System
Photo: A. Blair, Exxon NZ.



Wellhead Support Flange/Gland
Photo: E. Buck, Works NZ.

RESULTS

The well was placed back on production in mid April 1989 following the cleanout and the installation of the injection system.

After three weeks continuous operation the mass output of the well had not changed and no rundown was evident. However, at the beginning of week four the air compressor supplying the pneumatic pumps broke down. Two days elapsed before the air supply was reinstated and during this time the well's output had run down by approximately 2 tonne/hour of steam and 10 tonne/hour of mass flow.

Based on the success of the first three weeks operation the dose rate of the chemical was decreased to 3ppm. This was done by maintaining the same concentration but decreasing the injection rate to 12 litres/ hour.

Problems with air and electrical supply continued during May, June and July. During this period well rundown was detectable and averaged 0.8 t/hr/month.

Since then reliable dosing has resulted in approximately 0.7 t/hr/month. This is 35% of the expected run down of 2 t/hr/month.

A new air supply system has been installed and has made the surface system more reliable.

Since February 2, 1990 the well has been treated at a dose rate of 1 ppm. At the date of submission of this paper it appears that no increase in rundown occurred during the following five weeks of production. This raises interesting possibilities.

During the duration of the trial rundown has averaged 0.7 t/hr/month no matter what the dosage rate of inhibitor. (Fig 6). The historical figure for this well is 2 t/hr/month. Clearly scale inhibition is taking place to some extent but yet the well is still running down. Rundown is independent of treatment.

Downhole conditions at the bottom of the capillary treating string now differ substantially from the past.

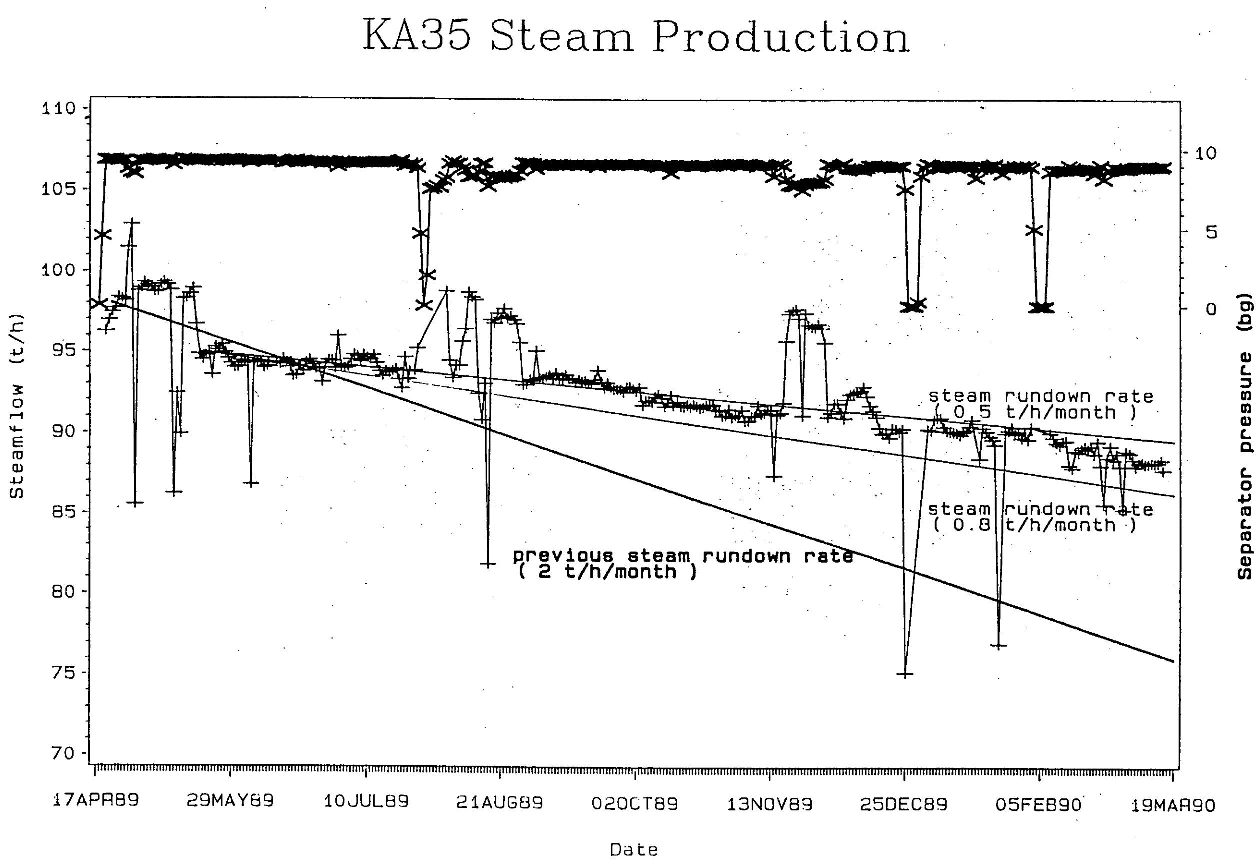


Fig 6 Graph showing the steam rundown of KA35.

This is due to the introduction of the 3" diameter sinker bar into the 7 5/8" slotted liner. What has been created is a 6 metre long annular chamber. The flow regime here would be severely altered as compared to the well's previous completion. Well fluids accelerating through the reduced cross sectional area of the liner at this point would experience pressure drop and turbulence with possible cavitation effects. Dissolved carbon dioxide would come out of solution thus causing pH elevation with subsequent deposition of calcium carbonate scale.

The scale inhibitor discharge ports are located at the top of this sinker bar. Thus any scale deposition below would continue unhindered. Even very slight scale deposition would affect production rates here as the liner area is already reduced by 18% at this point.

Should this be the case, and only a workover would confirm this, the answer would be to simply relocate the injection ports to the bottom of the sinker bar thus also extending full inhibition to this area. Utilisation of a longer sinker bar of reduced cross section would also minimise possible pressure drop effects.

CONCLUSION

The data collected from this trial to date clearly indicates that the antiscalant chemical significantly reduces the production rundown at dose rates down to 1 ppm. With improvements in the reliability of the surface system and possible modifications to the sinker bar assembly the well rundown could be further reduced.

ACKNOWLEDGEMENTS

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