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Experiences with Different Calcite Inhibitor in the Mahanagdong Geothermal Field

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ABSTRACT

There are two existing Calcite Inhibition Systems (CIS) installed in Mahanagdong sector of Leyte Geothermal Production Field. The calcite saturation indices (CSI) of wells MG1 and MG19 reached around 0.4-0.7 (log $Q/K>0$ indicates calcite supersaturation) and calcite mineral deposition were observed in these wells requiring periodic mechanical clearing during the initial commercial utilization in 1998. Thereafter, CIS installations were commissioned in 2001 to minimize calcite deposition and prolong the utilization of the wells before a work-over. The calcite inhibition systems have continuously functioned effectively in minimizing calcite deposition in the wellbore, extending the wells' productivity for a longer period of almost 4 years before CIS tubing replacement and opportunity mechanical clearing is conducted. Since commissioning, the two wells have been dosed at different times with four types of calcite inhibitors chemically known to be aqueous solution of polyacrylates (3 inhibitors) and polymaleic anhydrides (1 inhibitor). This paper discusses the experiences and performances of the calcite inhibition systems in Mahanagdong in the utilization of these different calcite inhibitors.

1. INTRODUCTION

Wells MG1 and MG19 of the Mahanagdong sector in Leyte Geothermal Production Field are two of the several wells in the central part of Mahanagdong that experienced calcite blockages in the wellbore. Currently, these two wells have existing Calcite Inhibition Systems (CIS) to prevent rapid deposition of calcite scales that requires periodic mechanical clearing of these scales and thus maintain their productivity for a longer period and reduce on work-over costs.

During initial discharges in 1995, MG1 was found with calcite blockage within the well's production liner during downhole survey using a 3"ø Go-Devil tool. Calcite scales were also recovered in MG19 using a 5"ø scraper. The high scaling potential was validated during initial commercial utilization of the wells with the high Calcite Saturation Index (CSI) at log Q/K ~0.6 (Q/K ~4.0) based on stable 1998 chemistry data. The wells were then fully blocked with calcite scales in a matter of 5 (in MG1) to 17 months (in MG19) of continuous utilization (Herras, et.al, 2000). Frequent mechanical clearing were conducted when mass flows or steam flows of the wells declined by ~50%. Mechanical clearing using a rig cleaned the wellbores from calcite scales and improved their output. In the early utilization of MG19 in 1998 without CIS, the mass flow of the well was reduced by ~60% and output declined from 6 MW to 2 MW in a period of nine months. Both MG1 and MG19 underwent three separate work-overs in 1999-2001 (Table 1) before the installation of the Calcite Inhibition System (CIS) in April and September 2001, respectively.

2. THE CALCITE INHIBITION SYSTEMS (CIS) IN MG1D AND MG19

2.1 CIS Installation

MG1 CIS was commissioned in April 2001 after the well was worked-over in March 2001. In MG19, after the August 2001 work-over, CIS was installed and then commissioned in September 2001. As shown in Figure 1, the CIS is composed of three main sub-systems: (1) the tank system, (2) the pump system, and (3) the downhole injection system. Figure 2 shows the detailed components of the CIS. The tank system includes the pre-mix tank for the required amount of pure inhibitor, water tank, the mixing tank for the water-inhibitor mixture and the feed tank for the final injectate solution. There are three pump requirements: a transfer pump that conveys the chemical from the original container to the pre-mix tank, a re-circulating pump that ensures a homogeneous solution of the inhibitor and a metering or dosing pump that injects the desired concentration of chemical to the downhole injection system. A back-up dosing pump is required so that a switch-over can readily be done regularly once-a-month or during emergency situation. The chemical is injected down to the pre-determined injection depth based on the simulated flash point through a ¼-inch diameter capillary tubing weighed down by a sinker bar with injection port holes at its end.

In MG1, from a pre-work-over steam flow of 6 kg/s, it increased to ~12 kg/s after the work-over. Calcite inhibitor at 10% feed concentration and dosing rate of 10-11 LPH was injected at 1750m depth starting April 2001 which sustained the well's output for about three years until the next capillary tubing replacement and work-over (Table 1). In MG19, calcite inhibitor was injected at 1850m with similar dosing concentration and rate with MG1.

Table 1. Workovers Conducted in Wells MG-1 and MG-19 for the Period 1999-2008.

MG-1		MG-19	
Workover	**Remarks**	**Workover**	**Remarks**
March 1999	Without CIS	March 1999	Without CIS
June 1999	Without CIS	July 1999	Without CIS
March 2001	Without CIS	August 2001	Without CIS
January 2004	With CIS	August 2003	With CIS
		December 2008	With CIS

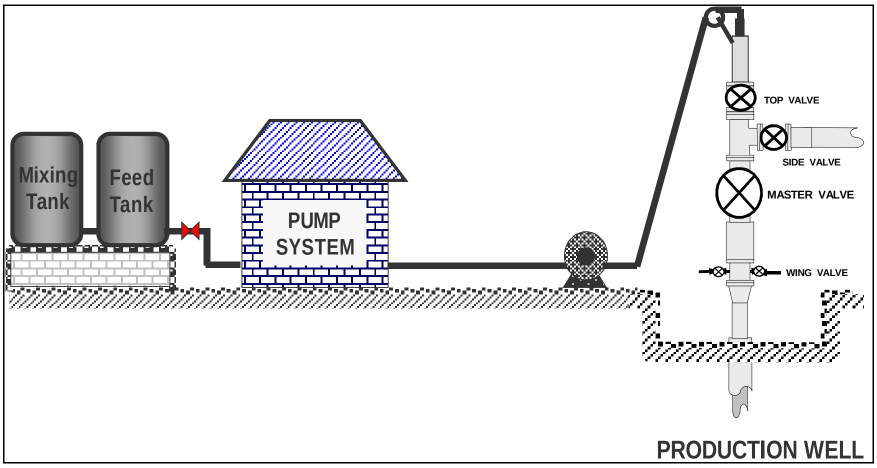

Figure 2: Simplified Schematic Diagram of the Calcite Inhibition System (CIS).

2.2 CIS Monitoring

While the CIS capillary tubing is being run-in to the desired injection depth at 1750 mMD (for MG1) and 1850 mMD (for MG19), water flushing is conducted using the CIS dosing system. Pump parameters particularly the injection pressure is closely monitored to check for the presence of leaks or obstruction during run-in. Residence time measurement using water prior run-in is conducted to initially estimate the time it takes the inhibitor to flow through and come-out of the very long tubing, albeit at atmospheric condition, and at the same time to flush the tubing of unwanted particulates. After the capillary tubing is set at the injection depth, residence time is again measured using a colored tracer like sodium fluorescein. This determines that the tubing will deliver successfully the chemical inhibitor up to the injection depth. Afterwards, the system is flushed again with water until the injection pressure stabilizes. When stable pressure is attained, chemical inhibitor injection commences. The following parameters are then regularly monitored: injection pressure, pump stroke, injection rate, feed solution level and chemical stock. Of prime importance is the achievement of the required injection rate which must be updated when changes in the well's mass flow occurs and this is calculated and compared with the target line concentration as specified by the chemical supplier.

3. USE OF DIFFERENT CALCITE INHIBITORS IN MAHANAGDONG

The use of chemical inhibitors to minimize calcite deposition problems has proved to be successful in wells MG1 and MG19 since CIS was commissioned in 2001. Table 2 presents the different inhibitors used at different periods and the corresponding monitored parameters. Three of these inhibitors are the polyacrylate type and one inhibitor was polymaleic type. The availability of these types of calcite inhibitors depend on the winning chemical supplier in the tender for supply of these inhibitors, but both types are acceptable and has been used by EDC.

3.1 Physical and Chemical Properties

3.1.1 Aqueous Solution of Polyacrylates (PAA)

Liquid scalants such as polyacrylates are popular in calcite inhibition application. Table 3 summarizes the physical and chemical properties of the three polyacrylates type of inhibitors used in Mahanagdong. Since the chemical inhibitors are proprietary in nature by the chemical suppliers, and since we do not want to endorse one chemical over the other, for this paper's purposes, we will designate them as PAA#1, PAA#2 and PAA#3.

Table 2. Calcite Inhibitor Dosing Parameters Since CIS Commissioning in 2001.

Well	Mass Flow, kg/s	Feed Solution, %v/v	Line Conc., ppm	Dosing Rate, LPH	Consumption, kg/mo	Inhibitor	Period Utilized
MG-1	80	10	5	12	1096	PAA#1	Apr01-Jul02
	60	3	2	11.4	312	PMA	Jul02-Feb05
	75	7	4	13.6	788	PAA#2	Mar05
	55	6	4	11.4	576	PAA#2	Feb06-Mar07
	55	3	2	11.2	286	PAA#3	Mar07- present
MG-19	90	10	5	11	1004	PAA#1	Sep8-13, '01
	90	4	2	12.9	471	PMA	Oct01-Jul03
	90	5	2	10.4	475	PMA	Aug03-Feb05
	95	9	4	13.4	999	PAA#2	Mar05
	80	7	4	12.5	737	PAA#2	Feb06-Mar07
	80	4	2	12.3	419	PAA#3	Mar07-Sep07; Jan09-present

PAA #1 and PAA #2 exhibit similar formulation except that PAA #1 has been neutralized with NaOH as shown by its higher pH levels, and PAA #2 is a high-purity formulation of PAA #1. Suppliers neutralize them to render these highly concentrated electrolytes less corrosive. PAA #3, on the other hand, has low pH at pH=2.2-3.0. The supplier claimed that steric consideration allows the acid forms to be more effective than the neutralized form. They lean on this benefit hence the acid form of PAA #3. But handling the inhibitor at this state is risky and hazardous particularly during chemical preparation which is done manually thrice a week. Thus, chemical resistant, non-porous gloves and goggles must be worn at all times during the preparation. PAA #3 is further diluted with water to 3-4% v/v to achieve the 2 ppm target line concentration.

These polyacrylates having a polar functional group of COO^- (carboxylate) rendering them the negative charges in water, attach to the growing calcium carbonate or calcite ($CaCO_3$) crystals. When the crystals become negatively charged, the calcite crystals are prevented from growing by dispersion. The net effect is therefore crystal distortion and dispersion in this chronological order, governed by the principle on crystal growth and the basic concept on reaction that “like repels like”. In this manner, small calcite crystals are formed which can readily be transported by the flowing geothermal fluid.

There are two screening tests used for selecting the appropriate inhibitor: NACE standard test to determine the inhibition efficiency of the inhibitor and thermal stability test to check if the inhibitor will not degrade if exposed to high temperature (~280°C) and that it will not lose its inhibition efficiency after the exposure. The 5 ppm PAA #1 at 70°C showed 100% inhibition efficiency during the NACE test (Candelaria, 2001). PAA #2 has lower inhibition efficiency showed during the NACE test but this is of higher purity formulation than PAA #1 since it has low sulfur content. Sulfur is used as a catalyst in the manufacturing process. Commercially available PAA inhibitors in the market claim that they are thermally stable up to 300°C. To be certain that PAA #1 (together with a PMA available during MG1 CIS commissioning in 2001) was appropriate for high-temperature application in MG1, a thermal stability test was conducted. The 10% of PAA #1 was exposed to temperature of 200-260°C in 2 hours then increased to 280°C for 5 minutes using a furnace to simulate its stability at downhole condition. Upon exposure to 280°C, the solution initially formed black deposits but re-dissolved to form a pale yellow solution. The density and elution rate (a measure of the flow property of a polymer) of the heated solution did not change suggesting the absence of possible clogging tendency of the solution in the tubing while injected downhole. However, a chemical change did occur with the change in color of the solution (clear solution to pale yellow solution) which might affect its inhibition efficiency at high temperature injection. On the other hand, at a lower temperature (230°C), the solution turned yellowish brown but did not form black residue. Although PAA #1 failed in these NACE tests even at 230°C, field experiences (in wells APO-1D and MO-2) showed that PAA #1 can be used up to a temperature of 240°C (Candelaria, 2001). Thus, PAA #1 was used in Mahanagdong.

However, after only one week of CIS operation in MG19, the tubing was blocked and was later analyzed to be the degraded calcite inhibitor exposed to temperature of ~280°C, the injection depth temperature in MG19. The application of this type of inhibitor is being limited to geothermal fields with temperature at injection depth ≤250°C (Candelaria, 2001). Hence, a new high-temperature calcite inhibitor of the polymaleic type was used after re-commissioning the MG19 CIS in October 2001. However, beginning 2005, chemical suppliers offered PAA’s, such as PAA#2 and PAA#3, that are stable at higher temperatures. These PAA’s are of high purity formulations (unlike PAA#1) and were enhanced to withstand higher temperature making them technically qualifying for Mahanagdong CIS application which has temperature of ~280°C.

3.1.2 Aqueous Solution of Polymaleic Anhydrides (PMA)

PMA’s just like the PAA’s are also polymers but with a cyclic monomeric units (Table 3). They have almost the same action in inhibiting massive calcite crystal formation through crystal distortion and then dispersion. These are known to be thermally stable up to ~300°C (Candelaria, 2001). During the thermal stability test for MG1 CIS inhibitor (simultaneous with PAA #1 thermal stability test), the performance of PAA #1 and PMA were compared up to a maximum of 280°C. It was found that the PMA underwent lesser degree of spectral change as compared to the PAA #1 suggesting that the PMA is more thermally stable.

Table 3. Physical and Chemical Properties of the Inhibitors.

Inhibitor	Description/ Chemical Name	Physical State, Color, Appearance	Solubility in Water	Spec. Gravity	pH	Viscosity cp
PAA Monomer: $(CH_2{=}CHCOO-)$ #1	An aqueous solution of an acrylate polymer, a sulphate and sodium bisulfite	Liquid, organic, clear to slightly hazy, colorless	100%	1.27-1.32 (@60°F) ASTM D-1298	5.4-8.0 (neat) ASTM E-70	51 (@60°F) ASTM D-2983
#2	An aqueous solution of a polyacrylate	Clear orange	100%	1.17 (@60°F) ASTM D-1298	4.6 (neat) ASTM E-70	*Not provided*
Inhibitor	**Description/ Chemical Name**	**Physical State, Color, Appearance**	**Solubility in Water**	**Spec. Gravity**	**pH**	**Viscosity cp**
PMA	*Not provided*	Yellow to amber liquid, mild odor	100%	1.268 (@70°F)	4.8 (5% sol.)	3720 (@70°F)

Note: All information taken from the Material Safety Data Sheet (MSDS) provided by the supplier.

PMA's and PAA's are similar in terms of solubility to water (completely soluble) and have close specific gravity values. The evident difference is its very high viscosity in pure form at 3720 cps. The transfer pump used to transfer the pure chemical inhibitor to the pre-mix tank is most affected thus it must be suitable to handle this highly viscous inhibitor. However, the higher viscosity could also mean that there is greater amount of the active compound. PMA suppliers recommended lower treatment concentration (at 2 ppm) thus requiring also lower consumption per month.

3.2 Performance of the Calcite Inhibitors in Mahanagdong

In Mahanagdong, the CIS using different chemical inhibitors have been effective and successful in prolonging the productivity of wells MG1 and MG19 before another work-over is conducted. Throughout the 8 years of CIS operation in Mahanagdong, four different chemical inhibitors were used at different periods. In this section of the paper, we will present the performance of the chemical inhibitors using the parameters evaluated such as problems encountered, flow data of the respective wells, consumption and cost, which are related to the required feed concentration and target concentration, and safety considerations.

3.2.1 Problems Encountered

Among the calcite inhibitors used in MG1 and MG19, only in the use of PAA #1 that CIS tubing clogging was encountered after only 5 days of CIS commissioning in MG19. The indicators that the tubing was clogged-up were increase in injection pressure (from 460 psig to 600 psig) and decline in dosing rate (from 15 LPH to 1 LPH). When the tubing was pulled out, about 5-mm deposit close to the nozzle tip was found. The deposit was very hard (metallic when pricked) with black adherent deposition. Scanning Electron Microscope (SEM) analysis of the deposit by the supplier yielded elemental composition of Fe (65%), S (10%) with minor element Ni (<10%) and other trace elements. Evaluation of the results showed the deposits to be corrosion products and degraded PAA #1 as indicated by S.

Corrosion was believed to occur from the reaction of sulphur (which is left-over in the manufacture of PAA #1) with the material to produce metallic sulphide (e.g. iron sulphide) especially since PAA #1 feed concentration was at 10% v/v. The inhibitor solution collected from the tubing (close to the nozzle tip) was likewise evaluated for inhibition efficiency using NACE test. The sample was turbid with fine black deposits. The NACE test showed that the heated inhibitor had already exhibited poor inhibition property. Previous tests reveal also that the formation of black deposits for PAA #1 is an indicator of thermal degradation and loss of its inhibition property. FT-IR spectra of the black deposit show the absorption bands in the 1000-3000 cm^{-1} region characteristic of organic compounds indicating that the inhibitor was chemically altered. The possible mechanisms of PAA #1 degradation include: (1) PAA#1 can form anhydride with heating at temperatures above 250°C; (2) crosslinking with alkaline or transition metals or between polymer chains in the presence of sulphur (Candelaria, 2001). Note that PAA #1 was used in MG1 for more than one year of continuous dosing without tubing clogging problem encountered. MG1 reservoir temperature during this period ranged from 242-264°C which is lower compared with MG19 (>270°) which could be the reason that clogging problem was not observed in MG1 during PAA #1 utilization.

Due to their low pH and the presence of active components which are not disclosed by the chemical supplier for proprietary reason, as in the case of PAA #3 which is known only by its product name, exposure to this inhibitor can cause potential health effects such as irritation, pain, coughing and redness of skin (referred from MSDS). Potential hazards of the other PAA's are irritation and allergy (to sulphite in PAA #1 if sensitive to this component). By using the proper protective equipment and following the handling procedure strictly, these health hazards can be avoided.

3.2.2 Consumption and Cost

The tender process for the annual requirement of calcite inhibitor starts with the determination of the well's downhole conditions such as mass flow, injection depth and temperature. These will be the bases for the selection process for a suitable inhibitor. The inhibitors submitted by chemical suppliers have to be evaluated in terms of thermal stability and inhibition efficiency through the laboratory screening tests and cost-effectiveness through a bidding process. The annual supply requirement is then awarded to the chemical supplier who can pass through this selection process and come-out as the most cost effective offer.

Among the PAA's, PAA #1 required the highest annual consumption (13,150 kg) while PAA #3 would need only about 5000 kg yearly consumption as PAA #3 supplier recommended lower treatment concentration. In terms of cost per kg PAA #3 is the most expensive, but since the target line treatment concentration is lower and annual consumption is lowest, on the basis of yearly cost of consumption, the use of PAA #3 is the most economical (Table 4).

On a per kilogram basis, PMA is the most expensive. However, since the target line treatment concentration is only at 2 ppm (unlike PAA #1 and PAA #2 which is at 4-5 ppm), the PMA is competitive in terms of annual consumption and cost, and close to PAA #3 (Table 4).

Table 4 shows that the annual cost for chemical dosing is at about 2 million pesos. However, this is a lot cheaper than the periodic mechanical clearing using a rig which were conducted in as close as 3 months before the CIS was installed. Both MG1 and MG19 were mechanically cleared of calcite blockages twice in 1999. The revenue loss during the two clearing activity in a year per well was computed at 39 to 52 million pesos. Chemical dosing is more economical even with just one work-over in a year like in 2001. Revenue loss for one work-over is at 20 to 26 million pesos. Revenue loss is calculated based on a 45-day outage while well is cut-out for a mechanical clearing operation, well heat-up and discharge prior to cut-in back to system.

3.2.3 Flow Parameters

Flow parameters are important indicators in assessing inhibitor performance. Calcite scaling can be indirectly recognized by declines in mass flow and consequently steam flow. Also, some inhibitors cannot attain 100% inhibition efficiency such that declines in mass and steam flows still occur. On the other hand, cooler water inflow such as in MG1 has the effect of increasing the water flow, and consequently, the mass flow. Therefore, an observed decline in mass flow is an indication of blockage due to calcite deposition restricting the flow of the well.

Between the use of PAA #1 and PAA #2, PAA #2 appears to be more effective as indicated by the lower calculated decline rates on the mass flow and steam flow (0.3-1.1 kg/s-mo for PAA #1 vs 0.2-0.6 kg/s-mo for PAA#2) of well MG1 while being dosed with PAA #2 (note that PAA #1 use in MG19 was immediately discontinued because of the incident of tubing clogging). PAA #3 gave also good flow indicators with low decline rates. However, with only 6 measured flow data points since start of monitoring and the insufficient data from MG19 since dosing was interrupted when the capillary tubing parted, it cannot conclusively be said that PAA #3 is more effective compared to the other PAA's or compared to the PMA (Table 4, Figures 3 & 4). With the re-commissioning of MG19 CIS after running-in a new capillary tubing last January 2009, monitoring PAA #3's performance and effectiveness can proceed.

Figures 3 and 4 show that the mass and steam flows of MG1 and MG19 were generally stable while PMA was in use (decline rates of 0.1-0.2 kg/s-mo for PMA vs 0.2-1.1 kg/s-mo for PAA's). The drastic drop in mass flow in MG19 shown in Figure 4 does not reflect the inhibitor's effectivity or efficiency since that time the injection depth was shallower at 1400m than the target depth of 1850m which resulted to poor inhibition and eventually, the huge drop in the well's mass flow. Injection depth was not able to be set further below the flash point due to an obstruction in the wellbore encountered shallower while running-in the CIS tubing.

PAA #1 was utilized for over a year in MG1 but was later replaced by PMA due to relatively high mass flow decline rate observed at ~1.6 kg/s-mo while using PAA #1 (Siega et al, 2005). PMA was utilized for the longest period (≥3 years) with generally stable mass flow of the wells. PAA #2 ranked next in length of utilization at ~2 years with likewise stable flows. Finally, PAA #3 has been utilized for 6-23 months already and is the current inhibitor utilized both for MG1 and MG19.

Table 4. Comparison of the Different Inhibitors Used.

Type of Inhibitor		***Annual Consumption/ Cost**	****Cost/ kg**	**Bore Output Change Kg/s-mo**		**Advantages**	**Disadvantages**
				ΔMF	**ΔSF**		
				Baseline (w/o CIS)			
				-3.4 to -4.5	**-0.6 to -1.0**		
PAA	#1	13,150 kg		-1.1 (MG1 only)	-0.3 (MG1 only)	-Neutralized -Less viscous	-Tends to undergo thermal degradation at ~280°C (indicator: presence of black deposits)& loss in inhibition efficiency (Candelaria, 2001) - Requires relatively high feed solution concentration compared to other inhibitors (10%)
	#2	12,000kg/ MP*1,731 (max)* 8,844kg/ MP*1,276* MF=80kg/s	144.23 (@4ppm dosage)	-0.4 to -0.6	-0.2 to -0.3	-Near neutral pH for safer handling	Requires relatively high feed solution concentration compared to other inhibitors (9%)
	#3	5,030kg/ MP*1,171*	232.84 (@2ppm dosage)	+0.09 (MG1 only)	-0.02 (MG1 only)	-Low required target line conc. (2ppm) -Most economical (on annual basis)	Acidic (pH=2.2-3.0)/corrosive, chemical to be handled with utmost caution
PMA		5,700kg/ MP*1,610 (max)* 5,256kg/ MP*1,485* MF=80kg/s	282.51 (@2ppm dosage)	-0.1 to +0.4	-0.1 to -0.2	-Low required target line conc. (2ppm) -Near neutral pH for safer handling -Thermally stable up to ~280°C (wells' T at depth)	-Very viscous, feed solution has to be diluted to reduce viscosity -Higher cost on a per kg basis

***using the highest amount consumed**
****as of Nov2006 bid price**

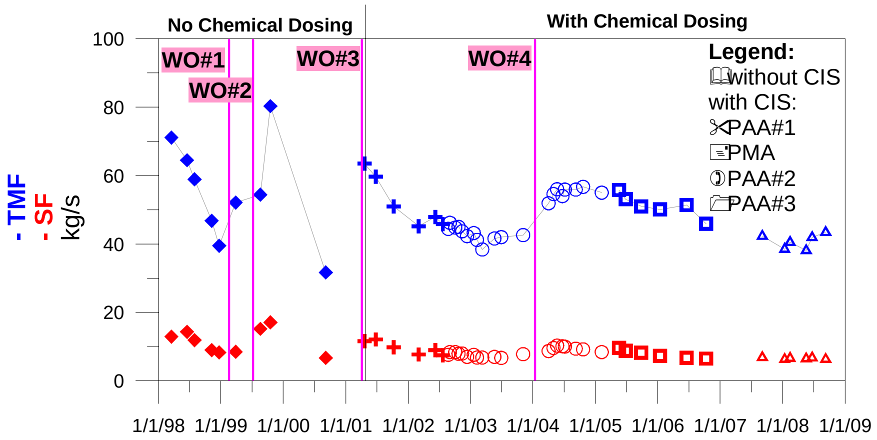

Figure 3. Well MG1 flow trends.

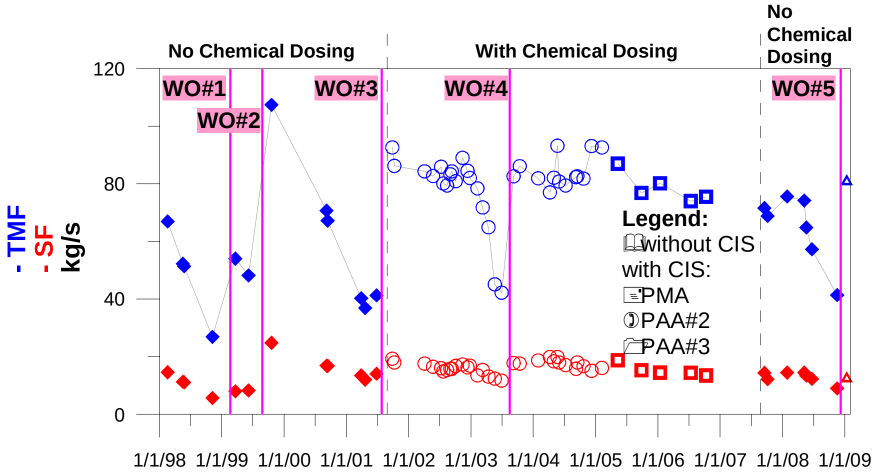

Figure 4: Well MG19 flow trends. Decline in mass flow (see enclosed values by green oval) was observed after running in the tubing at 1400 m setting depth in Dec 2002 rather than at the target depth of 1850 m resulting to decline in the performance of the well

3.2.4 Calcite Saturation Index (CSI) and Reservoir Calcium Trends

Calcite deposition potential for wells MG1 and MG19 is high as indicated by their high CSI levels (Figures 5 & 6) at about 4-5 (Q/K>1.0 or loq Q/K >0 indicates calcite supersaturation). At dosed condition, if the high CSI or the calcite oversaturated condition of the fluid is maintained, this can suggest absence of scaling since it is inhibited by the calcite inhibitor. In this condition, calcium level at fluid discharge is maintained and the CSI as calculated remains high. On the other hand, during calcite deposition, calcium is expected to decline as it is consumed in the reaction process and deposited. But calcium level alone is insufficient to monitor deposition or inhibition (Nogara et al., 2001).

Geochemical monitoring in MG1 and MG19 generally observes that calcium level is more stable at dosed condition as compared to the period before the CIS was installed (before 2001). A transient increase in calcium concentration was observed immediately after the work-overs (before CIS installation in 2001), but this is readily depleted due to rapid calcite scaling resulting to frequent work-overs of the wells. However, after CIS implementation, reservoir calcium (Ca_{res}) concentration was almost generally stable particularly for MG19, except for a declining trend in the later part of 2008 at undosed condition. The decline in Ca_{res} in the latter part of 2008 reflected also a simultaneous mass flow decline as calcite deposition may have already ensued as the fluid is calcite supersaturated (Q/K,CSI>1.0). Figure 6 shows that for MG19 during dosed conditions, CSI values at 240°C are generally clustered above the saturation line which means that the well has high potential for scaling but is inhibited during dosing by the chemical inhibitor.

However, Figure 6 further shows that there were episodes of CSI declines which coincided with mass flow declines even during dosed conditions. This shows that some inhibitors are not 100%effective in inhibition, thus decline in mass flow in some periods while dosing are still observed.

Figure 5B shows decreasing Ca_{res} in MG1 since 2007, while prior to this, Ca_{res} shows generally stable trend. Ca_{res} trend in MG1 since 2007 indicates possible calcite deposition or dilution as an effect of cold fluid inflow. Initially, CSI values in MG1 lie above the saturation line, indicating effective inhibition. On the other hand, the reservoir temperature is also declining as the well is affected by cold fluid inflow. Note that as early as 2006, all CSI values were already indicative of undersaturation with respect to calcite. It is postulated that with this phenomenon, the equilibrium condition of calcite in MG1 was already altered as calcite is more soluble at lower temperatures due to its retrograde solubility. There are two possible mechanisms happening inside the well to explain this observation: (1) the fluid can hold more calcium (due to increased solubility) at the lower temperature due to cold inflow resulting to the undersaturated condition; or (2) active deposition is occurring inside the well as indicated by decline in mass flow. With this complication in the reservoir process on cooler fluid inflow, CSI and calcium trends alone cannot be interpreted in relation to whether inhibition is effective or not. Intensive geochemical monitoring is conducted with fluid samples collected for complete chemistry during with and without calcite inhibitor dosing to fully evaluate the shift of MG1 CSI values to <1.0. The evaluation aims to later decide whether a CIS is still necessary in its operation.

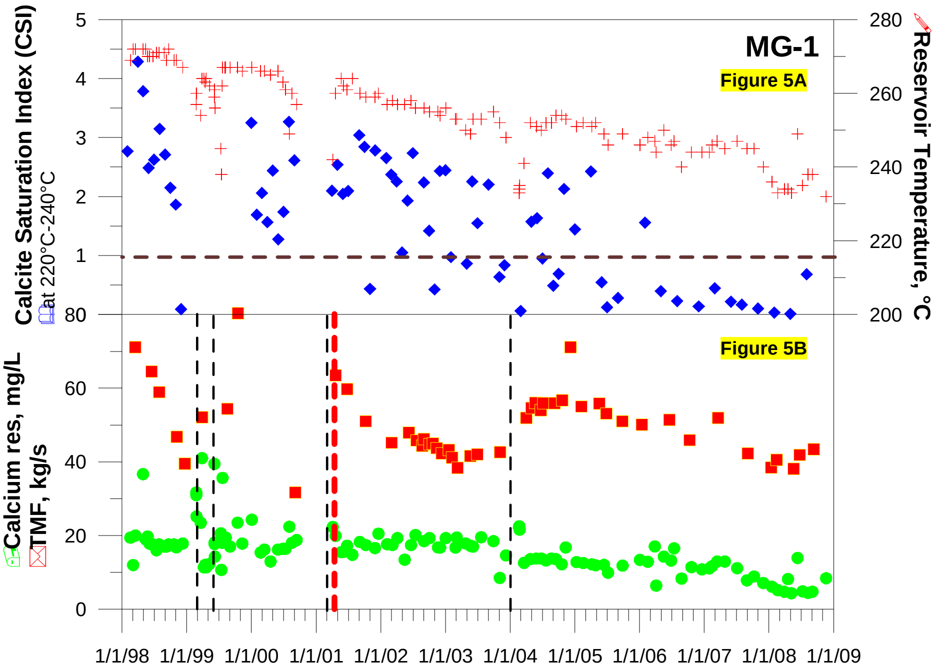

Figure 5: A. Reservoir temperature and Calcite Saturation Indices (CSI) of MG-1. Note the declining trend of temperature due to cooler inflow affecting the well. Brown dashed line at Y=1.0 (left-y axis) is the calcite saturation line. B. Plot correlating MG-1 reservoir calcium and mass flow measured by tracer flow test. Black dashed lines correspond to workovers conducted. Red, thick dashed line indicates the CIS commissioning

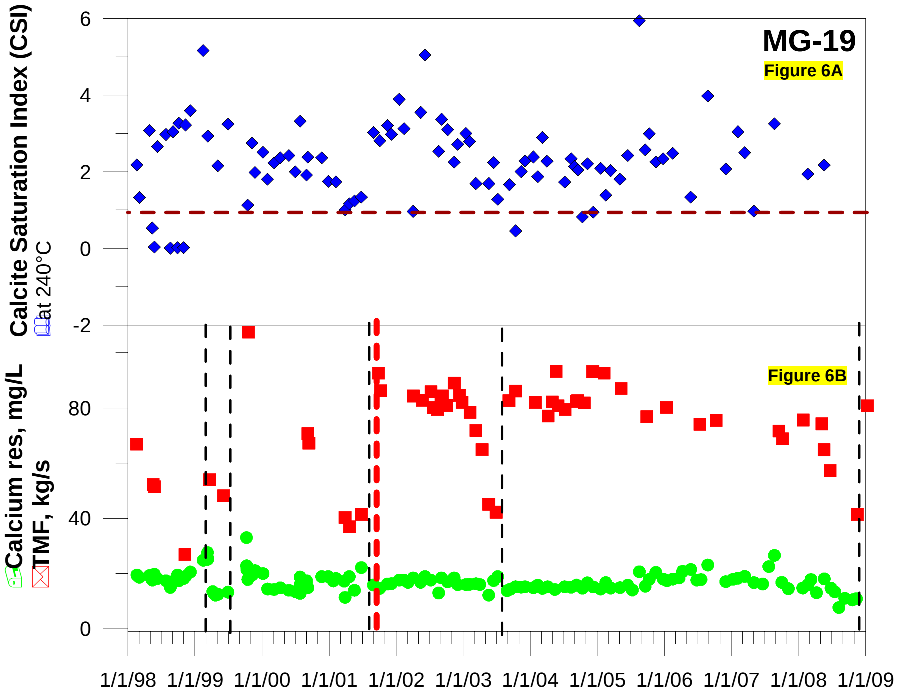

Figure 6: A. Calcite Saturation Indices (CSI) of MG-19. Brown dashed line at Y=1.0 (left-y axis) is the calcite saturation line. B. Plot correlating MG-19 reservoir calcium and mass flow measured by tracer flow test. Black dashed lines correspond to workovers conducted. Red, thick dashed line indicates the CIS commissioning

SUMMARY AND CONCLUSIONS

The Calcite Inhibition Systems in Mahanagdong wells MG1 and MG19 have been effective in sustaining the productivity of the wells that are affected by calcite deposition. This resulted to less downtime in the wells utilization for the costly revival by mechanical clearing work-over. The most important consideration in the selection of the most suitable calcite inhibitor is its applicability to the well to be dosed and its stability at injection depth temperatures. In the case of MG19, the inhibitor must retain its stability and inhibition property at injection temperature of ~280°C.

Among the four calcite inhibitors used in Mahanagdong, PMA was used for the longest period (≥3 years). PAA #2, which is a high-purity formulation of PAA #1, and PMA are the two most suitable inhibitors considering their performance in over 2-3 years. Both have been thermally stable at the injection depth temperature and effectively inhibited massive calcite deposition since the mass flow and steam flow decline rates of the wells was reduced by 80-90%, comparing the decline rates before and after CIS was installed. Considering their annual requirement, PAA #2 requires more since its target line concentration is at 4 ppm while PMA is only at 2 ppm. On an annual consumption basis, using the well's mass flow of 80 kg/s, about 8,844 kg of PAA #2 is consumed, while around 5,256 kg of PMA is consumed. Even if PMA is more expensive on a per kg basis, total annual cost of consumption is competitive to PAA #2 (or even to PAA #3), due to the lower target line concentration and lower annual kg consumption. Taking into account the length of use, stability and its efficiency in maintaining the mass flow of the well, PMA has so far exhibited the better advantage. Although the advantage is not that significant to disqualify PAA's in future tenders for chemical inhibitor supply. PAA #3's performance cannot yet be fully evaluated due to insufficient data as inhibitor was still recently used and utilization in MG19 was interrupted when the CIS tubing was parted. Monitoring the performance of PAA #3 in MG19 proceeded beginning January 2009 after re-commissioning MG19 CIS with new tubing installed.

An additional complication for the MG1 case is that the well is affected by cold inflow reservoir process, altering in a way the downhole temperature, and hence the solubility of temperature-dependent minerals such as calcite. With this premise, either CSI or Ca_{res} alone cannot be used in determining whether chemical dosing (particularly during the period when CSI<1.0) is effective or not due to the inherent change in the well's chemistry with the interference from cooler fluid inflow to the well. Nonetheless, the above parameters must be evaluated in tandem with other physical data such as flow parameters. The decline in mass flow will indicate if deposition is occurring, but decline in steam flow cannot be quantified if how much is due to cooler water inflow or calcite deposition. Thus, caution has been exercised in interpreting recent MG1 data (since 2007) in relation to calcite inhibition effectiveness. What is certain is that the calcite inhibitors had served well in sustaining the commercial life of MG1 and MG19 much longer than when there was no CIS installed.

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