Effect of Aquifer Dumpflood on the Reservoir Scale Tendency and Subsurface Equipment Corrosion

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ABSTRACT

Corrosion and scale precipitation from natural water are an interactive and highly complex physical, chemical and electrochemical process that is still poorly understood and over which we have limited control. At some phases of the field development plans of ADMA-OPCO, aquifer dump flood was used extensively to maintain the reservoir pressure through fifty eight (58) dump flood water wells in Zakum field. Powered sea water injection was introduced in 1982 and many of the dump flood wells were converted to single or dual powered injectors.

Most of the completion recovered from water injection wells in the past 15 years suffers extensive corrosion and deposition of mineral scales particularly in wells with open or partially sealed old aquifer. Increased water injection demand to maintain the reservoir pressure and to sweep the formation oil has imposed increasing challenges on the operating authorities to demonstrate that the integrity of water injection wells is assured and that the target water injection is achieved.

This paper discusses the corrosion and mineral scale problems experienced in ADMA-OPCO subsurface water injection facilities, identifies the root cause and addresses a set of remedial actions which should result in reducing the failure rate, minimising work over intervention and improving our capabilities to inject more clean water into the reservoir.

1. INTRODUCTION

ADMA-OPCO suffers extensive corrosion damage on its topside and sub-surface water injection handling equipment in the past years. This damage resulted in shutdown of the injection facilities in many occasions and affected our capability to push as much water into the reservoir to maintain its pressure.

At least 50% of the water injection subsea transmission network which is made of sixty eight (68) subsea pipelines is no longer fit for service due to aggressive internal corrosion. Many of the subsea lines are due for replacement in the coming few years and the remaining ones are at a high risk of failure. Recovered completions from water injection wells were badly corroded, perforated in many locations and parted in many wells which resulted in prolonged work over.

The quality of injection water was continuously blamed to be responsible for all failures experienced in the water injection system from the seawater intake facilities to the well bore.

Stringent mitigation measures were employed to ensure highest water quality is deployed to the formation. Accordingly, all water injection modules were overhauled in the past few years. New chemical treatment regime was introduced and mechanical cleaning of all subsea lines was completed twice during the past five years. As a result, major decline in the failure rate of topside and subsea pipelines was noted, the quality of injection water has improved in most locations, yet downhole tubing high failure rate remained unchanged.

Oxygen diffusion to the topside facilities from leaking pump seals and fittings was found to be the major cause of topside facilities failure. Sulphate Reducing Bacteria (SRB) was found responsible for the subsea lines damage (11) but downhole corrosion of the tubular good remained to be explained.

Comprehensive completion inspection scheme was introduced to allow tubing segregation and identification to enable proper inspection. The historic records of most water injection wells with dump flood background were reviewed to find common facts which may explain the failure mechanism.

Original sea water and aquifer water samples were reviewed and fresh surface samples were collected to enable predicting the current and future scale tendencies.

The exercise was very helpful in understanding the threat, identifying the principal cause of damage and allowing driving a set of recommendations, which should prevent similar failure in the future. However, we admit that we have failed to precisely describe the exact failure mechanism, which should have explained what was really happening down hole.

2. WATER FLOODING

2.1. History of Water Flooding As early as 1875, oil producing operators concluded that water injection into the reservoir could be an effective method for driving oil flow within the formation (1). These observations resulted from accidental intercommunication of natural forces under favorable circumstances which lead to increase in production.

First documented water flood was in Pennsylvania’s Bradford field. The accidental flooding of the field thought to have begun in 1905, six years after the field began production. Flooding continued for 15 years, during the time production rate trend upward.

Water flooding has then become a well proven technique to sustain reservoir pressure. Other operators soon improved and adopted this technique which has become very much wide spread between 1944 and 1949.

It is readily apparent that water is the cheapest fluid and that improvement in the water flood technology are still occurring as a result of better control of fluid movement in the formation. In general terms, water flooding either from natural sources (aquifer dump) or pressurized surface water (sea or river water) has proven to maximize the recovery factor of original oil in place during the life of the field (5).

At the early years of an oil field’s production life, primary recovery utilizing the natural energy of the reservoir has caused hydrocarbon flow into the well bore. After some time the natural energy of the reservoir is depleted. To continue production some secondary recovery methods must be implemented. Several methods to enhance oil recovery of proven track records other than water flooding are also known to the oil fields, among which are :-

- Displacement of Miscible Gas
- Chemical Flooding

- Polymers Flooding
- Thermal Recovery (Steam Flooding)
- In-situ Combustion

However, it is readily apparent that water is the cheapest fluid and water flood either from natural geothermal or surface sources is the most commonly used technology for secondary oil recovery.

2.2. Water Flood in ADMA-OPCO Like many other operators, ADMA-OPCO, has used geothermal "aquifer" water as a primary tool to maintain the reservoir pressure. Accordingly, fifty eight aquifer dump wells were drilled and used to dump aquifer water to the reservoirs to shepherd the crude oil towards the production wells and to maintain its pressure since 1972. Geothermal natural aquifer water was identified in the formation layers of ADMA-OPCO concession areas, namely, Simsima and Umm Er-Radhuma. In the year 1983 power treated seawater injection plants were commissioned. The plants were capable of delivering up to 770,000 barrels of treated water per day through seven treatment modules located at the offshore super complexes. Many of the original aquifer dump flood wells were converted to single or dual injectors to allow seawater injection to the formation.

Each of the seven sea water treatment modules is made of four sand filters and one deaeration (vacuum) tower. Incoming raw sea water to the filters is treated with chlorine gas to control bacterial and marine growth. Upstream of the filters Bentonite and Polyelectrolyte are injected as filtrate aids.

Oxygen and residual chlorine are stripped in the vacuum tower. Biocide "A" is injected upstream of the vacuum tower to control bacterial growth in the topside handling equipments while scale inhibitor is injected at the top of the tower to control mineral scale build-up mainly Calcium Carbonate ($CaCO_3$) on the packing of the deareator column (8).

Downstream of the vacuum tower, oxygen scavenger (Ammonium Bi-sulphite) is injected to scavenger the remaining traces of oxygen to meet the water quality specification. Biocide "B" is injected downstream the booster pump to ensure bacterial control in the water distribution network and downhole equipment.

The water quality specification at the modules is established as:-

▪ Coulter Count	70	particle >2 microns in 0.05m1
▪ Oxygen Level	<10	ppb
▪ Turbidity	<0.1	ppm
▪ SRB Count	<2	colonies/mi
▪ Residual Chlorine	0.2-0.5	ppm

However, at the injection wells the specification calls for

▪ Coulter Count	200	particle >2 microns in 0.05 ml
▪ Oxygen Level	Nil	
▪ Turbidity	<0.1	ppm
▪ SRB Count	<10	colonies/mi
▪ Residual Chlorine	Nil	

Treated water is routed to one hundred nine (109) injection wells through a network of subsea pipelines which extend for over 300 kilometers.

Corrosion is monitored through a number of LPR probes and weight loss coupons located at both the water injection modules and the injection towers. Water quality is monitored through a defined schedule for samples collection at modules and towers to ensure that the injection water meets the design specification.

3. WATER INJECTION NETWORK CORROSION

Since the 1990s many corrosion problems started to appear in the sea water production, distribution and injection network which threatened our investment and affected our capabilities to displace the required quantity and quality of water into the reservoir. Corrosion problems at different parts of the water injection network were found slightly different in nature, which dictated that different methodology and investigation tools were used to arrive to the root causes.

3.1. Topside Facilities at Super Complexes Severe thinning in the topside pipe work which results in perforation and rupture of the pipe work continuously surprises the Integrity team. Reasons of such a repeated failure were found to be due to oxygen ingress into the system via leaking pump seals and other loose connections in the system. This is combined with a higher level of residual chlorine gas concentration well above the maximum acceptable level. Overhaul of the vacuum pumps on the deareation towers resulted in better control of the residual oxygen and chlorine gas.

Repair of the booster and injection pumps defected seals reduces to a reasonable level the oxygen ingress to the water injection system. Although we believe that a better control of the chlorine and oxygen level was maintained, yet the rate of failure is still above the industry acceptable level and more work needs to be done to achieve higher level of control. The following mitigation measures were, therefore, considered:

- Upgrade the corrosion monitoring technique at modules.
- Survey the facilities to identify spots for oxygen ingress.
- Ensure that the design level of residual chlorine is not exceeded.
- Apply stringent QA/QC protocol on supplied water injection chemical package.
- Apply Risk Based Inspection (RBI) technique and improve the written scheme of examination for topside piping to identify locations susceptible to highest risk of failure.

Lately, SRB active bacteria in non-flowing parts of the system was added to other possible causes which resulted in a recent rupture of 2300 psi operated 10” cross over at the complex (Figures 1-2).

3.2. Subsea Transmission Lines Over 300 kilometers of subsea lines are connected to the water injection modules to distribute 770,000 barrels of treated seawater to over one hundred nine (109) wells in Zakum field.

The subsea lines experienced seventeen (17) leakages up to the year 2003. Thorough investigation revealed that the corrosion is due to microbial corrosion by SRB. A remnant life assessment (RLA) study was conducted to assess the health of the network. The study revealed that at least half of the subsea pipeline network requires immediate replacement and other pipes are at a high risk of failure unless remedial actions are implemented to minimize the risk to an acceptable level. Accordingly, a comprehensive corrosion control scheme was established which is mainly based on mechanically cleaning the entire network.

The scheme was fully implemented and the result was that no more leaks were recorded in the subsea network since 2003 (Figures 3-5). Nine pipelines were already replaced with new ones equipped with a permanent routine pigging facility. Side streams were installed to allow measuring sessile bacteria enumeration on a continuous basis. Residual biocide measurements were also established to ensure that the optimum kill dose is injected. Intelligent pigging of selective lines is ongoing to assure pipelines fitness for service and to validate the RLA prediction model.

Accordingly, the following measures were considered to mitigate corrosion in the subsea network:

- Provide all new replacement water injection lines with permanent pigging facilities to allow cleaning of all lines using conventional bi-directional pigs, once every 3 months.
- Install side streams at all remote water injection towers to monitor SRB bacterial growth.
- Upgrade the corrosion monitoring system to include all water injection towers.
- Carry out residual biocide measurements at selective remote towers, once every 6 months.
- Improve the SRB sampling and measurement procedures to allow most accurate methods to be used.
- Carry out an audit by a third party to review ADMA-OPCO current microbial mitigation measures and control strategy and identify gaps.

3.3. Downhole Subsurface Equipment ADMA-OPCO operates one hundred nine (109) water injection wells in Zakum field, fifty eight (58) of which were originally designed as aquifer dump flood wells (Figure 16).

During the past 15 years, over thirty (30) water injection wells were worked over mainly as a result of downhole communication problems. Most of the recovered completions were badly corroded, perforated at many locations and parted in many wells at different depths. Mineral scales were found deposited at both the internal and external walls of the recovered tubing. However, at this stage the recorded rate of deposition is very minimal and does not represent a threat to our production facilities.

With the topside and subsea transmission lines corrosion problems are in mind.

Failure of water injection subsurface equipments was wrongly attributed to the quality of injection water

For many years, this perception was believed through out the organization and focus was only given to improve the corrosion control means applied on topside and subsea transmission lines.

In 2004 ADMA-OPCO established a more systematic mechanism to inspect tubular goods recovered from worked-over wells. This involved numbering of the recovered tubing and color coding short and long string tubing to allow segregation during land inspection.

Obvious observations which attracted the attention of the inspection engineers assigned to carry out inspection on recovered tubing were that some parts of the recovered tubing showed major corrosion damage while others are in a remarkably good condition with no corrosion or scale build up both externally and internally. Correlating the recovered joints to relative well depth revealed that only tubing located at depth corresponded to the aquifer water production zone suffered corrosion damage.

3.4. Observation on Recovered Completion Archived "Well files" were reviewed to find out the historical background of many water injection wells in order to understand the historical performance, early workover objectives and old completion inspection reports. The task was reasonably successful and fifteen (15) completion recovery reports were identified which allowed segregating the conditions of the recovered completion into three distinct groups.

Group A

Includes two wells, namely, ZK-234 and ZK-202. Both were in service for 20 and 23 years, respectively. Both wells were drilled and completed with type 2B completion, as a diverted single powered injector into Thamama V. Both wells were never used as aquifer dump flood during their service life (Figure 6).

Observation

The recovered completion from both wells was inspected during the year 2004. The inspection reports clearly described the recovered completions being free from corrosion damage and scale build up, both externally and internally. MVRT corrosion log was run in the 9 5/8" casing of ZK 234 and ZK- 202 in November 2004.The survey revealed that the casing is as good as the tubing and no corrosion damage internally or externally (Figures 7-8).

Group B

Includes two original dump flood wells, namely, ZK-136 and ZK-116. Both wells were completed using 9S standard dump flood completion. ZK-136 was drilled in 1978 while ZK-116 was drilled and has been in service since 1982.

Observation

According to the inspection reports of the recovered completions, the packers and many feet of tubing and landing nipples were found generally in a good condition with no signs of internal or external corrosion. It is worth mentioning that the dump flood completion (9S) extended only for about 500 to 550 ft into the hole while the tubing part exposed to the aquifer water did not exceed few feet.

Group C

Includes eleven completion recovery reports. All wells belonging to this group were originally drilled as dump flood and were converted at some stage of their service life into sea water power injectors. The old aquifer zone was isolated to allow power injection using one of the following mechanisms:

- 7" Scab liner set against aquifer perforation.
- 7" Temporary tie - back liner.
- 7" Cemented ties - back liner.
- Cement squeezes aquifer.
- Encapsulating aquifer between two packers without isolation.

Figure 9 graphically illustrates the different types of completion used in the water injection wells and aquifer isolation technique.

Historical background of all wells belonging to this group is described in details as follows:

Well ZK-151 Brief History ZK-151 was completed as a dump flood in 1978 and was converted to dual injector in 1979 into Thamama IVA, B&C. A 7" scab liner was installed to seal the aquifer zone. Communication between long and short strings was detected and the well was shutdown in December 1988. During 1990 the well was worked over to complete the well as a dual segregated power injector through type 16 non-standard completion. The recovered completion was in service for less than 9 years.

Well ZK-158 Brief History Water injection well ZK-158 was drilled and completed in March 1979 as a dual injector. During May 1989 wire line exploratory work revealed that both tubing strings are in communication. Water injection continued however, until the well was worked over in 1990.

Well ZK-145 Brief History ZK-145 was drilled and completed in July 1978 as a vertical dump flood from Umm Er-Radhuma and Simsima aquifers into Thamama IVA B&C.

The well was worked over in December 1979 and recompleted as a dual injector into Thamama IVA/B/C with 15A completion after installing a 7" scab liner (between 3070' to 4890' BRT). Communication between strings and the 9 5/8" tubing annulus was reported in October 1984 after 5 years of service. No detailed inspection reports were included but the covering memo dated 13th February 1994 detailed the following:

> "The severe corrosion attack noted at one side of the tubular is similar to that observed in other examined tubular. This type of damage associated with converted dump flood wells is believed to be the result of corrosion for the obliterated aquifers. It is, therefore, recommended to replace 15A completion by 16C type"

Well ZK-154 Brief History ZK-154 was drilled and completed with type 9 MLS completion in January 1979 as a deviated dump flood well from Simsima aquifer into Thamama IVA, B&C reservoirs. The first work over was carried out in 1980 to convert the well to a dual powered injector into Thamama IVA, B&C through type 1 5A completion. 7" Scab liner was installed to seal the aquifer zone which extended for 5300" to 5619" BRT. During the work, over communication was confirmed between the three injection zones. Long string has been shut-off since November 1985 due to plugging off with deposits. Short string was closed since December 1989. The well was worked over for the second time during October 1990.

Well ZK-129 Brief History ZK-129 was completed as a deviated dump flood well in December 1977. During August 1979, the well was converted to a dual power injector which required the setting of a scab liner across the original dump flood aquifer perforations. During October 1989, logging surveys revealed communication between the two strings. In 1990 the well was worked over to recover the existing completion and to be recompleted using 17 M (NS) completion.

Well ZK-127 Brief History This well was completed in January 1978 as a deviated dump flood well from Simsima aquifer into Thamama VM reservoir through type 9S completion. A dump rate of 800 BWRD was measured using the full bore flowmeter. During 1985, the well was worked over to be converted to a segregated dual injector with 16M non-standard completion. A 7" temporary tie back liner was installed to stop aquifer dump. In 1994, the injection performance drastically increased from 3000 BWPD to 12000 BWPD at 1750 PSIG WHIP which revealed that injected water is being directed to the aquifer which was thought to be sealed.

Well ZK-141 Brief History ZK-141 was completed as a deviated dump flood injector type 9S completion in 1978. In 1980 the well was converted as a dual powered injector into Thamama IVA, B&C through Type 15A completion. The aim of the last work which was completed in April 1990 was to complete the well as a dual segregated powered injector into Thamama IV A & C using type 17M non standard completion.

Well ZK-81 Brief History ZK-081 was drilled as observation well for Thamama IA and Thamama II formation. In June 1976, the well was completed as a dump flood from Simsima and Umm Er-Radhuma aquifers into Thamama IVA, B&C sub zones. The well was suspended at the mud line.

The well was worked over in November 1976 to extend the casing from the mud line, install a wellhead, and to run a dump flood completion. In July 1977, the well was converted to an observation well into Thamama IVA, B&C sub zones. During 1977 work over the aquifer perforations were not isolated and were only straddled between the two packers. In August 1991 a communication test was carried out which revealed communication between the 3½" tubing and the annulus above the FB1 packer.

Well ZK-161 Brief History ZK-161 is a vertically drilled completion dating back to May 1979. XL 161 has a dual injection capacity. Whirling incidents revealed a stuck 2.75" sliding sleeve in December 1984. During 1990 workover, the production strings were parted at 620 feet BRT.

Well ZK-144 Brief History ZK-144 was drilled and completed in July 1978 as a deviated commingled dump- flood well from Simsima aquifer into Thamama IV A, B&C reservoir through type 9S completion.

In November 1984, the well was recompleted as an injection/observation well with type 16NS completion. The well was in operation for 19 years since the first workover. AFL and HRT logs conducted in 2002 indicated that the majority of injection water is moving up to aquifer through tubing leak.

Well ZK-152 Brief History ZK-152 was drilled and completed in November 1978 as a deviated dump flood well from Simsima aquifers into Thamama IVA, B&C reservoir through type 9S completion. The well was worked over in 1980 to be completed as dual injector into Thamama IVA, B&C with completion type 16NS and 7" scab liner was set against aquifer perforation. ZK-152 was worked over for the second time in June 1991 to complete the well as a dual injector with type 16NS completion and the 7" scab liner was recovered. In April 2003 a drastic change in the injection rate was observed and communication between the long and short strings was confirmed. In April 2004 the well was worked over for the third time to eliminate the mechanical failure and recomplete the well as a dual injector into Thamama VA, B&C through type 16C completion.

Accordingly, during the period from 1991 to 2004 (13 years), the short and long stings at the zone located between the 9 5/8 RDH packer and the 7" OTIS perforation packer were exposed to Simsima and Um Rudhuma aquifer.

Observation

The observed failure mechanism among all the eleven completions which were originally drilled as dump flood wells was very much common in nature. The similarity is described as follows:

- Tubing, flow coupling and adjustable spacers above the 9 5/8" RHD dual production packer are free from corrosion and scale build up, both internally and externally.
- Tubing below the FB-1 retainer production packer is free from corrosion and scale build up, both internally and externally.
- All tubing located below the 9 5/8" RHD and above FB-1 retainer production packer is severely corroded from the external surface and pitting in many locations. No metal loss was reported in

any recovered tubing from the internal surface.

- The pits in many cases are interconnecting and lead in many locations to complete holes or a series of connected hole up to the length of 70-80 cm long (Figure 10).
- Severe preferential corrosion attack was noted on the coupling characterised by an **ARC** or **V** shaped metal wastage on the box and collar (Figure 11**).** The metal loss was noted to be on one side along the entire length of the strings, which is the side in contact with the casing. This may lead to the belief that the casing some how acts as a cathode relative to the tubing which is the anode site in this galvanic corrosion cell.
- The average corrosion rate was measured to be at 0.58 mm/year.
- In many workover the completions were parted and up to forty seven (47) fishing jobs were performed in one well, namely ZK-127.
- In two wells SRB bacteria was detected using Rapid Check II kit at a 10^5 colonies/ml. These results are obtained in ZK-127& ZK-14 wells where external corrosion at the face exposed to the aquifer was corroded to perforation and SRB contaminated sea water was allowed to flow to the aquifer.

4. SCALE PRECIPITATION TENDENCY

4.1. Water Equilibrium State

During the conversion of the aquifer dump flood wells into powered sea water injection the two may come to be mixed together at the well bore or at the annulus space under the prevailing downhole conditions. Accordingly, the natural aquifer water that may have been at thermal and chemical equilibrium with heated reservoir rocks can be exposed to substantial changes in temperature and pressure. This can affect the solubility of a variety of dissolved mineral species. The mechanism of mineral scales formation is dependent upon the degree of supersaturation of the water with respect to particular minerals and the rate of temperature, pressure and pH change (10). An increase in the partial pressure of gases in water may, in turn, increase or decrease the mobility of some other constituents. Oxygen decreases the mobility of iron while carbon dioxide increases the mobility of many constituents of which calcium is the most important (12).

The reduction of the fluid temperature can decrease the solubility of metal sulphide species and allow them to precipitate individually or collectively. For calcium carbonate, the reverse is true; it is more soluble at a lower temperature. Changes in fluid pressure can allow a phase change to take place; it is either boiling or exsolution of dissolved gases. Loss of dissolved gases (carbon dioxide or hydrogen sulphide) from the geothermal water can also drastically affect the pH, and as well, the solubility of both calcium carbonate and sulphide minerals. The precipitation of dissolved solids from geothermal fluids is a virtually ubiquitous phenomenon which takes place in geothermal fluids at a different chemical composition over a wide range of temperatures.

4.1.1. Calcium Sulphate Deposition There are two forms of calcium sulphate which are known in the water flooding system:

Gypsum	$CaSO_4 . 2 H_2O$ at 100°F or less	
Anhydrite	$CaSO_4$	above 100°F

Aquifer water has a TDS level measure at 265,000 mg/litre. At such an extremely high level the presence of NaC1 and other salts increase the solubility of Gypsum or Anhydrite. Any change of the

TDS below the 150,000 mg/liter will cause the solubility of Ca^{++} and SO_4 to decrease and eventually precipitate.

As the sea water injection (40,000 mg/liter) is mixed up with the aquifer water, the TDS level dramatically decreased to a level beyond the critical 150,000 mg/litre which resulted in decreasing the solubility of Ca^{++} & SO_4 ions and cause their precipitation into the subsurface equipment. This explains the presence of $CaSO_4$ scales in US-55. Temperature has an effect on the type of calcium sulphate scale. At the reservoir temperature, Arthydride is less soluble than Gypsum at a temperature above 37°C. For deeper hotter wells, anhydrite may be the preferred form.

$\mathbf{Ca^{++}}$ (Aquifer Water) + $\mathbf{SO_4}$ (Sea water) → $\mathbf{CaSO_4}$ **(Gypsum or Anhydrite)**

4.1.2. Calcium Carbonate Deposition Calcium carbonate is a polymorphous mineral and exists in several modifications. The two polymorphs commonly formed in nature are calcite and aragonite. Calcium carbonate precipitates can form in geothermal waters by the combination of calcium ions with carbonate ions. The solubility of calcite, aragonite may be expressed by the following reaction:

$$\mathbf{Ca^{++} + 2\,HCO_3 \leftrightarrows CaCO_3 + CO_2\uparrow + H_2O}$$

The solubility of the carbonate minerals is strongly influenced by the pH and the activity of the carbon dioxide dissolved in geothermal waters. In solutions held at a constant total pressure, the solubility increases with increasing carbon dioxide concentration. At any given carbon dioxide pressure in the vapour phase, the solubility of calcium carbonate decreases with increasing temperature.

4.1.3. Scale Prediction The scaling tendency of ADMA-OPCO reservoir was not well explored and quantified. The effect of water injection (dump flood or seawater) was merely discussed. However, lately with the increased dependence in the water injection to maintain the reservoir pressure more focus was given on better understanding of the reservoir scale tendency. Accordingly, a scale tendency study team was formed and assigned to develop a situation report which includes producing a master scale tendency profile of all wells using mathematical scale prediction model. There are several mathematical approaches available for predicting the scaling tendencies of geothermal water. Changes in the water by cooling, boiling or other processes within the system can be modeled and subsequent changes in chemistry evaluated. This is an important tool for the assessment of production characteristics of the water. Changes in geothermal water over time are also clearly demonstrated by comparing the changes in mineral equilibrium in different water samples collected through-out the service life of the reservoir.

Accordingly, original and historical water analysis reports were collected, a wide produced water sample collection and analysis program was completed and all operating data were fed into a Scale Prediction Model to allow identifying the scale tendency of every water injection and oil production well in ADMA-OPCO. Furthermore, the study includes a review of the historical dump flood on the scaling tendency of the reservoir. Apparently, dump flood water is not compatible with the injection water and there is a great tendency to precipitate calcium sulphate scales under the current reservoir condition.

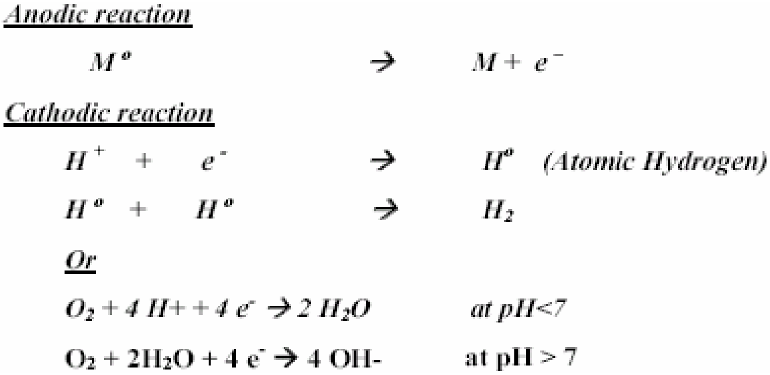
The model result with regards to the high tendency of the aquifer water/injection water mix to precipitate $CaSO_4$ scale was validated by the physical presence of calcium sulphate scales found in US-55 during the 2005 workover.

The high concentration of sea water sulphate at 3,200 mg/litre and the corresponding high level of calcium of the aquifer water when mixed together under the reservoir pressure resulted in the formation of $CaSO_4$ scales. Excessive scale deposition was found in the borehole which resulted in bonding the short and long strings together and made it absolutely difficult to recover the existing completion. US-55 is currently abandoned until appropriate chemical cleaning program is completed to dissolve the scale gluing the two strings together.

5. CORROSION

5.1. Type of Corrosion Almost all types of corrosion were reported to be associated with natural aquifer water. The corrosive effects of a geothermal water on metals depend upon the chemical composition of that fluid. Geothermal waters have a wide range of composition including strongly acidic waters containing sulphur and halogen acids which actively corrode most common alloys. Neutral-pH waters might lay down protective scales of calcite or metal oxides. Corrosive attack on steel is reduced as the pH rises. The loss of dissolved gases is usually beneficial from a corrosion standpoint since the loss of carbon dioxide will tend to raise the pH in many geothermal waters. The only gas of any corrosive consequence is oxygen. Although the solubility of oxygen decreases to a minimum as the temperature rises near 100°C, it is very important to exclude oxygen contact with geothermal water.

The exact mechanism of corrosion attack has not been unequivocally identified but theoretically, possible processes include chemical attack by hydrogen sulphide, carbon dioxide, chloride, hydrogen ions bacterial and galvanic corrosion may contribute to different level in the corrosion damage of the subsurface equipments. Pitting is a localised form of attack in which pits develop in the metal surface. Pitting is often associated with the breakdown of a passivation film or surface scale. High concentrations of chloride and hydrogen ions stimulate the dissolution ferric ions. For the initiation of the pitting corrosion the rate of metal dissolution needs to be momentarily high at one particular point. The cathodic reaction occurring in conjunction with pitting is considered to be the reduction of oxygen to hydroxyl ions. This means that the presence of oxygen or other oxidizing agents is one absolute condition for the initiation of pitting.



Anodic reaction

$M^o \rightarrow M + e^-$

Cathodic reaction

$H^+ + e^- \rightarrow H^o$ *(Atomic Hydrogen)*

$H^o + H^o \rightarrow H_2$

Or

$O_2 + 4\,H^+ + 4\,e^- \rightarrow 2\,H_2O$ at $pH<7$

$O_2 + 2H_2O + 4\,e^- \rightarrow 4\,OH^-$ at $pH > 7$

5.2. Key Corrosive Species The species that are of greatest interest in geothermal water in relation to corrosion are hydrogen ion, chloride ion, hydrogen sulphide, carbon dioxide and oxygen. Microbiological corrosion is another mechanism which is common in water injection systems.

Principal effects of the main corrosive species are described briefly as follows:

Hydrogen Ion

Corrosion rate of most materials increases as pH decreases. The susceptibility of steels to stress corrosion cracking increases with increasing hydrogen ion concentration (lower pH). The main types of corrosion are pitting and stress corrosion cracking. A value of 6.5 or below, in water with a high carbon dioxide concentration, e.g., 20 mg/l indicates that acid attack and direct hydrogen evolution are likely to occur. Higher pH values (above 8) are usually associated with water that causes localized pitting instead of general corrosion, particularly if dissolved oxygen is present.

Chloride Ion

Chloride ion causes local breakdown of passive films. High chloride concentration causes increased solubility of iron in geothermal water by forming highly soluble complexes with the ferric ion. Stress corrosion cracking (SCC) is a type of failure promoted by a combination of the action of specific chemicals such as chloride ion and tensile stress

Hydrogen Sulphide

The effect of hydrogen sulphide on iron compounds is less predictable. Accelerated attack occurs in some cases and inhibition in others. Hydrogen sulphide is ubiquitous at the parts per million or parts per billion levels in geothermal waters.

General corrosion by hydrogen sulphide in geothermal water proceeds in such a way that iron is oxidized to soluble ferrous iron at the anode and hydrogen sulphide dissociates into hydrosulfide and sulphide ions at the cathode. The threshold concentration for attack is less than 30 ppb hydrogen sulphide. The presence of hydrogen sulphide in geothermal water indicates reducing water capable of dissolving iron. Sulphide Stress Cracking (SSC) is another form of corrosion that may occur due to tensile stress and environments involving hydrogen sulphide in an aqueous phase. Hydrogen blistering which may occur in low strength steels exposed to water containing hydrogen sulphide is similar. Sulphide stress cracking decreases in severity with increased temperature.

Carbon Dioxide

Carbon dioxide occurs naturally in many geothermal waters and has a major corrosive effect on steels. It is a mild oxidizing agent that causes increased corrosion of steel. At high temperatures, stable iron carbonate film which slows the corrosion rate compared to predicted values is formed. Carbonic acid is believed to provide for an alternative cathodic half-reaction which yields bicarbonate ions and hydrogen. Large concentrations of carbon dioxide, particularly at the pressure encountered in deep wells, are converted to carbonic acid. This causes a decrease in the pH of the water.

However, the primary effects of carbon dioxide in geothermal systems involve carbonate species and pH changes. In acidic solutions, carbon dioxide can accelerate the uniform corrosion of carbon steels. The pH of geothermal water is largely controlled by carbon dioxide.

Oxygen

Oxygen is present in low concentrations in most geothermal water. It is a very strong cathodic depolarizer where Hydrogen is consumed in the cathodic reaction so active corrosion cell is promoted. Only a few ppb of oxygen in hot water is needed to cause aggressive localized and pitting corrosion. At low oxygen levels, the corrosion products are mainly iron sulphides (pyrite, pyrrhotite). As the oxygen level increases, magnetite becomes the major product.

SRB Corrosion

It is almost universal that injection water contains SRB when introduced to the reservoir. These bacteria will be subjected to much higher pressure that prevails and also to higher temperature. Localized corrosion processes such as that related to bacterial sulphate reduction can cause severe damage to steel.

When hydrogen sulphide in low-temperature water is detected, there is a reason to suspect the presence of suiphide-reducing bacteria. These can cause troublesome and very persistent localized pitting in addition to the general sulphide attack.

The injection of the deareated cold sea water into the formation can provide a number of key elements for microbiological H_2S generation. The cooling effect of the sea water reduces the temperature of the rock around the injector within the thermal viability limits of life of these micro organisms. The deareated sea water is poised at suitable reducing condition for an aerobic sulphate reducing bacteria and the abundance of sulphate (3200 mg/litres) supplies the reducible sulphur source. The pH of the sea water or the sea water/aquifer water mix is within the most optimum range for microbial activity and the flooding ensures an ever increasing mixing zone with the formation water in which growth condition can be met. Finally, the sea water is the vector for continued SRB inoculation. Sea water is rich in sulphate for bacterial reduction, moreover, it lacks the necessary organic carbon for growth where as the reverse is true for the down hole prior to water injection. This suggests the possibility of a stable zone becoming established around an injector in which all the favourable conditions necessary to support SRB bacteria to flourish exist and to produce H_2S. In other terms, the reservoir is laterally considered a great Bioreactor (6).

There were enough evidences from close monitoring of the quality of water delivered to the reservoir that a good number of SRB bacteria are swept to the reservoir. The presence of SRB may explain the presence of iron sulphide scale found in the recovered tubing but not necessarily confirms that the extensive corrosion damage noted in the water injections wells subsurface equipment.

5.3. Prediction of Corrosion The concentrations of chemical constituents in geothermal water can be used to predict the kinds of problems which might be encountered. Corrosion and scaling processes are complex and interactive. For this reason, no single test or index is an infallible indicator of these processes. Nevertheless, certain accelerated performance tests have proven to be of considerable value in selecting construction materials. The pH value can be used as a semi-quantitative indicator of the probable intensity or corrosion attack.

5.4. Corrosion Monitoring Downhole corrosion monitoring equipment have never been used in water injection system in ADMA-OPCO. Top side weight loss coupons measurements for both the water treatment modules and injection towers were collected for the past ten years. Corrosion rate at most locations was less than 1 mpy (0.026 mm/year) which is fairly acceptable by the industry standard and cannot explain the excessive metal loss experienced in the down hole equipment. Few wells showed relatively high corrosion rate which is related to high Microbiological activity in the corresponding subsea lines accelerated by the exceptional very low velocity calculated at 0.025 meters/second in some lines. The low velocity is attributed to the poor injectivity of corresponding wells, example is ZK 280.

In general, there was no reasonable correlation between the corrosion measurements obtained from the topside weight loss coupons installed at the well head towers injection headers and the high corrosion rate measured at 0.58mm/year in subsurface equipment.

5.5. Downhole Corrosion Logs Many downhole corrosion logs were run in the past three years in some of the water injection wells. Six logs were completed in the tubing and other three were run into the open hole casing. Both mechanical caliber and Magnetic Flux Leakage (MFL) tools were used. MFL is now the preferred technique being capable of reading both internal and external corrosion. The data generated out of the downhole corrosion logs were very useful in understanding the extent of downhole corrosion and its distribution (9). Reasonable correlation was obtained when a detailed comparison of the downhole corrosion data against the pulled out tubing. This correlation is best presented in ZK 144. It became more obvious from the many logs run into the tubing or the casing that:

- Minimum casing corrosion was reported even on wells that showed extensive corrosion to the tubing. This suggests that the casing for some reasons is acting as a cathode with respect to the anode (The tubing in this case) in the corrosion process. This may explain the V shaped metal wastage of the tubing box in deviated wells where the box came to electric contact with the casing.
- No corrosion was recorded on the outer surface of the casing even at the aquifer zone.
- Tubing corrosion is only limited to the external surface and negligible metal loss on the internal surface. The tubing logs made it obviously clear that external corrosion of the tubing was only recorded at the area confined between the two packers and exposed to the aquifer or sea water/aquifer mix.

5.6. Corrosion Mechanism in Downhole Equipment It is well established that downhole tubing corrosion took place only at the presence of the aquifer water. Other water injection wells with no communication with geothermal aquifer water were absolutely free from corrosion damage.

Thorough review of all possible corrosion damages which can lead to such corrosion make us to believe that subsurface equipment corrosion is simply due to initiation of galvanic cell between the casing (Cathodic site) and the tubing (Anodic site). The V shaped metal wastage on the tubing box of every single joint of the completion strengthened this argument (Figure 12).

The high total dissolved salts (TDS) of the aquifer water measured at 267,000 - 275,000 mg/liters provide excellent electrolyte to enable high iron dissolution and electron movement.

The high chloride concentration in aquifer water at 168,000 mg/liters causes increased solubility of iron by forming highly soluble complex with ferric ions. It also causes local break down of the passive film that may exist and accelerate more iron ions dissolution.

It is well established that carbon dioxide is present in most geothermal waters (4). The possible presence of CO_2 gas in Simsima or Umm Er-Radhuma aquifer may explain the downhole subsurface equipment corrosion damage.

It is extremely remote to have oxygen in geothermal water at the prevailing geothermal pressure and temperature. However, if oxygen is present it acts as a cathodic depolarizer and consumes atomic hydrogen H ~ accelerates the corrosion reaction.

The presence of low percentage of iron sulphide at 0.1-0.3 % weight on the surface of the recovered completions suggests that H_2S gas either naturally occurring in the aquifer water or being generated as a result of SRB growth in the well bore is present in a very low concentration. Hence, it has little contribution to the corrosion damage experienced in the water injection wells.

Unless appropriate sampling technique is used to collect representative water samples from the aquifer wells under the downhole conditions, the exact corrosion mechanism which results in subsurface equipment failure shall remain subject to speculations and less confidently explained.

6. CONCLUSION

- Injection sea water and Simsima/Umm Er-Radhuma aquifer are not compatible. A very high affinity to precipitate Calcium Sulphate scales ($CaSO_4$) exists. This was physically experienced in US 55. Aquifer water has, however, a self scaling tendency to precipitate Calcium Carbonate scales ($CaCO_3$) as it is subjected to the cooling effect of the injection water and the loss of CO_2 gas which is assumed to be consumed in the corrosion process (Figure 13).

- Injection sea water is not responsible for the corrosion damage experienced in most water injection wells. This is supported by the fact that corrosion of tubing is limited to the external surface and is confined to the area located between the two packers. There is no evidence of corrosion damage in wells which were never been used as aquifer dump, i.e., ZK-234 and ZK-202.

- Although the exact corrosion damaging mechanism was not confidently identified, galvanic corrosion between the casing and the tubing accelerate by the presence of CO_2 gas may be the most logical damaging mechanism.

- Aquifer, cement squeeze, installation of 7"scab liner or temporary tie back liner proved not to be efficient means to isolate the aquifer zone. Running permanent 7" tie back liner with cement squeeze shall be the method to be adopted in future work over unless there are other proven technologies with a track record of success.

- Normal carbon steel completion grade 52 or equivalent proved to be a cost effective material for water injection wells provided that aquifer is satisfactorily isolated. ZK-202 and ZA-232 are typical examples which support this finding.

7. RECOMMENDATIONS

- Identify water injection wells at highest risks of tubing failure with open or leaking aquifer and scheduled for immediate work over. Early intervention shall reduce the number of fishing jobs and the work over duration.

- Seal aquifer zones using permanent 7" tie back liner extended across the entire aquifer zone.

- Although SRB is not the principal cause for the corrosion damage of the water injection wells subsurface equipments, it may on long term, result in uncontrolled reservoir souring. A full scale Microbiological study shall commence and address mitigation measures to reduce potential reservoir souring.

- Scale tendency of the reservoir as a result of many years of aquifer dump flood shall be addressed as part of the downhole scale management task force deliverables.

- Run 'Magnetic Flux Leakage' downhole corrosion logs at wells of the highest risk. Results of the logs shall be used to schedule work over on wells at advanced stage of corrosion.

- Carry out periodical sampling and laboratory tests on top of the fill samples to carry out complete chemical and biological tests.

- The 2003 tubular goods inspection exercise provides valuable information, which enabled better understanding of the reservoir corrosion and scale behavior. Reservoir is a dynamic environment and will keep on changing as it matures. Accordingly, inspection of every recovered completion shall continue to enable monitoring the reservoir continual changes and avoid future surprises.

ACKNOWLEDGEMENT

The author would like to thank **ADMA-OPCO** Management for permission to publish this article. The author also acknowledges the contribution of Mr. Magdy Al Mansy, Well Integrity Engineer Mr. Khalid Chishti, Petrophysicist of ZKAU and Mr. Antonio Martinez, Corrosion Engineer of IASSD who extended their support in adding valuable information and views to this article without which this paper would not have been possible

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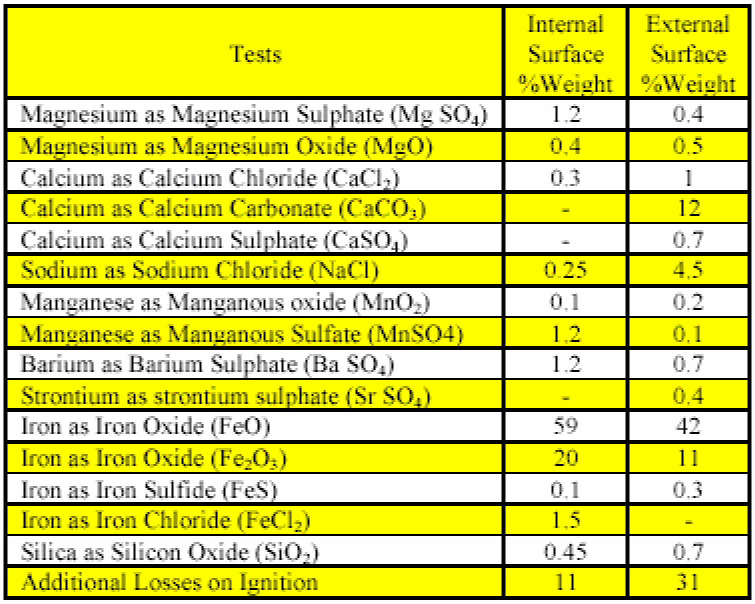
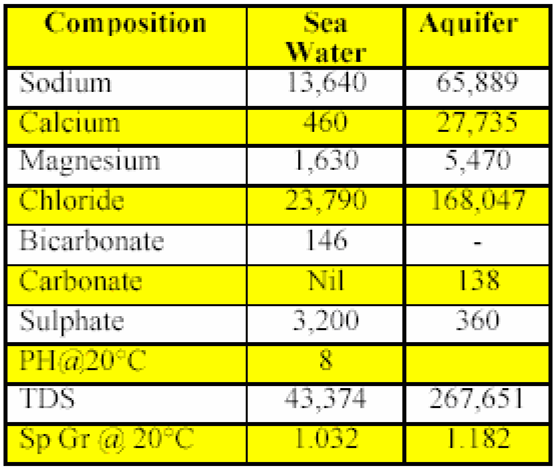


Tests	Internal Surface %Weight	External Surface %Weight
Magnesium as Magnesium Sulphate (Mg SO_4)	1.2	0.4
Magnesium as Magnesium Oxide (MgO)	0.4	0.5
Calcium as Calcium Chloride ($CaCl_2$)	0.3	1
Calcium as Calcium Carbonate ($CaCO_3$)	-	12
Calcium as Calcium Sulphate ($CaSO_4$)	-	0.7
Sodium as Sodium Chloride (NaCl)	0.25	4.5
Manganese as Manganous oxide (MnO_2)	0.1	0.2
Manganese as Manganous Sulfate (MnSO4)	1.2	0.1
Barium as Barium Sulphate (Ba SO_4)	1.2	0.7
Strontium as strontium sulphate (Sr SO_4)	-	0.4
Iron as Iron Oxide (FeO)	59	42
Iron as Iron Oxide (Fe_2O_3)	20	11
Iron as Iron Sulfide (FeS)	0.1	0.3
Iron as Iron Chloride ($FeCl_2$)	1.5	-
Silica as Silicon Oxide (SiO_2)	0.45	0.7
Additional Losses on Ignition	11	31

Table 1 – Chemical Analysis of Scale Samples
ZK-152 April 2004



Composition	Sea Water	Aquifer
Sodium	13,640	65,889
Calcium	460	27,735
Magnesium	1,630	5,470
Chloride	23,790	168,047
Bicarbonate	146	-
Carbonate	Nil	138
Sulphate	3,200	360
PH@20°C	8	
TDS	43,374	267,651
Sp Gr @ 20°C	1.032	1.182

Table 2 – Typical Analysis of Sea and Aquifer Water

Figure 1 – Rupture of 14" Water Injection Line at ZK-77

Figure 2 – Rupture of 10" Non-Flowing Crossover at the Water Injection Platform

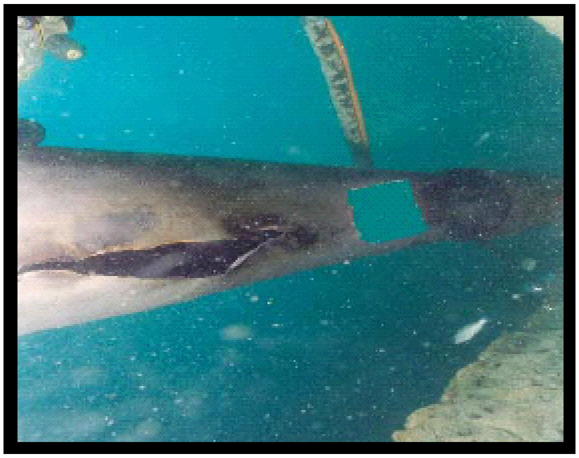


Figure 3 – Corrosion Damage at 6 O'clock Position
Due to SRB Activity

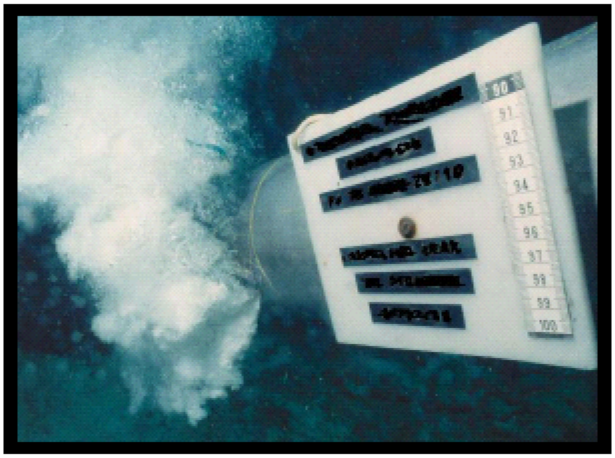


Figure 4

Figure 5 – Inside of the Failed Pipe
Note the interconnected pits

Figure 6 – Tubular Goods Recovered from ZK-234 after Twenty Years of Service

Figure 7 – Corroded Completion Recovered from ZK-144 Short String Against the Aquifer

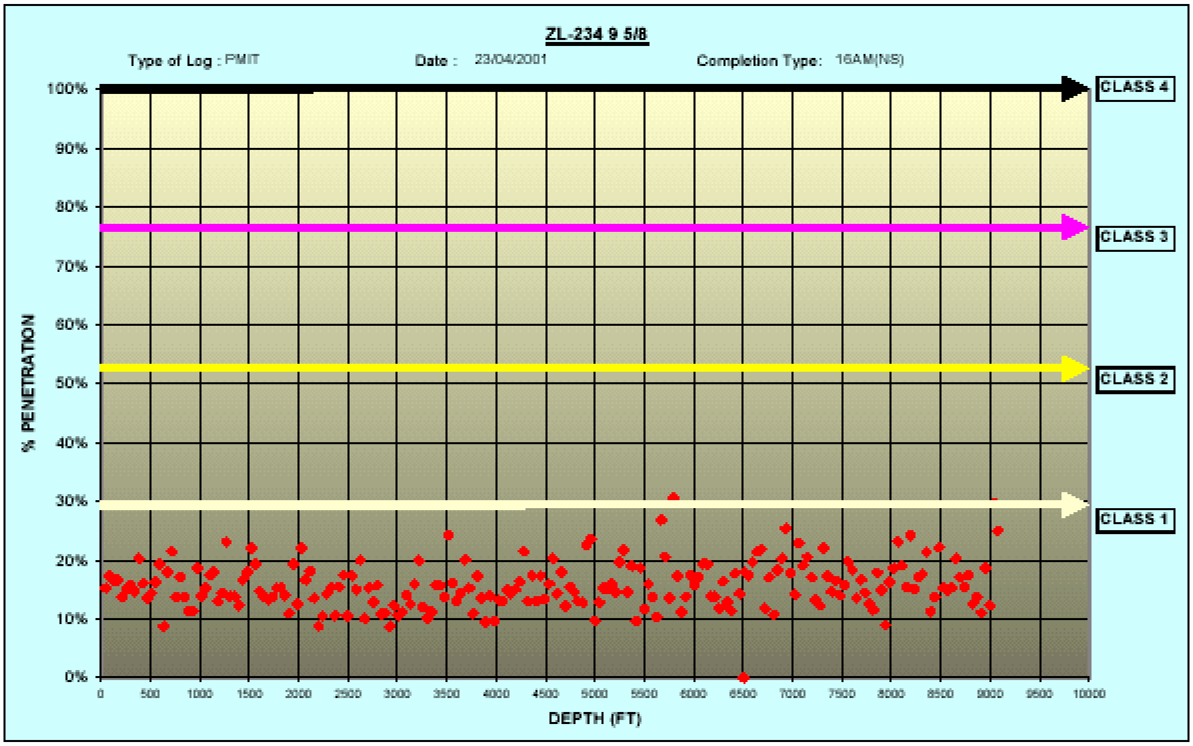


Figure 8 – ZK-234 MVRT Log in 9-5/8" Casing

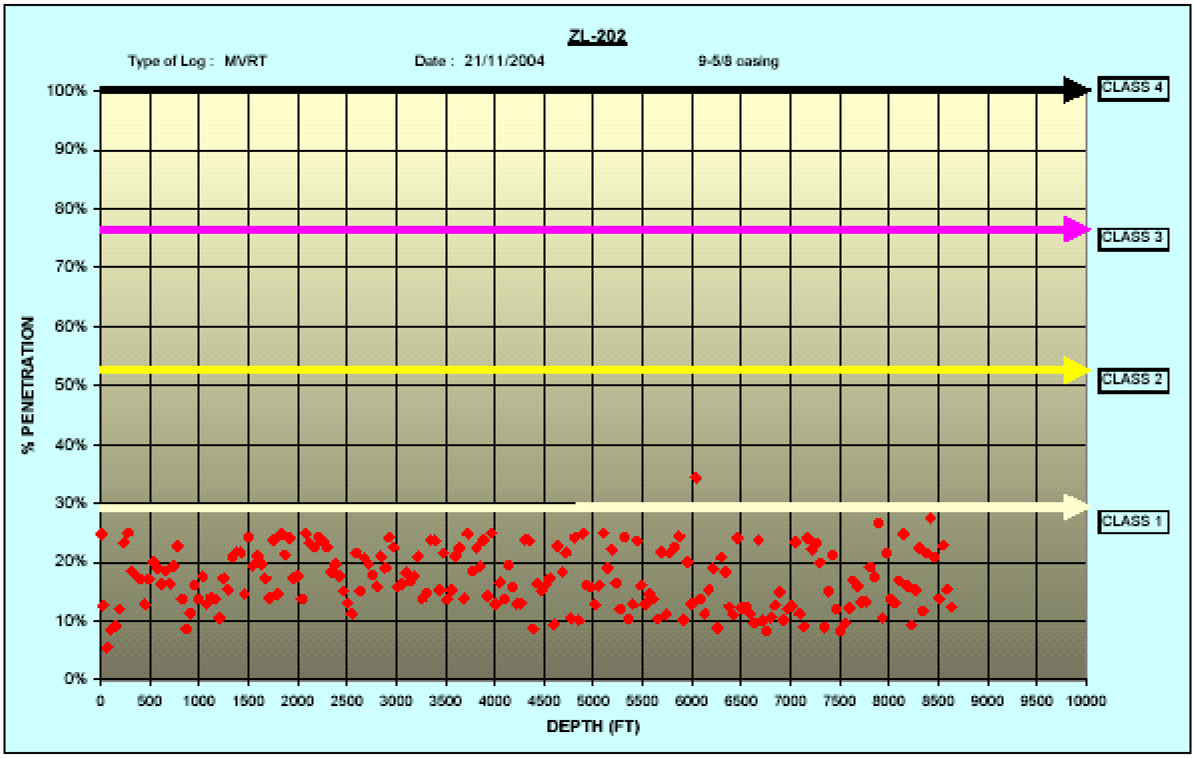


Figure 9 – ZK-202 MVRT Log in 9-5/8" Casing

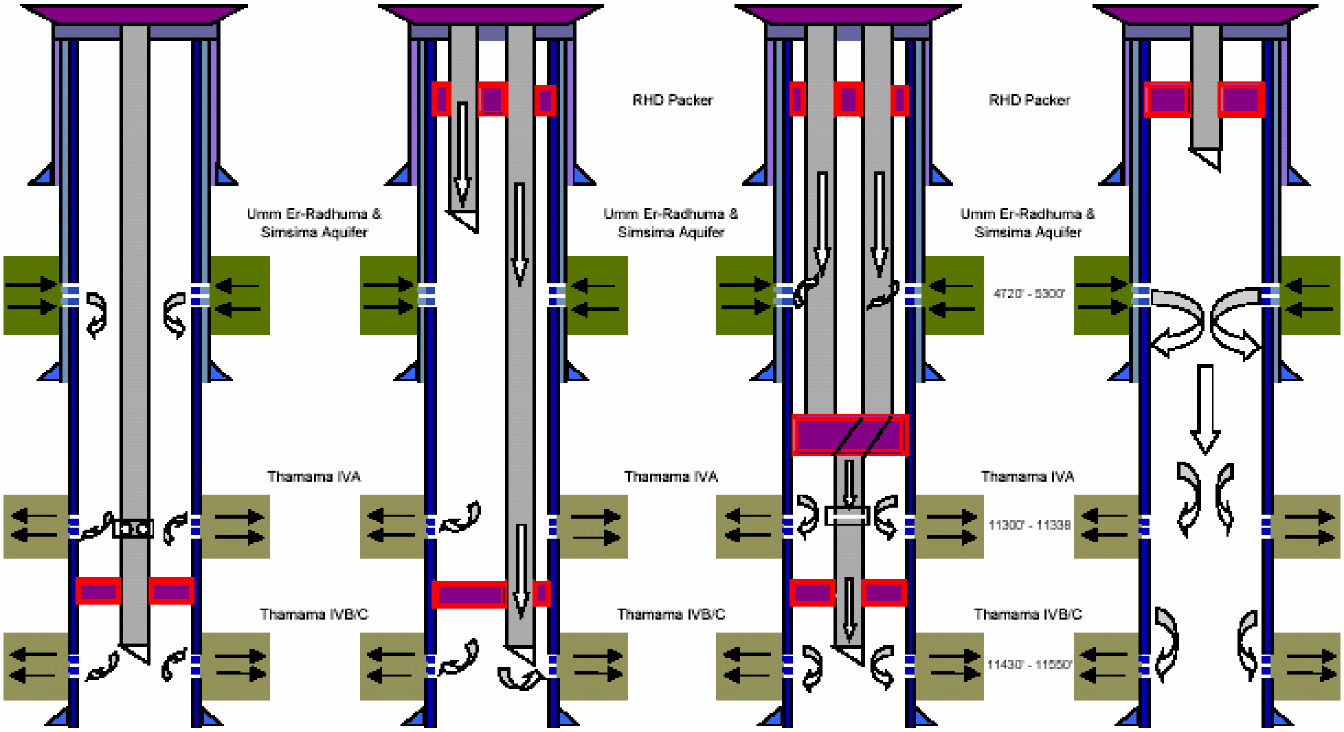


Figure 10 – Different Type of Water Injection Completions & Aquifer Isolation Technique

Figure 11 – Interconnected Corrosion Holes all Aligned to One Side in Contact with the Casing

Figure 12 – Note the **V** Shaped Corrosion Damage which is Common on all Completions and in Every Joint

Figure 13 – **V** Shaped Damage to the Tubing Box in ZK-152 – see arrows

Figure 14 – Iron Oxides & Calcium Carbonate Scale Deposition on the Internal Tubing Surface of ZK-152

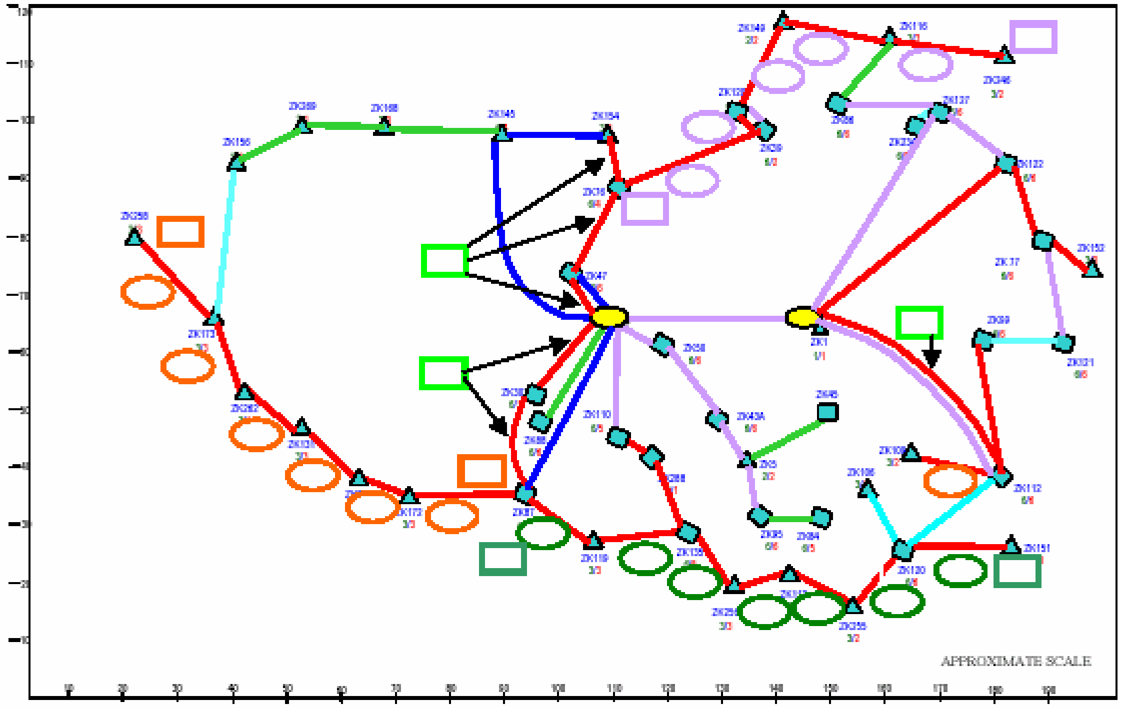


Figure 15 – Zakum Field Subsea Water Distribution Network

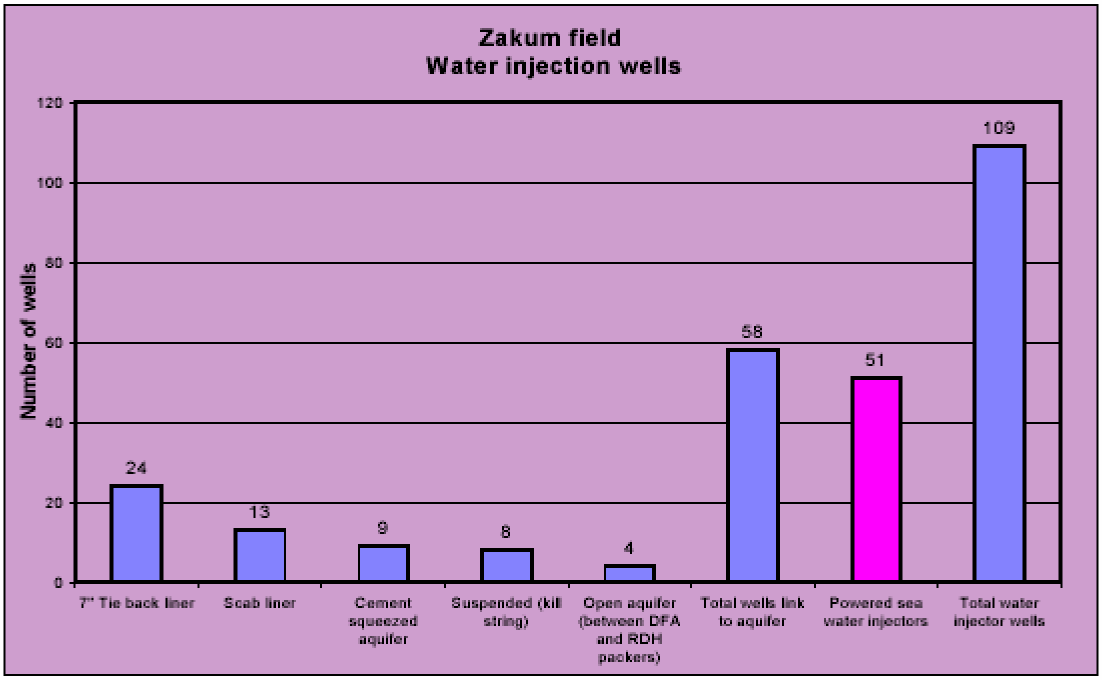


Figure 16 – Water Injection Wells with Dump Flood History