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MCAS EL TORO
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Southwest Division
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Building 128
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FROM: _____
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November 19, 1996

Mr. Joseph Joyce
BRAC Environmental Coordinator
MCAS El Toro and Navy
Building T-2006
P.O. Box 95004
Santa Ana, CA 92709-5001

Subject: Submittal of Final Draft Evaluation of In-Well Corrosion at MCAS El Toro by Environmental Management for MCAS El Toro

Dear Mr. Joyce:

We have examined the issue of in-well corrosion at MCAS El Toro using the CLEAN I and recent CDM Federal Programs Corp. data. Our findings indicate that observed increases in dissolved and total nickel over the past four years appear to be the result of in-well corrosion. We believe that microbiologically influenced corrosion may be the dominant mechanism for the observed effects. The effect of sampling technique on aqueous concentrations seems to be of much less significance.

Several interrelated factors have contributed to in-well corrosion at MCAS El Toro. Geochemical indicators and calculated corrosion indices support the presence of corrosive waters. Although the well design attempted to mitigate the corrosive environment the overall result was disappointing. By 1996 many of the dedicated pumps installed since 1992 were found to be physically corroded. The data suggest that groundwater chemistry in the immediate vicinity of the wells is being affected to a limited degree by corrosion of well materials and release of metal corrosion products.

The observable increase in nickel concentrations over time was indicative of recent releases of this element to groundwater. Since nickel is a metal that is not involved in any biological cycle only the physical introduction of nickel into groundwater near a well could result in the observed increases. The absence of any known or suspected metals releases at the locations examined in our study supports the assertion that in-well corrosion of the stainless steel casing and pump housing has introduced nickel into the groundwater/well system. There were not enough data to examine temporal trends of dissolved chromium and iron. However, these metals represent a significant fraction by weight of the type 304 stainless steel pump housing and well screen/casing materials. Therefore it seems likely that dissolved chromium and iron are probably also increasing in the groundwater adjacent to wells experiencing corrosion.

Although the wells were designed to last 30 years it is reasonable to assume that this goal will not be met. The pump manufacturer has stated that type 304 stainless steel pumps originally installed can only be expected to last one year under the current conditions if they were continuously left in the wells. Our review of the data indicate that without the effect of microbiologically influenced corrosion, this prediction is somewhat pessimistic. However, the rapid nature of the corrosion experienced at MCAS El Toro, the fluctuating iron concentrations and reported sulfide present in the well waters indicates the probable presence of both iron bacteria and sulfate reducing bacteria. Due to the aggressive water and distinct possibility of microbiologically influenced corrosion at MCAS El Toro it is likely that the pumps and well screens will continue to corrode even with high quality welds.

We have included several recommendations at the end of the attached document to assist the Navy with planning for future activities related to in-well corrosion. We suggest that future groundwater analyses include sulfide, iron bacteria, sulfate reducing bacteria and slime causing bacteria. The bacterial measurements can be conducted by Bechtel's staff microbiologists and chemists. We have also been in contact with Dr. Brenda Little of the Microbiologically Influenced Corrosion Section of the Naval Research Laboratory in Stennis Space Center, MS. Dr. Little has worked with Bechtel on these issues in the past and has indicated that she is enthusiastic about the opportunity to assist SWDIV with this study.

We are pleased to have been able to assist the Navy in refining their understanding of the corrosion issue at MCAS El Toro and are ready to provide additional support if needed. We look forward to further discussions on this issue.

Sincerely,

Dante J. Tedaldi, Ph.D., P.E.
Technical Quality Assurance MCAS El Toro

DT/sp

Attachment: Calculation Package for Corrosion Study

CALCULATION COVER SHEET

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COMMENTS:

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1	Incorporate internal comments	15+	—	Brian J Sawosh	Jeff Goldman	Dante	Oct 12 96

RECORD OF REVISIONS

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ATTACHMENT F (Stoecker, 1995)

1 Groundwater Metals Data Interpretation for MCAS El Toro

1.1 Introduction

Groundwater at MCAS El Toro is suspected of having corrosive conditions. Since 1992, 163 monitoring wells have been installed by the Department of the Navy at or near the Station. The well screens were type 304 stainless steel. Many of these wells had dedicated stainless steel type 304 pumps in them. Since the time of installation, most of these pumps have been operated only twice with no maintenance.

By early 1996, 45 of the 92 electric submersible pumps were non-operational, apparently due to corrosion. This represents a 49 percent failure rate. The damaged pumps were removed by Bechtel and not replaced. Considering the limited use of these pumps, this appears to be an extremely high rate of failure (BNI 1996a). Eight of the failed pumps were sent to the manufacturer (Grundfos Pumps Corp.) for analysis and diagnosis. Their findings are summarized in this calculation package.

In the spring of 1996 CDM Federal Programs Corp. conducted a one-time sampling of all 163 wells. Chromium, nickel, and iron concentrations appear to be elevated with respect to previous measurements. Chromium concentrations were as high as 1,880 µg/L and nickel concentrations were as high as 6,980 µg/L. Comparisons between previous sampling periods indicated that the nickel concentrations at several wells have increased over 3.5 times in the past three years.

1.2 Purpose

These observations suggest that the highly corrosive conditions of the groundwater environment at MCAS El Toro have leached metals from the well screen and dedicated submersible pumps. The purpose of this calculation package is to examine the 1996 data and determine if apparent trends in dissolved metals concentrations were supported by the data and establish the possible reasons for these trends.

1.3 Definitions

For the purposes of this discussion corrosion is defined as the destruction of metallic materials by chemical or biochemical action, and incrustation is defined as a condition where material precipitates onto a metallic surface.

1.4 Discussion of Why Stainless Steel Corrodes

In nature metals are not found in the earth in the elemental forms which are typically reported by analytical laboratories. Ores which are found in nature are oxidized forms of the metals combined with other naturally occurring minerals. When an elemental alloy of metal is placed back in the ground in the form of a groundwater well screen or dedicated pump there is a strong tendency for it to revert back to its mineral form (Driscoll 1986). This process is called corrosion.

There are five basic types of corrosion: general, galvanic, pitting/ crevice, intergranular, stress-corrosion cracking (Driscoll 1986, see Attachment A for more information). Stainless steel type 304 is prone to crevice corrosion (Oakley and Korte 1996). Crevice corrosion occurs at the connection of two metal parts and at badly executed welds on the steel. When these areas are filled with solution, a strong current density can occur. The surface inside the crevice becomes active and active stainless steel is lower on the galvanic chart than passive stainless steel. The reason that the surface becomes active is that a halogen such as chlorine can displace oxygen in the protective coating and create an area where the steel is unprotected or active. The active stainless steel acts as the anode and the passive stainless steel acts as the cathode. Because the current is relatively strong due to the large surface area of the cathode and the small surface area of the anode, corrosion occurs in these areas at a must faster rate than over the rest of the stainless steel surface. The passive monomolecular film coating that is normally associated with type 304 stainless steel is compromised in areas were crevice corrosion is happening.

1.5 Microbiologically Influenced Corrosion

Microbiologically Influenced Corrosion (MIC) is corrosion that is enhanced by bacterial activity. MIC often occurs near weldments in austenitic stainless steels. Pitting may be in the weld, in the heat affected zone , along the fusion line, or in the base of the metal near the weld (Borenstein 1991). Many different species of bacteria can partake in MIC. However the main classes of organisms are iron-related bacteria, sulfate reducing bacteria, nitrate reducing and slime forming bacteria (Pope and Morris 1995).

MIC is different than chemical corrosion in a number of ways. The bacteria are able to detect areas on the metal surface that are most prone to corrosion. They will then form a colony in these defect areas. Most bacteria cells are about 0.2 to 5 micrometers (μm) wide and 1 to 10 μm long (Stoecker 1995). The colonies can easily attach in surface defects that may be only 25μm deep. Once the colony is attached to the metal they start to form nodules in which they live. The MIC is not associated with general attack due to their size and it occurs only in localized areas such as crevices.

MIC mechanisms have been generalized by Pope and Morris (1995). The three phases of development are shown in Figure 10. In the first phase the site of attack is selected based on the metallurgic features such as heat affected zones, roughness, or preexisting corrosion. Once the bacteria have found a site the colony excretes extracellular material that is sticky and will trap organic and inorganic material necessary for the growth of the colony. In the second phase of MIC a micro-environment within a nodule forms. The concentrations of oxygen, iron, manganese and pH are vastly different than over the unaffected surface of the metal. The pH can drop as low as 4. This drastically different environment creates conditions very conducive to corrosion, causing the nodule to expand and deepen. Within phase two the colony becomes fixed which will eventually lead to pit or crevice corrosion. The pit serves as the anode.

The principles of corrosion remain the same but MIC is different because the bacteria can affect the environment within the nodule enough that groundwater conditions that are not normally corrosive become corrosive. Moreover, corrosive conditions can be accelerated by the presence of MIC. By the third phase the pit is mature and tunneling may be observed due the nature in which the bacteria expand the nodule. Short chain fatty acids are also produced which maintain the low pH. Once the MIC pitting is mature and in phase 3 simply adding biocide to try to kill the MIC bacteria is not enough because the bacteria can hide in the nodules. A mechanical and chemical cleaning is necessary.

The data presented in this report indicates that microbiologically influenced crevice corrosion is likely to be occurring in the well screens and dedicated pumps.

2 Groundwater Data Presentation and Review

Aluminum, chromium, iron and nickel were the metals of interest for this study. Chromium, iron and nickel are metals found in type 304 stainless steel. Type 304 stainless steel has 18 to 20 percent chromium, 8 to 12 percent nickel, 64 to 70 percent iron (Weast 1978). Aluminum is a metal that is ubiquitous in the environment and is not contained in stainless steel. Trends in these metals can be used to establish the relative impacts of silts and clays and corrosion on aqueous chemistry.

2.1 Filtered Versus Unfiltered Data Review

This calculation package was developed to examine if there were any trends between metals concentrations (e.g., between aluminum and chromium). For convenience, only the eight wells that had the pumps analyzed by the manufacturer Grundfos are discussed. Since most aluminum results were less than the detection limit (see Table 1) the direct observation of trends associated with this analyte was not possible. Within Table 1 filtered and unfiltered pairs that have a relative percent difference (RPD) of greater than 25 percent were understood to be significantly

different. These pairs are highlighted in bold. Nine metals are shown in Table 1, major cations and anions representative of general chemistry are excluded.

2.1.1 Chromium and Iron

The chromium and iron results from 1992 can not be directly compared to the 1996 samples. Typically, chromium and iron are associated with particulate matter and will not pass through a 0.45 µm filter (Oakley and Korte 1996). Only the 1996 data set contains both filtered and unfiltered results for all the wells. The unfiltered chromium and iron results from 1996 seem to be elevated with respect to filtered results from previous events but there are no data for direct comparisons. Thus, the chromium and iron data cannot be used to directly support a corrosion theory.

2.1.2 Aluminum

The aluminum data were examined to see if they could provide an indication as to whether concentrations were increasing due to increases in particulate fines in the wells. Aluminum was undetected at 200 µg/L in both the filtered and unfiltered samples. Turbidity within samples collected from these wells varied between 0 and 67 NTU. Since only filtered samples were analyzed in 1992 no temporal trends can be assessed.

2.1.3 Nickel

Nickel results were similar between the filtered and unfiltered samples. The RPD[1] were calculated for each of the eight nickel pairs. The minimum RPD was zero because nickel was not detected in one sample. If this sample is excluded the minimum is 1.7 percent and the maximum is 42.7 percent with the arithmetic mean of 13.2 percent. As stated previously a RPD of 25 percent or less was representative of equivalent concentration. This leads to the conclusion that all of the nickel in the groundwater is soluble and dissolved in the groundwater.

A second check to assess whether or not the filtered and unfiltered data were representative of the same population and were numerically similar was performed. The Mann-Whitney non-parametric statistical test was used for this evaluation (Haber and Runyon 1977). The results are shown on Table 2. For a one tailed test with the level of significance set at 0.005 (confidence of 99.5) the results support the null hypothesis. Thus the filtered and unfiltered nickel samples were demonstrated to be the same.

Previous researchers found that dissolved nickel is not normally found in uncontaminated groundwater because it precipitates as insoluble hydroxides or sulfides which formed originally at excessive pH (Allen et al. 1993). Typically, when nickel ions are introduced to groundwater,

[1] RPD was calculated by the following formula: $RPD = X_2 - X_1 / (X_1 + X_2 /2)$.

they remain soluble at neutral pH (Bubb and Lester 1991). Thus, the elevated dissolved nickel levels are evidence of recent leaching into groundwater. The source of this leaching is probably the corroding type 304 stainless steel.

2.2 Nickel Comparisons and Trends

Nickel resides mainly in a dissolved state in groundwater under the conditions prevalent at MCAS El Toro. This fact makes nickel different than the other metals of interest because the filtered data of 1992 can be used with the 1996 data to look for trends.

Data was reviewed for eight wells to test the hypothesis that nickel concentrations in groundwater have increased over time due to corrosion of the type 304 stainless steel. Between 1992 and 1996 nickel concentrations at the eight wells have significantly increased (on average by 3.5 times). As noted above nickel should reside in a dissolved state in groundwater of the quality reported at MCAS El Toro (Oakley and Korte 1996); thus filtered data from 1992 are usable and comparable to 1996 data. Table 3 and Figures 2 through 9 show the nickel results and the temporal trends.

Seven out of the eight wells show an apparent increasing trend in nickel concentrations over time. The average magnitude of the increase was relatively large. One well does not follow this a trend because most of the data were reported as below detection limits. The 1992 mean nickel concentration was 49 µg/L while the 1996 arithmetic mean concentration was 190 µg/L(Table 2). The 1993 data included high concentrations which appear to be anomalous. The cumulative data suggest that the 1993 data may have been affected by a systematic problem in the lab or be artifacts. For these reasons the 1993 data were not considered in this analysis.

There was an observable increase in nickel concentrations over time. Nickel is a metal that is not involved in any biological cycle. Therefore, only the physical introduction of nickel into the groundwater near the well could result in the observed increase. This conceptual model supports the hypothesis that the corrosion of the stainless steel casing and pump housing has introduced nickel into the groundwater/well system.

2.3 Grundfos Observations and Corrosion Index Calculation

Eight pumps were sent to Grundfos. In all cases the manufacture found physical evidence of corrosion in the pumps. Table 4 summarizes Grundfos Pumps Corp. analysis. The pumps were constructed out of type 304 stainless steel. Grundfos stated that the pumps would only last one year due to the groundwater conditions encountered in the wells. They found various parts corroded including the motor lead termination screws, the rotors, the motor couplings and that inner stators. The pumps were also incrustated with red iron oxide that in some cases locked the motor shafts from rotating.

Grundfos also calculated the Riddick corrosion index for each well. Data from 1992 was used in the calculation. They found that in all wells the corrosion index was greater than 50. A score above 50 indicates that the groundwater conditions are corrosive. In five of the eight wells the score was above 100 which indicates extremely corrosive conditions are present.

Key factors that lead to the corrosive conditions in the wells were noted by Grundfos. The total dissolved solids (TDS) were high and in most cases exceeded 1000 ppm. Manganese and iron concentrations exceeded 5 µg/L. The sodium concentrations averaged around 88 mg/L. The calcium ion concentrations were very high and were 10 to 20 times higher than the corrosion and incrustation cut off concentrations.

2.4 Well Construction and Pump Installation

No cathodic corrosion protection mechanisms were installed in any of the eight wells examined in this report (Jacobs 1994). The wells were constructed with a type 304 stainless steel sump followed by type 304 stainless steel screen and then connected to schedule 40 PVC material. The quality of the welds within the screen is unknown. If the workmanship of the welds within the screen was low then the corrosion of these screens is likely to be accelerated.

Dedicated pumps were placed in all 163 wells. The pumps were installed by connecting the pump housing to stainless steel discharge pipes of unknown grade. Teflon tape was used between the threads of the pump housing and the pipe. The discharge pipes extended to the surface and were connected to PVC caps that had rubber grommets. When the pumps were installed the electrical wires that connected the pumps to the control box were allowed to hang in standing water at the top of the well completion monuments. These wires became severely corroded and crumbed when moved. This was observed by CLEAN II field personnel (BNI 1996c). The wires were connected to the electrical and mechanical components of the pumps. When the pumps were inspected the pump housings were not corroded but many of the electrical and mechanical components had become corroded (Grundfos Pumps Corp. 1996).

2.5 Well Sampling Methods

The wells were sampled using a dedicated or portable down hole sampling pump. The wells were purged until temperature, pH, and specific conductance stabilized or three casing volumes of groundwater had been removed, whichever occurred first. The samples were collected directly from the pump. The filtered samples were prepared in the field and then shipped to the laboratory for analysis (BNI 1995).

The CDM Federal Programs Corp. calculation of the well volumes included only the water within the casing and not the water within the filter pack outside of the casing. This leads to

underestimating the true well volume. Also in many instances less than three well volumes were collected because the parameters stabilized.

Oakley and Korte (1996) concluded that high volume purging combined with sampling from the pump discharge should produce the lowest nickel and chromium concentrations in the sample. They also noted that high purge volumes were required to yield the lowest nickel concentrations while the lowest chromium values were obtained when nondisruptive techniques were used. The sampling techniques used by CDM Federal Programs Inc. do not appear to have adversely affected the measured concentrations directly; however, it is possible that more thorough purging would have resulted in lower nickel concentrations.

3 Calculations

This section contains corrosion calculations of the groundwater using 1996 groundwater data. Groundfos calculated the corrosion potential for the eight wells using 1992 data and found water quality within all of the wells to be corrosive. An ion balance for both data sets is also presented.

3.1 Ryzner Index

The Ryzner index is an analytical method that predicts the incrusting or corrosive nature of water. The Ryzner index is adapted from the Langelier index and it is incorporates alkalinity as calcium carbonate, total dissolved solids, and pH. The Ryzner and the Langelier Indices are based on corrosion of carbon steel. A water is corrosive if the index is higher than 7 and incrusting if lower than 7 (Driscoll 1986). The Ryzner index was calculated for the eight wells from which the pumps were removed and sent to Grundfos. In every case the index was greater than 7. This indicates that all of the wells have groundwater that is corrosive.

Beyond using the Ryzner index an analysis of the groundwater geochemistry can show the nature of the groundwater (see Table 5) for carbon steel. When pH is less than 7 the groundwater is acidic and corrosive conditions can occur. Dissolved oxygen (DO) levels greater than 2 mg/L indicate potentially corrosive conditions. The maximum DO in water with chloride concentration equal to 100 mg/L at 20°C is about 9.1 mg/L (see Attachment C). In some wells CDM Federal Programs Corp. reported DO measurements greater than 9.1 mg/L (CDM 1996). It appears that the calibration may have been incorrect. However, the true values are likely greater than 2 mg/L.

When the total dissolved solids (TDS) level is greater than 1000 mg/L the electrical conductivity is high enough to cause significant electrolytic corrosion. Carbon dioxide gas levels greater than 50 mg/L may create an acidic and corrosive environment. Measurements of carbon were not collected; however, Grundfos used an equilibrium equation to estimate carbon dioxide levels. If chlorides are greater than 250 to 500 mg/L can also support in well corrosion.

Incrusting water deposits will occur if the following conditions are true:

1. pH is above 7.5
2. Carbonate hardness exceeds 300 mg/L
3. Iron exceeds 500 µg/L
4. Manganese exceeds 200 µg/L and pH is high, precipitation of Mn is likely if oxygen is present

In the laboratory, type 304 stainless steel will not corrode in the groundwater conditions encountered at MCAS El Toro. Due to its resistance to corrosion type 304 stainless steel is often used for condenser tubing where water is highly oxygenated, at temperatures around 120°F and chloride concentrations often exceeding 500 mg/L. Table 8 from Uhlig's Corrosion Handbook (1948) indicates that even 10 percent HCl resulted in only 0.065 inches penetration per year (ipy) corrosion of 304. Boiling lactic acid is the only solution tested that would result in the high corrosion rates found at MCAS El Toro. Figure 11 indicates that even solutions of 1 percent sodium chloride result in very low corrosion rates of 304, unless temperatures of greater than 60°C are reached. This would certainly rule out corrosion by 100 mg/L chloride ion at ambient temperatures. Figure 12 indicates the pH of a 4 percent sodium chloride solution must drop to 3 before serious corrosion of 304 stainless would occur. This test was run at 90°C. From this information the chemical corrosion of 304 at pH 6.5 with 100 mg/L chloride present at ambient temperatures must be ruled out.

3.2 Ion Balance

An ion balance was performed for both the 1992 and 1996 groundwater data (see Table 6 and 7). An ion balance simply tests the assumption that any water body has a overall electrical charge of zero. This analysis is useful in comparing laboratories and the accuracy of the data from each lab. In theory both labs should have very comparable results.

Overall the analyses of the cations from both labs are very similar. However the anions, and in particular bicarbonate and chlorides, differs between the two data sets. The 1996 data tends to underestimate the chloride and bicarbonate results. This causes the relative percent difference to be high in some of the wells in the 1996 data. However, these variations do not limit the usability of the data.

4 Conclusions

4.1 Hexavalent Chromium

Stainless steel type 304 has 18 to 20 percent chromium. When corrosion occurs the elemental chromium is oxidized to divalent and trivalent forms. It is possible for the trivalent chromium to be further oxidized to hexavalent chromium, depending upon the thermodynamics of the environment. The redox/ pH phase diagram in Figure 1 shows that for neutral pH (pH ≈ 7) the redox should be greater than 400 millivolts (corrected for a reference electrode) for hexavalent chrome to be stable and present.

The redox values for the eight wells were reported to be around 100 to 200 mV. But CDM reported uncorrected values. The values are not corrected to the reference electrode and thus the values are probably less than reported. The reduction oxidation potential for the wells are not oxidizing enough to allow hexavalent chromium to be thermodynamically stable. Thus the chromium ions corroded from the stainless steel will be in the form of divalent and trivalent chromium and not in the hexavalent form.

4.2 General Conclusions

Several interrelated factors have contributed to in well corrosion at MCAS El Toro. Although, the well design attempted to mitigate the corrosive environment, the overall result was disappointing. The wells were designed to last 30 years (CH_2M Hill 1996), but it is reasonable to assume that this goal will not be met. Without inspecting of the well screens the actual damage is impossible to assess. However, Grundfos estimated that type 304 stainless steel pumps would last one year under the current conditions if they are continuously left in the wells. Whereas the well screens can be expected to last longer than the pumps, a 30 year life seems overly optimistic.

Geochemical indicators and the calculated Riddick and Ryzner corrosion indices support the presence of corrosive waters. Furthermore, the eight pumps that were examined were found to be physically corroded. It appears that the groundwater chemistry in the immediate vicinity of the wells is being affected by the corrosion of the well materials. The observable increase in nickel concentrations over time was indicative of recent releases of this element to groundwater. Since nickel is a metal that is not involved in any biological cycle only the physical introduction of nickel into the groundwater near the well could result in the observed increases. In-well corrosion of the stainless steel casing and pump housing appears to have introduced nickel into the groundwater/well system. While there are not enough data to look at the trends of chromium and iron these metals do seem to be elevated and are probably also increasing in the wells.

The analytical groundwater data has maximum total concentrations of 4.8 mg/L iron, 0.6 mg/L chromium, and 0.8 mg/L nickel. Iron corrosion products were reported on pump components and are indicative of corrosion. Since type 304 stainless steel should not appreciably corrode in the MCAS El Toro groundwater environment, it appears that MIC is present. MIC does cause corrosion of 304 stainless steel and the bacteria causing MIC are often present in groundwater.

The rapid nature of the corrosion experienced at MCAS El Toro, the fluctuating iron concentrations and reported sulfide present in the well waters indicate the probable presence of both iron bacteria and sulfate reducing bacteria. Slime typically present at sites with MIC, was noted to be over the red oxide on some of the pumps. Due to the aggressive water and possible MIC at MCAS El Toro it is likely that the pumps and well screens will continue to corrode even with high quality welds. The screens have not been visually inspected but the likelihood of finding corrosion on the well screen is high. There is a good possibility that a combination of iron and sulfate reducing bacteria are at the center of the corrosion mechanism.

5 Recommendations

The following steps are recommended to confirm the presence of MIC in the well systems:

1. Sample and reanalyze those wells showing the highest concentrations of iron, chromium and nickel (currently within scope of long-term groundwater monitoring program).

    a) Analyses should include pH, conductivity, iron, chromium, nickel, dissolved oxygen, and temperature (within current scope).

    b) New analyses should include sulfide, iron bacteria, sulfate reducing bacteria and slime causing bacteria. Bacterial measurements should be sampled at wells using Hach bacterial tests kits (new scope).

    c) Care should be taken to determine pH, dissolved oxygen, temperature, and conductivity at the sample location being careful not to aerate the sample. Bacterial samples should be taken previous to purging of groundwater wells.

2. If bacteria are found in well water consider addition of an oxidizing biocide like chlorine to remove and control bacteria and MIC. However, if the MIC is in phase 3, physical and chemical removal of the corrosion may be necessary to completely eliminate the corrosion.

3. Metal corrosion products may be taken for scanning electron microscope evaluation, if desired. Dr. Brenda Little with the Microbiologically Influenced Corrosion Section from the Naval Research Laboratory in Stennis Space Center, Mississippi has worked with Bechtel in the past on MIC issues and has been contracted by CTO-080 staff. Dr. Little may be available if required.

If MIC is found and not controlled, rapid corrosion of the stainless steel well components will reoccur.

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TABLES

Table 1
MCAS El Toro Selected Metals Results
Filtered and Unfiltered 1996 Data

Station ID	Base Screen Depth (Ft BGS)	Sample Date	Sample Type	Turbidity (NTU)	Aluminum	Chromium	Copper	Iron	Lead	Manganese	Nickel	Selenium	Zinc
06_UGMW28	180	16-Feb-96	F	9	200.0 U	**10.0 U**	25.0 U	**100.0 U**	**4.0**	15.0 U	260.0	37.0	**20.0 U**
06_UGMW28	180	16-Feb-96	UF		200.0 U	**61.0**	25.0 U	**430.0**	**10.0**	15.0 U	280.0	35.0	**37.0**
07_DBMW43	190	19-Feb-96	F	67	200.0 U	**10.0 U**	**25.0 U**	**119.0**	**4.0**	**44.0**	**670.0**	5.0 U	**20.0 U**
07_DBMW43	190	19-Feb-96	UF		200.0 U	**585.0**	**45.0**	**4810.0**	**10.0**	**160.0**	**882.0**	5.0 U	**58.0**
07_DGMW71	155	13-Feb-96	F	0	200.0 U	**10.0 U**	25.0 U	**100.0 U**	3.0 U	15.0 U	56.0	5.0 U	20.0 U
07_DGMW71	155	13-Feb-96	UF		200.0 U	**33.0**	25.0 U	**545.0**	3.0 U	15.0 U	57.0	5.0 U	20.0 U
07_DGMW72	150	13-Feb-96	F	0	200.0 U	**10.0 U**	25.0 U	**100.0 U**	3.0 U	15.0 U	45.0	5.0 U	20.0 U
07_DGMW72	150	13-Feb-96	UF		200.0 U	**22.0**	25.0 U	**240.0**	3.0 U	15.0 U	48.0	5.0 U	20.0 U
09_DGMW75	154	14-Feb-96	F	52	200.0 U	**10.0 U**	25.0 U	**100.0 U**	**3.0 U**	**36.0**	380.0	43.0	20.0 U
09_DGMW75	154	14-Feb-96	UF		200.0 U	**340.0**	25.0 U	**4160.0**	**6.0**	**66.0**	390.0	49.0	20.0 U
12_UGMW31	145	14-Feb-96	F	-10	200.0 U	10.0 U	25.0 U	100.0 U	**4.0**	15.0 U	48.0	**7.0**	20.0 U
12_UGMW31	145	14-Feb-96	UF		200.0 U	10.0 U	25.0 U	100.0 U	**3.0 U**	19.0	50.0	**9.0**	20.0 U
21_DBMW56	132	15-Feb-96	F	0	200.0 U	**10.0 U**	25.0 U	**100.0 U**	**3.0**	15.0 U	**46.0**	5.0 U	20.0 U
21_DBMW56	132	15-Feb-96	UF		200.0 U	**20.0**	25.0 U	**176.0**	**4.0**	15.0 U	**71.0**	5.0 U	20.0 U
22_DBMW47	156	15-Feb-96	F	2	200.0 U	10.0 U	25.0 U	**100.0 U**	3.0 U	15.0 U	40.0 U	13.0	20.0 U
22_DBMW47	156	15-Feb-96	UF		200.0 U	12.0	25.0 U	**114.0**	3.0 U	15.0 U	40.0 U	11.0	20.0 U

All metals results in units of ug/L.
Sample pairs in bold indicate a relative percent difference of at least 25 percent.
F = filtered sample; UF = unfiltered sample.

Table 2

Descreptive and Non-Parametric Statistics of Nickel Data

1992, 1993, 1996 Filtered Data

Mean 1992 data	49.072222
Std. Dev. 1992 data	73.882623
Mean 1993 data	238.575
Std. Dev. 1993 data	246.00605
Mean 1996 data	190.625
Std. Dev. 1996 data	233.04747

All nickel results in units of ug/L.

1996 Filtered vs. Unfiltered Data

Mann-Whitney U-Test to prove data has the same population

Alpha=0.005 for a one tailed test
Null hypothesis Filtered and Unfiltered data has the same population

Filtered Data	Rank	Unfiltered Data	Rank
260	11	280	12
670	15	882	16
56	8	57	9
45	3	48	5
380	13	390	14
48	6	50	7
46	4	71	10
40	1	40	2
R_1= 61		R_2= 75	
n_1= 8		n_2= 8	

$U=n_1*n_2+(n_1*(n_1+1)/2)-R_1$

U= 39 U'= 39

If n_1= 8 and n_2= 8 then a U statistic between 7 and 57 indicates the null hypothesis

Table 3

Nickel Results

MCAS El Toro Groundwater Monitoring Program

All Results in Micrograms per Liter (ug/L)

Station ID	Base Screen Depth (Ft BGS)	Sample Date	Sample Type	Nickel 100.0	
06_UGMW28	180	13-Nov-92	F	230.0	
		9-Jul-93	F	643.0	
		16-Feb-96	F	260.0	
		16-Feb-96	UF	260.0	
07_DBMW43	190	1-Dec-92	F	95.8	
		25-Jun-93	F	615.0	
		19-Feb-96	F	670.0	
		19-Feb-96	UF	662.0	
07_DGMW71	155	15-Dec-92	F	49.6	
		22-Jun-93	F	190.0	
		13-Feb-96	F	56.0	
		13-Feb-96	UF	57.0	
07_DGMW72	150	19-Nov-92	F	11.6	B
		21-Jul-93	F	19.7	B
		15-Oct-93	F	72.8	
		13-Feb-96	F	45.0	
		13-Feb-96	UF	48.0	
09_DGMW75	154	1-Dec-92	F	14.8	B
		12-Jul-93	F	144.0	
		14-Feb-96	F	380.0	
		14-Feb-96	UF	390.0	
12_UGMW31	145	8-Oct-92	F	12.1	B
		7-Jul-93	F	106.0	
		14-Feb-96	F	48.0	
		14-Feb-96	UF	50.0	
21_DBMW56	132	18-Nov-92	F	13.3	B
		18-Nov-92	F	10.6	B
		24-Jun-93	F	116.0	
		15-Feb-96	F	46.0	
		15-Feb-96	UF	71.0	
22_DBMW47	156	29-Sep-92	F	7.7	U
		13-Jul-93	F	21.8	B
		15-Feb-96	F	40.0	U
		15-Feb-96	UF	40.0	U

1) Data Qualification Flags:

U = The material was analyzed for, but was not detected above the level of the associated value.

B = Conc. that is less than Contract required detection limit but greater than or equal to instrument detection limit.

2) Regulatory standards in ug/L are listed at the top of the column.

Federal Maximum Contaminant Level (MCL) was used for nickel

3) = Result exceeds regulatory standard

4) F=Filtered sample, UF=Unfiltered

Table 4

Grundofos Pumps Corp. Findings

Parameter	Corrosive/ Incrustation levels		Typical GW Values (Class 1)	22DBMW47	21DGMW56	07DGMW72	07DGMW71	07DBMW43	06UGMW28	09DGMW75	12UGMW31
pH	<7		6.5-8.5		7.83	7.8	7.68		7.07	6.36	
DO (ppm)	>2		0-0.5								
H2S (ppm)	>1		0-0.5								
Sulfate (ppm)	>350		0-50	263	228	241	217	194	332	423	263
TDS (ppm)	>1,000		3-700	1,130	1,080	1,120	937	880	1,830	1,370	1,000
Chlorides (ppm)	>500		0-150	228	189	241	217	195	541	273	211
CO2 (ppm)	>50		2-22								
Temp (F)	>80		40-70		66.1	65.2	70.3		73.6	78	
Iron (ppb)	>5		0.1-5		5.1	24.5	12	9	54.5		20.8
Manganese (ppb)	>5		<0.05	5.4	7.2	8.4	19	80	197	12.1	33.4
Sodium (ppb)	>4,000			82,800	78,300	88,300	85,100	70,100	109,000	115,000	77,100
Calcium (ppb)	>10,000			187,000	161,000	135,000	138,000	122,800	284,000	218,000	177,000
Conductivity (uMho/cm)	>2,000		100-1,600		1580	1590	1800		3200	2830	
Silica (ppm)	>100		0-20								
Nitrates (ppm)	>45		0-45	18.7	22.7	14.8	15.4	14.8	18.6	23.6	22.5
ALK (Bicarbonate) (ppm)				232	248	209	182	153	156	191	229
HAR (CaCO3) (ppm)				(190)	(202)	(255)	(222)	(128)	(136)	(155)	(153)
Corrosion Index (CI)	**>100**		**0-50**	**67**	**50**	**122**	**124**	**100**	**270**	**138**	**85**
"Summary" out of Tolerance Parameters				TDS>1000 Ca>10,000 Na>4,000 Mn>5 High incrustation potential	TDS>1000 Ca>10,000 Na>4,000 Mn>5 Fe>5 High incrustation potential	TDS>1000 Ca>10,000 Na>4,000 Mn>5 Fe>5 Cl>100 High incrustation and corrosion potential	Ca>10,000 Na>4,000 Mn>5 Fe>5 Cl>100 High incrustation and corrosion potential	Ca>10,000 Na>4,000 Mn>5 Fe>5 Cl>100 High incrustation and corrosion potential	TDS>1000 Ca>10,000 Na>4,000 Mn>5 Fe>5 Cl>500 High incrustation and corrosion potential	TDS>1000 Ca>10,000 Na>4,000 Mn>5 SO4>350 Cond>2,000 Cl>100 High incrustation and corrosion potential	TDS>1000 Ca>10,000 Na>4,000 Mn>5 Fe>5 High incrustation and corrosion potential
Inspection Summary				Motor lead termination screws corroded. Rotor cladding deformed where corrosion has penetrated SS cladding. Corrosion *through inner stator* lining	Pump components look fine. Screen and suction incrustated with red iron oxide. Motor lead termination screws corroded. Rotor iron corroded (rotor pre-cladding).	Pump end incrusted from FeO2. Rotor iron severely corroded where cladding breached by corrosion. CaCO3 deposits noted in stator chamber.	Stator impacted with deposits and rotor corroded. All fasteners corroded (Rotor - pre-cladding). Rotor locked with incrustation.	Stator incrustated with deposits. Motor lead *screws corroded. Iron* bacteria (red) stained pump end.	Pump end coated with red residue. Motor *lead screws corroded.* Stator lining corroded. Rotor corrosion accelerated where cladding breached by corrosion.	Motor shaft locked as a result of incrustation. *Motor jammed as a* result of SS cladding breach. Motor coupling corroded.	Motor coupling corroded and failed. Motor grounded but free to rotate. Presence of red iron oxide and sand in PE.
Utilization Recommendation	(A) Recommended *(B) Conditionally Recommended* (C) Not Recommended			(B) if conductivity is <2000. Would *require additional* runtime and quarterly service	(B) provided unit is run periodically *(1x per month min)* and serviced quarterly	(C) Anticipated life 1 yr or less if *dedicated.*	(C) Anticipated life 1 yr or less if dedicated.	(C) Anticipated life 1 yr or less if dedicated.	(C) Anticipated life 1 yr or less if dedicated.	(C) Anticipated life 1 yr or less if dedicated.	(B) if serviced and run quarterly. 304SS material is not accecptable. 316SS product would hold up better.

Reference Sources

1)Osmonics - Pure Water Handbook
2) Missouri Water Well Handbook
3) Layne Field Manual
4) Johnson - Groundwater and Wells
5) ASTM Groundwater Short Course Notes

Key factors that affect corrosion

(1) Dissolved CO2
(2) Dissolved O2
(3) Dissolved H2S
(4) High TDS with high conductivity
(5) High chlorides
(6) High sulfates
(7) Elevated temperture

Misc. Notes

(1) Seawater chlorides - 19,000 ppm (49.5/1190)
(2) 10 ppm DO @ ATM presure is normal, only 13 DO is possible in H2O
(3) All wells approximately 10' AMSL
(4) Pumps installed late 92/ early 93 and never run after installation.
(5) Pumps pulled 2/96
(6) Typical life expectation of 304SS in seawater is 2-4 wks.
(6) Typical life expectation of 316SS in seawater is 6 months.

Riddick Corrosion Index calculation

CI = [CO2+0.5(HAR-ALK)]+[(Cl2+2N)*(75/ALK)]
CO2=2(assumed) in calculations

CI = 0-5 Extremely non-corrosive
6-25 non-corrosive
26-50 Moderately corrosive
51-75 Corrosive
76-100 Very corrosive
101+ Extremely corrosive

Dissolved solids, ppm Classifications

(1) <1,000 Fresh Water
(2) 1,000-3,000 Slightly Saline (Brackish)
(3) 3,000 - 10,000 Moderately Saline (Brackish)
(4) 10,000 - 35,000 Very Saline (Seawater)
(5) >35,000 Brine

Table 5

MCAS El Toro

Corrosive and Incrustating Data Table

Parameter	Corrosive/ Incrustation Concentration	06_UGMW28	07_DBMW43	07_DGMW71	07_DGMW72	09_DGMW75	12_UGMW31	21_DBMW56	22_DBMW47
pH	<7 (corr.) >7.5 (incrust.)	6.8	7.0	6.7	6.6	6.9	6.9	6.4	6.9
DO (mg/L)	>2	7.3	7.1	9.4	8.2	8.6	7.6	9.3	7.9
TDS (mg/L)	>1000	1700.0	656.0	1010.0	935.0	1340.0	944.0	798.0	1180.0
CO_2 (mg/L) [1]	>50	82.2	34.4	116.1	116.1	55.5	68.4	211.3	70.1
Chlorides (mg/L)	>250-500	393.0	141.0	245.0	237.0	284.0	181.0	152.0	231.0
Iron (ug/L)	>500	430.0	4810.0	545.0	240.0	4160.0	100.0 U	176.0	114.0
Manganese (ug/L)	>200	15.0 U	160.0	15.0 U	15.0 U	66.0	19.0	15.0 U	15.0 U
Hardness (CO_3^{--}) (mg/L)	>300	2.0 U	2.0 U	2.0 U	2.0 U	2.0 U	2.0 U	2.0 U	2.0 U
Bicarbonate (mg/L)		222.0	154.0	249.0	222.0	207.0	238.0	249.0	233.0
Calcium (mg/L)		286.0	97.0	141.0	136.0	216.0	181.0	162.0	165.0

[1] Carbon Dioxide is calculated as H_2CO_3 and assuming the following equation : $[H^+]*[HCO_3^-]/[H_2CO_3]=4.45E-7$

[2] 1996 Data

Table 6
MCAS El Toro
Ion Balance 1992 Data

Parameter	06_UGMW28	Equivalents (meq)	07_DBMW43	Equivalents (meq)	07_DGMW71	Equivalents (meq)	07_DGMW72	Equivalents (meq)	09_DGMW75	Equivalents (meq)	12_UGMW31	Equivalents (meq)	21_DBMW56	Equivalents (meq)	22_DBMW47	Equivalents (meq)
TDS (mg/L)	1830		880		937		1120		1370		1000		1080		1130	
Conductivity	2030		897		1350		1290		1780		1350		1290		1400	
Cations																
Sodium (mg/L)	109.000	4.743	70.100	3.050	85.100	3.703	88.800	3.864	116.000	5.048	77.100	3.355	78.300	3.407	82.800	3.603
Potassium (mg/L)	7.220	0.185	3.680	0.094	2.700	0.069	2.250	0.058	2.480	0.063	2.510	0.064	2.110	0.054	2.460	0.063
Calcium (mg/L)	264.000	13.174	122.800	6.128	139.000	6.936	136.000	6.787	216.000	10.779	177.000	8.833	161.000	8.034	187.000	9.332
Iron (mg/L)	0.055	0.002	0.009	0.000	0.012	0.000	0.024	0.001	0.001 [2]	0.000	0.021	0.001	0.005	0.000	0.001 [2]	0.000
Magnesium (mg/L)	73.000	6.007	33.400	2.748	35.500	2.921	40.300	3.316	58.900	4.847	50.700	4.172	45.300	3.726	50.500	4.156
Total Cation (meq)		**24.111**		**12.021**		**13.630**		**14.026**		**20.737**		**16.425**		**15.223**		**17.153**
Anions																
Bicarbonate (mg/L)	136.000	-2.229	126.000	-2.065	182.000	-2.983	209.000	-3.425	156.000	-2.557	188.000	-3.081	200.000	-3.278	190.000	-3.114
Chlorides (mg/L)	541.000	-15.260	185.000	-5.218	217.000	-6.121	241.000	-6.798	273.000	-7.700	211.000	-5.952	188.000	-5.303	228.000	-6.431
Sulfate (mg/L)	332.000	-6.912	144.000	-2.998	174.000	-3.623	112.000	-2.332	423.000	-8.807	263.000	-5.476	228.000	-4.747	263.000	-5.476
Nitrate/Nitrite (mg/L)	18.800	-0.606	14.600	-0.471	15.400	-0.497	14.800	-0.477	23.600	-0.761	22.500	-0.726	22.000	-0.710	18.700	-0.603
Total Anions (meq)		**-25.007**		**-10.752**		**-13.223**		**-13.032**		**-19.825**		**-15.234**		**-14.037**		**-15.624**
RPD		-4%		11%		3%		7%		4%		8%		8%		9%

[1] 1996 Data
[2] Analyte not detected, assumed to be half the detection limit.

Table 7
MCAS El Toro
Ion Balance 1996 Data

Parameter	06_UGMW28	Equivalents (meq)	07_DBMW43	Equivalents (meq)	07_DGMW71	Equivalents (meq)	07_DGMW72	Equivalents (meq)	09_DGMW75	Equivalents (meq)	12_UGMW31	Equivalents (meq)	21_DBMW56	Equivalents (meq)	22_DBMW47	Equivalents (meq)
TDS (mg/L)	1700		656		1010		935		1340		944		798		1180	
Conductivity	2030		897		1350		1290		1780		1350		1290		1400	
Cations																
Sodium (mg/L)	104.000	4.526	76.000	3.307	88.000	3.829	92.000	4.003	153.000	6.658	83.000	3.612	89.000	3.873	103.000	4.482
Potassium (mg/L)	4.510	0.115	9.420	0.241	2.430	0.062	2.270	0.058	3.520	0.090	3.030	0.078	2.920	0.075	3.890	0.100
Calcium (mg/L)	286.000	14.272	97.000	4.841	141.000	7.036	136.000	6.787	216.000	10.779	181.000	9.032	162.000	8.084	165.000	8.234
Iron (mg/L)	0.050 [2]	0.002	0.119	0.004	0.050 [2]	0.002	0.050 [2]	0.002	0.050 [2]	0.002	0.050 [2]	0.002	0.050 [2]	0.002	0.050 [2]	0.002
Magnesium (mg/L)	72.000	5.925	24.000	1.975	37.000	3.045	37.000	3.045	65.000	5.349	53.000	4.361	48.000	3.950	59.000	4.855
Total Cation (meq)		**24.840**		**10.368**		**13.974**		**13.895**		**22.877**		**17.085**		**15.983**		**17.672**
Anions																
Hardness (CO_3^-) (mg/L)	1.000 [2]	-0.033	1.000 [2]	-0.033	1.000 [2]	-0.033	1.000 [2]	-0.033	1.000 [2]	-0.033	1.000 [2]	-0.033	1.000 [2]	-0.033	1.000 [2]	-0.033
Bicarbonate (mg/L)	222.000	-3.638	154.000	-2.524	249.000	-4.081	222.000	-3.638	207.000	-3.392	238.000	-3.901	249.000	-4.081	233.000	-3.819
Chlorides (mg/L)	393.000	-11.085	141.000	-3.977	245.000	-6.911	237.000	-6.685	284.000	-8.011	181.000	-5.105	152.000	-4.287	231.000	-6.516
Sulfate (mg/L)	345.000	-7.183	105.000	-2.186	118.000	-2.457	71.000	-1.478	369.000	-7.682	190.000	-3.956	152.000	-3.165	169.000	-3.519
Nitrate/Nitrite (mg/L)	18.000	-0.581	14.000	-0.452	14.000	-0.452	17.000	-0.548	26.000	-0.839	26.000	-0.839	18.000	-0.581	17.000	-0.548
Total Anions (meq)		**-22.520**		**-9.172**		**-13.933**		**-12.383**		**-19.958**		**-13.834**		**-12.147**		**-14.434**
RPD		10%		12%		0%		12%		14%		21%		27%		20%

[1] 1996 Data
[2] Analyte not detected, assumed to be half the detection limit.

Table 8 : Corrosion Rates of 304 Stainless Steel in Various Liquid Media

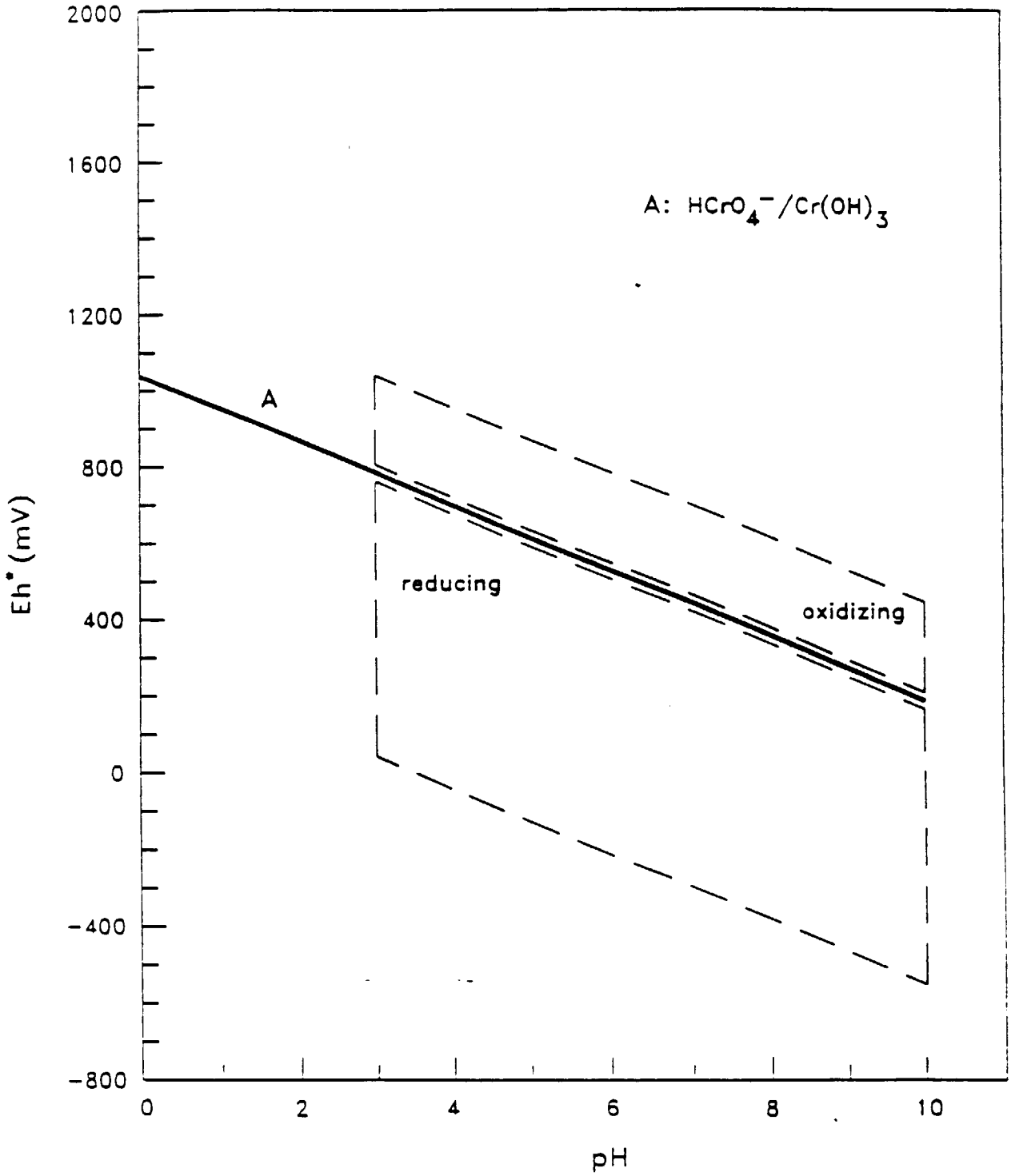
Corrosive Medium	Temperature	Duration of Test, hours	Wt. Loss	
			mdd	ipy
20% Nitric acid	Room	1	Nil*	.....
20% Nitric acid	Boiling	18	Nil	.....
3% Nitric acid	Boiling	18	Nil	.....
1% Nitric acid	Boiling	18	Nil	.....
Nitric acid fumes	110° C (230° F)	13	100	0.018
10% Hydrochloric acid	Room	1	360	0.065
10% Sulfuric acid	Room	1	432	0.079
1% H_2SO_4 + 2% HNO_3	Room	17	Nil	.....
0.25% H_2SO_4 + 0.25% HNO_3	Room	17	Nil	.....
10% Acetic acid, C. P.	Room	3	Nil	.....
10% Acetic acid, C. P.	Boiling	12	Nil	.....
Glacial acetic acid, U. S. P.	Room	276	0.1	0.000
Glacial acetic acid, U. S. P.	Boiling	167	130	0.024
Crude acetic acid	Boiling	166	375.5	0.068
10% Phosphoric acid, C. P.	Boiling	17	Nil	.....
10% Carbolic acid, C. P.	Boiling	16	Nil	.....
10% Chromic acid (tech.)	Boiling	41	204	0.037
Concentrated sulfurous acid	Room	22	Nil	.....
0.5% Lactic acid	Boiling	16	4.1	0.001
1.0% Lactic acid	65° C (150° F)	16	Nil	.....
2.0% Lactic acid	Boiling	16	5.1	0.001
50% Lactic acid	Boiling	16	12,240	2.23
85% Lactic acid	Boiling	16	1,560	0.284
10% Tartaric acid	Boiling	39	Nil	.....
1% Oxalic acid	Boiling	39	177.6	0.032
10% Oxalic acid	Room	17	139.2	0.025
10% Formic acid	Boiling	1	3,240	0.590
10% Formic acid	Room	17	2.4	0.000
10% Malic acid	Room	17	Nil	.....
10% Sodium sulfite	Boiling	16	Nil	.....
10% Sodium bisulfate	Boiling	16	Nil	.....
10% Ammonium sulfate	Boiling	16	Nil	.....
10% Ammonium chloride	Boiling	16	Pitted	.....
Lemon juice	Room	89	Nil	.....
Orange juice	Room	91	Nil	.....
Sweet cider	Room	23	Nil	.....
Canned rhubarb	Boiling	16	Nil	.....
Canned tomatoes	Boiling	16	Nil	.....
10% Sodium hydroxide	Boiling	41	Nil	.....

* "Nil" refers to a weight loss of the specimen not detectable within time of the test.

FIGURES

Figure 1
Eh/pH Phase Diagram

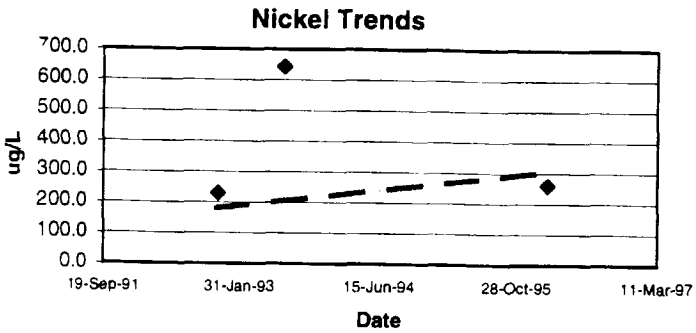
The dashed lines define Eh-pH boundaries commonly encountered in soils and sediments.

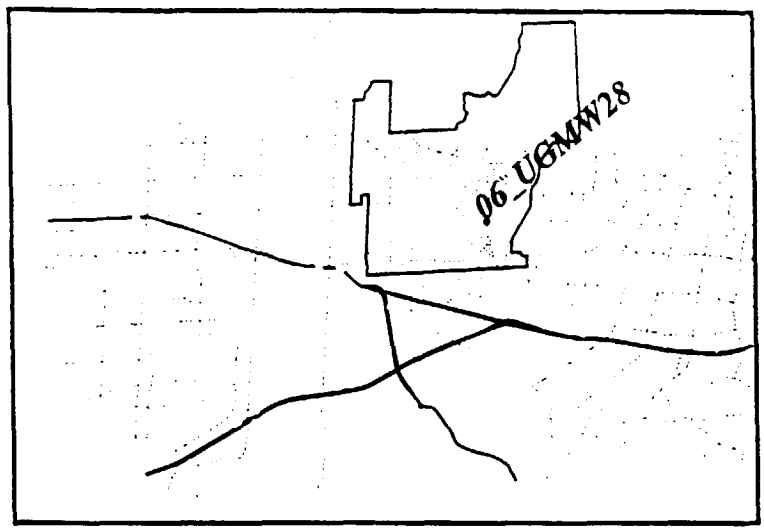


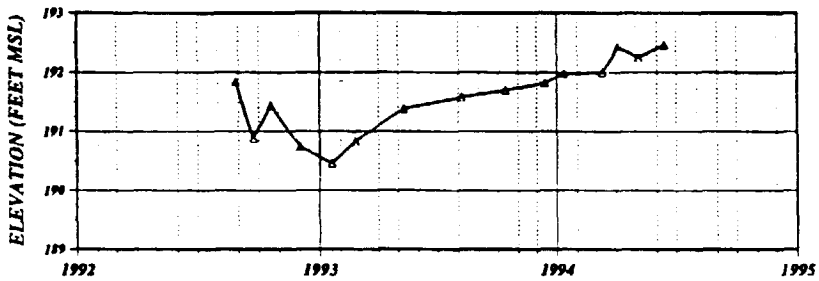
Note the Eh values plotted on this diagram are corrected for the reference electrode voltage: 244 mV units must be added to the measured value when a separate calomel electrode is used, or 199 mV units must be added if a combination platinum electrode is used.

06_UGMW28

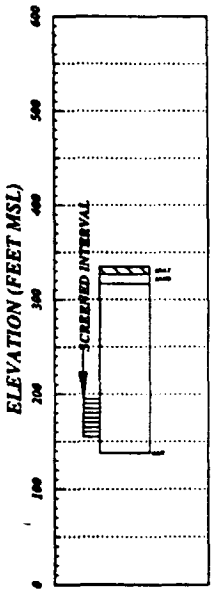
FIGURE 2







GROUNDWATER LEVEL HYDROGRAPH



DEPTH (ft bgs)	LITH.	ELEV. (ft msl)
8.0	CLAY	326.9
18.0	SAND	316.9
197.0	TD	137.9

LEGEND

TD = Total Depth
msl = Mean Sea Level
bgs = Below Ground Surface

06UGMW28

TDS (mg/L)	1700
S Value	23.24
Ca (mg/L)	286
0.4*Ca	114
Alkalinity (mg/L)	182
C Value	8.6
pH	6.79
Ryznar Stability Index (I=S-C-pH)	7.85

06_UGMW28 WELL CONSTRUCTION SUMMARY

WELL TYPE	MONITORING WELL			
CASE DIA(INCHES)	4.00		SURF. CASING MAT.	
SCREEN DIA(INCHES)	4.00		CASING MAT.	S40 PVC
SURF ELEV(FT MSL)	334.86		SCREEN MAT.	S.STEEL
	(ft bgs)	(ft msl)		
BORE DEPTH	198.00	136.86		
CASE TOP				
CASE BASE	140.00	194.86		
SCREEN TOP	140.00	194.86		
SCREEN BASE	180.00	154.86		

NOTE: NA OR BLANK = INFORMATION NOT AVAILABLE

WELL 06_UGMW28

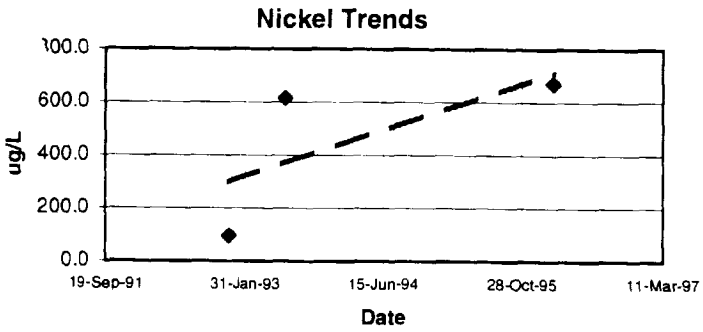
MCAS EL TORO GROUNDWATER QUALITY DATA REPORT

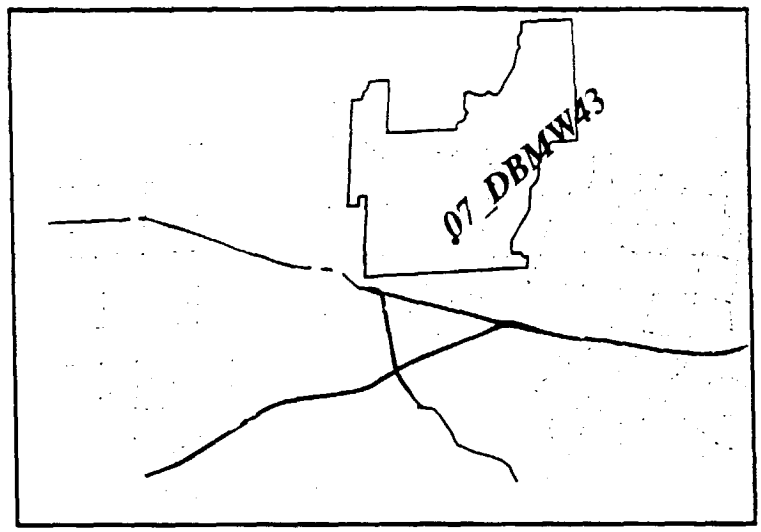
DATA PROCESSED BY CH2M HILL

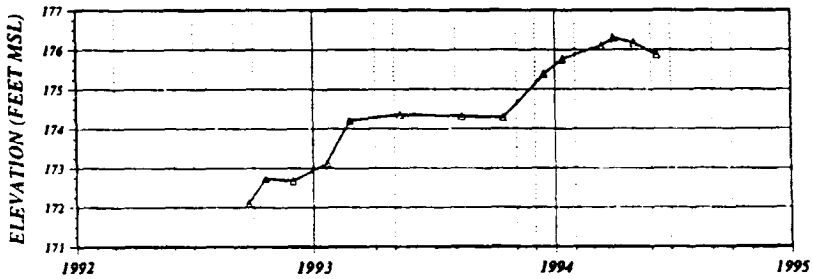
Fri Sep 23 12:43:33 1994

07_DBMW43

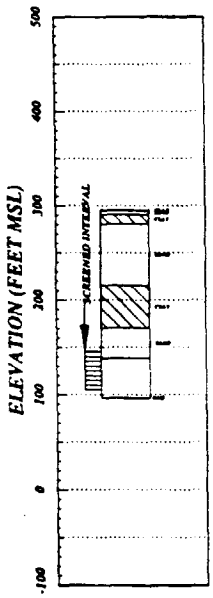
FIGURE 3







GROUNDWATER LEVEL HYDROGRAPH



DEPTH (ft bgs)	LITH.	ELEV. (ft msl)
1.0	CLAY	294.3
5.0	SAND	290.3
15.0	CLAY	280.3
80.0	SAND	215.3
125.0	CLAY	170.3
157.0	SAND	138.3
199.0	TD	96.3

LEGEND

TD = Total Depth
msl = Mean Sea Level
bgs = Below Ground Surface

07DBMW43

TDS (mg/L)	656
S Value	23.16
Ca (mg/L)	97
0.4*Ca	39
Alkalinity (mg/L)	127
C Value	7.4
pH	7.01
Ryznar Stability Index (I=S-C-pH)	8.75

07_DBMW43 WELL CONSTRUCTION SUMMARY

WELL TYPE	MONITORING WELL			
CASE DIA(INCHES)	4.00		SURF. CASING MAT.	
SCREEN DIA(INCHES)	4.00		CASING MAT.	S40 PVC
SURF ELEV(FT MSL)	295.30		SCREEN MAT.	S.STEEL
	(ft bgs)	(ft msl)		
BORE DEPTH	199.00	96.30		
CASE TOP				
CASE BASE	150.40	144.90		
SCREEN TOP	150.00	145.30		
SCREEN BASE	190.00	105.30		

NOTE: NA OR BLANK = INFORMATION NOT AVAILABLE

WELL 07_DBMW43

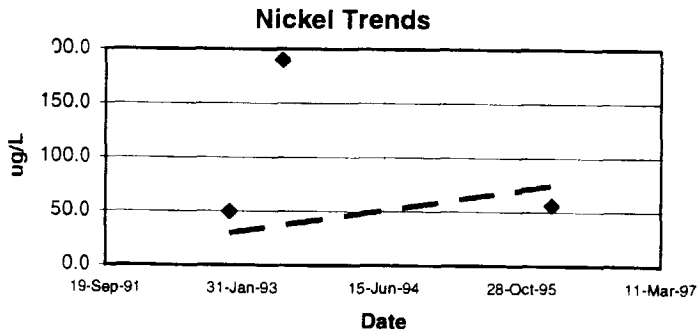
MCAS EL TORO GROUNDWATER QUALITY DATA REPORT

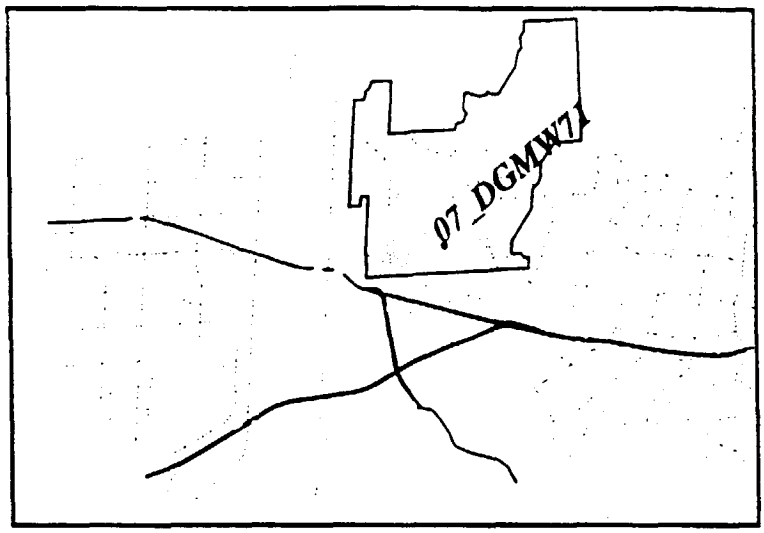
DATA PROCESSED BY CH2M HILL

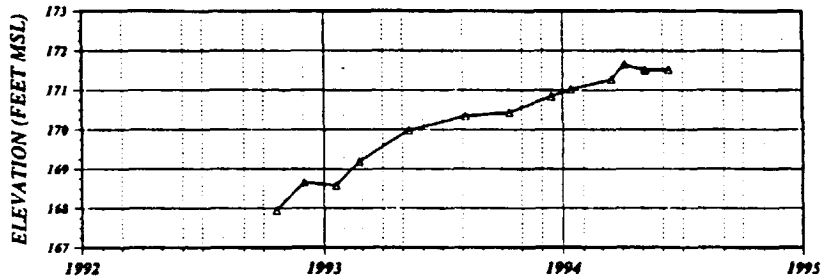
Fri Sep 23 15:01:17 1994

07_DGMW71

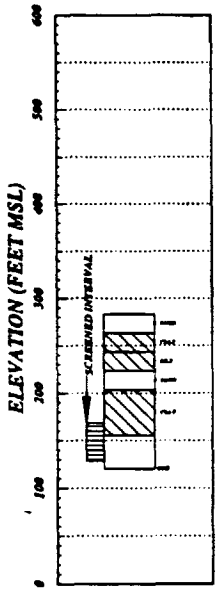
FIGURE 4







GROUNDWATER LEVEL HYDROGRAPH



DEPTH (ft bgs)	LITH.	ELEV. (ft msl)
20.0	SAND	263.4
40.0	CLAY	243.4
60.0	SILT	223.4
80.0	SAND	203.4
128.0	CLAY	155.4
163.0	TD	120.4

LEGEND

TD = Total Depth
msl = Mean Sea Level
bgs = Below Ground Surface

07DGMW71

TDS (mg/L)	1010
S Value	23.21
Ca (mg/L)	141
0.4*Ca	56
Alkalinity (mg/L)	204
C Value	8.1
pH	6.69
Ryznar Stability Index (I=S-C-pH)	8.42

07_DGMW71 WELL CONSTRUCTION SUMMARY

WELL TYPE	MONITORING WELL			
CASE DIA(INCHES)	4.00		SURF. CASING MAT.	
SCREEN DIA(INCHES)	4.00		CASING MAT.	S40 PVC
SURF ELEV(FT MSL)	283.44		SCREEN MAT.	S.STEEL
	(ft bgs)	(ft msl)		
BORE DEPTH	163.00	120.44		
CASE TOP				
CASE BASE	115.00	168.44		
SCREEN TOP	115.00	168.44		
SCREEN BASE	155.00	128.44		

NOTE: NA OR BLANK = INFORMATION NOT AVAILABLE

WELL 07_DGMW71

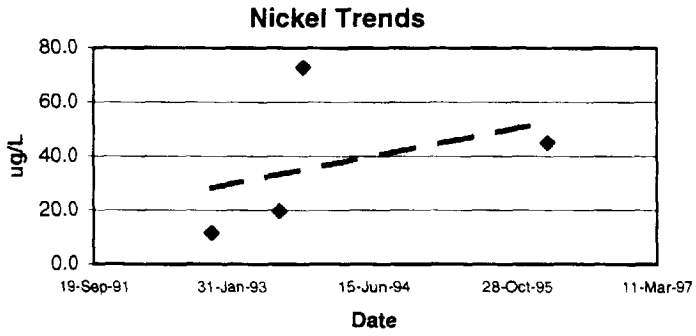
MCAS EL TORO GROUNDWATER QUALITY DATA REPORT

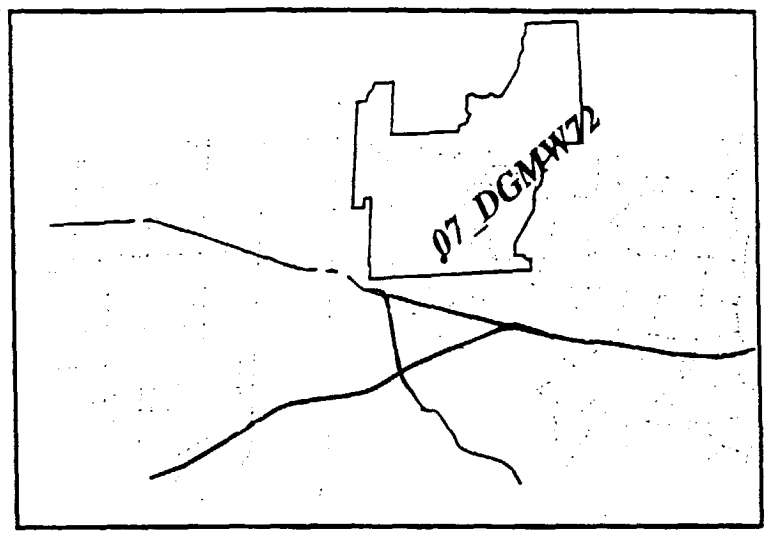
DATA PROCESSED BY CH2M HILL

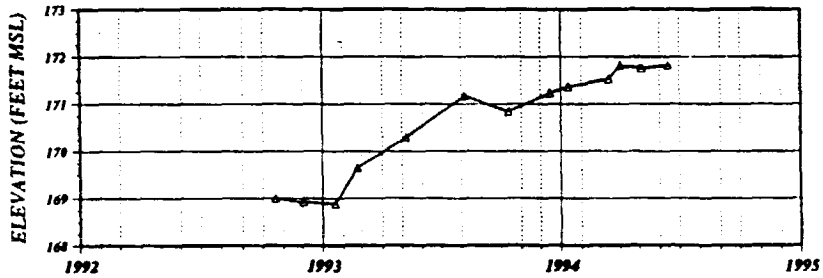
Tue Jul 26 11:55:07 1994

07_DGMW72

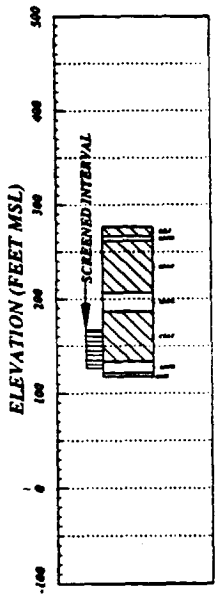
FIGURE 5







GROUNDWATER LEVEL HYDROGRAPH



DEPTH (ft bgs)	LITH.	ELEV. (ft msl)
10.0	SILT	266.7
15.0	SAND	261.7
70.0	CLAY	206.7
90.0	SAND	186.7
143.0	CLAY	133.7
155.0	SAND	121.7
159.0	TD	117.7

LEGEND

TD = Total Depth
msl = Mean Sea Level
bgs = Below Ground Surface

07DGMW72

TDS (mg/L)	935
S Value	23.19
Ca (mg/L)	136
0.4*Ca	54
Alkalinity (mg/L)	182
C Value	8
pH	6.64
Ryznar Stability Index (I=S-C-pH)	8.55

07_DGMW72 WELL CONSTRUCTION SUMMARY

WELL TYPE	MONITORING WELL			
CASE DIA(INCHES)	4.00		SURF. CASING MAT.	
SCREEN DIA(INCHES)	4.00		CASING MAT.	S40 PVC
SURF ELEV(FT MSL)	276.70		SCREEN MAT.	S.STEEL
	(ft bgs)	(ft msl)		
BORE DEPTH	158.00	118.70		
CASE TOP				
CASE BASE	110.00	166.70		
SCREEN TOP	110.00	166.70		
SCREEN BASE	150.00	126.70		

NOTE: NA OR BLANK = INFORMATION NOT AVAILABLE

WELL 07_DGMW72

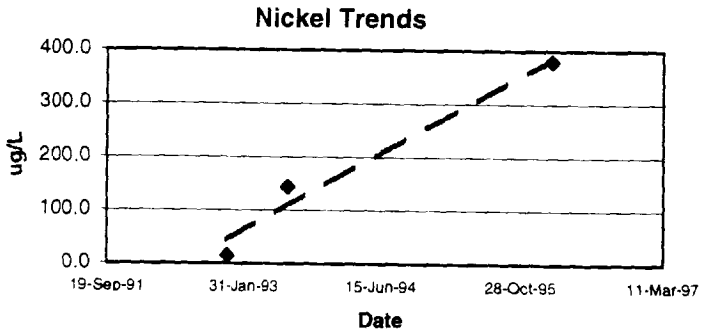
MCAS EL TORO GROUNDWATER QUALITY DATA REPORT

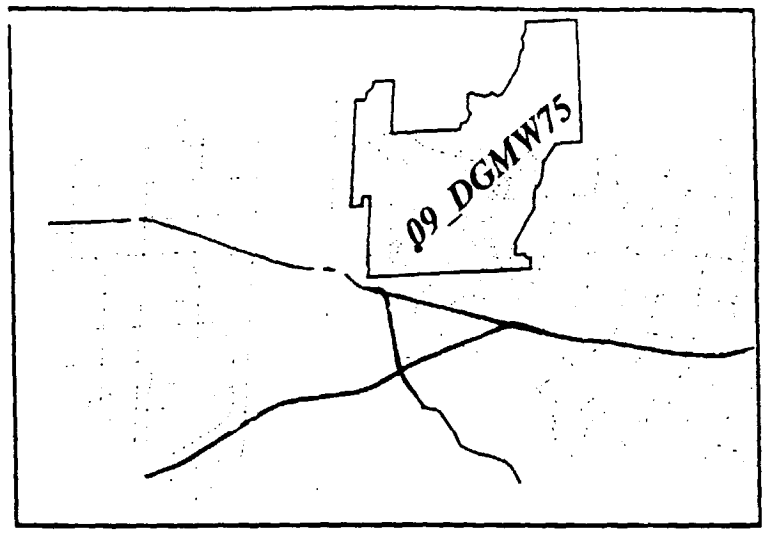
DATA PROCESSED BY CH2M HILL

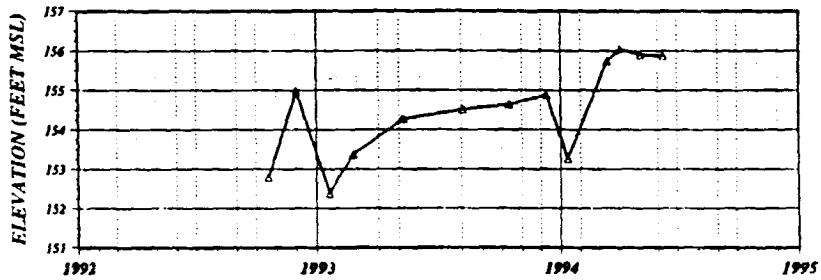
Tue Jul 26 11:56:45 1994

09_DGMW75

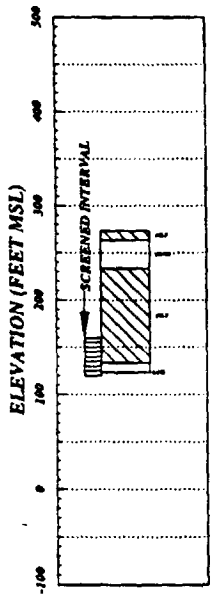
FIGURE 6







GROUNDWATER LEVEL HYDROGRAPH



DEPTH (ft bgs)	LITH.	ELEV. (ft msl)
10.0	SILT	263.4
40.0	SAND	233.4
140.0	SILT	133.4
150.0	TD	123.4

LEGEND

TD = Total Depth
msl = Mean Sea Level
bgs = Below Ground Surface

09DGMW75

TDS (mg/L)	1340
S Value	23.22
Ca (mg/L)	216
0.4*Ca	86
Alkalinity (mg/L)	169
C Value	8.4
pH	6.93
Ryznar Stability Index (I=S-C-pH)	7.89

09_DGMW75 WELL CONSTRUCTION SUMMARY

WELL TYPE	MONITORING WELL			
CASE DIA(INCHES)	4.00		SURF. CASING MAT.	
SCREEN DIA(INCHES)	4.00		CASING MAT.	S40 PVC
SURF ELEV(FT MSL)	273.40		SCREEN MAT.	S.STEEL
	(ft bgs)	(ft msl)		
BORE DEPTH	165.00	108.40		
CASE TOP				
CASE BASE	114.00	159.40		
SCREEN TOP	114.00	159.40		
SCREEN BASE	154.00	119.40		

NOTE: NA OR BLANK = INFORMATION NOT AVAILABLE

WELL 09_DGMW75

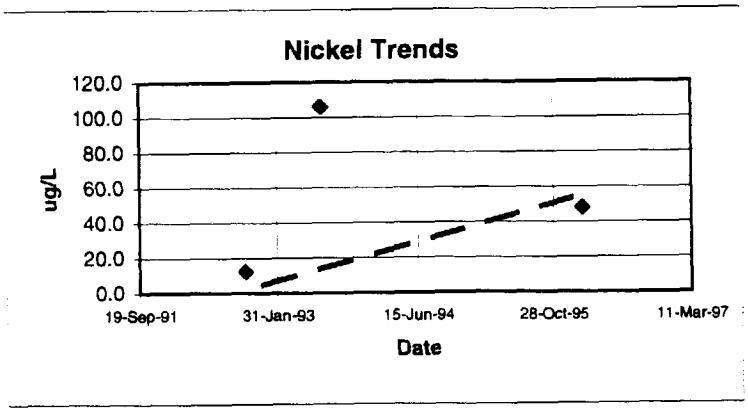
MCAS EL TORO GROUNDWATER QUALITY DATA REPORT

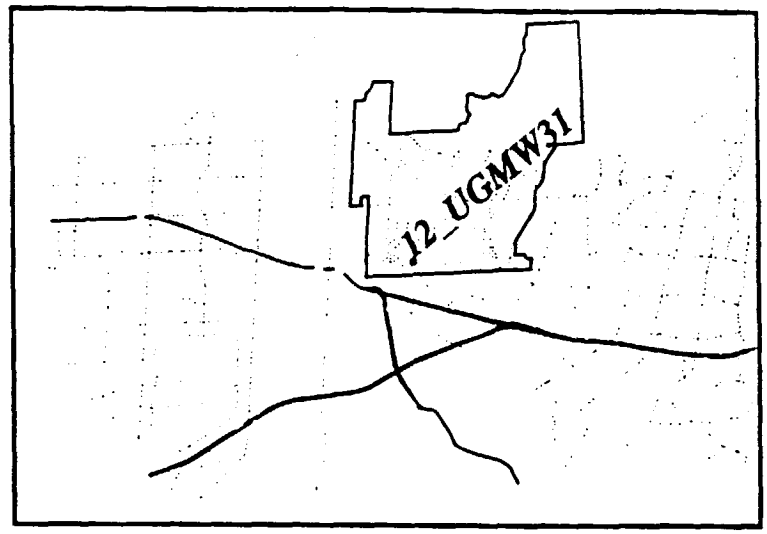
DATA PROCESSED BY CH2M HILL

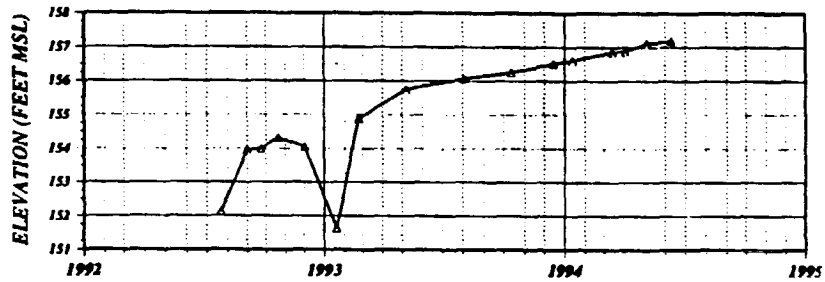
Tue Jul 26 12:08:43 1994

12_UGMW31

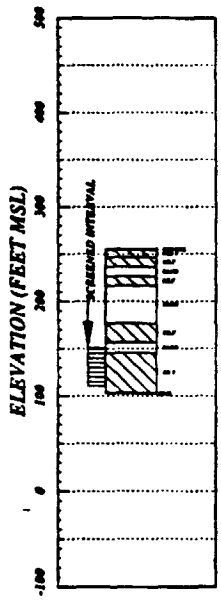
FIGURE 7







GROUNDWATER LEVEL HYDROGRAPH



DEPTH (ft bgs)	LITH.	ELEV. (ft msl)
1.0	GRAVEL	254.6
9.0	CLAY	246.6
19.0	SILT	236.6
29.0	SAND	226.6
39.0	SILT	216.6
79.0	SAND	176.6
99.0	SILT	156.6
110.0	SAND	145.6
152.0	SILT	103.6
153.0	TD	102.6

LEGEND

TD = Total Depth
msl = Mean Sea Level
bgs = Below Ground Surface

12UGMW31

TDS (mg/L)	944
S Value	23.19
Ca (mg/L)	181
0.4*Ca	72
Alkalinity (mg/L)	195
C Value	8.3
pH	6.9
Ryznar Stability Index (I=S-C-pH)	7.99

12_UGMW31 WELL CONSTRUCTION SUMMARY

WELL TYPE	MONITORING WELL			
CASE DIA(INCHES)	4.00		SURF. CASING MAT.	
SCREEN DIA(INCHES)	4.00		CASING MAT.	S40 PVC
SURF ELEV(FT MSL)	255.60		SCREEN MAT.	S.STEEL
	(ft bgs)	(ft msl)		
BORE DEPTH	153.00	102.60		
CASE TOP				
CASE BASE	105.00	150.60		
SCREEN TOP	105.00	150.60		
SCREEN BASE	145.00	110.60		

NOTE: NA OR BLANK = INFORMATION NOT AVAILABLE

WELL 12_UGMW31

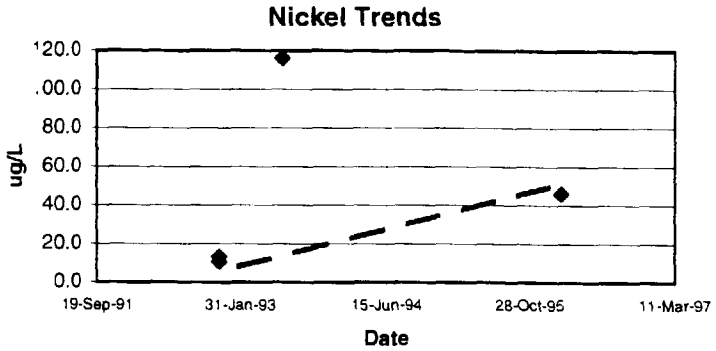
MCAS EL TORO GROUNDWATER QUALITY DATA REPORT

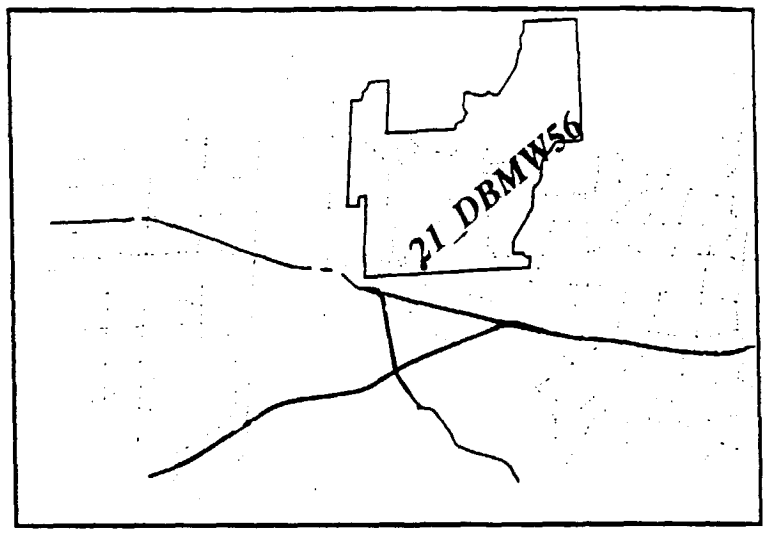
DATA PROCESSED BY CH2M HILL

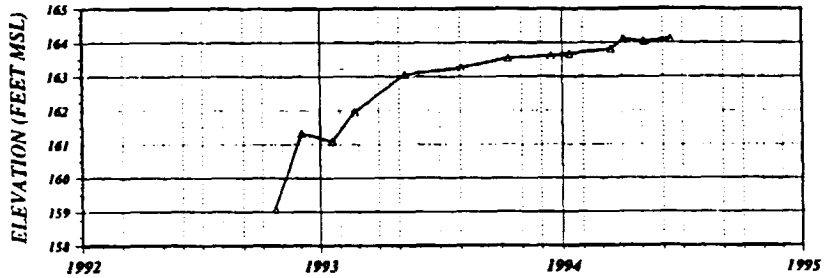
Tue Jul 26 12:15:02 1994

21_DBMW56

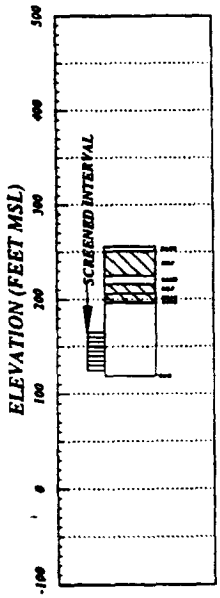
FIGURE 8







GROUNDWATER LEVEL HYDROGRAPH



DEPTH (ft bgs)	LITH.	ELEV. (ft msl)
5.0	SAND	250.9
31.0	SILT	224.9
40.0	SAND	215.9
50.0	SILT	205.9
59.0	CLAY	196.9
60.0	SAND	195.9
137.0	TD	118.9

LEGEND

TD = Total Depth
msl = Mean Sea Level
bgs = Below Ground Surface

21DBMW56

TDS (mg/L)	798
S Value	23.18
Ca (mg/L)	162
0.4*Ca	65
Alkalinity (mg/L)	204
C Value	8.2
pH	6.43
Ryznar Stability Index (I=S-C-pH)	8.55

21_DBMW56 WELL CONSTRUCTION SUMMARY

WELL TYPE	MONITORING WELL			
CASE DIA(INCHES)	4.00		SURF. CASING MAT.	
SCREEN DIA(INCHES)	4.00		CASING MAT.	S40 PVC
SURF ELEV(FT MSL)	255.87		SCREEN MAT.	S.STEEL
	(ft bgs)	(ft msl)		
BORE DEPTH	140.00	115.87		
CASE TOP				
CASE BASE	91.00	164.87		
SCREEN TOP	91.00	164.87		
SCREEN BASE	131.00	124.87		

NOTE: NA OR BLANK = INFORMATION NOT AVAILABLE

WELL 21_DBMW56

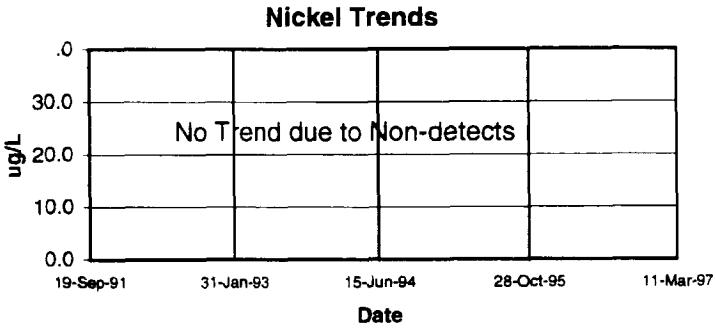
MCAS EL TORO GROUNDWATER QUALITY DATA REPORT

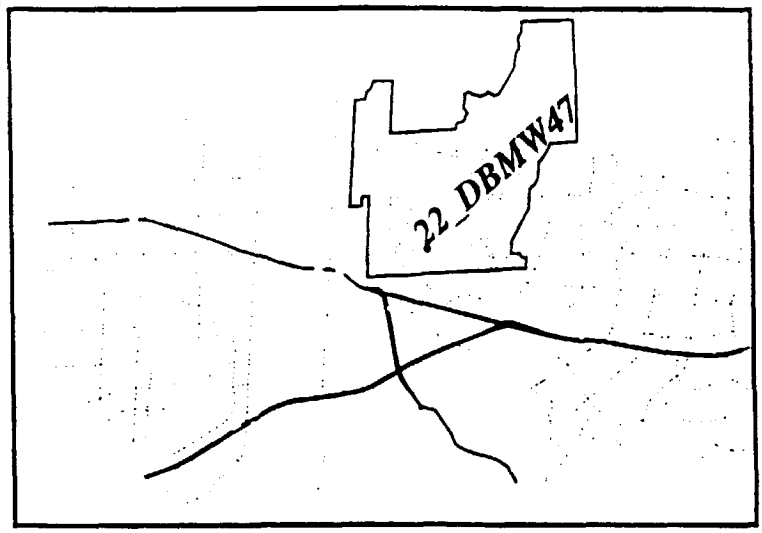
DATA PROCESSED BY CH2M HILL

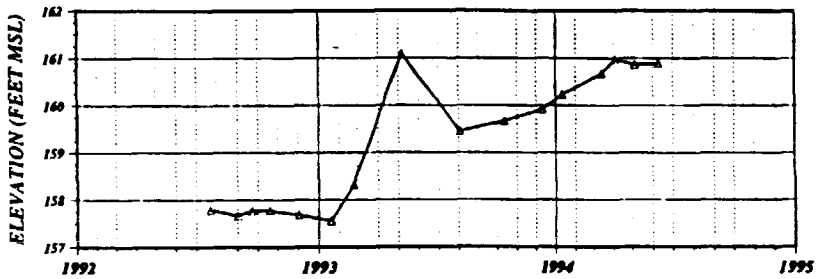
Tue Jul 26 15:06:25 1994

22_DBMW47

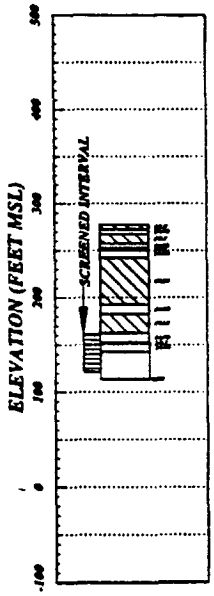
FIGURE 9







GROUNDWATER LEVEL HYDROGRAPH



DEPTH (ft bgs)	LITH.	ELEV. (ft msl)
5.0	SILT	272.5
10.0	SAND	267.5
20.0	SILT	257.5
25.0	SAND	252.5
27.0	SILT	250.5
35.0	SAND	242.5
85.0	CLAY	192.5
95.0	SAND	182.5
115.0	CLAY	162.5
125.0	SAND	152.5
126.0	SILT	151.5
135.0	SAND	142.5
164.0	TD	113.5

LEGEND

TD = Total Depth
msl = Mean Sea Level
bgs = Below Ground Surface

22DBMW47

TDS (mg/L)	1180
S Value	23.21
Ca (mg/L)	165
0.4*Ca	66
Alkalinity (mg/L)	191
C Value	8.2
pH	6.88
Ryznar Stability Index (I=S-C-pH)	8.13

22_DBMW47 WELL CONSTRUCTION SUMMARY

WELL TYPE	MONITORING WELL			
CASE DIA(INCHES)	4.00		SURF. CASING MAT.	
SCREEN DIA(INCHES)	4.00		CASING MAT.	S40 PVC
SURF ELEV(FT MSL)	277.50		SCREEN MAT.	S.STEEL
	(ft bgs)	(ft msl)		
BORE DEPTH	162.00	115.50		
CASE TOP	-1.00	278.50		
CASE BASE	116.00	161.50		
SCREEN TOP	116.00	161.50		
SCREEN BASE	156.00	121.50		

NOTE: NA OR BLANK = INFORMATION NOT AVAILABLE

WELL 22_DBMW47

MCAS EL TORO GROUNDWATER QUALITY DATA REPORT

DATA PROCESSED BY CH2M HILL

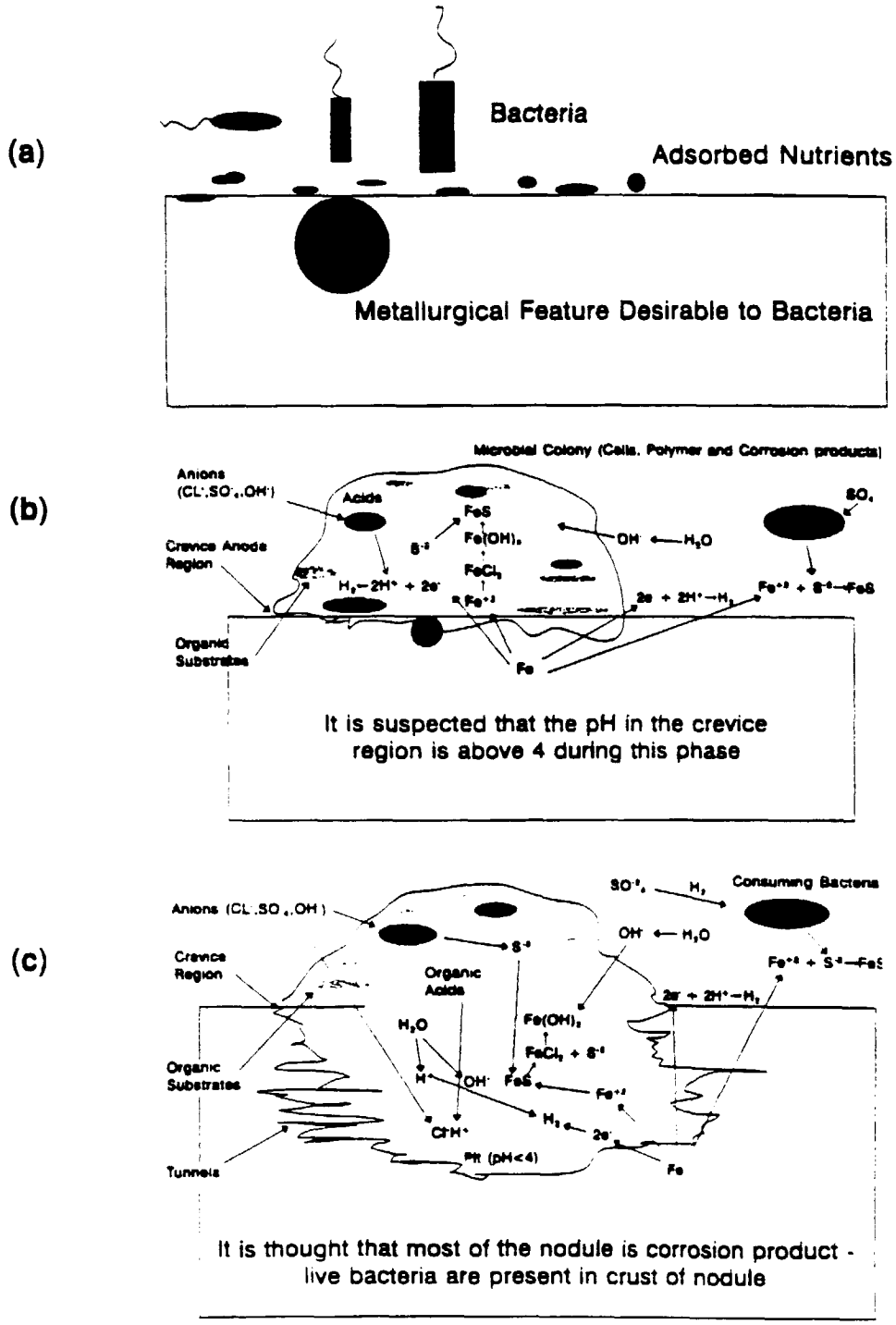
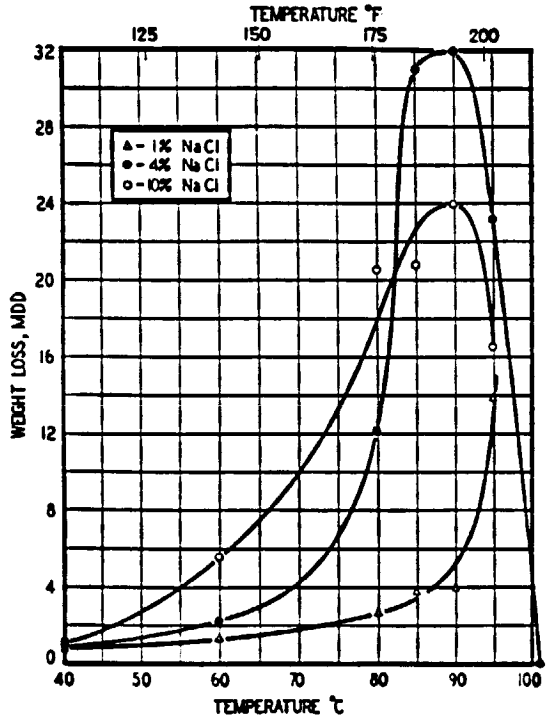


Figure 10

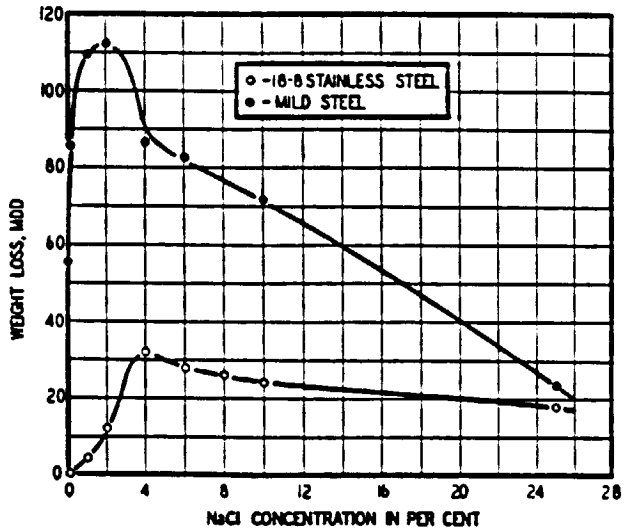
MIC development model. (a) Phase 1. Recognition of desirable sites. (b) Phase 2. Colony formation and crevice corrosion begins and anode is fixed. (c) Phase 3. Nodule is formed over "mature" pit.

(Pope and Morris)

Figure 11 Corrosion of 304 Stainless Steel in NaCl Solutions at Various Concentrations and Temperatures

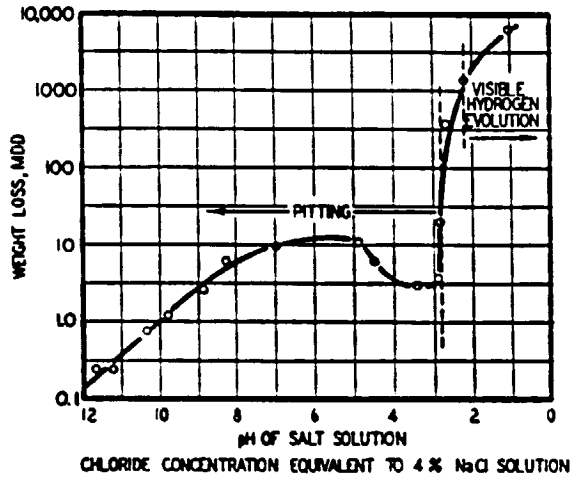


Effect of Temperature on Corrosion of 18-8 in Sodium Chloride Solutions.



Effect of Salt Concentration on Corrosion at 90° C (194° F).

Figure 12 : **Effect of pH on the Corrosion Rate of 304 Stainless Steel in 4% NaCl**



ATTACHMENT A

GROUNDWATER AND WELLS

Groundwater
and
Wells

Second Edition

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Principal Author and Editor

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culated entrance velocity. Similarly, entrance velocities from the finer grained layers will be lower than average. Experience has shown that these velocity differences along the screen are not serious if the screen is designed to the recommended average entrance velocity of 0.1 ft/sec.

Continuous slot screens with diameters smaller than the casing are often used in wells. Figure 13.13 shows the installation of a well in the Chicot Formation in southern Louisiana. The expected yield of 1,800 gpm (9,810 m^3/day) or more required the use of 20-in (508-mm) casing to provide adequate space for the pump. Selection of a 12-in (305-mm) diameter pipe-size well screen assured an uphole velocity of less than 5 ft/sec (1.5 m/sec), and provided enough open area so that the entrance velocity would not exceed 0.1 ft/sec (0.03 m/sec).

When the pump is set within pipe that connects two screen sections, the screen diameter for all screen sections set above the lowest anticipated pump setting should be selected from Table 13.1. Any screen section below the pump-setting position, however, can be of smaller diameter if the conditions for entrance and uphole velocities are met.

SELECTION OF MATERIAL

Three factors govern the choice of material used to fabricate well screens. These are (1) water quality, (2) potential presence of iron bacteria, and (3) strength requirements of the screen.

Water Quality

The chemical nature of groundwater is determined from a water quality analysis. The analysis usually shows whether the groundwater is corrosive or incrusting. In some cases, the water may cause both corrosion and incrustation. Corrosion of a low-carbon steel well screen is more likely to be a cause of well failure than is corrosion of casing constructed of similar material. Enlargement of screen openings resulting from removal of only a few thousandths of an inch of metal can permit sediment to enter the well. On the other hand, corrosion could remove 0.125 to 0.250 in (3.2 to 6.4 mm) of the casing wall and still leave enough wall thickness to prevent collapse of the well or entrance of undesirable water and sediment. It is important, therefore, to use a well screen fabricated from corrosion-resistant material (Table 13.9).

The following list of indicators of corrosive water can help the well designer recognize potentially corrosive conditions:

1. Low pH. If the pH value is less than 7, the water is acidic, and corrosive conditions are indicated. Similarly, a Ryznar Stability Index value greater than 7 indicates corrosive conditions.

2. Dissolved oxygen. If dissolved oxygen exceeds 2 mg/ℓ, corrosive water is indicated. Dissolved oxygen may be found in shallow wells in unconfined aquifers.

3. Hydrogen sulfide. Hydrogen sulfide in groundwater can be detected readily by its characteristic rotten-egg odor. Less than 1 mg/ℓ can cause severe corrosion, and this amount can be detected by odor and taste.

4. Total dissolved solids. If total dissolved solids exceed 1,000 mg/ℓ, electrical conductivity of the water is great enough to cause serious electrolytic corrosion. To avoid electrolytic corrosion, metal well screens must be made of a single, corrosion-resistant metal.

5. Carbon dioxide. If the amount of this gas exceeds 50 mg/ℓ, corrosive water is indicated.

6. Chlorides. If the chloride content of the water exceeds 500 mg/ℓ, corrosion can be expected.

The presence of two or more corrosive agents appears to intensify the corrosive attack on metals, compared with the effect caused by individual agents. See Chapter 19 for more information on corrosion and incrustation.

In corrosive waters, metal screens must be constructed of durable materials. In most cases, Type 304 stainless steel will perform satisfactorily for many years. Under extremely corrosive conditions, or for waste disposal wells, other types of material may be required. These include Type 316L stainless steel, Inconel 600, Monel 400, Carpenter 20Cb-3, Incoloy 825, and Hastelloy C. Thermoplastic screens are corrosion resistant, but may not have sufficient strength for some applications. The well-design engineer should contact the well-screen manufacturer for specific recommendations on screen materials for corrosive conditions.

Incrusting water deposits minerals on the screen surface and in the pores of the formation just outside the screen. These deposits plug both the screen openings and the formation. Indicators of incrusting groundwater are:

1. High pH. If the pH value is above 7.5, the water will tend to be incrusting. A Ryznar Stability Index of less than 7 also indicates incrusting conditions.

2. Carbonate hardness. If the carbonate hardness of the groundwater exceeds 300 mg/ℓ, incrustation of calcium carbonate (lime scale) is likely.

3. Iron. If the iron content of the water exceeds 0.5 mg/ℓ, precipitation of iron is likely, although some precipitation may begin at concentrations as low as 0.25 mg/ℓ.

4. Manganese. If the manganese content of the water exceeds 0.2 mg/ℓ and the pH value is high, precipitation of manganese is likely if oxygen is present.

Two well-known analytical methods have been devised to predict the incrusting or corrosive tendencies of a particular water. These methods are called the Langelier and the Ryznar Stability Indices. Langelier was the first to develop a method for predicting the saturation pH (pHs), which he based on the calcium carbonate ($CaCO_3$) equilibrium values taking into account dissociation factors for carbonic acid, bicarbonate, and carbonate, and the theoretical solubility of calcium carbonate (Kemmer, 1979). If the actual pH of a water is below the calculated pHs level, the water has a negative Langelier Index and will dissolve calcium carbonate. Under this condition, the water would probably be corrosive to steel if dissolved oxygen is present. On the other hand, if the measured pH is higher than the pHs, the Langelier Index is positive and, being supersaturated with calcium carbonate, incrustants will probably form. In general, the greater the deviation of the actual pH from the pHs, the more pronounced the chemical instability will be. The Langelier Index is defined as:

$$\text{Langelier Index} = \text{pH} - \text{pHs}$$

Ryznar adapted the Langelier Index to reflect more accurately the incrusting or corrosive tendencies. This index is used widely for predicting the reaction of metal objects in saturated subsurface environments. A water is corrosive if the index is higher than 7, and incrusting if lower than 7. Determination of the Ryznar Stability Index is explained in Appendix 13.J.

Mineral deposits from incrusting-type groundwater are often removed by putting

a strong solution of hydrochloric (muriatic) or sulfamic acid into the well to dissolve the deposits. Metal well screens used in this type of water should be made of corrosion resistant materials to withstand the corrosive effect of the acid treatment. Type 304 stainless steel well screens have been acid-treated successfully, although common sense dictates limiting the screen's exposure time to the acid. The addition of a corrosion inhibitor to the acid, however, will greatly extend the time a metal screen can be safely exposed to acid (see Chapter 19).

Figure 13.14. Iron and manganese oxides incrust this small-diameter plastic casing. *(H. Gehlke)*

Thermoplastic and fiberglass screens are highly resistant to many forms of corrosion, but are generally as susceptible to incrustation as metal screens. Figure 13.14 shows a small-diameter plastic casing incrusted with iron and manganese oxides. Apparently, the smooth walls of plastic casing do not retard the accumulation of minerals under incrusting conditions. Incrustants can also form in the screen slot openings. Repeated acid treatment of incrustants in plastic or fiberglass screens will usually not harm the screen body.

Bacteria

The most common bacteria affecting the condition of a well are iron bacteria (also see Chapter 19). Iron bacteria are nuisance organisms that cause plugging of pores in water-bearing formations and openings in well screens, but are noninjurious to health. Iron bacteria produce accumulations of slimy material of gel-like consistency, and oxidize and precipitate dissolved iron and manganese. The combined effect of the growing organisms and the precipitating minerals can plug a well almost completely within a short time. Cases have been reported where a 75 percent reduction in well yield has occurred in three months to a year.

Introduction of a strong solution of chlorine is effective in controlling iron bacteria. Other bactericides (oxidants) such as chlorine dioxide also are effective, but may be more expensive to use. Acid is often used following the chlorine treatment to dissolve the precipitated iron and manganese, thus making it possible to remove them from the zone surrounding the well. The chlorine MUST be removed from the well, however, before the acid is placed in the well. When iron bacteria are known to exist, a well screen fabricated from a corrosion-resistant material should be selected to withstand the damaging effects of repeated chemical treatments.

Screen Strength

Choice of well screen material may be dictated by strength requirements. The three loads, or forces, imposed on a screen are column load (vertical compression), tensile load (extending forces), and collapse pressure (horizontal forces). While a borehole is open during the installation of the screen and pipe, a screen attached directly to

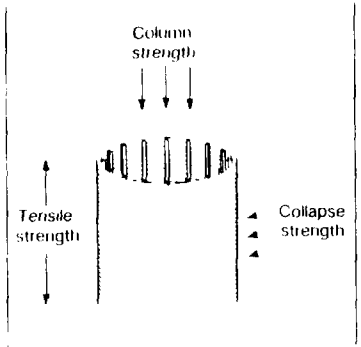

Figure 13.15. All screens have certain tensile, column, and collapse strengths that depend on the material used to construct the screen (plastic, steel, etc.), dimensions of the screen components, and the slot configuration (continuous slot, bridge slot, louvered slot, etc.). The constructional components of a continuous-slot screen are selected to withstand the three major stresses that are placed on the screen during construction and use of the well. The [illegible] and tensile strength required during well [illegible] tion are provided by the longitudinal [illegible] shape and massiveness of the wrapping wi[illegible] vide the necessary collapse resistance during development and long term use of the

the casing may have to support the entire weight of the pipe. This burden exerts a column load on the screen. A tensile load is exerted on the screen when long sections of screen and casing are installed. The screen must have enough tensile strength to hold temporarily any casing or screen suspended below it. After the borehole materials slough against the screen, earth pressures exert horizontal stresses on the screen, especially during development. The screen must have adequate collapse resistance to withstand both earth and hydraulic pressures (Figure 13.15). Failure to properly analyze these two forces can cause the loss of the well at considerable expense to the well owner, contractor, or engineer. Most collapse failures occur during installation, filter packing, and development, when horizontal forces are maximized (Figure 13.16).

A screen's resistance to both column and tensile loading is directly proportional to the yield strength of the material used in fabricating the screen, whereas the collapse resistance is proportional to the material's modulus of elasticity. For continuous-slot screens, the weight of the pipe column is supported by the cross-sectional area of the vertical rods; for louvered or bridge-slot screens, the casing above is supported by the cross-sectional area of the non-slotted portion of the casing. The screen must remain in alignment with the casing above it, or a severe reduction in column strength will occur. Thus, centering guides are used to keep the screen or slotted casing straight if the screen is more than 20 ft (6.1 m) long. Guides should be installed at least every 40 ft (12.2 m) on long screens. Column strength is important only until formation materials slough around the screen; thereafter, the earth materials hold the casing and screen.

Screen collapse strength is provided by the massiveness of the materials used to build the screen. For continuous-slot screens, the height* of the wrapping wire is the principal factor in determining collapse strength. The amount of open area also has a direct effect on the resistance to collapse pressures. In general, as the

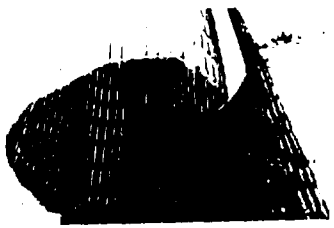

Figure 13.16. The collapse strength of this screen was insufficient to withstand development pressures because too many perforations were made in an attempt to create more open area.

*See Figure 12.8, page 399, for the meaning of wire height.

screens present an almost solid vertical metal surface to the horizontal jet. Continuous-slot screens, on the other hand, have maximum open area and slot configurations that maximize the impact of flow from the jetting tool.

The shape of the screen openings is also important in influencing the effectiveness of the agitation created by the jet. In other words, certain slot configurations will allow the jetting energy to reach deeper into the formation. The best type of opening is a V-shaped slot that widens toward the inside of the screen. When the jet is projected through this V-shaped opening as shown in Figure 15.18 (page 519), the slot opening concentrates the effect of the stream like a second nozzle or venturi. Other slot configurations tend to block or disperse the stream and reduce its force before it reaches the incrusted formation beyond the outer face of the screen.

WELL FAILURE FROM CORROSION

Metals are generally not found in nature in forms that can be used directly by man. They usually exist as ores, that is, stable mineral compounds that are in physical and chemical harmony with the natural environment. These natural minerals must be processed by electrochemical methods to reduce the ores to elemental metals that are suitable for pumps, casing, and well screens. Thus, the chemical and physical properties of ores differ from those of the pure metals. Unfortunately, in the elemental state most metals are not inherently stable. In the environment, elemental metals naturally revert back into more stable mineral compounds. This reaction, called corrosion, is a completely natural process that changes the chemical and physical properties of metals, frequently destroys the usefulness of fabricated metallic articles or structures, and may, over time, reduce or destroy metal products. Corrosion, then, is really the natural reversion of metal to its former state.

Corrosion can severely limit the useful life of water wells in four ways.

1. Enlargement of screen slots or development of holes in the casing, followed by sand pumping.
2. Reduction in strength, followed by failure of well screen or casing.
3. Deposition of corrosion products, thereby blocking screen-slot openings and reducing yield.
4. Inflow of low-quality water caused by corrosion of the casing.

Chemical and Electrochemical Corrosion

Corrosion results from chemical and electrochemical processes. Chemical corrosion occurs when a particular constituent is present in water in sufficient concentration to cause rapid removal of material over broad areas. Commonly, these constituents are carbon dioxide (CO_2), oxygen (O_2), hydrogen sulfide (H_2S), hydrochloric acid (HCl), chloride (Cl), and sulfuric acid (H_2SO_4). Chemical corrosion can cause severe damage in wells, regardless of the amount of total dissolved solids. The number of wells affected by chemical corrosion is small, however, in comparison to wells affected by electrochemical corrosion.

In electrochemical corrosion, flow of an electric current facilitates the corrosive attack on a metal. Two conditions are necessary: a difference in electrical potential on metal surfaces, and water containing enough dissolved solids to be a conductive fluid (electrolyte). A potential (electrical) difference may develop between two different kinds of metals, or between nearby but separate areas on the surface of the

same metal. Differences in potential on the same metal surface—such as steel pipe—can occur (1) at heat affected areas around welded joints, (2) at heated areas around torch cut slots, (3) at work hardened areas around machine cut slots, (4) at cut surfaces of exposed threads at pipe joints, and (5) at breaks in surface coatings such as paint and mill scale. In these cases, both a cathode and an anode develop; metal is removed from the anode.

Bimetallic corrosion results when two different metals are in contact and immersed

Table 19.7. Galvanic Series of Metals and Alloys

↑ Noble or cathodic	Platinum
	Gold
	Graphite
	Titanium
	Silver
	Chlorimet 3 (62 Ni, 18 Cr, 18 Mo)
	Hastelloy C (62 Ni, 17 Cr, 15 Mo)
	18-8 Mo stainless steel (passive)
	18-8 stainless steel (passive)
	Chromium stainless steel 11–30% Cr (passive)
	Inconel (passive) (80 Ni, 13 Cr, 7 Fe)
	Nickel (passive)
	Silver solder
	Monel (70 Ni, 30 Cu)
	Cupronickels (60–90 Cu, 30–10 Ni)
	Bronzes (Cu-Sn)
	Copper
	Brasses (Cu-Zn)
	Chlorimet 2 (66 Ni, 32 Mo, 1 Fe)
	Hastelloy B (60 Ni, 30 Mo, 6 Fe, 1 Mn)
	Inconel (active)
	Nickel (active)
	Tin
	Lead
	Lead-tin solders
	18-8 Mo stainless steel (active)
	18-8 stainless steel (active)
	Ni-Resist (high Ni cast iron)
	Chromium stainless steel, 13% Cr (active)
	Cast iron
	Steel or iron
	2024 aluminum (4.5 Cu, 1.5 Mg, 0.6 Mn)
Active or anodic ↓	Cadmium
	Commercially pure aluminum (1100)
	Zinc
	Magnesium and magnesium alloys

(Fontana and Greene, 1978)

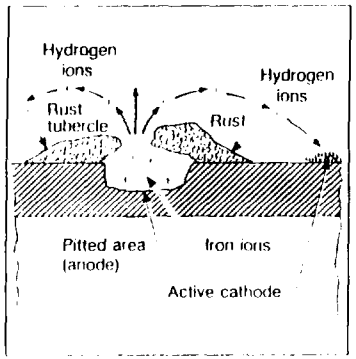

Figure 19.10a. Anodes and cathodes can develop in nearby areas on the same metal surface, resulting in corrosion.

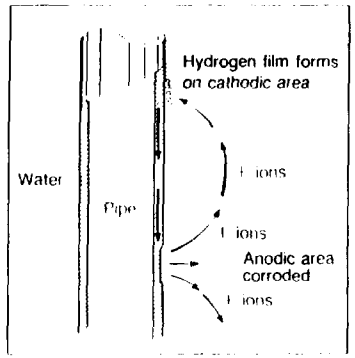

Figure 19.10b. Corrosion of iron at anodic areas leads to the deposition of iron hydroxide and oxide rust at cathodic areas.

in an electrolyte. A galvanic cell is created and corrosion occurs as the electrochemical action proceeds. A well screen made of two different metals, such as low-carbon steel and stainless steel, will be damaged because the mild-steel portion is corroded by the galvanic action.

The relative potential between different metals can be estimated from the galvanic series shown in Table 19.7. The farther apart the position of any two metals in this series, the greater the voltage that will be developed in a galvanic cell. When two dissimilar metals are coupled in a conductive fluid, the metal nearer the bottom of the galvanic series (less noble) becomes the anode and therefore suffers corrosion. The one nearer the top becomes the cathode and usually remains free of attack.

When electrochemical corrosion takes place, corrosion products may be deposited at the cathode (Figure 19.10). These deposits are usually voluminous. If iron or steel is corroded, the corrosion products are iron combined with other elements and are normally ferric hydroxide or ferric oxide. Deposition of corrosion products that results in blocked screen-slot openings and reduced well yields is evidence of electrochemical corrosion.

Prevention and Treatment of Corrosion

The following observations concerning corrosion have been developed from experience and apply to many situations in the groundwater industry:

1. If low-carbon steel is attacked in a particular type of water by chemical corrosion, it will corrode faster if connected to a metal higher in the galvanic series (Table 19.7). This is why stainless steel end fittings should always be used on both ends of stainless steel screens. If they are not, corrosion is concentrated on the relatively small area of mild steel that is welded to the stainless steel. The corrosion rate, however, is considerably lower a short distance away from a connection between two dissimilar metals.
2. Work-hardened material corrodes more rapidly than the same metal that is in an annealed (heat treated) condition.
3. Stressed parts are more likely to corrode than are unstressed parts.

4. Higher temperatures increase corrosion rates. The rate of corrosion accelerates with increasing temperature, generally doubling for each additional 18°F (10°C).
5. High fluid velocities increase corrosion rates in most cases.
6. Dissolved gases such as oxygen, carbon dioxide, hydrogen sulfide, and methane in water increase corrosion rates.
7. Generally, electrochemical corrosion causes loss of material on only parts of well screens and casings, with some of these corrosion products deposited elsewhere. This usually occurs in water that is slightly acidic, with total dissolved solids greater than 1,000 mg/L. A reduction in yield caused by plugging of the screen openings by deposition of corrosion products or by structural failure of the screen can result from corrosion.

In recent years many screen manufacturers have built most of their products out of Type 304 stainless steel. This is because stainless steel is resistant to corrosion caused by underground environments and chemicals added during well rehabilitation, and the price difference between stainless steel and low carbon steel has narrowed significantly since the mid-1960s. Use of Type 304 stainless steel in most freshwater applications assures the well owner of long-term resistance to corrosion. Certain chemical and physical situations do exist, however, that can lead to severe damage to stainless steel screens; even more resistant materials such as Hastelloy C, Carpenter 20Cb, or Type 316 stainless steel must then be used.

The fundamental resistance of stainless steel to corrosion comes from a protective coating that forms on its surface. This coating is a "passive" film that is resistant to further oxidation or other forms of chemical attack. Although this chemically passive film may be monomolecular in thickness, it is generally protective in oxidizing environments (See Appendix 13.1). The film is produced by the combination of oxygen in water, and constituents of the steel. When the amount of free chromium exceeds 11 percent, steels do not normally form red rust. Thus, chromium is the element that makes stainless steels "stainless."

Stainless steels, however, are subject to corrosion by halogen salts, primarily chlorides, that can easily penetrate the passive film and allow corrosive attack to proceed. Chlorides are generally found only in low concentrations in aquifers used for water supply, but road deicing salts, sewage water, salt water intrusion, or other forms of subsurface contamination can raise chloride concentrations significantly. Chlorides are soluble, active ions and form electrolytes that can enhance the corrosion rate of stainless steel.

Five basic types of corrosion in stainless steels are recognized:

- General
- Galvanic
- Pitting
- Intergranular
- Stress-corrosion cracking

All corrosion of stainless steel can be related to these five types; the causes of each are discussed below.

General Corrosion

General corrosion is the uniform dissolution of metal over the entire surface exposed to a corrodent and results from the uniform breakdown of the passive film that

initially covers the surface. General corrosion may be reduced or even prevented by selecting materials that are resistant in corrosive environments. On the other hand, excessive acid treatment of well screens can cause general corrosion that leads to a widening of the slots. General corrosion can be measured by the rate of metal loss over a surface. This rate is usually given in mils (thousandths of an inch) per year (mpy).

Galvanic Corrosion

Two dissimilar metal alloys connected electrically to a voltmeter and suspended in an electrolyte will show an electrical potential between them, because one alloy will dissolve in the electrolyte more readily than the other. The more active of the two contacting metals will be anodic to the other and will give up metal to the solution, leading to galvanic corrosion. The metal that serves as the cathode will be protected and will show no loss to the corrodent. It would lose metal, however, if it were not in contact with the anodic metal. This is the basis of cathodic protection, where a metal lower in the galvanic series is sacrificed by being electrically connected to the metal to be protected.

Galvanic corrosion is so well known that dissimilar metals of significant difference in voltage (far apart in the galvanic series) are seldom joined. However, when it is necessary to have dissimilar metals in the same corrosive environment, they should be kept apart by nonconductive gaskets (dielectric material) and insulated bolts, or the anodic alloy should have far greater surface area than the cathodic alloy. Most groundwaters have a relatively low concentration of dissolved solids, and thus their ability to conduct electrical current is limited. Consequently, the practice of joining low-carbon steel casing to stainless steel well screens does not cause severe galvanic corrosion to the casing because the anodic metal has a large surface area. Welding rings fitted to the ends of stainless steel screens should always be made of stainless steel, however. Most corrosion is galvanic in nature, and a thorough understanding of galvanic attack can prevent premature failure of wells.

Cathodic Protection

In groundwater environments where galvanic corrosion poses a potential problem, the well screen, casing, and pump can be protected by means of a cathodic protection system. Cathodic protection for equipment installed underground can be achieved by supplying electrons to the metallic components of the system to be protected. In other words, if an electrical current is caused to flow to a metal casing from the surrounding groundwater, the rate of metal dissolution is greatly retarded. If the current flows the other way — from the metal to the electrolyte — corrosion of the metal casing is accelerated.

The casing, or any metallic structure placed underground, can be protected by initiating current in the proper direction by proper galvanic coupling or by impressing a current from an external power supply. Figure 19.11 shows how a metallic well casing can be protected by the installation of a sacrificial anode. For example, a magnesium anode can be connected to the casing by a coated copper wire. Current flows from the magnesium block through the electrolyte (groundwater), and deposition of the corrosion products occurs on the casing as the anode is slowly taken into solution. The current returns to the anode by way of the copper wire. Some wells are

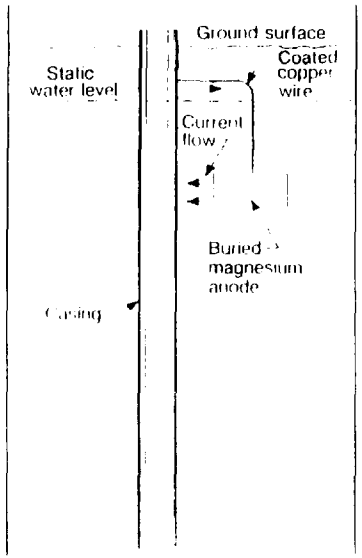

Figure 19.11. A sacrificial anode is connected to a steel casing to prevent corrosion of the casing. Current flows from the anode to the casing through the groundwater. Magnesium ions are thereby transferred to the casing, and eventually the anode is destroyed.

protected by a long cable fastened directly to the casing and suspended in the well below the static water level. This cable, made of a metal less noble than the casing, acts as the anode. Every few years, the hanging cable is replaced. Current can also be impressed by an external dc power source. The anode is usually placed in a material such as bentonite so that the electrical connection between the anode and the surrounding earth materials is maximized.

The size of the anode used in cathodic protection depends on the current flowing between the anode and cathode. The potential of the cathode can be measured by placing a high-resistance voltmeter in the ground (presumably saturated). This measurement is then used to suggest the size and number of anodes required for complete protection. Spacing of the anodes may be affected by distribution of the currents at various depths adjacent to the well bore. Current flow may be much higher in certain areas because of the presence of clay or other materials that offer less resistance to the applied current.

Pitting

In this form of attack, the rate of corrosion is greater at some areas than other. The depth of pitting is more significant than the number of pits, since one deep pit would limit the well life more than a large number of shallow pits. Pitting is a destructive form of corrosion because only one or two perforations can cause well failure. In many cases, failures caused by pitting often occur over rather short periods preceded by years of little or no corrosion.

Pitting of stainless steels occurs where the corrosive environment penetrates the passive film at only a few points rather than over the entire surface area of the metal as in general corrosion. Pitting is initiated when small areas lose their passivity, become active, and begin to react with surrounding passive areas. Note that "active" stainless steel has a lower place on the galvanic chart that has "passive" stainless steel, with the active being the anodic. Because the passivated surface area or cathode is large, the comparatively smaller active area has relatively intense current density and the local metal loss is large. Pitting usually occurs when the corrodent contains one of the halogens (chlorine, bromine, fluorine), these can displace the oxygen in the passive film on the stainless steel and create a local break or a small area where the stainless is unprotected or active. This active area can become a pit if oxygen is excluded by soil accumulations along the surface or is excluded by chemical action

Table 19.8. Resistance of Some Materials to Pitting

↑ Increasing pitting resistance ↓	Type 304 stainless steel Type 316 stainless steel Hastelloy F, Nionel, or Durimet 20 Hastelloy C or Chlorimet 3 Titanium

(Fontana and Greene, 1978)

from surface crevices or irregularities.

The corrosive attack at the active area is exaggerated because of both the current density and the autocatalytic nature of the pitting process in which the pit tends to retain electrolyte and exclude the oxygen that would otherwise repassivate the area. This aspect of pitting corrosion is sometimes referred to as "concentration-cell corrosion." As the depth of the pit increases, conditions for pitting are maintained and the pit will quickly penetrate even thick-walled casing. Each pit acts as a battery that operates by consuming its container.

When halogens are known to be present, pitting may be minimized by using stainless steels alloyed with molybdenum. The higher molybdenum content of certain stainless steels, such as Type 316, is important in preventing pitting. Table 19.8 lists several materials in relation to their resistance to pitting. The various alloying elements that affect pitting resistance are given in Table 19.9.

Intergranular Corrosion

This type of corrosion is restricted, occurring only at grain boundaries. It is often observed when stainless steel is bent, resulting in distinct surface fissures or cracks that follow the grain boundaries.

All austenitic stainless steels contain a small amount of carbon in solution in the austenite. Carbon is precipitated out rapidly at the grain boundaries of the steel within a temperature range of 950°F (510°C) to 1,450°F (788°C); this is called the sensitizing

Table 19.9. Effects of Alloying on Pitting Resistance of Stainless Steel

Element	Effect on Pitting Resistance
Chromium	Increases
Nickel	Increases
Molybdenum	Increases
Silicon	Decreases, increases when present with molybdenum
Titanium and columbium	Decreases resistance in $FeCl_3$; other mediums no effect
Sulfur and selenium	Decreases
Carbon	Decreases, especially in sensitized condition
Nitrogen	Increases

(Greene and Fontana, 1959)

temperature. Carbon combines preferentially with chromium, and precipitates at the grain boundaries in the form of chromium carbide. Thus, the area adjacent to the grain boundary is lower in chromium content and is less resistant to corrosion than the rest of the grain. Under attack, the grain boundaries are dissolved, thus leading to grain disaggregation.

There are three methods available to the corrosion engineer to reduce intergranular corrosion. The first method is to anneal the stainless steel after it has been sensitized. The steel is heated to the proper annealing temperature and quickly cooled through the sensitizing range at such a rate that the carbides are not permitted to precipitate. The second method of avoiding intergranular attack is to minimize the carbon content. If the steel contains less than 0.06 to 0.08 percent carbon, a continuous film of chromium carbide will not precipitate at the grain boundaries during the brief exposure to the sensitizing temperature. Thus, this extra-low carbon alloy can be welded successfully with no loss of corrosion resistance along the grain boundaries. The third and perhaps surest way to avoid intergranular corrosion is to alloy the metal with titanium or columbium, which are strong carbide formers. The carbon then forms a titanium or columbium carbide rather than a chromium carbide, and the alloy is thus stabilized against chromium carbide formation.

Stress-Corrosion Cracking

All metals are subject to stress corrosion cracking. If a metal is under tensile stress in a corrosive environment, stress corrosion cracking may develop. The tensile stress may be residual stress resulting from cold working or quenching after heat treatment or may originate from externally applied stress, as in the shafting components of a deep-well turbine pump. Solutions containing chloride usually promote stress corrosion cracking in austenitic stainless steels. Stress corrosion cracking can be reduced by annealing to relieve the stress developed during fabrication or by selecting materials that are resistant to the potentially corrosive environment.

PUMP MAINTENANCE

Water well pumps are generally built to high engineering standards, utilizing the best materials. Unfortunately, pumps often operate under less than ideal physical and chemical conditions. Thus, they are subject to a wide range of potential maintenance requirements.

The condition of the pumping unit can be evaluated from the following checklist (applying in part to both vertical turbine and submersible pumps):

- Does the pump operate on its original design curve?
- Is there excessive heating of the motor?
- Has there been a change in the bearing noise level?
- Has there been any change in the pattern of oil consumption of the motor?
- Is there excessive vibration?
- Has the amperage or voltage load to the pump changed?
- Are there cavitation noises or any other unusual sounds?
- Has cracking or uneven settlement of the pad or ground around the pump occurred?

Once a problem is recognized, maintenance must be performed.

A complete analysis of pump maintenance is beyond the scope of this book, but

APPENDIX 13.J.
Calculating the Ryznar Stability Index

The Ryznar Stability Index for a water sample can be calculated from the following equation:

$$I = S - C - \text{pH}$$

where I is the Ryznar Stability Index and S and C are factors derived from Figures 1 and 2, based on total dissolved solids, methyl orange alkalinity, and calcium ion concentration (0.4 × calcium hardness).

The steps to determine S and C are:

1. Obtain a value for S using the known total dissolved solids and Figure 1.
2. Obtain a value for C using the methyl orange alkalinity, the calcium ion concentration, and Figure 2.

For example, assume that a water analysis produces the following data:

pH = 7.0
Total dissolved solids = 400 mg/ℓ
Methyl orange alkalinity = 200 mg/ℓ
Calcium hardness = 125 mg/ℓ

Note that the calcium ion concentration for the Ryznar Stability Index equation is 0.4 × 125 = 50 mg/ℓ.

1. The value of S from Figure 1 is 23.12.
2. The value of C from Figure 2 is 8.0.
3. The Ryznar Stability Index, I, is 23.12 − 8.0 − 7.0 = 8.12.

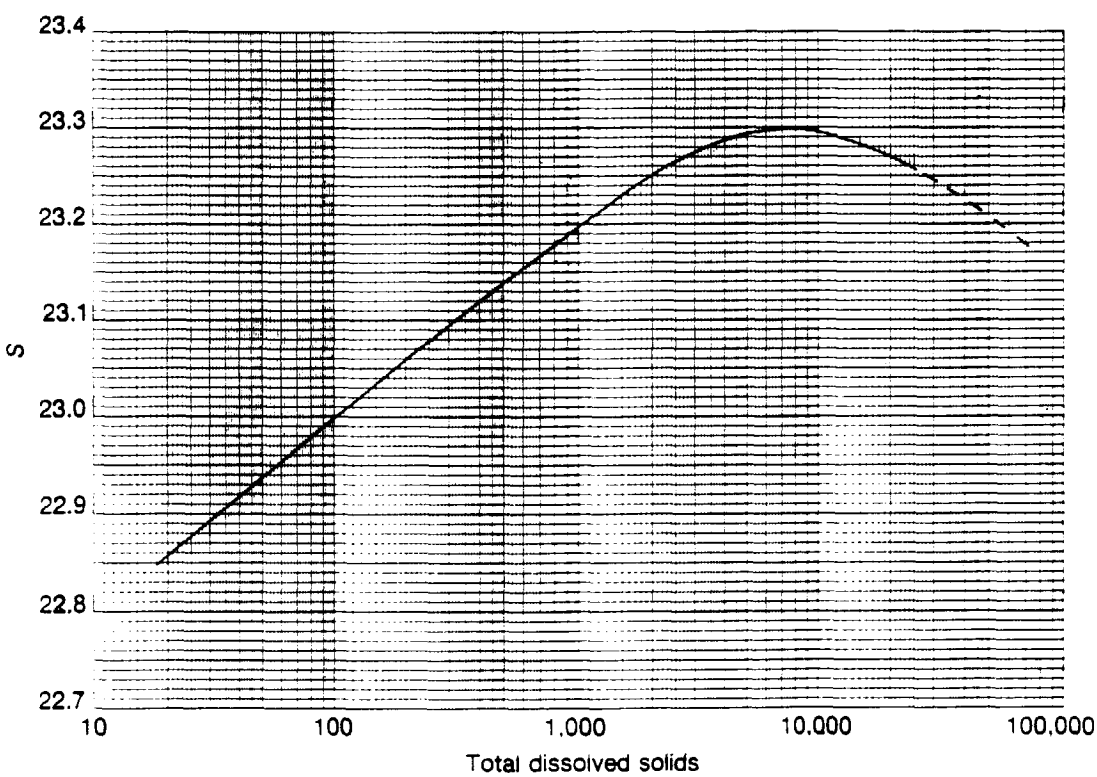

Figure 1. ***S*** **value as a function of total dissolved solids.**

Appendix 13.J. Continued

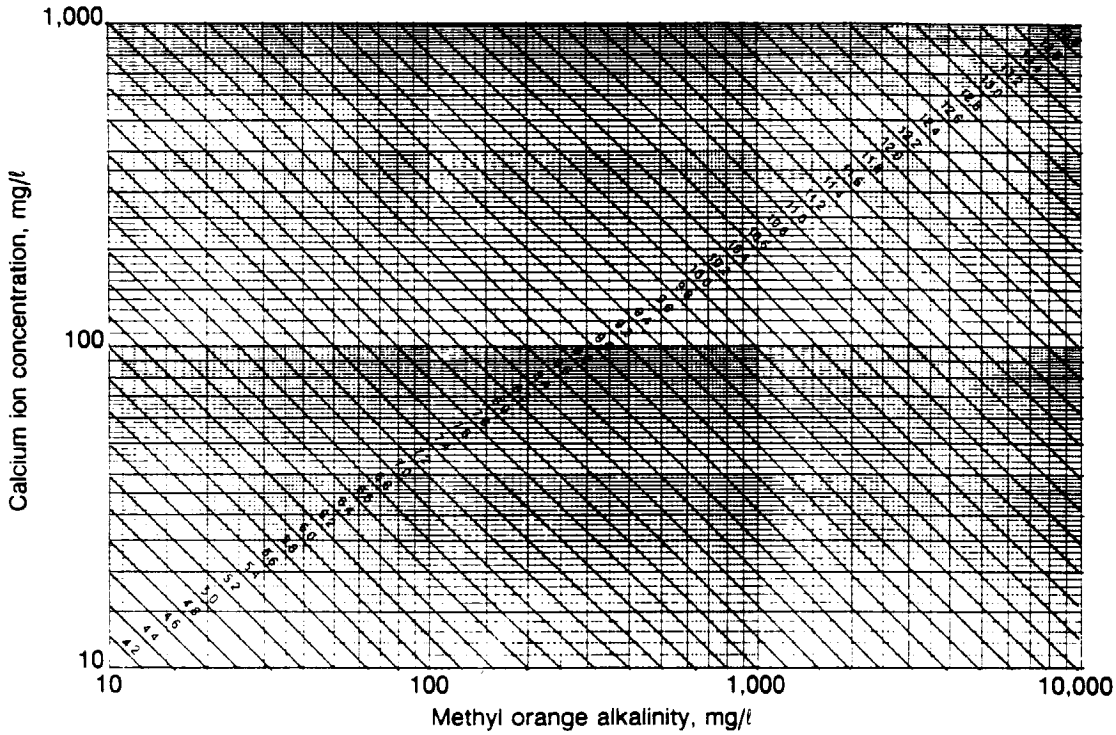

Figure 2. *C* **value as a function of calcium ion concentration and methyl orange alkalinity.**

ATTACHMENT B

NICKEL AND CHROMIUM IN GROUNDWATER SAMPLES AS INFLUENCED BY WELL CONSTRUCTION AND SAMPLING METHODS

Nickel and Chromium in Ground Water Samples as Influenced by Well Construction and Sampling Methods

by D. Oakley and N.E. Korte

Abstract

An investigation of elevated concentrations of nickel and chromium in certain ground water samples collected at Williams Air Force Base (AFB) indicated that type 304 stainless steel well materials are the source. Chloride in the ground water has apparently caused crevice corrosion of the stainless steel well screens installed during site characterization. An evaluation of site geochemistry suggested that chromium released from the well screen would precipitate, while nickel would remain dissolved. Thus, low-flow purging and sampling significantly reduces the chromium found in the ground water samples because such sampling minimizes the collection of artificially entrained particulates. In contrast to chromium, nickel concentrations did not decrease during low-flow purging and sampling, indicating that it is dissolved. Nickel and chromium concentrations are both low following high-volume purging when turbidity levels are stabilized below 10 nephelometric turbidity units prior to sampling. In the latter case, chromium concentration is low because particulate collection is minimized, and nickel concentration is low because of increased dilution. Based on these results, it is recommended that elevated levels of nickel and chromium in ground water samples collected from stainless steel monitoring wells be carefully evaluated, because well materials may be the source. In addition, although low-volume purging is increasingly becoming the sampling method of choice, high-volume purging may be a useful means of determining whether the well materials influence nickel and chromium concentrations.

Pages 93–99

Introduction

This paper presents the results of an investigation of chromium and nickel detected in ground water samples collected from a subset of the wells at Williams Air Force Base (AFB), Mesa, Arizona. Base activities had resulted in contamination at a number of sites. Prominent among these are the base landfill and the liquid fuels storage area (LFSA).

The approximately 34-acre (13.8 ha) landfill was used for disposal of general base refuse from 1941 until 1976. Since 1987, trichloroethene (TCE), tetrachloroethene (PCE), and benzene have been detected in downgradient ground water samples. The concentrations of these contaminants, however, are below action limits, and remediation is not required.

The LFSA, in use since 1942, consisted of underground storage tanks and thousands of feet of delivery pipe. Spills and leaks resulted in a free product plume. An associated dissolved contaminant plume is approximately 1700 feet (518 m) long and 600 feet (183 m) wide. The unconfined aquifer underneath the LFSA is now being remediated by means of a horizontal well pump-and-treat system.

The landfill and LFSA are not sources of nickel and chromium based on the results of the preliminary assessment (USAF 1984) and the site investigation (SI) (USAF 1986, 1987). The SI included the installation and repetitive sampling of a number of monitoring wells. Thus, it was surprising when samples

collected from wells installed from 1989 to 1991 as part of the remedial investigation (RI) (IT Corp. 1992) contained both nickel (up to 1320 mg/L) and chromium (up to 54,500 mg/L).

Hydrogeologic Setting

A hydrostratigraphic column for Williams AFB is presented in Figure 1. The unsaturated zone is composed of channel, floodplain, terrace, and alluvial fan deposits (Laney and Hahn 1986). An unconfined aquifer, aquitard, and semiconfined aquifer underlie the unsaturated zone. These units are composed of playa, alluvial fan, and fluvial deposits. The unconfined aquifer, the zone contaminated by base operations, has generally poor ambient water quality with total dissolved solids (TDS) ranging as high as 3000 mg/L. Chloride is typically 600 to 900 mg/L and sulfate 50 to 300 mg/L. The hydraulic conductivity, because of the high percentage of fines, is approximately 3 feet per day (ft/d) (1×0^{-5} m/s), although the formation is highly heterogenous. Fully penetrating vertical wells typically yield 1 to 3 gallons per minute (gal/min) (4 to 12 L/m) during long-term pumping tests.

Monitoring Well Installation

Monitoring wells installed during the SI (USAF 1986, 1987) were constructed with 4-inch-diameter (10 cm), 60-foot-long (18 m), wire-wrapped stainless steel screens of an unknown grade and carbon steel risers. During the RI, a different contractor installed additional monitoring wells at the landfill and LFSA (IT Corp. 1992). These 4-inch-diameter (10 cm) wells were constructed with 40-foot-long (12 m), wire-wrapped type 304 stainless steel screens, with a 20-foot-long (6 m) stainless steel riser pipe above the screen and PVC riser pipe to the ground surface.

Chromium and Nickel Results

Initially, ground water samples were collected when a minimum of three well volumes had been purged (1.5 gpm) with a piston pump; when pH, temperature, and specific conductance had stabilized, and when the well had recovered to 80 percent of the initial well volume. Purge volumes were typically 70 to 80 gallons. Samples were collected with a bottom fill bailer and were not filtered. Laboratory sample preparation included digestion of any particulate matter that was collected. The same laboratory analyzed all of the samples discussed in this paper using standard spectroscopic methods.

Tables 1 and 2 summarize nickel and chromium results from 1986 through June 1993 for each well at the landfill and LFSA. These data show that the frequency of detection and average concentrations are much higher in samples from wells installed during the RI. These results suggest that well construction is responsible. It is also noted that the concentrations reported often were not consistent and reproducible from one sampling event to the next. The lack of consistency is believed to be due to the method of sample

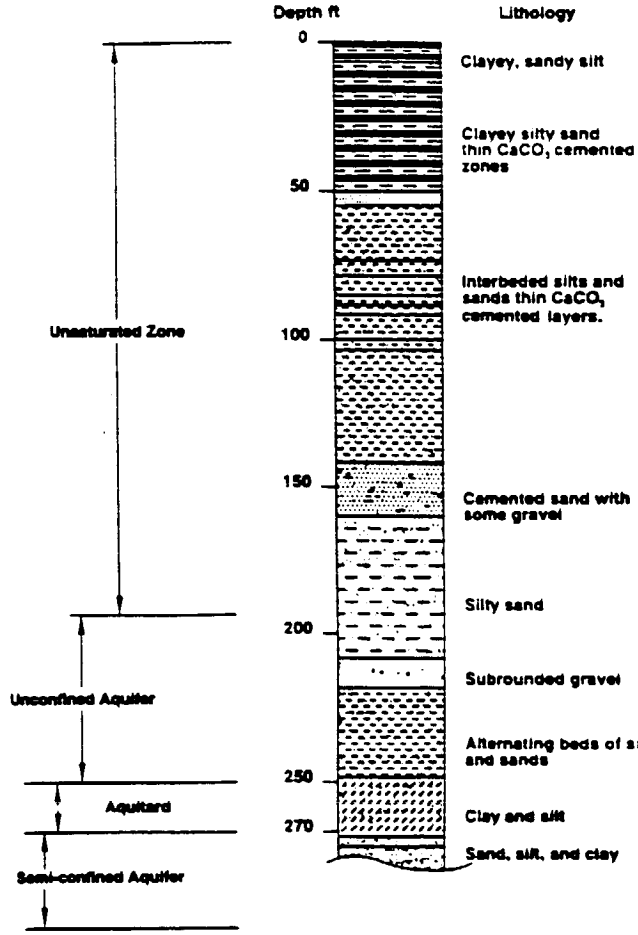

Figure 1. Hydrostratigraphic column for the study area.

collection. Recent research has shown that insertion sampling devices such as bailers, and subsequent rap sampling, results in the collection of particulate matt that is not representative of the mobile pollutant lo in the aquifer (Puls et al. 1991; Kearl et al. 1992).

Source

The first consideration was whether the nickel a chromium were naturally occurring. Typically nickel not found in uncontaminated ground water because occurs naturally chiefly as insoluble hydroxides or s fides (Allen et al. 1993), which are formed originally pH extremes. However, when dissolved nickel is intr duced to ground water via a waste stream, it can rema dissolved and mobile because of the system's neutr pH and because it can be readily desorbed from cl (Bubb and Lester 1991). In addition, the high inorgan salt content of the ground water at Williams AFB pr vides competition from other cations for available sor tion sites (Bowman et al. 1981), and chloride compl formation potentially inhibits nickel sorption (Don 1978). Chromium occurs naturally in ground water, b precipitation kinetics are so rapid and dissolutio kinetics so slow that the concentration of Cr(III) uncontaminated systems remains well below drinki water standards (Rai et al. 1989). Likewise, the tra levels of naturally occurring Cr(VI) that could b released would be reduced and precipitated (Rai et a 1989; Bartlett 1991; Puls et al. 1992; Anderson et a

Table 1
Nickel and Chromium Concentrations (1986–1993) at the Williams AFB Landfill

			Nickel				Chromium			
	Aquifer Zone	Number of Wells	Number of Analyses	Number of Detections	Range of Detections, µg/L	Average Concentration of Detections, µg/L	Number of Analyses	Number of Detections	Range of Detections µg/L	Average Concentration of Detections µg/L
Site investigation wells installed 1986–1987										
Downgradient	Semiconfined	3	34	2	7.2 to 9.8	8.5	34	5	4.0 to 5.7	5.0
Downgradient	Unconfined	1	12	4	10.6 to 30.0	18.6	12	7	4.3 to 9.2	6.6
Background*	Semiconfined	2	27	5	10.5 to 50.0	20.8	27	7	4.3 to 16.2	7.6
Total		6	73	11	7.2 to 50	17.8	73	19	4.0 to 16.2	6.5
Remedial investigation wells installed 1989–1991										
Downgradient	Unconfined	5	79	70	32 to 607	181.3	79	61	3.8 to 6020	622.9
Background	Unconfined	1	8	8	64.5 to 1320	416.3	8	8	3.8 to 11,000	2206.0
Total		6	87	78	32.3 to 1320	222.3	87	69	3.8 to 11,000	806.4

*Background wells are defined as hydraulically upgradient from the landfill.

Table 2
Nickel and Chromium Concentrations (1986–1993) at the Williams AFB Liquid Fuels Storage Area

			Nickel				Chromium			
	Aquifer Zone	Number of Wells	Number of Analyses	Number of Detections	Range of Detections, µg/L	Average Concentration of Detections, µg/L	Number of Analyses	Number of Detections	Range of Detections µg/L	Average Concentration of Detections µg/L
Site investigation wells installed 1986–1987										
Downgradient	Semiconfined	1	3	0	—	—	3	0	—	—
Downgradient	Unconfined	3	12	0	—	—	12	1	5.9	5.9
Background*	Semiconfined	2	3	0	—	—	3	0	—	—
Background	Unconfined	1	1	0	—	—	1	0	—	—
Total		7	19	0	—	—	19	1	5.9	5.9
Remedial investigation wells installed 1989–1991										
Downgradient	Unconfined	18	93	49	12.5 to 640	121.8	93	59	4.5 to 8080	294.6
Background	Unconfined	9	51	49	10.1 to 5333	395.8	51	48	4.2 to 54,500	1903.7
Downgradient	Semiconfined	2	12	9	13.0 to 566	260.9	12	12	14.9 to 198	73.9
Total		29	156	107	10.1 to 5333	259.0	156	119	4.2 to 54,500	921.4
Horizontal recovery well installed 1992										
Downgradient	Unconfined	1	14	3	4.2 to 11.6	7.2	14	1	6.5	6.5

*Background wells are defined as those consistently containing less than 5 µg/L benzene in ground water samples.

1992).

This investigation then focused on how nickel and chromium could be contributed by well construction materials. The most recent installations were performed with type 304 stainless steel, but records did not identify the type of steel nor the manufacturer for the screens used in the pre-1989 installations. However, it is likely, based both on experience and consultation with suppliers, that type 304 was used. Type 316, the only other widely available steel used in well screen, is sufficiently more expensive that a special order, likely to be documented in site records, would have been required.

Stainless steel used in well construction has enough chromium (18 percent) to offer corrosion resistance and enough nickel (8 percent) to ensure an austenite structure (a nonmagnetic, high-temperature form of iron) at room temperature. Hewitt (1993 and 1994) reported that such steel may contribute nickel and chromium in concentrations that exceed ground water standards set by the U.S. Environmental Protection Agency (U.S. EPA) under the Safe Drinking Water Act (SDWA).

Sampling Effects

To evaluate whether monitoring well construction materials were the source of nickel and chromium, several tests were performed. First, ground water samples were collected from a horizontal production well installed at the LFSA. The horizontal well is

screened at a depth of 235 feet (72 m) and is constructed with type 304 stainless steel screen and an epoxy-coated carbon steel riser. Ground water samples (filtered and unfiltered) were collected from the pump discharge line seven times during a 75-day pumping test performed at 28 gal/min (106 L/m). The results showed that nickel and chromium were not reported in concentrations exceeding 12 µg/L (Table 2).

In another test, monitoring well LF-08 (well volume = 70 gallons) was purged at 1 gal/min (3.8 L/m) for 24 hours in order to determine how the purge volume affected nickel and chromium concentrations. The pump was located 2 to 5 feet (0.6 to 1.5 m) above the bottom of the screen. Samples were collected after stabilization of pH, temperature, dissolved oxygen, and specific conductance, after the removal of three well volumes, and again after 8, 16, and 24 hours. Both filtered and unfiltered samples were collected. The concentration of nickel declined steadily throughout the test, from a high of 101 µg/L to a low of 44 µg/L (Figure 2). Such a decline is consistent with the hypothesis that nickel is an artifact of the well. The water that flowed to the well, as it was pumped, diluted the nickel released by the well itself. There was little difference in the filtered and unfiltered sample results, indicating that the nickel is dissolved or associated with particles <0.45 µm, a finding consistent with the behavior of nickel in this type of geochemical environment.

For chromium there are major differences between the filtered and unfiltered sample results (Figure 3). Filtered samples showed no detectable chromium, while concentrations in unfiltered samples ranged from 10 to 53 µg/L. The results demonstrate that chromium is associated with particulate matter. The chromium concentrations for the unfiltered samples were also affected by the method of sampling. The initial and 24-hour samples were collected with a bailer, while the samples at 8 and 16 hours were collected from the pump discharge line. The highest chromium concentrations were from the unfiltered bailed samples, a fact consistent with recent research suggesting that sampling with a bailer causes high turbidity, leading to erroneously high metal concentrations (Puls et al. 1991; Kearl et al. 1992).

Based on these results, a low-flow method of sampling was used for the September 1993 quarterly sampling (Puls et al. 1991; Kearl et al. 1992). A piston pump was placed in the middle of the saturated interval, unlike previous sampling events where the pump was placed 2 to 5 feet (0.6 to 1.5 m) above the bottom of the screen. The wells were purged at a rate of 0.26 gal/min (1 L/m) until turbidity stabilized at a value <10 nephelometric turbidity units (NTUs), and pH, conductivity, dissolved oxygen, and temperature stabilized to within 10 percent. No minimum purging volume was used. Samples were not filtered and were collected directly from the piston pump discharge hose. For this test, the average concentration for nickel (Table 3) is greater than the average for wells from previous sampling rounds (307 µg/L vs. 259 µg/L). This variation in concentration may be a result of moving the pump. The result may also indicate that

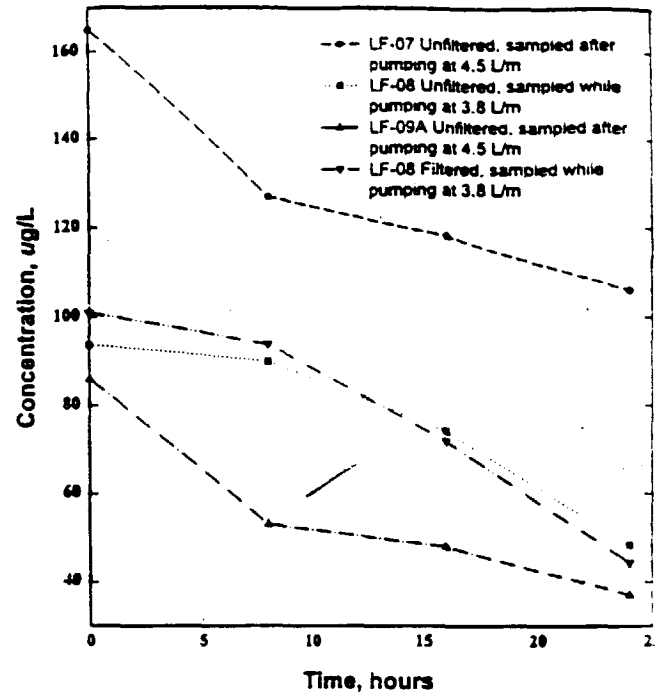

Figure 2. Variation of Nickel concentrations while pumping at 1 gal/min (3.8 L/m). (LF-08 sample at 0 and 24 hours were bailed, and at 8 and 16 hours were collected with a pump).

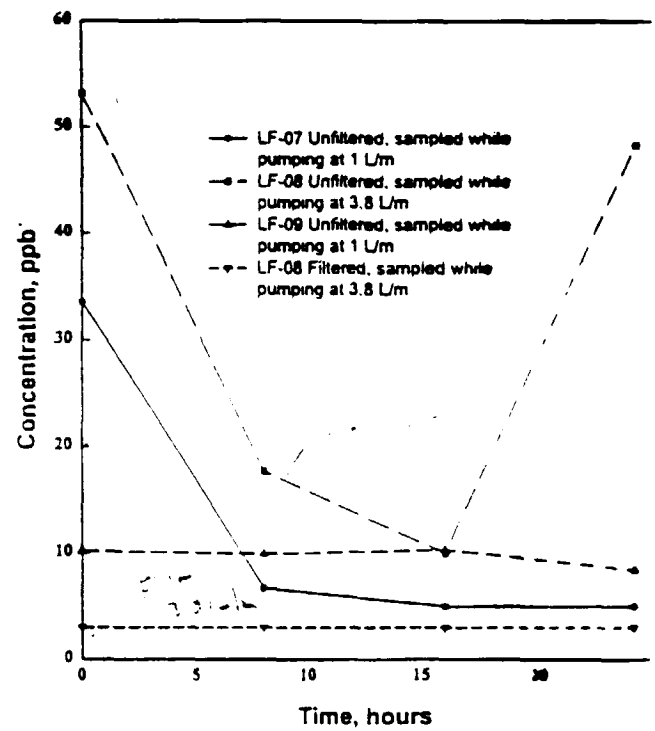

Figure 3. Variation of Chromium concentrations while pumping at approximately 1 gal/min (3.8 L/m). (LF-08 sample at 0 and 24 hours were bailed, and at 8 and 16 hours were collected with a pump).

low-flow purging did not produce enough water to dilut the dissolved nickel near the well. Instead, with low-flo purging, dilution is minimized, and the concentrations ar the highest. In contrast, the average chromium concentra tion was 131 µg/L (Table 3), well below the historic average of more than 900 µg/L. The large difference i concentration indicates that low-flow purging combine

with sampling from the pump significantly reduced the collection of colloidal chromium relative to previous sampling rounds. It had previously been noted that high-volume purging with sampling directly from the discharge hose produced samples with low turbidity. Thus, it was concluded that high-volume purging combined with sampling from the pump discharge should produce the lowest nickel and chromium concentrations in the ground water samples.

Table 3
September 1993 Low-Flow Purging and Sampling

Well ID	Nickel, µg/L	Chromium, µg/L
Landfill		
W-12	201	75.9
W-08	118	182
W-07	117	515
W-09A	304	111
W-11	528	208
W-10	631	141
Average	317	206
LFSA		
W-25	170	44.8
W-26	914	76.6
W-27	533	181
W-19	62.2	26.1
W-17	60.8	88
W-14	547	149
W-11	26.2	16.2
W-07	ND	ND
W-10	87.1	17.2
Average	300	75
Overall average	307	131

Consequently, additional 24-hour pump and sampling tests were performed on LF-07 and LF-09A. The wells were purged at 1.2 gal/min (4.5 L/m) with the pump intake located in the center of the screen section. The flow rate was reduced to 0.26 gal/min (1 L/m) while sampling and field parameters stabilized prior to all sampling. Unfiltered samples were collected at three well volumes and at 8, 16, and 24 hours. For LF-07, as expected, nickel concentrations declined throughout the test from a high of 165 µg/L to a low of 106 µg/L (Figure 2). Chromium concentrations also declined throughout the test from a high of 34 µg/L to a low of less than 5 µg/L (Figure 3). For LF-09A, similar results were observed. These results are consistent with the low concentrations of nickel and chromium (<12 µg/L) observed in the horizontal well during the 75-day pumping test.

Corrosion Mechanisms

These data demonstrate that the behaviors of nickel and chromium are consistent with their being contributed by the well construction materials. Two questions remained, however:

1. What are the probable corrosion mechanisms, and would these mechanisms be promoted by site conditions?
2. What is the difference in well installations so that the more recent installations promote corrosion and the pre-1989 ones do not?

All steel is susceptible to pitting and crevice corrosion when exposed to aqueous solutions containing aggressive anions such as chloride. Either mechanism involves oxidation of the corroding material and reduction of a constituent of the corrosive environment (Lula 1986).

Pitting

Predicting when pitting will occur is difficult because heat treatment, surface condition, and fabrication procedures (e.g., time, temperature, polishing) may change the response of the steel from relative inertness to unacceptable reactivity (Lula 1986; Szklarska-Smialowska 1986). These facts suggest that the preparation of the steel is a possible explanation of why well screens of the same composition installed at Williams AFB could differ in their resistance to corrosion.

Crevice

Localized attack in natural waters is usually not due to pitting but to crevice corrosion (Kain et al. 1984), which is associated with stagnant solution found in narrow gaps such as joints between two metal parts and badly executed welds. Because of the immobility of the solution in the crevice, exchange with the bulk solution is relatively slow. Metal inside the crevice acts as an anode, while the remaining metal surface in contact with the bulk electrolyte acts as a cathode. The anodic dissolution of metal in the crevice leads to local accumulation of metal cations. To maintain neutrality, anions (primarily Cl^-) migrate from the bulk electrolyte into the crevice. Because of the hydrolysis of the metal, acidity increases and the protective film breaks down.

Kain et al. (1984) examined the susceptibility to corrosion of both type 304 and 316 steels. The tests showed that, in natural waters of a composition similar to that found at Williams AFB (pH of 7.5, Cl^- up to 600 ppm), type 316 was resistant to crevice corrosion. Type 304, on the other hand, would corrode under conditions of severe (tighter and deeper) crevice geometry. Exposure time, however, had little effect on promoting additional corrosion. Tests in simulated Colorado river waters and other natural waters identified crevice corrosion for type 304 at Cl^- contents as low as 100 ppm. However, this steel was also resistant in 90 percent of the cases where Cl^- was between 100 and 1000 ppm.

Thus, minor variations in the crevice gap, especially in the 0.1 to 1 µm range, can have greater significance than variations in bulk environmental chemistry (Old-

field and Sutton 1980; Kain 1990).

Condition of the Well Screens

Several well contractors were consulted regarding the quality of typical, wire-wound stainless steel well screens. Seven suppliers were identified. The cost of flush joint, threaded screen that is cleaned and prepackaged varied from approximately $28 to $56 per foot. Interviews with several experienced well contractors revealed that screens from one supplier were typically uniformly polished with welds that were typically tight and intact. In contrast, screens from some of the other suppliers often contained bends and broken welds. At Williams AFB, it is known that the 1990–91 screens were provided by one of the manufacturers whose screens were described as sometimes having imperfect welds.

Conclusion

It is concluded, therefore, that crevice corrosion in stainless steel wells is the source of nickel and chromium found in ground water samples collected at Williams AFB. Moreover, the difference in quality of the stainless steel wells and screens between two manufacturers is believed to be the reason that one set of wells produced significant chromium and nickel in ground water, while another set did not. Finally, the data demonstrate that the sampling method significantly affects the concentrations of chromium and nickel observed. Sampling with a bailer yields higher chromium concentrations because more particulates are collected. Low-flow sampling with micropurging yields the highest nickel concentrations because there is less dilution, but chromium concentrations are low because fewer colloids are collected. High-volume purging prior to sampling from the pump discharge produces the lowest chromium and nickel concentrations because dilution is increased and particulate collection is minimized.

Acknowledgments

The authors acknowledge the assistance of the three anonymous reviewers who provided helpful comments on the original draft of this manuscript.

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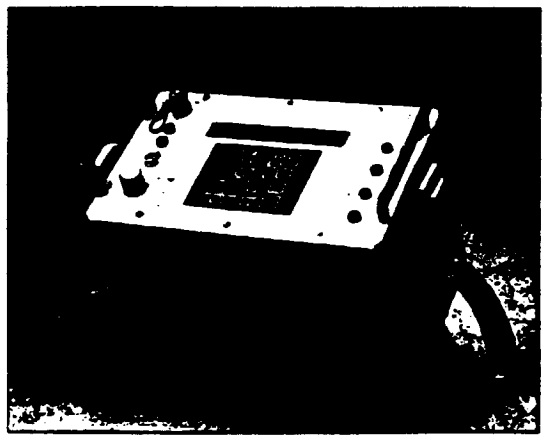

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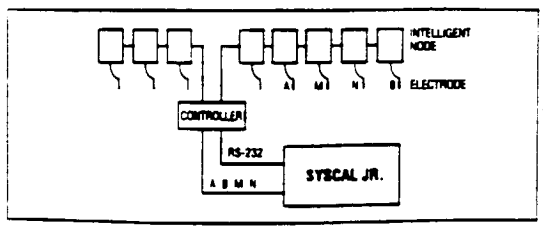

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ATTACHMENT C

REVIEW COMMENTS ON DRAFT QUARTERLY GROUNDWATER MONITORING REPORT FOR MCAS EL TORO

1. Technical Comments

1.1. AIR ENTRAINMENT

In Appendix D the report notes that air entrainment in water collected at selected locations as reported by DTSC in 1993 has been confirmed. The issue of air entrainment in the discharge of 4-inch well pumps appears to have been deferred to the "...well pump maintenance activities." It is not clear what the intent of this statement is. Please provide detail as to what the next actions are with respect to this confirmed problem.

1.2. DISSOLVED METALS

Table 7-1. Inspection of the data indicates that significant increases in the measured concentrations of several metals have occurred. Of particular interest are chromium and iron which in some cases increased by over two orders of magnitude. A brief review indicates that there is often a strong relationship between these two analytes. In unfiltered samples, iron levels are approximately 10 times the chromium levels. This situation should be examined in detail since the elevated chromium levels are significant. A recent publication, 1996 Winter Ground Water Monitoring Review pp. 93-99, "Nickel and Chromium in Ground Water Samples as Influenced by Well Construction and Sampling Methods," provides an excellent reference on this phenomenon. The authors should examine the potential reasons for the apparent increase and provide an explanation of the situation in the final report. Crevice corrosion in the stainless steel wells may be the source of the chromium; however, modifications to samplings technique may be successful in alleviating the inclusion of corrosion releases into the samples. The filtered and unfiltered samples are an excellent source of information for the examination of the effect of colloids on the measured metals values. It appears that the effect of filtering was significant for only these two metals.

1.3. DISSOLVED OXYGEN

The measured dissolved oxygen levels listed in Appendix C are often in excess of the theoretical maximum for natural waters. The solubility of oxygen for water exposed to water-saturated air at atmospheric pressure and no salinity ranges between 9.7 and 8.1 mg/L between 17 and 26°C respectively. Moreover, with increasing salinity the solubility of oxygen decreases. See the table below.

Dissolved Oxygen Relationships Standard Methods, 17th Ed. 1989

Temperature, °C	Dissolved Oxygen, mg/L Chlorinity = 0	Dissolved Oxygen, mg/L Chlorinity = 10
17	9.7	8.7
18	9.5	8.5
19	9.3	8.3
20	9.1	8.2
21	8.9	8.0
22	8.7	7.9
23	8.6	7.7
24	8.4	7.6
25	8.3	7.5
26	8.1	7.3

At least 25 percent (43 out of 163) of the reported dissolved oxygen values for MCAS El Toro are in excess of the theoretical maximum. A closer examination of these data is required because a substantial proportion of the other measurements are at or very near saturation. This situation does not appear likely given that the Marine Corps' geochemical model for the station proposes that substantial pyrite oxidation is occurring throughout the vadose and saturated zone. Therefore it can be expected that oxygen consumption during pyrite oxidation would reduce dissolved oxygen values to levels noticeably less than those reported. This decrease does not include further reductions due to the consumption of dissolved oxygen by reaction in the organic-rich layers of the surface soils. Freeze and Cherry (Groundwater, 1979; p. 245) have noted that in recharge areas of silty or clayey soils, groundwater commonly does not contain detectable dissolved oxygen. Thus, the predictions and expected conditions do not support the measured dissolved oxygen values and the data collection techniques should be reexamined to ensure that proper procedures were followed and instrument calibrations were verified.

ATTACHMENT D

MICROBIOLOGICALLY INFLUENCED CORROSION OF AUSTENITIC STAINLESS STEEL WELDMENTS

Microbiologically Influenced Corrosion of Austenitic Stainless Steel Weldments[1]

Susan Watkins Borenstein
Pacific Gas & Electric Co., One California St., San Francisco, CA 94106

Microbiologically influenced corrosion (MIC) of austenitic stainless steels often occurs at weldments and may be misdiagnosed as attack resulting from conventional chloride or crevice corrosion. Examples with photomicrographs of MIC at weldments made with various stainless steel base metals and weld metals are given.

Microbiologically influenced corrosion (MIC) is the term used for the phenomenon in which corrosion is initiated or accelerated or both by microorganisms. Costly pitting failures of austenitic stainless steel components by MIC have occurred at locations ranging from power generating to chemical processing plants. MIC commonly results when water is left in stainless steel systems after hydrotesting. While these conditions do not usually produce serious corrosion problems, they are conditions ideal for MIC.

Water may contain several classes of microorganisms. These organisms immediately begin colonizing and produce a biofilm when exposed to a metal surface. This film, usually nonuniform in its coverage, acts as a concentration cell and promotes corrosion. In addition, the metabolic processes of the microorganisms can influence the corrosion behavior of materials by (1) destroying protective surface films, (2) producing a localized acid environment, (3) creating corrosive deposits, or (4) altering anodic and cathodic reactions, depending on the environment and organisms involved.[1] These processes may occur either alone or in combinations.

For austenitic stainless steels, the characteristic MIC visual signs typically may include pitting at or adjacent to welds, pitting with a small surface opening and a large subsurface cavity, discrete localized deposits, and reddish-brown rust-colored mounds or tubercles.[2] Fresh deposits may appear slimy and have distinctive odors.

In addition, during metallographic examination sometimes preferential attack of stringers, or one phase of the two-phase weld, is found. Either the austenite or the ferrite phase or both may be attacked. Chlorides are sometimes found in a pit, even when the exposure was to extreme good low-chloride water.

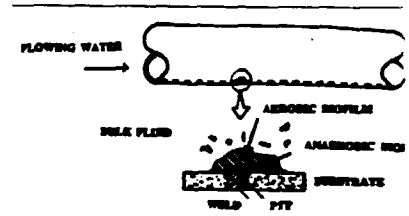

FIGURE 1
A mound at a weldment with a biofilm formed the inside surface with a pit underneath.

For reasons not well unde stood, MIC often occurs ne weldments. Figure 1 depicts mound at a weldment, a biofil formed on the inside surface of pipe weld, and a pit beneath th mound.[3] Figures 2 and 3 sho other common occurrences: pi ting at the heat-affected zon (HAZ), pitting at the fusion lin and pitting in the base metal ne the weld.

There may also be variation on a theme. MIC and stress corr sion cracking (SCC) at a weldmer have occurred; Figure 4 show sensitization and MIC. For reason not known, MIC often occurs i combination with either SCC o sensitized structures at weldment in austenitic stainless steels. Mor importantly, conditions resistan to SCC or material resistant to sen

[1]Presented to NACE Task Group T-5A-28, CORROSION/90, Las Vegas, Nevada.

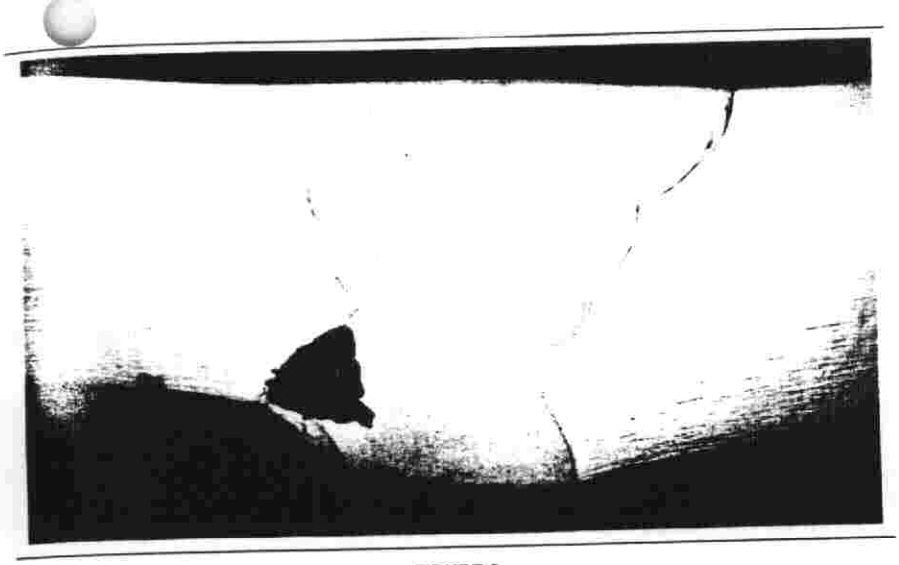

FIGURE 2
Cross-section of weld showing pitting at the fusion line and pitting in the base metal near the weld. (Original magnification 5X.)

FIGURE 3
Cross-section of weld showing pitting at the weld extending into the heat-affected zone. (Original magnification 5X.)

FIGURE 4
Cross-section of area near a weld showing pitting and a sensitized structure. (Original magnification 250X.)

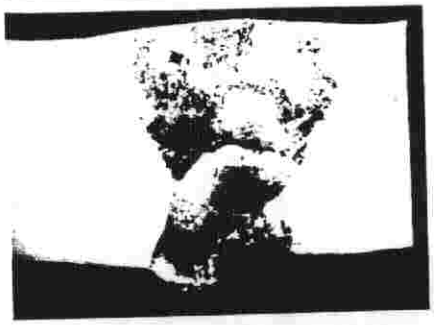

FIGURE 5
Cross-section of weld showing pitting at the weld of type 304L base metal and type 308L filler metal. (Original magnification 5X.)

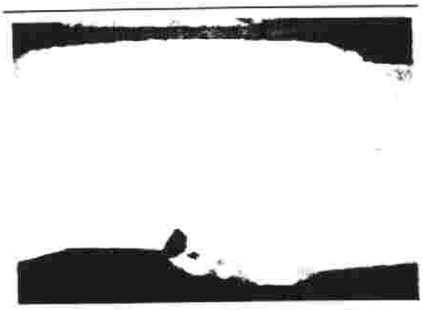

FIGURE 6
Cross-section of a weld showing pitting at a weld of type 316L metal using type 308L filler metal. (Original magnification 5X.)

FIGURE 7
Cross-section of weld showing pitting at the weld of type 316 base metal and type 316 filler metal. (Original magnification 5X.)

sitization are susceptible to failure by MIC. Resistance to SCC or sensitization is not sufficient to make a structure resistant to MIC.

Various combinations of common austenitic stainless steel base metals and weld metals are susceptible to MIC. These include type 304L (UNS S30403) base metal using 308L (UNS S30803) filler metal (Figure 5), type 316L (UNS S31603) base metal using 308L weld metal (Figure 6), and 316L using 316L (Figure 7).

Weldments made with various base metals (types 304L and 316L) and weld metals (types 308L and 312 [UNS S31200]) with different ferrite contents are susceptible to MIC.[4] These include 304L base metal using 308L filler metal with low ferrite, 304L base metal using 308L weld metal with medium ferrite, and 304L using 312 with high ferrite. Interestingly, additional sections of each combination that were solution annealed and pickled were found by field testing not to be susceptible to MIC. The so-

lution annealing and pickling may produce a component with less susceptibility to corrosion.

Additional conditions that appear to be susceptible to MIC include heat tint on a surface near a weldment, poor joint fit creating a discontinuity at the joint, poor quality welding, such as lack of penetration at the root, gouges or grinding marks, and residual stress.

In summary, we know the following:

- MIC often occurs near weldments in austenitic stainless steels. The pitting may be in the weld, in the HAZ, along the fusion line, or in the base metal near the weld. Either or both phases, austenite and delta ferrite, may be susceptible to MIC. In general, two-phase microstructures are less corrosion resistant than single-phase structures.
- Various combinations of austenitic stainless steel weld metals and base metals have failed by MIC. Matching filler metals, higher alloyed filler metals, and lower alloyed filler metals have all experienced failures by MIC.
- Weldments made with various amounts of ferrite content (low, medium, and high) to both 304L and 316L base metals have all experienced failures.
- SCC is sometimes found in combination with MIC in failures of austenitic stainless steel weldments.
- Sensitization is sometimes found in combination with MIC in failures of austenitic stainless steel weldments.
- Solution annealing and pickling may produce welds that are less susceptible to MIC.
- Surface conditions that are com monly associated with poor co rosion resistance, such as he tint, may produce conditio that are susceptible to MIC.
- Surface conditions that are com monly associated with residu stresses, such as gouges, ma produce conditions that are su ceptible to MIC.

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ATTACHMENT E

SOME EXPERIENCES WITH MICROBIOLOGICALLY INFLUENCED CORROSION OF PIPELINES

Some Experiences with Microbiologically Influenced Corrosion of Pipelines

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A condensed version of the author's experience with microbiologically influenced corrosion (MIC) of gas and liquid hydrocarbon pipelines is presented. Details of case histories and laboratory and field trials, and considerations in detection, monitoring, and mitigation of MIC in the pipeline and natural gas storage field industries are discussed.

Microbiologically influenced corrosion (MIC) is corrosion that is influenced in some way by the presence and activities of microorganisms or their metabolites. It almost always acts in concert with other corrosion mechanisms and may, at times, appear to be crevice corrosion, underdeposit acid attack, oxygen concentration cell corrosion, ion concentration cell corrosion, carbon dioxide (CO_2) corrosion, etc. MIC of most industrial metals and alloys has been reported.[1,2] Mechanisms for MIC, methods of detection and monitoring, and mitigation strategies have been the subject of numerous articles.[1-7]

Adapted from a paper originally presented at the NACE South Central Region Conference in Wichita, Kansas, October 1994.

Examples of MIC in Pipeline Industry

Figure 1 gives an example of MIC on the external surface of a pipeline. Almost all cases of MIC on external surfaces are associated with disbonded coatings or other areas shielded from cathodic protection (CP). Often, the pipeline is in contact with wet clays which have little scaling potential. This situation is thought to create a condition in which the demand for CP continues at a high level over long periods of time and in which CP may not be distributed equally over the surface of holidays and surrounding disbondments. This may allow microbes to colonize and initiate corrosion at some sites. Whether CP can reverse this condition after it has initiated is still unknown.

Figures 2 and 3 are cases of MIC on internal surfaces of pipelines. A very high percentage of cases of internal MIC occur at locations in the

FIGURE 1
Disbonded pipeline coating associated with localized, external MIC.

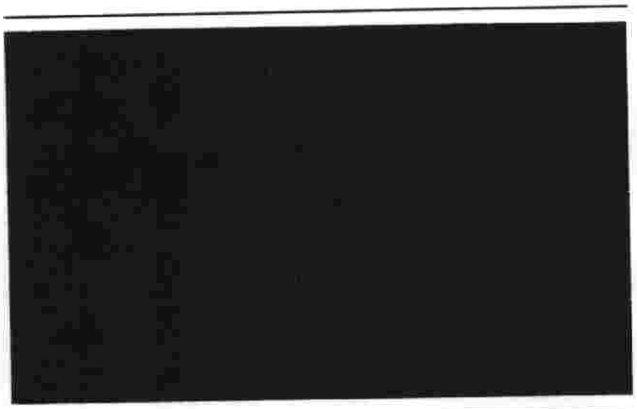

FIGURE 2
Internal MIC of a natural gas pipeline.

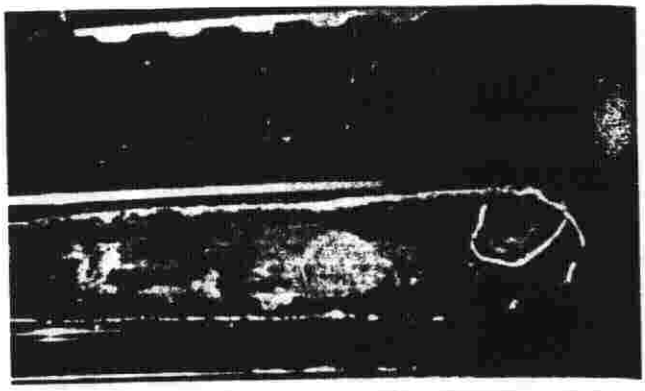

FIGURE 3
Internal MIC of a liquid hydrocarbon pipeline.

pipeline where water, salts, microbes, and nutrient sources (hydrocarbons and detritus) are in contact with the steel for extended periods of time (for example, at low points or drips). In these locations, colonization by microorganisms can occur, with corrosion initiated by microbes or by other mechanisms (for instance, CO_2). This is usually followed by several mechanisms operating in concert to produce a pitting-type corrosion.

Microbes Involved in MIC

Most types of microbes in waters or soils have the potential to participate in MIC of some type of metal or alloy.[3,4] MIC of pipelines has been documented as involving aerobic, anaerobic, slime-forming, acid-producing, sulfate-reducing, nitrate-reducing, iron-oxidizing, and iron-reducing bacteria. Within each of these general physiological groups are hundreds of individual species of bacteria. MIC is almost always due to the action of microbiological communities containing many different types of microbes. The composition of the community changes with each stage in the development of a MIC site and from one location to another. Figure 4 demonstrates colonization of a surface over a 12-day period and shows that colonization is not uniform, thereby creating the potential for differences in conditions under

TABLE 1
Mechanisms Potentially Involved in Cases of MIC

Mechanism	Description
Cathodic depolarization	• The classic mechanism for MIC of steel and iron proposed by von Wolzgen Kuhr in 1934. • This mechanism is based on the idea that the rate-limiting step in corrosion is the dissociation of hydrogen from the cathodic site. • It is thought that sulfate-reducing bacteria (SRB) consume hydrogen through the action of their hydrogenase enzymes, and thus "depolarize" the cathode, accelerating corrosion. • Some investigators still believe that this mechanism is the important one for MIC of iron and steels, despite the fact that numerous experiments using SRB in pure culture gave corrosion rates far less than those seen at field sites and less than those measured in experiments using MIC communities.
Formation of occluded area on metal surface	• This mechanism is based on the observation that when microorganisms form colonies on the surface of a metal, they do not form uniform layers, but rather, local "community centers." • The sites chosen for initial colonization may be related to such metallurgical features as roughness, preexisting corrosion sites, inclusions, or surface charge. • Once the colony has formed, it produces sticky polymers which tend to attract and aggregate other biological and nonbiological (metals and chloride, for example) species to the colonization sites. • This, in addition to the metabolism of available oxygen, iron, manganese, etc., results in conditions within and under the colonies very different from those on the surrounding metal. • This leads to the formation of crevices and oxygen and ion concentration cells, allowing corrosion to proceed.
Fixing the anodic sites	• This parallels the development of the occluded cell. The presence and activities of the microbes creates a condition under the colony in which incipient pitting leads to pitting driven principally by microbiological activities. • This is made possible by the fact that most of the microbiological community usually remains fixed to the colonization site (although progeny may find other colonization sites). • This causes the anodic site to become "fixed." This is a principal reason for the fact that more than 90% of MIC is seen as pitting-type corrosion.
Underdeposit acid attack	• Most of the final products of MIC community metabolism are short-chain fatty acids (acetic acid is the most common). • Acetic acid is very aggressive to carbon steel when concentrated under a colony or other deposit. • This is the case both at field sites and in the laboratory.

FIGURE 4
Colonization of steel surface after (a) 1 day, (b) 3 days, and (c) 12 days of exposure to tap water.

the MIC community and on the relatively bare surrounding metal.

MIC Mechanisms

We have proposed a general model for the development of MIC (Figure 5).[5] Initial attachment of microbes may be related to preexisting corrosion, metallurgical factors (weld, inclusion, etc.), or other local conditions. This model predicts that simple chemical treatment to kill microbes will not solve the corrosion problem once it is in the advanced stages, but rather, mechanical cleaning, chemical cleaning, chemical treatment, or some combination of all three are required.

Listed in Table 1 are the mechanisms thought to be among those potentially involved in cases of MIC. This is not meant to be an exclusive list, but rather a listing of important mechanisms for which there is documented evidence from laboratory and field studies.

Detecting and Monitoring MIC

A variety of methods have been used or proposed for use in the detection/diagnosis of MIC and for online monitoring. A review of these methods' advantages and disadvantages in the pipeline industry has been published.[7] The following is a presentation of those methods which have proved useful to the author and co-workers in research and consulting work on pipelines.[5-7]

Viable culture tests can determine the types and numbers of microbes present in samples. Performed correctly, these tests are simple and quantitative. Viable culture tests should be done immediately after sample collection. The samples must be processed carefully to avoid killing microbes of importance to a proper diagnosis. Detailed procedures for sample collection and processing are given by Pope.[7] Certain field sampling and culture kits also

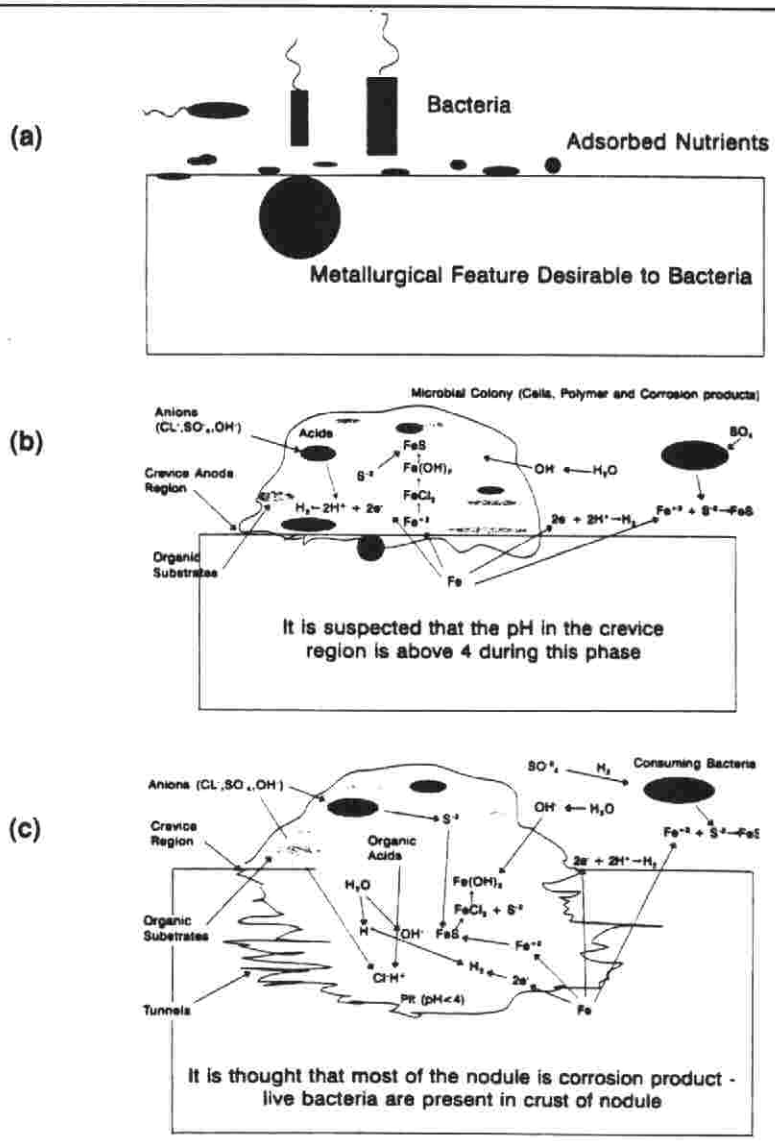

FIGURE 5
MIC development model. (a) Phase 1. Recognition of desirable sites. (b) Phase 2. Colony formation and crevice corrosion begins and anode is fixed. (c) Phase 3. Nodule is formed over "mature" pit.

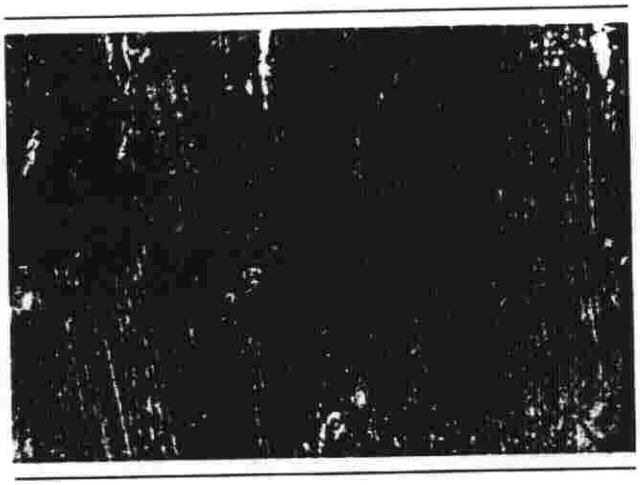

FIGURE 6
Surface pit showing corrosion product in pit.

FIGURE 7
Same pit after cleaning with a nylon brush (note cup-like pits inside large pit).

provide detailed instructions for sample collection, processing, and interpretation.

Monitoring MIC in the laboratory is quite different from that in actual pipelines.

Microscopic examination of samples can be done on-site or later. The sample can be examined using a light or fluorescence microscope after staining with a dye that attaches to biological materials. Specific types of microbes in samples can be detected using fluorescently labeled antibody probes. These techniques require the use of a relatively expensive microscope and a trained observer, but they offer considerable useful information regarding the numbers and types of microbes in the sample, their physiological status, and their relationship to the corrosion site or products.

Because the presence of certain chemical species is indicative or supportive of the diagnosis of MIC, chemical characterization of the corrosion products is important. For example, the presence of ferrous iron, sulfide, and low pH and the absence of carbonate and calcium at an external corrosion site would support the diagnosis of MIC. This should be confirmed by microbiological culture and metallurgical characterization of the site, along with consideration of the conditions (coating, CP, soil, etc.) at the site. Qualitative tests for such chemical species as sulfide, ferrous iron, and pH should be done immediately after sample collection; otherwise, changes in the chemical species or pH can occur. These tests can be done in the field using simple, rapid, and inexpensive techniques and commercially available test kits.

Metallurgical characterization of the potential MIC site should be done in the field, if possible. Some guidelines are available that may assist metallurgical examination.[8,9] Examples of metallurgical features associated with an underdeposit acid attack form of MIC are shown in Figures 6 and 7.

Monitoring MIC in laboratory settings is quite different from that in actual pipelines. The author and colleagues involved in research for various clients have concluded that a monitoring program should include determination of as many of the following characteristics as possible.

Monitoring Internal Sites

When monitoring for MIC at internal sites, one should determine local conditions, including the presence of water and water quality (pH, presence of salts, CO_2, sulfides, etc.), viable microbes in liquids and especially on metal surfaces, and operational conditions (pipeline pigging, treatment with corrosion inhibitor and biocides, etc.). It is critical that coupons used in monitoring be of the same metallurgy and surface condition as the pipe itself. Polished coupons will rarely be colonized or corroded in the same way or to the same extent as mill-finished coupons. It is also crucial that the coupons be located where conditions are conducive to the development of MIC, that is, the worst-case conditions for the pipeline under consideration.

Coupons used for MIC monitoring should be removed and processed immediately using culture and microscopic examination for microbes and corrosion.[7] An attempt must be made to correlate the presence and activities of microbes to corrosion; simply the presence of microbes in a sample is rarely sufficient to prove MIC involvement in the corrosion events at the site.

Monitoring External Sites

For external sites, soil chemistry, conditions of coating, and levels of CP should be monitored as best possible. This might be done using coupons with coatings, holidays, CP, etc.[7]

Mitigating MIC

Mitigation of internal MIC must be done only after careful monitoring and consideration of the local situation; otherwise, considerable time and money can be spent performing unnecessary treatment or possibly

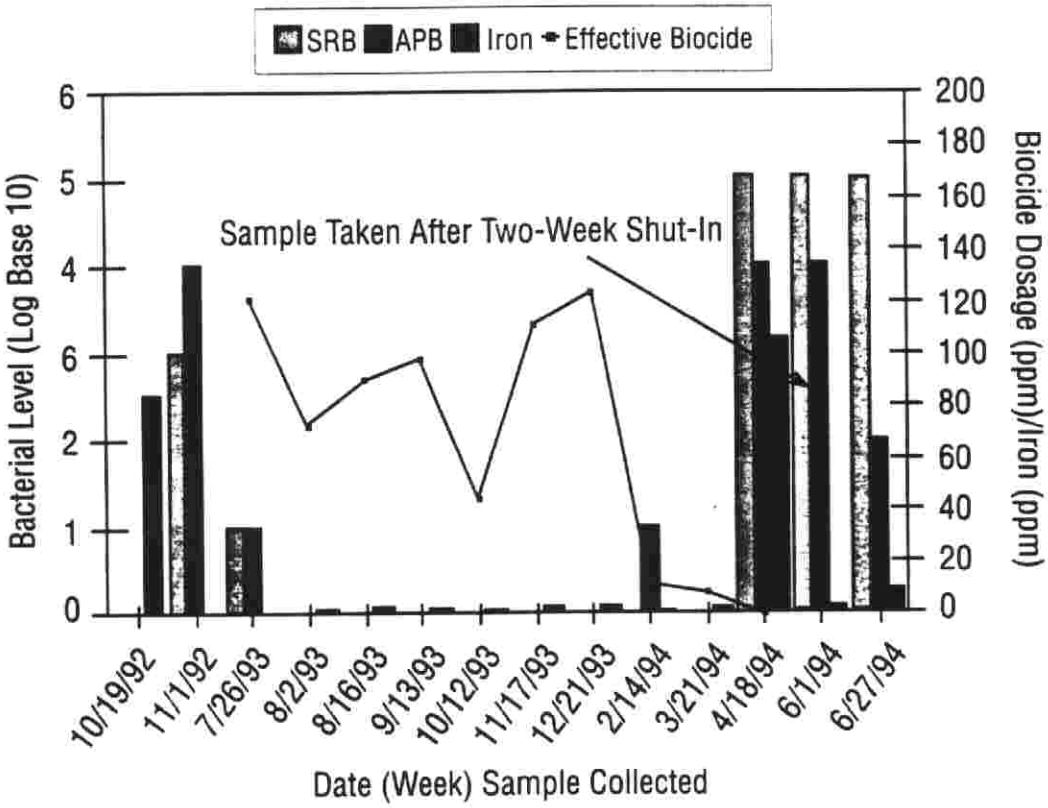

FIGURE 8
Data for a well at a gas storage field after treatment with an effective biocide. Note the effects of discontinuing treatment during a shut-in.

undertreating the pipeline. A more detailed discussion of mitigation methods, their application, and monitoring of treatment success has been published.[7]

Physical Methods

If possible, pigging, especially with the aid of a cleaning agent such as alcohol during the first few runs, appears to be an effective means of combatting MIC and other forms of internal corrosion. Pigging is effective because it disturbs the corrosion sites and removes water, microbes, corrosion products, and food for microbes. It also allows treatment chemicals access to the area of active corrosion in the pits, which gives them a better chance to do their job.

Chemical Methods

Corrosion inhibitors and biocides can be useful in combatting MIC, especially in preventing MIC from becoming established. However, it is imperative that treatments be tested on actual samples, including metal surfaces, from the sites to be treated, to determine whether the treatment regime will work there and to avoid overtreating. Details of field tests and methods of testing mitigation measures have been reported.[7,9]

Significant incompatibilities can exist between corrosion and scale inhibitors and some biocides. These must be checked before chemical treatment is implemented.

Chemical treatments can be used with great success and economy, and minimal exposure of the environment and personnel if the principles of targeted treatment, optimization, and minimization are followed. This requires finding the sources of the microbes, water, etc., and applying treatment as close to the source as possible using the minimum amount of biocide or corrosion inhibitor necessary. This must be followed by aggressive monitoring to make sure that the treatment continues to work.

Targeted treatment was used in an offshore, 30-location production, gathering, and transmission system that suffered from MIC. Two platforms were found to contribute most of the microbes to the system. Treating the separators on these platforms resulted in clean-up of the entire system, with a large decrease in MIC problems and cost of treatment.

Figure 8 shows the results of treatment at a gas storage field well with an effective biocide and the effects of discontinuing treatment during a shut-in. This graphic also demonstrates the utility of continued monitoring to optimize treatment.

Another biocide, a quaternary amine (QA), used at the same field

failed to control microbes in the fluid phase; however, on fresh metal surfaces, the QA formed a film that apparently discouraged microbiological colonization of the metal surface and subsequent corrosion. The reasons for this are under study, as are attempts to optimize the use of such chemicals to combat MIC. This has important industrial implications because QA biocides also inhibit other corrosion mechanisms and are much more environmentally benign than other effective biocides.

Conclusion

MIC is a type of corrosion attack influenced by the presence and activity of microorganisms. It almost always acts in concert with other corrosion mechanisms, and at times may appear as other types of corrosion attack. For external MIC, relationships of local environmental conditions and CP levels are important. For internal MIC, relationships regarding fluids chemistry, flow conditions, and physical and/or chemical treatments must be investigated. Involved in MIC are surface-associated microbiological communities; these may include slime-forming, acid-producing, and sulfate-reducing bacteria, among others. It is important to review and analyze all chemical, biological, operational, and metallurgical information when a diagnosis of MIC is made. Treatment of systems should be targeted as close to the source of microbes as possible.

Acknowledgments

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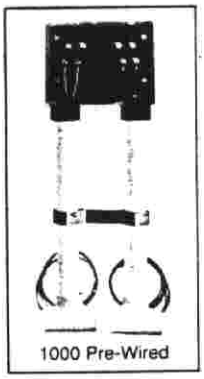
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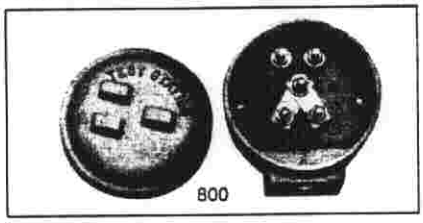
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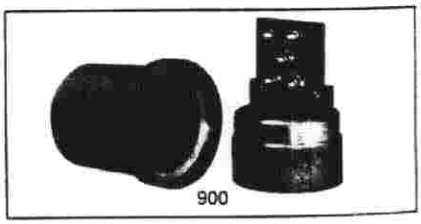
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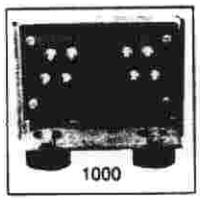
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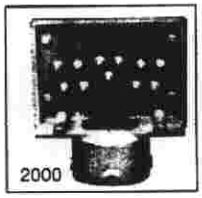
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May 1995 • Volume 34 • Number 5

About the Cover
MIC deposits removed from a seam weld in a stainless steel tank (which had been exposed to stagnant well water) reveal pits confined primarily to weld metal.

Photo source:
A Practical Manual on Microbiologically Influenced Corrosion.
(See update on NACE's best-selling book on page 66.)

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ATTACHMENT F

MICROBIOLOGICAL AND ELECTROCHEMICAL TYPES OF CORROSION: BACK TO BASICS

Microbiological and Electrochemical Types of Corrosion: Back to Basics

John G. Stoecker II
Stoecker & Associates, 740 Penny Court, Manchester, MO 63011

The topographic characteristics of electrochemically corroded metals and alloys are classified with respect to the types of corrosion. Case histories demonstrate that chemical environments can produce the same topographic characteristics as microbes with or without microbiological involvement. The causes of this electrochemical and microbiological corrosion are examined from the perspective of thermodynamic energy exchange.

Fifteen years ago, papers and presentations on microbiologically influenced corrosion (MIC) created various reactions of disbelief. The hostile respondents usually pointed out that the MIC damage being shown was typical of damage done in a specific chemical environment on the metal or alloy under consideration. Those of us whose primary focus was corrosion by chemical environments knew this to be true, but fortunately, many of us maintained an open mind to other possibilities. In this article, several cases of "look-alike" MIC and chemical corrosion are reviewed to point out the differences that led to the conclusion of cause.

Today MIC is a legitimate field of study in the overall task of combating corrosion. The fear is that our MIC roots have been forgotten in this rapidly expanding and very lucrative field of study. This fear was reinforced recently by several authors who used the term "classic" when referring to damage attributed to MIC. This author has never found a classic case of MIC in 15 years of study.

Thermodynamics

Most metals exist in their natural state as compounds (oxides, carbonates, sulfides, etc.). This is their thermodynamically stable state. Humans dig these compounds out of the ground, use energy to extract the metal, and then make it into useful items.

Using iron as an example:

Hematite (iron oxide plus impurities) + coke (carbon) + limestone (removes impurities) + energy = Fe (iron as metal) + carbon monoxide/dioxide + slag (impurities) (1)

Iron is extracted from one of its ores, hematite. Coke is the source of carbon that removes the oxygen from the iron, and lime is used to remove impurities, leaving the iron with approximately 4% residual carbon. The main point to consider in this equation is the energy necessary to remove the metal from its ore.

If these metals are exposed to a natural environment, they will revert to their natural state by corroding to form compounds. Corrosion is possible only if its products are more thermodynamically stable than the reactants. Most corrosion reactions are electrochemical, and this discussion is restricted to this phenomenon.

Types of Corrosion

The cases that follow are intended to supplement the examples presented by C.P. Dillon of the several forms where look-alike MIC and chemical corrosion have been identified.[1]

General Attack

Figure 1 shows a 1/2-in. (1.27-cm)-diam copper pipe that has suffered general attack because of exposure to ammonium sulfate and moist air.[2] Ammonium sulfate was sprayed on a wooden structure as a fire retardant. Copper lines were then attached to the bottom of the coated floor joists in a very damp crawl

FIGURE 1
General attack of 1/2-in. (1.27-cm)-diam copper pipe.

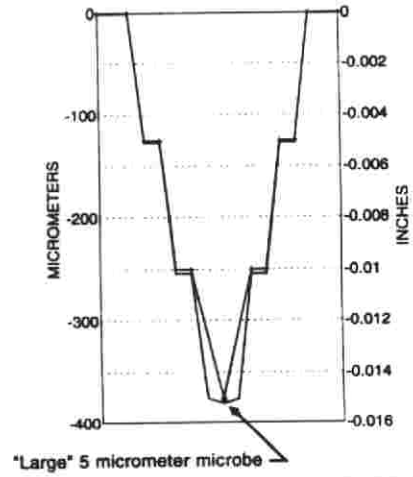

FIGURE 2
Microbe's view of surface defects of various depths.

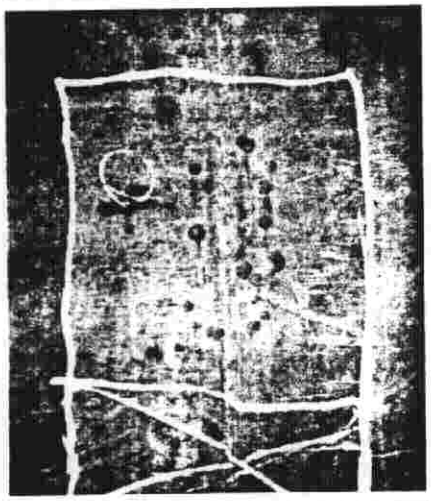

FIGURE 3
Typical deposits associated with a vertical seam weld inside a type 304 SS demineralized hot water tank. Deposits are rust colored, changing to dark brown to black at the metal surface, which is typical for MIC.

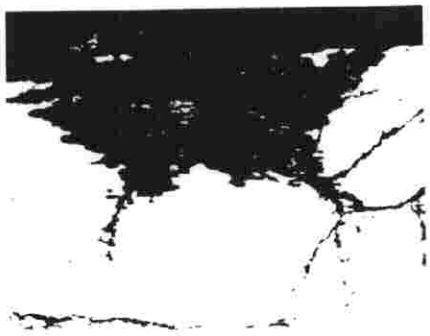

FIGURE 4
Photomicrograph of a section through a typical deposit and pit in the wall of the tank (magnification 12.8x, reduced 43%; 10% oxalic etch).

FIGURE 5
Photomicrograph of intergranular grain lifting corrosion of the same attack as shown in Figure 4 (magnification 400x, reduced 39%).

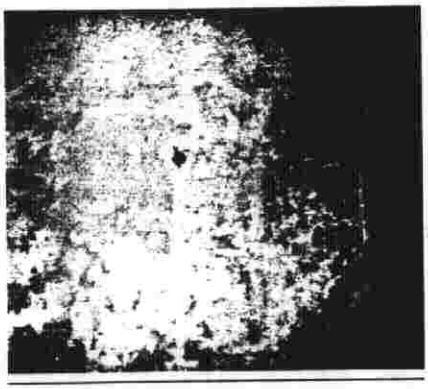

FIGURE 6
Microbiological deposit at a seemingly unaffected location on the surface of an alloy plate in the tank.

space. Within two to three months, the corrosion of the copper by moist ammonium sulfate penetrated the pipe at every joist support location. This example shows general attack that is localized to the contact location with the corrodent.

Microbes are not usually associated with general attack like this because of their size and minuscule footprint. Bacteria are usually 0.2 to 5 µm wide and 1 to 10 µm long, although some filaments may be several hundred micrometers in length.[3] Figure 2 provides a graphic size relationship between a large 5-µm microbe and a surface defect that is 381 µm deep in steps of 127 µm.

Intergranular Attack

Intergranular corrosion is caused by specific anodic areas along the grain boundaries, which corrode more rapidly than the grains themselves. These areas may be intermetallic or formed by heat-induced metallurgical changes, such as welding or stress relief. Intergranular attack is often observed in the heat-affected zones (HAZ) of welds.

Many case histories on MIC show that microbes are attracted to welds and HAZ, where they participate in the corrosion process. Figure 3 shows typical deposits associated with the HAZ of a vertical seam weld inside a type 304 stainless steel (SS) (UNS S30400) tank.[4] These deposits were proved to have been "built" by gram-positive rods that appeared to form both spores and slime, suggesting a *Bacillus spp.* in the hot demineralized water environment in this tank. Figure 4 shows a typical deposit and the corrosion damage in the tank wall beneath the deposit.

The corrosive attack initially appeared to be a grain boundary phenomenon. Figure 5 shows that regions close to the original surface appeared to contain exposed entire grains. Deeper within the cross section, where gross attack ceased, grains were observed that seemed to have detached from the metal matrix. If that were the case, as further corrosion occurred and after sufficient amounts of the surrounding matrix were removed, entire grains would be free to literally drop out of the matrix and be washed from their original area within the section.

Why microbes are attracted to welds and HAZ has been a matter of conjecture for some time. It appears that microbes are attracted to these

locations because of heat-induced changes in the energy level in the metal or alloy. The microbes seem to be able to identify these variations in energy levels and the anodic locations where they can more easily influence the corrosion process. This ability to identify anodic locations could explain why microbes will colonize a point in the middle of a seemingly unaffected plate, as shown in Figure 6 (from the same tank already mentioned).

It has also been observed that microbes "build" deposits and tubercles required for their survival in a specific environment. In the case above, the deposits were hard, which tended to protect the thermophilic microbes from the hot 75 to 90°C demineralized water. On the other end of the scale, Figure 7 shows what appear to be "depressions" in the bottom of a galvanized steel cooling water tower basin.[5] No discrete mounds or deposits were found, but rather, within each pit was a very loose collection of fine, dark-brown particles. Typical bright and active pits were found after the basin was drained and dried. The *Thiobacillus* and *Desulfovibrio* species that were identified in this environment evidently did not require protection from high temperature, velocity, etc., and built their "home" using loose, fine particles.

Dealloying Attack

Dealloying attack, sometimes called selective leaching, is the selective removal of elements, phases, or constituents from a metal alloy. Examples include: dezincification of brasses, where the corrosive loss of zinc leaves weak, porous copper; denickelification of alloy 400 (UNS N04400), where the loss of nickel also leaves weak, porous copper; and graphitization of cast iron, where the loss of iron leaves weak, porous carbon. Leached alloys usually have a sponge rock appearance.

Microbes have been shown to participate in dealloying attack.[6] Figure 8 shows an alloy 400 heat exchanger tube that was corroded in Gulf Coast water service. Figure 9 is a scanning electron micrograph of a corrosion cell on the inside surface of the same heat exchanger tube. Chemical analysis tended to support the observation of selective leaching of nickel from this alloy, with the probable participation of *Pseudomonas*, sulfate-reducing, and sulfate-oxidizing bacteria.[6]

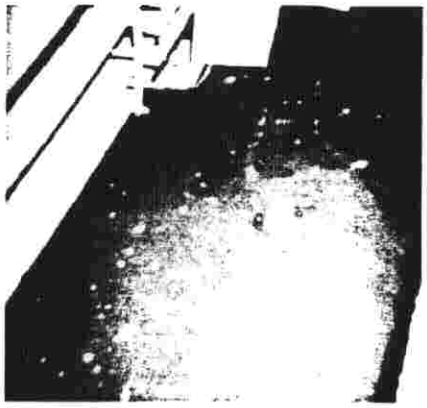

FIGURE 7
Pits (white spots) with residue intact, as seen through water in cooling tower basin. Note the apparent absence of (normally dark) corrosion product and discrete bacteria mounds. (Photo courtesy of R.A. Schultz.)

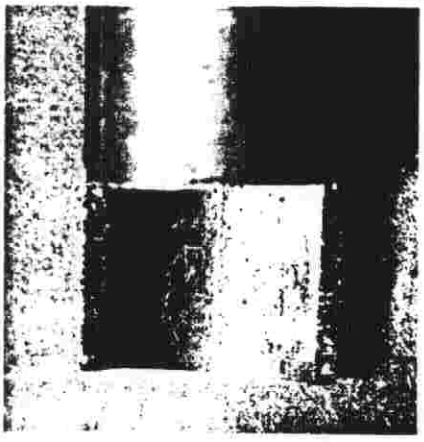

FIGURE 8
Localized corrosion of alloy 400 heat exchanger tube.

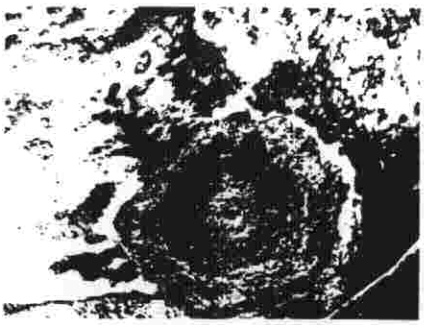

FIGURE 9
Micrograph of a corrosion cell on the inside surface of the alloy 400 tube.

Localized Attack

Localized attack can exhibit a number of configurations. *Pitting* is the most common term used to describe localized corrosion, whether the damage is shaped like potholes; deep, small-diameter needles; or anything in between. Even crevice corrosion, which is the most prevalent form of localized attack in the chemical industry, is often referred to as pitting.

MIC generally produces localized attack because of the microbes' minuscule size and footprint, as described previously. However, the damage caused by chemical corrosion and MIC can look exactly alike. Figure 10 shows crevice attack in the weld between the side wall and the tray support in a type 304 SS column in a chemical process. Based only on this section view as evidence, the damage might easily be identified as MIC "classic" tunneling. However, microbes cannot exist in this chemical environment: No water is present, the temperature is too high, the chemical is toxic, etc. Formic acid, formaldehyde, formalin, and other chemicals under specific conditions can produce the same tunneling crevice attack as MIC.

Figure 11 shows a section through a type 304 SS pipe and weld that has suffered "classic" MIC tunneling. MIC is thought to have caused the damage shown in Figure 11 because this piping system's only exposure was to potable hydrotest water at ambient temperature. The reader should be the judge as to whether the exclusiveness of the term *classic* can be used to describe tunneling damage that is thought to be caused by MIC.

Chemicals can also produce corrosion damage in pipelines that looks almost exactly like that caused by MIC. Figure 12 shows a section through a 3-in. (7.62-cm) extra-strong carbon steel pipe that exhibits local-

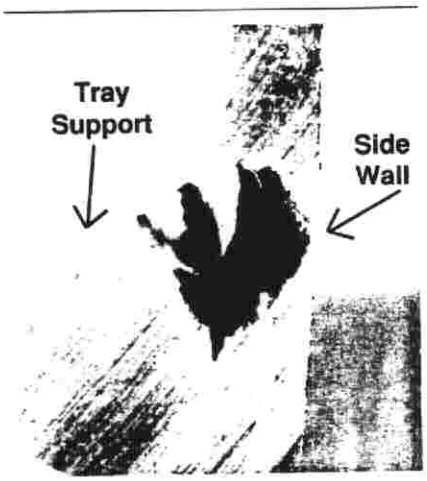

FIGURE 10
Section through a type 304 SS chemical finishing column showing crevice attack of a weld between the side wall and a tray support.

ized attack along its bottom inside surface. Water was readily available inside this piping system, and the temperature was maintained at a level conducive to bacterial growth. However, the chemical in the piping system was heavier than water, which

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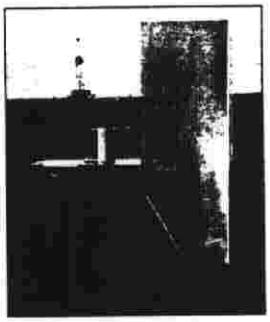

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FIGURE 11
Weld cross section showing a typical subsurface cavity (magnification approximately 15x, reduced 51%).

forced the water phase to the top of the pipe, where MIC would be expected. In addition, the chemical in this piping system is not palatable to any form of life and therefore rules out any form of MIC.

Cracking Phenomena

Stress corrosion cracking (SCC) of metals and alloys is a common problem along with other stress-induced forms of corrosion damage. Usually tensile stress, chemical concentration, temperature, and other factors control SCC. Caustic will crack and embrittle steel, ammonia and amine will crack brass, and chlorides will crack stainless steels.[1]

Microbes seem to have the ability to gather and/or produce chemicals and compounds to assist them in influencing a corrosion process. As an example, Figure 13 shows chloride SCC of type 304 SS initiated in the pit under the microbiological deposit shown in Figures 3 and 4. Although chlorine is toxic to most bacteria, this particular microbe gathers and uses chloride ions. The chloride is then available for processes to damage the SS. Electron probe microanalyses elemental plots across a typical crack found that the *Bacillus spp.* had increased the chlorine, probably as chlorides, content deep in the cracks near their tips. The concentration of the chlorides, the 75 to 90°C operating temperature, and the residual stress in the alloy all worked together to crack the austenitic SS.

This bacteria's use of chlorides is not unusual. Chloride SCC was also

FIGURE 12
Section through a 3-in. (7.62-cm) extra-strong carbon steel pipe showing localized attack along the bottom inside surface.

FIGURE 13
Photomicrograph at higher magnification of cracks shown in Figure 4. The branched transgranular cracks are typical of chloride SCC of austenitic stainless steel (magnification 125x, reduced 50%, 10% oxalic etch).

found in association with the austenitic SS damage shown in Figure 11. *Gallionella* iron bacteria is thought to have been involved in this corrosion damage.

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Editor's Note: *Many photos in this article are taken from "A Practical Manual on Microbiologically Influenced Corrosion" (Houston, TX: NACE, 1993).*

More information is available in CORROSION/94 paper no. 259, presented in Baltimore, Maryland.

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About the Cover
MIC deposits removed from a seam weld in a stainless steel tank (which had been exposed to stagnant well water) reveal pits confined primarily to weld metal.

Photo source:
A Practical Manual on Microbiologically Influenced Corrosion.
(See update on NACE's best-selling book on page 66.)

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