



WINMAR
consulting services, inc.

RFP# CBD SOL RQ18021

**ASSESSMENT OF CURRENT PIPELINE
FLUSHING AND DECOMMISSIONING
REQUIREMENTS
RESEARCH AND FIELD TESTING
“FLUSHING PHASE B”**

FINAL REPORT

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ASSESSMENT OF CURRENT PIPELINE FLUSHING AND DECOMMISSIONING REQUIREMENTS - RESEARCH AND FIELD TESTING “FLUSHING PHASE B”

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SECTION 1
INTRODUCTION

1. Introduction

The abbreviated name for this project is “Flushing Phase B.” **The purpose of this study is to assist the MMS in assessing -- and if necessary, scoping and preparing -- regulations for the flushing, handling, and possible reactivation of out-of-service pipelines.** This project focused on pipelines that have been taken out of service and flushed and filled with inhibited seawater. In keeping with this purpose, WINMAR has: reviewed current regulations for temporarily taking pipelines out-of-service lines, reviewed current practices for taking pipelines temporarily out-of-service, and reviewed practices, tools, and technologies for flushing and preserving out-of-service lines. WINMAR also assessed the effectiveness and risk/safety of the tools and practices, Finally, WINMAR performed field tests (offshore in-situ) to assess the condition of 4 out-of-service pipelines.

The project methodology for Flushing Phase B was carried out in a number of phases, as detailed below:

- 1) **Identification Phase:** The first step in this phase was a review of current regulations and practices for pipeline decommissioning and reuse -- temporary and permanent abandonments (MMS). This covered any existing regulations and/or recommended practice for out of service pipelines.
- 2) **Interaction Phase:** This phase was performed concurrently with Phase 1. Because Winmar has an excellent working relationship with the majority of the contractors in the Gulf of Mexico, we met with them to investigate pipeline decommissioning effectiveness, and the effects of time and the offshore environment on out-of-service pipelines. Contractors included:
 - Platform and pipeline owners and operators
 - Pipeline pigging and maintenance contractors
 - Pipeline corrosion and corrosion inhibitor companies
- 3) **Assessment Phase:** **The thrust of this phase was to assess how well out-of-service pipelines fare in the marine environment - over time - for later use.** Specifically, we assessed the risks to the environment, and health and safety of operations, for the different pipeline types and varying time the lines were out of service.

To aid in the assessment, a qualitative risk analysis was used to form a reuse matrix based on a number of factors. The factors used were: pipeline product, presence of H₂S, CO₂, and of course age. The matrix will be used to compare the pipeline samples retrieved from offshore in order to grade them in condition.

This project assumed that external corrosion protection techniques were continued during the pipeline's temporary abandonment stage.

- 4) **Data Gathering Phase:** This phase entailed gathering information during pipeline decommissioning, in order to gauge the effectiveness of the regulations/guidelines which were determined during the Assessment Phase.

Because Winmar decommissions pipelines which were formerly out-of-service, we had the opportunity to actually examine the pipelines in-situ, and assess their condition. Since we know the age of the pipelines tested, and when they were taken out of service, we were able to draw MANY valuable conclusions. Data acquired consisted of:

- **Catching and sampling the fluids that were in the out-of-service pipeline.** These fluids were sampled at pre-determined intervals, and analyzed for the presence of corrosion products.
- **Catching and sampling fluids during pipeline flushing.** This test was performed on the pipelines during the actual decommissioning phase. The flushwater was sampled at pre-determined intervals and analyzed for the presence of hydrocarbons, corrosion products, oxygen, and chlorides and sulfates.

- 5) **Conclusion Phase:** At this stage, Winmar has compiled and presented recommendations for regulation of out-of-service pipelines. These recommendations were discussed with MMS pipeline specialists before being summarized and finalized in the report. WINMAR also targeted and recommended specific measures that can improve the safety and effectiveness of temporary abandonment/decommissioning and/or reuse of offshore pipelines.

Definitions: In order to avoid confusion, it is important to define “Out of Service” and “Abandoned” as the terms relate to pipelines. The definitions will also be included on future regulatory updates.

Out-of-Service: A pipeline that is out-of-service is still connected either at one end or at both ends, but it is not flowing. An out-of-service pipeline may or may not be filled with inhibited seawater. The out of service period begins when the line has not been flowed for 30 consecutive days. Taking a line out of service does not require MMS approval, however notification is required.

Abandoned: An abandoned pipeline has been cut at BOTH ends. The line has either been removed, or the ends of the pipeline plugged and buried in-place. Abandoning a pipeline requires MMS approval.

SECTION 2
OBJECTIVES

2. Objectives

The objectives of this project are many-fold, but to summarize:

- 1) Provide data to the MMS on the condition of various types of out-of-service pipelines through research and in-field testing. This data includes the composition of any product remaining in the pipeline, the composition of seawater/inhibitor in the pipeline (if present), and the composition of seawater used to flush the pipeline.
- 2) Assist the MMS in determining if the “Pickled” (Shut in greater than 2 but less than 5 years, flushed and filled with inhibited seawater) pipeline regulations are adequate for ensuring pipeline safety and containment. This objective must be met for the various types of pipelines – treated/untreated, gas/oil/condensate, etc.
- 3) Collect information through research and field testing to determine the effectiveness of various corrosion inhibitors for the “Pickled” pipelines. Determine if the generic requirement for use of “corrosion inhibitor” is adequate, too strict, or too lenient a term.
- 4) Gain a general understanding of condition of pipelines on the OCS in the Gulf of Mexico through the collection of out-of-service pipeline samples.

SECTION 3
PROCEDURES

3. Procedures

This section of the report describes the field-testing portion of the project. Below is the detailed procedure that was supplied to the contractor prior to any offshore work/pipeline decommissioning.

A. Offshore Procedures

General: Field trip to site will confirm location and work area available to flush pipeline. Brief Field Personnel on flushing procedure. Company procedures are to be incorporated into flush procedure. Confirm location and type of Pipeline End Flanges. Review contingency clean-up plans and fluid disposal with Field Foreman. Check flanged connection for integrity. Check for Check Valves.

1. Verify communication link is working between crews at both ends of the pipeline.
2. Verify that pipeline is LOCKED and TAGGED OUT and line has ZERO PRESSURE before removing pipeline-end flanges.
3. Check pipeline for check valves.
4. Remove pipeline end flanges and install ANSI 600 Ball valves onto flange ends at both platforms. Close block valves.
5. Install all gauges/meters and verify both units have all openings closed and/or plugged.
6. Install fill line from pump to flushing head. This line to have an overflow by-pass to divert water overboard and a meter beyond the by-pass in order to know volume of water pumped into line. Flow direction to be controlled with block valves before meter and on overboard line.
7. Install pipe discharge line with meter from receiving end to storage/receiving tanks or to production process equipment.
8. Hook up Sampling Valve at receiving location.
9. Take the first sample using appropriate sample jars.
10. Verify pipeline and discharge line at receiving end are open.
11. Check flow meter and zero.
12. Confirm Production Platform crew is ready to receive water. Open block valve. Divert flow from overboard to flushing head using in-line block valves.
13. Check pressure gauges to ensure no built up in pressure is occurring at flushing site.
14. Check with receiving crew that flow has started.
15. Take two samples, one sample into Mineral Pattern Analysis Bottle and one into Oil and Grease Bottle, at 25%, 50%, and 75% line volume intervals.
16. Monitor pressure. Do not let pressure build up beyond 1000 PSI. Stop pumping if pressure starts to exceed 1440 PSI.
17. Once fluid returns, capture 2 fluid samples. One sample into Mineral Pattern Analysis Bottle and one into Oil and Grease Bottle.

18. Label ALL sample bottles.
19. Open by-pass valve at Well Platform before shutting down pump and then closing block valve located before meter.
20. Check and bleed all pressure from fill line and pipeline. Verify zero pressure before removing any piping at either end of pipeline.
21. At Well Platform, disconnect pump and fill line. Re-confirm zero pressure and remove flushing head and block valve. Re-install blind flange initially removed from pipeline.
22. At Production Platform, remove discharge line. Re-confirm zero pressure and remove receiving hose and block valve. Re-install blind flange initially removed from pipeline.
23. Secure samples for shipment to Laboratory. Send field report copies to office.
24. De Mob equipment and personnel to shore base.

B. Pictorial Presentation

This section provides a pictorial presentation of how the offshore field testing phase was performed.



Photo #1 The flowmeter reads in hundreds of gallons pumped. It was “zeroed” and calibrated prior to commencing work.



Photo #2

An assortment of flanges were kept on-hand to ensure a good fit-up to the pipeline.



Photo #3

This picture shows the typical workspread used, as well as typical well protector platforms. The flushing pump is located on the jackup boat, and a hose connects the pump to the pipeline via a hose that runs across the gangway.



Photo #4

This photo shows a typical top-of-riser sample point at the receiving platform.

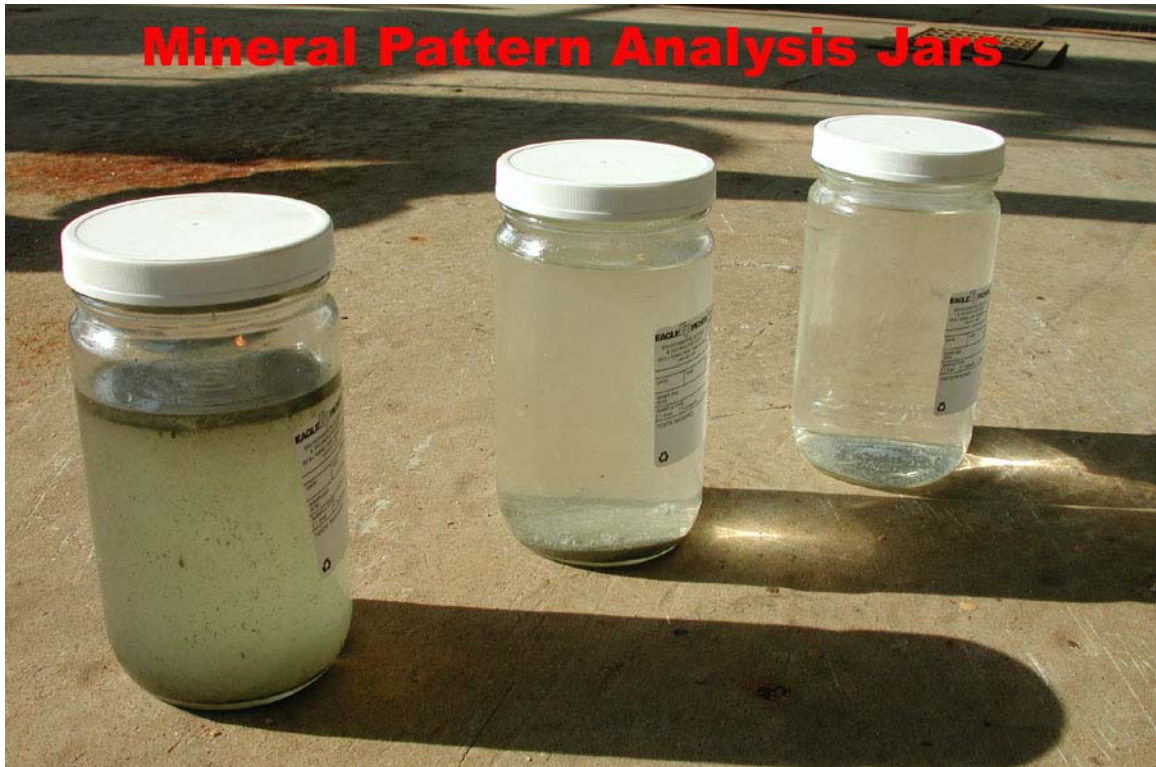


Photo #5

MPA Jars come cleaned, sealed and certified. To take a sample, jars are simply filled, and sealed.



Photo #6

The plastic Zero Head Space jars are used for taking samples, which cannot have any atmospheric air in them. Once the jars are filled with liquid, they can be purged of air and sealed. WINMAR used these jars to catch samples for oxygen and nitrogen testing.

SECTION 4

BACKGROUND AND ASSUMPTIONS

4. Background and Assumptions

The following sections summarize the results for the various samples taken. The results are compiled and displayed graphically in order to help interpret and analyze the data. For each pipeline tested, the results are organized into sections. The sections are listed below, along with any assumptions made during the data interpretation:

Sample/Locations Observations

The location of the samples was derived by analyzing the amount of fluid pumped at the time the sample was taken. The flowmeter was used to obtain this volume, and the internal pipeline diameter was used to convert this volume to a distance. This process assumes that the flow in the line is uniform, and that no multi-phase flow occurs. It also assumes that the pipeline internal diameter is the same throughout the line. The average rate of flow of flushwater was approximately 100 GPM.

Gas Composition Observations

No gas samples were taken therefore no assumptions were made.

Flushwater Composition Observations

No assumptions were made. The data is plotted exactly the same as the lab results.

Oil and Grease Observations

No assumptions were made for this analysis. For comparison purposes, all of the oil and grease measurements were normalized, based on volume flushed divided by total pipeline volume. These normalized results were also all plotted on the same graph, for comparison of all the different oil and grease flushing profiles.

Pipe Cutout Observations

At this time no cutout samples were taken. These samples are scheduled to be retrieved at a later date in conjunction with platform removal operations.

Pipe Vintage and Diameters

The pipelines tested were all of the 1960 – 1972 vintage and between 4 and 8 inches in diameter.

Reference and Baseline Material

Some reference material was used in the analysis and comparison of Natural Seawater (NSW). These charts and articles are included in this section. This reference material has an excellent description of the ions and elements present in Seawater, and how they react with each other and with other ions/elements.

Gaseous composition of dry air.

Constituent	Chemical symbol	Mole percent
Nitrogen	N ₂	78.084
Oxygen	O ₂	20.947
Argon	Ar	0.934
Carbon dioxide	CO ₂	0.0350
Neon	Ne	0.001818
Helium	He	0.000524
Methane	CH ₄	0.00017
Krypton	Kr	0.000114
Hydrogen	H ₂	0.000053
Nitrous oxide	N ₂ O	0.000031
Xenon	Xe	0.0000087
Ozone*	O ₃	trace to 0.0008
Carbon monoxide	CO	trace to 0.000025
Sulfur dioxide	SO ₂	trace to 0.00001
Nitrogen dioxide	NO ₂	trace to 0.000002
Ammonia	NH ₃	trace to 0.0000003

* Low concentrations in troposphere; ozone maximum in the 30- to 40-km regime of the equatorial region.

Mackenzie, F.T. and J.A. Mackenzie (1995) **Our changing planet**. Prentice-Hall, Upper Saddle River, NJ, p 288-307.

(After Warneck, 1988; Anderson, 1989; Wayne, 1991.)

COMPOSITION OF AIR

Gas	% of Earth Atmosphere at sea level (dry air)
Nitrogen	78.08
Oxygen	20.95
Argon	0.93
Carbon dioxide	0.03
Neon	0.0018
Helium	0.0005
Krypton	0.0001
Xenon	0.00001

TEXT AND DIAGRAMS BY RANDY HOLMES FARLEY

Understanding Seawater

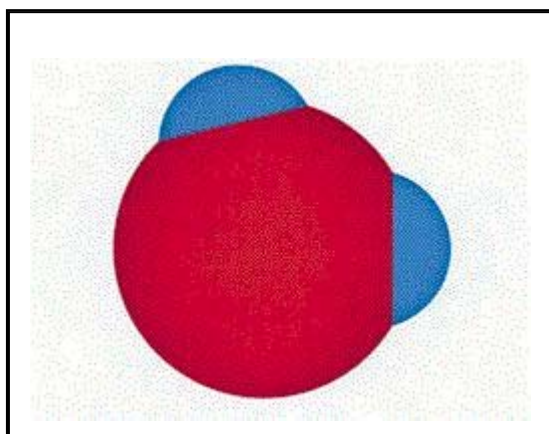
The chemistry of marine aquaria is a complex subject and one that is not easily described in a short article. Previous articles on marine chemistry in *Aquarium Frontiers* authored by Craig Bingman have dealt with selected topics of interest to marine aquarists. In particular, these articles have focused on the biochemistry taking place in aquaria. In this article I will endeavor to provide an understanding of seawater itself, rather than how the components are used by the tank inhabitants.

Do you have an opinion on the issues raised in this article? Join in the discussion by going to: [Understanding Seawater](#).

What's In Seawater?

Major species

Seawater has been found to contain virtually every chemical element, although some of them are found in very small concentrations. Water is, of course, the most abundant molecule, comprising about 97 percent of seawater. Water itself is far more complicated than is generally recognized and has been an active area of chemical research for more than a hundred years.

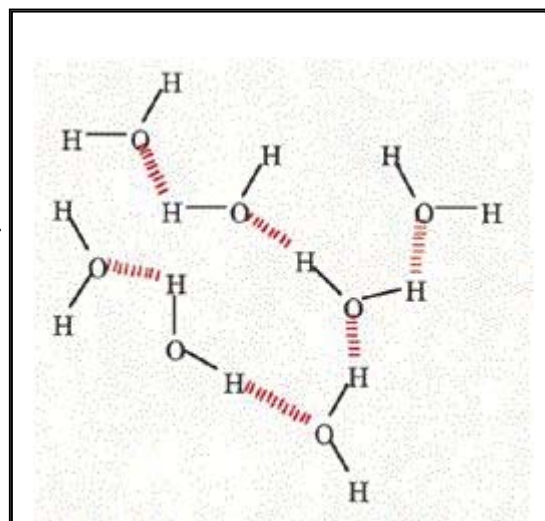


A space filling model of a water molecule (H₂O), where the oxygen atom is shown in red and the hydrogen atoms are shown in blue.

One of the remarkable things about water is that it is liquid at room temperature. Based simply on its molecular weight, it ought to be a gas. Nitrogen (N₂) and oxygen (O₂) are much heavier than water (H₂O), and yet they are gasses and water is a liquid. Why?

The reason involves the hydrogen bonding that takes place in water. The hydrogen atom of one molecule of water interacts strongly with the

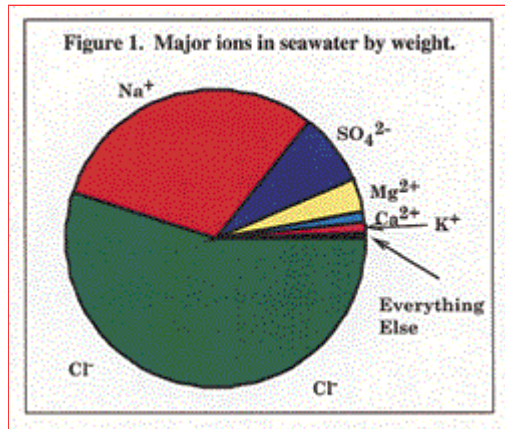
oxygen atom of a nearby water molecule. This interaction is much weaker than the bond between atoms within a single water molecule, but it is strong enough to make the water molecules "prefer" to be surrounded by each other, rather than floating around individually, as they would in a gas. Hydrogen bonding is best viewed as a fleeting interaction between water molecules that lasts only a tiny fraction of a second before breaking. Once broken, however, they quickly reform, perhaps to a different water molecule. On balance, each water molecule is bonded to one or two other water molecules almost all of the time.



The extended hydrogen bonding network in water. Hydrogen bonds are indicated in red.

Major ions

Most of the remaining constituents of seawater are inorganic ions. The major components of seawater — all ions present at greater than 1 part per million (ppm) or 1 milligram per liter (mg/L) — are shown in *Figure 1* and *Table I*. A different definition of major ions based on the numbers of ions present, rather than the weight of those ions, has a slightly different list, with lithium being added. Together, these ions account for 99.9 percent of the dissolved solutes in seawater.



It is clear from *Figure 1* that seawater contains mostly table salt (sodium and chloride). In fact, sodium and chloride comprise 86 percent of the ions present in seawater, by weight.

One important point about these concentrations: they are correct for typical seawater, which contains about 35 parts of salt by weight per thousand parts of seawater (35 ppt). This seawater has a specific gravity of around 1.027, so it may be higher than is maintained in

Species	Concentration milligrams per liter (mg/L)
Cl ⁻ (chloride)	19,000
Na ⁺ (sodium)	10,500
SO ₄ ²⁻ (sulfate)	2700
Mg ²⁺ (magnesium)	1280
Ca ²⁺ (calcium)	412
K ⁺ (potassium)	399
HCO ₃ ⁻ (bicarbonate)	110
Br ⁻ (bromide)	67
CO ₃ ²⁻ (carbonate)	20
Sr ²⁺ (strontium)	7.9
B(OH) ₃ + B(OH) ₄ ⁻ (borate)	5 (as Boron)
F ⁻ (fluoride)	1.3
Organics	1 to 2
Everything else combined (except dissolved gasses)	Less than 1

many marine aquaria. As the salinity of seawater is varied, these concentrations move up and down together. Consequently, if an aquarium contains water with a specific gravity of 1.023, the salinity is about 30 ppt and all of the concentrations in *Table I* are reduced by about 14 percent.

A logical question to ask is why do we not hear much discussion about chloride, sulfate or sodium levels in marine aquaria, if they are among the most abundant ions? The answer is that while they are very important, their abundance makes it difficult for them to become significantly depleted or enriched without altering the salinity. Of course, one could start out with a salt mix that did not contain the correct proportions, but assuming one starts out correctly, there isn't any normal activity in a marine aquarium that will significantly change the levels of these ions (without changing salinity).

All of these major ions are essentially unchanged in concentration at different locations in the ocean, except as salinity changes move them all up or down together. Ions that do not change concentration from place to place are referred to as “conservative type” ions, a description that also applies to some of the minor and trace elements that are discussed below.

I have also included organics on this list, though they traditionally are not considered a major specie. As will be discussed below, organics are important in seawater, but are poorly understood.

Minor ions

There are various definitions, of which ions in seawater constitute the “minor ions.” By some

definitions, the list of constituents is rather long. *Table II* shows just a few of the constituents of seawater that are often labeled as minor ions. The more abundant of these are sometimes lumped with the major ions (such as lithium), while the least abundant (such as iron) are often lumped in with trace elements. Ions in this category often vary significantly with location in the ocean. That is primarily because many of them are tightly linked to biological activity. These ions can be locally depleted if biological activity is high enough. Ions that vary in this fashion are referred to as “nutrient type” ions, because they are consumed by one or more types of organism.

Trace elements

There is much discussion about trace elements in marine aquaria and for good reason. Most chemicals dissolved in seawater are classified as trace elements simply because there are so many ions and molecules present at very low concentrations. In many cases, these ions are quite variable in concentration from place to place and also as a function of depth. Anyone wishing to view extensive lists of these ions is advised to check out one of the references given at the end of this article.

Many of these trace elements are metals. While people typically view dissolved heavy metals as toxic, a great many of them are essential for organisms. Their toxicity is primarily related to their concentration: a happy medium is essential, where enough of each of these metals is present for life to exist, but not so much is present as to be toxic.

A perfect example is copper. It is present in natural seawater at about 0.25 parts per billion (ppb), which is about a thousand times less than the toxic levels often used to kill microorganisms in the treatment of sick marine fish. It is, however, absolutely necessary for many animals to have copper available to them to survive.

Some of the most important trace elements to marine aquarists are those involved in the nitrogen cycle (ammonia/nitrite/nitrate). These are discussed in detail below.

Organics

The nature of organic molecules is certainly the most complicated aspect of seawater chemistry. Organics comprise about 2 ppm of seawater. Of this 2 ppm, the majority is in the form of dissolved organic carbon (DOC). DOC includes all fully dissolved organic compounds and any particulates that are small enough to pass through a 0.45-micron (μm) glass fiber filter. Strictly speaking then, it is not all fully dissolved. Any organic particles greater than 0.45 μm are called particulate organic carbon (POC). The POC is about a factor of 10 lower in concentration than DOC and is composed of living and dead organisms, as well as assemblies of organic molecules.

DOC is an incredibly complicated mixture of molecules that represents billions of years of biological waste products from uncounted numbers of different organisms, combined with reactions catalyzed by light, heat, inorganic catalysts (metals), biological processes, and many other factors. It includes carbohydrates (20 to 35 percent of the total), humic substances (10 to 30 percent of the total), amino

TABLE II
Some of the Minor and Trace Ions in Seawater

Species	Concentration milligrams per liter (mg/L)
Li ⁺ (lithium)	0.17
Rb ⁺ (rubidium)	0.12
H ₂ PO ₄ ⁻ + HPO ₄ ²⁻ + PO ₄ ³⁻ (phosphate)	0.0 to 0.3
IO ₃ ⁻ (iodate)	0.03 to 0.06
I ⁻ (iodide)	0 to 0.03
Ba ⁺ (barium)	0.004 to 0.02
Al ³⁺ (aluminum)	0.00014 to 0.001
Fe ²⁺ + Fe ³⁺ (iron)	0.000006 to 0.00014
Zn ²⁺ (zinc)	0.000003 to 0.0006

acids and proteins (2 to 3 percent), hydrocarbons (less than 1 percent), carboxylic acids (1 percent) and steroids (trace).

There is also a great deal of uncharacterized organic material. In fact, the study of seawater organics is an active area of research. Additionally, the summation of all dissolved organics in the ocean is a pool of carbon larger than carbon dioxide in the atmosphere, so it cannot be ignored by those looking at the planetary carbon cycle. In addition to carbon, these organics contain significant amounts of oxygen, nitrogen, phosphorus, and sulfur.

It is probably also safe to say that most, if not all, closed marine systems have higher organic levels than the ocean, although hard numbers are difficult to come by. The desire to reduce these organic levels is one of the reasons for the popularity of skimmers with marine aquaria.

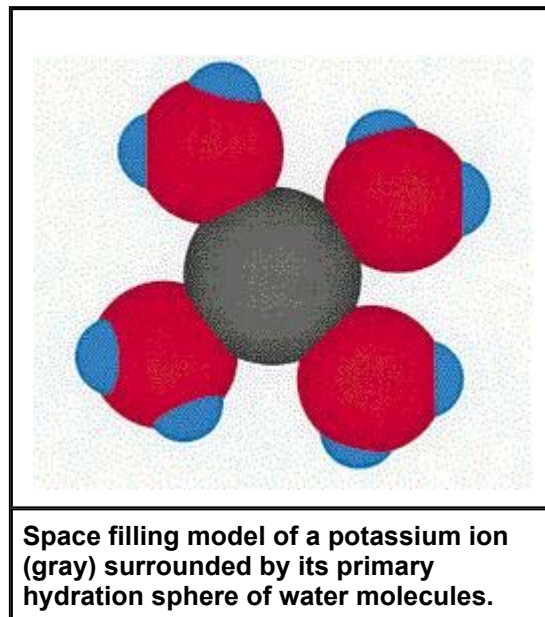
What Forms Do Ions Take In Seawater?

In the previous sections I have described what ions are present in seawater, but I have not presented the forms they typically take. Contrary to popular belief, many of these ions are attached to each other in solution and do not act as completely individual species. This tendency to form ion pairs in solution is much more prevalent for some ions (e.g., Ca^{2+} , Mg^{2+} , CO_3^{2-} , F^- , OH^-) than it is for some others (e.g., Na^+ , K^+ , Cl^- , Br^-). In general, the tendency to form ion pairs is higher for ions with a higher net charge. In the next few sections, I will present an overview of some of these interactions and why they are important.

Simple ions

The simplest positively charged ions in solution are sodium (Na^+) and potassium (K^+). They are primarily free ions, with a shell of three to four tightly bound water molecules attached to them. This is known as the “primary hydration sphere.” These water molecules are fairly tightly bound, but are rapidly exchanged with other water molecules from the bulk solution (at a rate of about a billion exchanges per second for each ion!). Beyond this first shell are another 10 to 20 water molecules that are less tightly bound, but that are still strongly influenced by the metal ion. These types of hydrating water molecules are present for all ions in solution and won't be mentioned further for each ion in turn.

A small proportion of both sodium and potassium (about 5 percent) exists as ion pairs with sulfate, forming NaSO_4^- and KSO_4^- . This type of ion pair is best viewed as a temporary association between the two ions and may only last for a very small fraction of a second before the ions move apart. Nevertheless, this type of association can have very important implications for the behavior of these ions, as will be shown below. Ions forming such pairs actually “touch” each other. That is, most or all of the hydrating water molecules that are in between them have been temporarily removed. This removal of the intervening water molecules is the primary distinction between ion pairs and ions that are simply near each other.



The simplest negatively charged ions, chloride (Cl^-) and bromide (Br^-), form few ion pairs in solution. They are primarily present in the form of hydrated free ions, with two and one tightly bound water molecules, respectively.

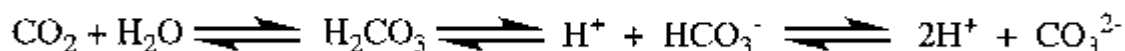
Carbonate

One of the more complex interactions, and one that is very important for marine reefkeepers, involves carbonate (CO_3^{2-}). Carbonate is primarily ion paired in solution, with only about 15 percent of it actually present as free CO_3^{2-} at any given point in time. This fact is very important to the maintenance of calcium and alkalinity levels in aquaria, because it is the free carbonate concentration that “wants” to precipitate with calcium as calcium carbonate (CaCO_3). If the free carbonate levels rise too much, the calcium levels will drop due to CaCO_3 precipitation.

So, what is carbonate ion paired with? Primarily magnesium, forming soluble MgCO_3 . This is the reason why magnesium levels are so important in marine aquaria for maintenance of simultaneously high levels of alkalinity and calcium. If magnesium is too low, more carbonate will be in the free form and will “want” to precipitate as calcium carbonate.

Carbonate is also ion paired to sodium and calcium, forming soluble NaCO_3^- and CaCO_3 , respectively. The soluble calcium ion pair sounds odd, but it is essentially one individual molecule of CaCO_3 that is soluble in water: it is not precipitated out of the solution. The fact that carbonate is also ion paired by sodium is one of the reasons that salinity has an impact on the amount of calcium and alkalinity that can be maintained in solution: lower salinity means lower sodium, which means more free carbonate and a greater likelihood of precipitation of CaCO_3 .

Ion pairing has another large effect on carbonate that is more subtle. In water, carbon dioxide hydrates to form H_2CO_3 , which can then break up (ionize) into protons (H^+), bicarbonate (HCO_3^-) and carbonate (CO_3^{2-}).

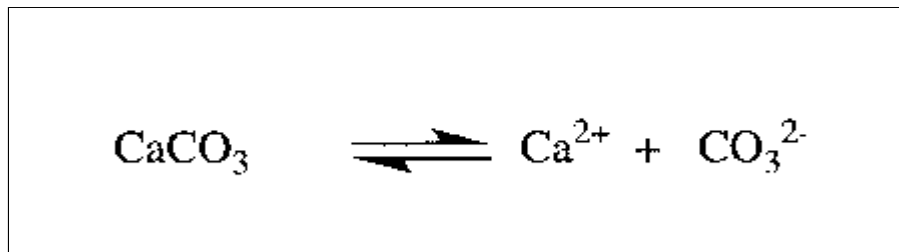


When CO_2 is added to water, the system will come to equilibrium with specific concentrations of each of the species shown above. By LeChatelier’s principle, if one takes away something from one side of the equilibrium, the equilibrium will shift in that direction. For example, if carbonate is removed from the system, then each of the reactions shown will proceed to the right, effectively replacing some of the carbonate that was removed.

Importantly, that is exactly the effect that takes place in seawater when carbonate is “removed” by forming ion pairs. It is only the “free” concentration of these species that determines the position of the chemical equilibrium, so carbonate in the form of an ion pair does not “count,” and the equilibrium shifts strongly to the right. If one then counts carbonate in all forms (free and ion paired) it is found to

be far higher in seawater than in freshwater at the same pH and ion pairing is the primary reason.

The exact same effect can be seen in the solubility of CaCO_3 .



In this case, if CaCO_3 is added to water, it breaks apart into Ca^{2+} and CO_3^{2-} . Eventually, an equilibrium is reached where no more CaCO_3 will dissolve. However, if some of the carbonate is removed by ion pairing (and some of the Ca^{2+} as well), then additional CaCO_3 can dissolve to replace those that were "lost." This is the primary reason that CaCO_3 is approximately 15 times more soluble in seawater than in freshwater.

Calcium, magnesium and strontium

Calcium, magnesium and strontium are primarily present in the free form, hydrated by six to eight tightly bound water molecules. A small percentage (about 15 percent) is present as an ion pair with sulfate. Much smaller percentages are present as ion pairs with carbonate and bicarbonate. Importantly, while these complexes involve only a small percentage of the total calcium and magnesium, they involve a large portion of the total carbonate (which is possible because there is so much calcium and magnesium compared to carbonate).

Sulfate

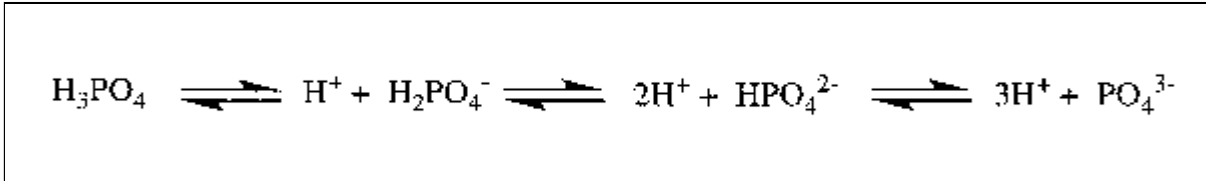
As mentioned above, sulfate forms ionic interactions with most positively charged species in seawater. In fact, more than half of it is in the form of an ion pair, with NaSO_4^- and MgSO_4 dominating.

Phosphate

Phosphate in marine aquaria is of tremendous importance because it is often a limiting nutrient for algae growth. In seawater, the amount of phosphate present is typically quite low (usually less than 0.1 ppm) and often varies significantly from location to location. In many marine aquaria, however, the phosphate concentration can be significantly higher (up to several ppm).

The ability to export phosphate from marine aquaria has been the topic of lengthy discussion and is the object of numerous commercial products. The nature of the inorganic phosphate present in marine aquaria, however, is certainly more complicated than traditionally credited.

Inorganic phosphate can exist in a number of forms, in a manner analogous to carbonate.

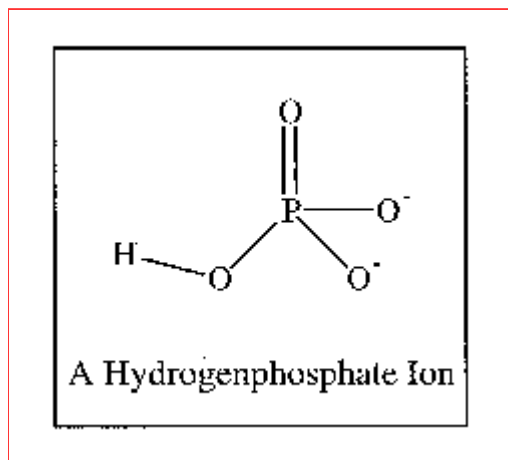


Ignoring ion pairing and complex formation for the moment, phosphate is primarily found in the HPO_4^{2-} and PO_4^{3-} forms in seawater. This is quite different than in freshwater at the same pH, where the H_2PO_4^- and HPO_4^{2-} forms predominate. *Table III* shows the forms of phosphate present in seawater at a pH of 8.1.

To a large extent, the high proportion of phosphate present in the PO_4^{3-} form in seawater is due to ion pairing, just as in the case of carbonate. These various phosphate species pair extensively with magnesium and calcium in seawater. PO_4^{3-} is nearly completely ion paired (96 percent), while only 44 percent of HPO_4^{2-} is paired. This is what causes the shift in the equilibrium to more of the PO_4^{3-} form in seawater compared to freshwater (just as it does for carbonate).

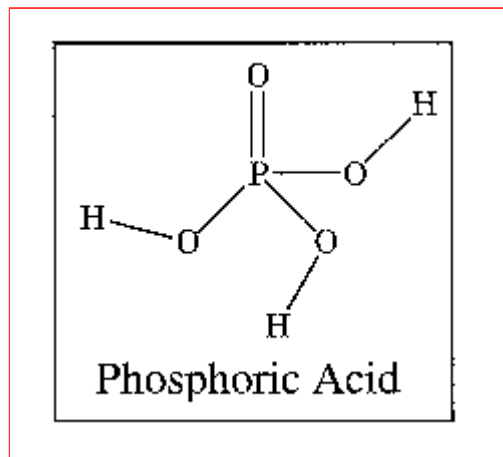
TABLE III
Speciation of Phosphate in Seawater

Form	Percentage of total in seawater (at pH 8.0)
H_3PO_4	trace
H_2PO_4^-	0.5 percent
HPO_4^{2-}	79.2 percent
PO_4^{3-}	20.4 percent



Additionally, phosphate will interact with certain ions in a manner that is much stronger than simple ion pairs. Phosphate can, for example, complex with a number of positively charged species, including both metals (e.g., iron) and organics. These interactions further serve to reduce the concentration of free phosphate.

Phosphorus is also contained in dissolved organics. While natural seawater has more inorganic phosphate



than organic forms, this may not be true in aquaria where much higher organic levels prevail.

Metals

The metals, in particular, are strongly ion paired in solution. Copper primarily forms soluble CuCO_3 , iron forms soluble $\text{Fe}(\text{OH})_3$ and silicon (not strictly a metal) forms $(\text{Si}(\text{OH})_4)$. Some of the other metals that are biologically important (e.g., zinc, molybdenum, manganese, cobalt) form a wide variety of ion pairs with different ions in solution. In some cases, the number of different species that form is extensive. *Table IV* shows the speciation of copper in seawater at a pH of 8.1.

In recent years, however, it has become more and more apparent that

TABLE IV

certain metals are largely complexed to organic materials, even in natural saltwater where the level of organics is low. In a marine aquarium, the level of organics can be higher than in the ocean, so such complexes are even more likely to form.

In addition to complexation of metals to the widespread organics present in the oceans (e.g., humic acids), there is also the possibility of complexation to specific organics that were made exclusively for that purpose. For many microorganisms, metals such as iron are limiting nutrients for growth and these creatures have designed systems to bring iron to them.

Bacteria and fungi, for example, release organic compounds called siderophores into the environment. They are large organic molecules with a very high affinity for iron. The released siderophores eventually encounter an iron atom and bind very strongly to it. The organisms themselves have enzymes in their outer membranes that interact strongly with siderophores that contain iron, and transport them into the cell. Consequently, the siderophores can be viewed as collection devices for iron.

Of course, many of the siderophores released into the ocean are not quickly reabsorbed by the microorganisms and remain in solution. In a closed marine aquarium with a large population of microorganisms, one would expect that such molecules would be present in solution. Consequently, many metals in solution may be bound by such molecules.

Additionally, many aquarists intentionally add complexing agents in the various supplements they add to their aquaria. These include EDTA and citrate, which are two common forms for adding iron. These will equilibrate with other metals already in the tank and the tank will then contain a variety of metals complexed to these organics.

Nitrogen compounds

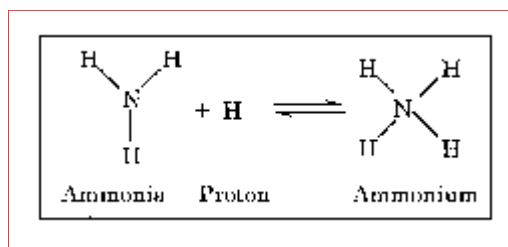
The primary nitrogen compound in seawater is nitrogen gas (N_2). It is present at about 11 ppm at 25 degrees Celsius (77 degrees Fahrenheit), although its solubility is a strong function of temperature, with nearly twice as much dissolving in near freezing seawater. Nitrogen gas is present at a higher concentration than any other dissolved gas, with oxygen (O_2) at 7 ppm, argon (Ar) at 0.4 ppm and all others at sub-ppb levels (not including carbon dioxide, which is primarily ionized in seawater).

There are certain organic and inorganic forms of nitrogen at concentrations lower than nitrogen gas. The organic forms are poorly defined, but include such molecules as proteins.

The inorganic forms are much more familiar to aquarists as components of the nitrogen cycle. The concentrations of these components in seawater are highly variable. In natural seawater, ammonia (NH_3) ranges in concentration from 0.02 to 8 ppm (as ammonia), nitrite (NO_2^-) ranges from 0.005 to 0.2 ppm (as nitrite) and nitrate (NO_3^-) ranges from 0.06 to 30 ppm (as nitrate). These values vary by location, depth and time of year. Other inorganic forms present at much lower concentration include hydroxylamine (NH_2OH), nitrous oxide (N_2O), and hyponitrite ($N_2O_2^{2-}$).

Ammonia exists in two forms in seawater. The primary form is

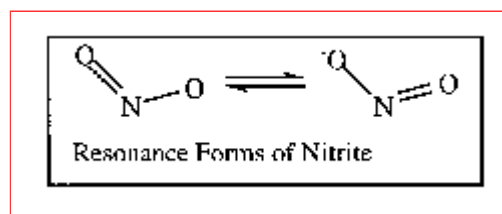
Speciation of Copper in Seawater	
Copper form	Percentage of total
$CuCO_3$	73.8
$Cu(CO_3)_2^{2-}$	14.2
$Cu(OH)^+$	4.9
Cu^{2+}	3.9
$Cu(OH)_2$	2.2
$CuSO_4$	1.0
$CuHCO_3^+$	0.1



ammonium (NH_4^+), which accounts for about 95 percent of the total in seawater at a pH of 8.1. The secondary form is free ammonia (NH_3), which accounts for the remaining 5 percent. These proportions vary strongly with pH and the free ammonia form rises as pH rises, to about 50 percent of the total at a pH of 9.5.

The toxicity of ammonia towards fish has been found to depend upon pH, with some researchers observing lower toxicity at lower pH. It has been suggested that this relationship between toxicity and pH is due to the proportion of ammonia in each form at a given pH. While these ideas seem to have been accepted by many in the aquarium hobby, the exact cause of this relationship is unclear and is beyond the scope of this article. This topic is discussed in more detail in *Captive Seawater Fishes* (Spotte 1992).

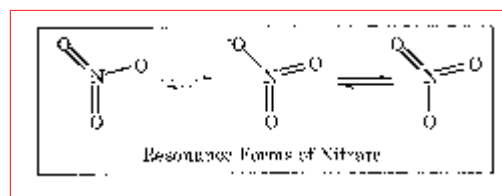
Nitrite and nitrate are both interesting molecules in that they exist in a number of resonance forms. If one draws a simple structure for these molecules it appears that the oxygen atoms are not all exactly the same, with one carrying a negative charge, while the others do not. Experimentally, however, this has not been found to be the case: all oxygen atoms are exactly equivalent.



How can this be? Resonance forms are a simple way of thinking about this, with the various forms interconverting extremely rapidly. The only thing required to convert one form to another is to move electrons around within the ion, so it can happen essentially instantly. In reality, the electrons are spread around these ions in such a way that each oxygen on average carries a partial negative charge ($-\frac{3}{4}$ in the case of nitrite; $-\frac{1}{3}$ in the case of nitrate).

Iodine

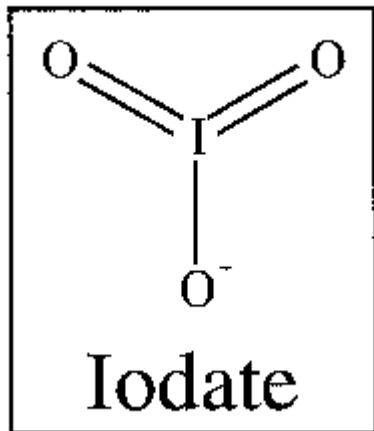
Iodine seems to get an amazingly disproportionate amount of discussion with respect to marine aquaria and much of it is incorrect. The reasons for this are many, but are primarily related to its chemical and biochemical complexity. In fact, its chemical complexity is far greater than many aquarists are aware.



Iodine takes two primary forms in seawater: iodide (I^-) and iodate (IO_3^-). The often quoted value for the total concentration of iodine in seawater (0.06 ppm) is reasonably accurate, although the value varies significantly. This value, however, is a combination of both iodide and iodate. It is not correct to state that seawater contains 0.06 ppm of iodide. The value for iodide is more typically around 0.01 ppm or less, although it is sometimes as high as 0.03 ppm and sometimes as low as 0.002 ppm. The remainder is iodate.

Additionally, the interconversion between iodide and iodate in seawater is very slow. This reaction is believed to be mediated in a number of ways, including catalysis by light and microorganisms. It is probably safe to say, however, that the two are not in equilibrium in marine aquaria. One effect of this lack of equilibrium is that dosing one type does not necessarily give you any of the other type.

It is not well known which forms are used by which



organisms, so I will not comment on the necessity of maintaining specific levels of iodide or iodate. There is good evidence, however, that iodide is rapidly depleted in marine aquaria, although it is not well established where it goes. Conversion of iodide to iodate has been observed in aquaria, but this may not represent a significant sink. Iodate itself is much slower to become depleted from marine aquaria and can build up to toxic levels if it is being actively dosed.

An additional complication is that some aquarists dose a third form of iodine: I_2 . Lugol's solution, for example, is a combination of iodide and iodine. When iodine (as I_2) is added to seawater, it quickly reacts to form other iodine species that probably end up as both iodide and iodate in marine tanks.

Conclusion

There are, of course, many other details of seawater chemistry that may be of interest to marine aquarists. This article is only a first pass at understanding the chemistry behind what is happening in our tanks.

For those wanting a more in depth exposure to marine chemistry, I recommend two books: *Captive Seawater Fishes. Science and Technology* by Stephen Spotte (Wiley-Interscience, New York. Pp. 942.) and *Chemical Oceanography, Second Edition* by Frank J. Millero (CRC Press, Boca Raton, FL. Pp. 469.).

The Spotte book is excellent, with sections directed specifically toward aquarium chemistry. It covers chemistry from the standpoint of aquarium keeping, rather than understanding of the natural ocean. It is also practically oriented, rather than directed toward a deep chemical understanding of phenomena.

The Millero book will only be of interest to those who are undaunted by chemical reactions and jargon. It is, however, the best marine chemistry book I have encountered. It gives a tremendous amount of detail about natural marine systems, but has no discussion about aquaria. Most of the chemical data in this paper was pulled from this book.

Previous "Biochemistry of Reef Aquariums" columns in *Aquarium Frontiers* magazine have also dealt with selected topics of interest to marine aquarists, especially the column on "Ion Pairing, Buffer Perturbation and Phosphate Export in Marine Aquariums" (Bingman, C. 1996. *Aquarium Frontiers* 3 [1]:10-17).

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Detailed Composition of Seawater

at 3.5% salinity

Element	At.weight	ppm	Element	At.weight	ppm
Hydrogen H ₂ O	1.00797	110,000	Molybdenum Mo	0.09594	0.01
Oxygen H ₂ O	15.9994	883,000	Ruthenium Ru	101.07	0.0000007
Sodium NaCl	22.9898	10,800	Rhodium Rh	102.905	.
Chlorine NaCl	35.453	19,400	Palladium Pd	106.4	.
Magnesium Mg	24.312	1,290	Argentum (silver) Ag	107.870	0.00028
Sulfur S	32.064	904	Cadmium Cd	112.4	0.00011
Potassium K	39.102	392	Indium In	114.82	.
Calcium Ca	10.08	411	Stannum (tin) Sn	118.69	0.00081
Bromine Br	79.909	67.3	Antimony Sb	121.75	0.00033
Helium He	4.0026	0.0000072	Tellurium Te	127.6	.
Lithium Li	6.939	0.170	Iodine I	166.904	0.064
Beryllium Be	9.0133	0.0000006	Xenon Xe	131.30	0.000047
Boron B	10.811	4.450	Cesium Cs	132.905	0.0003
Carbon C	12.011	28.0	Barium Ba	137.34	0.021
Nitrogen ion	14.007	15.5	Lanthanum La	138.91	0.0000029
Fluorine F	18.998	13	Cerium Ce	140.12	0.0000012
Neon Ne	20.183	0.00012	Praesodymium Pr	140.907	0.00000064
Aluminium Al	26.982	0.001	Neodymium Nd	144.24	0.0000028
Silicon Si	28.086	2.9	Samarium Sm	150.35	0.00000045
Phosphorus P	30.974	0.088	Europium Eu	151.96	0.0000013
Argon Ar	39.948	0.450	Gadolinium Gd	157.25	0.0000007
Scandium Sc	44.956	<0.000004	Terbium Tb	158.924	0.00000014
Titanium Ti	47.90	0.001	Dysprosium Dy	162.50	0.00000091
Vanadium V	50.942	0.0019	Holmium Ho	164.930	0.00000022
Chromium Cr	51.996	0.0002	Erbium Er	167.26	0.00000087
Manganese Mn	54.938	0.0004	Thulium Tm	168.934	0.00000017
Ferrum (Iron) Fe	55.847	0.0034	Ytterbium Yb	173.04	0.00000082
Cobalt Co	58.933	0.00039	Lutetium Lu	174.97	0.00000015
Nickel Ni	58.71	0.0066	Hafnium Hf	178.49	<0.000008
Copper Cu	63.54	0.0009	Tantalum Ta	180.948	<0.0000025
Zinc Zn	65.37	0.005	Tungsten W	183.85	<0.000001
Gallium Ga	69.72	0.00003	Rhenium Re	186.2	0.0000084
Germanium Ge	72.59	0.00006	Osmium Os	190.2	.
Arsenic As	74.922	0.0026	Iridium Ir	192.2	.
Selenium Se	78.96	0.0009	Platinum Pt	195.09	.
Krypton Kr	83.80	0.00021	Aurum (gold) Au	196.967	0.000011
Rubidium Rb	85.47	0.120	Mercury Hg	200.59	0.00015
Strontium Sr	87.62	8.1	Thallium Tl	204.37	.
Yttrium Y	88.905	0.000013	Lead Pb	207.19	0.00003
Zirconium Zr	91.22	0.000026	Bismuth Bi	208.980	0.00002
Niobium Nb	92.906	0.000015	Thorium Th	232.04	0.0000004
			Uranium U	238.03	0.0033
			Plutonium Pu	(244)	.

Note! ppm= parts per million = mg/litre = 0.001g/kg.

source: Karl K Turekian: *Oceans*. 1968. Prentice-Hall

DISSOLVED OXYGEN TABLE (mg/l)

Temperature °C	0	5	10	Salinity 15	(ppt) 20	25	30	35
0	14.6	14.11	13.64	13.18	12.74	12.31	11.9	11.5
2	13.81	13.36	12.91	12.49	12.07	11.67	11.29	10.91
4	13.09	12.67	12.25	11.85	11.47	11.09	10.73	10.38
6	12.44	12.04	11.65	11.27	10.91	10.56	10.22	9.89
8	11.83	11.46	11.09	10.74	10.4	10.07	9.75	9.44
10	11.28	10.92	10.58	10.25	9.93	9.62	9.32	9.03
12	10.77	10.43	10.11	9.8	9.5	9.21	8.92	8.65
14	10.29	9.98	9.68	9.38	9.1	8.82	8.55	8.29
16	9.86	9.56	9.28	9	8.73	8.47	8.21	7.97
18	9.45	9.17	8.9	8.64	8.38	8.14	7.9	7.66
20	9.08	8.81	8.56	8.31	8.06	7.83	7.6	7.38
22	8.73	8.48	8.23	8	7.77	7.54	7.33	7.12
24	8.4	8.16	7.93	7.71	7.49	7.28	7.07	6.87
26	8.09	7.87	7.65	7.44	7.23	7.03	6.83	6.64
28	7.81	7.59	7.38	7.18	6.98	6.79	6.61	6.42
30	7.54	7.33	7.14	6.94	6.75	6.57	6.39	6.22

72°f ⇨

SECTION 5
RESULTS AND OBSERVATIONS
LINE 22

5. Results and Observations – Line 22 Bulk Oil / Non-inhibited

a. Sample/Locations Observations

Water samples were taken at the top of the riser before flushing began. All bolts and flange seals were intact and did not indicate any leakage. All other samples were taken at the same location. Water samples seemed uniform, and representative of the flush fluid stream.

b. Flushwater Composition Observations

The flushwater composition for line 22 is plotted in the results section. Natural Seawater composition is also plotted for comparison purposes. The ions/elements plotted are: Alkalinity (CO₃), Barium, Calcium, Iron, Magnesium, and Potassium. Because of their high values (in PPM), Chlorides and Sulfates are plotted on a separate chart.

For the flushwater, the mineral pattern relative to NSW is summarized below:

Alkalinity (bicarb) – Higher/Same
Barium – Same
Calcium – Lower/ (First sample much lower)
Iron – Higher
Magnesium – Lower
Potassium – Lower
Chloride – Lower
Sulfate – Lower/Higher

The first sample, containing the most hydrocarbons was MUCH lower than NSW in almost all elements/ions tested for.

The iron content is plotted as a separate graph in order to focus on these values. The first sample had a very high iron concentration of .14 ppm (ppm also equals milligrams/liter). Observations from the field could explain this very high concentration. The sample was taken at the very front of the flushwater “slug.” This slug picked up metal debris, as is typical in most flushing operations. This debris included metal particles, which were picked up from the pipe wall. The sampling procedure “dissolved” these metal particles and recorded them as a concentration value. The third and fourth samples were high as well, but this too can be attributed to a slugging effect during flushing operations.

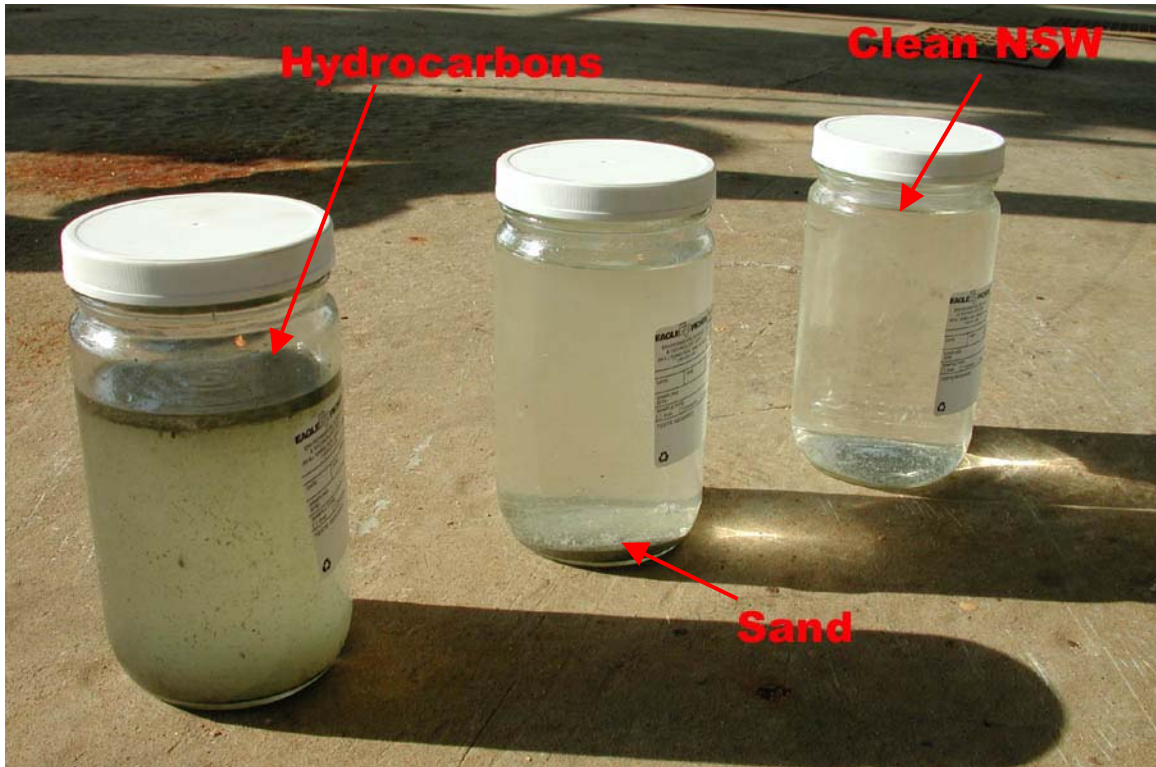


Photo #12 – Typical Mineral Pattern Analysis Samples

The ions/elements to focus on from this analysis are those found in steel corrosion products: FeO₂, FeS. The samples showed higher than NSW concentrations of both Fe and S, indicating that corrosion has taken place, however, it is difficult to derive specific corrosion features from this data.

c. Oil and Grease Observations

Samples taken at the end of the flushing operation had no detectable oil and grease concentration. The detection limit is 2.5 PPM. The last sample was taken when approximately 1.00x the pipeline volume had been flushed. The graph shows a very rapid drop in oil and grease concentration; with the non-detectable limit appearing to be reached at 1.0x flush volume.



PIPELINE FLUSHING AND SAMPLING RECORD

I. Pipeline Information

MMS Segment No.	22
Date:	6/10/2002
<u>Pipeline Origination</u> Area Block Platform Lease	
<u>Pipeline Destination</u> Area Block Platform Lease	
Pipeline Size (in)	4
Pipelines Length (ft)	1,600
Pipeline Volume (bbls)	25

II. Flushing Information

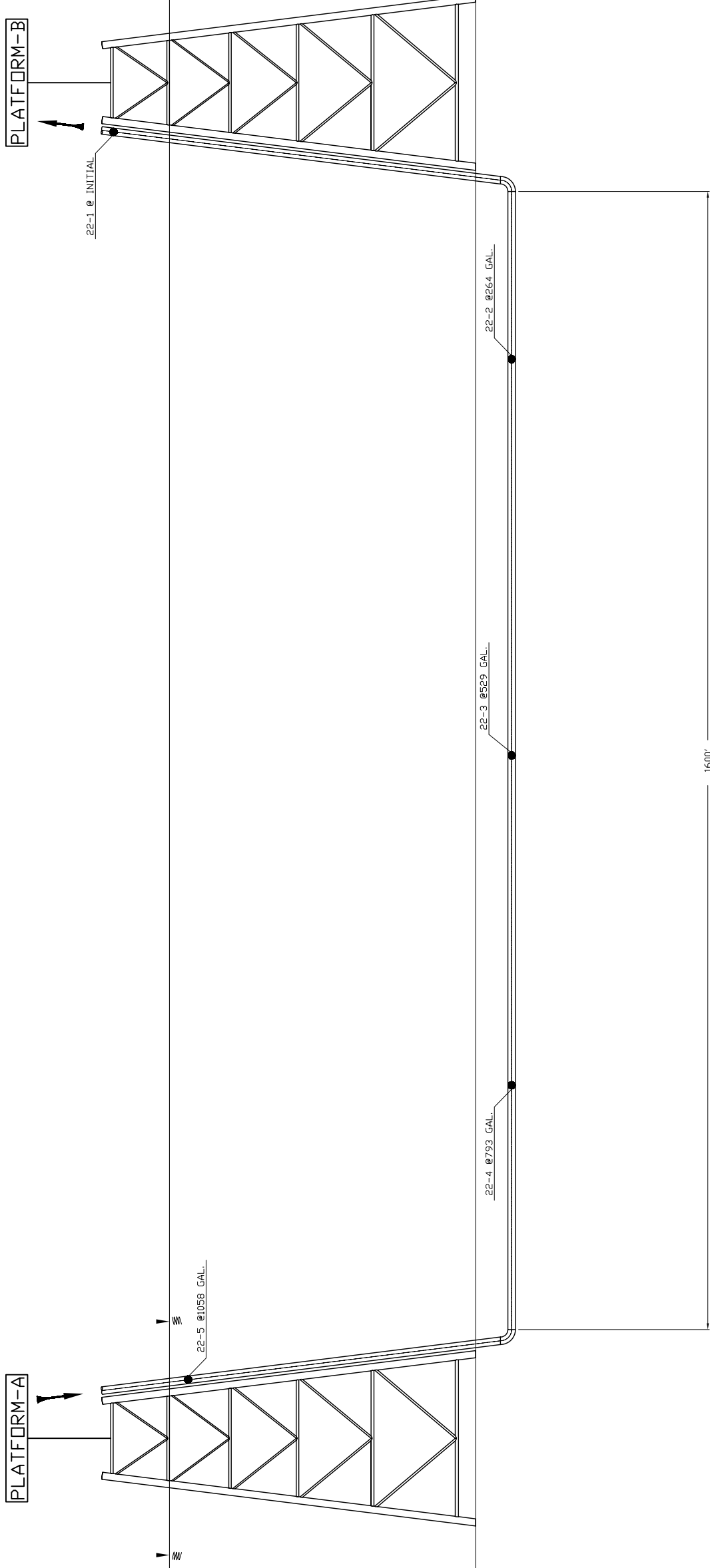
<u>Flushing Information</u> Volume Flushed Flow Rate (GPM) Pigged Used Type of Pig Size of Pig Clean Returns	2100 gal. 100 No No No Yes
<u>Inhibitor</u> Chemical Inhibitor Used Type of Chemical Quantity of Chemical	
<u>Origination Riser</u> Riser blind flanged w/ vent valve Pipeline Tagged	Yes Yes
<u>Destination Riser</u> Riser blind flanged w/ vent valve Pipeline Tagged	Yes Yes
Comments:	
Company Representative	
Signature	



III. Sampling Data - Tracking Information

Sample Location					
Platform:					
Pipeline Sampling Site:		Top of Riser Bleed Valve			
Flushing Start Time:		8:00			
Gas Samples		Sample ID	Sample Date	Vol. Flushed (g)	H2S (PPM)
Vacuum Tubes					
Plastic Bags					
Water Samples		Sample ID	Sample Date	Vol. Flushed (g)	Notes
Mineral Pattern Analysis					
		22-1	06/10/02	0	
		22-2	06/10/02	264	
		22-3	06/10/02	529	
		22-4	06/10/02	793	
Oil and Grease Analysis		22-5	06/10/02	1,058	
		22-1	06/10/02	0	
		22-2	06/10/02	264	
		22-3	06/10/02	529	
		22-4	06/10/02	793	
		22-5	06/10/02	1,058	
Comments:					
Company Representative					
Signature					

FIGURE 1 LINE 22



PL SEGMENT	22
LENGTH	1600 FT.
VOLUME FLUSHED	2100 GAL.
PL VOLUME FLG/FLG	1058 GAL.

REV	DATE	DESCRIPTION	BY	APPD
0	7/02	ISSUED	CSA	WT

PROJECT #	WM0129
PIPELINE SAMPLE LOCATIONS	LINE 22
DATE	7/02
CSA	WM00129A
DATE	7/02
DATE	7/02
DATE	7/02



PROJECT #	WM0129
PIPELINE SAMPLE LOCATIONS	LINE 22
DATE	7/02
CSA	WM00129A
DATE	7/02
DATE	7/02

Figure 2 - Flushwater Composition - Line 22

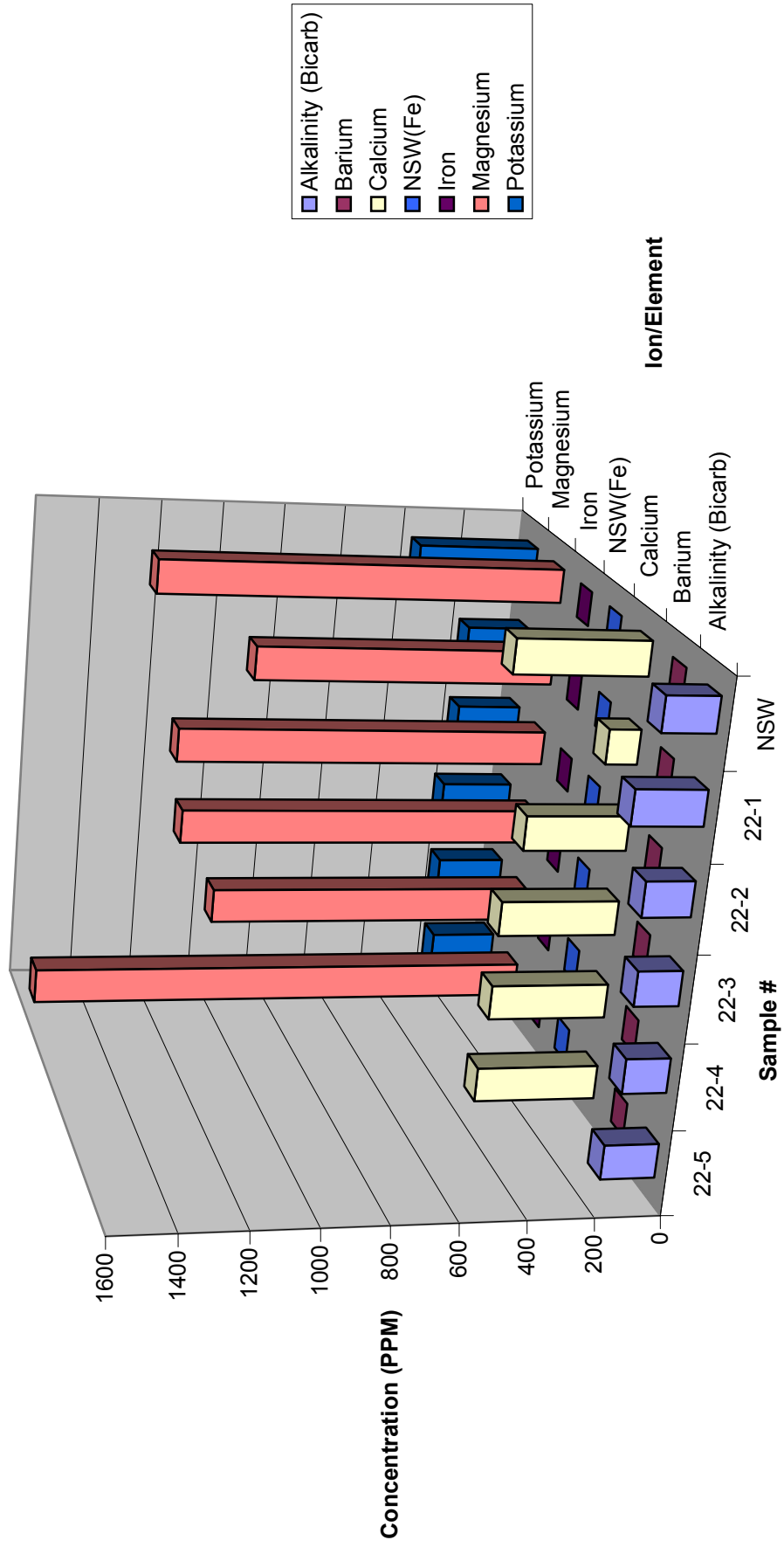


Figure 3 - Chloride and Sulfate - Line 22

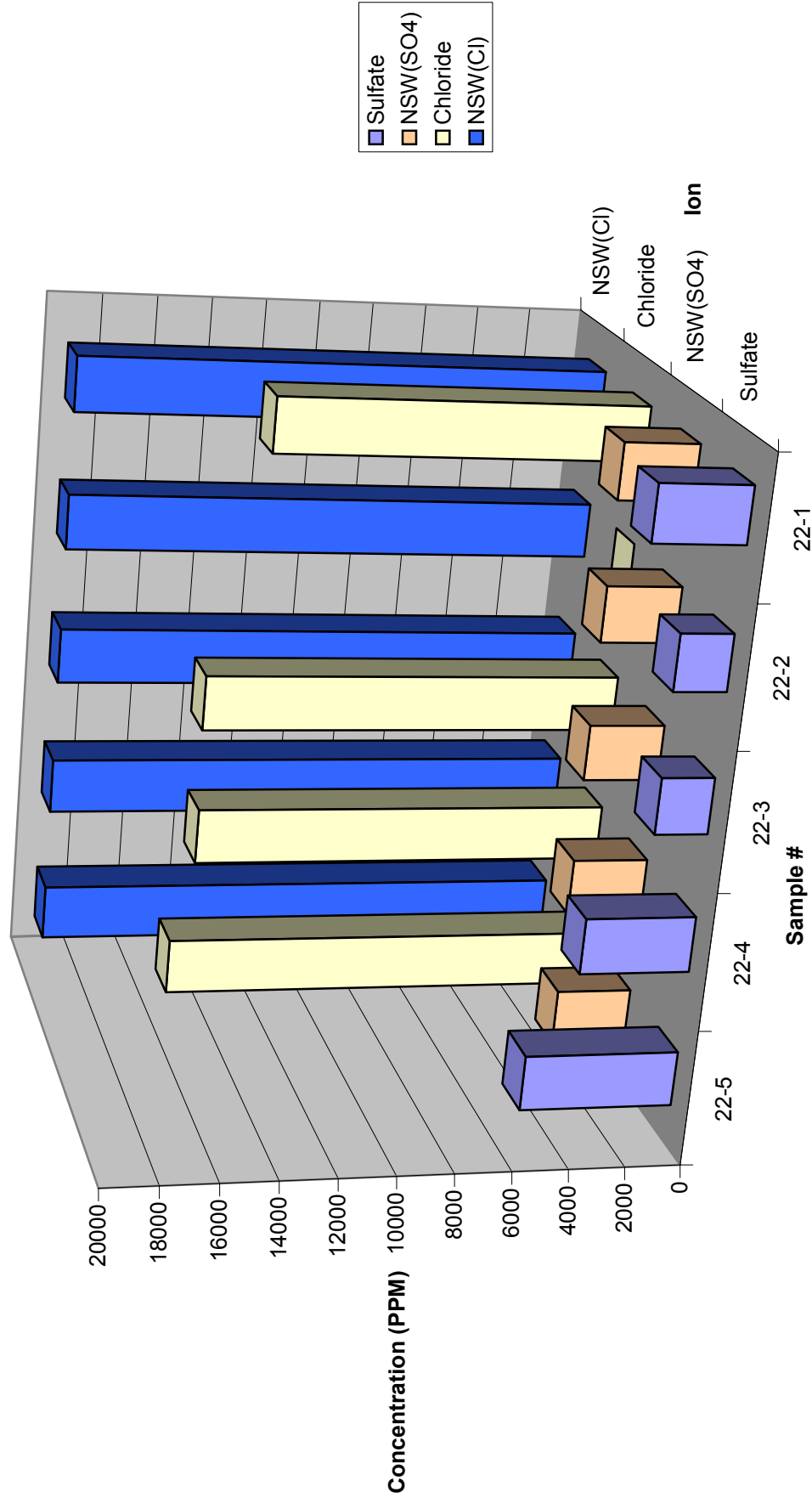
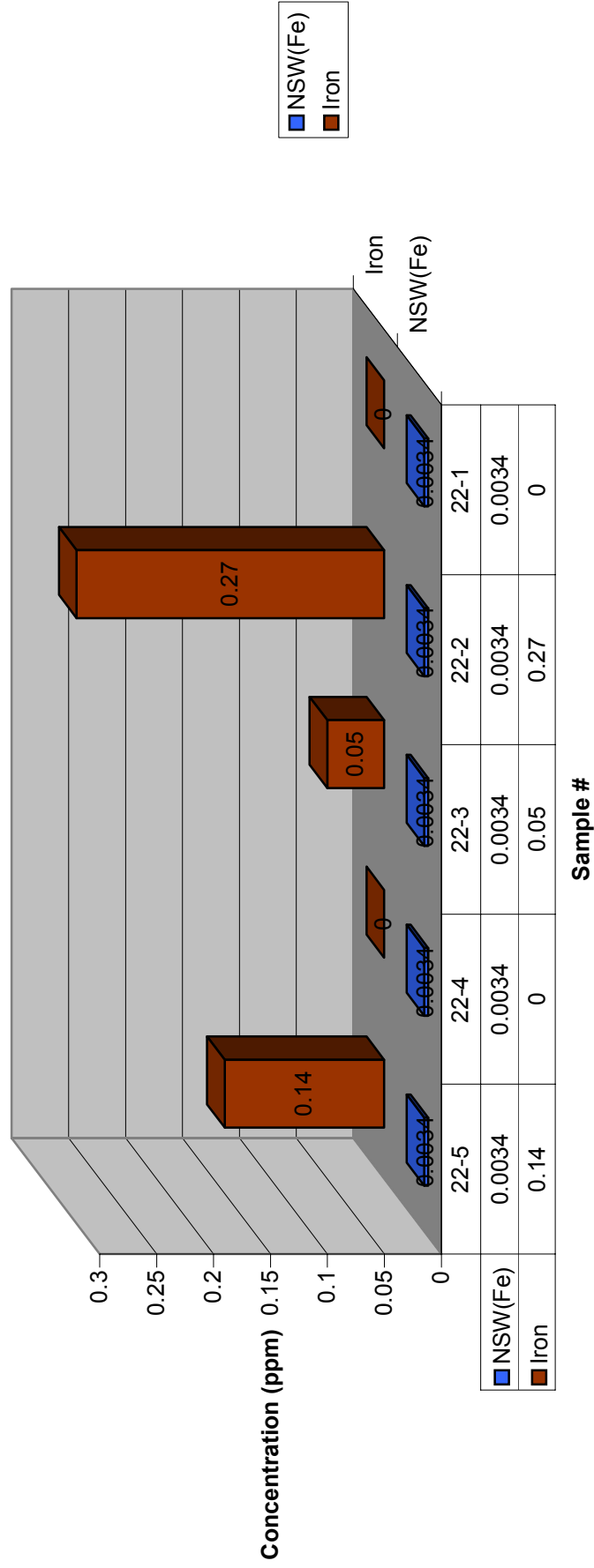
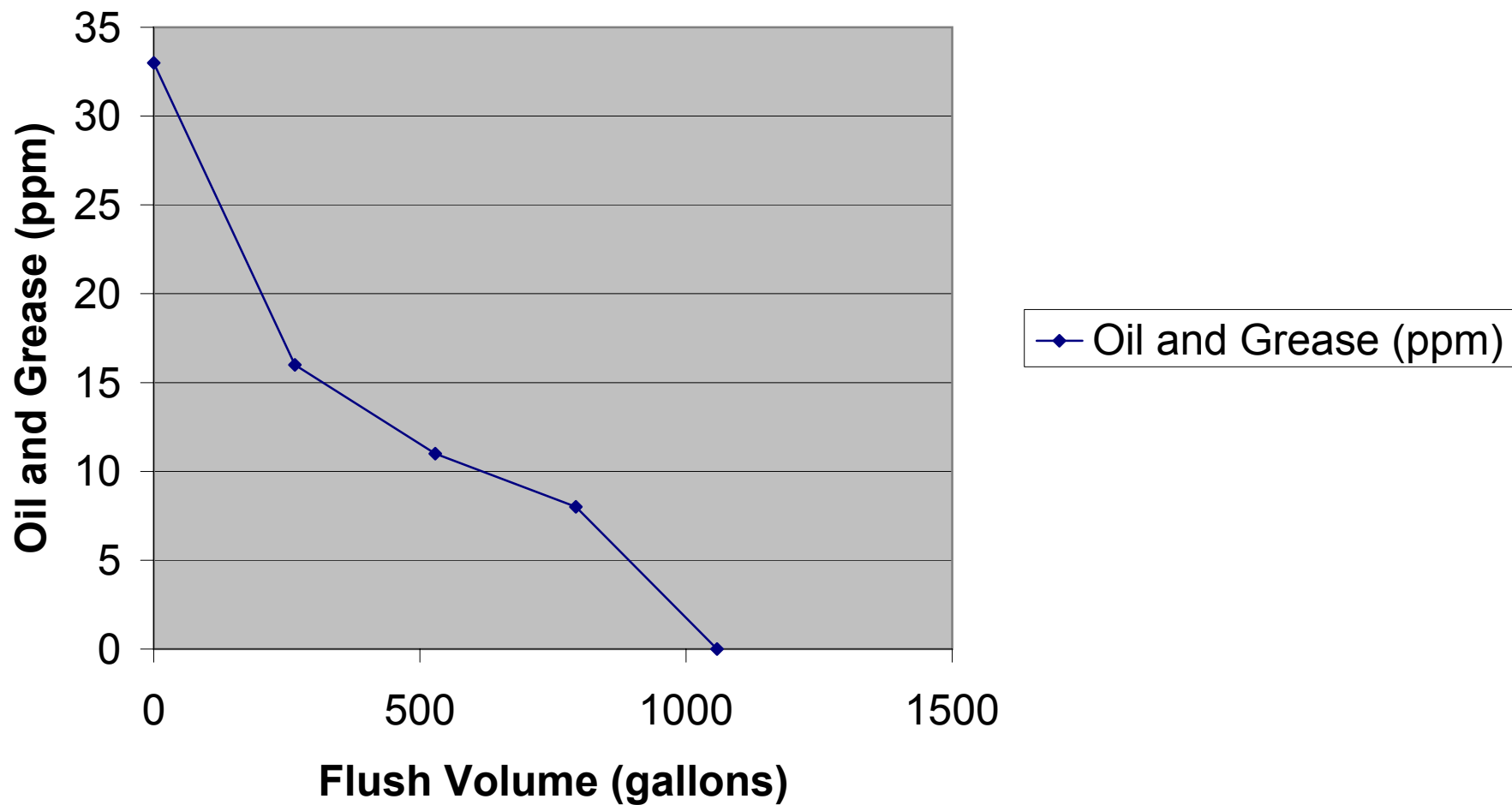


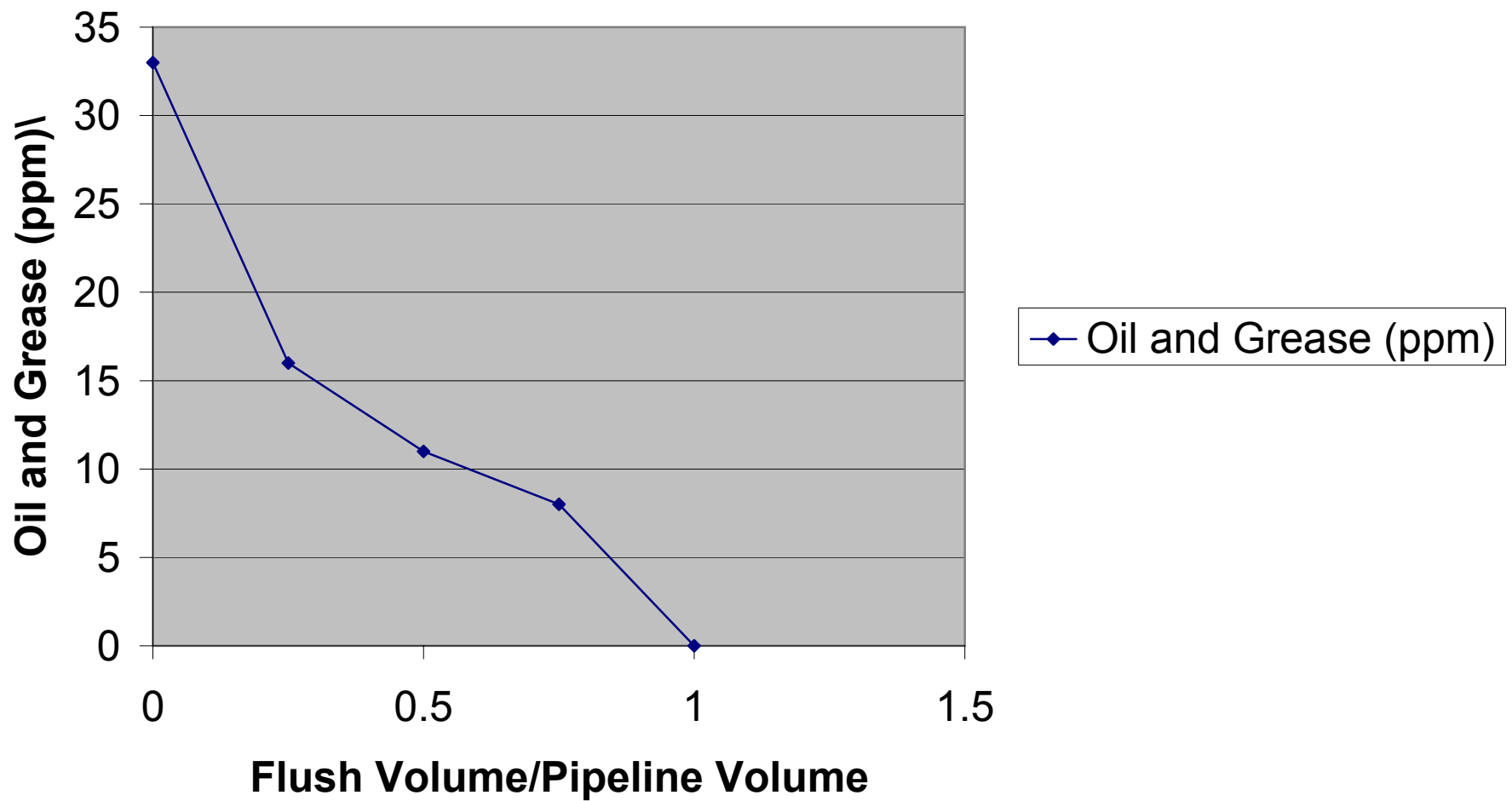
Figure 4 - Iron Concentration - Line 22



**Figure 5 - Oil and Grease vs. Flush Volume - Line
22**



**Figure 6 - Oil and Grease vs Flush Volume - Line
22**





LINE 22

Client Sample ID #1 Collected: 06/10/2002 0:00 SPL Sample ID: 02060834-01

Site:

Analyses/Method	Result	Rep.Limit	Dil. Factor	QUAL	Date Analyzed	Analyst	Seq. #
OIL & GREASE, TOTAL RECOVERABLE			MCL	E413.1	Units: mg/L		
Oil & Grease, Total Recoverable	16	6	1		06/21/02 14:00	DB	409972

Qualifiers:

ND/U - Not Detected at the Reporting Limit	>MCL - Result Over Maximum Contamination Limit(MCL)
B - Analyte detected in the associated Method Blank	D - Surrogate Recovery Unreportable due to Dilution
* - Surrogate Recovery Outside Advisable QC Limits	MI - Matrix Interference
J - Estimated Value between MDL and PQL	



LINE 22

Client Sample ID #2 **Collected: 06/10/2002 0:00** **SPL Sample ID: 02060834-02**

Site:

Analyses/Method	Result	Rep.Limit	Dil. Factor	QUAL	Date Analyzed	Analyst	Seq. #
OIL & GREASE, TOTAL RECOVERABLE							
			MCL	E413.1	Units: mg/L		
Oil & Grease, Total Recoverable	33	6	1		06/21/02 14:00	DB	409973

Qualifiers:
ND/U - Not Detected at the Reporting Limit
B - Analyte detected in the associated Method Blank
* - Surrogate Recovery Outside Advisable QC Limits
J - Estimated Value between MDL and PQL

>MCL - Result Over Maximum Contamination Limit(MCL)
D - Surrogate Recovery Unreportable due to Dilution
MI - Matrix Interference

6/25/02 8:44:06 AM



LINE 22

Client Sample ID #3 Collected: 06/10/2002 0:00 SPL Sample ID: 02060834-03

Site:

Analyses/Method	Result	Rep.Limit	Dil. Factor	QUAL	Date Analyzed	Analyst	Seq. #
OIL & GREASE,TOTAL RECOVERABLE				MCL			
				E413.1			
Oil & Grease,Total Recoverable	8	6	1		06/21/02 14:00	DB	409974

Qualifiers: ND/U - Not Detected at the Reporting Limit >MCL - Result Over Maximum Contamination Limit(MCL)
 B - Analyte detected in the associated Method Blank D - Surrogate Recovery Unreportable due to Dilution
 * - Surrogate Recovery Outside Advisable QC Limits MI - Matrix Interference
 J - Estimated Value between MDL and PQL

6/25/02 8:44:06 AM



LINE 22

Client Sample ID #4 Collected: 06/10/2002 0:00 SPL Sample ID: 02060834-04

Site: [illegible]

Analyses/Method	Result	Rep.Limit	Dil. Factor	QUAL	Date Analyzed	Analyst	Seq. #
OIL & GREASE, TOTAL RECOVERABLE							
		MCL		E413.1	Units: mg/L		
Oil & Grease, Total Recoverable	ND	5	1		06/21/02 14:00	DB	409975

Qualifiers: ND/U - Not Detected at the Reporting Limit >MCL - Result Over Maximum Contamination Limit(MCL)
B - Analyte detected in the associated Method Blank D - Surrogate Recovery Unreportable due to Dilution
* - Surrogate Recovery Outside Advisable QC Limits MI - Matrix Interference
J - Estimated Value between MDL and PQL



LINE 22

Client Sample ID #5 Collected: 06/10/2002 0:00 SPL Sample ID: 02060834-05

Site: [faded text]

Analyses/Method	Result	Rep.Limit	Dil. Factor	QUAL	Date Analyzed	Analyst	Seq. #
OIL & GREASE, TOTAL RECOVERABLE				MCL	E413.1	Units: mg/L	
Oil & Grease, Total Recoverable	11	6	1		06/21/02 14:00	DB	409976

Qualifiers:

- ND/U - Not Detected at the Reporting Limit
- B - Analyte detected in the associated Method Blank
- * - Surrogate Recovery Outside Advisable QC Limits
- J - Estimated Value between MDL and PQL
- >MCL - Result Over Maximum Contamination Limit(MCL)
- D - Surrogate Recovery Unreportable due to Dilution
- MI - Matrix Interference

Certificate of Analysis No. L1-02060834-05A

FOR: WINMAR CONSULTING SERVICES, I
 5700 NORTHWEST CENTR
 HOUSTON TX 77092

P.O. #:

DATE: 06/24/02

Attn:

PROJECT: WINMAR_01
 SITE:
 SAMPLED BY:
 SAMPLE ID: #5

PROJECT NO:
 MATRIX: Water
 DATE SAMPLED: 6/10/02
 DATE RECEIVED: 6/18/02

ANALYTICAL DATA

CATIONS	mg/L	mEq/L
Sodium - Na (calc.)	9282	403.75
Calcium - Ca	379	18.91
Magnesium - Mg	1590	130.80
Iron - Fe(Total)	0.14	0.01
Barium - Ba	0	0.00
Potassium - (mg/L)	210	5.38

ANIONS	mg/L	mEq/L
Chloride - Cl	15700	442.88
Bicarbonate - HCO ₃	165	2.70
Sulfate - SO ₄	5440	113.26
Carbonate - CO ₃	ND	0.00

WET CHEMISTRY	RESULT
Total Dissolved Solids (calc.) mg/L	32766

Specific Gravity 60/60 Deg. F	1.021
----------------------------------	-------

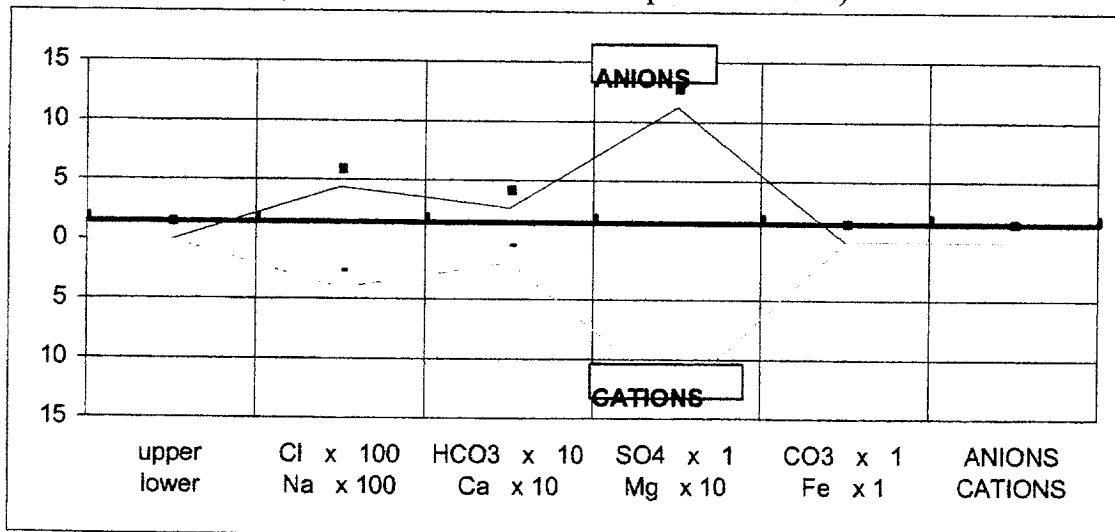
Resistivity (ohm*meters) 75 Deg.F	0.28
--------------------------------------	------

pH st units	7.5
----------------	-----

ND = Not Detected
 NA = Not Analyzed

MINERAL ANALYSIS PATTERN

(Number Below Ion Name mEq/liter/Scale Unit)



FOR: WINMAR CONSULTING SERVICES, I
 5700 NORTHWEST CENTR
 HOUSTON TX 77092

P.O. #:

DATE: 06/24/02

Attn:

PROJECT: WINMAR_01
 SITE:
 SAMPLED BY:
 SAMPLE ID: #4

PROJECT NO:
 MATRIX: Water
 DATE SAMPLED: 6/10/02
 DATE RECEIVED: 6/18/02

ANALYTICAL DATA

CATIONS	mg/L	mEq/L
Sodium - Na (calc.)	9129	397.06
Calcium - Ca	364	18.16
Magnesium - Mg	1040	85.55
Iron - Fe(Total)	0	0.00
Barium - Ba	0	0.00
Potassium - (mg/L)	216	5.54

ANIONS	mg/L	mEq/L
Chloride - Cl	15000	423.13
Bicarbonate - HCO ₃	134	2.20
Sulfate - SO ₄	3890	80.99
Carbonate - CO ₃	ND	0.00

WET CHEMISTRY	RESULT
Total Dissolved Solids (calc.) mg/L	29773

Specific Gravity 60/60 Deg. F	1.021
----------------------------------	-------

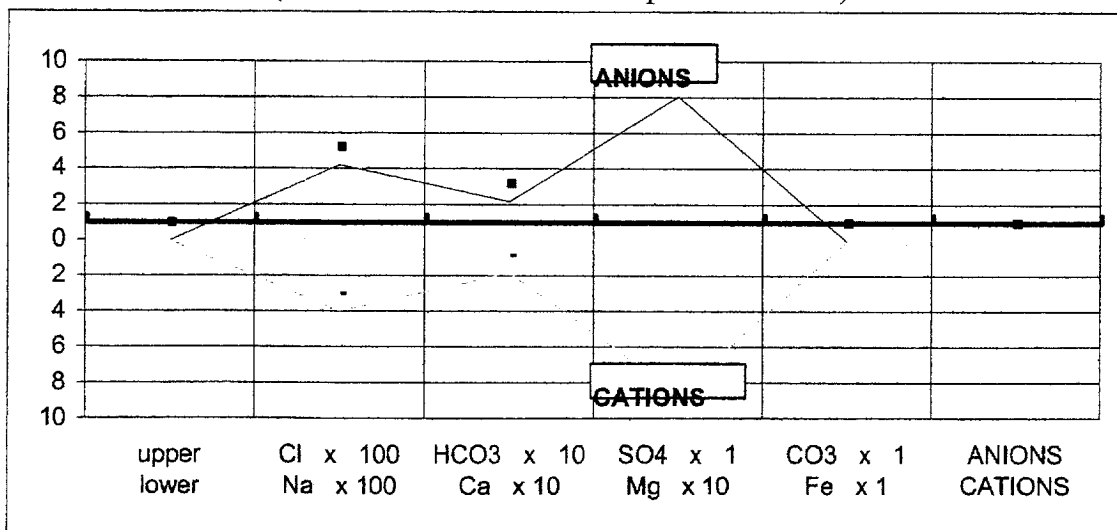
Resistivity (ohm*meters) 75 Deg.F	0.28
--------------------------------------	------

pH st units	7.55
----------------	------

ND = Not Detected
 NA = Not Analyzed

MINERAL ANALYSIS PATTERN

(Number Below Ion Name mEq/liter/Scale Unit)



Certificate of Analysis No. L1-02060834-03A

FOR: WINMAR CONSULTING SERVICES, I
 5700 NORTHWEST CENTR
 HOUSTON TX 77092

P.O. #:
 DATE: 06/24/02

Attn:
 PROJECT: WINMAR_01
 SITE:
 SAMPLED BY:
 SAMPLE ID: #3

PROJECT NO:
 MATRIX: Water
 DATE SAMPLED: 6/10/02
 DATE RECEIVED: 6/18/02

ANALYTICAL DATA

CATIONS	mg/L	mEq/L
Sodium - Na (calc.)	7991	347.60
Calcium - Ca	364	18.16
Magnesium - Mg	1160	95.43
Iron - Fe(Total)	0.05	0.00
Barium - Ba	0	0.00
Potassium - (mg/L)	230	5.89

ANIONS	mg/L	mEq/L
Chloride - Cl	15100	425.95
Bicarbonate - HCO ₃	134	2.20
Sulfate - SO ₄	1870	38.93
Carbonate - CO ₃	ND	0.00

WET CHEMISTRY	RESULT
Total Dissolved Solids (calc.) mg/L	26849

Specific Gravity 60/60 Deg. F	1.022
----------------------------------	-------

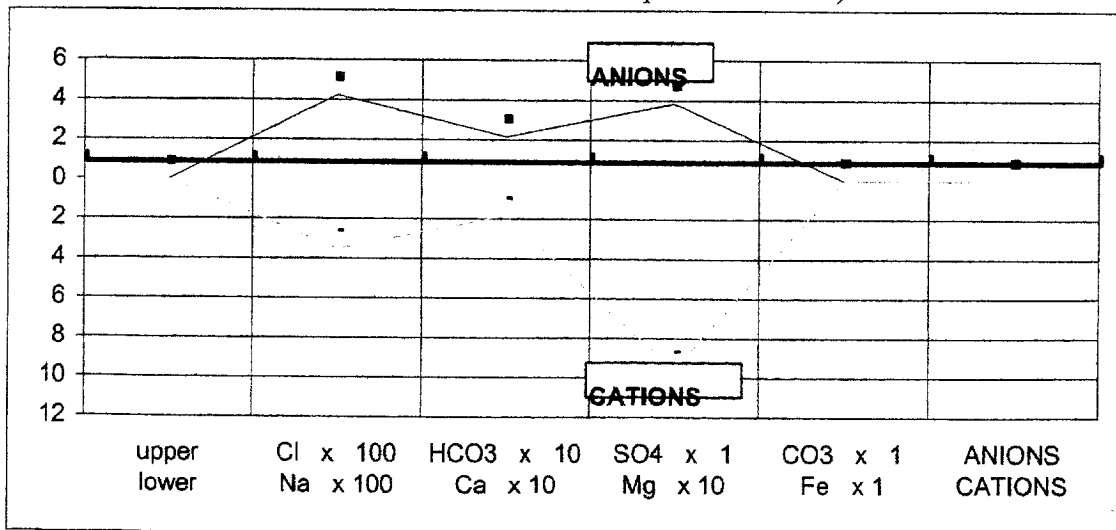
Resistivity (ohm*meters) 75 Deg.F	0.29
--------------------------------------	------

pH st units	7.61
----------------	------

ND = Not Detected
 NA = Not Analyzed

MINERAL ANALYSIS PATTERN

(Number Below Ion Name mEq/liter/Scale Unit)



Certificate of Analysis No. L1-02060834-02A

FOR: WINMAR CONSULTING SERVICES, I
 5700 NORTHWEST CENTR
 HOUSTON TX 77092

P.O. #:
 DATE: 06/24/02

Attn: PROJECT: WINMAR_01 PROJECT NO:
 SITE: MATRIX: Water
 SAMPLED BY: DATE SAMPLED: 6/10/02
 SAMPLE ID: #2 DATE RECEIVED: 6/18/02

ANALYTICAL DATA

CATIONS	mg/L	mEq/L
Sodium - Na (calc.)	8070	351.02
Calcium - Ca	318	15.87
Magnesium - Mg	1190	97.89
Iron - Fe(Total)	0.27	0.01
Barium - Ba	0	0.00
Potassium - (mg/L)	207	5.30

ANIONS	mg/L	mEq/L
Chloride - Cl	15200	428.77
Bicarbonate - HCO ₃	146	2.39
Sulfate - SO ₄	1870	38.93
Carbonate - CO ₃	ND	0.00

WET CHEMISTRY	RESULT
Total Dissolved Solids (calc.) mg/L	27001

Specific Gravity 60/60 Deg. F	1.022
----------------------------------	-------

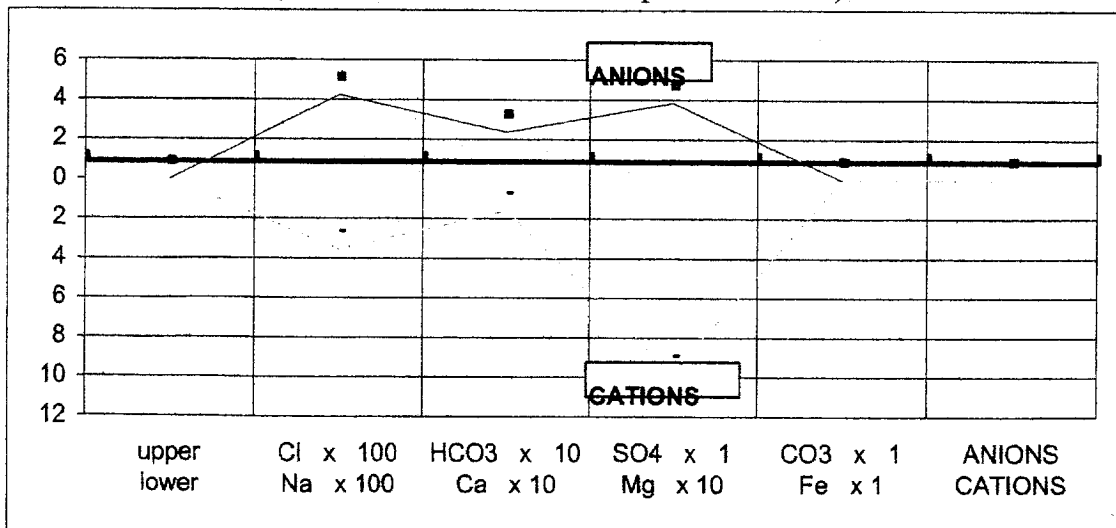
Resistivity (ohm*meters) 75 Deg.F	0.29
--------------------------------------	------

pH st units	7.77
----------------	------

ND = Not Detected
 NA = Not Analyzed

MINERAL ANALYSIS PATTERN

(Number Below Ion Name mEq/liter/Scale Unit)



SECTION 6
RESULTS AND OBSERVATIONS
Line 23

6. Results and Observations – Line 23 Bulk Oil / Inhibited

a. Sample Locations Observations

Water samples were taken at the top of the riser before flushing began. All bolts and flange seals were intact and did not indicate any leakage. All other samples were taken at the same location. Water samples seemed uniform, and representative of the flush fluid stream.

b. Flushwater Composition Observations

The flushwater composition for segment 23 is plotted in the results section. Natural Seawater composition is also plotted for comparison purposes. The ions/elements plotted are: Alkalinity (CO₃), Barium, Calcium, Iron, Magnesium, and Potassium. Because of their high values (in PPM), Chlorides and Sulfates are plotted on a separate chart.

For the flushwater, the mineral pattern relative to NSW is summarized below:

Alkalinity (bicarb) – Higher/Same
Barium – Same
Calcium – Lower
Iron – Higher
Magnesium – Lower
Potassium – Lower
Chloride – Lower
Sulfate – Lower

The plot of the Iron Concentration shows an initial concentration of .33 and .34 ppm respectively followed by a sharp increase (.96 ppm). The explanation for this occurrence is the same as for segment number 22. Slugging during flushing operations loosened and purged internal corrosion from the line as is common.

c. Oil and Grease Observations

Samples taken at the end of the flushing operation had no detectable oil and grease concentration. The detection limit is 2.5 PPM. The last sample was taken when approximately 1.00x the pipeline volume had been flushed. The graph shows a very rapid drop in oil and grease concentration; with the non-detectable limit appearing to be reached at 1.0x flush volume.



PIPELINE FLUSHING AND SAMPLING RECORD

I. Pipeline Information

MMS Segment No.	23
Date:	6/11/2002
Pipeline Origination Area Block Platform Lease	
Pipeline Destination Area Block Platform Lease	
Pipeline Size (in)	4
Pipelines Length (ft)	1,350
Pipeline Volume (bbls)	21

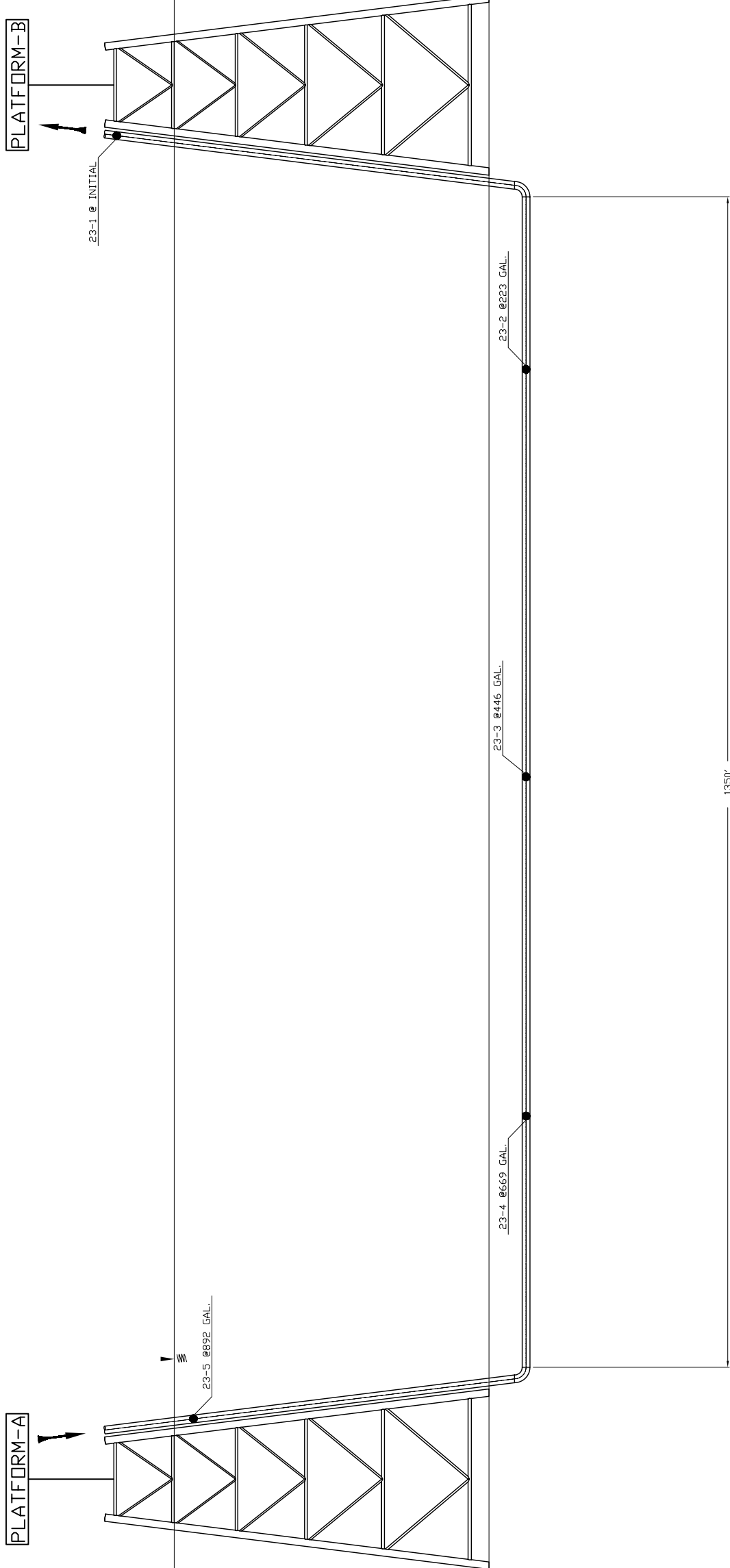
II. Flushing Information

Flushing Information Volume Flushed Flow Rate (GPM) Pigged Used Type of Pig Size of Pig Clean Returns	1785 gal. 100 No No No Yes
Inhibitor Chemical Inhibitor Used Type of Chemical Quantity of Chemical	
Origination Riser Riser blind flanged w/ vent val Pipeline Tagged	Yes Yes
Destination Riser Riser blind flanged w/ vent val Pipeline Tagged	Yes Yes
Comments:	
Company Representative	
Signature	

III. Sampling Data - Tracking Information

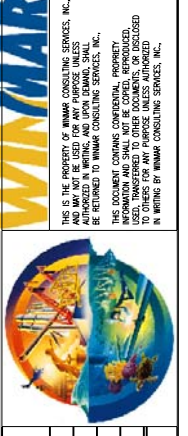
Sample Location				
Platform:				
Pipeline Sampling Site:		Top of Riser Bleed Valve		
Flushing Start Time:		8:00		
Gas Samples	Sample ID	Sample Date	Vol. Flushed (g)	H2S (PPM)
Vacuum Tubes				
Plastic Bags				
Water Samples	Sample ID	Sample Date	Vol. Flushed (g)	Notes
Mineral Pattern Analysis				
	23-1	06/11/02	0	
	23-2	06/11/02	223	
	23-3	06/11/02	446	
	23-4	06/11/02	669	
Oil and Grease Analysis	23-5	06/11/02	892	
	23-1	06/11/02	0	
	23-2	06/11/02	223	
	23-3	06/11/02	446	
	23-4	06/11/02	669	
	23-5	06/11/02	892	
Comments:				
Company Representative				
Signature				

FIGURE 7 LINE 23



PL SEGMENT	23
LENGTH	1350 FT.
VOLUME FLUSHED	1785 GAL.
PL VOLUME FLG/FLG	892 GAL.

REV	DATE	DESCRIPTION	BY	APPD
0	7/02	ISSUED	CSA	WT



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PROJECT # WM0129	
PIPELINE SAMPLE LOCATIONS	
LINE	23
DATE	7/02
CSA	WT
DWG. NO.	WM00129B
REV.	0

Figure 8 - Flushwater Composition - Line 23

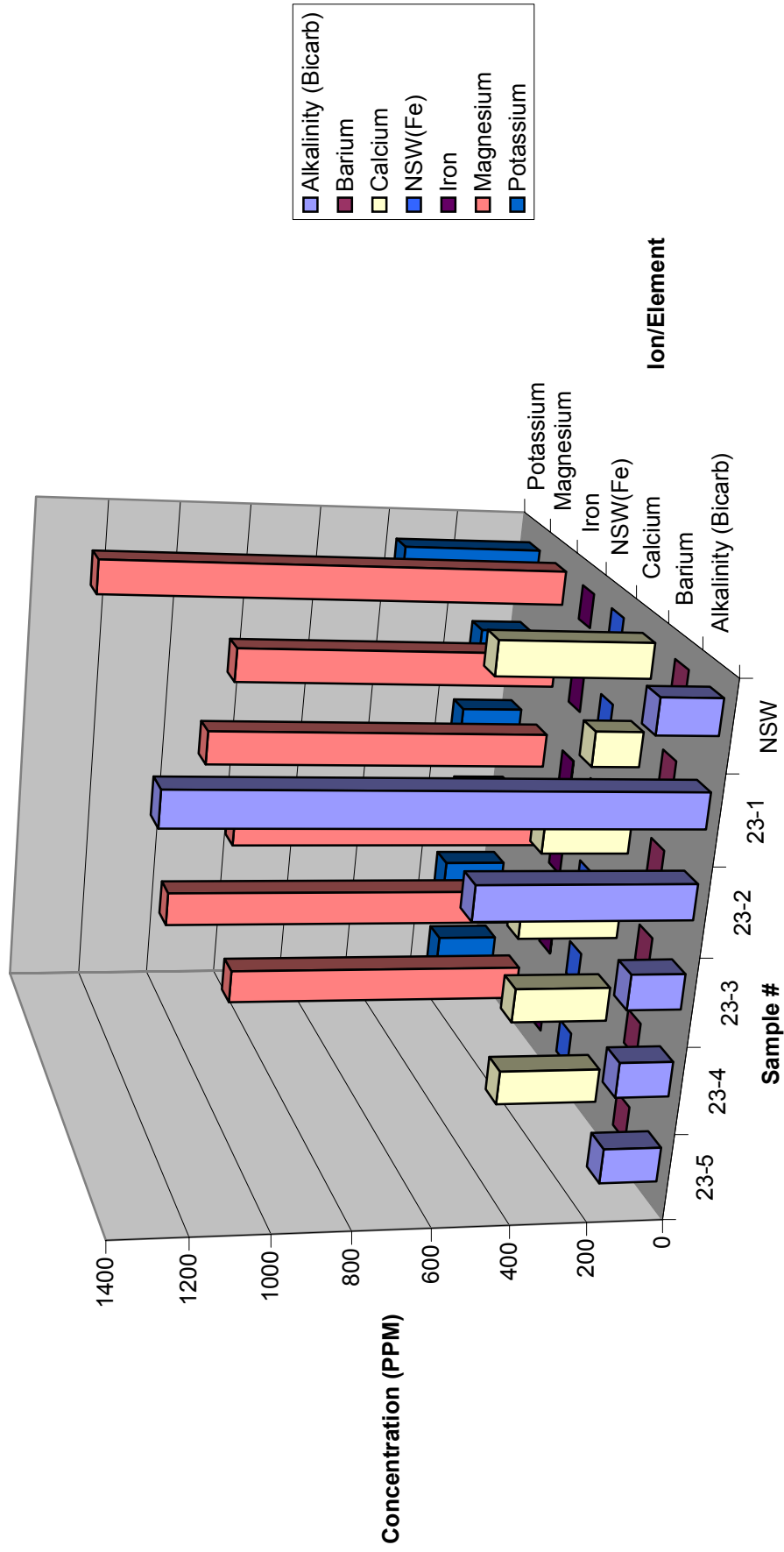


Figure 9 - Chloride and Sulfate - Line 23

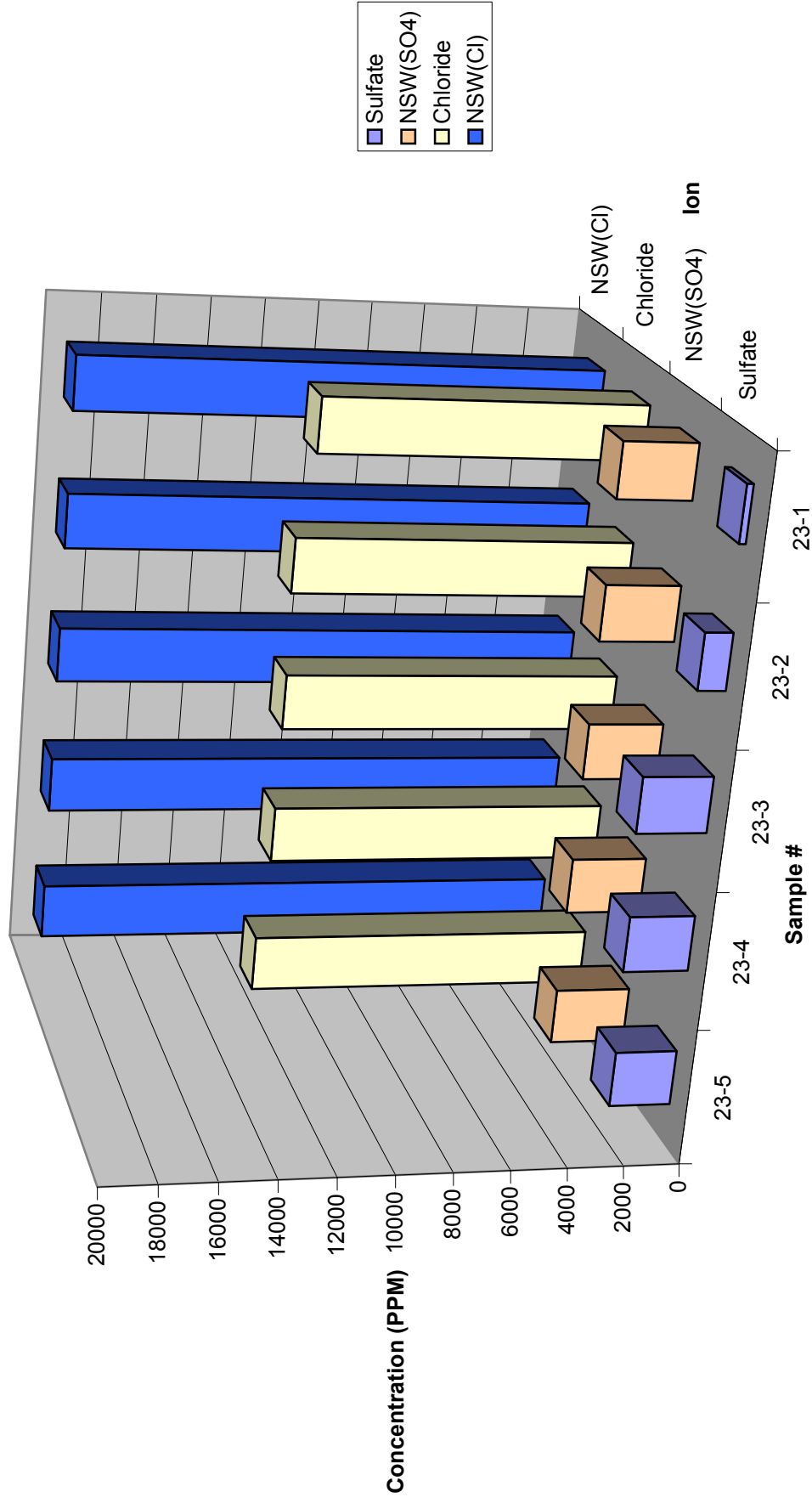
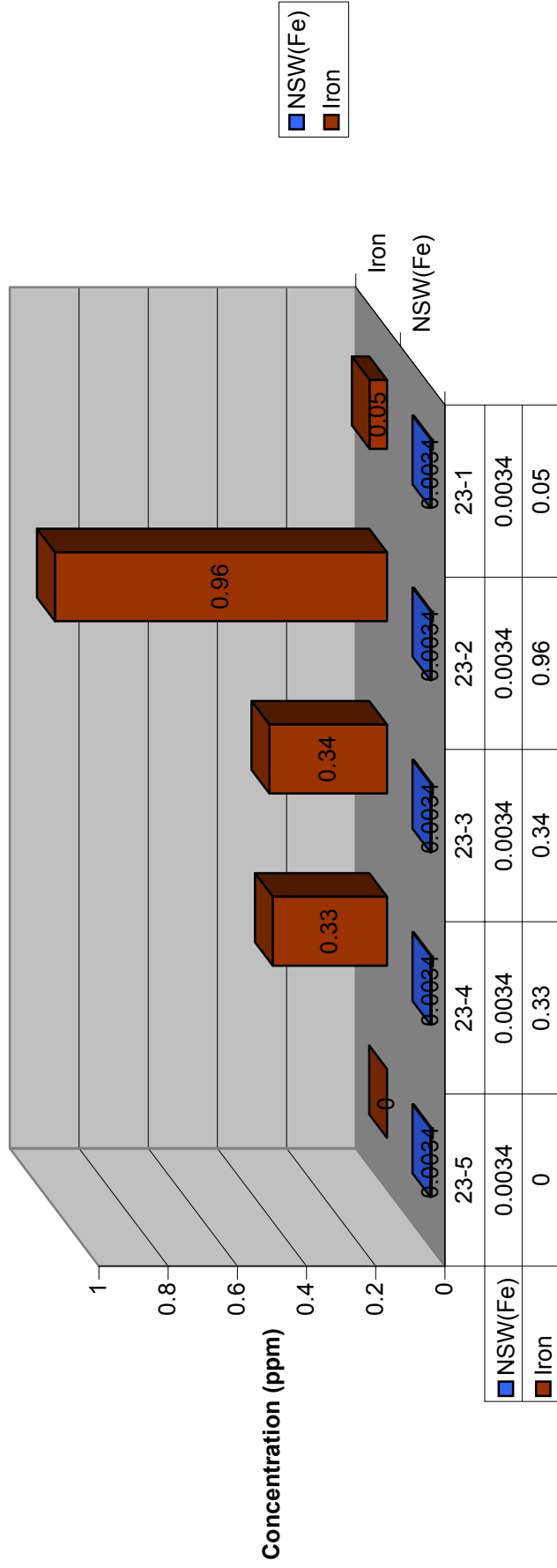
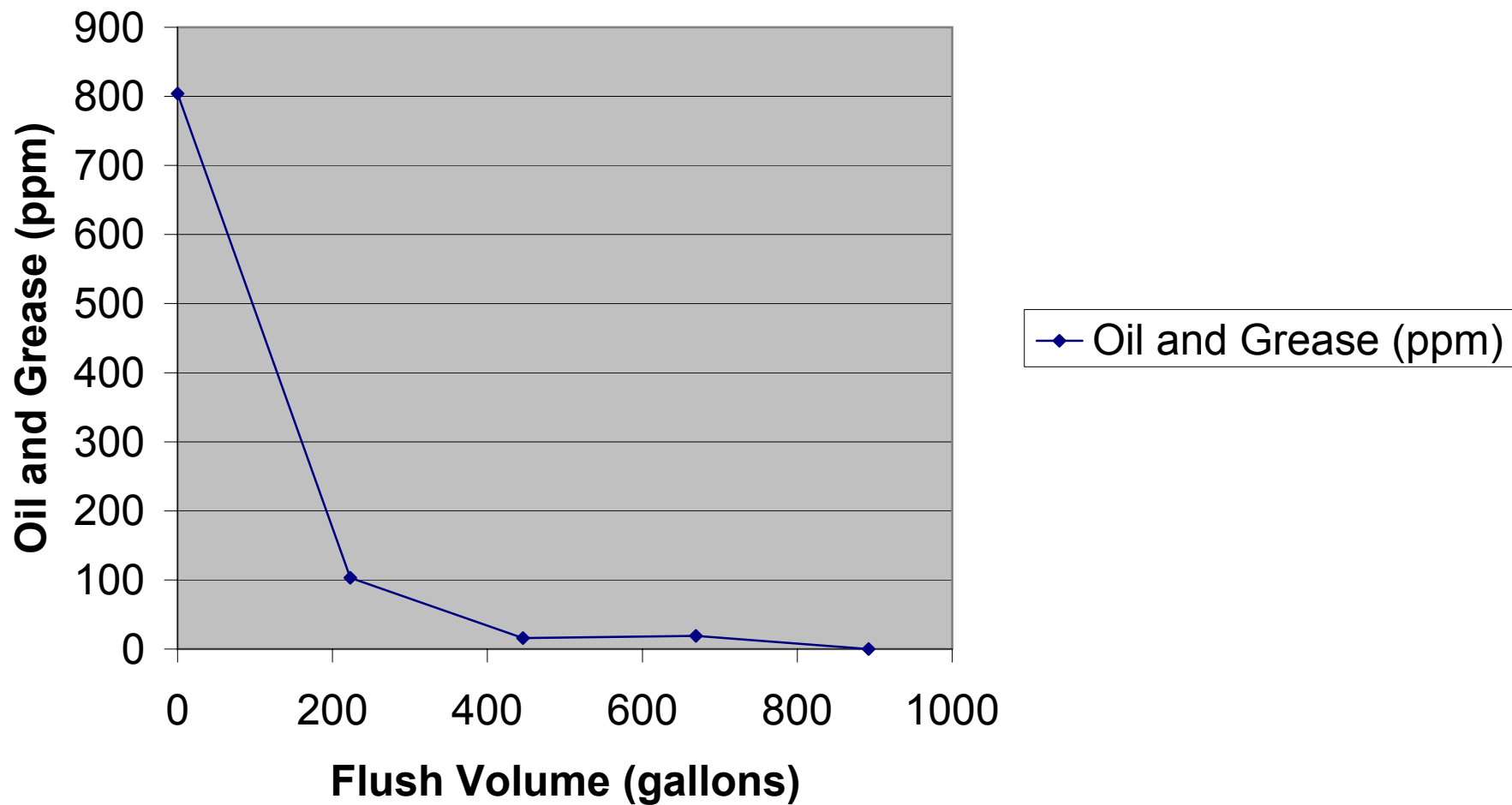


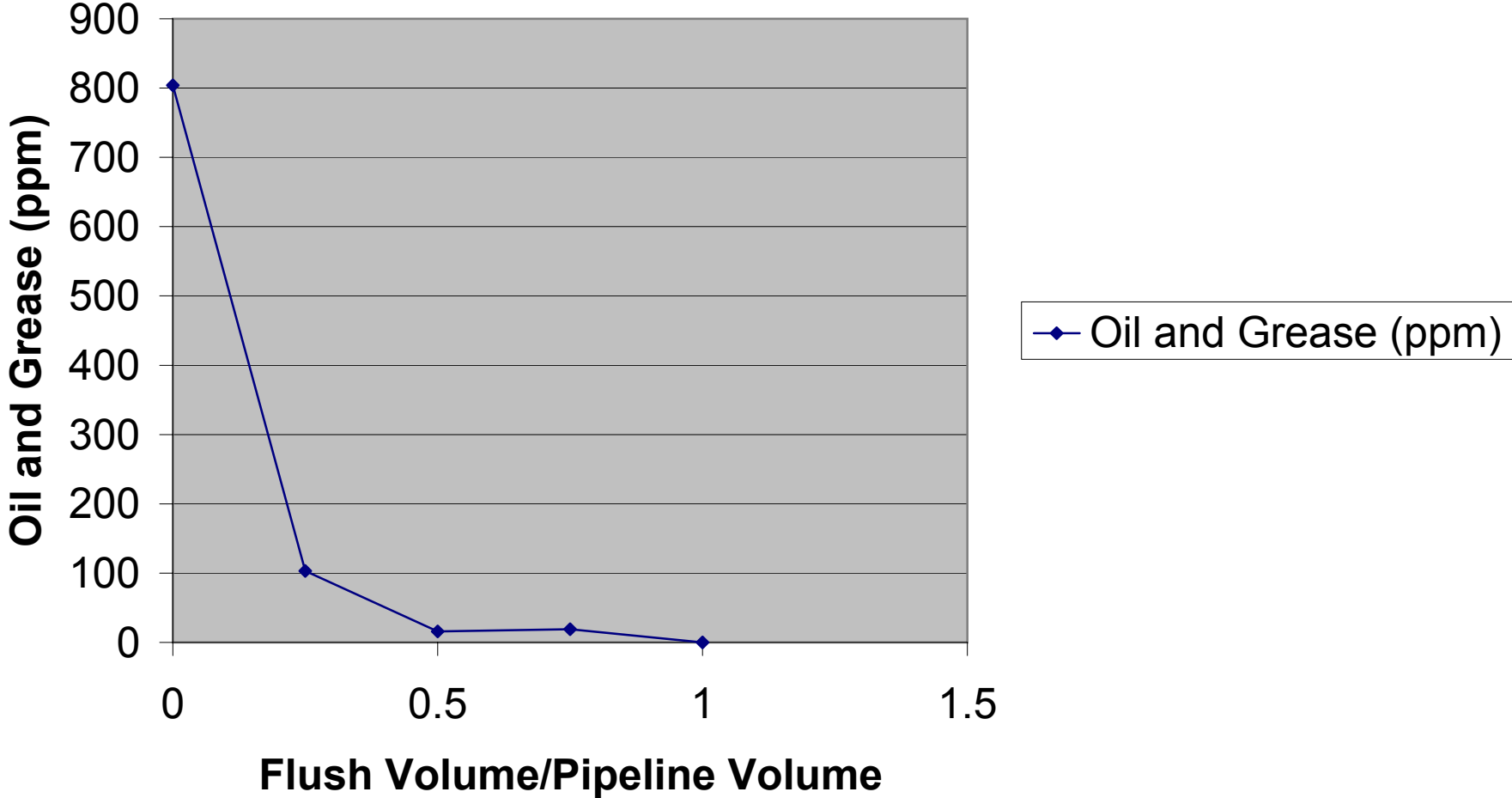
Figure 10 - Iron Concentration - Line 23



**Figure 11 - Oil and Grease vs. Flush Volume -
Line 23**



**Figure 12 - Oil and Grease vs. Flush Volume -Line
23**





LINE 23

Client Sample ID #1 Collected: 06/12/2002 0:00 SPL Sample ID: 02060836-01

Site:

Analyses/Method	Result	Rep.Limit	Dil. Factor	QUAL	Date Analyzed	Analyst	Seq. #
OIL & GREASE, TOTAL RECOVERABLE				MCL	E413.1	Units: mg/L	
Oil & Grease, Total Recoverable	804	5	1		06/24/02 9:00	DB	410247

Qualifiers:
ND/U - Not Detected at the Reporting Limit
B - Analyte detected in the associated Method Blank
* - Surrogate Recovery Outside Advisable QC Limits
J - Estimated Value between MDL and PQL

>MCL - Result Over Maximum Contamination Limit(MCL)
D - Surrogate Recovery Unreportable due to Dilution
MI - Matrix Interference



LINE 23

Client Sample ID #2	Collected: 06/12/2002 0:00	SPL Sample ID: 02060836-02
---------------------	----------------------------	----------------------------

Site:

Analyses/Method	Result	Rep.Limit	Dil. Factor	QUAL	Date Analyzed	Analyst	Seq. #
OIL & GREASE.TOTAL RECOVERABLE			MCL	E413.1	Units: mg/L		
Oil & Grease, Total Recoverable	103	6	1		06/24/02 9:00	DB	410248

Qualifiers:	ND/U - Not Detected at the Reporting Limit	>MCL - Result Over Maximum Contamination Limit(MCL)
	B - Analyte detected in the associated Method Blank	D - Surrogate Recovery Unreportable due to Dilution
	* - Surrogate Recovery Outside Advisable QC Limits	MI - Matrix Interference
	J - Estimated Value between MDL and PQL	



LINE 23

Client Sample ID #3 Collected: 06/12/2002 0:00 SPL Sample ID: 02060836-03

Site:

Analyses/Method	Result	Rep.Limit	Dil. Factor	QUAL	Date Analyzed	Analyst	Seq. #
OIL & GREASE, TOTAL RECOVERABLE				MCL			
				E413.1	Units: mg/L		
Oil & Grease, Total Recoverable	16	5	1		06/24/02 9:00	DB	410249

Qualifiers:
ND/U - Not Detected at the Reporting Limit
B - Analyte detected in the associated Method Blank
* - Surrogate Recovery Outside Advisable QC Limits
J - Estimated Value between MDL and PQL

>MCL - Result Over Maximum Contamination Limit(MCL)
D - Surrogate Recovery Unreportable due to Dilution
MI - Matrix Interference

6/25/02 8:47:00 AM



LINE 23

Client Sample ID #4 Collected: 06/12/2002 0:00 SPL Sample ID: 02060836-04

Site:

Analyses/Method	Result	Rep.Limit	Dil. Factor	QUAL	Date Analyzed	Analyst	Seq. #
OIL & GREASE, TOTAL RECOVERABLE			MCL	E413.1	Units: mg/L		
Oil & Grease, Total Recoverable	19	6	1		06/24/02 9:00	DB	410250

Qualifiers: ND/U - Not Detected at the Reporting Limit >MCL - Result Over Maximum Contamination Limit(MCL)
B - Analyte detected in the associated Method Blank D - Surrogate Recovery Unreportable due to Dilution
* - Surrogate Recovery Outside Advisable QC Limits MI - Matrix Interference
J - Estimated Value between MDL and PQL

Certificate of Analysis No. L1-02060836-01A

FOR: WINMAR CONSULTING SERVICES, I
 5700 NORTHWEST CENTR
 HOUSTON TX 77092

P.O. #:
 DATE: 06/24/02

Attn:
 PROJECT: WINMAR_01
 SITE:
 SAMPLED BY:
 SAMPLE ID: #1

PROJECT NO:
 MATRIX: Water
 DATE SAMPLED: 6/12/02
 DATE RECEIVED: 6/18/02

ANALYTICAL DATA

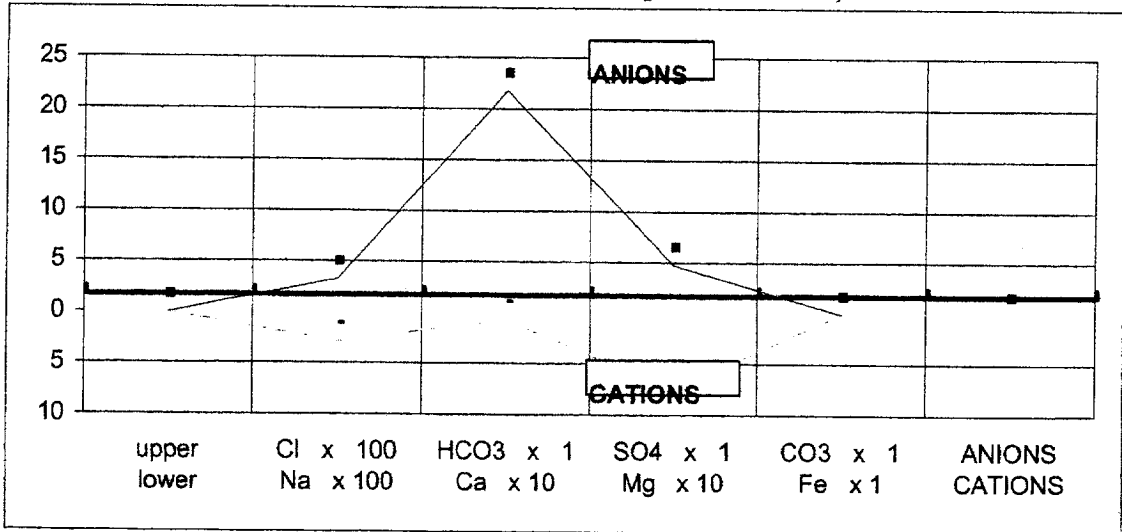
CATIONS	mg/L	mEq/L
Sodium - Na (calc.)	6329	275.29
Calcium - Ca	128	6.39
Magnesium - Mg	901	74.12
Iron - Fe(Total)	0.05	0.00
Barium - Ba	0	0.00
Potassium - (mg/L)	144	3.69

ANIONS	mg/L	mEq/L
Chloride - Cl	11800	332.86
Bicarbonate - HCO ₃	1330	21.80
Sulfate - SO ₄	232	4.83
Carbonate - CO ₃	ND	0.00

WET CHEMISTRY	RESULT
Total Dissolved Solids (calc.) mg/L	20864
Specific Gravity 60/60 Deg. F	1.014
Resistivity (ohm*meters) 75 Deg.F	0.35
pH st units	8.21

ND = Not Detected
 NA = Not Analyzed

MINERAL ANALYSIS PATTERN
 (Number Below Ion Name mEq/liter/Scale Unit)



Certificate of Analysis No. L1-02060836-02A

FOR: WINMAR CONSULTING SERVICES, I
 5700 NORTHWEST CENTR
 HOUSTON TX 77092

P.O. #:
 DATE: 06/24/02

Attn:
 PROJECT: WINMAR_01
 SITE:
 SAMPLED BY:
 SAMPLE ID: #2

PROJECT NO:
 MATRIX: Water
 DATE SAMPLED: 6/12/02
 DATE RECEIVED: 6/18/02

ANALYTICAL DATA

CATIONS	mg/L	mEq/L
Sodium - Na (calc.)	6469	281.38
Calcium - Ca	234	11.68
Magnesium - Mg	963	79.22
Iron - Fe(Total)	0.96	0.03
Barium - Ba	0	0.00
Potassium - (mg/L)	174	4.46

ANIONS	mg/L	mEq/L
Chloride - Cl	12300	346.97
Bicarbonate - HCO ₃	561	9.19
Sulfate - SO ₄	990	20.61
Carbonate - CO ₃	ND	0.00

WET CHEMISTRY	RESULT
Total Dissolved Solids (calc.) mg/L	21692

Specific Gravity 60/60 Deg. F	1.016
----------------------------------	-------

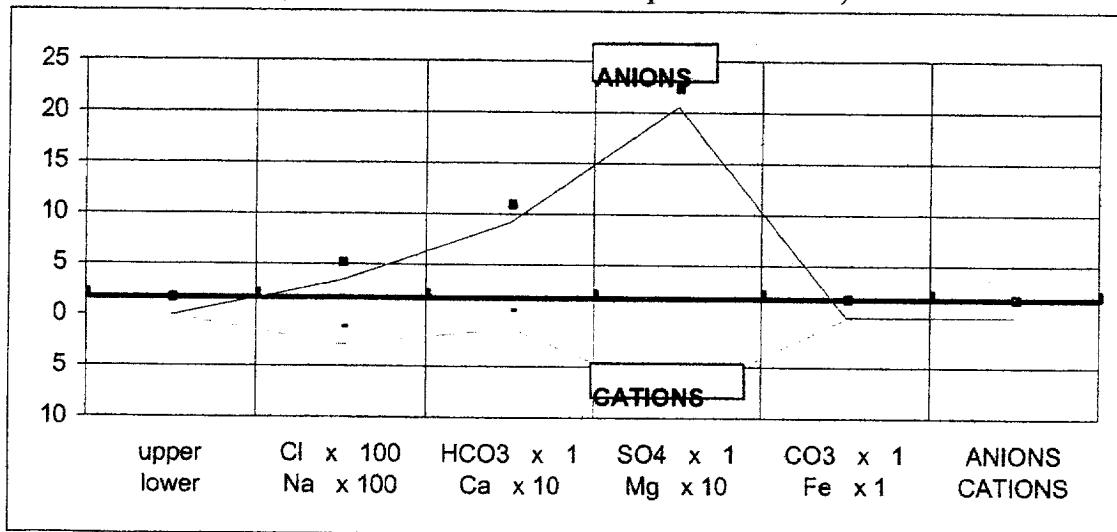
Resistivity (ohm*meters) 75 Deg.F	0.34
--------------------------------------	------

pH st units	7.85
----------------	------

ND = Not Detected
 NA = Not Analyzed

MINERAL ANALYSIS PATTERN

(Number Below Ion Name mEq/liter/Scale Unit)



Certificate of Analysis No. L1-02060836-03A

FOR: WINMAR CONSULTING SERVICES, I
 5700 NORTHWEST CENTR
 HOUSTON TX 77092

P.O. #:
 DATE: 06/24/02

Attn:
 PROJECT: WINMAR_01
 SITE:
 SAMPLED BY:
 SAMPLE ID: #3

PROJECT NO:
 MATRIX: Water
 DATE SAMPLED: 6/12/02
 DATE RECEIVED: 6/18/02

ANALYTICAL DATA

CATIONS	mg/L	mEq/L
Sodium - Na (calc.)	7110	309.28
Calcium - Ca	269	13.42
Magnesium - Mg	870	71.57
Iron - Fe(Total)	0.34	0.01
Barium - Ba	0	0.00
Potassium - (mg/L)	148	3.79

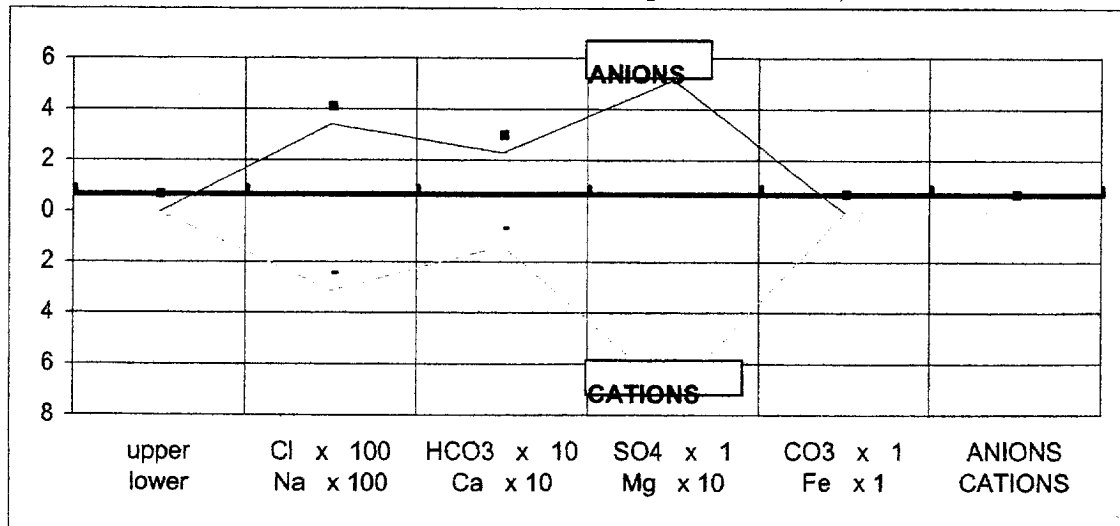
ANIONS	mg/L	mEq/L
Chloride - Cl	12200	344.15
Bicarbonate - HCO ₃	140	2.29
Sulfate - SO ₄	2480	51.63
Carbonate - CO ₃	ND	0.00

WET CHEMISTRY	RESULT
Total Dissolved Solids (calc.) mg/L	23218
Specific Gravity 60/60 Deg. F	1.018
Resistivity (ohm*meters) 75 Deg.F	0.33
pH st units	7.67

ND = Not Detected
 NA = Not Analyzed

MINERAL ANALYSIS PATTERN

(Number Below Ion Name mEq/liter/Scale Unit)



Certificate of Analysis No. L1-02060836-04A

FOR: WINMAR CONSULTING SERVICES, I
 5700 NORTHWEST CENTR
 HOUSTON TX 77092

P.O. #:
 DATE: 06/24/02

Attn:
 PROJECT: WINMAR_01

PROJECT NO:
 MATRIX: Water

SITE:
 SAMPLED BY:
 SAMPLE ID: #4

DATE SAMPLED: 6/12/02
 DATE RECEIVED: 6/18/02

ANALYTICAL DATA

CATIONS	mg/L	mEq/L
Sodium - Na (calc.)	6702	291.54
Calcium - Ca	260	12.97
Magnesium - Mg	1040	85.55
Iron - Fe(Total)	0.33	0.01
Barium - Ba	0	0.00
Potassium - (mg/L)	174	4.46

ANIONS	mg/L	mEq/L
Chloride - Cl	12200	344.15
Bicarbonate - HCO ₃	140	2.29
Sulfate - SO ₄	2310	48.09
Carbonate - CO ₃	ND	0.00

WET CHEMISTRY	RESULT
Total Dissolved Solids (calc.) mg/L	22827

Specific Gravity 60/60 Deg. F	1.018
----------------------------------	-------

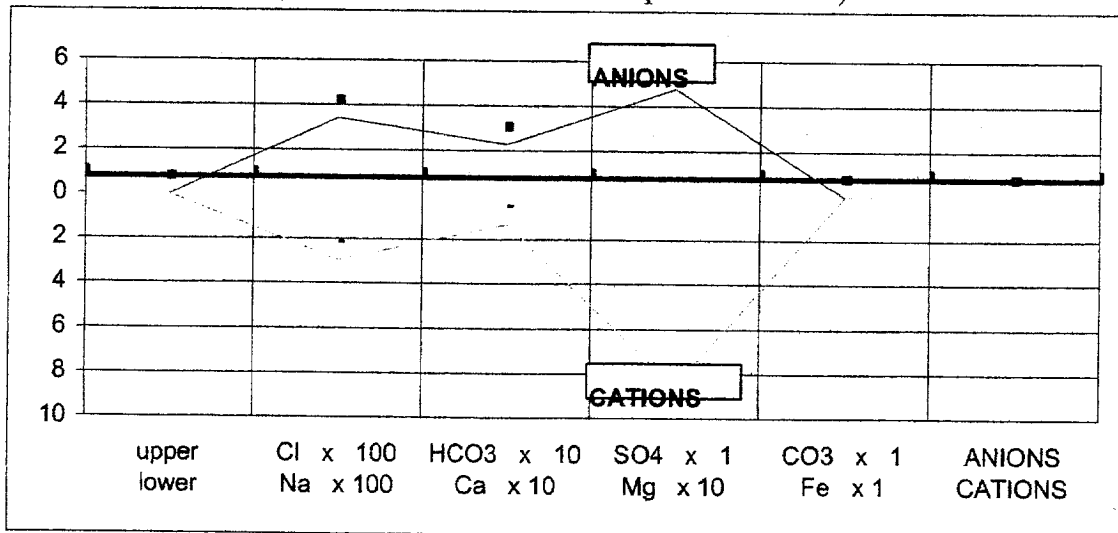
Resistivity (ohm*meters) 75 Deg.F	0.34
--------------------------------------	------

pH st units	7.6
----------------	-----

ND = Not Detected
 NA = Not Analyzed

MINERAL ANALYSIS PATTERN

(Number Below Ion Name mEq/liter/Scale Unit)



SECTION 7
RESULTS AND OBSERVATIONS
Line 24

7. Results and Observations – Line 24 Bulk Oil / Inhibited

a. Sample Locations Observations

Water samples were taken at the top of the riser before flushing began. All bolts and flange seals were intact and did not indicate any leakage. All other samples were taken at the same location. Water samples seemed uniform, and representative of the flush fluid stream.

b. Gas Composition Observations

This line was completely filled with inhibited seawater, therefore no gas was present.

c. Flushwater Composition Observations

The flushwater composition for segment 24 is plotted in the results section. Natural Seawater composition is also plotted for comparison purposes. The ions/elements plotted are: Alkalinity (CO₃), Barium, Calcium, Iron, Magnesium, and Potassium. Because of their high values (in PPM), Chlorides and Sulfates are plotted on a separate chart.

For the flushwater, the mineral pattern relative to NSW is summarized below:

Alkalinity (bicarb) – Equal
Barium – Equal
Calcium – Lower/Higher/Equal
Iron – Higher
Magnesium – Lower
Potassium – Similar/Lower
Chloride – Lower
Sulfate – Similar/Higher

d. Oil and Grease Observations

Samples taken at the end of the flushing operation had no detectable oil and grease concentration. The detection limit is 2.5 PPM. The last sample was taken when approximately 1.00x the pipeline volume had been flushed. The graph shows a very rapid drop in oil and grease concentration, with the non-detectable limit appearing to be reached at .25x flush volume.



PIPELINE FLUSHING AND SAMPLING RECORD

I. Pipeline Information

MMS Segment No.	24
Date:	6/12/2002
Pipeline Origination Area Block Platform Lease	
Pipeline Destination Area Block Platform Lease	
Pipeline Size (in)	4
Pipelines Length (ft)	2,489
Pipeline Volume (bbls)	39

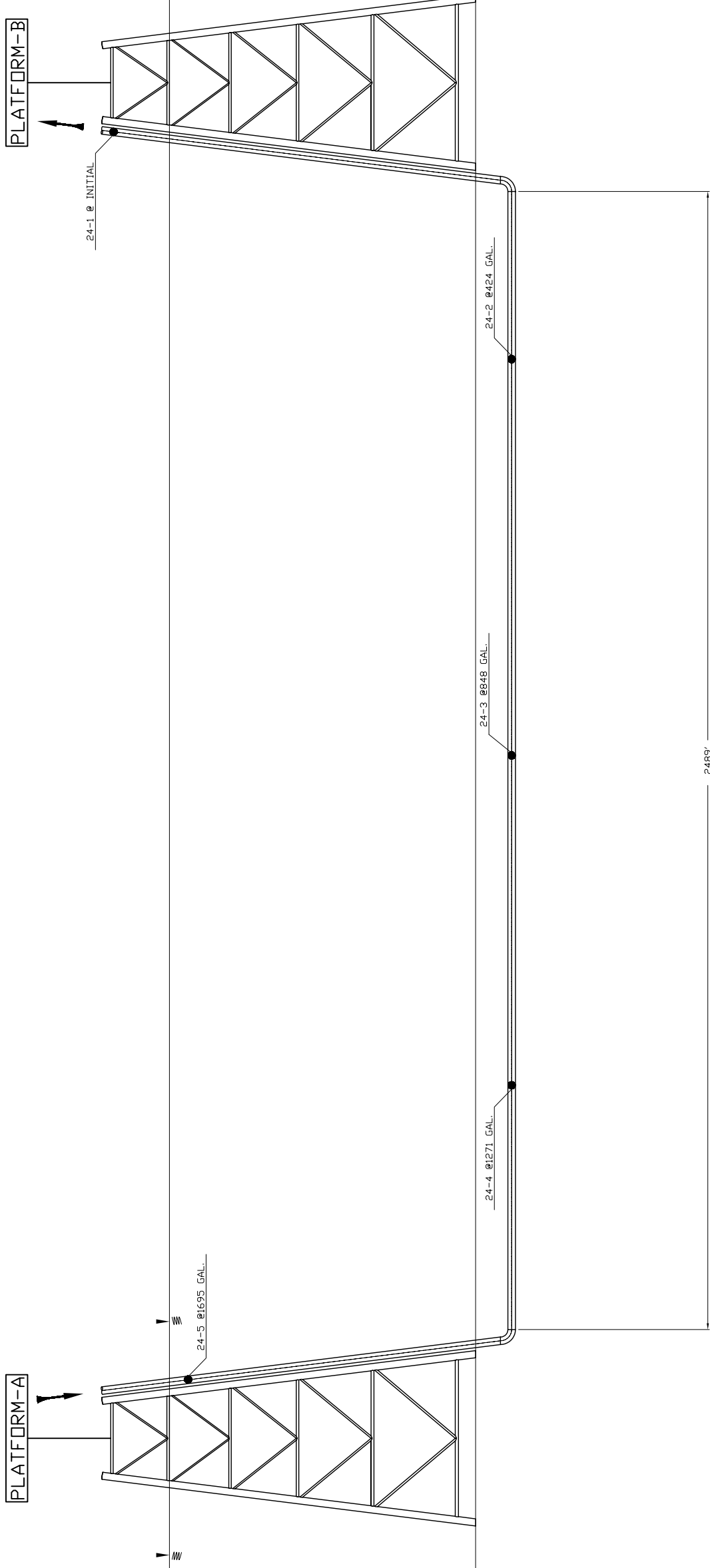
II. Flushing Information

Flushing Information Volume Flushed Flow Rate (GPM) Pigged Used Type of Pig Size of Pig Clean Returns	3290 100 No No No Yes
Inhibitor Chemical Inhibitor Used Type of Chemical Quantity of Chemical	
Origination Riser Riser blind flanged w/ vent val Pipeline Tagged	Yes Yes
Destination Riser Riser blind flanged w/ vent val Pipeline Tagged	Yes Yes
Comments:	
Company Representative	
Signature	

III. Sampling Data - Tracking Information

Sample Location				
Platform:				
Pipeline Sampling Site:		Top of Riser Bleed Valve		
Flushing Start Time:		8:00		
Gas Samples	Sample ID	Sample Date	Vol. Flushed (g)	H2S (PPM)
Vacuum Tubes				
Plastic Bags				
Water Samples	Sample ID	Sample Date	Vol. Flushed (g)	Notes
Mineral Pattern Analysis				
	24-1	06/12/02	0	
	24-2	06/12/02	424	
	24-3	06/12/02	848	
	24-4	06/12/02	1,271	
Oil and Grease Analysis	24-5	06/12/02	1,695	
	24-1	06/12/02	0	
	24-2	06/12/02	424	
	24-3	06/12/02	848	
	24-4	06/12/02	1,271	
	24-5	06/12/02	1,695	
Comments:				
Company Representative				
Signature				

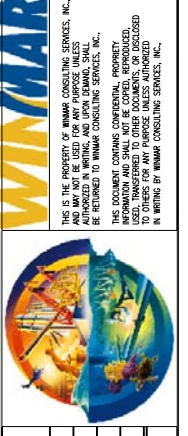
FIGURE 13 LINE 24



PL SEGMENT	24
LENGTH	2489 FT.
VOLUME FLUSHED	3290 GAL.
PL VOLUME FLG/FLG	1695 GAL.

REV	DATE	DESCRIPTION	BY	APPD
0	7/02	ISSUED	CSA	WT

PROJECT #	WM0129
PIPELINE SAMPLE LOCATIONS	LINE 24
DATE	7/02
CSA	WM00129C
REV.	0



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Figure 15 - Chloride and Sulfate - Line 24

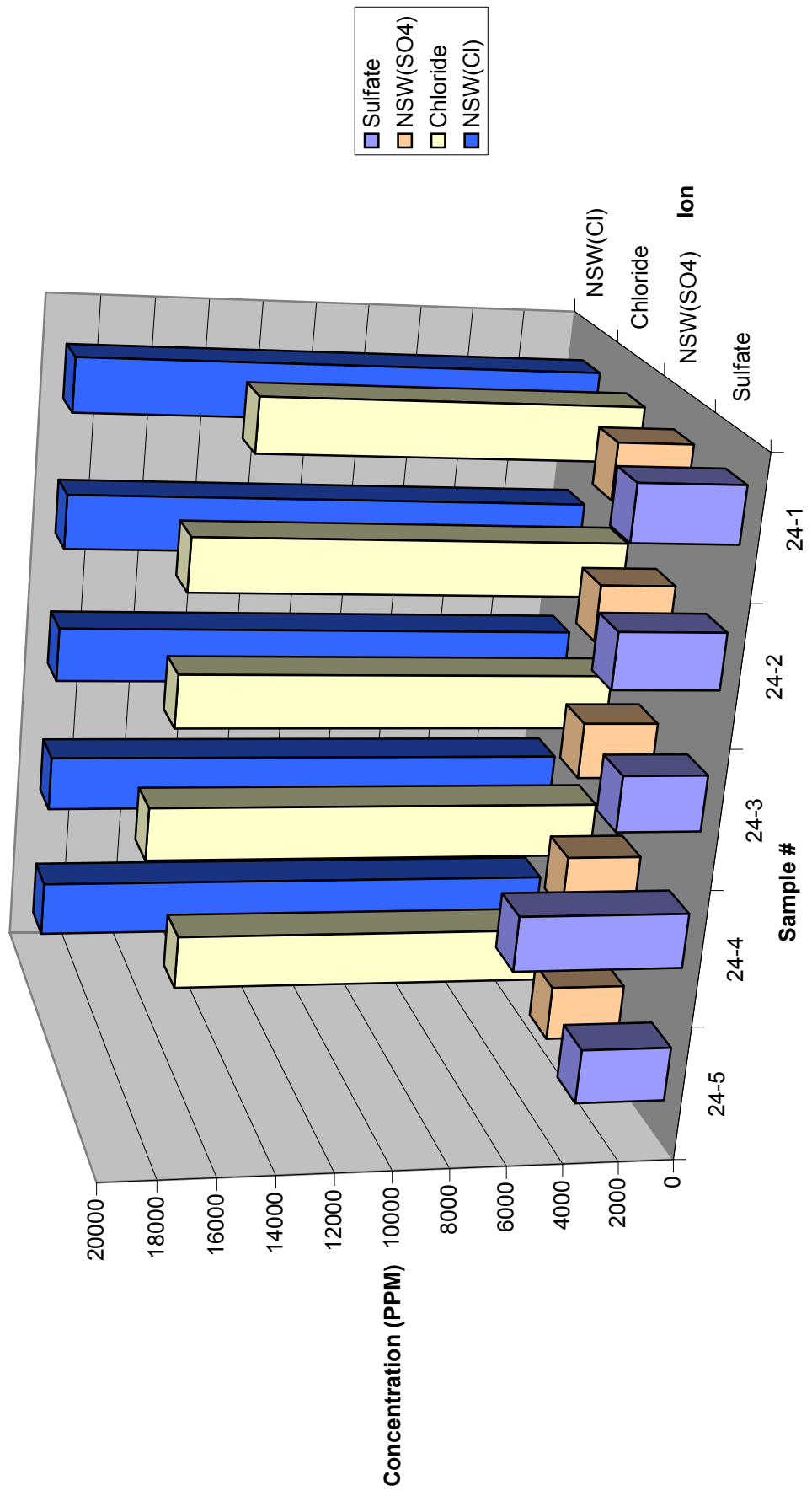


Figure 16 - Iron Concentration - Line 24

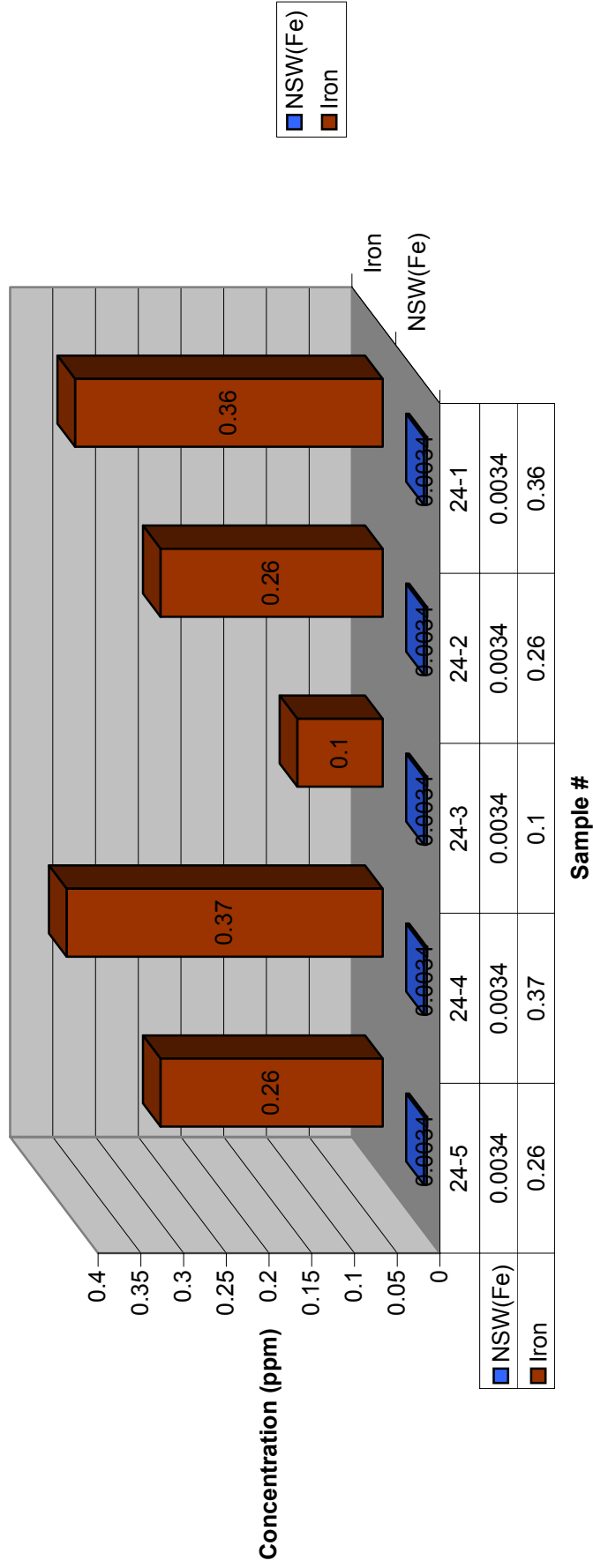
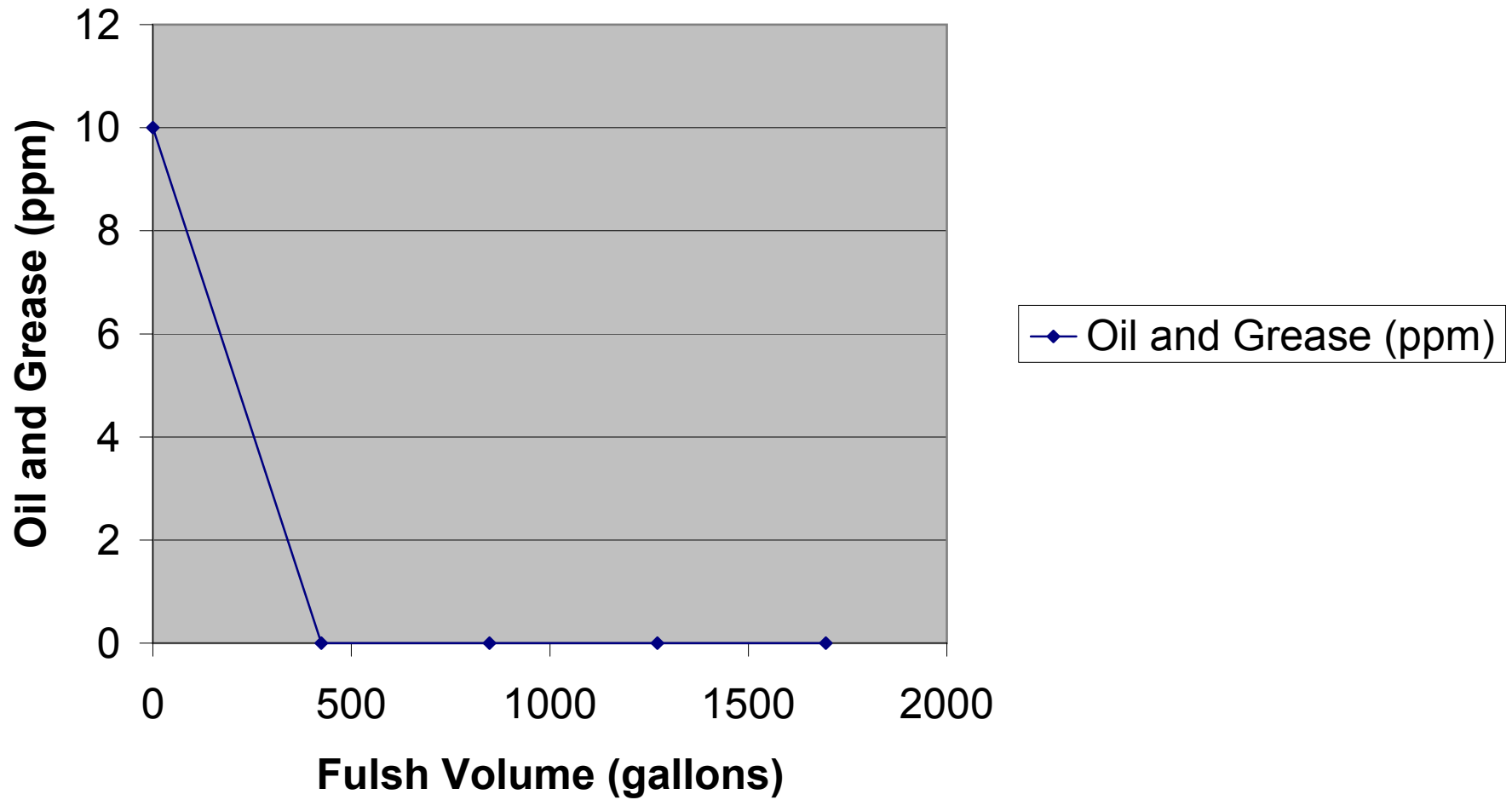
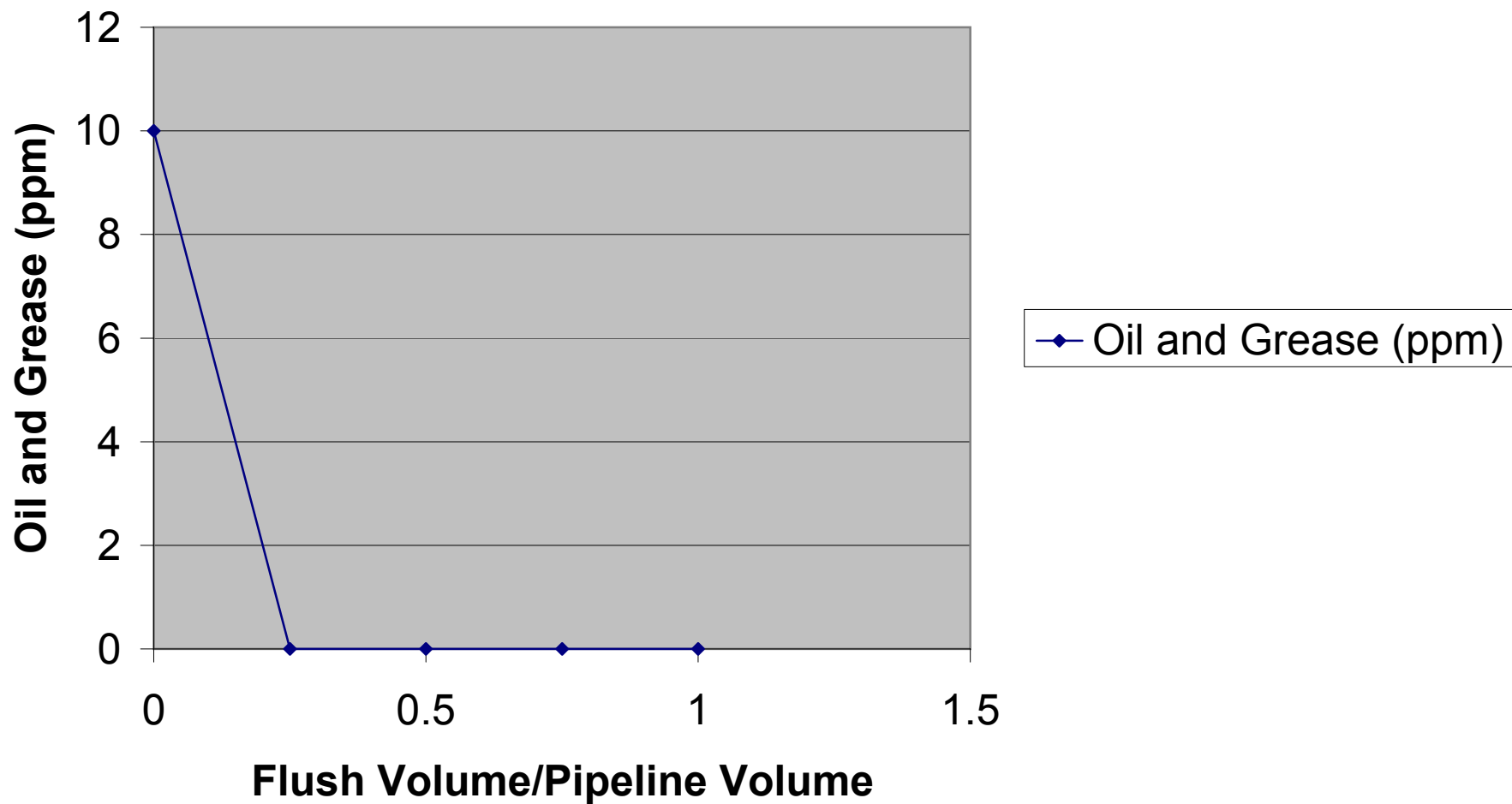


Figure 17 - Oil and Grease vs Flush Volume - Line 24



**Figure 18 - Oil and Grease vs. Flush Volume -
Line 24**





LINE 24

Client Sample ID #1	Collected: 06/11/2002 0:00	SPL Sample ID: 02060835-01
----------------------------	-----------------------------------	-----------------------------------

Site:

Analyses/Method	Result	Rep.Limit	Dil. Factor	QUAL	Date Analyzed	Analyst	Seq. #
OIL & GREASE, TOTAL RECOVERABLE			MCL	E413.1	Units: mg/L		
Oil & Grease, Total Recoverable	10	6	1		06/21/02 14:00	DB	409977

Qualifiers:

ND/U - Not Detected at the Reporting Limit	>MCL - Result Over Maximum Contamination Limit(MCL)
B - Analyte detected in the associated Method Blank	D - Surrogate Recovery Unreportable due to Dilution
* - Surrogate Recovery Outside Advisable QC Limits	MI - Matrix Interference
J - Estimated Value between MDL and PQL	

6/25/02 8:45:55 AM



LINE 24

Client Sample ID #2	Collected: 06/11/2002 0:00	SPL Sample ID: 02060835-02
---------------------	----------------------------	----------------------------

Site:

Analyses/Method	Result	Rep.Limit	Dil. Factor	QUAL	Date Analyzed	Analyst	Seq. #
OIL & GREASE, TOTAL RECOVERABLE			MCL	E413.1	Units: mg/L		
Oil & Grease, Total Recoverable	ND	5	1		06/21/02 14:00	DB	409978

Qualifiers:	ND/U - Not Detected at the Reporting Limit B - Analyte detected in the associated Method Blank * - Surrogate Recovery Outside Advisable QC Limits J - Estimated Value between MDL and PQL	>MCL - Result Over Maximum Contamination Limit(MCL) D - Surrogate Recovery Unreportable due to Dilution MI - Matrix Interference
--------------------	--	--

6/25/02 8:45:56 AM



LINE 24

Client Sample ID #3 Collected: 06/11/2002 0:00 SPL Sample ID: 02060835-03

Site:

Analyses/Method	Result	Rep.Limit	Dil. Factor	QUAL	Date Analyzed	Analyst	Seq. #
OIL & GREASE.TOTAL RECOVERABLE			MCL	E413.1	Units: mg/L		
Oil & Grease, Total Recoverable	ND	5	1		06/21/02 14:00	DB	409979

Qualifiers: ND/U - Not Detected at the Reporting Limit >MCL - Result Over Maximum Contamination Limit(MCL)
B - Analyte detected in the associated Method Blank D - Surrogate Recovery Unreportable due to Dilution
* - Surrogate Recovery Outside Advisable QC Limits MI - Matrix Interference
J - Estimated Value between MDL and PQL

6/25/02 8:45:56 AM



Client Sample ID #4	Collected: 06/11/2002 0:00	SPL Sample ID: 02060835-04
---------------------	----------------------------	----------------------------

Site:

Analyses/Method	Result	Rep.Limit	Dil. Factor	QUAL	Date Analyzed	Analyst	Seq. #
OIL & GREASE,TOTAL RECOVERABLE			MCL	E413.1	Units: mg/L		
Oil & Grease,Total Recoverable	ND	5	1		06/21/02 14:00	DB	409980

Qualifiers: ND/U - Not Detected at the Reporting Limit B - Analyte detected in the associated Method Blank * - Surrogate Recovery Outside Advisable QC Limits J - Estimated Value between MDL and PQL	>MCL - Result Over Maximum Contamination Limit(MCL) D - Surrogate Recovery Unreportable due to Dilution MI - Matrix Interference
--	--



LINE 24

Client Sample ID #5 Collected: 06/11/2002 0:00 SPL Sample ID: 02060835-05

Site:

Analyses/Method	Result	Rep.Limit	Dil. Factor	QUAL	Date Analyzed	Analyst	Seq. #
OIL & GREASE, TOTAL RECOVERABLE			MCL	E413.1	Units: mg/L		
Oil & Grease, Total Recoverable	ND	5	1		06/21/02 14:00	DB	409981

Qualifiers:
ND/U - Not Detected at the Reporting Limit
B - Analyte detected in the associated Method Blank
* - Surrogate Recovery Outside Advisable QC Limits
J - Estimated Value between MDL and PQL
>MCL - Result Over Maximum Contamination Limit(MCL)
D - Surrogate Recovery Unreportable due to Dilution
MI - Matrix Interference

6/25/02 8:45:57 AM

Certificate of Analysis No. L1-02060835-05A

FOR: WINMAR CONSULTING SERVICES, I
 5700 NORTHWEST CENTR
 HOUSTON TX 77092

P.O. #:
DATE: 06/24/02

Attn:
PROJECT: WINMAR_01
SITE:
SAMPLED BY:
SAMPLE ID: #5

PROJECT NO:
MATRIX: Water
DATE SAMPLED: 6/11/02
DATE RECEIVED: 6/18/02

ANALYTICAL DATA

CATIONS	mg/L	mEq/L
Sodium - Na (calc.)	8925	388.22
Calcium - Ca	398	19.86
Magnesium - Mg	1070	88.02
Iron - Fe(Total)	0.26	0.01
Barium - Ba	0	0.00
Potassium - (mg/L)	208	5.33

ANIONS	mg/L	mEq/L
Chloride - Cl	15300	431.59
Bicarbonate - HCO ₃	146	2.39
Sulfate - SO ₄	3240	67.46
Carbonate - CO ₃	ND	0.00

WET CHEMISTRY	RESULT
Total Dissolved Solids (calc.) mg/L	29287

Specific Gravity 60/60 Deg. F	1.021
----------------------------------	-------

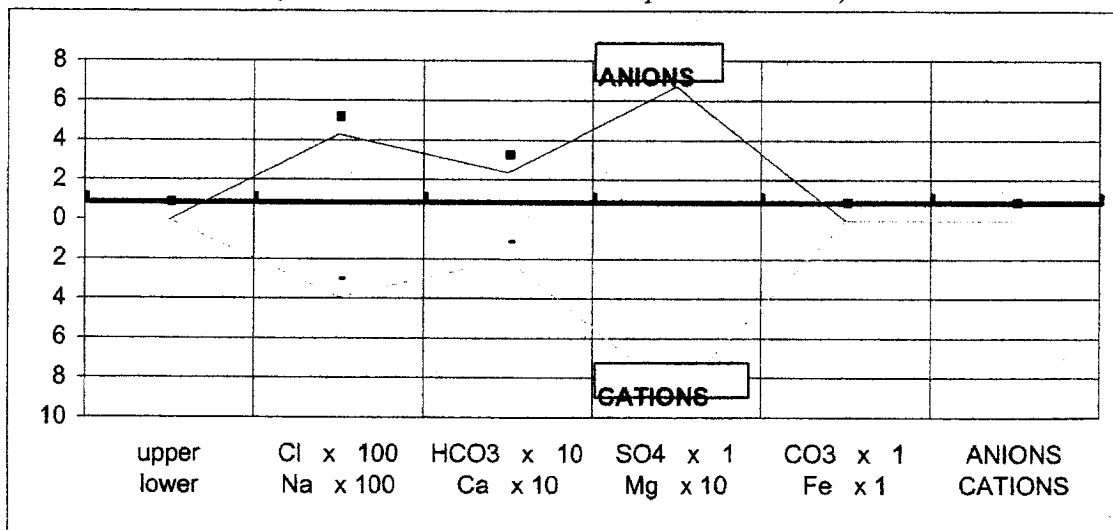
Resistivity (ohm*meters) 75 Deg.F	0.27
--------------------------------------	------

pH st units	7.47
----------------	------

ND = Not Detected
 NA = Not Analyzed

MINERAL ANALYSIS PATTERN

(Number Below Ion Name mEq/liter/Scale Unit)



Certificate of Analysis No. L1-02060835-04A

FOR: WINMAR CONSULTING SERVICES, I
 5700 NORTHWEST CENTR
 HOUSTON TX 77092

P.O. #:

DATE: 06/24/02

Attn:

PROJECT: WINMAR_01

PROJECT NO:

SITE:

MATRIX: Water

SAMPLED BY:

DATE SAMPLED: 6/11/02

SAMPLE ID: #4

DATE RECEIVED: 6/18/02

ANALYTICAL DATA

CATIONS	mg/L	mEq/L
Sodium - Na (calc.)	11476	499.19
Calcium - Ca	324	16.17
Magnesium - Mg	949	78.07
Iron - Fe(Total)	0.37	0.01
Barium - Ba	0	0.00
Potassium - (mg/L)	218	5.59

ANIONS	mg/L	mEq/L
Chloride - Cl	16700	471.09
Bicarbonate - HCO ₃	146	2.39
Sulfate - SO ₄	6030	125.55
Carbonate - CO ₃	ND	0.00

WET CHEMISTRY	RESULT
Total Dissolved Solids (calc.) mg/L	35844

Specific Gravity 60/60 Deg. F	1.021
----------------------------------	-------

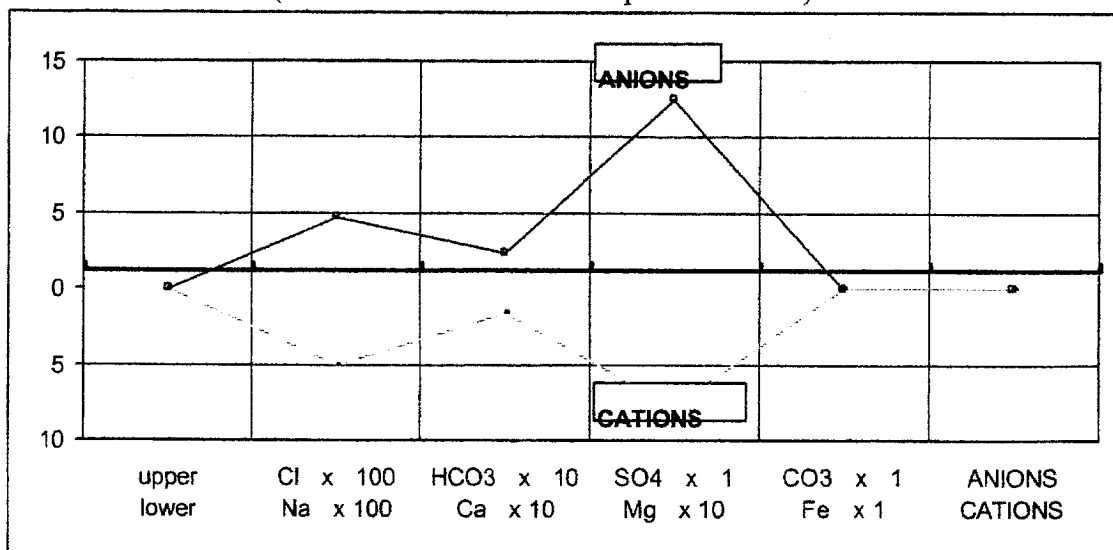
Resistivity (ohm*meters) 75 Deg.F	0.28
--------------------------------------	------

pH st units	7.45
----------------	------

ND = Not Detected
 NA = Not Analyzed

MINERAL ANALYSIS PATTERN

(Number Below Ion Name mEq/liter/Scale Unit)



Certificate of Analysis No. L1-02060835-03A

FOR: WINMAR CONSULTING SERVICES, I
 5700 NORTHWEST CENTR
 HOUSTON TX 77092

P.O. #:
DATE: 06/24/02

Attn:

PROJECT: WINMAR_01
SITE:
SAMPLED BY:
SAMPLE ID: #3

PROJECT NO:
MATRIX: Water
DATE SAMPLED: 6/11/02
DATE RECEIVED: 6/18/02

ANALYTICAL DATA

CATIONS	mg/L	mEq/L
Sodium - Na (calc.)	9219	401.02
Calcium - Ca	427	21.31
Magnesium - Mg	1050	86.38
Iron - Fe(Total)	0.1	0.00
Barium - Ba	0	0.00
Potassium - (mg/L)	296	7.59

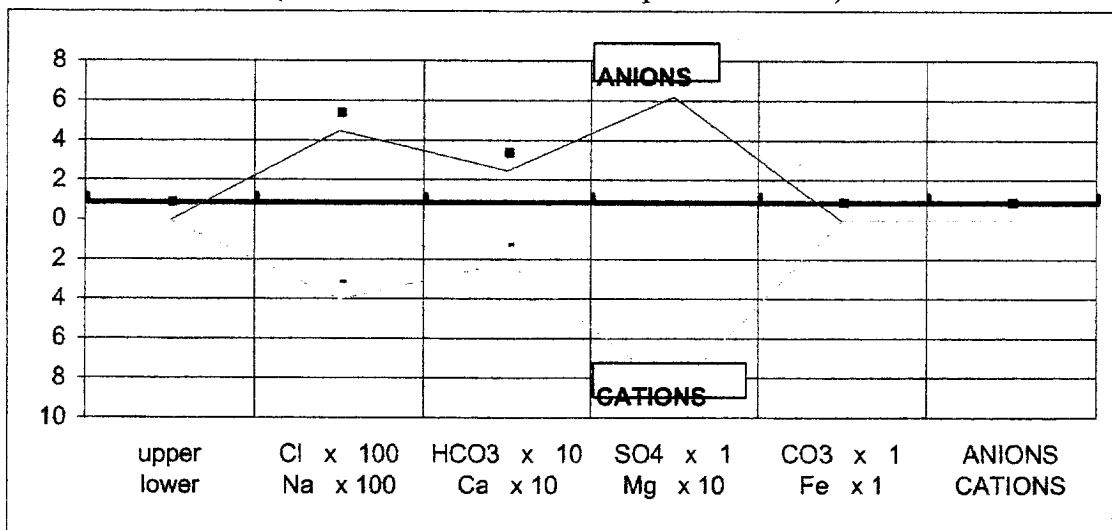
ANIONS	mg/L	mEq/L
Chloride - Cl	16000	451.34
Bicarbonate - HCO ₃	152	2.49
Sulfate - SO ₄	3000	62.46
Carbonate - CO ₃	ND	0.00

WET CHEMISTRY	RESULT
Total Dissolved Solids (calc.) mg/L	30145
Specific Gravity 60/60 Deg. F	1.022
Resistivity (ohm*meters) 75 Deg.F	0.28
pH st units	7.48

ND = Not Detected
 NA = Not Analyzed

MINERAL ANALYSIS PATTERN

(Number Below Ion Name mEq/liter/Scale Unit)



Certificate of Analysis No. L1-02060835-02A

FOR: WINMAR CONSULTING SERVICES, I
 5700 NORTHWEST CENTR
 HOUSTON TX 77092

P.O. #:

DATE: 06/24/02

Attn:

PROJECT: WINMAR_01

PROJECT NO:

SITE:

MATRIX: Water

SAMPLED BY:

DATE SAMPLED: 6/11/02

SAMPLE ID: #2

DATE RECEIVED: 6/18/02

ANALYTICAL DATA

CATIONS	mg/L	mEq/L
Sodium - Na (calc.)	9318	405.29
Calcium - Ca	620	30.94
Magnesium - Mg	1030	84.73
Iron - Fe(Total)	0.26	0.01
Barium - Ba	0	0.00
Potassium - (mg/L)	341	8.74

ANIONS	mg/L	mEq/L
Chloride - Cl	15900	448.52
Bicarbonate - HCO ₃	152	2.49
Sulfate - SO ₄	3780	78.70
Carbonate - CO ₃	ND	0.00

WET CHEMISTRY	RESULT
Total Dissolved Solids (calc.) mg/L	31141

Specific Gravity 60/60 Deg. F	1.021
----------------------------------	-------

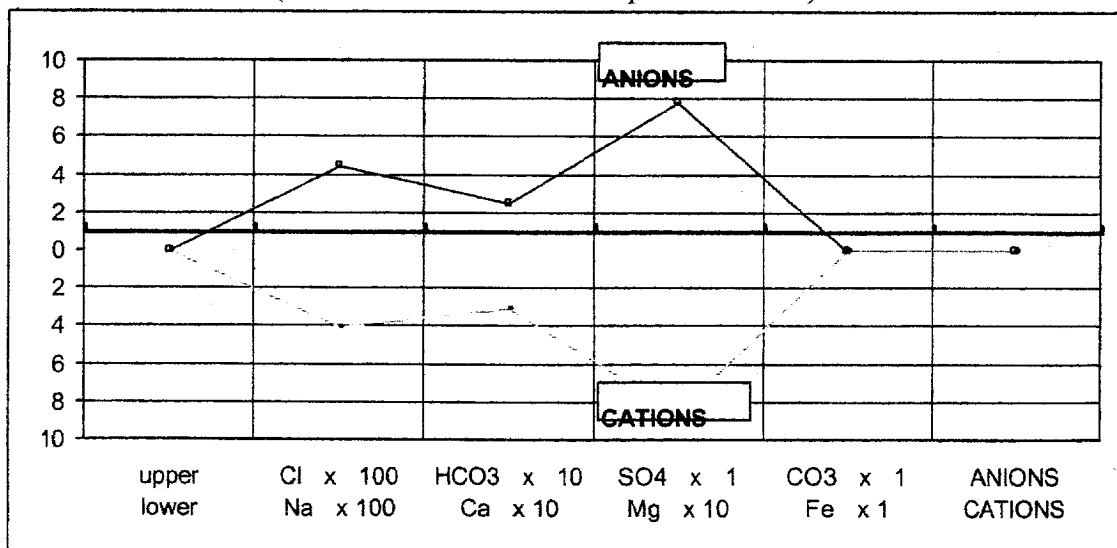
Resistivity (ohm*meters) 75 Deg.F	0.28
--------------------------------------	------

pH st units	7.4
----------------	-----

ND = Not Detected
 NA = Not Analyzed

MINERAL ANALYSIS PATTERN

(Number Below Ion Name mEq/liter/Scale Unit)



SECTION 8
RESULTS AND OBSERVATIONS

Line 25

8. Results and Observations – Line 25 Bulk Oil / Inhibited

a. Sample Locations Observations

Water samples were taken at the top of the riser before flushing began. All bolts and flange seals were intact and did not indicate any leakage. All other samples were taken at the same location. Water samples seemed uniform, and representative of the flush fluid stream.

b. Flushwater Composition Observations

The flushwater composition for segment 25 is plotted in the results section. Natural Seawater composition is also plotted for comparison purposes. The ions/elements plotted are: Alkalinity (CO₃), Barium, Calcium, Iron, Magnesium, and Potassium. Because of their high values (in PPM), Chlorides and Sulfates are plotted on a separate chart.

For the flushwater, the mineral pattern relative to NSW is summarized below:

Alkalinity (bicarb) – Higher/Same
Barium – Same
Calcium – Lower
Iron – Higher
Magnesium – Lower/Same
Potassium – Lower
Chloride – Lower
Sulfate – Lower

The plot of the Iron Concentration shows an initial concentration of 39.4 and 5.7 ppm respectively followed by a sharp increase (65.5 ppm). The explanation for this occurrence is the same as for segment number 22. Slugging during flushing operations loosened and purged internal corrosion from the line as is common.

c. Oil and Grease Observations

Samples taken at the end of the flushing operation had no detectable oil and grease concentration. The detection limit is 2.5 PPM. The last sample was taken when approximately 1.00x the pipeline volume had been flushed. The graph shows a very rapid drop in oil and grease concentration; with the non-detectable limit appearing to be reached at 1.0x flush volume.



consulting services, inc.

PIPELINE FLUSHING AND SAMPLING RECORD

I. Pipeline Information

MMS Segment No.	Line 25
Date:	6/2/2001
Pipeline Origination Area Block Platform Lease	
Pipeline Destination Area Block Platform Lease	
Pipeline Size (in)	8
Pipelines Length (ft)	9,200
Pipeline Volume (gallons/bbls)	23,920 / 570

II. Flushing Information

Flushing Information Volume Flushed Flow Rate (GPM) Pigged Used Type of Pig Size of Pig Clean Returns	40,000 100
Inhibitor Chemical Inhibitor Used Type of Chemical Quantity of Chemical	N
Origination Riser Riser blind flanged w/ vent valve Pipeline Tagged	Y Y
Destination Riser Riser blind flanged w/ vent valve Pipeline Tagged	Y Y
Comments:	
Company Representative	JAMES WISEMAN
Signature	

III. Sampling Data - Tracking Information

Sample Location Platform: Pipeline Sampling Site: Flushing Start Time:	800			
Water Samples	Sample ID	Sample Date	Vol. Flushed (g)	H2S (PPM)
Mineral Pattern Analysis	25-1	6/2/2001	0	0
	25-2	6/2/2001	8,000	0
	25-3	6/2/2001	16,000	0
	25-4	6/2/2001	30,000	0
	25-5	6/2/2001	40,000	0
	Sample ID	Sample Date	Vol. Flushed (g)	Notes
	25-1	6/2/2001	0	
	25-2	6/2/2001	8,000	
	25-3	6/2/2001	16,000	
	25-4	6/2/2001	30,000	
	25-5	6/2/2001	40,000	
Oil and Grease Analysis				
Comments:				
Company Representative	JAMES WISEMAN			
Signature				

Figure 20 - Chloride and Sulfate - Line 25

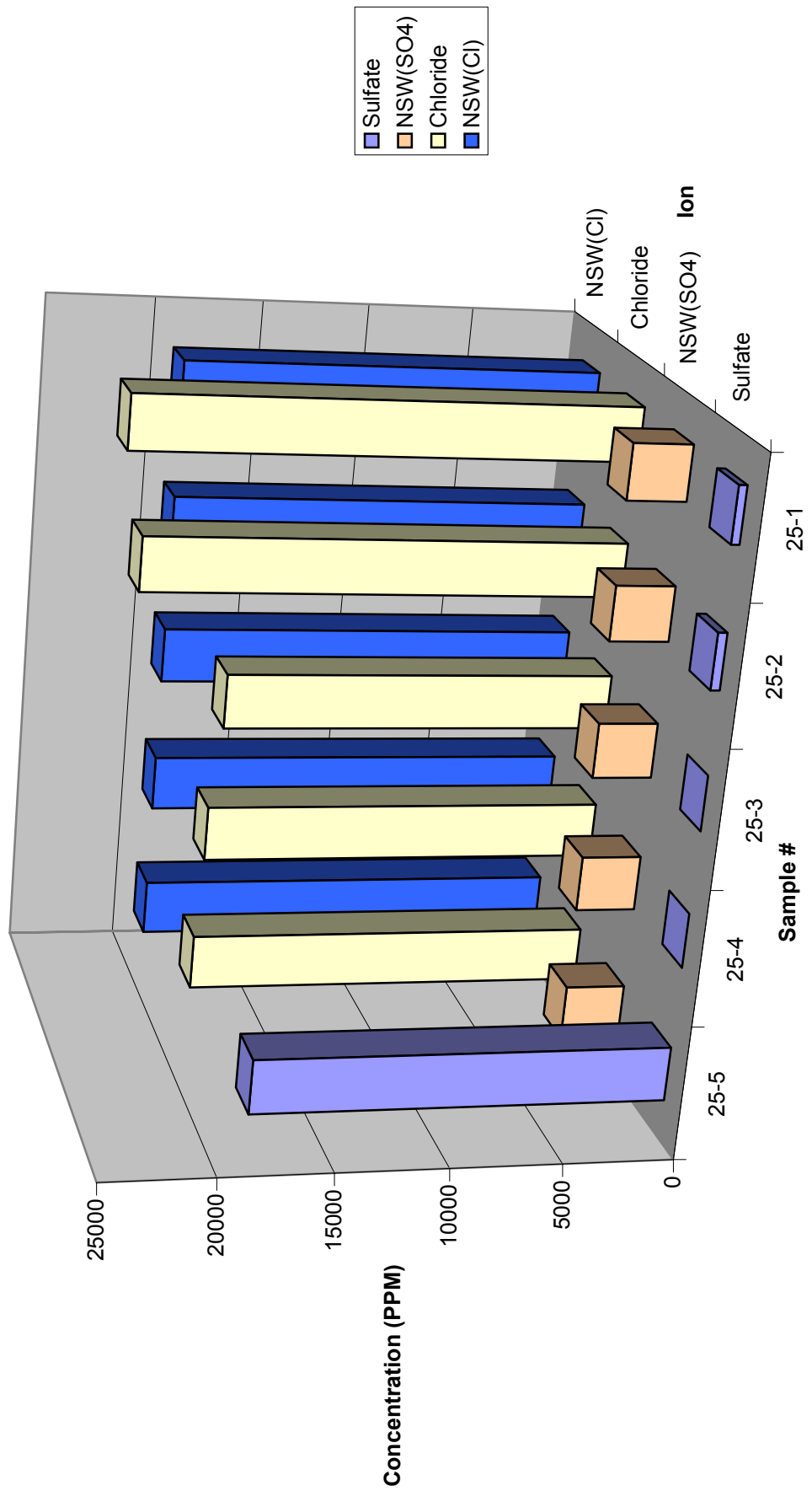


Figure 21 - Iron Concentration - Line 25

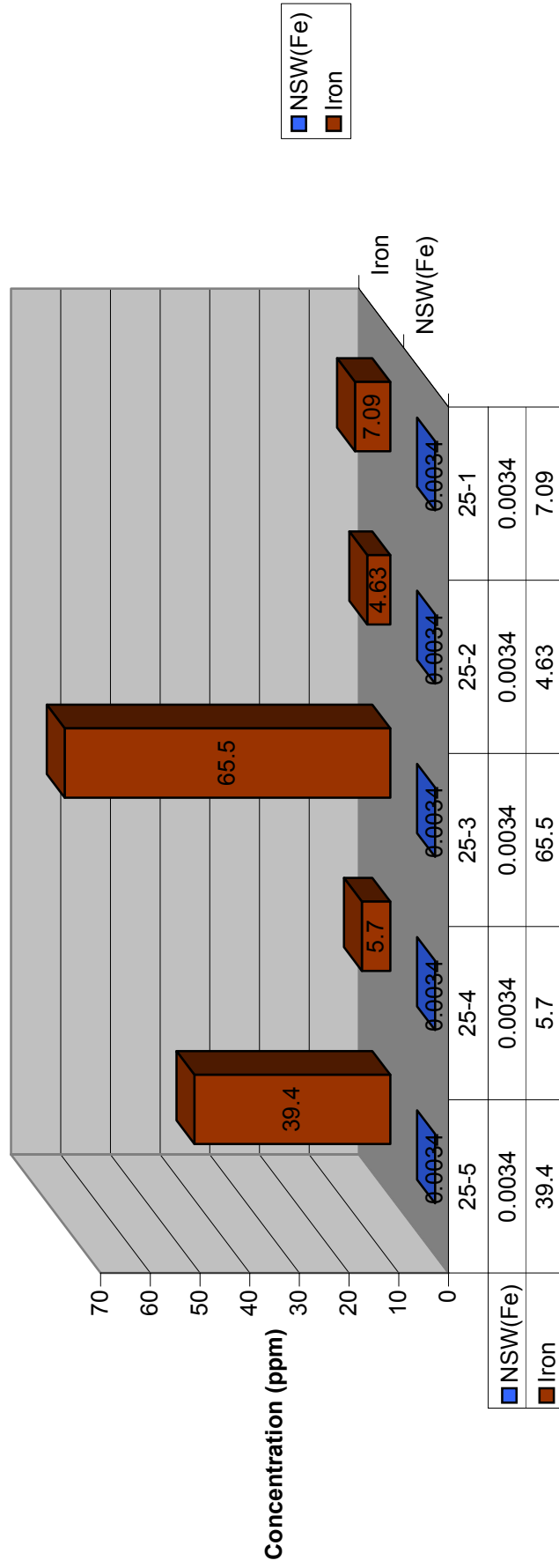
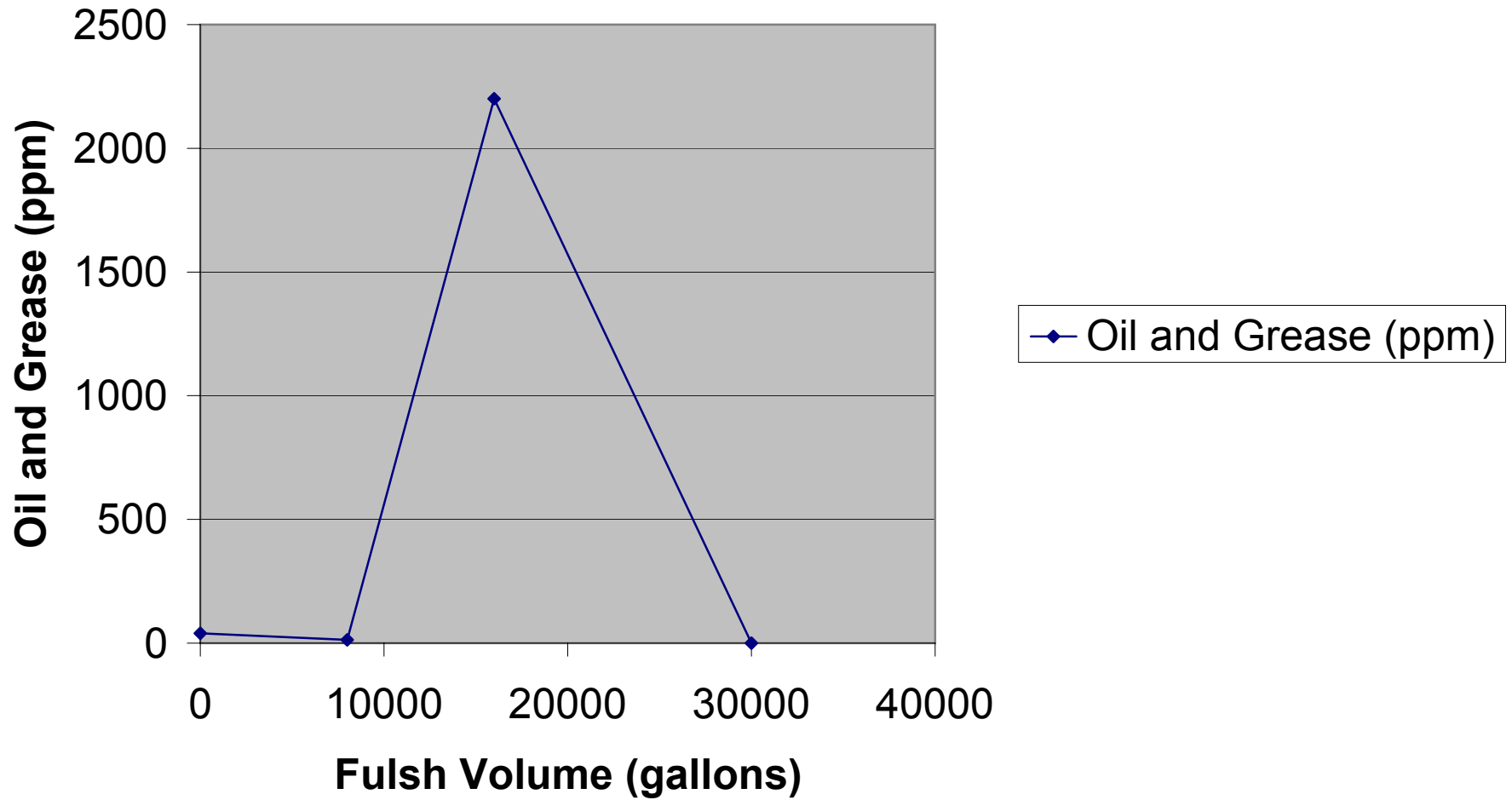


Figure 22 - Oil and Grease vs Flush Volume - Line 25



**Figure 23 - Oil and Grease vs. Flush Volume -
Line 25**

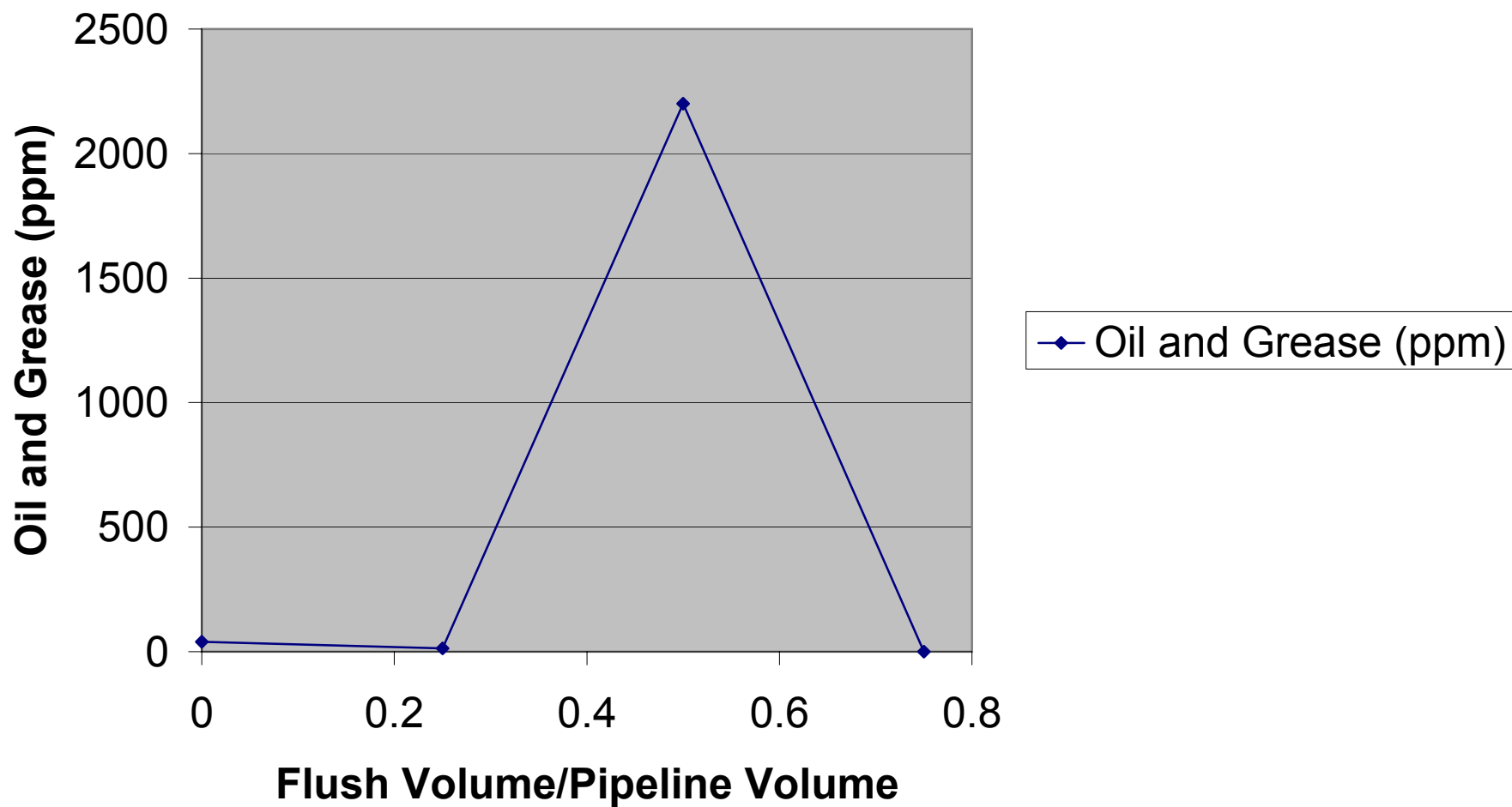
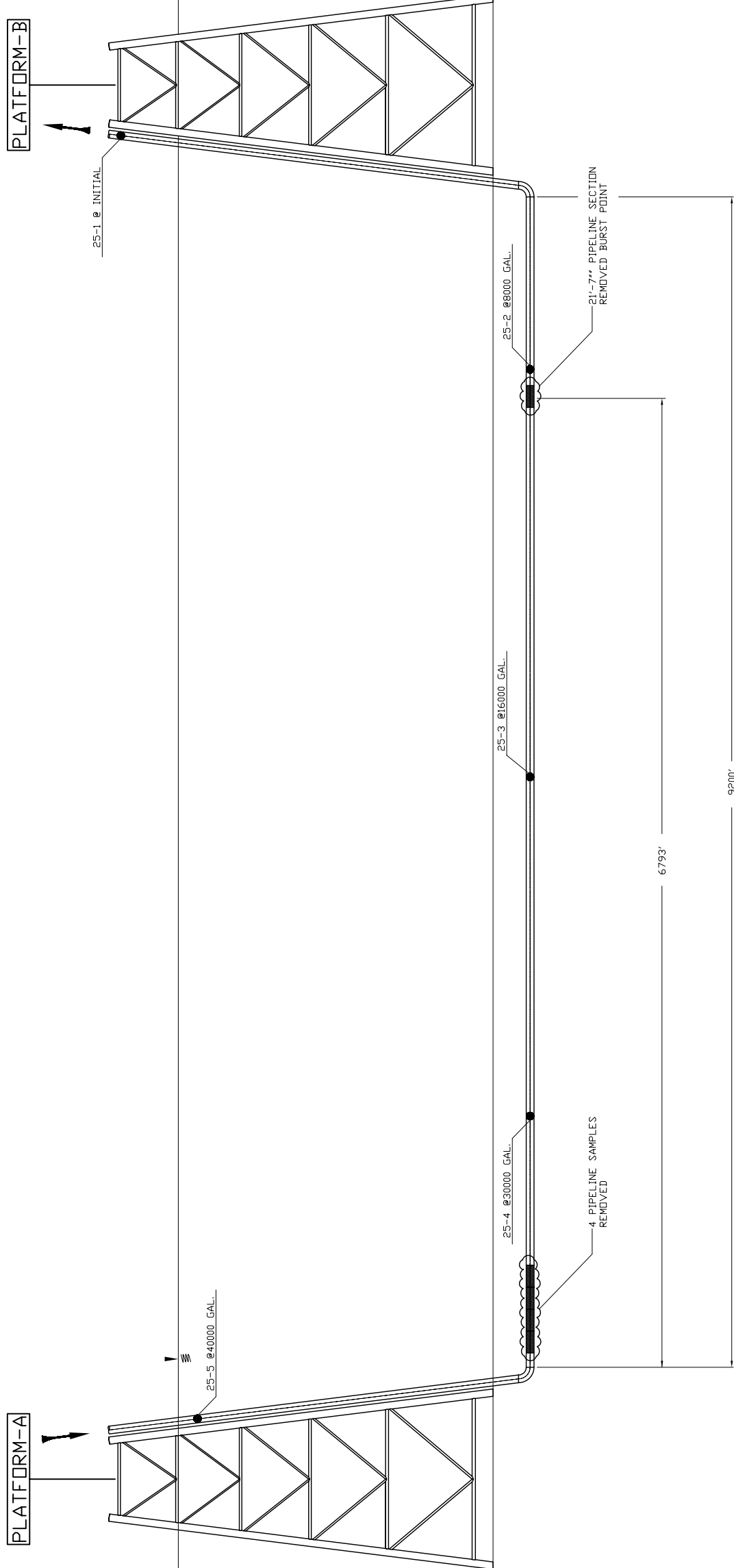


FIGURE 24 LINE 25



PL SEGMENT	25
LENGTH	9200 FT.
VOLUME FLUSHED	40000 GAL.
PL VOLUME FLG/FLG	23920 GAL.

REV	DATE	DESCRIPTION	BY	APPD
0	11/00	ISSUED	CSA	JW




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PROJECT # WM0070			
PIPELINE SAMPLE LOCATIONS			
CSA	DATE	DWG. NO.	REV.
	11/00	WM0070C	0
LINE 25			



HOUSTON LABORATORY
8880 INTERCHANGE DRIVE
HOUSTON, TEXAS 77054
(713) 660-0901

Client Sample ID 0 gals. Collected: 6/3/01 SPL Sample ID: 01060917-01

Site: Houston

Analyses/Method	Result	Rep.Limit	Dil. Factor	QUAL	Date Analyzed	Analyst	Seq. #
ALKALINITY, BICARBONATE				MCL M2320 B	Units: mg/L		
Alkalinity, Bicarbonate	505	2.00	1		06/28/01 9:00		724773
ALKALINITY, CARBONATE				MCL M2320 B	Units: mg/L		
Alkalinity, Carbonate	370	2.00	1		06/28/01 9:00		724797
CHLORIDE, TOTAL				MCL E325.3	Units: mg/L		
Chloride	22900	500	500		06/29/01 11:30		735107
METALS BY METHOD 6010B, TOTAL				MCL SW6010B	Units: mg/L		
Barium	7.2	0.0250	5		07/09/01 18:45		736374
Calcium	37.7	0.500	5		07/08/01 0:18		734972
Iron	7.09	0.100	5		07/09/01 18:45		736374
Magnesium	37.1	0.500	5		07/08/01 0:18		735199
Potassium	105	10.0	5		07/08/01 0:18		734972
OIL & GREASE, TOTAL RECOVERABLE				MCL E413.1	Units: mg/L		
Oil & Grease, Total Recoverable	40	2.0	1		06/29/01 14:20		722639
PH				MCL E150.1	Units: pH Units		
pH	9.3	0.10	1		06/27/01 10:00		723785
RESISTANCE @ 25 C				MCL 120.1	Units: Mohms-cm		
Resistance	18.4	0.00100	1		07/03/01 12:00		731601
SPECIFIC GRAVITY @ 25 C				MCL ASTM D-1429	Units: @ 25 C		
Specific Gravity	1.032	0	1		07/07/01 13:00		731798
SULFATE, TOTAL				MCL E375.4	Units: mg/L		
Sulfate	4.7	1.00	1		06/28/01 11:00		727470
TOTAL DISSOLVED SOLIDS				MCL TDS-MINERAL	Units: mg/L		
Total Dissolved Solids, Calculated	39100	10.0	1		07/11/01 12:30		737585
TOTAL SODIUM, CALCULATED				MCL TDS-MINERAL	Units: mg/L		
Total Sodium, Calculated	15100	10.0	1		07/11/01 12:30		737548
TOTAL SUSPENDED SOLIDS				MCL E160.2	Units: mg/L		
Suspended Solids (Residue, Non-Filterable)	22	4.00	1		07/03/01 18:30		730101

Qualifiers: ND/U - Not Detected at the Reporting Limit >MCL - Result Over Maximum Contamination Limit(MCL)
 B - Analyte detected in the associated Method Blank D - Surrogate Recovery Unreportable due to Dilution
 * - Surrogate Recovery Outside Advisable QC Limits MI - Matrix Interference
 J - Estimated Value between MDL and PQL



HOUSTON LABORATORY
8880 INTERCHANGE DRIVE
HOUSTON, TEXAS 77054
(713) 660-0801

Client Sample ID 8000 gal. Collected: 6/3/01 SPL Sample ID: 01060917-05

Site: Houston

Analyses/Method	Result	Rep.Limit	Dil. Factor	QUAL	Date Analyzed	Analyst	Seq. #
ALKALINITY, BICARBONATE				MCL			Units: mg/L
Alkalinity, Bicarbonate	450	2.00	1	M2320 B	06/28/01 9:00		724778
ALKALINITY, CARBONATE				MCL			Units: mg/L
Alkalinity, Carbonate	414	2.00	1	M2320 B	06/28/01 9:00		724802
CHLORIDE, TOTAL				MCL			Units: mg/L
Chloride	22000	500	500	E325.3	06/29/01 11:30		735114
METALS BY METHOD 6010B, TOTAL				MCL			Units: mg/L
Barium	9.24	0.0250	5	SW8010B	07/09/01 19:05		736378
Calcium	53.1	0.500	5		07/08/01 1:24		734983
Iron	4.63	0.100	5		07/09/01 19:05		736378
Magnesium	43.9	0.500	5		07/08/01 1:24		735214
Potassium	128	10.0	5		07/08/01 1:24		734983
OIL & GREASE, TOTAL RECOVERABLE				MCL			Units: mg/L
Oil & Grease, Total Recoverable	13	2.0	1	E413.1	06/28/01 14:20		722643
PH				MCL			Units: pH Units
pH	9.4	0.10	1	E150.1	06/27/01 10:00		723790
RESISTANCE @ 25 C				MCL			Units: Mohms-cm
Resistance	18.2	0.00100	1	120.1	07/03/01 12:00		731606
SPECIFIC GRAVITY @ 25 C				MCL			Units: @ 25 C
Specific Gravity	1.031	0	1	ASTM D-1429	07/07/01 13:00		731802
SULFATE, TOTAL				MCL			Units: mg/L
Sulfate	ND	1.00	1	E375.4	06/26/01 11:00		727478
TOTAL DISSOLVED SOLIDS				MCL			Units: mg/L
Total Dissolved Solids, Calculated	37600	10.0	1	TDS-MINERAL	07/11/01 12:30		737589
TOTAL SODIUM, CALCULATED				MCL			Units: mg/L
Total Sodium, Calculated	14500	10.0	1	TDS-MINERAL	07/11/01 12:30		737552
TOTAL SUSPENDED SOLIDS				MCL			Units: mg/L
Suspended Solids (Residue, Non-Filterable)	22	4.00	1	E160.2	07/03/01 18:30		730105

Qualifiers: ND/U - Not Detected at the Reporting Limit >MCL - Result Over Maximum Contamination Limit(MCL)
 B - Analyte detected in the associated Method Blank D - Surrogate Recovery Unreportable due to Dilution
 * - Surrogate Recovery Outside Advisable QC Limits MI - Matrix Interference
 J - Estimated Value between MDL and PQL



HOUSTON LABORATORY
 8880 INTERCHANGE DRIVE
 HOUSTON, TEXAS 77054
 (713) 660-0901

Client Sample ID 16000 gal. Collected: 6/3/01 SPL Sample ID: 01060917-09

Site: Houston

Analyses/Method	Result	Rep.Limit	Dil. Factor	QUAL	Date Analyzed	Analyst	Seq. #
ALKALINITY, BICARBONATE			MCL	M2320 B	Units: mg/L		
Alkalinity, Bicarbonate	261	2.00	1		06/28/01 9:00		724783
ALKALINITY, CARBONATE			MCL	M2320 B	Units: mg/L		
Alkalinity, Carbonate	ND	2.00	1		06/28/01 9:00		724807
CHLORIDE, TOTAL			MCL	E325.3	Units: mg/L		
Chloride	17800	250	250		06/29/01 11:30		735121
METALS BY METHOD 6010B, TOTAL			MCL	SW6010B	Units: mg/L		
Barium	1.18	0.0250	5		07/09/01 19:24		736382
Calcium	307	0.500	5		07/08/01 2:31		734997
Iron	65.5	0.100	5		07/09/01 19:24		736382
Magnesium	1040	1.00	10		07/08/01 2:37		735224
Potassium	329	10.0	5		07/08/01 2:31		734997
OIL & GREASE, TOTAL RECOVERABLE			MCL	E413.1	Units: mg/L		
Oil & Grease, Total Recoverable	2200	2.0	1		06/28/01 14:20		722647
PH			MCL	E150.1	Units: pH Units		
pH	7.4	0.10	1		06/27/01 10:00		723796
RESISTANCE @ 25 C			MCL	120.1	Units: Mohms-cm		
Resistance	24.9	0.00100	1		07/03/01 12:00		731611
SPECIFIC GRAVITY @ 25 C			MCL	ASTM D-1429	Units: @ 25 C		
Specific Gravity	1.021	0	1		07/07/01 13:00		731806
SULFATE, TOTAL			MCL	E375.4	Units: mg/L		
Sulfate	3120	250	250		06/28/01 11:00		727484
TOTAL DISSOLVED SOLIDS			MCL	TDS-MINERAL	Units: mg/L		
Total Dissolved Solids, Calculated	33500	10.0	1		07/11/01 12:30		737593
TOTAL SODIUM, CALCULATED			MCL	TDS-MINERAL	Units: mg/L		
Total Sodium, Calculated	10600	10.0	1		07/11/01 12:30		737556
TOTAL SUSPENDED SOLIDS			MCL	E160.2	Units: mg/L		
Suspended Solids (Residue, Non-Filterable)	922	8.00	2		07/03/01 18:30		730112

Qualifiers: ND/U - Not Detected at the Reporting Limit
 B - Analyte detected in the associated Method Blank
 * - Surrogate Recovery Outside Advisable QC Limits
 J - Estimated Value between MDL and PQL

>MCL - Result Over Maximum Contamination Limit(MCL)
 D - Surrogate Recovery Unreportable due to Dilution
 MI - Matrix Interference



HOUSTON LABORATORY
8880 INTERCHANGE DRIVE
HOUSTON, TEXAS 77054
(713) 660-0901

Client Sample ID 30000 gal. Collected: 6/3/01 SPL Sample ID: 01060917-13

Site: Houston

Analyses/Method	Result	Rep.Limit	Dil. Factor	QUAL	Date Analyzed	Analyst	Seq. #
ALKALINITY, BICARBONATE				MCL			
Alkalinity, Bicarbonate	121	2.00	1	M2320 B	06/28/01 9:00		724788
						Units: mg/L	
ALKALINITY, CARBONATE				MCL			
Alkalinity, Carbonate	ND	2.00	1	M2320 B	06/28/01 9:00		724812
						Units: mg/L	
CHLORIDE, TOTAL				MCL			
Chloride	18200	250	250	E325.3	06/29/01 11:30		735130
						Units: mg/L	
METALS BY METHOD 6010B, TOTAL				MCL			
Barium	0.0852	0.0250	5	SW6010B	07/09/01 20:03		736388
Calcium	397	0.500	5		07/07/01 23:26		734966
Iron	5.7	0.100	5		07/09/01 20:03		736388
Magnesium	1280	1.00	10		07/07/01 23:45		735189
Potassium	406	10.0	5		07/07/01 23:26		734968
						Units: mg/L	
OIL & GREASE, TOTAL RECOVERABLE				MCL			
Oil & Grease, Total Recoverable	ND	2.0	1	E413.1	06/28/01 14:20		722651
						Units: mg/L	
PH				MCL			
pH	7.7	0.10	1	E150.1	06/27/01 10:00		723801
						Units: pH Units	
RESISTANCE @ 25 C				MCL			
Resistance	20.4	0.00100	1	120.1	07/03/01 12:00		731616
						Units: Mohms-cm	
SPECIFIC GRAVITY @ 25 C				MCL			
Specific Gravity	1.028	0	1	ASTM D-1429	07/07/01 13:00		731811
						Units: @ 25 C	
SULFATE, TOTAL				MCL			
Sulfate	3140	250	250	E375.4	06/26/01 11:00		727490
						Units: mg/L	
TOTAL DISSOLVED SOLIDS				MCL			
Total Dissolved Solids, Calculated	33800	10.0	1	TDS-MINERAL	07/11/01 12:30		737597
						Units: mg/L	
TOTAL SODIUM, CALCULATED				MCL			
Total Sodium, Calculated	10200	10.0	1	TDS-MINERAL	07/11/01 12:30		737561
						Units: mg/L	
TOTAL SUSPENDED SOLIDS				MCL			
Suspended Solids (Residue, Non-Filterable)	30	4.00	1	E160.2	07/03/01 18:30		730119
						Units: mg/L	

Qualifiers: ND/U - Not Detected at the Reporting Limit
 B - Analyte detected in the associated Method Blank
 * - Surrogate Recovery Outside Advisable QC Limits
 J - Estimated Value between MDL and PQL

>MCL - Result Over Maximum Contamination Limit(MCL)
 D - Surrogate Recovery Unreportable due to Dilution
 MI - Matrix Interference



HOUSTON LABORATORY
6880 INTERCHANGE DRIVE
HOUSTON, TEXAS 77054
(713) 660-0801

Client Sample ID 40000 gal. Collected: 6/3/01 SPL Sample ID: 01060917-17

Site: Houston

Analyses/Method	Result	Rep.Limit	Dil. Factor	QUAL	Date Analyzed	Analyst	Seq. #
ALKALINITY, BICARBONATE				MCL	M2320 B	Units: mg/L	
Alkalinity, Bicarbonate	161	2.00	1		06/28/01 9:00		724792
ALKALINITY, CARBONATE				MCL	M2320 B	Units: mg/L	
Alkalinity, Carbonate	ND	2.00	1		06/28/01 9:00		724816
CHLORIDE, TOTAL				MCL	E325.3	Units: mg/L	
Chloride	18400	250	250		06/29/01 11:30		735135
METALS BY METHOD 6010B, TOTAL				MCL	SW6010B	Units: mg/L	
Barium	0.31	0.0250	5		07/09/01 20:25		736392
Calcium	397	0.500	5		07/08/01 4:40		735027
Iron	39.4	0.100	5		07/09/01 20:25		736392
Magnesium	1300	1.00	10		07/08/01 4:45		735238
Potassium	403	10.0	5		07/08/01 4:40		735027
PH				MCL	E150.1	Units: pH Units	
pH	7.1	0.10	1		06/27/01 10:00		723806
RESISTANCE @ 25 C				MCL	120.1	Units: Mohms-cm	
Resistance	23	0.00100	1		07/03/01 12:00		731620
SPECIFIC GRAVITY @ 25 C				MCL	ASTM D-1428	Units: @ 25 C	
Specific Gravity	1.029	0	1		07/07/01 13:00		731815
SULFATE, TOTAL				MCL	E375.4	Units: mg/L	
Sulfate	3100	250	250		06/28/01 11:00		727495
TOTAL DISSOLVED SOLIDS				MCL	TDS-MINERAL	Units: mg/L	
Total Dissolved Solids, Calculated	34100	10.0	1		07/11/01 12:30		737601
TOTAL SODIUM, CALCULATED				MCL	TDS-MINERAL	Units: mg/L	
Total Sodium, Calculated	10300	10.0	1		07/11/01 12:30		737570
TOTAL SUSPENDED SOLIDS				MCL	E160.2	Units: mg/L	
Suspended Solids (Residue, Non-Filterable)	1800	8.00	2		07/03/01 18:30		730125

Qualifiers: ND/U - Not Detected at the Reporting Limit
B - Analyte detected in the associated Method Blank
* - Surrogate Recovery Outside Advisable QC Limits
J - Estimated Value between MDL and PQL

>MCL - Result Over Maximum Contamination Limit(MCL)
D - Surrogate Recovery Unreportable due to Dilution
MI - Matrix Interference

9. Recommendations and Conclusions

a. Flushing “A” Conclusions (From Report Dated 3/25/01)

All of the pipelines tested for this phase were installed in 1964. Based on the Results and Observations for the four pipeline segments where complete data was obtained - WINMAR was able to qualitatively rank the pipeline conditions. This is shown in Table 1 below. The pipelines were ranked according to the criteria listed in the table header: presence of pits, metal loss, pooled water, flushwater iron concentration, and weld erosion.

Segment	Rank	Pits Present	Metal Loss	Pooled Water	Highest Iron Concentration	Weld Erosion
2826	#1	No	No	No	117 PPM	No
2824	#2	No	Yes	Yes	302 PPM	Yes
2820	#3	Yes	No	No	70 PPM	Yes
2822	#4	Yes	Yes	Yes	76 PPM	No

Table 1 – Pipeline Ranking

The conclusions and recommendations in this section are based on the Results and Observations from the Flushing “A” report. Each conclusion will be presented, then followed by the relevant photos or results for that conclusion.

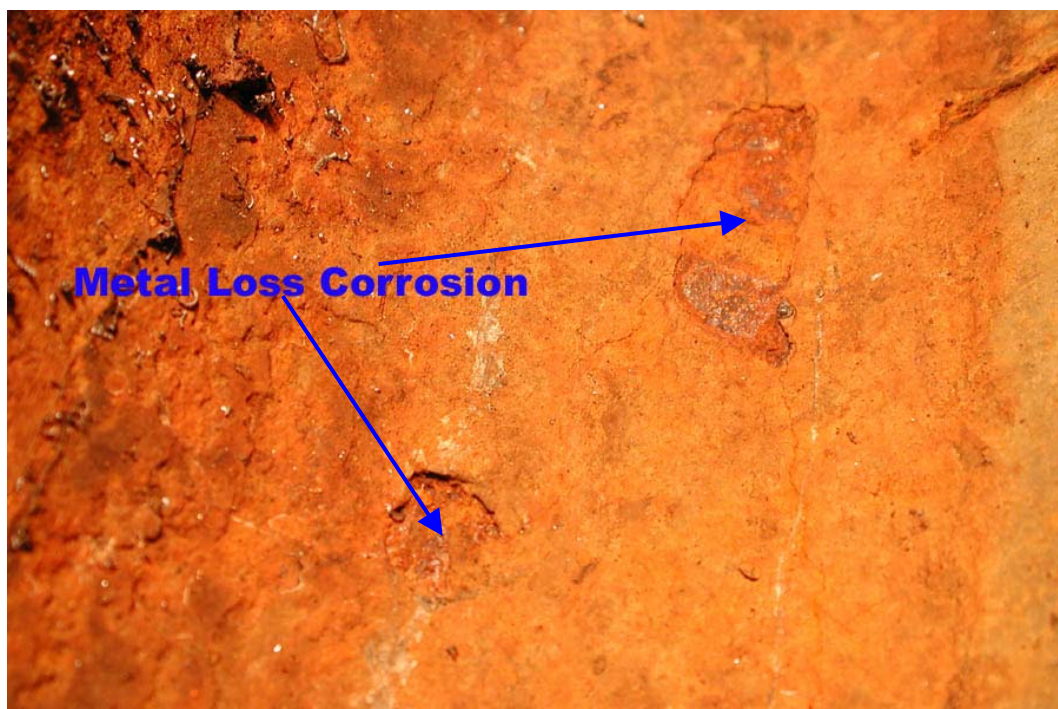
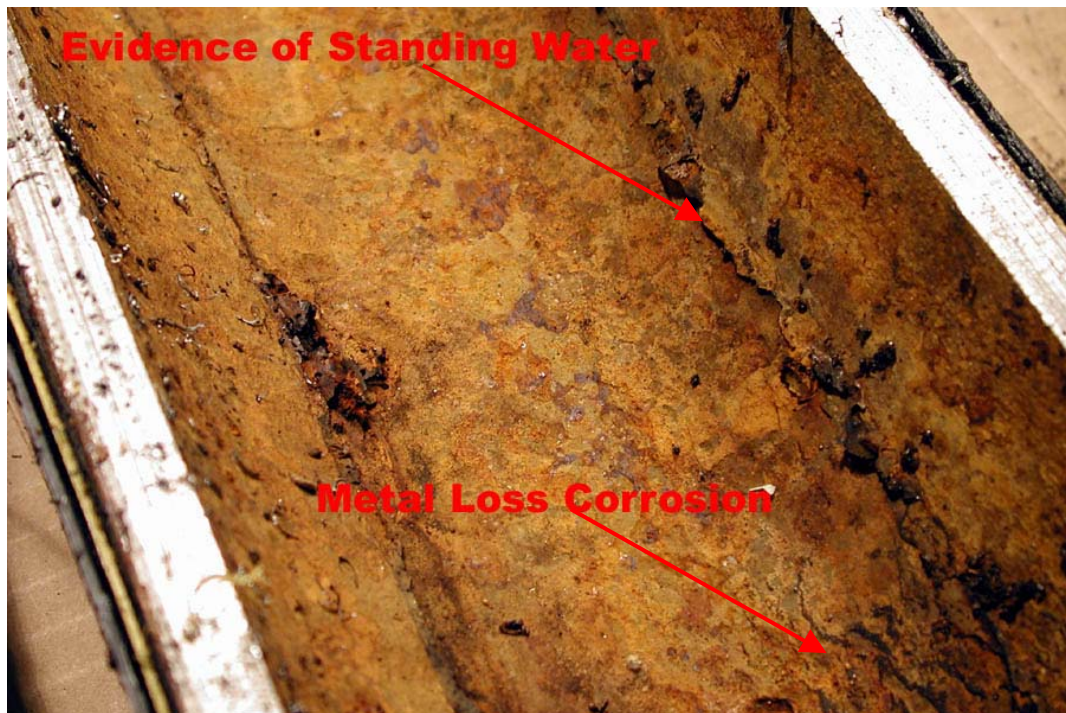
Conclusion 1) Having the unused pipeline open to air versus sealed doesn’t seem to have an impact on the line condition.

This is based on analysis of segments 2824 and 2826. Since the air is heavier than methane, it was present in the bottom of the pipeline. These two gas pipelines were in very similar condition however, despite being filled with different fluids. Segment 2824 showed metal loss corrosion but this was in the bottom of the pipeline that contained standing water. The “dry” portions of the lines were in very much the same condition, despite the presence of oxygen in the air-filled line.

Conclusion 2) Standing water from wellstream production pools in the pipeline causes metal loss corrosion. The standing water also provides a medium for the growth of sulfide reducing bacteria.

This standing water seemed to be the primary cause of loss of integrity for the pipelines tested. Segment 2824 showed evidence of standing water (as seen in the following photos). Since this line had never been pigged (non-pigable line) the water present in the pipeline must have come from wellstream production. The sample taken near the

well-protector platform showed evidence of being filled approximately 15% with water. Depending on the pipeline elevation (high and low spots) along its length, it could have contained either more, or less water. This is demonstrated in the following pictures (from segment 2824):



Conclusion 3) Composition of pipeline flush and fill water is important.

If possible, the operator should endeavor to NOT suck up any mud or particulate matter from the ocean, when filling a pipeline with seawater. This mud/sludge contains a “soup” of bacteria in much higher concentrations than found in surface seawater. These bacteria can and will contribute to Microbial Induced Corrosion (MIC). Segment 2822 shows evidence of being filled with seawater with a very high amount of suspended solids. It also shows signs of pitting corrosion at the pipeline/tubeturn weld. This is shown in the following photos from the segment 2822 pipeline sample:





Conclusion 4) Pitting corrosion is highly variable and unpredictable. Pits are present in some of the pipelines tested and not in others - despite the exact same production. Pits were present in the pipeline filled with water (2822), and also in one pipeline that was not (segment 2820). Based on this information, and this small sample size, it is necessary to conclude that we cannot correlate pitting corrosion to pipeline conditions for these tests. It may be present to correlate the two after future flushing tests yield a larger sample size.

b. Flushing "B" Conclusions

The conclusions for this phase are based on the data gathered from the following four pipelines. Initial iron concentrations rapidly approached the level of NSW as the pipeline volume was displaced during flushing. Initially high oil and grease concentrations dropped to non detect levels as the flushing volume approached one and a half times the pipeline volume. Flushing rates of 100 GPM appeared to produce acceptable results. Conclusions about the corrosion behavior of the oil pipelines in Phase B could not be established since three of the pipelines were not removed and pipeline samples were unavailable. A visual inspection of line 25 showed little surface corrosion and no scale. Mineral patterns analysis showed low average iron counts. A summary of the lines tested and their results are as follows:

Line #	Type of pipeline (bulk/processed/gas condensate)	Inhibitor Present (yes/no)	Initial Oil/Grease Concentrations (PPM)	Final Oil/Grease Concentrations (PPM)	Average Iron Content (PPM)	Flushing Flow Rate (GPM)
22	Bulk Oil	N	33	0	0.09	100
23	Bulk Oil	Y	804	0	0.32	100
24	Bulk Oil	Y	10	0	0.27	100
25	Bulk Oil	Y	1	0	24.46	100

Line 25 – Internal Pipe Photos



c. Final Conclusion

Corrosion occurred in all of the pipelines tested. The iron concentration in the fluid samples fluctuated over the length of the pipeline and may indicate active corrosion located randomly along the length of the pipeline. Phase A for the gas pipelines exhibited higher iron concentrations than Phase B for the oil pipelines. This difference may be a function of the amount of water present in the pipeline while out of service and the effectiveness of the corrosion inhibitor utilized.

30 CFR 250.1001 defines out of service pipelines as those pipelines that have not been used to transport oil, natural gas, sulfur or produced water for more than 30 consecutive days. The requirements for taking a pipeline out of service are listed in 30 CFR 250.1006. For pipelines out of service one year or less, isolate the pipeline with a blind flange or a closed block valve at each end of the pipeline. For pipelines out of service between one to five years, flush and fill the pipeline with inhibited seawater. After five years the pipeline should be decommissioned. The requirements for decommissioning pipelines are listed in 30 CFR 250.1750 through 250.1754.

WINMAR believes that the current industry practice for the flushing of out-of-service pipelines, removes contaminants from the pipelines to a level the same or lower than that of NSW. Flushing volumes of one and a half to two times the pipeline volume at a rate of 100 GPM appears adequate. These practices appear to leave the pipeline clean enough for reuse or to be decommissioned in place. In limited cases it may be necessary to pig the pipeline as part of the flushing process to remove paraffin or other viscous adhering products.

SECTION 10

APPENDIX

CORROSION INHIBITOR INFORMATION

10. Appendix - Corrosion Inhibitor Information

Many different kinds of inhibitors are available, each serving its own different function. The three most common are:

- Oxygen Scavenger (Uses sulfite to bind oxygen $SO_2 \rightarrow SO_4$)
- Corrosion Inhibitor (Amine coating “seals” internal pipe wall)
- Biocide (Kills bacteria that cause corrosion (Sulfide Reducing Bacteria (SRB's))

According to the vendors and contractors polled, Oxygen scavenger is not always necessary. For closed lines, oxygen will be depleted quickly, and once it is all used, that type of corrosion ceases. Large new lines can be designed for this very small amount of corrosion.

Biocide is the most important inhibitor for out of service lines because SRB's can sit in an out of service line and cause pits. The SRB's use the sulfate in seawater as a respiration source, making sulfuric acid, which causes pitting. In an out of service line, these bacteria have a perfect environment (Moist/Wet, oxygen poor, abundant sulfate source, etc.)

Information sheets were gathered from Champion Technologies and Baker Petrolite. These are included in this Appendix as reference material.

Baker Petrolite's Oxygen Depletion graph/information differs from ours. They show oxygen depletion versus time for a pipeline that is filled with uninhibited seawater and closed. This is interesting information that is relevant to the Flushing Phase B project.



Baker Petrolite

Protection of Pipelines During Hydrostatic Testing

Product Data



Baker Petrolite

INTRODUCTION

Before a new or rehabilitated pipeline is placed into service, it must be tested for integrity at a pressure above its designed working pressure. This is usually done with water, which may remain in the system for an extended period of time.

Water used in hydrostatic testing usually comes from one of several sources: aquifers, rivers, ponds, seas, etc. The use of water from any of these sources can cause corrosion and introduce bacteria into the pipeline. The severity of the problem is dependent upon the type and quality of water used, the length of time the water remains in the line, and the ambient temperature.

While the line is filled with water it is subjected to three types of corrosion:

1. Direct reaction of dissolved oxygen with the steel pipe to form ferric oxide/hydroxide. Pitting may be initiated. This mechanism is not generally serious because the concentration of dissolved oxygen in the water is rapidly depleted due to the reaction with the pipe wall. Our tests indicate that corrosion due to oxygen content, even with air-saturated waters, is usually minimal in a closed steel pipeline and problems rarely result from this mechanism.
2. Localized pitting and corrosion resulting from the growth of sulfate reducing bacteria (SRB) and acid producing bacteria (APB).
3. Attack by hydrogen sulfide produced as a result of SRB growth.

Mechanisms 2 and 3, which involve bacterial growth, are the most serious concerns in hydrotest waters. Sea water and high TDS brines have a greater potential for corrosion than fresh water due to their higher conductivity and sulfate levels.

Conventional wisdom has it that to protect against corrosion during hydrostatic testing, you must add three types of chemicals to the water: an oxygen scavenger, a biocide and a corrosion inhibitor. For large or long pipelines, this can be exceedingly expensive.

Baker Petrolite Corporation research data indicates that much of this expense is not necessary. In a closed system, oxygen is exhausted long before pitting due to oxygen becomes a problem. Controlling bacterial growth is generally sufficient to protect a pipeline from hydrotest damage. This can be accomplished by adding a biocide to the water prior to introducing it into the pipeline.

CHEMICAL TREATMENT RECOMMENDATIONS FOR HYDROSTATIC TEST WATERS

The following recommendations apply to both fresh water and sea water.

Biocide: X-CIDE® 102 is recommended for hydrostatic test waters. It should be used at a concentration of 250 ppm to 1000 ppm based on the total volume of water. Biocides are always recommended for hydrostatic test water unless chlorinated water (from a city water supply) is used.

Corrosion Inhibitor: If a corrosion inhibitor is desired, CRW 201 is recommended at a concentration of 100 ppm to 200 ppm based on the total volume of water.

Product Data



Baker Petrolite

Oxygen Scavenger: Although Baker Petrolite laboratory experiments and field experience indicate that corrosion problems due to the oxygen content of hydrostatic test waters rarely occur, an oxygen scavenger is sometimes requested as additional protection. In such a case, Baker Petrolite OSW 490C oxygen scavenger is recommended for removal of dissolved oxygen. Recommended dosage is 11 ppm OSW 490C oxygen scavenger for each ppm oxygen in the hydrotest water. Fresh water at 68 degrees F may contain up to 9 ppm dissolved oxygen.

PRODUCT APPLICATION

Before pumping the hydrostatic test water into the pipeline, a specific treatment regime should be followed to avoid interactions between products. The oxygen scavenger will deactivate the biocide, so they should not be mixed. The following is a recommended procedure for treating and mixing the water.

1. If oxygen removal is desired, measure the amount of dissolved oxygen in the water to be treated. Determine the amount of oxygen scavenger needed (11ppm OSW 490C oxygen scavenger per ppm oxygen in the water).
2. To remove oxygen, add the required amount of OSW 490C oxygen scavenger to the water tank. Mix gently; do not overmix; avoid introducing extra air into the tank. Allow approximately 15 minutes for complete scavenging. Since X-CIDE 102 biocide will interact with the oxygen scavenger, it is important to allow the recommended scavenging time to avoid biocide deactivation.
3. Add the required amount of X-CIDE 102 biocide to the tank and mix gently.
4. A corrosion inhibitor, CRW 201 can then be added to the hydrotest water if desired.

Steps 3 and 4 may be interchanged as the X-CIDE 102 biocide and CRW 201 are fully compatible.

FLUID DISPOSAL

HYDROSTATIC TEST FLUIDS CONTAINING RESIDUAL LEVELS OF BIOCIDES, AND/OR CORROSION INHIBITORS, SHOULD BE DISPOSED OF IN ACCORDANCE WITH PERTINENT STATE AND FEDERAL REGULATIONS.

The two most commonly practiced methods of disposal for hydrostatic test waters are direct discharge to receiving waters or discharge to a wastewater treatment plant. When test fluids are discharged directly to a receiving water, caution should be exercised to ensure that the level of residual biocide is below the threshold level which is capable of producing toxic effects in aquatic organisms. The hydrostatic test water can also be disposed in any salt water disposal well which is classified to handle oilfield waste.

Hydrostatic test fluids containing X-CIDE 102 biocide may be detoxified prior to their release to surface waters. Based on the residual level of biocide, a 1:1 ratio of OSW 490C oxygen scavenger should be used. An in-line mixer or surge tank should be used to promote mixing of the detoxifying agent with the hydrostatic test water. A 30-second contact time is sufficient for detoxification to take place. If the discharge from a hydrostatic test displaces a substantial percentage of the receiving water (e.g., a stream or a small bay), then the discharge should be re-aerated to avoid a fish kill due to the lack of oxygen.

Product Data



Baker Petrolite

Hydrostatic test fluids containing X-CIDE 102 biocide may also be discharged to a wastewater treatment plant. Aerobic bacteria are capable of utilizing X-CIDE 102 biocide as a nutrient source at concentrations of 25 ppm or less. Studies have shown that X-CIDE 102 biocide has an affinity for any type of proteinaceous material and will bind to it irreversibly. Bound X-CIDE 102 biocide is also readily biodegraded.

The results of aquatic toxicity tests carried out with X-CIDE 102 biocide and CRW 201 corrosion inhibitor are in the attached EcoTox™ reports.

Standard BOD/COD tests were performed with each product. Results of the studies indicate that both the biocide and corrosion inhibitor are readily biodegraded.

The octanol/water partition coefficient for X-CIDE 102 biocide indicates that this chemical has little propensity to bioconcentrate in the environment.

PRODUCT EVALUATION

A series of tests were conducted to (a) assess the need for chemical inhibition of hydrostatic test waters and (b) identify and evaluate the most effective program having the widest applicability.

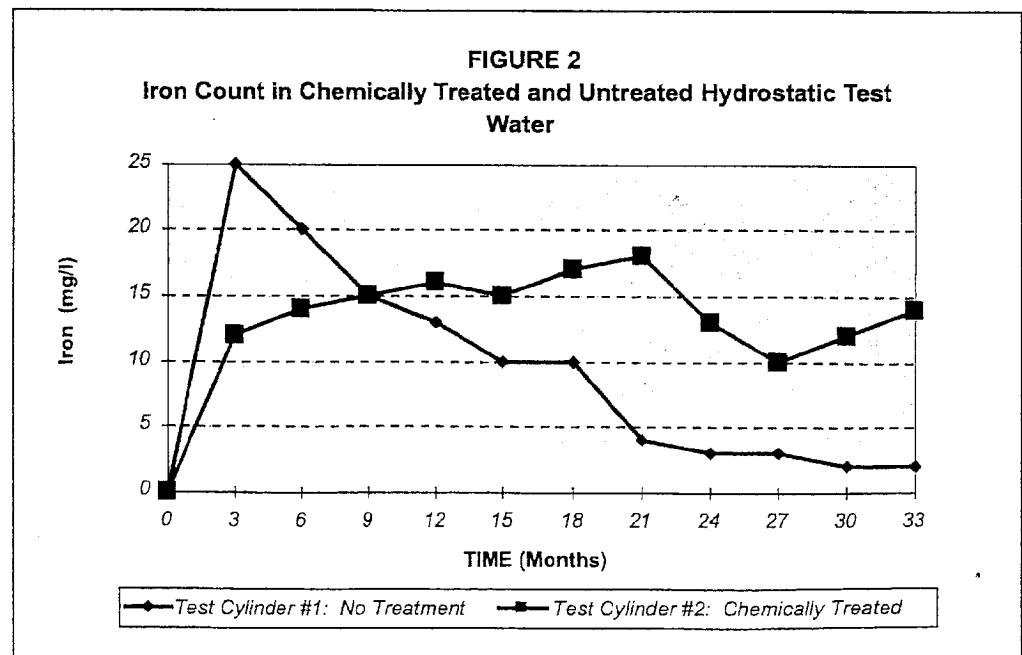
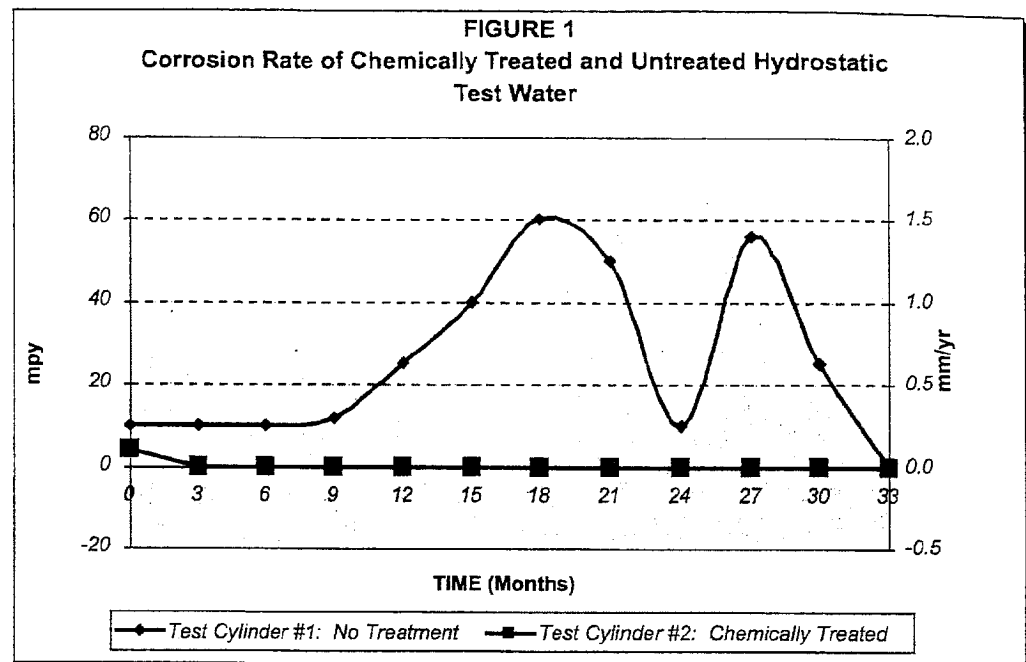
1. Long term field evaluations were carried out in conjunction with a major oil company. These tests consisted of periodic monitoring of test cylinders made from sealed pipeline lengths. One test cylinder contained uninhibited sea water, while the sea water in the other cylinder was treated with an oxygen scavenger, a biocide, and a corrosion inhibitor. Monitoring consisted of LPR readings (instantaneous corrosion rate), soluble iron concentration measurements, and SRB enumeration (by the API RP 38 method), each taken periodically over 33 months.
2. The rate of oxygen depletion in air saturated waters was measured in test cylinders made from sealed pipeline sections of various diameters containing fresh water and sea water. In addition, the effect of the reaction of oxygen with the pipe wall was assessed over a period of time.
3. The effectiveness of selected chemicals was assessed in laboratory studies over an extended period of time in both fresh water and sea water.

The results of monitoring corrosion rate, iron concentration, and number of SRBs in the pipeline test cylinders are shown in Figures 1, 2, and 3. These outdoor tests were carried out in a temperate climate where the cylinders were subjected to ambient temperature fluctuations. Test cylinder 1 contained untreated sea water, whereas the sea water in cylinder 2 was treated with an oxygen scavenger, biocide, and corrosion inhibitor. Figure 1 shows a plot of instantaneous corrosion rate against time. The corrosion rate in cylinder 1 fluctuates widely between 8 mpy (0.2 mm/yr) and 59 mpy (1.5 mm/yr), the peaks occurring in the summer months when the ambient temperatures are the highest. The treated cylinder showed very low corrosion rates in the 0.04 to 0.08 mpy range (0.001-0.002 mm/yr). In Figure 3, the SRB levels rise to a constant 1-9 colonies/mL in the untreated fluid, whereas they remain zero in the treated cylinder. In quiescent conditions such as these, SRB colonies will attach to the pipe wall rather than float freely in the water, so low populations in the test cylinder water would be expected. A measure of bacterial activity can be gained from Figure 2 which shows a plot of soluble iron concentration in the water versus time. In the treated cylinder, the iron level remains relatively constant at 10-20 ppm; however, in the untreated cylinder, the soluble iron concentration rises initially up to 25 ppm and then falls to below 2 ppm. This is caused by the precipitation of insoluble iron sulfide, which is a result of dissolved iron reacting with hydrogen sulfide produced by SRB growth.

Product Data



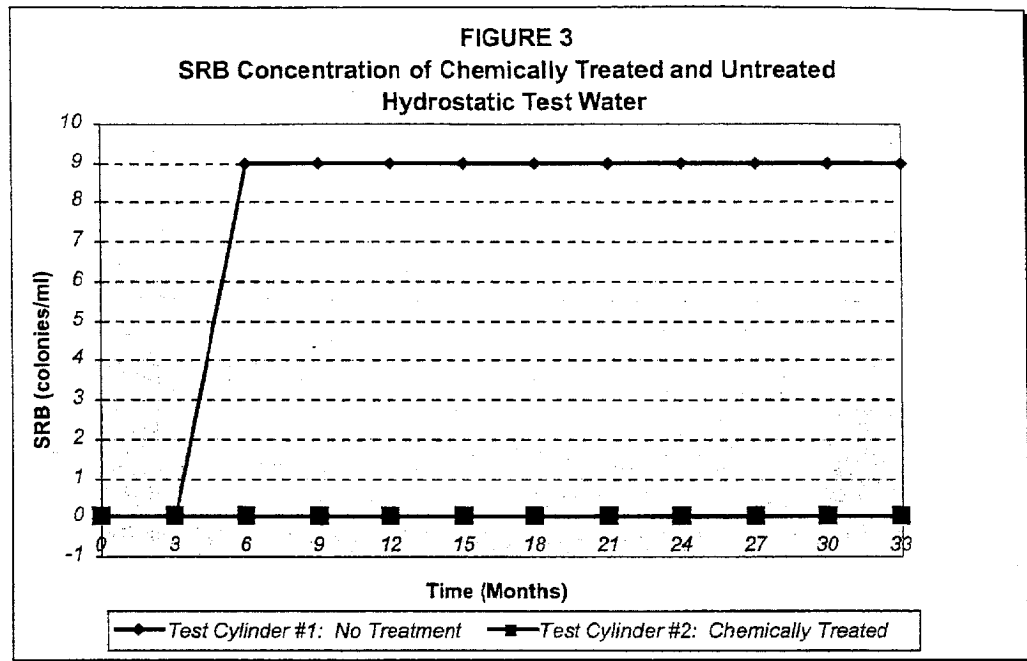
Baker Petrolite



Product Data



Baker Petrolite



The time required for oxygen depletion to approximately 100 ppb in both fresh and sea water in a range of pipe diameters is shown in Table 1. The oxygen in the largest diameter (10" or 250 mm) cylinder was depleted in 48 hours. Metal coupons suspended in the water in the cylinders were examined after 4 months for signs of oxygen attack. No evidence of pitting was observed.

TABLE 1
Oxygen Depletion in Water-Filled Pipelines

Line Size		Water Type	Initial O ₂ (ppm)	Hours to 100 ppb
MM.	Inches			
250	10	fresh	7.2	48
100	4	fresh	6.8	26
50	2	fresh	7.0	20
250	10	sea	4.5	48
100	4	sea	4.0	30
50	2	sea	4.5	18

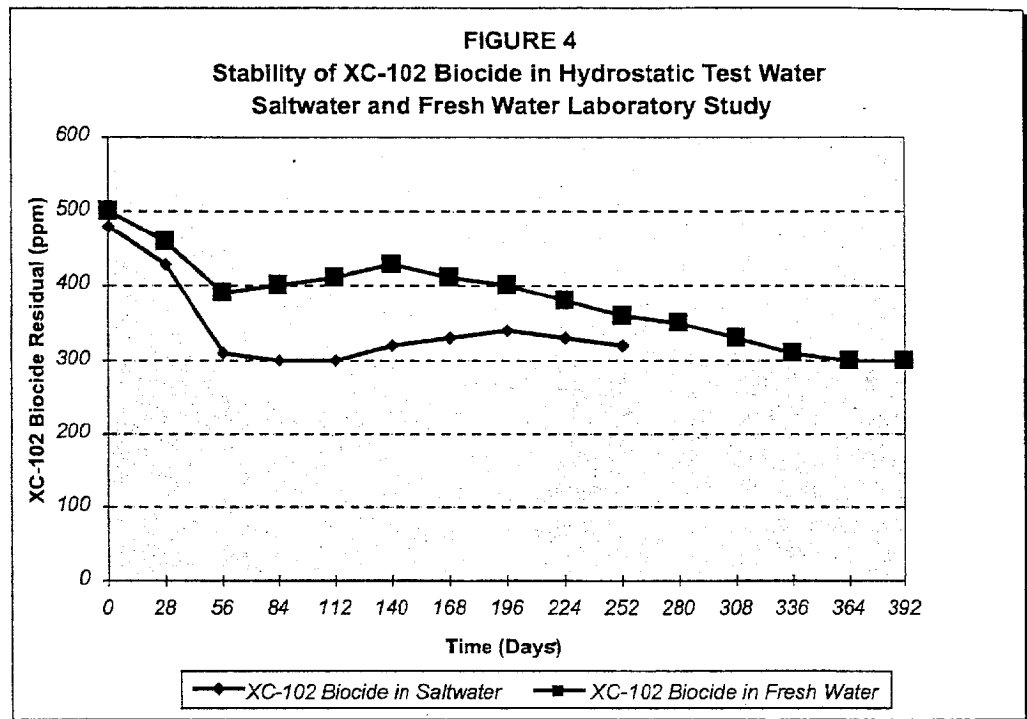
Temperature 20 - 22°C

Product Data



Baker Petrolite

The results of biocide stability tests for X-CIDE 102 biocide are shown in Figure 4. The concentration of X-CIDE 102 biocide falls from 500 ppm and stabilizes at about 300 ppm in both fresh water and sea water.



Product Data



Baker Petrolite

CRW132 Corrosion Inhibitor

DESCRIPTION:

CRW132 is a water-soluble blend of filming amines, surfactant, and oxygen scavenger. It is an excellent packer fluid inhibitor as well as a hydrostatic test and general waterflood inhibitor.

APPLICATION:

Applications vary with specific system conditions. Contact your local Baker Petrolite products representative for advice on your system.

Your Baker Petrolite representative can evaluate your system's performance, specify the appropriate treatment and equipment, and design a comprehensive application program.

TYPICAL PROPERTIES:

Specific Gravity, 77°F(25°C)	0.97
Specific Weight, 77°F(25°C)	8.07 lbs/US gal
Flash Point, PMCC	88°F(31°C)
Pour Point	-40°F(-40°C)
Solubility (brine)	Soluble
Solubility (water)	Soluble

FEATURES AND BENEFITS:

Feature:

- Combination formula

Benefit:

- Minimizes product inventory

Feature:

- Residuals easily monitored

Benefit:

- Treatment cost minimized

Feature:

- Excellent cold weather handling properties

Benefit:

- Minimal storage and pumping requirements

MATERIAL COMPATIBILITY:

Suitable:

Metals:	admiralty brass, copper, 304 stainless steel, 316 stainless steel
Plastics:	PLEXIGLAS, HD polyethylene, HD polypropylene, PVC
Elastomers:	fiberglass, TEFLON

Not Suitable:

Metals:	aluminum, mild steel
Plastics:	
Elastomers:	Buna N (rubber), neoprene, HYPALON, VITON

SAFETY AND HANDLING:

Before handling, storage or use, see the Material Safety Data Sheet (MSDS) for details.

Baker Petrolite 24 Hour Emergency Hotline:

1-800-424-9300 (CHEMTREC) U.S.A.

1-613-996-6666 (CANUTEC) Canada

Baker Petrolite Customer Care Hotline:

1-800-872-1916 (8 a.m. to 5 p.m. CST)

Disclaimer of Liability: Baker Petrolite Corporation (BPC) warrants to purchaser, but no third parties or others, the specifications for the product shall fall within a generally recognized range for typical physical properties established by BPC when the product departs BPC's point of origin and that any services shall only be performed in accordance with applicable written work documents. BPC MAKES NO OTHER WARRANTY OR GUARANTEE OF ANY KIND, EXPRESS OR IMPLIED, INCLUDING NO IMPLIED WARRANTY OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE, REGARDING ANY SERVICES PERFORMED OR PRODUCT SUPPLIED. BPC will give purchaser the benefit of BPC's best judgement in making interpretations of data, but does not guarantee the accuracy or correctness of such interpretations. BPC's recommendations contained herein are advisory only and without representations as to the results. BPC shall not be liable for any indirect, special, punitive, exemplary or consequential damages or losses from any cause whatsoever including but not limited to its negligence.

BPPD2000 (2/99)

Product Data



Baker Petrolite

CRW9070 Corrosion Inhibitor

DESCRIPTION:

CRW9070 corrosion inhibitor is an amine based corrosion inhibitor which can be used to treat oil wells, water injection systems and packer fluids. It is soluble in fresh water and brines up to 12.0 pounds per gallon. CRW9070 provides protection from corrosion caused by both CO₂ and H₂S.

APPLICATION:

CRW9070 corrosion inhibitor should be applied via continuous injection. A concentration of 10-50 ppm in the produced fluids is sufficient in most applications. The optimum rate needed should be based on the data obtained from the monitoring program.

For packer fluids, 0.5-2.0% should be mixed into the brine prior to injection into the annulus.

Your Baker Petrolite representative can evaluate your system's performance, specify the appropriate treatment and equipment, and design a comprehensive application program.

TYPICAL PROPERTIES:

Form	Liquid
Specific Gravity @ 72°F	0.924
Specific Weight @ 72°F	7.70 lbs/US gal
Flash Point	62°F
Pour Point	-35°F
Solubility	Water soluble
pH	9.0-12.0

FEATURES AND BENEFITS:

Feature:

- Thermally stable

Benefit:

- Effective in hot wells

Feature:

- Excellent brine solubility

Benefit:

- Mixes easily with packer fluids

Feature:

- Very water soluble

Benefit:

- Particularly effective in high fluid wells

Feature:

- Detergent properties

Benefit:

- Helps prevent under deposit corrosion

MATERIAL COMPATIBILITY:

Suitable:

Metals: admiralty brass, aluminum, copper, mild steel, 304 stainless steel, 316 stainless steel

Plastics: HD polyethylene

Elastomers: TEFLON, VITON

Not Suitable:

Metals:

Plastics: HD polypropylene, fiberglass

Elastomers: BUNA N (rubber), neoprene, HYPALON

SAFETY AND HANDLING:

Before handling, storage or use, see the Material Safety Data Sheet (MSDS) for details.

Baker Petrolite 24 Hour Emergency Hotline:

1-800-424-9300 (CHEMTREC) U.S.A.

1-613-996-6666 (CANUTEC) Canada

Baker Petrolite Customer Care Hotline:

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BPPD2022 (09/98)

Champion is very aware of the effect that chemicals can have on marine life and the environment as a whole. We take our responsibility as a chemical supplier very seriously and for a number of years an Environmental Policy has been an integral part of our corporate ideology.

The Blacksmith range of hydrotesting chemicals has both fully toxicity tested by the UK authorities under the Offshore Chemical Notification Scheme (OCNS). This category system reflects the toxicological properties, environmental impact and usage volume of chemicals offshore in the UK sector.

In January 1996, the new system of Harmonised Offshore Chemical Notification Format came into force. This scheme standardises the methods for testing, evaluation and approval of offshore exploration and production chemicals throughout the entire North East Atlantic Sector. This revised notification scheme supercedes the voluntary OCNS but is sufficiently similar that the old classifications will remain valid for a given period. The periods for which these will remain valid are as follows:

Category 4 : Until 1st June 1997

Category 3 : Until 1st January 1998

Category 2 : Until 1st January 1998

Category 1 : Until 1st January 1999

Category 0 : Until 1st January 2000

In addition, the revised prior notification tonnage triggers have also been amended. These are now set for the cumulative quantity of all chemicals used within each group at individual installations. This differs from the old OCNS for which the tonnage triggers were based upon the discharge of individual chemicals.

The UK Department and Trade and Industry (DTI) regulate the environmental classification of chemicals for offshore use. In doing so, each chemical is awarded a category based on its toxicity profile. Summarised below are a selection of low toxicity packages.

Product	Application	HOCNF Category*
Champion B1150 (Bactron K-54)	Biocide	C
Champion B1710	Biocide	D
Champion OS2 (Cortron RU-206)	Oxygen Scavenger	E (OS Parcom List 'A')
Champion CP1900	Corrosion Inhibitor	B
Champion Fluorescein Dye	Leak Detection Dye	D
Champion Cleardye*	Leak Detection Dye	E



BLACKSMITH B1150

Product Data Sheet

Product Description

Blacksmith B1150 is a highly effective biocide used to control microbiological problems in both land based and offshore systems. Chemically, it comprises of a 50% solution of Glutaraldehyde.

Product Application

Blacksmith B1150 is an excellent non-selective biocide for the destruction of the major bacterial strains and is also effective against some fungi and algae.

Blacksmith B1150 is water miscible liquid which forms clear solutions in both fresh water and concentrated brines.

This product is one of the most environmentally acceptable biocides on the market.

Chemical & Physical Properties

Form:	Liquid
Colour:	Clear, colourless/light yellow
Odour:	Pungent
pH (20degC):	3-4
Boiling Water:	95degC approx.
Water Solubility:	Completely miscible
Relative Density (20degC):	1.113
Viscosity (20degC):	20mPa.s

Dosage

Blacksmith B1150 should be injected neat into the system at a dosage rate of 75-200ppm, for batch fill testing operations. Champion will be able to advise on the optimum concentration subject to systems conditions.

Environmental Information

Blacksmith B1150 is an environmentally friendly combined product and has been awarded an HOCNF Category of 1[C].

This product is also approved by the relevant authorities for use in the Danish, Dutch and Norwegian Sectors of the North Sea.



BLACKSMITH OS2

Product Data Sheet

Product Description

Blacksmith OS2 is an aqueous solution of Ammonium Bisulphite (63-65%). This product has been designed to rapidly scavenge dissolved oxygen from seawater at normal temperatures for pipeline operations and water injection systems.

This product should be injected neat into the treatment solution with the minimum exposure to air.

Product Application

Blacksmith OS2 should be injected into the treatment solution with the minimum exposure to air. For hydrotest applications it is important that Blacksmith OS2 is added to the test medium before the injection point of other hydrotesting chemicals. This product is one of the most economical methods for reducing the dissolved oxygen content to below 10ppb.

Chemical & Physical Properties

Form:	Liquid
Colour:	Clear, light yellow
Odour:	Pungent sulphurous
pH (20°C):	4.8-5.6
Boiling Point:	105°C approx.
Water Solubility:	Completely miscible
Relative Density (20°C):	1.32-1.40

Dosage

Blacksmith OS2 should be injected at 155ppm as this dosage level will ensure a rapid rate of oxygen depletion.

Environmental Information

Blacksmith OS2 is an environmentally friendly combined product and has been awarded an HOCNF Category of E (OSPARCOM List A).



BLACKSMITH CP1900

Product Data Sheet

Product Description

Blacksmith CP1900 is a highly formulated film-forming imadazoline salt based corrosion inhibitor designed to provide corrosion protection for hydrotest operations.

This is achieved by either a continuous injection operation during pipeline flooding or as a batch treatment program, prior to pipeline start-up.

Product Application

Blacksmith CP1900 is a highly active corrosion inhibitor which effectively forms a protective barrier between the test medium and the walls of the pipeline. This product was formulated in order to have a greater environmental acceptability whilst providing enhanced corrosion protection at a low dosage level. Blacksmith CP1900 is completely miscible in fresh water and salt water mediums and is active over a wide pH range.

Chemical & Physical Properties

Form:	Liquid
Colour:	Clear amber
Flash Point:	>65°C
Relative Density (20°C):	0.996
Viscosity (25°C):	5cP

Dosage

Blacksmith CP1900 should be injected neat into the system, if used for continuous injection at a dosage rate of 100-200ppm. Dosage levels for batch treatment programmes are subject to system conditions and therefore a Champion representative can assist with dosage recommendations.

Environmental Information

Blacksmith CP1900 has been awarded an HOCNF Category B.



BLACKSMITH FLUORESCEIN DYE

Product Data Sheet

Product Description

Blacksmith Fluorescein Dye can be supplied in solid or liquid form although for hydrotesting operations the liquid form is generally favoured. Chemically, it is the sodium salt of hydroxy-o-carbonyl phenyl fluorene and has a dark orange appearance in the concentrate form.

Product Application

Blacksmith Fluorescein Dye exhibits an intense green colour upon dilution and is generally detected by UV light at 491nm making it an excellent tracer dye for use in leak detection. Blacksmith Fluorescein Dye is most commonly used for hydrotest and cementing operations. This product is generally regarded as the full strength industry standard.

Chemical & Physical Properties

Form:	Liquid
Colour:	Dark orange
Odour:	None
pH (@2% in water):	12
Relative Density (20°C):	1.0 - 1.1
Solubility:	Completely soluble in fresh and sea water.

Dosage

Blacksmith Fluorescein Dye is typically dosed in the range of 25-40ppm for hydrotest applications and 1000-4000ppm for cementing applications.



BLACKSMITH CLEAR DYE

Product Data Sheet

Product Description

Blacksmith Clear Dye is an optically sensitive tracer dye for hydrostatic testing and can be supplied in both the solid or liquid form, although for hydrotesting operations the liquid form is generally favoured. Chemically, it is an anionic fluorescent compound which offers substantial advantages over existing dye-based tracer systems.

Product Application

Blacksmith Clear Dye has been formulated to be used for hydrotest leak and pressure test operations for both fresh and saline water. This product operates as a readily traceable detector when activated by UV light although it is invisible under white light. Blacksmith Clear Dye offers advantages over more familiar leak test tracers such as Blacksmith Fluorescein Dye as the visible discharge can not be observed.

Chemical & Physical Properties

Form:	Liquid
Colour:	Yellow Solution
Odour:	None
pH:	8-9.5
Solubility (@20°C):	completely miscible

Dosage

A Champion representative can advise of the required dosage levels based on the system conditions.

Attached is the Absorption spectra for Blacksmith Clear Dye (Ref. Figure 1).

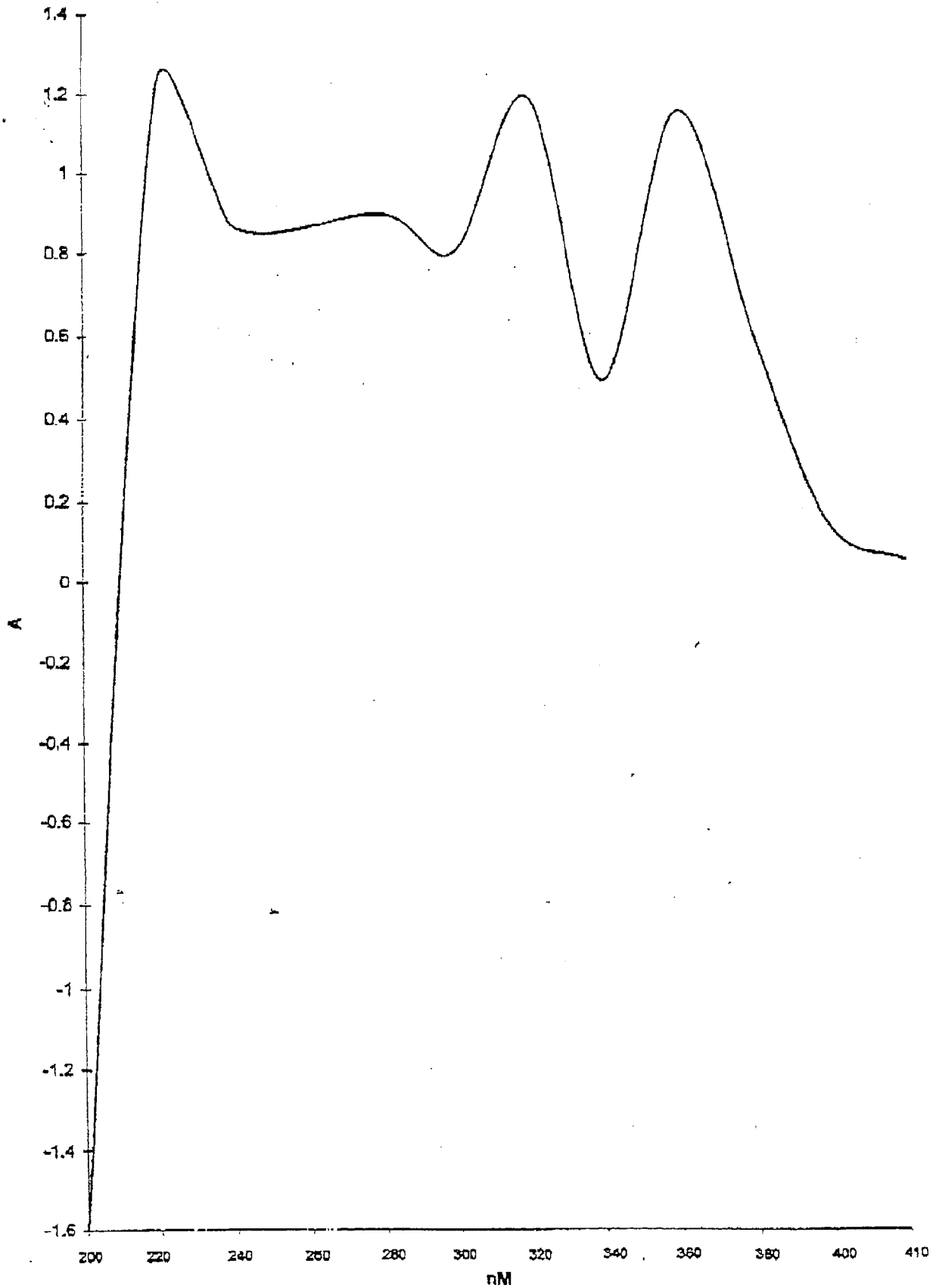


Figure 1: Absorption spectra profile for Blacksmith Clear Dye



SUBSEA SPECIAL PRODUCTS

Innovative Chemical Solutions

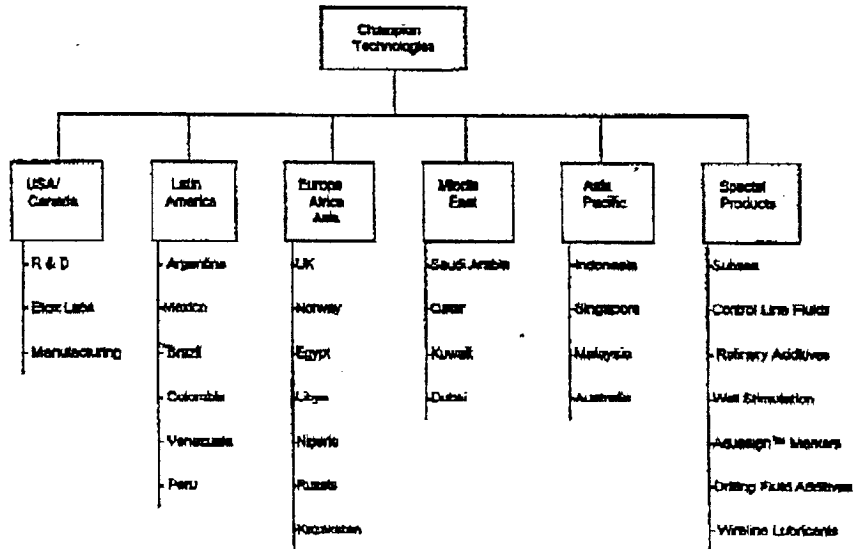
- Hydrotesting Corrosion Inhibition
- Leak Detection
- Wax Removal
- Solid State Chemistries
- Pipeline Bundle Protection
- Pipeline Swabbing
- Free-flooding Pipelay Inhibition
- Hydrocarbon Decontamination
- Subsea Tie-in
- ROV/Diver Intervention
- Descaling

Company Overview

For over a decade Blacksmith has maintained its position as a leading North Sea oilfield chemicals service company whilst also developing a significant international portfolio through its Special Products range.

Following Blacksmith's acquisition in 1988 by Champion Technologies Inc, an International leader in speciality oilfield chemicals, Champion Technologies Special Products operates as a specialist division dealing primarily within the global service industry sector. Through Champion's established world wide infrastructure this group is able to service an increasing customer base with its Special Products and application technologies.

These Special Products are internationally recognised and respected and carry unparalleled track records. Many are industry standards and extensively used by the service industries leading contractors. Any Special Products material is available globally from any company location.



Special Products and their applications are serviced by trained and experienced individuals that work in partnership with users to modify existing or develop new chemistry deployment solutions.

Subsea Special Products

For over a decade Champion Technologies (formerly Blacksmith) has been the leader in the supply of chemical related products, services and consultancy to the North Sea Subsea and pipeline service industry.

This experience is also exported widely and in particular Champion's strategic position in the South East Asian and Latin American subsea markets is comparable to that held in the North Sea.

A range of low toxicity chemistries available for deployment in several physical forms are customised to meet specific operational conditions has secured Champion's involvement in over 100 major pipeline commissioning and decommissioning projects achieving several industry records and notable firsts. A full track record is detailed on the back page.

Blacksmith's and now Champion's unique position of dedicating an experienced project team to the subsea service industry sector allows expert technical, operational and environmental advice on the selection/application of chemicals. Cooperation with locally experienced Champion operations means a rapid high level of assistance is always available to overseas customers.

The core application of Champion's Subsea Special Products range is corrosion inhibition chemistry. Corrosion is such a vital consideration in subsea operations in that every activity where metallurgy is exposed to seawater, the potential for corrosion should be evaluated and prevented. A basic overview of the common corrosion process is enclosed within this document. In addition, throughout the past 2 years Champion has worked extensively on deepwater corrosion prevention techniques which allow chemistries to be deployed under difficult engineering and operational circumstances where the standard approaches to corrosion inhibition are not possible. However, deepwater corrosion follows a unique set of pathways, whereby an illustration of this process has been attached.

An application guide for Champion Subsea Special Products is included over. However, final selection of a Special Product and application technique usually occurs in consultation with the user and evaluates various factors, i.e. environmental, operational time and costs.

Full technical details on any application or product shall be provided on request.

Standard Seawater Corrosion Inhibition

Oxygen Scavengers	Removes dissolved oxygen from water to prevent oxygen induced corrosion. Oxygen Scavengers are designed to provide a rapid rate of oxygen depletion, i.e. at 5°C, to reduce the oxygen content by 95%, well within the first minute of injection.	Blacksmith OS2 Blacksmith OS3
Biocides	Remove bacteria from water to prevent microbiological induced corrosion. Biocides are designed to be effective on a wide range of strains, e.g. Aerobic, Anaerobic and Sulphate Reducing Bacteria. Biofilm penetration is also advantageous to eliminate biomass build up.	Blacksmith B1150 Blacksmith B1660 Blacksmith B1370 Blacksmith B1710 Blacksmith B1200
Corrosion Inhibitors	Provide tenacious film through adsorption of the inhibitor molecules onto the metal surface. The inhibitor film protects the metal from corrosion and prevents any bacterial fouling becoming directly attached to the surface.	Blacksmith CP1300/E Blacksmith CP1900 Blacksmith CP1820
Cocktail Products	Combination chemicals that contain one or more of the individual biocide, corrosion inhibitor and oxygen scavenger components.	Blacksmith O-3970R

Naval Corrosion Inhibition

Hydrotesting Sticks for free-flooding equipment or 'on-line' chemical insertion whilst at sea	<p>Specific water treatment chemistries custom developed in solid form with dissolution rates designed to introduce chemistries under given operational conditions and time scales.</p> <ul style="list-style-type: none"> • Inserted into various equipment (e.g. spool pieces/tees) prior to load out. • Inserted into gaskets prior to seal plate changes/runner installation. • ROV/diver insertion for spool pieces/tees and during hook up operations. • Eliminates divers exposure to chemicals. • Bonded for temporary fixing to equipment by water soluble adhesives providing delayed chemical deployment. 	<p>Biocides Sticks Oxygen Scavenger Sticks Corrosion Inhibitor Sticks Cocktail sticks Dye Sticks</p>
Water Treatment Gels for free-flooding equipment	Specific water treatment chemistries custom developed in soluble gel form designed to introduce active 'corrosion inhibitor' chemistry under operational conditions and time scales. Provides high level localised corrosion protection.	<p>Biocides Oxygen Scavengers Corrosion Inhibitors Cocktails</p>
Water Treatment Coatings for pipeline applications	Liquid inhibitor packages designed to set with hard smooth finish. Used for 'on-line' seawater inhibition treatment of pipelines during free flooding operations. Contain water soluble corrosion inhibitor, biocide, oxygen scavenger and can be applied by brush/spray onto internal pipe surface prior to lay.	<p>Biocides Oxygen Scavengers Corrosion Inhibitors Cocktails</p>
Vapour Phase Inhibitors	Products designed to be added to the liquid test medium. On dewatering the VPI will be retained on the internal surfaces and release a corrosion inhibitor vapour which coats the metal and provides protection.	Blacksmith VPI series

Specialist Gels

Decontamination Gels	Remove hydrocarbons and retain contamination absorbed within structure of the moving gel. Decontaminates pipework to less than 40ppm oil in water post flush.	Blacksmith Muscol 6 Gel
Swabbing Gels	Contain dehydrated solvent to act hydroscopically on the pipelines internals. LIR and retain water contamination absorbed within structure of the moving gel.	Blacksmith Methanol Solgel Blacksmith MEG Solgel
Pick Up Gels	Water or hydrocarbon based gels designed to remove pipeline debris leaving the internal surface in either a hydrophilic or hydrophobic state.	Blacksmith Aqua Solgel Blacksmith Gel Oil 10/11
Isolation Gels/Gel Plugs	Highly viscous or pre-formed water or hydrocarbon based gels used in pigging and isolation operations.	Blacksmith Solgels/Gelcoil Series

Leak Detection

Leak Detection Dyes	Leak detection via visual and optical fluorescence. Leak detection via optical fluorescence (chemical is colourless - no seawater colouration). Very Low Toxicity.	Blacksmith Fluorescan LT Blacksmith Clear Dye
Leak Detection Slits/Gels	As above in stick or gel form	As above in stick/gel

Pipeline Blockage Removal

Wax/Scale Removal	The removal of wax and scale from a pipeline can normally be satisfied by routing pigging operations under some circumstances the effectiveness of pigging can be improved with the use of chemical treatments. The exact formulation of the chemical is selected as being specific to the wax or scale.	Blacksmith Scale Dissolver range Blacksmith Wax Dissolver range
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Pipeline RFO Conditioning

Swabbing Solvents	Glycols or methanol used in pipeline drying operations where advantageous over Nitrogen or vacuum.	Methanol and Glycols
Pipeline Conditioning	Post dewatering an inhibitor gel pig or slug of oil/gas phase corrosion inhibitor can be run. This conditions the pipe internal surfaces to reactive fluids/gas pre protected.	Blacksmith CP1315

OVERVIEW OF DEEPWATER CORROSION PROCESS

