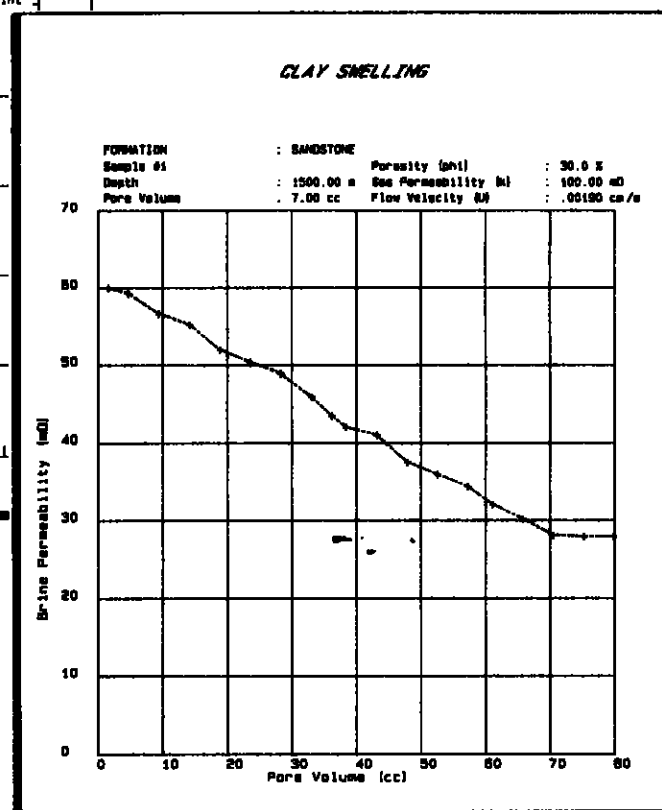
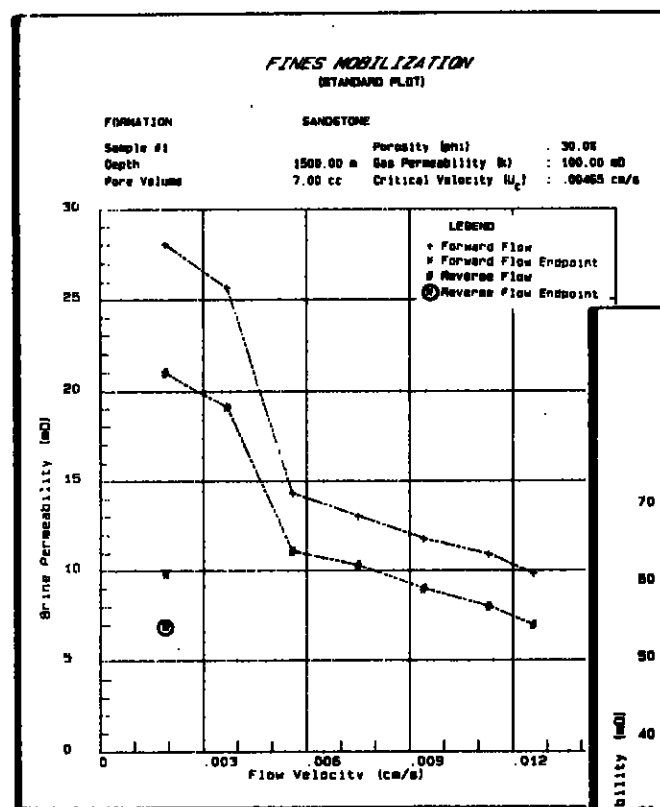


# WATERFLOOD SENSITIVITY STUDY

MOGC DALY  
9-14-10-29W1M



Prepared for  
**TUNDRA OIL AND GAS LTD.**

FILE NO: 89-GC-253-1

August 10, 1989



**PRODUCTION ENGINEERING RESEARCH & DEVELOPMENT**

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SECTION 1

## EXECUTIVE SUMMARY

This report contains the results of two water/water and one water/rock compatibility (waterflood sensitivity) tests.

The water compatibility study (Section 2) on Bakken brine versus Lodgepole brine and Bakken brine versus Jurassic brine confirmed that both the proposed injection brines are compatible in all proportions with the formation brine.

A waterflood sensitivity test (clay swelling followed by fines mobilization with Jurassic brine) was done on one of the two samples selected from the Bakken Formation in the MOGC DALY 9-14-10-29W1M well.

During the clay swell portion of the test, permeability declined from 11.88 md to 9.10 md during the first 22 pore volumes flooded, but was restored to 11.38 md over the next 8 pore volumes and remained constant, within experimental error, over the subsequent 10 pore volumes. The slight reduction in permeability is attributed to a slight swelling of traces of smectite, in combination with some fines migration. Clay swelling is concluded to be an insignificant problem in the reservoir.

The test showed a serious problem of fines mobilization with a drop in absolute permeability of 82% (12.19 md to 2.24 md) during forward flow. No significant permeability restoration was observed with flow reversal. A low critical velocity of 0.0294 cm/min was measured. This equates to field conditions of 1 to 2 m<sup>3</sup>/ per day adjacent to the wellbore which means that fines will be moved within the reservoir at any production rate. The significance of this problem will be dependent upon the areal distribution of the fines.

The fines migration problem must be addressed, because blockage of pore throats will result in higher fluid differential pressures and higher residual oil saturations.

## EXPERIMENTAL PROCEDURE

A general description of waterflood sensitivity testing is included in the Appendix at the end of Section 1; the following are pertinent details of the procedure used for the sample tested from the Bakken Formation in the MOGC Daly 9-14-10-29W1 well.

Two plug samples each 2.5 cm in diameter, were cut (with 5% KCl as a lubricant) from full diameter sample #17 as recommended by Tundra Oil and Gas Ltd. The samples were cleaned in a reflux soxhlet extraction apparatus using toluene, acetone and methanol in succession; were dried in an oven at 80°C for 24 hours; and were subsequently tested for their basic petrophysical properties (i.e. gas permeability, porosity and grain density).

As presented in Table 1, the permeability of sample #2 (40.14 md) had a better correlation with that of the full diameter sample (33.0 md as measured by Core Laboratories); therefore, sample #2 was selected for the dynamic testing.

The clay swelling test (permeability versus pore volume throughput) and the fines mobilization test (permeability versus flow velocity) were conducted under the following reservoir conditions:

Pore Pressure: 5.39 MPa

Overburden Pressure: 17.50 MPa

Temperature: 21°C

Fluids used: Bakken formation brine for baseline absolute permeability and Jurassic formation brine for clay swelling and fines mobilization tests.

Both fluids were filtered (0.45 micron) and deaerated before use. The sample was vacuum saturated to 100% of its pore volume with Bakken formation brine, mounted in a core holder, and pressurized to reservoir pressures. Sixteen pore volumes of Bakken formation brine were flooded through the sample at a low volumetric flow rate of 4 cc/hr (approx.

0.014 cm/min) to establish an equilibrium baseline absolute permeability of 11.88 md. Subsequently, a switch from Bakken formation brine to Jurassic injection brine was made, maintaining a constant flow rate of 4 cc/hr. Differential pressure across the sample was constantly monitored to record any permeability decline due to swelling clays.

When the differential pressure had stabilized, and no further permeability decline was observed, the flowrate was incrementally increased. The differential pressure across the sample was continually monitored at each increment. After the highest flowrate was reached, the flowrate was lowered to the original flowrate (4 cc/hr) for a permeability comparison (forward flow end point). If this end point permeability were similar to the original value, then any permeability change at the higher flowrates would be assumed to be due to turbulent flow. However, if the end point permeability were significantly different from the original value, then it could be concluded that the change in permeability was actually in response to a physical change in the sample.

The flowrate was subsequently reversed, and the differential pressure across the sample was again constantly monitored. The reverse flow started at 4 cc/hr and was incrementally increased to the same maximum value as in the forward direction. Finally, the flowrate was lowered to the original value (4 cc/hr) for another permeability comparison (reverse flow end point).

## DISCUSSION OF RESULTS

The experimental results are presented in a series of tables and figures. These tables and figures provide the following information:

1. Sampling summary (Table 1). This summary contains the basic petrophysical properties for both the plug samples, and for the full diameter sample from which they were taken.
2. Experimental results (Table 2). This summary presents the results of the clay swell test, the fines mobilization test, and the comparison of gas and liquid permeabilities.
3. Tabular and graphical presentations of permeability versus pore volume throughput and permeability versus flow velocity for the samples tested (Tables 3 and 4 and Figures 1 and 2).

The baseline absolute brine permeability of 11.88 md to Bakken brine is 30% of the gas permeability of 40.14 md (Table 2). This large difference is attributed to the fact that the gas permeability was measured at a net overburden pressure of 2.41 MPa compared to the reservoir net overburden pressure of 12.11 MPa used for the liquid permeability measurement. Therefore, the measured gas permeability is probably optimistically high and the liquid permeability is more realistic with proper overburden pressure constriction applied to the pore throats.

Upon completion of an equilibrium absolute permeability to formation brine (Bakken), a low constant flow rate (4 cc/hr or 0.014 cm/min) injection water (Jurassic) flood was done on the sample. The permeability declined from 11.88 md to 9.10 md during the first 22 pore volumes flooded, but rebounded to 11.38 md over the next 8 pore volumes throughput, and remained constant (within experimental error) over the subsequent 10 pore volumes flooded (Table 3 and Figure 1). Although a virtually constant flowrate was maintained for most of the clay-swelling part of the experiment, a slight discontinuity occurred when the pump ran out of fluid after 23 pore volumes throughput. At this stage the pump was isolated by closing a valve in order to maintain a

constant pore pressure of 5.39 MPa while the pump was being refilled. Also, as a usual procedural step, the sample bypass was opened before starting to refill the pump in order to avoid a pressure surge in the system. Despite all these precautions an extremely small pressure disturbance was inevitably caused just by turning the pump off and may be the reason for an increased permeability after the 23rd pore volume throughput. In any event, it may be safely concluded that there is not a significant clay swelling problem in this sample. Although there may be some slight permeability reduction due to swelling of trace amounts of smectite (see petrology report by Core Laboratories), and associated fines migration. This fines migration would be due to disruption of fines by swelling of clays.

The fines migration portion of the test indicated that there is a significant fines migration problem and a rather low critical velocity of 0.0294 cm/min (Table 4, Figure 2). During forward flow, the permeability plummeted with increasing flow velocity from 12.19 md to 2.24 md (the two permeabilities measured at the same flow rate, 4 cc/hr). After a partial recovery of permeability to 4.41 md during flow in the reverse direction, the permeability declined even further to 1.47 md (a drop of 88%). The results confirm the conclusions made in the earlier petrological study by Core Laboratories Ltd. in which the potential for dolomite/illite fines movement was recognized.

The critical velocity determined in the laboratory equates to field flow rates of 1 to 2 m<sup>3</sup>/day adjacent to the wellbore. This is interpreted to mean that fines will be moved within the reservoir at any production rate. The significance of this problem will probably be dependent, however, upon the areal distribution of the fines.

The migrating fines may cause blockage of pore throats which implies higher fluid pressures to induce flow. Also, blocked pore throats may result in leaving oil in the pores as the fluids will preferentially flow through the easiest flow paths which have been already flushed of oil.

August 10, 1989

TUNDRA OIL AND GAS LTD.

MOGC DALY  
9-14-10-29W1M



Formation : Bakken

**SAMPLE SUMMARY**

Sample Number	Top Depth (m)	Gas Permeability (mD)	Porosity (%)	Grain Density (kg/m <sup>3</sup> )	Length /Dia. (cm)
1	859.62	14.55	17.8	2690	4.49 x 2.52
2	859.66	40.14	20.1	2687	4.49 x 2.51
17	859.42	35.70	18.0	2690	Full Diameter



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MOGC DALY  
9-14-10-29W1M



Formation : Bakken

### EXPERIMENTAL RESULTS

Sample Number	Gas* Permeability	Liquid** Permeability (md)	Clay Swell	Fines Mobilization
1	14.55	N/A	N/A	N/A
2	40.14	11.88	Minor	Major

\* Gas permeability net overburden pressure = 2.41 MPa  
Liquid permeability net overburden pressure = 12.11 MPa

\*\* Absolute permeability to Bakken formation brine.

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MOGC DALY  
9-14-10-29W1M

Sample #2

Formation : Bakken  
Depth : 859.66 m

Gas Permeability (k) : 40.14 md  
Porosity (phi) : 20.1 %  
Grain Density (rho) : 2687 kg/m<sup>3</sup>

Pore Volume : 4.48 cc  
Flow Velocity : 0.0146 cm/min

**PERMEABILITY VERSUS PORE VOLUME THROUGHPUT DATA  
(CLAY SWELLING)**

Pore Volumes (cc)	Brine Permeability (mD)
0.0	11.88*
1.3	11.86
2.5	11.16
3.6	10.71
7.3	10.38
14.9	9.61
17.2	9.26
19.8	9.20
22.1	9.10
29.6	11.38
38.1	11.61
39.4	11.14
40.0	11.39

\* Absolute permeability to Bakken formation brine.

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WELL NAME: M06C DALY

LOCATION: 9-14-10-29W1



DATE: AUG 03, 1989

FILE: 89-8C-253

## CLAY SWELLING

BAKKEN FORMATION

SAMPLE # 2

Depth : 859.66 m  
Gas Permeability (k) : 40.14 md Pore Volume : 4.48 cc  
Porosity (phi) : 20.1 % Flow Velocity : .0148 cm/min  
Grain Density (rho) : 2887 kg/m<sup>3</sup> Injection Water : Jurassic

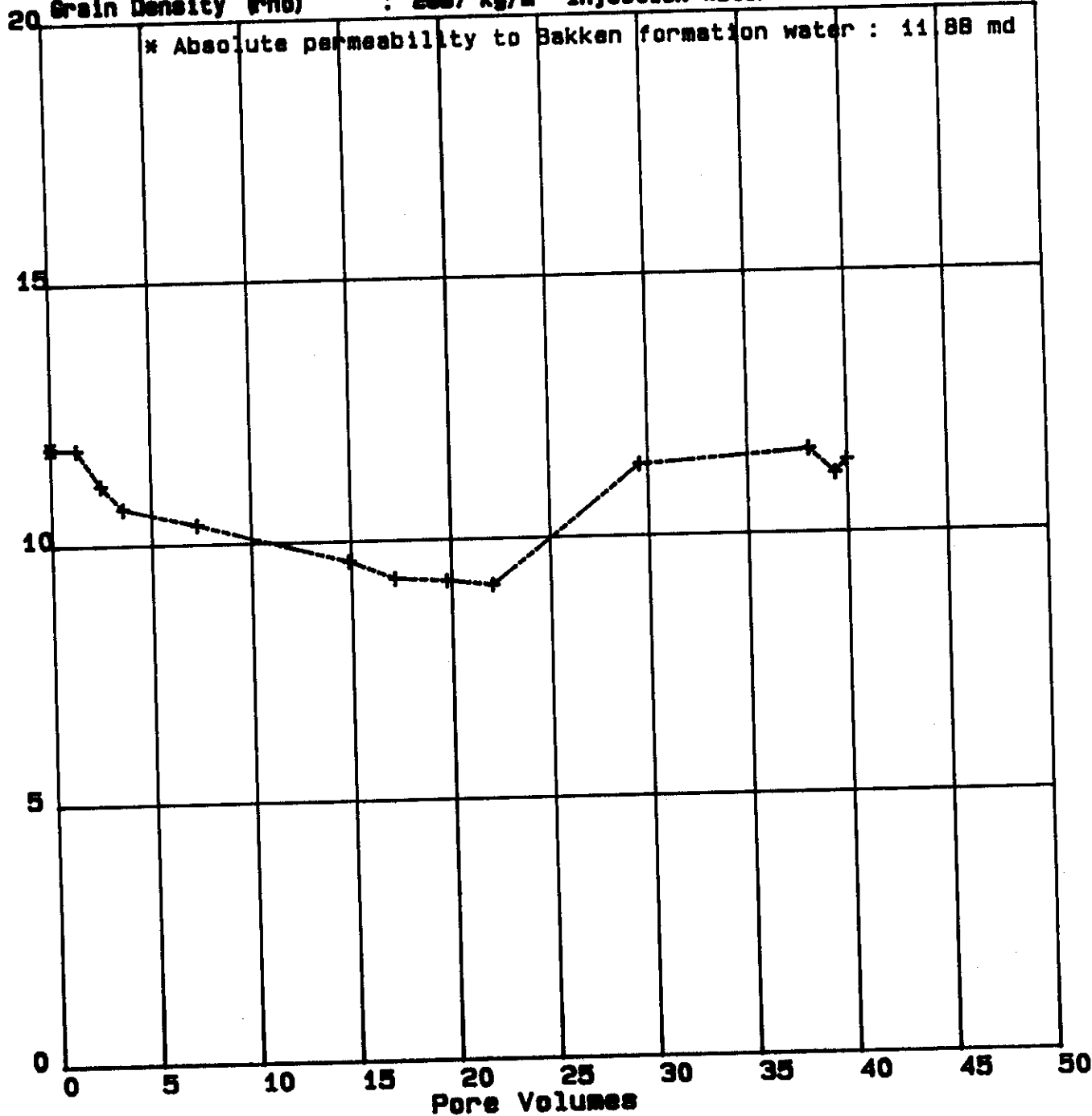


Figure 1

August 10, 1989

TUNDRA OIL AND GAS LTD.



MOGC DALY  
9-14-10-29W1M

Sample #2

Formation : Bakken  
Depth : 859.66 m  
Gas Permeability (k) : 40.14 md  
Porosity (phi) : 20.1 %  
Grain Density : 2687 kg/m<sup>3</sup>  
Pore Volume : 4.48 cc  
Critical Velocity (U<sub>c</sub>) : 0.0294 cm/min

**PERMEABILITY VERSUS FLOW VELOCITY  
(FINES MOBILIZATION)**

Run Number	Liquid Permeability (mD)	Differential Pressure (kPa)	Flow Velocity (cm/min)	Flow Rate (cc/hr)
Forward Flow				
1	12.19	9.0	0.0146	4.34
2	12.26	17.9	0.0294	8.74
3	8.13	54.5	0.0594	17.65
4	6.44	103.3	0.0892	26.52
5	4.50	244.2	0.1473	43.81
6	3.44	649.3	0.2998	89.14
7	3.19	853.1	0.3653	108.61
8	2.50	1325.4	0.4445	132.18
9	2.68	2075.1	0.7450	221.52
Forward Flow End Point				
10	2.24	46.3	0.0143	4.25
Reserve Flow				
11	3.83	26.5	0.0137	4.07
12	4.39	50.0	0.0298	8.86
13	4.41	99.1	0.0594	17.67
14	3.96	163.2	0.0878	26.10
15	3.00	360.5	0.1470	43.72
16	2.55	650.0	0.2257	67.10
17	2.34	934.8	0.2973	88.41
18	2.23	1212.2	0.3676	109.30
19	2.01	1892.4	0.5156	153.32
20	1.73	3048.0	0.7148	212.55
Reverse Flow End Point				
21	1.47	71.4	0.0142	4.23

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WELL NAME: M06C DALY

LOCATION: 9-14-10-29W1

GEOTECH

DATE: AUG 04, 1989

FILE: 89-GC-253

# FINES MOBILIZATION STANDARD PLOT

BAKKEN FORMATION

SAMPLE # 2

Depth : 859.86 m  
Gas Permeability (k) : 40.14 md Pore Volume : 4.48 cc  
Porosity (phi) : 20.1 % Critical Velocity ( $U_c$ ) : .0294 cm/min  
Grain Density (rho) : 2687 kg/m<sup>3</sup> Injection Water : Jurassic

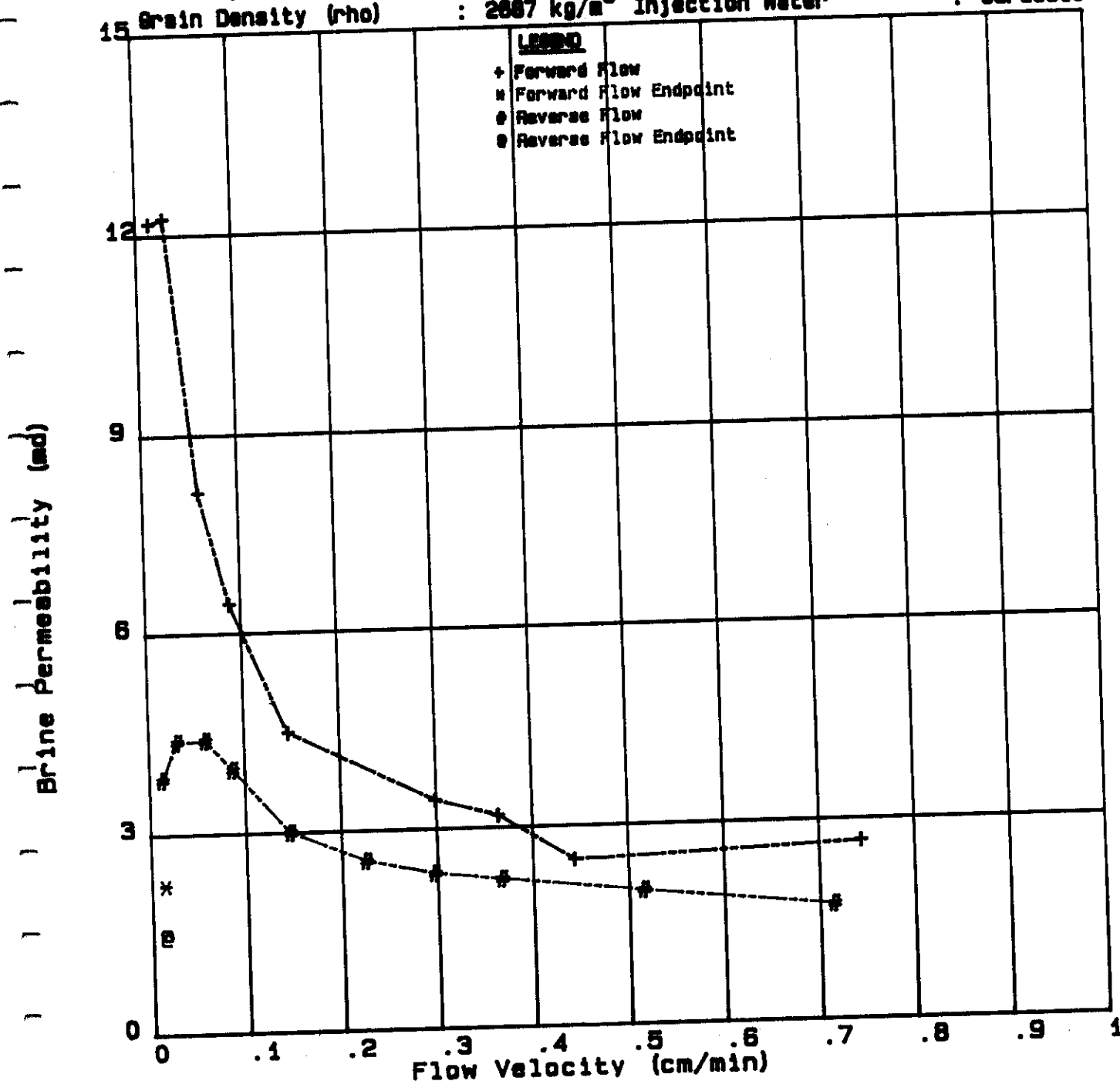


Figure 2

**APPENDIX**  
**WATERFLOOD SENSITIVITY TESTING**



## TECHNICAL NOTE 84-005

### WATERFLOOD SENSITIVITY

#### What is waterflood sensitivity?

Although permeability is ideally considered to be only a function of the matrix structure, it is an experimental fact that if a core is flooded with different liquids, different permeabilities will be measured. This observation is generally explained by assuming that liquid-liquid and liquid-matrix interactions lead to changes in the matrix structure. These reservoir sensitivities are of three basic types:

1. Liquid-liquid incompatibilities,
2. Liquid-matrix chemical reactions,
3. Liquid-matrix mechanical reactions.

Water introduced into a reservoir usually contains a number of inorganic and sometimes organic salts in solution. If the injected water is incompatible with the formation water, an insoluble precipitate will form. The formation of a precipitate will result in a reduction in permeability, plugging of injection wells and cause a build up of scale in the well and water handling equipment. Some of the more common ions that frequently occur in oilfield waters and that cause precipitation reactions are:  $\text{Ca}^{+2}$ ,  $\text{Sr}^{+2}$ ,  $\text{Ba}^{+2}$ ,  $\text{Fe}^{+2}$ ,  $\text{HCO}_3^-$  and  $\text{SO}_4^{-2}$ .

Water is generally considered to be a non-reactive substance. However, it is both present in virtually all reservoirs and, depending on its chemical nature, may react with some matrix materials. The major reason for this phenomenon is the presence of swelling clays. The degree of hydration, hence the amount of swelling, of these clays depends on the salinity of the water. Since the amount of swelling affects the sizes of pores and pore throats, the permeability of a rock can depend on the salinity of the water flowing through it. It is often the case that the water used in waterflood processes does not have the same chemistry, particularly salinity, as that in the original formation. This can lead to severe permeability impairment.

As a liquid flows through pore spaces, small particles, such as kaolinite booklets and other fine grained materials, may be broken away from the pore walls, move toward pore throats, and be trapped. The reduced pore throat size leads to a reduced permeability. (Although this problem may also arise when gases flow, the higher momentum of flowing liquids aggravates the problem.) This phenomena, known as

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finer migration, arises from a mechanical interaction between the liquid and the rock and depends on the velocity of the fluid. Below a certain value, termed the critical velocity, fines do not move; once the critical velocity is surpassed, a very sudden drop in permeability is often observed. This indicates the onset of fines movement, as they are entrained by the liquid as it flows through the pores. For velocities greater than the critical value, the permeability suffers a continuous decrease with increasing flow velocity because fines continue to be displaced. Reducing the velocity below the critical velocity does not lead to a permeability recovery - the pore throats still remain plugged. Reversing the flow, however, does lead to a permeability recovery; the reversed flow clears the pore throats providing that the flow velocity does not exceed the critical value and the fines cannot be re-entrained.

#### **How is waterflood sensitivity studied at GEOTECH?**

At GEOTECH reservoir sensitivity is studied by a three stage program:

1. Liquid-liquid compatibility,
2. Permeability versus pore volume throughput tests,
3. Permeability versus flow velocity tests.

The procedure for the liquid-liquid compatibility test is as follows:

1. Both the injection and formation waters are analyzed for the major and minor components (Routine Formation Water Analysis).
2. Eleven mixtures of formation and injection waters are prepared ranging from 100% formation to 100% injection in 10% increments. The turbidity of these solutions is measured at 0, 2, 4, 8, 24, 48 and 72 hours. An increase in the turbidity indicates that a precipitation reaction has occurred. Turbidity is used to measure the incompatibility because it is far more sensitive than a visual test.
3. From the analysis of the injection and formation waters, the Saturation Index, Stability Index and Corrosion Tendency for mixtures of 70% formation - 30% injection, 50% formation - 50% injection and 30% formation - 70% injection are calculated. This is done to confirm the test results and allows one to predict the severity of corrosion and scale deposition that may occur.

The procedure for the permeability versus pore volume throughput test is as follows:



1. A plug is cut from a core and carefully cleaned by flushing it with solvents. The air permeability, porosity and grain density of the plug is measured.
2. The plug is saturated with reservoir brine, sealed in a plastic sleeve, and placed in a pressure chamber. The chamber is heated to reservoir temperature and pressurized to the overburden pressure.
3. The core is flooded, at reservoir pore pressure and a low flow velocity, for a period of up to 48 hours. The permeability is measured at regular intervals.
4. The permeability is plotted as a function of pore volume throughput.

The permeability versus flow velocity test is typically performed immediately after the permeability versus pore volume throughput test. The procedure is as follows:

1. The core is flooded at increasing flow velocities. At each flow velocity, the flow is allowed to stabilize and the permeability is measured.
2. The flow velocity is reduced to its original value to allow direct comparison of the initial and final permeabilities in the same flow regime (turbulence may occur at high flow velocities, causing permeability reductions which could be misinterpreted as fines migrations).
3. The flow direction is reversed and steps 1 and 2 are repeated.
4. The permeability is plotted as a function of flow velocity.

If desired, both the permeability as a function of pore volume throughput test and the permeability as a function of flow velocity may be performed in the presence of a residual oil saturation.

SECTION 2

**WATER COMPATIBILITY STUDY**

**LODGEPOLE 14-14-10-29  
and  
JURASSIC 16-11-10-29**

versus

**BAKKEN 9-14-10-29**

prepared for

**TUNDRA OIL AND GAS**

File Number: 89A55615

Date: July 25, 1989

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## EXECUTIVE SUMMARY

### Bakken 9-14-10-29 versus Lodgepole 14-14-10-29

Results of the compatibility study confirm that these two waters are compatible in all proportions. Results of analyses on 70:30, 50:50 and 30:70 mixtures of the two waters indicate changes in chemical composition and calcium carbonate scaling indicators that are indicative of simple mixing of the waters and confirm that no precipitate formation occurred. Scaling calculations indicate that there should be no calcium carbonate or calcium sulphate scaling.

### Bakken 9-14-10-29 versus Jurassic 16-11-10-29

Results of the compatibility study confirm that these two waters are compatible in all proportions. Results of analyses on 70:30, 50:50 and 30:70 mixtures of the two waters indicate changes in chemical composition and calcium carbonate scaling indicators that indicative of simple mixing of the waters and confirm that no precipitate formation occurred. Scaling calculations indicate that there should be no calcium carbonate or calcium sulphate scaling.

It should be noted that the Jurassic water has a much lower salinity than the Bakken water, 13,177 ppm compared to 63,662 ppm. If the Bakken formation has swelling clays the lower salinity of the Jurassic may result in clay swelling problems with a corresponding loss of effective permeability in the reservoir. The Waterflood Sensitivity studies being done in conjunction with this study will address this issue.

## EXECUTIVE SUMMARY

### Bakken 9-14-10-29 versus Lodgepole 14-14-10-29

Results of the compatibility study confirm that these two waters are compatible in all proportions. Results of analyses on 70:30, 50:50 and 30:70 mixtures of the two waters indicate changes in chemical composition and calcium carbonate scaling indicators that are indicative of simple mixing of the waters and confirm that no precipitate formation occurred. Scaling calculations indicate that there should be no calcium carbonate or calcium sulphate scaling.

### Bakken 9-14-10-29 versus Jurassic 16-11-10-29

Results of the compatibility study confirm that these two waters are compatible in all proportions. Results of analyses on 70:30, 50:50 and 30:70 mixtures of the two waters indicate changes in chemical composition and calcium carbonate scaling indicators that indicative of simple mixing of the waters and confirm that no precipitate formation occurred. Scaling calculations indicate that there should be no calcium carbonate or calcium sulphate scaling.

It should be noted that the Jurassic water has a much lower salinity than the Bakken water, 13,177 ppm compared to 63,662 ppm. If the Bakken formation has swelling clays the lower salinity of the Jurassic may result in clay swelling problems with a corresponding loss of effective permeability in the reservoir. The Waterflood Sensitivity studies being done in conjunction with this study will address this issue.

## INTRODUCTION

One of the primary concerns in the implementation of an effective waterflood or water disposal program is the compatibility between the fluid which is being injected into the reservoir and formation water. Chemical reactions between two waters that can cause precipitate formation and negatively influence aquifer permeability and/or damage injection wells can be listed as:

1. Precipitation of alkaline earth metals such as calcium, barium, strontium and magnesium as relatively insoluble carbonates, sulfates, orthophosphates, fluorides and hydroxides.
2. Precipitation of metals such as iron, aluminum, manganese, chromium, and cadmium as insoluble carbonates, bicarbonates, hydroxides, orthophosphates and sulfides.
3. Precipitation of oxidation-reduction reaction products.

Although all these reactions are feasible during water injection operations, only a few of them would be anticipated under normal circumstances. Most often problems are limited to precipitates such as calcium and barium sulfates along with calcium carbonate and iron hydroxides. To avoid compatibility problems it may be necessary to treat the water prior to injection. The most radical treatment system would consist of such processes as ion exchange or chemical precipitation to remove scale forming ions; calcium, magnesium, sulphate and bicarbonate.

Though the compatibility between the injection and formation water is essential for any successful water injection operation, it is not the only criterion to be met. The other desired properties of the injection water for trouble free operation are as follows:

1. The water should not be corrosive to the water handling facilities.
2. It should not contain suspended matter in sufficient quantity to clog injection wells.
3. Content of calcium and magnesium salts should be over 10% of the total dissolved solids in the event that any swelling type clays are present in the formation to be flooded.
4. The water should be oxygen free.
5. Preferably, the concentration of biodegradable organic matter should be low in order to not nourish the growth of bacteria and algae.

## EXPERIMENTAL

Details of the analytical procedure are presented in **APPENDIX B: EXPERIMENTAL PROCEDURE.**

Tundra Oil and Gas requested that detailed water compatibility studies be undertaken between Bakken 9-14-10-29 water and two other waters identified as Lodgepole 14-14-10-29 and Jurassic 16-11-10-29. Results of the Detailed Water Compatibility are reported herein.



## CHEMICAL CHARACTERISTICS OF THE TEST WATERS

The inorganic compositions of the three test waters are presented in APPENDIX A as Water Analysis Reports 5615-W1, W2 and W6. The results of these analyses are summarized below:

### 1. Bakken 9-14-10-29 (5615-W1)

Inspection of the Bakken water analysis results indicate that this water is quite saline, 63,662 ppm, with a corresponding total dissolved solids of 66,757 mg/L. The pH, 7.16, along with the bicarbonate, 261 mg/L, lead to both the Stability Index, 4.96, and Saturation Index, 1.09, indicating a modest tendency for calcium carbonate scaling. Although the sulphate concentration is quite high at 2,150 mg/L, calcium sulphate scaling calculations, after Skillman, McDonald and Stiff, indicate no tendency for calcium ~~carbonate~~ <sup>Sulphate</sup> scaling.

### 2. Lodgepole 14-14-10-29 (5615-W2)

Inspection of the Lodgepole water analysis results indicate that this water is very saline, 167,133 ppm, with a corresponding total dissolved solids of 171,935 mg/L. The pH, 7.44, along with the bicarbonate, 209 mg/L, lead to both the Stability Index, 4.19, and Saturation Index, 1.62, indicating a modest tendency for calcium carbonate scaling. Although the sulphate concentration is very high at 3,840 mg/L, calcium sulphate scaling calculations, after Skillman, McDonald and Stiff, indicate no tendency for calcium ~~carbonate~~ <sup>Sulphate</sup> scaling.

### 3. Jurassic 16-11-10-29 (5615-W6)

Inspection of the Jurassic water analysis results indicate that this water is of low salinity, 13,177 ppm, with a corresponding total dissolved solids of 23,004 mg/L. The pH, 7.56, along with the bicarbonate, 545 mg/L, lead to both the Stability Index, 4.46, and Saturation Index, 1.54, indicating a modest tendency for calcium carbonate scaling. Although the sulphate concentration is extremely high at 6180 mg/L, calcium sulphate scaling calculations, after Skillman, McDonald and Stiff, indicate no tendency for calcium ~~carbonate~~ <sup>Sulphate</sup> scaling.

## RESULTS OF THE DETAILED WATER COMPATIBILITY STUDY

Results of the Visual Water Compatibility Study, solution transmittances as a function of time for the water mixtures, are presented in APPENDIX B as Tables 1 and 2. Results the Detailed Water Compatibility Study are discussed below:

### 1. Bakken 9-14-10-29 versus Lodgepole 14-14-10-29

Inspection of the Visual Compatibility data presented in Table 1 of APPENDIX B confirms that the solutions were clear and colorless and the transmittances remained above the general 90% transmittance limit for compatibility throughout the 72 hour test period. As a result these waters may be taken as being compatible in all proportions.

Water analyses on the 70:30, 50:50 and 30:70 mixtures are presented in APPENDIX A as water analysis reports 5615-W3, W4 and W5. Inspection of these data indicate the changes in chemical composition and calcium carbonate scaling indicators that would be expected upon simple mixing of these waters and confirm that no precipitate formation occurred. Calcium sulphate scaling calculations were done on the 50:50 mixture and confirm that there should be no scaling.

### 2. Bakken 9-14-10-29 versus Jurassic 16-11-10-29

Inspection of the Visual Compatibility data presented in Table 2 of APPENDIX B confirms that the solutions were clear and colorless and the transmittances remained above the general 90% transmittance limit for compatibility throughout the 72 hour test period. As a result these waters may be taken as being compatible in all proportions.

Water analyses on the 70:30, 50:50 and 30:70 mixtures are presented in APPENDIX A as water analysis reports 5615-W7, W8 and W9. Inspection of these data indicate the changes in chemical composition and calcium carbonate scaling indicators that would be expected upon simple mixing of these waters and confirm that no precipitate formation occurred. Calcium sulphate scaling calculations were done on the 50:50 mixture and confirm that there should be no scaling.

It should be noted that the Jurassic water has a much lower salinity than the Bakken water, 13,177 ppm compared to 63,662 ppm. If the Bakken formation has swelling clays the lower salinity of the Jurassic may result in clay swelling problems with a corresponding loss of effective permeability in the reservoir. The Waterflood Sensitivity studies being done in conjunction with this study will address this issue.

**APPENDIX A**  
**WATER ANALYSIS REPORTS**

**APPENDIX A**  
**WATER ANALYSIS REPORTS**



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## WATER ANALYSIS

CONTAINER IDENTITY  
**5615F3**

OPERATOR'S NAME  
**TUNDRA OIL & GAS**

SAMPLE LOCATION

WELL NAME

**DETAILED WATER COMPATIBILITY**

**9-14-10-29**

ELEVATIONS  
KB

GRD

FIELD OR AREA

POOL OR ZONE

**BAKKEN**

NAME OF SAMPLER

COMPANY

TEST TYPE NO

TEST RECOVERY

SAMPLING POINT

AMT. AND TYPE OF CUSHION

MUD RESISTIVITY  $\Omega/m$

MULTIPLE RECOVERY  
TEST INTERVAL  
FROM

PUMPING

FLOWING

GAS LIFT

SWAB

TO

WATER

$m^3/d$

OIL

$m^3/d$

GAS

$10^3 m^3/d$

SEPARATOR

TREATER

RESERVOIR

SAMPLED

RECEIVED

PERFORATIONS  
FROM

GAUGE PRESSURE K/Pa

TEMPERATURE ( $^{\circ}C$ )

TO

DATE SAMPLED

Y M D

H:M

DATE RECEIVED

Y M D

DATE ANALYZED

Y M D

ANALYST

**12-JUL-89**

**17-JUL-89**

**21-JUL-89**

**LE**

### SUMMARY DATA

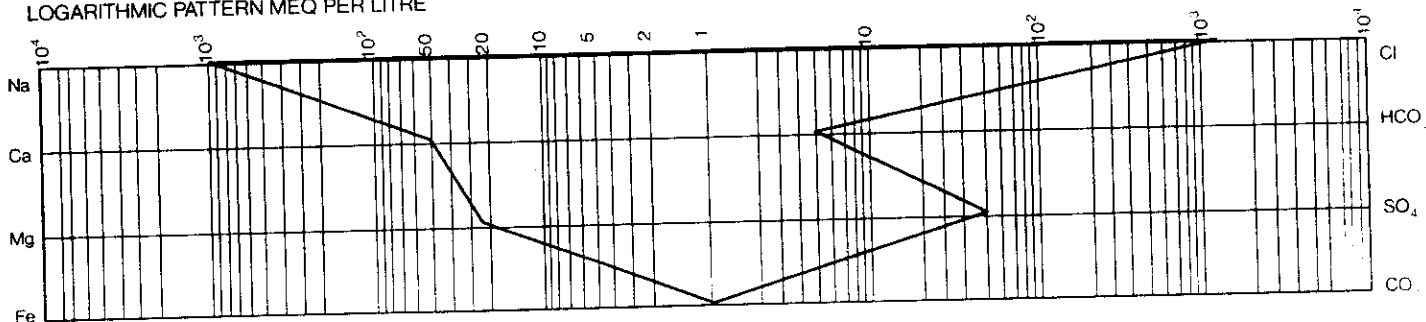
TOTAL HARDNESS AS $CaCO_3$	<b>3740</b>	$g/m^3$
TOTAL ALKALINITY	<b>214</b>	$g/m^3$
SALINITY AS NaCl	<b>63662</b>	ppm
SATURATION INDEX	<b>1.09</b>	
STABILITY INDEX	<b>4.96</b>	
CORROSION TENDENCY	<b>267</b>	

CaCO3 SCALING TENDENCY

CaCO3 SCALING TENDENCY

Scaling calculations done at 30 C

LOGARITHMIC PATTERN MEQ PER LITRE



REMARKS

**GEOTECH**nical resources ltd.4500 - 5th STREET N.E., CALGARY, ALBERTA T2E 7C3  
(403) 230-4128**WATER ANALYSIS  
DETAILED REPORT**OPERATOR'S NAME **TUNDRA OIL & GAS**FILE NUMBER **89AS5615**WELL NAME **DETAILED WATER COMPATIBILITY**LABORATORY NUMBER **5615-W1**LOCATION **9-14-10-29**

SAMPLING POINT

## CATIONS

## ANIONS

ION	g/m <sup>3</sup>	MASS FRACTION	MEQ/L	ION	g/m <sup>3</sup>	MASS FRACTION	MEQ/L
Na	24000	0.36	1044	Cl	38700	0.6	1093
K	320	0.00	8.2	Br			
Ca	994	0.01	49.6	I	5.2	0.00	0.04
Mg	300	0.00	24.7	F			
Ba	< 0.05			HCO <sub>3</sub>	261	0.00	4.3
Sr	19.8	0.00	0.45	CO <sub>3</sub>	0.00	0.00	0.00
Fe	< 0.05			OH	0.00	0.00	0.00
Mn				SO <sub>4</sub>	2150	0.03	44.8
Al				H <sub>2</sub> S			
Si				PO <sub>4</sub>			
B	7.79						
U							
Th							

TOTAL SOLIDS (g/m<sup>3</sup>)

EVAPORATED AT 110°C EVAPORATED AT 180°C

AT IGNITION

CALCULATED

**66757**

SPECIFIC GRAVITY

at 15°C

REFRACTIVE INDEX (R)

**1.353** at 25°C

OBSERVED pH

at 25°C

**7.16**

RESISTIVITY (RW) Ω m

**0.111** at 25°C

REDOX POTENTIAL (Eh)

DISSOLVED O<sub>2</sub>g/m<sup>3</sup>

## TOTAL METALS

METAL	g/m <sup>3</sup>
-------	------------------

Fe

Mn

Cations/Anions: **0.99**

Interval: to

KB: GRD:

Perfs to

REMARKS



# GEOTECHnical resources ltd.

4500 - 5th STREET N.E., CALGARY, ALBERTA T2E 7C3  
(403) 230-4128

## WATER ANALYSIS

CONTAINER IDENTITY  
**5615F2**

OPERATOR'S NAME

**TUNDRA OIL & GAS**

SAMPLE LOCATION

WELL NAME

**DETAILED WATER COMPATIBILITY**

**14-14-10-29**

ELEVATIONS  
KB

GRD

FIELD OR AREA

POOL OR ZONE

NAME OF SAMPLER

COMPANY

**LODGEPOLE**

TEST TYPE NO

TEST RECOVERY

SAMPLING POINT

AMT. AND TYPE OF CUSHION

MUD RESISTIVITY  $\Omega/m$

MULTIPLE RECOVERY  
TEST INTERVAL  
FROM

PUMPING

FLOWING

GAS LIFT

SWAB

TO

WATER

$m^3/d$

OIL

$m^3/d$

GAS

$10^3 m^3/d$

SEPARATOR

TREATER

RESERVOIR

SAMPLED

RECEIVED

PERFORATIONS  
FROM

GAUGE PRESSURE K/Pa

TEMPERATURE ( $^{\circ}C$ )

TO

DATE SAMPLED

Y M D

H: M

DATE RECEIVED

Y M D

DATE ANALYZED

Y M D

ANALYST

**12-JUL-89**

**17-JUL-89**

**21-JUL-89**

**LE**

### SUMMARY DATA

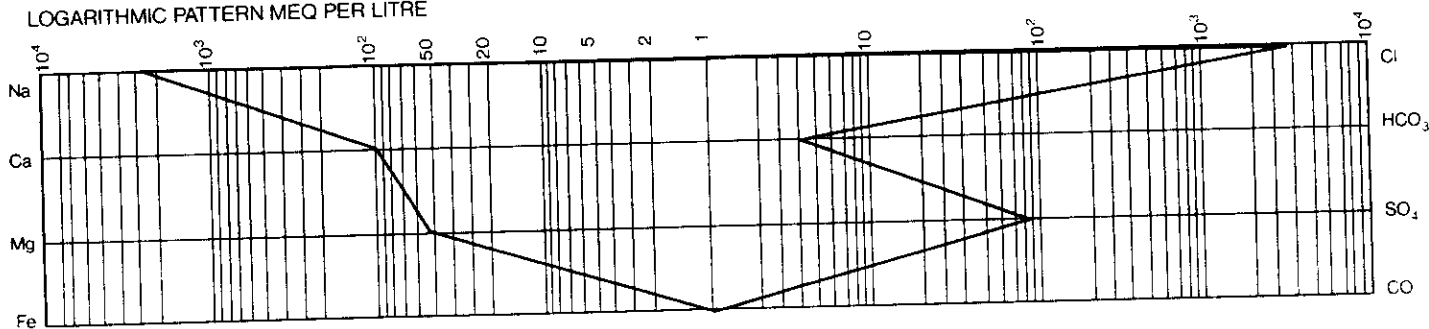
TOTAL HARDNESS AS $CaCO_3$	<b>8121</b>	$g/m^3$
TOTAL ALKALINITY	<b>171</b>	$g/m^3$
SALINITY AS NaCl	<b>167133</b>	ppm
SATURATION INDEX	<b>1.62</b>	
STABILITY INDEX	<b>4.19</b>	
CORROSION TENDENCY	<b>210</b>	

**CaCO3 SCALING TENDENCY**

**CaCO3 SCALING TENDENCY**

Scaling calculations done at 30 C

LOGARITHMIC PATTERN MEQ PER LITRE



REMARKS

**GEOTECH** *Technical resources Ltd.*4500 - 5th STREET N.E., CALGARY, ALBERTA T2E 7C3  
(403) 230-4128**WATER ANALYSIS  
DETAILED REPORT**OPERATOR'S NAME **TUNDRA OIL & GAS**FILE NUMBER **89AS5615**WELL NAME **DETAILED WATER COMPATIBILITY**LABORATORY NUMBER **5615-W2**LOCATION **14-14-10-29**

SAMPLING POINT

**CATIONS**

ION	g/m <sup>3</sup>	MASS FRACTION	MEQ/L
Na	62800	0.37	2732
K	581	0.00	14.9
Ca	2180	0.01	109
Mg	638	0.00	52.5
Ba	< 0.05		
Sr	44.5	0.00	1.02
Fe	< 0.05		
Mn			
Al			
Si			
B	19.1		
U			
Th			

**ANIONS**

ION	g/m <sup>3</sup>	MASS FRACTION	MEQ/L
Cl	101600	0.6	2868
Br			
I	24	0.00	0.19
F			
HCO <sub>3</sub>	209	0.00	3.4
CO <sub>3</sub>	0.00	0.00	0.00
OH	0.00	0.00	0.00
SO <sub>4</sub>	3840	0.02	80
H <sub>2</sub> S			
PO <sub>4</sub>			

**TOTAL SOLIDS (g/m<sup>3</sup>)**

EVAPORATED AT 110°C EVAPORATED AT 180°C

AT IGNITION CALCULATED  
**171935**SPECIFIC GRAVITY at 15°C REFRACTIVE INDEX (R) at 25°C  
**1.368**OBSERVED pH at 25°C RESISTIVITY (RW) Ω m at 25°C  
**7.44** **0.056**REDOX POTENTIAL (Eh) DISSOLVED O<sub>2</sub> g/m<sup>3</sup>**TOTAL METALS**

METAL	g/m <sup>3</sup>
Fe	
Mn	

Cations/Anions: **0.99**

Interval: to

KB: GRD:

Perfs to

REMARKS



**GEOTECH** *technical resources ltd.*4500 - 5th STREET N.E., CALGARY, ALBERTA T2E 7C3  
(403) 230-4128**WATER ANALYSIS**

CONTAINER IDENTITY

OPERATOR'S NAME

**TUNDRA OIL & GAS**

SAMPLE LOCATION

WELL NAME

**DETAILED WATER COMPATIBILITY**

FIELD OR AREA

POOL OR ZONE

NAME OF SAMPLER

COMPANY

ELEVATIONS  
KB

GRD

TEST TYPE NO

TEST RECOVERY

SAMPLING POINT

**70% BAKKEN / 30% LODGEPOLE**

AMT. AND TYPE OF CUSHION

MUD RESISTIVITY  $\Omega/m$ MULTIPLE RECOVERY  
TEST INTERVAL  
FROM

PUMPING

FLOWING

GAS LIFT

SWAB

TO

WATER

 $m^3/d$ 

OIL

 $m^3/d$ 

GAS

 $10^3 m^3/d$ 

SEPARATOR

TREATER

RESERVOIR

SAMPLED

RECEIVED

PERFORATIONS  
FROM

GAUGE PRESSURE K/Pa

TEMPERATURE ( $^{\circ}C$ )

TO

DATE SAMPLED

Y M D

**12-JUL-89**

H:M

DATE RECEIVED

Y M D

**17-JUL-89**

DATE ANALYZED

Y M D

**21-JUL-89**

ANALYST

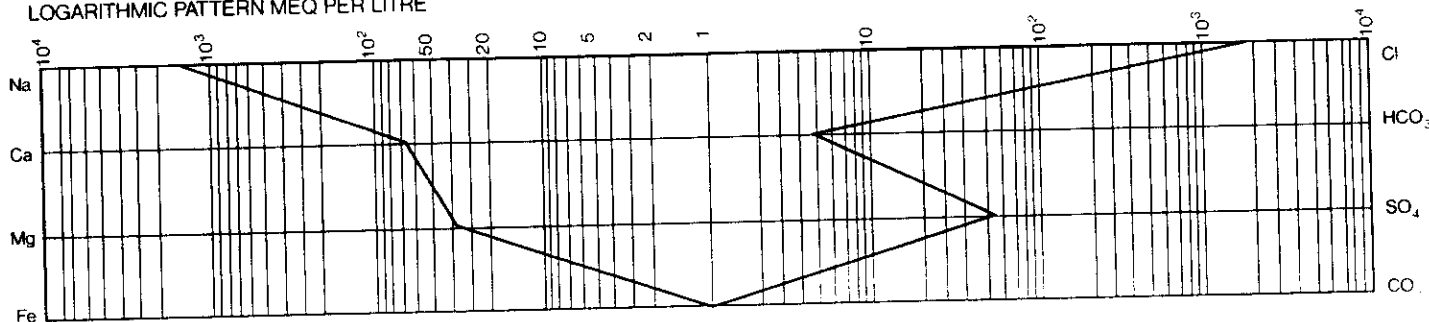
**LE****SUMMARY DATA**

TOTAL HARDNESS AS $CaCO_3$	5171	$g/m^3$
TOTAL ALKALINITY	214	$g/m^3$
SALINITY AS NaCl	96562	ppm
SATURATION INDEX	1.47	
STABILITY INDEX	4.44	
CORROSION TENDENCY		

 **$CaCO_3$  SCALING TENDENCY** **$CaCO_3$  SCALING TENDENCY**

Scaling calculations done at 30 C

LOGARITHMIC PATTERN MEQ PER LITRE



REMARKS



**GEOTECH** *nical resources ltd.*  
4500 - 5th STREET N.E., CALGARY, ALBERTA T2E 7C3  
(403) 230-4128

# WATER ANALYSIS DETAILED REPORT

OPERATOR'S NAME	TUNDRA OIL & GAS	FILE NUMBER	89AS5615
WELL NAME	DETAILED WATER COMPATIBILITY	LABORATORY NUMBER	5615-W3
LOCATION			
SAMPLING POINT	70% BAKKEN / 30% LODGEPOLE		

CATIONS				ANIONS				TOTAL SOLIDS (g/m <sup>3</sup> )	
ION	g/m <sup>3</sup>	MASS FRACTION	MEQ/L	ION	g/m <sup>3</sup>	MASS FRACTION	MEQ/L	EVAPORATED AT 110°C	EVAPORATED AT 180°C
Na	35700	0.36	1553	Cl	58700	0.61	1656	AT IGNITION	CALCULATED
K	418	0.00	10.7	Br					99364
Ca	1370	0.01	68.4	I	8.4	0.00	0.07	SPECIFIC GRAVITY	REFRACTIVE INDEX (R)
Mg	417	0.00	34.3	F				at 15°C	1.356 at 25°C
Ba	< 0.05			HCO <sub>3</sub>	261	0.00	4.3	OBSERVED pH	RESISTIVITY (RW) Ω m
Sr	28.4	0.00	0.65	CO <sub>3</sub>	0.00	0.00	0.00	7.40 at 25°C	0.080 at 25°C
Fe	< 0.05			OH	0.00	0.00	0.00	REDOX POTENTIAL (En)	DISSOLVED O <sub>2</sub>
Mn				SO <sub>4</sub>	2450	0.02	51		g/m <sup>3</sup>
Al				H <sub>2</sub> S					
Si				PO <sub>4</sub>					
B	11.6								
U									
Th									

Cations/Anions: 0.97

Interval: to

KB: GRD:

Perfs to

## TOTAL METALS

METAL	g/m <sup>3</sup>
Fe	
Mn	

REMARKS



# GEOTECHnical resources ltd.

4500 - 5th STREET N.E., CALGARY, ALBERTA T2E 7C3  
(403) 230-4128

## WATER ANALYSIS

FILE NUMBER	89AS5615
LABORATORY NUMBER	5615-W4

CONTAINER IDENTITY

OPERATOR'S NAME

**TUNDRA OIL & GAS**

SAMPLE-LOCATION

WELL NAME

**DETAILED WATER COMPATIBILITY**

FIELD OR AREA

POOL OR ZONE

NAME OF SAMPLER

COMPANY

ELEVATIONS  
KB

GRD

TEST TYPE NO

TEST RECOVERY

SAMPLING POINT

**50% BAKKEN / 50% LODGEPOLE**

AMT. AND TYPE OF CUSHION

MUD RESISTIVITY  $\Omega/m$

MULTIPLE RECOVERY  
TEST INTERVAL  
FROM

PUMPING

FLOWING

GAS LIFT

SWAB

TO

WATER

$m^3/d$

OIL

$m^3/d$

GAS

$10^3 m^3/d$

SEPARATOR

TREATER

RESERVOIR

SAMPLED

RECEIVED

PERFORATIONS  
FROM

GAUGE PRESSURE K/Pa  
TEMPERATURE (°C)

TO

DATE SAMPLED

Y M D

H:M

DATE RECEIVED

Y M D

DATE ANALYZED

Y M D

ANALYST

12-JUL-89

17-JUL-89

21-JUL-89

LE

### SUMMARY DATA

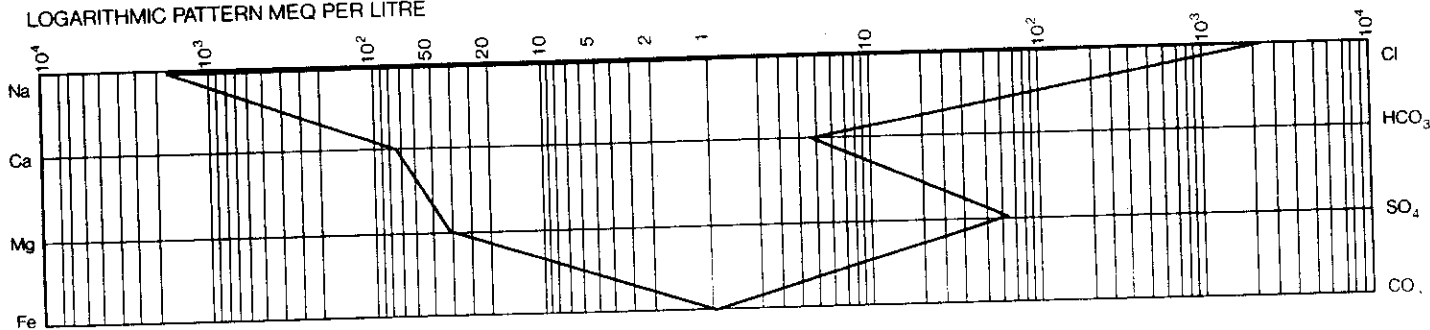
TOTAL HARDNESS AS $CaCO_3$	6092	$g/m^3$
TOTAL ALKALINITY	200	$g/m^3$
SALINITY AS NaCl	116302	ppm
SATURATION INDEX	1.56	
STABILITY INDEX	4.31	
CORROSION TENDENCY		

CaCO3 SCALING TENDENCY

CaCO3 SCALING TENDENCY

Scaling calculations done at 30 C

LOGARITHMIC PATTERN MEQ PER LITRE



REMARKS

**GEOTECH** nical resources ltd.4500 - 5th STREET N.E., CALGARY, ALBERTA T2E 7C3  
(403) 230-4128**WATER ANALYSIS  
DETAILED REPORT**OPERATOR'S NAME **TUNDRA OIL & GAS**FILE NUMBER **89AS5615**WELL NAME **DETAILED WATER COMPATIBILITY**LABORATORY NUMBER **5615-W4**

LOCATION

SAMPLING POINT **50% BAKKEN / 50% LODGEPOLE**

## CATIONS

## ANIONS

ION	g/m <sup>3</sup>	MASS FRACTION	MEQ/L	ION	g/m <sup>3</sup>	MASS FRACTION	MEQ/L
Na	43200	0.36	1880	Cl	70700	0.61	1997
K	480	0.00	12.3	Br			
Ca	1630	0.01	81.3	I	11	0.00	0.09
Mg	482	0.00	39.6	F			
Ba	< 0.05			HCO <sub>3</sub>	243	0.00	4
Sr	32.1	0.00	0.73	CO <sub>3</sub>	0.00	0.00	0.00
Fe	< 0.05			OH	0.00	0.00	0.00
Mn				SO <sub>4</sub>	2820	0.02	58.7
Al				H <sub>2</sub> S			
Si				PO <sub>4</sub>			
B	14						
U							
Th							

TOTAL SOLIDS (g/m<sup>3</sup>)

EVAPORATED AT 110°C EVAPORATED AT 180°C

AT IGNITION CALCULATED  
**119612**SPECIFIC GRAVITY at 15°C REFRACTIVE INDEX (R) at 25°C  
**1.359**OBSERVED pH at 25°C RESISTIVITY (RW) Ω m at 25°C  
**7.44** **0.070**REDOX POTENTIAL (Eh) DISSOLVED O<sub>2</sub> g/m<sup>3</sup>

## TOTAL METALS

METAL	g/m <sup>3</sup>
Fe	
Mn	

Cations/Anions: **0.98**

Interval: to

KB: GRD:

Perfs to

REMARKS

**GEOTECH** *technical resources ltd.*4500 - 5th STREET N.E., CALGARY, ALBERTA T2E 7C3  
(403) 230-4128**WATER ANALYSIS**

FILE NUMBER	89AS5615
LABORATORY NUMBER	5615-W5

CONTAINER IDENTITY

OPERATOR'S NAME

**TUNDRA OIL & GAS**

SAMPLE LOCATION

WELL NAME

**DETAILED WATER COMPATIBILITY**ELEVATIONS  
KB

GRD

FIELD OR AREA

POOL OR ZONE

NAME OF SAMPLER

COMPANY

TEST TYPE NO

TEST RECOVERY

SAMPLING POINT

AMT. AND TYPE OF CUSHION

MUD RESISTIVITY  $\Omega/m$ MULTIPLE RECOVERY  
TEST INTERVAL  
FROM**30% BAKKEN / 70% LODGEPOLE**

PUMPING

FLOWING

GAS LIFT

SWAB

TO

WATER

 $m^3/d$ 

OIL

 $m^3/d$ 

GAS

 $10^3 m^3/d$ 

SEPARATOR

TREATER

RESERVOIR

SAMPLED

RECEIVED

PERFORATIONS  
FROM

GAUGE PRESSURE K/Pa

TEMPERATURE (°C)

TO

DATE SAMPLED

Y M D

H:M

DATE RECEIVED

Y M D

DATE ANALYZED

Y M D

ANALYST

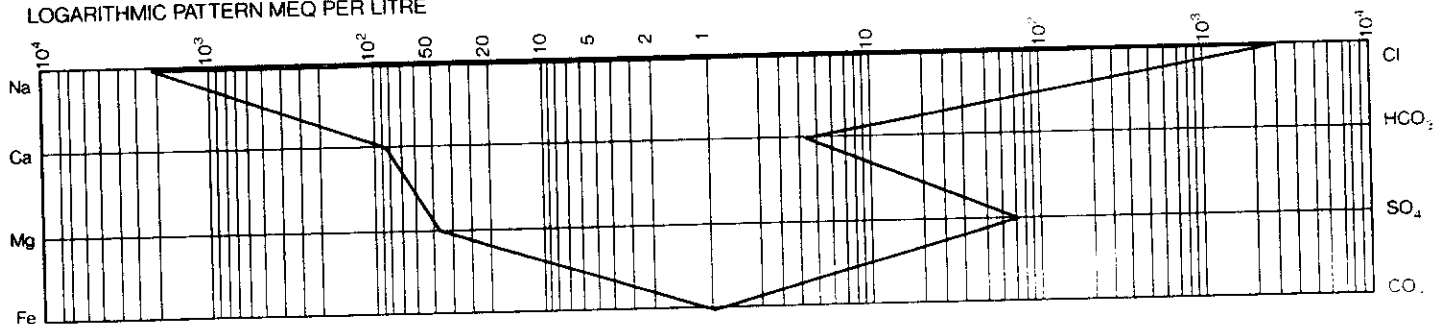
**12-JUL-89****17-JUL-89****21-JUL-89****LE****SUMMARY DATA**

TOTAL HARDNESS AS $CaCO_3$	6927	$g/m^3$
TOTAL ALKALINITY	187	$g/m^3$
SALINITY AS NaCl	137029	ppm
SATURATION INDEX	1.62	
STABILITY INDEX	4.22	
CORROSION TENDENCY		

**CaCO3 SCALING TENDENCY****CaCO3 SCALING TENDENCY**

Scaling calculations done at 30 C

LOGARITHMIC PATTERN MEQ PER LITRE



REMARKS



**GEOTECH** *Technical resources Ltd.*  
4500 - 5th STREET N.E., CALGARY, ALBERTA T2E 7C3  
(403) 230-4128

# WATER ANALYSIS DETAILED REPORT

**TUNDRA OIL & GAS**

OPERATOR'S NAME

FILE  
NUMBER

**89AS5615**

**DETAILED WATER COMPATIBILITY**

WELL NAME

LABORATORY  
NUMBER

**5615-W5**

LOCATION

SAMPLING POINT

**30% BAKKEN / 70% LODGEPOLE**

## CATIONS

## ANIONS

ION	g/m <sup>3</sup>	MASS FRACTION	MEQ/L	ION	g/m <sup>3</sup>	MASS FRACTION	MEQ/L
Na	52600	0.37	2288	Cl	83300	0.6	2352
K	534	0.00	13.7	Br			
Ca	1860	0.01	92.8	I	14.8	0.00	0.12
Mg	544	0.00	44.7	F			
Ba	< 0.05			HCO <sub>3</sub>	228	0.00	3.7
Sr	37.2	0.00	0.85	CO <sub>3</sub>	0.00	0.00	0.00
Fe	< 0.05			OH	0.00	0.00	0.00
Mn				SO <sub>4</sub>	3310	0.02	68.9
Al				H <sub>2</sub> S			
Si				PO <sub>4</sub>			
B	15.8						
U							
Th							

TOTAL SOLIDS (g/m<sup>3</sup>)

EVAPORATED AT 110°C EVAPORATED AT 180°C

AT IGNITION CALCULATED  
**142444**

SPECIFIC GRAVITY at 15°C REFRACTIVE INDEX (R) at 25°C  
**1.362**

OBSERVED pH at 25°C RESISTIVITY (RW) Ω m at 25°C  
**7.47** **0.063**

REDOX POTENTIAL (Eh) DISSOLVED O<sub>2</sub> g/m<sup>3</sup>

## TOTAL METALS

METAL	g/m <sup>3</sup>
-------	------------------

Fe

Mn

Cations/Anions: **1.01**

Interval: to

KB: GRD:

Perfs to

REMARKS

**GEOTECH** *technical resources ltd.*4500 - 5th STREET N.E., CALGARY, ALBERTA T2E 7C3  
(403) 230-4128**WATER ANALYSIS**

CONTAINER IDENTITY

**5615F1**

OPERATOR'S NAME

**TUNDRA OIL & GAS**

SAMPLE LOCATION

WELL NAME

**DETAILED WATER COMPATIBILITY****16-11-10-29**ELEVATIONS  
KB

GRD

FIELD OR AREA

POOL OR ZONE

**JURASSIC**

NAME OF SAMPLER

COMPANY

TEST TYPE NO

TEST RECOVERY

SAMPLING POINT

AMT. AND TYPE OF CUSHION

MUD RESISTIVITY  $\Omega/m$ MULTIPLE RECOVERY  
TEST INTERVAL  
FROM

PUMPING

FLOWING

GAS LIFT

SWAB

TO

WATER

 $m^3/d$ 

OIL

 $m^3/d$ 

GAS

 $10^3 m^3/d$ 

SEPARATOR

TREATER

RESERVOIR

SAMPLED

RECEIVED

PERFORATIONS  
FROM

GAUGE PRESSURE K/Pa

TEMPERATURE ( $^{\circ}C$ )

TO

DATE SAMPLED

Y M D

**12-JUL-89**

H:M

DATE RECEIVED

Y M D

**17-JUL-89**

DATE ANALYZED

Y M D

**21-JUL-89**

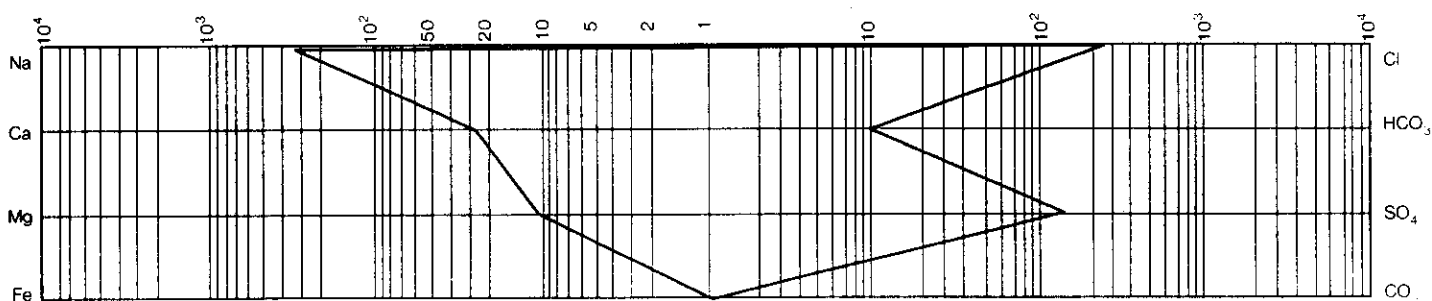
ANALYST

**LE****SUMMARY DATA**

TOTAL HARDNESS AS $CaCO_3$	<b>1913</b>	$g/m^3$
TOTAL ALKALINITY	<b>447</b>	$g/m^3$
SALINITY AS NaCl	<b>13177</b>	ppm
SATURATION INDEX	<b>1.54</b>	
STABILITY INDEX	<b>4.46</b>	
CORROSION TENDENCY	<b>39.7</b>	

 **$CaCO_3$  SCALING TENDENCY** **$CaCO_3$  SCALING TENDENCY****Scaling calculations done at 30 C**

LOGARITHMIC PATTERN MEQ PER LITRE



REMARKS

**GEOTECH** *Technical resources Ltd.*4500 - 5th STREET N.E., CALGARY, ALBERTA T2E 7C3  
(403) 230-4128**WATER ANALYSIS  
DETAILED REPORT**OPERATOR'S NAME **TUNDRA OIL & GAS**FILE NUMBER **89AS5615**WELL NAME **DETAILED WATER COMPATIBILITY**LABORATORY NUMBER **5615-W6**LOCATION **16-11-10-29**

SAMPLING POINT

**CATIONS****ANIONS**

ION	g/m <sup>3</sup>	MASS FRACTION	MEQ/L	ION	g/m <sup>3</sup>	MASS FRACTION	MEQ/L
Na	7450	0.32	325	Cl	8010	0.35	226
K	127	0.01	3.2	Br			
Ca	535	0.02	26.7	I	1.8	0.00	0.01
Mg	137	0.01	11.3	F			
Ba	< 0.05			HCO <sub>3</sub>	545	0.02	8.9
Sr	11	0.00	0.25	CO <sub>3</sub>	0.00	0.00	0.00
Fe	< 0.05			OH	0.00	0.00	0.00
Mn				SO <sub>4</sub>	6180	0.27	129
Al				H <sub>2</sub> S			
Si				PO <sub>4</sub>			
B	7.1						
U							
Th							

TOTAL SOLIDS (g/m<sup>3</sup>)

EVAPORATED AT 110°C EVAPORATED AT 180°C

AT IGNITION

CALCULATED

**23004**

SPECIFIC GRAVITY

at 15°C

REFRACTIVE INDEX (R)

**1.345**

at 25°C

OBSERVED pH

at 25°C

**7.56**

RESISTIVITY (RW) Ω m

**0.306**

at 25°C

REDOX POTENTIAL (Eh)

DISSOLVED O<sub>2</sub>g/m<sup>3</sup>**TOTAL METALS**

METAL	g/m <sup>3</sup>
-------	------------------

Fe

Mn

Cations/Anions: **1.01**

Interval: to

KB: GRD:

Perfs to

REMARKS



**GEOTECH** *resources ltd.*4500 - 5th STREET N.E., CALGARY, ALBERTA T2E 7C3  
(403) 230-4128**WATER ANALYSIS**

CONTAINER IDENTITY

FILE NUMBER ► **89AS5615**LABORATORY NUMBER ► **5615-W7**

OPERATOR'S NAME

**TUNDRA OIL & GAS**

SAMPLE LOCATION

WELL NAME

ELEVATIONS  
KB

GRD

**DETAILED WATER COMPATIBILITY**

FIELD OR AREA

POOL OR ZONE

NAME OF SAMPLER

COMPANY

TEST TYPE NO

TEST RECOVERY

SAMPLING POINT

**70% BAKKEN / 30% JURASSIC**

AMT. AND TYPE OF CUSHION

MUD RESISTIVITY  $\Omega/m$ MULTIPLE RECOVERY  
TEST INTERVAL  
FROM

PUMPING

FLOWING

GAS LIFT

SWAB

TO

WATER

 $m^3/d$ 

OIL

 $m^3/d$ 

GAS

 $10^3 m^3/d$ PERFORATIONS  
FROM

GAUGE PRESSURE K/Pa

TEMPERATURE (°C)

SEPARATOR

TREATER

RESERVOIR

SAMPLED

RECEIVED

TO

DATE SAMPLED

Y M D

**12-JUL-89**

H:M

DATE RECEIVED

Y M D

**17-JUL-89**

DATE ANALYZED

Y M D

**21-JUL-89**

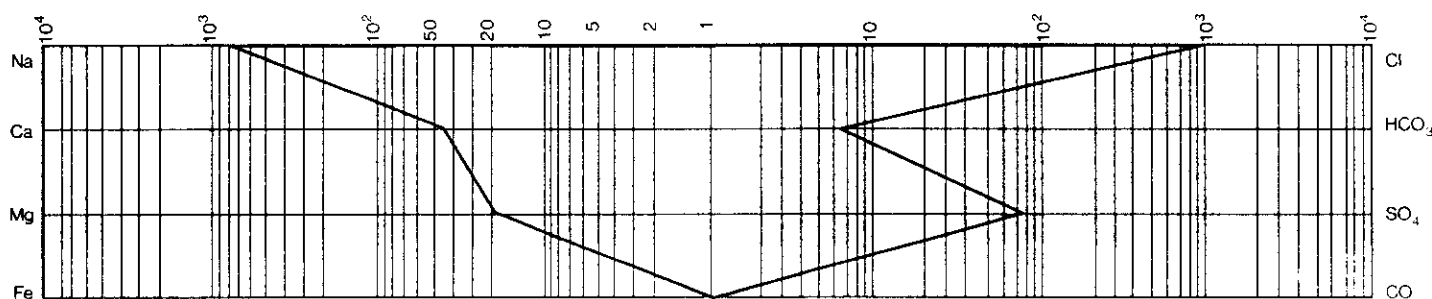
ANALYST

**LE****SUMMARY DATA**

TOTAL HARDNESS AS $CaCO_3$	<b>3230</b>	$g/m^3$
TOTAL ALKALINITY	<b>291</b>	$g/m^3$
SALINITY AS NaCl	<b>48693</b>	ppm
SATURATION INDEX	<b>1.58</b>	
STABILITY INDEX	<b>4.4</b>	
CORROSION TENDENCY	<b>157</b>	

**CaCO3 SCALING TENDENCY****CaCO3 SCALING TENDENCY****Scaling calculations done at 30 C**

LOGARITHMIC PATTERN MEQ PER LITRE



REMARKS

**GEOTECH** *Technical resources Ltd.*4500 - 5th STREET N.E., CALGARY, ALBERTA T2E 7C3  
(403) 230-4128**WATER ANALYSIS  
DETAILED REPORT**

OPERATOR'S NAME	TUNDRA OIL & GAS	FILE NUMBER	89AS5615
WELL NAME	DETAILED WATER COMPATIBILITY	LABORATORY NUMBER	5615-W7
LOCATION			
SAMPLING POINT	70% BAKKEN / 30% JURASSIC		

CATIONS				ANIONS				TOTAL SOLIDS (g/m <sup>3</sup> )	
ION	g/m <sup>3</sup>	MASS FRACTION	MEQ/L	ION	g/m <sup>3</sup>	MASS FRACTION	MEQ/L	EVAPORATED AT 110°C	EVAPORATED AT 180°C
Na	18600	0.35	810	Cl	29600	0.55	837	AT IGNITION	CALCULATED
K	302	0.01	7.7	Br					53446
Ca	865	0.02	43.2	I	3.8	0.00	0.03	SPECIFIC GRAVITY	REFRACTIVE INDEX (R)
Mg	255	0.00	21	F				at 15°C	at 25°C
Ba	< 0.05			HCO <sub>3</sub>	355	0.01	5.8	OBSERVED pH	1.351
Sr	17.4	0.00	0.4	CO <sub>3</sub>	0.00	0.00	0.00	at 25°C	RESISTIVITY (RW) Ω m
Fe	< 0.05			OH	0.00	0.00	0.00	7.57	0.133
Mn				SO <sub>4</sub>	3440	0.06	71.6	REDOX POTENTIAL (Eh)	DISSOLVED O <sub>2</sub>
Al				H <sub>2</sub> S					g/m <sup>3</sup>
Si				PO <sub>4</sub>					
B	7.74								
U									
Th									

TOTAL METALS	
METAL	g/m <sup>3</sup>
Fe	
Mn	

Cations/Anions: 0.96

Interval: to

KB: GRD:

Perfs to

REMARKS

**GEOTECH** *resources ltd.*4500 - 5th STREET N.E., CALGARY, ALBERTA T2E 7C3  
(403) 230-4128**WATER ANALYSIS**

CONTAINER IDENTITY

FILE NUMBER ► **89AS5615**

OPERATOR'S NAME

**TUNDRA OIL & GAS**

SAMPLE LOCATION

WELL NAME

ELEVATIONS  
KB

GRD

**DETAILED WATER COMPATIBILITY**

FIELD OR AREA

POOL OR ZONE

NAME OF SAMPLER

COMPANY

TEST TYPE NO

TEST RECOVERY

SAMPLING POINT

AMT. AND TYPE OF CUSHION

MUD RESISTIVITY  $\Omega/m$ MULTIPLE RECOVERY  
TEST INTERVAL  
FROM**50% BAKKEN / 50% JURASSIC**

PUMPING

FLOWING

GAS LIFT

SWAB

TO

WATER

 $m^3/d$ 

OIL

 $m^3/d$ 

GAS

 $10^3 m^3/d$ PERFORATIONS  
FROM

GAUGE PRESSURE K/Pa

TEMPERATURE (°C)

SEPARATOR

TREATER

RESERVOIR

SAMPLED

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TO

DATE SAMPLED

Y M D

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DATE RECEIVED

Y M D

DATE ANALYZED

Y M D

ANALYST

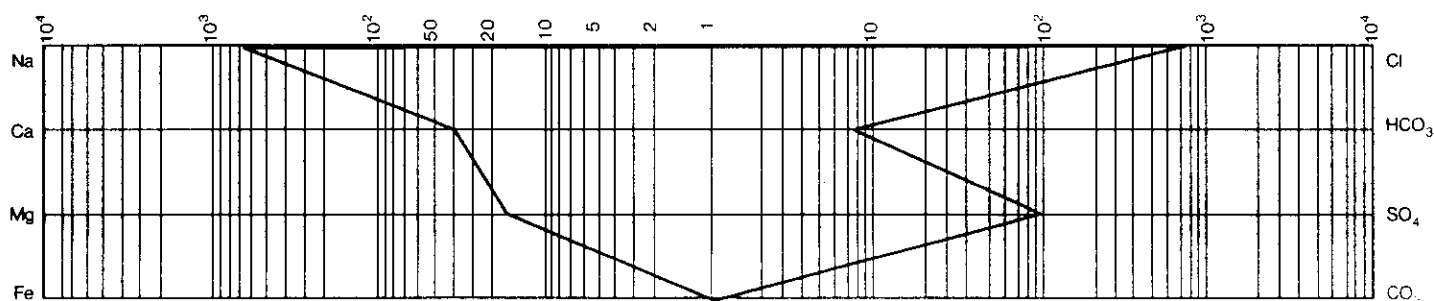
**12-JUL-89****17-JUL-89****21-JUL-89****LE****SUMMARY DATA**

TOTAL HARDNESS AS $CaCO_3$	<b>2797</b>	$g/m^3$
TOTAL ALKALINITY	<b>344</b>	$g/m^3$
SALINITY AS NaCl	<b>38329</b>	ppm
SATURATION INDEX	<b>1.72</b>	
STABILITY INDEX	<b>4.25</b>	
CORROSION TENDENCY	<b>110</b>	

**CaCO3 SCALING TENDENCY****CaCO3 SCALING TENDENCY**

Scaling calculations done at 30 C

LOGARITHMIC PATTERN MEQ PER LITRE



REMARKS

**GEOTECH** *Technical resources Ltd.*4500 - 5th STREET N.E., CALGARY, ALBERTA T2E 7C3  
(403) 230-4128**WATER ANALYSIS  
DETAILED REPORT**OPERATOR'S NAME **TUNDRA OIL & GAS**FILE NUMBER **89AS5615**WELL NAME **DETAILED WATER COMPATIBILITY**LABORATORY NUMBER **5615-W8**

LOCATION

SAMPLING POINT **50% BAKKEN / 50% JURASSIC**

## CATIONS

## ANIONS

ION	g/m <sup>3</sup>	MASS FRACTION	MEQ/L	ION	g/m <sup>3</sup>	MASS FRACTION	MEQ/L
Na	15800	0.35	688	Cl	23300	0.52	660
K	229	0.01	5.9	Br			
Ca	750	0.02	37.4	I	2.6	0.00	0.02
Mg	220	0.00	18.1	F			
Ba	< 0.05			HCO <sub>3</sub>	419	0.01	6.9
Sr	15.6	0.00	0.36	CO <sub>3</sub>	0.00	0.00	0.00
Fe	< 0.05			OH	0.00	0.00	0.00
Mn				SO <sub>4</sub>	4300	0.1	89.5
Al				H <sub>2</sub> S			
Si				PO <sub>4</sub>			
B	7.48						
U							
Th							

TOTAL SOLIDS (g/m<sup>3</sup>)

EVAPORATED AT 110°C EVAPORATED AT 180°C

AT IGNITION CALCULATED  
**45044**SPECIFIC GRAVITY REFRACTIVE INDEX (R)  
at 15°C **1.349** at 25°COBSERVED pH RESISTIVITY (RW) Ω m  
**7.70** at 25°C **0.157** at 25°CREDOX POTENTIAL (Eh) DISSOLVED O<sub>2</sub> g/m<sup>3</sup>

## TOTAL METALS

METAL	g/m <sup>3</sup>
Fe	
Mn	

Cations/Anions: **0.99**

Interval: to

KB: GRD:

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REMARKS

**GEOTECH** *Technical resources Ltd.*4500 - 5th STREET N.E., CALGARY, ALBERTA T2E 7C3  
(403) 230-4128**WATER ANALYSIS**

CONTAINER IDENTITY

OPERATOR'S NAME

**TUNDRA OIL & GAS**

SAMPLE LOCATION

WELL NAME

**DETAILED WATER COMPATIBILITY**

FIELD OR AREA

POOL OR ZONE

NAME OF SAMPLER

COMPANY

ELEVATIONS  
KB

GRD

TEST TYPE NO

TEST RECOVERY

SAMPLING POINT

AMT. AND TYPE OF CUSHION

MUD RESISTIVITY  $\Omega/m$ MULTIPLE RECOVERY  
TEST INTERVAL  
FROM**30% BAKKEN / 70% JURASSIC**

PUMPING

FLOWING

GAS LIFT

SWAB

TO

WATER

 $m^3/d$ 

OIL

 $m^3/d$ 

GAS

 $10^3 m^3/d$ PERFORATIONS  
FROM

GAUGE PRESSURE K/Pa

TEMPERATURE (°C)

SEPARATOR

TREATER

RESERVOIR

SAMPLED

RECEIVED

TO

DATE SAMPLED

Y M D

**12-JUL-89**

H:M

DATE RECEIVED

Y M D

**17-JUL-89**

DATE ANALYZED

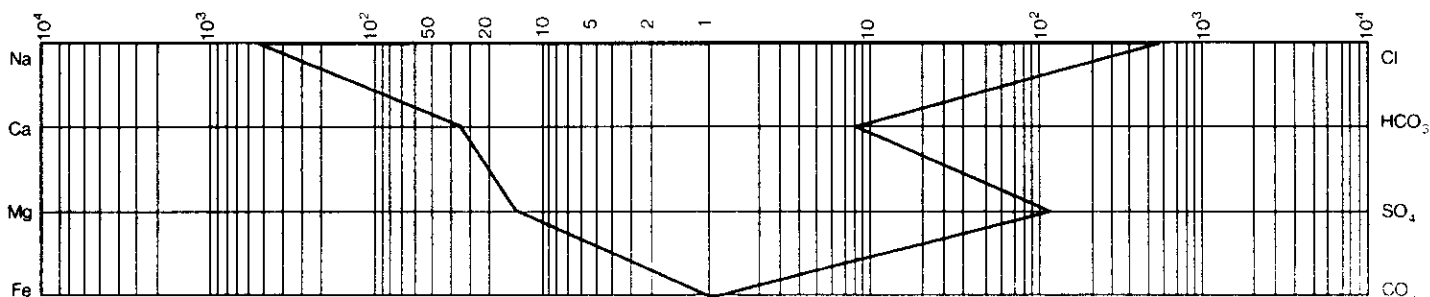
Y M D

**21-JUL-89**

ANALYST

**LE****SUMMARY DATA**

TOTAL HARDNESS AS $CaCO_3$	<b>2461</b>	$g/m^3$
TOTAL ALKALINITY	<b>370</b>	$g/m^3$
SALINITY AS NaCl	<b>28130</b>	ppm
SATURATION INDEX	<b>1.81</b>	
STABILITY INDEX	<b>4.18</b>	
CORROSION TENDENCY	<b>80.1</b>	

**CaCO3 SCALING TENDENCY****CaCO3 SCALING TENDENCY****Scaling calculations done at 30 C****LOGARITHMIC PATTERN MEQ PER LITRE**

REMARKS

**GEOTECH** nical resources ltd.4500 - 5th STREET N.E., CALGARY, ALBERTA T2E 7C3  
(403) 230-4128**WATER ANALYSIS  
DETAILED REPORT**

OPERATOR'S NAME	TUNDRA OIL & GAS	FILE NUMBER	89AS5615
WELL NAME	DETAILED WATER COMPATIBILITY	LABORATORY NUMBER	5615-W9
LOCATION			
SAMPLING POINT	30% BAKKEN / 70% JURASSIC		

CATIONS				ANIONS				TOTAL SOLIDS (g/m <sup>3</sup> )	
ION	g/m <sup>3</sup>	MASS FRACTION	MEQ/L	ION	g/m <sup>3</sup>	MASS FRACTION	MEQ/L	EVAPORATED AT 110°C	EVAPORATED AT 180°C
Na	12600	0.35	549	Cl	17100	0.47	483	AT IGNITION	CALCULATED
K	171	0.00	4.4	Br					36413
Ca	669	0.02	33.4	I	2.1	0.00	0.02	SPECIFIC GRAVITY	REFRACTIVE INDEX (R)
Mg	188	0.01	15.5	F				at 15°C	1.348 at 25°C
Ba	< 0.05			HCO <sub>3</sub>	451	0.01	7.4	OBSERVED pH	RESISTIVITY (RW) Ω m
Sr	13.8	0.00	0.31	CO <sub>3</sub>	0.00	0.00	0.00	7.81 at 25°C	0.198 at 25°C
Fe	< 0.05			OH	0.00	0.00	0.00	REDOX POTENTIAL (Eh)	DISSOLVED O <sub>2</sub>
Mn				SO <sub>4</sub>	5210	0.14	109		g/m <sup>3</sup>
Al				H <sub>2</sub> S					
Si				PO <sub>4</sub>					
B	7.63								
U									
Th									

TOTAL METALS	
METAL	g/m <sup>3</sup>
Fe	
Mn	

Cations/Anions: 1.01

Interval: to

KB: GRD:

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REMARKS

**APPENDIX B**

**DATA FROM THE DETAILED WATER COMPATIBILITY STUDY**

**TABLE 1**  
**DETAILED WATER COMPATABILITY STUDY**  
**TUNDRA OIL AND GAS**

Date: July 31, 1989

File No: 89AS5615

W1: 9-14-10-29 BAKKEN  
W2: 14-14-10-29 LODGEPOLE

Temperature: 23°C  
Wavelength: 420 nm

**% TRANSMITTANCE AS A FUNCTION OF TIME**

	<u>%W1</u>	<u>%W2</u>	<u>0 hr</u>	<u>4 hr</u>	<u>8 hr</u>	<u>24 hr</u>	<u>48 hr</u>	<u>72 hr</u>
1	100	0	95.2	94.1	94.5	93.9	95.0	93.9
2	90	10	97.0	96.0	96.0	95.0	95.1	95.3
3	80	20	97.5	94.9	95.0	94.9	93.9	93.8
4	70	30	94.9	91.9	91.9	91.8	92.0	92.2
5	60	40	95.9	93.5	93.9	93.0	93.2	94.0
6	50	50	93.9	91.2	91.5	91.2	92.2	92.8
7	40	60	95.0	91.2	91.0	90.4	92.1	92.9
8	30	70	93.0	90.0	90.5	89.9	92.0	91.3
9	20	80	92.0	90.4	91.5	91.2	92.0	93.7
10	10	90	90.2	90.9	91.2	91.1	92.9	93.9
11	0	100	93.2	89.3	90.9	90.0	92.1	92.9

**COMMENTS :** Blank is deionized water.

0 hr: Mixtures #1 to #11 clear, colorless.

4 hr: Mixtures show no visual change.

8 hr: Mixtures show no visual change.

24 hr: Mixtures show no visual change.

48 hr: Mixtures show no visual change.

72 hr: Mixtures show no visual change.



**TABLE 2**  
**DETAILED WATER COMPATABILITY STUDY**  
**TUNDRA OIL AND GAS**

Date: July 31, 1989

File No: 89AS5615

W1: 9-14-10-29 BAKKEN  
W2: 16-11-10-29 JURASSIC

Temperature: 23°C  
Wavelength: 420 nm

**% TRANSMITTANCE AS A FUNCTION OF TIME**

	<u>%W1</u>	<u>%W2</u>	<u>0 hr</u>	<u>4 hr</u>	<u>8 hr</u>	<u>24 hr</u>	<u>48 hr</u>	<u>72 hr</u>
1	100	0	95.2	94.1	94.5	93.9	95.0	93.9
2	90	10	95.9	95.8	96.0	94.0	95.6	95.8
3	80	20	96.2	95.0	95.9	95.0	94.0	94.3
4	70	30	97.6	96.7	96.8	95.8	95.3	94.8
5	60	40	95.2	96.5	96.5	96.3	95.0	95.0
6	50	50	95.7	92.0	92.7	91.0	94.0	92.9
7	40	60	95.8	94.1	95.0	93.0	93.0	93.0
8	30	70	95.8	93.9	94.7	92.3	94.0	93.0
9	20	80	94.2	93.1	93.5	91.9	91.2	91.9
10	10	90	93.8	94.0	94.8	92.9	92.5	93.2
11	0	100	92.0	92.6	93.1	91.7	90.8	90.5

**COMMENTS :** Blank is deionized water.

0 hr: Mixtures #1 to #11 clear, colorless.

4 hr: Mixtures show no visual change.

8 hr: Mixtures show no visual change.

24 hr: Mixtures show no visual change.

48 hr: Mixtures show no visual change.

72 hr: Mixtures show no visual change.

APPENDIX C  
EXPERIMENTAL PROCEDURE

The detailed water compatibility study consists of:

- chemical analysis of each water
- visual water compatibility study between each water
- chemical analysis of three water mixtures from each water compatibility study
- theoretical calculations and evaluation of each compatibility study

The visual water compatibility study consists of preparing mixtures of waters varying from 100% of one water to 100% of the other in steps of 10%. The stability of these water mixtures is monitored as a function of time by determining the transmittance of the sample. If a precipitate forms, the solution transmittance will decrease due to light scattering from the precipitate particles. With this procedure, a light precipitate, with small particles, will result in a greater decrease than a heavy precipitate with large particles. Thus, the transmittance data must be coupled with visual observations regarding the character of any precipitate which forms. The general interpretation is that if the transmittance remains above 93%, there is no visible precipitate formation and the solutions can be taken as being compatible, for transmittance between 89% and 93% the solution is slightly cloudy, for transmittance between 82% and 89% the solution is cloudy with some precipitate formation, for a transmittance between 76% and 82% the solution is turbid with distinct precipitate and for a transmittance less than 76% the solution is strongly turbid with settled precipitate. As the transmittance decreases from 93% the waters are becoming progressively more incompatible and below 82% the waters should be taken as being incompatible.

Using information obtained from the chemical analyses, the calcium carbonate Saturation Index and Stability Index along with the Corrosion Tendency are calculated. A value of the Saturation Index less than zero indicates potential corrosion while a value greater than zero indicates a scaling tendency. A value of the Stability Index less than 6.5 indicates a scaling tendency while a value greater than 6.5 indicates potential corrosion. A value of the Corrosion Tendency greater than 0.1 indicates potential corrosion if there is dissolved oxygen present in the water.

In addition, the calcium sulphate scaling tendency is calculated after the method of Skillman and Davis.