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ANDERSON - SOUTH PIERSON
FORMATION DAMAGE STUDY

Prepared for

Anderson Exploration Ltd.

Prepared by

Hycal Energy Research Laboratories Ltd.

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SUMMARY

SUMMARY

Study Objective

At the request of Kelly Kingsmith of Anderson Exploration Limited (Anderson), Hycal Energy Research Laboratories Ltd. conducted a formation damage study using reservoir material from the Spearfish formation of the South Pierson area. The study was initiated to optimize the performance of the planned horizontal injection wells. The objective of this study was to evaluate drilling fluid performance by investigating the leakoff characteristics and regain permeability performance. A water injectivity test was also conducted to assess the effectiveness of the drilling fluid additives.

Conclusions

The following conclusions are provided to enhance understanding of the laboratory data and to offer additional insight relative to Hycal's experience with laboratory and field processes. They represent our interpretation as to possible mechanisms and physical phenomena that may be occurring within the laboratory models that have been studied. These laboratory experiments are microscale representations of the field scenario; however, macroscale phenomena may override behaviour exhibited in the laboratory. A more thorough development of these conclusions is presented in the "Discussion" section of the report.

1. Representative samples from the 12-9-2-29 and 8-8-2-29 W6M wells were restored to native wettability using produced crude oil.

2. Static oil drop contact angle measurements were used to assess the reservoir wettability. Results indicated that the reservoir is moderately oil wetting.

3. Prior to flow tests, a compatibility test was conducted between the crude oil and "Distillate 822", a base oil which was used to prepare the drilling mud. The test results indicate that the two oils are compatible.

4. Two drilling fluids were evaluated; both were based on the "Distillate 822" oil. The difference between the two fluids was that one had an oil wetting agent (Optiwet) added and the other did not. In terms of water injectivity, the drilling fluid with the oil wetting agent definitely exhibited an improvement in water injectivity when compared with the drilling fluid without the oil wetting agent. Based on this, the oil wetting agent "Optiwet" is recommended.

5. An additive called "Hi Perm" was tested as a possible enhancing agent for water injection. However, the intended effects of the additive were not known and the test results were not conclusive in assessing its effect.

DISCUSSION

DISCUSSION

Core material from the 08-08-002-29 W1M and 12-09-002-27 W1M wells was selected to represent the zone of interest in the South Pierson area. A total of eight (8) core plugs were selected and x-radiography was utilized to verify the sample quality. The x-ray images are shown in Appendix A. A synthetic brine based on an analysis of samples of "sour" water from the field was used to approximate the formation water. The compositional results of this produced water is shown in Appendix B. Dead oil was received from the same well and was utilized to represent the reservoir fluid for this study. The core plugs were restored to their native wettability state using the procedures described in the "Procedures and Equipment" section. All tests were conducted at a temperature of 42°C and the cores were subjected to a confining pressure equivalent to a reservoir net overburden of 20000 kPa.

Oil-Oil Compatibility Test

Prior to any core flow tests, the compatibility of the reservoir crude oil and the drilling fluid base oil was tested. In a 24 hour test conducted at the reservoir temperature of 42°C, no precipitate or emulsion was observed. The two oils were deemed to be compatible under test conditions. At the conclusion of the compatibility tests, the oil mixture was filtered and a weight gain was measured with filter paper. The weight gain is likely due to suspended solids and/or unevaporated heavy ends of the crude oil.

Static Oil-Water Contact Angle Measurements

Oil-water contact angle measurements were conducted to assess the reservoir wettability. Restored core material was used as the test matrix for these tests. Measured contact angles of 125-126° were determined on samples with three to four weeks of restoration. These contact angles indicated that the reservoir matrix/fluid system was moderately oil wetted. These data were compared to an earlier study conducted by Hycal from the same field and formation and found to be consistent. In the earlier study, three contact angles were measured on three separate samples, and the contact angles were measured at 140, 46 and 135°. Although the sample lot was quite small (at four samples total), it was concluded that the reservoir may have local variations of wettability likely due to variations of lithology, but the overall representative wettability would be in the category of moderately oil wet. Digital images of the measured contact angles for this study are shown in Tables 3 and 4.

Core #14, Mud Leakoff/Regain Permeability Test with Distillate 822 and Optiwet

This sample, with an air permeability of 3.0 mD, was selected to represent the medium quality of the reservoir. After the wettability restoration process, a baseline effective permeability to oil was measured at 0.085 mD at a drawdown pressure of 1380 kPa. At a higher drawdown pressure of 2690 kPa, the oil permeability was measured at 0.15 mD. The mud system for this test had the "Optiwet" additive which is a oil wetting agent with the intent of increasing the oil wetting tendencies of the near wellbore region. After exposure to this fluid, regain permeabilities to oil were measured at incrementally increasing drawdown pressures. The first sign of stable flow was established at a drawdown pressure of 2758 kPa. At this pressure, regain permeability was measured at 0.012 mD or less than 10% of the average baseline value. At the maximum tested drawdown pressure of 6895 kPa, the regain permeability was measured at 0.015 mD or 12.5 % of baseline. Since a strongly oil wetting system would exhibit low relative permeability to the oil phase, it would appear that the "Optiwet" may be successful in enhancing the oil wetting characteristics of the reservoir. A water injection test was conducted following the oil regain permeability measurements to assess the water injectivity performance. After an initial transient period where the water displaced out the mobile oil saturation, the effective permeability to water began to increase with throughput. After an injection of 26.5 pore volumes of fresh water, the effective permeability to water was measured at 0.24 mD, which is an improvement of nearly 63% over the baseline oil permeability. The water injection was continued for an additional 14 pore volumes with the additive "HiPerm" added into the fresh water at a concentration of 8 ml/litre. The effective water permeability continued to improve to 0.45 mD or nearly 300% of the baseline oil permeability. Since the effective water permeability was steadily increasing before adding the additive "Hi Perm", its sole effect on permeability was not conclusive. The composition of the "Hi Perm" was not known at the time of writing. Results of this test are shown in Tables 5 to 7 and in Figures 2 and 3.

Core #24, Mud Leakoff/Regain Permeability with Distillate 822

A second test using a sample of similar quality (Kair = 4.0 mD) was conducted using the same mud system as the previous test without the wettability agent "Optiwet". Baseline oil permeability for this sample was measured at 0.12 mD at a drawdown pressure of 1380 kPa and 0.115 mD at 2690 kPa. Following exposure to the drilling fluid, regain permeability to oil was measured at 0.101 at a drawdown pressure of 1379 kPa, over 85% of the baseline value. At a drawdown pressure of 2758 kPa, full regain was realized. This would suggest that without the oil wetting enhancing agent "Optiwet", the reservoir/fluid system exhibited much less oil wet behaviour. Again, fresh water was injected following the regain permeabilities to assess the water injectivity. After a transition stage where all mobile oil was produced, the permeability to water stabilized at 0.078 mD; only 68% of the baseline oil permeability value. More importantly, the effective permeability to water only improved from 0.071 mD to 0.078 mD between 17.5 to 28 pore volumes of water injection. This lower water injectivity and the high regain permeability to oil indicates that this system is behaving in a fashion much less oil-wet than the previous test. Subsequent injection of the fresh water with the additive "Hi Perm" did not improve the water injectivity by any significant amount. Tabulated results for this test are shown in Tables 8 to10 and graphical results are presented in Figures 4 and 5.

Overall, test results favour adding an oil wetting agent in the drilling fluid for a water injection well. The data supports that an increase in the oil wetting tendencies in the near wellbore region will improve the relative permeability to water in the effected zone, and thus the water injectivity will improve correspondingly. However, the intended effects of the additive "Hi Perm" were not known and the test results were not conclusive in assessing the effects.

PROCEDURES &
EQUIPMENT

PROCEDURES AND EQUIPMENT

Core Handling and Preparation

Core material for the study was obtained from the Home South Pierson 08-08-002-29 W1M and 12-09-002-29 W1M wells. The core plug samples were drilled from the intervals between 1020 metres and 1035 metres.

A total of eight (8) core plugs, 38 mm in diameter, were drilled from the full diameter core material using a 5% potassium chloride as a lubricating fluid to minimize the potential for damage of insitu clay mineralogy and prevent any other damage to the core during drilling. These small plug samples were subjected to cleaning using methanol/chloroform and methanol/toluene solvent in an effort to strip the pore space of hydrocarbon material.

Routine air permeability and porosity measurements were conducted on the small plug samples to aid in the selection of representative core material for testing. Table 1 summarizes the sample parameters.

Sufficient volumes of stock tank crude oil from the 11-08-002-29 W1M well were supplied by Anderson to be utilized as reservoir fluids for this study. Produced water was also received from the same well and used to represent formation brine for sample preparation. Excess formation core material was pulverized to generate a size distribution of <38 micron fines which was added to the mud systems to simulate the generated drill solids not removed by the surface solids control equipment.

Wettability Restoration

Core samples used in the tests were cleaned samples and a wettability restoration procedure was utilized to restore the rock wettability to original in-situ conditions. Since all reservoirs initially exist in a water-wet state with oil migration occurring into the reservoir following deposition and hydration, the restoration procedure is conducted to simulate the actual field scenario.

The cores, prepared with the appropriate initial water saturation, are mounted in lead sleeves. Unoxidized dead crude oil is then introduced into the cores (migration stage) at reservoir temperature for a recommended period of six weeks (1100 hours) as discussed in the literature. At the beginning of each week, a fresh supply of oil is circulated through the core followed by a static interval to allow the wettability transformation reaction to occur (if the tendency exists).

The wettability restoration procedure is important if the rock has a natural tendency to become less water-wet (i.e. neutral to oil-wet), as normal extraction procedures tend to remove the polar and asphaltic components which cause an oil-wetted pore surface to be established. The long-term exposure of the crude oil generally allows an equilibrium concentration of these polar and asphaltic constituents to be re-adsorbed on the rock surface allowing the samples to revert to their natural in-situ wettability. Restoring the correct wettability condition is significant to experimentation because the wetting phase contacting the rock matrix acts as the conduit (or barrier) between invading fluids and rock mineralogy thereby controlling the propensity for rock-fluid interactions. Wettability can also have a profound influence on the efficiency of immiscible displacement processes.

Contact Angle Test

The contact angle test is conducted using restored or preserved state core material with representative wettability characteristics. The angle of interface between the core material and reservoir crude oil is measured in an anaerobic (i.e. formation water) environment using the following procedure:

Contact Angle Procedure

1. The restored or preserved state core material (at maximum oil saturation) is placed in a formation water bath.

2. The dead reservoir crude oil is placed on the core face and allowed to come to equilibrium with the surface.

3. An image of the fluid-rock interface is obtained from which the interface angle is measured directly.

Mud Leakoff/Regain Permeability Test (Oil Reservoir)

The core samples to be tested were mounted using the equipment outlined in the "Description of Equipment" section using high capacity flow heads to conduct whole drilling fluid across the face of the core sample.

Core samples were maintained at the specified reservoir temperature of 42°C and a net overburden pressure of 20000 kPag was applied to each sample to simulate the net effective overburden stress in the reservoir. The laboratory net overburden stress was corrected using Poisson's ratio to account for the triaxial stress condition exerted on the sample in the core holder. This correction ensures that field stress load conditions are simulated to yield representative rock compression and realistic flow conductivity for the reservoir material.

All synthetic mud samples had representative volumes of rock microfines (< 38 microns) added to simulate load material concentrations which occur downstream of solids control equipment at the drilling rig (i.e. actual field mud samples do not have microfines added). The following procedure was then used for each sample:

Mud Leakoff Procedure

1. Displace reservoir crude oil through the restored or preserved core (Direction 1) at the specified reservoir conditions to determine the initial effective permeability to crude oil at immobile water saturation. This displacement is conducted at low rate to minimize the potential for fines migration.

2. Displace supplied whole drilling fluid (rock microfines in suspension) across the simulated sand face (Direction 2) at representative field overbalance conditions. Formation of mud filter cake occurred at the sand face as drilling fluid filtrate leaks off into the simulated near wellbore region (relative to the fluid loss characteristics of the drilling mud).

   Cumulative leakoff volume was recorded to estimate total depth of filtrate invasion into the rock matrix.

3. Resume flow of crude oil (Direction 1) to simulate an inflow production clean-up cycle following drilling. Measure the stabilized regain permeability to crude and compare initial and final permeabilities to determine the degree of permeability impairment caused by the overbalance mud exposure.

Description of General Displacement Test Equipment

Equipment that is used in conventional displacement experiments is common to most core flow evaluation techniques. A detailed schematic of the specific apparatus configuration is provided in Figure 1 of this report. General descriptions of the laboratory equipment utilized for these tests appear in the following paragraphs.

Core Mounting

The core sample to be tested is placed in a 3.81 cm ID flexible confining sleeve. The ductility of the sleeve allows a confining external overburden pressure to be transferred to the core in a radial and axial mode to simulate reservoir pressure. The core, mounted within the sleeve, is placed inside a 7.5 cm ID steel core holder that can simulate reservoir pressures of up to 68.9 MPa. This pressure is applied by filling the annular space between the core sleeve and the core holder with non-damaging mineral oil. The annular fluid is then compressed with a hydraulic pump to obtain the desired overburden pressure. The core holder ends each contain two ports to facilitate fluid displacement and pressure measurements at each end of the core.

High Capacity Core Flow Heads

For experiments which utilize highly viscous fluids and/or which contain a significant suspended solids load, specially designed high capacity core flow heads are used to conduct fluid with solids or additives to the rock face to minimize the potential for flow impedance in the apparatus. Conventional 316 SS is used to fabricate this equipment for applications where reservoir operating conditions are not extreme.

Pressure Measurements

Pressure differential is monitored using Validyne pressure transducers. The transducers are mounted directly across the core and measure the pressure differential between the injection and production ends. The pressure transducers have ranges of sensitivity ranging from 0 to 14 and 0 to 26000 kPa and are rated to 0.01% of the full scale value. The appropriate transducer size is selected based upon the expected permeability and associated range of accompanying differential pressures for a given core sample. The signal from the pressure transducer appears on a multi-channel digital Validyne terminal from which the test operator records pressure readings during the displacement processes. The signal can also be downloaded to a computerized continuing data acquisition system for long-term runs.

Temperature Control

The core holder and associated injection fluids are contained in a temperature controlled air bath to simulate reservoir temperature. The oven contains a circulating air system to eliminate internal temperature gradients and can control at temperatures from 20 to 200°C with a rated accuracy of ±1°C.

Fluid Displacement

A highly accurate positive displacement pump is used to inject fluids into the core. The pump can inject fluids at rates from 0.6 to 8200 cm^3/hr and at pressures of up to 68.9 MPa, with an accuracy of ± 0.01 cm^3. The pump is filled with distilled water that displaces hydrocarbon fluid, test fluid or immiscible buffer fluid which in turn displaces test fluid into the core relative to the specific application. The experimental system has been designed to minimize dead volumes and to ensure that the entire system is at pressure equilibrium prior to any fluid change. Backpressure on the system (for full reservoir condition tests) is controlled using a 316 SS controlling backpressure regulator rated accurate to 0.5% of the setpoint value. This regulator allows for the smooth production of fluids from the system at any required flowrate and setpoint pressure.

TABLES

TABLE 1
ANDERSON - SOUTH PIERSON
FORMATION DAMAGE STUDY
ROUTINE CORE ANALYSIS

Sample No.	Depth (m)	Permeability (mD)	Porosity (fraction)	Grain Density (kg/m^3)
South Pierson 08-08-2-29 W1M				
26	1031.80	2.81	0.181	2700
36	1034.55	1.51	0.173	2710
South Pierson 12-09-2-29 W1M				
9	1024.10	0.99	0.163	2700
14	1024.95	3.02	0.129	2730
17	1025.60	12	0.166	2710
22A	1026.85	2.87	0.187	2700
22B	1026.92	2.34	0.163	2700
24	1027.35	4.03	0.156	2720

TABLE 2
ANDERSON - SOUTH PIERSON
FORMATION DAMAGE STUDY
FLUID COMPATIBILITY TEST SUMMARY

Fluid #1:	Distillate 822
Fluid #2:	South Pierson Produced Oil
Test Temperature:	42°C

Mixtures		**Emulsion**				
Fluid #1 (%)	**Fluid #2 (%)**	**Immediate**	**10 Minutes**	**1 Hour**	**12 Hours**	**24 Hours**
90 70 50 30 10	10 30 50 70 90	None Observed	None Observed	None Observed	None Observed	None Observed

Observations:
No emulsion was observed in any of the mixture ratios of the two fluids. The fluids are deemed to be compatible under test conditions. However, at the conclusion of the compatibility tests, the mixture was filtered and a weight gain was measured with the filter paper. This weight gain may be due to suspended solids and/or unevaporated heavy ends of the crude oil.

TABLE 3
ANDERSON - SOUTH PIERSON
FORMATION DAMAGE STUDY
CONTACT ANGLE WETTABILITY TEST

Field Name:	SOUTH PIERSON
Well Location:	12-09-002-29 W1M
Core Number:	9
Depth (m):	1024.1
Test Temperature (°C):	25
Restoration Status:	3 weeks aging period
Oil Sample:	Crude Oil from 11-8-2-29 W1M
Bath Fluid:	Synthetic Formation Brine
Contact Angle (degree):	**125**

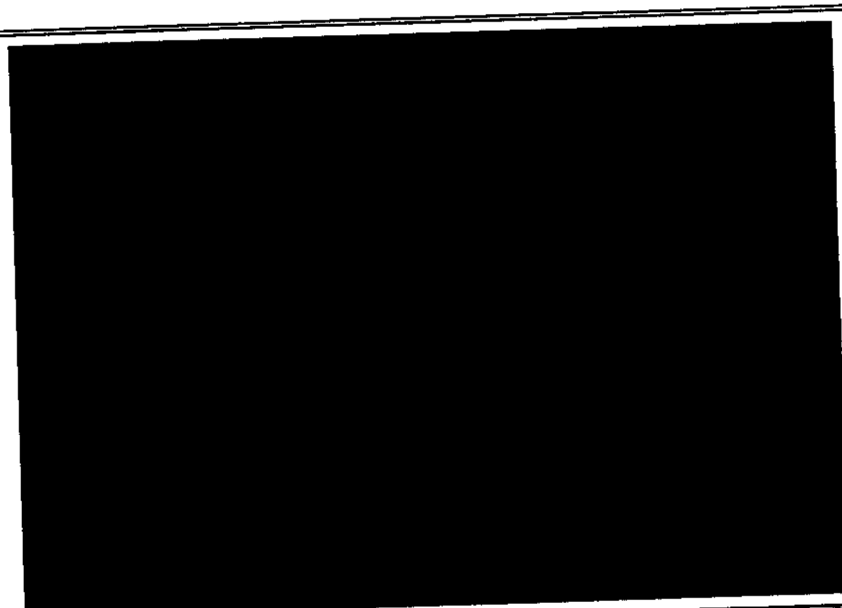

TABLE 4
ANDERSON - SOUTH PIERSON
FORMATION DAMAGE STUDY
CONTACT ANGLE WETTABILITY TEST

Field Name:	SOUTH PIERSON
Well Location:	12-09-002-29 W1M
Core Number:	9
Depth (m):	1024.1
Test Temperature (°C):	25
Restoration Status:	4 weeks aging period
Oil Sample:	Crude Oil from 11-8-2-29 W1M
Bath Fluid:	Synthetic Formation Brine
Contact Angle (degree):	**126**

TABLE 5
ANDERSON - SOUTH PIERSON
FORMATION DAMAGE STUDY
CORE #14 - MUD LEAKOFF WITH DISTILLATE 822 AND OPTIWET
CORE AND TEST PARAMETERS

Core Number	14
Depth (m)	1024.95
Field Name	South Pierson
Well Location	12-9-2-92 W1M
Length (cm)	2.953
Diameter (cm)	3.7955
Effective Flow Area (cm^2)	11.31
Bulk Volume (cm^3)	33.41
Porosity (fraction)	0.129
Pore Volume (cm^3)	4.31
Routine Air Permeability (mD)	3.02
Test Temperature (°C)	42
Oil Viscosity (mPa·s)	5.13
Net Overburden Pressure (kPag)	20000
Mud Overbalance Pressure (kPag)	5190
Rock Microfine Concentration (kg/m^3)	30
Rock Microfine Size (micron)	>38

TABLE 6
ANDERSON - SOUTH PIERSON
FORMATION DAMAGE STUDY
CORE #14 - MUD LEAKOFF WITH DISTILLATE 822 AND OPTIWET
PERMEABILITY SUMMARY

Test Phase	Permeability (mD)	Regain Permeability (%)
Initial Permeability to Crude Oil (Direction #1) @		
1380 kPa Drawdown	0.085	Baseline
2690 kPa Drawdown	0.15	Values
Mud Leakoff (Direction #2)	-	-
Regain Permeability to Crude Oil (Direction #1) @		
2758 kPa Drawdown	0.012	9.9
3448 kPa Drawdown	0.013	10.9
6895 kPa Drawdown	0.015	12.5
2758 kPa Drawdown	0.009	7.7
Permeability to Injection Water (Cuml. Injection PV)		
3.7	0.043	28.7
7.0	0.027	18.0
8.8	0.048	32.0
12.8	0.13	86.7
14.4	0.16	103.3
15.6	0.18	119.3
18.3	0.19	126.0
21.4	0.21	140.0
23.2	0.23	154.0
26.2	0.24	159.3
26.5	0.24	162.7
Permeability to Injection Water with High Perm (Cuml. Injection PV)		
28.1	0.27	179.3
32.0	0.34	228.7
34.3	0.36	242.7
37.8	0.41	274.0
41.5	0.44	294.7
42.0	0.44	291.3
42.2	0.45	297.3

TABLE 7
ANDERSON - SOUTH PIERSON
FORMATION DAMAGE STUDY
CORE #14 - MUD LEAKOFF WITH DISTILLATE 822 AND OPTIWET
LEAKOFF CHARACTER SUMMARY

Leakoff Exposure Time	240 minutes
Time to Sealoff	Did not seal off
Total Leakoff Volume (240 minutes)	*23.9 cc
Linear Filtrate Penetration Depth (240 minutes)	16.4 cm
* Assuming 100% Filtrate Sweep Efficiency	

TABLE 8
ANDERSON - SOUTH PIERSON
FORMATION DAMAGE STUDY
CORE #24 - MUD LEAKOFF WITH DISTILLATE 822
CORE AND TEST PARAMETERS

Core Number	24
Depth (m)	1027.35
Field Name	South Pierson
Well Location	12-9-2-92 W1M
Length (cm)	2.56
Diameter (cm)	3.697
Effective Flow Area (cm^2)	10.73
Bulk Volume (cm^3)	27.48
Porosity (fraction)	0.156
Pore Volume (cm^3)	4.29
Routine Air Permeability (mD)	4.03
Test Temperature (°C)	42
Oil Viscosity (mPa·s)	5.13
Net Overburden Pressure (kPag)	20000
Mud Overbalance Pressure (kPag)	5560
Rock Microfine Concentration (kg/m^3)	30
Rock Microfine Size (micron)	>38

TABLE 9
ANDERSON - SOUTH PIERSON
FORMATION DAMAGE STUDY
CORE #24 - MUD LEAKOFF WITH DISTILLATE 822
PERMEABILITY SUMMARY

Test Phase	Permeability (mD)	Regain Permeability (%)
Initial Permeability to Crude Oil (Direction #1) @		
1380 kPa Drawdown	0.123	Baseline
2690 kPa Drawdown	0.115	Values
Mud Leakoff (Direction #2)	-	-
Regain Permeability to Crude Oil (Direction #1) @		
1379 kPa Drawdown	0.101	85.7
2758 kPa Drawdown	0.120	101.3
Permeability to Injection Water (Cuml. Injection PV)		
3.9	0.022	19.1
5.8	0.031	27.0
8.0	0.044	38.3
11.5	0.062	53.9
14.7	0.067	58.3
17.5	0.071	61.7
18.7	0.072	62.6
20.3	0.074	64.3
21.4	0.074	64.3
22.7	0.074	64.3
24.0	0.076	66.1
25.7	0.078	67.8
28.0	0.078	67.8
Permeability to Injection Water with High Perm (Cuml. Injection PV)		
30.0	0.040	34.8
32.2	0.050	43.5
35.9	0.065	56.5
38.8	0.069	60.0
39.0	0.069	60.0
44.2	0.069	60.0
46.5	0.071	61.7
48.9	0.076	66.1
50.0	0.081	70.4

TABLE 10
ANDERSON - SOUTH PIERSON
FORMATION DAMAGE STUDY
CORE #24 - MUD LEAKOFF WITH DISTILLATE 822
LEAKOFF CHARACTER SUMMARY

Leakoff Exposure Time	240 minutes
Time to Sealoff	Did not seal off
Total Leakoff Volume (240 minutes)	*59.0 cc
Linear Filtrate Penetration Depth (240 minutes)	35.2 cm
* Assuming 100% Filtrate Sweep Efficiency	

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FIGURES

FIGURE 1
ANDERSON - SOUTH PIERSON
DRILLING FLUID LEAKOFF/FLUID SENSITIVITY EVALUATION APPARATUS

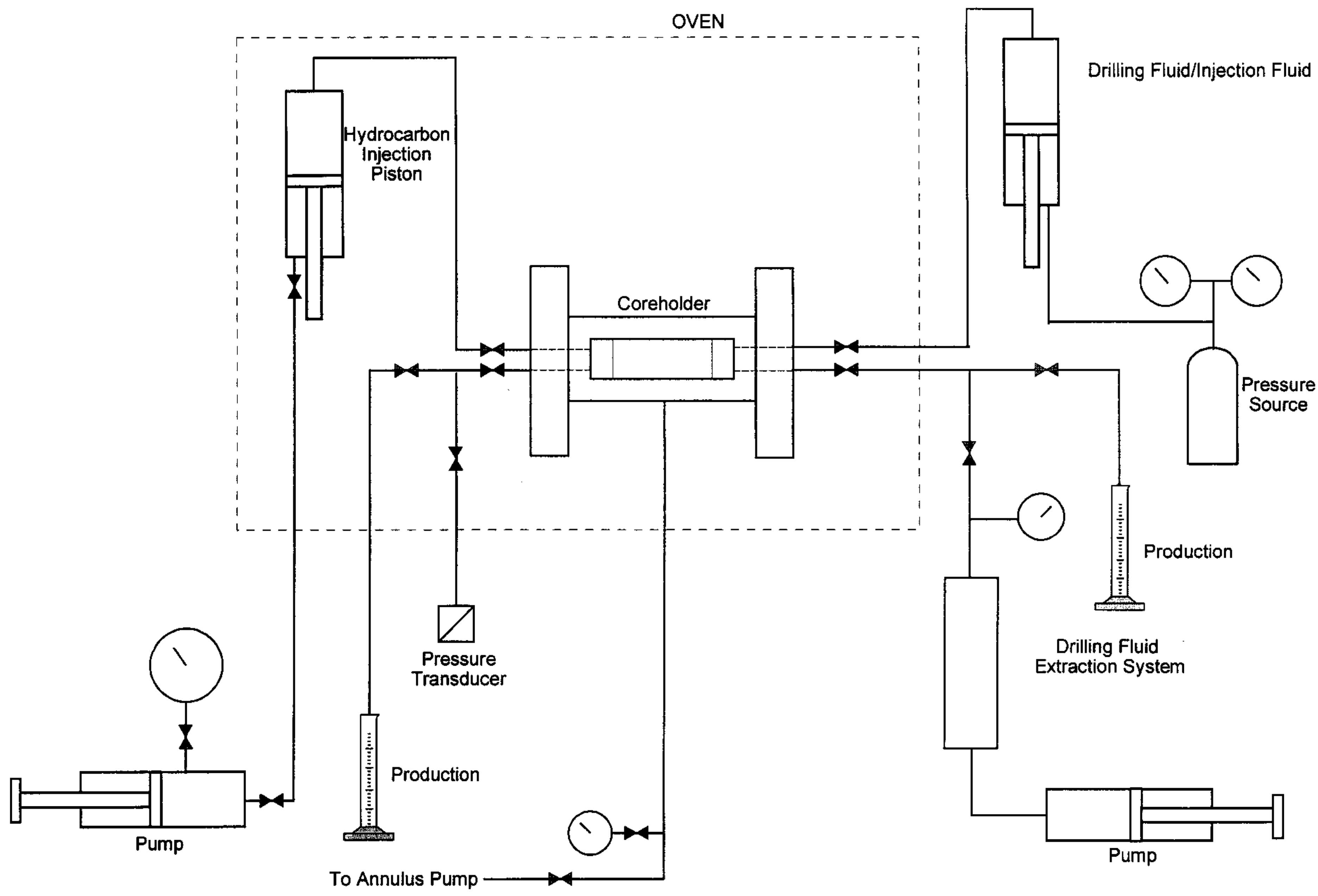

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FIGURE 2
ANDERSON - SOUTH PIERSON
FORMATION DAMAGE STUDY
CORE #14- MUD LEAKOFF WITH DISTILLATE 822 & OPTIWET
MUD FILTRATE INVASION DEPTH VS EXPOSURE TIME

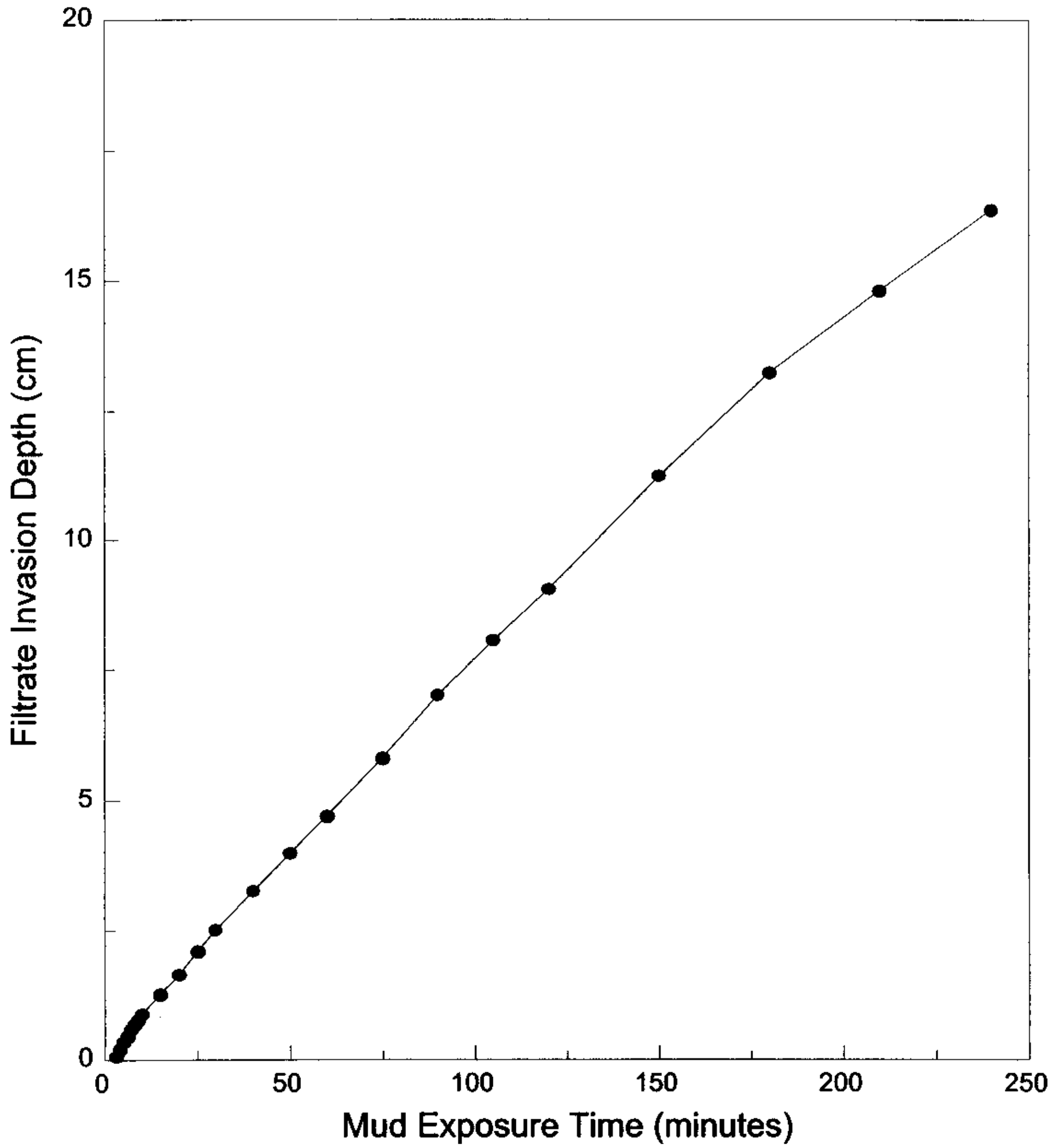

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FIGURE 3
ANDERSON - SOUTH PIERSON
FORMATION DAMAGE STUDY
CORE #14- MUD LEAKOFF WITH DISTILLATE 822 & OPTIWET
INJECTION WATER PERMEABILITY PROFILE

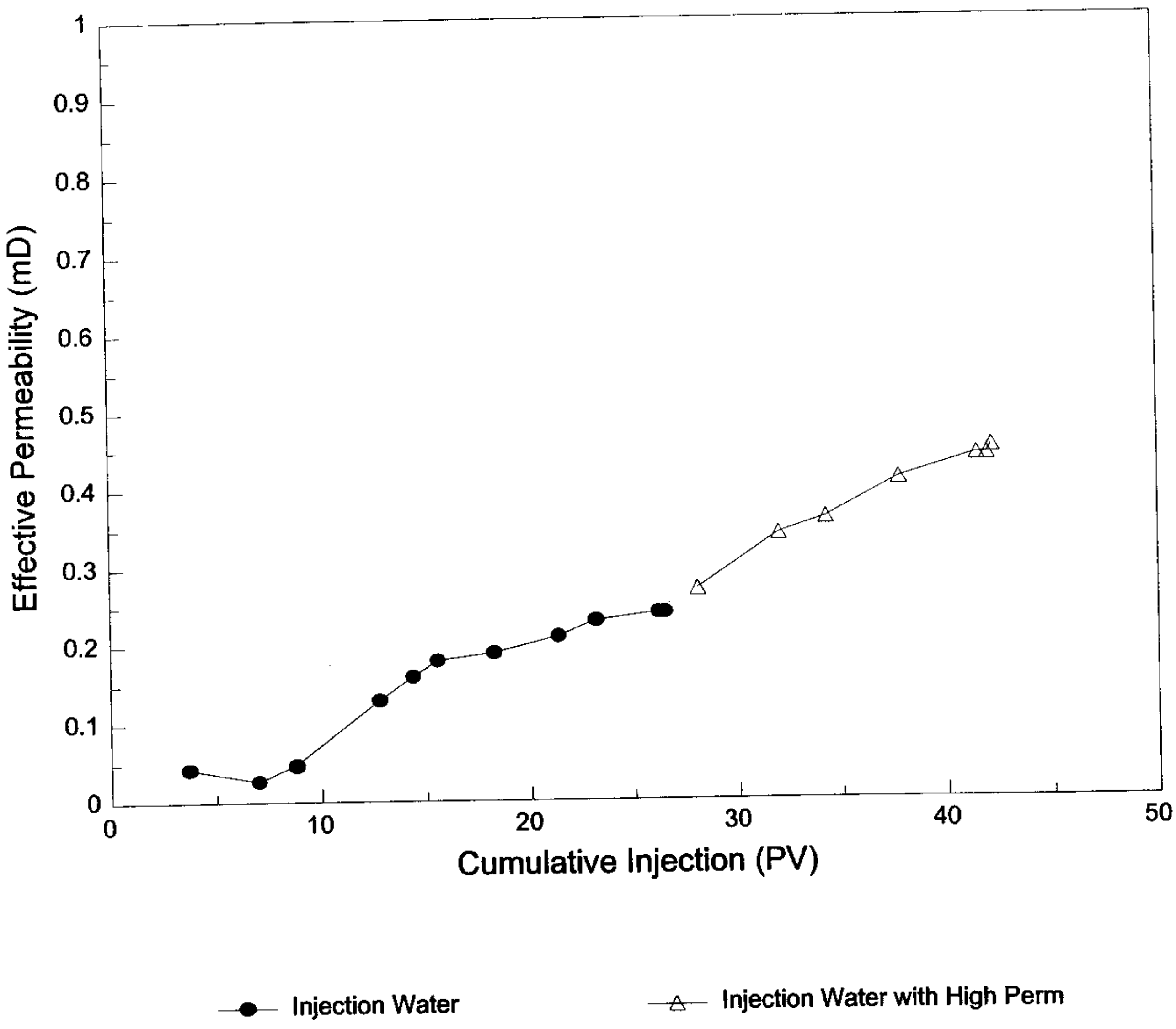

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FIGURE 4
ANDERSON - SOUTH PIERSON
FORMATION DAMAGE STUDY
CORE #24- MUD LEAKOFF WITH DISTILLATE 822
MUD FILTRATE INVASION DEPTH VS EXPOSURE TIME

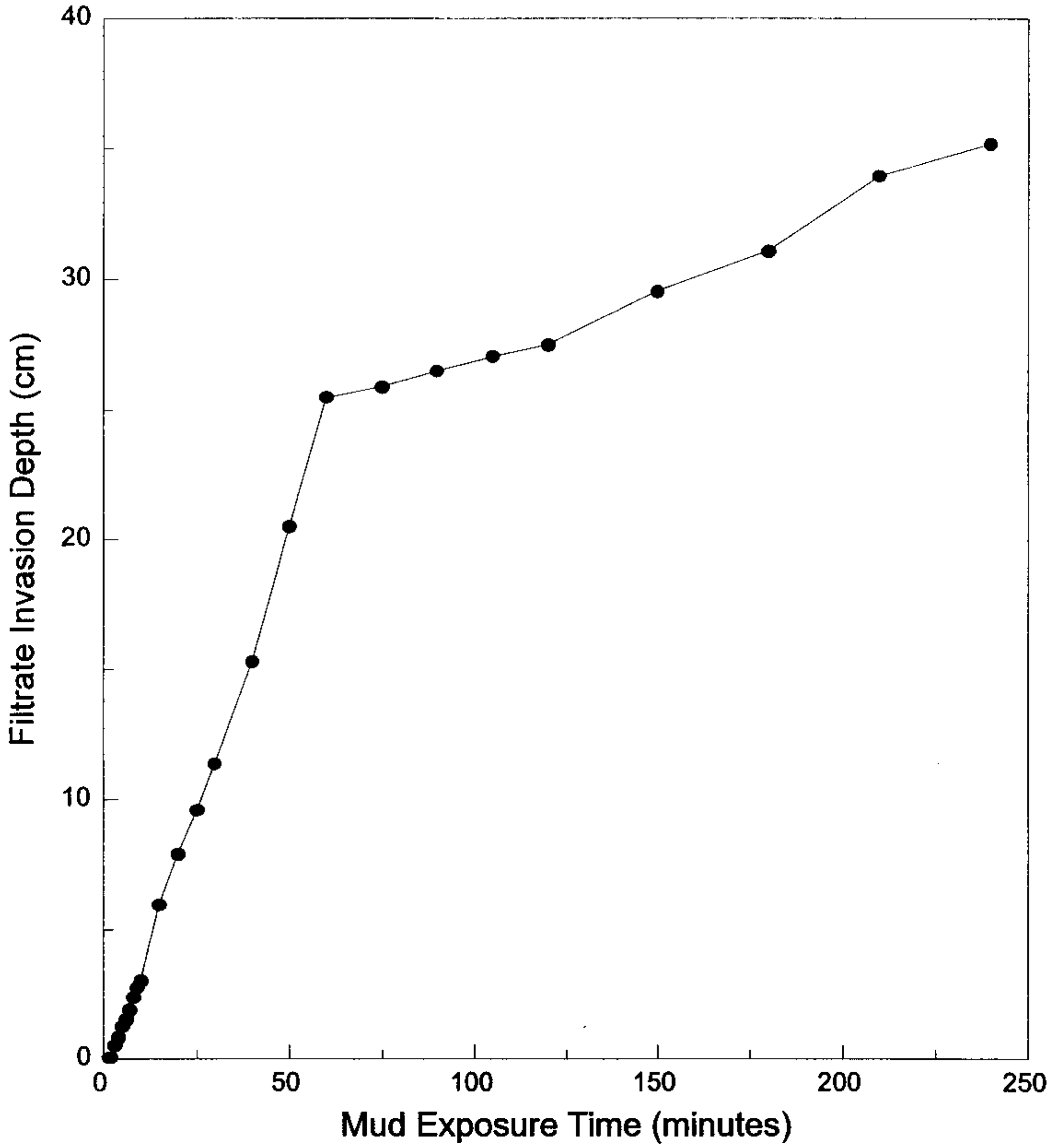

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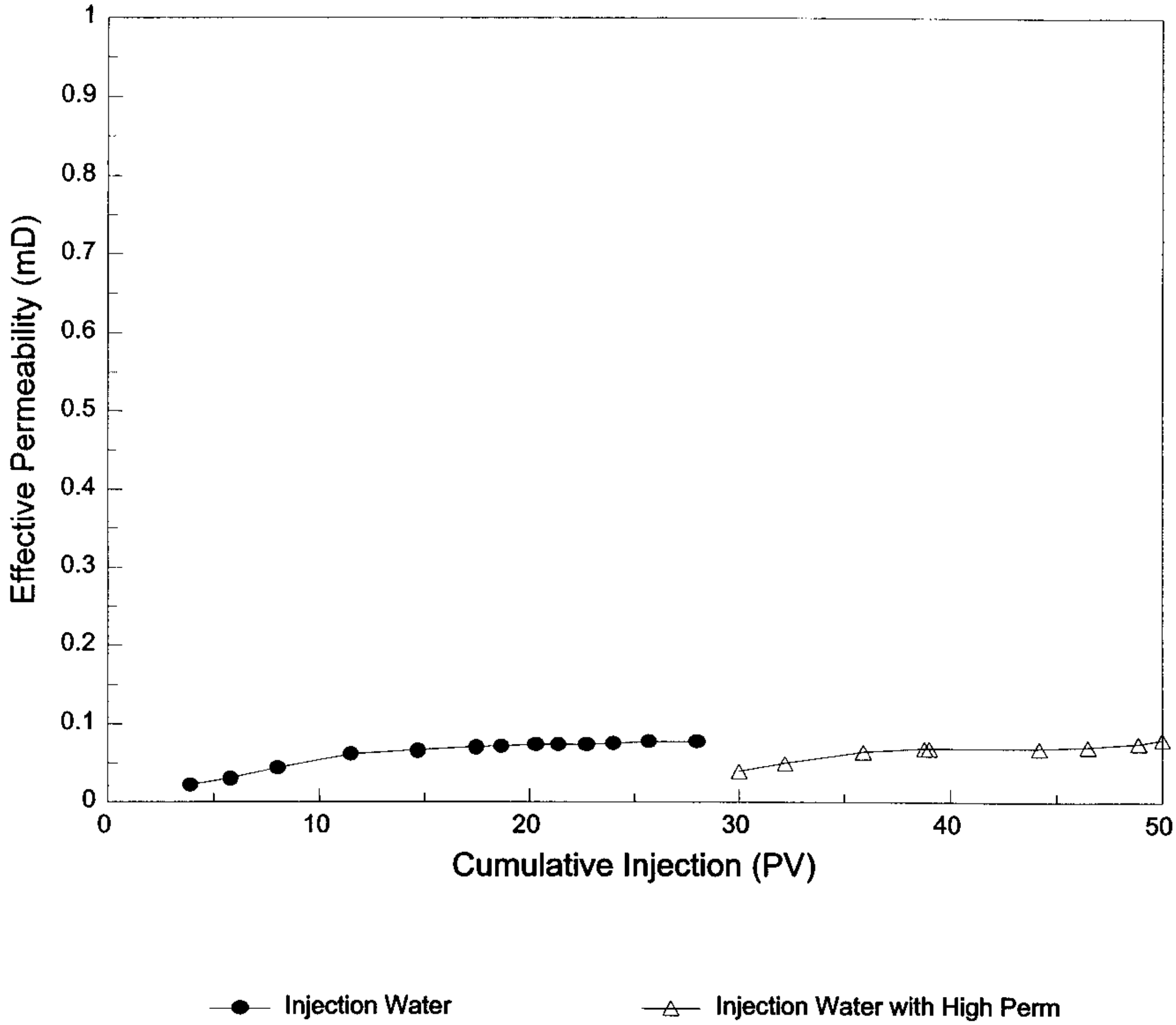
FIGURE 5
ANDERSON - SOUTH PIERSON
FORMATION DAMAGE STUDY
CORE #24- MUD LEAKOFF WITH DISTILLATE 822
INJECTION WATER PERMEABILITY PROFILE



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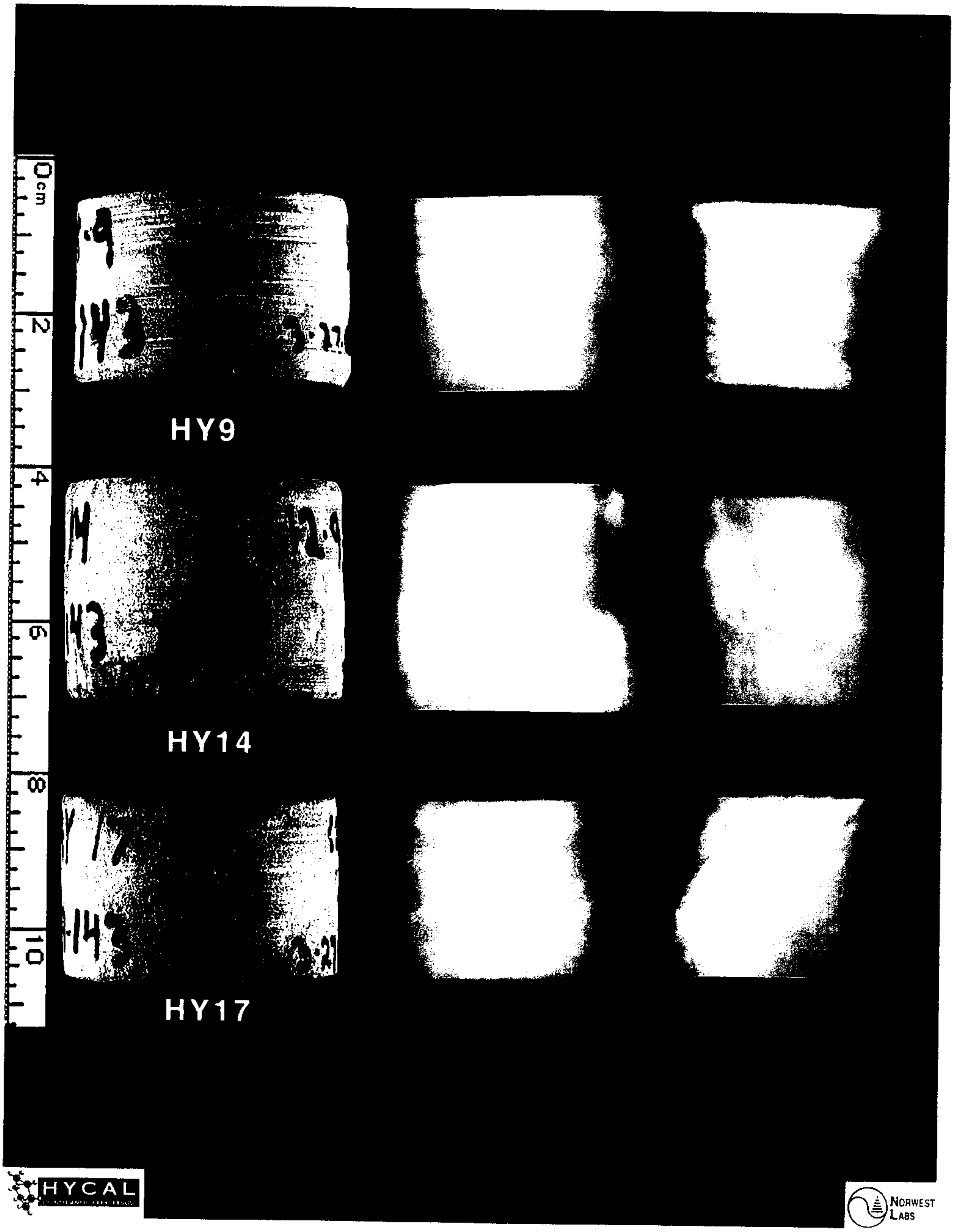
APPENDICES

APPENDIX A

CORE SAMPLE SELECTION
X-RAY IMAGES AND COLOR PHOTOGRAPHY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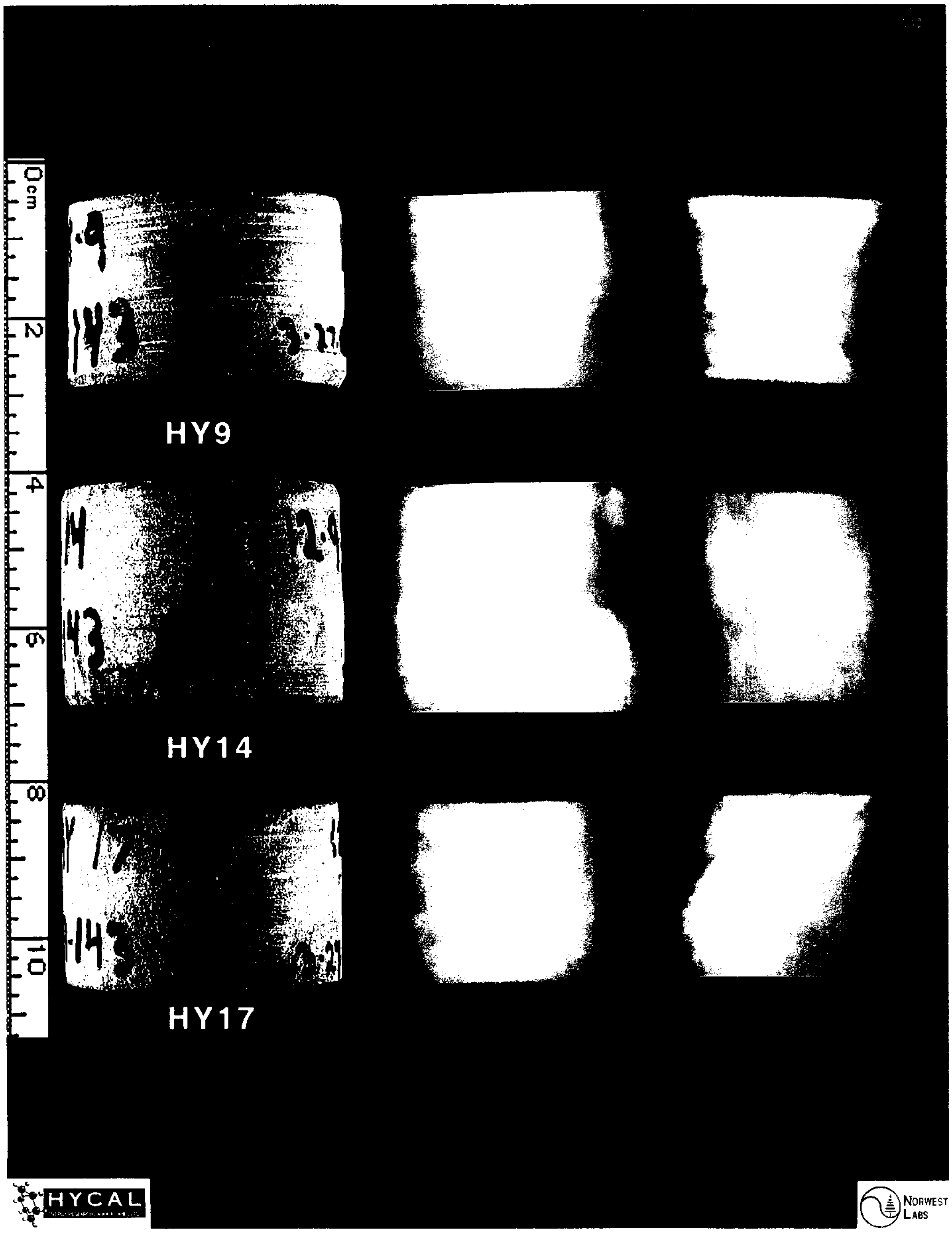

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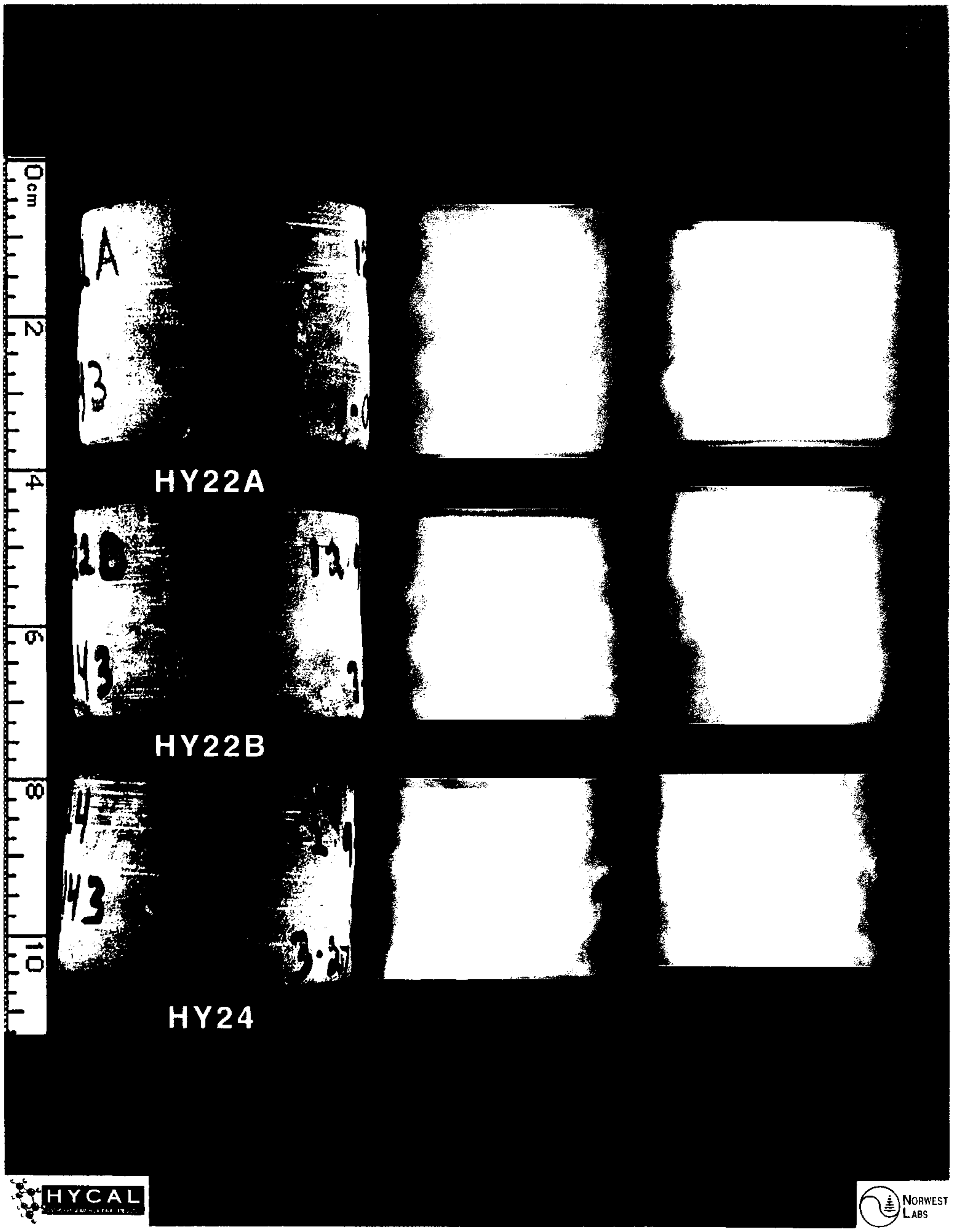
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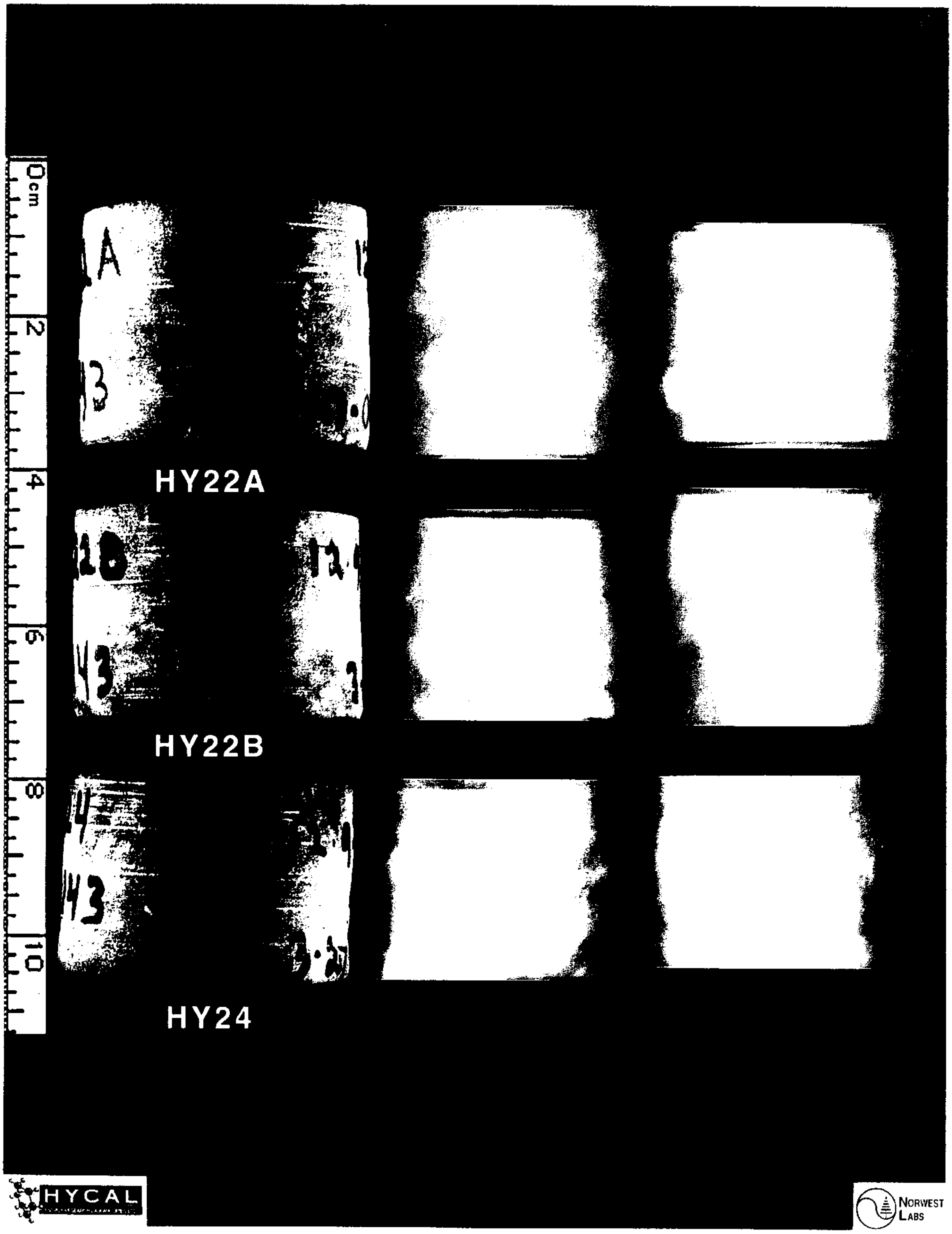
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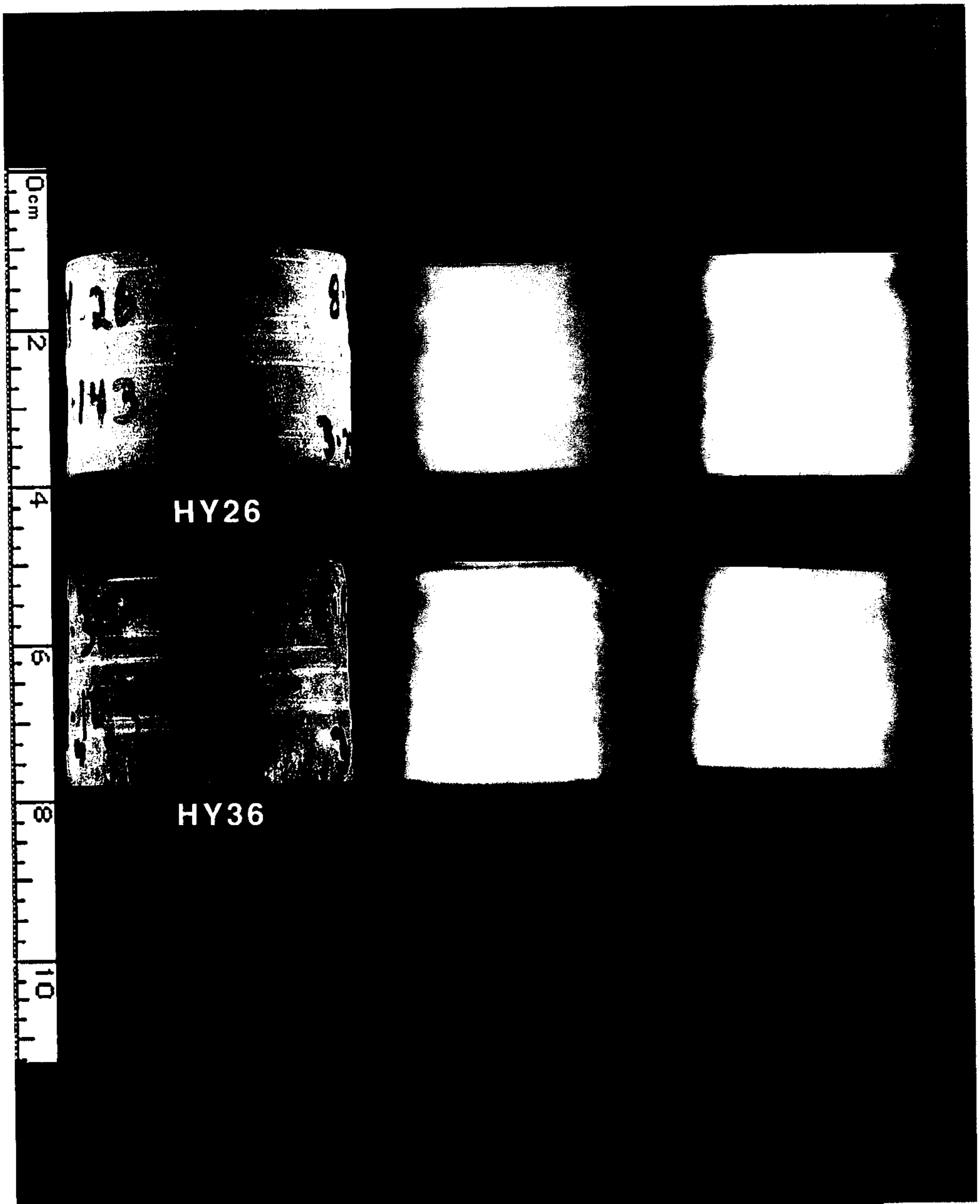
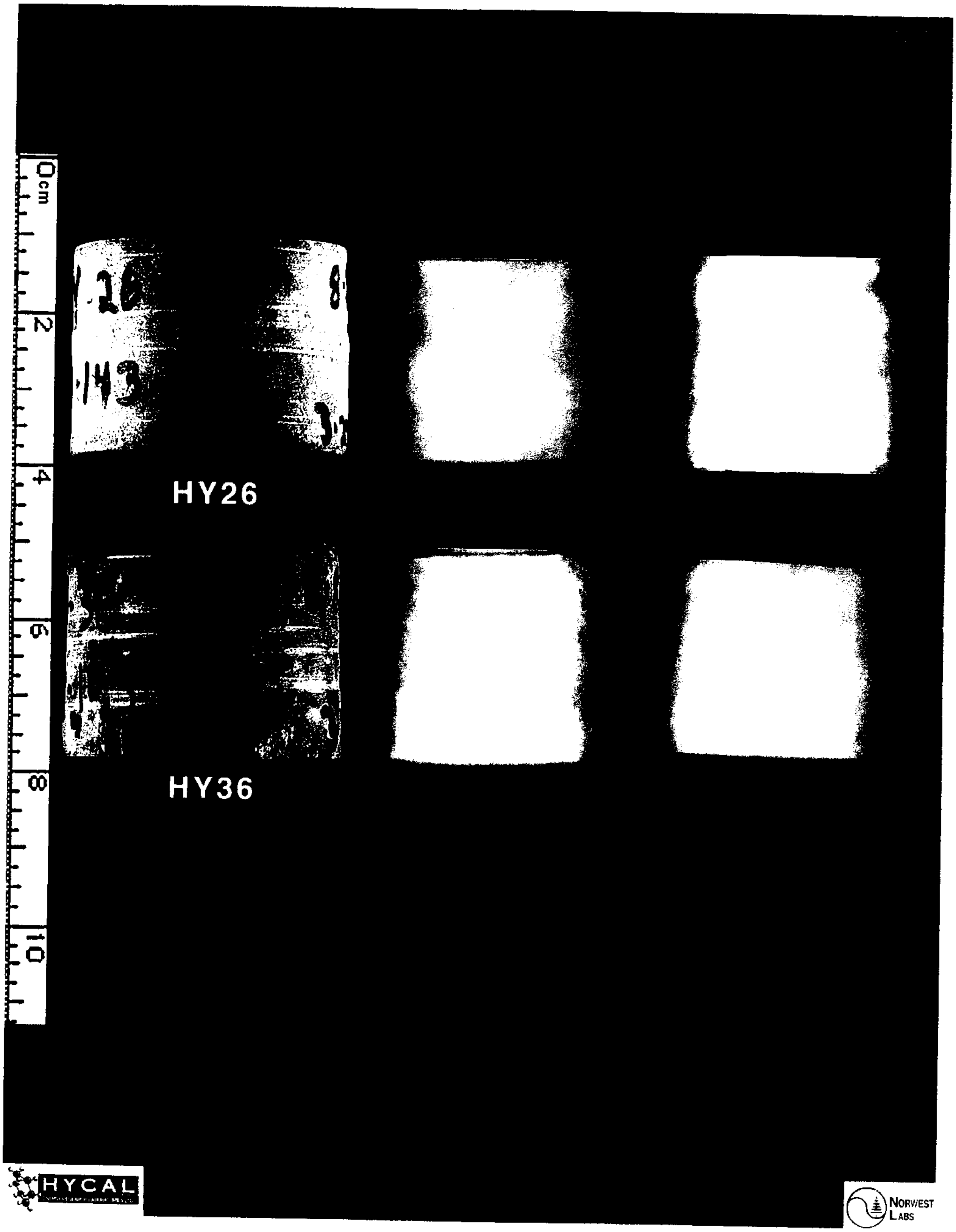
HYCAL
NORWEST
LABS



HYCAL

NORWEST LABS


HY26
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HYCAL
NORWEST LABS

APPENDIX B

DETAILED WATER ANALYSIS
OF PRODUCED "SOUR" WATER

NORWEST LABS

Energy Resource Group

4605 - 12 Street NE, Calgary, Alberta T2E 4R3
Phone (403) 291-3024

WATER ANALYSIS

C00-09800-01
Laboratory Report Number

Page 1 of 2

Hycal Energy Research Laboratories Ltd.
Operator

Container Identity

Location

#20946 Project 99143 Anderson S Pierson
Well Name

KB Elev, m | GR Elev, m

Field/Area | Pool / Zone | Sampler | Company

Test Type | No

Multiple Recovery

Test Recovery:

Test Interval, m

Perforations, m

Sample Point | Amount & Type of Cushion | Mud Resistivity @ 25°C

Type of Production: Pumping ___ Flowing ___ Gas Lift ___ Swab ___

Production Rates: Water ___ m³/d Oil ___ m³/d Gas ___ 10³ m³/d

Gauge Pressure, kPa

Temperature, °C

Separator | Treater | Reservoir | Source | Sampled | Received

- -
Date Sampled (Y-M-D)

2000-03-31
Date Received (Y-M-D)

2000-04-06
Date Reported (Y-M-D)

A. Worku
Analyst

Other Information

Ion	mg/L	Mass Fraction	meq/L
Na	64 900	0.3585	2 823.15
K	940	0.0052	24.06
Ca	1 201	0.0066	59.94
Mg	728	0.0040	59.87
Ba	0.0113	0.0000	0.00
Sr	33.2	0.0002	0.76
Fe	0.032	0.0000	0.00
B	42.2	0.0002	11.70
Mn	0.0380	0.0000	0.00

Ion	mg/L	Mass Fraction	meq/L
Cl	110 000	0.6077	3 102.00
Br	148	0.0008	1.85
I	<5		
HCO3	122	0.0007	2.00
SO4	2 913	0.0161	60.60
CO3	0	0.0000	0.00
OH	0	0.0000	0.00
H2S			

Total Dissolved Solids, mg/L

Evaporated @ 110°C	Evaporated @ 180°C
188 300	

At Ignition	Calculated
179 200	181 029

Organic Matter:

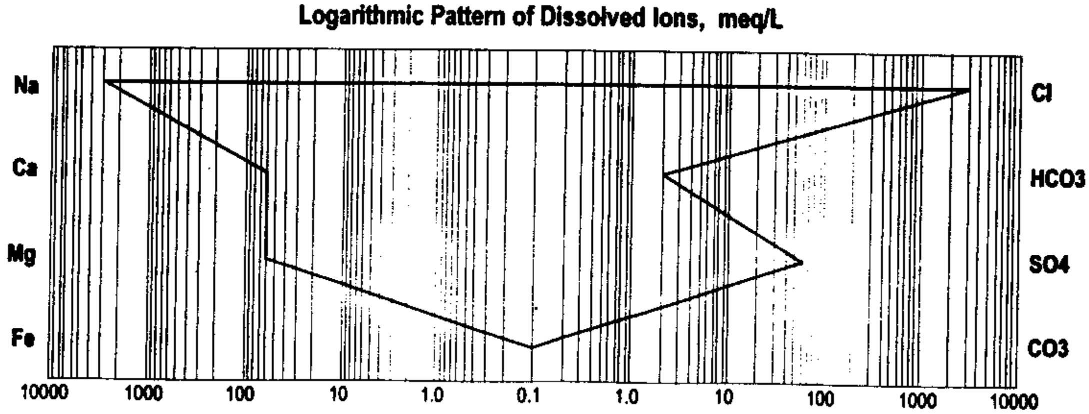
Relative Density	Refractive Index
1.123	1.3628 @ 25°C

Observed pH	Resistivity ohm.m
6.6 @ 21 °C	0.072 @ 25°C

Remarks

Colourless filtrate recovered from a sample containing trace sediment.

Logarithmic Pattern of Dissolved Ions, meq/L



Supervisor S. SARGIOUS

Approved R. PAUL

NORWEST LABS

4605 – 12th Street N.E. Calgary, Alberta T2E 4R3

HYCAL ENERGY RESEARCH LABORATORIES LTD.

Well Name:	#20946 Project 99143 Anderson S Pierson	Report No: C00-09800
Date Received:	2000-03-31	Page 2 of 2
Date Reported:	2000-04-06	

Calcium Carbonate Scaling Tendency Calculations

Stiff and Davis Stability Index ($pH-pH_s$): -0.75 @ 21°C

Remarks:

The Stiff and Davis Stability Index is an extension of the Langlier Index and is used as an indicator of the calcium carbonate scaling tendencies of oilfield brine.

A positive index indicates scaling tendencies.

A negative index indicates corrosive tendencies.

An index of zero indicates the water is in chemical equilibrium and will neither deposit nor dissolve calcium carbonate.

It should be noted that water is a precariously balanced system of ions and changes can occur from time of sampling to time of analysis.

For example, the loss of dissolved carbon dioxide will result in higher pH levels.

Calcium carbonate scaling tendencies increase as pH levels increase.

Higher temperatures can also increase calcium carbonate precipitation.

Skillman, McDonald and Stiff Calcium Sulphate Solubility

Calculated Solubility:	109.6 meq/L
Actual Concentration:	60.1meq/L

Indicates calcium sulphate scale formation is unlikely.

Reference:

Skillman, H. L., MacDonald, J. P. Jr., and Stiff, H. A. Jr., "A Simple, Accurate, Fast Method for Calculating Calcium Sulphate Solubility in Oilfield Brine". Presented at Spring Meeting of the Southwestern Division of Production of the API, Lubbock, Texas, March 12-24, 1969.

Supervisor: S. Sargious

Approved: R. Paul

Please direct any inquiries regarding this report to the supervisor.