Tundra oil and gas ltd.

September 25, 1992

Department of Energy and Mines
Petroleum Branch
555 - 330 Graham Avenue
Winnipeg, MB
R3C 4E3

Attention: Mr. John Fox

Dear Sir:

Re: 1992 PRESSURE SURVEY
- Daly Bakken 'D' Pool

Please find enclosed the results of the above survey (see Attachment 1). As evidenced from a 300 kPa pressure increase from October 1991 to May 1992 in well 05-13-10-29 (the most productive well in the pool), the Daly Bakken 'D' reservoir pressure has been maintained. Based on the recent field rate of 31 ST.m3/D (August 1992) which stands at slightly higher than the averaged 1989 rate of 29 ST.m3/D, the Daly Bakken 'D' waterflood is performing satisfactorily.

Should you have any questions regarding this matter, please do not hesitate to contact us.

Sincerely,

TUNDRA OIL AND GAS LTD.

S. M. Chen

Shing-Ming Chen
Senior Reservoir Engineer

SMC/bp

Enclosures

cc Robert G. Puchniak

1313-One Lombard Place, Winnipeg, Manitoba, Canada R3B 0X3 Telephone: (204) 934-5850 Fax (204) 934-5820

ATTACHMENT 1: 1992 PRESSURE SURVEY RESULTS- DALY BAKKEN 'D' POOL

WELL	DATE	S.I.Period (day)	P @ the end of S.I.(kPa)	Estimated P (P*) kPa	Remarks
05-13-10-29	1992.05	5	1398	1600	Approximately 300 kPa higher than 1991.10pressure (prior to well 08-14 water injection)
12-13-10-29	1992.06	17	4488	5200	
01-14-10-29	1992.08	27	1842	3000	(1)
10-14-10-29	1992.09	12	1131	2200	(1)

Remarks:-

(1) Wells 01-14, 10-14 and 07-14 are producers which have little response to waterflood in this pool.

A long-term pressure build-up test was recommended for 01-14 to identify the possible barrier between 01-14 and 08-14.

July 7, 1992

File: Field / Pool Files

Daly Bakken D Pool
Pressure Survey

Mr. Shing-Ming Chen
Senior Reservoir Engineer
Tundra Oil and Gas Ltd.
1313 - One Lombard Place
WINNIPEG, Manitoba
R3B OX3

Dear Mr. Chen:

Re: Daly Bakken D Pool
Annual Pressure Survey

Your plans to conduct pressure build-up tests on four wells in the pool in 1992, as outlined in your letter dated May 13, 1992, is hereby approved.

Please submit a copy of the pressure test results as soon as possible after completion of the surveys.

Yours truly,

ORIGINAL SIGNED BY
JOHN N. FOX
John N. Fox, P. Eng.
Chief Petroleum Engineer

Tundra oil and gas ltd.

May 13, 1992

Department of Energy and Mines
Petroleum Branch
555 - 330 Graham Avenue
Winnipeg, Manitoba
R3C 4A5

ATTN: Mr. John Fox

Dear Sir:

RE: PRESSURE SURVEY
North Ebor Units #1 and #2, Daly Bakken 'D' Pool

As required by the terms of the Oil and Natural Gas Conservation Board Order No. PM67, enclosed please find a list of wells Tundra intends to survey for your approval. Four producers will be shut-in and fluid levels will be monitored until the stable bottomhole pressures can be determined.

Based on recent production performances, both North Ebor Units #1 and #2 appear to have responded favorably to water injections in wells 08-14-10-29 and 16-14-10-29. The above pressure survey results, in conjunction with other field data, will be used for waterflood efficiency evaluations in our in-house reservoir engineering analysis scheduled for the fourth quarter, 1992.

Should you have any questions, please do not hesitate to contact us.

Sincerely,

S. M. Chen

Shing-Ming Chen
Senior Reservoir Engineer

SMC/src
Enclosure

cc: Robert G. Puchniak
Tim Howell

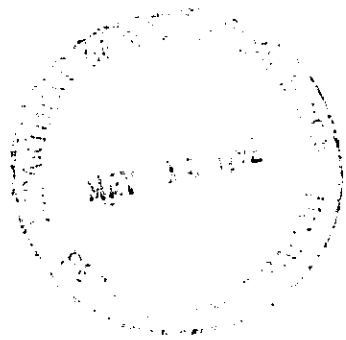
Attachment 1: Pressure Survey - North EBOR Units #1 and #2, Daly Bakken 'D' Pool

Well	Type of survey	Estimated S.I. period (days)	Remarks
05-13-10-29	Acoustic Survey	5	P. stabilized @ 1,112 kPa after a 4-day shut-in in 1991.10 (prior to 8-14 water inj.)
12-13-10-29	Acoustic Survey	10-14	P. survey will be conducted prior to well stimulation.
01-14-10-29	Acoustic Survey	10-14	(1)
10-14-10-29	Acoustic Survey	10-14	(1)

Remark:-

(1) Wells 01-14-10-29 and 10-14-10-29 are perhaps the only two wells which have little response or not responded as expected to waterflood in this pool.

Tundra oil and gas ltd.



May 13, 1992

Department of Energy and Mines
Petroleum Branch
555 - 330 Graham Avenue
Winnipeg, Manitoba
R3C 4A5

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Should you have any questions, please do not hesitate to contact us.

Sincerely,

S. M. Chen

Shing-Ming Chen
Senior Reservoir Engineer

SMC/src
Enclosure

cc: Robert G. Puchniak
Tim Howell

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12-13-10-29	Acoustic Survey	10-14	P. survey will be conducted prior to well stimulation.
01-14-10-29	Acoustic Survey	10-14	(1)
10-14-10-29	Acoustic Survey	10-14	(1)

Remark:-

(1) Wells 01-14-10-29 and 10-14-10-29 are perhaps the only two wells which have little response or not responded as expected to waterflood in this pool.

File
Pressure
surveys
Daly Belda
D Pool

MEMORANDUM

DATE

TO: Dan/Bob

FROM: Tim

RE: Daly 5-13-10-29 Reservior Pressure

A build-up test was recently completed at above well for a 1 week period. Fluid level and casing pressure remained static for the final 4 days of build-up. Results were as follows:

Fluid level - 76 joints (760 m K.B.)

Casing Pressure - 40 PSIG (276 kPa)

Fluid above perfs: 102 m

P* Static = 276 kPa + (93.8 m x 8.0 kPa/m) + (8.2 x 10.5 kPa/m) = 1112 kPa.

(**NOTE:** Hydrostatic pressure due to gas column is negligible.)

Tundra oil and gas ltd.

FILE:
N. EBOR UNIT No. 1
PRESSURE
SURVEYS

May 9, 1991

Department of Energy and Mines
Petroleum Branch
555 - 330 Graham Avenue
Winnipeg, MB
R3C 4A5

Attention: Mr. John Fox, Chief Petroleum Engineer

Dear Mr. Fox:

Re: Average Reservoir Pressure Determination
North Ebor Unit No. 1

As required by Rule 3(2) of the Oil and Natural Gas Conservation Board Order No. PM62, approving pressure maintenance by water injection in the subject pool, Tundra Oil and Gas Ltd. submits the attached reservoir pressure measurements as an estimate of reservoir pressure in the Unit area in March of 1991.

While the Order requires that between six and twelve months after injection commencement, a reservoir pressure measurement be taken on a Unit well, Tundra drilled a well in an adjacent spacing unit (10-14-10-29 W1M) in March, 1991, and performed a drillstem test on the correlative Bakken zone (see attached map). The results of this test are submitted as a representative measurement of average reservoir pressure in the pool at that time. Based on a Horner extrapolation of the second shut-in pressure, the average reservoir pressure is in the order of 5710 kPa (abs), or 828 psia. This compares favourably with the estimate of 4480-4960 kPa (abs) or 650-719 psia, as measured in the 2-23-10-29 W1M well last June, prior to the commencement of water injection in the 16-14 well, and indicates the zone is being repressured, but will require continued injection in order to return the zone to initial pressure in the 8600 kPa (abs) or 1250 psia range.

At the time the 10-14 well was drilled, the 4-13 and 13-12 locations were also drilled in an area of the reservoir outside the waterflood. The pressure data obtained from these tests was also of good quality, and indicates a pressure gradient across the pool. The 4-13 well, which offsets both the high volume 5-13 well, and another good producer in 1-14, indicated an average pressure in this area of only

1313-One Lombard Place, Winnipeg, Manitoba, Canada R3B 0X3 Telephone: (204) 934-5850 Fax (204) 934-5820

Tundra
oil and gas ltd.

4350 kPa (abs), or 670 psia, some 160 psi less than the 10-14 well. The drillstem test from the 13-12 location, which is one LSD further removed from production, extrapolated to a reservoir pressure of 6230 kPa (abs) or 904 psia. Clearly, this indicates that:

a) There is pressure communication in the Bakken zone throughout the pool, and
b) There is a need for pressure maintenance in the south half of the pool.

For these two wells, the Horner plots and related analyses have been included for comparitive purposes.

In addition to the foregoing, these data appear to confirm the validity of utilizing drillstem tests, when available, as the preferred method of measurement of average reservoir pressure.

Future surveys of existing Unit producing wells are not likely to yield as good quality data as these three drillstem tests. Our experience has shown that, after several months or years of production from a low rate Bakken well, it will likely be necessary to shut it in for at least 30-60 days to obtain data which is amenable to extrapolation. It is much easier to obtain valid pressure data on high volume producing wells in waterfloods such as the Virden Scallion and Daly pools. Therefore, in the case of Bakken waterfloods such as this, we believe the Board should consider relaxation of the requirement of Rule 3(2) to perform annual pressure surveys, and require only that new wells drilled into the pool be drillstem tested. It would appear that the zone is being repressured, and that the success of the waterflood is best measured by continued production and injection monitoring.

Please advise as to your thoughts in this latter regard.

Yours truly,

Derek C. Longfield, P. Eng.
Consultant

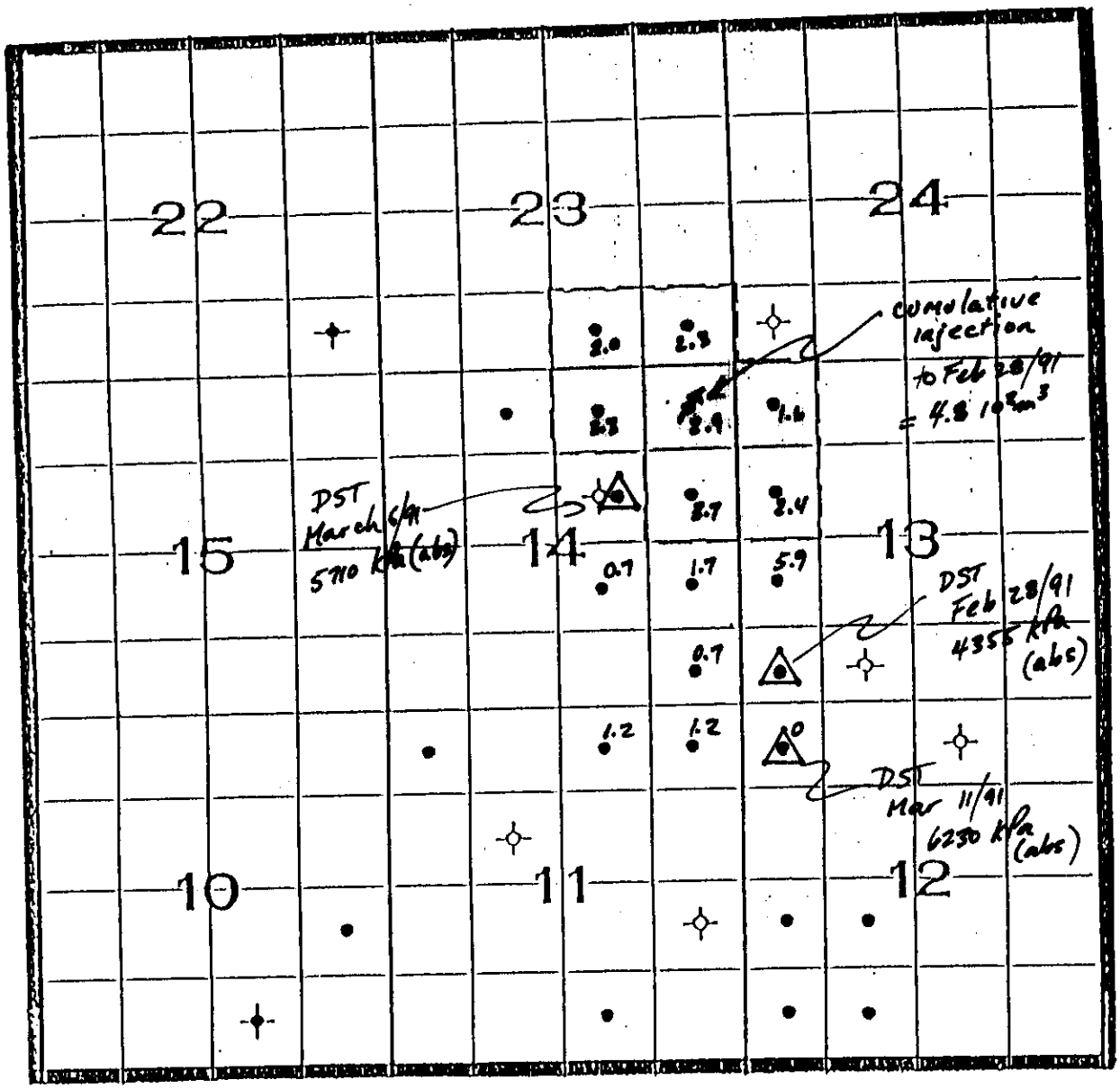
DCL/ck

Enclosures

TUNDRA OIL AND GAS

Rge 29w1

Twp 10



N. EBOR PILOT WATERFLOOD

Bakken 'D' Pool
Cumulative Oil
Production to Feb 28/91
($10^3 m^3$)

UNIT AREA

10-14-10-29 WlM

DRILLSTEM TEST DATA AND ANALYSIS

DOUBLE K OILFIELD TESTING LTD.

WELL DATA

Well Name	TUNDRA DALY
Well Location	10-14-10-29-W1M
Customer	TUNDRA OIL & GAS LTD.
Customer Rep	TIM HOWELL
Tester	KENT FOWLER
Test Type	CONVENTIONAL STRADDLE
Date	MARCH 6,1991
Test No.	ONE
Formation	BAKKEN
Interval	855-862
Total Depth	877
KB Tie	527.13 GR. 522.93

TIME PRESSURE DATA

	Preflow 10 mins.	ISI 56 mins.	Flow 58 mins.	FSI 117 mins.	
		In Out X	In X Out	In Out X	In Out
		Rec. No. 22149	Rec. No. 12592	Rec. No. 6165	Rec. No.
		Range 24821	Range 28958	Range 28269	Range
		Depth 858.25	Depth 859.78	Depth 863.92	Depth
Initial Hydrostatic Pressure		9850		9958	
Initial Shut-In Pressure		5573	CLOCK STOPPED		
Initial Flow Pressure		839			
Final Flow Pressure		1030			
Final Shut-In Pressure		5405			
Final Hydrostatic Pressure		9770		9865	
	PREFLOW	416			

FLUID RECOVERY

Total Recovery	78	Meters	
Recovered	41	Meters of	OIL STAINED MUD.
Recovered	37	Meters of	FROTHY MUD CUT OIL.
Recovered		Meters of	
Recovered		Meters of	

GAS RECOVERY

Measured with Flow Time Minutes	Reading KPA	Temperature °C	Orifice Size MM	Flow Rate M3/D

TEST DATA

Meters of Net Pay	0.8	Percentage Porosity	14.0
Drill Pipe Size	114.3 XH	Drill Pipe Weight	24.7
Drill Collar ID	63.5	Meters of Collars Above Tool	146.05
Main Hole Size	200	Packer Size	177
Cushion Amount	NIL	Cushion Type	NIL
Weight to Set Packer	15	Weight to Pull Loose	2
Bottom Hole Temperature		Bottom Choke Size	25.4
Mud Type GEL CHEM	Vis 90	F/C 1.6	W.L. 12.0 Wt. 1175

REMARKS PREFLOW: WEAK AIR BLOW DECREASING TO FAINT AT 2 MINUTES AND REMAINING STEADY. VALVE OPEN: FAINT AIR BLOW THROUGHOUT. TOOL OPEN AT 05:24.

TUNDRA DALY Well Name
10-14-10-29-W1M Well Location
Test No.
Date

DOUBLE K OILFIELD TESTING LTD.

TOOL SEQUENCE REPORT

WELL NAME: TUNDRA DALY LOCATION: 10-14-10-29-W1M

D.S.T. No. ONE

TOOL	LENGTH	O.D.
P.O.S.	.305	153
X.O.S.	.263	153
S.I.T.	1.664	1127
HYDRAULIC TOOL	1.710	127
JARS	2.017	119
SAFETY JOINT	.670	127
PACKER	1.335	177
	8.108	
T.C.	.970	125
PERF	2.438	121
RECORDER	1.530	122
RECORDER	1.530	122
B.O.S.	.305	122
STUB	.300	127
	7.073	
PACKER	2.005	177
RECORDER	1.530	122
BLANK	.610	121
X.O.S.	.263	153
DRILL PIPE	9.670	114
X.O.S.	.263	153
BULLNOSE	.742	122
	15.083	

PAGE ONE

WELL NAME: TUNDRA DALY
LOCATION: 10-14-10-29-W1M
FORMATION: BAKKEN

REC. NO. 22149
DST. NO. ONE
DEPTH 858.25

TIME - PRESSURE INCREMENTS

REMARKS	TIME MIN.	PRESSURE kPa	(T + Delta t) / Delta t
RUNNING IN HOLE	0	0	
INITIAL HYDROSTATIC PRESSURE	62	9850	
	75	9850	
FIRST FLOW PERIOD	0	356	
FINAL FLOWING PRESSURE	10	416	
BUILD-UP AFTER FIRST FLOW	0	416	
	5	1995	3.00
	10	5042	2.00
	15	5267	1.67
	20	5373	1.50
	25	5439	1.40
	30	5478	1.33
	35	5511	1.29
	40	5531	1.25
	45	5544	1.22
	50	5558	1.20
INITIAL SHUT-IN PRESSURE	56	5573	1.18
SECOND FLOW PERIOD	0	5573	
	1	839	
	10	813	
	20	839	
	30	892	
	40	958	
	50	998	
FINAL FLOWING PRESSURE	56	1030	

WELL NAME: TUNDRA DALY
LOCATION: 10-14-10-29-W1M
FORMATION: BAKKEN

REC. NO. 22149
DST. NO. ONE
DEPTH 858.25

TIME - PRESSURE INCREMENTS

REMARKS	TIME MIN.	PRESSURE kPa	(T + Delta t) / Delta t
BUILD-UP AFTER 2nd FLOW	0	1030	
	5	1606	14.20
	10	2973	7.60
	15	4295	5.40
	20	4718	4.30
	25	4890	3.64
	30	4989	3.20
	35	5062	2.89
	40	5121	2.65
	45	5161	2.47
	50	5194	2.32
	55	5227	2.20
	60	5254	2.10
	65	5273	2.02
	70	5293	1.94
	75	5313	1.88
	80	5326	1.83
	85	5339	1.78
	90	5352	1.73
	95	5366	1.69
	100	5379	1.66
	105	5386	1.63
	110	5399	1.60
SECOND SHUT-IN PERIOD	117	5405	1.56
PULLING OUT OF HOLE	0	5405	
FINAL HYDROSTATIC PRESSURE	1	9770	
	12	9770	
OUT OF HOLE	76	0	

ELL NAME: TUNDRA DALY
ELL LOCATION: 10-14-10-29-W1M
ORMATION: BAKKEN
RECOVERY TYPE USED IN CALCULATIONS: OIL

REC NO. 22149
DST NO. ONE
DEPTH 858.25
INTERVAL 855-862

SUMMARY OF CALCULATIONS

1 FIRST SHUT-IN

EXTRAPOLATED FORMATION PRESSURE	5685	KPA
SLOPE OF EXTRAPOLATED LINE	1575	KPA/CYCLE
ROOT MEAN SQUARE DEVIATION OF FITTED LINE		KPA
NUMBER OF POINTS IN SHUT-IN	11	
NUMBER OF POINTS USED FOR EXTRAPOLATION	5	

2 SECOND SHUT-IN

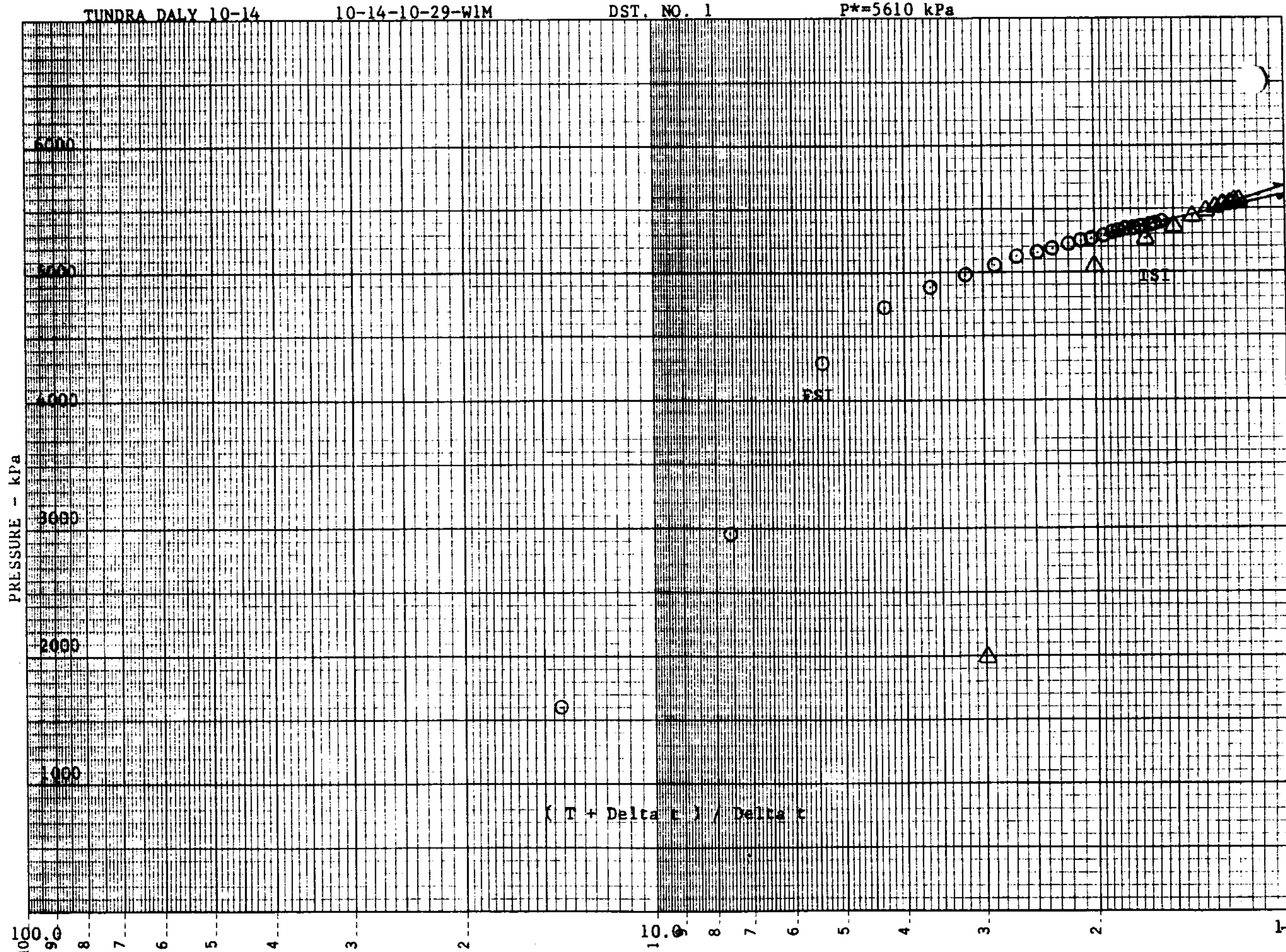
EXTRAPOLATED FORMATION PRESSURE	5610	KPA
SLOPE OF EXTRAPOLATED LINE	1098	KPA/CYCLE
ROOT MEAN SQUARE DEVIATION OF FITTED LINE		KPA
NUMBER OF POINTS IN SHUT-IN	23	
NUMBER OF POINTS USED FOR EXTRAPOLATION	9	
DIFFERENCE (2ND-1ST EXTRAPOLATION)	75	KPA

3 RESERVOIR AND FLUID PROPERTIES

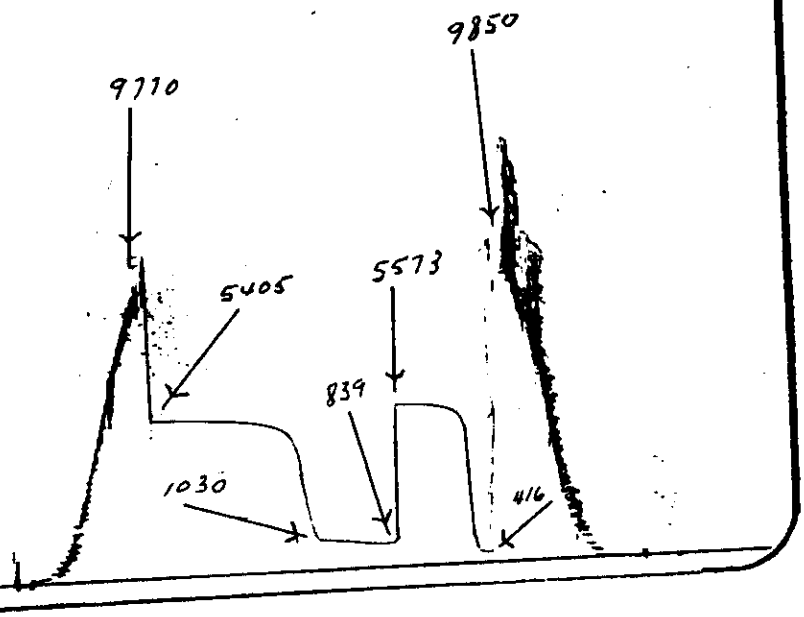
NET PAY	0.8	M
RESERVOIR POROSITY	14.0	PERCENT
PRODUCTION RATE	5.39	M3/D
FORMATION VOLUME FACTOR	1.064	RM3/STM3
FLUID VISCOSITY	4.5	MPA.S
TOTAL COMPRESSIBILITY X 10-6	98.05	/KPA
RESERVOIR TEMPERATURE	31	CEL
FINAL FLOWING PRESSURE	1030	KPA
TOTAL FLOW TIME	66	MIN

4 CALCULATION RESULTS

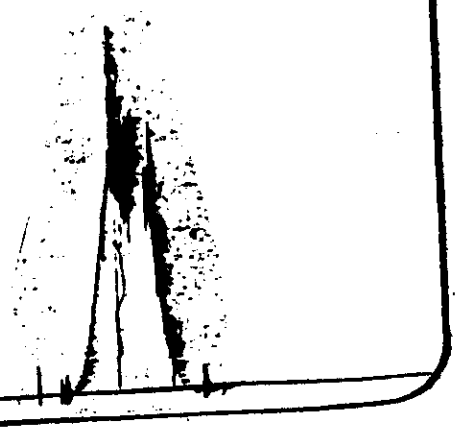
ESTIMATED DAMAGE RATIO	0.9	
PERMEABILITY THICKNESS	165.6	MD FT
PERMEABILITY	63.0	MD
SKIN FACTOR		
APPROXIMATE DRAINAGE RADIUS	27.5	M
PRODUCTIVITY INDEX	0.051	M3**3/KPA
PRODUCTION WITH DAMAGE REMOVED		M3/D



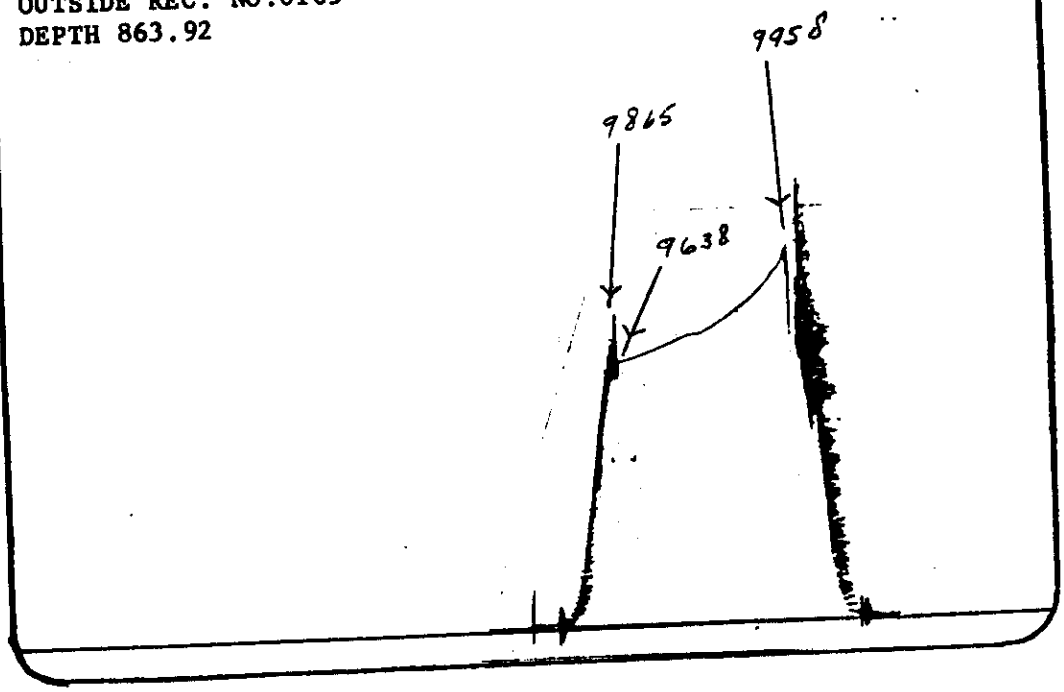
TUNDRA DALY 10-14
DST. NO. 1
OUTSIDE REC. NO. 22149
DEPTH 858.25



TUNDRA DALY 10-14
DST. NO. 1
INSIDE REC. NO.12592
DEPTH 859.78
CLOCK STOPPED



TUNDRA DALY 10-14
DST. NO. 1
OUTSIDE REC. NO.6165
DEPTH 863.92



4-13-10-29 WLM

DRILLSTEM TEST ANALYSIS

REC NO. 22149
DST NO. ONE
DEPTH 62.89

WELL NAME: TUNDRA DALY
WELL LOCATION: 4-13-10-29-W1M
FORMATION: BAKKEN
INTERVAL 858-865
RECOVERY TYPE USED IN CALCULATIONS: OIL

SUMMARY OF CALCULATIONS

1 FIRST SHUT-IN

EXTRAPOLATED FORMATION PRESSURE	4405	KPA
SLOPE OF EXTRAPOLATED LINE	1010	KPA/CYCLE
ROOT MEAN SQUARE DEVIATION OF FITTED LINE		KPA
NUMBER OF POINTS IN SHUT-IN	12	
NUMBER OF POINTS USED FOR EXTRAPOLATION	7	

2 SECOND SHUT-IN

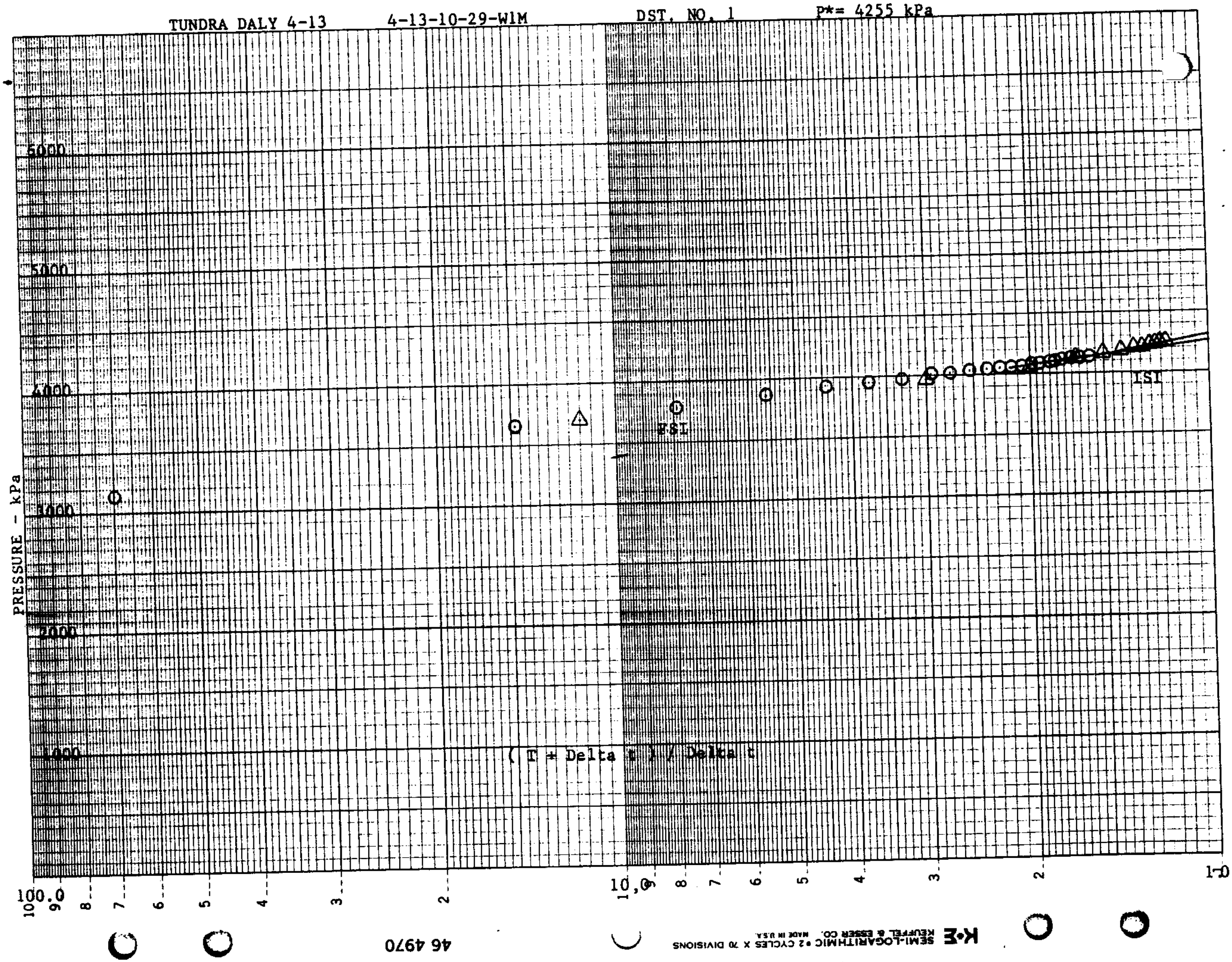
EXTRAPOLATED FORMATION PRESSURE	4255	KPA
SLOPE OF EXTRAPOLATED LINE	625	KPA/CYCLE
ROOT MEAN SQUARE DEVIATION OF FITTED LINE		KPA
NUMBER OF POINTS IN SHUT-IN	24	
NUMBER OF POINTS USED FOR EXTRAPOLATION	12	
DIFFERENCE (2ND-1ST EXTRAPOLATION)	150	KPA

3 RESERVOIR AND FLUID PROPERTIES

NET PAY	1.2	M
RESERVOIR POROSITY	27.0	PERCENT
PRODUCTION RATE	20.5	M3/D
FORMATION VOLUME FACTOR	1.063	RM3/STM3
FLUID VISCOSITY	5.0	MPA.S
TOTAL COMPRESSIBILITY X 10-6	91.15	/KPA
RESERVOIR TEMPERATURE	31	CEL
FINAL FLOWING PRESSURE	2418	KPA
TOTAL FLOW TIME	69	MIN

4 CALCULATION RESULTS

ESTIMATED DAMAGE RATIO	0.587	
PERMEABILITY THICKNESS	1230	MD FT
PERMEABILITY	312	MD
SKIN FACTOR	44.2	M
APPROXIMATE DRAINAGE RADIUS	0.484	M3**3/KF
PRODUCTIVITY INDEX		M3/D
PRODUCTION WITH DAMAGE REMOVED		



TUNDRA DALY 4-13
4-13-10-29-W1M
DST. NO. 1
P*= 4255 kPa
PRESSURE - kPa
6000
5000
4000
3000
2000
1000
ISI
FSI
(T + Delta t) / Delta t
100.0
10.0
1.0
K•E SEMI-LOGARITHMIC • 2 CYCLES X 70 DIVISIONS
KEUFFEL & ESSER CO. MADE IN U.S.A.
46 4970

13-12-10-29 WLM

DRILLSTEM TEST ANALYSIS

REC NO. 12592
DST NO. ONE
DEPTH 860.78

WELL NAME: TUNDRA DALY
WELL LOCATION: 13-12-10-29-W1M
FORMATION: BAKKON
RECOVERY TYPE USED IN CALCULATIONS: OIL INTERVAL 858-865

SUMMARY OF CALCULATIONS

1 FIRST SHUT-IN

EXTRAPOLATED FORMATION PRESSURE	6115	KPA
SLOPE OF EXTRAPOLATED LINE	690	KPA/CYCLE
ROOT MEAN SQUARE DEVIATION OF FITTED LINE		KPA
NUMBER OF POINTS IN SHUT-IN	12	
NUMBER OF POINTS USED FOR EXTRAPOLATION	7	

2 SECOND SHUT-IN

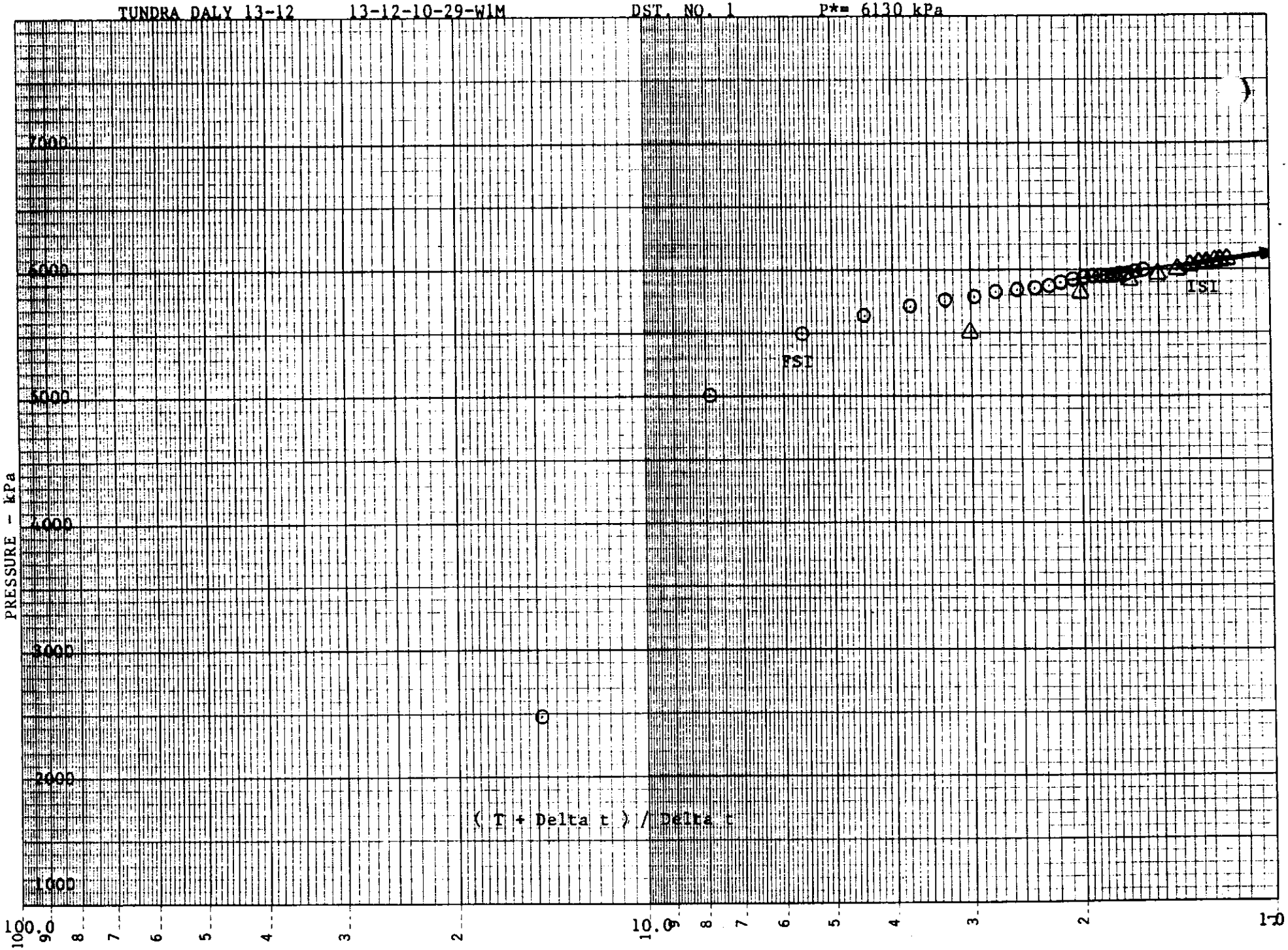
EXTRAPOLATED FORMATION PRESSURE	6190	KPA
SLOPE OF EXTRAPOLATED LINE	660	KPA/CYCLE
ROOT MEAN SQUARE DEVIATION OF FITTED LINE		KPA
NUMBER OF POINTS IN SHUT-IN	23	
NUMBER OF POINTS USED FOR EXTRAPOLATION	11	
DIFFERENCE (2ND-1ST EXTRAPOLATION)		KPA

3 RESERVOIR AND FLUID PROPERTIES

NET PAY	1.0	M
RESERVOIR POROSITY	16.0	PERCENT
PRODUCTION RATE	6.616	M3/D
FORMATION VOLUME FACTOR	1.063	RM3/STM3
FLUID VISCOSITY	5.0	MPA.S
TOTAL COMPRESSIBILITY X 10-6	96.67	/KPA
RESERVOIR TEMPERATURE	31	CEL
FINAL FLOWING PRESSURE	1125	KPA
TOTAL FLOW TIME	69	MIN

4 CALCULATION RESULTS

ESTIMATED DAMAGE RATIO	7.22	
PERMEABILITY THICKNESS	375.4	MD FT
PERMEABILITY	114.5	MD
SKIN FACTOR	33.8	M
APPROXIMATE DRAINAGE RADIUS	0.057	M**3/KP
PRODUCTIVITY INDEX	47.8	M3/D
PRODUCTION WITH DAMAGE REMOVED		



F.U
Pressure
Surveys
N. EBOR Unit
No. 1

ROUTE SLIP - BOARD CORRESPONDEN

APPLICATION NO. ——

DATE: MAY 16

TITLE: N. EBOR UNIT No. 1 - Pressure Survey

ROUTING: Draft (Reviewed)

John Fox ✓
Bob Dubreuil ✓

Final Draft (Reviewed and Signed)

John Fox ✓
Bob Dubreuil ✓

DO NOT SEND TO BOARD UNLESS BOX BELOW IS CHECKED.

☑ DATE SENT TO BOARD: May 21/91

BOARD ACTION REQUIRED:

	Date Returned to Petroleum
Board Order _____	_____
Board Letter Denying request to modify pressure survey requirements	May 22/91
Other (Specify) _____	_____

DATE SENT TO APPLICANT May 22/91 dl

OTHER ACTION (SPECIFY) _____

Manitoba Return to Petroleum for distribution.

Action / Route Slip

Date: May 21, 1991

To: Clare Moster, Deputy Chairman

From: John N. Fox
Chief Petroleum Engineer

Re: North Ebor Unit No. 1
Pressure Survey Requirements

Telephone:

ASSISTANT DEPUTY MINISTER ENERGY MAY 23 1991 DEPARTMENT OF ENERGY and MINES

- ☐ Take Action
- ☐ Per Your Request
- ☐ Circulate, Initial and Return
- ☐ For Approval and Signature
- ☐ Make Copies
- ☐ May We Discuss
- ☐ For Your Information
- ☐ Return With Comments or Revisions
- ☐ Draft Reply for Signature
- ☐ Please File

Comments: Attached is a letter denying Tundra's request for relaxation of pressure survey requirements (Board Order No. PM 62) for N. Ebor Unit No. 1.

Tundra had requested permission to use only DST pressures on newly drilled wells, as opposed to annual pressure surveys.

JND

MG-1298 PS-f-182 8940100671

Manitoba

The Oil and Natural Gas Conservation Board

Room 309
Legislative Building
Winnipeg, Manitoba, CANADA
R3C 0V8

(204) 945-3130

May 21, 1991

Mr. Derek C. Longfield, P. Eng.
Consultant
Tundra Oil and Gas Ltd.
1313 Richardson Building
One Lombard Place
Winnipeg, Manitoba
R3B 0X3

Dear Mr. Longfield:

Re: North Ebor Unit No. 1
Annual Pressure Survey Requirements

The pressure data submitted for North Ebor Unit No. 1 satisfies the requirements of Subsection 3(1) of Board Order No. PM 62.

With respect to Tundra's request for a relaxation of the requirements of Subsection 3(1), the Board remains of the opinion that an annual pressure survey is still required for North Ebor Unit No. 1 for the following reasons:

1) the pressure fall-off test at 16-14-10-29 required only a 12 day shut-in and yielded accurate pressure data, and

2) pressure data in a small pool like the Daly Bakken D Pool can be used to determine oil-in-place by material balance, enhancing the understanding of pool performance.

The Board is prepared to accept the drillstem test pressure measured at A10-14-10-29 adjacent to the Unit in March 1991 as fulfilling the 1991 pressure survey requirement. The next pressure survey for North Ebor Unit No. 1 should be scheduled for the spring of 1992.

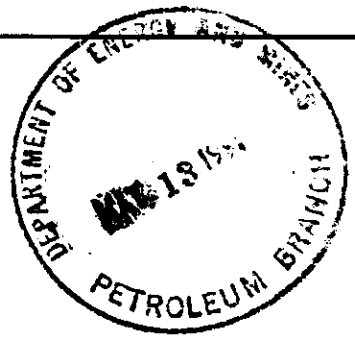
If you have any questions, please contact John N. Fox, Chief Petroleum Engineer at 945-6574.

Yours respectfully,

ORIGINAL SIGNED BY
H. CLARE MOSTER

H. Clare Moster
Deputy Chairman

Tundra oil and gas ltd.



May 9, 1991

Department of Energy and Mines
Petroleum Branch
555 - 330 Graham Avenue
Winnipeg, MB
R3C 4A5

Attention: Mr. John Fox, Chief Petroleum Engineer

Dear Mr. Fox:

Re: Average Reservoir Pressure Determination
North Ebor Unit No. 1

As required by Rule 3(2) of the Oil and Natural Gas Conservation Board Order No. PM62, approving pressure maintenance by water injection in the subject pool, Tundra Oil and Gas Ltd. submits the attached reservoir pressure measurements as an estimate of reservoir pressure in the Unit area in March of 1991.

While the Order requires that between six and twelve months after injection commencement, a reservoir pressure measurement be taken on a Unit well, Tundra drilled a well in an adjacent spacing unit (10-14-10-29 W1M) in March, 1991, and performed a drillstem test on the correlative Bakken zone (see attached map). The results of this test are submitted as a representative measurement of average reservoir pressure in the pool at that time. Based on a Horner extrapolation of the second shut-in pressure, the average reservoir pressure is in the order of 5710 kPa (abs), or 828 psia. This compares favourably with the estimate of 4480-4960 kPa (abs) or 650-719 psia, as measured in the 2-23-10-29 W1M well last June, prior to the commencement of water injection in the 16-14 well, and indicates the zone is being repressured, but will require continued injection in order to return the zone to initial pressure in the 8600 kPa (abs) or 1250 psia range.

At the time the 10-14 well was drilled, the 4-13 and 13-12 locations were also drilled in an area of the reservoir outside the waterflood. The pressure data obtained from these tests was also of good quality, and indicates a pressure gradient across the pool. The 4-13 well, which offsets both the high volume 5-13 well, and another good producer in 1-14, indicated an average pressure in this area of only

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Tundra oil and gas ltd.

4350 kPa (abs), or 670 psia, some 160 psi less than the 10-14 well. The drillstem test from the 13-12 location, which is one LSD further removed from production, extrapolated to a reservoir pressure of 6230 kPa (abs) or 904 psia. Clearly, this indicates that:

a) There is pressure communication in the Bakken zone throughout the pool, and
b) There is a need for pressure maintenance in the south half of the pool.

For these two wells, the Horner plots and related analyses have been included for comparitive purposes.

In addition to the foregoing, these data appear to confirm the validity of utilizing drillstem tests, when available, as the preferred method of measurement of average reservoir pressure.

Future surveys of existing Unit producing wells are not likely to yield as good quality data as these three drillstem tests. Our experience has shown that, after several months or years of production from a low rate Bakken well, it will likely be necessary to shut it in for at least 30-60 days to obtain data which is amenable to extrapolation. It is much easier to obtain valid pressure data on high volume producing wells in waterfloods such as the Virden Scallion and Daly pools. Therefore, in the case of Bakken waterfloods such as this, we believe the Board should consider relaxation of the requirement of Rule 3(2) to perform annual pressure surveys, and require only that new wells drilled into the pool be drillstem tested. It would appear that the zone is being repressured, and that the success of the waterflood is best measured by continued production and injection monitoring.

Please advise as to your thoughts in this latter regard.

Yours truly,

Derek C. Longfield, P. Eng.
Consultant

DCL/ck

Enclosures

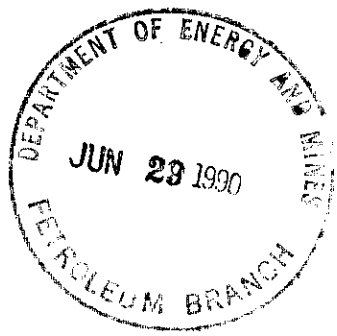
Tundra oil and gas ltd.

NEW FILE "PRESSURE SURVEY" and N. Daly Unit No. 1

June 29, 1990

Department of Energy and Mines
Petroleum Branch
555 - 330 Graham Avenue
Winnipeg, Manitoba
R3C 4A5

VIA COURIER



Attention: Mr. John Fox

Dear Mr. Fox:

RE: PRESSURE BUILDUP SURVEY AND ESTIMATE OF AVERAGE RESERVOIR PRESSURE TUNDRA DALY 2-23-10-29 WPM

As required by the Oil and Natural Gas Conservation Board Order No. PM62, relating to the implementation of a waterflood project in the Daly Bakken D Pool, attached please find the results of the subject pressure survey which was conducted to arrive at an estimate of the average reservoir pressure in the subject pool prior to the inception of waterflood operations.

Static bottomhole pressures have been calculated utilizing an acoustic well sounding device for computing length and, therefore, the hydrostatic pressure of the fluid column and then adding this value to the measured casinghead pressure. The attached Table 1 details the results of the survey. In addition, the attached Table 2 details well data and assumptions used to determine equivalent producing times for the Horner time calculations. Due to a recent fracture stimulation of the well, pre-survey production rates were much higher than had been experienced over the first year of production so that two Horner plots were generated assuming the transient was:

a) unaffected by the frac and subsequent 16 day production period;

b) reflecting a stabilized reservoir condition subsequent to the frac.

It would appear as though the former assumption is closer to reality by the shape of the Horner and type curve plots.

. . . /2

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Following are our interpretations of this test:

a) Based on the type curve plot, the well was in linear flow (half slope) for the first 50 hours of shut-in whereupon it began to deviate and move into a linear-radial transition phase.

b) The average reservoir pressure appears to have dropped from the extrapolated pressure of 5383 kPa (abs) from the second shut-in of the DST to some 4480 - 4960 kPa (abs) on this survey. Given the varied production history, and the length of extrapolation on the Horner plot, we believe this to be the best range that can be estimated. This drop in pressure is expected given the reduced initial pressure in this location due to prior withdrawals of older adjacent wells and continued production from the area.

c) The data quality is good and suggests that this type of survey should be sufficient for determining future average reservoir pressure in the pool subsequent to waterflood inception.

d) Immediate waterflood implementation is essential in order to return the reservoir to initial pressure conditions and to maximize recoverable reserves from this pool.

Should you have any questions relating to this test or the attached interpretation, please feel from to call me at 934-5850.

Yours truly,

Derek Longfield, P. Eng.

Derek Longfield, P. Eng.
Consulting Engineer

DL/ck

Enclosures

TABLE 1

Pressure Data
Acoustic Well Sounder Survey
Tundra Daly 2-23-10-29 WPM

ΔT	Casinghead Pressure kPa (g)	Fluid Column (1) Pressure kPa (g)	PWS kPa (g)	$\frac{tc(a) + \Delta t}{\Delta T}$ (2)	$\frac{tc(b) + \Delta t}{\Delta T}$ (3)
0	344	0	344	---	---
24	413	868	1,281	400	104.8
32	414	1,025	1,439	300	78.8
50	427	1,262	1,689	192.3	50.8
78.5	448	1,577	2,025	122.8	32.7
95	448	1,656	2,104	101.7	27.2

(1) Using fluid gradient of 8.32 kPa/m based on last producing water cut of 10 percent - no gas gradient accounted for.

(2) Using prefrac rates and cumulatives.

(3) Using postfrac rates and cumulatives.

TABLE 2

Well Data
Acoustic Well Sounder Survey
Tundra Daly 2-23-10-29 WPM

Shut-in Date/Time:	1990-06-25 0900 hrs.	
Cumulative Oil Production:	758.5 m^3	pre-frac
	126.4 m^3	post-frac
	884.9 m^3	total
Cumulative Water Production:	22.5 m^3	pre-frac
	15.9 m^3	post-frac
	38.4 m^3	total
Cumulative Fluid Production:	781.0 m^3	pre-frac
	923.3 m^3	total
Pre-frac Production:	7.76/4 = 1.94 m^3	oil/d
	0.08/4 = 0.02 m^3	water/d
Post-frac Production:	7.9 m^3	oil/d
	1.0 m^3	water/d

1) Calculation of corrected flow time (tc)

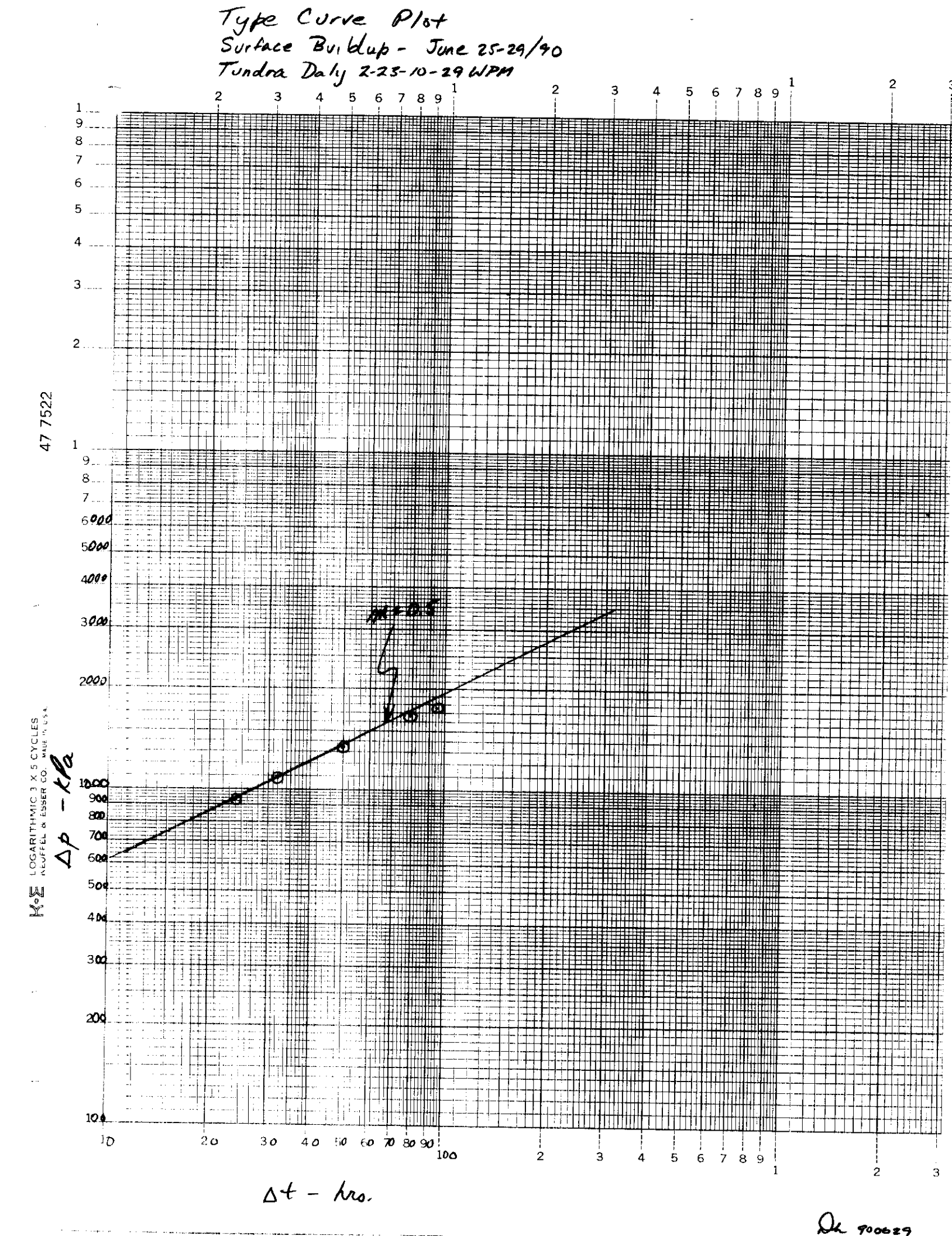
a) Assuming pre-frac cumulatives/rates:

$$tc(a) = \frac{(758.5 + 22.5)}{(1.94 + .02)} \times 24 = 9{,}563 \text{ hrs.}$$

b) Assuming post-frac cumulatives/rates:

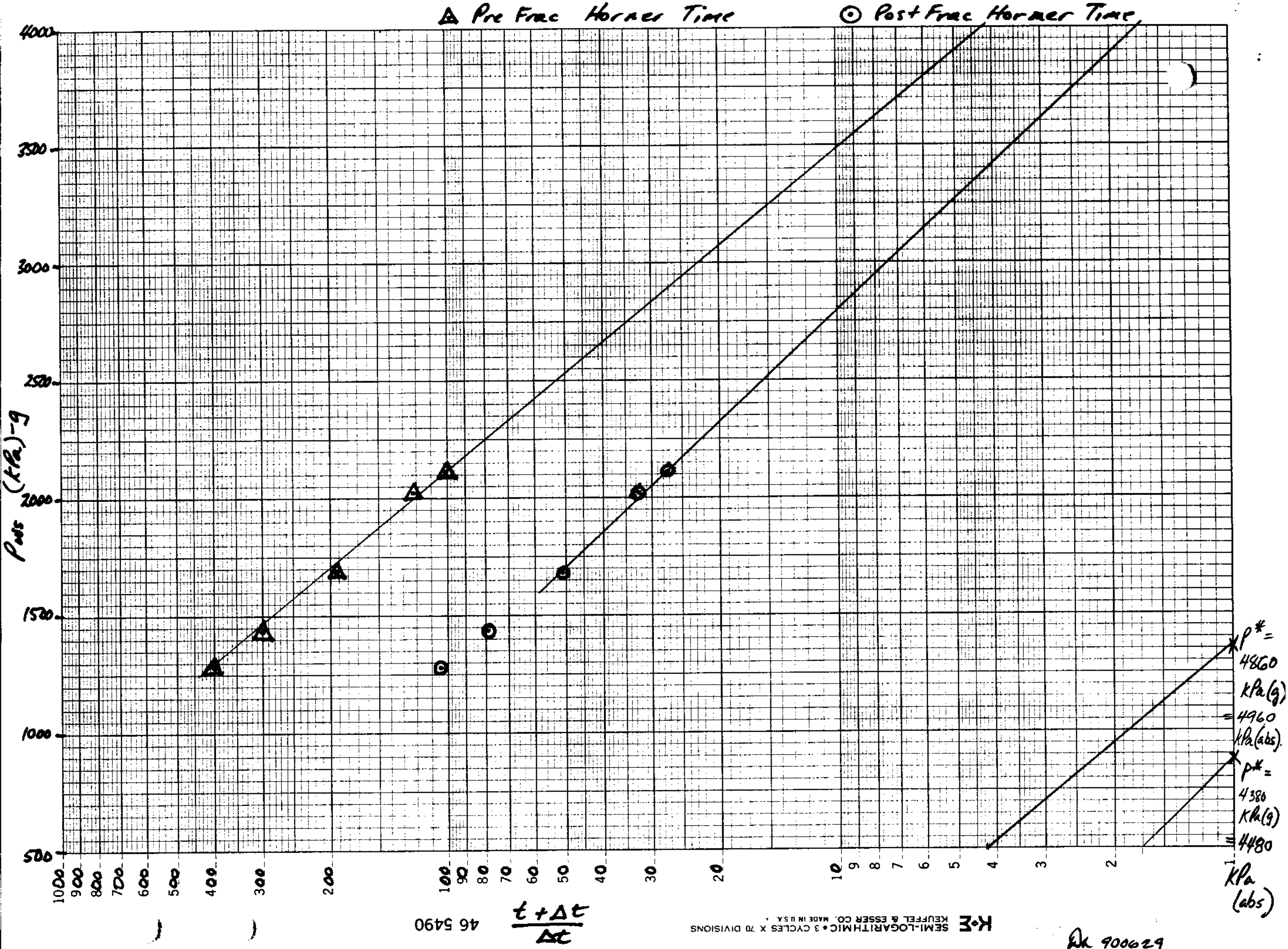
$$tc(b) = \frac{(884.9 + 38.4)}{(7.9 + 1.0)} \times 24 = 2{,}490 \text{ hrs.}$$

Type Curve Plot
Surface Buildup - June 25-29/90
Tundra Daly 2-23-10-29 WPM

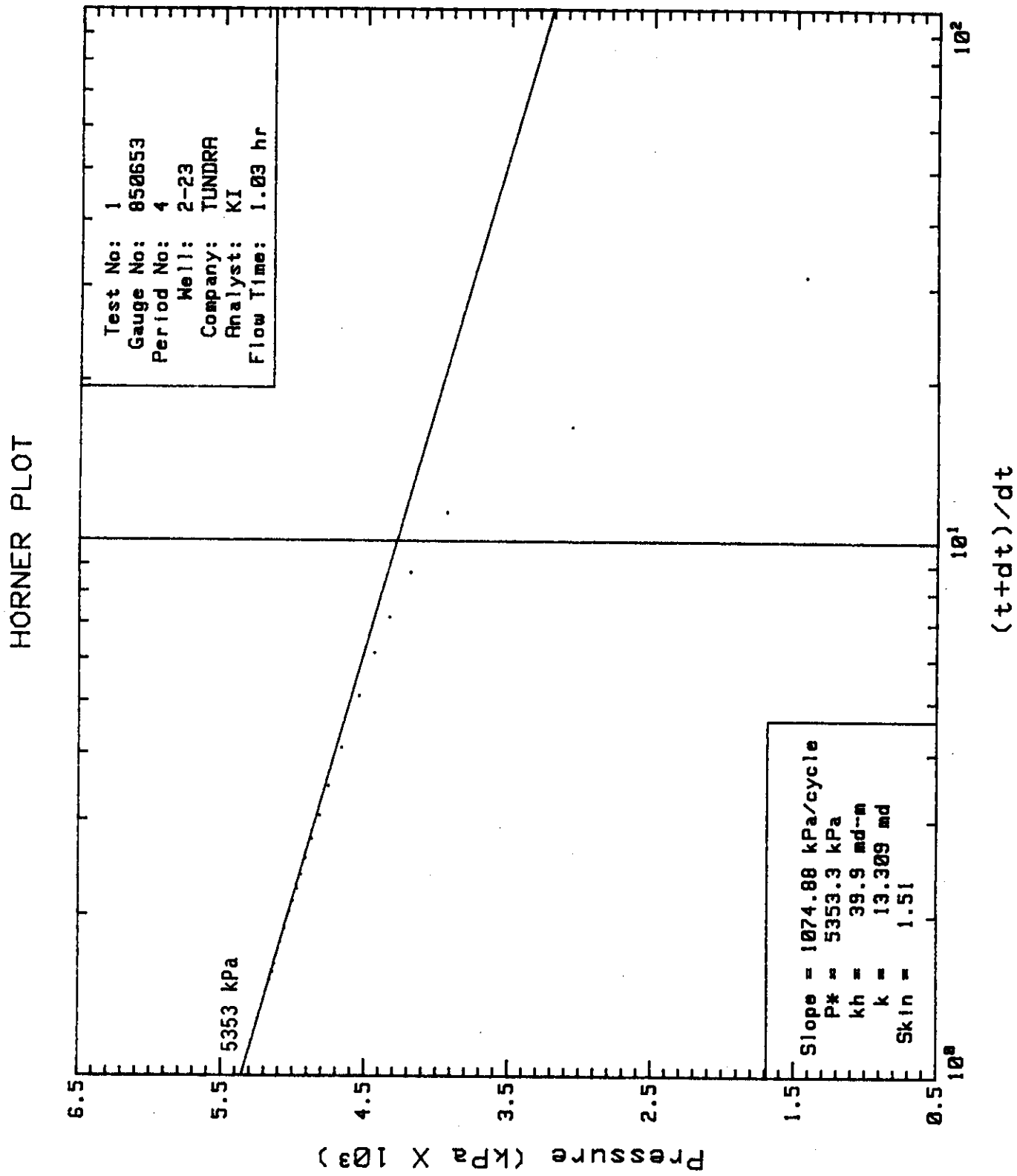


DK 900629

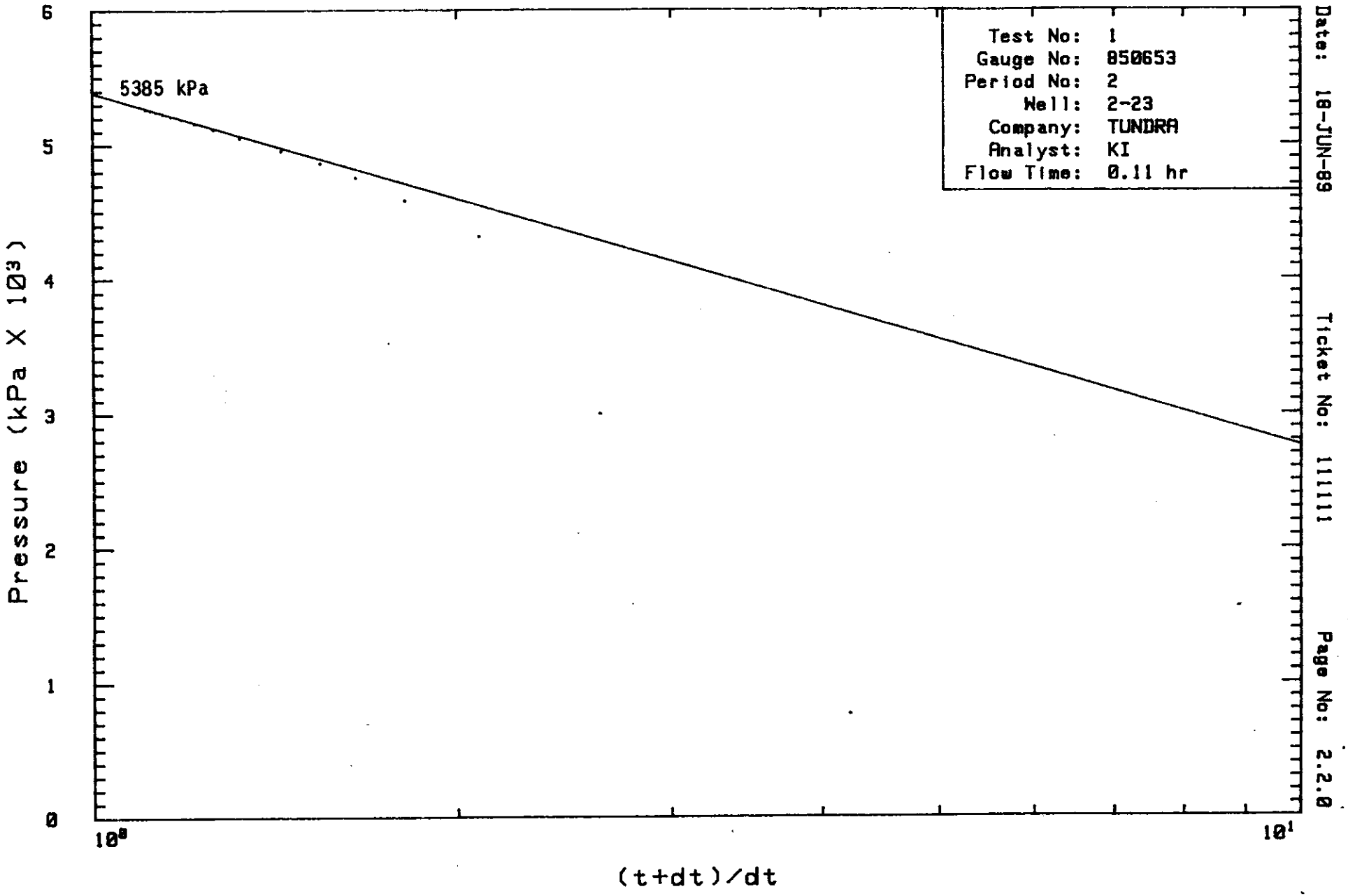
Horner Plot - Tundra Daly 2-23-10-29 W1M June 25-29/90



Dk 900629


HORNER PLOT
Test No: 1
Gauge No: 850653
Period No: 4
Well: 2-23
Company: TUNDRA
Analyst: KI
Flow Time: 1.03 hr
Slope = 1074.88 kPa/cycle
P* = 5353.3 kPa
kh = 39.9 md-m
k = 13.309 md
Skin = 1.51
5353 kPa
6.5
5.5
4.5
3.5
2.5
1.5
0.5
Pressure (kPa X 10³)
10⁰
10¹
10²
(t+dt)/dt

HORNER PLOT


5385 kPa
Test No: 1
Gauge No: 850653
Period No: 2
Well: 2-23
Company: TUNDRA
Analyst: KI
Flow Time: 0.11 hr
Pressure (kPa X 10³)
0
1
2
3
4
5
6
10⁰
10¹
(t+dt)/dt
Date: 18-JUN-89
Ticket No: 111111
Page No: 2.2.0