

# LEGEND

- OILWELL
- SUSPENDED OILWELL
- INJECTION WELL
- ABANDONED OILWELL
- S SONOLOG

NEW  
INJECTORS

REACTIVATED  
INJECTORS

1986 Subsurface Pressure Survey  
Datum Depth Pressures (kPa)

DALY UNIT No. 3

MAP OF AREA

Datum Depth -237.7 m SS

$\Delta P = P_{1986} - P_{1985} \text{ (kPa)} \pm$

## Daly Unit #3 Production Summary - (1984-10 to 1985-05)

### Monthly Production:

month	m <sup>3</sup> -oil	m <sup>3</sup> /d	Wells Producing	Average Production (m <sup>3</sup> /well/day)	
84-08	2139.8	69.0	46	1.50	
84-09	2329.1	77.6	46	1.69	
84-10	2305.7	74.4	46	1.62	
84-11	2438.4	81.3	46	1.77	
84-12	2400.5	77.4	46	1.68	
85-01	2397.5	77.3	45	1.72	5-4 Shut-in
85-02	2207.4	78.8	45	1.75	
85-03	2388.6	77.0	45	1.71	
85-04	2257.1	75.2	45	1.67	
85-05	2489.7	80.3	41	1.96	5 wells on BHP Sure 11-1 Reactivated

### Monthly Injections:

month	m <sup>3</sup> -water	m <sup>3</sup> /day	Wells Injecting	Average Injection (m <sup>3</sup> /well/day)	Average Inject. Press.
84-08	6542.0	211.0	16	13.2	7800
(Plant Pressure Increased) 84-09	11956.0	398.5	16	24.9	8000
84-10	11131.0	359.1	16	22.5	8300
84-11	10761.0	358.7	16	22.4	8400
84-12	12926.0	417.0	18	23.2	8400
85-01	11870.0	382.9	18	21.3	8000
(Fox Tripex Pump Started) 85-02	13464.0	480.7	18	26.7	8400
85-03	17644.0	568.2	19	29.9	8100
85-04	15610.0	520.3	19	27.3	8200
85-05	15488.0	499.6	19	26.3	8300

## Well Stimulations:

9-11-10-28 - performed 3800 l 28% HCl acid wash/squeeze treatment and changed BH pump (1985-04-18)

Production Tests:	1.32 m <sup>3</sup> OPD	] 85-04-08
	0.0 m <sup>3</sup> WPD	
	4.78 m <sup>3</sup> OPD	] 85-05-07
	0.60 m <sup>3</sup> WPD	

5-13-10-28 - performed 3800 l 28% HCl acid wash/squeeze treatment and changed BH pump (85-04-30)  
- well on vacuum after treatment

Production Tests:	0.80 m <sup>3</sup> OPD	] 85-04-22
	0.22 m <sup>3</sup> WPD	
	m <sup>3</sup> OPD	]
	m <sup>3</sup> WPD	

10-13-10-28 - 3100 l 15% HCl Gelled-Staged acid squeeze <sup>1985-05-</sup>  
- could not wash as well was on vacuum (no press)  
- well not tested since treatment

5-12-10-28 - 4500 l 28% HCl acid wash/squeeze treatment 1985-05-  
- well not tested since treatment

## Reactivations:

11-1-10-28 - reactivated as a producer 1985-05-09

- currently producing 0.4-0.5 m<sup>3</sup>OPD cutting 0% BS

5-14-10-28 - water shut-off attempted; well reactivated 1984-0

- well shut-in 1985-01 as well was cutting 100% BS+V

## Injection Well Conversions:

7-13-10-28 - converted to injection 1984-11-29  
- well currently injecting  $60 \text{ m}^3 \text{ WPD}$  @  $8300 \text{ kPa}$

11-13-10-28 - converted to injection 1984-11-22  
- well currently injecting  $50 \text{ m}^3 \text{ WPD}$  @  $8100 \text{ kPa}$

13-2-10-28 - converted to injection 1985-12-19  
- well currently injecting  $50 \text{ m}^3 \text{ WPD}$  @  $7800 \text{ kPa}$

1985 Bottom-Hole Pressure Survey - commenced during May and June, 1985

Results of the pressure survey indicates in general that the reservoir pressure has increased, to some degree, in areas where existing or new injection wells are situated. Most significant was the increase in pressure from  $8550 \text{ kPa}$  to  $9135 \text{ kPa}$  at 5-12, a well in the good pay region of the reservoir that is at the center of a 5-spot flood pattern. It should be noted that pressure at 5-12h only increased  $300 \text{ kPa}$  between 1981 and 1984. Increase in reservoir pressure were also noted at 13-13 and 15-13, both adjacent to new injection wells on section 13. Pressures at some of the east flank wells were noted to have decreased from last year. Most significant are the very low pressures in section 24. Reservoir pressure at 2-24 has dropped from  $1655 \text{ kPa}$  to  $1035 \text{ kPa}$ , and pressure at 7-24 is only  $825 \text{ kPa}$ . There

is presently no injection wells on (or near) section 24. Pressures have also dropped at 13-6 and 1-13 since last years survey.

See attached map For BHP Survey Results.

### 15-1 Injection Plants:

The 15-1-10-28 Water Injection Plant was rebuilt in June, 1984 to accomodate increased injection rates. In September - October, 84 the plant injection pressure was increased From 7800 kPa to 8400 kPa, increasing injection rates from about 200 m<sup>3</sup> WPD to between 350 m<sup>3</sup> and 400 m<sup>3</sup> WPD. A high output Ajax Triplex pump was installed in February, 1985, and allowed for present injection rates of around 500 m<sup>3</sup> WPD.

At present the Ajax Triplex runs 24 hours per day and the original plant triplex pump runs about 5 hours per day. Plant pressure with one pump running is approximately 8700 kPa, and 9200 kPa when both pumps are running.

### Scale Inhibitor Program:

Presently there are 9 wells on scale inhibition. The treatments involve squeezing 210 l of scale inhibitor to the formation with a 10 m<sup>3</sup> water over-flush, and are lasting 8 to 12 months. Results to date have been good, as pump changes at these wells have been greatly reduced. It is planned to further expand the program to include wells whose production has been

increased by carbonate scale buildup in the well bores.

### Projects Planned (1985-06 to 1985-12):

- 1) Convert to injection wells 4-14 and 6-14-10-28 once easements are recieved to install injection line.
- 2) Repair casing leaks and reactivate to injection 10A-1 WIW, 14-11 WIW and 16-11 WIW (10A-1 is approved and will commence in 1985-07; 14-11 and 16-11 are awaiting Vertilog casing inspection logs). Also stimulate and reactivate 6-11 WIW.
- 3) Attempt to shut-off water zone at 7-2-10-28 and reactivate as a producing well. If successful, other shut-offs may be attempted at 5-11 and 16-10.
- 4) Acidize 12-11 WIW to increase water injection rate. Also may try a hydrocarbon cleanup chemical squeeze and a surfactant squeeze on 2 other injection wells in attempt to increase low injection rates. Further injection well treatments may follow.
- 5) Perform 6 to 10 acid treatments on producing wells in attempt to increase production. The acid stimulations to date have seen very good success (see Well Stimulations) in cleaning up the wells and increasing production rates.
- 6) Evaluate possible submersible pump installations at high Fluid level wells in section 23 to increase oil production.

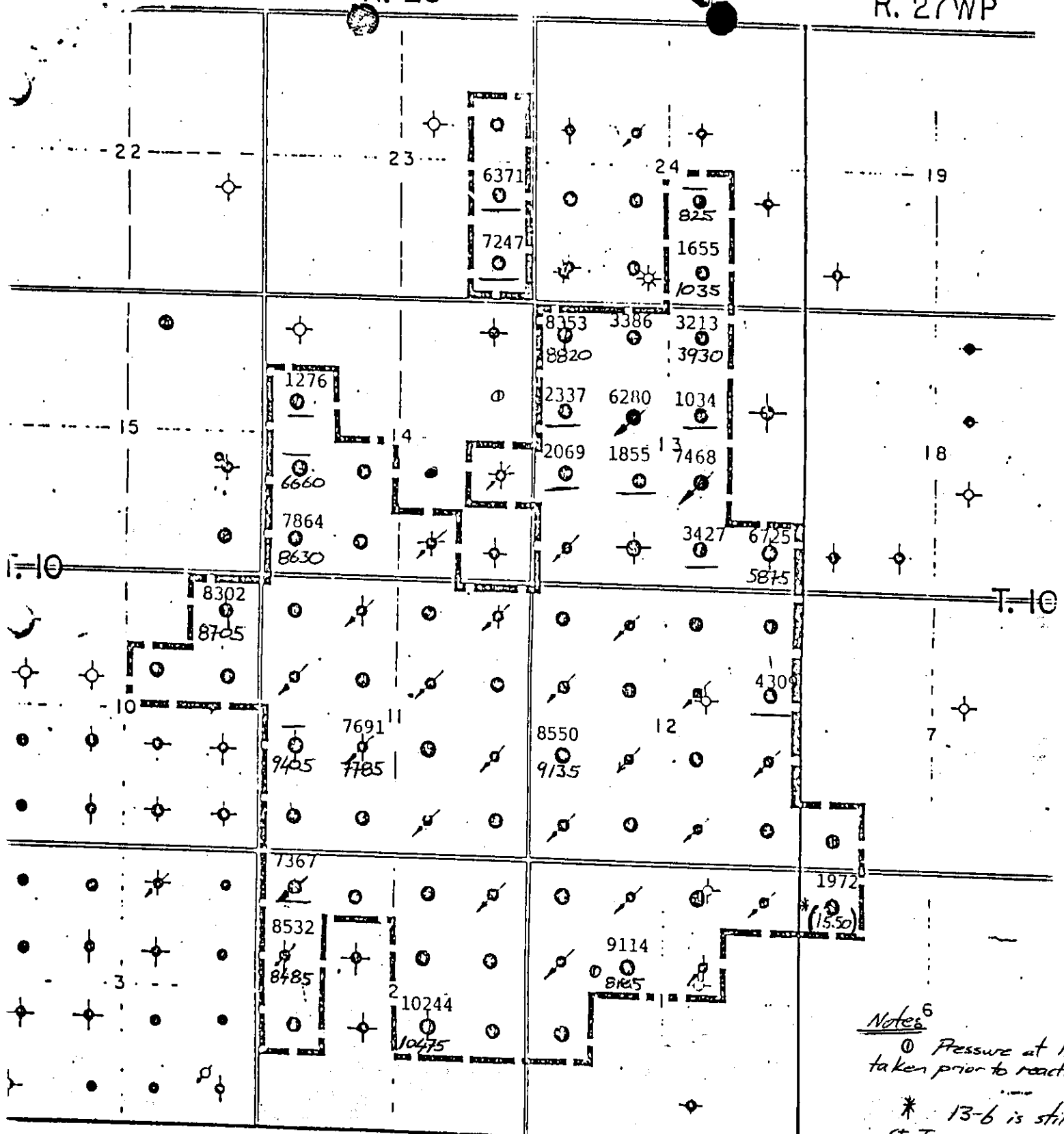
7) Continue expansion of Scale Inhibitor Program to wells where carbonate scale causes excessive pump wear (low run lives) or decreases in production rates.

### Other Comments:

Ongoing sonolog surveys are carried out monthly to monitor Fluid levels and pump performance. It has been noted in some wells that Fluid levels have risen slightly (30m - 80m) in the last 5 or 6 months. It may be too early to conclude anything from this, but results to the increase waterflood injection rates do look positive and Favowable.

R. 28

R. 27WP



Notes<sup>6</sup>  
 ① Pressure at 11 taken prior to reactivation  
 \* 13-6 is still SI For survey; pressure is still building

## LEGEND

- OILWELL
- ⊙ SUSPENDED OILWELL
- ⊕ INJECTION WELL

## FIGURE 1

1985 ~~Bottom Hole~~ Bottom Hole Pressure Survey

1984 TRIANNUAL  
 BOTTOM HOLE PRESSURE SURVEY  
 DATUM DEPTH -238 m S.S.

DALY UNIT No. 3

9100 1984 BHPSurvey MAP OF AREA

8500 1985 BHPSurvey 1984 - 02 - 11  
 (Pressures in kPa)

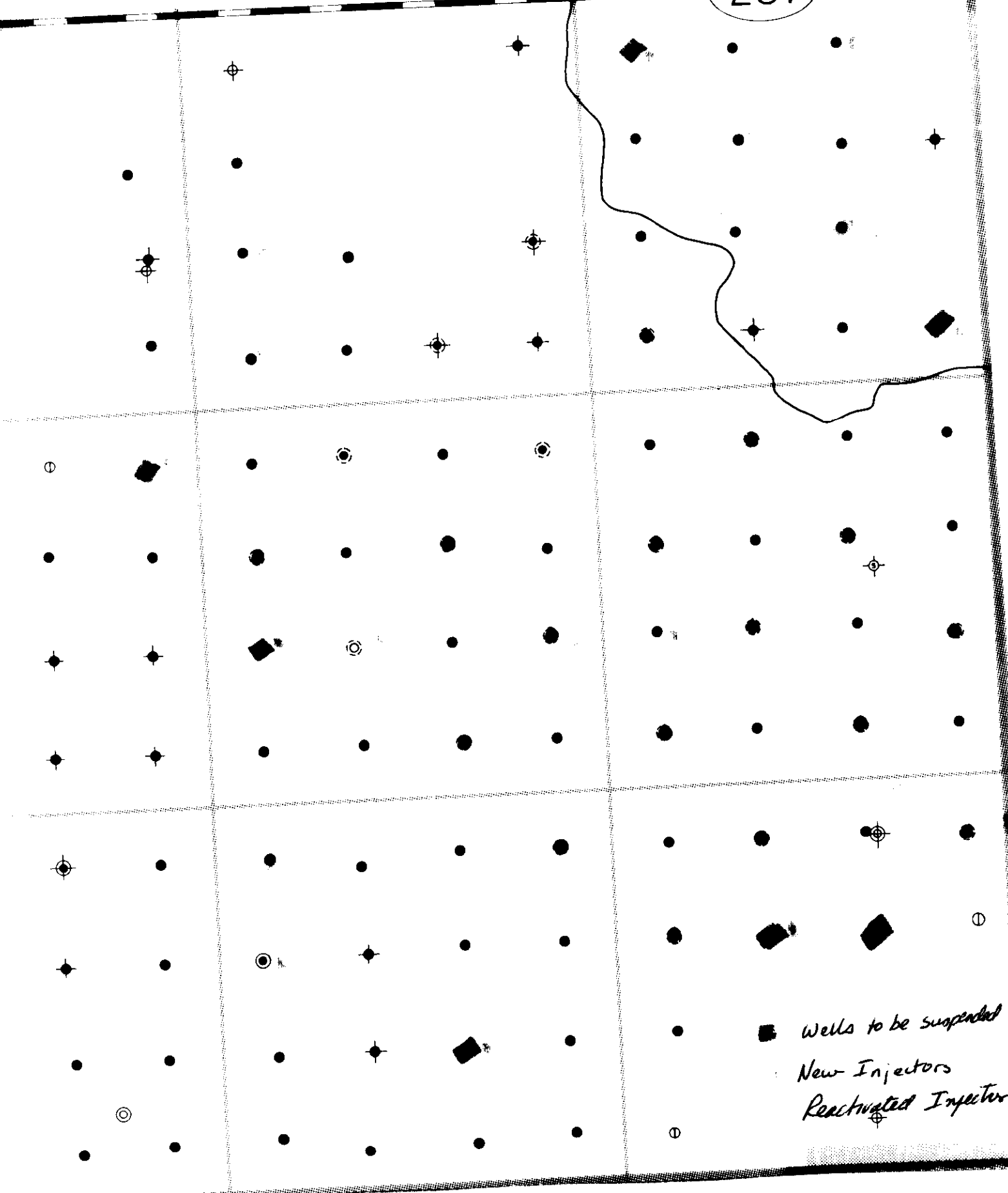


# NEW OR REACTIVATED INJECTORS

## DATE ON INJ.

Well  
 13-2-10-28  
 7-13-10-28  
 11-13-10-28  
 4-14-10-28  
 6-14-10-28  
 6-11-10-28 (R)  
 14-11-10-28 (R)  
 16-11-10-28 (R)

-  
 Dec 22/84  
 Dec 19/84  
 -  
 -  
 -  
 -  
 -





MANITOBA

THE OIL AND NATURAL GAS CONSERVATION BOARD  
309 LEGISLATIVE BUILDING  
WINNIPEG, MANITOBA  
R3C 0V8

September 17, 1984

Chevron Canada Resources Limited  
Box 100  
Virden, Manitoba  
R0M 2C0

Attention: Mr. C. G. Falden, P. Eng.  
Area Supervisor

Dear Sir:

Re: Daly Unit No. 3 - Waterflood Expansion

Further to your application dated July 3, 1984, you are hereby advised that the following modifications to pressure maintenance operations in Daly Unit No. 3 are approved.

Additional Injectors

Pursuant to the provisions of Pressure Maintenance Rule 1(1) of Board Order No. PM 31, injection of water into the Lodgepole Formation of the Mississippian Age in the wells:

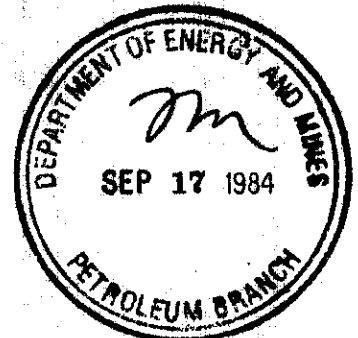
Chevron Haskett Daly WEN 13-2-10-28 (WPM)  
Chevron Daly WEN 7-13-10-28 (WPM)  
Chevron Daly WEN 11-13-10-28 (WPM)  
Chevron Daly Prev. WEN 4-14-10-28 (WPM)  
Chevron Daly Prev. WEN 6-14-10-28 (WPM)

is hereby approved, provided that prior to commencing injection, approval of individual recompletion programs shall first be obtained from the Director of the Petroleum Branch.

Maximum Wellhead Injection Pressure

Pursuant to the provisions of Pressure Maintenance Rule No. 4 of Board Order No. PM 31, the maximum wellhead pressure at which water is injected shall not exceed 10 000 kPa for all approved water injection wells in Daly Unit No. 3, except for Chevron Daly Prev. WEN 6-14-10-28 (WPM) which shall be limited to 8 500 kPa.

...2



COPY

Additional Production and Pressure Monitoring Requirements

Commencing in 1985 and continuing until further notice, Chevron shall obtain for each well, at least twice in each calendar year, a production test for the purpose of determining each well's oil rate and producing water-oil ratio.

Commencing in 1985, Chevron shall conduct comprehensive annual surveys to determine the static bottom hole pressure in the Unit. A list of specific wells to be surveyed in each year shall be submitted for approval to the Director of the Petroleum Branch.

Yours sincerely

THE OIL AND NATURAL GAS  
CONSERVATION BOARD

ORIGINAL SIGNED BY  
IAN HAUGH

Ian Haugh  
Deputy Chairman

bc: Marc Eliesen  
J. F. Redgwell  
Petroleum Branch

HCM/IH/bb

# MANIT<sup>BA</sup>

## Inter-Departmental Memo

Date August 16, 1984

To The Oil and Natural Gas  
Conservation Board

From H. Clare Moster  
Director  
Petroleum Branch

Marc Eliesen - Chairman  
Dr. I. Haugh - Deputy Chairman  
J. F. Redgwell - Member

Telephone

Subject Re: Daly Unit No. 3 - Waterflood Expansion

In its letter of July 3, 1984, Chevron Canada Resources Limited applied for approval to modify its pressure maintenance operations in Daly Unit No. 3. The modifications involved conversion of five wells to water injection, reactivation of three suspended water injectors and increasing the maximum permissible injection pressure to 10 000 kPa.

Notice of the application was published in the Manitoba Gazette on July 21, 1984, in the Virden Empire Advance on July 18, 1984 and in the Gopher Creek Chronicle on July 25, 1984. Copies of the notice were also sent to all working interest owners with lands offsetting the Unit.

The Board received a letter, dated July 25, 1984 from Don and Katherine Angell as potentially affected mineral owners in the Unit Area. Mr. and Mrs. Angell have requested that copies of supporting studies be made available to them and contend that Chevron's statement that "all land owners in the immediate area have been contacted to inform them of our plans" is untrue. In its response to the above letter, the Board directed Mrs. Angell to direct requests for additional information to Chevron and indicates that "if no further response is received from you prior to August 13, 1984, we shall assume your concerns have been addressed." As of August 15, 1984, the Board has received no further correspondence from Mrs. Angell.

### Recommendation:

It is recommended that the application by Chevron be approved subject to increased pressure and production monitoring requirements as discussed in the Branch's memo of July 9, 1984 (page 4).

It is recommended that the approval be communicated to Chevron by letter (draft attached) outlining the additional monitoring requirements.

### Discussion:

Board Order No. PM31 which provides for pressure maintenance operations in Daly Unit No. 3 approves injection into a specific list of wells and "from time to time in other such wells as the Board may approve." Similar provisions relating to maximum injection pressure and frequency of pressure measurements are also contained in the above-noted order and in Order No. PM38. Consequently, it would appear to be unnecessary to issue a Board Order to cover the proposed changes.

  
H. Clare Moster

LRD/sb  
Att:

First Fold

DRAFT

Chevron Canada Resources Limited  
Box 100  
Virden, Manitoba  
ROM 2C0

Attention: Mr. C. G. Folden, P. Eng.,  
Area Supervisor

Dear Sir:

Re: Daly Unit No. 3 - Waterflood Expansion

Further to your application dated July 3, 1984, you are hereby advised that the following modifications to pressure maintenance operations in Daly Unit No. 3 are approved.

Additional Injectors

Pursuant to the provisions of Pressure Maintenance Rule 1(1) of Board Order No. PM31, injection of water into the Lodgepole Formation of the Mississippian Age in the wells:

Chevron Haskett Daly WIW 13-2-10-28 (WPM)

Chevron Daly WIW 7-13-10-28 (WPM)

Chevron Daly WIW 11-13-10-28 (WPM)

Chevron Daly Prov. WIW 4-14-10-28 (WPM)

Chevron Daly Prov. WIW 6-14-10-28 (WPM)

is hereby approved. Approval of individual recompletion programs prior to commencing operations must also be obtained from the Petroleum Branch.

Maximum Wellhead Injection Pressure

Pursuant to the provisions of Pressure Maintenance Rule No. 4, the maximum wellhead pressure at which water is injected shall not exceed 10 000 kPa for all approved water injection wells, except Chevron Daly Prov. WIW 6-14-10-28 (WPM) which shall be limited to 8 500 kPa.

. . . 2 . . .

Additional Production and Pressure Monitoring Requirements

Commencing in 1985 and continuing until further notice, Chevron will be required to obtain for each well, a production test for the purpose of determining the well's oil rate and producing water-oil ratio, a minimum of twice in each calendar year.

In addition, commencing in 1985, Chevron will be required to conduct a comprehensive <sup>annual</sup> survey to determine the static bottom hole pressure in the Unit. A list of specific wells to be surveyed shall be subject to the concurrence of the Petroleum Branch.

I. Haugh  
Deputy Chairman  
The Oil and Natural Gas  
Conservation Board

July 31, 1984

Don and Katherine Angell  
Box 430  
Virden, Manitoba  
R0M 2C0

Attention: Mrs. Katherine A. Angell

Dear Mrs. Angell:

Re: Daly Unit No. 3  
Waterflood Expansion

Receipt of your letter dated July 25, 1984 is acknowledged.

You indicate in your letter that there may be information in support of the application from Chevron Canada Resources Limited that you may not have received.

I would suggest that you contact Mr. Cal Folden at Chevron's Virden office and determine what additional information there may be that you may wish to see, and make arrangements with Mr. Folden to either view the material or receive a copy.

If no further response is received from you prior to August 13, 1984, we shall assume your concerns have been addressed.

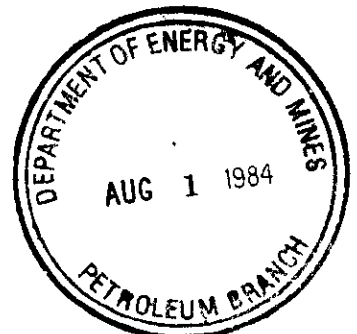
Yours sincerely

THE OIL AND NATURAL GAS  
CONSERVATION BOARD

ORIGINAL SIGNED BY  
IAN HAUGH

Ian Haugh  
Deputy Chairman

HCM/IH/bb  
bc: Marc Eliesen  
J. F. Redgwell  
Petroleum Branch





Box 430  
VIRIDEN, Manitoba  
R0M 2C0

THE OIL AND NATURAL GAS  
CONSERVATION BOARD  
WINNIPEG, MANITOBA

JUL 30 1984

RECEIVED

July 25, 1984

The Oil and Natural Gas Conservation Board  
Province of Manitoba  
555 - 330 Graham Avenue  
WINNIPEG, Manitoba  
R3C 4E3

ATTENTION: Dr. Ian Haugh

Dear Dr. Haugh

Re: Daly Unit #3  
Waterflood expansion

As a freehold owner of minerals adjacent to proposed injection wells we wish to receive more information regarding the application. The application from Chevron Canada Resources refers to the 82-09 report by Mr. R. D. Trimble as support of the application. This report is not part of the copy of application we received from Chevron. If this report supports said application we would like to receive a copy of same. The application also refers to Daly Unit #1. If there is supporting evidence we wish to receive this also.

Mr. Folden states in the application that " all landowners in the immediate area have been contacted to inform them of our plans ". This statement is not true. We are landowners that have land that will be affected and we have not been approached by Chevron.  
Thankyou.

Yours truly,




Don and Katherine Angell


*Per Cal Folden  
general plans were  
discussed with Angell  
in mid June.*

over a thousand bucks apiece, if you can  
ans purchased during the Viet Nam War  
of \$1,314 apiece, — full third will go to  
er (Colt's) and to designers (Fairchild  
version, manufactured in comparatively  
unit price) in any sporting goods shop  
50 in import duties!  
Ontario (where else?) to make it from  
erta crude oil.  
he 800,000 the Americans abandoned in  
is an M-16!



Tanks threw away any time they had a  
what we're buying for \$1,314 apiece!  
in Quebec (where else?) for \$1.43 a shot,  
t to you for 50 cents retail!  
957, it replaces our old-fashioned FN,  
n 1956!  
e way to 300 metres. Very modern: our  
hit a man at 1,000 or so!  
.223" calibre, a far better choice would  
rich can be made in just about any  
and uses only the cheapest steel in its  
ing within the Commonwealth, and we  
merican toy, "Jammin' Jenny" than a  
lent.  
e, typical of what Canadian politicians  
l be the least interesting election the  
the one with the highest proportion of  
a fed up!  
take a nap!



he  
of it  
me  
ler!



I just LOVE  
Shish Kabob,  
don't you?

Canada Wide

Canada Wide

## NOTICE under the Mines Act Daly Oil Field

Chevron Canada Resources Limited  
has made application to modify its  
pressure maintenance operations in  
Daly Unit No. 3 as follows:

1: Initiate water injection in the follow-  
ing wells:

Chevron Haskett Daly	13-2-10-28
	WPM
Chevron Daly	7-13-10-28WPM
Chevron Daly	11-13-10-28WPM
Chevron Daly Prov.	4-14-10-28WPM
Chevron Daly Prov.	6-14-10-28WPM

2: Increase the maximum allowable  
wellhead injection pressure from 1300  
psig (8 962 kPa) to 10 000 kPa.

*If no valid objection or intervention  
in writing is received by the Board at  
555-330 Graham Ave., Winnipeg, Ma-  
nitoba, R3C 4E3, within 14 days of the  
publication of this notice, the Board  
may approve the application.*

*Copies of the application may be  
obtained from Chevron Canada Re-  
sources Limited, P.O. Box 100, Virden,  
manitoba, R0M 2C0.*

*Dated at Winnipeg this 10th day of  
July, 1984.*

Ian Haugh  
Deputy Chairman

### This Week in Canada

On July 28, in 1755, it  
was decided to deport  
the Acadians from  
Nova Scotia, and in  
1885, the trial of Louis  
Riel opened at Regina.



ignore reality entirely.

Which brings us to The Suits — Turner and  
Mulroney.

Until one of them admits we're flirting with the wrong  
sort of girl, we will become even more diseased.



Gary Dunford

### DRESS UP, BUT ONLY A LITTLE

We're morally  
opposed to restaurants  
that presume to groom  
their customers with  
intimidating signs like  
No Jeans Allowed and  
Proper Attire  
Requested.

But you *do* have to  
grin at the shy dress  
demand made by the  
Diamond, a nightclub  
in Toronto. They  
advise:

"Dress Code  
Casually Upscale."  
Tasteful. Very taste-  
ful.

...

### A MODEST PROPOSAL

Hey, gang: TV's  
Love Boat is in Lenin-  
grad!

They're filming the  
fall launch in the Rus-  
sian port.

But where is the  
Western ambassador  
who'll quickly take our  
dynamite proposal to  
the Kremlin?

The Russians hand  
over their dissidents.

And we give them  
Capt. Merrill Steubing,  
joyful Julie, Isaac the  
bozo bartender, the oily  
Doc, the grinning  
Gopher, the captain's  
obnoxious niece, Don  
Ameche, Phyllis Diller,

Tab Hunter, George  
Hamilton and all the  
rest of the fast-fading  
former stars waving  
from the ship's rail.

Simple?

The best ideas  
always are.

(In Hollywood, the  
good news is that *The  
Love Boat* got to Lenin-  
grad safely. The bad  
news is that it's coming  
back.)

...

### DID YOU KNOW?

□ That there's a  
Three Stooges video  
game on its way to  
arcades? (It's the 50th  
anniversary of the  
goofs' entry into show-  
biz, ya know.) The  
video game lets play-  
ers run Larry, Curly  
and Moe through a  
maze, and throw pies,  
trade slaps and smash  
furniture. If this isn't  
worth 50¢, what is?

□ That Gal-  
lagher — the weird but  
wonderful come-  
dian — advises kids  
should never eat break-  
fast? "Kids who eat a  
healthy breakfast are  
the only ones who  
throw up in gym  
class." Wasn't it Gal-  
lagher who wondered  
"if 25% of the popu-  
lation is seriously stu-  
pid, why are we upset  
with 10% unemploy-  
ment?" Beats

## Gross

ayer's diet here

1 Lawn Tennis  
ul Wimbledon  
oney this year  
ia Navratilova  
ir own Brinks

ige, even mer-  
a forget about

Said Mac: "It's nice to think that you can make your  
mark in a sport, but I don't think you can compare  
today's players to those of 50 years ago. Everything  
changes with the times and in 20 years maybe there will  
be somebody playing better tennis than I am. A guy like  
(Pat) Cash, who is now a good player, definitely has the  
potential to be a great player.

"That is what is great about sports — there's always  
someone who may be better than the next guy. I have  
lived through the rivalries with (Bjorn) Borg, (Jim)  
Connors and (Ivan) Lendl, and I'm looking forward to  
another rivalry with another guy."

In my view, before John McEnroe can be regarded as  
the greatest of all time he must first win a couple more  
Wimbledon and U.S. Open tournaments, plus the Aus-  
tralian and French.



"Speaking  
of Canada..."

"We in Canada believe  
that good fences are  
necessary."

— Prime Minister John  
Diefenbaker



(b) livestock, (c) honey, (d) peat moss.  
Docket 12116

Hyndman Transport (1972) Limited  
Wroxeter, Ontario.

Application for extension of Public Service Vehicle Certificate for the transportation of powdered milk for Peebles Products Ltd. from its installation at the City of Cornwall to the Ontario/Manitoba border at or near West Hawk Lake for furtherance to Nutro Vet Feed Limited at St. Malo in the Province of Manitoba.

Docket 12147

Hyndman Transport (1972) Limited  
Wroxeter, Ontario.

Application for extension of Public Service Vehicle Certificate for the transportation of goods for Niagara Chemical, Division of 129652 Canada Inc.;

(a) from various points in the Province of Ontario to various points in the Province of Manitoba.

(b) from various points in the Province of Ontario through the Province of Manitoba for furtherance to points in the Provinces of

Saskatchewan, Alberta and British Columbia. Corridor Authority only. No pick-ups or drop-offs in transit in the Province of Manitoba.

Provided that the licensee be restricted to the use of trailers or semi-trailers designed primarily for the carriage of livestock.

Anyone wishing to make representation or oppose the granting of the above applications, must file such notice with the Secretary of the Board; 200-301 Weston Street, Winnipeg, Manitoba, either by mail or personal filing prior to 4:30 P.M., Tuesday, August 7th, 1984. Notices received after this date will not be accepted. Subsequent to the above date the applications will be scheduled for Public Hearing and the Applicant and anyone who opposed will be notified as to the date, time and place of the Hearing.

L. G. OLIJNEK,

Secretary.

THE MANITOBA MOTOR  
TRANSPORT BOARD.

—29

#### UNDER THE MINES ACT

Tundra Oil and Gas has made application to recomplete the well known as

Tundra Pierson 9-18-3-28

located on Legal Subdivision 9 of Section 18, Township 3, Range 28, West of the Principal Meridian, as a salt water disposal well. The proposed zone of disposal is the Mission Canyon 1 Formation.

If no valid objection in writing is received by the Board at 555-330 Graham Avenue, Winnipeg, Manitoba, R3C 4E3, within 14 days of the publication of this notice, the Board may approve the application.

Dated at Winnipeg this 10th day of July, 1984.

—29

IAN HAUGH,  
Deputy Chairman.

#### Daly Oil Field

Chevron Canada Resources Limited has made application to modify its pressure maintenance operations in Daly Unit No. 3 as follows:

1. Initiate water injection in the following wells:

Chevron Haskett Daly 13-2-10-28 (WPM)

Chevron Daly 7-13-10-28 (WPM)

Chevron Daly 11-13-10-28 (WPM)

Chevron Daly Prov. 4-14-10-28 (WPM)

Chevron Daly Prov. 6-14-10-28 (WPM)

2. Increase the maximum allowable well-head injection pressure from 1300 psig (8,962 kPa) to 10,000 kPa.

If no valid objection or intervention in writing is received by the Board at 555-330 Graham Ave., Winnipeg, Manitoba, R3C 4E3, within 14 days of the publication of this notice, the Board may approve the application.

Copies of the application may be obtained from Chevron Canada Resources Limited, P.O. Box 100, Virden, Manitoba, R0M 2C0.

Dated at Winnipeg, this 10th day of July, 1984.

—29

IAN HAUGH,  
Deputy Chairman.

In 2:16.2, Irish Country Boy, sixth  
in 2:10.2, owned by Ruth Stewart.

Race No. 10—Justly Speed, first  
in 2:16, owned by Aurele and Cecile  
Vodon.

The races were rained out on  
Sunday.

#### INDISPUTABLE

Don't be turned off by the fellow  
who is different from the  
rest—he'll produce far more than  
the one who is indifferent.

#### NAYSAYERS

The naysayers who are sure it  
can't be done often refuse to  
acknowledge all the people  
successfully getting it done.

#### NOTICE

##### UNDER THE MINES ACT

##### DALY OIL FIELD

Chevron Canada Resources  
Limited has made application to  
modify its pressure maintenance  
operations in Daly Unit No. 3 as  
follows:

1. Initiate water injection in the  
following wells:  
Chevron Haskett Daly 13-2-10-28  
(WPM)  
Chevron Daly 7-13-10-28 (WPM)  
Chevron Daly 11-13-10-28 (WPM)  
Chevron Daly Prov. 4-14-10-28  
(WPM)  
Chevron Daly Prov. 6-14-10-28  
(WPM)
2. Increase the maximum allow-  
able wellhead injection pressure  
from 1300 psig (8,962 kPa) to  
10,000 kPa.

If no valid objection or interven-  
tion in writing is received by the  
Board at 555 - 330 Graham Ave.,  
Winnipeg, Manitoba, R3C 4E3,  
within 14 days of publication of this  
notice, the Board may approve the  
application.

Copies of the application may be  
obtained from Chevron Canada  
Resources Limited, P.O. Box 100,  
Virden, Manitoba, R0M 2C0.

Dated at Winnipeg this 10th day  
of July, 1984.

IAN HAUGH  
Deputy Chairman

kg **46¢**

U.S. Grown, Large Size

**Cantaloupe** .....

Fresh, Manitoba Grown, Green & Tender

**Broccoli** .....

## CHEESE SLIC

Kraft, Processed, Singles,  
24 slices, 500 g .....

## NIBLETS CO

Cream Style Fancy, 298 mL,

Whole Kernel Fancy, 341 mL .....

## CHEEZ WHI

Kraft, Processed  
Spread, 500 g .....

## DINNERS & ST

Burn's, Seven

Varieties, 680 g .....

**FREE  
DELIVERY**

VIRD

**Hi-**

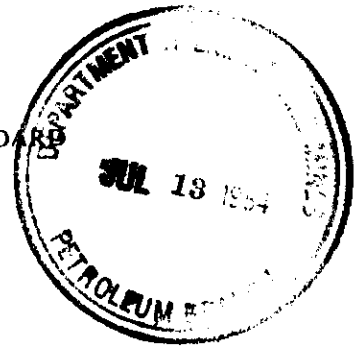
MANY NON  
SPE

**KING S**



MANITOBA

THE OIL AND NATURAL GAS CONSERVATION BOARD  
309 LEGISLATIVE BUILDING  
WINNIPEG, MANITOBA  
R3C 0V8



July 12, 1984

Chevron Canada Resources Limited  
Box 100  
Virden, Manitoba  
ROM 2C0

Attention: C. G. Folden  
Area Supervisor

Dear Sirs:

re: Daly Unit #3 Waterflood Expansion

This is to acknowledge receipt of your letter  
of July 3, 1984 relating to the proposed water flood expansion  
in Daly Unit #3.

Yours sincerely

THE OIL AND NATURAL GAS  
CONSERVATION BOARD

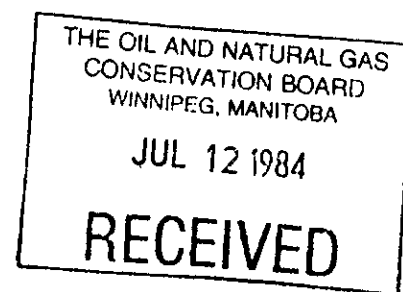
Ian Haugh  
Deputy Chairman

IH/bb

bc: Marc Eliesen  
J.F. Redgwell  
Petroleum Branch



## Chevron Canada Resources Limited



Box 100  
Virden, Manitoba  
R0M 2C0

1984-07-03

The Oil and Natural Gas Conservation Board  
Province of Manitoba  
Attention: Dr. Ian Haugh  
555 - 330 Graham Avenue  
Winnipeg, Manitoba  
R3C 4E3

### DALY UNIT #3

### WATERFLOOD EXPANSION

Dear Sir:

Chevron Canada Resources, operator of Daly Unit #3, hereby applies to The Oil and Natural Gas Conservation Board for the following:

- A. Approval to expand the Daly Unit #3 waterflood by conversion of five existing wells to water injection:

Chevron Haskett Daly	13-2-10-28 WPM	
Chevron Daly Province	4-14-10-28 WPM	
Chevron Daly Province	6-14-10-28 WPM	
Chevron Daly	7-13-10-28 WPM	
Chevron Daly	11-13-10-28 WPM	and

- B. Approval to increase the maximum operating injection pressure to 10.0 MPa.

### A. Well Conversions

A detailed discussion on each of the wells, that approval of conversion to injection is requested, is given below.

#### 1. 13-2-10-28

Conversion of 13-2-10-28, although off pattern, is located to give excellent support to 14-2, 3-11 and 4-11 and would not be detrimental to the existing 5 spot pattern. Figure No. 2, a map of Daly Unit #3, indicating producing rates and well status is attached. The 13-2 well was a good producer declining slowly over 20 years until it finally waterflooded out in 1971, apparently due to water disposal in 15-3-10-28 which has swept oil into the unit from the west. As this disposal well is now abandoned, converting 13-2 to injection would continue this sweep towards our offsetting producers. Without this pressure support trapped oil will be left in this area and/or oil will be swept out of the unit towards the S.W. due to the existing waterflood.

2. 4 & 6-14-10-28

Conversion of 4-14-10-28 and 6-14-10-28 are required due to the lack of pressure support in the N.W. lobe of the unit. 12-14 was reactivated as a producing well in 1982 producing 5.2 m<sup>3</sup> of clean oil/day (average over 16 days) but has since declined to 1.3 m<sup>3</sup>/day (1983-05 test) indicating reduced support. A recent recompletion of this well in the Middle Daly failed to improve production. Both of these locations are onpattern with the other injectionw ells. The 6-14 well is presently producing at 0.4 m<sup>3</sup> clean oil/day and is positioned to support 3-14 and 12-14 with little loss of production due to conversion. The 4-14 well is positioned to support two presently producing unit wells as well as 16-10 and 5-14 which are presently suspended but are potential recompletion and reactivation candidates. Centoba's 1-15 well outside the unit will also benefit from injection and negotiations are in progress to include this well in the Unit.

3. 7 & 11-13-10-28

The wells 1, 7, 11 and 13-13-10-28 lie in a syncline low running from N.W. to S.E. These wells all progressively watered out prematurely from 1958 to 1964 due to natural water encroachment along the syncline from the N.W. The offsetting wells along the flanks are all relatively good wells and would appear to be benefitting from natural water drive. This would indicate that when the syncline wells watered out, the water continued moving upflank towards the remaining producing wells. Conversion of the subject wells to injection (although off pattern) would add to this natural water drive by increasing the reservoir pressure in the area and thus accelerate production in upflank wells. The 1981 and 1984 pressure surveys confirm the presence of the syncline (Figure 3 - Pressure Survey Map), because the reservoir pressure is higher and similar along the trend. The pressure decreases dramatically away from the syncline. The pressure at 13-13 is higher then 11 and 7 of 13 indicating the possibility of a pressure fence to the northwest which will increase the effectiveness of injection into 7 and 11 of 13.

Wells to the north, more than one location away from the syncline, are suffering from low reservoir pressure and if response to injection into 7 and 11 of 13 is realized, further expansion of the waterflood to the north would be considered. Any future expansion to the north would be placed on pattern with the syncline injectors.

Converting on pattern wells such as 2-13 and 6-13 would not be feasible as this would reverse the flow from natural water encroachment and force oil back into the previously flooded syncline.

As most of the conversion locations are edge wells and affect producing entities outside of the unit, negotiations will be undertaken to include these locations in unit enlargement. As noted above, if 7 and 11 of 13 conversions result in production response, additional waterflood expansion to the north is planned.

B. Increased maximum operating injection pressure

A high pressure pilot waterflood was attempted in 1971 on a single well at 14-1-10-28 which was inconclusive as far as response to offsetting wells is concerned due to the short duration of the test (8 months).

The test did however indicate that injectivity could be dramatically increased by exceeding the formation fracture pressure as injectivity increased from 8.0 m<sup>3</sup>/d @ 7.5 MPa to 80 m<sup>3</sup>/d @ 8.6 MPa.

It is Chevron's opinion that exceeding the formation fracture pressure will not result in irreparable damage or loss of reserves. As the waterflood is mature, the flood front is sufficiently far away from the injectors to prevent bypassing of reserves by a fracture system. Any fracture initiated will not extend far into the formation due to the still relatively low injection rates and high fracture fluid loss properties of water. If a fracture develops into underlying water, a proportion of the injected water will be lost, however the remainder will continue to enter the oil zone and extend the present sweep. As the fracture will be unsupported by sand, reducing pressure on any well exhibiting unacceptable water loss will tend to close the fracture.

In support of the application to increase maximum operating pressure, we refer you to previous correspondence between Chevron and the Petroleum Branch (82-09 report by Mr. R. D. Trimble). In the report, increased productivity resulting from increased injection rates (accomplished by raising injection pressure above fracture pressure) is discussed in detail. The conclusion that this approach is feasible is in part based on success to date with a high rate injection scheme in Daly Unit #1.

A substantial portion of the accelerated production would be incremental because many wells would not last 66 years, which is the estimated remaining life of the field with the present wells and mode of operation. It would not be economic to replace many wells when they had to be abandoned because of deteriorated casing.

The higher operating pressure applied for would require replacement of some of the injection system as shown in Figure 2. The pipelines will be replaced with high pressure fibreglass pipe. The entire system will be pressure tested at 11 MPa. The water plant at 15-1-10-28 will also be replaced and upgraded to the higher pressure rating.

Additional salt water required to inject at the higher rates is available from Chevron Canada Resources Limited 12-29-10-28 Daly wholly owned facility.

C. Reactivate 6, 14 and 16 of 11 injection wells (already approved)

The suspended injection wells, 6, 14 and 16 of 11, have been suspended for more than 10 years because of poor response to waterflooding. With increased injection rates and based on good Unit waterflood response overall, on a voidage balance basis, it is felt there is justification to reactivate these wells. Although approval of these reactivations has already been obtained, implementation would depend upon approval of the entire expansion application.

The estimated increased production rate for the next 25 years resulting from all the above changes is shown by Figure No. 1. The production forecast is based on R. Trimble's report, the results of a similar project in Daly Unit #1 and anticipated response to the additional injection wells.



The forecasts were terminated in the year 2023 because production beyond that is difficult to justify (downhole well equipment has a limited life and over 40 years is a long time to project). Theoretically the Base case should extend to the year 2050 and the Incremental case to 2030 based on a terminal water-oil ratio of 30. The Incremental case has  $420 \times 10^3 \text{ m}^3$  of incremental oil production.

The implementation of the above modifications to the Daly Unit #3 waterflood is dependent upon approval of our accompanying application for New Oil status for royalty and mineral tax purposes for oil production above the projected present decline rate. The resulting reduced Crown royalties and incremental mineral taxes would make the project economically feasible.

All the landowners in the immediate area have been contacted to inform them of our plans. If new and replacement lines are to be installed this year they will have to be done during the summer months and therefore an early approval on this application would be appreciated.

Yours truly,



C. G. Folden, P. Eng.  
Area Supervisor  
Virden

CGF/clm

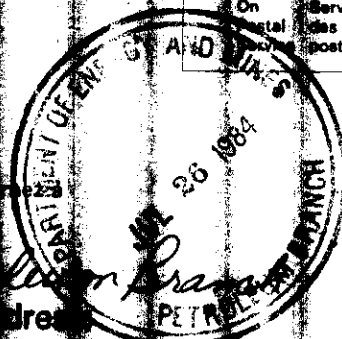
Attachments

Canada Postes  
P.S. Canada

**A** Office of Origin **B** Bureau d'origine  
 Registration No. / Numéro d'enregistrement  
 Date: 8-2-84  
 Post Office of Mailing / Bureau d'expédition  
 Winnipeg

**AR**

*SRD*



**A** Return to **B** Retourner à

*Petroleum Branch*  
 New Address:  
 555-330 Graham Avenue  
 Winnipeg, Manitoba  
 R3C 4E3

Canada Postes  
P.S. Canada

**A** Office of Origin **B** Bureau d'origine  
 Registration No. / Numéro d'enregistrement  
 Date: 8-2-84  
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 Winnipeg

**AR**

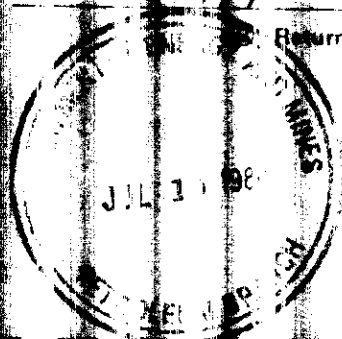
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**A** Office of Origin **B** Bureau d'origine  
 Registration No. / Numéro d'enregistrement  
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**A** Return to **B** Retourner à

*Petroleum Branch*  
 New Address:  
 555-330 Graham Avenue  
 Winnipeg, Manitoba  
 R3C 4E3



Acknowledgement of Receipt		Avis de réception	
To be completed by Office of origin		A remplir par le Bureau d'origine	
Name of Addressee <b>Triton Petroleum Limited</b>		Nom du destinataire	
P.O. Box R.R. or A.D. No. 1 Street C.P. n° de R.R. ou d'app. n° et rue <b>10th Flr., Two Energy Square 4849 Greenville Avenue</b>			
City <b>Dallas</b>	Province <b>Texas</b>	Country <b>U.S.A.</b>	Pays <b>U.S.A.</b>
CODE postal <b>75206</b>			
Office of Destination		Bureau destinataire	
This advice should be signed by the addressee or authorized representative of the postal administration of the country of destination provided by the postal administration of delivery and returned by first mail to the address shown on the back.		Cet avis doit être signé par le destinataire ou son représentant ou, si le règlement du pays de destination le comporte, par l'agent du bureau de destination et renvoyé par le premier courrier à l'adresse indiquée au recto.	
The registered item referred to at was delivered on		19	
Signature of Postmaster or Office of Delivery	Signature de l'agent du bureau de destination	Signature of Addressee or Authorized Representative	Signature du destinataire ou de son représentant
<i>[Signature]</i>		<i>[Signature]</i>	
		33-086-230 (11-80)	

Acknowledgement of Receipt		Avis de réception	
To be completed by Office of origin		A remplir par le Bureau d'origine	
Name of Addressee <b>Condor Petroleum Incorporated</b>		Nom du destinataire	
P.O. Box R.R. or A.D. No. 1 Street C.P. n° de R.R. ou d'app. n° et rue <b>301 - 845 Broad St.</b>			
City <b>Regina</b>	Province <b>Saskatchewan</b>	Country <b>Canada</b>	Pays <b>Canada</b>
CODE postal <b>S4R 1X7</b>			
Office of Destination		Bureau destinataire	
This advice should be signed by the addressee or authorized representative of the postal administration of the country of destination provided by the postal administration of delivery and returned by first mail to the address shown on the back.		Cet avis doit être signé par le destinataire ou son représentant ou, si le règlement du pays de destination le comporte, par l'agent du bureau de destination et renvoyé par le premier courrier à l'adresse indiquée au recto.	
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<i>[Signature]</i>		<i>[Signature]</i>	
		33-086-230 (11-80)	

Acknowledgement of Receipt		Avis de réception	
To be completed by Office of origin		A remplir par le Bureau d'origine	
Name of Addressee <b>Centoba Oil Co. Ltd.</b>		Nom du destinataire	
P.O. Box R.R. or A.D. No. 1 Street C.P. n° de R.R. ou d'app. n° et rue <b>c/o J. Wiens, Box 115</b>			
City <b>Virden</b>	Province <b>Manitoba</b>	Country <b>Canada</b>	Pays <b>Canada</b>
CODE postal <b>ROM 2C0</b>			
Office of Destination		Bureau destinataire	
This advice should be signed by the addressee or authorized representative of the postal administration of the country of destination provided by the postal administration of delivery and returned by first mail to the address shown on the back.		Cet avis doit être signé par le destinataire ou son représentant ou, si le règlement du pays de destination le comporte, par l'agent du bureau de destination et renvoyé par le premier courrier à l'adresse indiquée au recto.	
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		33-086-230 (11-80)	

# Acknowledgment of Receipt Avis de réception

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Name of addressee  
 Nom du destinataire  
**Beaverhead Resources Ltd.**

P.O. Box / Boîte postale No. & Street / C.P. n° de R.R. ou d'app. n° et rue  
**900 Bow Valley Square 1, 202 Sixth Ave. S.W.**

City / Ville  
**Calgary Alberta**

Country / Pays  
**Canada**

Postal Code / CODE postal  
**T2P 2R9**

**(D) Office of Destination**  
 Cet avis doit être signé par le destinataire ou son représentant ou, si le règlement du pays de destination le comporte, par l'agent du bureau de destination et renvoyé par le premier courrier à l'adresse indiquée au recto.

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**July 17/84**

33-086-230 (11-80)

# Acknowledgment of Receipt Avis de réception

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 À remplir par le Bureau d'origine

Name of addressee  
 Nom du destinataire  
**Resman Oil & Gas Ltd.**

P.O. Box / Boîte postale No. & Street / C.P. n° de R.R. ou d'app. n° et rue  
**#2810, 250 - Sixth Avenue S.W.**

City / Ville  
**Calgary Alberta**

Country / Pays  
**Canada**

Postal Code / CODE postal  
**T2P 3H7**

**(D) Office of Destination**  
 Cet avis doit être signé par le destinataire ou son représentant ou, si le règlement du pays de destination le comporte, par l'agent du bureau de destination et renvoyé par le premier courrier à l'adresse indiquée au recto.

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Date Stamp / Timbre à date du bureau de destination  
**JUL 17 1984**

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**[Signature]**

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33-086-230 (11-80)

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A Office of Origin / Bureau d'origine  
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Date: 7-25-78  
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On Postal Service / Service des postes

Return to / Retournez à

*Petroleum Branch*  
New Address:  
555-330 Graham Avenue  
Winnipeg, Manitoba  
R3C 4E3

Canada Post / Canada Post  
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Registration / Numéro d'identification  
Date: 8-1-80  
Post Office / Bureau d'expédition: Wm. P. P.

Canada Post / Postes Canada  
On Postal Service / Service des postes

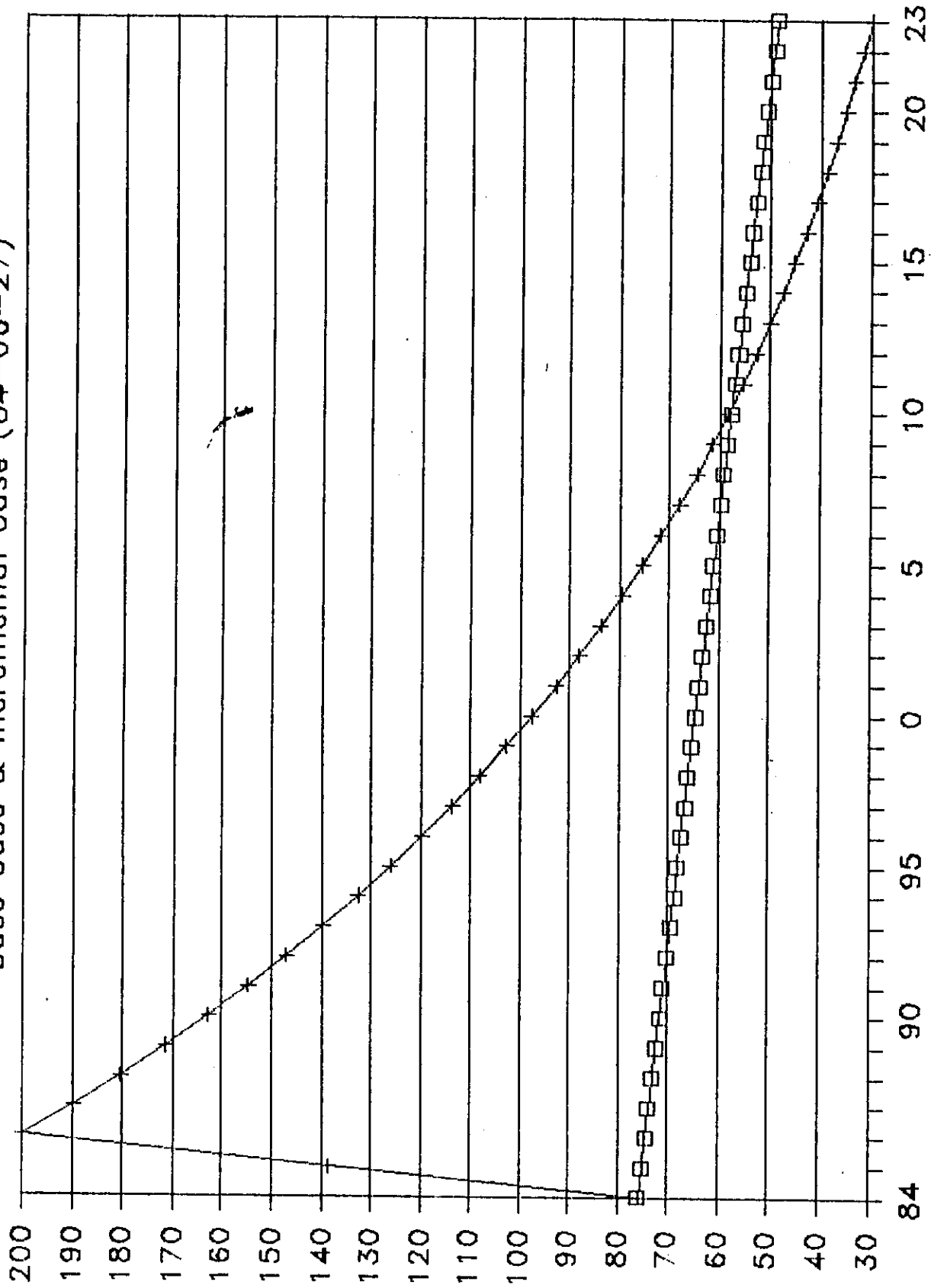
Return to / Retournez à

B Retournez à

*Petroleum Branch*  
New Address:  
555-330 Graham Avenue  
Winnipeg, Manitoba  
R3C 4E3

# DALY UNIT #3 - PRODUCTION FORECAST

Base Case & Incremental Case (84-06-27)



□ Base + DATE + Incr.

FIGURE 1

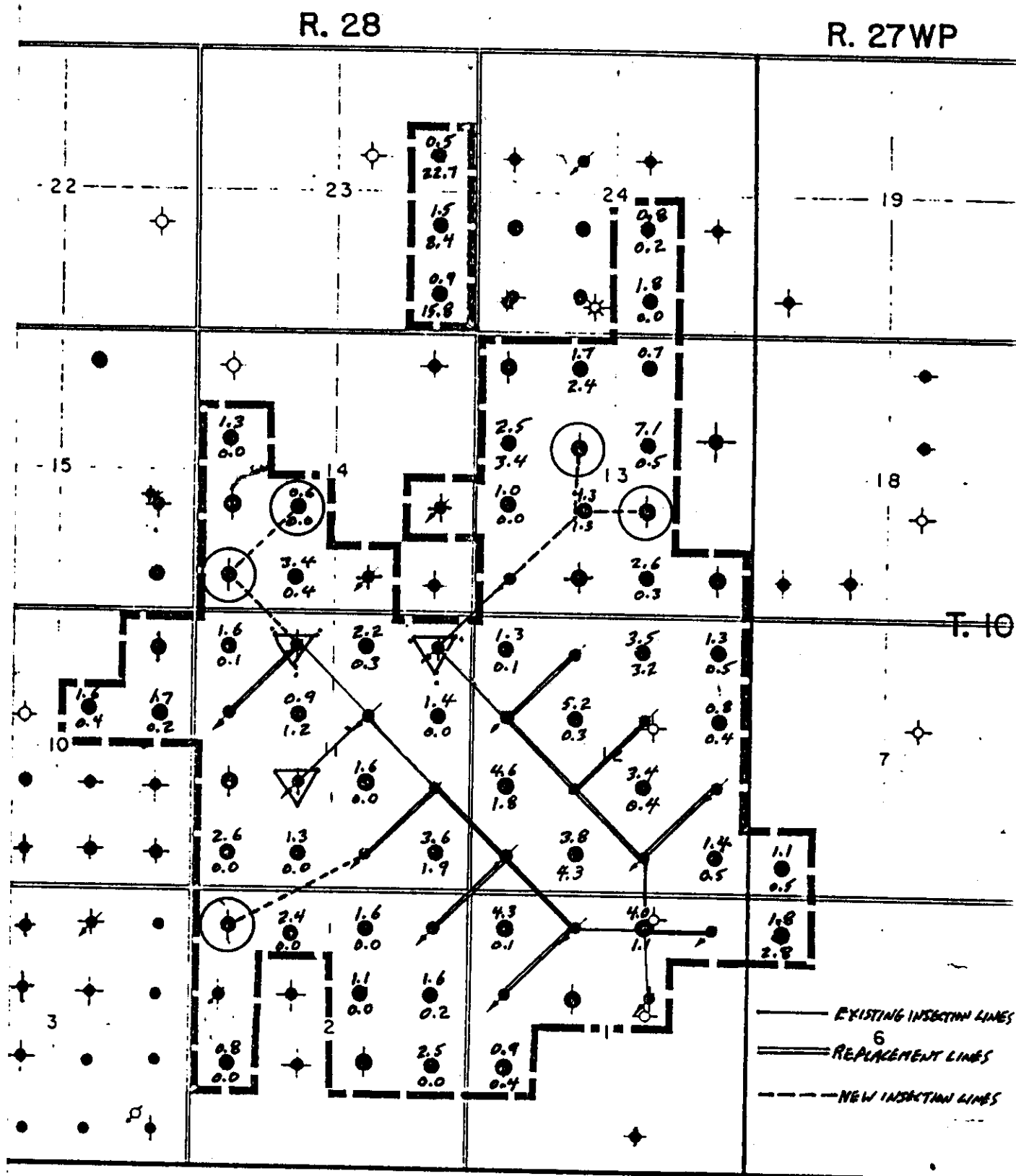
FIGURE 1A

## Daly Unit #3 - PRODUCTION FORECAST

Base Case and Incremental Case (due to expanded waterflood)

1984-06-27

YEAR	BASE PRODUCTION CUBIC M./DAY	INCREMENTAL PRODUCTION CUBIC M./DAY
1984	76	76
1985	75.3	138.5
1986	74.6	200
1987	73.9	190
1988	73.2	180.5
1989	72.5	171.5
1990	71.8	162.9
1991	71.1	154.8
1992	70.4	147.1
1993	69.7	139.7
1994	69	132.7
1995	68.3	126.1
1996	67.6	119.8
1997	66.9	113.8
1998	66.2	108.1
1999	65.5	102.7
2000	64.8	97.6
2001	64.1	92.7
2002	63.4	88.1
2003	62.7	83.7
2004	62	79.5
2005	61.3	75.5
2006	60.6	71.7
2007	59.9	68.1
2008	59.2	64.7
2009	58.5	61.5
2010	57.8	58.4
2011	57.1	55.5
2012	56.4	52.7
2013	55.7	50.1
2014	55	47.6
2015	54.3	45.2
2016	53.6	42.9
2017	52.9	40.8
2018	52.2	38.8
2019	51.5	36.9
2020	50.8	35.1
2021	50.1	33.3
2022	49.4	31.6
2023	48.7	30



LEGEND



PROPOSED NEW INJECTORS



OILWELL



PROPOSED REACTIVATIONS



SUSPENDED OILWELL



INJECTION WELL

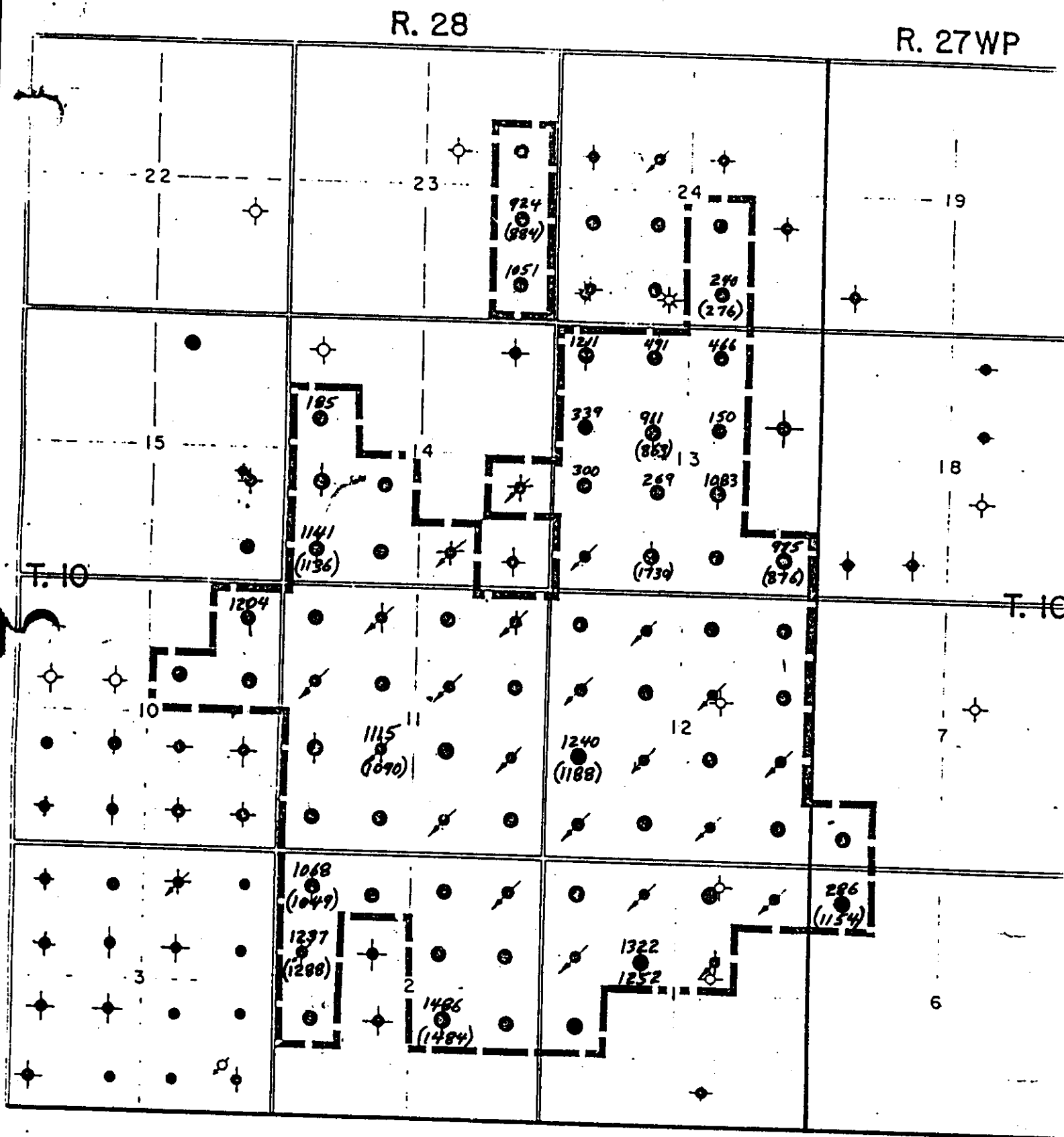
FIGURE 2

WELL PRODUCTION TESTS  
OIL  
WATER (m³/DAY)

DALY UNIT No. 3

MAP OF AREA





# LEGEND

- OILWELL
- ⦿ SUSPENDED OILWELL
- ⊗ INJECTION WELL

FIGURE 3

BOTTOM HOLE PRESSURE SURVEY - YEAR 1984  
 DALY UNIT No. 3  
 DATUM DEPTH - 780 FT.S.S.  
 MAP OF AREA  
 (1981)

July 12, 1984

Queen's Printer  
Statutory Publications Division  
200 Vaughan Street

Brad Thiessen  
Petroleum Administrator  
Petroleum Branch  
333 - 1st Graham Avenue

MANITOBA GAZETTE

Please have the two (2) attached Notices appear in the next  
issue of the Manitoba Gazette under The Mines Act.

R

Brad Thiessen

BT/ch

Attachments



MANITOBA

THE OIL AND NATURAL GAS CONSERVATION BOARD  
309 LEGISLATIVE BUILDING  
WINNIPEG, MANITOBA  
R3C 0V8

NOTICE

UNDER THE MINES ACT

DALY OIL FIELD

Chevron Canada Resources Limited has made application to modify its pressure maintenance operations in Daly Unit No. 3 as follows:

1. Initiate water injection in the following wells:

Chevron Haskett Daly	13-	2-10-28	(WPM)
Chevron Daly		7-13-10-28	(WPM)
Chevron Daly		11-13-10-28	(WPM)
Chevron Daly Prov.		4-14-10-28	(WPM)
Chevron Daly Prov.		6-14-10-28	(WPM)

2. Increase the maximum allowable wellhead injection pressure from 1300 psig (8 962 kPa) to 10 000 kPa.

If no valid objection or intervention in writing is received by the Board at 555 - 330 Graham Ave., Winnipeg, Manitoba, R3C 4E3, within 14 days of the publication of this notice, the Board may approve the application.

Copies of the application may be obtained from Chevron Canada Resources Limited, P. O. Box 100, Virden, Manitoba, R0M 2C0.

Dated at Winnipeg this 10<sup>th</sup> day of July, 1984.

Ian Haugh  
Deputy Chairman

# MANIT<sup>BA</sup>

## Inter-Departmental Memo

Date July 9th, 1984

To The Oil and Natural Gas  
Conservation Board

From H. Clare Moster  
Director, Petroleum Branch

Marc Eliesen - Chairman  
Dr. I. Haugh - Deputy Chairman  
J. F. Redgwell - Member

Telephone

Subject Daly Unit No. 3 - Expansion of Pressure Maintenance Operations

Chevron Canada Resources Limited, as operator of the Daly Unit No. 3, has made application for approval to modify its pressure maintenance operations in the Unit by conversion of five wells to water injection wells and by increasing the maximum allowable wellhead injection pressure to 10 000 kPa.

### Recommendation:

It is recommended that notice of the application be published in The Manitoba Gazette, the Virden Empire-Advance, the Gopher Creek Chronicle and sent to potentially affected offset working interest owners. In the absence of valid objections to the notice, it is recommended that the application be approved by the Board as provided for in Board Order No. PM31. A copy of the proposed notice is attached.

### Discussion:

#### 1. History

Waterflooding in the area of Daly Unit No. 3 was initiated early in the development of the pool. In July 1953, an 80 acre pilot waterflood was initiated in the southern part of the Unit area. The pilot scheme was expanded in 1954, 1955 and again in 1957 resulting in a five spot waterflood covering approximately 1 180 acres out of a total Unit area of 3 200 acres. Figure No. 1 shows the Unit area and outlines the presently active injection patterns.

As the result of pressure maintenance, a substantial volume of incremental production has occurred in the Unit area. Figure No. 2 is a copy of a graph of estimated incremental recovery due to the project taken from the 1971 project progress report. It is noted that virtually all post 1971 production was considered attributable to pressure maintenance operations.

In August 1981, Chevron made application to abandon six water injection wells which had been inactive for a number of years due to lack of injectivity and associated production response or downhole mechanical problems. Upon review of this proposal, the Petroleum Branch, noting that the proposal would result in abandonment of a major portion of the scheme, requested that Chevron review alternatives prior to proceeding with the abandonments. In response to the Branch's concerns, Chevron conducted an engineering study of the profitability of both an infill injection program and a program of increased injection pressures and rates. The study concluded that infill injection or increased injection pressure would only accelerate production and would result in no incremental oil recovery. The report did conclude, however, that such acceleration would be economically attractive as it may result in avoidance of replacement of deteriorating wells. The Petroleum Branch, in subsequent discussions

with Chevron, pointed out that the study considered only modifications in the existing pressure maintenance area and did not evaluate the feasibility of expansion of the existing patterns or use of a reduced pattern area in portions of the Unit that had either not been flooded or had not shown response to injection. As a result of these discussions and further studies, Chevron is now proposing modifications to the scheme which would:

- 1) resume injection in areas that had shown marginal injectivity and response
- 2) expand injection into portions of the reservoir previously unflooded
- 3) accelerate recovery by increasing maximum injection pressures from the current limiting level of 8 962 kPa to 10 000 kPa.

(Note: The additional and reactivated injection patterns are shown on Figure 1)

In finalizing its plans, Chevron conducted a detailed reservoir pressure survey in the Unit this spring. Specifically the northern part of the Unit was surveyed extensively. The results of the survey are presented as Figure 3 of Chevron's application. The survey indicates relatively low pressures in much of the reservoir in Section 13-10-28 and in portions of Section 14-10-28. The survey also indicates high pressures in the central part of Section 13 which is a slight structural low. This may be due to the lower structure but more likely reflects communication with an underlying aquifer in the area. Further evidence of minimal pressure support in this part of the Unit is the decline in the total fluid production of recently reactivated wells in the area. (e.g.: Chevron North Daly 2-24-10-28 declined from a clean oil rate of 5.5 m<sup>3</sup>/d in October 1982 shortly after reactivation, to a clean oil rate of 1.38 m<sup>3</sup>/d in April 1984).

#### Expanded Injection

The proposed injectors fall into 3 groups:

a) Chevron Haskett Daly 13-2-10-28. This well is a watered out producer. Conversion of the well to injection would prevent oil migration out of the Unit and should enhance production in the area by increasing reservoir pressure. Injection at this location may affect non Unit production in Lsd. 16 of Section 3-10-28 (WPM) which may necessitate inclusion of this tract in the Unit in the future. Having regard for performance of pressure maintained wells to the east and the fact that 13-2 is watered out, conversion of this well presents minimal risk to ultimate recovery and is likely to result in increased recovery.

b) Chevron Daly Prov. 4-14-10-28 (WPM) and Chevron Daly Prov. 6-14-10-28 (WPM). Conversion of these wells represents a north west extension of pressure maintenance operations on the same pattern as has been established elsewhere in the Unit. The 6-14 well is currently a marginal producer while 4-14 has watered out (probably due to communication with the underlying aquifer). As in the case of 13-2, the potential loss of reserves is minimal and there is a possibility of substantial incremental production. Injection at 4-14 will probably affect production at the non-Unit offset in Lsd. 1 of Section 15-10-28 (WPM). Negotiations to include this tract in the Unit are underway.

c) Chevron Daly 7-13-10-28 (WPM) and Chevron Daly 11-13-10-28 (WPM). Both of these wells have watered out. Injection in the area should assist the natural water drive and maintain or increase reservoir pressures to the north east and south west. As above, the potential loss of reserves is minimal while incremental production may be substantial.

Based on the limited risk and significant potential of Chevron's expanded injection plans, approval of this phase of the proposal is recommended.

#### Reactivation of Injectors

Chevron's plans to reactivate three suspended injection wells in Section 11-10-28 will probably assist in pressure maintenance and displacement in the area. However, due to relatively high pressures in this area and the demonstrated limited effectiveness of this injection, the effects of reactivation are not expected to be major. As Chevron has noted, Petroleum Branch approval to proceed with these reactivations has been given.

#### Increase of Maximum Wellhead Injection Pressure

Board Order No. PM31 which authorizes pressure maintenance operations in Daly Unit No. 3 limits maximum wellhead injection pressures to 1300 psig (8962 kPa). The current injection pressure (April 1984) is 7 500 kPa. Based on results of a limited field test conducted in 1971, Chevron indicates that by increasing injection pressure to the order of 9 000 kPa, reservoir fracturing will occur thereby allowing substantially increased water injection rates. While this will likely have no beneficial effect on ultimate oil recovery in the established waterflood area, it will increase the viability of the reactivated wells and the new injection wells. Also, as Chevron suggests, the acceleration of recovery may indirectly increase ultimate reserves by avoidance of well abandonments for mechanical reasons during the latter stages of depletion when re-drilling would not be economical.

Injection above the fracture pressure could cause reduced sweep efficiency in areas where a substantial water bank had not built-up. Specifically, the well Chevron Daly Prov. 6-14-10-28 is currently producing clean oil indicating the absence of any water bank in this area. Injection pressure in this situation should initially be maintained to levels below the fracture pressure. This could probably be accomplished by use of a wellhead choke at this location.

### Monitoring of Expanded Scheme

In order to measure the success of the expanded pressure maintenance scheme, a number of monitoring programs are recommended. These are discussed briefly below.

1) Well Test Data. Reliable well test data should be obtained on all wells prior to initiation of injection. Subsequent to initiation of the program, testing of each well on a semi-annual basis should be undertaken. The Branch will confirm with Chevron that facilities to accomplish this testing are available.

2) Board Order No. PM38 provides for tri-annual pressure surveys in Daly Unit No. 3. With expansion of the project, it is felt that more frequent pressure surveys should be conducted at least during the initial years. Consequently it is recommended that annual pressure surveys be required. Individual survey plans will be developed between Chevron and the Petroleum Branch.

### Offset Operators

As noted above, Chevron's planned additional injection could potentially effect offset operators. Figure No. 3 indicates all offset operators within  $\frac{1}{2}$  mile of Daly Unit No. 3. Only two offset operators, Beaverhead and Centoba are likely to be affected by Chevron's proposal. It is recommended that the attached notice be published in the Gazette, the local newspapers and sent to all offset operators.

### Approval Process

Attachment No. 1 to this memo is a copy of Board Order No. PM31. It is noted that injection is approved for a specified list of wells and "from time to time in such other wells as the Board may approve". Similar provisions apply to maximum wellhead injection pressure and frequency of pressure measurements, both in this Order and in Board Order No. PM38. Consequently, approval can be in the form of a letter from the Board setting out the approval and stating any terms, conditions or additional requirements.

~~Original~~ Signed by H. C. Mester

H. Clare Mester

HCM/sb  
Att:



MANITOBA

THE OIL AND NATURAL GAS CONSERVATION BOARD  
309 LEGISLATIVE BUILDING  
WINNIPEG, MANITOBA  
R3C 0V8

NOTICE

UNDER THE MINES ACT

DALY OIL FIELD

Chevron Canada Resources Limited has made application to modify its pressure maintenance operations in Daly Unit No. 3 as follows:

1. Initiate water injection in the following wells:

Chevron Haskett Daly	13-	2-10-28	(WPM)
Chevron Daly	7-	13-10-28	(WPM)
Chevron Daly	11-	13-10-28	(WPM)
Chevron Daly Prov.	4-	14-10-28	(WPM)
Chevron Daly Prov.	6-	14-10-28	(WPM)

2. Increase the maximum allowable wellhead injection pressure from 1300 psig (8 962 kPa) to 10 000 kPa.

If no valid objection or intervention in writing is received by the Board at 555 - 330 Graham Ave., Winnipeg, Manitoba, R3C 4E3, within 14 days of the publication of this notice, the Board may approve the application.

Copies of the application may be obtained from Chevron Canada Resources Limited, P. O. Box 100, Virden, Manitoba, R0M 2C0.

Dated at Winnipeg this            day of            , 1984.

Ian Haugh  
Deputy Chairman



## Manitoba Regulation 51/77

Being

## THE OIL AND NATURAL GAS CONSERVATION BOARD

ORDER NO. PM 31

*An Order Pertaining to Pressure Maintenance by Water Flooding*

DALY UNIT NO. 3

*Made and Passed Pursuant to "The Mines Act", Cap. M160, of the Continuing Consolidation of the Statutes of Manitoba, and Amendments Thereto, by The Oil and Natural Gas Conservation Board of Manitoba*

(Filed March 15, 1977)

WHEREAS, subsection (9)(d) of Section 62 of "The Mines Act", being Chapter M160 of the Continuing Consolidation of the Statutes of Manitoba, provides as follows:

"62(9) Without restricting the generality of subsection (8) the board, with the approval of the minister, may make orders

(d) requiring the repressuring, recycling, or pressure maintenance, of any pool or portion thereof where it is economical so to do, and for that purpose where necessary requiring the introduction or injection into any pool or portion thereof of gas, air, water, or other substance;"

AND WHEREAS, the Board, received a submission dated September 2, 1976, from Chevron Standard Limited, as Operator of Daly Unit No. 3, requesting the Board issue an order pertaining to pressure maintenance by water flooding within the Unit Area of Daly Unit No. 3.

AND WHEREAS, upon due consideration of the submission by Chevron Standard Limited, the Board has found:

- (a) That the pressure maintenance by water flooding of a certain part of the Daly Field in Manitoba, comprising the Unit Area of the Daly Unit No. 3, is necessary to prevent waste, and to increase the recovery of oil;
- (b) That the value of the estimated additional recovery of oil resulting from such operation will exceed the estimated additional cost incidental to the conduct of such operation; and
- (c) That such operation will result in general advantage to the owners of oil and gas rights within the Unit Area.

AND WHEREAS, Unitization Order No. 23 provides for the appointment of Chevron Standard Limited as Unit Operator.

NOW, THEREFORE, the Board orders:

1. This Order replaces all existing water flooding permits and approvals under which the water flood in Daly Unit No. 3 is now operating.
2. (a) The Unit Operator shall continue to carry out pressure maintenance operations by the injection of water to the Lodgepole Formation of the Mississippian Age underlying the Unit Area;



shall be in accordance with, and subject to,

## NANCE RULES

gepole Formation of the Mississippian Age

28

28

28

28

28

1-10-28

1-10-28

1-10-28

11-10-28

11-10-28

11-10-28

11-10-28

2-10-28

2-10-28

2-10-28

2-10-28

28

28

28

8

8

8

er wells as the Board may direct, or, upon  
may approve;

any remedial work required to be per-  
d to in this clause, endeavour to maintain

subclause (2), the Board may, upon  
approve the suspension of water injection,  
the pressure maintenance operation in the  
ected.

Unit Operator shall satisfy the Board as  
iod of treatment of the water to be

ource of water being injected, the Unit  
to the suitability of the water to be

port to the Board any indication of chan-  
r to producing wells, or any indication of  
tributable to the pressure maintenance

4. The Unit Operator shall immediately report to the Board if the maximum surface pressure of injected water in any of the wells referred to in Clause 1 hereof exceeds 1300 psig; stating reasons, duration and effects of such increase of surface injection pressure on the progress, performance and efficacy of the pressure maintenance program and overall oil recovery. The Board may prescribe from time to time a maximum pressure, or a maximum or a minimum rate, at which water shall be injected to any well in the Unit.
5. At least once every second year, commencing in 1978, unless otherwise directed by the Board, the Unit Operator shall carry out a subsurface pressure survey program to determine the reservoir pressure in the producing wells in the Unit. The Unit Operator shall submit the details of such program to the Petroleum Branch including the wells to be surveyed, the measurement technique to be used and the intended shut-in periods for each well, and approval must be obtained from the Branch before the program is carried out. After having the program approved and carried out a report must be submitted to the Branch including:
  - (1) The pressure data obtained from the program;
  - (2) An isobaric map of the reservoir or Unit based on the data obtained;
  - (3) A discussion of the survey results and pressure distribution in the reservoir.

In the event the surface pressure of injected water in any of the wells referred to in Clause 1 hereof exceeds 1300 psig, the Unit Operator shall carry out the subsurface pressure survey program at least annually, unless otherwise directed by the Board, commencing the year following the date such pressure was reached.
6. The Unit Operator shall, not later than the twenty-fifth day of each month, file with the Petroleum Branch a report of the quantity, source and pressure of water injected during the preceding month to each well referred to in Clause 1 hereof.
7. (1) Unless otherwise authorized in writing by the Board, the Unit Operator shall, within six weeks of the expiration of each yearly period commencing on the first day of January, 1978 file with the Board a report of the progress, performance, and efficacy of the pressure maintenance program during the period;
- (2) Subject to any direction in writing of the Board to the contrary, a report required by this clause may, at the discretion of the Unit Operator, be in two parts.

The first of which parts shall set out graphically and from the commencement of the operation of the pressure maintenance program:

- (a) the daily average rate during each month of oil production of each producing well;
- (b) the average water-oil ratio during each month of each producing well;
- (c) the monthly cumulative oil and water production from each producing well;
- (d) the daily average rate during each month of water injection to each injection well;
- (e) the daily average water injection pressure during each month at each injection well;
- (f) the monthly cumulative volume of water injected to each injection well;
- (g) the average injectivity index during each month, for each water injection well, which index, at the discretion of the Unit Operator, may be determined as

- (i) the daily injection rate divided by the average injection well-head pressure, or
- (ii) any similar index that the Board, on the application of the Unit Operator, may approve; and
- (h) the date and type of any well treatment or workover which shall be indicated on the graph.

The second of which parts shall contain:

- (a) calculations of the balance during each month between water injected to, and fluids withdrawn from the Unitized Strata;
- (b) such other interpretative information as the Unit Operator considers necessary to evaluate adequately the progress, performance, and efficacy of the pressure maintenance program;
- (c) an outline of the method actually in use for the quality control, and treatment of the water, or, where there has been no change in the control or treatment from that outlined in a previous report, a statement to that effect; and
- (d) a detailed economic summary of the Unit for the year. This summary shall outline the total revenue from crude oil sales, show a breakdown of the operating costs according to general category, indicate the average production cost per barrel of oil produced during the period and the Unit net revenue before deducting royalties and taxes.

- (3) If a report required by this Clause is in the form provided for in subclause (2), the Board, at any time, may make the first part of the report available to the public, and, after one year from the end of the period for which the report is made, may make the second part of the report available to the public, and, if the report is not in the form provided for in subclause (2), the Board may make the whole of the report available to the public at any time.

- 3. This Order shall be effective at the hour of eight o'clock in the forenoon, official time, on the first day of May, A.D., 1977.

Oil and Natural Gas Order No. PM 31,  
made and passed this 9th day of  
March, A.D., 1977, at the City  
of Winnipeg, in the Province of  
Manitoba, by The Oil and Natural  
Gas Conservation Board.

Approved:

"S. Green"

Sidney Green,  
Minister of Mines, Resources and  
Environmental Management.

"Jas. T. Cawley"

Jas. T. Cawley, P. Eng.,  
Chairman,  
The Oil and Natural Gas  
Conservation Board.

"J.S. Roper"

J.S. Roper,  
Deputy Chairman,  
The Oil and Natural Gas  
Conservation Board.

"Ian Haugh"

Dr. I. Haugh,  
Member,  
The Oil and Natural Gas  
Conservation Board.

Manitoba Re

Being a Regulation Under Section 292 of  
Manner and Position for Affixing of

In this regulation:

1. "Act" means The Highway Traffic Act.
2. Before affixing the validation sticker to plate shall be thoroughly cleaned of dirt.
3. Except in the case of a traction engine, lower right corner of the rear number plate and the lower right corner of the front plate.
4. Manitoba Regulation 42/74 repealed.

FIGURE No. 3  
OFFSET OPERATORS

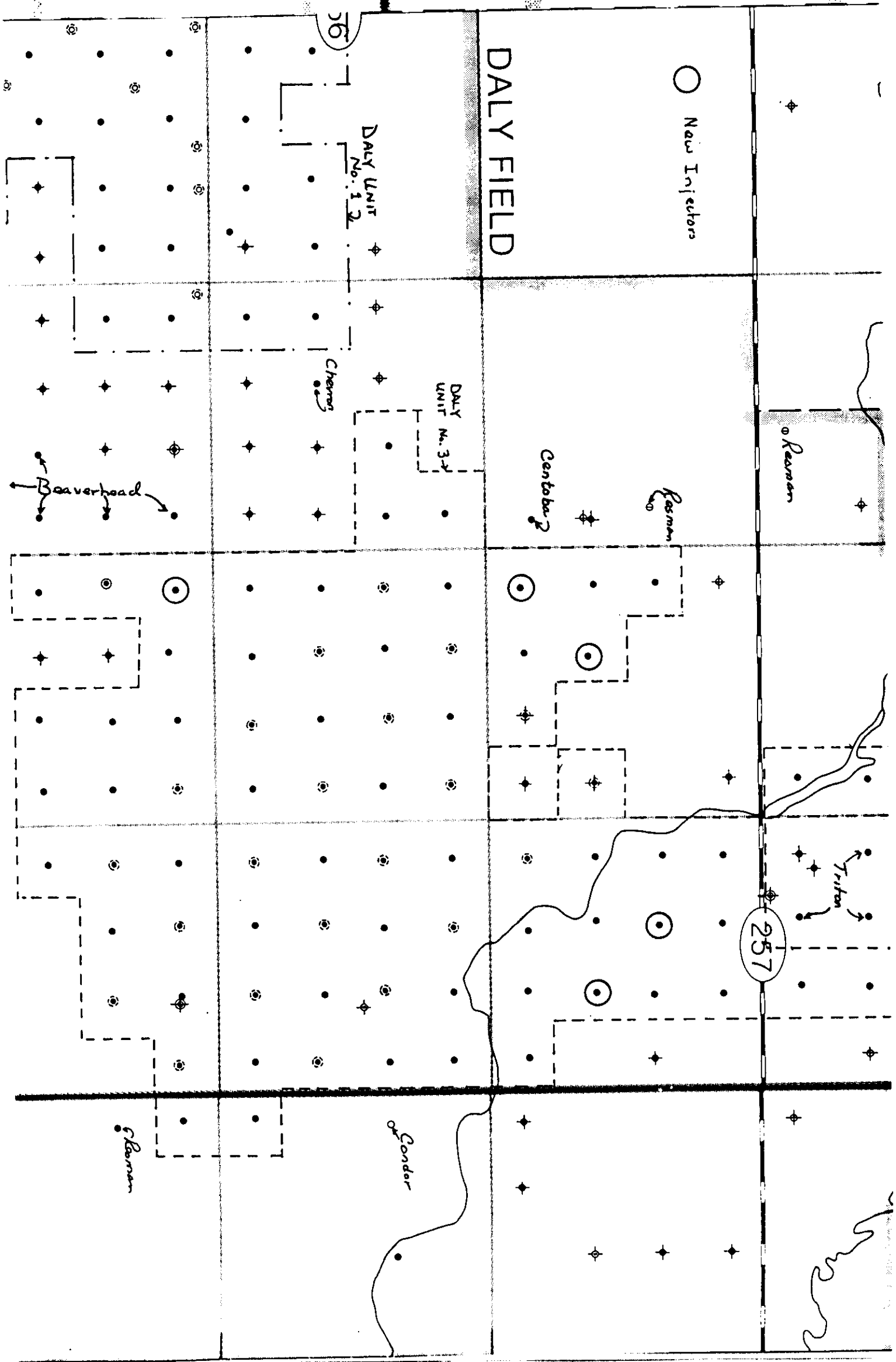


FIGURE 2  
DAILY WATER FLOOD  
TOTAL PRODUCTION

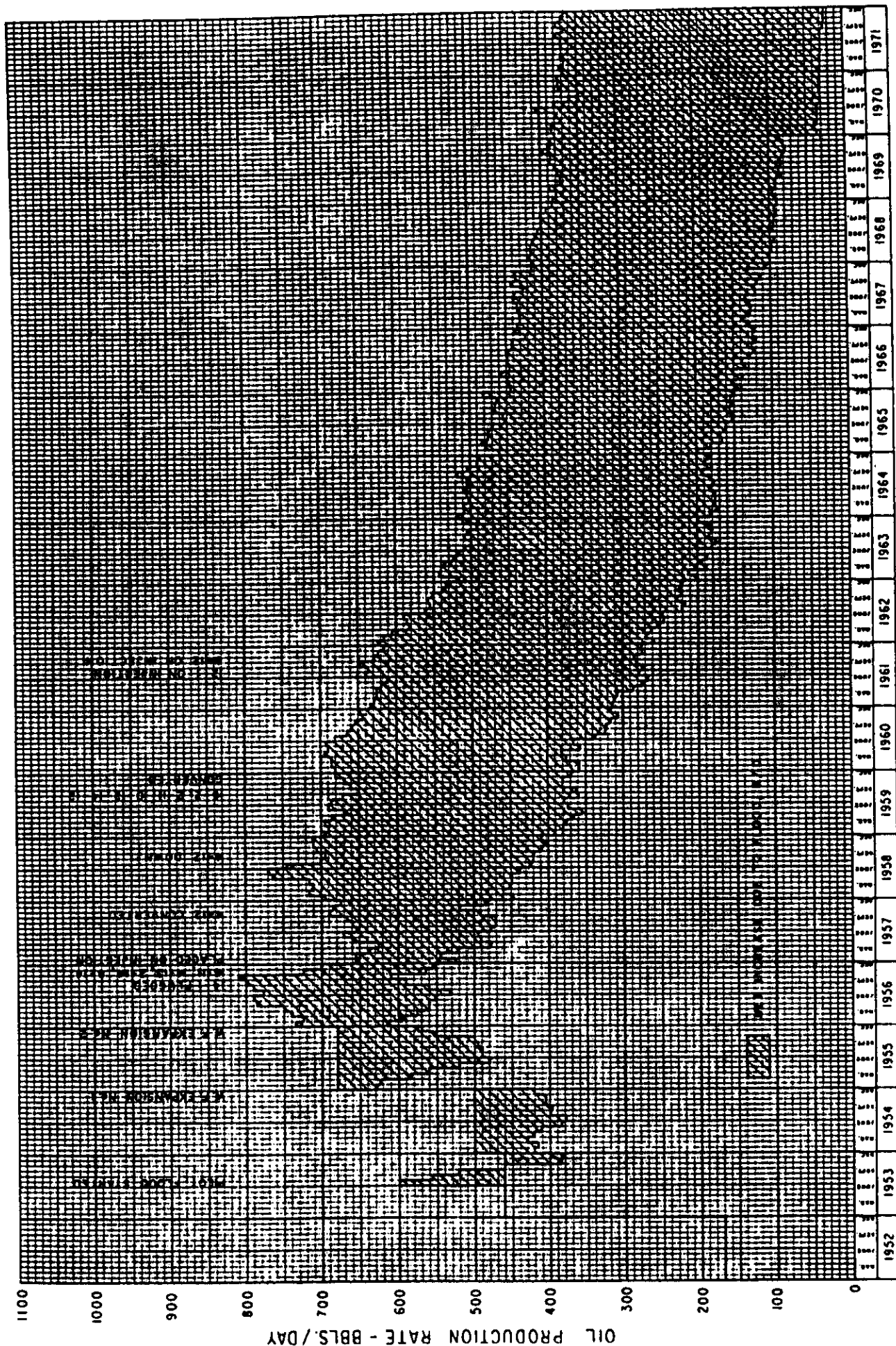
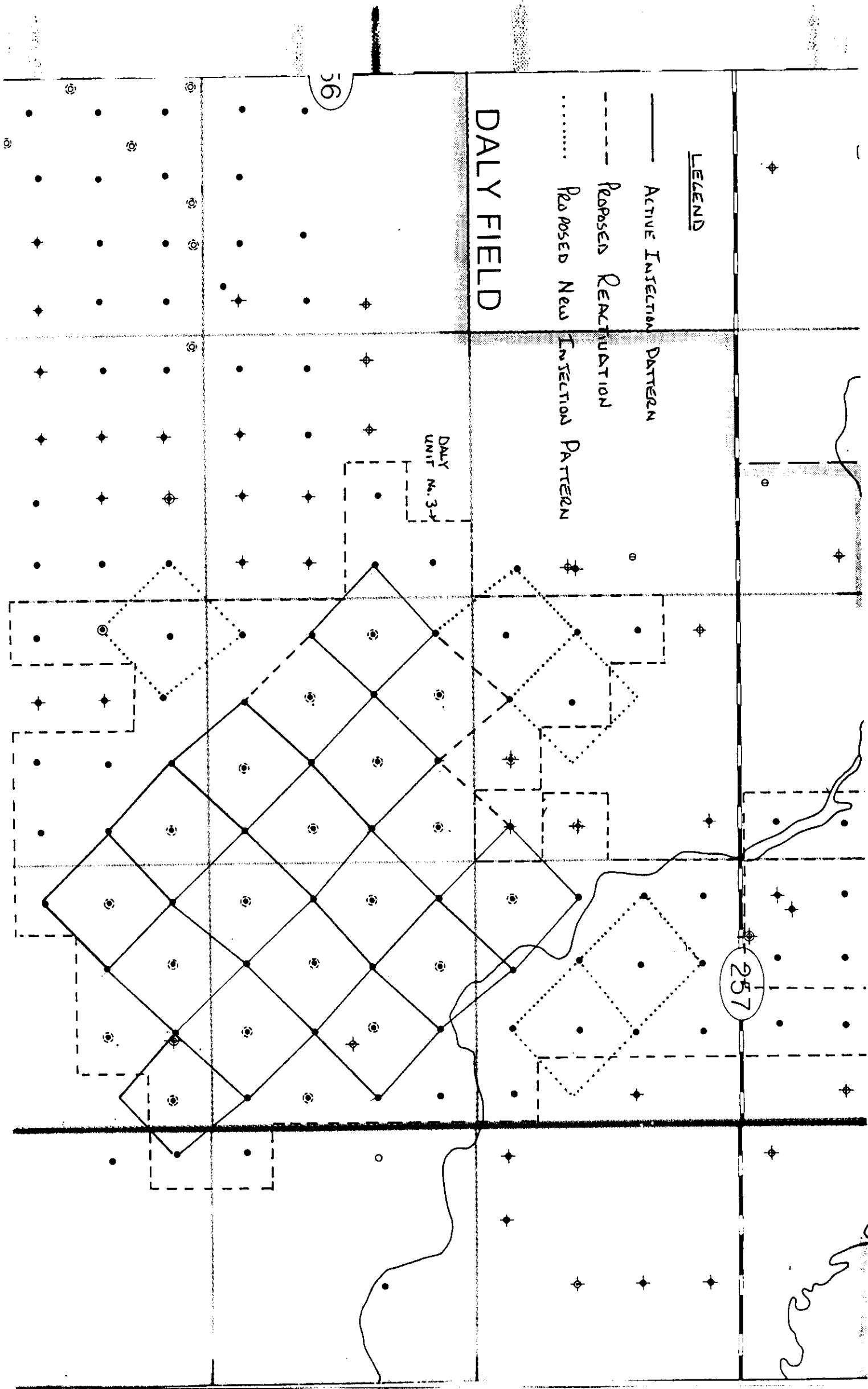
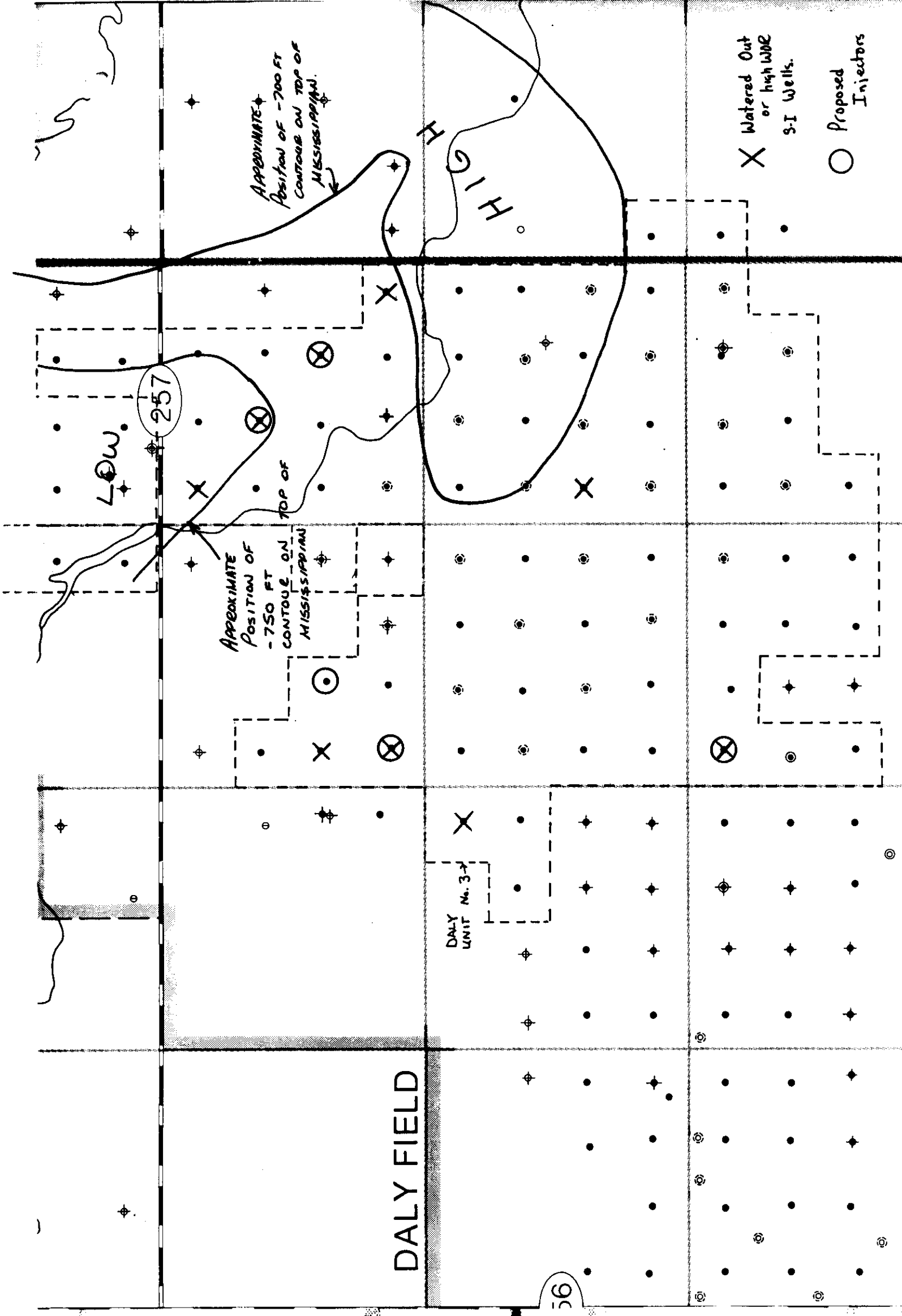


FIG. No. 1





X Watered Out  
or high WDE  
S-I Wells.

○ Proposed  
Injectors

DALY FIELD

DALY  
UNIT No. 3

APPROXIMATE  
POSITION OF  
-750 FT  
CONTOUR ON  
TOP OF  
MISSISSIPPIAN

APPROXIMATE  
POSITION OF -700 FT  
CONTOUR ON TOP OF  
MISSISSIPPIAN

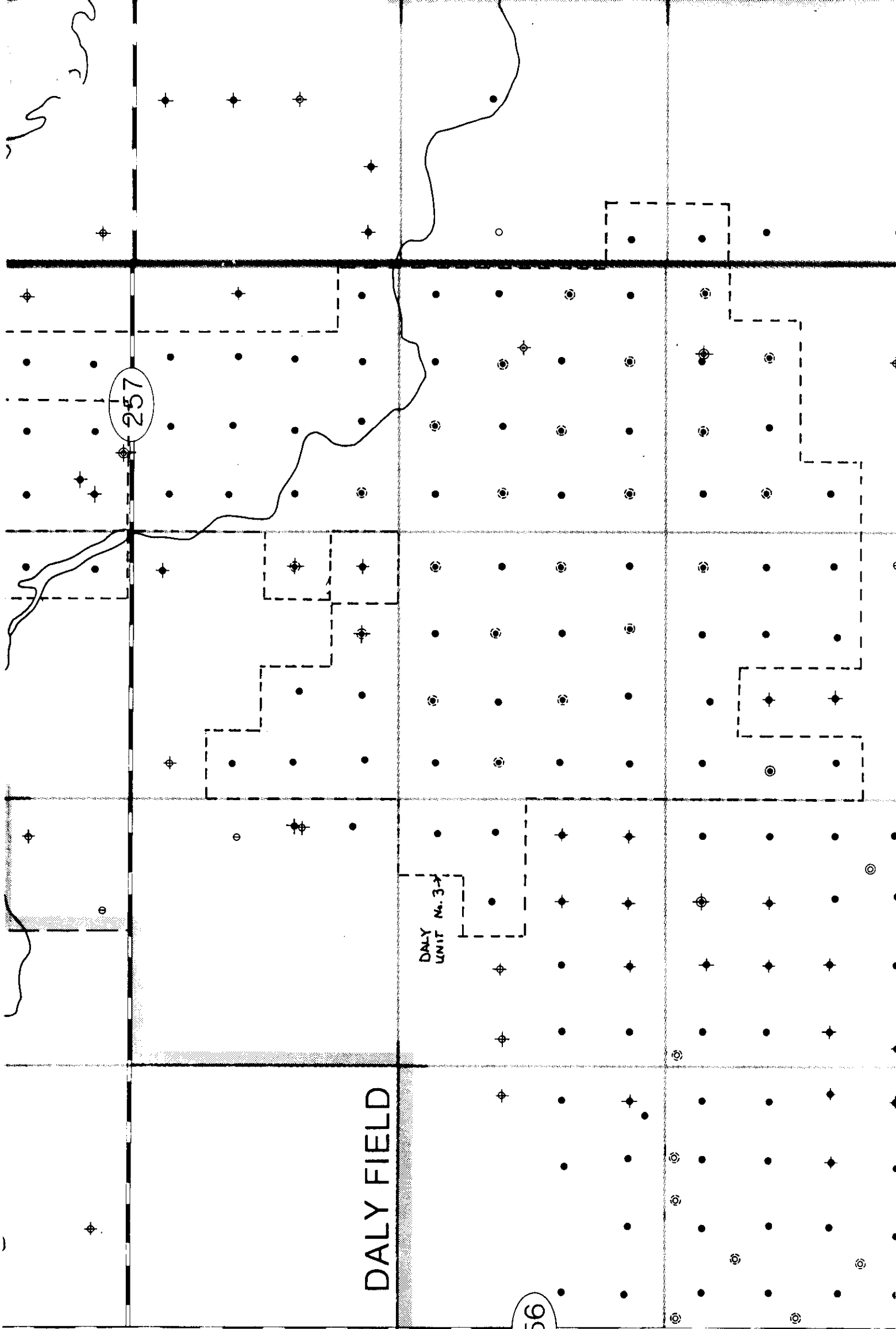
LOW

HIGH

257

56





A DALY UNIT 3 - Infill Drilling

I ) Our primary concern which prompted our request that Chevron consider infill injection in Daly Unit 3 was to ensure maximum recovery in those parts of the unit where, injection had been relatively ineffective in obtaining production response or where little or no injection had been attempted.

Where injection on an 80 acre pattern had been unsuccessful in Daly Unit 3 in a large portion of the Unit, injection on a 40 acre basis in Daly Unit 1 had met with some degree of success in most wells. This more consistently positive result led to our request that 40 acre injection be considered in the non-responding or non-injecting areas of Daly Unit 3.

II ) I don't think there is any question that the responding areas of both Units will have roughly equivalent recoveries and I concur that the only benefit to infill drilling or increasing injection would be one of acceleration.

III ) Along these lines, I would reiterate our concern that the recovery in the non-responding parts of the Unit may not be being maximized and ask for your comments with regards to a pilot 40 acre 5 spot <sup>or other action</sup> in this area. (Say SW $\frac{1}{4}$  - 14 or Section 13).

IV ) Further, with respect to plans to increase injection into certain wells in the better part of the Unit, would this increase be accomplished at the expense of injection into the remaining wells?

If so, this would result in acceleration of the better parts of the Unit at the expense of the poorer areas and could lead to premature abandonment as the Lower productivity areas would no longer have the economic support of the higher productivity areas.

V ) Other comments on report

1. What is basis that infill drilling and increasing injection would accelerate recovery to the same degree. (Page 3)
2. Consideration of other possible patterns for 40 acre spacing (i.e.: conversion of 2 wells from injection to production and drilling of a central injector (backflooding). (Page 5)

3. Page 6 appears to be stating that per well injection rate in Daly Unit 3 can be brought up to the level of Daly Unit 1 with no increase in injection pressure. This appears to ignore the concept of permeability.

Based on current injection parameters, it appears that an increase in injection pressure of 200 psi would only marginally increase injection rates.

*fracturing*

4. Assuming an injection rate increase of 200 psi, what precautions would be taken to ensure an increase in salt water spills would not occur.

5. Appendix D. Relationship of voidage ratio to water loss to aquifer appears to ignore the notion of reservoir fillup. Such estimates would have to utilize cumulative numbers, pressures and fluid properties (i.e.: material balance).

B) Status of development/outpost drilling plans in the Daly area. *other areas*

C) Status of West Butler

D) I. Comments on reactivated wells. Plans to reactivate or abandon additional inactive wells.

II. Specifically, suspension approvals have expired on:

13-13-10-28

6-3-11-26

11-32-9-28

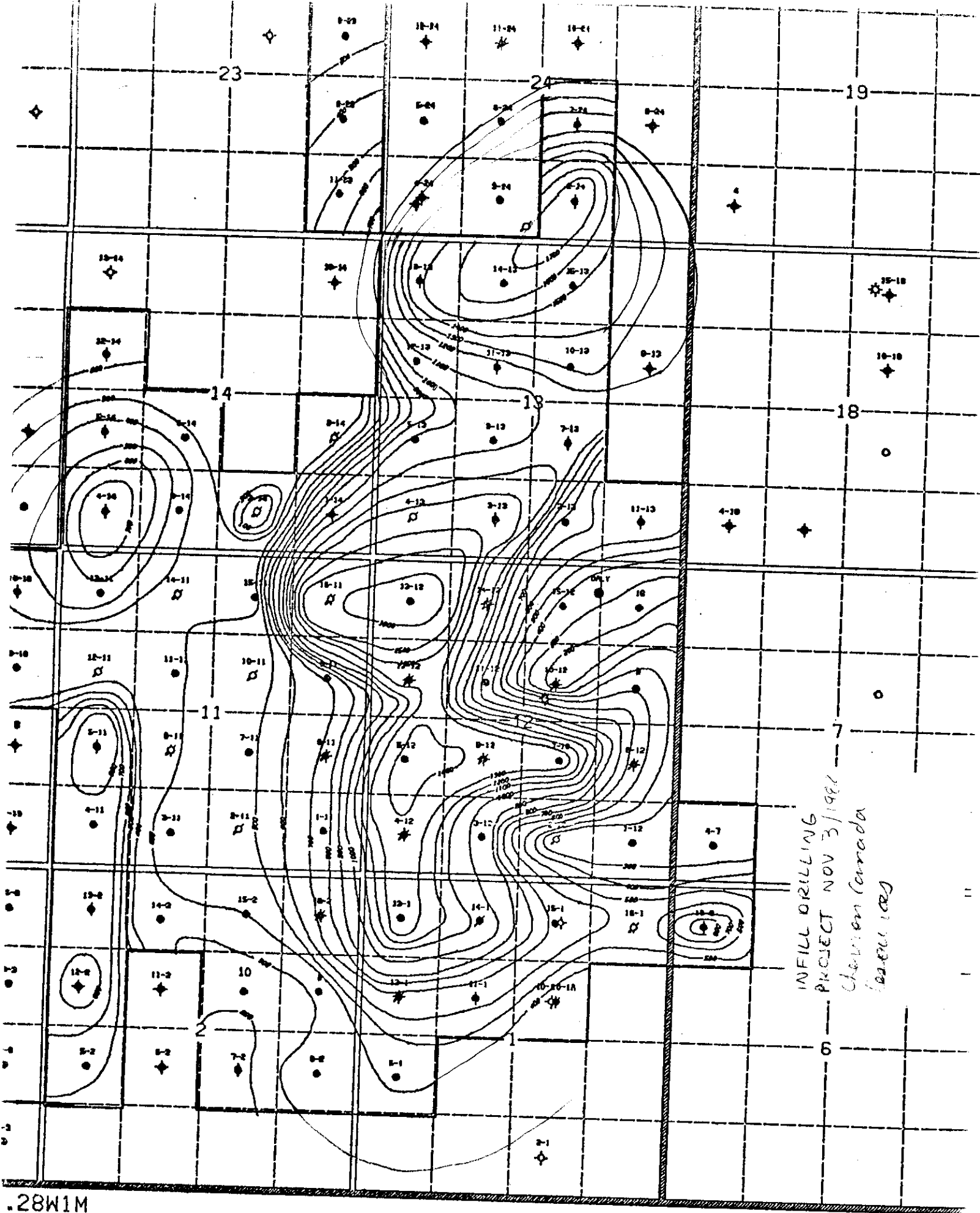
11-29-9-28 - *Prob react.*

What are plans for the wells??

E) What is the status of Chevron's studies regarding enhanced recovery potential of Chevron operated Manitoba reservoirs. What methods are or should be considered?

F) What is planned for Chevron's Waskada well (10-7-1-25).


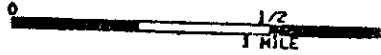
G) Any other areas of activity which Chevron is contemplating or any other areas that you wish to discuss.

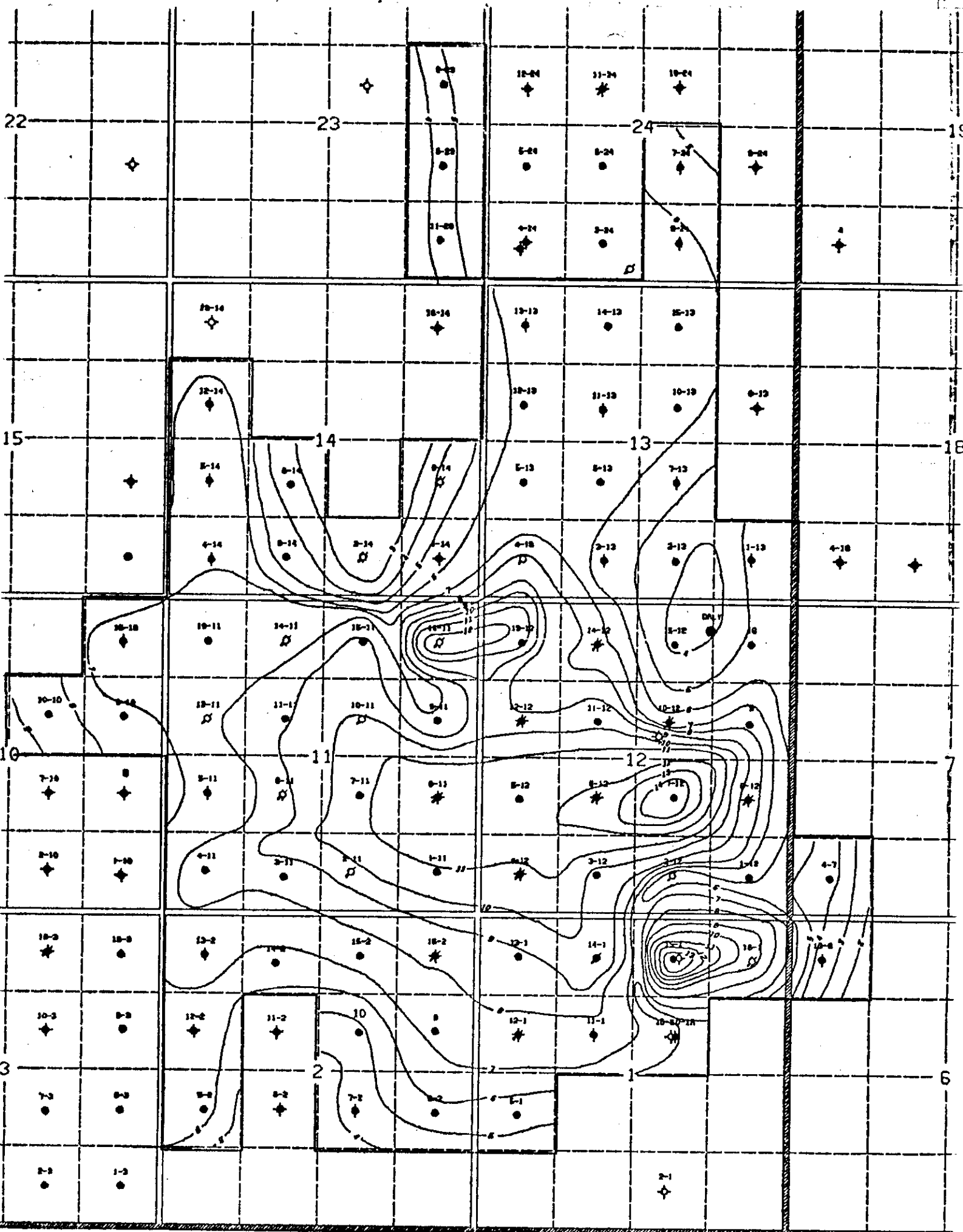


INFILL DRILLING  
PROJECT NOV 3/1991  
Chevron Canada  
Lester 1009

.28W1M

R.27

		
CHEVRON STANDARD		
DALY AREA		
TOTAL PERMEABILITY FEET		
CONTOUR INTERVAL - 100 MD		
		
SCALE	DATE	AUTO-TRAIL NO.
1 INCH = 1000 FT	AUG. 6, 1982	DC433



R.28W1M

ST B61 0.0.1.P/40 Acres  
105 STB

R.2

9

20

21

22

23

2

Current Recovery  
m<sub>3</sub>

- 0-5000
- 5000-10000
- 10,000-20000
- 20000-50000
- 50000 + over.

17

16

15

14

13

8

9

10

11

12

1

5

4

3

2

1

x Pressures to be increased.

20

21

22

23

Ultimate Recovery

0-10000

10,000-15000

20000-50000

50,000-100,000

100,000 & over

17

16

15

14

13

8

9

10

11

12

5

4

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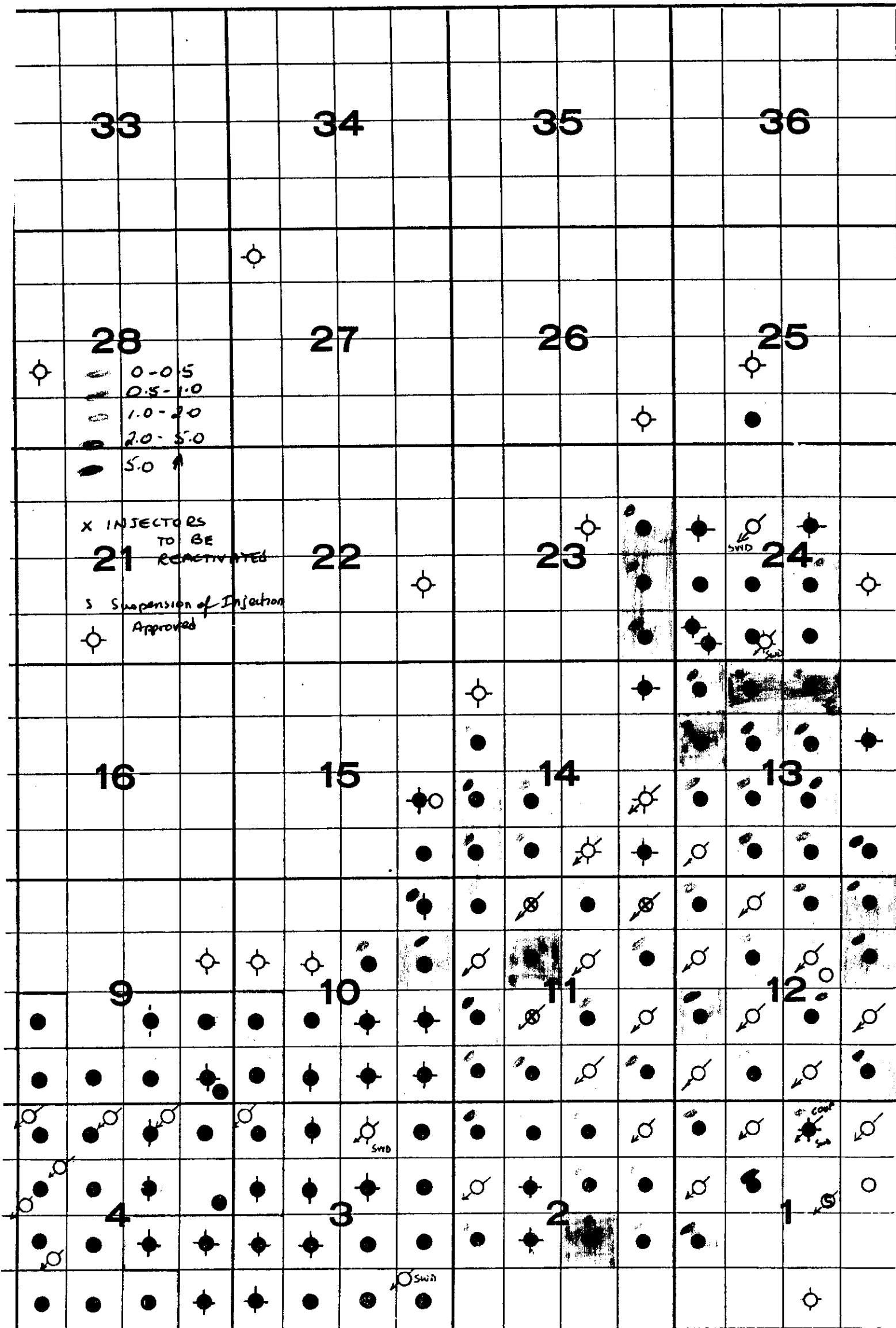
2

1

INACTIVE INJECTORS

Rge. 28

P.M.





INJECTION INDEX ( $m^3/day/well/kPa$  (wellhead))

INJECTION  
INDEX  
 $m^3/d/w/kPa$

.0

DALY UNIT NO. 1

.001

DALY UNIT NO. 3

.0001

D | J F M A M J J A S  
1981 | 1982

# DALY UNIT NO 1

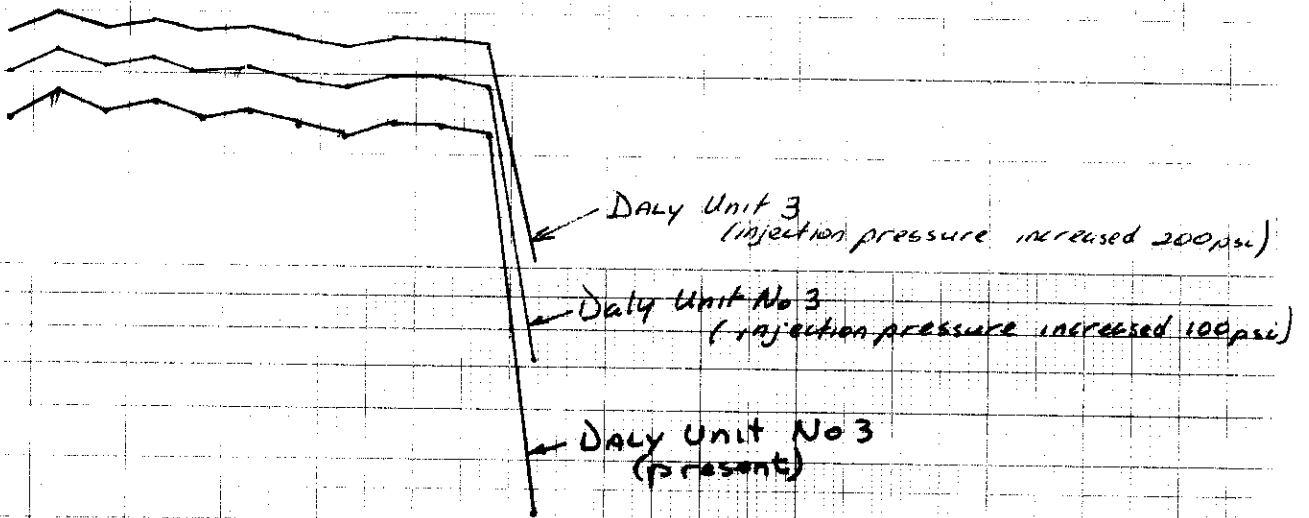
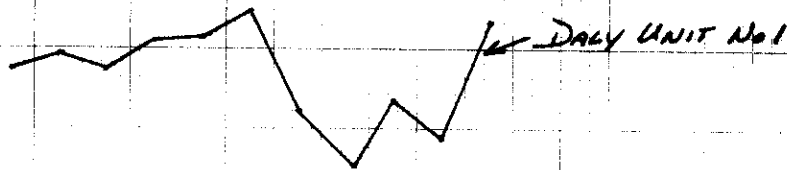
Month	Inj	Wells	Inj/well/D.	AVE WHP	INT/W/D/KPA
8-82	24502.4	9	87.82	7737 *	0.00135
7-82	16227.3	9	<del>1805</del> 58.16	7452	0.00780
6-82	17979.6	9	64.44	7674	0.00840
5-82	14636.0	9	52.46	7226	0.00726
4-82	17328.7	9	64.18	7355	0.00873
3-82	25555.0	9	91.59	7523	0.01217
2-82	21077.4	9	83.64	7636	0.01095
1-82	22,848.9	9	81.90	7385	0.01109

\* estimated.

# DALY UNIT NO. 3

<u>Month</u>	<u>INT</u>	<u>WELLS</u>	<u>INT/WELL/D</u>	<u>P</u>	<u>INT/WELL/D/KPA</u>
9-82	1543.0	16	3.21	6314	0.000509
8-82	6186.0	16	12.47	7514	0.001660
7-82	6382	16	12.86	7431	0.001730
6-82	6268	16	13.05	7434	0.001756
5-82	6144	16	12.38	7428	0.001667
4-82	6214	15	13.81	7445	0.001855
3-82	6711	15	14.43	7444	0.001939
2-82	5889	16	13.14	7434	0.001767
1-82	6934	16	13.98	7437	0.001880
12-81	6690	16	13.49	7437	0.001814

# INJECTION RATES m<sup>3</sup>/acre/day



O N D J F M A M J J A S O  
 1981 | 1982

## DALY UNIT 1

## DALY UNIT 3

WATER MONTH	INJECTED INT.	/ ACRE INT / ACRE / DAY
9-82		
8-82	24502.4	<del>68.06</del> 2.20
7-82	16227.3	<del>45.08</del> 1.45
6-82	17979.6	<del>49.99</del> 1.66
5-82	14636.0	1.31
4-82	17328.7	1.60
3-82	25555.0	2.29
2-82	21077.4	2.09
1-82	22848.9	2.05
12-81	20708.9	1.86
11-81	21165.3	1.96
10-81	20718.7	1.86

INT	INT / A
15430	.103 0.041 .07
<del>1573.0</del> 6186	.223 0.161 .19
<del>6186.0</del> 6382	.228 0.166 .19
<del>6382.0</del> 6268.1	.230 0.168 .19
<del>6268.1</del> 6144.0	.222 0.160 .19
<del>6144.0</del> 6214.0	.281 0.167 .19
<del>6214.0</del> 6711.0	.231 0.175 .20
<del>6711.0</del> 5889.0	.232 0.170 .20
<del>5889.0</del> 6934.0	.242 0.180 .21
<del>6934.0</del> 6690.0	.246 0.174 .20
<del>6690.0</del> 6961	.249 0.187 .21
<del>6961</del> 6527	.232 0.170 .20

INJECTIVITY IS A FUNCTION OF PERMEABILITY

$$\Delta P = -70.6 \frac{q \mu B}{kh} \frac{r_w^2}{4 \eta t}$$

$$\text{injection index} = 0.0018 \text{ m}^3/\text{d}/\text{kPa}/\text{well}$$

To allow the same injection rate /acre /day in Daly Unit 3.

say  $2.0 \text{ m}^3/\text{day}/\text{acre}$

would need monthly injection in Daly Unit 3

$$\text{of } 2.0 \times 1240 \times 30 = \frac{67,704}{24,400} \text{ m}^3 \text{ more}$$

$$\text{or } \frac{423.5}{4650} \text{ m}^3/\text{well}/\text{day} \text{ more}$$

$$\text{injection index in Daly Unit 3} = 0.0018 \text{ m}^3/\text{d}/\text{kPa}/\text{well}$$

$$\text{Additional injection pressure} = 235,083 \text{ kPa}$$

If pressure were increased 200 psi (1379 kPa) per well rate would increase by  $\frac{24.8}{2.48} \text{ m}^3/\text{d}$  or  $10.31 \text{ m}^3/\text{d}/\text{acre}$ .

DALY UNIT No 1

- No of Patterns = 9
- No of acres / pattern = 40
- No of acres under waterflood.  
 $= 9 \times 40 = 360$

Daly Unit 2

No of active patterns 14 complete  
2 incomplete  
 $= 14 + 0.75 \times 2 = 15.5$

No of acres / pattern = 80

Acres under Waterflood  
 $= 80 \times 15.5 = 1240 \text{ ac.}$

# Current Water Cut vs Frac B.D pressure

0-0.5	2-13	3000
	5-13	2600
	6-13	2900
	10-13	2500 - NO B.D FEED AT 2500

Ave (4)

2750

2.0-5.0	12-13	3200
	14-13	2600
	15-13	<u>2700</u>

Ave (3)

2833

5.0 ↑	1-13	3000
	7-13	3200
	11-13	2900
	13-13	<u>3100</u>

Ave (4)

3050



Well	<u>Prod to 12/31/81</u>	<u>Rem. Res by Decl. Anal</u>	<u>Ult. Rec. Res.</u>
5-1	1700.3	4461.0	6161.0
4-7	6976.1	9018	15994.1
11-1	758.3	0	758.3
13-1	480378	47423	95460.8
15-1	50349.1	79982	130.331
5-2	8588.3	1640	102283
7-2	3147.4	0	3147.4
8-2	25638.8	11,961	37599.8
9-2	20641.2	8896	29537.2
10-2	9888.2	14769	24657.2
13-2	32120.0	0	32120.0
14-2	23545.3	20441	43986.3
15-2	16356.5	33426	49782.5
9-10	8763.8	688	9451.8
10-10	14631.9	9779	24410.9
16-10	907.9	0	907.9
1-11	61081.1	117,673	178754.1
3-11	13276.0	7843	21119
4-11	26955.7	123492	150447.7
5-11	6598.4	0	6598.4
7-11	22699.3	11974	34673.3
9-11	24792.7	3317	28109.7
11-11	11691.2	2403	14094.2 <del>72623.0</del>
13-11	37407.0	35216	72623.0
15-11	29219.5	38294	67513.5
1-12	29074.1	17043	46117.1
3-12	96544.4	38667	125261.4

5-12	84,555.4	194,760	279,315.4
7-12	27844.8	20782	48626.8
9-12	10875.9	4261	15136.9
11-12	43933.1	87007	130940.1
13-12	17725.5	16732	34457.5
15-12	32188.2	95002	127190.2
16-12	1514099.8	5399	19498.8
1-13	5163.9	0	5163.9
2-13	26885.9	47372	74227.9
3-13	4271.0	0	4271.0
5-13	14797.7	11013	25810.7
6-13	32831.7	47944	80775.7
7-13	4108.9	0	4108.9
10-13	39118.6	11901	50019.6
11-13	8516.3	0	8516.3
12-13	28967.6	29929	58896.6
13-13	8930.6	0	8930.6
14-13	26199.3	327	26526.0
15-13	13527.8	881	14138.8
3-14	34403.9	91062	125465.3
4-14	12296.3	0	12296.3
5-14	7168.7	0	7168.0
6-14	7090.7	22135	29225.0
12-14	5880.2	0	5880.2

Wells

Wells Not offset by  
Active Injector

~~0 - 10000~~

0 - 10000	13	7	54%
10000 - 25000	9	4	44%
25000 - 50000	13	4	31%
50000 - 100000	7	2	29%
100000 + ↑	8	2	25%



**Chevron Standard Limited**

Box 100  
Virden, Manitoba  
R0M 2C0

1982-10-27

Dept. of Energy and Mines  
Petroleum Branch  
975 Century Street  
Winnipeg, Manitoba  
R3H 0W4

Attention: Mr. L. R. Dubreuil  
Chief Petroleum Engineer

Re: Daly Unit No. 3

Gentlemen:

In response to your letter of 1982-05-26, the potential for increased recovery in Daly Unit No. 3 is being evaluated. The attached preliminary report by R. D. Trimble, Calgary Reservoir Engineering, summarizes the results of work done to date. The two modifications to the existing scheme that were looked at are:

- (1) infill drilling (smaller injection pattern)
- (2) increased injection rates

The results of the study indicate that the two above cases would have the same cumulative oil recovery as the existing scheme without any modifications. The only difference is that the production would be accelerated with substantial investment in Case (1) and relatively minor investment in Case (2). We are planning on injection at higher rates (and pressures) in several patterns to confirm the results of this study.

We are presently looking at increasing injection into 2-12, 6-12, 8-12, 10-12, 12-12, 14-12, and 4-13 by preferentially injecting into these wells. We will formally apply to you when our plans are firmed up.

Another significant conclusion from this report is that the estimated ultimate recoveries in Daly Unit No. 1 and No. 3 are approximately the same.

We will keep you informed of our conclusions and plans for Daly Unit No. 3 waterflood project.

Yours truly,

*C. G. Folden*

C. G. Folden, P. Eng.

Area Supervisor

Virden Area

CGF/cm

*Does this mean injecting into other wells will be reduced. If yes, the production would be reduced. No consideration of recovery in the unit at the expense of the poorer areas. This is contrary to our initial concerns.*

CHEVRON STANDARD LIMITED  
ENGINEERING DIVISION

DALY UNIT NO. 3  
INFILL DRILLING AND INCREASED INJECTION RATE  
STUDY  
SEPTEMBER, 1982

PREPARED BY:

R. D. TRIMBLE  
CALGARY, ALBERTA

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## INTRODUCTION

Daly Unit No. 3, operated by Chevron Standard Limited in Manitoba, is presently producing oil from the Mississippian Lodgepole Formation. Waterflooding of the unit began in two phases in 1953 and 1955. The flood pattern consists of 80-acre 5-spots within the central portion of the unit. In 1981, applications to abandon six suspended water injection wells in the unit due to low injectivity or casing damage were submitted by Chevron to Manitoba's Department of Energy and Mines, Petroleum Branch. In a letter dated 1981-08-26, the Petroleum Branch responded to the applications by requesting "a review of the potential for increasing productivity and recovery by reduction of the [flood] pattern area from 80 acres to 40 acres in Daly Unit No. 3." The Petroleum Branch thus held the applications pending the result of Chevron's review.

The Petroleum Branch's response was prompted by its cursory comparison of present oil recoveries in Daly Unit No. 3 and neighboring Daly Unit No. 1 (Non-Operated Joint Venture, also producing from Mississippian Lodgepole). Present recovery of original oil-in-place appears to be significantly higher in Daly Unit No. 1 where waterflooding was implemented on partial 40-acre 5-spots starting in 1971. Thus, the Petroleum Branch believed that incremental oil recovery could possibly be achieved in Unit No. 3 by "an infill injection scheme" which would reduce flood pattern size from 80 to 40 acres.

This report responds to the Petroleum Branch's request by providing:

1. A comparison of ultimate oil recoveries in Daly Unit No. 1 and Unit No. 3 to determine if a smaller flood pattern yields incremental oil recovery.
2. An economic evaluation for present worth profitability of both an infill drilling project and an increased injection rate program in Daly Unit No. 3.



### CONCLUSIONS AND RECOMMENDATIONS

1. Waterflooding on 40-acre 5-spot patterns in Daly Unit No. 1 will yield no incremental oil recovery as compared to the 80-acre 5-spot waterflood in Unit No. 3 (See Appendices B and C). On a percentage of original oil-in-place (OOIP) basis, the estimated ultimate recoveries for the two units are:

#### Ultimate Recovery

Daly Unit No. 1	-	32.0% of OOIP
Daly Unit No. 3	-	31.8% of OOIP

Thus, infill drilling to reduce flood pattern size in Unit No. 3 would not improve ultimate recovery.

2. Significant oil production rate acceleration has taken place in Unit No. 1. Thus, the stage of oil reservoir depletion is more advanced in Unit No. 1 than Unit No. 3 (See Appendix C). A comparison of present recoveries reveals:

#### Present Recovery

Daly Unit No. 1	-	25.6% of OOIP
Daly Unit No. 3	-	12.5% of OOIP

Production history trends also reveal that Unit No. 1 will be depleted sooner than Unit No. 3.

	<u>Year of Production Start</u>	<u>Year of Abandonment</u>
Daly Unit No. 1	- 1952	1996
Daly Unit No. 3	- 1951	2050

Unit No. 1's rate acceleration as compared to Unit No. 3 may be due to the following:

- i) 40-acre 5-spot flood patterns in Unit No. 1 vs. 80-acre 5-spot patterns in Unit No. 3.
- ii) average water injection rate in Unit No. 1 is four times greater than injection rate in Unit No. 3.

Implementation of smaller flood patterns and/or higher injection rates in Unit No. 3 could thus cause significant rate acceleration.

3. Rate acceleration of oil production in Unit No. 3 could be economically attractive for two reasons:

- i) incremental improvement in Unit No. 3's present worth net profit.
- ii) accelerated depletion shortens reservoir life span, thus reducing the possibility of required well redrilling or recompleting as well casing deteriorates.

4. Three economic cases, outlined in detail in Appendix E, can be used to determine the profitability of rate acceleration in Unit No. 3. The cases are as follows:

- i) Case I - No Rate Acceleration (No Capital Expenditure) (Base Case). The reservoir depletes under prevailing conditions by 2050.
- ii) Case II - Rate Acceleration by Infill Drilling (Incremental Case). The reservoir depletes under rate acceleration by 2014 after implementation of smaller flood patterns.
- iii) Case III - Rate Acceleration by Increased Injection Rate (Existing System)(Incremental Case). The reservoir depletes under rate acceleration by 2014 after injection rates are increased using present injection system.

*Reduction  
to original  
res. pressure  
and in. of oil  
would be  
returning to  
same depl.  
Magnitude of increased rate?  
Res. Pressure req'd to get same  
output?*

Increasing injection rates in 4 injectors in one 80-acre 5-spot would allow the opportunity to see whether oil rate acceleration in the flood pattern's producer yielded sufficient incremental present worth net profit over the existing case of constant injection rates. Case II is not economic on the present worth net profit basis.

## DISCUSSION

The crux of the problem of whether a smaller waterflood pattern (as in Daly Unit No. 1) yields higher ultimate oil recovery than larger patterns (as in Unit No. 3) rests in an extrapolation of current production trends. Simply comparing present recoveries of original oil-in-place, as the Manitoba Petroleum Branch seemed to do in its letter dated 1981-08-26, does not give a sound basis on which to predict ultimate recoveries. Though Daly Unit No. 1's present recovery of original oil-in-place is significantly higher than the present recovery of Unit No. 3, the discrepancy in recovery between the two units merely represents an oil production rate acceleration in Unit No. 1. For a realistic prediction of ultimate oil recovery, an extrapolation of both units' water-oil ratio data, as described in Appendix B, reveals nearly identical ultimate recoveries for both units.

The implementation of increased injection rates and smaller flood patterns in Unit No. 3 could cause similar oil rate acceleration as that experienced in Unit No. 1. However, increased injection rates using the present injection system appear to be the economically sound approach to rate acceleration. As outlined in Appendix E, the large capital expenditures required to infill drill and reduce pattern size in Unit No. 3 renders this option uneconomical from a present worth of incremental profit standpoint. The necessity of large expenditures is due to the manner in which the reduction of flood pattern size would have to be carried out. By comparing maps of Unit No. 1 (Figure 5) and Unit No. 3 (Figure 6), the difference in flood patterns between the two units becomes apparent. Reduction of flood pattern size from 80 acres to 40 acres in Unit No. 3 would involve drilling four producing wells in the corners of a present producer's 40 acre spacing unit followed by conversion to injection of the present producer. This operation is naturally more expensive than the infill drilling of water injection wells at the corners of a producer's 40-acre spacing unit as was done in Unit No. 1. Thus, "an infill injection scheme," as suggested by Manitoba's Petroleum Branch, could not be implemented in Unit No. 3.

Finally, Appendix D deals with the possibility that Unit No. 1's rate acceleration is more directly attributable to its higher injection rates, not its smaller flood patterns. Thus, increasing Unit No. 3's injection rates using the present injection system may be sound from both a reservoir engineering and economic standpoint.

Another important fact to note is that Unit No. 1 achieves its higher injection rates with approximately the same average wellhead injection pressure as found in Unit No. 3. This fact may make large expenditures to replace present flowlines in Unit No. 3 unnecessary since an increase in injection rate would not require an increase in wellhead pressure. Thus, the Case III economic analysis of increased injection rate using the present injection system could be more economically attractive due to lower flowline investment than is assumed in Appendix E.

explain  
How can  
injection  
rate be  
increased  
without an  
increase in  
injection pressure

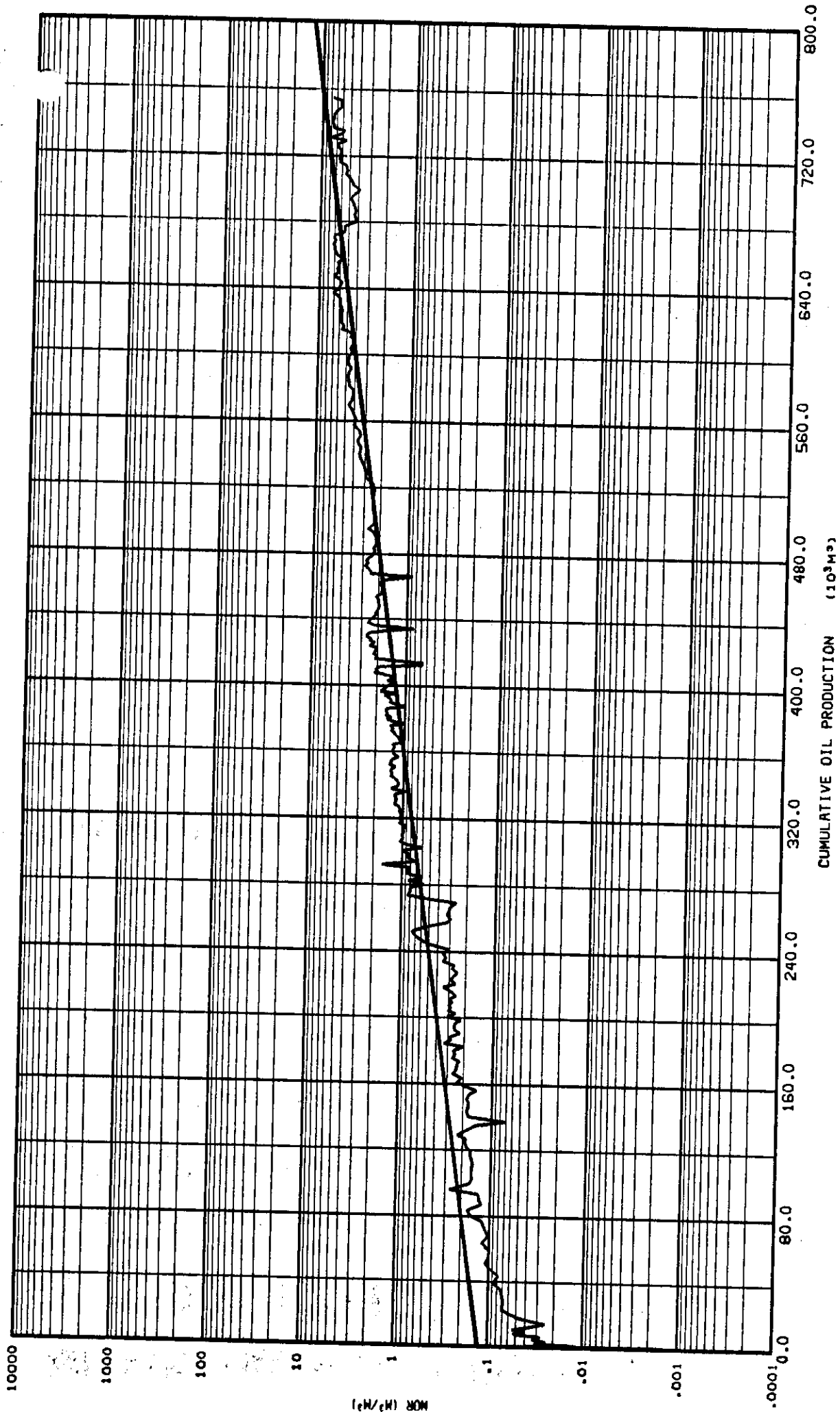


FIG. 1  
DALY UNIT NO. 1  
LOG WOR VS. CUMULATIVE PRODUCTION

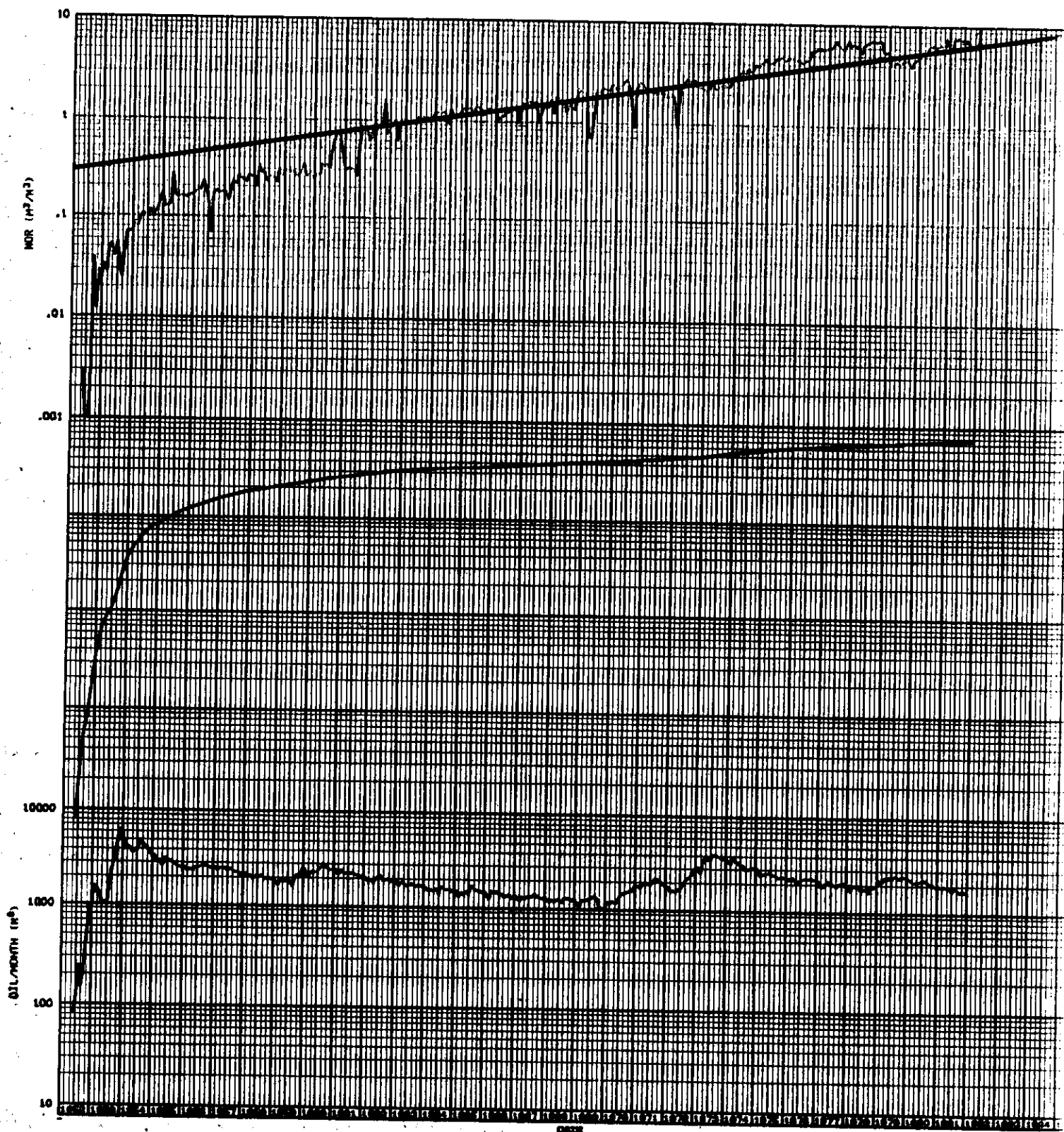


FIG. 2  
DALY UNIT NO.1  
PRODUCTION PLOT

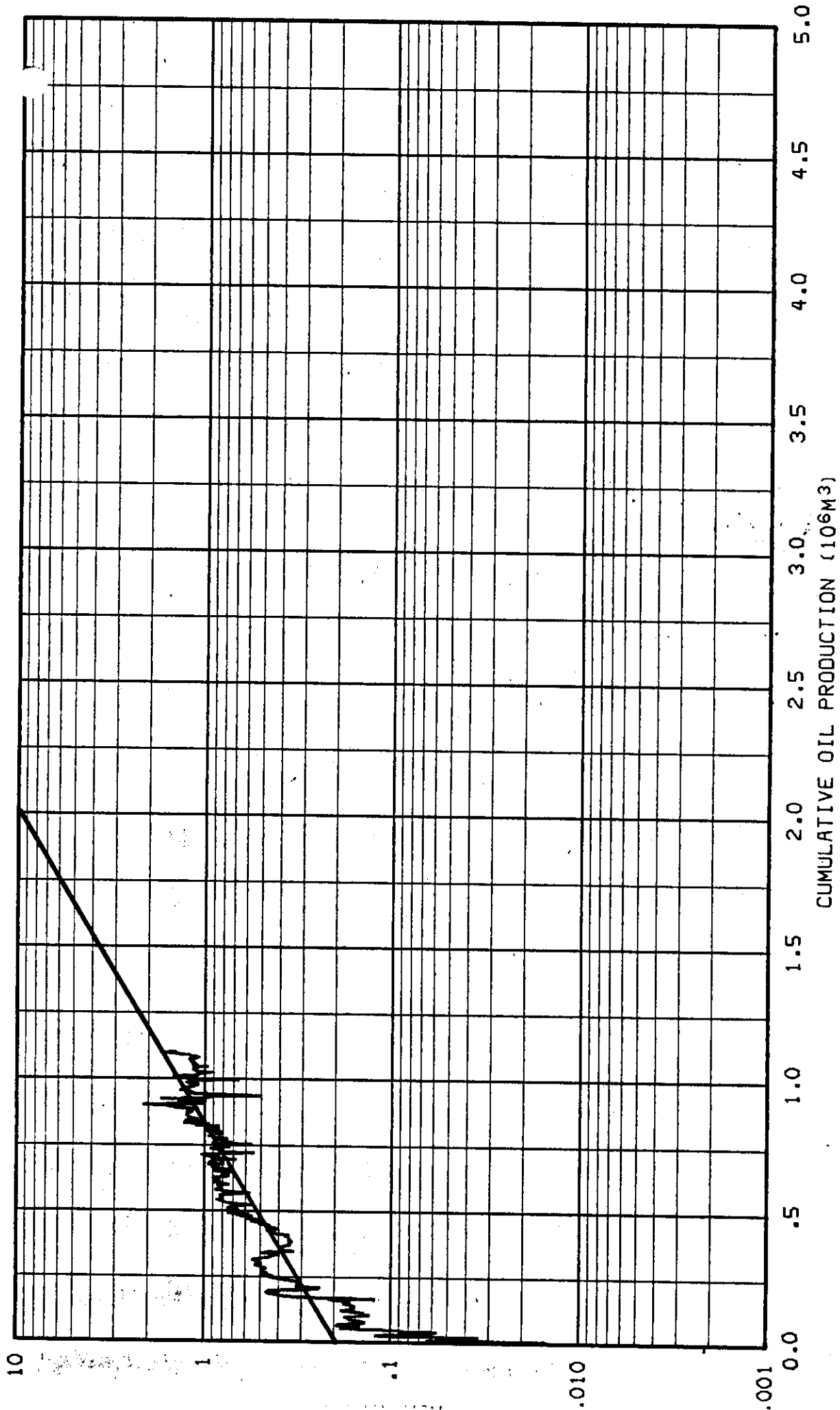


FIG. 3  
DAILY UNIT NO. 3  
LOG WOR VS. CUMULATIVE PRODUCTION



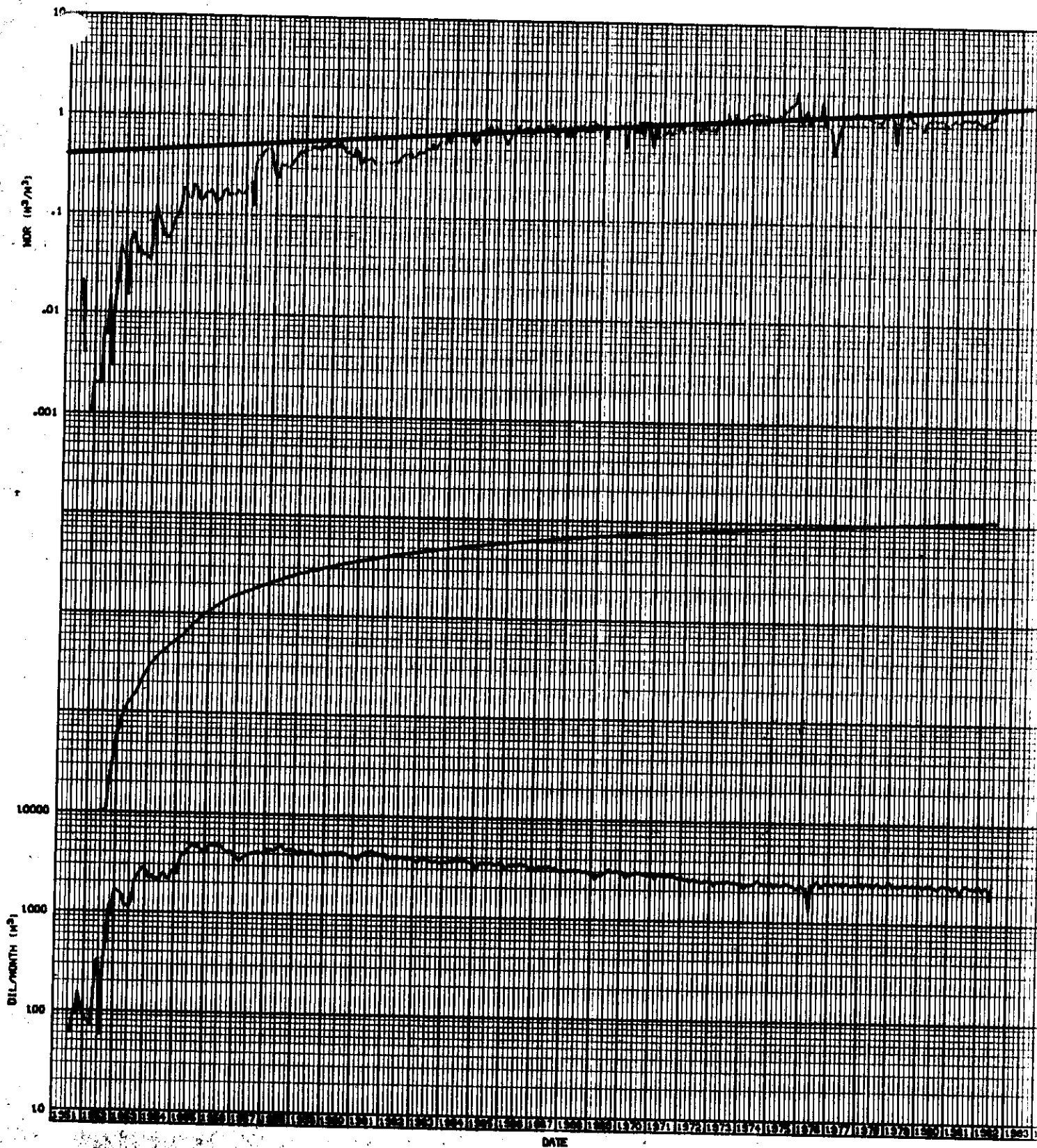


FIG. 4  
DALY UNIT NO.3  
PRODUCTION PLOT

## APPENDIX A

### COMPARISON OF ORIGINAL OIL-IN-PLACE

For a meaningful comparison of original oil-in-place numbers in Unit No. 1 and No. 3, these numbers should be presented on a STB/acre-ft basis. The following equation is used to estimate the original oil-in-place.

$$N = \frac{7758 \phi S_{oi}^1}{B_o}$$

N - Original oil-in-place (STB)  
 $\phi$  - Porosity (Fractional)  
 $S_{oi}$  - Original Oil Saturation (Fractional)  
 $B_o$  - Shrinkage Factor (bbl/STB)

The values of the parameters  $\phi$ ,  $S_{oi}$  and  $B_o$  are averages for Daly Field wells which were calculated from core and log data in the "Secondary Recovery Report: Daly, Manitoba (September 1953)." All of the parameter values are given below:

$$\begin{aligned}\phi &= 0.107 \\ S_{oi} &= 0.605 \\ B_o &= 1.08 \text{ bbl/STB}\end{aligned}$$

With the assumption that  $\phi$ ,  $S_{oi}$  and  $B_o$  are the same for both units, the original oil-in-place (OOIP) values, on a STB/acre-ft basis, will also be the same.

#### Original Oil-In-Place - Daly Unit No. 1 and No. 3

$$N = \frac{(7758)(0.107)(0.605)}{1.08} = 465 \text{ STB/acre - ft.}$$

To estimate the OOIP for both units on a STB basis, the reservoir rock volume in each unit must be determined. These volumes are found by planimentering net pay isopachs.

Daly Unit No. 1 - Reservoir Rock Volume = 40 368 acre-ft.\*  
Daly Unit No. 3 - Reservoir Rock Volume = 106 695 acre-ft.\*

$$\text{Daly Unit No. 1 - } N = (465 \text{ STB/acre-ft})(40\,368 \text{ acre-ft}) = \underline{\underline{18\,771\,000 \text{ STB}}}$$

$$\text{Daly Unit No. 3 - } N = (465 \text{ STB/acre-ft})(106\,695 \text{ acre-ft}) = \underline{\underline{49\,613\,000 \text{ STB}}}$$

\*Only the areas presently under waterflood were considered for the reservoir rock volume determination.

## APPENDIX B

### ESTIMATION OF ULTIMATE OIL RECOVERY AND RESERVOIR LIFE

#### A. INTRODUCTION

With 30 years of production history available for both units, enough reservoir performance data exist to utilize two graphical techniques. The first technique involves plotting log of water-oil ratio (WOR) vs. cumulative oil production ( $N_p$ ) and can be used to estimate ultimate oil recovery. The second technique, requiring a plot of log WOR vs. time ( $t$ ), can give an estimate of reservoir life. Both of these plots tend to have linear trends which can be extrapolated out to an economically terminal WOR ( $WOR_t$ ). At the  $WOR_t$ , both ultimate recovery and reservoir life can be estimated.

#### B. STRAIGHT LINE EQUATIONS

The analytical methods used with both of these plots are outlined below:

##### 1. Log WOR Vs. $N_p$

A linear trend on a log WOR vs.  $N_p$  plot can be described by the following straight line equation:

$$\log WOR = m N_p + b \quad (1)$$

The slope of the straight line,  $m$ , is defined as:

$$m = \frac{\Delta \log WOR}{\Delta N_p} \quad (2)$$

The vertical axis intercept of the straight line,  $b$ , is determined from the plot.

Once the equation is determined, the ultimate oil recovery ( $N_{pt}$ ) at  $WOR_t$  can be calculated by manipulation of equation 1.

$$N_{pt} = \frac{\log WOR_t - b}{m} \quad (3)$$

## 2. Log WOR Vs. T

By the same reasoning used above, the straight line equation for a log WOR vs. t plot is defined as:

$$\log \text{WOR} = m t + b \quad (4)$$

$$m = \frac{\Delta \log \text{WOR}}{\Delta t} \quad (5)$$

The reservoir life ( $t_t$ ) can be expressed as:

$$t_t = \frac{\log \text{WOR}_t - b}{m} \quad (6)$$

## C. CALCULATIONS

The economically terminal WOR ( $\text{WOR}_t$ ) is assumed to be 30.

### 1. Daly Unit No. 1

From Figure 1, "Daly Unit No. 1: Log WOR Vs. Cumulative Production," and Figure 2, "Daly Unit No. 1: Production Plot Summary," the following calculations can be made.

#### Ultimate Oil Recovery (Figure 1)

- i) Slope (m) of straight line trend (red line drawn on plot) from equation 2.

$$m = 2.50 \times 10^{-6}$$

- ii) Vertical axis intercept (b)

$$b = \log (0.12) = -0.92$$

- iii) Ultimate oil recovery ( $N_{pt}$ ), from equation 3.

$$\begin{aligned} N_{pt} &= \frac{\log \text{WOR}_t - b}{m} = \frac{\log (30) + 0.92}{2.50 \times 10^{-6}} \\ &= 9.59 \times 10^5 \text{ STM}^3 = 6.03 \times 10^6 \text{ STB} \end{aligned}$$

### Reservoir Life (Figure 2)

- i) Slope (m) of straight line trend (red line drawn on plot), from equation 5.

$$m = 4.56 \times 10^{-2}$$

- ii) Vertical axis intercept (b)

$$b = \log (0.30) = -0.52$$

- iii) Reservoir life ( $t_t$ ), from equation 6.

$$t_t = \frac{\log \text{WOR}_t - b}{m} = \frac{\log (30) + 0.52}{4.56 \times 10^{-2}} = 43.8 \text{ years}$$

- iv) The year in which the unit would cease to be economically productive can be easily calculated.

$$\text{Year of abandonment} = Y_a = 1952 + 43.8 = 1995.8.$$

### 2. Daly Unit No. 3

From Figure 3, "Daly Unit No. 3: Log WOR Vs. Cumulative Production Summary," and Figure 4, "Daly Unit No. 3: Production Plot Summary," the same calculations can be made as with Daly Unit No. 1 above.

### Ultimate Oil Recovery (Figure 3)

i)  $m = 8.57 \times 10^{-7}$

ii)  $b = \log (0.20) = -0.70$

iii)  $N_{pt} = \frac{\log \text{WOR}_t - b}{m} = \frac{\log (30) + 0.70}{8.67 \times 10^{-7}} = 2.51 \times 10^6 = 15.8 \times 10^6 \text{ STB}$

### Reservoir Life (Figure 4)

i)  $m = 1.9 \times 10^{-2}$

ii)  $b = \log (0.4) = -0.40$

iii)  $t_t = \frac{\log \text{WOR}_t - b}{m} = \frac{\log (30) + 0.40}{1.9 \times 10^{-2}} = 98.8 \text{ years}$

iv)  $Y_a = 1951 + t_t = 1951 + 98.8 = 2049.8$

The above ultimate oil recovery and reservoir life numbers are compared in Appendix C.

APPENDIX C  
COMPARISON OF PRESENT AND ULTIMATE  
OIL RECOVERIES

Oil recoveries for the two units are best compared on a STB/acre-ft basis. Recoveries in those areas presently being waterflooded are of particular interest. Thus, the cumulative oil production numbers given below are sum totals of the cumulative numbers for those wells directly or diagonally offset by a water injection well.

A. PRESENT OIL RECOVERY

	1.	2.	3. $((1) \div (2))$	4. $(3) \div \frac{\text{STB}^*}{465 \text{ acre-ft}}$
	<u>Cum Oil Prod to 6/82 (STB)</u>	<u>Reservoir Rock Vol. (acre-ft)</u>	<u>Present Recovery (STB/ acre-ft)</u>	<u>% Recovery of OOIP</u>
Daly Unit #1	4 803 792	40 368	119	25.6%
Daly Unit #3	6 156 850	106 695	58	12.5%

B. ULTIMATE OIL RECOVERY ( $N_{pt}$ ) AND YEAR OF ABANDONMENT ( $Y_a$ )(CALCULATED IN APPENDIX B)

	1.	2.	3.	4. $(1) \div (3)$	5. $(4) \div \frac{\text{STB}}{465 \text{ acre-ft.}}$
	<u><math>N_{pt}</math> (STB)</u>	<u><math>Y_a</math></u>	<u>Reservoir Rock Vol. (acre-ft)</u>	<u><math>N_{pt}</math> (STB/acre-ft)</u>	<u>% Recovery of OOIP</u>
Daly Unit #1	6 030 000	1995.8	40 368	149	32.0%
Daly Unit #3	15 800 000	2049.8	106 695	148	31.8%

\*Original oil-in-place of 465 STB/acre-ft. calculated in Appendix A.

## APPENDIX D

### Comparison of Water Injection and Reservoir Voidage (1981)

	Production (STB/day)			Water Injection (STB/day)	Average Wellhead Injection Pressure (psig)	Ratio- Total Voidage to Injection
	<u>Oil</u>	<u>Water</u>	<u>Total</u>			
Daly Unit No. 1	459	2 687	3 146	4 566	1 137	0.69
Daly Unit No. 3	484	561	1 045	1 247	1 080	0.84

By comparison of the above values, for approximately the same average wellhead pressure, Daly Unit No. 1's water injection rate exceeds Unit No. 3's injection rate by a factor of 3.7. Unit No. 1's total fluid production rate also exceeds Unit No. 3's production rate by a factor of 3. The ratio of total voidage to injection indicates that perhaps 31% of Unit No. 1's injected water is lost to the aquifer while 16% of Unit No. 3's injected water may meet the same fate.

*How  
about  
reservoir  
f. # 212?*

Despite the higher percentage loss of injection to the aquifer in Unit No. 1, the above data indicate a definite correlation between injection rate and fluid production rate. Given Unit No. 3's lower present oil recovery (12.5% of OOIP) and the assumption that reservoir parameters are identical in each unit, tripling Unit No. 3's injection rate could reasonably be expected to result in an initial tripling in oil production rate as response. Naturally, Unit No. 3's oil production rate would then begin to decline more steeply than before the increase in injection rate due to more rapid reservoir depletion. This assumption of an initially direct correlation between injection rate and oil production rate is incorporated into the Case II and Case III economic analyses which are described in detail in Appendix E.

## APPENDIX E

### ECONOMIC ANALYSES

#### A. INTRODUCTION

As indicated in Appendix C, an equivalent ultimate oil recovery of approximately 148 STB/acre-ft is expected in both Daly Unit No. 1 and No. 3. Due to this equivalent recovery, waterflooding on a 40-acre 5-spot pattern in Unit No. 1 will result in no incremental oil recovery, on STB/acre-ft basis, as compared to the 80-acre 5-spot flood pattern of Unit No. 3. Therefore, the assumption can be made that no incremental oil recovery would result from conversion of Unit No. 3's 80-acre 5-spot patterns to 40-acre 5-spot patterns.

However, since present oil recovery in Unit No. 1 is 119 STB/acre-ft with an expected year of abandonment ( $Y_a$ ) of 1996 while Unit No. 3's present recovery is 58 STB/acre-ft with  $Y_a$  of 2050\*, significant acceleration of oil production in Unit No. 1 has taken place. This production acceleration is likely a function of either the closer spacing or higher injection rates in Unit No. 1 (See Appendix D). Acceleration could also be expected in Unit No. 3 after converting to smaller flood patterns and increasing injection rates due to similar reservoir conditions in both units. Even without incremental oil recovery, the capital expenditures involved in achieving production acceleration in Unit No. 3 could be profitable from the standpoint of present worth economics. Also, with many of Unit No. 3's producing wells already 30 years old, earlier depletion of the reservoir by acceleration reduces the future risk of well recompletion and redrilling becoming necessary as well casing deteriorates.

\*Recovery and  $Y_a$  numbers from Appendix C.



To evaluate the profitability of implementing closer well spacing and higher injection rates in Unit No. 3, three economic cases were developed: Case I (Base Case) - No Rate Acceleration (No Capital Expenditure); Case II (Incremental Case) - Rate Acceleration by Infill Drilling; and, Case III (Incremental Case) - Rate Acceleration by Increased Injection Rate (Existing System). Each case is described separately below.

## **B. CASE DESCRIPTIONS**

### **Case I - No Rate Acceleration (No Capital Expenditure)**

#### **Base Case**

Case I represents an economic analysis of Daly Unit No. 3 assuming present operating conditions prevail until abandonment (no infill drilling or increased injection rate). Thus, Case II and Case III are compared to Case I to determine if the first two cases offer incremental present worth profitability.

Case I economics are based on the following assumptions:

- i) Old old prices as per Analytical Division "Forecast of Future Inflated Value of Canadian Crude Oil in Canadian Dollars Per Unit of Production" dated 1982-05-20. Adjusted for API correction.
- ii) Operating costs, including well, flow-line, battery and injection system operating cost and transportation cost, considered on a \$/producing well/day basis. Inflated as per Memorandum "Revisions to Evaluation Procedures," by R. R. Dutka dated 1982-05-20.
- iii) Annual oil production rate:
  - constant at present rate (189 000 STB/year), 1983-1993.
  - declines at 1%/year, 1994 - 2032.
  - declines at 5%/year, 2033 - 2050.
  - field abandoned 2050.
- iv) Number of producing wells constant at 42.

## Case II - Rate Acceleration by Infill Drilling

### Incremental Case

Case II represents an economic analysis of Daly Unit No. 3 after infill drilling new producing wells and converting old producers to water injectors to reduce 5-spot waterflood pattern size from 80 acres to 40 acres. Injection rates in present and newly converted water injectors would be tripled to approach the rates employed in Unit No. 1.

#### Assumptions:

- i) Old oil prices - same as Case I above
- ii) Operating cost - same basis and inflation factors as Case I above.  
Assumed to double 1 year after infill drilling program completed.
- iii) 48 infill producing wells drilled and completed - 1983.
- iv) 32 present producers converted to water injectors - 1983.
- v) Annual oil production rate:
  - present rate (189 000 STB/year), 1983
  - increase to 216 000 STB/year, 1984
  - increase to 648 000 STB/year, 1985
  - (waterflood response similar to Unit No. 1)
  - declines at 5%/year, 1986-1999
  - declines at 10%/year, 2000-2014
  - field abandoned 2014

#### vi) Investment (1983):

Total Well Drilling	\$11 997 000
Total Well Conversion	\$ 640 000
Battery Expansion	\$ 150 000
Water Plant Expansion	\$ 200 000
Additional Flowlines	\$ 950 400
Total Investment	<u>\$13 937 400</u>

*\$250,000/well*  
*\$20,000/well*

### Case III - Rate Acceleration By Increased Injection Rate (Existing System)

#### Incremental Case

Case III represents an economic analysis of Daly Unit No. 3 after approximately tripling the injection rate using the present water injection wells. Thus, waterflooding would continue with 80-acre 5-spot patterns. The key assumption is that oil response in producing wells would be identical to response in Case II (Infill Drilling). Production acceleration is thus assumed to be directly correlated to increased injection rates rather than closer well spacing.

#### Assumptions:

- i) Old oil prices - same as Case I.
- ii) Operating cost - same as Case I.\*
- iii) Annual oil production rate - same as Case II.
- iv) Investment (1983):

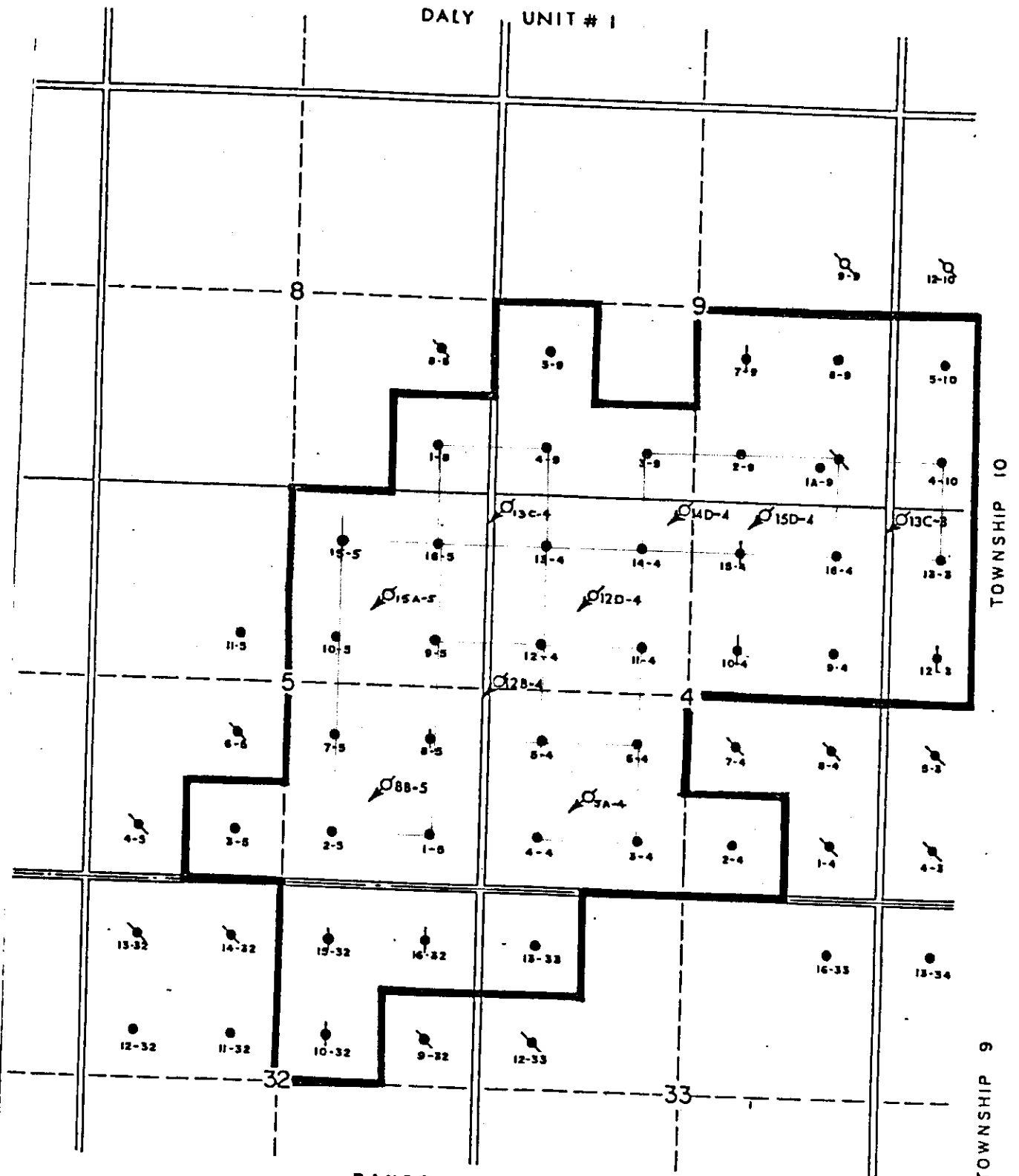
Battery Expansion	\$150 000
Water Plant Expansion	\$200 000
Replacement of Present Water Flowlines	<u>\$317 000</u>
Total Investment	\$667 000

- v) Field abandoned 2014

\*Incremental operating cost from increased injection rate relatively insignificant.

# RUNDLE PETROLEUMS LTD.

DALY UNIT # 1



RANGE 28 - W. P. M.

FIGURE 5

WEST DALY AREA

## LEGEND

• OILWELL

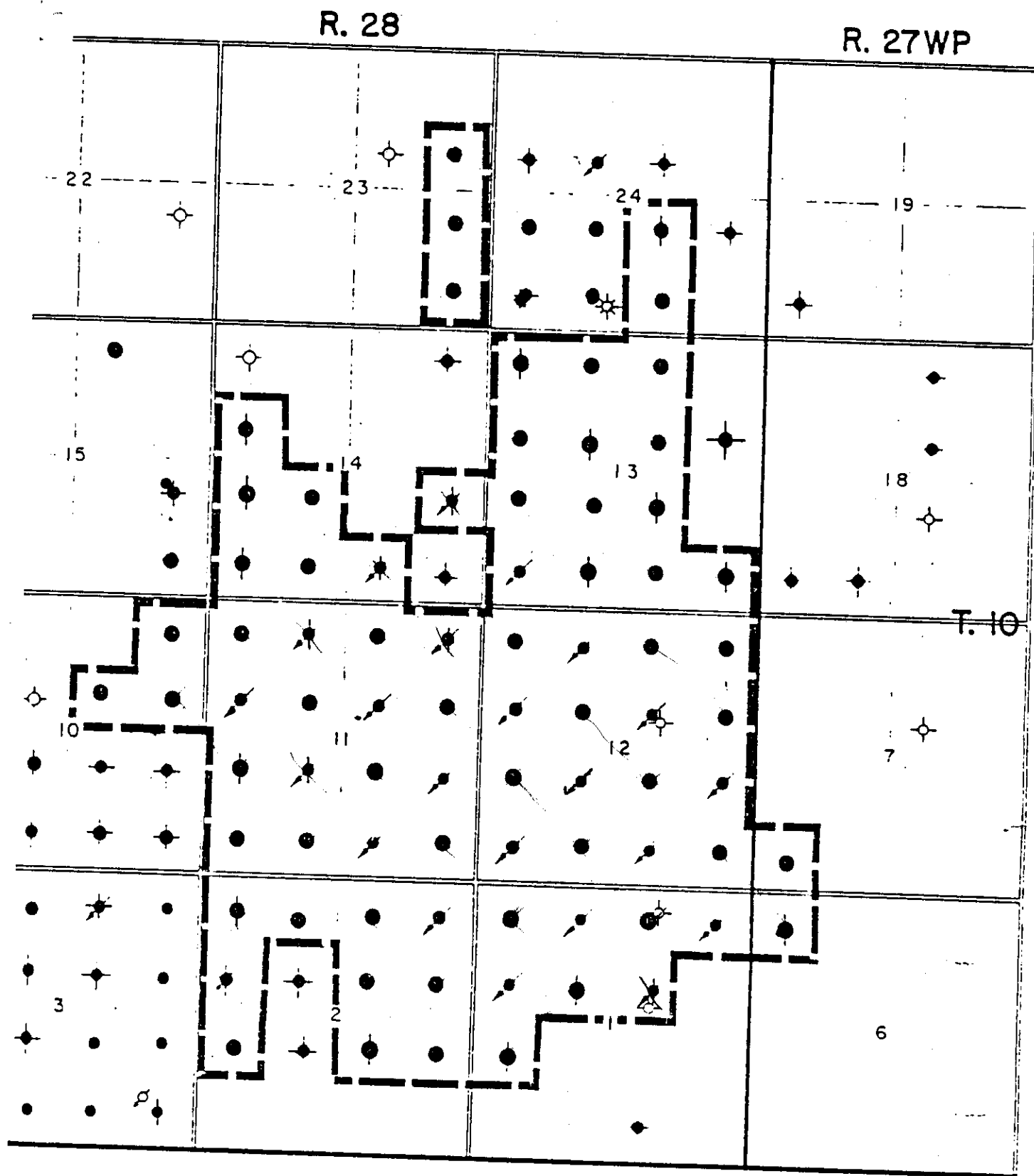
✕ ABANDONED OILWELL

○ DRY HOLE

○ INJECTION WELL

⬮ SUSPENDED OILWELL

0 1000' 2000'



# LEGEND

- OILWELL
- ◐ SUSPENDED OILWELL
- ⊕ INJECTION WELL
- ⊕ ABANDONED OILWELL

FIGURE 6

DALY UNIT No. 3  
MAP OF AREA

1931 - 12 - 31

## REFERENCES

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3. R. Zeeuwen  
"Daly Unit No. 3 - Infill Injection Report",  
Chevron Standard Limited, 1982-02-22.
4. F. E. Clark  
"Daly Field Extension Study"  
Chevron Standard Limited, 1981-09.

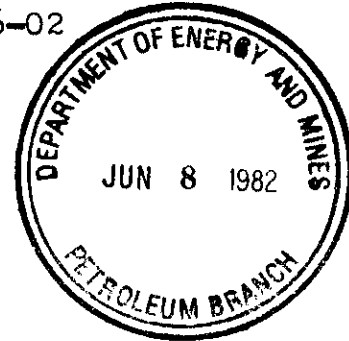


**Chevron Standard Limited**

Box 100 Virden, MB R0M 2C0

1982-06-02

Dept. of Energy & Mines  
Petroleum Branch  
975 Century Street  
Winnipeg, Manitoba  
R3H 0W4



Attention: Mr. L. R. Dubreuil  
Chief Petroleum Engineer

Re: Daly Unit No. 3 - Infill Injection

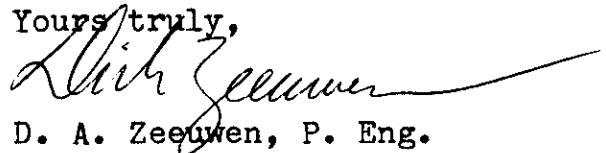
Dear Bob:

Even though results of our study on the feasibility of infill drilling in Daly Unit No. 3 have not been finalized we have some definite plans for the six suspended wells which, with your concurrence, will be carried out this year. Of the six wells originally proposed for abandonment, there appear to be two with almost no hope of ever being utilized effectively as producers or injectors. The two wells, 2 and 8 of 14-10-28, both with very poor permeability, whose history is described in correspondence previously sent to you are felt to be very high risk prospects for any type of rework, and should therefore be abandoned. The well 10A-1-10-28, adjacent to a proposed development well site 9-1-10-28, is submitted for suspension. It may be of use once the drilling of 9-1-10-28 confirms a possible extension of the reservoir in a South-Easterly direction.

Of the remaining three wells, we propose to reactivate all of them. The suspended injector 6-11 requires only tubing and a packer. The other two 14 and 16-11, both with casing damage will have injection strings cemented to surface following injection tests to ensure they will take water.

Since 10A-1-10-28 has a known hole in the casing string, there appears to be no need to confirm this at this point. If the decision is made to reactivate this well later, a liner will be run in order to comply with regulations. Attached please find applications for the subject wells. In our opinion, the above proposed actions will not detrimentally affect any future infill drilling or conversion of existing suspended producers to water injection wells. If approved the remedial work on 6-11, 14-11, and 16-11 will be carried out this summer. You will of course be advised as soon as possible of the conclusion of our study on Daly Unit No. 3 regarding the feasibility of infill drilling. If you have any questions on any of the above, do not hesitate to contact me.

Yours truly,

A handwritten signature in cursive script, appearing to read 'D. A. Zeeuwen', with a long horizontal flourish extending to the right.

D. A. Zeeuwen, P. Eng.

Area Supervisor

Virden Area

DAZ/ck





August 26, 1981

Chevron Standard Limited  
Box 100  
Virden, Manitoba  
R0M 2C0

Attention: D. A. Zeeuwen,  
Area Supervisor

Dear Dick:

Re: Application to Abandon

Lic. # 169	Chevron Daly WIW 10A-1-10-28
Lic. # 921	Chevron Daly Prov. WIW 6-11-10-28
Lic. # 945	Chevron Daly Prov. WIW 14-11-10-28
Lic. # 946	Chevron Daly Prov. WIW 16-11-10-28
Lic. # 954	Chevron Daly WIW 2-14-10-28
Lic. # 666	Chevron Daly WIW 8-14-10-28

Your applications to abandon the subject suspended water injection wells are acknowledged.

We feel that, in all these wells, there are valid reasons (casing damage, low injectivity, etc.) to consider abandonment, and also that supporting data which you submitted deals with these aspects of each well in a complete manner. However, in that abandonment of this group of wells essentially constitutes an abandonment of the waterflood scheme in certain areas where it has been, at best, only marginally successful, we feel that it is appropriate to consider alternatives to abandonment at this time.

Probably the most obvious untried alternative to effect an increase in recovery and productivity in the area is infill drilling to reduce pattern size from 80 acres to 40 acres. This approach has been followed with considerable success elsewhere in the Daly Field (Daly Unit No. 1).

A cursory analysis of well data (particularly core data) indicates that reservoir quality in the Daly Unit No. 1 area is, on the whole, approximately equivalent to that in Daly Unit No. 3, (being of better quality than Unit No. 3 areas which have not responded to waterflood and poorer than Unit No. 3 areas which have responded). Further, it is noted that the pre-waterflood characteristics (oil rate and watercut) of the majority of wells in both Units were similar. However, since injection was initiated in Daly Unit No. 1, substantial waterflood response has been observed in virtually every well which is directly or diagonally offset by a water injector. In Daly Unit No. 3, on the other hand, response has been limited to the areas of higher reservoir quality and even in such areas has not been as marked as in Daly Unit No. 1.

Table 1 summarizes a comparison of the two Units from a cumulative recovery and current productivity viewpoint based on May 1981 data. These figures illustrate that the Daly Unit No. 1 (40 acre pattern) waterflood has achieved substantially greater recovery and continues to be more productive than even the best areas at Daly Unit No. 3.

Based on this preliminary analysis, we conclude that a review of the potential for increasing productivity and recovery by reduction of the pattern area from 80 acres to 40 acres in Daly Unit No. 3 is warranted. Such a pattern conversion if it appears feasible would probably be best tested in a pilot pattern in an area which showed marginal response to the original waterflood. Success of such a pattern could be followed up by expansion into areas of progressively poorer reservoir quality. Failure would negate the need for testing in the poorer areas. Therefore, we request that you undertake such a review and that you report your preliminary findings to the Petroleum Branch by year end 1981.

In view of the foregoing and recognizing that the subject wells may have utility in part of an infill injection scheme, we will hold your applications pending the results of your review. In addition, all requirements to pressure test or repair casing in these wells will be suspended pending completion of your study.

Yours sincerely,

Original Signed By  
L. R. DUBREUIL

L. R. Dubreuil  
Chief Petroleum Engineer

LRD/lk

c.c. Dr. I. Haugh  
Virden Office

TABLE 1

Daly Unit No. 1 and Daly Unit No. 3

(Comparison of Cumulative Production and Current Productivity\*)

<u>Area/Unit</u>	<u>Cumulative Production bbl/Acre</u>	<u>Current Productivity (1981-05) bbl/Day/40 Acres</u>
Daly Unit No. 3 (area showing waterflood response)	3627	9.15
Daly Unit No. 3 (area showing no waterflood response)	1416	4.53
Daly Unit No. 1	4368	16.55

\* Wells considered restricted to those offset (diagonally or directly) by a water injection well.

# GROUP 'B'

18

5-12-10-21 O.H. 2362-2446 - 78' - No Coff. 8.28x113

7-12-10-28 O.H. 2247-2360 - 113'  
No Coff. 1700 - 2428.5'

50.0-52.4- 2.4x.5	- 21.5-27x3.8	- 22.1-33x25	- 24.1-34x3.9
55.9- 1.5x.5	- 22.8- 13x12	- 24.5- 17x3.9	- 27.2-33x3.2
56.1- 1.2x.9	- 24.2- 21x12	- 25.5- 26x242	- 28.2-35x1.3
57.1- 2.0x1.0	- 25.3- 21x13	- 28.6- 26x56	- 29.2-34x21.0
57.2- 2.6x2.9	- 26.8- 17x25	- 30.0- 24x21	- 32.2- 1.9x.5
57.7- 1.5x53	- 26.0- 32x9	- 33.0- 26x12	- 35.7-21x.2
57.8- 1.1x.5	- 26.2- 20x16	- 37.1- 9x11	- 37.2- 1.4x.3
57.8- 1.2x.1	- 27.2- 12x11	- 38.1- 14x24	- 38.1- 1.3x.1
57.4- 1.9x13	- 29.3- 16x11	- 38.1- 15x13	- 39.1- 1.2x3.3
57.8- 4.1x1.0	- 29.3- 12x1	- 38.2- 2.2x1.6	- 39.1- 2.4x1.2
58.1- 2.6x11	- 30.1- 17x0	- 38.3- 1.2x.3	- 43.7- 1.3x8.4
57.5- 1.4x.5	- 29.5- 28x27	- 38.3- 17x.6	- 46.2- 2.5x5.7
78.8- 1.5x.9	- 30.7- 1.2x.6	- 25.2- 27x1.4	- 47.5- 3.1x.4

TOTAL - 181.28

48.2- .9x.37  
54.5-5.7x.0  
55.5- 1.0x.3  
57.0- 1.5x.6  
58.4- 1.4x.0  
58.6- 1.2x5.7  
60.0- .4x.0

(10)

3-13-10-28 O.H. 2370.1 - 2387.1 = 17'  
CORED 2357 - 2387 = 17'

Total 324.30 fcs 17'

---

2-13-10-28 O.H. 2336.1 - 2351.0 = 14.90'  
CORED 2325 - 2351 = 4'

Total - 15.84 fcs 14.9'

18

16-11-10-28 O.H. 2343-2409 - 66'  
CORE FROM 2354-2406 ONLY - 52'

TOTAL - 1349.68 FOR 52'

15-11-10-28 O.H. 2409-2451 - 42'  
CORE FROM 2423.6-2451 - 27.4'

TOTAL - 177.35 FOR 27.4'

10-11-10-28 O.H. 2412.04 - 2457.32 - 45.3'  
CORE FROM 2387.0-2419.0 - 6.96'

2419.0 - 2412.2 - 6.8'

TOTAL - 77.27 FOR 6.96'

9-11-10-28 O.H. 2380-2425 - 45'  
CORED 2389-2401 - 12.0'

TOTAL - 21.46 FOR 12.0'

8-11-10-28 PERF. 2380-2400 - 20' O.H. 2413-2453 - 40'  
CORED 2396 - 2452

PERF INT. - 4' TOTAL 33.56  
O.H. 39' - TOTAL 43' } 246.90 FOR 43'

(21)

12-4-10-28 COMPLETION O.H. 2517-2541  
- TOTAL AREA CURED -

2517-18.7 -  $1.7 \times 2.3 = 3.91$   
- 20.7 -  $2.0 \times 1.2 = 2.40$   
- 22.0 -  $1.3 \times 5.0 = 6.50$   
- 24.2 -  $1 \times 3.3 = 3.30$   
- 26.0 -  $2 \times 10.0 = 20.00$   
- 28.5 -  $2.5 \times 11.0 = 27.50$   
- 32.0 -  $2 \times 12.0 = 24.00$   
- 34.0 -  $1 \times 15.0 = 15.00$   
- 35.0 -  $2 \times 1.4 = 2.80$   
- 36.0 -  $1 \times 6.8 = 6.80$   
- 37.0 -  $1 \times 0.64 = .64$   
- 38.0 -  $1.2 \times 6.8 = 8.16$   
- 40.0 -  $1.1 \times 15.0 = 16.50$

2539.3-2540.9  $1.1 \times 0.77 = .85$   
- 41.0  $.6 \times .64 = .38$

TOTAL FOR 24' - 142.04

11-4-10-28 COMPLETION O.H. 2486-2536

TOTAL FOR 50' - 273.62

2486-87.8 - $1.8 \times .06 =$	29-20.7 - $0.4 \times .67 =$	15.3-1.34 0 -
- 90.1 - $2.3 \times 4.7 =$	30-22.39 - $0.47 \times 4.3 =$	- 16.0-1.34 2.3 -
- 92.0 - $.8 \times 0 =$	31-24.25 - $0.6 \times 14.0 =$	17.4-.84 36.0 -
- 12.0 - $1.1 \times .49 =$	32-124.50 - $0.8 \times 2.3 =$	18.6-.64 2.1 -
- 95.0 - $3 \times 2.8 =$	33-44.10 - $0.8 \times 8.5 =$	- 19.2-1.24 3.0 -
- 96.7 - $1.7 \times .39 =$	36-144.18 - $1.3 \times .64 =$	- 19.7-.54 0 -
- 97.0 - $.3 \times .45 =$	10.3-4.84 6.1 -	20.5-.84 1.6 -
- 98.9 - $1.9 \times .67 =$	11.0-.77 8.5 -	- 21.2-.74 15.0 -
- 99.2 - $.3 \times 0 =$	11.7-.74 0 -	- 22.5-1.34 .58
- 99.4 - $.4 \times .67 =$	12.8-1.14 0.61 -	- 24.5-.24 1.18
500.2 - $.6 \times 11.0 =$	14.0-1.24 2.1 -	25.5-1.44 2.4 -
512.0 - $1.8 \times 11.0 =$		27-1.54 3.7



14D-4-10-28

COMPLETION - PERF. @ 2468.80 - 2473.72 - NOT CORFC

2508.83 - 2514.08

2519.98 - 2540.00

2508.87' - 2514.08'

2519.98' - 2540.0'

2508.87 - 2508.90	- .02 x -0.01
- 9.70	.9 x 0
10.5	.8 x .06
10.8	.3 x 0
11.5	.7 x .83
12.3	.8 x .77
13.2	.9 x .94
14.2	1.0 x 5.8
14.8	.6 x 3.2

2519.98' - 20.0	- .02 x .66	1 x 8.5
- 20.0	.2 x .35	.7 x 3
2.7	.3 x .1	.8 x 32
3.7	.5 x .04	1 x 0
4.0	1.0 x 12	1.0 x 39
5.0	.7 x 28	.7 x 47
	.9 x 2.4	.3 x 59
	1 x 6	1 x 7
	.8 x 5	1 x 95
	1 x 47	

1.4 x 6  
1.5 x 4  
2.0 x 4.4  
3.4 x 4.6

TOTAL 5.25' + 20.02 = 25.27'  
for 239.46

# GROUP 'A'

(7-5, 1-3, 12-4, 11-4, 140-4 - 10-28)

7-5-10-28- COMPLETION O.H. - 2525'-2559'

CORE ONLY GOES TO DEPTH OF 2546'

527.0 - 2.6 x 0 = 0	314-332 - 1.0 x 0 = 0	
412 - 1.6 x 5.5 = 8.80	23-323 - 1.2 x 1 = 1.2	
32-337 - .7 x 0 = 0	315-317 - .9 x 0 = 0	
13-323 - 2.4 x 3.4 = 8.16	427-436 - 1.3 x 1.2 = 1.6	TOTAL for 21' = 83.78
12-346 - 2.2 x .59 = 1.30	436-451 - 2.1 x 35.70	
93-412 - .24 x 2.7 = 0.54	1-455 - .4 x 0 = 0	
347-365 - 1.7 x 4.5 = 5.85	1-466 - .5 x .53 = 0.27	
16-366 - 1.6 x 19.20		

1-9-10-28 - COMPLETION O.H. - 2482'-2533'  
- TOTAL AREA CORRO -

2482-2483 - 1 x 479.0 = 479.0	1-14.6 - 3.6 x 3.8 = 35.28
23-54.1 - 3 x 8.8 = 26.4	18.0 - 3.4 x 12.0 = 40.80
136 - 2.54 x 0.90 = 2.25	20.4 - 2.4 x 6.5 = 15.60
412 - 2.6 x 1.80 = 4.68	23.7 - 3.7 x 23.0 = 75.90
92.5 - 2.34 x 25.0 = 57.5	27.2 - 4.0 x 2.9 = 35.60
15.5 - 77.5 - 2.0 x 1.3 = 2.6	30.3 - 2.6 x 42.0 = 39.20
78.5 - 2500 - 1.5 x 3.0 = 4.5	53.0 - 3.7 x 3.4 = 12.58
103.2 - 3.2 x 3.4 = 10.88	
3.8 - 5 - 2.2 x 6.1 = 13.42	TOTAL for 51' = 798.74
8.5 - 2.5 x 21.6 = 51.50	
10.0 - 1.5 x 9.1 = 13.65	
11.0 - 1 x 9.8 = 9.8	

Chevron has made application to abandon six suspended injection wells in Daly Unit No 3. The locations of the wells are ~~located~~<sup>indicated</sup> on Figure 1.

The six wells included in the application either have some mechanical problem (4) or are considered to be ineffective injectors (2)

Five of the six wells are located in the north west part of the unit. Production response in the area has been limited or negligible. Approval of the application would, in effect, result in abandonment of a significant portion of the waterflood project.

Generally, the wells have been reviewed and considered in Chevron's application in a fairly complete fashion on an individual basis. However, the combined effect of abandoning a significant portion of the waterflood or alternate courses of action have not been considered.

### Recommendations:

The attached draft letter be sent to Chevron requesting them to review the possibility of infill drilling to result in 40 acre patterns instead of the current 80 acre patterns particularly in the NW part of the unit. This would involve re equipping some of the injection wells for

production.

### Discussion.

The Daly Unit 3 waterflood is developed as a 5 spot pattern with each pattern including 80 acres. The central part of the waterflood (Section 12, W $\frac{1}{2}$  Section 11 and parts of Sections 1 & 2) have exhibited good response and resulted in increasing the daily production from a pre waterflood rate of 400 BPD (1954) to a peak rate of over 700 BPD in 1955. Current production rate is about 500 BPD.

Producers along the north and west edges of the unit have not shown any appreciable response to injection (see Fig 1)

The other waterflood in the Daly Field is located in Daly Unit 1 to the west. with This waterflood is also a five spot pattern but pattern areas are only 40 acres. Producers drilled on 40 acre spacing and injection wells are drilled on an infill basis.

In Daly unit 1, response was seen in ~~Both units are sim~~ virtually all wells which were offset by an injector which were produced fairly continuously

Injection in Daly Unit 1 resulted from an increase in pre flood productivity of 370 BPD to a peak rate of 850 BPD in 1973

I., comparing the ~~re~~ well and reservoir characteristics of the two units the following comments are made

- 1 The core kh of the completed ~~zone~~ of wells in Daly Unit 1 is somewhat greater than the equivalent kh in non responding wells in Daly Unit 3 and somewhat less than in responding wells. (see Figure 1)
2. Pre waterflood production rates in both units were in the range of 15-30 BPD.
3. Comparison of cumulative recovery /acre between the unresponding area of unit 3 and Unit 1, indicates Unit 1 recovery to be <sup>more than</sup> twice as great as the unresponded area of Unit 3. The current productive capacity on a rate/producing well basis is twice as great in Daly unit 1. Cumulative recovery /acre and current rate /well in Unit 1 also exceeds ~~Comparison of cumulative~~ these factors in the areas of unit 3 that responded (see table 1)
4. Pre flood production was basically water free ~~than~~ in the majority of both units.
5. Generally the waterflood in unit 1 has been more uniformly successful and has provided more marked longer lasting production response

Based on the superior response in unit 1 (40 acre patterns) I feel that infilling should be considered for Unit 3.

This would probably best be approached as a pilot in one of the patterns which showed marginal response to the 80 acre flood. Should response be experienced, development of progressively poorer areas would be required. If no response is seen, abandonment of the 6 injectors would proceed.

Such a pilot would require conversion of one or more injectors back to producers, drilling of a central injector as well as some engineering study to insure communication between wells.

A section using SP Logs from 3-11 to 14-11 shows good correlation between wells.

# DAILY UNIT 3 GROUP B

NON RESPONSIVE WELLS

5-1	3003	0.76
10A-1 W/W	547	-
11-1	758	-
12-1 W/W	3312	-
14-2	22801	2.00
15-2	15853	1.34
8-10 W/W	10889	-
9-10	8571	0.52
16-10	908	-
2-11 W/W	2705	-
3-11	1288	1.12
4-11	26135	2.23
5-11	6598	-
6-11 W/W	-	-
11-11	11393	0.79
12-11 W/W	11	-
13-11	13588	2.34
14-11	8	-
9-12	10550	0.90
16-12	13787	0.92
3-13	4271	-
4-13	2357	-
5-13	14460	0.84
6-13	31686	3.58
1-14	1435	-
2-14	2	-
3-14	33310	2.84
8-14	372	-

20.18 m<sup>3</sup>/day  $\Rightarrow$  0.72 m<sup>3</sup>/d/4000

252165  $\rightarrow$

1,586,070

1416 B/A.

28 x 40

## DALY UNIT 3

## GROUP A

## RESPONSIVE WELLS

13-1	46 835	3.16
14-1 (WI)	1782	-
15-1	49220	3.03
9-2	20130	1.34
10-2	9548	0.88
16-2 (WIW)	5085	-
1-11	59891	3.11
7-11	12885 22179	1.35
8-11 (WIW)	<del>24267</del> 2819	-
9-11	24267	1.35
10-11 (WIW)	28	-
15-11	28522	1.90
16-11 (WIW)	54	-
1-12	28393	2.76
2-12 (WIW)	3381	-
3-12	85469	3.16
4-12 (WIW)	17382	-
5-12	83027	4.22
6-12 (WIW)	1787	-
7-12	26920	2.84
8-12 (WIW)	2462	-
10-12 (WIW)	4171	-
11-12	42295	4.34
12-12 (WIW)	1341	-
13-12	17324	1.08
14-12 (WIW)	2816	-
15-12	31096	2.92
2-13	25968	2.66
8-2	24853	2.08

6 44 143  $\rightarrow$   $\begin{array}{r} 4207858 \\ 4051537 \\ \hline 29240 \end{array}$  3627  
267 BBL / ACRE

42.18 m<sup>3</sup>/day1.45 m<sup>3</sup>/day / 40 acres



# DALY UNIT 1

<u>Wel.</u>	<u>Cum P</u>	<u>Current Rate</u>
13-3	42 756	1.92
3-4	11 856	2.88
4-4	24 647	6.24
5-4	62 758	5.46
6-4	34 078	5.75
11-4	18 644	2.40
12-4	68 539	2.77
13-4	47 018	6.29
14-4	42 626	1.44
15-4	817	—
16-4	29 003	1.56
1-5	42 528	0.96
2-5	25 336	2.92
7-5	43 482	2.88
8-5	26 984	—
9-5	44 503	2.63
10-5	23 356	2.97
15-5	2422	1.92
16-5	29 347	5.37
1-8	10 940	0.96
1-9	19 086 + 645	2.24
2-9	35 922	2.10
3-9	27 994	2.80
4-9	8 734	0.19
4-10	<u>13 287</u>	1.12
737 308 $\Rightarrow$ $\frac{4,637,527}{25 \times 40} =$		4638 BBL/ACRE
		2.63 m <sup>3</sup> /d / 40 acres

# Daly Field - Core Data

Well	Interval analyzed	1st Cen	Skel. Cen.	Crustal Cen	Kh
13-2	2339 - 2463	2404	2427	2458	514.79
14-2	2335 - 2460.2	2393	2416	2440	191.52
15-2	2306 - 2431	2378	2405	2424	
16-3	2434 - 2444				67.62
12-3	2440 - 2530	<del>2400</del>			519.8
16-3	2344 - 2474.6				2160.2
4-4	2481 - 2546				90.03
6-4	2465 - 2526				
7-4	<del>2459</del> 2479 - 2510				11.94
8-4	2454 - 2515				42.65
11-4	<del>2471.0</del> <del>2522.4</del> 2552				25.14
12B-4	2502 - 2583				754.38
14-4	2500 - 2580				
7-5	2453 - 2546				
15-5	2500 - 2590				471.81
1-9	2411.8 - 2534				364.24
6-10	2361 - 2501				131.17
8-10	2414 - 2457				
12-10	2409 - 2504.3				39.47
2-11	2350 - 2428.9				Q
8-11	2396 - 2452				258.31
9-11	2389 - 2407				
10-11	2387 - 2419				
12-11	2389 - 2457				
14-11	2412 - 2428				
15-11	2423.6 - 2451				
<del>2427.6</del>	<del>2451</del>				
16-11	2354 - 2406				
2-12	2266 - 2351				
7-12	2250 - 2428.5				1335.11

10-12	2349 - 2637.5	
2-13	2325 - 2351	
3-13	2537 - 2387	
10-13	2363 - 2393	
14-13	2420 - 2472	
2-14	2375.0 2458 <del>2444.6</del> <del>2447</del> *	1232.46
8-14	2346 2407 *	28.76
12-14	2377 2466 *	53.01
4-14	2398.7 - 2476.5 *	143.73
8-22	2421 2509	754.65

Core kh of all ~~zones below~~ <sup>and including the top of Holbrook</sup> ~~the first~~ ~~connected~~  
to the Daly Shale.

Cutoffs 1 md and 10% porosity

# Legend

75' core in LOGSPORE  
TO DAY

- Wells showing response to injection
- Wells showing no response to injection
- Possible Response

17

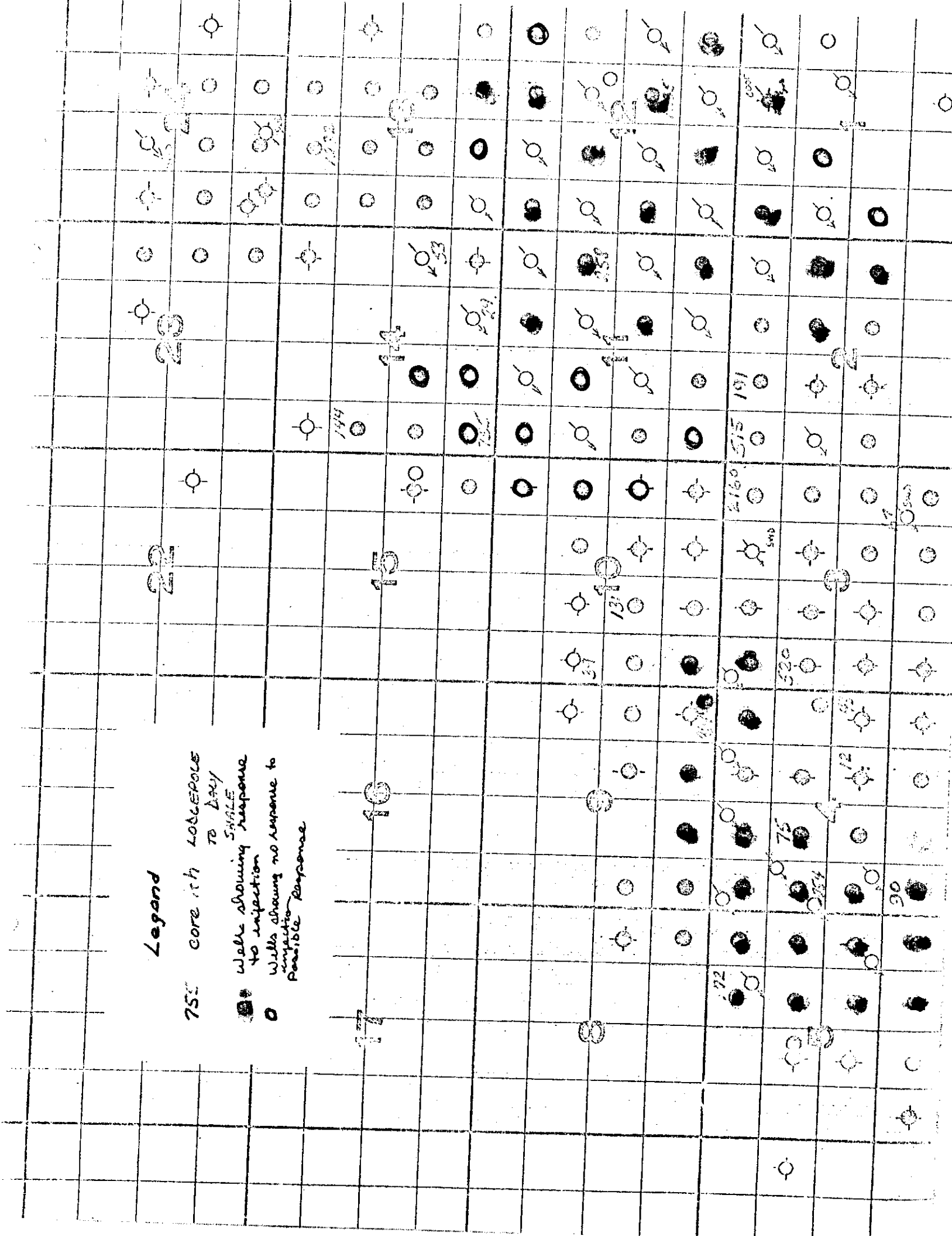
16

15

14

23

22



# DALY UNIT 1

## PRE RESPONSE TOTAL FLUIDS PRODUCTION (BPD)

13-3-10-28	1/2 72	OIL	11.5	WATER 0	TOTAL 11.5
4-4-10-28	mid 72		10.0	1.3	11.3
5-4-10-28	1/2 72		10.9	1.1	12.0
11-4-10-28	1/2 72		13.2	77.3	90.5
12-4-10-28	1/2 72		82.2	62.5	144.7
13-4-10-28	1/2 72		26.3	2.6	28.9
14-4-10-28	1/2 72		24.7	4.0	28.7
16-4-10-28	mid 72		9.2	0	9.2
1-5-10-28	early 72		21.4	32.9	54.3
2-5-10-28	late 71		13.2	608.6	621.8
7-5-10-28	early 72		9.9	9.4	19.3
8-5-10-28	early 72		9.9	9.4	19.3
9-5-10-28	1/2 72		9.9	6.6	16.5
10-5-10-28	early 72		4.3	11.5	15.8
16-5-10-28	early 72		9.9	9.4	19.3
1-9-10-28	early 72		9.2	5.3	13.5
2-9-10-28	1/2 72		9.9	1.8	11.7
3-9-10-28	1/2 73		9.9	3.3	13.2
4-10-10-28	mid 72		9.0	0	9.0

# DALY UNIT 1 - DECLINE ANALYSIS Responding Wells BASED ON PRE RESPONSE PRODUCTIVITY

Well	q <sub>i</sub>	q (1 year)	Decline %/year	Unit P <sub>i</sub> @ 18 P <sub>h</sub>	<sup>NP</sup> Cum Prod 5/81
13-3-10-28	6.5	5.3	18.46	9837	268 927
4-4	12.5	9.9	20.80	18000	150 018
5-4	3.6	2.6	27.78	2916	394 735
13-4	28.0		25.0 *	34257	295 734
14-4	20.0		25.0 *	24106	268 109
16-4	12.2	11.8	3.28	122 579	182 417
7-5	10.4	9.6	7.69	42878	273 493
8-5	10.4	9.6	7.69	42878	169 718
9-5	10.4	9.7	6.73	49245	279 915
10-5	5.2	4.2	19.23	7178	146 904
16-5	11.5	9.5	17.39	20061	184 587
1A-9	8.0	7.4	7.50	32773	120 041
2-9	13.5	9.2	31.85	11898	225 943
3-9					
<del>12-9</del>	12.8	10.0	21.88	17443	176 076
UNIT	480	360	25.0%	436 049	3,136,617

\* No initial decline, used averaged for Unit

% increase due to WF

$$= \frac{\text{Cum P} - \text{Nat. Decline } Np_{ULR}}{\text{Nat. Decline } Np_{ULR}}$$

$$= \frac{3136617 - 436049}{436049} = \underline{\underline{619\%}}$$

# DALY UNIT 3 (NO RESPONSE OR MINOR RESPONSE)

## ORE WATERFLOOD TOTAL FLUIDS PRODUCTION (BPD)

14-2-10-28	OK	12	WATER	4	TOTAL	16
15-2-10-28		7		1		8
3-11-10-28		13		1		14
4-11-10-28		11		1		12
5-11-10-28		16		0		16
11-11-10-28		14		23		37
13-11-10-28		80		3		83
3-13-10-28		18		0		18
5-13-10-28		14		4		18
6-13-10-28		38		7		45
3-14-10-28		50		8		58
6-14-10-28		15		1		16

AVE 28.4 BPD.  
 RANGE 8 - 83  
 MEDIAN 16

0-10	10-20	20-30	30-40	40+
8	16		37	83
	14			45
	12			58
	16			
	18			
	18			
	16			

Review decline and incremental recovery due to WF of Daly Unit 1 wells in the range of 10-30 BFPD (prior to response)

# CUMULATIVE RECOVERY / 40 ACRES ~~UNIT~~

DALY UNIT 1

DALY UNIT 3

MARGINAL RESPONDERS

13-3	268927
4-4	150018
5-4	394735
13-4	295734
14-4	268109
16-4	182417
7-5	273493
8-5	169718
9-5	279915
10-5	146904
16-5	184587
1A-9	120041
2-9	225943
3-9	<u>176076</u>

14-2	143411
15-2	99714
3-11	81045
4-11	164388
5-11	41500
11-11	71659
13-11	230131
3-13	26863
5-13	90944
6-13	199298
3-14	209513
6-14	42676

3 136 617

1,401,142

DALY UNIT 1

$$\text{Recovery / Acre} \frac{3136617}{14 \times 40} = 5601.84 / A.$$

DALY UNIT 3

$$\text{A) EXCLUDING } \frac{1401142}{12 \times 40} = 2912.12$$

INCLUDING MARGINAL RESPONDERS

6-11	—	
12-11	72	<u>1401142 + 17287</u>
14-11	50	40 x 17
4-13	14825	
8-14	2340	
	<u>17287</u>	





**Chevron Standard Limited**

Box 100  
Virden, Manitoba  
ROM 2C0  
1981-08-14



Dept. of Energy & Mines  
Mineral Resources Division  
Petroleum Branch  
989 Century Street  
Winnipeg, Manitoba  
R3H 0W4

Attention: Mr. H. C. Moster, Director Petroleum Branch

Dear Clare:

Enclosed are applications to abandon a number of wells all of which are located in the Daly field. Following the directive to pressure test the casings on suspended water injection wells, a review of suspended wells was undertaken to ascertain whether potential rework possibilities existed so that these operations could be carried out concurrent with pressure testing. In all cases it was deemed no rework possibilities existed and consequently we propose to abandon these wells this fall pending Chevron's internal and partner approval. I thought because of the number of wells involved that your required approval could be expedited, not to mention lessen your department's workload, if we provided copies of our proposals with appropriate back-up material. You will find all this material enclosed with the application forms. Please do not hesitate to contact us for further information.

Yours truly,

D. A. Zeeuwen, P. Eng.  
Area Supervisor

DAZ/clk

*Applications to abandon  
10A-1  
6-11  
14-11  
16-11  
returned to Olen  
JUNE 1982*

Virden, Manitoba  
1981-06-30

Recommendations for Abandonment  
Of Suspended Water Injection Wells  
Daly Unit #3

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Mr. D. A. Zeeuwen:

Proposals for abandonment of the suspended water injection wells 8-14, 2-14, 16-11, 6-11, 14-11, and 10A-1 of Daly Unit #3 are attached.

The study of these wells was initiated largely in response to a Government Directive (December 19, 1980) requiring Chevron to pressure test all suspended water injection wells, and thence commence any necessary remedial work by December 31, 1981. As a result of this Directive, Chevron is forced to evaluate the economic and technical usefulness of each well.

Briefly, the conclusions are as follows:

8-14-10-28 Abandon

This well injects primarily into a non-producing zone via a hydraulically induced fracture system. A rework would require the fishing of junk in the hole, and possibly a cement squeeze above the casing shoe. If the fracture system was successfully closed off, injection would become very difficult as the formation is very tight.

2-14-10-28 Abandon

This well injects at 1.5 bwpd without any apparent skin damage. Currently, the well has a hole in the casing requiring repair if the well is to remain suspended or go on injection again. The original frac job opened up a highly permeable zone just above the shaly zone. Later, a cement squeeze was performed to block the fractures, but left the well injecting into a very tight formation.

16-11-10-28 Abandon

This well is ineffective as an injector, possibly because most of the water injected enters the fraced zone above the producing interval. A rework would require the fishing of packer junk, a repair of the casing leak at about 1675' KB, and possibly a cement squeeze above the First Crinoidal (producing) zone. A rework on this well cannot be justified by its highly questionable and minor production response on 15-11.

6-11-10-28 Abandon

Although there is nothing wrong with the mechanical condition of this well requiring repair, the Petroleum Branch Directive does require that its casing be pressure tested. The geology of this well and its surrounding producers indicates that a significant production increase of up to 8 bopd might be achieved if only the injectivity into the producing zone could be increased. Unfortunately, the well was sandfraced down into the Shaly Zone and consequently cement squeezed. Furthermore, a 500 gal acid job failed to significantly decrease the well's skin factor, as evidenced by two falloff tests. In view of the failure of the last acid job and the unlikelyhood of a successful refracture, a rework on this well appears to be economically sub-marginal to marginal, depending on how much risk is associated with such a project.

14-11-10-28 Abandon

This well has a hole in the casing at 1250'. Little if any response has been indicated on offset producers. It was injecting at 20 bwpd when suspended in 1971, with all alternatives to increase injectivity being exhausted.

10A-1-10-28 Abandon

This injector is ineffective because of its low permeability and porosity (hence, low injectivity) and because it offsets only one current producer. Furthermore, a pressure test on the well indicates that a communication exists between water injected and the surface casing. As no production response in offsetting producers has been indicated, a rework to shut off the leak cannot be justified.

## Reference Sources

- 661.11 - Secondary Recovery Report - Daly Field; Dutka, R.R. and Wood, A.L.; Sept. 25, 1953
- 614.4 - Daly - Reservoir Studies
- 661.11.1 - Daly Waterflood Report; July 1958
- 661.15 - High Pressure Pilot Project - 14-1-10-28
- Daly Waterflood Progress Report; June 30, 1965
- 1979 Daly Unit #3 Progress Report; Feb. 1980
- Proposal for Unitization - Letter to The Oil and Natural Gas Board, Manitoba; November 7, 1975
- Request for Pressure Maintenance Order - Daly Unit #3; January 27, 1977
- Suspended Injection Wells, Daly Proposed Unit #3 - Memo from Al Hamberg to John Scott; June 4, 1975
- Well Files - 8-14, 2-14, 16-11, 6-11, 14-11, and other miscellaneous wells
- Mississippian Oil Fields of Southwestern Manitoba; McCabe, Hugh R.; Department of Mines and Natural Resources; Winnipeg, 1963
- Mississippian Stratigraphy of the Daly Oil Field; Organ, D.W. and Russin, G.M.; The Canadian Mining and Metallurgical Bulletin; March, 1956
- Notice to All Manitoba Operators - Directives from the Petroleum Branch - January 9, 1980; December 19, 1980; January 7, 1981
- Incremental Annual Cost vs Production - Economic Limit of Production - Worksheet from D. A. Zeeuwen
- Completion, Recovery/Injectivity Worksheet; Lionel Berry; January, 1981
- Completion Data Book; Virden Office

6-11, 14-11 & 16-11-10-28

- As an interim step, pending further evaluation of the desirability of infill injection in Daly Unit #3, Chevron proposes to reactivate 6-11, 14-11 and 16-11.
- These reactivations will provide additional pressure support (although probably limited) to an area with relatively low bottom hole pressures and thereby might result in an increase in production. They will also afford another look at the viability of the wells for use in both the present or a possible future infill injection scheme. Further, the wells will be reactivated and repaired ~~to~~ as required to meet Petroleum Branch requirements.
- 14-11 and 16-11 have known leaks and Chevron proposes to cement a string of tubing in the hole. This approach has been used elsewhere in the Units with good results.
- 6-11 has no known leak. However, prior to ~~completing~~ <sup>injecting</sup> with tubing and packer, the casing should be pressure tested to 3000 kPa pursuant to the Notice to Manitoba operators dated January 9, 1980.
- ~~All~~ All injection Lines should be tested to their ~~a~~ rated test pressure or 2 times the anticipated operating pressure. ~~There is no need to test the injection lines.~~