

MEMORANDUM

TO file 83-07-06 19__

FROM CF

SUBJECT Scallion - Suspended Wells OUR FILE

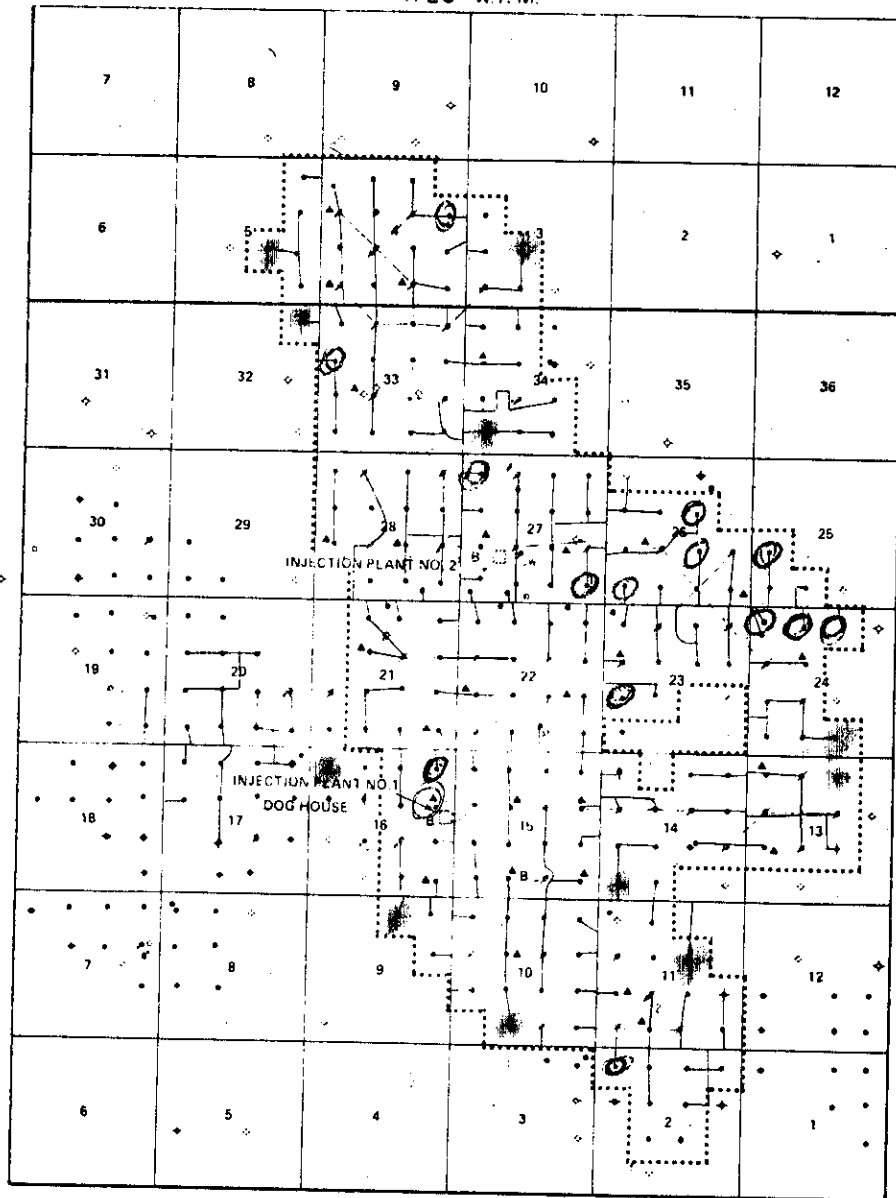
YOUR FILE

Present Plans

15-9-11-26	abandon
3-10	reactivate
10-11	abandon
4-14	W/W conversion
15-13	abandon
13-16 W.O.	abandon (reactivated & producing 100% water)
2-24	abandon
4-34	W/W conversion
16-32	1982 - Reactivated (82-10 @ .35 m ³ oil/d)
6-3-12-26	1984 Reactivation
7-5	Reactivated in 83 (83-06 .8 m ³ oil/d)

R 26 W.P.M.

T. 12



T. 11

LEGEND

- UNIT BOUNDARY
- ◇ INJECTION WELL
- SUSPENDED WELL
- ✕ ABANDONED WELL
- INJECTION LINE
- ◻ DEVONIAN WATER SUPPLY WELL
- ▲ RECTIFIER
- BATTERY

NORTH V. ROEN SCALLION UNIT NO. 1
AS OF 1981-12-31

Exhibit No 4

PROPOSAL FOR PRESSURE MAINTENANCE BY WATER FLOODING

The Applicants propose to unitize a portion of the North Viriden Scallion Field. The proposed Unit Area is shown in Figure 1 and consists of 217 oil wells. The purpose in unitizing this portion of the North Viriden Scallion Field is to facilitate the operation of a water flood in the subject area. An engineering report entitled "Reservoir Study - North Viriden Scallion Field" and dated August, 1961 has been included in support of this submission. The report indicates a primary recovery of 25,000,000 barrels from the proposed Unit Area. By comparison, water flood calculations indicate an estimated total ultimate primary and secondary recovery of 55,000,000 barrels from the same area. The details regarding these recovery estimates are provided in the accompanying Reservoir Study whereas Appendix I contains a summary of the investigation of the feasibility of water flooding. A water flood program is planned for the subject area in order to recover the approximate 30,000,000 barrels of additional oil. The type of water flood which is planned for North Viriden Scallion is an inverted 160 acre 9 spot pattern. This pattern is to be established in two phases by the conversion of certain wells to water injection. A detailed outline of the proposed water flood program is provided in Appendix II.

Unitization of the area under application will enable all interests in the subject area to be merged so that this portion of the reservoir may be operated as a single property. Under unit operation a maximum recovery efficiency and reduced production costs may be attained when water flooding is systematically applied to a large tract. This will be achieved by selecting injection wells without regard to property lines and by controlling injection and producing rates to obtain a high degree of recovery efficiency.

Certain wells in the proposed North Viriden Scallion Water Flood are required for conversion to water injection. A continued income from present wells, including those converted to injection, must be ensured to the owners. Additional production will also be obtained by the water flood and the unit must also provide a fair basis for sharing this benefit. The applicants submit that the participation formula provides a fair and equitable basis for sharing production.

It is noted in Figure 1 that a portion of the North Viriden Scallion Field has been excluded from the proposed unit and water flood area. The west flank is already operating under a strong natural water drive. Inclusion of this portion of the field in the proposed Unit Area is therefore not considered necessary. Certain additional acreage has also been excluded because it is not considered productive at this time. Steps have been taken to avoid any water flooding of these excluded lands. A further discussion of the lands which are excluded from the proposed unit area is provided in Appendix II. Notwithstanding the present exclusion of these lands from the proposed unit area if future development indicates they should be included, the Board, under Section 76 of The Mines Act may, at any time, hold a further hearing to consider adding these or any other lands to the unit area. Therefore, should any outside acreage be subsequently developed and proven productive, it could enter and participate in the unit by order of the Board. Similarly, should any of the west flank acreage which is presently excluded be shown to warrant water flooding, it could also enter and participate in the unit.

APPENDIX IInvestigation of the Feasibility of Water Flooding

The North Virden Scallion Field was discovered in December, 1953 and by the end of 1956 there were 167 wells on production. Production decline of individual wells indicated that some form of secondary recovery was necessary to increase the ultimate oil recovery from the field. Both geological and reservoir studies were therefore initiated to properly evaluate methods of secondary recovery.

During 1957, in conjunction with these studies, special laboratory water flood tests were run. The laboratory tests indicated that substantial additional oil could be recovered by water flooding. The "Reservoir Study - North Virden Scallion Field, Manitoba" dated August, 1961 may be briefly summarized as follows:

(1) The size and structure of the reservoir was studied to obtain an estimate of oil in place.

(2) The estimate of oil in place was compared with indicated primary performance from decline curves to arrive at an approximate estimate of primary oil reserves as a percentage of estimated original oil in place.

(3) The laboratory water flood test data was used in calculating the approximate amount of oil that could be obtained by water flooding the field.

(4) The primary reserve estimate and the water flood reserve estimate was compared to obtain an order of magnitude number which represents the possible gain which may result from water flooding.

SUMMARY OF PRIMARY RESERVE ESTIMATE

	<u>Cherty Zone</u>	<u>Oolitic Zone</u>	<u>Crinoidal Zone</u>	<u>Total</u>
Est. surface area				
- acres	8,410	7,290	4,130	
Est. average pay				
thickness - ft.	25.6	6.8	9.5	
Est. average por-				
osity - %	13.4	10.7	9.8	
Est. average water				
saturation - %	29	29	52	
Est. average initial				
oil sat. - %	71	71	48	
Formation volume				
factor res.bbls/				
S.T. bbl.	1.05	1.05	1.05	
Est.oil-in-place -				
bbls/acre ft.	705	568	348	
Total est. oil-in-				
place - bbls.	152,000,000	28,000,000	14,000,000	194,000,000
Total est. Primary				
Rec.Oil - bbls.				25,000,000
Est. Primary Rec.				
% of oil-in-place				12.9

SUMMARY OF ESTIMATE OF WATER FLOOD RESERVES

Twenty-five core plugs were selected on the basis of permeability distribution plots. The distribution of plugs by zones is as follows:

<u>Zone</u>	<u>Number of Samples Selected</u>	<u>Number of Samples Water Flooded by CRC</u>
Cherty	17	7
Oolitic	5	3
Crinoidal	<u>3</u>	<u>2</u>
Total	25	12

In the laboratory one inch diameter plugs were cut and re-saturated to simulate reservoir oil and water saturations and viscosities. The plugs were then flooded with brine solution until production of oil had practically ceased. The results are tabulated below:

	<u>Cherty Zone</u>	<u>Oolitic Zone</u>	<u>Crinoidal Zone</u>
Initial oil saturation - fraction of pore volume	0.76	0.79	0.67
Average oil saturation at breakthrough - fraction of pore volume	0.48	0.62	0.42
Average oil saturation at infinite WOR - fraction of pore volume	0.34	0.40	0.25
Average oil recoveries at breakthrough as % of original oil-in-place	36%	20%	38%

Using the above mentioned laboratory data and calculation procedures, which take into account such factors as areal and vertical sweep efficiencies and are described more fully in the Reservoir Study, it has been estimated that a properly engineered water flood might increase the ultimate recovery for the proposed Unit Area to 28.4% or 55,000,000 barrels. This is more than double the presently estimated 25,000,000 barrels which is expected under natural depletion.

APPENDIX IIDETAILS OF OPERATION TO BE CONDUCTED IN UNIT AREAIntroduction

The basic objective of the North Virden Scallion Water Flood proposal is to recover the greatest amount of oil consistent with sound economics. Injectivity to a large degree controls the choice of flood pattern which is desirable in initiating a water flood. Injectivity calculations have been made which indicate an average zone capacity of 1.84 B/D/md.ft. This suggests injection rates ranging up to 850 barrels per day with an average of about 250 barrels per day. These rates should be considered as illustrating the anticipated order of magnitude rather than the absolute values. The injectivity calculations indicate that North Virden Scallion can be flooded using an inverted 9 spot pattern. The applicants propose to water flood each of the Crinoidal, Oolitic and Cherty zones simultaneously. Completions are to be conducted in both injectors and producers with this in mind.

It is planned to initiate the North Virden Scallion water flood in two phases. Dependent on the degree of flood response a third phase could be introduced at some later date.

Initially 3,300 barrels per day of produced water will be injected into the reservoir contained in the Unit Area. It is estimated that approximately six wells will be converted to water injectors. The exact number of injection wells included in phase one will depend upon individual well injectivity and evaluation of subsurface water sources.

The advantages of instituting the water flood in two stages are as follows:

- (1) The performance of phase one injection and producing wells will assist in selecting the optimum water injection pattern and injection line system for phase two.
- (2) During construction and initial performance of phase one, additional subsurface water sources will be evaluated. It is proposed that the Duperow and Dawson Bay members of the Upper Devonian and the Ashville Sand be tested as potential water sources for phase two of the water flood scheme.

Figure 1 shows the proposed unit outline and the proposed injection wells in phase one and two. The number of injection wells has been determined by injectivity calculations with certain modifications as a result of consideration of fringe and window acreage.

It may be noted that all injection wells are located on even numbered legal subdivisions. An advantage of the inverted 160 acre 9 spot pattern is that the pattern can be converted to a complete 80

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acre 5 spot pattern if injectivity should prove to be much lower than anticipated.

The west flank of the North Virden Scallion Field has been excluded from the proposed unit area. The west flank is already influenced by a strong natural water drive and reservoir pressure is being maintained. Water oil ratios have increased pronouncedly due to water encroachment and are currently averaging approximately 80 percent. Consequently, it is not considered necessary or desirable to include the west flank.

Certain acreage which is encompassed by the unit boundary has also been excluded from the proposed unit area. This "window" acreage has no producing wells and is considered unproductive. On this basis, the "window" acreage has been excluded from the proposed unit area. Modifications have been made to the flood pattern to prevent any flooding of the "window" acreage. This has been done to provide the maximum degree of protection against flooding in any undeveloped areas where there appears to be any possibility of future development.

Some of the details related to the program of operations proposed under Phase I and Phase II are described in the following sections:

PHASE I

A. Source of Water for Injection

The source of water, for the Phase I nine spots, will be produced salt water. This salt water is presently being gathered in Calstan's North Virden Salt Water Gathering System No. 1 and disposed of in a well drilled down to the Dawson Bay formation and located on Lsd. 9-16-11-26. Five Calstan Batteries are connected to the plant on 9-16-11-26 by 4" and 6" Class 150 asbestos cement pipe, respectively as shown in Figure 2. The water gravity feeds, from boots located at each battery, to a tank on 9-16.

At present, approximately 3,100 barrels per day are being transported through the above lines. In addition, a line has been laid from the Dome-Canadian Superior Veldhouse Battery, located on 1-16-11-26, to the plant. This 2" Schedule 40 PVC plastic line is currently carrying approximately 200 BWPd. This makes the total amount of produced salt water available for flooding approximately 3,300 barrels per day which should be sufficient for the calculated stabilized injectivity rates for the six wells.

B. Expansion of the Plant #1 Facilities Located at 9-16-11-26 WPM.

A Salt Water Disposal plant is presently located at 9-16. It consists of a collection pit and high pressure pump for disposal of produced water in the area. This plant could be revised and expanded as required to handle additional water for injection purposes. Figure 3 shows a schematic diagram of the present plant.

C. High Pressure Injection System

It is proposed that all injection lines shall be cement

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lined steel, coated and wrapped. Injection lines in Phase I will be transporting produced salt water and will be buried 5 feet deep. The location of injection wells and a preliminary design showing the positioning of lines is shown on Figure 4.

Line losses were obtained from a set of flow curves for water based on the Hazen and Williams formula. A coefficient of friction of 100 was used for all steel and cement lined steel pipe. The interior diameter of all steel pipe was reduced by 0.4 inches to allow for cement lining. In general, pipe sizes were selected to maintain line losses below 2 psi/1,000 feet. Line sizes and calculated injection rates are also shown in Figure 4. Line sizing has been selected to provide for increased capacity should it be required.

D. Conversion of Wells to Water Injection

It is the intention of the operator to flood the three oil bearing horizons (Crinoidal, Oolitic & Cherty) simultaneously. A schematic diagram of a typical injection well is shown in figure 6. The following procedure outlines the program to be carried out in converting the wells to water injection. Additional work on the injection wells (i.e. spinner surveys, additions of plugging material, restimulating, etc.) may be required at a later date to remedy difficulties which cannot presently be anticipated.

- (1) Remove pump jack.
- (2) Pull pump, rods and tubing.
- (3) Run casing scraper.
- (4) Re-run open-end tubing.
- (5) Reverse circulate hole to T.D.
- (6) Perform salt water injection test at maximum surface pressure of 1000 psi.
- (7) Acidize well-bore if indicated necessary in (6).
- (8) Pull tubing.
- (9) Place well on injection down the casing until such time as well is "Pressured Up".
- (10) Run plastic-lined tubing injection string.
- (11) Fill casing annulus with oil.
- (12) Place well back on injection.

PHASE II

A. Source of Water for Injection

Alternative #1 - Subsurface Water Sources

It is planned to investigate the productivity of the Upper
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Devonian section at Calstan Scallion Prov. SWD 9-16-11-26 and Cdn. Sup. Whiteford Scallion SWD 8-28-11-26. These two wells are currently disposing of salt water production to the Upper Devonian. The 9-16 well has the entire Upper Devonian section open and is taking water on injection at rates up to 4,000 barrels per day. A drill stem test of the Dawson Bay formation of the Upper Devonian section at Calstan South Virden Prov. SWD 3-11-10-26 in the Virden Roselea Field gave a salt water rise of 50 bbls. in 37 minutes. The recovery, together with chart analysis indicates a formation of high permeability. Regional geology suggests that porous and permeable Dawson Bay and Duperow formations exist over a large general area. It is therefore expected that these Upper Devonian formations will provide an abundant source of injection water.

Ashville salt water disposal wells and high water cut Mississippian oil wells are two additional possible water sources which will be investigated.

Alternative #2 - Fresh Water Sources

If the investigation of possible subsurface water sources does not indicate an adequate water supply it would then be necessary to resort to fresh water sources.

A supply of fresh water could be obtained from the Assiniboine River Valley approximately two miles east of the North Virden Scallion Field. This would require drilling a supply well or wells in the valley and installing a pipeline to transport the water to the field area. Since this appears to be the most expensive alternative the project costs are based on a line to the river.

B. Injection Plants

Preliminary design indicates that injection plants could be located as follows:

Plant at 9-16

This plant was located at this point because of the existence of the SWD facilities which might be incorporated directly into the proposed waterflood. A concrete pit with skimming, settling, and clear-well is now in use along with overflow pit and pump house. Minor additions and changes to the present plant may allow its use as plant #1 in the water flood. The Devonian disposal well could be used as a water supply well initially and a water disposal well in the final stages of the water flood.

Plants at 2-26 and 7-33

These plants are so located because:

- (1) The line sizes in the high pressure system are substantially reduced by having two plants rather than one.
- (2) The plants are located roughly in the center of their respective injection areas.

(3) The proximity of Ashville wells or disposal lines are such that produced salt water may be utilized in the flood or disposed with a minimum of additional lines.

(4) The three plants would be located on fairly high ground and thus have all weather access.

The above described plant locations are shown in Figures 4 and 5.

C. High Pressure Injection System

The high pressure injection system for Phase II will be made up of 6", 4", 3" and 2" line pipe, respectively, as is shown in Figure 5.

All of the above would be nominal sized, Grade A line pipe tested to a pressure greater than the anticipated injection pressures. This pipe will be cement lined, wrapped, and buried to a depth of 5 or 7 feet respectively. Until Alternative #1 above can be investigated, it has been assumed that Plants #2 and #3 will be served by fresh water initially and therefore, that the pipe will be buried 7 feet.

It is the intention of the operator to utilize a computer program to obtain the optimum design and location of the high pressure injection lines for Phase II so that the amounts of pipe could be reduced and the line system could be changed.

D. Capital Cost Estimates

The following capital costs are based on Alternative #2 water source and are estimated to be maximum costs.

Phase I

Plant Costs	\$ 18,000
Lines	68,000
Well Conversions	18,000
Miscellaneous (survey, land, eng. etc.)	<u>16,000</u>

\$ 120,000

Phase II

Plant Costs	\$ 91,000
Lines	222,000
Well Conversions	95,000
Miscellaneous (surveys, land, eng. etc.)	<u>76,000</u>

\$ 484,000

Line to Assiniboine River

Lines	\$ 82,000
Well and Pump	<u>30,000</u>

\$ 112,000

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Possible Additional Flood Expansion

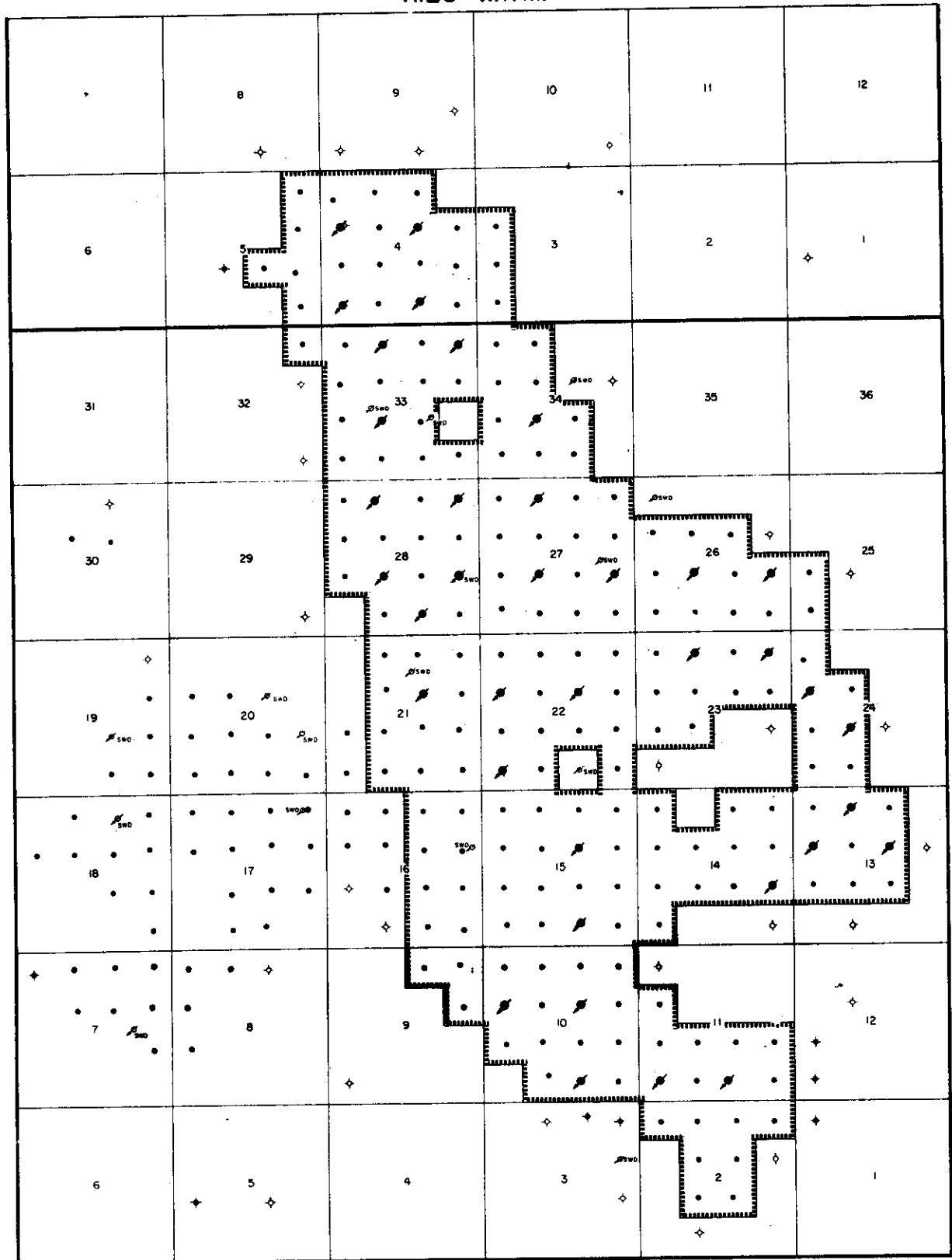
After the North Virden Scallion Unit #1, water flood has been in operation for three to four years, the performance of injection and producing wells contained in Phases I and II will dictate whether additional water injectors are required.

The addition of further injection wells located on even numbered Lsd's would compliment the existing pattern. This could be carried to an ultimate pattern of 80 acre 5 spots throughout the field. It is not expected that this degree of conversion will ever be required. However, to demonstrate the economic situation which this arrangement provides, a further economic breakdown is included under a complete 80 acre 5 spot flood pattern.

Lines	\$ 99,000
Wells	118,000
Miscellaneous (surveys, land, eng. etc.)	<u>27,000</u>
	\$ 244,000
	<hr/>
Estimated Maximum Total Cost	\$ 960,000
	<hr/> <hr/>

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FIGURE 1

PROPOSED NORTH VIRDEN SCALLION UNIT WATER FLOOD PATTERN

UNIT BOUNDARY
INJECTION WELL

SCALE IN MILES
0 1 2

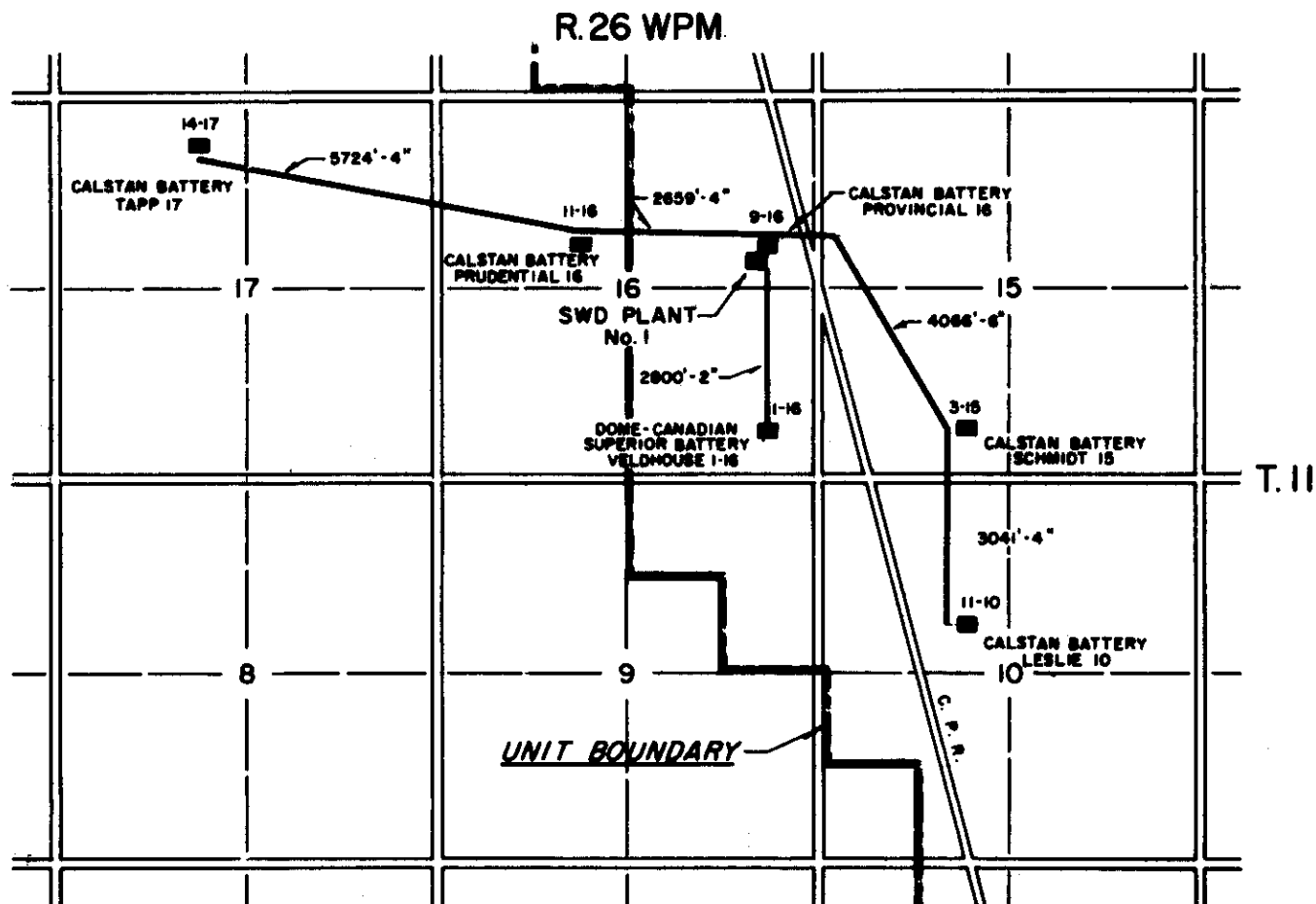


FIGURE 2
NORTH VIRDEN SCALLION FIELD
PLAN OF SALT WATER GATHERING
SYSTEM

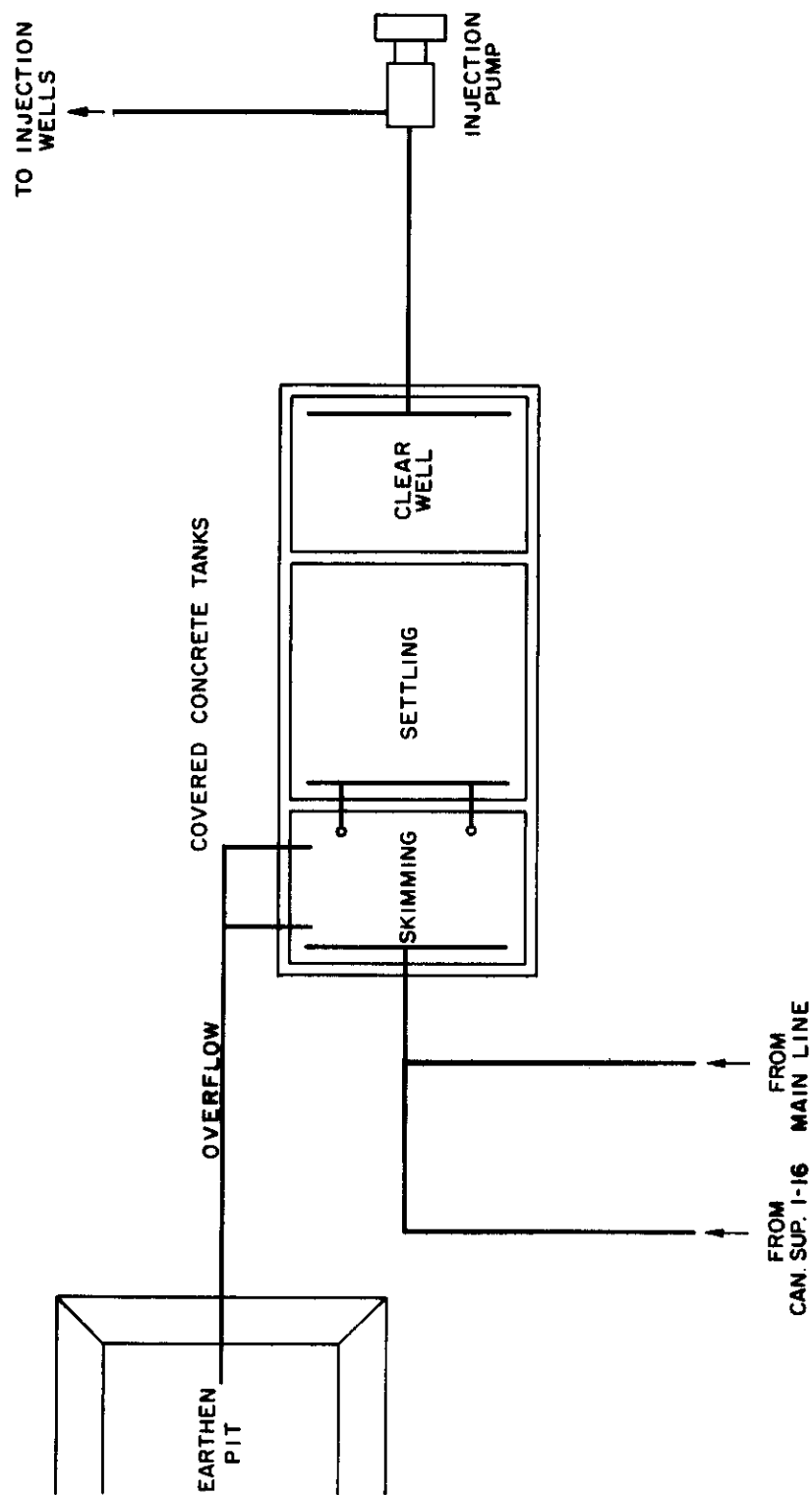
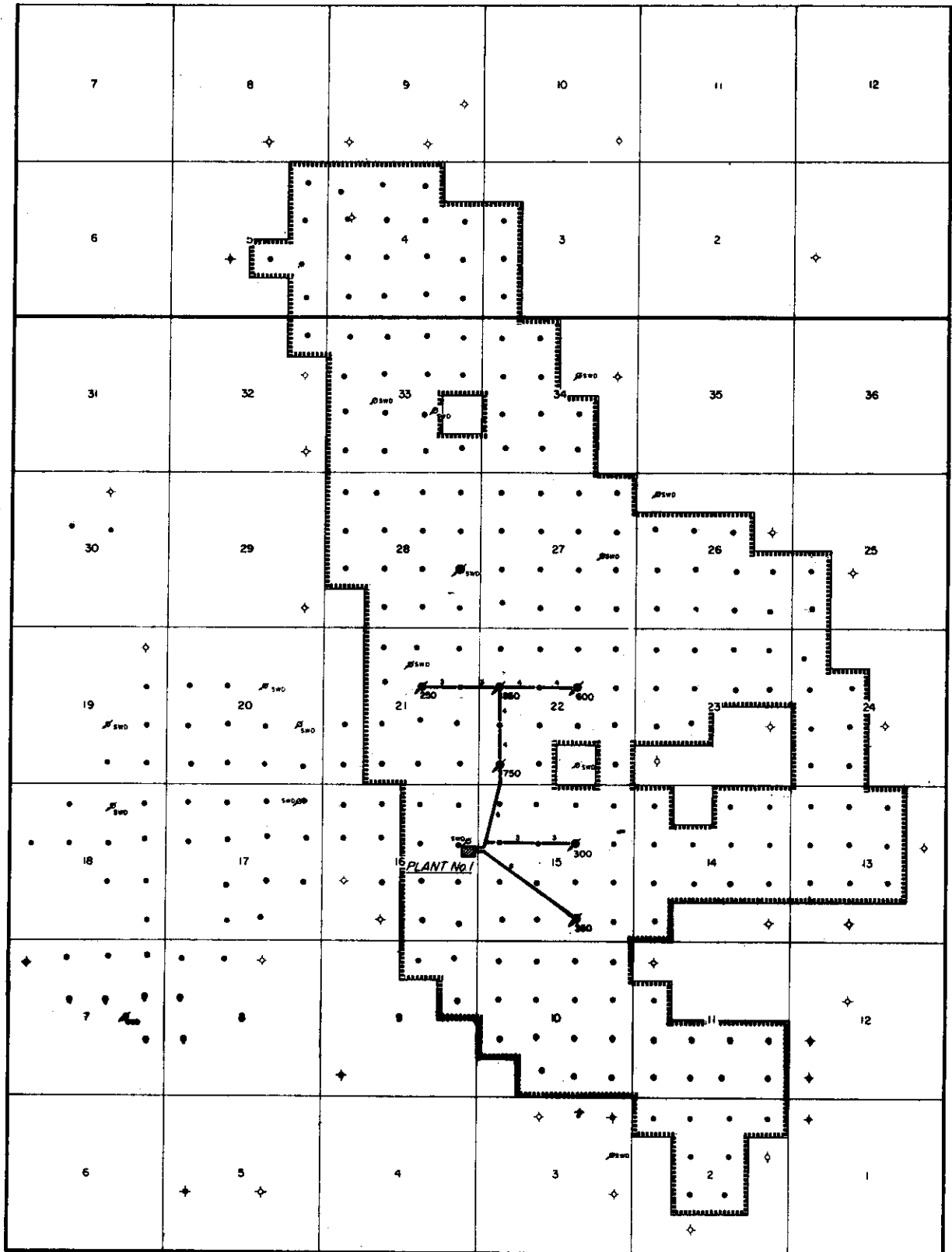


FIGURE 3
 NORTH VIRDEN SCALLION FIELD
 SCHEMATIC DIAGRAM
 OF
 EXISTING FACILITIES
 NORTH VIRDEN PLANT No.1

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FIGURE 4
PROPOSED NORTH VIRDEN SCALLION UNIT
WATER FLOOD PROGRAM - PHASE I

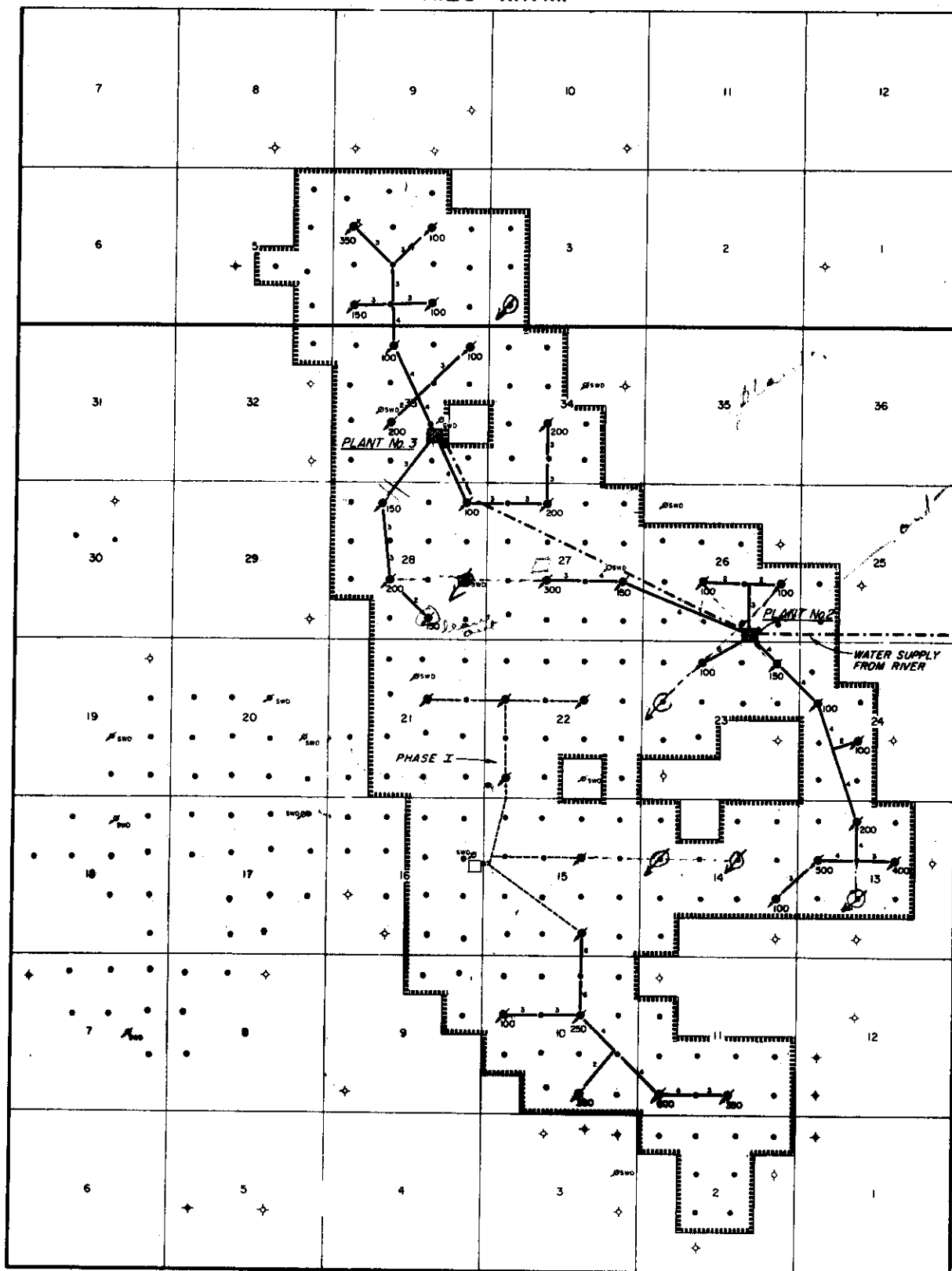
UNIT BOUNDARY
INJECTION WELL
INJECTION LINE, SIZE
250 INJECTIVITY RATE, B/D

SCALE IN MILES

OCT., 1961

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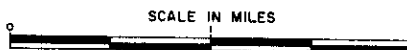
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FIGURE 5

PROPOSED NORTH VIRDEN SCALLION UNIT WATER FLOOD PROGRAM - PHASE II

- UNIT BOUNDARY
- INJECTION WELL
- INJECTION LINE, SIZE
- 250 INJECTIVITY RATE, B/D

OCT., 1961



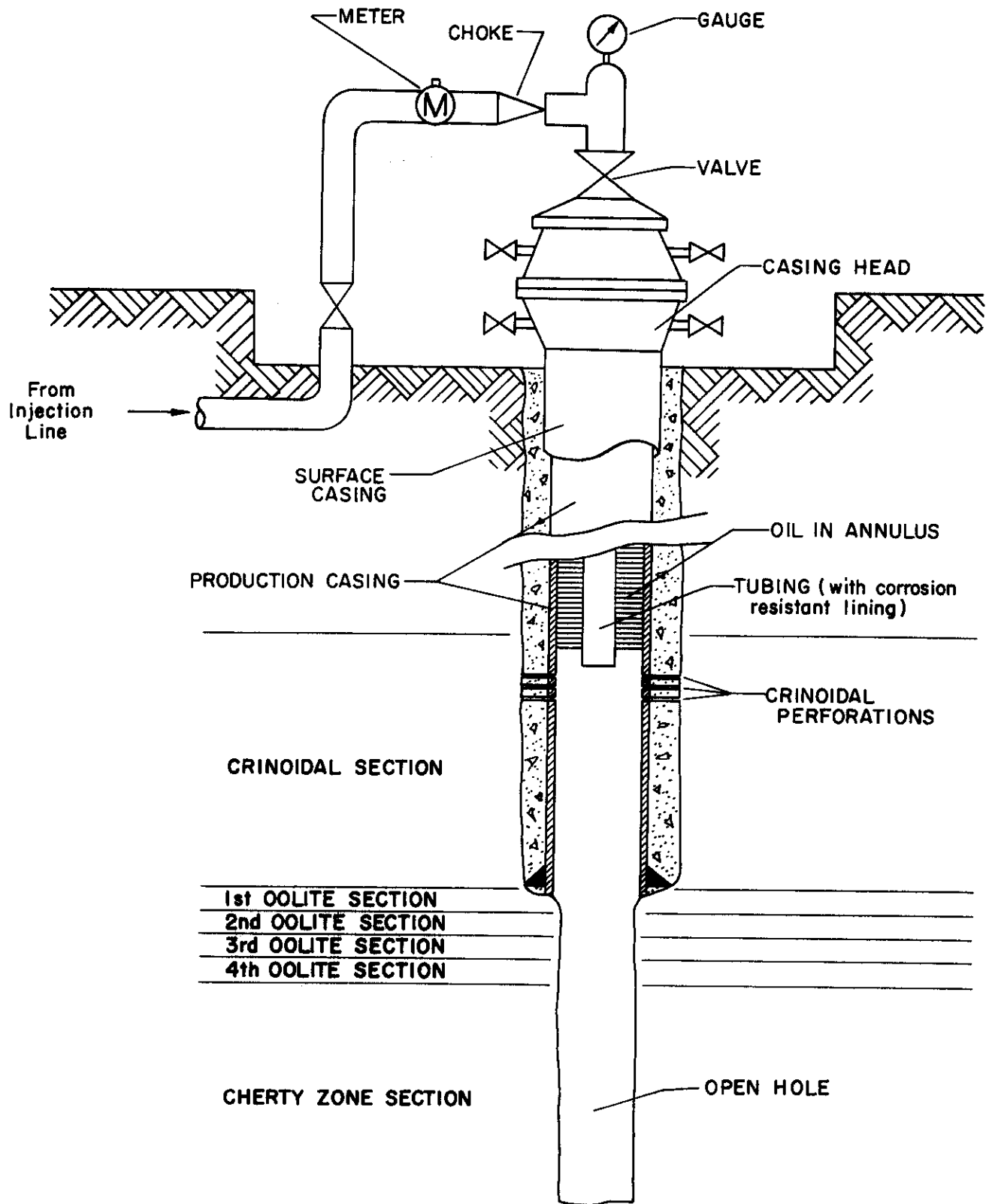


FIGURE 6

PROPOSED NORTH VIRDEN SCALLION UNIT
TYPICAL INJECTION WELL

REVIEW OF HIGH VOLUME FLUID WITHDRAWALS
NORTH VIRDEN-SCALLION UNIT NO. 1

Several wells in the North Virden-Scallion Unit No. 1 area are subjected to fluid withdrawal rates exceeding 100 barrels of oil per day, 1,000 barrels of fluid per day, or both. Figure 1 attached indicates the location of these high fluid withdrawal wells.

To confirm that high volume fluid withdrawals have not and will not adversely affect the producing characteristics and ultimate recovery of oil at wells producing at high rates, or to adjacent producing wells, a representative number of high volume operations were reviewed. The following three different high volume producing situations were considered.

Case A: The high volume well is offset directly by one injection well with other injection being distant. The subject well is directly offset by other producing wells. The example case considered was 1-21-11-26.

Case B: The high volume well is offset directly by more than one injection well. The subject well is directly offset by other producing wells. The example case considered was 9-14-11-26.

Case C: The high volume well is offset by distant injection and is influenced by natural water encroachment. The well is directly offset by other producing wells. The example cases considered were 5-15-11-26 and 9-16-11-26.

Cases A and B are representative of producing wells within the framework of the injection system. Case C is deemed to be representative of those potential

high volume withdrawal wells offsetting the Unit boundary on the west flank where the high volume potential is primarily attributable to natural water encroachment.

The following types of production plots were reviewed for each of the four example cases:

- (a) high volume well (entire production history)
- (b) individual directly offsetting producers (entire production history)
- (c) group plot of all producers offsetting the high volume well for the period 1963 to 1969, inclusive.

A copy of the above production plots for each of the example cases is attached hereto. (See Figures 2 to 32.)

The following are conclusions drawn from the review of the various production plots:

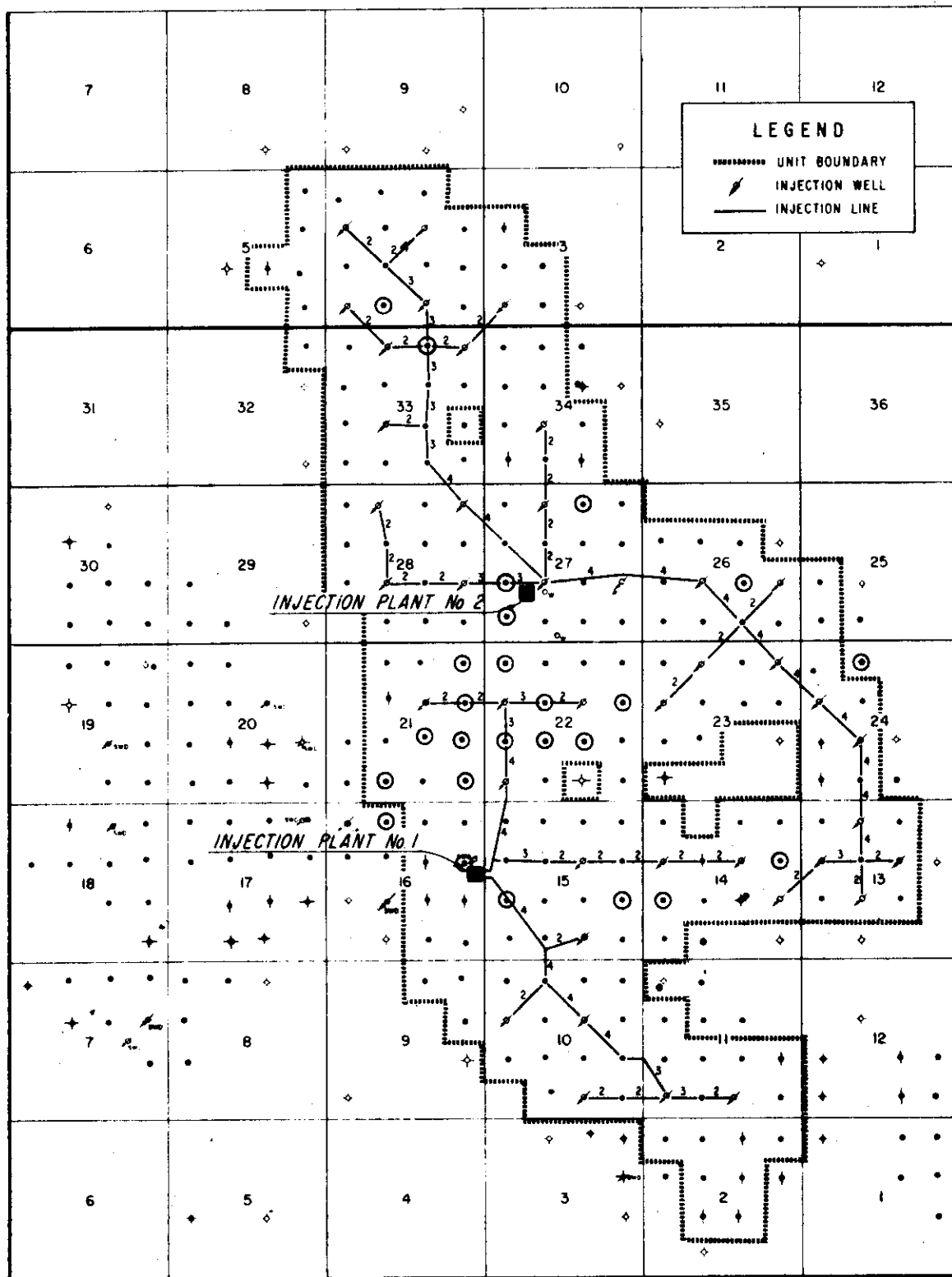
1. There is no indication that high volume withdrawals have had any, or will have any, detrimental effects on the production characteristics of the well exposed to high fluid withdrawals.
2. High volume withdrawals have had no adverse effect on the producing characteristics of the wells in close proximity to wells being produced at high rates.
3. There is no evidence or indication of the ultimate recovery at the high volume wells, or wells in close proximity to high volume wells, being influenced adversely by high volume withdrawals. The recovery to date for

the example case areas considered is higher than the overall Unit recovery to date. Indications are that this trend will continue.

4. There is no sound technical reason why production within the Unit area should be restricted at any Unit well or, at non-Unit wells where they are obviously producing under the influence of a strong natural water drive.

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⊙ HIGH VOLUME WELL
(ie PRODUCED EITHER 100 BOPD OR
1000 BFPD OR BOTH - DURING 1969)

FIGURE 1

NORTH VIRDEN SCALLION UNIT No.1

HIGH FLUID WITHDRAWAL WELLS

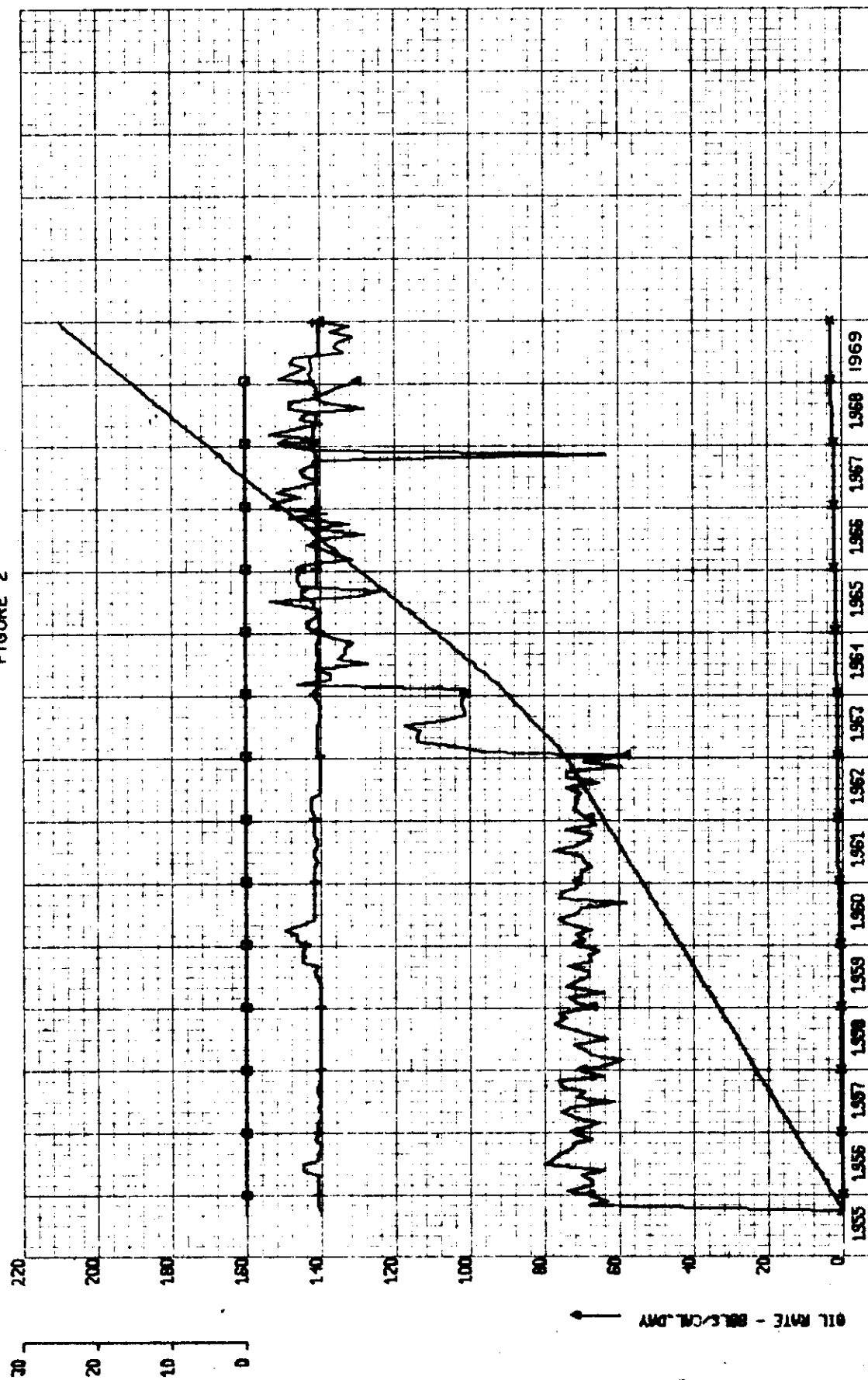


CASE A - EXAMPLE CASE LSD. 1-21-11-26

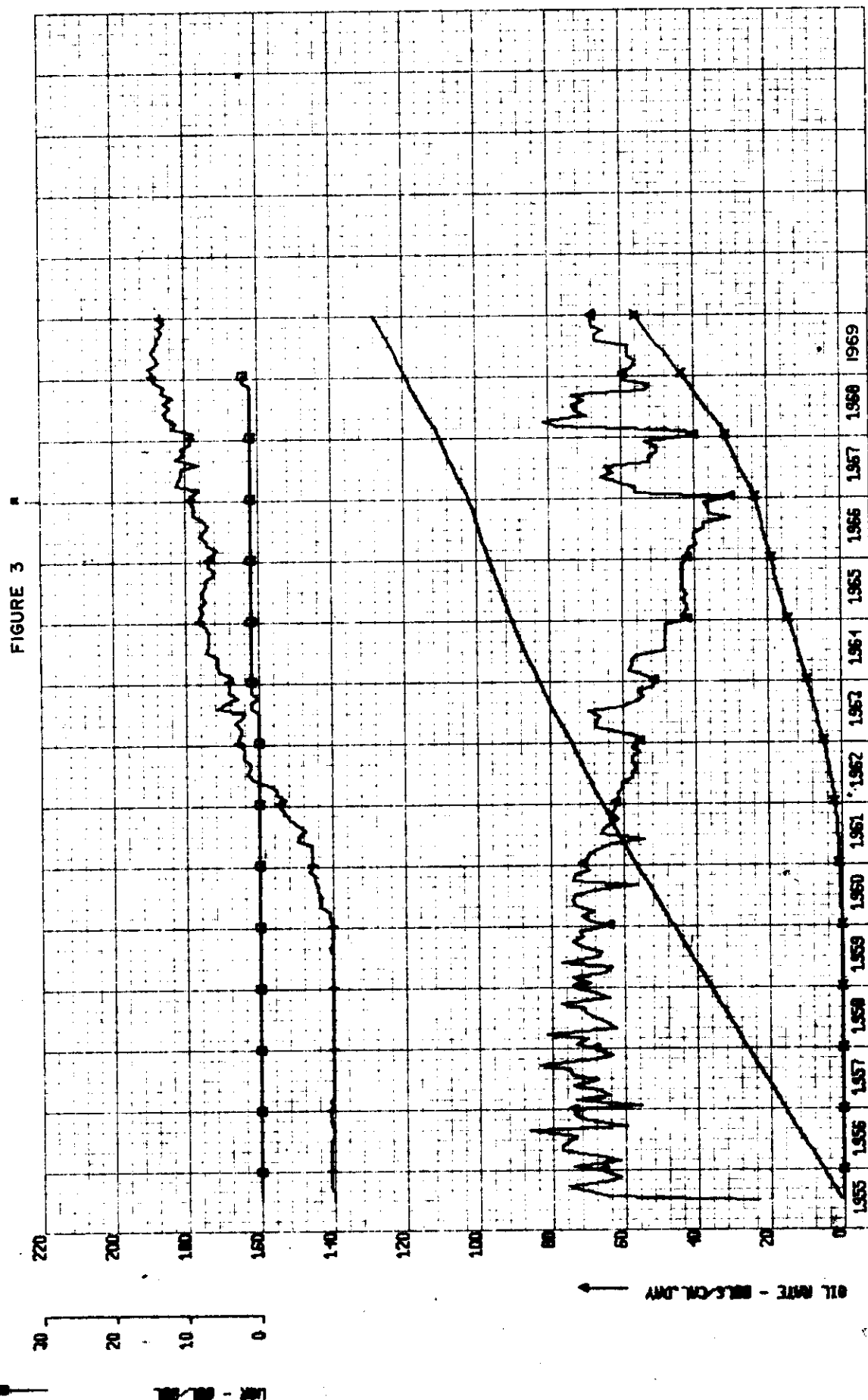
- Figure 2 - Lsd. 1-21-11-26 - high volume producer
- Figure 3 - Lsd. 2-21-11-26
- Figure 4 - Lsd. 7-21-11-26
- Figure 5 - Lsd. 8-21-11-26
- Figure 6 - Lsd. 5-22-11-26
- Figure 7 - Lsd. 13-15-11-26
- Figure 8 - Lsd. 15-16-11-26
- Figure 9 - Lsd. 16-16-11-26
- Figure 10 - Composite of Figure Nos. 3 to 9 inclusive

N.U. SCALLION UNIT 01-21-011-26-W1

FIGURE 2

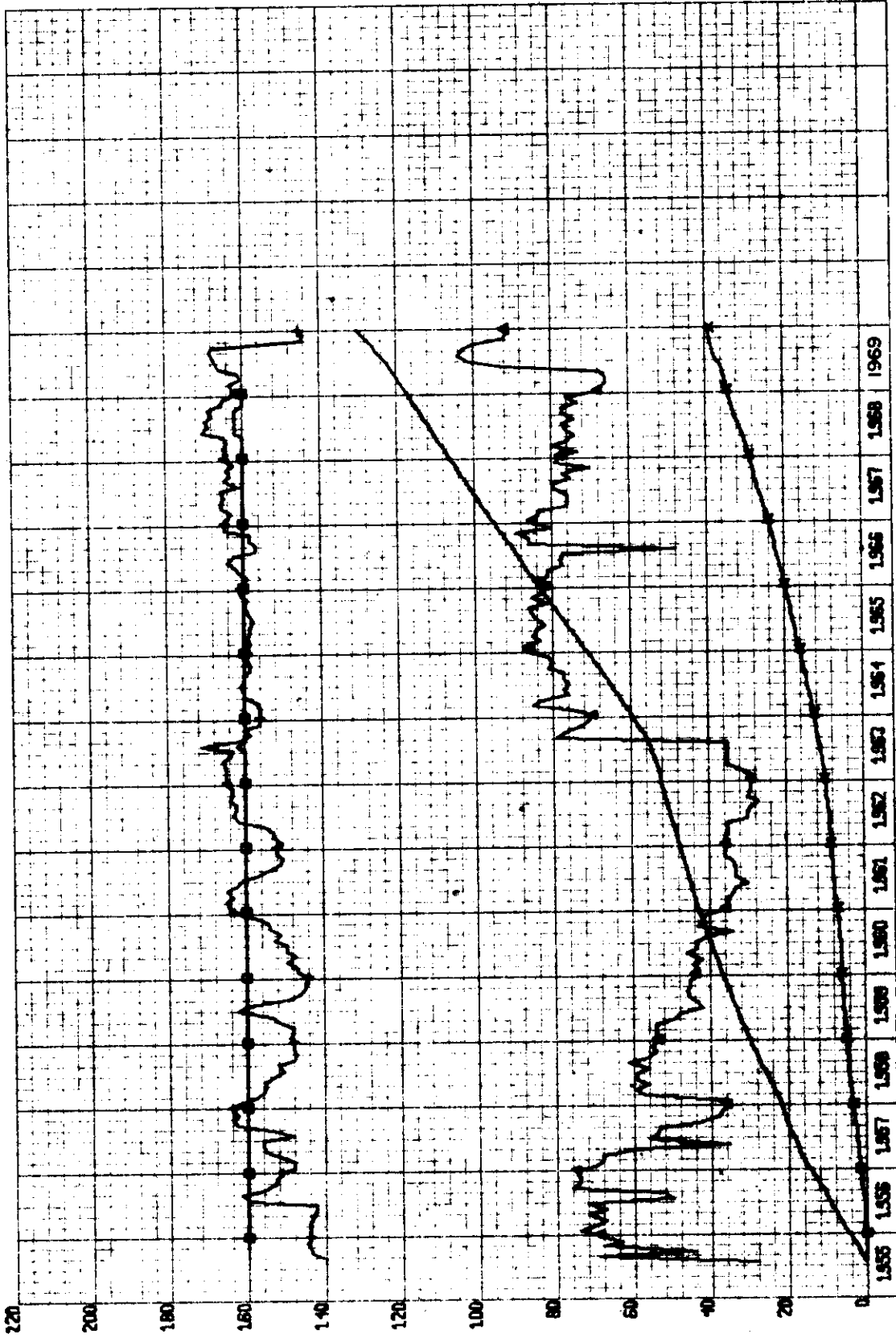


N.U. SCALLION UNIT 02-21-011-26-W1



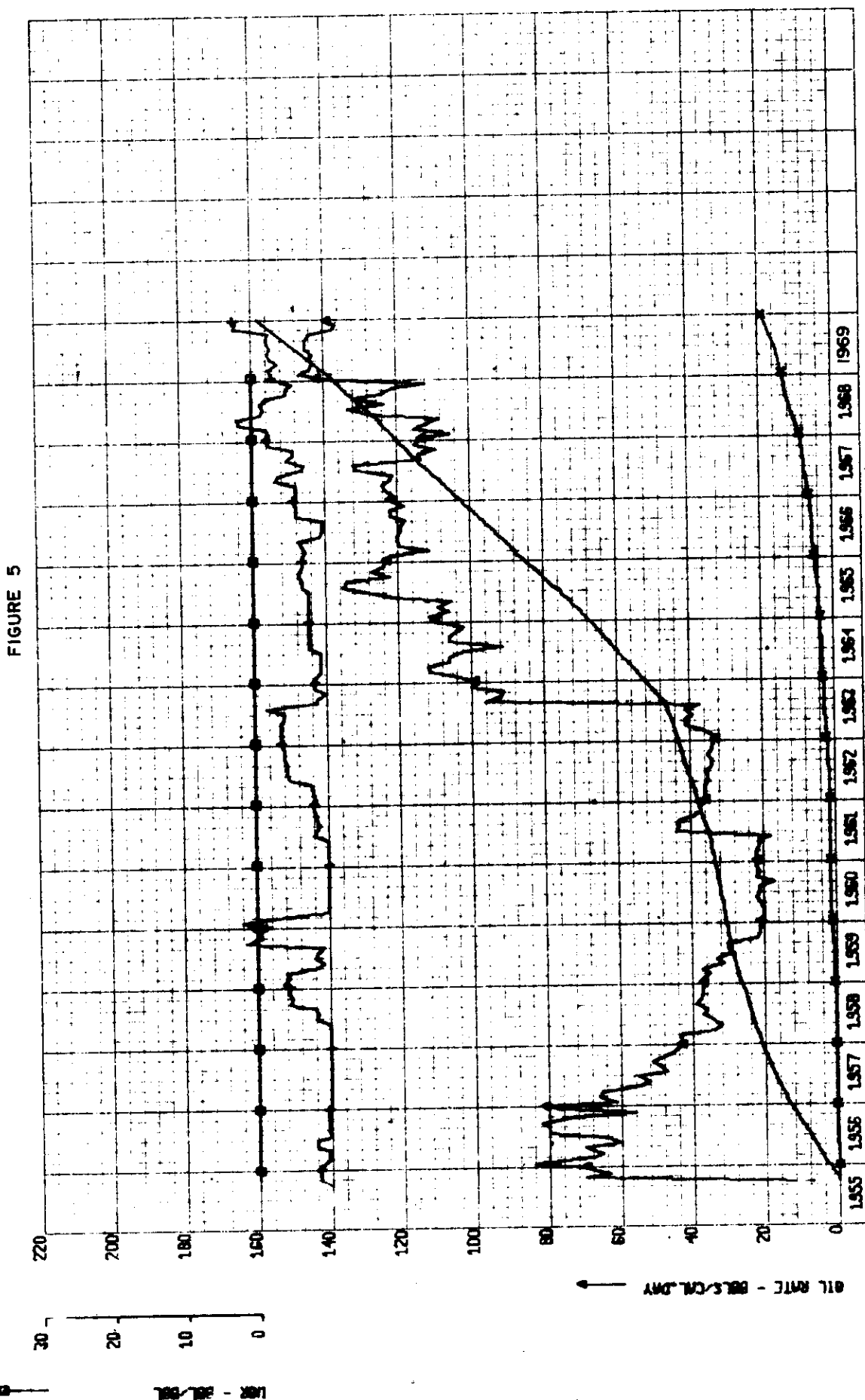
N.U. SCALLION UNIT 07-21-011-26-W1

FIGURE 4



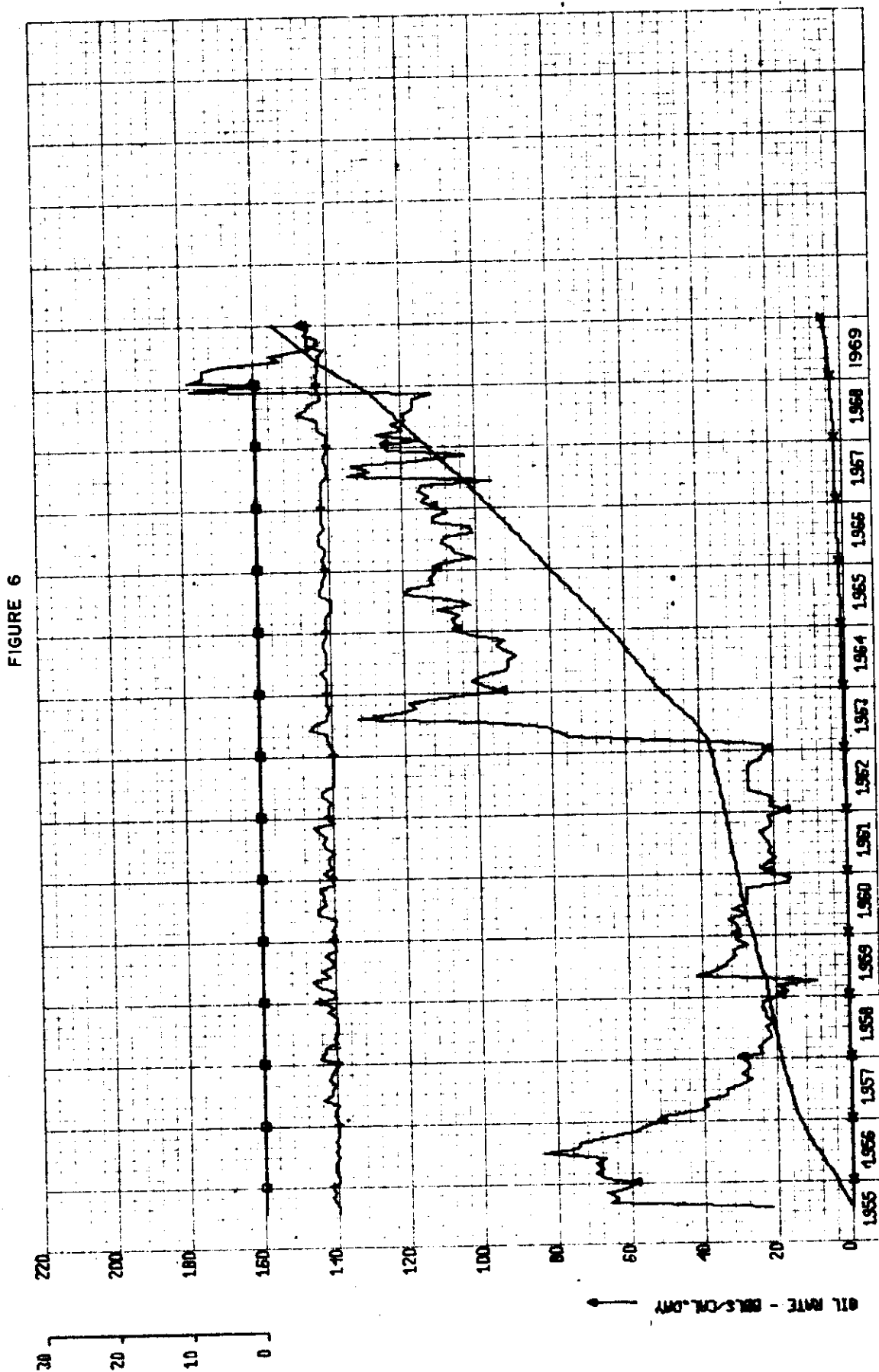
N.U. SCALLION UNIT 08-21-011-26-W1

FIGURE 5



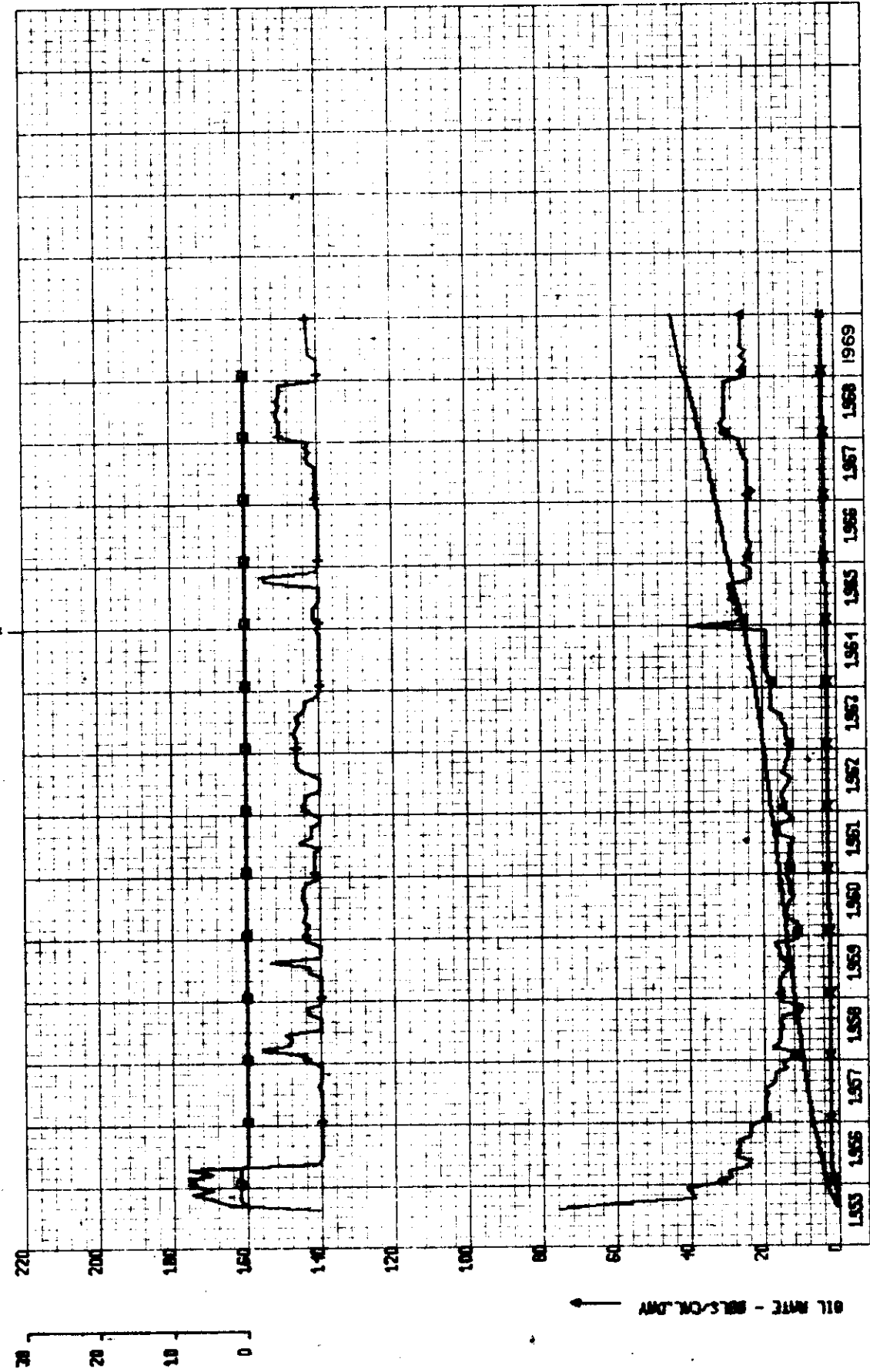
N.U. SCALLION UNIT 05-22-011-26-W1

FIGURE 6



N.V. SCALLION UNIT
13-15-011-26-W1

FIGURE 7

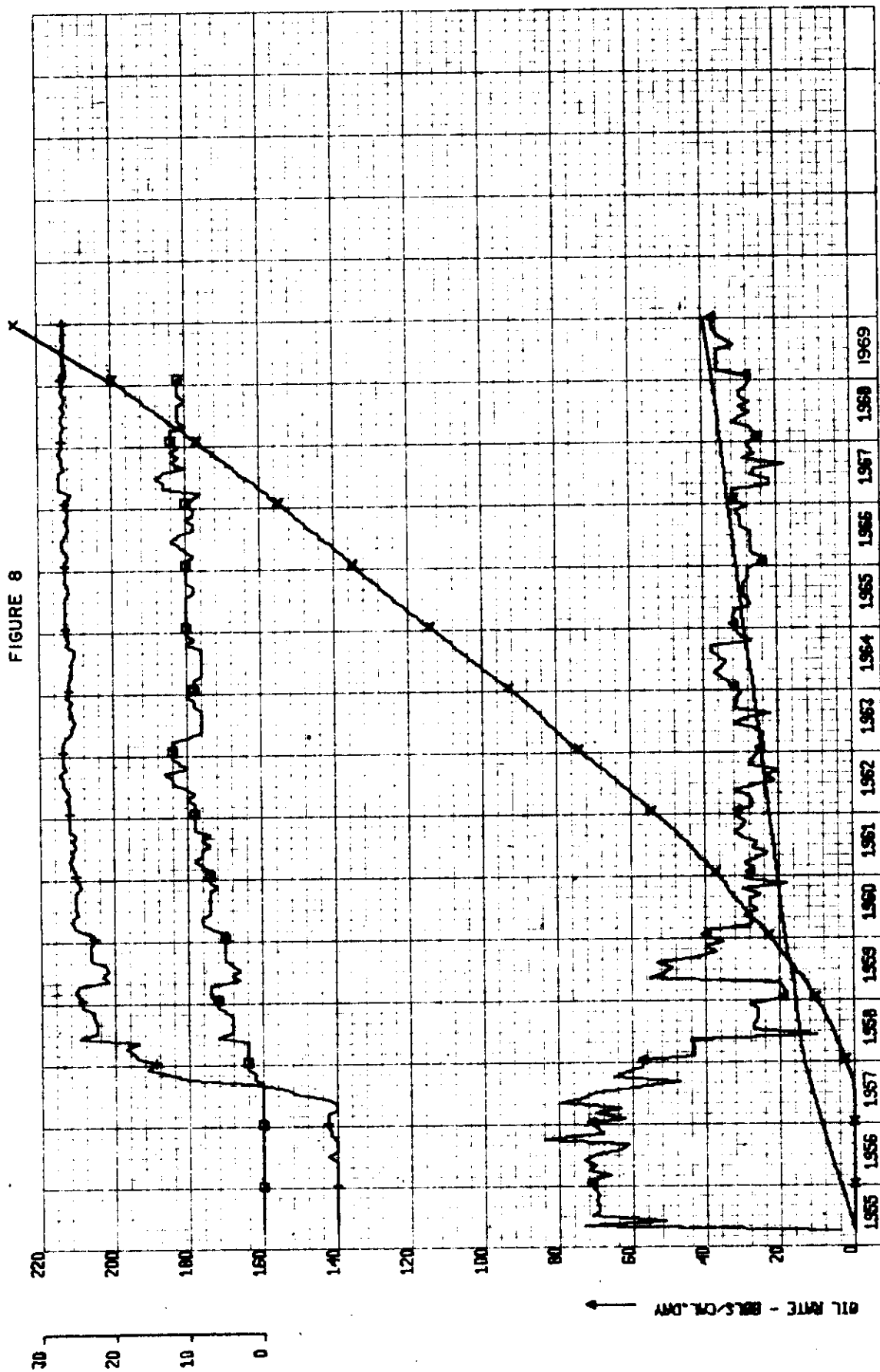


CLM. WATER - BBL/1000
WATER CUT - PCT

CLM. OIL - BBL/1000

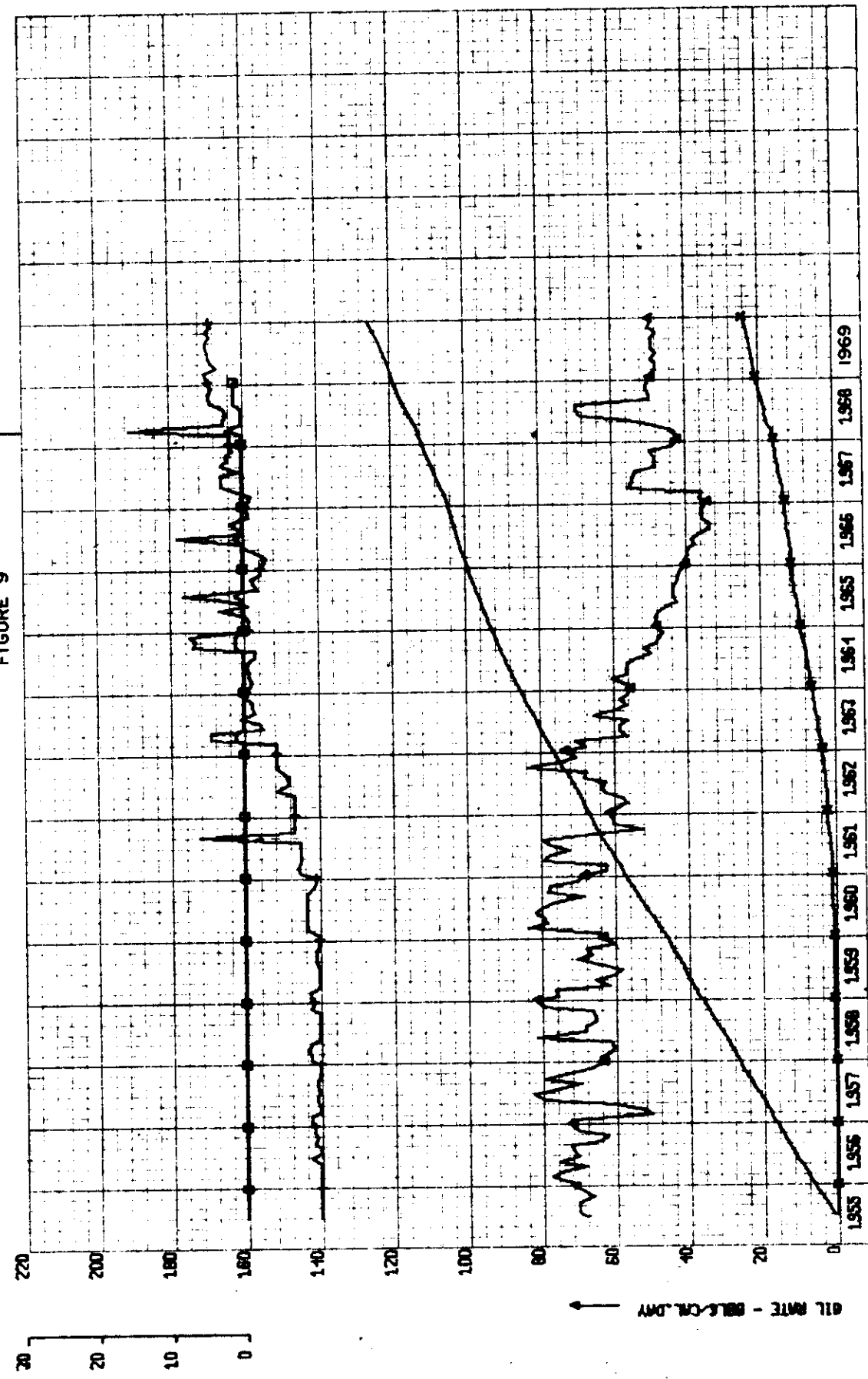
OIL RATE - BBL/CN.DAY

N.V. SCALLION UNIT 15-16-011-26-W1



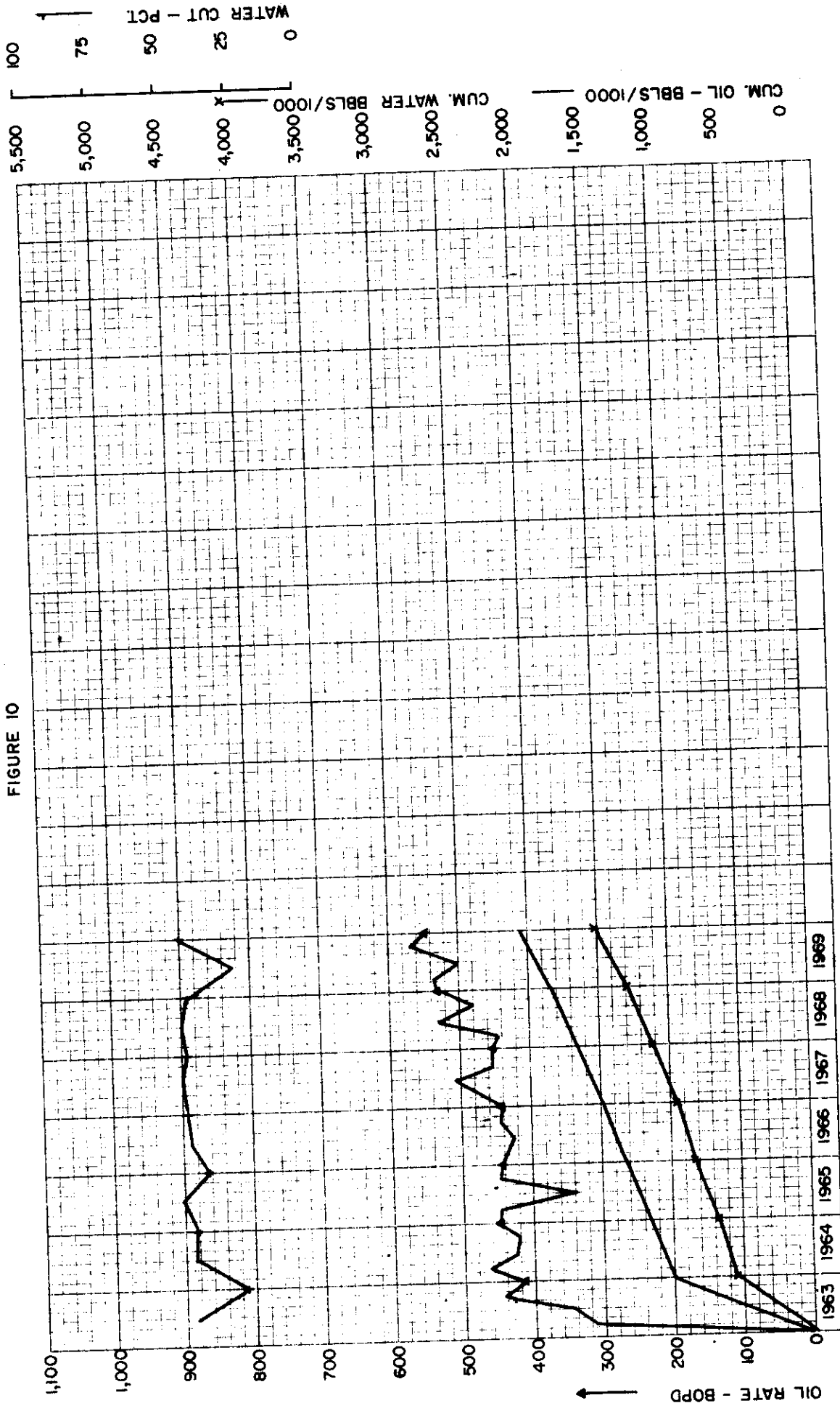
N.V. SCALLION UNIT 16-16-011-26-W1

FIGURE 9



COMPOSITE OF CASE A WELLS EXCLUDING 1-21-11-26

FIGURE 10



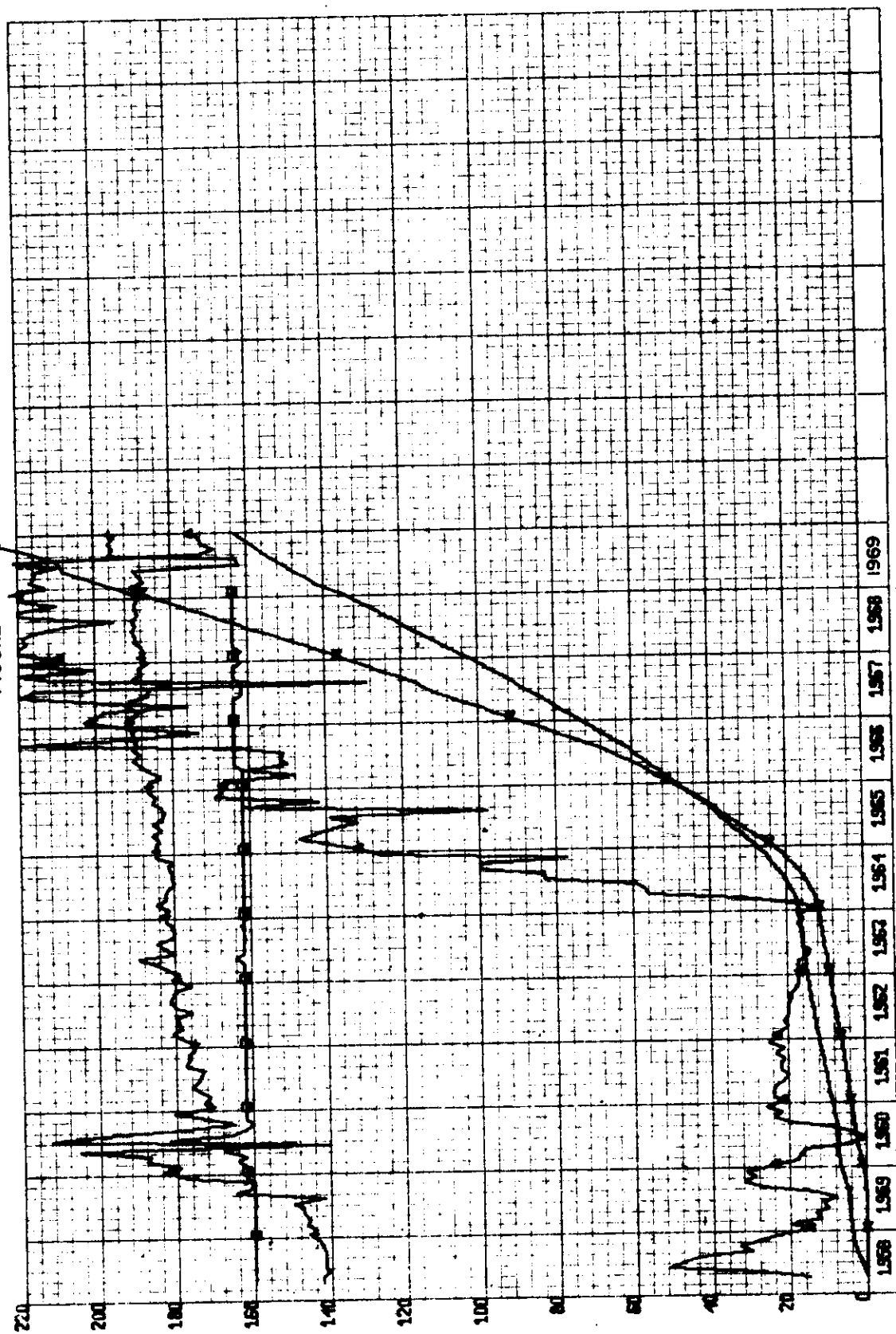
CASE B - EXAMPLE CASE LSD. 9-14-11-26

- Figure 11 - Lsd. 9-14-11-26 - high volume producer
- Figure 12 - Lsd. 7A-14-11-26
- Figure 13 - Lsd. 15-14-11-26
- Figure 14 - Lsd. 16-14-11-26
- Figure 15 - Lsd. 5-13-11-26
- Figure 16 - Lsd. 13-13-11-26
- Figure 17 - Composite of Figure Nos. 12 to 16 inclusive

N.V. SCALLION UNIT 09-14-011-26-U1

0
10
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20
30

FIGURE 11

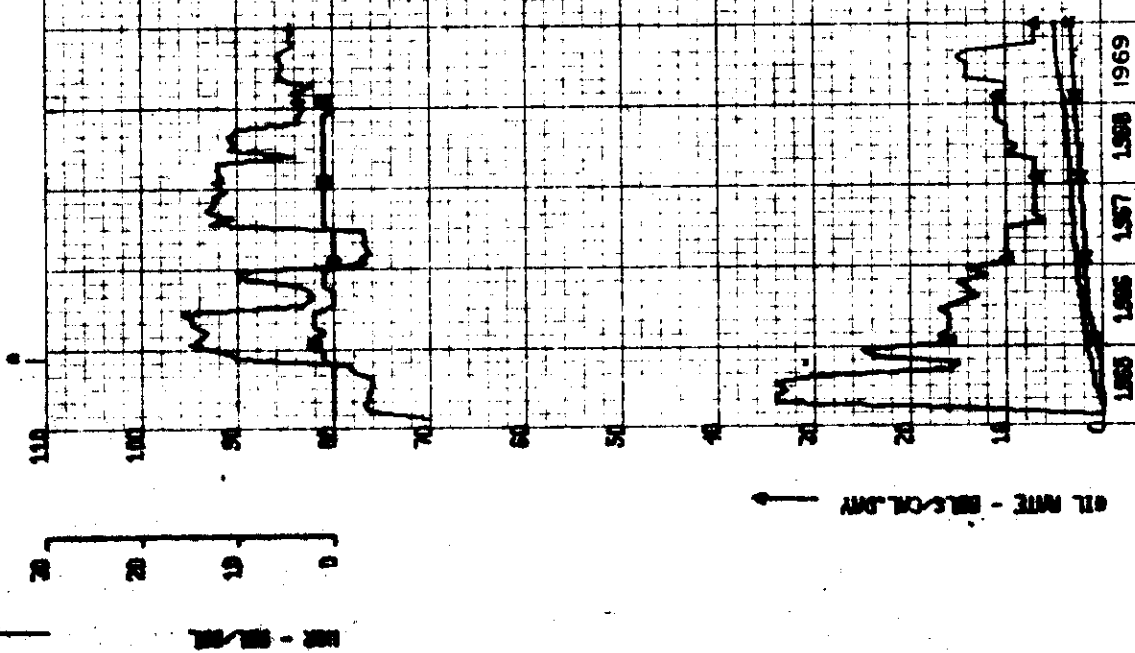


0
25
50
75
100

0
50
100
150
200
250
300
400
500
600

N.V. SCALLION UNIT 07A-14-011-26-W1

FIGURE 12



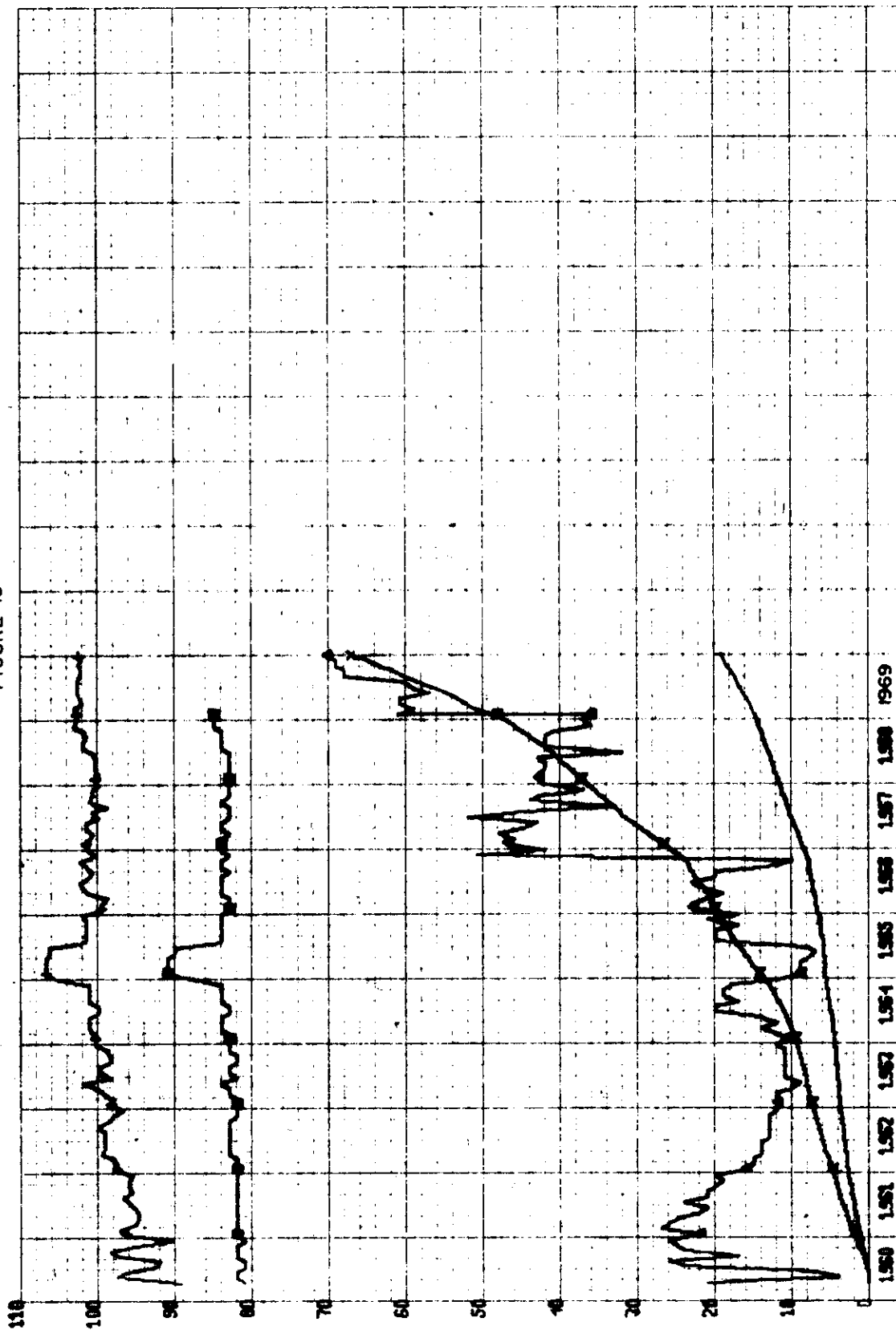
WATER - INLET - PCT. 0 25 50 75 100

OIL RATE - BBL/CAL.DAY 0 20 40 60 80 100

WATER CUT - PCT. 0 25 50 75 100

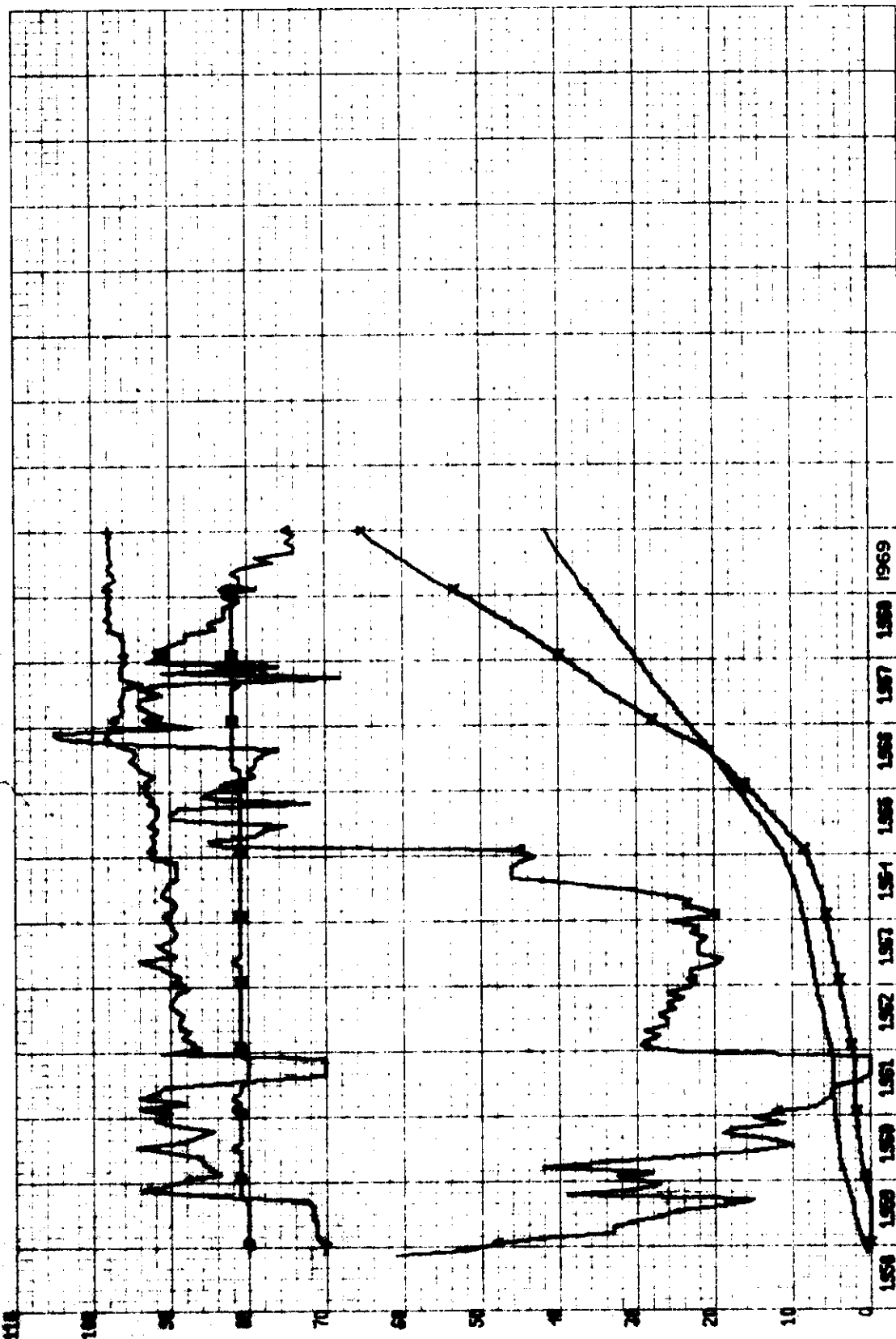
N.V. SCALLION UNIT 15-14-011-26-W1

FIGURE 13



N.U. SCALLION UNIT 16-14-011-26-W1

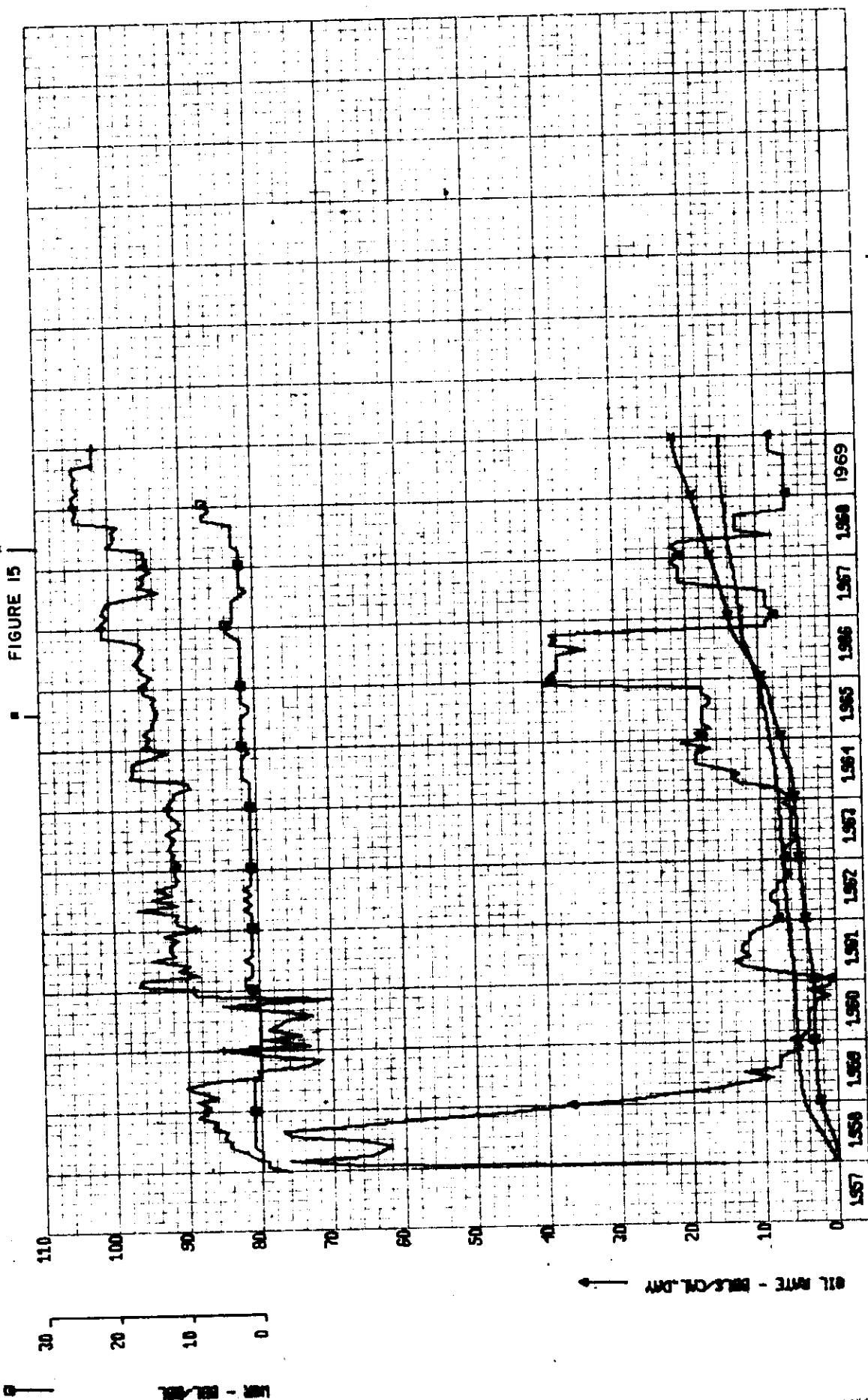
FIGURE 14



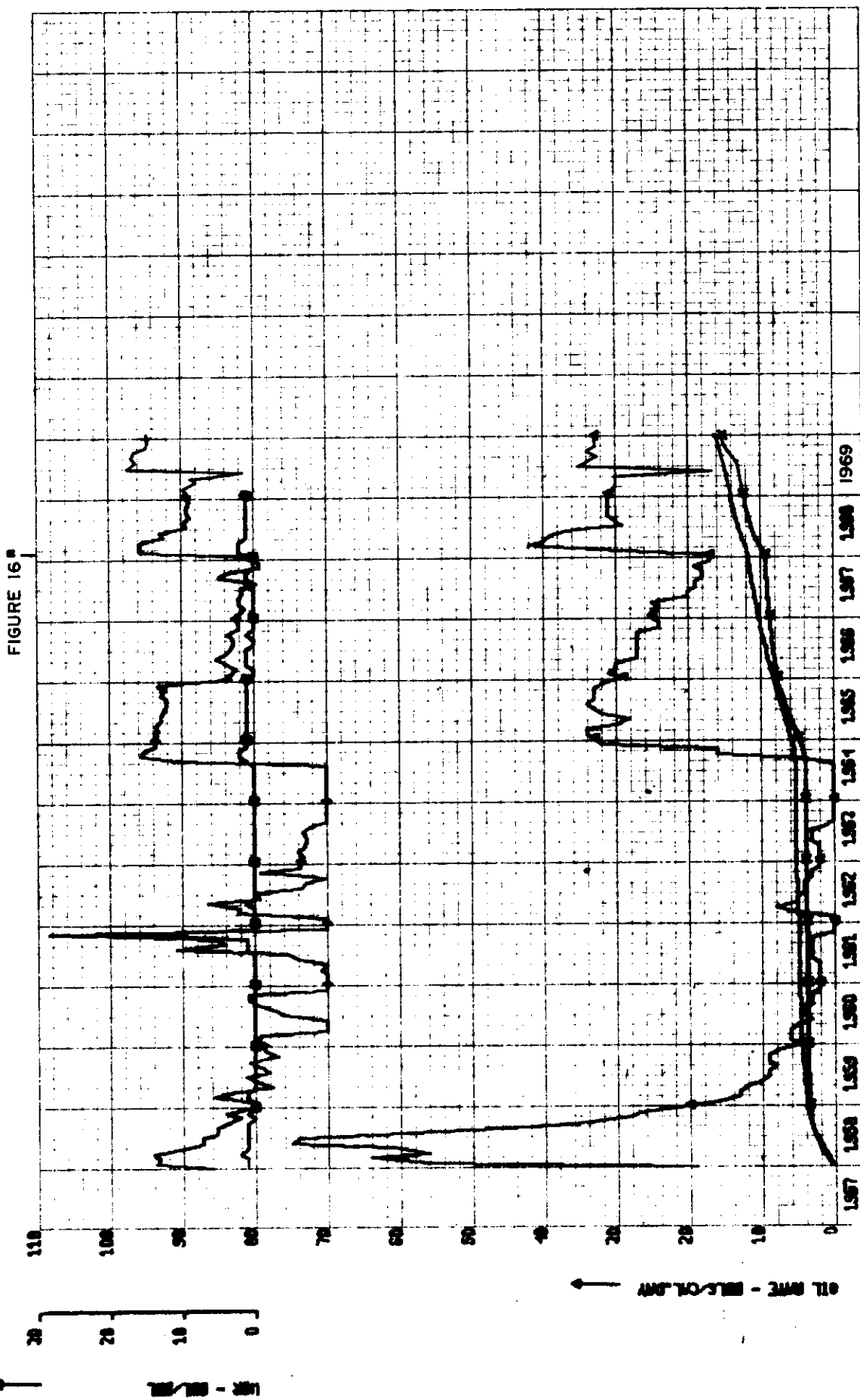
CLN. OIL - BBL/1000
WATER CUT - PCT.

OIL RATE - BBL/CN.DAY

N.U. SCALLION UNIT 05-13-011-26-W1

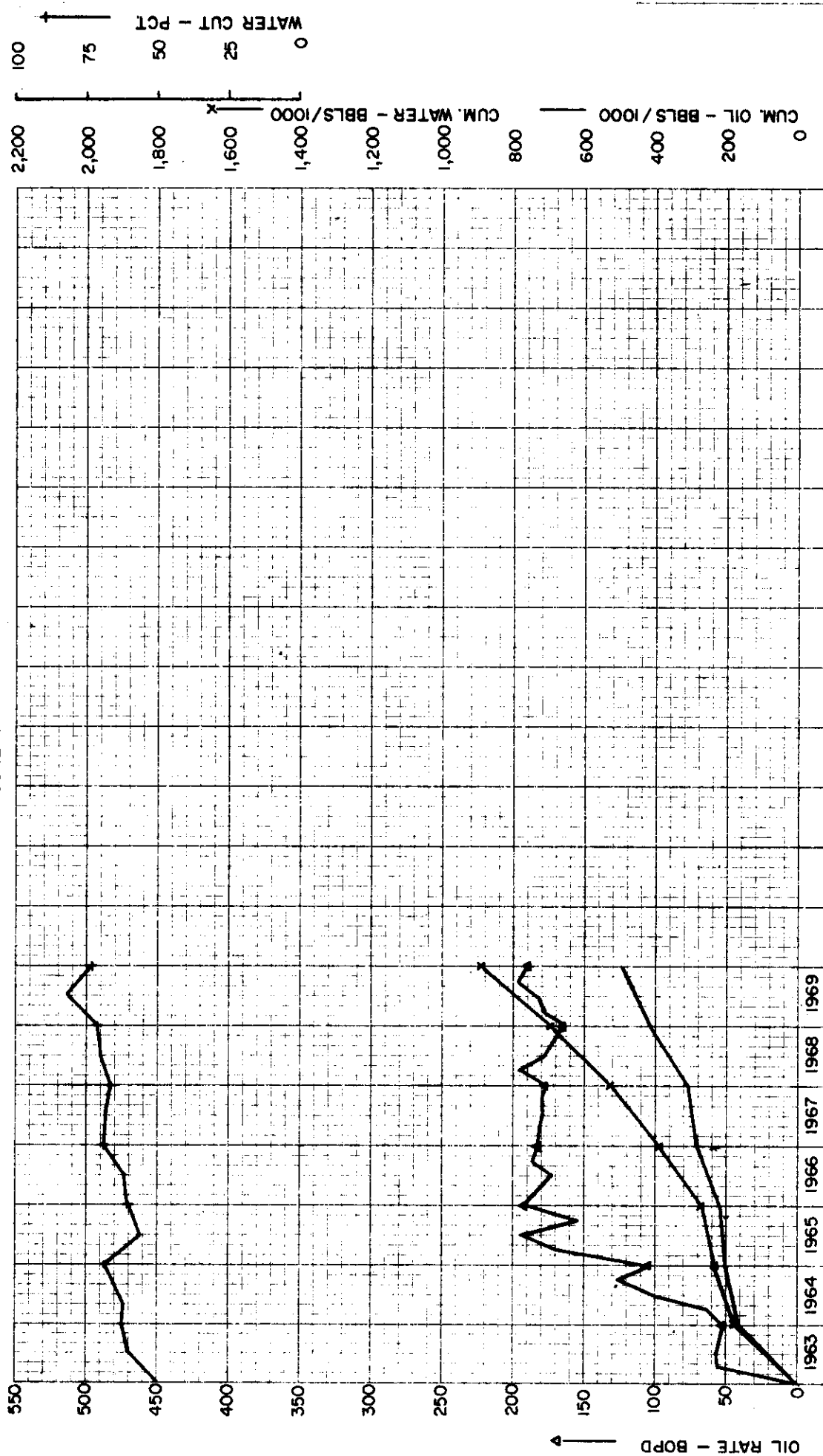


N.U. SCALLION UNIT 13-13-011-26-W1



COMPOSITE OF CASE B WELLS EXCLUDING 9-14-11-26

FIGURE 17

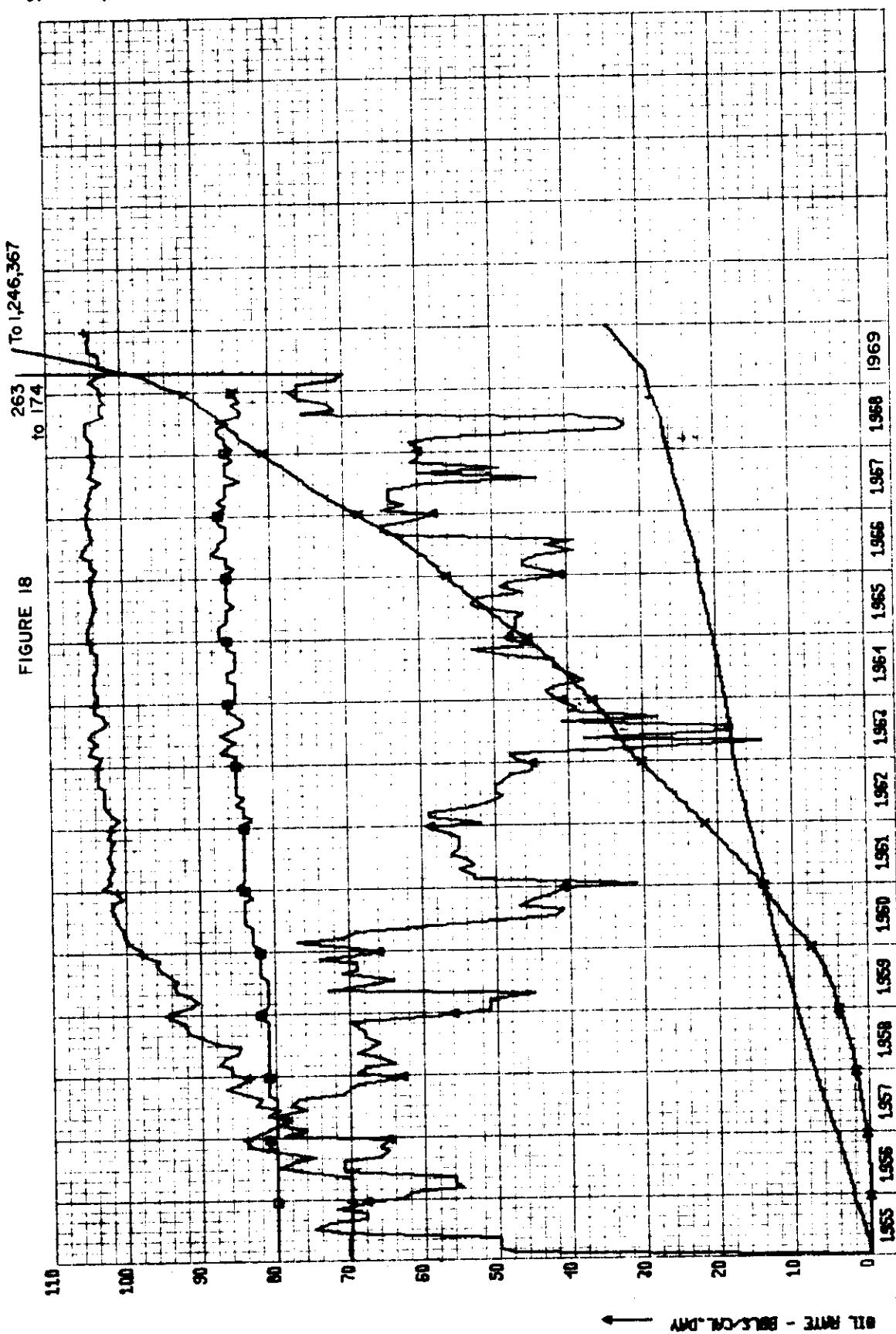


CASE C(a) - EXAMPLE CASE LSD. 5-15-11-26

- Figure 18 - Lsd. 5-15-11-26 - high volume producer
- Figure 19 - Lsd. 3-15-11-26
- Figure 20 - Lsd. 4-15-11-26
- Figure 21 - Lsd. 6-15-11-26
- Figure 22 - Lsd. 11-15-11-26
- Figure 23 - Lsd. 12-15-11-26
- Figure 24 - Lsd. 1-16-11-26
- Figure 25 - Lsd. 8-16-11-26
- Figure 26 - Lsd. 9-16-11-26
- Figure 27 - Composite of Figure Nos. 19 to 26 inclusive

N.U. SCALLION UNIT 05-15-011-26-U1

FIGURE 18



0 10 20 30

← OIL RATE - BBL/CAL.DAY

0 100 200 300 400 500 600 700 800 900 1000 1100

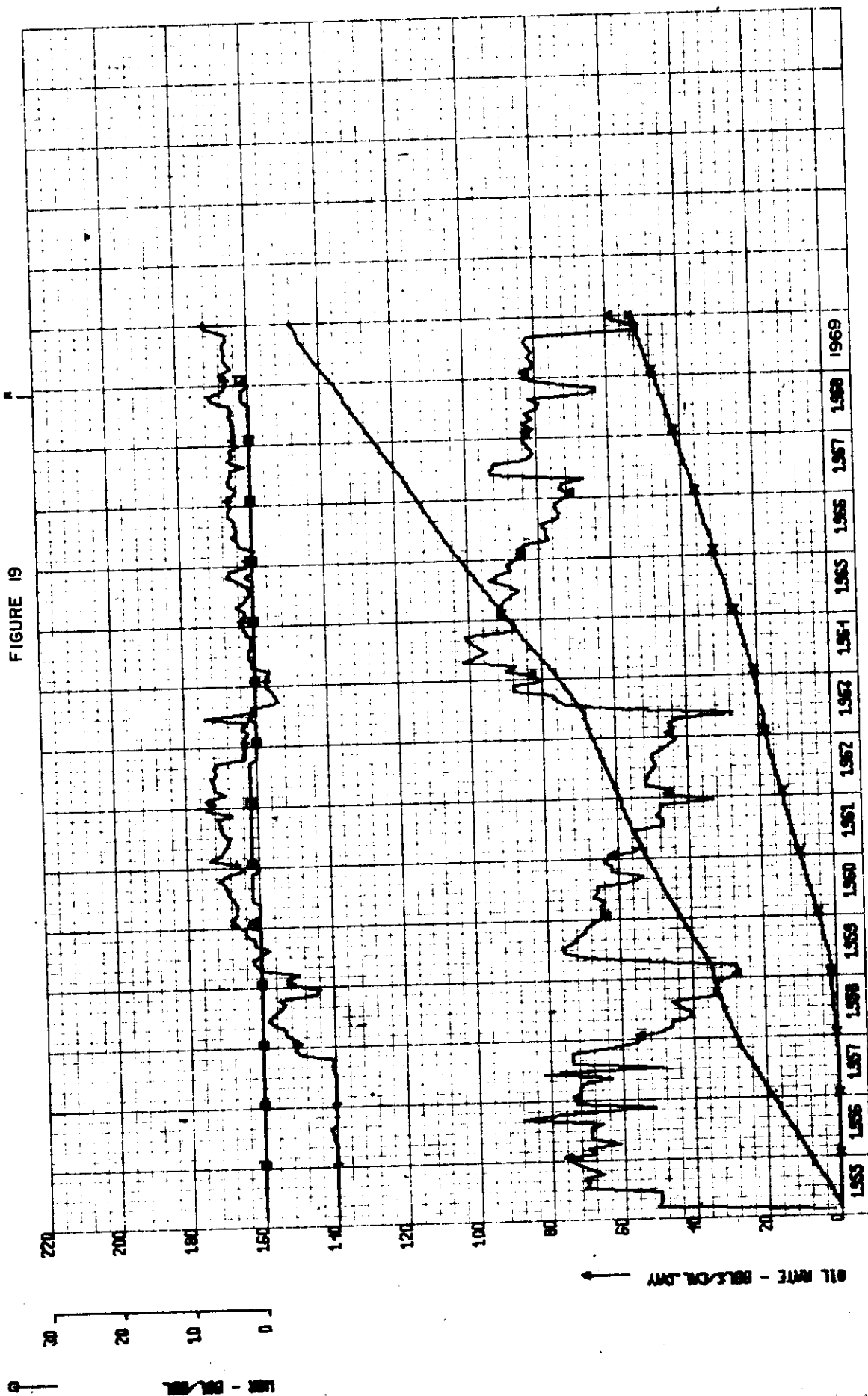
← CUM. OIL - BBL/1000

← CUM. WATER - BBL/1000

← WATER CUT - PCT

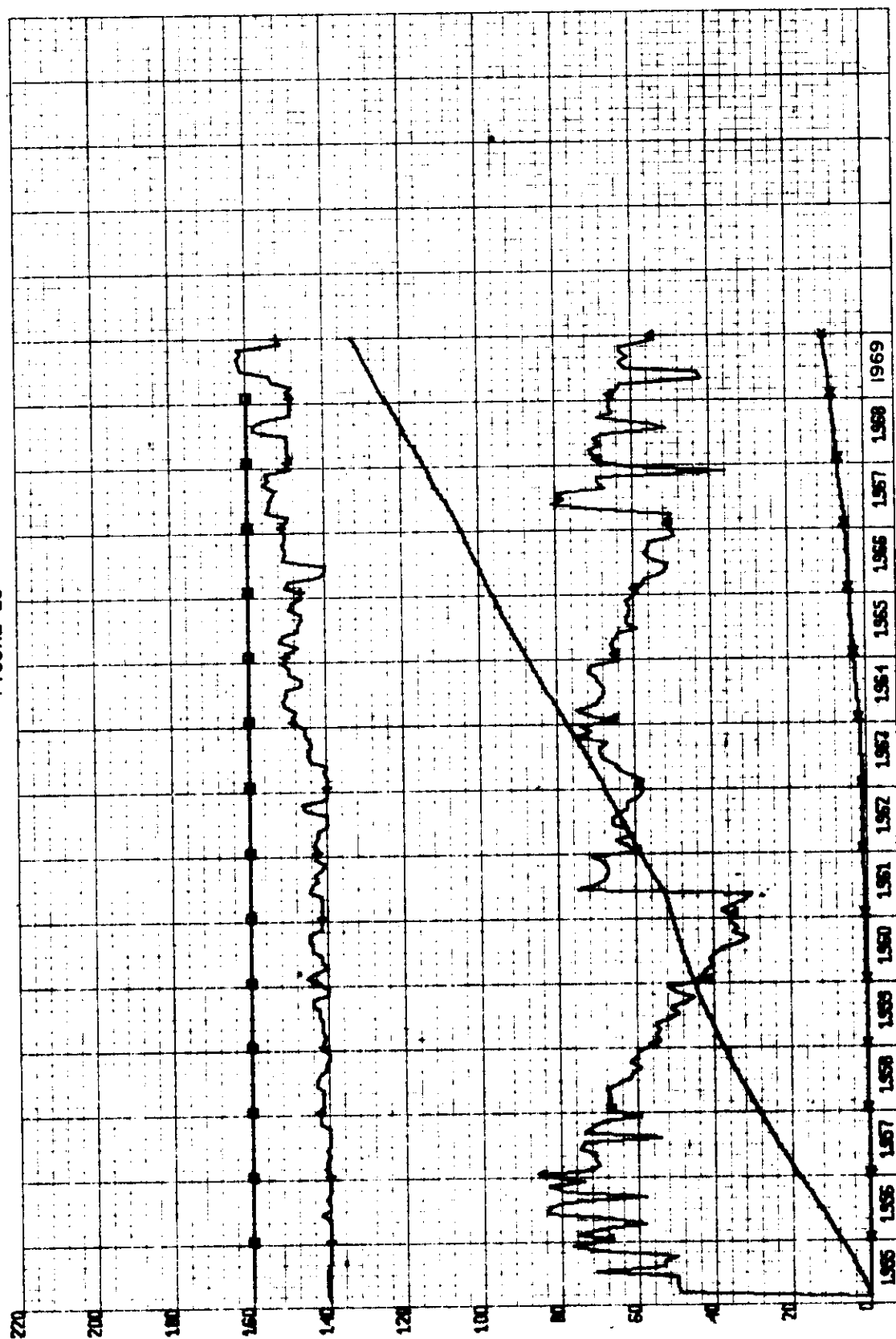
0 25 50 75 100

N.U. SCALLION UNIT 03-15-011-26-W1



N.U. SCALLION UNIT 04-15-011-26-W1

FIGURE 20



N.U. SCALLION UNIT 06-15-011-26-W1

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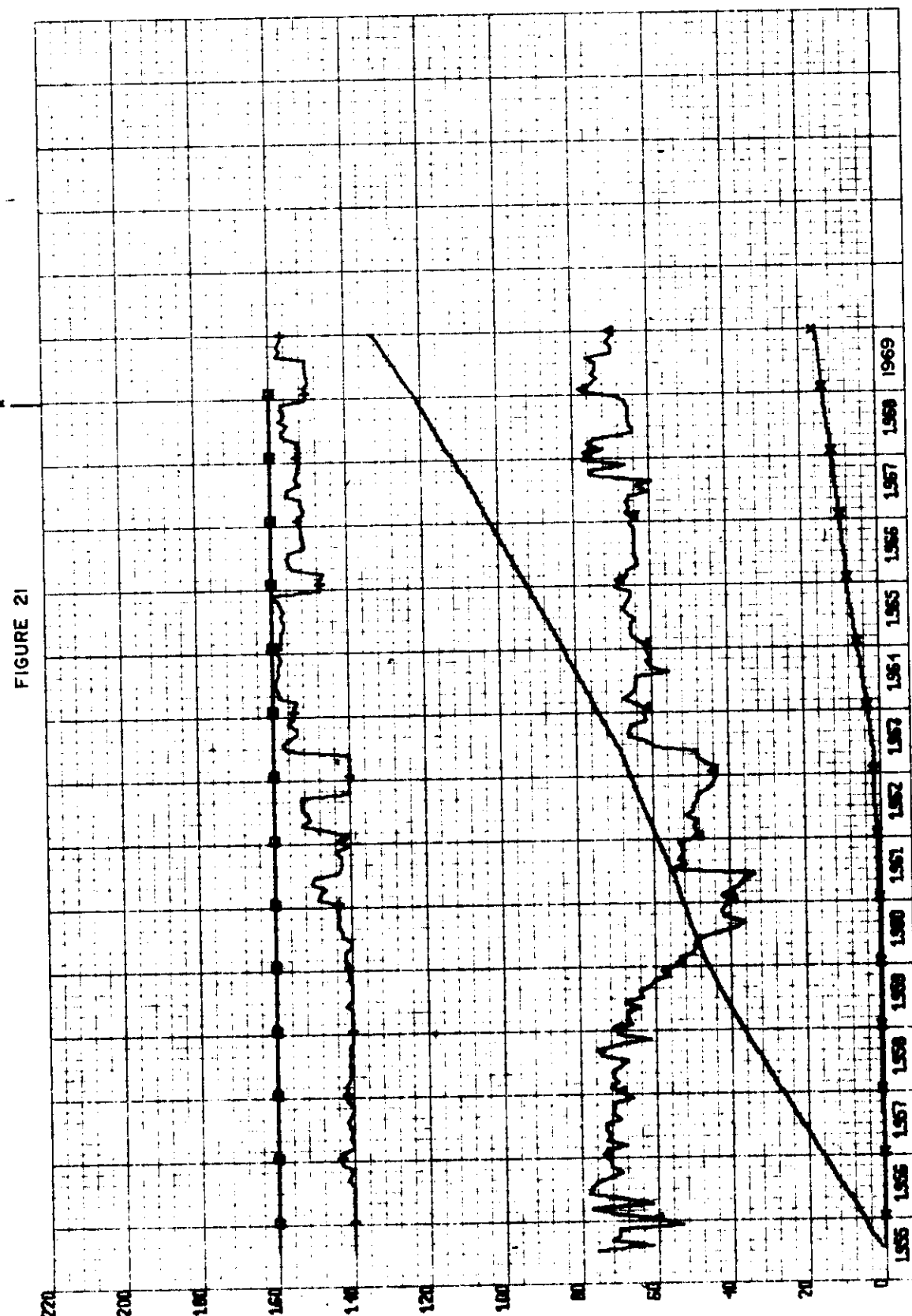
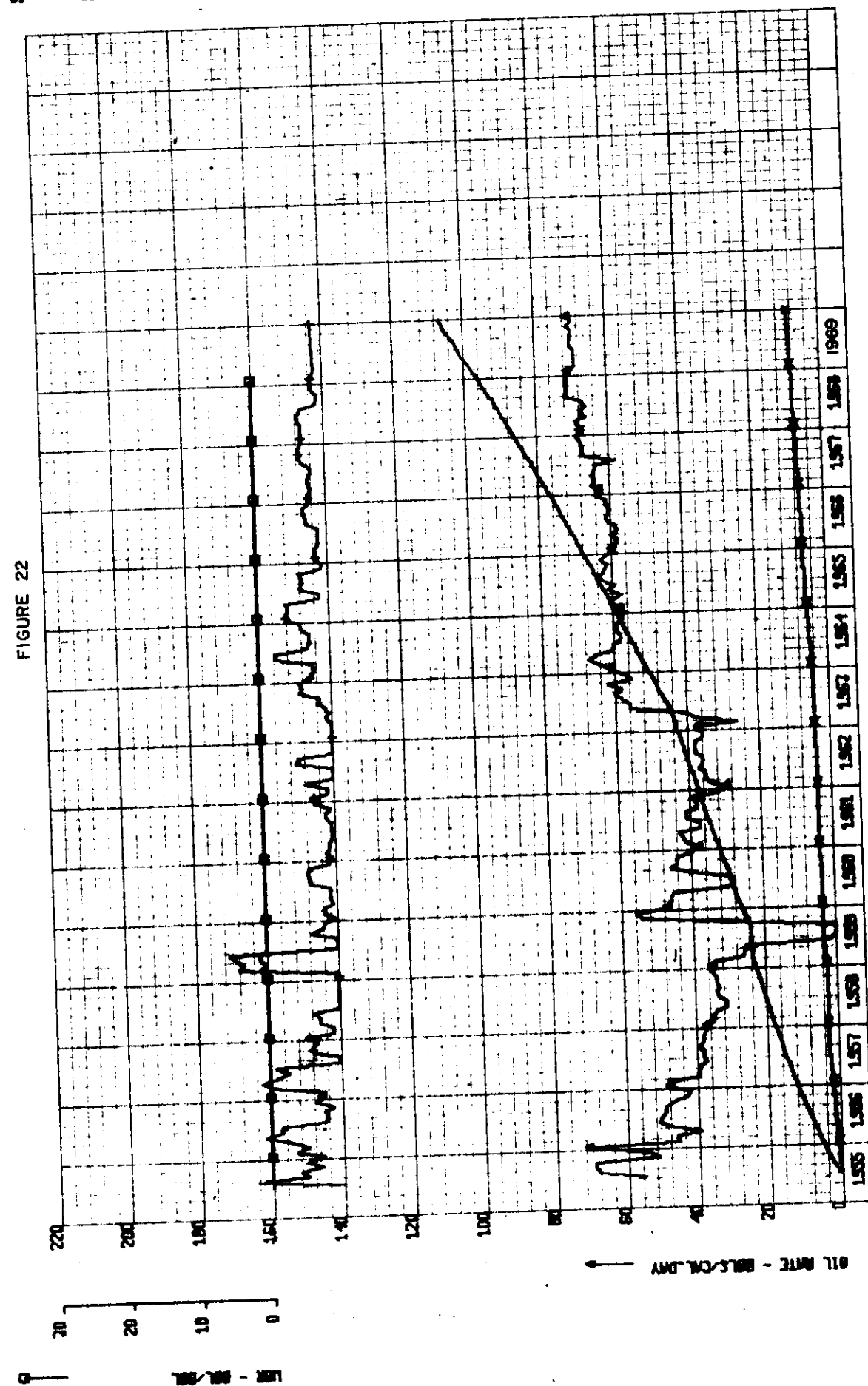


FIGURE 21

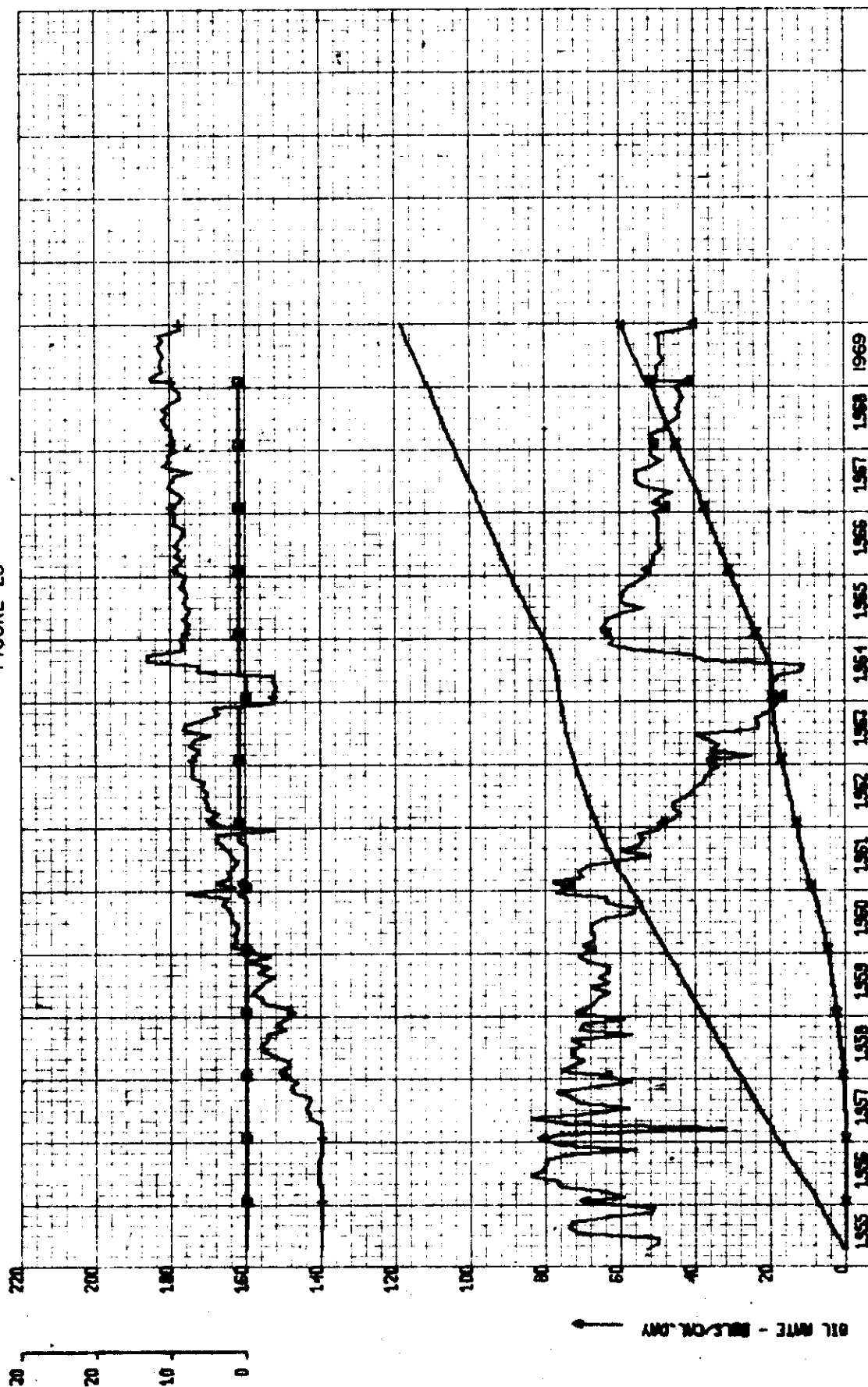
N.U. SCALLION UNIT 11-15-011-26-W1

FIGURE 22



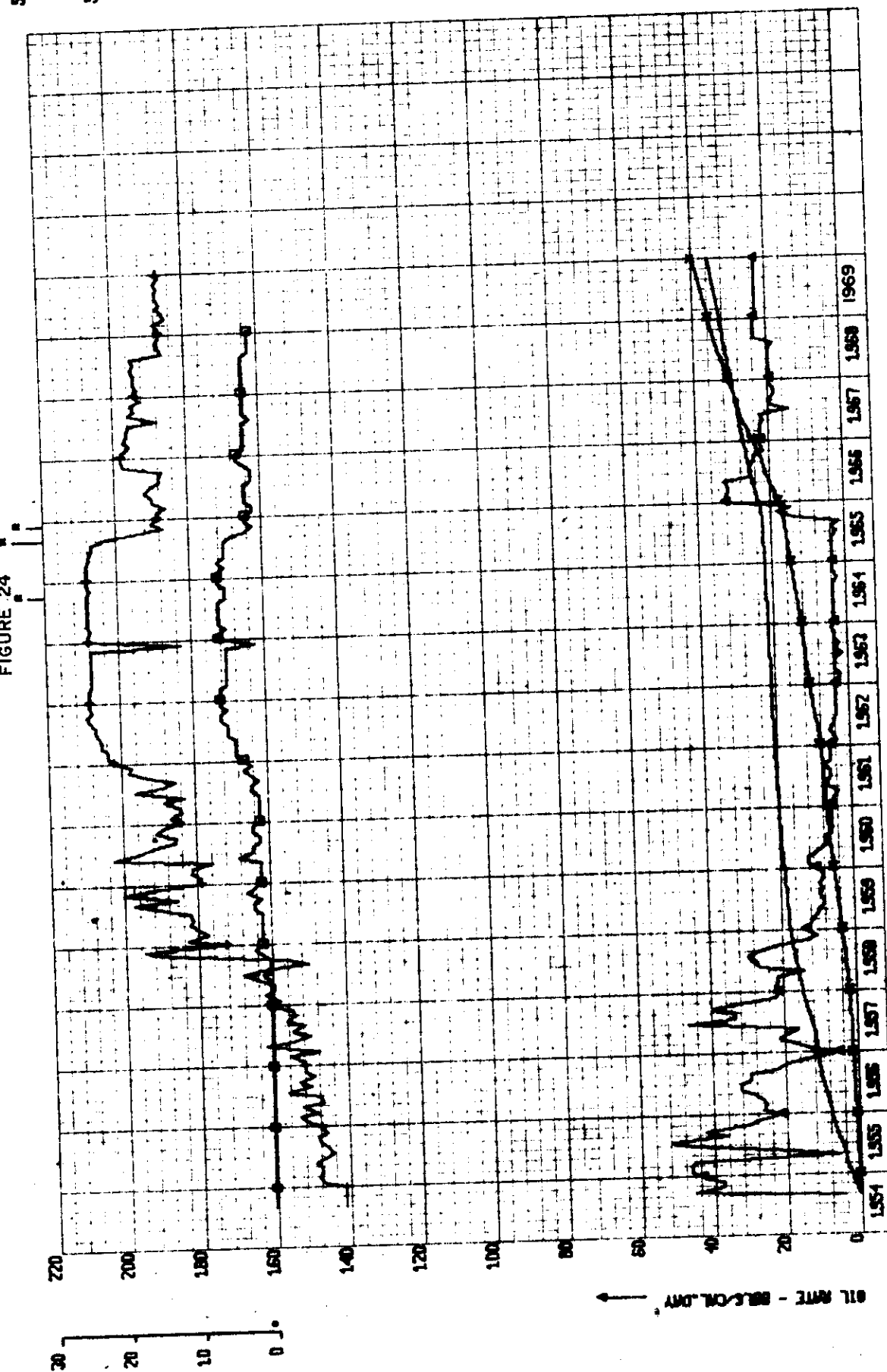
N.U. SCALLION UNIT 12-15-011-26-W1

FIGURE 23

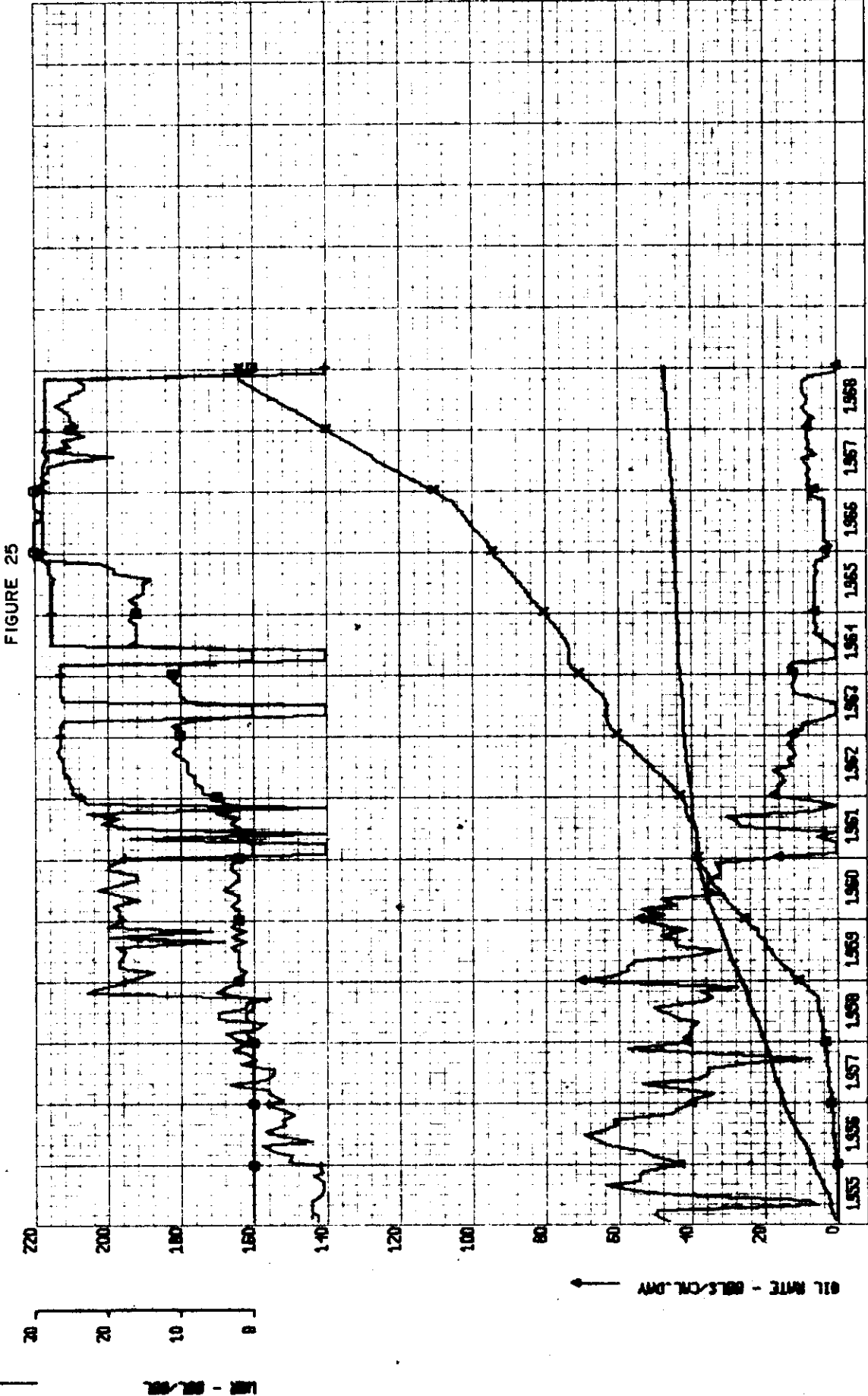


N.U. SCALLION UNIT 01-16-011-26-W1

FIGURE 24

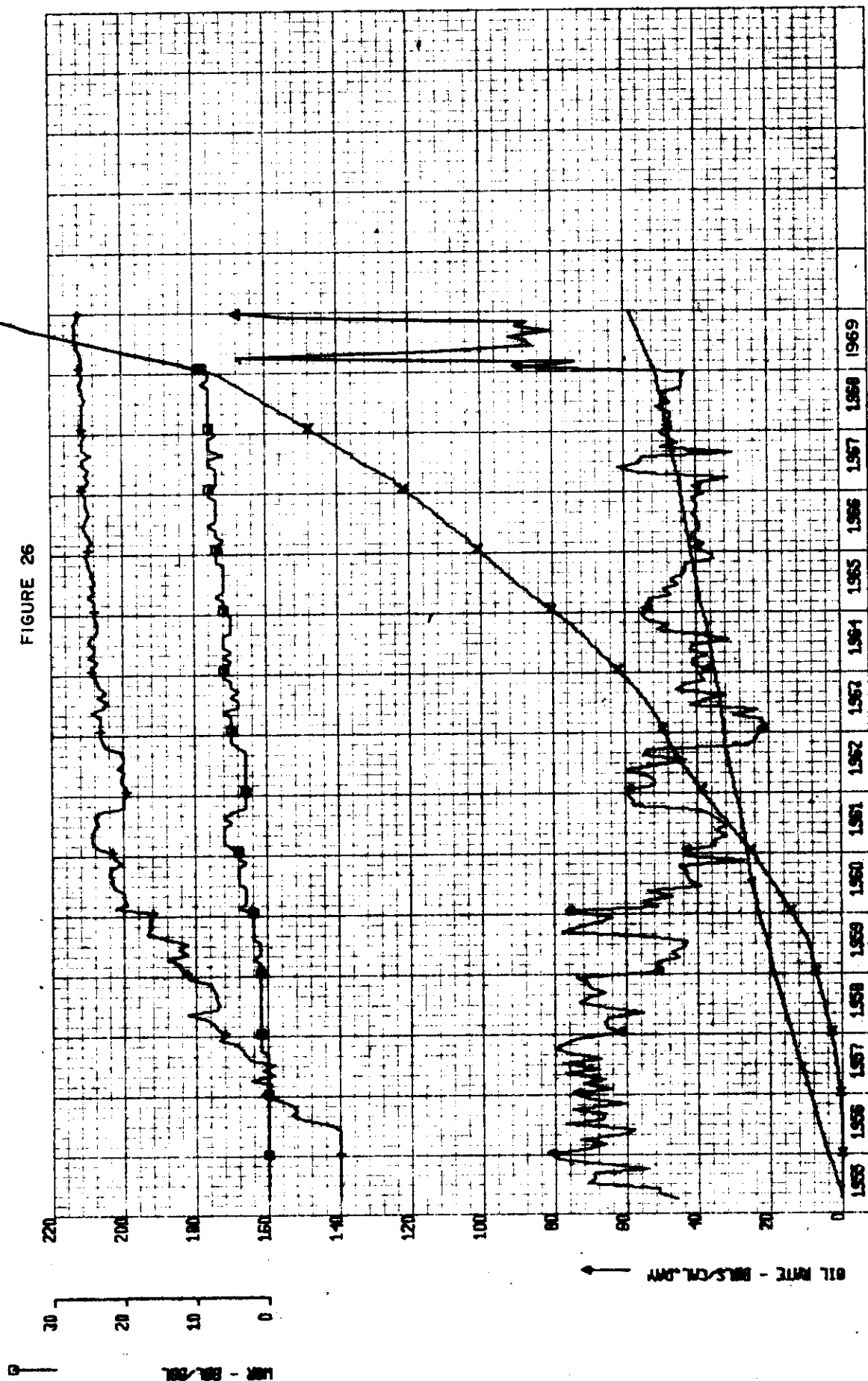


N.V. SCALLION UNIT
08-16-011-26-W1



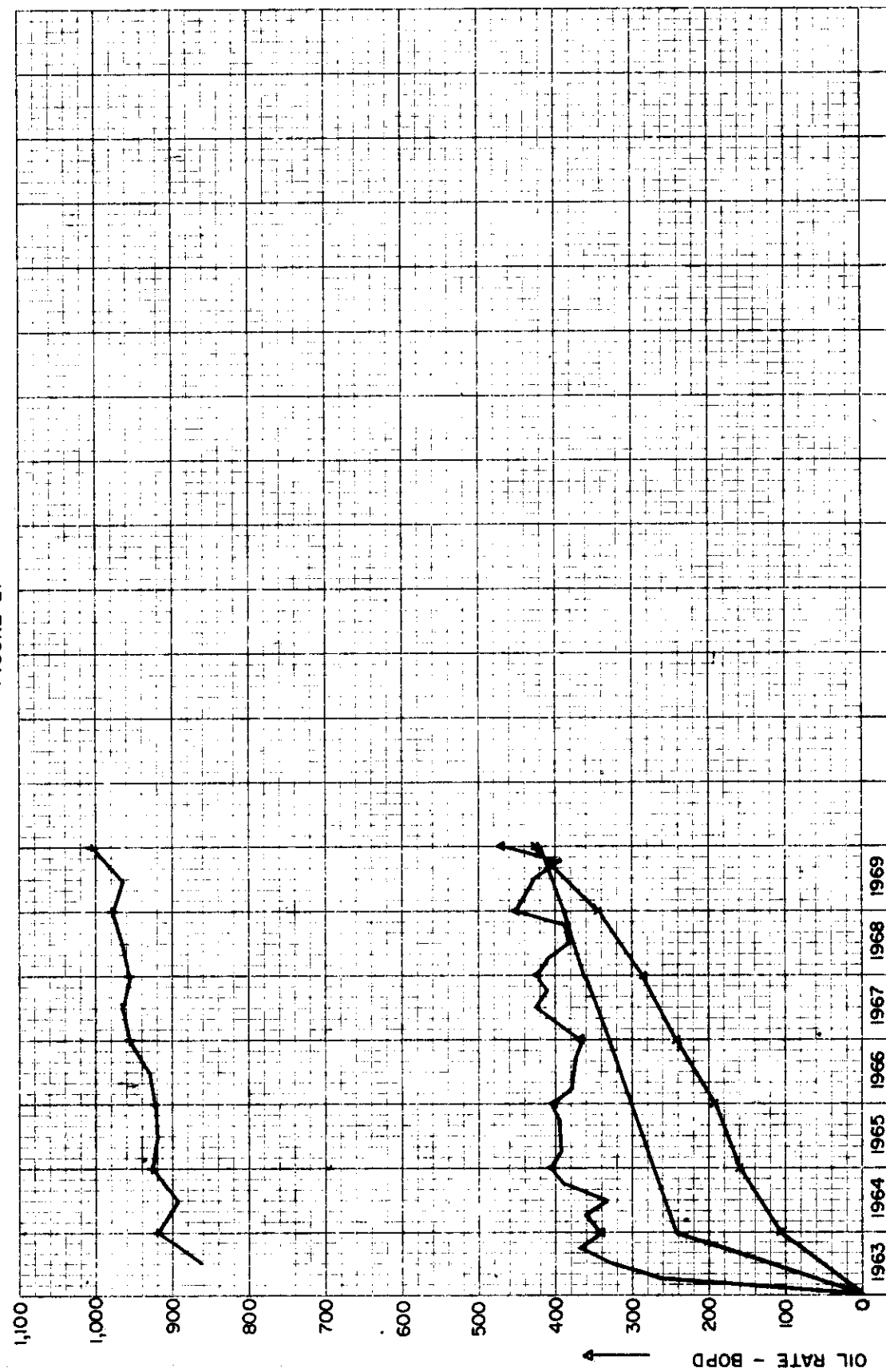
N. U. SCALLION UNIT 09-16-011-26-W1

FIGURE 26



COMPOSITE OF CASE C(a) WELLS EXCLUDING 5-15-11-26

FIGURE 27

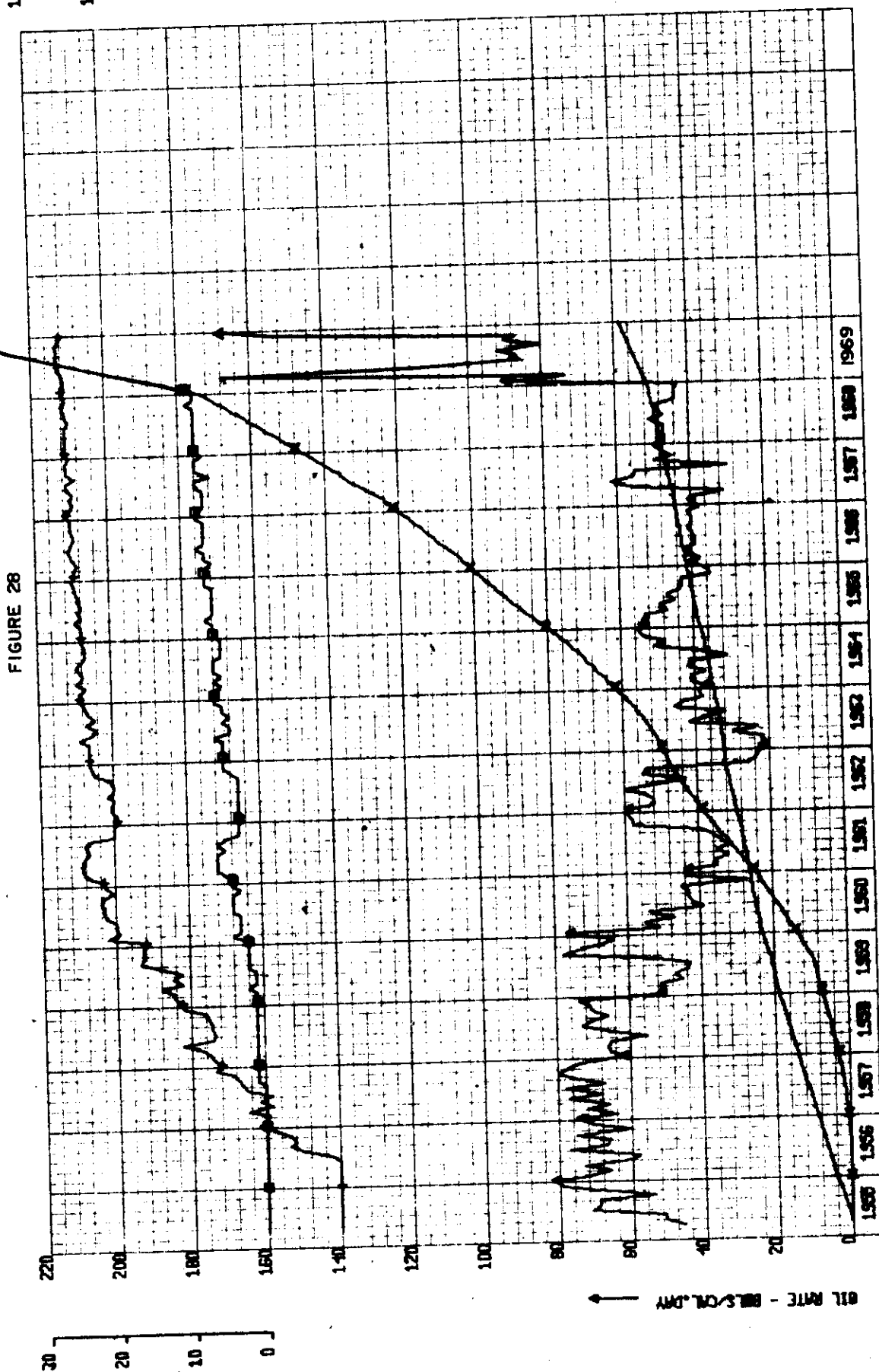


CASE C(b) - EXAMPLE CASE LSD. 9-16-11-26

- Figure 28 - Lsd. 9-16-11-26 - high volume producer
- Figure 8 - Lsd. 15-16-11-26 (see Case A)
- Figure 9 - Lsd. 16-16-11-26 (see Case A)
- Figure 18 - Lsd. 5-15-11-26 (see Case C)
- Figure 23 - Lsd. 12-15-11-26 (see Case C)
- Figure 25 - Lsd. 8-16-11-26 (see Case C)
- Figure 29 - Lsd. 13-15-11-26
- Figure 30 - Lsd. 7-16-11-26
- Figure 31 - Lsd. 10-16-11-26
- Figure 32 - Composite of above Figures, excluding Figure 28

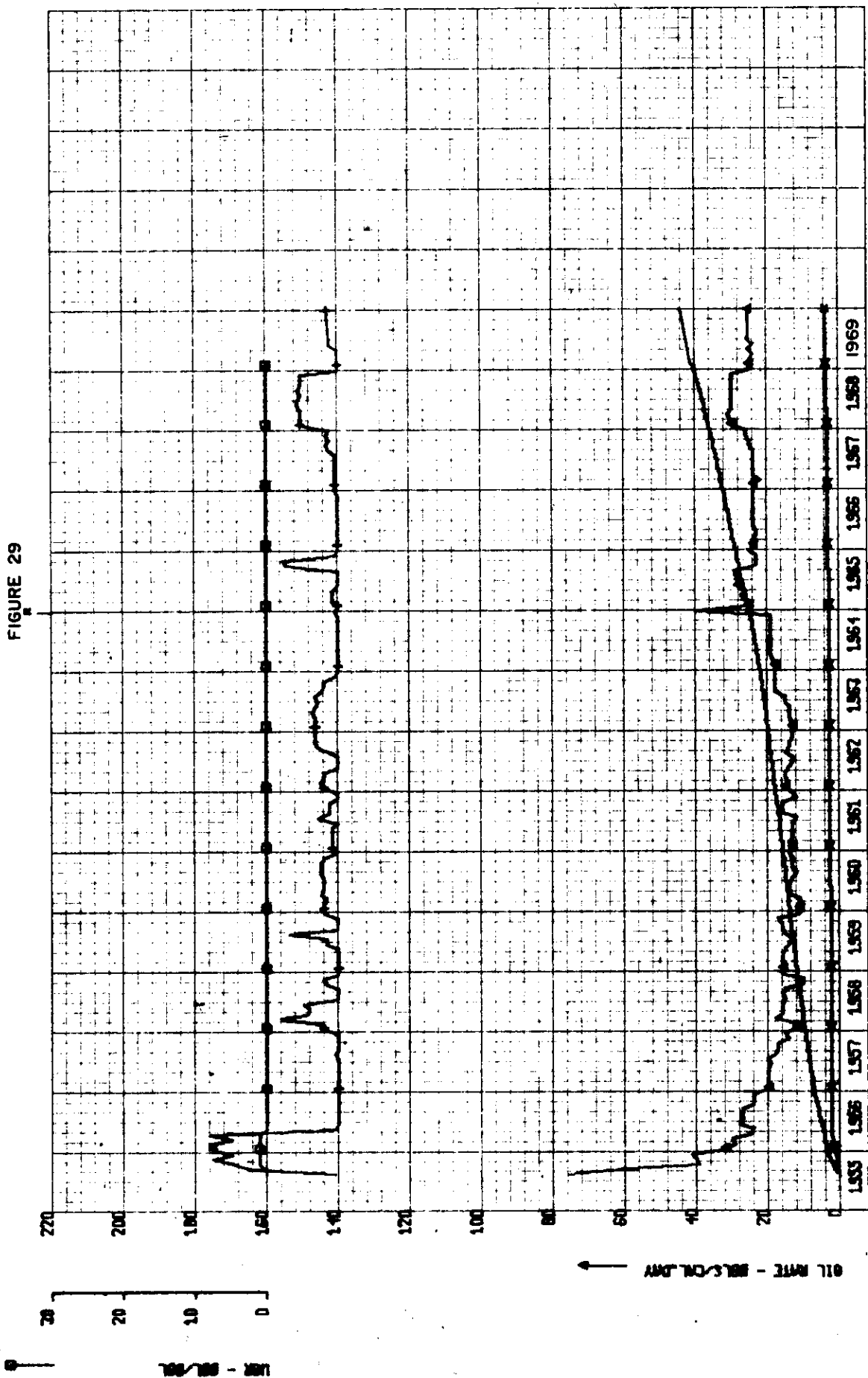
N.U. SCALLION UNIT
09-16-011-26-W1

FIGURE 28

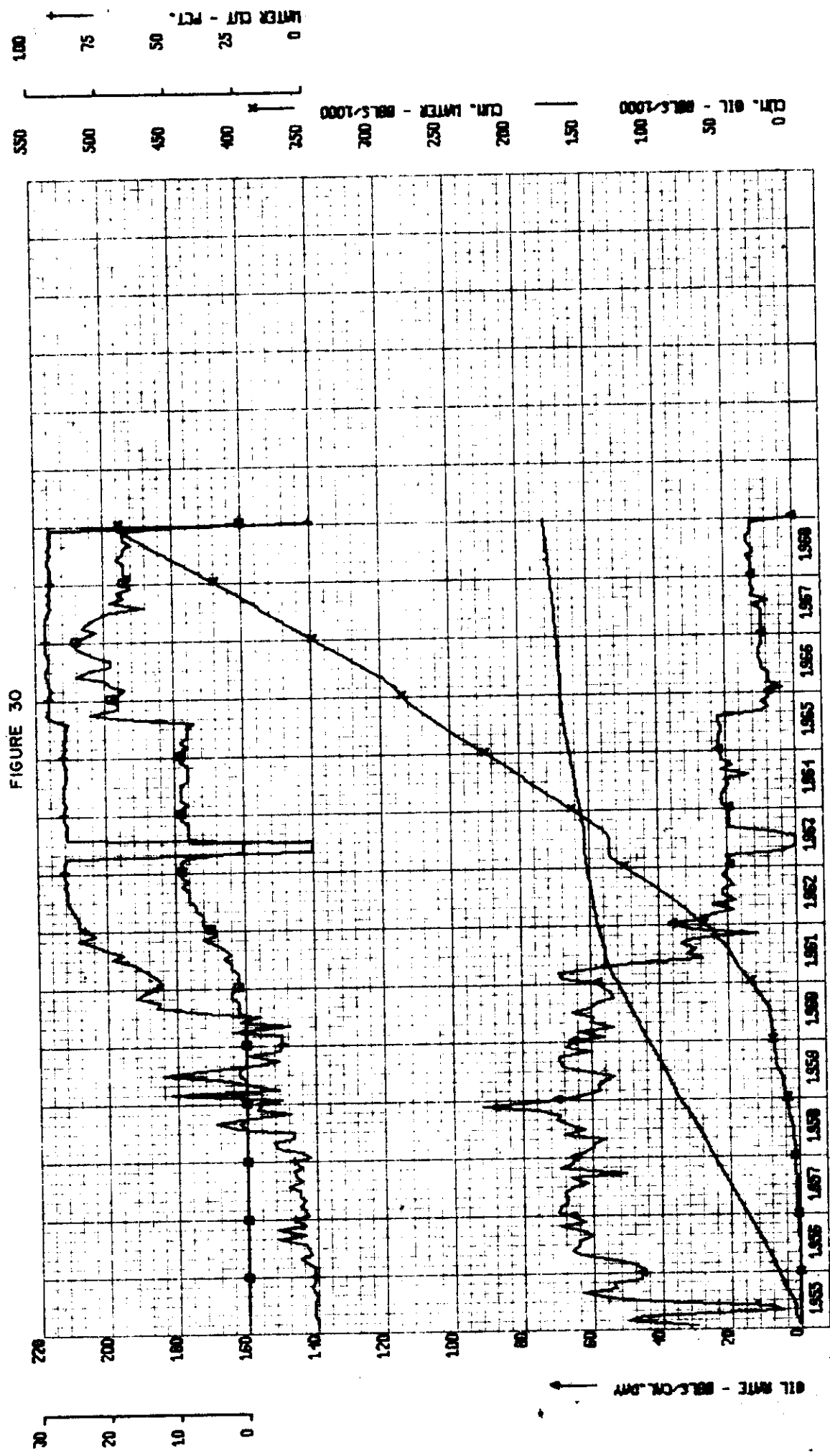


N.U. SCALLION UNIT 13-15-011-26-W1

FIGURE 29

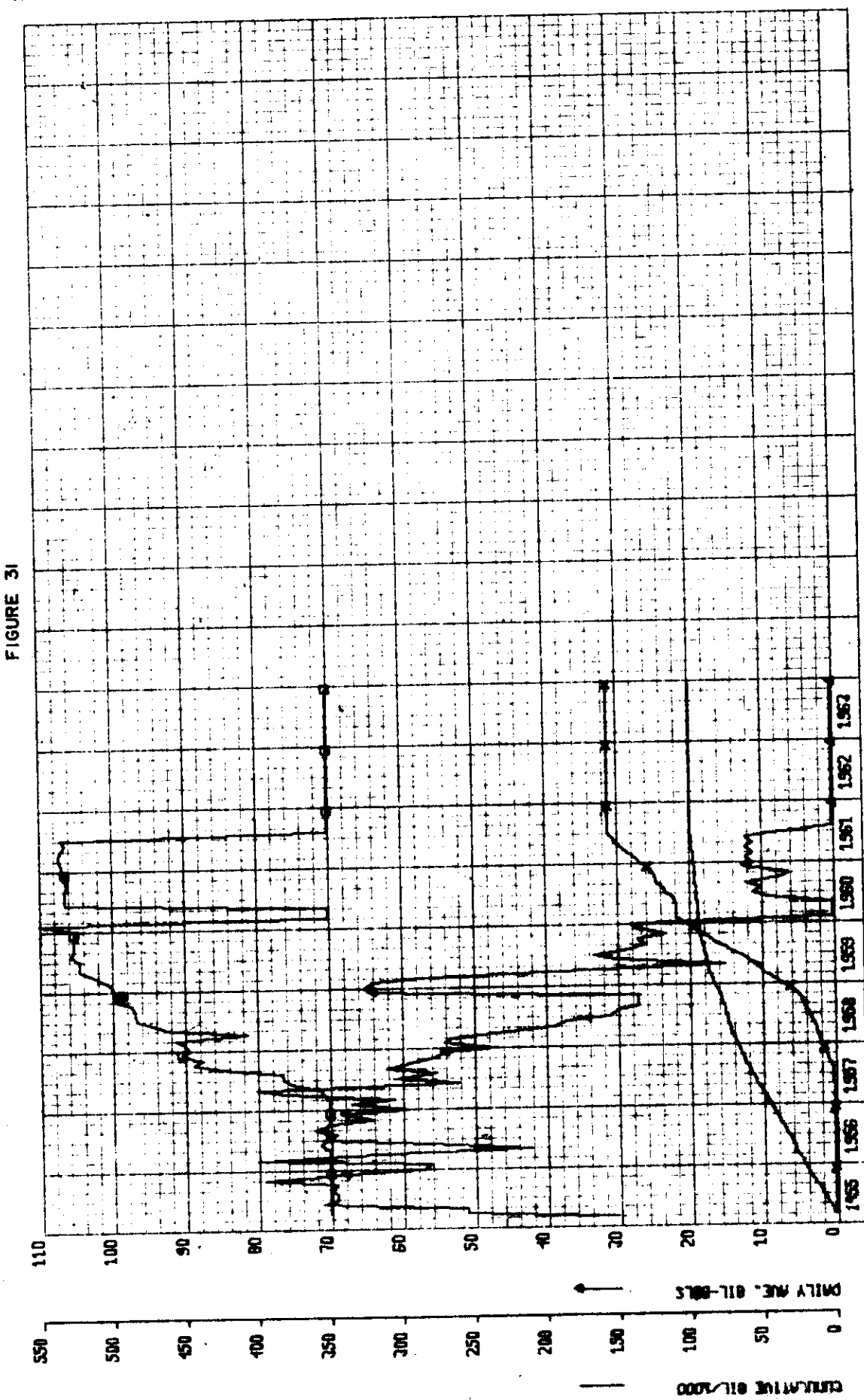


N.V. SCALLION UNIT 07-16-011-26-W1



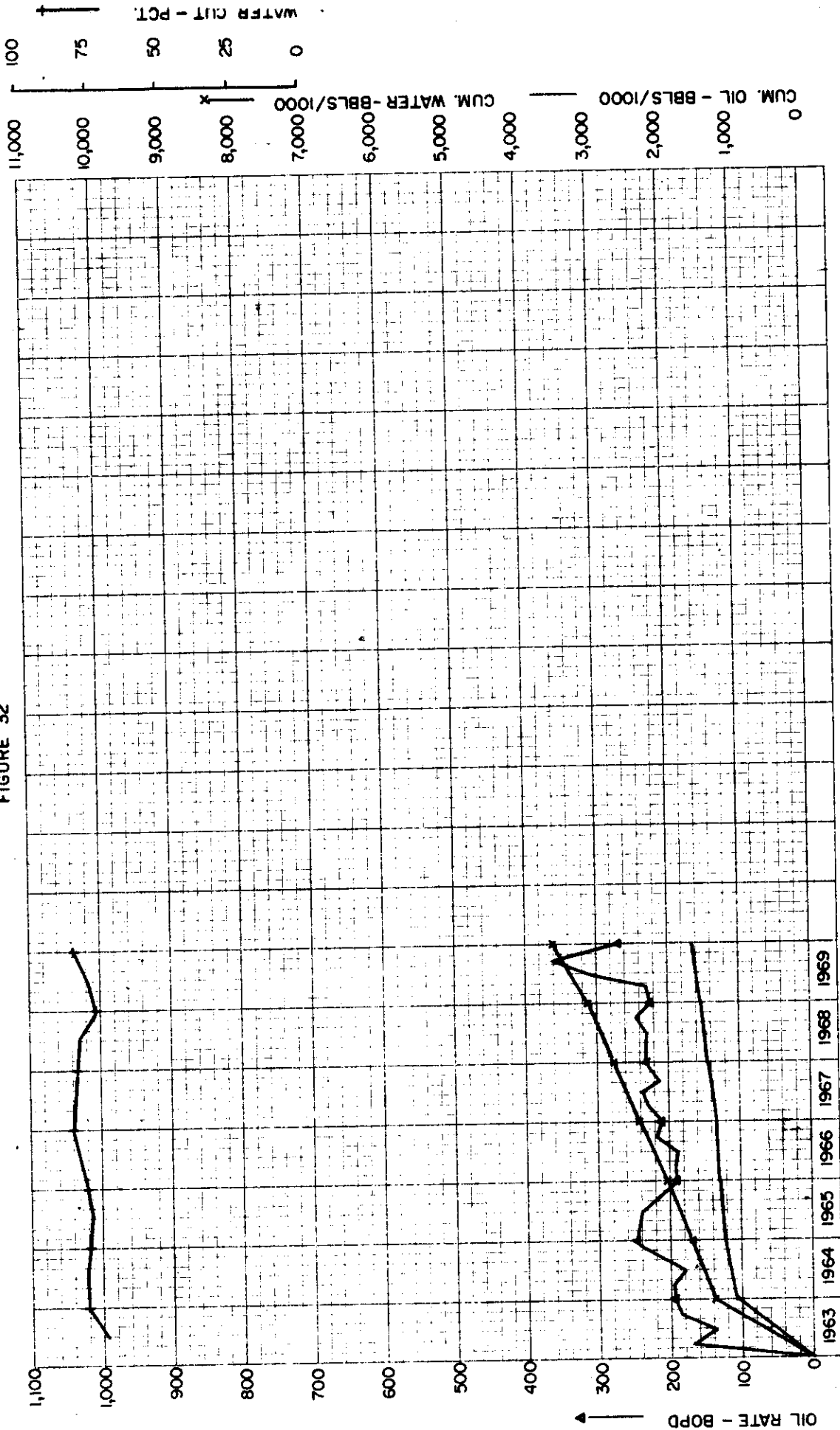
N.O.U. UNIT 10-16-011-26-W1

FIGURE 31



COMPOSITE OF CASE C(b) WELLS EXCLUDING 9-16-11-26

FIGURE 32



NORTH VIRDEN SCALLION UNIT NO. 1

MATHEMATICAL RESERVOIR SIMULATION

1970

CHEVRON STANDARD LIMITED
PRODUCING DEPARTMENT
CALGARY DIVISION

OCTOBER 1970
P. PISIO

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Production Plots: Calculated vs. Actual Production

SUMMARY OF RESULTS AND RECOMMENDATIONS

The following are the findings from the application of reservoir models FLOOD I and FLOOD II to the North Virden Scallion Unit No. 1:

1. The existing injection pattern will provide for reasonable areal coverage for all but one area. The recovery of approximately 1.9 MMSTB is in jeopardy with the existing pattern in the one corridor area.
2. Good areal coverage can be obtained by providing two additional producers in the corridor area and by converting additional wells to injection as they flood out.
3. The water supply well on LSD. 3-27-11-26 is suitably located for conversion to production at such time as the additional water supply is not required.
4. No changes in the injection-production system are necessary prior to floodout within the project area.
5. With some exceptions, the FLOOD models reasonably simulate the reservoir in the area.
6. It is recommended that further application of FLOOD II, to North Virden Scallion Unit No. 1, be deferred until additional history on the area is available.

MATHEMATICAL RESERVOIR SIMULATION OF NORTH VIRDEN SCALLION UNIT NO. 1

INTRODUCTION

During 1962, 217 wells on 40-acre spacing, producing from the Lodgepole formation of Mississippian age in the North Virden Scallion field were unitized into the North Virden Scallion Unit No. 1. An enlargement during 1964 increased the total wells to 219. Figure 1 presents a map of the existing unit area.

The producing horizon in the field is divided into six separate members, namely the Crinoidal, four Oolites and the Cherty Zone. Segregation of oil production from the separate members is neither practical nor normally attempted. Over portions of the field, a highly permeable zone referred to as the "leached zone" exists. Vertical fracturing is also present in portions of the field.

The original oil-in-place was determined to be 195 MMSTB. A calculated recovery factor of 28.4% yields an ultimate recoverable reserve of 55 MMSTB. An inverted nine-spot injection pattern is being used; however, stringent controls resulted in extreme modifications to the basic pattern. The final injection pattern resulted in a portion of the field having two adjacent rows of producers which could flood out almost simultaneously, leaving a corridor of unswept oil between the two rows of wells (see Figure 2).

In an attempt to optimize the areal coverage in the above-mentioned corridor, mathematical reservoir simulation was applied to the total Unit area commencing in 1964. During 1964 and 1965 the reservoir simulator FLOOD I was applied to the entire area. During 1968, FLOOD II, a successor to FLOOD I was applied to the area encompassing a suspected unswept corridor area.

This report presents a summary of the procedures used, the results and

conclusions to date, the application of the results, and the proposed additional work to be done with these or similar computer models. The detailed mathematics involved in the computations made by the model are not discussed in this report.

DISCUSSION

A. FLOOD I

FLOOD I consists of several computer subroutines, the combined primary feature of which for this project was a prediction of areal coverage by injected water in an idealized reservoir model.

Because of the semi-quantitative nature of the results obtained, these predictions cannot be considered exact, but only as a guide to be used in determining the behavior of the actual reservoir.

1. Assumptions

The following are assumptions associated with the application of the FLOOD I model:

1. The system is two-dimensional.
2. The fluids are incompressible.
3. Gravity and capillary forces do not affect the shape of the flood front.
4. The interface between the fluids is sharp and the mobility of the displaced fluid is equal to the mobility of the displacing fluid.

2. Operational Procedure

The Unit area was treated as approximately 2,400 distinct but interconnected cells. The cells were defined by a two-dimensional grid overlying the system, such that there were usually three cells between well grid points. Each cell face measured approximately 431 feet. Porosity, permeability, pay thickness, and pressure isopachs were used to assign values of these parameters to the

grid points in the model. Boundary conditions of the "no-flow" or "fixed pressure" type were assigned to all boundary and producing well grid points. Flow rates were designated at all injection well grid points. Using the above data, a pressure solution, resulting in a pressure assignment to each grid point, was obtained for the model. This pressure remained constant until such time as some change in the reservoir (such as floodout, additional injection wells, etc.) warranted an updated pressure solution for the model.

Because of the very limited pressure history available for the field, no attempt was made to history match. Through judicious manipulation of the basic input parameters, a suitable initial pressure solution was obtained.

The pressure solution, as well as other input data are used in the interface movement portion of the FLOOD I model. The frontal advance of interfaces is in accordance with the material balance equation and Darcy's equation for fluid flow in porous media.

The position of each waterflood interface is followed through the system in a step-wise manner by tracking the movement of up to 72 individual streamline points initially located on a small circle around each of the injection wells. By combining the average velocity of the streamline points and the time step size, new coordinates are computed for each point on each interface. The maximum distance that any point on any interface may advance, without the computer printing out an interface for each injection well, is an input parameter. The location of the interface at any given time is obtained by plotting the position of the points on the interfaces and connecting these points. The overall procedure is repeated for as many time steps as desired.

The model, as applied, terminated whenever three streamline points advanced to within 200 feet of a producing well. The well was

then considered flooded out, was shut-in, and the program restarted. For a detailed application, a new pressure solution would be obtained after a well flooded out. For a multi-injection well model such as North Virden Scallion, a detailed application over an appreciable time period would be very costly and time consuming.

Because it was desirable to determine the general trend that might be established in the flood fronts, at reasonable cost, only one pressure solution was used and one run was made. For this run, all producing wells except one, were shut-in and an 18-year prediction was made. One well must be on production for the program to run.

3. Results

Figure Nos. 3, 4, 5, 6 and 7 represent the locations of the flood fronts, respectively, at 1800, 2900, 3800, 4700 and 6700 days after commencement of injection.

Figure 7 confirms the existence of a problem area inasmuch as the recovery of waterflood oil from the corridor acreage would be in jeopardy if injection is allowed to proceed as at present. The two adjacent rows of producing wells would flood out at approximately the same time, leaving a corridor that was not effectively swept by injected water.

Good areal coverage was indicated for most of the remaining area.

4. Conclusions

The unswept corridor in the Unit area, which represents approximately 1.9 MMSTB of recoverable oil, indicates that the basic injection pattern in this area should be evaluated. Because reasonable areal coverage is indicated for the remainder of the area, it would be logical to further evaluate the injection pattern in the unswept corridor area only, using a smaller model.

5. Application of Results

During 1966, it became evident that an additional water supply was necessary for North Virden Scallion Unit No. 1. A second Devonian water source well was drilled and placed on stream. On the basis of FLOOD I results, this second well was located in the corridor area approximately midway between the two adjacent rows of producing wells. It is proposed that, at such time as the additional water supply is not necessary, the well will be converted to either a Mississippian producer or injection well, so that part of the problem in the corridor area would be solved.

6. Future Study

Future study employing the FLOOD I model in North Virden Scallion Unit No. 1 is not anticipated.

Additional study was conducted using the FLOOD II model during 1968. Only the problem corridor area was modelled on FLOOD II.

B. FLOOD II

The results from the application of FLOOD I indicated that an area of poor areal sweep existed in the modelled area (see Figure 7).

Inasmuch as FLOOD I was a cumbersome and costly program with which to attempt to resolve the problem area, its successor, FLOOD II, was used. Most of the input data used for FLOOD I was, with minor modification, adaptable to FLOOD II. Figure 8 presents a map showing that portion of the North Virden Scallion field that was modelled using FLOOD II.

1. Operational Procedure

The assumptions stated for FLOOD I apply to FLOOD II. Model preparation and operational procedures are very similar for both models.

FLOOD II advances the waterflood fronts systematically in accordance with the material balance equation and Darcy's equation for fluid flow in porous media, as does FLOOD I; however, a certain amount of logic is built into the program, and more can be introduced with the input data. Flooded out wells are automatically shut in, new pressure solutions are obtained and the flood fronts are advanced without terminating the run. The program calculates a fluid flow rate for each well for each pressure solution. The smaller model area was chosen for economic reasons; however, it was made large enough to avoid the occurrence of radical boundary effects.

The following are the cases considered using FLOOD II:

Case A: All producers were considered to be fixed pressure points with low pressures, since it was assumed that producing wells would be pumped off. Injection wells were considered

to be fixed flow points with the flow being equivalent to the actual injection rates up to the end of 1967 and estimated injection rates thereafter. The frontal advance prediction was made for approximately 6000 days.

Case B: The same initial assumption were made as in Case A. The well 15-21-11-26, which was indicated as a flooded out well by 1800 days, was converted to injection at 300 BWPD at 1900 days. At time 3600 days, an additional producer, well No. 52 (in the center of 16-21, 13-22, 4-27 and 1-28) was drilled in the corridor area. Also at time 3600 days, the water supply well at 3-27-11-26 was recompleted as a producer. The frontal advance prediction was made for approximately 7000 days. ✓

Case C: The same initial assumptions were made as in Case A. The well 15-21-11-26 was converted to water injection at 250 BWPD at time 3600 days. The flooded out producer at 13-23-11-26 was also converted to injection at 180 BWPD at time 3600 days. The frontal advance prediction was made for approximately 6700 days.

Case D: All wells, producers and injectors, were made constant pressure points. The producers were assumed to have very low pressure to reflect pumped-off conditions. The injectors were assigned reservoir pressures based on surface injection pressures with a maximum of 1,050 psig on surface. The frontal advance prediction was made for approximately 8100 days.

Case E: The same initial assumptions were made as in Case D. The flooded out producer at 15-21-11-26 was converted to a constant pressure injector at time 2400 days. Well No. 52 (located in the centre of 16-21, 13-22, 4-27 and 1-28) was

drilled and made a fixed pressure producer at time 3700 days. The water supply well on 3-27-11-26 was converted to a fixed pressure producer at time 3700 days. At time 5300 days the flooded out producer at 13-23-11-26 was converted to a fixed pressure injector. The frontal advance prediction was made for approximately 8100 days.

2. Results

Cases A, B, and C were based on the same initial assumptions, namely that the injectors were fixed flow points and that the producers were fixed pressure points. In each of these cases, the pressure solutions obtained yielded high pressures for most points; however, relatively, the pressures were not unreasonable.

The high pressures reflect poor input data, which could be the reservoir parameters, the fixed flow rates at injectors, the fixed pressures at producers, or a combination of two or more of these factors. It is known that within the model area there are sections where good, reliable reservoir parameters are not available. It is also known that, at some injection wells, the injected water is not all entering the modelled oil reservoir. This latter factor is perhaps the greatest single factor responsible for the high pressure solutions.

Cases D and E more closely approximate what will happen under the respective injection and producing situations. The calculated fluid flow rates for several wells for some of the time steps closely approximate the actual production experienced at these wells. This situation indicates that the model reasonably represents the actual reservoir. Cases D and E indicate a longer reservoir life than do the previous three cases.

The results from each of the cases are as follows:

Case A: Essentially the same areal coverage was obtained as in the FLOOD I prediction for this area. Pressures within the modelled area were as high as 5,500 psi on the pressure solution. This case does not suitably resolve the areal sweep in the corridor. Figure Nos. 9, 10, 11, 12 and 13 present the location of the flood fronts at 1900, 2500, 3600, 4500 and 6000 days after commencement of injection. Figure 14 represents the pressure solution at 3600 days.

Case B: Figure Nos. 15, 16, 17 and 18 present the flood fronts at 2500, 3500, 5500, and 7000 days after the first injection. The corridor area is exposed to reasonably good areal coverage except at the eastern end of the corridor. The pressure solutions for this case are similar to those obtained in Case A.

Case C: Figure Nos. 19, 20 and 21 indicate that most of the area in the corridor will be swept by injected water before all existing wells are flooded out. As in cases A and B the pressure solutions indicate some extremely high pressures. Figure 22 represents the pressure solution at 3900 days.

Case D: The results from Case D are comparable to those from Case A; however, a greater time period is required for Case D in order to advance the flood fronts a comparable distance. Both of these cases represent interpretations of areal sweep with the injection and producing systems continuing to operate as they are currently. Figure Nos. 23, 24, 25 and 26 indicate the locations of flood fronts at 2200, 3300, 5500 and 8100 days after injection started. The areal coverage at 8100 days is not good. Figure 27 represents the pressure solution at 3300 days. The pressures in this solution are more realistic than those in Cases A, B, and C.

Case E: At the expiration of 8100 days of injection, there are still three producers in the corridor area that have not flooded out. At 8100 days, it appears that good areal coverage would result in the area by a system represented by this case. Figure Nos. 28, 29, 30 and 31 present the flood fronts after 2400, 3400, 5200 and 8100 days of injection. Figure 32 represents the pressure solution after 2400 days of injection. Figure 33 represents the pressure solution after 5200 days of injection.

As previously stated, FLOOD II calculates the fluid flow rate at each well point with each pressure solution. The calculated rates were plotted for several wells for this Case E, along with the actual production history. These plots are presented following Figure 33. The FLOOD II model approximates the actual reservoir reasonably well in segments of the area as evidenced by a similarity between actual and calculated fluid flow rates. There are, however, cases where the forecast production bears little resemblance to the actual production, indicating poor reservoir modelling due to poor data.

3. Conclusions:

The following are conclusions drawn from the application of FLOOD II to the problem corridor area in North Virden Scallion Unit No. 1:

1. The current injection-production system in the area will not provide for effective areal coverage in the corridor area.
2. Good areal coverage could be obtained by providing two additional producers in the corridor area, and by converting additional wells to injection as they flood out.
3. The water supply well on LSD. 3-27-11-26 is suitably located for conversion to one of the producers mentioned in (2) above.

The other well would best be located centrally between 16-21, 13-22, 4-27 and 1-28.

4. The additional injectors that should be added to the system by the conversion of flooded out producers are 15-21-11-26 and 13-23-11-26. The conversion should be immediately upon flood-out of the producing wells.
5. No changes in the injection-production system are immediately necessary. Indications are that no changes are necessary prior to the floodout of the two wells mentioned in (4) above.
6. FLOOD II as applied reasonably simulates the reservoir in the area modelled, with some exceptions. Because these exceptions exist and because all results are semi-quantitative, it would be impractical, at this time, to apply much credence to results from runs which differed only by restricting injection in certain wells in an attempt to control the individual flood fronts.
7. As additional history under waterflood operations becomes available, particularly water breakthroughs, the model could be judiciously adjusted to more accurately simulate the reservoir. This could then be done by history matching the reservoir.

4. Future Application:

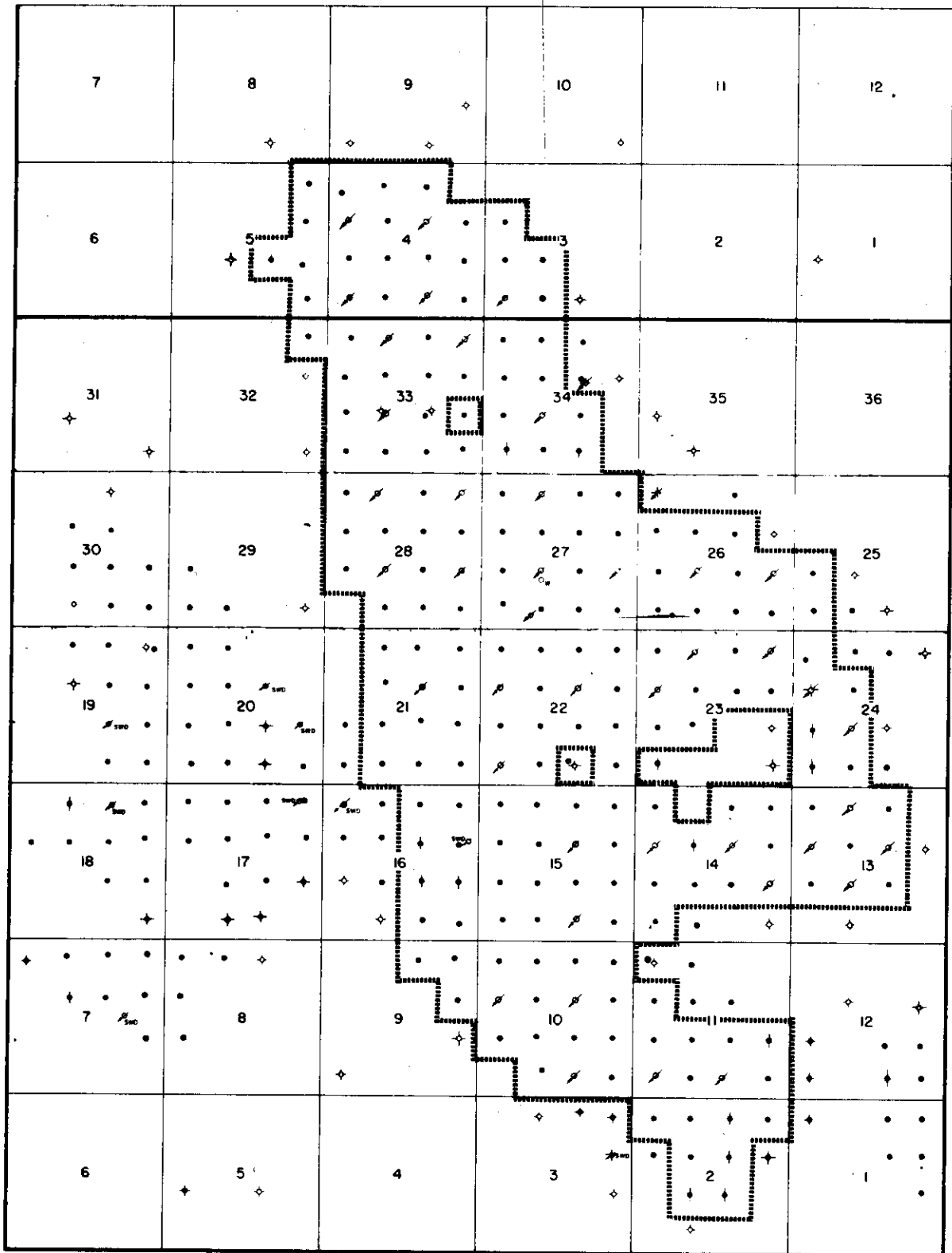
As more actual history is obtained from the area modelled by FLOOD II, the model can be made to more closely represent the reservoir. Identifiable breakthrough at some producers in the area would be of particular value in locating waterflood fronts in relation to time. It is at that time that a more quantitative interpretation can be applied to the results then obtained from reservoir simulation.

It is suggested that further application of FLOOD II to North Virden Scallion Unit No. 1 be deferred until additional history on the area is available.

ACKNOWLEDGEMENTS

Sincere appreciation is expressed to Messrs. J. E. Briggs, M. L. Wasserman, S. L. Roberts and J. A. Smith of Chevron Oil Field Research Company, La Habra, California, for their assistance in this study.

R.26 W.P.M.



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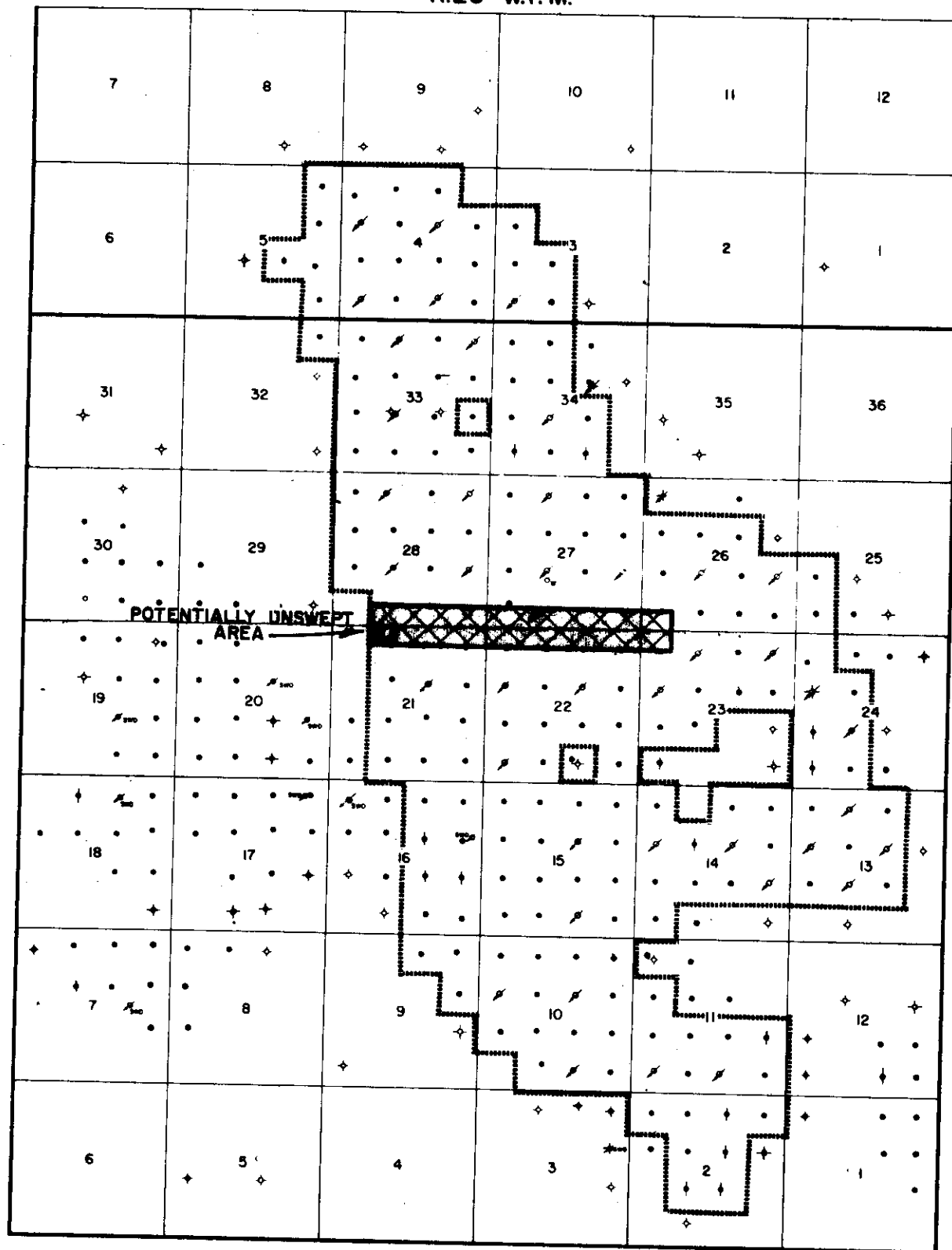
FIGURE 1

NORTH VIRDEN SCALLION UNIT No.1

AS OF JULY 1, 1970

R.26 W.P.M.

T.12



T.11

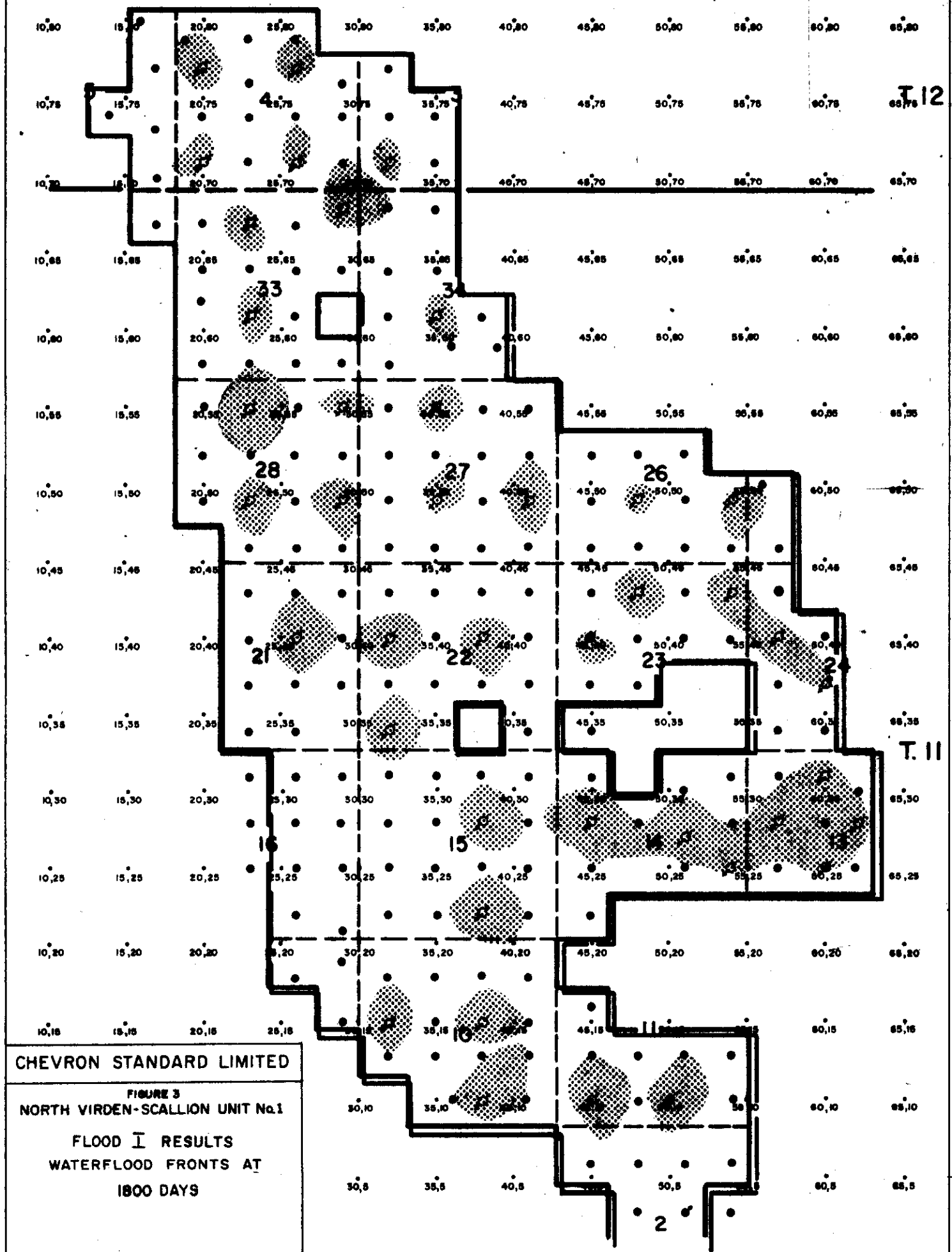
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FIGURE 2

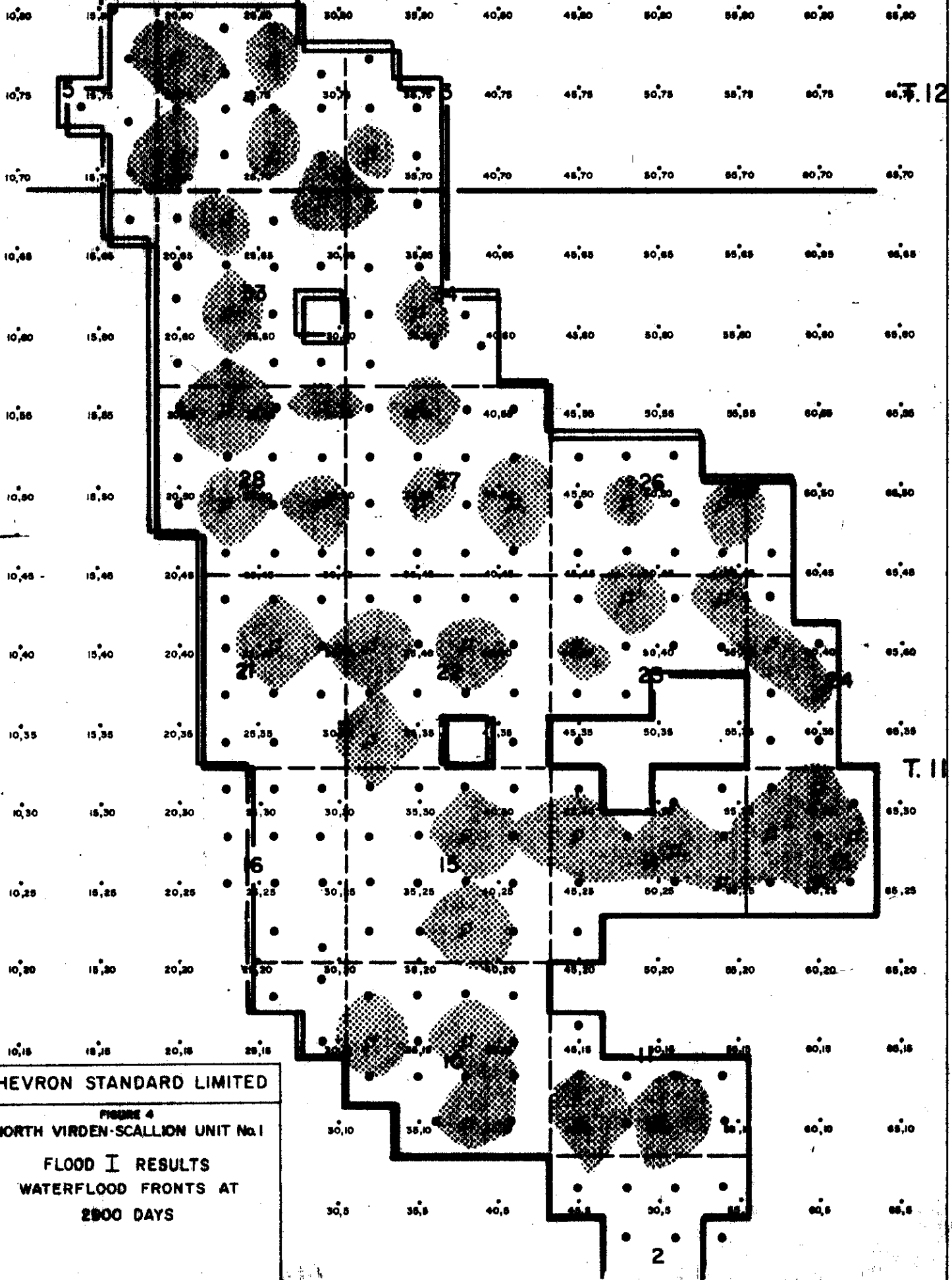
NORTH VIRDEN SCALLION UNIT No.1

WITH POTENTIALLY
UNSWEPT CORRIDOR

R.26 W.P.M.



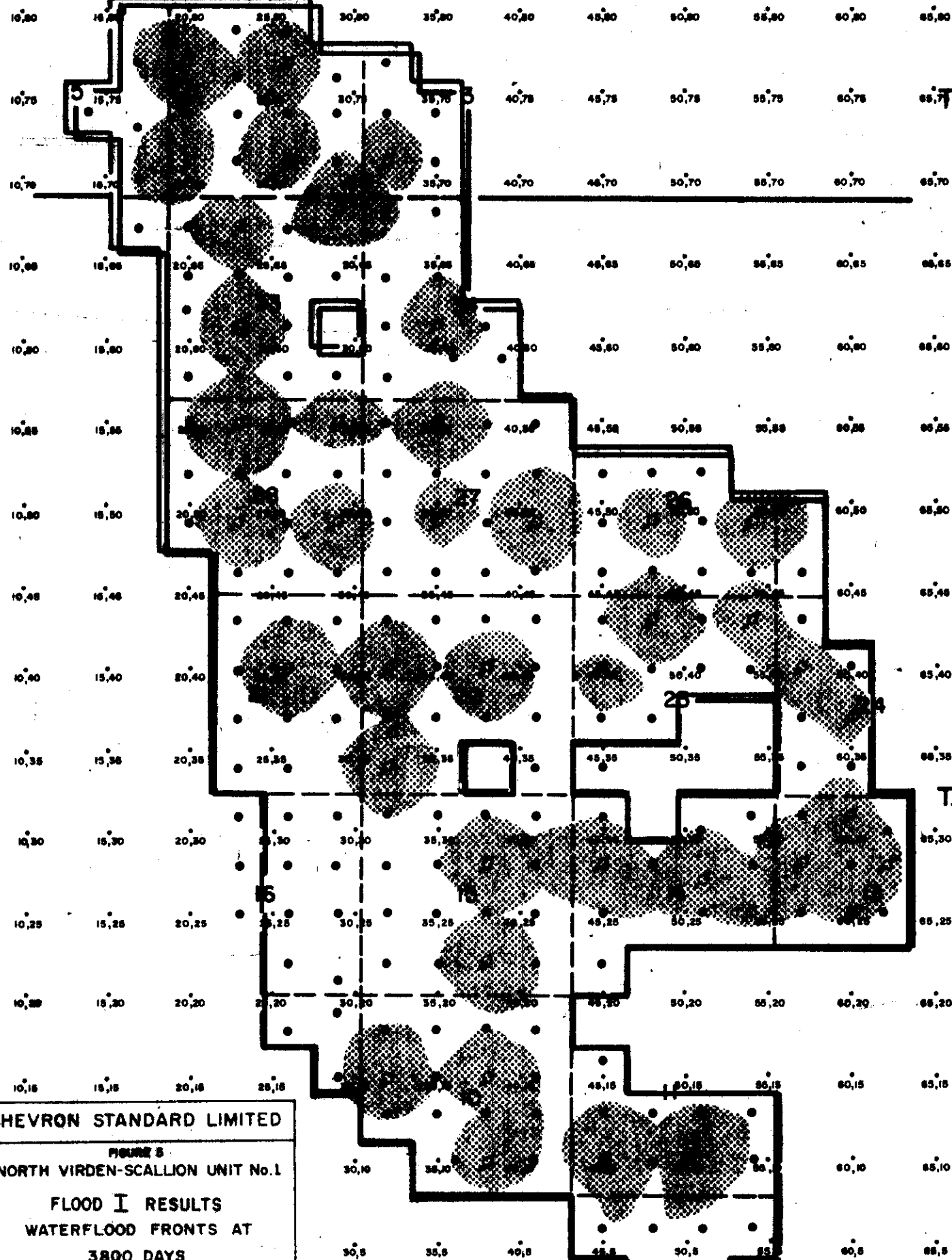
R.26 W.P.M.



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FIGURE 4
NORTH VIRDEN-SCALLION UNIT No.1
FLOOD I RESULTS
WATERFLOOD FRONTS AT
2800 DAYS

R.26 W.P.M.



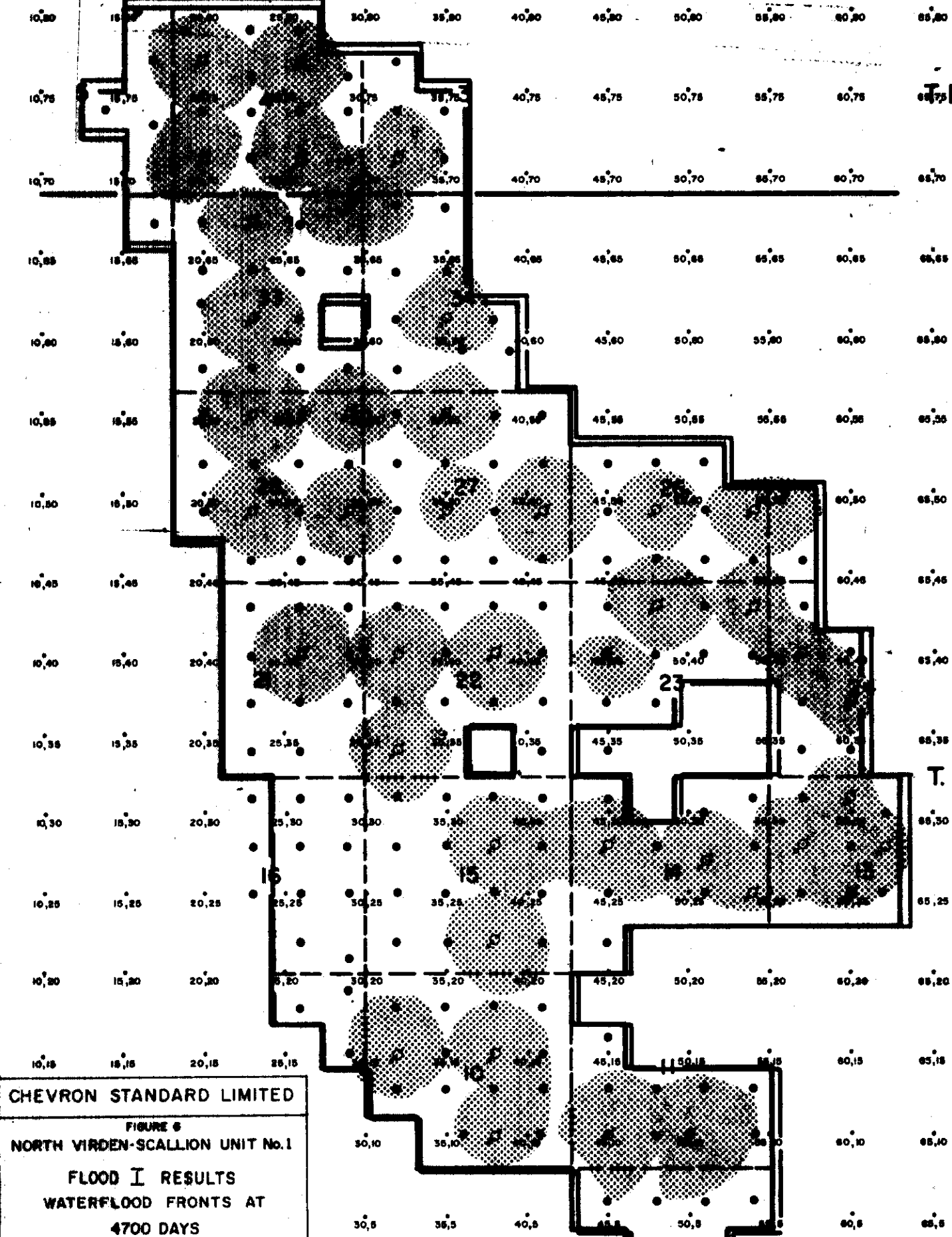
CHEVRON STANDARD LIMITED

FIGURE 5
NORTH VIRDEN-SCALLION UNIT No. 1
FLOOD I RESULTS
WATERFLOOD FRONTS AT
3800 DAYS

R.26 W.P.M.

T.12

T.11



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FIGURE 6

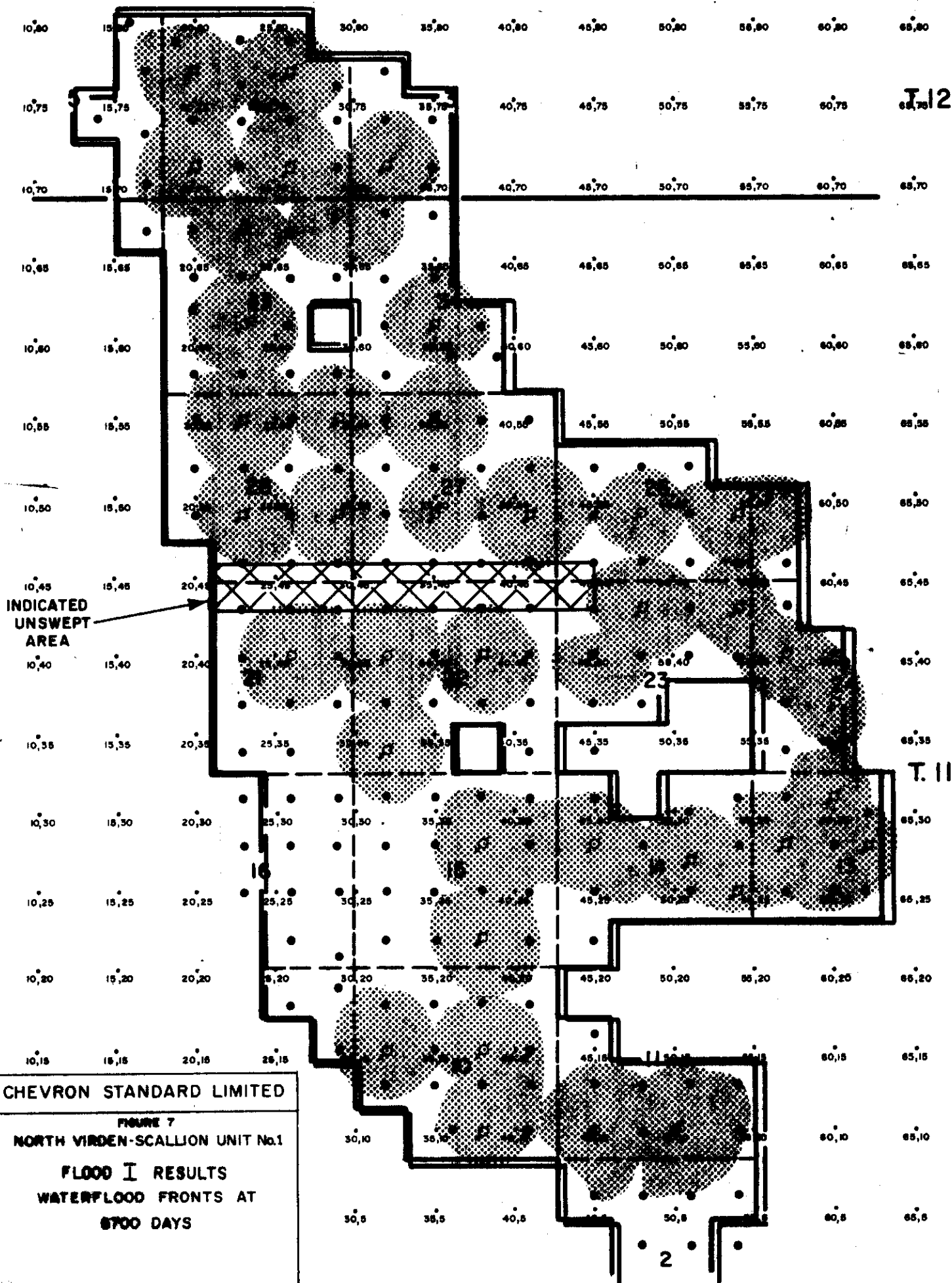
NORTH VIRDEN-SCALLION UNIT No.1

FLOOD I RESULTS

WATERFLOOD FRONTS AT

4700 DAYS

R.26 W.P.M.

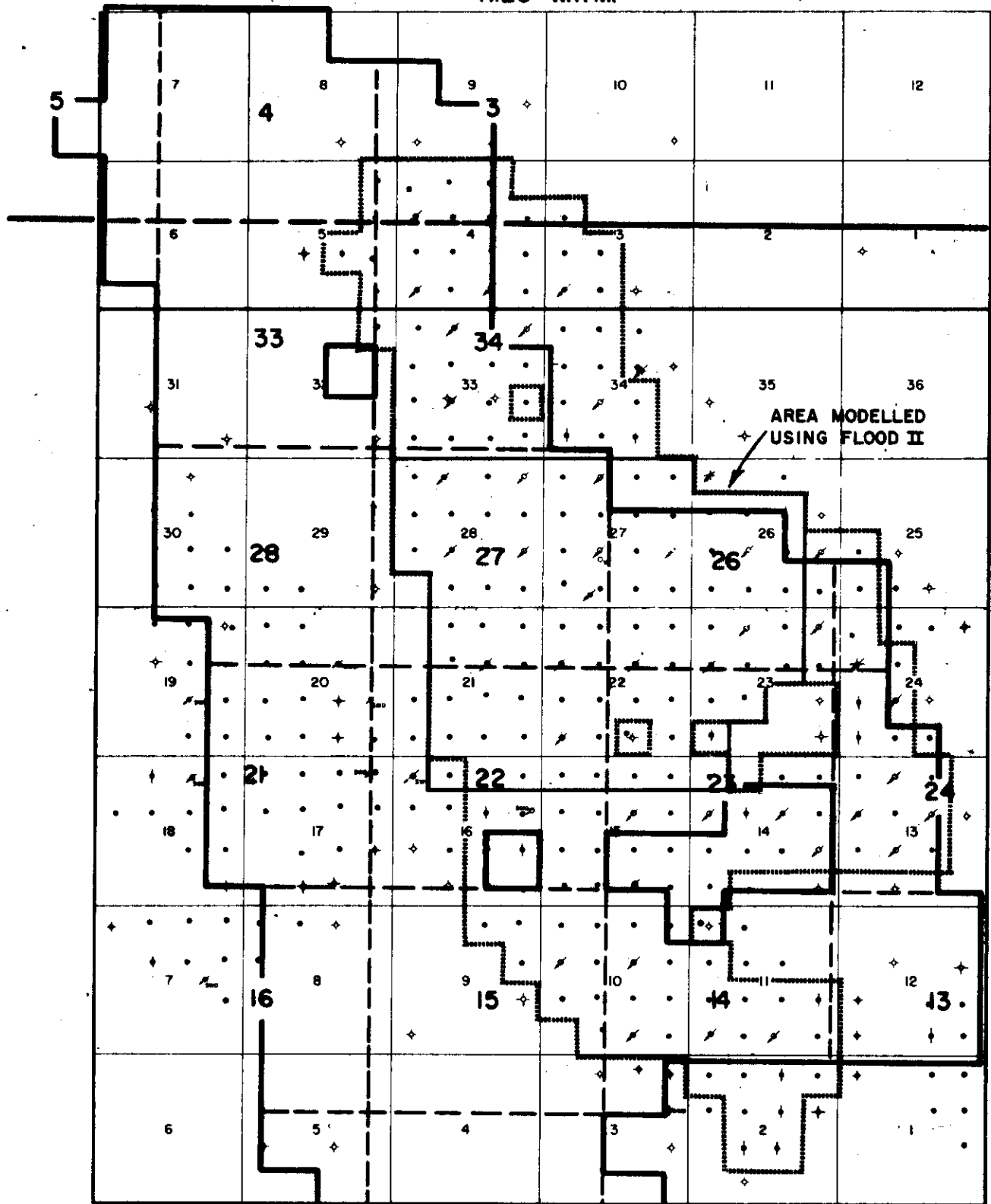


R.26 W.P.M.

R.26 W.P.M.

T.12

T.12



T.11

T.11

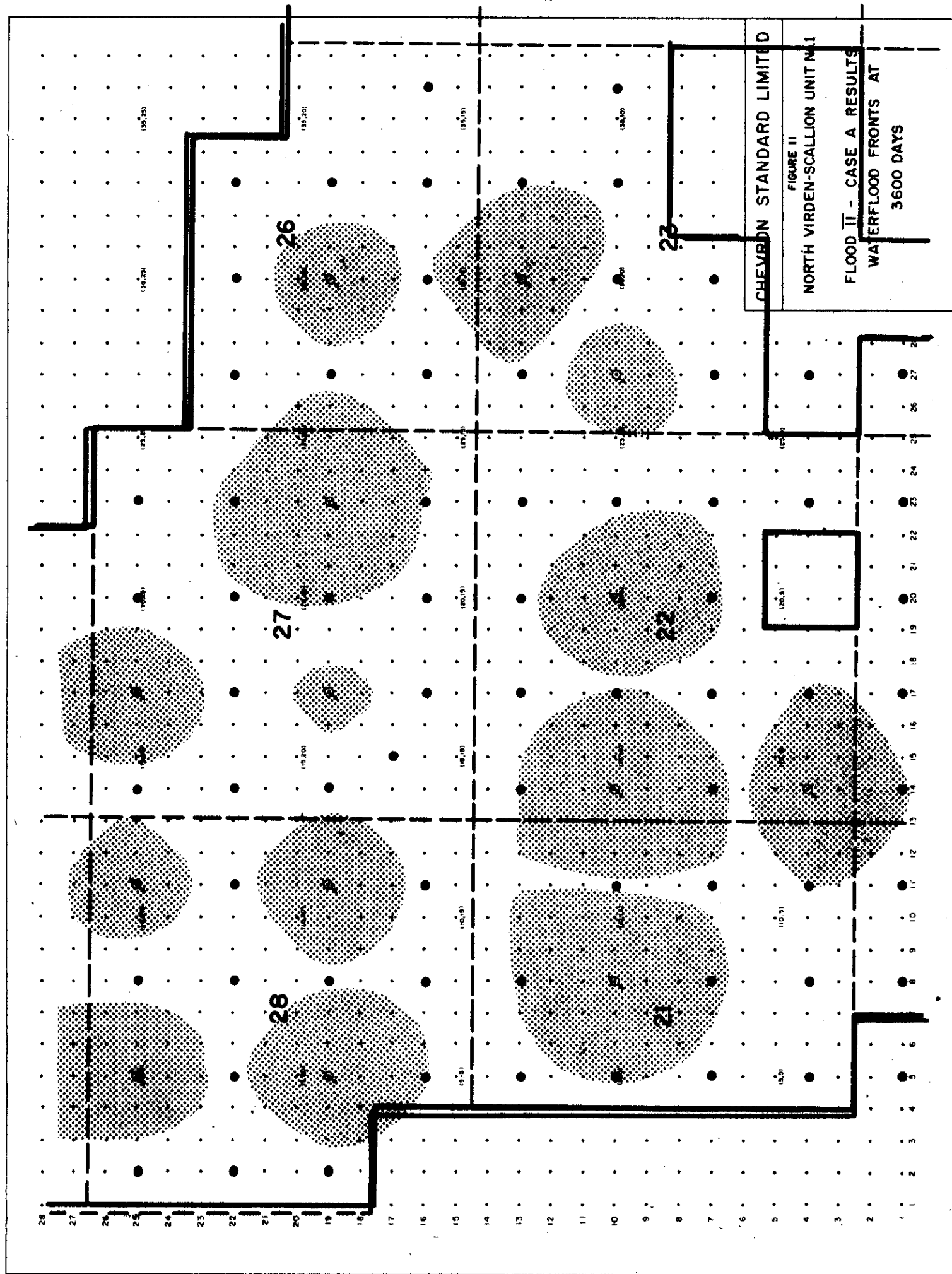
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FIGURE 8

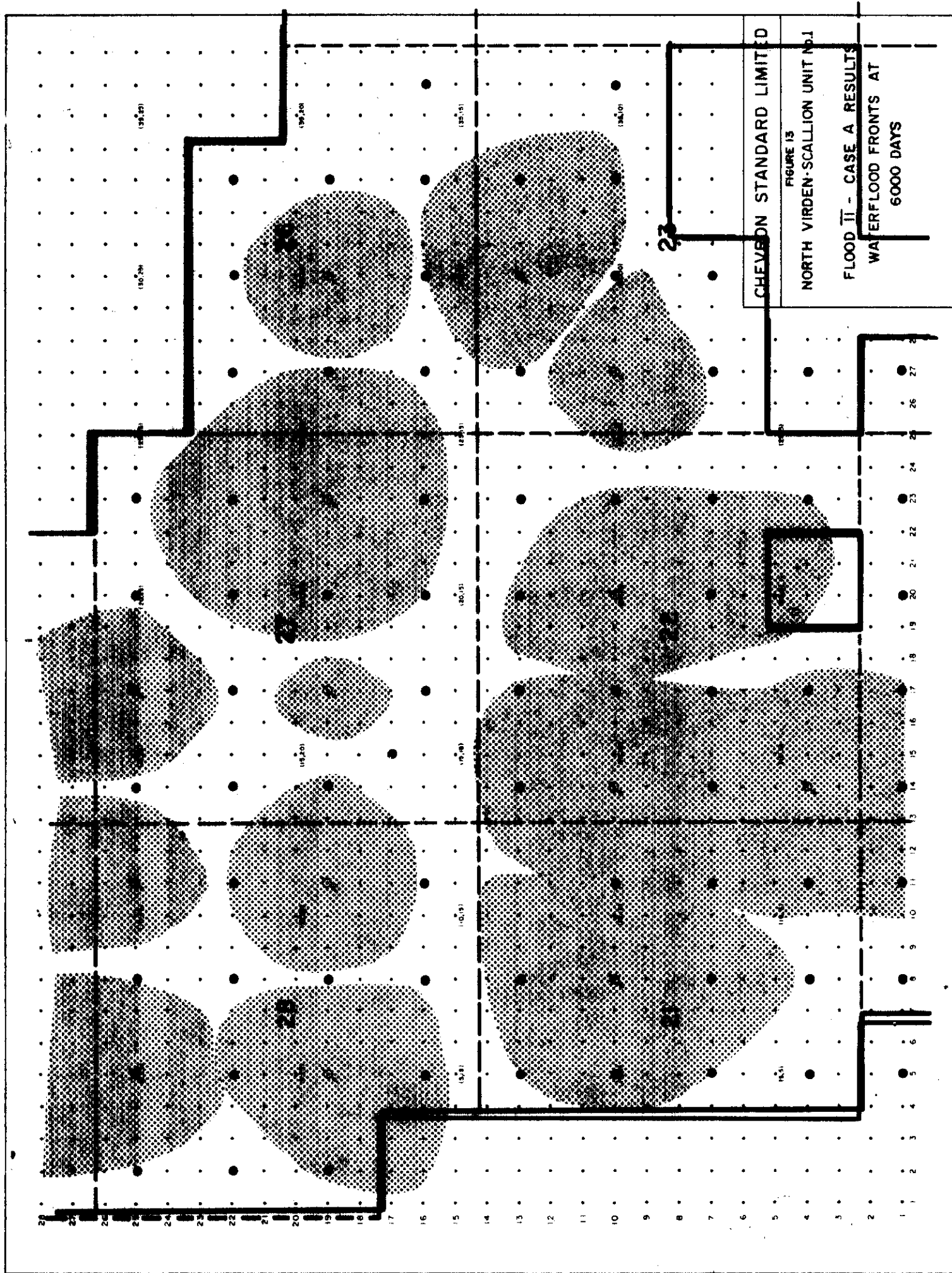
NORTH VERDEN SCALLION UNIT No.1

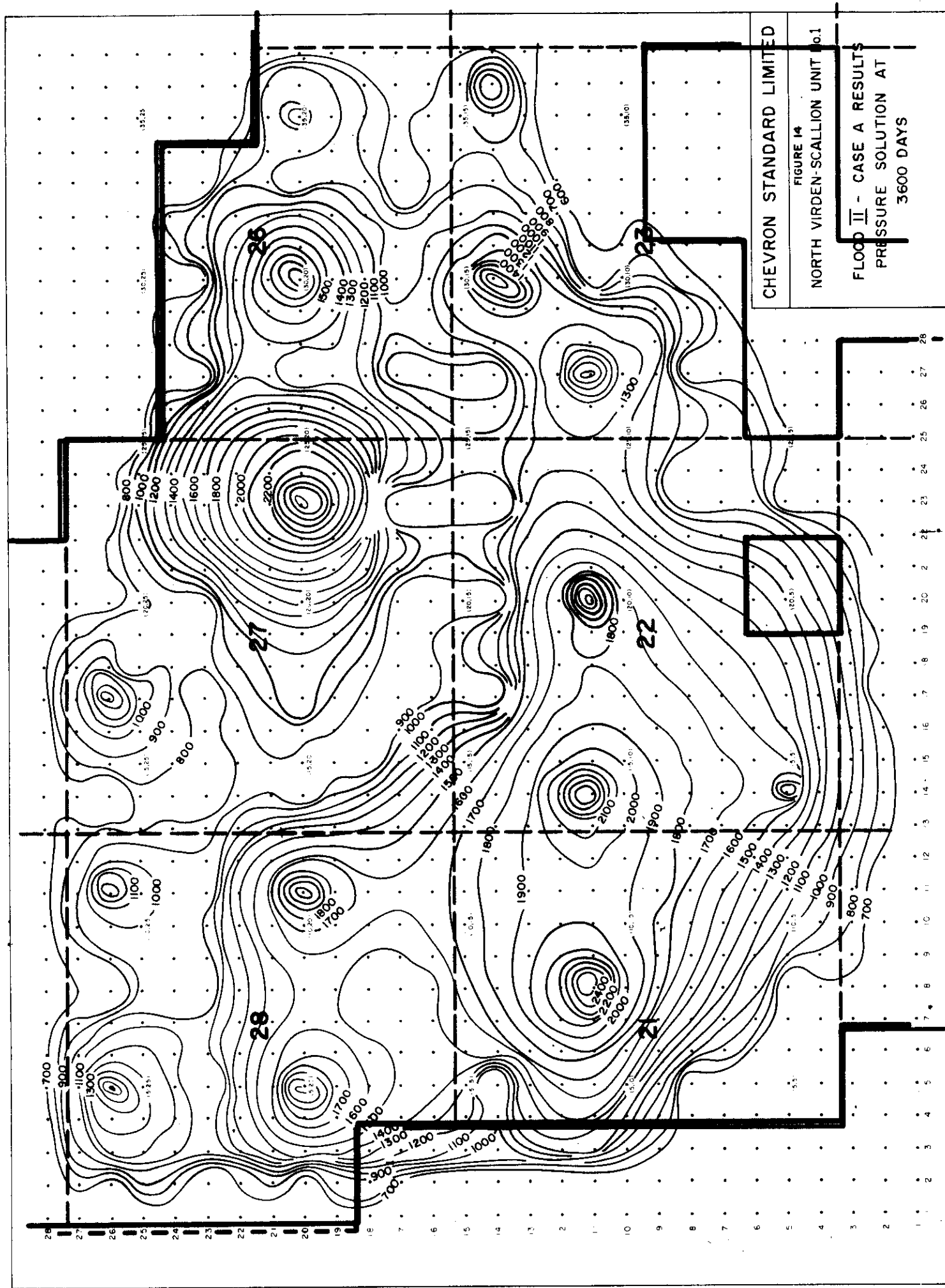
AREA MODELLED
USING FLOOD II

2







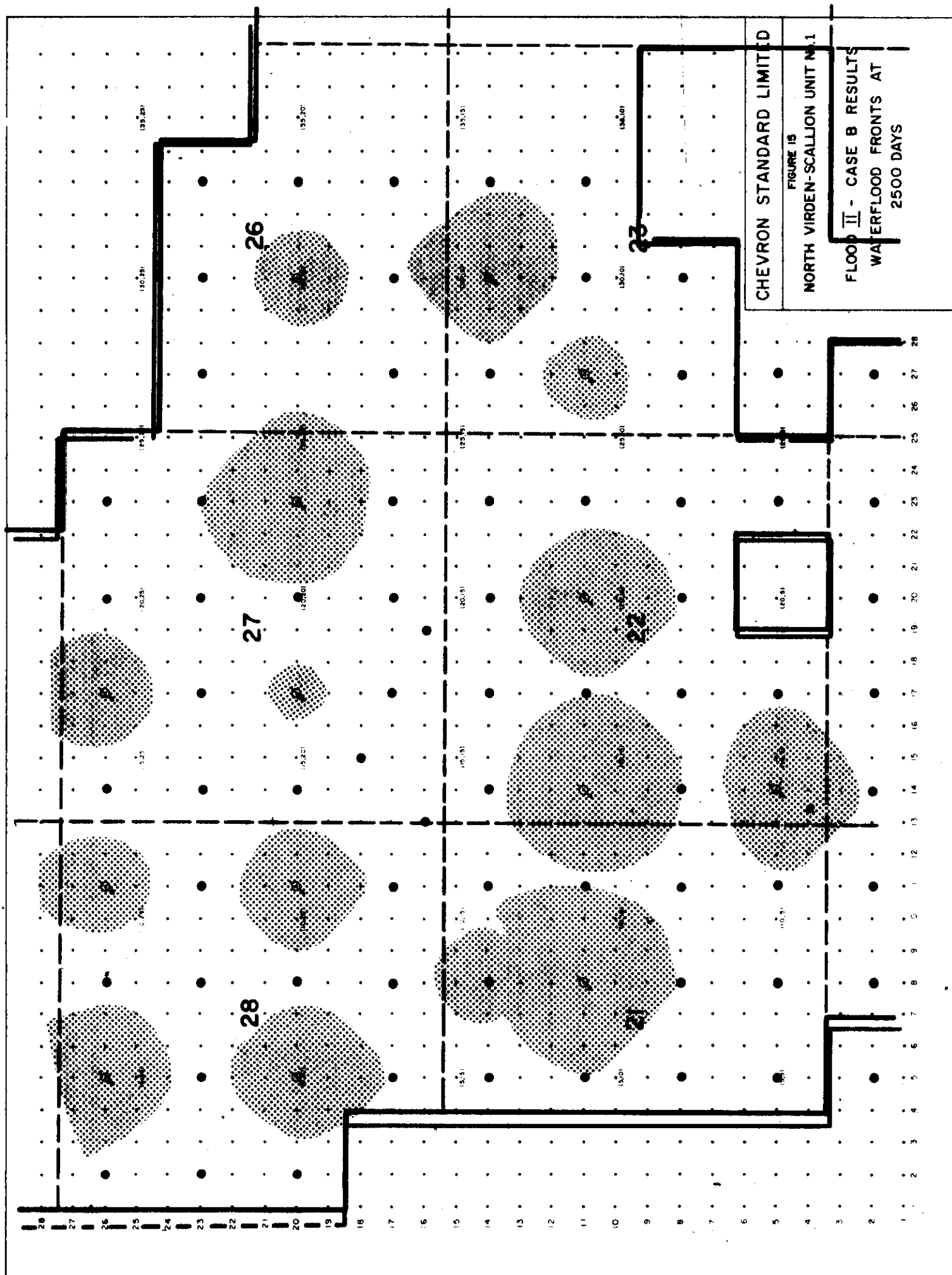


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FIGURE 14

NORTH VIRDEN-SCALLION UNIT No.1

FLOOD II - CASE A RESULTS
PRESSURE SOLUTION AT
3600 DAYS

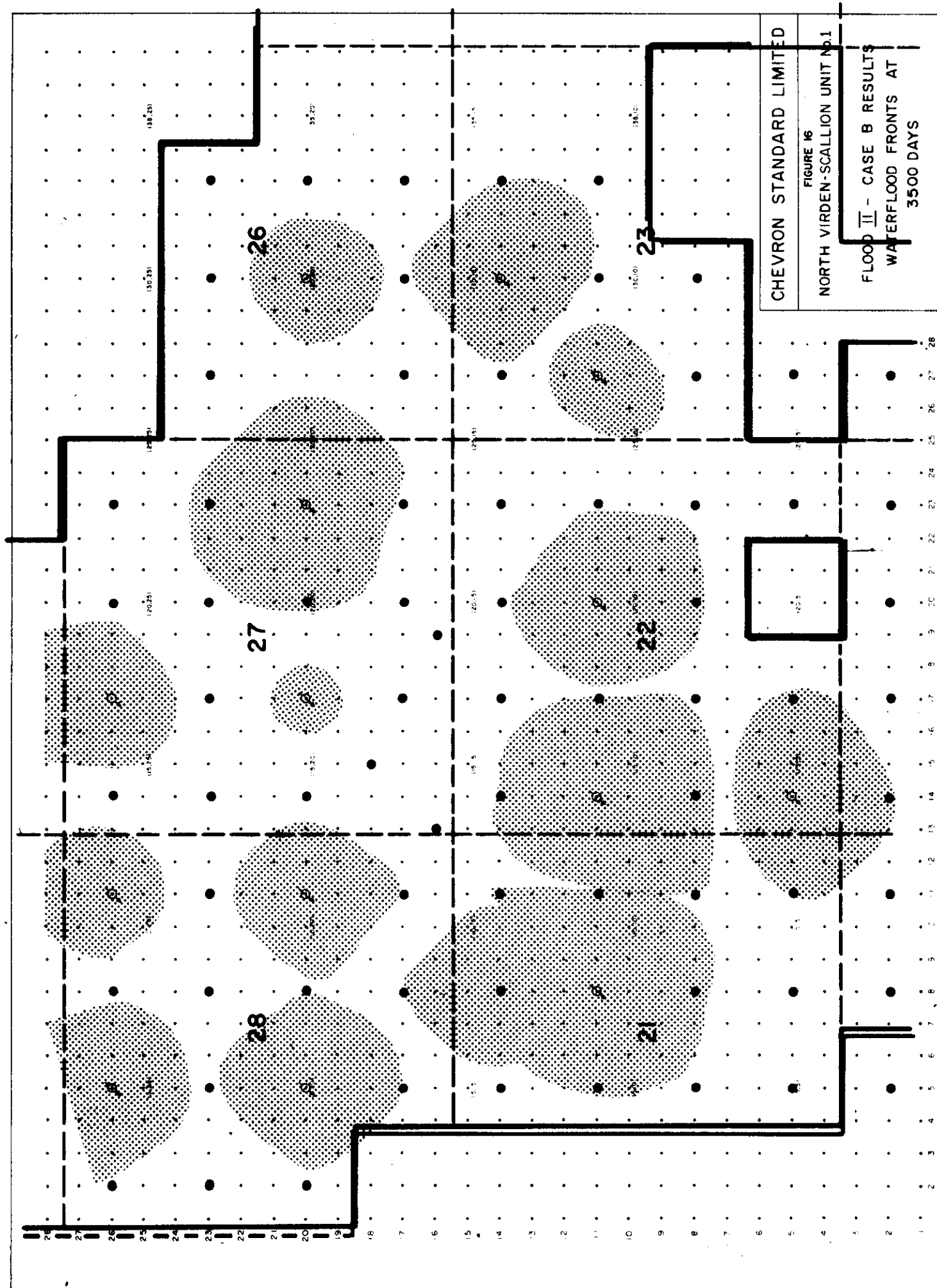


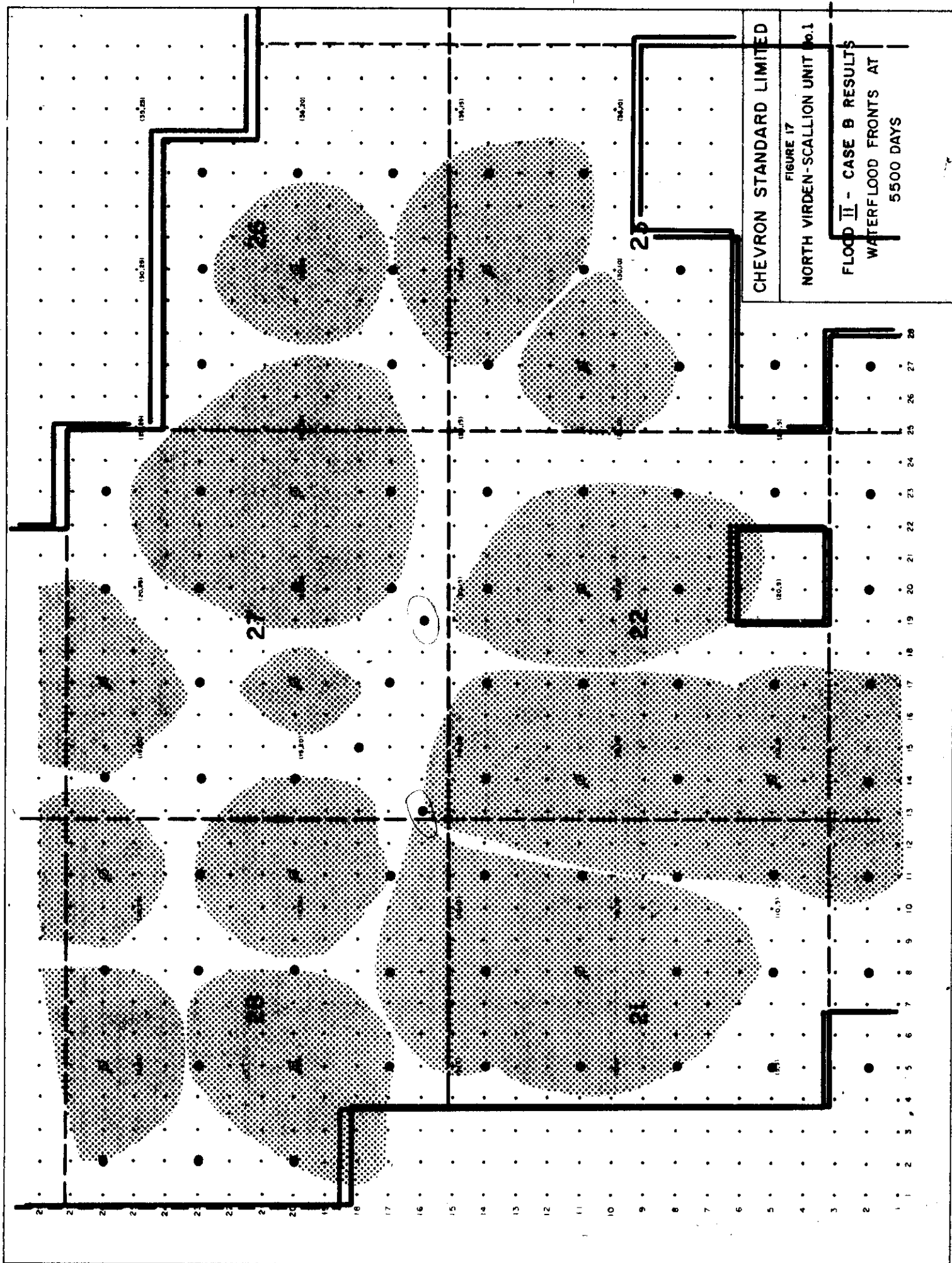
CHEVRON STANDARD LIMITED

FIGURE 15

NORTH VIRDEN-SCALLION UNIT No. 1

FLOOD II - CASE B RESULTS
WATERFLOOD FRONTS AT
2500 DAYS



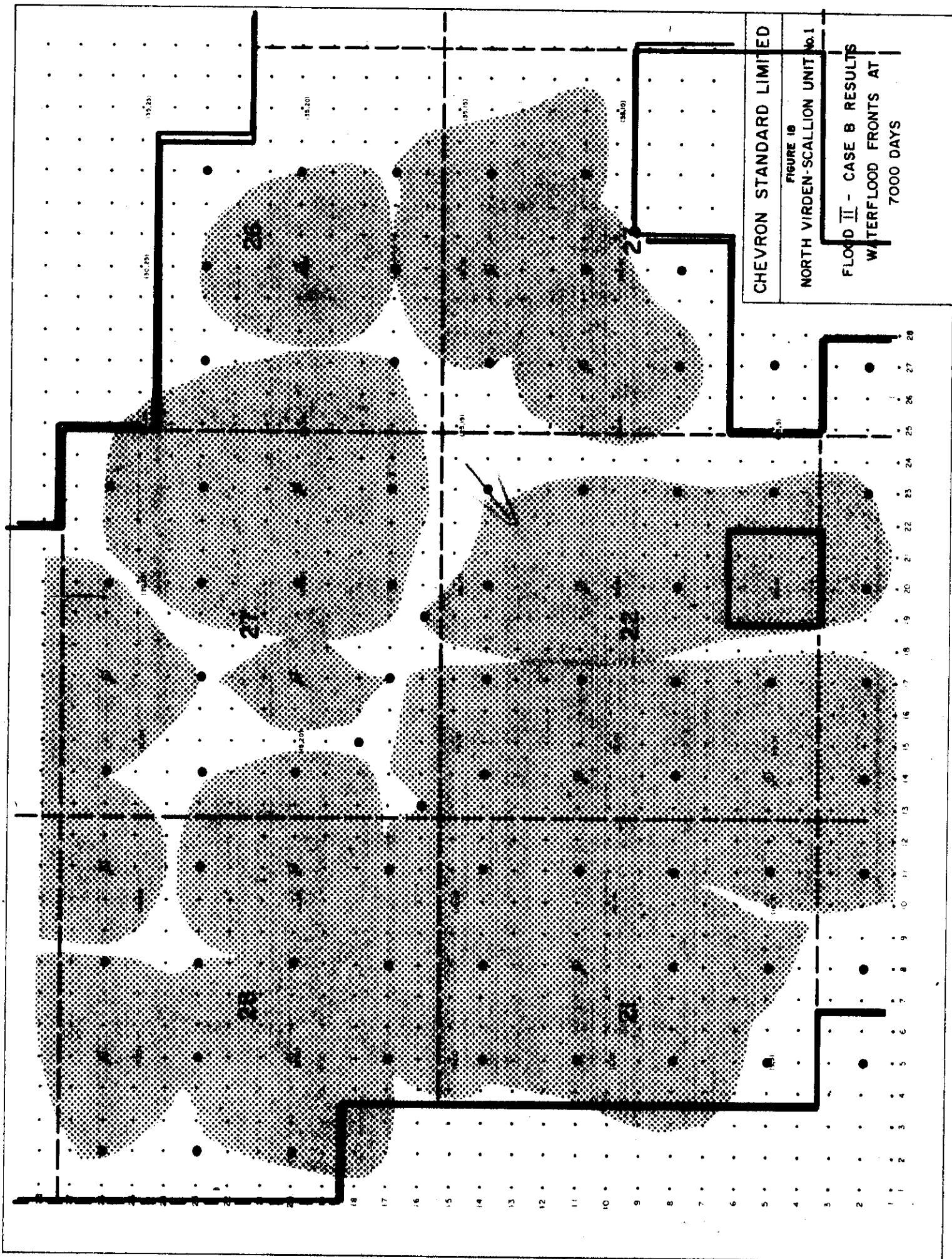


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FIGURE 17

NORTH VIRDEN-SCALLION UNIT No. 1

FLOOD II - CASE B RESULTS
WATERFLOOD FRONTS AT
5500 DAYS

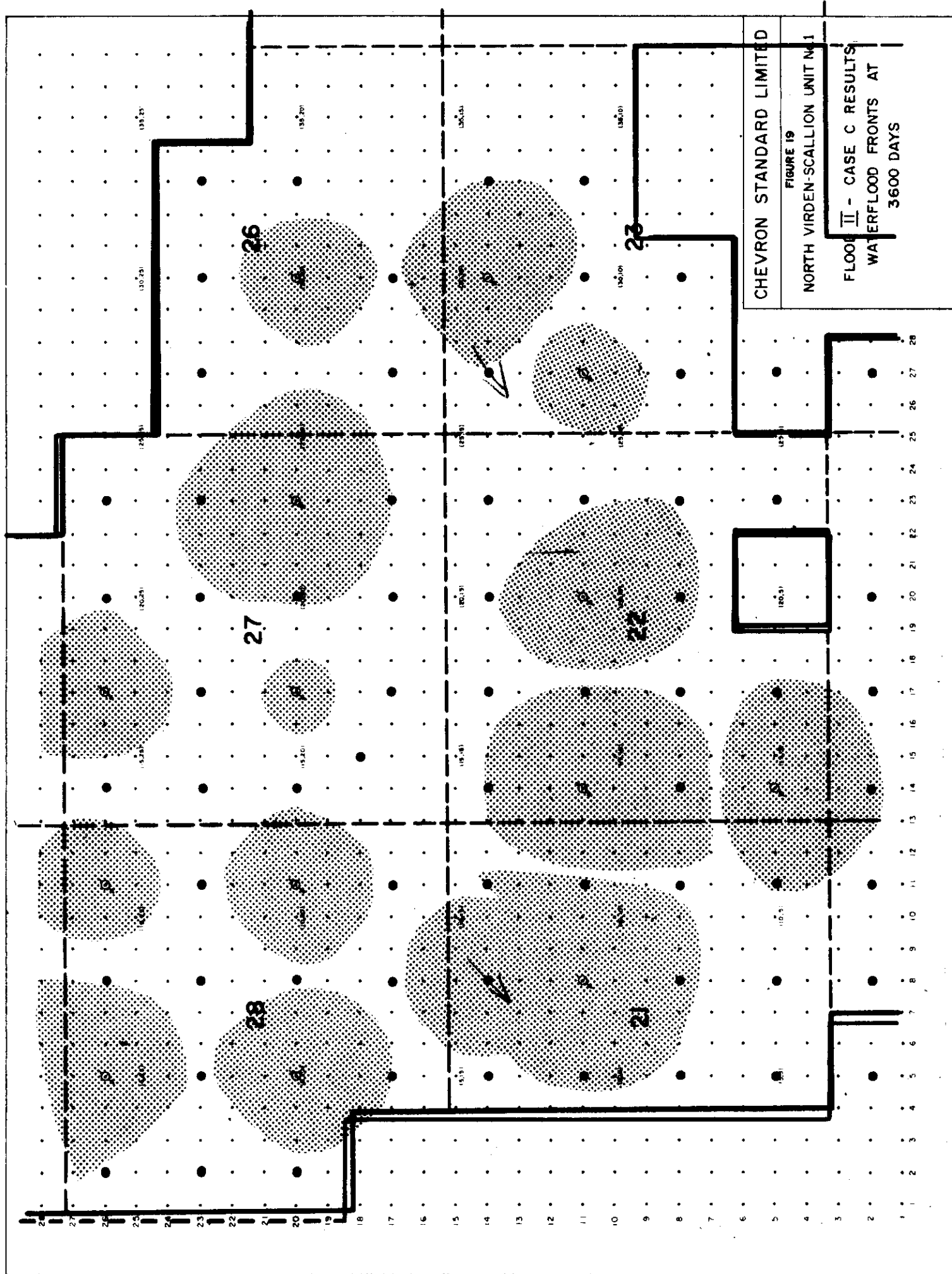


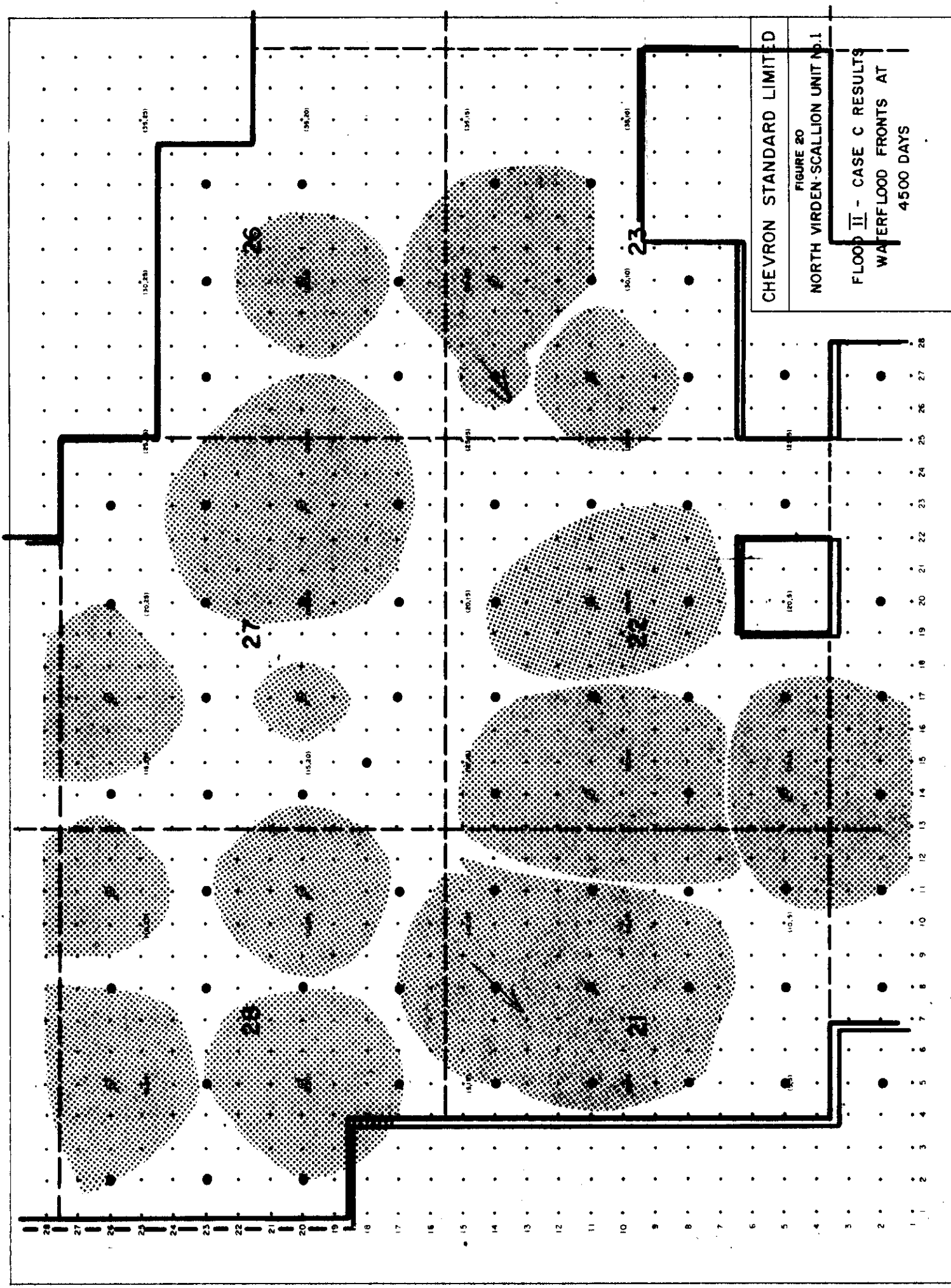
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FIGURE 10

NORTH VIRDEN SCALLION UNIT No. 1

FLOOD II - CASE B RESULTS
WATERFLOOD FRONTS AT
7000 DAYS





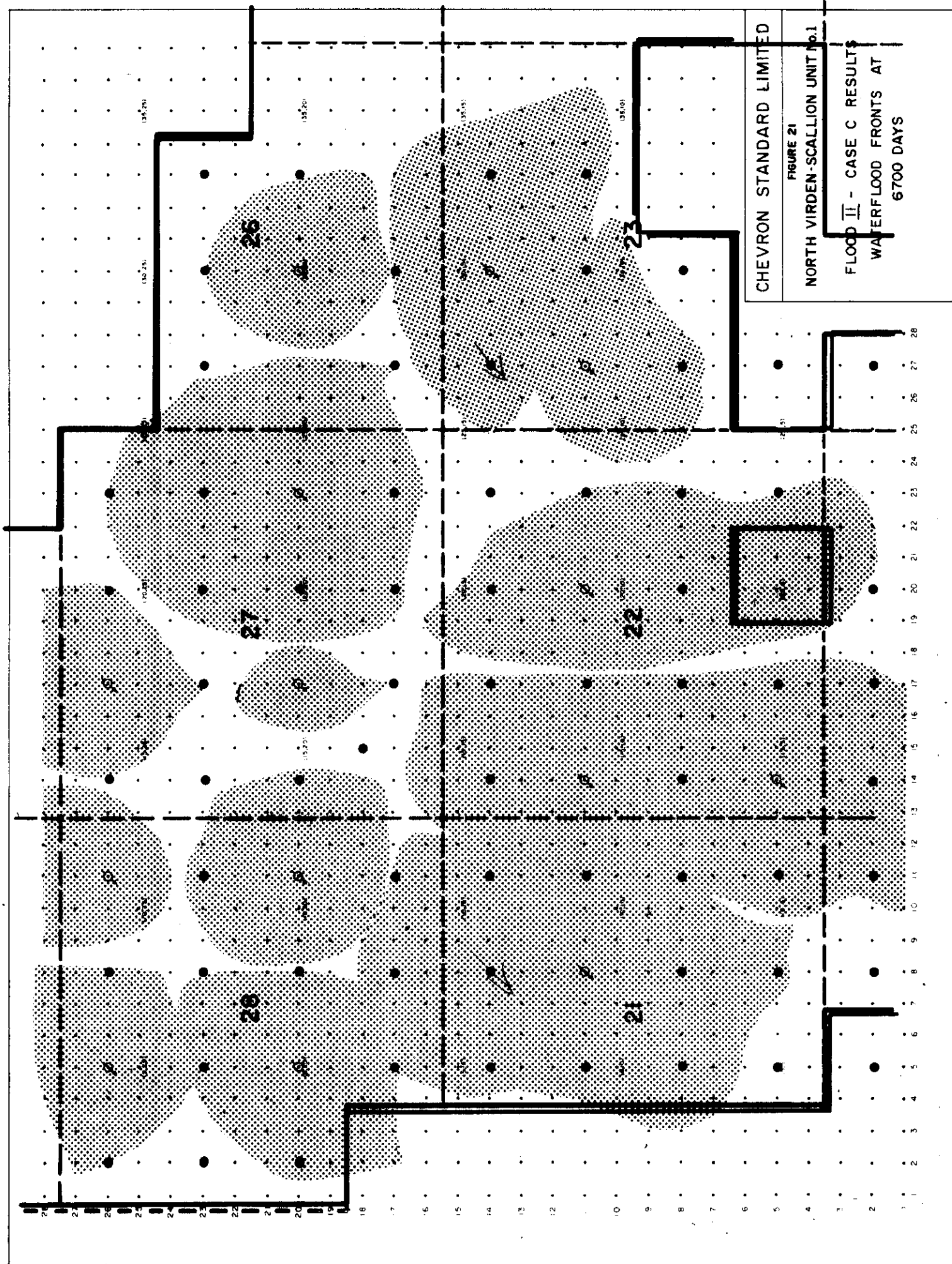
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FIGURE 20

NORTH VIRDEN-SCALLION UNIT No.1

FLOOD II - CASE C RESULTS

WATERFLOOD FRONTS AT 4500 DAYS

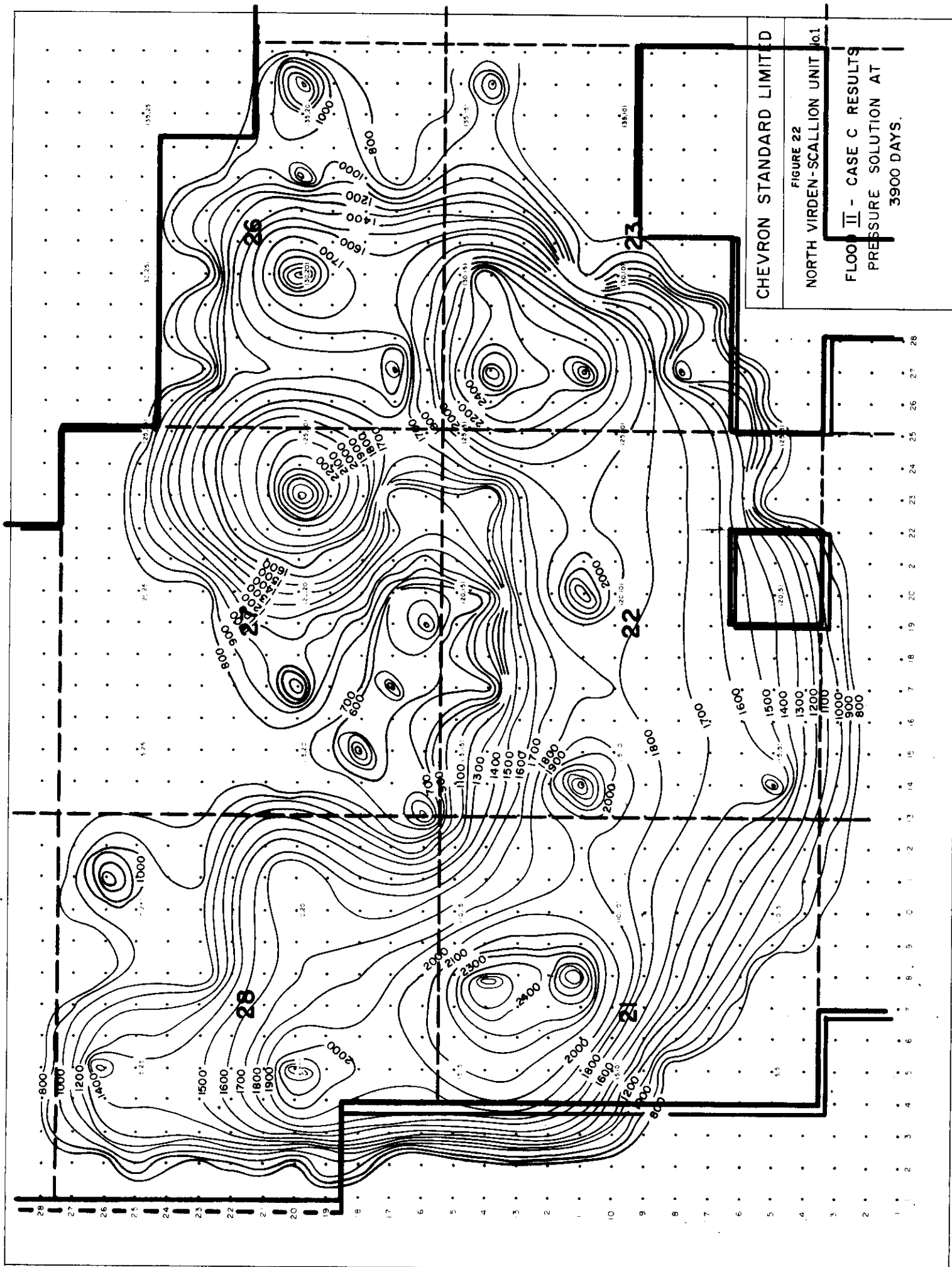


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FIGURE 21

NORTH VIRDEN-SCALLION UNIT No.1

FLOOD II - CASE C RESULTS
WATERFLOOD FRONTS AT
6700 DAYS

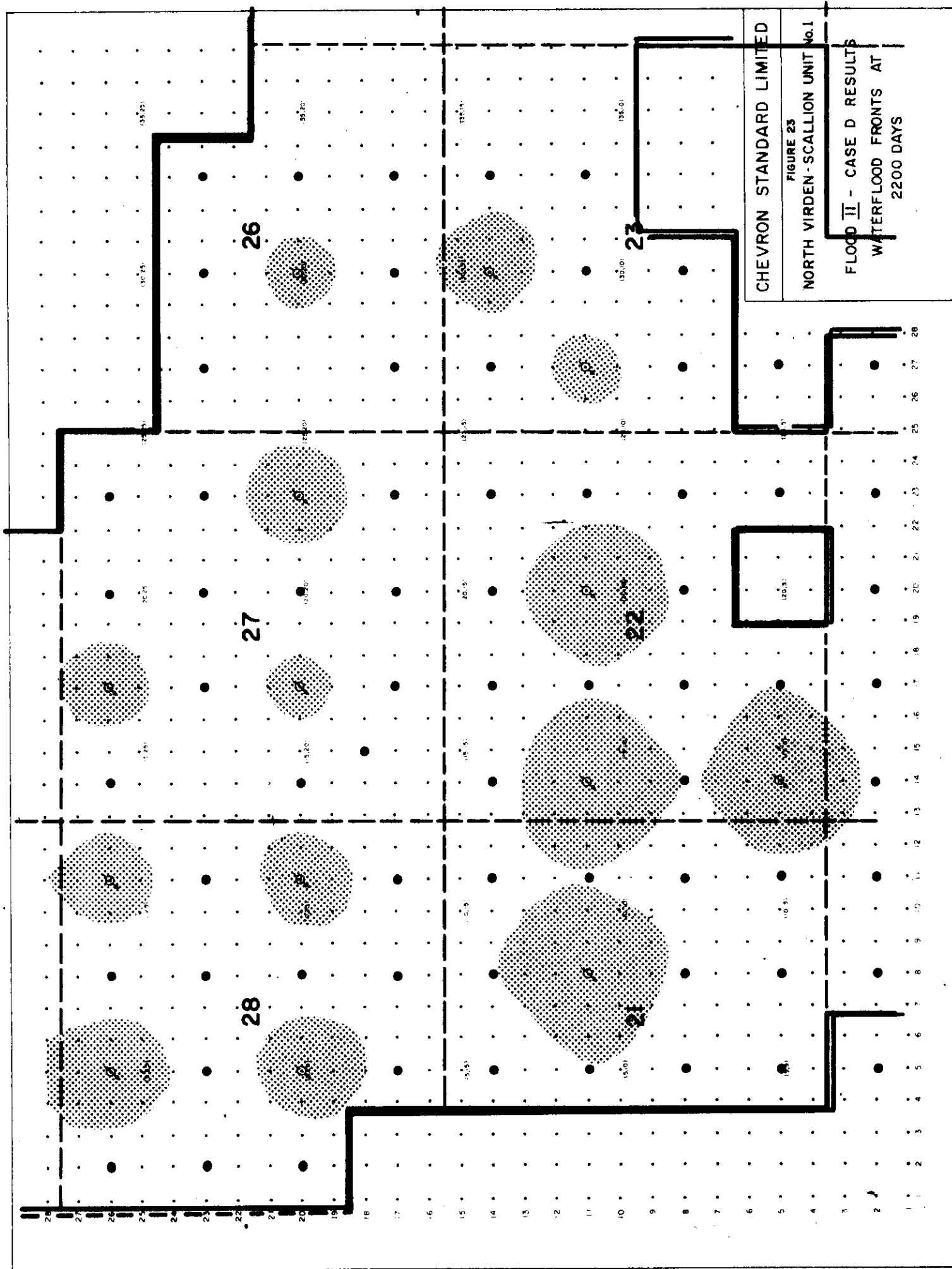


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FIGURE 22

NORTH VIRDEN-SCALLION UNIT No.1

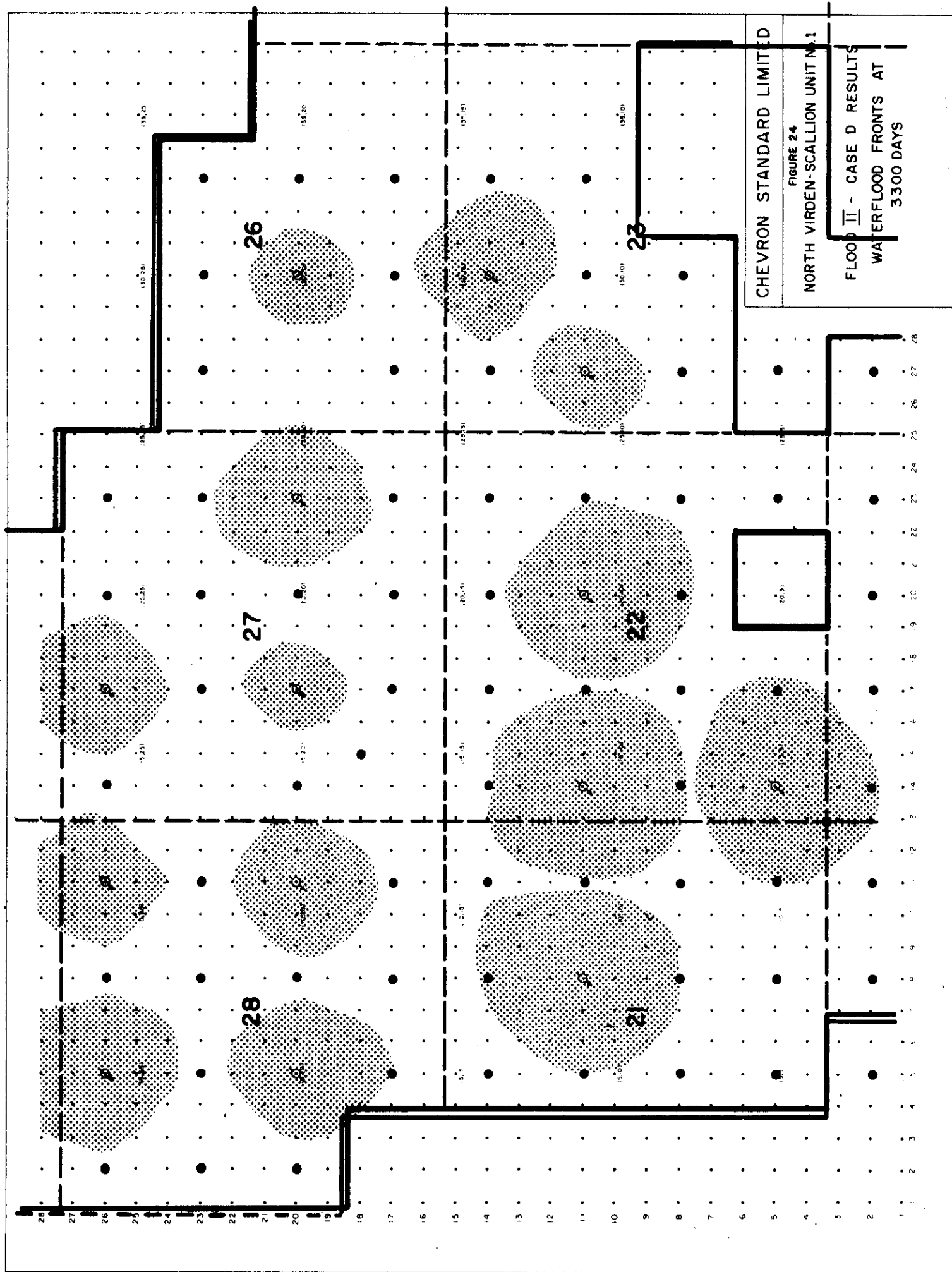
FLOOR II - CASE C RESULTS
PRESSURE SOLUTION AT
3900 DAYS.



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FIGURE 23
NORTH VIRDEN - SCALLION UNIT No. 1

FLOOD II - CASE D RESULTS
WATERFLOOD FRONTS AT
2200 DAYS

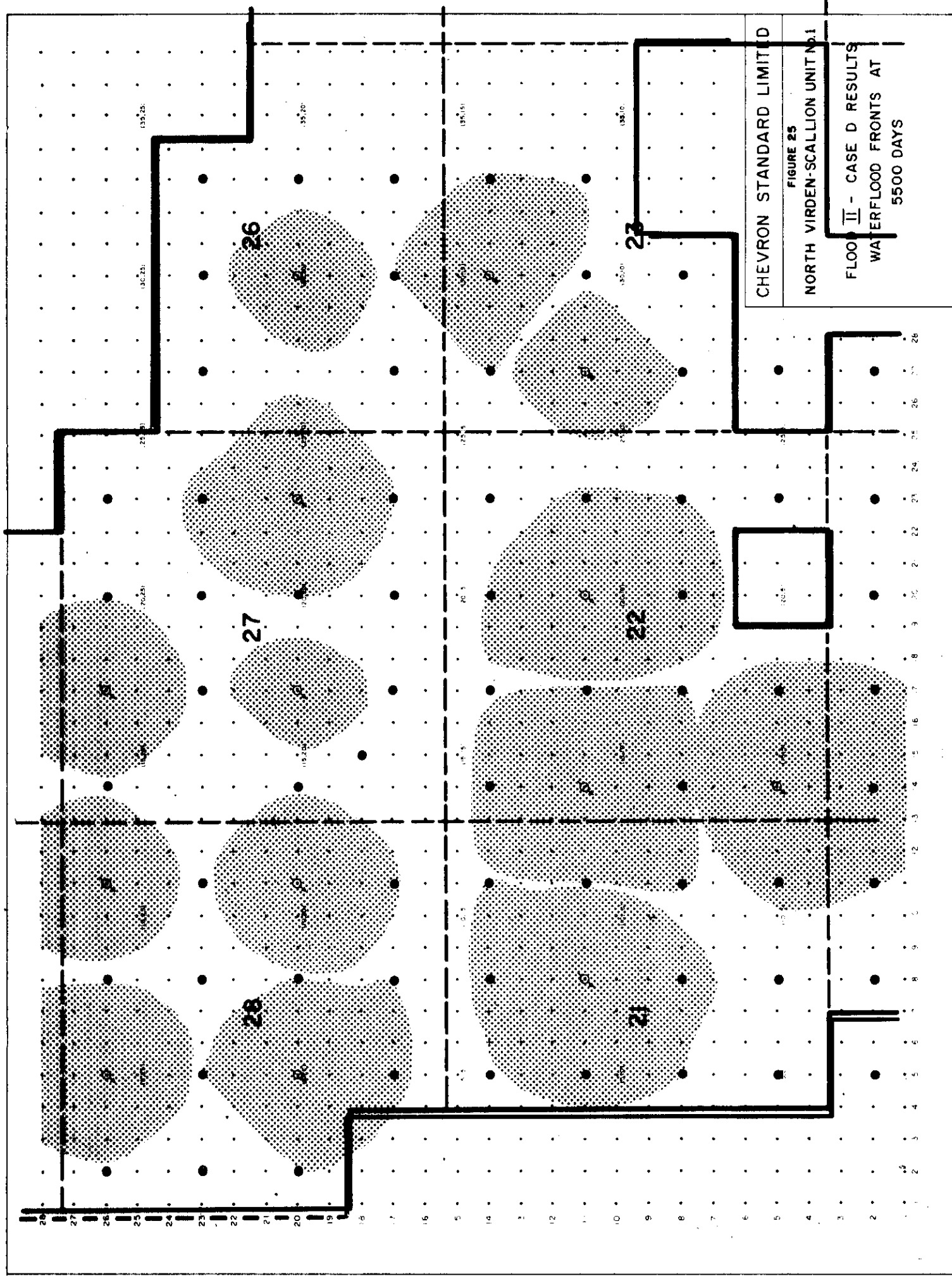


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FIGURE 24

NORTH VIRDEN-SCALLION UNIT No. 1

FLOOD II - CASE D RESULTS
WATERFLOOD FRONTS AT
3300 DAYS

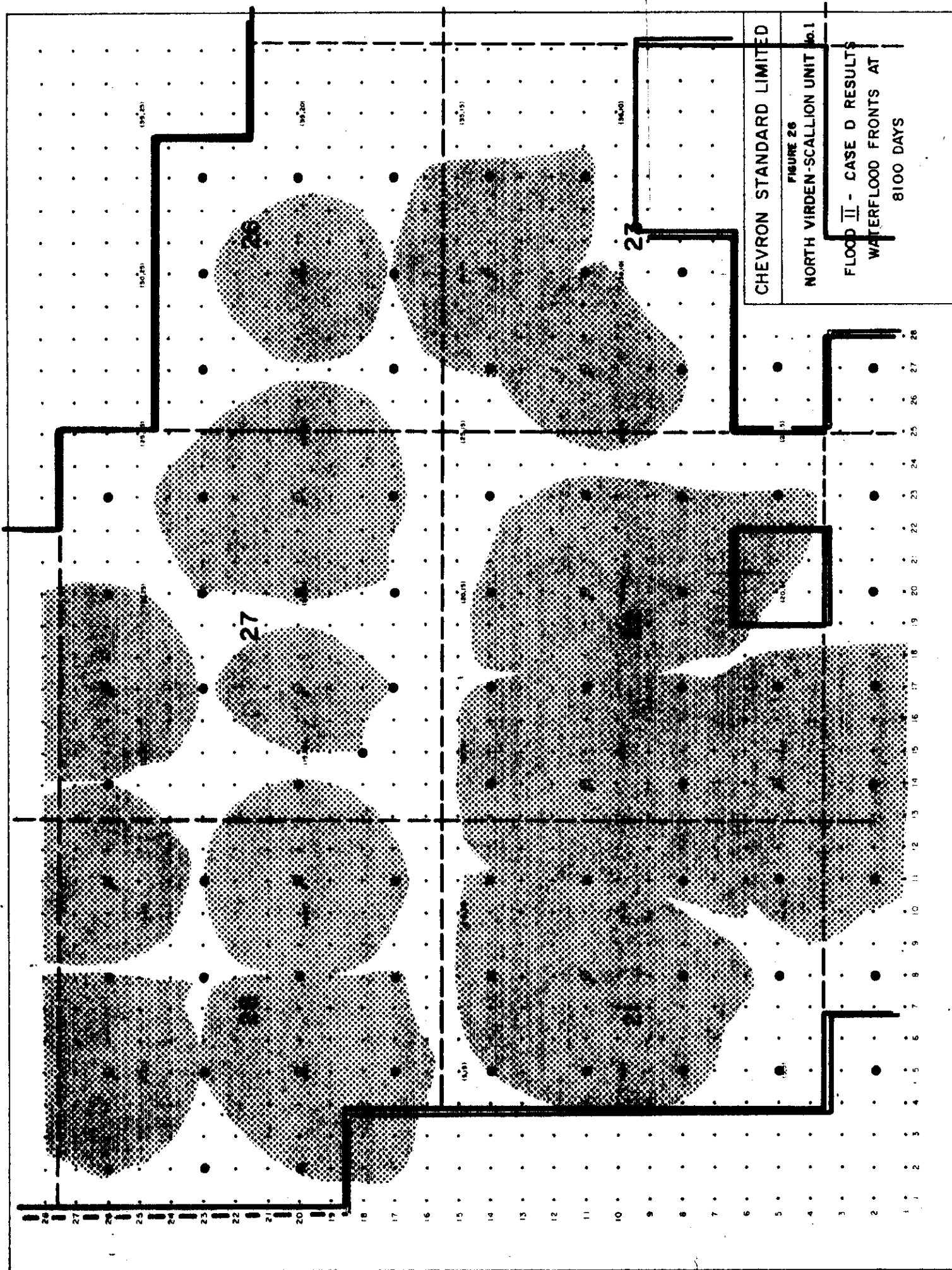


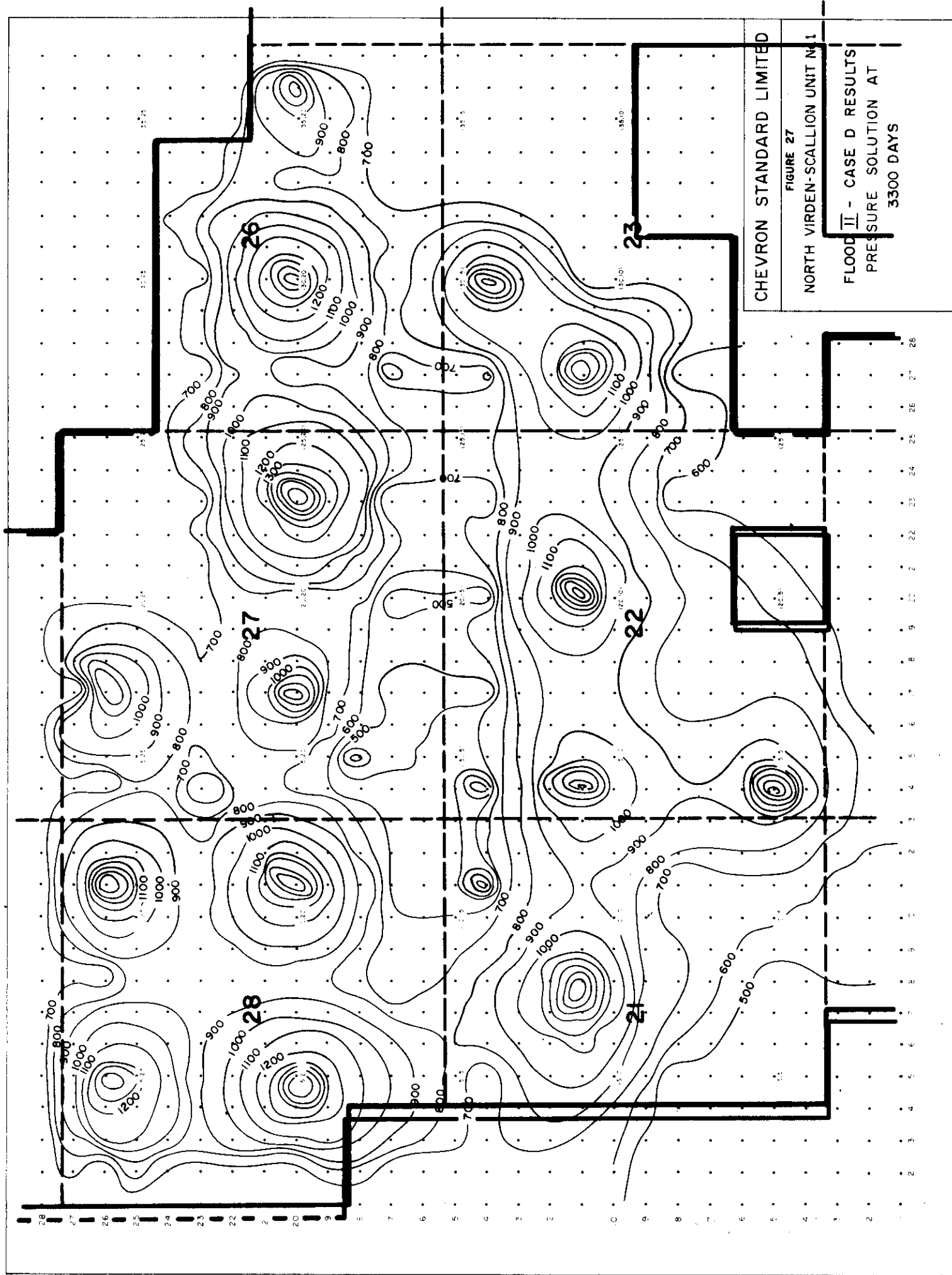
CHEVRON STANDARD LIMITED

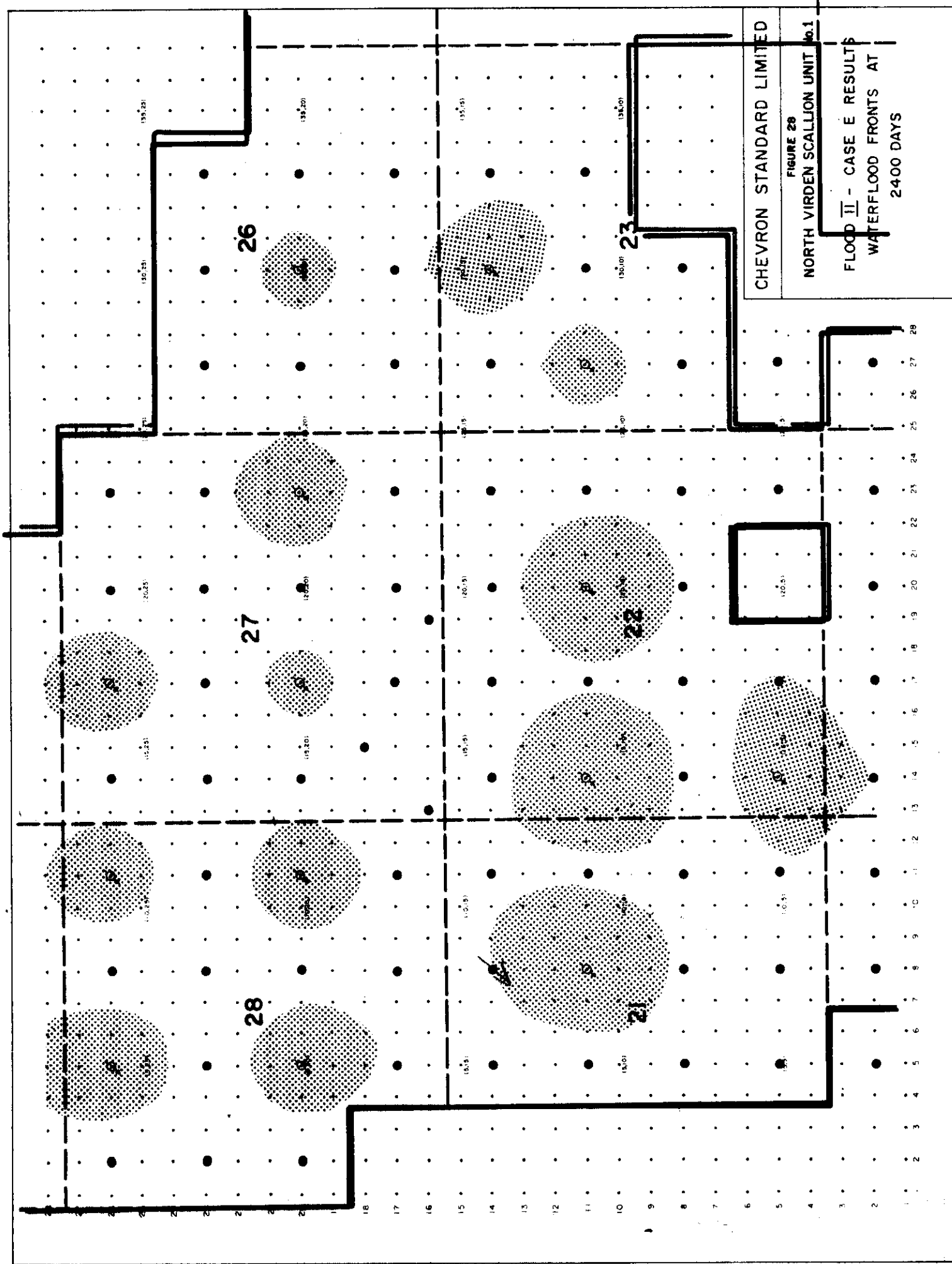
FIGURE 25

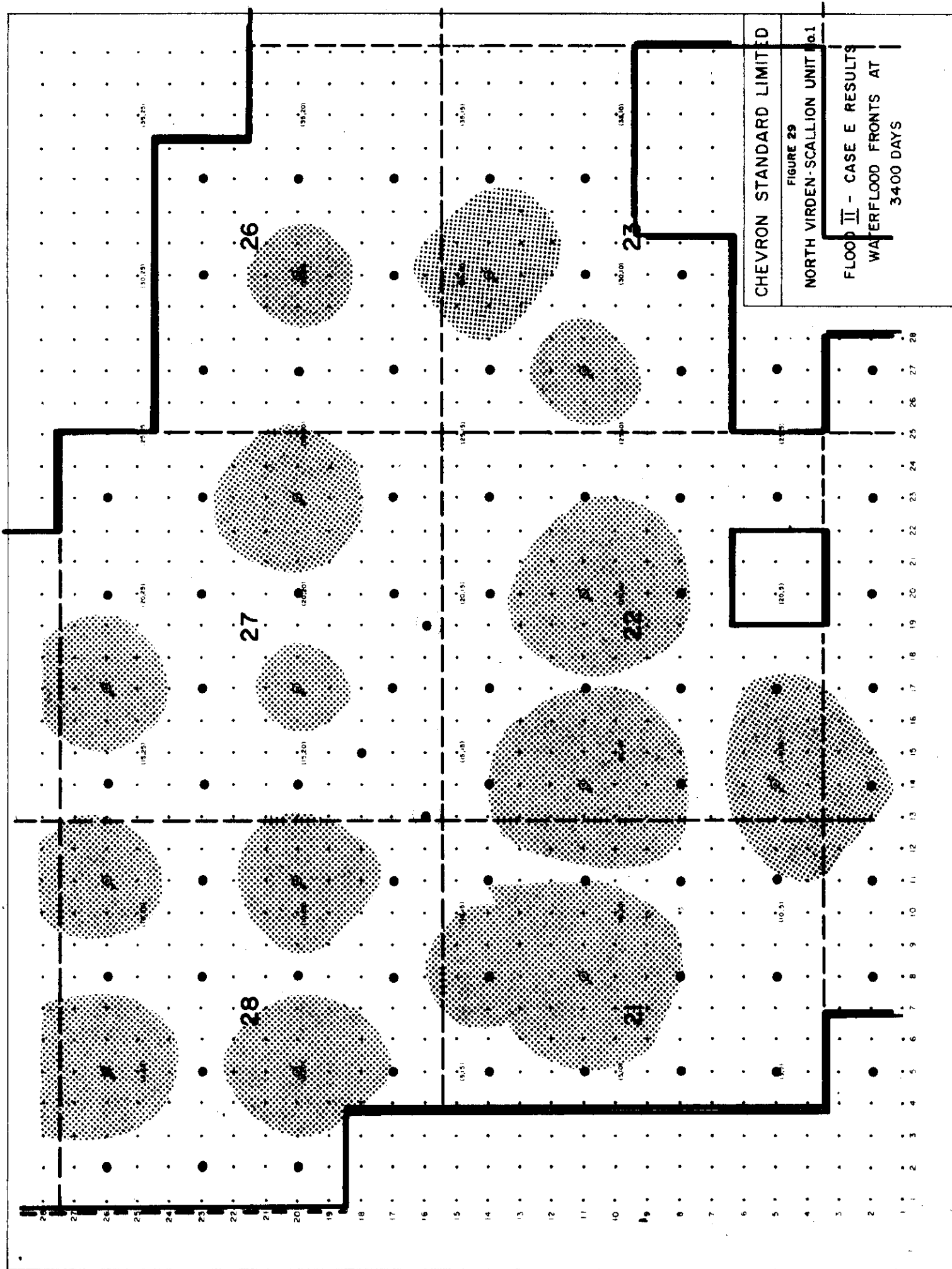
NORTH VIRDEN-SCALLION UNIT No. 1

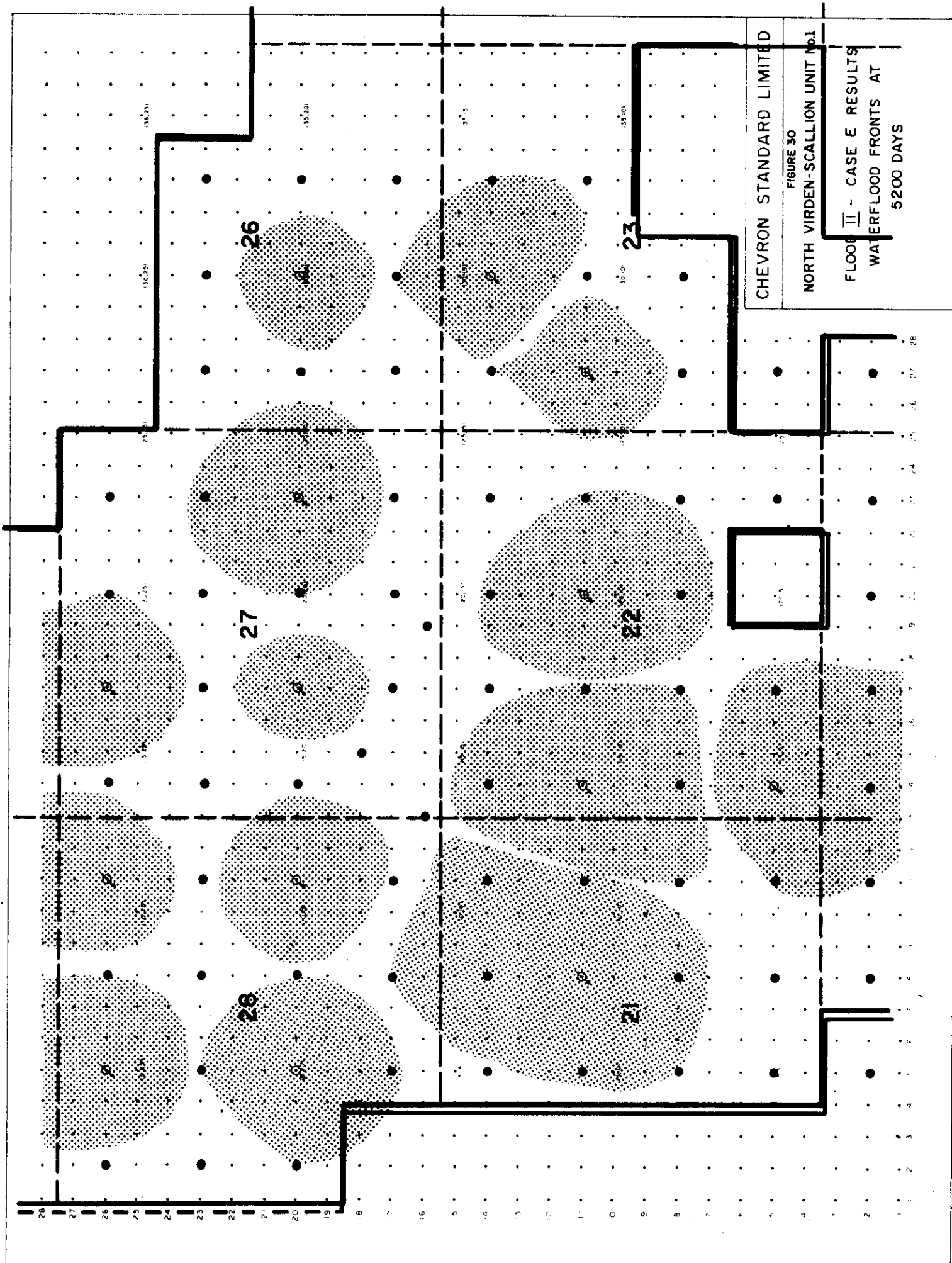
FLOOD II - CASE D RESULTS
WATERFLOOD FRONTS AT
5500 DAYS









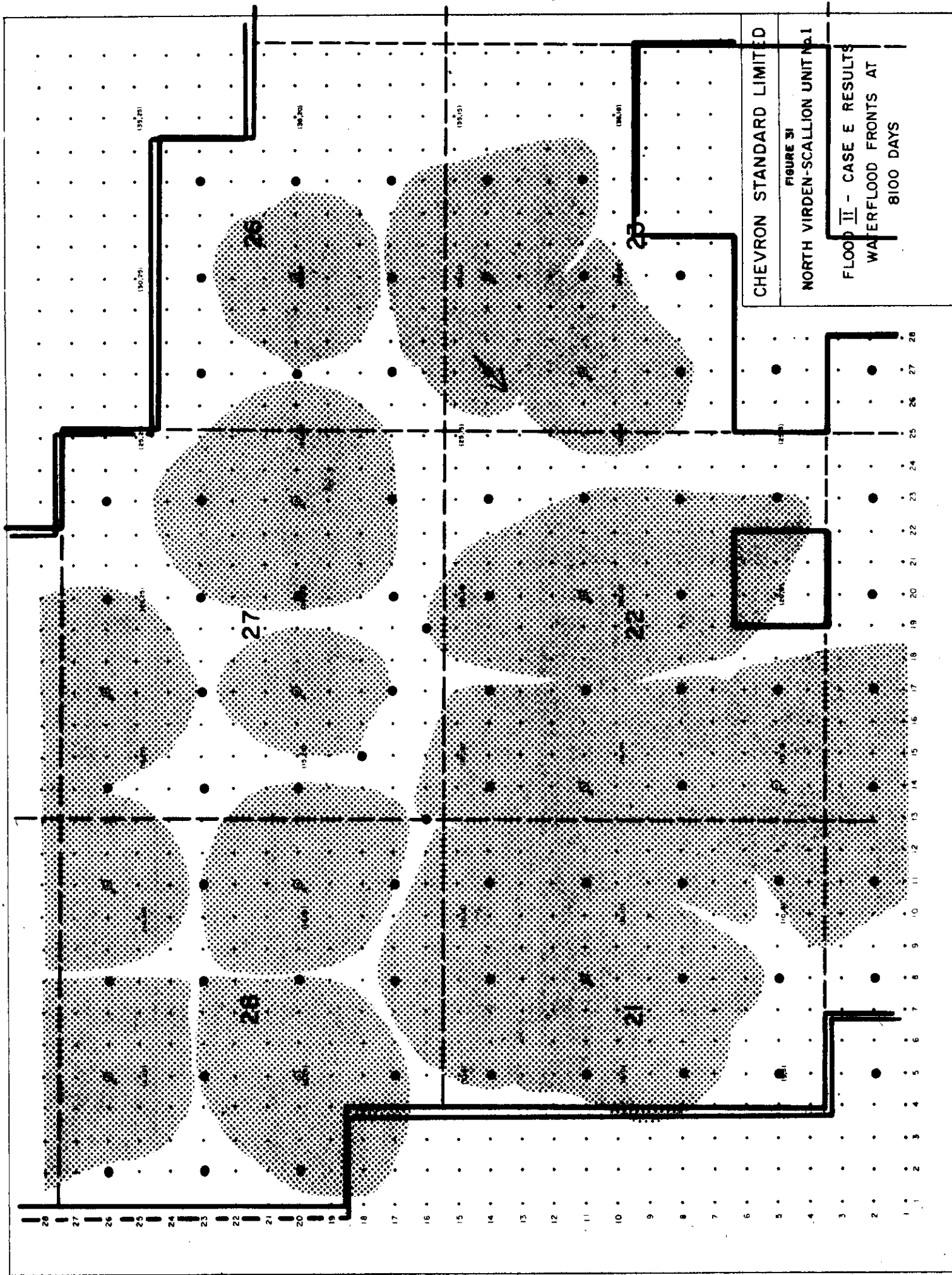


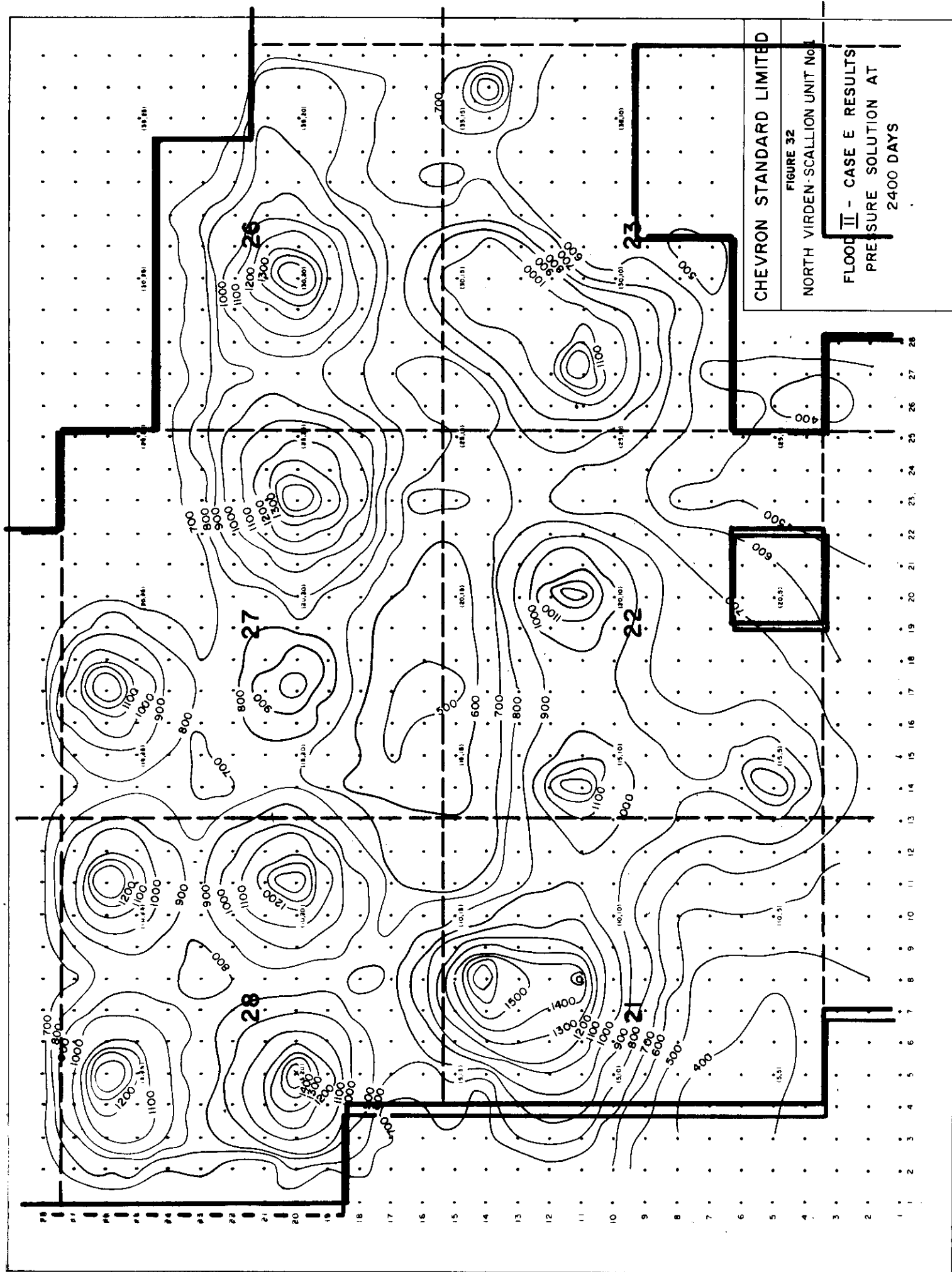
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FIGURE 30

NORTH VIRDEN-SCALLION UNIT No.1

FLOOD II - CASE E RESULTS
WATERFLOOD FRONTS AT
5200 DAYS



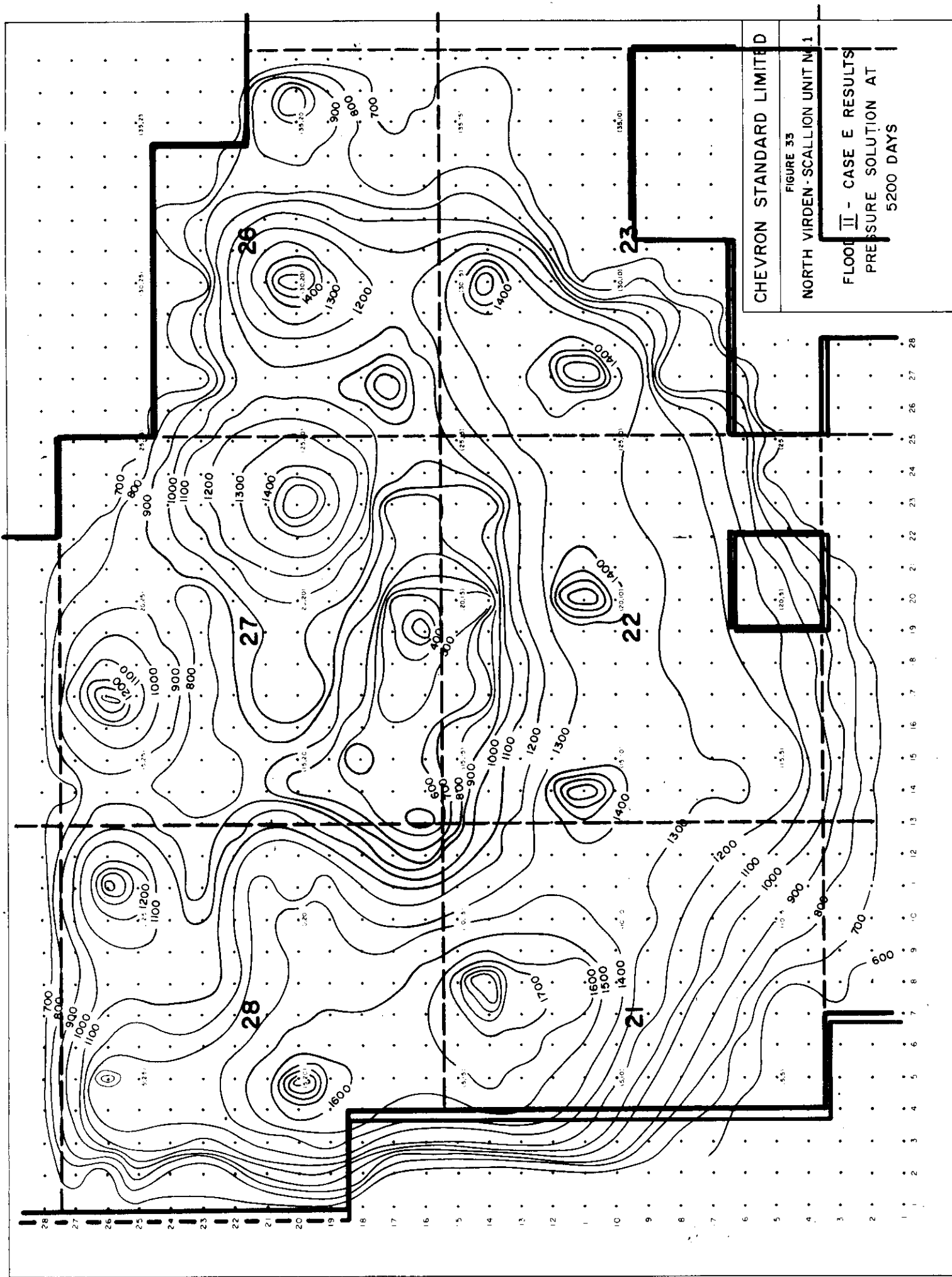


CHEVRON STANDARD LIMITED

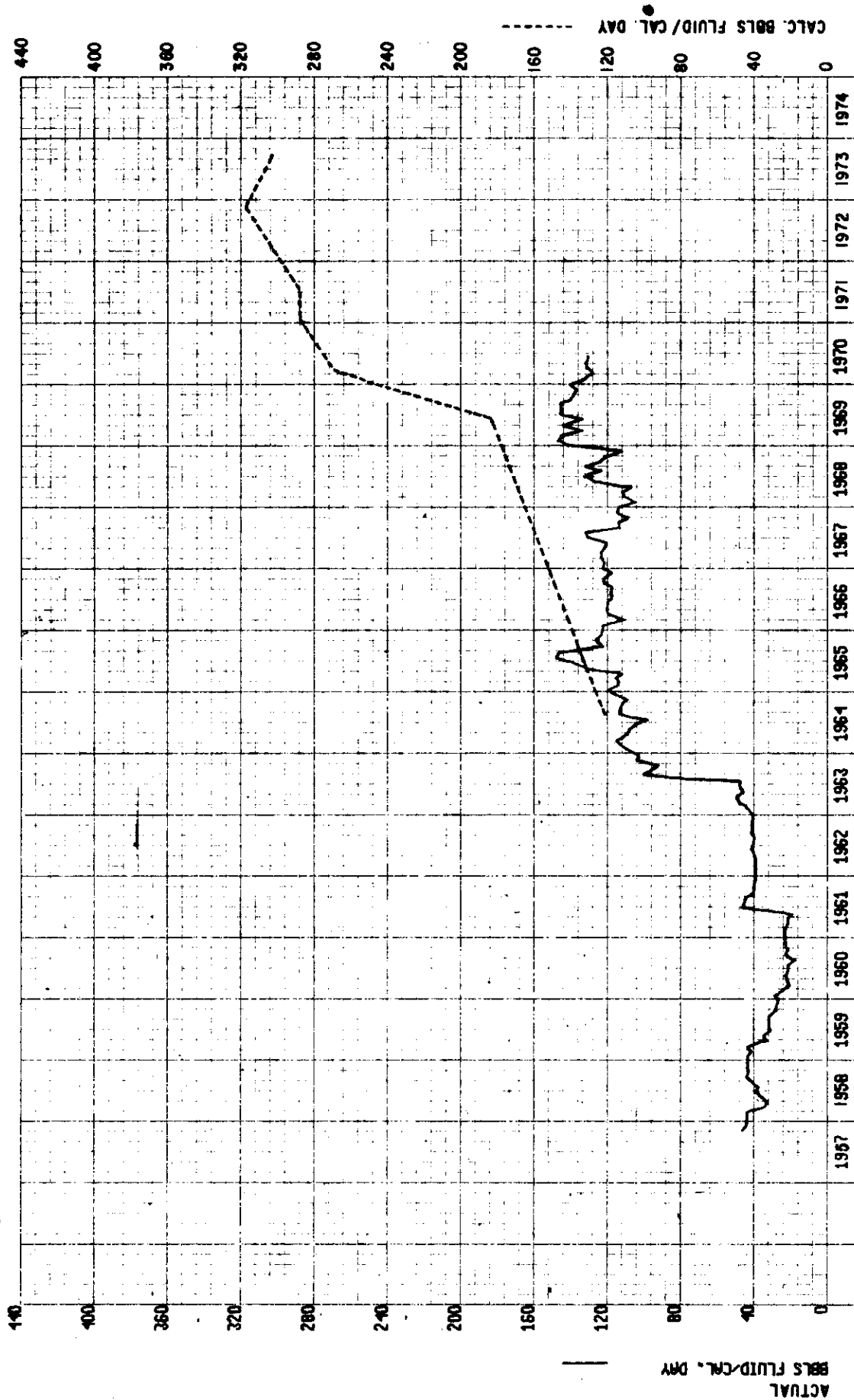
FIGURE 32

NORTH VIRDEN-SCALLION UNIT No. 1

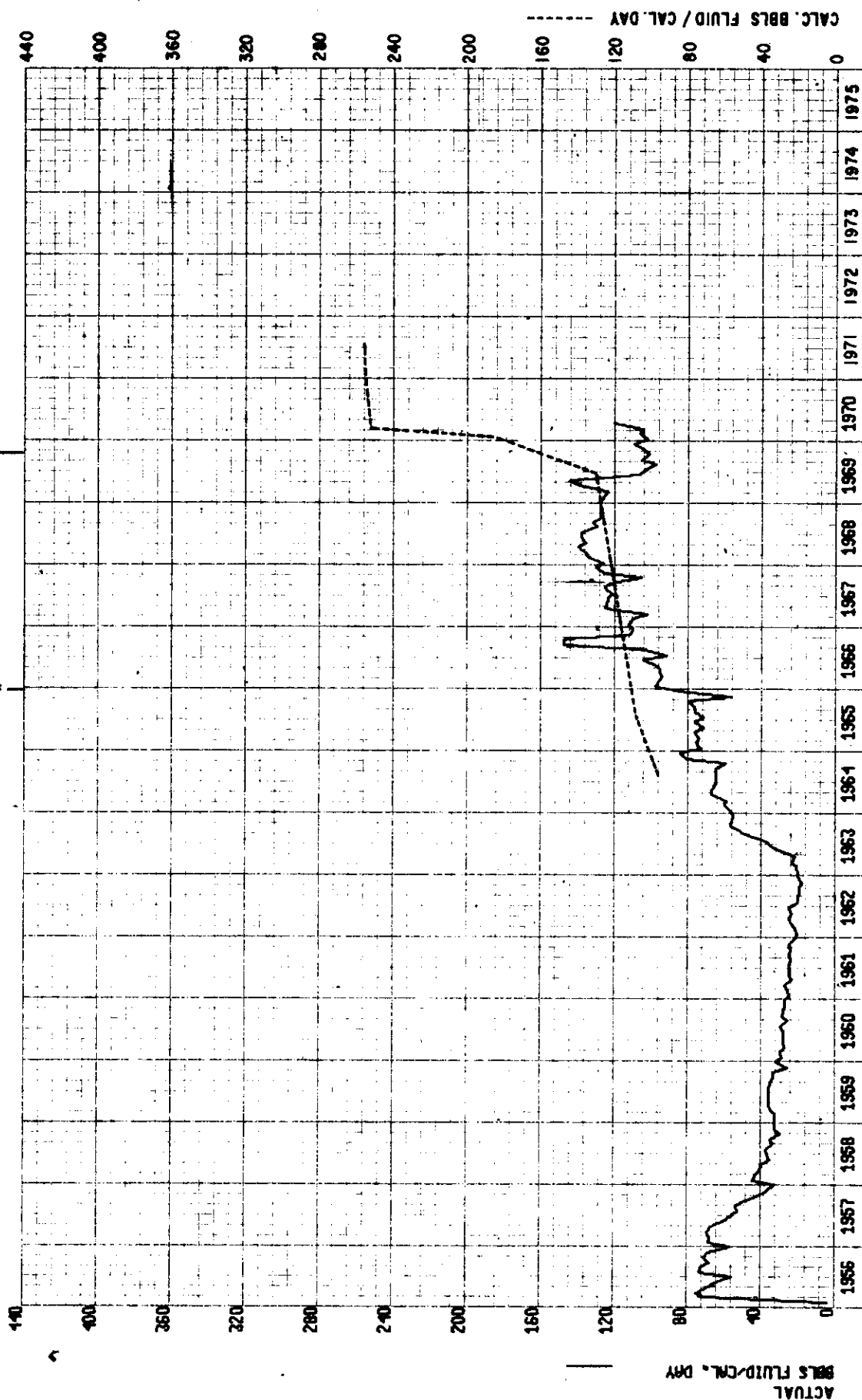
FLOOD II - CASE E RESULTS
PRESSURE SOLUTION AT
2400 DAYS



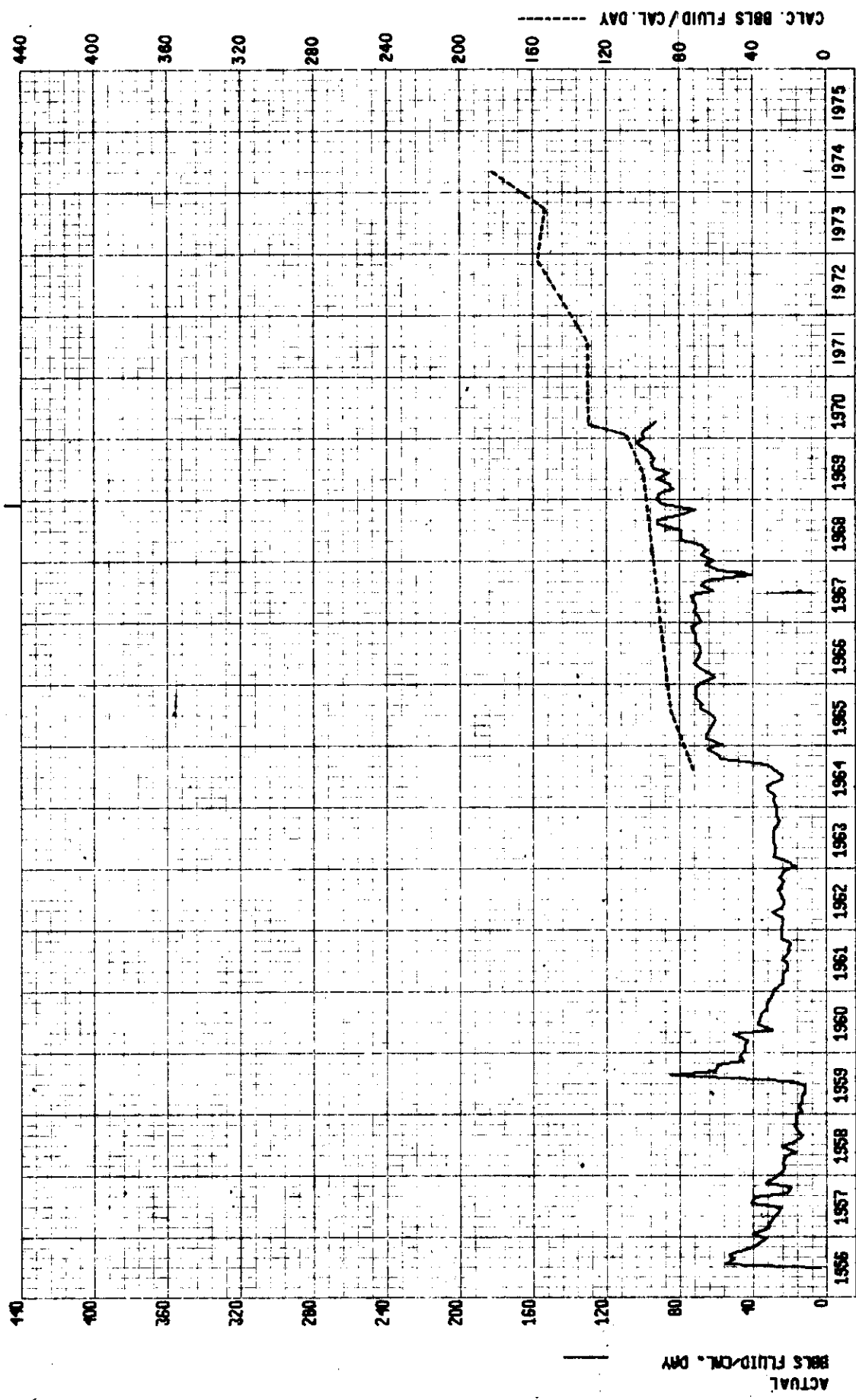
N.V. SCALLION FIELD 08-21-011-26-W1



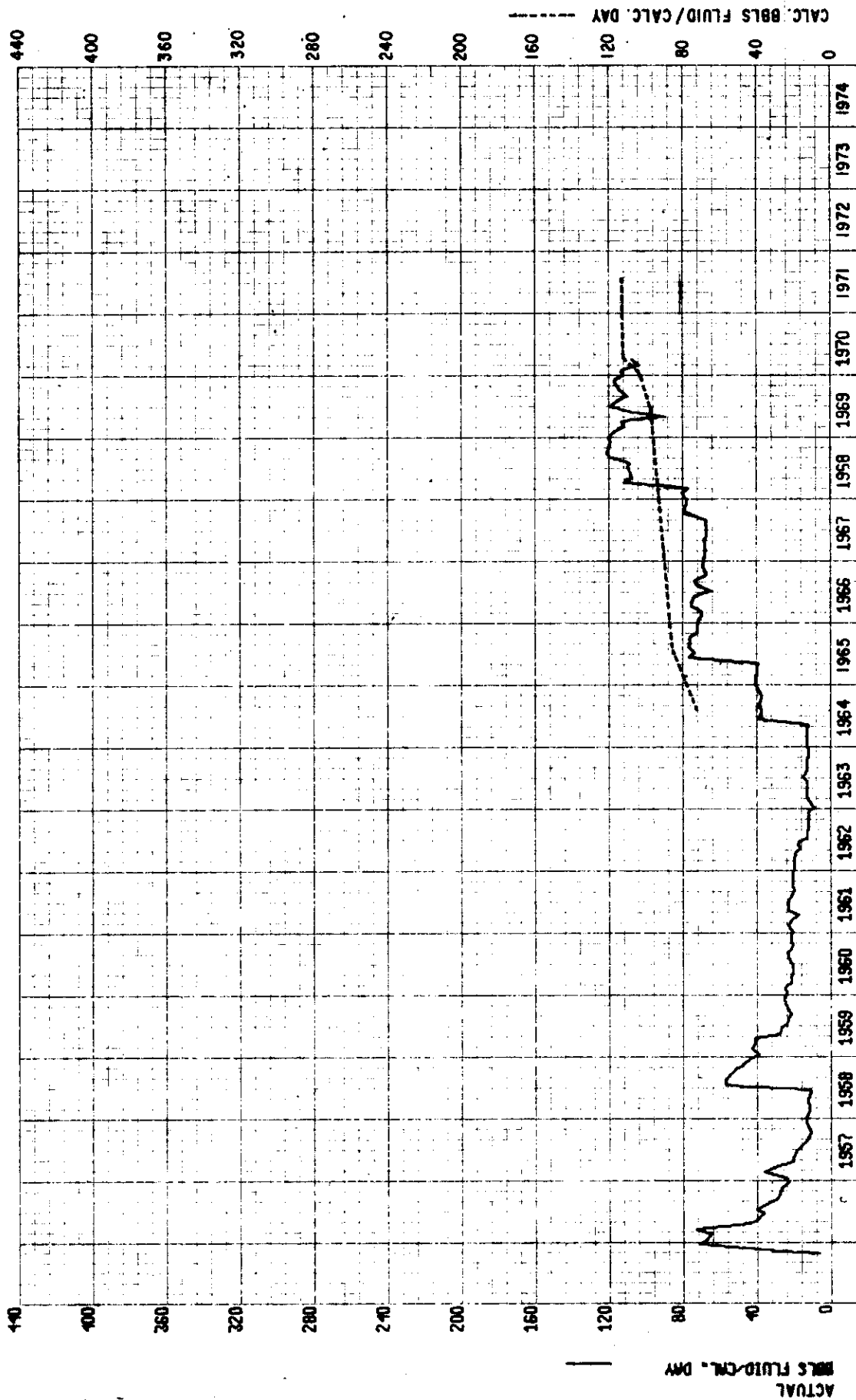
N.V. SCALLION FIELD 16-21-011-26-W1



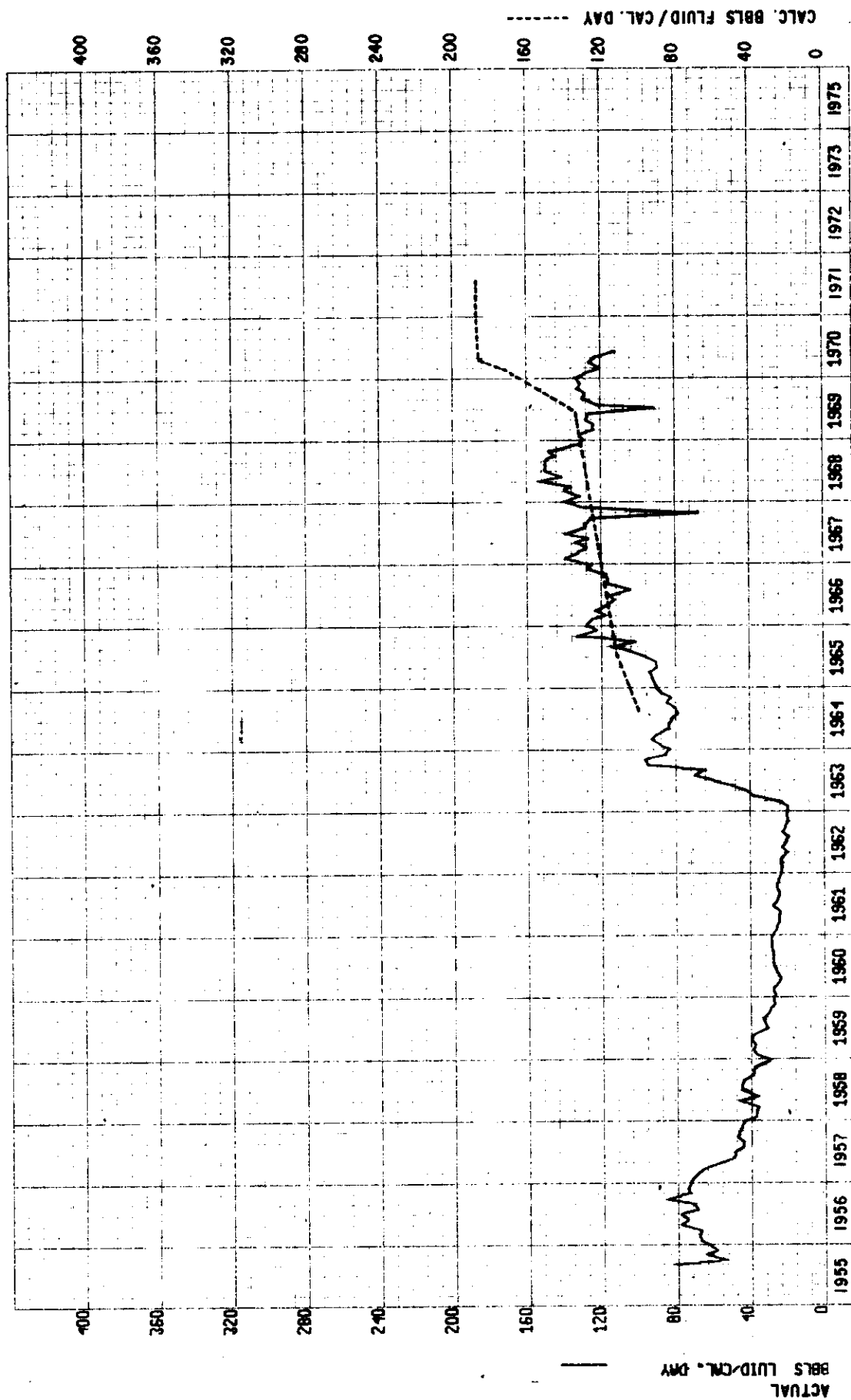
N.V. SCALLION FIELD 08-22-011-26-W1



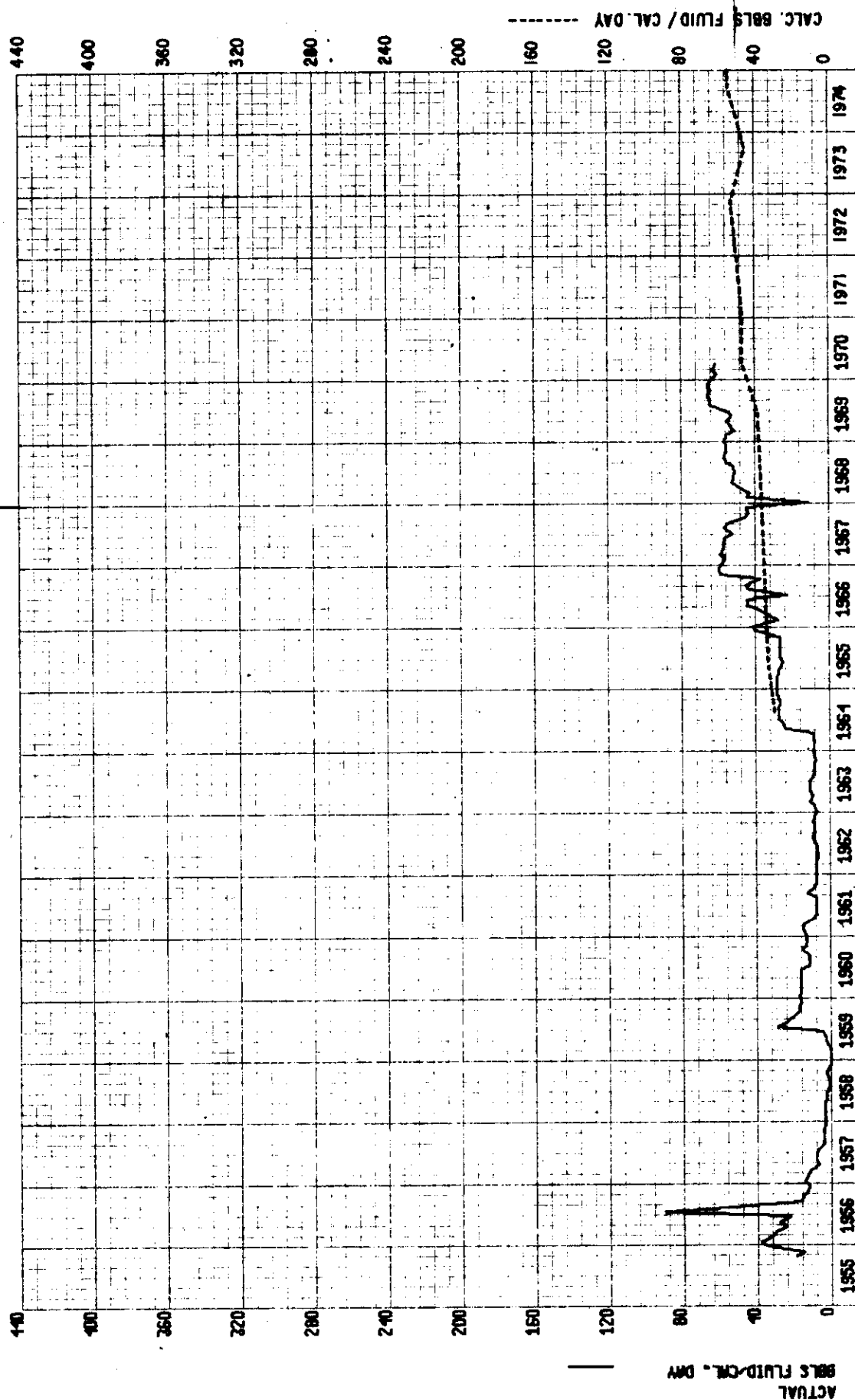
N.V. SCALLION FIELD 09-22-011-26-W1



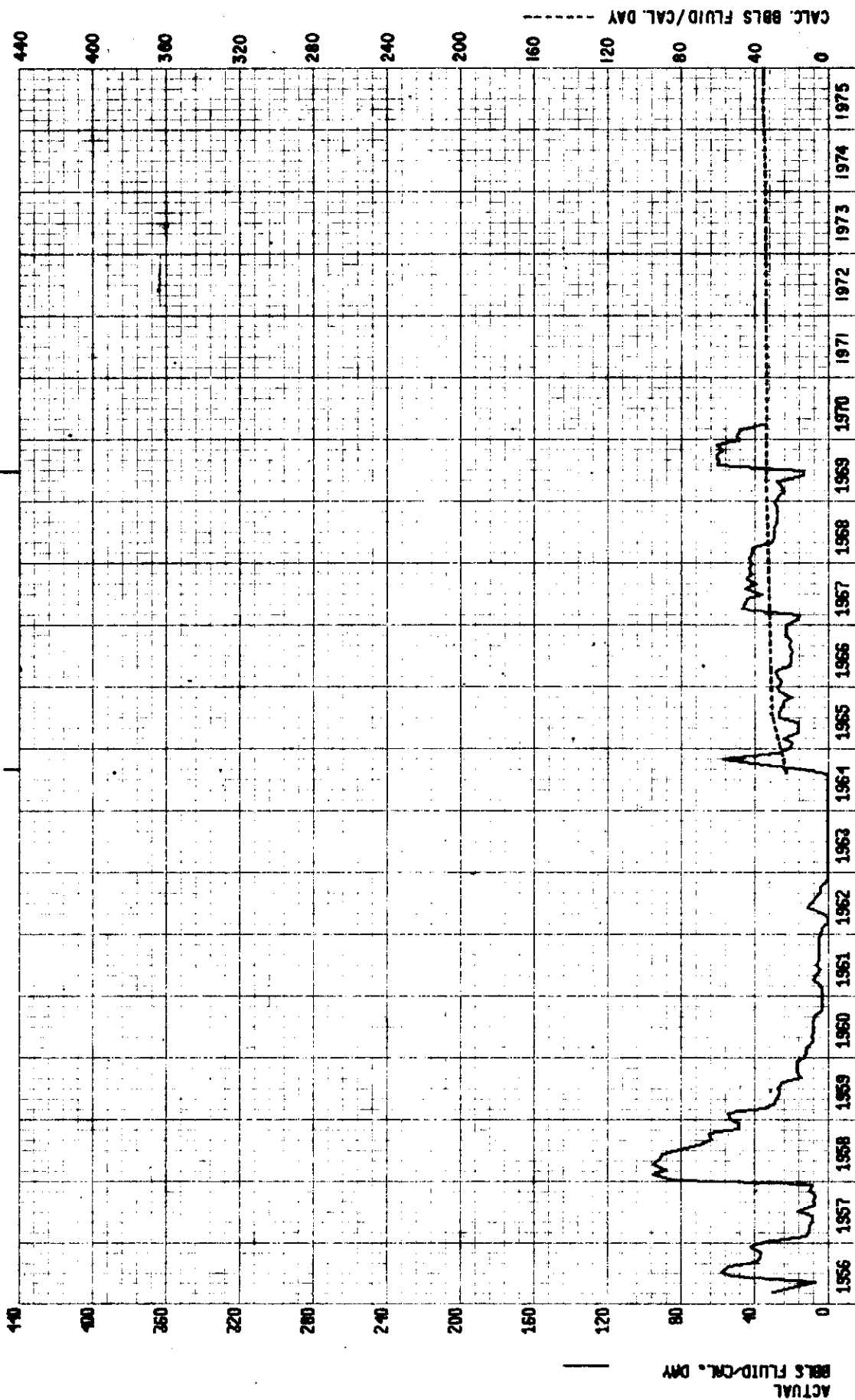
N.V. SCALLION FIELD 13-22-011-26-W1



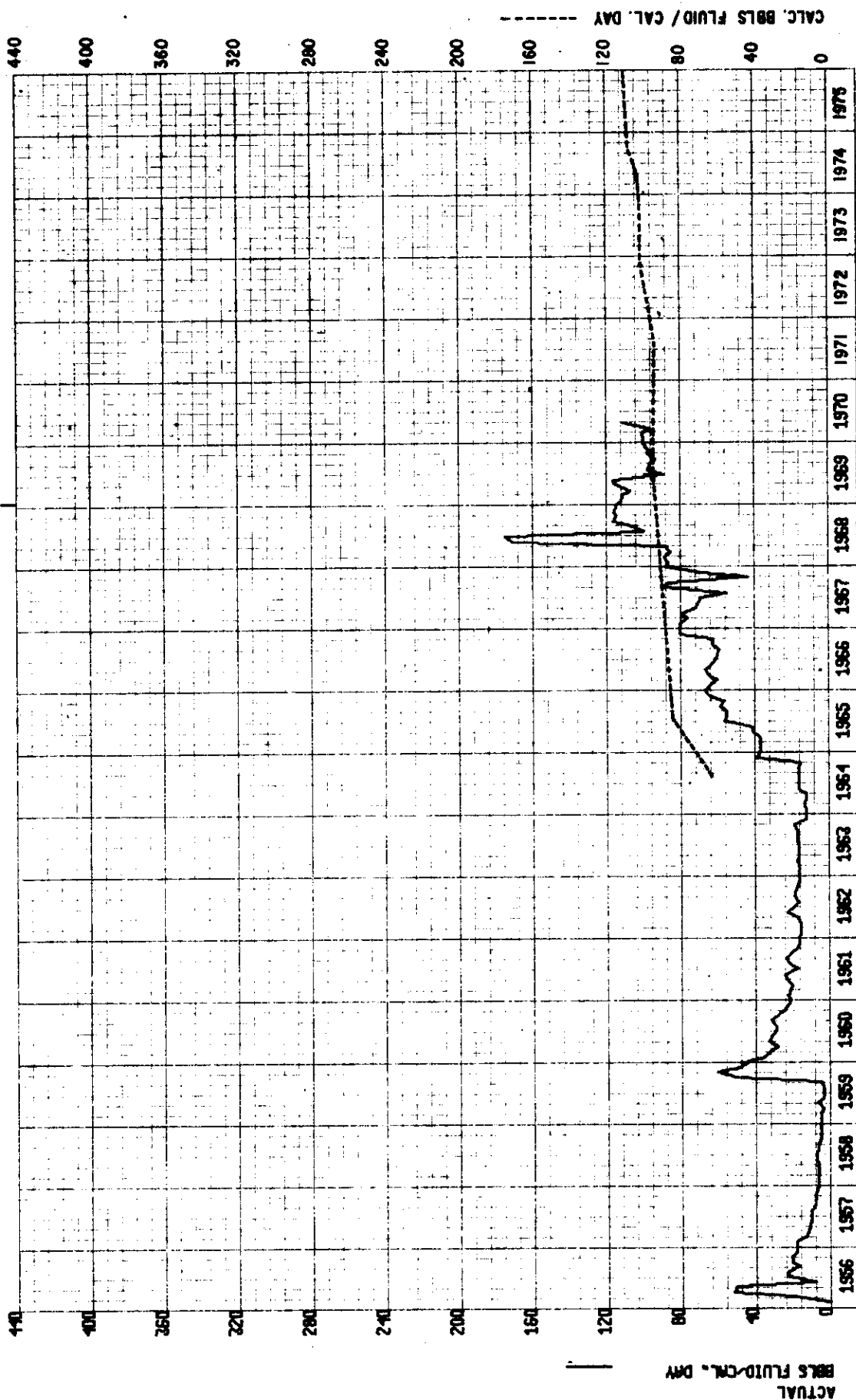
N. U. SCALLION FIELD 15-22-011-26-W1



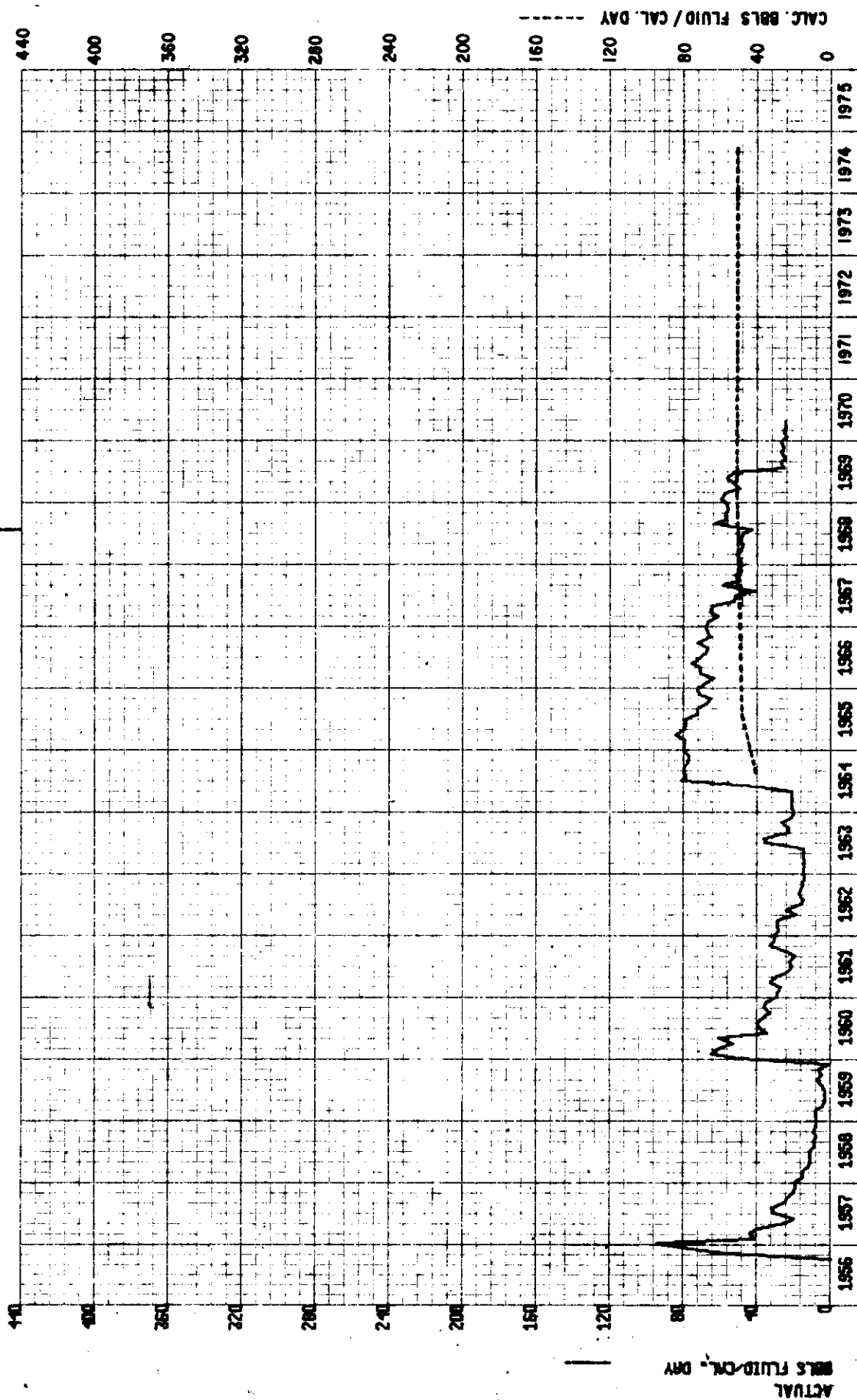
N.U. SCALLION FIELD 11-23-011-26-W1



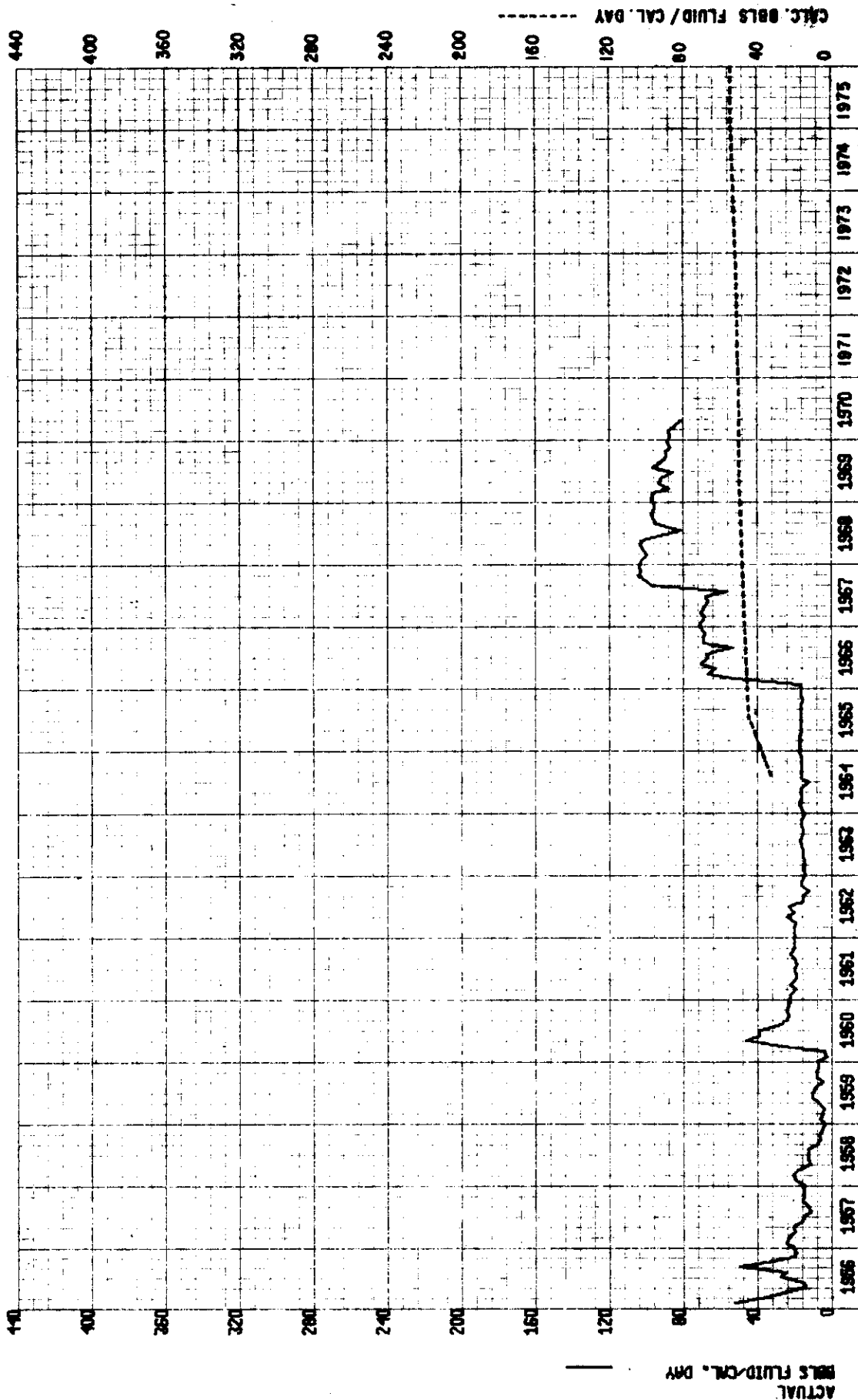
N.V. SCALLION FIELD 13-23-011-26-U1



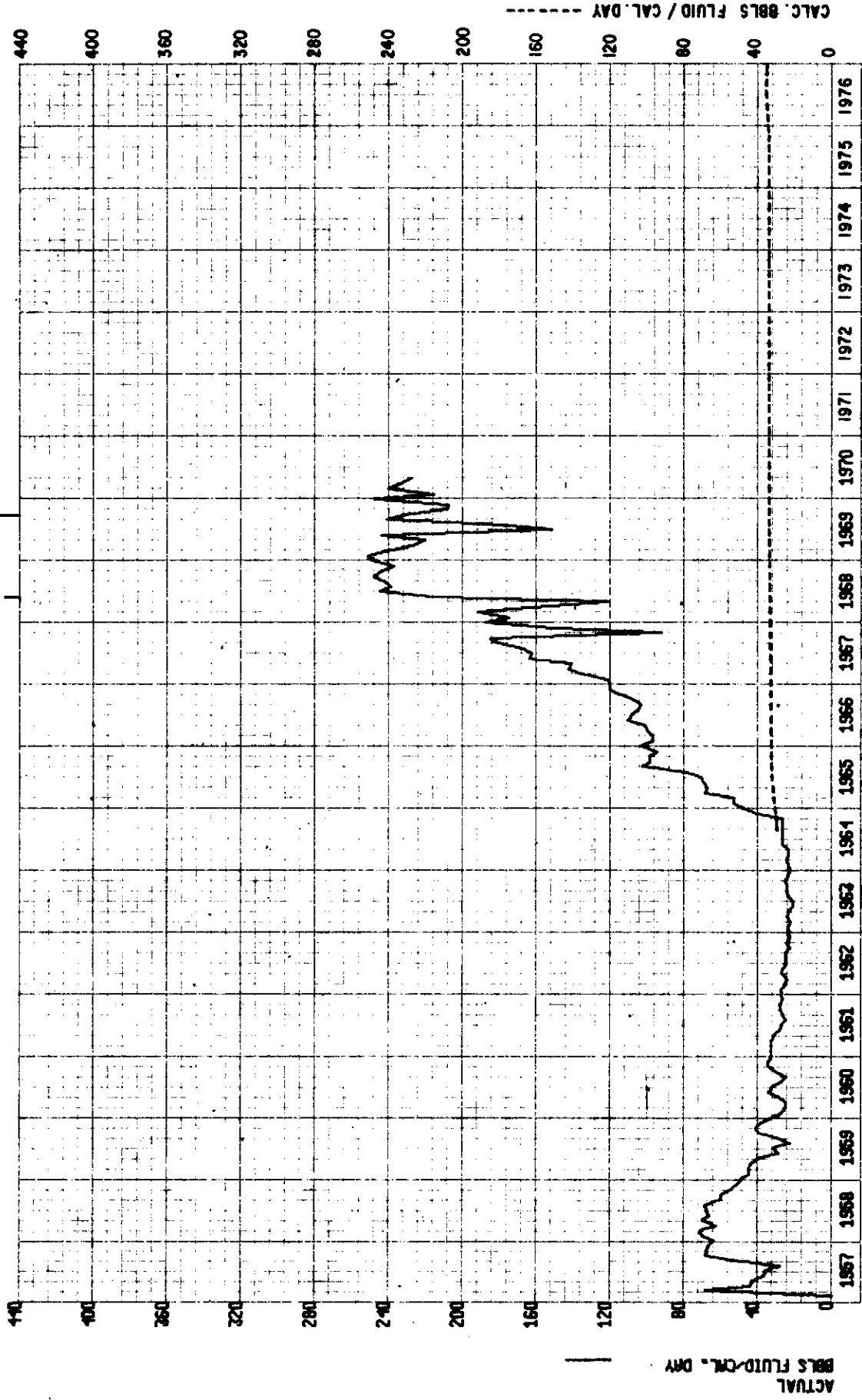
N.V. SCALLION FIELD 15-23-011-26-W1



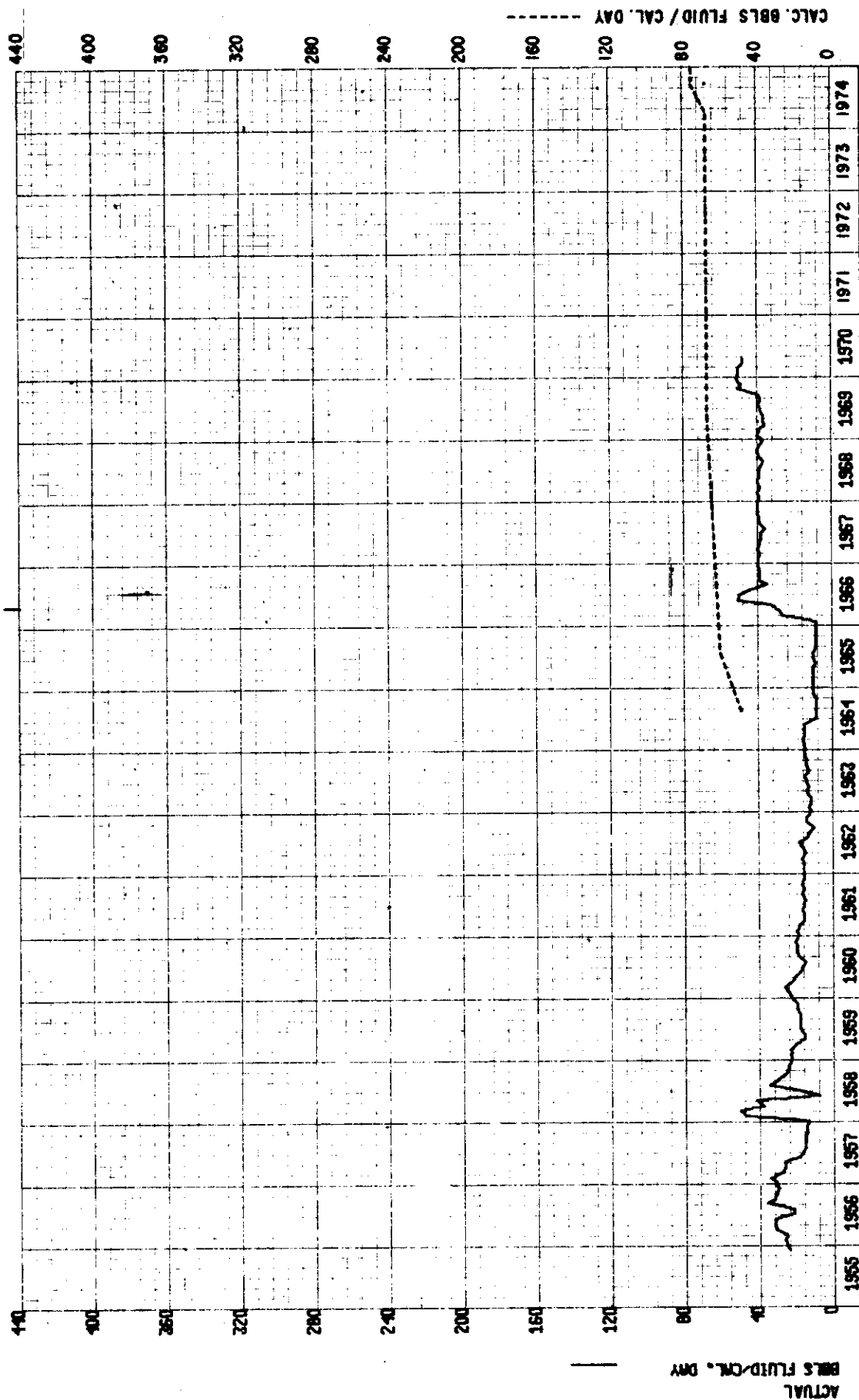
N.V. SCALLION FIELD 04-26-011-26-W1



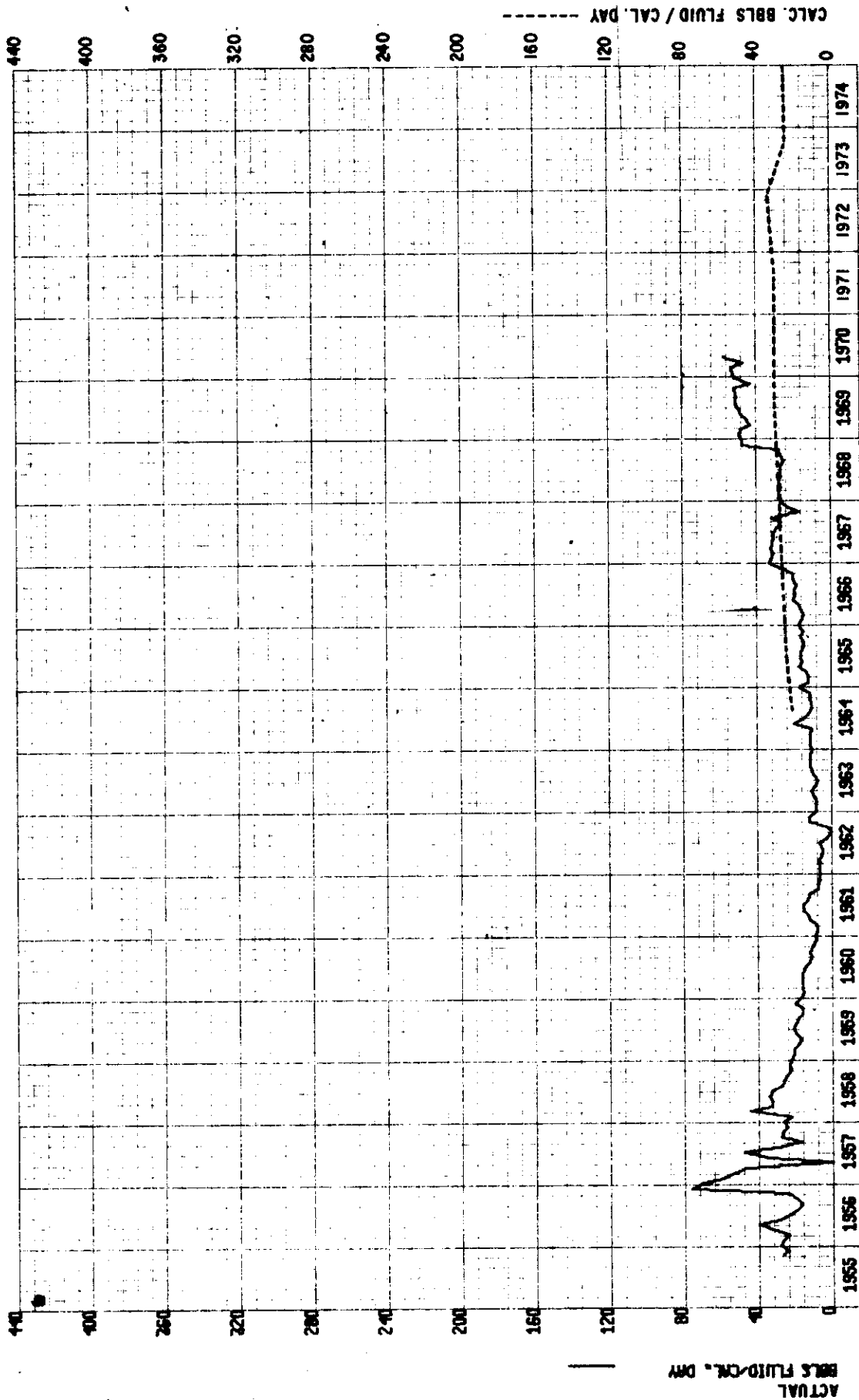
N.V. SCALLION FIELD 07-26-011-26-W1



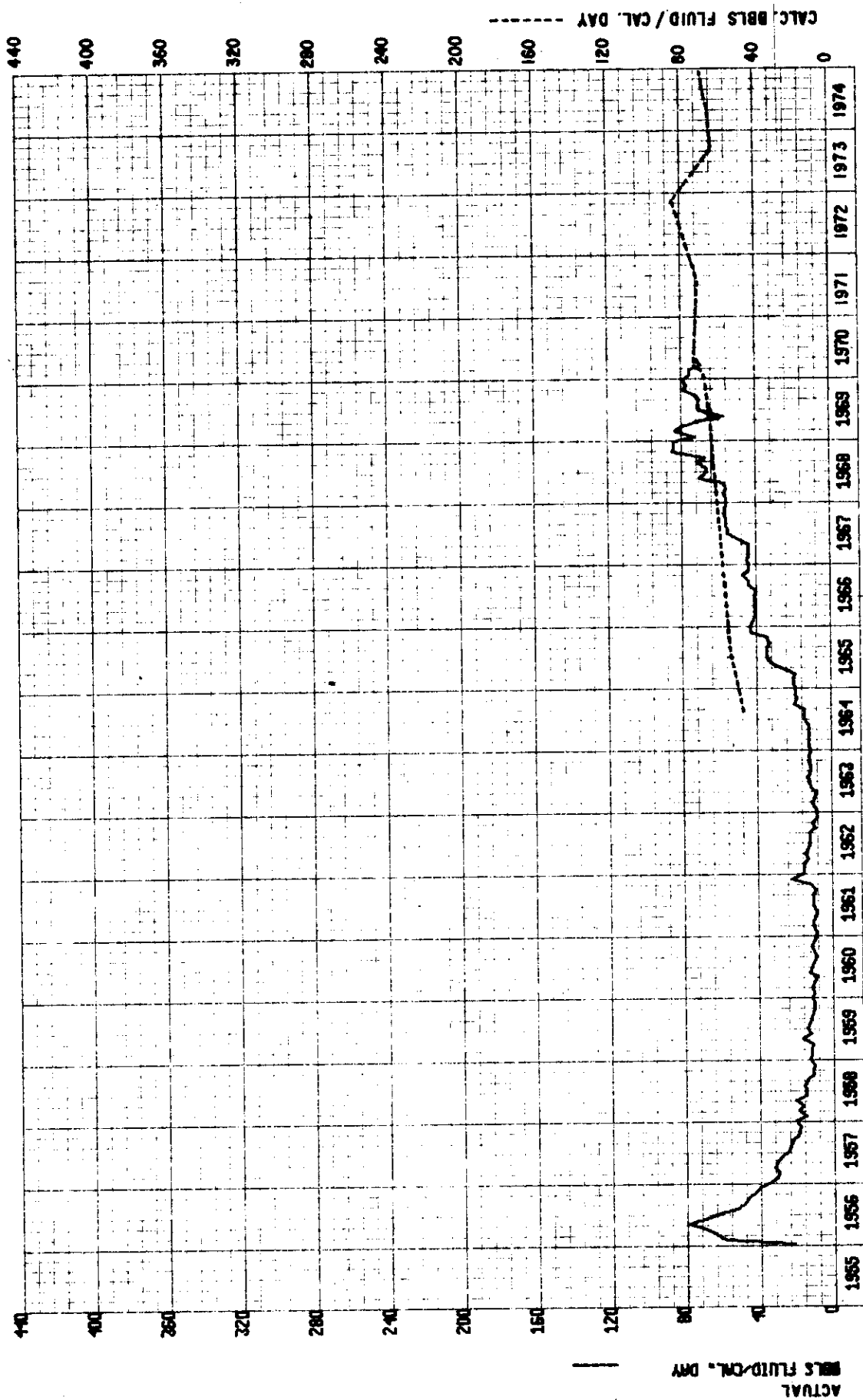
N.V. SCALLION FIELD 01-27-011-26-W1



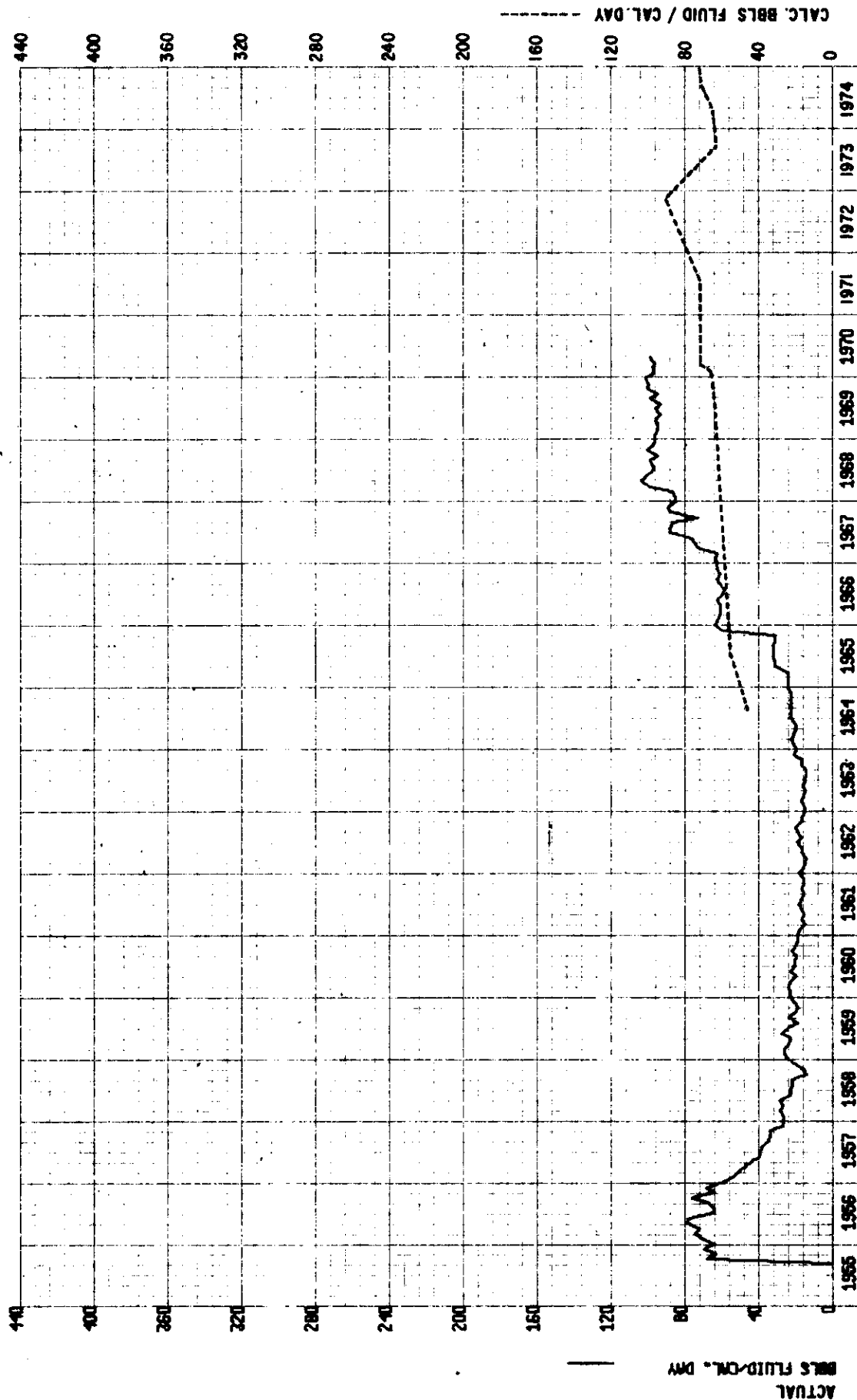
N.V. SCALLION FIELD 02-27-011-26-W1



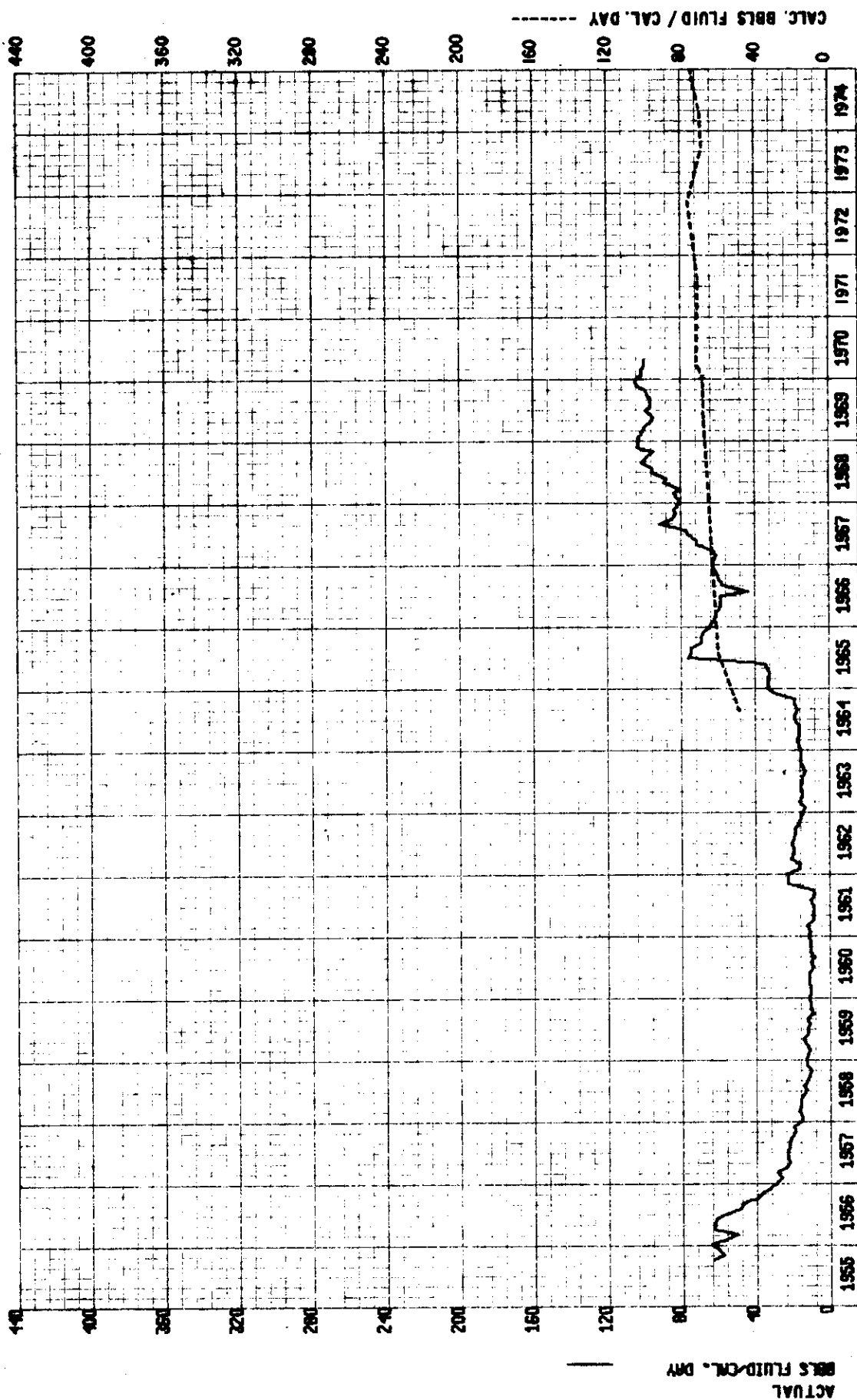
N.V. SCALLION FIELD
03-27-011-26-W1



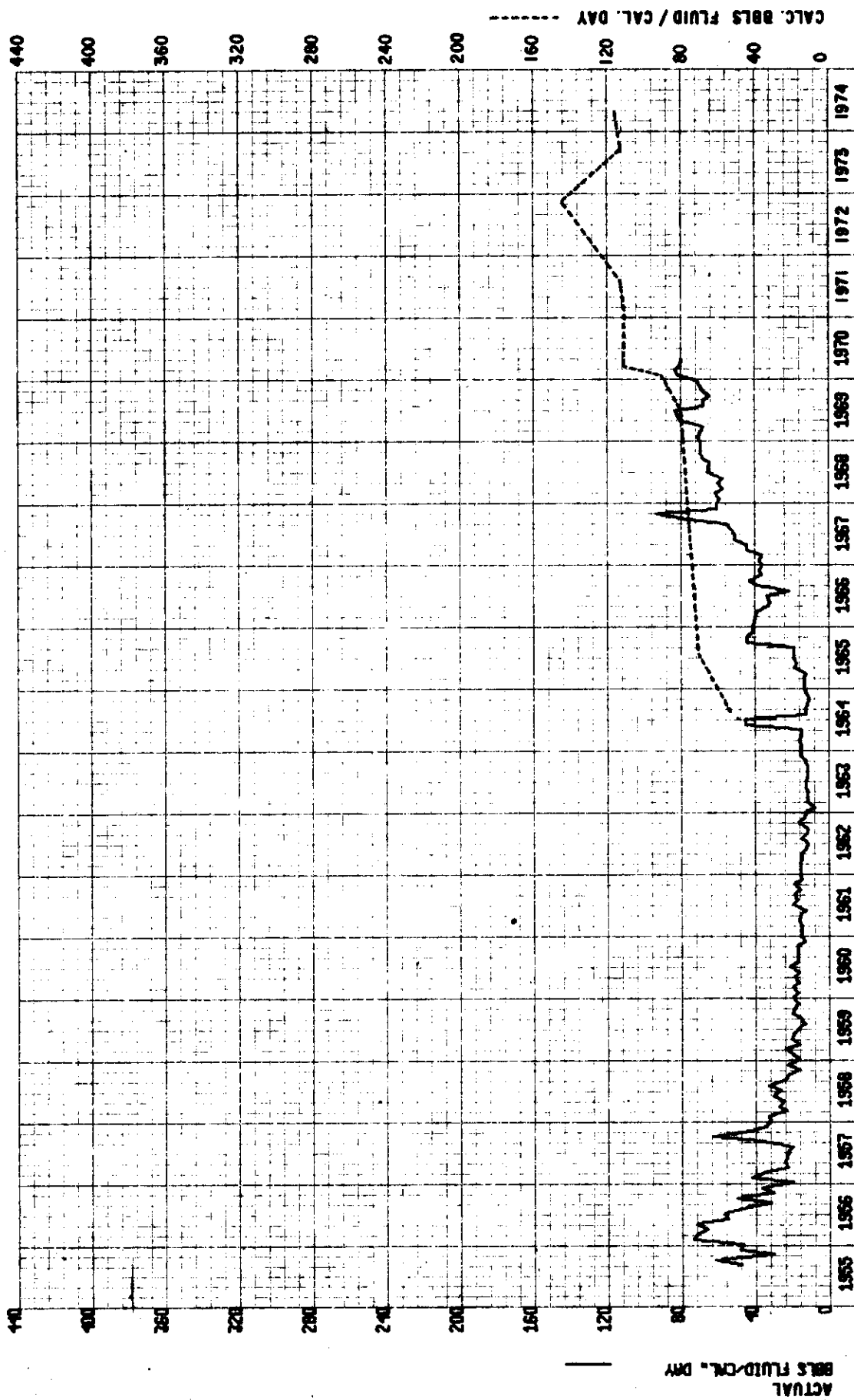
N.V. SCALLION FIELD
04-27-011-26-W1



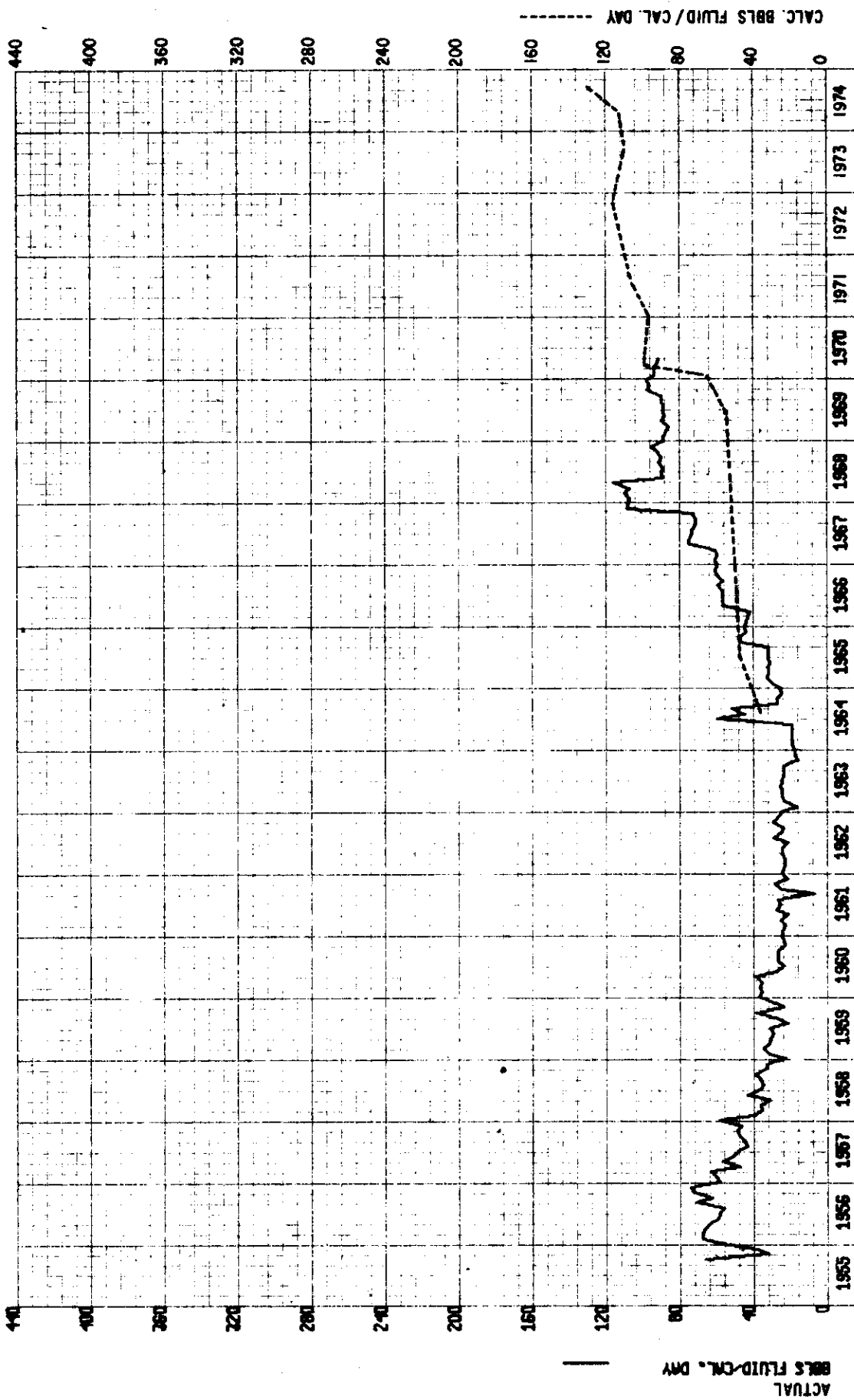
N.V. SCALLION FIELD 05-27-011-26-U1



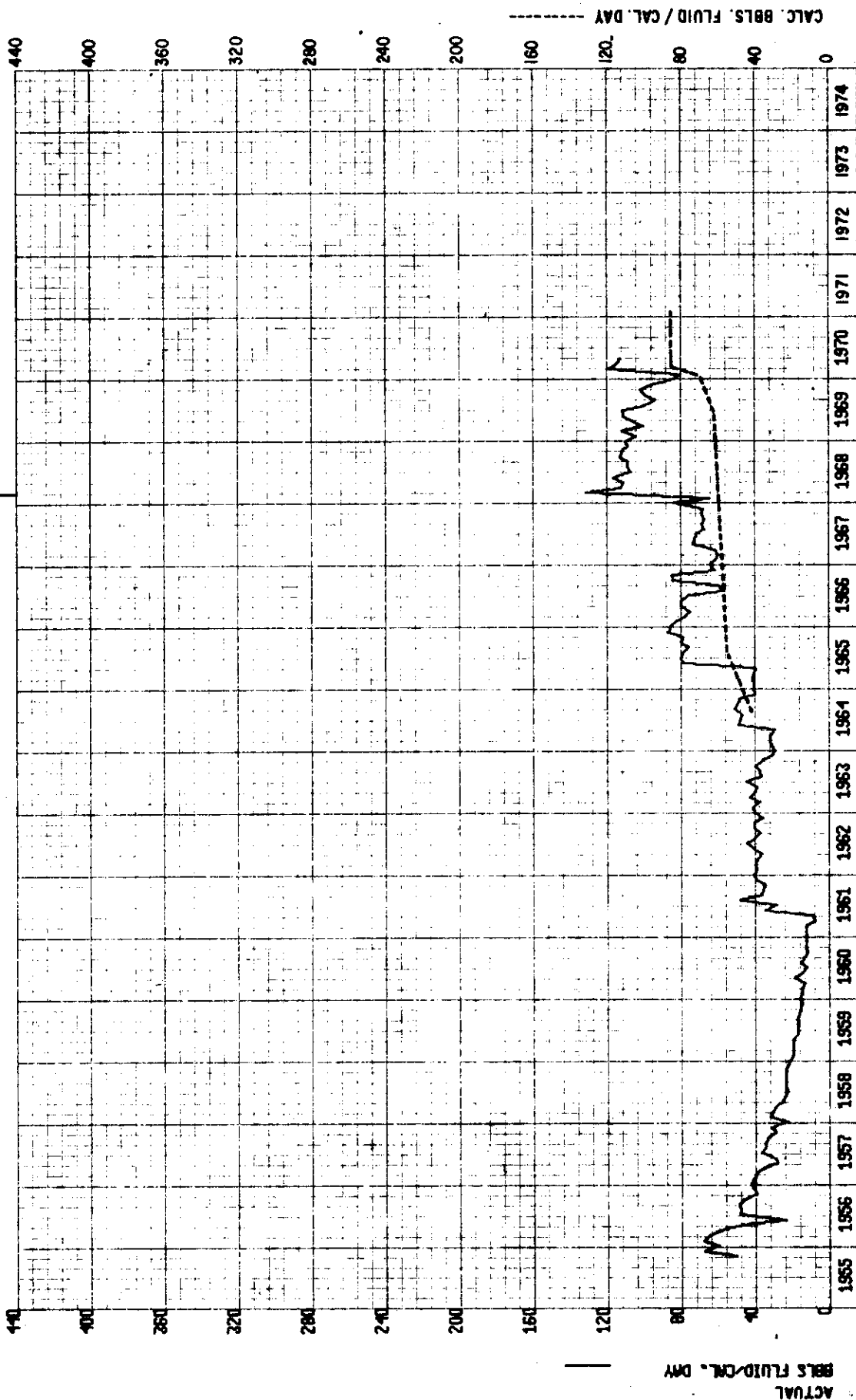
N.V. SCALLION FIELD 01-28-011-26-W1



N.V. SCALLION FIELD 02-28-011-26-W1



N.V. SCALLION FIELD 03-28-011-26-W1



N.V. SCALLION FIELD 10-28-011-26-W1

