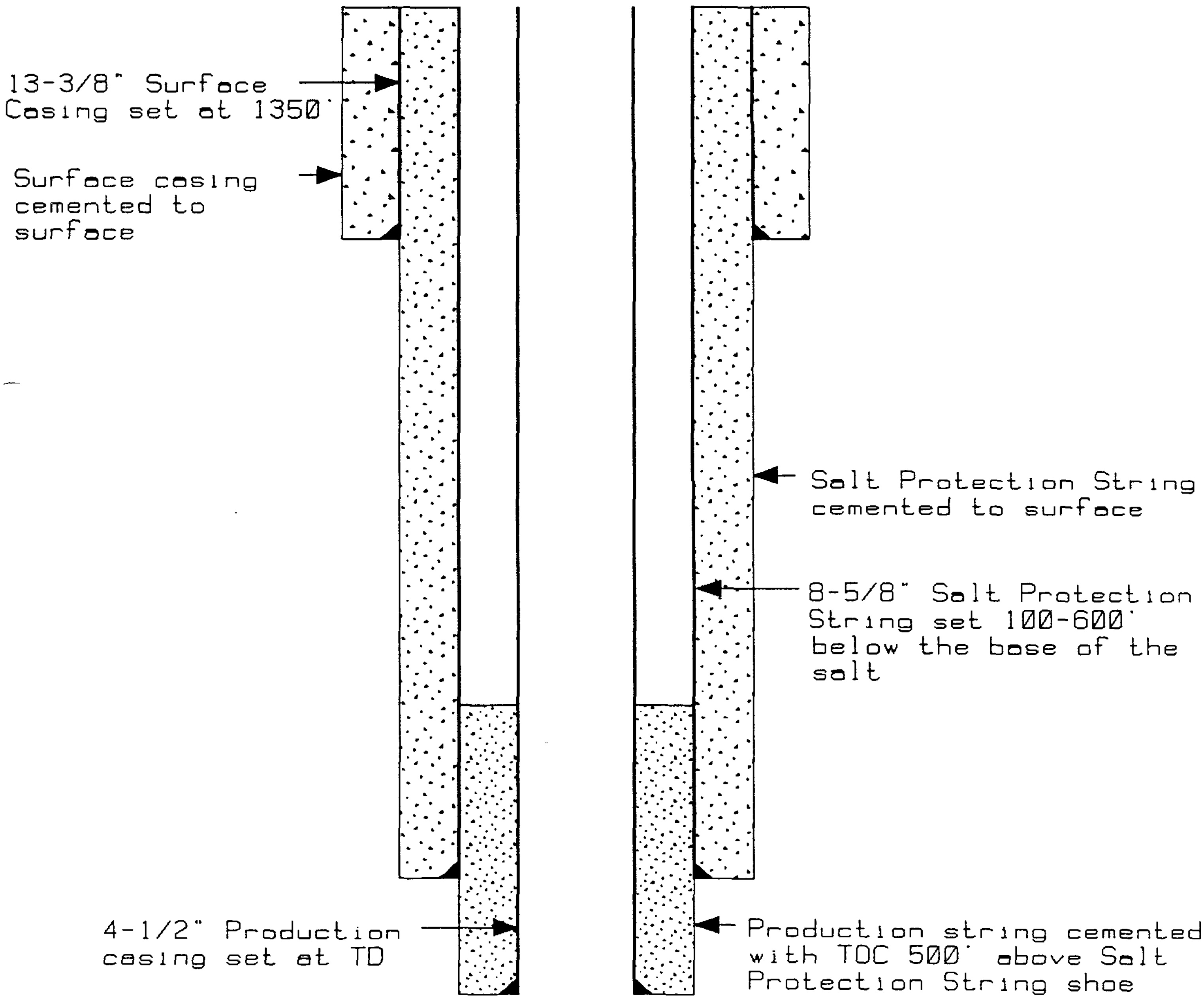
Wellbore Schematic

Salt Protection String in Place



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WELLBORE SCHEMATIC

OPTIONAL REMOVABLE SALT PROTECTION STRING

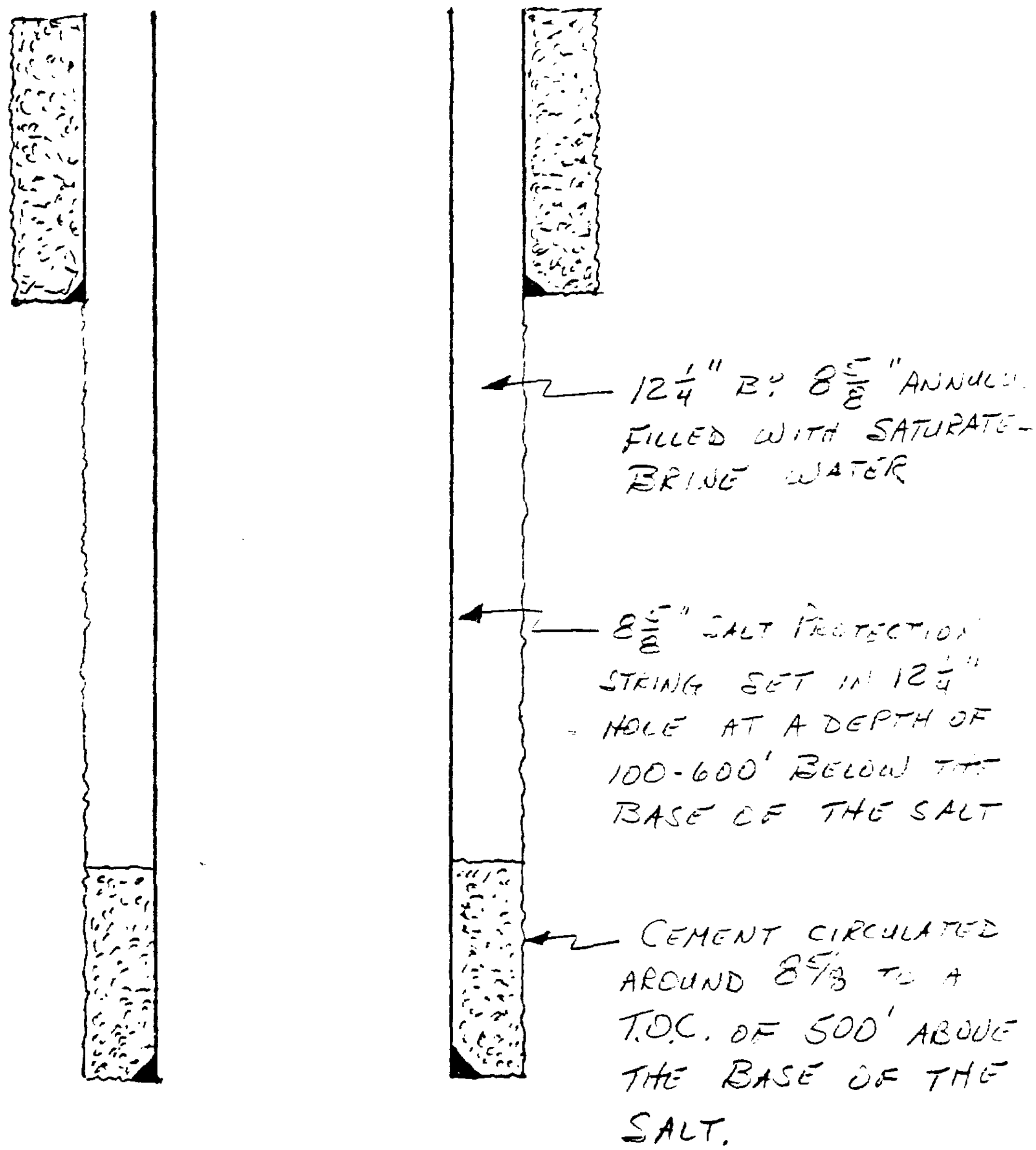

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FIGURE A-1

WELLBORE SCHEMATIC

SALT PROTECTION STRING REMOVED AT TD

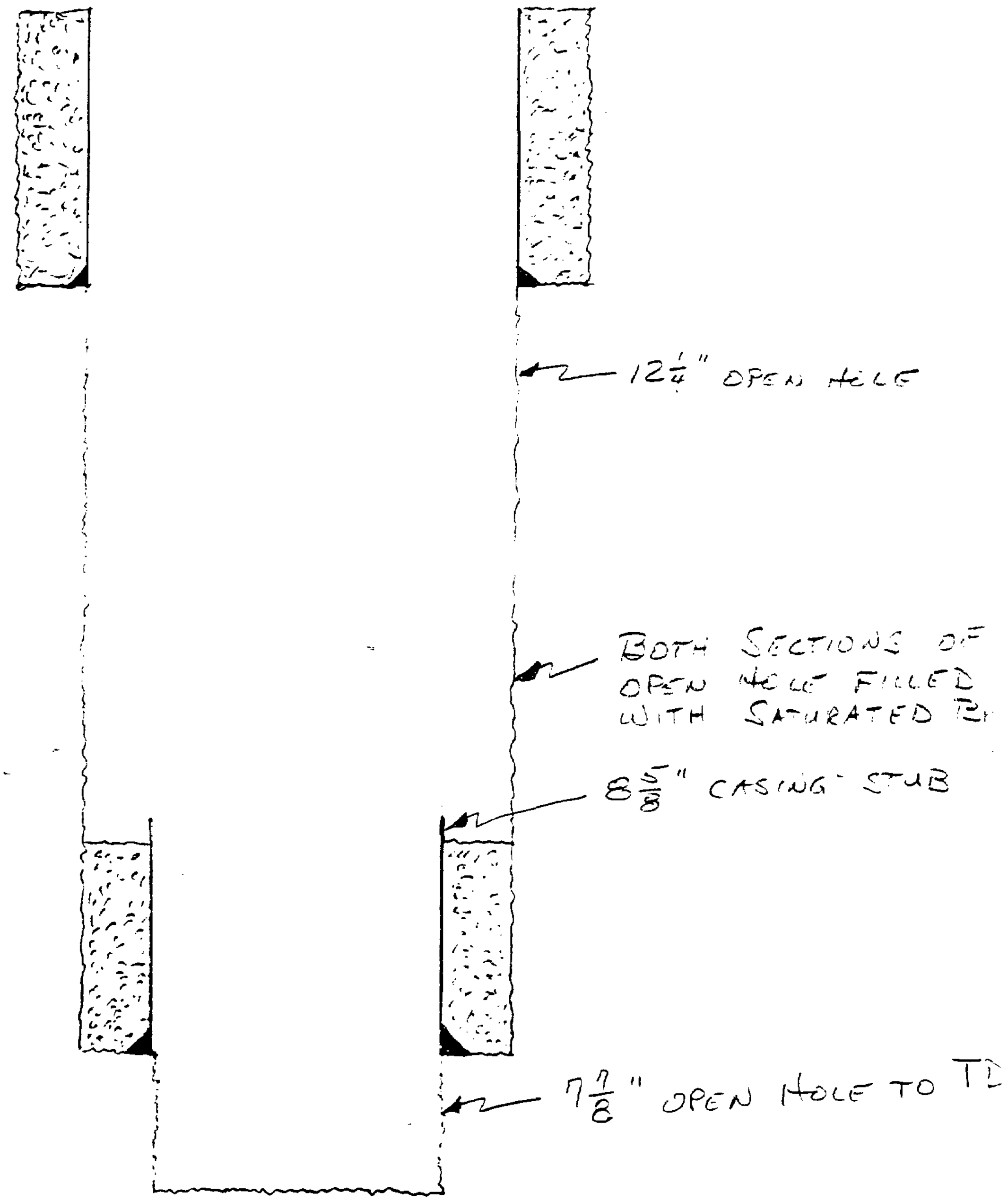

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FIGURE A-2

WELLBORE SCHEMATIC

$4\frac{1}{2}$" PRODUCTION STRING CEMENTED TO SURFACE

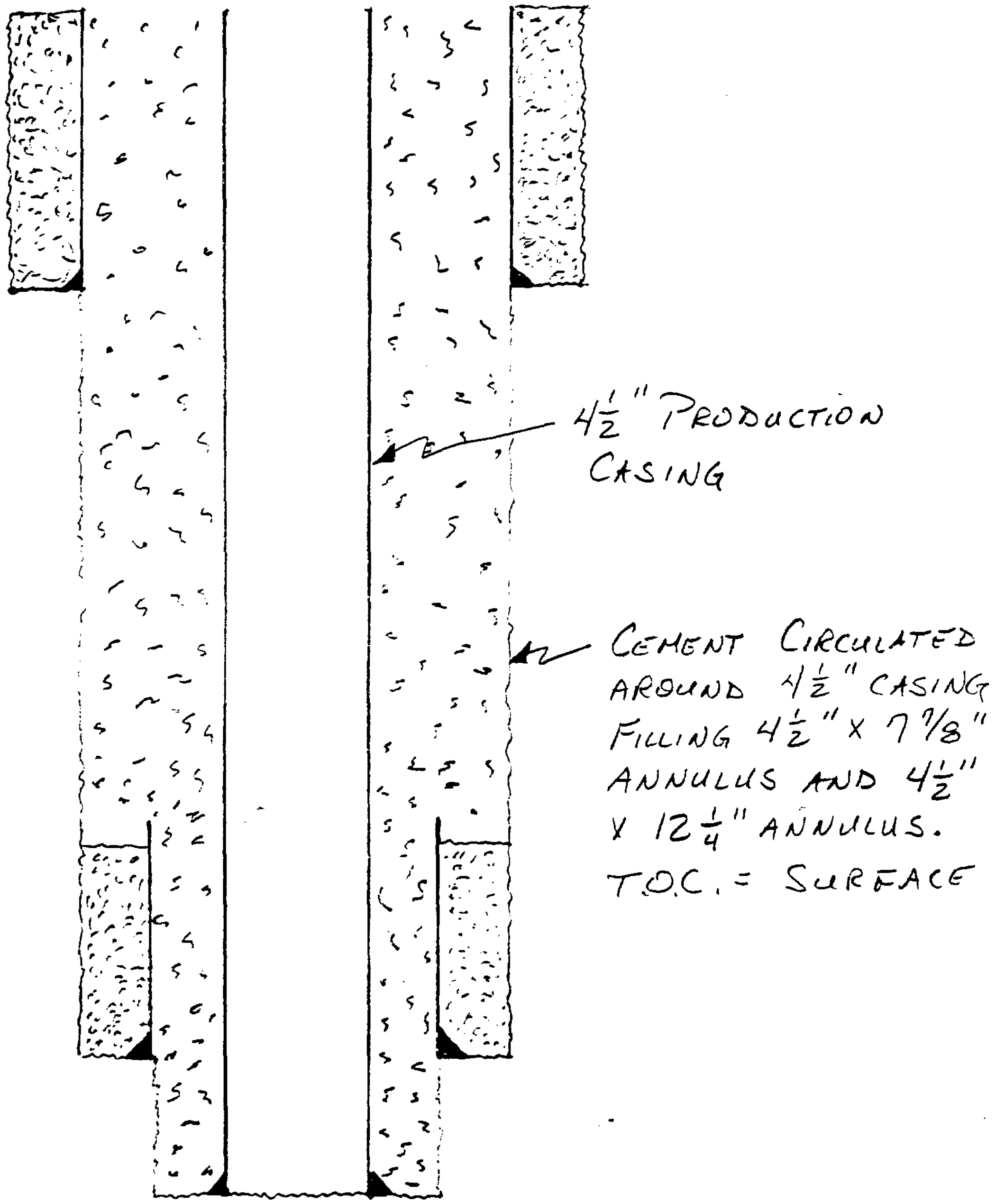

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FIGURE A-3

Wellbore Schematic

First Stage Cement In Place

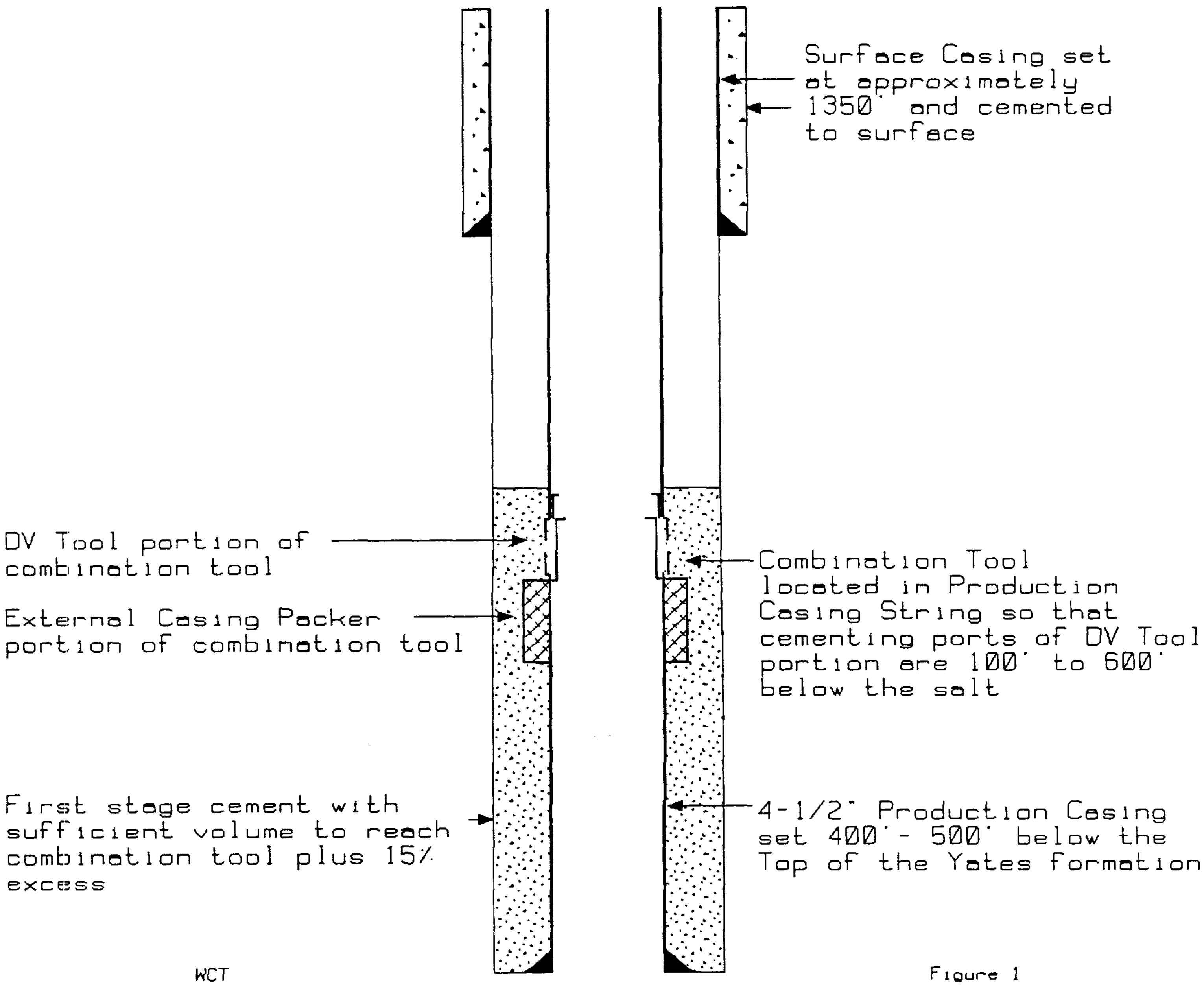

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Figure 1

Type 778-100 Packer Stage Cementing Collar*

This widely accepted Davis product combines an inflatable packer and a stage cementing collar into a singular unit. The stage collar portion of this tool uses the same sleeve and mechanical systems as the field-proven Davis Type 778 Stage Cementing Collar.

The packer portion of this tool uses the same element design as the field-proven Davis Type 100 Integral Casing Packer. This element consists of an innertube housed and protected by continuous, mechanically end-anchored, spring-steel reinforcing strips that are leafed on top of each other. These strips are encased in an oil-resistant outer rubber. Expansion is obtained by injecting fluid into the innertube. This injection forces partial un-leafing of the steel strips which in turn stretches the outer rubber until it effects a full-length seal against the bore it is run in, whether cased or open hole.

While the packer is expanding, the bottom end of the element is drawn up on a ratchet-type locking mechanism. This feature is intended to keep the element mechanically expanded so it can provide some form of support in the event of hydraulic failure.

Once inflation pressure is reached, simultaneous sealing of the fluid injection inlets and opening of the cementing ports occurs. This action allows the immediate introduction of fluid to the annulus after the packer is set. The inflation of the packer also serves to center the tool in the wellbore, leading to uniform distribution of cement as it exits the casing.

Although the combination packer stage collar serves two purposes, it is only one tool. This means that it can be serviced by one person, which eliminates the cost of the second person who would be required if a stage collar and inflatable packer were individually purchased from two separate companies.

The Davis Type 778-100 Packer Stage Cementing Collar has multiple applications. It can be used to:

- Keep the hydrostatic head of second-stage cement off first-stage cement.
- Keep the hydrostatic head of second-stage cement off pressure sensitive zones below it.
- Keep cement from falling around pre-drilled or slotted liners.
- Selectively place cement across widely separated zones of interest.
- Prevent gas migration that can ruin primary cement jobs and lead to annular gas problems at the surface and expensive squeeze work.

Davis Packer Stage Cementing Collar Type 778-100

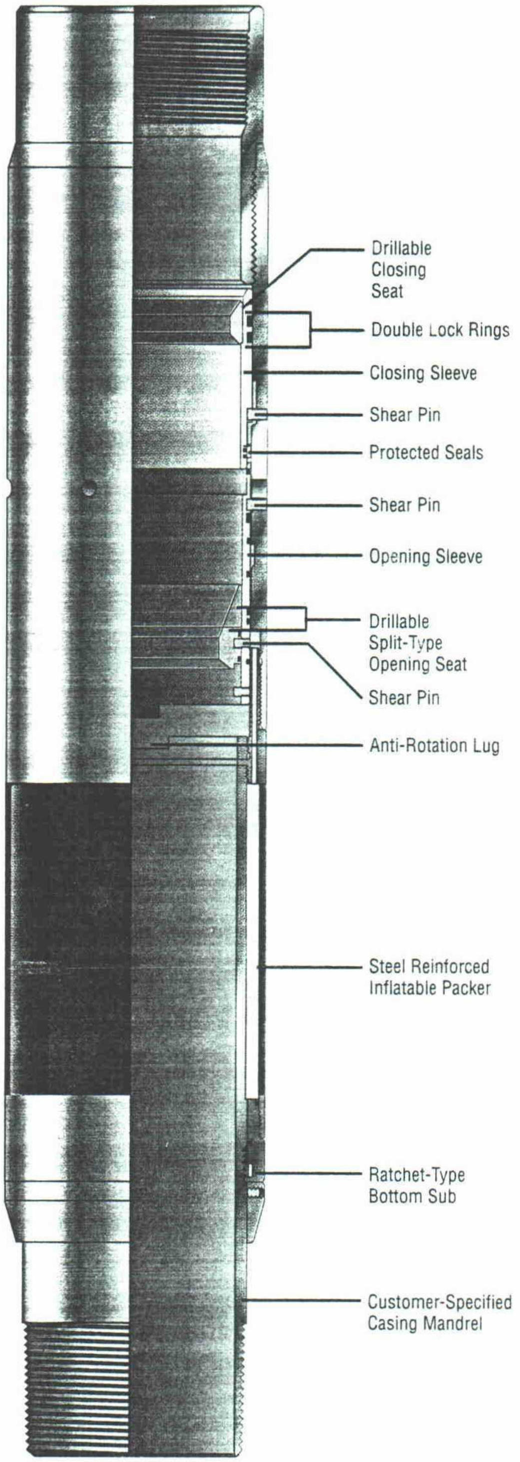
Nominal Casing Size (Inches)	Type Number 778-100-	Weight Range (Lbs.)	Drillout I.D. (Inches)	Maximum Diameter (Inches)	Opening		Closing		Opening Seat I.D. (Inches)	Closing Seat I.D. (Inches)	Maximum Recommended Differential Pressure (PSI) Across Packer in Various Hole Sizes (In.)						
					Pressure (PSI)	Force (Lbs.)	Pressure (PSI)	Force (Lbs.)			1000	1500	2000	2500	3000	3500	4000
4½	450-575	9.5-13.5	3.950	5¾	1200	21,000	1500	26,000	2.750	3.125	10¾	10¼	9¾	9¼	8¾	8¼	7¾
5	500-638	11.5-15.0	4.300	6⅜	1500	33,000	1500	33,000	2.750	3.250	11¼	10¾	10¼	9¾	9¼	8¾	8¼
5½	550-700	14.0-17.0 20.0-23.0	4.892 4.658	7	1500	39,000	1500	39,000	3.438	4.062	12	11½	11	10½	10	9½	9
6⅝	663-800	20.0-28.0	6.030	8	1200	45,000	1500	57,000	4.250	5.000	13	12½	12	11½	11	10½	10
7	700-825	23.0-26.0 29.0-35.0	6.276 6.200	8¼	1200	49,000	1500	62,000	4.625	5.125	13¼	12¾	12¼	11¾	11¼	10¾	10¼
7⅝	763-900	26.4-33.7	6.825	9¹⁄₁₆	1200	59,000	1500	74,000	4.750	5.500	14	13½	13	12½	12	11½	11
8⅝	863-1025	24.0-32.0	7.980	10¼	1000	64,000	1200	76,000	5.750	6.750	15¼	14¾	14¼	13¾	13¼	12¾	12¼
9⅝	963-1125	32.3-40.0 43.5-53.5	8.921 8.600	11¼	1000	78,000	1200	94,000	7.000	7.750	16¼	15¾	15¼	14¾	14¼	13¾	13¼
10¾	1075-1275	40.5-45.5 55.5-65.7	9.950 9.600	12¾	1000	100,000	1200	120,000	8.000	8.750	17¾	17¼	16¾	16¼	15¾	15¼	14¾
13⅜	1338-1575	54.5-61.0 68.0-72.0	12.515 12.415	15¾	900	133,000	1000	148,000	10.250	11.250	22¼	21¾	21¼	19¾	19¼	18¾	18¼

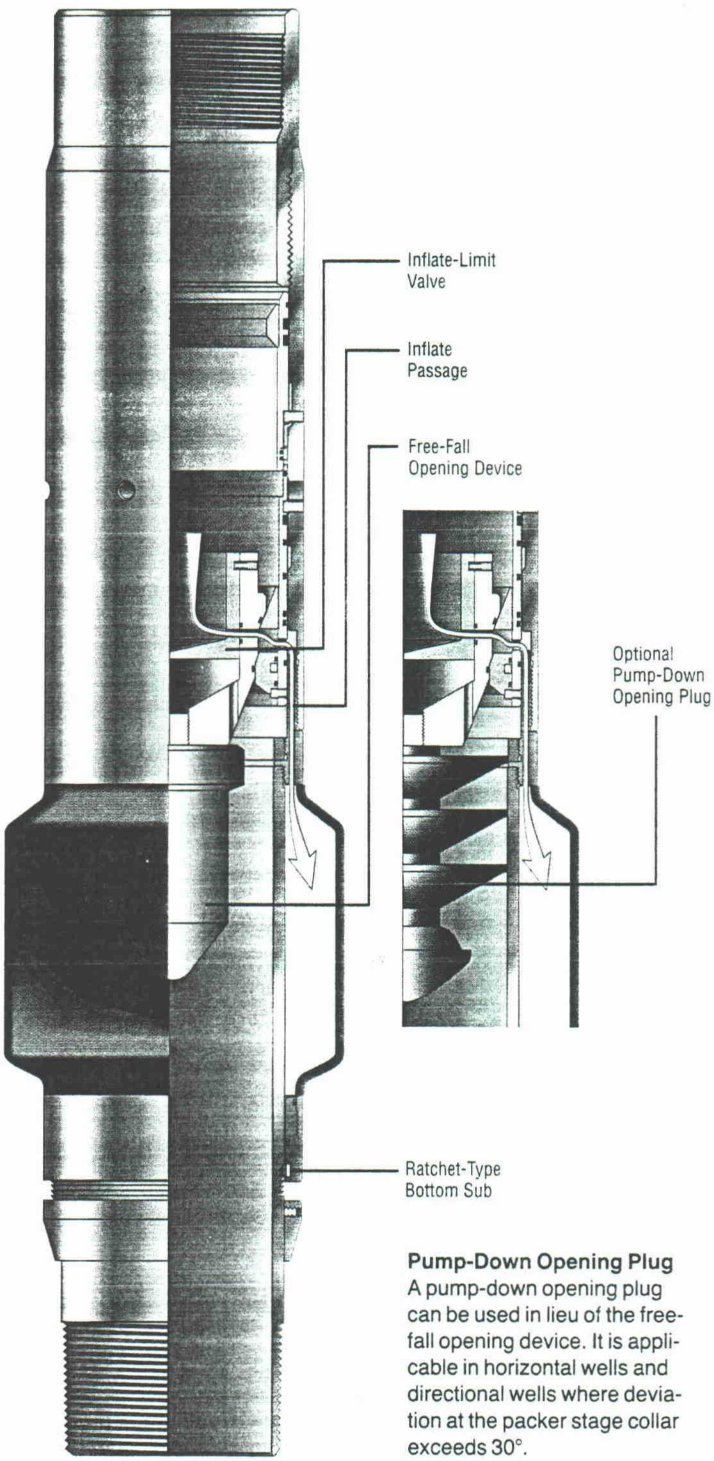
Note: Packer stage collars equipped with six cement ports. 1 1/4" diameter on sizes 7" and above and 1" diameter on smaller sizes. Standard seal length of inflatable packer elements is 36 inches. For special sizes or varying seal lengths consult your nearest Davis representative. Total length of packer stage collar is approximately 120" depending on type threads used.

With simple changes to tool IDs and plug and tripping device ODs, all three Davis stage collar designs–the mechanical, the hydraulic and the mechanical with inflatable packer, are made readily available for three-stage applications. See tables for standard sizes. Contact your Davis representative for availability of sizes not shown.

*U.S. Patent No. 5,024,273

The Type 778-100 Packer Stage Cementing Collar

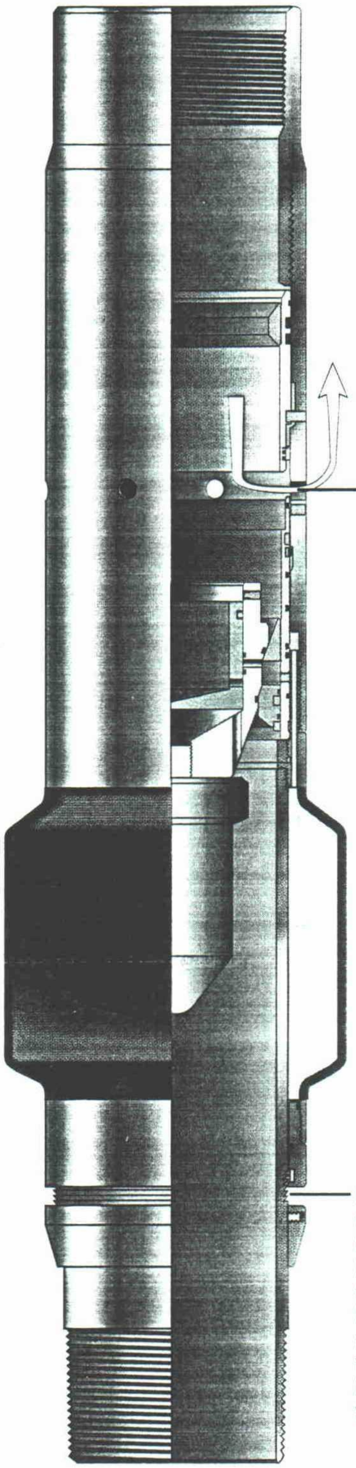


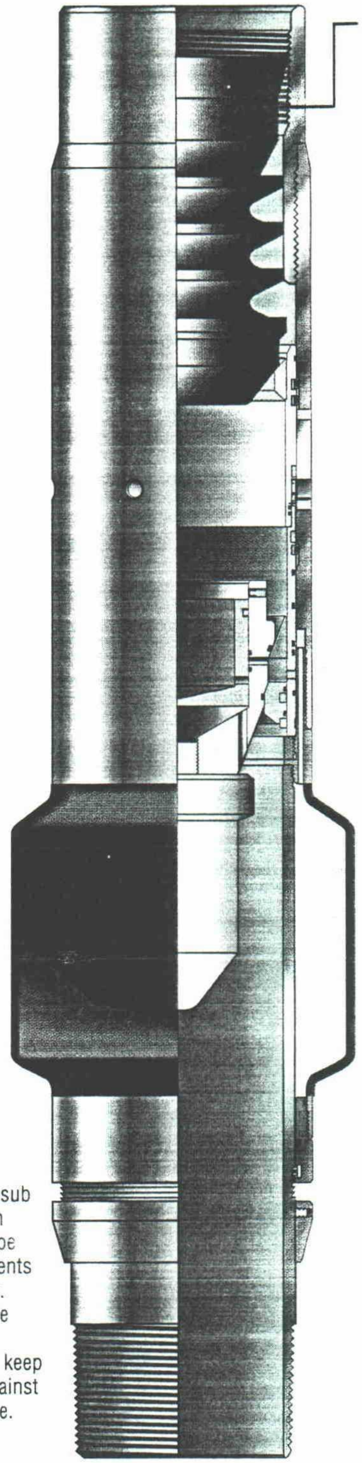


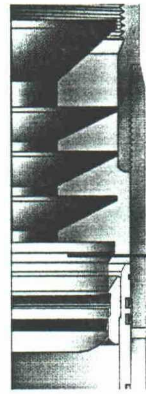
Pump-Down Opening Plug
A pump-down opening plug can be used in lieu of the free-fall opening device. It is applicable in horizontal wells and directional wells where deviation at the packer stage collar exceeds 30°.

Running in Hole
Shows packer stage cementing collar in running position with opening and closing sleeves pinned in place. Lower section of split-type opening seat isolates inflate passage preventing premature inflation of the packer.

Inflating Element
The free-fall opening device enters split-type opening seat shearing the pins in the lower section. This allows lower section to move down exposing the inflatable packer element to the fluid and pressure inside the casing. Fluid enters the packer element through the double-seal in the free-fall opening device and the split-type opening seat and inflation passage in the tool body.







Lock-Down Closing Plug
An optional lock-down closing plug is available on sizes 4½" through 7". The plug locks into the closing seat of the tool. This feature acts as a secondary cement check and is particularly applicable when the packer stage collar is run above slotted or open-ended pre-drilled liner and the possibility of fluid flow into the casing exists.

Opening Cement Ports
With the free-fall opening device in place, pressure applied to the casing shears the pins in the opening sleeve and moves it downward to the open and locked position. This movement seals off the inflate passage and permanently traps the correct inflate pressure in the packer. The inflate-limit valve in the free-fall opening device insures that the correct inflate pressure is achieved but never exceeded when opening tool.

Closing Cement Ports
Once cement has been displaced and the closing plug seats in the closing sleeve, additional pressure is applied to the casing. This pressure shears the pins and allows the closing sleeve to travel downward to its final closed and locked position. The pressure required to do this varies with tool size and the type of job performed.

Wellbore Schematic

DISPLACING SECOND STAGE CEMENT

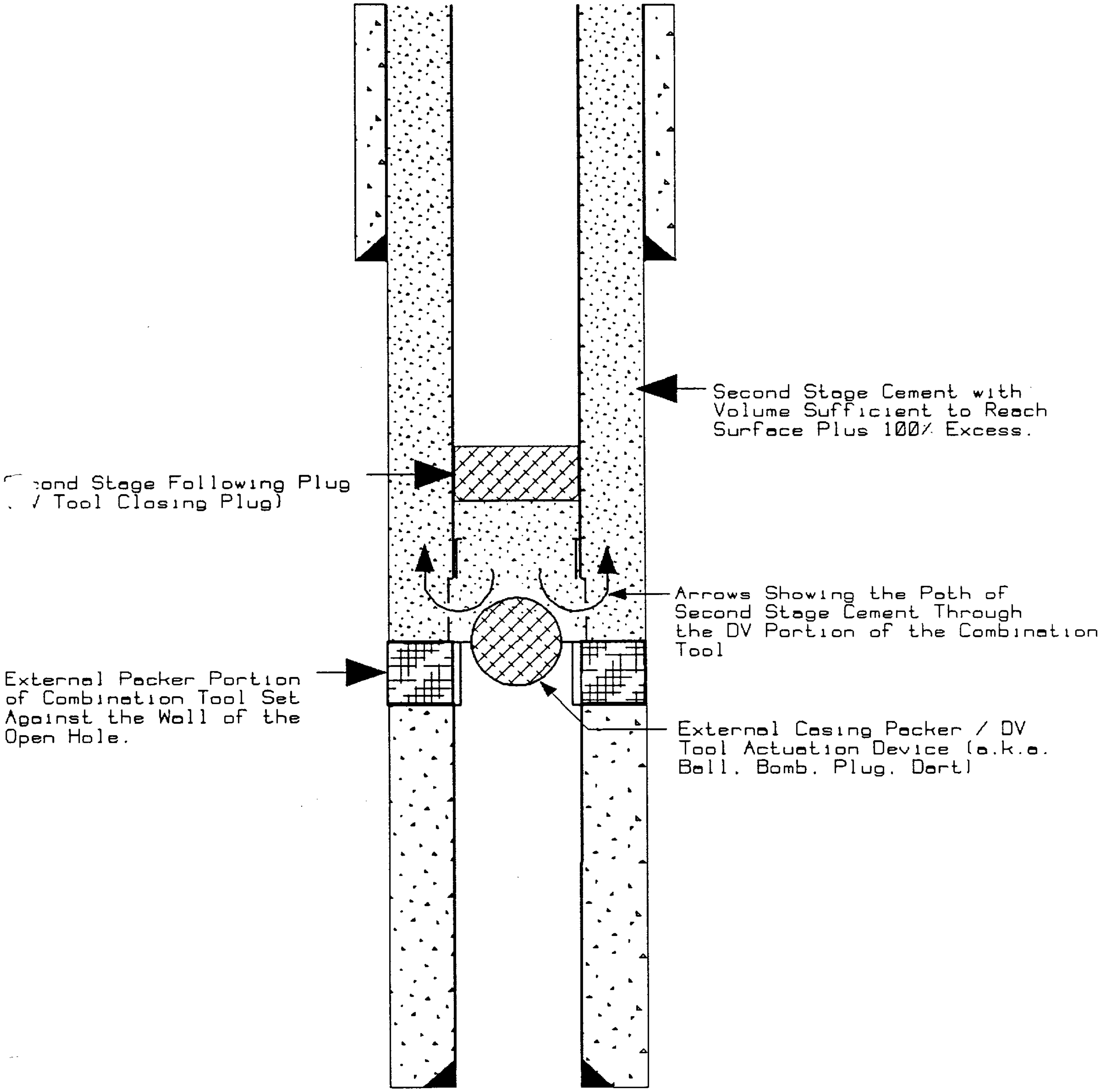


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Figure 2

Wellbore Schematic

SECOND STAGE CEMENT IN PLACE

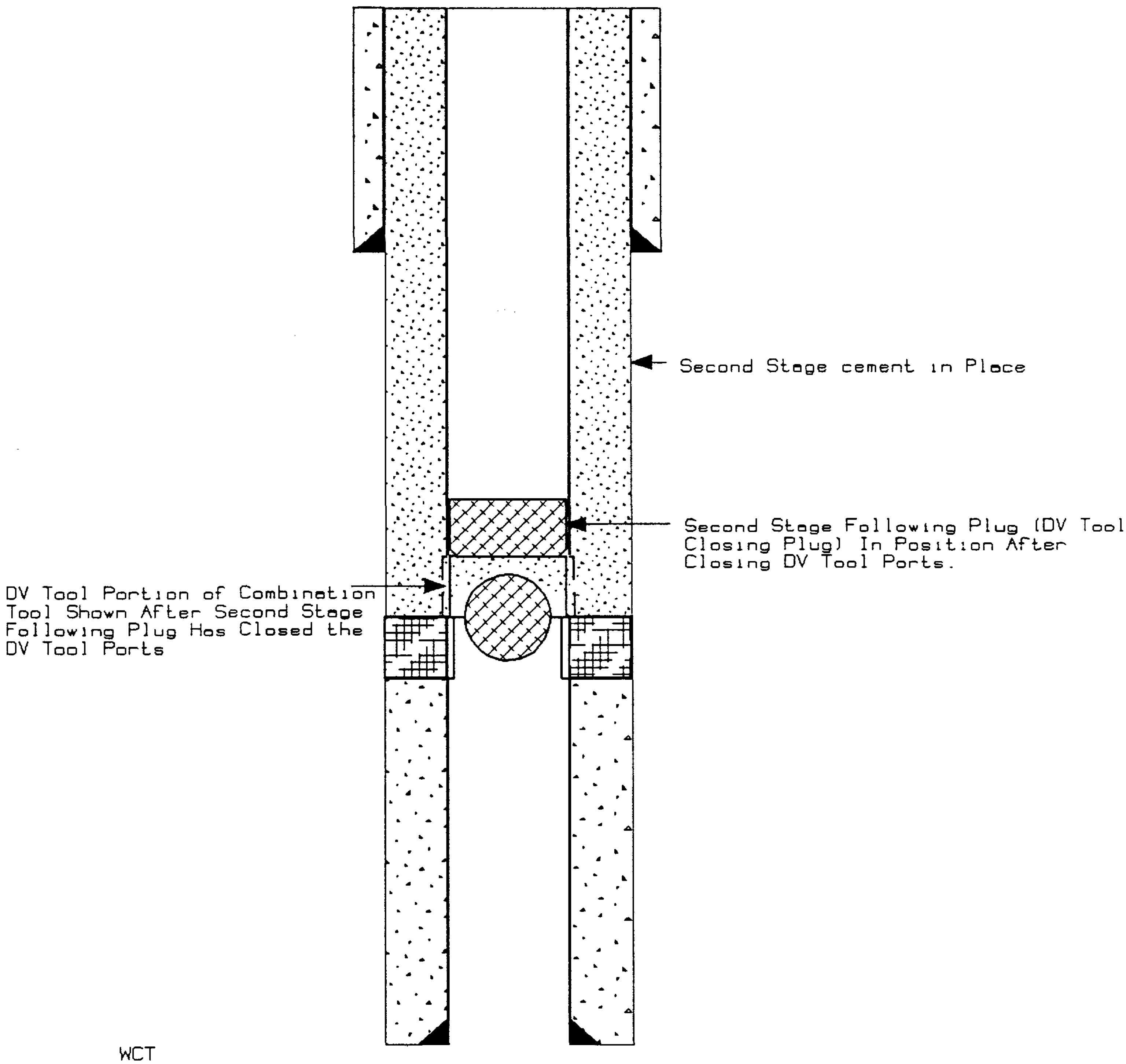

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Figure 3

MITCHELL ENERGY CORP.

Well Plan

ANANSAZI "4" STATE #1

Lea County, New Mexico

Prepared by:

William C. Thoroughman
Staff Drilling Engineer

WELL DATA

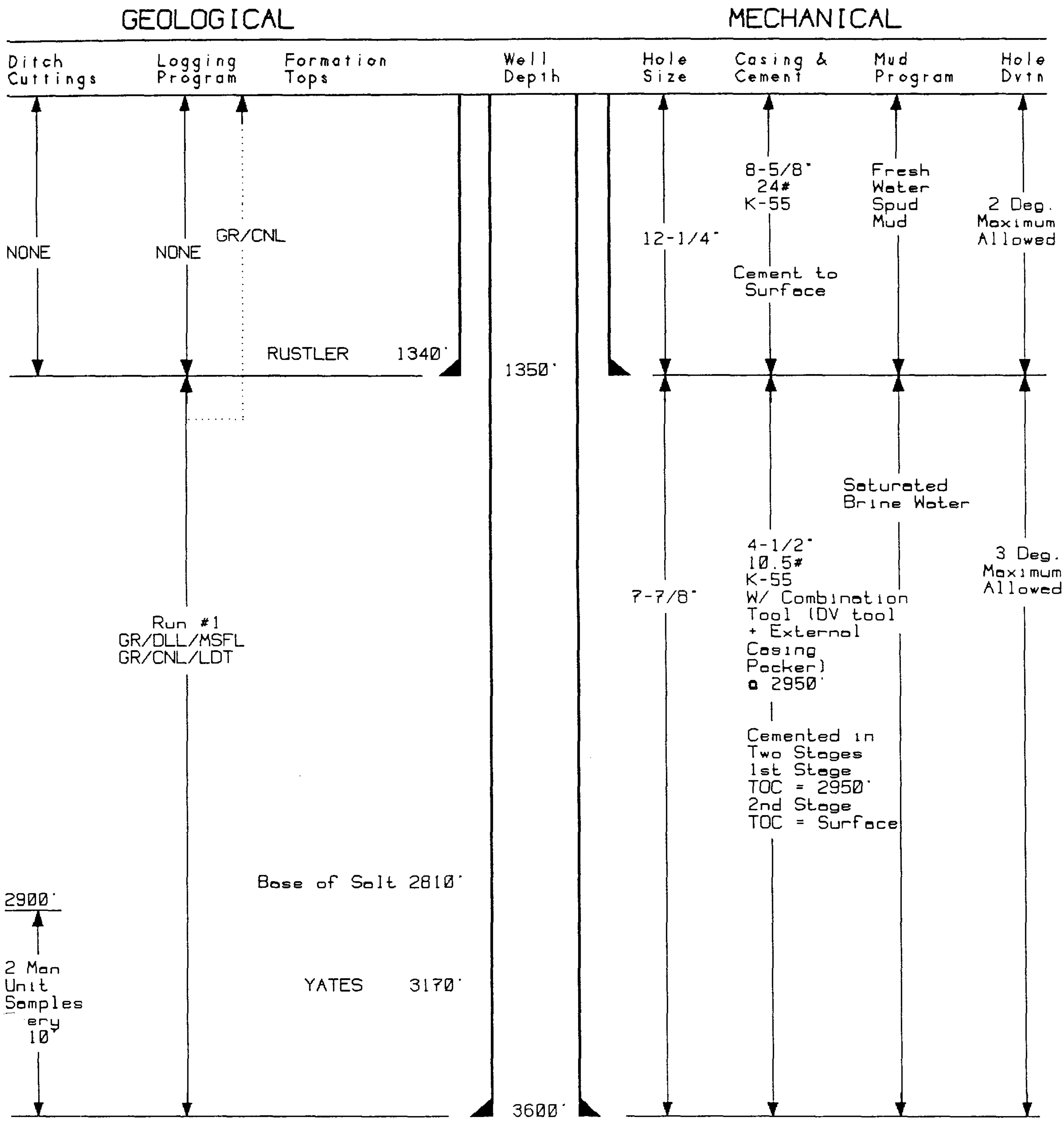
Company:	**Mitchell Energy Corporation**
Field:	**West Teas**
Name:	**Anasazi "4" State #1**
Objective:	**Yates**
Total Depth:	**3600'**

TABLE OF CONTENTS

DRILLING PROGNOSIS

. .ELD: **West Teas** WELL: **Anasazi "4" State #1**

OBJECTIVE: **Yates** ELEVATION:



DRILLING PROGRAM

ANASAZI "4" STATE #1

1.0 Set conductor at +/- 40' with rat hole machine.

2.0 Move in drilling rig and rig up same.

3.0 Drill 12-1/4" hole to +/- 1350'.

4.0 At 1350' circulate and condition hole for casing.

5.0 Run 8-5/8" casing as shown on the appropriate attachment, "Casing String Design".

   5.1 Once casing string is made up, circulate a minimum of one entire circulation while reciprocating casing.

6.0 Cement 8-5/8" casing as per attached cement program.

7.0 Cut off conductor and 8-5/8" casing and install 11" x 3MWP head as shown on attachment.

8.0 Nipple up 11" x 3MWP - BOP stack as shown on attachment.

9.0 Test annular BOP to 1000 psi. Test rams, choke manifold and all associated equipment to 1000 psi.

10.0 Drill 7-7/8" hole to +/- 3600'.

   10.1 Prior to drilling the float collar, pressure test the casing to 600 psi by closing the annular preventer and pressuring up to 600psi. Hold this pressure for a minimum of 30 minutes and record any pressure fluctuations. Report the results of this test on the morning report.

11.0 At 3600', condition hole for logs and log well as per attached "Geological Prognosis".

12.0 Following logging operations, trip back in hole and circulate a minimum of one complete circulation. Have the mud engineer perform a full check during this circulation and verify mud is in condition to run casing.

13.0 Once the order has been given to run pipe and the above conditions have been met, begin the trip out of the hole laying down the drill string to run casing.

14.0 Make up and run 4 1/2" casing as per the following:

A. Clean exposed threads on the guide shoe, first joint of 4 1/2" casing, float collar, and second joint of casing.

B. Apply thread lock to the above listed connections prior to make-up.

C. The bottom assembly of the casing assembly must be made up as follows with the first listed being the first in the hole:

1. Guide shoe
2. First joint of 4 1/2" casing
3. Float collar
4. 4 1/2" casing back to setting depth of 2950' (140' below the salt).
5. Combination Tool (DV Tool with External Casing Packer)
6. 4-1/2" casing back to surface.

D. Install centralizers as follows on the 4-1/2" casing:

1. 10' above the guide shoe by means of a stop collar.
2. Around the first coupling above the float collar.
3. Every third coupling back to the combination tool.
4. Around the coupling immediately below the combination tool.
5. Around the coupling immediately above the combination tool.
6. Every third coupling back to surface.

15. With casing on bottom, circulate mud a minimum of one circulation. Monitor returns to ensure hole is "clean".

16. Cement the 4 1/2" casing string as follows:

A. Reciprocate the casing during the <u>first stage</u> circulation and cementation.

B. Once the first stage cement is in place (Figure 1), drop the ***EXTERNAL CASING PACKER / DV TOOL ACTUATION DEVICE*** (a.k.a. Ball, Bomb, Plug, Dart (Figure 2)).

C. With guidance from the tool manufacturers representative, set the external casing packer and open the DV tool.

D. Circulate one complete circulation through the DV tool to ensure any residual cement from the first stage is removed from the annulus above the combination tool.

E. Pump the second stage cement into position followed by the ***SECOND STAGE FOLLOWING PLUG***. Displace cement and plug with drilling fluid. The ***SECOND STAGE FOLLOWING PLUG*** will close the DV tool ports when the cement is in place (Figure 3).

17. Set the slips on the 4 1/2" casing in the as cemented condition.

18. Install the "Bell Nipple" tubing head, and associated equipment comprising the B" section.

19. Once all contractual obligations are met, release the rig.

20. **!!!!!!!!!!! -- NET THE PITS -- !!!!!!!!!!!!!!!!**

Wellbore Schematic

First Stage Cement In Place

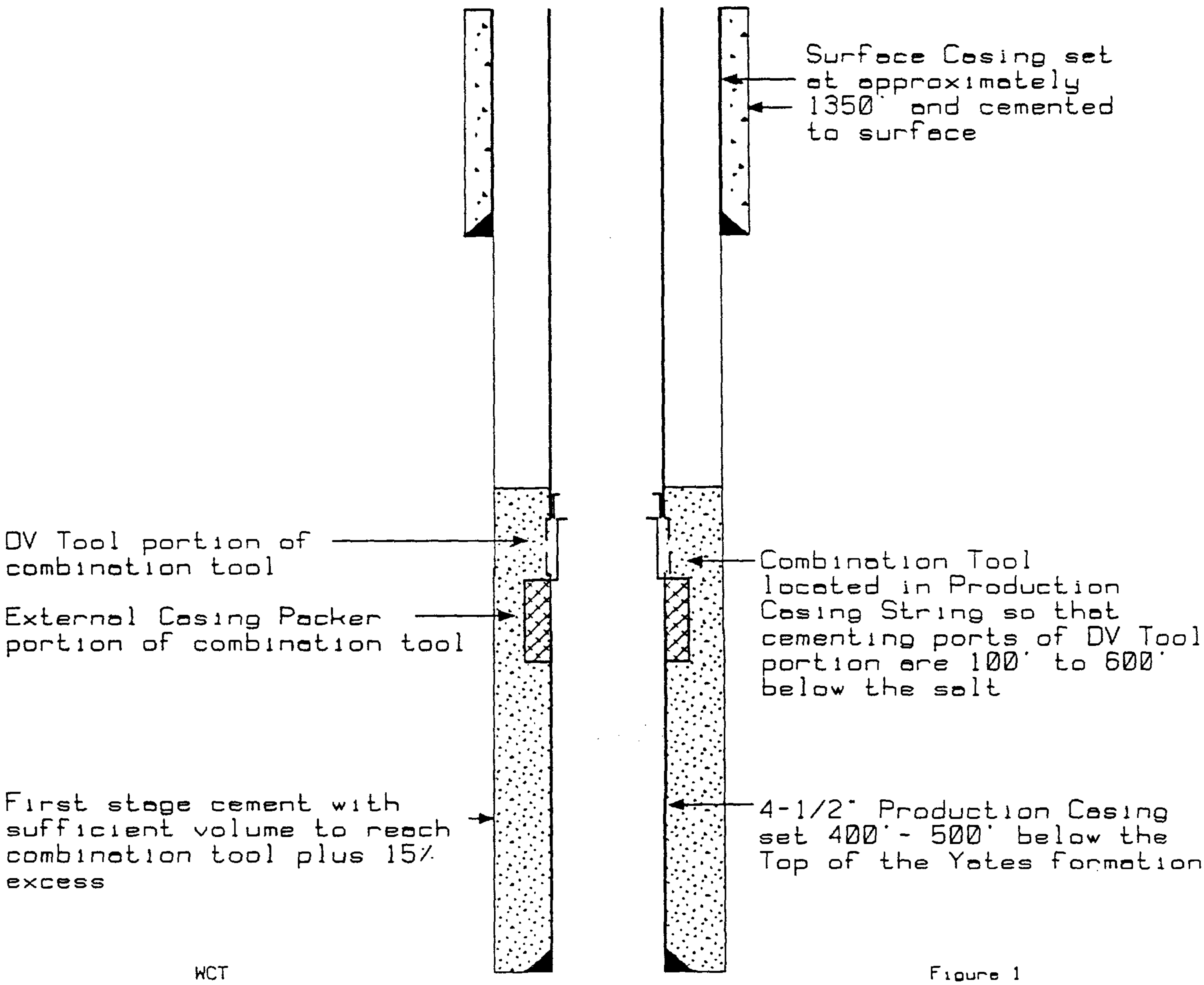


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Figure 1

Wellbore Schematic

DISPLACING SECOND STAGE CEMENT

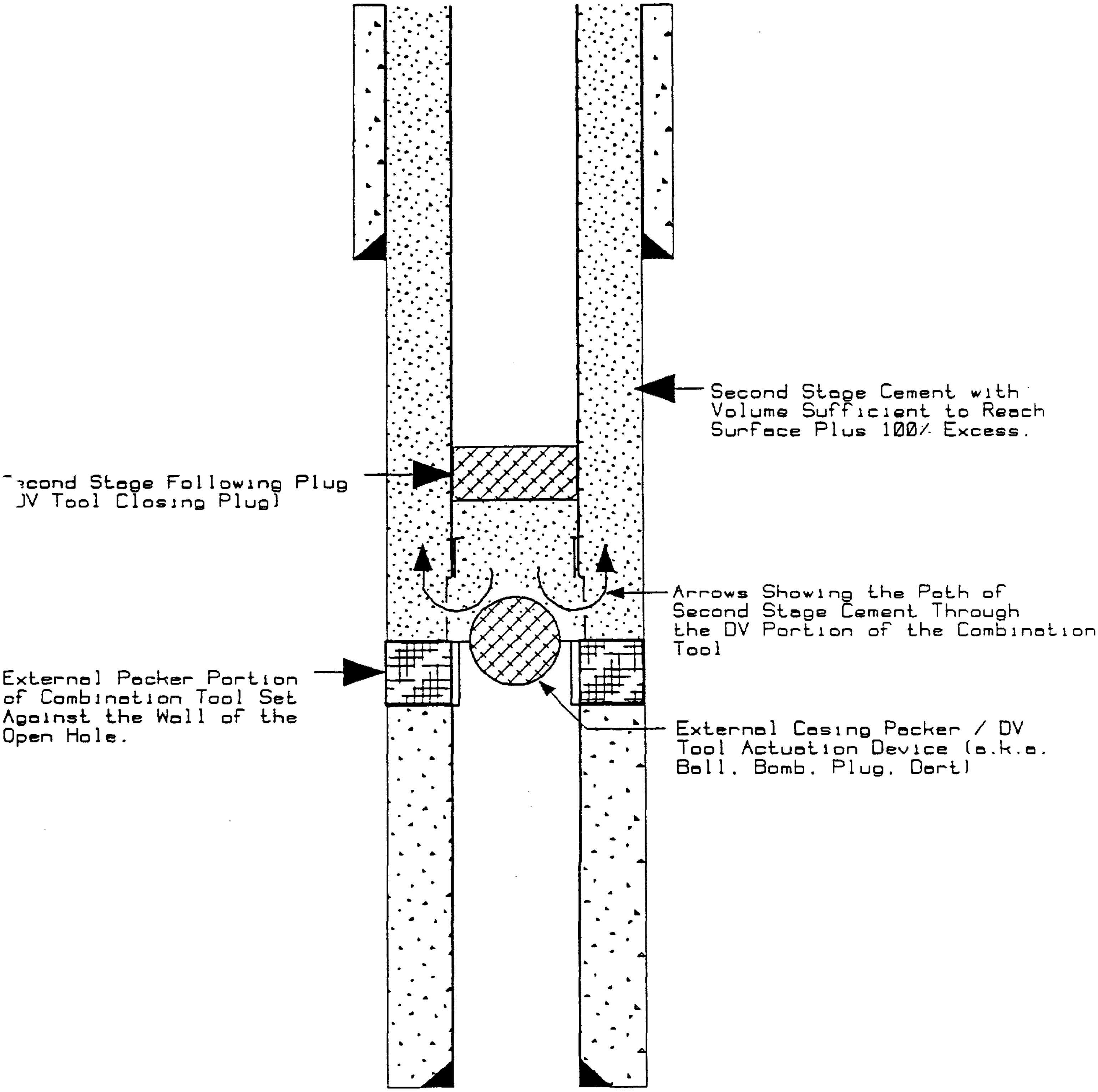

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Figure 2

Wellbore Schematic

SECOND STAGE CEMENT IN PLACE

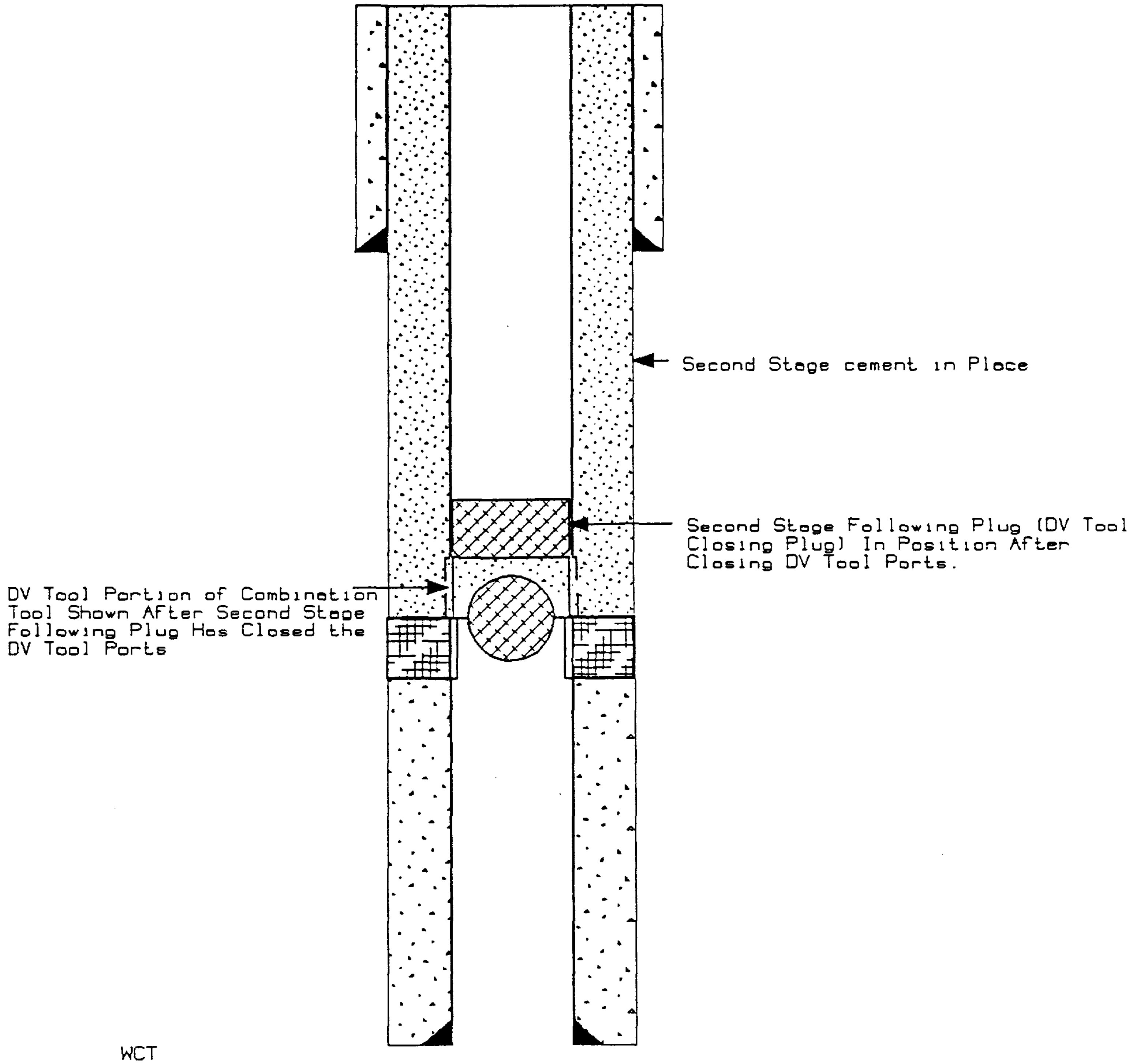

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Figure 3

MUD PROGRAM

ANASAZI "4" STATE #1

Depth Interval (feet)	*Density PPG)*	*Funnel Viscosity (Seconds)*	*Type Mud*	*Filtrate (cc)*
0-1350'	8.5	40-45	Spud Mud	NC
1350'-3600'	10.0	28	Saturated Brine Water	NC

ANASAZI "4" STATE #1

CASING STRING DESIGN

DEPTH:	1350'
TYPE:	Surface
SIZE:	8-5/8"
MUD WEIGHT:	8.5

Description	*Interval*	*Length Per Section*	*Weight Per Section*	*Cumm. Weight*	*Min. Strength*	*Tens. S.F.*
24#,ST&C,K-55	0-1350'	1350'	32400#	32400#	263,000	8.12

Collapse Force	**Resist*	*S.F.*	*Burst Force*	*Resist.*	*S.F.*	*Minimum Torque*	*Optimum Torque*	*Maximum Torque*
596	1370	2.29	624	2950	4.72	1970	2630	3290

* Tension effect on collapse resistance included

Procedure:

1. Clean threads on shoe joint , float collar, and guide shoe to bare shiny metal. Apply Thread Lock to connections prior to make-up.

2. The casing assembly will be made up as follows:

Note: Best-o-Life 2000 will be applied to all connections not receiving Thread Lock.

   a. Guide shoe
   b. Shoe Joint
   c. Float collar
   d. Remainder of casing string

3. Centralizers should be applied 10 feet above the guide shoe by means of a stop collar, around the first coupling above the float collar, and every fourth coupling back to surface.

ANASAZI "4" STATE #1

CASING STRING DESIGN

DEPTH:	**3600'**
TYPE:	**Production**
SIZE:	**4-1/2"**
MUD WEIGHT:	**10.0**

Description	*Interval*	*Length Per Section*	*Weight Per Section*	*Cumm. Weight*	*Min. Strength*	*Tens. S.F.*
10.5#,LT&C,K-55	0-3600'	3600'	37,800#	37,800#	146K	3.86

Collapse Force	*Resist*	*S.F.*	*Burst Force*	*Resist.*	*S.F.*	*Minimum Torque*	*Optimum Torque*	*Maximum Torque*
1872	4010	2.14	1740	4790	2.75	1100	1460	1825

Procedure:

Make up and run 4 1/2" casing as per the following:

A. Clean exposed threads on the guide shoe, first joint of 4 1/2" casing, float collar, and second joint of casing. Apply Thread Lock to these connections prior to make-up.

B. The bottom assembly of the casing assembly must be made up as follows with the first listed being the first in the hole:

Note: Seal Lube will be applied to all conections not receiving Thread Lock.

1. Guide shoe
2. First joint of 4 1/2" casing
3. Float collar
4. 4 1/2" casing back to setting depth of 2950' (140' below the salt).
5. Combination Tool (DV Tool with External Casing Packer)
6. 4-1/2" casing back to surface.

C. Install centralizers as follows on the 4-1/2" casing:

1. 10' above the guide shoe by means of a stop collar.
2. Around the first coupling above the float collar.
3. Every third coupling back to the combination tool.
4. Around the coupling immediately below the combination tool.
5. Around the coupling immediately above the combination tool.
6. Every third coupling back to surface.

ANASAZI "4" STATE #1

Cementing Program

8-5/8" Surface Casing

Depth:	1350'
Casing Size:	8-5/8"
Hole Size:	12.25"
Calculated Cement Fill:	1350'
Excess Calculated:	100%
Cementing Company:	Halliburton

Cement Recommendation:

Spacer: 20 Bbls Fresh Water

Slurry: 860 sacks Premium Plus + 2% CaCl2

Slurry Weight:	14.8 ppg
Slurry Yield:	1.34 cu.ft./sack

Procedure:

1. Utilize the two-plug system.
2. Wait on cement a minimum of 8 hours.

NOTE: VOLUME ADJUSTMENTS BASED ON THE CALIPER WILL BE UNATTAINABLE. THE STANDARD PRACTICE FOR SURFACE CASING CEMENT VOLUME DETERMINATION HAS BEEN CALCULATED (GAUGE HOLE PLUS 100% EXCESS). NO FURTHER CALCULATIONS WILL BE MADE FOR CEMENT VOLUME.

ANASAZI "4" STATE #1

Cementing Program

4-1/2" Production Casing

Depth:	3600'
Casing Size:	4-1/2"
Hole Size:	7-7/8"
Calculated Cement Fill:	3600' (In Two Stages)
Excess Calculated	
1st Stage:	15% over caliper
2nd Stage:	100%
Cementing Company:	Halliburton

Cement Recommendation:

1st Stage:

Slurry: 150 sacks Premium Plus + 2.5 #/sk Salt (Accelerator) + 0.4% HALAD-322 (Fluid Loss)

Slurry Weight:	14.8 ppg
Slurry Yield:	1.36 cu.ft./sack

2nd Stage:

Lead Slurry: 720 sacks Premium Plus + 1% CaCl2 + 15 #/sk Salt

Slurry Weight:	14.0 ppg
Slurry Yield:	1.75 cu.ft./sack

Tail Slurry: 80 sacks Premium Plus

Slurry Weight:	14.8 ppg
Slurry Yield:	1.32 cu.ft./sack

Procedure:

Cement the 4 1/2" casing string as follows:

A. Reciprocate the casing during the first stage circulation and cementation.

ANASAZI "4" STATE #1

Cementing Program

4-1/2" Production Casing
Continued

B. Once the first stage cement is in place (Figure 1), drop the ***EXTERNAL CASING PACKER / DV TOOL ACTUATION DEVICE*** (a.k.a. Ball, Bomb, Plug, Dart) .

C. With guidance from the tool manufacturers representative, set the external casing packer and open the DV tool.

D. Circulate one complete circulation through the DV tool to ensure any residual cement from the first stage is removed from the annulus above the combination tool.

E. Pump the second stage cement into position followed by the ***SECOND STAGE FOLLOWING PLUG***. Displace cement and plug with drilling fluid. The ***SECOND STAGE FOLLOWING PLUG*** will close the DV tool ports when the cement is in place

610-C003

MIDLAND AREA GEOLOGICAL PROGNOSIS

PROJECT:

WELL NAME: Anasazi "4" St. #1 PROSPECT or FIELD: Anasazi

TYPE WELL(WC/DEV): Dev PTD: 3600 PROSPECT NO: M2051 LEASE NO: 43731

SURFACE LOCATION:

COUNTY/STATE: Lea/New Mexico DIST FROM SEC LINES: 330' FSL AND 1980' FWL

BLK/TWP 20S SUR/RGE 33E SEC 4 DIST FROM LSE LINES: 330' FSL AND 1980' FWL

DISTANCE TO CRITICAL WELL: NA POTASH RESTRICTIONS: Yes (YES/NO)

OBJECTIVES AND FORMATION TOPS:

KB ELEV.: 3570 (EST/XXXX) REFERENCE WELLS: MEC Scharbauer "4" Fed. Com #1

Stevens & Tull Fed. "9" #2 (9-20-33)

FORMATION	DEPTH	SUBSEA	LITHOLOGY	PROD TYPE	PROB DST	HAZARDS
Rustler	1340	+2230	salt, anhy			
Base/Salt	2810	+760	anhy, dolo			
Yates	3170	+400	sd, dolo	oil		

TOTAL DEPTH: Seven Rivers 3600 -30 Dolo

EVALUATION:

ELECTRIC LOGGER: Schlumberger MUDLOGGER: MORCO CORE EVAL: Core Lab

LAND:

WI .50 NRI .375 OBLIGATIONS / DEADLINES: Need to spud by 10/12/93 to save Bass F.O.

ADDITIONAL:

Received Time Apr. 15. 10:23AM

GEOLOGICAL PROGNOSIS - Pg. 2

Well Name: Anasazi "4" St. #1 **Prospect No.** M2051

Formation Depth	Electrical Survey	Mud System	Mudlogger & Cores
	GR/CNL		
2900'			
Yates 3170'	Run 1: GR/CNL/LDT GR/DLL/MSFL	Cut Brine or Saturated Brine	Two Man Crew Standard logs from 2900' - TD 2 sets of mudlogger samples every 10'
TD 3600'			

Geologist: Dave Jordan

Date: Aug. 30, 1993

NRC

Received Time Apr. 15. 10:23AM

MINIMUM BLOWOUT PREVENTER REQUIREMENTS

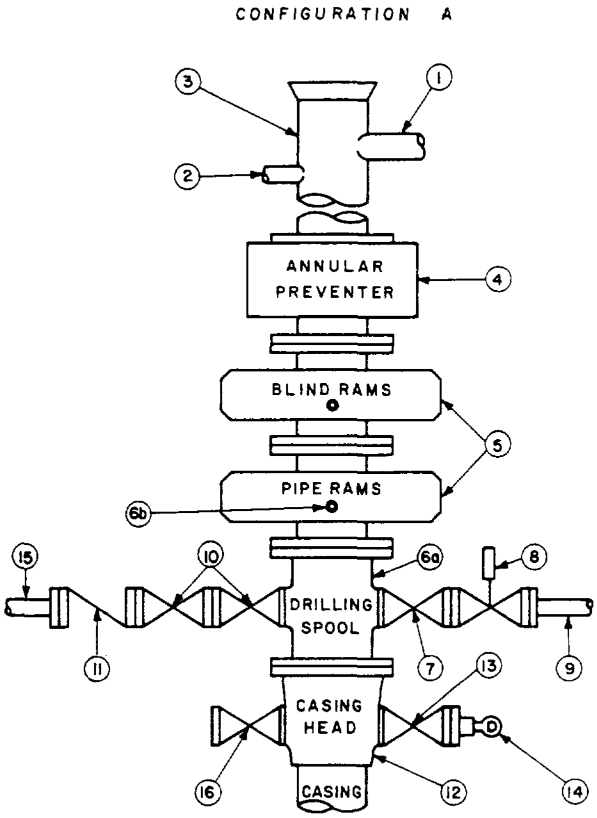
3,000 psi Working Pressure

3 MWP

STACK REQUIREMENTS

No.	Item	Min. I.D.	Min. Nominal
1	Flowline		
2	Fill up line		2"
3	Drilling nipple		
4	Annular preventer		
5	Two single or one dual hydraulically operated rams		
6a	Drilling spool with 2" min. kill line and 3" min choke line outlets		
	or		
6b	2" min. kill line and 3" min. choke line outlets in ram. (Alternate to 6a above.)		
7	Valve Gate ☐ Plug ☐	3-1/8"	
8	Gate valve—power operated	3-1/8"	
9	Line to choke manifold		3"
10	Valves Gate ☐ Plug ☐	2-1/16"	
11	Check valve	2-1/16"	
12	Casing head		
13	Valve Gate ☐ Plug ☐	1-13/16"	
14	Pressure gauge with needle valve		
15	Kill line to rig mud pump manifold		2"

OPTIONAL			
16	Flanged valve	1-13/16"	



CONTRACTOR'S OPTION TO FURNISH:

1. All equipment and connections above bradenhead or casinghead. Working pressure of preventers to be 3,000 psi, minimum.
2. Automatic accumulator (80 gallon, minimum) capable of closing BOP in 30 seconds or less and, holding them closed against full rated working pressure.
3. BOP controls, to be located near drillers position.
4. Kelly equipped with Kelly cock.
5. Inside blowout prevventer or its equivalent on derrick floor at all times with proper threads to fit pipe being used.
6. Kelly saver-sub equipped with rubber casing protector at all times.
7. Plug type blowout preventer tester.
8. Extra set pipe rams to fit drill pipe in use on location at all times.
9. Type RX ring gaskets in place of Type R.

MEC TO FURNISH:

1. Bradenhead or casinghead and side valves.
2. Wear bushing, if required.

GENERAL NOTES:

1. Deviations from this drawing may be made only with the express permission of MEC's Drilling Manager.
2. All connections, valves, fittings, piping, etc., subject to well or pump pressure must be flanged (suitable clamp connections acceptable) and have minimum working pressure equal to rated working pressure of preventers up through choke. Valves must be full opening and suitable for high pressure mud service.
3. Controls to be of standard design and each marked, showing opening and closing position.
4. Chokes will be positioned so as not to hamper or delay changing of choke beans. Replaceable parts for adjustable choke, other bean sizes, retainers, and choke wrenches to be conveniently located for immediate use.
5. All valves to be equipped with handwheels or handles ready for immediate use.
6. Choke lines must be suitably anchored.
7. Handwheels and extensions to be connected and ready for use.
8. Valves adjacent to drilling spool to be kept open. Use outside valves except for emergency.
9. All seamless steel control piping (3000 psi working pressure) to have flexible joints to avoid stress. Hoses will be permitted.
10. Casinghead connections shall not be used except in case of emergency.
11. Do not use kill line for routine fill-up operations.

MITCHELL ENERGY & DEVELOPMENT CORP. - ENERGY DIVISION

AUTHORITY FOR EXPENDITURE (AFE) COST ESTIMATE

Type Project (check 1 only)

[ ] Exploratory [ ] Injection [ ] Water Supply

[ ] Development [ ] Disposal [x] Depth 3600'

Form B-1 [ ] Add [ ] Change [ ] Delete

AFE Number ____________

Property/Well Name Anasazi "4" State #1

Project Description Drill (Yates) (with potash string)

Net Working Interest _._ _ _ _ _ _ _

Group Code ____________

Location Code ____________

Department Number 712

County Lea St. NM

Operator MEC

Estimated Date Project Will Be Completed ____________ (Mo./Yr.)

DRILLING COSTS

INTANGIBLE

		Amount
10	Dry Hole Abandonment	
11	Rig Mobilization and Demobilization	
12	Power and Fuel	
13	Water	
14	Solids Control Equipment Rental	
*15	Directional Equipment and Services	
16	Fishing Tools and Services	
17	Subsurface Casing Equipment	
18	Contract Labor and Service	1,000
19	Supervision - Company and/or Contract	3,000
50	Road and Site Preparation	20,000
51	Footage Contract Fee..........(TK)	135,000
52	Daywork Contract Fee	
53	Mud and Chemicals	
54	Bits and Reamers	
55	Drilling Tools and Equipment Rental	1,500
56	Cement and Cement Services	
*57	Open Hole Logging-Testing	12,500
*58	Drill Stem Testing	
59	Coring and Analysis	
60	Transportation	
61	Air/Marine Transportation	
63	Overhead	3,000
64	Insurance	
65	Company Labor and Services	
*66	Prospect Generation	3,000
67	Miscellaneous Services and Contingency	5,000
	TOTAL INTANGIBLE COSTS **************************	184,000

TANGIBLE

21	Casing-Drive Pipe & Conductor	
40	Casing-Surface 1350'- 13-3/8" 54.5# K-S (TK)	
41	Casing-Intermediate 2960'-8-5/8" 24# K-S (TK)	
42	Casinghead Equipment (Including Valves)	1,000
43	Casing Spool (Including Valves)	
44	Miscellaneous Equipment	
	TOTAL TANGIBLE COSTS ******************************	1,000

TOTAL DRILLING (DRY HOLE) COSTS **************************** 185,000

*Invalid for disposal and water supply wells.

MEDC 252-02

Rev. 4/29/85

Prepared by: WCT WCT/wct

Date Prepared: 4/20/94

MITCHELL ENERGY & DEVELOPMENT CORP. - ENERGY DIVISION
AUTHORITY FOR EXPENDITURE (AFE) COST ESTIMATE

Type Project (check 1 only)

___ Exploratory ___ Recompletion (Zone Change Only) ___ Disposal
X Development ___ Plug and Abandon (Previously Producing Well)
___ Injection ___ Water Supply Depth 3600'

Form B-2 ___ Add ___ Change ___ Delete
AFE Number ___
Property/Well Name Anasazi (Yates) w/ potash string
Project Discription Complete & equip
Net Working Interest ___

Group Code ___
Location Code ___
Dept Number 730
County Lea St NM
Operator Mitchell Energy Corp

Estimated Date Project Will be Completed ___ (Mo./Yr.)

COMPLETION COSTS	Example Only, Not For AFE	AMOUNT
INTANGIBLE		
22 Overhead		$2,000
23 Company Labor and Service		
24 Contract Labor and Services		15000
25 Air/Marine Transportation		
26 Other Transportation		3000
27 Plugging and Abandonment		
28 Rig Mobilization and Demobilization		
29 Supervision - Company and/or Contract		3000
30 Site Preparation and Clean-up		1000
31 Subsurface Casing Equipment		2000
32 Squeeze Cement and Service		
33 Completion Fluids		2000
34 Pump Truck Services		3000
35 Rental Tools		3000
36 Bits and Reamers		
37 Insurance		
38 Wireline Services		
39 Fishing Tools and Services		
*53 Tertiary Injectants		
68 Fencing		
83 Daywork Contract Fee		6000
84 Cement and Cement Services - Primary		6000
85 Acidizing and Fracturing		25000
*86 Cased Hole Logging and Perforating		3000
94 Miscellaneous Services and Contingency		1000
TOTAL INTANGIBLE COSTS		$75,000
TANGIBLE		
69 Tubinghead Equipment (Including valves)		$700
70 Casing-Production and/or Liner	3600' 4½", 10.5#, K-55, ST&C	16400
71 Tubing	3500' 2-3/8", 4.7#, J-55, EUE 8rd	8700
72 Packer and Subsurface Equipment		
73 Production Tree (Including Valves)		
74 Storage Tanks	2 - 210 bbl steel & 1 - 210 bbl fiberglass	9000
75 Separating Equipment		
76 Treating Equipment	4' x 20' 350 MBTU heater	10000
77 Artificial Lift Equipment	C114 - 143 - 74 w/ 66 Grade rod string	26800
78 Line Pipe		3000
79 Valves and Fittings Beyond Wellhead		3000
80 Miscellaneous Equipment		1400
81 Platform and Structures		
82 Metering Equipment		2000
87 Pumps		
90 Electrical Equipment		
91 Instrumentation Equipment		
96 Dehydrators and Dryers		
TOTAL TANGIBLE COSTS		$81,000
TOTAL COMPLETION COSTS		$156,000

$341,000

* Invalid for disposal and water supply wells.
MEDC 252-03
Rev. 4/29/85
com-b.wk1

Prepared By: Greg Colburn
Date Prepared: 06-Apr-94

MITCHELL ENERGY & DEVELOPMENT CORP. - ENERGY DIVISION

AUTHORITY FOR EXPENDITURE (AFE) COST ESTIMATE

Type Project (check 1 only)

[ ] Exploratory   [ ] Injection   [ ] Water Supply

[ ] Development   [ ] Disposal   [x] Depth 3600'

Form B-1 [ ] Add   [ ] Change   [ ] Delete

AFE Number ______

Property/Well Name Anasazi "4" State #1

Project Description Drill (Yates) (without potash string)

Net Working Interest _._ _ _ _ _ _ _

Group Code ______

Location Code ______

Department Number 712

County Lea   St. NM

Operator MEC

Estimated Date Project Will Be Completed ______ (Mo./Yr.)

DRILLING COSTS

INTANGIBLE

		Amount
10	Dry Hole Abandonment	
11	Rig Mobilization and Demobilization	
12	Power and Fuel	
13	Water	
14	Solids Control Equipment Rental	
*15	Directional Equipment and Services	
16	Fishing Tools and Services	
17	Subsurface Casing Equipment	
18	Contract Labor and Service	1,000
19	Supervision - Company and/or Contract	2,000
50	Road and Site Preparation	20,000
51	Footage Contract Fee..........(TK)	70,000
52	Daywork Contract Fee	
53	Mud and Chemicals	
54	Bits and Reamers	
55	Drilling Tools and Equipment Rental	1,000
56	Cement and Cement Services	
*57	Open Hole Logging-Testing	12,000
*58	Drill Stem Testing	
59	Coring and Analysis	
60	Transportation	
61	Air/Marine Transportation	
63	Overhead	2,500
64	Insurance	
65	Company Labor and Services	
*66	Prospect Generation	3,000
67	Miscellaneous Services and Contingency	5,000
	TOTAL INTANGIBLE COSTS **************************	116,500

TANGIBLE

21	Casing-Drive Pipe & Conductor	
40	Casing-Surface 1350'- 8-5/8" 24# K-S (TK)	
41	Casing-Intermediate	
42	Casinghead Equipment (Including Valves)	1,000
43	Casing Spool (Including Valves)	
44	Miscellaneous Equipment	
	TOTAL TANGIBLE COSTS *****************************	1,000

TOTAL DRILLING (DRY HOLE) COSTS ****************************** 117,500

*Invalid for disposal and water supply wells.

MEDC 252-02   Prepared by: WCT/wct

Rev. 4/29/85   Date Prepared: 4/20/94

MITCHELL ENERGY & DEVELOPMENT CORP. - ENERGY DIVISION
AUTHORITY FOR EXPENDITURE (AFE) COST ESTIMATE

Type Project (check 1 only)

___ Exploratory ___ Recompletion (Zone Change Only) ___ Disposal
X Development ___ Plug and Abandon (Previously Producing Well)
___ Injection ___ Water Supply Depth 3600'

Form B-2 ___ Add ___ Change ___ Delete	Group Code
AFE Number	Location Code
Property/Well Name Anasazi (Yates) w/o potash string	Dept Number 730
Project Discription Complete & equip	County Lea St NM
Net Working Interest	Operator Mitchell Energy Corp

Estimated Date Project Will be Completed ________ (Mo./Yr.)

COMPLETION COSTS — Example Only, Not For AFE

INTANGIBLE	AMOUNT
22 Overhead	$2,300
23 Company Labor and Service	
24 Contract Labor and Services	15000
25 Air/Marine Transportation	
26 Other Transportation	3000
27 Plugging and Abandonment	
28 Rig Mobilization and Demobilization	
29 Supervision - Company and/or Contract	3200
30 Site Preparation and Clean-up	1000
31 Subsurface Casing Equipment	9300
32 Squeeze Cement and Service	
33 Completion Fluids	2000
34 Pump Truck Services	3400
35 Rental Tools	3800
36 Bits and Reamers	300
37 Insurance	
38 Wireline Services	
39 Fishing Tools and Services	
*53 Tertiary Injectants	
68 Fencing	
83 Daywork Contract Fee	7200
84 Cement and Cement Services - Primary	12000
85 Acidizing and Fracturing	25000
*86 Cased Hole Logging and Perforating	3000
94 Miscellaneous Services and Contingency	1500
TOTAL INTANGIBLE COSTS	$92,000

117,500
+113,000
291,500

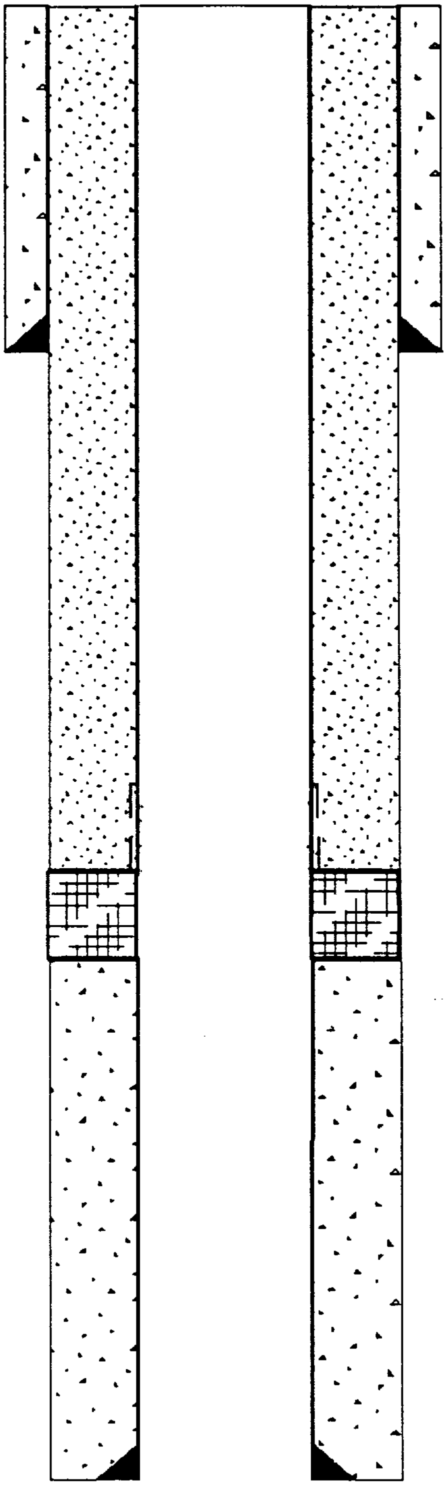
TANGIBLE		AMOUNT
69 Tubinghead Equipment (Including valves)		$700
70 Casing-Production and/or Liner	3600' 4½", 10.5#, K-55, ST&C	16400
71 Tubing	3500' 2-3/8", 4.7#, J-55, EUE 8rd	8700
72 Packer and Subsurface Equipment		
73 Production Tree (Including Valves)		
74 Storage Tanks	2 - 210 bbl steel & 1 - 210 bbl fiberglass	9000
75 Separating Equipment		
76 Treating Equipment	4' x 20' 350 MBTU heater	10000
77 Artificial Lift Equipment	C114 - 143 - 74 w/ 66 Grade rod string	26800
78 Line Pipe		3000
79 Valves and Fittings Beyond Wellhead		3000
80 Miscellaneous Equipment		1400
81 Platform and Structures		
82 Metering Equipment		2000
87 Pumps		
90 Electrical Equipment		
91 Instrumentation Equipment		
96 Dehydrators and Dryers		
TOTAL TANGIBLE COSTS		$81,000
TOTAL COMPLETION COSTS		$173,000

* Invalid for disposal and water supply wells.
MEDC 252-03
Rev. 4/29/85
com-b.wk1

GLC
Prepared By: Greg Colburn GLC
Date Prepared: 06-Apr-94

Wellbore Schematic

CEMENT, PLUGS, and COMBINATION TOOL AFTER DRILL OUT

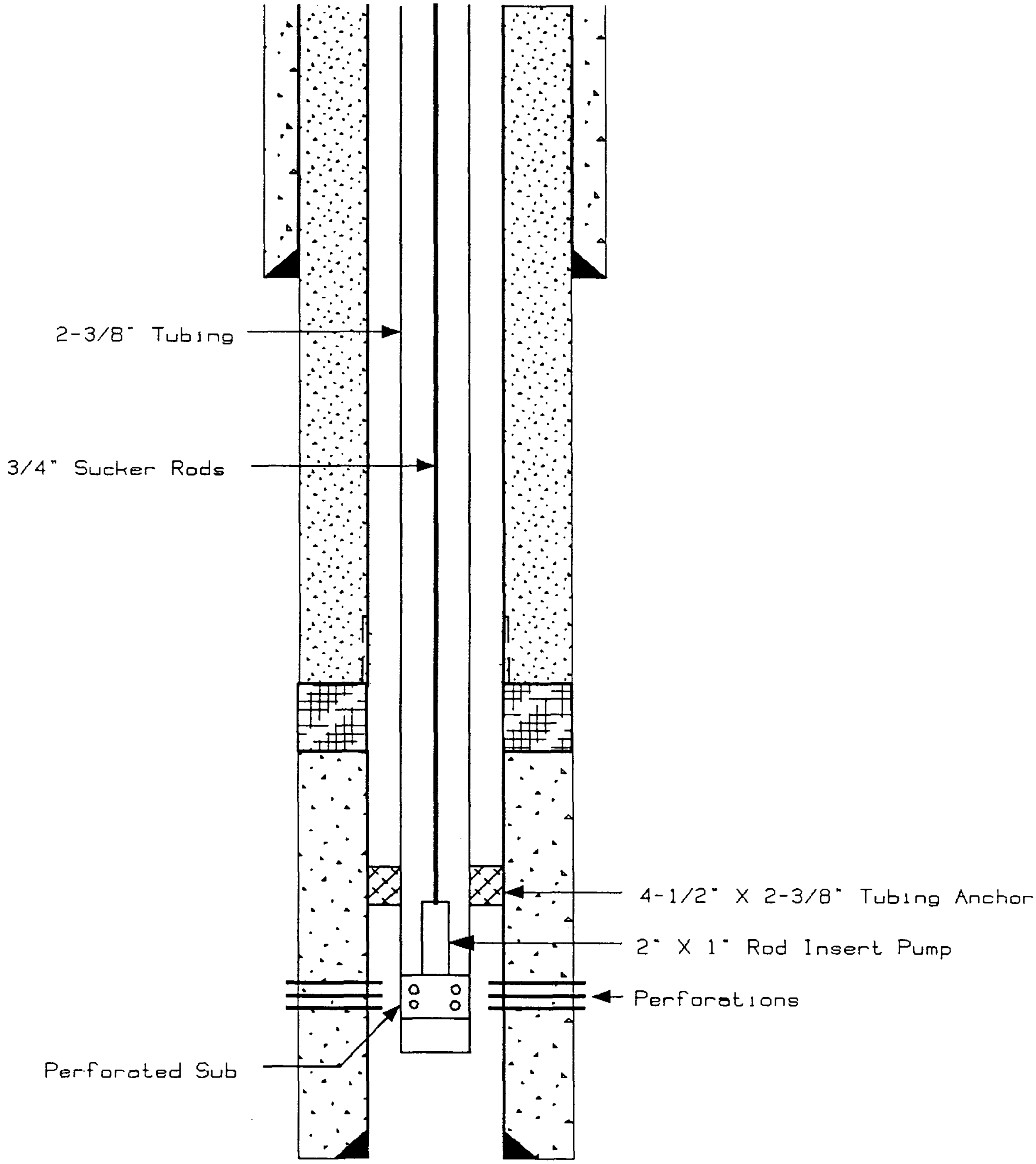


WCT

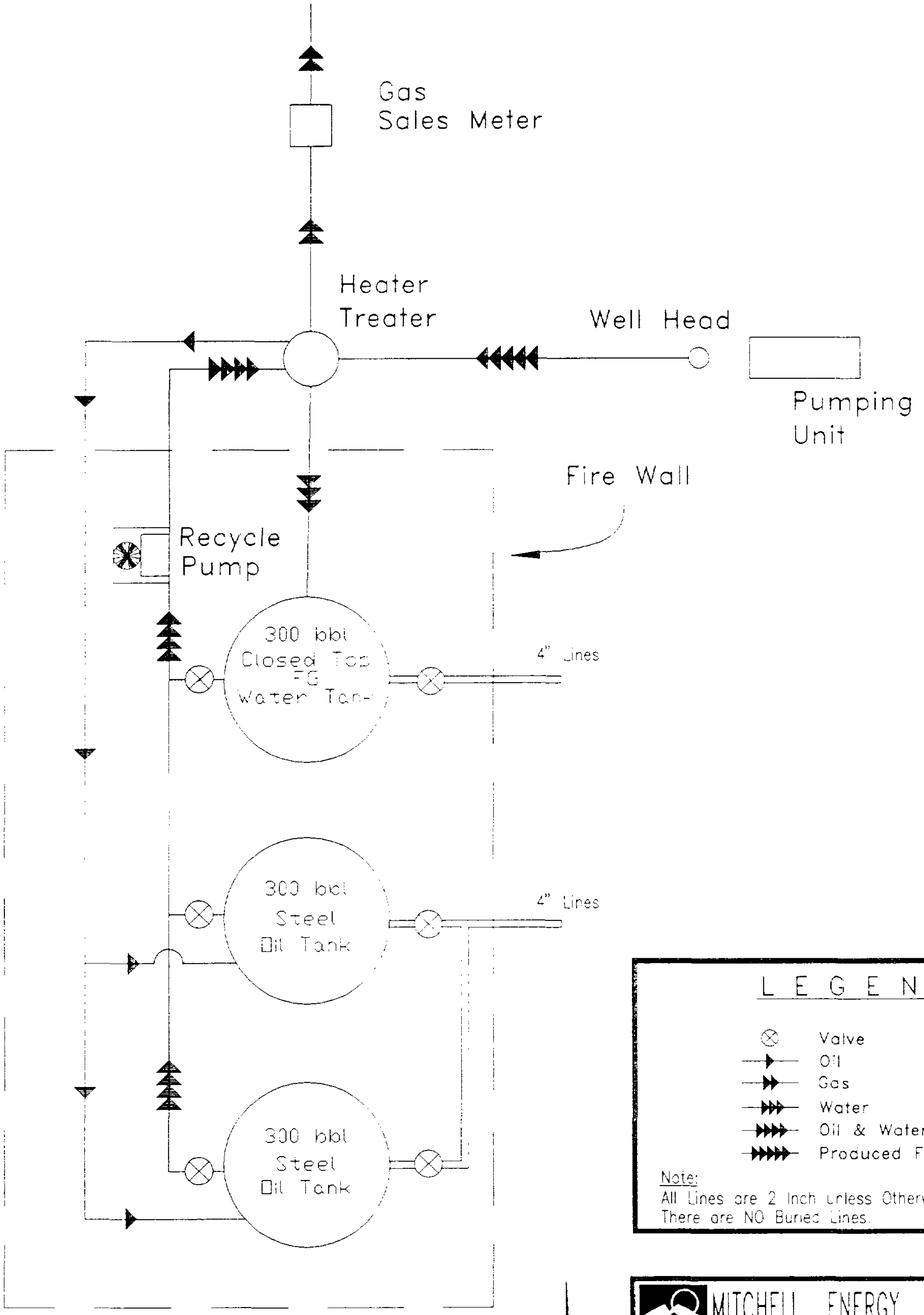
FIGURE 4

Wellbore Schematic

ROD PUMP SETUP



WCT/PJN



L E G E N D

⊗	Valve
—▸—	Oil
—▸▸—	Gas
—▸▸▸—	Water
—▸▸▸▸—	Oil & Water
—▸▸▸▸▸—	Produced Fluids

Note:
All Lines are 2 Inch unless Otherwise Specified
There are NO Buried Lines.

MITCHELL ENERGY CORPORATION
400 W. ILLINOIS STE. 1000 MIDLAND, TEXAS 79701

Generic Site Diagram

Yates Pumping Well

Date: 4-19-94

Scale: None

Diagram Located at :
Mitchell Energy Corporation
400 W. Illinois, Suite 1000
Midland, Texas 79701
(915) 682-5396

Generic Yates Oil Well
Completion Procedure

Procedure

1. MIRU completion unit. NU BOP.

2. RIH with 3-⅞" bit, 4-½" casing scraper, and 2-⅜", 4.7#, J-55, EUE 8rd tubing. Drill out DV tool. Continue in hole to PBTD. Circulate hole clean using 2% KCL water. POOH with tubing, scraper, and bit.

3. RU wireline. Run GR-CCL-CBL with x/y signature from PBTD to base of surface pipe. Evaluate CBL prior to perforating.

4. Test 4-½" casing to 3800 psi.

5. Perforate the pay zone using a 3-⅛" casing gun.

6. RIH with packer, seat nipple, and 2-⅜" tubing to ±100' above the top perforation. RU stimulation company. Reverse circulate small volume of acid to pickle tubing. RIH to depth of bottom perforation. Spot acid across perforated interval. Pull uphole to ±100' above the top perforation and set packer. Acidize perforations dropping ball sealers to divert acid. Flow well back immediately.

7. Swab back acid load.

8. Release packer, run through perforations to knock ball sealers off, and POOH.

9. ND BOP. NU frac head.

10. RU stimulation company. Frac well down 4-½" casing. Maximum surface treating pressure 3800 psi. Flow well back immediately for forced closure. Continue flow testing until well dies. ND frac head and NU BOP.

11. RIH with 2-⅜" notched collar, seat nipple, and 2-⅜" tubing. Reverse circulate clean to PBTD using 2% KCL water. POOH with tubing and notched collar.

12. RIH with one joint 2-⅜" tubing with notched collar on bottom, seat nipple, 2-⅜" tubing, tubing anchor, and 2-⅜" tubing to surface. Space tubing so seat nipple will be ±30' below bottom perforation and tubing anchor will be set ±60' above the top perforation. ND BOP and NU wellhead.

13. RIH with insert rod pump and ¾" sucker rod string. Seat pump and pressure test to 500 psi. RD and release completion unit.

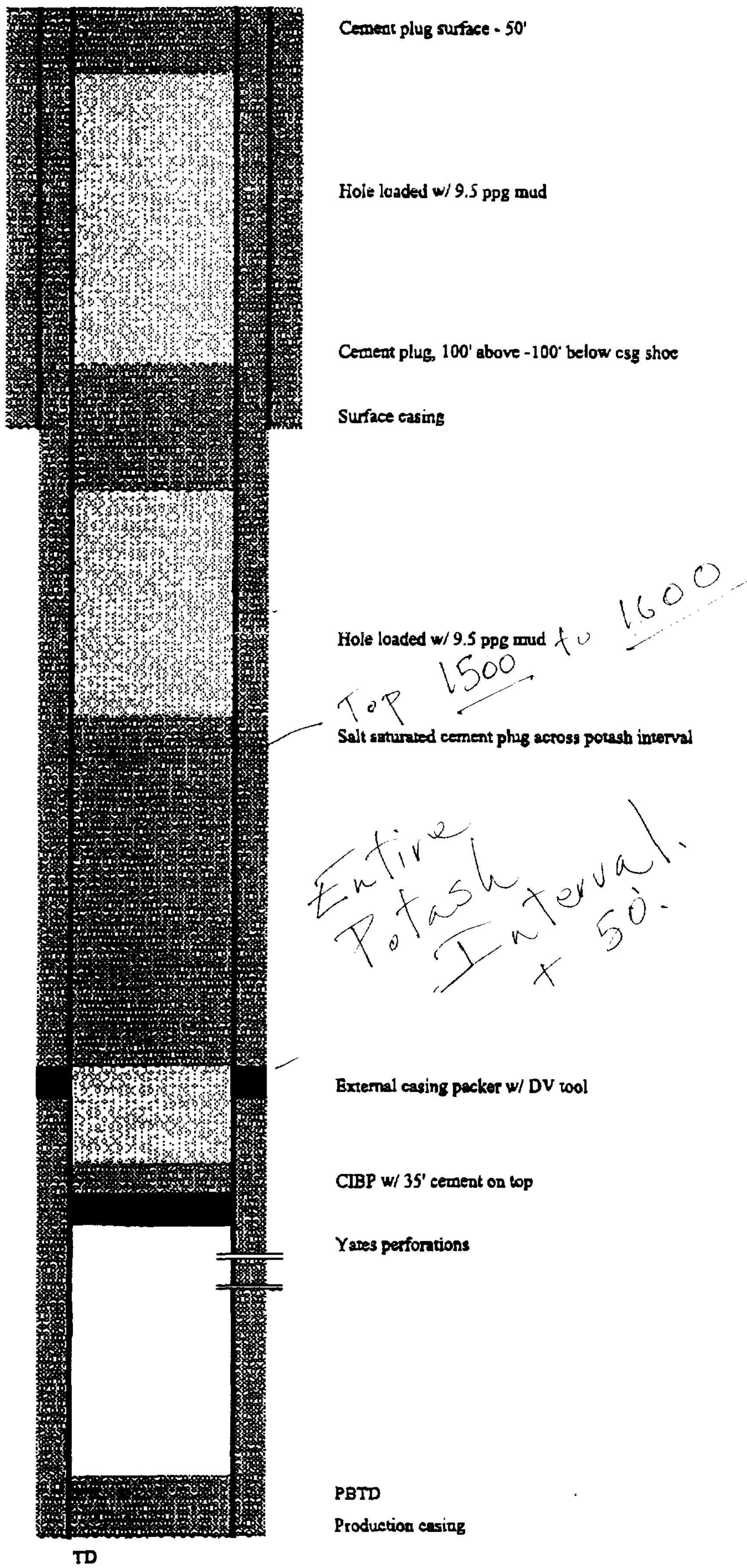
14. Set pumping unit and begin production.

Received Time Apr. 20. 8:25AM

Yates Pumping Well
No Potash String
Lea Co., NM
JGC 4-15-94

P&A

KB:
GL:



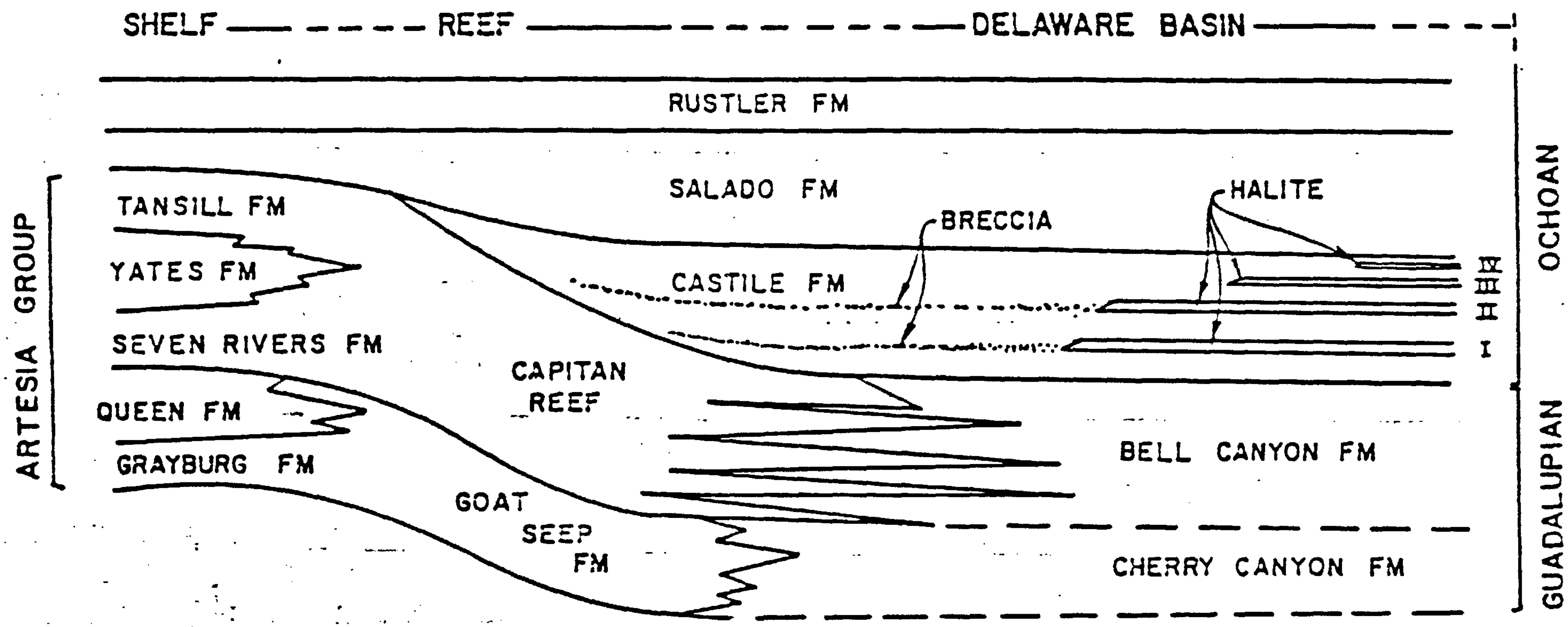
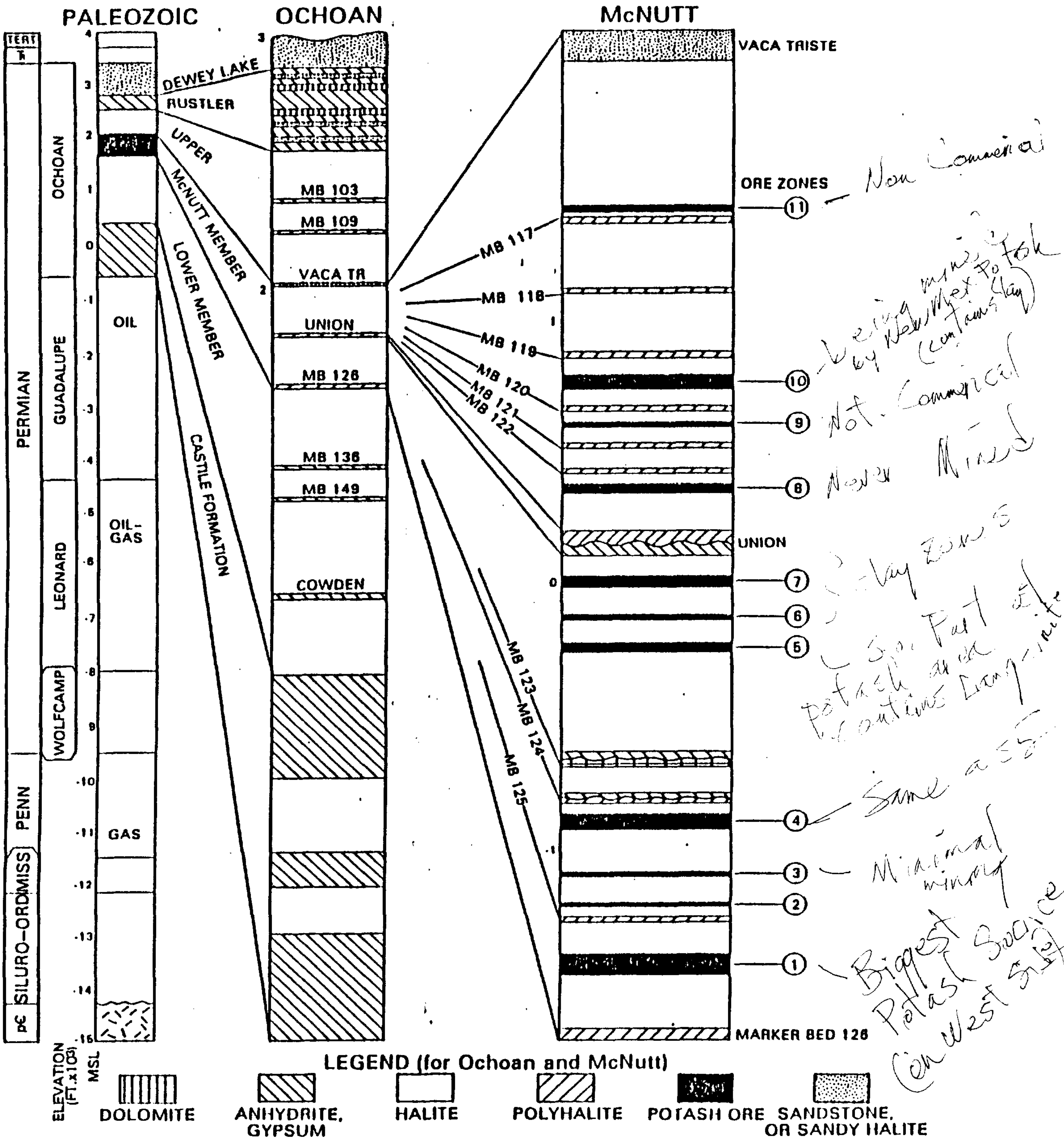


Figure 2. Informal members of the Castile Formation (after Anderson and others, 1972).



...nal stratigraphic column with expanded sections of the Ochoan Evaporite and McNutt Member of the Salado Formation (after Griswold, 1982)

GARY L. HUTCHINSON
1806 Arapahoe Street
Golden, CO 80401 - 1853