submitted in lieu of Form 3160-5

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

RECEIVED 96 SEP 25 PM 3:19 070 FARMINGTON, NM

Sundry Notices and Reports on Wells

1. **Type of Well**
GAS

5. **Lease Number**
SF-078197

6. **If Indian, All. or Tribe Name**

7. **Unit Agreement Name**

2. **Name of Operator**
MERIDIAN OIL

8. **Well Name & Number**
Nye Federal Com #2

3. **Address & Phone No. of Operator**
PO Box 4289, Farmington, NM 87499 (505) 326-9700

9. **API Well No.**
30-045-08566

4. **Location of Well, Footage, Sec., T, R, M**
1600'FNL, 1630'FEL, Sec.8, T-29-N, R-10-W, NMPM
G

10. **Field and Pool**
Blanco MV/Basin DK

11. **County and State**
San Juan Co, NM

12. **CHECK APPROPRIATE BOX TO INDICATE NATURE OF NOTICE, REPORT, OTHER DATA**

Type of Submission	Type of Action	
_X_ Notice of Intent	___ Abandonment	___ Change of Plans
	_X_ Recompletion	___ New Construction
___ Subsequent Report	___ Plugging Back	___ Non-Routine Fracturing
	___ Casing Repair	___ Water Shut off
___ Final Abandonment	___ Altering Casing	___ Conversion to Injection
	_X_ Other - Dakota pay add	

13. **Describe Proposed or Completed Operations**

It is intended to add the Mesaverde formation and add pay to the Dakota formation of the subject well according to the attached procedure and wellbore diagram.

RECEIVED
OCT 10 1996
OIL CON. DIV.
DIST. 3

14. **I hereby certify that the foregoing is true and correct.**

Signed Peggy Bradfield (2)Title Regulatory Administrator Date 9/24/96

(This space for Federal or State Office use)
APPROVED BY _____ Title _____ Date _____
CONDITION OF APPROVAL, if any:

APPROVED
OCT 2 1996
for Chip Harradon
DISTRICT MANAGER

NMOCD

District I
PO Box 1980, Hobbs, NM 88241-1980
District II
PO Drawer DD, Artesia, NM 88211-0719
District III
1000 Rio Brazos Rd., Aztec, NM 87410
District IV
PO Box 2088, Santa Fe, NM 87504-2088

State of New Mexico
Energy, Minerals & Natural Resources Department

OIL CONSERVATION DIVISION
PO Box 2088
Santa Fe, NM 87504-2088

RECEIVED
96 SEP 25 PM 2 10
070 FARMINGTON, NM

Form C-102
Revised February 21, 1994
Instructions on back
Submit to Appropriate District Office
State Lease - 4 Copies
Fee Lease - 3 Copies

☐ AMENDED REPORT

WELL LOCATION AND ACREAGE DEDICATION PLAT

API Number	Pool Code	Pool Name
30-045-08566	72319/71599	Blanco Mesaverde/Basin Dakota

Property Code	Property Name	Well Number
18413	NYE FEDERAL COM	2

OGRID No.	Operator Name	Elevation
14538	BURLINGTON RESOURCES OIL AND GAS COMPANY	5781

Surface Location

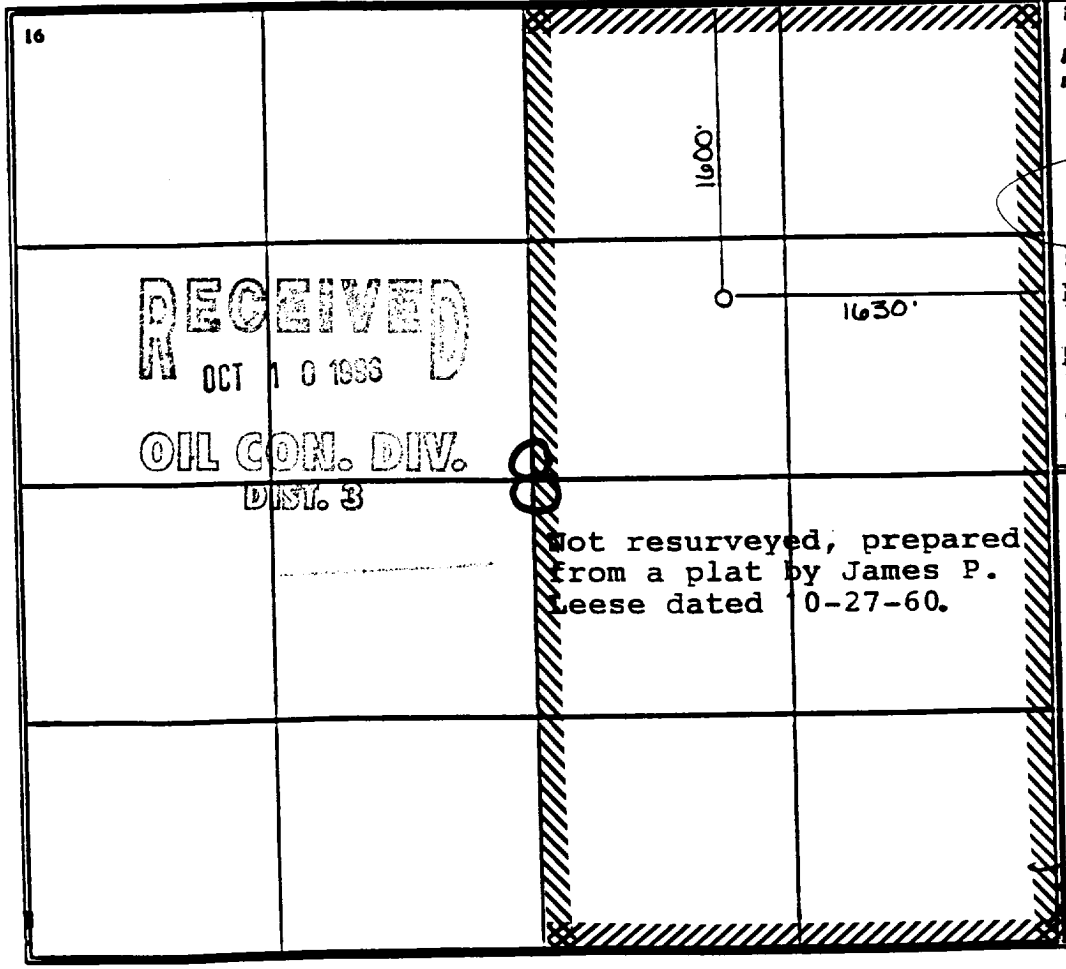
UL or lot no.	Section	Township	Range	Lot Idn	Feet from the	North/South line	Feet from the	East/West line	County
G	8	29 N	10 W		1600	North	1630	East	S.J.

Bottom Hole Location If Different From Surface

UL or lot no.	Section	Township	Range	Lot Idn	Feet from the	North/South line	Feet from the	East/West line	County

Dedicated Acres	Joint or Infill	Consolidation Code	Order No.
DK-E/308.68 MV-E/308.68			

NO ALLOWABLE WILL BE ASSIGNED TO THIS COMPLETION UNTIL ALL INTERESTS HAVE BEEN CONSOLIDATED OR A NON-STANDARD UNIT HAS BEEN APPROVED BY THE DIVISION



OPERATOR CERTIFICATION

I hereby certify that the information contained herein is true and complete to the best of my knowledge and belief

Signature

Peggy Bradfield
Printed Name

Regulatory Administrator
Title

9-24-96
Date

SURVEYOR CERTIFICATION

I hereby certify that the well location shown on this plat was plotted from field notes of actual surveys made by me or under my supervision, and that the same is true and correct to the best of my belief.

9-23-96
Date of Survey

Signature and Seal of Professional Surveyor:

NEALE C. EDWARDS
NEW MEXICO
6857

Certificate Number

NYE FEDERAL COM #2
Section 8G T29N R10W
MV/DK Payadd Procedure
Lat: 36.743393 Long: 107.904312

This procedure is the result of a 4 month long Dakota geological and completion efficiency study in Area 2 by C. Head and K. Killion. Any deviation from this procedure should be discussed with the authors prior to project implementation.

1. Test rig anchors and repair if necessary. Install 16-400 bbl frac tanks on location and fill with 2% KCl water. Filter all non-city water to 25 microns.

2. MOL and RU. Comply to all NMOCD, BLM, and MOI rules and regulations. Hold safety meeting. Record all wellhead pressures. **Pitot test well for 1 hour**. Kill well with 2% KCl water, if necessary. ND wellhead. NU BOP. Test operation of rams. NU relief lines.

3. TOOH laying down ≈ 6668' of 1-1/4" tubing (≈ 211 jts). Tally and inspect. Report any scale build-up on pipe. Change out equipment to run 2-3/8" tubing.

4. TIH with 2-3/8" J-55 tubing and 4-3/4" bit. Clean-out to 6800' with air and mist.** **Pitot test well for 1 hour.** Circulate hole with 2% KCl water. PUH to 6770'. RU stimulation company. Spot 300 gal 15% HCl across perforated interval.*** RD stimulation company. TOOH.

   **Do not drill out casing shoe at 6817'. The shoe is set in a high porosity wet sand. Note quality of cement while drilling out (drills hard, spotty, etc...).
   ***Acid should contain 5 gal/Mgal FE-1A (iron agent), 25#/Mgal FE-2 (iron agent), and 3 gal/Mgal HAI-81 (inhibitor)

5. RU wireline company with packoff. PU and RIH with CNL log. Log from 6800' - 6500' and from 4800'-3720'. POOH and LD CNL tool. PU and RIH with CBL tool. Log from 6800'- 1000'. POOH with CBL tool.

*****Lower Dakota*****

6. PU and RIH with Conventional 3-1/8" HEGS gun loaded 2 spf with DP34B 16 gram charges (Entrance hole=0.39, Penetration=10 in.). Perforate the Lower Dakota from 6748'- 6762' (28 holes).** POOH.

   **Do not perforate until engineer has evaluated CNL log.

7. PU and RIH with 5-1/2" RBP. Set RBP at 5000'. POOH. PU dump bailer. RIH and dump 2 sx sand on top of RBP at 5000'. POOH. PU and RIH with 3-3/8" port plug gun loaded 2 spf with DP38B 15 gram charges (Entrance hole=0.33",

Penetration=19 in.) Perforate two holes each at 4786' and 4560'. POOH and RD wireline company. TIH with 5-1/2" cement retainer and 2-3/8" tubing to 4580'. Set cement retainer. Attempt to circulate through squeeze holes. When returns have diminished, RU cementing company. "Suicide" squeeze the Lower Point Lookout interval with 50-60 sacks of Class "B" neat cement. Displace 100' above lower perforations. Sting out of retainer and POOH. WOC 12 hours before drilling out.

8. TIH with 4-3/4" bit and 2-3/8" tubing. Drill out cement and cement retainer. Pressure test squeeze holes to 1000 psi for 15 minutes. Record results. TOOH.

9. TIH with retrieving head on 2-3/8" tubing and retrieve 5-1/2" RBP at 5000'. POOH.

*****Lower Dakota (cont.)*****

10. TIH with 5-1/2" fullbore packer, 6 jts 2-7/8" 6.5# J-55 tubing, 2-7/8" x 3-1/2" crossover, and 3-1/2" 9.3# N-80 fracstring to surface. Set packer at 6730'. RU stimulation company. **Pressure test surface lines to 7000 psi**. Pump 1000 gals. of 15% HCl at 12-14 BPM.** Drop a total of 45 1.3 SG RCN ball sealers evenly spaced throughout the job. **Maximum pressure is 4800 psi. Anticipated surface treating pressure is 3500 psi at 14 BPM.** RD stimulation company. Unseat packer and TIH to knock balls off perfs. After perfs have been cleared, PUH and reset packer at 6730'. RU lubricator and swabbing equipment. Swab well to 3-1/2" crossover to recover load fluid. Continue swabbing until load is recovered and/or well kicks-off. **Pitot test well for 1 hour.** RD swab equipment and lubricator. Contact Production Engineering on results of test. Engineer will decide whether to fracture stimulate the lower Dakota interval to enhance production or proceed on to step **#12.**

    **Acid should contain 5 gal/Mgal FE-1A (iron agent), 25#/Mgal FE-2 (iron agent), 3 gal/Mgal HAI-81 (inhibitor), and 2 gal/Mgal SGA-HT

11. RU stimulation company. Hold safety meeting with **all** personnel. Pressure test surface lines to 9000 psi. **MAXIMUM PRESSURE IS 8000 PSI** (pipe friction in frac string = 3085 psi @ 20 BPM). **Anticipated surface treating pressure is 6050 psi at 20 BPM.**** Tag sand with 0.40 mCi/Mlbs Iridium-192. Monitor backside pressure during frac. Monitor bottomhole and surface treating pressure, rate, foam quality, and sand concentration with computer van. Frac during daylight **only**.

    **NOTE: Anticipated maximum treating pressure is 5350 psi (friction = 2124 psi) and 7100 psi (friction = 4112 psi) at 15 BPM and 25 BPM, respectively.

12. Fracture stimulate the lower Dakota interval using the following schedule:

Stage	Fluid Type	Downhole Foam Vol. (Gals.)	Clean Gel Vol. (Gals.)	Sand Vol. (lbs.)
Pad**	30# LG	10,000	3,000	
1.0 ppg	30# LG	5,500	1,650	5,500
1.5 ppg	30# LG	6,000	1,800	9,000
2.0 ppg	30# LG	9,000	2,700	18,000
3.0 ppg	30# LG	2,500	750	7,500
Flush	30# LG	2,400	720	
Totals		**35,400**	**10,620**	**40,000**

**Frac fluid should contain 0.18#/Mgal BE-6 (biocide), 30#/Mgal WG-19 (gelling agent), 0.25gal/Mgal BA-20 (pH buffer), 4gal/Mgal AQF-2 (foamer), 2gal/Mgal SSO-21M (surfactant), and 0.4#/Mgal SP (breaker).

13. Shut-in well immediately after stimulation for 3 hours to allow gel to break. Record ISIP, 5, 10, and 15 minute shut-in pressures.

14. After gel breaks, open well through choke manifold and monitor flow. Flow at 20 bbls/hr, or less, if sand is observed.

15. When well ceases to flow, unseat packer, TOOH, and LD 3-1/2" fracstring. Change-out equipment to run 2-3/8" tubing.

16. TIH with 2-3/8" tubing and notched collar and clean-out to 6800' until sand returns are minimal. **Take Pitot gauge for 1 hour.** When water returns are less than 2 BPH, TOOH.

17. PU, RIH, and set 5-1/2" RBP at 6600' on 2-3/8" tubing. Pressure backside to 1000 psi with rig pump for 15 minutes.*** Record results. Retrieve BP at 6600' and PUH to 4850'. Set 5-1/2" RBP. Circulate hole with 2% KCl water. PUH to 4730'. RU stimulation company. Spot 500 gal 15% HCl across perf interval. RD stimulation company. TOOH.

    ***If pressure test does not hold, TIH with packer and tubing and locate failure. Contact Production Engineering and a repair procedure will be provided.

18. RU wireline company. Run dump bailer and dump 2 sxs sand on top of the RBP. POOH with dump bailer. RD wireline company.

19. TIH with 5-1/2" fullbore packer and 1500' of 2-3/8" tubing.** Set packer. Pressure test RBP and casing to 3850 psi for 15 minutes.*** Record results. Release packer and TOOH.

**A casing squeeze was performed at 1210' on 3/96.
***If pressure test does not hold, TIH with packer and tubing and locate failure. Contact Production Engineering and a repair procedure will be provided.

*****Point Lookout*****

20. Perforate with 3-1/8" Conventional HSC with charges meeting requirements for average penetration in Berea of 12.0" and average perf diameter of 0.35". Perforate the following Point Lookout intervals with 1 spf. Perforate top down.

4460'	4540'	4638'
4470'	4560'	4646'
4480'	4565'	4656'
4490'	4574'	4677'
4500'	4580'	4695'
4510'	4596'	4700'
4520'	4616'	4726'
4530'	4630'	

Total: 23 holes.
POOH and RD wireline company.

21. TIH with 5-1/2" fullbore packer on 2-3/8" tubing and set at 4350'. If casing squeeze was required below 4350', TIH below squeeze hole with 5-1/2" packer and 2-3/8" tubing. RU stimulation company and prepare to breakdown and balloff with acid.***** Test surface lines to 5000 psi. Maximum pressure is 4000 psi. Anticipated surface treating pressure is 2300 psi at 12 BPM.** Pump 500 gal. of 15% HCl at 10-12 bbls/min. Drop a total of 40 7/8" 1.3 sp. gr. RCN ball sealers spaced evenly throughout the job. Record injection rate and all breakdown pressures throughout job. RD stimulation company. Unseat packer and TIH to knock balls off perfs. TOOH with tubing and packer.

***Acid should contain 5 gal/Mgal FE-1A (iron agent), 25#/Mgal FE-2 (iron agent), 3 gal/Mgal HAI-81 (inhibitor), and 2 gal/Mgal SGA-HT.

22. TIH with 5-1/2" fullbore packer on 3-1/2" tubing and set at 1500' only if casing tested. If casing squeeze was required, TIH to below squeeze hole with 5-1/2" packer and 3-1/2" frac string. RU stimulation company. Hold safety meeting.
Pressure test surface lines to 4850 psi.
Maximum treating pressure is 3850 psi.
Anticipated surface treating pressure is 3276 psi at 60 BPM.

Fracture Point Lookout according to the following schedule:

Fluid Type	Clean Volume Bbl	Prop. Conc. ppg	Total Prop. lbs	Proppant Type	Slurry Rate BPM
Slickwater**	281				60
Slickwater	952	0.50	20,000	20/40	60
Slickwater	833	1.00	35,000	20/40	60
Slickwater	714	1.50	45,000	20/40	60
Flush	83				60
Totals	***2,865***		***100,000***		

**Frac fluid should contain 0.5 gal/Mgal friction reducer, 2 gal/Mgal surfactant, and 0.3#/Mgal bacteriacide. All sand will be traced with 0.4 mCi/Mlbs Ir-192.

23. After 75% of the flush volume has been pumped, cut rate in half. Underflush top perf by 10% if well goes on a vacuum, otherwise, flush to top perf. RD stimulation company. Shut-in well for 1 hour to allow sand to fall. Flow well back at 20 bbls/hr (if necessary) until pressure decreases enough to release packer. Release packer and TOOH.

24. RU wireline company. Set 5-1/2" RBP at 4420'. RD wireline company. TIH with 5-1/2" fullbore packer on 2-3/8" tubing and set at 1500'. Pressure test RBP and casing to 3850 psi for 15 minutes. Record results. Release packer and TOOH. RU wireline company. Run dump bailer and dump 2 sxs sand on top of the RBP. POOH with dump bailer.

*****Menefee*****

25. Perforate with 3-1/8" Conventional HSC with charges meeting requirements for average penetration in Berea of 12.0" and average perf diameter of 0.35". Perf the following Menefee intervals with 1 shot every 4 foot.

4354'-4378' (7)
4320'-4324 (2)
4294'-4298' (2)
4266'-4270' (2)
4256'-4260' (2)
4222'-4234' (4)
4170'-4182' (4)
4132'-4136' (2)
4094'-4098' (2)

Total: 27 holes.
POOH and RD wireline company.

26. TIH with 5-1/2" fullbore packer on 2-3/8" tubing to 4380'. Spot 350 gal 15% Hcl across perforated interval. PUH with packer and set at 3950'. If casing squeeze was required below 3950', TIH to below squeeze hole with 5-1/2" packer and 2-3/8" tubing. RU stimulation company and prepare to breakdown and balloff with

acid.*** **Pressure test surface lines to 5000 psi.** Pump 750 gal of 15% HCl at 10-12 bbls/min. Drop a total of 50 7/8" 1.3 sp. gr. RCN ball sealers spaced evenly throughout the job. Record injection rate and all breakdown pressures throughout job. **Maximum pressure is 4000 psi. Anticipated surface treating pressure is 2905 psi at 12 BPM.** RD stimulation company. Release packer and TIH to knock balls off perfs. TOOH with tubing and packer.

***Acid should contain 5 gal/Mgal FE-1A (iron agent), 25#/Mgal FE-2 (iron agent), 3 gal/Mgal HAI-81 (inhibitor), and 2 gal/Mgal SGA-HT.

27. TIH with 5-1/2" fullbore packer on 3-1/2" tubing and set at 1500' only if casing tested. If casing squeeze was required, TIH to below squeeze hole with 5-1/2" packer and 3-1/2" frac string. RU stimulation company. Hold safety meeting.
Pressure test surface lines to 4850 psi.
Maximum treating pressure is 3850 psi.
Anticipated surface treating pressure is 3483 psi at 55 BPM.

Fracture Menefee according to the following schedule:

Fluid Type	Clean Volume Bbl	Prop. Conc. ppg	Total Prop. lbs	Proppant Type	Slurry Rate BPM
Slickwater**	281				55
Slickwater	952	0.50	20,000	20/40	55
Slickwater	833	1.00	35,000	20/40	55
Slickwater	714	1.50	45,000	20/40	55
Flush	75				55
Totals	***2,856***		***100,000***		

***Frac fluid should contain 0.5 gal/Mgal friction reducer, 2 gal/Mgal surfactant, and 0.3#/Mgal bacteriacide. All sand will be traced with 0.4 mCi/Mlbs Ir-192.

28. Flush to top perf. RD stimulation company. Shut-in well for 2 hours. Record ISIP, 5, 10, and 15 minute shut-in pressures. Flow well back at 20 bbls/hr until pressure decreases enough to release packer. Release packer and TOOH.

29. Flow back well at 20 bbls/hr until returns diminish. TIH with retrieving head and 2-3/8" tubing and clean out to RBP at 4420' until sand returns are minimal and water production is less than 2 BPH. Obtain **stabilized pitot** gauge. Release bridge plug and TOOH.

30. Flow back well at 20 bbls/hr until returns diminish. TIH with retrieving head and 2-3/8" tubing and clean out to RBP at 4850' until sand returns are minimal and water production is less than 2 BPH. Obtain **stabilized pitot** gauge. Release bridge plug and TOOH.

31. TIH with notched collar on 2-3/8" tubing and clean out to PBTD at 6800' until sand returns are minimal and water production is less than 2 BPH. Obtain **stabilized pitot** gauge. TOOH.

32. RU wireline company with lubricator and run After - Frac log from 6800'-6540' and from 4750'-4050'. POOH and RD wireline company.

33. TIH with expendable check, 1 jt 2-3/8" tubing, standard seating nipple, ≈ 54 jts 2-3/8" tubing, 5-1/2" retrievable fullbore packer, and 2-3/8" tubing to surface. Land tubing string at 6750'. Packer should be set at ≈ 5015'.

34. ND BOP and NU wellhead. Pump off plug. **Take final Pitot gauge and water sample from each formation.** Rig down and release rig.

35. Will move back on well to remove packer and commingle well when the proper regulatory approval has been recieved.

Approve: _____ 8/26/96
Team Leader

Approve: _____
Drilling Superintendent

VENDORS:

Wireline:	Schlumberger	325-5006
Fracturing:	Halliburton	325-3575
R.A. tagging	Protechnics	326-7133
Production Engineer	Office	599-4041
	Home	325-6579

KKK

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Pertinent Data Sheet - Nye Federal Com #2

Location: 1600' FNL & 1630' FEL, Unit G, Section 8, T29N, R10W, San Juan County, New Mexico

Field: Basin Dakota
Blanco Mesaverde

Elevation: 5781' GL
5792' KB

TD: 6818'
PBTD: 6775' (COTD)

Completed: 1/28/60

Spud Date: 12/14/60

DP #: 50400A

Casing Record:

Hole Size	Csg Size	Wt. & Grade	Depth Set	Cement (Top)
12-1/4"	8-5/8"	24.0# J-55	360'	225 sx (surf)
7-7/8'	5-1/2"	15.5# J-55	6817'	425sx. (3 stages)

Cement:

Surface: Set 349' of 8-5/8" casing at 360'. Cemented with 225 sacks 50/50 Poxmix w/ 2% CaCl2. Circulated to surface

1st Stage: Cemented with 175 sacks 50/50 Diamix w/4% gel. Top of CMT @ 5735' calc. (75%)

2nd Stage: Cemented with 150 sacks 50/50 Diamix w/2% gel & 12-1/2# Gilsonite/sx . Stage collar set @ 4551'. Top of CMT @ 3558' calc. (75%)

3rd Stage: Cemented with 100 sacks 50/50 Diamix w/4% gel. Stage collar set @ 2267'. Top of CMT @ 1648' calc. (75%) 3/96 SQZ TOC 130' (CBL)

Tubing Record:

Tbg. Size	Wt. & Grade	Depth Set
1-1/4"	2.4# J55	≈ 6668' (≈ 211 jts) SN 1 jt off bottom

Formation Tops:

Ojo Alamo	928'	Menefee	3930'
Kirtland	1039'	Point Lookout	4460'
Fruitland	1850'	Gallup	5679'
Pictured Cliffs	2157'	Greenhorn	6420'
Cliffhouse	3737'	Dakota	6548'

Logging Record: IEL, FORXO, CBL

Stimulation: Perf'd Dakota: 4 shots/foot -6612'-6640', 6667'-6676', 6700'-6704', and 6712'-6719' . Frac'd w/ 68,000# 20/40 and 68,000 gal slickwater. Dropped 50balls.

Workover History:

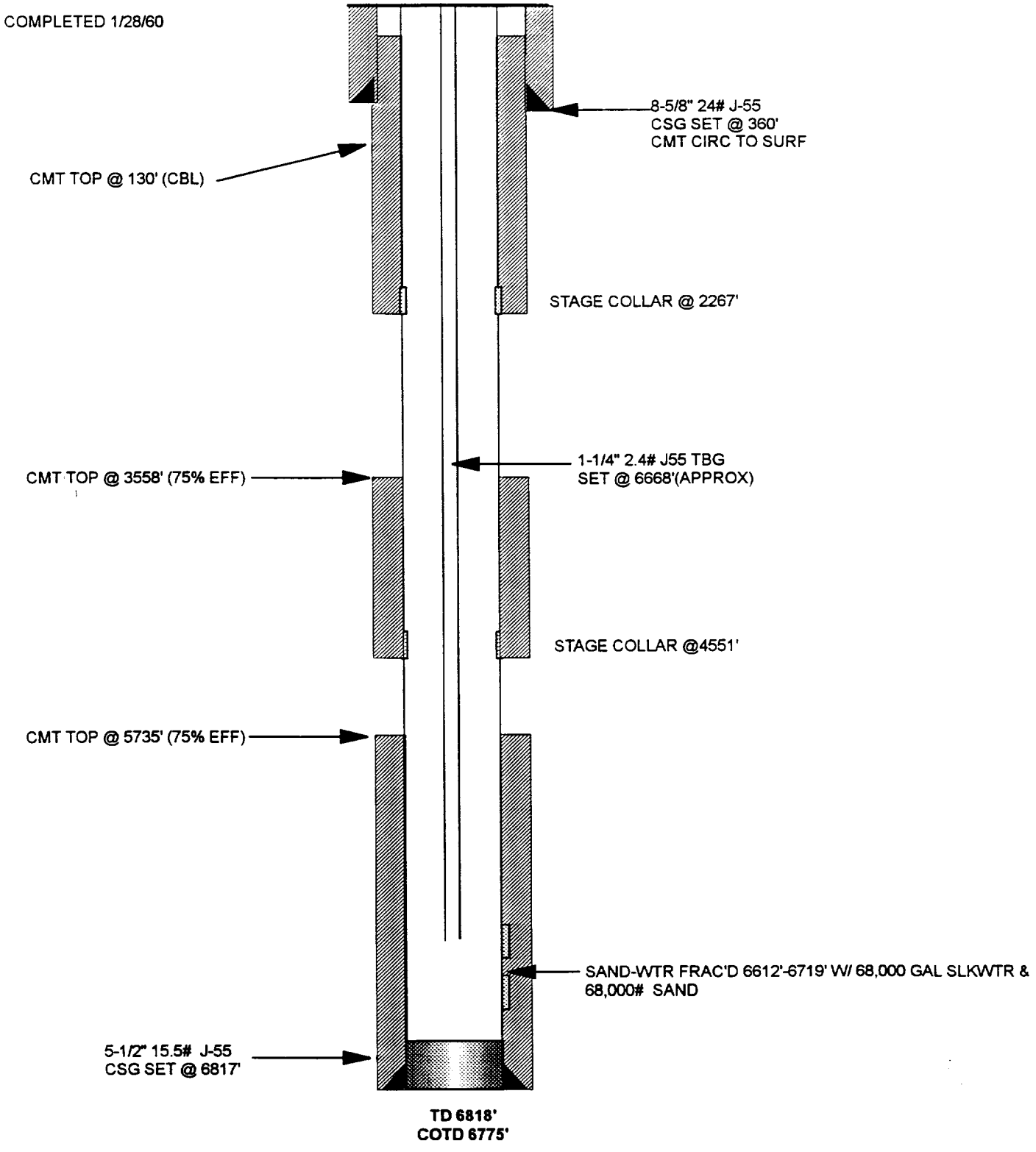
2/12/88: Found hole in tubing. Replaced bad jt and returned to production.
3/11/96: SQZ casing failure at 1210' w/ 350 sx Cls B w/ 2% CaCl2. TOC @ 130' (CBL)
4/15/96: Broach tubing

NYE FEDERAL COM #2

CURRENT

BASIN DAKOTA

UNIT G, SEC 8,T29N, R10W, SAN JUAN COUNTY, NM



NYE FEDERAL COM #2

PROPOSED

BASIN DAKOTA/BLANCO MESAVERDE

UNIT G, SEC 8,T29N, R10W, SAN JUAN COUNTY, NM