CASE 7116: DE NOVO SOUTHLAND ROYALTY COMPANY FOR DESIGNATION OF A TIGHT FORMATION, SAN JUAN COUNTY, NEW MEXICO
SEPTEMBER 29, 1981

Inc.

CASE NO.

7116

APPLICATION,
TRANSCRIPTS,
SMALL EXHIBITS,

ETC.

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON 20426

JAN 04 1985

IN REPLY REFER TO: N840-A

Mr. W. Perry Pearce
Department of Energy and Minerals
Oil Conservation Division
P.O. Box 2088
Santa Fe, New Mexico 87501

In Re: Tight Formation Recommendation
Docket No. RM79-76-115
(New Mexico-14)

Dakota Producing Interval
San Juan County, New Mexico
Case No. 7116 De NOVO
Order No. R-6747-A

Dear Mr. Pearce:

On April 19, 1982, the Commission received from the State of New Mexico Oil Conservation Division (New Mexico) a recommendation that the Dakota Producing Interval located in San Juan County, New Mexico, be designated as a tight formation.

On June 24, 1982, a letter (copy attached) was sent to New Mexico requesting additional information. No response was received by the Commission, and in May 1983 a member of your staff, Mr. Stogner, in a telephone conversation with our staff member Mr. Boyle, related that the information request had been passed on to the applicant which had not yet provided the additional information to New Mexico.

Over two years have passed since our letter was sent, therefore, please advise us of the current status of the recommendation and whether or not any progress has been made in resolving the problems. If no further progress can be made on this recommendation, please so advise and we will present it to the Commission for appropriate disposition.

Please advise if I may be of any assistance in this matter.

Very truly yours,

Howard Kilchrist

Howard Kilchrist, Director
Division of Producer Audits
and Pricing

cc: Department of the Interior
Bureau of Land Management
Albuquerque District Office (NGPA)
P.O. Box 6770
Albuquerque, New Mexico 87107

RECEIVED
JAN 11 1985
OIL CONSERVATION DIVISION
SANTA FE

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

JUN 2 4 1982

IN REPLY REFER TO: N840-A

Mr. W. Perry Pearce
Department of Energy and Minerals
Oil Conservation Division
P.O. Box 2088
Santa Fe, New Mexico 87501

In Re: State of New Mexico Recommendation
RM79-76-115
(New Mexico-14)
Dakota Producing Interval
San Juan County, New Mexico
Case No. 7116 De Novo
Order No. R-6747-A

Dear Mr. Pearce:

Staff review of the referenced tight formation recommendation indicates that additional information is required in order to complete our analysis. As related to a member of your staff, Mr. Stogner, in a telephone conversation of June 10, 1982, with our staff member Mr. Boyle, the area is subject to New Mexico Order No. R-1670-V, issued on May 22, 1979, which authorizes infill drilling in the Basin-Dakota Gas Pool. Accordingly, the spud dates of the existing wells are needed in order to determine the extent of development in the recommended area at the time the infill order was issued.

Your assistance in obtaining this additional information will be greatly appreciated.

Very truly yours,

Howard Kilchrist

Howard Kilchrist, Director
Division of NGPA Compliance

STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION DIVISION

January 17, 1985

TONEY ANAYA
GOVERNOR

POST OFFICE BOX 2088
STATE LAND OFFICE BUILDING
SANTA FE, NEW MEXICO 87501
(505) 827-5600

Federal Energy Regulatory Commission
Department of Energy
825 South Capitol Street
Washington, D.C. 20426

Attention: Howard Kilchrist,Director
Division of Producer Audits
and Pricing

RE: Tight Formation Recommendation
Docket No. RM79-76-115
(New Mexico-14)

Dakota Producing Interval
San Juan County, New Mexico
Case No. 7116 De NOVA
Order No. R-6747-A

Dear Mr. Kilchrist:

Per your letter dated January 4, 1985, enclosed please find a copy of either the NMOCD Form C-105, Completion Report, or the U.S. Interior Department's Form 9-330 for each well within the approved area as described in the subject Order No. R-6747-A. These forms show the spud date for the well along with other pertinent well data.

If any further information is required, please contact me. Thank you.

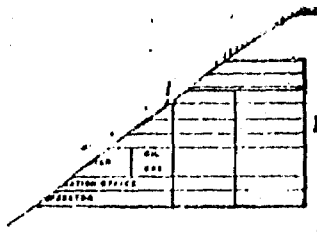
Sincerely,

MICHAEL E. STOGNER
Acting Chief Engineer

MS/db

cc: Department of Interior
Bureau of Land Management
Albuquerque Districe Office(NGPA)
P.O. Box 6770
Albuquerque, New Mexico 87107

Consolidated Oil & Gas, Inc.
1860 Lincoln Street
Suite 1300
Denver, Colorado 80295

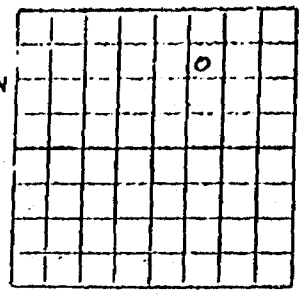


NEW MEXICO OIL CONSERVATION COMMISSION

MAIN OFFICE OCC Santa Fe, New Mexico

1962 JAN 12 AM 8:33

WELL RECORD



AREA 640 ACRES
LOCATE WELL CORRECTLY

Mail to District Office, Oil Conservation Commission, to which Form C-101 was sent not later than twenty days after completion of well. Follow instructions in Rules and Regulations of the Commission. Submit in QUINTUPLICATE. If State Land submit 6 Copies

Consolidated Oil & Gas, Inc. (Company or Operator) Wilmerding (Lease)

Well No. 1-9, in NW ¼ of NE ¼, of Sec. 9, T. 31N, R. 13W, NMPM.

Basin Dakota & Blanco Mesaverde Pool, San Juan County.

Well is 1090' feet from North line and 1750' feet from East line of Section 9. If State Land the Oil and Gas Lease No. is

Drilling Commenced October 11, 1961 Drilling was Completed November 12, 1961

Name of Drilling Contractor Huron Drilling Company

Address 2415 Mercantile Bank Building, Dallas, Texas

Elevation above sea level at Top of Tubing Head 5817, 5829 KB The information given is to be kept confidential until , 19

OIL SANDS OR ZONES

G No. 1, from 4451' to 4660' No. 4, from to

G No. 2, from 6630' to 6780' No. 5, from to

No. 3, from to No. 6, from to

IMPORTANT WATER SANDS

Include data on rate of water inflow and elevation to which water rose in hole.

No. 1, from to feet.

No. 2, from to feet.

No. 3, from to feet.

No. 4, from to feet.

RECEIVED JAN 4 1962 OIL CON. COM. DIST.

CASING RECORD

SIZE	WEIGHT PER FOOT	NEW OR USED	AMOUNT	KIND OF SHOE	CUT AND PULLED FROM	PERFORATIONS	PURPOSE
9 5/8	32.75	New	190	Guide		Sea Reverse	Surface
5 1/2	15.5	New	6800	Float		"	Production

MUDDING AND CEMENTING RECORD

SIZE OF HOLE	SIZE OF CASING	WHERE SET	NO. SACKS OF CEMENT	METHOD USED	MUD GRAVITY	AMOUNT OF MUD USED
13 3/4	9 5/8	190	140	Pump & plug		
7 7/8	5 1/2	6800	125 w/	1/2 cu. ft. Starta-Crete per sack thru shoe		
			100 sx	50-50 Pozmix thru stage collar at 4767'.		
			Squeezed shoe with 16 sx.			

RECORD OF PRODUCTION AND STIMULATION

(Record the Process used, No. of Qts. or Gals. used, interval treated or shot.)

Mesaverde-Sand-water frac with 100,000# 20-40 mesh sand, 72,000 gal. water spearhead with 1,000 gal. 15% acid.

Dakota--Sand-water frac with 100,000# 20-40 & 10-20 mesh sand and 103,000 gal. slicked water.

Result of Production Stimulation Production before stimulation -0- after- Mesaverde; actual flow 3 hour initial potential test - 344 MCFD, calculated absolute open flow 852 MCFD

Dakota - actual flow 3 hour initial potential 1080 MCFD Depth Cleaned Out 6780'

Form 9-330
(Rev. 5-63)

IWR-3-3-81 APD appd 8-31-79

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN DUPLICATE* (See other instructions on reverse side)

Form approved.
Budget Bureau No. 42-R355.5.

WELL COMPLETION OR RECOMPLETION REPORT AND LOG *

5. LEASE DESIGNATION AND SERIAL NO.: ~~N/A~~ 080280

6. IF INDIAN, ALLOTTEE OR TRIBE NAME: N/A

1a. TYPE OF WELL: OIL WELL ☐ GAS WELL ☒ DRY ☐ Other Dual Completion

b. TYPE OF COMPLETION: NEW WELL ☒ WORK OVER ☐ DEEP-EN ☐ PLUG BACK ☐ DIFF. RESVR. ☐ Other

7. UNIT AGREEMENT NAME: N/A

2. NAME OF OPERATOR: Getty Oil Company

8. FARM OR LEASE NAME: Mexico Federal R

3. ADDRESS OF OPERATOR: P.O. Box 3360 Casper, Wyoming 82602

9. WELL NO.: #1 EM

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements)*
At surface: ~~1120~~ 1130' FNL & 1805' FWL
At top prod. interval reported below
At total depth

10. FIELD AND POOL, OR WILDCAT: ~~Blanco Mesa Verde~~-Basin Dakota

11. SEC., T., R., M., OR BLOCK AND SURVEY OR AREA: Sec 12-T31N-R13W

RECEIVED MAR 2 1981 U.S. GEOLOGICAL SURVEY FARMINGTON, NEW MEXICO

14. PERMIT NO.	DATE ISSUED	12. COUNTY OR PARISH	13. STATE
		San Juan	New Mexico

15. DATE SPUDDED	16. DATE T.D. REACHED	17. DATE COMPL. (Ready to prod.)	18. ELEVATIONS (DF, RKB, RT, GR, ETC.)*	19. ELEV. CASINGHEAD
10-12-80	11-25-80	1-10-81	5794 GR	5795'

20. TOTAL DEPTH, MD & TVD	21. PLUG, BACK T.D., MD & TVD	22. IF MULTIPLE COMPL., HOW MANY*	23. INTERVALS DRILLED BY	ROTARY TOOLS	CABLE TOOLS
6910	6870	2	→	0-6910'	0

24. PRODUCING INTERVAL(S), OF THIS COMPLETION—TOP, BOTTOM, NAME (MD AND TVD)*
Dakota 6820 - 6842' and 6722 - 6800'.
Mesa Verde 4456 - 4725'

25. WAS DIRECTIONAL SURVEY MADE: No

26. TYPE ELECTRIC AND OTHER LOGS RUN
Dual Induction - SFL Compensated Neutron - Formation Density

27. WAS WELL CORED

RECEIVED MAR 13 1981 OIL CON. COM. DIST. 3

28. CASING RECORD (Report all strings set in well)

CASING SIZE	WEIGHT, LB./FT.	DEPTH SET (MD)	HOLE SIZE	CEMENTING RECORD	AMOUNT PULLED
10 3/4"	32.75	268	14 3/4"	275 sks	
7 7/8"	26.4	4072	9 3/4"	1050 sks	

29. LINER RECORD

SIZE	TOP (MD)	BOTTOM (MD)	SACKS CEMENT*	SCREEN (MD)
5 1/2"	3923	6910	575	

30. TUBING RECORD

SIZE	DEPTH SET (MD)	PACKER SET (MD)
	(685' 1" &	
2 3/8"	3894' 2 3/8")	4589'
	6653	4800'

31. PERFORATION RECORD (Interval, size and number)
Dakota w/23 holes-0.44 Jets from 6820-6842'
Dakota w/25 - 0.44" Holes at 6722-24',26,28, 29,30,32,34,36,38,40,60,61,62,63,64,65,66, 93,94,96,97,98,99, and 6800'.

32. ACID, SHOT, FRACTURE, CEMENT SQUEEZE, ETC.

DEPTH INTERVAL (MD)	AMOUNT AND KIND OF MATERIAL USED
6820-6842'	34 BBLS 15% HCL
	(See Attached)
6722-6800'	1500 Gal 15% HCL
	(See Attached)

33.* PRODUCTION

DATE FIRST PRODUCTION	PRODUCTION METHOD (Flowing, gas lift, pumping—size and type of pump)	WELL STATUS (Producing or shut-in)
Dakota 6-6-80	Dakota Flowing	Shut In

DATE OF TEST	HOURS TESTED	CHOKE SIZE	PROD'N. FOR TEST PERIOD →	OIL—BBL.	GAS—MCF.	WATER—BBL.	GAS-OIL RATIO
1-5-81	3	3/4"		0	58	15	0

FLOW. TUBING PRESS.	CASING PRESSURE	CALCULATED 24-HOUR RATE →	OIL—BBL.	GAS—MCF.	WATER—BBL.	OIL GRAVITY-API (CORR.)
24	Packer		0	AOF 467 MCFD	0	0

34. DISPOSITION OF GAS (Sold, used for fuel, vented, etc.)
Vented

TEST WITNESSED BY: Mark Kramer

35. LIST OF ATTACHMENTS
See attached Mesa Verde Test

OIL CON. COM. MAR 19 1981 DIST. 3

36. I hereby certify that the foregoing and attached information is complete and correct as determined from all available records

SIGNED Charles E Mowry for TITLE Area Superintendent DATE 3/13/81

SANTA FE

*(See Instructions and Spaces for Additional Data on Reverse Side)

FARMINGTON DIST.

NMOCC

Form 9-330
(Rev. 5-63)

SUBMIT IN DUPLICATE* (See other instructions on reverse side)

Form approved.
Budget Bureau No. 42-R355.5.

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

WELL COMPLETION OR RECOMPLETION REPORT AND LOG*

5. LEASE DESIGNATION AND SERIAL NO.: USA NM-10183

6. IF INDIAN, ALLOTTEE OR TRIBE NAME:

7. UNIT AGREEMENT NAME:

8. FARM OR LEASE NAME: Mexico-Federal "R"

9. WELL NO.: 1

10. FIELD AND POOL, OR WILDCAT: Basin Dakota

11. SEC., T., R., M., OR BLOCK AND SURVEY OR AREA: Sec. 12-T31N-R13W

1a. TYPE OF WELL: OIL WELL ☐ GAS WELL XX DRY ☐ Other

b. TYPE OF COMPLETION: NEW WELL X WORK OVER ☐ DEEP-EN ☐ PLUG BACK ☐ DIFF. RESVR. ☐ Other

2. NAME OF OPERATOR: Skelly Oil Company

3. ADDRESS OF OPERATOR: Box 3360, Casper, WY 82602

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements)*
At surface: 1830' FNL & 790' FEL Sec. 12-T31N-R13W
At top prod. interval reported below
At total depth: Same

14. PERMIT NO. | DATE ISSUED

12. COUNTY OR PARISH: San Juan | 13. STATE: NM

15. DATE SPUDDED	16. DATE T.D. REACHED	17. DATE COMPL. (Ready to prod.)	18. ELEVATIONS (DF, RKB, RT, GR, ETC.)*	19. ELEV. CASINGHEAD
9/8/76	9/21/76	10/28/76	5799' GR 5811' KB	-----

20. TOTAL DEPTH, MD & TVD	21. PLUG, BACK T.D., MD & TVD	22. IF MULTIPLE COMPL., HOW MANY*	23. INTERVALS DRILLED BY	ROTARY TOOLS	CABLE TOOLS
6900'	6900'		→	0-6900	--

24. PRODUCING INTERVAL(S), OF THIS COMPLETION—TOP, BOTTOM, NAME (MD AND TVD)*: Basin Dakota

25. WAS DIRECTIONAL SURVEY MADE: No

26. TYPE ELECTRIC AND OTHER LOGS RUN: Dual Induction & Formation Density & Gamma Ray

27. WAS WELL CORED: No

28. CASING RECORD (Report all strings set in well)

CASING SIZE	WEIGHT, LB./FT.	DEPTH SET (MD)	HOLE SIZE	CEMENTING RECORD	AMOUNT PULLED
10 3/4" OD	32.75#	223'	15 1/2"	225 sks	None
7 5/8" OD	26.4#	3909'	9 7/8"	850 sks	None

29. LINER RECORD

SIZE	TOP (MD)	BOTTOM (MD)	SACKS CEMENT*	SCREEN (MD)
5 1/2" od	3755'	6890'	336	---

30. TUBING RECORD

SIZE	DEPTH SET (MD)	PACKER SET (MD)
2 3/8"	6650'	-----

31. PERFORATION RECORD (Interval, size and number)
6665-75'; 6685-6705'; 6730-50';
6788-92'; 6816-28'; 6870-90';
1 shot per foot

32. ACID, SHOT, FRACTURE, CEMENT SQUEEZE, ETC.

DEPTH INTERVAL (MD)	AMOUNT AND KIND OF MATERIAL USED
6665-6890'	Treated w/4500 gals acid & 90,000 gals slick water & 61,400# sand.

33.* PRODUCTION

DATE FIRST PRODUCTION	PRODUCTION METHOD (Flowing, gas lift, pumping—size and type of pump)	WELL STATUS (Producing or shut-in)
shut-in	flowing	shut-in

DATE OF TEST	HOURS TESTED	CHOKE SIZE	PROD'N. FOR TEST PERIOD →	OIL—BBL.	GAS—MCF.	WATER—BBL.	GAS-OIL RATIO
11/9/76	24	48/64"		2 bbls condensate	1246	+14/day	---

FLOW. TUBING PRESS.	CASING PRESSURE	CALCULATED 24-HOUR RATE →	OIL—BBL.	GAS—MCF.	WATER—BBL.	OIL GRAVITY-API (CORR.)
305	520		---	----	-----	-----

34. DISPOSITION OF GAS (Sold, used for fuel, vented, etc.): Shut-in for P. L. connection

TEST WITNESSED BY: JAN 17 1977

35. LIST OF ATTACHMENTS

RECEIVED
JAN 21 1977
U. S. GEOLOGICAL SURVEY

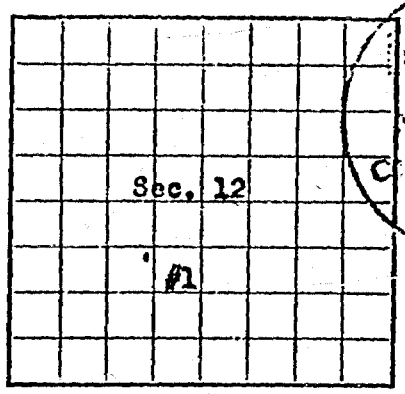
36. I hereby certify that the foregoing and attached information is complete and correct as determined from all available records

SIGNED: [signature] TITLE: Area Superintendent DATE: 1/13/77

JAN 20 1977

*(See Instructions and Spaces for Additional Data on Reverse Side)

orm 9-330



LOCATE WELL CORRECTLY

RECEIVED
NOV 6 1961
OIL CON. COM.
DIST. 3

Budget Bureau No. [illegible]
Approval expires 12-31-60.

U. S. LAND OFFICE [illegible]
SERIAL NUMBER [illegible]
LEASE OR PERMIT TO PROSPECT .....

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

U. S. GEOLOGICAL SURVEY
FARMINGTON, NEW MEXICO

LOG OF OIL OR GAS WELL

Company Skelly Oil Company Address Box 38 - Hobbs, New Mexico

Lessor or Tract Mexico-Fed "H" Field Basin Dakota & Blanco Mesaverde State New Mexico

Well No. 1 Sec. 12 T. 31N R. 13W Meridian N.M.P.M. County San Juan

Location 1850 ft. {N. / S} of S Line and 1650 ft. {E. / W} of W Line of Section 12 Elevation 5786' DF
(Derrick floor relative to sea level)

The information given herewith is a complete and correct record of the well and all work done thereon so far as can be determined from all available records.

Signed J. R. Cuba

Date October 31, 1961 Title Dist. Supt.

The summary on this page is for the condition of the well at above date.

Commenced drilling April 22, 1961 Finished drilling May 9, 19 61

OIL OR GAS SANDS OR ZONES

(Denote gas by G)

No. 1, from 4436' to 4630' (G) No. 4, from ..... to .....

No. 2, from 6652' to 6687' (G) No. 5, from ..... to .....

No. 3, from 6792' to 6796' (G) No. 6, from ..... to .....

IMPORTANT WATER SANDS

No. 1, from ..... to ..... No. 3, from ..... to .....

No. 2, from ..... to ..... No. 4, from ..... to .....

CASING RECORD

Size casing	Weight per foot	Threads per inch	Make	Amount	Kind of shoe	Cut and pulled from	Perforated From—	Perforated To—	Purpose
8-5/8"	24#	8-R	J-55	254'	Guide	—	—	—	Surface
4-1/2"	11.6#	8-R	J-55	6841'	Float	—	4435'	4532'	Oil String
	& 9.5#						6580'	6800'	

MUDDING AND CEMENTING RECORD

Size casing	Where set	Number sacks of cement	Method used	Mud gravity	Amount of mud used
8-5/8"	273'	200	Pump & Plug	—	—
4-1/2"	6855'	700	Pump & Plug	—	—

MARK

Form 9-330
(Rev. 5-63)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN DUPLICATE* (See other instructions on reverse side)

Form approved.
Budget Bureau No. 42-R355.5.

WELL COMPLETION OR RECOMPLETION REPORT AND LOG*

1a. TYPE OF WELL: OIL WELL ☐ GAS WELL ☒ DRY ☐ Other

b. TYPE OF COMPLETION: NEW WELL ☒ WORK OVER ☐ DEEP-EN ☐ PLUG BACK ☐ DIFF. RESVR. ☐ Other

2. NAME OF OPERATOR: Getty Oil Company

3. ADDRESS OF OPERATOR: Box 3360, Casper, Wyoming 82602

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements)*
At surface: 1025' FSL - 1120' FEL
At top prod. interval reported below
At total depth

5. LEASE DESIGNATION AND SERIAL NO.: ~~NM-080-280~~ N.M. 08028C
6. IF INDIAN, ALLOTTEE OR TRIBE NAME: N/A
7. UNIT AGREEMENT NAME: N/A
8. FARM OR LEASE NAME: Mexico Federal M
9. WELL NO.: 1-A
10. FIELD AND POOL, OR WILDCAT: Blanco-Mesa Verde
11. SEC., T., R., M., OR BLOCK AND SURVEY OR AREA: Sec. 12 - T31N-R13W
12. COUNTY OR PARISH: San Juan
13. STATE: NM
14. PERMIT NO.
DATE ISSUED

15. DATE SPUDDED	16. DATE T.D. REACHED	17. DATE COMPL. (Ready to prod.)	18. ELEVATIONS (DF, RKB, RT, GR, ETC.)*	19. ELEV. CASINGHEAD
12-30-79	2-3-80	5-30-80	5866' KB	-

20. TOTAL DEPTH, MD & TVD	21. PLUG, BACK T.D., MD & TVD	22. IF MULTIPLE COMPL., HOW MANY*	23. INTERVALS DRILLED BY	ROTARY TOOLS	CABLE TOOLS
7015'	4882'	1	→	0-7015'	0

24. PRODUCING INTERVAL(S), OF THIS COMPLETION—TOP, BOTTOM, NAME (MD AND TVD)*
4536'-4748' Mesaverde

25. WAS DIRECTIONAL SURVEY MADE: no

26. TYPE ELECTRIC AND OTHER LOGS RUN

27. WAS WELL CORED: no

28. CASING RECORD (Report all strings set in well)

CASING SIZE	WEIGHT, LB./FT.	DEPTH SET (MD)	HOLE SIZE	CEMENTING RECORD	AMOUNT PULLED
10 3/4"	32.75#	270'	14 3/4"	250 sks	-
7 5/8"	26.40#	4175'	9 3/4"	528 sks	

29. LINER RECORD

SIZE	TOP (MD)	BOTTOM (MD)	SACKS CEMENT*	SCREEN (MD)
5 1/2"	4002'	7015'	400 sks	

30. TUBING RECORD

SIZE	DEPTH SET (MD)	PACKER SET (MD)
2 3/8"	4726'	

RECEIVED
JUL 24 1980
OIL CON. COM.
DIST. 3

31. PERFORATION RECORD (Interval, size and number)
4536'-4748', 20 holes - .320" dia. SUGO

RECEIVED
JUL 21 1980
U.S. GEOLOGICAL SURVEY
FARMINGTON, N. M.

RECEIVED
OIL CONSERVATION DIVISION
SANTA FE

32. ACID, SHOT, FRACTURE, CEMENT SQUEEZE, ETC.

DEPTH INTERVAL (MD)	AMOUNT AND KIND OF MATERIAL USED
4536'-4748'	104,000 lbs 20-40 sand in 64,000 gal fluid (75% foam - 25% water) 1000 gal 15% Mod HCL acid

33.* PRODUCTION

DATE FIRST PRODUCTION	PRODUCTION METHOD (Flowing, gas lift, pumping—size and type of pump)	WELL STATUS (Producing or shut-in)
5-30-80	Flowing	Shut-in

DATE OF TEST	HOURS TESTED	CHOKE SIZE	PROD'N. FOR TEST PERIOD →	OIL—BBL.	GAS—MCF.	WATER—BBL.	GAS-OIL RATIO
5-30-80	3 hrs	3/4"	→	-	4517	-	-

FLOW. TUBING PRESS.	CASING PRESSURE	CALCULATED 24-HOUR RATE →	OIL—BBL.	GAS—MCF.	WATER—BBL.	OIL GRAVITY-API (CORR.)
314 psig	686 psig	→	-	8572	-	-

34. DISPOSITION OF GAS (Sold, used for fuel, vented, etc.)
Shut in waiting on P.L. connection

TEST WITNESSED BY: Paul Berhost

35. LIST OF ATTACHMENTS

ACCEPTED FOR RECORD

36. I hereby certify that the foregoing and attached information is complete and correct as determined from all available records

SIGNED D E Cab TITLE Area Superintendent DATE 7-17-80

*(See Instructions and Spaces for Additional Data on Reverse Side)

NMOCC

FARMINGTON DISTRICT
BY:

Form 9-330
(Rev. 5-63).

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN DUPLICATE* (See other instructions on reverse side)

Form approved.
Budget Bureau No. 42-R355.5.

WELL COMPLETION OR RECOMPLETION REPORT AND LOG*

5. LEASE DESIGNATION AND SERIAL NO.: USNM - 059848

6. IF INDIAN, ALLOTTEE OR TRIBE NAME:

7. UNIT AGREEMENT NAME:

8. FARM OR LEASE NAME: Freeman

9. WELL NO.: 1-A

10. FIELD AND POOL, OR WILDCAT: Basin Dakota

11. SEC., T., R., M., OR BLOCK AND SURVEY OR AREA: Sec 11-T31N, R13W NMPM

1a. TYPE OF WELL: OIL WELL ☐ GAS WELL ☒ DRY ☐ Other

b. TYPE OF COMPLETION: NEW WELL ☒ WORK OVER ☐ DEEP-EN ☐ PLUG BACK ☐ DIFF. RESVR. ☐ Other

2. NAME OF OPERATOR: Consolidated Oil & Gas, Inc.

3. ADDRESS OF OPERATOR: 1860 Lincoln Street, Lincoln Tower Bldg., Denver, CO 80295

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements)*
At surface: 790' FNL & 1980' FWL
At top prod. interval reported below: Same
At total depth: Same

14. PERMIT NO.: | DATE ISSUED: 5-28-78

12. COUNTY OR PARISH: San Juan | 13. STATE: New Mexico

15. DATE SPUDDED	16. DATE T.D. REACHED	17. DATE COMPL. (Ready to prod.)	18. ELEVATIONS (DF, RKB, RT, GR, ETC.)*	19. ELEV. CASINGHEAD
8-5-78	4-18-78	9-15-78	5719' GL, 5731' RKB	5719'

20. TOTAL DEPTH, MD & TVD	21. PLUG, BACK T.D., MD & TVD	22. IF MULTIPLE COMPL., HOW MANY*	23. INTERVALS DRILLED BY	ROTARY TOOLS	CABLE TOOLS
6800'	6750'	dual	→	0-6800'	----

24. PRODUCING INTERVAL(S), OF THIS COMPLETION—TOP, BOTTOM, NAME (MD AND TVD)*: 6562'-6687' Basin Dakota

25. WAS DIRECTIONAL SURVEY MADE: No

26. TYPE ELECTRIC AND OTHER LOGS RUN: Ind-Gr w/Caliper & CDL-CNL-GR

27. WAS WELL CORED: No

28. CASING RECORD (Report all strings set in well)

CASING SIZE	WEIGHT, LB./FT.	DEPTH SET (MD)	HOLE SIZE	CEMENTING RECORD	AMOUNT PULLED
8-5/8"	24.0#	249'	12-1/4"	200 sx Cl B	None
5-1/2"	15.5#	6790'	7-7/8"	1st stage: 427 sx Pozmix	None
				2nd stage: 387 sx Pozmix	None

29. LINER RECORD

SIZE	TOP (MD)	BOTTOM (MD)	SACKS CEMENT*	SCREEN (MD)

30. TUBING RECORD

SIZE	DEPTH SET (MD)	PACKER SET (MD)
1-1/2"	6530'	6520'

31. PERFORATION RECORD (Interval, size and number)
6562'-6887' (0.32") 24 holes

32. ACID, SHOT, FRACTURE, CEMENT SQUEEZE, ETC.

DEPTH INTERVAL (MD)	AMOUNT AND KIND OF MATERIAL USED
6562'-6887'	Acid w/1500 gals 15% H Cl
6562'-6887'	Frac'd w/90,750 gal 2% K Cl gelle
	& 105,416 # 20-40 sand

33.* PRODUCTION

DATE FIRST PRODUCTION	PRODUCTION METHOD (Flowing, gas lift, pumping—size and type of pump)	WELL STATUS (Producing or shut-in)
9-15-78	Flowing	SI WO pipeline connec.

DATE OF TEST	HOURS TESTED	CHOKE SIZE	PROD'N. FOR TEST PERIOD →	OIL—BBL.	GAS—MCF.	WATER—BBL.	GAS-OIL RATIO
9-15-78	3 hrs	3/4"	→	-----	221	-------	-----

FLOW. TUBING PRESS.	CASING PRESSURE	CALCULATED 24-HOUR RATE →	OIL—BBL.	GAS—MCF.	WATER—BBL.	OIL GRAVITY-API (CORR.)
137 psi	431 psi	→	-----	1773	-------	-------

34. DISPOSITION OF GAS (Sold, used for fuel, vented, etc.): Vented for test.

TEST WITNESSED BY: Neil Tefteller

35. LIST OF ATTACHMENTS: Set of open hole logs sent by Schlumberger

36. I hereby certify that the foregoing and attached information is complete and correct as determined from all available records.

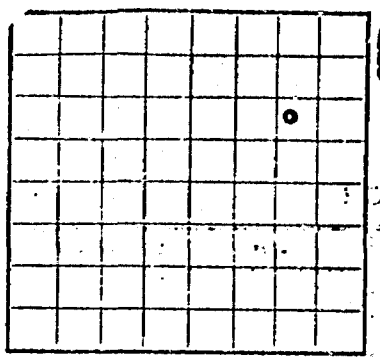
SIGNED O. T. Stogner Jr. TITLE Vice Pres., Operations Gulf Coast-West Tex Div DATE 10-31-78

NOV - 3 1978
OIL CON. COM.
DIST. 3

*(See Instructions and Spaces for Additional Data on Reverse Side)

NMOCC

Form 9-330



LOCATE WELL CORRECTLY

RECEIVED
JAN 5 1962
OIL CON. COM.
DIST. 3

Budget Bureau No. 42-R355.4.
Approval expires 12-31-60.

U. S. LAND OFFICE New Mexico
SERIAL NUMBER 059548
LEASE OR PERMIT TO PROSPECT

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

LOG OF OIL OR GAS WELL

Company Consolidated Oil & Gas, Inc. Address 2112 Tower Bldg, Denver, Colo.

Lessor or Tract Freeman Field Basin Dakota State New Mexico

Well No. 1-11 Sec. 11 T. 31N R. 13W Meridian NMPM County San Juan

Location 1620 ft. {N./S.} of N Line and 870 ft. {E./W.} of E Line of Section 11 Elevation 5770 KB
(Derrick floor relative to sea level)

The information given herewith is a complete and correct record of the well and all work done thereon so far as can be determined from all available records.

Signed James S. Lee

Date January 3, 1962 Title Chief Engineer

The summary on this page is for the condition of the well at above date.

Commenced drilling July 17, 1961 Finished drilling November 30, 1961

OIL OR GAS SANDS OR ZONES

(Denote gas by G)

G No. 1, from 4412 to 4520 No. 4, from ..... to .....

G No. 2, from 6560 to 6380 No. 5, from ..... to .....

No. 3, from ..... to ..... No. 6, from ..... to .....

IMPORTANT WATER SANDS

No. 1, from ..... to ..... No. 3, from ..... to .....

No. 2, from ..... to ..... No. 4, from ..... to .....

CASING RECORD

Size casing	Weight per foot	Threads per inch	Make	Amount	Kind of shoe	Cut and pulled from	Perforated From—	Perforated To—	Purpose
10 3/4	32.75	8 rd	H-40	191'	Guide		See Below		Surface
5 1/2	14&15.5	8 rd	J-55	6825'	Float				Production

MUDDING AND CEMENTING RECORD

Size casing	Where set	Number sacks of cement	Method used	Mud gravity	Amount of mud used
10 3/4	191	175	Pmp & plug		
5 1/2	6825	140 + 70 cu. ft. Strata Crete thru shoe			
		170 thru stage collar at 4710'			

FOLD | MARK

PLUGS AND ADAPTERS

Heaving plug—Material bridge plug w/1 sx. cement on top Length ..... Depth set 3600'

Adapters—Material ..... Size .....

Form 9-330
(Rev. 5-63)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN DUPLICATE* (See other instructions on reverse side)

Form approved.
Budget Bureau No. 42-R355.5.

WELL COMPLETION OR RECOMPLETION REPORT AND LOG*

MAY 15 1981
OIL CON. COM.
DIST. 3
RECEIVED
MAY 7 1981
U. S. GEOLOGICAL SURVEY
FARMINGTON, N. M.

1a. TYPE OF WELL:	OIL WELL ☐ GAS WELL ☒ DRY ☐ Other
b. TYPE OF COMPLETION:	NEW WELL ☒ WORK OVER ☐ DEEP-EN ☐ PLUG BACK ☐ DIFF. RESVR. ☐ Other
2. NAME OF OPERATOR	OKLAHOMA OIL COMPANY
3. ADDRESS OF OPERATOR	1120 One Energy Square, Dallas, Texas 75206
4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements)*	
At surface	800'/S & 1570'/E
At top prod. interval reported below	same
At total depth	same
5. LEASE DESIGNATION AND SERIAL NO.	NM-24907
6. IF INDIAN, ALLOTTEE OR TRIBE NAME	
7. UNIT AGREEMENT NAME	
8. FARM OR LEASE NAME	Nickles
9. WELL NO.	1E
10. FIELD AND POOL, OR WILDCAT	Basin Dakota
11. SEC., T., R., M., OR BLOCK AND SURVEY OR AREA	11-31N-13W
12. COUNTY OR PARISH	San Juan
13. STATE	NM
14. PERMIT NO.	
DATE ISSUED	

15. DATE SPUDDED	16. DATE T.D. REACHED	17. DATE COMPL. (Ready to prod.)	18. ELEVATIONS (DF, RKB, RT, GR, ETC.)*	19. ELEV. CASINGHEAD
12/30/80	1/11/81	4/3/81	5754 gr	5755

20. TOTAL DEPTH, MD & TVD	21. PLUG, BACK T.D., MD & TVD	22. IF MULTIPLE COMPL., HOW MANY*	23. INTERVALS DRILLED BY	ROTARY TOOLS	CABLE TOOLS
6875	6832	two	→	0-6875	

24. PRODUCING INTERVAL(S), OF THIS COMPLETION—TOP, BOTTOM, NAME (MD AND TVD)*: 6562-6780 Dakota

25. WAS DIRECTIONAL SURVEY MADE: Yes

26. TYPE ELECTRIC AND OTHER LOGS RUN: IES, CNL, FDC, GR, Caliper, CBL, CCL, VDL

27. WAS WELL CORED: No

28. CASING RECORD (Report all strings set in well)

CASING SIZE	WEIGHT, LB./FT.	DEPTH SET (MD)	HOLE SIZE	CEMENTING RECORD	AMOUNT PULLED
8 5/8	24	281	12 1/4	275 sk C/B + 2% $CaCl_2$	None
5 1/2	15.5 & 17#	6875	7 7/8	stg#1 235sk 50-50 poz	None
				stg#2 275 sk 50-50 poz	
				stg #3 330sk 65-35 poz	

29. LINER RECORD

SIZE	TOP (MD)	BOTTOM (MD)	SACKS CEMENT*	SCREEN (MD)
N/A				

30. TUBING RECORD

SIZE	DEPTH SET (MD)	PACKER SET (MD)
2 1/16	6510	6510

31. PERFORATION RECORD (Interval, size and number)

1-0.4" shot @ each of the depths below

6764-6780	0.4"	32
6702-6706	0.4"	8
6693-6696	0.4"	3
6657-6668	0.4"	22
6650-6654	0.4"	8
6640		
6632		
6624		
6620		
6618		
6612		
6604		
6600		
6594		
6588		
6582		
6566		
6562		

32. ACID, SHOT, FRACTURE, CEMENT SQUEEZE, ETC.

DEPTH INTERVAL (MD)	AMOUNT AND KIND OF MATERIAL USED
6562-6780	4000 gal 15% HCl
	Frac w/80,000 gal
	cross-linked gel w/105,000#
	20-40 sand

33.* PRODUCTION

DATE FIRST PRODUCTION	PRODUCTION METHOD (Flowing, gas lift, pumping—size and type of pump)	WELL STATUS (Producing or shut-in)
3/21/81	flowing	shut in

DATE OF TEST	HOURS TESTED	CHOKE SIZE	PROD'N. FOR TEST PERIOD →	OIL—BBL.	GAS—MCF.	WATER—BBL.	GAS-OIL RATIO
4/20/81	3	3/4"					

FLOW. TUBING PRESS.	CASING PRESSURE	CALCULATED 24-HOUR RATE →	OIL—BBL.	GAS—MCF.	WATER—BBL.	OIL GRAVITY-API (CORR.)
82	Packer		0	1429	0	

34. DISPOSITION OF GAS (Sold, used for fuel, vented, etc.): Vented

TEST WITNESSED BY: A.D. Miller

35. LIST OF ATTACHMENTS

ACCEPTED FOR RECORD
MAY 20 1981
FARMINGTON RESOURCE AREA

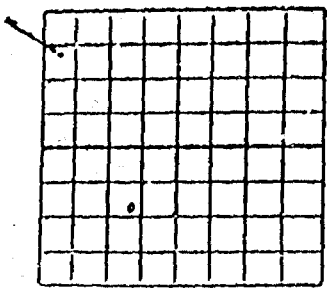
36. I hereby certify that the foregoing and attached information is complete and correct as determined from all available records

SIGNED John Alexander (John Alexander) TITLE Agent DATE 5/5/81

*(See Instructions and Spaces for Additional Data on Reverse Side)

NMOCC

(Revised 7/1/58)
(Form C-105)



AREA 640 ACRES
LOCATE WELL CORRECTLY

NEW MEXICO OIL CONSERVATION COMMISSION

Santa Fe, New Mexico

WELL RECORD

Mail to District Office, Oil Conservation Commission, to which Form C-101 was sent not later than twenty days after completion of well. Follow instructions in Rules and Regulations of the Commission. Submit in QUINTUPLICATE. If State Land submit 6 Copies

ADOBE OIL COMPANY (Company or Operator) Nickels (Lease)

Well No. 1, in NE ¼ of SW ¼, of Sec. 11, T. 31N, R. 13W, NMPM.

Blanco Mesa Verde Pool, San Juan County.

Well is 1450 feet from South line and 1730 feet from West line of Section 11. If State Land the Oil and Gas Lease No. is

Drilling Commenced 5-2, 19 61 Drilling was Completed 5-17, 19 61

Name of Drilling Contractor Great Western Drilling Company

Address Farmington, New Mexico

Elevation above sea level at Top of Tubing Head 5703 The information given is to be kept confidential until ....., 19.....

OIL SANDS OR ZONES

No. 1, from 4363' to ..... No. 4, from 4434' to .....

No. 2, from 4384' to ..... No. 5, from 6530' to .....

No. 3, from 4414' to ..... No. 6, from 6531' to .....
7 6600'
8 6644'

IMPORTANT WATER SANDS

Include data on rate of water inflow and elevation to which water rose in hole.

No. 1, from ..... to ..... feet. .....

No. 2, from ..... to ..... feet. .....

No. 3, from ..... to ..... feet. .....

No. 4, from ..... to ..... feet. .....

CASING RECORD

SIZE	WEIGHT PER FOOT	NEW OR USED	AMOUNT	KIND OF SHOE	CUT AND PULLED FROM	PERFORATIONS	PURPOSE
8-5/8"	24	New	291	Texas Pattern	--	--	Surface
5-1/2"	15.5	New	6700	Howco		4363, 4384, 4414, 4434, 6530, 6531, 6600, 6644	Oil String

MUDDING AND CEMENTING RECORD

SIZE OF HOLE	SIZE OF CASING	WHERE SET	NO. SACKS OF CEMENT	METHOD USED	MUD GRAVITY	AMOUNT OF MUD USED
11-1/4"	8-5/8"	291	200	Pumps & Plug		Cement circulated
7-7/8"	5-1/2	6700	200 sks btm	Pump & Plug		
			300 sks thru			
			D.V. Tool			

RECORD OF PRODUCTION AND STIMULATION

(Record the Process used, No. of Qts. or Gals. used, interval treated or shot.)

Acidized with 1000 gallons MCA. Frac with 77,000 gallons water with 25,000 pounds sand (6600' and 6644'). Acidize with 500 gallons MCA. Frac with 75,000 gallons water with 80,000 pounds sand (6530' and 6531'). Frac with 121,000 gallons water with 80,000 pounds sand using 16 balls (4363', 4384', 4414', 4434').

Result of Production Stimulation AOF Mesa Verde 2550 MCFPD.

Acp Dakota 1713 MCFPD.

This is a Dakota-Mesa Verde dual Depth Cleaned Out 6675

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OIL CON. COM.
DIST. 3

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OPERATOR		

Form C-105
Revised 1-1-65

NEW MEXICO OIL CONSERVATION COMMISSION
WELL COMPLETION OR RECOMPLETION REPORT AND LOG

5a. Indicate Type of Lease: State [ ] Fee [X]

5. State Oil & Gas Lease No.

1a. TYPE OF WELL: OIL WELL [ ] GAS WELL [X] DRY [ ] OTHER

b. TYPE OF COMPLETION: NEW WELL [X] WORK OVER [ ] DEEPEN [ ] PLUG BACK [ ] DIFF. RESVR. [ ] OTHER

7. Unit Agreement Name

8. Farm or Lease Name: Wilmerding

2. Name of Operator: Consolidated Oil & Gas, Inc.

9. Well No.: 1-M

3. Address of Operator: P. O. Box 2038 Farmington, NM 87401

10. Field and Pool, or Wildcat: Basin Dakota

4. Location of Well: UNIT LETTER C LOCATED 1120 FEET FROM THE North LINE AND 1850 FEET FROM THE West LINE OF SEC. 10 TWP. 31N RGE. 13W NMPM

12. County: San Juan

15. Date Spudded	16. Date T.D. Reached	17. Date Compl. (Ready to Prod.)	18. Elevations (DF, RKB, RT, GR, etc.)	19. Elev. Cashinghead
4-2-80	4-16-80	10-9-80	5813 RKB	5801

20. Total Depth	21. Plug Back T.D.	22. If Multiple Compl., How Many	23. Intervals Drilled By	Rotary Tools	Cable Tools
6939	6890	2	→	X	

24. Producing Interval(s), of this completion — Top, Bottom, Name: 6627 to 6846 DK

25. Was Directional Survey Made: No

26. Type Electric and Other Logs Run: IES & Compensated Density

27. Was Well Cored: No

28. CASING RECORD (Report all strings set in well)

CASING SIZE	WEIGHT LB./FT.	DEPTH SET	HOLE SIZE	CEMENTING RECORD	AMOUNT PULLED
8-5/8	24#	268	12¼	200 Sks.	None
5½	15½#	6935	7-7/8	825 Sks.	None

29. LINER RECORD

SIZE	TOP	BOTTOM	SACKS CEMENT	SCREEN

30. TUBING RECORD

SIZE	DEPTH SET	PACKER SET
1½	6728	5015!

31. Perforation Record (Interval, size and number)

6627 - 6846
26 .42 Holes

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DEC 02 1980
OIL CONSERVATION DIVISION
SANTA FE

32. ACID, SHOT, FRACTURE, CEMENT SQUEEZE, ETC.

DEPTH INTERVAL	AMOUNT AND KIND MATERIAL USED
6788 - 6846	26,200 gal X-linked gel and 19,450# sand
6627 - 6741	73,000 gal X-linked gel and 88,000# sand

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NOV 21
OIL CON. COM.
DIST. 3

33. PRODUCTION

Date First Production	Production Method (Flowing, gas lift, pumping — Size and type pump)	Well Status (Prod. or Shut-in)
10-9-80	Flowing	SI

Date of Test	Hours Tested	Choke Size	Prod'n. For Test Period →	Oil — Bbl.	Gas — MCF	Water — Bbl.	Gas — Oil Ratio
10-9-80	3	3/4			207		

Flow Tubing Press.	Casing Pressure	Calculated 24-Hour Rate →	Oil — Bbl.	Gas — MCF	Water — Bbl.	Oil Gravity — API (Corr.)
108	--			1655		

34. Disposition of Gas (Sold, used for fuel, vented, etc.): Vented

Test Witnessed By

35. List of Attachments

36. I hereby certify that the information shown on both sides of this form is true and complete to the best of my knowledge and belief.

SIGNED Jerry Moore TITLE Production Supt. DATE 11-12-80

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LAND OFFICE		
OPERATOR		

Form C-105
Revised 1-1-65

NEW MEXICO OIL CONSERVATION COMMISSION
WELL COMPLETION OR RECOMPLETION REPORT AND LOG

5a. Indicate Type of Lease: State ☐ Fee ☒

5. State Oil & Gas Lease No.

1a. TYPE OF WELL — OIL WELL ☐ GAS WELL ☒ DRY ☐ OTHER

b. TYPE OF COMPLETION — NEW WELL ☒ WORK OVER ☐ DEEPEN ☐ PLUG BACK ☐ DIFF. RESVR. ☐ OTHER

7. Unit Agreement Name

8. Farm or Lease Name: KLINE

2. Name of Operator: Consolidated Oil & Gas Inc.

9. Well No.: 1-M

3. Address of Operator: P. O. Box 2038 Farmington N.Mex. 87401

10. Field and Pool, or Wildcat: Basin Dakota

4. Location of Well: UNIT LETTER I LOCATED 1820 FEET FROM THE S LINE AND 1190 FEET FROM THE E LINE OF SEC. 10 TWP. 31N RGE. 13W NMPM

12. County: San Juan

15. Date Spudded	16. Date T.D. Reached	17. Date Compl. (Ready to Prod.)	18. Elevations (DF, RKB, RT, GR, etc.)	19. Elev. Cashinghead
4-16-80	5-2-80	9-24-80	5699 GR	No

20. Total Depth	21. Plug Back T.D.	22. If Multiple Compl., How Many	23. Intervals Drilled By	Rotary Tools	Cable Tools
6826	6808	2	→	X	

24. Producing Interval(s), of this completion — Top, Bottom, Name: 6506 - 6726 DK

25. Was Directional Survey Made: No

26. Type Electric and Other Logs Run: IES & Compensated Density

27. Was Well Cored: No

28. CASING RECORD (Report all strings set in well)

CASING SIZE	WEIGHT LB./FT.	DEPTH SET	HOLE SIZE	CEMENTING RECORD	AMOUNT PULLED
8-5/8	24#	253	12¼	275 sks	None
5½	15.5#	6832	7-7/8	955 sks	None

29. LINER RECORD

SIZE	TOP	BOTTOM	SACKS CEMENT	SCREEN

30. TUBING RECORD

SIZE	DEPTH SET	PACKER SET
1½	6608	4700

31. Perforation Record (Interval, size and number)

6506-6736
27 holes .32 hole

OCT 10 1980
OIL CON. DIVISION
C.L. CC: SANTA FE

32. ACID, SHOT, FRACTURE, CEMENT SQUEEZE, ETC.

DEPTH INTERVAL	AMOUNT AND KIND MATERIAL USED
6655-6736	500 gal acid 50.000 gel
	x linked gel 38.750 sd
6506-6629	500 gal acid 29 100 gal
	x linked gel 12.000 sd

33. PRODUCTION

Date First Production	Production Method (Flowing, gas lift, pumping — Size and type pump)	Well Status (Prod. or Shut-in)
9-17-80	Flowing	SI

Date of Test	Hours Tested	Choke Size	Prod'n. For Test Period →	Oil — Bbl.	Gas — MCF	Water — Bbl.	Gas-Oil Ratio
9-17-80	3 Hours	3/4			107		

Flow Tubing Press.	Casing Pressure	Calculated 24-Hour Rate →	Oil — Bbl.	Gas — MCF	Water — Bbl.	Oil Gravity — API (Corr.)
102	-			1574	?	

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OCT 6 1980
OIL CON. COM.
DIST. 3

34. Disposition of Gas (Sold, used for fuel, vented, etc.): Vented

Test Witnessed By: Tefteller

35. List of Attachments

36. I hereby certify that the information shown on both sides of this form is true and complete to the best of my knowledge and belief.

SIGNED Veryl Moore TITLE Production Supt. DATE 10-2-80

DATE 10-2-80

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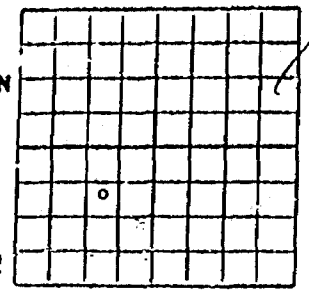
Checked by OCC
From C-104

NEW MEXICO OIL CONSERVATION COMMISSION

Santa Fe, New Mexico

WELL RECORD



AREA 640 ACRES
LOCATE WELL CORRECTLY

Mail to District Office, Oil Conservation Commission, to which Form C-101 was sent not later than twenty days after completion of well. Follow instructions in Rules and Regulations of the Commission. Submit in QUINTUPLICATE. If State Land submit 6 Copies

Consolidated Oil & Gas, Inc. (Company or Operator) Segal (Lease)

Well No. 1-10, in NE ¼ of SW ¼, of Sec. 10, T. 31N, R. 13W, NMPM.

Basin Dakota, Blanco Mesaverde Pool, San Juan County.

Well is 1844' feet from South line and 1850 feet from West line of Section 10. If State Land the Oil and Gas Lease No. is

Drilling Commenced January 25, 1962 Drilling was Completed February 19, 1962

Name of Drilling Contractor Huron Drilling Company

Address 2415 Mercantile Bank Building, Dallas, Texas

Elevation above sea level at Top of Tubing Head 5783' The information given is to be kept confidential until , 19

OIL SANDS OR ZONES

G No. 1, from 4402' to 4502' No. 4, from to

G No. 2, from 6567' to 6704' No. 5, from to

No. 3, from to No. 6, from to

IMPORTANT WATER SANDS

Include data on rate of water inflow and elevation to which water rose in hole.

No. 1, from to feet.

No. 2, from to feet.

No. 3, from to feet.

No. 4, from to feet.

RECEIVED
APR 16 1962
OIL CON. COM.
DIST. 3

CASING RECORD

SIZE	WEIGHT PER FOOT	NEW OR USED	AMOUNT	KIND OF SHOE	CUT AND PULLED FROM	PERFORATIONS	PURPOSE
9 5/8"	32.30	H-40 new	190'	Guide		See reverse	Surface
5 1/2"	15.5	J-55 new	6727'	Float		" "	Production

MUDDING AND CEMENTING RECORD

SIZE OF HOLE	SIZE OF CASING	WHERE SET	NO. SACKS OF CEMENT	METHOD USED	MUD GRAVITY	AMOUNT OF MUD USED
13 3/4	9 5/8	190	150	Pump & plug		
7 7/8	5 1/2	6727	310 / 63 cu. ft. Strata-crete	126 sx. plus 63 sx. Strata-crete thru shoe 184 sx. thru stage collar at 4676'		

RECORD OF PRODUCTION AND STIMULATION

(Record the Process used, No. of Qts. or Gals. used, interval treated or shot.)

Sand water frac - 4408'-4500' w/100,000# sand, 100,000 gal. water

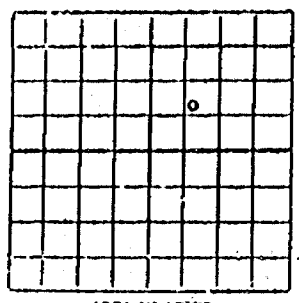
6571'-6702' x/110,000# sand, 153,000 gal. water and 1,000 gal. acid in three stages.

Result of Production Stimulation 3 hr. initial potential test thru 3/4" choke:

Mesaverde - 792 MCFD CAOF 1015 MCFD

Dakota - 1365 MCFD Depth Cleaned Out 6708'

(Revised 7/1/58)
(Form C-105)



AREA 640 ACRES
LOCATE WELL CORRECTLY

NEW MEXICO OIL CONSERVATION COMMISSION

Santa Fe, New Mexico

WELL RECORD

Mail to District Office, Oil Conservation Commission, to which Form C-101 was sent not later than twenty days after completion of well. Follow instructions in Rules and Regulations of the Commission. Submit in QUINTUPLICATE. If State Land submit 6 Copies

Consolidated Oil & Gas, Inc. (Company or Operator) Kline (Lease)

Well No. 1, in SW ¼ of NE ¼, of Sec. 10, T. 31N, R. 13W, NMPM.

Blanco Mesaverde & Basin Dakota Pool, San Juan County.

Well is 1850 feet from North line and 1550 feet from East line of Section 10. If State Land the Oil and Gas Lease No. is

Drilling Commenced April 17, 1961 Drilling was Completed May 24, 1961

Name of Drilling Contractor Huron Drilling Company, Inc.

Address 1700 Broadway, Denver 2, Colorado

Elevation above sea level at Top of Tubing Head 5715' 5727' KB The information given is to be kept confidential until , 19

OIL SANDS OR ZONES

No. 1, from 4285 to 4458 Gas No. 4, from to

No. 2, from 6525 to 6639 Gas No. 5, from to

No. 3, from to No. 6, from to

IMPORTANT WATER SANDS

Include data on rate of water inflow and elevation to which water rose in hole.

No. 1, from to feet.

No. 2, from to feet.

No. 3, from to feet.

No. 4, from to feet.

RECEIVED
JUN 26 1961
OIL CON. COM.
DIST. 3

CASING RECORD

SIZE	WEIGHT PER FOOT	NEW OR USED	AMOUNT	KIND OF SHOE	CUT AND PULLED FROM	PERFORATIONS	PURPOSE
9 5/8	32.75	New	193	Guide			Surface
5 1/2	15.5	New	6686	Float		See reverse side	Production

MUDDING AND CEMENTING RECORD

SIZE OF HOLE	SIZE OF CASING	WHERE SET	NO. SACKS OF CEMENT	METHOD USED	MUD GRAVITY	AMOUNT OF MUD USED
13 3/4	9 5/8	193	132	Pump & plug		
7 7/8	5 1/2	6686	225 thru shoe			
			200 thru stage collar at 4739			

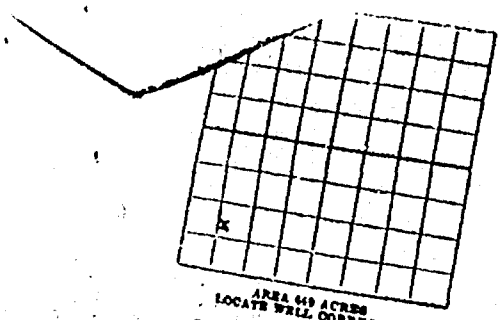
RECORD OF PRODUCTION AND STIMULATION

(Record the Process used, No. of Qts. or Gals. used, interval treated or shot.)

Sand-water frac - Mesaverde (4285 - 4458), 95,000# sand, 80,000 gal water
Dakota (6525 - 6639), 114,000# sand, 112,000 gal water, 1500 gal acid in three stages.

Result of Production Stimulation IPF Mesaverde - 786 mcf/d actual flow after three hours
IPF Dakota - 1858 mcf/d actual flow after three hours.

Depth Cleaned Out 6686



AREA 640 ACRES
LOCATE WELL CORRECTLY

Other Instructions (1/58)
(Form C-105)

NEW MEXICO OIL CONSERVATION COMMISSION
Santa Fe, New Mexico

WELL RECORD

Mail to District Office, Oil Conservation Commission, to which Form C-101 was sent not later than twenty days after completion of well. Follow instructions in Rules and Regulations of the Commission. Submit in QUINTUPLICATE. If State Land submit 6 Copies

Consolidated Oil & Gas, Inc. (Company or Operator) A. Gross (Lease)

Well No. 1-9, in NE ¼ of SW ¼, of Sec. 9, T. 31N, R. 13W, NMPM.

Basin Dakota Pool, San Juan County.

Well is 1650' feet from S line and 1850' feet from W line of Section 9. If State Land the Oil and Gas Lease No. is

Drilling Commenced June 26, 1961 Drilling was Completed July 16, 1961

Name of Drilling Contractor Byron Drilling Co.

Address 2415 Mercantile Bank Building, Dallas, Texas

Elevation above sea level at Top of Tubing Head 5874' KB The information given is to be kept confidential until _____, 19____.

OIL SANDS OR ZONES

No. 1, from 6660' to 6874' No. 4, from ____ to ____

No. 2, from ____ to ____ No. 5, from ____ to ____

No. 3, from ____ to ____ No. 6, from ____ to ____

IMPORTANT WATER SANDS

Include data on rate of water inflow and elevation to which water rose in hole.

No. 1, from ____ to ____ feet

No. 2, from ____ to ____ feet

No. 3, from ____ to ____ feet

No. 4, from ____ to ____ feet.

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AUG 16 1961
OIL CON. COM.
DIST. 3

CASING RECORD

SIZE	WEIGHT PER FOOT	NEW OR USED	AMOUNT	KIND OF SHOE	CUT AND PULLED FROM	PERFORATIONS	PURPOSE
10 3/4	32.75#	New	176'	Guide		See reverse side	Surface
5 1/2	14 & 15.5#	New	6900'	Float			Production

MUDDING AND CEMENTING RECORD

SIZE OF HOLE	SIZE OF CASING	WHERE SET	NO. SACKS OF CEMENT	METHOD USED	MUD GRAVITY	AMOUNT OF MUD USED
15"	13/3/4	176'	150	Pump & Plug		
7 7/8	5 1/2	6900'	125 thru shoe			
			150 thru stage collar at 4800'			

RECORD OF PRODUCTION AND STIMULATION

(Record the Process used, No. of Qts. or Gals. used, interval treated or shot.)

Sand water frac: w/120,500# (20-40 & 40-60 Mesh) sand, 130,000 gal. slicked water, 1,000 gal. acid

Result of Production Stimulation Flow volume thru 3/4" choke: 1,855 MCFD Calculated Absolute Open Flow Potential: 2,260 MCFD

Depth Cleaned Out 6874'

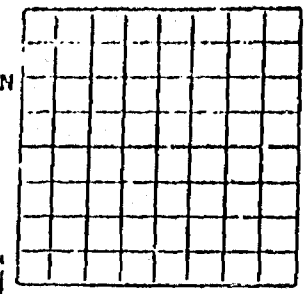
DISTRICT	
FILE	
U.S.G.S.	
LAND OFFICE	
TRANSPORTER	OIL / GAS
PRORATION OFFICE	
OPERATOR	

NEW MEXICO OIL CONSERVATION COMMISSION

Santa Fe, New Mexico

WELL RECORD

Mail to District Office, Oil Conservation Commission, to which Form C-101 was sent not later than twenty days after completion of well. Follow instructions in Rules and Regulations of the Commission. Submit in QUINTUPLICATE. If State Land submit 6 Copies



AREA 640 ACRES
LOCATE WELL CORRECTLY

Consolidated Oil & Gas, Inc. (Company or Operator) Baird (Lease)

Well No. 1-4, in SE ¼ of NE ¼, of Sec. 4, T. 31N, R. 13W, NMPM.

Basin Dakota-Blanco Mesaverde Pool, San Juan County.

Well is 1775 feet from North line and 790 feet from East line of Section 4. If State Land the Oil and Gas Lease No. is

Drilling Commenced February 21, 1962 Drilling was Completed March 15, 1962

Name of Drilling Contractor Huron Drilling Co.

Address 2415 Mercantile Bank Building, Dallas, Texas

Elevation above sea level at Top of Tubing Head 5862' KB The information given is to be kept confidential until , 19

OIL SANDS OR ZONES

G No. 1, from 4521 to 4628 No. 4, from to

G No. 2, from 6695 to 6830 No. 5, from to

No. 3, from to No. 6, from to

IMPORTANT WATER SANDS

Include data on rate of water inflow and elevation to which water rose in hole.

No. 1, from to feet.

No. 2, from to feet.

No. 3, from to feet.

No. 4, from to feet.

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OIL CON. COM.
DIST. 3

CASING RECORD

SIZE	WEIGHT PER FOOT	NEW OR USED	AMOUNT	KIND OF SHOE	CUT AND PULLED FROM	PERFORATIONS	PURPOSE
9 5/8"	36#	New	196'	Guide		See reverse	Surface
5 1/2"	15.5#	New	6863'	Float		" "	Production

MUDDING AND CEMENTING RECORD

SIZE OF HOLE	SIZE OF CASING	WHERE SET	NO. SACKS OF CEMENT	METHOD USED	MUD GRAVITY	AMOUNT OF MUD USED
13 3/4	9 5/8"	196'	175	Pump & plug		
7 5/8	5 1/2"	6863'	175 thru stage collar at		4677'	
			126 thru shoe			

RECORD OF PRODUCTION AND STIMULATION

(Record the Process used, No. of Qts. or Gals. used, interval treated or shot.)

DK - sand water frac with 80,000 lbs. of sand and 118,600 gal. water.

MV - sand water frac with 100,000 lbs. of sand and 100,800 gal. water.

Result of Production Stimulation DK - flow volume thru 3/4" choke: 2510 MCFD

MV - flow volume thru 3/4" choke: 240 MCFD

Calculated absolute open flow potential: 512 MCFD Depth Cleaned Out 6838'

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LAND OFFICE		
OPERATOR		

Form C-105
Revised 11-1-58

NEW MEXICO OIL CONSERVATION COMMISSION
WELL COMPLETION OR RECOMPLETION REPORT AND LOG

5a. Indicate Type of Lease: State ☐ Fee ☐

5. State Oil & Gas Lease No.

1a. TYPE OF WELL

b. TYPE OF COMPLETION
NEW WELL ☐ WORK OVER ☐ DEEPEN ☐ PLUG BACK ☐ DIFF. RESVR. ☐ OTHER

OIL WELL ☐ GAS WELL ☐ DRY ☐ OTHER

7. Unit Agreement Name

8. Farm or Lease Name: LANDAUER

2. Name of Operator: CONSOLIDATED OIL AND GAS, INC.

9. Well No.: 1-M

3. Address of Operator: P/O. BOX 2038 FARMINGTON, NEW MEXICO 87401

10. Field and Pool, or Wildcat: BASIN DAKOTA

4. Location of Well
UNIT LETTER I LOCATED 2255 FEET FROM THE S LINE AND 680 FEET FROM THE E LINE OF SEC. 3 TWP. 31N RGE. 13W NMPM

12. County: S.J.

15. Date Spudded	16. Date T.D. Reached	17. Date Compl. (Ready to Prod.)	18. Elevations (DF, RKB, RT, GR, etc.)	19. Elev. Cashinghead
~~8-24-80~~ 79	9-10-~~80~~ 79	4-11-80	5742 GL	

20. Total Depth	21. Plug Back T.D.	22. If Multiple Compl., How Many	23. Intervals Drilled By	Rotary Tools	Cable Tools
6870'	6850'	2	→	6870'	

24. Producing Interval(s), of this completion -- Top, Bottom, Name
6603 TO 6816 BASIN DAKOTA

25. Was Directional Survey Made: NO

26. Type Electric and Other Logs Run
IND/GR CNL/CDL

27. Was Well Cored: NO

28. CASING RECORD (Report all strings set in well)

CASING SIZE	WEIGHT LB./FT.	DEPTH SET	HOLE SIZE	CEMENTING RECORD	AMOUNT PULLED
8-5/8"	24#	277'	12-1/4	200 sks	NONE
5-1/2"	15.5#	6868'	7-7/8"	225 sks	NONE
		1 DV TOOL	4914'	265 sks	

29. LINER RECORD

SIZE	TOP	BOTTOM	SACKS CEMENT	SCREEN

30. TUBING RECORD

SIZE	DEPTH SET	PACKER SET
1-1/4	4594'	
1-1/2	6657'	6647

31. Perforation Record (Interval, size and number)

6807 - 6816 (.41 holes-10 holes)

6608 - 6756 (.41 hole -20 holes)

32. ACID, SHOT, FRACTURE, CEMENT SQUEEZE, ETC.

DEPTH INTERVAL	AMOUNT AND KIND MATERIAL USED
6807-6816	900 gal acid - 49,406 gal Klin
	gel - 57454# sand
6608-6756	1200 g. acid - 124,500 gal YF
	137,500# sand

33. PRODUCTION

Date First Production	Production Method (Flowing, gas lift, pumping - Size and type pump)	Well Status (Prod. or Shut-in)
4-11-80	FLOW	S.I.

Date of Test	Hours Tested	Choke Size	Prod'n. For Test Period →	Oil - Bbl.	Gas - MCF	Water - Bbl.	Gas-Oil Ratio
4-11-80	3HRS	3/4			261		

Flow Tubing Press.	Casing Pressure	Calculated 24-Hour Rate →	Oil - Bbl.	Gas - MCF	Water - Bbl.	Oil Gravity - API (Corr.)
				2091		

34. Disposition of Gas (Sold, used for fuel, vented, etc.)
VENTED

Test Witnessed By

35. List of Attachments

36. I hereby certify that the information shown on both sides of this form is true and complete to the best of my knowledge and belief.

SIGNED [signature] TITLE PROD. SUPT. DATE 4-24-80

MAY 19 1980
OIL CON. COM.
DIST. 3

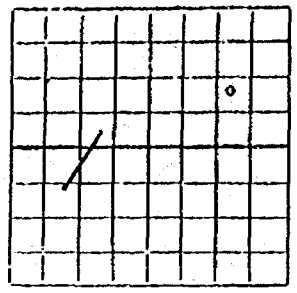
SANTA FE

NEW MEXICO OIL CONSERVATION COMMISSION (Form C-101 Revised 7/1/57)
Santa Fe, New Mexico

(Revised 7/1/58) (Form C-105)

NEW MEXICO OIL CONSERVATION COMMISSION
Santa Fe, New Mexico

WELL RECORD



AREA 640 ACRES
LOCATE WELL CORRECTLY

Mail to District Office, Oil Conservation Commission, to which Form C-101 was sent not later than twenty days after completion of well. Follow instructions in Rules and Regulations of the Commission. Submit in QUINTUPLICATE. If State Land submit 6 Copies

Consolidated Oil & Gas, Inc. (Company or Operator) Landauer (Lease)

Well No. 1-3, in NE ¼ of SW ¼, of Sec. 3, T. 31N, R. 13W, NMPM.

Basin Dakota Pool, San Juan County.

Well is 1430 feet from North line and 1120 feet from East line of Section 3. If State Land the Oil and Gas Lease No. is

Drilling Commenced August 21, 1961 Drilling was Completed October 1, 1961.

Name of Drilling Contractor Huron Drilling Co.

Address 2415 Mercantile Bank Bldg., Dallas, Texas

Elevation above sea level at Top of Tubing Head 5784' KB The information given is to be kept confidential until , 19

OIL SANDS OR ZONES

No. 1, from 6610' to 6780' No. 4, from to

No. 2, from to No. 5, from to

No. 3, from to No. 6, from to

IMPORTANT WATER SANDS

Include data on rate of water inflow and elevation to which water rose in hole.

No. 1, from to feet.

No. 2, from to feet.

No. 3, from to feet.

No. 4, from to feet.

RECEIVED
OCT 9 1961
OIL CON. COM.
DIST. 3

CASING RECORD

SIZE	WEIGHT PER FOOT	NEW OR USED	AMOUNT	KIND OF SHOE	CUT AND PULLED FROM	PERFORATIONS	PURPOSE
10 3/4	32.75	New	192'	Guide			Surface
5 1/2	15.5 & 17	New	6872'	Float		See reverse	Production

MUDDING AND CEMENTING RECORD

SIZE OF HOLE	SIZE OF CASING	WHERE SET	NO. SACKS OF CEMENT	METHOD USED	MUD GRAVITY	AMOUNT OF MUD USED
15"	10 3/4	192'	150	Pump & Plug		
7 7/8	5 1/2	6872'	222 thru shoe			
			265 thru stage collar at 4805'			

RECORD OF PRODUCTION AND STIMULATION

(Record the Process used, No. of Qts. or Gals. used, interval treated or shot.)

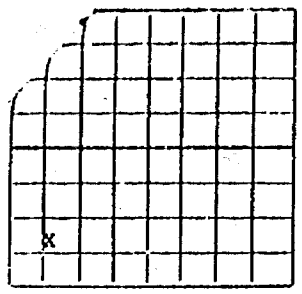
Sand-water frac: 100,000# 20-40 mesh sand, 100000 gal. slickened water, 3,000 gal. acid in 3 stages.

Result of Production Stimulation Flow volume thru 3/4" choke: 3050 MCFD

Calculated Absolute Open Flow Potential: 4110 MCFD

Depth Cleaned Out 6851'

(Revised 7/1/58)
(Form C-104)



AREA 640 ACRES
LOCATE WELL CORRECTLY

NEW MEXICO OIL CONSERVATION COMMISSION
Santa Fe, New Mexico

WELL RECORD

Mail to District Office, Oil Conservation Commission, to which Form C-101 was sent not later than twenty days after completion of well. Follow instructions in Rules and Regulations of the Commission. Submit in QUINTUPLICATE. If State Land submit 6 Copies

Consolidated Oil & Gas, Inc. (Company or Operator) O'Shea (Lease)

Well No. 1-3, in SW ¼ of SW ¼, of Sec. 3, T. 31N, R. 13W, NMPM.

Basin Dakota, Blanco Mesaverde Pool, San Juan County.

Well is 1813 feet from South line and 1875 feet from East line of Section 3. If State Land the Oil and Gas Lease No. is

Drilling Commenced May 12, 19 61. Drilling was Completed June 19, 19 61

Name of Drilling Contractor Huron Drilling Co.

Address 2415 Mercantile Bank Bldg., Dallas, Texas

Elevation above sea level at Top of Tubing Head 5818' KB The information given is to be kept confidential until , 19

OIL SANDS OR ZONES

No. 1, from 4486' to 4593' No. 4, from to

No. 2, from 6658' to 6890' No. 5, from to

No. 3, from to No. 6, from to

IMPORTANT WATER SANDS

Include data on rate of water inflow and elevation to which water rose in hole.

No. 1, from to feet.

No. 2, from to feet.

No. 3, from to feet.

No. 4, from to feet.

CASING RECORD

SIZE	WEIGHT PER FOOT	NEW OR USED	AMOUNT	KIND OF SHOE	CUT AND PULLED FROM	PERFORATIONS	PURPOSE
9 5/8	32.30	New	194	Guide		See reverse	Surface
5 1/2	15.5 & 17	New	6900	Float		side	Production

MUDDING AND CEMENTING RECORD

SIZE OF HOLE	SIZE OF CASING	WHERE SET	NO. SACKS OF CEMENT	METHOD USED	MUD GRAVITY	AMOUNT OF MUD USED
13 3/4	9 5/8	194	175			
7 7/8	5 1/2	6900	230 thru shoe			
			200 thru stage collar at 4793'			

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DIST.

RECORD OF PRODUCTION AND STIMULATION

(Record the Process used, No. of Qts. or Gals. used, interval treated or shot.)

Sand-water frac: MV-100,000# (20-40 mesh) sand, 100,000 gal. water.
DK-69,000# (40-60 and 20-40 mesh) sand, 87,000 gal. water,
1,000 gal. acid in two stages.

Result of Production Stimulation MV-Flow volume thru 3/4" choke: 735 MCFD Calculated Absolute Open Flow Potential: 1480 MCFD DK-Flow volume thru 3/4" choke: 1825 MCFD

Depth Cleaned Out 6886'

Form 9-330
(Rev. 5-63)

SUBMIT IN DUPLICATE* (See other instructions on reverse side)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

Form approved.
Budget Bureau No. 42-R355.5.

WELL COMPLETION OR RECOMPLETION REPORT AND LOG*

5. LEASE DESIGNATION AND SERIAL NO.: NM 1918

6. IF INDIAN, ALLOTTEE OR TRIBE NAME:

7. UNIT AGREEMENT NAME: NONE

8. FARM OR LEASE NAME: FEDERAL

9. WELL NO.: 1

10. FIELD AND POOL, OR WILDCAT: Basin Dakota-Blanco MV

11. SEC., T., R., M., OR BLOCK AND SURVEY OR AREA: Sec. 1: T31N-R13W

12. COUNTY OR PARISH: San Juan

13. STATE: New Mexico

1a. TYPE OF WELL: OIL WELL ☐ GAS WELL ☒ DRY ☐ Other

b. TYPE OF COMPLETION: NEW WELL ☒ WORK OVER ☐ DEEP-EN ☐ PLUG BACK ☐ DIFF. RESVR. ☐ Other

2. NAME OF OPERATOR: Palmer Oil & Gas Company

3. ADDRESS OF OPERATOR: P. O. Box 2564, Billings, Montana 59103

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements)*
At surface: 820' FEL, 1525' FSL
At top prod. interval reported below: SAME
At total depth: SAME

14. PERMIT NO. | DATE ISSUED

15. DATE SPUDDED	16. DATE T.D. REACHED	17. DATE COMPL. (Ready to prod.)	18. ELEVATIONS (DF, RKB, RT, GR, ETC.)*	19. ELEV. CASINGHEAD
9/22/76	10/6/76		5797 RKB	5785

20. TOTAL DEPTH, MD & TVD	21. PLUG, BACK T.D., MD & TVD	22. IF MULTIPLE COMPL., HOW MANY*	23. INTERVALS DRILLED BY	ROTARY TOOLS	CABLE TOOLS
6909' KB	6857' KB	Two	→	ALL	NONE

24. PRODUCING INTERVAL(S), OF THIS COMPLETION—TOP, BOTTOM, NAME (MD AND TVD)*
Dakota: Top - 6642', Bottom - 6786'
Mesa Verde: Top - 4465' Bottom - 4705'

25. WAS DIRECTIONAL SURVEY MADE: NO

26. TYPE ELECTRIC AND OTHER LOGS RUN
Induction -- Gamma Ray, Sidewall Neutron, CNL - Density

27. WAS WELL CORED: NO

23. CASING RECORD (Report all strings set in well)

CASING SIZE	WEIGHT, LB./FT.	DEPTH SET (MD)	HOLE SIZE	CEMENTING RECORD	AMOUNT PULLED
10-3/4"	40.50	315	15"	300 sx	0
7-5/8"	26.40	3939	9-3/4"	865 sx	0
5-1/2"	14.00	6895	6-3/4"	350sx	0

29. LINER RECORD

SIZE	TOP (MD)	BOTTOM (MD)	SACKS CEMENT*	SCREEN (MD)
5-1/2	3776	6895	350	

30. TUBING RECORD

SIZE	DEPTH SET (MD)	PACKER SET (MD)
2-3/8	6610	6610
2-3/8 - 1"	4437	----

31. PERFORATION RECORD (Interval, size and number)
Dakota: 2JSPF 6642-53, 6708-16, 6731-37, 6746-56 & 6784-86
Mesa Verde: 2JSPF 4465-82, 4508-17, 21-29, 47-51, 56-61, 76-89, 4622-23, 27-29, 41-42, 48-49, 59-61, 74-76, & 4697-4705'

32. ACID, SHOT, FRACTURE, CEMENT SQUEEZE, ETC.

DEPTH INTERVAL (MD)	AMOUNT AND KIND OF MATERIAL USED
6642-6786	2000 gals. 7½% & 65,375 # 20/40
4465-4529	56,500 # 20/40 & 19,500 # 10/20
4547-4705	250 gals. 15% & 56,500 # 20/40 & 19,500 # 10/20

33.* PRODUCTION

DATE FIRST PRODUCTION	PRODUCTION METHOD (Flowing, gas lift, pumping—size and type of pump)	WELL STATUS (Producing or shut-in)
SI	Flowing Dakota and Mesa Verde	W. O. Connection - SI

DATE OF TEST	HOURS TESTED	CHOKE SIZE	PROD'N. FOR TEST PERIOD →	OIL—BBL.	GAS—MCF.	WATER—BBL.	GAS-OIL RATIO
11/7/76 Dak	3	.750"		----	---	0	----
11/14/76 MV	3	.750"					

FLOW. TUBING PRESS.	CASING PRESSURE	CALCULATED 24-HOUR RATE →	OIL—BBL.	GAS—MCF.	WATER—BBL.	OIL GRAVITY-API (CORR.)
81 Dak.	Packer		---	2768	---	Not measured
216 MV	1016					Not measured

34. DISPOSITION OF GAS (Sold, used for fuel, vented, etc.)
Will be sold

TEST WITNESSED BY: Joe F. Elledge

35. LIST OF ATTACHMENTS
None

36. I hereby certify that the foregoing and attached information is complete and correct as determined from all available records

SIGNED Robert Ballantyne ~~Robert Ballantyne~~ TITLE Drilling Superintendent DATE 11/8/76

*(See Instructions and Spaces for Additional Data on Reverse Side)

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NOV 29 1976
OIL CON. COM.
DIST. 3

U. S. GEOLOGICAL SURVEY

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Form C-105
Revised 11-1-58

NEW MEXICO OIL CONSERVATION COMMISSION
WELL COMPLETION OR RECOMPLETION REPORT AND LOG

5a. Indicate Type of Lease: State ☐ Fee ☒

5. State Oil & Gas Lease No.

1a. TYPE OF WELL — OIL WELL ☐ GAS WELL ☒ DRY ☐ OTHER

b. TYPE OF COMPLETION — NEW WELL ☒ WORK OVER ☐ DEEPEN ☐ PLUG BACK ☐ DIFF. RESVR. ☐ OTHER

7. Unit Agreement Name

8. Farm or Lease Name: JAQUEZ

2. Name of Operator: CONSOLIDATED OIL & GAS, INC.

9. Well No.: 2

3. Address of Operator: PO BOX 2038, FARMINGTON, NEW MEXICO 87401

10. Field and Pool, or Wildcat: BASIN DAKOTA

4. Location of Well: UNIT LETTER K LOCATED 1730 FEET FROM THE S LINE AND 1740 FEET FROM THE W LINE OF SEC. 2 TWP. 31N RGE. 13W NMPM

12. County: SAN JUAN

15. Date Spudded	16. Date T.D. Reached	17. Date Compl. (Ready to Prod.)	18. Elevations (DF, RKB, RT, GR, etc.)	19. Elev. Cashinghead
2-26-80	3-11-80	11-6-80	5802 RKB	5790

20. Total Depth	21. Plug Back T.D.	22. If Multiple Compl., How Many	23. Intervals Drilled By →	Rotary Tools	Cable Tools
6945	6872	3		X	

24. Producing Interval(s), of this completion — Top, Bottom, Name: 6650 - 6864 DK

25. Was Directional Survey Made: NO

26. Type Electric and Other Logs Run: IES & CNL/CDL

27. Was Well Cored: NO

28. CASING RECORD (Report all strings set in well)

CASING SIZE	WEIGHT LB./FT.	DEPTH SET	HOLE SIZE	CEMENTING RECORD	AMOUNT PULLED
8 5/8	24#	268	12¼	200	NONE
5 1/2	15.5#	6944	7 7/8	240	NONE
		DV Tool	4819'	400	
		DV Tool	2157'	610	

29. LINER RECORD

SIZE	TOP	BOTTOM	SACKS CEMENT	SCREEN

30. TUBING RECORD

SIZE	DEPTH SET	PACKER SET
1½	6682	4900

31. Perforation Record (Interval, size and number)

6650 to 6770
18 - .32 Holes

32. ACID, SHOT, FRACTURE, CEMENT SQUEEZE, ETC.

DEPTH INTERVAL	AMOUNT AND KIND MATERIAL USED
6850-6864	500 gal acid, 24,000 gal x-l gel w/96800# sand
6650-6756	500 gal acid, 80,000 gal x-l gel w/89,500# sand

33. PRODUCTION

Date First Production	Production Method (Flowing, gas lift, pumping — Size and type pump)	Well Status (Prod. or Shut-in)
11-6-80	FLOW	S.I.

Date of Test	Hours Tested	Choke Size	Prod'n. For Test Period →	Oil — Bbl.	Gas — MCF	Water — Bbl.	Gas — Oil Ratio
11-6-80	3	?			153		

Flow Tubing Press.	Casing Pressure	Calculated 24-Hour Rate →	Oil — Bbl.	Gas — MCF	Water — Bbl.	Oil Gravity — API (Corr.)
				1226		

34. Disposition of Gas (Sold, used for fuel, vented, etc.): VENTED

Test Witnessed By: SONNY WILSON

35. List of Attachments

36. I hereby certify that the information shown on both sides of this form is true and complete to the best of my knowledge and belief.

SIGNED Veryl Moore TITLE PRODUCTION SUPT. DATE 12-3-80

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OPERATOR		

Form C-105
Revised 1-1-65

NEW MEXICO OIL CONSERVATION COMMISSION
WELL COMPLETION OR RECOMPLETION REPORT AND LOG

5. Indicate Type of Lease: State [ ] Fee [X]

6. State Oil & Gas Lease No.

7. Unit Agreement Name

8. Farm or Lease Name: O'Shea

9. Well No.: 1-M

10. Field and Pool, or Wildcat: Basin Dakota

1a. TYPE OF WELL — OIL WELL [ ] GAS WELL [X] DRY [ ] OTHER

b. TYPE OF COMPLETION — NEW WELL [X] WORK OVER [ ] DEEPEN [ ] PLUG BACK [ ] DIFF. RESVR. [ ] OTHER

2. Name of Operator: Consolidated Oil & Gas, Inc.

3. Address of Operator: 1860 Lincoln Street, Denver, Colorado 80295

4. Location of Well: UNIT LETTER F LOCATED 1450 FEET FROM THE north LINE AND 1750 FEET FROM THE west LINE OF SEC. 3 TWP. 31N RGE. 13W NMPM

12. County: San Juan

15. Date Spudded	16. Date T.D. Reached	17. Date Compl. (Ready to Prod.)	18. Elevations (DF, RKB, RT, GR, etc.)	19. Elev. Casinghead
7/28/79	8/22/79	12/8/79	GR 5838'	

20. Total Depth	21. Plug Back T.D.	22. If Multiple Compl., How Many	23. Intervals Drilled By →	Rotary Tools	Cable Tools
6928'	6909'	two		6920	8

24. Producing interval(s), of this completion — Top, Bottom, Name: 6706-6906 Dakota

25. Was Directional Survey Made: No

26. Type Electric and Other Logs Run: CNL, CBL/GR

27. Was Well Cored: No

28. CASING RECORD (Report all strings set in well)

CASING SIZE	WEIGHT LB./FT.	DEPTH SET	HOLE SIZE	CEMENTING RECORD	AMOUNT PULLED
8-5/8"	24.0#	282	12-1/4"	200 sx.	None
5-1/2"	15.5#	6918	7-7/8"	225 sx.	None
		DV tool @ 4868		265 sx.	

29. LINER RECORD

SIZE	TOP	BOTTOM	SACKS CEMENT	SCREEN

30. TUBING RECORD

SIZE	DEPTH SET	PACKER SET
1-1/2	6747	6650

31. Perforation Record (Interval, size and number)

6706-58 (0.32" - 11 holes)
6775-6906 (0.32" - 22 holes)

32. ACID, SHOT, FRACTURE, CEMENT SQUEEZE, ETC.

DEPTH INTERVAL	AMOUNT AND KIND MATERIAL USED
6706-58	1600 gals. acid; 107,000 gals. fluid w/152,000# sd.
6775-6906	200 gals. acid; 49,950 gals. fluid w/42,000# sd.

33. PRODUCTION

Date First Production	Production Method (Flowing, gas lift, pumping — Size and type pump)	Well Status (Prod. or Shut-in)
12/30/79	Flowing	SI, WO pipeline

Date of Test	Hours Tested	Choke Size	Prod'n. For Test Period →	Oil — Bbl.	Gas — MCF	Water — Bbl.	Gas — Oil Ratio
12/30/79	3	3/4"			273		

Flow Tubing Press.	Casing Pressure	Calculated 24-Hour Rate →	Oil — Bbl.	Gas — MCF	Water — Bbl.	Oil Gravity — API (Corr.)
148	1054			2182		

34. Disposition of Gas (Sold, used for fuel, vented, etc.): Vented for test

Test Witnessed By: Neil Teftellec

35. List of Attachments: Open hole logs previously furnished by Dresser Atlas

MAR 3 1980 OIL CON. COM. DIST. 3

36. I hereby certify that the information shown on both sides of this form is true and complete to the best of my knowledge and belief.

SIGNED [signature] TITLE Sr. Production Engr. DATE Feb. 28, 1980

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Form C-105
Revised 11-1-75

NEW MEXICO OIL CONSERVATION COMMISSION
WELL COMPLETION OR RECOMPLETION REPORT AND LOG

5a. Indicate Type of Lease: State ☐ Fee ☒

5. State Oil & Gas Lease No.

RECEIVED
AUG 7 1980
OIL CONSERVATION DIVISION
SANTA FE

1a. TYPE OF WELL
OIL WELL ☐ GAS WELL ☒ DRY ☐ OTHER

b. TYPE OF COMPLETION
NEW WELL ☒ WORK OVER ☐ DEEPEN ☐ PLUG BACK ☐ DIFF. RESVR. ☐ OTHER

7. Unit Agreement Name

8. Farm or Lease Name: JOHNSON

2. Name of Operator: OKLAHOMA OIL COMPANY

9. Well No.: 1E

3. Address of Operator: 4925 Greenville Ave., 1120 One Energy Square, Dallas, Texas 75206

10. Field and Pool, or Wildcat: BASIN DAKOTA

4. Location of Well
UNIT LETTER P LOCATED 1120 FEET FROM THE SOUTH LINE AND 1120 FEET FROM THE EAST LINE OF SEC. 21 TWP. 31N RGE. 13W NMPM

12. County: SAN JUAN

15. Date Spudded	16. Date T.D. Reached	17. Date Compl. (Ready to Prod.)	18. Elevations (DF, RKB, RT, GR, etc.)	19. Elev. Cashinghead
03/04/80	03/14/80	06/06/80	5685 GL	5686

20. Total Depth	21. Plug Back T.D.	22. If Multiple Compl., How Many	23. Intervals Drilled By	Rotary Tools	Cable Tools
6657	6614		→	0-6657	

24. Producing Interval(s), of this completion — Top, Bottom, Name: 6445-6544 DAKOTA

25. Was Directional Survey Made: YES

26. Type Electric and Other Logs Run: DIL, CNL-FDC, GR-Caliper, CCL

27. Was Well Cored: NO

28. CASING RECORD (Report all strings set in well)

CASING SIZE	WEIGHT LB./FT.	DEPTH SET	HOLE SIZE	CEMENTING RECORD	AMOUNT PULLED
8 5/8	24	200	12 1/4	200 C/B + 2% CaCl2	NONE
4 1/2	10.5	6657	7 7/8	Stg#1 285 sk 50-50 Poz	NONE
				Stg#2 580 sk 50-50 Poz	
				Stg#3 75 sk 65-35 Poz	

29. LINER RECORD

SIZE	TOP	BOTTOM	SACKS CEMENT	SCREEN
N/A				

30. 260 sk 50-50 Poz

SIZE	DEPTH SET	PACKER SET
2.375	6550	N/A

31. Perforation Record (Interval, size and number)

Interval	id	number
6445-6458	0.4"	26
6491-6496	0.4"	10
6530-6544	0.4"	28

32. ACID, SHOT, FRACTURE, CEMENT SQUEEZE, ETC.

DEPTH INTERVAL	AMOUNT AND KIND MATERIAL USED
6445-6544	60,000 gal gelled KCl water w/
	108,000# 20-40 sand

33. PRODUCTION

Date First Production	Production Method (Flowing, gas lift, pumping — Size and type pump)	Well Status (Prod. or Shut-in)
06/06/80	FLOWING	SHUT IN

Date of Test	Hours Tested	Choke Size	Prod'n. For Test Period →	Oil — Bbl.	Gas — MCF	Water — Bbl.	Gas — Oil Ratio
06/28/80	3	3/4					
Flow Tubing Press.	**Casing Pressure**	**Calculated 24-Hour Rate →**	**Oil — Bbl.**	**Gas — MCF**	**Water — Bbl.**	**Oil Gravity — API (Corr.)**	
129	602		0	1997	0		

JUL 31 1980
OIL CON. C...
DIST. 3

34. Disposition of Gas (Sold, used for fuel, vented, etc.): VENTED

Test Witnessed By

35. List of Attachments

36. I hereby certify that the information shown on both sides of this form is true and complete to the best of my knowledge and belief.

SIGNED John Alexander TITLE AGENT DATE July 30, 1980

No. of Copies Received		
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LAND OFFICE	1	
OPERATOR		

Form C-105
Revised 1-1-65

NEW MEXICO OIL CONSERVATION COMMISSION
WELL COMPLETION OR RECOMPLETION REPORT AND LOG

5a. Indicate Type of Lease: State [X] Fee [ ]

5. State Oil & Gas Lease No.: OG-2005

1a. TYPE OF WELL

b. TYPE OF COMPLETION: OIL WELL [ ] GAS WELL [X] DRY [ ] OTHER ____

NEW WELL [X] WORK OVER [ ] DEEPEN [ ] PLUG BACK [ ] DIFF. RESVR. [ ] OTHER

7. Unit Agreement Name:

8. Farm or Lease Name: State "BH" Gas Com.

2. Name of Operator: Pan American Petroleum Corporation

9. Well No.: 1

3. Address of Operator: Security Life Building, Denver, Colorado 80202

10. Field and Pool, or Wildcat: Basin Dakota

4. Location of Well: SW SW

UNIT LETTER M LOCATED 900 FEET FROM THE South LINE AND 870 FEET FROM THE West LINE OF SEC. 32 TWP. 31N RGE. 13W NMPM

12. County: San Juan

15. Date Spudded	16. Date T.D. Reached	17. Date Compl. (Ready to Prod.)	18. Elevations (DF, RKB, RT, GR, etc.)	19. Elev. Cashinghead
8-17-65	8-28-65	9-14-65	5639 RDB, 5625 GR	

20. Total Depth	21. Plug Back T.D.	22. If Multiple Compl., How Many	23. Intervals Drilled By	Rotary Tools	Cable Tools
6360	6325		→	Surface 6360	

24. Producing Interval(s), of this completion – Top, Bottom, Name: 6142-6224 Dakota

25. Was Directional Survey Made: No

26. Type Electric and Other Logs Run: IES, GR SONIC

27. Was Well Cored: No

28. CASING RECORD (Report all strings set in well)

CASING SIZE	WEIGHT LB./FT.	DEPTH SET	HOLE SIZE	CEMENTING RECORD	AMOUNT PULLED
8 5/8"	24#	380	12 1/4"	250	None
4 1/2"	10.5#	6360	7 7/8"	500 Sx-1st stage	None
				1000 Sx-2nd stage	
				Stage Collar at 4438	

29. LINER RECORD

SIZE	TOP	BOTTOM	SACKS CEMENT	SCREEN

30. TUBING RECORD

SIZE	DEPTH SET	PACKER SET
2 3/8"	6168	

31. Perforation Record (Interval, size and number)

6142-58, 6169-6174, 6218-24, 6202-12, with 2 shots/ft.

32. ACID, SHOT, FRACTURE, CEMENT SQUEEZE, ETC.

DEPTH INTERVAL	AMOUNT AND KIND MATERIAL USED
6142-6224	500 gal 15% acid, .8% Kcl,
	135# J-100, 60,000 #20-40 sand
	in 54,600 gal water.

33. PRODUCTION

Date First Production	Production Method (Flowing, gas lift, pumping – Size and type pump)	Well Status (Prod. or Shut-in)
9-14-65	Flowing	Shut In

Date of Test	Hours Tested	Choke Size	Prod'n. For Test Period →	Oil – Bbl.	Gas – MCF	Water – Bbl.	Gas – Oil Ratio
9-21-65	3	3/4"			373		

Flow Tubing Press.	Casing Pressure	Calculated 24-Hour Rate →	Oil – Bbl.	Gas – MCF	Water – Bbl.	Oil Gravity – API (Corr.)
241	714			2983		

34. Disposition of Gas (Sold, used for fuel, vented, etc.): To be sold to El Paso Natural Gas Company

Test Witnessed By:

35. List of Attachments: None

36. I hereby certify that the information shown on both sides of this form is true and complete to the best of my knowledge and belief.

SIGNED D. I. Tollefson TITLE Administrative Assistant DATE October 12, 1965

RECEIVED
OCT 14 1965
OIL CON. COM.
DIST. 3

Form 9-330

Budget Bureau No. 42-R355.4.
Approval expires 12-31-60.

U. S. LAND OFFICE Santa Fe
SERIAL NUMBER 078463-A
LEASE OR PERMIT TO PROSPECT

LOCATE WELL CORRECTLY

RECEIVED
MARC 1961
OIL CON. COM.
DRILLING & PROD.
CONSOLIDATED OIL & GAS, INC.

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

RECEIVED
MAR 31 1961
U. S. GEOLOGICAL SURVEY
NEW MEXICO

HALE-ADOBE NO. 1-28

San Juan County New Mexico

LOG OF OIL OR GAS WELL

Company Consolidated Oil & Gas, Inc. Address 2112 Tower Bldg. - 1700 Broadway
Denver 2, Colorado
Lessor or Tract Hale-Adobe Field Basin Dakota State New Mexico
Well No. 1-28 Sec. 28 T. 31N R. 13W Meridian NMPM County San Juan
Location 1450 ft. [N.] of N. Line and 1450 ft. [W.] of E. Line of Section Elevation 5674 KB

The information given herewith is a complete and correct record of the well and all work done thereon so far as can be determined from all available records.

Signed
2-16-61
Date February 28, 1961 Title Chief Engineer

The summary on this page is for the condition of the well at above date.

Commenced drilling 12-9, 19 61 Finished drilling 2-16-61, 19 61

OIL OR GAS SANDS OR ZONES

No. 1, from 6156 to 6260 No. 4, from to
No. 2, from to No. 5, from to
No. 3, from to No. 6, from to

IMPORTANT WATER SANDS

No. 1, from to No. 3, from to
No. 2, from to No. 4, from to

CASING RECORD

Size casing	Weight per foot	Threads per inch	Make	Amount	Kind of shoe	Cut and pulled from	Perforated From	Perforated To	Purpose
9 5/8	32.3#	8 rd		193					Surface
5 1/2	15.5#	8 rd		6493	Baker		6156	6260	Production
					Baker		6316	6420	
					Baker		6447	6453	
					Guide				
					Baker				

Producing Perforations

MUDDING AND CEMENTING RECORD

Size casing	Where set	Number sacks of cement	Method used	Mud gravity	Amount of mud used
9 5/8	193	200 2% HA-5	Pump & Plug		
5 1/2	6493	180 6% gel	Pump & Plug	FO through 3/4	choke.

PLUGS AND ADAPTERS

Heaving plug—Material Cement Length 40' Depth set 6453
Adapters—Material Size

SHOOTING RECORD

Size	Shell used	Explosive used	Quantity	Date	Depth shot	Depth cleaned out
		Sand-water Frac - 99,000 #Sand, 95,000 gal. water, 1000 gal. acid				

TOOLS USED

Rotary tools were used from 0 feet to 6510 feet, and from feet to feet
Cable tools were used from feet to feet, and from feet to feet

DATES

February 27, 1961, 19 61 Put to producing , 19

The production for the first 24 hours was barrels of fluid of which % was oil; %
emulsion; % water; and % sediment. Gravity, °B6.

If gas well, cu. ft. per 24 hours 2360 MCF Gallons gasoline per 1,000 cu. ft. of gas

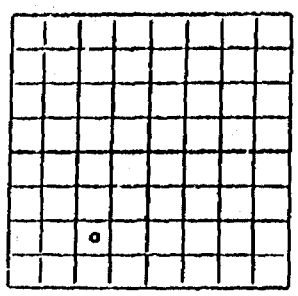
Rock pressure, lbs. per sq. in. 1219 S.I.P. 3 hour Initial Potential Test

EMPLOYEES

Bacon Drilling Co., Driller , Driller

FOLD MARK

(Revised 7/1/58)
(Form C-105)



NEW MEXICO OIL CONSERVATION COMMISSION

MAIN OFFICE OCC Santa Fe, New Mexico

1960 DEC 12 AM 9 00

WELL RECORD

Mail to District Office, Oil Conservation Commission, to which Form C-101 was sent not later than twenty days after completion of well. Follow instructions in Rules and Regulations of the Commission. Submit in QUINTUPLICATE. If State Land submit 6 Copies

ADOBE OIL COMPANY (Company or Operator) Harris (Lease)

Well No. 1, in SE ¼ of SW ¼, of Sec. 28, T. 31N, R. 13W, NMPM.

Undesignated Pool, San Juan County.

Well is 1600 feet from W line and 790 feet from S line of Section 28. If State Land the Oil and Gas Lease No. is .....

Drilling Commenced 9-29, 1960 Drilling was Completed 10-14, 1960

Name of Drilling Contractor Great Western Drilling Company

Address Midland, Texas

Elevation above sea level at Top of Tubing Head 5628 GL The information given is to be kept confidential until - - -, 1960

OIL SANDS OR ZONES

No. 1, from 1120 to 1140 No. 4, from ..... to .....

No. 2, from 4050 to 4120 No. 5, from ..... to .....

No. 3, from ..... to ..... No. 6, from ..... to .....

IMPORTANT WATER SANDS

Include data on rate of water inflow and elevation to which water rose in hole.

No. 1, from ..... to ..... feet. .....

No. 2, from ..... to ..... feet. .....

No. 3, from ..... to ..... feet. .....

No. 4, from ..... to ..... feet. .....

CASING RECORD

SIZE	WEIGHT PER FOOT	NEW OR USED	AMOUNT	KIND OF SHOE	CUT AND PULLED FROM	PERFORATIONS	PURPOSE
8-5/8"	24#	New	295	Texas	--	--	Surface
5-1/2"	15.5	New	6475	HOWCO	--	6246-6400	Oil string

MUDDING AND CEMENTING RECORD

SIZE OF HOLE	SIZE OF CASING	WHERE SET	NO. SACKS OF CEMENT	METHOD USED	MUD GRAVITY	AMOUNT OF MUD USED
11-1/2	8-5/8	295	200	Pump & plug	96	--
7-7/8	5-1/2	6475	200 + 200*	Pump & plug	95	--

RECORD OF PRODUCTION AND STIMULATION

(Record the Process used, No. of Qts. or Gals. used, Interval treated or shot.)

*D.V. tool at 4483' and 200 sxs. cement thru same.

Fractured with 95,600 gallons of water plus 100,000# sand thru perforations 6246-62, 6313-23, 6335-44 and 6380-6400.

Result of Production Stimulation Absolute Potential 2,377

Depth Cleaned Out 6438

Form 9-330

5 USGS
2 Anderson
1 File

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MAY 18 1962
GEOLOGICAL SURVEY

Form approved.
Budget Bureau No. 42-R355.4.

U. S. LAND OFFICE Santa Fe
SERIAL NUMBER [illegible] 053703
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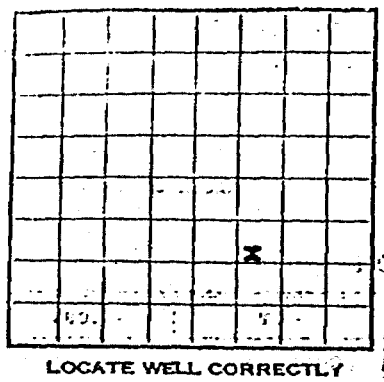
UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

[illegible]ORMATION RECORD—[illegible]



LOCATE WELL CORRECTLY

LOG OF OIL OR GAS WELL

Company Bruce Anderson & Beard Oil Co. Address 1007 E. Dustin Farmington, New Mexico

Lessor or Tract Federal Field Basin - Dakota State New Mexico

Well No. 1 Sec. 29 T. 31N R. 13W Meridian NMPM County San Juan

Location 1300 ft. [N.] of S. Line and 1830 ft. [E.] of E. Line of Sec. 29 Elevation 5578 G.L.

The information given herewith is a complete and correct record of the well and all work done thereon so far as can be determined from all available records.

Signed Original signed by T. A. Dugan

Date May 15, 1962 Title Consulting Engineer

The summary on this page is for the condition of the well at above date.

Commenced drilling April 9, 19 62 Finished drilling May 5, 19 62

OIL OR GAS SANDS OR ZONES

(Denote gas by G)

No. 1, from	6384 to 6402 (G)		No. 4, from	6318 to 6326 (G)	
No. 2, from	6252 to 6262 (G)		No. 5, from	6334 to 6342 (G)	
No. 3, from	6272 to 6292 (G)		No. 6, from	6376 to 6384 (G)	

IMPORTANT WATER SANDS

No. 1, from	to	No. 3, from	to
No. 2, from	to	No. 4, from	to

CASING RECORD

Size casing	Weight per foot	Threads per inch	Make	Amount	Kind of shoe	Cut and pulled from	Perforated From—	Perforated To—	Purpose
8 5/8"	24#	8rd	Spang	176.01	Tex Pattern				Surface
4 1/2"	10.5#	[illegible]	Spang	6413.46	Guide	Plowed aside in drilling	6324	6344	Production

MUDDING AND CEMENTING RECORD

Size casing	Where set	Number sacks of cement	Method used	Mud gravity	Amount of mud used
8 5/8"	127	135 sx	Pump Plug		
4 1/2"	6420	125 sx	Pump Plug		

FOLD MARK

PLUGS AND ADAPTERS

Heaving plug—Material Length Depth set

Adapters—Material Size

SHOOTING RECORD

5-USGS (Farmington) 1-Anderson 1-Beard Oil 1-File

Form 9-330
(Rev. 5-63)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN DUPLICATE* (See other instructions on reverse side)

Form approved.
Budget Bureau No. 42-R355.5.

WELL COMPLETION OR RECOMPLETION REPORT AND LOG*

5. LEASE DESIGNATION AND SERIAL NO.: NM 053798

6. IF INDIAN, ALLOTTEE OR TRIBE NAME:

7. UNIT AGREEMENT NAME:

8. FARM OR LEASE NAME: Federal

9. WELL NO.: #2

10. FIELD AND POOL, OR WILDCAT: Basin Dakota

11. SEC., T., R., M., OR BLOCK AND SURVEY OR AREA: Sec 30 T31N R13W

1a. TYPE OF WELL: OIL WELL ☐ GAS WELL ☒ DRY ☐ Other

b. TYPE OF COMPLETION: NEW WELL ☒ WORK OVER ☐ DEEP-EN ☐ PLUG BACK ☐ DIFF. RESVR. ☐ Other

2. NAME OF OPERATOR: Bruce Anderson

3. ADDRESS OF OPERATOR: Box 208, Farmington, NM 87401

4. LOCATION OF WELL (*Report location clearly and in accordance with any State requirements*)*
At surface: 1570' FSL - 1000' FEL
At top prod. interval reported below
At total depth

14. PERMIT NO. | DATE ISSUED

12. COUNTY OR PARISH: San Juan | 13. STATE: NM

15. DATE SPUDDED	16. DATE T.D. REACHED	17. DATE COMPL. (*Ready to prod.*)	18. ELEVATIONS (DF, RKB, RT, GR, ETC.)*	19. ELEV. CASINGHEAD
10-24-79	11-03-79	11-27-79	5657' GR	

20. TOTAL DEPTH, MD & TVD	21. PLUG, BACK T.D., MD & TVD	22. IF MULTIPLE COMPL., HOW MANY*	23. INTERVALS DRILLED BY	ROTARY TOOLS	CABLE TOOLS
6460'	6391'	Single - Gas	→	0-TD	

24. PRODUCING INTERVAL(S), OF THIS COMPLETION—TOP, BOTTOM, NAME (MD AND TVD)*: 6210-6356 Basin Dakota

25. WAS DIRECTIONAL SURVEY MADE: Yes

26. TYPE ELECTRIC AND OTHER LOGS RUN: GO Wireline IES and CDL logs

27. WAS WELL CORED: No

28. CASING RECORD (*Report all strings set in well*)

CASING SIZE	WEIGHT, LB./FT.	DEPTH SET (MD)	HOLE SIZE	CEMENTING RECORD	AMOUNT PULLED
8-5/8"	24#	203' RKB	12-1/4"	150 sx	---
4-1/2"	10.5#	6450' RKB	7-7/8"	325 sx 1st stage	
				500 sx 2nd stage	

29. LINER RECORD

SIZE	TOP (MD)	BOTTOM (MD)	SACKS CEMENT*	SCREEN (MD)

30. TUBING RECORD

SIZE	DEPTH SET (MD)	PACKER SET (MD)
1-1/2"	6343' RKB	

31. PERFORATION RECORD (*Interval, size and number*): 6210-6232, 6288-6294, 6297-6301, 6348-6356

RECEIVED
JAN 14 1980
OIL CON. COM.
DIST. 3

32. ACID, SHOT, FRACTURE, CEMENT SQUEEZE, ETC.

DEPTH INTERVAL (MD)	AMOUNT AND KIND OF MATERIAL USED
	See Sundry Notice 11-21-79 for detailed info

33.* PRODUCTION

DATE FIRST PRODUCTION	PRODUCTION METHOD (*Flowing, gas lift, pumping—size and type of pump*)	WELL STATUS (*Producing or shut-in*)
	Flowing	SI

DATE OF TEST	HOURS TESTED	CHOKE SIZE	PROD'N. FOR TEST PERIOD →	OIL—BBL.	GAS—MCF.	WATER—BBL.	GAS-OIL RATIO
12-5-79	3 hrs	3/4"			3415 AOF		

FLOW. TUBING PRESS.	CASING PRESSURE	CALCULATED 24-HOUR RATE →	OIL—BBL.	GAS—MCF.	WATER—BBL.	OIL GRAVITY-API (CORR.)
1960 SI	1970 SI			2776		

34. DISPOSITION OF GAS (*Sold, used for fuel, vented, etc.*): TEST WITNESSED BY

35. LIST OF ATTACHMENTS

RECEIVED
JAN 9 1980
OIL CON. COM.
DIST. 3

36. I hereby certify that the foregoing and attached information is complete and correct as determined from all available records.

ACCEPTED FOR RECORD

SIGNED T. A. Dugan Thomas A. Dugan TITLE Agent DATE 12-11-79

*(See Instructions and Spaces for Additional Data on Reverse Side)

NMOCC

FARMINGTON, NEW MEXICO DISTRICT
BY WS

5-USGS (Farmington) 1-Anderson 1-Beard Oil 1-File

Form 9-331
(Rev. 5-63)

SUBMIT IN DUPLICATE*
(See other instructions on reverse side)

Form approved.
Budget Bureau No. 42-R355.5.

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

WELL COMPLETION OR RECOMPLETION REPORT AND LOG*

5. LEASE DESIGNATION AND SERIAL NO.: NM 053798

6. IF INDIAN, ALLOTTEE OR TRIBE NAME:

1a. TYPE OF WELL: OIL WELL ☐ GAS WELL ☒ DRY ☐ Other

b. TYPE OF COMPLETION: NEW WELL ☒ WORK OVER ☐ DEEP-EN ☐ PLUG BACK ☐ DIFF. RESVR. ☐ Other

7. UNIT AGREEMENT NAME:

8. FARM OR LEASE NAME: Federal

2. NAME OF OPERATOR: Bruce Anderson

9. WELL NO.: #3

3. ADDRESS OF OPERATOR: Box 208, Farmington, NM 87401

10. FIELD AND POOL, OR WILDCAT: Basin Dakota

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements)*
At surface: 1190' FSL - 714' FWL
At top prod. interval reported below
At total depth

RECEIVED
JAN 14 1980
OIL CONSERVATION DIVISION
U. S. GEOLOGICAL SURVEY
FARMINGTON, N. M.

11. SEC., T., R., M., OR BLOCK AND SURVEY OR AREA: Sec 30 T31N R13W

14. PERMIT NO.: | DATE ISSUED:

12. COUNTY OR PARISH: San Juan | 13. STATE: NM

15. DATE SPUDDED	16. DATE T.D. REACHED	17. DATE COMPL. (Ready to prod.)	18. ELEVATIONS (DF, RKB, RT, GR, ETC.)*	19. ELEV. CASINGHEAD
11-5-79	11-15-79	12-3-79	5713' GL	

20. TOTAL DEPTH, MD & TVD	21. PLUG, BACK T.D., MD & TVD	22. IF MULTIPLE COMPL., HOW MANY*	23. INTERVALS DRILLED BY	ROTARY TOOLS	CABLE TOOLS
6490'	6446'	Single - Gas	→	0-TD	

24. PRODUCING INTERVAL(S), OF THIS COMPLETION—TOP, BOTTOM, NAME (MD AND TVD)*: 6252-6416'

25. WAS DIRECTIONAL SURVEY MADE: Yes

26. TYPE ELECTRIC AND OTHER LOGS RUN: IES & CDL

27. WAS WELL CORED: No

28. CASING RECORD (Report all strings set in well)

CASING SIZE	WEIGHT, LB./FT.	DEPTH SET (MD)	HOLE SIZE	CEMENTING RECORD	AMOUNT PULLED
8-5/8"	24#	220' RKB	12-1/4"	175 sx	-
4-1/2"	10.5#	6484'	7-7/8"	325 sx	-

29. LINER RECORD

SIZE	TOP (MD)	BOTTOM (MD)	SACKS CEMENT*	SCREEN (MD)

30. TUBING RECORD

SIZE	DEPTH SET (MD)	PACKER SET (MD)
1-1/2"	6346'	

31. PERFORATION RECORD (Interval, size and number)

6252-62, 6265-70, 6313-19, 6324-28, 6402-16

32. ACID, SHOT, FRACTURE, CEMENT SQUEEZE, ETC.

DEPTH INTERVAL (MD)	AMOUNT AND KIND OF MATERIAL USED
	See Sundry Notice 11-28-79 for detailed info

33.* PRODUCTION

DATE FIRST PRODUCTION	PRODUCTION METHOD (Flowing, gas lift, pumping—size and type of pump)	WELL STATUS (Producing or shut-in)
	Flowing	SI

DATE OF TEST	HOURS TESTED	CHOKE SIZE	PROD'N. FOR TEST PERIOD →	OIL—BBL.	GAS—MCF.	WATER—BBL.	GAS-OIL RATIO
12-11-79	3 hrs				824 AOF	-	

FLOW. TUBING PRESS.	CASING PRESSURE	CALCULATED 24-HOUR RATE →	OIL—BBL.	GAS—MCF.	WATER—BBL.	OIL GRAVITY-API (CORR.)
1190 SI	1375 SI			721		

34. DISPOSITION OF GAS (Sold, used for fuel, vented, etc.)

TEST WITNESSED BY

35. LIST OF ATTACHMENTS

36. I hereby certify that the foregoing and attached information is complete and correct as determined from all available records.

SIGNED T. H. Duggan (Thomas H. Duggan) TITLE Agent DATE 12-13-79

*(See Instructions and Spaces for Additional Data on Reverse Side)

NMOCC

Form 9-330

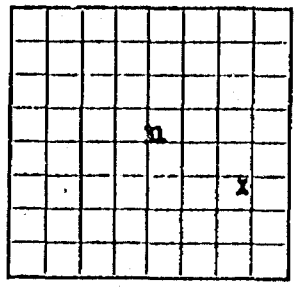
Budget Bureau No. 42-R355.4.
Approval expires 12-31-60.

U. S. LAND OFFICE Santa Fe
SERIAL NUMBER 053822 NM
LEASE OR PERMIT TO PROSPECT

RECEIVED
AUG 22 1962
OIL CON. COM.
DIST. 3

RECEIVED
AUG 21 1962
U. S. GEOLOGICAL SURVEY
FARMINGTON, NEW MEXICO

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY



LOCATE WELL CORRECTLY

LOG OF OIL OR GAS WELL

Company C. L. Mills Address 1402 Philtower Bldg. Tulsa, Okla.

Lessor or Tract Stribling Field Basin Dakota State New Mexico

Well No. 1 Sec. 31 T. 31N R. 13W Meridian NMPM County San Juan

Location 1565 ft. [N.] of S. Line and 1040 ft. [E.] of W. Line of Sec. 31 Elevation 5719
(Derrick floor relative to sea level)

The information given herewith is a complete and correct record of the well and all work done thereon so far as can be determined from all available records.

Signed [signature]

Date August 15, 1962 Title Petroleum Engineer

The summary on this page is for the condition of the well at above date.

Commenced drilling April 28, 19 62 Finished drilling May 24, 19 62

OIL OR GAS SANDS OR ZONES

(Denote gas by G)

No. 1, from 6208 to 6300 (G) No. 4, from ..... to .....

No. 2, from ..... to ..... No. 5, from ..... to .....

No. 3, from ..... to ..... No. 6, from ..... to .....

IMPORTANT WATER SANDS

No. 1, from 1600 to 1750 No. 3, from ..... to .....

No. 2, from 3200 to 4300 No. 4, from ..... to .....

CASING RECORD

Size casing	Weight per foot	Threads per inch	Make	Amount	Kind of shoe	Cut and pulled from	Perforated From—	Perforated To—	Purpose
8-5/8	24.0	8	Spang	100	Howco				Surface
4-1/2	10.5	8	Spang	6392	Howco		6216	6227	Production
							6259	6265	
							6273	6282	
							6289	6300	

MUDDING AND CEMENTING RECORD

Size casing	Where set	Number sacks of cement	Method used	Mud gravity	Amount of mud used
8-5/8	100	130	Howco 1-plug		
4-1/2	6402	200	DV tool @ 5716 - 100 sacks thru DV tool and Shoe @ 6402 - 100 sacks around shoe.		

MARK

FOLD

PLUGS AND ADAPTERS

Heaving plug—Material ..... Length ..... Depth set .....

Adapters—Material ..... Size .....

SHOOTING RECORD

Size	Shell used	Explosive used	Quantity	Date	Depth shot	Depth cleaned out

TOOLS USED

Rotary tools were used from 0 feet to 6420 feet, and from ..... feet to ..... feet

Cable tools were used from ..... feet to ..... feet, and from ..... feet to ..... feet

DATES

June 19, 19 62 Put to producing ....., 19.....

The production for the first 24 hours was ..... barrels of fluid of which .....% was oil; .....% emulsion; .....% water; and .....% sediment. Gravity, °Bé. .....

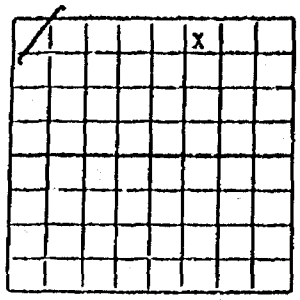
If gas well, cu. ft. per 24 hours 4503 I.P. Gallons gasoline per 1,000 cu. ft. of gas .....
5415 AOF

Rock pressure, lbs. per sq. in. 2052 Surface pressure

EMPLOYEES

....., Driller ....., Driller

Obsolete 7/1/52
(Form C-105)



AREA 640 ACRES
LOCATE WELL CORRECTLY

NEW MEXICO OIL CONSERVATION COMMISSION

MAIN OFFICE OCC
Santa Fe, New Mexico

1958 OCT 10 AM

WELL RECORD

Mail to District Office, Oil Conservation Commission, to which Form C-101 was sent not later than twenty days after completion of well. Follow instructions in Rules and Regulations of the Commission. Submit in QUINTUPLICATE. If State Land submit 6 Copies

Pan American Petroleum Corporation (Company or Operator) McCarty Gas Unit (Lease)

Well No. 1, in NW ¼ of NE ¼, of Sec. 15, T. 31N, R. 13W, NMPM.

Wildcat Pool, San Juan County.

Well is 840 feet from North line and 1840 feet from East line of Section 15. If State Land the Oil and Gas Lease No. is

Drilling Commenced July 19, 1958 Drilling was Completed September 30, 1958

Name of Drilling Contractor Brannon & Murray Drilling Company

Address Box 672, Coleman, Texas

Elevation above sea level at Top of Tubing Head Well plugged & abandoned The information given is to be kept confidential until , 19

OIL SANDS OR ZONES

No. 1, from None to No. 4, from to

No. 2, from to No. 5, from to

No. 3, from to No. 6, from to

IMPORTANT WATER SANDS

Include data on rate of water inflow and elevation to which water rose in hole.

No. 1, from None to feet.

No. 2, from to feet.

No. 3, from to feet.

No. 4, from to feet.

CASING RECORD

SIZE	WEIGHT PER FOOT	NEW OR USED	AMOUNT	KIND OF SHOE	CUT AND PULLED FROM	PERFORATIONS	PURPOSE
10-3/4"	32.75#	New	202	Guide			Surface
7-5/8"	26.4#	New	4725	Guide			Intermediate

MUDDING AND CEMENTING RECORD

SIZE OF HOLE	SIZE OF CASING	WHERE SET	NO. SACKS OF CEMENT	METHOD USED	MUD GRAVITY	AMOUNT OF MUD USED
15"	10-3/4"	312	225	Halliburton 2 plug		
9-5/8"	7-5/8"	4750	150	Halliburton 2 plug		

RECORD OF PRODUCTION AND STIMULATION

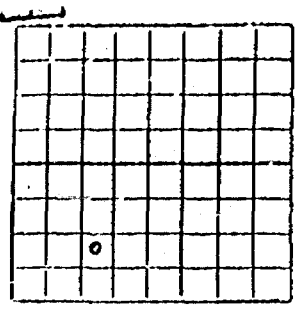
(Record the Process used, No. of Qts. or Gals. used, interval treated or shot.)

Perforated 4386 - 4676' with two shots per foot, fracked with 100,000# sand, 120,000 gallons water and 155 ball sealers in 5 stages. Formation broke at 1700#, average injection rate 77 barrels per minute, flushed at 40 barrels per minute.

Result of Production Stimulation Gas production 100,000 CFPD. Well non-commercial.

Depth Cleaned Out

(Revised 7/1/58)
(Form C-105)



AREA 640 ACRES
LOCATE WELL CORRECTLY

NEW MEXICO OIL CONSERVATION COMMISSION

Santa Fe, New Mexico

WELL RECORD

Mail to District Office, Oil Conservation Commission, to which Form C-101 was sent not later than twenty days after completion of well. Follow instructions in Rules and Regulations of the Commission. Submit in QUINTUPLICATE. If State Land submit 6 Copies

Consolidated Oil & Gas, Inc. (Company or Operator) Price (Lease)

Well No. 1-15, in SE ¼ of SW ¼, of Sec. 15, T. 31N, R. 13W, NMPM.

Blanco Mesaverde, Basin Dakota Pool, San Juan County.

Well is 895' feet from South line and 1470' feet from West line of Section 15. If State Land the Oil and Gas Lease No. is

Drilling Commenced July 9, 19 61 Drilling was Completed July 29, 19 61

Name of Drilling Contractor Huron Drilling Co.

Address 2415 Mercantile Bank Building, Dallas, Texas

Elevation above sea level at Top of Tubing Head 5745' KB The information given is to be kept confidential until , 19

OIL SANDS OR ZONES

No. 1, from 4336' to 4430' No. 4, from to

No. 2, from 6523' to 6627' No. 5, from to

No. 3, from to No. 6, from to

RECEIVED
SEP 8 1961
OIL CON. COM.
DIST. 3

IMPORTANT WATER SANDS

Include data on rate of water inflow and elevation to which water rose in hole.

No. 1, from to feet.

No. 2, from to feet.

No. 3, from to feet.

No. 4, from to feet.

CASING RECORD

SIZE	WEIGHT PER FOOT	NEW OR USED	AMOUNT	KIND OF SHOE	CUT AND PULLED FROM	PERFORATIONS	PURPOSE
10 3/4"	32.75	New	189'	Guide		See Reverse	Surface
5 1/2"	14 & 15.5	New	6674'	Float		" "	Production

MUDDING AND CEMENTING RECORD

SIZE OF HOLE	SIZE OF CASING	WHERE SET	NO. SACKS OF CEMENT	METHOD USED	MUD GRAVITY	AMOUNT OF MUD USED
15"	13 3/4"	189'	150	Pump & Plug-Circulated		
7 7/8"	5 1/2"	6674'	125 thru	shoe		
			125 thru	stage collar at 4701'		

RECORD OF PRODUCTION AND STIMULATION

(Record the Process used, No. of Qts. or Gals. used, interval treated or shot.)

Sand-water frac:

Mesaverde: 125,000# (20-40 mesh) sand, 140,000 gal. water

Dakota: 80,000# (20-40 & 40-60 mesh) sand, 105,000 gal. slicked water, 1500 gal. acid in 2 stages

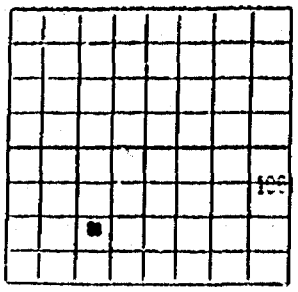
Result of Production Stimulation

MV Flow volume thru 3/4" choke: 50 MCFD

DK Flow volume thru 3/4" choke: 2460 MCFD

Depth Cleaned Out 6645'

Obsolete 7/1/52
(Form C-105)



NEW MEXICO OIL CONSERVATION COMMISSION

Santa Fe, New Mexico

WELL RECORD

Mail to District Office, Oil Conservation Commission, to which Form C-101 was sent not later than twenty days after completion of well. Follow instructions in Rules and Regulations of the Commission. Submit in QUINTUPLICATE. If State Land submit 6 Copies

Adobe Oil Company (Company or Operator) McCarty (Lease)

Well No. 1, in SE ¼ of SW ¼, of Sec. 14, T. 31N, R. 13W, NMPM.

Undesignated Pool, San Juan County.

Well is 790 feet from South line and 1600 feet from West line of Section 14. If State Land the Oil and Gas Lease No. is

Drilling Commenced 9-29, 1960 Drilling was Completed 10-20, 1960

Name of Drilling Contractor Pioneer Drilling Company

Address Farmington, New Mexico

Elevation above sea level at Top of Tubing Head 5630 The information given is to be kept confidential until , 19

OIL SANDS OR ZONES

No. 1, from 6450 to 6682 No. 4, from to

No. 2, from to No. 3, from to

No. 3, from to No. 6, from to

IMPORTANT WATER SANDS

Include data on rate of water inflow and elevation to which water rose in hole.

No. 1, from to feet.

No. 2, from to feet.

No. 3, from to feet.

No. 4, from to feet.

RECEIVED
DEC 27 1960
O. COM.

CASING RECORD

SIZE	WEIGHT PER FOOT	NEW OR USED	AMOUNT	KIND OF SHOE	CUT AND PULLED FROM	PERFORATIONS	PURPOSE
8-5/8	24	New	201	Texas Pat.	-	-	Surface
5-1/2	15.5	New	6682	Guide	-	6450-6596	Production String

MUDDING AND CEMENTING RECORD

SIZE OF HOLE	SIZE OF CASING	WHERE SET	NO. SACKS OF CEMENT	METHOD USED	MUD GRAVITY	AMOUNT OF MUD USED
11¼	8-5/8	201	175	Pump & Plug	-	-
7-7/8	5-1/2	6682	200	Pump & Plug	9.5	-
			300	DV @ 4613		

RECORD OF PRODUCTION AND STIMULATION

(Record the Process used, No. of Qts. or Gals. used, interval treated or shot.)

Treated perf. 6450-6512, 6528-32, 6548-54 & 6582-96 w/1500 gal MCA. Swbd to clean. Fraced down csg. 32,000 gal wtr & 32,0000 sd. Well sanded out, cleaned out & flowed to test. Well died in 4 hrs of flwg. Re-fraced w/33,000 gal wtr & 33,0000 sd. Ran tubing to 6585'.

Result of Production Stimulation

Tested 1,723 MCF/day C.A.P. on 12-9-60

6631

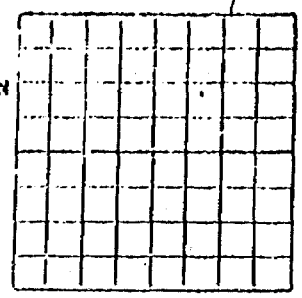
Depth Cleaned Out

NEW MEXICO OIL CONSERVATION COMMISSION

Santa Fe, New Mexico

WELL RECORD

Mail to District Office, Oil Conservation Commission, to which Form C-101 was sent not later than twenty days after completion of well. Follow instructions in Rules and Regulations of the Commission. Submit in QUINTUPLICATE. If State Land submit 6 Copies



AREA 640 ACRES
LOCATE WELL CORRECTLY

Adobe Oil Company (Company or Operator) Cuccia (Lease)

Well No. 1, in SW ¼ of NE ¼, of Sec. 14, T. 31N, R. 13W, NMPM.

Basin Dakota Pool, San Juan County.

Well is 1450 feet from North line and 1600 feet from East line of Section 14. If State Land the Oil and Gas Lease No. is

Drilling Commenced March 11, 19 62 Drilling was Completed June 10, 19 62

Name of Drilling Contractor Rico Drilling Company

Address Breckenridge, Texas

Elevation above sea level at Top of Tubing Head 5721' The information given is to be kept confidential until , 19

OIL SANDS OR ZONES

No. 1, from 6546' to 6572' No. 4, from to

No. 2, from 6612' to 6622' No. 5, from to

No. 3, from 6654' to 6660' No. 6, from to

IMPORTANT WATER SANDS

Include data on rate of water inflow and elevation to which water rose in hole.

No. 1, from to feet.

No. 2, from to feet.

No. 3, from to feet.

No. 4, from to feet.

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JUN 28 1962
OIL CON. COM.
DIST. 3

CASING RECORD

SIZE	WEIGHT PER FOOT	NEW OR USED	AMOUNT	KIND OF SHOE	CUT AND PULLED FROM	PERFORATIONS	PURPOSE
8-5/8"	24#	New	261'	Texas Pattern	--	--	Surface casing
4-1/2"	10.5#	New	6746'	HOWCO	--	6546'-72'	Oil String
						6612'-22'	
						6654'-60'	

MUDDING AND CEMENTING RECORD

SIZE OF HOLE	SIZE OF CASING	WHERE SET	NO. SACKS OF CEMENT	METHOD USED	MUD GRAVITY	AMOUNT OF MUD USED
12-1/4"	8-5/8"	261'	150	Pump & Plug		Cement Circ.
7-7/8"	4-1/2"	6746	300 Btm	Pump & Plug		
			200 DV Tool at 4748'			

RECORD OF PRODUCTION AND STIMULATION

(Record the Process used, No. of Qts. or Gals. used, interval treated or shot.)

Frac with 10,000 gallons water with 950# sand at 6654-60'.

Frac with 31,000 gallons water with 9050# sand at 6612-22'.

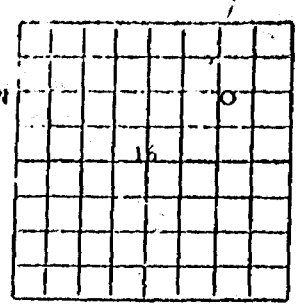
Frac with 92,500 gallons water with 50,000# sand at 6546-72'.

Result of Production Stimulation 1465 MCFPD

Depth Cleaned Out 6712'

NEW MEXICO OIL CONSERVATION COMMISSION
Santa Fe, New Mexico

WELL RECORD



AREA 640 ACRES
LOCATE WELL CORRECTLY

Mail to District Office, Oil Conservation Commission, to which Form C-101 was sent not later than twenty days after completion of well. Follow instructions in Rules and Regulations of the Commission. Submit in QUINTUPLICATE. If State Land submit 6 Copies

Consolidated Oil & Gas, Inc. (Company or Operator) Frankel (Lease)

Well No. 1-16, in SE ¼ of NE ¼, of Sec. 16, T. 31 North, R. 13 West, NMPM.

Basin Dakota Pool, San Juan County.

Well is 1650 feet from North line and 1170 feet from East line of Section 16. If State Land the Oil and Gas Lease No. is OG 794

Drilling Commenced 8-3, 19 62 Drilling was Completed October 3, 19 62

Name of Drilling Contractor Huron Drilling Company

Address 2415 Mercantile Bank Building, Dallas, Texas

Elevation above sea level at Top of Tubing Head 5756 GL 5768 KB The information given is to be kept confidential until _____, 19____

OIL SANDS OR ZONES

No. 1, from 6540 to 6644 No. 4, from _____ to _____

No. 2, from _____ to _____ No. 5, from _____ to _____

No. 3, from _____ to _____ No. 6, from _____ to _____

IMPORTANT WATER SANDS

Include data on rate of water inflow and elevation to which water rose in hole.

No. 1, from _____ to _____ feet. _____

No. 2, from _____ to _____ feet. _____

No. 3, from _____ to _____ feet. _____

No. 4, from _____ to _____ feet. _____

CASING RECORD

SIZE	WEIGHT PER FOOT	NEW OR USED	AMOUNT	KIND OF SHOE	CUT AND PULLED FROM	PERFORATIONS	PURPOSE
9-5/8	36	new	206	Guide		6546-6556	surface
5-1/2	15.5 & 14	new	6718	Float		6564-6567	production
						6576-6587	
						6615 - notch	
						6620 "	
						6637 "	

MUDDING AND CEMENTING RECORD

SIZE OF HOLE	SIZE OF CASING	WHERE SET	NO. SACKS OF CEMENT	METHOD USED	MUD GRAVITY	AMOUNT OF MUD USED
13-3/4	9-5/8	206	170	pump and plug		
8-5/8	5-1/2	6718	190 thru shoe, 184 thru stage collar at 4606			

RECORD OF PRODUCTION AND STIMULATION

(Record the Process used, No. of Qts. or Gals. used, interval treated or shot.)

Sand water frac in two stages with total of 500 gal acid, 70,600 gal water and 60,500# sand

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OCT 31 1962
OIL CON. COM.
DIST. 3

Result of Production Stimulation 3 hr Initial Potential Test.

Flowed 2295 MCF/D, CAOF 2551 MCF/D

Depth Cleaned Out 6674

Form 9-330

Budget Bureau No. 42-R355.4.
Approval expires 12-31-60.

U. S. LAND OFFICE Santa Fe
SERIAL NUMBER
LEASE OR PERMIT TO PROSPECT

RECEIVED
SEP 19 1962
U.S. GEOLOGICAL SURVEY

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

RECEIVED
SEP 19 1962
U.S. GEOLOGICAL SURVEY

LOCATE WELL CORRECTLY

LOG OF OIL OR GAS WELL

Company Century Exploration Co. Address B 168 Farmington N.M.
Lessor or Tract Allen Field Basin Dokato State New Mexico
Well No. 1 Sec. 18 T. 31N R. 13W Meridian NMPM County San Juan
Location 980 ft. [S.] of N Line and 799 ft. [E.] of W Line of ... Elevation 5722
(Derrick floor relative to sea level)

The information given herewith is a complete and correct record of the well and all work done thereon so far as can be determined from all available records.

Signed W. H. Hassaur
Date 9-18-62 Title Drlg. Supt.

The summary on this page is for the condition of the well at above date.

Commenced drilling 5-14, 1961 Finished drilling 6-17, 1961

OIL OR GAS SANDS OR ZONES

(Denote gas by G)

No. 1, from 6388 to 6407 G No. 4, from ... to ...
No. 2, from 6464 to 6488 G No. 5, from ... to ...
No. 3, from ... to ... No. 6, from ... to ...

IMPORTANT WATER SANDS

No. 1, from ... to ... No. 3, from ... to ...
No. 2, from ... to ... No. 4, from ... to ...

CASING RECORD

Size casing	Weight per foot	Threads per inch	Make	Amount	Kind of shoe	Cut and pulled from	Perforated From—	Perforated To—	Purpose
9-5/8	36	8	CF&I	200'	T. P.	none	none		surface
7"	20	10	CF&I	4400'	T. P.	none	none		protect water sands
4½	11.60	8	CF&I	6503'	Comm.	4050' Pc.	6388	6407	test
							6464	6484	test

RECORD OF OIL OR GAS SANDS

MUDDING AND CEMENTING RECORD

Size casing	Where set	Number sacks of cement	Method used	Mud gravity	Amount of mud used
9-5/8	200'	150	Halliburton	--	--
7"	4400'	150	" "	9.0	--
4½	6503'	150	" "	--	--

PLUGS AND ADAPTERS

Heaving plug—Material ... Length ... Depth set ...
Adapters—Material ... Size ...

SHOOTING RECORD

Size	Shell used	Explosive used	Quantity	Date	Depth shot	Depth cleaned out

TOOLS USED

Rotary tools were used from 0 feet to 6504 feet, and from ... feet to ... feet
Cable tools were used from ... feet to ... feet, and from ... feet to ... feet

DATES

9-18-62, 19... Put to producing 7-0, 1961
The production for the first 24 hours was 0 barrels of fluid of which ...% was oil; ...% emulsion; ...% water; and ...% sediment. Gravity, °Bé. ...
If gas well, cu. ft. per 24 hours ... Gallons gasoline per 1,000 cu. ft. of gas ...
Rock pressure, lbs. per sq. in. ...

EMPLOYEES

..., Driller R.E. Davis ..., Driller
T.A. McClain ..., Driller
E.T. Henderson ..., Driller

FORMATION RECORD

FOLD MARK

NEW MEXICO OIL CONSERVATION COMMISSION

Santa Fe, New Mexico

WELL RECORD

Mail to District Office, Oil Conservation Commission, to which Form C-101 was sent not later than twenty days after completion of well. Follow instructions in Rules and Regulations of the Commission. Submit in QUINTUPLICATE. If State Land submit 6 Copies

AREA 640 ACRES
LOCATE WELL CORRECTLY

Consolidated Oil & Gas, Inc. (Company or Operator) Nielsen (Lease)

Well No. 1-17, in NE ¼ of SE ¼, of Sec. 17, T. 31N, R. 13W, NMPM.

Basin Dakota Pool, San Juan County.

Well is 1850 feet from South line and 790 feet from East line of Section 17. If State Land the Oil and Gas Lease No. is

Drilling Commenced April 20, 1962. Drilling was Completed April 29, 1962

Name of Drilling Contractor Huron Drilling Co.

Address 2415 Mercantile Bank Building, Dallas, Texas

Elevation above sea level at Top of Tubing Head 5825' GL, 5837' KB. The information given is to be kept confidential until , 19

OIL SANDS OR ZONES

G No. 1, from 4348' to 4660' No. 4, from to

G No. 2, from 6563' to 6696' No. 5, from to

No. 3, from to No. 6, from to

IMPORTANT WATER SANDS

Include data on rate of water inflow and elevation to which water rose in hole.

No. 1, from to feet.

No. 2, from to feet.

No. 3, from to feet.

No. 4, from to feet.

RECEIVED
MAY 25 1962
OIL CON. COM.
DIST. 3

CASING RECORD

SIZE	WEIGHT PER FOOT	NEW OR USED	AMOUNT	KIND OF SHOE	CUT AND PULLED FROM	PERFORATIONS	PURPOSE
9 5/8"	32.75	H-40	196	Guide			Surface
5 1/2"	15.5	J-55	6731	Float			Production

MUDDING AND CEMENTING RECORD

SIZE OF HOLE	SIZE OF CASING	WHERE SET	NO. SACKS OF CEMENT	METHOD USED	MUD GRAVITY	AMOUNT OF MUD USED
13 3/4	9 5/8	196	175	Pump & plug		
7 7/8	5 1/2	6731	189 thru shoe			
			100 thru stage collar at 4671'			

RECORD OF PRODUCTION AND STIMULATION

(Record the Process used, No. of Qts. or Gals. used, interval treated or shot.)

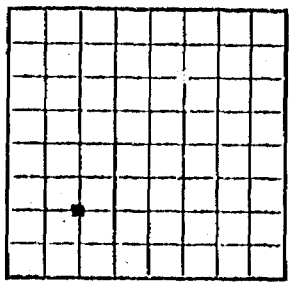
Sand water frac with 150,000# 20-40 and 40-60 mesh sand, 186,600 gal. of water. Broke down with 1000 gal. of acid.

Result of Production Stimulation Flow volume thru 3/4" choke: 2680 MCFD. Calculated absolute open flow potential: 3355 MCFD

Depth Cleaned Out 6710'

Returned for Logs

Form 9-330



LOCATE WELL CORRECTLY

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FEB 19 1962
OIL CON. COM.
DIST. 3

Form approved.
Budget Bureau No. 42-R355.4

U. S. LAND OFFICE Santa Fe
SERIAL NUMBER NM 0271
LEASE OR PERMIT TO PROSPECT

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

RECEIVED
Feb 19 1962
U. S. GEOLOGICAL SURVEY
FARMINGTON, NEW MEXICO

LOG OF OIL OR GAS WELL

Company Adobe Oil Company Address 1223 Petr. Life Bldg -Midland, Texas

Lessor or Tract Gallegos Field Basin Dakota State New Mexico

Well No. 1 Sec. 20 T. 31N R. 13W Meridian County San Juan

Location 1190 ft. [N.] of S Line and 1500 ft. [E.] of W Line of Sec. 20 Elevation 5662
(Derrick floor relative to sea level)

The information given herewith is a complete and correct record of the well and all work done thereon so far as can be determined from all available records.

Signed

Date February 14, 1962 Title A. T. Sindel Vice President

— The summary on this page is for the condition of the well at above date.

Commenced drilling 12-17-61, 19.... Finished drilling 1-6-62, 19....

OIL OR GAS SANDS OR ZONES

(Denote gas by G)

No. 1, from 6295 to 6500 G No. 4, from ..... to .....

No. 2, from ..... to ..... No. 5, from ..... to .....

No. 3, from ..... to ..... No. 6, from ..... to .....

IMPORTANT WATER SANDS

No. 1, from None to ..... No. 3, from ..... to .....

No. 2, from ..... to ..... No. 4, from ..... to .....

CASING RECORD

Size casing	Weight per foot	Threads per inch	Make	Amount	Kind of shoe	Cut and pulled from	Perforated From—	Perforated To—	Purpose
8-5/8"	24#	8rd		15 joints	289	TP			Surface
4-1/2"	10.5#	8rd		201 joints	6513	Baker	6306	6330	Prod. String
							6342	6352	
							6370	6390	
							6392	6410	

MUDDING AND CEMENTING RECORD

Size casing	Where set	Number sacks of cement	Method used	Mud gravity	Amount of mud used
8-5/8	289	200	Pump & Plug	Water	
4-1/2	6513	300cu ft	Pump & Plug	9.4#/gal	
		200 thru DV tool at 4457			

PLUGS AND ADAPTERS

Heaving plug—Material ..... Length ..... Depth set .....

Adapters—Material ..... Size .....

SHOOTING RECORD

Size	Shell used	Explosive used	Quantity	Date	Depth shot	Depth cleaned out

TOOLS USED

Rotary tools were used from ..... feet to 6520 feet, and from ..... feet to ..... feet

Cable tools were used from ..... feet to ..... feet, and from ..... feet to ..... feet

DATES

....., 19..... Put to producing: ....., 19.....

The production for the first 24 hours was ~~[illegible]~~ barrels of fluid of which .....% was oil; .....% emulsion; .....% water; and .....% sediment.

Gravity, °Bé. .....

If gas well, cu. ft. per 24 hours 2040 MCF Gallons gasoline per 1,000 cu. ft. of gas .....

Rock pressure, lbs. per sq. in. 1930

EMPLOYEES

Contract, Driller ....., Driller

....., Driller

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

LOG OF OIL OR GAS WELL

LOCATE WELL CORRECTLY

Company Tidal Oil Company Address [illegible]

Lessor or Tract [illegible] Field Basin-Dome State [illegible]

Well No. 2 Sec. 20 T. 31N R. 6W Meridian [illegible] County Park

Location 2430 ft. [illegible] of N Line and 1450 ft. [illegible] of W Line of Sec. 20 Elevation 7080

The information given herewith is a complete and correct record of the well and all work done thereon so far as can be determined from all available records.

Date [illegible] Signed [illegible] Title [illegible]

The summary on this page is for the condition of the well at above date.

Commenced drilling 12-10-59 Completed drilling 1-9-60 Initial production [illegible]

OIL OR GAS SANDS OR ZONES

No 1, from 6518 to 6534 No 4, from 6610 to 6640

No 2, from 6570 to 6580 No 5, from [illegible] to [illegible]

No 3, from 6596 to 6600 No 6, from [illegible] to [illegible]

IMPORTANT WATER SANDS

No 1, from None to [illegible] No 3, from [illegible] to [illegible]

No 2, from [illegible] to [illegible] No 4, from [illegible] to [illegible]

CASING RECORD

Size casing	Weight per foot	Threads per inch	Make	Amount	Kind of shoe	Cut and pulled from	Perforated		Purpose
							From	To	
8-5/8	28	8rd	T.S.	318	[illegible]	[illegible]	[illegible]	[illegible]	Surface
5-1/2	15.5	8rd	Lone Star	6754	Lovell	[illegible]	6518	6534	Production
							6570	6580	
							6596	6600	
							6610	6640	

MUDDING AND CEMENTING RECORD

Size casing	Where set	Number sacks of cement	Method used	Mud gravity	Amount of mud used
8-5/8	318	200 sx	Dump & plug	Water	None
5-1/2	6754	275 sx, pd thru btm	Dump & plug	9.1	[illegible]
		200 sx thru DV			
		1st @ 4663			

PLUGS AND ADAPTERS

Heaving plug—Material [illegible] Length [illegible] Depth [illegible]

Adapters—Material [illegible] Size [illegible]

SHOOTING RECORD

Size	Shell used	Explosive used	Quantity	Date	Depth shot	Depth cleaned out
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

TOOLS USED

Rotary tools were used from 0 ft. to 6754 ft., and from [illegible] ft. to [illegible] ft.

Cable tools were used from [illegible] ft. to [illegible] ft., and from [illegible] ft. to [illegible] ft.

DATES

Put to producing [illegible] 19[illegible]

The production for the first 24 hours was [illegible] barrels of fluid of which [illegible] % was oil; [illegible] % was emulsion; [illegible] % was water; and [illegible] % was sediment. A.P.I. Gravity [illegible]

If gas well, cu. ft. per 24 hours [illegible] Gallons gasoline per 1,000 cu. ft. of gas [illegible] Rock pressure, lbs. per sq. in. [illegible]

EMPLOYEES

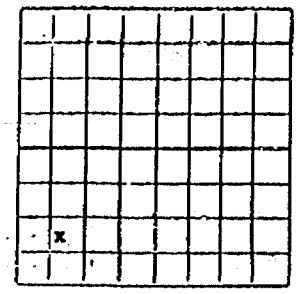
[illegible], Driller [illegible], Driller

[illegible], Driller [illegible], Driller

FORMATION RECORD

From	To	Total Thickness in Feet	Formation
[illegible]	[illegible]	[illegible]	[illegible]

Obsolete 1/1/60
(Form C-105)



AREA 640 ACRES
LOCATE WELL CORRECTLY

NEW MEXICO OIL CONSERVATION COMMISSION

Santa Fe, New Mexico

WELL RECORD

Mail to District Office, Oil Conservation Commission, to which Form C-101 was sent not later than twenty days after completion of well. Follow instructions in Rules and Regulations of the Commission. Submit in QUINTUPLICATE. If State Land submit 6 Copies

Adobe Oil Company (Company or Operator) Johnson (Lease)

Well No. 1, in SW ¼ of SW ¼, of Sec. 21, T. 31N, R. 13W, NMPM.

~~XXXXX~~ Basin-Dakota Pool, San Juan County.

Well is 885 feet from South line and 800 feet from West line of Section 21. If State Land the Oil and Gas Lease No. is .....

Drilling Commenced 12-30, 1960 Drilling was Completed 1-10, 1961.

Name of Drilling Contractor Great Western Drilling Company

Address Farmington, New Mexico

Elevation above sea level at Top of Tubing Head 5774 The information given is to be kept confidential until ....., 19.....

OIL SANDS OR ZONES

No. 1, from 6474 to 6486 No. 4, from 6605 to 6613

No. 2, from 6525 to 6530 No. 5, from ..... to .....

No. 3, from 6552 to 6558 No. 6, from ..... to .....

IMPORTANT WATER SANDS

Include data on rate of water inflow and elevation to which water rose in hole.

No. 1, from ..... to ..... feet. .....

No. 2, from ..... to ..... feet. .....

No. 3, from ..... to ..... feet. .....

No. 4, from ..... to ..... feet. .....

CASING RECORD

SIZE	WEIGHT PER FOOT	NEW OR USED	AMOUNT	KIND OF SHOE	CUT AND PULLED FROM	PERFORATIONS	PURPOSE
8-5/8	24	New	325	TD			Surface
5-1/2	15.5	New	6685	HOWCO		6474-86;	Oil String
						6525-30;	
						6552-58; & 6605-13	

MUDDING AND CEMENTING RECORD

SIZE OF HOLE	SIZE OF CASING	WHERE SET	NO. SACKS OF CEMENT	METHOD USED	MUD GRAVITY	AMOUNT OF MUD USED
11-1/4"	8-5/8	325	200	Pump & Plug		Cat. Circ.
7-7/8"	5-1/2	6685	300 sx btm.	Pump & Plug		
			200 sx D.V.	Tool		

RECORD OF PRODUCTION AND STIMULATION

(Record the Process used, No. of Qts. or Gals. used, interval treated or shot.)

Acidized with 2500 gallons MCA (6474'-6613')

Fraced with 100,000 gallons water and 95,000# sand (6474'-6613')

Acidized with 500 gallons mud acid (5816-31, 5840-46)

Squeezed with 148 sacks cement to 4000 psi (5816-31, 5840-46)

Result of Production Stimulation AOF 3347

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MAR 20 1961
OIL CONSERVATION COM.
DIST. 3

Depth Cleaned Out 6665'

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DISTRIBUTION		
STATE FE		
FILE		
U.S.G.S.		
LAND OFFICE		
TRANSPORTER	OIL	
	GAS	
PRORATION OFFICE		
OPERATOR		

Form C-105
Revised 7-1-58

NM

NEW MEXICO OIL CONSERVATION COMMISSION

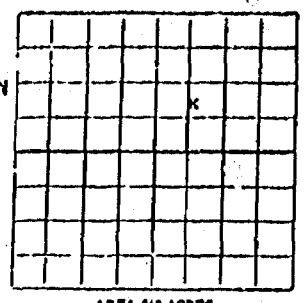
Santa Fe, New Mexico

FARM OFFICE OCC

WELL RECORD

1962 JAN 12 PM 1 59

Mail to District Office, Oil Conservation Commission, to which Form C-101 was sent not later than twenty days after completion of well. Follow instructions in Rules and Regulations of the Commission. Submit in QUINTUPLICATE. If State Land submit 6 Copies



AREA 640 ACRES
LOCATE WELL CORRECTLY

Adobe Oil Company (Company or Operator) Standard Nickles (Lease)

Well No. 1, in SW ¼ of NE ¼, of Sec. 21, T. 31N, R. 13W, NMPM.

Basin Dakota Pool, San Juan County.

Well is 1850 feet from North line and 1350 feet from East line of Section 21. If State Land the Oil and Gas Lease No. is

Drilling Commenced 11-29-61, 19.. Drilling was Completed 12-17-61, 19..

Name of Drilling Contractor Pico Drilling Company

Address Burch Hotel Bldg, Breckenridge, Texas

Elevation above sea level at Top of Tubing Head 5732 The information given is to be kept confidential until ....., 19..

OIL SANDS OR ZONES

No. 1, from 6448 to 6600 No. 4, from ..... to .....

No. 2, from ..... to ..... No. 5, from ..... to .....

No. 3, from ..... to ..... No. 6, from ..... to .....

IMPORTANT WATER SANDS

Include data on rate of water inflow and elevation to which water rose in hole.

No. 1, from ..... to ..... feet. .....

No. 2, from ..... to ..... feet. .....

No. 3, from ..... to ..... feet. .....

No. 4, from ..... to ..... feet. .....

CASING RECORD

SIZE	WEIGHT PER FOOT	NEW OR USED	AMOUNT	KIND OF SHOE	CUT AND PULLED FROM	PERFORATIONS	PURPOSE
8-5/8	21#	New	280	Texas Pattern	-		Surface
4-1/2	10.5#	New	6725	HOWCO	-	6462-80	oil string
						6515-25	
						6574-6600	

MUDDING AND CEMENTING RECORD

SIZE OF HOLE	SIZE OF CASING	WHERE SET	NO. SACKS OF CEMENT	METHOD USED	MUD GRAVITY	AMOUNT OF MUD USED
11-1/4	8-5/8	280	150	Pump & Plug		Cmt. circulated
7-7/8	4-1/2	6725	300 on btm	Pump & Plug		
			200 thru DV			

RECORD OF PRODUCTION AND STIMULATION

(Record the Process used, No. of Qts. or Gals. used, interval treated or shot.)

Acidized with 400 gallons HCA. Fraced with 114,000 gallons water and 60,500# sand.

Result of Production Stimulation Absolute open flow 4502 MCF/day

Depth Cleaned Out 6695

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FEB 16 1962
OIL CON. COM.
DIST. 3

STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION DIVISION

BRUCE KING
GOVERNOR

LARRY KEHOE
SECRETARY

POST OFFICE BOX 2088
STATE LAND OFFICE BUILDING
SANTA FE, NEW MEXICO 87501
(505) 827-2434

March 12, 1982

Mr. William F. Carr
Campbell, Byrd & Black
Attorneys at Law
Post Office Box 2208
Santa Fe, New Mexico

Re: CASE NO. 7116
ORDER NO. R-6747-A

Applicant:

Southland Royalty Company

Dear Sir:

Enclosed herewith are two copies of the above-referenced Commission order recently entered in the subject case.

Yours very truly,

JOE D. RAMEY
Director

JDR/fd

Copy of order also sent to:

Hobbs OCC x
Artesia OCC x
Aztec OCC x

Other Consolidated Oil & Gas, Inc.

Consolidated Oil & Gas, Inc.

LINCOLN TOWER BUILDING
1860 LINCOLN STREET
DENVER, COLORADO 80295
(303) 861-5252

RECEIVED
AUG 24 1981
OIL CONSERVATION DIVISION
SANTA FE

August 21, 1981

New Mexico Oil Conservation Division
P. O. Box 2088
Santa Fe, NM 87501

Gentlemen:

RE: Case No. 7116

Enclosed for filing please find application for de novo hearing in case No. 7116.

Very truly yours,

CONSOLIDATED OIL & GAS, INC.

Lynn Teschendorf
Attorney

LHT:drl

Enclosure

xc: William F. Carr

BEFORE THE
OIL CONSERVATION COMMISSION
STATE OF NEW MEXICO

In the matter of the application of Southland Royalty Company for designation of a tight formation, San Juan County, New Mexico

Case No. 7116
DE NOVO

Application

Comes now Consolidated Oil & Gas, Inc., by and through its undersigned attorney, being a party adversely affected by the decision herein, and hereby requests that this matter be heard de novo before the Commission, and as grounds therefor states:

1. The area described below was erroneously excluded from the provisions of Order No. R-6747:

Township 31 North, Range 12 West, NMPM
Sections 5 through 8: All
Sections 17 through 20: All
Section 30: All

Township 31 North, Range 13 West, NMPM
Sections 12 through 14: All
Sections 22 through 28: All
Sections 33 through 36: All

2. The findings are not supported by substantial evidence.

3. The order is discriminatory, arbitrary, capricious and unreasonable.

4. The order constitutes a violation of the Commission's statutory mandate of conservation and prevention of waste.

WHEREFORE, applicant requests that this matter be set for hearing before the Commission, and that the Commission enter its order granting the relief sought herein.

Respectfully submitted,

CONSOLIDATED OIL & GAS, INC.

By _____

Lynn Teschendorf, Attorney
1860 Lincoln Street, Suite 1300
Denver, CO 80295

RECEIVED
AUG 24 1981
OIL CONSERVATION DIVISION
SANTA FE

BEFORE THE
OIL CONSERVATION COMMISSION
STATE OF NEW MEXICO

In the matter of the application
of Southland Royalty Company
for designation of a tight
formation, San Juan County,
New Mexico

Case No. 7116
DE NOVO

Application

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1. The area described below was erroneously excluded from the provisions of Order No. R-6747:

Township 31 North, Range 12 West, NMPM
Sections 5 through 8: All
Sections 17 through 20: All
Section 30: All

Township 31 North, Range 13 West, NMPM
Sections 12 through 14: All
Sections 22 through 28: All
Sections 33 through 36: All

2. The findings are not supported by substantial evidence.

3. The order is discriminatory, arbitrary, capricious and unreasonable.

4. The order constitutes a violation of the Commission's statutory mandate of conservation and prevention of waste.

WHEREFORE, applicant requests that this matter be set for hearing before the Commission, and that the Commission enter its order granting the relief sought herein.

Respectfully submitted,

CONSOLIDATED OIL & GAS, INC.

By Lynn Teschendorf

Lynn Teschendorf, Attorney
1860 Lincoln Street, Suite 1300
Denver, CO 80295

Dockets Nos. 31-81 and 32-81 are tentatively set for October 7, and October 21, 1981. Applications for hearing must be filed at least 22 days in advance of hearing date.

DOCKET: EXAMINER HEARING - WEDNESDAY -SEPTEMBER 23, 1981

9 A.M. - OIL CONSERVATION DIVISION CONFERENCE ROOM
STATE LAND OFFICE BUILDING, SANTA FE, NEW MEXICO

The following cases will be heard before Richard L. Stamets, Examiner or Daniel S. Nutter, Alternate Examiner:

CASE 7353: Application of Texaco, Inc., for the amendment of Division Order No. R-5530, Lea County, New Mexico. Applicant, in the above-styled cause, seeks the amendment of Order No. R-5530, which authorized its Central Vacuum Unit Area Pressure Maintenace Project, to increase the total project area allowable, or as an alternative, to reclassify the project as a waterflood project.

CASE 7354: Application of Corona Oil Company, for a pilot steam-enhanced oil recovery project, Guadalupe County, New Mexico.
Applicant, in the above-styled cause, seeks authority to institute a pilot steam-enhanced oil recovery project in the Santa Rosa formation by using two existing wells and three additional wells to be drilled to complete a five spot pattern located in the NE/4 NW/4 of Section 17, Township 11 North, Range 26 East.

CASE 7355: Application of Doyle Hartman for directional drilling and an unorthodox location, Lea County, New Mexico. Applicant, in the above-styled cause, seeks authority to drill his Bates Well No. 3, the surface location of which is 1635 feet from the South line and 1210 feet from the West line of Section 20, Township 25 South, Range 37 East, in such a manner as to bottom it at a depth of 3500 feet in the Jalmat Gas Pool at an unorthodox location 2310 feet from the South line and 1650 feet from the West line of Section 20. The SW/4 of said Section 20 would be dedicated to the well.

CASE 7356: Application of S & I Oil Company for compulsory pooling, San Juan County, New Mexico. Applicant, in the above-styled cause, seeks an order pooling all mineral interests in the W/2 SW/4 of Section 12, Township 29 North, Range 15 West, Cha Cha-Gallup Oil Pool, to be dedicated to a well to be drilled at a standard location thereon. Also to be considered will be the cost of drilling and completing said well and the allocation of the cost thereof as well as actual operating costs and charges for supervision, designation of applicant as operator of the well, and a charge for risk involved in drilling said well.

CASE 7357: Application of Union Oil Company of California for compulsory pooling, Lea County, New Mexico. Applicant, in the above-styled cause, seeks an order pooling all mineral interests in the Atoka and Morrow formations underlying the W/2 of Section 16, Township 22 South, Range 33 East, to be dedicated to a well to be drilled at a standard location thereon. Also to be considered will be the cost of drilling and completing said well and the allocation of the cost thereof as well as actual operating costs and charges for supervision, designation of applicant as operator of the well, and a charge for risk involved in drilling said well.

CASE 7343: (Continued from September 9, 1981, Examiner Hearing)

Application of Caribou Four Corners, Inc. for compulsory pooling, San Juan County, New Mexico. Applicant, in the above-styled cause, seeks an order pooling all mineral interests in the Cha Cha Gallup Oil Pool underlying the E/2 NW/4 of Section 18, Township 29 North, Range 14 West, to be dedicated to a well to be drilled at a standard location thereon. Also to be considered will be the cost of drilling and completing said well and the allocation of the cost thereof as well as operating costs and charges for supervision, designation of applicant as operator of the well, and a charge for risk involved in drilling said well.

CASE 7358: Application of John Yuronka for compulsory pooling, Lea County, New Mexico.
Applicant, in the above-styled cause, seeks an order pooling all mineral interests in the Langley Mattix Pool underlying the SW/4 of Section 6, Township 23 South, Range 37 East, to form four 40-acre tracts, each to be dedicated to a well to be drilled at a standard location thereon. Also to be considered will be the cost of drilling and completing said wells and the allocation of the cost thereof as well as actual operating costs and charges for supervision, designation of applicant as operator of the wells, and a charge for risk involved in drilling said wells.

CASE 7359: Application of Energy Reserves Group for creation of a new gas pool and an unorthodox location, Roosevelt County, New Mexico.

Applicant, in the above-styled cause, seeks creation of a new Cisco gas pool for its Miller Com Well No. 1, located in Unit M of Section 12, Township 6 South, Range 33 East.

Applicant further seeks approval of an unorthodox location for its Miller "A" Well No. 1-Y, to be drilled 1800 feet from the South line and 1700 feet from the East line of Section 11 of the same township. The S/2 of said Section 11 to be dedicated to the well.

CASE 7345: (Continued from September 9, 1981, Examiner Hearing)

Application of Bass Enterprises Production Company for compulsory pooling, Lea County, New Mexico. Applicant, in the above-styled cause, seeks an order pooling all mineral interests in the Lovington Penn Pool underlying the N/2 NE/4 of Section 13, Township 16 South, Range 36 East, to be dedicated to a well to be drilled at a standard location thereon. Also to be considered will be the cost of drilling and completing said well and the allocation of the cost thereof as well as actual operating costs and charges for supervision, designation of applicant as operator of the well, and a charge for risk involved in drilling said well.

CASE 7360: Application of L. J. Buck for salt water disposal, Lea County, New Mexico.
Applicant, in the above-styled cause seeks authority to dispose of produced salt water into the Seven Rivers formation in the interval from 3221 feet to 3250 feet in his Monco Well No. 2 in Unit M of Section 25, Township 25 South, Range 36 East.

CASE 7352: (Continued from September 9, 1981 Examiner Hearing)

Application of Yates Petroleum Corporation for designation of a tight formation, Eddy County, New Mexico. Applicant, in the above-styled cause, pursuant to Section 107 of the Natural Gas Policy Act 18-CFR Section 271.701-705, seeks the designation as a tight formation of the Permo-Penn and formation underlying all of the following townships:

Township 17 South, Ranges 24 thru 26 East;

18 South, 24 and 25 East;

19 South, 23 thru 25 East;

20 South, 21 thru 24 East;

20½ South, 21 and 22 East;

21 South, 21 and 22 East;

Also Sections 1 thru 12 in 22 South, 21 and 22 East,

All of the above containing a total of 315,000 acres more or less.

CASE 7329: (Readvertised)

Application of Loco Hills Water Disposal Company for an exception to Order No. R-3221, Eddy County, New Mexico

Applicant, in the above-styled cause, seeks an exception to Order No. R-3221 to permit the commercial disposal of produced brine into several unlined surface pits located in the N/2 SW/4 SW/4 of Section 16, Township 17 South, Range 30 East.

Dockets Nos. 31-81 and 32-81 are tentatively set for October 7, and October 21, 1981. Applications for hearing must be filed at least 22 days in advance of hearing date.

DOCKET: COMMISSION HEARING - TUESDAY - SEPTEMBER 29, 1981

9 A.M. - OIL CONSERVATION DIVISION - MORGAN HALL
STATE LAND OFFICE BUILDING, SANTA FE, NEW MEXICO

CASE 7116: (DE NOVO)

Application of Southland Royalty Company for designation of a tight formation, San Juan County, New Mexico. Applicant, in the above-styled cause, seeks the designation of the Dakota formation underlying portions of Township 31 and 32 North, Ranges 10, 11, 12, and 13 west, containing 93,860 acres, more or less, as a tight formation pursuant to Section 107 of the Natural Gas Policy Act and 18 CFR Section 271.701-705.

Upon application of Consolidated Oil & Gas, Inc., this case will be heard De Novo pursuant to the provisions of Rule 1220.

CASE 7361: Application of Southland Royalty Company for designation of a tight formation, San Juan County, New Mexico. Applicant, in the above-styled cause, seeks the designation of the Dakota formation underlying all or portions of Township 31 North, Ranges 10 and 11 West, and Township 32 North, Ranges 10, 11, 12, and 13 West, containing 92,871 acres more or less, as a tight formation pursuant to Section 107 of the Natural Gas Policy Act and 18 CFR Section 271. 701-705.

CASE 7362: Application of R. A. Mendenhall Associates, Ltd., for compulsory pooling, Eddy County, New Mexico. Applicant, in the above-styled cause, seeks an order pooling all mineral interests in the Delaware Mountain Group formation underlying the NW/4 SE/4 of Section 10, Township 22 South, Range 27 East, to be dedicated to a well to be drilled at a standard location thereon. Also to be considered will be the cost of drilling and completing said well and the allocation of the cost thereof as well as actual operating costs and charges for supervision, designation of applicant as operator of the well, and a charge for risk involved in drilling said well.

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DAN

STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION COMMISSION

IN THE MATTER OF THE HEARING
CALLED BY THE OIL CONSERVATION
DIVISION OF NEW MEXICO FOR
THE PURPOSE OF CONSIDERING:

CASE NO. 7116 DE NOVO
Order No. R-6747-A

APPLICATION OF SOUTHLAND ROYALTY
COMPANY FOR DESIGNATION OF A
TIGHT FORMATION, SAN JUAN COUNTY,
NEW MEXICO.

ORDER OF THE COMMISSION

BY THE COMMISSION:

This cause came on for hearing de novo at 9:00 a.m. on September 29, 1981, at Santa Fe, New Mexico, before the Oil Conservation Commission of New Mexico, hereinafter referred to as the "Commission."

NOW, on this _____ day of March, 1982, the Commission, a quorum being present, having considered the testimony presented and the exhibits received at said hearing, and being fully advised in the premises,

FINDS:

(1) That due public notice having been given as required by law, the Commission has jurisdiction of this cause and the subject matter thereof.

(2) That this case originally came on for hearing on December 30, 1980, before Division Examiner Daniel S. Nutter.

(3) That at the original hearing of this case, Consolidated Oil & Gas, Inc., hereinafter referred to as Consolidated, asked for and was granted permission to intervene in the case, and the area considered for designation as a tight formation was broadened beyond the original lands applied for by Southland Royalty Company, hereinafter referred to as Southland, to include additional lands requested for designation as a tight formation by Consolidated.

(4) That Order No. R-6747 was entered in Case No. 7116 on August 7, 1981, and said order recommended for designation as a tight formation, pursuant to Section 107 of the Natural Gas Policy Act of 1978 and 18 C.F.R. Section 271.703, certain of the lands requested by Southland and certain of the lands requested by Consolidated, and made no recommendation for designation of the remaining lands requested by Southland and Consolidated.

(5) That on August 24, 1981, Consolidated, pursuant to Section 70-2-13, NMSA 1978 Comp., filed timely application for hearing de novo of Case No. 7116, and the case came on for hearing as noted above, on September 29, 1981.

(6) That Southland, having filed a new and separate application for designation of its area as a tight formation, withdrew from Case No. 7116 at the hearing de novo and asked that the original Southland lands be deleted from the hearing de novo and that that portion of the case relating to such lands be dismissed.

(7) That in accordance with the above, all of those lands covered by the Southland application in the original hearing of this case should be deleted and dismissed from further consideration.

(8) That henceforth in this case, this order shall be concerned with the application of Consolidated Oil & Gas, Inc., for designation of the Dakota formation as a tight formation, underlying the following described lands in San Juan County, New Mexico:

TOWNSHIP 31 SOUTH, RANGE 12 WEST, NMPM

Sections 5 through 8: All

Sections 17 through 20: All

Sections 29 through 32: All

TOWNSHIP 31 NORTH, RANGE 13 WEST, NMPM

Sections 1 through 36: All

containing 29,645 acres, more or less.

(9) That while the application was for designation of the Dakota formation as a tight formation, the Dakota formation constitutes but a portion of the "Dakota Producing Interval,"

which, as defined by the Division, comprises the vertical limits of the Basin-Dakota Gas Pool, being from the base of the Greenhorn Limestone to a point 400 feet below the base of said formation and consisting of the Graneros formation, the Dakota formation, and the productive upper portion of the Morrison formation.

(10) That inasmuch as practically all so-called "Dakota" wells drilled in the subject area are, or potentially are, tested in and/or completed in the entire Dakota Producing Interval, and the well data presented at the hearing of this case involves the entire Dakota Producing Interval, the application should be broadened to cover all of said producing interval throughout the area.

(11) That the Dakota Producing Interval, hereinafter referred to as the "Dakota," is comprised of sediments formed during late Cretaceous time. These sediments contain light to dark mottled gray fine to very fine-grained quartz sands in a silt and clay-sized matrix material of very low permeability.

(12) That from the logs available at the hearing, the top of the Dakota in the area ranges from a depth of 6103 feet to 6820 feet and averages some 6544 feet beneath the surface.

(13) That the only test data for calculated stabilized flow rates prior to stimulation for wells within the area indicates that in Township 31 North, Range 13 West, the Consolidated Wilmerding Well No. 1 in the NE/4 NW/4 of Section 10 had a flow rate "too small to measure," the Consolidated Kline Well No. 1 in the NE/4 SE/4 of Section 10 had a flow rate of 12.5 MCF of

gas per day, and the Consolidated Senter Well No. 1 in the NE/4 SE/4 of Section 24 had a combined flow rate from two zones of 55 MCF of gas per day. Further, that two Southland wells in the immediate area to the east but just outside the area under consideration, being in Sections 14 and 2, Township 31 North, Range 12 West, had flow rates of 22 and 224 MCF of gas per day, respectively.

(14) That none of the stabilized production rates cited above exceeds the maximum stabilized production rate set forth in 18 C.F.R. Section 271.703(c)(2)(i)(B) of 251 MCF per day for wells at the average depth to the top of the formation for this area (6544 feet), and it is not expected that the average well in the area will exceed such rate.

(15) That the calculated in situ permeability of the Dakota formation in the five wells cited in Finding No. (13) above is as follows: Wilmerding No. 1, less than 0.1 md; Kline No. 1, 0.0049 md; Senter No. 1, 0.0146 md in the Upper Dakota and 0.00068 md in the Lower Dakota; and the two Southland wells in the immediate area to the east, 0.0011 md and 0.0877 md, respectively.

(16) That the average in situ permeability for all wells in the area is not expected to exceed 0.1 md, the limit set forth in 18 C.F.R. Section 271.703(c)(2)(i)(A).

(17) That prior to stimulation, the average well in the area is expected to produce far less than the maximum five barrels of crude oil per day as set forth in 18 C.F.R. Section 271.703(c)(2)(i)(C).

(18) That 18 C.F.R. Section 271.703(c)(2)(i)(D) provides that "if the formation or any portion thereof was authorized to be developed by infill drilling prior to the date of recommendation and the jurisdictional agency has information which in its judgment indicates that such formation or portion subject to infill drilling can be developed absent the incentive price established in paragraph (a) of this section then the jurisdictional agency shall not include such formation or portion thereof in its recommendation."

(19) That the Division, by its Order No. R-1670-V, dated May 22, 1979, and effective July 1, 1979, approved infill drilling for the Basin-Dakota Gas Pool in San Juan and Rio Arriba Counties, New Mexico, and said pool includes the Dakota Producing Interval in the area under consideration here.

(20) That the Division, in approving infill drilling for the Basin-Dakota Gas Pool, based its approval on the premise that the reservoir was of low permeability and that 320-acre wells were not draining more than the 160-acre tract upon which they were located.

(21) That the remaining reserves under the 160-acre tract upon which the unit well is not located should be similar to, if not equal to, the original reserves under the 160-acre tract upon which the unit well is located.

(22) That according to Consolidated's Exhibit No. 8A, the average cost of a Dakota well completed in the area under consideration, hereinafter referred to as the area," is $475,400, and according to its Exhibit No. 12, operating costs

may be expected to total some $61,740 during the first 20 years of a well's life and approximately $3600 per year thereafter.

(23) That according to Consolidated's Exhibit No. 12, under Section 103 prices, a Dakota gas well in the area, with reserves recoverable over a 20-year period as indicated in Column 1 below, may be expected to yield a net income above well costs and operating costs, but before federal income taxes, as shown in Column 2 below and yield a rate of return on investment as shown in Column 3.

COLUMN 1	COLUMN 2	COLUMN 3
Reserves, MMCF	Net Income	Rates of Return
180	$ 120,297	3.18%
270	$ 479,860	9.54%
350	$ 837,754	15.78%
435	$1,200,854	22.12%
555	$1,778,604	30.32%

(24) That according to Consolidated's Exhibit No. 12, under Section 107 incentive prices, a Dakota gas well in the area, with 20-year reserves as indicated in Column 1 below may be expected to yield a net income above well costs and operating costs, but before federal income taxes, as shown in Column 2 below and yield a rate of return on investment as shown in Column 3.

COLUMN 1	COLUMN 2	COLUMN 3
Reserves, MMCF	Net Income	Rates of Return
180	$ 550,345	14.47%
270	$1,107,833	27.29%

350	$1,679,273	38.16%
435	$2,255,196	49.52%
555	$3,110,619	65.71%

(25) That according to Consolidated's Exhibit No. 13, under Section 103 prices, a Dakota gas well in the area with 20-year reserves as indicated in Column 1 below may be expected to yield a rate of return on investment plus operating expenses and after taxes as shown in Column 2 and obtain a payout as shown in Column 3.

COLUMN 1	COLUMN 2	COLUMN 3
Reserves, MMCF	Rate of Return, %	Payout In Years
180	2.25	17.37
270	6.65	9.33
350	10.47	6.57
435	14.44	5.14
555	19.72	4.09

(26) That according to the aforementioned Exhibit No. 13, under Section 107 incentive prices, a Dakota gas well in the area with 20-year reserves as indicated in Column 1 below may be expected to yield a rate of return on investment plus operating expenses and after taxes as shown in Column 2 and obtain a payout as shown in Column 3.

COLUMN 1	COLUMN 2	COLUMN 3
Reserves, MMCF	Rate of Return, %	Payout In Years
180	9.27	6.69
270	17.41	4.37
350	24.39	3.47

435	31.80	2.89
555	42.13	2.42

(27) That from the data shown in Finding No. (23) above, 20-year recoverable reserves in the range of 435 million cubic feet will yield a rate of return before taxes of 22.12 percent under Section 103 gas prices.

(28) That from the data shown in Finding No. (25) above, 20-year recoverable reserves in the range of 435 million cubic feet may be expected to pay out all drilling and operating costs, after taxes, in approximately 5.14 years under Section 103 gas prices.

(29) That in the judgment of the Commission, lands indicating 435 or more million cubic feet of gas reserves recoverable over a 20-year period can be developed absent the incentive price of Section 107 of the Natural Gas Pricing Act of 1978.

(30) That in the judgment of the Commission, land indicating less than 435 million cubic feet of gas reserves recoverable over a 20-year period are less likely to be developed without the incentive price of Section 107 of the Natural Gas Pricing Act of 1978 and therefore should be recommended for designation as a tight formation elibible for the incentive price.

(31) That Consolidated's Exhibit 1 shows the location of Dakota wells in the area, their 1980 production, and their cumulative production since completion, and the cumulative

production (over a period of approximately 20 years or less) ranges from very low obviously non-commercial wells to almost three billion cubic feet of gas.

(32) That in accordance with the Commission's previous findings that the Dakota is of low permeability and the original wells on 320-acre tracts were not draining more than the 160-acre tract upon which they were located, and that the reserves under the 160-acre upon which the original unit well is not located should be similar to, if not equal to, the original reserves under the 160-acre tract upon which the unit well is located, it is reasonable to assume that the infill wells in the area should recover gas reserves similar to, if not equal to, the cumulative reserves indicated on Consolidated's Exhibit 1.

(33) That pursuant to previous Findings Nos. (20) and (21), and to Findings Nos. (31) and (32) ~~, and (33)~~ above, and to Consolidated's Exhibit 1, it is reasonable to assume that the average infill well drilled in the following described area will encounter recoverable reserves of 435 million or more cubic feet of gas:

TOWNSHIP 31 NORTH, RANGE 12 WEST, NMPM

Sections 5 through 8: All

Sections 17 through 20: All

Sections 29 through 32: All

TOWNSHIP 31 NORTH, RANGE 13 WEST, NMPM

Section 13: All

Sections 22 through 27: All

Sections 33 through 36: All

containing 14,482 acres, more or less.

(34) That it is the judgment of the Commission that the above-described lands can be developed absent the incentive price established in 18 C.F.R. Section 271.703(a) and should not be further considered for recommendation for designation as a tight formation.

(35) That there are fresh water aquifers underlying the lands being considered, and these aquifers extend to a depth of approximately 1000 feet.

(36) That there is a vertical distance of some 5500 feet between the base of the lowermost of said aquifers and the top of the Dakota, and this distance, combined with the required casing and cementing program for wells in the area, will assure that development of the Dakota will not adversely affect the fresh water aquifers (during both hydraulic fracturing and waste disposal operations) that are or are expected to be used as a domestic or agricultural water supply.

(37) That the Dakota Producing Interval underlying the following lands meets all of the guidelines set forth in 18 C.F.R. Section 271.703(c)(2)(i), subsections (A), (B), (C), and (D), and should be recommended for designation as a tight formation:

TOWNSHIP 31 NORTH, RANGE 13 WEST, NMPM

Sections 1 through 12: All

Sections 14 through 21: All

Sections 28 through 32: All

containing some 15,163 acres, more or less, all in San Juan County, New Mexico.

IT IS THEREFORE ORDERED:

(1) That it be and hereby is recommended to the Federal Energy Regulatory Commission pursuant to Section 107 of the Natural Gas Policy Act of 1978, and 18 C.F.R. Section 271.703, that the Dakota Producing Interval, being from the base of the Greenhorn Limestone to a point 400 feet below the base of said formation and consisting of the Graneros formation, the Dakota formation and the productive upper portion of the Morrison formation, underlying the following described lands in San Juan County, New Mexico, be designated as a tight formation:

TOWNSHIP 31 NORTH, RANGE 13 WEST, NMPM

Sections 1 through 12: All

Sections 14 through 21: All

Sections 28 through 32: All

containing approximately 15,163 acres, more or less.

(2) That no recommendation is made as to those lands described in Finding No. (8) of this order which are not included in Order No. (1) above.

(3) That jurisdiction of this cause is retained for the entry of such further orders as the Division may deem necessary.

DONE at Santa Fe, New Mexico, on the day and year hereinabove designated.

HERBIE
DAN

STATE OF NEW MEXICO

ENERGY AND MINERALS DEPARTMENT

OIL CONSERVATION COMMISSION

IN THE MATTER OF THE HEARING
CALLED BY THE OIL CONSERVATION
DIVISION OF NEW MEXICO FOR
THE PURPOSE OF CONSIDERING:

CASE NO. 7116
Order No. R-6747-A

APPLICATION OF SOUTHLAND ROYALTY
COMPANY FOR DESIGNATION OF A
TIGHT FORMATION, SAN JUAN COUNTY,
NEW MEXICO.

ORDER OF THE COMMISSION

BY THE COMMISSION:

This cause came on for hearing de novo at 9:00 a.m. on September 29, 1981, at Santa Fe, New Mexico, before the Oil Conservation Commission of New Mexico, hereinafter referred to as the "Commission."

NOW, on this_____day of February, 1982, the Commission, a quorum being present, having considered the testimony presented and the exhibits received at said hearing, and being fully advised in the premises,

FINDS:

(1) That due public notice having been given as required by law, the Commission has jurisdiction of this cause and the subject matter thereof.

(2) That this case originally came on for hearing on December 30, 1980, before Division Examiner Daniel S. Nutter.

(3) That at the original hearing of this case, Consolidated Oil & Gas, Inc., hereinafter referred to as Consolidated, asked for and was granted permission to intervene in the case, and the area considered for designation as a tight formation was broadened beyond the original lands applied for by Southland Royalty Company, hereinafter referred to as Southland, to include additional lands requested for designation as a tight formation by Consolidated.

(4) That Order No. R-6747 was entered in Case No. 7116 on August 7, 1981, and said order recommended for designation as a tight formation, pursuant to Section 107 of the Natural Gas Policy Act of 1978 and 18 C.F.R. Section 271.703, certain of the lands requested by Southland and certain of the lands requested by Consolidated, and made no recommendation for designation of the remaining lands requested by Southland and Consolidated.

(5) That on August 24, 1981, Consolidated, pursuant to Section 70-2-13, NMSA 1978 Comp., filed timely application for hearing de novo of Case No. 7116, and the case came on for hearing as noted above, on September 29, 1981.

(6) That Southland, having filed a new and separate application for designation of its area as a tight formation, withdrew from Case No. 7116 at the hearing de novo and asked that the original Southland lands be deleted from the hearing de

novo and that that portion of the case relating to such lands be dismissed.

(7) That in accordance with the above, all of those lands covered by the Southland application in the original hearing of this case should be deleted and dismissed from further consideration.

(8) That henceforth in this case, this order shall be concerned with the application of Consolidated Oil & Gas, Inc., for designation of the Dakota formation as a tight formation, underlying the following described lands in San Juan County, New Mexico:

TOWNSHIP 31 SOUTH, RANGE 12 WEST, NMPM

Sections 5 through 8: All

Sections 17 through 20: All

Sections 29 through 32: All

TOWNSHIP 31 NORTH, RANGE 13 WEST, NMPM

Sections 1 through 36: All

containing 29,645 acres, more or less.

(9) That while the application was for designation of the Dakota formation as a tight formation, the Dakota formation constitutes but a portion of the "Dakota Producing Interval," which, as defined by the Division, comprises the vertical limits of the Basin-Dakota Gas Pool, being from the base of the Greenhorn Limestone to a point 400 feet below the base of said formation and consisting of the Graneros formation, the Dakota formation, and the productive upper ~~limit~~ portion of the Morrison formation.

(10) That inasmuch as practically all so-called "Dakota" wells drilled in the subject area are, or potentially are, tested in and/or completed in the entire Dakota Producing Interval, and the well data presented at the hearing of this case involves the entire Dakota Producing Interval, the application should be broadened to cover all of said producing interval throughout the area.

(11) That the Dakota Producing Interval, hereinafter referred to as the "Dakota," is comprised of sediments formed during late Cretaceous time. These sediments contain light to dark mottled gray fine to very fine-grained quartz sands in a silt and clay-sized matrix material of very low permeability.

Ex 7

(12) That from the logs available at the hearing, the top of the Dakota in the area ranges from a depth of 6103 feet to 6820 feet and averages some 6544 feet beneath the surface.

Exs. HA-HB-HC

(13) That the only test data for calculated stabilized flow rates prior to stimulation for wells within the area indicates that in Township 31 North, Range 13 West, the Consolidated Wilmerding Well No. 1 in the NE/4 NW/4 of Section 10 had a flow rate "too small to measure," the Consolidated Kline Well No. 1 in the NE/4 SE/4 of Section 10 had a flow rate of 12.5 MCF of gas per day, and the Consolidated Senter Well No. 1 in the NE/4 SE/4 of Section 24 had a combined flow rate from two zones of 55 MCF of gas per day. Further, that two Southland wells in the immediate area to the east but just outside the area under consideration, being in Sections 14 and 2, Township 31 North, Range 12 West, had flow rates of 22 and 224 MCF of gas per day, respectively.

Ex 5

(14) That none of the stabilized production rates cited above exceeds the maximum stabilized production rate set forth in 18 C.F.R. Section 271.703(c)(2)(i)(B) of 251 MCF per day for wells at the average depth to the top of the formation for this area (6544 feet), and it is not expected that the average well in the area will exceed such rate.

(15) That the calculated in situ permeability of the Dakota formation in the five wells cited in Finding No. (13) above is as follows: Wilmerding No. 1, less than 0.1 md; Kline No. 1, 0.0049 md; Senter No. 1, ~~0.00068~~ 0.0146 md in the Upper Dakota and ~~0.0146~~ 0.00068 md in the Lower Dakota; and the two Southland wells in the immediate area to the east, 0.0011 md and 0.0877 md, respectively.

EX 5

(16) That the average in situ permeability for all wells in the area is not expected to exceed 0.1 md, the limit set forth in 18 C.F.R. Section 271.703(c)(2)(i)(A).

(17) That prior to stimulation, the average well in the area is expected to produce far less than the maximum five barrels of crude oil per day as set forth in 18 C.F.R. Section 271.703(c)(2)(i)(C).

(18) That 18 C.F.R. Section 271.703(c)(2)(i)(D) provides that "if the formation or any portion thereof was authorized to be developed by infill drilling prior to the date of recommendation and the jurisdictional agency has information which in its judgment indicates that such formation or portion subject to infill drilling can be developed absent the incentive price established in paragraph (a) of this section then the jurisdictional agency shall not include such formation or portion thereof in its recommendation."

(19) That the Division, by its Order No. R-1670-V, dated May 22, 1979, and effective July 1, 1979, approved infill drilling for the Basin-Dakota Gas Pool in San Juan and Rio Arriba Counties, New Mexico, and said pool includes the Dakota Producing Interval in the area under consideration here.

(20) That the Division, in approving infill drilling for the Basin-Dakota Gas Pool, based its approval on the premise that the reservoir was of low permeability and that 320-acre wells were not draining more than the 160-acre tract upon which they were located.

(21) That the remaining reserves under the 160-acre tract upon which the unit well is not located should be similar to, if not equal to, the original reserves under the 160-acre tract upon which the unit well is located.

Ex & H

(22) That according to Consolidated's Exhibit No. 8A, the average cost of a Dakota well completed in the area under consideration, hereinafter referred to as the area," is $475,400, and according to its Exhibit No. 12, operating costs may be expected to total some $61,740 during the first 20 years of a well's life and approximately $3600 per year thereafter.

(23) That according to Consolidated's Exhibit No. 12, under Section 103 prices, a Dakota gas well in the area, with ~~recoverable~~ recoverable over a 20-yr period reserves, as indicated in Column 1 below, may be expected to yield a net income above well costs and operating costs, but before federal income taxes, as shown in Column 2 below and yield a rate of return on investment as shown in Column 3.

COLUMN 1	COLUMN 2	COLUMN 3

Reserves, MMCF	Net Income	Rates of Return
180	$ 120,297	3.18%
270	$ 479,860	9.54%
350	$ 837,754	15.78%
435	$1,200,854	22.12%
555	$1,778,604	30.32%

(24) That according to Consolidated's Exhibit No. 12, under Section 107 incentive prices, a Dakota gas well in the area, with 20-year ~~recoverable~~ reserves as indicated in Column 1 below may be expected to yield a net income above well costs and operating costs, but before federal income taxes, as shown in Column 2 below and yield a rate of return on investment as shown in Column 3.

COLUMN 1	COLUMN 2	COLUMN 3
Reserves, MMCF	Net Income	Rates of Return
180	$ 550,345	14.47%
270	$1,107,833	27.29%
350	$1,679,273	38.16%
435	$2,255,196	49.52%
555	$3,110,619	65.71%

(25) That according to Consolidated's Exhibit No. 13, under Section 103 prices, a Dakota gas well in the area with 20-year reserves as indicated in Column 1 below may be expected to yield a rate of return on investment plus operating expenses and after taxes as shown in Column 2 and obtain a payout as shown in Column 3.

COLUMN 1	COLUMN 2	COLUMN 3
Reserves, MMCF	Rate of Return, %	Payout In Years
180	2.25	17.37
270	6.65	9.33

350	10.47	6.57
435	14.44	5.14
555	19.72	4.09

(26) That according to the aforementioned Exhibit No. 13, under Section 107 incentive prices, a Dakota gas well in the area with 20-year reserves as indicated in Column 1 below may be expected to yield a rate of return on investment plus operating expenses and after taxes as shown in Column 2 and obtain a payout as shown in Column 3.

COLUMN 1	COLUMN 2	COLUMN 3
Reserves, MMCF	Rate of Return, %	Payout In Years
180	9.27	6.69
270	17.41	4.37
350	24.39	3.47
435	31.80	2.89
555	42.13	2.42

(27) That ~~it is the judgment of the Commission a rate of~~ the applicant is entitled to a reasonable rate of return on its investment of 20 percent before federal income taxes ~~that a rate of return~~ is a reasonable rate of return, and that from the data shown in Finding No. (23) above, 20-year recoverable reserves in the range of 435 million cubic feet will yield a rate of return before taxes of 22.12 percent under Section 103 gas prices.

(28) That from the data shown in Finding No. (24) above, it is apparent that Section 107 incentive prices are not necessary to achieve a 20 percent rate of return before taxes, except in the lowest range of 20-year recoverable reserves shown, i.e., 180 million cubic feet of gas.

(29) That ~~it is the judgment of the Commission that a~~ the applicant is entitled to a reasonable

payout on its investment, that a

reasonable payout for a Dakota well in the area is five years, and from the data shown in Finding No. (25) above, 20-year recoverable reserves in the range of 435 million cubic feet may be expected to pay out its drilling and operating costs, after taxes, in approximately 5.14 years under Section 103 prices.

(30) That from the data shown in Finding No. (26) above, it is apparent that Section 107 incentive prices are not necessary to achieve a 5-year payout except in the lowest range of 20-year recoverable reserves shown, i.e., 180 million cubic feet of gas.

(31) That it appears to the Commission that lands indicating 435 million or more cubic feet of ~~recoverable~~ gas reserves (recoverable over a 20-year period) can be economically developed absent the incentive price provided by Section 107 of the Natural Gas Policy Act of 1978, but that lands indicating less than 435 million cubic feet of ~~recoverable~~ gas reserves should be recommended for designation as a tight formation eligible for the incentive price.

(32) That Consolidated's Exhibit 1 shows the location of Dakota wells in the area, their 1980 production, and their cumulative production since completion, and the cumulative production (over a period of approximately 20 years or less) ranges from very low obviously non-commercial wells to almost three billion cubic feet of gas.

(33) That in accordance with the Commission's previous findings that the Dakota is of low permeability and the original wells on 320-acre tracts were not draining more than the 160-acre tract upon which they were located, and that the reserves under the 160-acre upon which the original unit well is not located should be similar to, if not equal to, the original reserves under the 160-acre tract upon which the unit well is

located, it is reasonable to assume that the infill wells in the area should recover gas reserves similar to, if not equal to, the cumulative reserves indicated on Consolidated's Exhibit 1.

(34) That pursuant to previous Findings Nos. (20) and (21), and to Findings Nos. (31), (32), and (33) above, and to Consolidated's Exhibit 1, it is reasonable to assume that the average infill well drilled in the following described area will encounter recoverable reserves of 435 million or more cubic feet of gas:

TOWNSHIP 31 NORTH, RANGE 12 WEST, NMPM

Sections 5 through 8: All

Sections 17 through 20: All

Sections 29 through 32: All

TOWNSHIP 31 NORTH, RANGE 13 WEST, NMPM

Section 13: All

Sections 22 through 27: All

Sections 33 through 36: All

containing 14,482 acres, more or less.

(35) That the above-described lands can be developed absent the incentive price established in 18 C.F.R. Section 271.703(a) and should not be further considered for recommendation for designation as a tight formation.

(36) That there are fresh water aquifers underlying the lands being considered, and these aquifers extend to a depth of approximately 1000 feet.

(37) That there is a vertical distance of some 5500 feet

between the base of the lowermost of said aquifers and the top of the Dakota, and this distance, combined with the required casing and cementing program for wells in the area, will assure that development of the Dakota will not adversely affect the fresh water aquifers (during both hydraulic fracturing and waste disposal operations) that are or are expected to be used as a domestic or agricultural water supply.

(38) That the Dakota Producing Interval underlying the following lands meets all of the guidelines set forth in 18 C.F.R. Section 271.703(c)(2)(i), subsections (A), (B), (C), and (D), and should be recommended for designation as a tight formation:

TOWNSHIP 31 NORTH, RANGE 13 WEST, NMPM

Sections 1 through 12: All

Sections 14 through 21: All

Sections 28 through 32: All

containing some 15,163 acres, more or less, all in San Juan County, New Mexico.

IT IS THEREFORE ORDERED:

(1) That it be and hereby is recommended to the Federal Energy Regulatory Commission pursuant to Section 107 of the Natural Gas Policy Act of 1978, and 18 C.F.R. Section 271.703, that the Dakota Producing Interval, being from the base of the Greenhorn Limestone to a point 400 feet below the base of said formation and consisting of the Graneros formation, the Dakota formation and the productive upper portion of the Morrison formation, underlying the following described lands in San Juan County, New Mexico, be designated as a tight formation:

TOWNSHIP 31 NORTH, RANGE 13 WEST, NMPM

Sections 1 through 12: All

Sections 14 through 21: All

Sections 28 through 32: All

containing approximately 15,163 acres, more or less.

(2) That no recommendation is made as to those lands described in Finding No. ~~(10)~~ (8) of this order which are not included in Order No. (1) above.

(3) That jurisdiction of this cause is retained for the entry of such further orders as the Division may deem necessary.

DONE at Santa Fe, New Mexico, on the day and year hereinabove designated.

STATE OF NEW MEXICO

OIL CONSERVATION COMMISSION

EMERY C. ARNOLD, Chairman

ALEX J. ARMIJO, Member

JOE D. RAMEY, Member & Secretary

S E A L

(27) That from the data shown in Finding No. (23) above, 20-year recoverable reserves in the range of 435 million cubic feet will yield a rate of return before taxes of 22.12 percent under Section 103 gas prices.

(28) That from the data shown in Finding No. (25) above, 20-year recoverable reserves in the range of 435 million cubic feet may be expected to pay out its drilling and operating costs, after taxes, in approximately 5.14 years under section 103 gas prices

(29) That in the judgment of the Commission lands indicating 435 or more million cubic feet of gas reserves recoverable over a 20 year period can be developed absent the incentive price of Section 107 of the Natural Gas Pricing Act of 1978.

(30) That in the judgment of the Commission lands indicating less than 435 million cubic feet of gas reserves recoverable over a 20 year period are less likely to be developed without the incentive price of Section 107

of the Natural Gas Pricing
Act of 1978 and therefore
should be recommended for
designation as a tight formation
eligible for the incentive price.

STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION COMMISSION

IN THE MATTER OF THE HEARING
CALLED BY THE OIL CONSERVATION
DIVISION OF NEW MEXICO FOR
THE PURPOSE OF CONSIDERING:

CASE NO. 7116 De Novo
Order No. R-6747-A

APPLICATION OF SOUTHLAND ROYALTY
COMPANY FOR DESIGNATION OF A
TIGHT FORMATION, SAN JUAN COUNTY,
NEW MEXICO.

ORDER OF THE COMMISSION

BY THE COMMISSION:

This cause came on for hearing de novo at 9:00 a.m. on September 29, 1981, at Santa Fe, New Mexico, before the Oil Conservation Commission of New Mexico, hereinafter referred to as the "Commission."

NOW, on this 11th day of March, 1982, the Commission, a quorum being present, having considered the testimony presented and the exhibits received at said hearing, and being fully advised in the premises,

FINDS:

(1) That due public notice having been given as required by law, the Commission has jurisdiction of this cause and the subject matter thereof.

(2) That this case originally came on for hearing on December 30, 1980, before Division Examiner Daniel S. Nutter.

(3) That at the original hearing of this case, Consolidated Oil & Gas, Inc., hereinafter referred to as Consolidated, asked for and was granted permission to intervene in the case, and the area considered for designation as a tight formation was broadened beyond the original lands applied for by Southland Royalty Company, hereinafter referred to as Southland, to include additional lands requested for designation as a tight formation by Consolidated.

(4) That Order No. R-6747 was entered in Case No. 7116 on August 7, 1981, and said order recommended for designation as a tight formation, pursuant to Section 107 of the Natural Gas Policy Act of 1978 and 18 C.F.R. Section 271.703, certain of the lands requested by Southland and certain of the lands requested

by Consolidated, and made no recommendation for designation of the remaining lands requested by Southland and Consolidated.

(5) That on August 24, 1981, Consolidated, pursuant to Section 70-2-13, NMSA 1978 Comp., filed timely application for hearing de novo of Case No. 7116, and the case came on for hearing as noted above, on September 29, 1981.

(6) That Southland, having filed a new and separate application for designation of its area as a tight formation, withdrew from Case No. 7116 at the hearing de novo and asked that the original Southland lands be deleted from the hearing de novo and that that portion of the case relating to such lands be dismissed.

(7) That in accordance with the above, all of those lands covered by the Southland application in the original hearing of this case should be deleted and dismissed from further consideration.

(8) That henceforth in this case, this order shall be concerned with the application of Consolidated Oil & Gas, Inc., for designation of the Dakota formation as a tight formation, underlying the following described lands in San Juan County, New Mexico:

TOWNSHIP 31 SOUTH, RANGE 12 WEST, NMPM
Sections 5 through 8: All
Sections 17 through 20: All
Sections 29 through 32: All

TOWNSHIP 31 NORTH, RANGE 13 WEST, NMPM
Sections 1 through 36: All

containing 29,645 acres, more or less.

(9) That while the application was for designation of the Dakota formation as a tight formation, the Dakota formation constitutes but a portion of the "Dakota Producing Interval," which, as defined by the Division, comprises the vertical limits of the Basin-Dakota Gas Pool, being from the base of the Greenhorn Limestone to a point 400 feet below the base of said formation and consisting of the Graneros formation, the Dakota formation, and the productive upper portion of the Morrison formation.

(10) That inasmuch as practically all so-called "Dakota" wells drilled in the subject area are, or potentially are, tested in and/or completed in the entire Dakota Producing Interval, and the well data presented at the hearing of this

case involves the entire Dakota Producing Interval, the application should be broadened to cover all of said producing interval throughout the area.

(11) That the Dakota Producing Interval, hereinafter referred to as the "Dakota," is comprised of sediments formed during late Cretaceous time. These sediments contain light to dark mottled gray fine to very fine-grained quartz sands in a silt and clay-sized matrix material of very low permeability.

(12) That from the logs available at the hearing, the top of the Dakota in the area ranges from a depth of 6103 feet to 6820 feet and averages some 6544 feet beneath the surface.

(13) That the only test data for calculated stabilized flow rates prior to stimulation for wells within the area indicates that in Township 31 North, Range 13 West, the Consolidated Wilmerding Well No. 1 in the NE/4 NW/4 of Section 10 had a flow rate "too small to measure," the Consolidated Kline Well No. 1 in the NE/4 SE/4 of Section 10 had a flow rate of 12.5 MCF of gas per day, and the Consolidated Senter Well No. 1 in the NE/4 SE/4 of Section 24 had a combined flow rate from two zones of 55 MCF of gas per day. Further, that two Southland wells in the immediate area to the east but just outside the area under consideration, being in Sections 14 and 2, Township 31 North, Range 12 West, had flow rates of 22 and 224 MCF of gas per day, respectively.

(14) That none of the stabilized production rates cited above exceeds the maximum stabilized production rate set forth in 18 C.F.R. Section 271.703(c)(2)(i)(B) of 251 MCF per day for wells at the average depth to the top of the formation for this area (6544 feet), and it is not expected that the average well in the area will exceed such rate.

(15) That the calculated in situ permeability of the Dakota formation in the five wells cited in Finding No. (13) above is as follows: Wilmerding No. 1, less than 0.1 md; Kline No. 1, 0.0049 md; Senter No. 1, 0.0146 md in the Upper Dakota and 0.00068 md in the Lower Dakota; and the two Southland wells in the immediate area to the east, 0.0011 md and 0.0877 md, respectively.

(16) That the average in situ permeability for all wells in the area is not expected to exceed 0.1 md, the limit set forth in 18 C.F.R. Section 271.703(c)(2)(i)(A).

(17) That prior to stimulation, the average well in the area is expected to produce far less than the maximum five

barrels of crude oil per day as set forth in 18 C.F.R. Section 271.703(c)(2)(i)(C).

(18) That 18 C.F.R. Section 271.703(c)(2)(i)(D) provides that "if the formation or any portion thereof was authorized to be developed by infill drilling prior to the date of recommendation and the jurisdictional agency has information which in its judgment indicates that such formation or portion subject to infill drilling can be developed absent the incentive price established in paragraph (a) of this section then the jurisdictional agency shall not include such formation or portion thereof in its recommendation."

(19) That the Division, by its Order No. R-1670-V, dated May 22, 1979, and effective July 1, 1979, approved infill drilling for the Basin-Dakota Gas Pool in San Juan and Rio Arriba Counties, New Mexico, and said pool includes the Dakota Producing Interval in the area under consideration here.

(20) That the Division, in approving infill drilling for the Basin-Dakota Gas Pool, based its approval on the premise that the reservoir was of low permeability and that 320-acre wells were not draining more than the 160-acre tract upon which they were located.

(21) That the remaining reserves under the 160-acre tract upon which the unit well is not located should be similar to, if not equal to, the original reserves under the 160-acre tract upon which the unit well is located.

(22) That according to Consolidated's Exhibit No. 8A, the average cost of a Dakota well completed in the area under consideration, hereinafter referred to as the area," is $475,400, and according to its Exhibit No. 12, operating costs may be expected to total some $61,740 during the first 20 years of a well's life and approximately $3600 per year thereafter.

(23) That according to Consolidated's Exhibit No. 12, under Section 103 prices, a Dakota gas well in the area, with reserves recoverable over a 20-year period as indicated in Column 1 below, may be expected to yield a net income above well costs and operating costs, but before federal income taxes, as shown in Column 2 below and yield a rate of return on investment as shown in Column 3.

COLUMN 1 Reserves, MMCF	COLUMN 2 Net Income	COLUMN 3 Rates of Return
180	$ 120,297	3.18%
270	$ 479,860	9.54%
350	$ 837,754	15.78%
435	$1,200,854	22.12%
555	$1,778,604	30.32%

(24) That according to Consolidated's Exhibit No. 12, under Section 107 incentive prices, a Dakota gas well in the area, with 20-year reserves as indicated in Column 1 below may be expected to yield a net income above well costs and operating costs, but before federal income taxes, as shown in Column 2 below and yield a rate of return on investment as shown in Column 3.

COLUMN 1 Reserves, MMCF	COLUMN 2 Net Income	COLUMN 3 Rates of Return
180	$ 550,345	14.47%
270	$1,107,833	27.29%
350	$1,679,273	38.16%
435	$2,255,196	49.52%
555	$3,110,619	65.71%

(25) That according to Consolidated's Exhibit No. 13, under Section 103 prices, a Dakota gas well in the area with 20-year reserves as indicated in Column 1 below may be expected to yield a rate of return on investment plus operating expenses and after taxes as shown in Column 2 and obtain a payout as shown in Column 3.

COLUMN 1 Reserves, MMCF	COLUMN 2 Rate of Return, %	COLUMN 3 Payout In Years
180	2.25	17.37
270	6.65	9.33
350	10.47	6.57
435	14.44	5.14
555	19.72	4.09

(26) That according to the aforementioned Exhibit No. 13, under Section 107 incentive prices, a Dakota gas well in the area with 20-year reserves as indicated in Column 1 below may be expected to yield a rate of return on investment plus operating expenses and after taxes as shown in Column 2 and obtain a payout as shown in Column 3.

COLUMN 1 Reserves, MMCF	COLUMN 2 Rate of Return, %	COLUMN 3 Payout In Years
180	9.27	6.69
270	17.41	4.37
350	24.39	3.47
435	31.80	2.89
555	42.13	2.42

(27) That from the data shown in Finding No. (23) above, 20-year recoverable reserves in the range of 435 million cubic feet will yield a rate of return before taxes of 22.12 percent under Section 103 gas prices.

(28) That from the data shown in Finding No. (25) above, 20-year recoverable reserves in the range of 435 million cubic feet may be expected to pay out all drilling and operating costs, after taxes, in approximately 5.14 years under Section 103 gas prices.

(29) That in the judgment of the Commission, lands indicating 435 or more million cubic feet of gas reserves recoverable over a 20-year period can be developed absent the incentive price of Section 107 of the Natural Gas Pricing Act of 1978.

(30) That in the judgment of the Commission, land indicating less than 435 million cubic feet of gas reserves recoverable over a 20-year period are less likely to be developed without the incentive price of Section 107 of the Natural Gas Pricing Act of 1978 and therefore should be recommended for designation as a tight formation elibible for the incentive price.

(31) That Consolidated's Exhibit 1 shows the location of Dakota wells in the area, their 1980 production, and their cumulative production since completion, and the cumulative production (over a period of approximately 20 years or less) ranges from very low obviously non-commercial wells to almost three billion cubic feet of gas.

(32) That in accordance with the Commission's previous findings that the Dakota is of low permeability and the original wells on 320-acre tracts were not draining more than the 160-acre tract upon which they were located, and that the reserves under the 160-acre upon which the original unit well is not located should be similar to, if not equal to, the original reserves under the 160-acre tract upon which the unit well is located, it is reasonable to assume that the infill wells in the area should recover gas reserves similar to, if not equal to, the cumulative reserves indicated on Consolidated's Exhibit 1.

(33) That pursuant to previous Findings Nos. (20) and (21), and to Findings Nos. (31) and (32) above, and to Consolidated's Exhibit 1, it is reasonable to assume that the average infill well drilled in the following described area will encounter recoverable reserves of 435 million or more cubic feet of gas:

TOWNSHIP 31 NORTH, RANGE 12 WEST, NMPM
Sections 5 through 8: All
Sections 17 through 20: All
Sections 29 through 32: All

TOWNSHIP 31 NORTH, RANGE 13 WEST, NMPM
Section 13: All
Sections 22 through 27: All
Sections 33 through 36: All

containing 14,482 acres, more or less.

(34) That it is the judgment of the Commission that the above-described lands can be developed absent the incentive price established in 18 C.F.R. Section 271.703(a) and should not be further considered for recommendation for designation as a tight formation.

(35) That there are fresh water aquifers underlying the lands being considered, and these aquifers extend to a depth of approximately 1000 feet.

(36) That there is a vertical distance of some 5500 feet between the base of the lowermost of said aquifers and the top of the Dakota, and this distance, combined with the required casing and cementing program for wells in the area, will assure that development of the Dakota will not adversely affect the fresh water aquifers (during both hydraulic fracturing and waste disposal operations) that are or are expected to be used as a domestic or agricultural water supply.

(37) That the Dakota Producing Interval underlying the following lands meets all of the guidelines set forth in 18 C.F.R. Section 271.703(c)(2)(i), subsections (A), (B), (C), and (D), and should be recommended for designation as a tight formation:

TOWNSHIP 31 NORTH, RANGE 13 WEST, NMPM
Sections 1 through 12: All
Sections 14 through 21: All
Sections 28 through 32: All

containing some 15,163 acres, more or less, all in San Juan County, New Mexico.

IT IS THEREFORE ORDERED:

(1) That it be and hereby is recommended to the Federal Energy Regulatory Commission pursuant to Section 107 of the Natural Gas Policy Act of 1978, and 18 C.F.R. Section 271.703, that the Dakota Producing Interval, being from the base of the Greenhorn Limestone to a point 400 feet below the base of said formation and consisting of the Graneros formation, the Dakota formation and the productive upper portion of the Morrison formation, underlying the following described lands in San Juan County, New Mexico, be designated as a tight formation:

TOWNSHIP 31 NORTH, RANGE 13 WEST, NMPM
Sections 1 through 12: All
Sections 14 through 21: All
Sections 28 through 32: All

containing approximately 15,163 acres, more or less.

(2) That no recommendation is made as to those lands described in Finding No. (8) of this order which are not included in Order No. (1) above.

(3) That jurisdiction of this cause is retained for the entry of such further orders as the Division may deem necessary.

DONE at Santa Fe, New Mexico, on the day and year hereinabove designated.

STATE OF NEW MEXICO
OIL CONSERVATION COMMISSION

EMERY C. ARNOLD, Chairman

ALEX J. ARMIJO, Member

JOE D. RAMEY, Member & Secretary

S E A L

DAKOTA TIGHT FORMATION
HEARING
CASE NO. 7116 DE NOVO

SEPTEMBER 29, 1981

BEFORE THE
OIL CONSERVATION COMMISSION
Santa Fe, New Mexico
Case No. 7116 DN Exhibit No. 1-17
Submitted by COG
Hearing Date 9-29-81

GEOGRAPHICAL AND GEOLOGICAL DESCRIPTION

Within the described area of Exhibit No. 1, the Dakota sands are light to dark mottled gray, fine to very fine-grained quartz sands. Silt and clay-sized matrix material can form a significant percentage of the bulk-rock composition. Because the matrix fraction tends to reduce greatly the effective permeability of the reservoir, natural and induced fractures are necessary for production from the Dakota reservoir.

Exhibit No. 3 is a type log which shows the base of the Mancos, the Greenhorn, the Graneros and the Dakota formations. The vertical limits of the Basin Dakota gas pool have been defined by the New Nexico Conservation Division to be from the base of the Greenhorn Limestone to a point 400 feet below the base of said formation and consists of the Graneros formation, the Dakota formation and the productive upper portion of the Morrison formation. The Graneros and first Dakota zones are the main producing zones in the Basin Dakota Field. The other Dakota zones and the upper Morrison zone have very low permeability. Production from these zones has been limited to date.

The sediments of the Dakota interval were formed during late Cretaceous time. The Dakota is bounded by an uncomformable contact with the Jurassic Morrison below and is gradational with the Cretaceous Mancos shale above and is found at an average depth of 6650 feet for the area outlined on Exhibit No. 1. The gross thickness of the formation varies from 200 to 300 feet.

Deposition of the Dakota sediments occurred during a regression of the late Cretaceous sea. This regression resulted in the following sequence of depositional environments from the base upward: 1. Braided stream sandstone; 2. Meandering stream complex (with minor associated coals); 3. Coastal shale; 4. Coastal sandstone. The lower two environments contain sands of minor areal extent whereas the coastal sandstones have significant extent. They are northwest-southeast trending linear sand bodies reflecting their beach and off-shore bar

depositional history. These upper Dakota sands appear to be the primary Dakota reservoirs.

Exhibits Nos.4A, 4B and 4C are cross sections that show the continuity of the Dakota zones across the area of this application. Cross section A-A' shows sand development in a North-South direction while cross-section B-B' shows sand development in an East-West direction. Cross-section C-C' shows the sand development in a Southwest-Northeast direction.

PERMEABILITY, GAS AND CRUDE PRODUCTION DATA
NORTHWEST PORTION - BASIN DAKOTA FIELD
SAN JUAN COUNTY, NEW MEXICO

Operator/ Lease	Well No.	Location	Spud Date	Depth	In Situ Gas Permeability (Md.)	Calculated Stabilized Gas Production Rate At Atmos Pressure (MCFD)	Crude Production (BPD)	FERC Allowed Rate MCFD	FERC Allowed Rate BOPD
Consolidated Oil & Gas Co. Wilmerding	1-M	NE/4 NW/4 10-31N-13W	4-2-80	6627-6846	less than 0.1	Flow too small to measure	0	251	
Consolidated Oil & Gas Co. Kline	1-M	NE/4 SE/4 10-31N-13W	4-16-80	6506-6736	0.0049	12.5	0	251	
Consolidated Oil & Gas Co. Senter	1-M	NE/4 SE/4 24-31N-13W	11-28-79	6898-6958 6740-6816	0.00068 0.0146	2.73 L.Dak 52.00 U.Dak 54.73	0 0 0	251	
Southland Royalty Co. East	7-E	SW 14-31N-12W (1)		7282-7448	0.0011	21.7	0	290	
Southland Royalty Co. Patterson 'B' Com.	1-E	SW 2-31N-12W (1)		7212-7385	0.0877	224.1	0	290	
El Paso Natural Gas Co. Case	8	NE 18-31N-11W (1)		7254-7406	0.0335 (2)	Not tested	--	290	
El Paso Natural Gas Co. Moore	8	SW 24-32N-12W (1)		7589-7800	0.0151 (2)	Not tested	--	336	

(1) Not within, but near the area of this application.
(2) Reference: Rex D. Thomas and Don C. Ward: "Effect of Overburden Pressure and Water Saturation on Gas Permeability of Tight Sandstone Cores". See Exhibit No. 7 .

Exhibit No. 5

CORRECTED COPY

FLUID SAMPLE DATA

Sampler Pressure _____ P.S.I.G. at Surface
Recovery: Cu. Ft. Gas _____
cc. Oil _____
cc. Water _____
cc. Mud _____
Tot. Liquid cc. _____
Gravity _____ ° API @ _____ °F.
Gas/Oil Ratio _____ cu. ft./bbl.

		RESISTIVITY	CHLORIDE CONTENT
Recovery Water	@ °F.		ppm
Recovery Mud	@ °F.		ppm
Recovery Mud Filtrate	@ °F.		ppm
Mud Pit Sample	@ Fresh °F.	water	ppm
Mud Pit Sample Filtrate	@ °F.		ppm

Mud Weight _____ vis _____ sec.

Date 7-31-80 Ticket Number 727294
Kind of D.S.T. CASED HOLE Halliburton Location FARMINGTON
Tester MR. BROWN / MR. ROBLES Witness
Drilling Contractor SPARTAN DRILLING COMPANY DR BC

EQUIPMENT & HOLE DATA

Formation Tested Basin Dakota
Elevation 6940' Ft.
Net Productive Interval 51' from 7284-7445' Ft.
All Depths Measured From Kelly Bushing
Total Depth 7480' Ft.
Main Hole/Casing Size 4 1/2" 10.5# Liner
Drill Collar Length - I.D. -
Drill Pipe Length 7229.9' I.D. 1.995"
Packer Depth(s) 7249' Ft.
Depth Tester Valve 7235.5' Ft.

Cushion TYPE Fresh water AMOUNT 4 bbls. Ft. Depth Back Pres. Valve — Surface Choke 1/8" Bottom Choke 5/8"

Recovered 1000' 240 Feet of water
Recovered Feet of
Recovered Feet of
Recovered Feet of
Recovered Feet of

Remarks See production test data sheet
0-Questionable

TEMPERATURE	Gauge No. 7489 Depth: 7245 Ft.	Gauge No. 5160 Depth: 7257.2' Ft.	Gauge No. Depth: Ft.	TIME (00:00-24:00 hrs.)
	24 Hour Clock	24 Hour Clock	Hour Clock	Tool Opened 0056
Est. °F.	Blanked Off No	Blanked Off Yes	Blanked Off	Opened Bypass 1100
Actual 190 °F.	Pressures	Pressures	Pressures	

		Field	Office	Field	Office	Field	Office	Reported Minutes	Computed Minutes
Initial Hydrostatic		3375 0	3120.6	3192 0	3117.2			—	—
First Period	Flow Initial	130.8	346.3-0	128	352.5 0			—	—
	Flow Final	130.8	150.3	128	147.4			120	126
	Closed in	2383	2382.2	2426.8	2382.1			484	478
Second Period	Flow Initial							—	—
	Flow Final								
	Closed in								
Third Period	Flow Initial							—	—
	Flow Final								
	Closed in								
Final Hydrostatic		3590 0	3120.6	3320 0	3117.2			—	—

FORM 161-82 — PRINTED IN U.S.A.

FORMATION TEST DATA

LITTLE'S 11/633 75C 3/80

Exhibit No. 6A

(6) 1.

Legal Location Sec. - Twp. - Rng. 14-31N-12W
Lease Name EAST
Well No. 7-E
Test No. 1
Tested Interval 7249-7480'
Field Area BASIN DAKOTA
Meas. From Tester Valve
County SAN JUAN
State NEW MEXICO
Lease Owner/Company Name SOUTHLAND ROYALTY COMPANY

Casing perfs._____ Bottom choke._____ Surf. temp._____ °F Ticket No. 727294

Gas gravity._____ Oil gravity._____ GOR._____

Spec. gravity._____ Chlorides._____ ppm Res._____ @ _____ °F

INDICATE TYPE AND SIZE OF GAS MEASURING DEVICE USED._____

Date Time a.m. p.m.	Choke Size	Surface Pressure psi	Gas Rate MCF	Liquid Rate BPD	Remarks
2218					On location, made up tools
2218					Trip in hole with tools
0016					On bottom
0056					Hydrospring opened
0056					Moderate blow to surface
0101	Blow Hose	.25#			
0102	"	1			
0103	"	2			
0.04	"	3			
0109	"	3.5			
0118	"	4			
0123	"	4			
0128	"	4.5			
0133	"	4			
0138		4.5			
0142		4.5			Gas to surface
0147	3/4"				Opened choke, flare to pit with 1/8"
					orifice tester
0256					Closed tool
1100					Trip out of hole with tools

FORM 102-81—PRINTED IN U.S.A.

PRODUCTION TEST DATA

LITTLE'S 96673 3M 8/74

SOUTHLAND ROYALTY COMPANY — 727294

Lease Owner/Company Name — Ticket Number

B.T. 7489 B.T. 5160 B.T. _____

Depth 7245' Depth 7257.2' Depth _____

INITIAL FLOW

	Time Defl. .000"	Log $\frac{t+\theta}{\theta}$	PSIG Temp. Corr.	Time Defl. .000"	Log $\frac{t+\theta}{\theta}$	PSIG Temp. Corr.	Time Defl. .000"	Log $\frac{t+\theta}{\theta}$	PSIG Temp. Corr.
0.	.0000		346.3-Q	.0000		352.5-Q			
1.	.0885		613.3*	.0861		155.9			
2.	.1566		165.5	.1522		160.2			
3.	.2247		163.3	.2184		153.8			
4.	.2928		156.8	.2846		149.5			
5.	.3609		154.6	.3508		149.5			
6.	.4290		150.3	.4170		147.4			

20 minute intervals
*Interval = 26 minutes
126 TOTAL MINUTES

INITIAL CLOSED IN PRESSURE

0.	.0000	-----	150.3	.0000	----	147.4			
1.	.0342	1.132	444.4	.0332	1.132	425.2			
2.	.0684	.862	684.0	.0664	.862	668.8			
3.	.1026	.714	893.2	.0996	.715	886.7			
4.	.1368	.617	1053.8	.1328	.617	1048.8			
5.	.1710	.545	1191.8	.1660	.546	1193.2			
6.	.2052	.490	1323.2	.1992	.490	1326.9			
7.	.2394	.446	1439.6	.2324	.446	1443.7			
8.	.2736	.410	1547.4	.2656	.410	1552.0			
9.	.3078	.379	1644.4	.2988	.379	1647.5			
10.	.3421	.353	1730.6	.3320	.353	1726.1			
11.	.4447	.293	1896.5	.4316	.294	1891.7			
12.	.5473	.251	2000.0	.5312	.252	1997.8			
13.	.6499	.220	2079.9	.6308	.220	2076.4			
14.	.7526	.196	2140.3	.7304	.196	2135.8			
15.	.8552	.177	2187.8	.8300	.177	2184.6			
16.	.9578	.161	2231.0	.9296	.161	2227.1			
17.	1.0605	.148	2265.6	1.0292	.148	2263.2			
18.	1.1631	.136	2293.7	1.1288	.137	2284.4			
19.	1.2657	.127	2319.6	1.2284	.127	2318.4			
20.	1.3684	.118	2343.4	1.3280	.119	2339.6			
21.	1.4710	.111	2360.6	1.4276	.111	2346.0			
22.	1.5736	.105	2375.8	1.5272	.105	2373.6			
23.	1.6350	.101	2382.2	1.5870	.101	2382.1			

First 10 intervals = 10 minutes each; next 12 intervals = 30 minutes each; last interval = 18 minutes
478 TOTAL MINUTES

Remarks: Q = Questionable

Gas Production

CORRECTED COPY

B.T. Gauge Numbers			7489	5160	Ticket Number	727294	
			PRESSURE	PRESSURE			
Initial Hydrostatic			3121	3117	Elevation	6940	ft.
Final Hydrostatic			3121	3117	Production Rate 1st Flow	21.6	MCF
1st Flow	Initial	Time	346	353	Production Rate 2nd Flow	-	MCF
	Final	126	150	147	Production Rate 3rd Flow	-	MCF
	Closed In Pressure	478	2382	2382	Hole Size	6.25	in.
2nd Flow	Initial	Time			Footage Tested	51	ft.
	Final				Mud Weight	8.33	lbs./gal.
	Closed In Pressure				Gas Viscosity	.020	cp
3rd Flow	Initial	Time			Gas Gravity	.70	—
	Final				Gas Compressibility	.85	—
	Closed In Pressure				Temperature	190	°F
Extrapolated Static Pressure		1st	2644	2639			
		2nd					
		3rd					
Slope P/10		1st	89	74			
		2nd					
		3rd					

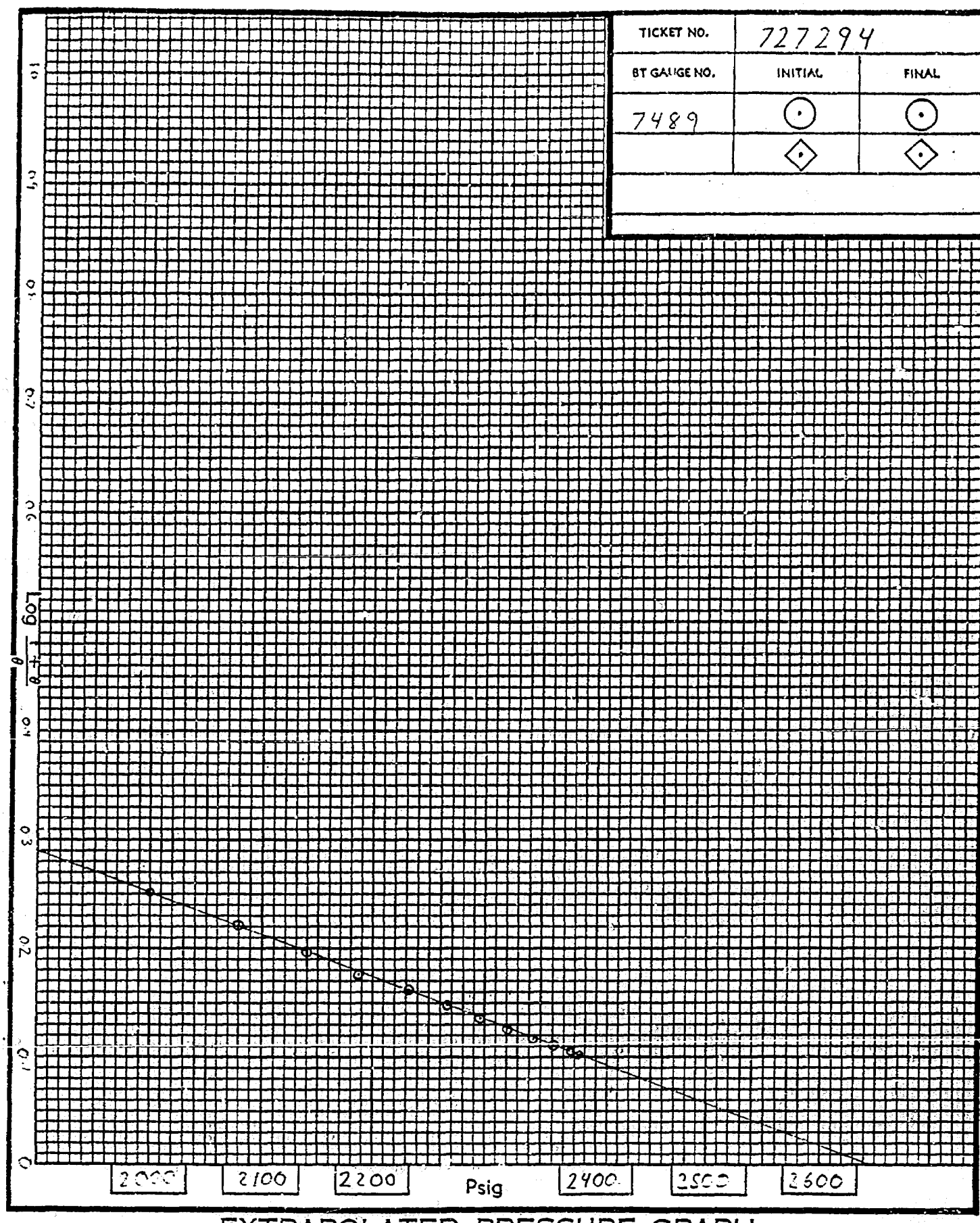
Remarks: (1) Calculations based on rates given by Bob Fielden 8-11-80 and net pay given by Marlin Thompson 10-6-80
(2) Gas gravity changed to 0.70-11-13-80

SUMMARY

PRODUCT	EQUATION	B.T. Gauge No. 7489 Depth 7245' FIRST	SECOND	THIRD	B.T. Gauge No. 5160 Depth 7257' FIRST	SECOND	THIRD	UNITS
Transmissibility	$\frac{Kh}{\mu} = \frac{1637\, Q_s\, ZT}{m}$	2.798			2.807			$\frac{md.\ ft.}{cp}$
Theoretical Flow Capacity	$Kh = \frac{Kh}{\mu}\ \mu$	.0560			.0561			md. ft.
Average Effective Permeability	$K = \frac{Kh}{h}$	.00110			.00110			md.
	$K_1 = \frac{Kh}{h_1}$	-			-			md.
Indicated Flow Capacity	$(Kh)_s = \frac{3200\, Q_s\, \mu\, ZT \log(0.472\, b/r_w)}{P_s^2 - P_f^2}$	.0066			.0067			md. ft.
Damage Ratio	$DR = \frac{\text{Theo. Flow Cap}}{\text{Indicated Flow Cap}} \quad \frac{Kh}{(Kh)_s}$	8.454			8.390			—
Indicated Flow Rate	$OF_1 = \frac{Q_s \quad P_s^2}{P_s^2 - P_f^2}$ Max.	21.670			21.667			MCFD
	$OF_2 = \frac{Q_s \quad P_s}{\sqrt{P_s^2 - P_f^2}}$ Min.	21.635			21.634			MCFD
Theoretical Potential Rate	$OF_3 = OF_1\ DR$ Max.	183.205			181.791			MCFD
	$OF_4 = OF_2\ DR$ Min.	182.910			181.509			MCFD
Approx. Radius of Investigation	$b \leq \sqrt{Kt}$ or $\sqrt{Kt_0}$	.632			.633			ft.
	$b_1 \leq \sqrt{K_1 t}$ or $\sqrt{K_1 t_0}$	-			-			ft.
Potentiometric Surface *	$Pot. = (El - GD) + (2.319\, Ps)$	-			-			ft.

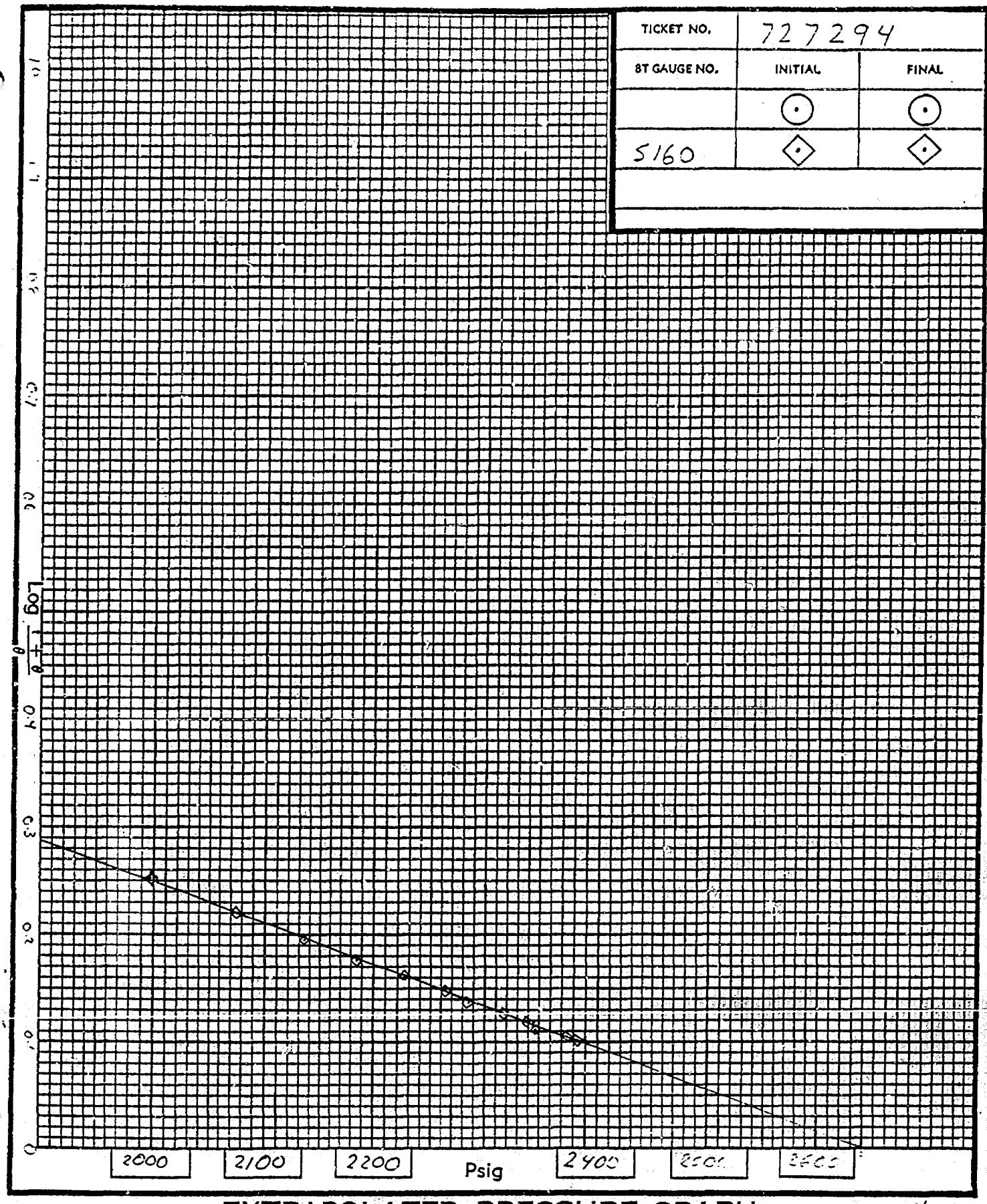
NOTICE: These calculations are based upon information furnished by you and taken from Drill Stem Test pressure charts, and are furnished you for your information. In furnishing such calculations and evaluations based thereon, Halliburton is merely expressing its opinion. You agree that Halliburton makes no warranty express or implied as to the accuracy of such calculations or opinions, and that Halliburton shall not be liable for any loss or damage, whether due to negligence or otherwise, in connection with such calculations and opinions.

TICKET NO.	727294	
BT GAUGE NO.	INITIAL	FINAL
7489	⊙	⊙
	◇	◇



EXTRAPOLATED PRESSURE GRAPH

TICKET NO.	727294	
8T GAUGE NO.	INITIAL	FINAL
	⊙	⊙
5160	◇	◇



EXTRAPOLATED PRESSURE GRAPH

TICKET NO. 727294

	O. D.	I. D.	LENGTH	DEPTH
Drill Pipe or Tubing	2 3/8"	1.995"	7229.9'	
Drill Collars				
Reversing Sub				
Water Cushion Valve				
Drill Pipe				
Drill Collars				
Handling Sub & Choke Assembly				
Dual CIP Valve	3.03"	1"	5'6"	7229.9'
Dual CIP Sampler				
Hydro-Spring Tester	3.03"	1.13"	4'10"	7235.5'
Multiple CIP Sampler				
Extension Joint				
AP Running Case	3.03"	2.31"	4'8½"	7245'
X over				
Hydraulic Jar				
VR Safety Joint	3.03"	1.75"	2'8½"	
Pressure Equalizing Crossover				
X over	3.03"	1.75"	1'	
Packer Assembly	4½"	1.90"	3'4"	7249'
Distributor				
Packer Assembly				
Perforated anchor	2 3/8"	1.90"	4'2"	
Flush Joint Anchor				
Pressure Equalizing Tube				
Blanked-Off B.T. Running Case				
Drill Collars				
Anchor Pipe Safety Joint				
Packer Assembly				
Distributor				
Packer Assembly				
Anchor Pipe Safety Joint				
Side Wall Anchor				
Drill Collars				
Flush Joint Anchor				
Blanked-Off B.T. Running Case	3.03"	2.31"	4'	7257.2'
Total Depth				7480'

FORM 157-52 — PRINTED IN U.S.A.

EQUIPMENT DATA

LITTLE'S 111664 7 5C 5/80

CONSOLIDATED OIL & GAS, INC.

WILMERDING NO. 1-M

NE/4 NW/4 10-T31N-R13W

BASIN DAKOTA FIELD

SAN JUAN COUNTY, NEW MEXICO

Data:

	Lower Dakota	Upper Dakota
Midperforations	6817'	6697'
Qg	Too Small to Measure	Not Tested
h (log)	27'	57'
K (permeability)	Inadequate gas to compute flow rate and permeability (K) is much less than 0.1 md.	

Exhibit No. 6B-1

CONSOLIDATED OIL & GAS, INC.

KLINE NO. 1M

NE/4 SE/4 10-31N-13W

BASIN DAKOTA FIELD

Calculation of Permeability Using Darcy's Law:

Data:

	Lower Dakota	Upper Dakota
Midperforations	6696'	6567'
Qg	12850 SCF (test)	Gas Too Small To Measure
h	38' feet (log)	
Pwf	38 Psia	
Pe	2592 Psia	
g_g	.70	
T	186°-646°R	
re	1320 feet	
rw	0.02 feet	
Psc	668 Psia	
Tsc	392°Rankin	
Ug	.014 cp	
Z	0.91	

Where:

Qg = gas flow rate
h = net pay
Pwf= flowing bottomhole pressure
Pe = shut-in bottomhole pressure at drainage radius, re
g_g = gas specific gravity
T = bottomhole temperature
re = drainage radius for 160 acre spacing
rw = wellbore radius
Psc= pseudo critical pressure
Tsc= pseudo critical temperature
Ug = gas viscosity
Z = compressibility factor for gas

Formula:

$$K = \frac{Q_g U_g T Z \ln(.6 l r_e / r_w)}{703 h (P_e^2 - P_{wf}^2)}$$

$$K = \frac{12850 \times .014 \times 646 \times .91 \times \ln(.6 l \times \frac{1320}{20})}{703 \times 33 \times (2592^2 - 38^2)}$$

$$K = .0000049 \quad D$$

$$K = .0049 \text{ md.}$$

Exhibit No. 6B-2

CONSOLIDATED OIL & GAS, INC.
SEWTER NO. 1M
NE/4 SE/4 24-T31N-R13W
BASIN DAKOTA FIELD
SAN JUAN COUNTY, NEW MEXICO

Calculation of Permeability Using Darcy's Law:

Data:

	Lower Dakota	Upper Dakota
Midperforations	6928	6728
Qg Scf (test)	2730	52000
h feet (log)	58	51
Pwf Psia	20	32
Pe by analogy & tests	2658	2592
G_g typical gravity field gas	.70	.70
T calculated	186°F(646°R)	186°F(646°R)
re feet	1320	1320
rw feet	.20	.20
Psc Psia	668	668
Tsc °Rankin	392°R	392°R
Ug cps(calc.)	.014	.014
Z (calc)	.91	.91

Where:

Qg = gas flow rate
h = net pay
Pwf= flowing bottomhole pressure
Pe = shut-in bottomhole pressure at drainage radius, re
G_g = gas specific gravity
T = bottomhole temperature
re = drainage radius for 160 acre spacing
rw = wellbore radius
Psc= pseudo critical pressure
Tsc= pseudo critical temperature
Ug = gas viscosity
Z = compressibility factor for gas

Formula:

$$Q_g = \frac{703Kh(Pe^2-Pf^2)}{UgTZ\ \ln(.61re/rw)} \qquad \text{and } K = \frac{Q_gUgTZ\ \ln(.61re/rw)}{703h(Pe^2-Pwf^2)}$$

Lower Dakota

$$K = \frac{2730(.014)(646)(.91)\ln(.61x\frac{1320}{.20})}{(703)(58)(2658^2-20^2)}$$

= .00000068 D
= .00068 md.

Upper Dakota

$$K = \frac{52000(.014)(646)(.91)\ln(.61x\frac{1320}{.20})}{(703)(51)(2592^2-32^2)}$$

= .0000146 D
= .0146 md.

Exhibit No. 6B-3

SOUTHLAND ROYALTY COMPANY
PATTERSON "B" COM. 1E
SW-2-31N-12W
BASIN DAKOTA FIELD
SAN JUAN COUNTY, NEW MEXICO

Calculation of Permeability using Darcy's Law:

Data:

Qg = 224,000 SCFD (open hole test)
h = 34 feet (log)
Pwf= 54 psia (measured at surface and calculated to bottomhole)
Pe = 2650 psia (DST in East No. 7E located 9600' to south)
g_g = .70
T = 190°F = 650°R (calc.)
re = 1320 feet
rw = 0.20 feet
Psc= 668 psia
Tsc= 392°R
Ug = .014 cps (calc.)
Z = .87 (calc.)

Where:

Qg = gas flow rate
h = net pay
Pwf= flowing bottomhole pressure
Pe = shut-in bottomhole pressure at drainage radius, re
g_g = gas specific gravity
T = bottomhole temperature
re = drainage radius for 160 acre spacing
rw = wellbore radius
Psc= pseudo critical pressure
Tsc= pseudo critical temperature
Ug = gas viscosity
Z = compressibility factor for gas

$$Qg = 703\ Kh\ \frac{(Pe^2 - Pwf^2)}{Ug\ T\ Z\ \ln(.61\ re/rw)}$$

$$K = \frac{Qg\ Ug\ T\ Z\ \ln(.61\ re/rw)}{(703\ h\ (Pe^2 - Pwf^2)}$$

$$K = 224{,}000\ (.014)\ \frac{(650)(.87)\ \ln(.61\ 1320/.20)}{703\ (34)\ (2650^2 - 542)}$$

K = .0000877 D.

K = .0877 md.

Exhibit No. 6B-4

EL PASO NATURAL GAS COMPANY
CASE NO. 8
NE-18-31N-11W
BASIN DAKOTA FIELD
SAN JUAN COUNTY, NEW MEXICO

Depth (feet)		Permeability (md.)
7254-55		.41
55-56		.32
56-57		.11
57-58		.02
58-59		.03
59-60		.12
60-61		.02
61-62		.07
7338-39		.09
39-40		.12
40-41		.04
41-42		.04
42-43		.04
43-44		.04
44-45		.02
45-46		.06
46-47		.07
47-48		.29
48-49		.03
49-50		.14
50-51		.07
51-52		.04
53-54		.56
54-55		.01
55-56		.24
7364-65		.07
65-66		.05
66-67		.08
67-68		.02
68-69		.52
69-70		.03
70-71		.23
71-72		.02
7390-91		.33
91-92		.03
92-93		.02
93-94		.02
Totals	37	4.42
Average Laboratory		.1195
Average In Situ		.0335

Exhibit No. 6C-1

EL PASO NATURAL GAS COMPANY
MOORE NO. 8
SW-24-32N-12W
BASIN DAKOTA FIELD
SAN JUAN COUNTY, NEW MEXICO

Depth (feet)		Permeability (md.)
7589-90		.01
7591-92		.01
7593-94		.05
7595-96		.01
7597-98		.07
7599-7600		.01
7601-02		.08
7603-04		.01
7605-06		.01
7607-08		.01
7609-10		.02
7611-12		.01
7670-71		.03
71-72		.05
72-73		.48
73-74		.01
74-75		.01
75-76		.07
76-77		.03
78-79		.01
79-80		.09
80-81		.01
81-82		.11
82-83		.17
83-84		.08
84-85		.01
85-86		.02
86-87		.01
87-88		.04
88-89		.01
89-90		.01
90-91		.29
91-92		.07
92-93		.02
93-94		.01
94-95		.01
95-96		.02
96-97		.02
97-98		.12
Totals	39	2.10
Average Laboratory		.0538
Average In-Situ		.0151

Exhibit No. 6C-2

Effect of Overburden Pressure and Water Saturation on Gas Permeability of Tight Sandstone Cores

Rex D. Thomas, SPE-AIME, U. S. Bureau of Mines
Don C. Ward, SPE-AIME, U. S. Bureau of Mines

Introduction

Research on the potential of nuclear explosions to stimulate gas production from low-permeability (tight) sandstone reservoirs is being conducted by the U. S. Bureau of Mines in cooperation with the Atomic Energy Commission. This report describes the part of that research that was conducted to establish correlation between permeability measured on dry cores at low external pressure (routine analysis) and permeability at reservoir conditions.

Cores used in this research were obtained from two Plowshare gas-stimulation projects. Project Gasbuggy cores from the Pictured Cliffs formation, Choza Mesa field, Rio Arriba County, N. M., can be described as very fine grained, slightly calcareous, well indurated sandstone. Project Wagon Wheel cores from the Fort Union formation, Pinedale field, Sublette County, Wyo., can be described as very fine grained, slightly calcareous, very well indurated sandstone.

Underground reservoirs are under considerable compressive stress as a result of the weight of overlying rocks (offset somewhat by internal-fluid pressure). The resultant net confining pressure or effective overburden pressure is referred to in this report simply as overburden pressure. The resulting effects on the physical properties of the reservoir rock have been studied.[1-5] Overburden pressure causes only a small decrease in porosity, which can usually be ignored.[5] This was confirmed for Project Gasbuggy and Project Wagon Wheel cores. A commercial laboratory found that the porosity of these cores is reduced by about 5 percent of the original porosity. The effect of overburden pressure on permeability, however, is appreciable and varies considerably for different reservoir rocks,[1,2] causing greater reductions in permeability for low-permeability rocks.[2,3] The effect of overburden pressure on relative permeability has been found to be small[4] or nonexistent.[5]

This report presents material that confirms and extends previous research findings on the effect that overburden pressure has upon the permeability of dry cores. Also presented are the results of research on the relative gas permeability of low-permeability cores under overburden pressure.

Apparatus and Procedure

Cylindrical cores 2.0 to 7.5 cm long and 2.5 cm in diameter were cut parallel to the bedding plane. After the cores were dried overnight in a vacuum oven (4.5 psia, 70°C), the gas (N_2) permeability of each core was measured in a Hassler cell. An external pressure of 100 psi over the inlet pressure was used to maintain a good seal between the rubber sleeve and the core.[6] Permeability was measured at inlet pressures of 45, 60, and 100 psia, with atmospheric pressure at the outlet. A bubble tube and timer were used to measure gas flow rate. Initial permeability (k_i) then was calculated by the Klinkenberg technique to correct for the effect of gas slippage. All other permeabilities reported here were calculated by this method.

In the same manner, permeability was measured at

Research conducted to determine the potential of nuclear explosions to stimulate gas production verifies that the gas permeability of tight sandstone cores is markedly decreased with increasing overburden pressure. Water saturation also reduces the gas permeability by a large amount. The relative permeability, however, does not change significantly with overburden pressure.

Exhibit No. 7

increasing external pressures of about 500, 1,000, 2,000, 3,000, 4,000, 5,000, and 6,000 psi. External pressures actually were somewhat higher to compensate for internal pressure. The core and staniless steel end pieces were placed in a rubber sleeve (piece of bicycle innertube) 0.1 cm thick. Rubber cement was used to seal the stainless steel end pieces to the rubber sleeve. Shrinkable plastic tubing proved unsatisfactory because high pressure was required to seal the core. The jacketed core was mounted in a high-pressure cell with distilled water as the external fluid.

Cores used in relative permeability studies were first subjected to high external pressure and then allowed to recover their initial permeability. Bulk volume, dry weight, and porosity were measured by conventional gas-expansion techniques. Cores then were subjected to a vacuum (0.3 psia) for 2 hours, immersed in water, and allowed to stand under a vacuum overnight. The cores were weighed and again subjected to vacuum overnight and weighed again to assure complete saturation. Most of the cores were completely saturated after one night. Porosity values calculated on the basis of water saturation are in good agreement with those measured by conventional gas-expansion techniques.

Water in the core was allowed to evaporate at atmospheric conditions to a saturation of about 70 percent and the core was placed in the holder for 2 hours under external pressure (100 psi above inlet) only so the water saturation was uniform. Gas permeability then was measured at three inlet pressures between 30 and 100 psia with atmospheric pressure at the outlet. This procedure was repeated for decreasing water saturations at the same external pressure. After the permeability was measured the core was weighed to determine if any water was lost. In all cases the amount lost was negligible. After the core was dried in a vacuum oven, the gas permeability at this external pressure was measured. The procedure was repeated for external pressures of 3,000 and 6,000 psi.

Results and Discussion

Effect of Overburden Pressure on Permeability

Core number, length, porosity, and initial permeability of the cores used in this research are shown in Table 1. The core number refers to the depth in feet at which the core was obtained. Typical plots of the effect of simulated overburden pressure on Gasbuggy cores are shown in Fig. 1. The permeability is decreased by about 75 percent at an overburden pressure of 3,000 psi and by 90 percent at 6,000 psi. The hydrostatic loading used in these experiments does not reproduce subsurface conditions exactly; in an actual reservoir the horizontal component of stress is usually less than the vertical component. Since the actual loading is not known, this method probably is as realtistic as any other. Cores that contain microfractures are affected to a greater extent, as shown in Fig. 2. In these cores the permeability is decreased by about 95 percent at a simulated overburden pressure of 3,000 psi, with most of the reduction occurring below 2,000 psi.

The data shown in Table 1 and Figs. 1 and 2 were obtained by subjecting the core to successive incre-

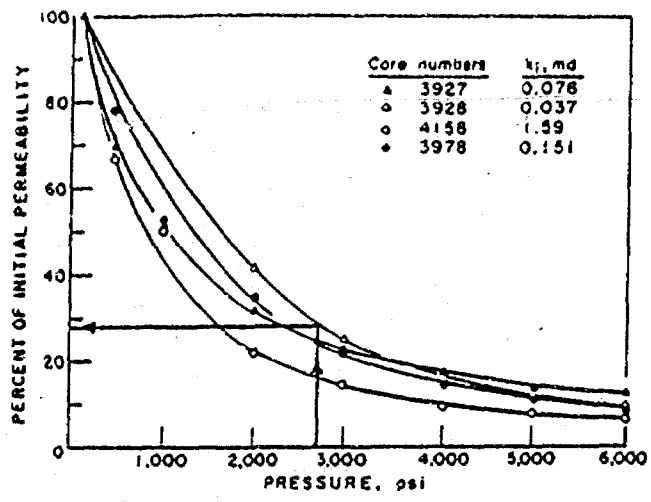


Fig. 1—Effect of overburden pressure on gas permeability of Gasbuggy cores.

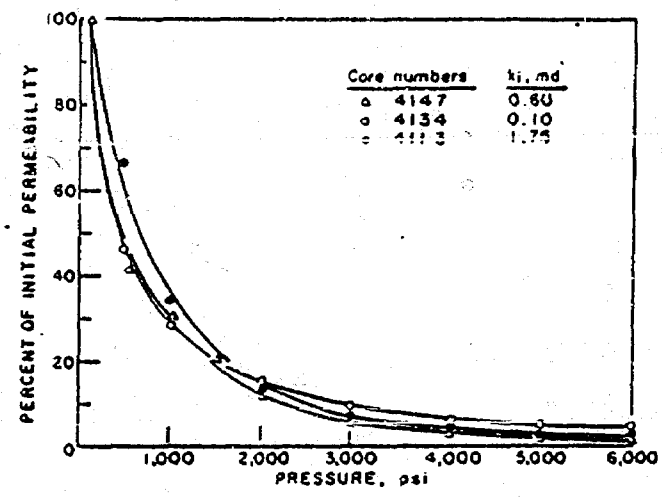


Fig. 2—Effect of overburden pressure on gas permeability of fractured Gasbuggy cores.

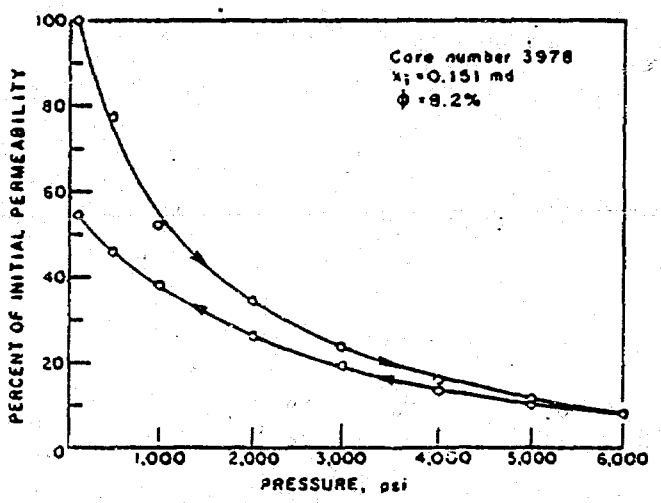


Fig. 3—Hysteresis effect at decreasing confining pressures.

TABLE 1—EFFECT OF OVERBURDEN PRESSURE ON GAS PERMEABILITY

Effective Overburden Pressure (psi):				500	1,000	2,000	3,000	4,000	5,000	6,000
Core Number*	Length (cm)	Porosity (percent)	k_i†	Permeability (md)						
Gasbuggy										
3927	2.1	8.1	0.076	0.053	0.040	0.024	0.0175	0.0132	0.0105	0.0095
3928	7.5	8.3	0.037	0.031	0.024	0.015	0.0093	0.0059	0.0046	0.0035
3978	2.1	8.2	0.151	0.118	0.078	0.052	0.036	0.024	0.0175	0.0132
4113**	2.1	10.1	1.75	1.16	0.602	0.252	0.113	0.068	0.042	0.029
4134**	2.1	11.6	0.10	0.046	0.029	0.0153	0.0095	0.0065	0.0055	0.0047
4146**	7.5	11.6	2.40	1.73	1.32	0.31	0.14	0.069	0.052	0.022
4147**	7.5	11.3	0.60	0.247	0.181	0.071	0.034	0.0186	0.011?	0.0082
4158	2.1	13.6	1.59	1.06	0.80	0.35	0.225	0.152	0.116	0.100
Wagon Wheel										
8084	3.8	7.7	0.028	0.022	0.020	0.010	0.0070	0.0047	0.0035	0.0030
8122	3.8	11.4	0.071	0.055	0.048	0.034	0.027	0.024	0.021	0.019
8975**	3.8	8.7	0.039	0.029	0.024	0.0114	0.0073	0.0048	0.0032	0.0025
10156	3.8	8.5	0.088	0.067	0.051	0.032	0.025	0.022	0.018	0.016
10990**	3.8	9.0	0.048	0.020	0.0175	0.0080	0.0050	0.0040	0.0025	0.0019

*Number denotes depth in feet.
**Slightly fractured.
†Initial permeability.

mental increases in external pressure. The core was assumed to be in equilibrium at each pressure when permeability measurements remained constant for 15 minutes, which required between 1 and 2 hours. A period of 30 minutes to an hour was required to attain equilibrium when the inlet pressure was changed. Consequently, each external pressure was maintained for a minimum of 2 hours.

The effect of decreasing external pressure was determined on a few cores, and typical results are shown in Fig. 3. Other researchers[2,3] have observed and shown that this hysteresis is mainly dependent on the stress history of the core. Cores generally recover their original permeability after 3 to 6 weeks at atmospheric conditions. This time could be shortened by storing the core in an oven at 70°C.

The effect of overburden pressure on the permeability of cores from Project Wagon Wheel is similar to that on cores from Project Gasbuggy, and typical results are shown in Fig. 6. The permeability is decreased to about 30 percent of initial permeability at an overburden pressure of 3,000 psi and to 20 percent at 6,000.

A study of the data in Table 1 indicates that the original porosity of the core and the reduction in permeability caused by overburden pressure are not related. Pore structure (fractures to uniform pores) is probably the governing factor.

Water Saturation Effects

The data in Table 2 show that the permeability decreased with increasing water saturation. The values at 20-, 40-, and 60-percent water saturation were obtained from individual relative-permeability curves for Gasbuggy and Wagon Wheel cores. Relative-permeability curves for three cores from Project Gasbuggy are shown in Fig. 4 with the data points for Core 3978. Data points were omitted for the other cores to avoid confusion. This figure shows that although gas permeability is reduced, the relative gas permeability of Gasbuggy cores is not significantly affected by increased overburden pressure. This conclusion is in agreement with the results of others.[4,5]

Extremely low values of permeability that resulted from water saturation and overburden pressure required that either long flow times or high inlet pressures (high differential across the core) be used. Since a high inlet pressure increases the end effects by changing the distribution of water in the core, long flow times were required. Although end-effect problems were encountered with the short cores (Cores 3978 and 4158), the permeability of these cores was

TABLE 2—EFFECT OF OVERBURDEN PRESSURE AND WATER SATURATION ON GAS PERMEABILITY

Water Saturation (percent):		0	20	40	60
Core Number	Pressure (psi)	Permeability (md)			
Gasbuggy					
3927	100	0.115	0.099	0.041	0.0023
3927	3,000	0.026	0.023	0.009	0.0005
3927	6,000	0.012	0.010	0.003	0.0002
3978	100	0.112	0.080	0.034	0.011
3978	3,000	0.036	0.026	0.011	0.005
3978	6,000	0.013	0.009	0.004	0.0013
4158	100	0.447	0.335	0.156	0.045
4158	3,000	0.075	0.056	0.026	0.0074
4158	6,000	0.027	0.020	0.010	0.0026
Wagon Wheel					
8084	100	0.038	0.030	0.014	0.0042
8084	3,000	0.012	0.0096	0.0043	0.0013
8084	6,000	0.0070	0.0056	0.0025	0.0008
8122	100	0.074	0.054	0.017	0.006
8122	3,000	0.027	0.020	0.008	0.002
8122	6,000	0.020	0.015	0.006	0.002
10156	100	0.100	0.074	0.029	0.003
10156	3,000	0.028	0.020	0.008	0.0008
10156	6,000	0.017	0.013	0.005	0.0005

high enough to yield reasonable results. Permeability measurements for Core 4161 (7.5 cm long, 0.053 md) required more than 2 hours per reading. These extremely long flow times can cause errors.

End effects, long flow times, and changes in permeability due to water saturation tend to decrease the accuracy of permeability measurements, especially at the higher water saturations.

The initial permeability of many of the dry cores used in this research was not reproducible following saturation and drying. The changes probably were caused by solution of material in the pores and by particle movement. These caused both increases and decreases in permeability. The variation, although sometimes large, usually was less than 5 percent; however, we feel that the relative permeability curves are essentially correct. To eliminate the effects of solution and particle movement, the permeability of the dry core following saturation, rather than the permeability initially measured, was used in calculating relative permeability.

A composite of the relative permeability curves for Gasbuggy cores is shown in Fig. 5. These curves are representative of permeabilities encountered in this formation. At a water saturation of 50 percent, the relative permeability of the cores ranges from 15 to 20 percent and is not affected by overburden pressure.

Similar results were obtained on cores from Project Wagon Wheel, as shown in Table 2 and Fig. 6 with data points for Core 8122. These cores were cut to a length of 3.8 cm to alleviate some of the long flow time and end-effect difficulties encountered with Gasbuggy cores. These curves are representative of the permeabilities encountered in the formation. At a water saturation of 50 percent, the relative permeability of these cores ranges from 12 to 21 percent. The data in these figures show, as do the data from Gasbuggy cores, that relative gas permeability is not significantly affected by increased overburden pressure.

Correlation with Nuclear Stimulation Projects

Many of the basin areas of the Rocky Mountain region consist of thick, low-permeability sandstones containing large quantities of natural gas. This type of reservoir has been the object of the AEC's Plowshare Program experiments, Projects Gasbuggy and Rulison, and proposed Projects Wagon Wheel, WASP, and Rio Blanco. Because most wells in these reservoirs have not been commercial, only limited reservoir-analysis and production-test data are available. Reservoir analysis is most difficult because low permeability requires long-term testing. Also, it is difficult to determine permeability and net pay from these tests. Knowledge of the gas permeability is necessary in predicting gas recovery, and because it is not economical to define the characteristics of different strata by well test, it is desirable to be able to relate laboratory-measured permeability to the true in-situ permeability.

Conventional analysis by a commercial laboratory (confirmed in our laboratory) of about 200 Gasbuggy cores gave an average initial gas permeability of 0.16 md on dry cores and an average water saturation of 48 percent. The effective overburden pressure of this

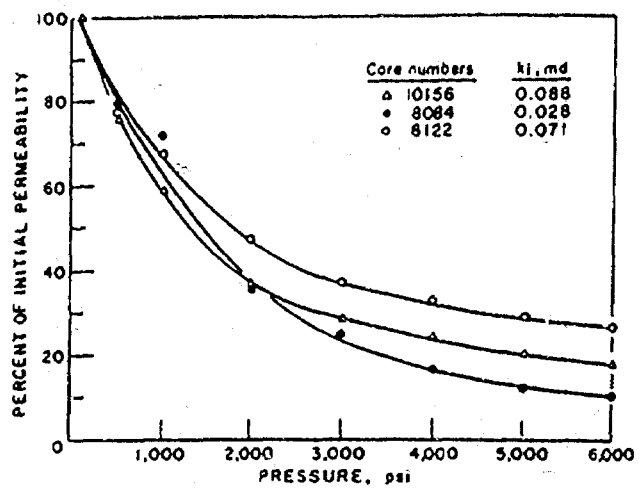


Fig. 4—Effect of overburden pressure on gas permeability of Wagon Wheel cores.

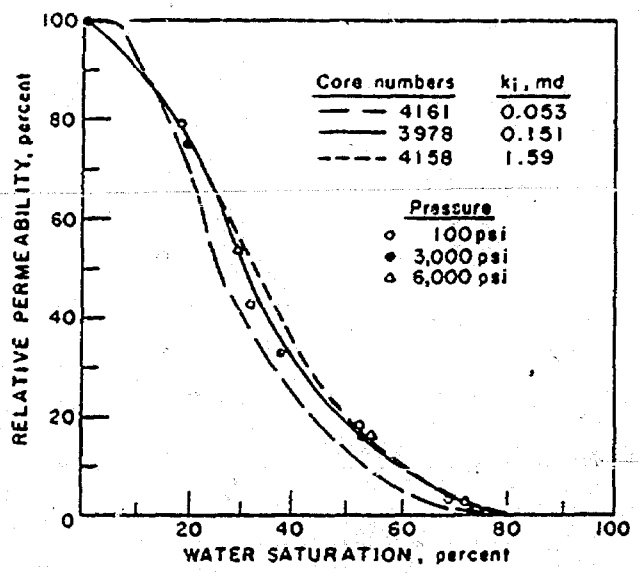


Fig. 5—Relative gas permeability of Gasbuggy cores.

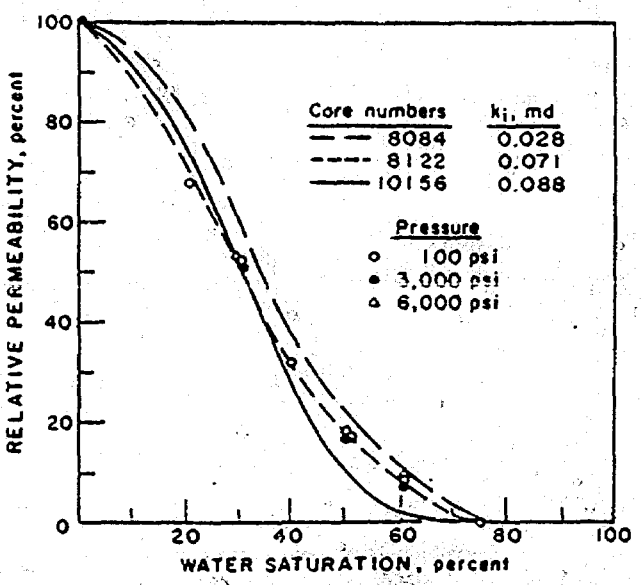


Fig. 6—Relative gas permeability of Wagon Wheel cores.

reservoir is about 3,000 psi. From Fig. 1, the reduction factor resulting from the overburden pressure is 0.25, and the reduction factor for a water saturation of 48 percent (Fig. 5) is 0.20; thus the total reduction is 5 percent of the initial permeability, or 0.008 md. This value compares favorably with permeability determinations of about 0.01 md from both preshot and postshot flow testing at Gasbuggy. The gas reservoir at Project Rulison is similar to that at Gasbuggy, having an average initial dry permeability of 0.11 md and an average water saturation of 45 percent. Simulated in-situ permeability has not yet been measured in the laboratory on Rulison cores; however, using an effective overburden pressure of 5,000 psi and curves of Gasbuggy core data (Figs. 1 and 5), the reduction factor because of overburden pressure would be 0.12 and that for water saturation 0.24. This results in a combined reduction to 3 percent of the initial permeability, or 0.003 md. Postshot production testing at Rulison is not complete, and the only preshot determination of permeability was made from tests of a 32-ft isolated zone that gave an average value of 0.008 md. No cores are available from this zone. Rulison reservoir rock is said to be less compressible than that of Gasbuggy; therefore Gasbuggy pressure-effect data would be expected to indicate a greater reduction for Rulison than actually exists.

The average initial permeability of dry Wagon Wheel cores is 0.068 md, with an average water saturation of 50 percent. An estimated effective overburden pressure of 3,000 psi gives a reduction factor of 0.28 (Fig. 4). Water saturation further reduces permeability by a factor of 0.18 (Fig. 6). Therefore, the total reduction in permeability is to approximately 5 percent of the initial permeability, or 0.0034 md. This value can be used to predict postshot gas recovery from the proposed Wagon Wheel experiment.

Cores are not yet available from Projects Rio Blanco and WASP.

Original manuscript received in Society of Petroleum Engineers office June 16, 1971. Revised manuscript received Dec. 20, 1971. Paper (SPE 3634) was presented at SPE 46th Annual Fall Meeting, held in New Orleans, Oct. 3-6, 1971.

Conclusions

The gas permeability of tight sandstone cores is markedly decreased with increasing overburden pressure. Most of the decrease takes place at pressures to 3,000 psi. At 3,000 psi, the permeability of unfractured samples ranges from 14 to 37 percent of the initial permeability. In fractured samples, permeability may be reduced to as low as 6 percent of initial permeability.

Water saturation also reduces the gas permeability greatly; however, the relative permeability does not change significantly with overburden pressure.

Permeability calculated from laboratory results are in good agreement with in-situ permeabilities determined from production test data. Although not confirmed, predictions for other projects appear to be reasonable.

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JPT

EXHIBIT 8A

Consolidated Oil & Gas, Inc.

WELL COST ESTIMATE

AVERAGE DAKOTA WELL WITH UPPER & LOWER DAKOTA, 2 FRACS

AFE No. _____
C.O.G. WI. _____

TO: Drill ( ) Recomplete ( ) Work Over ( )

State New Mexico County San Juan Field Basin Dakota

Lease Name Average Dakota Well Lease No. _____ Well No. Unnamed No. 1

Location: T13N, R12 & 13W - Average Dakota Well

DETAIL COST ESTIMATE				
INTANGIBLE COSTS	QUANTITY	PRICE	COST OF DRY HOLE	COST OF PRODUCER
Superintendence	15/25	300	4,500	7,500
Labor			1,000	3,500
Hauling				8,000
Drilling				
To Drill	7,000	$16/ft.	112,000	112,000
Day Work - W/DP	2	5,800	11,600	11,600
Day Work - W/out Drill pipe				
Other Completion Unit w/compl. equip.	10	2,500		25,000
Fuel			1,000	3,000
Water			9,000	11,000
Right of Way Damages			1,500	1,500
Drlg. Mud & Chemicals			22,000	24,000
Electric & Radioactivity Logs			16,000	16,000
Coring & Core Analysis				
Acidizing & Fracturing 2 Fracs using Nitrogen				75,000
Drill Stem Tests				
Gun Perforating & CBL 2 Dakota zones				8,000
Cement & Cementing Services) Surf.& 3-stage			4,000	23,000
Shoes, Collars, & Centralizers) Prod. w/DV tools				
Welding				
Road & Location			5,000	6,000
Bits & Coreheads				700
Mud Logging				
Plugging Expense			7,500	
Equipment Rental (Compressors, workstring,etc.)			5,000	16,000
Overhead			1,000	1,500
Contingencies 5%			10,000	17,600
TOTAL INTANGIBLE COSTS			211,100	370,900
PERMANENT EQUIPMENT				
Conductor Pipe "OD				
Surface Casing 8-5/8 "OD 24#	250		2,800	2,800
Prod. Casing4-1/2 " OD 10.5# ST&C	7000			39,900
Tubing 1-1/2 " OD 2.9# EUE	7000			17,500
Casing Head Assembly			1,300	1,300
Tubing Head Assembly)				9,500
Xmas Tree & Manifold Assembly)				
Production Packer				
Cathodic Protection				8,000
Bottom Hole Choke				
Miscellaneous Connections				4,000
Production Unit & Tank Battery				21,500
TOTAL Permanent Equipment			4,100	104,500
TOTAL COST OF COMPLETED WELL			215,200	475,400

Date: _____ Recommended by: _____

APPROVED (Company): _____ Approved by: _____

By: _____ Date: September 23, 1981

EXHIBIT 8-B

CONSOLIDATED OIL & GAS, INC.

	Cain 1-M	Jackson 2-E	Jaquez 2
Superintendent	$ 13,489	$ 4,409	$ 7,302
Labor	2,297	743	4,130
Hauling	7,426	4,826	7,133
Drilling - To Drill	105,530	107,544	90,736
Daywork	6,146	14,857	24,576
Other - Completion Rig	44,570	8,984	20,949
Fuel	3,798	246	10,449
Water	24,968	12,733	11,521
Right of Way Damages	-	-	2,000
Drilling Mud & Chemicals	37,187	32,948	34,962
Electric & Radioactivity Logs	15,840	11,381	12,929
Coring & Core Analysis	-	-	-
Acidizing & Fracturing	70,294	27,751	74,326
Tests (AOF & BHP)	1,190	673	1,298
Gun Perf. & Cs'd Hole Logging	5,975	7,300	8,790
Cement & Cementing Services	27,461	23,168	27,286
Welding	500	-	500
Road & Location	17,833	2,247	4,942
Bits & Coreheads	1,204	-	1,387
Overhead	-	1,096	-
Equipment Rental (Inc. Comp.)	29,094	7,166	50,700
Fishing Expense	43,648	-	-
Cathodic Protection	8,585	8,000	2,738
Total Initial Costs	$467,035	$276,072	$398,654
Surface Casing	$ 2,196	$ 2,337	$ 2,202
Production Casing	53,579	40,966	49,164
Tubing	16,166	17,311	15,951
Casing Head Assembly	1,320	1,320	1,320
Tubing Head Assembly	9,270	9,270	9,270
Xmas Tree & Manifold Assy.			
Production Packer			
Miscellaneous Connections	4,257	2,897	6,910
Separator & Production Tanks	13,614	11,005	12,942
Total Permanent Equipment	$100,402	$ 85,106	$ 97,759
TOTAL COST OF COMPLETED DAKOTA WELL*	$567,437	$361,178	$496,413

*Total Well Cost less Completion & Equipment Costs of Dual Zone (if any).

Note: Estimated Cost of Lower Dakota Completion	$110,402		$ 77,015

CONSOLIDATED OIL & GAS, INC.

	Kline 1-M	Langendorf 1-E	Mitchell 1-E
Superintendent	$ 14,768	$ 6,303	$ 7,851
Labor	9,174	3,584	8,819
Hauling	3,149	6,071	25,408
Drilling - To Drill	101,079	101,228	93,420
Daywork	5,807	7,639	48,985
Other - Completion Rig	41,400	17,877	20,113
Fuel	622	7,457	3,751
Water	6,529	21,236	4,555
Right of Way Damages	4,000	-	-
Drilling Mud & Chemicals	11,342	23,845	91,000
Electric & Radioactivity Logs	21,399	14,305	13,705
Coring & Core Analysis	-	-	-
Acidizing & Fracturing	75,323	83,944	74,037
Tests (AOF & BHP)	715	1,123	1,939
Gun Perf. & Cs'd Hole Logging	6,294	9,360	7,565
Cement & Cementing Services	24,024	25,132	12,687
Welding	-	500	-
Road & Location	9,977	5,419	5,725
Bits & Coreheads	-	1,492	-
Overhead	-	-	1,788
Equipment Rental (Inc. Comp.)	25,181	32,533	58,246
Fishing Expense	-	-	-
Cathodic Protection	4,748	8,146	8,160
Total Initial Costs	$365,531	$377,194	$487,754
Surface Casing	$ 3,141	$ 2,138	$ 2,194
Production Casing	52,026	47,765	41,102
Tubing	14,286	14,660	14,227
Casing Head Assembly	1,325	1,320	371
Tubing Head Assembly	9,250	9,270	9,710
Xmas Tree & Manifold Assy.			
Production Packer			
Miscellaneous Connections	5,642	10,957	3,849
Separator & Production Tanks	12,380	12,410	13,016
Total Permanent Equipment	$ 98,050	$ 98,520	$ 84,469
TOTAL COST OF COMPLETED DAKOTA WELL*	$463,581	$475,714	$572,223

*Total Well Cost less Completion & Equipment Costs of Dual Zone (if any).

Note: Estimated Cost of Lower Dakota Completion	$ 70,440	$ 76,390	$ 54,052

CONSOLIDATED OIL & GAS, INC.

	Neuman 1-E	Payne 1-E	Phillips 1-E
Superintendent	$ 4,624	$ 3,997	$ 8,974
Labor	359	3,022	4,967
Hauling	4,467	5,368	6,641
Drilling - To Drill	111,552	108,753	92,201
Daywork	15,316	12,988	6,627
Other - Completion Rig	13,154	18,036	19,205
Fuel	-	4,532	1,836
Water	15,851	18,592	6,000
Right of Way Damages	-	-	1,000
Drilling Mud & Chemicals	30,076	19,214	12,457
Electric & Radioactivity Logs	14,739	12,899	12,782
Coring & Core Analysis	-	-	-
Acidizing & Fracturing	34,738	75,960	67,794
Tests (AOF & BHP)	366	456	-
Gun Perf. & Cs'd Hole Logging	7,040	7,994	13,450
Cement & Cementing Services	16,072	27,079	25,099
Welding	-	500	304
Road & Location	2,472	3,146	8,178
Bits & Coreheads	-	1,428	-
Overhead	1,194	-	-
Equipment Rental (Inc. Comp.)	6,554	30,359	8,559
Fishing Expense	-	-	-
Cathodic Protection	8,008	8,519	8,425
Total Initial Costs	$286,582	$362,842	$304,499
Surface Casing	$ 2,073	$ 2,403	$ 2,543
Production Casing	42,779	53,260	53,179
Tubing	17,073	15,039	13,426
Casing Head Assembly	1,419	1,320	1,284
Tubing Head Assembly	6,375	9,270	10,590
Xmas Tree & Manifold Assy.			
Production Packer			
Miscellaneous Connections	2,848	2,823	3,846
Separator & Production Tanks	11,697	12,812	12,052
Total Permanent Equipment	$ 84,264	$ 96,927	$ 96,920
TOTAL COST OF COMPLETED DAKOTA WELL*	$370,846	$459,769	$401,419

*Total Well Cost less Completion & Equipment Costs of Dual Zone (if any)

Note: Estimated Cost of Lower Dakota Completion	-	$ 73,716	$ 32,391

CONSOLIDATED OIL & GAS, INC.

	Robinson Bros. 1-M	So. Union 1-M	So. Union 2-E
Superintendent	$ 11,258	$ 16,493	$ 7,129
Labor	1,760	3,272	3,406
Hauling	10,995	9,958	2,769
Drilling - To Drill	119,913	91,611	109,918
Daywork		30,638	11,541
Other - Completion Rig	16,062	68,746	25,227
Fuel	2,525	3,577	1,247
Water	3,000	19,732	9,935
Right of Way Damages	1,643	-	-
Drilling Mud & Chemicals	36,064	40,695	32,649
Electric & Radioactivity Logs	15,838	19,787	13,337
Coring & Core Analysis	-	14,176	-
Acidizing & Fracturing	54,731	71,878	56,294
Tests (AOF & BHP)	490	-	420
Gun Perf. & Cs'd Hole Logging	9,131	13,150	12,162
Cement & Cementing Services	29,273	27,273	18,445
Welding	-	337	-
Road & Location	23,095	4,806	3,575
Bits & Coreheads	1,568	2,827	-
Overhead	-	2,705	-
Equipment Rental (Inc. Comp.)	11,624	29,810	33,801
Fishing Expense	-	-	-
Cathodic Protection	6,001	8,300	4,003
Total Initial Costs	$354,971	$479,771	$345,858
Surface Casing	2,053	2,119	2,409
Production Casing	50,946	55,118	41,939
Tubing	14,983	14,795	18,725
Casing Head Assembly	1,320	1,320	1,419
Tubing Head Assembly	9,270	9,720	9,280
Xmas Tree & Manifold Assy.			
Production Packer			
Miscellaneous Connections	3,007	3,307	3,373
Separator & Production Tanks	12,640	13,211	14,776
Total Permanent Equipment	$ 94,219	$ 99,590	$ 91,921
TOTAL COST OF COMPLETED DAKOTA WELL*	$449,190	$579,361	$437,779

* Total Well Cost less Completion & Equipment Costs of Dual Zone (if any).

Note: Estimated Cost of Lower Dakota Completion	$ 43,433	$ 94,851	$ 58,494

CONSOLIDATED OIL & GAS, INC.

	Starr 1-M	Templeton 1-E	Wilmerding 1-M
Superintendent	$ 8,263	$ 11,290	$ 9,004
Labor	2,057	2,761	8,167
Hauling	4,118	10,337	5,929
Drilling - To Drill	102,014	85,888	93,441
Daywork	7,040	22,346	5,494
Other - Completion Rig	31,188	41,222	21,132
Fuel	2,053	2,357	725
Water	6,149	8,499	7,948
Right of Way Damages	-	4,000	2,000
Drilling Mud & Chemicals	26,879	29,000	18,834
Electric & Radioactivity Logs	16,950	21,443	18,294
Coring & Core Analysis	-	-	-
Acidizing & Fracturing	87,228	59,510	73,799
Tests (AOF & BHP)	-	506	1,058
Gun Perf. & Cs'd Hole Logging	8,742	6,881	5,259
Cement & Cementing Services	25,158	28,185	24,823
Welding	-	-	-
Road & Location	6,539	19,210	1,703
Bits & Coreheads	-	-	-
Overhead	-	3,190	-
Equipment Rental (Inc. Comp.)	28,212	42,160	15,368
Fishing Expense	-	-	-
Cathodic Protection	8,062	8,944	7,957
Total Initial Costs	$370,652	$407,729	$320,935
Surface Casing	$ 2,119	$ 2,186	$ 2,115
Production Casing	45,900	50,404	49,224
Tubing	14,500	15,675	14,237
Casing Head Assembly	1,320	1,320	1,320
Tubing Head Assembly	9,270	9,270	9,270
Xmas Tree & Manifold Assy.			
Production Packer			
Miscellaneous Connections	4,057	6,873	5,082
Separator & Production Tanks	12,577	14,025	12,380
Total Permanent Equipment	$ 89,743	$ 99,753	$ 93,628
TOTAL COST OF COMPLETED DAKOTA WELL*	$460,395	$507,482	$414,563
Note: Estimated Cost of Lower Dakota Completion	$ 58,682	$ 62,854	$ 42,443

*Total Well Cost less Completion & Equipment Costs of Dual Zone (if any).

CONSOLIDATED OIL & GAS, INC.

	Total	Average
Superintendent	$ 135,154	$ 9,010
Labor	58,518	3,901
Hauling	114,595	7,640
Drilling - To Drill	1,514,828	100,989
Daywork	220,000	14,666
Other - Completion Rig	407,865	27,191
Fuel	45,175	3,012
Water	177,248	11,817
Right of Way Damages	14,643	976
Drilling Mud & Chemicals	477,152	31,810
Electric & Radioactivity Logs	235,628	15,709
Coring & Core Analysis	14,176	945
Acidizing & Fracturing	987,607	65,840
Tests (AOF & BHP)	10,234	682
Gun Perf. & Cs'd Hole Logging	129,093	8,606
Cement & Cementing Services	361,165	24,078
Welding	2,641	176
Road & Location	118,867	7,924
Bits & Coreheads	9,906	660
Overhead	9,973	665
Equipment Rental (Inc. Comp.)	409,367	27,291
Fishing Expense	43,648	2,910
Cathodic Protection	108,596	7,240
Total Initial Costs	$5,606,079	$373,738
Surface Casing	$ 34,228	$ 2,282
Production Casing	727,351	48,490
Tubing	231,054	15,404
Casing Head Assembly	19,018	1,268
Tubing Head Assembly	138,355	9,224
Xmas Tree & Manifold Assy.		
Production Packer		
Miscellaneous Connections	69,728	4,649
Separator & Production Tanks	191,537	12,769
Total Permanent Equipment	$1,411,271	$ 94,085
TOTAL COST OF COMPLETED DAKOTA WELL*	$7,017,350	$467,823

* Total Well Cost less Completion & Equipment Costs of Dual Zone (if any).

Note: Estimated Cost of Lower Dakota Completion	$ 855,163	$ 65,782

Protection of Fresh Water

State and federal regulations currently provide for the protection of any fresh water aquifers that are being used or are expected to be used in the foreseeable future for domestic or agricultural water supplies. Three potential fresh water bearing formations in the area of interest are the San Jose, Nacimiento and Ojo Alamo. These three formations occur from the surface of the ground to a depth of approximately 1,000 feet in T31N, R13W and the western half of T31N, R12W.

The NMOCD by Rule 106 and the federal government regulations for protection of fresh water in oil and gas related activities both require the casing and cementing program to be designed to seal off fresh water bearing formations from oil and gas bearing formations. They fulfill this requirement by having the oil and gas operator cement the production casing with sufficient cement to bring it above the Dakota several hundred feet, to usually cement across the Mesaverde zone when it is productive, and then to circulate cement to surface from several hundred feet below the base of the Ojo Alamo formation. Additionally, surface casing is set and cemented to surface when drilling begins which protects the top several hundred feet.

The above casing and cementing programs provide adequate protection to the fresh water sands even though large stimulation treatments are required in the tight Dakota producing formation which is about 5,900 feet below the deepest fresh water zone.

EXHIBIT 10

CONSOLIDATED OIL & GAS, INC.

ASSUMPTIONS USED IN MAKING ECONOMIC CALCULATIONS
BASIN-DAKOTA FIELD
SAN JUAN COUNTY, NEW MEXICO

Drilling and Completion Costs (including tank battery)	$475,400
Operating Costs $/Mo.	150
Depth	7,000'
Consolidated Working Interest	100%
Royalty Interest Typical to Consolidated Holdings	24.5%
Liquid Yield (BBLS./MMCF)	3.85
Fully Adjusted Gas Price as of October 1, 1981 ($/MCF)	$3.14
Maximum Gas Price ($/MCF)	$10.42
Maximum Oil Price ($/BBL.)	$50.00
Rate of Price Escalation	7%
Severance Tax	8%
Deregulation Tax Data, Base Oil Price	$14.11
Windfall Profit Tax Rate	30%

Initial Post-stimulation Stabilized Production Rate (MCFD)	Forecast 20-Year Recovery - MMCF
89	180
150	270
189	350
232 (Expected Case)	435
400	555

EXHIBIT 11

ROYALTY INTEREST CONSIDERATION

In this particular area of the San Juan Basin, Consolidated's interests are typically burdened with a 12% ORRI in addition to the base 12 1/2% royalty, resulting in a 75.5% net revenue interest to a 100% working interest.

In the industry, there are two primary means of obtaining rights to drill and produce an oil and gas property. One is to take a lease from the mineral owner by the payment of a lease bonus, normally in the form of dollars per acre. This will normally result in the mineral owner retaining a 12 1/2% royalty. However, in this case, the economics of development should include those lease bonuses as they represent a real cost of oil and gas drilling.

The second means of obtaining oil and gas leases is through farm-ins from the party(ies) who have taken the base lease. This almost always entails payment of no lease bonus and assignment of an overriding royalty interest, which may or may not be convertible into a larger working interest.

This second route represents the means of Consolidated obtaining its leases in this area. Leases were taken from parties who had obtained the leases from the mineral owners.

TYPICAL CONSOLIDATED LEASES IN AREA

Well	Net Revenue Interest to 100% Working Interest - %	Total Royalty Burden - %
Cain 1-M	75.0	25.0
Jackson 2-E	75.0	25.0
Jaquez 2	86.5	13.5
Kline 1-M	77.1	22.9
Langendorf 1-E	75.0	25.0
Mitchell 1-E	75.0	25.0
Neuman 1-E	75.0	25.0
Payne 1-E	75.0	25.0
Phillips 1-E	75.0	25.0
Robinson Bros. 1-M	82.6	17.4
Southern Union 1-M	77.5	22.5
Southern Union 2-E	75.0	25.0
Starr 1-M	75.0	25.0
Templeton 1-E	76.6	23.4
Wilmerding 1-M	76.5	23.5

Thus, in our case, our economics are burdened with a typical total royalty burden of 24.5%, but are not burdened with lease bonuses.

It is important to note that the net present value of the 12% overriding royalty, which is not burdened by costs, approximates $50,000 per location. This is about $300 per acre, which is certainly in line with proven property lease bonuses being paid.

EXHIBIT 12

BEFORE TAX ECONOMICS

EXHIBIT 12

SECTION 103 PRICE
180 MMCF GROSS
20-YEAR RECOVERY

TYPICAL WELL
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO

DATE: 09/23/81.
TIME: 17.30.29.
FILE: TYPICAL
PROJ: 1

CONSOLIDATED OIL & GAS, INC.
ECONOMICS OF DEVELOPMENT

R E S E R V E S A N D E C O N O M I C S

AS OF DATE : 1/ 1/1981

END MO-YR	GROSS OIL PRODUCTION -MB-	GROSS GAS PRODUCTION -MMF-	OIL TO NET INTEREST -MB-	GAS TO NET INTEREST -MMF-	REVENUE TO INTEREST -M$-	NET INVESTMENT -M$-	NET OPER EXPENSES -M$-	NET INCOME BEFORE FIT -M$-	CUMULATIVE NET INCOME -M$-	30.000 PCT CUM. DISC NET INCOME -M$-
12-81	0.	0.	0.	0.	0.	475.400	1.863	-477.263	-477.263	-476.914
12-82	.157	40.758	.119	30.772	92.183	0.	1.993	90.190	-387.073	-415.892
12-83	.109	28.518	.082	21.531	68.987	0.	2.133	66.854	-320.219	-381.097
12-84	.081	21.072	.061	15.910	54.559	0.	2.283	52.276	-267.943	-360.168
12-85	.063	16.206	.048	12.235	44.920	0.	2.442	42.478	-225.465	-347.086
12-86	.049	12.850	.037	9.702	38.090	0.	2.613	35.477	-189.988	-338.682
12-87	.040	10.439	.030	7.881	33.119	0.	2.795	30.324	-159.664	-333.156
12-88	.034	8.649	.025	6.530	29.401	0.	2.992	26.409	-133.255	-329.454
12-89	.028	7.283	.022	5.499	26.465	0.	3.201	23.264	-109.991	-326.946
12-90	.024	6.216	.018	4.693	24.156	0.	3.425	20.731	-89.260	-325.226
12-91	.020	5.368	.015	4.053	22.254	0.	3.600	18.654	-70.606	-324.036
12-92	.018	4.683	.013	3.536	20.750	0.	3.600	17.150	-53.456	-323.194
12-93	.016	4.120	.012	3.110	19.501	0.	3.600	15.901	-37.555	-322.594
12-94	.014	3.654	.011	2.759	18.465	0.	3.600	14.865	-22.690	-322.162
12-95	.013	3.262	.010	2.463	17.624	0.	3.600	14.024	-8.666	-321.849
12-96	.011	2.930	.008	2.212	16.887	0.	3.600	13.287	4.621	-321.621
12-97	.010	2.647	.008	1.999	16.302	0.	3.600	12.702	17.323	-321.453
12-98	.009	2.402	.006	1.813	15.804	0.	3.600	12.204	29.527	-321.329
12-99	.009	2.191	.007	1.654	15.433	0.	3.600	11.833	41.360	-321.236
12- 0	.008	2.005	.006	1.514	14.789	0.	3.600	11.189	52.549	-321.169
5 TOT	.713	185.253[1]	.538	139.866	589.689	475.400	61.740	52.549	52.549	-321.169
AFTER	.056	14.747	.043	11.134	108.680	0.	40.932	67.748	120.297	-321.023
TOTAL	.769	200.000	.581	151.000	698.369	475.400	102.672	120.297	120.297	-321.023

CUM.	0.	0.	NET OIL REVENUE	20.470	5 PCT	-68.867	40 PCT	-352.615
			NET GAS REVENUE	677.899	10 PCT	-168.442	50 PCT	-374.061
ULT.	.769	200.000	NET PROD REVENUE	0.	15 PCT	-228.890	60 PCT	-389.576
					20 PCT	-269.508	80 PCT	-410.463
CUM NET INC/INV(1)	.25		CUM NET PW/INV(1)	-.68	30 PCT	-321.023	100 PCT	-423.791
GROSS WELLS	1		LIFE (YEARS)	31.37				
MONTHS 1ST YEAR	12		RATE OF RETURN,PCT	3.18				
INITIAL W.I., PCT	100.0000		INITIAL N.I., PCT	75.5000				

1 - 20-year total does not precisely match heading due to computer scheduling technique.

TYPICAL WELL
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO

CONSOLIDATED OIL & GAS, INC.
ECONOMICS OF DEVELOPMENT

2X SECTION 103 PRICE
180 MMCF GROSS
20-YEAR RECOVERY

RESERVES AND ECONOMICS

AS OF DATE : 2/ 1/1981

DATE: 09/23/81.
TIME: 17.30.32.
FILE: TYPICAL
PROJ: 2

END MO-YR	GROSS OIL PRODUCTION -----MB-----	GROSS GAS PRODUCTION -----MMF---	OIL TO NET INTEREST -----MB----	GAS TO NET INTEREST ----MMF---	REVENUE TO INTEREST ----M$----	NET INVESTMENT ----M$----	NET OPER EXPENSES ----M$----	NET INCOME BEFORE FIT ----M$----	CUMULATIVE NET INCOME ----M$----	30,000 PCT CUM. DISC NET INCOME ----M$----
12-81	0.	0.	0.	0.	0.	475.400	1.863	-477.263	-477.263	-476.914
12-82	.149	38.640	.112	29.173	171.810	0.	1.993	169.817	-307.446	-362.016
12-83	.104	27.168	.079	20.512	129.231	0.	2.133	127.098	-180.348	-295.867
12-84	.078	20.145	.059	15.210	102.558	0.	2.283	100.275	-80.073	-255.722
12-85	.059	15.533	.044	11.727	84.591	0.	2.442	82.149	2.076	-230.423
12-86	.048	12.343	.037	9.319	71.957	0.	2.613	69.344	71.420	-213.995
12-87	.038	10.043	.028	7.582	62.621	0.	2.795	59.826	131.246	-203.093
12-88	.032	8.332	.025	6.291	55.618	0.	2.992	52.626	183.872	-195.717
12-89	.027	7.024	.020	5.303	50.164	0.	3.201	46.963	230.835	-190.653
12-90	.024	6.001	.018	4.531	44.256	0.	3.425	40.831	271.666	-187.266
12-91	.020	5.187	.015	3.916	38.237	0.	3.600	34.637	306.303	-185.056
12-92	.017	4.527	.013	3.418	33.356	0.	3.600	29.756	336.059	-183.596
12-93	.015	3.986	.011	3.009	29.370	0.	3.600	25.770	361.829	-182.623
12-94	.014	3.537	.011	2.671	26.086	0.	3.600	22.486	384.315	-181.970
12-95	.012	3.160	.009	2.386	23.288	0.	3.600	19.688	404.003	-181.530
12-96	.011	2.839	.008	2.143	20.930	0.	3.600	17.330	421.333	-181.232
12-97	.010	2.565	.008	1.937	18.912	0.	3.600	15.312	436.645	-181.030
12-98	.009	2.330	.007	1.759	17.177	0.	3.600	13.577	450.222	-180.892
12-99	.008	2.124	.006	1.603	15.651	0.	3.600	12.051	462.273	-180.798
12- 0	.007	1.946	.005	1.470	14.327	0.	3.600	10.727	473.000	-180.733
5 TOT	.682	177.430 [1]	.515	133.960	1010.140	475.400	61.740	473.000	473.000	-180.733
AFTER	.087	22.570	.066	17.040	166.378	0.	89.033	77.345	550.345	-180.592
TOTAL	.769	200.000	.581	151.000	1176.518	475.400	150.773	550.345	550.345	-180.592
CUM.	0.	0.								
ULT.	.769	200.000								

CUM NET INC/INV(1)	1.16	CUM NET FW/INV(1)	-.38	5 PCT	258.352	40 PCT	-240.579
GROSS WELLS	1	LIFE (YEARS)	44.73	10 PCT	94.204	50 PCT	-281.556
MONTHS 1ST YEAR	12	RATE OF RETURN,PCT	14.47	15 PCT	-11.106	60 PCT	-311.255
INITIAL W.I., PCT	100.0000	INITIAL N.I., PCT	75.5000	20 PCT	-84.587	80 PCT	-351.240
				30 PCT	-180.592	100 PCT	-376.733

NET OIL REVENUE	20.762	
NET GAS REVENUE	1155.756	
NET PROD REVENUE	0.	

1 - 20-year total does not precisely match heading due to computer scheduling technique.

TYPICAL WELL
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO

CONSOLIDATED OIL & GAS, INC.
ECONOMICS OF DEVELOPMENT

SECTION 103 PRICE
270 MMCF GROSS
20-YEAR RECOVERY

DATE: 09/23/81.
TIME: 17.30.35.
FILE: TYPICAL
PROJ: 3

R E S E R V E S A N D E C O N O M I C S

AS OF DATE : 1/ 1/1981

END MO-YR	GROSS OIL PRODUCTION ----MB----	GROSS GAS PRODUCTION ----MMF---	OIL TO NET INTEREST ----MB----	GAS TO NET INTEREST ----MMF---	REVENUE TO INTEREST ----M$----	NET INVESTMENT ----M$----	NET OPER EXPENSES ----M$----	NET INCOME BEFORE FIT ----M$----	CUMULATIVE NET INCOME ----M$----	30.000 PCT CUM. DISC NET INCOME ----M$----
12-81	0.	0.	0.	0.	0.	475.400	1.863	-477.263	-477.263	-476.914
12-82	.224	58.192	.169	43.935	131.610	0.	1.993	129.617	-347.646	-389.216
12-83	.158	41.084	.119	31.018	99.406	0.	2.133	97.273	-250.373	-338.589
12-84	.117	30.554	.089	23.069	79.100	0.	2.283	76.817	-173.556	-307.835
12-85	.091	23.613	.068	17.827	65.431	0.	2.442	62.989	-110.567	-288.437
12-86	.072	18.795	.055	14.191	55.721	0.	2.613	53.108	-57.459	-275.856
12-87	.059	15.316	.044	11.563	48.601	0.	2.795	45.806	-11.653	-267.509
12-88	.049	12.720	.037	9.604	43.209	0.	2.992	40.217	28.564	-261.871
12-89	.042	10.733	.032	8.103	39.026	0.	3.201	35.825	64.389	-258.008
12-90	.035	9.179	.026	6.930	35.654	0.	3.425	32.229	96.618	-255.335
12-91	.030	7.938	.023	5.994	32.924	0.	3.600	29.324	125.942	-253.464
12-92	.027	6.933	.021	5.234	30.732	0.	3.600	27.132	153.074	-252.132
12-93	.024	6.105	.018	4.612	28.925	0.	3.600	25.325	178.399	-251.176
12-94	.020	5.422	.015	4.094	27.372	0.	3.600	23.772	202.171	-250.486
12-95	.019	4.845	.014	3.658	26.166	0.	3.600	22.566	224.737	-249.982
12-96	.017	4.356	.013	3.289	25.129	0.	3.600	21.529	246.266	-249.612
12-97	.015	3.937	.011	2.972	24.251	0.	3.600	20.651	266.917	-249.339
12-98	.014	3.576	.011	2.700	23.549	0.	3.600	19.949	286.866	-249.136
12-99	.012	3.263	.009	2.464	22.934	0.	3.600	19.334	306.200	-248.985
12- 0	.012	2.988	.009	2.256	22.043	0.	3.600	18.443	324.643	-248.874
S TOT	1.037	269.553[1]	.783	203.513	861.783	475.400	61.740	324.643	324.643	-248.874
AFTER	.117	30.447	.088	22.987	224.431	0.	69.214	155.217	479.860	-248.617
TOTAL	1.154	300.000	.871	226.500	1086.214	475.400	130.954	479.860	479.860	-248.617
CUM.	0.	0.								
ULT.	1.154	300.000								

NET OIL REVENUE	31.082	5 PCT	146.960	40 PCT	-295.589
NET GAS REVENUE	1055.132	10 PCT	-14.819	50 PCT	-327.278
NET PROD REVENUE	0.	15 PCT	-109.112	60 PCT	-350.113
		20 PCT	-171.144	80 PCT	-380.745
		30 PCT	-248.617	100 PCT	-400.232
CUM NET INC/INV(1)	1.01	CUM NET PW/INV(1)	-.52		
GROSS WELLS	1	LIFE (YEARS)	39.23		
MONTHS 1ST YEAR	12	RATE OF RETURN,PCT	9.54		
INITIAL W.I., PCT	100.0000	INITIAL N.I., PCT	75.5000		

1 - 20-year total does not precisely match heading due to computer scheduling technique.

TYPICAL WELL
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO

CONSOLIDATED OIL & GAS, INC.
ECONOMICS OF DEVELOPMENT

2X SECTION 103 PRICE
270 MMCF GROSS
20-YEAR RECOVERY

DATE: 09/23/81.
TIME: 17.30.38.
FILE: TYPICAL
PROJ: 4

R E S E R V E S A N D E C O N O M I C S

AS OF DATE : 1/ 1/1981

END MO-YR	GROSS OIL PRODUCTION -MB-	GROSS GAS PRODUCTION -MMF-	OIL TO NET INTEREST -MB-	GAS TO NET INTEREST -MMF-	REVENUE TO INTEREST -M$-	NET INVESTMENT -M$-	NET OPER EXPENSES -M$-	NET INCOME BEFORE FIT -M$-	CUMULATIVE NET INCOME -M$-	30.000 PCT CUM. DISC NET INCOME -M$-
12-81	0.	0.	0.	0.	0.	475.400	1.863	-477.263	-477.263	-476.914
12-82	.222	57.678	.168	43.547	256.452	0.	1.993	254.459	-222.804	-304.748
12-83	.155	40.339	.117	30.456	191.895	0.	2.133	189.762	-33.042	-205.984
12-84	.115	29.796	.086	22.496	151.683	0.	2.283	149.400	116.358	-146.172
12-85	.088	22.909	.067	17.296	124.784	0.	2.442	122.342	238.700	-108.495
12-86	.070	18.162	.053	13.712	105.865	0.	2.613	103.252	341.952	-84.035
12-87	.056	14.753	.042	11.139	91.994	0.	2.795	89.199	431.151	-67.780
12-88	.047	12.220	.036	9.226	81.572	0.	2.992	78.580	509.731	-56.765
12-89	.040	10.289	.030	7.768	73.497	0.	3.201	70.296	580.027	-49.186
12-90	.034	8.782	.025	6.631	64.728	0.	3.425	61.303	641.330	-44.101
12-91	.029	7.583	.022	5.725	55.890	0.	3.600	52.290	693.620	-40.765
12-92	.025	6.614	.019	4.993	48.739	0.	3.600	45.139	738.759	-38.549
12-93	.023	5.819	.018	4.394	42.915	0.	3.600	39.315	778.074	-37.065
12-94	.019	5.161	.014	3.896	38.014	0.	3.600	34.414	812.488	-36.066
12-95	.018	4.607	.013	3.479	33.969	0.	3.600	30.369	842.857	-35.387
12-96	.016	4.138	.013	3.124	30.506	0.	3.600	26.906	869.763	-34.925
12-97	.014	3.737	.010	2.821	27.533	0.	3.600	23.933	893.696	-34.609
12-98	.014	3.393	.011	2.562	25.044	0.	3.600	21.444	915.140	-34.391
12-99	.011	3.092	.008	2.334	22.761	0.	3.600	19.161	934.301	-34.241
12- 0	.011	2.832	.008	2.139	20.880	0.	3.600	17.280	951.581	-34.137
S TOT	1.007	261.904[1]	.760	197.738	1488.721	475.400	61.740	951.581	951.581	-34.137
AFTER	.147	38.096	.111	28.762	280.834	0.	124.582	156.252	1107.833	-33.900
TOTAL	1.154	300.000	.871	226.500	1769.555	475.400	186.322	1107.833	1107.833	-33.900
CUM.	0.	0.								
ULT.	1.154	300.000								

NET OIL REVENUE	31.254	5 PCT	633.782	40 PCT	-123.663
NET GAS REVENUE	1738.301	10 PCT	380.437	50 PCT	-184.942
NET PROD REVENUE	0.	15 PCT	220.726	60 PCT	-229.350
		20 PCT	110.076	80 PCT	-289.155
		30 PCT	-33.900	100 PCT	-327.305

CUM NET INC/INV(1)	2.33	CUM NET FW/INV(1)	-.07
GROSS WELLS	1	LIFE (YEARS)	54.61
MONTHS 1ST YEAR	12	RATE OF RETURN,PCT	27.29
INITIAL W.I., PCT	100.0000	INITIAL N.I., PCT	75.5000

1 - 20-year total does not precisely match heading due to computer scheduling technique.

SECTION 103 PRICE
350 MMCF GROSS
20-YEAR RECOVERY

TYPICAL WELL
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO

DATE: 09/23/81.
TIME: 17.30.41.
FILE: TYPICAL
PROJ: 5

CONSOLIDATED OIL & GAS, INC.
ECONOMICS OF DEVELOPMENT

R E S E R V E S A N D E C O N O M I C S

AS OF DATE : 1/ 1/1981

END MO-YR	GROSS OIL PRODUCTION ----MB----	GROSS GAS PRODUCTION ----MMF----	OIL TO NET INTEREST ----MB----	GAS TO NET INTEREST ----MMF----	REVENUE TO INTEREST ----M$----	NET INVESTMENT ----M$----	NET OPER EXPENSES ----M$----	NET INCOME BEFORE FIT ----M$----	CUMULATIVE NET INCOME ----M$----	30.000 PCT CUM. DISC NET INCOME ----M$----
12-81	0.	0.	0.	0.	0.	475.400	1.863	-477.263	-477.263	-476.914
12-82	.297	77.258	.224	58.330	174.581	0.	1.993	172.588	-304.675	-360.141
12-83	.209	54.306	.158	41.001	131.290	0.	2.133	129.157	-175.518	-292.921
12-84	.155	40.258	.117	30.395	104.156	0.	2.283	101.873	-73.645	-252.135
12-85	.119	31.038	.090	23.433	85.921	0.	2.442	83.479	9.834	-226.427
12-86	.095	24.660	.072	18.619	73.066	0.	2.613	70.453	80.287	-209.737
12-87	.077	20.064	.058	15.148	63.609	0.	2.795	60.814	141.101	-198.655
12-88	.064	16.643	.048	12.565	56.498	0.	2.992	53.506	194.607	-191.155
12-89	.054	14.029	.041	10.592	50.966	0.	3.201	47.765	242.372	-186.004
12-90	.046	11.986	.035	9.050	46.565	0.	3.425	43.140	285.512	-182.426
12-91	.040	10.359	.030	7.821	42.995	0.	3.600	39.395	324.907	-179.913
12-92	.035	9.042	.026	6.826	40.073	0.	3.600	36.473	361.380	-178.123
12-93	.031	7.961	.024	6.011	37.684	0.	3.600	34.084	395.464	-176.836
12-94	.027	7.063	.020	5.333	35.689	0.	3.600	32.089	427.553	-175.904
12-95	.024	6.309	.018	4.763	34.048	0.	3.600	30.448	458.001	-175.224
12-96	.022	5.669	.017	4.280	32.699	0.	3.600	29.099	487.100	-174.724
12-97	.019	5.123	.014	3.868	31.538	0.	3.600	27.938	515.038	-174.354
12-98	.018	4.651	.014	3.511	30.621	0.	3.600	27.021	542.059	-174.080
12-99	.017	4.242	.012	3.203	29.864	0.	3.600	26.264	568.323	-173.874
12- 0	.015	3.884	.012	2.932	28.632	0.	3.600	25.032	593.355	-173.724
8 TOT	1.364	354.545[1]	1.030	267.681	1130.495	475.400	61.740	593.355	593.355	-173.724
AFTER	.174	45.455	.131	34.319	335.035	0.	90.636	244.399	837.754	-173.368
TOTAL	1.538	400.000	1.161	302.000	1465.530	475.400	152.376	837.754	837.754	-173.368

CUM.	0.	0.	NET OIL REVENUE	40.964	5 PCT	361.477	40 PCT	-235.890		
			NET GAS REVENUE	1424.566	10 PCT	139.915	50 PCT	-278.045		
ULT.	1.538	400.000	NET PROD REVENUE	0.	15 PCT	12.931	60 PCT	-308.418		
					20 PCT	-70.066	80 PCT	-349.169		
CUM NET INC/INV(1)	1.76		CUM NET PW/INV(1)	-.36	30 PCT	-173.368	100 PCT	-375.103		
GROSS WELLS	1		LIFE (YEARS)	45.18						
MONTHS 1ST YEAR	12		RATE OF RETURN,PCT	15.78						
INITIAL W.I., PCT	100.0000		INITIAL N.I., PCT	75.5000						

1 - 20-year total does not precisely match heading due to computer scheduling technique.

2X SECTION 103 PRICE
350 MMCF GROSS
20-YEAR RECOVERY

TYPICAL WELL
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO

DATE: 09/23/81.
TIME: 17.30.45.
FILE: TYPICAL
PROJ: 6

CONSOLIDATED OIL & GAS, INC.
ECONOMICS OF DEVELOPMENT

R E S E R V E S A N D E C O N O M I C S

AS OF DATE : 1/ 1/1981

END YR	GROSS OIL PRODUCTION MB	GROSS GAS PRODUCTION MMF	OIL TO NET INTEREST MB	GAS TO NET INTEREST MMF	REVENUE TO INTEREST M$	NET INVESTMENT M$	NET OPER EXPENSES M$	NET INCOME BEFORE FIT M$	CUMULATIVE NET INCOME M$	30.000 PCT CUM. DISC NET INCOME M$
12-81	0.	0.	0.	0.	0.	475.400	1.863	-477.263	-477.263	-476.914
12-82	.283	73.538	.214	55.521	326.833	0.	1.993	324.840	-152.423	-257.128
12-83	.200	52.083	.151	39.323	247.654	0.	2.133	245.521	93.098	-129.345
12-84	.149	38.822	.112	29.310	197.531	0.	2.283	195.248	288.346	-51.177
12-85	.116	30.053	.088	22.690	163.643	0.	2.442	161.201	449.547	-1.532
12-86	.092	23.955	.069	18.087	139.567	0.	2.613	136.954	586.501	30.911
12-87	.075	19.540	.057	14.752	121.819	0.	2.795	119.024	705.525	52.601
12-88	.063	16.245	.047	12.265	108.423	0.	2.992	105.431	810.956	67.379
12-89	.053	13.716	.040	10.356	97.952	0.	3.201	94.751	905.707	77.596
12-90	.045	11.737	.034	8.861	86.490	0.	3.425	83.065	988.772	84.486
12-91	.039	10.157	.030	7.669	74.868	0.	3.600	71.268	1060.040	89.033
12-92	.034	8.875	.025	6.700	65.416	0.	3.600	61.816	1121.856	92.067
12-93	.030	7.823	.023	5.907	57.663	0.	3.600	54.063	1175.919	94.108
12-94	.027	6.946	.021	5.244	51.210	0.	3.600	47.610	1223.529	95.491
12-95	.024	6.209	.018	4.688	45.773	0.	3.600	42.173	1265.702	96.433
12-96	.021	5.584	.016	4.216	41.145	0.	3.600	37.545	1303.247	97.078
12-97	.020	5.048	.015	3.811	37.231	0.	3.600	33.631	1336.878	97.522
12-98	.017	4.587	.012	3.463	33.789	0.	3.600	30.189	1367.067	97.829
12-99	.016	4.185	.013	3.160	30.846	0.	3.600	27.246	1394.313	98.042
12- 0	.015	3.834	.011	2.894	28.270	0.	3.600	24.670	1418.983	98.191
8 TOT	1.319	342.937[1]	.996	258.917	1956.123	475.400	61.740	1418.983	1418.983	98.191
AFTER	.219	57.063	.165	43.083	420.613	0.	160.323	260.290	1679.273	98.537
TOTAL	1.538	400.000	1.161	302.000	2376.736	475.400	222.063	1679.273	1679.273	98.537

CUM.	0.	0.	NET OIL REVENUE	41.457	5 PCT	997.174	40 PCT	-19.365
			NET GAS REVENUE	2335.279	10 PCT	650.840	50 PCT	-99.512
ULT.	1.538	400.000	NET PROD REVENUE	0.	15 PCT	436.263	60 PCT	-157.417
					20 PCT	288.890	80 PCT	-235.160
CUM NET INC/INV(1)		3.53	CUM NET PW/INV(1)	.21	30 PCT	98.537	100 PCT	-284.608
GROSS WELLS		1	LIFE (YEARS)	64.53				
MONTHS 1ST YEAR		12	RATE OF RETURN,PCT	38.16				
INITIAL W.I., PCT		100.0000	INITIAL N.I., PCT	75.5000				

1 - 20-year total does not precisely match heading due to computer scheduling technique.

TYPICAL WELL
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO

CONSOLIDATED OIL & GAS, INC.
ECONOMICS OF DEVELOPMENT

SECTION 103 PRICE
435 MMCF GROSS
20-YEAR RECOVERY

DATE: 09/23/81.
TIME: 17.30.49.
FILE: TYPICAL
PROJ: 7

R E S E R V E S A N D E C O N O M I C S

AS OF DATE : 1/ 1/1981

END MO-YR	GROSS OIL PRODUCTION ----MB----	GROSS GAS PRODUCTION ----MMF---	OIL TO NET INTEREST ----MB----	GAS TO NET INTEREST ----MMF---	REVENUE TO INTEREST ----M$-----	NET INVESTMENT ----M$----	NET OPER EXPENSES ----M$----	NET INCOME BEFORE FIT ----M$----	CUMULATIVE NET INCOME ----M$----	30.000 PCT CUM. DISC NET INCOME ----M$----
12-81	0.	0.	0.	0.	0.	475.400	1.863	-477.263	-477.263	-476.914
12-82	.370	96.303	.279	72.709	217.790	0.	1.993	215.797	-261.466	-330.906
12-83	.260	67.487	.197	50.952	163.300	0.	2.133	161.167	-100.299	-247.026
12-84	.192	49.922	.145	37.692	129.260	0.	2.283	126.977	26.678	-196.190
12-85	.148	38.424	.111	29.010	106.470	0.	2.442	104.028	130.706	-164.153
12-86	.117	30.489	.089	23.019	90.395	0.	2.613	87.782	218.488	-143.358
12-87	.095	24.782	.071	18.710	78.625	0.	2.795	75.830	294.318	-129.540
12-88	.079	20.540	.060	15.508	69.770	0.	2.992	66.778	361.096	-120.179
12-89	.067	17.301	.051	13.062	62.884	0.	3.201	59.683	420.779	-113.744
12-90	.057	14.772	.043	11.153	57.403	0.	3.425	53.978	474.757	-109.267
12-91	.049	12.760	.037	9.634	52.950	0.	3.600	49.350	524.107	-106.118
12-92	.043	11.134	.032	8.406	49.342	0.	3.600	45.742	569.849	-103.873
12-93	.037	9.798	.028	7.398	46.339	0.	3.600	42.739	612.588	-102.259
12-94	.034	8.691	.026	6.561	43.942	0.	3.600	40.342	652.930	-101.088
12-95	.030	7.760	.022	5.859	41.895	0.	3.600	38.295	691.225	-100.232
12-96	.026	6.972	.020	5.264	40.178	0.	3.600	36.578	727.803	-99.604
12-97	.025	6.297	.019	4.754	38.823	0.	3.600	35.223	763.026	-99.138
12-98	.022	5.717	.017	4.316	37.635	0.	3.600	34.035	797.061	-98.792
12-99	.020	5.213	.015	3.936	36.668	0.	3.600	33.068	830.129	-98.533
12- 0	.018	4.772	.013	3.603	35.164	0.	3.600	31.564	861.693	-98.344
S TOT	1.689	439.134[1]	1.275	331.546	1398.833	475.400	61.740	861.693	861.693	-98.344
AFTER	.234	60.866	.177	45.954	448.659	0.	109.498	339.161	1200.854	-97.891
TOTAL	1.923	500.000	1.452	377.500	1847.492	475.400	171.238	1200.854	1200.854	-97.891

CUM.	0.	0.	NET OIL REVENUE	52.021	5 PCT	575.870	40 PCT -175.980
			NET GAS REVENUE	1795.471	10 PCT	294.632	50 PCT -228.623
ULT.	1.923	500.000	NET PROD REVENUE	0.	15 PCT	135.124	60 PCT -266.554
					20 PCT	31.225	80 PCT -317.455
CUM NET INC/INV(1)		2.53	CUM NET PW/INV(1)	-.21	30 PCT	-97.891	100 PCT -349.859
GROSS WELLS		1	LIFE (YEARS)	50.42			
MONTHS 1ST YEAR		12	RATE OF RETURN,PCT	22.12			
INITIAL W.I., PCT		100.0000	INITIAL N.I., PCT	75.5000			

1 - 20-year total does not precisely match heading due to computer scheduling technique.

TYPICAL WELL
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO

2X SECTION 103 PRICE
435 MMCF GROSS
20-YEAR RECOVERY

DATE: 09/23/81.
TIME: 17.30.52.
FILE: TYPICAL
PROJ: 8

CONSOLIDATED OIL & GAS, INC.
ECONOMICS OF DEVELOPMENT

R E S E R V E S A N D E C O N O M I C S

AS OF DATE : 1/ 1/1981

END YR	GROSS OIL PRODUCTION MB	GROSS GAS PRODUCTION MMF	OIL TO NET INTEREST MB	GAS TO NET INTEREST MMF	REVENUE TO INTEREST M$	NET INVESTMENT M$	NET OPER EXPENSES M$	NET INCOME BEFORE FIT M$	CUMULATIVE NET INCOME M$	30.000 PCT CUM. DISC NET INCOME M$
12-81	0.	0.	0.	0.	0.	475.400	1.863	-477.263	-477.263	-476.914
12-82	.353	91.757	.267	69.277	409.246	0.	1.993	407.253	-70.010	-201.369
12-83	.219	64.844	.188	48.957	309.444	0.	2.133	307.311	237.301	-41.425
12-84	.186	48.257	.140	36.434	246.428	0.	2.283	244.145	481.446	56.319
12-85	.143	37.313	.108	28.171	203.855	0.	2.442	201.413	682.859	118.347
12-86	.115	29.712	.087	22.433	173.727	0.	2.613	171.114	853.973	158.883
12-87	.093	24.220	.070	18.286	151.503	0.	2.795	148.708	1002.681	185.982
12-88	.077	20.121	.058	15.191	134.609	0.	2.992	131.617	1134.298	204.431
12-89	.066	16.982	.050	12.822	121.439	0.	3.201	118.238	1252.536	217.180
12-90	.055	14.524	.041	10.965	107.031	0.	3.425	103.606	1356.142	225.774
12-91	.049	12.564	.037	9.486	92.637	0.	3.600	89.037	1445.179	231.455
12-92	.042	10.975	.032	8.286	80.892	0.	3.600	77.292	1522.471	235.248
12-93	.037	9.671	.028	7.302	71.281	0.	3.600	67.681	1590.152	237.803
12-94	.033	8.584	.025	6.481	63.275	0.	3.600	59.675	1649.827	239.536
12-95	.030	7.673	.023	5.793	56.577	0.	3.600	52.977	1702.804	240.720
12-96	.026	6.898	.019	5.208	50.829	0.	3.600	47.229	1750.033	241.531
12-97	.024	6.236	.018	4.708	45.968	0.	3.600	42.368	1792.401	242.091
12-98	.022	5.663	.017	4.275	41.751	0.	3.600	38.151	1830.552	242.479
12-99	.020	5.168	.015	3.902	38.100	0.	3.600	34.500	1865.052	242.749
12- 0	.018	4.733	.014	3.574	34.881	0.	3.600	31.281	1896.333	242.937
8 TOT	1.638	425.895[1]	1.237	321.551	2433.473	475.400	61.740	1896.333	1896.333	242.937
AFTER	.285	74.105	.215	55.949	546.250	0.	187.387	358.863	2255.196	243.380
TOTAL	1.923	500.000	1.452	377.500	2979.723	475.400	249.127	2255.196	2255.196	243.380

CUM.	0.	0.	NET OIL REVENUE	57.663	5 PCT	1371.533	40 PCT	95.869
			NET GAS REVENUE	2922.060	10 PCT	935.092	50 PCT	-4.419
ULT.	1.923	500.000	NET PROD REVENUE	0.	15 PCT	666.069	60 PCT	-76.891
					20 PCT	481.561	80 PCT	-174.221
CUM NET INC/INV(1)		4.74	CUM NET PW/INV(1)	.51	30 PCT	243.380	100 PCT	-236.149
GROSS WELLS		1	LIFE (YEARS)	72.05				
MONTHS 1ST YEAR		12	RATE OF RETURN,PCT	49.52				
INITIAL W.I., PCT		100.0000	INITIAL N.I., PCT	75.5000				

1 - 20-year total does not precisely match heading due to computer scheduling technique.

TYPICAL WELL
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO

CONSOLIDATED OIL & GAS, INC.
ECONOMICS OF DEVELOPMENT

SECTION 103 PRICE
555 MMCF GROSS
20-YEAR RECOVERY

R E S E R V E S A N D E C O N O M I C S

AS OF DATE : 1/ 1/1981

DATE: 09/23/81.
TIME: 17.30.56.
FILE: TYPICAL
PROJ: 9

END MO-YR	GROSS OIL PRODUCTION ----MB----	GROSS GAS PRODUCTION ----MMF---	OIL TO NET INTEREST ----MB----	GAS TO NET INTEREST ----MMF---	REVENUE TO INTEREST ----M$----	NET INVESTMENT ----M$----	NET OPER EXPENSES ----M$----	NET INCOME BEFORE FIT ----M$----	CUMULATIVE NET INCOME ----M$----	30.000 PCT CUM. DISC NET INCOME ----M$----
12-81	0.	0.	0.	0.	0.	475.400	1.863	-477.263	-477.263	-476.914
12-82	.460	119.706	.347	90.378	270.718	0.	1.993	268.725	-208.538	-295.095
12-83	.327	84.952	.247	64.139	205.554	0.	2.133	203.421	-5.117	-189.223
12-84	.244	63.416	.184	47.879	164.201	0.	2.283	161.918	156.801	-124.399
12-85	.189	49.148	.143	37.107	136.179	0.	2.442	133.737	290.538	-83.213
12-86	.151	39.208	.114	29.602	116.260	0.	2.613	113.647	404.185	-56.290
12-87	.123	32.006	.093	24.164	101.552	0.	2.795	98.757	502.942	-38.294
12-88	.102	26.622	.077	20.100	90.417	0.	2.992	87.425	590.367	-26.039
12-89	.087	22.492	.066	16.981	81.749	0.	3.201	78.548	668.915	-17.570
12-90	.074	19.252	.056	14.536	74.802	0.	3.425	71.377	740.292	-11.649
12-91	.064	16.666	.048	12.582	69.159	0.	3.600	65.559	805.851	-7.467
12-92	.056	14.569	.042	11.000	64.555	0.	3.600	60.955	866.806	-4.475
12-93	.049	12.843	.037	9.696	60.758	0.	3.600	57.158	923.964	-2.317
12-94	.044	11.408	.033	8.613	57.658	0.	3.600	54.058	978.022	-.747
12-95	.040	10.199	.031	7.701	55.083	0.	3.600	51.483	1029.505	.403
12-96	.035	9.174	.026	6.926	52.894	0.	3.600	49.294	1078.799	1.250
12-97	.032	8.296	.024	6.264	51.115	0.	3.600	47.515	1126.314	1.878
12-98	.029	7.538	.022	5.691	49.622	0.	3.600	46.022	1172.336	2.346
12-99	.026	6.879	.020	5.193	48.374	0.	3.600	44.774	1217.110	2.696
12- 0	.024	6.303	.018	4.759	46.453	0.	3.600	42.853	1259.963	2.954
8 TOT	2.156	560.677 [1]	1.628	423.311	1797.103	475.400	61.740	1259.963	1259.963	2.954
AFTER	.344	89.323	.259	67.439	658.443	0.	139.802	518.641	1778.604	3.575
TOTAL	2.500	650.000	1.887	490.750	2455.546	475.400	201.542	1778.604	1778.604	3.575

CUM.	0.	0.	NET OIL REVENUE	68.204		5 PCT	892.206	40 PCT	-96.579
			NET GAS REVENUE	2387.342		10 PCT	515.278	50 PCT	-163.786
ULT.	2.500	650.000	NET PROD REVENUE	0.		15 PCT	305.641	60 PCT	-212.055
						20 PCT	170.362	80 PCT	-276.622
CUM NET INC/INV(1)		3.74	CUM NET PW/INV(1)	.01		30 PCT	3.575	100 PCT	-317.602
GROSS WELLS		1	LIFE (YEARS)	58.83					
MONTHS 1ST YEAR		12	RATE OF RETURN,PCT	30.32					
INITIAL W.I., PCT		100.0000	INITIAL N.I., PCT	75.5000					

1 - 20-year total does not precisely match heading due to computer scheduling technique.

2X SECTION 103 PRICE
555 MMCF GROSS
20-YEAR RECOVERY

TYPICAL WELL
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO

DATE: 09/23/81.
TIME: 17.30.59.
FILE: TYPICAL
PROJ: 10

CONSOLIDATED OIL & GAS, INC.
ECONOMICS OF DEVELOPMENT

R E S E R V E S A N D E C O N O M I C S

AS OF DATE : 1/ 1/1981

END MO-YR	GROSS OIL PRODUCTION ----MB----	GROSS GAS PRODUCTION ----MMF---	OIL TO NET INTEREST ----MB----	GAS TO NET INTEREST ----MMF---	REVENUE TO INTEREST ----M$----	NET INVESTMENT ----M$----	NET OPER EXPENSES ----M$----	NET INCOME BEFORE FIT ----M$----	CUMULATIVE NET INCOME ----M$----	30.000 PCT CUM. DISC NET INCOME ----M$----
12-81	0.	0.	0.	0.	0.	475.400	1.863	-477.263	-477.263	-476.914
12-82	.458	119.067	.346	89.896	529.379	0.	1.993	527.406	50.143	-120.073
12-83	.323	83.950	.244	63.382	399.364	0.	2.133	397.231	447.374	86.670
12-84	.240	62.373	.181	47.091	317.507	0.	2.283	315.224	762.598	212.871
12-85	.185	48.167	.140	36.367	262.362	0.	2.442	259.920	1022.518	292.917
12-86	.147	38.317	.111	28.929	223.328	0.	2.613	220.715	1243.233	345.203
12-87	.120	31.210	.090	23.563	194.657	0.	2.795	191.862	1435.095	380.165
12-88	.100	25.912	.076	19.564	172.981	0.	2.992	169.989	1605.084	403.994
12-89	.084	21.856	.063	16.501	156.091	0.	3.201	152.890	1757.974	420.479
12-90	.072	18.685	.054	14.107	137.706	0.	3.425	134.281	1892.255	431.617
12-91	.062	16.157	.047	12.199	119.094	0.	3.600	115.494	2007.749	438.986
12-92	.054	14.109	.041	10.652	103.992	0.	3.600	100.392	2108.141	443.913
12-93	.048	12.428	.036	9.383	91.618	0.	3.600	88.018	2196.159	447.236
12-94	.043	11.029	.033	8.327	81.318	0.	3.600	77.718	2273.877	449.493
12-95	.038	9.856	.028	7.442	72.655	0.	3.600	69.055	2342.932	451.035
12-96	.034	8.858	.026	6.687	65.293	0.	3.600	61.693	2404.625	452.096
12-97	.030	8.007	.023	6.046	58.994	0.	3.600	55.394	2460.019	452.828
12-98	.028	7.271	.021	5.489	53.598	0.	3.600	49.998	2510.017	453.336
12-99	.026	6.632	.019	5.007	48.904	0.	3.600	45.304	2555.321	453.691
12- 0	.023	6.075	.018	4.587	44.769	0.	3.600	41.168	2596.489	453.938
S TOT	2.115	549.959 [1]	1.597	415.219	3133.629	475.400	61.740	2596.489	2596.489	453.938
AFTER	.385	100.041	.290	75.531	737.441	0.	223.311	514.130	3110.619	454.526
TOTAL	2.500	650.000	1.887	490.750	3871.070	475.400	285.051	3110.619	3110.619	454.526

CUM.	0.	0.	NET OIL REVENUE	68.442	5 PCT	1919.652	40 PCT	263.782
			NET GAS REVENUE	3802.628	10 PCT	1350.602	50 PCT	134.117
ULT.	2.500	650.000	NET PROD REVENUE	0.	15 PCT	1001.633	60 PCT	40.412
					20 PCT	762.682	80 PCT	-85.451
CUM NET INC/INV(1)		6.54	CUM NET PW/INV(1)	.96	30 PCT	454.526	100 PCT	-165.556
GROSS WELLS		1	LIFE (YEARS)	82.03				
MONTHS 1ST YEAR		12	RATE OF RETURN,PCT	65.71				
INITIAL W.I., PCT		100.0000	INITIAL N.I., PCT	75.5000				

1 - 20-year total does not precisely match heading due to computer scheduling technique.

EXHIBIT 13

AFTER TAX ECONOMICS

EXHIBIT 13

SECTION 103 PRICE
180 MMCF GROSS
20-YEAR RECOVERY

TYPICAL WELL
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO

CONSOLIDATED OIL & GAS, INC.
ECONOMICS OF DEVELOPMENT

DATE: 09/23/81.
TIME: 17.31.54.
FILE: TYPICAL
PROJ: 1

A F T E R T A X E C O N O M I C S

AS OF DATE: 1/ 1/1981

-END- YR	NET OIL MB	NET GAS MMF	REVENUE TO INT. M$	OPER. EXPENSE M$	NET INCOME M$	CAPITAL INVEST. M$	DEPR. M$	DEPL. M$	INCOME TAX M$	CASH FLOW M$	CUM. NET PW M$
12-81	0.	0.	0.	1.863	-1.863	475.400	52.965	0.	-73.290	-403.972	-412.448
12-82	.119	30.772	92.183	1.593	90.190	0.	45.401	0.	20.603	69.587	-365.366
12-83	.082	21.531	68.987	2.133	66.854	0.	38.918	0.	12.851	54.003	-337.259
12-84	.061	15.910	54.559	2.283	52.276	0.	33.360	0.	8.701	43.575	-319.814
12-85	.048	12.235	44.920	2.442	42.478	0.	28.597	0.	6.385	36.093	-308.698
12-86	.037	9.702	38.090	2.613	35.477	0.	24.513	0.	5.043	30.434	-301.489
12-87	.030	7.881	33.119	2.795	30.324	0.	21.013	0.	4.283	26.041	-296.744
12-88	.025	6.530	29.401	2.992	26.409	0.	18.012	0.	3.863	22.546	-293.583
12-89	.022	5.499	26.465	3.201	23.264	0.	15.440	0.	3.599	19.665	-291.463
12-90	.018	4.693	24.156	3.425	20.731	0.	13.235	0.	3.448	17.283	-290.029
12-91	.015	4.053	22.254	3.600	18.654	0.	11.345	0.	3.362	15.292	-289.054
12-92	.013	3.536	20.750	3.600	17.150	0.	9.725	0.	3.416	13.734	-288.380
12-93	.012	3.110	19.501	3.600	15.901	0.	8.336	0.	3.480	12.421	-287.911
12-94	.011	2.759	18.465	3.600	14.865	0.	7.146	0.	3.551	11.314	-287.582
12-95	.010	2.463	17.624	3.600	14.024	0.	6.125	0.	3.633	10.391	-287.350
12-96	.008	2.212	16.887	3.600	13.287	0.	5.251	0.	3.697	9.590	-287.185
12-97	.008	1.999	16.302	3.600	12.702	0.	4.501	0.	3.773	8.929	-287.067
12-98	.006	1.813	15.804	3.600	12.204	0.	3.858	0.	3.839	8.365	-286.982
12-99	.007	1.654	15.433	3.600	11.833	0.	3.307	0.	3.922	7.911	-286.920
12- 0	.006	1.514	14.789	3.600	11.189	0.	2.835	0.	3.843	7.346	-286.876
S TOT	.538	139.866	589.689	61.740	527.949	475.400	353.882	0.	32.002	20.548	-286.876
AFTER	.043	11.134	108.680	40.932	67.748	0.	17.018	0.	23.336	44.412	-286.782
TOTAL	.581	151.000	698.369	102.672	595.697	475.400	370.900	0.	55.338	64.960	-286.782

RECAP

	GROSS	W.I.	NET
INTEREST FRACTION	1.000000	1.000000	.755000
OIL RESERVES,MB	.769	.769	.581
GAS RESERVES,MMCF	200.000	200.000	151.000
PRODUCTS	0.	0.	0.
REVENUE,M$	1008.627	1008.627	698.369
OPERATING EXPENSE,M$	102.672	102.672	102.672
TANGIBLES,M$	370.900	370.900	370.900
INTANGIBLES,M$	104.500	104.500	104.500
INITIAL OIL PRICE ($/B)		34.00	
INITIAL GAS PRICE ($/M)		3.1452	

LIFE (YEARS)	31.37
GROSS OIL WELLS	0.
GROSS GAS WELLS	1.000
RATE OF RETURN,PCT	2.25
DISCOUNT RATE,PCT	30.0
PAYOUT YEARS	17.37
W.I. BEFORE PAYOUT,PCT	100.00
W.I. AFTER PAYOUT,PCT	100.00

DIS PCT	PW OF NET M$
5	-79.359
10	-158.457
15	-208.077
20	-242.269
30	-286.783
40	-314.844
50	-334.330
70	-359.835
100	-381.946

TYPICAL WELL
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO

CONSOLIDATED OIL & GAS, INC.
ECONOMICS OF DEVELOPMENT

2X SECTION 103 PRICE
180 MMCF GROSS
20-YEAR RECOVERY

DATE: 09/23/81.
TIME: 17.31.57.
FILE: TYPICAL
PROJ: 2

A F T E R T A X E C O N O M I C S

AS OF DATE: 1/ 1/1981

-END- MO-YR	NET OIL MB-----	NET GAS MMF-----	REVENUE TO INT. M$-----	OPER. EXPENSE M$-----	NET INCOME M$-----	CAPITAL INVEST. M$-----	DEPR. M$---	DEPL. M$----	INCOME TAX M$----	CASH FLOW M$-----	CUM. NET PW M$------
12-81	0.	0.	0.	1.863	-1.863	475.400	52.965	0.	-73.290	-403.972	-412.448
12-82	.112	29.173	171.810	1.993	169.817	0.	45.401	0.	57.231	112.586	-336.273
12-83	.079	20.512	129.231	2.133	127.098	0.	38.918	0.	40.563	86.535	-291.235
12-84	.059	15.210	102.558	2.283	100.275	0.	33.360	0.	30.781	69.494	-263.413
12-85	.044	11.727	84.591	2.442	82.149	0.	28.597	0.	24.634	57.515	-245.700
12-86	.037	9.319	71.957	2.613	69.344	0.	24.513	0.	20.622	48.722	-234.158
12-87	.028	7.582	62.621	2.795	59.826	0.	21.013	0.	17.854	41.972	-226.510
12-88	.025	6.291	55.618	2.992	52.626	0.	18.012	0.	15.922	36.704	-221.365
12-89	.020	5.303	50.164	3.201	46.963	0.	15.440	0.	14.501	32.462	-217.865
12-90	.018	4.531	44.256	3.425	40.831	0.	13.235	0.	12.694	28.137	-215.531
12-91	.015	3.916	38.237	3.600	34.637	0.	11.345	0.	10.714	23.923	-214.004
12-92	.013	3.418	33.356	3.600	29.756	0.	9.725	0.	9.214	20.542	-212.996
12-93	.011	3.009	29.370	3.600	25.770	0.	8.336	0.	8.020	17.750	-212.326
12-94	.011	2.671	26.086	3.600	22.486	0.	7.146	0.	7.056	15.430	-211.878
12-95	.009	2.386	23.288	3.600	19.688	0.	6.125	0.	6.239	13.449	-211.578
12-96	.008	2.143	20.930	3.600	17.330	0.	5.251	0.	5.556	11.774	-211.375
12-97	.008	1.937	18.912	3.600	15.312	0.	4.501	0.	4.973	10.339	-211.239
12-98	.007	1.759	17.177	3.600	13.577	0.	3.858	0.	4.471	9.106	-211.146
12-99	.006	1.603	15.651	3.600	12.051	0.	3.307	0.	4.022	8.029	-211.083
12- 0	.005	1.470	14.327	3.600	10.727	0.	2.835	0.	3.630	7.097	-211.041
9 TOT	.515	133.960	1010.140	61.740	948.400	475.400	353.882	0.	225.407	247.592	-211.041
AFTER	.066	17.040	166.378	89.033	77.345	0.	17.018	0.	27.751	49.594	-210.949
TOTAL	.581	151.000	1176.518	150.773	1025.745	475.400	370.900	0.	253.158	297.186	-210.949

RECAP

	GROSS	W.I.	NET
INTEREST FRACTION	1.000000	1.000000	.755000
OIL RESERVES,MB	.769	.769	.581
GAS RESERVES,MMCF	200.000	200.000	151.000
PRODUCTS	0.	0.	0.
REVENUE,M$	1696.859	1696.859	1176.518
OPERATING EXPENSE,M$	150.773	150.773	150.773
TANGIBLES,M$	370.900	370.900	370.900
INTANGIBLES,M$	104.500	104.500	104.500

INITIAL OIL PRICE ($/B)	34.00
INITIAL GAS PRICE ($/M)	5.2903

LIFE (YEARS)	44.73
GROSS OIL WELLS	0.
GROSS GAS WELLS	1.000
RATE OF RETURN,PCT	9.27
DISCOUNT RATE,PCT	30.0
PAYOUT YEARS	6.69
W.I. BEFORE PAYOUT,PCT	100.00
W.I. AFTER PAYOUT,PCT	100.00

DIS PCT	PW OF NET M$
5	97.269
10	-16.656
15	-90.483
20	-142.414
30	-210.950
40	-254.345
50	-284.378
70	-323.334
100	-356.535

TYPICAL WELL
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO

CONSOLIDATED OIL & GAS, INC.
ECONOMICS OF DEVELOPMENT

SECTION 103 PRICE
270 MMCF GROSS
20-YEAR RECOVERY

DATE: 09/23/81.
TIME: 17.32.00.
FILE: TYPICAL
PROJ: 3

A F T E R T A X E C O N O M I C S

AS OF DATE: 1/ 1/1981

-END- MO-YR	NET OIL MB	NET GAS MMF	REVENUE TO INT. M$	OPER. EXPENSE M$	NET INCOME M$	CAPITAL INVEST. M$	DEPR. M$	DEPL. M$	INCOME TAX M$	CASH FLOW M$	CUM. NET PW M$
12-81	0.	0.	0.	1.863	-1.863	475.400	52.965	0.	-73.290	-403.972	-412.448
12-82	.169	43.935	131.610	1.993	129.617	0.	45.401	0.	38.739	90.878	-350.960
12-83	.119	31.018	99.406	2.133	97.273	0.	38.918	0.	26.843	70.430	-314.305
12-84	.089	23.069	79.100	2.283	76.817	0.	33.360	0.	19.990	56.827	-291.554
12-85	.068	17.827	65.431	2.442	62.989	0.	28.597	0.	15.821	47.168	-277.028
12-86	.055	14.191	55.721	2.613	53.108	0.	24.513	0.	13.154	39.954	-267.563
12-87	.044	11.563	48.601	2.795	45.806	0.	21.013	0.	11.405	34.401	-261.294
12-88	.037	9.604	43.209	2.992	40.217	0.	18.012	0.	10.214	30.003	-257.088
12-89	.032	8.103	39.026	3.201	35.825	0.	15.440	0.	9.377	26.448	-254.236
12-90	.026	6.930	35.654	3.425	32.229	0.	13.235	0.	8.737	23.492	-252.288
12-91	.023	5.994	32.924	3.600	29.324	0.	11.345	0.	8.270	21.054	-250.945
12-92	.021	5.234	30.732	3.600	27.132	0.	9.725	0.	8.007	19.125	-250.006
12-93	.018	4.612	28.925	3.600	25.325	0.	8.336	0.	7.815	17.510	-249.345
12-94	.015	4.094	27.372	3.600	23.772	0.	7.146	0.	7.648	16.124	-248.877
12-95	.014	3.658	26.166	3.600	22.566	0.	6.125	0.	7.563	15.003	-248.542
12-96	.013	3.289	25.129	3.600	21.529	0.	5.251	0.	7.488	14.041	-248.300
12-97	.011	2.972	24.251	3.600	20.651	0.	4.501	0.	7.429	13.222	-248.126
12-98	.011	2.700	23.549	3.600	19.949	0.	3.858	0.	7.402	12.547	-247.998
12-99	.009	2.464	22.934	3.600	19.334	0.	3.307	0.	7.372	11.962	-247.904
12- 0	.009	2.256	22.043	3.600	18.443	0.	2.835	0.	7.180	11.263	-247.837
S TOT	.783	203.513	861.783	61.740	800.043	475.400	353.882	0.	157.164	167.479	-247.837
AFTER	.088	22.987	224.431	69.214	155.217	0.	17.018	0.	63.572	91.645	-247.683
TOTAL	.871	226.500	1086.214	130.954	955.260	475.400	370.900	0.	220.736	259.124	-247.683

RECAP

	GROSS	W.I.	NET
INTEREST FRACTION	1.000000	1.000000	.755000
OIL RESERVES,MB	1.154	1.154	.871
GAS RESERVES,MMCF	300.000	300.000	226.500
PRODUCTS	0.	0.	0.
REVENUE,M$	1568.430	1568.430	1086.214
OPERATING EXPENSE,M$	130.954	130.954	130.954
TANGIBLES,M$	370.900	370.900	370.900
INTANGIBLES,M$	104.500	104.500	104.500

INITIAL OIL PRICE ($/B)	34.00
INITIAL GAS PRICE ($/M)	3.1452

LIFE (YEARS)	39.23
GROSS OIL WELLS	0.
GROSS GAS WELLS	1.000
RATE OF RETURN,PCT	6.65
DISCOUNT RATE,PCT	30.0
PAYOUT YEARS	9.33
W.I. BEFORE PAYOUT,PCT	100.00
W.I. AFTER PAYOUT,PCT	100.00

DIS PCT	PW OF NET M$
5	37.143
10	-75.519
15	-143.403
20	-189.154
30	-247.684
40	-284.050
50	-309.067
70	-341.487
100	-369.224

TYPICAL WELL
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO

CONSOLIDATED OIL & GAS, INC.
ECONOMICS OF DEVELOPMENT

2X SECTION 103 PRICE
270 MMCF GROSS
20-YEAR RECOVERY

DATE: 09/23/81.
TIME: 17.32.04.
FILE: TYPICAL
PROJ: 4

A F T E R T A X E C O N O M I C S

AS OF DATE: 1/ 1/1981

-END- YR	NET OIL MB	NET GAS MMF	REVENUE TO INT. M$	OPER. EXPENSE M$	NET INCOME M$	CAPITAL INVEST. M$	DEPR. M$	DEPL. M$	INCOME TAX M$	CASH FLOW M$	CUM. NET PW M$
12-81	0.	0.	0.	1.863	-1.863	475.400	52.965	0.	-73.290	-403.972	-412.448
12-82	.168	43.547	256.452	1.993	254.459	0.	45.401	0.	96.167	158.292	-305.348
12-83	.117	30.456	191.895	2.133	189.762	0.	38.918	0.	69.388	120.374	-242.698
12-84	.086	22.496	151.683	2.283	149.400	0.	33.360	0.	53.378	96.022	-204.256
12-85	.067	17.296	124.784	2.442	122.342	0.	28.597	0.	43.123	79.219	-179.859
12-86	.053	13.712	105.865	2.613	103.252	0.	24.513	0.	36.220	67.032	-163.979
12-87	.042	11.139	91.994	2.795	89.199	0.	21.013	0.	31.366	57.833	-153.441
12-88	.036	9.226	81.572	2.992	78.580	0.	18.012	0.	27.861	50.719	-146.331
12-89	.030	7.768	73.497	3.201	70.296	0.	15.440	0.	25.234	45.062	-141.472
12-90	.025	6.631	64.728	3.425	61.303	0.	13.235	0.	22.111	39.192	-138.222
12-91	.022	5.725	55.890	3.600	52.290	0.	11.345	0.	18.835	33.455	-136.087
12-92	.019	4.993	48.739	3.600	45.139	0.	9.725	0.	16.290	28.849	-134.671
12-93	.018	4.394	42.915	3.600	39.315	0.	8.336	0.	14.250	25.065	-133.725
12-94	.014	3.896	38.014	3.600	34.414	0.	7.146	0.	12.543	21.871	-133.090
12-95	.013	3.479	33.969	3.600	30.369	0.	6.125	0.	11.152	19.217	-132.660
12-96	.013	3.124	30.506	3.600	26.906	0.	5.251	0.	9.961	16.945	-132.369
12-97	.010	2.821	27.533	3.600	23.933	0.	4.501	0.	8.939	14.994	-132.171
12-98	.011	2.562	25.044	3.600	21.444	0.	3.858	0.	8.089	13.355	-132.035
12-99	.008	2.334	22.761	3.600	19.161	0.	3.307	0.	7.293	11.868	-131.942
12- 0	.008	2.139	20.880	3.600	17.280	0.	2.835	0.	6.645	10.635	-131.878
S TOT	.760	197.738	1488.721	61.740	1426.981	475.400	353.882	0.	445.555	506.026	-131.878
AFTER	.111	28.762	280.834	124.582	156.252	0.	17.018	0.	64.049	92.204	-131.735
TOTAL	.871	226.500	1769.555	186.322	1583.233	475.400	370.900	0.	509.604	598.230	-131.735

RECAP

	GROSS	W.I.	NET
INTEREST FRACTION	1.000000	1.000000	.755000
OIL RESERVES,MB	1.154	1.154	.871
GAS RESERVES,MMCF	300.000	300.000	226.500
PRODUCTS	0.	0.	0.
REVENUE,M$	2552.111	2552.111	1769.555
OPERATING EXPENSE,M$	186.322	186.322	186.322
TANGIBLES,M$	370.900	370.900	370.900
INTANGIBLES,M$	104.500	104.500	104.500

INITIAL OIL PRICE ($/B)	34.00
INITIAL GAS PRICE ($/M)	6.2903

LIFE (YEARS)	54.61
GROSS OIL WELLS	0.
GROSS GAS WELLS	1.000
RATE OF RETURN,PCT	17.41
DISCOUNT RATE,PCT	30.0
PAYOUT YEARS	4.37
W.I. BEFORE PAYOUT,PCT	100.00
W.I. AFTER PAYOUT,PCT	100.00

DIS PCT	PW OF NET M$
5	299.962
10	137.897
15	34.703
20	-37.297
30	-131.736
40	-191.210
50	-232.206
70	-285.113
100	-329.844

TYPICAL WELL
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO

CONSOLIDATED OIL & GAS, INC.
ECONOMICS OF DEVELOPMENT

SECTION 103 PRICE
350 MMCF GROSS
20-YEAR RECOVERY

DATE: 09/23/81.
TIME: 17.32.07.
FILE: TYPICAL
PROJ: 5 -

A F T E R T A X E C O N O M I C S

AS OF DATE: 1/ 1/1981

-END- MO-YR	NET OIL MB	NET GAS MMF	REVENUE TO INT. M$	OPER. EXPENSE M$	NET INCOME M$	CAPITAL INVEST. M$	DEPR. M$	DEPL. M$	INCOME TAX M$	CASH FLOW M$	CUM. NET PW M$
12-81	0.	0.	0.	1.863	-1.863	475.400	52.965	0.	-73.290	-403.972	-412.448
12-82	.224	58.330	174.581	1.993	172.588	0.	45.401	0.	58.506	114.082	-335.260
12-83	.158	41.001	131.290	2.133	129.157	0.	38.918	0.	41.510	87.647	-289.644
12-84	.117	30.395	104.156	2.283	101.873	0.	33.360	0.	31.516	70.357	-261.476
12-85	.090	23.433	85.921	2.442	83.479	0.	28.597	0.	25.246	58.233	-243.542
12-86	.072	18.619	73.066	2.613	70.453	0.	24.513	0.	21.132	49.321	-231.859
12-87	.058	15.148	63.609	2.795	60.814	0.	21.013	0.	18.309	42.505	-224.113
12-88	.048	12.565	56.498	2.992	53.506	0.	18.012	0.	16.327	37.179	-218.901
12-89	.041	10.592	50.966	3.201	47.765	0.	15.440	0.	14.870	32.895	-215.354
12-90	.035	9.050	46.565	3.425	43.140	0.	13.235	0.	13.756	29.384	-212.917
12-91	.030	7.821	42.995	3.600	39.395	0.	11.345	0.	12.903	26.492	-211.227
12-92	.026	6.826	40.073	3.600	36.473	0.	9.725	0.	12.304	24.169	-210.041
12-93	.024	6.011	37.684	3.600	34.084	0.	8.336	0.	11.844	22.240	-209.201
12-94	.020	5.333	35.689	3.600	32.089	0.	7.146	0.	11.474	20.615	-208.602
12-95	.018	4.763	34.048	3.600	30.448	0.	6.125	0.	11.188	19.260	-208.172
12-96	.017	4.280	32.699	3.600	29.099	0.	5.251	0.	10.970	18.129	-207.861
12-97	.014	3.868	31.538	3.600	27.938	0.	4.501	0.	10.781	17.157	-207.634
12-98	.014	3.511	30.621	3.600	27.021	0.	3.858	0.	10.655	16.366	-207.467
12-99	.012	3.203	29.864	3.600	26.264	0.	3.307	0.	10.560	15.704	-207.345
12- 0	.012	2.932	28.632	3.600	25.032	0.	2.835	0.	10.211	14.821	-207.255
S TOT	1.030	267.681	1130.495	61.740	1068.755	475.400	353.882	0.	280.772	312.584	-207.255
AFTER	.131	34.319	335.035	90.636	244.399	0.	17.018	0.	104.597	139.804	-207.048
TOTAL	1.161	302.000	1465.530	152.376	1313.154	475.400	370.900	0.	385.369	452.387	-207.048

RECAP

	GROSS	W.I.	NET
INTEREST FRACTION	1.000000	1.000000	.755000
OIL RESERVES,MB	1.538	1.538	1.161
GAS RESERVES,MMCF	400.000	400.000	302.000
PRODUCTS	0.	0.	0.
REVENUE,M$	2116.810	2116.810	1465.530
OPERATING EXPENSE,M$	152.376	152.376	152.376
TANGIBLES,M$	370.900	370.900	370.900
INTANGIBLES,M$	104.500	104.500	104.500
INITIAL OIL PRICE ($/B)		34.00	
INITIAL GAS PRICE ($/M)		3.1452	

LIFE (YEARS)	45.18
GROSS OIL WELLS	0.
GROSS GAS WELLS	1.000
RATE OF RETURN,PCT	10.47
DISCOUNT RATE,PCT	30.0
PAYOUT YEARS	6.57
W.I. BEFORE PAYOUT,PCT	100.00
W.I. AFTER PAYOUT,PCT	100.00

DIS PCT	PW OF NET M$
5	152.955
10	8.027
15	-77.503
20	-134.573
30	-207.049
40	-251.813
50	-282.482
70	-322.042
100	-355.655

TYPICAL WELL
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO

CONSOLIDATED OIL & GAS, INC.
ECONOMICS OF DEVELOPMENT

2X SECTION 103 PRICE
350 MMCF GROSS
20-YEAR RECOVERY

DATE: 09/23/81.
TIME: 17.32.10.
FILE: TYPICAL
PROJ: 6

A F T E R T A X E C O N O M I C S

AS OF DATE: 1/ 1/1981

-END- YR	NET OIL MB-----	NET GAS MMF-----	REVENUE TO INT. M$-----	OPER. EXPENSE M$-----	NET INCOME M$-----	CAPITAL INVEST. M$-----	DEPR. M$---	DEPL. M$----	INCOME TAX M$----	CASH FLOW M$-----	CUM. NET PW M$------
12-81	0.	0.	0.	1.863	-1.863	475.400	52.965	0.	-73.290	-403.972	-412.448
12-82	.214	55.521	326.833	1.993	324.840	0.	45.401	0.	128.542	196.298	-279.633
12-83	.151	39.323	247.654	2.133	245.521	0.	38.918	0.	95.037	150.484	-201.313
12-84	.112	29.310	197.531	2.283	195.248	0.	33.360	0.	74.468	120.780	-152.958
12-85	.088	22.690	163.643	2.442	161.201	0.	28.597	0.	60.998	100.203	-122.099
12-86	.069	18.087	139.567	2.613	136.954	0.	24.513	0.	51.723	85.231	-101.908
12-87	.057	14.752	121.819	2.795	119.024	0.	21.013	0.	45.085	73.939	-88.435
12-88	.047	12.265	108.423	2.992	105.431	0.	18.012	0.	40.213	65.218	-79.293
12-89	.040	10.356	97.952	3.201	94.751	0.	15.440	0.	36.483	58.268	-73.010
12-90	.034	8.861	86.490	3.425	83.065	0.	13.235	0.	32.122	50.943	-68.785
12-91	.030	7.669	74.868	3.600	71.268	0.	11.345	0.	27.565	43.703	-65.996
12-92	.025	6.700	65.416	3.600	61.816	0.	9.725	0.	23.962	37.854	-64.138
12-93	.023	5.907	57.663	3.600	54.063	0.	8.336	0.	21.034	33.029	-62.891
12-94	.021	5.244	51.210	3.600	47.610	0.	7.146	0.	18.614	28.996	-62.049
12-95	.018	4.688	45.773	3.600	42.173	0.	6.125	0.	16.582	25.591	-61.478
12-96	.016	4.216	41.145	3.600	37.545	0.	5.251	0.	14.855	22.690	-61.088
12-97	.015	3.811	37.231	3.600	33.631	0.	4.501	0.	13.400	20.231	-60.820
12-98	.012	3.463	33.789	3.600	30.189	0.	3.858	0.	12.112	18.077	-60.637
12-99	.013	3.160	30.846	3.600	27.246	0.	3.307	0.	11.012	16.234	-60.510
12- 0	.011	2.894	28.270	3.600	24.670	0.	2.835	0.	10.044	14.626	-60.422
S TOT	.996	258.917	1956.123	61.740	1894.383	475.400	353.882	0.	660.561	758.423	-60.422
AFTER	.165	43.083	420.613	160.323	260.290	0.	17.018	0.	111.907	148.385	-60.220
TOTAL	1.161	302.000	2376.736	222.063	2154.673	475.400	370.900	0.	772.468	906.807	-60.220

RECAP

	GROSS	W.I.	NET
INTEREST FRACTION	1.000000	1.000000	.755000
OIL RESERVES,MB	1.538	1.538	1.161
GAS RESERVES,MMCF	400.000	400.000	302.000
PRODUCTS	0.	0.	0.
REVENUE,M$	3428.403	3428.403	2376.736
OPERATING EXPENSE,M$	222.063	222.063	222.063
TANGIBLES,M$	370.900	370.900	370.900
INTANGIBLES,M$	104.500	104.500	104.500
INITIAL OIL PRICE ($/B)		34.00	
INITIAL GAS PRICE ($/M)		6.2903	

LIFE (YEARS)	64.53
GROSS OIL WELLS	0.
GROSS GAS WELLS	1.000
RATE OF RETURN,PCT	24.39
DISCOUNT RATE,PCT	30.0
PAYOUT YEARS	3.47
W.I. BEFORE PAYOUT,PCT	100.00
W.I. AFTER PAYOUT,PCT	100.00

DIS PCT	PW OF NET M$
---	---
5	496.161
10	283.905
15	151.090
20	59.262
30	-60.221
40	-134.889
50	-186.073
70	-251.727
100	-306.788

SECTION 103 PRICE
435 MMCF GROSS
20-YEAR RECOVERY

TYPICAL WELL
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO

CONSOLIDATED OIL & GAS, INC.
ECONOMICS OF DEVELOPMENT

DATE: 09/23/81.
TIME: 17.32.13.
FILE: TYPICAL
PROJ: 7

A F T E R T A X E C O N O M I C S

AS OF DATE: 1/ 1/1981

-END- YR	NET OIL MB	NET GAS MMF	REVENUE TO INT. M$	OPER. EXPENSE M$	NET INCOME M$	CAPITAL INVEST. M$	DEPR. M$	DEPL. M$	INCOME TAX M$	CASH FLOW M$	CUM. NET PW M$
12-81	0.	0.	0.	1.863	-1.863	475.400	52.965	0.	-73.290	-403.972	-412.448
12-82	.279	72.709	217.790	1.993	215.797	0.	45.401	0.	78.382	137.415	-319.473
12-83	.197	50.952	163.300	2.133	161.167	0.	38.918	0.	56.235	104.932	-264.860
12-84	.145	37.692	129.260	2.283	126.977	0.	33.360	0.	43.064	83.913	-231.265
12-85	.111	29.010	106.470	2.442	104.028	0.	28.597	0.	34.698	69.330	-209.914
12-86	.089	23.019	90.395	2.613	87.782	0.	24.513	0.	29.104	58.678	-196.014
12-87	.071	18.710	78.625	2.795	75.830	0.	21.013	0.	25.216	50.614	-186.791
12-88	.060	15.508	69.770	2.992	66.778	0.	18.012	0.	22.432	44.346	-180.575
12-89	.051	13.062	62.884	3.201	59.683	0.	15.440	0.	20.352	39.331	-176.334
12-90	.043	11.153	57.403	3.425	53.978	0.	13.235	0.	18.742	35.236	-173.411
12-91	.037	9.634	52.950	3.600	49.350	0.	11.345	0.	17.482	31.868	-171.378
12-92	.032	8.406	49.342	3.600	45.742	0.	9.725	0.	16.568	29.174	-169.946
12-93	.028	7.398	46.339	3.600	42.739	0.	8.336	0.	15.825	26.914	-168.930
12-94	.026	6.561	43.942	3.600	40.342	0.	7.146	0.	15.270	25.072	-168.202
12-95	.022	5.859	41.895	3.600	38.295	0.	6.125	0.	14.798	23.497	-167.677
12-96	.020	5.264	40.178	3.600	36.578	0.	5.251	0.	14.411	22.167	-167.296
12-97	.019	4.754	38.823	3.600	35.223	0.	4.501	0.	14.132	21.091	-167.017
12-98	.017	4.316	37.635	3.600	34.035	0.	3.858	0.	13.881	20.154	-166.812
12-99	.015	3.936	36.668	3.600	33.068	0.	3.307	0.	13.690	19.378	-166.661
12- 0	.013	3.603	35.164	3.600	31.564	0.	2.835	0.	13.215	18.349	-166.550
S TOT	1.275	331.546	1398.833	61.740	1337.093	475.400	353.882	0.	404.207	457.486	-166.550
AFTER	.177	45.954	448.659	109.498	339.161	0.	17.018	0.	148.184	190.975	-166.291
TOTAL	1.452	377.500	1847.492	171.238	1676.254	475.400	370.900	0.	552.391	648.461	-166.291

RECAP

	GROSS	W.I.	NET
INTEREST FRACTION	1.000000	1.000000	.755000
OIL RESERVES,MB	1,923	1,923	1,452
GAS RESERVES,MMCF	500,000	500,000	377,500
PRODUCTS	0.	0.	0.
REVENUE,M$	2667.369	2667.369	1847.492
OPERATING EXPENSE,M$	171.238	171.238	171.238
TANGIBLES,M$	370.900	370.900	370.900
INTANGIBLES,M$	104.500	104.500	104.500

INITIAL OIL PRICE ($/B)	34.00
INITIAL GAS PRICE ($/M)	3.1452

LIFE (YEARS)	50.42
GROSS OIL WELLS	0.
GROSS GAS WELLS	1.000
RATE OF RETURN,PCT	14.44
DISCOUNT RATE,PCT	30.0
PAYOUT YEARS	5.14
W.I. BEFORE PAYOUT,PCT	100.00
W.I. AFTER PAYOUT,PCT	100.00

DIS PCT	PW OF NET M$
5	268.705
10	91.567
15	-11.521
20	-79.877
30	-166.292
40	-219.461
50	-255.793
70	-302.514
100	-342.023

TYPICAL WELL
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO

CONSOLIDATED OIL & GAS, INC.
ECONOMICS OF DEVELOPMENT

2X SECTION 103 PRICE
435 MMCF GROSS
20-YEAR RECOVERY

DATE: 09/23/81.
TIME: 17.32.17.
FILE: TYPICAL
PROJ: 8

AFTER TAX ECONOMICS

AS OF DATE: 1/ 1/1981

-END- MO-YR	NET OIL MB-----	NET GAS MMF-----	REVENUE TO INT. M$-----	OPER. EXPENSE M$-----	NET INCOME M$-----	CAPITAL INVEST. M$-----	DEPR. M$---	DEPL. M$----	INCOME TAX M$----	CASH FLOW M$-----	CUM. NET PW M$------
12-81	0.	0.	0.	1.863	-1.863	475.400	52.965	0.	-73.290	-403.972	-412.448
12-82	.267	59.277	409.246	1.993	407.253	0.	45.401	0.	166.452	240.801	-249.523
12-83	.188	48.957	309.444	2.133	307.311.	0.	38.918	0.	123.461	183.850	-153.836
12-84	.140	36.434	246.428	2.283	244.145	0.	33.360	0.	96.961	147.184	-94.911
12-85	.108	28.171	203.855	2.442	201.413	0.	28.597	0.	79.496	121.917	-57.364
12-86	.087	22.433	173.727	2.613	171.114	0.	24.513	0.	67.436	103.678	-32.804
12-87	.070	18.286	151.503	2.795	148.708	0.	21.013	0.	58.740	89.968	-16.409
12-88	.058	15.191	134.609	2.992	131.617	0.	18.012	0.	52.258	79.359	-5.285
12-89	.050	12.822	121.439	3.201	118.238	0.	15.440	0.	47.287	70.951	2.364
12-90	.041	10.965	107.031	3.425	103.606	0.	13.235	0.	41.571	62.035	7.510
12-91	.037	9.486	92.637	3.600	89.037	0.	11.345	0.	35.738	53.299	10.910
12-92	.032	8.286	80.892	3.600	77.292	0.	9.725	0.	31.081	46.211	13.178
12-93	.028	7.302	71.281	3.600	67.681	0.	8.336	0.	27.299	40.382	14.703
12-94	.025	6.481	63.275	3.600	59.675	0.	7.146	0.	24.163	35.512	15.734
12-95	.023	5.793	56.577	3.600	52.977	0.	6.125	0.	21.552	31.425	16.436
12-96	.019	5.208	50.829	3.600	47.229	0.	5.251	0.	19.310	27.919	16.916
12-97	.018	4.708	45.968	3.600	42.368	0.	4.501	0.	17.419	24.949	17.246
12-98	.017	4.275	41.751	3.600	38.151	0.	3.858	0.	15.775	22.376	17.473
12-99	.015	3.902	38.100	3.600	34.500	0.	3.307	0.	14.349	20.151	17.631
12- 0	.014	3.574	34.881	3.600	31.281	0.	2.835	0.	13.095	18.196	17.740
S TOT	1.237	321.551	2433.473	61.740	2371.733	475.400	353.882	0.	880.143	1016.192	17.740
AFTER	.215	55.949	546.250	187.387	358.863	0.	17.018	0.	157.247	201.614	17.995
TOTAL	1.452	377.500	2979.723	249.127	2730.596	475.400	370.900	0.	1037.390	1217.806	17.995

RECAP

	GROSS	W.I.	NET
INTEREST FRACTION	1.000000	1.000000	.755000
OIL RESERVES,MB	1.923	1.923	1.452
GAS RESERVES,MMCF	500.000	500.000	377.500
PRODUCTS	0.	0.	0.
REVENUE,M$	4289.840	4289.840	2979.723
OPERATING EXPENSE,M$	249.127	249.127	249.127
TANGIBLES,M$	370.900	370.900	370.900
INTANGIBLES,M$	104.500	104.500	104.500

INITIAL OIL PRICE ($/B)	34.00
INITIAL GAS PRICE ($/M)	6.2903

LIFE (YEARS)	72.05
GROSS OIL WELLS	0.
GROSS GAS WELLS	1.000
RATE OF RETURN,PCT	31.80
DISCOUNT RATE,PCT	30.0
PAYOUT YEARS	2.89
W.I. BEFORE PAYOUT,PCT	100.00
W.I. AFTER PAYOUT,PCT	100.00

DIS PCT	PW OF NET M$
5	698.295
10	437.396
15	275.185
20	163.304
30	17.995
40	-72.662
50	-134.723
70	-214.185
100	-280.620

TYPICAL WELL
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO

CONSOLIDATED OIL & GAS, INC.
ECONOMICS OF DEVELOPMENT

SECTION 103 PRICE
555 MMCF GROSS
20-YEAR RECOVERY

DATE: 09/23/81.
TIME: 17.32.20.
FILE: TYPICAL
PROJ: 9

AFTER TAX ECONOMICS

AS OF DATE: 1/ 1/1981

-END- YR-MO	NET OIL MB	NET GAS MMF	REVENUE TO INT. M$	OPER. EXPENSE M$	NET INCOME M$	CAPITAL INVEST. M$	DEPR. M$	DEPL. M$	INCOME TAX M$	CASH FLOW M$	CUM. NET PW M$
12-81	0.	0.	0.	1.863	-1.863	475.400	52.965	0.	-73.290	-403.972	-412.448
12-82	.347	90.378	270.718	1.993	268.725	0.	45.401	0.	102.729	165.996	-300.136
12-83	.247	64.139	205.554	2.133	203.421	0.	38.918	0.	75.671	127.750	-233.647
12-84	.184	47.879	164.201	2.283	161.918	0.	33.360	0.	59.136	102.782	-192.498
12-85	.143	37.107	136.179	2.442	133.737	0.	28.597	0.	48.365	85.372	-166.207
12-86	.114	29.602	116.260	2.613	113.647	0.	24.513	0.	41.002	72.645	-148.997
12-87	.093	24.164	101.552	2.795	98.757	0.	21.013	0.	35.762	62.995	-137.518
12-88	.077	20.100	90.417	2.992	87.425	0.	18.012	0.	31.930	55.495	-129.739
12-89	.066	16.981	81.749	3.201	78.548	0.	15.440	0.	29.030	49.518	-124.400
12-90	.056	14.536	74.802	3.425	71.377	0.	13.235	0.	26.745	44.632	-120.698
12-91	.048	12.582	69.159	3.600	65.559	0.	11.345	0.	24.938	40.621	-118.106
12-92	.042	11.000	64.555	3.600	60.955	0.	9.725	0.	23.566	37.389	-116.271
12-93	.037	9.696	60.758	3.600	57.158	0.	8.336	0.	22.458	34.700	-114.961
12-94	.033	8.613	57.658	3.600	54.058	0.	7.146	0.	21.580	32.478	-114.018
12-95	.031	7.701	55.083	3.600	51.483	0.	6.125	0.	20.864	30.619	-113.334
12-96	.026	6.926	52.894	3.600	49.294	0.	5.251	0.	20.260	29.034	-112.835
12-97	.024	6.264	51.115	3.600	47.515	0.	4.501	0.	19.786	27.729	-112.468
12-98	.022	5.691	49.622	3.600	46.022	0.	3.858	0.	19.395	26.627	-112.198
12-99	.020	5.193	48.374	3.600	44.774	0.	3.307	0.	19.075	25.699	-111.997
12- 0	.018	4.759	46.453	3.600	42.853	0.	2.835	0.	18.408	24.445	-111.849
S TOT	1.628	423.311	1797.103	61.740	1735.363	475.400	353.882	0.	587.410	672.552	-111.849
AFTER	.259	67.439	658.443	139.802	518.641	0.	17.018	0.	230.747	287.894	-111.499
TOTAL	1.887	490.750	2455.546	201.542	2254.004	475.400	370.900	0.	818.157	960.446	-111.499

RECAP

	GROSS	W.I.	NET
INTEREST FRACTION	1.000000	1.000000	.755000
OIL RESERVES,MB	2.500	2.500	1.887
GAS RESERVES,MMCF	650.000	650.000	490.750
PRODUCTS	0.	0.	0.
REVENUE,M$	3544.802	3544.802	2455.546
OPERATING EXPENSE,M$	201.542	201.542	201.542
TANGIBLES,M$	370.900	370.900	370.900
INTANGIBLES,M$	104.500	104.500	104.500
INITIAL OIL PRICE ($/B)		34.00	
INITIAL GAS PRICE ($/M)		3.1452	

LIFE (YEARS)	58.83
GROSS OIL WELLS	0.
GROSS GAS WELLS	1.000
RATE OF RETURN,PCT	19.72
DISCOUNT RATE,PCT	30.0
PAYOUT YEARS	4.09
W.I. BEFORE PAYOUT,PCT	100.00
W.I. AFTER PAYOUT,PCT	100.00

DIS PCT	PW OF NET M$
5	439.496
10	210.706
15	80.556
20	-4.743
30	-111.500
40	-176.585
50	-220.782
70	-277.247
100	-324.605

TYPICAL WELL
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO

CONSOLIDATED OIL + GAS, INC.
ECONOMICS OF DEVELOPMENT

2X SECTION 103 PRICE
555 MMCF GROSS
20-YEAR RECOVERY

DATE: 09/23/81.
TIME: 17.32.24.
FILE: TYPICAL
PROJ: 10

A F T E R T A X E C O N O M I C S

AS OF DATE: 1/ 1/1981

-END- MO-YR	NET OIL MB-----	NET GAS MMF-----	REVENUE TO INT. M$------	OPER. EXPENSE M$-----	NET INCOME M$-----	CAPITAL INVEST. M$-----	DEPR. M$---	DEPL. M$----	INCOME TAX M$----	CASH FLOW M$-----	CUM. NET PW M$------
12-81	0.	0.	0.	1.863	-1.863	475.400	52.965	0.	-73.290	-403.972	-412.448
12-82	.346	89.896	529.399	1.993	527.406	0.	45.401	0.	221.722	305.684	-205.623
12-83	.244	63.382	399.364	2.133	397.231	0.	38.918	0.	164.824	232.407	-84.665
12-84	.181	47.091	317.507	2.283	315.224	0.	33.360	0.	129.657	185.567	-10.373
12-85	.140	36.367	262.362	2.442	259.920	0.	28.597	0.	106.409	153.511	36.902
12-86	.111	28.929	223.328	2.613	220.715	0.	24.513	0.	90.253	130.462	67.808
12-87	.090	23.563	194.657	2.795	191.862	0.	21.013	0.	78.591	113.271	88.449
12-88	.076	19.564	172.981	2.992	169.989	0.	18.012	0.	69.909	100.080	102.478
12-89	.063	16.501	156.091	3.201	152.890	0.	15.440	0.	63.227	89.663	112.146
12-90	.054	14.107	137.706	3.425	134.281	0.	13.235	0.	55.681	78.600	118.665
12-91	.047	12.199	119.094	3.600	115.494	0.	11.345	0.	47.909	67.585	122.977
12-92	.041	10.652	103.992	3.600	100.392	0.	9.725	0.	41.707	58.685	125.857
12-93	.036	9.383	91.618	3.600	88.018	0.	8.336	0.	36.654	51.364	127.797
12-94	.033	8.327	81.318	3.600	77.718	0.	7.146	0.	32.463	45.255	129.111
12-95	.028	7.442	72.655	3.600	69.055	0.	6.125	0.	28.948	40.107	130.007
12-96	.026	6.687	65.293	3.600	61.693	0.	5.251	0.	25.963	35.730	130.621
12-97	.023	6.046	58.994	3.600	55.394	0.	4.501	0.	23.411	31.983	131.044
12-98	.021	5.489	53.598	3.600	49.998	0.	3.858	0.	21.224	28.774	131.336
12-99	.019	5.007	48.904	3.600	45.304	0.	3.307	0.	19.319	25.985	131.539
13- 0	.018	4.587	44.768	3.600	41.168	0.	2.835	0.	17.633	23.535	131.681
S TOT	1.597	415.219	3133.629	61.740	3071.889	475.400	353.882	0.	1202.214	1394.276	131.681
AFTER	.290	75.531	737.441	223.311	514.130	0.	17.018	0.	228.672	285.458	132.013
TOTAL	1.887	490.750	3871.070	285.051	3586.019	475.400	370.900	0.	1430.886	1679.734	132.013

RECAP

	GROSS	W.I.	NET
INTEREST FRACTION	1.000000	1.000000	.755000
OIL RESERVES,MB	2.500	2.500	1.887
GAS RESERVES,MMCF	650.000	650.000	490.750
PRODUCTS	0.	0.	0.
REVENUE,M$	5582.550	5582.550	3871.070
OPERATING EXPENSE,M$	285.051	285.051	285.051
TANGIBLES,M$	370.900	370.900	370.900
INTANGIBLES,M$	104.500	104.500	104.500

INITIAL OIL PRICE ($/B)	34.00
INITIAL GAS PRICE ($/M)	6.2903

LIFE (YEARS)	82.03
GROSS OIL WELLS	0.
GROSS GAS WELLS	1.000
RATE OF RETURN,PCT	42.13
DISCOUNT RATE,PCT	30.0
PAYOUT YEARS	2.42
W.I. BEFORE PAYOUT,PCT	100.00
W.I. AFTER PAYOUT,PCT	100.00

DIS PCT	PW OF NET M$
5	994.256
10	661.766
15	456.388
20	315.109
30	132.013
40	18.010
50	-59.914
70	-159.497
100	-242.499

CONSOLIDATED OIL & GAS, INC.
RATE OF RETURN (BFIT)
VS.
20 YR. RECOVERY PER WELL
BASIN DAKOTA FIELD
T30, 31, & 32N - R12 & 13W

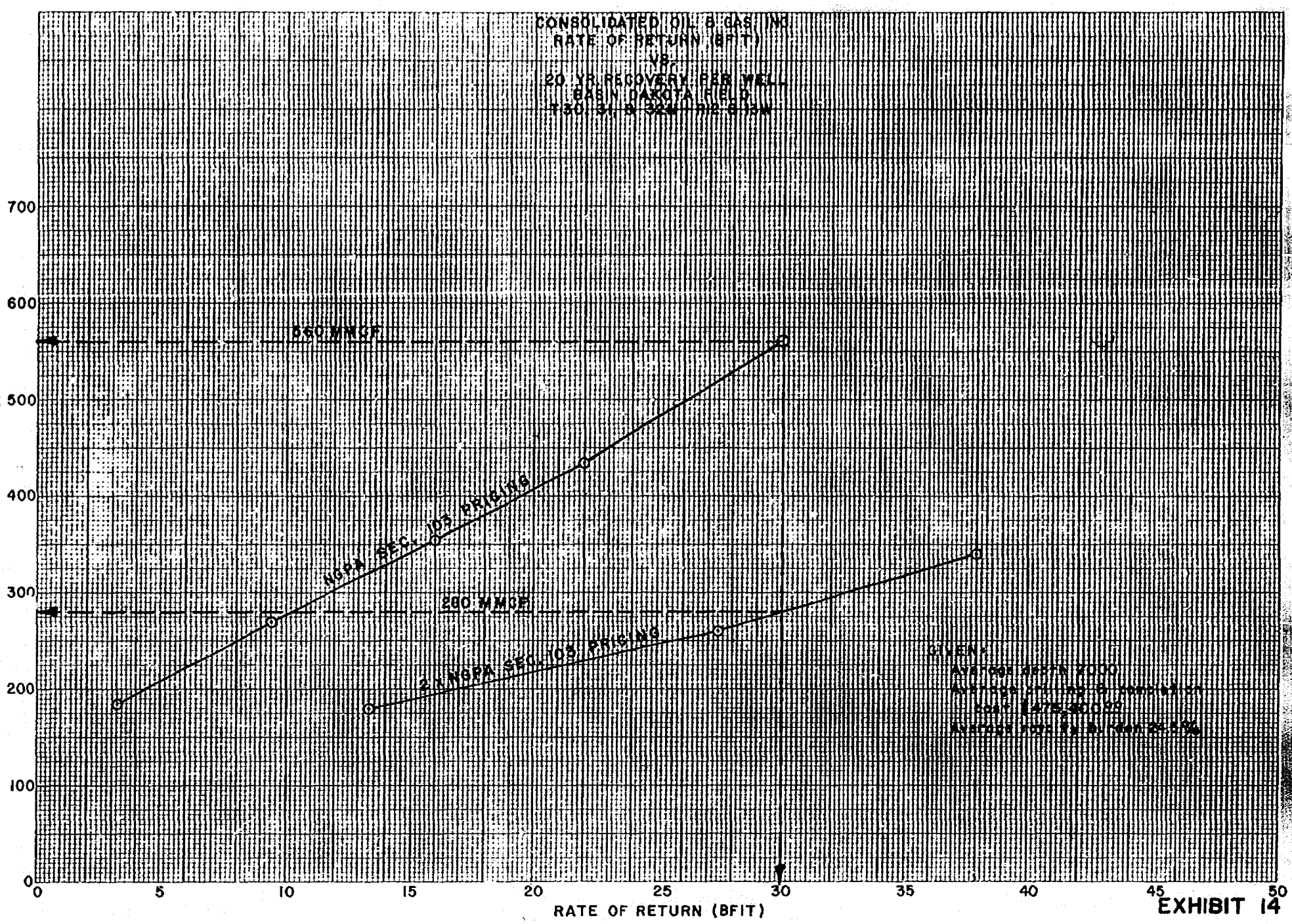


EXHIBIT 14

CONSOLIDATED OIL & GAS, INC.
RATE OF RETURN (AFIT)
VS.
20 YR. RECOVERY PER WELL
BASIN DAKOTA FIELD
T30, 31, R 32W & R12 & 13W

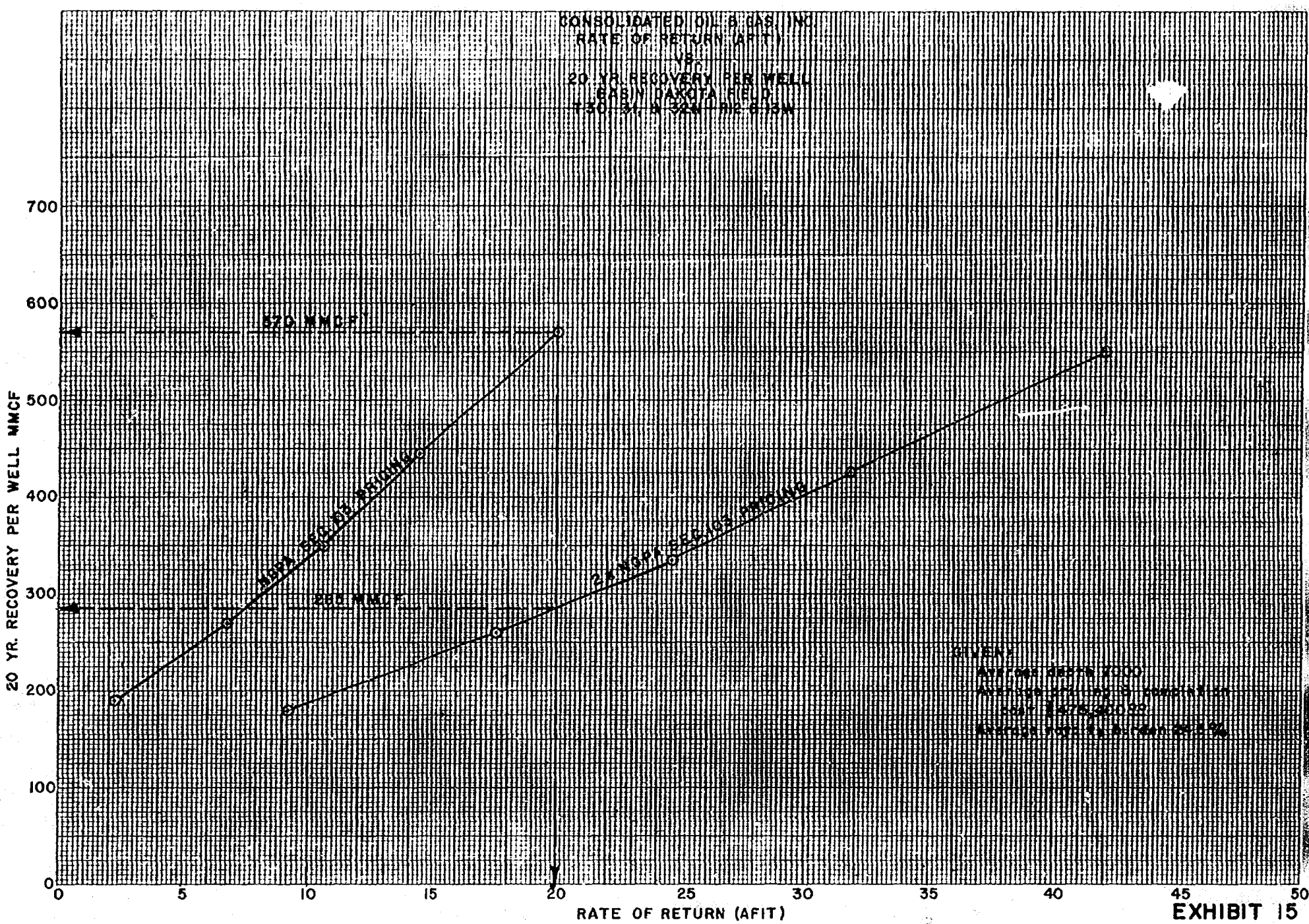


EXHIBIT 15

EXHIBIT 16

RATE OF RETURN JUSTIFICATION

All investment decisions, whether by individuals or corporations, are matters of selection between competing alternatives. If discretionary dollars are invested by an individual in a new house, those same dollars can't be put in a savings account. Every individual and corporation has a myriad of things that can be done with cash flows. Each can make long-term investments, short-term investments, pay off debt, or simply convert funds to current consumption. Each and every spending decision is made in this context, whether or not the spender does any quantified analysis.

Corporations, who have strong fiduciary responsibilities for shareholders' investments, also must continually select between alternatives in making investment decisions. This process must consist of two broad steps. The first is the "hurdle" rate of return determination which must reflect its costs of capital. A corporation has only two sources of capital -- equity and debt.

Equity, or selling additional stock, as a source of funds is becoming more expensive for corporations. This is because of the alternatives available to investors. Investors can earn 17% to 18% on safe money market funds. They can earn 15 3/4% on high grade commercial paper, 16 1/2% on federally guaranteed CD's, 14 1/2% on Federal treasury bills, and 17% to 20% on New York Stock Exchange high grade corporate bonds. Equity issues, in order to attract buyers, must necessarily be priced so that investors can earn, through dividends and stock appreciation, at least 20% since stock is inherently riskier than bonded indebtedness. Many corporations, in trying to attract additional equity, have been forced to issue stock below its "book value," which is dilutive to prior shareholders.

Debt, as an alternative source of capital, is also becoming more expensive. Two primary sources of debt exist for a corporation. One is the public market through issuance of debentures. As mentioned above, these issues, if they can be sold at all, are costing 17% to 20%. Again, this high cost is a function of alternatives. Why should an investor accept less than 17% to 20% on corporate bonds which do have some associated risk when he can earn a guaranteed 16 1/2% on CD's or other safer investments?

The second source of debt is bank borrowings. The following table shows bank prime rate since 1/1/79.

MONTH	AVERAGE PRIME RATE - %
1/79	11.75
2/79	11.75
3/79	11.75
4/79	11.75
5/79	11.75
6/79	11.75
7/79	11.75

MONTH	AVERAGE PRIME RATE - %
8/79	12.25
9/79	13.50
10/79	15.25
11/79	15.50
12/79	15.25
1/80	15.25
2/80	16.75
3/80	19.50
4/80	19.00
5/80	14.50
6/80	12.00
7/80	11.00
8/80	11.50
9/80	13.00
10/80	14.50
11/80	17.75
12/80	21.50
1/81	19.50
2/81	19.00
3/81	17.50
4/81	18.00
5/81	20.50
6/81	20.00
7/81	20.50
8/81	20.50

These prime rates are reflective of the banks' costs of funds. With banks paying 16 1/2% for their funds, prime must be in the 19% to 20% range. It is important to note that very few people or corporations can borrow at prime. Most borrowers pay some multiple of prime or some percentage over prime. In our case, we pay prime plus .5%, for a current interest cost of approximately 20%.

Thus, our corporate cost of capital is 20% for equity and 20% for debt, or 20% overall. Making investments with less than 20% earnings rate would be an imprudent decision which would eventually degrade our shareholders' investment. Even acceptance of a 20% rate of return must necessarily incorporate the belief that interest rates will abate in the future so that a 20% earnings rate project will make future contributions in excess of its costs.

The question may be asked regarding use of cash flow from older properties developed with lower cost capital to generate new capital. This brings up the second necessary step in investment decision-making after a cost of capital has been determined. This step is the selection between competing alternatives. Consolidated, like many oil and gas concerns, since 1976 has invested considerably more in oil and gas properties and drilling than was returned through its profits. For 1976 through year end 1980, Consolidated spent $51.3 million on oil and gas development while net earnings totalled $15.8 million. This gap between earnings and investment was largely funded by increased bank debt. Corporate bank debt now exceeds $50 million at an interest cost of approximately 20%. This is pertinent because repayment of that bank

debt with corporate cash flow represents a guaranteed 20% rate of return. This is not a situation peculiar to Consolidated. Very few substantial oil and gas entities are debt free, and most carry a similar earnings/investment differential.

When managements are reviewing proposed oil and gas drilling investments with rates of return below 20%, they know they have "risk free" alternative investments with comparable returns, namely paying off corporate bank debt or buying any of the high yielding treasury bills, CD's, or money market funds.

Thus, with alternative risk-free investment opportunities available for earning 20%, with costs of capital near 20%, there is certainly justification for an oil and gas investment to yield a substantially greater return. In determining how much greater than 20% the rate should be, several factors need to be considered.

Evaluation and rate of return economics do not account for corporate general and administrative expense. These include accounting and financial functions, costs of federal, state and local compliance required before, during and after drilling and production, as well as all geologic and engineering functions. Consolidated has one of the lower "burdens" in industry, yet even ours is approximately 20% of invested capital. This means that for us to earn 20% at the corporate level, projects evaluated at the field or lease level must earn approximately 24%.

In addition, a risk factor must be considered. The risks in this infill program's viability are, a) those inherent in any drilling operations, b) regulatory exposure to price controls, increased taxes including local, state and federal, and c) lower recoveries than estimated. A reasonable, if not minimal risk factor is 25%. This would translate to an additional 6% return above the "break-even" rate of 24%, resulting in a total return of 30%.

In the analyses of rates of return on oil and gas investments, it is permissible to view 20 years of forecast performance. The bulk of reserves on a well are produced in the first 20 years and over 98% of the present value is derived. For example, in the instant case, a typical well in the 21st year would be producing only 11.5 mcfd, which when discounted at 30% is worth only (.00038) X 11.5, or .004 mcfd of present production. For this reason, the economic forecasts and display of results in Exhibits 12 through 15 reflect gross gas recoveries forecast in the first 20 years. Even though, with sufficient price incentives, many of these wells will produce for 40 or 50 years at low rates, the gas recovered adds almost nothing to present worth, upon which investment decisions are made.

As can be seen on Exhibit 14, this indicates a necessary 20 year recovery of 560 mmcf per well at NGPA Section 103 prices. This exceeds expected recovery of 435 mmcf. With tight gas sands pricing, the required recovery would drop to approximately 280 mmcf per well, which would make the program viable.

The returns and analyses presented thus far have been before income tax. It is both instructive and appropriate to consider after income tax results and requirements. When the same economic forecasts are used to evaluate this Basin-Dakota area, with income taxes being charged to cash flows and tax credits being taken on investments, lower project earnings and rates of return result. The required after tax rate of return need not be as high as the pre-tax return and in fact is well analyzed in prior FPC proceedings. On August 28, 1975, the FPC found in Opinion No. 742 (aff. Op. 742-A, July 27, 1976) that small producers are entitled to a 20% after tax rate of return. The higher rate than previously allowed was justified by com-

bined risk increase, higher equity financing and greater debt cost for small producers. In 1975, prime interest rates averaged only 7.86%. The significantly higher 1980 and 1981 costs of equity and debt certainly justify an earnings rate much in excess of 20%. How much higher is then the question. In Opinion 742, the FPC allowed an earnings rate of prime plus 12.14%. This would dictate an earnings rate of over 32%. This is not an unreasonable goal for an oil and gas investor, but it represents a "weighted" target across a myriad of types of wells, all with varying risks. What then should the return be on a development well drilling program, such as the Dakota? It should certainly be in excess of 20%, but in the instant case, it is not necessary to determine how much in excess. Even at a 20% after tax rate of return the required average 20 year recovery per well, 570 mmcf, far exceed those expected.

Thus, in this case, the Basin-Dakota infill program in this area yields subeconomic results at Section 103 prices whether evaluated on a pre-tax or after tax basis. Our corporate policy certainly reflects this since we ceased our infill drilling program last year and will not resume drilling until sufficient price incentive exists. Our economic analyses presented herein are not "hollow" exercises -- we have been diverting investment from this area to other areas and we see no reason to use capital costing 20% for this area at current allowed prices.

EXHIBIT 17

DAKOTA INFILL WELLS

PREVIOUSLY DRILLED

Well Name	Spud Date	Economic Status at 103 Price (Current)
Cain 1-M	5/17/80	50 MCFD - Will not cover interest on costs
Jackson 2-E	8/4/80	100 MCFD - Requires compression - Will not cover interest
Jaquez 2	2/25/80	170 MCFD - Too early to predict
Kline 1-M	4/17/80	13-30 MCFD - Will not cover interest
Langendorf 1-E	6/1/80	240 MCFD - Will cover interest
Mitchell 1-E	1/26/80	35 MCFD - Indeterminate
Neuman 1-E	9/2/80	78 MCFD - Will not cover interest - requires compression
Payne 1-E	8/9/80	260 MCFD - Will cover interest
Phillips 1-E	2/26/80	175 MCFD - Will cover interest
Robinson Bros. 1-M	6/10/80	55 MCFD - Will not cover interest
So. Union 1-M	3/12/80	Trace - Will not cover interest
So. Union 2-E	8/19/80	140 MCFD - Requires compression - Will not cover interest
Starr 1-M	5/2/80	230 MCFD - Marginally covers interest
Templeton 1-E	7/8/80	210 MCFD - Marginally covers interest
Wilmerding 1-M	4/2/80	65 MCFD - Will not cover interest

SUMMARY

9 - wells are not covering interest on investment

5 - wells are marginally covering interest

1 - indeterminate

United States Department of the Interior

OFFICE OF THE SECRETARY

Minerals Management Service
South Central Region
P. O. Box 20124
Albuquerque, New Mexico 87125

OIL CONSERVATION DIVISION
MAR 18 1982
SANTA FE

MAR 16 1982

Mr. W. Perry Pearce
Oil Conservation Division
State of New Mexico
P. O. Box 2088
Santa Fe, New Mexico 87501

Dear Mr. Pearce:

This jurisdictional agency concurs in the recommendation of the State of New Mexico, Case No. 7116 De Novo, Order No. R-6747-A, dated March 11, 1982, that the Dakota formation underlying the described lands in subject order in San Juan County, New Mexico, be designated as a Section 107 tight formation.

It is requested that this concurrence be included with the recommendation submitted to the Federal Energy Regulatory Commission.

Sincerely yours,

James W. Shelton
FOR Gene F. Daniel
Deputy Minerals Manager
Oil and Gas

DAKOTA TIGHT FORMATION
HEARING
CASE NO. 7116 DE NOVO

SEPTEMBER 29, 1981

BEFORE THE
OIL CONSERVATION COMMISSION
Santa Fe, New Mexico
Case No. 7116 DN Exhibit No. 1-17
Submitted by COG
Hearing Date 9-29-81

GEOGRAPHICAL AND GEOLOGICAL DESCRIPTION

Within the described area of Exhibit No. 1, the Dakota sands are light to dark mottled gray, fine to very fine-grained quartz sands. Silt and clay-sized matrix material can form a significant percentage of the bulk-rock composition. Because the matrix fraction tends to reduce greatly the effective permeability of the reservoir, natural and induced fractures are necessary for production from the Dakota reservoir.

Exhibit No. 3 is a type log which shows the base of the Mancos, the Greenhorn, the Graneros and the Dakota formations. The vertical limits of the Basin Dakota gas pool have been defined by the New Nexico Conservation Division to be from the base of the Greenhorn Limestone to a point 400 feet below the base of said formation and consists of the Graneros formation, the Dakota formation and the productive upper portion of the Morrison formation. The Graneros and first Dakota zones are the main producing zones in the Basin Dakota Field. The other Dakota zones and the upper Morrison zone have very low permeability. Production from these zones has been limited to date.

The sediments of the Dakota interval were formed during late Cretaceous time. The Dakota is bounded by an uncomformable contact with the Jurassic Morrison below and is gradational with the Cretaceous Mancos shale above and is found at an average depth of 6650 feet for the area outlined on Exhibit No. 1. The gross thickness of the formation varies from 200 to 300 feet.

Deposition of the Dakota sediments occurred during a regression of the late Cretaceous sea. This regression resulted in the following sequence of depositional environments from the base upward: 1. Braided stream sandstone; 2. Meandering stream complex (with minor associated coals); 3. Coastal shale; 4. Coastal sandstone. The lower two environments contain sands of minor areal extent whereas the coastal sandstones have significant extent. They are northwest-southeast trending linear sand bodies reflecting their beach and off-shore bar

depositional history. These upper Dakota sands appear to be the primary Dakota reservoirs.

Exhibits Nos.4A, 4B and 4C are cross sections that show the continuity of the Dakota zones across the area of this application. Cross section A-A' shows sand development in a North-South direction while cross-section B-B' shows sand development in an East-West direction. Cross-section C-C' shows the sand development in a Southwest-Northeast direction.

PERMEABILITY, GAS AND CRUDE PRODUCTION DATA
NORTHWEST PORTION - BASIN DAKOTA FIELD
SAN JUAN COUNTY, NEW MEXICO

Operator/ Lease	Well No.	Location	Spud Date	Depth	In Situ Gas Permeability (Md.)	Calculated Stabilized Gas Production Rate At Atmos Pressure (MCFD)	Crude Production (BPD)	FERC Allowed Rate MCFD	FERC Allowed Rate BOPD
Consolidated Oil & Gas Co. Wilmerding	1-M	NE/4 NW/4 10-31N-13W	4-2-80	6627-6846	less than 0.1	Flow too small to measure	0	251	
Consolidated Oil & Gas Co. Kline	1-M	NE/4 SE/4 10-31N-13W	4-16-80	6506-6736	0.0049	12.5	0	251	
Consolidated Oil & Gas Co. Senter	1-M	NE/4 SE/4 24-31N-13W	11-28-79	6898-6958 6740-6816	0.00068 0.0146	2.73 L.Dak 52.00 U.Dak 54.73	0 0 0	251	
Southland Royalty Co. East	7-E	SW 14-31N-12W (1)		7282-7448	0.0011	21.7	0	290	
Southland Royalty Co. Patterson 'B' Com.	1-E	SW 2-31N-12W (1)		7212-7385	0.0877	224.1	0	290	
El Paso Natural Gas Co. Case	8	NE 18-31N-11W (1)		7254-7406	0.0335 (2)	Not tested	--	290	
El Paso Natural Gas Co. Moore	8	SW 24-32N-12W (1)		7589-7800	0.0151 (2)	Not tested	--	336	

(1) Not within, but near the area of this application.
(2) Reference: Rex D. Thomas and Don C. Ward: "Effect of Overburden Pressure and Water Saturation on Gas Permeability of Tight Sandstone Cores". See Exhibit No. 7 .

Exhibit No. 5

CORRECTED COPY

FLUID SAMPLE DATA

Sampler Pressure _____ P.S.I.G. at Surface
Recovery: Cu. Ft. Gas _____
cc. Oil _____
cc. Water _____
cc. Mud _____
Tot. Liquid cc. _____
Gravity _____ ° API @ _____ °F.
Gas/Oil Ratio _____ cu. ft./bbl.

	RESISTIVITY			CHLORIDE CONTENT
Recovery Water	____	@ ____	°F.	____ ppm
Recovery Mud	____	@ ____	°F.	____ ppm
Recovery Mud Filtrate	____	@ ____	°F.	____ ppm
Mud Pit Sample	____	@ Fresh water	°F.	____ ppm
Mud Pit Sample Filtrate	____	@ ____	°F.	____ ppm

Mud Weight _____ vis _____ sec.

Date 7-31-80 | Ticket Number 727294
Kind of D.S.T. CASED HOLE | Halliburton Location FARMINGTON
Tester MR. BROWN / MR. ROBLES | Witness
Drilling Contractor SPARTAN DRILLING COMPANY DR BC

EQUIPMENT & HOLE DATA

Formation Tested Basin Dakota
Elevation 6940' Ft.
Net Productive Interval 51' from 7284-7445' Ft.
All Depths Measured From Kelly Bushing
Total Depth 7480' Ft.
Main Hole/Casing Size 4 1/2" 10.5# Liner
Drill Collar Length - I.D. -
Drill Pipe Length 7229.9' I.D. 1.995"
Packer Depth(s) 7249' Ft.
Depth Tester Valve 7235.5' Ft.

Cushion TYPE Fresh water AMOUNT 4 bbls. Ft. | Depth Back Pres. Valve | Surface Choke 1/8" | Bottom Choke 5/8"

Recovered 1000' 240 Feet of water
Recovered Feet of
Recovered Feet of
Recovered Feet of
Recovered Feet of

Remarks See production test data sheet

Q-Questionable

TEMPERATURE	Gauge No. 7489		Gauge No. 5160		Gauge No.		TIME (00:00-24:00 hrs.)	
	Depth: 7245 Ft.		Depth: 7257.2' Ft.		Depth: Ft.			
	24 Hour Clock		24 Hour Clock		Hour Clock		Tool	
Est. °F.	Blanked Off No		Blanked Off Yes		Blanked Off		Opened 0056	
Actual 190 °F.	Pressures		Pressures		Pressures		Opened Bypass 1100	
	Field	Office	Field	Office	Field	Office	Reported Minutes	Computed Minutes
Initial Hydrostatic	3375 0	3120.6	3192 0	3117.2				
First Period Flow Initial	130.8	346.3-0	128	352.5 0			—	—
First Period Flow Final	130.8	150.3	128	147.4			120	126
First Period Closed in	2383	2382.2	2426.8	2382.1			484	478
Second Period Flow Initial							—	—
Second Period Flow Final								
Second Period Closed in								
Third Period Flow Initial							—	—
Third Period Flow Final								
Third Period Closed in								
Final Hydrostatic	3590 0	3120.6	3320 0	3117.2			—	—

Legal Location Sec. - Twp. - Rng. 14-31N-12W
Lease Name EAST
Well No. 7-E
Test No. 1
Tested Interval 7249-7480'
Field Area BASIN DAKOTA
Meas. From Tester Valve
County SAN JUAN
State NEW MEXICO
Lease Owner/Company Name SOUTHLAND ROYALTY COMPANY

FORM 181-42 – PRINTED IN U.S.A.

FORMATION TEST DATA

LITTLE'S 11033 7SC 2/80

Exhibit No. 6A

(6) 1.

Casing perfs._____ Bottom choke_____ Surf. temp_____ °F Ticket No. 727294

Gas gravity_____ Oil gravity_____ GOR_____

Spec. gravity_____ Chlorides_____ ppm Res._____ @_____ °F

INDICATE TYPE AND SIZE OF GAS MEASURING DEVICE USED_____

Date Time a.m. p.m.	Choke Size	Surface Pressure psi	Gas Rate MCF	Liquid Rate BPD	Remarks
2218					On location, made up tools
2218					Trip in hole with tools
0016					On bottom
0056					Hydrospring opened
0056					Moderate blow to surface
0101	Blow Hose	.25#			
0102	"	1			
0103	"	2			
0.04	"	3			
0109	"	3.5			
0118	"	4			
0123	"	4			
0128	"	4.5			
0133	"	4			
0138		4.5			
0142		4.5			Gas to surface
0147	3/4"				Opened choke, flare to pit with 1/8"
					orifice tester
0256					Closed tool
1100					Trip out of hole with tools

FORM 182-RI—PRINTED IN U.S.A.

PRODUCTION TEST DATA

LITTLE'S 96672 3M 8/74

SOUTHLAND ROYALTY COMPANY — Lease Owner/Company Name

727294 — Ticket Number

B.T. 7489 Depth 7245'

B.T. 5160 Depth 7257.2'

B.T. _____ Depth _____

INITIAL FLOW

	Time Defl. .000"	Log $\frac{t+\theta}{\theta}$	PSIG Temp. Corr.	Time Defl. .000"	Log $\frac{t+\theta}{\theta}$	PSIG Temp. Corr.	Time Defl. .000"	Log $\frac{t+\theta}{\theta}$	PSIG Temp. Corr.
0.	.0000		346.3-Q	.0000		352.5-Q			
1.	.0885		613.3*	.0861		155.9			
2.	.1566		165.5	.1522		160.2			
3.	.2247		163.3	.2184		153.8			
4.	.2928		156.8	.2846		149.5			
5.	.3609		154.6	.3508		149.5			
6.	.4290		150.3	.4170		147.4			
	20 minute intervals								
	*Interval = 26 minutes								
	126 TOTAL MINUTES								
	INITIAL CLOSED IN PRESSURE								
0.	.0000	-----	150.3	.0000	----	147.4			
1.	.0342	1.132	444.4	.0332	1.132	425.2			
2.	.0684	.862	684.0	.0664	.862	668.8			
3.	.1026	.714	893.2	.0996	.715	886.7			
4.	.1368	.617	1053.8	.1328	.617	1048.8			
5.	.1710	.545	1191.8	.1660	.546	1193.2			
6.	.2052	.490	1323.2	.1992	.490	1326.9			
7.	.2394	.446	1439.6	.2324	.446	1443.7			
8.	.2736	.410	1547.4	.2656	.410	1552.0			
9.	.3078	.379	1644.4	.2988	.379	1647.5			
10.	.3421	.353	1730.6	.3320	.353	1726.1			
11.	.4447	.293	1896.5	.4316	.294	1891.7			
12.	.5473	.251	2000.0	.5312	.252	1997.8			
13.	.6499	.220	2079.9	.6308	.220	2076.4			
14.	.7526	.196	2140.3	.7304	.196	2135.8			
15.	.8552	.177	2187.8	.8300	.177	2184.6			
16.	.9578	.161	2231.0	.9296	.161	2227.1			
17.	1.0605	.148	2265.6	1.0292	.148	2263.2			
18.	1.1631	.136	2293.7	1.1288	.137	2284.4			
19.	1.2657	.127	2319.6	1.2284	.127	2318.4			
20.	1.3684	.118	2343.4	1.3280	.119	2339.6			
21.	1.4710	.111	2360.6	1.4276	.111	2346.0			
22.	1.5736	.105	2375.8	1.5272	.105	2373.6			
23.	1.6350	.101	2382.2	1.5870	.101	2382.1			
	First 10 intervals = 10 minutes each; next 12 intervals = 30 minutes each; last interval = 18 minutes								
	478 TOTAL MINUTES								

Remarks: _____

Q = Questionable

Gas Production

CORRECTED COPY

B.T. Gauge Numbers			7489	5160	Ticket Number	727294	
			PRESSURE	PRESSURE			
Initial Hydrostatic			3121	3117	Elevation	6940	ft.
Final Hydrostatic			3121	3117	Production Rate 1st Flow	21.6	MCF
1st Flow	Initial	Time	346	353	Production Rate 2nd Flow	-	MCF
	Final	126	150	147	Production Rate 3rd Flow	-	MCF
	Closed In Pressure	478	2382	2382	Hole Size	6.25	in.
2nd Flow	Initial	Time			Footage Tested	51	ft.
	Final				Mud Weight	8.33	lbs./gal.
	Closed In Pressure				Gas Viscosity	.020	cp
3rd Flow	Initial	Time			Gas Gravity	.70	—
	Final				Gas Compressibility	.85	—
	Closed In Pressure				Temperature	190	°F
Extrapolated Static Pressure		1st	2644	2639			
		2nd					
		3rd					
Slope P/10		1st	89	74			
		2nd					
		3rd					

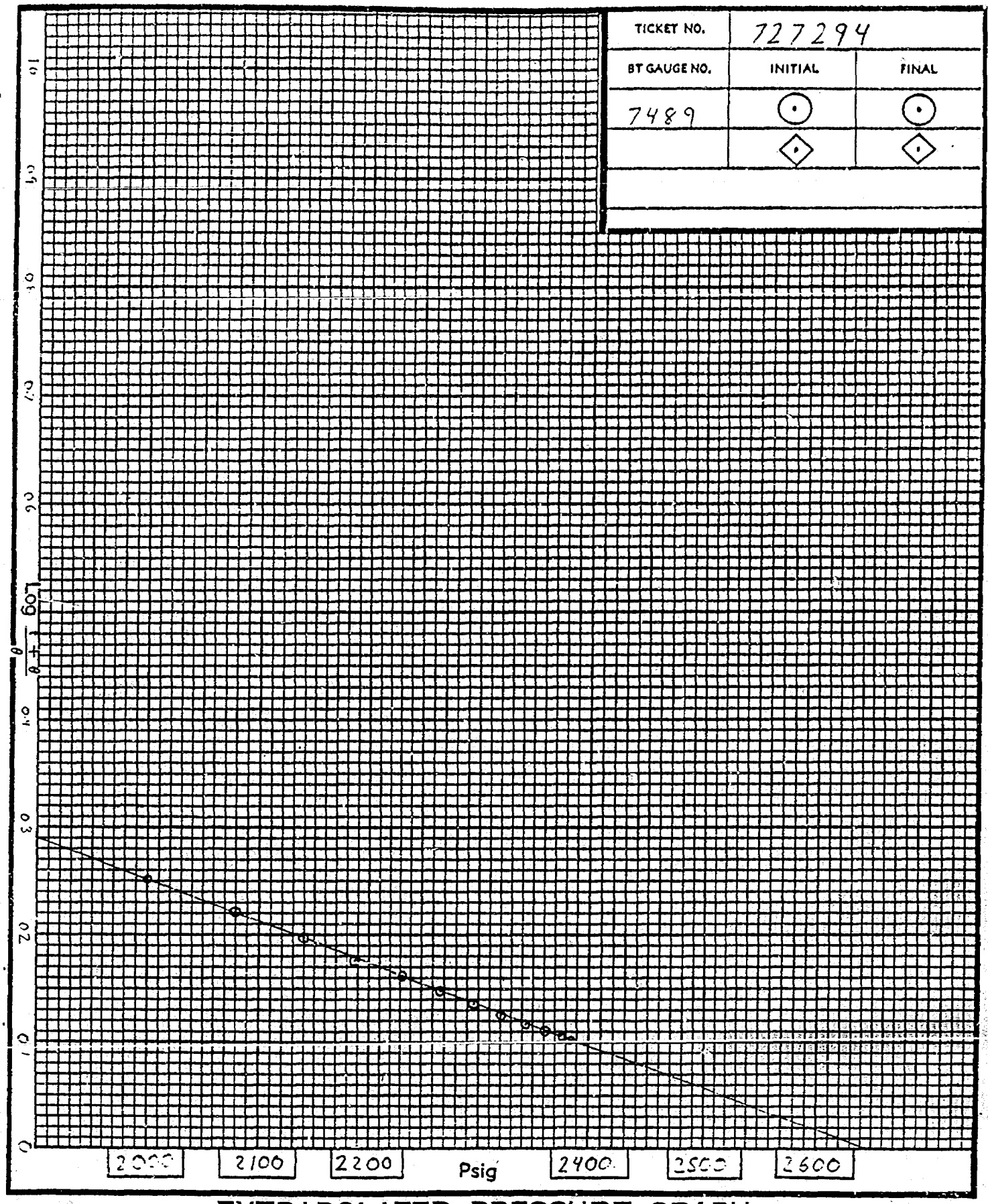
Remarks: (1) Calculations based on rates given by Bob Fielden 8-11-80 and net pay given by Marlin Thompson 10-6-80
(2) Gas gravity changed to 0.70-11-13-80

SUMMARY

PRODUCT	EQUATION	B.T. Gauge No. 7489 Depth 7245' FIRST	SECOND	THIRD	B.T. Gauge No. 5160 Depth 7257' FIRST	SECOND	THIRD	UNITS
Transmissibility	$\frac{Kh}{\mu} = \frac{1637\,Q_g\,ZT}{m}$	2.798			2.807			$\frac{md.\,ft.}{cp}$
Theoretical Flow Capacity	$Kh = \frac{Kh}{\mu}\,\mu$	.0560			.0561			md. ft.
Average Effective	$K = \frac{Kh}{h}$	.00110			.00110			md.
Permeability	$K_1 = \frac{Kh}{h_1}$	-			-			md.
Indicated Flow Capacity	$(Kh)_g = \frac{3200\,Q_g\,\mu\,ZT\,\mathrm{Log}(0.472\,b/r_w)}{P_s^2 - P_f^2}$	.0066			.0067			md. ft.
Damage Ratio	$DR = \frac{\text{Theo. Flow Cap}}{\text{Indicated Flow Cap}} \frac{Kh}{(Kh)_g}$	8.454			8.390			—
Indicated Flow Rate	$OF_1 = \frac{Q_g\ P_s^2}{P_s^2 - P_f^2}$ Max.	21.670			21.667			MCFD
	$OF_2 = \frac{Q_g\ P_s}{\sqrt{P_s^2 - P_f^2}}$ Min.	21.635			21.634			MCFD
Theoretical Potential Rate	$OF_3 = OF_1\ DR$ Max.	183.205			181.791			MCFD
	$OF_4 = OF_2\ DR$ Min.	182.910			181.509			MCFD
Approx. Radius of Investigation	$b \cong \sqrt{Kt}$ or $\sqrt{Kt_0}$	.632			.633			ft.
	$b_1 \cong \sqrt{K_1 t}$ or $\sqrt{K_1 t_0}$	-			-			ft.
Potentiometric Surface *	$Pot. = (EI - GD) + (2.319\,Ps)$	-			-			ft.

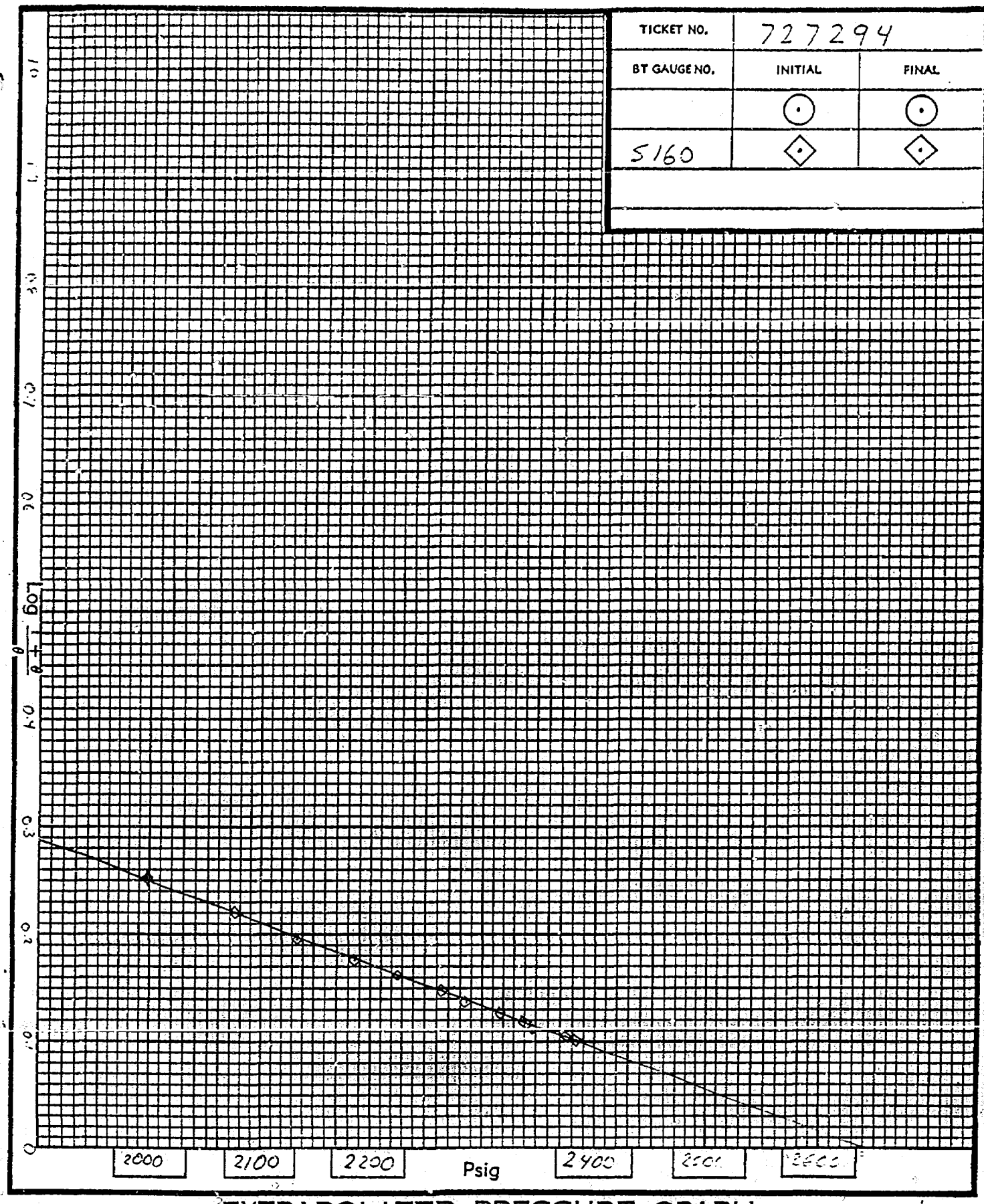
NOTICE: These calculations are based upon information furnished by you and taken from Drill Stem Test pressure charts, and are furnished you for your information. In furnishing such calculations and evaluations based thereon, Halliburton is merely expressing its opinion. You agree that Halliburton makes no warranty express or implied as to the accuracy of such calculations or opinions, and that Halliburton shall not be liable for any loss or damage, whether due to negligence or otherwise, in connection with such calculations and opinions.

TICKET NO.	727294	
BT GAUGE NO.	INITIAL	FINAL
7489	⊙	⊙
	◇	◇



EXTRAPOLATED PRESSURE GRAPH

TICKET NO.	727294	
BT GAUGE NO.	INITIAL	FINAL
	⊙	⊙
5160	◇	◇



EXTRAPOLATED PRESSURE GRAPH

FORM 184—PRINTED IN U.S.A.

LITTLE'S

TICKET NO. 727294

	O. D.	I. D.	LENGTH	DEPTH
Drill Pipe or Tubing	2 3/8"	1.995"	7229.9'	
Drill Collars				
Reversing Sub				
Water Cushion Valve				
Drill Pipe				
Drill Collars				
Handling Sub & Choke Assembly				
Dual CIP Valve	3.03"	1"	5'6"	7229.9'
Dual CIP Sampler				
Hydro-Spring Tester	3.03"	1.13"	4'10"	7235.5'
Multiple CIP Sampler				
Extension Joint				
AP Running Case	3.03"	2.31"	4'8½"	7245'
X over				
Hydraulic Jar				
VR Safety Joint	3.03"	1.75"	2'8¼"	
Pressure Equalizing Crossover				
X over	3.03"	1.75"	1'	
Packer Assembly	4½"	1.90"	3'4"	7249'
Distributor				
Packer Assembly				
Perforated anchor	2 3/8"	1.90"	4'2"	
Flush Joint Anchor				
Pressure Equalizing Tube				
Blanked-Off B.T. Running Case				
Drill Collars				
Anchor Pipe Safety Joint				
Packer Assembly				
Distributor				
Packer Assembly				
Anchor Pipe Safety Joint				
Side Wall Anchor				
Drill Collars				
Flush Joint Anchor				
Blanked-Off B.T. Running Case	3.03"	2.31"	4'	7257.2'
Total Depth				7480'

FORM 107-R2 – PRINTED IN U.S.A.

EQUIPMENT DATA

UTILITY PRINT 75C 3/80

CONSOLIDATED OIL & GAS, INC.

WILMERDING NO. 1-M

NE/4 NW/4 10-T31N-R13W

BASIN DAKOTA FIELD

SAN JUAN COUNTY, NEW MEXICO

Data:

	Lower Dakota	Upper Dakota
Midperforations	6817'	6697'
Qg	Too Small to Measure	Not Tested
h (log)	27'	57'
K (permeability)	Inadequate gas to compute flow rate and permeability (K) is much less than 0.1 md.	

Exhibit No. 6B-1

CONSOLIDATED OIL & GAS, INC.

KLINE NO. 1M

NE/4 SE/4 10-31N-13W

BASIN DAKOTA FIELD

Calculation of Permeability Using Darcy's Law:

Data:

	Lower Dakota	Upper Dakota
Midperforations	6696'	6567'
Qg	12850 SCF (test)	Gas Too Small To Measure
h	38' feet (log)	
Pwf	38 Psia	
Pe	2592 Psia	
g_g	.70	
T	186°-646°R	
re	1320 feet	
rw	0.02 feet	
Psc	668 Psia	
Tsc	392°Rankin	
Ug	.014 cp	
Z	0.91	

Where:

Qg = gas flow rate
h = net pay
Pwf = flowing bottomhole pressure
Pe = shut-in bottomhole pressure at drainage radius, re
g_g = gas specific gravity
T = bottomhole temperature
re = drainage radius for 160 acre spacing
rw = wellbore radius
Psc = pseudo critical pressure
Tsc = pseudo critical temperature
Ug = gas viscosity
Z = compressibility factor for gas

Formula:

$$K = \frac{Q_g U_g T Z \ln(.61re/rw)}{703h(Pe^2 - Pwf^2)}$$

$$K = \frac{12850x.014x646x.91x\ln(.61x\frac{1320}{.20})}{703x38x(2592^2 - 38^2)}$$

$$K = .0000049 \text{ D}$$

$$K = .0049 \text{ md.}$$

Exhibit No. 6B-2

CONSOLIDATED OIL & GAS, INC.
SEMTER NO. 1M
NE/4 SE/4 24-T31N-R13W
BASIN DAKOTA FIELD
SAN JUAN COUNTY, NEW MEXICO

Calculation of Permeability Using Darcy's Law:

Data:

	Lower Dakota	Upper Dakota
Midperforations	6928	6728
Qg Scf (test)	2730	52000
h feet (log)	58	51
Pwf Psia	20	32
Pe by analogy & tests	2658	2592
G_g typical gravity field gas	.70	.70
T calculated	186°F(646°R)	186°F(646°R)
re feet	1320	1320
rw feet	.20	.20
Psc Psia	668	668
Tsc °Rankin	392°R	392°R
Ug cps(calc.)	.014	.014
Z (calc)	.91	.91

Where:

Qg = gas flow rate
h = net pay
Pwf= flowing bottomhole pressure
Pe = shut-in bottomhole pressure at drainage radius, re
gg = gas specific gravity
T = bottomhole temperature
re = drainage radius for 160 acre spacing
rw = wellbore radius
Psc= pseudo critical pressure
Tsc= pseudo critical temperature
Ug = gas viscosity
Z = compressibility factor for gas

Formula:

$$Qg = \frac{703Kh(Pe^2-Pf^2)}{UgTZ\ \ln(.61re/rw)} \qquad \text{and } K = \frac{QgUgTZ\ \ln(.61re/rw)}{703h(Pe^2-Pwf^2)}$$

Lower Dakota

$$K = \frac{2730(.014)(646)(.91)\ln(.61x\frac{1320}{.20})}{(703)(58)(2658^2-20^2)}$$

= .00000068 D
= .00068 md.

Upper Dakota

$$K = \frac{52000(.014)(646)(.91)\ln(.61x\frac{1320}{.20})}{(703)(51)(2592^2-32^2)}$$

= .0000146 D
= .0146 md.

Exhibit No. 6B-3

SOUTHLAND ROYALTY COMPANY
PATTERSON "B" COM. 1E
SW-2-31N-12W
BASIN DAKOTA FIELD
SAN JUAN COUNTY, NEW MEXICO

Calculation of Permeability using Darcy's Law:

Data:

Qg = 224,000 SCFD (open hole test)
h = 34 feet (log)
Pwf= 54 psia (measured at surface and calculated to bottomhole)
Pe = 2650 psia (DST in East No. 7E located 9600' to south)
g_g = .70
T = 190°F = 650°R (calc.)
re = 1320 feet
rw = 0.20 feet
Psc= 668 psia
Tsc= 392°R
Ug = .014 cps (calc.)
Z = .87 (calc.)

Where:

Qg = gas flow rate
h = net pay
Pwf= flowing bottomhole pressure
Pe = shut-in bottomhole pressure at drainage radius, re
g_g = gas specific gravity
T = bottomhole temperature
re = drainage radius for 160 acre spacing
rw = wellbore radius
Psc= pseudo critical pressure
Tsc= pseudo critical temperature
Ug = gas viscosity
Z = compressibility factor for gas

$$Qg = 703\ Kh\ \frac{(Pe^2 - Pwf^2)}{Ug\ T\ Z\ \ln\ (.61\ re/rw)}$$

$$K = \frac{Qg\ Ug\ T\ Z\ \ln\ (.61\ re/rw)}{(703\ h\ (Pe^2 - Pwf^2)}$$

$$K = 224{,}000\ (.014)\frac{(650)(.87)\ \ln\ (.61\ 1320/.20)}{703\ (34)\ (2650^2-54^2)}$$

K = .0000877 D.

K = .0877 md.

Exhibit No. 6B-4

EL PASO NATURAL GAS COMPANY
CASE NO. 8
NE-18-31N-11W
BASIN DAKOTA FIELD
SAN JUAN COUNTY, NEW MEXICO

Depth (feet)		Permeability (md.)
7254-55		.41
55-56		.32
56-57		.11
57-58		.02
58-59		.03
59-60		.12
60-61		.02
61-62		.07
7338-39		.09
39-40		.12
40-41		.04
41-42		.04
42-43		.04
43-44		.04
44-45		.02
45-46		.06
46-47		.07
47-48		.29
48-49		.03
49-50		.14
50-51		.07
51-52		.04
53-54		.56
54-55		.01
55-56		.24
7364-65		.07
65-66		.05
66-67		.08
67-68		.02
68-69		.52
69-70		.03
70-71		.23
71-72		.02
7390-91		.33
91-92		.03
92-93		.02
93-94		.02
Totals	37	4.42
Average Laboratory		.1195
Average In Situ		.0335

Exhibit No. 6C-1

EL PASO NATURAL GAS COMPANY
MOORE NO. 8
SW-24-32N-12W
BASIN DAKOTA FIELD
SAN JUAN COUNTY, NEW MEXICO

Depth (feet)		Permeability (md.)
7589-90		.01
7591-92		.01
7593-94		.05
7595-96		.01
7597-98		.07
7599-7600		.01
7601-02		.08
7603-04		.01
7605-06		.01
7607-08		.01
7609-10		.02
7611-12		.01
7670-71		.03
71-72		.05
72-73		.48
73-74		.01
74-75		.01
75-76		.07
76-77		.03
78-79		.01
79-80		.09
80-81		.01
81-82		.11
82-83		.17
83-84		.08
84-85		.01
85-86		.02
86-87		.01
87-88		.04
88-89		.01
89-90		.01
90-91		.29
91-92		.07
92-93		.02
93-94		.01
94-95		.01
95-96		.02
96-97		.02
97-98		.12
Totals	39	2.10
Average Laboratory		.0538
Average In-Situ		.0151

Exhibit No. 6C-2

Effect of Overburden Pressure and Water Saturation on Gas Permeability of Tight Sandstone Cores

Rex D. Thomas, SPE-AIME, U. S. Bureau of Mines
Don C. Ward, SPE-AIME, U. S. Bureau of Mines

Research conducted to determine the potential of nuclear explosions to stimulate gas production verifies that the gas permeability of tight sandstone cores is markedly decreased with increasing overburden pressure. Water saturation also reduces the gas permeability by a large amount. The relative permeability, however, does not change significantly with overburden pressure.

Introduction

Research on the potential of nuclear explosions to stimulate gas production from low-permeability (tight) sandstone reservoirs is being conducted by the U. S. Bureau of Mines in cooperation with the Atomic Energy Commission. This report describes the part of that research that was conducted to establish correlation between permeability measured on dry cores at low external pressure (routine analysis) and permeability at reservoir conditions.

Cores used in this research were obtained from two Plowshare gas-stimulation projects. Project Gasbuggy cores from the Pictured Cliffs formation, Choza Mesa field, Rio Arriba County, N. M., can be described as very fine grained, slightly calcareous, well indurated sandstone. Project Wagon Wheel cores from the Fort Union formation, Pinedale field, Sublette County, Wyo., can be described as very fine grained, slightly calcareous, very well indurated sandstone.

Underground reservoirs are under considerable compressive stress as a result of the weight of overlying rocks (offset somewhat by internal-fluid pressure). The resultant net confining pressure or effective overburden pressure is referred to in this report simply as overburden pressure. The resulting effects on the physical properties of the reservoir rock have been studied.[1-5] Overburden pressure causes only a small decrease in porosity, which can usually be ignored.[5] This was confirmed for Project Gasbuggy and Project Wagon Wheel cores. A commercial laboratory found that the porosity of these cores is reduced by about 5 percent of the original porosity. The effect of overburden pressure on permeability, however, is appreciable and varies considerably for different reservoir rocks,[1,2] causing greater reductions in permeability for low-permeability rocks.[2,3] The effect of overburden pressure on relative permeability has been found to be small[4] or nonexistent.[5]

This report presents material that confirms and extends previous research findings on the effect that overburden pressure has upon the permeability of dry cores. Also presented are the results of research on the relative gas permeability of low-permeability cores under overburden pressure.

Apparatus and Procedure

Cylindrical cores 2.0 to 7.5 cm long and 2.5 cm in diameter were cut parallel to the bedding plane. After the cores were dried overnight in a vacuum oven (4.5 psia, 70°C), the gas (N_2) permeability of each core was measured in a Hassler cell. An external pressure of 100 psi over the inlet pressure was used to maintain a good seal between the rubber sleeve and the core.[6] Permeability was measured at inlet pressures of 45, 60, and 100 psia, with atmospheric pressure at the outlet. A bubble tube and timer were used to measure gas flow rate. Initial permeability (k_i) then was calculated by the Klinkenberg technique to correct for the effect of gas slippage. All other permeabilities reported here were calculated by this method.

In the same manner, permeability was measured at

Exhibit No. 7

increasing external pressures of about 500, 1,000, 2,000, 3,000, 4,000, 5,000, and 6,000 psi. External pressures actually were somewhat higher to compensate for internal pressure. The core and staniless steel end pieces were placed in a rubber sleeve (piece of bicycle innertube) 0.1 cm thick. Rubber cement was used to seal the stainless steel end pieces to the rubber sleeve. Shrinkable plastic tubing proved unsatisfactory because high pressure was required to seal the core. The jacketed core was mounted in a high-pressure cell with distilled water as the external fluid.

Cores used in relative permeability studies were first subjected to high external pressure and then allowed to recover their initial permeability. Bulk volume, dry weight, and porosity were measured by conventional gas-expansion techniques. Cores then were subjected to a vacuum (0.3 psia) for 2 hours, immersed in water, and allowed to stand under a vacuum overnight. The cores were weighed and again subjected to vacuum overnight and weighed again to assure complete saturation. Most of the cores were completely saturated after one night. Porosity values calculated on the basis of water saturation are in good agreement with those measured by conventional gas-expansion techniques.

Water in the core was allowed to evaporate at atmospheric conditions to a saturation of about 70 percent and the core was placed in the holder for 2 hours under external pressure (100 psi above inlet) only so the water saturation was uniform. Gas permeability then was measured at three inlet pressures between 30 and 100 psia with atmospheric pressure at the outlet. This procedure was repeated for decreasing water saturations at the same external pressure. After the permeability was measured the core was weighed to determine if any water was lost. In all cases the amount lost was negligible. After the core was dried in a vacuum oven, the gas permeability at this external pressure was measured. The procedure was repeated for external pressures of 3,000 and 6,000 psi.

Results and Discussion

Effect of Overburden Pressure on Permeability

Core number, length, porosity, and initial permeability of the cores used in this research are shown in Table 1. The core number refers to the depth in feet at which the core was obtained. Typical plots of the effect of simulated overburden pressure on Gasbuggy cores are shown in Fig. 1. The permeability is decreased by about 75 percent at an overburden pressure of 3,000 psi and by 90 percent at 6,000 psi. The hydrostatic loading used in these experiments does not reproduce subsurface conditions exactly; in an actual reservoir the horizontal component of stress is usually less than the vertical component. Since the actual loading is not known, this method probably is as realtistic as any other. Cores that contain microfractures are affected to a greater extent, as shown in Fig. 2. In these cores the permeability is decreased by about 95 percent at a simulated overburden pressure of 3,000 psi, with most of the reduction occurring below 2,000 psi.

The data shown in Table 1 and Figs. 1 and 2 were obtained by subjecting the core to successive incre-

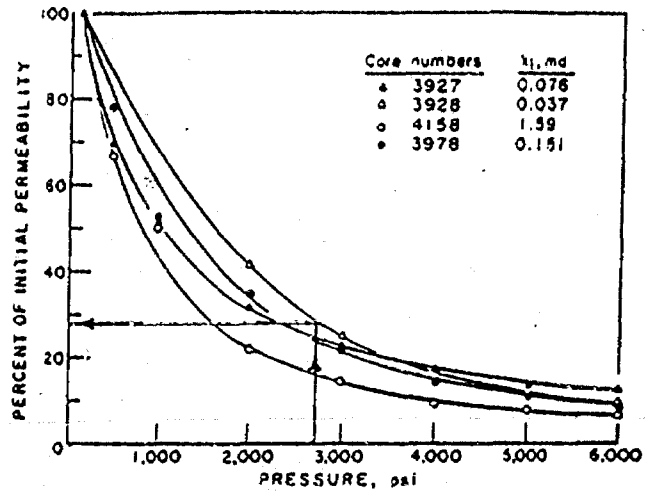


Fig. 1—Effect of overburden pressure on gas permeability of Gasbuggy cores.

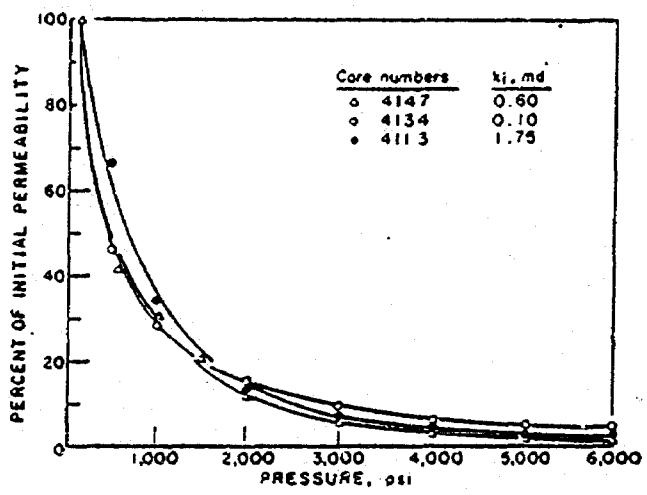


Fig. 2—Effect of overburden pressure on gas permeability of fractured Gasbuggy cores.

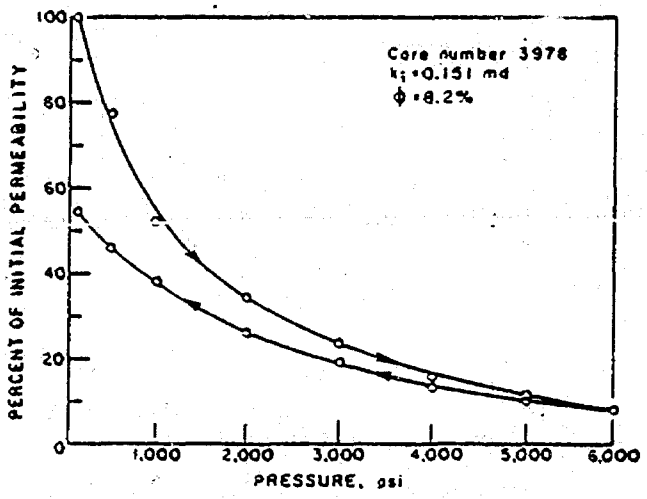


Fig. 3—Hysteresis effect at decreasing confining pressures.

TABLE 1—EFFECT OF OVERBURDEN PRESSURE ON GAS PERMEABILITY

Effective Overburden Pressure (psi):				500	1,000	2,000	3,000	4,000	5,000	6,000
Core Number*	Length (cm)	Porosity (percent)	k_i†	Permeability (md)						
Gasbuggy										
3927	2.1	8.1	0.076	0.053	0.040	0.024	0.0175	0.0132	0.0105	0.0095
3928	7.5	8.3	0.037	0.031	0.024	0.015	0.0093	0.0059	0.0046	0.0035
3978	2.1	8.2	0.151	0.118	0.078	0.052	0.036	0.024	0.0175	0.0132
4113**	2.1	10.1	1.75	1.16	0.602	0.252	0.113	0.068	0.042	0.029
4134**	2.1	11.6	0.10	0.046	0.029	0.0153	0.0095	0.0065	0.0055	0.0047
4146**	7.5	11.6	2.40	1.73	1.32	0.31	0.14	0.069	0.052	0.022
4147**	7.5	11.3	0.60	0.247	0.181	0.071	0.034	0.0186	0.0118	0.0082
4158	2.1	13.6	1.59	1.06	0.80	0.35	0.225	0.152	0.116	0.100
Wagon Wheel										
8084	3.8	7.7	0.028	0.022	0.020	0.010	0.0070	0.0047	0.0035	0.0030
8122	3.8	11.4	0.071	0.055	0.048	0.034	0.027	0.024	0.021	0.019
8975**	3.8	8.7	0.039	0.029	0.024	0.0114	0.0073	0.0048	0.0032	0.0025
10156	3.8	8.5	0.088	0.067	0.051	0.032	0.025	0.022	0.018	0.016
10990**	3.8	9.0	0.048	0.020	0.0175	0.0080	0.0050	0.0040	0.0025	0.0019

*Number denotes depth in feet.
**Slightly fractured.
†Initial permeability.

mental increases in external pressure. The core was assumed to be in equilibrium at each pressure when permeability measurements remained constant for 15 minutes, which required between 1 and 2 hours. A period of 30 minutes to an hour was required to attain equilibrium when the inlet pressure was changed. Consequently, each external pressure was maintained for a minimum of 2 hours.

The effect of decreasing external pressure was determined on a few cores, and typical results are shown in Fig. 3. Other researchers[2,3] have observed and shown that this hysteresis is mainly dependent on the stress history of the core. Cores generally recover their original permeability after 3 to 6 weeks at atmospheric conditions. This time could be shortened by storing the core in an oven at 70°C.

The effect of overburden pressure on the permeability of cores from Project Wagon Wheel is similar to that on cores from Project Gasbuggy, and typical results are shown in Fig. 6. The permeability is decreased to about 30 percent of initial permeability at an overburden pressure of 3,000 psi and to 20 percent at 6,000.

A study of the data in Table 1 indicates that the original porosity of the core and the reduction in permeability caused by overburden pressure are not related. Pore structure (fractures to uniform pores) is probably the governing factor.

Water Saturation Effects

The data in Table 2 show that the permeability decreased with increasing water saturation. The values at 20-, 40-, and 60-percent water saturation were obtained from individual relative-permeability curves for Gasbuggy and Wagon Wheel cores. Relative-permeability curves for three cores from Project Gasbuggy are shown in Fig. 4 with the data points for Core 3978. Data points were omitted for the other cores to avoid confusion. This figure shows that although gas permeability is reduced, the relative gas permeability of Gasbuggy cores is not significantly affected by increased overburden pressure. This conclusion is in agreement with the results of others.[4,5]

Extremely low values of permeability that resulted from water saturation and overburden pressure required that either long flow times or high inlet pressures (high differential across the core) be used. Since a high inlet pressure increases the end effects by changing the distribution of water in the core, long flow times were required. Although end-effect problems were encountered with the short cores (Cores 3978 and 4158), the permeability of these cores was

TABLE 2—EFFECT OF OVERBURDEN PRESSURE AND WATER SATURATION ON GAS PERMEABILITY

Water Saturation (percent):		0	20	40	60
Core Number	Pressure (psi)	Permeability (md)			
Gasbuggy					
3927	100	0.115	0.099	0.041	0.0023
3927	3,000	0.026	0.023	0.009	0.0005
3927	6,000	0.012	0.010	0.003	0.0002
3978	100	0.112	0.080	0.034	0.011
3978	3,000	0.036	0.026	0.011	0.004
3978	6,000	0.013	0.009	0.004	0.0013
4158	100	0.447	0.335	0.156	0.045
4158	3,000	0.075	0.056	0.026	0.0074
4158	6,000	0.027	0.020	0.010	0.0026
Wagon Wheel					
8084	100	0.038	0.030	0.014	0.0042
8084	3,000	0.012	0.0096	0.0043	0.0013
8084	6,000	0.0070	0.0056	0.0025	0.0008
8122	100	0.074	0.054	0.017	0.006
8122	3,000	0.027	0.020	0.008	0.002
8122	6,000	0.020	0.015	0.006	0.002
10156	100	0.100	0.074	0.029	0.003
10156	3,000	0.028	0.020	0.008	0.0008
10156	6,000	0.017	0.013	0.005	0.0005

high enough to yield reasonable results. Permeability measurements for Core 4161 (7.5 cm long, 0.053 md) required more than 2 hours per reading. These extremely long flow times can cause errors.

End effects, long flow times, and changes in permeability due to water saturation tend to decrease the accuracy of permeability measurements, especially at the higher water saturations.

The initial permeability of many of the dry cores used in this research was not reproducible following saturation and drying. The changes probably were caused by solution of material in the pores and by particle movement. These caused both increases and decreases in permeability. The variation, although sometimes large, usually was less than 5 percent; however, we feel that the relative permeability curves are essentially correct. To eliminate the effects of solution and particle movement, the permeability of the dry core following saturation, rather than the permeability initially measured, was used in calculating relative permeability.

A composite of the relative permeability curves for Gasbuggy cores is shown in Fig. 5. These curves are representative of permeabilities encountered in this formation. At a water saturation of 50 percent, the relative permeability of the cores ranges from 15 to 20 percent and is not affected by overburden pressure.

Similar results were obtained on cores from Project Wagon Wheel, as shown in Table 2 and Fig. 6 with data points for Core 8122. These cores were cut to a length of 3.8 cm to alleviate some of the long flow time and end-effect difficulties encountered with Gasbuggy cores. These curves are representative of the permeabilities encountered in the formation. At a water saturation of 50 percent, the relative permeability of these cores ranges from 12 to 21 percent. The data in these figures show, as do the data from Gasbuggy cores, that relative gas permeability is not significantly affected by increased overburden pressure.

Correlation with Nuclear Stimulation Projects

Many of the basin areas of the Rocky Mountain region consist of thick, low-permeability sandstones containing large quantities of natural gas. This type of reservoir has been the object of the AEC's Plowshare Program experiments, Projects Gasbuggy and Rulison, and proposed Projects Wagon Wheel, WASP, and Rio Blanco. Because most wells in these reservoirs have not been commercial, only limited reservoir-analysis and production-test data are available. Reservoir analysis is most difficult because low permeability requires long-term testing. Also, it is difficult to determine permeability and net pay from these tests. Knowledge of the gas permeability is necessary in predicting gas recovery, and because it is not economical to define the characteristics of different strata by well test, it is desirable to be able to relate laboratory-measured permeability to the true in-situ permeability.

Conventional analysis by a commercial laboratory (confirmed in our laboratory) of about 200 Gasbuggy cores gave an average initial gas permeability of 0.16 md on dry cores and an average water saturation of 48 percent. The effective overburden pressure of this

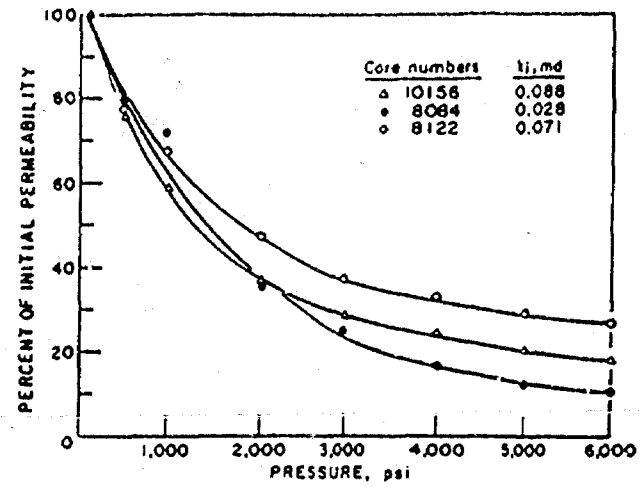


Fig. 4—Effect of overburden pressure on gas permeability of Wagon Wheel cores.

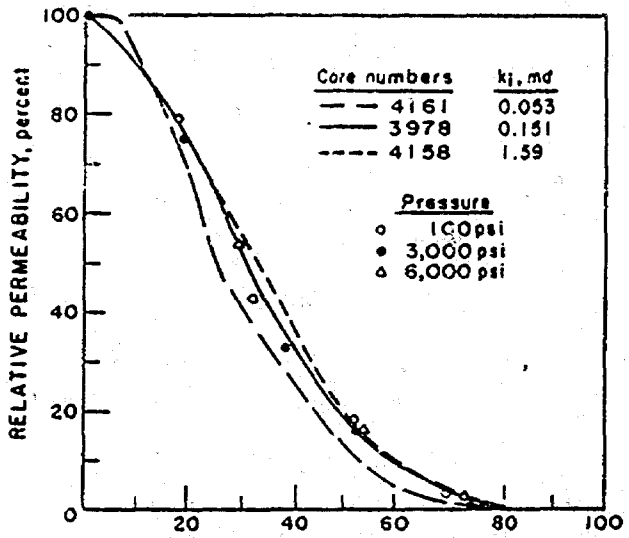


Fig. 5—Relative gas permeability of Gasbuggy cores.

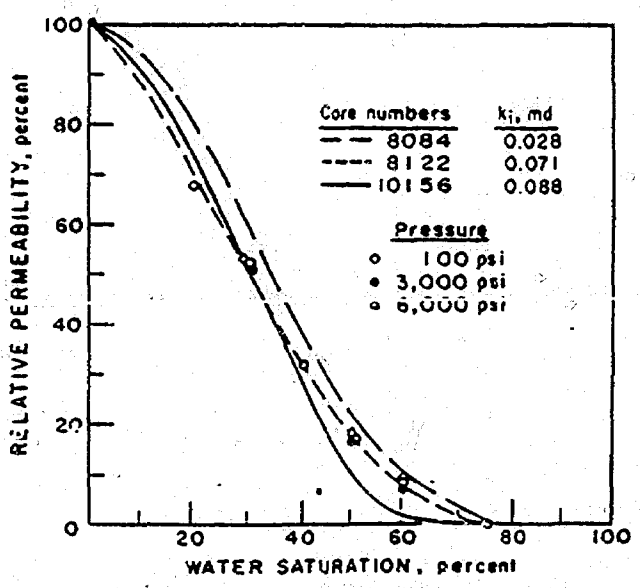


Fig. 6—Relative gas permeability of Wagon Wheel cores.

reservoir is about 3,000 psi. From Fig. 1, the reduction factor resulting from the overburden pressure is 0.25, and the reduction factor for a water saturation of 48 percent (Fig. 5) is 0.20; thus the total reduction is 5 percent of the initial permeability, or 0.008 md. This value compares favorably with permeability determinations of about 0.01 md from both preshot and postshot flow testing at Gasbuggy. The gas reservoir at Project Rulison is similar to that at Gasbuggy, having an average initial dry permeability of 0.11 md and an average water saturation of 45 percent. Simulated in-situ permeability has not yet been measured in the laboratory on Rulison cores; however, using an effective overburden pressure of 5,000 psi and curves of Gasbuggy core data (Figs. 1 and 5), the reduction factor because of overburden pressure would be 0.12 and that for water saturation 0.24. This results in a combined reduction to 3 percent of the initial permeability, or 0.003 md. Postshot production testing at Rulison is not complete, and the only preshot determination of permeability was made from tests of a 32-ft isolated zone that gave an average value of 0.008 md. No cores are available from this zone. Rulison reservoir rock is said to be less compressible than that of Gasbuggy; therefore Gasbuggy pressure-effect data would be expected to indicate a greater reduction for Rulison than actually exists.

The average initial permeability of dry Wagon Wheel cores is 0.068 md, with an average water saturation of 50 percent. An estimated effective overburden pressure of 3,000 psi gives a reduction factor of 0.28 (Fig. 4). Water saturation further reduces permeability by a factor of 0.18 (Fig. 6). Therefore, the total reduction in permeability is to approximately 5 percent of the initial permeability, or 0.0034 md. This value can be used to predict postshot gas recovery from the proposed Wagon Wheel experiment.

Cores are not yet available from Projects Rio Blanco and WASP.

Original manuscript received in Society of Petroleum Engineers office June 16, 1971. Revised manuscript received Dec. 20, 1971. Paper (SPE 3634) was presented at SPE 46th Annual Fall Meeting, held in New Orleans, Oct. 3-6, 1971.

Conclusions

The gas permeability of tight sandstone cores is markedly decreased with increasing overburden pressure. Most of the decrease takes place at pressures to 3,000 psi. At 3,000 psi, the permeability of unfractured samples ranges from 14 to 37 percent of the initial permeability. In fractured samples, permeability may be reduced to as low as 6 percent of initial permeability.

Water saturation also reduces the gas permeability greatly; however, the relative permeability does not change significantly with overburden pressure.

Permeability calculated from laboratory results are in good agreement with in-situ permeabilities determined from production test data. Although not confirmed, predictions for other projects appear to be reasonable.

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EXHIBIT 8A

Consolidated Oil & Gas, Inc.

WELL COST ESTIMATE

AVERAGE DAKOTA WELL WITH UPPER & LOWER DAKOTA, 2 FRACS

AFE No. _____
C.O.G. WI. _____

TO: Drill ( ) Recomplete ( ) Work Over ( )

State New Mexico County San Juan Field Basin Dakota

Lease Name Average Dakota Well Lease No. _____ Well No. Unnamed No. 1

Location: T13N, R12 & 13W - Average Dakota Well

DETAIL COST ESTIMATE				
INTANGIBLE COSTS	QUANTITY	PRICE	COST OF DRY HOLE	COST OF PRODUCER
Superintendence	15/25	300	4,500	7,500
Labor			1,000	3,500
Hauling				8,000
Drilling				
To Drill	7,000	$16/ft.	112,000	112,000
Day Work - W/DP	2	5,800	11,600	11,600
Day Work - W/out Drill pipe				
Other Completion Unit w/compl. equip.	10	2,500		25,000
Fuel			1,000	3,000
Water			9,000	11,000
Right of Way Damages			1,500	1,500
Drlg. Mud & Chemicals			22,000	24,000
Electric & Radioactivity Logs			16,000	16,000
Coring & Core Analysis				
Acidizing & Fracturing 2 Fracs using Nitrogen				75,000
Drill Stem Tests				
Gun Perforating & CBL 2 Dakota zones				8,000
Cement & Cementing Services) Surf.& 3-stage			4,000	23,000
Shoes, Collars, & Centralizers) Prod. w/DV tools				
Welding				
Road & Location			5,000	6,000
Bits & Coreheads				700
Mud Logging				
Plugging Expense			7,500	
Equipment Rental (Compressors, workstring,etc.			5,000	16,000
Overhead			1,000	1,500
Contingencies 5%			10,000	17,600
TOTAL INTANGIBLE COSTS			211,100	370,900
PERMANENT EQUIPMENT				
Conductor Pipe "OD				
Surface Casing 8-5/8"OD 24#	250		2,800	2,800
Prod. Casing4-1/2" OD 10.5# ST&C	7000			39,900
Tubing 1-1/2" OD 2.9# EUE	7000			17,500
Casing Head Assembly			1,300	1,300
Tubing Head Assembly				9,500
Xmas Tree & Manifold Assembly)				
Production Packer				
Carbodic Protection				8,000
Bottom Hole Choke				
Miscellaneous Connections				4,000
Production Unit & Tank Battery				21,500
TOTAL Permanent Equipment			4,100	104,500
TOTAL COST OF COMPLETED WELL			215,200	475,400

Date: _____ Recommended by: _____

APPROVED (Company): _____ Approved by: _____

By: _____ Date: September 23, 1981

EXHIBIT 8-B

CONSOLIDATED OIL & GAS, INC.

	Cain 1-M	Jackson 2-E	Jaquez 2
Superintendent	$ 13,489	$ 4,409	$ 7,302
Labor	2,297	743	4,130
Hauling	7,426	4,826	7,133
Drilling - To Drill	105,530	107,544	90,736
Daywork	6,146	14,857	24,576
Other - Completion Rig	44,570	8,984	20,949
Fuel	3,798	246	10,449
Water	24,968	12,733	11,521
Right of Way Damages	-	-	2,000
Drilling Mud & Chemicals	37,187	32,948	34,962
Electric & Radioactivity Logs	15,840	11,381	12,929
Coring & Core Analysis	-	-	-
Acidizing & Fracturing	70,294	27,751	74,326
Tests (AOF & BHP)	1,190	673	1,298
Gun Perf. & Cs'd Hole Logging	5,975	7,300	8,790
Cement & Cementing Services	27,461	23,168	27,286
Welding	500	-	500
Road & Location	17,833	2,247	4,942
Bits & Coreheads	1,204	-	1,387
Overhead	-	1,096	-
Equipment Rental (Inc. Comp.)	29,094	7,166	50,700
Fishing Expense	43,648	-	-
Cathodic Protection	8,585	8,000	2,738
Total Initial Costs	$467,035	$276,072	$398,654
Surface Casing	$ 2,196	$ 2,337	$ 2,202
Production Casing	53,579	40,966	49,164
Tubing	16,166	17,311	15,951
Casing Head Assembly	1,320	1,320	1,320
Tubing Head Assembly	9,270	9,270	9,270
Xmas Tree & Manifold Assy.			
Production Packer			
Miscellaneous Connections	4,257	2,897	6,910
Separator & Production Tanks	13,614	11,005	12,942
Total Permanent Equipment	$100,402	$ 85,106	$ 97,759
TOTAL COST OF COMPLETED DAKOTA WELL*	$567,437	$361,178	$496,413

*Total Well Cost less Completion & Equipment Costs of Dual Zone (if any).

Note: Estimated Cost of Lower Dakota Completion	$110,402		$ 77,015

CONSOLIDATED OIL & GAS, INC.

	Kline 1-M	Langendorf 1-E	Mitchell 1-E
Superintendent	$ 14,768	$ 6,303	$ 7,851
Labor	9,174	3,584	8,819
Hauling	3,149	6,071	25,408
Drilling - To Drill	101,079	101,228	93,420
Daywork	5,807	7,639	48,985
Other - Completion Rig	41,400	17,877	20,113
Fuel	622	7,457	3,751
Water	6,529	21,236	4,555
Right of Way Damages	4,000	-	-
Drilling Mud & Chemicals	11,342	23,845	91,000
Electric & Radioactivity Logs	21,399	14,305	13,705
Coring & Core Analysis	-	-	-
Acidizing & Fracturing	75,323	83,944	74,037
Tests (AOF & BHP)	715	1,123	1,939
Gun Perf. & Cs'd Hole Logging	6,294	9,360	7,565
Cement & Cementing Services	24,024	25,132	12,687
Welding	-	500	-
Road & Location	9,977	5,419	5,725
Bits & Coreheads	-	1,492	-
Overhead	-	-	1,788
Equipment Rental (Inc. Comp.)	25,181	32,533	58,246
Fishing Expense	-	-	-
Cathodic Protection	4,748	8,146	8,160
Total Initial Costs	$365,531	$377,194	$487,754
Surface Casing	$ 3,141	$ 2,138	$ 2,194
Production Casing	52,026	47,765	41,102
Tubing	14,286	14,660	14,227
Casing Head Assembly	1,325	1,320	371
Tubing Head Assembly	9,250	9,270	9,710
Xmas Tree & Manifold Assy.			
Production Packer			
Miscellaneous Connections	5,642	10,957	3,849
Separator & Production Tanks	12,380	12,410	13,016
Total Permanent Equipment	$ 98,050	$ 98,520	$ 84,469
TOTAL COST OF COMPLETED DAKOTA WELL*	$463,581	$475,714	$572,223

*Total Well Cost less Completion & Equipment Costs of Dual Zone (if any).

Note: Estimated Cost of Lower Dakota Completion	$ 70,440	$ 76,390	$ 54,052

CONSOLIDATED OIL & GAS, INC.

	Neuman 1-E	Payne 1-E	Phillips 1-E
Superintendent	$ 4,624	$ 3,997	$ 8,974
Labor	359	3,022	4,967
Hauling	4,467	5,368	6,641
Drilling - To Drill	111,552	108,753	92,201
Daywork	15,316	12,988	6,627
Other - Completion Rig	13,154	18,036	19,205
Fuel	-	4,532	1,836
Water	15,851	18,592	6,000
Right of Way Damages	-	-	1,000
Drilling Mud & Chemicals	30,076	19,214	12,457
Electric & Radioactivity Logs	14,739	12,899	12,782
Coring & Core Analysis	-	-	-
Acidizing & Fracturing	34,738	75,960	67,794
Tests (AOF & BHP)	366	456	-
Gun Perf. & Cs'd Hole Logging	7,040	7,994	13,450
Cement & Cementing Services	16,072	27,079	25,099
Welding	-	500	304
Road & Location	2,472	3,146	8,178
Bits & Coreheads	-	1,428	-
Overhead	1,194	-	-
Equipment Rental (Inc. Comp.)	6,554	30,359	8,559
Fishing Expense	-	-	-
Cathodic Protection	8,008	8,519	8,425
Total Initial Costs	$286,582	$362,842	$304,499
Surface Casing	$ 2,073	$ 2,403	$ 2,543
Production Casing	42,779	53,260	53,179
Tubing	17,073	15,039	13,426
Casing Head Assembly	1,419	1,320	1,284
Tubing Head Assembly	6,375	9,270	10,590
Xmas Tree & Manifold Assy.			
Production Packer			
Miscellaneous Connections	2,848	2,823	3,846
Separator & Production Tanks	11,697	12,812	12,052
Total Permanent Equipment	$ 84,264	$ 96,927	$ 96,920
TOTAL COST OF COMPLETED DAKOTA WELL*	$370,846	$459,769	$401,419
Note: Estimated Cost of Lower Dakota Completion	-	$ 73,716	$ 32,391

*Total Well Cost less Completion & Equipment Costs of Dual Zone (if any)

CONSOLIDATED OIL & GAS, INC.

	Robinson Bros. 1-M	So. Union 1-M	So. Union 2-E
Superintendent	$ 11,258	$ 16,493	$ 7,129
Labor	1,760	3,272	3,406
Hauling	10,995	9,958	2,769
Drilling - To Drill	119,913	91,611	109,918
Daywork		30,638	11,541
Other - Completion Rig	16,062	68,746	25,227
Fuel	2,525	3,577	1,247
Water	3,000	19,732	9,935
Right of Way Damages	1,643	-	-
Drilling Mud & Chemicals	36,064	40,695	32,649
Electric & Radioactivity Logs	15,838	19,787	13,337
Coring & Core Analysis	-	14,176	-
Acidizing & Fracturing	54,731	71,878	56,294
Tests (AOF & BHP)	490	-	420
Gun Perf. & Cs'd Hole Logging	9,131	13,150	12,162
Cement & Cementing Services	29,273	27,273	18,445
Welding	-	337	-
Road & Location	23,095	4,306	3,575
Bits & Coreheads	1,568	2,827	-
Overhead	-	2,705	-
Equipment Rental (Inc. Comp.)	11,624	29,810	33,801
Fishing Expense	-	-	-
Cathodic Protection	6,001	8,300	4,003
Total Initial Costs	$354,971	$479,771	$345,858
Surface Casing	2,053	2,119	2,409
Production Casing	50,946	55,118	41,939
Tubing	14,983	14,795	18,725
Casing Head Assembly	1,320	1,320	1,419
Tubing Head Assembly	9,270	9,720	9,280
Xmas Tree & Manifold Assy.			
Production Packer			
Miscellaneous Connections	3,007	3,307	3,373
Separator & Production Tanks	12,640	13,211	14,776
Total Permanent Equipment	$ 94,219	$ 99,590	$ 91,921
TOTAL COST OF COMPLETED DAKOTA WELL*	$449,190	$579,361	$437,779
Note: Estimated Cost of Lower Dakota Completion	$ 43,433	$ 94,851	$ 58,494

* Total Well Cost less Completion & Equipment Costs of Dual Zone (if any).

CONSOLIDATED OIL & GAS, INC.

	Starr 1-M	Templeton 1-E	Wilmerding 1-M
Superintendent	$ 8,263	$ 11,290	$ 9,004
Labor	2,057	2,761	8,167
Hauling	4,118	10,337	5,929
Drilling - To Drill	102,014	85,888	93,441
Daywork	7,040	22,346	5,494
Other - Completion Rig	31,188	41,222	21,132
Fuel	2,053	2,357	725
Water	6,149	8,499	7,948
Right of Way Damages	-	4,000	2,000
Drilling Mud & Chemicals	26,879	29,000	18,834
Electric & Radioactivity Logs	16,950	21,443	18,294
Coring & Core Analysis	-	-	-
Acidizing & Fracturing	87,228	59,510	73,799
Tests (AOF & BHP)	-	506	1,058
Gun Perf. & Cs'd Hole Logging	8,742	6,881	5,259
Cement & Cementing Services	25,158	28,185	24,823
Welding	-	-	-
Road & Location	6,539	19,210	1,703
Bits & Coreheads	-	-	-
Overhead	-	3,190	-
Equipment Rental (Inc. Comp.)	28,212	42,160	15,368
Fishing Expense	-	-	-
Cathodic Protection	8,062	8,944	7,957
Total Initial Costs	$370,652	$407,729	$320,935
Surface Casing	$ 2,119	$ 2,186	$ 2,115
Production Casing	45,900	50,404	49,224
Tubing	14,500	15,675	14,237
Casing Head Assembly	1,320	1,320	1,320
Tubing Head Assembly	9,270	9,270	9,270
Xmas Tree & Manifold Assy.			
Production Packer			
Miscellaneous Connections	4,057	6,873	5,082
Separator & Production Tanks	12,577	14,025	12,380
Total Permanent Equipment	$ 89,743	$ 99,753	$ 93,628
TOTAL COST OF COMPLETED DAKOTA WELL*	$460,395	$507,482	$414,563
*Total Well Cost less Completion & Equipment Costs of Dual Zone (if any).			
Note: Estimated Cost of Lower Dakota Completion	$ 58,682	$ 62,854	$ 42,443

CONSOLIDATED OIL & GAS, INC.

	Total	Average
Superintendent	$ 135,154	$ 9,010
Labor	58,518	3,901
Hauling	114,595	7,640
Drilling - To Drill	1,514,828	100,989
Daywork	220,000	14,666
Other - Completion Rig	407,865	27,191
Fuel	45,175	3,012
Water	177,248	11,817
Right of Way Damages	14,643	976
Drilling Mud & Chemicals	477,152	31,810
Electric & Radioactivity Logs	235,628	15,709
Coring & Core Analysis	14,176	945
Acidizing & Fracturing	987,607	65,840
Tests (AOF & BHP)	10,234	682
Gun Perf. & Cs'd Hole Logging	129,093	8,606
Cement & Cementing Services	361,165	24,078
Welding	2,641	176
Road & Location	118,867	7,924
Bits & Coreheads	9,906	660
Overhead	9,973	665
Equipment Rental (Inc. Comp.)	409,367	27,291
Fishing Expense	43,648	2,910
Cathodic Protection	108,596	7,240
Total Initial Costs	$5,606,079	$373,738
Surface Casing	$ 34,228	$ 2,282
Production Casing	727,351	48,490
Tubing	231,054	15,404
Casing Head Assembly	19,018	1,268
Tubing Head Assembly	138,355	9,224
Xmas Tree & Manifold Assy.		
Production Packer		
Miscellaneous Connections	69,728	4,649
Separator & Production Tanks	191,537	12,769
Total Permanent Equipment	$1,411,271	$ 94,085
TOTAL COST OF COMPLETED DAKOTA WELL*	$7,017,350	$467,823 ✓

total for 15 wells — ave for 15 wells

* Total Well Cost less Completion & Equipment Costs of Dual Zone (if any).

Note: Estimated Cost of Lower Dakota Completion — $ 855,163 — $ 65,782

Protection of Fresh Water

State and federal regulations currently provide for the protection of any fresh water aquifers that are being used or are expected to be used in the foreseeable future for domestic or agricultural water supplies. Three potential fresh water bearing formations in the area of interest are the San Jo[illegible], Nacimiento and Ojo Alamo. These three formations occur from the surface of the ground to a depth of approximately 1,000 feet in T31N, R13W and the western half of T31N, R12W.

The NMOCD by Rule 106 and the federal government regulations for protection of fresh water in oil and gas related activities both require the casing and cementing program to be designed to seal off fresh water bearing formations from oil and gas bearing formations. They fulfill this requirement by having the oil and gas operator cement the production casing with sufficient cement to bring it above the Dakota several hundred feet, to usually cement across the Mesaverde zone when it is productive, and then to circulate cement to surface from several hundred feet below the base of the Ojo Alamo formation. Additionally, surface casing is set and cemented to surface when drilling begins which protects the top several hundred feet.

The above casing and cementing programs provide adequate protection to the fresh water sands even though large stimulation treatments are required in the tight Dakota producing formation which is about 5,900 feet below the deepest fresh water zone.

EXHIBIT 10

CONSOLIDATED OIL & GAS, INC.

ASSUMPTIONS USED IN MAKING ECONOMIC CALCULATIONS
BASIN-DAKOTA FIELD
SAN JUAN COUNTY, NEW MEXICO

Drilling and Completion Costs (including tank battery)	$475,400
Operating Costs $/Mo.	150
Depth	7,000'
Consolidated Working Interest	100%
Royalty Interest Typical to Consolidated Holdings	24.5%
Liquid Yield (BBLS./MMCF)	3.85
Fully Adjusted Gas Price as of October 1, 1981 ($/MCF)	$3.14
Maximum Gas Price ($/MCF)	$10.42
Maximum Oil Price ($/BBL.)	$50.00
Rate of Price Escalation	7%
Severance Tax	8%
Deregulation Tax Data, Base Oil Price	$14.11
Windfall Profit Tax Rate	30%

Initial Post-stimulation Stabilized Production Rate (MCFD)	Forecast 20-Year Recovery - MMCF
89	180
150	270
189	350
232 (Expected Case)	435
400	555

EXHIBIT 11

ROYALTY INTEREST CONSIDERATION

In this particular area of the San Juan Basin, Consolidated's interests are typically burdened with a 12% ORRI in addition to the base 12 1/2% royalty, resulting in a 75.5% net revenue interest to a 100% working interest.

In the industry, there are two primary means of obtaining rights to drill and produce an oil and gas property. One is to take a lease from the mineral owner by the payment of a lease bonus, normally in the form of dollars per acre. This will normally result in the mineral owner retaining a 12 1/2% royalty. However, in this case, the economics of development should include those lease bonuses as they represent a real cost of oil and gas drilling.

The second means of obtaining oil and gas leases is through farm-ins from the party(ies) who have taken the base lease. This almost always entails payment of no lease bonus and assignment of an overriding royalty interest, which may or may not be convertible into a larger working interest.

This second route represents the means of Consolidated obtaining its leases in this area. Leases were taken from parties who had obtained the leases from the mineral owners.

TYPICAL CONSOLIDATED LEASES IN AREA

Well	Net Revenue Interest to 100% Working Interest - %	Total Royalty Burden - %
Cain 1-M	75.0	25.0
Jackson 2-E	75.0	25.0
Jaquez 2	86.5	13.5
Kline 1-M	77.1	22.9
Langendorf 1-E	75.0	25.0
Mitchell 1-E	75.0	25.0
Neuman 1-E	75.0	25.0
Payne 1-E	75.0	25.0
Phillips 1-E	75.0	25.0
Robinson Bros. 1-M	82.6	17.4
Southern Union 1-M	77.5	22.5
Southern Union 2-E	75.0	25.0
Starr 1-M	75.0	25.0
Templeton 1-E	76.6	23.4
Wilmerding 1-M	76.5	23.5

Thus, in our case, our economics are burdened with a typical total royalty burden of 24.5%, but are not burdened with lease bonuses.

It is important to note that the net present value of the 12% overriding royalty, which is not burdened by costs, approximates $50,000 per location. This is about $300 per acre, which is certainly in line with proven property lease bonuses being paid.

EXHIBIT 12

BEFORE TAX ECONOMICS

EXHIBIT 12

SECTION 103 PRICE
180 MMCF GROSS
20-YEAR RECOVERY

TYPICAL WELL
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO

DATE: 09/23/81.
TIME: 17.30.29.
FILE: TYPICAL
PROJ: 1

CONSOLIDATED OIL & GAS, INC.
ECONOMICS OF DEVELOPMENT

R E S E R V E S A N D E C O N O M I C S

AS OF DATE: 1/ 1/1981

END MO-YR	GROSS OIL PRODUCTION MB (1)	GROSS GAS PRODUCTION MMF (2)	OIL TO NET INTEREST MB (3)	GAS TO NET INTEREST MMF (4)	REVENUE TO INTEREST M$ (5)	NET INVESTMENT M$ (6)	NET OPER EXPENSES M$ (7)	NET INCOME BEFORE FIT M$ (8)	CUMULATIVE NET INCOME M$ (9)	30,000 PCT CUM. DISC NET INCOME M$ (10)
12-81	0.	0.	0.	0.	0.	475.400	1.863	-477.263	-477.263	-476.914
12-82	.157	40.758	.119	30.772	92.183	0.	1.993	90.190	-387.073	-415.892
12-83	.109	28.518	.082	21.531	68.987	0.	2.133	66.854	-320.219	-381.097
12-84	.081	21.072	.061	15.910	54.559	0.	2.283	52.276	-267.943	-360.168
12-85	.063	16.206	.048	12.235	44.920	0.	2.442	42.478	-225.465	-347.086
12-86	.049	12.850	.037	9.702	38.090	0.	2.613	35.477	-189.988	-338.682
12-87	.040	10.439	.030	7.881	33.119	0.	2.795	30.324	-159.664	-333.156
12-88	.034	8.649	.025	6.530	29.401	0.	2.992	26.409	-133.255	-329.454
12-89	.028	7.283	.022	5.499	26.465	0.	3.201	23.264	-109.991	-326.946
12-90	.024	6.216	.018	4.693	24.156	0.	3.425	20.731	-89.260	-325.226
12-91	.020	5.368	.015	4.053	22.254	0.	3.600	18.654	-70.606	-324.036
12-92	.018	4.683	.013	3.536	20.750	0.	3.600	17.150	-53.456	-323.194
12-93	.016	4.120	.012	3.110	19.501	0.	3.600	15.901	-37.555	-322.594
12-94	.014	3.654	.011	2.759	18.465	0.	3.600	14.865	-22.690	-322.162
12-95	.013	3.262	.010	2.463	17.624	0.	3.600	14.024	-8.666	-321.849
12-96	.011	2.930	.008	2.212	16.887	0.	3.600	13.287	4.621	-321.621
12-97	.010	2.647	.008	1.999	16.302	0.	3.600	12.702	17.323	-321.453
12-98	.009	2.402	.006	1.813	15.804	0.	3.600	12.204	29.527	-321.329
12-99	.009	2.191	.007	1.654	15.433	0.	3.600	11.833	41.360	-321.236
12- 0	.008	2.005	.006	1.514	14.789	0.	3.600	11.189	52.549	-321.169
5 TOT	.713	185.253[1]	.538	139.866	589.689	475.400	61.740	52.549	52.549	-321.169
AFTER	.056	14.747	.043	11.134	108.680	0.	40.932	67.748	120.297	-321.023
TOTAL	.769	200.000	.581	151.000	698.369	475.400	102.672	120.297	120.297	-321.023

CUM.	0.	0.	NET OIL REVENUE	20.470	5 PCT	-68.867	40 PCT	-352.615
ULT.	.769	200.000	NET GAS REVENUE	677.899	10 PCT	-168.442	50 PCT	-374.061
			NET PROD REVENUE	0.	15 PCT	-228.890	60 PCT	-389.576
					20 PCT	-269.508	80 PCT	-410.463
CUM NET INC/INV(1)	.25		CUM NET PW/INV(1)	-.68	30 PCT	-321.023	100 PCT	-423.791
GROSS WELLS	1		LIFE (YEARS)	31.37				
MONTHS 1ST YEAR	12		RATE OF RETURN,PCT	3.18				
INITIAL W.I., PCT	100.0000		INITIAL N.I., PCT	75.5000				

1 - 20-year total does not precisely match heading due to computer scheduling technique.

TYPICAL WELL
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO

CONSOLIDATED OIL & GAS, INC.
ECONOMICS OF DEVELOPMENT

2X SECTION 103 PRICE
180 MMCF GROSS
20-YEAR RECOVERY

R E S E R V E S A N D E C O N O M I C S

AS OF DATE : 1/ 1/1981

DATE: 09/23/81.
TIME: 17.30.32.
FILE: TYPICAL
PROJ: 2

END MO-YR	GROSS OIL PRODUCTION ----MB----	GROSS GAS PRODUCTION ----MMF---	OIL TO NET INTEREST ----MB----	GAS TO NET INTEREST ----MMF---	REVENUE TO INTEREST ----M$----	NET INVESTMENT ----M$----	NET OPER EXPENSES ----M$----	NET INCOME BEFORE FIT ----M$----	CUMULATIVE NET INCOME ----M$----	30,000 PCT CUM. DISC NET INCOME ----M$----
12-81	0.	0.	0.	0.	0.	475.400	1.863	-477.263	-477.263	-476.914
12-82	.149	38.640	.112	29.173	171.810	0.	1.993	169.817	-307.446	-362.016
12-83	.104	27.168	.079	20.512	129.231	0.	2.133	127.098	-180.348	-295.867
12-84	.078	20.145	.059	15.210	102.558	0.	2.283	100.275	-80.073	-255.722
12-85	.059	15.533	.044	11.727	84.591	0.	2.442	82.149	2.076	-230.423
12-86	.048	12.343	.037	9.319	71.957	0.	2.613	69.344	71.420	-213.995
12-87	.038	10.043	.028	7.582	62.621	0.	2.795	59.826	131.246	-203.093
12-88	.032	8.332	.025	6.291	55.618	0.	2.992	52.626	183.872	-195.717
12-89	.027	7.024	.020	5.303	50.164	0.	3.201	46.963	230.835	-190.653
12-90	.024	6.001	.018	4.531	44.256	0.	3.425	40.831	271.666	-187.266
12-91	.020	5.187	.015	3.916	38.237	0.	3.600	34.637	306.303	-185.056
12-92	.017	4.527	.013	3.418	33.356	0.	3.600	29.756	336.059	-183.596
12-93	.015	3.986	.011	3.009	29.370	0.	3.600	25.770	361.829	-182.623
12-94	.014	3.537	.011	2.671	26.086	0.	3.600	22.486	384.315	-181.970
12-95	.012	3.160	.009	2.386	23.288	0.	3.600	19.688	404.003	-181.530
12-96	.011	2.839	.008	2.143	20.930	0.	3.600	17.330	421.333	-181.232
12-97	.010	2.565	.008	1.937	18.912	0.	3.600	15.312	436.645	-181.030
12-98	.009	2.330	.007	1.759	17.177	0.	3.600	13.577	450.222	-180.892
12-99	.008	2.124	.006	1.603	15.651	0.	3.600	12.051	462.273	-180.798
12- 0	.007	1.946	.005	1.470	14.327	0.	3.600	10.727	473.000	-180.733
9 TOT	.682	177.430 [1]	.515	133.960	1010.140	475.400	61.740	473.000	473.000	-180.733
AFTER	.087	22.570	.066	17.040	166.378	0.	89.033	77.345	550.345	-180.592
TOTAL	.769	200.000	.581	151.000	1176.518	475.400	150.773	550.345	550.345	-180.592
CUM.	0.	0.								
ULT.	.769	200.000								

NET OIL REVENUE	20.762	5 PCT	258.352
NET GAS REVENUE	1155.756	10 PCT	94.204
NET PROD REVENUE	0.	15 PCT	-11.106
		20 PCT	-84.587
		30 PCT	-180.592

CUM NET INC/INV(1)	1.16	CUM NET PW/INV(1)	-.38
GROSS WELLS	1	LIFE (YEARS)	44.73
MONTHS 1ST YEAR	12	RATE OF RETURN,PCT	14.47
INITIAL W.I., PCT	100.0000	INITIAL N.I., PCT	75.5000

40 PCT	-240.579
50 PCT	-281.556
60 PCT	-311.255
80 PCT	-351.240
100 PCT	-376.733

1 - 20-year total does not precisely match heading due to computer scheduling technique.

Rec 103 price x 2
180 mcf/mo
Rec. Res.

TYPICAL WELL
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO

CONSOLIDATED OIL & GAS, INC.
ECONOMICS OF DEVELOPMENT

SECTION 103 PRICE
270 MMCF GROSS
20-YEAR RECOVERY

DATE: 09/23/81.
TIME: 17.30.35.
FILE: TYPICAL
PROJ: 3

RESERVES AND ECONOMICS

AS OF DATE : 1/ 1/1981

END MO-YR	GROSS OIL PRODUCTION ----MB----	GROSS GAS PRODUCTION ----MMF---	OIL TO NET INTEREST ----MB----	GAS TO NET INTEREST ----MMF---	REVENUE TO INTEREST ----M$----	NET INVESTMENT ----M$----	NET OPER EXPENSES ----M$----	NET INCOME BEFORE FIT ----M$----	CUMULATIVE NET INCOME ----M$----	30.000 PCT CUM. DISC NET INCOME ----M$----
12-81	0.	0.	0.	0.	0.	475.400	1.863	-477.263	-477.263	-476.914
12-82	.224	58.192	.169	43.935	131.610	0.	1.993	129.617	-347.646	-389.216
12-83	.158	41.084	.119	31.018	99.406	0.	2.133	97.273	-250.373	-338.589
12-84	.117	30.554	.089	23.069	79.100	0.	2.283	76.817	-173.556	-307.835
12-85	.091	23.613	.068	17.827	65.431	0.	2.442	62.989	-110.567	-288.437
12-86	.072	18.795	.055	14.191	55.721	0.	2.613	53.108	-57.459	-275.856
12-87	.059	15.316	.044	11.563	48.601	0.	2.795	45.806	-11.653	-267.509
12-88	.049	12.720	.037	9.604	43.209	0.	2.992	40.217	28.564	-261.871
12-89	.042	10.733	.032	8.103	39.026	0.	3.201	35.825	64.389	-258.008
12-90	.035	9.179	.026	6.930	35.654	0.	3.425	32.229	96.618	-255.335
12-91	.030	7.938	.023	5.994	32.924	0.	3.600	29.324	125.942	-253.464
12-92	.027	6.933	.021	5.234	30.732	0.	3.600	27.132	153.074	-252.132
12-93	.024	6.109	.018	4.612	28.925	0.	3.600	25.325	178.399	-251.176
12-94	.020	5.422	.015	4.094	27.372	0.	3.600	23.772	202.171	-250.486
12-95	.019	4.845	.014	3.658	26.166	0.	3.600	22.566	224.737	-249.982
12-96	.017	4.356	.013	3.289	25.129	0.	3.600	21.529	246.266	-249.612
12-97	.015	3.937	.011	2.972	24.251	0.	3.600	20.651	266.917	-249.339
12-98	.014	3.576	.011	2.700	23.549	0.	3.600	19.949	286.866	-249.136
12-99	.012	3.263	.009	2.464	22.934	0.	3.600	19.334	306.200	-248.985
12- 0	.012	2.988	.009	2.256	22.043	0.	3.600	18.443	324.643	-248.874
8 TOT	1.037	269.553[1]	.783	203.513	861.783	475.400	61.740	324.643	324.643	-248.874
AFTER	.117	30.447	.088	22.987	224.431	0.	69.214	155.217	479.860	-248.617
TOTAL	1.154	300.000	.871	226.500	1086.214	475.400	130.954	479.860	479.860	-248.617

CUM.	0.	0.	NET OIL REVENUE	31.082	5 PCT	146.960	40 PCT -295.589
			NET GAS REVENUE	1055.132	10 PCT	-14.819	50 PCT -327.278
ULT.	1.154	300.000	NET PROD REVENUE	0.	15 PCT	-109.112	60 PCT -350.113
					20 PCT	-171.144	80 PCT -380.745
CUM NET INC/INV(1)		1.01	CUM NET PW/INV(1)	-.52	30 PCT	-248.617	100 PCT -400.232
GROSS WELLS		1	LIFE (YEARS)	39.23			
MONTHS 1ST YEAR		12	RATE OF RETURN,PCT	9.54			
INITIAL W.I., PCT		100.0000	INITIAL N.I., PCT	75.5000			

1 - 20-year total does not precisely match heading due to computer scheduling technique.

270 million
100 years

Sec 103 price

TYPICAL WELL
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO

CONSOLIDATED OIL & GAS, INC.
ECONOMICS OF DEVELOPMENT

2X SECTION 103 PRICE
270 MMCF GROSS
20-YEAR RECOVERY

DATE: 09/23/81.
TIME: 17.30.38.
FILE: TYPICAL
PROJ: 4

R E S E R V E S A N D E C O N O M I C S

AS OF DATE : 1/ 1/1981

END MO-YR	GROSS OIL PRODUCTION ----MB----	GROSS GAS PRODUCTION ----MMF---	OIL TO NET INTEREST ----MB----	GAS TO NET INTEREST ----MMF---	REVENUE TO INTEREST ----M$-----	NET INVESTMENT ----M$----	NET OPER EXPENSES ----M$----	NET INCOME BEFORE FIT ----M$----	CUMULATIVE NET INCOME ----M$----	30.000 PCT CUM. DISC NET INCOME ----M$----
12-81	0.	0.	0.	0.	0.	475.400	1.863	-477.263	-477.263	-476.914
12-82	.222	57.678	.168	43.547	256.452	0.	1.993	254.459	-222.804	-304.748
12-83	.155	40.339	.117	30.456	191.895	0.	2.133	189.762	-33.042	-205.984
12-84	.115	29.796	.086	22.498	151.683	0.	2.283	149.400	116.358	-146.172
12-85	.088	22.909	.067	17.296	124.784	0.	2.442	122.342	238.700	-108.495
12-86	.070	18.162	.053	13.712	105.865	0.	2.613	103.252	341.952	-84.035
12-87	.056	14.753	.042	11.139	91.994	0.	2.795	89.199	431.151	-67.780
12-88	.047	12.220	.036	9.226	81.572	0.	2.992	78.580	509.731	-56.765
12-89	.040	10.289	.030	7.768	73.497	0.	3.201	70.296	580.027	-49.186
12-90	.034	8.782	.025	6.631	64.729	0.	3.425	61.303	641.330	-44.101
12-91	.029	7.583	.022	5.725	55.890	0.	3.600	52.290	693.620	-40.765
12-92	.025	6.614	.019	4.993	48.739	0.	3.600	45.139	738.759	-38.549
12-93	.023	5.819	.018	4.394	42.915	0.	3.600	39.315	778.074	-37.065
12-94	.019	5.161	.014	3.896	38.014	0.	3.600	34.414	812.488	-36.066
12-95	.018	4.607	.013	3.479	33.969	0.	3.600	30.369	842.857	-35.387
12-96	.016	4.138	.013	3.124	30.506	0.	3.600	26.906	869.763	-34.925
12-97	.014	3.737	.010	2.821	27.533	0.	3.600	23.933	893.696	-34.609
12-98	.014	3.393	.011	2.562	25.044	0.	3.600	21.444	915.140	-34.391
12-99	.011	3.092	.008	2.334	22.761	0.	3.600	19.161	934.301	-34.241
12- 0	.011	2.832	.008	2.139	20.880	0.	3.600	17.280	951.581	-34.137
S TOT	1.007	261.904[1]	.760	197.738	1488.721	475.400	61.740	951.581	951.581	-34.137
AFTER	.147	38.096	.111	28.762	280.834	0.	124.582	156.252	1107.833	-33.900
TOTAL	1.154	300.000	.871	226.500	1769.555	475.400	186.322	1107.833	1107.833	-33.900
CUM.	0.	0.								
ULT.	1.154	300.000								

CUM NET INC/INV(1)	2.33	CUM NET PW/INV(1)	-.07
GROSS WELLS	1	LIFE (YEARS)	54.61
MONTHS 1ST YEAR	12	RATE OF RETURN,PCT	27.29
INITIAL W.I., PCT	100.0000	INITIAL N.I., PCT	75.5000

NET OIL REVENUE	31.254	5 PCT	633.782	40 PCT	-123.663
NET GAS REVENUE	1738.301	10 PCT	380.437	50 PCT	-184.942
NET PROD REVENUE	0.	15 PCT	220.726	60 PCT	-229.350
		20 PCT	110.076	80 PCT	-289.155
		30 PCT	-33.900	100 PCT	-327.305

1 - 20-year total does not precisely match heading due to computer scheduling technique.

270 Million
Rec. Reserves

Rec 103 price x 2

SECTION 103 PRICE
350 MMCF GROSS
20-YEAR RECOVERY

TYPICAL WELL
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO

DATE: 09/23/81.
TIME: 17.30.41.
FILE: TYPICAL
PROJ: 5

CONSOLIDATED OIL & GAS, INC.
ECONOMICS OF DEVELOPMENT

R E S E R V E S A N D E C O N O M I C S

AS OF DATE : 1/ 1/1981

END MO-YR	GROSS OIL PRODUCTION ----MB----	GROSS GAS PRODUCTION ----MMF---	OIL TO NET INTEREST ----MB----	GAS TO NET INTEREST ----MMF---	REVENUE TO INTEREST ----M$----	NET INVESTMENT ----M$----	NET OPER EXPENSES ----M$----	NET INCOME BEFORE FIT ----M$----	CUMULATIVE NET INCOME ----M$----	30.000 PCT CUM. DISC NET INCOME ----M$----
12-81	0.	0.	0.	0.	0.	475.400	1.863	-477.263	-477.263	-476.914
12-82	.297	77.258	.224	58.330	174.581	0.	1.993	172.588	-304.675	-360.141
12-83	.209	54.306	.158	41.001	131.290	0.	2.133	129.157	-175.518	-292.921
12-84	.155	40.258	.117	30.395	104.156	0.	2.283	101.873	-73.645	-252.135
12-85	.119	31.038	.090	23.433	85.921	0.	2.442	83.479	9.834	-226.427
12-86	.095	24.660	.072	18.619	73.066	0.	2.613	70.453	80.287	-209.737
12-87	.077	20.064	.058	15.148	63.609	0.	2.795	60.814	141.101	-198.655
12-88	.064	16.643	.048	12.565	56.498	0.	2.992	53.506	194.607	-191.155
12-89	.054	14.029	.041	10.592	50.966	0.	3.201	47.765	242.372	-186.004
12-90	.046	11.986	.035	9.050	46.565	0.	3.425	43.140	285.512	-182.426
12-91	.040	10.359	.030	7.821	42.995	0.	3.600	39.395	324.907	-179.913
12-92	.035	9.042	.026	6.826	40.073	0.	3.600	36.473	361.380	-178.123
12-93	.031	7.961	.024	6.011	37.684	0.	3.600	34.084	395.464	-176.836
12-94	.027	7.063	.020	5.333	35.689	0.	3.600	32.089	427.553	-175.904
12-95	.024	6.309	.018	4.763	34.048	0.	3.600	30.448	458.001	-175.224
12-96	.022	5.669	.017	4.280	32.699	0.	3.600	29.099	487.100	-174.724
12-97	.019	5.123	.014	3.868	31.538	0.	3.600	27.938	515.038	-174.354
12-98	.018	4.651	.014	3.511	30.621	0.	3.600	27.021	542.059	-174.080
12-99	.017	4.242	.012	3.203	29.864	0.	3.600	26.264	568.323	-173.874
12- 0	.015	3.884	.012	2.932	28.632	0.	3.600	25.032	593.355	-173.724
S TOT	1.364	354.545[1]	1.030	267.681	1130.495	475.400	61.740	593.355	593.355	-173.724
AFTER	.174	45.455	.131	34.319	335.035	0.	90.636	244.399	837.754	-173.368
TOTAL	1.538	400.000	1.161	302.000	1465.530	475.400	152.376	837.754	837.754	-173.368

CUM.	0.	0.	NET OIL REVENUE	40.964	5 PCT	361.477	40 PCT	-235.890
			NET GAS REVENUE	1424.566	10 PCT	139.915	50 PCT	-278.045
ULT.	1.538	400.000	NET PROD REVENUE	0.	15 PCT	12.931	60 PCT	-308.418
					20 PCT	-70.066	80 PCT	-349.169
CUM NET INC/INV(1)		1.76	CUM NET PW/INV(1)	-.36	30 PCT	-173.368	100 PCT	-375.103
GROSS WELLS		1	LIFE (YEARS)	45.18				
MONTHS 1ST YEAR		12	RATE OF RETURN,PCT	15.78				
INITIAL W.I., PCT		100.0000	INITIAL N.I., PCT	75.5000				

1 - 20-year total does not precisely match heading due to computer scheduling technique.

350 billion
Acc Res.

Acc 103 price

2X SECTION 103 PRICE
350 MMCF GROSS
20-YEAR RECOVERY

TYPICAL WELL
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO

DATE: 09/23/81.
TIME: 17.30.45.
FILE: TYPICAL
PROJ: 6

CONSOLIDATED OIL & GAS, INC.
ECONOMICS OF DEVELOPMENT

R E S E R V E S A N D E C O N O M I C S

AS OF DATE : 1/ 1/1981

END NO-YR	GROSS OIL PRODUCTION -----MB-----	GROSS GAS PRODUCTION ----MMF---	OIL TO NET INTEREST ----MB-----	GAS TO NET INTEREST -----MMF---	REVENUE TO INTEREST ----M$----	NET INVESTMENT ----M$-----	NET OPER EXPENSES ----M$----	NET INCOME BEFORE FIT -----M$----	CUMULATIVE NET INCOME ----M$----	30.000 PCT CUM. DISC NET INCOME ----M$----
12-81	0.	0.	0.	0.	0.	475.400	1.063	-477.263	-477.263	-476.914
12-82	.283	73.538	.214	55.521	326.833	0.	1.993	324.840	-152.423	-257.128
12-83	.200	52.083	.151	39.323	247.654	0.	2.133	245.521	93.098	-129.345
12-84	.149	38.822	.112	29.310	197.531	0.	2.283	195.248	288.346	-51.177
12-85	.116	30.053	.088	22.690	163.643	0.	2.442	161.201	449.547	-1.532
12-86	.092	23.955	.069	18.087	139.567	0.	2.613	136.954	586.501	30.911
12-87	.075	19.540	.057	14.752	121.819	0.	2.795	119.024	705.525	52.601
12-88	.063	16.245	.047	12.265	108.423	0.	2.992	105.431	810.956	67.379
12-89	.053	13.716	.040	10.356	97.952	0.	3.201	94.751	905.707	77.596
12-90	.045	11.737	.034	8.861	86.490	0.	3.425	83.065	988.772	84.486
12-91	.039	10.157	.030	7.669	74.868	0.	3.600	71.268	1060.040	89.033
12-92	.034	8.875	.025	6.700	65.416	0.	3.600	61.816	1121.856	92.067
12-93	.030	7.823	.023	5.907	57.663	0.	3.600	54.063	1175.919	94.108
12-94	.027	6.946	.021	5.244	51.210	0.	3.600	47.610	1223.529	95.491
12-95	.024	6.209	.018	4.688	45.773	0.	3.600	42.173	1265.702	96.433
12-96	.021	5.584	.016	4.216	41.145	0.	3.600	37.545	1303.247	97.078
12-97	.020	5.048	.015	3.811	37.231	0.	3.600	33.631	1336.878	97.522
12-98	.017	4.587	.012	3.463	33.789	0.	3.600	30.189	1367.067	97.829
12-99	.016	4.185	.013	3.160	30.846	0.	3.600	27.246	1394.313	98.042
12- 0	.015	3.834	.011	2.894	28.270	0.	3.600	24.670	1418.983	98.191
8 TOT	1.319	342.937[1]	.996	258.917	1956.123	475.400	61.740	1418.983	1418.983	98.191
AFTER	.219	57.063	.165	43.083	420.613	0.	160.323	260.290	1679.273	98.537
TOTAL	1.538	400.000	1.161	302.000	2376.736	475.400	222.063	1679.273	1679.273	98.537
CUM.	0.	0.								
ULT.	1.538	400.000								

NET OIL REVENUE	41.457	5 PCT	997.174	40 PCT	-19.365		
NET GAS REVENUE	2335.279	10 PCT	650.840	50 PCT	-99.512		
NET PROD REVENUE	0.	15 PCT	436.263	60 PCT	-157.417		
		20 PCT	288.890	80 PCT	-235.160		
		30 PCT	98.537	100 PCT	-284.608		
CUM NET INC/INV(1)	3.53	CUM NET PW/INV(1)	.21				
GROSS WELLS	1	LIFE (YEARS)	64.53				
MONTHS 1ST YEAR	12	RATE OF RETURN,PCT	38.16				
INITIAL W.I., PCT	100.0000	INITIAL N.I., PCT	75.5000				

1 - 20-year total does not precisely match heading due to computer scheduling technique.

350 million
Mcf, Res.

Rec 103 price x 2

TYPICAL WELL
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO

CONSOLIDATED OIL & GAS, INC.
ECONOMICS OF DEVELOPMENT

SECTION 103 PRICE
435 MMCF GROSS
20-YEAR RECOVERY

DATE: 09/23/81.
TIME: 17.30.49.
FILE: TYPICAL
PROJ: 7

RESERVES AND ECONOMICS

AS OF DATE : 1/ 1/1981

END MO-YR	GROSS OIL PRODUCTION -----MB-----	GROSS GAS PRODUCTION -----MMF---	OIL TO NET INTEREST -----MB-----	GAS TO NET INTEREST ----MMF---	REVENUE TO INTEREST ----M$-----	NET INVESTMENT ----M$-----	NET OPER EXPENSES ----M$-----	NET INCOME BEFORE FIT ----M$-----	CUMULATIVE NET INCOME ----M$-----	30.000 PCT CUM. DISC NET INCOME -----M$----
12-81	0.	0.	0.	0.	0.	475.400	1.863	-477.263	-477.263	-476.914
12-82	.370	96.303	.279	72.709	217.790	0.	1.993	215.797	-261.466	-330.906
12-83	.260	67.487	.197	50.952	163.300	0.	2.133	161.167	-100.299	-247.026
12-84	.192	49.922	.145	37.692	129.260	0.	2.283	126.977	26.678	-196.190
12-85	.148	38.424	.111	29.010	106.470	0.	2.442	104.028	130.706	-164.153
12-86	.117	30.489	.089	23.019	90.395	0.	2.613	87.782	218.488	-143.358
12-87	.095	24.782	.071	18.710	78.625	0.	2.795	75.830	294.318	-129.540
12-88	.079	20.540	.060	15.508	69.770	0.	2.992	66.778	361.096	-120.179
12-89	.067	17.301	.051	13.062	62.884	0.	3.201	59.683	420.779	-113.744
12-90	.057	14.772	.043	11.153	57.403	0.	3.425	53.978	474.757	-109.267
12-91	.049	12.760	.037	9.634	52.950	0.	3.600	49.350	524.107	-106.118
12-92	.043	11.134	.032	8.406	49.342	0.	3.600	45.742	569.849	-103.873
12-93	.037	9.798	.028	7.398	46.339	0.	3.600	42.739	612.588	-102.259
12-94	.034	8.691	.026	6.561	43.942	0.	3.600	40.342	652.930	-101.088
12-95	.030	7.760	.022	5.859	41.895	0.	3.600	38.295	691.225	-100.232
12-96	.026	6.972	.020	5.264	40.178	0.	3.600	36.578	727.803	-99.604
12-97	.025	6.297	.019	4.754	38.823	0.	3.600	35.223	763.026	-99.138
12-98	.022	5.717	.017	4.316	37.635	0.	3.600	34.035	797.061	-98.792
12-99	.020	5.213	.015	3.936	36.668	0.	3.600	33.068	830.129	-98.533
12- 0	.018	4.772	.013	3.603	35.164	0.	3.600	31.564	861.693	-98.344
S TOT	1.689	439.134[1]	1.275	331.546	1398.833	475.400	61.740	861.693	861.693	-98.344
AFTER	.234	60.866	.177	45.954	448.659	0.	109.498	339.161	1200.854	-97.891
TOTAL	1.923	500.000	1.452	377.500	1847.492	475.400	171.238	1200.854	1200.854	-97.891

CUM.	0.	0.	NET OIL REVENUE	52.021	5 PCT	575.870	40 PCT	-175.980
			NET GAS REVENUE	+ 1795.471	10 PCT	294.632	50 PCT	-228.623
ULT.	1.923	500.000	NET PROD REVENUE	0.	15 PCT	135.124	60 PCT	-266.554
					20 PCT	31.225	80 PCT	-317.455
CUM NET INC/INV(1)		2.53	CUM NET PW/INV(1)	-.21	30 PCT	-97.891	100 PCT	-349.859
GROSS WELLS		1	LIFE (YEARS)	50.42				
MONTHS 1ST YEAR		12	RATE OF RETURN,PCT	22.12				
INITIAL W.I., PCT		100.0000	INITIAL N.I., PCT	75.5000				

1 - 20-year total does not precisely match heading due to computer scheduling technique.

435 MMCF
200. MBO

SEC 103 PRICE

TYPICAL WELL
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO

CONSOLIDATED OIL & GAS, INC.
ECONOMICS OF DEVELOPMENT

2X SECTION 103 PRICE
435 MMCF GROSS
20-YEAR RECOVERY

DATE: 09/23/81.
TIME: 17.30.52.
FILE: TYPICAL
PROJ: 8

R E S E R V E S A N D E C O N O M I C S

AS OF DATE : 1/ 1/1981

END NO-YR	GROSS OIL PRODUCTION ----MB----	GROSS GAS PRODUCTION ----MMF---	OIL TO NET INTEREST ----MB----	GAS TO NET INTEREST ----MMF---	REVENUE TO INTEREST ----M$----	NET INVESTMENT ----M$----	NET OPER EXPENSES ----M$----	NET INCOME BEFORE FIT ----M$----	CUMULATIVE NET INCOME ----M$----	30.000 PCT CUM. DISC NET INCOME ----M$----
12-81	0.	0.	0.	0.	0.	475.400	1.863	-477.263	-477.263	-476.914
12-82	.353	91.757	.267	69.277	409.246	0.	1.993	407.253	-70.010	-201.368
12-83	.249	64.844	.188	48.957	309.444	0.	2.133	307.311	237.301	-41.425
12-84	.186	48.257	.140	36.434	246.428	0.	2.283	244.145	481.446	56.319
12-85	.143	37.313	.108	28.171	203.855	0.	2.442	201.413	682.859	118.347
12-86	.115	29.712	.087	22.433	173.727	0.	2.613	171.114	853.973	158.883
12-87	.093	24.220	.070	18.286	151.503	0.	2.795	148.708	1002.681	185.982
12-88	.077	20.121	.058	15.191	134.609	0.	2.992	131.617	1134.298	204.431
12-89	.066	16.982	.050	12.822	121.439	0.	3.201	118.238	1252.536	217.180
12-90	.055	14.524	.041	10.965	107.031	0.	3.425	103.606	1356.142	225.774
12-91	.049	12.564	.037	9.486	92.637	0.	3.600	89.037	1445.179	231.455
12-92	.042	10.975	.032	8.286	80.892	0.	3.600	77.292	1522.471	235.248
12-93	.037	9.671	.028	7.302	71.281	0.	3.600	67.681	1590.152	237.803
12-94	.033	8.584	.025	6.481	63.275	0.	3.600	59.675	1649.827	239.536
12-95	.030	7.673	.023	5.793	56.577	0.	3.600	52.977	1702.804	240.720
12-96	.026	6.898	.019	5.208	50.829	0.	3.600	47.229	1750.033	241.531
12-97	.024	6.236	.018	4.708	45.968	0.	3.600	42.368	1792.401	242.091
12-98	.022	5.663	.017	4.275	41.751	0.	3.600	38.151	1830.552	242.479
12-99	.020	5.168	.015	3.902	38.100	0.	3.600	34.500	1865.052	242.749
12- 0	.018	4.733	.014	3.574	34.881	0.	3.600	31.281	1896.333	242.937
8 TOT	1.638	425.895[1]	1.237	321.551	2433.473	475.400	61.740	1896.333	1896.333	242.937
AFTER	.285	74.105	.215	55.949	546.250	0.	187.387	358.863	2255.196	243.380
TOTAL	1.923	500.000	1.452	377.500	2979.723	475.400	249.127	2255.196	2255.196	243.380
CUM.	0.	0.								
ULT.	1.923	500.000								

CUM NET INC/INV(1)	4.74	CUM NET PW/INV(1)	.51
GROSS WELLS	1	LIFE (YEARS)	72.05
MONTHS 1ST YEAR	12	RATE OF RETURN,PCT	49.52
INITIAL W.I., PCT	100.0000	INITIAL N.I., PCT	75.5000

NET OIL REVENUE	57.663	5 PCT	1371.533	40 PCT	95.869
NET GAS REVENUE	2922.060	10 PCT	935.092	50 PCT	-4.419
NET PROD REVENUE	0.	15 PCT	666.069	60 PCT	-76.891
		20 PCT	481.561	80 PCT	-174.221
		30 PCT	243.380	100 PCT	-236.149

1 - 20-year total does not precisely match heading due to computer scheduling technique.

435 million
Mcf. Rev.

Sec 103 price X 2

TYPICAL WELL
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO

CONSOLIDATED OIL + GAS, INC.
ECONOMICS OF DEVELOPMENT

SECTION 103 PRICE
555 MMCF GROSS
20-YEAR RECOVERY

DATE: 09/23/81.
TIME: 17.30.56.
FILE: TYPICAL
PROJ: 9

R E S E R V E S A N D E C O N O M I C S

AS OF DATE : 1/ 1/1981

END YR	GROSS OIL PRODUCTION MB	GROSS GAS PRODUCTION MMF	OIL TO NET INTEREST MB	GAS TO NET INTEREST MMF	REVENUE TO INTEREST M$	NET INVESTMENT M$	NET OPER EXPENSES M$	NET INCOME BEFORE FIT M$	CUMULATIVE NET INCOME M$	30.000 PCT CUM. DISC NET INCOME M$
12-81	0.	0.	0.	0.	0.	475.400	1.863	-477.263	-477.263	-476.914
12-82	.460	119.706	.347	90.378	270.718	0.	1.993	268.725	-208.538	-295.095
12-83	.327	84.952	.247	64.139	205.554	0.	2.133	203.421	-5.117	-189.223
12-84	.244	63.416	.184	47.879	164.201	0.	2.283	161.918	156.801	-124.399
12-85	.189	49.148	.143	37.107	136.179	0.	2.442	133.737	290.538	-83.213
12-86	.151	39.208	.114	29.602	116.260	0.	2.613	113.647	404.185	-56.290
12-87	.123	32.006	.093	24.164	101.552	0.	2.795	98.757	502.942	-38.294
12-88	.102	26.622	.077	20.100	90.417	0.	2.992	87.425	590.367	-26.039
12-89	.087	22.492	.066	16.981	81.749	0.	3.201	78.548	668.915	-17.570
12-90	.074	19.252	.056	14.536	74.802	0.	3.425	71.377	740.292	-11.649
12-91	.064	16.666	.048	12.582	69.159	0.	3.600	65.559	805.851	-7.467
12-92	.056	14.569	.042	11.000	64.555	0.	3.600	60.955	866.806	-4.475
12-93	.049	12.843	.037	9.696	60.758	0.	3.600	57.158	923.964	-2.317
12-94	.044	11.408	.033	8.613	57.658	0.	3.600	54.058	978.022	-.747
12-95	.040	10.199	.031	7.701	55.083	0.	3.600	51.483	1029.505	.403
12-96	.035	9.174	.026	6.926	52.894	0.	3.600	49.294	1078.799	1.250
12-97	.032	8.296	.024	6.264	51.115	0.	3.600	47.515	1126.314	1.878
12-98	.029	7.538	.022	5.691	49.622	0.	3.600	46.022	1172.336	2.346
12-99	.026	6.879	.020	5.193	48.374	0.	3.600	44.774	1217.110	2.696
12- 0	.024	6.303	.018	4.759	46.453	0.	3.600	42.853	1259.963	2.954
8 TOT	2.156	560.677 [1]	1.628	423.311	1797.103	475.400	61.740	1259.963	1259.963	2.954
AFTER	.344	89.323	.259	67.439	658.443	0.	139.802	518.641	1778.604	3.575
TOTAL	2.500	650.000	1.887	490.750	2455.546	475.400	201.542	1778.604	1778.604	3.575

CUM.	0.	0.	NET OIL REVENUE	68.204	5 PCT	892.206	40 PCT	-96.579
			NET GAS REVENUE	2387.342	10 PCT	515.278	50 PCT	-163.786
ULT.	2.500	650.000	NET PROD REVENUE	0.	15 PCT	305.641	60 PCT	-212.055
					20 PCT	170.362	80 PCT	-276.622
CUM NET INC/INV(1)		3.74	CUM NET PW/INV(1)	.01	30 PCT	3.575	100 PCT	-317.602
GROSS WELLS		1	LIFE (YEARS)	58.83				
MONTHS 1ST YEAR		12	RATE OF RETURN,PCT	30.32				
INITIAL W.I., PCT		100.0000	INITIAL N.I., PCT	75.5000				

1 - 20-year total does not precisely match heading due to computer scheduling technique.

555 million Sec 103 price
Rec res.

2X SECTION 103 PRICE
555 MMCF GROSS
20-YEAR RECOVERY

TYPICAL WELL
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO

DATE: 09/23/81.
TIME: 17.30.59.
FILE: TYPICAL
PROJ: 10

CONSOLIDATED OIL & GAS, INC.
ECONOMICS OF DEVELOPMENT

R E S E R V E S A N D E C O N O M I C S

AS OF DATE : 1/ 1/1981

END MO-YR	GROSS OIL PRODUCTION -MB-	GROSS GAS PRODUCTION -MMF-	OIL TO NET INTEREST -MB-	GAS TO NET INTEREST -MMF-	REVENUE TO INTEREST -M$-	NET INVESTMENT -M$-	NET OPER EXPENSES -M$-	NET INCOME BEFORE FIT -M$-	CUMULATIVE NET INCOME -M$-	30.000 PCT CUM. DISC NET INCOME -M$-
12-81	0.	0.	0.	0.	0.	475.400	1.863	-477.263	-477.263	-476.914
12-82	.458	119.067	.346	89.896	529.399	0.	1.993	527.406	50.143	-120.073
12-83	.323	83.950	.244	63.382	399.364	0.	2.133	397.231	447.374	86.670
12-84	.240	62.373	.181	47.091	317.507	0.	2.283	315.224	762.598	212.871
12-85	.185	48.167	.140	36.367	262.362	0.	2.442	259.920	1022.518	292.917
12-86	.147	38.317	.111	28.929	223.328	0.	2.613	220.715	1243.233	345.203
12-87	.120	31.210	.090	23.563	194.657	0.	2.795	191.862	1435.095	380.165
12-88	.100	25.912	.076	19.564	172.981	0.	2.992	169.989	1605.084	403.994
12-89	.084	21.856	.063	16.501	156.091	0.	3.201	152.890	1757.974	420.479
12-90	.072	18.685	.054	14.107	137.706	0.	3.425	134.281	1892.255	431.617
12-91	.062	16.157	.047	12.199	119.094	0.	3.600	115.494	2007.749	438.986
12-92	.054	14.109	.041	10.652	103.992	0.	3.600	100.392	2108.141	443.913
12-93	.048	12.428	.036	9.383	91.618	0.	3.600	88.018	2196.159	447.236
12-94	.043	11.029	.033	8.327	81.318	0.	3.600	77.718	2273.877	449.493
12-95	.038	9.856	.028	7.442	72.655	0.	3.600	69.055	2342.932	451.035
12-96	.034	8.858	.026	6.687	65.293	0.	3.600	61.693	2404.625	452.096
12-97	.030	8.007	.023	6.046	58.994	0.	3.600	55.394	2460.019	452.828
12-98	.028	7.271	.021	5.489	53.598	0.	3.600	49.998	2510.017	453.336
12-99	.026	6.632	.019	5.007	48.904	0.	3.600	45.304	2555.321	453.691
12- 0	.023	6.075	.018	4.587	44.768	0.	3.600	41.168	2596.489	453.938
8 TOT	2.115	349.959 [1]	1.597	415.219	3133.629	475.400	61.740	2596.489	2596.489	453.938
AFTER	.385	100.041	.290	75.531	737.441	0.	223.311	514.130	3110.619	454.526
TOTAL	2.500	650.000	1.887	490.750	3871.070	475.400	285.051	3110.619	3110.619	454.526

CUM.	0.	0.	NET OIL REVENUE	68.442	5 PCT	1919.652	40 PCT 263.782
			NET GAS REVENUE	3802.628	10 PCT	1350.602	50 PCT 134.117
ULT.	2.500	650.000	NET PROD REVENUE	0.	15 PCT	1001.633	60 PCT 40.412
					20 PCT	762.682	80 PCT -85.451
CUM NET INC/INV(1)		6.54	CUM NET PW/INV(1)	.96	30 PCT	454.526	100 PCT -165.556
GROSS WELLS		1	LIFE (YEARS)	82.03			
MONTHS 1ST YEAR		12	RATE OF RETURN,PCT	65.71 ✓			
INITIAL W.I., PCT		100.0000	INITIAL N.I., PCT	75.5000			

1 - 20-year total does not precisely match heading due to computer scheduling technique.

555 million
Acc. 103 price × 2

EXHIBIT 13

AFTER TAX ECONOMICS

Annual Depreciation of Tangible Well Costs
Total tangibles 370,900

370,900 − (.1428 × 370,900)	=	317,935
317,935 − (.1428 × 317,935)	=	272,534
272,534 − (.1428 × 272,534)	=	233,616
233,616 − (.1428 × 233616)	=	200,256
200,256 − (.1428 × 200,256)	=	171,659
171,659 − (.1428 × 171,659)	=	147,146
147,146 − (.1428 × 147,146)	=	126,133
126,133 − (.1428 × 126,133)	=	108,121
108,121 − (.1428 × 108,121)	=	92681
92,681 − (.1428 × 92681)	=	79.446
79,446 − (.1428 × 79446)	=	68,101
68,101 − (.1428 × 68101)	=	58376
58,376 − (.1428 × 58376)	=	50040
50,040 − (.1428 × 50040)	=	42894
42894 − (.1428 × 42894)	=	36769
36769 − (1428 × 36769)	=	31518
31518 − (.1428 × 31518)	=	27017
27017 − (.1428 × 27017)	=	23159
23159 − (.1428 × 23159)	=	19852
19852 − (.1428 × 19852)	=	17018

first 20 years: 353,882

after 20 years: 17,018

370,900

EXHIBIT 13

SECTION 103 PRICE
180 MMCF GROSS
20-YEAR RECOVERY

TYPICAL WELL
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO

CONSOLIDATED OIL + GAS, INC.
ECONOMICS OF DEVELOPMENT

DATE: 09/23/81.
TIME: 17.31.54.
FILE: TYPICAL
PROJ: 1

Depreciate Tangibles @ .1428/yr (370,900)

A F T E R T A X E C O N O M I C S

AS OF DATE: 1/ 1/1981

-END- MO-YR	NET OIL MB	NET GAS MMF	REVENUE TO INT. M$	OPER. EXPENSE M$	NET INCOME M$ Col4-Col5	CAPITAL INVEST. M$	DEPR. M$	DEPL. M$	INCOME TAX M$ Col6-Col8 x46%	CASH FLOW M$ Col6-Col10	CUM. NET PW M$
12-81	0.	0.	0.	1,863	-1,863	475,400	52,965	0.	-73,290	-403,972	-412,448
12-82	.119	30,772	92,183	1,993	90,190	0.	45,401	0.	20,603	69,587	-365,366
12-83	.082	21,531	68,987	2,133	66,854	0.	38,918	0.	12,851	54,003	-337,259
12-84	.061	15,910	54,559	2,283	52,276	0.	33,360	0.	8,701	43,575	-319,814
12-85	.048	12,235	44,920	2,442	42,478	0.	28,597	0.	6,385	36,093	-308,698
12-86	.037	9,702	38,090	2,613	35,477	0.	24,513	0.	5,043	30,434	-301,489
12-87	.030	7,881	33,119	2,795	30,324	0.	21,013	0.	4,283	26,041	-296,744
12-88	.025	6,530	29,401	2,992	26,409	0.	18,012	0.	3,863	22,546	-293,583
12-89	.022	5,499	26,465	3,201	23,264	0.	15,440	0.	3,599	19,665	-291,463
12-90	.018	4,693	24,156	3,425	20,731	0.	13,235	0.	3,448	17,283	-290,029
12-91	.015	4,053	22,254	3,600	18,654	0.	11,345	0.	3,362	15,292	-289,054
12-92	.013	3,536	20,750	3,600	17,150	0.	9,725	0.	3,416	13,734	-288,380
12-93	.012	3,110	19,501	3,600	15,901	0.	8,336	0.	3,480	12,421	-287,911
12-94	.011	2,759	18,465	3,600	14,865	0.	7,146	0.	3,551	11,314	-287,582
12-95	.010	2,463	17,624	3,600	14,024	0.	6,125	0.	3,633	10,391	-287,350
12-96	.008	2,212	16,887	3,600	13,287	0.	5,251	0.	3,697	9,590	-287,185
12-97	.008	1,999	16,302	3,600	12,702	0.	4,501	0.	3,773	8,929	-287,067
12-98	.006	1,813	15,804	3,600	12,204	0.	3,858	0.	3,839	8,365	-286,982
12-99	.007	1,654	15,433	3,600	11,833	0.	3,307	0.	3,922	7,911	-286,920
12- 0	.006	1,514	14,789	3,600	11,189	0.	2,835	0.	3,843	7,346	-286,876
S TOT	.538	139,866	589,689	61,740	527,949	475,400	353,882	0.	32,002	20,548	-286,876
AFTER	.043	11,134	108,680	40,932	67,748	0.	17,018	0.	23,336	44,412	-286,782
TOTAL	.581	151,000	698,369	102,672	595,697	475,400	370,900	0.	55,338	64,960	-286,782-

Σ = 400,898 in 17 yrs
.37(8365) = 3096
400,898 + 3096 = 403,994 = payout in 17.37 yrs.

RECAP

	GROSS	W.I.	NET
INTEREST FRACTION	1.000000	1.000000	.755000
OIL RESERVES,MB	.769	.769	.581
GAS RESERVES,MMCF	200.000	200.000	151.000
PRODUCTS	0.	0.	0.
REVENUE,M$	1008.627	1008.627	698.369
OPERATING EXPENSE,M$	102.672	102.672	102.672
TANGIBLES,M$	370.900	370.900	370.900
INTANGIBLES,M$	104.500	104.500	104.500

(Gross 8.3%) x .755 = net WI
presumably wind fuse projects land severance taxes

INITIAL OIL PRICE ($/B)	34.00
INITIAL GAS PRICE ($/M)	3.1452

LIFE (YEARS)	31.37
GROSS OIL WELLS	0.
GROSS GAS WELLS	1.000
RATE OF RETURN,PCT	2.25
DISCOUNT RATE,PCT	30.0
PAYOUT YEARS	17.37
W.I. BEFORE PAYOUT,PCT	100.00
W.I. AFTER PAYOUT,PCT	100.00

DIS PCT	PW OF NET M$
5	-79.359
10	-158.457
15	-208.077
20	-242.269
30	-286.783-
40	-314.844
50	-334.330
70	-359.835
100	-381.946

180 MMCF 103

TYPICAL WELL
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO

CONSOLIDATED OIL & GAS, INC.
ECONOMICS OF DEVELOPMENT

2X SECTION 103 PRICE
180 MMCF GROSS
20-YEAR RECOVERY

DATE: 09/23/81.
TIME: 17.31.57.
FILE: TYPICAL
PROJ: 2

A F T E R T A X E C O N O M I C S

AS OF DATE: 1/ 1/1981

-END- YR	NET OIL MB-----	NET GAS MMF-----	REVENUE TO INT. M$-----	OPER. EXPENSE M$-----	NET INCOME M$-----	CAPITAL INVEST. M$-----	DEPR. M$---	DEPL. M$----	INCOME TAX M$----	CASH FLOW M$-----	CUM. NET PW M$------
12-81	0.	0.	0.	1.863	-1.863	475.400	52.965	0.	-73.290	-403.972	-412.448
12-82	.112	29.173	171.810	1.993	169.817	0.	45.401	0.	57.231	112.586	-336.273
12-83	.079	20.512	129.231	2.133	127.098	0.	38.918	0.	40.563	86.535	-291.235
12-84	.059	15.210	102.558	2.283	100.275	0.	33.360	0.	30.781	69.494	-263.413
12-85	.044	11.727	84.591	2.442	82.149	0.	28.597	0.	24.634	57.515	-245.700
12-86	.037	9.319	71.957	2.613	69.344	0.	24.513	0.	20.622	48.722	-234.136
12-87	.028	7.582	62.621	2.795	59.826	0.	21.013	0.	17.854	41.972	-226.510
12-88	.025	6.291	55.618	2.992	52.626	0.	18.012	0.	15.922	36.704	-221.365
12-89	.020	5.303	50.164	3.201	46.963	0.	15.440	0.	14.501	32.462	-217.865
12-90	.018	4.531	44.256	3.425	40.831	0.	13.235	0.	12.694	28.137	-215.531
12-91	.015	3.916	38.237	3.600	34.637	0.	11.345	0.	10.714	23.923	-214.004
12-92	.013	3.418	33.356	3.600	29.756	0.	9.725	0.	9.214	20.542	-212.996
12-93	.011	3.009	29.370	3.600	25.770	0.	8.336	0.	8.020	17.750	-212.326
12-94	.011	2.671	26.086	3.600	22.486	0.	7.146	0.	7.056	15.430	-211.878
12-95	.009	2.386	23.288	3.600	19.688	0.	6.125	0.	6.239	13.449	-211.578
12-96	.008	2.143	20.930	3.600	17.330	0.	5.251	0.	5.556	11.774	-211.375
12-97	.008	1.937	18.912	3.600	15.312	0.	4.501	0.	4.973	10.339	-211.239
12-98	.007	1.759	17.177	3.600	13.577	0.	3.858	0.	4.471	9.106	-211.146
12-99	.006	1.603	15.651	3.600	12.051	0.	3.307	0.	4.022	8.029	-211.083
12- 0	.005	1.470	14.327	3.600	10.727	0.	2.835	0.	3.630	7.097	-211.041
S TOT	.515	133.960	1010.140	61.740	948.400	475.400	353.882	0.	225.407	247.592	-211.041
AFTER	.066	17.040	166.378	89.033	77.345	0.	17.018	0.	27.751	49.594	-210.949
TOTAL	.581	151.000	1176.518	150.773	1025.745	475.400	370.900	0.	253.158	297.186	-210.949

RECAP

	GROSS	W.I.	NET
INTEREST FRACTION	1.000000	1.000000	.755000
OIL RESERVES,MB	.769	.769	.581
GAS RESERVES,MMCF	200.000	200.000	151.000
PRODUCTS	0.	0.	0.
REVENUE,M$	1696.859	1696.859	1176.518
OPERATING EXPENSE,M$	150.773	150.773	150.773
TANGIBLES,M$	370.900	370.900	370.900
INTANGIBLES,M$	104.500	104.500	104.500

INITIAL OIL PRICE ($/B)	34.00
INITIAL GAS PRICE ($/M)	6.2903

LIFE (YEARS)	44.73
GROSS OIL WELLS	0.
GROSS GAS WELLS	1.000
RATE OF RETURN,PCT	9.27
DISCOUNT RATE,PCT	30.0
PAYOUT YEARS	6.69
W.I. BEFORE PAYOUT,PCT	100.00
W.I. AFTER PAYOUT,PCT	100.00

DIS PCT	PW OF NET M$
5	97.269
10	-16.656
15	-90.483
20	-142.414
30	-210.950
40	-254.345
50	-284.378
70	-323.334
100	-356.535

180
103

TYPICAL WELL
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO

CONSOLIDATED OIL & GAS, INC.
ECONOMICS OF DEVELOPMENT

SECTION 103 PRICE
270 MMCF GROSS
20-YEAR RECOVERY

DATE: 09/23/81.
TIME: 17.32.00.
FILE: TYPICAL
PROJ: 3

A F T E R T A X E C O N O M I C S

AS OF DATE: 1/ 1/1981

-END- MO-YR	NET OIL MB-----	NET GAS MMF-----	REVENUE TO INT. M$-----	OPER. EXPENSE M$-----	NET INCOME M$-----	CAPITAL INVEST. M$-----	DEPR. M$---	DEPL. M$----	INCOME TAX M$----	CASH FLOW M$-----	CUM. NET PW M$------
12-81	0.	0.	0.	1.863	-1.863	475.400	52.965	0.	-73.290	-403.972	-412.448
12-82	.169	43.935	131.610	1.993	129.617	0.	45.401	0.	38.739	90.878	-350.960
12-83	.119	31.018	99.406	2.133	97.273	0.	38.918	0.	26.843	70.430	-314.305
12-84	.089	23.069	79.100	2.283	76.817	0.	33.360	0.	19.990	56.827	-291.554
12-85	.068	17.827	65.431	2.442	62.989	0.	28.597	0.	15.821	47.168	-277.028
12-86	.055	14.191	55.721	2.613	53.108	0.	24.513	0.	13.154	39.954	-267.563
12-87	.044	11.563	48.601	2.795	45.806	0.	21.013	0.	11.405	34.401	-261.294
12-88	.037	9.604	43.209	2.992	40.217	0.	18.012	0.	10.214	30.003	-257.088
12-89	.032	8.103	39.026	3.201	35.825	0.	15.440	0.	9.377	26.448	-254.236
12-90	.026	6.930	35.654	3.425	32.229	0.	13.235	0.	8.737	23.492	-252.288
12-91	.023	5.994	32.924	3.600	29.324	0.	11.345	0.	8.270	21.054	-250.945
12-92	.021	5.234	30.732	3.600	27.132	0.	9.725	0.	8.007	19.125	-250.006
12-93	.018	4.612	28.925	3.600	25.325	0.	8.336	0.	7.815	17.510	-249.345
12-94	.015	4.094	27.372	3.600	23.772	0.	7.146	0.	7.648	16.124	-248.877
12-95	.014	3.638	26.166	3.600	22.566	0.	6.125	0.	7.563	15.003	-248.542
12-96	.013	3.289	25.129	3.600	21.529	0.	5.251	0.	7.488	14.041	-248.300
12-97	.011	2.972	24.251	3.600	20.651	0.	4.501	0.	7.429	13.222	-248.126
12-98	.011	2.700	23.549	3.600	19.949	0.	3.858	0.	7.402	12.547	-247.998
12-99	.009	2.464	22.934	3.600	19.334	0.	3.307	0.	7.372	11.962	-247.904
12- 0	.009	2.256	22.043	3.600	18.443	0.	2.835	0.	7.180	11.263	-247.837
S TOT	.793	203.513	861.783	61.740	800.043	475.400	353.882	0.	157.164	167.479	-247.837
AFTER	.088	22.987	224.431	69.214	155.217	0.	17.018	0.	63.572	91.645	-247.683
TOTAL	.871	226.500	1086.214	130.954	955.260	475.400	370.900	0.	220.736	259.124	-247.683

RECAP

	GROSS	W.I.	NET
INTEREST FRACTION	1.000000	1.000000	.755000
OIL RESERVES,MB	1.154	1.154	.871
GAS RESERVES,MMCF	300.000	300.000	226.500
PRODUCTS	0.	0.	0.
REVENUE,M$	1568.430	1568.430	1086.214
OPERATING EXPENSE,M$	130.954	130.954	130.954
TANGIBLES,M$	370.900	370.900	370.900
INTANGIBLES,M$	104.500	104.500	104.500

INITIAL OIL PRICE ($/B)	34.00
INITIAL GAS PRICE ($/M)	3.1452

LIFE (YEARS)	39.23
GROSS OIL WELLS	0.
GROSS GAS WELLS	1.000
RATE OF RETURN,PCT	6.65
DISCOUNT RATE,PCT	30.0
PAYOUT YEARS	9.33
W.I. BEFORE PAYOUT,PCT	100.00
W.I. AFTER PAYOUT,PCT	100.00

DIS PCT	PW OF NET M$
5	37.143
10	-75.519
15	-143.403
20	-189.154
30	-247.684
40	-284.050
50	-309.067
70	-341.487
100	-369.224

270 MM
103

TYPICAL WELL
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO

CONSOLIDATED OIL & GAS, INC.
ECONOMICS OF DEVELOPMENT

2X SECTION 103 PRICE
270 MMCF GROSS
20-YEAR RECOVERY

DATE: 09/23/81.
TIME: 17.32.04.
FILE: TYPICAL
PROJ: 4

A F T E R T A X E C O N O M I C S

AS OF DATE: 1/ 1/1981

-END- NO-YR	NET OIL MB	NET GAS MMF	REVENUE TO INT. M$	OPER. EXPENSE M$	NET INCOME M$	CAPITAL INVEST. M$	DEPR. M$	DEPL. M$	INCOME TAX M$	CASH FLOW M$	CUM. NET PW M$
12-81	0.	0.	0.	1.863	-1.863	475.400	52.965	0.	-73.290	-403.972	-412.448
12-82	.168	43.547	256.452	1.993	254.459	0.	45.401	0.	96.167	158.292	-305.348
12-83	.117	30.456	191.895	2.133	189.762	0.	38.918	0.	69.388	120.374	-242.698
12-84	.086	22.496	151.683	2.283	149.400	0.	33.360	0.	53.378	96.022	-204.256
12-85	.067	17.296	124.784	2.442	122.342	0.	28.597	0.	43.123	79.219	-179.859
12-86	.053	13.712	105.865	2.613	103.252	0.	24.513	0.	36.220	67.032	-163.979
12-87	.042	11.139	91.994	2.795	89.199	0.	21.013	0.	31.366	57.833	-153.441
12-88	.036	9.226	81.572	2.992	78.580	0.	18.012	0.	27.861	50.719	-146.331
12-89	.030	7.768	73.497	3.201	70.296	0.	15.440	0.	25.234	45.062	-141.472
12-90	.025	6.631	64.728	3.425	61.303	0.	13.235	0.	22.111	39.192	-138.222
12-91	.022	5.725	55.890	3.600	52.290	0.	11.345	0.	18.835	33.455	-136.087
12-92	.019	4.993	48.739	3.600	45.139	0.	9.725	0.	16.290	28.849	-134.671
12-93	.018	4.394	42.915	3.600	39.315	0.	8.336	0.	14.250	25.065	-133.725
12-94	.014	3.896	38.014	3.600	34.414	0.	7.146	0.	12.543	21.871	-133.090
12-95	.013	3.479	33.969	3.600	30.369	0.	6.125	0.	11.152	19.217	-132.660
12-96	.013	3.124	30.506	3.600	26.906	0.	5.251	0.	9.961	16.945	-132.369
12-97	.010	2.821	27.533	3.600	23.933	0.	4.501	0.	8.939	14.994	-132.171
12-98	.011	2.562	25.044	3.600	21.444	0.	3.858	0.	8.089	13.355	-132.035
12-99	.008	2.334	22.761	3.600	19.161	0.	3.307	0.	7.293	11.868	-131.942
12- 0	.008	2.139	20.880	3.600	17.280	0.	2.835	0.	6.645	10.635	-131.878
S TOT	.760	197.738	1488.721	61.740	1426.981	475.400	353.882	0.	445.555	506.026	-131.878
AFTER	.111	28.762	280.834	124.582	156.252	0.	17.018	0.	64.049	92.204	-131.735
TOTAL	.871	226.500	1769.555	186.322	1583.233	475.400	370.900	0.	509.604	598.230	-131.735

RECAP

	GROSS	W.I.	NET
INTEREST FRACTION	1.000000	1.000000	.755000
OIL RESERVES,MB	1.154	1.154	.871
GAS RESERVES,MMCF	300.000	300.000	226.500
PRODUCTS	0.	0.	0.
REVENUE,M$	2552.111	2552.111	1769.555
OPERATING EXPENSE,M$	186.322	186.322	186.322
TANGIBLES,M$	370.900	370.900	370.900
INTANGIBLES,M$	104.500	104.500	104.500
INITIAL OIL PRICE ($/B)		34.00	
INITIAL GAS PRICE ($/M)		6.2903	

LIFE (YEARS)	54.61
GROSS OIL WELLS	0.
GROSS GAS WELLS	1.000
RATE OF RETURN,PCT	17.41
DISCOUNT RATE,PCT	30.0
PAYOUT YEARS	4.37
W.I. BEFORE PAYOUT,PCT	100.00
W.I. AFTER PAYOUT,PCT	100.00

DIS PCT	PW OF NET M$
5	299.962
10	137.897
15	34.703
20	-37.297
30	-131.736
40	-191.210
50	-232.206
70	-285.113
100	-329.844

270
103%

TYPICAL WELL
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO

CONSOLIDATED OIL & GAS, INC.
ECONOMICS OF DEVELOPMENT

SECTION 103 PRICE
350 MMCF GROSS
20-YEAR RECOVERY

DATE: 09/23/81.
TIME: 17.32.07.
FILE: TYPICAL
PROJ: 5

A F T E R T A X E C O N O M I C S

AS OF DATE: 1/ 1/1981

-END- MO-YR	NET OIL MB-----	NET GAS MMF-----	REVENUE TO INT. M$-----	OPER. EXPENSE M$-----	NET INCOME M$-----	CAPITAL INVEST. M$-----	DEPR. M$---	DEPL. M$----	INCOME TAX M$----	CASH FLOW M$-----	CUM. NET PW M$------
12-81	0.	0.	0.	1.863	-1.863	475.400	52.965	0.	-73.290	-403.972	-412.448
12-82	.224	58.330	174.581	1.993	172.588	0.	45.401	0.	58.506	114.082	-335.260
12-83	.158	41.001	131.290	2.133	129.157	0.	38.918	0.	41.510	87.647	-289.644
12-84	.117	30.395	104.156	2.283	101.873	0.	33.360	0.	31.516	70.357	-261.476
12-85	.090	23.433	85.921	2.442	83.479	0.	28.597	0.	25.246	58.233	-243.542
12-86	.072	18.619	73.066	2.613	70.453	0.	24.513	0.	21.132	49.321	-231.859
12-87	.058	15.148	63.609	2.795	60.814	0.	21.013	0.	18.309	42.505	-224.113
12-88	.048	12.565	56.498	2.992	53.506	0.	18.012	0.	16.327	37.179	-218.901
12-89	.041	10.592	50.966	3.201	47.765	0.	15.440	0.	14.870	32.895	-215.354
12-90	.035	9.050	46.565	3.425	43.140	0.	13.235	0.	13.756	29.384	-212.917
12-91	.030	7.821	42.995	3.600	39.395	0.	11.345	0.	12.903	26.492	-211.227
12-92	.026	6.826	40.073	3.600	36.473	0.	9.725	0.	12.304	24.169	-210.041
12-93	.024	6.011	37.684	3.600	34.084	0.	8.336	0.	11.844	22.240	-209.201
12-94	.020	5.333	35.689	3.600	32.089	0.	7.146	0.	11.474	20.615	-208.602
12-95	.018	4.763	34.048	3.600	30.448	0.	6.125	0.	11.188	19.260	-208.172
12-96	.017	4.280	32.699	3.600	29.099	0.	5.251	0.	10.970	18.129	-207.861
12-97	.014	3.868	31.538	3.600	27.938	0.	4.501	0.	10.781	17.157	-207.634
12-98	.014	3.511	30.621	3.600	27.021	0.	3.858	0.	10.655	16.366	-207.467
12-99	.012	3.203	29.864	3.600	26.264	0.	3.307	0.	10.560	15.704	-207.345
12- 0	.012	2.932	28.632	3.600	25.032	0.	2.835	0.	10.211	14.821	-207.255
S TOT	1.030	267.681	1130.495	61.740	1068.755	475.400	353.882	0.	280.772	312.584	-207.255
AFTER	.131	34.319	335.035	90.636	244.399	0.	17.018	0.	104.597	139.804	-207.048
TOTAL	1.161	302.000	1465.530	152.376	1313.154	475.400	370.900	0.	385.369	452.387	-207.048

RECAP

	GROSS	W.I.	NET
INTEREST FRACTION	1.000000	1.000000	.755000
OIL RESERVES,MB	1.538	1.538	1.161
GAS RESERVES,MMCF	400.000	400.000	302.000
PRODUCTS	0.	0.	0.
REVENUE,M$	2116.810	2116.810	1465.530
OPERATING EXPENSE,M$	152.376	152.376	152.376
TANGIBLES,M$	370.900	370.900	370.900
INTANGIBLES,M$	104.500	104.500	104.500
INITIAL OIL PRICE ($/B)		34.00	
INITIAL GAS PRICE ($/M)		3.1452	

LIFE (YEARS)	45.18
GROSS OIL WELLS	0.
GROSS GAS WELLS	1.000
RATE OF RETURN,PCT	10.47
DISCOUNT RATE,PCT	30.0
PAYOUT YEARS	6.57
W.I. BEFORE PAYOUT,PCT	100.00
W.I. AFTER PAYOUT,PCT	100.00

DIS PCT	PW OF NET M$
5	152.955
10	8.027
15	-77.503
20	-134.573
30	-207.049
40	-251.813
50	-282.482
70	-322.042
100	-355.655

350MM
10%

TYPICAL WELL
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO

CONSOLIDATED OIL & GAS, INC.
ECONOMICS OF DEVELOPMENT

2X SECTION 103 PRICE
350 MMCF GROSS
20-YEAR RECOVERY

DATE: 09/23/81.
TIME: 17.32.10.
FILE: TYPICAL
PROJ: 6

A F T E R T A X E C O N O M I C S

AS OF DATE: 1/ 1/1981

-END- MO-YR	NET OIL MB-----	NET GAS MMF-----	REVENUE TO INT. M$-----	OPER. EXPENSE M$-----	NET INCOME M$-----	CAPITAL INVEST. M$-----	DEPR. M$---	DEPL. M$---	INCOME TAX M$----	CASH FLOW M$-----	CUM. NET PW M$------
12-81	0.	0.	0.	1.863	-1.863	475.400	52.965	0.	-73.290	-403.972	-412.448
12-82	.214	55.521	326.833	1.993	324.840	0.	45.401	0.	128.542	196.298	-279.633
12-83	.151	39.323	247.654	2.133	245.521	0.	38.918	0.	95.037	150.484	-201.313
12-84	.112	29.310	197.531	2.283	195.248	0.	33.360	0.	74.468	120.780	-152.958
12-85	.088	22.690	163.643	2.442	161.201	0.	28.597	0.	60.998	100.203	-122.099
12-86	.069	18.087	139.567	2.613	136.954	0.	24.513	0.	51.723	85.231	-101.908
12-87	.057	14.752	121.817	2.793	119.024	0.	21.013	0.	45.085	73.939	-88.435
12-88	.047	12.265	108.423	2.992	105.431	0.	18.012	0.	40.213	65.218	-79.293
12-89	.040	10.356	97.952	3.201	94.751	0.	15.440	0.	36.483	58.268	-73.010
12-90	.034	8.861	86.490	3.425	83.065	0.	13.235	0.	32.122	50.943	-68.785
12-91	.030	7.669	74.868	3.600	71.268	0.	11.345	0.	27.565	43.703	-65.996
12-92	.025	6.700	65.416	3.600	61.816	0.	9.725	0.	23.962	37.854	-64.138
12-93	.023	5.907	57.663	3.600	54.063	0.	8.336	0.	21.034	33.029	-62.891
12-94	.021	5.244	51.210	3.600	47.610	0.	7.146	0.	18.614	28.996	-62.049
12-95	.018	4.688	45.773	3.600	42.173	0.	6.125	0.	16.582	25.591	-61.478
12-96	.016	4.216	41.145	3.600	37.545	0.	5.251	0.	14.855	22.690	-61.088
12-97	.015	3.811	37.231	3.600	33.631	0.	4.501	0.	13.400	20.231	-60.820
12-98	.012	3.463	33.789	3.600	30.189	0.	3.858	0.	12.112	18.077	-60.637
12-99	.013	3.160	30.846	3.600	27.246	0.	3.307	0.	11.012	16.234	-60.510
12- 0	.011	2.894	28.270	3.600	24.670	0.	2.835	0.	10.044	14.626	-60.422
8 TOT	.996	258.917	1956.123	61.740	1894.383	475.400	353.882	0.	660.561	758.423	-60.422
AFTER	.165	43.083	420.613	160.323	260.290	0.	17.018	0.	111.907	148.385	-60.220
TOTAL	1.161	302.000	2376.736	222.063	2154.673	475.400	370.900	0.	772.468	906.807	-60.220

RECAP

	GROSS	W.I.	NET
INTEREST FRACTION	1.000000	1.000000	.755000
OIL RESERVES,MB	1.538	1.538	1.161
GAS RESERVES,MMCF	400.000	400.000	302.000
PRODUCTS	0.	0.	0.
REVENUE,M$	3428.403	3428.403	2376.736
OPERATING EXPENSE,M$	222.063	222.063	222.063
TANGIBLES,M$	370.900	370.900	370.900
INTANGIBLES,M$	104.500	104.500	104.500
INITIAL OIL PRICE ($/B)		34.00	
INITIAL GAS PRICE ($/M)		6.2903	

LIFE (YEARS)	64.53
GROSS OIL WELLS	0.
GROSS GAS WELLS	1.000
RATE OF RETURN,PCT	24.39
DISCOUNT RATE,PCT	30.0
PAYOUT YEARS	3.47
W.I. BEFORE PAYOUT,PCT	100.00
W.I. AFTER PAYOUT,PCT	100.00

DIS PCT	PW OF NET M$
5	496.161
10	283.905
15	151.090
20	59.262
30	-60.221
40	-134.889
50	-186.073
70	-251.727
100	-306.788

350
103 x 2

SECTION 103 PRICE
435 MMCF GROSS
20-YEAR RECOVERY

TYPICAL WELL
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO

CONSOLIDATED OIL & GAS, INC.
ECONOMICS OF DEVELOPMENT

DATE: 09/23/81.
TIME: 17.32.13.
FILE: TYPICAL
PROJ: 7

A F T E R T A X E C O N O M I C S

AS OF DATE: 1/ 1/1981

-END- YR	NET OIL MB	NET GAS MMF	REVENUE TO INT. M$	OPER. EXPENSE M$	NET INCOME M$	CAPITAL INVEST. M$	DEPR. M$	DEPL. M$	INCOME TAX M$	CASH FLOW M$	CUM. NET PW M$
12-81	0.	0.	0.	1.863	-1.863	475.400	52.965	0.	-73.290	-403.972	-412.448
12-82	.279	72.709	217.790	1.993	215.797	0.	45.401	0.	78.382	137.415	-319.473
12-83	.197	50.952	163.300	2.133	161.167	0.	38.918	0.	56.235	104.932	-244.860
12-84	.145	37.692	129.260	2.283	126.977	0.	33.360	0.	43.064	83.913	-231.265
12-85	.111	29.010	106.470	2.442	104.028	0.	28.597	0.	34.698	69.330	-209.914
12-86	.089	23.019	90.395	2.613	87.782	0.	24.513	0.	29.104	58.678	-196.014
12-87	.071	18.710	79.625	2.795	75.830	0.	21.013	0.	25.216	50.614	-186.791
12-88	.060	15.508	69.770	2.992	66.778	0.	18.012	0.	22.432	44.346	-180.575
12-89	.051	13.062	62.884	3.201	59.683	0.	15.440	0.	20.352	39.331	-176.334
12-90	.043	11.153	57.403	3.425	53.978	0.	13.235	0.	18.742	35.236	-173.411
12-91	.037	9.634	52.950	3.600	49.350	0.	11.345	0.	17.482	31.868	-171.378
12-92	.032	8.406	49.342	3.600	45.742	0.	9.725	0.	16.568	29.174	-169.946
12-93	.028	7.398	46.339	3.600	42.739	0.	8.336	0.	15.825	26.914	-168.930
12-94	.026	6.561	43.942	3.600	40.342	0.	7.146	0.	15.270	25.072	-168.202
12-95	.022	5.859	41.895	3.600	38.295	0.	6.125	0.	14.798	23.497	-167.677
12-96	.020	5.264	40.178	3.600	36.578	0.	5.251	0.	14.411	22.167	-167.296
12-97	.019	4.754	38.823	3.600	35.223	0.	4.501	0.	14.132	21.091	-167.017
12-98	.017	4.316	37.635	3.600	34.035	0.	3.858	0.	13.881	20.154	-166.812
12-99	.015	3.936	36.668	3.600	33.068	0.	3.307	0.	13.690	19.378	-166.661
12- 0	.013	3.603	35.164	3.600	31.564	0.	2.835	0.	13.215	18.349	-166.550
S TOT	1.275	331.546	1398.833	61.740	1337.093	475.400	353.882	0.	404.207	457.486	-166.550
AFTER	.177	45.954	448.659	109.498	339.161	0.	17.018	0.	148.184	190.975	-166.291
TOTAL	1.452	377.500	1847.492	171.238	1676.254	475.400	370.900	0.	552.391	648.461	-166.291

RECAP

	GROSS	W.I.	NET
INTEREST FRACTION	1.000000	1.000000	.755000
OIL RESERVES,MB	1.923	1.923	1.452
GAS RESERVES,MMCF	500.000	500.000	377.500
PRODUCTS	0.	0.	0.
REVENUE,M$	2667.369	2667.369	1847.492
OPERATING EXPENSE,M$	171.238	171.238	171.238
TANGIBLES,M$	370.900	370.900	370.900
INTANGIBLES,M$	104.500	104.500	104.500

INITIAL OIL PRICE ($/B)	34.00
INITIAL GAS PRICE ($/M)	3.1452

LIFE (YEARS)	50.42
GROSS OIL WELLS	0.
GROSS GAS WELLS	1.000
RATE OF RETURN,PCT	14.44
DISCOUNT RATE,PCT	30.0
PAYOUT YEARS	5.14
W.I. BEFORE PAYOUT,PCT	100.00
W.I. AFTER PAYOUT,PCT	100.00

DIS PCT	PW OF NET M$
5	268.705
10	91.567
15	-11.521
20	-79.877
30	-166.292
40	-219.461
50	-255.793
70	-302.514
100	-342.023

395,590 5 yrs
8382 14% 5 yrs
403,972 yr
total = 5.14 years.

476,400 mcf
171,238 percent
646,638 total mcf.

435 MMF
105

TYPICAL WELL
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO

CONSOLIDATED OIL & GAS, INC.
ECONOMICS OF DEVELOPMENT

2X SECTION 103 PRICE
435 MMCF GROSS
20-YEAR RECOVERY

DATE: 09/23/81.
TIME: 17.32.17.
FILE: TYPICAL
PROJ: 8

A F T E R T A X E C O N O M I C S

AS OF DATE: 1/ 1/1981

-END- MO YR	NET OIL MB	NET GAS MMF	REVENUE TO INT. M$	OPER. EXPENSE M$	NET INCOME M$	CAPITAL INVEST. M$	DEPR. M$	DEPL. M$	INCOME TAX M$	CASH FLOW M$	CUM. NET PW M$
12-81	0.	0.	0.	1.863	-1.863	475.400	52.965	0.	-73.290	-403.972	-412.448
12-82	.267	69.277	409.246	1.993	407.253	0.	45.401	0.	166.452	240.801	-249.523
12-83	.188	48.957	309.444	2.133	307.311	0.	38.918	0.	123.461	183.850	-153.836
12-84	.140	36.434	246.428	2.283	244.145	0.	33.360	0.	96.961	147.184	-94.911
12-85	.108	28.171	203.855	2.442	201.413	0.	28.597	0.	79.496	121.917	-57.364
12-86	.087	22.433	173.727	2.613	171.114	0.	24.513	0.	67.436	103.678	-32.804
12-87	.070	18.286	151.503	2.795	148.708	0.	21.013	0.	58.740	89.968	-16.409
12-88	.058	15.191	134.609	2.992	131.617	0.	18.012	0.	52.258	79.359	-5.285
12-89	.050	12.822	121.439	3.201	118.238	0.	15.440	0.	47.287	70.951	2.364
12-90	.041	10.965	107.031	3.425	103.606	0.	13.235	0.	41.571	62.035	7.510
12-91	.037	9.486	92.637	3.600	89.037	0.	11.345	0.	35.738	53.299	10.910
12-92	.032	8.286	80.892	3.600	77.292	0.	9.725	0.	31.081	46.211	13.178
12-93	.028	7.302	71.281	3.600	67.681	0.	8.336	0.	27.299	40.382	14.703
12-94	.025	6.481	63.275	3.600	59.675	0.	7.146	0.	24.163	35.512	15.734
12-95	.023	5.793	56.577	3.600	52.977	0.	6.125	0.	21.552	31.425	16.436
12-96	.019	5.208	50.829	3.600	47.229	0.	5.251	0.	19.310	27.919	16.916
12-97	.018	4.708	45.968	3.600	42.368	0.	4.501	0.	17.419	24.949	17.246
12-98	.017	4.275	41.751	3.600	38.151	0.	3.858	0.	15.775	22.376	17.473
12-99	.015	3.902	38.100	3.600	34.500	0.	3.307	0.	14.349	20.151	17.631
12- 0	.014	3.574	34.881	3.600	31.281	0.	2.835	0.	13.085	18.196	17.740
S TOT	1.237	321.551	2433.473	61.740	2371.733	475.400	353.882	0.	880.143	1016.192	17.740
AFTER	.215	55.949	546.250	187.387	358.863	0.	17.018	0.	157.247	201.614	17.995
TOTAL	1.452	377.500	2979.723	249.127	2730.596	475.400	370.900	0.	1037.390	1217.806	17.995

RECAP

	GROSS	W.I.	NET
INTEREST FRACTION	1.000000	1.000000	.755000
OIL RESERVES,MB	1.923	1.923	1.452
GAS RESERVES,MMCF	500.000	500.000	377.500
PRODUCTS	0.	0.	0.
REVENUE,M$	4289.840	4289.840	2979.723
OPERATING EXPENSE,M$	249.127	249.127	249.127
TANGIBLES,M$	370.900	370.900	370.900
INTANGIBLES,M$	104.500	104.500	104.500
INITIAL OIL PRICE ($/B)		34.00	
INITIAL GAS PRICE ($/M)		6.2903	

LIFE (YEARS)	72.05
GROSS OIL WELLS	0.
GROSS GAS WELLS	1.000
RATE OF RETURN,PCT	31.80
DISCOUNT RATE,PCT	30.0
PAYOUT YEARS	2.89
W.I. BEFORE PAYOUT,PCT	100.00
W.I. AFTER PAYOUT,PCT	100.00

DIS PCT	PW OF NET M$
5	698.295
10	437.396
15	275.185
20	163.304
30	17.995
40	-72.662
50	-134.723
70	-214.185
100	-280.620

435
103X

TYPICAL WELL
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO

CONSOLIDATED OIL & GAS, INC.
ECONOMICS OF DEVELOPMENT

SECTION 103 PRICE
555 MMCF GROSS
20-YEAR RECOVERY

DATE: 09/23/81.
TIME: 17.32.20.
FILE: TYPICAL
PROJ: 9

A F T E R T A X E C O N O M I C S

AS OF DATE: 1/ 1/1981

-END- MO-YR	NET OIL MB	NET GAS MMF	REVENUE TO INT. M$	OPER. EXPENSE M$	NET INCOME M$	CAPITAL INVEST. M$	DEPR. M$	DEPL. M$	INCOME TAX M$	CASH FLOW M$	CUM. NET PW M$
12-81	0.	0.	0.	1.863	-1.863	475.400	52.965	0.	-73.290	-403.972	-412.448
12-82	.347	90.378	270.718	1.993	268.725	0.	45.401	0.	102.729	165.996	-300.136
12-83	.247	64.139	205.554	2.133	203.421	0.	38.918	0.	75.671	127.750	-233.647
12-84	.184	47.879	164.201	2.283	161.918	0.	33.360	0.	59.136	102.782	-192.498
12-85	.143	37.107	136.179	2.442	133.737	0.	28.597	0.	48.365	85.372	-166.207
12-86	.114	29.602	116.260	2.613	113.647	0.	24.513	0.	41.002	72.645	-148.997
12-87	.093	24.164	101.552	2.795	98.757	0.	21.013	0.	35.762	62.995	-137.518
12-88	.077	20.100	90.417	2.992	87.425	0.	18.012	0.	31.930	55.495	-129.739
12-89	.066	16.981	81.749	3.201	78.548	0.	15.440	0.	29.030	49.518	-124.400
12-90	.056	14.536	74.802	3.425	71.377	0.	13.235	0.	26.745	44.632	-120.698
12-91	.048	12.582	69.159	3.600	65.559	0.	11.345	0.	24.938	40.621	-118.106
12-92	.042	11.000	64.555	3.600	60.955	0.	9.725	0.	23.566	37.389	-116.271
12-93	.037	9.696	60.758	3.600	57.158	0.	8.336	0.	22.458	34.700	-114.961
12-94	.033	8.613	57.658	3.600	54.058	0.	7.146	0.	21.580	32.478	-114.018
12-95	.031	7.701	55.083	3.600	51.483	0.	6.125	0.	20.864	30.619	-113.334
12-96	.026	6.926	52.894	3.600	49.294	0.	5.251	0.	20.260	29.034	-112.835
12-97	.024	6.264	51.115	3.600	47.515	0.	4.501	0.	19.786	27.729	-112.468
12-98	.022	5.691	49.622	3.600	46.022	0.	3.858	0.	19.395	26.627	-112.198
12-99	.020	5.193	48.374	3.600	44.774	0.	3.307	0.	19.075	25.699	-111.997
12- 0	.018	4.759	46.453	3.600	42.853	0.	2.835	0.	18.408	24.445	-111.849
8 TOT	1.628	423.311	1797.103	61.740	1735.363	475.400	353.882	0.	587.410	672.552	-111.849
AFTER	.259	67.439	658.443	139.802	518.641	0.	17.018	0.	230.747	287.894	-111.499
TOTAL	1.887	490.750	2455.546	201.542	2254.004	475.400	370.900	0.	818.157	960.446	-111.499

RECAP

	GROSS	W.I.	NET
INTEREST FRACTION	1.000000	1.000000	.755000
OIL RESERVES,MB	2.500	2.500	1.887
GAS RESERVES,MMCF	650.000	650.000	490.750
PRODUCTS	0.	0.	0.
REVENUE,M$	3544.802	3544.802	2455.546
OPERATING EXPENSE,M$	201.542	201.542	201.542
TANGIBLES,M$	370.900	370.900	370.900
INTANGIBLES,M$	104.500	104.500	104.500

INITIAL OIL PRICE ($/B) 34.00
INITIAL GAS PRICE ($/M) 3.1452

LIFE (YEARS)	58.83
GROSS OIL WELLS	0.
GROSS GAS WELLS	1.000
RATE OF RETURN,PCT	19.72
DISCOUNT RATE,PCT	30.0
PAYOUT YEARS	4.09
W.I. BEFORE PAYOUT,PCT	100.00
W.I. AFTER PAYOUT,PCT	100.00

DIS PCT	PW OF NET M$
5	439.496
10	210.706
15	80.556
20	-4.743
30	-111.500
40	-176.585
50	-220.782
70	-277.247
100	-324.605

555MM
103

TYPICAL WELL
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO

CONSOLIDATED OIL + GAS, INC.
ECONOMICS OF DEVELOPMENT

2X SECTION 103 PRICE
555 MMCF GROSS
20-YEAR RECOVERY

DATE: 09/23/81.
TIME: 17.32.24.
FILE: TYPICAL
PROJ: 10

A F T E R T A X E C O N O M I C S

AS OF DATE: 1/ 1/1981

-END- MO-YR	NET OIL MB	NET GAS MMF	REVENUE TO INT. M$	OPER. EXPENSE M$	NET INCOME M$	CAPITAL INVEST. M$	DEPR. M$	DEPL. M$	INCOME TAX M$	CASH FLOW M$	CUM. NET PW M$
12-81	0.	0.	0.	1.863	-1.863	475.400	52.965	0.	-73.290	-403.972	-412.448
12-82	.346	89.896	529.399	1.993	527.406	0.	45.401	0.	221.722	305.684	-205.623
12-83	.244	63.382	399.364	2.133	397.231	0.	38.918	0.	164.824	232.407	-84.665
12-84	.181	47.091	317.507	2.283	315.224	0.	33.360	0.	129.657	185.567	-10.373
12-85	.140	36.367	262.362	2.442	259.920	0.	28.597	0.	106.409	153.511	36.902
12-86	.111	28.929	223.328	2.613	220.715	0.	24.513	0.	90.253	130.462	67.808
12-87	.090	23.563	194.657	2.795	191.862	0.	21.013	0.	78.591	113.271	88.449
12-88	.076	19.564	172.981	2.992	169.989	0.	18.012	0.	69.909	100.080	102.478
12-89	.063	16.501	156.091	3.201	152.890	0.	15.440	0.	63.227	89.663	112.146
12-90	.054	14.107	137.706	3.425	134.281	0.	13.235	0.	55.681	78.600	118.665
12-91	.047	12.199	119.094	3.600	115.494	0.	11.345	0.	47.909	67.585	122.977
12-92	.041	10.652	103.992	3.600	100.392	0.	9.725	0.	41.707	58.685	125.857
12-93	.036	9.383	91.618	3.600	88.018	0.	8.336	0.	36.654	51.364	127.797
12-94	.033	8.327	81.318	3.600	77.718	0.	7.146	0.	32.463	45.255	129.111
12-95	.028	7.442	72.655	3.600	69.055	0.	6.125	0.	28.948	40.107	130.007
12-96	.026	6.687	65.293	3.600	61.693	0.	5.251	0.	25.963	35.730	130.621
12-97	.023	6.046	58.994	3.600	55.394	0.	4.501	0.	23.411	31.983	131.044
12-98	.021	5.489	53.598	3.600	49.998	0.	3.858	0.	21.224	28.774	131.336
12-99	.019	5.007	48.904	3.600	45.304	0.	3.307	0.	19.319	25.985	131.539
12- 0	.018	4.587	44.768	3.600	41.168	0.	2.835	0.	17.633	23.535	131.681
S TOT	1.597	415.219	3133.629	61.740	3071.889	475.400	353.882	0.	1202.214	1394.276	131.681
AFTER	.290	75.531	737.441	223.311	514.130	0.	17.018	0.	228.672	285.458	132.013
TOTAL	1.887	490.750	3871.070	285.051	3586.019	475.400	370.900	0.	1430.886	1679.734	132.013

RECAP

	GROSS	W.I.	NET
INTEREST FRACTION	1.000000	1.000000	.755000
OIL RESERVES,MB	2.500	2.500	1.887
GAS RESERVES,MMCF	650.000	650.000	490.750
PRODUCTS	0.	0.	0.
REVENUE,M$	5582.550	5582.550	3871.070
OPERATING EXPENSE,M$	285.051	289.051	285.051
TANGIBLES,M$	370.900	370.900	370.900
INTANGIBLES,M$	104.500	104.500	104.500
INITIAL OIL PRICE ($/B)		34.00	
INITIAL GAS PRICE ($/M)		6.2903	

LIFE (YEARS)	82.03
GROSS OIL WELLS	0.
GROSS GAS WELLS	1.000
RATE OF RETURN,PCT	42.13
DISCOUNT RATE,PCT	30.0
PAYOUT YEARS	2.42
W.I. BEFORE PAYOUT,PCT	100.00
W.I. AFTER PAYOUT,PCT	100.00

DIS PCT	PW OF NET M$
5	994.256
10	661.766
15	456.388
20	315.109
30	132.013
40	18.010
50	-59.914
70	-159.497
100	-242.499

555 MM
103 ✓

CONSOLIDATED OIL & GAS, INC.
RATE OF RETURN (BFIT)
VS.
20 YR. RECOVERY PER WELL
BASIN DAKOTA FIELD
T30, 31, R 32W thru R 13W

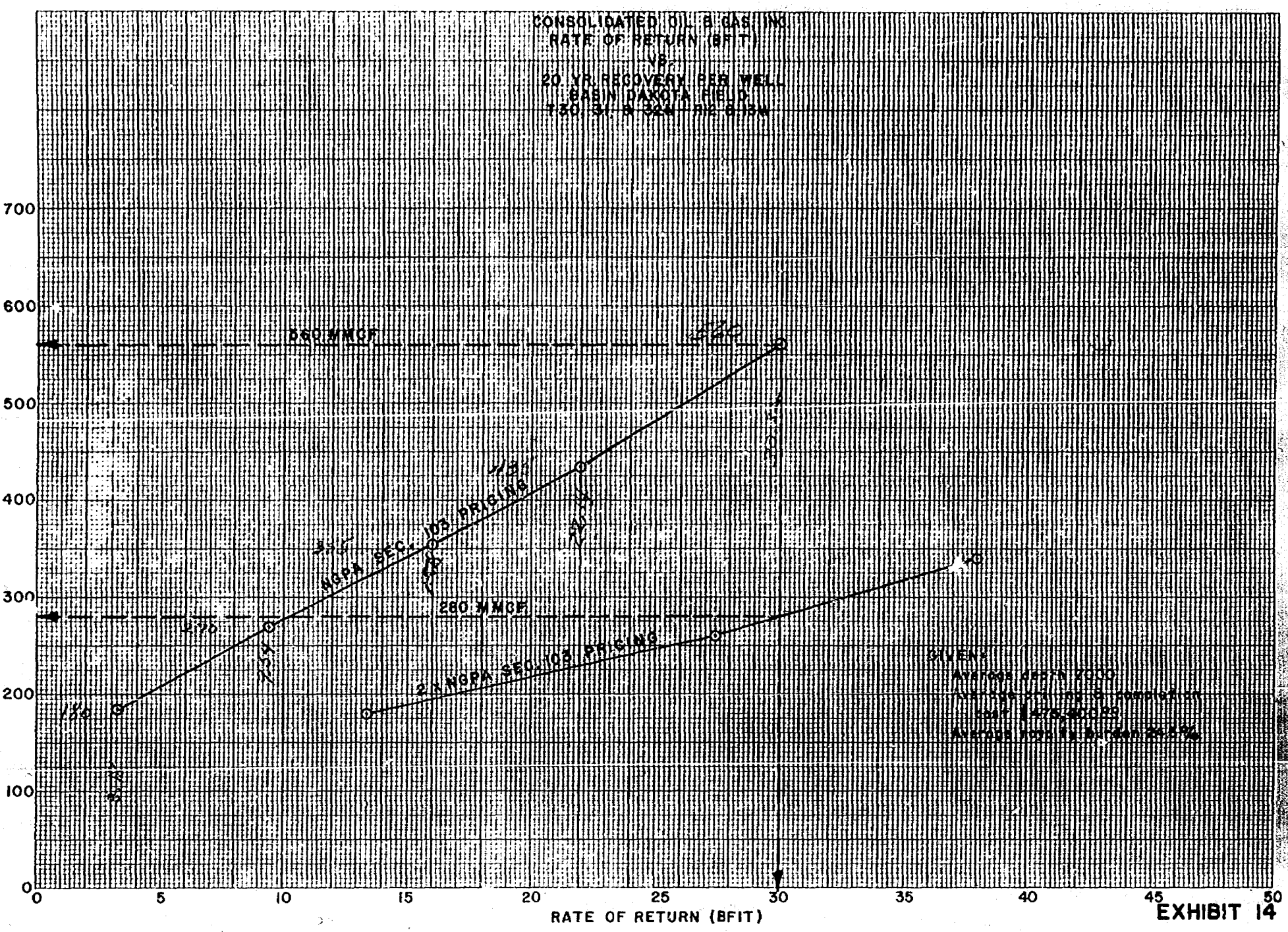

EXHIBIT 14

CONSOLIDATED OIL & GAS, INC
RATE OF RETURN (AFIT)
VS.
20 YR. RECOVERY PER WELL
BASIN DAKOTA FIELD
T30, 31, & 32N - R12 & 13W

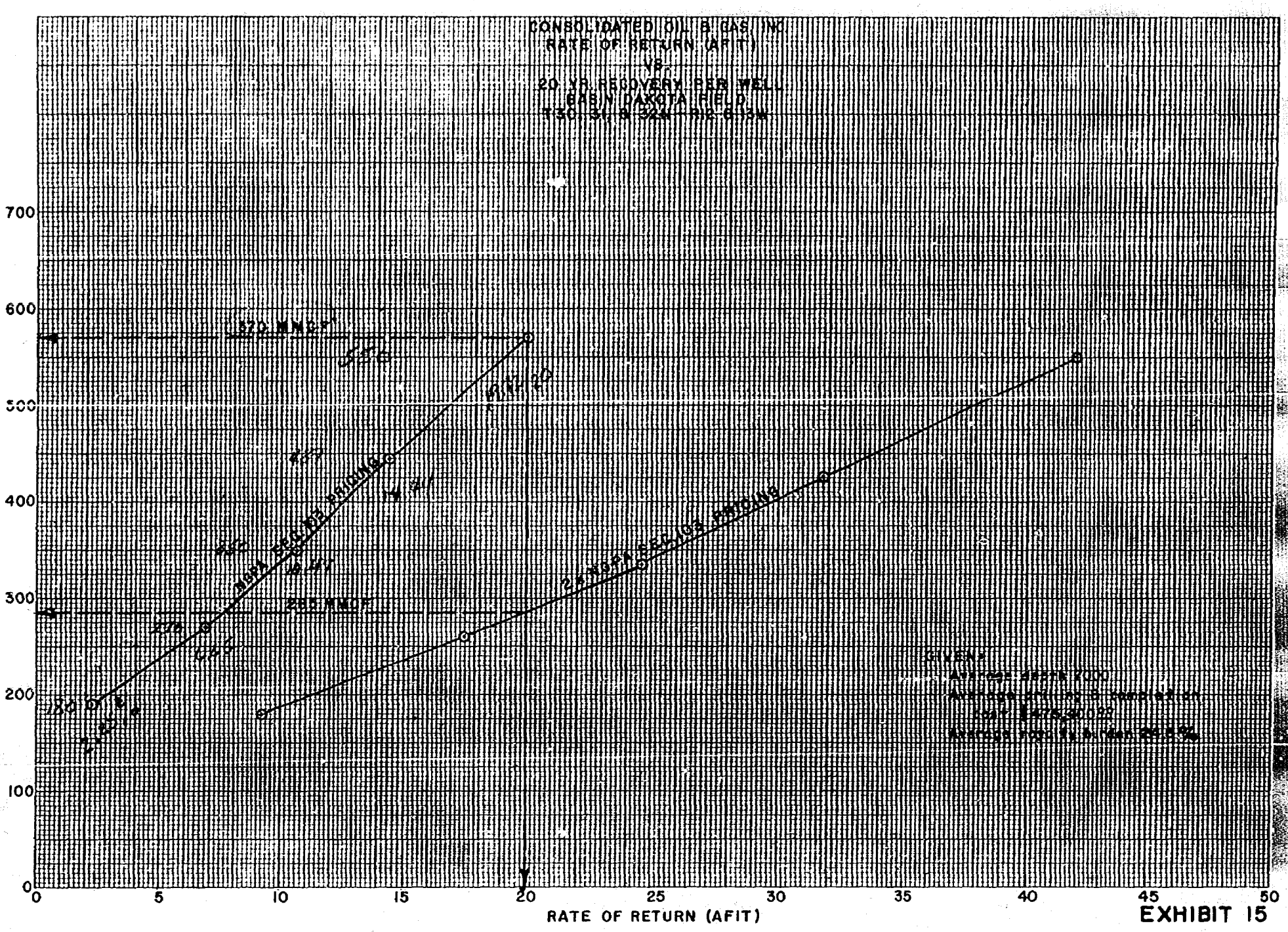

EXHIBIT 15

EXHIBIT 16

RATE OF RETURN JUSTIFICATION

All investment decisions, whether by individuals or corporations, are matters of selection between competing alternatives. If discretionary dollars are invested by an individual in a new house, those same dollars can't be put in a savings account. Every individual and corporation has a myriad of things that can be done with cash flows. Each can make long-term investments, short-term investments, pay off debt, or simply convert funds to current consumption. Each and every spending decision is made in this context, whether or not the spender does any quantified analysis.

Corporations, who have strong fiduciary responsibilities for shareholders' investments, also must continually select between alternatives in making investment decisions. This process must consist of two broad steps. The first is the "hurdle" rate of return determination which must reflect its costs of capital. A corporation has only two sources of capital -- equity and debt.

Equity, or selling additional stock, as a source of funds is becoming more expensive for corporations. This is because of the alternatives available to investors. Investors can earn 17% to 18% on safe money market funds. They can earn 15 3/4% on high grade commercial paper, 16 1/2% on federally guaranteed CD's, 14 1/2% on Federal treasury bills, and 17% to 20% on New York Stock Exchange high grade corporate bonds. Equity issues, in order to attract buyers, must necessarily be priced so that investors can earn, through dividends and stock appreciation, at least 20% since stock is inherently riskier than bonded indebtedness. Many corporations, in trying to attract additional equity, have been forced to issue stock below its "book value," which is dilutive to prior shareholders.

Debt, as an alternative source of capital, is also becoming more expensive. Two primary sources of debt exist for a corporation. One is the public market through issuance of debentures. As mentioned above, these issues, if they can be sold at all, are costing 17% to 20%. Again, this high cost is a function of alternatives. Why should an investor accept less than 17% to 20% on corporate bonds which do have some associated risk when he can earn a guaranteed 16 1/2% on CD's or other safer investments?

The second source of debt is bank borrowings. The following table shows bank prime rate since 1/1/79.

MONTH	AVERAGE PRIME RATE - %
1/79	11.75
2/79	11.75
3/79	11.75
4/79	11.75
5/79	11.75
6/79	11.75
7/79	11.75

MONTH	AVERAGE PRIME RATE - %
8/79	12.25
9/79	13.50
10/79	15.25
11/79	15.50
12/79	15.25
1/80	15.25
2/80	16.75
3/80	19.50
4/80	19.00
5/80	14.50
6/80	12.00
7/80	11.00
8/80	11.50
9/80	13.00
10/80	14.50
11/80	17.75
12/80	21.50
1/81	19.50
2/81	19.00
3/81	17.50
4/81	18.00
5/81	20.50
6/81	20.00
7/81	20.50
8/81	20.50

These prime rates are reflective of the banks' costs of funds. With banks paying 16 1/2% for their funds, prime must be in the 19% to 20% range. It is important to note that very few people or corporations can borrow at prime. Most borrowers pay some multiple of prime or some percentage over prime. In our case, we pay prime plus .5%, for a current interest cost of approximately 20%.

Thus, our corporate cost of capital is 20% for equity and 20% for debt, or 20% overall. Making investments with less than 20% earnings rate would be an imprudent decision which would eventually degrade our shareholders' investment. Even acceptance of a 20% rate of return must necessarily incorporate the belief that interest rates will abate in the future so that a 20% earnings rate project will make future contributions in excess of its costs.

The question may be asked regarding use of cash flow from older properties developed with lower cost capital to generate new capital. This brings up the second necessary step in investment decision-making after a cost of capital has been determined. This step is the selection between competing alternatives. Consolidated, like many oil and gas concerns, since 1976 has invested considerably more in oil and gas properties and drilling than was returned through its profits. For 1976 through year end 1980, Consolidated spent $51.3 million on oil and gas development while net earnings totalled $15.8 million. This gap between earnings and investment was largely funded by increased bank debt. Corporate bank debt now exceeds $50 million at an interest cost of approximately 20%. This is pertinent because repayment of that bank

debt with corporate cash flow represents a guaranteed 20% rate of return. This is not a situation peculiar to Consolidated. Very few substantial oil and gas entities are debt free, and most carry a similar earnings/investment differential.

When managements are reviewing proposed oil and gas drilling investments with rates of return below 20%, they know they have "risk free" alternative investments with comparable returns, namely paying off corporate bank debt or buying any of the high yielding treasury bills, CD's, or money market funds.

Thus, with alternative risk-free investment opportunities available for earning 20%, with costs of capital near 20%, there is certainly justification for an oil and gas investment to yield a substantially greater return. In determining how much greater than 20% the rate should be, several factors need to be considered.

Evaluation and rate of return economics do not account for corporate general and administrative expense. These include accounting and financial functions, costs of federal, state and local compliance required before, during and after drilling and production, as well as all geologic and engineering functions. Consolidated has one of the lower "burdens" in industry, yet even ours is approximately 20% of invested capital. This means that for us to earn 20% at the corporate level, projects evaluated at the field or lease level must earn approximately 24%.

In addition, a risk factor must be considered. The risks in this infill program's viability are, a) those inherent in any drilling operations, b) regulatory exposure to price controls, increased taxes including local, state and federal, and c) lower recoveries than estimated. A reasonable, if not minimal risk factor is 25%. This would translate to an additional 6% return above the "break-even" rate of 24%, resulting in a total return of 30%.

In the analyses of rates of return on oil and gas investments, it is permissible to view 20 years of forecast performance. The bulk of reserves on a well are produced in the first 20 years and over 98% of the present value is derived. For example, in the instant case, a typical well in the 21st year would be producing only 11.5 mcfd, which when discounted at 30% is worth only (.00038) X 11.5, or .004 mcfd of present production. For this reason, the economic forecasts and display of results in Exhibits 12 through 15 reflect gross gas recoveries forecast in the first 20 years. Even though, with sufficient price incentives, many of these wells will produce for 40 or 50 years at low rates, the gas recovered adds almost nothing to present worth, upon which investment decisions are made.

As can be seen on Exhibit 14, this indicates a necessary 20 year recovery of 560 mmcf per well at NGPA Section 103 prices. This exceeds expected recovery of 435 mmcf. With tight gas sands pricing, the required recovery would drop to approximately 280 mmcf per well, which would make the program viable.

The returns and analyses presented thus far have been before income tax. It is both instructive and appropriate to consider after income tax results and requirements. When the same economic forecasts are used to evaluate this Basin-Dakota area, with income taxes being charged to cash flows and tax credits being taken on investments, lower project earnings and rates of return result. The required after tax rate of return need not be as high as the pre-tax return and in fact is well analyzed in prior FPC proceedings. On August 28, 1975, the FPC found in Opinion No. 742 (aff. Op. 742-A, July 27, 1976) that small producers are entitled to a 20% after tax rate of return. The higher rate than previously allowed was justified by com-

bined risk increase, higher equity financing and greater debt cost for small producers. In 1975, prime interest rates averaged only 7.86%. The significantly higher 1980 and 1981 costs of equity and debt certainly justify an earnings rate much in excess of 20%. How much higher is then the question. In Opinion 742, the FPC allowed an earnings rate of prime plus 12.14%. This would dictate an earnings rate of over 32%. This is not an unreasonable goal for an oil and gas investor, but it represents a "weighted" target across a myriad of types of wells, all with varying risks. What then should the return be on a development well drilling program, such as the Dakota? It should certainly be in excess of 20%, but in the instant case, it is not necessary to determine how much in excess. Even at a 20% after tax rate of return the required average 20 year recovery per well, 570 mmcf, far exceed those expected.

Thus, in this case, the Basin-Dakota infill program in this area yields subeconomic results at Section 103 prices whether evaluated on a pre-tax or after tax basis. Our corporate policy certainly reflects this since we ceased our infill drilling program last year and will not resume drilling until sufficient price incentive exists. Our economic analyses presented herein are not "hollow" exercises -- we have been diverting investment from this area to other areas and we see no reason to use capital costing 20% for this area at current allowed prices.

EXHIBIT 17

DAKOTA INFILL WELLS

PREVIOUSLY DRILLED

Well Name	Spud Date	Economic Status at 103 Price (Current)
Cain 1-M	5/17/80	50 MCFD - Will not cover interest on costs
Jackson 2-E	3/4/80	100 MCFD - Requires compression - Will not cover interest
Jaquez 2	2/25/80	170 MCFD - Too early to predict
Kline 1-M	4/17/80	13-30 MCFD - Will not cover interest
Langendorf 1-E	6/1/80	240 MCFD - Will cover interest
Mitchell 1-E	1/26/80	35 MCFD - Indeterminate
Neuman 1-E	9/2/80	78 MCFD - Will not cover interest - requires compression
Payne 1-E	8/9/80	260 MCFD - Will cover interest
Phillips 1-E	2/26/80	175 MCFD - Will cover interest
Robinson Bros. 1-M	6/10/80	55 MCFD - Will not cover interest
So. Union 1-M	3/12/80	Trace - Will not cover interest
So. Union 2-E	8/19/80	140 MCFD - Requires compression - Will not cover interest
Starr 1-M	5/2/80	230 MCFD - Marginally covers interest
Templeton 1-E	7/8/80	210 MCFD - Marginally covers interest
Wilmerding 1-M	4/2/80	65 MCFD - Will not cover interest

SUMMARY

9 - wells are not covering interest on investment

5 - wells are marginally covering interest

1 - indeterminate

STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION DIVISION
STATE LAND OFFICE BLDG.
SANTA FE, NEW MEXICO
29 September 1981

COMMISSION HEARING

IN THE MATTER OF:

Application of Southland Royalty Company for designation of a Tight formation, San Juan County, New Mexico.

CASE 7116

BEFORE: Commissioner Ramey
Commissioner Arnold

TRANSCRIPT OF HEARING

A P P E A R A N C E S

For the Oil Conservation Division: W. Perry Pearce, Esq.
Legal Counsel to the Division
State Land Office Bldg.
Santa Fe, New Mexico 87501

For the Applicant: William F. Carr, Esq.
CAMPBELL, BYRD, & BLACK P.A.
Jefferson Place
Santa Fe, New Mexico 87501

A P P E A R A N C E S

For Consolidated Oil & Gas: Lynn Teschendorf, Esq.
House Counsel for Consolidated
Denver, Colorado

I N D E X

FLOYD E. ELLISON, JR.

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DAVID W. WILSON

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MR. RAMEY: The hearing will come to order. Will everybody please speak loudly today. We do not have a reporter; we have a taper.

Call the first case on the docket, which is Case 7116.

MR. PEARCE: Application of Southland Royalty Company for designation of a tight formation, San Juan County, New Mexico.

MR. CARR: May it please the Commission, my name is William F. Carr, with the law firm Campbell, Byrd, and Black, P. A., of Santa Fe, appearing on behalf of Southland Royalty Company.

MS. TESCHENDORF: Lynn Teschendorf, appearing on behalf of Consolidated Oil and Gas.

MR. CARR: May it please the Commission, Southland at this time would request that this acreage which falls within the advertised area in this case be deleted from this hearing and that that part of the case be dismissed.

It is our intention, as the Commission is aware, not to participate in this hearing but to request that our acreage be deleted, thereby enabling Consolidated to present its evidence for its acreage in this case independent of Southland.

Southland, as you're aware, has filed an

application for designation of a tight formation for the same lands. That application is docketed as the next case on the Commission's docket.

MR. RAMEY: All right. Any objection to that, Ms. Teschendorf?

MS. TESCHENDORF: No objection.

MR. RAMEY: All right. We will proceed in that manner.

Did you want to question anyone from Southland's case?

MR. CARR: Yes. I will question him in the next hearing.

MR. RAMEY: Oh, all right. Okay. All right.

Okay, you can proceed, then, with your case.

MS. TESCHENDORF: Thank you. I have two witnesses to be sworn in.

MR. RAMEY: Will the witnesses stand and be sworn?

(Witnesses sworn.)

MS. TESCHENDORF: If the Commission please,

since this is a de novo proceeding, Consolidated does not wish to incorporate any part of the previous record; however, we will use information from certain of the Southland exhibits, since it is a matter of public record in the previous hearing.

Consolidated did not submit copies of its exhibits fifteen days prior to hearing, as required by the rules; however, waivers were obtained from both the USGS and Mr. Ramey at the beginning of September.

And with that I'd like to call my first witness, Mr. Ellison.

FLOYD E. ELLISON, JR.

being called as a witness and being duly sworn upon his oath, testified as follows, to-wit:

DIRECT EXAMINATION

BY MS. TESCHENDORF:

Q. Would you please state your name, by whom you're employed, and in what capacity?

A. My name is Floyd E. Ellison, Junior. I am employed by Consolidated Oil and Gas, Inc., as their Vice President of Operations for the Rocky Mountain Area.

Q. And you are a petroleum engineer, is that correct?

A. That is correct.

Q. And have your qualifications as a witness been made a matter of record before the Division before?

A. Yes, they have.

Q. Are you familiar with the facts concerning this particular case?

A. Yes, I am.

MS. TESCHENDORF: Is the witness considered qualified?

MR. RAMEY: He is considered qualified.

Q. Mr. Ellison, what is Consolidated seeking with this application?

A. Consolidated is seeking tight formation qualification for the Dakota formation in all of Township 31 North, 13 West, and the western two tiers of sections in Township 31 North, 12 West.

Q. Okay.

A. San Juan County, New Mexico.

Q. Would you refer to what we've marked as Exhibit One, that's on the wall to your left, and describe what that shows?

A. Exhibit One is a base map of the area that Consolidated Oil and Gas would like classed as tight formation, and on the map is shown both the 1980 oil and gas

production and then the cumulative oil and gas production from all of these wells through December 31st, 1980.

Also shown by a little triangle are the infill wells, Dakota infill wells for the area, as well as the three wells in which Consolidated Oil and Gas has permeability data based on flow rates.

Q. Those are marked in red, are they not?

A. They are marked in red.

Q. And would you outline for the Commissioners the area that we're interested in today?

A. Okay. The area that we're interested in includes all of Township 31 North, 13 West, and the western two tiers of sections for 31 North and 12 West.

Q. That area is outlined with a dashed line, is that correct?

A. That's correct.

Q. You can just stay there, Floyd, but we've also marked an Exhibit Number Two. Could you just explain what that is?

A. Okay. Exhibit Number Two is the geologic -- geographical and geological description of the area involved.

Q. And I think the Commissioners can read that at their leisure.

Now would you refer to Exhibit Three-A and describe that?

A. Okay. Three-A is an induction spherically focussed log of the interval in question, and it begins, the log itself begins at the base of the Mancos and of course it goes through the Greenhorn, the Graneros shale, the Graneros sand, which is also many times and within Consolidated usually referred to as the top of the Dakota, on down through the Dakota zone, and this particular well, I think you actually go down and maybe touch into the top of the Morrison.

MR. RAMEY: So your Dakota producing interval is from the top of the Greenhorn to --

A. Yes, it's basically anywhere from the top of the Greenhorn on down through the base of the Dakota or in the very top of the -- of the Morrison can be included as -- and referred to as Dakota.

MR. ARNOLD: Excuse me, I thought that was the base of the Greenhorn and the top of the Dakota.

A. Okay, the base of the Greenhorn, let me correct it.

Q. Would you refer now to Exhibit Three-B and state what that shows?

A. Okay. Three-B is actually the computer process log in which certain data is input. The companies

like Schlumberger and Dresser, and others, then input certain data and they try to describe the zones as they are, their lithology, their porosities, their oil and gas and water saturations, and in this case they describe -- they try to describe what is taking place in that particular interval.

I will point out certain things because this is pertinent to some degree to the situation that we have.

Number one, the Graneros sand which we have found has produced a great deal of our production, doesn't really show all that much gas saturation and yet we know historically that that is where a great deal of it is from, and so apparently it's showing some invasion which has pushed it out through the fractures, so it does not show that as being quite so gas-bearing.

But my primary purpose in showing this particular log shows in the base of the Dakota. In the Phillips 1-E Well, this lower base Dakota in which an interval that does appear wet, described in the logs, we also thinking if we perforated it and tested it natural, and did get gas out of it. We subsequently did frac it and did get gas along with some water out of this interval and it is still producing from this interval.

So based upon this and two or three others in which we have had the same type situation, we have

been in some of the wells perforating the Lower Dakota and have been being able to get some gas production from this Lower Dakota. In many cases we are getting some water, but we're also getting some gas reserves along with it.

Q. Would you describe the completion techniques used, that Consolidated uses in completing these Dakota wells?

A. Yes. Consolidated Oil and Gas, of course, has been running pipe all the way through the base of the Dakota, and then we have been perforating in most cases this Lower Dakota, and we have found through our fracing and other things that there is -- there does seem to be some difference between the Lower Dakota and the Upper Dakota and Graneros sand portion in the back pressures. We have -- we have been experiencing 800 to 1000 pounds difference in the instantaneous shut-in pressure, the back pressure that has been taking place.

For that reason it has required that instead of being able to frac the entire interval all at one time, this requires us to isolate the Lower Dakota and to frac it separately and then to frac the upper zone, and at the same time to speed up the cleaning up procedure, we have been including some nitrogen in the -- in the frac fluid so that it will go back and clean up a little quicker.

So that, of course, has increased the expense of our drilling and completion technique, or cost. But by the same token that is about the only way that we felt that we could go ahead and try to get some additional reserves out of the Lower Dakota.

Q Would you now refer to what has been marked as Exhibit Four-A and describe what that shows?

A Okay. Four-A is a cross section of the area that we're interested in and it actually begins with a well, the Rollison Brothers 1-M, which is just north of the section that we have asked to be included as tight gas designation, and it goes basically north and south down to the southernmost well here, which is the Langgendorf 1-E.

And it is primarily showing that the Dakota formation is basically continuous throughout that interval going from north to south.

Q And Exhibit Four-B.

A Exhibit Four-B is a cross section across this same interval on the -- actually on the northern portion of this township and it's showing from the Mitchell 1-E across to the Wilmerding 1-M, and again, it does show the continuity of the -- of the Dakota Graneros sand interval going through that -- across that interval.

Q And Four-C?

A. Four-C is another cross section beginning with the Mitchell 1-E and angling from the southwesterly to a northeasterly direction, again showing the continuity of the Dakota and Graneros sand going across that particular area that we are interested in.

MS. TESCHENDORF: Do the Commissioners have any questions on these exhibits as long as the witness is still up here?

Q. Back in the exhibit booklet, would you now refer to what we've marked as Exhibit Five and explain what that shows?

A. Okay. Exhibit Five is a table showing seven wells and some permeability data that has been developed on each one of these wells. Three wells are Consolidated wells. Two wells are Southland Royalty wells. And two wells are El Paso Natural Gas wells.

Q. Would you go through the stabilized production rates, and these are pre-stimulation, is that correct?

A. Yes, these are pre-stimulation.

The Consolidated Oil and Gas Wilmerding Well, the permeability data we could not, and I might just comment at this point, the three wells that Consolidated Oil and Gas did the flow tests on to insure that we were not ex-

periencing any mud plugging or mud damage, we perforated the intervals, we acidized them with a small acid job and swabbed them back to clean it up, and then we did request a witness from the Corporation Commission to witness the tests and they observed the flow tests that were described.

And in the case of the Wilmerding, the flow rate was even too small to measure and of course by calculations all you can say from that is it has to be less than the one millidarcy that is required, or the .1 millidarcy required.

The Klein Well, we tested the interval from 6506 to 6736 and the flow rate was 12-1/2 Mcf per day, and by doing a Darcy formula calculation it comes up to the .0049 millidarcies, as shown.

The Consolidated Oil and Gas Center Well had a flow rate out of the Lower Dakota of 2.73 Mcf, which calculates to .00068 millidarcies, and a 52 Mcf per day rate out of the Upper Dakota, which calculates to .0146 millidarcies.

The Southland Royalty Company well, the east well is -- had a flow rate of 21 7. The Southland Royalty Patterson "B" Community Well had a 224.1 Mcf per day rate, and of course it showed a .0877 millidarcy calculation.

The El Paso Natural Gas Company Case

Well and also the Moore Well are calculated from core analysis and all. They weren't tested, and of course, the calculations which are shown here are based upon a formula that is used to come up with what the millidarcies would be from a core analysis.

Q Are all these wells, their stabilized production rates, are they all within the FERC allowed rates?

A They all are, yes.

Q Do any of these wells expect to show any crude oil production?

A Well, the -- what crude oil production there would be would be less than the five barrel of oil per day that is required.

Q Would any of Consolidated's wells qualify for tight formation pricing if this application were approved?

A Yes, from what we can tell all of these wells that were tested here and assuming from that that this is representative of other wells in the area, that they -- they would qualify for the tight gas.

Q And these are all wells that were spudded after July 16th of 1979?

A Yes, they were.

Q Would you now refer to Exhibit Six-A,

which has a number of pages, seven page exhibit, and describe that?

A. Okay. Six-A is a -- and there are several pages to it, in which it shows the data of a DST that was run on the Southland Royalty East 7-E Well, and then from it then there was a build-up run on it and from that, as can be shown on page four, the calculations for the permeability is .00110.

Q. That is marked with an arrow, is it not?

A. That is marked with an arrow.

Q. Exhibit Six-B?

A. Exhibit Six-B is the calculations for the Wilmerding 1-M and of course this is the one in which the -- the rate was too small to measure, so there was inadequate gas actually to compute the flow rate using the Darcy method, and therefor it has to be assumed that it is less than .1 of a millidarcy.

Q. That's page one of Exhibit Six-B. What is page two?

A. Okay. Page two of Exhibit Six-B is the Darcy permeability calculations on the Klein No. 1-M, Consolidated Oil and Gas Klein No. 1-M, and from it, based upon the flow rate, the calculated permeability using the Darcy formula is .0049 millidarcies.

Exhibit Six-B-3 is Consolidated Oil and

Gas Center No. 1-M, and it shows the calculations using the Darcy formula, and shows that the Lower Dakota permeability is .00068; the Upper Dakota permeability is .0146.

Q. And the next page?

A. Okay. Exhibit Six-B-4 is the Southland Royalty Company Patterson B Community 1-E and using the flows from it, using the Darcy formula, the permeability for that well is .0877.

Q. Now refer to Exhibit Six-C and explain that.

A. Exhibit Six-C-1, on through, well, Six-C-1 is the calculated permeability from the cores of the El Paso Natural Gas Company Case No. 1 WEll.

Q. It's No. 8, I believe.

A. Excuse me, I'm sorry, Case No. 8 Well, and it shows that the average laboratory permeability is .1195, but the average in situ permeability is .0335.

Q. And page two of that exhibit?

A. Page two of that exhibit is the El Paso Natural Gas Company Moore No. 8, and it shows the average laboratory permeability being .0538 but the average in situ permeability being .0151.

Q. And would you now refer to Exhibit Seven and explain that?

A. Okay. Exhibit Number Seven is a paper describing how you convert laboratory permeability to in situ permeability.

Q. This is for core analysis?

A. For core analysis, and this is how the in situ permeability for Exhibits Nos. Six-C-1 and Six-C-2 were calculated.

And it is an industry method for trying to convert the two -- or the measured permeability to in situ permeability due to the fact that laboratory permeabilities will be high for two or three reasons. One of them is that the overburden pressure has been released and therefor it allows the pore space to enlarge just slightly. Also is the fact that within the pore space is water and of course in the laboratory you have changed that and taken some of the water out, so therefor the gas can in a laboratory sense flow through this tight sandstone easier than it can in situ.

So this is the method -- a method that is used to convert from one method -- from the laboratory tested permeability to in situ permeability.

Q. Mr. Ellison, all the types of calculations used to determine permeability that you've described in Exhibits Six and Seven, are they all generally accepted methods used in the industry?

A. Yes, they are.

Q. Would you now refer to what we've marked as Exhibit Eight-A and describe that?

A. Exhibit Eight-A is Consolidated Oil and Gas Company's estimated well costs for drilling a Dakota well in this area and completing in both the Upper and the Lower DAkota, which would require two fracs.

Q. Does Consolidated -- has Consolidated drilled a number of its Dakota infills as Mesaverde-Dakota duals?

A. Yes. The majority of the wells that we have drilled, for instance, this past year, the majority of them were dual Mesaverde-Dakota wells, and of course this was part of the reason that we chose to drill these, is the fact that the economics were better if done for both, than just for one.

But Consolidated now has pretty well drilled up all of the Mesaverde infills that we have in this area, and from now on they'll be basically single Dakota wells.

Q. But the part that you have shown in Exhibit A and when we get to Exhibit B, the actual costs, you have taken the Mesaverde share of the cost out of these figures, have you not?

A. Yes, we have, as best -- as best we could. We removed the Mesaverde completion and equipment costs out of the costs shown and this is our best estimate of what it will cost us to drill and complete a Dakota well in both zones.

Q. Would you now refer to Exhibit Eight-B, which has a number of pages, and describe what that shows?

A. Okay. Exhibit Eight-B is the -- are the drilling costs that Consolidated actually experienced during the year 1980. Of course, it can be noted that even the -- going through there that some of the wells drilled earlier in the year were much less than some of those drilled later in the year, and a lot of that is due to the fact that the drilling costs, that the contractors were charging us, increased,over last year increased about 50 percent on a per foot basis. It's very interesting to note that when rigs were very short the costs were going up very rapidly. Now that the drilling is cut back, when we were going out to check to see what the footage prices were this year, nearly a year after our last well, that the footage cost has remained the same over this last year, and I think it's due to the American way of doing things, which is whenever there is an excess of things, that the -- that people drop off on what their price is, and I like the system in that -- in the fact that the free

market does allow these things to go up and down.

But that was one reason that we were able to maintain our well cost estimate as shown on Figure Eight-A, basically about the same as it was one year ago.

Q Now the first five pages of Exhibit Eight-B contain actual well costs for a number of these wells we have drilled. Is that correct?

A That is correct. And --

Q And page six shows what?

A Page six shows the total of all of the categories shown and then the average for this well, and of course, last year it should be noted that the -- that the total cost to drill and complete a Dakota well to both zones was nearly the same as what we are estimating it to be at this point, and of course it does, we did note at the bottom, the -- our best estimate of how much the Lower Dakota completion did add -- add to this cost so that can be subtracted out in our costs for had we not been trying to complete the Lower Dakota.

Q What is the average cost of a Dakota completion in that area?

A Okay. We are -- we are showing that it is -- okay, last year our average cost was $467,823.

Q And what was the cost of the Lower Dakota

completion?

A. And the Lower Dakota completion cost was $65,782.

I might note, and I think this is always worth remembering in trying to do this, one single well may cost a whole lot less, but when you average in various things that can happen, like fishing jobs, such things as severe lost circulation, and things like that, it has to be remembered that we are dealing with an average cost for the area and not the best cost that somebody maybe has drilled as the lowest cost well in the field.

All of these things have to be included, and it was very interesting in trying to call around and getting some other people's costs how they, whenever they'd say, yeah, we had a problem on this one well, and so that isn't represented, and so I would have to say yes, but it is represented because it has to be included in the average for the area.

Q. Would you now refer to Exhibit Nine and just without reading through it describe to the Commissioners what that shows?

A. Exhibit Nine is a showing of how the fresh water in the area will be protected.

Q And we do show which formations are bearing fresh water in that area and where they occur, is that correct?

A That is correct.

Q In your opinion will the development of this formation adversely affect any fresh water aquifers that are or are expected to be used as domestic or agricultural water supply?

A No, it will not hurt them.

Q Were Exhibits One through Nine prepared by you or under your direction?

A That is correct.

MS. TESCHENDORF: At this time I'll offer Exhibits One through Nine.

MR. RAMEY: Exhibits One through Nine will be admitted.

Are there any questions of this witness?

Ms. Teschendorf, I assume that in the packets here we have all of the exhibits that are on the wall?

MS. TESCHENDORF: Yes, you do.

MR. RAMEY: Thank you.

DAVID W. WILSON

being called as a witness and being duly sworn upon his oath, testified as follows, to-wit:

DIRECT EXAMINATION

BY MS. TESCHENDORF:

Q. Would you please state your name, your position, and by whom you're employed?

A. Yes. My name is David W. Wilson. My position is Vice President of Corporate Development for Consolidated Oil and Gas.

Q. And would you please describe to the Commissioners your educational and employment background?

A. I graduated from Tulsa University in 1968 with a degree in engineering mathematics.

Prior to graduation and for the next six and a half years I worked with Sunray DX Oil Company, subsequently Sun Oil Company after Sun acquired Sunray, in the capacity of a production engineer, reservoir engineer.

I was also an acquisition engineer, which involved property appraisal and acquisition of both companies, as well as producing oil and gas properties, and I designed and was responsible for various corporate economic

models, both pre-tax and after-tax.

After that I joined Champlin Petroleum Company for two and a half years. I was there in charge of exploration and production, economic justification, and assistant to the executive vice president, where I reviewed all corporate investments by Champlin, which is a subsidiary of Union Pacific Railroad. I was in charge of an off shore task force for Champlin Petroleum, and I at the end of that period became Regional Manager for Champlin Petroleum in the Rocky Mountain area.

I subsequently joined Williams Exploration Company in Tulsa as Acquisition Manager for approximately a year and a half. I left Williams Company to join Consolidated in January of 1977 in the dual capacity at that time as Vice President of Corporate Development and Vice President of Exploration.

I have subsequently taken over just the corporate development side. In that capacity I'm responsible for budget planning, acquisition, as well as the Federal and Federal Compliance Group, insofar as pricing and regulations are concerned.

Q. Are you familiar with the economics of the proposed drilling program in this area?

A. Yes, I am.

MS. TESCHENDORF: Is the witness considered qualified to testify?

MR. RAMEY: Yes, he is considered qualified.

Q You may want to refer back to Exhibit One, Mr. Wilson, but would you describe Consolidated's Dakota infill drilling program, when it started, its development?

A We began our first infill phase, or the first phase of our infill program in 1978, which was primarily Mesaverde infill program.

After passage of the Natural Gas Policy Act in November of 1978, Consolidated, upon the belief, or in the belief, in reviewing the Natural Gas Policy Act, we began in mid-1979 drilling infill development wells in the San Juan Basin, originally picking out the better locations that had both Mesaverde and Dakota potential.

This program was undertaken based on two primary facts, our estimate of drilling costs at that point in time, and our belief and in the interpretation of the regs that any well drilled after July of 1979, that subsequently qualified for tight gas sands pricing would receive tight gas sands pricing.

That program continued through the end of 1980, to November of 1980, and in this particular area we

drilled fifteen wells in 1980.

Based upon what had happened in the regulatory area, where one more time in the industry by a company accelerating its drilling program, it stood the likelihood of getting a much lower price than if they had waited to drill wells, and based on the fact that as Mr. Ellison mentioned, our costs had escalated by better than 50 percent during the year, in 1980 we, as a corporation, completely ceased our infill development drilling program.

Q. Exhibit One shows the infill -- the Dakota infills that we drilled in that area, is that correct?

A. Yes.

Q. And they're marked with triangles?

A. Yes.

Q. Why are we presenting economic testimony in this case, Mr. Wilson?

A. Because it is now a requirement of FERC that in order to qualify for tight gas sand pricing in an area that infill drilling has been undertaken, that economics be presented to show the necessity of the higher price to justify drilling.

Q. Would you now refer to Exhibit Number Ten and explain that to the Commission?

A. Exhibit Ten are the economics reflecting

our costs, or the economic assumptions, pardon me, that we used in running the economic analyses to evaluate the drilling program in this area to determine what threshold of recovery and production rate performance we had to have in order to justify the drilling, the continuation of drilling in this area.

Some of the major assumptions are that the drilling costs per well, drilling and completion costs, will be $475,400. We included in the economics, both in the costs and in the reserves, the cost of picking up the Lower Dakota zone that Mr. Ellison discussed, because we feel that that is a valid investment to make and if we do not spend the money to obtain the reserves in that Lower Dakota at the time you're drilling the original well, the consumer will never see that gas at any point in the future because you cannot afford to drill that zone on its own.

So on an incremental cost basis we feel that it's a worthwhile investment that will bring more gas, gas supplies to the market.

The other, the other assumptions are -- are fairly straightforward. Operating costs of $150 a month, which I think is important to note that that only includes at the field level operating costs. It does not cover any corporate, general, and administrative expense, which I'll

discuss in the economics later on.

7000 foot depth, I don't need to go through those. I think they're all shown on Exhibit Ten.

The only thing I would like to mention on the fully adjusted gas price, that does reflect Section 103 pricing under the NGPA, with about a $2.50 base price and 1180 BTU, plus an 8 percent severance tax.

I think at the bottom of that page you will see a column that shows initial post-stimulation stabilized production rate, a range of those running from 89,000 cubic feet per day up to 400,000 cubic feet per day, and that rate is shown as opposed to its forecast 20-year recovery in millions of cubic feet.

This, we ran this range of rates in 20-year gross recovery in order to look at sensitivity to prices in oder to -- to determine whether or not to go ahead with the program. This is really the basis for our economics forecast.

In reviewing the results of the wells drilled thus far in the program, our expected pay shows that post-stimulation producing rate of 232,000 cubic feet per day, is what we would expect a typical well, an average well, in this area to do, and that would yield over a 20-year period recovery of 435-million cubic feet.

The economics that we have presented later will incorporate that recovery over a 20-year period.

Q. The only other thing I would like you to point out on this exhibit is the royalty interest typical to Consolidated's holdings. What is that?

A. The total royalty interest, including the base, is 24-1/2 percent, which is a typical interest in this area for Consolidated.

Q. And with that, would you refer to Exhibit Eleven and explain it?

A. Exhibit Eleven discusses why our royalty interest is higher than 12-1/2 percent, and basically what we're showing or saying in Exhibit Eleven is that in the oil business there are two ways to obtain rights to drill and produce on leases.

If you are able to obtain the original base leases under which you only have to give a 12-1/2 percent royalty, then of course, that's all that would burden the economics. But in that case you would have paid money up front, or a bonus, in order to obtain those rights to drill, which would be justifiable to include in the economics.

The second means of obtaining the right to drill on a lease is by taking a farm-in from the original lease owner. In this case typically he carves out, retains,

an overriding royalty interest and sometimes that royalty interest is convertible into an even larger working interest.

Consolidated obtained the leases in this area through that second means, where we were not the original party taking the lease; we were the second party. The original party required that we carve out typically 12 percent overriding royalty interest to him, leaving us with 74-1/2 percent.

I think it's interesting to note that in viewing our average economics in the area, the present worth of the 12 percent overriding royalty interest, when equated back to acreage, runs about $300 an acre, which is a fairly typical acreage price in this area.

If we had acquired our acreage through that means, then the same costs would have been justifiable economic cost in the project.

Q. Is this 24-1/2 percent royalty fairly common for other companies in this area?

A. Yes, very common for companies that -- that have subsequently -- that have taken the lease from the original lease owner. In fact, some companies have overriding royalty interests as high as 17-1/2 or 18 percent.

Q. Would you now refer to Exhibit Number Twelve and explain that to the Commission?

A. Exhibit Number Twelve is a series of

output sheets from our economics model that go through the range of rates and recovery as shown on Exhibit Ten, whereby we -- we are attempting to run sensitivity analyses to recovery and rates versus -- for Exhibit Twelve this is before tax with Section 103 pricing, or two times six and 103 pricing.

We were trying to run a range of economics based on our low price, high price, low recovery, and a high -- and a high recovery.

It's a fairly straightforward economics model, showing forecast gross oil and gas production, forecast net oil and gas production. This is to 100 percent of the working interest adjusted by the total royalty. Showing the revenue to the working interest, the net investment required to be made by the working interest owners, the operating expenses, then allowing you to be -- to come to a net income before Federal Income Tax, a cumulative net income, and then showing a 30 percent discounted present worth.

Along the bottom of these runs you will see several economic indicators that most models will -- will put out, cumulative -- several -- several economic indicators, and I think those are all fairly straightforward, and I don't need to discuss those.

Q Would you now refer to Exhibit Number Thirteen, some pages later?

A. Exhibit Thirteen is the same base economic forecast --

MR. RAMEY: Where is Exhibit Thirteen?

MS. TESCHENDORF: There's another big, empty, white sheet before you get up to that.

MR. RAMEY: Okay.

MS. TESCHENDORF: Before the graphs. Okay?

MR. ARNOLD: Okay, thank you.

A. These economics take the same base forecast as done in Exhibit Twelve, the same pre-tax forecast, and convert those to after-tax economics. The headings there, of course, show the net oil, the net gas, to the working interests after the royalty has been carved out, the revenue to that interest, the operating expense, the net income at the lease level, the capital investment required, and then it's schedules, depreciation, depletion, calculates the income tax in order to come to an after-tax cash flow.

This model gives credit for investments that generate tax credit and the paid income tax on cash flows above -- above investments.

I think that is -- taxes are something that we have to live with, which is why we -- why we incorporate an after-tax economic analysis in -- in the presenta-

tion.

Q. What rates of return were you using in these two exhibits, Twelve and Thirteen?

A. I used a -- Exhibits Twelve and Thirteen actually, those two exhibits were running a range of rate of return versus price versus recoveries.

I think Exhibit Fourteen is -- Exhibit Fourteen, which is a graph, shows the economics and the minimum 20-year recovery required at various rates of return with two different pricings forecasts used, NGPA Section 103, and two times NGPA Section 103.

I think it's important to note, and I should probably go back to Exhibit Twelve, but I think it's important to note that these forecasts assume that prices continue to increase in the future. I have not used low pricing forecasts and they very rapidly get to $10.00 an Mcf, which more than reflects the escalations that would be received under both Section 103 or under stripper pricing, if that would become a factor on any of the wells.

Exhibit Fourteen shows that on a pre-tax basis in order to return, or in order to earn 30 percent, we would need a minimum recovery over a 20-year period of 560-million cubic feet average per well.

At two times Section 103 NGPA pricing,

that minimum recovery required drops to about 280-million cubic feet per well.

Our forecast, based on results thus far of the Dakota infill program, are that the average well over a 20-year period will recover about 435-million cubic feet per well, which is substantially below that we -- that we require to have just to have any major or significant economic return, which is 560-million cubic feet over a 20-year period.

Q. So before tax you were using a 30 percent rate of return,is that correct?

A. That's correct.

Q. Will you now refer to Exhibit Fifteen?

A. Exhibit Fifteen is basically the same type of graph. It plots for Section 103 pricing and for two times Section 103 pricing. It plots the 20-year recovery required versus rate of return. We have based our required rate of return after tax. We have required 20 percent, which requires that the average well in the area over a 20-year period recover 570 MMCF at NGPA Section 103 pricing; with two times NGPA 103 pricing that required amount drops to 285 MMCF per well average recovery.

Q. Will you now refer to Exhibit Sixteen and explain how you came up with your rates of return?

A. Yes. Exhibit Sixteen is a rate of return

justification. It's what we have to look at as a corporation in order to make investment decisions, because we do have strong fiduciary responsibility to our shareholders.

All investment decisions must necessarily incorporate two major factors. One, represents the concept of what is your money costing you.

In Consolidated's case, or in any corporation's case, there are only two major sources of funding. One source is equity, one source, or selling stock. The second source is debt.

Equity has some cost because shareholders expect some economic return or they will not invest in the stock. The question then becomes how much do they expect to earn on stock. Investors can currently earn 17 to 18 percent on money market funds. They can earn 15-3/4 on very high grade commercial paper. They can earn 16-1/2 on Federally guaranteed CD's. They can earn 14-1/2 on Treasury bills, and they can earn 17 to 20 percent on very high grade corporate bonds that trade on the New York Stock Exchange.

No equity investor will buy stock in any corporation unless he expects to earn a minimum of 20 percent on his investment. That locks in the cost of equity for a corporation.

Debt exists as an alternative source of

capital and debt, we have two, two means of obtaining funds. Those are through the public market, and again going back to the same investors having the same alternative investments, which means that public debentures, public bonds offered, currently investors can earn 17 to 20 percent on high grade corporate bonds, so for any oil and gas concern to raise public funds through the debt method or through debenture, they're going to incur a cost there of about 20 percent.

The second source of debt, of course, is bank debt. In Exhibit Sixteen I've shown a schedule of bank prime rates since early 1979. As you can see, recently it's been very stable in the 20 percent range.

I would like to point out that very few individuals or corporations can borrow money at prime. Typically, most have to pay some percentage of prime or some add on percentage rate to prime.

This is very simple. The banks' money are costing them from people on deposit and through CD's and that type of thing 16-1/2 to 17 percent. They have to require 20 percent interest being paid or they can't -- or they can't exist.

So we're left with our three sources of funds, being equity, costing 20 percent; public debentures, costing 20 percent; bank debt, costing 20 percent, which makes

it very easy to average. We know our average corporate cost of funds, present day, is approximately 20 percent. To earn any less than 20 percent would be to deny our fiduciary responsibility to shareholders because we would be degrading their investment.

The next source of funds which may be brought up, which really is -- is a strong part of the fiduciary responsibility to shareholders, is the investment of cash flow from older properties that typically were made with money costing in the past considerably less than 20 percent. This brings up the second step in the investment decisions that have to made by corporations, which is when you have cash flow available, or when you have funds available, what are the alternative investment opportunities that you have available?

One very safe alternative investment opportunity is represented by repayment of your own corporate debt. Since 1976 Consolidated, like most independents, has spent more in oil and gas development than we've made. Since 1976 we've spent $51.3-million in oil and gas exploration and development. Our profits have been $15.8-million.

This gap, this difference has been funded by bank debt, which is now costing us slightly in excess of 20 percent.

When we have cash flow available from prior investments, we have an absolutely, leadpipe cinch, guaranteed rate of return of 20 percent called pay off your debts. Any project that we would invest in would have to earn more than that or it would make no economic sense to the corporation.

Thus we're left with alternatives. We can also buy commercial paper. We can also buy inner bonds that earn 20 percent. We know we can earn 20 percent, so the question then becomes, how much more should we require for any oil and gas development program or exploration program?

Like most companies, and in our economics we have only reflected the costs at the field level. We also have to consider corporate G & A, which is not a small cost in the oil and gas business any more, and for every dollar that we spend in new capital investment our corporate G & A is going to run approximately 20 percent.

Last year we spent about $20-million at the field level on all projects and it cost us, not reflected in the economics as you would normally appraise them, about $3-million to spend that type of money, plus continuing G & A associated with all the accounting functions which go on even after production.

A good way to look at this is that this

increases the minimum required rate of return from 20 percent to 24 percent. In other words, what we're saying is that for the corporation to earn 20 percent, the project at the field level has to earn at least 24 percent, and that's before risk.

You then get into the -- that breaks you even with alternative investments, again one of the major ones being to pay off our own bank debt, what type of a risk premium should you -- should you require for an oil and gas drilling program. These risks, as we see them, are risks inherent in any drilling operation. Frankly the major risk over the last ten years has been regulatory exposure to price control, the increased taxes, and who knows what in the future, and lower recoveries than estimated.

A very reasonable, and I think minimal, risk premium above absolutely safe investments is 25 percent. If you take 25 percent of the 24, that's 6 percent, which gets us to our minimum required pre-tax return of 30 percent. That's again on a before tax requirement.

I think it's pertinent at this point to point out that it's certainly feasible to only view 20 years of performance on these wells because the bulk of the wells are -- are produced in the first 20 years, plus well in excess of 98 percent of the net present value is derived in the first -- in the first 20 years. So production, even

though there may be reserves in production for 40 to 50 years, those do not -- and that, by the way, is price sensitive, if the price incentive exists beyond that point in time, any reserves produced beyond 20 years would not have any influence on the economic investment decisions being -- being made today.

To reiterate, back on Exhibit Fourteen, using a 30 percent before tax earnings rate, indicates a necessary 20-year recovery of 560-million cubic feet per well, which is certainly in excess of the 435-million expected.

With tight gas sand pricing that requirement will drop to 280, which would make the program viable.

Again I would like to point out these -- the return -- the rate of return and analogy presented so far is before tax. I think we also have to consider after tax economics with the recognition that your after tax rate of return will always be less than your before tax rate of return.

Rather than trying to go through a detailed tax analysis, as I went through before tax analysis, I think we can turn directly to FPC Opinion Number 742. In August, 1975, the FPC found that small producers at that time were entitled to a 20 percent after tax rate of return. This opinion was affirmed in 742-A on July 27, 1976. This was a higher rate than previously allowed but they, the FPC found for the 20 percent minimum after tax -- or the 20 percent

after tax rate of return due to increased risk, higher equity, and greater debt cost for small producers.

I think it's pertinent to point out that at that time the prime rate was averaging 7.86 percent when the FPC allowed an after tax return of 20 percent.

That certainly, with prime rate exceeding now 20 percent, or averaging 20 percent, certainly justifies and after tax rate of return in excess of 20 percent.

But this is not -- it's not necessary to go through any discussion of how much higher should that after tax rate of return be because even with the 20 percent after tax criterion more 20-year gas recovery is required than we will get out of this area.

If you go back to, I believe it's Exhibit Fifteen, a 20 percent after tax rate of return would require that the average well recover 570-million cubic feet over a 20-year period, which is certainly in excess of the 435-million that's expected in this area.

So under both criterion on a before tax basis and on an after tax basis, this program is not -- or let's say can be classified as sub-economic at Section 103 prices.

I would like to point out to the Commission that these are not hollow economic runs that we've made.

We stopped our infill drilling program in 1980 and we will not resume our infill drilling program until sufficient economic incentive through prices are available.

Q. Consolidated is a small producer, is it not?

A. Yes, it is.

Q. And as to how you came up with the 20 percent after tax rate of return, this equates approximately with the 30 percent before tax rate of return, does it not?

A. Surprisingly, the results are very -- are very similar. They weren't designed that way but they came out extremely close.

Q. Referring to Exhibit Seventeen, has Consolidated drilled any Dakota infill wells that will not be economic at Section 103 prices?

A. Exhibit -- yes. Exhibit Seventeen is a list of the fifteen wells, Dakota infill wells, that we drilled in this area in 1980. The exhibit shows the wells, the spud date, and the current economic status at Section 103 pricing.

Out of those fifteen wells we have nine that have been drilled that are not recovering even the interest on their investment at Section 103 prices. We have five wells, or a third of them, that are only marginally covering the interest costs on the investment made to drill

the wells, and we have one well that it's a little bit too early to tell as to whether it is going to be economic at Section 103 pricing.

This is the crux of the reason that we have stopped the infill program.

Q. Mr. Wilson, what are your conclusions therefor as to the necessity of incentive price before Consolidated will continue drilling Dakota wells in this area?

A. They are absolutely essential, as I -- as I mentioned, we will not resume the Dakota infill drilling program in this area absent price incentive greater than what we currently have with Section 103 pricing.

We have better places to go spend our money.

Q. Do you have anything further you wish to add to your testimony?

A. No.

Q. Were Exhibits Ten through Seventeen prepared by you or under your supervision?

A. Yes, they were.

MS. TESCHENDORF: That's all I have of this witness, and I do have a closing statement, if you want it now or later.

MR. RAMEY: Do you want to tender your

exhibits at this time?

MS. TESCHENDORF: Yes.

MR. RAMEY: Ten through Seventeen?

MS. TESCHENDORF: Yes.

MR. RAMEY: They will be admitted.

Any questions of Mr. Wilson? Mr. Arnold.

CROSS EXAMINATION

BY MR. ARNOLD:

Q Mr. Wilson, I believe you and Mr. Ellison both mentioned that there was a 50 percent increase in contract drilling costs about a year ago, or I'm not sure when the increase took place.

A They -- they took place, I could recall, in 1978 when we originally were -- were looking at the program to start it. Our estimated drilling and completion costs for a Dakota well were about $275 -$285,000.

MR. ELLISON: Okay, I might answer that. Our footage costs begin in 1980, or the very tail end of 1979, I'm just talking about the footage costs, right at $10.00, make that $10.50 a foot, or something like that.

When we drilled our last well in that area our footage costs were $15.50 and we had an interest in a well by another operator right in the same immediate area

that was drilled in December of last year, that was $19.51 on footage.

All right, when we went out, and of course I think everybody then started shutting down with the drilling in this area, and I'm sure that part of that had to do with the cost going up so dramatically, of course there's been a bunch of rigs, as I understand, a bunch of rigs move out and a lot of things have happened, when we went out here when I was preparing this and checking, trying to get some estimates on what the footage price was at this stage of the game, we find out that they were $15.50 and $16.00 as two of the numbers coming in to us, so apparently the supply and demand situation as far as -- had its affect on the drilling costs going out there. I'm sure their costs have not gone up that rapidly but there's a shortage of rigs, so --

MR. ARNOLD: That was really what my question was to go to here. You said before that the 50 percent in drilling cost, you thought, was strictly due to a rig shortage.

MR. ELLISON: Well, it should be 50 percent -- our total drilling cost did not go up 50 percent from the beginning of the year to the end of the year. Our footage cost --

MR. ARNOLD: The thing is that the cost

went up 50 percent due to a rig shortage.

MR. ELLISON: Yeah.

MR. ARNOLD: Without -- there probably was some inflation built into that, all right --

MR. ELLISON: Yes.

MR. ARNOLD: But I -- and then suddenly you developed a situation the next year where you had an over supply of rigs, and you say the cost levels off. It doesn't appear to me that supply and demand is working all that well. It would appear that 50 percent increase was due primarily to a rig shortage, an over supply of rigs should bring it down. Does it ever work that way any more?

A. Well, I was going to say, just like I said, the one at the tail end of that year that we had an interest in was $19.00. This was actually a contract that was made after we had finished ours.

MR. ARNOLD: So you did have --

MR. ELLISON: It was $19.51 and it -- and I'm saying a year later, of course there should have been some inflation and everything else, if their costs had gone up, it had dropped back down -- apparently the cost out in that area, or what we were quoted here over the last few weeks, they said that they were drilling for $15.50 to $16.00.

MR. ARNOLD: But I presume you think then

that the 50 percent increase was a justifiable increase based upon inflationary additional costs, or otherwise it would appear that cost could come down.

Maybe I just don't understand.

MR. ELLISON: Well, I think part -- part of that could be tied into the fact they also are facing the paying interest, you know, high interest rates on the new rigs brought in, so I'm sure that their -- their increase over that year would probably be greater than the cost of living and greater than 15 percent, but I think they were taking advantage. Again, our good, old, American system, which I agree to as far as supply and demand and things like that, it tends to balance out.

MR. ARNOLD: I agree to it, also, but I think you need to look at it once in awhile and make sure it's working all right.

MR. ELLISON: Yeah. But over the last year it has not increased. In other words, it may have gone higher, we're not sure, see, we dropped out of the picture at that point. I don't know how much higher it got but it is at least no higher right now a year later than it was a year ago.

MR. ARNOLD: Thank you.

MR. RAMEY: Any other questions of Mr.

Wilson? Mr. Chavez.

QUESTIONS BY MR. CHAVEZ:

Q. Mr. Wilson, since your employment with Consolidated Oil and Gas, has Consolidated Oil and Gas consistently paid 20 percent rate of return to its investors?

A. Yes.

Q. Is that --

A. We are not a dividend paying corporation, although very few independent oil and gas companies do pay dividends. Investors in any stock are looking for at least a 20 percent rate of return through a combination of either dividends or stock appreciation, and we have been able to do that since I've been with Consolidated.

Q. Is that pretty well standard for the oil and gas industry or say small corporations which -- or businesses such as yours to pay in that amount or is that above average or below average?

A. We're probably slightly above average. How far above average I couldn't -- I couldn't really say, but typically the -- the independent sector since the early '70s has seen two periods where we've had fairly high returns until we get caught in cost/price squeezes. We saw fairly high returns after 1973 when of course the price of oil and

gas both went up. By 1976-77 we'd gotten ourselves caught in a cost/price squeeze, so for the'76-77 era we certainly return to our shareholders 20 percent, although we had done better than 20 percent for the three years prior to that.

We had the same thing coming out of the Natural Gas Policy Act. We had basically'79 and'80 that were above the 20 percent, and 1981 has not been, or we have not returned 20 percent to our shareholders.

But on an average, we'll do that.

Q. Okay, referring to Exhibit Seventeen, there are four wells, the Cane 1-N, Klein 1-M, and the Mitchell 1-E, and the Robinson Brothers 1-N.

A. I just got two of those, Mr. Chavez. Can you go through those again for me?

Q. I'm sorry.

A. Okay.

Q. The Cane 1-N.

A. Okay.

Q. Klein 1-M, the Mitchell 1-E, and the Robinson Brothers 1-M.

A. Yes.

Q. The Dakota zones of these wells produce less than 60 Mcf a day but apparently these are multiple completions, is that correct?

A. Yes, they are.

MR. ELLISON: The Mitchell well isn't. It's a single.

MR. CHAVEZ: Oh, that's right, the Mitchell 1-E would be a single.

Q. Okay, then would not that well qualify for a stripper gas price?

A. Yes, that well would qualify for a stripper if that 35 Mcf a day stays, of course, below 60,000 per day, and it's still indeterminant even at stripper price as to whether it's economic because the stripper price is not on a BTU adjusted basis; not that much in excess of the Section 103 price. It's about fifty cents per million BTU additional price.

Q. Okay. Does the Mesaverde formation, say like in Klein 1-M, which is a very low Dakota producer, does production from the Mesaverde zone, or the other zone, whichever is completed in that well, is that what keeps that well above stripper classification?

A. I believe that's correct. Unfortunately I don't have the other zone's production, but I don't think as yet we have qualified that as stripper, and we have one person in our company that watches all wells being produced company-wide to qualify for a stripper status.

Q Okay. Going on to the idea of stripper pricing, Exhibit Number Thirteen, under Section 103, where you have the printout, computer printout, recovery of 555 MMCF gross with 20 year recovery, -- well, I have difficulty reading this.

Referring to that particular page -- do you have that?

MS. TESCHENDORF: The first page of Exhibit Thirteen?

MR. CHAVEZ: No, it would be Exhibit Thirteen, where the heading says Section 103 Price 555 MMCF Gross.

A Is that Section 12 or 13?

Q Well, I thought I --

A It's easier to work with Section 12.

Q Okay, it's Section 13, actually the second page of Exhibit Fourteen.

A Okay.

MS. TESCHENDORF: Okay.

A Okay.

Q Okay, on that particular hypothetical well, it shows a total net gas of 490, and I guess that would be MMCF, is that correct?

A Uh-huh.

Q. This would fit more your typical Dakota well?

A. Yes, although we keyed that off the -- the primary part of the forecast that we made sure was correct was the first 20 years, so go right above there and that's roughly 423.

Q. Okay, and your --

A. But that's not the typical because the 550-million gross is -- is gross before deduction for royalty, whereas that column that you're looking at is after adjusting for the 24-1/2 percent royalty interest.

Q. Okay.

A. That's net production whereas the label is gross production.

Q. Okay. Well, referring to Exhibit Ten, you said that your forecast for 20 year recovery MMCF, typical was 435 MMCF?

A. Yes.

Q. Is that gross?

A. That's gross, and that would imply approximately -- I can get you the number very quickly. Approximately 330 net to the working interest.

Q. Okay, so which of this then would be more -- which one of these pages would be more appropriate?

Maybe the previous page which shows a --

A. Actually, Exhibit Twelve is alittle more descriptive to work with because that shows in all of the computer runs in Exhibit Twelve it shows both gross and net production.

Q. Okay, which -- which one of those pages would be for your typical well, then?

A. The typical well would be the -- the one labeled -- it's about five or six sheets back. It's labeled Section 103 Price 435 MMCF Gross 20 Year Recovery.

Q. Okay. Okay, on that you show a rate of return of 22.12 percent at the bottom.

A. Uh-huh.

Q. Okay, that's before taxes?

A. That's before taxes. All of Exhibit Twelve are before tax economics.

Q. I note that in the year 1987, between '87 and '88, the well production itself switches from what would be a Section 103 price to make it eligible as a single completion for stripper gas price.

A. Yes.

Q. And the revenue does not show that change.

A. I think it does, sir. In 19 -- at that

point in time our average price in 1988 is $4.75, average gas price, if you --

Q. Which page is that on?

A. It's not shown. You'd have to calculate it based on -- you would have to back from the revenue. You've have to back out the condensate income and then divide that by the net gas. It works out $4.75, which is considerably in excess of stripper price, currently.

Q. At the current rate of increase of stripper price, then?

A. That's about what stripper pricing would be at that point in time.

Q. Okay. Back on Exhibit Ten, where you forecast a 20 year recovery, you expect a 435 MMCF in 20 years. This is the typical well. Does this include the new wells which were completed and put on production?

A. Yes, it includes the -- the reviewing not only the 15 wells that were drilled last year and the performance of the wells drilled in 1979, plus general knowledge in the area, since we operate well over 200 wells in the San Juan Basin since the late '50s, and it's based on a typical rate/time performance projection, based on -- on the way the Dakota wells perform.

Q. Okay. In the previous testimony by

Southland Royalty they showed the forecast for this area of ultimate recovery, which was about three quarters of this volume. Have you reviewed their exhibit on how they calculated the volumes and tell us where your differences might be from theirs in the same general area?

A. No, I have not -- I have not reviewed theirs and felt no requirement to because we have drilled the infill wells in this area and we're very comfortable in looking at performance on our own wells with our -- with our completion techniques.

If the Southland reserves are -- or recoveries are lower, than that would further enhance our argument, I would think. Maybe we're too optimistic in the forecast. I certainly don't think that we're pessimistic.

Going back to this stripper notion very quickly, I think that the prices that we're using at the times these wells qualify, if that incentive is even available to producers in 1987, 1988, because again, one of the risks in any program of this nature is that we haven't had a three year period in the 1970's where the entire regulatory pricing situation hasn't been totally turned upside down, so I don't know that I could count on great stripper incentive prices in 1987 or 1988, but I think it is pertinent to point out that the price we're assuming in our economics is considerably

above stripper pricing allowed today.

Q And the idea of multiple completions, should you receive this tight sands designation and the wells be eligible for Section 107 pricing, would you still continue to drill these multiple completions or Dakota singles in this area?

A Well, it's -- it depends on at what point in time we would reinstitute our infill drilling program and, frankly, what the pricing incentives are at that time and what the regulations are at that time.

Q What -- do you have a well planned at this time for which you could get the go-ahead once this --

A No, we do not.

Q Okay.

MR. ELLISON: We don't have any more Mesaverde infills to drill out in this area. We have drilled up our Mesaverde infills and all that is remaining are single Dakotas if we were to do any drilling out in this area.

Q Okay.

MS. TESCHENDORF: I'd like to point out a couple things, too, on these strippers with Mr. Ellison.

Mr. Ellison, on Exhibit Seventeen, all these Dakota infills, I believe all of these have been looked at to see whether or not they would qualify for stripper prices,

is that correct?

MR. ELLISON: They have been. The Mitchell 1-E is the only one that's just recently dropped down in this category and I think it's being reviewed right now.

MS. TESCHENDORF: But up to this point it has not been eligible for stripper pricing, is that correct?

MR. ELLISON: Correct.

MS. TESCHENDORF: And another thing I wanted to point out, I believe you testified that many of these wells were targeted as duals because the costs were so great that you felt that the increase in production might pay back more of the cost, so that even if the Dakota zone was a stripper because the FERC regulations require adding production, you still might not be able to qualify for the stripper prices, is that correct?

MR. ELLISON: Yes, that's correct.

MR. CHAVEZ: Okay, that's all the questions I have for Mr. Wilson.

MR. RAMEY: Mr. Nutter, did you have a question?

QUESTIONS BY MR. NUTTER:

Q. Mr. Wilson, I believe you stated that under your assumed economic picture with a 74-1/2 percent

working interest in the wells and a requirement of 30 percent rate of return before taxes, that you'd have to have 560,000 Mcf to make a well pay.

A. Over a 20 year period.

Q. Under the Section 103 prices.

A. Yes, sir, that's correct.

Q. And some 280,000, I believe it was, something in that vicinity --

A. Yes, two times 103 prices.

Q. Right.

A. Yes, sir.

Q. Now, you also stated that you felt that the average well in here would recover only 430,000 Mcf, is that correct?

A. Yes, sir.

Q. Now that's the average well in what area, the entire area that Consolidated is requesting here?

A. No, sir, in this instant area and in the area of our 1980 infill drilling program before we ceased it.

Q. Well, I mean the 430,000 is the average reserves in the 48 sections that you're seeking the designation for?

A. It's based on the performance that we have seen on the wells that we have drilled in this area with

our completion techniques, and they're not -- we're not speaking of them in terms of reserves, we're speaking of -- of estimated recovery over a 20 year period.

Of course, reserves are quite sensitive. Whether or not these wells will produce beyond 20 years is directly a function of price and whether you can afford to operate them at that point in time.

Q. The wells that you've got in there now, many of them have produced 20 years or more, though, haven't they?

A. Yes.

Q. Okay. Now, the order that Consolidated has under appeal here today granted a portion of the area and denied a portion of the area. Now, in the portion of the area that was denied there has been recovered reserves so far, or in other words, ultimate recoveries that far exceeded the 560,000 Mcf that you think necessary, haven't they?

A. In some areas, yes.

Q. As a matter of fact --

A. But again, this is --

Q. -- isn't it true that you've got wells in this area that recovered over 2 billion cubic feet of gas to date?

A. Yes, sir, that's true, but when you

drill the offset you -- you can't say that you would recover that in the offset well.

Q Well, wasn't the testimony in the infill drilling hearing such that it was indicated that the original reserves -- or that the reserves under the undrilled 40 -- 160 would be almost equal to the reserves under the drilling 160?

MS. TESCHENDORF: We have not testified as to that.

MR. NUTTER: Have you offered any exhibits here showing the actual reserves under these tracts today, Ms. Teschendorf?

MS. TESCHENDORF: I don't -- other than our Exhibit Number One, which shows cumulative production of wells that have been producing, and the 1980 production, that's all we have submitted to you.

MR. NUTTER: So we do have cumulative production from the original wells through 1980 in this area, is that true?

MR. ELLISON: Yes. I'd like to address the subject, Dan.

What we are finding, and that is in the infill, we're finding some wells in which we're seeing original pressure. We have run across three or four of them in which

the pressure was grossly depleted. The majority of them have been just slightly depleted.

So we are seeing a range and I'm not sure at this point, you know, as far as to pick ahead of time when you were going to drill this well what you're going to run into. I'm not sure that we can really see that, but we have seen the range all the way from original pressures, all the way down to, I think one of them we found in the area like 580 bottom hole pressure, which showed that it definitely had been, but we have not been able to point out and say what we are going to see in any particular well.

MR. NUTTER: Well, isn't it also true that on the original drilling program here that some pressure differentials were detected in the drilling of the original wells? Some wells had higher pressures than others?

MR. ELLISON: What I've seen of it, yes, but I haven't seen the wide variation. I've seen several hundred pounds, and just looking at some pressures I saw several hundred pounds. I did not see those that were quite low, like we did experience in the case in point, the Mitchell 1-E Well, in which we did see a gross depletion on it. But we have seen the full range and so from a standpoint of producing gas from the total area, that the infill program is necessary because there are certain areas that it's not being --

that it's not being drained and it's a matter of trying to pick and choose and not really knowing where we're going to find depletion and where we're not going to.

Q. I don't know who to address the question to, you, Mr. Ellison, or Mr. Wilson, but in order to make a determination of whether the infill -- or the tight formation price is a necessary incentive here, isn't it necessary for the Commission in looking at the economics of this to know what the reserves are under the -- under the area? We know that the reserves are going to be better in portions of it than they are in other portions. The Commission did in the original order grant the tight formation part -- designation in the outer part of Consolidated's area where the reserves were less and where it was obvious that the incentive price was necessary.

In the sweet part of the pool I don't know if the incentive price is necessary and we don't have a reserve picture here, a reserve calculation, to tell that it is necessary.

A. Well, I think that the problem with that argument, though, Mr. Nutter, is that if you go through in this area and carve out the good wells from the area, those that will qualify, if you take a look at Exhibit Seventeen, for example, the fifteen wells that we know abso-

lutely what they're doing because they're wells that we drilled last year, if you go through and carve out all the wells that don't need the incentive, then you leave yourself in the position that the wells that are much less than the average wouldn't be economic at $12.00 a Million BTU or $15.00 a million BTU.

Q And Consolidated is not going to drill uneconomic wells no matter what the price is, so out on the edges where you don't have any reserves, you're not going to drill wells if the price is $1000 an Mcf if it's not going to make enough MCF's.

A Well, we're, again, not talking about reserves. We're talking about rate performance that we have a handle on based on the wells that we've drilled thus far, and just for descriptive purposes, what that translates into as far as our 20 year economic forecast period.

Q But you're talking about fifteen wells there that have a very short production history. What I'm looking at is a given area that has a 20 or 25 year producing history and cumulative reserves up there will show that over 2-billion cubic feet of gas has been produced from many of those wells.

Now, assuming that the infill drilling program is necessary in order to recover the gas, you can

expect to approach 2-billion cubic feet on some of those infill wells, I believe, and you haven't separated the 2-billion cubic feet wells out from the -- from the marginal wells on the edge.

A. We drilled in these wells. This program of which -- again I go back to Exhibit Seventeen, which is actual performance on wells drilled, we drilled what we thought were the better locations in that area. Any -- any corporation is going -- going into an infill drilling program will high grade.

Q. I believe that.

A. Okay, and that's what we did, and it's based upon that average performance of the wells drilled thus far. As we step out into weaker areas in all probability the performance would not come up to this level.

Q. But you don't have calculated reserves for those tracts, for those wells that are drilled, do you?

A. No, that's -- that's a meaningless number, because again, our economics are dependent upon what income will be produced from the wells early in the life and certainly extending to a period of no more than -- no more than twenty years.

The reserves in this area, if you had an extremely large price, these wells would produce 70 - 80

years and result in enormous reserves.

Q. Well --

A. But again, even producing beyond twenty years is not worth anything to an investor. It doesn't influence your decision. You are sensitive only in economics to what the early production history is on a well.

Q. Well, this is not a question, it's merely an observation, but I was noticing an article in the Western Oil Reporter the other day regarding tight formations.

They said one of the attractive things about the tight formation drilling is that the reserves are being depleted over a forty or fifty year period and long after permeable reservoirs have been depleted, they've got money in the bank waiting to be produced.

A. That -- that may be true, but those reserves are still going to be there.

Q. But you're looking at today's cash flow and saying we can't drill these because we don't have a high enough cash flow. You're overlooking the fact that you've got 2-billion cubic feet of gas to be produced forty years from now -- or --

A. I'm not overlooking that fact at all. I can go drill those wells in ten years or in fifteen years, whenever it makes economic sense, but at the present time I

have a bank debt costing 20 percent interest that I know I can earn 20 percent on there. At an effective interest cost of over 20 percent the average well you drill today in 21 years would be producing about 11-1/2 thousand cubic feet per day, a typical well in the 21st year. That is worth on today's basis .004 Mcf per day, which --

Q. Well, that's hope interest rates aren't 20 percent 20 years from now.

A. Well, I do too, but we didn't create those and they certainly represent -- we know we can take our cash flow from old properties and pay off bank debt and earn a 20 percent guaranteed rate of return. It makes no sense for us to drill wells and earn less that that on a present day basis; when interest rates drop below 10 percent, then we may change our criterion to some extent.

MR. NUTTER: That's all the questions and observations I have.

MR. RAMEY: Thank you. Mr. Chavez?

MR. CHAVEZ: Along those lines, before this hearing is over, could you perhaps circle those wells on Exhibit One, or indicate which wells produced over 570 Mcf for the first 20 years of their life, and those which are expected to produce that much or more for the first 20 years of their life?

It seems like on the east side of this area which you're applying for there are these wells which, as Mr. Nutter has addressed, have had these high recoveries, yet on the west side the recoveries aren't -- aren't as high, and that would probably be helpful in making a decision on this, if you could just indicate --

A. I think on those, maybe that is actually there and it would be just a matter of circling them, but it does show the cumulatives, those that are over that amount.

MR. CHAVEZ: Well some of these have produced for more than 20 years.

A. Well, I was just going to say -- okay, you're talking about more than 20. I'm not sure that we have the records.

MR. ELLISON: I don't think that we do.

A. I think our best bet would be to circle those that have produced over -- over the 2-billion that you're talking about, just off the cumulative map.

Basically, the majority of those wells were drilled 20, 21, years ago, in that range. In other words, there were a few wells drilled, let's say, in '57. The majority of them were probably drilled from '59 to '62, so we're really talking about the cumulatives up there being approximately 20 years.

MR. CHAVEZ: Okay.

A. In this area. But I think that the cumulative numbers would be basically representative of the 20 year --

MR. CHAVEZ: Okay. I have some questions for Mr. Ellison now.

Mr. Ellison, on Exhibit Number Five, four of the wells which you note with a parenthetical number one are not within but you say near the area of this application; however they are five or six miles away.

Do you consider that -- that that -- the four bottom wells on the tabulation -- do you consider that to be representative of this area at that distance?

WEll, of course, not including, but I think that the Dakota formation itself, I think typically, as is shown, that it has been tight out in that general area. Going back to the previous Southland case, some of that stuff was out of their area and yet was considered typical of Dakota production, although it wasn't within their area, and these, let me just point out where a couple or three of these were. I think one of them is like, what, in Section 2, I believe, if I'm not mistaken. Another one is right down here in -- in --

MS. TESCHENDORF: 13 and 24?

MR. ELLISON: Let's see Those in 32 -- excuse me, 31 and 32. We've got one in Section 2, which would be right here, just about two miles off of the map. One is in 14, which would only-- that would be again about two miles off, or actually, only a little over a mile off. So that would take care of those two.

We have one that's in Section 18 of 11, which is on over a way, and then the one in Section 4 of 32, 12, which is right here.

So they're just barely off the map that we're talking about, so they somewhat represent what is happening in the Dakota in that area.

MR. CHAVEZ: Okay. On Exhibit Eight-A the well cost here, you show a compressor at $16,000 to rent one. Compressor and work string, what was the purpose of this?

MR. ELLISON: Okay, where we were doing on our compression and -- of course part of this had to do when we dualing,especially with the Mesaverde, and in the dual was the fact that we were taking a compressor out there. We were using nitrogen to clean it up and then before we moved on we were needing to know what was happening in these lower zones and get them cleaned up prior to moving on to the next zone.

We were using the compressor to circulate and jet the fluid out of the hole and get as much fluid back out of the hole as possible.

I do know that some of the others out in that area are using gas to do this. We were using compressors to do this. Another approach sometimes is to go ahead and frac and then later on try to swab back.

But it's -- it's a trade off somewhat of how long do you leave your -- your rig on there? Do you swab or do you use a compressor to try to clean it up, and it's just sort of a difference in technique

If you've got a single zone some people just go ahead and frac it and move off and two or three weeks later come back and try to do it.

We did try that on some of these wells. Apparently other people had success doing it, and we ended up having -- several weeks later going out there and putting a rig on, back on it, and sitting there swabbing, and had to swab for a number of days trying to get the well to clean up enough so that we could even make a test or anything else.

So it's just a difference in technique and we were just using a compressor to pump air down on the annulus side and let fluid up the tubing.

MR. CHAVEZ: Is this a common practice

in areas like this where you may have low productivity wells and liquids being produced?

MR. ELLISON: Yes. In other words, I -- it's done in quite a few areas. I'm not sure -- I know that are others that are using this technique in this area. I don't know who all is doing it, but others -- I am aware of some right in this area that are using gas, and they put gas in the backside and lift it up the tubing, and I'm not sure how they justify their price of buying gas and doing that or offset it against the -- against the price others are paying to rent a compressor, so it's using the same technique, just one is using a compressor and the other is using high pressure gas to go ahead and do the same thing.

MR. CHAVEZ: Okay. Under other completion work you know -- is that figure 10 days as a quantity, 10 days $2500?

MR. ELLISON: Yes, uh-huh.

MR. CHAVEZ: And is that for the -- just the Dakota portion of the completion?

MR. ELLISON: Yes. That would be both zones because we do have the problem of having to work with one zone and trying to clean up the Lower Dakota, and this does take, by the time you move in and then you do the perforating and the fracing and then you spend a couple or three

days with cleaning up that zone, and then you move -- then you set your bridge plug and move on to the next zone, and it's a total -- what I'm putting in there is a total of 10 days for the completion unit with -- with some of their equipment that they carry along with it.

So we're dealing with a total of 10 days from the time you start to move the completion unit in until you complete in both zones and try to clean both of them up and move it off.

MR. CHAVEZ: Are there other operators say within the general area, say a couple townships around it, complete in the Upper and Lower Dakota that do not use this clean up technique --

MR. ELLISON: I'm not aware particularly of how many others are trying to work or do anything on the Lower Dakota. I know that some have talked about problems in the Lower, you know, that they just automatically write off the Lower Dakota and say it's wet. And I know that some of them have said so and even in this area.

We have one well down right in this general area in which the initial well is not producing hardly anything from the Upper Dakota and the Graneros section, and we drilled it and drilled into the Lower Dakota and got a kick on it which surprised everybody, and we have a good

Dakota zone out of the lower zone, and we have a good Lower Dakota Well right off over in this general area.

MS. TESCHENDORF: Mr. Ellison, could you define for the record what area you're talking about?

MR. ELLISON: Okay, it is our Clayton 1-M Well, I believe, or 1-E Well, which is -- I'm trying to remember the exact location. It was in Section -- let me see, I don't have a map so I'm not sure -- but it is in Township 30 North and 12 West.

MS. TESCHENDORF: A couple miles southeast of the desired area?

MR. ELLISON: Yeah, three or four miles southeast of this area right in here. I'm not sure about the exact section, but we did, that is another place in which we were successful in getting additional gas reserves out of the Lower Dakota in this area.

And the Upper Dakota, when we fraced it and tried to bring it back, the original well was not very good in the Upper Dakota and our new well, when we fraced it we just got almost nothing out of it, but the Lower Dakota, it's been a good Lower Dakota well. Or a good Dakota well.

MR. CHAVEZ: These other producing Dakota wells in your efficient area, are they also completed in the Lower Dakota or the majority of them, or --

A. Well, part of them are, not all of them. The majority of them are, yes. We have made an attempt. I'm not sure, I think that we would agree to some extent, in this area right in here, that the Lower Dakota does, our experience has been that apparently it is unproductive.

MR. CHAVEZ: Uh-huh.

MR. ELLISON: But in this area and in this area we have gotten some production, some gas production out of the Lower Dakota, and we are getting some, a little bit of -- we are getting some water with it, but you know, it's a trade off, so can you afford to handle the water to get the additional gas production, and at this point we are saying that it is worth the extra effort. It's more expensive to do so and we are having additional operating costs. They're due to handling of the water. But at least right now, in our judgment, it is worth the extra expense to do so.

MR. CHAVEZ: Have your own supervisory costs of drilling some of these wells risen over, say, the last year and if they have, to what extent?

MR. WILSON: Are you talking about the G & A costs and --

MR. CHAVEZ: Yes, supervisory while drilling.

MR. WILSON: Supervisory and above?

MR. CHAVEZ: Uh-huh.

MR. WILSON: Such as things as the cost for these kinds of hearings and --

MR. CHAVEZ: Well, I think the reason I'm asking this question is because of the exhibit that you presented in your previous testimony when this case was first heard showed superintendent cost of $4000, and that would be Exhibit Nineteen.

Exhibit Eight-A for today's testimony shows a cost of $7500, which is almost 50 percent --

MR. WILSON: Yeah, I can --

MS. TESCHENDORF: Mr. Chairman, we have not incorporated the record or any of the exhibits from the previous testimony and therefor I would request that the statement as to that would be stricken from the record.

MR. PEARCE: Excuse me, Ms. Teschendorf, if you would refresh my recollection, I believe in your opening statement this morning you mentioned that in fact testimony had been presented previously and that it was a matter of public record. Am I mistaken in my recollection of what you said?

MS. TESCHENDORF: I said that the Southland exhibits that we were referring to had been made a matter of public record.

MR. PEARCE: Your position, then, on this question is that the Southland portion of the previous case, which has been dismissed,is a matter of public record, and yours is not, is that your position?

And if so, could you explain that to me, please?

MS. TESCHENDORF: All right. This is a -- this is a de novo proceeding. I have not, I think to keep the record clear, I have not incorporated the transcript or the record previously submitted.

Southland's exhibits, or the information that we have included from Southland, from other companies, from El Paso, is evidence that we can obtain from any source. Perhaps I should not characterize it as having been taken from the previous case.

But in any case, this is a de novo proceeding and in order to keep the record clear, I would prefer just to have no reference to the previous testimony at all.

MR. PEARCE: Excuse me, if I may break into question the witness for a moment. I believe we are with Mr. Ellison.

Your Exhibit Eight-A shows administrative costs of some $7500, is that correct, Mr. Ellison?

MR. ELLISON: That is correct, sir.

MR. PEARCE: Could you tell me, sir, the rate of increase that Consolidated Oil and Gas has experienced in that number over the last twelve months?

MR. ELLISON: Okay, I think what I can answer on that is, earlier I didn't realize as far as when preparing earlier AFE's that there had been as much charge to that account, and if you'll look at the average, we find that actually that number is 9000, the average of those fifteen wells.

I feel that we can reduce that but if we had people assigned to those wells during the drilling and completion, and had -- in other words, that we actually had people assigned to the wells longer than what I had earlier anticipated, I therefor feel that I need to charge and expect more to be charged against that number than what I had originally thought.

I think that I can do better than what the average was but -- but basically if you assume what a charge is for the people that were assigned to it, and we did use some contract personnel, originally we didn't realize we were going to, but we were so thin we had to hire contract personnel on some of our drilling completions and of course the price that we're dealing with there is now in the neighborhood of $350, $400 a day, using them, and so that

isn't assigning all that much to superintendent. That is direct supervision, is direct supervision, is what that is.

MR. WILSON: Can I also point out that this cost of superintendents is not reflective of the G & A burden that I referred to in the -- in the economic discussion. This is, again, just field level, field level cost.

MR. ELLISON: The number down at the lower part is the only G & A in the sense that you referred to, which is the overhead, which is shown as $1500 for the total. That is the only amount that we as a company are allowed to charge has to do with what our contracts call for, that the superintendents is the actual, direct supervision that actually occurred on the well.

MS. TESCHENDORF: Mr. Ramey, can I consider that you -- may we strike references to previous testimony?

MR. RAMEY: I think we can do that.

MS. TESCHENDORF: Thank you.

MR. RAMEY: We do like to keep the record clear.

Any other questions of the witnesses?

MR. CHAVEZ: Just one more of Mr. Ellison. Mr. Ellison, are you aware of whether or not operators in the surrounding area consider the Lower Dakota zone as productive

and try to make completions in it?

MR. ELLISON: I have asked one or two around there. I think maybe one or two are maybe attempting to in that area. I have talked to one or two who say, well, we just consider that the logs say that they're wet, so we don't make any attempt at all.

But as I pointed out on this particular one, the logs on that one, and the Phillips 1-E, indicated it was wet. We were very much surprised when we perforated it and tested it, naturally, that we flowed gas from that zone.

MR. CHAVEZ: Okay, so --

MR. ELLISON: So it's just a matter of interpret -- part of it's a matter of interpretation of the logs and what you experience.

I have to admit that over in the portion of 31 North and 12 West the indications are, in the attempts that we've made in that area, even though the logs indicated that they were gas productive, that we have had to handle quite a bit of water in that area, and we have had problems trying to handle it.

But that on 13 West we thus far are happy with the results as we were with the well that I made mention to earlier in 30 North and 12 West.

MR. CHAVEZ: Okay, then could part of

the difference between your calculated recoverable reserves and some other operators be because you do include that Lower Dakota zone and some of the operators may not?

MR. ELLISON: That is possible. I would also interject that I think that was referred to in the reference to the -- to the Southland Royalty reserves was based upon that particular area which appears that based upon the cumulative reserves in that area, I would say, are less, upon an average are less.

I think that the area that they were talking about and dealing with, based upon the history, would indicate that their reserves in that area are even less than in this area.

MR. CHAVEZ: Okay, that's all the questions I have.

MR. RAMEY: Any other questions of the witness? He may be excused.

Anything further in this case, Ms. Teschendorf?

MS. TESCHENDORF: Yes, sir. In the course of our presentation today Consolidated has shown that the average -- average in situ gas permeability throughout the pay section is less than one tenth of a millidarcy.

We've shown that stabilized production

rates against atmospheric pressure of wells completed for production in the Dakota, without stimulation, are not expected to exceed the maximum allowable set out in the FERC guidlines.

And we've shown that wells drilled into the Dakota are not expected to produce more than five barrels of crude oil a day.

Clearly the Dakota meets the geological and engineering criteria for a tight formation.

However, as we've shown, infill drilling has already taken place. The evidence presented, however, has established that the majority of these infills will be uneconomic and that Consolidated cannot pursue its Dakota drilling program absent an incentive price.

The economics described to you by Mr. Wilson clearly indicate that the costs involved justify the incentive price.

We've also shown that the royalty burden on Consolidated's leases makes an incentive price necessary.

It is submitted that the FERC intended all extraordinary costs to be considered in determining whether reasonable incentives are necessary.

IN the San Juan Basin part of Consolidated's costs must be ascribed to the high royalty burden it carries.

To summarize, both the engineering and geological evidence, and the economics, show that the Dakota should be qualified as a tight formation, and if the Commission should deny Consolidated's application, it would be violating its statutory mandate of conservation and prevention of waste, since Conosolidated would be unable to resume drilling and producing in the area.

MR. RAMEY: Thank you.

Anyone have anything further to add in this case?

If not, we'll take the case under advisement.

(Hearing concluded.)

SALLY W. BOYD, C.S.R.
Rt. 1 Box 193-B
Santa Fe, New Mexico 87501
Phone (505) 455-7409

C E R T I F I C A T E

I, SALLY W. BOYD, C.S.R., DO HEREBY CERTIFY that the foregoing Transcript of Hearing before the Oil Conservation Division was reported by me* that the said transcript is a full, true, and correct record of the hearing, prepared by me to the best of my ability.

Sally W. Boyd

REPORTER'S NOTE:

***This hearing was recorded by Florene Davidson of the Commission's staff in the absence of the reporter. Thereafter, and using the tapes provided by her, the reporter transcribed the said hearing.**

STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION DIVISION

BRUCE KING
GOVERNOR

LARRY KEHOE
SECRETARY

POST OFFICE BOX 2088
STATE LAND OFFICE BUILDING
SANTA FE, NEW MEXICO 87501
(505) 827-2434

April 16, 1982

Mr. Howard Kilchrist
Federal Energy Regulatory Comm.
Department of Energy
825 North Capitol Street, N.E.
Washington, D. C. 20426

Re: Tight Formation Designation
Order No. R-6747-A

Dear Mr. Kilchrist:

Enclosed please find the Recommendation and exhibits of the New Mexico Oil Conservation Division for designation of certain portions of the Dakota formation in San Juan County, New Mexico, as a tight formation.

Sincerely,

W. PERRY PEARCE
General Counsel

WPP/dr

enc.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

NGPA SECTION 107 TIGHT FORMATION RECOMMENDATION	)	Docket No._____
STATE OF NEW MEXICO OIL CONSERVATION DIVISION OF THE ENERGY AND MINERALS DEPARTMENT	)	

RECOMMENDATION FOR TIGHT
FORMATION DESIGNATION UNDER
SECTION 107 OF THE NGPA.

Consolidated Oil and Gas Company, pursuant to Section 107 of the Natural Gas Policy Act, 18 CFR §271.703 of the FERC regulations, and the Special Rules and Procedures for Tight Formation Designations under Section 107 of the Natural Gas Policy Act of 1978 of the Oil Conservation Division, petitioned the Oil Conservation Division for tight formation designation of a portion of the Dakota formation in San Juan County, New Mexico.

After notice and hearing on the application of Consolidated Oil and Gas Company, the Oil Conservation Division hereby recommends that that portion of the Dakota formation which is described in Exhibit A (being Oil Conservation Division Order No. R-6747-A) attached hereto and incorporated by reference, be designated a tight formation. Additionally, the Oil Conservation Division, submits herewith Exhibits B, a copy of the transcripts and exhibits presented to the Division, and C, a copy of a letter evidencing the concurrence of the Minerals Management Service, attached hereto and incorporated herein by reference, which are supporting data required under 18 CFR §271.703(c)(3) of the FERC regulations and Minerals Management Service ratification of this recommendation, respectively.

Respectfully submitted,

W. PERRY PEARCE
Attorney for the
Oil Conservation Division

VERIFICATION

STATE OF NEW MEXICO)
)ss.
COUNTY OF SANTA FE)

W. PERRY PEARCE, being first duly sworn, on oath, states that he is an attorney for the Oil Conservation Division of the Energy and Minerals Department of the State of New Mexico; that he has executed the foregoing document with full power and authority to do so; and that the matters and facts set forth therein are true to the best of his information, knowledge and belief.

W. PERRY PEARCE

Subscribed and sworn to before me, this 16th day of April, 1982.

NOTARY PUBLIC

My Commission Expires:

Oct 28, 1985

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of the foregoing Recommendation on Consolidated Oil and Gas Company in accordance with the requirements of Section 1.17 of the Rules of Practice and Procedure.

Dated this 16th day of April, 1982.

W. PERRY PEARCE

DAKOTA TIGHT FORMATION
HEARING
CASE NO. 7116 DE NOVO

SEPTEMBER 29, 1981

BEFORE THE
OIL CONSERVATION COMMISSION
Santa Fe, New Mexico
Case No. 7116 DN Exhibit No. 1-17
Submitted by COG
Hearing Date 9-29-81

GEOGRAPHICAL AND GEOLOGICAL DESCRIPTION

Within the described area of Exhibit No. 1, the Dakota sands are light to dark mottled gray, fine to very fine-grained quartz sands. Silt and clay-sized matrix material can form a significant percentage of the bulk-rock composition. Because the matrix fraction tends to reduce greatly the effective permeability of the reservoir, natural and induced fractures are necessary for production from the Dakota reservoir.

Exhibit No. 3 is a type log which shows the base of the Mancos, the Greenhorn, the Graneros and the Dakota formations. The vertical limits of the Basin Dakota gas pool have been defined by the New Nexico Conservation Division to be from the base of the Greenhorn Limestone to a point 400 feet below the base of said formation and consists of the Graneros formation, the Dakota formation and the productive upper portion of the Morrison formation. The Graneros and first Dakota zones are the main producing zones in the Basin Dakota Field. The other Dakota zones and the upper Morrison zone have very low permeability. Production from these zones has been limited to date.

The sediments of the Dakota interval were formed during late Cretaceous time. The Dakota is bounded by an uncomformable contact with the Jurassic Morrison below and is gradational with the Cretaceous Mancos shale above and is found at an average depth of 6650 feet for the area outlined on Exhibit No. 1. The gross thickness of the formation varies from 200 to 300 feet.

Deposition of the Dakota sediments occurred during a regression of the late Cretaceous sea. This regression resulted in the following sequence of depositional environments from the base upward: 1. Braided stream sandstone; 2. Meandering stream complex (with minor associated coals); 3. Coastal shale; 4. Coastal sandstone. The lower two environments contain sands of minor areal extent whereas the coastal sandstones have significant extent. They are northwest-southeast trending linear sand bodies reflecting their beach and off-shore bar

depositional history. These upper Dakota sands appear to be the primary Dakota reservoirs.

Exhibits Nos.4A, 4B and 4C are cross sections that show the continuity of the Dakota zones across the area of this application. Cross section A-A' shows sand development in a North-South direction while cross-section B-B' shows sand development in an East-West direction. Cross-section C-C' shows the sand development in a Southwest-Northeast direction.

PERMEABILITY, GAS AND CRUDE PRODUCTION DATA
NORTHWEST PORTION - BASIN DAKOTA FIELD
SAN JUAN COUNTY, NEW MEXICO

Operator/ Lease	Well No.	Location	Spud Date	Depth	In Situ Gas Permeability (Md.)	Calculated Stabilized Gas Production Rate At Atmos Pressure (MCFD)	Crude Production (BPD)	FERC Allowed Rate MCFD	FERC Allowed Rate BOPD
Consolidated Oil & Gas Co. Wilmerding	1-H	NE/4 NW/4 10-31N-13W	4-2-80	6627-6846	less than 0.1	Flow too small to measure	0	251	
Consolidated Oil & Gas Co. Kline	1-H	NE/4 SE/4 10-31N-13W	4-16-80	6506-6736	0.0049	12.5	0	251	
Consolidated Oil & Gas Co. Senter	1-H	NE/4 SE/4 24-31N-13W	11-28-79	6898-6958	0.00068	2.73 L.Dak	0		
				6740-6816	0.0146	52.00 U.Dak	0		
						54.73	0	251	
Southland Royalty Co. East	7-E	SW 14-31N-12W (1)		7282-7448	0.0011	21.7	0	290	
Southland Royalty Co. Patterson 'B' Com.	1-E	SW 2-31N-12W (1)		7212-7385	0.0877	224.1	0	290	
El Paso Natural Gas Co. Case	8	NE 18-31N-11W (1)		7254-7406	0.0335 (2)	Not tested	--	290	
El Paso Natural Gas Co. Moore	8	SW 24-32N-12W (1)		7589-7800	0.0151 (2)	Not tested	--	336	

(1) Not within, but near the area of this application.
(2) Reference: Rex D. Thomas and Don C. Ward: "Effect of Overburden Pressure and Water Saturation on Gas Permeability of Tight Sandstone Cores". See Exhibit No. 7 .

Exhibit No. 5

CORRECTED COPY

FLUID SAMPLE DATA

Sampler Pressure _____ P.S.I.G. at Surface
Recovery: Cu. Ft. Gas _____
cc. Oil _____
cc. Water _____
cc. Mud _____
Tot. Liquid cc. _____
Gravity _____ ° API @ _____ °F.
Gas/Oil Ratio _____ cu. ft./bbl.

	RESISTIVITY	CHLORIDE CONTENT
Recovery Water	____ @ ____ °F.	____ ppm
Recovery Mud	____ @ ____ °F.	____ ppm
Recovery Mud Filtrate	____ @ ____ °F.	____ ppm
Mud Pit Sample	____ @ Fresh water °F.	____ ppm
Mud Pit Sample Filtrate	____ @ ____ °F.	____ ppm
Mud Weight	____ vis	____ sec.

Date 7-31-80 Ticket Number 727294
Kind of D.S.T. CASED HOLE Halliburton Location FARMINGTON
Tester MR. BROWN / MR. ROBLES Witness
Drilling Contractor SPARTAN DRILLING COMPANY DR 8C

EQUIPMENT & HOLE DATA

Formation Tested Basin Dakota
Elevation 6940' Ft.
Net Productive Interval 51' from 7284-7445' Ft.
All Depths Measured From Kelly Bushing
Total Depth 7480' Ft.
Main Hole/Casing Size 4 1/2" 10.5# Liner
Drill Collar Length - I.D. -
Drill Pipe Length 7229.9' I.D. 1.995"
Packer Depth(s) 7249' Ft.
Depth Tester Valve 7235.5' Ft.

Cushion TYPE Fresh water AMOUNT 4 bbls. Ft. Depth Back Pres. Valve 1000' Surface Choke 1/8" Bottom Choke 5/8"
Recovered 240 Feet of water
Recovered Feet of
Recovered Feet of
Recovered Feet of
Recovered Feet of

Remarks See production test data sheet
0-Questionable

TEMPERATURE	Gauge No. 7489 Depth: 7245 Ft.	Gauge No. 5160 Depth: 7257.2' Ft.	Gauge No. Depth: Ft.	TIME (00:00-24:00 hrs.)
	24 Hour Clock	24 Hour Clock	Hour Clock	Tool Opened 0056
Est. °F.	Blanked Off No	Blanked Off Yes	Blanked Off	Opened Bypass 1100
Actual 190 °F.	Pressures	Pressures	Pressures	

	Field	Office	Field	Office	Field	Office	Reported Minutes	Computed Minutes
Initial Hydrostatic	3375 0	3120.6	3192 0	3117.2				
First Period Flow Initial	130.8	346.3-0	128	352.5 0			—	—
First Period Flow Final	130.8	150.3	128	147.4			120	126
First Period Closed in	2383	2382.2	2426.8	2382.1			484	478
Second Period Flow Initial							—	—
Second Period Flow Final								
Second Period Closed in								
Third Period Flow Initial							—	—
Third Period Flow Final								
Third Period Closed in								
Final Hydrostatic	3590 0	3120.6	3320 0	3117.2			—	—

FORM 181-83 — PRINTED IN U.S.A.

FORMATION TEST DATA

LITTLE'S 11603 75C 2/80

Exhibit No. 6A

Legal Location Sec. - Twp. - Rng. 14-31N-12W
Lease License EAST
Well No. 7-E
Test No. 1
Tested Interval 7249-7480'
Field Area BASIN DAKOTA
Meas. From Tester Valve
County SAN JUAN
State NEW MEXICO
Lease Owner/Company Name SOUTHLAND ROYALTY COMPANY

6
1.

Casing perfs._____ Bottom choke_____ Surf. temp_____ °F Ticket No. 727294

Gas gravity_____ Oil gravity_____ GOR_____

Spec. gravity_____ Chlorides_____ ppm Res._____ @_____ °F

INDICATE TYPE AND SIZE OF GAS MEASURING DEVICE USED_____

Date Time a.m. p.m.	Choke Size	Surface Pressure psi	Gas Rate MCF	Liquid Rate BPD	Remarks
2218					On location, made up tools
2218					Trip in hole with tools
0016					On bottom
0056					Hydrospring opened
0056					Moderate blow to surface
0101	Blow Hose	.25#			
0102	"	1			
0103	"	2			
0.04	"	3			
0109	"	3.5			
0118	"	4			
0123	"	4			
0128	"	4.5			
0133	"	4			
0138		4.5			
0142		4.5			Gas to surface
0147	3/4"				Opened choke, flare to pit with 1/8"
					orifice tester
0256					Closed tool
1100					Trip out of hole with tools

FORM 102-R1—PRINTED IN U.S.A.

PRODUCTION TEST DATA

LITTLE'S 20672 SM 9/74

SOUTHLAND ROYALTY COMPANY — 727294

Lease Owner/Company Name — Ticket Number

B.T. 7489 — B.T. 5160 — B.T. ____

Depth 7245' — Depth 7257.2' — Depth ____

INITIAL FLOW

	Time Defl. .000"	Log $\frac{t+\theta}{\theta}$	PSIG Temp. Corr.	Time Defl. .000"	Log $\frac{t+\theta}{\theta}$	PSIG Temp. Corr.	Time Defl. .000"	Log $\frac{t+\theta}{\theta}$	PSIG Temp. Corr.
0.	.0000		346.3-Q	.0000		352.5-Q			
1.	.0885		613.3*	.0861		155.9			
2.	.1566		165.5	.1522		160.2			
3.	.2247		163.3	.2184		153.8			
4.	.2928		156.8	.2846		149.5			
5.	.3609		154.6	.3508		149.5			
6.	.4290		150.3	.4170		147.4			
	20 minute intervals								
	*Interval = 26 minutes								
	126 TOTAL MINUTES								
	INITIAL CLOSED IN PRESSURE								
0.	.0000	-----	150.3	.0000	----	147.4			
1.	.0342	1.132	444.4	.0332	1.132	425.2			
2.	.0684	.862	684.0	.0664	.862	668.8			
3.	.1026	.714	893.2	.0996	.715	886.7			
4.	.1368	.617	1053.8	.1328	.617	1048.8			
5.	.1710	.545	1191.8	.1660	.546	1193.2			
6.	.2052	.490	1323.2	.1992	.490	1326.9			
7.	.2394	.446	1439.6	.2324	.446	1443.7			
8.	.2736	.410	1547.4	.2656	.410	1552.0			
9.	.3078	.379	1644.4	.2988	.379	1647.5			
10.	.3421	.353	1730.6	.3320	.353	1726.1			
11.	.4447	.293	1896.5	.4316	.294	1891.7			
12.	.5473	.251	2000.0	.5312	.252	1997.8			
13.	.6499	.220	2079.9	.6308	.220	2076.4			
14.	.7526	.196	2140.3	.7304	.196	2135.8			
15.	.8552	.177	2187.8	.8300	.177	2184.6			
16.	.9578	.161	2231.0	.9296	.161	2227.1			
17.	1.0605	.148	2265.6	1.0292	.148	2263.2			
18.	1.1631	.136	2293.7	1.1288	.137	2284.4			
19.	1.2657	.127	2319.6	1.2284	.127	2318.4			
20.	1.3684	.118	2343.4	1.3280	.119	2339.6			
21.	1.4710	.111	2360.6	1.4276	.111	2346.0			
22.	1.5736	.105	2375.8	1.5272	.105	2373.6			
23.	1.6350	.101	2382.2	1.5870	.101	2382.1			
	First 10 intervals = 10 minutes each; next 12 intervals = 30 minutes each; last interval = 18 minutes								
	478 TOTAL MINUTES								

Remarks: Q = Questionable

Gas Production

CORRECTED COPY

B.T. Gauge Numbers			7489	5160	Ticket Number	727294	
			PRESSURE	PRESSURE			
Initial Hydrostatic			3121	3117	Elevation	6940	ft.
Final Hydrostatic			3121	3117	Production Rate 1st Flow	21.6	MCF
1st Flow	Initial	Time	346	353	Production Rate 2nd Flow	-	MCF
	Final	126	150	147	Production Rate 3rd Flow	-	MCF
	Closed In Pressure	478	2382	2382	Hole Size	6.25	in.
2nd Flow	Initial	Time			Footage Tested	51	ft.
	Final				Mud Weight	8.33	lbs./gal.
	Closed In Pressure				Gas Viscosity	.020	cp
3rd Flow	Initial	Time			Gas Gravity	.70	—
	Final				Gas Compressibility	.85	—
	Closed In Pressure				Temperature	190	°F
Extrapolated Static Pressure		1st	2644	2639			
		2nd					
		3rd					
Slope P/10		1st	89	74			
		2nd					
		3rd					

Remarks: (1) Calculations based on rates given by Bob Fielden 8-11-80 and net pay given by Marlin Thompson 10-6-80
(2) Gas gravity changed to 0.70-11-13-80

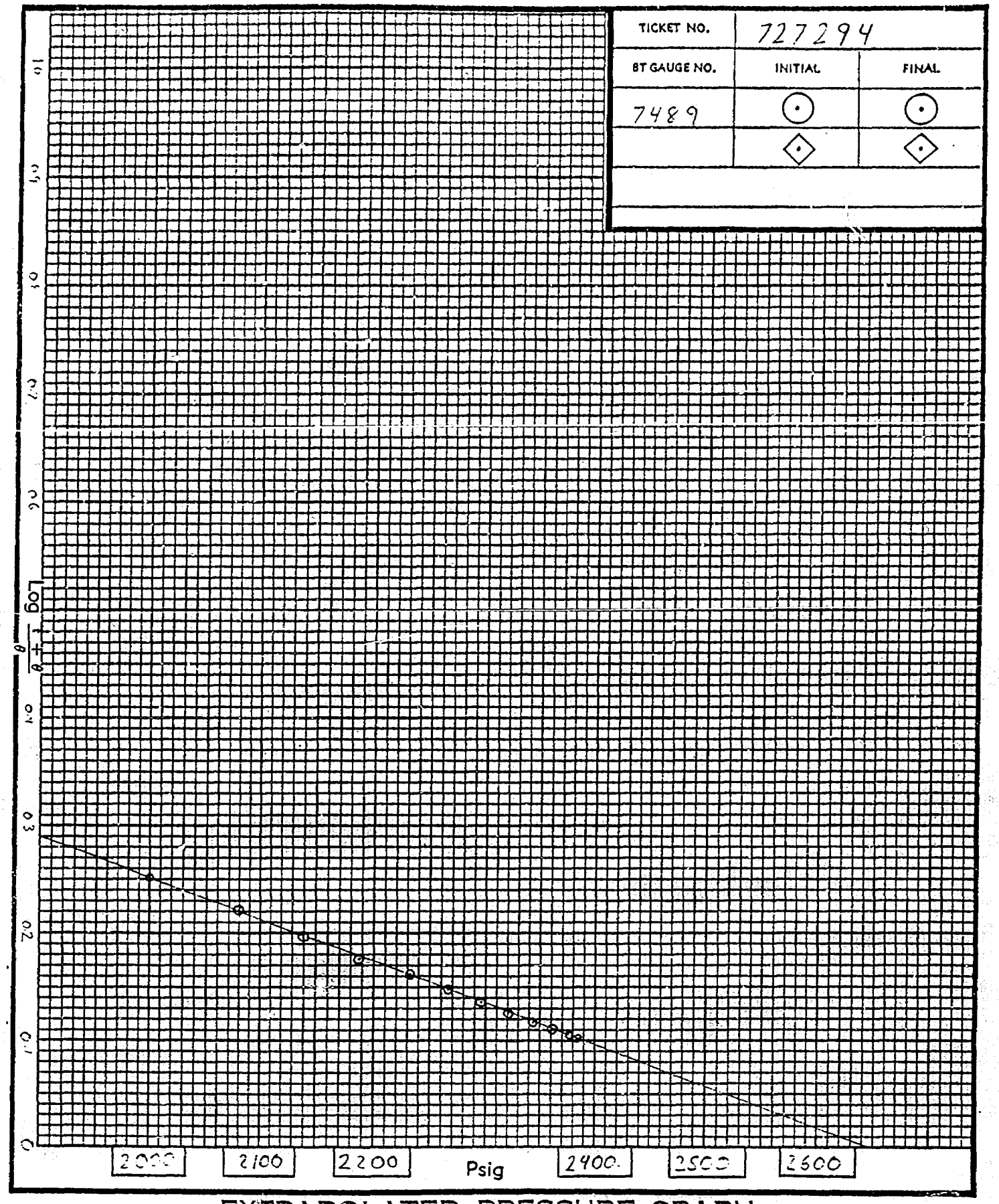
SUMMARY

B.T. Gauge No. 7489, Depth 7245' — B.T. Gauge No. 5160, Depth 7257'

PRODUCT	EQUATION	FIRST	SECOND	THIRD	FIRST	SECOND	THIRD	UNITS
Transmissibility	$\frac{Kh}{\mu} = \frac{1637\, Q_g\, ZT}{m}$	2.798			2.807			$\frac{md.\ ft.}{cp}$
Theoretical Flow Capacity	$Kh = \frac{Kh}{\mu}\ \mu$	.0560			.0561			md. ft.
Average Effective Permeability	$K = \frac{Kh}{h}$	.00110	[redacted]		.00110	[redacted]		md.
	$K_1 = \frac{Kh}{h_1}$	-			-			md.
Indicated Flow Capacity	$(Kh)_g = \frac{3200\, Q_g\, \mu\, ZT \log(0.472\, b/r_w)}{P_s^2 - P_f^2}$	.0066			.0067			md. ft.
Damage Ratio	$DR = \frac{\text{Theo. Flow Cap}}{\text{Indicated Flow Cap}}\ \frac{Kh}{(Kh)_g}$	8.454			8.390			—
Indicated Flow Rate	$OF_1 = \frac{Q_g\ P_s^2}{P_s^2 - P_f^2}$ Max.	21.670			21.667			MCFD
	$OF_2 = \frac{Q_g\ P_s}{\sqrt{P_s^2 - P_f^2}}$ Min.	21.635			21.634			MCFD
Theoretical Potential Rate	$OF_3 = OF_1\ DR$ Max.	183.205			181.791			MCFD
	$OF_4 = OF_2\ DR$ Min.	182.910			181.509			MCFD
Approx. Radius of Investigation	$b \leq \sqrt{Kt}$ or $\sqrt{Kt_0}$	.632			.633			ft.
	$b_1 \leq \sqrt{K_1 t}$ or $\sqrt{K_1 t_0}$	-			-			ft.
Potentiometric Surface *	$Pot. = (El - GD) + (2.319\, Ps)$	-			-			ft.

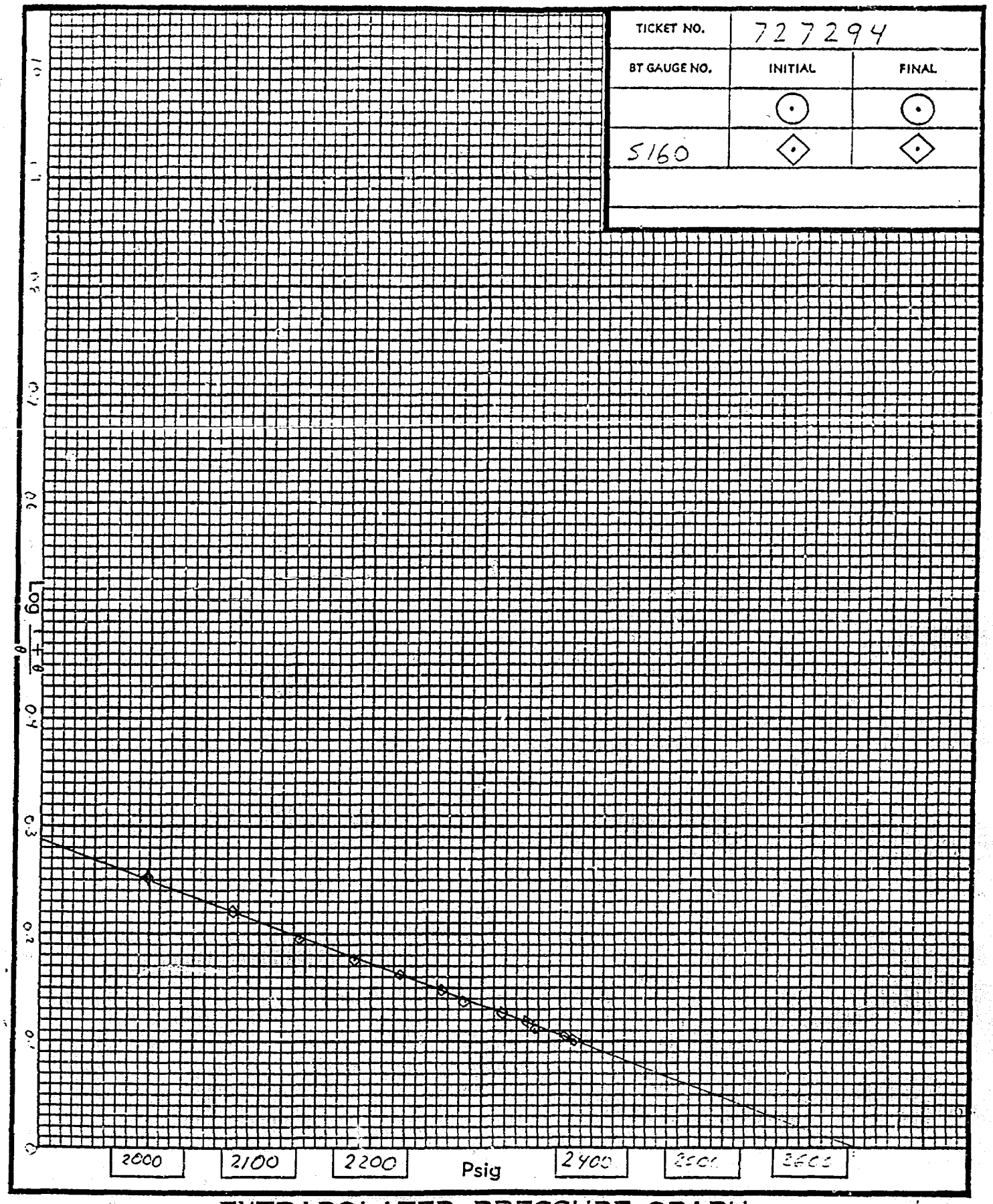
NOTICE: These calculations are based upon information furnished by you and taken from Drill Stem Test pressure charts, and are furnished you for your information. In furnishing such calculations and evaluations based thereon, Halliburton is merely expressing its opinion. You agree that Halliburton makes no warranty express or implied as to the accuracy of such calculations or opinions, and that Halliburton shall not be liable for any loss or damage, whether due to negligence or otherwise, in connection with such calculations and opinions.

TICKET NO.	727294	
BT GAUGE NO.	INITIAL	FINAL
7489	⊙	⊙
	◇	◇



EXTRAPOLATED PRESSURE GRAPH

TICKET NO.	727294	
BT GAUGE NO.	INITIAL	FINAL
	⊙	⊙
5160	◇	◇



EXTRAPOLATED PRESSURE GRAPH

FORM 184—PRINTED IN U.S.A.

LITTLE'S

TICKET NO. 727294

	O. D.	I. D.	LENGTH	DEPTH
Drill Pipe or Tubing	2 3/8"	1.995"	7229.9'	
Drill Collars				
Reversing Sub				
Water Cushion Valve				
Drill Pipe				
Drill Collars				
Handling Sub & Choke Assembly				
Dual CIP Valve	3.03"	1"	5'6"	7229.9'
Dual CIP Sampler				
Hydro-Spring Tester	3.03"	1.13"	4'10"	7235.5'
Multiple CIP Sampler				
Extension Joint				
AP Running Case	3.03"	2.31"	4'8½"	7245'
X over				
Hydraulic Jar				
VR Safety Joint	3.03"	1.75"	2'8½"	
Pressure Equalizing Crossover				
X over	3.03"	1.75"	1'	
Packer Assembly	4½"	1.90"	3'4"	7249'
Distributor				
Packer Assembly				
Perforated anchor	2 3/8"	1.90"	4'2"	
Flush Joint Anchor				
Pressure Equalizing Tube				
Blanked-Off B.T. Running Case				
Drill Collars				
Anchor Pipe Safety Joint				
Packer Assembly				
Distributor				
Packer Assembly				
Anchor Pipe Safety Joint				
Side Wall Anchor				
Drill Collars				
Flush Joint Anchor				
Blanked-Off B.T. Running Case	3.03"	2.31"	4'	7257.2'
Total Depth				7480'

FORM 167-52 – PRINTED IN U.S.A.

EQUIPMENT DATA

LITTLE'S 11M66 75C 2/60

CONSOLIDATED OIL & GAS, INC.

WILMERDING NO. 1-M

NE/4 NW/4 10-T31N-R13W

BASIN DAKOTA FIELD

SAN JUAN COUNTY, NEW MEXICO

Data:

	Lower Dakota	Upper Dakota
Midperforations	6817'	6697'
Qg	Too Small to Measure	Not Tested
h (log)	27'	57'
K (permeability)	Inadequate gas to compute flow rate and permeability (K) is much less than 0.1 md.	

Exhibit No. 6B-1

CONSOLIDATED OIL & GAS, INC.

KLINE NO. 1M

NE/4 SE/4 10-31N-13W

BASIN DAKOTA FIELD

Calculation of Permeability Using Darcy's Law:

Data:

	Lower Dakota	Upper Dakota
Midperforations	6696'	6567'
Qg	12850 SCF (test)	Gas Too Small To Measure
h	38' feet (log)	
Pwf	38 Psia	
Pe	2592 Psia	
g_g	.70	
T	186°-646°R	
re	1320 feet	
rw	0.02 feet	
Psc	668 Psia	
Tsc	392°Rankin	
Ug	.014 cp	
Z	0.91	

Where:

Qg = gas flow rate
h = net pay
Pwf= flowing bottomhole pressure
Pe = shut-in bottomhole pressure at drainage radius, re
g_g = gas specific gravity
T = bottomhole temperature
re = drainage radius for 160 acre spacing
rw = wellbore radius
Psc= pseudo critical pressure
Tsc= pseudo critical temperature
Ug = gas viscosity
Z = compressibility factor for gas

Formula:

$$K = \frac{Q_g U_g T Z \ln(.6 l r_e / r_w)}{703 h (P_e^2 - P_{wf}^2)}$$

$$K = \frac{12850 \times .014 \times 646 \times .91 \times \ln(.6 l \times \frac{1320}{20})}{703 \times 38 \times (2592^2 - 38^2)}$$

$$K = .0000049 \quad D$$

$$K = .0049 \text{ md.}$$

Exhibit No. 6B-2

CONSOLIDATED OIL & GAS, INC.
SENTER NO. 1E
NE/4 SE/4 24-T31N-R13W
BASIN DAKOTA FIELD
SAN JUAN COUNTY, NEW MEXICO

Calculation of Permeability Using Darcy's Law:

Data:

	Lower Dakota	Upper Dakota
Midperforations	6928	6728
Qg Scf (test)	2730	52000
h feet (log)	58	51
Pwf Psia	20	32
Pe by analogy & tests	2658	2592
G_g typical gravity field gas	.70	.70
T calculated	186°F(646°R)	186°F(646°R)
re feet	1320	1320
rw feet	.20	.20
Psc Psia	668	668
Tsc °Rankin	392°R	392°R
Ug cps(calc.)	.014	.014
Z (calc)	.91	.91

Where:

Qg = gas flow rate
h = net pay
Pwf= flowing bottomhole pressure
Pe = shut-in bottomhole pressure at drainage radius, re
g_g = gas specific gravity
T = bottomhole temperature
re = drainage radius for 160 acre spacing
rw = wellbore radius
Psc= pseudo critical pressure
Tsc= pseudo critical temperature
Ug = gas viscosity
Z = compressibility factor for gas

Formula:

$$Qg = \frac{703Kh(Pe^2-Pf^2)}{UgTZ\ \ln(.61re/rw)} \qquad \text{and } K = \frac{QgUgTZ\ \ln(.61re/rw)}{703h(Pe^2-Pwf^2)}$$

Lower Dakota

$$K = \frac{2730(.014)(646)(.91)\ln(.61x\frac{1320}{.20})}{(703)(58)(2658^2-20^2)}$$

= .00000068 D
= .00068 md.

Upper Dakota

$$K = \frac{52000(.014)(646)(.91)\ln(.61x\frac{1320}{.20})}{(703)(51)(2592^2-32^2)}$$

= .0000146 D
= .0146 md.

Exhibit No. 6B-3

SOUTHLAND ROYALTY COMPANY
PATTERSON "B" COM. 1E
SW-2-31N-12W
BASIN DAKOTA FIELD
SAN JUAN COUNTY, NEW MEXICO

Calculation of Permeability using Darcy's Law:

Data:

Qg = 224,000 SCFD (open hole test)
h = 34 feet (log)
Pwf= 54 psia (measured at surface and calculated to bottomhole)
Pe = 2650 psia (DST in East No. 7E located 9600' to south)
g_g = .70
T = 190°F = 650°R (calc.)
re = 1320 feet
rw = 0.20 feet
Psc= 668 psia
Tsc= 392°R
Ug = .014 cps (calc.)
Z = .87 (calc.)

Where:

Qg = gas flow rate
h = net pay
Pwf= flowing bottomhole pressure
Pe = shut-in bottomhole pressure at drainage radius, re
g_g = gas specific gravity
T = bottomhole temperature
re = drainage radius for 160 acre spacing
rw = wellbore radius
Psc= pseudo critical pressure
Tsc= pseudo critical temperature
Ug = gas viscosity
Z = compressibility factor for gas

$$Qg = 703\ Kh\ \frac{(Pe^2 - Pwf^2)}{Ug\ T\ Z\ \ln\ (.61\ re/rw)}$$

$$K = \frac{Qg\ Ug\ T\ Z\ \ln\ (.61\ re/rw)}{(703\ h\ (Pe^2 - Pwf^2)}$$

$$K = 224{,}000\ (.014)\frac{(650)(.87)\ \ln\ (.61\ 1320/.20)}{703\ (34)\ (2650^2-542)}$$

K = .0000877 D.

K = .0877 md.

Exhibit No. 6B-4

EL PASO NATURAL GAS COMPANY
CASE NO. 8
NE-18-31N-11W
BASIN DAKOTA FIELD
SAN JUAN COUNTY, NEW MEXICO

Depth (feet)	Permeability (md.)
7254-55	.41
55-56	.32
56-57	.11
57-58	.02
58-59	.03
59-60	.12
60-61	.02
61-62	.07
7338-39	.09
39-40	.12
40-41	.04
41-42	.04
42-43	.04
43-44	.04
44-45	.02
45-46	.06
46-47	.07
47-48	.29
48-49	.03
49-50	.14
50-51	.07
51-52	.04
53-54	.56
54-55	.01
55-56	.24
7364-65	.07
65-66	.05
66-67	.08
67-68	.02
68-69	.52
69-70	.03
70-71	.23
71-72	.02
7390-91	.33
91-92	.03
92-93	.02
93-94	.02
Totals 37	4.42
Average Laboratory	.1195
Average In Situ	.0335

Exhibit No. 6C-1

EL PASO NATURAL GAS COMPANY
MOORE NO. 8
SW-24-32N-12W
BASIN DAKOTA FIELD
SAN JUAN COUNTY, NEW MEXICO

Depth (feet)		Permeability (md.)
7589-90		.01
7591-92		.01
7593-94		.05
7595-96		.01
7597-98		.07
7599-7600		.01
7601-02		.08
7603-04		.01
7605-06		.01
7607-08		.01
7609-10		.02
7611-12		.01
7670-71		.03
71-72		.05
72-73		.48
73-74		.01
74-75		.01
75-76		.07
76-77		.03
78-79		.01
79-80		.09
80-81		.01
81-82		.11
82-83		.17
83-84		.08
84-85		.01
85-86		.02
86-87		.01
87-88		.04
88-89		.01
89-90		.01
90-91		.29
91-92		.07
92-93		.02
93-94		.01
94-95		.01
95-96		.02
96-97		.02
97-98		.12
Totals	39	2.10
Average Laboratory		.0538
Average In-Situ		.0151

Exhibit No. 6C-2

Effect of Overburden Pressure and Water Saturation on Gas Permeability of Tight Sandstone Cores

Rex D. Thomas, SPE-AIME, U. S. Bureau of Mines
Don C. Ward, SPE-AIME, U. S. Bureau of Mines

Introduction

Research on the potential of nuclear explosions to stimulate gas production from low-permeability (tight) sandstone reservoirs is being conducted by the U. S. Bureau of Mines in cooperation with the Atomic Energy Commission. This report describes the part of that research that was conducted to establish correlation between permeability measured on dry cores at low external pressure (routine analysis) and permeability at reservoir conditions.

Cores used in this research were obtained from two Plowshare gas-stimulation projects. Project Gasbuggy cores from the Pictured Cliffs formation, Choza Mesa field, Rio Arriba County, N. M., can be described as very fine grained, slightly calcareous, well indurated sandstone. Project Wagon Wheel cores from the Fort Union formation, Pinedale field, Sublette County, Wyo., can be described as very fine grained, slightly calcareous, very well indurated sandstone.

Underground reservoirs are under considerable compressive stress as a result of the weight of overlying rocks (offset somewhat by internal-fluid pressure). The resultant net confining pressure or effective overburden pressure is referred to in this report simply as overburden pressure. The resulting effects on the physical properties of the reservoir rock have been studied.[1-3] Overburden pressure causes only a small decrease in porosity, which can usually be ignored.[3] This was confirmed for Project Gasbuggy and Project Wagon Wheel cores. A commercial laboratory found that the porosity of these cores is reduced by about 5 percent of the original porosity. The effect of overburden pressure on permeability, however, is appreciable and varies considerably for different reservoir rocks,[1,2] causing greater reductions in permeability for low-permeability rocks.[2,3] The effect of overburden pressure on relative permeability has been found to be small[4] or nonexistent.[5]

This report presents material that confirms and extends previous research findings on the effect that overburden pressure has upon the permeability of dry cores. Also presented are the results of research on the relative gas permeability of low-permeability cores under overburden pressure.

Apparatus and Procedure

Cylindrical cores 2.0 to 7.5 cm long and 2.5 cm in diameter were cut parallel to the bedding plane. After the cores were dried overnight in a vacuum oven (4.5 psia, 70°C), the gas (N_2) permeability of each core was measured in a Hassler cell. An external pressure of 100 psi over the inlet pressure was used to maintain a good seal between the rubber sleeve and the core.[6] Permeability was measured at inlet pressures of 45, 60, and 100 psia, with atmospheric pressure at the outlet. A bubble tube and timer were used to measure gas flow rate. Initial permeability (k_i) then was calculated by the Klinkenberg technique to correct for the effect of gas slippage. All other permeabilities reported here were calculated by this method.

In the same manner, permeability was measured at

Research conducted to determine the potential of nuclear explosions to stimulate gas production verifies that the gas permeability of tight sandstone cores is markedly decreased with increasing overburden pressure. Water saturation also reduces the gas permeability by a large amount. The relative permeability, however, does not change significantly with overburden pressure.

Exhibit No. 7

increasing external pressures of about 500, 1,000, 2,000, 3,000, 4,000, 5,000, and 6,000 psi. External pressures actually were somewhat higher to compensate for internal pressure. The core and staniless steel end pieces were placed in a rubber sleeve (piece of bicycle innertube) 0.1 cm thick. Rubber cement was used to seal the stainless steel end pieces to the rubber sleeve. Shrinkable plastic tubing proved unsatisfactory because high pressure was required to seal the core. The jacketed core was mounted in a high-pressure cell with distilled water as the external fluid.

Cores used in relative permeability studies were first subjected to high external pressure and then allowed to recover their initial permeability. Bulk volume, dry weight, and porosity were measured by conventional gas-expansion techniques. Cores then were subjected to a vacuum (0.3 psia) for 2 hours, immersed in water, and allowed to stand under a vacuum overnight. The cores were weighed and again subjected to vacuum overnight and weighed again to assure complete saturation. Most of the cores were completely saturated after one night. Porosity values calculated on the basis of water saturation are in good agreement with those measured by conventional gas-expansion techniques.

Water in the core was allowed to evaporate at atmospheric conditions to a saturation of about 70 percent and the core was placed in the holder for 2 hours under external pressure (100 psi above inlet) only so the water saturation was uniform. Gas permeability then was measured at three inlet pressures between 30 and 100 psia with atmospheric pressure at the outlet. This procedure was repeated for decreasing water saturations at the same external pressure. After the permeability was measured the core was weighed to determine if any water was lost. In all cases the amount lost was negligible. After the core was dried in a vacuum oven, the gas permeability at this external pressure was measured. The procedure was repeated for external pressures of 3,000 and 6,000 psi.

Results and Discussion

Effect of Overburden Pressure on Permeability

Core number, length, porosity, and initial permeability of the cores used in this research are shown in Table 1. The core number refers to the depth in feet at which the core was obtained. Typical plots of the effect of simulated overburden pressure on Gasbuggy cores are shown in Fig. 1. The permeability is decreased by about 75 percent at an overburden pressure of 3,000 psi and by 90 percent at 6,000 psi. The hydrostatic loading used in these experiments does not reproduce subsurface conditions exactly; in an actual reservoir the horizontal component of stress is usually less than the vertical component. Since the actual loading is not known, this method probably is as realtistic as any other. Cores that contain microfractures are affected to a greater extent, as shown in Fig. 2. In these cores the permeability is decreased by about 95 percent at a simulated overburden pressure of 3,000 psi, with most of the reduction occurring below 2,000 psi.

The data shown in Table 1 and Figs. 1 and 2 were obtained by subjecting the core to successive incre-

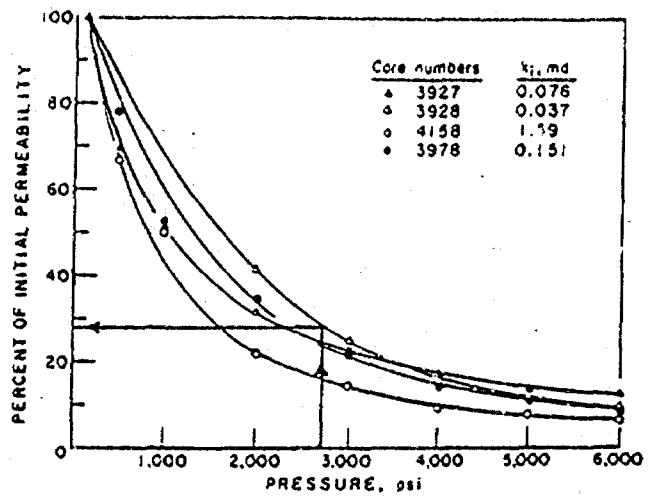


Fig. 1—Effect of overburden pressure on gas permeability of Gasbuggy cores.

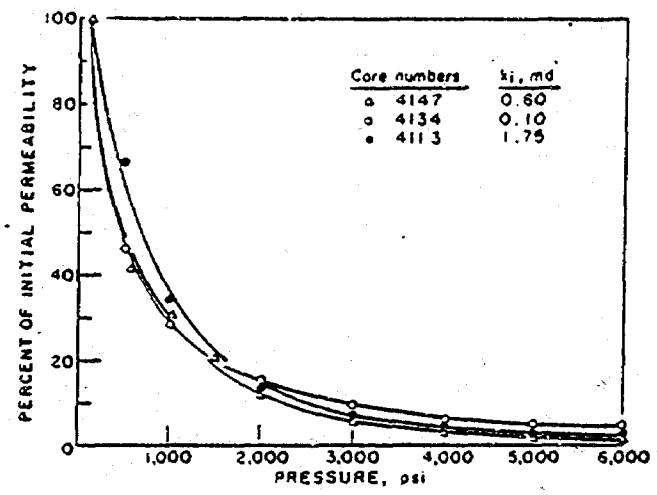


Fig. 2—Effect of overburden pressure on gas permeability of fractured Gasbuggy cores.

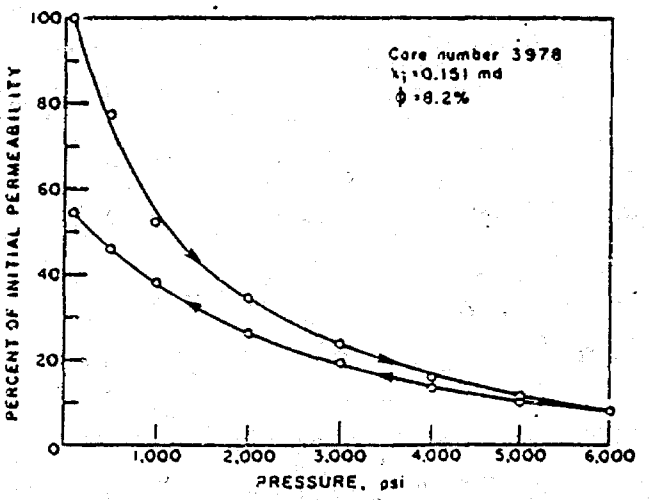


Fig. 3—Hysteresis effect at decreasing confining pressures.

TABLE 1—EFFECT OF OVERBURDEN PRESSURE ON GAS PERMEABILITY

Effective Overburden Pressure (psi):				500	1,000	2,000	3,000	4,000	5,000	6,000
Core Number*	Length (cm)	Porosity (percent)	k_i†	Permeability (md)						
Gasbuggy										
3927	2.1	8.1	0.076	0.053	0.040	0.024	0.0175	0.0132	0.0105	0.0095
3928	7.5	8.3	0.037	0.031	0.024	0.015	0.0093	0.0059	0.0046	0.0035
3978	2.1	8.2	0.151	0.118	0.078	0.052	0.036	0.024	0.0175	0.0132
4113**	2.1	10.1	1.75	1.16	0.602	0.252	0.113	0.068	0.042	0.029
4134**	2.1	11.6	0.10	0.046	0.029	0.0153	0.0095	0.0065	0.0055	0.0047
4146**	7.5	11.6	2.40	1.73	1.32	0.31	0.14	0.069	0.052	0.022
4147**	7.5	11.3	0.60	0.247	0.181	0.071	0.034	0.0186	0.0118	0.0082
4158	2.1	13.6	1.59	1.06	0.80	0.35	0.225	0.152	0.116	0.100
Wagon Wheel										
8084	3.8	7.7	0.028	0.022	0.020	0.010	0.0070	0.0047	0.0035	0.0030
8122	3.8	11.4	0.071	0.055	0.048	0.034	0.027	0.024	0.021	0.019
8975**	3.8	8.7	0.039	0.029	0.024	0.0114	0.0073	0.0048	0.0032	0.0025
10156	3.8	8.5	0.088	0.067	0.051	0.032	0.025	0.022	0.018	0.016
10990**	3.8	9.0	0.048	0.020	0.0175	0.0080	0.0050	0.0040	0.0025	0.0019

*Number denotes depth in feet.
**Slightly fractured.
†Initial permeability.

mental increases in external pressure. The core was assumed to be in equilibrium at each pressure when permeability measurements remained constant for 15 minutes, which required between 1 and 2 hours. A period of 30 minutes to an hour was required to attain equilibrium when the inlet pressure was changed. Consequently, each external pressure was maintained for a minimum of 2 hours.

The effect of decreasing external pressure was determined on a few cores, and typical results are shown in Fig. 3. Other researchers[2,3] have observed and shown that this hysteresis is mainly dependent on the stress history of the core. Cores generally recover their original permeability after 3 to 6 weeks at atmospheric conditions. This time could be shortened by storing the core in an oven at 70°C.

The effect of overburden pressure on the permeability of cores from Project Wagon Wheel is similar to that on cores from Project Gasbuggy, and typical results are shown in Fig. 6. The permeability is decreased to about 30 percent of initial permeability at an overburden pressure of 3,000 psi and to 20 percent at 6,000.

A study of the data in Table 1 indicates that the original porosity of the core and the reduction in permeability caused by overburden pressure are not related. Pore structure (fractures to uniform pores) is probably the governing factor.

Water Saturation Effects

The data in Table 2 show that the permeability decreased with increasing water saturation. The values at 20-, 40-, and 60-percent water saturation were obtained from individual relative-permeability curves for Gasbuggy and Wagon Wheel cores. Relative-permeability curves for three cores from Project Gasbuggy are shown in Fig. 4 with the data points for Core 3978. Data points were omitted for the other cores to avoid confusion. This figure shows that although gas permeability is reduced, the relative gas permeability of Gasbuggy cores is not significantly affected by increased overburden pressure. This conclusion is in agreement with the results of others.[4,5]

Extremely low values of permeability that resulted from water saturation and overburden pressure required that either long flow times or high inlet pressures (high differential across the core) be used. Since a high inlet pressure increases the end effects by changing the distribution of water in the core, long flow times were required. Although end-effect problems were encountered with the short cores (Cores 3978 and 4158), the permeability of these cores was

TABLE 2—EFFECT OF OVERBURDEN PRESSURE AND WATER SATURATION ON GAS PERMEABILITY

Water Saturation (percent):		0	20	40	60
Core Number	Pressure (psi)	Permeability (md)			
Gasbuggy					
3927	100	0.115	0.099	0.041	0.0023
3927	3,000	0.026	0.023	0.009	0.0005
3927	6,000	0.012	0.010	0.003	0.0002
3978	100	0.112	0.080	0.034	0.011
3978	3,000	0.036	0.026	0.011	0.004
3978	6,000	0.013	0.009	0.004	0.0013
4158	100	0.447	0.335	0.156	0.045
4158	3,000	0.075	0.056	0.026	0.0074
4158	6,000	0.027	0.020	0.010	0.0026
Wagon Wheel					
8084	100	0.038	0.030	0.014	0.0042
8084	3,000	0.012	0.0096	0.0043	0.0013
8084	6,000	0.0070	0.0056	0.0025	0.0008
8122	100	0.074	0.054	0.017	0.006
8122	3,000	0.027	0.020	0.008	0.002
8122	6,000	0.020	0.015	0.006	0.002
10156	100	0.100	0.074	0.029	0.003
10156	3,000	0.028	0.020	0.008	0.0008
10156	6,000	0.017	0.013	0.005	0.0005

high enough to yield reasonable results. Permeability measurements for Core 4161 (7.5 cm long, 0.053 md) required more than 2 hours per reading. These extremely long flow times can cause errors.

End effects, long flow times, and changes in permeability due to water saturation tend to decrease the accuracy of permeability measurements, especially at the higher water saturations.

The initial permeability of many of the dry cores used in this research was not reproducible following saturation and drying. The changes probably were caused by solution of material in the pores and by particle movement. These caused both increases and decreases in permeability. The variation, although sometimes large, usually was less than 5 percent; however, we feel that the relative permeability curves are essentially correct. To eliminate the effects of solution and particle movement, the permeability of the dry core following saturation, rather than the permeability initially measured, was used in calculating relative permeability.

A composite of the relative permeability curves for Gasbuggy cores is shown in Fig. 5. These curves are representative of permeabilities encountered in this formation. At a water saturation of 50 percent, the relative permeability of the cores ranges from 15 to 20 percent and is not affected by overburden pressure.

Similar results were obtained on cores from Project Wagon Wheel, as shown in Table 2 and Fig. 6 with data points for Core 8122. These cores were cut to a length of 3.8 cm to alleviate some of the long flow time and end-effect difficulties encountered with Gasbuggy cores. These curves are representative of the permeabilities encountered in the formation. At a water saturation of 50 percent, the relative permeability of these cores ranges from 12 to 21 percent. The data in these figures show, as do the data from Gasbuggy cores, that relative gas permeability is not significantly affected by increased overburden pressure.

Correlation with Nuclear Stimulation Projects

Many of the basin areas of the Rocky Mountain region consist of thick, low-permeability sandstones containing large quantities of natural gas. This type of reservoir has been the object of the AEC's Plowshare Program experiments, Projects Gasbuggy and Rulison, and proposed Projects Wagon Wheel, WASP, and Rio Blanco. Because most wells in these reservoirs have not been commercial, only limited reservoir-analysis and production-test data are available. Reservoir analysis is most difficult because low permeability requires long-term testing. Also, it is difficult to determine permeability and net pay from these tests. Knowledge of the gas permeability is necessary in predicting gas recovery, and because it is not economical to define the characteristics of different strata by well test. it is desirable to be able to relate laboratory-measured permeability to the true in-situ permeability.

Conventional analysis by a commercial laboratory (confirmed in our laboratory) of about 200 Gasbuggy cores gave an average initial gas permeability of 0.16 md on dry cores and an average water saturation of 48 percent. The effective overburden pressure of this

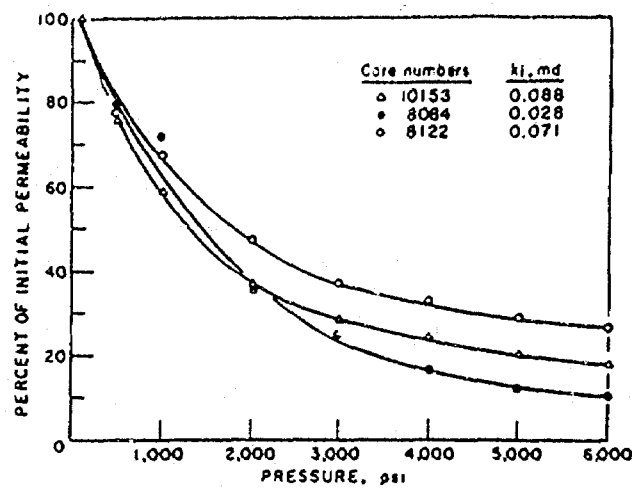


Fig. 4—Effect of overburden pressure on gas permeability of Wagon Wheel cores.

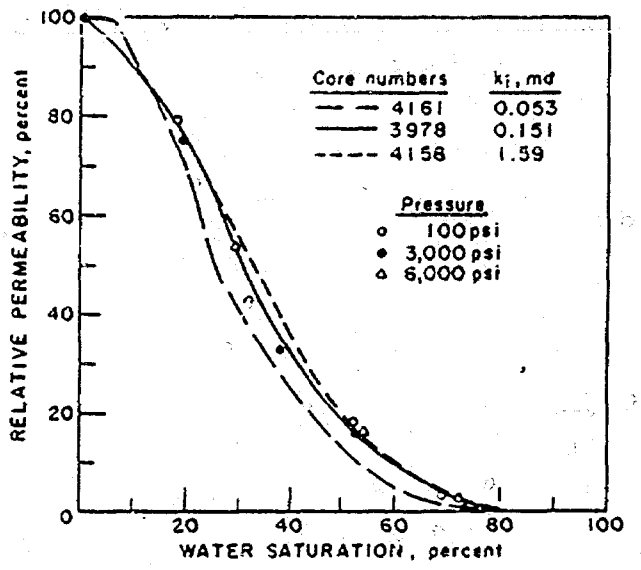


Fig. 5—Relative gas permeability of Gasbuggy cores.

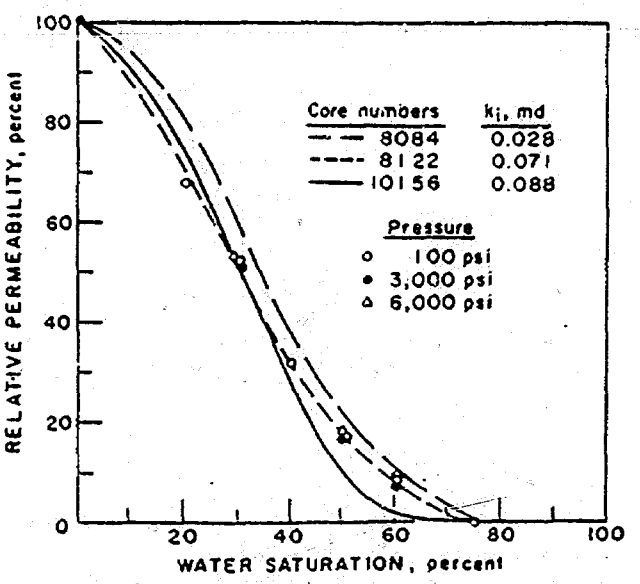


Fig. 6—Relative gas permeability of Wagon Wheel cores.

reservoir is about 3,000 psi. From Fig. 1, the reduction factor resulting from the overburden pressure is 0.25, and the reduction factor for a water saturation of 48 percent (Fig. 5) is 0.20; thus the total reduction is 5 percent of the initial permeability, or 0.008 md. This value compares favorably with permeability determinations of about 0.01 md from both preshot and postshot flow testing at Gasbuggy. The gas reservoir at Project Rulison is similar to that at Gasbuggy, having an average initial dry permeability of 0.11 md and an average water saturation of 45 percent. Simulated in-situ permeability has not yet been measured in the laboratory on Rulison cores; however, using an effective overburden pressure of 5,000 psi and curves of Gasbuggy core data (Figs. 1 and 5), the reduction factor because of overburden pressure would be 0.12 and that for water saturation 0.24. This results in a combined reduction to 3 percent of the initial permeability, or 0.003 md. Postshot production testing at Rulison is not complete, and the only preshot determination of permeability was made from tests of a 32-ft isolated zone that gave an average value of 0.008 md. No cores are available from this zone. Rulison reservoir rock is said to be less compressible than that of Gasbuggy; therefore Gasbuggy pressure-effect data would be expected to indicate a greater reduction for Rulison than actually exists.

The average initial permeability of dry Wagon Wheel cores is 0.068 md, with an average water saturation of 50 percent. An estimated effective overburden pressure of 3,000 psi gives a reduction factor of 0.28 (Fig. 4). Water saturation further reduces permeability by a factor of 0.18 (Fig. 6). Therefore, the total reduction in permeability is to approximately 5 percent of the initial permeability, or 0.0034 md. This value can be used to predict postshot gas recovery from the proposed Wagon Wheel experiment.

Cores are not yet available from Projects Rio Blanco and WASP.

Original manuscript received in Society of Petroleum Engineers office June 16, 1971. Revised manuscript received Dec. 20, 1971. Paper (SPE 3634) was presented at SPE 46th Annual Fall Meeting, held in New Orleans, Oct. 3-6, 1971.

Conclusions

The gas permeability of tight sandstone cores is markedly decreased with increasing overburden pressure. Most of the decrease takes place at pressures to 3,000 psi. At 3,000 psi, the permeability of unfractured samples ranges from 14 to 37 percent of the initial permeability. In fractured samples, permeability may be reduced to as low as 6 percent of initial permeability.

Water saturation also reduces the gas permeability greatly; however, the relative permeability does not change significantly with overburden pressure.

Permeability calculated from laboratory results are in good agreement with in-situ permeabilities determined from production test data. Although not confirmed, predictions for other projects appear to be reasonable.

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EXHIBIT 3A

Consolidated Oil & Gas, Inc.

WELL COST ESTIMATE

AVERAGE DAKOTA WELL WITH UPPER & LOWER DAKOTA, 2 FRACS

AFE No. _____
C.O.G. WI. _____

TO: Drill ( ) Recomplete ( ) Work Over ( )

State New Mexico County San Juan Field Basin Dakota

Lease Name Average Dakota Well Lease No. _____ Well No. Unnamed No. 1

Location: T13N, R12 & 13W - Average Dakota Well

DETAIL COST ESTIMATE

INTANGIBLE COSTS	QUANTITY	PRICE	COST OF DRY HOLE	COST OF PRODUCER
Superintendence	15/25	300	4,500	7,500
Labor			1,000	3,500
Hauling				8,000
Drilling				
To Drill	7,000	$16/Ft.	112,000	112,000
Day Work - W/DP	2	5,800	11,600	11,600
Day Work - W/out Drill pipe				
Other Completion Unit w/compl. equip.	10	2,500		25,000
Fuel			1,000	3,000
Water			9,000	11,000
Right of Way Damages			1,500	1,500
Drlg. Mud & Chemicals			22,000	24,000
Electric & Radioactivity Logs			16,000	16,000
Coring & Core Analysis				
Acidizing & Fracturing 2 Fracs using Nitrogen				75,000
Drill Stem Tests				
Gun Perforating & CBL 2 Dakota zones				8,000
Cement & Cementing Services) Surf.& 3-stage			4,000	23,000
Shoes, Collars, & Centralizers) Prod. w/DV tools				
Welding				
Road & Location			5,000	6,000
Bits & Coreheads				700
Mud Logging				
Plugging Expense			7,500	
Equipment Rental (Compressors, workstring,etc.)			5,000	16,000
Overhead			1,000	1,500
Contingencies 5%			10,000	17,600
TOTAL INTANGIBLE COSTS			211,100	370,900
PERMANENT EQUIPMENT				
Conductor Pipe "OD				
Surface Casing 8-5/8"OD 24#	250		2,800	2,800
Prod. Casing4-1/2" OD 10.5# ST&C	7000			39,900
Tubing 1-1/2" OD 2.9# EUE	7000			17,500
Casing Head Assembly			1,300	1,300
Tubing Head Assembly)				9,500
Xmas Tree & Manifold Assembly)				
Production Packer				
Cathodic Protection				8,000
Bottom Hole Choke				
Miscellaneous Connections				4,000
Production Unit & Tank Battery				21,500
TOTAL Permanent Equipment			4,100	104,500
TOTAL COST OF COMPLETED WELL			215,200	475,400

Date: _____ Recommended by: _____

APPROVED (Company): _____ Approved by: _____

By: _____ Date: September 23, 1981

EXHIBIT 8-B

CONSOLIDATED OIL & GAS, INC.

	Cain 1-M	Jackson 2-E	Jaquez 2
Superintendent	$ 13,489	$ 4,409	$ 7,302
Labor	2,297	743	4,130
Hauling	7,426	4,826	7,133
Drilling - To Drill	105,530	107,544	90,736
Daywork	6,146	14,857	24,576
Other - Completion Rig	44,570	8,984	20,949
Fuel	3,798	246	10,449
Water	24,968	12,733	11,521
Right of Way Damages	-	-	2,000
Drilling Mud & Chemicals	37,187	32,948	34,962
Electric & Radioactivity Logs	15,840	11,381	12,929
Coring & Core Analysis	-	-	-
Acidizing & Fracturing	70,294	27,751	74,326
Tests (AOF & BHP)	1,190	673	1,298
Gun Perf. & Cs'd Hole Logging	5,975	7,300	8,790
Cement & Cementing Services	27,461	23,168	27,286
Welding	500	-	500
Road & Location	17,833	2,247	4,942
Bits & Coreheads	1,204	-	1,387
Overhead	-	1,096	-
Equipment Rental (Inc. Comp.)	29,094	7,166	50,700
Fishing Expense	43,648	-	-
Cathodic Protection	8,585	8,000	2,738
Total Initial Costs	$467,035	$276,072	$398,654
Surface Casing	$ 2,196	$ 2,337	$ 2,202
Production Casing	53,579	40,966	49,164
Tubing	16,166	17,311	15,951
Casing Head Assembly	1,320	1,320	1,320
Tubing Head Assembly	9,270	9,270	9,270
Xmas Tree & Manifold Assy.			
Production Packer			
Miscellaneous Connections	4,257	2,897	6,910
Separator & Production Tanks	13,614	11,005	12,942
Total Permanent Equipment	$100,402	$ 85,106	$ 97,759
TOTAL COST OF COMPLETED DAKOTA WELL*	$567,437	$361,178	$496,413

*Total Well Cost less Completion & Equipment Costs of Dual Zone (if any).

Note: Estimated Cost of Lower Dakota Completion	$110,402		$ 77,015

CONSOLIDATED OIL & GAS, INC.

	Kline 1-M	Langendorf 1-E	Mitchell 1-E
Superintendent	$ 14,768	$ 6,303	$ 7,851
Labor	9,174	3,584	8,819
Hauling	3,149	6,071	25,408
Drilling - To Drill	101,079	101,228	93,420
Daywork	5,807	7,639	48,985
Other - Completion Rig	41,400	17,877	20,113
Fuel	622	7,457	3,751
Water	6,529	21,236	4,555
Right of Way Damages	4,000	-	-
Drilling Mud & Chemicals	11,342	23,845	91,000
Electric & Radioactivity Logs	21,399	14,305	13,705
Coring & Core Analysis	-	-	-
Acidizing & Fracturing	75,323	83,944	74,037
Tests (AOF & BHP)	715	1,123	1,939
Gun Perf. & Cs'd Hole Logging	6,294	9,360	7,565
Cement & Cementing Services	24,024	25,132	12,687
Welding	-	500	-
Road & Location	9,977	5,419	5,725
Bits & Coreheads	-	1,492	-
Overhead	-	-	1,788
Equipment Rental (Inc. Comp.)	25,181	32,533	58,246
Fishing Expense	-	-	-
Cathodic Protection	4,748	8,146	8,160
Total Initial Costs	$365,531	$377,194	$487,754
Surface Casing	$ 3,141	$ 2,138	$ 2,194
Production Casing	52,026	47,765	41,102
Tubing	14,286	14,660	14,227
Casing Head Assembly	1,325	1,320	371
Tubing Head Assembly	9,250	9,270	9,710
Xmas Tree & Manifold Assy.			
Production Packer			
Miscellaneous Connections	5,642	10,957	3,849
Separator & Production Tanks	12,380	12,410	13,016
Total Permanent Equipment	$ 98,050	$ 98,520	$ 84,469
TOTAL COST OF COMPLETED DAKOTA WELL*	$463,581	$475,714	$572,223

*Total Well Cost less Completion & Equipment Costs of Dual Zone (if any).

Note: Estimated Cost of Lower Dakota Completion	$ 70,440	$ 76,390	$ 54,052

CONSOLIDATED OIL & GAS, INC.

	Neuman 1-E	Payne 1-E	Phillips 1-E
Superintendent	$ 4,624	$ 3,997	$ 8,974
Labor	359	3,022	4,967
Hauling	4,467	5,368	6,641
Drilling - To Drill	111,552	108,753	92,201
Daywork	15,316	12,988	6,627
Other - Completion Rig	13,154	18,036	19,205
Fuel	-	4,532	1,836
Water	15,851	18,592	6,000
Right of Way Damages	-	-	1,000
Drilling Mud & Chemicals	30,076	19,214	12,457
Electric & Radioactivity Logs	14,739	12,899	12,782
Coring & Core Analysis	-	-	-
Acidizing & Fracturing	34,738	75,960	67,794
Tests (AOF & BHP)	366	456	-
Gun Perf. & Cs'd Hole Logging	7,040	7,994	13,450
Cement & Cementing Services	16,072	27,079	25,099
Welding	-	500	304
Road & Location	2,472	3,146	8,178
Bits & Coreheads	-	1,428	-
Overhead	1,194	-	-
Equipment Rental (Inc. Comp.)	6,554	30,359	8,559
Fishing Expense	-	-	-
Cathodic Protection	8,008	8,519	8,425
Total Initial Costs	$286,582	$362,842	$304,499
Surface Casing	$ 2,073	$ 2,403	$ 2,543
Production Casing	42,779	53,260	53,179
Tubing	17,073	15,039	13,426
Casing Head Assembly	1,419	1,320	1,284
Tubing Head Assembly	6,375	9,270	10,590
Xmas Tree & Manifold Assy.			
Production Packer			
Miscellaneous Connections	2,848	2,823	3,846
Separator & Production Tanks	11,697	12,812	12,052
Total Permanent Equipment	$ 84,264	$ 96,927	$ 96,920
TOTAL COST OF COMPLETED DAKOTA WELL*	$370,846	$459,769	$401,419

*Total Well Cost less Completion & Equipment Costs of Dual Zone (if any)

Note: Estimated Cost of Lower Dakota Completion - $ 73,716 $ 32,391

CONSOLIDATED OIL & GAS, INC.

	Robinson Bros. 1-M	So. Union 1-M	So. Union 2-E
Superintendent	$ 11,258	$ 16,493	$ 7,129
Labor	1,760	3,272	3,406
Hauling	10,995	9,958	2,769
Drilling - To Drill	119,913	91,611	109,918
Daywork		30,638	11,541
Other - Completion Rig	16,062	68,746	25,227
Fuel	2,525	3,577	1,247
Water	3,000	19,732	9,935
Right of Way Damages	1,643	-	-
Drilling Mud & Chemicals	36,064	40,695	32,649
Electric & Radioactivity Logs	15,838	19,787	13,337
Coring & Core Analysis	-	14,176	-
Acidizing & Fracturing	54,731	71,878	56,294
Tests (AOF & BHP)	490	-	420
Gun Perf. & Cs'd Hole Logging	9,131	13,150	12,162
Cement & Cementing Services	29,273	27,273	18,445
Welding	-	337	-
Road & Location	23,095	4,806	3,575
Bits & Coreheads	1,568	2,827	-
Overhead	-	2,705	-
Equipment Rental (Inc. Comp.)	11,624	29,810	33,801
Fishing Expense	-	-	-
Cathodic Protection	6,001	8,300	4,003
Total Initial Costs	$354,971	$479,771	$345,858
Surface Casing	2,053	2,119	2,409
Production Casing	50,946	55,118	41,939
Tubing	14,983	14,795	18,725
Casing Head Assembly	1,320	1,320	1,419
Tubing Head Assembly	9,270	9,720	9,280
Xmas Tree & Manifold Assy.			
Production Packer			
Miscellaneous Connections	3,007	3,307	3,373
Separator & Production Tanks	12,640	13,211	14,776
Total Permanent Equipment	$ 94,219	$ 99,590	$ 91,921
TOTAL COST OF COMPLETED DAKOTA WELL*	$449,190	$579,361	$437,779
Note: Estimated Cost of Lower Dakota Completion	$ 43,433	$ 94,851	$ 58,494

* Total Well Cost less Completion & Equipment Costs of Dual Zone (if any).

CONSOLIDATED OIL & GAS, INC.

	Starr 1-M	Templeton 1-E	Wilmerding 1-M
Superintendent	$ 8,263	$ 11,290	$ 9,004
Labor	2,057	2,761	8,167
Hauling	4,118	10,337	5,929
Drilling - To Drill	102,014	85,888	93,441
Daywork	7,040	22,346	5,494
Other - Completion Rig	31,188	41,222	21,132
Fuel	2,053	2,357	725
Water	6,149	8,499	7,948
Right of Way Damages	-	4,000	2,000
Drilling Mud & Chemicals	26,879	29,000	18,834
Electric & Radioactivity Logs	16,950	21,443	18,294
Coring & Core Analysis	-	-	-
Acidizing & Fracturing	87,228	59,510	73,799
Tests (AOF & BHP)	-	506	1,058
Gun Perf. & Cs'd Hole Logging	8,742	6,881	5,259
Cement & Cementing Services	25,158	28,185	24,823
Welding	-	-	-
Road & Location	6,539	19,210	1,703
Bits & Coreheads	-	-	-
Overhead	-	3,190	-
Equipment Rental (Inc. Comp.)	28,212	42,160	15,368
Fishing Expense	-	-	-
Cathodic Protection	8,062	8,944	7,957
Total Initial Costs	$370,652	$407,729	$320,935
Surface Casing	$ 2,119	$ 2,186	$ 2,115
Production Casing	45,900	50,404	49,224
Tubing	14,500	15,675	14,237
Casing Head Assembly	1,320	1,320	1,320
Tubing Head Assembly	9,270	9,270	9,270
Xmas Tree & Manifold Assy.			
Production Packer			
Miscellaneous Connections	4,057	6,873	5,082
Separator & Production Tanks	12,577	14,025	12,380
Total Permanent Equipment	$ 89,743	$ 99,753	$ 93,628
TOTAL COST OF COMPLETED DAKOTA WELL*	$460,395	$507,482	$414,563

*Total Well Cost less Completion & Equipment Costs of Dual Zone (if any).

Note: Estimated Cost of Lower Dakota Completion	$ 58,682	$ 62,854	$ 42,443

CONSOLIDATED OIL & GAS, INC.

	Total	Average
Superintendent	$ 135,154	$ 9,010
Labor	58,518	3,901
Hauling	114,595	7,640
Drilling - To Drill	1,514,828	100,989
Daywork	220,000	14,666
Other - Completion Rig	407,865	27,191
Fuel	45,175	3,012
Water	177,248	11,817
Right of Way Damages	14,643	976
Drilling Mud & Chemicals	477,152	31,810
Electric & Radioactivity Logs	235,628	15,709
Coring & Core Analysis	14,176	945
Acidizing & Fracturing	987,607	65,840
Tests (AOF & BHP)	10,234	682
Gun Perf. & Cs'd Hole Logging	129,093	8,606
Cement & Cementing Services	361,165	24,078
Welding	2,641	176
Road & Location	118,867	7,924
Bits & Coreheads	9,906	660
Overhead	9,973	665
Equipment Rental (Inc. Comp.)	409,367	27,291
Fishing Expense	43,648	2,910
Cathodic Protection	108,596	7,240
Total Initial Costs	$5,606,079	$373,738
Surface Casing	$ 34,228	$ 2,282
Production Casing	727,351	48,490
Tubing	231,054	15,404
Casing Head Assembly	19,018	1,268
Tubing Head Assembly	138,355	9,224
Xmas Tree & Manifold Assy.		
Production Packer		
Miscellaneous Connections	69,728	4,649
Separator & Production Tanks	191,537	12,769
Total Permanent Equipment	$1,411,271	$ 94,085
TOTAL COST OF COMPLETED DAKOTA WELL*	$7,017,350	$467,823

* Total Well Cost less Completion & Equipment Costs of Dual Zone (if any).

Note: Estimated Cost of Lower Dakota Completion	$ 855,163	$ 65,782

EXHIBIT 9

Protection of Fresh Water

State and federal regulations currently provide for the protection of any fresh water aquifers that are being used or are expected to be used in the foreseeable future for domestic or agricultural water supplies. Three potential fresh water bearing formations in the area of interest are the San Jose, Nacimiento and Ojo Alamo. These three formations occur from the surface of the ground to a depth of approximately 1,000 feet in T31N, R13W and the western half of T31N, R12W.

The NMOCD by Rule 106 and the federal government regulations for protection of fresh water in oil and gas related activities both require the casing and cementing program to be designed to seal off fresh water bearing formations from oil and gas bearing formations. They fulfill this requirement by having the oil and gas operator cement the production casing with sufficient cement to bring it above the Dakota several hundred feet, to usually cement across the Mesaverde zone when it is productive, and then to circulate cement to surface from several hundred feet below the base of the Ojo Alamo formation. Additionally, surface casing is set and cemented to surface when drilling begins which protects the top several hundred feet.

The above casing and cementing programs provide adequate protection to the fresh water sands even though large stimulation treatments are required in the tight Dakota producing formation which is about 5,900 feet below the deepest fresh water zone.

EXHIBIT 10

CONSOLIDATED OIL & GAS, INC.

ASSUMPTIONS USED IN MAKING ECONOMIC CALCULATIONS
BASIN-DAKOTA FIELD
SAN JUAN COUNTY, NEW MEXICO

Drilling and Completion Costs (including tank battery)	$475,400
Operating Costs $/Mo.	150
Depth	7,000'
Consolidated Working Interest	100%
Royalty Interest Typical to Consolidated Holdings	24.5%
Liquid Yield (BBLS./MMCF)	3.85
Fully Adjusted Gas Price as of October 1, 1981 ($/MCF)	$3.14
Maximum Gas Price ($/MCF)	$10.42
Maximum Oil Price ($/BBL.)	$50.00
Rate of Price Escalation	7%
Severance Tax	8%
Deregulation Tax Data, Base Oil Price	$14.11
Windfall Profit Tax Rate	30%

Initial Post-stimulation Stabilized Production Rate (MCFD)	Forecast 20-Year Recovery - MMCF
89	180
150	270
189	350
232 (Expected Case)	435
400	555

EXHIBIT 11

ROYALTY INTEREST CONSIDERATION

In this particular area of the San Juan Basin, Consolidated's interests are typically burdened with a 12% ORRI in addition to the base 12 1/2% royalty, resulting in a 75.5% net revenue interest to a 100% working interest.

In the industry, there are two primary means of obtaining rights to drill and produce an oil and gas property. One is to take a lease from the mineral owner by the payment of a lease bonus, normally in the form of dollars per acre. This will normally result in the mineral owner retaining a 12 1/2% royalty. However, in this case, the economics of development should include those lease bonuses as they represent a real cost of oil and gas drilling.

The second means of obtaining oil and gas leases is through farm-ins from the party(ies) who have taken the base lease. This almost always entails payment of no lease bonus and assignment of an overriding royalty interest, which may or may not be convertible into a larger working interest.

This second route represents the means of Consolidated obtaining its leases in this area. Leases were taken from parties who had obtained the leases from the mineral owners.

TYPICAL CONSOLIDATED LEASES IN AREA

Well	Net Revenue Interest to 100% Working Interest - %	Total Royalty Burden - %
Cain 1-M	75.0	25.0
Jackson 2-E	75.0	25.0
Jaquez 2	86.5	13.5
Kline 1-M	77.1	22.9
Langendorf 1-E	75.0	25.0
Mitchell 1-E	75.0	25.0
Neuman 1-E	75.0	25.0
Payne 1-E	75.0	25.0
Phillips 1-E	75.0	25.0
Robinson Bros. 1-M	82.6	17.4
Southern Union 1-M	77.5	22.5
Southern Union 2-E	75.0	25.0
Starr 1-M	75.0	25.0
Templeton 1-E	76.6	23.4
Wilmerding 1-M	76.5	23.5

Thus, in our case, our economics are burdened with a typical total royalty burden of 24.5%, but are not burdened with lease bonuses.

It is important to note that the net present value of the 12% overriding royalty, which is not burdened by costs, approximates $50,000 per location. This is about $300 per acre, which is certainly in line with proven property lease bonuses being paid.

EXHIBIT 12

BEFORE TAX ECONOMICS

EXHIBIT 12

SECTION 103 PRICE
180 MMCF GROSS
20-YEAR RECOVERY

TYPICAL WELL
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO

DATE: 09/23/81.
TIME: 17.30.29.
FILE: TYPICAL
PROJ: 1

CONSOLIDATED OIL & GAS, INC.
ECONOMICS OF DEVELOPMENT

R E S E R V E S A N D E C O N O M I C S

AS OF DATE: 1/ 1/1981

END MO-YR	GROSS OIL PRODUCTION -----MB----	GROSS GAS PRODUCTION ----MMF---	OIL TO NET INTEREST ----MB----	GAS TO NET INTEREST ----MMF---	REVENUE TO INTEREST ----M$----	NET INVESTMENT ----M$----	NET OPER EXPENSES ----M$----	NET INCOME BEFORE FIT ----M$----	CUMULATIVE NET INCOME ----M$----	30.000 PCT CUM. DISC NET INCOME ----M$----
12-81	0.	0.	0.	0.	0.	475.400	1.863	-477.263	-477.263	-476.914
12-82	.157	40.758	.119	30.772	92.183	0.	1.993	90.190	-387.073	-415.892
12-83	.109	28.518	.082	21.531	68.987	0.	2.133	66.854	-320.219	-381.097
12-84	.081	21.072	.061	15.910	54.559	0.	2.283	52.276	-267.943	-360.168
12-85	.063	16.206	.048	12.235	44.920	0.	2.442	42.478	-225.465	-347.086
12-86	.049	12.850	.037	9.702	38.090	0.	2.613	35.477	-189.988	-338.682
12-87	.040	10.439	.030	7.881	33.119	0.	2.795	30.324	-159.664	-333.156
12-88	.034	8.649	.025	6.530	29.401	0.	2.992	26.409	-133.255	-329.454
12-89	.028	7.283	.022	5.499	26.465	0.	3.201	23.264	-109.991	-326.946
12-90	.024	6.216	.018	4.693	24.156	0.	3.425	20.731	-89.260	-325.226
12-91	.020	5.368	.015	4.053	22.254	0.	3.600	18.654	-70.606	-324.036
12-92	.018	4.683	.013	3.536	20.750	0.	3.600	17.150	-53.456	-323.194
12-93	.016	4.120	.012	3.110	19.501	0.	3.600	15.901	-37.555	-322.594
12-94	.014	3.654	.011	2.759	18.465	0.	3.600	14.865	-22.690	-322.162
12-95	.013	3.262	.010	2.463	17.624	0.	3.600	14.024	-8.666	-321.849
12-96	.011	2.930	.008	2.212	16.887	0.	3.600	13.287	4.621	-321.621
12-97	.010	2.647	.008	1.999	16.302	0.	3.600	12.702	17.323	-321.453
12-98	.009	2.402	.006	1.813	15.804	0.	3.600	12.204	29.527	-321.329
12-99	.009	2.191	.007	1.654	15.433	0.	3.600	11.833	41.360	-321.236
12- 0	.008	2.005	.006	1.514	14.789	0.	3.600	11.189	52.549	-321.169
S TOT	.713	185.253[1]	.538	139.866	589.689	475.400	61.740	52.549	52.549	-321.169
AFTER	.056	14.747	.043	11.134	108.680	0.	40.932	67.748	120.297	-321.023
TOTAL	.769	200.000	.581	151.000	698.369	475.400	102.672	120.297	120.297	-321.023

CUM.	0.	0.	NET OIL REVENUE	20.470	5 PCT	-68.867	40 PCT	-352.615
ULT.	.769	200.000	NET GAS REVENUE	677.899	10 PCT	-168.442	50 PCT	-374.061
			NET PROD REVENUE	0.	15 PCT	-228.890	60 PCT	-389.576
					20 PCT	-269.508	80 PCT	-410.463
CUM NET INC/INV(1)		.25	CUM NET PW/INV(1)	-.68	30 PCT	-321.023	100 PCT	-423.791
GROSS WELLS		1	LIFE (YEARS)	31.37				
MONTHS 1ST YEAR		12	RATE OF RETURN,PCT	3.18				
INITIAL W.I., PCT		100.0000	INITIAL N.I., PCT	75.5000				

1 - 20-year total does not precisely match heading due to computer scheduling technique.

TYPICAL WELL
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO

CONSOLIDATED OIL & GAS, INC.
ECONOMICS OF DEVELOPMENT

2X SECTION 103 PRICE
180 MMCF GROSS
20-YEAR RECOVERY

R E S E R V E S A N D E C O N O M I C S

AS OF DATE : 1/ 1/1981

DATE: 09/23/81.
TIME: 17.30.32.
FILE: TYPICAL
PROJ: 2

END MO-YR	GROSS OIL PRODUCTION ----MB----	GROSS GAS PRODUCTION -----MMF---	OIL TO NET INTEREST ----MB----	GAS TO NET INTEREST ----MMF---	REVENUE TO INTEREST ----M$----	NET INVESTMENT ----M$----	NET OPER EXPENSES ----M$----	NET INCOME BEFORE FIT ----M$----	CUMULATIVE NET INCOME ----M$----	30.000 PCT CUM. DISC NET INCOME ----M$----
12-81	0.	0.	0.	0.	0.	475.400	1.863	-477.263	-477.263	-476.914
12-82	.149	38.640	.112	29.173	171.810	0.	1.993	169.817	-307.446	-362.016
12-83	.104	27.168	.079	20.512	129.231	0.	2.133	127.098	-180.348	-295.867
12-84	.078	20.145	.059	15.210	102.558	0.	2.283	100.275	-80.073	-255.722
12-85	.059	15.533	.044	11.727	84.591	0.	2.442	82.149	2.076	-230.423
12-86	.048	12.343	.037	9.319	71.957	0.	2.613	69.344	71.420	-213.995
12-87	.038	10.043	.028	7.582	62.621	0.	2.795	59.826	131.246	-203.093
12-88	.032	8.332	.025	6.291	55.618	0.	2.992	52.626	183.872	-195.717
12-89	.027	7.024	.020	5.303	50.164	0.	3.201	46.963	230.835	-190.653
12-90	.024	6.001	.018	4.531	44.256	0.	3.425	40.831	271.666	-187.266
12-91	.020	5.187	.015	3.916	38.237	0.	3.600	34.637	306.303	-185.056
12-92	.017	4.527	.013	3.418	33.356	0.	3.600	29.756	336.059	-183.596
12-93	.015	3.986	.011	3.009	29.370	0.	3.600	25.770	361.829	-182.623
12-94	.014	3.537	.011	2.671	26.086	0.	3.600	22.486	384.315	-181.970
12-95	.012	3.160	.009	2.386	23.288	0.	3.600	19.688	404.003	-181.530
12-96	.011	2.839	.008	2.143	20.930	0.	3.600	17.330	421.333	-181.232
12-97	.010	2.565	.008	1.937	18.912	0.	3.600	15.312	436.645	-181.030
12-98	.009	2.330	.007	1.759	17.177	0.	3.600	13.577	450.222	-180.892
12-99	.008	2.124	.006	1.603	15.651	0.	3.600	12.051	462.273	-180.798
12- 0	.007	1.946	.005	1.470	14.327	0.	3.600	10.727	473.000	-180.733
S TOT	.682	177.430 [1]	.515	133.960	1010.140	475.400	61.740	473.000	473.000	-180.733
AFTER	.087	22.570	.066	17.040	166.378	0.	89.033	77.345	550.345	-180.592
TOTAL	.769	200.000	.581	151.000	1176.518	475.400	150.773	550.345	550.345	-180.592
CUM.	0.	0.								
ULT.	.769	200.000								

NET OIL REVENUE	20.762	5 PCT	258.352	40 PCT	-240.579
NET GAS REVENUE	1155.756	10 PCT	94.204	50 PCT	-281.556
NET PROD REVENUE	0.	15 PCT	-11.106	60 PCT	-311.255
		20 PCT	-84.587	80 PCT	-351.240
CUM NET INC/INV(1)	1.16	CUM NET PW/INV(1)	-.38	30 PCT	-180.592	100 PCT	-376.733
GROSS WELLS	1	LIFE (YEARS)	44.73				
MONTHS 1ST YEAR	12	RATE OF RETURN,PCT	14.47				
INITIAL W.I., PCT	100.0000	INITIAL N.I., PCT	75.5000				

1 - 20-year total does not precisely match heading due to computer scheduling technique.

TYPICAL WELL
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO

CONSOLIDATED OIL & GAS, INC.
ECONOMICS OF DEVELOPMENT

SECTION 103 PRICE
270 MMCF GROSS
20-YEAR RECOVERY

DATE: 09/23/81.
TIME: 17.30.35.
FILE: TYPICAL
PROJ: 3

R E S E R V E S A N D E C O N O M I C S

AS OF DATE : 1/ 1/1981

END MO-YR	GROSS OIL PRODUCTION ----MB----	GROSS GAS PRODUCTION -----MMF---	OIL TO NET INTEREST ----MB----	GAS TO NET INTEREST ----MMF---	REVENUE TO INTEREST ----M$----	NET INVESTMENT ----M$----	NET OPER EXPENSES ----M$----	NET INCOME BEFORE FIT ----M$----	CUMULATIVE NET INCOME ----M$----	30.000 PCT CUM. DISC NET INCOME ----M$----
12-81	0.	0.	0.	0.	0.	475.400	1.863	-477.263	-477.263	-476.914
12-82	.224	58.192	.169	43.935	131.610	0.	1.993	129.617	-347.646	-389.216
12-83	.158	41.084	.119	31.018	99.406	0.	2.133	97.273	-250.373	-338.589
12-84	.117	30.554	.089	23.069	79.100	0.	2.283	76.817	-173.556	-307.835
12-85	.091	23.613	.068	17.827	65.431	0.	2.442	62.989	-110.567	-288.437
12-86	.072	18.795	.055	14.191	55.721	0.	2.613	53.108	-57.459	-275.856
12-87	.059	15.316	.044	11.563	48.601	0.	2.795	45.806	-11.653	-267.509
12-88	.049	12.720	.037	9.604	43.209	0.	2.992	40.217	28.564	-261.871
12-89	.042	10.733	.032	8.103	39.026	0.	3.201	35.825	64.389	-258.008
12-90	.035	9.179	.026	6.930	35.654	0.	3.425	32.229	96.618	-255.335
12-91	.030	7.938	.023	5.994	32.924	0.	3.600	29.324	125.942	-253.464
12-92	.027	6.933	.021	5.234	30.732	0.	3.600	27.132	153.074	-252.132
12-93	.024	6.109	.018	4.612	28.925	0.	3.600	25.325	178.399	-251.176
12-94	.020	5.422	.015	4.094	27.372	0.	3.600	23.772	202.171	-250.486
12-95	.019	4.845	.014	3.658	26.166	0.	3.600	22.566	224.737	-249.982
12-96	.017	4.356	.013	3.289	25.129	0.	3.600	21.529	246.266	-249.612
12-97	.015	3.937	.011	2.972	24.251	0.	3.600	20.651	266.917	-249.339
12-98	.014	3.576	.011	2.700	23.549	0.	3.600	19.949	286.866	-249.136
12-99	.012	3.263	.009	2.464	22.934	0.	3.600	19.334	306.200	-248.985
12- 0	.012	2.988	.009	2.256	22.043	0.	3.600	18.443	324.643	-248.874
8 TOT	1.037	269.553[1]	.783	203.513	861.783	475.400	61.740	324.643	324.643	-248.874
AFTER	.117	30.447	.088	22.987	224.431	0.	69.214	155.217	479.860	-248.617
TOTAL	1.154	300.000	.871	226.500	1086.214	475.400	130.954	479.860	479.860	-248.617
CUM.	0.	0.								
ULT.	1.154	300.000								

NET OIL REVENUE	31.082	5 PCT	146.960	40 PCT	-295.589		
NET GAS REVENUE	1055.132	10 PCT	-14.819	50 PCT	-327.278		
NET PROD REVENUE	0.	15 PCT	-109.112	60 PCT	-350.113		
		20 PCT	-171.144	80 PCT	-380.745		
CUM NET INC/INV(1)	1.01	CUM NET PW/INV(1)	-.52	30 PCT	-248.617	100 PCT	-400.232
GROSS WELLS	1	LIFE (YEARS)	39.23				
MONTHS 1ST YEAR	12	RATE OF RETURN,PCT	9.54				
INITIAL W.I., PCT	100.0000	INITIAL N.I., PCT	75.5000				

1 - 20-year total does not precisely match heading due to computer scheduling technique.

TYPICAL WELL
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO

2X SECTION 103 PRICE
270 MMCF GROSS
20-YEAR RECOVERY

DATE: 09/23/81.
TIME: 17.30.38.
FILE: TYPICAL
PROJ: 4

CONSOLIDATED OIL & GAS, INC.
ECONOMICS OF DEVELOPMENT

R E S E R V E S A N D E C O N O M I C S

AS OF DATE : 1/ 1/1981

END MO-YR	GROSS OIL PRODUCTION ----MB----	GROSS GAS PRODUCTION ----MMF---	OIL TO NET INTEREST ----MB----	GAS TO NET INTEREST ----MMF---	REVENUE TO INTEREST ----M$----	NET INVESTMENT ----M$----	NET OPER EXPENSES ----M$----	NET INCOME BEFORE FIT ----M$----	CUMULATIVE NET INCOME ----M$----	30.000 PCT CUM. DISC NET INCOME ----M$----
12-81	0.	0.	0.	0.	0.	475.400	1.863	-477.263	-477.263	-476.914
12-82	.222	57.678	.168	43.547	256.452	0.	1.993	254.459	-222.804	-304.748
12-83	.155	40.339	.117	30.456	191.895	0.	2.133	189.762	-33.042	-205.984
12-84	.115	29.796	.086	22.496	151.683	0.	2.283	149.400	116.358	-146.172
12-85	.088	22.909	.067	17.296	124.784	0.	2.442	122.342	238.700	-108.495
12-86	.070	18.162	.053	13.712	105.865	0.	2.613	103.252	341.952	-84.035
12-87	.056	14.753	.042	11.139	91.994	0.	2.795	89.199	431.151	-67.780
12-88	.047	12.220	.036	9.226	81.572	0.	2.992	78.580	509.731	-56.765
12-89	.040	10.289	.030	7.768	73.497	0.	3.201	70.296	580.027	-49.186
12-90	.034	8.782	.025	6.631	64.728	0.	3.425	61.303	641.330	-44.101
12-91	.029	7.583	.022	5.725	55.890	0.	3.600	52.290	693.620	-40.765
12-92	.025	6.614	.019	4.993	48.739	0.	3.600	45.139	738.759	-38.549
12-93	.023	5.819	.018	4.394	42.915	0.	3.600	39.315	778.074	-37.065
12-94	.019	5.161	.014	3.896	38.014	0.	3.600	34.414	812.488	-36.066
12-95	.018	4.607	.013	3.479	33.969	0.	3.600	30.369	842.857	-35.387
12-96	.016	4.138	.013	3.124	30.506	0.	3.600	26.906	869.763	-34.925
12-97	.014	3.737	.010	2.821	27.533	0.	3.600	23.933	893.696	-34.609
12-98	.014	3.393	.011	2.562	25.044	0.	3.600	21.444	915.140	-34.391
12-99	.011	3.092	.008	2.334	22.761	0.	3.600	19.161	934.301	-34.241
12- 0	.011	2.832	.008	2.139	20.880	0.	3.600	17.280	951.581	-34.137
S TOT	1.007	261.904[1]	.760	197.738	1488.721	475.400	61.740	951.581	951.581	-34.137
AFTER	.147	38.096	.111	28.762	280.834	0.	124.582	156.252	1107.833	-33.900
TOTAL	1.154	300.000	.871	226.500	1769.555	475.400	186.322	1107.833	1107.833	-33.900
CUM.	0.	0.								
ULT.	1.154	300.000								

NET OIL REVENUE	31.254		5 PCT	633.782	40 PCT	-123.663
NET GAS REVENUE	1738.301		10 PCT	380.437	50 PCT	-184.942
NET PROD REVENUE	0.		15 PCT	220.726	60 PCT	-229.350
			20 PCT	110.076	80 PCT	-289.155
CUM NET INC/INV(1)	2.33	CUM NET PW/INV(1)	-.07	30 PCT	-33.900	100 PCT -327.305
GROSS WELLS	1	LIFE (YEARS)	54.61			
MONTHS 1ST YEAR	12	RATE OF RETURN,PCT	27.29			
INITIAL W.I., PCT	100.0000	INITIAL N.I., PCT	75.5000			

1 - 20-year total does not precisely match heading due to computer scheduling technique.

SECTION 103 PRICE
350 MMCF GROSS
20-YEAR RECOVERY

TYPICAL WELL
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO

DATE: 09/23/81.
TIME: 17.30.41.
FILE: TYPICAL
PROJ: 5

CONSOLIDATED OIL & GAS, INC.
ECONOMICS OF DEVELOPMENT

R E S E R V E S A N D E C O N O M I C S

AS OF DATE : 1/ 1/1981

END MO-YR	GROSS OIL PRODUCTION ----MB----	GROSS GAS PRODUCTION ----MMF---	OIL TO NET INTEREST ----MB----	GAS TO NET INTEREST ----MMF---	REVENUE TO INTEREST ----M$----	NET INVESTMENT ----M$----	NET OPER EXPENSES ----M$----	NET INCOME BEFORE FIT ----M$----	CUMULATIVE NET INCOME ----M$----	30.000 PCT CUM. DISC NET INCOME ----M$----
12-81	0.	0.	0.	0.	0.	475.400	1.863	-477.263	-477.263	-476.914
12-82	.297	77.258	.224	58.330	174.581	0.	1.993	172.588	-304.675	-360.141
12-83	.209	54.306	.158	41.001	131.290	0.	2.133	129.157	-175.518	-292.921
12-84	.155	40.258	.117	30.395	104.156	0.	2.283	101.873	-73.645	-252.135
12-85	.119	31.038	.090	23.433	85.921	0.	2.442	83.479	9.834	-226.427
12-86	.095	24.660	.072	19.619	73.066	0.	2.613	70.453	80.287	-209.737
12-87	.077	20.064	.058	15.148	63.609	0.	2.795	60.814	141.101	-198.655
12-88	.064	16.643	.048	12.565	56.498	0.	2.992	53.506	194.607	-191.155
12-89	.054	14.029	.041	10.592	50.966	0.	3.201	47.765	242.372	-186.004
12-90	.046	11.986	.035	9.050	46.565	0.	3.425	43.140	285.512	-182.426
12-91	.040	10.359	.030	7.821	42.995	0.	3.600	39.395	324.907	-179.913
12-92	.035	9.042	.026	6.826	40.073	0.	3.600	36.473	361.380	-178.123
12-93	.031	7.961	.024	6.011	37.684	0.	3.600	34.084	395.464	-176.836
12-94	.027	7.063	.020	5.333	35.689	0.	3.600	32.089	427.553	-175.904
12-95	.024	6.309	.018	4.763	34.048	0.	3.600	30.448	458.001	-175.224
12-96	.022	5.669	.017	4.280	32.699	0.	3.600	29.099	487.100	-174.724
12-97	.019	5.123	.014	3.868	31.538	0.	3.600	27.938	515.038	-174.354
12-98	.018	4.651	.014	3.511	30.621	0.	3.600	27.021	542.059	-174.080
12-99	.017	4.242	.012	3.203	29.864	0.	3.600	26.264	568.323	-173.874
12- 0	.015	3.884	.012	2.932	28.632	0.	3.600	25.032	593.355	-173.724
S TOT	1.364	354.545[1]	1.030	267.681	1130.495	475.400	61.740	593.355	593.355	-173.724
AFTER	.174	45.455	.131	34.319	335.035	0.	90.636	244.399	837.754	-173.368
TOTAL	1.538	400.000	1.161	302.000	1465.530	475.400	152.376	837.754	837.754	-173.368

CUM.	0.	0.	NET OIL REVENUE	40.964	5 PCT	361.477	40 PCT	-235.890
			NET GAS REVENUE	1424.566	10 PCT	139.915	50 PCT	-278.045
INT.	1.538	400.000	NET PROD REVENUE	0.	15 PCT	12.931	60 PCT	-308.418
					20 PCT	-70.066	80 PCT	-349.169
CUM NET INC/INV(1)		1.76	CUM NET PW/INV(1)	-.36	30 PCT	-173.368	100 PCT	-375.103
GROSS WELLS		1	LIFE (YEARS)	45.18				
MONTHS 1ST YEAR		12	RATE OF RETURN,PCT	15.78				
INITIAL W.I., PCT		100.0000	INITIAL N.I., PCT	75.5000				

1 - 20-year total does not precisely match heading due to computer scheduling technique.

2X SECTION 103 PRICE
350 MMCF GROSS
20-YEAR RECOVERY

TYPICAL WELL
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO

DATE: 09/23/81.
TIME: 17.30.45.
FILE: TYPICAL
PROJ: 6

CONSOLIDATED OIL & GAS, INC.
ECONOMICS OF DEVELOPMENT

R E S E R V E S A N D E C O N O M I C S

AS OF DATE : 1/ 1/1981

END MO-YR	GROSS OIL PRODUCTION ----MB----	GROSS GAS PRODUCTION ----MMF---	OIL TO NET INTEREST ----MB----	GAS TO NET INTEREST ----MMF---	REVENUE TO INTEREST ----M$----	NET INVESTMENT ----M$----	NET OPER EXPENSES ----M$----	NET INCOME BEFORE FIT ----M$----	CUMULATIVE NET INCOME ----M$----	30.000 PCT CUM. DISC NET INCOME ----M$----
12-81	0.	0.	0.	0.	0.	475.400	1.863	-477.263	-477.263	-476.914
12-82	.283	73.538	.214	55.521	326.833	0.	1.993	324.840	-152.423	-257.128
12-83	.200	52.083	.151	39.323	247.654	0.	2.133	245.521	73.098	-129.345
12-84	.149	38.822	.112	29.310	197.531	0.	2.283	195.248	288.346	-51.177
12-85	.116	30.053	.088	22.690	163.643	0.	2.442	161.201	449.547	-1.532
12-86	.092	23.955	.069	18.087	139.567	0.	2.613	136.954	586.501	30.911
12-87	.075	19.540	.057	14.752	121.819	0.	2.795	119.024	705.525	52.601
12-88	.063	16.245	.047	12.265	108.423	0.	2.992	105.431	810.956	67.379
12-89	.053	13.716	.040	10.356	97.952	0.	3.201	94.751	905.707	77.596
12-90	.045	11.737	.034	8.861	86.490	0.	3.425	83.065	988.772	84.486
12-91	.039	10.157	.030	7.669	74.868	0.	3.600	71.268	1060.040	89.033
12-92	.034	8.875	.025	6.700	65.416	0.	3.600	61.816	1121.856	92.067
12-93	.030	7.823	.023	5.907	57.663	0.	3.600	54.063	1175.919	94.108
12-94	.027	6.946	.021	5.244	51.210	0.	3.600	47.610	1223.529	95.491
12-95	.024	6.209	.018	4.688	45.773	0.	3.600	42.173	1265.702	96.433
12-96	.021	5.584	.016	4.216	41.145	0.	3.600	37.545	1303.247	97.078
12-97	.020	5.048	.015	3.811	37.231	0.	3.600	33.631	1336.878	97.522
12-98	.017	4.587	.012	3.463	33.789	0.	3.600	30.189	1367.067	97.829
12-99	.016	4.185	.013	3.160	30.846	0.	3.600	27.246	1394.313	98.042
12- 0	.015	3.834	.011	2.894	28.270	0.	3.600	24.670	1418.983	98.191
S TOT	1.319	342.937[1]	.996	258.917	1956.123	475.400	61.740	1418.983	1418.983	98.191
AFTER	.219	57.063	.165	43.083	420.613	0.	160.323	260.290	1679.273	98.537
TOTAL	1.538	400.000	1.161	302.000	2376.736	475.400	222.063	1679.273	1679.273	98.537
CUM.	0.	0.								
ULT.	1.538	400.000								

CUM NET INC/INV(1)	3.53	CUM NET PW/INV(1)	.21
GROSS WELLS	1	LIFE (YEARS)	64.53
MONTHS 1ST YEAR	12	RATE OF RETURN,PCT	38.16
INITIAL W.I., PCT	100.0000	INITIAL N.I., PCT	75.5000

NET OIL REVENUE	41.457	5 PCT	997.174	40 PCT	-19.365
NET GAS REVENUE	2335.279	10 PCT	650.840	50 PCT	-99.512
NET PROD REVENUE	0.	15 PCT	436.263	60 PCT	-157.417
		20 PCT	288.890	80 PCT	-235.160
		30 PCT	98.537	100 PCT	-284.608

1 - 20-year total does not precisely match heading due to computer scheduling technique.

TYPICAL WELL
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO

CONSOLIDATED OIL & GAS, INC.
ECONOMICS OF DEVELOPMENT

SECTION 103 PRICE
435 MMCF GROSS
20-YEAR RECOVERY

DATE: 09/23/81.
TIME: 17.30.49.
FILE: TYPICAL
PROJ: 7

R E S E R V E S A N D E C O N O M I C S

AS OF DATE : 1/ 1/1981

END MO-YR	GROSS OIL PRODUCTION ----MB----	GROSS GAS PRODUCTION ----MMF---	OIL TO NET INTEREST ----MB----	GAS TO NET INTEREST ----MMF---	REVENUE TO INTEREST ----M$----	NET INVESTMENT ----M$----	NET OPER EXPENSES ----M$----	NET INCOME BEFORE FIT ----M$----	CUMULATIVE NET INCOME ----M$----	30.000 PCT CUM. DISC NET INCOME ----M$----
12-81	0.	0.	0.	0.	0.	475.400	1.863	-477.263	-477.263	-476.914
12-82	.370	96.303	.279	72.709	217.790	0.	1.993	215.797	-261.466	-330.906
12-83	.260	67.487	.197	50.952	163.300	0.	2.133	161.167	-100.299	-247.026
12-84	.192	49.922	.145	37.692	129.260	0.	2.283	126.977	26.678	-196.190
12-85	.148	38.424	.111	29.010	106.470	0.	2.442	104.028	130.706	-164.153
12-86	.117	30.489	.089	23.019	90.395	0.	2.613	87.782	218.488	-143.358
12-87	.095	24.782	.071	18.710	78.625	0.	2.795	75.830	294.318	-129.540
12-88	.079	20.540	.060	15.508	69.770	0.	2.992	66.778	361.096	-120.179
12-89	.067	17.301	.051	13.062	62.884	0.	3.201	59.683	420.779	-113.744
12-90	.057	14.772	.043	11.153	57.403	0.	3.425	53.978	474.757	-109.267
12-91	.049	12.760	.037	9.634	52.950	0.	3.600	49.350	524.107	-106.118
12-92	.043	11.134	.032	8.406	49.342	0.	3.600	45.742	569.849	-103.873
12-93	.037	9.798	.028	7.398	46.339	0.	3.600	42.739	612.588	-102.259
12-94	.034	8.691	.026	6.561	43.942	0.	3.600	40.342	652.930	-101.088
12-95	.030	7.760	.022	5.859	41.895	0.	3.600	38.295	691.225	-100.232
12-96	.026	6.972	.020	5.264	40.178	0.	3.600	36.578	727.803	-99.604
12-97	.025	6.297	.019	4.754	38.823	0.	3.600	35.223	763.026	-99.138
12-98	.022	5.717	.017	4.316	37.635	0.	3.600	34.035	797.061	-98.792
12-99	.020	5.213	.015	3.936	36.668	0.	3.600	33.068	830.129	-98.533
12- 0	.018	4.772	.013	3.603	35.164	0.	3.600	31.564	861.693	-98.344
S TOT	1.689	439.134[1]	1.275	331.546	1398.833	475.400	61.740	861.693	861.693	-98.344
AFTER	.234	60.866	.177	45.954	448.659	0.	109.498	339.161	1200.854	-97.891
TOTAL	1.923	500.000	1.452	377.500	1847.492	475.400	171.238	1200.854	1200.854	-97.891

CUM.	0.	0.	NET OIL REVENUE	52.021	5 PCT	575.870	40 PCT -175.980
			NET GAS REVENUE	1795.471	10 PCT	294.632	50 PCT -228.623
ULT.	1.923	500.000	NET PROD REVENUE	0.	15 PCT	135.124	60 PCT -266.554
					20 PCT	31.225	80 PCT -317.455
CUM NET INC/INV(1)		2.53	CUM NET PW/INV(1)	-.21	30 PCT	-97.891	100 PCT -349.859
GROSS WELLS		1	LIFE (YEARS)	50.42			
MONTHS 1ST YEAR		12	RATE OF RETURN,PCT	22.12			
INITIAL W.I., PCT		100.0000	INITIAL N.I., PCT	75.5000			

1 - 20-year total does not precisely match heading due to computer scheduling technique.

TYPICAL WELL
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO

2X SECTION 103 PRICE
435 MMCF GROSS
20-YEAR RECOVERY

DATE: 09/23/81.
TIME: 17.30.52.
FILE: TYPICAL
PROJ: 8

CONSOLIDATED OIL & GAS, INC.
ECONOMICS OF DEVELOPMENT

R E S E R V E S A N D E C O N O M I C S

AS OF DATE : 1/ 1/1981

END NO-YR	GROSS OIL PRODUCTION ----MB----	GROSS GAS PRODUCTION ----MMF---	OIL TO NET INTEREST ----MB----	GAS TO NET INTEREST ----MMF---	REVENUE TO INTEREST ----M$----	NET INVESTMENT ----M$----	NET OPER EXPENSES ----M$----	NET INCOME BEFORE FIT ----M$----	CUMULATIVE NET INCOME ----M$----	30.000 PCT CUM. DISC NET INCOME ----M$----
12-81	0.	0.	0.	0.	0.	475.400	1.863	-477.263	-477.263	-476.914
12-82	.353	91.757	.267	69.277	409.246	0.	1.993	407.253	-70.010	-201.368
12-83	.249	64.844	.188	48.957	309.444	0.	2.133	307.311	237.301	-41.425
12-84	.186	48.257	.140	36.434	246.428	0.	2.283	244.145	481.446	56.319
12-85	.143	37.313	.108	28.171	203.855	0.	2.442	201.413	682.859	118.347
12-86	.115	29.712	.087	22.433	173.727	0.	2.613	171.114	853.973	158.883
12-87	.093	24.220	.070	18.286	151.503	0.	2.795	148.708	1002.681	185.982
12-88	.077	20.121	.058	15.191	134.609	0.	2.992	131.617	1134.298	204.431
12-89	.066	16.982	.050	12.822	121.439	0.	3.201	118.238	1252.536	217.180
12-90	.055	14.524	.041	10.965	107.031	0.	3.425	103.606	1356.142	225.774
12-91	.049	12.564	.037	9.486	92.637	0.	3.600	89.037	1445.179	231.455
12-92	.042	10.975	.032	8.286	80.892	0.	3.600	77.292	1522.471	235.248
12-93	.037	9.671	.028	7.302	71.281	0.	3.600	67.681	1590.152	237.803
12-94	.033	8.584	.025	6.481	63.275	0.	3.600	59.675	1649.827	239.536
12-95	.030	7.673	.023	5.793	56.577	0.	3.600	52.977	1702.804	240.720
12-96	.026	6.898	.019	5.208	50.829	0.	3.600	47.229	1750.033	241.531
12-97	.024	6.236	.018	4.708	45.968	0.	3.600	42.368	1792.401	242.091
12-98	.022	5.663	.017	4.275	41.751	0.	3.600	38.151	1830.552	242.479
12-99	.020	5.168	.015	3.902	38.100	0.	3.600	34.500	1865.052	242.749
12- 0	.018	4.733	.014	3.574	34.881	0.	3.600	31.281	1896.333	242.937
S TOT	1.638	425.895[1]	1.237	321.551	2433.473	475.400	61.740	1896.333	1896.333	242.937
AFTER	.285	74.105	.215	55.949	546.250	0.	187.387	358.863	2255.196	243.380
TOTAL	1.923	500.000	1.452	377.500	2979.723	475.400	249.127	2255.196	2255.196	243.380
CUM.	0.	0.								
ULT.	1.923	500.000								

NET OIL REVENUE	57.663	5 PCT	1371.533	40 PCT	95.869
NET GAS REVENUE	2922.060	10 PCT	935.092	50 PCT	-4.419
NET PROD REVENUE	0.	15 PCT	666.069	60 PCT	-76.891
		20 PCT	481.561	80 PCT	-174.221
		30 PCT	243.380	100 PCT	-236.149

CUM NET INC/INV(1)	4.74	CUM NET PW/INV(1)	.51
GROSS WELLS	1	LIFE (YEARS)	72.05
MONTHS 1ST YEAR	12	RATE OF RETURN,PCT	49.52
INITIAL W.I., PCT	100.0000	INITIAL N.I., PCT	75.5000

1 - 20-year total does not precisely match heading due to computer scheduling technique.

TYPICAL WELL
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO

CONSOLIDATED OIL & GAS, INC.
ECONOMICS OF DEVELOPMENT

SECTION 103 PRICE
555 MMCF GROSS
20-YEAR RECOVERY

RESERVES AND ECONOMICS

AS OF DATE : 1/ 1/1981

DATE: 09/23/81.
TIME: 17.30.56.
FILE: TYPICAL
PROJ: 9

END MO-YR	GROSS OIL PRODUCTION ----MB----	GROSS GAS PRODUCTION ----MMF---	OIL TO NET INTEREST ----MB----	GAS TO NET INTEREST ----MMF---	REVENUE TO INTEREST ----M$----	NET INVESTMENT ----M$----	NET OPER EXPENSES ----M$----	NET INCOME BEFORE FIT ----M$----	CUMULATIVE NET INCOME ----M$----	30.000 PCT CUM. DISC NET INCOME ----M$----
12-81	0.	0.	0.	0.	0.	475.400	1.863	-477.263	-477.263	-476.914
12-82	.460	119.706	.347	90.378	270.718	0.	1.993	268.725	-208.538	-295.095
12-83	.327	84.952	.247	64.139	205.554	0.	2.133	203.421	-5.117	-189.223
12-84	.244	63.416	.184	47.879	164.201	0.	2.283	161.918	156.801	-124.399
12-85	.189	49.148	.143	37.107	136.179	0.	2.442	133.737	290.538	-83.213
12-86	.151	39.208	.114	29.602	116.260	0.	2.613	113.647	404.185	-56.290
12-87	.123	32.006	.093	24.164	101.552	0.	2.795	98.757	502.942	-38.294
12-88	.102	26.622	.077	20.100	90.417	0.	2.992	87.425	590.367	-26.039
12-89	.087	22.492	.066	16.981	81.749	0.	3.201	78.548	668.915	-17.570
12-90	.074	19.252	.056	14.536	74.802	0.	3.425	71.377	740.292	-11.649
12-91	.064	16.666	.048	12.582	69.159	0.	3.600	65.559	805.851	-7.467
12-92	.056	14.569	.042	11.000	64.555	0.	3.600	60.955	866.806	-4.475
12-93	.049	12.843	.037	9.696	60.758	0.	3.600	57.158	923.964	-2.317
12-94	.044	11.408	.033	8.613	57.658	0.	3.600	54.058	978.022	-.747
12-95	.040	10.199	.031	7.701	55.083	0.	3.600	51.483	1029.505	.403
12-96	.035	9.174	.026	6.926	52.894	0.	3.600	49.294	1078.799	1.250
12-97	.032	8.296	.024	6.264	51.115	0.	3.600	47.515	1126.314	1.878
12-98	.029	7.538	.022	5.691	49.622	0.	3.600	46.022	1172.336	2.346
12-99	.026	6.879	.020	5.193	48.374	0.	3.600	44.774	1217.110	2.696
12- 0	.024	6.303	.018	4.759	46.453	0.	3.600	42.853	1259.963	2.954
8 TOT	2.156	560.677 [1]	1.628	423.311	1797.103	475.400	61.740	1259.963	1259.963	2.954
AFTER	.344	89.323	.259	67.439	658.443	0.	139.802	518.641	1778.604	3.575
TOTAL	2.500	650.000	1.887	490.750	2455.546	475.400	201.542	1778.604	1778.604	3.575

CUM.	0.	0.	NET OIL REVENUE	68.204	5 PCT	892.206	40 PCT	-96.579
			NET GAS REVENUE	2387.342	10 PCT	515.278	50 PCT	-163.706
ULT.	2.500	650.000	NET PROD REVENUE	0.	15 PCT	305.641	60 PCT	-212.055
					20 PCT	170.362	80 PCT	-276.622
CUM NET INC/INV(1)		3.74	CUM NET PW/INV(1)	.01	30 PCT	3.575	100 PCT	-317.602
GROSS WELLS		1	LIFE (YEARS)	58.83				
MONTHS 1ST YEAR		12	RATE OF RETURN,PCT	30.32				
INITIAL W.I., PCT		100.0000	INITIAL N.I., PCT	75.5000				

1 - 20-year total does not precisely match heading due to computer scheduling technique.

2X SECTION 103 PRICE
555 MMCF GROSS
20-YEAR RECOVERY

TYPICAL WELL
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO

DATE: 09/23/81.
TIME: 17.30.59.
FILE: TYPICAL
PROJ: 10

CONSOLIDATED OIL & GAS, INC.
ECONOMICS OF DEVELOPMENT

R E S E R V E S A N D E C O N O M I C S

AS OF DATE : 1/ 1/1981

END MO-YR	GROSS OIL PRODUCTION ----MB----	GROSS GAS PRODUCTION ----MMF---	OIL TO NET INTEREST ----MB----	GAS TO NET INTEREST ----MMF---	REVENUE TO INTEREST ----M$----	NET INVESTMENT ----M$----	NET OPER EXPENSES ----M$----	NET INCOME BEFORE FIT ----M$----	CUMULATIVE NET INCOME ----M$----	30.000 PCT CUM. DISC NET INCOME ----M$----
12-81	0.	0.	0.	0.	0.	475.400	1.863	-477.263	-477.263	-476.914
12-82	.458	119.067	.346	89.896	529.399	0.	1.993	527.406	50.143	-120.073
12-83	.323	83.950	.244	63.382	399.364	0.	2.133	397.231	447.374	86.670
12-84	.240	62.373	.181	47.091	317.507	0.	2.283	315.224	762.598	212.871
12-85	.185	48.167	.140	36.367	262.362	0.	2.442	259.920	1022.518	292.917
12-86	.147	38.317	.111	28.929	223.328	0.	2.613	220.715	1243.233	345.203
12-87	.120	31.210	.090	23.563	194.657	0.	2.795	191.862	1435.095	380.165
12-88	.100	25.912	.076	19.564	172.981	0.	2.992	169.989	1605.084	403.994
12-89	.084	21.856	.063	16.501	156.091	0.	3.201	152.890	1757.974	420.479
12-90	.072	18.695	.054	14.107	137.706	0.	3.425	134.281	1892.255	431.617
12-91	.062	16.157	.047	12.199	119.094	0.	3.600	115.494	2007.749	438.986
12-92	.054	14.109	.041	10.652	103.992	0.	3.600	100.392	2108.141	443.913
12-93	.048	12.428	.036	9.383	91.618	0.	3.600	88.018	2196.159	447.236
12-94	.043	11.029	.033	8.327	81.318	0.	3.600	77.718	2273.877	449.493
12-95	.038	9.856	.028	7.442	72.655	0.	3.600	69.055	2342.932	451.035
12-96	.034	8.858	.026	6.687	65.293	0.	3.600	61.693	2404.625	452.096
12-97	.030	8.007	.023	6.046	58.994	0.	3.600	55.394	2460.019	452.828
12-98	.028	7.271	.021	5.489	53.598	0.	3.600	49.998	2510.017	453.336
12-99	.026	6.632	.019	5.007	48.904	0.	3.600	45.304	2555.321	453.691
12- 0	.023	6.075	.018	4.587	44.768	0.	3.600	41.168	2596.489	453.938
S TOT	2.115	549.959 [1]	1.597	415.219	3133.629	475.400	61.740	2596.489	2596.489	453.938
AFTER	.385	100.041	.290	75.531	737.441	0.	223.311	514.130	3110.619	454.526
TOTAL	2.500	650.000	1.887	490.750	3871.070	475.400	285.051	3110.619	3110.619	454.526
CUM.	0.	0.								
ULT.	2.500	650.000								

NET OIL REVENUE	68.442	5 PCT	1919.652	40 PCT	263.782
NET GAS REVENUE	3802.628	10 PCT	1350.602	50 PCT	134.117
NET PROD REVENUE	0.	15 PCT	1001.633	60 PCT	40.412
		20 PCT	762.682	80 PCT	-85.451
CUM NET PW/INV(1)	.96	30 PCT	454.526	100 PCT	-165.556
LIFE (YEARS)	82.03				
RATE OF RETURN,PCT	65.71				
INITIAL N.I., PCT	75.5000				

CUM NET INC/INV(1)	6.54
GROSS WELLS	1
MONTHS 1ST YEAR	12
INITIAL W.I., PCT	100.0000

1 - 20-year total does not precisely match heading due to computer scheduling technique.

EXHIBIT 13

AFTER TAX ECONOMICS

EXHIBIT 13

SECTION 103 PRICE
180 MMCF GROSS
20-YEAR RECOVERY

TYPICAL WELL
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO

CONSOLIDATED OIL & GAS, INC.
ECONOMICS OF DEVELOPMENT

DATE: 09/23/81.
TIME: 17.31.54.
FILE: TYPICAL
PROJ: 1

A F T E R T A X E C O N O M I C S

AS OF DATE: 1/ 1/1981

-END- MO-YR	NET OIL MB	NET GAS MMF	REVENUE TO INT. M$	OPER. EXPENSE M$	NET INCOME M$	CAPITAL INVEST. M$	DEPR. M$	DEPL. M$	INCOME TAX M$	CASH FLOW M$	CUM. NET PW M$
12-81	0.	0.	0.	1.863	-1.863	475.400	52.965	0.	-73.290	-403.972	-412.448
12-82	.119	30.772	92.183	1.993	90.190	0.	45.401	0.	20.603	69.587	-365.366
12-83	.082	21.531	68.987	2.133	66.854	0.	38.918	0.	12.851	54.003	-337.259
12-84	.061	15.910	54.559	2.283	52.276	0.	33.360	0.	8.701	43.575	-319.814
12-85	.048	12.235	44.920	2.442	42.478	0.	28.597	0.	6.385	36.093	-308.698
12-86	.037	9.702	38.090	2.613	35.477	0.	24.513	0.	5.043	30.434	-301.489
12-87	.030	7.881	33.119	2.795	30.324	0.	21.013	0.	4.283	26.041	-296.744
12-88	.025	6.530	29.401	2.992	26.409	0.	18.012	0.	3.863	22.546	-293.583
12-89	.022	5.499	26.465	3.201	23.264	0.	15.440	0.	3.599	19.665	-291.463
12-90	.018	4.693	24.156	3.425	20.731	0.	13.235	0.	3.448	17.283	-290.029
12-91	.015	4.053	22.254	3.600	18.654	0.	11.345	0.	3.362	15.292	-289.054
12-92	.013	3.536	20.750	3.600	17.150	0.	9.725	0.	3.416	13.734	-288.380
12-93	.012	3.110	19.501	3.600	15.901	0.	8.336	0.	3.480	12.421	-287.911
12-94	.011	2.759	18.465	3.600	14.865	0.	7.146	0.	3.551	11.314	-287.582
12-95	.010	2.463	17.624	3.600	14.024	0.	6.125	0.	3.633	10.391	-287.350
12-96	.008	2.212	16.887	3.600	13.287	0.	5.251	0.	3.697	9.590	-287.185
12-97	.008	1.999	16.302	3.600	12.702	0.	4.501	0.	3.773	8.929	-287.067
12-98	.006	1.813	15.804	3.600	12.204	0.	3.858	0.	3.839	8.365	-286.992
12-99	.007	1.654	15.433	3.600	11.833	0.	3.307	0.	3.922	7.911	-286.920
12- 0	.006	1.514	14.789	3.600	11.189	0.	2.835	0.	3.843	7.346	-286.876
S TOT	.538	139.866	589.689	61.740	527.949	475.400	353.882	0.	32.002	20.548	-286.876
AFTER	.043	11.134	108.680	40.932	67.748	0.	17.018	0.	23.336	44.412	-286.782
TOTAL	.581	151.000	698.369	102.672	595.697	475.400	370.900	0.	55.338	64.960	-286.782

RECAP

	GROSS	W.I.	NET
INTEREST FRACTION	1.000000	1.000000	.755000
OIL RESERVES,MB	.769	.769	.581
GAS RESERVES,MMCF	200.000	200.000	151.000
PRODUCTS	0.	0.	0.
REVENUE,M$	1008.627	1008.627	698.369
OPERATING EXPENSE,M$	102.672	102.672	102.672
TANGIBLES,M$	370.900	370.900	370.900
INTANGIBLES,M$	104.500	104.500	104.500
INITIAL OIL PRICE ($/B)		34.00	
INITIAL GAS PRICE ($/M)		3.1452	

LIFE (YEARS)	31.37
GROSS OIL WELLS	0.
GROSS GAS WELLS	1.000
RATE OF RETURN,PCT	2.25
DISCOUNT RATE,PCT	30.0
PAYOUT YEARS	17.37
W.I. BEFORE PAYOUT,PCT	100.00
W.I. AFTER PAYOUT,PCT	100.00

DIS PCT	PW OF NET M$
5	-79.359
10	-158.457
15	-208.077
20	-242.269
30	-286.783
40	-314.844
50	-334.330
70	-359.835
100	-381.946

TYPICAL WELL
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO

CONSOLIDATED OIL & GAS, INC.
ECONOMICS OF DEVELOPMENT

2X SECTION 103 PRICE
180 MMCF GROSS
20-YEAR RECOVERY

DATE: 09/23/81.
TIME: 17.31.57.
FILE: TYPICAL
PROJ: 2

A F T E R T A X E C O N O M I C S

AS OF DATE: 1/ 1/1981

-END- YR	NET OIL MB	NET GAS MMF	REVENUE TO INT. M$	OPER. EXPENSE M$	NET INCOME M$	CAPITAL INVEST. M$	DEPR. M$	DEPL. M$	INCOME TAX M$	CASH FLOW M$	CUM. NET PW M$
12-81	0.	0.	0.	1.863	-1.863	475.400	52.965	0.	-73.290	-403.972	-412.448
12-82	.112	29.173	171.810	1.993	169.817	0.	45.401	0.	57.231	112.586	-336.273
12-83	.079	20.512	129.231	2.133	127.098	0.	38.918	0.	40.563	86.535	-291.235
12-84	.059	15.210	102.558	2.283	100.275	0.	33.360	0.	30.781	69.494	-263.413
12-85	.044	11.727	84.591	2.442	82.149	0.	28.597	0.	24.634	57.515	-245.700
12-86	.037	9.319	71.957	2.613	69.344	0.	24.513	0.	20.622	48.722	-234.158
12-87	.028	7.582	62.621	2.795	59.826	0.	21.013	0.	17.854	41.972	-226.510
12-88	.025	6.291	55.618	2.992	52.626	0.	18.012	0.	15.922	36.704	-221.365
12-89	.020	5.303	50.164	3.201	46.963	0.	15.440	0.	14.501	32.462	-217.865
12-90	.018	4.531	44.256	3.425	40.831	0.	13.235	0.	12.694	28.137	-215.531
12-91	.015	3.916	38.237	3.600	34.637	0.	11.345	0.	10.714	23.923	-214.004
12-92	.013	3.418	33.356	3.600	29.756	0.	9.725	0.	9.214	20.542	-212.996
12-93	.011	3.009	29.370	3.600	25.770	0.	8.336	0.	8.020	17.750	-212.326
12-94	.011	2.671	26.086	3.600	22.486	0.	7.146	0.	7.056	15.430	-211.878
12-95	.009	2.386	23.288	3.600	19.688	0.	6.125	0.	6.239	13.449	-211.578
12-96	.008	2.143	20.930	3.600	17.330	0.	5.251	0.	5.556	11.774	-211.375
12-97	.008	1.937	18.912	3.600	15.312	0.	4.501	0.	4.973	10.339	-211.239
12-98	.007	1.759	17.177	3.600	13.577	0.	3.858	0.	4.471	9.106	-211.146
12-99	.006	1.603	15.651	3.600	12.051	0.	3.307	0.	4.022	8.029	-211.083
12- 0	.005	1.470	14.327	3.600	10.727	0.	2.835	0.	3.630	7.097	-211.041
S TOT	.515	133.960	1010.140	61.740	948.400	475.400	353.882	0.	225.407	247.592	-211.041
AFTER	.066	17.040	166.378	89.033	77.345	0.	17.018	0.	27.751	49.594	-210.949
TOTAL	.581	151.000	1176.518	150.773	1025.745	475.400	370.900	0.	253.158	297.186	-210.949

RECAP

	GROSS	W.I.	NET
INTEREST FRACTION	1.000000	1.000000	.755000
OIL RESERVES,MB	.769	.769	.581
GAS RESERVES,MMCF	200.000	200.000	151.000
PRODUCTS	0.	0.	0.
REVENUE,M$	1696.859	1696.859	1176.518
OPERATING EXPENSE,M$	150.773	150.773	150.773
TANGIBLES,M$	370.900	370.900	370.900
INTANGIBLES,M$	104.500	104.500	104.500

INITIAL OIL PRICE ($/B) 34.00
INITIAL GAS PRICE ($/M) 6.2903

LIFE (YEARS)	44.73
GROSS OIL WELLS	0.
GROSS GAS WELLS	1.000
RATE OF RETURN,PCT	9.27
DISCOUNT RATE,PCT	30.0
PAYOUT YEARS	6.69
W.I. BEFORE PAYOUT,PCT	100.00
W.I. AFTER PAYOUT,PCT	100.00

DIS PCT	PW OF NET M$
5	97.269
10	-16.656
15	-90.483
20	-142.414
30	-210.950
40	-254.345
50	-284.378
70	-323.334
100	-356.535

TYPICAL WELL
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO

CONSOLIDATED OIL & GAS, INC.
ECONOMICS OF DEVELOPMENT

SECTION 103 PRICE
270 MMCF GROSS
20-YEAR RECOVERY

DATE: 09/23/81.
TIME: 17.32.00.
FILE: TYPICAL
PROJ: 3

A F T E R T A X E C O N O M I C S

AS OF DATE: 1/ 1/1981

-END- MO-YR	NET OIL MB	NET GAS MMF	REVENUE TO INT. M$	OPER. EXPENSE M$	NET INCOME M$	CAPITAL INVEST. M$	DEPR. M$	DEPL. M$	INCOME TAX M$	CASH FLOW M$	CUM. NET PW M$
12-81	0.	0.	0.	1.863	-1.863	475.400	52.965	0.	-73.290	-403.972	-412.448
12-82	.169	43.935	131.610	1.993	129.617	0.	45.401	0.	38.739	90.878	-350.960
12-83	.119	31.018	99.406	2.133	97.273	0.	38.918	0.	26.843	70.430	-314.305
12-84	.089	23.069	79.100	2.283	76.817	0.	33.360	0.	19.990	56.827	-291.554
12-85	.068	17.827	65.431	2.442	62.989	0.	28.597	0.	15.821	47.168	-277.028
12-86	.055	14.191	55.721	2.613	53.108	0.	24.513	0.	13.154	39.954	-267.563
12-87	.044	11.563	48.601	2.795	45.806	0.	21.013	0.	11.405	34.401	-261.294
12-88	.037	9.604	43.209	2.992	40.217	0.	18.012	0.	10.214	30.003	-257.088
12-89	.032	8.103	39.026	3.201	35.825	0.	15.440	0.	9.377	26.448	-254.236
12-90	.026	6.930	35.654	3.425	32.229	0.	13.235	0.	8.737	23.492	-252.288
12-91	.023	5.994	32.924	3.600	29.324	0.	11.345	0.	8.270	21.054	-250.945
12-92	.021	5.234	30.732	3.600	27.132	0.	9.725	0.	8.007	19.125	-250.006
12-93	.018	4.612	28.925	3.600	25.325	0.	8.336	0.	7.815	17.510	-249.345
12-94	.015	4.094	27.372	3.600	23.772	0.	7.146	0.	7.648	16.124	-248.877
12-95	.014	3.658	26.166	3.600	22.566	0.	6.125	0.	7.563	15.003	-248.542
12-96	.013	3.289	25.129	3.600	21.529	0.	5.251	0.	7.488	14.041	-248.300
12-97	.011	2.972	24.251	3.600	20.651	0.	4.501	0.	7.429	13.222	-248.126
12-98	.011	2.700	23.549	3.600	19.949	0.	3.858	0.	7.402	12.547	-247.998
12-99	.009	2.464	22.934	3.600	19.334	0.	3.307	0.	7.372	11.962	-247.904
12- 0	.009	2.256	22.043	3.600	18.443	0.	2.835	0.	7.180	11.263	-247.837
S TOT	.783	203.513	861.783	61.740	800.043	475.400	353.882	0.	157.164	167.479	-247.837
AFTER	.088	22.987	224.431	69.214	155.217	0.	17.018	0.	63.572	91.645	-247.683
TOTAL	.871	226.500	1086.214	130.954	955.260	475.400	370.900	0.	220.736	259.124	-247.683

RECAP

	GROSS	W.I.	NET
INTEREST FRACTION	1.000000	1.000000	.755000
OIL RESERVES,MB	1.154	1.154	.871
GAS RESERVES,MMCF	300.000	300.000	226.500
PRODUCTS	0.	0.	0.
REVENUE,M$	1568.430	1568.430	1086.214
OPERATING EXPENSE,M$	130.954	130.954	130.954
TANGIBLES,M$	370.900	370.900	370.900
INTANGIBLES,M$	104.500	104.500	104.500

INITIAL OIL PRICE ($/B)	34.00
INITIAL GAS PRICE ($/M)	3.1452

LIFE (YEARS)	39.23
GROSS OIL WELLS	0.
GROSS GAS WELLS	1.000
RATE OF RETURN,PCT	6.65
DISCOUNT RATE,PCT	30.0
PAYOUT YEARS	9.33
W.I. BEFORE PAYOUT,PCT	100.00
W.I. AFTER PAYOUT,PCT	100.00

DIS PCT	PW OF NET M$
5	37.143
10	-75.519
15	-143.403
20	-189.154
30	-247.684
40	-284.050
50	-309.067
70	-341.487
100	-369.224

TYPICAL WELL
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO

CONSOLIDATED OIL & GAS, INC.
ECONOMICS OF DEVELOPMENT

2X SECTION 103 PRICE
270 MMCF GROSS
20-YEAR RECOVERY

DATE: 09/23/81.
TIME: 17.32.04.
FILE: TYPICAL
PROJ: 4

A F T E R T A X E C O N O M I C S

AS OF DATE: 1/ 1/1981

-END- MO-YR	NET OIL MB-----	NET GAS MMF-----	REVENUE TO INT. M$-----	OPER. EXPENSE M$-----	NET INCOME M$-----	CAPITAL INVEST. M$-----	DEPR. M$---	DEPL. M$----	INCOME TAX M$----	CASH FLOW M$-----	CUM. NET PW M$------
12-81	0.	0.	0.	1.863	-1.863	475.400	52.965	0.	-73.290	-403.972	-412.448
12-82	.168	43.547	256.452	1.993	254.459	0.	45.401	0.	96.167	158.292	-305.348
12-83	.117	30.456	191.895	2.133	189.762	0.	38.918	0.	69.388	120.374	-242.698
12-84	.086	22.496	151.683	2.283	149.400	0.	33.360	0.	53.378	96.022	-204.256
12-85	.067	17.296	124.784	2.442	122.342	0.	28.597	0.	43.123	79.219	-179.859
12-86	.053	13.712	105.865	2.613	103.252	0.	24.513	0.	36.220	67.032	-163.979
12-87	.042	11.139	91.994	2.795	89.199	0.	21.013	0.	31.366	57.833	-153.441
12-88	.036	9.226	81.572	2.992	78.580	0.	18.012	0.	27.861	50.719	-146.331
12-89	.030	7.768	73.497	3.201	70.296	0.	15.440	0.	25.234	45.062	-141.472
12-90	.025	6.631	64.728	3.425	61.303	0.	13.235	0.	22.111	39.192	-138.222
12-91	.022	5.725	55.890	3.600	52.290	0.	11.345	0.	18.835	33.455	-136.087
12-92	.019	4.993	48.739	3.600	45.139	0.	9.725	0.	16.290	28.849	-134.671
12-93	.018	4.394	42.915	3.600	39.315	0.	8.336	0.	14.250	25.065	-133.725
12-94	.014	3.896	38.014	3.600	34.414	0.	7.146	0.	12.543	21.871	-133.090
12-95	.013	3.479	33.969	3.600	30.369	0.	6.125	0.	11.152	19.217	-132.660
12-96	.013	3.124	30.506	3.600	26.906	0.	5.251	0.	9.961	16.945	-132.369
12-97	.010	2.821	27.533	3.600	23.933	0.	4.501	0.	8.939	14.994	-132.171
12-98	.011	2.562	25.044	3.600	21.444	0.	3.858	0.	8.089	13.355	-132.035
12-99	.008	2.334	22.761	3.600	19.161	0.	3.307	0.	7.293	11.868	-131.942
12- 0	.008	2.139	20.880	3.600	17.280	0.	2.835	0.	6.645	10.635	-131.878
S TOT	.760	197.738	1488.721	61.740	1426.981	475.400	353.882	0.	445.555	506.026	-131.878
AFTER	.111	28.762	280.834	124.582	156.252	0.	17.018	0.	64.049	92.204	-131.735
TOTAL	.871	226.500	1769.555	186.322	1583.233	475.400	370.900	0.	509.604	598.230	-131.735

RECAP

	GROSS	W.I.	NET
INTEREST FRACTION	1.000000	1.000000	.755000
OIL RESERVES,MB	1.154	1.154	.871
GAS RESERVES,MMCF	300.000	300.000	226.500
PRODUCTS	0.	0.	0.
REVENUE,M$	2552.111	2552.111	1769.555
OPERATING EXPENSE,M$	186.322	186.322	186.322
TANGIBLES,M$	370.900	370.900	370.900
INTANGIBLES,M$	104.500	104.500	104.500

INITIAL OIL PRICE ($/B)	34.00
INITIAL GAS PRICE ($/M)	6.2903

LIFE (YEARS)	54.61
GROSS OIL WELLS	0.
GROSS GAS WELLS	1.000
RATE OF RETURN,PCT	17.41
DISCOUNT RATE,PCT	30.0
PAYOUT YEARS	4.37
W.I. BEFORE PAYOUT,PCT	100.00
W.I. AFTER PAYOUT,PCT	100.00

DIS PCT	PW OF NET M$
5	299.962
10	137.897
15	34.703
20	-37.297
30	-131.736
40	-191.210
50	-232.206
70	-285.113
100	-329.844

TYPICAL WELL
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO

CONSOLIDATED OIL & GAS, INC.
ECONOMICS OF DEVELOPMENT

SECTION 103 PRICE
350 MMCF GROSS
20-YEAR RECOVERY

DATE: 09/23/81.
TIME: 17.32.07.
FILE: TYPICAL
PROJ: 5 -

A F T E R T A X E C O N O M I C S

AS OF DATE: 1/ 1/1981

-END- MO-YR	NET OIL MB	NET GAS MMF	REVENUE TO INT. M$	OPER. EXPENSE M$	NET INCOME M$	CAPITAL INVEST. M$	DEPR. M$	DEPL. M$	INCOME TAX M$	CASH FLOW M$	CUM. NET PW M$
12-81	0.	0.	0.	1.863	-1.863	475.400	52.965	0.	-73.290	-403.972	-412.448
12-82	.224	58.330	174.581	1.993	172.588	0.	45.401	0.	58.506	114.082	-335.260
12-83	.158	41.001	131.290	2.133	129.157	0.	38.918	0.	41.510	87.647	-289.644
12-84	.117	30.395	104.156	2.283	101.873	0.	33.360	0.	31.516	70.357	-261.476
12-85	.090	23.433	85.921	2.442	83.479	0.	28.597	0.	25.246	58.233	-243.542
12-86	.072	18.619	73.066	2.613	70.453	0.	24.513	0.	21.132	49.321	-231.859
12-87	.058	15.148	63.609	2.795	60.814	0.	21.013	0.	18.309	42.505	-224.113
12-88	.048	12.565	56.498	2.992	53.506	0.	18.012	0.	16.327	37.179	-218.901
12-89	.041	10.592	50.966	3.201	47.765	0.	15.440	0.	14.870	32.895	-215.354
12-90	.035	9.050	46.565	3.425	43.140	0.	13.235	0.	13.756	29.384	-212.917
12-91	.030	7.821	42.995	3.600	39.395	0.	11.345	0.	12.903	26.492	-211.227
12-92	.026	6.826	40.073	3.600	36.473	0.	9.725	0.	12.304	24.169	-210.041
12-93	.024	6.011	37.684	3.600	34.084	0.	8.336	0.	11.844	22.240	-209.201
12-94	.020	5.333	35.689	3.600	32.089	0.	7.146	0.	11.474	20.615	-208.602
12-95	.018	4.763	34.048	3.600	30.448	0.	6.125	0.	11.188	19.260	-208.172
12-96	.017	4.280	32.699	3.600	29.099	0.	5.251	0.	10.970	18.129	-207.861
12-97	.014	3.868	31.538	3.600	27.938	0.	4.501	0.	10.781	17.157	-207.634
12-98	.014	3.511	30.621	3.600	27.021	0.	3.858	0.	10.655	16.366	-207.467
12-99	.012	3.203	29.864	3.600	26.264	0.	3.307	0.	10.560	15.704	-207.345
12- 0	.012	2.932	28.632	3.600	25.032	0.	2.835	0.	10.211	14.821	-207.255
S TOT	1.030	267.681	1130.495	61.740	1068.755	475.400	353.882	0.	280.772	312.584	-207.255
AFTER	.131	34.319	335.035	90.636	244.399	0.	17.018	0.	104.597	139.804	-207.048
TOTAL	1.161	302.000	1465.530	152.376	1313.154	475.400	370.900	0.	385.369	452.387	-207.048

RECAP

	GROSS	W.I.	NET
INTEREST FRACTION	1.000000	1.000000	.755000
OIL RESERVES,MB	1.538	1.538	1.161
GAS RESERVES,MMCF	400.000	400.000	302.000
PRODUCTS	0.	0.	0.
REVENUE,M$	2116.810	2116.810	1465.530
OPERATING EXPENSE,M$	152.376	152.376	152.376
TANGIBLES,M$	370.900	370.900	370.900
INTANGIBLES,M$	104.500	104.500	104.500

INITIAL OIL PRICE ($/B)	34.00
INITIAL GAS PRICE ($/M)	3.1452

LIFE (YEARS)	45.18
GROSS OIL WELLS	0.
GROSS GAS WELLS	1.000
RATE OF RETURN,PCT	10.47
DISCOUNT RATE,PCT	30.0
PAYOUT YEARS	6.57
W.I. BEFORE PAYOUT,PCT	100.00
W.I. AFTER PAYOUT,PCT	100.00

DIS PCT	PW OF NET M$
5	152.955
10	8.027
15	-77.503
20	-134.573
30	-207.049
40	-251.813
50	-282.482
70	-322.042
100	-355.655

TYPICAL WELL
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO

CONSOLIDATED OIL & GAS, INC.
ECONOMICS OF DEVELOPMENT

2X SECTION 103 PRICE
350 MMCF GROSS
20-YEAR RECOVERY

DATE: 09/23/81.
TIME: 17.32.10.
FILE: TYPICAL
PROJ: 6

A F T E R T A X E C O N O M I C S

AS OF DATE: 1/ 1/1981

-END- MO-YR	NET OIL MB-----	NET GAS MMF-----	REVENUE TO INT. M$-----	OPER. EXPENSE M$-----	NET INCOME M$-----	CAPITAL INVEST. M$-----	DEPR. M$---	DEPL. M$----	INCOME TAX M$----	CASH FLOW M$-----	CUM. NET PW M$------
12-81	0.	0.	0.	1.863	-1.863	475.400	52.965	0.	-73.290	-403.972	-412.448
12-82	.214	55.521	326.833	1.993	324.840	0.	45.401	0.	128.542	196.298	-279.633
12-83	.151	39.323	247.654	2.133	245.521	0.	38.918	0.	95.037	150.484	-201.313
12-84	.112	29.310	197.531	2.283	195.248	0.	33.360	0.	74.468	120.780	-152.958
12-85	.088	22.690	163.643	2.442	161.201	0.	28.597	0.	60.998	100.203	-122.099
12-86	.069	18.087	139.567	2.613	136.954	0.	24.513	0.	51.723	85.231	-101.908
12-87	.057	14.752	121.819	2.795	119.024	0.	21.013	0.	45.085	73.939	-88.435
12-88	.047	12.265	108.423	2.992	105.431	0.	18.012	0.	40.213	65.218	-79.293
12-89	.040	10.356	97.952	3.201	94.751	0.	15.440	0.	36.483	58.268	-73.010
12-90	.034	8.861	86.490	3.425	83.065	0.	13.235	0.	32.122	50.943	-68.785
12-91	.030	7.669	74.868	3.600	71.268	0.	11.345	0.	27.565	43.703	-65.996
12-92	.025	6.700	65.416	3.600	61.816	0.	9.725	0.	23.962	37.854	-64.138
12-93	.023	5.907	57.663	3.600	54.063	0.	8.336	0.	21.034	33.029	-62.891
12-94	.021	5.244	51.210	3.600	47.610	0.	7.146	0.	18.614	28.996	-62.049
12-95	.018	4.688	45.773	3.600	42.173	0.	6.125	0.	16.582	25.591	-61.478
12-96	.016	4.216	41.145	3.600	37.545	0.	5.251	0.	14.855	22.690	-61.088
12-97	.015	3.811	37.231	3.600	33.631	0.	4.501	0.	13.400	20.231	-60.820
12-98	.012	3.463	33.789	3.600	30.189	0.	3.858	0.	12.112	18.077	-60.637
12-99	.013	3.160	30.846	3.600	27.246	0.	3.307	0.	11.012	16.234	-60.510
12- 0	.011	2.894	28.270	3.600	24.670	0.	2.835	0.	10.044	14.626	-60.422
S TOT	.996	258.917	1956.123	61.740	1894.383	475.400	353.882	0.	660.561	758.423	-60.422
AFTER	.165	43.083	420.613	160.323	260.290	0.	17.018	0.	111.907	148.385	-60.220
TOTAL	1.161	302.000	2376.736	222.063	2154.673	475.400	370.900	0.	772.468	906.807	-60.220

RECAP

	GROSS	W.I.	NET
INTEREST FRACTION	1.000000	1.000000	.755000
OIL RESERVES,MB	1.538	1.538	1.161
GAS RESERVES,MMCF	400.000	400.000	302.000
PRODUCTS	0.	0.	0.
REVENUE,M$	3428.403	3428.403	2376.736
OPERATING EXPENSE,M$	222.063	222.063	222.063
TANGIBLES,M$	370.900	370.900	370.900
INTANGIBLES,M$	104.500	104.500	104.500

INITIAL OIL PRICE ($/B)	34.00
INITIAL GAS PRICE ($/M)	6.2903

LIFE (YEARS)	64.53
GROSS OIL WELLS	0.
GROSS GAS WELLS	1.000
RATE OF RETURN,PCT	24.39
DISCOUNT RATE,PCT	30.0
PAYOUT YEARS	3.47
W.I. BEFORE PAYOUT,PCT	100.00
W.I. AFTER PAYOUT,PCT	100.00

DIS PCT	PW OF NET M$
5	496.161
10	283.905
15	151.090
20	59.262
30	-60.221
40	-134.889
50	-186.073
70	-251.727
100	-306.788

SECTION 103 PRICE
435 MMCF GROSS
20-YEAR RECOVERY

TYPICAL WELL
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO

CONSOLIDATED OIL & GAS, INC.
ECONOMICS OF DEVELOPMENT

DATE: 09/23/81.
TIME: 17.32.13.
FILE: TYPICAL
PROJ: 7

AFTER TAX ECONOMICS

AS OF DATE: 1/ 1/1981

-END- MO-YR	NET OIL MB	NET GAS MMF	REVENUE TO INT. M$	OPER. EXPENSE M$	NET INCOME M$	CAPITAL INVEST. M$	DEPR. M$	DEPL. M$	INCOME TAX M$	CASH FLOW M$	CUM. NET PW M$
12-81	0.	0.	0.	1.863	-1.863	475.400	52.965	0.	-73.290	-403.972	-412.448
12-82	.279	72.709	217.790	1.993	215.797	0.	45.401	0.	78.382	137.415	-319.473
12-83	.197	50.952	163.300	2.133	161.167	0.	38.918	0.	56.235	104.932	-264.860
12-84	.145	37.692	129.260	2.283	126.977	0.	33.360	0.	43.064	83.913	-231.265
12-85	.111	29.010	106.470	2.442	104.028	0.	28.597	0.	34.698	69.330	-209.914
12-86	.089	23.019	90.395	2.613	87.782	0.	24.513	0.	29.104	58.678	-196.014
12-87	.071	18.710	78.625	2.795	75.830	0.	21.013	0.	25.216	50.614	-186.791
12-88	.060	15.508	69.770	2.992	66.778	0.	18.012	0.	22.432	44.346	-180.575
12-89	.051	13.062	62.884	3.201	59.683	0.	15.440	0.	20.352	39.331	-176.334
12-90	.043	11.153	57.403	3.425	53.978	0.	13.235	0.	18.742	35.236	-173.411
12-91	.037	9.634	52.950	3.600	49.350	0.	11.345	0.	17.482	31.868	-171.378
12-92	.032	8.406	49.342	3.600	45.742	0.	9.725	0.	16.568	29.174	-169.946
12-93	.028	7.398	46.339	3.600	42.739	0.	8.336	0.	15.825	26.914	-168.930
12-94	.026	6.561	43.942	3.600	40.342	0.	7.146	0.	15.270	25.072	-168.202
12-95	.022	5.859	41.895	3.600	38.295	0.	6.125	0.	14.798	23.497	-167.677
12-96	.020	5.264	40.178	3.600	36.578	0.	5.251	0.	14.411	22.167	-167.296
12-97	.019	4.754	38.823	3.600	35.223	0.	4.501	0.	14.132	21.091	-167.017
12-98	.017	4.316	37.635	3.600	34.035	0.	3.858	0.	13.881	20.154	-166.812
12-99	.015	3.936	36.668	3.600	33.068	0.	3.307	0.	13.690	19.378	-166.661
12- 0	.013	3.603	35.164	3.600	31.564	0.	2.835	0.	13.215	18.349	-166.550
S TOT	1.275	331.546	1398.833	61.740	1337.093	475.400	353.882	0.	404.207	457.486	-166.550
AFTER	.177	45.954	448.659	109.498	339.161	0.	17.018	0.	148.184	190.975	-166.291
TOTAL	1.452	377.500	1847.492	171.238	1676.254	475.400	370.900	0.	552.391	648.461	-166.291

RECAP

	GROSS	W.I.	NET
INTEREST FRACTION	1.000000	1.000000	.755000
OIL RESERVES,MB	1.923	1.923	1.452
GAS RESERVES,MMCF	500.000	500.000	377.500
PRODUCTS	0.	0.	0.
REVENUE,M$	2667.369	2667.369	1847.492
OPERATING EXPENSE,M$	171.238	171.238	171.238
TANGIBLES,M$	370.900	370.900	370.900
INTANGIBLES,M$	104.500	104.500	104.500

INITIAL OIL PRICE ($/B)	34.00
INITIAL GAS PRICE ($/M)	3.1452

LIFE (YEARS)	50.42
GROSS OIL WELLS	0.
GROSS GAS WELLS	1.000
RATE OF RETURN,PCT	14.44
DISCOUNT RATE,PCT	30.0
PAYOUT YEARS	5.14
W.I. BEFORE PAYOUT,PCT	100.00
W.I. AFTER PAYOUT,PCT	100.00

DIS PCT	PW OF NET M$
5	268.705
10	91.567
15	-11.521
20	-79.877
30	-166.292
40	-219.461
50	-255.793
70	-302.514
100	-342.023

TYPICAL WELL
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO

CONSOLIDATED OIL & GAS, INC.
ECONOMICS OF DEVELOPMENT

2X SECTION 103 PRICE
435 MMCF GROSS
20-YEAR RECOVERY

DATE: 09/23/81.
TIME: 17.32.17.
FILE: TYPICAL
PROJ: 0

AFTER TAX ECONOMICS

AS OF DATE: 1/ 1/1981

-END- MO-YR	NET OIL MB-----	NET GAS MMF-----	REVENUE TO INT. M$-----	OPER. EXPENSE M$-----	NET INCOME M$-----	CAPITAL INVEST. M$-----	DEPR. M$---	DEPL. M$----	INCOME TAX M$-----	CASH FLOW M$-----	CUM. NET PW M$------
12-81	0.	0.	0.	1.863	-1.863	475.400	52.965	0.	-73.290	-403.972	-412.448
12-82	.267	69.277	409.246	1.993	407.253	0.	45.401	0.	166.452	240.801	-249.523
12-83	.188	48.957	309.444	2.133	307.311	0.	38.918	0.	123.461	183.850	-153.836
12-84	.140	36.434	246.428	2.283	244.145	0.	33.360	0.	96.961	147.184	-94.911
12-85	.108	28.171	203.855	2.442	201.413	0.	28.597	0.	79.496	121.917	-57.364
12-86	.087	22.433	173.727	2.613	171.114	0.	24.513	0.	67.436	103.678	-32.804
12-87	.070	18.286	151.503	2.795	148.708	0.	21.013	0.	58.740	89.968	-16.409
12-88	.058	15.191	134.609	2.992	131.617	0.	18.012	0.	52.258	79.359	-5.285
12-89	.050	12.822	121.439	3.201	118.238	0.	15.440	0.	47.287	70.951	2.364
12-90	.041	10.965	107.031	3.425	103.606	0.	13.235	0.	41.571	62.035	7.510
12-91	.037	9.486	92.637	3.600	89.037	0.	11.345	0.	35.738	53.299	10.910
12-92	.032	8.286	80.892	3.600	77.292	0.	9.725	0.	31.081	46.211	13.178
12-93	.028	7.302	71.281	3.600	67.681	0.	8.336	0.	27.299	40.382	14.703
12-94	.025	6.481	63.275	3.600	59.675	0.	7.146	0.	24.163	35.512	15.734
12-95	.023	5.793	56.577	3.600	52.977	0.	6.125	0.	21.552	31.425	16.436
12-96	.019	5.208	50.829	3.600	47.229	0.	5.251	0.	19.310	27.919	16.916
12-97	.018	4.708	45.968	3.600	42.368	0.	4.501	0.	17.419	24.949	17.246
12-98	.017	4.275	41.751	3.600	38.151	0.	3.858	0.	15.775	22.376	17.473
12-99	.015	3.902	38.100	3.600	34.500	0.	3.307	0.	14.349	20.151	17.631
12- 0	.014	3.574	34.881	3.600	31.281	0.	2.835	0.	13.085	18.196	17.740
S TOT	1.237	321.551	2433.473	61.740	2371.733	475.400	353.882	0.	880.143	1016.192	17.740
AFTER	.215	55.949	546.250	187.387	358.863	0.	17.018	0.	157.247	201.614	17.995
TOTAL	1.452	377.500	2979.723	249.127	2730.596	475.400	370.900	0.	1037.390	1217.806	17.995

RECAP

	GROSS	W.I.	NET
INTEREST FRACTION	1.000000	1.000000	.755000
OIL RESERVES,MB	1.923	1.923	1.452
GAS RESERVES,MMCF	500.000	500.000	377.500
PRODUCTS	0.	0.	0.
REVENUE,M$	4289.840	4289.840	2979.723
OPERATING EXPENSE,M$	249.127	249.127	249.127
TANGIBLES,M$	370.900	370.900	370.900
INTANGIBLES,M$	104.500	104.500	104.500
INITIAL OIL PRICE ($/B)		34.00	
INITIAL GAS PRICE ($/M)		6.2903	

LIFE (YEARS)	72.05
GROSS OIL WELLS	0.
GROSS GAS WELLS	1.000
RATE OF RETURN,PCT	31.80
DISCOUNT RATE,PCT	30.0
PAYOUT YEARS	2.89
W.I. BEFORE PAYOUT,PCT	100.00
W.I. AFTER PAYOUT,PCT	100.00

DIS PCT	PW OF NET M$
5	698.295
10	437.396
15	275.185
20	163.304
30	17.995
40	-72.662
50	-134.723
70	-214.185
100	-280.620

TYPICAL WELL
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO

CONSOLIDATED OIL & GAS, INC.
ECONOMICS OF DEVELOPMENT

SECTION 103 PRICE
555 MMCF GROSS
20-YEAR RECOVERY

DATE: 09/23/81.
TIME: 17.32.20.
FILE: TYPICAL
PROJ: 9

AFTER TAX ECONOMICS

AS OF DATE: 1/ 1/1981

-END- MO-YR	NET OIL MB-----	NET GAS MMF-----	REVENUE TO INT. M$-----	OPER. EXPENSE M$-----	NET INCOME M$-----	CAPITAL INVEST. M$-----	DEPR. M$---	DEPL. M$----	INCOME TAX M$----	CASH FLOW M$-----	CUM. NET PW M$------
12-81	0.	0.	0.	1.863	-1.863	475.400	52.965	0.	-73.290	-403.972	-412.448
12-82	.347	90.378	270.718	1.993	268.725	0.	45.401	0.	102.729	165.996	-300.136
12-83	.247	64.139	205.554	2.133	203.421	0.	38.916	0.	75.671	127.750	-233.647
12-84	.184	47.879	164.201	2.283	161.918	0.	33.360	0.	59.136	102.782	-192.498
12-85	.143	37.107	136.179	2.442	133.737	0.	28.597	0.	48.365	85.372	-166.207
12-86	.114	29.602	116.260	2.613	113.647	0.	24.513	0.	41.002	72.645	-148.997
12-87	.093	24.164	101.552	2.795	98.757	0.	21.013	0.	35.762	62.995	-137.518
12-88	.077	20.100	90.417	2.992	87.425	0.	18.012	0.	31.930	55.495	-129.739
12-89	.066	16.981	81.749	3.201	78.548	0.	15.440	0.	29.030	49.518	-124.400
12-90	.056	14.536	74.802	3.425	71.377	0.	13.235	0.	26.745	44.632	-120.698
12-91	.048	12.582	69.159	3.600	65.559	0.	11.345	0.	24.938	40.621	-118.106
12-92	.042	11.000	64.555	3.600	60.955	0.	9.725	0.	23.566	37.389	-116.271
12-93	.037	9.696	60.758	3.600	57.158	0.	8.336	0.	22.458	34.700	-114.961
12-94	.033	8.613	57.658	3.600	54.058	0.	7.146	0.	21.580	32.478	-114.018
12-95	.031	7.701	55.083	3.600	51.483	0.	6.125	0.	20.864	30.619	-113.334
12-96	.026	6.926	52.894	3.600	49.294	0.	5.251	0.	20.260	29.034	-112.835
12-97	.024	6.264	51.115	3.600	47.515	0.	4.501	0.	19.786	27.729	-112.468
12-98	.022	5.691	49.622	3.600	46.022	0.	3.858	0.	19.395	26.627	-112.198
12-99	.020	5.193	48.374	3.600	44.774	0.	3.307	0.	19.075	25.699	-111.997
12- 0	.018	4.759	46.453	3.600	42.853	0.	2.835	0.	18.408	24.445	-111.849
S TOT	1.628	423.311	1797.103	61.740	1735.363	475.400	353.882	0.	587.410	672.552	-111.849
AFTER	.259	67.439	658.443	139.802	518.641	0.	17.018	0.	230.747	287.894	-111.499
TOTAL	1.887	490.750	2455.546	201.542	2254.004	475.400	370.900	0.	818.157	960.446	-111.499

RECAP

	GROSS	W.I.	NET
INTEREST FRACTION	1.000000	1.000000	.755000
OIL RESERVES,MB	2.500	2.500	1.887
GAS RESERVES,MMCF	650.000	650.000	490.750
PRODUCTS	0.	0.	0.
REVENUE,M$	3544.802	3544.802	2455.546
OPERATING EXPENSE,M$	201.542	201.542	201.542
TANGIBLES,M$	370.900	370.900	370.900
INTANGIBLES,M$	104.500	104.500	104.500
INITIAL OIL PRICE ($/B)		34.00	
INITIAL GAS PRICE ($/M)		3.1452	

LIFE (YEARS)	58.83
GROSS OIL WELLS	0.
GROSS GAS WELLS	1.000
RATE OF RETURN,PCT	19.72
DISCOUNT RATE,PCT	30.0
PAYOUT YEARS	4.09
W.I. BEFORE PAYOUT,PCT	100.00
W.I. AFTER PAYOUT,PCT	100.00

DIS PCT	PW OF NET M$
5	439.496
10	210.706
15	80.556
20	-4.743
30	-111.500
40	-176.585
50	-220.782
70	-277.247
100	-324.605

TYPICAL WELL
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO

CONSOLIDATED OIL & GAS, INC.
ECONOMICS OF DEVELOPMENT

2X SECTION 103 PRICE
555 MMCF GROSS
20-YEAR RECOVERY

DATE: 09/23/81.
TIME: 17.32.24.
FILE: TYPICAL
PROJ: 10

AFTER TAX ECONOMICS

AS OF DATE: 1/ 1/1981

-END- YR	NET OIL MB	NET GAS MMF	REVENUE TO INT. M$	OPER. EXPENSE M$	NET INCOME M$	CAPITAL INVEST. M$	DEPR. M$	DEPL. M$	INCOME TAX M$	CASH FLOW M$	CUM. NET PW M$
12-81	0.	0.	0.	1.863	-1.863	475.400	52.965	0.	-73.290	-403.972	-412.448
12-82	.346	89.896	529.399	1.993	527.406	0.	45.401	0.	221.722	305.684	-205.623
12-83	.244	63.382	399.364	2.133	397.231	0.	38.918	0.	164.824	232.407	-84.665
12-84	.181	47.091	317.507	2.283	315.224	0.	33.369	0.	129.657	185.567	-10.373
12-85	.140	36.367	262.362	2.442	259.920	0.	28.597	0.	106.409	153.511	36.902
12-86	.111	28.929	223.328	2.613	220.715	0.	24.513	0.	90.253	130.462	67.808
12-87	.090	23.563	194.657	2.795	191.862	0.	21.013	0.	78.591	113.271	88.449
12-88	.076	19.564	172.981	2.992	169.989	0.	18.012	0.	69.909	100.080	102.478
12-89	.063	16.501	156.091	3.201	152.890	0.	15.440	0.	63.227	89.663	112.146
12-90	.054	14.107	137.706	3.425	134.281	0.	13.235	0.	55.681	78.600	118.665
12-91	.047	12.199	119.094	3.600	115.494	0.	11.345	0.	47.909	67.585	122.977
12-92	.041	10.652	103.992	3.600	100.392	0.	9.725	0.	41.707	58.685	125.857
12-93	.036	9.383	91.618	3.600	88.018	0.	8.336	0.	36.654	51.364	127.797
12-94	.033	8.327	81.318	3.600	77.718	0.	7.146	0.	32.463	45.255	129.111
12-95	.028	7.442	72.655	3.600	69.055	0.	6.125	0.	28.948	40.107	130.007
12-96	.026	6.687	65.293	3.600	61.693	0.	5.251	0.	25.963	35.730	130.621
12-97	.023	6.046	58.994	3.600	55.394	0.	4.501	0.	23.411	31.983	131.044
12-98	.021	5.489	53.598	3.600	49.998	0.	3.858	0.	21.224	28.774	131.336
12-99	.019	5.007	48.904	3.600	45.304	0.	3.307	0.	19.319	25.985	131.539
12- 0	.018	4.587	44.768	3.600	41.168	0.	2.835	0.	17.633	23.535	131.681
S TOT	1.597	415.219	3133.629	61.740	3071.889	475.400	353.882	0.	1202.214	1394.276	131.681
AFTER	.290	75.531	737.441	223.311	514.130	0.	17.018	0.	228.672	285.458	132.013
TOTAL	1.887	490.750	3871.070	285.051	3586.019	475.400	370.900	0.	1430.886	1679.734	132.013

RECAP

	GROSS	W.I.	NET
INTEREST FRACTION	1.000000	1.000000	.755000
OIL RESERVES,MB	2.500	2.500	1.887
GAS RESERVES,MMCF	650.000	650.000	490.750
PRODUCTS	0.	0.	0.
REVENUE,M$	5582.550	5582.550	3871.070
OPERATING EXPENSE,M$	285.051	285.051	285.051
TANGIBLES,M$	370.900	370.900	370.900
INTANGIBLES,M$	104.500	104.500	104.500

INITIAL OIL PRICE ($/B)	34.00
INITIAL GAS PRICE ($/M)	6.2903

LIFE (YEARS)	82.03
GROSS OIL WELLS	0.
GROSS GAS WELLS	1.000
RATE OF RETURN,PCT	42.13
DISCOUNT RATE,PCT	30.0
PAYOUT YEARS	2.42
W.I. BEFORE PAYOUT,PCT	100.00
W.I. AFTER PAYOUT,PCT	100.00

DIS PCT	PW OF NET M$
5	994.256
10	661.766
15	456.388
20	313.109
30	132.013
40	18.010
50	-59.914
70	-159.497
100	-242.499

CONSOLIDATED OIL & GAS, INC.
RATE OF RETURN (BFIT)
VS.
20 YR. RECOVERY PER WELL
BASIN DAKOTA FIELD
T30, 31, & 32N - R12 & 13W

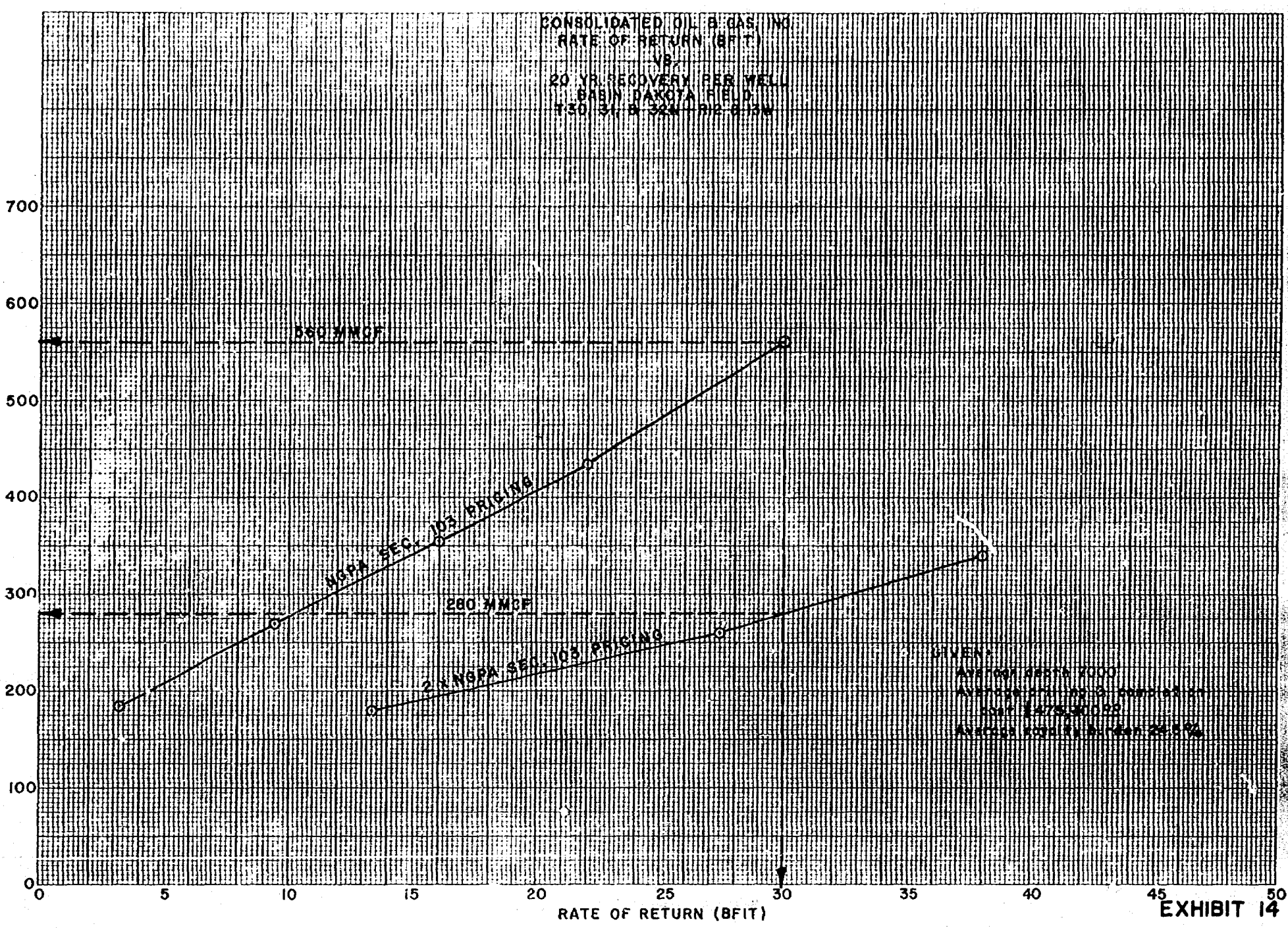

EXHIBIT 14

CONSOLIDATED OIL & GAS, INC.
RATE OF RETURN (BFIT)
VS.
20 YR. RECOVERY PER WELL
BASIN DAKOTA FIELD
T 30, 31, & 32 N - R 12 & 13 W.

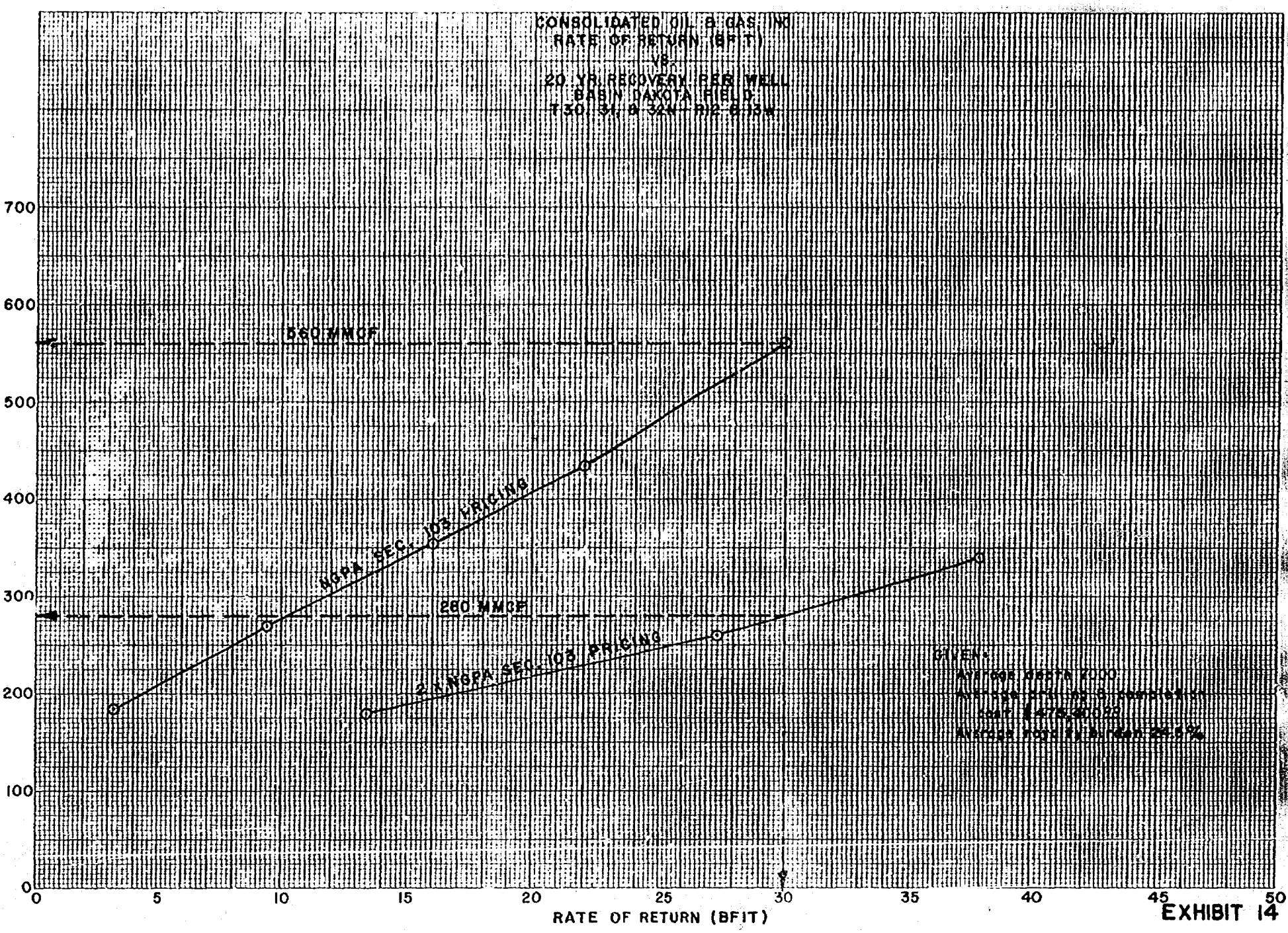

EXHIBIT 14

CONSOLIDATED OIL & GAS, INC.
RATE OF RETURN (AFIT)
VS.
20 YR. RECOVERY PER WELL
BASIN DAKOTA FIELD
T30-31N, R-12W THRU R-13W

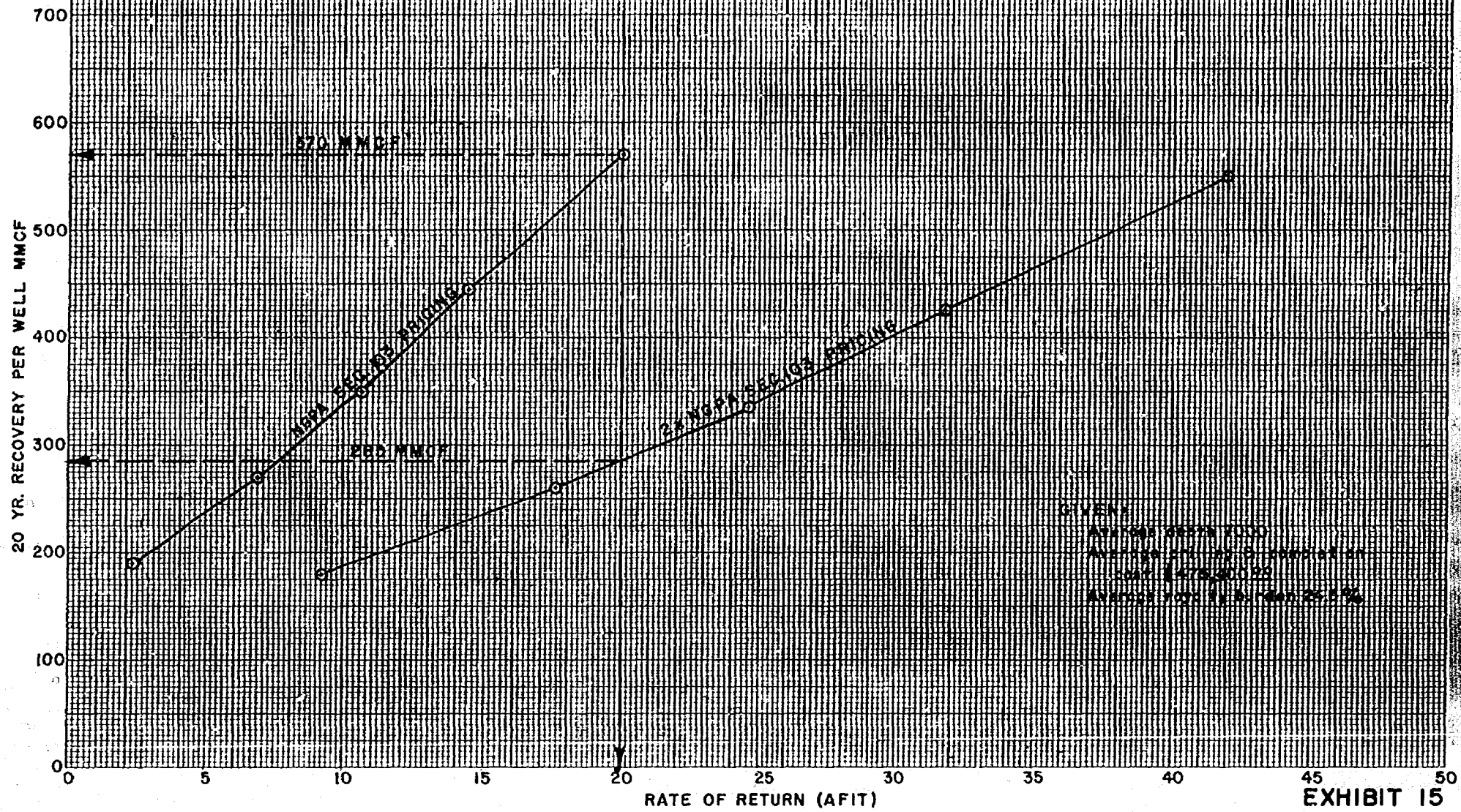

EXHIBIT 15

EXHIBIT 16

RATE OF RETURN JUSTIFICATION

All investment decisions, whether by individuals or corporations, are matters of selection between competing alternatives. If discretionary dollars are invested by an individual in a new house, those same dollars can't be put in a savings account. Every individual and corporation has a myriad of things that can be done with cash flows. Each can make long-term investments, short-term investments, pay off debt, or simply convert funds to current consumption. Each and every spending decision is made in this context, whether or not the spender does any quantified analysis.

Corporations, who have strong fiduciary responsibilities for shareholders' investments, also must continually select between alternatives in making investment decisions. This process must consist of two broad steps. The first is the "hurdle" rate of return determination which must reflect its costs of capital. A corporation has only two sources of capital -- equity and debt.

Equity, or selling additional stock, as a source of funds is becoming more expensive for corporations. This is because of the alternatives available to investors. Investors can earn 17% to 18% on safe money market funds. They can earn 15 3/4% on high grade commercial paper, 16 1/2% on federally guaranteed CD's, 14 1/2% on Federal treasury bills, and 17% to 20% on New York Stock Exchange high grade corporate bonds. Equity issues, in order to attract buyers, must necessarily be priced so that investors can earn, through dividends and stock appreciation, at least 20% since stock is inherently riskier than bonded indebtedness. Many corporations, in trying to attract additional equity, have been forced to issue stock below its "book value," which is dilutive to prior shareholders.

Debt, as an alternative source of capital, is also becoming more expensive. Two primary sources of debt exist for a corporation. One is the public market through issuance of debentures. As mentioned above, these issues, if they can be sold at all, are costing 17% to 20%. Again, this high cost is a function of alternatives. Why should an investor accept less than 17% to 20% on corporate bonds which do have some associated risk when he can earn a guaranteed 16 1/2% on CD's or other safer investments?

The second source of debt is bank borrowings. The following table shows bank prime rate since 1/1/79.

MONTH	AVERAGE PRIME RATE - %
1/79	11.75
2/79	11.75
3/79	11.75
4/79	11.75
5/79	11.75
6/79	11.75
7/79	11.75

MONTH	AVERAGE PRIME RATE - %
8/79	12.25
9/79	13.50
10/79	15.25
11/79	15.50
12/79	15.25
1/80	15.25
2/80	16.75
3/80	19.50
4/80	19.00
5/80	14.50
6/80	12.00
7/80	11.00
8/80	11.50
9/80	13.00
10/80	14.50
11/80	17.75
12/80	21.50
1/81	19.50
2/81	19.00
3/81	17.50
4/81	18.00
5/81	20.50
6/81	20.00
7/81	20.50
8/81	20.50

These prime rates are reflective of the banks' costs of funds. With banks paying 16 1/2% for their funds, prime must be in the 19% to 20% range. It is important to note that very few people or corporations can borrow at prime. Most borrowers pay some multiple of prime or some percentage over prime. In our case, we pay prime plus .5%, for a current interest cost of approximately 20%.

Thus, our corporate cost of capital is 20% for equity and 20% for debt, or 20% overall. Making investments with less than 20% earnings rate would be an imprudent decision which would eventually degrade our shareholders' investment. Even acceptance of a 20% rate of return must necessarily incorporate the belief that interest rates will abate in the future so that a 20% earnings rate project will make future contributions in excess of its costs.

The question may be asked regarding use of cash flow from older properties developed with lower cost capital to generate new capital. This brings up the second necessary step in investment decision-making after a cost of capital has been determined. This step is the selection between competing alternatives. Consolidated, like many oil and gas concerns, since 1976 has invested considerably more in oil and gas properties and drilling than was returned through its profits. For 1976 through year end 1980, Consolidated spent $51.3 million on oil and gas development while net earnings totalled $15.8 million. This gap between earnings and investment was largely funded by increased bank debt. Corporate bank debt now exceeds $50 million at an interest cost of approximately 20%. This is pertinent because repayment of that bank

debt with corporate cash flow represents a guaranteed 20% rate of return. This is not a situation peculiar to Consolidated. Very few substantial oil and gas entities are debt free, and most carry a similar earnings/investment differential.

When managements are reviewing proposed oil and gas drilling investments with rates of return below 20%, they know they have "risk free" alternative investments with comparable returns, namely paying off corporate bank debt or buying any of the high yielding treasury bills, CD's, or money market funds.

Thus, with alternative risk-free investment opportunities available for earning 20%, with costs of capital near 20%, there is certainly justification for an oil and gas investment to yield a substantially greater return. In determining how much greater than 20% the rate should be, several factors need to be considered.

Evaluation and rate of return economics do not account for corporate general and administrative expense. These include accounting and financial functions, costs of federal, state and local compliance required before, during and after drilling and production, as well as all geologic and engineering functions. Consolidated has one of the lower "burdens" in industry, yet even ours is approximately 20% of invested capital. This means that for us to earn 20% at the corporate level, projects evaluated at the field or lease level must earn approximately 24%.

In addition, a risk factor must be considered. The risks in this infill program's viability are, a) those inherent in any drilling operations, b) regulatory exposure to price controls, increased taxes including local, state and federal, and c) lower recoveries than estimated. A reasonable, if not minimal risk factor is 25%. This would translate to an additional 6% return above the "break-even" rate of 24%, resulting in a total return of 30%.

In the analyses of rates of return on oil and gas investments, it is permissible to view 20 years of forecast performance. The bulk of reserves on a well are produced in the first 20 years and over 98% of the present value is derived. For example, in the instant case, a typical well in the 21st year would be producing only 11.5 mcfd, which when discounted at 30% is worth only (.00038) X 11.5, or .004 mcfd of present production. For this reason, the economic forecasts and display of results in Exhibits 12 through 15 reflect gross gas recoveries forecast in the first 20 years. Even though, with sufficient price incentives, many of these wells will produce for 40 or 50 years at low rates, the gas recovered adds almost nothing to present worth, upon which investment decisions are made.

As can be seen on Exhibit 14, this indicates a necessary 20 year recovery of 560 mmcf per well at NGPA Section 103 prices. This exceeds expected recovery of 435 mmcf. With tight gas sands pricing, the required recovery would drop to approximately 280 mmcf per well, which would make the program viable.

The returns and analyses presented thus far have been before income tax. It is both instructive and appropriate to consider after income tax results and requirements. When the same economic forecasts are used to evaluate this Basin-Dakota area, with income taxes being charged to cash flows and tax credits being taken on investments, lower project earnings and rates of return result. The required after tax rate of return need not be as high as the pre-tax return and in fact is well analyzed in prior FPC proceedings. On August 28, 1975, the FPC found in Opinion No. 742 (aff. Op. 742-A, July 27, 1976) that small producers are entitled to a 20% after tax rate of return. The higher rate than previously allowed was justified by com-

bined risk increase, higher equity financing and greater debt cost for small producers. In 1975, prime interest rates averaged only 7.86%. The significantly higher 1980 and 1981 costs of equity and debt certainly justify an earnings rate much in excess of 20%. How much higher is then the question. In Opinion 742, the FPC allowed an earnings rate of prime plus 12.14%. This would dictate an earnings rate of over 32%. This is not an unreasonable goal for an oil and gas investor, but it represents a "weighted" target across a myriad of types of wells, all with varying risks. What then should the return be on a development well drilling program, such as the Dakota? It should certainly be in excess of 20%, but in the instant case, it is not necessary to determine how much in excess. Even at a 20% after tax rate of return the required average 20 year recovery per well, 570 mmcf, far exceed those expected.

Thus, in this case, the Basin-Dakota infill program in this area yields subeconomic results at Section 103 prices whether evaluated on a pre-tax or after tax basis. Our corporate policy certainly reflects this since we ceased our infill drilling program last year and will not resume drilling until sufficient price incentive exists. Our economic analyses presented herein are not "hollow" exercises -- we have been diverting investment from this area to other areas and we see no reason to use capital costing 20% for this area at current allowed prices.

EXHIBIT 17

DAKOTA INFILL WELLS

PREVIOUSLY DRILLED

Well Name	Spud Date	Economic Status at 103 Price (Current)
Cain 1-M	5/17/80	50 MCFD - Will not cover interest on costs
Jackson 2-E	8/4/80	100 MCFD - Requires compression - Will not cover interest
Jaquez 2	2/25/80	170 MCFD - Too early to predict
Kline 1-M	4/17/80	13-30 MCFD - Will not cover interest
Langendorf 1-E	6/1/80	240 MCFD - Will cover interest
Mitchell 1-E	1/26/80	35 MCFD - Indeterminate
Neuman 1-E	9/2/80	78 MCFD - Will not cover interest - requires compression
Payne 1-E	8/9/80	260 MCFD - Will cover interest
Phillips 1-E	2/26/80	175 MCFD - Will cover interest
Robinson Bros. 1-M	6/10/80	55 MCFD - Will not cover interest
So. Union 1-M	3/12/80	Trace - Will not cover interest
So. Union 2-E	8/19/80	140 MCFD - Requires compression - Will not cover interest
Starr 1-M	5/2/80	230 MCFD - Marginally covers interest
Templeton 1-E	7/8/80	210 MCFD - Marginally covers interest
Wilmerding 1-M	4/2/80	65 MCFD - Will not cover interest

SUMMARY

9 - wells are not covering interest on investment

5 - wells are marginally covering interest

1 - indeterminate

STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION DIVISION
STATE LAND OFFICE BLDG.
SANTA FE, NEW MEXICO
29 September 1981

COMMISSION HEARING

IN THE MATTER OF:

Application of Southland Royalty Company for designation of a Tight formation, San Juan County, New Mexico.

CASE 7116

de novo

BEFORE: Commissioner Ramey
Commissioner Arnold

TRANSCRIPT OF HEARING

A P P E A R A N C E S

For the Oil Conservation Division: W. Perry Pearce, Esq.
Legal Counsel to the Division
State Land Office Bldg.
Santa Fe, New Mexico 87501

For the Applicant: William F. Carr, Esq.
CAMPBELL, BYRD, & BLACK P.A.
Jefferson Place
Santa Fe, New Mexico 87501

A P P E A R A N C E S

For Consolidated Oil & Gas: Lynn Teschendorf, Esq.
House Counsel for Consolidated
Denver, Colorado

I N D E X

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MR. RAMEY: The hearing will come to order. Will everybody please speak loudly today. We do not have a reporter; we have a taper.

Call the first case on the docket, which is Case 7116.

MR. PEARCE: Application of Southland Royalty Company for designation of a tight formation, San Juan County, New Mexico.

MR. CARR: May it please the Commission, my name is William F. Carr, with the law firm Campbell, Byrd, and Black, P. A., of Santa Fe, appearing on behalf of Southland Royalty Company.

MS. TESCHENDORF: Lynn Teschendorf, appearing on behalf of Consolidated Oil and Gas.

MR. CARR: May it please the Commission, Southland at this time would request that this acreage which falls within the advertised area in this case be deleted from this hearing and that that part of the case be dismissed.

It is our intention, as the Commission is aware, not to participate in this hearing but to request that our acreage be deleted, thereby enabling Consolidated to present its evidence for its acreage in this case independent of Southland.

Southland, as you're aware, has filed an

application for designation of a tight formation for the same lands. That application is docketed as the next case on the Commission's docket.

MR. RAMEY: All right. Any objection to that, Ms. Teschendorf?

MS. TESCHENDORF: No objection.

MR. RAMEY: All right. We will proceed in that manner.

Did you want to question anyone from Southland's case?

MR. CARR: Yes. I will question him in the next hearing.

MR. RAMEY: Oh, all right. Okay. All right.

Okay, you can proceed, then, with your case.

MS. TESCHENDORF: Thank you. I have two witnesses to be sworn in.

MR. RAMEY: Will the witnesses stand and be sworn?

(Witnesses sworn.)

MS. TESCHENDORF: If the Commission please,

since this is a de novo proceeding, Consolidated does not wish to incorporate any part of the previous record; however, we will use information from certain of the Southland exhibits, since it is a matter of public record in the previous hearing.

Consolidated did not submit copies of its exhibits fifteen days prior to hearing, as required by the rules; however, waivers were obtained from both the USGS and Mr. Ramey at the beginning of September.

And with that I'd like to call my first witness, Mr. Ellison.

FLOYD E. ELLISON, JR.

being called as a witness and being duly sworn upon his oath, testified as follows, to-wit:

DIRECT EXAMINATION

BY MS. TESCHENDORF:

Q. Would you please state your name, by whom you're employed, and in what capacity?

A. My name is Floyd E. Ellison, Junior. I am employed by Consolidated Oil and Gas, Inc., as their Vice President of Operations for the Rocky Mountain Area.

Q. And you are a petroleum engineer, is that correct?

A. That is correct.

Q. And have your qualifications as a witness been made a matter of record before the Division before?

A. Yes, they have.

Q. Are you familiar with the facts concerning this particular case?

A. Yes, I am.

MS. TESCHENDORF: Is the witness considered qualified?

MR. RAMEY: He is considered qualified.

Q. Mr. Ellison, what is Consolidated seeking with this application?

A. Consolidated is seeking tight formation qualification for the Dakota formation in all of Township 31 North, 13 West, and the western two tiers of sections in Township 31 North, 12 West.

Q. Okay.

A. San Juan County, New Mexico.

Q. Would you refer to what we've marked as Exhibit One, that's on the wall to your left, and describe what that shows?

A. Exhibit One is a base map of the area that Consolidated Oil and Gas would like classed as tight formation, and on the map is shown both the 1980 oil and gas

production and then the cumulative oil and gas production from all of these wells through December 31st, 1980.

Also shown by a little triangle are the infill wells, Dakota infill wells for the area, as well as the three wells in which Consolidated Oil and Gas has permeability data based on flow rates.

Q. Those are marked in red, are they not?

A. They are marked in red.

Q. And would you outline for the Commissioners the area that we're interested in today?

A. Okay. The area that we're interested in includes all of Township 31 North, 13 West, and the western two tiers of sections for 31 North and 12 West.

Q. That area is outlined with a dashed line, is that correct?

A. That's correct.

Q. You can just stay there, Floyd, but we've also marked an Exhibit Number Two. Could you just explain what that is?

A. Okay. Exhibit Number Two is the geologic -- geographical and geological description of the area involved.

Q. And I think the Commissioners can read that at their leisure.

Now would you refer to Exhibit Three-A and describe that?

A. Okay. Three-A is an induction spherically focussed log of the interval in question, and it begins, the log itself begins at the base of the Mancos and of course it goes through the Greenhorn, the Graneros shale, the Graneros sand, which is also many times and within Consolidated usually referred to as the top of the Dakota, on down through the Dakota zone, and this particular well, I think you actually go down and maybe touch into the top of the Morrison.

MR. RAMEY: So your Dakota producing interval is from the top of the Greenhorn to --

A. Yes, it's basically anywhere from the top of the Greenhorn on down through the base of the Dakota or in the very top of the -- of the Morrison can be included as -- and referred to as Dakota.

MR. ARNOLD: Excuse me, I thought that was the base of the Greenhorn and the top of the Dakota.

A. Okay, the base of the Greenhorn, let me correct it.

Q. Would you refer now to Exhibit Three-B and state what that shows?

A. Okay. Three-B is actually the computer process log in which certain data is input. The companies

like Schlumberger and Dresser, and others, then input certain data and they try to describe the zones as they are, their lithology, their porosities, their oil and gas and water saturations, and in this case they describe -- they try to describe what is taking place in that particular interval.

I will point out certain things because this is pertinent to some degree to the situation that we have.

Number one, the Graneros sand which we have found has produced a great deal of our production, doesn't really show all that much gas saturation and yet we know historically that that is where a great deal of it is from, and so apparently it's showing some invasion which has pushed it out through the fractures, so it does not show that as being quite so gas-bearing.

But my primary purpose in showing this particular log shows in the base of the Dakota. In the Phillips 1-E Well, this lower base Dakota in which an interval that does appear wet, described in the logs, we also thinking if we perforated it and tested it natural, and did get gas out of it. We subsequently did frac it and did get gas along with some water out of this interval and it is still producing from this interval.

So based upon this and two or three others in which we have had the same type situation, we have

been in some of the wells perforating the Lower Dakota and have been being able to get some gas production from this Lower Dakota. In many cases we are getting some water, but we're also getting some gas reserves along with it.

Q. Would you describe the completion techniques used, that Consolidated uses in completing these Dakota wells?

A. Yes. Consolidated Oil and Gas, of course, has been running pipe all the way through the base of the Dakota, and then we have been perforating in most cases this Lower Dakota, and we have found through our fracing and other things that there is -- there does seem to be some difference between the Lower Dakota and the Upper Dakota and Graneros sand portion in the back pressures. We have -- we have been experiencing 800 to 1000 pounds difference in the instantaneous shut-in pressure, the back pressure that has been taking place.

For that reason it has required that instead of being able to frac the entire interval all at one time, this requires us to isolate the Lower Dakota and to frac it separately and then to frac the upper zone, and at the same time to speed up the cleaning up procedure, we have been including some nitrogen in the -- in the frac fluid so that it will go back and clean up a little quicker.

So that, of course, has increased the expense of our drilling and completion technique, or cost. But by the same token that is about the only way that we felt that we could go ahead and try to get some additional reserves out of the Lower Dakota.

Q. Would you now refer to what has been marked as Exhibit Four-A and describe what that shows?

A. Okay. Four-A is a cross section of the area that we're interested in and it actually begins with a well, the Rollison Brothers 1-M, which is just north of the section that we have asked to be included as tight gas designation, and it goes basically north and south down to the southernmost well here, which is the Langgendorf 1-E.

And it is primarily showing that the Dakota formation is basically continuous throughout that interval going from north to south.

Q. And Exhibit Four-B.

A. Exhibit Four-B is a cross section across this same interval on the -- actually on the northern portion of this township and it's showing from the Mitchell 1-E across to the Wilmerding 1-M, and again, it does show the continuity of the -- of the Dakota Graneros sand interval going through that -- across that interval.

Q. And Four-C?

A. Four-C is another cross section beginning with the Mitchell 1-E and angling from the southwesterly to a northeasterly direction, again showing the continuity of the Dakota and Graneros sand going across that particular area that we are interested in.

MS. TESCHENDORF: Do the Commissioners have any questions on these exhibits as long as the witness is still up here?

Q. Back in the exhibit booklet, would you now refer to what we've marked as Exhibit Five and explain what that shows?

A. Okay. Exhibit Five is a table showing seven wells and some permeability data that has been developed on each one of these wells. Three wells are Consolidated wells. Two wells are Southland Royalty wells. And two wells are El Paso Natural Gas wells.

Q. Would you go through the stabilized production rates, and these are pre-stimulation, is that correct?

A. Yes, these are pre-stimulation.

The Consolidated Oil and Gas Wilmerding Well, the permeability data we could not, and I might just comment at this point, the three wells that Consolidated Oil and Gas did the flow tests on to insure that we were not ex-

periencing any mud plugging or mud damage, we perforated the intervals, we acidized them with a small acid job and swabbed them back to clean it up, and then we did request a witness from the Corporation Commission to witness the tests and they observed the flow tests that were described.

And in the case of the Wilmerding, the flow rate was even too small to measure and of course by calculations all you can say from that is it has to be less than the one millidarcy that is required, or the .1 millidarcy required.

The Klein Well, we tested the interval from 6506 to 6736 and the flow rate was 12-1/2 Mcf per day, and by doing a Darcy formula calculation it comes up to the .0049 millidarcies, as shown.

The Consolidated Oil and Gas Center Well had a flow rate out of the Lower Dakota of 2.73 Mcf, which calculates to .00068 millidarcies, and a 52 Mcf per day rate out of the Upper Dakota, which calculates to .0146 millidarcies.

The Southland Royalty Company well, the east well is -- had a flow rate of 21.7. The Southland Royalty Patterson "B" Community Well had a 224.1 Mcf per day rate, and of course it showed a .0877 millidarcy calculation.

The El Paso Natural Gas Company Case

Well and also the Moore Well are calculated from core analysis and all. They weren't tested, and of course, the calculations which are shown here are based upon a formula that is used to come up with what the millidarcies would be from a core analysis.

Q. Are all these wells, their stabilized production rates, are they all within the FERC allowed rates?

A. They all are, yes.

Q. Do any of these wells expect to show any crude oil production?

A. Well, the -- what crude oil production there would be would be less than the five barrel of oil per day that is required.

Q. Would any of Consolidated's wells qualify for tight formation pricing if this application were approved?

A. Yes, from what we can tell all of these wells that were tested here and assuming from that that this is representative of other wells in the area, that they -- they would qualify for the tight gas.

Q. And these are all wells that were spudded after July 16th of 1979?

A. Yes, they were.

Q. Would you now refer to Exhibit Six-A,

which has a number of pages, seven page exhibit, and describe that?

A. Okay. Six-A is a -- and there are several pages to it, in which it shows the data of a DST that was run on the Southland Royalty East 7-E Well, and then from it then there was a build-up run on it and from that, as can be shown on page four, the calculations for the permeability is .00110.

Q. That is marked with an arrow, is it not?

A. That is marked with an arrow.

Q. Exhibit Six-B?

A. Exhibit Six-B is the calculations for the Wilmerding 1-M and of course this is the one in which the -- the rate was too small to measure, so there was inadequate gas actually to compute the flow rate using the Darcy method, and therefor it has to be assumed that it is less than .1 of a millidarcy.

Q. That's page one of Exhibit Six-B. What is page two?

A. Okay. Page two of Exhibit Six-B is the Darcy permeability calculations on the Klein No. 1-M, Consolidated Oil and Gas Klein No. 1-M, and from it, based upon the flow rate, the calculated permeability using the Darcy formula is .0049 millidarcies.

Exhibit Six-B-3 is Consolidated Oil and

Gas Center No. 1-M, and it shows the calculations using the Darcy formula, and shows that the Lower Dakota permeability is .00068; the Upper Dakota permeability is .0146.

Q. And the next page?

A. Okay. Exhibit Six-B-4 is the Southland Royalty Company Patterson B Community 1-E and using the flows from it, using the Darcy formula, the permeability for that well is .0877.

Q. Now refer to Exhibit Six-C and explain that.

A. Exhibit Six-C-1, on through, well, Six-C-1 is the calculated permeability from the cores of the El Paso Natural Gas Company Case No. 1 WEll.

Q. It's No. 8, I believe.

A. Excuse me, I'm sorry, Case No. 8 Well, and it shows that the average laboratory permeability is .1195, but the average in situ permeability is .0335.

Q. And page two of that exhibit?

A. Page two of that exhibit is the El Paso Natural Gas Company Moore No. 8, and it shows the average laboratory permeability being .0538 but the average in situ permeability being .0151.

Q. And would you now refer to Exhibit Seven and explain that?

A. Okay. Exhibit Number Seven is a paper describing how you convert laboratory permeability to in situ permeability.

Q. This is for core analysis?

A. For core analysis, and this is how the in situ permeability for Exhibits Nos. Six-C-1 and Six-C-2 were calculated.

And it is an industry method for trying to convert the two -- or the measured permeability to in situ permeability due to the fact that laboratory permeabilities will be high for two or three reasons. One of them is that the overburden pressure has been released and therefor it allows the pore space to enlarge just slightly. Also is the fact that within the pore space is water and of course in the laboratory you have changed that and taken some of the water out, so therefor the gas can in a laboratory sense flow through this tight sandstone easier than it can in situ.

So this is the method -- a method that is used to convert from one method -- from the laboratory tested permeability to in situ permeability.

Q. Mr. Ellison, all the types of calculations used to determine permeability that you've described in Exhibits Six and Seven, are they all generally accepted methods used in the industry?

A. Yes, they are.

Q. Would you now refer to what we've marked as Exhibit Eight-A and describe that?

A. Exhibit Eight-A is Consolidated Oil and Gas Company's estimated well costs for drilling a Dakota well in this area and completing in both the Upper and the Lower DAkota, which would require two fracs.

Q. Does Consolidated -- has Consolidated drilled a number of its Dakota infills as Mesaverde-Dakota duals?

A. Yes. The majority of the wells that we have drilled, for instance, this past year, the majority of them were dual Mesaverde-Dakota wells, and of course this was part of the reason that we chose to drill these, is the fact that the economics were better if done for both, than just for one.

But Consolidated now has pretty well drilled up all of the Mesaverde infills that we have in this area, and from now on they'll be basically single Dakota wells.

Q. But the part that you have shown in Exhibit A and when we get to Exhibit B, the actual costs, you have taken the Mesaverde share of the cost out of these figures, have you not?

A. Yes, we have, as best -- as best we could. We removed the Mesaverde completion and equipment costs out of the costs shown and this is our best estimate of what it will cost us to drill and complete a Dakota well in both zones.

Q. Would you now refer to Exhibit Eight-B, which has a number of pages, and describe what that shows?

A. Okay. Exhibit Eight-B is the -- are the drilling costs that Consolidated actually experienced during the year 1980. Of course, it can be noted that even the -- going through there that some of the wells drilled earlier in the year were much less than some of those drilled later in the year, and a lot of that is due to the fact that the drilling costs, that the contractors were charging us, increased,over last year increased about 50 percent on a per foot basis. It's very interesting to note that when rigs were very short the costs were going up very rapidly. Now that the drilling is cut back, when we were going out to check to see what the footage prices were this year, nearly a year after our last well, that the footage cost has remained the same over this last year, and I think it's due to the American way of doing things, which is whenever there is an excess of things, that the -- that people drop off on what their price is, and I like the system in that -- in the fact that the free

market does allow these things to go up and down.

But that was one reason that we were able to maintain our well cost estimate as shown on Figure Eight-A, basically about the same as it was one year ago.

Q. Now the first five pages of Exhibit Eight-B contain actual well costs for a number of these wells we have drilled. Is that correct?

A. That is correct. And --

Q. And page six shows what?

A. Page six shows the total of all of the categories shown and then the average for this well, and of course, last year it should be noted that the -- that the total cost to drill and complete a Dakota well to both zones was nearly the same as what we are estimating it to be at this point, and of course it does, we did note at the bottom, the -- our best estimate of how much the Lower Dakota completion did add -- add to this cost so that can be subtracted out in our costs for had we not been trying to complete the Lower Dakota.

Q. What is the average cost of a Dakota completion in that area?

A. Okay. We are -- we are showing that it is -- okay, last year our average cost was $467,823.

Q. And what was the cost of the Lower Dakota

completion?

A. And the Lower Dakota completion cost was $65,782.

I might note, and I think this is always worth remembering in trying to do this, one single well may cost a whole lot less, but when you average in various things that can happen, like fishing jobs, such things as severe lost circulation, and things like that, it has to be remembered that we are dealing with an average cost for the area and not the best cost that somebody maybe has drilled as the lowest cost well in the field.

All of these things have to be included, and it was very interesting in trying to call around and getting some other people's costs how they, whenever they'd say, yeah, we had a problem on this one well, and so that isn't represented, and so I would have to say yes, but it is represented because it has to be included in the average for the area.

Q. Would you now refer to Exhibit Nine and just without reading through it describe to the Commissioners what that shows?

A. Exhibit Nine is a showing of how the fresh water in the area will be protected.

Q. And we do show which formations are bearing fresh water in that area and where they occur, is that correct?

A. That is correct.

Q. In your opinion will the development of this formation adversely affect any fresh water aquifers that are or are expected to be used as domestic or agricultural water supply?

A. No, it will not hurt them.

Q. Were Exhibits One through Nine prepared by you or under your direction?

A. That is correct.

MS. TESCHENDORF: At this time I'll offer Exhibits One through Nine.

MR. RAMEY: Exhibits One through Nine will be admitted.

Are there any questions of this witness?

Ms. Teschendorf, I assume that in the packets here we have all of the exhibits that are on the wall?

MS. TESCHENDORF: Yes, you do.

MR. RAMEY: Thank you.

DAVID W. WILSON

being called as a witness and being duly sworn upon his oath, testified as follows, to-wit:

DIRECT EXAMINATION

BY MS. TESCHENDORF:

Q. Would you please state your name, your position, and by whom you're employed?

A. Yes. My name is David W. Wilson. My position is Vice President of Corporate Development for Consolidated Oil and Gas.

Q. And would you please describe to the Commissioners your educational and employment background?

A. I graduated from Tulsa University in 1968 with a degree in engineering mathematics.

Prior to graduation and for the next six and a half years I worked with Sunray DX Oil Company, subsequently Sun Oil Company after Sun acquired Sunray, in the capacity of a production engineer, reservoir engineer.

I was also an acquisition engineer, which involved property appraisal and acquisition of both companies, as well as producing oil and gas properties, and I designed and was responsible for various corporate economic

models, both pre-tax and after-tax.

After that I joined Champlin Petroleum Company for two and a half years. I was there in charge of exploration and production, economic justification, and assistant to the executive vice president, where I reviewed all corporate investments by Champlin, which is a subsidiary of Union Pacific Railroad. I was in charge of an off shore task force for Champlin Petroleum, and I at the end of that period became Regional Manager for Champlin Petroleum in the Rocky Mountain area.

I subsequently joined Williams Exploration Company in Tulsa as Acquisition Manager for approximately a year and a half. I left Williams Company to join Consolidated in January of 1977 in the dual capacity at that time as Vice President of Corporate Development and Vice President of Exploration.

I have subsequently taken over just the corporate development side. In that capacity I'm responsible for budget planning, acquisition, as well as the Federal and Federal Compliance Group, insofar as pricing and regulations are concerned.

Q. Are you familiar with the economics of the proposed drilling program in this area?

A. Yes, I am.

MS. TESCHENDORF: Is the witness considered qualified to testify?

MR. RAMEY: Yes, he is considered qualified.

Q. You may want to refer back to Exhibit One, Mr. Wilson, but would you describe Consolidated's Dakota infill drilling program, when it started, its development?

A. We began our first infill phase, or the first phase of our infill program in 1978, which was primarily Mesaverde infill program.

After passage of the Natural Gas Policy Act in November of 1978, Consolidated, upon the belief, or in the belief, in reviewing the Natural Gas Policy Act, we began in mid-1979 drilling infill development wells in the San Juan Basin, originally picking out the better locations that had both Mesaverde and Dakota potential.

This program was undertaken based on two primary facts, our estimate of drilling costs at that point in time, and our belief and in the interpretation of the regs that any well drilled after July of 1979, that subsequently qualified for tight gas sands pricing would receive tight gas sands pricing.

That program continued through the end of 1980, to November of 1980, and in this particular area we

drilled fifteen wells in 1980.

Based upon what had happened in the regulatory area, where one more time in the industry by a company accelerating its drilling program, it stood the likelihood of getting a much lower price than if they had waited to drill wells, and based on the fact that as Mr. Ellison mentioned, our costs had escalated by better than 50 percent during the year, in 1980 we, as a corporation, completely ceased our infill development drilling program.

Q. Exhibit One shows the infill -- the Dakota infills that we drilled in that area, is that correct?

A. Yes.

Q. And they're marked with triangles?

A. Yes.

Q. Why are we presenting economic testimony in this case, Mr. Wilson?

A. Because it is now a requirement of FERC that in order to qualify for tight gas sand pricing in an area that infill drilling has been undertaken, that economics be presented to show the necessity of the higher price to justify drilling.

Q. Would you now refer to Exhibit Number Ten and explain that to the Commission?

A. Exhibit Ten are the economics reflecting

our costs, or the economic assumptions, pardon me, that we used in running the economic analyses to evaluate the drilling program in this area to determine what threshold of recovery and production rate performance we had to have in order to justify the drilling, the continuation of drilling in this area.

Some of the major assumptions are that the drilling costs per well, drilling and completion costs, will be $475,400. We included in the economics, both in the costs and in the reserves, the cost of picking up the Lower Dakota zone that Mr. Ellison discussed, because we feel that that is a valid investment to make and if we do not spend the money to obtain the reserves in that Lower Dakota at the time you're drilling the original well, the consumer will never see that gas at any point in the future because you cannot afford to drill that zone on its own.

So on an incremental cost basis we feel that it's a worthwhile investment that will bring more gas, gas supplies to the market.

The other, the other assumptions are -- are fairly straightforward. Operating costs of $150 a month, which I think is important to note that that only includes at the field level operating costs. It does not cover any corporate, general, and administrative expense, which I'll

discuss in the economics later on.

7000 foot depth, I don't need to go through those. I think they're all shown on Exhibit Ten.

The only thing I would like to mention on the fully adjusted gas price, that does reflect Section 103 pricing under the NGPA, with about a $2.50 base price and 1180 BTU, plus an 8 percent severance tax.

I think at the bottom of that page you will see a column that shows initial post-stimulation stabilized production rate, a range of those running from 89,000 cubic feet per day up to 400,000 cubic feet per day, and that rate is shown as opposed to its forecast 20-year recovery in millions of cubic feet.

This, we ran this range of rates in 20-year gross recovery in order to look at sensitivity to prices in oder to -- to determine whether or not to go ahead with the program. This is really the basis for our economics forecast.

In reviewing the results of the wells drilled thus far in the program, our expected pay shows that post-stimulation producing rate of 232,000 cubic feet per day, is what we would expect a typical well, an average well, in this area to do, and that would yield over a 20-year period recovery of 435-million cubic feet.

The economics that we have presented later will incorporate that recovery over a 20-year period.

Q. The only other thing I would like you to point out on this exhibit is the royalty interest typical to Consolidated's holdings. What is that?

A. The total royalty interest, including the base, is 24-1/2 percent, which is a typical interest in this area for Consolidated.

Q. And with that, would you refer to Exhibit Eleven and explain it?

A. Exhibit Eleven discusses why our royalty interest is higher than 12-1/2 percent, and basically what we're showing or saying in Exhibit Eleven is that in the oil business there are two ways to obtain rights to drill and produce on leases.

If you are able to obtain the original base leases under which you only have to give a 12-1/2 percent royalty, then of course that's all that would burden the economics. But in that case you would have paid money up front, or a bonus, in order to obtain those rights to drill, which would be justifiable to include in the economics.

The second means of obtaining the right to drill on a lease is by taking a farm-in from the original lease owner. In this case typically he carves out, retains,

an overriding royalty interest and sometimes that royalty interest is convertible into an even larger working interest.

Consolidated obtained the leases in this area through that second means, where we were not the original party taking the lease; we were the second party. The original party required that we carve out typically 12 percent overriding royalty interest to him, leaving us with 74-1/2 percent.

I think it's interesting to note that in viewing our average economics in the area, the present worth of the 12 percent overriding royalty interest, when equated back to acreage, runs about $300 an acre, which is a fairly typical acreage price in this area.

If we had acquired our acreage through that means, then the same costs would have been justifiable economic cost in the project.

Q. Is this 24-1/2 percent royalty fairly common for other companies in this area?

A. Yes, very common for companies that -- that have subsequently -- that have taken the lease from the original lease owner. In fact, some companies have overriding royalty interests as high as 17-1/2 or 18 percent.

Q. Would you now refer to Exhibit Number Twelve and explain that to the Commission?

A. Exhibit Number Twelve is a series of

output sheets from our economics model that go through the range of rates and recovery as shown on Exhibit Ten, whereby we -- we are attempting to run sensitivity analyses to recovery and rates versus -- for Exhibit Twelve this is before tax with Section 103 pricing, or two times six and 103 pricing.

We were trying to run a range of economics based on our low price, high price, low recovery, and a high -- and a high recovery.

It's a fairly straightforward economics model, showing forecast gross oil and gas production, forecast net oil and gas production. This is to 100 percent of the working interest adjusted by the total royalty. Showing the revenue to the working interest, the net investment required to be made by the working interest owners, the operating expenses, then allowing you to be -- to come to a net income before Federal Income Tax, a cumulative net income, and then showing a 30 percent discounted present worth.

Along the bottom of these runs you will see several economic indicators that most models will -- will put out, cumulative -- several -- several economic indicators, and I think those are all fairly straightforward, and I don't need to discuss those.

Q. Would you now refer to Exhibit Number Thirteen, some pages later?

A. Exhibit Thirteen is the same base economic forecast --

MR. RAMEY: Where is Exhibit Thirteen?

MS. TESCHENDORF: There's another big, empty, white sheet before you get up to that.

MR. RAMEY: Okay.

MS. TESCHENDORF: Before the graphs. Okay?

MR. ARNOLD: Okay, thank you.

A. These economics take the same base forecast as done in Exhibit Twelve, the same pre-tax forecast, and convert those to after-tax economics. The headings there, of course, show the net oil, the net gas, to the working interests after the royalty has been carved out, the revenue to that interest, the operating expense, the net income at the lease level, the capital investment required, and then it's schedules, depreciation, depletion, calculates the income tax in order to come to an after-tax cash flow.

This model gives credit for investments that generate tax credit and the paid income tax on cash flows above -- above investments.

I think that is -- taxes are something that we have to live with, which is why we -- why we incorporate an after-tax economic analysis in -- in the presenta-

tion.

Q. What rates of return were you using in these two exhibits, Twelve and Thirteen?

A. I used a -- Exhibits Twelve and Thirteen actually, those two exhibits were running a range of rate of return versus price versus recoveries.

I think Exhibit Fourteen is -- Exhibit Fourteen, which is a graph, shows the economics and the minimum 20-year recovery required at various rates of return with two different pricings forecasts used, NGPA Section 103, and two times NGPA Section 103.

I think it's important to note, and I should probably go back to Exhibit Twelve, but I think it's important to note that these forecasts assume that prices continue to increase in the future. I have not used low pricing forecasts and they very rapidly get to $10.00 an Mcf, which more than reflects the escalations that would be received under both Section 103 or under stripper pricing, if that would become a factor on any of the wells.

Exhibit Fourteen shows that on a pre-tax basis in order to return, or in order to earn 30 percent, we would need a minimum recovery over a 20-year period of 560-million cubic feet average per well.

At two times Section 103 NGPA pricing,

that minimum recovery required drops to about 280-million cubic feet per well.

Our forecast, based on results thus far of the Dakota infill program, are that the average well over a 20-year period will recover about 435-million cubic feet per well, which is substantially below that we -- that we require to have just to have any major or significant economic return, which is 560-million cubic feet over a 20-year period.

Q. So before tax you were using a 30 percent rate of return,is that correct?

A. That's correct.

Q. Will you now refer to Exhibit Fifteen?

A. Exhibit Fifteen is basically the same type of graph. It plots for Section 103 pricing and for two times Section 103 pricing. It plots the 20-year recovery required versus rate of return. We have based our required rate of return after tax. We have required 20 percent, which requires that the average well in the area over a 20-year period recover 570 MMCF at NGPA Section 103 pricing; with two times NGPA 103 pricing that required amount drops to 285 MMCF per well average recovery.

Q. Will you now refer to Exhibit Sixteen and explain how you came up with your rates of return?

A. Yes. Exhibit Sixteen is a rate of return

justification. It's what we have to look at as a corporation in order to make investment decisions, because we do have strong Fiduciary responsibility to our shareholders.

All investment decisions must necessarily incorporate two major factors. One, represents the concept of what is your money costing you.

In Consolidated's case, or in any corporation's case, there are only two major sources of funding. One source is equity, one source, or selling stock. The second source is debt.

Equity has some cost because shareholders expect some economic return or they will not invest in the stock. The question then becomes how much do they expect to earn on stock. Investors can currently earn 17 to 18 percent on money market funds. They can earn 15-3/4 on very high grade commercial paper. They can earn 16-1/2 on Federally guaranteed CD's. They can earn 14-1/2 on Treasury bills, and they can earn 17 to 20 percent on very high grade corporate bonds that trade on the New York Stock Exchange.

No equity investor will buy stock in any corporation unless he expects to earn a minimum of 20 percent on his investment. That locks in the cost of equity for a corporation.

Debt exists as an alternative source of

capital and debt, we have two, two means of obtaining funds. Those are through the public market, and again going back to the same investors having the same alternative investments, which means that public debentures, public bonds offered, currently investors can earn 17 to 20 percent on high grade corporate bonds, so for any oil and gas concern to raise public funds through the debt method or through debenture, they're going to incur a cost there of about 20 percent.

The second source of debt, of course, is bank debt. In Exhibit Sixteen I've shown a schedule of bank prime rates since early 1979. As you can see, recently it's been very stable in the 20 percent range.

I would like to point out that very few individuals or corporations can borrow money at prime. Typically, most have to pay some percentage of prime or some add on percentage rate to prime.

This is very simple. The banks' money are costing them from people on deposit and through CD's and that type of thing 16-1/2 to 17 percent. They have to require 20 percent interest being paid or they can't -- or they can't exist.

So we're left with our three sources of funds, being equity, costing 20 percent; public debentures, costing 20 percent; bank debt, costing 20 percent, which makes

it very easy to average. We know our average corporate cost of funds, present day, is approximately 20 percent. To earn any less than 20 percent would be to deny our fiduciary responsibility to shareholders because we would be degrading their investment.

The next source of funds which may be brought up, which really is -- is a strong part of the fiduciary responsibility to shareholders, is the investment of cash flow from older properties that typically were made with money costing in the past considerably less than 20 percent. This brings up the second step in the investment decisions that have to made by corporations, which is when you have cash flow available, or when you have funds available, what are the alternative investment opportunities that you have available?

One very safe alternative investment opportunity is represented by repayment of your own corporate debt. Since 1976 Consolidated, like most independents, has spent more in oil and gas development than we've made. Since 1976 we've spent $51.3-million in oil and gas exploration and development. Our profits have been $15.8-million.

This gap, this difference has been funded by bank debt, which is now costing us slightly in excess of 20 percent.

When we have cash flow available from prior investments, we have an absolutely, leadpipe cinch, guaranteed rate of return of 20 percent called pay off your debts. Any project that we would invest in would have to earn more than that or it would make no economic sense to the corporation.

Thus we're left with alternatives. We can also buy commercial paper. We can also buy inner bonds that earn 20 percent. We know we can earn 20 percent, so the question then becomes, how much more should we require for any oil and gas development program or exploration program?

Like most companies, and in our economics we have only reflected the costs at the field level. We also have to consider corporate G & A, which is not a small cost in the oil and gas business any more, and for every dollar that we spend in new capital investment our corporate G & A is going to run approximately 20 percent.

Last year we spent about $20-million at the field level on all projects and it cost us, not reflected in the economics as you would normally appraise them, about $3-million to spend that type of money, plus continuing G & A associated with all the accounting functions which go on even after production.

A good way to look at this is that this

increases the minimum required rate of return from 20 percent to 24 percent. In other words, what we're saying is that for the corporation to earn 20 percent, the project at the field level has to earn at least 24 percent, and that's before risk.

You then get into the -- that breaks you even with alternative investments, again one of the major ones being to pay off our own bank debt, what type of a risk premium should you -- should you require for an oil and gas drilling program. These risks, as we see them, are risks inherent in any drilling operation. Frankly the major risk over the last ten years has been regulatory exposure to price control, the increased taxes, and who knows what in the future, and lower recoveries than estimated.

A very reasonable, and I think minimal, risk premium above absolutely safe investments is 25 percent. If you take 25 percent of the 24, that's 6 percent, which gets us to our minimum required pre-tax return of 30 percent. That's again on a before tax requirement.

I think it's pertinent at this point to point out that it's certainly feasible to only view 20 years of performance on these wells because the bulk of the wells are -- are produced in the first 20 years, plus well in excess of 98 percent of the net present value is derived in the first -- in the first 20 years. So production, even

though there may be reserves in production for 40 to 50 years, those do not -- and that, by the way, is price sensitive, if the price incentive exists beyond that point in time, any reserves produced beyond 20 years would not have any influence on the economic investment decisions being -- being made today.

To reiterate, back on Exhibit Fourteen, using a 30 percent before tax earnings rate, indicates a necessary 20-year recovery of 560-million cubic feet per well, which is certainly in excess of the 435-million expected.

With tight gas sand pricing that requirement will drop to 280, which would make the program viable.

Again I would like to point out these -- the return -- the rate of return and analogy presented so far is before tax. I think we also have to consider after tax economics with the recognition that your after tax rate of return will always be less than your before tax rate of return.

Rather than trying to go through a detailed tax analysis, as I went through before tax analysis, I think we can turn directly to FPC Opinion Number 742. In August, 1975, the FPC found that small producers at that time were entitled to a 20 percent after tax rate of return. This opinion was affirmed in 742-A on July 27, 1976. This was a higher rate than previously allowed but they, the FPC found for the 20 percent minimum after tax -- or the 20 percent

after tax rate of return due to increased risk, higher equity, and greater debt cost for small producers.

I think it's pertinent to point out that at that time the prime rate was averaging 7.86 percent when the FPC allowed an after tax return of 20 percent.

That certainly, with prime rate exceeding now 20 percent, or averaging 20 percent, certainly justifies and after tax rate of return in excess of 20 percent.

But this is not -- it's not necessary to go through any discussion of how much higher should that after tax rate of return be because even with the 20 percent after tax criterion more 20-year gas recovery is required than we will get out of this area.

If you go back to, I believe it's Exhibit Fifteen, a 20 percent after tax rate of return would require that the average well recover 570-million cubic feet over a 20-year period, which is certainly in excess of the 435-million that's expected in this area.

So under both criterion on a before tax basis and on an after tax basis, this program is not -- or let's say can be classified as sub-economic at Section 103 prices.

I would like to point out to the Commission that these are not hollow economic runs that we've made.

We stopped our infill drilling program in 1980 and we will not resume our infill drilling program until sufficient economic incentive through prices are available.

Q. Consolidated is a small producer, is it not?

A. Yes, it is.

Q. And as to how you came up with the 20 percent after tax rate of return, this equates approximately with the 30 percent before tax rate of return, does it not?

A. Surprisingly, the results are very -- are very similar. They weren't designed that way but they came out extremely close.

Q. Referring to Exhibit Seventeen, has Consolidated drilled any Dakota infill wells that will not be economic at Section 103 prices?

A. Exhibit -- yes. Exhibit Seventeen is a list of the fifteen wells, Dakota infill wells, that we drilled in this area in 1980. The exhibit shows the wells, the spud date, and the current economic status at Section 103 pricing.

Out of those fifteen wells we have nine that have been drilled that are not recovering even the interest on their investment at Section 103 prices. We have five wells, or a third of them, that are only marginally covering the interest costs on the investment made to drill

the wells, and we have one well that it's a little bit too early to tell as to whether it is going to be economic at Section 103 pricing.

This is the crux of the reason that we have stopped the infill program.

Q. Mr. Wilson, what are your conclusions therefor as to the necessity of incentive price before Consolidated will continue drilling Dakota wells in this area?

A. They are absolutely essential, as I -- as I mentioned, we will not resume the Dakota infill drilling program in this area absent price incentive greater than what we currently have with Section 103 pricing.

We have better places to go spend our money.

Q. Do you have anything further you wish to add to your testimony?

A. No.

Q. Were Exhibits Ten through Seventeen prepared by you or under your supervision?

A. Yes, they were.

MS. TESCHENDORF: That's all I have of this witness, and I do have a closing statement, if you want it now or later.

MR. RAMEY: Do you want to tender your

exhibits at this time?

MS. TESCHENDORF: Yes.

MR. RAMEY: Ten through Seventeen?

MS. TESCHENDORF: Yes.

MR. RAMEY: They will be admitted.

Any questions of Mr. Wilson? Mr. Arnold.

CROSS EXAMINATION

BY MR. ARNOLD:

Q. Mr. Wilson, I believe you and Mr. Ellison both mentioned that there was a 50 percent increase in contract drilling costs about a year ago, or I'm not sure when the increase took place.

A. They -- they took place, I could recall, in 1978 when we originally were -- were looking at the program to start it. Our estimated drilling and completion costs for a Dakota well were about $275 -$285,000.

MR. ELLISON: Okay, I might answer that. Our footage costs begin in 1980, or the very tail end of 1979, I'm just talking about the footage costs, right at $10.00, make that $10.50 a foot, or something like that.

When we drilled our last well in that area our footage costs were $15.50 and we had an interest in a well by another operator right in the same immediate area

that was drilled in December of last year, that was $19.51 on footage.

All right, when we went out, and of course I think everybody then started shutting down with the drilling in this area, and I'm sure that part of that had to do with the cost going up so dramatically, of course there's been a bunch of rigs, as I understand, a bunch of rigs move out and a lot of things have happened, when we went out here when I was preparing this and checking, trying to get some estimates on what the footage price was at this stage of the game, we find out that they were $15.50 and $16.00 as two of the numbers coming in to us, so apparently the supply and demand situation as far as -- had its affect on the drilling costs going out there. I'm sure their costs have not gone up that rapidly but there's a shortage of rigs, so --

MR. ARNOLD: That was really what my question was to go to here. You said before that the 50 percent in drilling cost, you thought, was strictly due to a rig shortage.

MR. ELLISON: Well, it should be 50 percent -- our total drilling cost did not go up 50 percent from the beginning of the year to the end of the year. Our footage cost --

MR. ARNOLD: The thing is that the cost

went up 50 percent due to a rig shortage.

MR. ELLISON: Yeah.

MR. ARNOLD: Without -- there probably was some inflation built into that, all right --

MR. ELLISON: Yes.

MR. ARNOLD: But I -- and then suddenly you developed a situation the next year where you had an over supply of rigs, and you say the cost levels off. It doesn't appear to me that supply and demand is working all that well. It would appear that 50 percent increase was due primarily to a rig shortage, an over supply of rigs should bring it down. Does it ever work that way any more?

A. Well, I was going to say, just like I said, the one at the tail end of that year that we had an interest in was $19.00. This was actually a contract that was made after we had finished ours.

MR. ARNOLD: So you did have --

MR. ELLISON: It was $19.51 and it -- and I'm saying a year later, of course there should have been some inflation and everything else, if their costs had gone up, it had dropped back down -- apparently the cost out in that area, or what we were quoted here over the last few weeks, they said that they were drilling for $15.50 to $16.00.

MR. ARNOLD: But I presume you think then

that the 50 percent increase was a justifiable increase based upon inflationary additional costs, or otherwise it would appear that cost could come down.

Maybe I just don't understand.

MR. ELLISON: Well, I think part -- part of that could be tied into the fact they also are facing the paying interest, you know, high interest rates on the new rigs brought in, so I'm sure that their -- their increase over that year would probably be greater than the cost of living and greater than 15 percent, but I think they were taking advantage. Again, our good, old, American system, which I agree to as far as supply and demand and things like that, it tends to balance out.

MR. ARNOLD: I agree to it, also, but I think you need to look at it once in awhile and make sure it's working all right.

MR. ELLISON: Yeah. But over the last year it has not increased. In other words, it may have gone higher, we're not sure, see, we dropped out of the picture at that point. I don't know how much higher it got but it is at least no higher right now a year later than it was a year ago.

MR. ARNOLD: Thank you.

MR. RAMEY: Any other questions of Mr.

Wilson? Mr. Chavez.

QUESTIONS BY MR. CHAVEZ:

Q. Mr. Wilson, since your employment with Consolidated Oil and Gas, has Consolidated Oil and Gas consistently paid 20 percent rate of return to its investors?

A. Yes.

Q. Is that --

A. We are not a dividend paying corporation although very few independent oil and gas companies do pay dividends. Investors in any stock are looking for at least a 20 percent rate of return through a combination of either dividends or stock appreciation, and we have been able to do that since I've been with Consolidated.

Q. Is that pretty well standard for the oil and gas industry or say small corporations which -- or businesses such as yours to pay in that amount or is that above average or below average?

A. We're probably slightly above average. How far above average I couldn't -- I couldn't really say, but typically the -- the independent sector since the early '70s has seen two periods where we've had fairly high returns until we get caught in cost/price squeezes. We saw fairly high returns after 1973 when of course the price of oil and

gas both went up. By 1976-77 we'd gotten ourselves caught in a cost/price squeeze, so for the'76-77 era we certainly return to our shareholders 20 percent, although we had done better than 20 percent for the three years prior to that.

We had the same thing coming out of the Natural Gas Policy Act. We had basically'79 and'80 that were above the 20 percent, and 1981 has not been, or we have not returned 20 percent to our shareholders.

But on an average, we'll do that.

Q. Okay, referring to Exhibit Seventeen, there are four wells, the Cane 1-N, Klein 1-M, and the Mitchell 1-E, and the Robinson Brothers 1-N.

A. I just got two of those, Mr. Chavez. Can you go through those again for me?

Q. I'm sorry.

A. Okay.

Q. The Cane 1-N.

A. Okay.

Q. Klein 1-M, the Mitchell 1-E, and the Robinson Brothers 1-M.

A. Yes.

Q. The Dakota zones of these wells produce less than 60 Mcf a day but apparently these are multiple completions, is that correct?

A. Yes, they are.

MR. ELLISON: The Mitchell well isn't. It's a single.

MR. CHAVEZ: Oh, that's right, the Mitchell 1-E would be a single.

Q. Okay, then would not that well qualify for a stripper gas price?

A. Yes, that well would qualify for a stripper if that 35 Mcf a day stays, of course, below 60,000 per day, and it's still indeterminant even at stripper price as to whether it's economic because the stripper price is not on a BTU adjusted basis; not that much in excess of the Section 103 price. It's about fifty cents per million BTU additional price.

Q. Okay. Does the Mesaverde formation, say like in Klein 1-M, which is a very low Dakota producer, does production from the Mesaverde zone, or the other zone, whichever is completed in that well, is that what keeps that well above stripper classification?

A. I believe that's correct. Unfortunately I don't have the other zone's production, but I don't think as yet we have qualified that as stripper, and we have one person in our company that watches all wells being produced company-wide to qualify for a stripper status.

Q. Okay. Going on to the idea of stripper pricing, Exhibit Number Thirteen, under Section 103, where you have the printout, computer printout, recovery of 555 MMCF gross with 20 year recovery, -- well, I have difficulty reading this.

Referring to that particular page -- do you have that?

MS. TESCHENDORF: The first page of Exhibit Thirteen?

MR. CHAVEZ: No, it would be Exhibit Thirteen, where the heading says Section 103 Price 555 MMCF Gross.

A. Is that Section 12 or 13?

Q. Well, I thought I --

A. It's easier to work with Section 12.

Q. Okay, it's Section 13, actually the second page of Exhibit Fourteen.

A. Okay.

MS. TESCHENDORF: Okay.

A. Okay.

Q. Okay, on that particular hypothetical well, it shows a total net gas of 490, and I guess that would be MMCF, is that correct?

A. Uh-huh.

Q. This would fit more your typical Dakota well?

A. Yes, although we keyed that off the -- the primary part of the forecast that we made sure was correct was the first 20 years, so go right above there and that's roughly 423.

Q. Okay, and your --

A. But that's not the typical because the 550-million gross is -- is gross before deduction for royalty, whereas that column that you're looking at is after adjusting for the 24-1/2 percent royalty interest.

Q. Okay.

A. That's net production whereas the label is gross production.

Q. Okay. Well, referring to Exhibit Ten, you said that your forecast for 20 year recovery MMCF, typical was 435 MMCF?

A. Yes.

Q. Is that gross?

A. That's gross, and that would imply approximately -- I can get you the number very quickly. Approximately 330 net to the working interest.

Q. Okay, so which of this then would be more -- which one of these pages would be more appropriate?

Maybe the previous page which shows a --

A. Actually, Exhibit Twelve is alittle more descriptive to work with because that shows in all of the computer runs in Exhibit Twelve it shows both gross and net production.

Q. Okay, which -- which one of those pages would be for your typical well, then?

A. The typical well would be the -- the one labeled -- it's about five or six sheets back. It's labeled Section 103 Price 435 MMCF Gross 20 Year Recovery.

Q. Okay. Okay, on that you show a rate of return of 22.12 percent at the bottom.

A. Uh-huh.

Q. Okay, that's before taxes?

A. That's before taxes. All of Exhibit Twelve are before tax economics.

Q. I note that in the year 1987, between '87 and '88, the well production itself switches from what would be a Section 103 price to make it eligible as a single completion for stripper gas price.

A. Yes.

Q. And the revenue does not show that change.

A. I think it does, sir. In 19 -- at that

point in time our average price in 1988 is $4.75, average gas price, if you --

Q. Which page is that on?

A. It's not shown. You'd have to calculate it based on -- you would have to back from the revenue. You've have to back out the condensate income and then divide that by the net gas. It works out $4.75, which is considerably in excess of stripper price, currently.

Q. At the current rate of increase of stripper price, then?

A. That's about what stripper pricing would be at that point in time.

Q. Okay. Back on Exhibit Ten, where you forecast a 20 year recovery, you expect a 435 MMCF in 20 years. This is the typical well. Does this include the new wells which were completed and put on production?

A. Yes, it includes the -- the reviewing not only the 15 wells that were drilled last year and the performance of the wells drilled in 1979, plus general knowledge in the area, since we operate well over 200 wells in the San Juan Basin since the late '50s, and it's based on a typical rate/time performance projection, based on -- on the way the Dakota wells perform.

Q. Okay. In the previous testimony by

Southland Royalty they showed the forecast for this area of ultimate recovery, which was about three quarters of this volume. Have you reviewed their exhibit on how they calculated the volumes and tell us where your differences might be from theirs in the same general area?

A. No, I have not -- I have not reviewed theirs and felt no requirement to because we have drilled the infill wells in this area and we're very comfortable in looking at performance on our own wells with our -- with our completion techniques.

If the Southland reserves are -- or recoveries are lower, than that would further enhance our argument, I would think. Maybe we're too optimistic in the forecast. I certainly don't think that we're pessimistic.

Going back to this stripper notion very quickly, I think that the prices that we're using at the times these wells qualify, if that incentive is even available to producers in 1987, 1988, because again, one of the risks in any program of this nature is that we haven't had a three year period in the 1970's where the entire regulatory pricing situation hasn't been totally turned upside down, so I don't know that I could count on great stripper incentive prices in 1987 or 1988, but I think it is pertinent to point out that the price we're assuming in our economics is considerably

above stripper pricing allowed today.

Q. And the idea of multiple completions, should you receive this tight sands designation and the wells be eligible for Section 107 pricing, would you still continue to drill these multiple completions or Dakota singles in this area?

A. Well, it's -- it depends on at what point in time we would reinstitute our infill drilling program and, frankly, what the pricing incentives are at that time and what the regulations are at that time.

Q. What -- do you have a well planned at this time for which you could get the go-ahead once this --

A. No, we do not.

Q. Okay.

MR. ELLISON: We don't have any more Mesaverde infills to drill out in this area. We have drilled up our Mesaverde infills and all that is remaining are single Dakotas if we were to do any drilling out in this area.

Q. Okay.

MS. TESCHENDORF: I'd like to point out a couple things, too, on these strippers with Mr. Ellison.

Mr. Ellison, on Exhibit Seventeen, all these Dakota infills, I believe all of these have been looked at to see whether or not they would qualify for stripper prices,

is that correct?

MR. ELLISON: They have been. The Mitchell 1-E is the only one that's just recently dropped down in this category and I think it's being reviewed right now.

MS. TESCHENDORF: But up to this point it has not been eligible for stripper pricing, is that correct?

MR. ELLISON: Correct.

MS. TESCHENDORF: And another thing I wanted to point out, I believe you testified that many of these wells were targeted as duals because the costs were so great that you felt that the increase in production might pay back more of the cost, so that even if the Dakota zone was a stripper because the FERC regulations require adding production, you still might not be able to qualify for the stripper prices, is that correct?

MR. ELLISON: Yes, that's correct.

MR. CHAVEZ: Okay, that's all the questions I have for Mr. Wilson.

MR. RAMEY: Mr. Nutter, did you have a question?

QUESTIONS BY MR. NUTTER:

Q. Mr. Wilson, I believe you stated that under your assumed economic picture with a 74-1/2 percent

working interest in the wells and a requirement of 30 percent rate of return before taxes, that you'd have to have 560,000 Mcf to make a well pay.

A. Over a 20 year period.

Q. Under the Section 103 prices.

A. Yes, sir, that's correct.

Q. And some 280,000, I believe it was, something in that vicinity --

A. Yes, two times 103 prices.

Q. Right.

A. Yes, sir.

Q. Now, you also stated that you felt that the average well in here would recover only 430,000 Mcf, is that correct?

A. Yes, sir.

Q. Now that's the average well in what area, the entire area that Consolidated is requesting here?

A. No, sir, in this instant area and in the area of our 1980 infill drilling program before we ceased it.

Q. Well, I mean the 430,000 is the average reserves in the 48 sections that you're seeking the designation for?

A. It's based on the performance that we have seen on the wells that we have drilled in this area with

our completion techniques, and they're not -- we're not speaking of them in terms of reserves, we're speaking of -- of estimated recovery over a 20 year period.

Of course, reserves are quite sensitive. Whether or not these wells will produce beyond 20 years is directly a function of price and whether you can afford to operate them at that point in time.

Q. The wells that you've got in there now, many of them have produced 20 years or more, though, haven't they?

A. Yes.

Q. Okay. Now, the order that Consolidated has under appeal here today granted a portion of the area and denied a portion of the area. Now, in the portion of the area that was denied there has been recovered reserves so far, or in other words, ultimate recoveries that far exceeded the 560,000 Mcf that you think necessary, haven't they?

A. In some areas, yes.

Q. As a matter of fact --

A. But again, this is --

Q. -- isn't it true that you've got wells in this area that recovered over 2 billion cubic feet of gas to date?

A. Yes, sir, that's true, but when you

drill the offset you -- you can't say that you would recover that in the offset well.

Q. Well, wasn't the testimony in the infill drilling hearing such that it was indicated that the original reserves -- or that the reserves under the undrilled 40 -- 160 would be almost equal to the reserves under the drilling 160?

MS. TESCHENDORF: We have not testified as to that.

MR. NUTTER: Have you offered any exhibits here showing the actual reserves under these tracts today, Ms. Teschendorf?

MS. TESCHENDORF: I don't -- other than our Exhibit Number One, which shows cumulative production of wells that have been producing, and the 1980 production, that's all we have submitted to you.

MR. NUTTER: So we do have cumulative production from the original wells through 1980 in this area, is that true?

MR. ELLISON: Yes. I'd like to address the subject, Dan.

What we are finding, and that is in the infill, we're finding some wells in which we're seeing original pressure. We have run across three or four of them in which

the pressure was grossly depleted. The majority of them have been just slightly depleted.

So we are seeing a range and I'm not sure at this point, you know, as far as to pick ahead of time when you were going to drill this well what you're going to run into. I'm not sure that we can really see that, but we have seen the range all the way from original pressures, all the way down to, I think one of them we found in the area like 580 bottom hole pressure, which showed that it definitely had been, but we have not been able to point out and say what we are going to see in any particular well.

MR. NUTTER: Well, isn't it also true that on the original drilling program here that some pressure differentials were detected in the drilling of the original wells? Some wells had higher pressures than others?

MR. ELLISON: What I've seen of it, yes, but I haven't seen the wide variation. I've seen several hundred pounds, and just looking at some pressures I saw several hundred pounds. I did not see those that were quite low, like we did experience in the case in point, the Mitchell 1-E Well, in which we did see a gross depletion on it. But we have seen the full range and so from a standpoint of producing gas from the total area, that the infill program is necessary because there are certain areas that it's not being --

that it's not being drained and it's a matter of trying to pick and choose and not really knowing where we're going to find depletion and where we're not going to.

Q. I don't know who to address the question to, you, Mr. Ellison, or Mr. Wilson, but in order to make a determination of whether the infill -- or the tight formation price is a necessary incentive here, isn't it necessary for the Commission in looking at the economics of this to know what the reserves are under the -- under the area? We know that the reserves are going to be better in portions of it than they are in other portions. The Commission did in the original order grant the tight formation part -- designation in the outer part of Consolidated's area where the reserves were less and where it was obvious that the incentive price was necessary.

In the sweet part of the pool I don't know if the incentive price is necessary and we don't have a reserve picture here, a reserve calculation, to tell that it is necessary.

A. Well, I think that the problem with that argument, though, Mr. Nutter, is that if you go through in this area and carve out the good wells from the area, those that will qualify, if you take a look at Exhibit Seventeen, for example, the fifteen wells that we know abso-

lutely what they're doing because they're wells that we drilled last year, if you go through and carve out all the wells that don't need the incentive, then you leave yourself in the position that the wells that are much less than the average wouldn't be economic at $12.00 a Million BTU or $15.00 a million BTU.

Q. And Consolidated is not going to drill uneconomic wells no matter what the price is, so out on the edges where you don't have any reserves, you're not going to drill wells if the price is $1000 an Mcf if it's not going to make enough MCF's.

A. Well, we're, again, not talking about reserves. We're talking about rate performance that we have a handle on based on the wells that we've drilled thus far, and just for descriptive purposes, what that translates into as far as our 20 year economic forecast period.

Q. But you're talking about fifteen wells there that have a very short production history. What I'm looking at is a given area that has a 20 or 25 year producing history and cumulative reserves up there will show that over 2-billion cubic feet of gas has been produced from many of those wells.

Now, assuming that the infill drilling program is necessary in order to recover the gas, you can

expect to approach 2-billion cubic feet on some of those infill wells, I believe, and you haven't separated the 2-billion cubic feet wells out from the -- from the marginal wells on the edge.

A. We drilled in these wells. This program of which -- again I go back to Exhibit Seventeen, which is actual performance on wells drilled, we drilled what we thought were the better locations in that area. Any -- any corporation is going -- going into an infill drilling program will high grade.

Q. I believe that.

A. Okay, and that's what we did, and it's based upon that average performance of the wells drilled thus far. As we step out into weaker areas in all probability the performance would not come up to this level.

Q. But you don't have calculated reserves for those tracts, for those wells that are drilled, do you?

A. No, that's -- that's a meaningless number, because again, our economics are dependent upon what income will be produced from the wells early in the life and certainly extending to a period of no more than -- no more than twenty years.

The reserves in this area, if you had an extremely large price, these wells would produce 70 - 80

years and result in enormous reserves.

Q. Well --

A. But again, even producing beyond twenty years is not worth anything to an investor. It doesn't influence your decision. You are sensitive only in economics to what the early production history is on a well.

Q. Well, this is not a question, it's merely an observation, but I was noticing an article in the Western Oil Reporter the other day regarding tight formations.

They said one of the attractive things about the tight formation drilling is that the reserves are being depleted over a forty or fifty year period and long after permeable reservoirs have been depleted, they've got money in the bank waiting to be produced.

A. That -- that may be true, but those reserves are still going to be there.

Q. But you're looking at today's cash flow and saying we can't drill these because we don't have a high enough cash flow. You're overlooking the fact that you've got 2-billion cubic feet of gas to be produced forty years from now -- or --

A. I'm not overlooking that fact at all. I can go drill those wells in ten years or in fifteen years, whenever it makes economic sense, but at the present time I

have a bank debt costing 20 percent interest that I know I can earn 20 percent on there. At an effective interest cost of over 20 percent the average well you drill today in 21 years would be producing about 11-1/2 thousand cubic feet per day, a typical well in the 21st year. That is worth on today's basis .004 Mcf per day, which --

Q. Well, et's hope interest rates aren't 20 percent 20 years from now.

A. Well, I do too, but we didn't create those and they certainly represent -- we know we can take our cash flow from old properties and pay off bank debt and earn a 20 percent guaranteed rate of return. It makes no sense for us to drill wells and earn less that that on a present day basis; when interest rates drop below 10 percent, then we may change our criterion to some extent.

MR. NUTTER: That's all the questions and observations I have.

MR. RAMEY: Thank you. Mr. Chavez?

MR. CHAVEZ: Along those lines, before this hearing is over, could you perhaps circle those wells on Exhibit One, or indicate which wells produced over 570 Mcf for the first 20 years of their life, and those which are expeeted to produce that much or more for the first 20 years of their life?

It seems like on the east side of this area which you're applying for there are these wells which, as Mr. Nutter has addressed, have had these high recoveries, yet on the west side the recoveries aren't -- aren't as high, and that would probably be helpful in making a decision on this, if you could just indicate --

A. I think on those, maybe that is actually there and it would be just a matter of circling them, but it does show the cumulatives, those that are over that amount.

MR. CHAVEZ: Well some of these have produced for more than 20 years.

A. Well, I was just going to say -- okay, you're talking about more than 20. I'm not sure that we have the records.

MR. ELLISON: I don't think that we do.

A. I think our best bet would be to circle those that have produced over -- over the 2-billion that you're talking about, just off the cumulative map.

Basically, the majority of those wells were drilled 20, 21, years ago, in that range. In other words, there were a few wells drilled, let's say, in '57. The majority of them were probably drilled from '59 to '62, so we're really talking about the cumulatives up there being approximately 20 years.

MR. CHAVEZ: Okay.

A. In this area. But I think that the cumulative numbers would be basically representative of the 20 year --

MR. CHAVEZ: Okay. I have some questions for Mr. Elliison now.

Mr. Ellison, on Exhibit Number Five, four of the wells which you note with a parenthetical number one are not within but you say near the area of this application; however they are five or six miles away.

Do you consider that -- that that -- the four bottom wells on the tabulation -- do you consider that to be representative of this area at that distance?

WEll, of course, not including, but I think that the Dakota formation itself, I think typically, as is shown, that it has been tight out in that general area. Going back to the previous Southland case, some of that stuff was out of their area and yet was considered typical of Dakota production, although it wasn't within their area, and these, let me just point out where a couple or three of these were. I think one of them is like, what, in Section 2, I believe, if I'm not mistaken. Another one is right down here in -- in --

MS. TESCHENDORF: 13 and 24?

MR. ELLISON: Let's see Those in 32 -- excuse me, 31 and 32. We've got one in Section 2, which would be right here, just about two miles off of the map. One is in 14, which would only-- that would be again about two miles off, or actually, only a little over a mile off. So that would take care of those two.

We have one that's in Section 18 of 11, which is on over a way, and then the one in Section 4 of 32, 12, which is right here.

So they're just barely off the map that we're talking about, so they somewhat represent what is happening in the Dakota in that area.

MR. CHAVEZ: Okay. On Exhibit Eight-A the well cost here, you show a compressor at $16,000 to rent one. Compressor and work string, what was the purpose of this?

MR. ELLISON: Okay, where we were doing on our compression and -- of course part of this had to do when we dualing,especially with the Mesaverde, and in the dual was the fact that we were taking a compressor out there. We were using nitrogen to clean it up and then before we moved on we were needing to know what was happening in these lower zones and get them cleaned up prior to moving on to the next zone.

We were using the compressor to circulate and jet the fluid out of the hole and get as much fluid back out of the hole as possible.

I do know that some of the others out in that area are using gas to do this. We were using compressors to do this. Another approach sometimes is to go ahead and frac and then later on try to swab back.

But it's -- it's a trade off somewhat of how long do you leave your -- your rig on there? Do you swab or do you use a compressor to try to clean it up, and it's just sort of a difference in technique

If you've got a single zone some people just go ahead and frac it and move off and two or three weeks later come back and try to do it.

We did try that on some of these wells. Apparently other people had success doing it, and we ended up having -- several weeks later going out there and putting a rig on, back on it, and sitting there swabbing, and had to swab for a number of days trying to get the well to clean up enough so that we could even make a test or anything else.

So it's just a difference in technique and we were just using a compressor to pump air down on the annulus side and let fluid up the tubing.

MR. CHAVEZ: Is this a common practice

in areas like this where you may have low productivity wells and liquids being produced?

MR. ELLISON: Yes. In other words, I -- it's done in quite a few areas. I'm not sure -- I know that are others that are using this technique in this area. I don't know who all is doing it, but others -- I am aware of some right in this area that are using gas, and they put gas in the backside and lift it up the tubing, and I'm not sure how they justify their price of buying gas and doing that or offset it against the -- against the price others are paying to rent a compressor, so it's using the same technique, just one is using a compressor and the other is using high pressure gas to go ahead and do the same thing.

MR. CHAVEZ: Okay. Under other completion work you show -- is that figure 10 days as a quantity, 10 days $2500?

MR. ELLISON: Yes, uh-huh.

MR. CHAVEZ: And is that for the -- just the Dakota portion of the completion?

MR. ELLISON: Yes. That would be both zones because we do have the problem of having to work with one zone and trying to clean up the Lower Dakota, and this does take, by the time you move in and then you do the perforating and the fracing and then you spend a couple or three

days with cleaning up that zone, and then you move -- then you set your bridge plug and move on to the next zone, and it's a total -- what I'm putting in there is a total of 10 days for the completion unit with -- with some of their equipment that they carry along with it.

So we're dealing with a total of 10 days from the time you start to move the completion unit in until you complete in both zones and try to clean both of them up and move it off.

MR. CHAVEZ: Are there other operators say within the general area, say a couple townships around it complete in the Upper and Lower Dakota that do not use this clean up technique --

MR. ELLISON: I'm not aware particularly of how many others are trying to work or do anything on the Lower Dakota. I know that some have talked about problems in the Lower, you know, that they just automatically write off the Lower Dakota and say it's wet. And I know that some of them have said so and even in this area.

We have one well down right in this general area in which the initial well is not producing hardly anything from the Upper Dakota and the Graneros section, and we drilled it and drilled into the Lower Dakota and got a kick on it which surprised everybody, and we have a good

Dakota zone out of the lower zone, and we have a good Lower Dakota Well right off over in this general area.

MS. TESCHENDORF: Mr. Ellison, could you define for the record what area you're talking about?

MR. ELLISON: Okay, it is our Clayton 1-M Well, I believe, or 1-E Well, which is -- I'm trying to remember the exact location. It was in Section -- let me see, I don't have a map so I'm not sure -- but it is in Township 30 North and 12 West.

MS. TESCHENDORF: A couple miles southeast of the desired area?

MR. ELLISON: Yeah, three or four miles southeast of this area right in here. I'm not sure about the exact section, but we did, that is another place in which we were successful in getting additional gas reserves out of the Lower Dakota in this area.

And the Upper Dakota, when we fraced it and tried to bring it back, the original well was not very good in the Upper Dakota and our new well, when we fraced it we just got almost nothing out of it, but the Lower Dakota, it's been a good Lower Dakota well. Or a good Dakota well.

MR. CHAVEZ: These other producing Dakota wells in your efficient area, are they also completed in the Lower Dakota or the majority of them, or --

A. Well, part of them are, not all of them. The majority of them are, yes. We have made an attempt. I'm not sure, I think that we would agree to some extent, in this area right in here, that the Lower Dakota does, our experience has been that apparently it is unproductive.

MR. CHAVEZ: Uh-huh.

MR. ELLISON: But in this area and in this area we have gotten some production, some gas production out of the Lower Dakota, and we are getting some, a little bit of -- we are getting some water with it, but you know, it's a trade off, so can you afford to handle the water to get the additional gas production, and at this point we are saying that it is worth the extra effort. It's more expensive to do so and we are having additional operating costs. They're due to handling of the water. But at least right now, in our judgment, it is worth the extra expense to do so.

MR. CHAVEZ: Have your own supervisory costs of drilling some of these wells risen over, say, the last year and if they have, to what extent?

MR. WILSON: Are you talking about the G & A costs and --

MR. CHAVEZ: Yes, supervisory while drilling.

MR. WILSON: Supervisory and above?

MR. CHAVEZ: Uh-huh.

MR. WILSON: Such as things as the cost for these kinds of hearings and --

MR. CHAVEZ: Well, I think the reason I'm asking this question is because of the exhibit that you presented in your previous testimony when this case was first heard showed superintendent cost of $4000, and that would be Exhibit Nineteen.

Exhibit Eight-A for today's testimony shows a cost of $7500, which is almost 50 percent --

MR. WILSON: Yeah, I can --

MS. TESCHENDORF: Mr. Chairman, we have not incorporated the record or any of the exhibits from the previous testimony and therefor I would request that the statement as to that would be stricken from the record.

MR. PEARCE: Excuse me, Ms. Teschendorf, if you would refresh my recollection, I believe in your opening statement this morning you mentioned that in fact testimony had been presented previously and that it was a matter of public record. Am I mistaken in my recollection of what you said?

MS. TESCHENDORF: I said that the Southland exhibits that we were referring to had been made a matter of public record.

MR. PEARCE: Your position, then, on this question is that the Southland portion of the previous case, which has been dismissed, is a matter of public record, and yours is not, is that your position?

And if so, could you explain that to me, please?

MS. TESCHENDORF: All right. This is a -- this is a de novo proceeding. I have not, I think to keep the record clear, I have not incorporated the transcript or the record previously submitted.

Southland's exhibits, or the information that we have included from Southland, from other companies, from El Paso, is evidence that we can obtain from any source. Perhaps I should not characterize it as having been taken from the previous case.

But in any case, this is a de novo proceeding and in order to keep the record clear, I would prefer just to have no reference to the previous testimony at all.

MR. PEARCE: Excuse me, if I may break into question the witness for a moment. I believe we are with Mr. Ellison.

Your Exhibit Eight-A shows administrative costs of some $7500, is that correct, Mr. Ellison?

MR. ELLISON: That is correct, sir.

MR. PEARCE: Could you tell me, sir, the rate of increase that Consolidated Oil and Gas has experienced in that number over the last twelve months?

MR. ELLISON: Okay, I think what I can answer on that is, earlier I didn't realize as far as when preparing earlier AFE's that there had been as much charge to that account, and if you'll look at the average, we find that actually that number is 9000, the average of those fifteen wells.

I feel that we can reduce that but if we had people assigned to those wells during the drilling and completion, and had -- in other words, that we actually had people assigned to the wells longer than what I had earlier anticipated, I therefor feel that I need to charge and expect more to be charged against that number than what I had originally thought.

I think that I can do better than what the average was but -- but basically if you assume what a charge is for the people that were assigned to it, and we did use some contract personnel, originally we didn't realize we were going to, but we were so thin we had to hire contract personnel on some of our drilling completions and of course the price that we're dealing with there is now in the neighborhood of $350, $400 a day, using them, and so that

isn't assigning all that much to superintendent. That is direct supervision, is direct supervision, is what that is.

MR. WILSON: Can I also point out that this cost of superintendents is not reflective of the G & A burden that I referred to in the -- in the economic discussion. This is, again, just field level, field level cost.

MR. ELLISON: The number down at the lower part is the only G & A in the sense that you referred to, which is the overhead, which is shown as $1500 for the total. That is the only amount that we as a company are allowed to charge has to do with what our contracts call for, that the superintendents is the actual, direct supervision that actually occurred on the well.

MS. TESCHENDORF: Mr. Ramey, can I consider that you -- may we strike references to previous testimony?

MR. RAMEY: I think we can do that.

MS. TESCHENDORF: Thank you.

MR. RAMEY: We do like to keep the record clear.

Any other questions of the witnesses?

MR. CHAVEZ: Just one more of Mr. Ellison. Mr. Ellison, are you aware of whether or not operators in the surrounding area consider the Lower Dakota zone as productive

and try to make completions in it?

MR. ELLISON: I have asked one or two around there. I think maybe one or two are maybe attempting to in that area. I have talked to one or two who say, well, we just consider that the logs say that they're wet, so we don't make any attempt at all.

But as I pointed out on this particular one, the logs on that one, and the Phillips 1-E, indicated it was wet. We were very much surprised when we perforated it and tested it, naturally, that we flowed gas from that zone.

MR. CHAVEZ: Okay, so --

MR. ELLISON: So it's just a matter of interpret -- part of it's a matter of interpretation of the logs and what you experience.

I have to admit that over in the portion of 31 North and 12 West the indications are, in the attempts that we've made in that area, even though the logs indicated that they were gas productive, that we have had to handle quite a bit of water in that area, and we have had problems trying to handle it.

But that on 13 West we thus far are happy with the results as we were with the well that I made mention to earlier in 30 North and 12 West.

MR. CHAVEZ: Okay, then could part of

the difference between your calculated recoverable reserves and some other operators be because you do include that Lower Dakota zone and some of the operators may not?

MR. ELLISON: That is possible. I would also interject that I think that was referred to in the reference to the -- to the Southland Royalty reserves was based upon that particular area which appears that based upon the cumulative reserves in that area, I would say, are less, upon an average are less.

I think that the area that they were talking about and dealing with, based upon the history, would indicate that their reserves in that area are even less than in this area.

MR. CHAVEZ: Okay, that's all the questions I have.

MR. RAMEY: Any other questions of the witness? He may be excused.

Anything further in this case, Ms. Teschendorf?

MS. TESCHENDORF: Yes, sir. In the course of our presentation today Consolidated has shown that the average -- average in situ gas permeability throughout the pay section is less than one tenth of a millidarcy.

We've shown that stabilized production

rates against atmospheric pressure of wells completed for production in the Dakota, without stimulation, are not expected to exceed the maximum allowable set out in the FERC guidlines.

And we've shown that wells drilled into the Dakota are not expected to produce more than five barrels of crude oil a day.

Clearly the Dakota meets the geological and engineering criteria for a tight formation.

However, as we've shown, infill drilling has already taken place. The evidence presented, however, has established that the majority of these infills will be uneconomic and that Consolidated cannot pursue its Dakota drilling program absent an incentive price.

The economics described to you by Mr. Wilson clearly indicate that the costs involved justify the incentive price.

We've also shown that the royalty burden on Consolidated's leases makes an incentive price necessary.

It is submitted that the FERC intended all extraordinary costs to be considered in determining whether reasonable incentives are necessary.

IN the San Juan Basin part of Consolidated's costs must be ascribed to the high royalty burden it carries.

NEW MEXICO OIL CONSERVATION COMMISSION

COMMISSION HEARING

SANTA FE, NEW MEXICO

Hearing Date SEPTEMBER 29, 1981 Time: 9:00 A.M.

NAME	REPRESENTING	LOCATION
Conrad Reid	Dallas Gas Pipeline	Midland, TX
Richard A Mendenhall	SELF	Midland Tex
Paul W. Benckell	El Paso Natural Gas Co.	El Paso TX
Jeff Pearl	El Paso Natural Gas Co.	El Paso, Texas
Lynn Jenkins	Consolidated Oil & Gas	Denver, Co
MARCAN THOMPSON	SOUTHLAND ROYALTY CO.	FT. WORTH, TEX
William L. Carr	Campbell, Byrd & Black	Santa Fe
Sue Umshler	USGS, CD	Albuq, NM
Bob Shaw	Byram	Santa Fe
E. Chavez	OCD	Artesia
Floyd E Ellesar, Jr	Consolidated Oil & Gas, Inc	Denver, Colo

NEW MEXICO OIL CONSERVATION COMMISSION

COMMISSION HEARING

SANTA FE, NEW MEXICO

Hearing Date SEPTEMBER 29, 1981 Time: 9:00 A.M.

NAME	REPRESENTING	LOCATION

To summarize, both the engineering and geological evidence, and the economics, show that the Dakota should be qualified as a tight formation, and if the Commission should deny Consolidated's application, it would be violating its statutory mandate of conservation and prevention of waste, since Conosolidated would be unable to resume drilling and producing in the area.

MR. RAMEY: Thank you.

Anyone have anything further to add in this case?

If not, we'll take the case under advisement.

(Hearing concluded.)

C E R T I F I C A T E

I, SALLY W. BOYD, C.S.R., DO HEREBY CERTIFY that the foregoing Transcript of Hearing before the Oil Conservation Division was reported by ~~me~~*; that the said transcript is a full, true, and correct record of the hearing, prepared by me to the best of my ability.

Sally W. Boyd

REPORTER'S NOTE:

*This hearing was recorded by Florene Davidson of the Commission's staff in the absence of the reporter. Thereafter, and using the tapes provided by her, the reporter transcribed the said hearing.

SALLY W. BOYD, C.S.R.
Rt. 1 Box 193-B
Santa Fe, New Mexico 87501
Phone (505) 455-7409

CORRECTED COPY

FLUID SAMPLE DATA

Sampler Pressure _____ P.S.I.G. at Surface
Recovery: Cu. Ft. Gas _____
cc. Oil _____
cc. Water _____
cc. Mud _____
Tot. Liquid cc. _____
Gravity _____ ° API @ _____ °F.
Gas/Oil Ratio _____ cu. ft./bbl.

		RESISTIVITY		CHLORIDE CONTENT
Recovery Water	@	°F.		ppm
Recovery Mud	@	°F.		ppm
Recovery Mud Filtrate	@	°F.		ppm
Mud Pit Sample	@ Fresh water	°F.		ppm
Mud Pit Sample Filtrate	@	°F.		ppm

Mud Weight _____ vis _____ sec.

Date 7-31-80 Ticket Number 727294
Kind of D.S.T. CASED HOLE Halliburton Location FARMINGTON
Tester MR. BROWN / MR. ROBLES Witness
Drilling Contractor SPARTAN DRILLING COMPANY DR BC

EQUIPMENT & HOLE DATA

Formation Tested Basin Dakota
Elevation 6940' Ft.
Net Productive Interval 51' from 7284-7445' Ft.
All Depths Measured From Kelly Bushing
Total Depth 7480' Ft.
Main Hole/Casing Size 4 1/2" 10.5# Liner
Drill Collar Length - I.D. -
Drill Pipe Length 7229.9' I.D. 1.995"
Packer Depth(s) 7249' Ft.
Depth Tester Valve 7235.5' Ft.

Cushion TYPE Fresh water AMOUNT 4 bbls. Ft. Depth Back Pres. Valve 1000' Surface Choke 1/8" Bottom Choke 5/8"

Recovered 240 Feet of water
Recovered Feet of
Recovered Feet of
Recovered Feet of
Recovered Feet of

Meas. From Tester Valve

Remarks See production test data sheet

Q-Questionable

TEMPERATURE	Gauge No. 7489 Depth: 7245 Ft.	Gauge No. 5160 Depth: 7257.2' Ft.	Gauge No. Depth: Ft.	TIME (00:00-24:00 hrs.)
	24 Hour Clock	24 Hour Clock	Hour Clock	Tool Opened 0056
Est. °F.	Blanked Off No	Blanked Off Yes	Blanked Off	
Actual 190 °F.	Pressures	Pressures	Pressures	Opened Bypass 1100

		Field	Office	Field	Office	Field	Office	Reported Minutes	Computed Minutes
Initial Hydrostatic		3375 0	3120.6	3192 0	3117.2				
First Period Flow	Initial	130.8	346.3-0	128	352.5 0			—	—
	Final	130.8	150.3	128	147.4			120	126
	Closed in	2383	2382.2	2426.8	2382.1			484	478
Second Period Flow	Initial							—	—
	Final								
	Closed in								
Third Period Flow	Initial							—	—
	Final								
	Closed in								
Final Hydrostatic		3590 0	3120.6	3320 0	3117.2			—	—

FORM 181-82 — PRINTED IN U.S.A.

FORMATION TEST DATA

LITTLE'S 11033 75C 2/80

Legal Location Sec. - Twp. - Rng. 14-31N-12W
Lease Name EAST
Well No. 7-E
Test No. 1
Tested Interval 7249-7480'
Field Area BASIN DAKOTA
County SAN JUAN
State NEW MEXICO
Lease Owner/Company Name SOUTHLAND ROYALTY COMPANY

(9)

727294

Casing perfs._____ Bottom choke_____ Surf. temp_____ °F Ticket No._____

Gas gravity_____ Oil gravity_____ GOR_____

Spec. gravity_____ Chlorides_____ ppm Res._____ @_____ °F

INDICATE TYPE AND SIZE OF GAS MEASURING DEVICE USED_____

Date Time a.m. p.m.	Choke Size	Surface Pressure psi	Gas Rate MCF	Liquid Rate BPD	Remarks
2218					On location, made up tools
2218					Trip in hole with tools
0016					On bottom
0056					Hydrospring opened
0056					Moderate blow to surface
0101	Blow Hose	.25#			
0102	"	1			
0103	"	2			
0.04	"	3			
0109	"	3.5			
0118	"	4			
0123	"	4			
0128	"	4.5			
0133	"	4			
0138		4.5			
0142		4.5			Gas to surface
0147	3/4"				Opened choke, flare to pit with 1/8"
					orifice tester
0256					Closed tool
1100					Trip out of hole with tools

FORM 182-R1—PRINTED IN U.S.A.

PRODUCTION TEST DATA

LITTLE'S 96672 IM 8/74

SOUTHLAND ROYALTY COMPANY — 727294

Lease Owner/Company Name — Ticket Number

B.T. 7489 — B.T. 5160 — B.T. ____

Depth 7245' — Depth 7257.2' — Depth ____

INITIAL FLOW

	Time Defl. .000"	Log $\frac{t+\theta}{\theta}$	PSIG Temp. Corr.	Time Defl. .000"	Log $\frac{t+\theta}{\theta}$	PSIG Temp. Corr.	Time Defl. .000"	Log $\frac{t+\theta}{\theta}$	PSIG Temp. Corr.
0.	.0000		346.3-Q	.0000		352.5-Q			
1.	.0885		613.3*	.0861		155.9			
2.	.1566		165.5	.1522		160.2			
3.	.2247		163.3	.2184		153.8			
4.	.2928		156.8	.2846		149.5			
5.	.3609		154.6	.3508		149.5			
6.	.4290		150.3	.4170		147.4			

20 minute intervals
*Interval = 26 minutes
120 TOTAL MINUTES

INITIAL CLOSED IN PRESSURE

0.	.0000	-----	150.3	.0000	----	147.4			
1.	.0342	1.132	444.4	.0332	1.132	425.2			
2.	.0684	.862	684.0	.0664	.862	668.8			
3.	.1026	.714	893.2	.0996	.715	886.7			
4.	.1368	.617	1053.8	.1328	.617	1048.8			
5.	.1710	.545	1191.8	.1660	.546	1193.2			
6.	.2052	.490	1323.2	.1992	.490	1326.9			
7.	.2394	.446	1439.6	.2324	.446	1443.7			
8.	.2736	.410	1547.4	.2656	.410	1552.0			
9.	.3078	.379	1644.4	.2988	.379	1647.5			
10.	.3421	.353	1730.6	.3320	.353	1726.1			
11.	.4447	.293	1896.5	.4316	.294	1891.7			
12.	.5473	.251	2000.0	.5312	.252	1997.8			
13.	.6499	.220	2079.9	.6308	.220	2076.4			
14.	.7526	.196	2140.3	.7304	.196	2135.8			
15.	.8552	.177	2187.8	.8300	.177	2184.6			
16.	.9578	.161	2231.0	.9296	.161	2227.1			
17.	1.0605	.148	2265.6	1.0292	.148	2263.2			
18.	1.1631	.136	2293.7	1.1288	.137	2284.4			
19.	1.2657	.127	2319.6	1.2284	.127	2318.4			
20.	1.3684	.118	2343.4	1.3280	.119	2339.6			
21.	1.4710	.111	2360.6	1.4276	.111	2346.0			
22.	1.5736	.105	2375.8	1.5272	.105	2373.6			
23.	1.6350	.101	2382.2	1.5870	.101	2382.1			

First 10 intervals = 10 minutes each; next 12 intervals = 30 minutes each; last interval = 18 minutes
478 TOTAL MINUTES

Remarks:

Q = Questionable

Gas Production

CORRECTED COPY

B.T. Gauge Numbers			7489	5160	Ticket Number		727294
			PRESSURE	PRESSURE			
Initial Hydrostatic			3121	3117	Elevation		6940 ft.
Final Hydrostatic			3121	3117	Production Rate	1st Flow	21.6 MCF
1st Flow	Initial	Time	346	353		2nd Flow	- MCF
	Final	126	150	147		3rd Flow	- MCF
	Closed In Pressure	478	2382	2382	Hole Size		6.25 in.
2nd Flow	Initial	Time			Footage Tested		51 ft.
	Final				Mud Weight		8.33 lbs./gal.
	Closed In Pressure				Gas Viscosity		.020 cp
3rd Flow	Initial	Time			Gas Gravity		.70 —
	Final				Gas Compressibility		.85 —
	Closed In Pressure				Temperature		190 °F
Extrapolated Static Pressure		1st	2644	2639			
		2nd					
		3rd					
Slope P/10		1st	89	74			
		2nd					
		3rd					

Remarks: (1) Calculations based on rates given by Bob Fielden 8-11-80 and net pay given by Marlin Thompson 10-6-80
(2) Gas gravity changed to 0.70-11-13-80

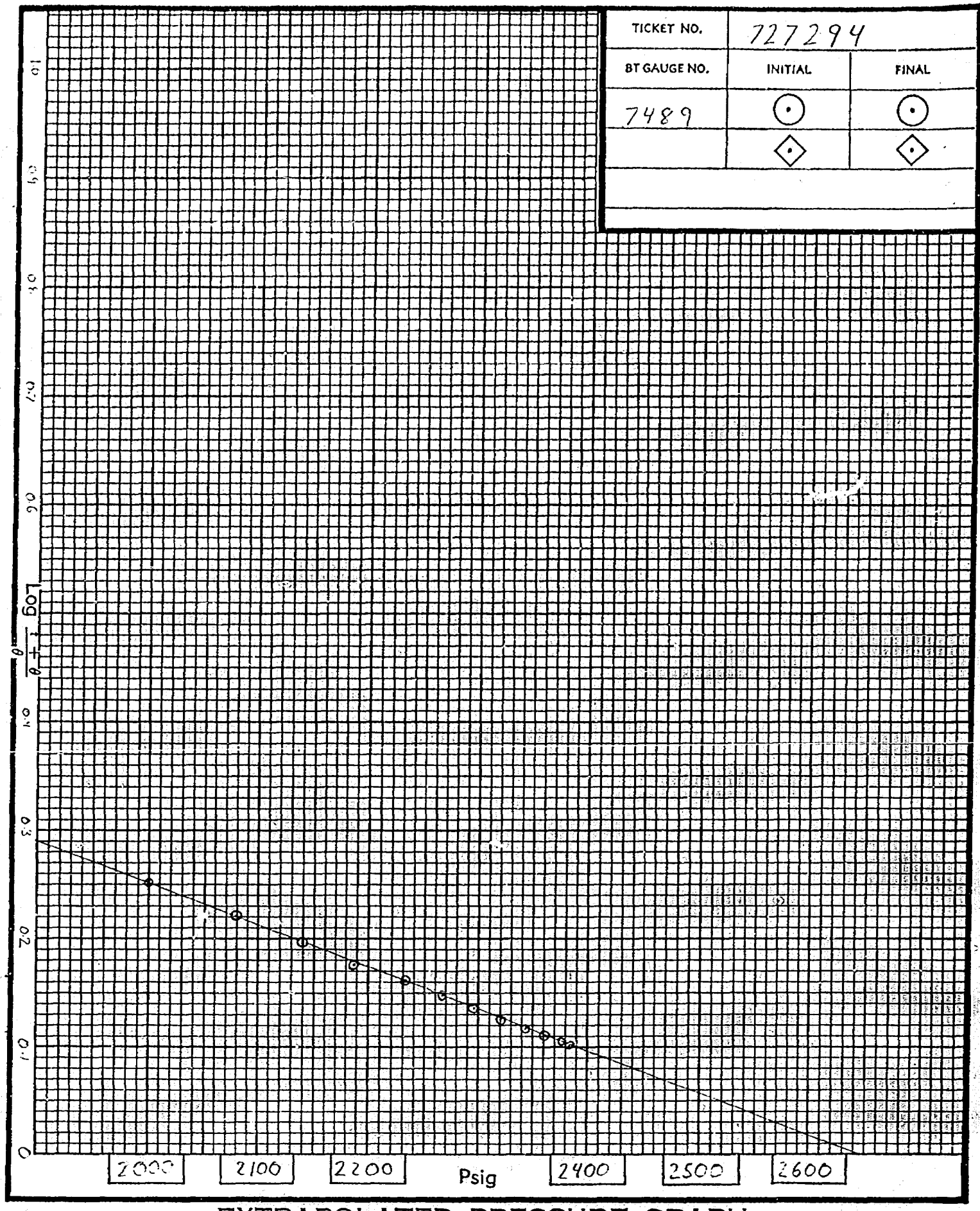
SUMMARY

PRODUCT	EQUATION	B.T. Gauge No. 7489 Depth 7245' FIRST	SECOND	THIRD	B.T. Gauge No. 5160 Depth 7257' FIRST	SECOND	THIRD	UNITS
Transmissibility	$\frac{Kh}{\mu} = \frac{1637\ Q_g\ ZT}{m}$	2.798			2.807			md. ft. / cp
Theoretical Flow Capacity	$Kh = \frac{Kh}{\mu}\ \mu$	.0560			.0561			md. ft.
Average Effective	$K = \frac{Kh}{h}$	.00110			.00110			md.
Permeability	$K_1 = \frac{Kh}{h_1}$	-			-			md.
Indicated Flow Capacity	$(Kh)_s = \frac{3200\ Q_g\ \mu\ ZT\ \text{Log}(0.472\ b/r_w)}{P_s^2 - P_f^2}$	.0066			.0067			md. ft.
Damage Ratio	$DR = \frac{\text{Theo. Flow Cap}}{\text{Indicated Flow Cap}} \frac{Kh}{(Kh)_s}$	8.454			8.390			—
Indicated Flow Rate	$OF_1 = \frac{Q_g\ P_s^2}{P_s^2 - P_f^2}$ Max.	21.670			21.667			MCFD
	$OF_2 = \frac{Q_g\ P_s}{\sqrt{P_s^2 - P_f^2}}$ Min.	21.635			21.634			MCFD
Theoretical Potential Rate	$OF_3 = OF_1\ DR$ Max.	183.205			181.791			MCFD
	$OF_4 = OF_2\ DR$ Min.	182.910			181.509			MCFD
Approx. Radius of Investigation	$b \leftrightarrows \sqrt{Kt}$ or $\sqrt{Kt_0}$	.632			.633			ft.
	$b_1 \leftrightarrows \sqrt{K_1 t}$ or $\sqrt{K_1 t_0}$	-			-			ft.
Potentiometric Surface *	$Pot. = (El - GD) + (2.319\ Ps)$	-			-			ft.

NOTICE: These calculations are based upon information furnished by you and taken from Drill Stem Test pressure charts, and are furnished you for your information. In furnishing such calculations and evaluations based thereon, Halliburton is merely expressing its opinion. You agree that Halliburton makes no warranty express or implied as to the accuracy of such calculations or opinions, and that Halliburton shall not be liable for any loss or damage, whether due to negligence or otherwise, in connection with such calculations and opinions.

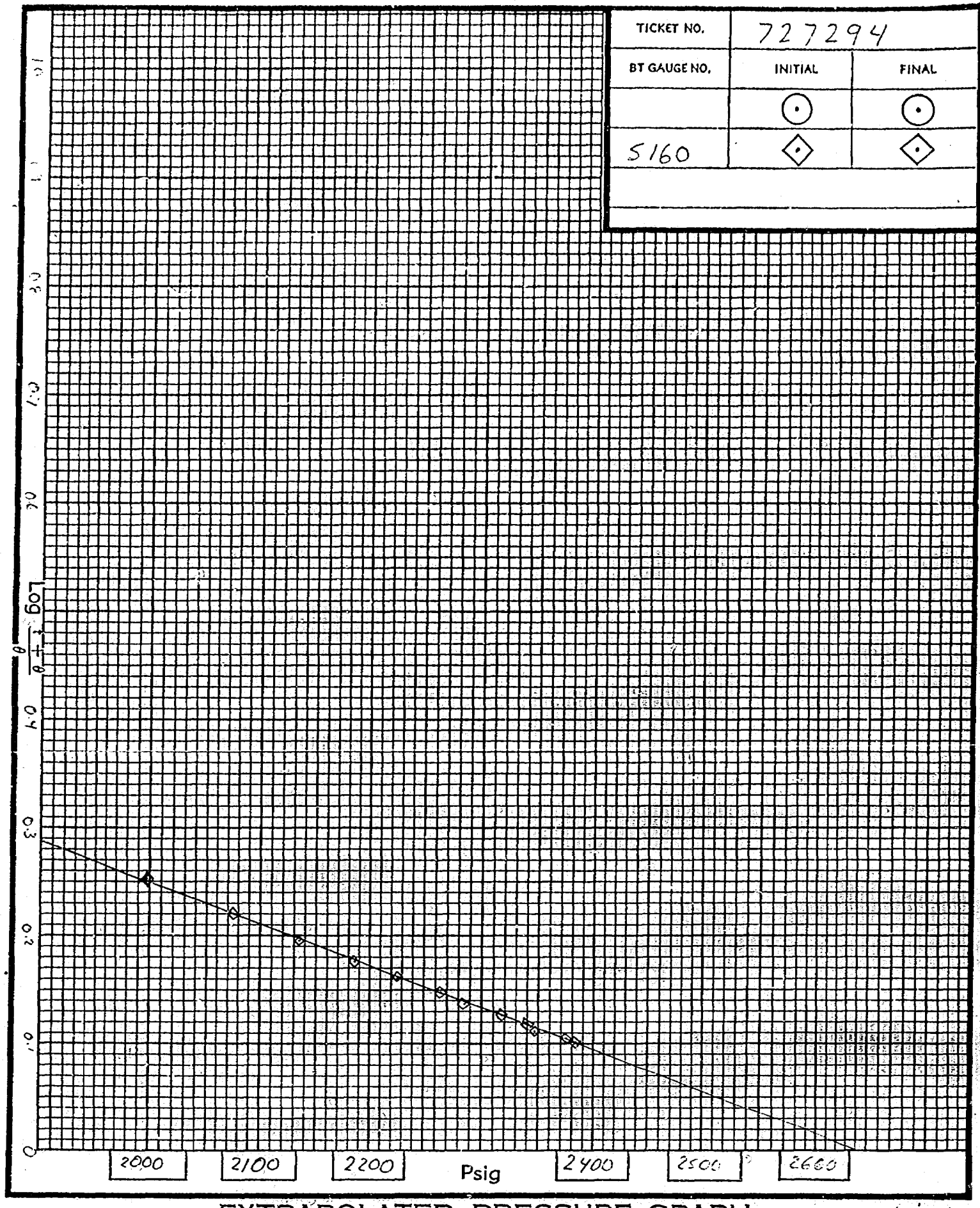
FORM 165-R1—PRINTED IN U.S.A. INTERPRETATIONS AND CALCULATIONS LITTLE'S

TICKET NO.	727294	
BT GAUGE NO.	INITIAL	FINAL
7489	⊙	⊙
	◇	◇



EXTRAPOLATED PRESSURE GRAPH

TICKET NO.	727294	
BT GAUGE NO.	INITIAL	FINAL
	⊙	⊙
5160	◇	◇



EXTRAPOLATED PRESSURE GRAPH

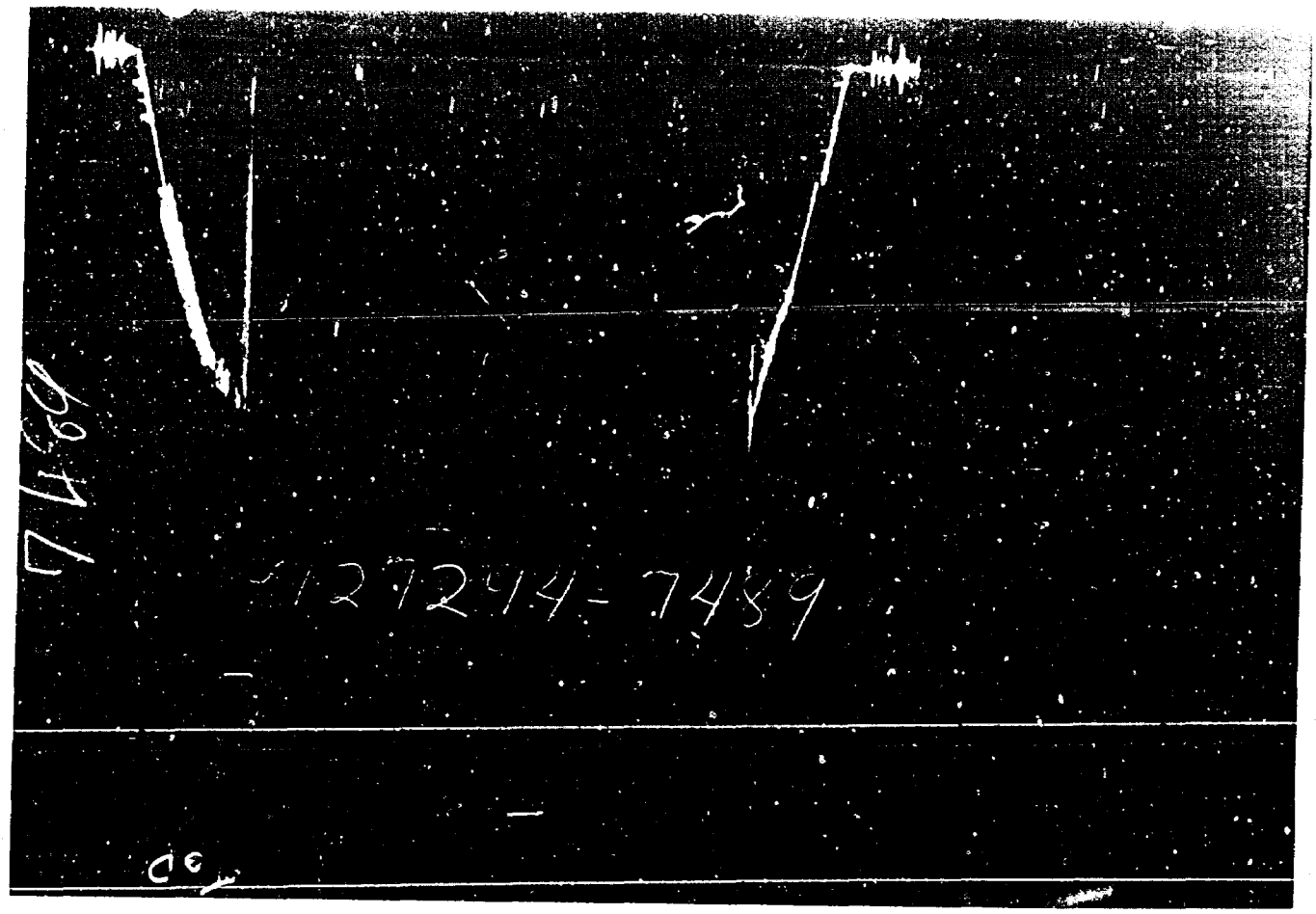
TICKET NO. 727254

	O.D.	I.D.	LENGTH	DEPTH
Drill Pipe or Tubing	2 3/8"	1.995"	7229.9'	
Drill Collars				
Reversing Sub				
Water Cushion Valve				
Drill Pipe				
Drill Collars				
Handling Sub & Choke Assembly				
Dual CIP Valve	3.03"	1"	5'6"	7229.9'
Dual CIP Sampler				
Hydro-Spring Tester	3.03"	1.13"	4'10"	7235.5'
Multiple CIP Sampler				
Extension Joint				
AP Running Case	3.03"	2.31"	4'8½"	7245'
X over				
Hydraulic Jar				
VR Safety Joint	3.03"	1.75"	2'8¼"	
Pressure Equalizing Crossover				
X over	3.03"	1.75"	1'	
Packer Assembly	4½"	1.90"	3'4"	7249'
Distributor				
Packer Assembly				
Perforated anchor	2 3/8"	1.90"	4'2"	
Flush Joint Anchor				
Pressure Equalizing Tube				
Blanked-Off B.T. Running Case				
Drill Collars				
Anchor Pipe Safety Joint				
Packer Assembly				
Distributor				
Packer Assembly				
Anchor Pipe Safety Joint				
Side Wall Anchor				
Drill Collars				
Flush Joint Anchor				
Blanked-Off B.T. Running Case	3.03"	2.31"	4'	7257.2'
Total Depth				7480'

FORM 187-E2 – PRINTED IN U.S.A.

EQUIPMENT DATA

LITTLE'S HIGH 75C 2/80


D4460
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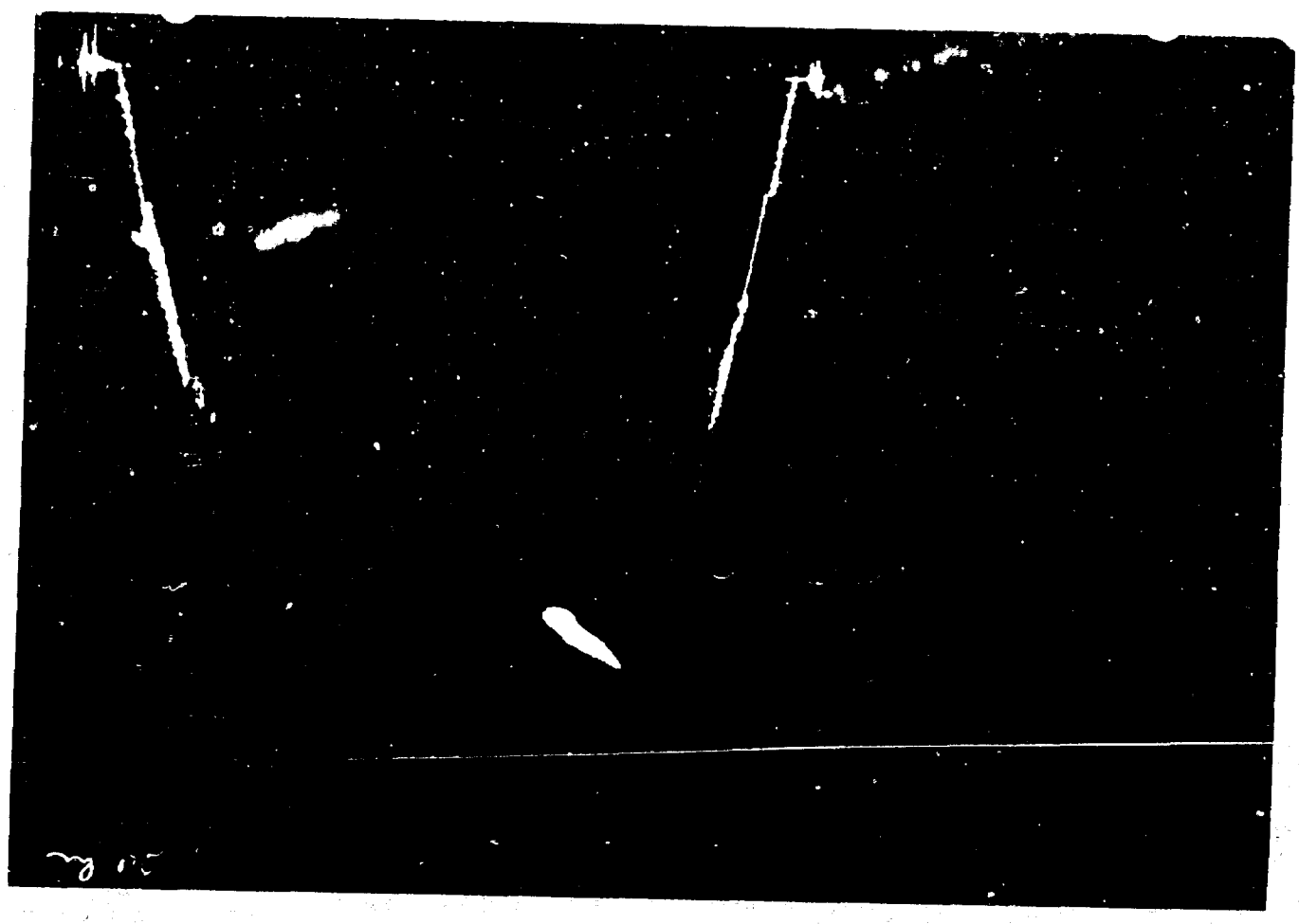

EXHIBIT NO. 13

MULATIVE PRODUCTION AND ULTIMATE RESERVES
BASIN DAKOTA FIELD
SAN JUAN COUNTY, NEW MEXICO

Operator	Lease	Well No.	Location	Cumulative Production (1-1-80) Gas (MCF)	Cumulative Production (1-1-80) Oil (BBLS)	Remaining Reserves (1-1-80) Gas (MCF)	Remaining Reserves (1-1-80) Oil (BBLS)	Ultimate Reserves Gas (MCF)	Ultimate Reserves Oil (BBLS)
Supron Energy	Payne	3A	SW-20-32N-10W	0	0	152,300	590	152,300	590
Supron Energy	Payne	2A	NW-21-32N-10W	0	0	312,100	1,202	312,100	1,202
Supron Energy	Payne	4A	SE-22-32M-10W	0	0	609,800	2,958	609,800	2,958
Tenneco	Wilkins	1	NE-24-32N-10W	29,306	0	0	0	29,306	0
Tenneco	Barnes	1	NE-26-32N-11W	261,364	0	0	0	261,364	0
Southland Royalty	Decker	4	SW-10-32N-12W	129,055	456	110,757	0	239,812	456
Southland Royalty	Hubbard	2	SW-11-32N-12W	71,276	177	75,749	0	147,025	177
Southland Royalty	Chamberlain	1	NE-14-32N-12W	47,873	60	0	0	47,873	60
Southland Royalty	Hubbard	3	NE-15-32N-12W	41,700	0	0	0	41,700	0
Southland Royalty	Hubbard	4	SW-15-32N-12W	117,951	1,171	353,699	701	471,650	1,872
Southland Royalty	Culpepper Martin	12	SW-20-32N-12W	68,173	1,062	49,440	635	117,613	1,697
Southland Royalty	Culpepper Martin	15	NE-21-32N-12W	82,784	1,045	53,714	181	136,498	1,226
Southland Royalty	Culpepper Martin	5	SW-22-32N-12W	118,654	2,677	21,889	1,624	140,543	4,301
Southland Royalty	Culpepper Martin	4	SW-28-32N-12W	96,795	1,533	188,831	2,182	285,626	3,715
Southland Royalty	Culpepper Martin	13	SW-29-32N-12W	84,312	837	101,373	152	185,685	989
Union Texas	Culpepper Martin	5	NW-31-32N-12W	0	0	110,100	424	110,100	424
Southland Royalty	State Line	1	NW-13-32N-13W	0	0	190,200	732	190,200	732
Southland Royalty	State Line	2	NE-14-32N-13W	0	0	49,900	192	49,900	192
Hill & Llewellyn	USA	1	SE-24-32N-13W	0	0	65,200	251	65,200	251
Supron Energy	USA	2	SW-24-32N-13W	0	0	51,100	196	51,100	196
Tenneco	Montoya 25	1M	NW-25-32N-13W	0	0	150,300	579	150,300	579
Tenneco	Montoya 25	1	NE-25-32N-13W	0	0	198,400	764	198,400	764
Consolidated Oil & Gas	Ripley	2A	SE-26-32N-13W	0	0	310,200	1,194	310,200	1,194
Consolidated Oil & Gas	Ripley	1	SW-26-32N-13W	98,297	491	0	0	98,297	491
Palmer	Montoya 27	1	SE-27-32N-13W	0	0	355,200	1,368	355,200	1,368
Consolidated Oil & Gas	Robinson Bros.	1M	SW-34-32N-13W	0	0	124,900	481	124,900	481
Consolidated Oil & Gas	Robinson Bros.	1	SE-34-32N-13W	128,755	526	0	0	128,755	526
Consolidated Oil & Gas	Montoya	1	NE-35-32N-13W	39,880	0	18,166	0	58,046	0
Consolidated Oil & Gas	Montoya	1M	SE-35-32N-13W	20,003	759	294,268	8,526	314,271	9,285
Supron Energy	Write State	1	NE-36-32N-13W	37,720	63	0	0	37,720	63
Consolidated Oil & Gas	Pan American State	1	SW-36-32N-13W	158,858	1,538	29,974	290	188,832	1,828
Delhi-Taylor	Atlantic "A"	4	SW-27-31N-10W	432,580	0	0	0	432,580	0
Tenneco	Atlantic	1	NE-34-31N-10W	200,942	0	0	0	200,942	0
Tenneco	Childers	1	NW-01-31N-10W	0	0	410,200	1,579	410,200	1,579
Southland Royalty	Titt	2	SW-35-31N-11W	238,504	375	0	0	238,504	375
TOTALS		35		2,504,782	12,770	4,387,760	26,801	6,892,542	39,571
AGE				71,565	365	125,365	766	196,930	1,131

EXHIBIT NO. 13

CUMULATIVE PRODUCTION AND ULTIMATE RESERVES
BASIN DAKOTA FIELD
SAN JUAN COUNTY, NEW MEXICO

Operator	Lease	Well No.	Location	Cumulative Production (1-1-80) Gas (MCF)	Cumulative Production (1-1-80) Oil (BBLS)	Remaining Reserves (1-1-80) Gas (MCF)	Remaining Reserves (1-1-80) Oil (BBLS)	Ultimate Reserves Gas (MCF)	Ultimate Reserves Oil (BBLS)
Supron Energy	Payne	3A	SW-20-32N-10W	0	0	152,300	590	152,300	590
Supron Energy	Payne	2A	NW-21-32N-10W	0	0	312,100	1,202	312,100	1,202
Supron Energy	Payne	4A	SE-22-32M-10W	0	0	609,800	2,958	609,800	2,958
Tenneco	Wilkins	1	NE-24-32N-10W	29,306	0	0	0	29,306	0
Tenneco	Barnes	1	NE-26-32N-11W	261,364	0	0	0	261,364	0
Southland Royalty	Decker	4	SW-10-32N-12W	129,055	456	110,757	0	239,812	456
Southland Royalty	Hubbard	2	SW-11-32N-12W	71,276	177	75,749	0	147,025	177
Southland Royalty	Chamberlain	1	NE-14-32N-12W	47,873	60	0	0	47,873	60
Southland Royalty	Hubbard	3	NE-15-32N-12W	41,700	0	0	0	41,700	0
Southland Royalty	Hubbard	4	SW-15-32N-12W	117,951	1,171	353,699	701	471,650	1,872
Southland Royalty	Culpepper Martin	12	SW-20-32N-12W	68,173	1,062	49,440	635	117,613	1,697
Southland Royalty	Culpepper Martin	15	NE-21-32N-12W	82,784	1,045	53,714	181	136,498	1,226
Southland Royalty	Culpepper Martin	5	SW-22-32N-12W	118,654	2,677	21,889	1,624	140,543	4,301
Southland Royalty	Culpepper Martin	4	SW-28-32N-12W	96,795	1,533	188,831	2,182	285,626	3,715
Southland Royalty	Culpepper Martin	13	SW-29-32N-12W	84,312	837	101,373	152	185,685	989
Union Texas	Culpepper Martin	5	NW-31-32N-12W	0	0	110,100	424	110,100	424
Southland Royalty	State Line	1	NW-13-32N-13W	0	0	190,200	732	190,200	732
Southland Royalty	State Line	2	NE-14-32N-13W	0	0	49,900	192	49,900	192
Hill & Llewellyn	USA	1	SE-24-32N-13W	0	0	65,200	251	65,200	251
Supron Energy	USA	2	SW-24-32N-13W	0	0	51,100	196	51,100	196
Tenneco	Montoya 25	1M	NW-25-32N-13W	0	0	150,300	579	150,300	579
Tenneco	Montoya 25	1	NE-25-32N-13W	0	0	198,400	764	198,400	764
Consolidated Oil & Gas	Ripley	2A	SE-26-32N-13W	0	0	310,200	1,194	310,200	1,194
Consolidated Oil & Gas	Ripley	1	SW-26-32N-13W	98,297	491	0	0	98,297	491
Palmer	Montoya 27	1	SE-27-32N-13W	0	0	355,200	1,368	355,200	1,368
Consolidated Oil & Gas	Robinson Bros.	1M	SW-34-32N-13W	0	0	124,900	481	124,900	481
Consolidated Oil & Gas	Robinson Bros.	1	SE-34-32N-13W	128,755	526	0	0	128,755	526
Consolidated Oil & Gas	Montoya	1	NE-35-32N-13W	39,880	0	18,166	0	58,046	0
Consolidated Oil & Gas	Montoya	1M	SE-35-32N-13W	20,003	759	294,268	8,526	314,271	9,285
Supron Energy	Write State	1	NE-36-32N-13W	37,720	63	0	0	37,720	63
Consolidated Oil & Gas	Pan American State	1	SW-36-32N-13W	158,858	1,538	29,974	290	188,832	1,828
Delhi-Taylor	Atlantic "A"	4	SW-27-31N-10W	432,580	0	0	0	432,580	0
Tenneco	Atlantic	1	NE-34-31N-10W	200,942	0	0	0	200,942	0
Tenneco	Childers	1	NW-01-31N-10W	0	0	410,200	1,579	410,200	1,579
Southland Royalty	Titt	2	SW-35-31N-11W	238,504	375	0	0	238,504	375
TOTALS		35		2,504,782	12,770	4,387,760	20,801	6,892,542	39,571
AVERAGE				71,565	365	125,365	766	196,930	1,131

EXHIBIT NO. 13

CUMULATIVE PRODUCTION AND ULTIMATE RESERVES
BASIN DAKOTA FIELD
SAN JUAN COUNTY, NEW MEXICO

Operator	Lease	Well No.	Location	Cumulative Production (1-1-80) Gas (MCF)	Cumulative Production (1-1-80) Oil (BBLS)	Remaining Reserves (1-1-80) Gas (MCF)	Remaining Reserves (1-1-80) Oil (BBLS)	Ultimate Reserves Gas (MCF)	Ultimate Reserves Oil (BBLS)
Supron Energy	Payne	3A	SW-20-32N-10W	0	0	152,300	590	152,300	590
Supron Energy	Payne	2A	NW-21-32N-10W	0	0	312,100	1,202	312,100	1,202
Supron Energy	Payne	4A	SE-22-32M-10W	0	0	609,800	2,958	609,800	2,958
Tenneco	Wilkins	1	NE-24-32N-10W	29,306	0	0	0	29,306	0
Tenneco	Barnes	1	NE-26-32N-11W	261,364	0	0	0	261,364	0
Southland Royalty	Decker	4	SW-10-32N-12W	129,055	456	110,757	0	239,812	456
Southland Royalty	Hubbard	2	SW-11-32N-12W	71,276	177	75,749	0	147,025	177
Southland Royalty	Chamberlain	1	NE-14-32N-12W	47,873	60	0	0	47,873	60
Southland Royalty	Hubbard	3	NE-15-32N-12W	41,700	0	0	0	41,700	0
Southland Royalty	Hubbard	4	SW-15-32N-12W	117,951	1,171	353,699	701	471,650	1,872
Southland Royalty	Culpepper Martin	12	SW-20-32N-12W	68,173	1,062	49,440	635	117,613	1,697
Southland Royalty	Culpepper Martin	15	NE-21-32N-12W	82,784	1,045	53,714	181	136,498	1,226
Southland Royalty	Culpepper Martin	5	SW-22-32N-12W	118,654	2,677	21,889	1,624	140,543	4,301
Southland Royalty	Culpepper Martin	4	SW-28-32N-12W	96,795	1,533	188,831	2,182	285,626	3,715
Southland Royalty	Culpepper Martin	13	SW-29-32N-12W	84,312	837	101,373	152	185,685	989
Union Texas	Culpepper Martin	5	NW-31-32N-12W	0	0	110,100	424	110,100	424
Southland Royalty	State Line	1	NW-13-32N-13W	0	0	190,200	732	190,200	732
Southland Royalty	State Line	2	NE-14-32N-13W	0	0	49,900	192	49,900	192
Hill & Llewellyn	USA	1	SE-24-32N-13W	0	0	65,200	251	65,200	251
Supron Energy	USA	2	SW-24-32N-13W	0	0	51,100	196	51,100	196
Tenneco	Montoya 25	1M	NW-25-32N-13W	0	0	150,300	579	150,300	579
Tenneco	Montoya 25	1	NE-25-32N-13W	0	0	198,400	764	198,400	764
Consolidated Oil & Gas	Ripley	2A	SE-26-32N-13W	0	0	310,200	1,194	310,200	1,194
Consolidated Oil & Gas	Ripley	1	SW-26-32N-13W	98,297	491	0	0	98,297	491
Palmer	Montoya 27	1	SE-27-32N-13W	0	0	355,200	1,368	355,200	1,368
Consolidated Oil & Gas	Robinson Bros.	1M	SW-34-32N-13W	0	0	124,900	481	124,900	481
Consolidated Oil & Gas	Robinson Bros.	1	SE-34-32N-13W	128,755	526	0	0	128,755	526
Consolidated Oil & Gas	Montoya	1	NE-35-32N-13W	39,880	0	18,166	0	58,046	0
Consolidated Oil & Gas	Montoya	1M	SE-35-32N-13W	20,003	759	294,268	8,526	314,271	9,285
Supron Energy	Write State	1	NE-36-32N-13W	37,720	63	0	0	37,720	63
Consolidated Oil & Gas	Pan American State	1	SW-36-32N-13W	158,858	1,538	29,974	290	188,832	1,828
Delhi-Taylor	Atlantic "A"	4	SW-27-31N-10W	432,580	0	0	0	432,580	0
Tenneco	Atlantic	1	NE-34-31N-10W	200,942	0	0	0	200,942	0
Tenneco	Childers	1	NW-01-31N-10W	0	0	410,200	1,579	410,200	1,579
Southland Royalty	Titt	2	SW-35-31N-11W	238,504	375	0	0	238,504	375
TOTALS		35		2,504,782	12,770	4,387,760	26,801	6,892,542	39,571
AVERAGE				71,565	365	125,365	766	196,930	1,131

PROJECT: SRC UNNAMED NO. 1
BASIN DAKOTA
SAN JUAN NEW MEXICO
MINIMUM ECONOMICS 103

FILE: CSRC1 PREP. BY: MRT
INIT. INVEST. DATE: 04/01/1981
INIT. PROD. DATE: 10/01/1981

1. BEFORE INCOME TAX NOT DISCOUNTED (M$)

NET INCOME BEFORE INVESTMENT:	$1372.	RISK COST:	$226.	RATIO:	6.1
PROFIT AFTER INVESTMENT:	$993.	INVESTMENT:	$379.	RATIO:	2.6

2. RISK PARAMETERS

TRAP: 1.00 RESERVOIR: 1.00 HYDROCARBON: 1.00 TOTAL RISK FACTOR: 1.00

3. OBJECTIVE TEST (M$)

NET INCOME BEFORE TAX DISC. @9%: $576.
NET INCOME BEFORE TAX DISC. @15%: $404. ADJUSTED FOR RISK: $404.
MINIMUM OBJECTIVE:((RISK COST)(1-RF) + (DISC. DEV. COST)(RF))1.25 : $474.
ABOVE OR BELOW SRC OBJECTIVE: $69.-

O.T.R. = $404. / $379. = 1.07

4. PAYOUT (YRS) AFTER TAX: 5.3 BEFORE TAX: 5.7

5. AFTER TAX RATE OF RETURN NO RISK: 15.3 RISK ADJUSTED: 15.3

6. COST PER EQUIVALENT MCF $1.56/MCF

7. RISK FACTOR SENSITIVITY

RISK FACTOR	RISK ADJUSTED AFTER TAX ROR	ABOVE OR BELOW SRC OBJECTIVE (M$)
0.80	13.3	$112.-
0.60	10.5	$155.-
0.40	6.6	$197.-
0.20	0.7	$240.-
0.10	0.0	$261.-
0.05	0.0	$272.-
MINIMUM: 1.33	17.6	$0.

8. PROJECT DATA

TOTAL LIFE (YRS):	30.6
FLAT LIFE (YRS):	5.6
W.I. BEFORE/AFTER PAYOUT:	100.000%/100.000%
N.I. BEFORE/AFTER PAYOUT:	86.500%/ 86.500%
REVERT. INT. AMOUNT (M$):	0.
NET OIL RESERVES (MBBLS):	1.
NET GAS RESERVES (MMCF):	238.
GROSS PRODUCING WELLS:	1.
GROSS DEVELOP. DRY HOLES:	0.
DEPTH (FT):	7000.

RISK COSTS (M$)

DRYHOLE:	226.
ACREAGE:	0.
SEISMIC:	0.
TOTAL	226.

9. UNIT PRICING (GAS) INITIAL: $3.11/MCF MAXIMUM: $10.42/MCF

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CSRC1,1,MRT
1,Y,GAS,4104,10,1981
3.85,3.85,N,7000,N,N,0
SRC UNNAMED NO. 1
BASIN DAKOTA
SAN JUAN NEW MEXICO
MINIMUM ECONOMICS 103
G,226,0,0,1,1,1,1984,3.70
42.76,3.11,50,10.42,7,7,14.11,70,0,146.7,
100,13.5,0,0,6,8,8,6
HYP,0,300,275,0,125,END
1981.4,G,121,258,1,0,END
```

EXHIBIT NO. 14

SOUTHLAND ROYALTY COMPANY
DRILLING ECONOMICS MODEL
BEFORE TAX ECONOMICS - DETAIL REPORT

PROJECT: SRC UNNAMED NO. 1
SAN JUAN NEW MEXICO
- BASIN DAKOTA
- MINIMUM ECONOMICS 103

PREPARED BY: MRT
FILE: CSRC1
INITIAL INVESTMENT DATE: 04/01/1981
INITIAL PRODUCTION DATE: 10/01/1981

YEAR	GROSS PRODUCTION MBBL/YR	GROSS PRODUCTION MMCF/YR	NET PRODUCTION MBBL/YR	NET PRODUCTION MMCF/YR	PRICES $/BBL	PRICES $/MCF	REVENUES AND TAXES M$ OIL	GAS	TOTAL	P.TAX	D.TAX	NET	LEASE OPR. EXP. M$	INCOME M$ NET	INCOME M$ DISC@15%	DEV&EQP EXP. M$
1981	0.	11.	0.	10.	43.86	3.19	2.	31.	33.	3.	1.	30.	0.	29.	28.	379.
1982	0.	34.	0.	29.	46.67	3.39	5.	100.	105.	8.	2.	94.	0.	93.	77.	0.
1983	0.	24.	0.	21.	49.93	3.63	4.	76.	80.	6.	2.	72.	0.	70.	51.	0.
1984	0.	19.	0.	17.	50.00	4.63	3.	77.	80.	6.	1.	73.	0.	70.	44.	0.
1985	0.	16.	0.	14.	50.00	4.95	3.	68.	71.	6.	1.	64.	0.	63.	34.	0.
1986	0.	14.	0.	12.	50.00	5.29	3.	63.	65.	5.	1.	59.	0.	57.	27.	0.
1987	0.	12.	0.	11.	50.00	5.66	3.	60.	62.	5.	1.	56.	0.	53.	22.	0.
1988	0.	11.	0.	9.	50.00	6.06	2.	57.	59.	4.	1.	54.	0.	51.	18.	0.
1989	0.	10.	0.	9.	50.00	6.48	2.	56.	57.	4.	1.	52.	0.	49.	15.	0.
1990	0.	9.	0.	8.	50.00	6.94	2.	54.	56.	4.	0.	51.	0.	48.	13.	0.
1991	0.	8.	0.	7.	50.00	7.42	1.	54.	55.	4.	0.	51.	0.	47.	11.	0.
1992	0.	8.	0.	7.	50.00	7.94	1.	54.	55.	4.	0.	51.	0.	47.	10.	0.
1993	0.	7.	0.	6.	50.00	8.50	1.	54.	56.	4.	0.	51.	0.	47.	8.	0.
1994	0.	7.	0.	6.	50.00	9.09	1.	55.	56.	4.	0.	51.	0.	47.	7.	0.
1995	0.	7.	0.	6.	50.00	9.73	1.	55.	57.	5.	0.	52.	5.	47.	6.	0.
S-TOT	1.	198.	1.	171.	49.06	5.35	32.	916.	948.	76.	11.	861.	44.	818.	373.	379.
AFTER	0.	77.	0.	67.	50.00	10.42	13.	694.	707.	57.	0.	651.	97.	554.	31.	0.
TOTAL	1.	275.	1.	238.	49.33	6.77	45.	1610.	1655.	132.	11.	1512.	140.	1372.	404.	379.

PRICE ASSUMPTIONS	OIL	GAS
INITIAL PRICE:	$42.76	$3.11
AVERAGE PRICE:	$49.33	$6.77
MAXIMUM PRICE:	$50.00	$10.42
AVG. ESC. TO MAX.:	7.00%	7.00%

COST ASSUMPTIONS		
INITIAL LOE/WELL/MO:	$146.	
ESCALATION RATE:	7.00%	
MAXIMUM LOE/WELL/MO:	$503.	
PROD. TAX RATE:	8.00%	8.00%

PRODUCTION		
PRODUCING DEV. WELLS-GROSS/NET	1 / 1.00	
DRY DEV. WELLS-GROSS/NET	0 / 0.00	
INITIAL DAILY PRODUCTION-		
.TOTAL NET	0.BBLS	116.MCF
.GROSS/WELL:	1.BBLS	135.MCF
FLAT LIFE:	5.6 YRS	
PRODUCTION LIFE:	30.6 YRS	
AVG. PRODUCTION DECLINE/YR.:	8.54%	
YIELD (BBLS/MMCF):	3.9MAX.	3.9MIN.
AVG. WELL DEPTH	7000.FT.	

OWNERSHIP	
W.I. BEFORE/AFTER PAYOUT:	100.00%/100.00%
N.R.I. BEFORE/AFTER PAYOUT:	86.50%/ 86.50%
REVERT. INT. AMOUNT (M$):	$0./ 0.0YRS
OPERATED:	YES
TANGIBLE INVEST. (M$):	$121.
INTANGIBLE INVEST. (M$):	$258.

DEREGULATION TAX DATA
BASE PRICE/BBL: $14.1 TAX RATE 70.0%

PROJECT: SRC UNNAMED NO. 1
BASIN DAKOTA
SAN JUAN NEW MEXICO
MINIMUM ECONOMICS 103

FILE: CSRC1 PREP. BY: MRT
INIT. INVEST. DATE: 04/01/1981
INIT. PROD. DATE: 10/01/1981

1. BEFORE INCOME TAX NOT DISCOUNTED (M$)

NET INCOME BEFORE INVESTMENT:	$1372.	RISK COST:	$226.	RATIO:	6.1
PROFIT AFTER INVESTMENT:	$993.	INVESTMENT:	$379.	RATIO:	2.6

2. RISK PARAMETERS

TRAP: 1.00 RESERVOIR: 1.00 HYDROCARBON: 1.00 TOTAL RISK FACTOR: 1.00

3. OBJECTIVE TEST (M$)

NET INCOME BEFORE TAX DISC. @9%:	$576.		
NET INCOME BEFORE TAX DISC. @15%:	$404.	ADJUSTED FOR RISK:	$404.
MINIMUM OBJECTIVE:((RISK COST)(1-RF) + (DISC. DEV. COST)(RF))1.25 :			$474.
		ABOVE OR BELOW SRC OBJECTIVE:	$69.-

O.T.R. = $404. / $379. = 1.07

4. PAYOUT (YRS) AFTER TAX: 5.3 BEFORE TAX: 5.7

5. AFTER TAX RATE OF RETURN NO RISK: 15.3 RISK ADJUSTED: 15.3

6. COST PER EQUIVALENT MCF $1.56/MCF

7. RISK FACTOR SENSITIVITY

RISK FACTOR	RISK ADJUSTED AFTER TAX ROR	ABOVE OR BELOW SRC OBJECTIVE (M$)
0.80	13.3	$112.-
0.60	10.5	$155.-
0.40	6.6	$197.-
0.20	0.7	$240.-
0.10	0.0	$261.-
0.05	0.0	$272.-
MINIMUM: 1.33	17.6	$0.

8. PROJECT DATA

TOTAL LIFE (YRS):	30.6
FLAT LIFE (YRS):	5.6
W.I. BEFORE/AFTER PAYOUT:	100.000%/100.000%
N.I. BEFORE/AFTER PAYOUT:	86.500%/ 86.500%
REVERT. INT. AMOUNT (M$):	0.
NET OIL RESERVES (MBBLS):	1.
NET GAS RESERVES (MMCF):	238.
GROSS PRODUCING WELLS:	1.
GROSS DEVELOP. DRY HOLES:	0.
DEPTH (FT):	7000.

RISK COSTS (M$)

DRYHOLE:	226.
ACREAGE:	0.
SEISMIC:	0.
TOTAL	226.

9. UNIT PRICING (GAS) INITIAL: $3.11/MCF MAXIMUM: $10.42/MCF

```
CSRC1,1,MRT
1,Y,GAS,4104,10,1981
3.85,3.85,N,7000,N,N,0
SRC UNNAMED NO. 1
BASIN DAKOTA
SAN JUAN NEW MEXICO
MINIMUM ECONOMICS 103
G,226,0,0,1,1,1,1984,3.70
42.76,3.11,50,10.42,7,7,14.11,70,0,146,7,
100,13.5,0,0,0,8,8,0
HYP,0,300,275,0,125,END
1981.4,G,121,258,1,0,END
```

EXHIBIT NO. 14

SOUTHLAND ROYALTY COMPANY
DRILLING ECONOMICS MODEL
BEFORE TAX ECONOMICS - DETAIL REPORT

PROJECT: SRC UNNAMED NO. 1
SAN JUAN NEW MEXICO

- BASIN DAKOTA
- MINIMUM ECONOMICS 103

PREPARED BY: MRT
FILE: CSRC1
INITIAL INVESTMENT DATE: 04/01/1981
INITIAL PRODUCTION DATE: 10/01/1981

YEAR	GROSS PRODUCTION MBBL/YR	GROSS PRODUCTION MMCF/YR	NET PRODUCTION MBBL/YR	NET PRODUCTION MMCF/YR	PRICES $/BBL	PRICES $/MCF	REVENUES AND TAXES M$ OIL	GAS	TOTAL	P.TAX	D.TAX	NET	LEASE OPR. EXP. M$	INCOME M$ NET	INCOME M$ DISC@15%	DEV&EQP EXP. M$
1981	0.	11.	0.	10.	43.86	3.19	2.	31.	33.	3.	1.	30.	0.	29.	28.	379.
1982	0.	34.	0.	29.	46.67	3.39	5.	100.	105.	8.	2.	94.	0.	93.	77.	0.
1983	0.	24.	0.	21.	49.93	3.63	4.	76.	80.	6.	2.	72.	0.	70.	51.	0.
1984	0.	19.	0.	17.	50.00	4.63	3.	77.	80.	6.	1.	72.	0.	70.	44.	0.
1985	0.	16.	0.	14.	50.00	4.95	3.	68.	71.	6.	1.	64.	0.	62.	34.	0.
1986	0.	14.	0.	12.	50.00	5.29	3.	63.	65.	5.	1.	59.	0.	57.	27.	0.
1987	0.	12.	0.	11.	50.00	5.66	3.	60.	63.	5.	1.	56.	0.	53.	23.	0.
1988	0.	11.	0.	9.	50.00	6.06	3.	57.	59.	5.	1.	54.	0.	51.	18.	0.
1989	0.	10.	0.	9.	50.00	6.48	2.	56.	57.	5.	1.	52.	0.	49.	15.	0.
1990	0.	9.	0.	8.	50.00	6.94	2.	55.	56.	5.	0.	51.	0.	48.	13.	0.
1991	0.	8.	0.	7.	50.00	7.42	1.	54.	55.	4.	0.	51.	0.	47.	11.	0.
1992	0.	8.	0.	7.	50.00	7.94	1.	54.	55.	4.	0.	51.	0.	47.	10.	0.
1993	0.	7.	0.	6.	50.00	8.50	1.	54.	56.	4.	0.	51.	0.	47.	8.	0.
1994	0.	7.	0.	6.	50.00	9.09	1.	55.	56.	4.	0.	51.	0.	47.	7.	0.
1995	0.	7.	0.	6.	50.00	9.73	1.	55.	57.	5.	0.	52.	5.	47.	6.	0.
S-TOT	1.	198.	1.	171.	49.06	5.35	32.	916.	948.	76.	11.	861.	44.	818.	373.	379.
AFTER	0.	77.	0.	67.	50.00	10.42	13.	694.	707.	57.	0.	651.	97.	554.	31.	0.
TOTAL	1.	275.	1.	238.	49.33	6.77	45.	1610.	1655.	132.	11.	1512.	140.	1372.	404.	379.

PRICE ASSUMPTIONS	OIL	GAS
INITIAL PRICE:	$42.76	$3.11
AVERAGE PRICE:	$49.33	$6.77
MAXIMUM PRICE:	$50.00	$10.42
AVG. ESC. TO MAX.:	7.00%	7.00%

COST ASSUMPTIONS		
INITIAL LOE/WELL/MO:	$146.	
ESCALATION RATE:	7.00%	
MAXIMUM LOE/WELL/MO:	$503.	
PROD. TAX RATE:	8.00%	8.00%

PRODUCTION		
PRODUCING DEV. WELLS-GROSS/NET	1 / 1.00	
DRY DEV. WELLS-GROSS/NET	0 / 0.00	
INITIAL DAILY PRODUCTION-		
.TOTAL NET	0.BBLS	116.MCF
.GROSS/WELL:	1.BBLS	135.MCF
FLAT LIFE:	5.6 YRS	
PRODUCTION LIFE:	30.6 YRS	
AVG. PRODUCTION DECLINE/YR.:	8.54%	
YIELD (BBLS/MMCF):	3.9MAX.	3.9MIN.
AVG. WELL DEPTH	7000.FT.	

OWNERSHIP	
W.I. BEFORE/AFTER PAYOUT:	100.00%/100.00%
N.I. BEFORE/AFTER PAYOUT:	86.50%/ 86.50%
REVERT. INT. AMOUNT (M$):	$0./ 0.0YRS
OPERATED:	YES
TANGIBLE INVEST. (M$):	$121.
INTANGIBLE INVEST. (M$):	$258.

DEREGULATION TAX DATA

BASE PRICE/BBL: $14.1 TAX RATE 70.0%

PROJECT: SRC UNNAMED NO. 1
BASIN DAKOTA
SAN JUAN NEW MEXICO
MINIMUM ECONOMICS 103

FILE: CSRC1 PREP. BY: MRT
INIT. INVEST. DATE: 04/01/1981
INIT. PROD. DATE: 10/01/1981

1. BEFORE INCOME TAX NOT DISCOUNTED (M$)

NET INCOME BEFORE INVESTMENT: $1372. RISK COST: $226. RATIO: 6.1
PROFIT AFTER INVESTMENT: $993. INVESTMENT: $379. RATIO: 2.6

2. RISK PARAMETERS

TRAP: 1.00 RESERVOIR: 1.00 HYDROCARBON: 1.00 TOTAL RISK FACTOR: 1.00

3. OBJECTIVE TEST (M$)

NET INCOME BEFORE TAX DISC. @9%: $576.
NET INCOME BEFORE TAX DISC. @15%: $404. ADJUSTED FOR RISK: $404.
MINIMUM OBJECTIVE:((RISK COST)(1-RF) + (DISC. DEV. COST)(RF))1.25 : $474.
ABOVE OR BELOW SRC OBJECTIVE: $69.-

O.T.R. = $404. / $379. = 1.07

4. PAYOUT (YRS) AFTER TAX: 5.3 BEFORE TAX: 5.7

5. AFTER TAX RATE OF RETURN NO RISK: 15.3 RISK ADJUSTED: 15.3

6. COST PER EQUIVALENT MCF $1.56/MCF

7.

RISK FACTOR SENSITIVITY	RISK FACTOR	RISK ADJUSTED AFTER TAX ROR	ABOVE OR BELOW SRC OBJECTIVE (M$)
	0.80	13.3	$112.-
	0.60	10.5	$155.-
	0.40	6.6	$197.-
	0.20	0.7	$240.-
	0.10	0.0	$261.-
	0.05	0.0	$272.-
MINIMUM:	1.33	17.6	$0.

8. PROJECT DATA

TOTAL LIFE (YRS):	30.6
FLAT LIFE (YRS):	5.6
W.I. BEFORE/AFTER PAYOUT:	100.000%/100.000%
N.I. BEFORE/AFTER PAYOUT:	86.500%/ 86.500%
REVERT. INT. AMOUNT (M$):	0.
NET OIL RESERVES (MBBLS):	1.
NET GAS RESERVES (MMCF):	238.
GROSS PRODUCING WELLS:	1.
GROSS DEVELOP. DRY HOLES:	0.
DEPTH (FT):	7000.

RISK COSTS (M$)

DRYHOLE:	226.
ACREAGE:	0.
SEISMIC:	0.
TOTAL	226.

9. UNIT PRICING (GAS) INITIAL: $3.11/MCF MAXIMUM: $10.42/MCF

```
CSRC1,1,MRT
1,Y,GAS,4104,10,1981
3.85,3.85,N,7000,N,N,0
SRC UNNAMED NO. 1
BASIN DAKOTA
SAN JUAN NEW MEXICO
MINIMUM ECONOMICS 103
G,226,0,0,1,1,1,1984,3.70
42.76,3.11,50,10.42,7,7,14.11,70,0,146,7,
100,13.5,0,0,0,8,8,0
HYP,0,300,275,0,125,END
1981.4,G,121,258,1,0,END
```

EXHIBIT NO. 14

SOUTHLAND ROYALTY COMPANY

DRILLING ECONOMICS MODEL

BEFORE TAX ECONOMICS - DETAIL REPORT

PROJECT: SRC UNNAMED NO. 1
SAN JUAN NEW MEXICO

- BASIN DAKOTA
- MINIMUM ECONOMICS 103

PREPARED BY: MRT
FILE: CSRC1
INITIAL INVESTMENT DATE: 04/01/1981
INITIAL PRODUCTION DATE: 10/01/1981

YEAR	GROSS PRODUCTION MBBL/YR	GROSS PRODUCTION MMCF/YR	NET PRODUCTION MBBL/YR	NET PRODUCTION MMCF/YR	PRICES $/BBL	PRICES $/MCF	REVENUES AND TAXES M$ OIL	GAS	TOTAL	P.TAX	D.TAX	NET	LEASE OPR. EXP. M$	INCOME M$ NET	INCOME M$ DISC@15%	DEV&EQP EXP. M$
1981	0.	11.	0.	10.	43.86	3.19	2.	31.	33.	3.	1.	30.	0.	29.	28.	379.
1982	0.	34.	0.	29.	46.67	3.39	4.	100.	105.	8.	2.	94.	0.	93.	77.	0.
1983	0.	24.	0.	21.	49.93	3.63	3.	76.	80.	6.	2.	72.	0.	70.	51.	0.
1984	0.	19.	0.	17.	50.00	4.62	3.	77.	80.	6.	1.	72.	0.	70.	44.	0.
1985	0.	16.	0.	14.	50.00	4.95	3.	68.	71.	6.	1.	64.	0.	62.	34.	0.
1986	0.	14.	0.	12.	50.00	5.29	3.	63.	65.	5.	1.	59.	0.	57.	27.	0.
1987	0.	12.	0.	11.	50.00	5.66	3.	60.	62.	5.	1.	56.	0.	53.	22.	0.
1988	0.	11.	0.	9.	50.00	6.06	3.	57.	59.	5.	1.	54.	0.	51.	18.	0.
1989	0.	10.	0.	9.	50.00	6.48	2.	54.	57.	4.	1.	51.	0.	49.	15.	0.
1990	0.	9.	0.	8.	50.00	6.94	2.	52.	54.	4.	0.	51.	4.	48.	13.	0.
1991	0.	8.	0.	7.	50.00	7.42	1.	54.	55.	4.	0.	51.	4.	47.	11.	0.
1992	0.	8.	0.	7.	50.00	7.94	1.	54.	55.	4.	0.	51.	4.	47.	10.	0.
1993	0.	7.	0.	6.	50.00	8.50	1.	54.	56.	4.	0.	51.	4.	47.	8.	0.
1994	0.	7.	0.	6.	50.00	9.09	1.	55.	56.	4.	0.	51.	4.	47.	7.	0.
1995	0.	7.	0.	6.	50.00	9.73	1.	55.	57.	5.	0.	52.	5.	47.	6.	0.
S-TOT	1.	198.	1.	171.	49.06	5.35	32.	916.	948.	76.	11.	861.	44.	818.	373.	379.
AFTER	0.	77.	0.	67.	50.00	10.42	13.	694.	707.	57.	0.	651.	97.	554.	31.	0.
TOTAL	1.	275.	1.	238.	49.33	6.77	45.	1610.	1655.	132.	11.	1512.	140.	1372.	404.	379.

PRICE ASSUMPTIONS	OIL	GAS
INITIAL PRICE:	$42.76	$3.11
AVERAGE PRICE:	$49.33	$6.77
MAXIMUM PRICE:	$50.00	$10.42
AVG. ESC. TO MAX.:	7.00%	7.00%

COST ASSUMPTIONS		
INITIAL LOE/WELL/MO:	$146.	
ESCALATION RATE:	7.00%	
MAXIMUM LOE/WELL/MO:	$503.	
PROD. TAX RATE:	8.00%	8.00%

PRODUCTION		
PRODUCING DEV. WELLS-GROSS/NET	1 / 1.00	
DRY DEV. WELLS-GROSS/NET	0 / 0.00	
INITIAL DAILY PRODUCTION-		
.TOTAL NET	0.BBLS	116.MCF
.GROSS/WELL:	1.BBLS	135.MCF
FLAT LIFE:	5.6 YRS	
PRODUCTION LIFE:	30.6 YRS	
AVG. PRODUCTION DECLINE/YR.:	8.54%	
YIELD (BBLS/MMCF):	3.9MAX.	3.9MIN.
AVG. WELL DEPTH	7000.FT.	

OWNERSHIP	
W.I. BEFORE/AFTER PAYOUT:	100.00%/100.00%
N.I. BEFORE/AFTER PAYOUT:	86.50%/ 86.50%
REVERT. INT. AMOUNT (M$):	$0./ 0.0YRS
OPERATED:	YES
TANGIBLE INVEST. (M$):	$121.
INTANGIBLE INVEST. (M$):	$258.

DEREGULATION TAX DATA

BASE PRICE/BBL: $14.1 TAX RATE 70.0%

SOUTHLAND ROYALTY COMPANY
PATTERSON "B" COM. 1E
SW-2-31N-12W
BASIN DAKOTA FIELD
SAN JUAN COUNTY, NEW MEXICO

Calculation of Permeability using Darcy's Law:

Data:

Qg = 224,000 SCFD (open hole test)
h = 34 feet (log)
Pwf= 54 psia (measured at surface and calculated to bottomhole)
Pe = 2650 psia (DST in East No. 7E located 9600' to south)
g_g = .70
T = 190°F = 650°R (calc.)
re = 1320 feet
rw = 0.20 feet
Psc= 668 psia
Tsc= 392°R
Ug = .014 cps (calc.)
Z = .87 (calc.)

Where:

Qg = gas flow rate
h = net pay
Pwf= flowing bottomhole pressure
Pe = shut-in bottomhole pressure at drainage radius, re
g_g = gas specific gravity
T = bottomhole temperature
re = drainage radius for 160 acre spacing
rw = wellbore radius
Psc= pseudo critical pressure
Tsc= pseudo critical temperature
Ug = gas viscosity
Z = compressibility factor for gas

$$Qg = 703\ Kh\ \frac{(Pe^2 - Pwf^2)}{Ug\ T\ Z\ \ln\ (.61\ re/rw)}$$

$$K = \frac{Qg\ Ug\ T\ Z\ \ln\ (.61\ re/rw)}{(703\ h\ (Pe^2 - Pwf^2)}$$

$$K = 224{,}000\ (.014)\frac{(650)(.87)\ \ln\ (.61\ 1320/.20)}{703\ (34)\ (2650^2-54^2)}$$

K = .0000877 D.

K = .0877 md.

must in area

BEFORE EXAMINER NUTTER
OIL CONSERVATION DIVISION
SRC EXHIBIT NO. 6
CASE NO. _____

6

SOUTHLAND ROYALTY COMPANY
PIERCE NO. 2
SW-30-31N-10W
BASIN DAKOTA FIELD
SAN JUAN COUNTY, NEW MEXICO

Calculation of Permeability using Darcy's Law:

Data:

Qg = 208,000 SCFD (potential test)
h = 55 feet (log)
Pwf= 24 psia (calc.)
Pe = 2520 psia (calc.)
g_g = .70
T = 186°F = 646°R (calc.)
re = 1320 feet
rw = .13 feet
Psc= 668 psia
Tsc= 392
Ug = .014 cps (calc.)
Z = .91 (calc.)

Where:

Qg = gas flow rate
h = net pay
Pwf= flowing bottomhole pressure
Pe = shut-in bottomhole pressure at drainage radius, re
g_g = gas specific gravity
T = bottomhole temperature
re = drainage radius for 160 acre spacing
rw = wellbore radius
Psc= pseudo critical pressure
Tsc= pseudo critical temperature
Ug = gas viscosity
Z = compressibility factor for gas

$$Qg = 703Kh \frac{(Pe^2 - Pwf^2)}{Ug\ T\ Z\ \ln(.61\ re/rw)}$$

$$K = \frac{Qg\ Ug\ T\ Z\ \ln(.61\ re/rw)}{703\ h\ (Pe^2 - Pwf^2)}$$

$$K = 208{,}000 \frac{(.014)(646)(.91)\ \ln(.61\ 1320/.13)}{703\ (55)\ (2520^2 - 24^2)}$$

K = .0000609 D.

K = .0609 md.

BEFORE EXAMINER NUTTER
OIL CONSERVATION DIVISION
SRC EXHIBIT NO. 7
CASE NO. _____

7

BEFORE EXAMINER NUTTER
OIL CONSERVATION DIVISION
SRC EXHIBIT NO. 8
CASE NO. _____

Effect of Overburden Pressure and Water Saturation on Gas Permeability of Tight Sandstone Cores

Rex D. Thomas, SPE-AIME, U. S. Bureau of Mines
Don C. Ward, SPE-AIME, U. S. Bureau of Mines

Research conducted to determine the potential of nuclear explosions to stimulate gas production verifies that the gas permeability of tight sandstone cores is markedly decreased with increasing overburden pressure. Water saturation also reduces the gas permeability by a large amount. The relative permeability, however, does not change significantly with overburden pressure.

Introduction

Research on the potential of nuclear explosions to stimulate gas production from low-permeability (tight) sandstone reservoirs is being conducted by the U. S. Bureau of Mines in cooperation with the Atomic Energy Commission. This report describes the part of that research that was conducted to establish correlation between permeability measured on dry cores at low external pressure (routine analysis) and permeability at reservoir conditions.

Cores used in this research were obtained from two Plowshare gas-stimulation projects. Project Gasbuggy cores from the Pictured Cliffs formation, Choza Mesa field, Rio Arriba County, N. M., can be described as very fine grained, slightly calcareous, well indurated sandstone. Project Wagon Wheel cores from the Fort Union formation, Pinedale field, Sublette County, Wyo., can be described as very fine grained, slightly calcareous, very well indurated sandstone.

Underground reservoirs are under considerable compressive stress as a result of the weight of overlying rocks (offset somewhat by internal-fluid pressure). The resultant net confining pressure or effective overburden pressure is referred to in this report simply as overburden pressure. The resulting effects on the physical properties of the reservoir rock have been studied.[1-5] Overburden pressure causes only a small decrease in porosity, which can usually be ignored.[5] This was confirmed for Project Gasbuggy and Project Wagon Wheel cores. A commercial laboratory found that the porosity of these cores is reduced by about 5 percent of the original porosity. The effect of overburden pressure on permeability, however, is appreciable and varies considerably for different reservoir rocks,[1,2] causing greater reductions in permeability for low-permeability rocks.[2,3] The effect of overburden pressure on relative permeability has been found to be small[4] or nonexistent.[5]

This report presents material that confirms and extends previous research findings on the effect that overburden pressure has upon the permeability of dry cores. Also presented are the results of research on the relative gas permeability of low-permeability cores under overburden pressure.

Apparatus and Procedure

Cylindrical cores 2.0 to 7.5 cm long and 2.5 cm in diameter were cut parallel to the bedding plane. After the cores were dried overnight in a vacuum oven (4.5 psia, 70°C), the gas (N_2) permeability of each core was measured in a Hassler cell. An external pressure of 100 psi over the inlet pressure was used to maintain a good seal between the rubber sleeve and the core.[6] Permeability was measured at inlet pressures of 45, 60, and 100 psia, with atmospheric pressure at the outlet. A bubble tube and timer were used to measure gas flow rate. Initial permeability (k_i) then was calculated by the Klinkenberg technique to correct for the effect of gas slippage. All other permeabilities reported here were calculated by this method.

In the same manner, permeability was measured at

8

increasing external pressures of about 500, 1,000, 2,000, 3,000, 4,000, 5,000, and 6,000 psi. External pressures actually were somewhat higher to compensate for internal pressure. The core and staniless steel end pieces were placed in a rubber sleeve (piece of bicycle innertube) 0.1 cm tiick. Rubber cement was used to seal the stainless steel end pieces to the rubber sleeve. Shrinkable plastic tubing proved unsatisfactory because high pressure was required to seal the core. The jacketed core was mounted in a high-pressure cell with distilled water as the external fluid.

Cores used in relative permeability studies were first subjected to high external pressure and then allowed to recover their initial permeability. Bulk volume, dry weight, and porosity were measured by conventional gas-expansion techniques. Cores then were subjected to a vacuum (0.3 psia) for 2 hours, immersed in water, and allowed to stand under a vacuum overnight. The cores were weighed and again subjected to vacuum overnight and weighed again to assure complete saturation. Most of the cores were completely saturated after one night. Porosity values calculated on the basis of water saturation are in good agreement with those measured by conventional gas-expansion techniques.

Water in the core was allowed to evaporate at atmospheric conditions to a saturation of about 70 percent and the core was placed in the holder for 2 hours under external pressure (100 psi above inlet) only so the water saturation was uniform. Gas permeability then was measured at three inlet pressures between 30 and 100 psia with atmospheric pressure at the outlet. This procedure was repeated for decreasing water saturations at the same external pressure. After the permeability was measured the core was weighed to determine if any water was lost. In all cases the amount lost was negligible. After the core was dried in a vacuum oven, the gas permeability at this external pressure was measured. The procedure was repeated for external pressures of 3,000 and 6,000 psi.

Results and Discussion

Effect of Overburden Pressure on Permeability

Core number, length, porosity, and initial permeability of the cores used in this research are shown in Table 1. The core number refers to the depth in feet at which the core was obtained. Typical plots of the effect of simulated overburden pressure on Gasbuggy cores are shown in Fig. 1. The permeability is decreased by about 75 percent at an overburden pressure of 3,000 psi and by 90 percent at 6,000 psi. The hydrostatic loading used in these experiments does not reproduce subsurface conditions exactly; in an actual reservoir the horizontal component of stress is usually less than the vertical component. Since the actual loading is not known, this method probably is as realtistic as any other. Cores that contain microfractures are affected to a greater extent, as shown in Fig. 2. In these cores the permeability is decreased by about 95 percent at a simulated overburden pressure of 3,000 psi, with most of the reduction occurring below 2,000 psi.

The data shown in Table 1 and Figs. 1 and 2 were obtained by subjecting the core to successive incre-

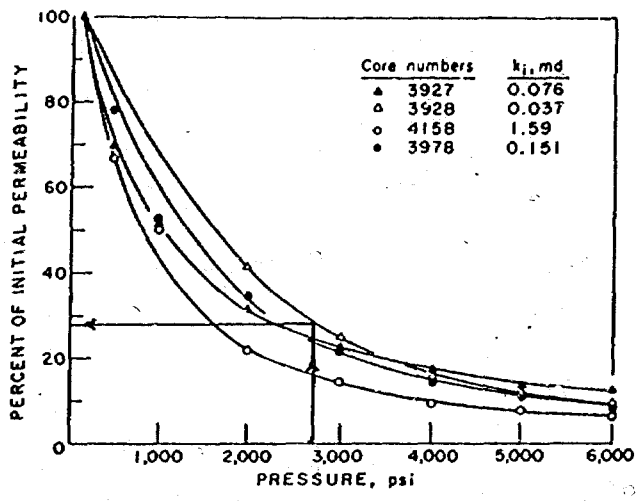

Fig. 1—Effect of overburden pressure on gas permeability of Gasbuggy cores.

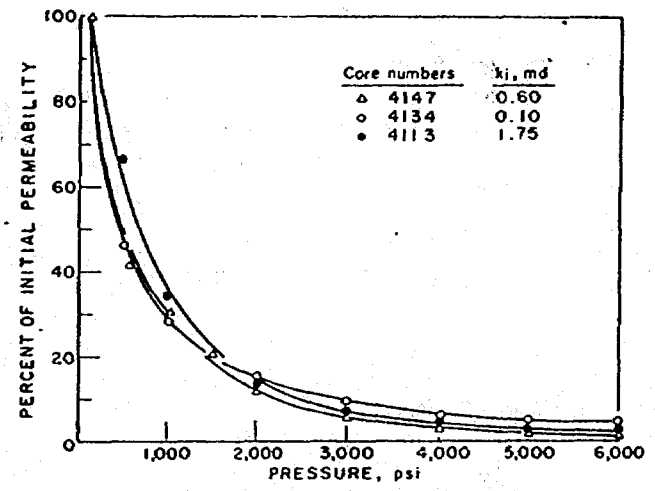

Fig. 2—Effect of overburden pressure on gas permeability of fractured Gasbuggy cores.

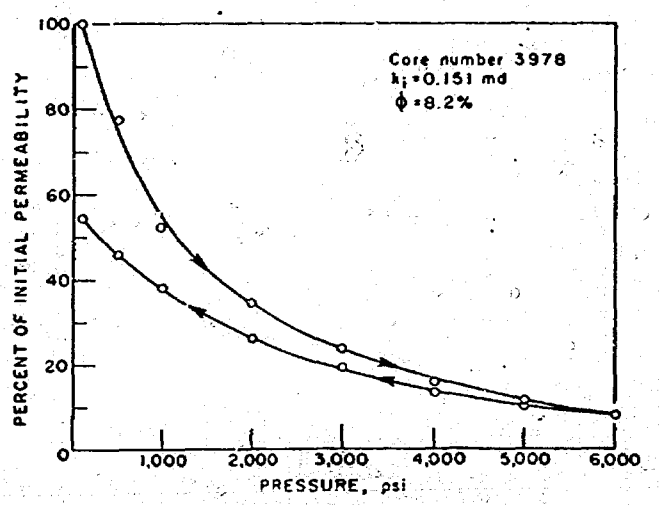

Fig. 3—Hysteresis effect at decreasing confining pressures.

TABLE 1—EFFECT OF OVERBURDEN PRESSURE ON GAS PERMEABILITY

Effective Overburden Pressure (psi):				500	1,000	2,000	3,000	4,000	5,000	6,000
Core Number*	Length (cm)	Porosity (percent)	k_i†	Permeability (md)						
Gasbuggy										
3927	2.1	8.1	0.076	0.053	0.040	0.024	0.0175	0.0132	0.0105	0.0095
3928	7.5	8.3	0.037	0.031	0.024	0.015	0.0093	0.0059	0.0046	0.0035
3978	2.1	8.2	0.151	0.118	0.078	0.052	0.036	0.024	0.0175	0.0132
4113**	2.1	10.1	1.75	1.16	0.602	0.252	0.113	0.068	0.042	0.029
4134**	2.1	11.6	0.10	0.046	0.029	0.0153	0.0095	0.0065	0.0055	0.0047
4146**	7.5	11.6	2.40	1.73	1.32	0.31	0.14	0.069	0.052	0.022
4147**	7.5	11.3	0.60	0.247	0.181	0.071	0.034	0.0186	0.0118	0.0082
4158	2.1	13.6	1.59	1.06	0.80	0.35	0.225	0.152	0.116	0.100
Wagon Wheel										
8084	3.8	7.7	0.028	0.022	0.020	0.010	0.0070	0.0047	0.0035	0.0030
8122	3.8	11.4	0.071	0.055	0.048	0.034	0.027	0.024	0.021	0.019
8975**	3.8	8.7	0.039	0.029	0.024	0.0114	0.0073	0.0048	0.0032	0.0025
10156	3.8	8.5	0.088	0.067	0.051	0.032	0.025	0.022	0.018	0.016
10390**	3.8	9.0	0.048	0.020	0.0175	0.0080	0.0050	0.0040	0.0025	0.0019

*Number denotes depth in feet.
**Slightly fractured.
†Initial permeability.

mental increases in external pressure. The core was assumed to be in equilibrium at each pressure when permeability measurements remained constant for 15 minutes, which required between 1 and 2 hours. A period of 30 minutes to an hour was required to attain equilibrium when the inlet pressure was changed. Consequently, each external pressure was maintained for a minimum of 2 hours.

The effect of decreasing external pressure was determined on a few cores, and typical results are shown in Fig. 3. Other researchers[2,3] have observed and shown that this hysteresis is mainly dependent on the stress history of the core. Cores generally recover their original permeability after 3 to 6 weeks at atmospheric conditions. This time could be shortened by storing the core in an oven at 70°C.

The effect of overburden pressure on the permeability of cores from Project Wagon Wheel is similar to that on cores from Project Gasbuggy, and typical results are shown in Fig. 6. The permeability is decreased to about 30 percent of initial permeability at an overburden pressure of 3,000 psi and to 20 percent at 6,000.

A study of the data in Table 1 indicates that the original porosity of the core and the reduction in permeability caused by overburden pressure are not related. Pore structure (fractures to uniform pores) is probably the governing factor.

Water Saturation Effects

The data in Table 2 show that the permeability decreased with increasing water saturation. The values at 20-, 40-, and 60-percent water saturation were obtained from individual relative-permeability curves for Gasbuggy and Wagon Wheel cores. Relative-permeability curves for three cores from Project Gasbuggy are shown in Fig. 4 with the data points for Core 3978. Data points were omitted for the other cores to avoid confusion. This figure shows that although gas permeability is reduced, the relative gas permeability of Gasbuggy cores is not significantly affected by increased overburden pressure. This conclusion is in agreement with the results of others.[4,5]

Extremely low values of permeability that resulted from water saturation and overburden pressure required that either long flow times or high inlet pressures (high differential across the core) be used. Since a high inlet pressure increases the end effects by changing the distribution of water in the core, long flow times were required. Although end-effect problems were encountered with the short cores (Cores 3978 and 4158), the permeability of these cores was

TABLE 2—EFFECT OF OVERBURDEN PRESSURE AND WATER SATURATION ON GAS PERMEABILITY

Water Saturation (percent):		0	20	40	60
Core Number	Pressure (psi)	Permeability (md)			
Gasbuggy					
3927	100	0.115	0.099	0.041	0.0023
3927	3,000	0.026	0.023	0.009	0.0005
3927	6,000	0.012	0.010	0.003	0.0002
3978	100	0.112	0.080	0.034	0.011
3978	3,000	0.036	0.026	0.011	0.004
3978	6,000	0.013	0.009	0.004	0.0013
4158	100	0.447	0.335	0.156	0.045
4158	3,000	0.075	0.056	0.026	0.0074
4158	6,000	0.027	0.020	0.010	0.0026
Wagon Wheel					
8084	100	0.038	0.030	0.014	0.0042
8084	3,000	0.012	0.0096	0.0043	0.0013
8084	6,000	0.0070	0.0056	0.0025	0.0008
8122	100	0.074	0.054	0.017	0.006
8122	3,000	0.027	0.020	0.008	0.002
8122	6,000	0.020	0.015	0.006	0.002
10156	100	0.100	0.074	0.029	0.003
10156	3,000	0.028	0.020	0.008	0.0008
10156	6,000	0.017	0.013	0.005	0.0005

high enough to yield reasonable results. Permeability measurements for Core 4161 (7.5 cm long, 0.053 md) required more than 2 hours per reading. These extremely long flow times can cause errors.

End effects, long flow times, and changes in permeability due to water saturation tend to decrease the accuracy of permeability measurements, especially at the higher water saturations.

The initial permeability of many of the dry cores used in this research was not reproducible following saturation and drying. The changes probably were caused by solution of material in the pores and by particle movement. These caused both increases and decreases in permeability. The variation, although sometimes large, usually was less than 5 percent; however, we feel that the relative permeability curves are essentially correct. To eliminate the effects of solution and particle movement, the permeability of the dry core following saturation, rather than the permeability initially measured, was used in calculating relative permeability.

A composite of the relative permeability curves for Gasbuggy cores is shown in Fig. 5. These curves are representative of permeabilities encountered in this formation. At a water saturation of 50 percent, the relative permeability of the cores ranges from 15 to 20 percent and is not affected by overburden pressure.

Similar results were obtained on cores from Project Wagon Wheel, as shown in Table 2 and Fig. 6 with data points for Core 8122. These cores were cut to a length of 3.8 cm to alleviate some of the long flow time and end-effect difficulties encountered with Gasbuggy cores. These curves are representative of the permeabilities encountered in the formation. At a water saturation of 50 percent, the relative permeability of these cores ranges from 12 to 21 percent. The data in these figures show, as do the data from Gasbuggy cores, that relative gas permeability is not significantly affected by increased overburden pressure.

Correlation with Nuclear Stimulation Projects

Many of the basin areas of the Rocky Mountain region consist of thick, low-permeability sandstones containing large quantities of natural gas. This type of reservoir has been the object of the AEC's Plowshare Program experiments, Projects Gasbuggy and Rulison, and proposed Projects Wagon Wheel, WASP, and Rio Blanco. Because most wells in these reservoirs have not been commercial, only limited reservoir-analysis and production-test data are available. Reservoir analysis is most difficult because low permeability requires long-term testing. Also, it is difficult to determine permeability and net pay from these tests. Knowledge of the gas permeability is necessary in predicting gas recovery, and because it is not economical to define the characteristics of different strata by well test, it is desirable to be able to relate laboratory-measured permeability to the true in-situ permeability.

Conventional analysis by a commercial laboratory (confirmed in our laboratory) of about 200 Gasbuggy cores gave an average initial gas permeability of 0.16 md on dry cores and an average water saturation of 48 percent. The effective overburden pressure of this

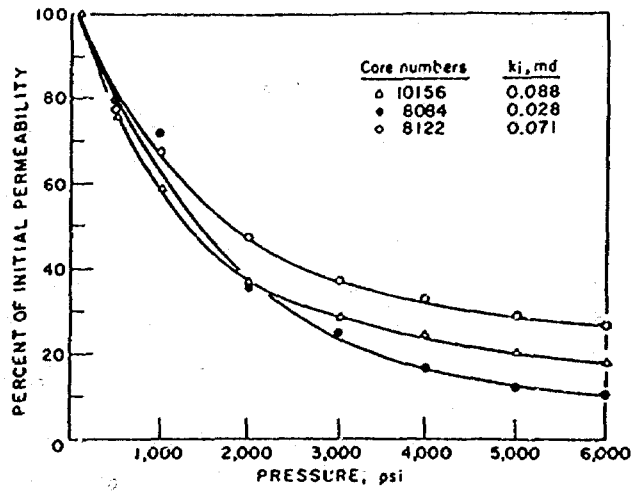

Fig. 4—Effect of overburden pressure on gas permeability of Wagon Wheel cores.

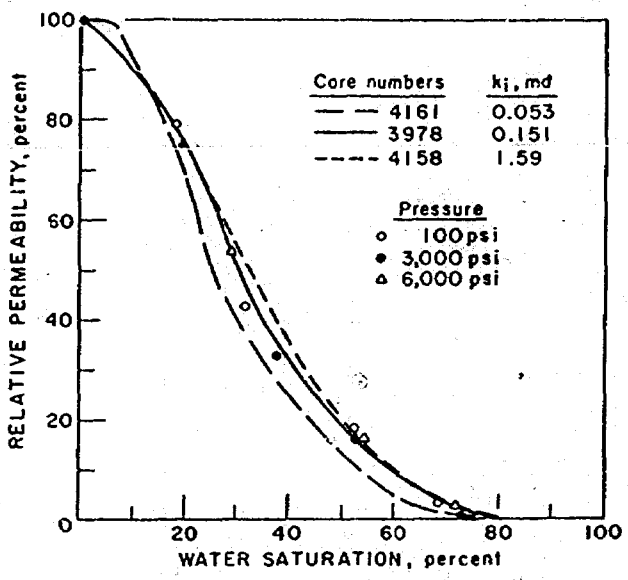

Fig. 5—Relative gas permeability of Gasbuggy cores.

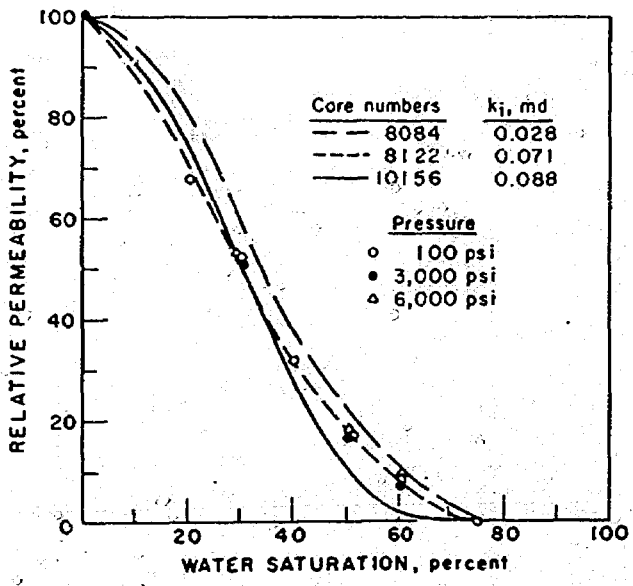

Fig. 6—Relative gas permeability of Wagon Wheel cores.

reservoir is about 3,000 psi. From Fig. 1, the reduction factor resulting from the overburden pressure is 0.25, and the reduction factor for a water saturation of 48 percent (Fig. 5) is 0.20; thus the total reduction is 5 percent of the initial permeability, or 0.008 md. This value compares favorably with permeability determinations of about 0.01 md from both preshot and postshot flow testing at Gasbuggy. The gas reservoir at Project Rulison is similar to that at Gasbuggy, having an average initial dry permeability of 0.11 md and an average water saturation of 45 percent. Simulated in-situ permeability has not yet been measured in the laboratory on Rulison cores; however, using an effective overburden pressure of 5,000 psi and curves of Gasbuggy core data (Figs. 1 and 5), the reduction factor because of overburden pressure would be 0.12 and that for water saturation 0.24. This results in a combined reduction to 3 percent of the initial permeability, or 0.003 md. Postshot production testing at Rulison is not complete, and the only preshot determination of permeability was made from tests of a 32-ft isolated zone that gave an average value of 0.008 md. No cores are available from this zone. Rulison reservoir rock is said to be less compressible than that of Gasbuggy; therefore Gasbuggy pressure-effect data would be expected to indicate a greater reduction for Rulison than actually exists.

The average initial permeability of dry Wagon Wheel cores is 0.068 md, with an average water saturation of 50 percent. An estimated effective overburden pressure of 3,000 psi gives a reduction factor of 0.28 (Fig. 4). Water saturation further reduces permeability by a factor of 0.18 (Fig. 6). Therefore, the total reduction in permeability is to approximately 5 percent of the initial permeability, or 0.0034 md. This value can be used to predict postshot gas recovery from the proposed Wagon Wheel experiment.

Cores are not yet available from Projects Rio Blanco and WASP.

Original manuscript received in Society of Petroleum Engineers office June 16, 1971. Revised manuscript received Dec. 20, 1971. Paper (SPE 3634) was presented at SPE 46th Annual Fall Meeting, held in New Orleans, Oct. 3-6, 1971.

Conclusions

The gas permeability of tight sandstone cores is markedly decreased with increasing overburden pressure. Most of the decrease takes place at pressures to 3,000 psi. At 3,000 psi, the permeability of unfractured samples ranges from 14 to 37 percent of the initial permeability. In fractured samples, permeability may be reduced to as low as 6 percent of initial permeability.

Water saturation also reduces the gas permeability greatly; however, the relative permeability does not change significantly with overburden pressure.

Permeability calculated from laboratory results are in good agreement with in-situ permeabilities determined from production test data. Although not confirmed, predictions for other projects appear to be reasonable.

References

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3. Vairogs, Juris, Hearn, C. L., Dareing, D. W. and Rhoades, V. W.: "Effect of Rock Stress on Gas Production from Low-Permeability Reservoirs," *J. Pet. Tech.* (Sept., 1971) 1161-1167.
4. Wilson, J. W.: "Determination of Relative Permeability Under Simulated Reservoir Conditions," *AIChE Jour.* (1956) 2, 94.
5. Fatt, I.: "The Effect of Overburden Pressure on Relative Permeability," *Trans.*, AIME (1953) 198, 325-326.
6. *API Recommended Practice for Core-Analysis Procedure*, API RP 40, Dallas (1960) 35.

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EXPLANATION OF METHOD USED
TO DETERMINE IN SITU PERMEABILITY
FROM ROUTINE CORE ANALYSIS
BASIN DAKOTA FIELD
SAN JUAN COUNTY, NEW MEXICO

Exhibit No. 8 is a paper entitled "Effect of Overburden Pressure and Water Saturation on Gas Permeability of Tight Sandstone Cores", by Rex D. Thomas and Don C. Ward. This paper presents a method of determining the relationship between routine laboratory and in situ permeability. In this method initial (laboratory) permeability was determined at 100 psi (or less) external pressure. In situ conditions were then simulated by measuring the permeability at various pressures ranging from 500 to 6000 psi. Percent of initial permeability (ratio of permeability at 100 psi to permeability at higher pressures) was then plotted versus pressure. The results of the work is shown in Figure 1, page 121, of the above paper. Using Core No. 3928, which has permeability very near the average of the five test wells in this application, and a bottomhole pressure of 2650 psi, the factor necessary to correct laboratory permeability to in situ permeability is determined to 0.28.

The authors used cores from the Pictured Cliffs formation in a well in Rio Arriba County, New Mexico. This well is located approximately 50 miles southeast of the proposed tight gas area. Cores from the Dakota formation could be expected to provide results very similar to those obtained from the Pictured Cliffs formation.

The water present in the reservoir also causes the in situ permeability to be less than laboratory permeability as is discussed in Exhibit No. 8. No correction, however, has been made for water saturation.

BEFORE EXAMINER NUTTER
OIL CONSERVATION DIVISION
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CASE NO. _____

9

EL PASO NATURAL GAS COMPANY
CASE NO. 8
NE-18-31N-11W
BASIN DAKOTA FIELD
SAN JUAN COUNTY, NEW MEXICO

Depth (feet)		Permeability (md.)
7254-55		.41
55-56		.32
56-57		.11
57-58		.02
58-59		.03
59-60		.12
60-61		.02
61-62		.07
7338-39		.09
39-40		.12
40-41		.04
41-42		.04
42-43		.04
43-44		.04
44-45		.02
45-46		.06
46-47		.07
47-48		.29
48-49		.03
49-50		.14
50-51		.07
51-52		.04
53-54		.56
54-55		.01
55-56		.24
7364-65		.07
65-66		.05
66-67		.08
67-68		.02
68-69		.52
69-70		.03
70-71		.23
71-72		.02
7390-91		.33
91-92		.03
92-93		.02
93-94		.02
Totals	37	4.42
Average Laboratory		.1195
Average In Situ		.0335

not in area

BEFORE EXAMINER NUTTER
OIL CONSERVATION DIVISION
SRC EXHIBIT NO. 10
CASE NO.

10

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CORE ANALYSIS RESULTS

Company EL PASO NATURAL GAS COMPANY Formation GRANEROS File RP-3-1441
Well CASE # 8 Core Type DIAMOND CONV. Report 5/26/61
Field BASIN DAKOTA Drilling Fluid WATER BASE MUD Analysts McCOMAS
County SAN JUAN State NEW MEX. Elev. 6245 GR Location SEC 18 T31N R11W

Lithological Abbreviations

SAND-SD	COLOR-CLR	ANHYDRITE-ANHY	SANDY-SDY	FINE-FN	CRYSTALLINE-XLN	BROWN-BRN	FRACTURED-FRAC	SLIGHTLY-SLY
SHALE-SH	CHERT-CH	CONGLOMERATE-CONG	SHALY-SHY	MEDIUM-MED	GRAIN-GRN	GRAY-GY	LAMINATION-LAM	VERY-V
LIME-LM	GYPSUM-GYP	FOSSILIFEROUS-FOSS	LIMY-LMY	COARSE-CSE	GRANULAR-GRNL	GGY-VGY	STYLOLITIC-STY	WITH-W

SAMPLE NUMBER	DEPTH FEET	PERMEABILITY MILLIDARCYS	POROSITY PERCENT	RESIDUAL SATURATION PER CENT PORE OIL	TOTAL WATER	SAMPLE DESCRIPTION AND REMARKS
1	7251-52	0.04	3.8	18.4	57.6	VERTICAL FRACTURE
2	52-53	0.65	3.9	17.9	38.3	" "
3	53-54	0.07	3.9	17.9	46.0	" "

7251-7254 This interval is essentially non-productive.

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CORE ANALYSIS RESULTS

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Well CASE # 8 Core Type DIAMOND CONV. Date 5/27/61
Field BASIN DAKOTA Drilling Fluid WATER BASE MUD Analysts McCOMAS
County SAN JUAN State NEW MEX. Elev. 6245 GR Location SEC 18 T31N R11W

Lithological Abbreviations

SAND-SD	CONGLOMERATE-CONG	ANHYDRITE-ANHY	SANDY-SDY	RED-RD	GRAIN-GRN	BROWN-BRN	FRACTURED-FRAC	SLIGHTLY-SLY
SHALE-SH	CHERT-CH	SALT-SLT	SHALY-SHY	RED BEDS-RDBDS	GRAVEL-GVL	GRAY-GY	LAMINATION-LAM	VERY-V
LIME-LM	GYP & GYP	FOSSILIFEROUS-FOSS	TINY-TNY	DENSE-DSE	GRANULAR-GRNL	VUGGY-VGY	STYLOLITIC-STY	WITH-W

SAMPLE NUMBER	DEPTH FEET	PERMEABILITY MILLIDARCYS	POROSITY PER CENT	RESIDUAL SATURATION PER CENT PORE OIL	RESIDUAL SATURATION PER CENT PORE TOTAL WATER	SAMPLE DESCRIPTION AND REMARKS
4	7254-55	0.41	3.4	20.3	53.0	VERTICAL FRACTURE
5	55-56	0.32	4.4	15.9	50.0	" "
6	56-57	0.11	3.2	15.6	65.6	" "
7	57-58	0.02	3.9	17.9	64.1	" "
8	58-59	0.03	3.8	13.1	65.8	" "
9	59-60	0.12	3.6	5.6	75.0	" "
10	60-61	0.02	3.7	5.4	78.4	" "
11	61-62	0.07	3.9	0.0	74.5	" "
12	62-63	0.04	4.2	4.8	83.4	" "
13	63-64	0.04	4.8	10.4	79.3	" "
14	64-65	0.01	3.5	5.7	83.0	" "
15	65-66	0.03	3.7	0.0	89.1	" "
16	66-67	<0.01	3.8	13.1	65.9	" "
17	67-68	0.04	4.4	11.4	79.6	" "
18	68-69	0.01	4.0	17.5	60.1	" "
19	69-70	0.07	3.4	14.7	70.6	" "
20	70-71	<0.01	3.8	18.4	63.2	" "
21	71-72	0.05	5.5	12.7	41.9	" "
22	72-73	0.01	4.8	14.5	56.0	" "
23	73-74	0.10	4.9	10.2	67.4	" "
24	74-75	0.01	5.1	13.7	56.9	" "
25	75-76	0.05	5.3	13.2	66.1	" "

7254-7276 This interval is essentially non-productive.

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Well CASE # 8 Core Type DIAMOND CONV. Date 5/29/61
Field BASIN DAKOTA Drilling Fluid WATER BASE MUD Analysts McCOMAS
County SAN JUAN State NEW MEX. Elev. 6245 GR Location SEC 18 T31N R11W

Lithological Abbreviations

SAND-SD	DOLOMITE-DOL	ANHYDRITE-ANHY	SANDY-SDY	FINE-FN	CRYSTALLINE-XLN	BROWN-BRN	FRACTURED-FRAC	SLIGHT-
SHALE-SH	CHERT-CH	CONGLOMERATE-CONG	SHALY-SHY	MEDIUM-MED	GRAIN-GRN	GRAY-GY	LAMINATION-LAM	VERY-
LIME-LM	GYPSUM-GYP	FOSSIL-FEROUS-FOS	LIMY-LMY	COARSE-CSE	GRANULAR-GRNL	VUGGY-VGY	STYLOLITIC-STY	WITH-W

SAMPLE NUMBER	DEPTH FEET	PERMEABILITY MILLIDARCYS	POROSITY PER CENT	RESIDUAL SATURATION PER CENT PORE OIL	RESIDUAL SATURATION PER CENT PORE TOTAL WATER	SAMPLE DESCRIPTION AND REMARKS
26	7335-36	0.05	2.8	0.0	85.9	VERTICAL FRACTURE
27	36-37	0.04	2.3	0.0	74.1	"
28	37-38	0.05	2.7	0.0	74.1	"
29	38-39	0.09	3.3	6.1	60.6	"
30	39-40	0.12	3.7	5.4	78.1	"
31	40-41	0.04	2.8	0.0	71.6	"
32	41-42	0.04	1.9	0.0	89.5	"
33	42-43	0.04	4.0	17.5	59.8	"
34	43-44	0.04	2.8	0.0	71.6	"
35	44-45	0.02	2.5	0.0	64.1	"
36	45-46	0.06	4.2	0.0	59.4	"
37	46-47	0.07	4.8	0.0	45.7	"
38	47-48	0.29	5.0	4.0	40.0	"
39	48-49	0.03	4.7	0.0	25.4	"
40	49-50	0.14	7.8	0.0	20.4	"
41	50-51	0.07	7.4	0.0	24.3	"
42	51-52	0.04	2.2	0.0	77.4	"

7335-7345 This interval is essentially non-productive.

7345-7351 This interval is capable of producing gas, the average characteristics are; Porosity (5.7% average) Total Water saturation (35.8% average), Residual Oil Saturation (0.7% average) and Permeability (0.11 md./ft. average). The fractures in this interval are open and will enhance the permeability quite a bit.

7351-7352 This one foot interval is essentially non-productive.

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Well CASE # 8 Core Type DIAMOND CONV. 5/30/61
Field BASIN DAKOTA Drilling Fluid WATER BASE MUD McCOMB
County SAN JUAN State NEW MEXICO Elev. 6245 GR Location S 8 T31N R11W

Lithological Abbreviations

SAND-SD	DOLOMITE-DO	ANHYDRITE-ANHY	SANDY-SDY	FINE-FN	CRYSTALLINE-X'LN	BROWN-BRN	
SHALE-SH	CHERT-CH	CONGLOMERATE-CONG	SHALY-SHY	MEDIUM-MED	BRAIN-BRN	GRAY-GY	
LIME-LM	GYPSUM-GYP	FOSSILIFEROUS-FOSS	LIMY-LMY	COARSE-CR	GRANULAR-GRNL		

SAMPLE NUMBER	DEPTH FEET	PERMEABILITY MILLIDARCYS	POROSITY PER CENT	RESIDUAL SATURATION PER CENT PORE OIL	RESIDUAL SATURATION PER CENT PORE TOTAL WATER	SAMPLE DESCRIPTION AND REMARKS
43	7353-54	0.56	1.4	0.0	42.9	VERTICAL FRACTURE
44	54-55	0.01	1.1	0.0	36.3	" "
45	55-56	0.24	2.0	0.0	65.0	" "
46	7363-64	0.02	4.5	0.0	40.0	" "
47	64-65	0.07	6.9	0.0	28.0	" "

7353-7356 This interval is essentially non-productive from the matrix rock. It is possible that the fractures could contribute gas.

7363-7365 This two foot interval is capable of producing a low capacity gas, with most of the gas coming from the fractures.

[illegible]

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Well CASE # 8 | Core Type DIAMOND CONV. | Date Report 5/31/61
Field BASIN DAKOTA | Drilling Fluid WATER BASE MUD | Analysts McCOMAS
County SAN JUAN | State NEW MEX. | Elev. 6245 GR | Location SEC 18 T31N R11W

Lithological Abbreviations

SAND-SD SHALE-SH LIME-LM	DOLOMITE-DOL CHERT-CH GYPSUM-GYP	ANHYDRITE-ANHY CONGLOMERATE-CONG FOSSILIFEROUS-FOSS	SANDY-SDY SHALY-SHY LIMY-LMY	FINE-FN MEDIUM-MED COARSE-CSE	CRYSTALLINE-XLN GRAIN-GRN GRANULAR-GRNL	BROWN-BRN GRAY-GY VUGGY-VGY	FRACTURED-FRAC LAMINATION-LAM STYLOLITIC-STY	SLIGHTLY-
VERY-V
WITH-W

SAMPLE NUMBER	DEPTH FEET	PERMEABILITY MILLIDARCYS	POROSITY PER CENT	RESIDUAL SATURATION PER CENT PORE OIL	RESIDUAL SATURATION PER CENT PORE TOTAL WATER	SAMPLE DESCRIPTION AND REMARKS
48	7365-66	0.05	2.7	0.0	74.0	VERTICAL FRACTURE
49	66-67	0.08	3.9	0.0	51.2	" "
50	67-68	0.02	2.2	0.0	95.5	" "
51	68-69	0.52	2.2	0.0	63.6	" "
52	69-70	0.03	2.7	0.0	74.0	" "
53	70-71	0.23	2.6	0.0	96.0	" "
54	71-72	0.02	2.6	0.0	96.0	" "

7365-7372 This interval is essentially non-productive.

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File No. 6

CORE ANALYSIS RESULTS

Company EL PASO NATURAL GAS COMPANY Formation DAKOTA RP-3-1411
Well CASE # 8 Core Type DIAMOND CONV. Date Report 5/31/61
Field BASIN DAKOTA Drilling Fluid WATER BASE MUD Analysts McCOMAS
County SAN JUAN State NEW MEX. Elev 6245 GR Location SEC 18 T31N R11W

Lithological Abbreviations

SAND-SD SHALE-SH LIME-LM | DOLOMITE-DOL CHERT-CH GYPSUM-GYP | ANHYDRITE-ANHY CONGLOMERATE-CONG FOSSILIFEROUS-FOSS | SANDY-SDY SHALY-SHY LIMY-LMY | FINE-FN MEDIUM-MED COARSE-CSE | CRYSTALLINE-XLN GRAIN-GRN GRANULAR-GRNL | BROWN-BRN GRAY-GY VUGGY-VGY | FRACTURED-FRAC LAMINATION-LAM STYLOLITIC-STY | SLIGHTLY-V. WITH-W.

SAMPLE NUMBER	DEPTH FEET	PERMEABILITY MILLIDARCYS	POROSITY PER CENT	RESIDUAL SATURATION PER CENT PORE OIL	RESIDUAL SATURATION PER CENT PORE TOTAL WATER	SAMPLE DESCRIPTION AND REMARKS
55	7375-76	0.17	3.0	0.0	50.0	VERTICAL FRACTURE
56	76-77	0.07	2.0	0.0	65.0	" "
57	7383-84	0.07	6.2	0.0	33.9	" "
58	84-85	0.34	9.4	0.0	28.8	" "
59	85-86	0.07	6.7	0.0	35.8	" "
60	86-87	0.12	3.5	0.0	34.4	" "
61	87-88	0.02	3.6	0.0	69.5	" "
62	7390-91	0.33	2.4	0.0	87.4	" "
63	91-92	0.03	1.8	0.0	72.2	" "
64	92-93	0.02	3.5	0.0	54.4	" "
65	93-94	0.02	3.5	0.0	57.1	" "
66	94-95	0.15	3.7	0.0	45.9	" "
67	95-96	0.02	2.1	0.0	71.3	" "
68	96-97	0.04	2.5	0.0	67.9	" "
69	97-97.5	0.02	1.4	0.0	64.1	" "

7375-7377 This interval is essentially non-productive.

7383-7388 This interval is capable of producing gas, primarily from the fractures. The average characteristics are: Porosity (5.8% average) Total Water saturation (40.4% average) Residual Oil saturation (0.0% average) and Permeability (0.12 md./ft average)

7390-7397.5 This interval is essentially non-productive.

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CORE ANALYSIS RESULTS

Company EL PASO NATURAL GAS COMPANY Formation DAKOTA File RP-3-1441
Well CASE # 8 Core Type DIAMOND CONV. Report 6/1/61
Field BASIN DAKOTA Drilling Fluid WATER BASE MUD Analysts McCOMAS
County SAN JUAN State NEW MEX. Elev. 6245 GR Location SEC 18 T31N R11W

Lithological Abbreviations

SAND-SD	DOLOMITE-DOL	ANHYDRITE-ANHY	SANDY-SDY	FINE-FN	CRYSTALLINE-XLN	BROWN-BRN	FRACTURED-FRAC	SLIGHTLY-SLY
SHALE-SH	CHERT-CH	CONGLOMERATE-CONG	SHALY-SHY	MEDIUM-MED	GRAIN-GRN	GRAY-GY	LAMINATION-LAM	VERY-V
LIME-LM	GYPSUM-GYP	FOSSILIFEROUS-FOSS	-MY-LMY	COARSE-CSE	GRANULAR-GRNL	VUGGY-VGY	STYLOLITIC-STY	WITH-W

SAMPLE NUMBER	DEPTH FEET	PERMEABILITY MILLIDARCYS	POROSITY PER CENT	RESIDUAL SATURATION PER CENT PORE OIL	RESIDUAL SATURATION PER CENT PORE TOTAL WATER	SAMPLE DESCRIPTION AND REMARKS
70	7422-23	<0.01	1.8	0.0	94.6	VERTICAL FRACTURE
71	23-24	<0.01	0.6	0.0	66.6	" "
72	24-25	<0.01	2.3	0.0	95.6	" "
73	25-26	<0.01	1.6	0.0	81.2	" "
74	26-27	0.01	1.9	0.0	89.5	" "

7422-7427 This interval is essentially non-productive.

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JUN 5 1961
RESERVOIR ENGINEERING

8

CORE ANALYSIS RESULTS

Company EL PASO NATURAL GAS COMPANY Formation DAKOTA File 3-1441
Well CASE #8 Core Type DIAMOND CONV. Date Report 6/2/61
Field BASIN DAKOTA Drilling Fluid WATER BASE MUD Analysts McComa 8
County SAN JUAN State NEW MEX. Elev. 6245 GR Location SEC 18 T31N R11W

Lithological Abbreviations

SAND-SD	DOLOMITE-DOL	ANHYDRITE-ANHY	SANDY-SDY	FINE-FN	CRYSTALLINE-XLN	BROWN-BRN	FRACTURED-FRAC	SLIGHTLY-SL
SHALE-SH	CHERT-CH	CONGLOMERATE-CONG	SHALY-SHY	MEDIUM-MED	GRAIN-GRN	GRAY-GY	LAMINATION-LAM	VERY-V
LIME-LM	GYPSUM-GYP	FOSSILIFEROUS-FOSS	LIMY-LMY	COARSE-CSE	GRANULAR-GRNL	VUGGY-VGY	STYLOLITIC-STY	WITH-W

SAMPLE NUMBER	DEPTH FEET	PERMEABILITY MILLIDARCYS	POROSITY PER CENT	RESIDUAL SATURATION PER CENT PORE OIL	RESIDUAL SATURATION PER CENT PORE TOTAL WATER	SAMPLE DESCRIPTION AND REMARKS
75	7445-46	0.02	1.0	0.0	90.0	VERTICAL FRACTURE
76	46-47	0.02	2.6	0.0	96.2	
77	7454-55	0.03	2.6	19.2	65.5	VERTICAL FRACTURE

7445-7447 This interval is essentially non-productive.

7454-7455 This interval is essentially non-productive.

7489 24

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CA-20

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

RECEIVED
JUN 5 1961
RESERVOIR
ENGINEERING

CORE ANALYSIS RESULTS

Company EL PASO NATURAL GAS COMPANY | Formation DAKOTA | File RP-3-1441
Well CASE # 8 | Core Type DIAMOND CONV. | Date Report 6/2/61
Field BASIN DAKOTA | Drilling Fluid WATER BASE MUD | Analysts McCOMAS
County SAN JUAN | State NEW MEX. | Elev. 6245 GR | Location SEC 18 T31N R11W

Lithological Abbreviations

SAND-SD	DOLOMITE-DOL	ANHYDRITE-ANHY	SANDY-SDY	FINE-FN	CRYSTALLINE-XLN	BROWN-BRN	FRACTURED-FRAC	SLIGHTLY-SL/
SHALE-SH	CHERT-CH	CONGLOMERATE-CONG	SHALY-SHY	MEDIUM-MED	GRAIN-GRN	GRAY-GY	LAMINATION-LAM	VERY-V/
LIME-LN	GYPSUM-GYP	FOSSILIFEROUS-FOSS	LIMY-LMY	COARSE-CSE	GRANULAR-GRNL	VUGGY-VGY	STYLOLITIC-STY	WITH-W/

SAMPLE NUMBER	DEPTH FEET	PERMEABILITY MILLIDARCYS	POROSITY PER CENT	RESIDUAL SATURATION PER CENT PORE OIL	RESIDUAL SATURATION PER CENT PORE TOTAL WATER	SAMPLE DESCRIPTION AND REMARKS
78	7462-63	0.03	6.0	0.0	71.8	VERTICAL FRACTURE
79	63-64	0.03	3.5	0.0	74.0	" "
80	64-65	0.02	2.4	0.0	91.6	" "
81	65-66	0.80	5.4	0.0	68.5	" "
82	66-67	0.69	4.0	0.0	10.0	" "

7462-7467 This interval is essentially non-productive. It is possible that continuation of this interval will be low-capacity water productive.

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CA-5

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

RECEIVED
JUN 6 1961
RESERVOIR ENGINEERING

CORE ANALYSIS RESULTS

Company EL PASO NATURAL GAS COMPANY Formation DAKOTA File RP-3-1441
Well CASE # 8 Core Type DIAMOND CONV. Date 6/4/61
Field BASIN DAKOTA Drilling Fluid WATER BASE MUD Analysts McCOMAS
County SAN JUAN State NEW MEXICO Elev. 6245 GR Location SEC 18 T31N R11W

Lithological Abbreviations

SAND-SD	DOLOMITE-DOL	ANHYDRITE-ANHY	SANDY-SDY	FINE-FN	CRYSTALLINE-XLN	BROWN-BRN	FRACTURED-FRAC	SLIGHTLY-SLY
SHALE-SH	CHERT-CH	CONGLOMERATE-CONG	SHALY-SHY	MEDIUM-MED	GRAIN-GRN	GRAY-GY	LAMINATION-LAM	VERY-V/
LIME-LM	GYPSUM-GYP	FOSSILIFEROUS-FOSS	LIMY-LMY	COARSE-CSE	GRANULAR-GRNL	VUGGY-VGY	STYLOLITIC-STY	WITH-W

SAMPLE NUMBER	DEPTH FEET	PERMEABILITY MILLIDARCYS	POROSITY PER CENT	RESIDUAL SATURATION PER CENT PORE OIL	RESIDUAL SATURATION PER CENT PORE TOTAL WATER	SAMPLE DESCRIPTION AND REMARKS
83	7473-74	0.03	2.7	0.0	62.7	
84	74-75	0.07	4.6	0.0	34.6	
85	75-76	0.30	5.6	0.0	28.5	VERTICAL FRACTURE
86	76-77	0.13	2.5	0.0	72.0	" "
87	77-78	0.10	4.6	0.0	26.0	
88	78-79	0.28	5.0	0.0	39.8	
89	79-80	0.22	6.0	0.0	26.6	
90	80-81	0.39	5.4	0.0	25.8	VERTICAL FRACTURE
91	81-82	22	6.7	0.0	23.8	" "
92	82-83	11	15.0	0.0	75.5	
93	83-84	11	14.4	0.0	81.5	

7473-7482 Although this interval has water saturations normally associated with gas production, it is in permeable contact with interval from 7482 to 7484, which is definitely water productive. Any completion in the interval from 7473 to 7482 would probably result in water.

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CA-20

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

RECEIVED
JUN 6 1961
RESERVOIR ENGINEERING

File No. 11

CORE ANALYSIS RESULTS

Company EL PASO NATURAL GAS COMPANY Formation DAKOTA File FP-3-1441
Well CASE # 8 Core Type DIAMOND CONV. Date Report 6/5/61
Field BASIN DAKOTA Drilling Fluid WATER BASE MUD Analysts McCOMAS
County SAN JUAN State NEW MEX. Elev 6245 GR Location SEC 18 T31N R11W

Lithological Abbreviations

SAND-SD SHALE-SH LIME-LM	DOLOMITE-DO. CHERT-CH GYPSUM-GYP	ANHYDRITE-ANHY CONGLOMERATE-CONG FOSSILIFEROUS-FOSS	SANDY-SDY SHALY-SHY LIMY-LMY	FINE-FN MEDIUM-MED COARSE-CSE	CRYSTALLINE-XLN GRAIN-GRN GRANULAR-GRNL	BROWN-BRN GRAY-GY VUGGY-VGY	FRACTURED-FRAC LAMINATION-LAM STYLOLITIC-STY	SLIGHTLY-SL/ VERY-V/ WITH-W/

SAMPLE NUMBER	DEPTH FEET	PERMEABILITY MILLIDARCYS	POROSITY PER CENT	RESIDUAL SATURATION PER CENT PORE OIL	RESIDUAL SATURATION PER CENT PORE TOTAL WATER	SAMPLE DESCRIPTION AND REMARKS
94	7489-90	137	14.9	0.0	64.4	
95	90-91	0.52	7.7	0.0	75.4	
96	91-92	0.25	9.1	2.2	82.4	
97	92-93	19	11.2	0.0	61.6	
98	93-94	149	13.5	0.0	69.6	
99	94-95	97	13.7	1.5	71.5	
100	95-96	0.44	14.1	0.0	71.0	
101	96-97	0.32	15.3	1.3	69.2	
102	97-98	0.11	13.8	0.0	75.6	
103	98-99	0.17	15.2	0.0	77.0	
104	99-7500	128	19.1	0.0	66.0	
105	7500-01	99	16.0	0.0	68.1	
106	01-02	152	16.1	1.2	72.6	
107	02-03	201	16.7	1.2	77.4	
108	03-04	88	17.2	0.0	72.6	
109	04-05	167	17.6	0.0	73.0	
110	05-06	4.4	13.5	0.0	69.5	
111	06-07	0.68	9.1	0.0	74.6	
112	07-08	0.01	8.5	0.0	76.5	
113	08-09	0.07	8.9	0.0	72.0	
114	09-10	0.03	5.9	0.0	61.0	
115	10-11	0.38	6.9	0.0	58.0	
116	11-12	0.08	7.0	0.0	68.5	
117	12-13	0.12	7.2	0.0	85.0	

7489-7513 This interval is water productive.

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EL PASO NATURAL GAS COMPANY
MOORE NO. 8
SW-24-32N-12W
BASIN DAKOTA FIELD
SAN JUAN COUNTY, NEW MEXICO

Depth (feet)		Permeability (md.)
7589-90		.01
7591-92		.01
7593-94		.05
7595-96		.01
7597-98		.07
7599-7600		.01
7601-02		.08
7603-04		.01
7605-06		.01
7607-08		.01
7609-10		.02
7611-12		.01
7670-71		.03
71-72		.05
72-73		.48
73-74		.01
74-75		.01
75-76		.07
76-77		.03
78-79		.01
79-80		.09
80-81		.01
81-82		.11
82-83		.17
83-84		.08
84-85		.01
85-86		.02
86-87		.01
87-88		.04
88-89		.01
89-90		.01
90-91		.29
91-92		.07
92-93		.02
93-94		.01
94-95		.01
95-96		.02
96-97		.02
97-98		.12
Totals	39	2.10
Average Laboratory		.0538
Average In-Situ		.0151

in area

BEFORE EXAMINER NUTTER
OIL CONSERVATION DIVISION
SRC EXHIBIT NO. 11
CASE NO. _____

11

CORE LABORATORIES, INC. *Petroleum Reservoir Engineering*

COMPANY EL PASO NATURAL GAS COMPANY — DATE ON 4/23/61 — FILE NO. RP-3-1425
WELL MOORE # 8 — DATE OFF 5/1/61 — ENGRS. McCOMAS
FIELD BASIN-DAKOTA — FORMATION AS NOTED — ELEV. 6556 GR
COUNTY SAN JUAN — STATE N. MEXICO — DRLG. FLD. WATER BASE MUD — CORES DIAMOND CONV.
LOCATION SEC 27 T32N R12W — REMARKS SAMPLED BY CLI AT DIRECTION OF CLIENT

SAND · LIMESTONE · CONGLOMERATE · CHERT · SHALE · DOLOMITE · VERTICAL FRACTURE

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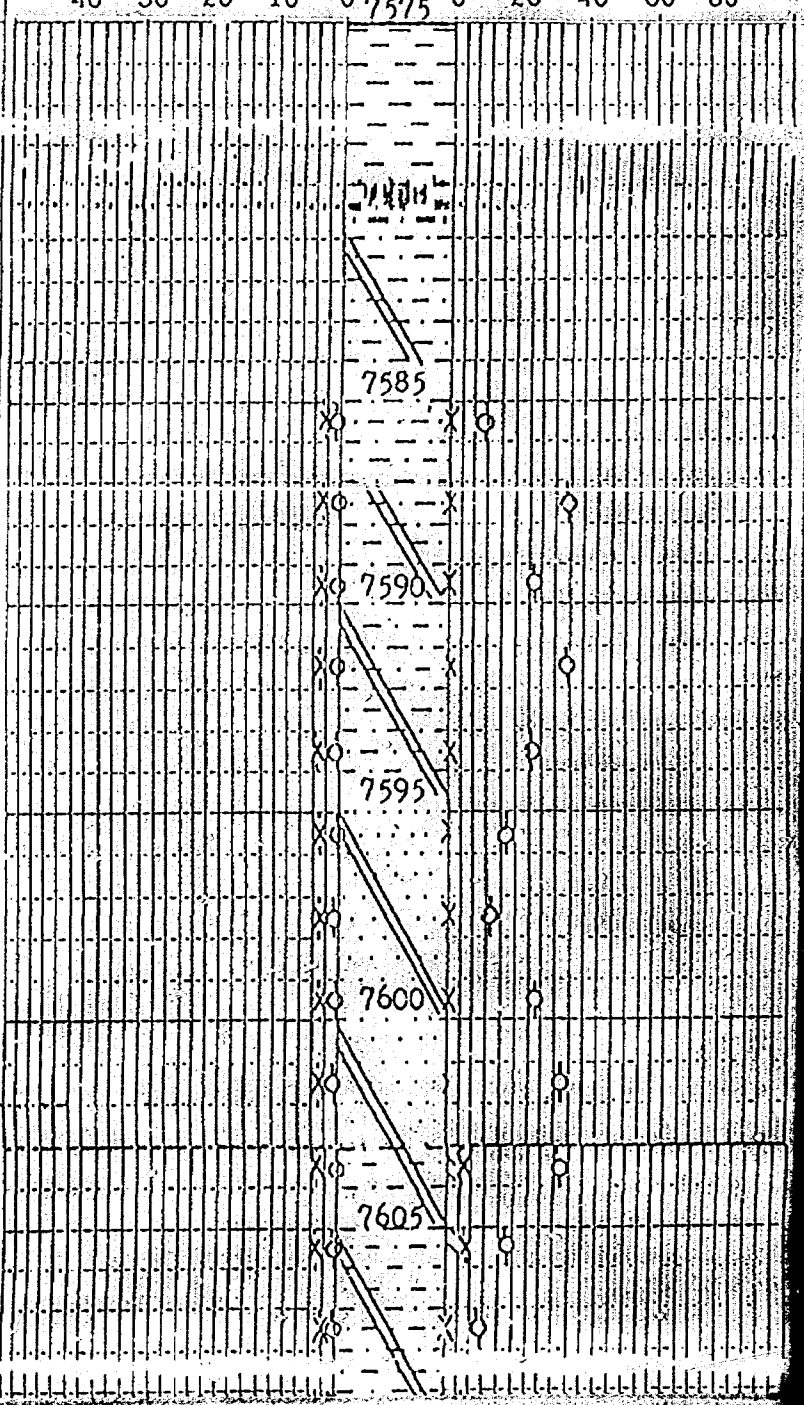
TABULAR DATA and INTERPRETATION

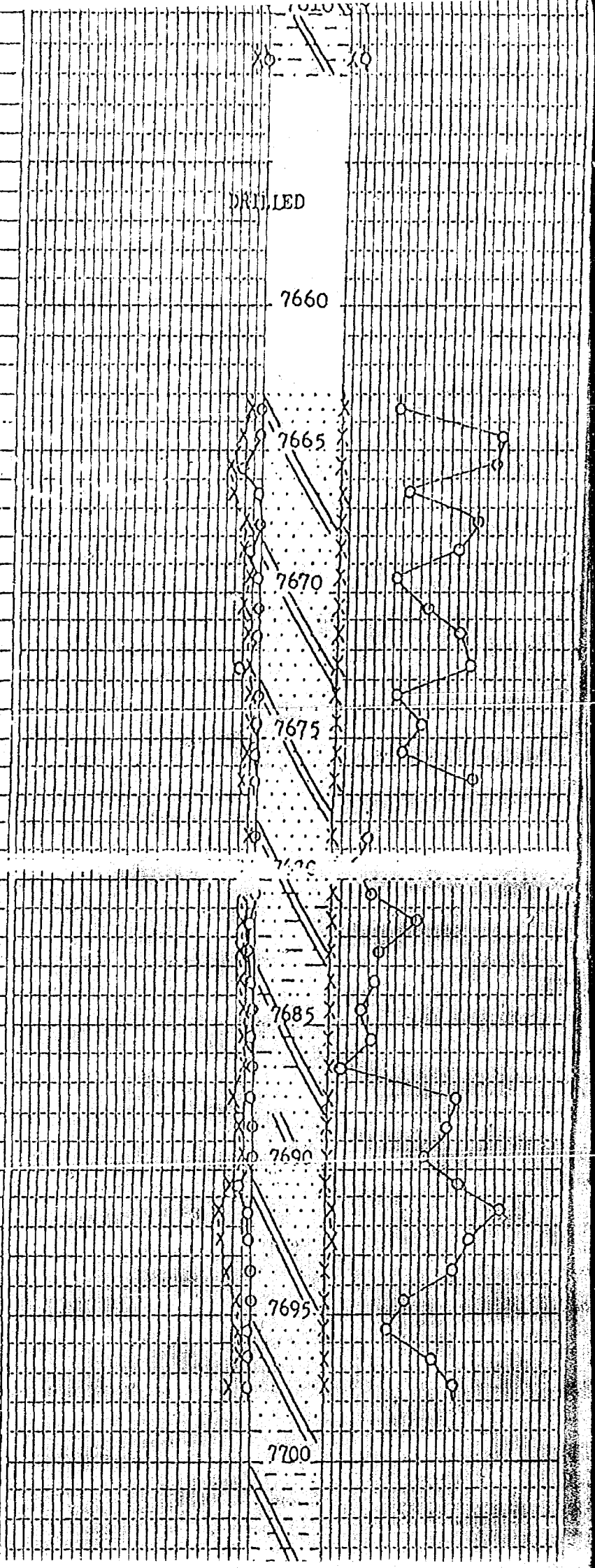
SAMPLE NUMBER	DEPTH FEET	PERM. MD.	POROSITY %	RESIDUAL SATURATION % PORE SPACE OIL	RESIDUAL SATURATION % PORE SPACE TOTAL WATER		# PROD
			GRANEROS				
1	7585-86	0.02	2.5	0.0	88.1		
2	7587-88	<0.01	3.1	0.0	64.7		
3	7589-90	0.01	2.9	0.0	75.9		
4	7591-92	<0.01	3.4	0.0	64.9		
5	7593-94	0.05	3.6	0.0	75.1		
6	7595-96	<0.01	3.4	0.0	82.4		
7	7597-98	0.07	3.1	0.0	87.1		
8	7599-7600	<0.01	3.0	0.0	73.4		
9	7601-02	0.08	3.0	0.0	66.7		
10	7603-04	<0.01	3.3	6.1	66.9		
11	7605-06	0.01	3.3	6.1	81.9		
12	7607-08	<0.01	1.7	0.0	88.4		

COMPLETION COREGRAPH

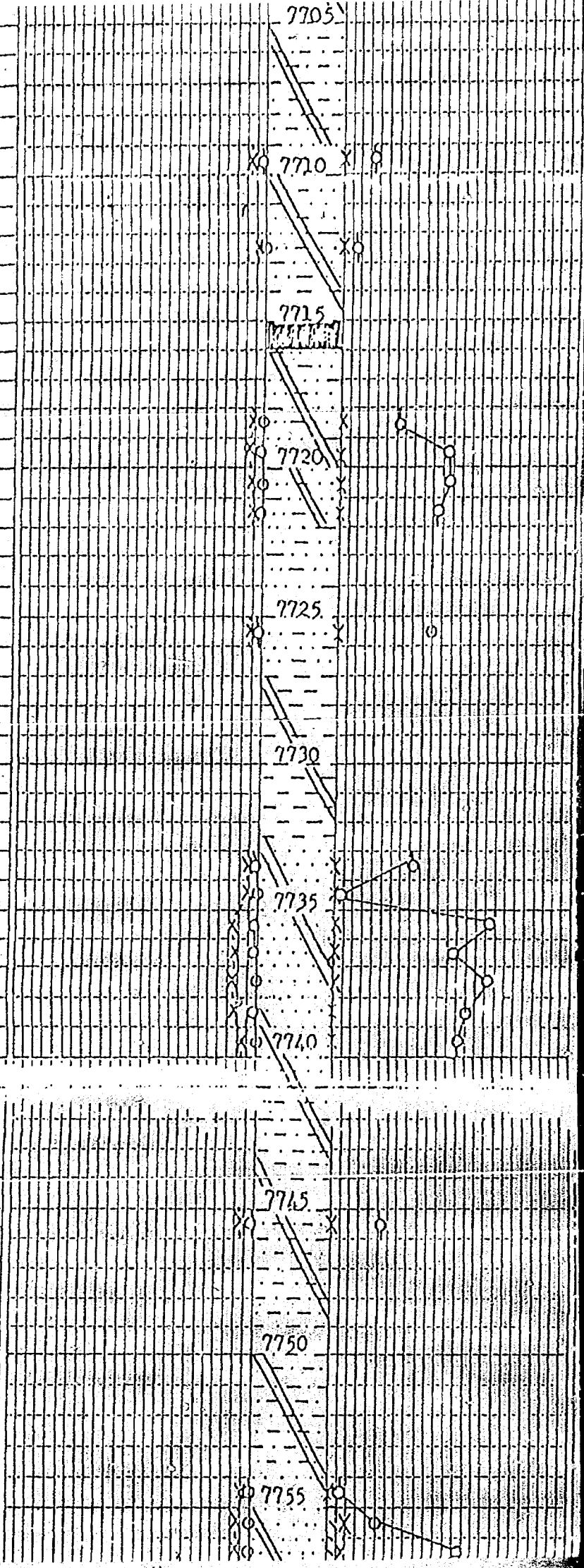
PERMEABILITY o—o MILLIDARCYS: 5 4 3 2 1 0
TOTAL WATER o—o PERCENT PORE SPACE: 80 60 40 20 0
POROSITY x---x PERCENT: 40 30 20 10 0
OIL SATURATION x---x PERCENT PORE SPACE: 0 20 40 60 80



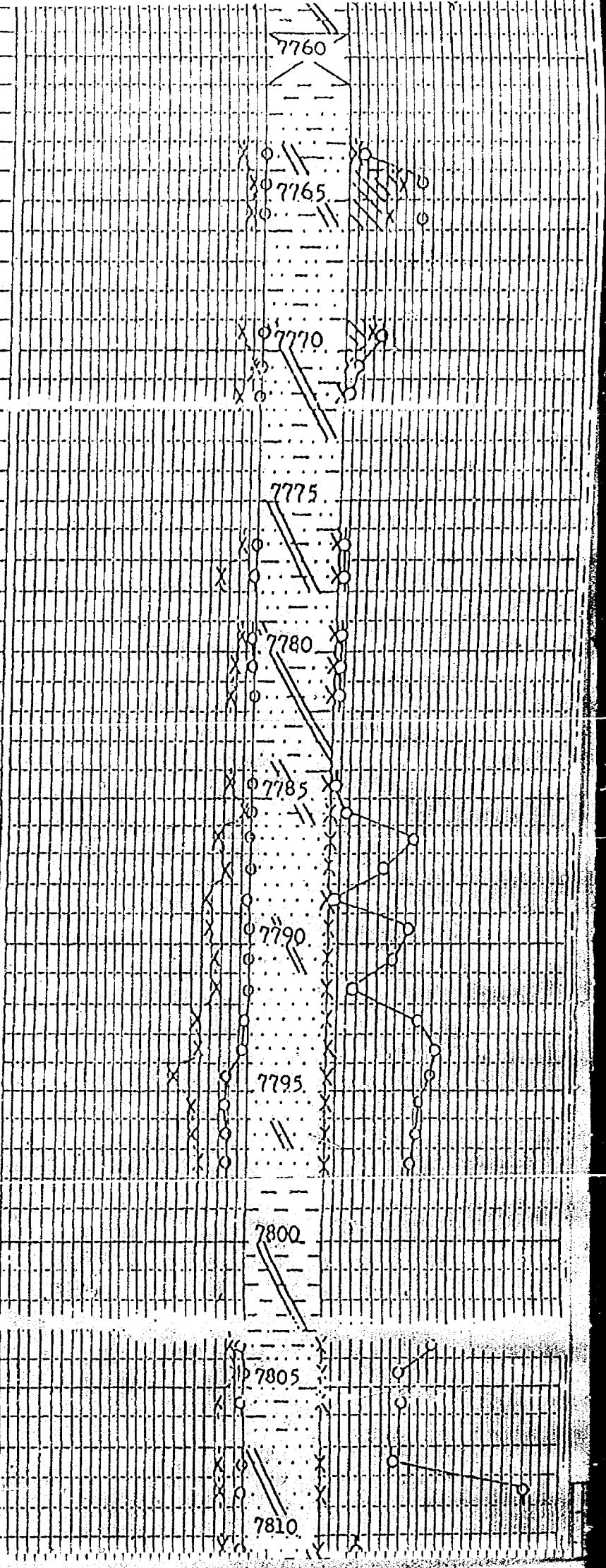
14	7611-12	<0.01	3.0	0.0	92.4	
			DAKOTA			
15	7662-64	0.01	2.4	0.0	75.0	
16	64-65	0.03	5.2	0.0	30.6	
17	65-66	0.41	7.4	0.0	32.3	
18	66-67	0.10	6.6	0.0	69.5	
19	67-68	0.04	4.0	0.0	40.0	
20	68-69	0.26	2.5	0.0	48.1	
21	69-70	0.07	2.8	0.0	75.4	
22	70-71	0.03	4.0	0.0	60.0	
23	71-72	0.05	2.5	0.0	47.0	
24	72-73	0.48	2.8	0.0	42.9	
25	73-74	0.01	2.7	0.0	74.2	
26	74-75	0.01	1.9	0.0	63.2	
27	75-76	0.07	2.8	0.0	71.6	
28	76-77	0.03	4.0	0.0	40.0	
29	7678-79	<0.01	1.3	0.0	84.7	
30	79-80	0.09	[illegible]		[illegible]	
31	80-81	0.01	3.2	0.0	84.0	
32	81-82	0.11	2.2	0.0	64.0	
33	82-83	0.17	2.5	0.0	80.0	
34	83-84	0.08	3.3	0.0	81.5	
35	84-85	0.01	2.4	0.0	87.6	
36	85-86	0.02	2.3	0.0	82.7	
37	86-87	<0.01	2.2	0.0	95.6	
38	87-88	0.04	1.7	0.0	44.5	
39	88-89	0.01	3.7	0.0	48.4	
40	89-90	<0.01	2.4	0.0	58.5	
41	90-91	0.29	5.0	0.0	44.0	
42	91-92	0.07	7.7	2.6	26.0	
43	92-93	0.02	6.6	3.0	39.5	
44	93-94	0.01	4.8	0.0	45.9	
45	94-95	0.01	3.0	0.0	66.7	
46	95-96	0.02	2.7	0.0	74.6	
47	96-97	0.02	2.2	0.0	54.5	
48	97-98	0.12	1.4	0.0	15.5	



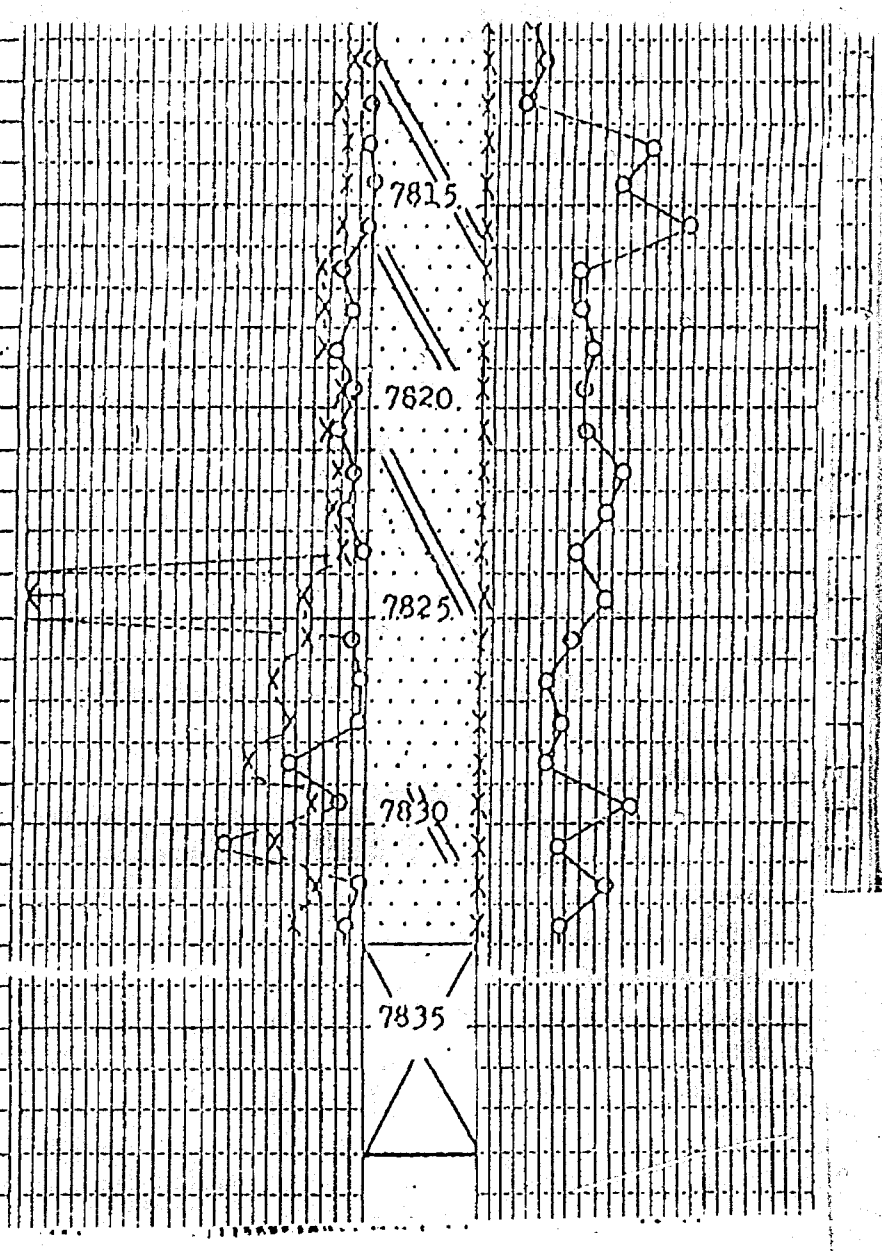
49	7709-10	0.07	2.9	0.0	86.1	
50	7712-13	<0.01	1.7	0.0	94.1	
51	7718-19	<0.01	2.7	0.0	74.1	
52	19-20	0.02	3.7	0.0	54.0	
53	20-21	<0.01	3.0	0.0	53.1	
54	21-22	0.02	2.8	0.0	57.2	
55	7725-26	0.07	2.5	20.0	60.0	
56	7733-34	0.05	1.8	0.0	66.6	
57	34-35	<0.01	2.7	0.0	96.6	
58	35-36	0.04	5.8	0.0	34.4	
59	36-37	0.04	4.9	0.0	48.9	
60	37-38	<0.01	5.7	0.0	35.0	
61	38-39	0.02	5.2	0.0	44.0	
62	39-40	<0.01	3.4	0.0	47.0	
63	7745-46	<0.01	2.4	0.0	79.2	
64	7754-55	<0.01	2.0	0.0	95.0	
65	55-56	<0.01	2.5	8.0	80.0	
66	56-57	<0.01	3.3	6.1	45.5	



68	7763-64	<0.01	5.2	3.8	92.3	
69	64-65	<0.01	2.2	22.5	68.2	
70	65-66	<0.01	2.8	17.8	68.1	
71	7769-70	<0.01	4.8	10.4	85.5	
72	70-71	<0.01	1.8	0.0	95.0	
73	71-72	0.01	4.2	0.0	97.9	
74	7776-77	0.01	3.9	0.0	97.5	
75	77-78	0.02	8.0	0.0	97.5	
76	7779-80	0.03	3.8	0.0	97.5	
77	80-81	0.03	4.5	0.0	97.9	
78	81-82	<0.01	4.5	0.0	97.9	
79	7784-85	0.01	5.1	0.0	98.0	
80	85-86	<0.01	1.4	0.0	93.2	
81	86-87	0.02	7.7	0.0	65.0	
82	87-88	<0.01	5.3	0.0	78.3	
83	88-89	0.05	9.4	0.0	97.6	
84	89-90	0.02	8.2	0.0	67.1	
85	90-91	0.01	7.6	0.0	72.4	
86	91-92	0.01	7.2	0.0	89.0	
87	92-93	0.10	11.5	0.0	62.6	
88	93-94	0.11	10.6	1.9	54.0	
89	94-95	0.11	15.3	0.0	58.2	
90	95-96	0.46	11.8	0.0	60.1	
91	96-97	0.44	11.5	0.0	63.5	
92	97-98	0.43	10.0	0.0	65.0	
93	7803-04	0.05	2.6	0.0	54.0	
94	04-05	<0.01	1.9	0.0	68.5	
95	05-06	0.05	5.6	8.9	67.9	
96	7807-08	0.03	5.7	0.0	71.9	
97	08-09	0.03	5.3	0.0	15.1	



98	10-11	0.04	4.2	0.0	64.4
99	11-12	0.02	3.1	0.0	81.0
100	12-13	0.02	4.7	0.0	87.3
101	13-14	0.02	4.0	0.0	50.0
102	14-15	<0.01	4.0	0.0	59.6
103	15-16	0.02	4.3	0.0	37.1
104	16-17	0.14	7.5	2.7	69.4
105	17-18	0.29	6.9	0.0	69.5
106	18-19	0.52	6.0	0.0	66.6
107	19-20	0.21	3.8	0.0	68.2
108	20-21	0.14	5.0	0.0	68.0
109	21-22	0.23	4.2	0.0	57.0
110	22-23	0.32	5.0	0.0	61.8
111	23-24	0.05	4.0	0.0	70.0
112	24-25	7.7	8.8	0.0	61.3
113	25-26	0.21	8.3	0.0	71.0
114	26-27	0.07	13.9	0.0	79.4
115	27-28	0.12	10.9	0.0	75.2
116	28-29	1.1	17.2	0.0	78.1
117	29-30	0.37	7.9	0.0	54.4
118	30-31	2.1	13.0	0.0	74.6
119	31-32	0.02	6.6	0.0	60.5
120	32-33	0.21	10.0	0.0	71.0



BEFORE EXAMINER NUTTER
OIL CONSERVATION DIVISION
SRC EXHIBIT NO. 12
CASE NO.

PERMEABILITY, GAS AND CRUDE PRODUCTION DATA
BASIN DAKOTA FIELD
SAN JUAN COUNTY, NEW MEXICO

Operator/Lease	Well No.	Location	Depth	In Situ Gas Permeability (Md.)	Stabilized Production Rate: Measured (MCFD)	Stabilized Production Rate: Calculated at Atmospheric Pressure (MCFD)	Crude Production (BPD)	Remarks
Southland Royalty Co. East X	7E	SW-14-31N-12W	7282-7448	.0011	21.6	21.7	0	Permeability calculated from pressure build-up
Southland Royalty Co. Patterson "B" Com. X	1E	SW-2-31N-12W	7212-7385	.0877	224.0	224.1	0	Permeability calculated using Darcy's Law
Aztec Oil & Gas Co. Pierce X	2	SW-30-31N-10W	6898-7104	.0609	208.0	208.1	0	Permeability calculated using Darcy's Law
2) El Paso Natural Gas Co. Case	8	NE-18-31N-11W	7254-7406	.0335	--	--	--	Permeability from core data (1) In situ permeability determined to be 28% of permeability from routine core analysis
2) El Paso Natural Gas Co. Moore	8	SW-24-32N-12W	7589-7800	.0151	--	--	--	Permeability from core data (1) In situ permeability determined to be 28% of permeability from routine core analysis

and Don C. Ward: "Effect of Overburden Pressure and Water Saturation on Gas Permeability of ıe Cores", Journal of Petroleum Technology, February, 1972, 120-124 (See Exhibit No. 8)

mation was not tested.

12

BEFORE EXAMINER NUTTER
OIL CONSERVATION DIVISION
SRC EXHIBIT NO. 13
CASE NO.

CUMULATIVE PRODUCTION AND ULTIMATE RESERVES
BASIN DAKOTA FIELD
SAN JUAN COUNTY, NEW MEXICO

Operator	Lease	Well No.	Location	Cumulative Production (1-1-80) Gas (MCF)	Cumulative Production (1-1-80) Oil (BBLS)	Remaining Reserves (1-1-80) Gas (MCF)	Remaining Reserves (1-1-80) Oil (BBLS)	Ultimate Reserves Gas (MCF)	Ultimate Reserves Oil (BBLS)
Tenneco	Wilkins	1	NE-24-32N-10W	29,306	0	0	0	29,306	0
Tenneco	Barnes	1	NE-26-32N-11W	261,364	0	0	0	261,364	0
Southland Royalty	Decker	4	SW-10-32N-12W	129,055	456	110,757	0	239,812	456
Southland Royalty	Hubbard	2	SW-11-32N-12W	71,276	177	75,749	0	147,025	177
Southland Royalty	Chamberlain	1	NE-14-32N-12W	47,873	60	0	0	47,873	60
Southland Royalty	Hubbard	3	NE-15-32N-12W	41,700	0	0	0	41,700	0
Southland Royalty	Hubbard	4	SW-15-32N-12W	117,951	1,171	353,699	701	471,650	1,872
Southland Royalty	Culpepper Martin	12	SW-20-32N-12W	68,173	1,062	49,440	635	117,613	1,697
Southland Royalty	Culpepper	15	NE-21-32N-12W	82,784	1,045	53,714	181	136,498	1,226
Southland Royalty	Culpepper Martin	5	SW-22-32N-12W	118,654	2,677	21,889	1,624	140,543	4,301
Tenneco	Moore	1	NW-25-32N-12W	150,109	0	0	0	150,109	0
Tenneco	Hubbard	1	SE-25-32N-12W	430,872	0	118,134	0	549,006	0
Southland Royalty	Decker	2	NE-26-32N-12W	86,930	285	46,571	0	133,501	285
Tenneco	Moore "C"	2	NW-26-32N-12W	384,093	1,284	250,514	0	634,607	1,284
Tenneco	Moore "C"	1	SE-27-32N-12W	500,205	1,803	175,347	0	675,552	1,803
Southland Royalty	Culpepper Martin	4	SW-28-32N-12W	96,795	1,533	188,831	2,182	285,626	3,715
Southland Royalty	Culpepper Martin	13	SW-29-32N-12W	84,312	837	101,373	152	185,685	989
Southland Royalty	Culpepper Martin	10	SW-32-32N-12W	402,396	3,513	352,593	690	754,989	4,203
Southland Royalty	Culpepper Martin	3	SW-33-32N-12W	256,054	1,535	361,586	1,928	617,640	3,463
Southland Royalty	Culpepper Martin	17	SE-33-32N-12W	77,114	591	1,335,936	7,636	1,411,050	8,227
Consolidated Oil & Gas	Ripley	1	SW-26-32N-13W	98,297	491	0	0	98,297	491
Benson-Montin-Greer	La Plata	1	SW-30-32N-13W	183,726	0	187,451	0	371,177	0
Benson-Montin-Greer	La Plata	2	NW-30-32N-13W	319,414	0	302,340	0	621,754	0
Consolidated Oil & Gas	Robinson Bros.	1	SE-34-32N-13W	128,755	526	0	0	128,755	526
Consolidated Oil & Gas	Montoya	1	NE-35-32N-13W	39,880	0	18,166	0	58,046	0
Consolidated Oil & Gas	Montoya	1M	SE-35-32N-13W	20,003	759	294,268	8,526	314,271	9,285
Supron Energy	Write State	1	NE-36-32N-13W	37,720	63	0	0	37,720	63
Consolidated Oil & Gas	Pan American State	1	SW-36-32N-13W	158,858	1,538	29,974	290	188,832	1,828
	Atlantic "A"	4	SW-27-31N-10W	432,580	0	0	0	432,580	0
	Atlantic	1	NE-34-31N-10W	200,942	0	0	0	200,942	0
	Titt	2	SW-35-31N-11W	238,504	375	0	0	238,504	375
		31		5,293,695	21,781	4,428,332	24,545	9,722,027	46,326
				170,764	702	142,850	792	313,614	1,494

13

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0001:1,Y,GAS,5320,10,1981
0002:3.85,3.85,N,7000,N,N
0003:SRC UNNAMED NO. 1
0004:BASIN DAKOTA
0005:SAN JUAN NEW MEXICO
0006:MINIMUM ECONOMICS-103
0007:G,226,0,0,1,1,1
0008:42.76,3.11,50,10.42,7,7,14.11,70,0,146,7,19
0009:100,13.5,0,0,0,8,8,0
0010:HYP,0,300,350,0,125,END
0011:1981.4,G,121,258,1,0,END
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BEFORE EXAMINER NUTTER
OIL CONSERVATION DIVISION
SRC EXHIBIT NO. 14
CASE NO. _____

41

SOUTHLAND ROYALTY COMPANY
BEFORE TAX ECONOMICS - DETAIL REPORT

PROJECT: SRC UNNAMED NO. 1
SAN JUAN NEW MEXICO

- BASIN DAKOTA
- MINIMUM ECONOMICS-103

PREPARED BY: MT
FILE: DATA47 DATE: 12-3-80
INITIAL INVESTMENT DATE: 04/01/1981
INITIAL PRODUCTION DATE: 10/01/1981

YEAR	GROSS PRODUCTION MBBL/YR	GROSS PRODUCTION MMCF/YR	NET PRODUCTION MBBL/YR	NET PRODUCTION MMCF/YR	PRICES $/BBL	PRICES $/MCF	REVENUES AND TAXES M$ OIL	GAS	TOTAL	P.TAX	D.TAX	NET	LEASE OPR. EXP. M$	INCOME M$ NET	INCOME M$ DISC@9%	DEVASOP EXP. M$
1981	0.	15.	0.	13.	42.76	3.11	2.	39.	41.	3.	01.	37.	0.	37.	35.	379.
1982	0.	42.	0.	36.	45.75	3.33	6.	121.	128.	10.	03.	115.	2.	113.	99.	00.
1983	0.	29.	0.	25.	48.96	3.56	5.	90.	95.	8.	02.	85.	2.	83.	67.	00.
1984	0.	23.	0.	20.	50.00	3.81	4.	75.	79.	6.	02.	71.	2.	69.	51.	00.
1985	0.	19.	0.	16.	50.00	4.08	3.	67.	70.	6.	01.	63.	2.	61.	41.	00.
1986	0.	16.	0.	14.	50.00	4.36	3.	61.	64.	5.	01.	58.	2.	56.	35.	00.
1987	0.	14.	0.	12.	50.00	4.67	2.	58.	60.	5.	01.	54.	2.	52.	30.	00.
1988	0.	13.	0.	11.	50.00	4.99	2.	55.	57.	5.	01.	52.	2.	50.	26.	00.
1989	0.	12.	0.	10.	50.00	5.34	2.	54.	56.	4.	00.	51.	2.	49.	23.	00.
1990	0.	11.	0.	9.	50.00	5.72	2.	53.	54.	4.	00.	50.	2.	48.	21.	00.
1991	0.	10.	0.	9.	50.00	6.12	2.	52.	54.	4.	00.	49.	2.	47.	19.	00.
1992	0.	9.	0.	8.	50.00	6.55	2.	52.	53.	4.	00.	49.	2.	47.	17.	00.
1993	0.	9.	0.	7.	50.00	7.00	1.	52.	53.	4.	00.	49.	2.	47.	16.	00.
1994	0.	8.	0.	7.	50.00	7.49	1.	52.	54.	4.	00.	49.	2.	47.	15.	00.
1995	0.	8.	0.	7.	50.00	8.02	1.	53.	54.	4.	00.	50.	2.	48.	14.	00.
S-TOT	1.	237.	1.	205.	48.67	4.57	38.	934.	973.	78.	11.	883.	31.	852.	509.	379.
AFTER	0.	113.	0.	98.	50.00	10.19	19.	1000.	1019.	81.	00.	937.	50.	887.	118.	00.
TOTAL	1.	350.	1.	303.	49.10	6.39	57.	1934.	1991.	159.	11.	1821.	81.	1739.	627.	379.

PRICE ASSUMPTIONS	OIL	GAS
INITIAL PRICE:	$42.76	$3.11
AVERAGE PRICE:	$49.10	$ 6.39
MAXIMUM PRICE:	$50.00	$10.42
AVG. ESC.TO MAXM.	7.00%	7.00%

COST ASSUMPTIONS		
INITIAL LOE/WELL/MO:	$146.	
ESCALATION RATE:	7.00%	
MAXIMUM LOE/WELL/MO:	$185.	
PROD. TAX RATE:	8.00%	8.00%

PRODUCTION		
PRODUCING DEV. WELLS-GROSS/NET:	1 / 1.00	
DRY DEV. WELLS-GROSS/NET:	0 / 0.00	
INITIAL DAILY PRODUCTION-		
.TOTAL NET:	01.BBLS	151.MCF
GROSS/WELL:	01.BBLS	174.MCF
FLAT LIFE:	5.5 YRS	
PRODUCTION LIFE:	36.9 YRS	
AVG. PRODUCTION DECLINE/YR.:	7.52 %	
YIELD (BBLS/MMCF):	3.9MAX.	3.9MIN.
AVG. WELL DEPTH (Ft.):	7000	

OWNERSHIP	
W.I. BEFORE/AFTER PAYOUT:	100.00% 100.00%
N.I. BEFORE/AFTER PAYOUT:	86.50% 86.50%
REVERT. INT. AMOUNT (M$):	$000.1 0.0YRS
OPERATED:	YES
TANGIBLE INVEST. (M$):	$121.
INTANGIBLE INVEST. (M$):	$258.

DE-REGULATION TAX DATA
BASE PRICE/BBL.: $14.1 TAX RATE: 70.0%

SOUTHLAND ROYALTY COMPANY
DRILLING ECONOMICS SUMMARY PREP. BY: MT
FILE: DATA47 DATE: 12-3-80

PROJECT: SRC UNNAMED NO. 1
BASIN DAKOTA
SAN JUAN NEW MEXICO
MINIMUM ECONOMICS-10

Initial Investment Date: 04/01/1981
Initial Production Date: 10/01/1981

1. NOT DISCOUNTED (BEFORE INCOME TAX)
   Net Income Before Capital: $1739. Risk Cost: $226. Ratio: 7.7
   Profit After Capital: $1360. Capital: $379. Ratio: 3.6
2. RISK PARAMETERS
   Trap: 1.00 Reservoir: 1.00 Hydrocarbon: 1.00 Total(R.F.): 1.00
3. OBJECTIVE TEST
   Discounted @9% Before Tax Net Income: $627.
   Adjusted For Risk: $627.
   CAPITAL:(Risk Cost*(1-R.F.) + R.F.*Disc. Develop. Cost)*1.25: $474.
   Above Or Below SRC Objective: $153.
4. PAYOUT (yrs)
   Before Tax: 5.05 After Tax: 5.74
5. AFTER TAX RATE OF RETURN
   No Risk: 15.53 Risk Adjusted: 15.53
6. COST PER EQUIVALENT BBL & MCF $7.34/BBL $1.22/MCF
7. RISK FACTOR SENSITIVITY

	RISK FACTOR	RISK ADJUSTED AFTER TAX ROR	ABOVE OR BELOW SRC OBJECTIVE
	0.80	13.2	$66.
	0.60	10.5	$21.-
	0.40	7.0	$108.-
	0.20	2.0	$195.-
	0.10	0.1	$239.-
	0.05	0.1	$261.-
Minimum:	0.95	15.0	$132.

8. PROJECT DATA:

Total Life (yrs):	36.9	
Flat Life (yrs):	5.5	
W.I. Before/After Payout:	100.000%	100.000%
N.I. Before/After Payout:	86.500%	86.500%
Revert. Int. Amount (M$):	0.	
Excise Tax (M$):	11.	
Net Oil Reserves (MBBLS):	01.	
Net Gas Reserves (MMCF):	303.	
Gross Producing Wells:	1.	
Gross Develop. Dry Holes:	0.	
Depth (ft):	7000	

RISK COSTS (M$) :

Dryhole:	226.
Acreage:	00.
Seismic:	00.
Total:	-226.

9. UNIT PRICING <GAS>
   Initial/Maximum: $3.11/ $10.42

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0001:1,Y,GAS,2280,10,1981
0002:3.85,3.85,N,7000,N,N
0003:SRC UNNAMED NO. 1
0004:BASIN DAKOTA
0005:SAN JUAN NEW MEXICO
0006:MINIMUM ECONOMICS-2 X 103
0007:G,226,0,0,1,1,1
0008:42.76,6.22,50,10.42,7,7,14.11,70,0,146,7,19
0009:100,13.5,0,0,0,8,8,0
0010:HYP,0,300,150,0,125,END
0011:1981.4,G,121,258,1,0,END
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BEFORE EXAMINER NUTTER
OIL CONSERVATION DIVISION
SRC EXHIBIT NO. 15
CASE NO. _____

15

SOUTHLAND ROYALTY COMPANY
BEFORE TAX ECONOMICS - DETAIL REPORT

PREPARED BY: MT
FILE: DATA48 DATE: 12-3-80
INITIAL INVESTMENT DATE: 04/01/1981
INITIAL PRODUCTION DATE: 10/01/1981

PROJECT: SRC UNNAMED NO. 1
SAN JUAN NEW MEXICO

- BASIN DAKOTA
- MINIMUM ECONOMICS-2 X 103

YEAR	GROSS PRODUCTION MBBL/YR	GROSS PRODUCTION MMCF/YR	NET PRODUCTION MBBL/YR	NET PRODUCTION MMCF/YR	PRICES $/BBL	PRICES $/MCF	REVENUES AND TAXES M$ OIL	GAS	TOTAL	P.TAX	D.TAX	NET	LEASE OPR. EXP. M$	INCOME M$ NET	INCOME M$ DISC@9%	DEV&EQP EXP. M$
1981	0.	6.	0.	6.	42.76	6.22	1.	35.	36.	3.	00.	32.	0.	32.	31.	379.
1982	0.	21.	0.	18.	45.75	6.66	3.	118.	121.	10.	01.	110.	2.	108.	95.	00.
1983	0.	15.	0.	13.	48.96	7.12	3.	95.	98.	8.	01.	89.	2.	87.	70.	00.
1984	0.	13.	0.	11.	50.00	7.62	2.	83.	85.	7.	01.	77.	2.	75.	55.	00.
1985	0.	11.	0.	9.	50.00	8.15	2.	75.	77.	6.	01.	70.	2.	68.	46.	00.
1986	0.	9.	0.	8.	50.00	8.72	2.	70.	72.	6.	01.	65.	2.	63.	39.	00.
1987	0.	8.	0.	7.	50.00	9.33	1.	67.	68.	5.	01.	62.	2.	60.	34.	00.
1988	0.	7.	0.	6.	50.00	9.99	1.	65.	66.	5.	00.	60.	2.	58.	30.	00.
1989	0.	7.	0.	6.	50.00	10.42	1.	62.	63.	5.	00.	58.	2.	55.	27.	00.
1990	0.	6.	0.	5.	50.00	10.42	1.	57.	58.	5.	00.	53.	2.	51.	22.	00.
1991	0.	6.	0.	5.	50.00	10.42	1.	53.	54.	4.	00.	49.	2.	47.	19.	00.
1992	0.	5.	0.	5.	50.00	10.42	1.	49.	50.	4.	00.	46.	2.	44.	16.	00.
1993	0.	5.	0.	4.	50.00	10.42	1.	46.	47.	4.	00.	43.	2.	41.	14.	00.
1994	0.	5.	0.	4.	50.00	10.42	1.	44.	45.	4.	00.	41.	2.	39.	12.	00.
1995	0.	5.	0.	4.	50.00	10.42	1.	41.	42.	3.	00.	39.	2.	37.	11.	00.
-TOT	0.	130. 129	0.	112.	48.84	6.55	21.	960.	981.	78.	06.	896.	31.	865.	522.	379.
FTER	0.	20.	0.	17.	50.00	10.42	3.	182.	185.	15.	00.	171.	11.	159.	36.	00.
OTAL	1.	150.	0.	130.	49.00	8.80	24.	1142.	1167.	93.	06.	1067.	42.	1025.	558.	379.

PRICE ASSUMPTIONS	OIL	GAS
INITIAL PRICE:	$42.76	$6.22
AVERAGE PRICE:	$49.00	$ 8.80
MAXIMUM PRICE:	$50.00	$10.42
AVG. ESC.TO MAXM.	7.00%	7.00%

COST ASSUMPTIONS		
INITIAL LOE/WELL/MO:	$146.	
ESCALATION RATE:	7.00%	
MAXIMUM LOE/WELL/MO:	$185.	
PROD. TAX RATE:	8.00%	8.00%

PRODUCTION		
PRODUCING DEV. WELLS-GROSS/NET:	1 / 1.00	
DRY DEV. WELLS-GROSS/NET:	0 / 0.00	
INITIAL DAILY PRODUCTION-		
.TOTAL NET:	00.BBLS	65.MCF
GROSS/WELL:	00.BBLS	75.MCF
FLAT LIFE:	5.5 YRS	
PRODUCTION LIFE:	19.3 YRS	
AVG. PRODUCTION DECLINE/YR.:	10.02 %	
YIELD (BBLS/MMCF):	3.9MAX.	3.9MIN.
AVG. WELL DEPTH (Ft.):	7000	

OWNERSHIP

W.I. BEFORE/AFTER PAYOUT:	100.00%	100.00%
N.I. BEFORE/AFTER PAYOUT:	86.50%	86.50%
REVERT. INT. AMOUNT (M$):	$000.	0.0YRS
OPERATED:	YES	
TANGIBLE INVEST. (M$):	$121.	
INTANGIBLE INVEST. (M$):	$258.	

DE-REGULATION TAX DATA
BASE PRICE/BBL.: $14.1 TAX RATE: 70.0%

SOUTHLAND ROYALTY COMPANY
DRILLING ECONOMICS SUMMARY PREP. BY: MT
FILE: DATA48 DATE: 12-3-80

PROJECT: SRC UNNAMED NO. 1
BASIN DAKOTA
SAN JUAN NEW MEXICO
MINIMUM ECONOMICS-2

Initial Investment Date: 04/01/1981
Initial Production Date: 10/01/1981

1. NOT DISCOUNTED (BEFORE INCOME TAX)
   Net Income Before Capital: $1025. Risk Cost: $226. Ratio: 4.5
   Profit After Capital: $646. Capital: $379. Ratio: 1.7
2. RISK PARAMETERS
   Trap: 1.00 Reservoir: 1.00 Hydrocarbon: 1.00 Total(R.F.): 1.00
3. OBJECTIVE TEST
   Discounted @9% Before Tax Net Income: $558.
   Adjusted For Risk: $558.
   CAPITAL:(Risk Cost*(1-R.F.) + R.F.*Disc. Develop. Cost)*1.25: $474.
   Above Or Below SRC Objective: $84.
4. PAYOUT (yrs)
   Before Tax: 4.89 After Tax: 5.39
5. AFTER TAX RATE OF RETURN
   No Risk: 15.23 Risk Adjusted: 15.23
6. COST PER EQUIVALENT BBL & MCF $17.13/BBL $2.86/MCF
7. RISK FACTOR SENSITIVITY

	RISK FACTOR	RISK ADJUSTED AFTER TAX ROR	ABOVE OR BELOW SRC OBJECTIVE
	0.80	12.6	$11.
	0.60	9.3	$62.-
	0.40	4.7	$136.-
	0.20	0.1	$209.-
	0.10	0.1	$246.-
	0.05	0.1	$264.-
Minimum:	0.97	15.0	$75.

8. PROJECT DATA:

Total Life (yrs):	19.3	
Flat Life (yrs):	5.5	
W.I. Before/After Payout:	100.000%	100.000%
N.I. Before/After Payout:	86.500%	86.500%
Revert. Int. Amount (M$):	0.	
Excise Tax (M$):	6.	
Net Oil Reserves (MBBLS):	00.	
Net Gas Reserves (MMCF):	130.	
Gross Producing Wells:	1.	
Gross Develop. Dry Holes:	0.	
Depth (ft):	7000	

RISK COSTS (M$) :

Dryhole:	226.
Acreage:	00.
Seismic:	00.
Total:	226.

9. UNIT PRICING <GAS>
   Initial/Maximum: $6.22/ $10.42

ASSUMPTIONS USED IN MAKING ECONOMIC CALCULATIONS
BASIN DAKOTA FIELD
SAN JUAN COUNTY, NEW MEXICO

Drilling and completions costs		378,560.00
Operating costs ($/well-month)		146.00
Depth (feet)		7,050.00
Southland Royalty working interest (%)		100.00
Royalty interest (%)		13.50
Date of initial production		10-1-81
Initial production rate (MCFD)	103 case	150
	2 x 103 case	75
Liquid yield (BBLS/MMCF)		3.85
Fully adjusted gas price as of 10-1-81 ($/MCF)	103 case	3.11
	2 x 103 case	6.22
Oil price as of 10-1-81 ($/BBL)		42.76
Maximum gas price ($/MCF)		10.42
Maximum oil price ($/BBL)		50.00
Rate of price escalation (%)		7.00
Severance Tax (%)		8.00
Deregulation Tax data	Base Oil price ($/BBL)	14.11
	Tax Rate (%)	70.00

BEFORE EXAMINER NUTTER
OIL CONSERVATION DIVISION
SRC EXHIBIT NO. 16
CASE NO. _____

16

SOUTHLAND ROYALTY COMPANY
AUTHORITY FOR EXPENDITURE

— AFE —

☐ ORIGINAL
☐ SUPPLEMENTAL

COMPANY 01 AFE NAME SRC - Unnamed No. 1 DATE 12-2-80
REC. I.D. 01 PROSPECT NAME _____ CODE _____ SEQ. 000 ADD

COST CENTER	PROJECT	SUB-PROJECT	AFE NO.	DISTRICT
☐ EXPLORATION	San Juan Basin			Farmington
☒ PRODUCTION	170			3025

01 ☐ DRILLING
02 ☐ WILDCAT
03 ☒ DEVELOPMENT
04 ☐ RECOMPLETION
05 ☐ PLUG & ABANDON
06 ☐ L & W EQUIPMENT
07 ☐ CONSTRUCTION
08 ☐ SECONDARY RECOVERY
09 ☐ LEASEHOLD PURCH
10 ☐ FARM-IN
11 ☐ GEOPHYSICAL
12 ☐ DHC OR BHC
13 ☐ PROD PROP PURCH
14 ☐ WORKOVER
99 ☐ OTHER

PROPERTY NO. _____ NAME SRC - Unnamed
WELL NO. 1 NAME Unnamed EST. TOTAL DEPTH 7050'
STATE New Mexico CODE 30 COUNTY San Juan CODE 045
FIELD Basin Dakota
LOCATION T32N, R12W

FORMATION Dakota
OBLIGATIONS _____
LOCATION MEETS ☐ STATE RULES ☒ FIELD RULES, FIELD SPACING 320 ACRES
THIS WELL 320 ACRES
IF JOINT INTEREST PROJECT SUBJECT TO ☐ CARRIED INT ☐ NET PROFIT INT
RIGHT TO CONVERT TO W.I. ☐ OPERATING OWNER & W.I. SRC - 1.0000
JOINT OPERATING AGREEMENT NO. _____
COMPANY W.I. 1.0000 COMPANY REVENUE INTEREST .865

COMPLETED COST	TOTAL	CO-OWNER	CO NET
I.D.C.	257,560		257,560
TANGIBLE	121,000		121,000
L. EQUIP			
TOTAL	378,560		378,560
EXPLORATION, ETC COST			

DRY HOLE COST	TOTAL	CO-OWNER	CO NET
I.D.C.	184,180		184,180
TANGIBLE	41,440		41,440
TOTAL	225,620		225,620
LESS: DHC			
TOTAL	225,620		225,620
RETIREMENT COST			
REMOVAL			
SALV/REC			
NET COST			

REASON FOR EXPENDITURE Drill and complete a Dakota well.

PROPOSED STARTING DATE ____/____/____ ESTIMATED COMPLETION DATE ____/____/____
LEASE EXPIRATION DATE ____/____/____ DRILLING OBLIGATION DATE ____/____/____

APPROVED ☐ REJECTED ☐ IN BUDGET YES ☐ NO ☐ BUDGET # _____

DISTRICT PRODUCTION DATE	F. W. TITLE & RECORD CLEARANCE DATE	EXECUTIVE APPROVAL DATE	F. W. FINANCIAL DATE
DISTRICT EXPLORATION DATE	V. P. PRODUCTION DATE	CO-OWNER DATE	

Mar

BEFORE EXAMINER NUTTER
OIL CONSERVATION DIVISION
SRC EXHIBIT NO. 17
CASE NO. _____

17

AUTHORIZATION FOR EXPENDITURE

SOUTHLAND ROYALTY COMPANY
1000 FORT WORTH CLUB TOWER
FT. WORTH, TEXAS 76102

COMPANY NO 01 (1)

RECORD ID 02 (2-3)
SEQ 000 (14-16)

AFE NUMBER (10-13)

ADD A (17) CHANGE (17) DELETE (17)

PROPERTY NUMBER (18-26)

AFE DATE 12 / 2 / 80 (27-32) NAME SRC - Unnamed No. 1 (33-72)

ORIGINAL O (73) SUPPLEMENTAL (73) PRODUCER (74) DRY HOLE (74) SRC OPERATOR Y (75) MANUAL (76)

AUTHORITY IS REQUESTED TO: Drill and complete a Dakota well.

WILDCAT (77) DEV. D (77)

LOCATION: T32N, R12W, San Juan County, New Mexico

FOOTAGE			ESTIMATED COST PRODUCING $	ESTIMATED COST DRY HOLE $
		TANGIBLE - 249		
	01 01	Conductor or Drive Pipe		
200'	01 02	Casing 9 5/8", 32.3#, H-40	2,940	2,940
4650'	03	7", 23.0#, K-55	49,200	36,900
1900'	04	4 1/2", 10.5#, K-55	10,130	
350'	05	4 1/2", 11.6#, K-55	2,030	
	06			
	07			
	08			
7000'	02 09	Tubing 2 3/8", 4.7#, J-55	21,560	
	03 10	Wellhead	8,840	1,600
	04 11	Packer		
	04 12	Artificial Lift		
	05 13	Tank Battery	22,270	
	10 14	Other Equipment Liner Hanger	4,030	
	15	TOTAL TANGIBLE 100%	$121,000	$ 41,440
	16	SRC 1.0000 %	$121,000	$ 41,440
		INTANGIBLE - 248		
	01 17	Drilling 7050' ft. @ $ 14.00 /ft.	98,700	98,700
	01 18	Rig, Day Work 2 Days @ $ 4,700.00 /day	9,400	9,400
	01 19	Rig Moving Costs	2,900	1,200
	01 20	Completion Rig 3 Days @ $ 3,650.00 /day	10,950	
	02 21	Roustabout & Miscellaneous Labor	5,000	1,500
	03 22	Auto, Trucking, Barge, Tug	5,350	4,500
	04 23	Roads, Canals, Location, Damages, Cleanup	6,000	6,000
	05 24	Mud, Oil, Water, Chemicals	15,500	13,500
	06 25	Drill Stem Tests		
	06 26	Electric Logs & Bond Logs	10,060	10,060
	07 27	Cement, Centralizer, Scratchers, Service	12,510	7,590
	08 28	Bits, Fuel	4,250	1,500
	08 29	Rental Equipment	7,710	4,730
	09 30	Core & Analyses		
	09 31	Bottle Tests & Sidewall Cores		
	09 32	Perforate	6,660	
	09 33	Acid & Frack	27,500	
	09 34	Geological & Engineering		
	09 35	Mud Logger	600	600
	10 36	Cost of Control Insurance (SRC Only)		
	10 37	Miscellaneous & Unforseen 15% Contingency	33,470	23,900
	11&12 38	District & Overhead Expense	1,000	1,000
	39	TOTAL INTANGIBLE 100%	$257,560	$184,180
	40	SRC 1.0000 %	$257,560	$184,180
	41	GRAND TOTAL COSTS	$378,560	$225,620
	42	SRC 1.0000 %	$378,560	$225,620

AUTHORIZATION REQUESTED

AUTHORIZATION APPROVED

BY: _____

DATE: _____

Dockets Nos. 1-81 and 2-81 are tentatively set for January 14 and 28, 1981. Applications for hearing must be filed at least 22 days in advance of hearing date.

DOCKET: EXAMINER HEARING - TUESDAY - DECEMBER 30, 1980

9 A.M. - OIL CONSERVATION DIVISION CONFERENCE ROOM,
STATE LAND OFFICE BUILDING, SANTA FE, NEW MEXICO

The following cases will be heard before Daniel S. Nutter, Examiner, or Richard L. Stamets, Alternate Examiner:

CASE 7113: Application of Fred Pool, Jr. for a dual completion, Chaves County, New Mexico. Applicant, in the above-styled cause, seeks approval for the dual completion of his Grynberg Com Fed. Well No. 1 located in Unit J of Section 13, Township 6 South, Range 24 East, to produce gas from the Abo and Pennsylvanian formations.

CASE 7051: (Continued from November 25, 1980, Examiner Hearing)

Application of Petro Lewis Corporation for downhole commingling, Lea County, New Mexico. Applicant, in the above-styled cause, seeks approval for the downhole commingling of Blinebry and Drinkard production in the wellbore of its L. G. Warlick "B" Well No. 2 located in Unit G of Section 19, Township 21 South, Range 37 East.

CASE 6940: (Continued from November 25, 1980, Examiner Hearing)

Application of Adobe Oil Company for compulsory pooling, Lea County, New Mexico. Applicant, in the above-styled cause, seeks an order pooling all mineral interests down through the Wolfcamp formation underlying the NW/4 SE/4 for oil and the SE/4 for gas, Section 23, Township 20 South, Range 38 East, to be dedicated to a well to be drilled at a standard location thereon. Also to be considered will be the cost of drilling and completing said well and the allocation of the cost thereof as well as actual operating costs and charges for supervision, designation of applicant as operator of the well, and a charge for risk involved in drilling said well.

CASE 7103: (Continued from December 10, 1980, Examiner Hearing)

Application of E. L. Latham, Jr. for compulsory pooling, Eddy County, New Mexico. Applicant, in the above-styled cause, seeks an order pooling all mineral interests in the Wolfcamp thru Pennsylvanian formations underlying the N/2 of Section 7, Township 22 South, Range 26 East, to be dedicated to a well to be drilled at a standard location thereon. Also to be considered will be the cost of drilling and completing said well and the allocation of the cost thereof as well as actual operating costs and charges for supervision, designation of applicant as operator of the well, and a charge for risk involved in drilling said well.

CASE 7114: Application of Yates Petroleum Corporation for an unorthodox gas well location, Eddy County, New Mexico. Applicant, in the above-styled cause, seeks approval for the unorthodox location of its Rio Penasco "JX" Well No. 2, a Morrow test to be drilled 660 feet from the South and East lines of Section 35, Township 18 South, Range 25 East, the S/2 of said Section 35 to be dedicated to the well.

CASE 7115: Application of Yates Petroleum Corporation for an unorthodox gas well location, Eddy County, New Mexico. Applicant, in the above-styled cause, seeks approval for the unorthodox location of a Morrow test well to be drilled 660 feet from the South and East lines of Section 14, Township 17 South, Range 26 East, the S/2 of said Section 14 to be dedicated to the well.

CASE 7116: Application of Southland Royalty Company for designation of a tight formation, San Juan County, New Mexico. Applicant, in the above-styled cause, seeks the designation of the Dakota formation underlying portions of Townships 31 and 32 North, Ranges 10, 11, 12, and 13 West, containing 93,860 acres, more or less, as a tight formation pursuant to Section 107 of the Natural Gas Policy Act and 18 CFR Section 271.701-705.

CAMPBELL, BYRD & BLACK, P.A.
LAWYERS

JACK M. CAMPBELL
HARL D. BYRD
BRUCE D. BLACK
MICHAEL B. CAMPBELL
WILLIAM F. CARR
BRADFORD C. BERGE
WILLIAM G. WARDLE

JEFFERSON PLACE
SUITE I - 110 NORTH GUADALUPE
POST OFFICE BOX 2208
SANTA FE, NEW MEXICO 87501
TELEPHONE: (505) 988-4421
TELECOPIER: (505) 983-6043

October 8, 1981

Mr. Joe D. Ramey
Director
Oil Conservation Division
New Mexico Department of
Energy and Minerals
Post Office Box 2088
Santa Fe, New Mexico 87501

HAND DELIVERED

Re: Case 7361: Application of Southland Royalty Company for Designation of a Tight Formation, San Juan County, New Mexico

Dear Mr. Ramey:

Enclosed are three copies of revised Exhibit Nos. 13 and 14 which were requested by the Commission at the September 29, 1981 hearing on the above-referenced application. Exhibit 13 has been revised by excluding all wells in Sections 25, 26, 27, 32 and 33 of Township 32 North, Range 12 West. All newly drilled and completed wells governed by this application have been included. Please note that the revised average ultimate gas reserves for the 35 wells in the subject area is 196,930 mcf compared to the previous average of 313,614 mcf.

The economic calculations were run on the same basis as before, except that stripper prices were used and a discount factor of 15% was used, instead of 9%. On this basis, reserves of 275,000 mcf are required for minimum economics compared to the 350,000 mcf figure previously submitted. The minimum rate of return was still assumed to be 15%.

If you need additional information in reaching your decision on this application, please advise.

Very truly yours,

William F. Carr

William F. Carr
Attorney for Southland Royalty Company

WFC:lr

Depths to top of WK

Cross Section A

6710.
7220. ✓
7152.

Cross Section B

5234. ✓
6808.
6844.
7106.

shallow 5234
deep 7220

ave 6753

NUMBER, NAME AND
PURPOSE OF EACH EXHIBIT
BASIN DAKOTA FIELD
SAN JUAN COUNTY, NEW MEXICO

Exhibit Number	Exhibit Name	Purpose of Exhibit
1	Completion and Production Map	Show location of Dakota completions, production from Dakota completions, proposed tight gas area, location of cross sections, test wells and dry holes
2	Type Log	Show log characteristics and depth of Dakota formation
3	Cross Section A-A'	Show Dakota formation development in a north-south direction
4	Cross Section B-B'	Show Dakota formation development in an east-west direction
5	Formation Testing Service Report	Show in situ permeability from pressure buildup analysis
6	Darcy Law Calculation	Show in situ permeability from Darcy Law calculation
7	Darcy Law Calculation	Show in situ permeability from Darcy Law calculation
8	Technical Paper	Show relaitonship of in situ permeability to laboratory permeability
9	Explanation of Paper	Explain method of determining in situ permeability from routine core analysis
10	Core Analysis	Show in situ permeability from core analysis
11	Core Analysis	Show in situ permeability from core analysis

Exhibit Number	Exhibit Name	Purpose of Exhibit
12	Permeability, Gas and Crude Production Data	Show in situ permeability, stabilized production rate and crude production from each test well
13	Cumulative Production and Ultimate Reserves	Show cumulative production and ultimate reserves for each well in the proposed tight formation area
14	Economic Calculation	Show economics of drilling and completing a Dakota well at the 103 gas price
15	Economic Calculation	Show economics of drilling and completing a Dakota well at 200% of the 103 price
16	Economic Assumptions	Show assumptions used in making economic calculations
17	Authority for Expenditure	Show cost to drill and complete a Dakota well

NUMBER, NAME AND
PURPOSE OF EACH EXHIBIT
BASIN DAKOTA FIELD
SAN JUAN COUNTY, NEW MEXICO

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7	Darcy Law Calculation	Show in situ permeability from Darcy Law calculation
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17	Authority for Expenditure	Show cost to drill and complete a Dakota well

STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION DIVISION
STATE LAND OFFICE BLDG.
SANTA FE, NEW MEXICO
30 December 1980

EXAMINER HEARING

IN THE MATTER OF:

Application of Southland Royalty Company for designation of a tight formation, San Juan County, New Mexico.

CASE 7116

BEFORE: Daniel S. Nutter

TRANSCRIPT OF HEARING

A P P E A R A N C E S

For the Oil Conservation Division: Ernest L. Padilla, Esq.
Legal Counsel to the Division
State Land Office Bldg.
Santa Fe, New Mexico 87501

For the Applicant: William F. Carr, Esq.
CAMPBELL & BLACK P. A.
Jefferson Place
Santa Fe, New Mexico 87501

A P P E A R A N C E S

For Consolidated Oil & Gas: Lynn Teschendorf, Esq.
CONSOLIDATED OIL AND GAS
Denver, Colorado

I N D E X

MARLIN R. THOMPSON

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FLOYD E. ELLISON, JR.

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MR. NUTTER: We'll call next Case Number 7116.

MR. PADILLA: Application of Southland Royalty Company for a designation of a tight formation, San Juan County, New Mexico.

MR. CARR: May it please the Examiner, my name is William F. Carr, with the law firm Campbell and Black, P. A., Santa Fe, New Mexico, appearing on behalf of Southland Royalty Company.

I have one witness who needs to be sworn.

(Witness sworn.)

MR. NUTTER: Okay, we'll call for appearances in Case Number 7116.

MS. TESCHENDORF: Lynn Teschendorf, appearing on behalf of Consolidated Oil and Gas.

I'll have one witness, also, who needs to be sworn.

(Witness sworn.)

MARLIN R. THOMPSON

being called as a witness and being duly sworn upon his oath, testified as follows, to-wit:

DIRECT EXAMINATION

BY MR. CARR:

Q. Will you state your name and place of residence?

A. My name is Marlin Thompson. I live at 905 Rocky Canyon in Arlington, Texas.

Q. Mr. Thompson, by whom are you employed?

A. Southland Royalty Company.

Q. And in what capacity?

A. As a reservoir engineer.

Q. Would you please summarize for the Examiner your educational background and your work experience?

A. Graduated from the University of Texas in 1963 with a Bachelor of Science in petroleum engineering.

Worked 11-1/2 years with Texaco, 5-1/2 as a production engineer and 6 as a reservoir engineer.

Worked one year for Capitol Resources as a production engineer.

Worked two years for Hunt Oil Company as a reservoir engineer, and the last 2-1/2 years with South-

land Royalty Company as a reservoir engineer, working primarily in the San Juan Basin.

Q. Have you previously testified as an expert witness in reservoir engineering before this Commission?

A. Yes, I have.

Q. And have you previously testified before the Texas Railroad Commission in this capacity?

A. Yes, I have.

Q. Are you familiar with the application of Southland Royalty Company in this case?

A. Yes, I am.

Q. And are you familiar with the acreage which is the subject matter of this case?

A. Yes, I am.

MR. CARR: Mr. Nutter, are the witness' qualifications as an -- acceptable as a reservoir engineer?

MR. NUTTER: Yes, they are.

Q. Mr. Thompson, will you briefly state what Southland Royalty Company seeks with this application?

A. Southland Royalty Company is seeking approval to have a portion of the Basin Dakota Field approved as tight formation, according to Section 107 of the Natural Gas Policy Act.

Q. Have you prepared certain exhibits for

introduction in this case?

A. Yes, I have.

Q. Have these exhibits previously been submitted to the Oil Conservation Division and the USGS with a statement of the meaning and purpose of the exhibits, as is required by the Oil Conservation Division rules governing applications for designation of tight formations?

A. Yes, I have.

Q. Will you please refer to what has been marked for identification as Applicant's Exhibit Number One, and explain to Mr. Nutter what it is and what it shows?

A. Okay. Exhibit Number One is a completion and production map. This shows all the Dakota completions in the area of this application. It shows the 1979 annual oil and gas production; these are the upper figures, gas first and then oil second. It also shows the cumulative gas and oil production up through 1979 for each of the wells in the area of this application.

It shows we have five wells, test -- we call test wells for which permeability and rate data are submitted. It shows those five wells. It shows the area that we propose to --

MR. NUTTER: How are those wells identified, those five wells you're talking about?

A. Those five wells are identified with a circle.

MR. NUTTER: Okay, there are three of them on the northwest -- or on the north/south cross section and then there are two on the east leg of the east/west cross section, is that it?

A. I can read the locations. One in Section 24 of 32,12.

MR. NUTTER: Okay.

A. Okay, there's one in Section 2 of 31, 12.

MR. NUTTER: Okay.

A. One in Section 14 of 31, 12.

MR. NUTTER: Okay.

A. One in Section 18 of 31, 11.

MR. NUTTER: Okay.

A. And one in Section 30 of 31, 10.

MR. NUTTER: Okay.

A. Okay, this exhibit One also shows the area that we propose to designate as tight formation. We would like to make one exception, though. We learned since we made this exhibit that there are two sections, Section 30 and 31 of 32, 13, that are actually in the Ute Dome-Dakota Field.

MR. NUTTER: What are the section numbers

A. Sections 30 and 31 of 32, 13. These are on the west side of the map up to the northwest.

MR. NUTTER: Okay.

A. We'd like to exclude those two sections.

MR. NUTTER: Section 30 is the section on Exhibit One that has two wells shown on it.

A. That's correct.

MR. NUTTER: And Section 31 is the well -- is the section immediately south of that.

A. That is correct. There is a well, a real recent well that has been drilled there in the northwest quarter.

MR. NUTTER: And those two sections you are requesting will be deleted from the application.

A. Yes, sir.

MR. NUTTER: We will delete Sections 30 and 31 from the application and testimony here today won't relate to that area.

A. Okay. This map also shows, it shows two wells, and these are identified by a triangle, it shows two wells that were completed in the Dakota formation but didn't ever produce, and one of these is located in Section 30 of 31 North, 10 West. The other is located in Section 32 of 32 North, 12 West. These are two wells that were completed and

never produced.

There are five dry holes indicated by a square that are located throughout the area. This exhibit also shows the location of those five wells. We'll have comments about those later.

MR. NUTTER: Mr. Thompson, now the second well that you mentioned as not having produced, as indicated by a triangle, you said was in Section 32?

A. Section 32 of 32 North, 12 West.

MR. NUTTER: I don't believe that's 32, is it?

A. Yes, sir.

MR. NUTTER: Is that that well, the second well from the right on the east/west cross section?

A. Okay, one of the wells -- one of the wells in Section 30 of 31, 10. The other one I referred to is up in Section 32 of 32, 12.

There is another well with a triangle.

MR. NUTTER: Okay.

A. There is another well with a triangle. It's in Section 15 of 31, 11. That's probably the one you're looking at. This well also falls in that category, so there are really three wells instead of two.

MR. NUTTER: Okay, there are three wells.

A. Right, that's --

MR. NUTTER: I was looking at the wrong one.

A. Right, there was three instead of two.

MR. NUTTER: Okay.

A. There's a correction on that.

MR. NUTTER: Okay.

A. This exhibit also shows the location of two cross sections, A-A' and B-B', which we'll show as exhibits later.

Q. Mr. Thompson, will you now refer to what's been marked as Southland Royalty Company Exhibit Number Two and explain to Mr. Nutter what this shows?

A. Exhibit Number Two is a type log. This well is located, referring to Exhibit One, this well is located in Section 32 of 32, 12.

This log shows, it shows the log characteristics of the various sands in the Dakota formation, and also the depth of the Dakota formation.

Q. What are the main producing intervals in the Dakota?

A. The main producing zones are the Greness and the First Dakota Sand, the Upper Dakota Sand.

Q. Are there other producing zones in the

Basin Dakota Field?

A. Yes, there is. Some of the lower Dakota sands and the Morris do produce in some areas of the field.

Q. And, Mr. Thompson, what is the average depth from the surface to the top of the Dakota formation in the subject area?

A. 7050 feet.

Q. I now direct your attention to Southland Royalty Company's Exhibit Number Three, which is the north/south cross section and ask that you explain to Mr. Nutter what this shows.

A. Exhibit Three, it shows the continuity of the Dakota sands across the area of this application; also shows the thicknesses of the sands.

Q. In your opinion does the Dakota underlie the entire area governed by the application?

A. Yes, it does.

Q. And in your opinion is the formation productive throughout this area?

A. Yes, it is productive. It is not commerically productive at current prices, but I would -- I think it is productive throughout the area.

Q. Will you now refer to Applicant's Exhibit Number Four and explain to Mr. Nutter what this shows?

A. Okay, Exhibit Number Four is a cross section in the northwest/southeast direction, and it shows the same thing Exhibit Number Three does. It shows the continuity of the sand across the area.

Q. Mr. Thompson, what is the average in situ permeability for the Dakota formation in the recommended area?

A. It's less than 0.1 millidarcy.

Q. And what methods have you employed in making this determination?

A. We've actually used three different methods. We used a pressure build-up analysis on one well. We used the Darcy flow equation on two wells, and used core analysis on two wells.

Q. Will you now refer to Exhibit Number Five and review this for the Examiner?

A. Okay. Exhibit Number Five is a formation test service report. This represents the results of a pressure build-up test using drill stem test tools in a well, East No. 7-E that's located in Section 14 of Township 31 North, Range 12 West.

Permeabilities, as can be seen in this report, permeability from this pressure build-up data is 0.0011 millidarcies.

MR. NUTTER: Is that the well on Exhibit

One, Mr. Thompson?

A. Yes, sir.

MR. NUTTER: That's indicated with a circle and then in the legend shown to be a test well?

A. Yes, sir, that's the well located in Section 14 of 31, 12, on Exhibit Number One, identified with a circle.

MR. NUTTER: Okay, so that well, then, is the well that's on Exhibit Five.

A. Yes, sir.

MR. NUTTER: Thank you.

Q. And this well was tested prior to stimulation, is that correct?

A. Yes, it was. We perforated the well, we flowed it till it stabilized, we shut it in for a build-up, and then took the build-up data and calculated the permeability.

Q. Will you now refer to Applicant's Exhibits Six and Seven and review these for Mr. Nutter?

A. Exhibits Six and Seven are calculations using the Darcy flow equation to calculate the permeability for these two wells, and these two wells are Patterson "B" Com No. 1-E. It's located in Section 2 -- located in Section 2 of Township 31 North, Range 12 West.

The other is the Pearce No. 2 located in Section 30 of Township 31 North, Range 10 West.

Exhibit Six, what we did, we flowed -- we flowed Patterson "B" Com No. 1 until it stabilized prior to stimulation, produced at a rate of 224,000 cubic feet. We then took -- we shut the well in until it built up and got the built up pressure, the shut-in build-up pressure. We took other known reservoir and geological data, engineering and geological data, and we calculated the permeability from the Darcy flow equation, and this permeability calculated to be 0.0877 millidarcies. That's for Patterson "B" Com 1-E.

In a similar manner on Pearce No. 2 we calculated a permeability of 0.0609 millidarcies.

Q. Will you now refer to Exhibits Eight and Nine and explain these to Mr. Nutter?

A. Exhibit Eight is a paper entitled Effect of Overburden Pressure and Water Saturation on Gas Permeability of Tight Sandstone Cores. This paper presents a method of converting laboratory permeability, which you obtain through core analysis, to in situ or reservoir permeability.

Exhibit Number Nine is -- is simply an explanation of how the method was applied to the permeability in situ permeability.

Q. Will you now refer to Exhibits Ten and

Eleven and review these for Mr. Nutter?

A. Okay. Exhibits Ten and Eleven are core analysis reports on two wells. The first one is Case No. 8, which is located in Section 18 of Township 31 North, Range 11 West, and Weir No. 8, which is located in Section 24 of Township 32 North, Range 12 West.

MR. NUTTER: Now let's see, don't get away from me, I want to see where they are.

A. Okay. Going back to Exhibit Number One, Case No. 8 is the well that's located with a circle that's located in Section 18 of 31 North, 11 West.

MR. NUTTER: Okay, is that the section where there's a well with a circle and a square?

A. Yes, sir, that's the well.

MR. NUTTER: Also a well that's shown to be a new well.

A. Yes, sir.

MR. NUTTER: And the one we're talking about is the one with the circle and the square?

A. Yes, sir, that's correct.

MR. NUTTER: Okay, that's the well that is on Exhibit Ten.

A. Yes, sir.

MR. NUTTER: Is that correct?

A. That's correct.

MR. NUTTER: Okay, and the next well, then?

A. The other well is in Section 24 of 32 North, 12 West. It also has a circle and a square. It's in the southwest quarter, the only well in that section.

MR. NUTTER: It's in Section what?

A. Section 24 of 32 North, 12 West. It's in the cross section, too.

MR. NUTTER: Okay, and that's the well that's on Exhibit Eleven, is it?

A. Yes, sir, that's correct.

Each one of these exhibits, Exhibit Number Ten, the bulk of the exhibit is the actual core analysis. The first page of that exhibit is a summary of the core data from just the productive interval, taking the log and picking out the zones that would actually be productive and just using the core data from those zones, that's what's contained on the first page of Exhibit Ten. And what we've done is calculated the average permeability for those 37 samples and determined what the average laboratory permeability is. Then we've taken the paper, Exhibit Eight, and determined the in situ permeability. The average laboratory calculation would be 0.1195 millidarcies. When we use the paper, the data from

the paper, to convert it to in situ permeability, it turns out to be 0.0335 millidarcies.

MR. NUTTER: Okay, for the record, Mr. Thompson, would you explain very briefly why the in situ permeability is a fraction of what the laboratory permeability would be?

A. Okay. Laboratory permeability is run at low pressures, 100 pounds or less, and in the reservoir, this Dakota reservoir, the pressure is about 2650 pounds. So this overburden, that's the reservoir pressure, but this depth of 7000 feet, you have an overburden pressure that would approach probably 0.8 psi per foot of depth.

Anyway, the overburden pressure would be substantially higher than 100 pounds.

MR. NUTTER: So in other words, what this amounts to is that when the core is removed from the reservoir, the pressure on the core is decreased, the core, in effect, expands, and the permeability increases?

A. That is correct.

MR. NUTTER: Okay.

A. On Exhibit Number Eleven, refer to it, referring to the first page of Exhibit Eleven, again this is a summary of the cores from the producing interval only, 39 samples, the average laboratory permeability is 0.0538 milli-

darcies, while the average in situ permeability, using the data from Exhibit Eight, is 0.0151 millidarcies. This is Exhibit Number Eleven.

Q. Mr. Thompson, are the methods that you've employed in determining in situ permeability generally accepted by the oil and gas industry?

A. Yes, they are.

Q. Were stabilized production rates taken on any of the test wells?

A. Yes, they were taken on three wells, East No. 7-E, Patterson "B" Com No. 1-E, and Pierce No. 2.

Q. Now were these taken before or after stimulation?

A. The ones on East 7-E and Patterson "B" Com 1-E were taken before stimulation. Pierce No. 2 was taken after stimulation.

Q. And what were the rates obtained?

A. The rates calculated to atmospheric conditions for East No. 7-E, the rate was 21.7 Mcf per day.

For Patterson "B" Com No. 1-E, 224.1 Mcf per day.

The Pierce No. 2, 208.1 Mcf per day.

Q. What is the maximum gas production rate permitted for this depth interval under tight formation guide-

lines?

A. 290 Mcf per day.

Q. And that's from the depth interval 7000 feet to 7500 feet?

A. That's correct.

Q. Will you now refer to Applicant's Exhibit Number Twelve and review this for Mr. Nutter?

A. Okay, Exhibit Number 12 is just a summary sheet, showing the five test wells, showing the permeability, gas production and crude production, for these five wells. It also shows the methods used to obtain the permeability.

Q. It shows that each of the test wells fall within the general guidelines as to production rates?

A. That is correct.

Q. How much crude oil did the test wells produce?

A. Actually they produced a very small amount. It was too small to measure.

Q. Are any other liquids produced by these wells?

A. No, it is not.

Q. Do any of the offsetting wells produce crude oil?

A. Yes, they do.

Q. Are any wells in the subject area producing 5 barrels of crude oil per day or more?

A. No, they're not.

Q. Do you anticipate that any wells in the subject area would produce more than 5 barrels of crude oil per day?

A. No, sir.

Q. Are there fresh water-bearing formations in the immediate area?

A. Yes, there are. There's really three potentially fresh bearing -- fresh water-bearing formations throughout the area. These include the San Jose, the Nacimento, and the Ojo Alamo.

Q. At what depths are these formations encountered?

A. They vary throughout the area but the average is from the surface of the ground to 1200 feet.

Q. Are you familiar with the Oil Conservation Division and Federal regulations for the protection of fresh water?

A. Yes, I am.

Q. Are the current casing and cementing requirements sufficient to protect fresh water aquifers in the

area which is the subject of this application?

A. Yes, they are.

Q. In completing Dakota wells in the area, do you employ large fracture treatments?

A. Yes, sir, we do.

Q. Would any currently contemplated completion techniques affect fresh water zones in the area?

A. No, sir, it would not. There's approximately 5800 feet difference in depth from the base of the fresh water to the top of the Dakota. This -- this distance, plus the other cementing of the casing would insure that the fresh water is protected.

MR. NUTTER: Mr. Thompson, you mentioned the interval that the fresh water is produced in. Would you give us the depths of those three formations, please, the approximate depths?

A. I don't -- I don't have them. I can furnish those at a later date. I don't have those available right now.

MR. NUTTER: I think it would be interesting to have that notation in the record if you could furnish it. You said, though, that the overall interval was from what to what?

A. From the surface of the ground to 1200

feet.

MR. NUTTER: The surface to 1200.

A. We picked a point about in the middle of the section. It does vary quite a bit from east to west.

MR. NUTTER: All right.

Q. Generally speaking, Mr. Thompson, when the water zones are encountered at a lower interval, is the Dakota producing interval also encountered at a lower depth?

A. Yes, it would be also at a lower level by about the same amount.

Q. In your opinion will current regulations insure that the development of the portion of the Dakota formation which is the subject of this application not adversely affect or impair any fresh water aquifers used for domestic or agricultural use during either hydraulic fracturing or waste disposal operations?

A. Yes, it will.

Q. Now I'd like you to refer to Exhibits Thirteen through Seventeen and review for the Examiner the data contained therein concering reserves and the general economics of developing this area.

A. Okay. Exhibit Thirteen is a tabulation showing the cumulative production and the ultimate recovery, ultimate reserves for the 31 wells that are producing or

have produced in the area of this application.

As can be seen, the average ultimate reserves for each of these wells is 313 -- 313,614 Mcf.

Referring to Exhibit Fourteen, there are -- all of the average are -- referring back to Thirteen, the average recovery is 313,614 Mcf. There are fifteen of those wells that expect to recover less than 200 Mcf per day, or a total of 200,000 Mcf ultimate recovery.

Exhibit Number Fourteen is an economic calculation showing the minimum amount of reserves necessary to provide economics for drilling a Dakota Well.

And Exhibit Fourteen shows that at current 103 prices, 350,000 Mcf of gas are necessary to provide minimum economics, and minimum economics in our company standard is a 15 percent rate of return.

I also believe this is --

MR. NUTTER: Okay, where do we find -- where do we find that, Mr. Thompson, on this Exhibit Fourteen?

A. Okay, if you go down --

MR. NUTTER: Where do we find, first of all, the -- you stated that that was the basis -- that that was calculated on the basis of your current economics and current prices.

A. Yes, sir.

MR. NUTTER: Okay, where is the current price noted in here?

A. Okay, turn to the second page, is probably the best place to look.

MR. NUTTER: That first one just is a summary sheet, right?

A. Yes, sir, that's the input data.

Looking at the second column from the left, where it says MMCF per year, gross production, MMCF per year, down at the bottom there's a total of 350.

MR. NUTTER: Okay.

A. Okay, that -- that is the ultimate reserves. That's the reserve figure for that well, gas reserve figure.

MR. NUTTER: You're figuring a new well to be drilled in 1981 and would be depleted in 1995, is that it?

A. No, sir. This program shows the first fifteen years of production and you see a sub-total and then the after section there.

MR. NUTTER: Okay.

A. See, actually if you'd refer to lower middle, we show a production life of 36.9 years, so that's the projected life of this well.

MR. NUTTER: So it makes 237 in its first fifteen years and then an additional 113 in the remainder of the life ---

A. That's correct.

MR. NUTTER: --- for a total reserve, then, of 350.

A. That's correct.

MR. NUTTER: Okay.

A. The price is lower left, you see the oil and gas prices, and we used a gas price of $3.11. This is adjusted for BTU and pressure base.

MR. NUTTER: Okay.

A. And it would be the price that we'd expect to receive when we start production in 10-1-81.

MR. NUTTER: Okay.

A. On the next page, the third page, it shows the rate of return and the payout. That's the middle of the page; the rate of return is item five, and it shows that these -- this was -- these reserves of 350,000 Mcf will provide a rate of return of 15.5 percent.

MR. NUTTER: Okay.

A. Also shows a payout of 5, slightly over 5 years.

Referring to Exhibit Fifteen, Exhibit

Fifteen is a similar calculation. In this case we've assumed 200 percent of 103 prices.

MR. NUTTER: Or $6.22.

A. Right, and we've determined what reserves are necessary to justify a well under these conditions. Again looking at page two, you can see that only 150,000 Mcf of gas reserves are required to justify a well at these higher prices. Again you can see the life of a well is 19.3 years and initial price of $6.22.

MR. NUTTER: So Exhibit -- Exhibit Fifteen doesn't change the time of payout or the rate of return on the same quantity of gas that Exhibit Fourteen did. It cuts the amount of reserves available and recalculates the rate of return and the time of payout. For 150,000 Mcf, rather than the other one was based on 350,000.

A. The purpose of these two calculations was to determine what the minimum amount of gas reserves were to --

MR. NUTTER: I see.

A. -- provide minimum economics, and this -- it's a trial and error solution. We made several calculations until we arrived at this one that gave us this 150. We were looking for the lowest number that would still justify drilling the well.

MR. NUTTER: Now, the average reserves in the area, according to Exhibit Thirteen, are 313,000 Mcf.

A. That is correct.

MR. NUTTER: Did you make the calculation based on an average well?

A. No, sir.

MR. NUTTER: Or 313,000 Mcf?

A. No, sir, I did not. It takes 350 to justify a well at 103 prices, so the 350 --

MR. NUTTER: Yeah, but if you want a 15 percent payout and a payout in five years.

A. That's correct.

MR. NUTTER: Yeah.

A. Which we consider a bottom line.

MR. NUTTER: I see.

A. So we're saying that the average well won't justify it at 103 prices. Also, if you'll look at -- if you go back to Exhibit Thirteen, it shows those -- that the average -- the cumulative production, a lot of these wells that had pretty high cums are real close in to some good production. The farther you get out into this area that we're applying for, the poorer the wells get.

MR. NUTTER: Well, you've got one well in here that I imagine raised the average reserves consider-

ably. You've got one well there that made almost five times the average reserves.

A. That is correct, and of course, that kind of hurts your average, but again, these are close in and the reservoir conditions deteriorate as you go out away from that good production.

MR. NUTTER: Where is that well, by the way? 33 of 32, 12, I guess.

A. It's a fairly new well without much cum, but that's what we think it will ultimately make.

MR. NUTTER: Is that the well that shows 7591?

A. Yes, sir.

MR. NUTTER: Uh-huh. So it hasn't made that amount of gas --

A. Oh, no, no.

MR. NUTTER: -- it's just what you're expecting.

A. That's what we think it will make ultimately, and that's what we're talking about, is ultimate recovery.

MR. NUTTER: Uh-huh.

A. There's some estimating going on. There is some projection going on, you know, in getting that ulti-

mate.

Exhibit Thirteen shows the cum and then what we think the remaining is, and the last column on the right is the ultimate, which is the sum of the cumulative and remaining.

MR. NUTTER: Right.

Q. Will you now review Exhibit Number Seventeen for Mr. Nutter?

MR. NUTTER: We didn't do Sixteen, did we, Bill?

A. I don't believe we did.

Q. Okay, then I suggest you review Exhibit Number Sixteen.

A. Exhibit Sixteen is simply a tabulation showing the assumptions that were made in this economic calculation, and they are the assumptions that we make in our routine economic calculations that our company makes. We did escalate gas prices; we escalated operating costs; we used a deregulation tax, a severance tax; all the things necessary to calculate economics.

Q. Now will you go to Exhibit Number Seventeen?

A. Exhibit Number Seventeen is just a typical Authority for Expenditure that shows the typical costs,

typical current cost for drilling and completing and stimulating a Dakota well at the average depth of 7050 feet. This value as of the present is -- we believe, is $378,560. This is what it's costing us today to drill DAkota wells in this area.

Q. How, Mr. Thompson, what conclusions can you draw from this economic data?

A. That more wells can be drilled in this area. We're talking about the area of this application, but we do need some incentive pricing to -- to justify this drilling because of the high cost.

Q. Has infill drilling been authorized for the Basin Dakota Field?

A. Yes, it has.

Q. Approximately how many acres are included within this field?

A. Approximately 800,000.

Q. In your opinion would infill wells be economical in this portion of the Basin Dakota Field?

A. Not at current prices. It would be at-- the area of this application? They would be at incentive prices. They wouldn't be at current prices.

Q. Is it your testimony that the economic calculations and the information which you have presented

concerning the costs of these wells, that that would apply equally to infill wells in the area as to the original well drilled on these proration units?

A. Yes.

Q. Now would you refer back to Exhibit Number One? I believe you indicated there were a number of dry holes --

A. Yes, sir.

Q. -- in the area, and also certain wells which never produced after initial potential.

A. Yes, I believe there actually are three wells that were completed but never did produce. Only two of them are in the area of the application; one of them is outside the area of the application, that we talked about earlier. That's the one in Section 15 of 31, 11. But there are two, one in Section 30 of 31, 10, and one in Section 32 of 32, 12, that were completed, stimulated and potentialed, but they never did produce commercially.

Q. What conclusions can you draw from this fact?

A. I think this indicates the very low permeability of the formation. I think that's why they didn't produce commercially.

In addition, there are five dry holes

throughout the area, indicated by the squares on Exhibit A. This is also an indication that the reservoir is very tight in this part of the field.

Q. Now I believe three of the test wells which you have testified to are not located within the proposed area, is that correct?

A. That is correct.

Q. How would you characterize the area in which they're located?

A. It's in a more prolific producing area than the area of this application.

Q. Would these wells technically meet the guidelines to qualify for 107 prices?

A. Yes, they would.

Q. Would you just briefly now summarize the conclusions -- your conclusions concerning the suitability of the proposed area for classification as a tight formation?

A. I think we've presented data to show that permeability throughout the area is less than 0.1 millidarcy; that stabilized producing rates are less than that prescribed; that oil production would be less than 5 barrels per day; that fresh water will be protected.

Q. In your opinion will the data presented at this hearing support these conclusions for the entire area

covered by this application?

A. Yes, they will.

Q. In your opinion is the 107 price necessary to provide a reasonable incentive for the development of the natural gas from the Dakota formation in this area?

A. Yes, it is.

Q. Were Exhibits One through Seventeen prepared by you or under your direction and supervision?

A. Yes, they were.

Q. Did you also prepare the geographical and geological description which was originally submitted to the Commission and USGS with these exhibits?

A. In conjunction with our geologist in Farmington.

MR. CARR: Mr. Nutter, we would request that that be marked as Southland Royalty Company's Exhibit Number Eighteen, so that it is part of the official record, and would ask at this time that Applicant's Exhibits One through Eighteen be admitted into the record.

MR. NUTTER: Now what is Exhibit Eighteen?

MR. CARR: Exhibit Eighteen would be the geographical and geological description that is --

MR. NUTTER: That's the other folder?

MR. CARR: Yes, sir, which is the summary

which we originally submitted with the exhibits.

MR. NUTTER: Okay, why don't you have this marked, then, as Exhibit Eighteen on the front cover preferably?

And you're offering these exhibits at this time?

MR. CARR: Yes, sir.

MR. NUTTER: Southland Exhibits One through Eighteen will be admitted in evidence.

Q. Mr. Thompson, in your opinion will granting this application be in the best interest of conservation, the prevention of waste, and the protection of correlative rights?

A. Yes, it will.

MR. CARR: Mr. Nutter, at this time we have nothing further of Mr. Thompson on direct. We would note that we had intended to submit an additional set of the exhibits to be transmitted to FERC, but we recently learned that they're now requesting three sets be submitted, and we will supply those in the next several days to you.

MR. NUTTER: Okay, is Mr. Thompson ready for cross examination now?

MR. CARR: He's ready.

CROSS EXAMINATION

BY MR. NUTTER:

Q. Mr. Thompson, now the wells that you depicted on Exhibit Number Thirteen are -- are they all in the area of interest?

A. Yes, sir.

Q. Or are they in the area down south of the area of interest, or the area of interest, let's define that.

A. The area of interest is outlined on Exhibit A by the heavy line, heavy dashed line.

Q. Okay, so it is the area that's over here to the far right of the exhibit and has a little piece of the cross section sticking into it with one well; then it comes across the north and has two wells on the cross section --

A. Yes, sir.

Q. -- the north/south cross section; and then it extends to the west and has two wells on a cross section east/west.

A. Yes, sir.

Q. And the 30 -- how many wells are on Exhibit Thirteen?

A. 31.

Q. 31. The 31 wells, then, are all included in that area?

A. Yes, sir, all within that area that we're proposing to designate.

Q. Now we have a whole lot of production data on wells to the south and west of the area. As a general rule, is the area that you're requesting to considered today, the area of interest, a better area than the area that you're not including in your application?

A. No, on the contrary, it's a poorer area.

Q. That's what I meant to say, I thought you'd say it was a poorer area.

And the area that you're requesting is a poorer area than the area to the south --

A. Yes, sir.

Q. -- where most of the wells are drilled.

A. And the production data we supply does indicate that.

Q. Well, now, we really don't have much data on the eastern half of the area of interest.

A. No, sir.

Q. How we can tell that the area up there is not as good or better than this area to the south down here?

A. It's true we have limited data; however, we do have -- we have a well in Section 24 of 32, 10, that's

only produced an ultimate of 29,000 Mcf, indicating the permeability would be very low up there.

We have two wells down in 31, 10, one's in Section 27 and one in Section 34. Now the one in 27 did produce enough to provide minimum economics; the one in 34 did not.

Of course, we have the well over in 30 that we referred to before in Section 30, that did not produce at all.

There is a well up in Section 26 of 32, 11, that only produced 261,000 Mcf, which is not, you know, doesn't meet minimum standards.

Q. Now you've got two new wells up here, indicated as being new wells. Do you have any data on those?

A. No, sir, we do not. We'd have the initial completion, I'm sure, on them, but the initial potential can sometimes be used as an indicator, but it's not really -- not a real good indicator in this area. If you only look at the initial potential in some of our wells over here in Section 32 of Township 32, 13, you'd think they'd be good wells, but they just don't perform that well. They drop off. One of the characteristics of a tight formation is they come in at a pretty good rate, but they drop off very rapidly, and I believe those two wells up there will probably not -- I

don't think they'll be economical, myself.

Q. Those are the two northernmost wells there?

A. The two -- right.

Q. The two wells in 13 and 14?

A. What I'm referring to in 32, 10, in Sections --

Q. Well, I meant the wells that you said were pretty good wells on potential in 32, 13.

A. Okay, I was really referring to 33, 12.

Q. Oh.

A. Those in Sections 10 and 11 and 13 and 15, those areas, those wells have come in maybe at 2-million a day, but they just don't produce satisfactorily. You can see the cums of some of them, less than 100,000 Mcf. None of them, you know, made the necessary 350,000.

So initial potential alone is not a good criteria. I don't think any of this will be economical out here at 103 prices. Admittedly, we don't have a lot of data to substantiate that.

It's really difficult to go out there and develop data because of the risk of having uneconomical wells. You hate to go out there and drill a well and spend $300,000 plus just to develop some data, when there's a good chance

you won't get your money back.

With the incentive pricing there would be a lot more incentive or more justification for recommending wells to be drilled out in there.

That's the reason we used data, we tried to use data even though it wasn't in the proposed area, it's nearby, and we tried to show that these wells, that they meet the qualifications in a better area, and it follows, then, that the wells in the poorer area should also meet the qualifications.

Q. You didn't apply any economic tests to these wells in the better -- better area and show it on your exhibits?

A. No, sir, I did not. They would certainly be economical. If they could make more than 350,000 Mcf they would be economical and they make much more than that. They're good economics. Like, for example, in Township 32, 12, those are good wells.

Q. Pretty -- relatively high cumulative recoveries there.

A. Yes, sir, they are, and we would expect our infill wells to be, you know, to produce a lot of gas there, too; not as -- probably not quite as much as the original, but maybe approach what the originals make, and it's

not uncommon for a well to make 2-billion in that area.

MR. NUTTER: Are there any further questions of the witness?

MR. PADILLA: Mr. Examiner, I have a couple of questions, if I may.

CROSS EXAMINATION

BY MR. PADILLA:

Q. Mr. Thompson, would you explain to me what the relevance is of Exhibit Eight?

A. Exhibit Eight?

Q. Yes.

A. The purpose of Exhibit Eight is to -- is to present a method of converting laboratory permeability to in situ or reservoir permeability. The requirement, as I understand it, is less than 0.1 millidarcy in situ permeability. When you use core data, standard core analysis run in the laboratory is not in situ permeability. It's what we call laboratory permeability, and this is simply a method of converting that laboratory permeability to in situ permeability, which we felt was necessary because that was what was required.

Q. So the purpose of this is not to show that -- the purpose is informing us how you went through your

procedures for calculating permeability, is that correct? This does not apply to this formation but you used this data in compiling your --

A. That's correct. The data we used, actually we used figure one on page 121 of that paper, and we used -- we used the Core Number 3927 -- or 3928, which has permeability similar to what we have -- what we've seen in the Dakota here. This particular -- this data, particular data, came from the Pictured Cliffs formation in the San Juan Basin, about fifteen miles to the southeast. We believe that the Dakota and the Pictured Cliffs would be very similar, and we believe that if we ran this same data on the Dakota formation we'd have similar results.

But this, what figure one shows, that at a reservoir pressure, at least, of 2650 pounds, that the in situ permeability would be 28 percent of what the laboratory permeability is, and that's what the lines and the arrows indicate on that particular graph.

MR. NUTTER: This EXhibit Eight, Mr. Thompson, talks about the -- or it's a discussion of the effects of the overburden on the permeability in Gas Buggy and Wagon Wheel. Where was WAgon Wheel?

A. I'm not sure where it was. Wait just a second and I'll tell you. I did not use that data. I felt

like the Pictured Cliffs data in the San Juan Basin would be more appropriate.

Whit Union formation in Pinedale Field, Sublett County, Wyoming. (sic)

MR. NUTTER: Okay.

So it's up in Wyoming. I know that Amoco has done some similar work in the Cotton Valley formation over in east Texas, and they came up with similar results.

Q. Mr. Thompson, on Exhibit Twelve you say at the bottom on the analysis, that the Dakota was not productive in a couple of formations. What does that -- what does that mean?

A. Okay, these were dry holes and just no production test was made. I don't believe they even set pipe on the wells. They just drilled through and logged it in those two cases and cored it; they didn't set pipe and make a test.

They simply used the core data for the permeability data, but we didn't have any, you know, any production there.

Q. So in other words, you went back to Exhibit Eight on those wells, is that --

A. Those are the two wells we used Exhibit

Eight to determine in situ permeability.

Q. Okay.

A. Using laboratory permeability from the core analysis.

Q. Now on Exhibit Sixteen, the cost for drilling each one of those wells, or the average cost, I guess, you would calculate those.

A. Yes, sir.

Q. What percentage of that would be attributable to stimulation procedures or stimulation processes that you would get from the wells?

A. I believe on the second page of Exhibit Seventeen we have that data; $27,500 for the acid frac treatment down near the bottom of the second page of Exhibit Seventeen. That would be just the stimulation itself, $27,500. There's a detail -- the second page of Exhibit Seventeen is a detail of costs.

Q. Would you explain what the actual procedures were for stimulating a well of this nature?

A. Actually, normally our procedure, of course, we'd perforate the well first, holes in the casing, of course, out through the cement. Then we normally inject a small acid job, using ball sealers to -- we drop ball sealers during the acid job to seal off. The first perforations to

take acid, we drop balls to seal them off and to force subsequent holes to take stimulation, until hopefully all the holes have taken some acid to break the formation down.

Then we follow this with usually a fairly large frac job. We spearhead this frac with water and then we follow that with -- we start putting sand in the water in increasing amounts. We start out with a very low concentration of sand, maybe a half a pound per gallon, and finally maybe get up to two or three pounds per gallon, pounds of sand per gallon. This is injected.

The purpose is to -- action to fracture the formation, to actually open up the formation. That's the purpose of the fluid. The purpose of the sand is to hold this fracture open once we have fractured it, the sand, it props the fracture open and allows the gas to flow to the wellbore through these fractures.

Q. Do you believe there's sufficient distance between the area that you're fracing and the fresh water aquifers to prevent any contamination of fresh water?

A. Yes, very definitely. It's approximately 5800 feet and I don't think there would ever be any problem of fracturing that far. In fact, I'm sure it wouldn't, it would not fracture that far. These fractures -- we've run a number of temperature surveys and different surveys, and these

fractures normally don't go above the Dakota formation over 100 feet.

Q. Now looking at Exhibit One, in relation to infill drilling, would you consider the area that is excluded from the application, in other words, the area that seems to have commercial wells, would that -- would you consider that to be an area substantially developed by -- within an infill area?

A. Yes, sir.

Q. And so for that reason you would -- you have excluded that area?

A. We've excluded it primarily because it's economic at current prices. It qualifies. It makes the criteria as far as permeability and rate and crude production, but it doesn't meet the -- if you consider economics, it is economic at current prices, so that's why we've excluded it.

Q. Would you say that that's an area that's substantially developed, especially in your acreage, where you have three or four wells to a section?

A. Yes, sir.

Q. And there really aren't any infill area -- infill wells in the area that you have applied for?

A. There would be some, yes, sir. There would be some drilled, in particular in Township 32 North,

Range 12 West.

Q. But there aren't any --

A. No, there hasn't been any drilled yet, no, sir. There would be if this is approved but there haven't been yet, no, sir.

MR. PADILLA: I believe that's all I have at this time.

RECROSS EXAMINATION

BY MR. NUTTER:

Q. Now, Mr. Thompson, in your discussion on page 9 of conversion of the laboratory permeability to the in situ permeability, you're referring to Core Number 3928. Is Core Number 3928 the core that we've got here in Exhibit Five?

A. No, sir.

Q. Which core was 3928?

A. It's simply the core that the -- the authors of that paper used --

Q. Oh.

A. -- to make that analysis. There's no connection between it and Exhibit Five.

Q. Okay, so -- all right, I thought that was your discussion of what you had determined on your --

A. No, sir.

Q. -- in situ permeability.

A. It's simply -- I had to pick one of those -- I picked one of those curves to interpret my in situ permeability, and that 3928 turned out to be more like our -- the permeability of our cores, or our -- from our calculations of permeability of our formation.

Q. Okay.

A. Formation in this area.

Q. Okay, now their lab tests and their calculations ran from zero or 100 pounds, I guess it was, up to 6000 pounds.

A. Yes, sir.

Q. What was your pressure that you used on your calculations?

A. 2650. It's indicated there on Figure 1 of the paper.

Q. Okay. Now, is this your -- is this your drawing here on this?

A. Yes, sir, the line with the arrows, that I put that on there, right.

Q. Okay, that's not part of the paper, then.

A. No, sir, it is not.

Q. So you used an assumed rock pressure here

of 2650.

A. That's correct.

Q. And hit this curve and came over here to your 28 percent. Then you applied the 28 percent to your laboratory permeability, is that it?

A. That's correct.

Q. Okay.

MR. NUTTER: Are there any other questions of Mr. Thompson? Yes, please.

MS. UMSHLER: USGS with two questions for you.

CROSS EXAMINATION

BY MS. UMSHLER:

Q. First of all, do you have a percentage of breakdown on the ownership of land in the area?

A. No, no, sir, I do not. Our acreage is indicated by the shading, and other than that I don't know.

Q. But you don't have a State or Federal breakdown?

A. No, sir.

Q. And one other question, on Exhibit Thirteen, you show the royalty interest rate of 13-1/2 percent?

A. Yes, sir.

Q. How did you arrive at that percent?

A. That's an average. Some of it's 12-1/2 percent; some of it's quite a bit more than that. This is purely a typical average.

Q. Okay, thank you.

MR. NUTTER: Does that royalty interest include overriding royalties?

A. Yes, sir, total, total royalty. One percent of that probably is an override.

CROSS EXAMINATION

BY MR. BUCKINGHAM:

Q. Allen Buckingham, I also have a question.

MR. NUTTER: Are you also with the GS?

MR. BUCKINGHAM: Yes, sir.

Q. I have a question, Mr. Thompson. You mention, I believe, that there was no infill wells in your area that you are requesting tight formation?

A. Yes, sir.

Q. Reading from, and if you'll look at Exhibit Eighteen where you're talking about geographical and geological description, number three where you're talking about Township 32 North, Range 12 West, --

A. Okay.

Q. -- in Section 26, there's an infill well No. 2-E;in Section 27 there an infill well No. 1-E. Do you have any information --

A. No, sir, I don't. And they've been proposed since I prepared this exhibit.

Q. Although I believe it really is not that material because of the information that you have submitted as far as economic information, that it's not economical for a 103 price, I just wondered if you had any information on any other infill wells?

A. No, sir, I do not. I don't have any knowledge of any being drilled. Perhaps some have been proposed recently.

Q. Okay, thank you.

MR. NUTTER: Are there any further questions? Mr. Chavez.

CROSS EXAMINATION

BY MR. CHAVEZ:

Q. Mr. Thompson, by definition the Basin Dakota Pool contains more than just the Dakota formation.

A. Yes, sir.

Q. It contains the Graneros and also the Morrison, a portion of the Morrison.

A. Yes, sir.

Q. On your exhibit which -- is it Thirteen, which lists the producing wells, do you know which ones of those are committed -- completed in -- let's see, Thirteen, are completed in just the Dakota producing interval, or if those are completed in --

A. I'd say all of them are. I'd have to check to be sure, but I'd say they're all completed in either the Graneros or the first Dakota, or both. Usually we complete in the both the Graneros or the first Dakota. I don't think any would be in the lower Dakota or the -- or the Morrison. I'd have to check that to be 100 percent, but that's what I believe to be correct.

Q. What were the average shut-in times for the build-up tests that you showed on your first exhibit there.

A. That's Exhibit Five. We shut -- the well was shut in for 8 hours.

Q. I'm sorry?

A. For 8 hours. Exhibit Number Five.

Q. Okay, how about Exhibit Six? Exhibit Six and I think Seven, also, has a pressure test. What was the average shut-in time for those?

A. I don't have that. That would be an extremely long one. What we did on these is, we -- after the

wells were completed and were shut-in, it would be an extremely long -- I don't have a figure, I could get it, but it would be a matter of days on those two, because this shut-in pressure was taken after the wells were completed and shut-in awaiting pipeline, so those were extremely long shut-in times.

The Exhibit Five was on drill stem test and that was only 8 hours.

Q. What was the radius -- I don't see a calculated radius of investigation for the Exhibits Six and Seven. Did you --

A. No, we assumed that the drainage would be the spacing, which is --

Q. No, the investigation of the test?

A. Okay, we did not calculate that, no, and did not use that. We used the radius of drainage of 160 acres.

Q. Was the stimulation on the wells which are listed in Exhibit Thirteen pretty standard for each of those wells, or were there some major differences?

A. I would say they're probably standard. Most of these are older wells. I really don't -- I didn't really investigate that, but I think most of them are pretty standard.

Q. Well, the older wells have used, perhaps,

in general not as large a stimulation as the new wells?

A. They could be somewhat smaller, although I don't, in the ones I have looked at I don't see that much difference, but I'm sure there are some differences.

There's a lot of difference in opinion on -- on just, you know, how valuable the greater -- the larger stimulations are. We as a company don't do large stimulations. Some companies do. There is a question in our mind as to whether or not the larger ones are justified.

So we're stimulating very similar to what we were back in the days when we drilled these wells.

Perhaps some of the other companies are using larger stimulations.

Q. Okay, are the production rates of the newer wells that you've completed pretty much different from the wells that you drilled originally, or say some of the first wells you drilled in this area?

A. They're pretty close to the same. Some of them are somewhat lower at first. Some of them come in -- start a little bit lower and improve; probably some little bit of damage from the stimulation. Most of them come in -- after they stabilize, most of them will stabilize at 300 or 400 Mcf per day -- MMCF per day, 3-or-400 Mcf per day, in the good areas. Of course we haven't drilled any in this poor

area that we're talking about.

MR. NUTTER: Are there any other questions of the witness? He may be excused.

Do you have anything more, Mr. Carr?

MR. CARR: Nothing further, Mr. Nutter.

MR. NUTTER: We'll take a fifteen minute recess.

(Thereupon a recess was taken.)

MR. NUTTER: Ms. Teschendorf, I believe you wanted to put some testimony on?

MS. TESCHENDORF: Yes, sir. My name is Lynn Teschendorf. I'm appearing here on behalf of Consolidated Oil and Gas.

Consolidated has some data that we would like to offer in support of Southland's application in this case, and we would also like to ask the Examiner, Consolidated is mainly interested in Townships 31, 13, and 31, 12, which were covered by the advertisement but are not covered, apparently, by Southland's application, as we did not learn until yesterday evening.

We also found out fairly recently, so

we are not as well prepared as we would like to be, so I'll go ahead and present what we've got and make a motion at that time.

MR. NUTTER: Okay.

MS. TESCHENDORF: I have one witness who has been sworn.

FLOYD E. ELLISON, JR.

being called as a witness and being duly sworn upon his oath, testified as follows, to-wit:

DIRECT EXAMINATION

BY MS. TESCHENDORF:

Q. Would you please state your name, occupation, and by whom you're employed?

A. Floyd E. Ellison, Jr.. I'm Vice President of Consolidated Oil and Gas, and my background is petroleum engineering, having a petroleum engineering degree from the University of Wyoming in 1957.

Q. Have you previously testified before the Division or one of its examiners?

A. Yes, I have.

Q. And are you familiar with the facts concerning this particular case?

A. Yes, I am.

MS. TESCHENDORF: Is the witness considered qualified?

MR. NUTTER: Yes, he is.

Q. Mr. Ellison, would you refer to Exhibit One and explain what that shows, basically?

A. Exhibit One is a map showing Consolidated Oil and Gas's acreage, and the only thing that is really updated regarding placement of wells is that on Consolidated's acreage itself, and the cumulative curves -- or the cumulative's shown here have not been updated since 1971, so they should not be confused with those of the previous map on the application earlier submitted.

Q. But the current status of Consolidated's wells is correct as far as where they are and what formations they're completed in, is tha correct?

A. Yes, I believe so.

Q. Okay. What acreage is Consolidated mainly interested in in this area?

A. Consolidated's acreage is primarily in 13, 31, with a little bit in 12 of 31, and also we do have just a little bit of acreage in the area of application, which is in 13, 32.

Q. Has Consolidated been involved in an

infill drilling program on this acreage?

A. Yes, we have. We have been fairly active in the last couple of years infilling, and especially in the Dakota this last year.

Q. We have three wells we would like to present data on. Would you please name those wells and give their locations?

A. The first one is that under Exhibit Number Two, the Wilmerding 1-M.

Q. Why don't you just spot them on Exhibit One for the Examiner and then we'll go on to the other exhibits?

A. Okay, it's the northeast quarter of the northwest quarter of Section 10 of 31, 13.

Q. Okay, and where is the second well?

A. The second well is that shown on Exhibit Number Three, which is the Kline 1-M, and it's in the southeast quarter of Section 10, 31, 13.

The third well is the Senter 1-M, and it's in the southeast quarter of Section 24, 31, 13.

Q. And these wells are outside the area that has been outlined by Southland Royalty, is that correct?

A. That is correct.

Q. But they are very close to their acreage

A. Yes, I think it has a significant bearing on the type of formation that we're dealing with in the area.

Q. Would you refer now to Exhibit Number Two, which is the data sheet on the Wilmerding 1-M, and describe that exhibit?

A. Okay. Our Wilmerding 1-M, this well was completed out of both the lower and the upper Dakota. The only portion we ran a test on was the lower Dakota, having some mechanical difficulties when we got to the upper Dakota and we chose not to try to run a test.

But in the lower Dakota we perforated 8 perforations for limited entry-type frac job between 6788 and 6846. We acidized this with 250 gallons of 7-1/2 percent acid with ball sealers so that we could eliminate any type of formation damage that may have occurred during drilling, so that we could feel reasonably comfortable with the fact that it was testing the formation as it really was when we did try to test it.

We did test it and it flowed just a little bit of gas, back. It tested through a critical prover with a 1-inch orifice. This was witnessed by members of the New Mexico Oil Conservation Commission and our own people, and the measurement from that interval was too small to measure.

Q. What was the stabilized production rate on the lower Dakota, then?

A. Okay, it was, the rate was actually too small to measure through the 1/8th inch orifice, which would put it down in the less than, say, one or two Mcf per day; it would be below that figure.

Q. So that is definitely less than the FERC guideline of approximately 251 Mcf a day.

A. That is correct.

Q. Did you get any crude oil production from the Dakota in this well?

A. No, we did not.

Q. What was the spud date of the Wilmerding?

A. Spud date for the Wilmerding was April the 2nd, 1980.

Q. Okay. From these tests that you ran on this well, did these tests give you any indication as to the permeability in the area?

A. If Darcy's law is applied, run through the calculations, which we do not have here, but it would very definitely show well below 0.1 of a millidarcy.

MS. TESCHENDORF: Again I apologize to the Examiner, we didn't have time enough between the notice and the hearing date to get all this data prepared, but we

can submit it later, if you would like.

Q. Let's refer to Exhibit Number Three, on the Kline 1-M, and discuss that.

A. Okay, on the Kline 1-M we perforated both the lower Dakota and the upper Dakota and we did treat them separately and tested them separately.

The lower Dakota was perforated between 6655 and 6736 with 9 perforations. It was acidized with 300 gallons of acid and ball sealers. The acid was then -- and the flush water was then swabbed back. The flow rate through a critical prover, using a 1/8th inch orifice plate, we produced it for 5 hours at a maximum rate of just under 13 Mcf per day. This was also witnessed by the Commission.

The upper Dakota is perforated with 17 perforations between 6506 and 66[illegible]; was acidized with 500 gallons of acid and 30 ball sealers. We also swabbed it back until it was dry, and flowing it for four hours through a 1/8th inch orifice, a critical prover, the gas rate was too small to measure.

Q. And this well also, the stabilized production rates fell below those specified in the FERC guidelines?

A. That is correct, and it also, if one were to apply Darcy's flow equation, it would show less than

0.1 of a millidarcy.

Q. And was there any crude oil production from this well?

A. There was not.

Q. When was the well spudded?

A. This well was spudded in April 17th, 1980.

Q. Let's go on to Exhibit Number Four.

A. Exhibit Number Four is for the Senter 1-M. This well was also perforated and tested separately from the lower Dakota and the upper Dakota. The lower Dakota had 13 perforations between 6898 and 6958. It was acidized with 500 gallons of acid and 25 ball sealers. It was swabbed back and a long flow test was taken under the direction of Tefteller, Incorporated, and witnessed by the Commission, and the rates, the initial rates on it for the -- trying an open flow, was 2.73 Mcf, or less than 3 Mcf per day. After three hours it was less than 2 Mcf per day, and allowing it to flow overnight, at 7:00 o'clock the next morning it was still flowing at less than 2 Mcf per day.

On the upper Dakota it was perforated it looks like 13, I believe it was, perforations from 6740 to 6816; acidized with 500 gallons of acid and 22 ball sealers. It also was swabbed down. Tefteller ran a flow test on it,

which was witnessed by the Commission, and the final rate, or the -- it flowed for 21 hours and the well stabilized over the last 16-1/2 hours at a 52 Mcf per day rate.

Q. Any crude oil production?

A. None. No, there was not.

Q. And does this well also, would you, in your opinion say, have less than 0.1 of a millidarcy throughout?

A. Yes, I believe if the Darcy flow equation is applied to this rate it would also show that it is less than 0.1 of a millidarcy.

Q. Let's talk about the economics of some of these wells. You have stated that Consolidated has been quite extensively participating in an infill drilling program in this township. Is this infill drilling program still going on?

A. Well, we have just recently stopped our infill drilling program to evaluate where we stand. We are experiencing a very rapid increase in drilling cost rates, especially the footage cost going up so fast, in fact, this last year it's gone up over 30 percent just for the footage cost itself. I think it's probably more like 50 percent over what we were getting one year ago and what it is today for the last wells we have drilled.

The other costs have also gone up, so I think we would be very close to maybe at least a 30 percent increase in drilling costs over this past year, so we see a collision course taking place between the inflation adjusted 103 price and what our drilling costs are, and for that reason we have felt that we need to shutdown our infill drilling program, evaluate our recent wells that we have drilled to see whether or not that we should be taking the risk of trying to drill additional units.

Q. When we started the infill drilling program the Section 103 price was considered sufficient incentive, is that correct?

A. That is correct.

Q. And very recently Consolidated management has taken the position that with the increase in prices, that the Section 103 price is no longer sufficient, and that, therefor drilling further wells would be uneconomic, is that correct?

A. From the standpoint that we are evaluating it. It looks like that it is going to begin to eliminate many of the wells that we would have drilled, and we will have to look more carefully at each one to see whether or not that we are interested in -- in risking our money to infill drill. I think it will be on a selective basis, much more

of a selective basis now than it would have been three months ago, even.

Q. Would a higher incentive price change that position?

A. Very definitely. It would increase the number of wells that we would be willing to risk drilling on an infill program.

Q. Is there anything you wish to add to your testimony at this point?

A. Well, I think other than the fact that we see, and I think we've talked to other operators, the fact that we do see a collision course between the costs of drilling and the inflation adjusted 103 price, that I think based on that, we are very definitely going to have to become very selective in what wells that we can afford to drill, and each passing month it's going to increase as far as the number of wells that we will have to eliminate that we can drill.

Q. Were Exhibits One through Four prepared by you or under your supervision?

A. That is correct.

MS. TESCHENDORF: I'd like to offer these exhibits.

MR. NUTTER: Consolidated's Exhibits One through Four will be admitted in evidence.

MS. TESCHENDORF: And I would like to ask the Examiner to consider including these townships in an order, if you should approve this tight formation application.

Like I said, it was included in the advertisement; however, we can also come in with a separate application should that be necessary.

MR. NUTTER: Okay, we will consider that, Ms. Teschendorf.

MS. TESCHENDORF: I have nothing further.

CROSS EXAMINATION

BY MR. NUTTER:

Q. Mr. Ellison, now taking these wells that you have the data on individually, the Wilmerding No. 1, which is in the northeast of the northwest of Section 10, 31, 13, I presume that that well has dedicated to it the west half of Section 10 and that it is an infill well with the well that's in the southwest quarter?

A. No. It -- the Wilmerding is one of the rare ones that goes across a section line over into Section 9 in the northwest quarter -- or northeast quarter of Section 9 and the northwest quarter of Section 10, is the Wilmerding 320-acre spacing.

Q. Okay, so it is an infill well, then.

A. It is an infill well.

Q. With the well that's in Section 9.

A. That is correct.

Q. All right, now that well in Section 9 shows a cumulative production of 135,000 Mcf, is that it?

A. That is -- I believe that is the old one. We may be able to tell from the Southland Exhibit One what that well has -- what the cumulative is on that. Just one minute.

It shows the cumulative being 188 with it only having made 8-million for the entire year last year.

Q. In other words, this figure is not up-to-date here?

A. No, I think I made reference that that cumulative on our wells there was only through 1971.

Q. Oh.

A. So they have not been updated. We did not get a chance, in trying to get this together under short notice, a chance to update all our cumulatives.

Q I see, so that is noted in the legend here of your Exhibit One, that this is through 12-1-71.

A. That is correct.

Q. Okay. Then the well --

A. May I interject something right here?

I think very possibly, even with the 103 prices, had we not had a dual infill as far as -- although both the Mesaverde and the Dakota on this particular well were very marginal, we chose to go ahead and -- and attempt it, thinking that between the two zones we could get a payout.

With current prices now I don't think we would have attempted, even with the dual costs. which cut down on your development costs, I'm not sure that we would have even drilled the well.

Q. Okay, then the other well in Section 10, which is the well that's on the Exhibit Three, is the Kline No. 1.

A. That is correct.

Q. And that's an infill well with the well that's in the northwest -- northeast quarter of Section 10.

A. That is correct.

Q. Now, through 1971 that well shows that it had made 467,000 Mcf, and on Southland's exhibit, would that be the well that shows 679,000?

A. That is correct, and again, if you draw curves and assume what the cumulatives are, if you'll notice the well in the northeast quarter of Section 15, and you'll see that it is 294 with only making 8-million last year, which means that its cumulative is probably going to be something

less than 350--million, or somewhere in the neighborhood of 350--million, and therefor, we are going from a good well to a poor well and it puts it in the very marginal category, in other words, of whether or not that you will get a payout, and again we had a marginal Mesaverde that we are going to be dualing it with, which we felt at the time probably brought it up into an area that we could afford to drill it.

Q. Well, if we strike a --- if we strike an actual average between the well in the northeast quarter of 10 and the well in the northeast quarter of 15, we would be averaging 700 with 300 or coming out with a 500,000 Mcf well, which would be in excess of necessary amount to pay out on a well, according to Southland's testimony.

A. Yeah, according to Southland's testimony, but with the increase of the drilling costs that we are seeing, in other words, we could drill it this year, but at the rate that the drilling costs are going up, could we afford to drill it next year or the following year. In other words, this has to deal with the incentive of doing so.

Also, I'm not sure that we would maybe live with the 15 percent based upon the cost of money and all we have nowadays, I'm not sure that we would live with 15 percent rate of return when the cost of money is over 21 percent.

Q. Well now, you've had other infill wells that have been drilled in this area --

A. Yes.

Q. -- that Ms. Teschendorf's talking about.

A. That is correct. We have quite a number in it.

Q. Did you select these three wells as being the poorer of the infill wells that you have drilled?

A. No, this didn't even -- in other words, when we decided to just get some information, we just -- we went out there and they were the ones that were available at that time when we were talking about it.

Q. Uh-huh.

A. And I'm not sure -- well, I was going to say the Senter Well over there where it was, as you can see, it was close to a very good well.

Q. Well, I can see that there are some wells there that have very good cumulative recovery, the east offset has made over 2-billion cubic feet.

A. That's right, and it's one -- probably the best well, or one of the very best wells that Consolidated has, and yet from the results of the test, you can see that the in situ permeability and flow rate from the two different both the upper and the lower Dakota zones did not meet the

criteria -- or does meet the criteria of the 0.1 millidarcy and less than 251 Mcf.

Q. So you may have tight spots in here and also some sweet spots in the formation.

A. That is correct.

I think we also should maybe point out that we, as we were going through our infill program, we were trying to pick some of the very best wells, you know, from a management standpoint it is much better to go after the best ones to start with to make you get the best payout, and then you begin to move towards your marginal ones. So for the most part we have -- we have drilled our better locations and that is one reason, as far as evaluating do we or do we not want to continue into the infill program, the remaining wells we had to drill are not in as good a part of, or the sweeter part of the Dakota as some of these others are that we're moving off.

Now we do have a few good ones,that appear to be good ones, remaining.

Q. Well, do you think that the fact that you're getting these poor wells in here is an indication that maybe the drainage from the original wells in the Dakota formation were better than had been anticipated and there just isn't much gas left?

A. What we have run bottom hole pressures on these, the majority of our wells have had near original bottom hole pressures, surprisingly. We had -- I think we've had like three of them that showed real low, and --

Q. Where they did get into a --

A. Yeah, and we --

Q. -- reservoir that has been drained.

A. Yeah. Let me just point out one of them. Up in the Mitchell in Section 5 of 12, 31 -- 31, 12, that Mitchell 1-E Well.

Q. That's a new well?

A. That is a brand new well and I think our bottom hole pressure on that was 400 and some pounds.

And another one was down in the -- I think the Southern Union well down in -- the one that offsets the real good well, if you'll look at that.

Q. Okay, the 1-M in 30?

A. Right, in Section 19, the 1-M Well there.

Q. Okay.

A. It also had a low bottom hole pressure, but that has been the exception rather than the rule. The majority of ours have had good bottom hole pressures remaining.

Q. Indicating no drainage, or little drainage.

A. Indicating no or little drainage, yeah. We've had some that are original and some that are not much, you know, a couple hundred pounds below original, stuff like that. We've been -- we've been very pleased by the pressures that we've been experiencing except for two or three cases.

Q. But what you're doing, you're just drilling into the tight spots.

A. That's true, but it may be that the tight -- we don't know this, and this comes into the risk factor, of when you drill you're not sure whether you're going to be in a tight or a sweet spot, and this comes back to the economics of do you or do you not.

MR. NUTTER: Are there any other questions of Mr. Ellison?

CROSS EXAMINATION

BY MR. CHAVEZ:

Q. Mr. Ellison, you mentioned your limited entry perforations, do you think that one perforation every three or four foot is adequate to -- in order to get a test that's required by the FERC testing the formation without stimulation?

A. If you'll go through the calculations as far as Darcy's law and things like that, yes, I would say

that this -- this does adequately test. When we are using the acid to get out into the formations, the flow rate and the loss, and all of that, coming to a perforation, and we're talking about over a short interval, under those circumstances I would say, and there's a lot of data in the literature and all of that, that shows that you're not hurting your permeability calculations or anything like that significantly.

Q. Did you take any fluid level analyses to see whether there may have been fluid accumulations in the wellbore that would have caused a low rate of gas production?

A. We had swabbed those right down to the time of starting into run the test itself. In other words, we swabbed it and made sure that it was dry and that there was no fluid entry, we were getting no fluid entry, almost nil fluid entry.

So it should -- it should be a good, valid test.

MR. CHAVEZ: That's all.

MR. NUTTER: Mr. Padilla?

CROSS EXAMINATION

BY MR. PADILLA:

Q. Mr. Ellison, let me hand you what has been marked as Southland's Exhibit Number One, and I'm also

going to hand you a red pencil so that you can mark on that map the area of interest that you are applying for.

MR. NUTTER: So in other words, Mr. Ellison, the line that you've drawn on the exhibit for Mr. Padilla includes all of Township 31 North and 13 West, and the western-most two rows of sections in Township 31 North, Range 12 West, is that it?

A. That is correct.

MR. NUTTER: So there's 12 sections in 31, 12, and 36 sections in 31, 13.

A. That is correct.

MR. NUTTER: Okay, and those have been outlined in a red line of wavy design.

A. That is correct.

MR. NUTTER: On Southland's Exhibit One.

Q. Mr. Ellison, there's some area in Township 31 North, and I think it's between 13 West and 12 West, that has three and four wells to a section. I'm specifically talking about Section 18 of 12 West, 31 North, and Section 19 and then Section 24 of 31, 13 West, and there are some other sections in that area that have at least three wells, or have three wells. Do you have any information as to the commerciability of those wells with respect to the Section 103 price?

A. The information that I have, for instance, right now in Section 24, the Senter 1-M Well is very -- which is in the southeast quarter offsetting that very, very good well, it's very questionable on -- as it stands right now and our production -- producing capacity and all of that, it is noncommercial. In other words, it will not pay back the drilling costs.

The infill well for the Southern Union well on the south -- southeast quarter of Section 19 is also another well that will not -- we will not recover our completion and drilling expense.

MS. TESCHENDORF: I might point out that a lot of these wells you're looking at are not Dakota wells. Okay?

A. No, the ones that --

MS. TESCHENDORF: You can see on there that they're marked with the formation.

A. Okay, these are the ones he's talking about, these right here, which are the ones that include ours.

MS. TESCHENDORF: Okay.

A. So these -- our Senter Well and our -- or our Senter 1-M Well and our Southern Union 1-M Well will not pay out. The Lee 1-M Well -- I'm talking about in the

Dakota -- the Lee 1-M Well, which is also in the northwest quarter of Section 30 of 12, 13, will not pay out, and the infill well, the Mitchell Well previously referred to up in Section 5, in the northeast quarter -- or northwest quarter of Section 5 of 12, 31, will not pay out. And of course, that payout, the loss on those has to be picked up by the wells that will pay out from that same area.

The other -- the other wells, several wells you have there have not been put on stream, so I cannot tell you, several of these wells, whether we will get a pay out or not.

Q. Have some of the older wells in that area paid out already, to your knowledge?

A. Yes, I'm sure that they have. That was back, they were drilled back in the '50's and with the drilling costs much lower and all that. Of course, the gas price was much lower.

But we have, you know, it's a mixture of the new wells, some have gotten good payouts and others will not have any payouts, but the total drilling program has to be balanced with what happens to all the wells.

Q. Now moving further to the east, I believe Mr. Thompson testified that the wells in 31 North, 12 West and 11 West, he believed that area -- those wells in that area

were commercial, and for that reason they were excluded from Southland's application. How would you distinguish this area that we have just been talking about with the one that Southland excluded from their application?

A. Well, I think what we're talking about there is the Dakota has what many refer to as fairway, or sweet areas, and stuff like that. That is a sweeter area, more in the fairway than that as you move west. So based upon cumulatives already shown on his map, those wells do much better. I have no idea what the -- other than from his testimony -- what the in situ perms are or the natural flow rates, although they still may fall within the guidelines -- or fall within the criteria set forth for a tight gas formation.

Q. Now, going to your Exhibit Number Two, and I believe your Exhibit Number Three, aren't those in fact dry holes? Those wells, the information from those wells, aren't they dry holes?

A. No, they are not. They -- they are being completed into the line and they did make -- it appears both are commercial wells.

Q. This information that's --

A. Oh, you mean as far as if a person were to look at this would he back off and say these are dry holes,

and not try to make a completion? Is that your question?

Q. Yes.

A. Very, I would say if he were to run a DST on it and get this type of information, it would be very likely, prior to knowing what happens with fracing and things like that, that a person could -- could walk off of them. In other words, it could be interpreted that I don't feel that we should attempt a completion, that the risk is too high to run pipe and try to frac it, and things like that.

We have -- Consolidated has gone the approach that we cannot evaluate very well from DST's and to some degree even from logs, and we have drilled wells, set pipe, and attempted completions because we have not been able to come to a good judgment on should we or should we not run pipe and complete it based upon what we've seen on logs and through DST's.

Q. Well, let me ask my question this way, also. When you say a gas rate was too small to measure, is that before or after stimulation?

A. This is after the acid stimulation, in which we made sure that there was no formation damage, and should give us an in situ type of flow rate. This was the -- this was before a frac job, a fracture stimulation.

Q. After you stimulated the wells, then they

became producers?

A. That is correct.

MR. PADILLA: I have no further questions.

MR. NUTTER: Does anyone have any further questions of Mr. Ellison? He may be excused.

Do you have anything further, Ms. Teschendorf?

MS. TESCHENDORF: I don't believe so.

MR. NUTTER: Ms. Teschendorf, I understand the FERC wants three copies of exhibits. Would you furnish us with three original sets of these exhibits?

MS. TESCHENDORF: We certainly can.

MR. NUTTER: With a postage paid envelope to send them in?

MS. TESCHENDORF: We certainly will.

MR. NUTTER: And also I would imagine unless you've already furnished copies of these exhibits to the USGS, you should furnish them a set.

MS. TESCHENDORF: We've got the extra copies of the other exhibits we can give you. We'll have to get extra copies of the maps made.

MR. NUTTER: Do you have anything further, Ms. Teschendorf?

MS. TESCHENDORF: No, sir.

MR. NUTTER: Does anyone have anything they wish to offer in Case Number 7116?

We'll take the case under advisement and the hearing is adjourned.

(Hearing concluded.)

C E R T I F I C A T E

I, SALLY W. BOYD, C.S.R., DO HEREBY CERTIFY that the foregoing Transcript of Hearing before the Oil Conservation Division was reported by me; that the said transcript is a full, true, and correct record of the hearing, prepared by me to the best of my ability.

Sally W. Boyd C.S.R.

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. 7116, heard by me on 12/30 19 80.

_____, Examiner
Oil Conservation Division

SALLY W. BOYD, C.S.R.
Rt. 1 Box 193-B
Santa Fe, New Mexico 87501
Phone (505) 455-7409

STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION DIVISION
STATE LAND OFFICE BLDG.
SANTA FE, NEW MEXICO
30 December 1980

EXAMINER HEARING

IN THE MATTER OF:

Application of Southland Royalty Company for designation of a tight formation, San Juan County, New Mexico.

CASE 7116

BEFORE: Daniel S. Nutter

TRANSCRIPT OF HEARING

A P P E A R A N C E S

For the Oil Conservation Division: Ernest L. Padilla, Esq.
Legal Counsel to the Division
State Land Office Bldg.
Santa Fe, New Mexico 87501

For the Applicant: William F. Carr, Esq.
CAMPBELL & BLACK P. A.
Jefferson Place
Santa Fe, New Mexico 87501

A P P E A R A N C E S

For Consolidated Oil & Gas: Lynn Teschendorf, Esq.
CONSOLIDATED OIL AND GAS
Denver, Colorado

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MR. NUTTER: We'll call next Case Number 7116.

MR. PADILLA: Application of Southland Royalty Company for a designation of a tight formation, San Juan County, New Mexico.

MR. CARR: May it please the Examiner, my name is William F. Carr, with the law firm Campbell and Black, P. A., Santa Fe, New Mexico, appearing on behalf of Southland Royalty Company.

I have one witness who needs to be sworn.

(Witness sworn.)

MR. NUTTER: Okay, we'll call for appearances in Case Number 7116.

MS. TESCHENDORF: Lynn Teschendorf, appearing on behalf of Consolidated Oil and Gas.

I'll have one witness, also, who needs to be sworn.

(Witness sworn.)

MARLIN R. THOMPSON

being called as a witness and being duly sworn upon his oath, testified as follows, to-wit:

DIRECT EXAMINATION

BY MR. CARR:

Q. Will you state your name and place of residence?

A. My name is Marlin Thompson. I live at 905 Rocky Canyon in Arlington, Texas.

Q. Mr. Thompson, by whom are you employed?

A. Southland Royalty Company.

Q. And in what capacity?

A. As a reservoir engineer.

Q. Would you please summarize for the Examiner your educational background and your work experience?

A. Graduated from the University of Texas in 1963 with a Bachelor of Science in petroleum engineering.

Worked 11-1/2 years with Texaco, 5-1/2 as a production engineer and 6 as a reservoir engineer.

Worked one year for Capitol Resources as a production engineer.

Worked two years for Hunt Oil Company as a reservoir engineer, and the last 2-1/2 years with South-

land Royalty Company as a reservoir engineer, working primarily in the San Juan Basin.

Q. Have you previously testified as an expert witness in reservoir engineering before this Commission?

A. Yes, I have.

Q. And have you previously testified before the Texas Railroad Commission in this capacity?

A. Yes, I have.

Q. Are you familiar with the application of Southland Royalty Company in this case?

A. Yes, I am.

Q. And are you familiar with the acreage which is the subject matter of this case?

A. Yes, I am.

MR. CARR: Mr. Nutter, are the witness' qualifications as an -- acceptable as a reservoir engineer?

MR. NUTTER: Yes, they are.

Q. Mr. Thompson, will you briefly state what Southland Royalty Company seeks with this application?

A. Southland Royalty Company is seeking approval to have a portion of the Basin Dakota Field approved as tight formation, according to Section 107 of the Natural Gas Policy Act.

Q. Have you prepared certain exhibits for

introduction in this case?

A. Yes, I have.

Q. Have these exhibits previously been submitted to the Oil Conservation Division and the USGS with a statement of the meaning and purpose of the exhibits, as is required by the Oil Conservation Division rules governing applications for designation of tight formations?

A. Yes, I have.

Q. Will you please refer to what has been marked for identification as Applicant's Exhibit Number One, and explain to Mr. Nutter what it is and what it shows?

A. Okay. Exhibit Number One is a completion and production map. This shows all the Dakota completions in the area of this application. It shows the 1979 annual oil and gas production; these are the upper figures, gas first and then oil second. It also shows the cumulative gas and oil production up through 1979 for each of the wells in the area of this application.

It shows we have five wells, test -- we call test wells for which permeability and rate data are submitted. It shows those five wells. It shows the area that we propose to --

MR. NUTTER: How are those wells identified, those five wells you're talking about?

A. Those five wells are identified with a circle.

MR. NUTTER: Okay, there are three of them on the northwest -- or on the north/south cross section and then there are two on the east leg of the east/west cross section, is that it?

A. I can read the locations. One in Section 24 of 32,12.

MR. NUTTER: Okay.

A. Okay, there's one in Section 2 of 31, 12.

MR. NUTTER: Okay.

A. One in Section 14 of 31, 12.

MR. NUTTER: Okay.

A. One in Section 18 of 31, 11.

MR. NUTTER: Okay.

A. And one in Section 30 of 31, 10.

MR. NUTTER: Okay.

A. Okay, this exhibit One also shows the area that we propose to designate as tight formation. We would like to make one exception, though. We learned since we made this exhibit that there are two sections, Section 30 and 31 of 32, 13, that are actually in the Ute Dome-Dakota Field.

MR. NUTTER: What are the section numbers

A. Sections 30 and 31 of 32, 13. These are on the west side of the map up to the northwest.

MR. NUTTER: Okay.

A. We'd like to exclude those two sections.

MR. NUTTER: Section 30 is the section on Exhibit One that has two wells shown on it.

A. That's correct.

MR. NUTTER: And Section 31 is the well -- is the section immediately south of that.

A. That is correct. There is a well, a real recent well that has been drilled there in the northwest quarter.

MR. NUTTER: And those two sections you are requesting will be deleted from the application.

A. Yes, sir.

MR. NUTTER: We will delete Sections 30 and 31 from the application and testimony here today won't relate to that area.

A. Okay. This map also shows, it shows two wells, and these are identified by a triangle, it shows two wells that were completed in the Dakota formation but didn't ever produce, and one of these is located in Section 30 of 31 North, 10 West. The other is located in Section 32 of 32 North, 12 West. These are two wells that were completed and

never produced.

There are five dry holes indicated by a square that are located throughout the area. This exhibit also shows the location of those five wells. We'll have comments about those later.

MR. NUTTER: Mr. Thompson, now the second well that you mentioned as not having produced, as indicated by a triangle, you said was in Section 32?

A. Section 32 of 32 North, 12 West.

MR. NUTTER: I don't believe that's 32, is it?

A. Yes, sir.

MR. NUTTER: Is that that well, the second well from the right on the east/west cross section?

A. Okay, one of the wells -- one of the wells in Section 30 of 31, 10. The other one I referred to is up in Section 32 of 32, 12.

There is another well with a triangle.

MR. NUTTER: Okay.

A. There is another well with a triangle. It's in Section 15 of 31, 11. That's probably the one you're looking at. This well also falls in that category, so there are really three wells instead of two.

MR. NUTTER: Okay, there are three wells

A. Right, that's --

MR. NUTTER: I was looking at the wrong one.

A. Right, there was three instead of two.

MR. NUTTER: Okay.

A. There's a correction on that.

MR. NUTTER: Okay.

A. This exhibit also shows the location of two cross sections, A-A' and B-B', which we'll show as exhibits later.

Q. Mr. Thompson, will you now refer to what's been marked as Southland Royalty Company Exhibit Number Two and explain to Mr. Nutter what this shows?

A. Exhibit Number Two is a type log. This well is located, referring to Exhibit One, this well is located in Section 32 of 32, 12.

This log shows, it shows the log characteristics of the various sands in the Dakota formation, and also the depth of the Dakota formation.

Q. What are the main producing intervals in the Dakota?

A. The main producing zones are the Greness and the First Dakota Sand, the Upper Dakota Sand.

Q. Are there other producing zones in the

Basin Dakota Field?

A. Yes, there is. Some of the lower Dakota sands and the Morris do produce in some areas of the field.

Q. And, Mr. Thompson, what is the average depth from the surface to the top of the Dakota formation in the subject area?

A. 7050 feet.

Q. I now direct your attention to Southland Royalty Company's Exhibit Number Three, which is the north/south cross section and ask that you explain to Mr. Nutter what this shows.

A. Exhibit Three, it shows the continuity of the Dakota sands across the area of this application; also shows the thicknesses of the sands.

Q. In your opinion does the Dakota underlie the entire area governed by the application?

A. Yes, it does.

Q. And in your opinion is the formation productive throughout this area?

A. Yes, it is productive. It is not commerically productive at current prices, but I would -- I think it is productive throughout the area.

Q. Will you now refer to Applicant's Exhibit Number Four and explain to Mr. Nutter what this shows?

A. Okay, Exhibit Number Four is a cross section in the northwest/southeast direction, and it shows the same thing Exhibit Number Three does. It shows the continuity of the sand across the area.

Q. Mr. Thompson, what is the average in situ permeability for the Dakota formation in the recommended area?

A. It's less than 0.1 millidarcy.

Q. And what methods have you employed in making this determination?

A. We've actually used three different methods. We used a pressure build-up analysis on one well. We used the Darcy flow equation on two wells, and used core analysis on two wells.

Q. Will you now refer to Exhibit Number Five and review this for the Examiner?

A. Okay. Exhibit Number Five is a formation test service report. This represents the results of a pressure build-up test using drill stem test tools in a well, East No. 7-E that's located in Section 14 of Township 31 North, Range 12 West.

Permeabilities, as can be seen in this report, permeability from this pressure build-up data is 0.0011 millidarcies.

MR. NUTTER: Is that the well on Exhibit

One, Mr. Thompson?

A. Yes, sir.

MR. NUTTER: That's indicated with a circle and then in the legend shown to be a test well?

A. Yes, sir, that's the well located in Section 14 of 31, 12, on Exhibit Number One, identified with a circle.

MR. NUTTER: Okay, so that well, then, is the well that's on Exhibit Five.

A. Yes, sir.

MR. NUTTER: Thank you.

Q. And this well was tested prior to stimulation, is that correct?

A. Yes, it was. We perforated the well, we flowed it till it stabilized, we shut it in for a build-up, and then took the build-up data and calculated the permeability.

Q. Will you now refer to Applicant's Exhibits Six and Seven and review these for Mr. Nutter?

A. Exhibits Six and Seven are calculations using the Darcy flow equation to calculate the permeability for these two wells, and these two wells are Patterson "B" Com No. 1-E. It's located in Section 2 -- located in Section 2 of Township 31 North, Range 12 West.

The other is the Pearce No. 2 located in Section 30 of Township 32 North, Range 10 West.

Exhibit Six, what we did, we flowed -- we flowed Patterson "B" Com No. 1 until it stabilized prior to stimulation, produced at a rate of 224,000 cubic feet. We then took -- we shut the well in until it built up and got the built up pressure, the shut-in build-up pressure. We took other known reservoir and geological data, engineering and geological data, and we calculated the permeability from the Darcy flow equation, and this permeability calculated to be 0.0877 millidarcies. That's for Patterson "B" Com 1-E.

In a similar manner on Pearce No. 2 we calculated a permeability of 0.0609 millidarcies.

Q. Will you now refer to Exhibits Eight and Nine and explain these to Mr. Nutter?

A. Exhibit Eight is a paper entitled Effect of Overburden Pressure and Water Saturation on Gas Permeability of Tight Sandstone Cores. This paper presents a method of converting laboratory permeability, which you obtain through core analysis, to in situ or reservoir permeability.

Exhibit Number Nine is -- is simply an explanation of how the method was applied to the permeability, in situ permeability.

Q. Will you now refer to Exhibits Ten and

Eleven and review these for Mr. Nutter?

A. Okay. Exhibits Ten and Eleven are core analysis reports on two wells. The first one is Case No. 8, which is located in Section 18 of Township 31 North, Range 11 West, and Weir No. 8, which is located in Section 24 of Township 32 North, Range 12 West.

MR. NUTTER: Now let's see, don't get away from me, I want to see where they are.

A. Okay. Going back to Exhibit Number One, Case No. 8 is the well that's located with a circle that's located in Section 18 of 31 North, 11 West.

MR. NUTTER: Okay, is that the section where there's a well with a circle and a square?

A. Yes, sir, that's the well.

MR. NUTTER: Also a well that's shown to be a new well.

A. Yes, sir.

MR. NUTTER: And the one we're talking about is the one with the circle and the square?

A. Yes, sir, that's correct.

MR. NUTTER: Okay, that's the well that is on Exhibit Ten.

A. Yes, sir.

MR. NUTTER: Is that correct?

A. That's correct.

MR. NUTTER: Okay, and the next well, then?

A. The other well is in Section 24 of 32 North, 12 West. It also has a circle and a square. It's in the southwest quarter, the only well in that section.

MR. NUTTER: It's in Section what?

A. Section 24 of 32 North, 12 West. It's in the cross section, too.

MR. NUTTER: Okay, and that's the well that's on Exhibit Eleven, is it?

A. Yes, sir, that's correct.

Each one of these exhibits, Exhibit Number Ten, the bulk of the exhibit is the actual core analysis. The first page of that exhibit is a summary of the core data from just the productive interval, taking the log and picking out the zones that would actually be productive and just using the core data from those zones, that's what's contained on the first page of Exhibit Ten. And what we've done is calculated the average permeability for those 37 samples and determined what the average laboratory permeability is. Then we've taken the paper, Exhibit Eight, and determined the in situ permeability. The average laboratory calculation would be 0.1195 millidarcies. When we use the paper, the data from

the paper, to convert it to in situ permeability, it turns out to be 0.0335 millidarcies.

MR. NUTTER: Okay, for the record, Mr. Thompson, would you explain very briefly why the in situ permeability is a fraction of what the laboratory permeability would be?

A. Okay. Laboratory permeability is run at low pressures, 100 pounds or less, and in the reservoir, this Dakota reservoir, the pressure is about 2650 pounds. So this overburden, that's the reservoir pressure, but this depth of 7000 feet, you have an overburden pressure that would approach probably 0.8 psi per foot of depth.

Anyway, the overburden pressure would be substantially higher than 100 pounds.

MR. NUTTER: So in other words, what this amounts to is that when the core is removed from the reservoir, the pressure on the core is decreased, the core, in effect, expands, and the permeability increases?

A. That is correct.

MR. NUTTER: Okay.

A. On Exhibit Number Eleven, refer to it, referring to the first page of Exhibit Eleven, again this is a summary of the cores from the producing interval only, 39 samples, the average laboratory permeability is 0.0538 milli-

darcies, while the average in situ permeability, using the data from Exhibit Eight, is 0.0151 millidarcies. This is Exhibit Number Eleven.

Q. Mr. Thompson, are the methods that you've employed in determining in situ permeability generally accepted by the oil and gas industry?

A. Yes, they are.

Q. Were stabilized production rates taken on any of the test wells?

A. Yes, they were taken on three wells. East No. 7-E, Patterson "B" Com No. 1-E, and Pierce No. 2.

Q. Now were these taken before or after stimulation?

A. The ones on East 7-E and Patterson "B" Com 1-E were taken before stimulation. Pierce No. 2 was taken after stimulation.

Q. And what were the rates obtained?

A. The rates calculated to atmospheric conditions for East No. 7-E, the rate was 21.7 Mcf per day.

For Patterson "B" Com No. 1-E, 224.1 Mcf per day.

The Pierce No. 2, 208.1 Mcf per day.

Q. What is the maximum gas production rate permitted for this depth interval under tight formation guide-

lines?

A. 290 Mcf per day.

Q. And that's from the depth interval 7000 feet to 7500 feet?

A. That's correct.

Q. Will you now refer to Applicant's Exhibit Number Twelve and review this for Mr. Nutter?

A. Okay, Exhibit Number 12 is just a summary sheet, showing the five test wells, showing the permeability, gas production and crude production, for these five wells. It also shows the methods used to obtain the permeability.

Q. It shows that each of the test wells fall within the general guidelines as to production rates?

A. That is correct.

Q. How much crude oil did the test wells produce?

A. Actually they produced a very small amount. It was too small to measure.

Q. Are any other liquids produced by these wells?

A. No, it is not.

Q. Do any of the offsetting wells produce crude oil?

A. Yes, they do.

Q. Are any wells in the subject area producing 5 barrels of crude oil per day or more?

A. No, they're not.

Q. Do you anticipate that any wells in the subject area would produce more than 5 barrels of crude oil per day?

A. No, sir.

Q. Are there fresh water-bearing formations in the immediate area?

A. Yes, there are. There's really three potentially fresh bearing --- fresh water bearing formations throughout the area. These include the San Jose, the Nacimento, and the Ojo Alamo.

Q. At what depths are these formations encountered?

A. They vary throughout the area but the average is from the surface of the ground to 1200 feet.

Q. Are you familiar with the Oil Conservation Division and Federal regulations for the protection of fresh water?

A. Yes, I am.

Q. Are the current casing and cementing requirements sufficient to protect fresh water aquifers in the

area which is the subject of this application?

A. Yes, they are.

Q. In completing Dakota wells in the area, do you employ large fracture treatments?

A. Yes, sir, we do.

Q. Would any currently contemplated completion techniques affect fresh water zones in the area?

A. No, sir, it would not. There's approximately 5800 feet difference in depth from the base of the fresh water to the top of the Dakota. This -- this distance, plus the other cementing of the casing would insure that the fresh water is protected.

MR. NUTTER: Mr. Thompson, you mentioned the interval that the fresh water is produced in. Would you give us the depths of those three formations, please, the approximate depths?

A. I don't -- I don't have them. I can furnish those at a later date. I don't have those available right now.

MR. NUTTER: I think it would be interesting to have that notation in the record if you could furnish it. You said, though, that the overall interval was from what to what?

A. From the surface of the ground to 1200

feet.

MR. NUTTER: The surface to 1200.

A. We picked a point about in the middle of the section. It does vary quite a bit from east to west.

MR. NUTTER: All right.

Q. Generally speaking, Mr. Thompson, when the water zones are encountered at a lower interval, is the Dakota producing interval also encountered at a lower depth?

A. Yes, it would be also at a lower level by about the same amount.

Q. In your opinion will current regulations insure that the development of the portion of the Dakota formation which is the subject of this application not adversely affect or impair any fresh water aquifers used for domestic or agricultural use during either hydraulic fracturing or waste disposal operations?

A. Yes, it will.

Q. Now I'd like you to refer to Exhibits Thirteen through Seventeen and review for the Examiner the data contained therein concering reserves and the general economics of developing this area.

A. Okay. Exhibit Thirteen is a tabulation showing the cumulative production and the ultimate recovery, ultimate reserves for the 31 wells that are producing or

have produced in the area of this application.

As can be seen, the average ultimate reserves for each of these wells is 313 -- 313,614 Mcf.

Referring to Exhibit Fourteen, there are -- all of the average are -- referring back to Thirteen, the average recovery is 313,614 Mcf. There are fifteen of those wells that expect to recover less than 200 Mcf per day, or a total of 200,000 Mcf ultimate recovery.

Exhibit Number Fourteen is an economic calculation showing the minimum amount of reserves necessary to provide economics for drilling a Dakota Well.

And Exhibit Fourteen shows that at current 103 prices, 350,000 Mcf of gas are necessary to provide minimum economics, and minimum economics in our company standard is a 15 percent rate of return.

I also believe this is --

MR. NUTTER: Okay, where do we find -- where do we find that, Mr. Thompson, on this Exhibit Fourteen?

A. Okay, if you go down --

MR. NUTTER: Where do we find, first of all, the -- you stated that that was the basis -- that that was calculated on the basis of your current economics and current prices.

A. Yes, sir.

MR. NUTTER: Okay, where is the current price noted in here?

A. Okay, turn to the second page, is probably the best place to look.

MR. NUTTER: That first one just is a summary sheet, right?

A. Yes, sir, that's the input data.

Looking at the second column from the left, where it says MMCF per year, gross production, MMCF per year, down at the bottom there's a total of 350.

MR. NUTTER: Okay.

A. Okay, that -- that is the ultimate reserves. That's the reserve figure for that well, gas reserve figure.

MR. NUTTER: You're figuring a new well to be drilled in 1981 and would be depleted in 1995, is that it?

A. No, sir. This program shows the first fifteen years of production and you see a sub-total and then the after section there.

MR. NUTTER: Okay.

A. See, actually if you'd refer to lower middle, we show a production life of 36.9 years, so that's the projected life of this well.

MR. NUTTER: So it makes 237 in its first fifteen years and then an additional 113 in the remainder of the life --

A. That's correct.

MR. NUTTER: --- for a total reserve, then, of 350.

A. That's correct.

MR. NUTTER: Okay.

A. The price is lower left, you see the oil and gas prices, and we used a gas price of $3.11. This is adjusted for BTU and pressure base.

MR. NUTTER: Okay.

A. And it would be the price that we'd expect to receive when we start production in 10-1-81.

MR. NUTTER: Okay.

A. On the next page, the third page, it shows the rate of return and the payout. That's the middle of the page; the rate of return is item five, and it shows that these -- this was --- these reserves of 350,000 Mcf will provide a rate of return of 15.5 percent.

MR. NUTTER: Okay.

A. Also shows a payout of 5, slightly over 5 years.

Referring to Exhibit Fifteen, Exhibit

Fifteen is a similar calculation. In this case we've assumed 200 percent of 103 prices.

MR. NUTTER: Or $6.22.

A. Right, and we've determined what reserves are necessary to justify a well under these conditions. Again looking at page two, you can see that only 150,000 Mcf of gas reserves are required to justify a well at these higher prices. Again you can see the life of a well is 19.3 years and initial price of $6.22.

MR. NUTTER: So Exhibit -- Exhibit Fifteen doesn't change the time of payout or the rate of return on the same quantity of gas that Exhibit Fourteen did. It cuts the amount of reserves available and recalculates the rate of return and the time of payout. For 150,000 Mcf, rather than the other one was based on 350,000.

A. The purpose of these two calculations was to determine what the minimum amount of gas reserves were to --

MR. NUTTER: I see.

A. -- provide minimum economics, and this -- it's a trial and error solution. We made several calculations until we arrived at this one that gave us this 150. We were looking for the lowest number that would still justify drilling the well.

MR. NUTTER: Now, the average reserves in the area, according to Exhibit Thirteen, are 313,000 Mcf.

A. That is correct.

MR. NUTTER: Did you make the calculation based on an average well?

A. No, sir.

MR. NUTTER: Or 313,000 Mcf?

A. No, sir, I did not. It takes 350 to justify a well at 103 prices, so the 350 --

MR. NUTTER: Yeah, but if you want a 15 percent payout and a payout in five years.

A. That's correct.

MR. NUTTER: Yeah.

A. Which we consider a bottom line.

MR. NUTTER: I see.

A. So we're saying that the average well won't justify it at 103 prices. Also, if you'll look at -- if you go back to Exhibit Thirteen, it shows those -- that the average -- the cumulative production, a lot of these wells that had pretty high cums are real close in to some good production. The farther you get out into this area that we're applying for, the poorer the wells get.

MR. NUTTER: Well, you've got one well in here that I imagine raised the average reserves consider-

ably. You've got one well there that made almost five times the average reserves.

A. That is correct, and of course, that kind of hurts your average, but again, these are close in and the reservoir conditions deteriorate as you go out away from that good production.

MR. NUTTER: Where is that well, by the way? 33 of 32, 12, I guess.

A. It's a fairly new well without much cum, but that's what we think it will ultimately make.

MR. NUTTER: Is that the well that shows 7591?

A. Yes, sir.

MR. NUTTER: Uh-huh. So it hasn't made that amount of gas --

A. Oh, no, no.

MR. NUTTER: -- it's just what you're expecting.

A. That's what we think it will make ultimately, and that's what we're talking about, is ultimate recovery.

MR. NUTTER: Uh-huh.

A. There's some estimating going on. There is some projection going on, you know, in getting that ulti-

mate.

Exhibit Thirteen shows the cum and then what we think the remaining is, and the last column on the right is the ultimate, which is the sum of the cumulative and remaining.

MR. NUTTER: Right.

Q Will you now review Exhibit Number Seventeen for Mr. Nutter?

MR. NUTTER: We didn't do Sixteen, did we, Bill?

A I don't believe we did.

Q Okay, then I suggest you review Exhibit Number Sixteen.

A Exhibit Sixteen is simply a tabulation showing the assumptions that were made in this economic calculation, and they are the assumptions that we make in our routine economic calculations that our company makes. We did escalate gas prices; we escalated operating costs; we used a deregulation tax, a severance tax; all the things necessary to calculate economics.

Q Now will you go to Exhibit Number Seventeen?

A Exhibit Number Seventeen is just a typical Authority for Expenditure that shows the typical costs,

typical current cost for drilling and completing and stimulating a Dakota well at the average depth of 7050 feet. This value as of the present is -- we believe, is $378,560. This is what it's costing us today to drill DAkota wells in this area.

Q. How, Mr. Thompson, what conclusions can you draw from this economic data?

A. That more wells can be drilled in this area. We're talking about the area of this application, but we do need some incentive pricing to -- to justify this drilling because of the high cost.

Q. Has infill drilling been authorized for the Basin Dakota Field?

A. Yes, it has.

Q. Approximately how many acres are included within this field?

A. Approximately 800,000.

Q. In your opinion would infill wells be economical in this portion of the Basin Dakota Field?

A. Not at current prices. It would be at-- the area of this application? They would be at incentive prices. They wouldn't be at current prices.

Q. Is it your testimony that the economic calculations and the information which you have presented

concerning the costs of these wells, that that would apply equally to infill wells in the area as to the original well drilled on these proration units?

A. Yes.

Q. Now would you refer back to Exhibit Number One? I believe you indicated there were a number of dry holes --

A. Yes, sir.

Q. -- in the area, and also certain wells which never produced after initial potential.

A. Yes, I believe there actually are three wells that were completed but never did produce. Only two of them are in the area of the application; one of them is outside the area of the application, that we talked about earlier. That's the one in Section 15 of 31, 11. But there are two, one in Section 30 of 31, 10, and one in Section 32 of 32, 12, that were completed, stimulated and potentialed, but they never did produce commercially.

Q. What conclusions can you draw from this fact?

A. I think this indicates the very low permeability of the formation. I think that's why they didn't produce commercially.

In addition, there are five dry holes

throughout the area, indicated by the squares on Exhibit A. This is also an indication that the reservoir is very tight in this part of the field.

Q. Now I believe three of the test wells which you have testified to are not located within the proposed area, is that correct?

A. That is correct.

Q. How would you characterize the area in which they're located?

A. It's in a more prolific producing area than the area of this application.

Q. Would these wells technically meet the guidelines to qualify for 107 prices?

A. Yes, they would.

Q. Would you just briefly now summarize the conclusions -- your conclusions concerning the suitability of the proposed area for classification as a tight formation?

A. I think we've presented data to show that permeability throughout the area is less than 0.1 millidarcy; that stabilized producing rates are less than that prescribed; that oil production would be less than 5 barrels per day; that fresh water will be protected.

Q. In your opinion will the data presented at this hearing support these conclusions for the entire area

covered by this application?

A. Yes, they will.

Q. In your opinion is the 107 price necessary to provide a reasonable incentive for the development of the natural gas from the Dakota formation in this area?

A. Yes, it is.

Q. Were Exhibits One through Seventeen prepared by you or under your direction and supervision?

A. Yes, they were.

Q. Did you also prepare the geographical and geological description which was originally submitted to the Commission and USGS with these exhibits?

A. In conjunction with our geologist in Farmington.

MR. CARR: Mr. Nutter, we would request that that be marked as Southland Royalty Company's Exhibit Number Eighteen, so that it is part of the official record, and would ask at this time that Applicant's Exhibits One through Eighteen be admitted into the record.

MR. NUTTER: Now what is Exhibit Eighteen?

MR. CARR: Exhibit Eighteen would be the geographical and geological description that is --

MR. NUTTER: That's the other folder?

MR. CARR: Yes, sir, which is the summary

which we originally submitted with the exhibits.

MR. NUTTER: Okay, why don't you have this marked, then, as Exhibit Eighteen on the front cover preferably?

And you're offering these exhibits at this time?

MR. CARR: Yes, sir.

MR. NUTTER: Southland Exhibits One through Eighteen will be admitted in evidence.

Q. Mr. Thompson, in your opinion will granting this application be in the best interest of conservation, the prevention of waste, and the protection of correlative rights?

A. Yes, it will.

MR. CARR: Mr. Nutter, at this time we have nothing further of Mr. Thompson on direct. We would note that we had intended to submit an additional set of the exhibits to be transmitted to FERC, but we recently learned that they're now requesting three sets be submitted, and we will supply those in the next several days to you.

MR. NUTTER: Okay, is Mr. Thompson ready for cross examination now?

MR. CARR: He's ready.

CROSS EXAMINATION

BY MR. NUTTER:

Q. Mr. Thompson, now the wells that you depicted on Exhibit Number Thirteen are -- are they all in the area of interest?

A. Yes, sir.

Q. Or are they in the area down south of the area of interest, or the area of interest, let's define that.

A. The area of interest is outlined on Exhibit A by the heavy line, heavy dashed line.

Q. Okay, so it is the area that's over here to the far right of the exhibit and has a little piece of the cross section sticking into it with one well; then it comes across the north and has two wells on the cross section --

A. Yes, sir.

Q. -- the north/south cross section; and then it extends to the west and has two wells on a cross section east/west.

A. Yes, sir.

Q. And the 30 --- how many wells are on Exhibit Thirteen?

A. 31.

Q. 31. The 31 wells, then, are all included in that area?

A. Yes, sir, all within that area that we're proposing to designate.

Q. Now we have a whole lot of production data on wells to the south and west of the area. As a general rule, is the area that you're requesting to considered today, the area of interest, a better area than the area that you're not including in your application?

A. No, on the contrary, it's a poorer area.

Q. That's what I meant to say, I thought you'd say it was a poorer area.

And the area that you're requesting is a poorer area than the area to the south --

A. Yes, sir.

Q. -- where most of the wells are drilled.

A. And the production data we supply does indicate that.

Q. Well, now, we really don't have much data on the eastern half of the area of interest.

A. No, sir.

Q. How we can tell that the area up there is not as good or better than this area to the south down here?

A. It's true we have limited data; however, we do have -- we have a well in Section 24 of 32, 10, that's

only produced an ultimate of 29,000 Mcf, indicating the permeability would be very low up there.

We have two wells down in 31, 10, one's in Section 27 and one in Section 34. Now the one in 27 did produce enough to provide minimum economics; the one in 34 did not.

Of course, we have the well over in 30 that we referred to before in Section 30, that did not produce at all.

There is a well up in Section 26 of 32, 11, that only produced 261,000 Mcf, which is not, you know, doesn't meet minimum standards.

Q Now you've got two new wells up here, indicated as being new wells. Do you have any data on those?

A. No, sir, we do not. We'd have the initial completion, I'm sure, on them, but the initial potential can sometimes be used as an indicator, but it's not really -- not a real good indicator in this area. If you only look at the initial potential in some of our wells over here in Section 32 of Township 32, 13, you'd think they'd be good wells, but they just don't perform that well. They drop off. One of the characteristics of a tight formation is they come in at a pretty good rate, but they drop off very rapidly, and I believe those two wells up there will probably not -- I

don't think they'll be economical, myself.

Q. Those are the two northernmost wells there?

A. The two -- right.

Q. The two wells in 13 and 14?

A. What I'm referring to in 32, 10, in Sections --

Q. Well, I meant the wells that you said were pretty good wells on potential in 32, 13.

A. Okay, I was really referring to 33, 12.

Q. Oh.

A. Those in Sections 10 and 11 and 13 and 15, those areas, those wells have come in maybe at 2-million a day, but they just don't produce satisfactorily. You can see the cums of some of them, less than 100,000 Mcf. None of them, you know, made the necessary 350,000.

So initial potential alone is not a good criteria. I don't think any of this will be economical out here at 103 prices. Admittedly, we don't have a lot of data to substantiate that.

It's really difficult to go out there and develop data because of the risk of having uneconomical wells. You hate to go out there and drill a well and spend $300,000 plus just to develop some data, when there's a good chance

you won't get your money back.

With the incentive pricing there would be a lot more incentive or more justification for recommending wells to be drilled out in there.

That's the reason we used data, we tried to use data even though it wasn't in the proposed area, it's nearby, and we tried to show that these wells, that they meet the qualifications in a better area, and it follows, then, that the wells in the poorer area should also meet the qualifications.

Q. You didn't apply any economic tests to these wells in the better --- better area and show it on your exhibits?

A. No, sir, I did not. They would certainly be economical. If they could make more than 350,000 Mcf they would be economical and they make much more than that. They're good economics. Like, for example, in Township 32, 12, those are good wells.

Q. Pretty -- relatively high cumulative recoveries there.

A. Yes, sir, they are, and we would expect our infill wells to be, you know, to produce a lot of gas there, too; not as -- probably not quite as much as the original, but maybe approach what the originals make, and it's

not uncommon for a well to make 2-billion in that area.

MR. NUTTER: Are there any further questions of the witness?

MR. PADILLA: Mr. Examiner, I have a couple of questions, if I may.

CROSS EXAMINATION

BY MR. PADILLA:

Q. Mr. Thompson, would you explain to me what the relevance is of Exhibit Eight?

A. Exhibit Eight?

Q. Yes.

A. The purpose of Exhibit Eight is to -- is to present a method of converting laboratory permeability to in situ or reservoir permeability. The requirement, as I understand it, is less than 0.1 millidarcy in situ permeability. When you use core data, standard core analysis run in the laboratory is not in situ permeability. It's what we call laboratory permeability, and this is simply a method of converting that laboratory permeability to in situ permeability, which we felt was necessary because that was what was required.

Q. So the purpose of this is not to show that -- the purpose is informing us how you went through your

procedures for calculating permeability, is that correct? This does not apply to this formation but you used this data in compiling your --

A. That's correct. The data we used, actually we used figure one on page 121 of that paper, and we used -- we used the Core Number 3927 -- or 3928, which has permeability similar to what we have -- what we've seen in the Dakota here. This particular -- this data, particular data, came from the Pictured Cliffs formation in the San Juan Basin, about fifteen miles to the southeast. We believe that the Dakota and the Pictured Cliffs would be very similar, and we believe that if we ran this same data on the Dakota formation we'd have similar results.

But this, what figure one shows, that at a reservoir pressure, at least, of 2650 pounds, that the in situ permeability would be 28 percent of what the laboratory permeability is, and that's what the lines and the arrows indicate on that particular graph.

MR. NUTTER: This EXhibit Eight, Mr. Thompson, talks about the -- or it's a discussion of the effects of the overburden on the permeability in Gas Buggy and Wagon Wheel. Where was WAgon Wheel?

A. I'm not sure where it was. Wait just a second and I'll tell you. I did not use that data. I felt

like the Pictured Cliffs data in the San Juan Basin would be more appropriate.

Fort
~~Wint~~ Union formation in Pinedale Field, Sublett County, Wyoming. (sic)

MR. NUTTER: Okay.

So it's up in Wyoming. I know that Amoco has done some similar work in the Cotton Valley formation over in east Texas, and they came up with similar results.

Q. Mr. Thompson, on Exhibit Twelve you say at the bottom on the analysis, that the Dakota was not productive in a couple of formations. What does that -- what does that mean?

A. Okay, these were dry holes and just no production test was made. I don't believe they even set pipe on the wells. They just drilled through and logged it in those two cases and cored it; they didn't set pipe and make a test.

They simply used the core data for the permeability data, but we didn't have any, you know, any production there.

Q. So in other words, you went back to Exhibit Eight on those wells, is that --

A. Those are the two wells we used Exhibit

Eight to determine in situ permeability.

Q. Okay.

A. Using laboratory permeability from the core analysis.

Q. Now on Exhibit Sixteen, the cost for drilling each one of those wells, or the average cost, I guess, you would calculate those.

A. Yes, sir.

Q. What percentage of that would be attributable to stimulation procedures or stimulation processes that you would get from the wells?

A. I believe on the second page of Exhibit Seventeen we have that data; $27,500 for the acid frac treatment down near the bottom of the second page of Exhibit Seventeen. That would be just the stimulation itself, $27,500. There's a detail -- the second page of Exhibit Seventeen is a detail of costs.

Q. Would you explain what the actual procedures were for stimulating a well of this nature?

A. Actually, normally our procedure, of course, we'd perforate the well first, holes in the casing, of course, out through the cement. Then we normally inject a small acid job, using ball sealers to -- we drop ball sealers during the acid job to seal off. The first perforations to

take acid, we drop balls to seal them off and to force subsequent holes to take stimulation, until hopefully all the holes have taken some acid to break the formation down.

Then we follow this with usually a fairly large frac job. We spearhead this frac with water and then we follow that with -- we start putting sand in the water in increasing amounts. We start out with a very low concentration of sand, maybe a half a pound per gallon, and finally maybe get up to two or three pounds per gallon, pounds of sand per gallon. This is injected.

The purpose is to -- action to fracture the formation, to actually open up the formation. That's the purpose of the fluid. The purpose of the sand is to hold this fracture open once we have fractured it, the sand, it props the fracture open and allows the gas to flow to the wellbore through these fractures.

Q. Do you believe there's sufficient distance between the area that you're fracing and the fresh water aquifers to prevent any contamination of fresh water?

A. Yes, very definitely. It's approximately 5800 feet and I don't think there would ever be any problem of fracturing that far. In fact, I'm sure it wouldn't, it would not fracture that far. These fractures -- we've run a number of temperature surveys and different surveys, and these

fractures normally don't go above the Dakota formation over 100 feet.

Q. Now looking at Exhibit One, in relation to infill drilling, would you consider the area that is excluded from the application, in other words, the area that seems to have commercial wells, would that -- would you consider that to be an area substantially developed by -- within an infill area?

A. Yes, sir.

Q. And so for that reason you would -- you have excluded that area?

A. We've excluded it primarily because it's economic at current prices. It qualifies. It makes the criteria as far as permeability and rate and crude production but it doesn't meet the -- if you consider economics, it is economic at current prices, so that's why we've excluded it.

Q. Would you say that that's an area that's substantially developed, especially in your acreage, where you have three or four wells to a section?

A. Yes, sir.

Q. And there really aren't any infill area -- infill wells in the area that you have applied for?

A. There would be some, yes, sir. There would be some drilled, in particular in Township 32 North,

Range 12 West.

Q. But there aren't any --

A. No, there hasn't been any drilled yet, no, sir. There would be if this is approved but there haven't been yet, no, sir.

MR. PADILLA: I believe that's all I have at this time.

RECROSS EXAMINATION

BY MR. NUTTER:

Q. Now, Mr. Thompson, in your discussion on page 9 of conversion of the laboratory permeability to the in situ permeability, you're referring to Core Number 3928. Is Core Number 3928 the core that we've got here in Exhibit Five?

A. No, sir.

Q. Which core was 3928?

A. It's simply the core that the -- the authors of that paper used --

Q. Oh.

A. -- to make that analysis. There's no connection between it and Exhibit Five.

Q. Okay, so -- all right, I thought that was your discussion of what you had determined on your --

A. No, sir.

Q. -- in situ permeability.

A. It's simply -- I had to pick one of those -- I picked one of those curves to interpret my in situ permeability, and that 3928 turned out to be more like our -- the permeability of our cores, or our -- from our calculations of permeability of our formation.

Q. Okay.

A. Formation in this area.

Q. Okay, now their lab tests and their calculations ran from zero or 100 pounds, I guess it was, up to 6000 pounds.

A. Yes, sir.

Q. What was your pressure that you used on your calculations?

A. 2650. It's indicated there on Figure 1 of the paper.

Q. Okay. Now, is this your -- is this your drawing here on this?

A. Yes, sir, the line with the arrows, that, I put that on there, right.

Q. Okay, that's not part of the paper, then.

A. No, sir, it is not.

Q. So you used an assumed rock pressure here

of 2650.

A. That's correct.

Q. And hit this curve and came over here to your 28 percent. Then you applied the 28 percent to your laboratory permeability, is that it?

A. That's correct.

Q. Okay.

MR. NUTTER: Are there any other questions of Mr. Thompson? Yes, please.

MS. UMSHLER: USGS with two questions for you.

CROSS EXAMINATION

BY MS. UMSHLER:

Q. First of all, do you have a percentage of breakdown on the ownership of land in the area?

A. No, no, sir, I do not. Our acreage is indicated by the shading, and other than that I don't know.

Q. But you don't have a State or Federal breakdown?

A. No, sir.

Q. And one other question, on Exhibit Thirteen, you show the royalty interest rate of 13-1/2 percent?

A. Yes, sir.

Q. How did you arrive at that percent?

A. That's an average. Some of it's 12-1/2 percent; some of it's quite a bit more than that. This is purely a typical average.

Q. Okay, thank you.

MR. NUTTER: Does that royalty interest include overriding royalties?

A. Yes, sir, total, total royalty. One percent of that probably is an override.

CROSS EXAMINATION

BY MR. BUCKINGHAM:

Q. Allen Buckingham, I also have a question.

MR. NUTTER: Are you also with the GS?

MR. BUCKINGHAM: Yes, sir.

Q. I have a question, Mr. Thompson. You mention, I believe, that there was no infill wells in your area that you are requesting tight formation?

A. Yes, sir.

Q. Reading from, and if you'll look at Exhibit Eighteen where you're talking about geographical and geological description, number three where you're talking about Township 32 North, Range 12 West, --

A. Okay.

Q. . -- in Section 26, there's an infill well No. 2-E;in Section 27 there an infill well No. 1 E. Do you have any information --

A. No, sir, I don't. And they've been proposed since I prepared this exhibit.

Q. Although I believe it really is not that material because of the information that you have submitted as far as economic information, that it's not economical for a 103 price, I just wondered if you had any information on any other infill wells?

A. No, sir, I do not. I don't have any knowledge of any being drilled. Perhaps some have been proposed recently.

Q. Okay, thank you.

MR. NUTTER: Are there any further questions? Mr. Chavez.

CROSS EXAMINATION

BY MR. CHAVEZ:

Q. Mr. Thompson, by definition the Basin Dakota Pool contains more than just the Dakota formation.

A. Yes, sir.

Q. It contains the Graneros and also the Morrison, a portion of the Morrison.

A. Yes, sir.

Q. On your exhibit which -- is it Thirteen, which lists the producing wells, do you know which ones of those are committed -- completed in -- let's see, Thirteen, are completed in just the Dakota producing interval, or if those are completed in --

A. I'd say all of them are. I'd have to check to be sure, but I'd say they're all completed in either the Graneros or the first Dakota, or both. Usually we complete in the both the Graneros or the first Dakota. I don't think any would be in the lower Dakota or the -- or the Morrison. I'd have to check that to be 100 percent, but that's what I believe to be correct.

Q. What were the average shut-in times for the build-up tests that you showed on your first exhibit there.

A. That's Exhibit Five. We shut -- the well was shut in for 8 hours.

Q. I'm sorry?

A. For 8 hours. Exhibit Number Five.

Q. Okay, how about Exhibit Six? Exhibit Six and I think Seven, also, has a pressure test. What was the average shut-in time for those?

A. I don't have that. That would be an extremely long one. What we did on these is, we -- after the

wells were completed and were shut-in, it would be an extremely long -- I don't have a figure, I could get it, but it would be a matter of days on those two, because this shut-in pressure was taken after the wells were completed and shut-in awaiting pipeline, so those were extremely long shut-in times.

The Exhibit Five was on drill stem test and that was only 8 hours.

Q. What was the radius -- I don't see a calculated radius of investigation for the Exhibits Six and Seven. Did you --

A. No, we assumed that the drainage would be the spacing, which is --

Q. No, the investigation of the test?

A. Okay, we did not calculate that, no, and did not use that. We used the radius of drainage of 160 acres.

Q. Was the stimulation on the wells which are listed in Exhibit Thirteen pretty standard for each of those wells, or were there some major differences?

A. I would say they're probably standard. Most of these are older wells. I really don't -- I didn't really investigate that, but I think most of them are pretty standard.

Q. Well, the older wells have used, perhaps,

in general not as large a stimulation as the new wells?

A. They could be somewhat smaller, although I don't, in the ones I have looked at I don't see that much difference, but I'm sure there are some differences.

There's a lot of difference in opinion on -- on just, you know, how valuable the greater -- the larger stimulations are. We as a company don't do large stimulations. Some companies do. There is a question in our mind as to whether or not the larger ones are justified.

So we're stimulating very similar to what we were back in the days when we drilled these wells.

Perhaps some of the other companies are using larger stimulations.

Q. Okay, are the production rates of the newer wells that you've completed pretty much different from the wells that you drilled originally, or say some of the first wells you drilled in this area?

A. They're pretty close to the same. Some of them are somewhat lower at first. Some of them come in -- start a little bit lower and improve; probably some little bit of damage from the stimulation. Most of them come in -- after they stabilize, most of them will stabilize at 300 or 400 Mcf per day -- MMCF per day, 3 or 400 Mcf per day, in the good areas. Of course we haven't drilled any in this poor

area that we're talking about.

MR. NUTTER: Are there any other questions of the witness? He may be excused.

Do you have anything more, Mr. Carr?

MR. CARR: Nothing further, Mr. Nutter.

MR. NUTTER: We'll take a fifteen minute recess.

(Thereupon a recess was taken.)

MR. NUTTER: Ms. Teschendorf, I believe you wanted to put some testimony on?

MS. TESCHENDORF: Yes, sir. My name is Lynn Teschendorf. I'm appearing here on behalf of Consolidated Oil and Gas.

Consolidated has some data that we would like to offer in support of Southland's application in this case, and we would also like to ask the Examiner, Consolidated is mainly interested in Townships 31, 13, and 31, 12, which were covered by the advertisement but are not covered, apparently, by Southland's application, as we did not learn until yesterday evening.

We also found out fairly recently, so

we are not as well prepared as we would like to be, so I'll go ahead and present what we've got and make a motion at that time.

MR. NUTTER: Okay.

MS. TESCHENDORF: I have one witness who has been sworn.

FLOYD E. ELLISON, JR.

being called as a witness and being duly sworn upon his oath, testified as follows, to-wit:

DIRECT EXAMINATION

BY MS. TESCHENDORF:

Q. Would you please state your name, occupation, and by whom you're employed?

A. Floyd E. Ellison, Jr.. I'm Vice President of Consolidated Oil and Gas, and my background is petroleum engineering, having a petroleum engineering degree from the University of Wyoming in 1957.

Q. Have you previously testified before the Division or one of its examiners?

A. Yes, I have.

Q. And are you familiar with the facts concerning this particular case?

A. Yes, I am.

MS. TESCHENDORF: Is the witness considered qualified?

MR. NUTTER: Yes, he is.

Q. Mr. Ellison, would you refer to Exhibit One and explain what that shows, basically?

A. Exhibit One is a map showing Consolidated Oil and Gas's acreage, and the only thing that is really updated regarding placement of wells is that on Consolidated's acreage itself, and the cumulative curves -- or the cumulative's shown here have not been updated since 1971, so they should not be confused with those of the previous map on the application earlier submitted.

Q. But the current status of Consolidated's wells is correct as far as where they are and what formations they're completed in, is thatcorrect?

A. Yes, I believe so.

Q. Okay. What acreage is Consolidated mainly interested in in this area?

A. Consolidated's acreage is primarily in 13, 31, with a little bit in 12 of 31, and also we do have just a little bit of acreage in the area of application, which is in 13, 32.

Q. Has Consolidated been involved in an

infill drilling program on this acreage?

A. Yes, we have. We have been fairly active in the last couple of years infilling, and especially in the Dakota this last year.

Q. We have three wells we would like to present data on. Would you please name those wells and give their locations?

A. The first one is that under Exhibit Number Two, the Wilmerding 1-M.

Q. Why don't you just spot them on Exhibit One for the Examiner and then we'll go on to the other exhibits?

A. Okay, it's the northeast quarter of the northwest quarter of Section 10 of 31, 13.

Q. Okay, and where is the second well?

A. The second well is that shown on Exhibit Number Three, which is the Kline 1-M, and it's in the southeast quarter of Section 10, 31, 13.

The third well is the Senter 1-M, and it's in the southeast quarter of Section 24, 31, 13.

Q. And these wells are outside the area that has been outlined by Southland Royalty, is that correct?

A. That is correct.

Q. But they are very close to their acreage.

A. Yes, I think it has a significant bearing on the type of formation that we're dealing with in the area.

Q. Would you refer now to Exhibit Number Two, which is the data sheet on the Wilmerding 1-M, and describe that exhibit?

A. Okay. Our Wilmerding 1-M, this well was completed out of both the lower and the upper Dakota. The only portion we ran a test on was the lower Dakota, having some mechanical difficulties when we got to the upper Dakota and we chose not to try to run a test.

But in the lower Dakota we perforated 8 perforations for limited entry-type frac job between 6788 and 6846. We acidized this with 250 gallons of 7-1/2 percent acid with ball sealers so that we could eliminate any type of formation damage that may have occurred during drilling, so that we could feel reasonably comfortable with the fact that it was testing the formation as it really was when we did try to test it.

We did test it and it flowed just a little bit of gas back. It tested through a critical prover with a 1-inch orifice. This was witnessed by members of the New Mexico Oil Conservation Commission and our own people, and the measurement from that interval was too small to measure.

Q. What was the stabilized production rate on the lower Dakota, then?

A. Okay, it was, the rate was actually too small to measure through the 1/8th inch orifice, which would put it down in the less than, say, one or two Mcf per day; it would be below that figure.

Q. So that is definitely less than the FERC guideline of approximately 251 Mcf a day.

A. That is correct.

Q. Did you get any crude oil production from the Dakota in this well?

A. No, we did not.

Q. What was the spud date of the Wilmerding?

A. Spud date for the Wilmerding was April the 2nd, 1980.

Q. Okay. From these tests that you ran on this well, did these tests give you any indication as to the permeability in the area?

A. If Darcy's law is applied, run through the calculations, which we do not have here, but it would very definitely show well below 0.1 of a millidarcy.

MS. TESCHENDORF: Again I apologize to the Examiner, we didn't have time enough between the notice and the hearing date to get all this data prepared, but we

can submit it later, if you would like.

Q. Let's refer to Exhibit Number Three, on the Kline 1-M, and discuss that.

A. Okay, on the Kline 1-M we perforated both the lower Dakota and the upper Dakota and we did treat them separately and tested them separately.

The lower Dakota was perforated between 6655 and 6736 with 9 perforations. It was acidized with 300 gallons of acid and ball sealers. The acid was then -- and the flush water was then swabbed back. The flow rate through a critical prover, using a 1/8th inch orifice plate, we produced it for 5 hours at a maximum rate of just under 13 Mcf per day. This was also witnessed by the Commission.

The upper Dakota is perforated with 17 perforations between 6506 and 6629; was acidized with 500 gallons of acid and 30 ball sealers. We also swabbed it back until it was dry, and flowing it for four hours through a 1/8th inch orifice, a critical prover, the gas rate was too small to measure.

Q. And this well also, the stabilized production rates fell below those specified in the FERC guidelines?

A. That is correct, and it also, if one were to apply Darcy's flow equation, it would show less than

0.1 of a millidarcy.

Q. And was there any crude oil production from this well?

A. There was not.

Q. When was the well spudded?

A. This well was spudded in April 17th, 1980.

Q. Let's go on to Exhibit Number Four.

A. Exhibit Number Four is for the Senter 1-M. This well was also perforated and tested separately from the lower Dakota and the upper Dakota. The lower Dakota had 13 perforations between 6898 and 6958. It was acidized with 500 gallons of acid and 25 ball sealers. It was swabbed back and a long flow test was taken under the direction of Tefteller, Incorporated, and witnessed by the Commission, and the rates, the initial rates on it for the -- trying an open flow, was 2.73 Mcf, or less than 3 Mcf per day. After three hours it was less than 2 Mcf per day, and allowing it to flow overnight, at 7:00 o'clock the next morning it was still flowing at less than 2 Mcf per day.

On the upper Dakota it was perforated it looks like 13, I believe it was, perforations from 6740 to 6816; acidized with 500 gallons of acid and 22 ball sealers. It also was swabbed down. Tefteller ran a flow test on it,

which was witnessed by the Commission, and the final rate, or the -- it flowed for 21 hours and the well stabilized over the last 16-1/2 hours at a 52 Mcf per day rate.

Q Any crude oil production?

A None. No, there was not.

Q And does this well also, would you, in your opinion say, have less than 0.1 of a millidarcy throughout?

A Yes, I believe if the Darcy flow equation is applied to this rate it would also show that it is less than 0.1 of a millidarcy.

Q Let's talk about the economics of some of these wells. You have stated that Consolidated has been quite extensively participating in an infill drilling program in this township. Is this infill drilling program still going on?

A Well, we have just recently stopped our infill drilling program to evaluate where we stand. We are experiencing a very rapid increase in drilling cost rates, especially the footage cost going up so fast, in fact, this last year it's gone up over 30 percent just for the footage cost itself. I think it's probably more like 50 percent over what we were getting one year ago and what it is today for the last wells we have drilled.

The other costs have also gone up, so I think we would be very close to maybe at least a 30 percent increase in drilling costs over this past year, so we see a collision course taking place between the inflation adjusted 103 price and what our drilling costs are, and for that reason we have felt that we need to shutdown our infill drilling program, evaluate our recent wells that we have drilled to see whether or not that we should be taking the risk of trying to drill additional units.

Q. When we started the infill drilling program the Section 103 price was considered sufficient incentive, is that correct?

A. That is correct.

Q. And very recently Consolidated management has taken the position that with the increase in prices, that the Section 103 price is no longer sufficient, and that, therefor drilling further wells would be uneconomic, is that correct?

A. From the standpoint that we are evaluating it. It looks like that it is going to begin to eliminate many of the wells that we would have drilled, and we will have to look more carefully at each one to see whether or not that we are interested in -- in risking our money to infill drill. I think it will be on a selective basis, much more

of a selective basis now than it would have been three months ago, even.

Q. Would a higher incentive price change that position?

A. Very definitely. It would increase the number of wells that we would be willing to risk drilling on an infill program.

Q. Is there anything you wish to add to your testimony at this point?

A. Well, I think other than the fact that we see, and I think we've talked to other operators, the fact that we do see a collision course between the costs of drilling and the inflation adjusted 103 price, that I think based on that, we are very definitely going to have to become very selective in what wells that we can afford to drill, and each passing month it's going to increase as far as the number of wells that we will have to eliminate that we can drill.

Q. Were Exhibits One through Four prepared by you or under your supervision?

A. That is correct.

MS. TESCHENDORF: I'd like to offer these exhibits.

MR. NUTTER: Consolidated's Exhibits One through Four will be admitted in evidence.

MS. TESCHENDORF: And I would like to ask the Examiner to consider including these townships in an order, if you should approve this tight formation application.

Like I said, it was included in the advertisement; however, we can also come in with a separate application should that be necessary.

MR. NUTTER: Okay, we will consider that, Ms. Teschendorf.

MS. TESCHENDORF: I have nothing further.

CROSS EXAMINATION

BY MR. NUTTER:

Q. Mr. Ellison, now taking these wells that you have the data on individually, the Wilmerding No. 1, which is in the northeast of the northwest of Section 10, 31, 13, I presume that that well has dedicated to it the west half of Section 10 and that it is an infill well with the well that's in the southwest quarter?

A. No. It - the Wilmerding is one of the rare ones that goes across a section line over into Section 9 in the northwest quarter -- or northeast quarter of Section 9 and the northwest quarter of Section 10, is the Wilmerding 320-acre spacing.

Q. Okay, so it is an infill well, then.

A. It is an infill well.

Q. With the well that's in Section 9.

A. That is correct.

Q. All right, now that well in Section 9 shows a cumulative production of 135,000 Mcf, is that it?

A. That is -- I believe that is the old one. We may be able to tell from the Southland Exhibit One what that well has -- what the cumulative is on that. Just one minute.

It shows the cumulative being 188 with it only having made 8-million for the entire year last year.

Q. In other words, this figure is not up-to-date here?

A. No, I think I made reference that that cumulative on our wells there was only through 1971.

Q. Oh.

A. So they have not been updated. We did not get a chance, in trying to get this together under short notice, a chance to update all our cumulatives.

Q. I see, so that is noted in the legend here of your Exhibit One, that this is through 12-1-71.

A. That is correct.

Q. Okay. Then the well --

A. May I interject something right here?

I think very possibly, even with the 103 prices, had we not had a dual infill as far as -- although both the Mesaverde and the Dakota on this particular well were very marginal, we chose to go ahead and -- and attempt it, thinking that between the two zones we could get a payout.

With current prices now I don't think we would have attempted, even with the dual costs, which cut down on your development costs, I'm not sure that we would have even drilled the well.

Q. Okay, then the other well in Section 10, which is the well that's on the Exhibit Three, is the Kline No. 1.

A. That is correct.

Q. And that's an infill well with the well that's in the northwest -- northeast quarter of Section 10.

A. That is correct.

Q. Now, through 1971 that well shows that it had made 467,000 Mcf, and on Southland's exhibit, would that be the well that shows 679,000?

A. That is correct, and again, if you draw curves and assume what the cumulatives are, if you'll notice the well in the northeast quarter of Section 15, and you'll see that it is 294 with only making 8-million last year, which means that its cumulative is probably going to be something

less than 350-million, or somewhere in the neighborhood of 350-million, and therefor, we are going from a good well to a poor well and it puts it in the very marginal category, in other words, of whether or not that you will get a payout, and again we had a marginal Mesaverde that we are going to be dualing it with, which we felt at the time probably brought it up into an area that we could afford to drill it.

Q. Well, if we strike a -- if we strike an actual average between the well in the northeast quarter of 10 and the well in the northeast quarter of 15, we would be averaging 700 with 300 or coming out with a 500,000 Mcf well, which would be in excess of necessary amount to pay out on a well, according to Southland's testimony.

A. Yeah, according to Southland's testimony, but with the increase of the drilling costs that we are seeing, in other words, we could drill it this year, but at the rate that the drilling costs are going up, could we afford to drill it next year or the following year. In other words, this has to deal with the incentive of doing so.

Also, I'm not sure that we would maybe live with the 15 percent based upon the cost of money and all we have nowadays, I'm not sure that we would live with 15 percent rate of return when the cost of money is over 21 percent.

Q. Well now, you've had other infill wells that have been drilled in this area --

A. Yes.

Q. -- that Ms. Teschendorf's talking about.

A. That is correct. We have quite a number in it.

Q. Did you select these three wells as being the poorer of the infill wells that you have drilled?

A. No, this didn't even -- in other words, when we decided to just get some information, we just -- we went out there and they were the ones that were available at that time when we were talking about it.

Q. Uh-huh.

A. And I'm not sure -- well, I was going to say the Senter Well over there where it was, as you can see, it was close to a very good well.

Q. Well, I can see that there are some wells there that have very good cumulative recovery, the east offset has made over 2-billion cubic feet.

A. That's right, and it's one -- probably the best well, or one of the very best wells that Consolidated has, and yet from the results of the test, you can see that the in situ permeability and flow rate from the two different both the upper and the lower Dakota zones did not meet the

criteria -- or does meet the criteria of the 0.1 millidarcy and less than 251 Mcf.

Q. So you may have tight spots in here and also some sweet spots in the formation.

A. That is correct.

I think we also should maybe point out that we, as we were going through our infill program, we were trying to pick some of the very best wells, you know, from a management standpoint it is much better to go after the best ones to start with to make you get the best payout, and then you begin to move towards your marginal ones. So for the most part we have -- we have drilled our better locations and that is one reason, as far as evaluating do we or do we not want to continue into the infill program, the remaining wells we had to drill are not in as good a part of, or the sweeter part of the Dakota as some of these others are that we're moving off.

Now we do have a few good ones, that appear to be good ones, remaining.

Q. Well, do you think that the fact that you're getting these poor wells in here is an indication that maybe the drainage from the original wells in the Dakota formation were better than had been anticipated and there just isn't much gas left?

A. What we have run bottom hole pressures on these, the majority of our wells have had near original bottom hole pressures, surprisingly. We had -- I think we've had like three of them that showed real low, and --

Q. Where they did get into a --

A. Yeah, and we --

Q. -- reservoir that has been drained.

A. Yeah. Let me just point out one of them. Up in the Mitchell in Section 5 of 12, 31 -- 31, 12, that Mitchell 1-E Well.

Q. That's a new well?

A. That is a brand new well and I think our bottom hole pressure on that was 400 and some pounds.

And another one was down in the -- I think the Southern Union well down in -- the one that offsets the real good well, if you'll look at that.

Q. Okay, the 1-M in 30?

A. Right, in Section 19, the 1-M Well there.

Q. Okay.

A. It also had a low bottom hole pressure, but that has been the exception rather than the rule. The majority of ours have had good bottom hole pressures remaining.

Q. Indicating no drainage, or little drainage.

A. Indicating no or little drainage, yeah. We've had some that are original and some that are not much, you know, a couple hundred pounds below original, stuff like that. We've been -- we've been very pleased by the pressures that we've been experiencing except for two or three cases.

Q. But what you're doing, you're just drilling into the tight spots.

A. That's true, but it may be that the tight -- we don't know this, and this comes into the risk factor, of when you drill you're not sure whether you're going to be in a tight or a sweet spot, and this comes back to the economics of do you or do you not.

MR. NUTTER: Are there any other questions of Mr. Ellison?

CROSS EXAMINATION

BY MR. CHAVEZ:

Q. Mr. Ellison, you mentioned your limited entry perforations, do you think that one perforation every three or four foot is adequate to -- in order to get a test that's required by the FERC testing the formation without stimulation?

A. If you'll go through the calculations as far as Darcy's law and things like that, yes, I would say

that this -- this does adequately test. When we are using the acid to get out into the formations, the flow rate and the loss, and all of that, coming to a perforation, and we're talking about over a short interval, under those circumstances I would say, and there's a lot of data in the literature and all of that, that shows that you're not hurting your permeability calculations or anything like that significantly.

Q. Did you take any fluid level analyses to see whether there may have been fluid accumulations in the wellbore that would have caused a low rate of gas production?

A. We had swabbed those right down to the time of starting into run the test itself. In other words, we swabbed it and made sure that it was dry and that there was no fluid entry, we were getting no fluid entry, almost nil fluid entry.

So it should -- it should be a good, valid test.

MR. CHAVEZ: That's all.

MR. NUTTER: Mr. Padilla?

CROSS EXAMINATION

BY MR. PADILLA:

Q. Mr. Ellison, let me hand you what has been marked as Southland's Exhibit Number One, and I'm also

going to hand you a red pencil so that you can mark on that map the area of interest that you are applying for.

MR. NUTTER: So in other words, Mr. Ellison, the line that you've drawn on the exhibit for Mr. Padilla includes all of Township 31 North and 13 West, and the western-most two rows of sections in Township 31 North, Range 12 West, is that it?

A. That is correct.

MR. NUTTER: So there's 12 sections in 31, 12, and 36 sections in 31, 13.

A. That is correct.

MR. NUTTER: Okay, and those have been outlined in a red line of wavy design.

A. That is correct.

MR. NUTTER: On Southland's Exhibit One.

Q. Mr. Ellison, there's some area in Township 31 North, and I think it's between 13 West and 12 West, that has three and four wells to a section. I'm specifically talking about Section 18 of 12 West, 31 North, and Section 19 and then Section 24 of 31, 13 West and there are some other sections in that area that have at least three wells, or have three wells. Do you have any information as to the commerciability of those wells with respect to the Section 103 price?

A. The information that I have, for instance, right now in Section 24, the Senter 1 M Well is very -- which is in the southeast quarter offsetting that very, very good well, it's very questionable on -- as it stands right now and our production -- producing capacity and all of that, it is noncommercial. In other words, it will not pay back the drilling costs.

The infill well for the Southern Union well on the south -- southeast quarter of Section 19 is also another well that will not -- we will not recover our completion and drilling expense.

MS. TESCHENDORF: I might point out that a lot of these wells you're looking at are not Dakota wells. Okay?

A. No, the ones that --

MS. TESCHENDORF: You can see on there that they're marked with the formation.

A. Okay, these are the ones he's talking about, these right here, which are the ones that include ours.

MS. TESCHENDORF: Okay.

A. So these -- our Senter Well and our -- or our Senter 1-M Well and our Southern Union 1-M Well will not pay out. The Lee 1-M Well -- I'm talking about in the

Dakota -- the Lee 1-M Well, which is also in the northwest quarter of Section 30 of 12, 13, will not pay out, and the infill well, the Mitchell Well previously referred to up in Section 5, in the northeast quarter -- or northwest quarter of Section 5 of 12, 31, will not pay out. And of course, that payout, the loss on those has to be picked up by the wells that will pay out from that same area.

The other - the other wells, several wells you have there have not been put on stream, so I cannot tell you, several of these wells, whether we will get a pay out or not.

Q. Have some of the older wells in that area paid out already, to your knowledge?

A. Yes, I'm sure that they have. That was back, they were drilled back in the '50's and with the drilling costs much lower and all that. Of course, the gas price was much lower.

But we have, you know, it's a mixture of the new wells, some have gotten good payouts and others will not have any payouts, but the total drilling program has to be balanced with what happens to all the wells.

Q. Now moving further to the east, I believe Mr. Thompson testified that the wells in 31 North, 12 West and 11 West, he believed that area -- those wells in that area

were commercial, and for that reason they were excluded from Southland's application. How would you distinguish this area that we have just been talking about with the one that Southland excluded from their application?

A. Well, I think what we're talking about there is the Dakota has what many refer to as fairway, or sweet areas, and stuff like that. That is a sweeter area, more in the fairway than that as you move west. So based upon cumulatives already shown on his map, those wells do much better. I have no idea what the -- other than from his testimony -- what the in situ perms are or the natural flow rates, although they still may fall within the guidelines -- or fall within the criteria set forth for a tight gas formation.

Q. Now, going to your Exhibit Number Two, and I believe your Exhibit Number Three, aren't those in fact dry holes? Those wells, the information from those wells, aren't they dry holes?

A. No, they are not. They -- they are being completed into the line and they did make -- it appears both are commercial wells.

Q. This information that's --

A. Oh, you mean as far as if a person were to look at this would he back off and say these are dry holes,

and not try to make a completion? Is that your question?

Q. Yes.

A. Very, I would say if he were to run a DST on it and get this type of information, it would be very likely, prior to knowing what happens with fracing and things like that, that a person could -- could walk off of them. In other words, it could be interpreted that I don't feel that we should attempt a completion, that the risk is too high to run pipe and try to frac it, and things like that.

We have -- Consolidated has gone the approach that we cannot evaluate very well from DST's and to some degree even from logs, and we have drilled wells, set pipe, and attempted completions because we have not been able to come to a good judgment on should we or should we not run pipe and complete it based upon what we've seen on logs and through DST's.

Q. Well, let me ask my question this way, also. When you say a gas rate was too small to measure, is that before or after stimulation?

A. This is after the acid stimulation, in which we made sure that there was no formation damage, and should give us an in situ type of flow rate. This was the -- this was before a frac job, a fracture stimulation.

Q. After you stimulated the wells, then they

became producers?

A. That is correct.

MR. PADILLA: I have no further questions.

MR. NUTTER: Does anyone have any further questions of Mr. Ellison? He may be excused.

Do you have anything further, Ms. Teschendorf?

MS. TESCHENDORF: I don't believe so.

MR. NUTTER: Ms. Teschendorf, I understand the FERC wants three copies of exhibits. Would you furnish us with three original sets of these exhibits?

MS. TESCHENDORF: We certainly can.

MR. NUTTER: With a postage paid envelope to send them in?

MS. TESCHENDORF: We certainly will.

MR. NUTTER: And also I would imagine unless you've already furnished copies of these exhibits to the USGS, you should furnish them a set.

MS. TESCHENDORF: We've got the extra copies of the other exhibits we can give you. We'll have to get extra copies of the maps made.

MR. NUTTER: Do you have anything further, Ms. Teschendorf?

MS. TESCHENDORF: No, sir.

MR. NUTTER: Does anyone have anything they wish to offer in Case Number 7116?

We'll take the case under advisement and the hearing is adjourned.

(Hearing concluded.)

SALLY W. BOYD, C.S.R.
Rt. 1 Box 193-B
Santa Fe, New Mexico 87501
Phone (505) 455-7409

C E R T I F I C A T E

I, SALLY W. BOYD, C.S.R., DO HEREBY CERTIFY that the foregoing Transcript of Hearing before the Oil Conservation Division was reported by me; that the said transcript is a full, true, and correct record of the hearing, prepared by me to the best of my ability.

Sally W. Boyd C.S.R.

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. 7116, heard by me on 12/30 1980.

_____, Examiner
Oil Conservation Division

BEFORE THE
STATE OF NEW MEXICO
OIL CONSERVATION DIVISION

In the matter of the application of Southland Royalty Company for designation of a tight formation, San Juan County, New Mexico

Case No. 7116

JAN 27 1981
OIL CONSERVATION DIVISION
SANTA FE

AFFIDAVIT

I, FLOYD E. ELLISON, being first duly sworn, depose and state that:

Permeability Calculations

Exhibits 5, 6 and 7 show the permeability calculations for the Wilmerding 1-M in Section 10, T31N, R13W, Kline 1-M in Section 10, T31N, R13W and Senter 1-M in Section 24, T31N, R13W based on the flow tests previously submitted (which were witnessed by New Mexico Oil Conservation Division personnel). In all cases the permeability calculations using Darcy's flow equation show the in situ permeability to be well below 0.1 md.

Well Cost Estimate

Consolidated's drilling and completion well cost estimate for an average depth 7,000' single Dakota completion totals $475,400 (see Exhibit 19). These costs are based on our experience in drilling and completing a number of wells this past year in the immediate area. Several significant differences with the Southland Royalty cost estimate are:

1. Consolidated's use of $16/ft. vs. Southland's $14/ft. The $16/ft. figure is our most recent quoted price and corresponds with inquiries we have made of other operators' footage prices. We have a working interest in a well recently drilled in the area in which the operator was required to pay $19.51/ft.

2. Consolidated's average mud and water costs are well above those shown on the Southland estimate. Some mud and water costs have been as low as Southland's estimate, but we have experienced severe lost circulation in the Mesaverde, Gallup and/or Dakota zones in several wells which brings the average mud and water cost to our estimate.

3. The recent requirement by both the state and USGS to cement across the Ojo Alamo and circulate cement to surface requires additional DV tools and cement. Southland's cementing and cementing tools estimate is below the costs we have been experiencing in our most recent wells.

4. Completion Costs. Consolidated's completion procedure differs in several ways from Southland's. Consolidated has recently been including the tight lower Dakota in its completions because we believe enough additional reserves can be added in certain wells to justify the additional completion expense. A major cause of the increased expense is the necessity to perforate, stimulate, and clean up the upper and lower Dakota separately. The tight lower Dakota has an approximate 800 - 1,000# higher treatment and ISIP than does the upper Dakota

which makes it necessary to frac and clean up the zone before moving on to the upper Dakota completion. Consolidated has also been using nitrogen in its frac treatments to aid clean up but its use does add to stimulation costs.

Economics

Based on Consolidated Oil & Gas's required after tax economic criteria, Consolidated needs approximately 650 MMCF of gas reserves with Section 103 prices and 335 MMCF of gas reserves with 2 X 103 prices to justify drilling a single Dakota completion, as shown on Exhibit 8. These reserve requirements are considerably above what we used to justify our drilling program in the area this past year and above what Southland Royalty has indicated they need. The required larger reserves are the result of these major differences:

1. The majority of our wells this past year were dual completions with the Mesaverde reserves helping pay out the drilling and completion costs.

2. The drilling and completion costs have increased dramatically with the differences between Consolidated and Southland Royalty's estimates having been previously discussed.

3. The net interest (after deducting royalty interest and overriding royalty interest) on Consolidated operated properties in the area is 75.5% vs. Southland Royalty's indicated 86.5%. The majority of Consolidated's properties are 75% leases due to Consolidated having to give up an additional 12.5% ORR before it could farm-in the acreage and drill the original wells in the 1950's and 1960's. This is a major cut out of the income without any offsetting help on the expense side.

4. The required rate of return (ROR) after taxes for Consolidated is 20% vs. Southland Royalty's indicated 15%. Consolidated cannot justify less than a 20% ROR in the present money market when we pay over 20% for the money we borrow. Investors, including Consolidated, can receive more than 15% interest on CD's without assuming any risk so surely assuming risk is worth something above the 15% Southland proposed.

Exhibit 9 shows the assumptions used for our economic calculations and Exhibits 10, 11, 12 and 13 show the before and after taxes economics for 300 MMCFG, 400 MMCFG, 500 MMCFG and 650 MMCFG reserves with 103 pricing and Exhibits 14, 15, 16, 17 and 18 show the before and after taxes economics for 200 MMCFG, 300 MMCFG, 400 MMCFG, 500 MMCFG and 650 MMCFG reserves for 2 X 103 pricing.

Protection of Fresh Water

State and federal regulations currently provide for the protection of any fresh water aquifers that are being used or are expected to be used in the foreseeable future for domestic or agricultural water supplies. Three potential fresh water bearing formations in the area of interest are the San Jose, Nacimiento and Ojo Alamo. These three formations occur from the surface of the ground to a depth of approximately 1,000 feet in T31N, R13W and the western half of T31N, R12W.

The NMOCD by Rule 106 and the federal government regulations for protection of fresh water in oil and gas related activities both require the casing and cementing program to be designed to seal off fresh water bearing formations from

oil and gas bearing formations. They fulfill this requirement by having the oil and gas operator cement the production casing with sufficient cement to bring it above the Dakota several hundred feet, to usually cement across the Mesaverde zone when it is productive, and then to circulate cement to surface from several hundred feet below the base of the Ojo Alamo formation. Additionally, surface casing is set and cemented to surface when drilling begins which protects the top several hundred feet.

The above casing and cementing programs provide adequate protection to the fresh water sands even though large stimulation treatments are required in the tight Dakota producting formation which is about 5,900 feet below the deepest fresk water zone.

Exhibits 5 through 19 were prepared by me or under my direction and supervision.

Floyd E. Ellison, Jr.
Vice President - Operations

STATE OF COLORADO)
) ss
CITY AND COUNTY OF DENVER)

On this 22nd day of January, 1981, before me personally appeared Floyd E. Ellison, Jr., to me known to be the person described in and who executed the foregoing Affidavit before me, and who acknowledged to me that he executed it as his own free act and deed.

WITNESS my hand and seal on this day and year last above written.

Patricia L. Burns
Notary Public

My Commission Expires:
My commission expires June 13, 1983

CONSOLIDATED OIL & GAS, INC.
Wilmerding 1-M
NE/4 NW/4 10-T31N-R13W
San Juan County, New Mexico

Lower Dakota

Perforations 6738', 6798', 6828', 6830', 6833', 6838', 6841', and 6846', (8-.32" diameter perforations)

Acidized with 250 gallons 7½% NE acid using 16 ball sealers.

Swabbed well down.

9/11/80

Flowed well through Critical Prover using 1/8" orifice plate. Gas rate too small to measure.

Test witnessed by Charles Gholson with NMOCC and Barney Jones with Consolidated Oil & Gas, Inc.

Did not test Upper Dakota.

Conoco Fed 2
Ox 7116

CONSOLIDATED OIL & GAS, INC.
Kline 1-M
NE/4 SE/4 10-T31N-R13W
San Juan County, New Mexico

Lower Dakota	Perforations 6655', 6658', 6668', 6672', 6676', 6715', 6720', 6724', 6729', 6734', and 6736', (9-.29" holes)
	Acidized with 300 gallons 7½% NE acid using 21 ball sealers. Balled off @ 5000#.
	Swabbed down and recovered water and acid.
	Flowed well through Critical Prover using 1/8" orifice plate. Produced 5 hours with maximum rate of 12.85 MCF/D.
8/22/80	Test witnessed by Rich Simmons of NMOCC and Chink Ashbrook with Consolidated Oil & Gas, Inc.
Upper Dakota	Perforations 6506', 6512', 6520', 6527', 6532', 6540', 6550', 6557', 6565', 6572', 6577', 6584', 6592', 6612', 6617', 6621', and 6629', (17 perforations .32" diameter)
	Acidized with 500 gallons 7½% NE acid with 30 ball sealers. Balled off @ 5500#.
	Swabbed well down.
	Flowed well 4 hours through Critical Prover using 1/8" orifice plate. Gas rate too small to measure.
8/28/80	Test witnessed by Richard H. Simmons of NMOCC and Chink Ashbrook with Consolidated Oil & Gas, Inc.

Conoco Ex 3
Cs 7416

CONSOLIDATED OIL & GAS, INC.
Senter 1-M
NE/4 SE/4 24-T31N-R13W
San Juan County, New Mexico

Lower Dakota — Perforations 6898', 6902', 6906', 6910', 6914', 6918', 6934', 6938', 6942', 6946', 6950', 6954', & 6958', (13-.33" diameter perforations)

Acidized with 500 gallons 15% NE acid using 25 ball sealers. Balled off @ 3200#.

Swabbed well down to get acid back.

5/20-21/80 — Tefteller, Inc. ran flow test on Dakota perforations 6898'-6958'.

5/20/80

12:45 p.m.	2.73 MCF/D
3:45 p.m.	1.91 MCF/D
7:00 a.m.	1.91 MCF/D

Test witnessed by Frank Chavez and Rich Simmons of NMOCC, Tobby Tefteller and Len Alexander with Tefteller and Aubrey Prather with Consolidated Oil & Gas, Inc.

Upper Dakota — Perforations 6740', 6745', 6759', 6776', 6782', 6786', 6794', 6808', 6810', 6814', and 6816'.

Acidized with 500 gallons 15% NE acid using 22 ball sealers. Balled off @ 3500#.

Swabbed well down.

6/4-5/80 — Tefteller, Inc. ran flow test on Dakota perforations 6740'-6816'.

Flowed total 21 hours. Well stabilized @ approximately 52 MCF/D rate over last 16½ hours.

Test witnessed by Rich Simmons with NMOCC, Tefteller testers, and Barney Jones with Consolidated Oil & Gas, Inc.

Cons Ex 4
CO 7116

CONSOLIDATED OIL & GAS, INC.
WILMERDING NO. 1M
NE/4 NW/4 10-T31N-R13W
BASIN DAKOTA FIELD
SAN JUAN COUNTY, NEW MEXICO

Data:

	Lower Dakota	Upper Dakota
Midperforations	6817'	6697'
Qg	To Small To Measure	Not Tested
h (log)	27'	57'
K (permeability)	Inadequate gas to compute flow rate and permeability (K) is much less than oil md.	

EXHIBIT 5

CONSOLIDATED OIL & GAS, INC.

KLINE NO. 1M

NE/4 SE/4 10-31N-13W

BASIN DAKOTA FIELD

Calculation of Permeability Using Darcy's Law:

Data:

	Lower Dakota	Upper Dakota
Midperforations	6696'	6567'
Qg	12850 SCF (test)	Gas Too Small To Measure
h	38' feet (log)	
Pwf	38 Psia	
Pe	2592 Psia	
g_g	.70	
T	186°-646°R	
re	1320 feet	
rw	0.02 feet	
Psc	668 Psia	
Tsc	392°Rankin	
Ug	.014 cp	
Z	0.91	

Where:

Qg = gas flow rate
h = net pay
Pwf= flowing bottomhole pressure
Pe = shut-in bottomhole pressure at drainage radius, re
g_g = gas specific gravity
T = bottomhole temperature
re = drainage radius for 160 acre spacing
rw = wellbore radius
Psc= pseudo critical pressure
Tsc= pseudo critical temperature
Ug = gas viscosity
Z = compressibility factor for gas

Formula:

$$K = \frac{QgUgTZ \ln(.61re/rw)}{703h(Pe^2-Pwf^2)}$$

$$K = \frac{12850x.014x646x.91x\ln(.61x\frac{1320}{20})}{703x33x(2592^2-38^2)}$$

$$K = .0000049 \ D$$

$$K = .0049 \ md.$$

EXHIBIT 6

CONSOLIDATED OIL & GAS, INC.
SEMER NO. 1M
NE/4 SE/4 24-T31N-R13W
BASIN DAKOTA FIELD
SAN JUAN COUNTY, NEW MEXICO

Calculation of Permeability Using Darcy's Law:

Data:

	Lower Dakota	Upper Dakota
Midperforations	6928	6728
Qg Scf (test)	2730	52000
h feet (log)	58	51
Pwf Psia	20	32
Pe by analogy & tests	2658	2592
G_g typical gravity field gas	.70	.70
T°calculated	186°F(646°R)	186°F(646°R)
re feet	1320	1320
rw feet	.20	.20
Psc Psia	668	668
Tsc °Rankin	392°R	392°R
Ug cps(calc.)	.014	.014
Z (calc)	.91	.91

Where:

Qg = gas flow rate
h = net pay
Pwf= flowing bottomhole pressure
Pe = shut-in bottomhole pressure at drainage radius, re
gg = gas specific gravity
T = bottomhole temperature
re = drainage radius for 160 acre spacing
rw = wellbore radius
Psc= pseudo critical pressure
Tsc= pseudo critical temperature
Ug = gas viscosity
Z = compressibility factor for gas

Formula:

$$Qg = \frac{703Kh(Pe^2-Pf^2)}{UgTZ\ in(.61re/rw)} \quad \text{and} \quad K = \frac{QgUgTZ\ ln\ (.61re/rw)}{703h(Pe^2-Pwf^2)}$$

Lower Dakota

$$K = \frac{2730(.014)(646)(.91)\ln(.61x\frac{1320}{.20})}{(703)(58)(2658^2-20^2)}$$

= .00000068 D
= 00068 md.

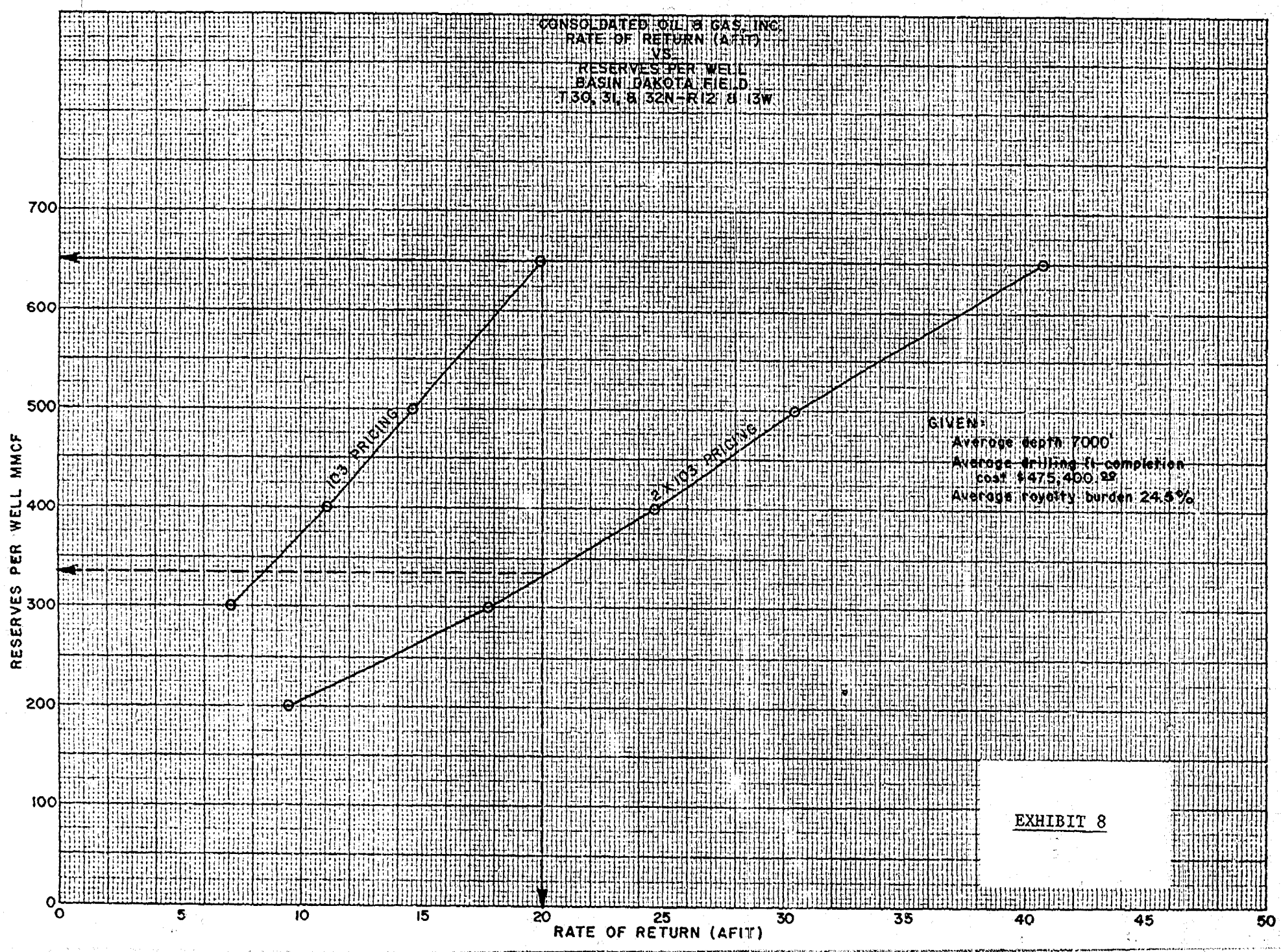
Upper Dakota

$$K = \frac{52000(.014)(646)(.91)\ln(.61x\frac{1320}{.20})}{(703)(51)(2592^2-32^2)}$$

= .0000146 D
= .0146 md.

EXHIBIT 7

K&E 10 X 10 TO THE CENTIMETER 46 1512
10 X 25 CM.
MADE IN U.S.A.
KEUFFEL & ESSER CO.



CONSOLIDATED OIL & GAS, INC.

ASSUMPTIONS USED IN MAKING ECONOMIC

CALCULATIONS

BASIN DAKOTA FIELD

SAN JUAN COUNTY, NEW MEXICO

Drilling and completion costs (including Tank Battery)	$475,400
Operating Costs $/mo	150
Depth	7000'
Consolidated Working Interest	100.00
Royalty Interest Typical to Consolidated Holdings	24.5
Initial Stabilized Production Rate(MCFD)	
200 MMCF Reserves	89
300 MMCF Reserves	150
400 MMCF Reserves	189
500 MMCF Reserves	232
650 MMCF Reserves	400
Liquid Yield (Bbls/MMCF)	3.85
Fully Adjusted Gas Price as of October 1, 1981 ($/Mcf)	$3.11
Maximum Gas Price ($/Mcf)	$10.42
Maximum Oil Price ($/Bbl)	$50.00
Rate of Price Escalation %	$7.00
Severance tax (%)	$8.00
Deregulation Tax Data, Base Oil Price	$14.11
Windfall Profit Tax Rate %	$30.00

EXHIBIT 9

TYPICAL WELL NO. 2
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO
300 MMF PER WELL 103 PRICE
CONSOLIDATED OIL & GAS
ECONOMICS OF DEVELOPMENT

DATE: 01/16/81.
TIME: 17.04.46.
FILE: TYPW2
PROJ: 3

R E S E R V E S A N D E C O N O M I C S

AS OF DATE : 1/ 1/1981

END MO-YR	GROSS OIL PRODUCTION ----MB----	GROSS GAS PRODUCTION ----MMF---	OIL TO NET INTEREST ----MB----	GAS TO NET INTEREST ----MMF---	REVENUE TO INTEREST ----M$----	NET INVESTMENT ----M$----	NET OPER EXPENSES ----M$----	NET INCOME BEFORE FIT ----M$----	CUMULATIVE NET INCOME ----M$----	20.000 PCT CUM. DISC NET INCOME ----M$----
12-81	.052	13.500	.039	10.192	30.441	475.400	1.800	-446.759	-446.759	-449.344
12-82	.213	55.523	.161	41.920	133.991	0.	1.926	132.065	-314.694	-351.316
12-83	.151	39.166	.114	29.571	101.073	0.	2.061	99.012	-215.682	-291.132
12-84	.112	29.108	.085	21.976	80.197	0.	2.205	77.992	-137.690	-252.310
12-85	.087	22.484	.065	16.976	66.157	0.	2.359	63.798	-73.892	-226.306
12-86	.068	17.890	.052	13.507	56.177	0.	2.525	53.652	-20.240	-208.397
12-87	.056	14.574	.042	11.003	48.897	0.	2.701	46.196	25.956	-195.770
12-88	.047	12.101	.035	9.136	43.421	0.	2.891	40.530	66.486	-186.698
12-89	.039	10.209	.030	7.708	39.168	0.	3.092	36.076	102.562	-180.085
12-90	.034	8.728	.026	6.590	35.829	0.	3.310	32.519	135.081	-175.204
12-91	.029	7.547	.021	5.698	33.078	0.	3.540	29.538	164.619	-171.573
12-92	.025	6.592	.019	4.977	30.841	0.	3.600	27.241	191.860	-168.831
12-93	.022	5.806	.017	4.383	29.011	0.	3.600	25.411	217.271	-166.737
12-94	.020	5.153	.015	3.891	27.520	0.	3.600	23.920	241.191	-165.122
12-95	.018	4.605	.014	3.476	26.276	0.	3.600	22.676	263.867	-163.869
S TOT	.973	252.986	.735	191.004	782.077	475.400	42.810	263.867	263.867	-163.869
AFTER	.181	47.014	.136	35.496	336.646	0.	91.117	245.529	509.396	-159.661
TOTAL	1.154	300.000	.871	226.500	1118.723	475.400	133.927	509.396	509.396	-159.661
CUM.	0.	0.								
ULT.	1.154	300.000								

CUM NET INC/INV(1)	1.07	NET OIL REVENUE	34.553	5 PCT	175.388	40 PCT	-297.050
GROSS WELLS	1	NET GAS REVENUE	1084.170	10 PCT	7.351	50 PCT	-332.659
MONTHS 1ST YEAR	12	NET PROD REVENUE	0.	15 PCT	-92.743	60 PCT	-358.345
INITIAL W.I., PCT	100.0000	CUM NET PW/INV(1)	-.34	20 PCT	-159.661	80 PCT	-392.507
		LIFE (YEARS)	40.31	30 PCT	-244.674	100 PCT	-413.687
		RATE OF RETURN,PCT	10.37				
		INITIAL N.I., PCT	75.5000				

EXHIBIT 10

300 MCF reserves @ 103 price

TYPICAL WELL NO. 2
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO
300 MMF PER WELL 103 PRICE
CONSOLIDATED OIL & GAS
ECONOMICS OF DEVELOPMENT

DATE: 01/16/81.
TIME: 17.20.11.
FILE: TYPW2
PROJ: 3

A F T E R T A X E C O N O M I C S

AS OF DATE: 1/ 1/1981

-END- MO-YR	NET OIL MB-----	NET GAS MMF-----	REVENUE TO INT. M$-----	OPER. EXPENSE M$-----	NET INCOME M$-----	CAPITAL INVEST. M$-----	DEPR. M$---	DEPL. M$----	INCOME TAX M$----	CASH FLOW M$-----	CUM. NET PW M$------
12-81	.039	10.192	30.441	1.800	28.641	475.400	52.965	0.	-61.834	-384.924	-393.293
12-82	.161	41.920	133.991	1.926	132.065	0.	45.401	0.	41.599	90.466	-326.142
12-83	.114	29.571	101.073	2.061	99.012	0.	38.918	0.	28.845	70.167	-283.492
12-84	.085	21.976	80.197	2.205	77.992	0.	33.360	0.	21.423	56.569	-255.334
12-85	.065	16.976	66.157	2.359	63.798	0.	28.597	0.	16.897	46.901	-236.217
12-86	.052	13.507	56.177	2.525	53.652	0.	24.513	0.	13.987	39.665	-222.977
12-87	.042	11.003	48.897	2.701	46.196	0.	21.013	0.	12.088	34.108	-213.654
12-88	.035	9.136	43.421	2.891	40.530	0.	18.012	0.	10.809	29.721	-207.001
12-89	.030	7.708	39.168	3.092	36.076	0.	15.440	0.	9.905	26.171	-202.204
12-90	.026	6.590	35.829	3.310	32.519	0.	13.235	0.	9.256	23.263	-198.712
12-91	.021	5.698	33.078	3.540	29.538	0.	11.345	0.	8.733	20.805	-196.155
12-92	.019	4.977	30.841	3.600	27.241	0.	9.725	0.	8.408	18.833	-194.259
12-93	.017	4.383	29.011	3.600	25.411	0.	8.336	0.	8.196	17.215	-192.840
12-94	.015	3.891	27.520	3.600	23.920	0.	7.146	0.	8.052	15.868	-191.769
12-95	.014	3.476	26.276	3.600	22.676	0.	6.125	0.	7.944	14.732	-190.955
8 TOT	.735	191.004	782.077	42.810	739.267	475.400	334.130	0.	144.308	119.561	-190.955
AFTER	.136	35.496	336.646	91.117	245.529	0.	36.770	0.	100.205	145.325	-188.384
TOTAL	.871	226.500	1118.723	133.927	984.796	475.400	370.900	0.	244.513	264.886	-188.384

RECAP

	GROSS	W.I.	NET
INTEREST FRACTION	1.000000	1.000000	.755000
OIL RESERVES,MB	1.154	1.154	.871
GAS RESERVES,MMCF	300.000	300.000	226.500
PRODUCTS	0.	0.	0.
REVENUE,M$	1617.726	1617.726	1118.723
OPERATING EXPENSE,M$	133.927	133.927	133.927
TANGIBLES,M$	370.900	370.900	370.900
INTANGIBLES,M$	104.500	104.500	104.500
INITIAL OIL PRICE ($/B)		44.23	
INITIAL GAS PRICE ($/M)		3.1100	

LIFE (YEARS)	40.31
GROSS OIL WELLS	0.
GROSS GAS WELLS	1.000
RATE OF RETURN,PCT	7.01
DISCOUNT RATE,PCT	20.0
PAYOUT YEARS	8.66
W.I. BEFORE PAYOUT,PCT	100.00
W.I. AFTER PAYOUT,PCT	100.00

DIS PCT	PW OF NET M$
5	46.322
10	-68.754
15	-139.728
20	-188.385
30	-251.770
40	-291.882
50	-319.812
70	-356.357
100	-387.734

TYPICAL WELL NO. 1
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO
400 MMF PER WELL 103 PRICE
CONSOLIDATED OIL & GAS
ECONOMICS OF DEVELOPMENT

DATE: 01/16/81.
TIME: 14.24.22.
FILE: TYPW
PROJ: 1

R E S E R V E S A N D E C O N O M I C S

AS OF DATE : 1/ 1/1981

END MO-YR	GROSS OIL PRODUCTION ----MB----	GROSS GAS PRODUCTION ----MMF---	OIL TO NET INTEREST ----MB----	GAS TO NET INTEREST ----MMF---	REVENUE TO INTEREST ----M$----	NET INVESTMENT ----M$----	NET OPER EXPENSES ----M$----	NET INCOME BEFORE FIT ----M$----	CUMULATIVE NET INCOME ----M$----	20.000 PCT CUM. DISC NET INCOME ----M$----
12-81	.065	16.860	.049	12.729	38.019	475.400	1.800	-439.181	-439.181	-442.475
12-82	.284	73.944	.214	55.828	178.457	0.	1.926	176.531	-262.650	-311.441
12-83	.200	51.934	.151	39.210	134.016	0.	2.061	131.955	-130.695	-231.233
12-84	.148	38.477	.112	29.050	106.009	0.	2.205	103.804	-26.891	-179.563
12-85	.114	29.651	.086	22.387	87.224	0.	2.359	84.865	57.974	-144.971
12-86	.091	23.550	.069	17.780	73.994	0.	2.525	71.469	129.443	-121.115
12-87	.073	19.155	.055	14.462	64.248	0.	2.701	61.547	190.990	-104.292
12-88	.061	15.886	.046	11.994	56.981	0.	2.891	54.090	245.080	-92.185
12-89	.052	13.388	.039	10.108	51.393	0.	3.092	48.301	293.381	-83.331
12-90	.044	11.437	.034	8.635	46.930	0.	3.310	43.620	337.001	-76.784
12-91	.038	9.882	.028	7.461	43.313	0.	3.540	39.773	376.774	-71.895
12-92	.033	8.625	.025	6.512	40.363	0.	3.600	36.763	413.537	-68.195
12-93	.029	7.593	.022	5.732	37.948	0.	3.600	34.348	447.885	-65.363
12-94	.026	6.737	.020	5.087	35.975	0.	3.600	32.375	480.260	-63.178
12-95	.023	6.016	.017	4.542	34.309	0.	3.600	30.709	510.969	-61.481
8 TOT	1.281	333.135	.967	251.517	1029.179	475.400	42.810	510.969	510.969	-61.481
AFTER	.257	66.865	.194	50.483	479.930	0.	113.385	366.545	877.514	-55.715
TOTAL	1.538	400.000	1.161	302.000	1509.109	475.400	156.195	877.514	877.514	-55.715
CUM.	0.	0.								
ULT.	1.538	400.000								

CUM NET INC/INV(1)	1.85	CUM NET PW/INV(1)	-.12		
GROSS WELLS	1	LIFE (YEARS)	46.50		
MONTHS 1ST YEAR	12	RATE OF RETURN,PCT	16.89		
INITIAL W.I., PCT	100.0000	INITIAL N.I., PCT	75.5000		

NET OIL REVENUE	46.139	5 PCT	399.260	40 PCT	-239.118
NET GAS REVENUE	1462.970	10 PCT	168.950	50 PCT	-286.561
NET PROD REVENUE	0.	15 PCT	33.973	60 PCT	-320.769
		20 PCT	-55.715	80 PCT	-366.248
		30 PCT	-169.281	100 PCT	-394.431

EXHIBIT 11

400 MMCF @ 103 price

TYPICAL WELL NO. 1
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO
400 MMF PER WELL 103 PRICE
CONSOLIDATED OIL & GAS
ECONOMICS OF DEVELOPMENT

DATE: 01/16/81.
TIME: 14.34.00.
FILE: TYPW
PROJ: 1

A F T E R T A X E C O N O M I C S

AS OF DATE: 1/ 1/1981

-END- YR	NET OIL MB	NET GAS MMF	REVENUE TO INT. M$	OPER. EXPENSE M$	NET INCOME M$	CAPITAL INVEST. M$	DEPR. M$	DEPL. M$	INCOME TAX M$	CASH FLOW M$	CUM. NET PW M$
12-81	.049	12.729	38.019	1.800	36.219	475.400	52.965	0.	-55.772	-383.408	-391.919
12-82	.214	55.828	178.457	1.926	176.531	0.	45.401	0.	60.320	116.211	-305.659
12-83	.151	39.210	134.016	2.061	131.955	0.	38.918	0.	42.797	89.158	-251.465
12-84	.112	29.050	106.009	2.205	103.804	0.	33.360	0.	32.404	71.400	-215.925
12-85	.086	22.387	87.224	2.359	84.865	0.	28.597	0.	25.883	58.982	-191.883
12-86	.069	17.780	73.994	2.525	71.469	0.	24.513	0.	21.600	49.869	-175.237
12-87	.055	14.462	64.248	2.701	61.547	0.	21.013	0.	18.646	42.901	-163.511
12-88	.046	11.994	56.981	2.891	54.090	0.	18.012	0.	16.596	37.494	-155.118
12-89	.039	10.108	51.393	3.092	48.301	0.	15.440	0.	15.116	33.185	-149.035
12-90	.034	8.635	46.930	3.310	43.620	0.	13.235	0.	13.977	29.643	-144.586
12-91	.028	7.461	43.313	3.540	39.773	0.	11.345	0.	13.077	26.696	-141.304
12-92	.025	6.512	40.363	3.600	36.763	0.	9.725	0.	12.437	24.326	-138.856
12-93	.022	5.732	37.948	3.600	34.348	0.	8.336	0.	11.965	22.383	-137.011
12-94	.020	5.087	35.975	3.600	32.375	0.	7.146	0.	11.605	20.770	-135.609
12-95	.017	4.542	34.309	3.600	30.709	0.	6.125	0.	11.308	19.401	-134.537
8 TOT	.967	251.517	1029.179	42.810	986.369	475.400	334.130	0.	251.959	259.009	-134.537
AFTER	.194	50.483	479.930	113.385	366.545	0.	36.770	0.	151.696	214.848	-131.057
TOTAL	1.161	302.000	1509.109	156.195	1352.914	475.400	370.900	0.	403.655	473.858	-131.057

RECAP

	GROSS	W.I.	NET
INTEREST FRACTION	1.000000	1.000000	.755000
OIL RESERVES,MB	1.538	1.538	1.161
GAS RESERVES,MMCF	400.000	400.000	302.000
PRODUCTS	0.	0.	0.
REVENUE,M$	2182.032	2182.032	1509.109
OPERATING EXPENSE,M$	156.195	156.195	156.195
TANGIBLES,M$	370.900	370.900	370.900
INTANGIBLES,M$	104.500	104.500	104.500
INITIAL OIL PRICE ($/B)		44.24	
INITIAL GAS PRICE (¢/M)		3.1100	

LIFE (YEARS)	46.50
GROSS OIL WELLS	0.
GROSS GAS WELLS	1.000
RATE OF RETURN,PCT	11.19
DISCOUNT RATE,PCT	20.0
PAYOUT YEARS	5.96
W.I. BEFORE PAYOUT,PCT	100.00
W.I. AFTER PAYOUT,PCT	100.00

DIS PCT	PW OF NET M$
5	172.562
10	21.671
15	-69.346
20	-131.058
30	-210.762
40	-260.814
50	-295.455
70	-340.402
100	-378.417

TYPICAL WELL NO. 4
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO
500 MMF PER WELL 103 PRICE
CONSOLIDATED OIL & GAS
ECONOMICS OF DEVELOPMENT

DATE: 01/16/81.
TIME: 17.04.56.
FILE: TYPW2
PROJ: 6

R E S E R V E S A N D E C O N O M I C S

AS OF DATE : 1/ 1/1981

100.0% - 75.5%

END MO-YR	GROSS OIL PRODUCTION ----MB----	GROSS GAS PRODUCTION ----MMF---	OIL TO NET INTEREST ----MB----	GAS TO NET INTEREST ----MMF---	REVENUE TO INTEREST ----M$----	NET INVESTMENT -----M$----	NET OPER EXPENSES ----M$----	NET INCOME BEFORE FIT ----M$----	CUMULATIVE NET INCOME ----M$----	20.000 PCT CUM. DISC NET INCOME ----M$----
12-81	.080	20.880	.060	15.764	47.072	475.400	1.800	-430.128	-430.128	-434.269
12-82	.355	92.219	.268	69.626	222.584	0.	1.926	220.658	-209.470	-270.480
12-83	.248	64.577	.188	48.755	166.622	0.	2.061	164.561	-44.909	-170.453
12-84	.184	47.743	.139	36.046	131.548	0.	2.205	129.343	84.434	-106.071
12-85	.141	36.733	.106	27.734	100.051	0.	2.359	105.692	190.126	-62.990
12-86	.112	29.138	.085	21.999	91.533	0.	2.525	89.008	279.134	-33.280
12-87	.091	23.677	.068	17.876	79.439	0.	2.701	76.738	385.872	-12.304
12-88	.076	19.620	.058	14.813	70.395	0.	2.891	67.504	423.376	2.806
12-89	.063	16.524	.047	12.476	63.391	0.	3.092	60.299	483.675	13.858
12-90	.055	14.106	.042	10.650	57.908	0.	3.310	54.598	538.273	22.054
12-91	.047	12.184	.035	9.199	53.407	0.	3.540	49.867	588.140	28.183
12-92	.040	10.629	.030	8.025	49.719	0.	3.600	46.119	634.259	32.825
12-93	.036	9.354	.028	7.062	46.759	0.	3.600	43.159	677.418	36.383
12-94	.032	8.295	.024	6.263	44.293	0.	3.600	40.693	718.111	39.129
12-95	.029	7.497	.022	5.592	42.266	0.	3.600	38.666	756.777	41.267
8 TOT	1.589	413.086	1.200	311.880	1274.987	475.400	42.810	756.777	756.777	41.267
AFTER	.334	86.914	.252	65.620	624.729	0.	132.842	491.887	1248.664	48.560
TOTAL	1.923	500.000	1.452	377.500	1899.716	475.400	175.652	1248.664	1248.664	48.560

CUM.	0.	0.	NET OIL REVENUE	57.749	5 PCT	622.058	40 PCT	-180.457
			NET GAS REVENUE	1841.967	10 PCT	330.138	50 PCT	-239.670
ULT.	1.923	500.000	NET PROD REVENUE	0.	15 PCT	160.754	60 PCT	-282.368
					20 PCT	48.560	80 PCT	-339.154
CUM NET INC/INV(1)		2.63	CUM NET PW/INV(1)	.10	30 PCT	-93.289	100 PCT	-374.362
GROSS WELLS		1	LIFE (YEARS)	51.90				
MONTHS 1ST YEAR		12	RATE OF RETURN,PCT	23.01				
INITIAL W.I., PCT		100.0000	INITIAL N.I., PCT	75.5000				

EXHIBIT 12

500 MMCF @ 103 price

TYPICAL WELL NO. 4
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO
500 MMF PER WELL 103 PRICE
CONSOLIDATED OIL & GAS
ECONOMICS OF DEVELOPMENT

DATE: 01/16/81.
TIME: 17.20.23.
FILE: TYPW2
PROJ: 6

AFTER TAX ECONOMICS

AS OF DATE: 1/ 1/1981

-END- MO-YR	NET OIL MB-----	NET GAS MMF-----	REVENUE TO INT. M$-----	OPER. EXPENSE M$-----	NET INCOME M$-----	CAPITAL INVEST. M$-----	DEPR. M$---	DEPL. M$----	INCOME TAX M$----	CASH FLOW M$-----	CUM. NET PW M$------
12-81	.060	15.764	47.072	1.800	45.272	475.400	52.965	0.	-53.851	-376.276	-385.454
12-82	.268	69.626	222.584	1.926	220.658	0.	45.401	0.	84.123	136.535	-284.108
12-83	.188	48.755	166.622	2.061	164.561	0.	38.918	0.	60.309	104.252	-220.739
12-84	.139	36.046	131.548	2.205	129.343	0.	33.360	0.	46.072	83.271	-179.290
12-85	.106	27.734	108.051	2.359	105.692	0.	28.597	0.	37.006	68.686	-151.293
12-86	.085	21.999	91.533	2.525	89.008	0.	24.513	0.	30.958	58.050	-131.916
12-87	.068	17.876	79.439	2.701	76.738	0.	21.013	0.	26.748	49.990	-118.252
12-88	.058	14.813	70.395	2.891	67.504	0.	18.012	0.	23.756	43.748	-108.459
12-89	.047	12.476	63.391	3.092	60.299	0.	15.440	0.	21.532	38.767	-101.354
12-90	.042	10.650	57.908	3.310	54.598	0.	13.235	0.	19.854	34.744	-96.138
12-91	.035	9.199	53.407	3.540	49.867	0.	11.345	0.	18.491	31.376	-92.282
12-92	.030	8.025	49.719	3.600	46.119	0.	9.725	0.	17.469	28.650	-89.398
12-93	.028	7.062	46.759	3.600	43.159	0.	8.336	0.	16.715	26.444	-87.218
12-94	.024	6.263	44.293	3.600	40.693	0.	7.146	0.	16.103	24.590	-85.558
12-95	.022	5.592	42.266	3.600	38.666	0.	6.125	0.	15.619	23.047	-84.284
8 TOT	1.200	311.880	1274.987	42.810	1232.177	475.400	334.130	0.	380.904	375.875	-84.284
AFTER	.252	65.620	624.729	132.842	491.887	0.	36.770	0.	218.456	273.431	-80.110
TOTAL	1.452	377.500	1899.716	175.652	1724.064	475.400	370.900	0.	599.360	649.305	-00.110

RECAP

	GROSS	W.I.	NET
INTEREST FRACTION	1.000000	1.000000	.755000
OIL RESERVES,MB	1.923	1.923	1.452
GAS RESERVES,MMCF	500.000	500.000	377.500
PRODUCTS	0.	0.	0.
REVENUE,M$	2746.654	2746.654	1899.716
OPERATING EXPENSE,M$	175.652	175.652	175.652
TANGIBLES,M$	370.900	370.900	370.900
INTANGIBLES,M$	104.500	104.500	104.500

INITIAL OIL PRICE ($/B)	44.24
INITIAL GAS PRICE ($/M)	3.1100

LIFE (YEARS)	51.90
GROSS OIL WELLS	0.
GROSS GAS WELLS	1.000
RATE OF RETURN,PCT	14.63
DISCOUNT RATE,PCT	20.0
PAYOUT YEARS	4.76
W.I. BEFORE PAYOUT,PCT	100.00
W.I. AFTER PAYOUT,PCT	100.00

DIS PCT	PW OF NET M$
5	278.539
10	99.079
15	-7.914
20	-80.111
30	-173.050
40	-231.254
50	-271.458
70	-323.487
100	-347.285

TYPICAL WELL NO. 5
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO
650 MMF PER WELL 103 PRICE
CONSOLIDATED OIL & GAS
ECONOMICS OF DEVELOPMENT

DATE: 01/19/81.
TIME: 15.51.31.
FILE: TYPW3
PROJ: 8

R E S E R V E S A N D E C O N O M I C S

AS OF DATE : 1/ 1/1981

END MO-YR	GROSS OIL PRODUCTION ----MB----	GROSS GAS PRODUCTION ----MMF---	OIL TO NET INTEREST ----MB----	GAS TO NET INTEREST ----MMF---	REVENUE TO INTEREST ----M$----	NET INVESTMENT ----M$----	NET OPER EXPENSES ----M$----	NET INCOME BEFORE FIT ----M$----	CUMULATIVE NET INCOME ----M$----	20.000 PCT CUM. DISC NET INCOME ----M$----
12-81	.138	36.000	.104	27.180	81.160	475.400	1.800	-396.040	-396.040	-403.370
12-82	.435	113.027	.329	85.335	272.783	0.	1.926	270.857	-125.183	-202.320
12-83	.309	80.174	.233	60.532	206.897	0.	2.061	204.836	79.653	-77.812
12-84	.230	59.826	.174	45.168	164.825	0.	2.205	162.620	242.273	3.133
12-85	.178	46.353	.134	34.997	136.350	0.	2.359	133.991	376.264	57.750
12-86	.142	36.970	.107	27.912	116.134	0.	2.525	113.609	489.873	95.672
12-87	.116	30.175	.088	22.782	101.241	0.	2.701	98.540	588.413	122.606
12-88	.097	25.095	.073	18.947	90.032	0.	2.891	87.141	675.554	142.112
12-89	.081	21.198	.061	16.005	81.329	0.	3.092	78.237	753.791	156.452
12-90	.070	18.144	.053	13.698	74.458	0.	3.310	71.148	824.939	167.132
12-91	.060	15.706	.045	11.858	68.826	0.	3.540	65.286	890.225	175.157
12-92	.053	13.727	.040	10.364	64.256	0.	3.600	60.656	950.881	181.262
12-93	.047	12.101	.036	9.136	60.506	0.	3.600	56.906	1007.787	185.953
12-94	.041	10.748	.031	8.115	57.375	0.	3.600	53.775	1061.562	189.583
12-95	.037	9.609	.028	7.255	54.809	0.	3.600	51.209	1112.771	192.413
8 TOT	2.034	528.853	1.536	399.284	1630.981	475.400	42.810	1112.771	1112.771	192.413
AFTER	.466	121.147	.351	91.466	872.308	0.	162.516	709.792	1822.563	202.173
TOTAL	2.500	650.000	1.887	490.750	2503.289	475.400	205.326	1822.563	1822.563	202.173
CUM.	0.	0.								
ULT.	2.500	650.000								

CUM NET INC/INV(1)	3.83	CUM NET PW/INV(1)	.43	5 PCT	950.746	40 PCT	-89.618
GROSS WELLS	1	LIFE (YEARS)	60.14	10 PCT	565.769	50 PCT	-164.696
MONTHS 1ST YEAR	12	RATE OF RETURN,PCT	31.72	15 PCT	346.324	60 PCT	-218.834
INITIAL W.I., PCT	100.0000	INITIAL N.I., PCT	75.5000	20 PCT	202.173	80 PCT	-290.984
				30 PCT	21.109	100 PCT	-335.965

NET OIL REVENUE	75.165
NET GAS REVENUE	2428.134
NET PROD REVENUE	0.

650 MMCF @ 103 price

EXHIBIT 13

TYPICAL WELL NO. 5
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO
650 MMF PER WELL 103 PRICE
CONSOLIDATED OIL & GAS
ECONOMICS OF DEVELOPMENT

DATE: 01/19/81.
TIME: 15.58.58.
FILE: TYPW3
PROJ: 8

A F T E R T A X E C O N O M I C S

AS OF DATE: 1/ 1/1981

-END- MO-YR	NET OIL MB-----	NET GAS MMF-----	REVENUE TO INT. M$-----	OPER. EXPENSE M$-----	NET INCOME M$-----	CAPITAL INVEST. M$-----	DEPR. M$---	DEPL. M$----	INCOME TAX M$-----	CASH FLOW M$-----	CUM. NET PW M$------
12-81	.104	27.180	81.160	1.800	79.360	475.400	52.965	0.	-37.489	-358.550	-369.387
12-82	.329	85.335	272.783	1.926	270.857	0.	45.401	0.	108.219	162.638	-248.665
12-83	.233	60.532	206.897	2.061	204.836	0.	38.918	0.	79.641	125.195	-172.566
12-84	.174	45.168	164.825	2.205	162.620	0.	33.360	0.	62.045	100.575	-122.504
12-85	.134	34.997	136.350	2.359	133.991	0.	28.597	0.	50.589	83.402	-88.508
12-86	.107	27.912	116.134	2.525	113.609	0.	24.513	0.	42.766	70.843	-64.861
12-87	.088	22.782	101.241	2.701	98.540	0.	21.013	0.	37.213	61.327	-48.098
12-88	.073	18.947	90.032	2.891	87.141	0.	18.012	0.	33.182	53.959	-36.020
12-89	.061	16.005	81.329	3.092	78.237	0.	15.440	0.	30.143	48.094	-27.205
12-90	.053	13.698	74.458	3.310	71.148	0.	13.235	0.	27.798	43.350	-20.698
12-91	.045	11.858	68.826	3.540	65.286	0.	11.345	0.	25.892	39.394	-15.855
12-92	.040	10.364	64.256	3.600	60.656	0.	9.725	0.	24.447	36.209	-12.211
12-93	.036	9.136	60.506	3.600	56.906	0.	8.336	0.	23.313	33.593	-9.442
12-94	.031	8.115	57.375	3.600	53.775	0.	7.146	0.	22.382	31.393	-7.323
12-95	.028	7.255	54.809	3.600	51.209	0.	6.125	0.	21.640	29.569	-5.688
8 TOT	1.536	399.284	1630.981	42.810	1588.171	475.400	334.130	0.	551.781	560.991	-5.688
AFTER	.351	91.466	872.308	162.516	709.792	0.	36.770	0.	323.051	386.741	-.231
TOTAL	1.887	490.750	2503.289	205.326	2297.963	475.400	370.900	0.	874.832	947.733	-.231

RECAP

	GROSS	W.I.	NET
INTEREST FRACTION	1.000000	1.000000	.755000
OIL RESERVES,MB	2.500	2.500	1.887
GAS RESERVES,MMCF	650.000	650.000	490.750
PRODUCTS	0.	0.	0.
REVENUE,M$	3618.829	3618.829	2503.289
OPERATING EXPENSE,M$	205.326	205.326	205.326
TANGIBLES,M$	370.900	370.900	370.900
INTANGIBLES,M$	104.500	104.500	104.500
INITIAL OIL PRICE ($/B)		44.24	
INITIAL GAS PRICE ($/M)		3.1100	

LIFE (YEARS)	60.14
GROSS OIL WELLS	0.
GROSS GAS WELLS	1.000
RATE OF RETURN,PCT	19.99
DISCOUNT RATE,PCT	20.0
PAYOUT YEARS	3.70
W.I. BEFORE PAYOUT,PCT	100.00
W.I. AFTER PAYOUT,PCT	100.00

DIS PCT	PW OF NET M$
5	449.427
10	221.599
15	88.581
20	-.232
30	-113.563
40	-184.017
50	-232.472
70	-294.939
100	-347.319

TYPICAL WELL NO. 3
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO
200 MMF PER WELL 2 X 103 PRICE
CONSOLIDATED OIL & GAS
ECONOMICS OF DEVELOPMENT

DATE: 01/16/81.
TIME: 17.04.53.
FILE: TYPW2
PROJ: 5

R E S E R V E S A N D E C O N O M I C S

AS OF DATE : 1/ 1/1981

END MO-YR	GROSS OIL PRODUCTION ----MB----	GROSS GAS PRODUCTION ----MMF---	OIL TO NET INTEREST ----MB----	GAS TO NET INTEREST ----MMF---	REVENUE TO INTEREST ----M$----	NET INVESTMENT ----M$----	NET OPER EXPENSES ----M$----	NET INCOME BEFORE FIT ----M$----	CUMULATIVE NET INCOME ----M$----	20.000 PCT CUM. DISC NET INCOME ----M$----
12-81	.031	8.010	.023	6.048	35.369	475.400	1.800	-441.831	-441.831	-444.877
12-82	.142	37.064	.108	27.983	175.112	0.	1.926	173.186	-268.645	-316.326
12-83	.101	26.041	.076	19.661	131.625	0.	2.061	129.564	-139.081	-237.571
12-84	.074	19.297	.056	14.569	104.225	0.	2.205	102.020	-37.061	-186.790
12-85	.057	14.874	.043	11.230	85.867	0.	2.359	83.508	46.447	-152.751
12-86	.045	11.814	.034	8.919	72.894	0.	2.525	70.369	116.816	-129.262
12-87	.037	9.611	.028	7.257	63.406	0.	2.701	60.705	177.521	-112.669
12-88	.031	7.971	.023	6.018	56.253	0.	2.891	53.362	230.883	-100.725
12-89	.026	6.719	.020	5.073	49.480	0.	3.092	46.388	277.271	-92.222
12-90	.022	5.739	.016	4.333	42.292	0.	3.310	38.982	316.253	-86.370
12-91	.019	4.960	.015	3.744	36.559	0.	3.540	33.019	349.272	-82.312
12-92	.017	4.329	.013	3.269	31.923	0.	3.600	28.323	377.595	-79.461
12-93	.014	3.812	.010	2.878	28.076	0.	3.600	24.476	402.071	-77.443
12-94	.013	3.381	.010	2.553	24.922	0.	3.600	21.322	423.393	-76.004
12-95	.012	3.020	.009	2.280	22.275	0.	3.600	18.675	442.068	-74.972
8 TOT	.641	166.642	.484	125.815	960.278	475.400	42.810	442.068	442.068	-74.972
AFTER	.128	33.358	.097	25.185	245.882	0.	111.483	134.399	576.467	-72.272
TOTAL	.769	200.000	.581	151.000	1206.160	475.400	154.293	576.467	576.467	-72.272
CUM.	0.	0.								
ULT.	.769	200.000								

NET OIL REVENUE	23.077	5 PCT	288.747	40 PCT	-245.532
NET GAS REVENUE	1183.083	10 PCT	119.299	50 PCT	-291.713
NET PROD REVENUE	0.	15 PCT	7.384	60 PCT	-325.139
		20 PCT	-72.272	80 PCT	-369.629
		30 PCT	-178.295	100 PCT	-397.181
CUM NET INC/INV(1)	1.21	CUM NET PW/INV(1)	-.15		
GROSS WELLS	1	LIFE (YEARS)	45.97		
MONTHS 1ST YEAR	12	RATE OF RETURN,PCT	15.46		
INITIAL W.I., PCT	100.0000	INITIAL N.I., PCT	75.5000		

EXHIBIT 14

200 MMCF @ 2X103 price

TYPICAL WELL NO. 3
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO
200 MMF PER WELL 2 X 103 PRICE
CONSOLIDATED OIL & GAS
ECONOMICS OF DEVELOPMENT

DATE: 01/16/81.
TIME: 17.20.19.
FILE: TYPW2
PROJ: 5

A F T E R T A X E C O N O M I C S

AS OF DATE: 1/ 1/1981

-END- MO-YR	NET OIL MB-----	NET GAS MMF-----	REVENUE TO INT. M$-----	OPER. EXPENSE M$-----	NET INCOME M$-----	CAPITAL INVEST. M$-----	DEPR. M$---	DEPL. M$----	INCOME TAX M$-----	CASH FLOW M$-----	CUM. NET PW M$------
12-81	.023	6.048	35.369	1.800	33.569	475.400	52.965	0.	-59.469	-382.361	-390.970
12-82	.108	27.983	175.112	1.926	173.186	0.	45.401	0.	61.337	111.849	-307.948
12-83	.076	19.661	131.625	2.061	129.564	0.	38.918	0.	43.510	86.054	-255.640
12-84	.056	14.569	104.225	2.205	102.020	0.	33.360	0.	32.957	69.063	-221.263
12-85	.043	11.230	85.867	2.359	83.508	0.	28.597	0.	26.357	57.151	-197.968
12-86	.034	8.919	72.894	2.525	70.369	0.	24.513	0.	22.011	48.358	-181.827
12-87	.028	7.257	63.406	2.701	60.705	0.	21.013	0.	19.052	41.653	-170.441
12-88	.023	6.018	56.253	2.891	53.362	0.	18.012	0.	16.968	36.394	-162.295
12-89	.020	5.073	49.480	3.092	46.388	0.	15.440	0.	14.855	31.533	-156.515
12-90	.016	4.333	42.292	3.310	38.982	0.	13.235	0.	12.359	26.623	-152.519
12-91	.015	3.744	36.559	3.540	33.019	0.	11.345	0.	10.403	22.616	-149.739
12-92	.013	3.269	31.923	3.600	28.323	0.	9.725	0.	8.927	19.396	-147.787
12-93	.010	2.878	28.076	3.600	24.476	0.	8.336	0.	7.747	16.729	-146.408
12-94	.010	2.553	24.922	3.600	21.322	0.	7.146	0.	6.805	14.517	-145.428
12-95	.009	2.280	22.275	3.600	18.675	0.	6.125	0.	6.024	12.651	-144.729
8 TOT	.484	125.815	960.278	42.810	917.468	475.400	334.130	0.	229.843	212.226	-144.729
AFTER	.097	25.185	245.882	111.483	134.399	0.	36.770	0.	46.862	87.537	-142.942
TOTAL	.581	151.000	1206.160	154.293	1051.867	475.400	370.900	0.	276.705	299.763	-142.942

RECAP

	GROSS	W.I.	NET
INTEREST FRACTION	1.000000	1.000000	.755000
OIL RESERVES,MB	.769	.769	.581
GAS RESERVES,MMCF	200.000	200.000	151.000
PRODUCTS	0.	0.	0.
REVENUE,M$	1741.181	1741.181	1206.160
OPERATING EXPENSE,M$	154.293	154.293	154.293
TANGIBLES,M$	370.900	370.900	370.900
INTANGIBLES,M$	104.500	104.500	104.500

INITIAL OIL PRICE ($/B)	44.25
INITIAL GAS PRICE ($/M)	6.2200

LIFE (YEARS)	45.97
GROSS OIL WELLS	0.
GROSS GAS WELLS	1.000
RATE OF RETURN,PCT	9.54
DISCOUNT RATE,PCT	20.0
PAYOUT YEARS	6.24
W.I. BEFORE PAYOUT,PCT	100.00
W.I. AFTER PAYOUT,PCT	100.00

DIS PCT	PW OF NET M$
5	105.241
10	-10.550
15	-87.665
20	-142.943
30	-217.253
40	-265.093
50	-298.521
70	-342.122
100	-379.151

TYPICAL WELL NO. 2
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO
300 MMF PER WELL 2 X 103 PRICE
CONSOLIDATED OIL & GAS
ECONOMICS OF DEVELOPMENT

DATE: 01/16/81.
TIME: 17.04.49.
FILE: TYPW2
PROJ: 4

R E S E R V E S A N D E C O N O M I C S

AS OF DATE : 1/ 1/1981

END MO-YR	GROSS OIL PRODUCTION -MB-	GROSS GAS PRODUCTION -MMF-	OIL TO NET INTEREST -MB-	GAS TO NET INTEREST -MMF-	REVENUE TO INTEREST -M$-	NET INVESTMENT -M$-	NET OPER EXPENSES -M$-	NET INCOME BEFORE FIT -M$-	CUMULATIVE NET INCOME -M$-	20.000 PCT CUM. DISC NET INCOME -M$-
12-81	.052	13.500	.039	10.192	59.603	475.400	1.800	-417.597	-417.597	-422.910
12-82	.212	55.054	.160	41.566	260.134	0.	1.926	258.208	-159.389	-231.249
12-83	.148	38.480	.112	29.053	194.462	0.	2.061	192.401	33.012	-114.300
12-84	.109	28.412	.082	21.451	153.458	0.	2.205	151.253	184.265	-39.012
12-85	.084	21.838	.064	16.487	126.079	0.	2.359	123.720	307.985	11.418
12-86	.067	17.308	.050	13.068	106.824	0.	2.525	104.299	412.284	46.232
12-87	.054	14.056	.041	10.612	92.726	0.	2.701	90.025	502.309	70.839
12-88	.044	11.642	.033	8.790	82.121	0.	2.891	79.230	581.539	88.574
12-89	.038	9.800	.029	7.399	72.173	0.	3.092	69.081	650.620	101.236
12-90	.032	8.364	.024	6.315	61.634	0.	3.310	58.324	708.944	109.991
12-91	.028	7.221	.021	5.452	53.236	0.	3.540	49.696	758.640	116.099
12-92	.024	6.298	.018	4.755	46.417	0.	3.600	42.817	801.457	120.409
12-93	.022	5.541	.017	4.183	40.868	0.	3.600	37.268	838.725	123.481
12-94	.018	4.914	.014	3.710	36.191	0.	3.600	32.591	871.316	125.681
12-95	.017	4.386	.012	3.312	32.335	0.	3.600	28.735	900.051	127.269
8 TOT	.949	246.814	.716	186.345	1418.261	475.400	42.810	900.051	900.051	127.269
AFTER	.205	53.186	.155	40.155	392.066	0.	147.513	244.553	1144.604	131.585
TOTAL	1.154	300.000	.871	226.500	1810.327	475.400	190.323	1144.604	1144.604	131.585

CUM.	0.	0.	NET OIL REVENUE	34.650	5 PCT	679.882	40 PCT	-127.100
			NET GAS REVENUE	1775.677	10 PCT	419.786	50 PCT	-196.062
ULT.	1.154	300.000	NET PROD REVENUE	0.	15 PCT	250.952	60 PCT	-246.045
					20 PCT	131.585	80 PCT	-312.739
CUM NET INC/INV(1)		2.41	CUM NET PW/INV(1)	.28	30 PCT	-26.768	100 PCT	-354.208
GROSS WELLS		1	LIFE (YEARS)	55.98				
MONTHS 1ST YEAR		12	RATE OF RETURN,PCT	28.07				
INITIAL W.I., PCT		100.0000	INITIAL N.I., PCT	75.5000				

EXHIBIT 15

300 MCF @ 2X103 price

TYPICAL WELL NO. 2
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO
300 MMF PER WELL 2 X 103 PRICE
CONSOLIDATED OIL & GAS
ECONOMICS OF DEVELOPMENT

DATE: 01/16/81.
TIME: 17.20.15.
FILE: TYPW2
PROJ: 4

A F T E R T A X E C O N O M I C S

AS OF DATE: 1/ 1/1981

-END- MO-YR	NET OIL MB	NET GAS MMF	REVENUE TO INT. M$	OPER. EXPENSE M$	NET INCOME M$	CAPITAL INVEST. M$	DEPR. M$	DEPL. M$	INCOME TAX M$	CASH FLOW M$	CUM. NET PW M$
12-81	.039	10.192	59.603	1.800	57.803	475.400	52.965	0.	-47.837	-369.759	-379.548
12-82	.160	41.566	260.134	1.926	258.208	0.	45.401	0.	102.147	156.061	-263.708
12-83	.112	29.053	194.462	2.061	192.401	0.	38.918	0.	73.672	118.729	-191.539
12-84	.082	21.451	153.458	2.205	151.253	0.	33.360	0.	56.588	94.665	-144.419
12-85	.064	16.487	126.079	2.359	123.720	0.	28.597	0.	45.659	78.061	-112.601
12-86	.050	13.068	106.824	2.525	104.299	0.	24.513	0.	38.297	66.002	-90.570
12-87	.041	10.612	92.726	2.701	90.025	0.	21.013	0.	33.126	56.899	-75.017
12-88	.033	8.790	82.121	2.891	79.230	0.	18.012	0.	29.385	49.845	-63.860
12-89	.029	7.399	72.173	3.092	69.081	0.	15.440	0.	25.748	43.333	-55.917
12-90	.024	6.315	61.634	3.310	58.324	0.	13.235	0.	21.643	36.681	-50.411
12-91	.021	5.452	53.236	3.540	49.696	0.	11.345	0.	18.408	31.288	-46.565
12-92	.018	4.755	46.417	3.600	42.817	0.	9.725	0.	15.884	26.933	-43.854
12-93	.017	4.183	40.868	3.600	37.268	0.	8.336	0.	13.887	23.381	-41.927
12-94	.014	3.710	36.191	3.600	32.591	0.	7.146	0.	12.214	20.377	-40.552
12-95	.012	3.312	32.335	3.600	28.735	0.	6.125	0.	10.833	17.882	-39.563
8 TOT	.716	186.345	1418.261	42.810	1375.451	475.400	334.130	0.	449.674	450.377	-39.563
AFTER	.155	40.155	392.066	147.513	244.553	0.	36.770	0.	99.737	144.817	-36.937
TOTAL	.871	226.500	1810.327	190.323	1620.004	475.400	370.900	0.	549.411	595.194	-36.937

RECAP

	GROSS	W.I.	NET
INTEREST FRACTION	1.000000	1.000000	.755000
OIL RESERVES,MB	1.154	1.154	.871
GAS RESERVES,MMCF	300.000	300.000	226.500
PRODUCTS	0.	0.	0.
REVENUE,M$	2613.276	2613.276	1810.327
OPERATING EXPENSE,M$	190.323	190.323	190.323
TANGIBLES,M$	370.900	370.900	370.900
INTANGIBLES,M$	104.500	104.500	104.500
INITIAL OIL PRICE ($/B)		44.23	
INITIAL GAS PRICE ($/M)		6.2200	

LIFE (YEARS)	55.98
GROSS OIL WELLS	0.
GROSS GAS WELLS	1.000
RATE OF RETURN,PCT	17.57
DISCOUNT RATE,PCT	20.0
PAYOUT YEARS	4.00
W.I. BEFORE PAYOUT,PCT	100.00
W.I. AFTER PAYOUT,PCT	100.00

DIS PCT	PW OF NET M$
5	308.592
10	145.691
15	38.988
20	-36.938
30	-138.459
40	-203.508
50	-248.782
70	-307.492
100	-356.805

TYPICAL WELL NO. 1A
BASIN DAKOTA .
SAN JUAN CO., NEW MEXICO
400 MMF PER WELL 2 X 103 PRICE
CONSOLIDATED OIL & GAS
ECONOMICS OF DEVELOPMENT

DATE: 01/16/81.
TIME: 14.24.28.
FILE: TYPW
PROJ: 2

R E S E R V E S A N D E C O N O M I C S

AS OF DATE : 1/ 1/1981

END MO-YR	GROSS OIL PRODUCTION ----MB----	GROSS GAS PRODUCTION ----MMF---	OIL TO NET INTEREST ----MB----	GAS TO NET INTEREST ----MMF---	REVENUE TO INTEREST ----M$----	NET INVESTMENT ----M$----	NET OPER EXPENSES ----M$----	NET INCOME BEFORE FIT ----M$----	CUMULATIVE NET INCOME ----M$----	20.000 PCT CUM. DISC NET INCOME ----M$----
12-81	.065	16.860	.049	12.729	74.440	475.400	1.800	-402.760	-402.760	-409.462
12-82	.271	70.407	.205	53.158	332.675	0.	1.926	330.749	-72.011	-163.955
12-83	.191	49.837	.144	37.627	251.837	0.	2.061	249.776	177.765	-12.131
12-84	.143	37.134	.108	28.036	200.583	0.	2.205	198.378	376.143	86.614
12-85	.111	28.738	.084	21.697	165.927	0.	2.359	163.568	539.711	153.286
12-86	.088	22.901	.066	17.290	141.325	0.	2.525	138.800	678.511	199.616
12-87	.072	18.677	.054	14.101	123.219	0.	2.701	120.518	799.029	232.559
12-88	.059	15.524	.045	11.721	109.513	0.	2.891	106.622	905.651	256.425
12-89	.051	13.108	.039	9.896	96.541	0.	3.092	93.449	999.100	273.554
12-90	.043	11.214	.032	8.467	82.638	0.	3.310	79.328	1078.428	285.461
12-91	.037	9.703	.028	7.326	71.513	0.	3.540	67.973	1146.401	293.816
12-92	.033	8.478	.025	6.401	62.508	0.	3.600	58.908	1205.309	299.746
12-93	.029	7.472	.022	5.641	55.087	0.	3.600	51.487	1256.796	303.990
12-94	.025	6.635	.019	5.009	48.891	0.	3.600	45.291	1302.087	307.047
12-95	.023	5.930	.017	4.478	43.718	0.	3.600	40.118	1342.205	309.264
8 TOT	1.241	322.618	.937	243.577	1860.415	475.400	42.810	1342.205	1342.205	309.264
AFTER	.297	77.382	.224	58.423	570.385	0.	184.514	385.871	1728.076	315.434
TOTAL	1.538	400.000	1.161	302.000	2430.800	475.400	227.324	1728.076	1728.076	315.434

CUM.	0.	0.	NET OIL REVENUE	46.389	5 PCT	1057.571	40 PCT	-25.540
			NET GAS REVENUE	2384.411	10 PCT	701.505	50 PCT	-115.595
ULT.	1.538	400.000	NET PROD REVENUE	0.	15 PCT	474.477	60 PCT	-180.632
					20 PCT	315.434	80 PCT	-267.091
CUM NET INC/INV(1)		3.63	CUM NET PW/INV(1)	.66	30 PCT	106.120	100 PCT	-320.649
GROSS WELLS		1	LIFE (YEARS)	66.25				
MONTHS 1ST YEAR		12	RATE OF RETURN,PCT	37.84				
INITIAL W.I., PCT		100.0000	INITIAL N.I., PCT	75.5000				

EXHIBIT 16

400 M²CF @ 2X103 price

TYPICAL WELL NO. 18
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO
400 MMF PER WELL 2 X 103 PRICE
CONSOLIDATED OIL & GAS
ECONOMICS OF DEVELOPMENT

DATE: 01/16/81.
TIME: 14.34.08.
FILE: TYPW
PROJ: 2

A F T E R T A X E C O N O M I C S

AS OF DATE: 1/ 1/1981

-END- MO-YR	NET OIL MB-----	NET GAS MMF-----	REVENUE TO INT. M$-----	OPER. EXPENSE M$-----	NET INCOME M$-----	CAPITAL INVEST. M$-----	DEPR. M$---	DEPL. M$----	INCOME TAX M$----	CASH FLOW M$-----	CUM. NET PW M$------
12-81	.049	12.729	74.440	1.800	72.640	475.400	52.965	0.	-39.018	-363.741	-374.092
12-82	.205	53.158	332.675	1.926	330.749	0.	45.401	0.	131.260	199.489	-226.017
12-83	.144	37.627	251.837	2.061	249.776	0.	38.918	0.	96.995	152.781	-133.150
12-84	.108	28.036	200.583	2.205	198.378	0.	33.360	0.	75.908	122.470	-72.189
12-85	.084	21.697	165.927	2.359	163.568	0.	28.597	0.	62.087	101.481	-30.824
12-86	.066	17.290	141.325	2.525	138.800	0.	24.513	0.	52.572	86.228	-2.042
12-87	.054	14.101	123.219	2.701	120.518	0.	21.013	0.	45.773	74.745	18.388
12-88	.045	11.721	109.513	2.891	106.622	0.	18.012	0.	40.761	65.861	33.130
12-89	.039	9.896	96.541	3.092	93.449	0.	15.440	0.	35.884	57.565	43.682
12-90	.032	8.467	92.638	3.310	79.328	0.	13.235	0.	30.403	48.925	51.025
12-91	.028	7.326	71.513	3.540	67.973	0.	11.345	0.	26.049	41.924	56.179
12-92	.025	6.401	62.508	3.600	58.908	0.	9.725	0.	22.624	36.284	59.831
12-93	.022	5.641	55.087	3.600	51.487	0.	8.336	0.	19.849	31.638	62.439
12-94	.019	5.009	48.891	3.600	45.291	0.	7.146	0.	17.547	27.744	64.311
12-95	.017	4.478	43.718	3.600	40.118	0.	6.125	0.	15.637	24.481	65.664
8 TOT	.937	243.577	1860.415	42.810	1817.605	475.400	334.130	0.	634.331	707.877	65.664
AFTER	.224	58.423	570.385	184.514	385.871	0.	36.770	0.	160.506	225.284	69.362
TOTAL	1.161	302.000	2430.800	227.324	2203.476	475.400	370.900	0.	794.917	933.161	69.362

RECAP

	GROSS	W.I.	NET
INTEREST FRACTION	1.000000	1.000000	.755000
OIL RESERVES,MB	1.538	1.538	1.161
GAS RESERVES,MMCF	400.000	400.000	302.000
PRODUCTS	0.	0.	0.
REVENUE,M$	3508.639	3508.639	2430.800
OPERATING EXPENSE,M$	227.324	227.324	227.324
TANGIBLES,M$	370.900	370.900	370.900
INTANGIBLES,M$	104.500	104.500	104.500
INITIAL OIL PRICE ($/B)		44.24	
INITIAL GAS PRICE ($/M)		6.2200	

LIFE (YEARS)	66.25
GROSS OIL WELLS	0.
GROSS GAS WELLS	1.000
RATE OF RETURN,PCT	24.69
DISCOUNT RATE,PCT	20.0
PAYOUT YEARS	3.09
W.I. BEFORE PAYOUT,PCT	100.00
W.I. AFTER PAYOUT,PCT	100.00

DIS PCT	PW OF NET M$
5	527.983
10	309.233
15	168.522
20	69.362
30	-62.046
40	-145.482
50	-203.133
70	-277.220
100	-338.575

TYPICAL NO. 4
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO
500 MMF PER WELL 2 X 103 PRICE
CONSOLIDATED OIL & GAS
ECONOMICS OF DEVELOPMENT

DATE: 01/16/81.
TIME: 17.05.01.
FILE: TYPW2
PROJ: 7

R E S E R V E S A N D E C O N O M I C S

AS OF DATE : 1/ 1/1981

END MO-YR	GROSS OIL PRODUCTION ----MB----	GROSS GAS PRODUCTION ----MMF---	OIL TO NET INTEREST ----MB----	GAS TO NET INTEREST ----MMF---	REVENUE TO INTEREST ----M$----	NET INVESTMENT ----M$----	NET OPER EXPENSES ----M$----	NET INCOME BEFORE FIT ----M$----	CUMULATIVE NET INCOME ----M$----	20.000 PCT CUM. DISC NET INCOME ----M$----
12-81	.080	20.880	.060	15.764	92.177	475.400	1.800	-385.023	-385.023	-393.384
12-82	.338	87.890	.256	66.357	415.275	0.	1.926	413.349	28.326	-86.566
12-83	.239	62.081	.180	46.872	313.739	0.	2.061	311.678	340.004	102.885
12-84	.178	46.184	.134	34.868	249.471	0.	2.205	247.266	587.270	225.964
12-85	.137	35.701	.104	26.955	206.105	0.	2.359	203.746	791.016	309.014
12-86	.109	28.422	.082	21.458	175.390	0.	2.525	172.865	963.881	366.714
12-87	.089	23.164	.067	17.489	152.811	0.	2.701	150.110	1113.991	407.746
12-88	.074	19.242	.056	14.528	135.769	0.	2.891	132.878	1246.869	437.488
12-89	.063	16.238	.048	12.260	119.587	0.	3.092	116.495	1363.364	458.842
12-90	.053	13.886	.040	10.483	102.321	0.	3.310	99.011	1462.375	473.704
12-91	.047	12.011	.035	9.069	88.565	0.	3.540	85.025	1547.400	484.165
12-92	.040	10.492	.030	7.921	77.327	0.	3.600	73.727	1621.127	491.576
12-93	.035	9.243	.027	6.979	68.114	0.	3.600	64.514	1685.641	496.893
12-94	.032	8.205	.024	6.194	60.497	0.	3.600	56.897	1742.538	500.734
12-95	.028	7.333	.021	5.537	54.047	0.	3.600	50.447	1792.985	503.522
8 TOT	1.542	400.972	1.164	302.734	2311.195	475.400	42.810	1792.985	1792.985	503.522
AFTER	.381	99.028	.288	74.766	729.970	0.	212.360	517.610	2310.595	511.352
TOTAL	1.923	500.000	1.452	377.500	3041.165	475.400	255.170	2310.595	2310.595	511.352

CUM.	0.	0.	NET OIL REVENUE	58.048	5 PCT	1442.260	40 PCT	85.847
			NET GAS REVENUE	2983.117	10 PCT	994.152	50 PCT	-26.512
ULT.	1.923	500.000	NET PROD REVENUE	0.	15 PCT	710.035	60 PCT	-107.669
					20 PCT	511.352	80 PCT	-215.581
CUM NET INC/INV(1)		4.86	CUM NET PW/INV(1)	1.08	30 PCT	250.110	100 PCT	-282.450
GROSS WELLS		1	LIFE (YEARS)	73.99				
MONTHS 1ST YEAR		12	RATE OF RETURN,PCT	47.42				
INITIAL W.I., PCT		100.0000	INITIAL N.I., PCT	75.5000				

EXHIBIT 17

500 MCF @ 2X103 price

TYPICAL NO. 4
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO
500 MMF PER WELL 2 X 103 PRICE
CONSOLIDATED OIL & GAS
ECONOMICS OF DEVELOPMENT

DATE: 01/16/81.
TIME: 17.20.27.
FILE: TYPW2
PROJ: 7

A F T E R T A X E C O N O M I C S

AS OF DATE: 1/ 1/1981

-END- MO-YR	NET OIL MB-----	NET GAS MMF-----	REVENUE TO INT. M$-----	OPER. EXPENSE M$-----	NET INCOME M$-----	CAPITAL INVEST. M$-----	DEPR. M$---	DEPL. M$----	INCOME TAX M$----	CASH FLOW M$-----	CUM. NET PW M$------
12-81	.060	15.764	92.177	1.800	90.377	475.400	52.965	0.	-32.201	-352.821	-364.194
12-82	.256	66.357	415.275	1.926	413.349	0.	45.401	0.	176.615	236.734	-188.473
12-83	.180	46.872	313.739	2.061	311.678	0.	38.918	0.	130.925	180.753	-78.603
12-84	.134	34.868	249.471	2.205	247.266	0.	33.360	0.	102.675	144.591	-6.632
12-85	.104	26.955	206.105	2.359	203.746	0.	28.597	0.	84.072	119.674	42.148
12-86	.082	21.458	175.390	2.525	172.865	0.	24.513	0.	71.209	101.656	76.080
12-87	.067	17.489	152.811	2.701	150.110	0.	21.013	0.	61.967	88.143	100.173
12-88	.056	14.528	135.769	2.891	132.878	0.	18.012	0.	55.136	77.742	117.575
12-89	.048	12.260	119.587	3.092	116.495	0.	15.440	0.	48.506	67.989	130.037
12-90	.040	10.483	102.321	3.310	99.011	0.	13.235	0.	41.172	57.839	138.719
12-91	.035	9.069	88.565	3.540	85.025	0.	11.345	0.	35.366	49.659	144.823
12-92	.030	7.921	77.327	3.600	73.727	0.	9.725	0.	30.721	43.006	149.151
12-93	.027	6.979	68.114	3.600	64.514	0.	8.336	0.	26.965	37.549	152.246
12-94	.024	6.194	60.497	3.600	56.897	0.	7.146	0.	23.881	33.016	154.475
12-95	.021	5.537	54.047	3.600	50.447	0.	6.125	0.	21.274	29.173	156.088
8 TOT	1.164	302.734	2311.195	42.810	2268.385	475.400	334.130	0.	878.283	914.703	156.088
AFTER	.288	74.766	729.970	212.360	517.610	0.	36.770	0.	230.804	286.807	160.541
TOTAL	1.452	377.500	3041.165	255.170	2785.995	475.400	370.900	0.	1109.087	1201.509	160.541

RECAP

	GROSS	W.I.	NET
INTEREST FRACTION	1.000000	1.000000	.755000
OIL RESERVES,MB	1.923	1.923	1.452
GAS RESERVES,MMCF	500.000	500.000	377.500
PRODUCTS	0.	0.	0.
REVENUE,M$	4389.581	4389.581	3041.165
OPERATING EXPENSE,M$	255.170	255.170	255.170
TANGIBLES,M$	370.900	370.900	370.900
INTANGIBLES,M$	104.500	104.500	104.500

INITIAL OIL PRICE ($/B)	44.24
INITIAL GAS PRICE ($/M)	6.2200

LIFE (YEARS)	73.99
GROSS OIL WELLS	0.
GROSS GAS WELLS	1.000
RATE OF RETURN,PCT	30.51
DISCOUNT RATE,PCT	20.0
PAYOUT YEARS	2.64
W.I. BEFORE PAYOUT,PCT	100.00
W.I. AFTER PAYOUT,PCT	100.00

DIS PCT	PW OF NET M$
5	704.975
10	444.349
15	277.709
20	160.541
30	5.518
40	-92.776
50	-160.616
70	-247.650
100	-319.490

TYPICAL WELL NO. 5A
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO
650 MMF PER WELL 2 X 103 PRICE
CONSOLIDATED OIL & GAS
ECONOMICS OF DEVELOPMENT

DATE: 01/19/81.
TIME: 15.51.36.
FILE: TYPH3
PROJ: 9

R E S E R V E S A N D E C O N O M I C S

AS OF DATE : 1/ 1/1981

END MO-YR	GROSS OIL PRODUCTION -----MB----	GROSS GAS PRODUCTION -----MMF---	OIL TO NET INTEREST -----MB-----	GAS TO NET INTEREST ----MMF---	REVENUE TO INTEREST ----M$----	NET INVESTMENT ----M$----	NET OPER EXPENSES ----M$----	NET INCOME BEFORE FIT ----M$----	CUMULATIVE NET INCOME ----M$----	20.000 PCT CUM. DISC NET INCOME ----M$----
12-81	.138	36.000	.104	27.180	158.927	475.400	1.800	-318.273	-318.273	-332.880
12-82	.433	112.444	.327	84.895	531.288	0.	1.926	529.362	211.089	60.052
12-83	.305	79.256	.230	59.838	400.533	0.	2.061	398.472	609.561	302.260
12-84	.226	58.871	.171	44.448	317.977	0.	2.205	315.772	925.333	459.439
12-85	.175	45.455	.132	34.319	262.431	0.	2.359	260.072	1185.405	565.447
12-86	.139	36.155	.105	27.297	223.120	0.	2.525	220.595	1406.000	639.080
12-87	.113	29.445	.085	22.231	194.243	0.	2.701	191.542	1597.542	691.436
12-88	.094	24.445	.071	18.456	172.480	0.	2.891	169.589	1767.131	729.396
12-89	.080	20.617	.061	15.565	151.838	0.	3.092	148.746	1915.877	756.661
12-90	.067	17.625	.050	13.307	129.862	0.	3.310	126.552	2042.429	775.657
12-91	.059	15.239	.045	11.506	112.345	0.	3.540	108.805	2151.234	789.031
12-92	.051	13.307	.038	10.047	98.084	0.	3.600	94.484	2245.718	798.541
12-93	.045	11.720	.034	8.848	86.389	0.	3.600	82.789	2328.507	805.365
12-94	.040	10.402	.031	7.854	76.676	0.	3.600	73.076	2401.583	810.298
12-95	.036	9.294	.027	7.017	68.518	0.	3.600	64.918	2466.501	813.886
8 TOT	2.001	520.275	1.511	392.808	2984.711	475.400	42.810	2466.501	2466.501	813.886
AFTER	.499	129.725	.376	97.942	956.245	0.	247.119	709.126	3175.627	824.033
TOTAL	2.500	650.000	1.887	490.750	3940.956	475.400	289.929	3175.627	3175.627	824.033

CUM.	0.	0.	NET OIL REVENUE	75.290	5 PCT	2021.816	40 PCT 276.633
			NET GAS REVENUE	3865.666	10 PCT	1444.111	50 PCT 131.446
ULT.	2.500	650.000	NET PROD REVENUE	0.	15 PCT	1079.159	60 PCT 26.226
					20 PCT	824.033	80 PCT -114.432
CUM NET INC/INV(1)		6.68	CUM NET PW/INV(1)	1.73	30 PCT	488.258	100 PCT -202.316
GROSS WELLS		1	LIFE (YEARS)	83.64			
MONTHS 1ST YEAR		12	RATE OF RETURN,PCT	63.31			
INITIAL W.I., PCT		100.0000	INITIAL N.I., PCT	75.5000			

EXHIBIT 18

650 M²CF @ 2X103 price

TYPICAL WELL NO. 5A
BASIN DAKOTA
SAN JUAN CO., NEW MEXICO
650 MMF PER WELL 2 X 103 PRICE
CONSOLIDATED OIL & GAS
ECONOMICS OF DEVELOPMENT

DATE: 01/19/81.
TIME: 15.59.03.
FILE: TYPW3
PROJ: 9

AFTER TAX ECONOMICS

AS OF DATE: 1/ 1/1981

-END- MO-YR	NET OIL MB-----	NET GAS MMF-----	REVENUE TO INT. M$-----	OPER. EXPENSE M$-----	NET INCOME M$-----	CAPITAL INVEST. M$-----	DEPR. M$---	DEPL. M$----	INCOME TAX M$----	CASH FLOW M$-----	CUM. NET PW M$------
12-81	.104	27.180	158.927	1.800	157.127	475.400	52.965	0.	-.161	-318.111	-332.732
12-82	.327	84.895	531.288	1.926	529.362	0.	45.401	0.	232.301	297.061	-112.232
12-83	.230	59.838	400.533	2.061	398.472	0.	38.918	0.	172.586	225.886	25.071
12-84	.171	44.448	317.977	2.203	315.772	0.	33.360	0.	135.558	180.214	114.774
12-85	.132	34.319	262.431	2.359	260.072	0.	28.597	0.	111.108	148.964	175.494
12-86	.105	27.297	223.120	2.525	220.595	0.	24.513	0.	94.119	126.476	217.710
12-87	.085	22.231	194.243	2.701	191.542	0.	21.013	0.	81.854	109.688	247.692
12-88	.071	18.456	172.480	2.891	169.589	0.	18.012	0.	72.757	96.832	269.367
12-89	.061	15.565	151.838	3.092	148.746	0.	15.440	0.	63.987	84.759	284.903
12-90	.050	13.307	129.862	3.310	126.552	0.	13.235	0.	54.392	72.160	295.734
12-91	.045	11.506	112.345	3.540	108.805	0.	11.345	0.	46.781	62.024	303.358
12-92	.038	10.047	98.084	3.600	94.484	0.	9.725	0.	40.684	53.800	308.774
12-93	.034	8.848	86.389	3.600	82.789	0.	8.336	0.	35.737	47.052	312.652
12-94	.031	7.854	76.676	3.600	73.076	0.	7.146	0.	31.646	41.430	315.448
12-95	.027	7.017	68.518	3.600	64.918	0.	6.125	0.	28.220	36.698	317.477
8 TOT	1.511	392.808	2984.711	42.810	2941.901	475.400	334.130	0.	1201.569	1264.931	317.477
AFTER	.376	97.942	956.245	247.119	709.126	0.	36.770	0.	322.731	386.395	323.135
TOTAL	1.887	490.750	3940.956	289.929	3651.027	475.400	370.900	0.	1524.300	1651.326	323.135

RECAP

	GROSS	W.I.	NET
INTEREST FRACTION	1.000000	1.000000	.755000
OIL RESERVES,MB	2.500	2.500	1.887
GAS RESERVES,MMCF	650.000	650.000	490.750
PRODUCTS	0.	0.	0.
REVENUE,M$	5688.415	5688.415	3940.956
OPERATING EXPENSE,M$	289.929	289.929	289.929
TANGIBLES,M$	370.900	370.900	370.900
INTANGIBLES,M$	104.500	104.500	104.500
INITIAL OIL PRICE ($/B)		44.24	
INITIAL GAS PRICE ($/M)		6.2200	

LIFE (YEARS)	83.64
GROSS OIL WELLS	0.
GROSS GAS WELLS	1.000
RATE OF RETURN,PCT	40.70
DISCOUNT RATE,PCT	20.0
PAYOUT YEARS	2.09
W.I. BEFORE PAYOUT,PCT	100.00
W.I. AFTER PAYOUT,PCT	100.00

DIS PCT	PW OF NET M$
5	1006.323
10	678.324
15	469.652
20	323.135
30	129.355
40	6.433
50	-78.478
70	-187.565
100	-277.621

Consolidated Oil & Gas, Inc.

WELL COST ESTIMATE

AVERAGE DAKOTA WELL WITH UPPER & LOWER DAKOTA, 2 FRACS.

AFE No. _____

C.O.G. WI. _____

TO: Drill (X) Recomplete ( ) Work Over ( )

State New Mexico County San Juan Field Basin Dakota

Lease Name Average Dakota Well Lease No. _____ Well No. Unnamed No. 1

Location: T31N, R12 & 13W - Average Dakota Well

DETAIL COST ESTIMATE				
INTANGIBLE COSTS	QUANTITY	PRICE	COST OF DRY HOLE	COST OF PRODUCER
Superintendence	15/20	200	3,000	4,000
Labor			1,000	2,500
Hauling			1,500	7,500
Drilling				
To Drill	7,000	16/ft.	112,000	112,000
Day Work - W/DP	2	5,600	11,200	11,200
Day Work - W/out Drill pipe				
Other Completion unit with compl. equip	12	2,500		30,000
Fuel			750	1,500
Water			10,000	14,000
Right of Way Damages			2,500	2,500
Drlg. Mud & Chemicals (Have been having LC)			17,500	17,500
Electric & Radioactivity Logs			16,500	19,500
Coring & Core Analysis				
Acidizing & Fracturing 2 fracs using Nitrogen				90,000
Drill Stem Tests				
Gun Perforating 2 Dakota zones				6,000
Cement & Cementing Services Surf. & 3-stage prod.			3,000	17,500
Shoes, Collars, & Centralizers DV tools prod.			1,000	5,000
Welding			250	750
Road & Location			4,000	4,000
Bits & Coreheads				750
Mud Logging				
Plugging Expense			7,500	
Directional Drilling Services				
Overhead			1,500	2,000
Tool Rental				5,000
Contingencies 5%			9,700	17,700
TOTAL INTANGIBLE COSTS			202,900	370,900
PERMANENT EQUIPMENT				
Conductor Pipe " OD				
Surface Casing 8-5/8" OD, 24#	250	10.00	2,500	2,500
Prod. Casing 5½ " OD 15.5#	7000	7.20		50,400
Tubing 1½ " OD	7000	2.30		16,100
Casing Head Assembly			1,500	1,500
Tubing Head Assembly				1,250
Xmas Tree & Manifold Assembly				8,250
Production Packer				
Tubing Catcher				
Bottom Hole Choke				
Miscellaneous Connections				2,000
Production Unit & Tank Battery				22,500
TOTAL Permanent Equipment			4,000	104,500
TOTAL COST OF COMPLETED WELL			206,900	475,400

EXHIBIT 19

Date: _____ Recommended by: _____

APPROVED (Company): _____ Approved by: _____

By: _____ Date: January 9, 1981

BEFORE THE
STATE OF NEW MEXICO
OIL CONSERVATION DIVISION

In the matter of the application of Southland Royalty Company for designation of a tight formation, San Juan County, New Mexico

Case No. 7116

AFFIDAVIT

I, FLOYD E. ELLISON, being first duly sworn, depose and state that:

Permeability Calculations

Exhibits 5, 6 and 7 show the permeability calculations for the Wilmerding 1-M in Section 10, T31N, R13W, Kline 1-M in Section 10, T31N, R13W and Senter 1-M in Section 24, T31N, R13W based on the flow tests previously submitted (which were witnessed by New Mexico Oil Conservation Division personnel). In all cases the permeability calculations using Darcy's flow equation show the in situ permeability to be well below 0.1 md.

Well Cost Estimate

Consolidated's drilling and completion well cost estimate for an average depth 7,000' single Dakota completion totals $475,400 (see Exhibit 19). These costs are based on our experience in drilling and completing a number of wells this past year in the immediate area. Several significant differences with the Southland Royalty cost estimate are:

1. Consolidated's use of $16/ft. vs. Southland's $14/ft. The $16/ft. figure is our most recent quoted price and corresponds with inquiries we have made of other operators' footage prices. We have a working interest in a well recently drilled in the area in which the operator was required to pay $19.51/ft.

2. Consolidated's average mud and water costs are well above those shown on the Southland estimate. Some mud and water costs have been as low as Southland's estimate, but we have experienced severe lost circulation in the Mesaverde, Gallup and/or Dakota zones in several wells which brings the average mud and water cost to our estimate.

3. The recent requirement by both the state and USGS to cement across the Ojo Alamo and circulate cement to surface requires additional DV tools and cement. Southland's cementing and cementing tools estimate is below the costs we have been experiencing in our most recent wells.

4. Completion Costs. Consolidated's completion procedure differs in several ways from Southland's. Consolidated has recently been including the tight lower Dakota in its completions because we believe enough additional reserves can be added in certain wells to justify the additional completion expense. A major cause of the increased expense is the necessity to perforate, stimulate, and clean up the upper and lower Dakota separately. The tight lower Dakota has an approximate 800 - 1,000# higher treatment and ISIP than does the upper Dakota

which makes it necessary to frac and clean up the zone before moving on to the upper Dakota completion. Consolidated has also been using nitrogen in its frac treatments to aid clean up but its use does add to stimulation costs.

Economics

Based on Consolidated Oil & Gas's required after tax economic criteria, Consolidated needs approximately 650 MMCF of gas reserves with Section 103 prices and 335 MMCF of gas reserves with 2 X 103 prices to justify drilling a single Dakota completion, as shown on Exhibit 8. These reserve requirements are considerably above what we used to justify our drilling program in the area this past year and above what Southland Royalty has indicated they need. The required larger reserves are the result of these major differences:

1. The majority of our wells this past year were dual completions with the Mesaverde reserves helping pay out the drilling and completion costs.

2. The drilling and completion costs have increased dramatically with the differences between Consolidated and Southland Royalty's estimates having been previously discussed.

3. The net interest (after deducting royalty interest and overriding royalty interest) on Consolidated operated properties in the area is 75.5% vs. Southland Royalty's indicated 86.5%. The majority of Consolidated's properties are 75% leases due to Consolidated having to give up an additional 12.5% ORR before it could farm-in the acreage and drill the original wells in the 1950's and 1960's. This is a major cut out of the income without any offsetting help on the expense side.

4. The required rate of return (ROR) after taxes for Consolidated is 20% vs. Southland Royalty's indicated 15%. Consolidated cannot justify less than a 20% ROR in the present money market when we pay over 20% for the money we borrow. Investors, including Consolidated, can receive more than 15% interest on CD's without assuming any risk so surely assuming risk is worth something above the 15% Southland proposed.

Exhibit 9 shows the assumptions used for our economic calculations and Exhibits 10, 11, 12 and 13 show the before and after taxes economics for 300 MMCFG, 400 MMCFG, 500 MMCFG and 650 MMCFG reserves with 103 pricing and Exhibits 14, 15, 16, 17 and 18 show the before and after taxes economics for 200 MMCFG, 300 MMCFG, 400 MMCFG, 500 MMCFG and 650 MMCFG reserves for 2 X 103 pricing.

Protection of Fresh Water

State and federal regulations currently provide for the protection of any fresh water aquifers that are being used or are expected to be used in the foreseeable future for domestic or agricultural water supplies. Three potential fresh water bearing formations in the area of interest are the San Jose, Nacimiento and Ojo Alamo. These three formations occur from the surface of the ground to a depth of approximately 1,000 feet in T31N, R13W and the western half of T31N, R12W.

The NMOCD by Rule 106 and the federal government regulations for protection of fresh water in oil and gas related activities both require the casing and cementing program to be designed to seal off fresh water bearing formations from

oil and gas bearing formations. They fulfill this requirement by having the oil and gas operator cement the production casing with sufficient cement to bring it above the Dakota several hundred feet, to usually cement across the Mesaverde zone when it is productive, and then to circulate cement to surface from several hundred feet below the base of the Ojo Alamo formation. Additionally, surface casing is set and cemented to surface when drilling begins which protects the top several hundred feet.

The above casing and cementing programs provide adequate protection to the fresh water sands even though large stimulation treatments are required in the tight Dakota producting formation which is about 5,900 feet below the deepest fresk water zone.

Exhibits 5 through 19 were prepared by me or under my direction and supervision.

Floyd E. Ellison, Jr.
Vice President - Operations

STATE OF COLORADO)
) ss
CITY AND COUNTY OF DENVER)

On this 22nd day of January, 1981, before me personally appeared Floyd E. Ellison, Jr., to me known to be the person described in and who executed the foregoing Affidavit before me, and who acknowledged to me that he executed it as his own free act and deed.

WITNESS my hand and seal on this day and year last above written.

Patricia G Burns
Notary Public

My Commission Expires:
My commission expires June 13, 1983

CONSOLIDATED OIL & GAS, INC.
Wilmerding 1-M
NE/4 NW/4 10-T31N-R13W
San Juan County, New Mexico

Lower Dakota	Perforations 6788', 6798', 6828', 6830', 6833', 6838', 6841', and 6846', (8-.32" diameter perforations.)
	Acidized with 250 gallons 7½% NE acid using 16 ball sealers.
	Swabbed well down.
9/11/80	Flowed well through Critical Prover using 1/8" orifice plate. Gas rate too small to measure.
	Test witnessed by Charles Gholson with NMOCC and Barney Jones with Consolidated Oil & Gas, Inc.
	Did not test Upper Dakota.

BEFORE EXAMINER NUTTER
OIL CONSERVATION DIVISION
COG EXHIBIT NO. 2
CASE NO. 7116

CONSOLIDATED OIL & GAS, INC.
Kline 1-M
NE/4 SE/4 10-T31N-R13W
San Juan County, New Mexico

Lower Dakota	Perforations 6655', 6658', 6668', 6672', 6676', 6715', 6720', 6724', 6729', 6734', and 6736', (9-.29" holes)
	Acidized with 300 gallons 7½% NE acid using 21 ball sealers. Balled off @ 5000#.
	Swabbed down and recovered water and acid.
	Flowed well through Critical Prover using 1/8" orifice plate. Produced 5 hours with maximum rate of 12.85 MCF/D.
8/22/80	Test witnessed by Rich Simmons of NMOCC and Chink Ashbrook with Consolidated Oil & Gas, Inc.
Upper Dakota	Perforations 6506', 6512', 6520', 6527', 6532', 6540', 6550', 6557', 6565', 6572', 6577', 6584', 6592', 6612', 6617', 6621', and 6629', (17 perforations .32" diameter)
	Acidized with 500 gallons 7½% NE acid with 30 ball sealers. Balled off @ 5500#.
	Swabbed well down.
	Flowed well 4 hours through Critical Prover using 1/8" orifice plate. Gas rate too small to measure.
8/28/80	Test witnessed by Richard H. Simmons of NMOCC and Chink Ashbrook with Consolidated Oil & Gas, Inc.

BEFORE EXAMINER NUTTER
OIL CONSERVATION DIVISION
COG EXHIBIT NO. 3
CASE NO. 7116

CONSOLIDATED OIL & GAS, INC.
Senter 1-M
NE/4 SE/4 24-T31N-R13W
San Juan County, New Mexico

Lower Dakota — Perforations 6898', 6902', 6906', 6910', 6914', 6918', 6934', 6938', 6942', 6946', 6950', 6954', & 6958', (13-.33" diameter perforations)

Acidized with 500 gallons 15% NE acid using 25 ball sealers. Balled off @ 3200#.

Swabbed well down to get acid back.

5/20-21/80 — Tefteller, Inc. ran flow test on Dakota perforations 6898'-6958'.

5/20/80

12:45 p.m.	2.73 MCF/D
3:45 p.m.	1.91 MCF/D
7:00 a.m.	1.91 MCF/D

Test witnessed by Frank Chavez and Rich Simmons of NMOCC, Tobby Tefteller and Len Alexander with Tefteller and Aubrey Prather with Consolidated Oil & Gas, Inc.

Upper Dakota — Perforations 6740', 6745', 6759', 6776', 6782', 6786', 6794', 6808', 6810', 6814', and 6816'.

Acidized with 500 gallons 15% NE acid using 22 ball sealers. Balled off @ 3500#.

Swabbed well down.

6/4-5/80 — Tefteller, Inc. ran flow test on Dakota perforations 6740'-6816'.

Flowed total 21 hours. Well stabilized @ approximately 52 MCF/D rate over last 16½ hours.

Test witnessed by Rich Simmons with NMOCC, Tefteller testers, and Barney Jones with Consolidated Oil & Gas, Inc.

BEFORE EXAMINER NUTTER
OIL CONSERVATION DIVISION
CO6 EXHIBIT NO. 4
CASE NO. 7116

CAMPBELL AND BLACK, P.A.
LAWYERS

JACK M. CAMPBELL
BRUCE D. BLACK
MICHAEL B. CAMPBELL
WILLIAM F. CARR

POST OFFICE BOX 2208
JEFFERSON PLACE
SANTA FE, NEW MEXICO 87501
TELEPHONE (505) 988-4421

December 11, 1980

Mr. Joe D. Ramey
Division Director
Oil Conservation Division
New Mexico Department of
Energy & Minerals
Post Office Box 2088
Santa Fe, New Mexico 87501

Re: Application of Southland Royalty Company
for Designation of Tight Formation,
San Juan County, New Mexico

Dear Mr. Ramey:

Enclosed in triplicate is the application of Southland Royalty Company in the above-referenced matter.

The applicant requests that this matter be included on the docket for the examiner hearing scheduled to be held on December 30, 1980.

Very truly yours,

William F. Carr

William F. Carr

WFC:lr

Enclosures

cc: Mr. Marlin Thompson

BEFORE THE

OIL CONSERVATION DIVISION

NEW MEXICO DEPARTMENT OF ENERGY AND MINERALS

IN THE MATTER OF THE APPLICATION
OF SOUTHLAND ROYALTY COMPANY,
FOR DESIGNATION OF TIGHT FORMATION, SAN JUAN COUNTY, NEW MEXICO.

Case 7116

APPLICATION

DEC 1 2 1980
OIL CONSERVATION DIVISION
SANTA FE

Comes now SOUTHLAND ROYALTY COMPANY, by and through its undersigned attorneys and as provided in the Oil Conservation Division's Special Rules and Procedures for Tight Formation Designations under Section 107 of the Natural Gas Policy Act of 1978 promulgated by Oil Conservation Division Order No. R-6388 on June 30, 1980, hereby makes application for an order designating certain portions of the Dakota formation (Basin Dakota Field) as a tight formation under Section 107 of the Natural Gas Policy Act of 1978 and in support of its application would show the Division:

1. Applicant is the owner and operator of certain interests in the Dakota formation (Basin Dakota Field) underlying the following described lands situated in San Juan County, New Mexico:

Township 32 North, Range 10 West, N.M.P.M.
Sections 7 through 36: All

Township 32 North, Range 11 West, N.M.P.M.
Sections 7 through 27: All
Sections 34 through 36: All

Township 32 North, Range 12 West, N.M.P.M.
Sections 7 through 33: All

Township 32 North, Range 13 West, N.M.P.M.
Sections 7 through 36: All

Township 31 North, Range 10 West, N.M.P.M.
Sections 1 through 36: All

Township 31 North, Range 11 West, N.M.P.M.
Section 1: All
Sections 12 and 13: All
Sections 22 through 27: All
Sections 34 through 36: All

Containing a total of 93,860.00 acres, more or less.

2. The Dakota formation is expected to have an estimated averave in situ gas permeability throughout the pay section of less than 0.1 millidarcy per foot.

3. The average depth of the top of the Dakota formation is 7050 feet and the stabilized production rate, against atmospheric pressure, of wells completed for production in said formation, without stimulation, is not expected to exceed 290 mcf of gas per day.

4. No well drilled into the Dakota formation in the above-described area is expected to produce, without stimulation, more than five barrels of crude oil per day.

5. Attached to this application and incorporated herein by reference is a complete set of exhibits which applicant proposes to offer or introduce at the hearing on this application, together with a statement of the meaning and purpose of each exhibit. These exhibits cover all aspects of the required evidentiary data described in Section D of the Oil Conservation Division's Special Rules and Procedures for Tight Sand Formation Designation under Section 107 of the Natural Gas Policy Act of 1978.

WHEREFORE, Applicant prays that this application be set for hearing before a duly appointed examiner of the Oil

Conservation Division and that after notice and hearing as required by law, the Division enter its order recommending to the Federal Energy Regulatory Commission that pursuant to 18 CFR, Section 271.701 - 705, that the Dakota formation underlying the above-described land be designated a tight formation, and making such other and further provisions as may be proper in the premises.

Respectfully submitted,

CAMPBELL AND BLACK, P.A.

By _____
William F. Carr
Attorneys for Applicant
Post Office Box 2208
Santa Fe, New Mexico 87501
Telephone: (505) 988-4421

Certificate of Service

I hereby certify that a copy of this Application and a complete set of all exhibits which Applicant proposes to offer or introduce at hearing, together with the statement of meaning and purpose of each, has been delivered to the United States Geological Survey in Albuquerque, New Mexico on this 12th day of December, 1980.

_____
William F. Carr

BEFORE THE

OIL CONSERVATION DIVISION

NEW MEXICO DEPARTMENT OF ENERGY AND MINERALS

IN THE MATTER OF THE APPLICATION OF SOUTHLAND ROYALTY COMPANY, FOR DESIGNATION OF TIGHT FORMATION, SAN JUAN COUNTY, NEW MEXICO.

Case 7116

APPLICATION

Comes now SOUTHLAND ROYALTY COMPANY, by and through its undersigned attorneys and as provided in the Oil Conservation Division's Special Rules and Procedures for Tight Formation Designations under Section 107 of the Natural Gas Policy Act of 1978 promulgated by Oil Conservation Division Order No. R-6388 on June 30, 1980, hereby makes application for an order designating certain portions of the Dakota formation (Basin Dakota Field) as a tight formation under Section 107 of the Natural Gas Policy Act of 1978 and in support of its application would show the Division:

DEC 02 1980
OIL CONS. DIVISION
SANTA FE

1. Applicant is the owner and operator of certain interests in the Dakota formation (Basin Dakota Field) underlying the following described lands situated in San Juan County, New Mexico:

Township 32 North, Range 10 West, N.M.P.M.
Sections 7 through 36: All

Township 32 North, Range 11 West, N.M.P.M.
Sections 7 through 27: All
Sections 34 through 36: All

Township 32 North, Range 12 West, N.M.P.M.
Sections 7 through 33: All

Township 32 North, Range 13 West, N.M.P.M.
Sections 7 through 36: All

Township 31 North, Range 10 West, N.M.P.M.
Sections 1 through 36: All

Township 31 North, Range 11 West, N.M.P.M.
Section 1: All
Sections 12 and 13: All
Sections 22 through 27: All
Sections 34 through 36: All

Containing a total of 93,860.00 acres, more or less.

2. The Dakota formation is expected to have an estimated averave in situ gas permeability throughout the pay section of less than 0.1 millidarcy per foot.

3. The average depth of the top of the Dakota formation is 7050 feet and the stabilized production rate, against atmospheric pressure, of wells completed for production in said formation, without stimulation, is not expected to exceed 290 mcf of gas per day.

4. No well drilled into the Dakota formation in the above-described area is expected to produce, without stimulation, more than five barrels of crude oil per day.

5. Attached to this application and incorporated herein by reference is a complete set of exhibits which applicant proposes to offer or introduce at the hearing on this application, together with a statement of the meaning and purpose of each exhibit. These exhibits cover all aspects of the required evidentiary data described in Section D of the Oil Conservation Division's Special Rules and Procedures for Tight Sand Formation Designation under Section 107 of the Natural Gas Policy Act of 1978.

WHEREFORE, Applicant prays that this application be set for hearing before a duly appointed examiner of the Oil

Conservation Division and that after notice and hearing as required by law, the Division enter its order recommending to the Federal Energy Regulatory Commission that pursuant to 18 CFR, Section 271.701 - 705, that the Dakota formation underlying the above-described land be designated a tight formation, and making such other and further provisions as may be proper in the premises.

Respectfully submitted,

CAMPBELL AND BLACK, P.A.

By William F. Carr

William F. Carr
Attorneys for Applicant
Post Office Box 2208
Santa Fe, New Mexico 87501
Telephone: (505) 988-4421

Certificate of Service

I hereby certify that a copy of this Application and a complete set of all exhibits which Applicant proposes to offer or introduce at hearing, together with the statement of meaning and purpose of each, has been delivered to the United States Geological Survey in Albuquerque, New Mexico on this 12th day of December, 1980.

William F. Carr

BEFORE THE

OIL CONSERVATION DIVISION

NEW MEXICO DEPARTMENT OF ENERGY AND MINERALS

IN THE MATTER OF THE APPLICATION
OF SOUTHLAND ROYALTY COMPANY,
FOR DESIGNATION OF TIGHT FORMA-
TION, SAN JUAN COUNTY, NEW MEXICO.

Case 7116

RECEIVED
DEC 12 1980
OIL CONSERVATION DIVISION
SANTA FE, NEW MEXICO

APPLICATION

Comes now SOUTHLAND ROYALTY COMPANY, by and through its undersigned attorneys and as provided in the Oil Conservation Division's Special Rules and Procedures for Tight Formation Designations under Section 107 of the Natural Gas Policy Act of 1978 promulgated by Oil Conservation Division Order No. R-6388 on June 30, 1980, hereby makes application for an order designating certain portions of the Dakota formation (Basin Dakota Field) as a tight formation under Section 107 of the Natural Gas Policy Act of 1978 and in support of its application would show the Division:

1. Applicant is the owner and operator of certain interests in the Dakota formation (Basin Dakota Field) underlying the following described lands situated in San Juan County, New Mexico:

Township 32 North, Range 10 West, N.M.P.M.
Sections 7 through 36: All

Township 32 North, Range 11 West, N.M.P.M.
Sections 7 through 27: All
Sections 34 through 36: All

Township 32 North, Range 12 West, N.M.P.M.
Sections 7 through 33: All

Township 32 North, Range 13 West, N.M.P.M.
Sections 7 through 36: All

Township 31 North, Range 10 West, N.M.P.M.
Sections 1 through 36: All

Township 31 North, Range 11 West, N.M.P.M.
Section 1: All
Sections 12 and 13: All
Sections 22 through 27: All
Sections 34 through 36: All

Containing a total of 93,860.00 acres, more or less.

2. The Dakota formation is expected to have an estimated averave in situ gas permeability throughout the pay section of less than 0.1 millidarcy per foot.

3. The average depth of the top of the Dakota formation is 7050 feet and the stabilized production rate, against atmospheric pressure, of wells completed for production in said formation, without stimulation, is not expected to exceed 290 mcf of gas per day.

4. No well drilled into the Dakota formation in the above-described area is expected to produce, without stimulation, more than five barrels of crude oil per day.

5. Attached to this application and incorporated herein by reference is a complete set of exhibits which applicant proposes to offer or introduce at the hearing on this application, together with a statement of the meaning and purpose of each exhibit. These exhibits cover all aspects of the required evidentiary data described in Section D of the Oil Conservation Division's Special Rules and Procedures for Tight Sand Formation Designation under Section 107 of the Natural Gas Policy Act of 1978.

WHEREFORE, Applicant prays that this application be set for hearing before a duly appointed examiner of the Oil

Conservation Division and that after notice and hearing as required by law, the Division enter its order recommending to the Federal Energy Regulatory Commission that pursuant to 18 CFR, Section 271.701 - 705, that the Dakota formation underlying the above-described land be designated a tight formation, and making such other and further provisions as may be proper in the premises.

Respectfully submitted,

CAMPBELL AND BLACK, P.A.

By William F. Carr

William F. Carr
Attorneys for Applicant
Post Office Box 2208
Santa Fe, New Mexico 87501
Telephone: (505) 988-4421

Certificate of Service

I hereby certify that a copy of this Application and a complete set of all exhibits which Applicant proposes to offer or introduce at hearing, together with the statement of meaning and purpose of each, has been delivered to the United States Geological Survey in Albuquerque, New Mexico on this 12th day of December, 1980.

William F. Carr

United States Department of the Interior

GEOLOGICAL SURVEY

South Central Region
P. O. Box 26124
Albuquerque, New Mexico 87125

SEP 4 1981

Mr. W. Perry Pearce
Oil Conservation Division
State of New Mexico
P. O. Box 2088
Santa Fe, New Mexico 87501

Dear Mr. Pearce:

This jurisdictional agency concurs in the recommendation of the State of New Mexico, Case No. 7116, Order No. R-6747, dated August 7, 1981, that the Dakota formation underlying the described lands in subject order in San Juan County, New Mexico, be designated as a Section 107 tight formation.

It is requested that this concurrence be included with the recommendation submitted to the Federal Energy Regulatory Commission.

Sincerely yours,

James W. Skelton

For Gene F. Daniel
Deputy Conservation Manager
Oil and Gas

Memo

From

FLORENE DAVIDSON
ADMINISTRATIVE SECRETARY

To Called in by Bill Carr
12/9/80

Southland Royalty Company
Designation of Tight
Formation

San Juan County
Dakota formation

T 31 and 32 N,
R 10, 11, 12, and 13W

93,860 acres

OIL CONSERVATION COMMISSION-SANTA FE

Dockets Nos. 1-81 and 2-81 are tentatively set for January 14 and 28, 1981. Applications for hearing must be filed at least 22 days in advance of hearing date.

DOCKET: EXAMINER HEARING - TUESDAY - DECEMBER 30, 1980

9 A.M. - OIL CONSERVATION DIVISION CONFERENCE ROOM,
STATE LAND OFFICE BUILDING, SANTA FE, NEW MEXICO

The following cases will be heard before Daniel S. Nutter, Examiner, or Richard L. Stamets, Alternate Examiner:

CASE 7113: Application of Fred Pool, Jr. for a dual completion, Chaves County, New Mexico. Applicant, in the above-styled cause, seeks approval for the dual completion of his Grynberg Com Fed. Well No. 1 located in Unit J of Section 13, Township 6 South, Range 24 East, to produce gas from the Abo and Pennsylvanian formations.

CASE 7051: (Continued from November 25, 1980, Examiner Hearing)

Application of Petro Lewis Corporation for downhole commingling, Lea County, New Mexico. Applicant, in the above-styled cause, seeks approval for the downhole commingling of Blinebry and Drinkard production in the wellbore of its L. G. Warlick "B" Well No. 2 located in Unit G of Section 19, Township 21 South, Range 37 East.

CASE 6940: (Continued from November 25, 1980, Examiner Hearing)

Application of Adobe Oil Company for compulsory pooling, Lea County, New Mexico. Applicant, in the above-styled cause, seeks an order pooling all mineral interests down through the Wolfcamp formation underlying the NW/4 SE/4 for oil and the SE/4 for gas, Section 23, Township 20 South, Range 38 East, to be dedicated to a well to be drilled at a standard location thereon. Also to be considered will be the cost of drilling and completing said well and the allocation of the cost thereof as well as actual operating costs and charges for supervision, designation of applicant as operator of the well, and a charge for risk involved in drilling said well.

CASE 7103: (Continued from December 10, 1980, Examiner Hearing)

Application of E. L. Latham, Jr. for compulsory pooling, Eddy County, New Mexico. Applicant, in the above-styled cause, seeks an order pooling all mineral interests in the Wolfcamp thru Pennsylvanian formations underlying the N/2 of Section 7, Township 22 South, Range 26 East, to be dedicated to a well to be drilled at a standard location thereon. Also to be considered will be the cost of drilling and completing said well and the allocation of the cost thereof as well as actual operating costs and charges for supervision, designation of applicant as operator of the well, and a charge for risk involved in drilling said well.

CASE 7114: Application of Yates Petroleum Corporation for an unorthodox gas well location, Eddy County, New Mexico. Applicant, in the above-styled cause, seeks approval for the unorthodox location of its Rio Penasco "JX" Well No. 2, a Morrow test to be drilled 660 feet from the South and East lines of Section 35, Township 18 South, Range 25 East, the S/2 of said Section 35 to be dedicated to the well.

CASE 7115: Application of Yates Petroleum Corporation for an unorthodox gas well location, Eddy County, New Mexico. Applicant, in the above-styled cause, seeks approval for the unorthodox location of a Morrow test well to be drilled 660 feet from the South and East lines of Section 14, Township 17 South, Range 26 East, the S/2 of said Section 14 to be dedicated to the well.

CASE 7116: Application of Southland Royalty Company for designation of a tight formation, San Juan County, New Mexico. Applicant, in the above-styled cause, seeks the designation of the Dakota formation underlying portions of Townships 31 and 32 North, Ranges 10, 11, 12, and 13 West, containing 93,860 acres, more or less, as a tight formation pursuant to Section 107 of the Natural Gas Policy Act and 18 CFR Section 271.701-705.

STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION DIVISION

BRUCE KING
GOVERNOR

LARRY KEHOE
SECRETARY

POST OFFICE BOX 2088
STATE LAND OFFICE BUILDING
SANTA FE, NEW MEXICO 87501
(505) 827-2434

August 7, 1981

Mr. William F. Carr
Campbell, Byrd & Black
Attorneys at Law
Post Office Box 2208
Santa Fe, New Mexico

Re: CASE NO. 7116
ORDER NO. R-6747

Applicant:

Southland Royalty Company

Dear Sir:

Enclosed herewith are two copies of the above-referenced Division order recently entered in the subject case.

Yours very truly,

JOE D. RAMEY
Director

JDR/fd

Copy of order also sent to:

Hobbs OCD x
Artesia OCD x
Aztec OCD x

Other Lynn Teschendorf

RECEIVED
SEP 14 1981
OIL CONSERVATION DIVISION
SANTA FE

FRED E. TURNER
OIL AND GAS PRODUCER
ONE ENERGY SQUARE - SUITE 852
4925 GREENVILLE AVENUE
DALLAS, TEXAS 75206
(214) 361-7010

September 10, 1981

Mr. W. Perry Pearce
General Counsel
State of New Mexico
Energy and Minerals Dept.
Oil Conservation Division
P. O. Box 2088
Santa Fe, New Mexico 87501

Re: Dakota Formation -
Tight Gas Determination
(Order 6746)

Dear Mr. Pearce:

Thank you for your nice letter of September 1, 1981 and for forwarding Order Nos. 6726 and 6747 to me. When Order 6746 becomes finalized with the paperwork, I would appreciate your office mailing me a copy of that order as well.

With very best wishes, I remain,

Yours very truly,

Fred E. Turner

FET/ewp

STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION DIVISION

IN THE MATTER OF THE HEARING
CALLED BY THE OIL CONSERVATION
DIVISION FOR THE PURPOSE OF
CONSIDERING:

CASE NO. 7116
Order No. R-6747

APPLICATION OF SOUTHLAND ROYALTY
COMPANY FOR DESIGNATION OF A TIGHT
FORMATION, SAN JUAN COUNTY, NEW MEXICO.

ORDER OF THE DIVISION

BY THE DIVISION:

This cause came on for hearing at 9 a.m. on December 30, 1980, at Santa Fe, New Mexico, before Examiner Daniel S. Nutter.

NOW, on this 7th day of August, 1981, the Division Director, having considered the testimony, the record, and the recommendations of the Examiner, and being fully advised in the premises,

FINDS:

(1) That due public notice having been given as required by law, the Division has jurisdiction of this cause and the subject matter thereof.

(2) That, pursuant to Section 107 of the Natural Gas Policy Act of 1978, and CFR Section 271.703, applicant Southland Royalty Company requested the designation as a "tight formation" of the Dakota formation underlying the following described lands:

SAN JUAN COUNTY, NEW MEXICO

TOWNSHIP 31 NORTH, RANGE 10 WEST, NMPM
Sections 1 through 36: All

TOWNSHIP 31 NORTH, RANGE 11 WEST, NMPM
Section 1: All
Sections 12 and 13: All
Sections 22 through 27: All
Sections 34 through 36: All

TOWNSHIP 32 NORTH, RANGE 10 WEST, NMPM
Sections 7 through 36: All

TOWNSHIP 32 NORTH, RANGE 11 WEST, NMPM
Sections 7 through 27: All
Sections 34 through 36: All

TOWNSHIP 32 NORTH, RANGE 12 WEST, NMPM
Sections 7 through 33: All

TOWNSHIP 32 NORTH, RANGE 13 WEST, NMPM
Sections 7 through 36: All

containing a total of 93,860.00 acres, more or less.

(3) That at the hearing, applicant requested dismissal of that portion of the application pertaining to Sections 30 and 31, Township 32 North, Range 13 West, NMPM, containing some 989.32 acres, more or less, leaving for consideration some 92,871 acres, more or less.

(4) That said request for dismissal should be approved, and no further consideration given herein to said lands.

(5) That at the hearing, Consolidated Oil and Gas, Incorporated, appeared and requested expansion of the area applied for by applicant Southland Royalty to also include the following described lands for consideration as a "tight formation":

SAN JUAN COUNTY, NEW MEXICO

TOWNSHIP 31 NORTH, RANGE 12 WEST, NMPM
Sections 5 through 8: All
Sections 17 through 20: All
Sections 29 through 32: All

TOWNSHIP 31 NORTH, RANGE 13 WEST, NMPM
Sections 1 through 36: All

containing a total of 29,645 acres, more or less.

(6) That although the aforesaid 29,645 acres, combined with the 92,871 acres remaining in the Southland application, exceeds the 93,860 acres stated in the legal notice for this case as being up for consideration, the 29,645 acres do lie within the area described in said legal notice, it having been advertised that consideration would be given to "the designation of the Dakota formation underlying portions of Townships 31 and 32 North, Ranges 10, 11, 12, and 13 West."

(7) That consideration for designation as a tight formation should be given to the Dakota formation underlying the lands described in Finding No. (5) above, as requested by Consolidated.

(8) That subsequent to the hearing on December 30, 1980, certain parties requested further additions to the lands being considered in this case for designation as a tight formation.

(9) That no evidence appears in the record to support such additional lands and they should not be considered further.

(10) That the lands with which this order will hereinafter be concerned are described as follows:

SAN JUAN COUNTY, NEW MEXICO

TOWNSHIP 31 NORTH, RANGE 10 WEST, NMPM
Sections 1 through 36: All

TOWNSHIP 31 NORTH, RANGE 11 WEST, NMPM
Section 1: All
Sections 12 and 13: All
Sections 22 through 27: All
Sections 34 through 36: All

TOWNSHIP 31 NORTH, RANGE 12 WEST, NMPM
Sections 5 through 8: All
Sections 17 through 20: All
Sections 29 through 32: All

TOWNSHIP 31 NORTH, RANGE 13 WEST, NMPM
Sections 1 through 36: All

TOWNSHIP 32 NORTH, RANGE 10 WEST, NMPM
Sections 7 through 36: All

TOWNSHIP 32 NORTH, RANGE 11 WEST, NMPM
Sections 7 through 27: All
Sections 34 through 36: All

TOWNSHIP 32 NORTH, RANGE 12 WEST, NMPM
Sections 7 through 33: All

TOWNSHIP 32 NORTH, RANGE 13 WEST, NMPM
Sections 7 through 29: All
Sections 32 through 36: All

containing 122,516 acres, more or less, and hereinafter referred to as the "area."

(11) That while the application was for designation of the Dakota formation as a tight formation, the Dakota formation constitutes but a portion of the "Dakota Producing Interval," which, as defined by the Division, comprises the vertical limits of the Basin-Dakota Gas Pool, being from the base of the Greenhorn Limestone to a point 400 feet below the base of said formation and consisting of the Graneros formation, the Dakota formation, and the productive upper limit of the Morrison formation.

(12) That inasmuch as practically all so-called "Dakota" wells drilled in the subject area are, or potentially are, tested in and/or completed in the entire Dakota Producing Interval, and the well data presented at the hearing of this case involves the entire Dakota Producing Interval, the application should be broadened to cover all of said producing interval throughout the area.

(13) That the Dakota Producing Interval, hereinafter referred to as the "Dakota," consists of a near blanket sandstone (probably an almost continuous series of northwest trending barrier beach sandstones composed of fine-grained quartose sandstones and carbonaceous shales with occasional conglomerates and coals in the basal part).

(14) That from the logs available at the hearing, the top of the Dakota in the area ranges from a depth of 5234 feet to 7220 feet and averages some 6603 feet beneath the surface.

(15) That the only test data for flow holes prior to stimulation for wells within the area indicates that Aztec Pierce Well No. 2 in Section 30, Township 31 North, Range 10 West, NMPM, had a stabilized production rate calculated at atmospheric pressure of 208.1 MCF of gas per day; that other wells in the immediate vicinity of the area but just outside had stabilized production rates calculated at atmospheric pressure prior to stimulation ranging from 21.7 MCF per/day to 224.1 MCF per day.

(16) That none of the stabilized production rates cited above exceeds the maximum stabilized production rate set forth in 18 C.F.R. Section 271.703(c)(2)(i)(B) of 251 MCF per day for wells at the average depth to the top of the formation for this area (6603 feet), and it is not expected that the average well in the area will exceed such rate.

(17) That in situ permeability calculations are available for only four wells in the area, being the Southland Pierce Well No. 2 and Moore No. 8, and the Consolidated Kline No. 1M and Senter No. 1M; that the in situ permeabilities calculated for said wells are .0609 md, .0151 md, .0049 md, and .0146 md, respectively, and average .0239 md.

(18) That the average in situ permeability for all wells in the area is not expected to exceed 0.1 md, the limit set forth in 18 C.F.R. Section 271.703(c)(2)(i)(A).

(19) That prior to stimulation, the average well in the area is expected to produce far less than the maximum five barrels of crude oil per day as set forth in 18 C.F.R. Section 271.703(c)(2)(i)(C).

(20) That 18 C.F.R. Section 271.703(c)(2)(i)(D) provides that "if the formation or any portion thereof was authorized to be developed by infill drilling prior to the date of recommendation and the jurisdictional agency has information which in its judgment indicates that such formation or portion subject to infill drilling can be developed absent the incentive price established in paragraph (a) of this section then the jurisdictional agency shall not include such formation or portion thereof in its recommendation."

(21) That the Division, by its Order No. R-1670-V, dated May 22, 1979, and effective July 1, 1979, approved infill drilling for the Basin-Dakota Gas Pool in San Juan and Rio Arriba Counties, New Mexico, and said pool includes the Dakota Producing Interval in the area under consideration here.

(22) That Southland in this hearing indicated that under current Section 103 prices of the NGPA of 1978, reserves of 350,000 MCF of gas are necessary to provide it with the economics necessary to justify drilling a Dakota well at its current drilling costs, while 150,000 MCF of reserves will justify a well at Section 107(c)(5) prices (tight formations).

(23) That Consolidated in this hearing indicated that under current Section 103 prices of the NGPA of 1978, reserves of 650,000 MCF of gas are necessary to provide it with the economics necessary to justify drilling a Dakota well at its current drilling costs, while 335,000 MCF of reserves will justify a well at Section 107(c)(5) prices (tight formations).

(24) That the wide discrepancy of reserves required to justify drilling according to these two companies' economic analyses probably results primarily from the following three factors:

(A) Southland is content with a 15 percent rate of return (ROR) on its investment while Consolidated requires a 20 percent ROR.

(B) Southland estimates that it can drill and complete a Dakota well in the area for approximately $378,560.00, while Consolidated estimates that it would cost $475,400.00.

(C) Southland, in its economic analysis, calculates an 86.5 percent working interest share of well proceeds with 13.5 percent going to royalty, while Consolidated calculates a 75.5 percent working interest share of well proceeds with 24.5 percent going to royalty and overriding royalty.

(25) That while the Consolidated desire for a 20 percent ROR is understandable, the Division believes that the 15 percent ROR sought by Southland is more reasonable.

(26) That it would appear that some items in the Consolidated estimate of well costs are excessive, and that the $378,560.00 estimate for a completed Dakota well is more realistic than the $475,400.00 estimate.

(27) That the standard royalty for most leases in the area is 12.5 percent, leaving an 87.5 percent share of well proceeds to the working interest.

(28) That there are an infinite number of overriding royalty arrangements, farm-in arrangements, and other deals by which drilling rights are obtained, and it would be impracticable, if not impossible, for the Division to accommodate each of these carved-out interests when calculating pricing and reserves requirements and determining necessary economic incentives.

(29) That the Southland working interest of 86.5 percent is essentially the same as a standard 87.5 working interest and should be used in this case rather than the Consolidated 75.5 percent working interest.

(30) That the economics as presented by Southland in this case are reasonable, and lands which indicate recoverable reserves of 350,000 MCF or more of gas should be dismissed from further consideration, while lands indicating recoverable reserves of less than 350,000 MCF of gas should be considered for recommendation as a tight formation.

(31) That the Division, in approving infill drilling for the Basin-Dakota Gas Pool, based its approval on the premise that the reservoir was of low permeability and that 320-acre wells were not draining more than the 160-acre tract upon which they were located.

(32) That the remaining reserves under the 160-acre tract upon which the unit well is not located should be similar to, if not equal to, the original reserves under the 160-acre tract upon which the unit well is located.

(33) That cumulative production figures and estimates of ultimate recoverable reserves were presented at the hearing for some of the developed tracts within the area, while cumulative production figures only are available for the remainder of the developed tracts.

(34) That to determine that under certain lands insufficient reserves are available to justify drilling absent the Section 107 incentive price, it is reasonable to make the following assumptions:

A. No primary drilling, i.e., no drilling on 320-acre spacing is prima facie evidence that the lands are edge lands to the reservoir and drilling has not occurred because of the probable marginal nature of the reserves.

B. Primary drilling has occurred but the calculated total ultimate reserves or the cumulative production for long-connected wells indicates low ultimate recovery (less than 350,000 MCF of gas).

(35) That to determine that under certain lands sufficient reserves may reasonably be expected to be recovered to justify drilling without the Section 107 incentive price, it is reasonable to make the following assumptions:

A. Calculated ultimate recoverable reserves are 350,000 MCF or more.

B. Calculated ultimate recoverable reserves are not available, but cumulative recoveries indicate that 350,000 MCF of gas already has been recovered.

(36) That the assumptions in Findings Nos. (34) B. and (35) A. and B. above may reasonably be based on offsetting wells in a given area.

(37) That primary drilling and some infill drilling has occurred on the following lands, and cumulative recoveries and/or estimates of remaining reserves indicate that more than 350,000 MCF of gas can be recovered by an average well therein, and therefore said lands can be developed absent the incentive price established in 18 C.F.R. Section 271.703(a) and should not be considered for recommendation for designation as a tight formation:

TOWNSHIP 31 NORTH, RANGE 12 WEST, NMPM	
Sections 5 through 8:	All
Sections 17 through 20:	All
Sections 29 through 32:	All

TOWNSHIP 31 NORTH, RANGE 13 WEST, NMPM	
Sections 12 through 14:	All
Sections 22 through 28:	All
Sections 33 through 36:	All

TOWNSHIP 32 NORTH, RANGE 12 WEST, NMPM	
Sections 25 through 27:	All
Sections 32 and 33:	All

containing 19,602 acres, more or less.

(38) That there are fresh water aquifers underlying the lands being considered, and these aquifers extend to a depth of approximately 1200 feet.

(39) That there is a vertical distance of some 5400 feet between the base of the lowermost of said aquifers and the top of the Dakota, and this distance, combined with the required casing and cementing program for wells in the area, will assure that development of the Dakota will not adversely affect the fresh water aquifers (during both hydraulic fracturing and waste disposal operations) that are or are expected to be used

as a domestic or agricultural water supply.

(40) That the Dakota Producing Interval underlying the following lands meets all of the guidelines set forth in 18 C.F.R. Section 271.703(c)(2)(i), subsections (A), (B), (C), and (D), and should be recommended for designation as a tight formation:

TOWNSHIP 31 NORTH, RANGE 10 WEST, NMPM
Sections 1 through 36: All

TOWNSHIP 31 NORTH, RANGE 11 WEST, NMPM
Section 1: All
Sections 12 and 13: All
Sections 22 through 27: All
Sections 34 through 36: All

TOWNSHIP 31 NORTH, RANGE 13 WEST, NMPM
Sections 1 through 11: All
Sections 15 through 21: All
Sections 29 through 32: All

TOWNSHIP 32 NORTH, RANGE 10 WEST, NMPM
Sections 7 through 36: All

TOWNSHIP 32 NORTH, RANGE 11 WEST, NMPM
Sections 7 through 27: All
Sections 34 through 36: All

TOWNSHIP 32 NORTH, RANGE 12 WEST, NMPM
Sections 7 through 24: All
Sections 28 through 31: All

TOWNSHIP 32 NORTH, RANGE 13 WEST, NMPM
Sections 7 through 29: All
Sections 32 through 36: All

containing some 102,914 acres, more or less, all in San Juan County, New Mexico.

IT IS THEREFORE ORDERED:

(1) That it be and hereby is recommended to the Federal Energy Regulatory Commission pursuant to Section 107 of the Natural Gas Policy Act of 1978, and 18 C.F.R. Section 271.703, that the Dakota Producing Interval, being from the base of the Greenhorn Limestone to a point 400 feet below the base of said formation and consisting of the Graneros formation, the Dakota

formation and the productive upper portion of the Morrison formation, underlying the following described lands in San Juan County, New Mexico, be designated as a tight formation:

TOWNSHIP 31 NORTH, RANGE 10 WEST, NMPM
Sections 1 through 36: All

TOWNSHIP 31 NORTH, RANGE 11 WEST, NMPM
Section 1: All
Sections 12 and 13: All
Sections 22 through 27: All
Sections 34 through 36: All

TOWNSHIP 31 NORTH, RANGE 13 WEST, NMPM
Sections 1 through 11: All
Sections 15 through 21: All
Sections 29 through 32: All

TOWNSHIP 32 NORTH, RANGE 10 WEST, NMPM
Sections 7 through 36: All

TOWNSHIP 32 NORTH, RANGE 11 WEST, NMPM
Sections 7 through 27: All
Sections 34 through 36: All

TOWNSHIP 32 NORTH, RANGE 12 WEST, NMPM
Sections 7 through 24: All
Sections 28 through 31: All

TOWNSHIP 32 NORTH, RANGE 13 WEST, NMPM
Sections 7 through 29: All
Sections 32 through 36: All

containing approximately 102,914 acres, more or less.

(2) That no recommendation is made as to those lands described in Finding No. (10) of this order which are not included in Order No. (1) above.

(3) That jurisdiction of this cause is retained for the entry of such further orders as the Division may deem necessary.

DONE at Santa Fe, New Mexico, on the day and year hereinabove designated.

STATE OF NEW MEXICO
OIL CONSERVATION DIVISION

JOE D. RAMEY
Director

S
fd/

STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION DIVISION

IN THE MATTER OF THE HEARING
CALLED BY THE OIL CONSERVATION
DIVISION FOR THE PURPOSE OF
CONSIDERING:

CASE NO. 7116
Order No. R-6747

APPLICATION OF SOUTHLAND ROYALTY
COMPANY FOR DESIGNATION OF A TIGHT
FORMATION, SAN JUAN COUNTY, NEW MEXICO.

Rec. 8-11
R-6747-A

ORDER OF THE DIVISION

BY THE DIVISION:

This cause came on for hearing at 9 a.m. on December 30, 1980, at Santa Fe, New Mexico, before Examiner Daniel S. Nutter.

NOW, on this 7th day of August, 1981, the Division Director, having considered the testimony, the record, and the recommendations of the Examiner, and being fully advised in the premises,

FINDS:

(1) That due public notice having been given as required by law, the Division has jurisdiction of this cause and the subject matter thereof.

(2) That, pursuant to Section 107 of the Natural Gas Policy Act of 1978, and CFR Section 271.703, applicant Southland Royalty Company requested the designation as a "tight formation" of the Dakota formation underlying the following described lands:

SAN JUAN COUNTY, NEW MEXICO

TOWNSHIP 31 NORTH, RANGE 10 WEST, NMPM
Sections 1 through 36: All

TOWNSHIP 31 NORTH, RANGE 11 WEST, NMPM
Section 1: All
Sections 12 and 13: All
Sections 22 through 27: All
Sections 34 through 36: All

TOWNSHIP 32 NORTH, RANGE 10 WEST, NMPM
Sections 7 through 36: All

TOWNSHIP 32 NORTH, RANGE 11 WEST, NMPM
Sections 7 through 27: All
Sections 34 through 36: All

TOWNSHIP 32 NORTH, RANGE 12 WEST, NMPM
Sections 7 through 33: All

TOWNSHIP 32 NORTH, RANGE 13 WEST, NMPM
Sections 7 through 36: All

containing a total of 93,860.00 acres, more or less.

(3) That at the hearing, applicant requested dismissal of that portion of the application pertaining to Sections 30 and 31, Township 32 North, Range 13 West, NMPM, containing some 989.32 acres, more or less, leaving for consideration some 92,871 acres, more or less.

(4) That said request for dismissal should be approved, and no further consideration given herein to said lands.

(5) That at the hearing, Consolidated Oil and Gas, Incorporated, appeared and requested expansion of the area applied for by applicant Southland Royalty to also include the following described lands for consideration as a "tight formation":

SAN JUAN COUNTY, NEW MEXICO

TOWNSHIP 31 NORTH, RANGE 12 WEST, NMPM
Sections 5 through 8: All
Sections 17 through 20: All
Sections 29 through 32: All

TOWNSHIP 31 NORTH, RANGE 13 WEST, NMPM
Sections 1 through 36: All

containing a total of 29,645 acres, more or less.

(6) That although the aforesaid 29,645 acres, combined with the 92,871 acres remaining in the Southland application, exceeds the 93,860 acres stated in the legal notice for this case as being up for consideration, the 29,645 acres do lie within the area described in said legal notice, it having been advertised that consideration would be given to "the designation of the Dakota formation underlying portions of Townships 31 and 32 North, Ranges 10, 11, 12, and 13 West."

(7) That consideration for designation as a tight formation should be given to the Dakota formation underlying the lands described in Finding No. (5) above, as requested by Consolidated.

(8) That subsequent to the hearing on December 30, 1980, certain parties requested further additions to the lands being considered in this case for designation as a tight formation.

(9) That no evidence appears in the record to support such additional lands and they should not be considered further.

(10) That the lands with which this order will hereinafter be concerned are described as follows:

SAN JUAN COUNTY, NEW MEXICO

TOWNSHIP 31 NORTH, RANGE 10 WEST, NMPM
Sections 1 through 36: All

TOWNSHIP 31 NORTH, RANGE 11 WEST, NMPM
Section 1: All
Sections 12 and 13: All
Sections 22 through 27: All
Sections 34 through 36: All

TOWNSHIP 31 NORTH, RANGE 12 WEST, NMPM
Sections 5 through 8: All
Sections 17 through 20: All
Sections 29 through 32: All

TOWNSHIP 31 NORTH, RANGE 13 WEST, NMPM
Sections 1 through 36: All

TOWNSHIP 32 NORTH, RANGE 10 WEST, NMPM
Sections 7 through 36: All

TOWNSHIP 32 NORTH, RANGE 11 WEST, NMPM
Sections 7 through 27: All
Sections 34 through 36: All

TOWNSHIP 32 NORTH, RANGE 12 WEST, NMPM
Sections 7 through 33: All

TOWNSHIP 32 NORTH, RANGE 13 WEST, NMPM
Sections 7 through 29: All
Sections 32 through 36: All

containing 122,516 acres, more or less, and hereinafter referred to as the "area."

(11) That while the application was for designation of the Dakota formation as a tight formation, the Dakota formation constitutes but a portion of the "Dakota Producing Interval," which, as defined by the Division, comprises the vertical limits of the Basin-Dakota Gas Pool, being from the base of the Greenhorn Limestone to a point 400 feet below the base of said formation and consisting of the Graneros formation, the Dakota formation, and the productive upper limit of the Morrison formation.

(12) That inasmuch as practically all so-called "Dakota" wells drilled in the subject area are, or potentially are, tested in and/or completed in the entire Dakota Producing Interval, and the well data presented at the hearing of this case involves the entire Dakota Producing Interval, the application should be broadened to cover all of said producing interval throughout the area.

(13) That the Dakota Producing Interval, hereinafter referred to as the "Dakota," consists of a near blanket sandstone (probably an almost continuous series of northwest trending barrier beach sandstones composed of fine-grained quartose sandstones and carbonaceous shales with occasional conglomerates and coals in the basal part).

(14) That from the logs available at the hearing, the top of the Dakota in the area ranges from a depth of 5234 feet to 7220 feet and averages some 6603 feet beneath the surface.

(15) That the only test data for flow rates prior to stimulation for wells within the area indicates that Aztec Pierce Well No. 2 in Section 30, Township 31 North, Range 10 West, NMPM, had a stabilized production rate calculated at atmospheric pressure of 208.1 MCF of gas per day; that other wells in the immediate vicinity of the area but just outside had stabilized production rates calculated at atmospheric pressure prior to stimulation ranging from 21.7 MCF per/day to 224.1 MCF per day.

(16) That none of the stabilized production rates cited above exceeds the maximum stabilized production rate set forth in 18 C.F.R. Section 271.703(c)(2)(i)(B) of 251 MCF per day for wells at the average depth to the top of the formation for this area (6603 feet), and it is not expected that the average well in the area will exceed such rate.

(17) That in situ permeability calculations are available for only four wells in the area, being the Southland Pierce Well No. 2 and Moore No. 8, and the Consolidated Kline No. 1M and Senter No. 1M; that the in situ permeabilities calculated for said wells are .0609 md, .0151 md, .0049 md, and .0146 md, respectively, and average .0239 md.

(18) That the average in situ permeability for all wells in the area is not expected to exceed 0.1 md, the limit set forth in 18 C.F.R. Section 271.703(c)(2)(i)(A).

(19) That prior to stimulation, the average well in the area is expected to produce far less than the maximum five barrels of crude oil per day as set forth in 18 C.F.R. Section 271.703(c)(2)(i)(C).

(20) That 18 C.F.R. Section 271.703(c)(2)(i)(D) provides that "if the formation or any portion thereof was authorized to be developed by infill drilling prior to the date of recommendation and the jurisdictional agency has information which in its judgment indicates that such formation or portion subject to infill drilling can be developed absent the incentive price established in paragraph (a) of this section then the jurisdictional agency shall not include such formation or portion thereof in its recommendation."

(21) That the Division, by its Order No. R-1670-V, dated May 22, 1979, and effective July 1, 1979, approved infill drilling for the Basin-Dakota Gas Pool in San Juan and Rio Arriba Counties, New Mexico, and said pool includes the Dakota Producing Interval in the area under consideration here.

(22) That Southland in this hearing indicated that under current Section 103 prices of the NGPA of 1978, reserves of 350,000 MCF of gas are necessary to provide it with the economics necessary to justify drilling a Dakota well at its current drilling costs, while 150,000 MCF of reserves will justify a well at Section 107(c)(5) prices (tight formations).

(23) That Consolidated in this hearing indicated that under current Section 103 prices of the NGPA of 1978, reserves of 650,000 MCF of gas are necessary to provide it with the economics necessary to justify drilling a Dakota well at its current drilling costs, while 335,000 MCF of reserves will justify a well at Section 107(c)(5) prices (tight formations).

(24) That the wide discrepancy of reserves required to justify drilling according to these two companies' economic analyses probably results primarily from the following three factors:

(A) Southland is content with a 15 percent rate of return (ROR) on its investment while Consolidated requires a 20 percent ROR.

(B) Southland estimates that it can drill and complete a Dakota well in the area for approximately $378,560.00, while Consolidated estimates that it would cost $475,400.00.

(C) Southland, in its economic analysis, calculates an 86.5 percent working interest share of well proceeds with 13.5 percent going to royalty, while Consolidated calculates a 75.5 percent working interest share of well proceeds with 24.5 percent going to royalty and overriding royalty.

(25) That while the Consolidated desire for a 20 percent ROR is understandable, the Division believes that the 15 percent ROR sought by Southland is more reasonable.

(26) That it would appear that some items in the Consolidated estimate of well costs are excessive, and that the $378,560.00 estimate for a completed Dakota well is more realistic than the $475,400.00 estimate.

(27) That the standard royalty for most leases in the area is 12.5 percent, leaving an 87.5 percent share of well proceeds to the working interest.

(28) That there are an infinite number of overriding royalty arrangements, farm-in arrangements, and other deals by which drilling rights are obtained, and it would be impracticable, if not impossible, for the Division to accommodate each of these carved-out interests when calculating pricing and reserves requirements and determining necessary economic incentives.

(29) That the Southland working interest of 86.5 percent is essentially the same as a standard 87.5 working interest and should be used in this case rather than the Consolidated 75.5 percent working interest.

(30) That the economics as presented by Southland in this case are reasonable, and lands which indicate recoverable reserves of 350,000 MCF or more of gas should be dismissed from further consideration, while lands indicating recoverable reserves of less than 350,000 MCF of gas should be considered for recommendation as a tight formation.

(31) That the Division, in approving infill drilling for the Basin-Dakota Gas Pool, based its approval on the premise that the reservoir was of low permeability and that 320-acre wells were not draining more than the 160-acre tract upon which they were located.

(32) That the remaining reserves under the 160-acre tract upon which the unit well is not located should be similar to, if not equal to, the original reserves under the 160-acre tract upon which the unit well is located.

(33) That cumulative production figures and estimates of ultimate recoverable reserves were presented at the hearing for some of the developed tracts within the area, while cumulative production figures only are available for the remainder of the developed tracts.

(34) That to determine that under certain lands insufficient reserves are available to justify drilling absent the Section 107 incentive price, it is reasonable to make the following assumptions:

A. No primary drilling, i.e., no drilling on 320-acre spacing is prima facie evidence that the lands are edge lands to the reservoir and drilling has not occurred because of the probable marginal nature of the reserves.

B. Primary drilling has occurred but the calculated total ultimate reserves or the cumulative production for long-connected wells indicates low ultimate recovery (less than 350,000 MCF of gas).

(35) That to determine that under certain lands sufficient reserves may reasonably be expected to be recovered to justify drilling without the Section 107 incentive price, it is reasonable to make the following assumptions:

A. Calculated ultimate recoverable reserves are 350,000 MCF or more.

B. Calculated ultimate recoverable reserves are not available, but cumulative recoveries indicate that 350,000 MCF of gas already has been recovered.

(36) That the assumptions in Findings Nos. (34) B. and (35) A. and B. above may reasonably be based on offsetting wells in a given area.

(37) That primary drilling and some infill drilling has occurred on the following lands, and cumulative recoveries and/or estimates of remaining reserves indicate that more than 350,000 MCF of gas can be recovered by an average well therein, and therefore said lands can be developed absent the incentive price established in 18 C.F.R. Section 271.703(a) and should not be considered for recommendation for designation as a tight formation:

TOWNSHIP 31 NORTH, RANGE 12 WEST, NMPM
Sections 5 through 8: All
Sections 17 through 20: All
Sections 29 through 32: All

TOWNSHIP 31 NORTH, RANGE 13 WEST, NMPM
Sections 12 through 14: All
Sections 22 through 28: All
Sections 33 through 36: All

TOWNSHIP 32 NORTH, RANGE 12 WEST, NMPM
Sections 25 through 27: All
Sections 32 and 33: All

containing 19,602 acres, more or less.

(38) That there are fresh water aquifers underlying the lands being considered, and these aquifers extend to a depth of approximately 1200 feet.

(39) That there is a vertical distance of some 5400 feet between the base of the lowermost of said aquifers and the top of the Dakota, and this distance, combined with the required casing and cementing program for wells in the area, will assure that development of the Dakota will not adversely affect the fresh water aquifers (during both hydraulic fracturing and waste disposal operations) that are or are expected to be used

as a domestic or agricultural water supply.

(40) That the Dakota Producing Interval underlying the following lands meets all of the guidelines set forth in 18 C.F.R. Section 271.703(c)(2)(i), subsections (A), (B), (C), and (D), and should be recommended for designation as a tight formation:

TOWNSHIP 31 NORTH, RANGE 10 WEST, NMPM
Sections 1 through 36: All

TOWNSHIP 31 NORTH, RANGE 11 WEST, NMPM
Section 1: All
Sections 12 and 13: All
Sections 22 through 27: All
Sections 34 through 36: All

TOWNSHIP 31 NORTH, RANGE 13 WEST, NMPM
Sections 1 through 11: All
Sections 15 through 21: All
Sections 29 through 32: All

TOWNSHIP 32 NORTH, RANGE 10 WEST, NMPM
Sections 7 through 36: All

TOWNSHIP 32 NORTH, RANGE 11 WEST, NMPM
Sections 7 through 27: All
Sections 34 through 36: All

TOWNSHIP 32 NORTH, RANGE 12 WEST, NMPM
Sections 7 through 24: All
Sections 28 through 31: All

TOWNSHIP 32 NORTH, RANGE 13 WEST, NMPM
Sections 7 through 29: All
Sections 32 through 36: All

containing some 102,914 acres, more or less, all in San Juan County, New Mexico.

IT IS THEREFORE ORDERED:

(1) That it be and hereby is recommended to the Federal Energy Regulatory Commission pursuant to Section 107 of the Natural Gas Policy Act of 1978, and 18 C.F.R. Section 271.703, that the Dakota Producing Interval, being from the base of the Greenhorn Limestone to a point 400 feet below the base of said formation and consisting of the Graneros formation, the Dakota

formation and the productive upper portion of the Morrison formation, underlying the following described lands in San Juan County New Mexico, be designated as a tight formation:

TOWNSHIP 31 NORTH, RANGE 10 WEST, NMPM
Sections 1 through 36: All

TOWNSHIP 31 NORTH, RANGE 11 WEST, NMPM
Section 1: All
Sections 12 and 13: All
Sections 22 through 27: All
Sections 34 through 36: All

TOWNSHIP 31 NORTH, RANGE 13 WEST, NMPM
Sections 1 through 11: All
Sections 15 through 21: All
Sections 29 through 32: All

TOWNSHIP 32 NORTH, RANGE 10 WEST, NMPM
Sections 7 through 36: All

TOWNSHIP 32 NORTH, RANGE 11 WEST, NMPM
Sections 7 through 27: All
Sections 34 through 36: All

TOWNSHIP 32 NORTH, RANGE 12 WEST, NMPM
Sections 7 through 24: All
Sections 28 through 31: All

TOWNSHIP 32 NORTH, RANGE 13 WEST, NMPM
Sections 7 through 29: All
Sections 32 through 36: All

containing approximately 102,914 acres, more or less.

(2) That no recommendation is made as to those lands described in Finding No. (10) of this order which are not included in Order No. (1) above.

(3) That jurisdiction of this cause is retained for the entry of such further orders as the Division may deem necessary.

DONE at Santa Fe, New Mexico, on the day and year hereinabove designated.

STATE OF NEW MEXICO
OIL CONSERVATION DIVISION

JOE D. RAMEY
Director

S E A L
fd/