WPO 39149

FINAL REPORT
Evaluation of Mineral Resources at the
Waste Isolation Pilot Plant (WIPP) Site

Volume 1
Executive Summary
Chapters I-II

Westinghouse Electric Corporation
Waste Isolation Division
Contract No. PO-75-WJJ644145Z

Executive Summary
Chapter I - Potential Industrial Mineral Resources
Chapter II - Environmental and Regulatory Requirements for Mining/Extraction Operations At or Near the WIPP Site

Submitted by

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Certification

We certify under penalty of law that this document was prepared under our supervision for Westinghouse Electric Corporation, Waste Isolation Division, Waste Isolation Pilot Plant by New Mexico Bureau of Mines and Mineral Resources, a division of New Mexico Institute of Mining & Technology. Based on our inquiry of the persons directly responsible for gathering the information, the information submitted is, to the best of our knowledge and belief, true, accurate, and complete.

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EXECUTIVE SUMMARY

The Waste Isolation Pilot Plant (WIPP) land withdrawal area occupies 16 mi^2, on the southeastern edge of the Known Potash Leasing Area (administered by BLM), about 30 miles southeast of Carlsbad, Eddy County, New Mexico. It is four miles on a side and is located in secs. 15 to 22 and 27 to 34 of T22S R31E. This study includes an additional study area about one mile wide surrounding the WIPP site and containing an additional 20 mi^2. The combined study area comprises about 36 mi^2.

The amount and value of natural resources under the WIPP land withdrawal area have not been calculated for more than ten years. This report performs this calculation using current and projected prices, production, geologic data, and conditions. The need for recalculating the volume and value of mineral resources within the boundaries of the WIPP land withdrawal area stems from the discovery of oil and associated natural gas in adjacent lease tracts during the late 1980s and early 1990s, and the approach of potash mining.

During the late 1980s and early 1990s oil was discovered in the lower parts of the Delaware Mountain Group (Permian: Cherry Canyon and Brushy Canyon Formations) along the eastern, southern, and western boundaries of the land withdrawal area. In the Delaware Basin as a whole, these formations were not generally recognized as exploratory and development targets until the late 1980s. Prior to that time, they were usually bypassed during drilling with little or no thought that they might contain economically recoverable oil resources. Although these two formations had been penetrated by thousands of wells throughout the Delaware Basin, few attempts were made to adequately test them.

The main reason for bypassing these formations during drilling was a lack of understanding of their reservoir production characteristics. Water saturations calculated from analysis of electric logs were often high and did not differentiate oil-productive sandstones from sandstones that would yield mostly water upon completion. However, recent developments in log analysis (Asquith and Thomerson, 1994) have made it possible to differentiate Delaware sandstones with a high percentage of movable hydrocarbons from those with a low percentage of movable hydrocarbons. This type of analysis, in conjunction with the discovery of several commercial oil pools in the Brushy Canyon Formation, set off an oil drilling boom throughout the Delaware Basin that continues to the present. The Delaware play is currently the primary exploration and development play in the Permian Basin and is one of the most active oil plays in the United States. Of special note in the vicinity of WIPP was the discovery and development of commercial oil accumulations in the Brushy Canyon Formation at Cabin Lake, Livingston Ridge, Lost Tank, and Los Medaños pools.

During the last decade or so, potash mining has continued and the mining front is now much closer to the WIPP boundary. Mining by IMC has reached the edge of the additional study area on the southwest side of WIPP. Future mining may occur mainly there or on the north.

The value of potash (sylvite and langbeinite) and petroleum (oil and gas) were calculated using iterative economic models commencing in 1996 and lasting until 2031 (potash), 2026 (petroleum), and 2038 (natural gas plus associated oil). The potash and petroleum resources produced over this time frame were calculated from estimates based on drill hole data and projections of data and geology as needed. The value calculation used these resource data and projections of historical cost, price, and other economic data.

Potash Reserves

The results of the potash resources and reserve calculation are:

Resources and reserves of the 4th langbeinite ore zone (short tons in millions).

Area, Type of Lease, and Scenario	Tons	Avg. % K_2O
Entire study area		
In-place resource (>4% K_2O & actual thickness)	168.7	8.02
BLM Lease Grade reserve (>4% K_2O & 4 ft mining height)	166.5	7.22
Minable reserve (>6.25% K_2O & 6 ft mining height)	72.4	7.95
Inside WIPP boundary		
In-place resource (>4% K_2O & actual thickness)	47.0	7.21
BLM Lease Grade reserve (>4% K_2O & 4 ft mining height)	40.5	6.99
Minable reserve (>6.25% K_2O & 6 ft mining height)	18.0	7.59
Outside of the WIPP boundary (about one mile)		
In-place resource (>4% K_2O & actual thickness)	121.7	8.33
BLM Lease Grade reserve (>4% K_2O & 4 ft mining height)	126.0	7.30
Minable reserve (>6.25% K_2O & 6 ft mining height)	54.4	8.07

Resources and reserves of the 10th sylvite ore zone (short tons in millions).

Area, Type of Lease, and Scenario	Tons	Avg. % K_2O
Combined Area		
In-place resource (>10% K_2O & actual thickness)	168.2	14.61
BLM Lease Grade reserve (>10% K_2O & 4 ft mining height)	157.3	14.64
Minable reserve (>12.25% K_2O & 4.5 ft mining height)	107.8	15.33
WIPP Area		
In-place resource (>10% K_2O & actual thickness)	53.7	14.26
BLM Lease Grade reserve (>10% K_2O & 4 ft mining height)	52.3	13.99
Minable reserve (>12.25% K_2O & 4.5 ft mining height)	30.6	15.00
Additional Area (~1 mile around WIPP)		
In-place resource (>10% K_2O & actual thickness)	114.5	14.77
BLM Lease Grade reserve (>10% K_2O & 4 ft mining height)	105.0	14.96
Minable reserve (>12.25% K_2O at 4.5 ft mining height)	77.2	15.46

In-place resources for other potash ore zones (short tons in millions).

Ore zone	Combined Area		WIPP Area		Additional Area	
	Tons	% K_2O	Tons	% K_2O	Tons	% K_2O
2nd (langbeinite >4% K_2O)	4.2	6.32	2.3	6.34	1.9	6.30
3rd (equivalent langbeinite >4% K_2O)	16.2	5.93	8.9	6.20	7.3	5.60
5th (langbeinite >4% K_2O)	17.8	6.81	4.9	5.74	12.9	7.22
8th (Sylvite >10% K_2O)	18.0	14.29	1.8	15.71	16.2	14.13
9th (Sylvite >10% K_2O)	1.8	12.37	0.5	11.70	1.3	12.63
11th (Sylvite >10% K_2O)			none			

Petroleum Reserves

The results of the calculation of probable petroleum resources are:

Oil and gas resources (probable)

	Combined Area	WIPP Area	Additional Area
Primary Oil (million bbls)	35.2	12.3	22.9
Secondary Oil (million bbls)	20.2	6.4	13.8
Oil Subtotals (million bbls)	55.4	18.7	36.7
Gas Subtotals (MCF)	354	186	168

NOTE: In addition, there is an unknown but significant amount of possible oil and gas resources beneath the WIPP land withdrawal area and surrounding one-mile-wide additional area.

Valuation of Oil and Gas

The results of the net present value (NPV) calculations for petroleum are as follows:

Present Values of taxes and royalties on oil production at a 15% Discount Rate (millions of dollars).

	Severance Tax	State Tax	Corporate Tax	Royalties
Combined Area	9.827	11.47	49.90	49.05
Additional Area	6.493	7.66	32.87	32.29
WIPP Area	3.378	3.9[illegible]	17.04	16.70

Present Values of taxes and royalties on gas production at a 5% Discount Rate (millions of dollars).

	Severance Tax	State Tax	Corporate Tax	Royalties
Combined Area	5.044	10.22	43.62	25.20
Additional Area	2.611	5.39	22.05	12.92
WIPP Area	2.42	4.98	20.62	12.11

Expected Net Present Values for oil and gas at a discount rate of 15% (millions of dollars).

	Combined Area	Wipp Area	Additional Area
Oil	37	13	24
Gas	96	46	50

Expected Net Present Value for oil and gas at a discount rate of 10% (millions of dollars).

	Combined Area	WIPP Area	Additional Area
Oil	74	27	47
Gas	133	64	69

Expected revenue present values at a discount rate of 15% (millions of dollars).

	Combined Area	WIPP Area	Additional Area
Oil	390	130	260
Gas	200	100	100

Expected revenue present values at a discount rate of 10% (millions of dollars).

	Combined Area	WIPP Area	Additional Area
Oil	510	170	340
Gas	270	130	140

Valuation of Potash

The results of the net present value (NPV) calculations for potash are tabulated below.

The case parameters are:

Case 1: Mining height 6 feet; mine recovery 60%
Case 2: Mining height 6 feet; mine recovery 80%
Case 3: Mining height 4.5 feet; mine recovery 90%

Expected revenue present values for mining sylvite at a discount rate of 15% (millions of dollars).

Capital Cost Scenario	Combined Area	WIPP Area	Additional Study area
no development cost	230	200	220
$5 million cost	190	170	190
new plant	140	NR	NR

NR=Not run

Expected revenue present values for mining langbeinite with no new development cost at a discount rate of 15% (millions of dollars).

Mining Scenario	Combined Area	WIPP Area	Additional Study area
Case 1	180	140	180
Case 2	180	140	180
Case 3	180	170	180

Expected revenue present values for mining langbeinite with $5 million in new development cost at a discount rate of 15% (millions of dollars).

Mining Scenario	Combined Area	WIPP Area	Additional Study area
Case 1	160	120	160
Case 2	160	120	160
Case 3	160	150	160

Expected revenue present values for mining langbeinite with a new plant at a discount rate of 15% (millions of dollars).

Mining Scenario	Combined Area	WIPP Area	Additional Study area
Case 1	120	NR	NR
Case 2	120	NR	NR
Case 3	120	NR	NR

NR=Not run

Expected net present values for mining sylvite at a discount rate of 15% (millions of dollars).

Capital Cost Scenario	Combined Area	WIPP Area	Additional Study Area
no development cost	50	31	47
$5 million cost	40	25	38
new plant	-31	NR	NR

NR=Not run

Expect net present values for mining langbeinite with no new development costs and a discount rate of 15% (millions of dollars).

Mining Scenario	Combined Area	WIPP Area	Additional Study area
Recovery 60%; Mine height 6 ft	42	19	42
80%; Mine height 6 ft	39	21	43
90%; Mine height 4.5 ft	53	46	53

Expected net present values of mining langbeinite with $5 million in new development cost and a discount rate of 15% (millions of dollars).

Mining Scenario	Combined Area	WIPP Area	Additional Study area
Case 1	31	13	29
Case 2	33	14	32
Case 3	43	34	42

Expected net present values for mining langbeinite with a new plant and a discount rate of 15% (millions of dollars).

Mining Scenario	Combined Area	WIPP Area	Additional Study area
Case 1	-28	NR	NR
Case 2	-26	NR	NR
Case 3	-13	NR	NR

NR=Not run

Additional Data

Data supporting the above resource and valuation calculations and ancillary topics are in various chapters. These cover: previous work; overviews of potash and petroleum; future mining, drill, and processing technology; regulations and environmental impacts; and a traditional engineering economics analysis. The attached list of chapter contents highlight these data.

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by
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by
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POTENTIAL INDUSTRIAL MINERAL RESOURCES AND RESERVES

George S. Austin

Potential mineral resources and reserves within the Waste Isolation Pilot Plant (WIPP) area have been evaluated in several ways (**Table 1**). However, the last new WIPP specific data were generated in 1983 (U.S. Department of Energy, 1983). Subsequent work on mineral concentrations merely refers to these older reports and does not add to the body of data. Therefore, the following examination of the previous work on the mineral resources and reserves of the WIPP site stresses the pre-1984 data but also mentions later summaries and opinions.

WIPP has been located in two separate areas through the years, and its dimensions and shape have been modified (**Fig. 1**). The original site northeast of the present site is identified as the ORNL (Oak Ridge National Laboratory) Study Area. The present site is identified as the Los Medaños site. The original size of the Los Medaños site was 18,960 acres or 29.625 mi^2, had an irregular boundary, and contained four control zones (I through IV). Some reports issued prior to the 1980 Department of Energy Final Environmental Impact Statement or FEIS (DOE, 1980) referred to these zones as "safety zones."

In 1982, WIPP was squared off to 16 sections (16 mi^2) or about 10,240 acres. Within the WIPP site boundary were three control zones (I–III) with the drill hole ERDA-9 at the center (see **Fig. 1**). Zone I covers about 100 acres enclosed by a chain-link fence. This zone contains the WIPP surface structures. Zone II defines the maximum extent of the planned underground development and contains about 1800 acres. The area between the outer boundary of control zone II and the WIPP outer boundary (identified as the WIPP site boundary) provides a minimum one-mile buffer area of intact salt at depth around zone II. This area between zone II and the WIPP site boundary includes all of former control zone III of about 6,200 acres and four additional triangular-shaped areas at the corners (see **Fig. 1**). Reports preceding the 1982 decision to square-off WIPP also have summaries for control zones I, II, and III, which also have ERDA-9 at the center, but the area contained is only 8100 acres or 12.656 mi^2. The data in these reports are based on a control zone III of about 6200 acres, not the present WIPP boundary zone containing about 8340 acres (10,240 acres–zones I and II or 1900 acres).

The move from the ORNL site to an area about 7 mi southwest was recommended by the U.S. Geological Survey on November 14, 1975 (Sandia National Laboratories, 1978, pp. 2–7). At about the same time, Sandia National Laboratories independently recommended the same general area for the repository site (Sandia National Laboratories, 1977b). At that time this new site (Los Medaños site) was thought to be east and south of the Known Potash Area (KPA), now known as the Known Potash Leasing Area (KPLA).

Drilling in 1975 and earlier, primarily by potash mining companies, indicated that the Los Medaños site contained economically significant potash mineralization. However, the Los Medaños site was selected as the "WIPP reference site" in the late summer of 1976. From August to October 1976, 21 additional holes were drilled by Sandia National Laboratories (P-series) to further test the area (U.S. Geological Survey, 1978a; Sandia National Laboratories, 1978, table 2-2, A). Six additional stratigraphic holes (WIPP 11, WIPP 13, WIPP 18, WIPP 19, WIPP 21, and WIPP 22) were drilled within the site in early 1978 (Sandia National Laboratories, 1978, table 2-2, B). These later (post-July 1976) for potash were only performed on P-series cores (G. B. Griswold, oral comm. December 1994). By December 1978, the potash enclave included the northern and western one-third of the Los Medaños site (Sandia National Laboratories, 1978, fig. 2-7).

On March 31, 1983, the U.S. Department of Energy issued the "Summary of the Results of the Evaluation of the WIPP Site and Preliminary Design Validation Program" (U.S. Department of Energy-161). The report concluded that the Los Medaños site fulfilled the intent of all of the site qualification factors and should therefore be used for the Waste Isolation Pilot Plant project.

The boundary of the KPA later was moved, effective July 19, 1985, to include nearly all of the 16-section WIPP site. Effective October 28, 1986, the site was entirely located within the slightly larger "Oil-potash Area as Designated by the Secretary" of the Department of the Interior.

Reports on WIPP were produced under contract from a number of agencies and have a limited circulation. In the past, some have been listed by the author(s) and some by the contractors. The dates of these reports are sometimes listed by the contracted date of delivery and sometimes by the actual date of delivery. For consistency in this presentation, all reports are listed by the contractor or agency and by the latest date on the title page. The author(s) are mentioned in the review, wherever possible, to ensure that the reader is aware of other possible listings of the report. Formal publications with wide circulation are listed by author in a standard reference format.

PREVIOUS WORK (by year)

Netherland, Sewell, and Associates, 1974

Netherland, Sewell, and Associates (1974) reviewed the hydrocarbon potential for the original Waste Isolation Pilot Plant (WIPP) site in southeastern New Mexico (straddling the boundary of Eddy and Lea Counties) east-northeast of the present site. This includes a three-square-mile area of southeastern New Mexico (SE¼ sec. 35 & S½ sec. 36 T21S R31E and sec. 1 & E½ of sec. 2 T22S R31E in Eddy County, and SW¼ sec. 31 T21S R32E and W½ sec. 6 T22S R32E in Lea County). It is identified as the ORNL (Oak Ridge National Laboratory) Study Area.

The report, authored by C. M. Netherland, examined the hydrocarbon potential of all formations from surface to granite basement on both geological and engineering analyses of reservoir performance. The ultimate recoveries of hydrocarbons, both on a regional and local scale, were included. It concluded that the ORNL Study Area and the acreage immediately adjoining the Study Area contain no economically recoverable oil and gas.

New Mexico Bureau of Mines & Mineral Resources, 1974

The New Mexico Bureau of Mines & Mineral Resources (1974) reported on the stratigraphy, structure, and geological evaluation of the oil and gas potential; petroleum exploration in the WIPP area; water injection and disposal wells; and geologic factors. The author was R. W. Foster, Senior Petroleum Geologist.

The report stated that the shallowest possible occurrence of oil is the upper part of the Bell Canyon Formation (Permian Delaware Mountain Group) at a depth of over 4000 ft. Rocks with the highest potential for gas at WIPP are of Silurian and Silurian/Devonian age at a depth of 13,000 to 16,000 ft. An exploratory test of oil and/or gas potential of the entire sedimentary-rock section near the center of the site would have to penetrate approximately 18,000 ft of sediments.

In order to estimate the potential for hydrocarbon production in the WIPP site area, a statistical evaluation of existing oil and gas exploration holes was used. The scarcity of drill holes in the immediate area of the proposed WIPP site necessitated the examination of all holes in an area much larger (1512 mi^2) than the 1974 Los Medaños WIPP area (18,960 acres or 29.625 mi^2). The oil and gas potential was determined in two ways, wildcat success ratios and productive acreage. The values determined for each section by the two methods were 559,411 to 1,266,795 barrels (bbls) of oil, 2,250,829 to 2,967,243 thousand cubic feet (MCF) of associated gas, 169,455 to 193,568 bbls of distillate, and 12,565,558 to 13,576,988 MCF of natural gas. Quoting this information, later reports commonly use the higher of the figures (productive acreage) and combine associated and natural gas to achieve in-place resource estimates for the original Los Medaños WIPP site of 29.6 mi^2. Crude oil was estimated at 37.7 million bbls, natural gas at 490 million MCF, and distillate at 5.7 million bbls.

Sipes, Williamson, and Aycock, 1976

Sipes, Williamson, and Aycock (1976), authored by J. J. Keesey, examined the potential for hydrocarbon reserves under the WIPP site and stressed "reasonable present worth analysis." Several factors such as the interstate market for gas and the influence of the potash enclave were considered.

The report states that no hydrocarbons are presently (1976) produced from the WIPP area, but oil and gas are being produced from 60 wells in the 368-mi^2 area around the site. The Delaware, Bone Springs, Wolfcamp, Strawn, Atoka, and Morrow zones produce about 22,682 MCF of gas and 429 bbls of oil per day. The (WIPP) area is considered rich in hydrocarbons. Proven producing and nonproducing reserves exist in two wells in the Los Medaños field area adjacent to the southwest corner of the site area. Proved undeveloped, probable, and possible reserves exist at six potential drilling locations in the Los Medaños field. Probable and possible reserves were assigned to 15 other potential drilling locations in the northwest and south-central portions of the WIPP site area. Total recoverable reserves projected for these wells were 62,253,244 MCF of gas and 409,628 bbls of oil. The future net undiscounted revenue to oil producers was estimated to be \$48,410,821. The future net revenue was estimated to be \$21,216,899, discounted at 10% per year. Fair market value for these projected reserves was estimated to be \$12,730,139, assuming a fair market factor of 0.60.

Lee Keeling and Associates, Inc., 1977a

This report is a fair market value appraisal of potash rights in four tracts of State of New Mexico land (301, 302, 303, and 304) in the WIPP site area. Core-hole data used were from a preliminary 1977 version of the U.S. Geological Survey (1978b) report by John, Cheeseman, Lorenz, and Millgate. Summary data for two drill holes (D-203 and D-160) near the southwest border of WIPP were received verbally from the Duval Sulphur and Potash Company (now Western Ag-Minerals), but were not verified by the appraiser. Langbeinite ore reserves in the fourth ore zone in Tract 303 were based entirely on the information on hole D-160.

With minimum thicknesses of 4.5 ft and minimum grade of 12.0% K_2O as sylvite or 5.0% K_2O as langbeinite, tonnages (in-place and recoverable at 80% extraction) were calculated. The total recoverable tonnage for all four tracts of land was 17.832 million short tons (million st) of langbeinite and 4.912 Mt of sylvite. If a new mine and plant were part of development, all four tracts were considered uneconomic. However, one (Tract 303) was considered to be economically attractive because of the proximity to existing plant facilities. In the case of Tracts 301 and 302 with indicated reserves, nominal values of \$25 per acre were assigned. For Tract 303 with measured reserves, the approximate income due the lessor in the future, discounted to current (1977) value, was used. For Tract 304, a nominal value of \$10 per acre was used. The total value for the four tracts was \$565,106 for the lessee, \$812,491 for the lessor (only for State of New Mexico land, no federal land) for a grand total of \$1,377,597.

Accompanying reviews by two U.S. Army Corps of Engineers appraisers questioned the many assumptions made by the authors, but both reviewers approved of the valuations.

Lee Keeling and Associates, Inc., 1977b

This appraisal was of the value of the oil and gas lease in S½ sec. 31 T22S R31E if access to the surface and the subsurface rights to 6000 ft were retained by the federal government. The Atoka Formation of Middle Pennsylvanian age was considered to be the primary objective, although Morrow (Lower Pennsylvanian) was a possibility as well. Gas and condensate were considered to be the prime hydrocarbon targets.

With full access to the surface, the appraiser estimated the value of the lease at $1,007,000. With no access to the surface and the subsurface rights down to 6000 ft, the loss of fair market value was estimated at $642,000.

Lee Keeling and Associates, Inc., 1977c

This report is an appraisal of the oil and gas rights underlying non-productive tracts in the east half of WIPP. All but two sections had mineral rights retained by the federal government. The remaining sections were owned by the State of New Mexico. Thirty-two test wells had been drilled within the appraisal region prior to 1975. A number of fields had been discovered, in decreasing order of importance Los Medaños, Cabin Lake, Red Tank, Quahada Ridge, and Sand Dunes (both Bone Springs and marginally producing Morrow and Atoka zones). All zones yielding oil and gas in the appraisal area were of Pennsylvanian or Permian age. None of the tracts involved in the appraisal (east half of WIPP site) were oil and gas productive. A review of the available data revealed no obvious drilling prospects. Consequently, none were assigned proved, probable, or possible undeveloped reserves.

The appraiser assigned a value of oil and gas leases of $75.00 per acre to all tracts with which the study was concerned. For mineral rights, $225 per acre was used, but discounted at a rate of 25% if not leased for potash mining but lying within the Known Potash Leasing Area (KPLA; this report used KPA). For mineral rights of leases within the KPLA and leased for potash mining, a discount rate of 50% was used. The appraised value of all tracts was determined to be $331,141, of which $250,256 was assigned to the lessee and $80,885 to the lessor.

Sipes, Williamson, and Aycock, 1977

The purpose of this appraisal, authored by J. J. Keesey, was to determine the fair market value of oil and gas reserves underlying the WIPP site (in three segments: all of the east half of the WIPP area; all of the west half, excluding the S½ sec. 31 T22S R31E; and the S½ sec. 31 T22S R31E). Based on results of the previous report (Sipes, Williamson, and Aycock, 1976), this analysis was limited to the production of natural gas and gas condensate from the deeper formations. These hydrocarbons were classified in the probable or proved undeveloped reserve categories. The study also was an appraisal of the fair market value of the hydrocarbon reserves underlying the four control zones (control zones I-IV) of the WIPP Site.

Although the author commented that multiple zones of oil and gas production could exist from the Delaware zone at 4200 ft to the Devonian zone at 15,800 ft, he maintained that the primary target would be the deeper natural-gas-producing formations rather than the shallower oil-producing formations. The proposed gas wells were the same as proposed earlier, but numbers were different due to (1) updated gas prices, (2) reimbursement for severance taxes, (3) forecasting of drilling times due to the announced plans by an oil company, (4) changes in discounting effects due to a later effective date, and (5) drilling costs to allow directional drilling under the known potash area.

The results of the appraisal are summarized as follows:

Area	Appraised Fair Market Value
East half of WIPP area	$ 818,791
West half of WIPP area, excluding the S½ sec. 31	$ 2,845,008
S½ sec. 31 T22S R31E	$ 223,400
Total WIPP area	**$ 3,887,199**

Sandia National Laboratories, 1977a

Twenty-one holes were drilled by Sandia National Laboratories to test the potash resources in the WIPP area. This report, edited by G. B. Griswold, supplied initial assay information on the samples obtained from the drilling program and was superseded by later information (U.S. Geological Survey, 1977a).

Sandia National Laboratories, 1977b

This report, authored by G. B. Griswold, covers the site selection and evaluation studies that include geologic mapping, geophysical surveys, drilling, and resource appraisal. It provides considerable technical detail of the parameters used to select the present site.

The lithium concentration of brines encountered in the ERDA 6 drill hole was 140 ppm. The volume of the reservoir was estimated to be in the range of 100,000 to 1 million bbls. If the reservoirs were limited to this size, they would not warrant development.

U.S. Bureau of Mines, 1977

A number of difficulties surround this report. Two different versions were issued in 1977. One contained proprietary information and is not available to us. The second was a public document identified as "Valuation of potash occurrences within the Waste Isolation Pilot Plant site in southeastern New Mexico," U.S. Bureau of Mines, Minerals Availability System Special Project ALO-18, 114 pp. No individual authors are identified in the literature describing the 1977 reports. In 1980, the public document was published with some revisions as "Valuation of potash occurrences within the Nuclear Waste Isolation Pilot Plant site in southeastern New Mexico," U.S. Bureau of Mines, Information Circular 8814, 94 pp. The authors of the published report are R. C. Weisner, J. F. Lemons, Jr., and L. V. Coppa.

The U.S. Bureau of Mines study was to determine the commercial value of potash occurrences in the WIPP site for the purpose of preparing an environmental impact statement. The concentrations and tonnages of potassium as sylvite and langbeinite in the potash ores zones within the site, as previously determined by the U.S. Geological Survey, were used.

Two groups of deposits, designated as mining units and occurring partly in the site, were determined to be commercial. Value determinations were based on estimated operating and capital costs of current (1977) mine-mill operations in the Carlsbad area. The present value of the parts of the mining units within the site, in terms of Federal and State taxes, royalties, and reasonable bonus bids, was estimated to be about $58.3 million. The authors estimated that about 24.5 million st of potash products would be produced from within the site over the life of the project. Additional 18.2 million st of potash products could be recovered from currently subeconomic mineralization within the site at some time in the future, if potash becomes more valuable compared to production costs.

U.S. Geological Survey, 1978a

This report, authored by C. L. Jones, consists of about 16 pages of text and 421 pages of basic data from the 21 drill holes logged by the U.S. Geological Survey on behalf of the WIPP project. The tabulation includes lithologic and geophysical logs of all borings, chemical analyses, and x-ray determinations and calculations to establish the modal mineralogic compositions of core samples from potash ore zones and mineralized salt beds.

Mineralogy was determined by x-ray diffraction and chemical composition by atomic absorption, titration, and gravimetric methods. Three laboratories were involved in the chemical analyses (Skyline Labs, Inc., Herron Testing Laboratories, Inc., and the U.S. Bureau of Mines). X-ray diffraction analysis was by the U.S. Geological Survey.

U.S. Geological Survey, 1978b

This U.S. Geological Survey (1978b) report, authored by C. B. John and others, states that seven ore zones (10th, 9th, 8th, 5th, 4th, 3rd, and 2nd) in the WIPP area (control zones I-IV) are considered to meet or exceed the U.S. Geological Survey (now BLM) leasing standards of 4 ft of 4% K_2O as langbeinite or 4 ft of 10% K_2O as sylvite, termed "lease grade" by the Survey. Using subsurface geologic mapping of the potash ore zones and data developed in other reports (U.S. Geological Survey, 1978a; Sandia National Laboratories, 1977a), the report states that these ore zones (at lease-grade minimum) contain 353.3 million st of potash ore, which is composed of 315.7 million st of measured ore and 37.6 million st of indicated ore. The latter designation is reserved for ore for which there is incomplete inspection and measurements, sampling is too widely spaced, etc.

The most important ore zones in WIPP are the 4th and 10th at or above "lease grade" that contain 218.5 million st of potash ore. The 4th ore zone contains the greatest estimated tonnage of potash reserves, 107.5 million st of measured langbeinite ore and additional 7.9 million st of indicated langbeinite ore, a total of about 115.4 million st. The other major ore zone, the 10th, at lease grade, contains 97.2 million st of measured potash ore and 5.9 million st of indicated ore of both ore mineralogies, a total of 103.1 million st.

If a lower-than-lease-minimum grade of ore is used (4 ft of a minimum of 3% K_2O as langbeinite or 4 ft of a minimum of 8% K_2O as sylvite), a resource of 484.2 million st of ore is estimated to be present (432.6 million st of measured ore and 51.6 million st of indicated ore). If a higher-than-lease-minimum grade is used (4 ft of a minimum of 8% K_2O as langbeinite or 4 ft of a minimum of 14% K_2O as sylvite), a reserve of 131.6 million st of ore is estimated to be present (126.9 million st of measured ore and 4.7 million st of indicated ore).

New Mexico Bureau of Mines & Mineral Resources, 1978

The New Mexico Bureau of Mines & Mineral Resources (1978), authored by W. T. Siemers and others, described the non-potash and non-hydrocarbon resources of the Los Medaños WIPP site within the original boundary (93 km^2 in the report, 34.6 mi^2). The authors estimated that about 80% of the area (74 km^2, 27.5 mi^2) was covered by caliche to an average depth of 4.25 ft (1.3 m), and thus the volume was 126 million yds^3 (96 million m^3). At an average density of 1.75 g/cm^3, 168 billion kg (185 million st) of caliche was estimated to be present within the site. They concluded that there was a very small market for WIPP-site caliche; the long-range estimate was for the market to continue, indicating little value for the caliche resource from the site.

Salt deposits on the WIPP site consist of nearly flat-lying subsurface beds in the Salado and Castile Formations. The top of the uppermost salt bed in the Salado Formation is about 542 ft below the surface (U.S. Geological Survey, 1978a, p. 290–292); the base of the lowest salt bed is at 2836 ft below the surface. Salado salt underlies the entire WIPP site (about 30 mi^2). Assuming an average specific gravity of 2.15, the site can be assumed to contain 118 billion short tons (bst) of Salado salt. The salt itself can be clay-rich and impure, and is interbedded with anhydrite, polyhalite, sandstone, and claystone. The underlying Castile Formation contains a salt bed about 1200 ft thick in the Los Medaños area, with the top of the salt at a depth of about 3000 ft. Although there are substantial salt resources beneath the WIPP site, surface supplies of salt in the immediate area and plentiful production from New Mexico and other areas in the United States indicate that the Salado and Castile salt below the WIPP site will not be developed.

Gypsum does not occur on the surface at the WIPP site, but as much as 100 ft is present in the subsurface in the Rustler Formation, particularly west of WIPP. According to the U.S. Geological Survey (1978b), Rustler gypsum grades into anhydrite and polyhalite beneath the site. Beneath WIPP, gypsum has a total thickness of about 40 ft and is distributed among one to five beds ranging from 5 to 60 ft thick. The top of the uppermost bed lies 335 ft below the surface and the base of the lowermost bed is at a depth of 1000 ft. Rustler gypsum underlies about 17 mi^2 of the site; since pure gypsum has a specific gravity of 2.32, an estimated 1.3 bst lie within WIPP boundaries. However, the quality of the Rustler gypsum is variable and the calculations above are based on pure gypsum. Due to adequate supplies of surface gypsum in southeastern New Mexico, west Texas, and in the Great Lakes, midcontinent, and west coast regions, all of them closer to large consuming areas, there is little likelihood that the Rustler gypsum resource will ever be developed.

Brine pockets, saturated with Na, K, Ca, and Mg chlorides and sulfates, occur frequently in the McNutt Member of the Salado Formation. Sandia National Laboratories (1977) reported that the largest known pocket contains an estimated 100,000 gal of brine; however, the average pocket is much smaller, containing only 10 to 100 gal. Borehole ERDA No. 6 produced saturated brine and H_2S from a fractured, gray, laminated Castile anhydrite unit 2711 ft below the surface. This brine contained 140 g/ml [sic, should be ppm] lithium. Although economic-grade lithium-bearing brines do occur within the boundaries of WIPP, insufficient data prevent an accurate estimation of the quantity. The brines seem to occur in small, isolated pockets containing 10 to 100 gal and are at least 1300 ft below the surface, which renders the economic potential of WIPP-site brine resource very small.

Other commodities possibly occurring in economic concentrations include sulfur, uranium, and tar sands. Each was carefully considered and excluded from potential economic importance within the WIPP site.

Agricultural and Industrial Minerals, Inc., 1978

The purpose of the Agricultural and Industrial Minerals, Inc. (1978) report, authored by W. A. Seedorff, Jr., was: (1) to define and evaluate the potash resources and reserves of the WIPP site, (2) to determine the impact on the industry and market supply if WIPP is withdrawn from mining, and (3) to determine the value of leaseholders' interests and the State's interests as lessor. Several assumptions were made: (1) the approximately one mile centers of drilling are sufficient to calculate approximate tonnages and grades; (2) 4.5 ft is the minimum mining thickness, and 5% K_2O as langbeinite <u>or</u> 12% K_2O as sylvite <u>or</u> 22% K_2O as "mixed ore" are the minimum grades; (3) chemical compositions and calculated mineralogy of drill holes on the site, as determined by the U.S. Geological Survey (1978a; 1978b) or obtained from "industry" (leaseholders), were correct; (4) geology of the site as established principally by the U.S. Geological Survey (1978a; 1978b) and Sandia National Laboratories (1977b) is correct; and (5) for the most part, the potash resources within WIPP will be developed as new mine and plant facilities.

The report did indicate, however, that fair value of the resources depends on the leaseholder's situation. It states "...International Minerals and Chemical Corporation [now IMC Fertilizer] has existing processing facilities and the portion of the deposit on their lease [within the WIPP area] is of similar or better grade than currently mined. To this leaseholder, the deposit is ore grade and we concur. On the other hand, we do not believe it is ore if all new mine, plant storage, and auxiliary facilities were required..." (Agricultural and Industrial Minerals, Inc., 1978, p. 11).

The conclusions of the Agricultural and Industrial Minerals, Inc. report were: (1) the WIPP site contains 153 million st of resources of which 29.7 million st are economically recoverable and classified as reserves; (2) the 29.7 million st of reserves may yield 4.2 million st of langbeinite and 1.8 million st of muriate (sylvite) for a total of 6.0 million st of product; (3) the total potash resource, potential reserves, and potential products are small in relation to Carlsbad or United States totals; and (4) zone IV of the site (outer zone) contains most (69)% of the resource tonnage. By releasing it for mining, the long-range impact of the withdrawal is minimized.

Sandia National Laboratories, 1978

The Sandia National Laboratories (1978) report, edited by D. W. Powers and others, restated in the executive summary that potash salts and natural gas are the only two resources of economic significance under the WIPP site. It included reviews of all previously considered mineral resources and appropriate references. Chapter 8 reviewed all mineral resources in detail. Citing a paper by Foster and Stipp (1961), the chapter's author (G. B. Griswold) stated that the Precambrian basement lies at a median depth of 18,000 ft at the WIPP site. He concluded that no development of mines is practical to exploit possible sulfides in the metamorphosed rhyolites and tuffs composing the basement. These resources had not been previously considered.

Sipes, Williamson, and Aycock, Inc., 1978

Sipes, Williamson, and Aycock, Inc. (1978) evaluated the hydrocarbon potential of a single tract of land within the WIPP area. Tract III is about 320 acres, mainly in the north part of sec. 36 T22S R31E. Proved undeveloped reserves were assigned to the Atoka "formation" and probable reserves to the Morrow "formation." Future net revenue, discounted 10% per annum, was projected at $5,566,653, and the fair market value for a single well on this tract was estimated to be $3,507,653 as of June 17, 1977. Directional drilling was considered feasible, requiring a horizontal displacement of 3000 ft. The incremental cost of directional drilling was projected to be $415,945 for a drilling date of January 1, 1978.

Sipes, Williamson, and Associates, 1979

Sipes, Williamson, and Associates (1979) developed three scenarios or cases that were evaluated for directional drilling to obtain the hydrocarbons underneath WIPP and to estimate the differential over conventional straight-hole drilling. The incremental cost for drilling all 55 wells from outside of zone IV (case A) was $87,226,000. The cost for drilling of 44 deviated holes and 11 straight holes in zone IV (case B) was $57,339,000. Drilling all wells from zone IV as straight holes (under zone IV) or as deviated holes (under zones I-III) had an incremental cost of $21,790,000. Assumptions made: (1) the primary target is Pennsylvanian rocks at an average depth of 14,750 ft, (2) well spacing is 320 acres, (3) drilling restrictions for potash areas do not apply, (4) minimum depth to beginning directional drilling is 4800 ft, (5) cost estimates are as of October 1979, (6) maximum bottom hole target has a radius of 500 ft, (7) the path of the directional hole below the kick-off point is not restricted, and (8) geologic structures are not factored into cost estimates. Theoretically, all of the wells can be drilled into pay zones beneath zones I-IV by directional methods from sites outside of control zone IV.

Sipes, Williamson, and Aycock, Inc., 1979a

Sipes, Williamson, and Aycock, Inc. (1979a) evaluated two tracts of land under lease to Nola Ptasynski and others for their fair market value for hydrocarbons, effective January 1, 1979. Tract 227M-1 contains about 80 acres, is in sec. 4 T23S R31E, and was appraised at $25,089. Tract 227M-2 contains about 270 acres, is in sec. 3 T23S R31E, and was appraised at $156,405. The latter tract would qualify for higher rates on gas because it is considered "new gas." In addition, the tracts were now in a recent expansion of the potash enclave.

Sipes, Williamson, and Aycock, Inc., 1979b

Sipes, Williamson, and Aycock, Inc. (1979b) evaluated a single tract of land for its hydrocarbon potential. Tract 219-1 contains about 80 acres, is in sec. 25 T22S R30E, and was under lease to the Continental Oil Company; it was appraised at a fair market value of $75,981, effective July 24, 1978. One drilling location was assigned to the tract.

Sipes, Williamson, and Aycock, Inc., 1979c

Sipes, Williamson, and Aycock, Inc. (1979c) evaluated Tract 221M for its hydrocarbon potential. The tract contains about 640 acres, is in sec. 26 T22S R31E, and was under lease to the Union Oil Company; it was appraised at a fair market value of $358,444. The tract was outside the 1977 expansion of the potash enclave and was devalued because it is poorly located relative to possible deeper hydrocarbon-bearing structures.

Sipes, Williamson, and Associates, 1980a

Sipes, Williamson, and Associates (1980a) reported on an engineering evaluation to determine the potential hydrocarbon reserves underlying the WIPP site area, associated costs for extraction, and income. Hydrocarbon reserves are associated with the Pennsylvanian "formation," which contains the Strawn, Morrow, and Atoka reservoirs. Values of reserves were based on a review of all wells that penetrated the Pennsylvanian "formation" in a 410-section area surrounding WIPP. Reserves identified were 390,843 bbls of condensate and 83,974,500 MCF of gas. Each was divided into four categories:

Categories	Condensate, bbls	Gas, MCF
	GROSS RESERVES	
Proved undeveloped	81,758	11,610,000
Probable	21,462	19,144,000
Possible	15,304	13,868,000
Unassigned acreage	272,319	39,352,500
Total	**390,842**	**83,974.500**
Percentage of reserves recoverable through straight drilling or directional drilling techniques	100	100

Gross wellhead value (future revenue) of oil and gas reserves, undiscounted	$287,502,346
Cost of recovery, undiscounted:	
Cost to drill and complete 54 wells:	
Case "A" - All of the 320-acre tracts within WIPP directionally drilled from locations adjacent to the WIPP boundary	$182,306,000
Case "B" - 43 wells directionally drilled from locations outside WIPP and 11 wells drilled from locations within control zone IV	$152,419,000
Case "C" - All wells drilled from zone IV, 31 locations as straight holes and 23 locations as directional holes	$117,631,000
Operating costs:	$ 10,146,324
Loss of revenue to the State of New Mexico, undiscounted: with no drilling allowed	$ 19,107,546
with drilling	$ 0

The information gathered represents all data compiled before May 1979. The effective date of the report is December 1, 1979, but the final date on the title page is January 18, 1980.

Sipes, Williamson, and Associates, 1980b

Sipes, Williamson, and Associates (1980b) evaluated the hydrocarbon potential of Tract 204M-2 within the WIPP site. It is in secs. 28 & 29 T22S R31E and contains about

1120 acres. Based on hydrocarbon reserves estimated at 1863 bbls of condensate and 1,448,000 MCF of gas, the fair market value of the tract was appraised at $777,642 as of December 1, 1979.

Sipes, Williamson, and Associates, 1980c

Tracts 204M-1, 204M-2, and 204M-3 under lease to the Superior Oil Company were evaluated by Sipes, Williamson, and Associates (1980c) for their fair market value of hydrocarbons effective February 1, 1980. Tract 204M-1 is in secs. 9 & 10 T22S R31E, contains about 1120 acres, and was appraised as having a value of $517,440. Tract 204M-2 is in secs. 28 & 29 T22S R31E, contains about 1120 acres, and was appraised as having a value of $841,578. Tract 204M-3 is in sec. 4 T23S R31E, contains about 239 acres, and was appraised as having a value of $147,501.

U.S. Department of Energy, 1980

The Final Environmental Impact Statement (FEIS) for WIPP is presented by the U.S. Department of Energy (DOE) in two volumes that include public and agency comments and numerous appendices of technical information. Chapter 9 deals specifically with denial of mineral resources, but others contain significant background information, such as the geology and hydrology of the site (Chapter 7), and irreversible and irretrievable commitments of resources (Chapter 11).

The mineral resources expected to underlie the four control zones of WIPP are caliche, gypsum, sylvite, langbeinite, crude oil, natural gas, and distillate. Only potassium salts and hydrocarbons above and below the repository, respectively, are considered of practical significance as reserves (**Table 2**; U.S. Department of Energy, 1980, table 9-14; see below). DOE found no technical or safety reason to prohibit drilling and mining in control zone IV of the type now practiced in the area. The exploitation of control zone IV would recover a significant fraction of the minerals, 73% of the langbeinite reserves and 53% of the natural gas.

Table 2 (U.S. Department of Energy, 1980, table 9-14; see below) lists resources of significance at WIPP based on data from New Mexico Bureau of Mines & Mineral Resources (1974), U.S. Geological Survey (1978b), U.S. Bureau of Mines (1977), and Agricultural and Industrial Minerals, Inc. (1979). Each resource and reserve is discussed based on data from subcontractors. The langbeinite reserves at WIPP are equivalent to about 15 yrs of production at current (1980) rates, with 73% occurring in the control zone IV. Zones I-III contain reserves equivalent to 4 yrs of production. All of the estimated natural gas and distillate resources under WIPP (zones I-III) can be reached (but at a high development cost) by vertical or deviated drilling from zone IV. However, no water-flood recovery or extensive hydrofracture stimulation from zone IV would be allowed. Holes would be plugged after their useful life. In summary, the State of New Mexico would lose $6 million for potash not mined and $9 million for natural gas not produced.

Weisner, Lemons, and Coppa, 1980

This U.S. Bureau of Mines Report of Investigation is a formal publication of the information given in the 1977 Minerals Availability System Special Project ALO-18.

Some additional information is given, but the data and conclusions are much the same as prior to 1978.

If only control zones I, II, and III are considered, 13.3 million st of ore (commercial mineralization) containing 5.5 million st of potash products would be unavailable. The value lost in terms of current (1977) dollars would be about $14.3 million. The gross market value of the products would be about $282.4 million. Similar figures were generated for sub-economic ("paramarginal") resources.

Sipes, Williamson, and Associates, 1981

Tracts 201M-3, 201M-4, and 201M-6 under lease to the Gulf Oil Corporation were evaluated by Sipes, Williamson, and Associates (1981) for their fair market value of hydrocarbons effective June 1, 1980. The tracts of about 640 acres each (total 1920 acres) are in secs. 21, 27 & 33 (respectively) T22S R31E. The fair market value of Tract 201M-3 was $2,027,664, that of Tract 201M-4 was $1,099,176, and that of Tract 201M-6 was $1,846,184.

D'Appolonia Consulting Engineers, Inc., 1982

The report by D'Appolonia Consulting Engineers, Inc. (1982) contains five chapters, only the first of which treats the amount of natural resources present at the WIPP site. Chapter 2 examines resource recovery methods and is useful when the economics of resource production is studied.

In section 1.1.2, the mineral and energy resources that underlie the four control zones (I-IV) named are caliche, gypsum, salt, potash, and hydrocarbons. **Table 1** (adapted from U.S. Department of Energy, 1980, tables 7-5 and 9-13) lists all of these resources and gives quantity, depth, richness, data source, and some comments. Caliche, gypsum, and salt (source of data: New Mexico Bureau of Mines & Mineral Resources, 1978) are not considered economic reserves. Potash resources (sylvite and langbeinite) are listed as 133.3 million st at 1600 ft below surface and 351.0 million st 1800 ft below surface, respectively (source of data: U.S. Geological Survey, 1978b). The richness of these materials is 8% K_2O and 3% K_2O with a 4-ft minimum thickness, respectively. The reserves are 27.43 million st of 13.33% K_2O and 48.46 million st of K_2O, sylvite and langbeinite, respectively (source: U.S. Bureau of Mines, 1977). Hydrocarbon resources (crude oil, natural gas, and distillate) are listed as 37.5 million bbls, 490 billion cubic feet (BCF), and 5.72 million bbls, all at 4000 to 20,000 ft below surface (source: New Mexico Bureau of Mines & Mineral Resources, 1974). The richness (physical and fuel properties) of these resources are 31 to 46 degrees API, 1100 BTU/ft^3, and 53 degrees API, respectively. The crude oil is not considered an economic reserve. The reserves of natural gas and distillate are listed as 44.62 BCF and 0.12 mb, both at depths of 14,000 ft (source: Sipes, Williamson, and Associates, 1980a).

In **Table 2** (adapted from U.S. Department of Energy, 1980, table 9-14), D'Appolonia Consulting Engineers, Inc. (1982) discuss the distribution of potash and hydrocarbon resources and reserves by WIPP site control zones. Only 39.1 million st of sylvite resource (29%) and 121.9 million st of the langbeinite resource (35%) are in control zones I, II, and III (source: U.S. Geological Survey, 1978b). Only 16.12 million bbls of the crude oil (43%), 211 BCF of natural gas (43%), and 2.46 million bbls of distillate (43%) resources are in zones I, II, and III (New Mexico Bureau of Mines & Mineral Resources, 1974). In considering reserves, D'Appolonia Consulting Engineers, Inc. (1982) cited the U.S. Department of the Interior (U.S. Bureau of Mines, 1977) to say that zones I, II, and III contain no economically extractable sylvite and only 13.3 million st (27%) of langbeinite ore. Similarly, 21.05 BCF of natural gas (47%) and 0.03 mb of distillate (25%) are economically extractable in the same zones (source: Sipes, Williamson, and Associates, 1980a). No crude oil reserves are considered present within any of the WIPP boundaries. All hydrocarbon reserves (natural gas and distillate) are recoverable by deviated drilling from zone IV (source: Sipes, Williamson, and Associates, 1979).

Citing Sipes, Williamson, and Aycock (1976) and Sipes, Williamson, and Associates (1979; 1980a), D'Appolonia Consulting Engineers, Inc. (1982) stated that an economic analysis of the WIPP area revealed that only the Morrow "Formation" of Pennsylvanian age is worthy of exploration risk and that gas production from the Atoka "Formation" is not large enough to justify exploration of this unit, although some production ancillary to Morrow production may be possible.

In **Table 3** (adapted from U.S. Department of Energy, 1980, table 7-6), the U.S. Geological Survey grade classification for potash ore with a minimum of 4 ft of thickness is as follows: "low" grade langbeinite is a minimum of 3% K_2O, "lease" grade is a minimum of 4%, and "high" grade is a minimum of 8%. "Low" grade sylvite is a minimum of 8% K_2O, "lease" grade is a minimum of 10%, and "high" grade is a minimum of 14%. The source of the information was U.S. Geological Survey (1978b).

D'Appolonia Consulting Engineers, Inc. (1982, p. 64) concluded that "activities related to potash and hydrocarbon resource extraction and solution mining from within (and outside of) control zone IV, using currently available and applicable technology, will not compromise the integrity of the WIPP waste facility and increase the likelihood of a breaching event." The Department of Energy cited this report (D'Appolonia Consulting Engineers, Inc., 1982) to justify removing any controls on extraction outside of control zone III and at more than 6000 ft beneath zones I-III.

All of the information in the report is from previous reports. In addition, the data are based on the original Los Medaños WIPP site of 18,960 acres or the pre-1982 control zones I-III of 8150 acres, not the post-1981 control zones I-III site of 10,240 acres.

Sandia National Laboratories, 1983

Sandia National Laboratories (1983) summarized the evaluation of the WIPP site to that date. The author (W. D. Weart) addressed the resources and the release of WIPP site zone IV for drilling and mining. Exploration for hydrocarbons below zones I, II, and III will be permitted below 6000 ft if the collars of these holes are outside of zone III and if reached by deviated drilling. Potentially economic potash (langbeinite) occurs only in zone III with minor "lease grade" potash in zones I and II (paragraph 4). In paragraph 5, Weart mentions that even if potash mining occurred in zones I-III, the 400 ft between the lowest potash ore-zone and the repository is sufficient to provide an acceptable barrier.

Even changing the hydrologic regime to cause subsidence over the potash workings would produce a vertical dissolution rate of 300 to 500 ft/million yrs, which is acceptable. The author discussed the hydrocarbon potential and indicated that natural gas is the prime target and may be present from 10,000 to 15,000 ft below the surface. In summary, some potash resources may be denied, but the potential natural gas is available by deviated drilling. Therefore the WIPP site is qualified with respect to natural resources, because this denial would be of little or no significance.

Environmental Evaluation Group, New Mexico, 1983

The Environmental Evaluation Group (EEG) report, authored by R. H. Neill and others, reviewed the existing plans for the WIPP site and concluded that it had been characterized sufficiently to warrant confidence in the validation of the site for permanent emplacement of transuranic waste. Of the possible natural resources considered (caliche, gypsum, salt (halite), potash, lithium, and hydrocarbons), EEG only singled out potash and hydrocarbons as potentially exploitable. The authors recommended that no potash mining be allowed in control zones I, II, or III and that deviated drilling may be allowed under the site at depths greater than 6000 ft. They also recommended that the federal government exercises active institutional control at the site for this purpose for at least 100 yrs after repository decommissioning. Additional recommendations were made, but none involving the size or accessibility of the site's mineral resources.

Resources and reserves with information sources were summarized by EEG in three tables. Table 5 is on the quantity depth, and richness of caliche, gypsum, salt (halite), sylvite ore, langbeinite ore, lithium, crude oil, natural gas, and distillate at the WIPP site. Table 6 is on the potash (sylvite and langbeinite) divided into resources and reserves and the percentage of each in control zone IV. Table 7 is of the potential natural gas and distillate within the site divided into the percentages within zones I-III and zone IV. All the data are from previous work. In addition, the information on zone III resources is for the "old" (pre-1982) zone III when zones I-III consisted of 8100 acres, not the present 10,240 acres.

Energy and Minerals Department (New Mexico), 1984

In 1983, at the request of Governor Toney Anaya, the New Mexico Energy and Minerals Department established a "Task Force on Mineral Resources at WIPP." Subcommittee I was charged with "reviewing available estimates of mineral and hydrocarbon resources within the WIPP boundary, identifying resource related issues, problems, and impacts (e.g. compensation for lost revenues) associated with the development of WIPP, and recommending possible options for resolving those conflicts...." The State's interest in doing so was because WIPP included two state sections (secs. 16 & 32 T22S R31E) that would not be developed. Revenues from New Mexico potash and hydrocarbon taxes on federal land within WIPP would be lost if those resources were not developed.

Subcommittee I addressed the economic impact of "squaring off" WIPP to 16 sections (4 by 4 sections) totaling 10,240 acres. They used 22% obtained by estimating the area of control zone IV on maps of lease-grade potash by the U.S. Geological Survey (1978), now included in the WIPP site boundary or modified zone III. This value was obtained by use of a planimeter. This factor (22%) was applied to both the tonnages of resources (4 ft thickness of either 3% K_2O and above as langbeinite or 8% K_2O and above as sylvite) and to reserves (4 ft thickness of either 4% K_2O and above as langbeinite or 10% K_2O and above as sylvite). The derived estimation of the potash resources within WIPP was 60 million st as sylvite and 172 million st as langbeinite. The derived estimation of the potash reserves within WIPP was 35 million st as sylvite and 127 million st as langbeinite.

The subcommittee used data generated by the U.S. Geological Survey (1978b) and assumed that resources and reserves are equally distributed among each of the 16 sections with the WIPP boundary. Because the two state sections total 1280 acres, the committee used 1280 acres/10,240 acres or the total area of post 1982 WIPP as the factor to obtain an estimation of the tonnages of potash resources and reserves in the two state sections. Sylvite resources and reserves were estimated at 7.5 million st and 4.4 million st, respectively. Langbeinite resources and reserves were estimated at 21.5 million st and 15.9 million st, respectively.

For the hydrocarbon potential in the two state sections, the New Mexico Energy and Minerals Department used the same method as for potash estimations. The 1974 New Mexico Bureau of Mines & Mineral Resources judgments of the potential per section were used as baseline information. The hydrocarbon resources potentially located beneath the two state sections were estimated to be 2.5 million bbls of oil, 33.1 MCF of natural gas, and 0.4 million bbls of distillate.

Environmental Evaluation Group, New Mexico, 1994

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Table 1. Evaluation of mineral resources beneath WIPP.

COMMODITY	Quantity present under WIPP	Present disposition as a resource	Reference	Other references
CALICHE	185 millon st[1,2]	Not considered a resource	New Mexico Bureau of Mines & Mineral Resources (1978)	Sandia National Laboratories (1983; 1978); Environmental Evaluation Group (1983); U.S. Department of Energy (1980)
GYPSUM	1.3 billion st[1,2]	Not considered a resource	New Mexico Bureau of Mines & Mineral Resources (1978)	Sandia National Laboratories (1983; 1978); Environmental Evaluation Group (1983); U.S. Department of Energy (1980)
HALITE (Salt)	198 billion st[1,2]	Not considered a resource	New Mexico Bureau of Mines & Mineral Resources (1978)	Sandia National Laboratories (1983; 1978); Environmental Evaluation Group (1983); U.S. Department of Energy (1980)
HYDROCARBONS				
Crude oil	37.50 million bbls[1,3] (as a resource)	Not considered unless prices rise substantially, but more recent reports suggest of major importance	Sipes, Williamson & Associates (1980a)	Environmental Evaluation Group (1994; 1983); Sandia National Laboratories (1991; 1983; 1978); Agricultural and Industrial Minerals (1978); Sipes, Williamson & Associates (1979; 1980b; 1980c; 1981); Sipes, Williamson & Aycock, (1976a; 1976b; 1978; 1979a; 1979b; 1979c); U.S. Department of Energy (1980); New Mexico Bureau of Mines & Mineral Resources (1974)

[1]Quantity present in original Los Medaños site of 18,960 acres.
[2]Data from New Mexico Bureau of Mines & Mineral Resources (1978).
[3]Data from New Mexico Bureau of Mines & Mineral Resources (1974).

Table 1. (cont.)

COMMODITY	Quantity present under WIPP	Present disposition as a resource	Reference	Other references
HYDROCARBONS (cont.)				
Natural gas	490.12 BCF[1,3] (as a resource) 83,974,500 MCF[1,4] (as reserves)	The main hydrocarbon of potential economic importance, but later reports suggest crude oil is more important	Sipes, Williamson & Associates (1980a)	Environmental Evaluation Group (1994; 1983); Sandia National Laboratories (1991; 1983; 1978); Agricultural and Industrial Minerals (1978); Sipes, Williamson & Associates (1979; 1980b; 1980c; 1981); Sipes, Williamson & Aycock, (1976a; 1976b; 1978; 1979a; 1979b; 1979c); U.S. Department of Energy (1980); New Mexico Bureau of Mines & Mineral Resources (1974)
Distillate	5.72 million bbls[1,3] (as a resource) 390,843 bbls[1,4] (as reserves)	Of potential economic importance	Sipes, Williamson & Associates (1980a)	Environmental Evaluation Group (1994; 1983); Sandia National Laboratories (1991; 1983; 1978); Agricultural and Industrial Minerals (1978); Sipes, Williamson & Associates (1979; 1980b; 1980c; 1981); Sipes, Williamson & Aycock, (1976a; 1976b; 1978; 1979a; 1979b; 1979c); U.S. Department of Energy (1980); New Mexico Bureau of Mines & Mineral Resources (1974)
LITHIUM	800 st[1,5] (resource only)	Not considered a resource	Sandia National Laboratories (1978)	Sandia National Laboratories (1983); Environmental Evaluation Group (1983); U.S. Department of Energy (1980; 1983); New Mexico Bureau of Mines & Mineral Resources (1978)
METALLIFEROUS SULFIDES	-	Not considered a resource	Sandia National Laboratories (1978)	Sandia National Laboratories (1983); U.S. Department of Energy (1980)

[4]Data from Sipes, Williams, and Associates, Inc., (1980a).

[5]Data for metal resource based on U.S. Department of Energy (1983).

Table 1. (cont.)

COMMODITY	Quantity present under WIPP	Present disposition as a resource	Reference	Other references
POTASSIUM SALTS				
Langbeinite	351 million st[1,6] (as a resource) 78 million st[1,7] (as reserves with 32% in zones I-III)[7]	Only ore of potash of economic importance present	U.S. Geological Survey (1978a)	Sandia National Laboratories (1983; 1978); Environmental Evaluation Group (1983); U.S. Department of Energy (1982; 1980); U.S. Geological Survey (1978a; 1978b); Agricultural and Industrial Minerals (1978); U.S. Bureau of Mines (1977)
Sylvite	133.2 million st[1,6] (as a resource) 54 million st[1,7] (as reserves with 18% in zones I-III)[7]	Not considered of economic importance	U.S. Geological Survey (1978a)	Sandia National Laboratories (1983; 1978); Environmental Evaluation Group (1983); U.S. Department of Energy (1982; 1980); U.S. Geological Survey (1978a; 1978b); Agricultural and Industrial Minerals (1978); U.S. Bureau of Mines (1977)
SULFUR	-	Not considered a resource	New Mexico Bureau of Mines & Mineral Resources (1978)	Sandia National Laboratories (1983; 1978) U.S. Department of Energy (1980)
TAR SANDS	-	Not considered a resource	New Mexico Bureau of Mines & Mineral Resources (1978)	Sandia National Laboratories (1983; 1978) U.S. Department of Energy (1980)
URANIUM	-	Not considered a resource	New Mexico Bureau of Mines & Mineral Resources (1978)	Sandia National Laboratories (1983; 1978) U.S. Department of Energy (1980)

[6]Data from U.S. Geological Survey (1978b).
[7]Data prepared from information in U.S. Geological Survey (1978b).

Table 2. Significance of the resources and reserves at the WIPP Site (U.S. Department of Energy, 1980, table 9-14; see below).

Deposit	WIPP site	Region	United States	World
	RESOURCES[a]			
Sylvite (at lease grade)				
Quantity, million st ore	88.5	4260	8500	850,000
Percentage at WIPP site		2.1	1.0	0.010
High grade	54. 0			
Low grade	133.2			
Langbeinite (at lease grade)				
Quantity, million st ore	264.2	1140	-No estimate available-	
Percentage at WIPP site		23 (21.5 as K_2O)		
High grade	77.6			
Low grade	351.0			
Crude oil				
Quantity, million bbls	37.50	1915	200,000	Not available
Percentage at WIPP site		2.0	0.019	
Natural gas				
Quantity, BCF	490	25,013	855,000	Not available
Percentage at WIPP site		2.0	0.057	
Distillate				
Quantity, million bbls	5.72	293	------Not available------	
Percentage at WIPP site		2.0		
	RESERVES[b]			
Sylvite[c]				
Quantity, million st K_2O	3.66	106	206	11,206
Percentage at WIPP site		3.4	1.8	0.033
Langbeinite[d]				
Quantity, million st K_20	0.92[d]	9.3	9.3	Not available
Percentage at WIPP site		10	10	
Crude oil				
Quantity, million st	Nil	471.7	29,486	646,000
Percentage at WIPP site		0	0	0
Natural gas				
Quantity, BCF	44.62	3865	208,800	2,520,000
Percentage at WIPP site		1.15	0.021	0.0018
Distillate				
Quantity, million bbls	0.12	169.1	35,500	Not available
Percentage at WIPP site		0.07	0.0003	

[a]Data sources: Hydrocarbons, Foster (1974) for the site and region; potash salts, John et al. (1978) for the site and region; Brobst and Pratt (1973) for U.S. oil and gas and the world resources of sylvite.

[b]Data sources: Hydrocarbons, Keesey (1979) for the site, American Petroleum Institute (1978) for the region, the United States, and the world; potash salts, U.S. Bureau of Mines (USBM, 1977).

[c]The U.S. Bureau of Mines (USBM, 1977) does not consider any sylvite to be commercial today. However, one bed (mining unit A-1) of sylvite was marginal and has been added to the reserve list.

[d]Estimated from the AIM (1979) study. The USBM estimate for the WIPP site is 4.41 million st K_20 equivalent, but no comparable USBM estimate is available for the entire district.

Table 3. Effect of allowing the exploitation of hydrocarbons and potash in control zone IV (after U.S. Department of Energy, 1980, table 9-19)

Deposit	In total site	In inner zones (I, II, III)	Percentage of total recoverable in Zone IV
		RESOURCES	
Sylvite[a] million st ore	133.2	39.1	71
Langbeinite[a] million st ore	351.0	121.9	65
Crude oil[b] million bbls	37.50	16.12	57
Natural gas[b] BCF	490	211	57
Distillate[b] million bbls	5.72	2.46	57
		RESERVES	
Sylvite[c,d] million st ore	27.43	Nil	100
Sylvite[c,d] million st K_2O	3.66	Nil	100
Langbeinite[c] million st ore	48.46	13.3	73
Langbeinite[c] million st K_2O	4.41	1.21	73
Crude oil million bbls	--	--	--
Natural gas[e] BCF	44.62	21.05	53
Distillate million bbls	0.12	0.03	75

[a]Data from U.S. Geological Survey (1978b, table 4).
[b]Computed from New Mexico Bureau of Mines & Mineral Resources (1974).
[c]Data from U.S. Bureau of Mines (1977, table 5).
[d]Sylvite considered subeconomic by U.S. Bureau of Mines (1977).
[e]Computed from data presented by Sipes, Williamson, and Associates (1980a), considering that only reserves under the inner safety zones are precluded from development.

Figure 1. Evolution of the radioactive waste repository in southeastern New Mexico from the Oak Ridge National Laboratory (ORNL) Study Area of 1974-1975, through the original Los Medaños Waste Isolation Pilot Project (WIPP) site of 1975-1982 with four control zones (I, II, III, and IV), to the present Los Medaños WIPP site of 1982-to present. The 1-mile-wide border also evaluated in this report and surrounding the present WIPP area is also shown.

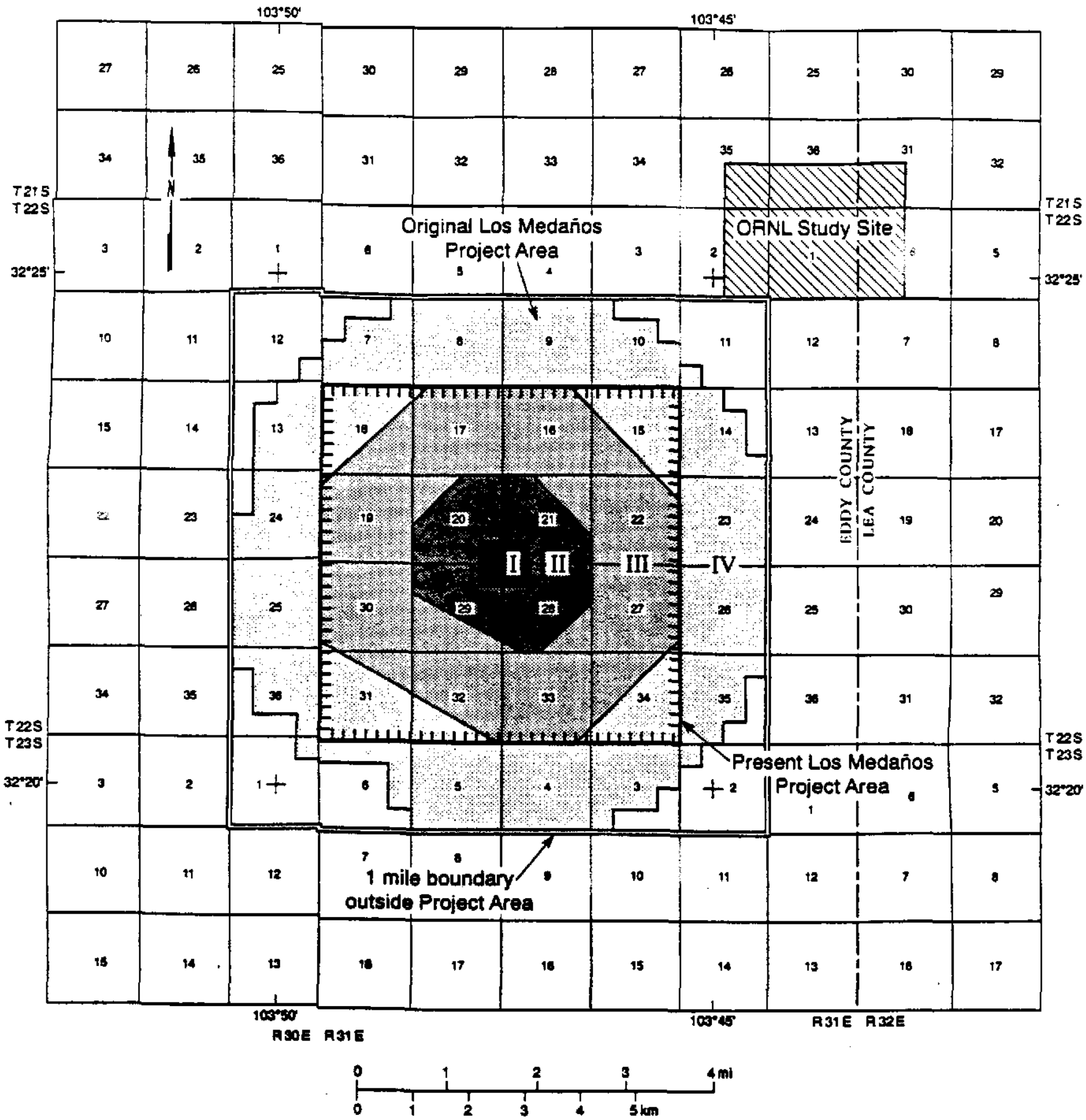

Figure 1. Evolution of the radioactive waste repository in southeastern New Mexico from the Oak Ridge National Laboratory (ORNL) Study Area of 1974-1975, through the original Los Medaños Waste Isolation Pilot Project (WIPP) site of 1975-1982 with four control zones (I, II, III, and IV), to the present Los Medaños WIPP site of 1982-to present. The 1-mile-wide border also evaluated in this report and surrounding the present WIPP area is also shown.

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Evaluation of Mineral Resources at the
Waste Isolation Pilot Plant (WIPP) Site

Chapter II

ENVIRONMENTAL AND REGULATORY REQUIREMENTS FOR MINING/EXTRACTION OPERATIONS AT OR NEAR THE WIPP SITE

by
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TABLES

ENVIRONMENTAL AND REGULATORY REQUIREMENTS FOR MINING/EXTRACTION OPERATIONS AT OR NEAR THE WIPP SITE

Julie Wanslow

The purpose of this section is to identify the environmental and regulatory requirements that may affect the extraction of oil and gas or the mining of potash at or near the Waste Isolation Pilot Plant (WIPP) site. The environmental and regulatory requirements are identified if they have changed since 1980 and if they are relevant to operations that mine or extract oil, gas, or potash. This information was obtained by researching the statutes, the associated rules and regulations, and environmental law handbooks. In addition, this section describes the levels of impact of the statutes and regulations on existing or new oil and gas extraction operations and potash mining operations. The level-of-impact information represents perceived levels based on information obtained from oil, gas, and potash operators near the WIPP site.

Clean Air Act

The Clean Air Act (CAA), 42 U.S.C. 7401 et seq., was first enacted in 1970 and amended several times, most recently in 1994. It establishes air emission limits for new and existing sources and delegates primary enforcement responsibility to the states. Each state must submit to the U.S. Environmental Protection Agency (EPA) a State Implementation Plan demonstrating how it will enforce the CAA requirements. New Mexico's first implementation plan was submitted in 1972 and since then has been regularly updated. The CAA regulations and standards are codified in 40 CFR Parts 50 to 88.

Operations that involve the subsurface mining or extraction of oil, gas, or potash may be subject to 40 CFR Part 60 (standards of performance for new stationary sources) and Part 61 (national emission standards for hazardous air pollutants). The EPA has delegated the administration of these programs to New Mexico (see *New Mexico Air Quality Control Act*).

Permits, special reports, and fees

No permits, special reports, and fees are required by the CAA regulations. Permits and associated fees are issued and collected by the Air Quality Bureau of the New Mexico Environment Department (NMED), which administers the delegated CAA programs (see *New Mexico Air Quality Control Act*).

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Clean Water Act

The Clean Water Act (CWA), 33 U.S.C. 1251 et seq., was enacted in 1972 to restore and maintain the chemical, physical, and biological integrity of the waters of the U.S. (excluding ground water). "Waters of the U.S." is broadly defined and may include almost any surface water as well as adjacent wetlands, intermittent streams, and arroyos. Since 1980, the CWA has been amended several times to include the oil spill and hazardous substances spill response and cleanup program and wetlands protection. The CWA regulatory programs are codified in 40 CFR Parts 100 to 149, Part 230, Part 300, and Parts 400 to 610.

Operations that involve the subsurface mining or extraction of oil, gas, or potash may be subject to the following CWA regulatory programs.

Section 404 Dredge and Fill Permit Program

The CWA Section 404 dredge and fill permit program, described in 40 CFR Part 230, regulates the discharge of dredged or fill material into waters of the U.S. at specified disposal sites. Originally, the intent of this program was to regulate disturbance of actual navigable waterways (i.e. bridge construction and stream bank stabilization). Recently, however, its focus has been expanded to protect wetlands, including wetlands not located on federal land. The U.S. Army Corps of Engineers, Albuquerque District, administers this program and issues permits in New Mexico.

National Pollutant Discharge Elimination System and Storm Water Discharge permits

The Environmental Protection Agency (EPA) administers the National Pollutant Discharge Elimination System (NPDES) and requires a permit for the discharge of pollutants from a point source into waters of the U.S. NPDES is codified in 40 CFR 122. Pollutants include any materials that change the characteristics of the water, including changes in pH and temperature. Storm-water runoff may need to be permitted; however, uncontaminated runoff from mining operations or oil and gas exploration is exempt from the permit requirements. A mining or oil and gas operation must submit an individual storm-water permit unless a general storm-water permit has been granted. On September 9, 1992, the EPA issued a baseline general permit for certain industrial activities. This permit provides limited coverage for mining activities and coverage for oil and gas extraction activities if, since 1987, no quantities of hazardous substances have been reported (as defined in 40 CFR Part 117, Table 117.3). Operators covered by the general permit must submit a Notice of Intent in accordance with Part II of this permit.

Spill Prevention, Control, and Countermeasures plans

Discharge of oil (40 CFR Parts 109 to 112) and hazardous substances (40 CFR Part 116) into waters of the U.S. is prohibited under the CWA (discharge of some hazardous substances is allowed if the activity is covered by a NPDES permit). Under 40 CFR Part 112, facilities that, because of their location, could reasonably be expected to discharge oil in harmful quantities (defined in the regulations) must prepare a Spill Prevention, Control, and Countermeasures (SPCC) plan.

Oil spill response

The oil spill response program is codified in 40 CFR Parts 110, 112, and 300. Title 40 CFR Part 300 includes notification requirements and establishes the federal organizational structure that responds to oil spills in waters of the U.S. (see *Comprehensive Environmental Response, Compensation, and Liability Act*). Any discharge that violates CWA Section 311(b)(3) must be reported (40 CFR 110.3-110.5). If the person responsible for the discharge does not undertake cleanup, the federal government will take appropriate action and submit a bill to the responsible party. Part 300 does not describe the types of activities that must be taken to clean up spilled oil; the SPCC plan required by 40 CFR Part 112 should include these specific activities (see *New Mexico Water Quality Act* and the *New Mexico Oil Conservation Division Regulations*).

Permits, special reports, and fees

EPA may require NPDES permits for discharges of waste water or storm water to waters of the U.S. No fees are currently required by EPA. A SPCC plan may be required for certain operations, as described above. Certain reporting requirements may be required for oil discharges, as described above. A CWA Section 404 Dredge and Fill permit issued by the U.S. Army Corps of Engineers may be required if a wetland area is affected. A filing fee for a permit is required by the Corps of Engineers and is described in 33 CFR 325.1.

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U.S. Environmental Protection Agency, 1994, Code of Federal Regulations Title 40, Protection of Environment, Subchapter D, Parts 100 to 149: Office of the Federal Register, National Archives and Records Administration, 1121 pp.

U.S. Environmental Protection Agency, 1994, Code of Federal Regulations Title 40, Protection of Environment, Parts 190 to 259: Office of the Federal Register, National Archives and Documents Administration, Washington, DC, 492 pp.

U.S. Environmental Protection Agency, 1994, Code of Federal Regulations Title 40, Protection of Environment, Part 300 to 399: Office of the Federal Register, National Archives and Records Administration, 497 pp.

U.S. Environmental Protection Agency, 1993, Code of Federal Regulations Title 40, Protection of Environment, Parts 425 to 699: Office of the Federal Register, National Archives and Records Administration, 802 pp.

U.S. Environmental Protection Agency, September 9, 1992, "Final NPDES General Permits for Storm Water Discharges Associated with Industrial Activity; Permit Language," *Federal Register*, Vol. 57, No. 175, pp. 41297–41342.

Comprehensive Environmental Response, Compensation, and Liability Act

The Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), 42 U.S.C. 9601 et seq., was enacted in 1980 to establish a mechanism for cleaning up sites contaminated with hazardous substances and wastes. The CERCLA requirements have been codified in 40 CFR Parts 300 (National Oil and Hazardous Substances Pollution Contingency Plan) and 302 (Hazardous Substance Designations, Reportable Quantities, and Release Notification Requirements).

Title 40 CFR Part 300 includes a complex program for identifying and cleaning up abandoned hazardous waste sites. The CERCLA program in 40 CFR Part 300 gives the U.S. government the authority to respond to the release or threatened release of hazardous pollutants or contaminants into the environment; establishes a broad scheme for imposing liability on responsible parties; and creates a fund, known as Superfund, to finance the cleanup of releases of hazardous substances (see 40 CFR 300.5 for definition). Hazardous substances include any pollutant or contaminant that may present an imminent and substantial danger to public health or welfare.

However, hazardous substances do not include petroleum, including crude oil or any fraction thereof that is not otherwise specifically listed or designated as a hazardous substance under Section (A) through (F) of Section 101(14) of CERCLA, or natural gas, natural gas liquids, liquefied natural gas, or synthetic gas usable for fuel (or mixtures of natural gas and such synthetic gas). According to EPA's interpretation, the petroleum exclusion applies to materials such as crude oil, petroleum feedstocks, and refined petroleum products. Title 40 CFR Part 302 contains the notification requirements for releases of CERCLA hazardous substances when releases exceed threshold amounts (i.e. "reportable quantities" in 40 CFR Part 302, Table 302.4).

Operations that involve the subsurface mining or extraction of oil, gas, or potash may be subject to the cleanup requirements of 40 CFR Part 300 if there are releases or threatened releases of hazardous pollutants or contaminants to the environment. In addition, these operations would be subject to the reporting requirements of 40 CFR Part 302 if releases of CERCLA hazardous substances to the environment exceed reportable quantities. These requirements do not apply to releases or threatened releases of substances that are excluded by the petroleum exclusion.

<u>Permits, special reports, and fees</u>

No permits or fees are associated with CERCLA. Reporting of releases of reportable quantities of regulated hazardous substances is required as described above.

References

Arbuckle, J., Brownell, F., Case, D., Halbleib, W., Jensen, L., Landfair, S., Lee, R., Miller, M., Nardi, K., Olney, A., Sarvadi, D., Spensley, J., Steinway, D., and Sullivan, T., 1993, Environmental Law Handbook, Twelfth Edition: Government Institutes Inc., Rockville, MD, 550 pp.

McCoy and Associates Inc., 1991, CERCLA Regulations and Keyword Index, 1991 Edition: McCoy and Associates Inc., Lakewood, CO, 401 pp.

U.S. Environmental Protection Agency, 1994, Code of Federal Regulations Title 40, Protection of Environment, Parts 300 to 399: Office of the Federal Register, National Archives and Records Administration, Washington, DC, 446 pp.

Emergency Planning and Community Right-To-Know Act

The Emergency Planning and Community Right-To-Know Act (EPCRA), 42 U.S.C. Parts 11001 to 11050, was enacted in 1986 to establish state and local response plans for emergencies caused by hazardous substance releases. EPCRA was added as part of the Superfund Amendments and Reauthorization Act, an amendment to CERCLA. EPCRA requires the owners and operators of facilities that store, use, or release hazardous chemicals, extremely hazardous substances, and CERCLA hazardous substances (see 40 CFR Part 355.20 for definitions) to comply with certain notification requirements, including notification of releases. The EPCRA regulations are codified in 40 CFR Parts 350 to 372 (see *New Mexico Hazardous Chemicals Information Act*).

Operations that involve the subsurface mining or extraction of oil, gas, or potash may be subject to certain notification requirements if an extremely hazardous substance is present at a site at or above threshold planning quantities specified in the regulations (40 CFR 355.30), or if a certain amount of extremely hazardous substance or CERCLA hazardous substance is released into the environment (40 CFR 355.40). These operations may be subject to the material safety data sheet reporting requirements and the inventory reporting requirements for each hazardous chemical (as defined in 40 CFR 370.1) present at the site (40 CFR, Part 370, Subpart B). In addition, these operations may be subject to the toxic chemical recordkeeping (40 CFR, Part 372, Subpart A) and reporting requirements (40 CFR, Part 372, Subpart B) for each toxic chemical (as defined in 40 CFR 372.10) released into the environment.

Permits, special reports, or fees

No permits or fees are associated with this act. Reporting requirements are referenced above.

References

Arbuckle, J., Brownell, F., Case, D., Halbleib, W., Jensen, L., Landfair, S., Lee, R., Miller, M., Nardi, K., Olney, A., Sarvadi, D., Spensley, J., Steinway, D., and Sullivan, T., 1993, Environmental Law Handbook, Twelfth Edition: Government Institutes Inc., Rockville, MD, 550 pp.

U.S. Environmental Protection Agency, 1993, Code of Federal Regulations Title 40, Protection of Environment, Parts 300 to 399: Office of the Federal Register, National Archives and Records Administration, Washington, DC, 504 pp.

Endangered Species Act

The Endangered Species Act (ESA), 16 U.S.C. Section 1531 to 1544, was enacted in 1973 and has been amended several times, most recently in 1982. The ESA provides a means of protecting the habitat of endangered and threatened plant and animal species in the United States. Under this act, all federal agencies are prohibited from allowing activities that could jeopardize the continued existence of any endangered or threatened species or critical habitat.

Operations that involve subsurface mining or the extraction of oil, gas, or potash are seen by this act as the applicant to whom a federal agency issues a permit or license. As such, these operations are affected by ESA only to the extent that the issuing agency is required to ensure that an authorized, funded, or executed activity does not jeopardize the continued existence of a listed species or its habitat.

Permits, special reports, and fees

No fees, permits, or special reports are applicable to ESA as it applies to the operations described above.

References

Senate Committee on Environment and Public Works, 1983, The Endangered Species Act As Amended by Public Law 97-304 (The Endangered Species Act Amendments of 1982): U.S. Government Printing Office, Washington, DC, 53 pp.

Executive Order 11990, Protection of Wetlands

Executive Order 11990, "Protection of Wetlands," signed on May 24, 1977, requires each federal agency to actively minimize the destruction, loss, or degradation of wetlands.

Whenever an agency is considering an action that could affect a wetland, that agency must weigh the proposed action against the following: public health, safety, and welfare; pollution, flood and storm hazards, and sediment and erosion; maintenance of natural systems, including conservation and long-term productivity of existing species, species and habitat diversity and stability, hydrologic utility, fish, wildlife, timber and food and fiber resources; and other uses of wetlands in the public interest, such as recreational, scientific, and cultural uses.

Operations that involve subsurface mining or the extraction of oil, gas, or potash may be subject to regulation by the affected agency under Executive Order 11990 if any of the activities might affect (or create) a wetland.

Permits, special reports, and fees

No permits, reports, or fees are associated with Executive Order 11990.

References

Carter, J., 1977, Executive Order 11990, Protection of Wetlands, Federal Register Document 77-15123: Office of the President of the United States, 2 pp.

Federal Insecticide, Fungicide, and Rodenticide Act

The Federal Insecticide, Fungicide, and Rodenticide Act of 1947 (FIFRA), 7 U.S.C. Section 136 et seq., has been amended four times, most recently by the Pesticide Monitoring Improvements Act in 1988. FIFRA requires the registration, certification, use, storage, disposal, transportation, and recall of pesticides. The regulations are codified under 40 CFR Parts 150 to 189 (see *New Mexico Pesticide Control Act*).

Operations that involve subsurface mining or the extraction of oil, gas, or potash would not be subject to 40 CFR Parts 150 to 165 and Parts 168 to 169, since these activities do not involve the manufacture of pesticides. If these operations use pesticides, they could be subject to the following regulations:

- Worker protection standards (40 CFR Part 170)
- Certification of applicators and experimental use (40 CFR Part 171 to 172)
- Standards enforcement (40 CFR Part 173, 177 to 179)

Permits, special reports, and fees

Documentation is required for reporting and recordkeeping purposes in the event of uncertified use of a pesticide under emergency conditions as defined in 40 CFR Part 166. Documentation is also required for certification of pesticide applicators (40 CFR Part 171) and permitting for experimental use of a pesticide (40 CFR Part 172). No fees are associated with FIFRA.

References

U.S Environmental Protection Agency, 1994, Code of Federal Regulations Title 40, Protection of Environment, Subchapter E, Parts 152-186: Office of the Federal Register, National Archives and Records Administration, Washington, DC, 664 pp.

Federal Mine Safety and Health Act

The Federal Mine Safety and Health Act (30 U.S.C. sec. 801 et seq.) was enacted in 1977 and amended several times, most recently in 1992. Its purpose is to develop and enforce health and safety standards and regulations for mine workers. The Mine Safety and Health Administration (MSHA) sets health and safety regulations for equipment and operations used in all subsurface mining activities. These regulations are codified in 30 CFR Parts 40 to 100. This act has no jurisdiction at oil and gas extraction sites.

Operations that involve subsurface mining of potash may be subject to the following MSHA safety regulations in 30 CFR:

- Filing and other administrative requirements (Subchapter G)
- Education and training (Subchapter H)
- Accidents, injuries, illnesses, employment, and production in mines (Subchapter M)
- Metal and nonmetal mine safety and health (Subchapter N)

Permits, special reports, and fees

No fees or permits are associated with MSHA. MSHA requires the person who operates a mine to file and/or maintain documentation including the following:

- Notification of legal identity as defined in 30 CFR, Subchapter G, Parts 41 and 42
- Information identifying the representative of miners, who is responsible for notifying the Department of Labor of any violations of this act
- Documents pertaining to a request for a safety standard modification
- Records of all employee training, as defined in 30 CFR Subchapter H
- Reports on any accidents, injuries, and illnesses that occur, as defined in 30 CFR Subchapter M, and associated investigation reports
- A quarterly employment report, as defined in 30 CFR Subchapter M, Subpart D
- Registration documents for independent contract mining service providers

References

U.S. Department of Labor, 1993, Code of Federal Regulations Title 30, Mineral Resources, Parts 40 to 199, Department of Labor: Office of the Federal Register, National Archives and Records Administration, Washington, DC, 777 pp.

Migratory Bird Treaty Act

The Migratory Bird Treaty Act, 16 U.S.C. 703 et seq., was first enacted in 1918 and last amended in 1989. The requirements of this act have been codified in 50 CFR Part 20 (Migratory Bird Hunting) and Part 21 (Migratory Bird Permits). Associated regulations are found in 50 CFR Subchapter A (General Provisions, Parts 1 to 3) and Subchapter B (Taking, Possession, Transportation, Sale, Purchase, Barter, Exportation, and Importation of Wildlife and Plants, Parts 10 to 17).

Part 20 (Migratory Bird Hunting) specifies the restrictions, conditions, and requirements for taking, possessing, transporting, shipping, exporting, or importing migratory game birds. Taking is defined as pursuing, shooting, shooting at, poisoning, wounding, killing, capturing, trapping, collecting, molesting or disturbing.

Part 21 (Migratory Bird Permits) includes general requirements and exceptions, specific permit requirements, and requirements for the control of depredating birds. In general, Part 21 forbids the following activities: taking, possessing, importing, exporting, transporting, selling, purchasing or bartering any migratory bird, or the parts, nests, or eggs of any such bird without a permit. However, if a permit is obtained, then the taking, possessing, importing, exporting, transporting, selling, purchasing, bartering, banding, or marking of migratory birds or their parts, nests, or eggs, may be allowed.

Operations that involve subsurface mining or the extraction of oil, gas, or potash may be subject to the requirements in 50 CFR as described above.

Permits, special reports, and fees

Part 20 requires foreign export permits for migratory game birds. There are no special reports required by the regulations. There is a general permit application fee required by 50 CFR, Section 13.11.

References

United States Code Volume 16, Section 703 et seq., Migratory Bird Treaty Act: Congress of the United States, Washington, DC, 3 pp.

U.S. Environmental Protection Agency, 1993, Code of Federal Regulations Title 50, Wildlife and Fisheries, Parts 1 to 199: Office of the Federal Register, National Archives and Records Administration, Washington DC, 658 pp.

Mineral and Leasing Act, Federal Land Policy and Management Act (Bureau of Land Management)

The Mineral and Leasing Act, 30 USC 22 et seq., and the Federal Land Policy and Management Act, 43 USC 1701 et seq., were enacted in 1920 and 1976, respectively, to establish laws governing the exploration and operation of mining activities on federally owned land. These laws promote the orderly and efficient exploration, development, and production of minerals. Since 1980, the regulations have been amended several times, most recently in 1993. The requirement relating to BLM mineral management on public lands has been codified in 43 CFR Part 3000.

Operations that involve subsurface mining or the extraction of oil, gas, or potash on BLM lands may be subject to the regulations for leasable minerals in 43 CFR Parts 3000 to 3590. These regulations include the following:

- Issuance of leases and terms and conditions (43 CFR 3101)
- Qualifications of leases (43 CFR 3102)
- Fees, rentals, and royalties (43 CFR 3103)
- Bonds (43 CFR 3104)
- Cooperative conservation (43 CFR 3105)

- Transfers (43 CFR 3106)
- Continuation (43 CFR 3107)
- Termination (43 CFR 3108)

Operations that involve the mining or extraction of minerals described above may be subject to Title 43 CFR Part 3809 if the operations degrade BLM land as described in Title 43 CFR Part 3809. Title 43 CFR Part 3809 establishes procedures to prevent unnecessary or undue degradation of federal lands that may result from the operation of authorized mineral operations. This section also provides for reclamation of disturbed areas and coordination with appropriate state agencies. All mining operations on federal lands or requiring access across federal lands are required to notify the District Office of the BLM having jurisdiction over the disturbed land (43 CFR 3809.1-3).

When a mining project is proposed to disturb an area in excess of five acres, an approved plan of operations is required (43 CFR 3809.1-4 through 1-9). This plan should describe the nature of the proposed disturbance, the steps to protect surface resources, and proposed steps to reclaim the land after cessation of mining. Operations filing such a plan require a National Environmental Policy Act environmental assessment prepared by the BLM (43 CFR 3809.2). All disturbances of federal land shall comply with federal and state laws including, but not limited to, those concerning air quality, water quality, solid waste, fisheries, wildlife, plant habitat, cultural and paleontological activities, and protection of survey monuments.

Permits, special reports, and fees

Operations in excess of five acres requires an operations plan as described above (43 CFR 3809). Lease agreements, with appropriate documentation and bonds as necessary, are required and described in 43 CFR 3000.

References

New Mexico Energy, Minerals, and Natural Resources Department, Mining and Mineral Division, Mine Registration and Geological Services, 1992, Permit Requirements for Energy and Minerals in New Mexico: New Mexico Energy, Minerals, and Natural Resources Department, Santa Fe, NM, 62 pp.

U.S. Department of Interior, 1993, Code of Federal Regulations Title 43, Public Lands: Interior, Subtitle B, Subchapter C, Parts 3000 to 3999: Office of the Federal Register, National Archives and Records Administration, Washington, DC, 905 pp.

National Environmental Policy Act

The National Environmental Policy Act (NEPA), 42 U.S.C. 4321 et seq., was enacted in 1969 and has been amended several times, most recently in 1993. NEPA establishes a national environmental policy requiring actions that involve federal agencies or federal funding to consider all significant aspects of the environmental effect(s) of a proposed action in the agency's decision-making process and to notify the public.

NEPA regulations, codified in 40 CFR 1501-1508, include the following:

- NEPA and agency planning (Part 1501)
- Environmental impact statement (Part 1502)
- Commenting (Part 1503)
- Predecision referrals of federal actions determined to be environmentally unsatisfactory (Part 1504)
- NEPA and agency decision making (Part 1505)
- Agency compliance (Part 1507)

Some federal agencies have issued their own regulations for complying with NEPA, such as the National Environmental Policy Act Compliance Program (DOE Order 5440.1E, issued in 1992), which provides compliance regulations for DOE-controlled lands; and 43 CFR Subchapter A, Subpart 1601 et seq. (1983), which provides compliance guidance for BLM-controlled lands.

Operations that are involved in subsurface mining or the extraction of oil, gas, or potash may be subject to requirements for evaluating the effect of the operations on the environment, unless the action was determined to be categorically excluded (40 CFR 1508.4).

Permits, special reports, and fees

No permits or fees are associated with NEPA. Depending on the effect of the proposed action, an environmental assessment or an environmental impact statement may be required.

References

Arbuckle, J., Brownell, F., Case, D., Halbleib, W., Jensen, L., Landfair, S., Lee, R., Miller, M., Nardi, K., Olney, A., Sarvadi, D., Spensley, J., Steinway, D., and Sullivan, T., 1993, Environmental Law Handbook, Twelfth Edition: Government Institutes Inc., Rockville, MD, 550 pp.

U.S. Environmental Protection Agency, 1993, Code of Federal Regulations Title 40, Protection of Environment, Parts 790 to end: Office of the Federal Register, National Archives and Records Administration, Washington, DC, 743 pp.

National Historic Preservation Act

The National Historic Preservation Act (16 USC sec. 470 et seq) was enacted in 1966 and has been amended several times, most recently in 1980. This act protects cultural resources in the United States and requires federal agencies to recover and preserve historic and archaeological data that would otherwise be lost during federal construction or other activities.

Operations that involve subsurface mining or the extraction of oil, gas, or potash are seen by this act as the applicant to whom a federal agency issues a permit or license. As such, these operations are affected by the National Historic Preservation Act only to the extent that the issuing agency is subject to regulation as described above.

Permits, special reports, and fees

No permits, special reports, or fees are associated with this act as it applies to the operations described herein.

References

United States Code Volume 16, Conservation, Subchapter II, National Historic Preservation, Section 470 et seq.: Congress of the United States, Washington, DC, p. 49 et seq.

U.S. Department of Energy, 1993, Waste Isolation Pilot Plant Site Environmental Report for 1992, DOE/WIPP 93-017: Office of Scientific and Technical Information, Oak Ridge, TN, 120 pp.

Occupational Safety and Health Act

The Occupational Safety and Health Act (the Act), 29 USC Sections 651-678, was enacted in 1970 and amended most recently in 1990. The Act ensures safe and healthful working conditions for workers in the United States. The Act requires employers to follow specific regulations and, where there are no specific regulations, imposes a "general duty" clause on employers to provide a safe and healthful workplace. The Act is codified in the Occupational Safety and Health Administration (OSHA) regulations (29 CFR 1910).

Operations that involve the extraction of oil or gas may be subject to OSHA regulations including the following:

- Regulatory standards for occupational health and environmental control (Subpart G)
- Hazardous materials (1910.102 to 111)
- Materials handling and storage (Subpart N)
- Tool handling (Subparts O-Q)
- Hazardous and toxic substances (29 CFR 1910.1000 to 1030)
- Personal protection equipment (Subpart I)
- General environmental controls (Subpart J)

NMED has been authorized by OSHA to administer and enforce the provisions of the regulations. For extraction industries (i.e. mining), OSHA regulates only those areas not regulated by the Mine Safety and Health Administration (MSHA) (see *Federal Mine Safety and Health Act*). In general, OSHA regulates those industries that are not on mine property.

Permits, special reports, and fees

No permits or fees are associated with this act. OSHA has numerous recordkeeping requirements, including maintaining all physical examination records for workers (29 CFR Subpart G) and records of all exposure incidents and monitoring measurements (29 CFR Subpart Z).

References

Arbuckle, J., Brownell, F., Case, D., Halbleib, W., Jensen, L., Landfair, S., Lee, R., Miller, M., Nardi, K., Olney, A., Saravadi, D, Spensley, J., Steinway, D., and Sullivan, T., 1993, Environmental Law Handbook, 12th Edition: Government Institutes Inc., Rockville, MD, 550 pp.

U.S. Department of Labor, 1993, Code of Federal Regulations Title 29, Labor, Part 1910: Office of the Federal Register, National Archives and Records Administration, Washington, DC, 1312 pp.

Protection of Bald and Golden Eagles Act

The Protection of Bald and Golden Eagles Act, 16 U.S.C. 668(a) et seq., was first enacted in 1940 and last amended in 1972. The requirements of this act have been codified in 50 CFR Part 22 (Eagle Permits). Associated regulations are found in 50 CFR Subchapter A (General Provisions, Parts 1-3) and Subchapter B (Taking, Possession, Transportation, Sale, Purchase, Barter, Exportation, and Importation of Wildlife and Plants, Parts 10-17).

50 CFR Part 22 (Eagle Permits) forbid the following activities: selling, purchasing, bartering, trading or offering for sale, purchase, barter, trade, export or import any bald eagle or golden eagle, alive or dead, or any part, nest, or egg thereof.

If a permit is obtained, then the taking, possession, and transportation of bald or golden eagles or their parts, nests, or eggs, may be allowed for the following purposes: for scientific or exhibition purposes of public museums, scientific societies, and zoological parks; for the religious purposes of Indian tribes; for depredation control purposes; for the protection of wildlife, or of agricultural or other interests.

A permit may also be obtained for the taking of golden eagle nests that interfere with resource development or recovery operations (e.g. mining and oil and gas extraction). The nests must be inactive and the taking must be compatible with the preservation of the nesting population of golden eagles.

Operations that involve subsurface mining or the extraction of oil, gas, or potash may be subject to the regulations as in 50 CFR as described above.

Permits, special reports, and fees

A permit is required as described in 50 CFR Part 22 for the taking, possession, and transportation of bald or golden eagles or their parts, nests, or eggs for the reasons cited above. No special reports are required by the regulations. A general permit application fee is required by 50 CFR, Section 13.11.

References

United States Code, Volume 16, Section 668(a) et seq., Protection of Bald and Golden Eagles: Congress of the United States, Washington, DC, 3 pp.

U.S. Environmental Protection Agency, 1993, Code of Federal Regulations Title 50, Wildlife and Fisheries, CFR Parts 1 to 199: Office of the Federal Register, National Archives and Records Administration, Washington, DC, 658 pp.

Resource Conservation and Recovery Act

The Resource Conservation and Recovery Act (RCRA), 42 USC 6901-6992K, was enacted in 1976 as an amendment to the Solid Waste Disposal Act. RCRA has been amended several times, most notably in 1980 and in 1984. RCRA Subtitle C, D, and I are described below.

RCRA Subtitle C - Hazardous Waste

RCRA Subtitle C (40 CFR Parts 260 to 271) includes the regulatory requirements for generators and transporters of hazardous waste and owners and operators of hazardous waste treatment, storage, and disposal (TSD) facilities. RCRA Subtitle C establishes a comprehensive "cradle-to-grave" system for regulating hazardous waste, including a manifest system for tracking hazardous wastes and a permitting system for hazardous waste treatment, storage, or disposal facilities. In addition, it includes a framework for implementing corrective action for releases of hazardous waste.

Operations that extract oil, gas, or potash may be subject to the following RCRA Subtitle C requirements:

- Generator requirements (Part 262)
- Interim-status requirements for owners/operators of TSD facilities (Part 265)
- Recycling requirements (Part 266)
- Disposal restriction requirements (Part 268)
- Permit requirements for owners/operators of TSD facilities (Parts 264 and 270)

Drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil or natural gas are specifically excluded from regulation under RCRA Subtitle C. Solid wastes produced by the extraction or beneficiation of potash are exempt from regulation by the mining waste exclusion in Part 261.4(b)(7).

Permits, special reports, and fees

The following permits, special reports, and administrative fees may be required for hazardous waste generators or TSD facilities:

- If a TSD facility is not operating under interim status (Part 270.70 to 270.73), a permit would be required for the treatment, storage (i.e. storage exceeding 90 days), or disposal of hazardous waste. These permit requirements are found in Part 264.

- The following reports may be required:

    - Biennial report (Part 262.41 for generator facilities (Part 262.41), for permitted TSD facilities (Part 264.75), and for interim-status TSD facilities (Part 265.75

    - Exception report for generator facilities (Part 262.55)

    - Unmanifested waste report for permitted TSD facilities (Part 264.76) and for interim-status TSD facilities (Part 265.76).

    - An annual report (Part 262.56) and exception report (Part 262.55) for generator facilities, if the hazardous waste is exported to another country

    - If required by the regulator, additional reports for generator facilities (Part 262.43), for permitted TSD facilities (Part 264.77), and for interim-status TSD facilities (Part 265.77)

    - If hazardous waste is placed in a land-based TSD unit (i.e. landfill, surface impoundment, land treatment facility), certain groundwater monitoring and reporting requirements must be met for permitted TSD units (Parts 264.90 to 264.100) and for interim-status TSD units (Parts 265.90 to 265.94).

The federal regulations do not require administrative fees. However, the New Mexico Environment Department does assess administrative fees for new permits and permit revisions (see *New Mexico Hazardous Waste Act*).

References

Arbuckle, J., Brownell, F., Case, D., Halbleib, W., Jensen, L., Landfair, S., Lee, R., Miller, M., Nardi, K., Olney, A., Sarvadi, D., Spensley, J., Steinway, D., and Sullivan, T., 1993, Environmental Law Handbook, Twelfth Edition: Government Institutes Inc., Rockville, MD, 550 pp.

U.S. Environmental Protection Agency, 1993, Code of Federal Regulations Title 40, Protection of Environment, Parts 260 to 299: Office of the Federal Register, National Archives and Records Administration, Washington, DC, 1088 pp.

RCRA Subtitle D - Solid Waste

RCRA Subtitle D provides minimum criteria for solid waste disposal facilities, corrective actions, and ground-water detection systems. The Subtitle D regulations are codified in 40 CFR Parts 255 to 258. These include the following:

- Criteria for the identification of regions and agencies for solid waste management (Part 255)
- Guidelines for the development and implementation of solid waste management plans for the states (Part 256)
- Criteria for classification of solid waste disposal facilities and practices (Part 257)
- Criteria for municipal solid waste landfills (Part 258)

Operations that extract oil, gas, or potash would not be subject to these regulations because it can be assumed that they would not be operating a solid waste disposal facility (see the *New Mexico Solid Waste Act*).

Permits, special reports, and fees

Because these operations would not be operating a solid waste disposal facility, permits, reports, or fees would not be applicable.

References

Arbuckle, J., Brownell, F., Case, D., Halbleib, W., Jensen, L., Landfair, S., Lee, R., Miller, M., Nardi, K., Olney, A., Sarvadi, D., Spensley, J., Steinway, D., and Sullivan, T., 1993, Environmental Law Handbook, Twelfth Edition: Government Institutes Inc., Rockville, MD, 550 pp.

U.S. Environmental Protection Agency, 1993, Code of Federal Regulations Title 40, Protection of Environment, Parts 190 to 259: Office of the Federal Register, National Archives and Records Administration, Washington, DC, 473 pp.

RCRA Subtitle I — Underground Storage Tanks

RCRA Subtitle I (42 USC Sections 6991 to 6991i) was enacted in 1984 to regulate underground storage tanks (UST) containing regulated substances. A regulated substance is any petroleum product or any materials defined under CERCLA Section 101(14) (40 CFR 302, Table 4). Subtitle I regulations are codified in 40 CFR 280. The purpose of the regulations is to prevent releases of contained substances as a result of structural failure or corrosion. The regulations impose minimum performance standards on new and upgraded UST systems and provide incentives, including the provision of funds, for the remediation of leaking UST that meet EPA minimum requirements.

New Mexico is authorized by EPA to administer the UST program in the state (see *New Mexico Hazardous Waste Act, Underground Storage Tank Regulations*).

Permits, special reports, and fees

Subtitle I does not require permits, reports, or fees (see *New Mexico Hazardous Waste Act, Underground Storage Tank Regulations* for a description of the permit, reporting, or fee requirements that would need to be met by mining or extraction operations if USTs are used to store regulated substances).

References

Arbuckle, J. , Brownell, F., Case, D., Halbleib, W., Jensen, L., Landfair, S., Lee, R., Miller, M., Nardi, K., Olney, A., Saravadi, D., Spensley, J., Steinway, D., and Sullivan, T., 1993, Environmental Law Handbook, Twelfth Edition: Government Institutes Inc., Rockville, MD, 550 pp.

U.S. Environmental Protection Agency, 1993, Code of Federal Regulations Title 40, Protection of Environment, Parts 260 to 299: Office of the Federal Register, National Archives and Records Administration, Washington, DC, 1088 pp.

Safe Drinking Water Act

The Safe Drinking Water Act (SDWA), 21 U.S.C. 349 and 42 U.S.C. 201 and 300f to 300j-9, was enacted in 1974 and amended in 1986 by the Public Health Service Act. SDWA gave EPA the authority to prepare and implement regulations for public water supply systems and underground sources of drinking water, to define maximum contaminant levels (MCLs) for certain water pollutants, to determine criteria for ensuring that drinking water supplies comply with MCLs, and to protect underground sources of drinking water from injections of contaminated fluids through the Underground Injection Control Program.

The SDWA authorized states to assume primary enforcement responsibility through the adoption of a state program with requirements as least as stringent as the federal program. The SDWA has authorized the New Mexico Environment Department to develop and enforce regulations for water supplies (see *New Mexico Environmental Improvement Act*) and to regulate underground injections (see *New Mexico Water Quality Act* for non-oil and gas injection wells and the *New Mexico Oil Conservation Division Regulations* for oil and gas injection wells). SDWA regulations are codified in 40 CFR Parts 141 to 149.

Public Water Supply Program. This program is codified in 40 CFR Parts 141 to 143 and Part 149. (Public water supply system is defined in 40 CFR 141.2, Subpart C.) These regulations include the following:

- National primary drinking water regulations, which specify the MCLs and the monitoring, analytical, and reporting requirements (Part 141)
- Implementing of Part 141 regulations, including responsibilities delegated to the states and EPA oversight of state programs (Part 142)

- National secondary drinking water regulations which address contaminants that affect the aesthetic qualities of water (e.g., taste, color, and smell) (Part 143)

Underground Injection Control Program. This program is codified in 40 CFR Part 144. These regulations include the following:

- General provisions (Subpart A)
- General program requirements (Subpart B)
- Authorization of underground injection by rule (Subpart C)
- Authorization by permit (Subpart D)
- Permit conditions (Subpart E)
- Financial requirements (Subpart F).

Operations that are involved in subsurface mining or the extraction of oil, gas, or potash may be subject to requirements of the SDWA if they require the creation of a public drinking supply or inject fluids underground that could contaminate a drinking water source.

Permits, special reports, and fees

No permits, fees, or reports are associated with the SDWA.

References

Arbuckle, J. , Brownell, F., Case, D., Halbleib, W., Jensen, L., Landfair, S., Lee, R., Miller, M., Nardi, K., Olney, A., Saravadi, D., Spensley, J., Steinway, D., and Sullivan, T., 1993, Environmental Law Handbook, Twelfth Edition: Government Institutes Inc., Rockville, MD, 550 pp.

U.S. Department of Energy, 1993, Waste Isolation Pilot Plant Site Environmental Report for 1992, DOE/WIPP 93-017: Office of Scientific and Technical Information, Oak Ridge, TN, 120 pp.

U.S. Environmental Protection Agency, 1994, Code of Federal Regulations Title 40, Protection of Environment, Subchapter D, Water Programs, Parts 100 to 149: Office of the Federal Register, National Archives and Records Administration, Washington, DC, 1064 pp.

Toxic Substances Control Act

The Toxic Substances Control Act (TSCA), 15 USC 2601 et seq., was enacted in 1976 to regulate substances that were not adequately regulated under other environmental programs. It has been amended three times, most recently in 1992. The TSCA regulations have been codified in 40 CFR Subchapter R, Parts 700 to 799.

Operations that involve subsurface mining or the extraction of oil, gas, or potash and that use or dispose of polychlorinated biphenyls (PCB) would be subject to regulations as described in 40 CFR Part 761, including the following:

- Manufacturing, processing, distribution in commerce, and use of PCBs and PCB items (Subpart B)
- Marking of PCBs and PCB items (Subpart C)
- PCB spill cleanup policy (Subpart G)
- General reco[illegible] [illegible]d reports (Subparts J)
- PCB waste disposal records and reports (Subpart K)

Permits, special reports, and fees

No permits or fees are associated w[illegible]h 40 CFR Part 761. Users of PC[illegible] or products containing PCBs would need to meet reporting requirements described in 40 CFR Part 761.

References

Arbuckle, J., Brownell, F., Case, D., Halbleib, W., Jensen, L., Landfair, S., Lee, R., Miller, M., Nardi, K., Olney, A., Saravadi, D., Spensley, J., Steinway, D., and Sullivan, T., 1993, Environm[illegible] Law Handbook, Twelfth Edition: Government Institutes Inc., Rockville, MD, [illegible]0 pp.

U.S. Environmental Protection Agency, 1993, Code of Federal Regulations Title 40, Protection of Environment, Parts 700 to 799, Office of the Federal Register, National Archives and Records Administration, Washington DC, 1350 pp.

Waste Isolation Pilot Plant Land Withdrawal Act, the WIPP Land Management Plan, and the DOE-BLM Memorandum of Understanding

WIPP Land Withdrawal Act

The Waste Isolation Pilot Plant (WIPP) Land Withdrawal Act restricts the mining of minerals and extraction of oil or gas on the withdrawn land and within 1 mi of the withdrawn land boundary at any time (including after the decommissioning of the WIPP Site), in order to protect the integrity of the disposal system.

The Land Withdrawal Act, Public Law 102-579, was enacted on October 30, 1992, to transfer the land under and around the WIPP site from the Bureau of Land Management (BLM) to the Department of Energy (DOE). The Land Withdrawal Act reserves the withdrawn land for authorized activities associated with the WIPP Project.

All subsurface mining for minerals or extraction of oil or gas (including slant drilling from outside the boundaries of the withdrawal area) is prohibited on the withdrawn land, with two exceptions. These exceptions are two 320-acre tracts of land within the withdrawal area that are leased for oil and gas development below 6000 ft from the surface (Federal Oil and Gas Leases No. NMNM 02953 and No. NMNM 02953C). These tracts are located in sec. 31 T22S R31E. Drilling within the first 6000 ft of the surface is prohibited in these two tracts.

Operations that involve subsurface mining or the extraction of oil, gas, or potash outside of the withdrawn land boundary could be subject to the WIPP Land Withdrawal Act as follows:

- If the operations occur within 1 mi of the withdrawn land boundary, they will be monitored by the DOE in coordination and cooperation with the BLM and/or the State of New Mexico. The BLM and the appropriate state agencies will forward the Permit to Drill applications and mining and reclamation plans to DOE for review and comment.

- If oil or gas activity will be conducted within 330 ft of the land withdrawal boundary, the operator must provide BLM with drillhole vertical deviations for each 500-ft drilling interval. In addition, the operator must provide BLM and DOE with a directional survey for bottom hole locations for drillholes that have a deviation of more than 5° or for drillholes that could deviate within 100 ft of the land withdrawal boundary. If a downhole vertical deviation survey indicates the potential for encroachment to the withdrawn land boundary, the BLM may require the operator to take corrective measures (i.e. side-tracking) or to cease drilling activity.

References

Congress of the United States, 1992, Waste Isolation Pilot Plant Land Withdrawal Act, Public Law 102-579: National Archives and Records Administration, Washington DC, 29 pp.

U.S. Department of Energy, 1994 Waste Isolation Pilot Plant Land Management Plan, DOE/WIPP 93-004: U.S. Department of Energy, Carlsbad, NM, 67 pp.

WIPP Land Management Plan

This plan was written as required by Section 4 of the WIPP Land Withdrawal Act and is consistent with the Federal Land Policy and Management Act of 1976. The WIPP Land Management Plan describes the use of the withdrawn land until the end of the decommissioning phase of the WIPP Project. The plan identifies resource values within the withdrawn area and promotes the concept of multiple-use management. The plan also provides opportunity for participation in the land use planning process by the public and local, state, and federal agencies.

Memorandum of Understanding Between the DOE and BLM

As a complement to the WIPP Land Management Plan, a memorandum of understanding (MOU) was executed between the DOE and the BLM as required by section 4(d) of the Land Withdrawal Act. The MOU assists in the implementation of the Land Management Plan. It provides for direct communications between officials of the

DOE and BLM regarding resource management issues within the Land Withdrawal Act. Additionally, it sets forth cooperative arrangements for administering decisions made by these two departments.

References

U.S. Department of Energy, 1994, Waste Isolation Pilot Plant Land Management Plan, DOE/WIPP 93-004, U.S. Department of Energy, Carlsbad, NM, 67 pp.

New Mexico Air Quality Control Act

The New Mexico Air Quality Control Act (AQCA), New Mexico Statutes Annotated (NMSA) 74-2-1 to 74-2-17, was enacted in 1967 and has been amended several times since 1980, most recently in 1994. The AQCA makes the New Mexico Environment Department (NMED) the regulatory agency that enforces all state air-quality regulations and delegated CAA requirements. New Mexico has adopted a more comprehensive regulatory approach than that required by the CAA and uses a comprehensive permitting program to control air emissions from new or modified stationary sources. The requirements in the state act are codified in the New Mexico Ambient Air Quality Standards and Air Quality Control Regulations (AQCR).

Operations that extract oil, gas, or potash must be permitted by NMED if their operations could exceed any AQCR standard. Generally, the AQCRs follow the CAA regulations in 40 CFR Parts 60 and 61. However, in some cases the AQCRs are more stringent than the federal regulations. Oil and gas production facilities are exempt from the permitting requirements for toxic air pollutants. Mining or extraction operations may be subject to the following AQCR regulations:

- Open burning (AQCR 301) (However, the burning of natural gas at gasoline plants and compressor stations and burning at oil and gas wells to avoid a serious safety hazard are exempted from the requirements of AQCR 301.)
- Smoke and visible emissions (AQCR 401) (However, the oil well drilling and servicing rigs are exempted from the requirements of AQCR 401.)
- Particulate-matter releases by oil burning equipment (AQCR 507)
- Particulate-matter releases from potash and or salt processing equipment (AQCR 508)
- Nitrogen dioxide releases from gas-burning equipment (AQCR 606)
- Hydrogen sulfide releases from hydrocarbon storage facilities (AQCR 631)
- Prevention of significant deterioration (AQCR 707)
- New-source performance standards (AQCR 750)
- National emission standards for hazardous air pollutants requirements (AQCR 771)

- Notification requirements when excess emissions occur during malfunction, start up, shutdown, or scheduled maintenance of equipment (AQCR 801)

The New Mexico Oil Conservation Division (OCD) regulates hydrogen sulfide emissions at the wellhead (see *New Mexico Oil Conservation Division Regulations*).

Permits, special reports, and fees

A permit is required for any person constructing or modifying a stationary source that has a potential emission rate of greater than 10 pounds per hour or 25 tons per year. A Notice of Intent must be filed with NMED if potential emissions are greater than 10 tons per year. AQCR 700 has the filing and permit fee schedules.

References

Adams, M., Fitzgerald, J., Lematta, B., Hayden, C., Keleher, M., Rochelle, J., Salazar, J., and Schaab, W., 1993, New Mexico Environmental Law Handbook, Third Edition: Government Institutes Inc., Rockville, MD, 417 pp.

New Mexico Energy, Minerals and Natural Resources Department, Mine Registration and Geological Services, 1992, Permit Requirements for Energy and Minerals in New Mexico: Energy, Minerals and Natural Resources Department, Santa Fe, NM, 62 pp.

New Mexico Environment Department, 1994, Ambient Air Quality Standards and Air Quality Control Regulations: New Mexico Environment Department, Santa Fe, NM, 504 pp.

New Mexico Cultural Properties Act

The New Mexico Cultural Properties Act (NMSA 18-6-1 through 18-6-17) was enacted in 1969 and has been amended several times, most recently in 1987. The purpose of the act is "to provide for the preservation, protection, and enhancement of structures, sites, and objects of historical significance within the state of New Mexico in a manner conforming with, but not limited by, the provisions of the National Historic Preservation Act" (NMSA 18-6-2). Regulation of this act is through the state Office of Cultural Affairs, Historic Preservation Division, which is responsible for the permitting of all archaeological surveys and excavations on lands owned or controlled by the state as well as on private lands.

Operations that are involved in subsurface mining or the extraction of oil, gas, or potash on state-owned or -controlled lands where archaeological sites or objects of antiquity or general scientific interest (as defined in Rule 87-8, Section 4b) are located are subject to the following regulations:

- Permitting procedures and requirements for authorized archaeological surveys and excavations (Section 5)

- Individual survey and excavation permits for state trust land (Section 6)

- Blanket survey permits for state trust land (Section 7)
- Survey and excavation permits for other state agency land (Section 8)
- Excavation permits for private land (Section 9)

Permits, special reports, and fees

Investigations conducted under contract to an individual, organization, or company undertaking exploration, construction, or development activities authorized by business leases, oil and gas leases, mineral leases, or other authority to enter state land may be issued a blanket permit for archaeological survey. Permits are required for all individual archeological survey and excavation activities on private land and on lands owned or controlled by the state.

Filing fees are associated with surveys permits; filing and inspection fees are associated with excavations; a blanket survey permit requires an annual fee. All permittees are required to submit a final report following the conclusion of fieldwork.

References

New Mexico Cultural Properties Review Committee, 1987, Regulations Pertaining to the Issuance of Permits to Conduct Archaeological Investigations, CPRC Rule 87-8: New Mexico Cultural Properties Review Committee, Santa Fe, NM, 29 pp.

New Mexico Endangered Plant Species Act

The New Mexico Endangered Plant Species Act (NMSA 9-10-10), enacted in 1985, protects and ensures the survival of those plant species determined by the New Mexico Natural Resources Department (NRD) to be endangered.

Operations that involve subsurface mining or the extraction of oil, gas, or potash may not be subject to this act unless any of the activities associated with the operation(s) involve the taking of an endangered plant species as defined in NRD Rule 85-3, Part 2. These activities would be subject to NRD Rule 85-3, Part 5, Permits.

Permits, special reports, and fees

In general, this act has no applicable permits, special reports, or fees. However, a permit for transplantation could be needed if an endangered plant species was in an area of land-use conversion (NRD Rule 85-3, Part 5.1.4.1); this permit requires submission of a proposal by the applicant (NRD Rule 85-3, Part 5.1.4.2).

References

Kerr, V. E., Rep., 1985, An Act Relating to the Natural Resources Department; Establishing an Endangered Plant Species Program; Enacting a Section of the NMSA 1978, Chapter 143, House Bill 347: The Legislature of the State of New Mexico, Santa Fe, NM, 3 pp.

New Mexico Natural Resources Department, 1985, Endangered Plant Species in New Mexico, NRD Rule 85-3: New Mexico Natural Resources Department, Santa Fe, NM, 10 pp.

New Mexico Environmental Improvement Act

The New Mexico Environmental Improvement Act (NMSA 74-1-1 to 74-1-11), enacted in 1991, authorizes the New Mexico Environment Department (NMED) to enforce the water supply requirements of the federal Safe Drinking Water Act (SDWA). The state water supply requirements are codified in the Water Supply Regulations (WSR). The additional public water supply requirements of the SDWA are found in the New Mexico Water Quality Control Commission Regulations (WQCCR) Part 4, and the SDWA underground injection control requirements are found in the WQCCR Part 5 (see *New Mexico Water Quality Act*).

Operations that involve the subsurface mining or extraction of oil, gas, or potash may be subject to requirements of the WSR if they create a public drinking supply as defined in WSR, Part I, Section 103. The WSR include the following:

- Requirements for water supply control (WSR, Part II)
- Monitoring and analytical requirements (WSR, Part III)
- Water supply construction (WSR, Part V)
- Filtration and disinfection (WSR, Part IX)
- Rural Infrastructure Act regulations (WSR, Part VIII)

Permits, special reports, and fees

Although a permit is not required, prior approval from NMED must be obtained for construction of any new public water supply system or modification of an existing system (WSR, Part V). An application must be submitted before starting construction or modification (WSR, Part V). There are numerous reporting requirements under the WSR, including public notification and recordkeeping (WSR, Part IV), and sampling and reporting of special contaminants (WSR, Part VII). No permits or fees are associated with the WSR.

References

Arbuckle, J., Brownell, F., Case, D., Halbleib, W., Jensen, L., Landfair, S., Lee, R., Miller, M., Nardi, K., Olney, A., Saravadi, D., Spensley, J., Steinway, D., and Sullivan, T., 1993, Environmental Law Handbook, Twelfth Edition: Government Institutes Inc., Rockville, MD, 550 pp.

New Mexico Environment Department Drinking Water Program, 1991, Water Supply Regulations: New Mexico Environment Department, Santa Fe, NM, 67 pp.

New Mexico Energy, Minerals and Natural Resources Department, Mining and Minerals Division, Mine Registration and Geological Services, 1992, Permit Requirements for Energy and Minerals in New Mexico: Mine Registration and Geological Services, Santa Fe, NM, 62 pp.

New Mexico Hazardous Chemicals Information Act

The New Mexico Hazardous Chemicals Information Act (HCIA), NMSA 74-4E-1 to 74-4E-9, was enacted in 1989. It establishes state-level systems of emergency planning and notification that address releases of extremely hazardous substances and a system that allows the public to learn of the presence of hazardous chemicals used in their communities and of any releases of those chemicals. The HCIA establishes how the federal Emergency Planning and Community Right-to-Know Act (EPCRA) and the EPCRA regulations are implemented in the state. The HCIA and EPCRA regulatory requirements are administered by the New Mexico Department of Public Safety.

Operations that involve the subsurface mining or extraction of oil, gas, or potash should consult the EPCRA and its regulations to determine their responsibilities under the HCIA (see *Emergency Planning and Community Right-To-Know Act*).

Permits, special reports, and fees

No permits are required by this act. The state charges a fee for each inventory form that is filed. Reporting requirements are referenced in EPCRA.

References

Adams, M., Fitzgerald, J., Lematta, B., Hayden, C., Keleher, M., Rochelle, J., Salazar, J., and Schaab, W., 1993, New Mexico Environmental Law Handbook, Third Edition: Government Institutes Inc., Rockville, MD, 417 pp.

New Mexico Hazardous Waste Act

The New Mexico Hazardous Waste Act, NMSA 74-4-1 to 74-4-13, was enacted in 1977 and substantially amended in 1981, 1987, and 1989. The requirements of the act have been codified in the New Mexico Hazardous Waste Management Regulations (20 NMAC 4.1) and the Underground Storage Tank (UST) Regulations.

New Mexico Hazardous Waste Management Regulations

The U.S. Environmental Protection Agency (EPA) has authorized the New Mexico Environment Department (NMED) to administer the RCRA Subtitle C program in the state. Incorporated in 20 NMAC 4.1 are the RCRA Subtitle C regulations by reference (40 CFR Parts 261 to 270 are equivalent with 20 NMAC 4.1, Parts II to Part IX). Part I is essentially equivalent with 40 CFR Part 260, except for the modifications and exceptions listed in Part I, Section 102. Part IX, Section 902, includes the procedural requirements for obtaining a permit for treatment, storage, or disposal of hazardous waste from the State of New Mexico.

Operations that extract oil, gas, or potash may be subject to the 20 NMAC 4.1 requirements (Parts I to IX) if they generate, treat, store, transport, or dispose of hazardous waste (see *RCRA Subtitle C-Hazardous Waste*).

Permits, special reports, and fees

If a mining or extraction operation meets the definition of a treatment, storage, or disposal facility but does not have interim status, then a permit would be required (20 NMAC 4.1, Parts V and IX). In addition, an administrative permit fee would be required by the state (see the Hazardous Waste Fee Regulations [HWFR-1]. RCRA Subtitle C, Hazardous Waste, describes the potential permits and reports that may be required.

References

Adams, M., Fitzgerald, J., Lematta, B., Hayden, C., Keleher, M., Rochelle, J., Salazar, J., and Schaab, W., 1993, New Mexico Environmental Law Handbook, Third Edition: Government Institutes Inc., Rockville, MD, 417 pp.

State of New Mexico, Environmental Improvement Board, 1991, Hazardous Waste Management Regulations (HWMR-6): State of New Mexico, Environmental Improvement Board, 24 pp.

New Mexico Underground Storage Tank Regulations

EPA has authorized NMED to administer the Underground Storage Tank (UST) program in the state. The UST regulations are authorized by the New Mexico Hazardous Waste Act referenced above and the New Mexico Ground Water Protection Act (NMSA 74-6B-1 to 74-6B-14). Operations that extract oil, gas, or potash and that own or operate a UST system may be subject to the following UST requirements:

- Tank registration (Part II)
- Payment of an annual fees (Part III)
- Tank design, construction, and installation (Part IV)
- Tank operation (Part V)
- Release detection (Part VI)
- Release reporting, investigation, and confirmation (Part VII)
- Temporary and permanent closure (Part VIII)
- Financial responsibility (Part IX)
- Administrative review (Part X)
- Miscellaneous (Part XI)
- Corrective action for UST systems containing petroleum (Part XII)
- Corrective action for UST systems containing other regulated substances (Part XIII)

- Certification of tank installers (Part XIV)

- Ground-water protection regulations (Part XV)

Permits, special reports, and fees

If a mining or extraction operation meets the definition of a hazardous waste treatment, storage, or disposal facility but does not have interim status, then a permit would be required (20 NMAC 4.1, Parts V and IX). In addition, an administrative permit fee would be required by the state (see the Hazardous Waste Fee Regulations [HWFR-1]). See RCRA Subtitle C for a description of the potential permits and reports that may be required.

Under this act, no permits are required for UST systems. However, there are reporting requirements and fees as referenced above.

References

Adams, M., Fitzgerald, J., Lematta, B., Hayden, C., Keleher, M., Rochelle, J., Salazar, J., and Schaab, W., 1993, New Mexico Environmental Law Handbook, Third Edition: Government Institutes Inc., Rockville, MD, 417 pp.

State of New Mexico Environmental Improvement Board, 1991, Hazardous Waste Management Regulations, 20 NMAC 4.1: State of New Mexico Environmental Improvement Board, Santa Fe, NM, 24 pp.

State of New Mexico Environmental Improvement Board, 1991, Underground Storage Tank Regulations: State of New Mexico Environmental Improvement Board, Santa Fe, NM, 188 pp.

Mine Registration, Reporting, and Safeguarding: New Mexico Energy, Mineral, and Natural Resources Department, Minerals and Mining Division Rule 89-1

Mine Registration, Reporting, and Safeguarding, Rule 89-1 of the New Mexico Energy, Mineral, and Natural Resources Department (EMNRD), Mining and Minerals Division (MMD), was enacted in 1989. EMNRD MMD 89-1 has three functions:

- Requirements for the registration of all mines, mills, and smelters operating or under construction (Rule 89-1, Section 2)

- Annual reporting requirements for mining operations, which include information regarding ownership, production, survey (Rule 89-1, Section 3)

- Requirements for filing a closure plan describing the methods to be used in closing or fencing off all openings on the property before suspending operations at a location (Rule 89-1, Part 2)

This act has no jurisdiction at oil and gas extraction sites. Operations that are involved in subsurface potash mining are subject to the regulations presented in Rule 89-1 as described above.

Permits, special reports, and fees

The following special reports are required:

- Mine Registration (Rule 89-1, Section 2)
- Annual Mine Reporting (Rule 89-1, Section 3)
- Notice of Intention to Suspend Operating and Report of Safeguarding (Rule 89-1, Part 2, Section 2.1)

A closure plan with accompanying plats must accompany the Notice of Intention to Suspend Operating. No permits or fees are required by this act.

References

New Mexico Energy, Mineral, and Natural Resources Department, Minerals and Mining Division, 1989, Rule 89-1, Mine Registration, Reporting, and Safeguarding: Energy, Mineral, and Natural Resources Department, Minerals and Mining Division, Santa Fe, NM, 20 pp.

New Mexico Mining Act

The New Mexico Mining Act (NMMA), NMSA Parts 69-36-1 to 60-36-20 (Repl. Pamp. 1993), was enacted in 1993 and promotes the responsible use and reclamation of lands affected by exploration, mining, or the extraction of minerals. This act regulates what has been traditionally known as "hard rock" or solid mineral mining. Explicitly exempt from regulation are the exploration and extraction of potash, caliche, geothermal resources, oil and natural gas (together with other chemicals recovered with them), commodities, byproduct materials and wastes regulated by the Nuclear Regulatory Commission, or waste regulated under RCRA Subtitle C (NMMA Rules and Regulations, 1994, Part 1.1, "Mineral"). The NMMA is codified in the New Mexico Mining Act rules, issued July 12, 1994.

NMMA rules include the following:

- Fees (NMMA Rule 2)
- Minimal impact operations (NMMA Rule 3)
- Exploration (NMMA Rule 4)
- Existing mine operations (NMMA Rule 5)
- New mining operations (NMMA Rules 6)
- Standby status (NMMA Rule 7)
- Permit transfer (NMMA Rule 8)

- Public participation (NMMA Rule 9)
- Variances (NMMA Rule 10)
- Inspection, enforcement, and penalties (NMMA Rule 11)
- Financial assurance requirements (NMMA Rule 12)
- Review of mining and reclamation practices (NMMA Rule 13)

Permits, special reports, and fees

Permits are required for each type of mining activity (e.g. minimal impact operations, exploration mining of new or existing operations). Reports may also be associated with these activities. Fees are determined by the schedule in NMMA Rule 2.

References

Adams, M., Fitzgerald, J., Lematta, B., Hayden, C., Keleher, M., Rochelle, J., Salazar, J., and Schaab, W., 1993, New Mexico Environmental Law Handbook, Third Edition: Government Institutes Inc., Rockville, MS, 417 pp.

New Mexico Energy, Minerals and Natural Resources Department, Mining and Minerals Division, New Mexico Mining Act Rules, July 12, 1993, Rules 1 to 13: Energy, Minerals, and Natural Resources Department, Santa Fe, NM, 118 pp.

New Mexico Energy, Minerals, and Natural Resources Department, Mining and Minerals Division, Mine Registration and Geological Services, 1992, Permit Requirements for Energy and Minerals in New Mexico: New Mexico Energy, Minerals, and Natural Resources Department, Santa Fe, NM, 62 pp.

New Mexico Oil Conservation Division Regulations

The Oil Conservation Division (OCD) of the New Mexico Energy, Minerals, and Natural Resources Department administers the laws and regulations relating to oil, gas, and geothermal resources under the authority of the New Mexico OCD Regulations (NMSA Part 70-2-1 et seq. and the Geothermal Resources Conservation Act (NMSA Part 71-5-1) and Water Quality Act (NMSA Part 74-6-1 et seq). The OCD Regulations have been codified in the NM OCD Rules and Regulations adopted March 1, 1993.

The OCD has jurisdiction and authority over all matters relating to oil and gas and prevention of associated waste and the protection of oil, gas, geothermal water, or other fresh waters. The OCD enforces the provisions of the OCD Regulations. The OCD is also charged with protecting fresh water. OCD, as a general rule, administers and enforces applicable regulations pertaining to both surface and ground-water discharges at oil and gas drilling and production sites, oil refineries, natural gas processing plants, geothermal installations, carbon dioxide facilities, oil and natural gas pipelines, compressor stations, and oil field services.

Operations that extract oil and gas may be subject to the following OCD regulations:

- Issuance of Permits Pertaining to Drilling (NM OCD Rules and Regulations, Rules 101 to 118)
- Abandonment and Plugging of Wells (Rules 201 to 204)
- Oil Production Operating Practices (Rules 301 to 314)
- Natural Gas Production Operating Practice (Rules 401 to 414)
- Oil Proration and Allocation (Rules 501 to 509)
- Gas Proration and Allocation (Rules 601 to 604)
- Secondary or Other Enhanced Recovery, Pressure Maintenance, Salt Water Disposal, and Underground Storage (Rules 701 to 711)
- Oil Purchasing and Transporting (Rules 801 to 804)
- Gas Purchasing and Transporting (Rules 901 to 902)
- Reports (Rules 1100 to 1136)
- Hearing Procedures and Administrative Details (Rules 1201 to 1304)

Permits, special reports, and fees

Each OCD activity requires a permit. Submission procedures are specific to each permitted activity and can be found in the OCD Rules and Regulations and appropriate policy memoranda issued by the OCD. A fee is required for natural gas applications. An Effluent Discharge Plan is required by users whose operations result in directly related effluent. Fees are based on size of discharge. Certain activities require either monthly reports of activities or notices (NM OCD Rules and Regulations, Rules 110 to 1122).

References

New Mexico Energy, Minerals, and Natural Resources Department, Mining and Minerals Division, Mine Registration and Geological Services, 1992, Permit Requirements for Energy and Minerals in New Mexico: New Mexico Energy, Minerals, and Natural Resources Department, Santa Fe, NM, 62 pp.

State of New Mexico Energy, Minerals, and Natural Resources Department, 1993, Oil Conservation Division Rules and Regulations: New Mexico Energy, Minerals, and Natural Resources Department, Santa Fe, NM, Sections A to O, 91 pp.

State of New Mexico Oil Conservation Division, Environmental Programs, Oil Conservation Division, 1993 Environmental Regulations: New Mexico Energy, Minerals, and Natural Resources Department, Santa Fe, NM, Parts 1 to 11, 365 pp.

New Mexico Pesticide Control Act

The New Mexico Pesticide Control Act (PCA), NMSA Sections 76-4-1 to 76-4-39, was enacted in 1976 and amended several times, most recently in 1989. PCA regulates the registration, labeling, use, storage, transportation, and disposal of pesticides and herbicides and the licensing of pesticide dealers, consultants, applicators, and operators. The PCA is patterned after Federal Insecticide, Fungicide, and Rodenticide Act (FIFRA), and its regulations are at least as stringent as those promulgated under FIFRA. The PCA is administered and enforced by the New Mexico Department of Agriculture.

Operations that involve subsurface mining or the extraction of oil, gas, or potash may be subject to the following regulations if they use pesticides:

- Prohibited acts (Section 76-4-5)
- Discarding and storing of pesticides and pesticide containers (Section 76-4-30)
- Records (Section 76-4-33)

Permits, special reports, and fees

Users of pesticides require certification, licensing or permitting only if they are public applicators of pesticides under NMSA Section 76-4-19. No fees or special reports are applicable.

References

Adams, M., Fitzgerald, J., Lematta, B., Hayden, C., Keleher, M., Rochelle, J., Salazar, J., and Schaab, W., 1993, New Mexico Environmental Law Handbook, Third Edition: Government Institutes Inc., Rockville, MD, 417 pp.

New Mexico Department of Agriculture, 1978, New Mexico Pesticide Act, NMSA Chapter 76, Article 4, Sections 1 through 39: New Mexico Department of Agriculture, Las Cruces, NM, 31 pp.

New Mexico Solid Waste Act

The New Mexico Solid Waste Act (NMSA 74-9-1 to 74-9-42) was enacted in 1990 to ensure the proper management of solid waste. The requirements of the act were codified in the New Mexico Solid Waste Management Regulations (SWMR-4). The State of New Mexico has received primacy for implementing the RCRA Subtitle D solid waste regulations.

Solid waste is defined as any garbage; refuse; sludge from a waste treatment plant, water supply treatment plant, or air pollution control facility; and other discarded material including solid, liquid, semi-solid, or contained gaseous material resulting from industrial, commercial, mining, and agricultural operations and community activities (Part I, Section 105.WWW). However, the following oil, gas, and mining wastes are exempt from this definition:

- Drilling fluids, produced waters, and other non-domestic wastes associated with the exploration, development or production, transportation, storage, treatment, or refinement of crude oil or natural gas (Part I, Section 105.WWW.1)

- Waste from the extraction, beneficiation, and processing of ores and minerals, including phosphate rock and overburden from the mining of uranium ore, coal, copper, molybdenum, and other ores and minerals (Part I, Section 105.WWW.3)

Operations that extract oil, gas, or potash may be subject to the SWMR-4 regulations if they transport, store, transfer, process, transform, recycle, or dispose of solid waste (see SWMR-4, Part I, Section 104). If the oil and gas or mining operations transport, store, transfer, process, transform, recycle, or dispose of solid waste, they must meet the requirements of SWMR-4, Part I, Section 106 (General Requirements) and Part I, Section 107 (Prohibited Acts). If oil and gas or mining operations do not operate an approved solid waste disposal facility, they are not subject to the following:

- Disposal facility reporting requirements in Part I, Section 109

- Permitting and operational requirements in Parts II to IX

- Application fee requirements in Appendix I.

Even though disposal is typically restricted to an approved facility, it may be allowed in locations other than an approved solid waste facility as described in Part I, Section 108, Exemptions.

Permits, special reports, and fees

No permitting, reporting, or fee requirements are associated with this act unless an oil and gas or mining operation operates an approved solid waste disposal facility. The permitting, reporting, and fee requirements are referenced above.

References

Adams, M., Fitzgerald, J., Lematta, B., Hayden, C., Keleher, M., Rochelle, J., Salazar, J., and Schaab, W., 1993, New Mexico Environmental Law Handbook, Third Edition: Government Institutes Inc., Rockville, MD, 417 pp.

State of New Mexico Environmental Improvement Board, 1994, Solid Waste Management Regulations (SWMR-4): State of New Mexico Environmental Improvement Board, Santa Fe, NM, 216 pp.

New Mexico Water Quality Act

The New Mexico Water Quality Act (WQA), NMSA 74-6-1 to 74-6-17, was enacted in 1978 and most recently amended in 1993. The act, which is New Mexico's counterpart to the federal Clean Water Act, governs discharges to both waters of the U.S. (see *Clean Water Act*) and ground water. The New Mexico Water Quality Control Commission (WQCC) has developed water quality standards for surface water and ground water and regulations (WQCCR) for implementing the provisions of the WQA. The WQA does not apply to any activity or condition that is subject to the authority of the Oil Conservation Division (OCD) Regulations. The OCD Regulations address the prevention or abatement of water pollution associated with oil and gas exploration and production, dry or abandoned wells, oil and gas storage facilities and oil-treating plant operations (see *New Mexico Oil Conservation Division Regulations*).

Operations that extract oil, gas, or potash may be subject to the WQCCRs described below.

Notice of intent regulations include the following:

- General provisions and procedures for water contaminant discharges to a surface watercourse or groundwater (WQCCR Part 1)
- Notice of Intent to Discharge with the NMED for any planned new water contaminant discharge or the change in character or location of an existing water contaminant discharge (WQCCR 1-201). (Discharges into a community sewer system or those subject to the NMED Liquid Waste Disposal Regulations are exempt. Also exempt are discharges associated with the production, refinement, and pipeline transmission of oil and gas or their products.) (See *New Mexico Oil Conservation Division Regulations*).
- Requirements governing any construction or modification of sewage systems that would substantially change the quantity or quality of their discharges (WQCCR 1-202). (Plans and specifications must be filed with NMED, except for plans, specifications, and reports associated with oil and gas production, transmission, and refinement, which are exempt from this WQCCR.)
- Requirements for unplanned facility discharges of any oil or other water contaminant when the discharge is enough to be detrimental to human health, animal or plant life, or property, or to unreasonably interfere with the public welfare (WQCCR 1-203)

Surface water regulations include the following:

- Requirements for discharges to surface watercourses that are not covered by or are in violation of an EPA-approved National Pollutant Discharge Elimination System (NPDES) permit (WQCCR Part 2) (See *Clean Water Act*)
- Prohibition on discharging into a watercourse of any effluent not meeting specified criteria (WQCCR 2-101)

- Prohibition on disposing of any refuse in a location where there is a reasonable possibility that the refuse will be moved into a natural watercourse (WQCCR 2-200) (Solids diverted from a stream and returned to it are not subject to this regulation.)

Groundwater regulations include the following:

- Requirements for discharges onto or below the ground surface that could contaminate groundwater (WQCCR Part 3) (These regulations are designed to protect all groundwater containing 10,000 milligrams per liter of total dissolved solids or less.)

- Requirement to submit an approved discharge plan for effluents or leachates unless the discharge is subject to enforceable limitations contained in a NPDES permit or the discharges or leachates are regulated by the OCD Regulations and other laws (WQCCR 3-105)

- Procedures for filing a discharge plan for discharges not exempted by WQCCR 3-106 to 3-115)

- Requirements for submitting the filing, flat, and discharge fees (WQCCR 3-114)

Public water supply include the following:

- Requirements for public drinking water and wastewater facilities (WQCRR Part 4) (See *Safe Drinking Water Act* and *New Mexico Environmental Improvement Act*.)

- Classification of public water supply systems and public wastewater facilities according to the population size (WQCCR 4-101 to 4-103)

- Requirements for operator certification for all public water supply or wastewater facilities, including systems that serve less than 500 individuals (WQCCR 4-201 to 4-210) (After December 1, 1995, these facilities must employ a certified operator.)

Underground injection control regulations include the following:

- Requirements for discharges into underground injection wells (WQCCR Part 5) (See *Safe Drinking Water Act*).

- Prohibition on discharging into an effluent disposal well or in-situ extraction well if the discharged effluents can move into groundwater containing 10,000 milligrams or less of total dissolved solids (WQCCR 5-101) (Exempted from this WQCRR are those effluent disposal wells regulated by the OCD or by the NMED Liquid Waste Disposal Regulations.)

- Requirements for submission and approval of a discharge plan for wells not exempt from the WQCCR (WQCCR 5-102 to 5-105)

- Technical criteria and performance standards that must be met by disposal and in-situ extraction wells (WQCCR 5-201 to 5-210)

- Requirements for notification (WQCCR 5-300)

Permits, special reports, and fees

A Ground-water Discharge Plan is required for all discharges of effluent or leachate that may move directly or indirectly into ground water containing 10,000 milligrams per liter or less of total dissolved solids. This requirement applies to mill-tailing dams, underground injection wells not related to oil and gas activities, and injection wells associated with uranium or other subsurface in-situ leach mining operations. However, brine production wells are regulated by the OCD. Fees are based on the discharge quantity or type of facility making the discharge (WQCCR Part 3-114). Approval is required by NMED for the construction or modification of regulated public water supply systems (WQCCR Part 4).

References

Adams, M., Fitzgerald, J., Lematta, B., Hayden, C., Keleher, M., Rochelle, J., Salazar, J., and Schaab, W., 1993, New Mexico Environmental Law Handbook, Third Edition: Government Institutes Inc., Rockville, MD, 417 pp.

New Mexico Energy, Minerals, and Natural Resources Department, Mining and Minerals Division, Mine Registration and Geological Services, 1992, Permit Requirements for Energy and Minerals in New Mexico: New Mexico Energy, Minerals, and Natural Resources Department, Santa Fe, NM, 62 pp.

New Mexico Water Quality Control Commission, 1993, Water Quality Control Commission Regulations: New Mexico Environment Department, Santa Fe, NM, 98 pp.

New Mexico Wildlife Conservation Act

The New Mexico Wildlife Conservation Act (WCA), NMSA Sections 17-2-37 to 17-2-46, was enacted in 1978. Under the WCA, the New Mexico Game Commission must develop a list of endangered species and review it every two years. In addition, the taking, possession, transportation, exportation, processing, selling or offering for sale, or shipment of any species listed on either the commission list or those lists included in the federal Endangered Species Act of 1973 and adopted by the commission are illegal.

Operations that involve subsurface mining or the extraction of oil, gas, or potash would be subject to the requirements of the WCA if these operations were involved in the taking of any listed species as defined above.

Permits, special reports, and fees

This act has no applicable permits, special reports, or fees.

References

New Mexico Game and Fish Department, 1978, New Mexico Wildlife Conservation Act, NMSA Chapter 17, Article 2, Sections 37 et seq.: New Mexico Game and Fish Department, Santa Fe, NM, 5 pp.

Impact Levels of Statutes and Regulations on Both Existing or New Oil, Gas, and Potash Mining Operations

The levels of impact of statutes and regulations on existing or new oil, gas, and potash mining operations are presented in Tables 1 and 2, respectively. Impacts are defined as factors (e.g. labor, cost, delays) that place restrictions on these operations. Because the impacts are perceived impacts based on information obtained from oil, gas, and potash operators, comparing the level-of-impact information in one table with the other table is not valid.

Existing oil and gas operations include activities associated with producing from identified pay zones in existing wells and extending or re-completing previously drilled boreholes to develop different pay zones. New oil and gas operations include activities associated with the drilling, completion, and production from new boreholes, as well as activities associated with existing oil and gas operations (e.g. road construction, site preparation, construction of mud pits).

As shown in Table 1, the levels of impact for both existing and new oil and gas operations were generally perceived to be high to medium. The information in Table 1 was provided by Chuck Moran, Landman; Randy Patterson, Land Manager; and Frank Yates, Vice President; of Yates Petroleum Inc. in Artesia, New Mexico. Yates Petroleum Company was selected for this input because it is a large independent oil and gas company with operations near the WIPP Site and is considered to be one of the operators that is most affected by the above-mentioned statutes and regulations.

Existing potash operations include continued production from existing mine tunnels (drifts), the horizontal extension of drifts to access new production areas, and the construction of new ventilation shafts for existing drifts. New potash operations include activities associated with the start-up of a new mine (e.g. construction of new entry and ventilation shafts and construction of beneficiation and processing facilities), as well as the activities associated with existing potash mine operations.

As shown in Table 2, the levels of impact for existing potash mines were generally perceived to be low. For new potash mines, the levels of impact were generally perceived to be low to medium, even though the permitting effort would be considerable. The levels of impact were presented for new potash operations, even though it is unlikely that new mining operations would ever be economically feasible near the WIPP Site. The available land around the WIPP site has been leased by companies that are positioned to access new areas by extending drifts from existing nearby mines. Due to high start-up costs the expansion of existing operations would be more cost-effective than the start-up of a new mine.

The information in Table 2 was provided by Scott Vail, the manager of safety and environmental services at IMC Fertilizer Inc., a potash operator near the WIPP Site. IMC was selected for this input because it is the largest potash operator near the WIPP Site and is considered to be one of the operators that is most affected by the above-mentioned statutes and regulations.

TABLE 1
Impact level of statutes and regulations on both existing and new oil and gas operations

Statute/Regulation	No Impact	Low Impact	Medium Impact	High Impact
Federal statutes and regulations				
Clean Air Act				Existing and New
Clean Water Act				Existing and New
Comprehensive Environmental Response, Compensation, and Liability Act				Existing and New
Emergency Planning, and Community-Right-to-Know Act		Existing and New		
Endangered Species Act				Existing and New
Executive Order 11990: Protection of Wetlands				Existing and New
Federal Insecticide, Fungicide, and Rodenticide Act		Existing and New		
Federal Mine Safety and Health Administration	Existing[a] and New[a]			
Migratory Bird Treaty Act				Existing and New
Mineral and Leasing Act and Federal Land Policy and Management Act, Bureau of Land Management Regulations				Existing[b] and New[b]
National Environmental Policy Act				Existing and New
National Historic Preservation Act		Existing[c]		New
Occupational Safety and Health Act				Existing and New
Protection of Bald and Golden Eagles Act			Existing and New	
RCRA[d] Subtitle C - Hazardous Waste				Existing and New
RCRA[d] Subtitle D - Solid Waste			Existing and New	
RCRA[d] Subtitle I - Underground Storage Tanks	Existing[e] and New[e]			

TABLE 1
Impact level of statutes and regulations on both existing and new oil and gas operations (continued)

Statute/Regulation	No Impact	Low Impact	Medium Impact	High Impact
Safe Drinking Water Act			Existing and New	
Toxic Substances Control Act		Existing and New		
Waste Isolation Pilot Plant (WIPP) Land Withdrawal Act, October 30, 1992, and the Memorandum of Understanding between Department of Energy and BLM and the WIPP Land Management Plan				Existing and New[f]
New Mexico statutes and regulations				
Air Quality Control Act				Existing and New
Cultural Properties Act		Existing[c][g]		New[h]
Endangered Plant Species Act				Existing and New
Environmental Improvement Act			Existing and New	
Hazardous Chemicals Information Act		Existing and New		
Hazardous Waste Act			Existing and New	
Mine Registration, Reporting, and Safeguarding, Rule 89-1	Existing[a] and New[a]			
Mining Act	Existing[a] and New[a]			
Oil Conservation Division Regulations				Existing and New
Pesticide Control Act		Existing and New		
Solid Waste Act			Existing and New	
Water Quality Act				Existing and New
Wildlife Conservation Act			Existing and New[h]	

TABLE 1
Impact level of statutes and regulations on both existing and new oil and gas operations
(continued)

<u>Notes</u>:

(a) - This act has no jurisdiction at these sites
(b) - Assuming the operations are located on BLM land
(c) - Assuming the site has been previously surveyed
(d) - Resource Conservation and Recovery Act
(e) - Assuming there are no underground storage tanks
(f) - Assuming the operations are located on or within close proximity to the withdrawn land
(g) - Assuming the operations are located on lands controlled or owned by the State of New Mexico or private land
(h) - Impact is medium to high

TABLE 2
Impact level of statutes and regulations on both existing and new potash mining operations

Statute/Regulation	No Impact	Low Impact	Medium Impact	High Impact
Federal statutes and regulations				
Clean Air Act		Existing[a] and New[b]		
Clean Water Act		Existing[c] and New[illegible]		
Comprehensive Environmental Response, Compensation, and Liability Act		Existing[d] and New[d]		
Emergency Planning, and Community-Right-to-Know Act		Existing and New		
Endangered Species Act		Existing[e] and New[e]		
Executive Order 11990: Protection of Wetlands		Existing and New		
Federal Insecticide, Fungicide, and Rodenticide Act		Existing and New		
Federal Mine Safety and Health Administration		Existing and New		
Migratory Bird Treaty Act		Existing[f] and New[f]	Existing[g] and New[g]	
Mineral and Leasing Act and Federal Land Policy and Management Act, Bureau of Land Management Regulations (BLM)		Existing[h]	New[h]	
National Environmental Policy Act		Existing[i]	New[i]	
National Historic Preservation Act		Existing[j]	New[k]	
Occupational Safety and Health Act	Existing[l] and New[l]			
Protection of Bald and Golden Eagles Act		Existing	New	
RCRA[m] Subtitle C - Hazardous Waste		Existing[n] and New[n]		
RCRA[m] Subtitle D - Solid Waste		Existing[o]	New[p]	
RCRA[m] Subtitle I - Underground Storage Tanks	Existing[q] and New[q]			
Safe Drinking Water Act		Existing[r] and New[r]		
Toxic Substances Control Act		Existing and New		

TABLE 2
Impact level of statutes and regulations on both existing and new potash mining operations (continued)

Statute/Regulation	No Impact	Low Impact	Medium Impact	High Impact
Waste Isolation Pilot Plant (WIPP) Land Withdrawal Act, October 30, 1992, and the Memorandum of Understanding between Department of Energy and BLM and the WIPP Land Management Plan				Existing and New[s]
New Mexico statutes and regulations				
Air Quality Control Act		Existing	New	
Cultural Properties Act		Existing[j][t]	New[k][t]	
Endangered Plant Species Act		Existing	New	
Environmental Improvement Act		Existing	New	
Hazardous Chemicals Information Act		Existing and New		
Hazardous Waste Act		Existing and New		
Mine Registration, Reporting, and Safeguarding, Rule 89-1			Existing and New	
Mining Act	Existing[l] and New[l]			
Oil Conservation Division Regulations	Existing[l] and New[l]			
Pesticide Control Act		Existing and New		
Solid Waste Act		Existing	New	
Water Quality Act	Existing[u] and New[u]			
Wildlife Conservation Act		Existing	New	

Notes:
(a) - Assumes processing permits in place for existing processing facilities
(b) - Assumes no new processing facilities will be built
(c) - Assumes a storm-water permit or storm-water controls may be required
(d) - Assumes no use of CERCLA-regulated substances
(e) - Assumes no federal or state habitat identified in the potash mining area and any impacts would be limited by the small surface disturbance
(f) - Assumes no surface impoundments
(g) - Assumes surface impoundments
(h) - Assumes operations located on BLM land
(i) - Assumes existing environmental assessment for potash mining in the two-county area identified all impacts
(j) - Assumes the site of surface disturbance previously surveyed and mitigated
(k) - Assumes site of surface disturbance not previously surveyed and mitigated
(l) - This act has no jurisdiction at these sites
(m) - Resource Conservation and Recovery Act
(n) - Assumes strictly limited use of hazardous chemicals
(o) - Assumes a state waiver obtained for on-site disposal of salt tailings, construction, and domestic waste

TABLE 2
Impact level of statutes and regulations on both existing and new potash mining operations (continued)

(p) - Assumes a state waiver not obtained for on-site disposal of salt tailings, construction, and domestic waste
(q) - Assumes no underground storage tanks
(r) - Assumes *non-community public water supply system*
(s) - Assumes the operations located within close proximity to the withdrawn land
(t) - Assumes the operations located on lands controlled or owned by the State of New Mexico or private land
(u) - Assumes water greater than 10,000 parts per million of total dissolved solids

FINAL REPORT
Evaluation of Mineral Resources at the
Waste Isolation Pilot Plant (WIPP) Site

Volume 2
Chapters III-VIII

Westinghouse Electric Corporation
Waste Isolation Division
Contract No. PO-75-WJJ644145Z

Submitted by

New Mexico Bureau of Mines & Mineral Resources
Campus Station
Socorro, NM 87801

March 31, 1995

Certification

We certify under penalty of law that this document was prepared under our supervision for Westinghouse Electric Corporation, Waste Isolation Division, Waste Isolation Pilot Plant by New Mexico Bureau of Mines and Mineral Resources, a division of New Mexico Institute of Mining & Technology. Based on our inquiry of the persons directly responsible for gathering the information, the information submitted is, to the best of our knowledge and belief, true, accurate, and complete.

Charles E. Chapin, Principal Investigator
Director and State Geologist
New Mexico Bureau of Mines and
Mineral Resources

Clinton P. Richardson, P.E.
Mining and Environmental Engineering
New Mexico Institute of
Mining & Technology
New Mexico Certification No. 11229
Expires December 31, 1995

Evaluation of Mineral Resources at the
Waste Isolation Pilot Plant (WIPP) Site

Chapter III

OVERVIEW OF THE CARLSBAD POTASH DISTRICT, NEW MEXICO

by
James M. Barker
George S. Austin

Westinghouse Electric Corporation
Waste Isolation Division
Contract No. PO-75-WJJ644145Z

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III

OVERVIEW OF THE CARLSBAD POTASH DISTRICT, NEW MEXICO

James M. Barker and George S. Austin

Potash is the common industrial term for potassium in various chemical combinations with sodium, magnesium, chloride, and sulfate (**Table 1**). Potassium is one of the three essential plant nutrients and is the "K" in the "NPK" fertilizer rating along with nitrogen (N) and phosphorus (P). The potassium in potash is reported as K_2O eq. wt.% (% K_2O hereafter), although potassium oxide is not directly present in natural potassium salts (**Table 2**). For potash fertilizers, K_2O is closest chemically to the form of potassium used by plants (Sullivan and Michael, 1986) and is the best means to compare fairly the diverse mineralogy of potash.

Important natural, commercial, soluble potassium salts are sylvite and langbeinite. Sylvinite, a mixture of sylvite and halite, is the typical ore mined in the Carlsbad Potash District (CPD) in southeastern New Mexico (**Fig. 1**). The CPD is near the northeastern border of the Delaware Basin (**Fig. 1**) and contains the largest domestic potash reserves. Soluble potash occurs primarily in Eddy and Lea counties, which contain the only potash mines in the state. The Potash Enclave (**Fig. 2**), also designated the Known Potash Leasing Area (KPLA), consists of that part of the CPD where federal and state lands require competitive bidding for mineral leases both under BLM management. The WIPP site is on the southeastern edge of the KPLA (**Fig. 2**) in Sec. 15-22 and 27-34 T22S R31E (**Plate 1**).

The KPLA lies between Carlsbad and Hobbs, NM, and comprises about 425 mi^2 (Cheeseman, 1978; Barker and Austin, 1993). The area underlain by other salts and less soluble potash minerals, such as polyhalite, is much larger than the KPLA (**Fig. 1**). The Salado Formation underlies about 58,000 mi^2, halite about 37,000 mi^2 and polyhalite about 27,000 mi^2 (Jones, 1972). Areal limits of the CPD are determined by drilling to the north, east, and south. The CPD is bounded on the west by dissolution truncation of shallow Salado evaporites caused by circulating groundwater in the Pecos River drainage basin (Griswold, 1982).

Potassium products (**Table 2**) from New Mexico are muriate of potash (potassium chloride, KCl; also called MOP, muriate, or sylvite by industry), langbeinite (potassium magnesium sulfate, $K_2SO_4 \cdot 2Mg(SO_4)_2$, called sulfate of potash magnesia or SOPM), and manufactured potassium sulfate (K_2SO_4, called sulfate of potash or SOP). MOP, sold in various grades (**Table 3**), comprises about 70% of New Mexico potash output; SOPM and SOP account for the remaining 30%. IMC Fertilizer (IMC), the largest producer in the CPD, supplies all three types of soluble potash salts (**Table 2**); other producers are more specialized.

The United States ranked fourth in world potash production at 1.94 million st (short tons) in 1992. New Mexico accounted for about 83% of domestic production (1.61 million st), supplied about 27% of domestic consumption (**Table 4**), and has about 57% of domestic reserves (Searls, 1993). The remaining 73% of consumption was imported primarily from Saskatchewan, Canada (91%). Domestic potash production is composed of about 75% as muriate, 20% as sulfate or langbeinite, and 5% in other forms (Searls, 1993). About 95% of soluble potash minerals are used in fertilizer, so potash trends closely parallel agricultural supply and demand during crop years (Searls, 1993). Most of the additional 5% is used in chemicals (O'Driscoll, 1990), mainly aqueous electrolysis of potash to potassium hydroxide. Potassium chemicals are used in medicines, pharmaceuticals, salt substitutes, soap, matches, glass, storage batteries, and other uses.

BRIEF HISTORY OF POTASH DEVELOPMENT

The following discussion of potash mining history draws heavily on Walls (1985) and Williams-Stroud et al. (1993). Early-large scale use of potash started in Germany in the mid-19th century. The modern United States potash industry is primarily a product of a World War I (WWI) embargo on German potash—the only large source then known—that drove prices to over \$500/st. Wartime potash (for saltpeter manufacture) was produced at over 100 plants, mainly in Nebraska and California, each with very small output. Bedded potash was discovered in 1925 in Eddy County, New Mexico, in Snowden McSweeney Well No. 1 on a V.H. McNutt permit near the center of that portion of the KPLA now mined (**Fig. 2**; T21S R30E). Potash was cored in April 1926, and the Federal Potash Exploration Act was passed in June.

The American Potash Co. was formed in 1926 for potash exploration in southeastern New Mexico. A 1062-ft shaft was started in December 1929 and completed in 1930. The first commercial potash from New Mexico was shipped in March 1931, 12 yrs after WWI. Assets of American Potash, incorporated in 1930 as United States Potash Co., are now owned by Mississippi Chemical (**Table 5**). The Potash Company of America (PCA) was formed in 1931 and completed a shaft in early 1934. The Santa Fe Railroad constructed a 20-mi spur from Carlsbad to the mine; later spurs were run to other mines and mills. The PCA mine is now operated by Eddy County Potash. By 1934, at least 11 companies were exploring for potash in southeastern New Mexico. In 1936, Union Potash & Chemical, Texas Potash, Independent Potash & Chemical, New Mexico Potash, and Carlsbad Potash merged into what is now IMC Fertilizer and began producing sylvite, langbeinite, and K_2SO_4 in 1940.

Domestic production supplied virtually all potash in the United States between 1941 and 1949. New Mexico produced about 1,000,000 st of marketable potash containing 525,000 st (short tons) of K_2O in 1941. New Mexico was the largest domestic potash producer in 1944, furnishing 85% of consumption. Active exploration by several companies in 1949 resulted in production in 1951 by Duval Texas Sulfur via two mine shafts at the Wills-Weaver mine. The potash operations of Duval are now Western Ag-Minerals. Southwest Potash, now controlled by Horizon Potash, began operation in 1952. The shaft of National Potash (now Mississippi Chemical) in Lea County, New Mexico, was completed in 1956, and production started in 1957. The Kerr-McGee facility, completed in 1957, delayed operation until 1965 and is now New Mexico Potash.

Minable potash was discovered in Saskatchewan, Canada, in 1952, but many factors prevented major production until the late 1950's with exports to the United States commencing in 1962. In 1964, U.S. domestic consumption permanently exceeded domestic production . The highest production year for New Mexico potash was 5.7 million st KCl or 3.3 million st K_2O in 1966. Production has decreased steadily as lower-cost Canadian potash has supplied an increasing share of U.S. potash consumption. The cross-over years were 1970 and 1971, when imports first exceeded domestic production. A low of 1.3 million st of K_2O was produced in 1986 in the United States. Overall U.S. potash capacity utilization declined from 83% (1984) to 61% (1985), made more significant because total capacity also declined during this period.

A dumping finding against Canadian producers by the International Trade Commission in 1987 and the 1988 antidumping agreement between the U.S. Department of Commerce and Canadian producers reversed the downward trend in output and utilization and revitalized the industry in New Mexico. Mississippi Chemical was reactivated in 1988 after several years on standby. Price increased after a 1988 anti-dumping agreement with Canada allowed AMAX to continue operation until its mine was purchased by Horizon in 1992 (closed in 1994) and has increased reserves at other properties in the Carlsbad Potash District. Large exports by the former USSR again depressed prices and demand in 1992-93. The impact of Canadian, Russian, and other competition, declining reserves and grades, and increased mining costs, led to many changes in ownership since 1985. Of the older companies, only Mississippi Chemical and IMC remain active (**Table 5**).

ECONOMIC GEOLOGY

Potash-bearing evaporites occur in Ochoan (Upper Permian) marine rocks in the Delaware basin portion of the Permian basin of west Texas and southeast New Mexico. Ochoan rocks, which are about 240 million years old, overlie Guadalupian carbonates and sandstones within the basin and overlie dominantly reefal carbonates along the basin flanks (many sources including King, 1948; Hayes, 1964; Pray, 1988; and Ulmer-Scholle et al., 1993). The Ochoan is divided into four formations (**Fig. 3**; Lowenstein, 1988): (1) the Castile Formation (oldest)--halite and banded anhydrite/limestone, (2) the Salado Formation--potash (ore mainly in the McNutt Member), halite, muddy halite, anhydrite, polyhalite, dolomite, and mudstone, (3) the Rustler Formation--halite, gypsum, anhydrite, siliclastic rocks, dolostone, and limestone, and (4) the Dewey Lake Redbeds (youngest)--siliclastic mudstone and sandstone. The Castile and basal portions of the Salado have extensive sections of laminated limestone/anhydrite cyclic couplets or "banding" (Madsen and Raup, 1988). Anhydrite interbeds in the Salado show extensive lateral continuity, although often replaced by polyhalite, allowing recognition of 43 marker beds in the CPD (Jones et al., 1960, 1960a).

The Salado Formation, up to a maximum of 670 m thick, is an evaporite sequence dominated by 200 to 400 m of halite and muddy halite in the KPLA (Lowenstein, 1988). It hosts 12 ore zones; 11 in the middle or McNutt Member (**Fig. 4**), and the 12th in the upper member. The area underlain by the 12 ore zones is about 1900 mi^2 (Lowenstein, 1988; Jones, 1972).

McNutt Member

The McNutt Member of the Salado Formation dips about 1° to the southeast within the Carlsbad Potash District and is about 120 m thick (Griswold, 1982). The McNutt contains evaporite minerals consisting of sylvite and langbeinite, together with halite, muddy halite, and accessory leonite, kainite, carnallite, polyhalite, kieserite, bloedite, and anhydrite (Barker and Austin, 1993; **Table 1**). In addition, the McNutt Member consists of non-evaporite minerals such as primary alkali feldspar, hematite, and quartz, and secondary magnesite, illite, clinochlore, talc, talc-saponite, corrensite, and uniform to completely random, interstratified clinochlore-saponite (Lowenstein, 1988; Bodine, 1978). All clay minerals appear to be well crystallized with sharp x-ray diffraction maxima.

Mudstone and siliclastic sediment in the muddy halite of the McNutt Member were derived from erosion of the surrounding basin margin dominantly to the north and east (Lowenstein, 1988). Lowenstein (1988) confirmed previous observations that the present potash salts formed later than the primary evaporite cycles and their overall distribution is independent of host lithology.

Potash ore zones are 1-3 m thick and are laterally consistent except where interrupted by salt horses, collapse features (Bachman, 1984), and igneous dikes (Calzia and Hiss, 1978). Commercial deposits were created in some localities by magnesium-undersaturated fluids moving through the zones, but in other areas late fluids destroyed ore, producing barren halite (salt horses). The McNutt Member is absent in the subsurface just west of the present mines (**Fig. 2**).

Ore zone 1 (**Fig. 4**) accounted for about 80% of past potash production, but it is essentially mined out at currently economic depths. Production is now chiefly from ore zones 3, 4, 5, and 10 which successively overlie zone 1. Mine levels in zone 7 are on standby. Langbeinite is produced from mixed sylvite and langbeinite ores in zones 4 and 5 (**Table 5**; Harben and Bates, 1990). Near the shallow western boundary of the KPLA, only ore zone 1, stratigraphically lowest, oldest, and richest in potash, was not removed by solution. A typical mixed ore from the Salado in the CPD contains 60% halite and

30% sylvite (usually together as sylvinite), with 5% langbeinite, 2% polyhalite, and 2% insolubles (Cheeseman, 1978).

The average sylvite ore grade in New Mexico decreased from 25-30% K_2O in the 1950's to about 14% today; langbeinite ore now averages 8-10% K_2O. Potash ore reserves are large within the district and should last for at least 25 to 35 yrs (**Table 6**) at current extraction rates.

SUMMARY OF POTASH-EVAPORITE ORIGIN

The majority of potash-bearing bedded-salt deposits originate from evaporation of either seawater or mixtures of seawater and other brines in restricted marine basins (Schmalz, 1969). The brine depth in an ancient evaporite basin undergoes fluctuations related to sea level, groundwater inflow, precipitation, runoff, and evaporation. Saline minerals can be deposited in deep or shallow water and sometimes during subaerial exposure (Williams-Stroud et al., 1993).

During evaporation of normal seawater, carnallite ($KCl \cdot MgCl_2 \cdot 6H_2O$) rather than sylvite (KCl) precipitates due to the high concentration of magnesium in seawater. Mixing of marine brines with other brines or with meteoric water may produce evaporite deposits without carnallite. Potash ore zones often are near the tops of halite beds in relatively thin layers because the potash is precipitated from brines of higher salinities occurring near the end of the evaporation sequence and later than halite beds. The sodium-to-potash ratio in seawater is about 27:1 so halite is very abundant compared to potash. Non-marine evaporite deposits occur but have mineralogy very similar to those in marine evaporites (Lowenstein et al., 1989) presenting further complications to origin interpretation.

Carnallite in a salt sequence can be altered to sylvite by the reaction of calcium- or magnesium-poor brine or meteoric water. In many instances, this diagenetic process occurs shortly after deposition of the carnallite layer, as in the case of potash deposits in Thailand (Hite, 1982). The soluble potassium salts of the Salado Formation and the McNutt Member formed by recycling of either primary carnallite or polyhalite, by migrating Mg- and Ca-poor fluids (Bodine, 1978), or by reactions in place based on changing brine composition, pressure, or temperature. Neither ore minerals, such as sylvite and langbeinite, nor most gangue potash minerals, such as leonite or kainite, are primary in the Salado. Alteration of evaporites is complex and may be syndepositional, postdepositional, or retrograde (Suwanich, 1991). Petrographic and textural relationships and chemical analysis of fluid inclusions of associated halite in potash evaporites suggest that sylvite is primary in some basins (Lowenstein and Spencer, 1990; Wardlaw, 1972). If so, magnesium in the brines must have been removed, perhaps due to the enrichment of calcium from other brines. Enrichment of seawater with respect to calcium will result in early depletion of sulfate with gypsum/anhydrite precipitation, and will prevent deposition of magnesium sulfates by restricting available sulfate. The magnesium sulfate-poor potash deposits probably precipitated from brines which were high in calcium, and constitute 60% or more of known potash basins (Hardie, 1991) although the Salado represents magnesium-rich potash deposition.

Most sub-basins of high-grade potash salts are found near the basin center surrounded by successively less soluble salt facies (symmetrical model), but some potash is restricted to the margins of the basin (asymmetrical model). An asymmetrical evaporite distribution, such as that in the Ochoan Delaware Basin, could be formed by the reflux model as first described by Ochsenius (1888) and others later (Lowenstein, 1988).

In the reflux model, a shallow bar, or sill, across the mouth of the basin (proximal end) restricts the flow of seawater, which evaporates into a salt-precipitating brine. The dense brine, with maximum concentration at the distal end, sinks to the bottom, and sets up an undercurrent of higher density brine back toward the proximal (sill) end. The sill, which restricts the inflow of seawater, allows inhibited flow of evaporation-concentrated brines back to the ocean. The least soluble salts are precipitated towards the sill, and the most soluble components precipitate in the deeper parts of the basin. The result is lateral facies changes in a tabular deposit that are due to the asymmetrical salinity gradients in the brine.

The classic reflux model of potash-deposition in the Delaware Basin suggests that the Salado Formation represents repeated cyclic drawdown and brine concentration in a shallow, marginal-marine basin with an intermittent inlet (Hovey Channel) to the southwest (**Fig. 1**). The Salado Formation and its middle member (McNutt Member) exhibit vertical stacks of two cycles (Type I and II; **Fig. 5**) on a larger scale (Lowenstein, 1988) than cycles in the Castile. Some potash salts are not included in the cycles because they are secondary as shown by their displacive and cross-cutting textures and distribution independent of host lithology (Lowenstein, 1988). Relative subsidence is necessary to allow the stacks to develop at least 46 Type I cycles in the Salado (Jones et al., 1960).

The Type I cycle in the Salado is marine dominated (seawater) and consists of an upward sequence, 1-11 m thick, of calcareous/siliclastic mudstone, anhydrite/polyhalite after gypsum, halite, and muddy halite. These record basin shallowing and brine concentration upward during progression from a stratified perennial lake or lagoon to a shallow ephemeral saline lake. The Type I cycle is related to sea level rise relative to the Salado basin and is not as common as Type II cycles (Lowenstein, 1988).

The Type II cycle is continental dominated (meteoric water) with some seawater from seepage or residual brines (brackish water). A Type II cycle is related to a drop in sea level and is volumetrically more important and more numerous than Type I cycles. It is 0.3-6 m thick and consists of halite grading upward into muddy halite. One or more Type II cycles separate Type I cycles yielding vertically stacked sedimentary packets representing a maximum time interval of 10^5 yrs per cycle. The Type II cycle is similar to the upper portion of a Type I cycle. The Type II shows no evidence of prolonged subaqueous exposure, compared to Type I, and has no anhydrite-gypsum, polyhalite or mudstone layers. The cumulative thickness of Type II exceeds that of Type I in the McNutt (Lowenstein, 1988).

Other hypotheses on the origin of Ochoan rocks near Carlsbad, NM, differ slightly to greatly from the classic reflux model. Leslie et al. (1993) believe that the laminated couplets of anhydrite and calcite/organic material, interbedded with massive to poorly laminated halite in the Castile and Salado Formations, were formed below wave base during a period of restricted circulation of marine water. Anderson (1993) suggests that the Castile Formation may be a "nonmarine" evaporite with considerable meteoric recharge.

MINING

The high solubility of most potash ores under New Mexico climates limits them to the subsurface—hence all mines in the CPD are underground. Mine depths range from about 270 to 425 m. These room-and-pillar mines are relatively clean, dry, and orderly because the beds being exploited are relatively shallow, regular, tabular, and nearly flat. Room-and-pillar mining is flexible and allows selective mining (Sullivan and Michael, 1986) so salt horses are easily bypassed and ore grade control is good. The location of barren salt horses is unpredictable, but they comprise up to 10% of the ore horizons and must be avoided. Low concentrations of methane are rarely encountered. Relief holes are drilled in ceilings to dissipate nitrogen (Williams-Stroud et al., in press). All mines in the CPD consist of at least two shafts for safety and ventilation and older mines have three or more shafts because working faces are now 5-8 km, or more, from the main shaft (Searls, 1985).

Continuous mining equipment adapted from coal mining is used to mine most potash ore although blasting is also used. Beds as thin as 1.2 m are mined with mechanical drum miners. Some harder ores, particularly langbeinite, require mechanical undercutters to prepare the working face for drilling and blasting, usually with ANFO (ammonium nitrate and fuel oil). In all cases, mechanical loaders, underground crushers, and conveyor belts are used to handle broken ore. Room-and-pillar methods remove 60-75% of the ore during initial mining. Subsequent removal of most of the support pillars allows extraction to exceed 90% (Sullivan and Michael, 1986; Barker and Austin, 1993). This is not done routinely, particularly when unmined overlying ore zones are present, but is usually done only when an area of the mine is being permanently closed.

MILLING

Mills in the CPD produce potash by combinations of separation, flotation, crystallization, leaching, and heavy media circuits related to specific ore. Output from these circuits is dried in fluid bed or rotary dryers and sized over screens to yield final products. Potash ore is ground to break up sylvite-halite agglomerates (Searls, 1985) followed by froth flotation (**Fig. 6**). Frothers such as cresylic acid, pine oil, or alcohol are added to the slurry. Sylvite is floated from halite in an aqueous solution saturated with both sodium and potassium chlorides at pulp densities of 20-35% solids and recovery generally exceeds 80%. Collectors typically are hydrochloride and acetate salts of aliphatic amines with carbon chain lengths of 12 to 24. IMC uses heavy media separation on sylvite/langbeinite ore prior to flotation and produces potassium sulfate by reacting potassium chloride with various sulfate materials including langbeinite. Western Ag-Minerals washes langbeinite ore to leach more soluble gangue without a flotation stage. Fine-grained MOP from flotation must be coarsened by compaction between rollers, crushed, and sized to bulk-blended fertilizer specifications.

The abundance and mineralogy of clay minerals are significant in processing potash ores, in particular, the clay-rich 10th ore zone. Clay-size particles (slimes), composed dominantly of clay minerals, make up from a trace to about 10% of ore zones in the CPD. Clay minerals absorb the reagents added early before the crystallization stage, thus raising reagent cost, and hinder recovery (see Gundiler, Vol. Two Chapter V) among several deleterious effects. Each mill is designed for a specific slimes content in its feed stock (**Fig. 7**). Thus some ore zones cannot be processed efficiently in specific plants. For example, the Mississippi Chemical mill can handle up to 4.5% slimes. Beneficiation by dissolution and vacuum recrystallization is used on clay-rich or fine-grained ores. This method is used by New Mexico Potash whose ores contain about 7% clay (Searls, 1985).

Clay minerals preferentially interact with the amines used to coat sylvite in sylvinite ores and frothers used in flotation cells (Searls, 1985). This is a result of the large surface areas of clays, their residual charges, adsorption, absorption, and colloid formation. Expandable trioctahedral clay minerals such as corrensite, saponite, and clinochlore-saponite have more surface area than other clay minerals and can form colloids with the brines of either the flotation or crystallization circuits. These characteristics of clay minerals interfere with beneficiation and increase chemical use.

Potash tailings in the CPD, largely halite and clay, are stored or disposed of on the surface. Solid wastes are piled and monitored for salt leakage, which is minimal owing to the semi-arid climate. Brines are evaporated in impoundments or in an expanded natural saline lake/saltpan. Methods for returning tailings to the mine are being studied but are more likely to be initiated in potash districts less price sensitive than the CPD.

SUMMARY OF ECONOMIC FACTORS

Activity by other industries can affect the production of potash from southeastern New Mexico; notable are agriculture, petroleum, and deep geologic waste disposal. The main use of potash as a fertilizer ties it to cyclic trends in the agricultural industry. These trends are related to complex interactions between weather and climate, advances in crop genetics, soil science, farming practices, GNP of importing nations, farm income,

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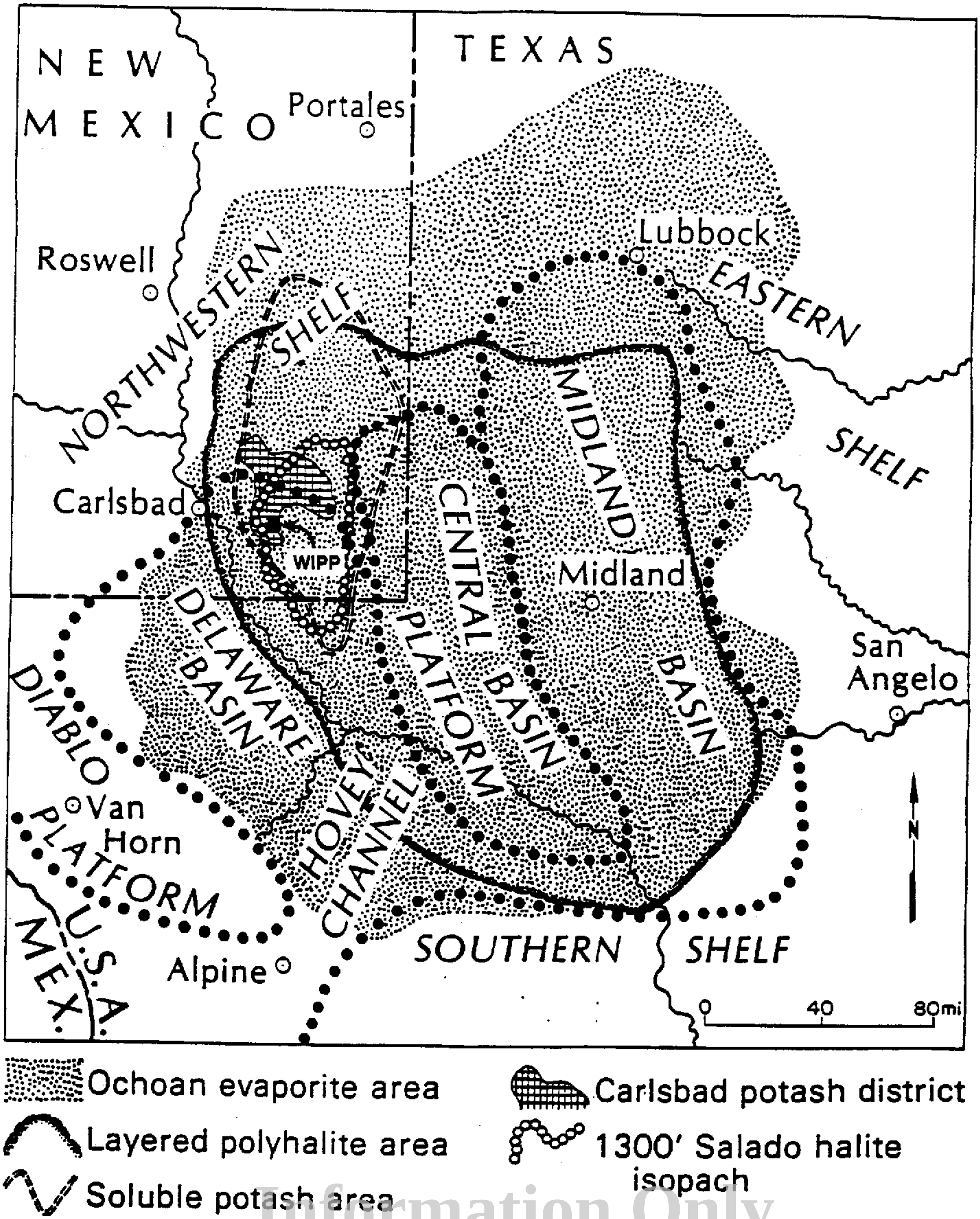
Fig. 1. Location of the Carlsbad Potash District in the southwestern United States and its relation to the regional subsurface geology (after Lowenstein, 1988; Austin, 1980; Jones, 1972).



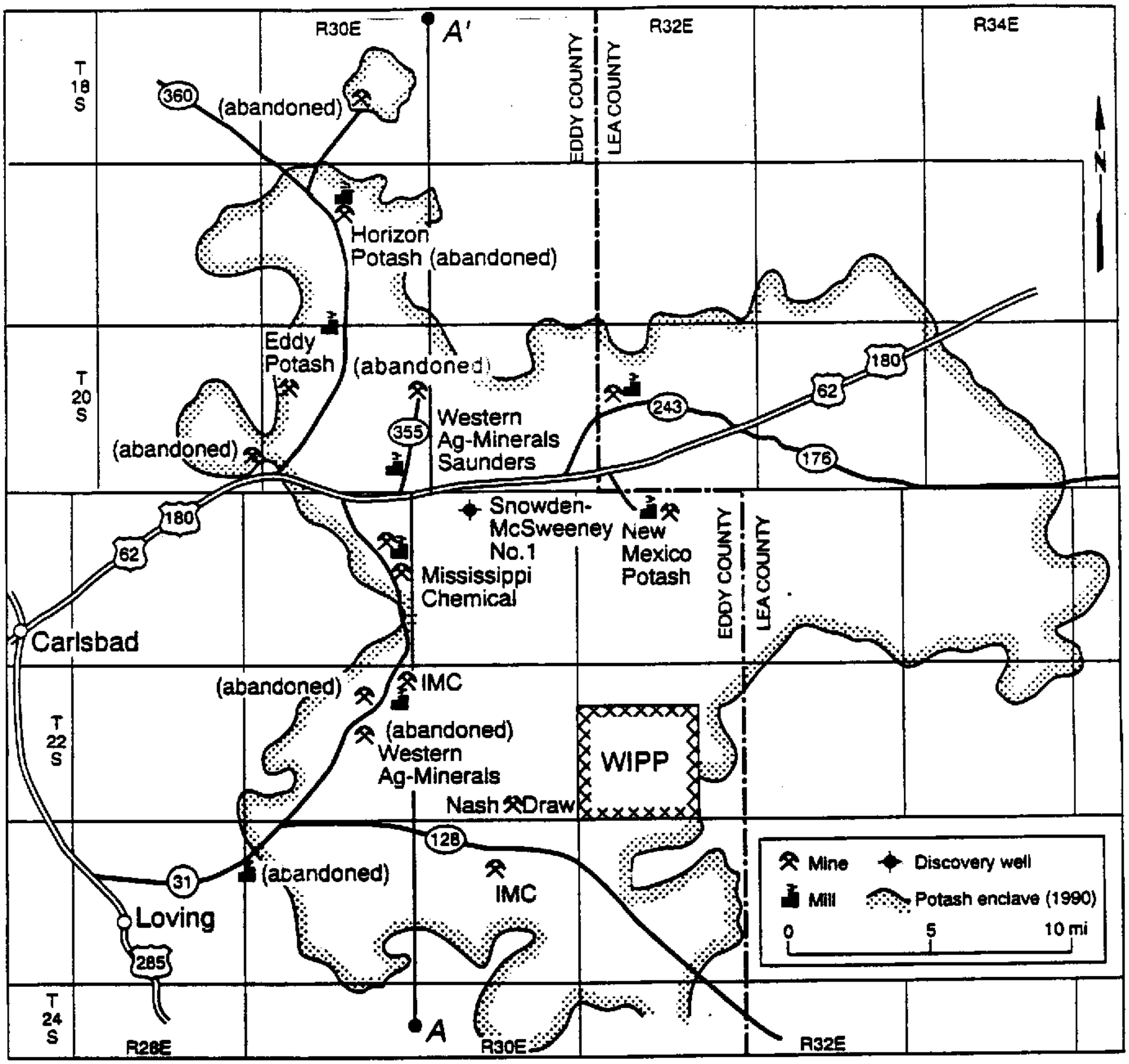


Fig. 2. Active, inactive, and abandoned potash facilities in Eddy and Lea Counties, southeastern New Mexico showing general outline of the Potash Enclave (KPLA) as of 1984. Only minor adjustments have occurred since 1984 (oral commun., U.S. Bureau of Land Management, Minerals Management Service, June 1990). Cross-section shown in Fig. 3 (A-A') is approximately along the east side of R30E (north) and R29S (south).

Figure 3. Diagrammatic north-south cross-section (A-A' on Fig. 2) and stratigraphic relationships of the northern edge of the Delaware Basin, southeastern New Mexico (after Austin, 1980; Jones, 1972).

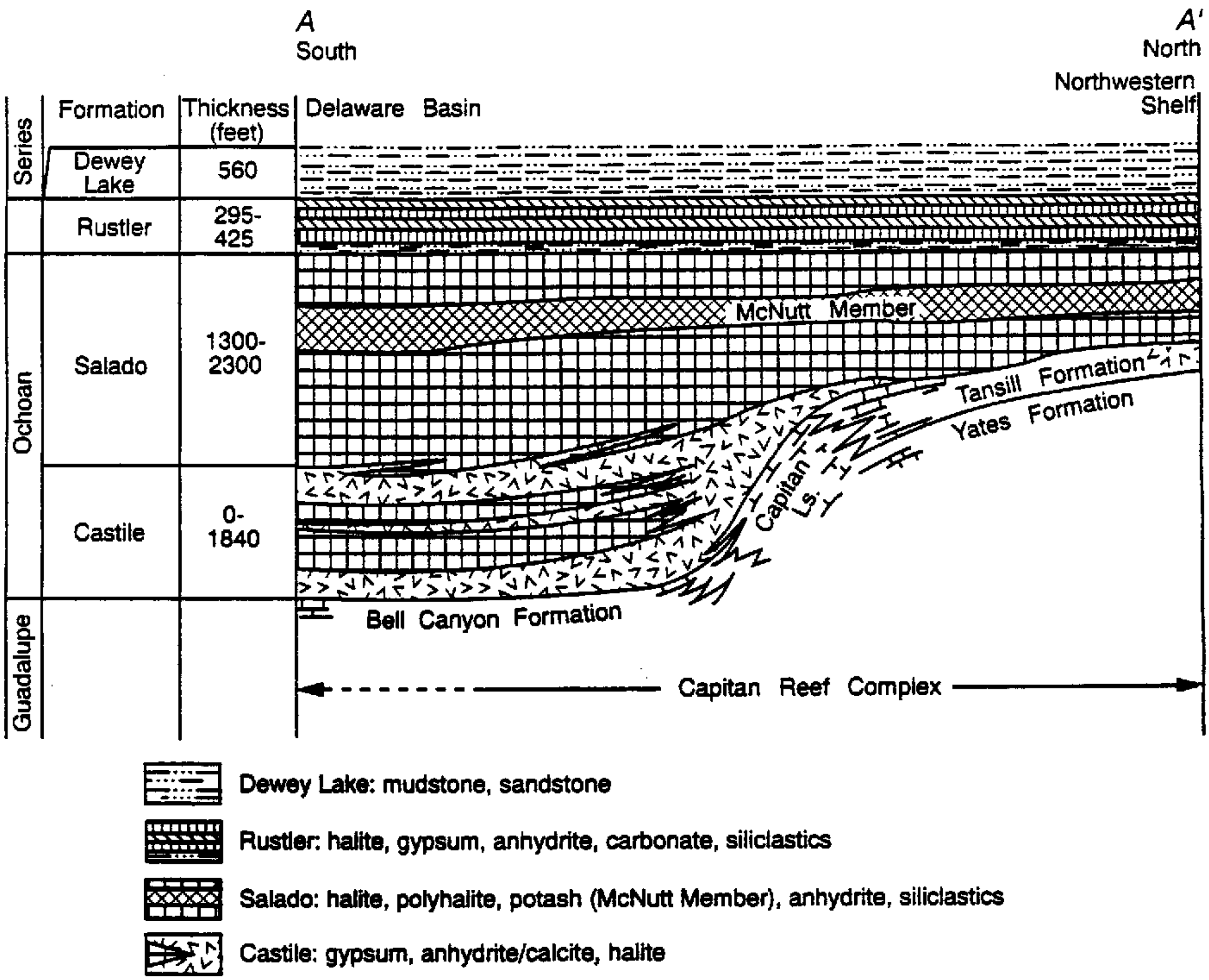


Fig. 4. Regional stratigraphic column with expanded sections of the Ochoan Evaporite and McNutt Member of the Salado Formation (after Griswold, 1982).

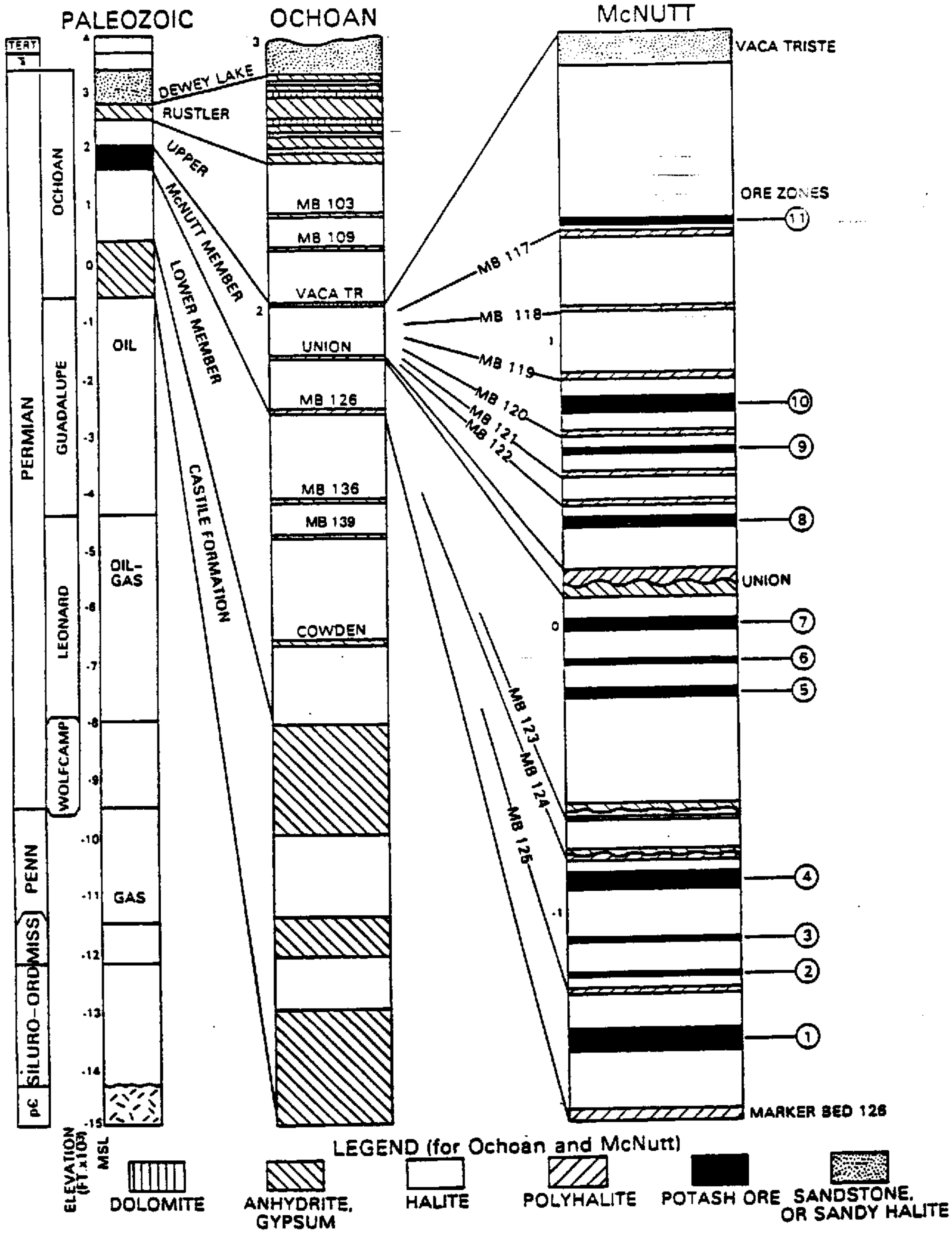


Fig. 5. Vertical cyclic sequences in the McNutt Member of the Salado Formation, with diagnostic sedimentary structures and textures and interpreted inflow waters (after Lowenstein, 1988).

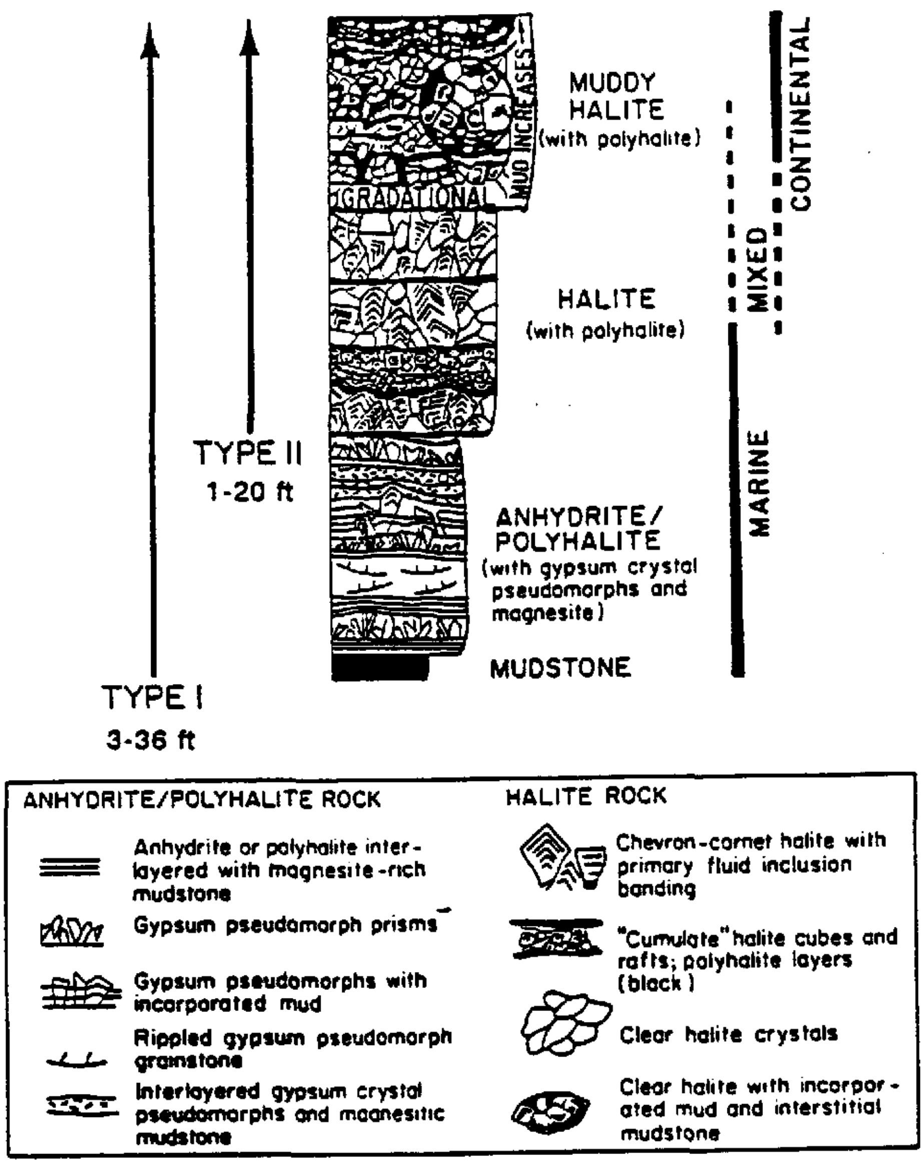


Fig. 6. Simplified potash flotation circuit (Sullivan and Michael, 1986).

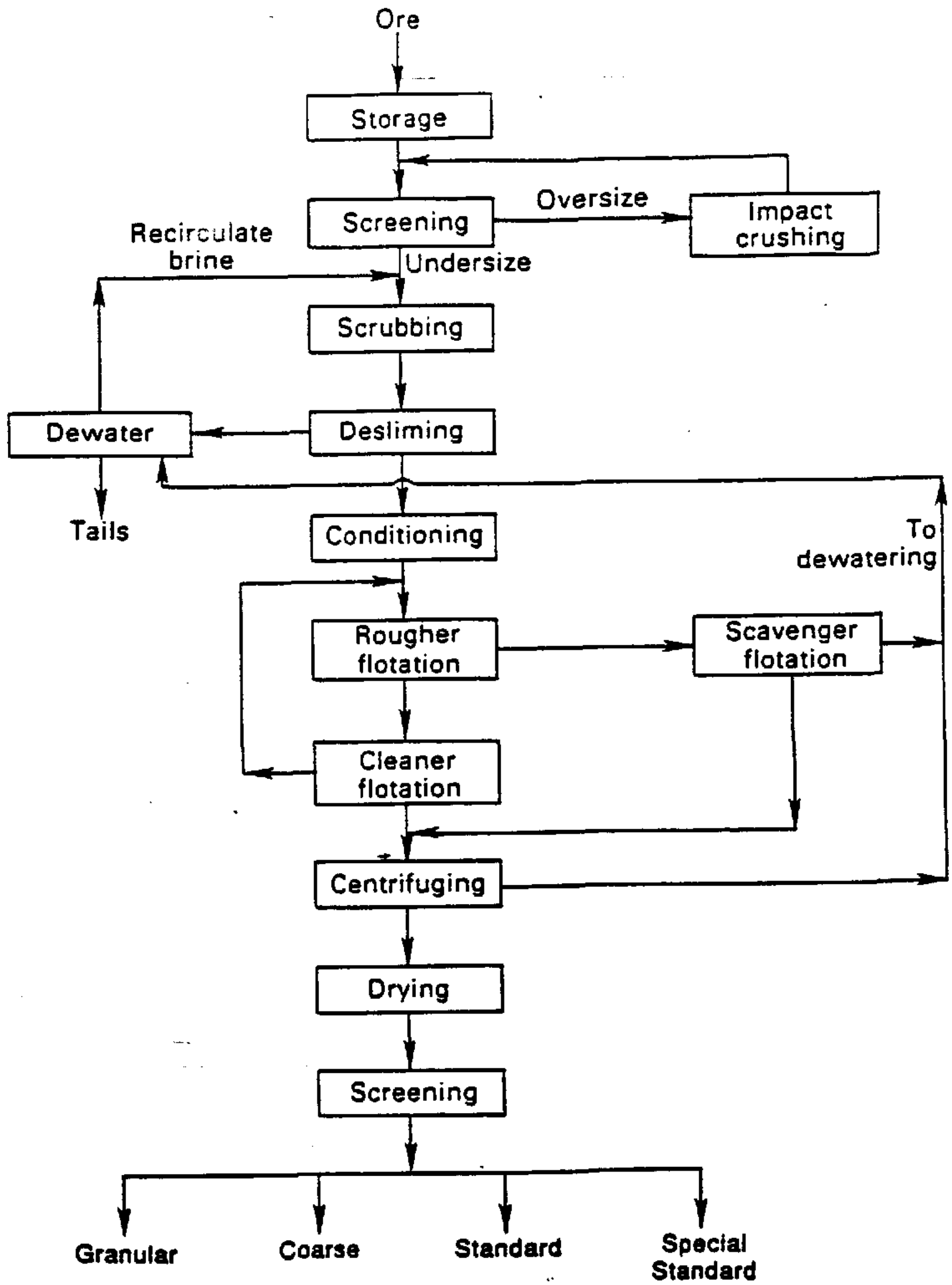


Fig. 7. Simplified potash crystallization circuit (Sullivan and Michael, 1986).

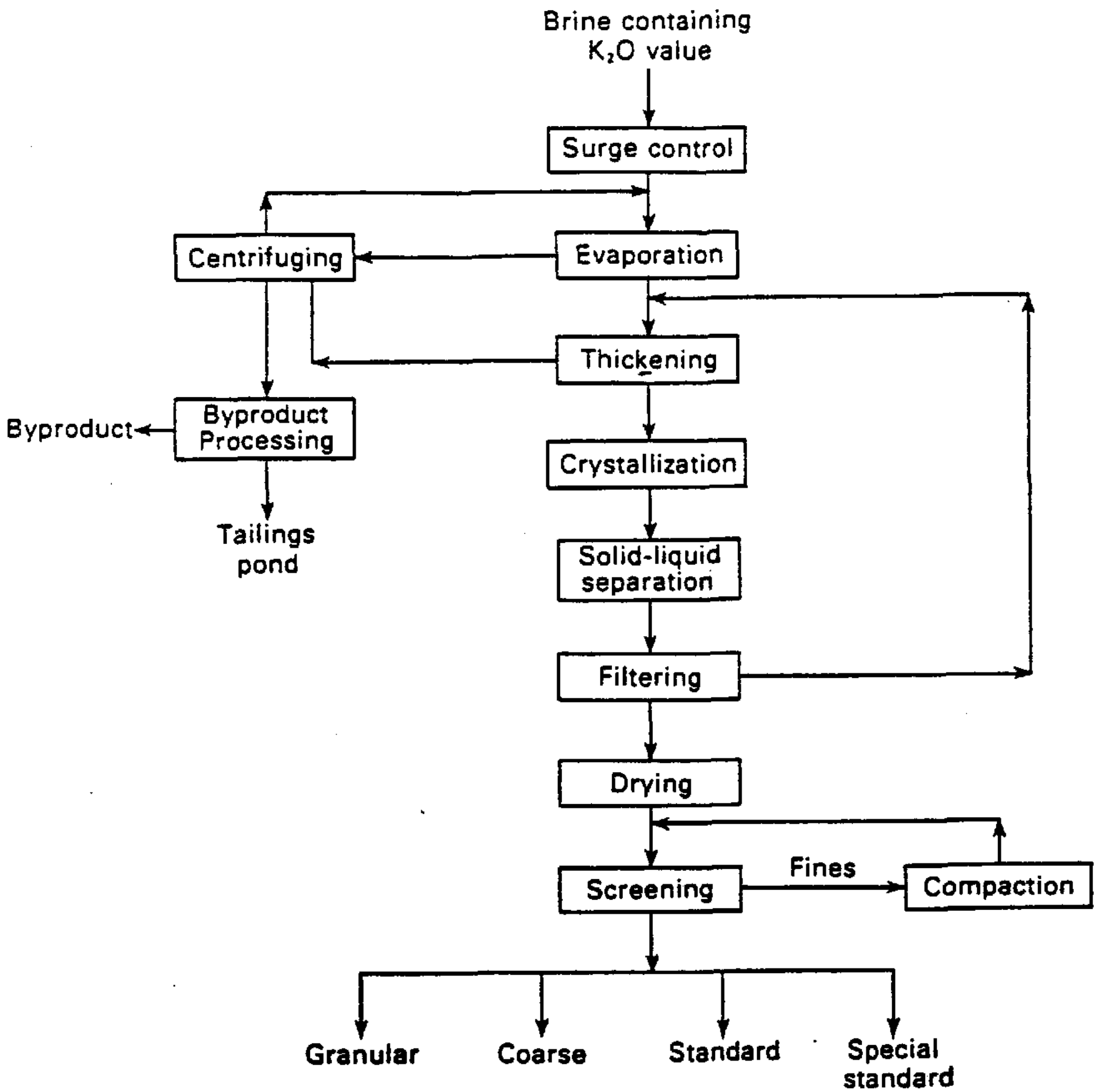


Table 1. Evaporite Minerals and Rocks of the Carlsbad Potash District

Mineral or Rock	Formula	Equivalent wt.% K	KCl	K_2O	K_2SO_4
Anhydrite*	$CaSO_4$	--	--	--	--
Arcanite	K_2SO_4	44.88	--	54.06	100.00
Bischofite	$MgCl_2 \cdot 6H_2O$	--	--	--	--
Bloedite	$Na_2SO_4 \cdot MgSO_4 \cdot 4H_2O$	--	--	--	--
Carnallite*	$KCl \cdot MgCl_2 \cdot 6H_2O$	14.07	26.83	16.95	--
Erytrosiderite	$2KCl \cdot FeCl_3 \cdot H_2O$	23.75	45.28	28.61	--
Glaserite	$K_3Na(SO_4)_2$	35.29	--	42.51	78.63
Glauberite	$Na_2SO_4 \cdot CaSO_4$	--	--	--	--
Gypsum*	$CaSO_4 \cdot 2H_2O$	--	--	--	--
Halite*	NaCl	--	--	--	--
Hydrophilite	$KCl \cdot CaCl_2 \cdot 6H_2O$	13.32	25.39	16.04	--
Kainite*	$MgSO_4 \cdot KCl \cdot 3H_2O$	15.71	29.94	18.92	--
Kieserite*	$MgSO_4 \cdot H_2O$	--	--	--	--
Langbeinite*	$K_2SO_4 \cdot 2MgSO_4$	18.84	--	22.70	41.99
Leonite*	$K_2SO_4 \cdot MgSO_4 \cdot 4H_2O$	21.33	--	25.69	47.52
Mirabilite	$Na_2SO_4 \cdot 10H_2O$	--	--	--	--
Polyhalite*	$K_2SO_4 \cdot MgSO_4 \cdot 2CaSO_4 \cdot 2H_2O$	12.97	--	15.62	28.90
Schoenite	$K_2SO_4 \cdot MgSO_4 \cdot 6H_2O$	19.42	--	23.39	43.27
Sylvinite*	KCl + NaCl	--	--	10-35	--
Sylvite*	KCl	52.44	100.00	63.17	--
Syngenite	$K_2SO_4 \cdot CaSO_4 \cdot H_2O$	23.81	--	28.68	53.06
Tachyhydrite	$CaCl_2 \cdot 2MgCl_2 \cdot 12H_2O$	--	--	--	--

After Griswold, 1982.
Only sylvite and langbeinite are presently ore minerals.
Hydrated potassium minerals are not amenable to existing concentration methods.
*Common minerals and rocks in the Carlsbad Potash District.

Table 2. K_2O Equivalent wt.% of Commercial Potash Minerals

Chemical Compound	Chemical Formula	Mineral Name	Industry Name	Max K_2O Eq. wt%	Grades K_2O Eq. wt.%	Remarks
Potassium chloride	KCl	sylvite	MOP, sylvite, muriate	63.18	61% (USA) 60%, 50%, 40%, 30% World	Coarse grades used to match sizes of N-P ingredients to minimize segregation
Potassium chloride + sodium chloride	KCl+NaCl	"sylvinite"	—	≈35	—	Easily mined with continuous miners
Potassium/magnesium double sulfate	$2MgSO_4 \cdot K_2SO_4$	langbeinite	SOPM, sulfate of potash magnesia	22.70	22% 21.5%	Preferred for tobacco, paper, potato, sugar beet, and citrus crops to prevent chloride burn; harder to mine than chlorides
Potassium sulfate	K_2SO_4	arcanite	SOP	54.06	50%	Preferred for tobacco, paper, potato, sugar beet and citrus crops to prevent chloride burn; mostly manufactured, some is natural
Potassium nitrate	K_2NO_3	nitre	—	—	—	Natural is only 14% K_2O (admixture) crude salt mixed with $NaNO_3$; mostly manufactured, some is natural
Potassium chloride	KCl	manure salts	—	19	—	Manufactured

After Searls, 1985; Adams and Hite, 1983; and Sullivan and Michael, 1986.

Table 3. Particle-Size Grades of Muriate of Potash (MOP, Muriate, Sylvite), Langbeinite (SOPM), and Sulfate of Potash (SOP) Products

Grade	Minimum K_2O Equiv. wt.%	Approximate Particle Size Range[1]		Type of Potash	Remarks
		Mesh[2]	Millimeters		
Granular	61, 50, 22	6-20	3.35-0.85	Muriate & sulfates	---
Blend[3]	60	6-14	3.35-1.18	Muriate	Replaces granular and coarse grades
Coarse	60	8-28	2.4-0.6	Muriate	---
Standard	60, 50, 22	14-65	1.2-0.21	Muriate & sulfates	---
Special Standard	60	35-150	0.4-0.11	Muriate & sulfate	Canada only
Soluble/ Suspension	62	35-150	0.4-0.11	Muriate	---
Chemical	63	NA	NA	Muriate	---

After Searls, 1985.
[1]From approximately 2% to 98% by wt.% cumulative.
[2]Tyler standard
[3]Blend = new grade with midpoint between 8 and 10 mesh introduced by Canadian producers.
NA = not applicable

Table 4. Potash Statistics for Calendar Years 1980 to 1994.

Calendar Mine Year	Marketable U.S. Production (1000 st K_2O)	Apparent U.S. Consumption (1000 st K_2O)	Net U.S. Import Reliance (%)	N.M. Share of U.S. Production (%)	N.M. Supply to U.S. Consumption (%)	Avg. Price NM Marketable Potash ($/st K_2O)	Value NM Production of Marketable Potash FOB (million $)
1980	2,468	6,999	65	83	29	$141	289
1981	2,377	6,849	65	84	29	$158	261
1982	1,966	5,647	65	82	29	$124	205
1983	1,575	6,231	75	87	22	$124	175
1984	1,724	6,638	74	90	23	$131	204
1985	1,429	5,893	76	87	21	$126	156
1986	1,325	5,338	75	82	20	$122	133
1987	1,391	5,609	75	87	22	$120	174
1988	1,677	5,803	71	89	26	$152	214
1989	1,758	5,678	65	89	31	$161	243
1990	1,888	5,963	68	89	28	$153	246
1991	1,928	5,779	68	85	28	$155	251
1992	1,879	5,898	68	83	27	$162	257
1993	1,660	5,988	72	82	23	$164	216
1994	1,571	5,941	74	81	21	NA	NA

Data modified from J. P. Searls, U.S. Bureau of Mines, oral commun., June 1990, June 1993, and January 1995, and U.S. Bureau of Mines Mineral Commodity Reports, Mineral Commodity Profiles, Mineral Industry Surveys, and Mineral Yearbooks (1980-1995).

NA - Not available

Table 5. General Mineralogy and Minability of Ore Zones of Presently Producing Companies in the Carlsbad Potash District

Ore Zone	Marker Bed Near Base*	General Mineralogy	Producing Company	Minability
Eleventh	MB 117	Mostly carnallite, minor sylvite, leonite	----	Not mined to date
Tenth	MB 120	Sylvite, sylvinite	New Mexico Potash, IMCF	Second best in the district; high-clay content (6-7%)
Ninth	MB 121	Carnallite, kieserite, sylvite	----	Not mined to date
Eighth	Union	Sylvite	----	Moderate reserves; important in future; high clay
Seventh	----	Sylvite, sylvinite	Mississippi Chemical	Moderate reserves; moderate clay (3-4%)
Sixth	----	Carnallite, kieserite, etc.	----	Not mined to date
Fifth	MB 123	Sylvite, langbeinite	IMCF	Moderate reserves; trace clay (1%)
Fourth	----	Langbeinite, sylvite	IMCF, Western Ag-Minerals	Principal source of langbeinite; mixed ore
Third	----	Sylvite, sylvinite	Horizon, Eddy Potash	Ranks 3rd in production of sylvite
Second	MB 125	Carnallite, kieserite, etc.	----	Not mined to date
First	MB 126	Sylvite, sylvinite	Eddy Potash	Was the major sylvite-producing zone, now nearly mined out

After Griswold, 1982; Searls, oral commun., June 1990.
*Base of marker bed; see Figure 4.

Table 6. General Mineralogy and Minability of Ore Zones of Presently Producing Companies in the Carlsbad Potash District

Ore Zone	Marker Bed Near Base	General Mineralogy	Producing Company	Minability
Tenth	MB 120	Sylvite, sylvinite	New Mexico Potash, IMCF	Second best in the district; high-clay content (6-7%)
Eighth	Union	Sylvite	-----	Moderate reserves; important in future; high clay
Seventh	-----	Sylvite, sylvinite	Mississippi Chemical	Moderate ore reserves; moderate clay (3-4%)
Fifth	MB 123	Sylvite, langbeinite	IMCF	Moderate ore reserves; trace clay (1%)
Fourth	-----	Langbeinite, sylvite	IMCF, Western Ag-Minerals	Principal source of langbeinite; mixed ore
Third	-----	Sylvite, sylvinite	Horizon, Eddy Potash	Ranks 3rd in production of sylvite
First	MB 126	Sylvite, sylvinite	Eddy Potash	Was the major sylvite-producing zone, now nearly mined out

Table 7. Active Potash Mines in New Mexico Showing Estimated Capacity, Average Ore Grade, and Mine Life at the Average 1992 Price of $89.44/t product

Operator	County	Product Capacity (st/yr[1])	Ore grade (% K_2O)	Mine life (yrs)
Eddy Potash Inc.[2]	Eddy	550,000	18	4
Horizon Potash Co.[3]	Eddy	450,000	12	6
IMC Fertilizer, Inc.	Eddy	1,000,000[4]	11[4]	33
Mississippi Chemical	Eddy	300,000	15	125
New Mexico Potash[2]	Eddy	450,000	14	25
Western Ag-Minerals[5]	Eddy	400,000	8[6]	30

Data from J.P. Searls, U.S. Bureau of Mines, oral commun., 1993.
[1]May not be operating at full capacity.
[2]Owned by Trans-Resource, Inc.
[3]Currently inactive and being closed.
[4]Muriate, langbeinite, and sulfate combined.
[5]Owned by Rayrock Resources of Canada.
[6]Langbeinite only.

Evaluation of Mineral Resources at the
Waste Isolation Pilot Plant (WIPP) Site

Chapter IV

FUTURE MINING TECHNOLOGY

by

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Contract No. PO-75-WJJ644145Z

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FUTURE MINING TECHNOLOGY

George B. Griswold

USING THE PAST TO PREDICT THE FUTURE

Looking at past developments is always the best method to predict what may occur in the future. The Carlsbad Potash Mining District has a long history extending from its discovery in 1925 to the commencement of production in 1931 and onward to the present, when it still accounts for 85% of all domestic production. The period from 1931 until 1965 was one of continuous expansion until there were seven operating companies. The need for potash was increasing throughout North America, and the potash deposits at Carlsbad were the richest source of supply. In the late 1960s rich deposits in Canada were brought on stream and a period of competition ensued not only with Canadian imports but among the seven Carlsbad producers as well. Simultaneously with these events the ore grade at Carlsbad continued to decline. Mining in the early years was from the rich and thick 1st ore zone. The mining height averaged 8 to 12 ft, and the grade ranged from 20 to 25% K_20 as sylvite. Langbeinite ores, mainly from the 4th ore zone, were also thick and averaged better than 10% K_20 as langbeinite.

Today the ore beds are thinner for the most part than the mining machines can excavate, which causes dilution of the in-place ore. The rich 1st ore zone is now almost depleted, and sylvite ores are mined mostly from the 5th, 7th, and 10th ore zones. The grade of these ores is now about 14% K_20 as sylvite. The major source of langbeinite continues to be the 4th ore zone, but the mining height is kept as low as possible and the average grade has dropped to 8% K_20 as langbeinite.

The Carlsbad area remains competitive in the domestic and international agricultural-fertilizer industry because the local operators continuously improve productivity. In addition, IMC Fertilizer, Inc. has a unique technology that treats mixed ore of langbeinite and sylvite.

A review of the historical data given in **Table 1** (see Chapter VI, Vol. 2) illustrates the increase in productivity of the Carlsbad mining companies. The measure of productivity used was tons of raw ore and tons of product per man-year. These data are given in columns L and M of **Table 1**. The tons of ore per man-year increased 5.44 times (from 1878 tons in 1940 to 10,221 tons in 1992). The tons of product per man-year increased, in spite of continuing decline in grade, from 793 to 1970 tons, representing a 2.48-fold increase. Column H tracks the historical record of the tons of ore required to make a single ton of product. It has increased from slightly less than three to more than five today, reflecting the continuing drop in ore grade.

The increase in the tons of ore to make a ton of product needs some qualification. In 1940 little langbeinite was produced, whereas today it accounts for about one-third of the product sold. The production data for langbeinite are held confidential to protect the privacy of the two producers, IMC Fertilizer, Inc. and Western Ag-Minerals Company. Therefore the annual production of "product" given in column B of **Table 1** is an aggregate of sylvite, langbeinite, and manufactured arcanite. However, the tons of ore required to make a ton of product are not the same. To illustrate, it takes about 5.2 tons of sylvite ore to make one ton of product. Whereas, for langbeinite it takes only about 3.2 tons to make one ton of product. But mining and processing costs are higher for langbeinite than for sylvite. Therefore the end result is that the price to cost ratio remains about the same for sylvite and langbeinite. What has changed is the ability of the mines to continuously increase the tons of product per man-year.

Note that worker productivity for both ore and product appears to have increased steadily from 1940 to the present. There are occasional bumps in the data, but they exhibit a relatively consistent growth. A combination of improvements in technology accounts for the productivity increases, among which are:

For mining:

1. Conversion from track haulage to conveyors.
2. Use of mechanical-arm loaders and undercut machines.
3. Use of shuttle buggies and ram cars to move ore from the face to conveyors.
4. Utilization of diesel and diesel-over-hydraulic for equipment to enhance mobility.
5. Use of rock bolts for ground control.
6. Usage of higher voltages and larger electric motors underground.
7. Use of ammonium nitrate–fuel oil explosive (ANFO) along with non-electric and consumable detonation systems.
8. The advent first of boring machines then drum mining machines.
9. Continuous improvements in belt conveyors including new extendible types.

For processing:

1. Flotation of non-metallic minerals.
2. Continued improvement in flotation reagents.
3. Improvement in flotation-cell design and operation.
4. Use of cyclones and centrifuges for separation of slimes.
5. Compacting of fines to produce coarser products.
6. Improvement in screening and sizing techniques.
7. Application of non-caking agents to products.
8. Continued improvement in handling, storage, and loading of products.

This listing is neither comprehensive nor chronological. Instead it is meant to illustrate that many improvements have been made over the years, none of which are called revolutionary, but in combination they result in a steady increase in efficiency of the overall process starting with the taking of raw ore from the underground mining face and ending with a salable product loaded into a rail car or truck.

Along with the improvements listed above came treatments of mixed sylvite and langbeinite ore. IMC Fertilizers, Inc. commenced work on the process almost immediately after opening their mine in 1940. Duval Sulphur and Potash Corporation produced manufactured arcanite (K_2SO_4) when they opened the Nash Draw mine in 1962; however, this process was terminated after a few years, and since then the mine has produced only langbeinite. The Nash Draw mine is now owned and operated by Western Ag-Minerals Company. The details of the process that IMC uses are held proprietary, so little technical information is available other than what is described in (see Chapter VI, Vol. 2).

IMC must be successful with their process, because that company continues to be the largest producer in Carlsbad while mining ores below the cut-off grades for single product. In addition, IMC appears to be steadily increasing the percentage of sulfate products in proportion to their muriate products. The company dominates the world market for langbeinite as a fertilizer mineral and is very competitive in the K_2SO_4 market.

The conclusion is that IMC or a company that has gained their expertise will be a candidate to mine the potash resources known in the vicinity of the WIPP Site. Indeed, IMC formerly held mineral leases within the WIPP boundary area, which were purchased by DOE in 1989 for a price exceeding $25 million. The company is attempting to replace those resources. They are now vying with Yates Petroleum Corporation and Pogo Production Company for potash mineral leases from the BLM along the northeastern borders of the WIPP Site. This is the same area which contains the bulk of the potash resources evaluated in this study. Therefore, it is the technology that IMC possesses and what future technical advances they may make that have the most relevance to whether or when the resources evaluated will be mined.

DEVELOPMENTS THAT CAN BE EXPECTED IN THE FUTURE

There are some developments which are almost certain to occur within the next decade or so.

Mineral processing

New techniques for better "in stream" analysis will become available to determine the exact mineral percentages of ore being processed in order to more efficiently tailor plant operations to increase recovery and lower energy consumption. Neutron-activation analysis holds this promise, but development of rugged instruments that can provide reliable and real-time analysis is a challenge that has not quite been met.

Better methods of compacting and sizing products will emerge in order to meet better the needs of the fertilizer industry. Western Ag-Minerals was recently granted a patent on a new process, and new developments are expected to occur. Other improvements will be in the area of materials handling. For example the use of tube conveyors to eliminate dust and particle degradation at conveyor-belt transfer points.

Recycling of water and reagents is expected to improve. The "energy crisis" of the late 1970s made all operators become more efficient in energy consumption at their plants and continued improvement is expected.

Underground mining

The mines are now highly mechanized, so no revolutionary concepts are foreseen in the near term. What can be expected is that heavier and more powerful drum miners will be used to mine the hard langbeinite ores of the 4th ore zone. Western Ag-Minerals Company is now investigating the use of such a machine. The advantages of converting to drum miners are severalfold: increase in mining production, mining at a lower height to improve ore grade, minimizing the workforce at the mining face which improves safety, and better ground control because mining advance is more rapid. A factor yet to be determined is whether drum miners will reduce the amount of langbeinite fines and so improve processing recovery.

IMC Fertilizer, Inc. is studying faster and safer ways of transporting personnel from the shaft entry out to the working faces. Distances are now five or more miles from the man-shafts, so transportation of personnel consumes a significant portion of working time.

Extendible conveyors, which are placed between the miners and the main belt lines, will be improved. The devices now in use were developed for coal mines, and the companies that use them for potash are making modifications to improve performance in their specific operations.

Remote control of mining machinery will increase. Today most continuous miners are operated by the worker using telemetry. New laser-guidance systems will be used to direct the mining advance and to continually adjust the height mined to minimize dilution. Mining height has been reduced to 4.5 ft, and may be further reduced to 4 ft or perhaps even less.

Roof bolting is used as the major method of ground control. Bolting can be done with on-board bolting machines on the continuous miners. This practice has not been fully implemented to date, but will become customary where ground conditions require regular bolting.

DEVELOPMENTS THAT CAN BE EXPECTED ONLY IN THE FAR FUTURE

Solution mining is the only method that can be reasonably predicted for the Carlsbad District. The system has been in use in Canada for ultra deep (>4000 ft) sylvite in

Saskatchewan and in thick but highly folded strata in New Brunswick. In the United States solution mining is used near Moab, Utah, to recover sylvite from an evaporite deposit that proved to be too difficult to mine conventionally because the strata were folded and contained considerable methane.

In Carlsbad, one experiment was conducted using hydraulic-fracturing techniques in an attempt to connect two relatively closely spaced holes. The experiment was only partially successful (Shock and Davis, 1970). Most people familiar with the Carlsbad potash deposits believe that the ore beds are too thin for the application of solution mining as it is now practiced in Canada. In addition, the deposits evaluated at WIPP contained langbeinite, which is not readily soluble. So if solution mining is employed in the vicinity of the WIPP Site, it will be to recover only sylvite.

However, all mines have held open the option of using solution mining once their sylvite deposits are fully mined out. The concept would rely on the fact that the open spaces left over from mining would allow ore remaining in pillars to be recovered. No specific plan has ever been formulated whereby a mine would be intentionally flooded and saturated sylvite brine recovered from boreholes. Solar evaporation would need to be used to concentrate the brine, because the solutions would be very dilute.

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Evaluation of Mineral Resources at the
Waste Isolation Pilot Plant (WIPP) Site

Chapter V

POTASH PROCESSING TECHNOLOGY

by
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POTASH PROCESSING TECHNOLOGY

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Introduction

Potash ores must be beneficiated to remove halite (NaCl), clays, and other insoluble material to produce marketable products. Silvinite (KCl + NaCl) and langbeinite ($K_2SO_4 \cdot 2MgSO_4$) are the two ore types currently mined in the Carlsbad Potash District. The average K_2O grade of silvinite ores is about 14–16% and that of langbeinite about 8–10% (Austin and Barker, 1993).

Sylvinite ores are generally beneficiated by flotation of sylvite (KCl) in saturated brine solutions using cationic collectors (primary aliphatic amines) and frothers. The product, muriate of potash, contains 60% K_2O and it is marketed in different size grades. Presence of clay minerals, however, may interfere with the flotation process. Clay minerals preferentially absorb the flotation reagents, causing excessive reagent consumption and hindering the recovery of sylvite. Therefore, they are removed prior to flotation by scrubbing and desliming (Scroggin, 1978). Flotation of clay minerals remaining in the pulp is further suppressed by using a starch or cellulose derivative and some fuel oil. Ores with much higher insoluble and clay content, i.e. 6–7%, are beneficiated by dissolution and selective crystallization from the resulting brines (Case, 1978; Zandon, 1985).

Langbeinite is mined in only two locations in the world. It has been mined continuously in the Carlsbad district since 1940 and intermittently in the Stebnik mine in the Ukraine since the 1930s (Rempe, 1982). Langbeinite is much less soluble than either sylvite or halite. Most often, it can be upgraded to 22% K_2O levels by selective dissolution of the more soluble minerals. However, polyhalite ($K_2SO_4 \cdot MgSO_4 \cdot 2CaSO_4 \cdot 2H_2O$), a frequent impurity, has solubility similar to langbeinite and may be difficult to remove.

Alternatively, because langbeinite has higher specific gravity (S.G. 2.83) than either sylvite (S.G. 1.99) or halite (S.G. 2.16), it can be separated from mixed ores using heavy-media separation processes in coarse sizes (Zandon, 1985). Langbeinite fines can be further beneficiated using anionic collectors (fatty acids) in conventional flotation circuits. The world's first langbeinite flotation circuit and a heavy-media circuit were installed at IMC's Carlsbad plant during the mid-60s, but the details of these operations have not been disclosed.

Excellent reviews on potash resources and potash processing are available in the readily accessible literature (Williams-Stroud et al., 1994; Sullivan and Michael, 1986; Zandon, 1985). Therefore, only a brief review of the recent advances in basic theory and processing technology, as it pertains to the Carlsbad District, is given in this report.

Flotation chemistry

Recently, non-equilibrium electrokinetic mobility measurements with a laser-Doppler electrophoresis technique allowed determination of dynamic surface charges of alkali halides in their saturated solutions (Yalamanchilli et al., 1993). It has been shown that, contrary to previously advanced theories (Roman et al., 1968), the surface charge of KCl is negative in KCl–NaCl saturated brine, whereas NaCl is positively charged. Furthermore, it is well known that KCl flotation occurs when amine concentrations exceed their solubility limits and micelle formation takes place. Recently, it was also shown that collector colloids exhibit distinct electrochemical properties; the iso-electric-point (iep) for dodecylamine is around pH 11 and iep's for other long chain amines are in the pH range from 10.2 to 11. Up to pH 11 these colloids are positively charged, and it is exactly at this pH that flotation of KCl ceases and flotation of NaCl begins. Therefore, it is concluded that collector colloids, rather than collector ions, affect the flotation of these salts (Laskowski, 1994).

An excess of potential-determining ions (i.e. K^+ and Na^+) can also change the surface charge of these salts. In addition, the presence of carnallite ($KCl \cdot MgCl_2 \cdot 6H_2O$) (or kieserite [$MgSO_4 \cdot H_2O$]) also effect the flotation of sylvite ores. The solubilities of both KCl and NaCl are drastically reduced in the presence of Mg^{2+} ions. A few percent $MgCl_2$ in KCl+NaCl brine, or sulfate-ion concentration in brine exceeding 2.5%, also depress sylvite flotation. These effects are more pronounced in the presence of carbonaceous clays (Laskowski, 1994). A better understanding of flotation chemistry may thus lead in the future to better plant control and improved recoveries.

Insoluble slimes/carnallite flotation

Identifying insoluble slimes and clay minerals in sylvinite ores, and the mechanism of collector absorption on different clays, have enabled Russian researchers to formulate reagents for better control of clay flotation using polymeric flocculants. These improvements have reportedly resulted in 20–40% decrease in collector consumption (Arsentiev and Leja, 1977). The U.S. Bureau of Mines researchers studied carnallite flotation and separation of clay minerals (Thompson and Huiatt, 1979; Foot et al., 1982, 1984). Continuous pilot-plant studies comparing (1) depression of insoluble slimes and direct flotation of carnallite, and (2) flotation of insoluble slimes before carnallite flotation resulted in similar recoveries and products. Carnallite is the major potash mineral that occurs with kieserite at the second, sixth, ninth, and eleventh ore zones in the District (Griswold, 1982). It is not mined commercially in this district, but it occurs as an impurity in sylvinite ores in some ore zones. High concentrations of carnallite adversely affect the sylvite flotation and may necessitate the installation of a pre-leach or bleed circuit before flotation (Zandon, 1985).

Flotation technology

Column flotation pilot-plant trials in Canada (Aliaga and Soto, 1993) and England (Burns et al., 1994) have shown better recoveries for coarse (+1.19 mm) particles, improved recoveries of fines (+5%), improved product grade, reduced insol recovery, and reduced power costs. These improvements justified replacement of two banks of rougher cells and one bank of cleaner cells with column cells at the Cleveland Potash, Ltd. plant (Burns et al., 1994).

Decreasing ore grades in the Carlsbad District would require finer grinding of ores to meet the product grade standard. It is, therefore, reasonable to assume that most flotation circuits in the District would benefit from the column cell technology, and it is likely that aging mechanical cells will eventually be replaced by column cells, particularly in the cleaning circuits.

Plant control

IMC Esterhazy operations improved plant efficiency by on-stream analysis of ore, improved flotation reagents and reagent control, centralized process control, and improved energy efficiency of the operation (Mayor, 1983). Implementation of such modifications in process control can be expected in most operations in the Carlsbad District.

Electrostatic separation

Potash operations in Germany (Singewald and Neitzel, 1983) and pilot plant trials at PCS Mining in Canada (Larmour, 1983) have shown that electrostatic separation is a viable alternative to flotation and heavy-media processes. The advantages to be gained by dry processing are both environmentally and economically significant. The process requires conditioning the ore with reagents in a controlled-humidity environment, and passing the ore through a separator where different minerals are attracted to oppositely charged electrodes. Reportedly, this process was developed and extensively tested in pilot-plant trials at IMC's Carlsbad plant, but the details of these tests have not been disclosed (Zandon, 1985).

Heavy-media separation

As discussed above, heavy-media separation (HMS) is used in the Carlsbad District for langbeinite processing. In this process, a fine suspension of magnetite is used to provide a medium in which the coarse heavy mineral (langbeinite) sinks and the light minerals (sylvite, halite) float. Usually, a cone- or drum-type vessel is used to facilitate separation and the medium (magnetite) is recovered from the screen undersize by magnetic separators. Heavy-media cyclones, which are widely used in coal cleaning, can exploit much smaller differences in the specific gravity of the minerals than conventional separators. For example, IMC's Esterhazy operations in Canada reportedly produce substantial tonnages of crystalline muriate from sylvinite ores (Zandon, 1985). Sylvinite ores in the Carlsbad District are known to have finer grain size than the Esterhazy ores, however, potential exists for wider use of heavy-media processes, particularly in langbeinite preconcentration prior to leaching and in processing mixed ores.

Solution mining, purification, crystallization

Thinly-bedded deposits, scarcity of fresh-water supplies, and high solution temperatures resulting in high salt solubility, render solution mining unlikely in the Carlsbad District (Davis and Shock, 1970; Husband, 1973). However, it is possible to envision wider use of solar energy and utilization of some technologies related to solution mining, such as solvent extraction (Rice and Chapman, 1990), to affect solution purification, concentration, and crystallization processes.

Discussion

Although there have been significant advances in understanding the mechanism of soluble-salt flotation and innovations in potash-processing technology, these advances are not expected to have an immediate impact on the Carlsbad Potash District. The declining sylvinite ore reserves, thinly bedded deposits of ancillary potash minerals in the District, and the proximity of vast Canadian potash reserves and abundant supplies render major changes in processing technologies in the Carlsbad District highly unlikely.

The Carlsbad Potash District operators, however, have traditionally been highly innovative and adaptive to changing market conditions. It is reasonable to assume that some of the new technologies, such as column flotation and heavy-media cyclone separation processes, would be implemented in the District. Nevertheless, these developments should not affect the ore-reserve calculations as far as the mineral potential of the WIPP site is concerned.

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Evaluation of Mineral Resources at the
Waste Isolation Pilot Plant (WIPP) Site

Chapter VI

MINING TECHNOLOGY

by

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OUTLINE OF MINING IN THE CARLSBAD POTASH DISTRICT

The early years

An excellent overview from the initial potash-ore discovery in 1925 up to 1990 has been given by Austin and Barker (1990). Production commenced in 1931 with sylvite mining from the 1st ore zone. By 1940 three companies were operating, and mining of langbeinite as well as sylvite was underway. The peak production year was in 1966 when a total of seven companies hoisted over 20 million tons that produced 5.1 million tons of marketable sylvite and langbeinite products worth $390 million in equivalent 1993 dollars. The total tons of product sold since startup through 1993 had a total market value of almost $14 billion in equivalent 1993 dollars. A complete history of production data is given in **Table 1**.

The Carlsbad miners faced a period of readjustment from 1972 through 1985 to allow for an oversupply of muriate due to the coming on stream of vast sylvite deposits in Canada. A series of trade agreements negotiated between the U.S. and Canada stabilized the market. These agreements were included in the recently signed North American Free Trade Agreement (NAFTA), so the future appears to be one of stability.

Current status

At present, five Carlsbad potash producers are operating: IMC Fertilizer, Inc., Eddy Potash, New Mexico Potash, Western Ag-Minerals, and Mississippi Potash (**Table 2**).

Langbeinite production data are not released by the State or the U.S. Bureau of Mines to protect the privacy of the two producing companies. Instead, these agencies report an aggregate production of the three products produced: muriate (sylvite), langbeinite, and manufactured K_2SO_4. However, a reasonable estimate is on the order of 1,000,000 tons of langbeinite, and K_2SO_4 products are now equivalent to one-third of all the Carlsbad production. The percent of sales value is slightly higher. It is important to note that langbeinite is produced only at Carlsbad. Occurrences are known elsewhere in the world, but production from them is minimal.

The five operating companies are vertically integrated, i.e. they mine, process, transport, and market agricultural fertilizers. The industry is quite competitive both on national and international scales, and it would be difficult for a new company to enter into potash mining in Carlsbad without the marketing capabilities that the current operators possess. This includes expertise in and production of other chemical fertilizers such as ammonium nitrate and phosphates. Most farmers fertilize their fields with mixes of these three chemicals plus others, so having production capabilities in all three is a distinct advantage.

The production capacity at Carlsbad is larger than that shown in **Table 2**, and this is true throughout the world. The reasons are twofold: first, there was a tendency to overexpand during the 1960s in the U.S., Canada, and elsewhere; and second, agriculture historically goes through cycles, both nationally and worldwide. Therefore, having surplus capacity is a must if a producer wishes to always satisfy (and thereby keep) its customers. The capital expense for constructing the processing plants has been amortized long ago, so having surplus capacity does not affect current operating cost on a ton-produced basis. However, the Carlsbad workforce has constricted since 1965, when it peaked at 3760, down to a current force of about 1400.

A unique feature of the chemical-fertilizer industry is the need for vast warehousing of products so as to maintain a steady production rate at the mines and plants while accommodating the farmers' cyclical needs for those products during the year. This explains the large warehouse structures that one sees at Carlsbad mines. A rule-of-thumb is that storage capacity amounts to about one-half of annual production capacity. The warehouses are full at the end of a calendar year and depleted by mid-summer.

Carlsbad in relation to other producing areas

The Carlsbad operators have been providing about 85% of domestic production, but that production falls far short of the nation's need for potassium-chloride fertilizer. Therefore, even if the four sylvite mines were operating at full capacity, there still would be the need for imports of muriate. The nation's needs for potassium sulfates (as either langbeinite or K_2SO_4) could be met because the two producers (IMC and Western Ag-Minerals) are in fact the world's largest suppliers of that special mineral. It is estimated that more than one-third of the langbeinite is exported, and the demand is growing on a worldwide basis. **Table 3** summarizes the last available data, i.e. 1988 through 1992. (*Table 3 comes directly from USBM-Potash-1992.*)

Most of Carlsbad's muriate is shipped by rail to farm consumers in the southern and coastal states. Shipments are increasingly being made by trucks because such a mode allows for the product to go directly to the fields, bypassing interim storage points. Langbeinite finds its principal use on citrus and tobacco crops, so again much of this product (and manufactured K_2SO_4) goes to the south. Langbeinite and K_2SO_4 are exported, with China, Japan, and Canada being the largest recent consumers. A full description of the potash-fertilizer industry is given annually by the U.S. Bureau of Mines. As of this writing, the 1992 report is the latest available and is the sole source of the information in **Table 3**.

Outlook for the future

The muriate production appears to be secure and stable for the foreseeable future. The Carlsbad mines have a freight advantage over imports from Canada. Much attention has focused on imports from Europe, particularly from the former U.S.S.R. There may be brief periods of dumping of muriate from those sources. However, the mines in Belarus have to transport and market the product through other newly independent states, each of which will seek a share of export earnings, this makes that supply not much of a threat to Carlsbad. The deposits in the Urals are burdened by a long rail route to export ports.In Thailand and Laos the known deposits are carnallite, which requires more expensive processing. When developed, these resources will no doubt find their buyers within the rapidly expanding Asian markets.

The outlook for langbeinite must be considered as bright until a new discovery is made elsewhere. Such a discovery is most likely to occur in the former U.S.S.R., but it would be plagued with the same complexity of mining, transport, and marketing as are their vast sylvite deposits.

Finally, the demand for chemical fertilizers will continue to grow in parallel with the world's population and even more so as underdeveloped nations attempt to become more efficient in their farming methods and land resources for such activity continues to shrink. The world's known potash production and reserves were reported by the USBM in Table 2 of their WIPP potash evaluation (Weisner et al., 1978). If correct, then the reserves are capable of supplying potash for the world's markets for the next 400 yrs.

The reserves in the Carlsbad District have been estimated at around 51 million tons equivalent K_2O (EMNRD, 1992). The life of the district would be on the order of 25 yrs from present. However, Austin and Barker (1990) have pointed out that longevity of individual mines varies considerably, with one lasting less than a decade and another over 100 yrs.

CURRENT MINING METHODS

Conventional mining—Conventional mining is a term often used in the Carlsbad mines to define the undercut-drill-blast-load-transport-convey mining method. In fact, this system is now limited to hard langbeinite ore mining only, so it is not the most common mining method currently used because sylvite ores are mined with drum mining machines. Nonetheless, a description of the conventional system is worthwhile in that it was used to evaluate the economics of mining and processing the 4th ore zone langbeinite resources in the WIPP area.

Figure 1 is a rather typical layout for conventional mining. The method is room and pillar. Pillar dimensions range from 30 to as much as 60 ft on a side depending on mining depth and extraction ratio. The pillars can be equidimensional or rectangular, but the aspect ratio is always near 1.0. Room widths hold fairly close to 28 ft. **Figure 1**

shows barrier pillars, but their use is not universal and later pillar extraction is always contemplated. For langbeinite ores the maximum pillar load is limited to about 4000 psi. The mining depth of the 4th ore zone in the WIPP area ranges from 1650 to 1850 ft. At that depth, the extraction for conventional room and pillar mining would be about 50%; however, 60% could be achieved if advance is rapid or if a retreat mining method is utilized.

A typical mining crew for conventional mining of langbeinite ores would consist of:

1- Undercut machine operator	1-Roof bolt operator
1- Drill jumbo operator	1-Relief person
1- Explosives person	1- Electrician
1- Arm-type loader operator	1- Mechanic
2- Shuttle car operators	1- Foreman

This 11 man crew can mine on the order of 1500 to 2000 tons in a 10-hour shift. Incidentally, 10-hour shifts have become rather common for underground personnel at Carlsbad mines in recent years. At one mine the total mine work force from Superintendent down to the relief worker hovers around 100 and that mine produces on the order of 1.3 million tons of raw ore annually. The traditional 2080 hours per employee year translates into an overall mine production rate of 6.25 tons per man-hour. At another mine, using similar methods but with better equipment, the productivity is probably around 10 tons per man-hour. Therefore, productivity is rather high at Carlsbad for underground mining using the conventional method.

Partial pillar extraction has been proven feasible at moderate depths in Carlsbad and in areas where there is little danger of flooding from overlying brine aquifers. The total extraction has reached over 80% of the in-place reserves. Surface subsidence does occur when pillars are extracted.

Mining heights reach the full thickness of the ore bed which on occasion becomes as much a 12 ft, but a more typical mining height is in the range of 6 to 8 ft. The size of the current ram or shuttle cars limits mining to no less than 5 ft. The ore mined by blasting can contain large fragments, so breakers are installed at all belt-feeder locations.

Continuous mining using drum miners—Most of the sylvite ores are being mined with the use of continuous mining methods utilizing drum miners. Extendible conveyor systems have been introduced in recent years so that the drum miners feed directly onto conveyors. One company utilizes diesel-powered ram cars that tram short distances to belt feeders. **Figures 2 and 3** show typical mine layouts. Long (up to 5000 ft) panels are mined in a retreating chevron or "herringbone" pattern. When mining sylvite at moderate depths (800 to 1200 ft) the extraction can exceed 90%. In deeper locations, barrier pillars are used to give long-term protection of beltways, in which case the overall extraction drops to about 80% but some of the barriers can be recovered.

One company has automated to the fullest possible extent the operation of the continuous mining machine and the mobile and extendible feed conveyor, so that only two people are required at the mining face. Another company using a similar but more fully controllable extendible conveyor needs four people at the face. Productivity per mining-face operator is as much as 50 tons per man-hour with either of these systems.

Continuous mining is ideal for thin ore seams. Currently, the mining height is as low as 4.5 ft, and the equipment in use can mine as low as 4.0 ft. Immediate subsidence occurs over the mined area. A general rule is that the surface expression of subsidence over high extraction areas amounts to 50–75% of the thickness mined.

Mineral processing—A separate section describes potash mineral processing, but an overview of the process that would be used for the specific langbeinite and mixed sylvite-langbeinite ores that are common in the WIPP area is included here because that type of plant was used in this economic evaluation. **Figure 4** is a simple flow sheet that is being used by IMC Fertilizer, Inc. to treat mixed ores. If the ore is just langbeinite, then it is treated by a rather simple but carefully controlled leaching method to produce as many as four final products depending on the grain-sizes of the raw ore.

If the ore is mixed, then it is first passed through a heavy media circuit to separate the two ore minerals. The heavy fraction (langbeinite-bearing) is passed back into the langbeinite-processing part of the plant. The sylvite fraction is concentrated by flotation. Additional langbeinite that escaped separation in the heavy media plant is recovered by refloation of the sylvite tailing. The recovered product is passed back in the langbeinite circuit.

An important ability of the IMC process is to combine the fine-particle products from both the langbeinite and sylvite circuits for additional treatment in a separate (not shown in **Figure 4**) part of the plant to manufacture K_2SO_4 product. The exact process is held proprietary to IMC; however, the process includes a first step of hydrating the langbeinite followed by reaction with dissolved sylvite to form K_2SO_4 and $MgCl_2$.

Hence, three products are produced from a mixed ore: sylvite, langbeinite, and manufactured arcanite (K_2SO_4). If the ores present within the WIPP area are mined, then the IMC method of treating mixed ores could be utilized.

ESTIMATION OF MINING, PROCESSING, AND CAPITAL COSTS

Total mining and processing cost was estimated on the basis of direct operating expense exclusive of both Federal and State income taxes. Also not included are local county taxes. However, the selling price for products was reduced 3% to account for royalties, rentals, and resource and severance taxes that are paid to Federal and State governments. Direct operating cost does include all costs including normal repair and maintenance, and periodic replacement of mining and processing components, but it does not include the major capital cost of initial installation and equipping the mine or processing plant.

Engineering economic analyses were done for three scenarios of potash resource development: Scenario I - mining encroaches into the area from a nearby mine in which there is no development cost. Scenario II - Mining encroaches into the area, but there is the need for a new shaft to provide quick access for mining crews and equipment plus improvement of ventilation. And Scenario III, where a new mining and processing plant is to be constructed solely for exploitation of the resources in the WIPP area.

The first two scenarios are more likely to occur, and Scenario III presents a case that would occur only if mining had ceased for whatever reason in the Carlsbad area for an extended period of time. The orebodies evaluated extend both north and south into currently active mines, so the conclusion was that the most logical and economic means for resources in the WIPP area to be mined will be by extension of existing operations rather than by developing an entirely new facility.

After considerable discussions with local mine operators, total mining and processing costs were set for the 4th and 10th ore zones. The final assumptions are given in **Table 4**. The input from the mining companies was helpful, but the marketing of potash products makes these operators direct competitors, which prevents them from offering precise costs. Therefore, the assumptions given in **Table 4** but they are within the realistic range of cost for the mining and processing methods that are currently used in the Carlsbad area.

4th ore zone—Two mining methods were selected for exploitation of the langbeinite-dominant ores of the 4th ore zone in the WIPP area. One was conventional mining with the mining height maintained at 6.0 ft. The second method assumed that heavy drum miners can be developed in the near future to allow continuous mining at 4.5 ft height. Three extractions: 60, 80, and 90%, depending on the mining method used. Plant recovery was held at 85% for all three cases.

10th ore zone—The 10th ore zone could be extracted by the more economical continuous mining method and at a high extraction of 90% of the in-place reserve. The lower mining and processing cost is justified because of the mining efficiency of the continuous mining method, but the recovery is dropped to 80% because much of the ore is mixed and in places contains considerable amounts of insolubles.

Market prices for products

Langbeinite along with a varying amount of manufactured K_2SO_4 would be sold at f.o.b. at the plant site for $74.80 per ton of product containing 22% K_2O. For sylvite the selling price was set at $72.00 per ton of product containing 60% K_2O. These prices are net after deduction of 3% for royalties and production taxes. On a per unit basis (defined as the value of 1% K_2O contained in the product) the net selling prices are $3.40 per unit K_2O in langbeinite and $1.20 per unit K_2O in sylvite products. Market prices have varied over a considerable range, but this is the best estimate of the current price in relationship to cost. The prices fall well within the high and low averages over the last 12 years (see **Table 1**).

Estimate of capacity

The reserves of the 4th and 10th ore zones are large, and no attempted was made to optimize the production rate to maximize profit in terms of rate of return of invested capital. Instead, the capacity of the langbeinite was set at 350,000 product (containing 22% K_2O) tons per year, which is equivalent to about one-third of the current production of the entire Carlsbad Potash District. For 10th ore zone sylvite reserves, the annual capacity was set at 400,000 tons muriate (containing 60% K_2O). These production rates are within a range compatible with future markets for Carlsbad potash products, assuming that the current mines are depleting current reserves.

An assumption was made that the reserves would be mined by a single operator. The reserves of both the 4th and 10th ore zones are adjacent and to a certain extent stacked, i.e. the 10th overlying the 4th.

Estimate of development cost and time to bring into production

For Scenario II, the cost of sinking a new man-shaft 1900 ft deep was estimated at $10 million and the time required to commence mining as one year. In that scenario, underground mining would be simultaneously extended into the area from IMC Fertilizer Inc. mining operations that had mined up to the southern and eastern boundaries of the WIPP Site. A precise location was not selected for the new shaft other than that it be located just northwest and outside WIPP.

For Scenario III, an estimate of $200 per annual ton of plant product capacity resulted in $70 million for the portion devoted to production of the 4th ore zone langbeinite reserves and $80 million for the sylvite reserves of the 10th. The total of $150 million would include two new shafts in addition to the processing plant. Three years would be needed to bring the new mine on stream. Some may say these costs are low for a new "greenfield" plant, but in actuality they may be too high because the new plant would probably involve modernization and expansion at an existing plant site where power, railhead, warehouses, and waste disposal facilities already existed.

Historical trend of mining and processing cost versus market price

The data presented in **Table 1** indicates that the operators have remained competitive over the years. As costs have increased so have productivity and market price. The price of the products was compared against the Composite Producers Price Index and a linear relationship indicated that the price of Carlsbad potash products had escalated in parallel with national inflation trends. As mining and processing costs increase for the Carlsbad producers, so will the price of their products.

Therefore, the engineering economic evaluations that follow assume that the differential between cost and sales will remain constant in the future. No allowance for inflation (or deflation) was used in the analysis. Additional economic evaluations that assume probable fluctuations in costs and sales are given in another section of this study (see Peter Anselmo, Section XIII).

ENGINEERING ECONOMIC EVALUATION OF POTASH RESERVES

Simple discounted cash-flow analyses were performed on the known potash resources, which allowed a determination of what portion of those resources could be defined as reserves using economic criteria that exist in the nearby mines. These criteria are given in **Table 4**.

Tables 5 through 16 present the results of three cases for mining methods and three development scenarios. The evaluations were done for three areas: within *WIPP*, the *additional study area*, and the total of the two which were called the *combined study area*. The results are summarized in **Table 17**.

Assignment of discount factor

A straightforward cash-flow analysis was used with a discount factor of 10%. Higher and lower discounts could be used, but the results would show the same trend. In other words, a higher discount rate will lower the present value of a particular product, but it will not change the cut-off grade or tons of reserve determination.

There is little inherent risk involved in developing the reserves because the volume and grade of the reserve are reasonably well defined and the experience gained by mining similar deposits in nearby mines indicates that the mining and processing costs used are in the same range as those operations.

CONCLUSIONS

Reserves within WIPP

None of the resources within WIPP met the criteria set for Scenario III. In that scenario an entirely new mine and processing plant would need to be constructed at a total cost of $150 million, with $70 million shared for the 4th ore zone and $80 million for the 10th ore zone. This finding is in essential agreement with the previous evaluation by the US Bureau of Mines.

Both the 4th and 10th ore zones met the criteria for Scenarios I and II. These are the two most likely scenarios for future development because they would probably be mined in conjunction with the much larger reserves that lie outside of the WIPP area.

Additional study area

For Scenarios I and II both the 4th and 10th ore zones were found to well exceed the economic criteria placed on their development. For Scenario III, the 10th ore zone was not econom... but the 4th would be viable even for Case 1 type mining, which would return in... ments at just a fraction below 10%.

Combined study area

The 4th ore zone is viable for all cases and scenarios. The 10th ore zone met the criteria except for Scenario III.

The effect of changes of mining and processing costs

The profit margin was determined as a function of ore grade. Profit margin is simply defined as the percentage by which the product sales exceed the mining and processing costs. The results of these calculations are given in Table **18**. The profit margin was used to determine cut-off grades. For the 4th ore zone 6.25% K_2O was selected as the cut-off, and for 10th ore zone 12.25% K_2O was selected. The same calculations were done assuming that the mining and processing costs were 10% higher and lower than the "base case." As expected, the cut-off grade became higher for the higher cost and lower for the lower costs.

Table 19 combines information from **Table 18** with the cash flow calculations given in **Tables 5 through 16**. The mining life for all the cases and scenarios are long except for those reserves within the WIPP boundary. For example, the mining life for the 4th ore zone that lies in the "Additional Area" ranges from 26 to as much as 70 years depending on which condition would prevail. For the 10th ore zone the mining life ranges from 27 to 58 years.

Therefore, direct engineering case flow calculations are not well suited to determining the actual value of the large and potentially profitable in-place resources at WIPP. Even using the modest discount rate of 10% means that $1.00 of earnings 10 years into the future has a present day value of $0.39, $1.00 in 20 years is worth $0.15, $1.00 in 30 years is worth $0.06, and by 40 years the present value almost disappears being worth only $0.02. Caution should be used with using the engineering economic evaluations given above.

Instead, actual exploitation of the potash resources will depend on factors such as future markets, the ability to actually acquire the mining leases in competition with those who also wish to the exploit known oil and gas resources, and when the potash would be needed to replace ore now being produced at neighboring mines. However, much of the potash resources in the WIPP area could be mined at a profit.

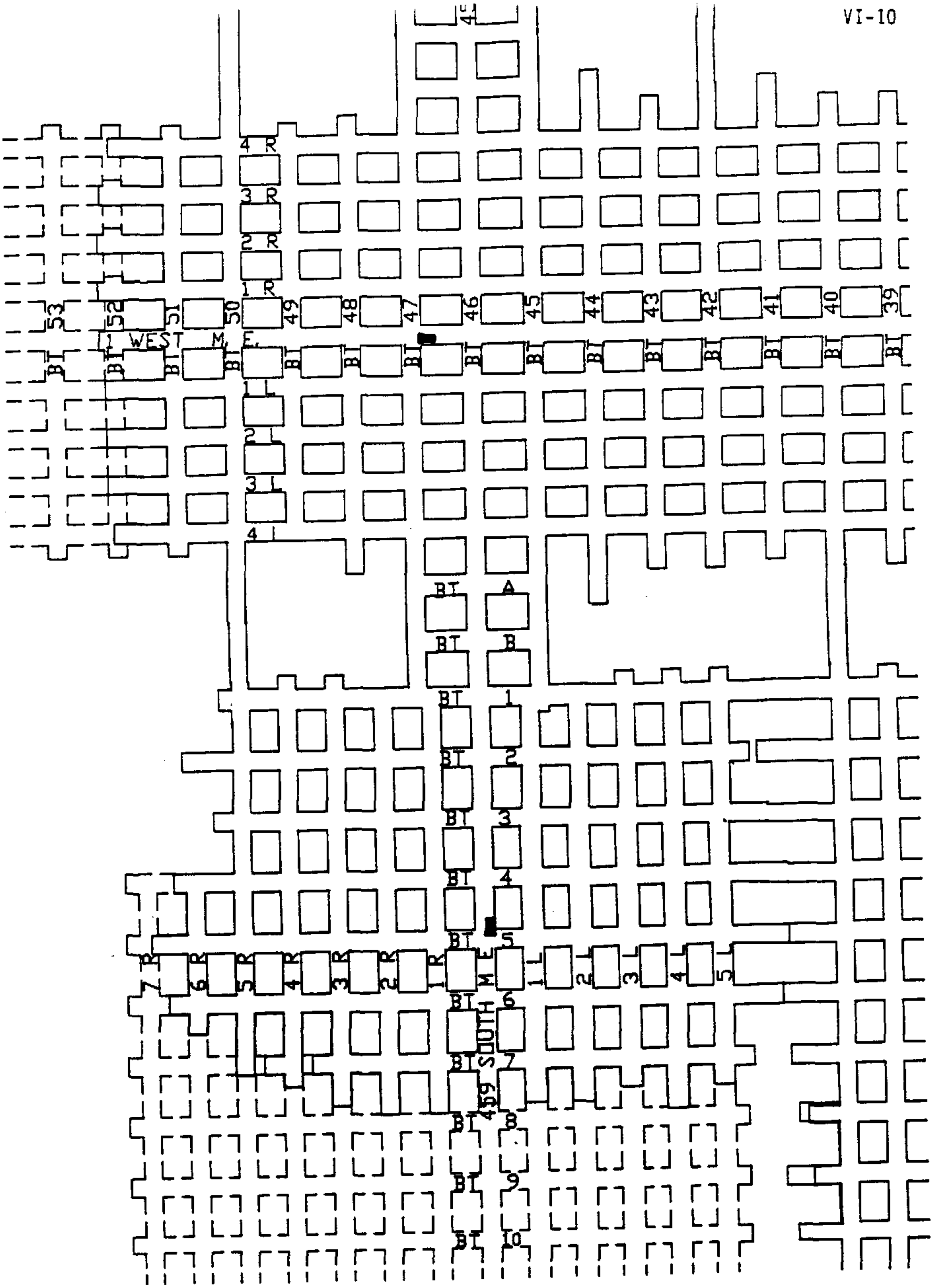


Figure 1. Room and pillar mining. Scale: 1" = 200'.

Figure 2. Continuous mining. Scale: 1" = 1000'.

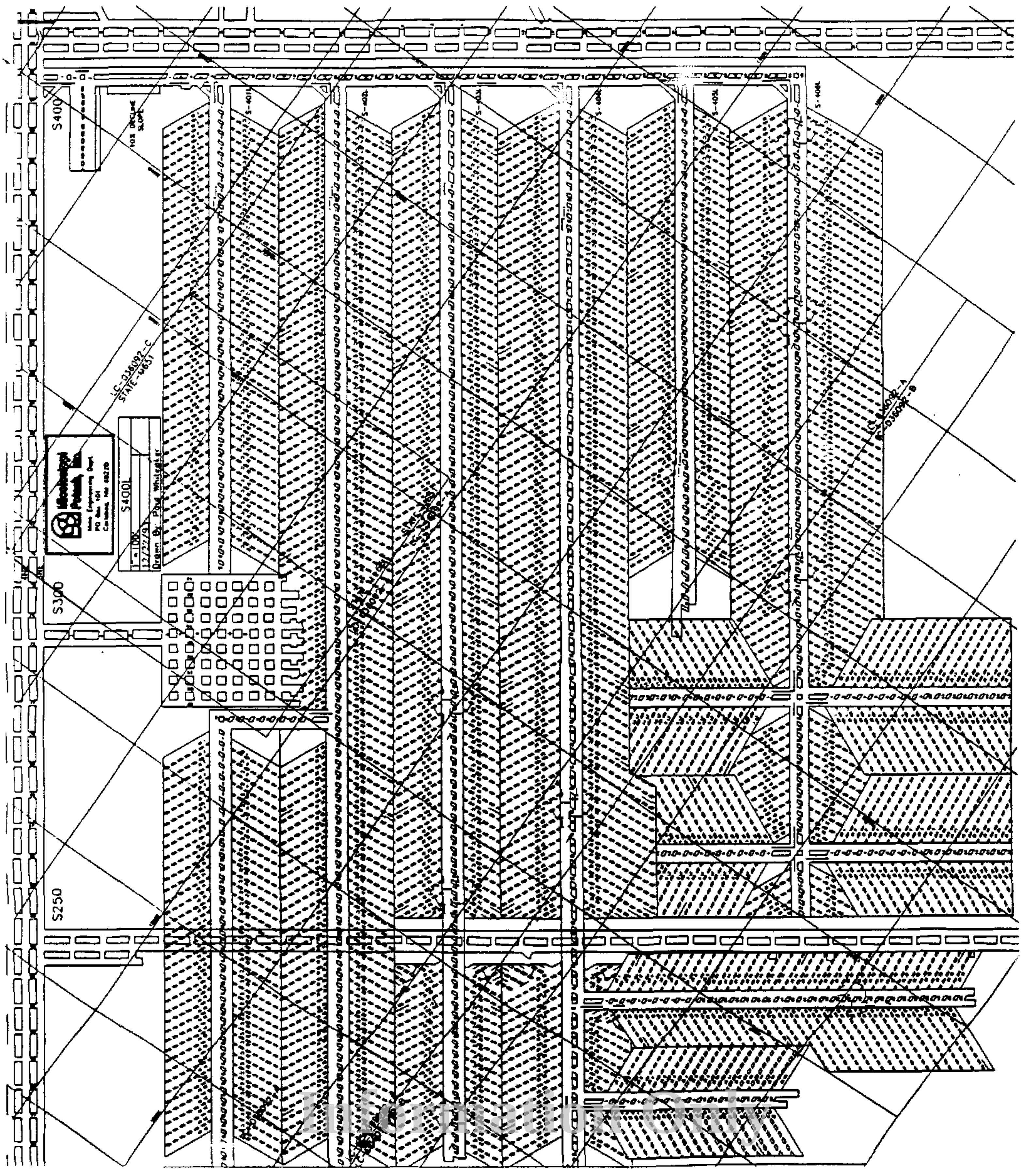
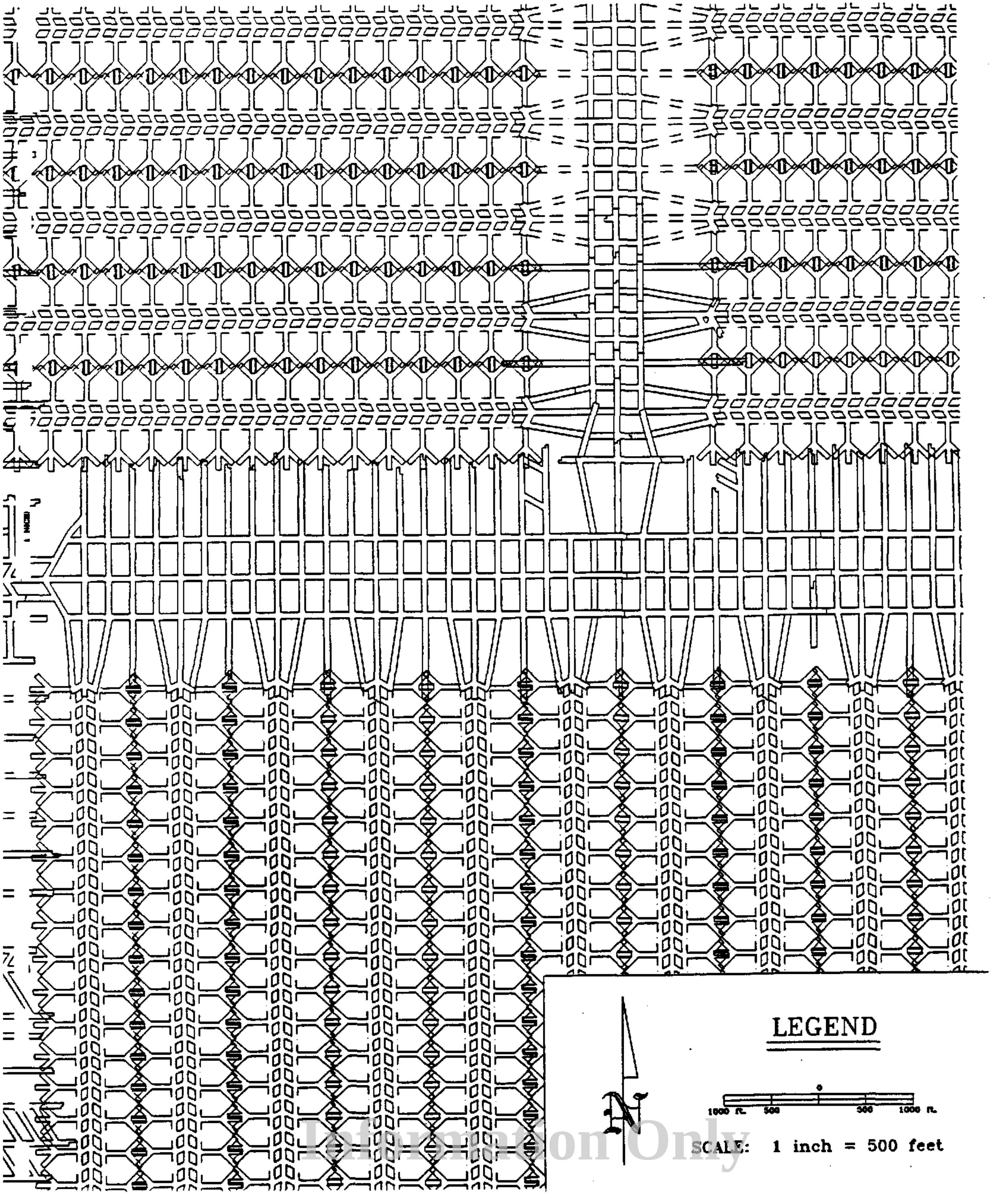


Figure 3. Continuous mining with barrier pillars.



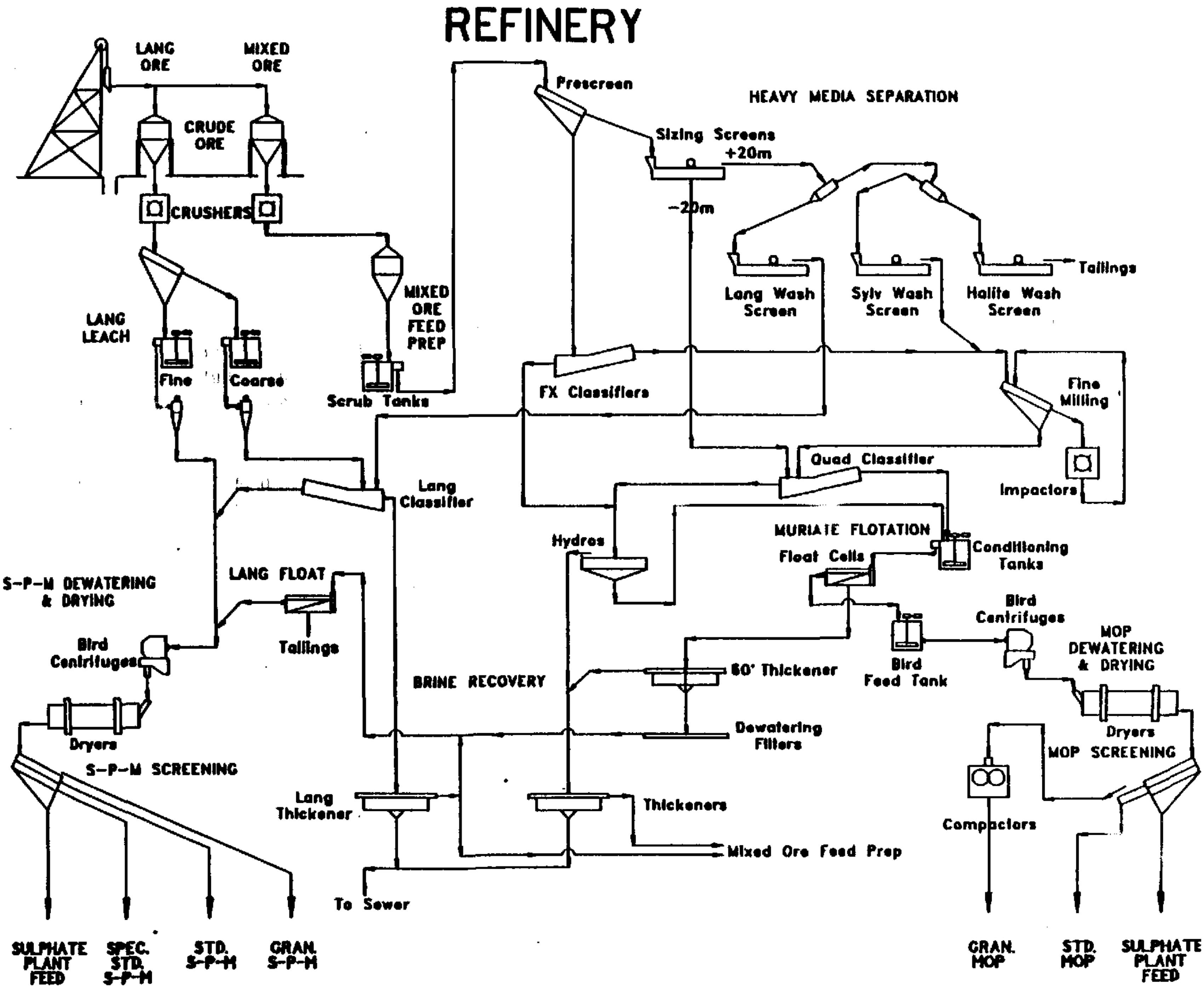


Figure 4. Mineral processing for mixed ore.

Table 1. Carlsbad Potash Production and Productivity From 1932 to 1993

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1	Year	Tons Product	Tons K20	Value	Ore Tons	Work	Product	Concentration	Price	Product	1993	Tons Ore	Tons Product	Year
2		Thousands	Thousands	$ Millions	Millions	Force	Grade	Ratio	Index	$/ton	$/ton	Man-Year	Man-Year	
3	1932		55	2.10					11.2					1932
4	1933		139	5.30					11.4					1933
5	1934		114	2.81					12.9					1934
6	1935		193	5.00	0.500				13.8					1935
7	1936		247	6.97	0.600				13.9					1936
8	1937		284	9.02	0.700				13.9					1937
9	1938		317	9.75	0.900				13.5					1938
10	1939		312	12.00	0.900				13.3					1939
11	1940		380	12.60	1.200				13.5					1940
12	1941		434	14.10	2.270	1209			15.1			1878		1941
13	1942		549	19.60	3.060	1412			17.0			2167		1942
14	1943	1179	604	21.90	3.433	1487	51.23%	2.91	17.8	18.58	124.08	2309	793	1943
15	1944	1304	680	24.70	3.749	1362	52.15%	2.88	17.9	18.94	125.82	2753	957	1944
16	1945	1360	733	25.50	3.950	1527	53.90%	2.90	18.2	18.75	122.49	2587	891	1945
17	1946		789	27.20	4.310	1816			20.8			2373		1946
18	1947	1659	881	28.00	4.656	1900	53.10%	2.81	25.6	16.88	78.39	2451	873	1947
19	1948	1851	968	29.20	5.108	2354	52.30%	2.76	27.7	15.78	67.71	2170	786	1948
20	1949	1744	932	28.00	4.853	2473	53.44%	2.78	26.3	16.06	72.58	1962	705	1949
21	1950	1878	1073	31.90	5.802	2632	57.14%	3.09	27.3	16.99	73.98	2204	714	1950
22	1951	2126	1218	43.43	6.818	2805	57.29%	3.11	30.4	20.43	79.90	2359	758	1951
23	1952	2439	1411	52.48	7.853	3098	57.85%	3.22	29.6	21.52	86.43	2535	787	1952
24	1953	2662	1553	58.08	9.010	3595	58.33%	3.38	29.2	21.82	88.84	2506	740	1953
25	1954	2954	1732	64.37	9.750	3508	58.64%	3.30	29.3	21.79	86.43	2779	842	1954
26	1955	3098	1826	69.06	10.956	3408	58.94%	3.54	29.3	22.29	90.46	3215	909	1955
27	1956	3279	1931	72.80	11.941	3591	58.69%	3.64	30.3	22.20	87.12	3325	913	1956
28	1957	3353	1977	73.24	12.895	3438	58.96%	3.85	31.2	21.84	83.24	3751	975	1957
29	1958	3650	2157	75.34	12.224	3345	59.10%	3.35	31.6	20.64	77.67	3654	1091	1958
30	1959	3821	2258	76.73	13.933	3201	59.09%	3.65	31.7	20.08	75.32	4353	1194	1959
31	1960	4092	2412	78.71	15.071	3380	58.94%	3.68	31.7	19.24	72.15	4459	1211	1960
32	1961	3882	2281	87.42	15.653	3542	58.76%	4.03	31.6	22.52	84.73	4419	1096	1961
33	1962	4206	2478	95.85	14.115	3575	58.87%	3.36	31.7	22.79	65.48	3948	1177	1962
34	1963	4213	2484	94.23	16.414	3582	58.96%	3.90	31.6	22.37	84.16	4582	1176	1963
35	1964	4815	2814	110.77	17.356	3590	58.44%	3.60	31.6	23.01	86.58	4835	1341	1964
36	1965	4607	2877	110.42	18.557	3759	58.11%	4.03	32.3	23.97	88.23	4937	1226	1965
37	1966	4872	2827	104.67	20.105	3619	58.03%	4.13	33.3	21.48	76.71	5555	1346	1966
38	1967	4797	2784	88.79	18.906	3479	58.04%	3.94	33.4	18.51	65.89	5434	1379	1967
39	1968	4425	2511	70.20	15.092	2773	56.75%	3.41	34.2	15.86	55.15	5442	1596	1968
40	1969	4433	2521	64.86	15.519	2824	56.87%	3.50	35.6	14.63	48.87	5914	1569	1969
41	1970	3966	2227	78.30	16.246	2645	56.15%	4.10	36.9	19.74	63.62	6142	1499	1970
42	1971	4101	2317	89.32	16.117	2646	56.50%	3.93	38.1	21.78	67.97	6091	1550	1971
43	1972	4089	2285	89.86	17.285	2583	55.88%	4.23	39.6	21.98	65.65	6744	1585	1972
44	1973	4414	2422	103.04	17.092	2694	54.87%	3.87	45.0	23.34	61.68	5906	1525	1973
45	1974	3885	2061	126.62	17.209	2801	53.05%	4.43	53.5	32.59	72.43	6143	1387	1974
46	1975	3221	1749	150.62	17.809	2953	54.30%	5.53	58.4	46.76	95.21	6031	1091	1975
47	1976	3889	2083	165.35	17.308	3058	53.56%	4.45	61.1	42.52	82.74	5660	1272	1976
48	1977	4012	2085	169.62	18.985	3104	51.97%	4.73	64.9	42.28	77.46	6116	1293	1977
49	1978	3717	1943	163.55	17.500	2848	52.27%	4.71	69.9	44.80	76.20	6776	1440	1978
50	1979	3873	2005	228.79	17.353	2724	51.77%	4.48	78.7	53.59	80.96	7022	1567	1979
51	1980	3845	1869	269.00	18.031	2874	51.28%	4.95	89.8	71.93	95.24	8916	1396	1980
52	1981	3118	1601	281.23	18.490	3079	51.35%	5.93	98.0	78.01	92.22	8628	1118	1981
53	1982	2872	1497	204.80	15.691	2660	52.12%	5.46	100.0	64.83	76.84	8502	1190	1982
54	1983	2525	1278	174.70	12.440	1644	50.61%	4.93	101.3	62.77	73.67	8341	1693	1983
55	1984	2799	1416	204.10	14.112	1641	50.66%	5.04	103.7	66.15	75.85	9479	1880	1984
56	1985	2249	1120	156.00	11.312	1329	49.80%	5.03	103.2	62.93	72.50	9382	1865	1985
57	1986	2013	987	132.90	9.779	1170	49.03%	4.86	102.2	59.89	69.88	9213	1897	1986
58	1987	2627	1323	174.20	11.400	1329	50.36%	4.34	102.8	60.18	69.58	9455	2179	1987
59	1988	2535	1271	213.90	12.508	1327	50.14%	4.93	104.8	76.51	85.10	10390	2106	1988
60	1989	2711	1365	242.62	14.167	1616	50.35%	5.23	112.2	81.19	88.04	9646	1849	1989
61	1990	2918	1451	245.57	14.891	1644	49.73%	5.12	116.3	76.35	78.05	10011	1957	1990
62	1991	2895	1470	250.87	16.296	1742	50.78%	5.63	116.5	78.61	80.23	10305	1832	1991
63	1992	2869	1436	250.62	16.039	1723	50.05%	5.59	117.2	81.14	82.32	10281	1835	1992
64	1993	2498	1190	215.90	12.963	1398	47.64%	5.19	119.8	78.41	78.41	10221	1970	1993
65									121.5					
66	Totals:		91987	6214	679									
67	Short Tons		94383		703									
68	1993 Dollars			13942										
69														
70	Column B, C and E	From USBM (short tons 1932-1977, metric after)												
71	Column C	From USBM (dollars in millions)												
72	Column F	From NM Mine Inspector 1941-1972, MSHA after												
73	Columns H thru M all based on short tons													
74														
75				Revised 1-31-95										

Table 2. Operating companies and their capacities

Company	Production (tons per yr)	Products
IMC Fertilizer, Inc.	1,100,000	muriate, langbeinite, potassium sulfate
Eddy Potash	450,000	muriate
New Mexico Potash	500,000	muriate
Western Ag-Minerals	375,000	langbeinite
Mississippi Potash	400,000	muriate
1993 Production	2,825,000 (estimate)	

Source: Austin and Barker (1990) and others.

Table 3. Salient potash[1] statistics. (Thousand metric tons and thousand dollars, unless otherwise specified.) (From USBM *Potash-1992.*)

	1988	1989	1990	1991	1992
United States:					
Production	2,999	3,132	3,360	3,446	3,341
K_2O equivalent	1,521	1,595	1,713	1,749	1,705
Sales by producers	2,802	3,008	3,391	3,327	3,467
K_2O equivalent	1,427	1,536	1,716	1,709	1,766
Value[2]	$240,300	$271,500	$303,300	[r]$304,500	$334,406
Average value per ton of product dollars	$85.75	$90.28	$89.46	$91.52	$96.45
Average value per ton of K_2O equivalent dollars	$168.37	$176.74	$176.80	$178.20	$189.36
Exports[3]	783	945	1,016	1,256	1,330
K_2O equivalent	380	446	470	624	663
Value[4]	NA	NA	$136,100	NA	NA
Imports for consumption[3, 5]	6,964	[6]5,618	6,952	[r]6,862	6,980
K_2O equivalent	4,217	[6]3,410	4,164	[r]4,158	4,227
Customs value	$623,000	$501,300	$545,700	$549,600	$577,800
Consumption, apparent[7]	8,983	[6]7,680	[r]9,327	[r]8,933	9,117
K_2O equivalent	5,264	[6]4,500	[r]5,410	[r]5,243	5,330
Yearend producers' stocks, K_2O equivalent	248	307	303	343	283
World: Production, marketable K_2O equivalent	[r]31,820	[r]28,916	[r]27,772	[r]26,094	[e]24,327

[e]Estimated. [r]Revised. NA Not available

[1] Includes muriate and sulfate of potash, potassium magnesium sulfate, and some parent salts. Excludes other chemical compounds containing potassium.

[2] F.o.b. mine.

[3] Excludes potassium chemicals and mixed fertilizers.

[4]F.a.s. U.S. port.

[5]Includes nitrate of potash.

[6]Imports probably underreported.

[7]Calculated from production plus imports minus exports plus or minus industry and Government stock changes.

Table 4. Summary of Operating and Development Factors

	A	B	C	D	E	F	G	H	I
1				4th Ore Zone (langbeinite)			10th Ore Zone (sylvite)		
2		Area of		Within	Additional	Entire	Within	Additional	Entire
3		Evaluation		WIPP	Area	Area	WIPP	Area	Area
4									
5		Plant Recovery, percent		85	85	85	80	80	80
6		Annual Production Rate, tons product		350000	350000	350000	400000	400000	400000
7		Cut-off Grade, %K20 (equivalent)		6.25	6.25	6.25	12.25	12.25	12.25
8		Net Selling Price, $ per ton product		74.80	74.80	74.80	72.00	72.00	72.00
9		Net Selling Price, $ per unit K20 per ton		3.40	3.40	3.40	1.20	1.20	1.20
10									
11		Mining Extraction, percent of in-place reserve							
12	Case 1	Conventional, no pillar extraction @ 6.0 ft.		60	60	60			
13	Case 2	Conventional, pillars extracted @ 6.0 ft.		80	80	80			
14	Case 3	Continuous Mining @ 4.5 ft.		90	90	90	90	90	90
15									
16		Mining and Processing Cost, $ per ton ore							
17	Case 1	Conventional, no pillar extraction @ 6.0 ft.		18.00	18.00	18.00			
18	Case 2	Conventional, pillars extracted @ 6.0 ft.		18.00	18.00	18.00			
19	Case 3	Continuous Mining @ 4.5 ft.		16.00	16.00	16.00	12.00	12.00	12.00
20									
21		Development Cost, dollars							
22	Scenario I	None required		0	0	0	0	0	0
23	Scenario II	New shaft only		5000000	5000000	5000000	5000000	5000000	5000000
24	Scenario III	New plant constructed		70000000	70000000	70000000	80000000	80000000	80000000
25									
26		Time to Develop, years							
27	Scenario I	None required		0.0	0.0	0.0	0.0	0.0	0.0
28	Scenario II	New shaft only		1.0	1.0	1.0	1.0	1.0	1.0
29	Scenario III	New plant constructed		3.0	3.0	3.0	3.0	3.0	3.0

Note: Net Selling Price is actual price sold fob at plant less 3 % to allow for royalties, resource and severence tax

Table 5. Case 1 - 4th ORE ZONE CASH FLOW (WIPP Area)
Mining Recovery = 60% and Mining Height = 6.0 Feet

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1													10 %	10 %
2	Grade	WIPP	In Place	Plant	Mine	Ratio	Product	Years	Mining	Tons	Annual	Profit	Avg	Present
3	% K20	Tons	Tons K20	Recov	Recov	Conc	Tons	Life	Years	Mined	Rate	For Period	PVF	Value Flow
4	3.25	8076268	262479	0.85	0.60	13.27	608473	1.74	17.58	4845761	2787330	-41709886	0.2035	-8486782
5	3.75	5045520	189207	0.85	0.60	11.50	438616	1.25	15.84	3027312	2415686	-21683122	0.2347	-5087949
6	4.25	5443080	231331	0.85	0.60	10.15	536267	1.53	14.58	3265848	2131488	-18672486	0.2680	-5003458
7	4.75	3108779	147667	0.85	0.60	9.08	342319	0.98	13.05	1865267	1907121	-7969355	0.3020	-2406823
8	5.25	1625560	85342	0.85	0.60	8.22	197838	0.57	12.07	975336	1725490	-2757763	0.3251	-896435
9	5.75	2471028	142084	0.85	0.60	7.50	329377	0.94	11.51	1482617	1575448	-2049718	0.3493	-715865
10	6.25	3613437	225840	0.85	0.60	6.90	523538	1.50	10.57	2168062	1449412	135504	0.3923	53153
11	6.75	3377740	227997	0.85	0.60	6.39	528540	1.51	9.07	2026644	1342048	3055166	0.4527	1382989
12	7.25	4405783	319419	0.85	0.60	5.95	740472	2.12	7.56	2643470	1249493	7804845	0.5381	4199408
13	7.75	6696090	518947	0.85	0.60	5.57	1203013	3.44	5.45	4017654	1168880	17667633	0.7010	12385831
14	8.25	2031761	167620	0.85	0.60	5.23	388574	1.11	2.01	1219057	1098039	7122338	0.8707	6201315
15	8.75	1124288	98375	0.85	0.60	4.93	228052	0.65	0.90	674573	1035294	4915949	0.9469	4655123
16	9.25	401858	37172	0.85	0.60	4.66	86171	0.25	0.25	241115	979332	2105535	0.9880	2080223
17	9.75	0	0					17.58	0.00					
18	>6.25	18037520	1369531				3174822	9.07		10822512		42671466		30904888
19														
20				SUMMARY	(In	Millions)								
21														
22							SCENARIO		I	II	III			
23				Tons Reserve In-place=					18.04	18.04	18.04			
24				Tons Actually Mined=					10.82	10.82	10.82			
25				Total Tons Product=					3.17	3.17	3.17			
26				Average Grade, % K20=					7.59%	7.59%	7.59%			
27				Total Cash Flow=					42.67	42.67	42.67			
28				Discounted Cash Flow (10%)=					30.90	30.90	30.90			
29				Development Cost=					0.00	5.00	70.00			
30				Time Delay, years=					0.00	1.00	3.00			
31				Present Value=					30.90	23.09	-52.65			

Table 6. Case 2 - 4th ORE ZONE CASH FLOW (WIPP Area)
Mining Recovery = 80% and Mining Height = 6.0 Feet

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1													10 %	10 %
2	Grade	WIPP	In Place	Plant	Mine	Ratio	Product	Years	Mining	Tons	Annual	Profit	Avg	Present
3	% K20	Tons	Tons K20	Recov	Recov	Conc	Tons	Life	Years	Mined	Rate	For Period	PVF	Value Flow
4	3.25	8076268	262479	0.85	0.80	9.95	811298	2.32	23.43	6461014	2787330	-55613181	0.1197	-6655537
5	3.75	5045520	189207	0.85	0.80	8.63	584822	1.67	21.12	4036416	2415686	-28910830	0.1447	-4184291
6	4.25	5443080	231331	0.85	0.80	7.61	715023	2.04	19.44	4354464	2131488	-24896648	0.1728	-4300957
7	4.75	3108779	147667	0.85	0.80	6.81	456425	1.30	17.40	2487023	1907121	-10625807	0.2026	-2153063
8	5.25	1625560	85342	0.85	0.80	6.16	263784	0.75	16.10	1300448	1725490	-3677017	0.2235	-821823
9	5.75	2471028	142084	0.85	0.80	5.63	430169	1.25	15.34	1976822	1575448	-2732957	0.2460	-672175
10	6.25	3613437	225840	0.85	0.80	5.18	698050	1.99	14.09	2890750	1449412	180672	0.2871	51878
11	6.75	3377740	227997	0.85	0.80	4.79	704719	2.01	12.09	2702192	1342048	4073554	0.3476	1415856
12	7.25	4405783	319419	0.85	0.80	4.46	987296	2.82	10.08	3524626	1249493	10406459	0.4376	4554088
13	7.75	6696090	518947	0.85	0.80	4.17	1604018	4.58	7.26	5356872	1168880	23556845	0.6228	14670541
14	8.25	2031761	167620	0.85	0.80	3.92	518099	1.48	2.68	1625409	1098039	9496451	0.8314	7895438
15	8.75	1124288	98375	0.85	0.80	3.70	304069	0.87	1.20	899430	1035294	6554599	0.9299	6095057
16	9.25	401858	37172	0.85	0.80	3.50	114695	0.33	0.33	321486	979332	2807380	0.9845	2763804
17	9.75	0	0											
18	>6.25	18037520	1369531				4233096	12.09		14430016		56895288		37394783
19														
20				**SUMMARY**		**(In Millions)**								
21														
22							**SCENARIO**		**I**	**II**	**III**			
23				Tons Reserve In-place=					18.04	18.04	18.04			
24				Tons Actually Mined=					14.43	14.43	14.43			
25				Total Tons Product=					4.23	4.23	4.23			
26				Average Grade, % K20=					7.59%	7.59%	7.59%			
27				Total Cash Flow=					56.9	56.9	56.9			
28				Discounted Cash Flow (10%)=					37.39	37.39	37.39			
29				Development Cost=					0.00	5.00	70.00			
30				Time Delay, years=					0.00	1.00	3.00			
31				Present Value=					37.39	29.00	-48.22			

Table 7. Case 3 - 4th ORE ZONE CASH FLOW (WIPP Area)
Mining Recovery = 90% and Mining Height = 4.5 Feet

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1													10 %	10 %
2	Grade	WIPP	In Place	Plant	Mine	Ratio	Product	Years	Mining	Tons	Annual	Profit	Avg	Present
3	% K20	Tons	Tons K20	Recov	Recov	Conc	Tons	Life	Years	Mined	Rate	For Period	PVF	Value Flow
4	3.25	5782492	187931	0.85	0.90	8.85	653487	1.87	30.15	5204243	2787330	-34387034	0.0617	-2122666
5	3.75	4810711	180402	0.85	0.90	7.67	627306	1.79	28.29	4329640	2415686	-22351766	0.0735	-1642613
6	4.25	4744246	201630	0.85	0.90	6.77	701124	2.00	26.49	4269821	2131488	-15873061	0.0881	-1397775
7	4.75	2904185	137949	0.85	0.90	6.05	479686	1.37	24.49	2613766	1907121	-5939784	0.1034	-614287
8	5.25	3095103	162493	0.85	0.90	5.48	565032	1.61	23.12	2785593	1725490	-2305078	0.1192	-274829
9	5.75	3571031	205334	0.85	0.90	5.00	714003	2.04	21.51	3213928	1575448	1984600	0.1419	281633
10	6.25	3843950	240247	0.85	0.90	4.60	835404	2.39	19.47	3459555	1449412	7135332	0.1752	1250386
11	6.75	2415074	163017	0.85	0.90	4.26	566856	1.62	17.08	2173567	1342048	7623785	0.2121	1617036
12	7.25	2199285	159448	0.85	0.90	3.97	554445	1.58	15.46	1979357	1249493	9802763	0.2471	2422160
13	7.75	6225078	482444	0.85	0.90	3.71	1677588	4.79	13.88	5602570	1168880	35842443	0.3348	12001550
14	8.25	3192607	263390	0.85	0.90	3.49	915879	2.62	9.08	2873346	1098039	22534218	0.4766	10740888
15	8.75	2494043	218229	0.85	0.90	3.29	758841	2.17	6.47	2244639	1035294	20847082	0.5987	12481684
16	9.25	1567620	145005	0.85	0.90	3.11	504221	1.44	4.30	1410858	979332	15142033	0.7111	10767132
17	9.75	1122362	109430	0.85	0.90	2.95	380519	1.09	2.86	1010126	929110	12300807	0.8021	9866572
18	10.25	896420	91883	0.85	0.90	2.81	319502	0.91	1.77	806778	883788	10990333	0.8823	9697002
19	10.75	802576	86277	0.85	0.90	2.68	300008	0.86	0.86	722318	842681	10883532	0.9600	10447916
20	>6.25	20915065	1719123				5977860	17.08		18823558		145966997		80041940
21				SUMMARY (In Millions)										
22							SCENARIO		I	II	III			
23				Tons Reserve In-place=					20.92	20.92	20.92			
24				Tons Actually Mined=					18.82	18.82	18.82			
25				Total Tons Product=					5.98	5.98	5.98			
26				Average Grade, % K20=					8.22%	8.22%	8.22%			
27				Total Cash Flow=					146.0	146.0	146.0			
28				Discounted Cash Flow (10%)=					80.0	80.0	80.0			
29				Development Cost=					0.00	5.00	70.00			
30				Time Delay, years=					0.00	1.00	3.00			
31				Present Value=					80.0	67.8	-9.9			

Table 8. Case 1 - 4th ORE ZONE CASH FLOW (Additional Area)
Mining Recovery = 60% and Mining Height = 6.0 Feet

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1													10 %	10 %
2	Grade	Additional	In Place	Plant	Mine	Ratio	Product	Years	Mining	Tons	Annual	Profit	Avg	Present
3	% K20	Tons	Tons K20	Recov	Recov	Conc	Tons	Life	Years	Mined	Rate	For Period	PVF	Value Flow
4	3.25	25468975	827742	0.85	0.60	13.27	1918856	5.48	57.35	15281385	2787330	-100971751	0.0055	-554618
5	3.75	40102300	1503836	0.85	0.60	11.50	3486166	9.96	51.86	24061380	2415686	-124216874	0.0115	-1424251
6	4.25	19045780	809446	0.85	0.60	10.15	1876442	5.36	41.90	11427468	2131488	-42481612	0.0238	-1010906
7	4.75	7829454	371899	0.85	0.60	9.08	862130	2.46	36.54	4697672	1907121	-10675461	0.0346	-368837
8	5.25	4248962	223071	0.85	0.60	8.22	5171[illegible]	1.48	34.08	2549377	1725490	-2109610	0.0417	-87944
9	5.75	3896344	224040	0.85	0.60	7.50	519365	1.48	32.60	2337806	1575448	1443595	0.0480	69301
10	6.25	4927451	307966	0.85	0.60	6.90	713920	2.04	31.12	2956471	1449412	6097721	0.0568	346251
11	6.75	6804701	459317	0.85	0.60	6.39	1064781	3.04	29.08	4082821	1342048	14320493	0.0723	1036001
12	7.25	10035503	727574	0.85	0.60	5.95	1686649	4.82	26.03	6021302	1249493	·29820497	0.1052	3137731
13	7.75	11886300	921188	0.85	0.60	5.57	2135482	6.10	21.22	7131780	1168880	45625563	0.1771	8078315
14	8.25	9779073	806774	0.85	0.60	5.23	1870248	5.34	15.11	5867444	1098039	46015428	0.3055	14056735
15	8.75	6122163	535689	0.85	0.60	4.93	1241825	3.55	9.77	3673298	10352[illegible]	34115753	[illegible]	15920632
16	9.25	5280898	488483	0.85	0.60	4.66	1132393	3.24	6.22	3168539	979332	34006343	0.6448	21925952
17	9.75	2621932	255638	0.85	0.60	4.42	592616	1.69	2.99	1573159	929110	19157146	0.8155	15621879
18	10.25	1468606	150532	0.85	0.60	4.21	348961	1.00	1.29	881164	883788	12003651	0.9270	11127396
19	10.75	416832	44809	0.85	0.60	4.01	103876	0.30	0.30	250099	842681	3768370	0.9860	3715447
20	>6.25	54416008	4390005				10176830	29.08		32649605		235064874		90904640
21				**SUMMARY (In Millions)**										
22							**SCENARIO**		I	II	III			
23				Tons Reserve In-place=					54.42	54.42	54.42			
24				Tons Actually Mined=					32.65	32.65	32.65			
25				Total Tons Product=					10.18	10.18	10.18			
26				Average Grade, % K20=					8.07%	8.07%	8.07%			
27				Total Cash Flow=					235.1	235.1	235.1			
28				Discounted Cash Flow (10%)=					90.9	90.9	90.9			
29				Development Cost=					0.00	5.00	70.00			
30				Time Delay, years=					0.00	1.00	3.00			
31				Present Value=					90.9	77.6	-1.7			

Table 9. Case 2 - 4th ORE ZONE CASH FLOW (Additional Area)
Mining Recovery = 80% and Mining Height = 6.0 Feet

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1													10 %	10 %
2	Grade	Additional	In Place	Plant	Mine	Ratio	Product	Years	Mining	Tons	Annual	Profit	Avg	Present
3	% K20	Tons	Tons K20	Recov	Recov	Conc	Tons	Life	Years	Mined	Rate	For Period	PVF	Value Flow
4	3.25	25468975	827742	0.85	0.80	9.95	2558474	7.31	76.46	20375180	2787330	-134629002	0.0010	-130476
5	3.75	40102300	1503836	0.85	0.80	8.63	4648221	13.28	69.15	32081840	2415686	-165622499	0.0026	-428214
6	4.25	19045780	809446	0.85	0.80	7.61	2501923	7.15	55.87	15236624	2131488	-56642150	0.0068	-387691
7	4.75	7829454	371899	0.85	0.80	6.81	1149506	3.28	48.72	6263563	1907121	-14233947	0.0113	-160173
8	5.25	4248962	223071	0.85	0.80	6.16	689491	1.97	45.44	3399170	1725490	-2812813	0.0145	-40658
9	5.75	3896344	224040	0.85	0.80	5.63	692487	1.98	43.47	3117075	1575448	1924794	0.0174	33582
10	6.25	4927451	307966	0.85	0.80	5.18	951894	2.72	41.49	3941961	1449412	8130294	0.0218	177448
11	6.75	6804701	459317	0.85	0.80	4.79	1419708	4.06	38.77	5443761	1342048	19093991	0.0301	575572
12	7.25	10035503	727574	0.85	0.80	4.46	2248865	6.43	34.71	8028402	1249493	39760663	0.0497	1975095
13	7.75	11886300	921188	0.85	0.80	4.17	2847309	8.14	28.29	9509040	1168880	60834083	0.0994	6048259
14	8.25	9779073	806774	0.85	0.80	3.92	2493664	7.12	20.15	7823258	1098039	61353904	0.2057	12622639
15	8.75	6122163	535689	0.85	0.80	3.70	1655767	4.73	13.03	4897730	1035294	45487671	0.3620	16465218
16	9.25	5280898	488483	0.85	0.80	3.50	1509857	4.31	8.30	4224718	979332	45341790	0.5570	25255931
17	9.75	2621932	255638	0.85	0.80	3.32	790155	2.26	3.98	2097546	929110	25542862	0.7619	19459851
18	10.25	1468606	150532	0.85	0.80	3.16	465281	1.33	1.73	1174885	883788	16004868	0.9039	14466351
19	10.75	416832	44809	0.85	0.80	3.01	138502	0.40	0.40	333466	842681	5024493	0.9813	4930629
20	>6.25	54416008	4390005				13569107	38.77		43532806		321550126		97046364
21				SUMMARY	(In	Millions)								
22							SCENARIO		I	II	III			
23				Tons Reserve In-place=					54.42	54.42	54.42			
24				Tons Actually Mined=					43.53	43.53	43.53			
25				Total Tons Product=					13.57	13.57	13.57			
26				Average Grade, % K20=					8.07%	8.07%	8.07%			
27				Total Cash Flow=					321.6	321.6	321.6			
28				Discounted Cash Flow (10%)=					97.0	97.0	97.0			
29				Development Cost=					0.00	5.00	70.00			
30				Time Delay, years=					0.00	1.00	3.00			
31				Present Value=					97.0	83.2	2.9			

Table 10. Case 3 - 4th ORE ZONE CASH FLOW (Additional Area)
Mining Recovery = 90% and Mining Height = 4.5 Feet

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1													10 %	10 %
2	Grade	Additional	In Place	Plant	Mine	Ratio	Product	Years	Mining	Tons	Annual	Profit	Avg	Present
3	% K20	Tons	Tons K20	Recov	Recov	Conc	Tons	Life	Years	Mined	Rate	For Period	PVF	Value Flow
4	3.25	16058729	521909	0.85	0.90	8.85	1814819	5.19	95.94	9635237	1858220	-18415347	0.0001	-2519
5	3.75	10979436	411729	0.85	0.90	7.67	1431694	4.09	90.75	6587662	1610458	1688088	0.0002	359
6	4.25	12530183	532533	0.85	0.90	6.77	1851762	5.29	86.66	7518110	1420992	18222019	0.0003	6065
7	4.75	24261188	1152406	0.85	0.90	6.05	4007231	11.45	81.37	14556713	1271414	66833508	0.0007	49397
8	5.25	17642060	926208	0.85	0.90	5.48	3220678	9.20	69.92	10585236	1150327	71542964	0.0020	141474
9	5.75	10413814	598794	0.85	0.90	5.00	2082171	5.95	60.72	6248288	1050298	55773784	0.0041	227045
10	6.25	7414443	463403	0.85	0.90	4.60	1611378	4.60	54.77	4448666	966275	49352386	0.0067	332199
11	6.75	4235447	285893	0.85	0.90	4.26	994127	2.84	50.17	2541268	894699	33700393	0.0096	323441
12	7.25	2764294	200411	0.85	0.90	3.97	696885	1.99	47.33	1658576	832995	25589761	0.0121	309186
13	7.75	4621685	358181	0.85	0.90	3.71	1245492	3.56	45.34	2773011	779254	48794595	0.0157	768037
14	8.25	4820710	397709	0.85	0.90	3.49	1382941	3.95	41.78	2892426	732026	57165184	0.0225	1286968
15	8.75	4741933	414919	0.85	0.90	3.29	1442787	4.12	37.83	2845160	690196	62397911	0.0331	2063945
16	9.25	6206689	574119	0.85	0.90	3.11	1996367	5.70	33.71	3724013	652888	89744068	0.0528	4741321
17	9.75	5638040	549709	0.85	0.90	2.95	1911488	5.46	28.00	3382824	619407	88854101	0.0899	7991936
18	10.25	7678424	787038	0.85	0.90	2.81	2736747	7.82	22.54	4607054	589192	130995833	0.1694	22186731
19	10.75	13783275	1481702	0.85	0.90	2.68	5152282	14.72	14.72	8269965	561788	253071266	0.4958	125480428
20	>6.25	54490497	5049680				17559116	50.17				790313112		165151992
21				SUMMARY		(In Millions)								
22							SCENARIO		I	II	III			
23				Tons Reserve In-place=					54.49	54.49	54.49			
24				Tons Actually Mined=					49.04	49.04	49.04			
25				Total Tons Product=					17.56	17.56	17.56			
26				Average Grade, % K20=					9.27%	9.27%	9.27%			
27				Total Cash Flow=					790.3	790.3	790.3			
28				Discounted Cash Flow (10%)=					165.2	165.2	165.2			
29				Development Cost=					0.00	5.00	70.00			
30				Time Delay, years=					0.00	1.00	3.00			
31				Present Value=					165.2	145.1	39.0			

Table 11. Case 1 - 4th ORE ZONE CASH FLOW (Combined Area)
Mining Recovery = 60% and Mining Height = 6.0 Feet

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1													10 %	10 %
2	Grade	Combined	In Place	Plant	Mine	Ratio	Product	Years	Mining	Tons	Annual	Profit	Avg	Present
3	% K20	Tons	Tons K20	Recov	Recov	Conc	Tons	Life	Years	Mined	Rate	For Period	PVF	Value Flow
4	3.25	33545243	1090220	0.85	0.60	13.27	2527329	7.22	74.92	20127146	2787330	-132990116	0.0011	-148634
5	3.75	45147820	1693043	0.85	0.60	11.50	3924782	11.21	67.70	27088692	2415686	-139845372	0.0027	-376249
6	4.25	24488860	1040777	0.85	0.60	10.15	2412709	6.89	56.49	14693316	2131488	-54622402	0.0064	-348296
7	4.75	10938233	519566	0.85	0.60	9.08	1204449	3.44	49.59	6562940	1907121	-14914281	0.0104	-155622
8	5.25	5874522	308412	0.85	0.60	8.22	714956	2.04	46.15	3524713	1725490	-2916700	0.0136	-39524
9	5.75	6367372	366124	0.85	0.60	7.50	848742	2.42	44.11	3820423	1575448	2359111	0.0168	39553
10	6.25	8540888	533806	0.85	0.60	6.90	1237458	3.54	41.68	5124533	1449412	10569349	0.0223	235420
11	6.75	10182441	687315	0.85	0.60	6.39	1593321	4.55	38.15	6109465	1342048	21428947	0.0327	701757
12	7.25	14441286	1046993	0.85	0.60	5.95	2427121	6.93	33.60	8664772	1249493	42912281	0.0566	2429440
13	7.75	18582390	1440135	0.85	0.60	5.57	3338495	9.54	26.66	11149434	1168880	71328504	0.1241	8853651
14	8.25	11810834	974394	0.85	0.60	5.23	2258822	6.45	17.12	7086500	1098039	55575879	0.2660	14781840
15	8.75	7246451	634064	0.85	0.60	4.93	1469877	4.20	10.67	4347871	1035294	40380848	0.4419	17844506
16	9.25	5682756	525655	0.85	0.60	4.66	1218564	3.48	6.47	3409654	979332	36594107	0.6372	23319229
17	9.75	2621932	255638	0.85	0.60	4.42	592616	1.69	2.99	1573159	929110	19157146	0.8155	15621879
18	10.25	1468606	150532	0.85	0.60	4.21	348961	1.00	1.29	881164	883788	12003651	0.9270	11127396
19	10.75	416832	44809	0.85	0.60	4.01	103876	0.30	0.30	250099	842681	3768370	0.9860	3715447
20	>6.25	72453528	5759536				13351652	38.15		43472117		303149734		98395145
21				SUMMARY (In Millions)										
22							SCENARIO		I	II	III			
23				Tons Reserve In-place=					72.45	72.45	72.45			
24				Tons Actually Mined=					43.47	43.47	43.47			
25				Total Tons Product=					13.35	13.35	13.35			
26				Average Grade, % K20=					7.95%	7.95%	7.95%			
27				Total Cash Flow=					303.1	303.1	303.1			
28				Discounted Cash Flow (10%)=					98.4	98.4	98.4			
29				Development Cost=					0.00	5.00	70.00			
30				Time Delay, years=					0.00	1.00	3.00			
31				Present Value=					98.4	84.5	3.9			

Table 12. Case 2 - 4th ORE ZONE CASH FLOW (Combined Area)
Mining Recovery = 80% and Mining Height = 6.0 Feet

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1													10 %	10 %
2	Grade	Combined	In Place	Plant	Mine	Ratio	Product	Years	Mining	Tons	Annual	Profit	Avg	Present
3	% K20	Tons	Tons K20	Recov	Recov	Conc	Tons	Life	Years	Mined	Rate	For Period	PVF	Value Flow
4	3.25	33545243	1090220	0.85	0.80	9.95	3369772	9.63	99.89	26836194	2787330	-177320154	0.0001	-20566
5	3.75	45147820	1693043	0.85	0.80	8.63	5233043	14.95	90.27	36118256	2415686	-186460497	0.0004	-69773
6	4.25	24488860	1040777	0.85	0.80	7.61	3216946	9.19	75.31	19591088	2131488	-72829870	0.0012	-86115
7	4.75	10938233	519566	0.85	0.80	6.81	1605931	4.59	66.12	8750586	1907121	-19885708	0.0023	-45342
8	5.25	5874522	308412	0.85	0.80	6.16	953275	2.72	61.53	4699618	1725490	-3888934	0.0032	-12564
9	5.75	6367372	366124	0.85	0.80	5.63	1131656	3.23	58.81	5093898	1575448	3145482	0.0043	13498
10	6.25	8540888	533806	0.85	0.80	5.18	1649944	4.71	55.58	6832710	1449412	14092465	0.0063	88318
11	6.75	10182441	687315	0.85	0.80	4.79	2124427	6.07	50.86	8145953	1342048	28571929	0.0105	299356
12	7.25	14441286	1046993	0.85	0.80	4.46	3236161	9.25	44.79	11553029	1249493	57216375	0.0217	1243807
13	7.75	18582390	1440135	0.85	0.80	4.17	4451327	12.72	35.55	14865912	1168880	95104672	0.0619	5888630
14	8.25	11810834	974394	0.85	0.80	3.92	3011763	8.61	22.83	9448667	1098039	74101173	0.1710	12674999
15	8.75	7246451	634064	0.85	0.80	3.70	1959836	5.60	14.22	5797161	1035294	53841131	0.3366	18122563
16	9.25	5682756	525655	0.85	0.80	3.50	1624752	4.64	8.62	4546205	979332	48792143	0.5484	26755964
17	9.75	2621932	255638	0.85	0.80	3.32	790155	2.26	3.98	2097546	929110	25542862	0.7619	19459851
18	10.25	1468606	150532	0.85	0.80	3.16	465281	1.33	1.73	1174885	883788	16[illegible]868	0.9039	14466351
19	10.75	416832	44809	0.85	0.80	3.01	138502	0.40	0.40	333466	842681	50[illegible]493	0.9813	4930629
20	>6.25	72453528	5759536				17802203	50.86		57962822		404199646		103842150
21				SUMMARY (In Millions)										
22							SCENARIO		I	II	III			
23				Tons Reserve In-place=					72.45	72.45	72.45			
24				Tons Actually Mined=					57.96	57.96	57.96			
25				Total Tons Product=					17.80	17.80	17.80			
26				Average Grade, % K20=					7.95%	7.95%	7.95%			
27				Total Cash Flow=					404.2	404.2	404.2			
28				Discounted Cash Flow (10%)=					103.8	103.8	103.8			
29				Development Cost=					0.00	5.00	70.00			
30				Time Delay, years=					0.00	1.00	3.00			
31				Present Value=					103.8	89.4	8.0			

Table 13. Case 3 - 4th ORE ZONE CASH FLOW (Combined Area)
Mining Recovery = 90% and Mining Height = 4.5 Feet

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1													10 %	10 %
2	Grade	Combined	In Place	Plant	Mine	Ratio	Product	Years	Mining	Tons	Annual	Profit	Avg	Present
3	% K20	Tons	Tons K20	Recov	Recov	Conc	Tons	Life	Years	Mined	Rate	For Period	PVF	Value Flow
4	3.25	21841221	709840	0.85	0.90	8.85	2468306	7.05	126.09	19657099	2787330	-129884281	0.0000	-1097
5	3.75	15790147	592131	0.85	0.90	7.67	2058999	5.88	119.04	14211132	2415686	-73364970	0.0000	-1148
6	4.25	17274429	734163	0.85	0.90	6.77	2552886	7.29	113.16	15546986	2131488	-57795921	0.0000	-1694
7	4.75	27165373	1290355	0.85	0.90	6.05	4486917	12.82	105.86	24448836	1907121	-55559979	0.0001	-4247
8	5.25	20737163	1088701	0.85	0.90	5.48	3785710	10.82	93.04	18663447	1725490	-15444002	0.0002	-3641
9	5.75	13984845	804129	0.85	0.90	5.00	2796174	7.99	82.23	12586361	1575448	7772078	0.0006	4490
10	6.25	11258393	703650	0.85	0.90	4.60	2446781	6.99	74.24	10132554	1449412	20898392	0.0012	24651
11	6.75	6650521	448910	0.85	0.90	4.26	1560983	4.46	67.25	5985469	1342048	20994032	0.0020	42737
12	7.25	4963579	359859	0.85	0.90	3.97	1251330	3.58	62.79	4467221	1249493	22123912	0.0030	66049
13	7.75	10846763	840624	0.85	0.90	3.71	2923079	8.35	59.21	9762087	1168880	62452950	0.0053	329157
14	8.25	8013317	661099	0.85	0.90	3.49	2298820	6.57	50.86	7211985	1098039	56559995	0.0107	606936
15	8.75	7235976	633148	0.85	0.90	3.29	2201628	6.29	44.29	6512378	1035294	60483714	0.0198	1197828
16	9.25	7774309	719124	0.85	0.90	3.11	2500589	7.14	38.00	6996878	979332	75093994	0.0376	2821075
17	9.75	6760402	659139	0.85	0.90	2.95	2292007	6.55	30.86	6084362	929110	74092316	0.0721	5345402
18	10.25	8574844	878922	0.85	0.90	2.81	3056250	8.73	24.31	7717360	883788	105129731	0.1494	15710428
19	10.75	14585851	1567979	0.85	0.90	2.68	5452291	15.58	15.58	13127266	842681	197795079	0.4760	94147419
20	>6.25	75405562	6768804				23536976	67.25		67865006		674725724		120267031
21				**SUMMARY**	**(In Millions)**									
22							**SCENARIO**		**I**	**II**	**III**			
23				Tons Reserve In-place=					75.41	75.41	75.41			
24				Tons Actually Mined=					67.87	67.87	67.87			
25				Total Tons Product=					23.54	23.54	23.54			
26				Average Grade, % K20=					8.98%	8.98%	8.98%			
27				Total Cash Flow=					674.7	674.7	674.7			
28				Discounted Cash Flow (10%)=					120.3	120.3	120.3			
29				Development Cost=					0.00	5.00	70.00			
30				Time Delay, years=					0.00	1.00	3.00			
31				Present Value=					120.3	104.3	20.4			

Table 14. Case 3 - 10th ORE ZONE CASH FLOW (WIPP Area)
Mining Recovery = 90% and Mining Height = 4.5 Feet

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1													10 %	10 %
2	Grade	WIPP	In Place	Plant	Mine	Ratio	Product	Years	Mining	Tons	Annual	Profit	Avg	Present
3	% K20	Tons	Tons K20	Recov	Recov	Conc	Tons	Life	Years	Mined	Rate	For Period	PVF	Value Flow
4	11.25	4712553	530162	0.80	0.90	7.41	636195	1.59	18.53	4241298	2666667	-5089557	0.1827	-930035
5	11.75	3960114	465313	0.80	0.90	7.09	558376	1.40	16.94	3564103	2553191	-2566154	0.2166	-555738
6	12.25	4841579	593093	0.80	0.90	6.80	711712	1.78	15.55	4357421	2448980	-1045781	0.2516	-263151
7	12.75	5585926	712206	0.80	0.90	6.54	854647	2.14	13.77	5027333	2352941	1206560	0.2890	348640
8	13.25	3723783	493401	0.80	0.90	6.29	592081	1.48	11.63	3351405	2264151	2413011	0.3536	853260
9	13.75	3500888	481372	0.80	0.90	6.06	577647	1.44	10.15	3150799	2181818	3780959	0.4047	1530307
10	14.25	3082509	439258	0.80	0.90	5.85	527109	1.32	8.70	2774258	2105263	4660754	0.4683	2182806
11	14.75	3371808	497342	0.80	0.90	5.65	596810	1.49	7.39	3034627	2033898	6554795	0.5121	3356663
12	15.25	1597172	243569	0.80	0.90	5.46	292282	0.73	5.90	1437455	1967213	3794881	0.5829	2212093
13	15.75	983814	154951	0.80	0.90	5.29	185941	0.46	5.16	885433	1904762	2762550	0.6280	1734784
14	16.25	1160094	188515	0.80	0.90	5.13	226218	0.57	4.70	1044085	1846154	3758705	0.6545	2460034
15	16.75	1002981	167999	0.80	0.90	4.98	201599	0.50	4.13	902683	1791045	3682946	0.6970	2567146
16	17.25	1342053	231504	0.80	0.90	4.83	277805	0.69	3.63	1207848	1739130	5507786	0.7220	3976556
17	17.75	797295	141520	0.80	0.90	4.69	169824	0.42	2.94	717566	1690141	3616530	0.7858	2841862
18	18.25	1484383	270900	0.80	0.90	4.57	325080	0.81	2.51	1335945	1643836	7374415	0.8070	5951439
19	18.75	930260	174424	0.80	0.90	4.44	209309	0.52	1.70	837234	1600000	5023404	0.8995	4518773
20	19.25	[illegible]14613	391663	0.80	0.90	4.33	469996	1.17	1.17	1831152	1558442	11865863	0.9455	11219703
21	>12.25	30597579	4588623				5506347	13.77		27537821		66003157		45754066
22				SUMMARY (In Millions)										
23							SCENARIO		I	II	III			
24				Tons Reserve In-place=					30.60	30.60	30.60			
25				Tons Actually Mined=					27.54	27.54	27.54			
26				Total Tons Product=					5.51	5.51	5.51			
27				Average Grade, % K20=					15.00%	15.00%	15.00%			
28				Total Cash Flow=					66.00	66.00	66.00			
29				Discounted Cash Flow (10%)=					45.75	45.75	45.75			
30				Development Cost=					0.00	5.00	70.00			
31				Time Delay, years=					0.00	1.00	3.00			
32				Present Value=					45.8	36.6	-45.6			

Table 15. Case 3 - 10th ORE ZONE CASH FLOW (Additional Area)
Mining Recovery = 90% and Mining Height = 4.5 Feet

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1													10 %	10 %
2	Grade	Additional	In Place	Plant	Mine	Ratio	Product	Years	Mining	Tons	Annual	Profit	Avg	Present
3	% K20	Tons	Tons K20	Recov	Recov	Conc	Tons	Life	Years	Mined	Rate	For Period	PVF	Value Flow
4	11.25	5621020	632365	0.80	0.90	7.41	758838	1.90	43.40	5058918	2666667	-6070702	0.0179	-108840
5	11.75	6850095	804886	0.80	0.90	7.09	965863	2.41	41.50	6165086	2553191	-4438862	0.0224	-99431
6	12.25	8959861	1097583	0.80	0.90	6.80	1317100	3.29	39.09	8063875	2448980	-1935330	0.0273	-52886
7	12.75	6888598	878296	0.80	0.90	6.54	1053955	2.63	35.80	6199738	2352941	1487937	0.0387	57650
8	13.25	8493179	1125346	0.80	0.90	6.29	1350415	3.38	33.16	7643861	2264151	5503580	0.0487	268123
9	13.75	7060676	970843	0.80	0.90	6.06	1165012	2.91	29.78	6354608	2181818	7625530	0.0681	519216
10	14.25	7451053	1061775	0.80	0.90	5.85	1274130	3.19	26.87	6705948	2105263	11265992	0.0933	1051017
11	14.75	8967901	1322765	0.80	0.90	5.65	1587318	3.97	23.69	8071111	2033898	17433600	0.1179	2055776
12	15.25	5494862	837966	0.80	0.90	5.46	1005560	2.51	19.72	4945376	1967213	13055792	0.1740	2272286
13	15.75	5812551	915477	0.80	0.90	5.29	1098572	2.75	17.20	5231296	1904762	16321643	0.2145	3500931
14	16.25	4315776	701314	0.80	0.90	5.13	841576	2.10	14.46	3884198	1846154	13983114	0.2772	3875584
15	16.75	3959202	663166	0.80	0.90	4.98	795800	1.99	12.35	3563282	1791045	14538190	0.3322	4829507
16	17.25	3057493	527418	0.80	0.90	4.83	632901	1.58	10.36	2751744	1739130	12547951	0.4062	5097258
17	17.75	3426921	608278	0.80	0.90	4.69	729934	1.82	8.78	3084229	1690141	15544514	0.4613	7171404
18	18.25	2430184	443509	0.80	0.90	4.57	532210	1.33	6.96	2187166	1643836	12073154	0.5524	6669334
19	18.75	2597287	486991	0.80	0.90	4.44	584390	1.46	5.63	2337558	1600000	14025350	0.7134	10005213
20	19.25	7213247	1388550	0.80	0.90	4.33	1666260	4.17	4.17	6491922	1558442	42067657	0.8199	34493288
21	>12.25	77168930	11931695				14318034	35.80		69452037		197474004		81866589
22				**SUMMARY**	**(In**	**Millions)**								
23							**SCENARIO**		I	II	III			
24				Tons Reserve In-place=					77.17	77.17	77.17			
25				Tons Actually Mined=					69.45	69.45	69.45			
26				Total Tons Product=					14.32	14.32	14.32			
27				Average Grade, % K20=					15.46%	15.46%	15.46%			
28				Total Cash Flow=					197.47	197.47	197.47			
29				Discounted Cash Flow (10%)=					81.87	81.87	81.87			
30				Development Cost=					0.00	5.00	70.00			
31				Time Delay, years=					0.00	1.00	3.00			
32				Present Value=					81.9	69.4	-18.5			

Table 16. Case 3 - 10th ORE ZONE CASH FLOW (Combined Area)
Mining Recovery = 90% and Mining Height = 4.5 Feet

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1													10 %	10 %
2	Grade	Combined	In Place	Plant	Mine	Ratio	Product	Years	Mining	Tons	Annual	Profit	Avg	Present
3	% K20	Tons	Tons K20	Recov	Recov	Conc	Tons	Life	Years	Mined	Rate	For Period	PVF	Value Flow
4	11.25	10333573	1162527	0.80	0.90	7.41	1395032	3.49	61.93	9300216	2666667	-11160259	0.0033	-36563
5	11.75	10810209	1270200	0.80	0.90	7.09	1524239	3.81	58.44	9729188	2553191	-7005015	0.0049	-33982
6	12.25	13801440	1690676	0.80	0.90	6.80	2028812	5.07	54.63	12421296	2448980	-2981111	0.0069	-20499
7	12.75	12474524	1590502	0.80	0.90	6.54	1908602	4.77	49.56	11227072	2352941	2694497	0.0112	30166
8	13.25	12216962	1618747	0.80	0.90	6.29	1942497	4.86	44.79	10995266	2264151	7916591	0.0172	136380
9	13.75	10561564	1452215	0.80	0.90	6.06	1742658	4.36	39.93	9505408	2181818	11406489	0.0276	314345
10	14.25	10533562	1501033	0.80	0.90	5.85	1801239	4.50	35.58	9480206	2105263	15926746	0.0437	695867
11	14.75	12339709	1820107	0.80	0.90	5.65	2184128	5.46	31.07	11105738	2033898	23988394	0.0604	1448567
12	15.25	7092034	1081535	0.80	0.90	5.46	1297842	3.24	25.61	6382831	1967213	16850673	0.1015	1709552
13	15.75	6796365	1070427	0.80	0.90	5.29	1284513	3.21	22.37	6116728	1904762	19084193	0.1347	2570565
14	16.25	5475870	889829	0.80	0.90	5.13	1067795	2.67	19.16	4928283	1846154	17741819	0.1814	3218357
15	16.75	4962183	831166	0.80	0.90	4.98	997399	2.49	16.49	4465965	1791045	18221136	0.2316	4219133
16	17.25	4399546	758922	0.80	0.90	4.83	910706	2.28	13.99	3959591	1739130	18055737	0.2933	5295525
17	17.75	4224216	749798	0.80	0.90	4.69	899758	2.25	11.72	3801794	1690141	19161044	0.3625	6946357
18	18.25	3914567	714408	0.80	0.90	4.57	857290	2.14	9.47	3523110	1643836	19447569	0.4458	8670047
19	18.75	3527547	661415	0.80	0.90	4.44	793698	1.98	7.32	3174792	1600000	19048754	0.6417	12223671
20	19.25	9247860	1780213	0.80	0.90	4.33	2136256	5.34	5.34	8323074	1558442	53933520	0.7753	41814515
21	>12.25	107766509	16520318				19824381	49.56		96989858		263477161		89293048
22				SUMMARY (In Millions)										
23							SCENARIO		I	II	III			
24				Tons Reserve In-place=					107.77	107.77	107.77			
25				Tons Actually Mined=					96.99	96.99	96.99			
26				Total Tons Product=					19.82	19.82	19.82			
27				Average Grade, % K20=					15.33%	15.33%	15.33%			
28				Total Cash Flow=					263.48	263.48	263.48			
29				Discounted Cash Flow (10%)=					89.29	89.29	89.29			
30				Development Cost=					0.00	5.00	70.00			
31				Time Delay, years=					0.00	1.00	3.00			
32				Present Value=					89.3	76.2	-12.9			

Table 17. Summary of Engineering Economic Analysis of Potash Reserves

Note: Tons and Dollars in Millions

	A	B	C	D	E	F	G	H
1			Reserve	Product	Mine Life	Cash Flow	DCF @ 10	Net Value
2			tons	tons	years	Dollars	Dollars	Dollars
3	**4th Ore Zone**							
4	**Within WIPP**							
5	Scenario I	Case 1	18.04	3.17	9.07	42.67	30.90	30.90
6		Case 2	18.04	4.23	12.09	56.90	37.39	37.39
7		Case 3	20.92	5.98	17.08	146.00	80.00	80.00
8	Scenario II	Case 1	18.04	3.17	9.07	42.67	30.90	23.09
9		Case 2	18.04	4.23	12.09	56.90	37.39	29.00
10		Case 3	20.92	5.98	17.08	146.00	80.00	67.80
11	Scenario III	Case 1	18.04	3.17	9.07	42.67	30.90	-52.65
12		Case 2	18.04	4.23	12.09	56.90	37.39	-48.22
13		Case 3	20.92	5.98	17.08	146.00	80.00	-9.90
14	**Additional Area**							
15	Scenario I	Case 1	54.42	10.18	29.08	235.10	90.90	90.90
16		Case 2	54.42	13.57	38.77	321.55	97.05	97.05
17		Case 3	54.49	17.56	50.17	790.30	165.20	165.20
18	Scenario II	Case 1	54.42	10.18	29.08	235.10	90.90	77.60
19		Case 2	54.42	13.57	38.77	321.55	97.05	83.20
20		Case 3	54.49	17.56	50.17	790.30	165.20	145.10
21	Scenario III	Case 1	54.42	10.18	29.08	235.10	90.90	-1.70
22		Case 2	54.42	13.57	38.77	321.55	97.05	2.90
23		Case 3	54.49	17.56	50.17	790.30	165.20	39.00
24	**Combined Area**							
25	Scenario I	Case 1	72.45	13.35	38.15	303.10	98.40	98.40
26		Case 2	72.45	17.80	50.86	404.20	103.84	103.84
27		Case 3	75.41	23.54	67.25	674.70	120.30	120.30
28	Scenario II	Case 1	72.45	13.35	38.15	303.10	98.40	84.50
29		Case 2	72.45	17.80	50.86	404.20	103.84	89.40
30		Case 3	75.41	23.54	67.25	674.70	120.30	104.30
31	Scenario III	Case 1	72.45	13.35	38.15	303.10	98.40	3.90
32		Case 2	72.45	17.80	50.86	404.20	103.84	8.00
33		Case 3	75.41	23.54	67.25	674.70	120.30	20.40
34								
35	**10th Ore Zone**							
36	**Within WIPP**							
37	Scenario I	Case 3	30.60	5.51	13.77	66.00	45.75	45.75
38	Scenario II	Case 3	30.60	5.51	13.77	66.00	45.75	36.60
39	Scenario III	Case 3	30.60	5.51	13.77	66.00	45.75	-45.60
40	**Additional Area**							
41	Scenario I	Case 3	77.17	14.32	35.80	197.47	81.87	81.87
42	Scenario II	Case 3	77.17	14.32	35.80	197.47	81.87	69.40
43	Scenario III	Case 3	77.17	14.32	35.80	197.47	81.87	-18.50
44	**Combined Area**							
45	Scenario I	Case 3	107.77	19.82	49.56	263.48	89.29	89.29
46	Scenario II	Case 3	107.77	19.82	49.56	263.48	89.29	76.20
47	Scenario III	Case 3	107.77	19.82	49.56	263.48	89.29	-12.90

Table 18. Profit Margin As A Function of Ore Grade

	A	B	C	D	E	F	G	H	I	J	K
1		Cut-off Calculations for the 4th Ore Zone (Langbeinite)									
2	% K20	Product	Tons Ore	Cost to Produce		Base Case		10% Higher Case		10% Lower Case	
3		Value	to	Per Ton		Cost	Cost	Cost	Cost	Cost	Cost
4		$/ton	Product	Product		$18/ton	$16/t	$19.8/t	$17.6/t	$16.2/t	$14.4/t
5				Case 1&2	Case 3	Case 1&2	Case 3	Case 1&2	Case 3	Case 1&2	Case 3
6	3.25	74.80	7.96	143.35	127.42	-47.8%	-41.3%	-52.6%	-46.6%	-42.0%	-34.8%
7	3.75	74.80	6.90	124.24	110.43	-39.8%	-32.3%	-45.3%	-38.4%	-33.1%	-24.7%
8	4.25	74.80	6.09	109.62	97.44	-31.8%	-23.2%	-38.0%	-30.2%	-24.2%	-14.7%
9	4.75	74.80	5.45	98.08	87.18	-23.7%	-14.2%	-30.7%	-22.0%	-15.3%	-4.7%
10	5.25	74.80	4.93	88.74	78.88	-15.7%	-5.2%	-23.4%	-13.8%	-6.3%	5.4%
11	5.75	74.80	4.50	81.02	72.02	-7.7%	3.9%	-16.1%	-5.6%	2.6%	15.4%
12	6.25	74.80	4.14	74.54	66.26	0.3%	12.9%	-8.8%	2.6%	11.5%	25.4%
13	6.75	74.80	3.83	69.02	61.35	8.4%	21.9%	-1.5%	10.8%	20.4%	35.5%
14	7.25	74.80	3.57	64.26	57.12	16.4%	31.0%	5.8%	19.0%	29.3%	45.5%
15	8.25	74.80	3.14	56.47	50.20	32.5%	49.0%	20.4%	35.5%	47.2%	65.6%
16	8.75	74.80	2.96	53.24	47.33	40.5%	58.0%	27.7%	43.7%	56.1%	75.6%
17	9.25	74.80	2.80	50.37	44.77	48.5%	67.1%	35.0%	51.9%	65.0%	85.6%
18	9.75	74.80	2.65	47.78	42.47	56.5%	76.1%	42.3%	60.1%	73.9%	95.7%
19	10.25	74.80	2.53	45.45	40.40	64.6%	85.1%	49.6%	68.3%	82.9%	105.7%
20	10.75	74.80	2.41	43.34	38.52	72.6%	94.2%	56.9%	76.5%	91.8%	115.7%
21	11.25	74.80	2.30	41.41	36.81	80.6%	103.2%	64.2%	84.7%	100.7%	125.8%
22											
23		Cut-off Calculations for the 10th Ore Zone (Sylvite)									
24							$12/t		$13.2/t		$10.8/t
25	9.75	72.00	7.69		92.31		-22.0%		-29.1%		-13.3%
26	10.25	72.00	7.32		87.80		-18.0%		-25.5%		-8.9%
27	10.75	72.00	6.98		83.72		-14.0%		-21.8%		-4.4%
28	11.25	72.00	6.67		80.00		-10.0%		-18.2%		0.0%
29	11.75	72.00	6.38		76.60		-6.0%		-14.5%		4.4%
30	12.25	72.00	6.12		73.47		-2.0%		-10.9%		8.9%
31	12.75	72.00	5.88		70.59		2.0%		-7.3%		13.3%
32	13.25	72.00	5.66		67.92		6.0%		-3.6%		17.8%
33	13.75	72.00	5.45		65.45		10.0%		0.0%		22.2%
34	14.25	72.00	5.26		63.16		14.0%		3.6%		26.7%
35	14.75	72.00	5.08		61.02		18.0%		7.3%		31.1%
36	15.25	72.00	4.92		59.02		22.0%		10.9%		35.6%
37	15.75	72.00	4.76		57.14		26.0%		14.5%		40.0%
38	16.25	72.00	4.62		55.38		30.0%		18.2%		44.4%
39	16.75	72.00	4.48		53.73		34.0%		21.8%		48.9%
40	17.25	72.00	4.35		52.17		38.0%		25.5%		53.3%
41	17.75	72.00	4.23		50.70		42.0%		29.1%		57.8%
42	18.25	72.00	4.11		49.32		46.0%		32.7%		62.2%
43	18.75	72.00	4.00		48.00		50.0%		36.4%		66.7%
44	19.25	72.00	3.90		46.75		54.0%		40.0%		71.1%
45	19.75	72.00	3.80		45.57		58.0%		43.6%		75.6%
46	20.25	72.00	3.70		44.44		62.0%		47.3%		80.0%
47	20.75	72.00	3.61		43.37		66.0%		50.9%		84.4%
48	21.25	72.00	3.53		42.35		70.0%		54.5%		88.9%
49	21.75	72.00	3.45		41.38		74.0%		58.2%		93.3%

Table 19. Mining Life Versus Cut-off Grade

	A	B	C	D	E	F	G	H
1							AREA	
2				Cost of	Cut-off	WIPP	Additional	Combined
3				Min & Proc.	Grade	Mining Life	Mining Life	Mining Life
4				($/Ton)	(% K20)	(Years)	(Years)	(Years)
5	4th ORE ZONE (LANGBEINITE)							
6	Case 1 (Mining Extraction = 60%)							
7		Cost 10 % Higher		19.80	6.75%	7.56	26.03	33.60
8		Base Case		18.00	6.25%	9.07	29.08	38.15
9		Cost 10 % Lower		16.20	5.25%	11.51	32.60	44.11
10	Case 2 (Mining Extraction = 80%)							
11		Cost 10 % Higher		19.80	6.75%	10.08	34.71	44.79
12		Base Case		18.00	6.25%	12.09	38.77	5.09
13		Cost 10 % Lower		16.20	5.25%	15.34	43.47	58.81
14	Case 3 (Mining Extraction = 90%)							
15		Cost 10 % Higher		17.60	5.75%	19.47	54.77	74.24
16		Base Case		16.00	5.25%	21.51	66.72	82.23
17		Cost 10 % Lower		14.40	4.75%	23.21	69.92	93.04
18								
19								
20	10th ORE ZONE (SYLVITE)							
21	Case 3 (Mining Extraction = 90%)							
22		Cost 10 % Higher		13.20	13.75%	8.70	26.87	35.58
23		Base Case		12.00	12.25%	13.77	35.80	49.56
24		Cost 10 % Lower		10.80	11.25%	16.94	41.50	58.44

Evaluation of Mineral Resources at the
Waste Isolation Pilot Plant (WIPP) Site

Chapter VII

METHOD OF POTASH RESERVE EVALUATION

by
George B. Griswold

Westinghouse Electric Corporation
Waste Isolation Division
Contract No. PO-75-WJJ644145Z

Submitted by

New Mexico Bureau of Mines and Mineral Resources
Campus Station
Socorro, NM 87801

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PLATES

METHOD OF POTASH RESERVE EVALUATION

George B. Griswold

Evaluation of potash reserves was based solely on subsurface information from 40 core holes previously drilled within and around the WIPP Site. The nearest underground mine operations are currently no closer than one mile from the outer boundary of WIPP. All 40 holes were drilled using brine (containing potassium as well as sodium chloride) to inhibit dissolution of potassic minerals. The results of chemical analyses of the ore-bearing intervals were adjusted to calculate the percentage equivalent as individual natural mineral species. Only the K_2O percentages as either sylvite or langbeinite were used to compute ore reserves.

The locations of the 40 drill holes used to compute potash reserves are shown on **Plate 1**. Also shown are 34 other potash core holes, all surrounding the WIPP boundary, that were drilled by potash or exploration companies. Records of ore intercepts of these 34 holes were not available to us. Information on them is held in confidence by the Bureau of Land Management (BLM) in accordance with CFR 3590. The reserve calculations are valid for the area *within the WIPP Site* itself because all drill-hole information within those bounds was available to us. Only the BLM, which has drilling records of all holes in the entire Carlsbad Potash Mining District, can verify the validity of reserve estimates made outside of WIPP. A reasonable estimate of the potash reserves is possible for an area extending about one mile outside of the WIPP boundary excepting the southwest quadrant of this perimeter area. The essential results of the reserve calculation are:

1. The 4th ore zone contains *BLM Lease Grade* langbeinite ore in the amounts of:
   40.5 million tons @ 6.99% K_2O grade within the WIPP area
   126.0 million tons @ 7.30% K_2O grade outside of the WIPP area
   166.5 million tons @ 7.22% K_2O grade in the entire study area

2. The 10th ore zone contains *BLM Lease Grade* sylvite ore in the amounts of:
   52.3 million tons @ 13.99% K_2O grade within the WIPP area
   105.0 million tons @ 14.96% K_2O grade outside of the WIPP area
   157.3 million tons @ 14.64% K_2O grade in the entire study area

3. Potash resources are present in the 2nd, 3rd, 5th, 8th, 9th, and 11th ore zones within the WIPP Site, but with minor exceptions do not meet the lease grade standards currently used by the BLM. These resources could only become minable if advanced thin-seam mining methods are developed in the future.

4. Most of the BLM Lease Grade reserves in the 4th and 10th ore zones are profitable using mining and processing technology currently employed by nearby potash producers. Nearby mines will eventually extend their underground workings to the

boundary of the WIPP enclave, and there will no be no need to build an entirely new potash mine and plant facility. Previous evaluators assumed that such a new facility would be required. The results indicated the following tonnages could be mined profitably:

4th ore zone: 72.4 million tons (6.0 ft mining height, >6.25% K_2O as langbeinite) of which 18.0 million tons lie within and 54.4 million tons outside of WIPP;

10th ore zone: 107.8 million tons (4.5 ft mining height, >12.25% K_2O as sylvite) of which 30.6 million tons lie within and 77.2 million tons outside of WIPP.

FORMULATION OF THE DRILL-HOLE DATABASE

Drill holes available for use in reserve calculations. In 1976 Sandia National Laboratories (SNL) in cooperation with the U.S. Geological Survey (USGS) drilled 21 potash-evaluation holes within and immediately adjacent to the current WIPP Site. Complete records of these 21 holes have been reported by Jones (1978). In addition, 18 potash-evaluation drill holes (seven within the current site and 12 immediately adjacent to the site) were drilled by private companies which submitted records of assayed intervals to the USGS Conservation Division (subsequently transferred to the BLM). Copies of these records were obtained from the BLM Carlsbad Resource Area Office. One additional hole, AEC No. 8, drilled as part of an earlier WIPP Site evaluation, was cored and assayed for potash. The hole lies just northeast of the WIPP boundary. These 40 holes provided the database for potash reserve calculations.

A complete listing of the 40 holes used in the reserve calculation is given in **Table 1** and their locations are shown on **Plate 1**.

Brief history of drill holes that constitute the database. In 1978 the USGS performed the first potash-reserve study at WIPP (John et al., 1978). In that report, the assay results of 37 of the 40 holes were given. The records of three industry drilled holes, I-377, I-456, and I-457, were obtained from the BLM. The assay records of these three holes became available to the public after the Department of Energy (DOE) bought out the lease holdings of IMC Fertilizers, Inc.

Special note is made of hole D-123 that is at the eastern edge of sec. 34 in the southeast corner of the WIPP Site. This hole was drilled to a depth of 1880 ft, deep enough to penetrate all the ore zones, but no assay records were provided to the BLM. The company that drilled the hole in 1953 (Duval Sulphur and Potash) apparently thought the core revealed no commercial potash. This hole was eliminated from our database. It had little effect on resource calculation.

As mentioned in the summary, additional potash core holes have been drilled in the area by mining or exploration companies, mostly to the west. However, the detailed records, including chemical analyses of suspected ore intercepts, have not been released to the public at the request of the companies. This restriction applies so long as the company holds the mineral lease on which the holes were drilled. The 34 such holes that exist in the map area are shown on **Plate 1** but are not listed in **Table 1**. It is noteworthy that all holes drilled within the existing WIPP Site have been available to us. For this reason the calculations within the WIPP Site should be considered as valid.

Hole locations. The locations of most of the 40 holes used in the reserve calculation are shown on the most current 7.5-minute USGS topographic quadrangle maps of the area. These locations were digitized using in the New Mexico (East Zone) coordinates. In the few cases where the holes were not shown on the maps, the locations were first posted on the appropriate quadrangle map using the survey description shown on the written drill records filed with the BLM Carlsbad office, and then their positions were digitized using a Calcomp Drawing Board Two. This phase of the work was done by Thomas R. Mann & Associates, Inc. under contract. That company also compiled the graphics for **Plate 1**.

Drill-hole elevations. The written drill record gives the elevation of the hole. The records then report formation changes, ore-zone intercepts, assays, etc. referenced as depths below the surface. These holes were drilled from the early 1950s to the late 1970s, and the surface elevations were surveyed from a variety of benchmarks. To further complicate matters, some records are to "drill-rig floor" and others to surface elevations.

The surface elevation was picked at each hole based on the current USGS 7.5 minute quadrangle maps in order to eliminate any survey errors. In cases where the depth measuring point was the drill-rig floor, a slight error may have been induced. However, potash drilling rigs are small units compared to oil-field rotaries, and the floor probably would be only 2 to 3 ft above ground level. For the purpose of compiling structure maps, the error would thus be insignificant.

Formation and ore-zone depths. The depths to ore came from the John et al., (1978) report for all but holes I-377, I-456, and I-457, for which the data came from records at BLM Carlsbad. Formation depths (Marker Beds) came from Jones (1978) for the "P-series" of 21 holes drilled by SNL-USGS in 1977 plus AEC No. 8. Formation depths for all of the remaining 18 holes came from records at BLM Carlsbad office.

Calculated mineral content and K_2O percentage of ore minerals. The calculation of the percent K_2O as sylvite or langbeinite is not a simple process. First, the suspected ore-bearing interval is selected by visual examination of the recovered core. Once the intervals are selected, the core is then split longitudinally with one half saved for reference and the other half sent for chemical analysis. In addition to the two ore minerals, sylvite (KCl) and langbeinite ($K_2SO_4 \cdot 2MgSO_4$), the ore beds in the Carlsbad Potash Mining District typically are a mixture of halite, anhydrite, polyhalite, a variety of other gangue minerals including but potassium-bearing minerals (such as carnallite) and magnesium sulfates (such as kieserite), and "insolubles" (mostly clay).

These ore and mineral calculations were performed by the USGS for the P-Series and AEC No. 8, and by the individual mining companies when they reported drilling results to the BLM. Therefore, the assay information entered into the database has been adjusted for the mineral suite present at each specific ore intercept. A few spot checks of these calculations were made, and found to be correct.

What then was entered into the database was the percent in K_2O units for sylvite or langbeinite. These are considered to be the only two economic minerals present. The usage of percent K_2O rather than the true chemical equivalent of potassium (KCl for sylvite or $K_2SO_4 \cdot 2MgSO_4$ for langbeinite) is a custom of the potassium fertilizer industry.

Ore intercepts. There are 11 known potash-bearing horizons in the Carlsbad Potash Mining District. They are numbered in sequence upward. The 40 drill holes that form the database encountered potash mineralization in all but the 1st, 6th, and 7th of these horizons. While the principal economic deposits are only in the 4th and 10th ore zones, all known mineral intercepts were entered into the database, and the in-place tons and grade were computed for each.

The drill records report the depths to tops, bottoms, and resulting thicknesses of each ore intercept. This information was placed into the database. In a few instances, John et al. (1978) reported double intercepts for a single ore bed when a lens of barren halite divided the bed into two layers. Most notably this occurred in the 4th ore zone intercept in hole P-21. This particular intercept was combined and corrected so that the data input was 7.35 ft of 5.88% K_2O as langbeinite. In all other cases the thicker reported intercepts were always selected.

Mixed ores. It is common in this area of the Carlsbad Potash Mining District to find ore that is a mixture of both sylvite and langbeinite. This is true for both the 4th and 10th ore zones in the vicinity of the WIPP Site. These mixed ores are being mined and processed with economic success by one of the mining companies, IMC Fertilizer, a few miles west and south of the WIPP Site.

The BLM has used an "Equivalent Grade" for such ore mixtures. The calculation is as follows:

Langbeinite-dominant ores: Equiv. K_2O = % K_2O as langbeinite + 0.4 x % K_2O as sylvite

Sylvite-dominant ores: Equiv. K_2O = % K_2O as sylvite + 2.5 × % K_2O as langbeinite

This 4:1 ratio is based on a balance of % K_2O between the two minerals and their sales value. The reserves of both the 4th and 10th ore zones were calculated using the Equivalent Grade: langbeinite-dominant for the 4th and sylvite-dominant for the 10th.

DEFINITIONS OF ORE RESERVES VERSUS ORE RESOURCES

The mining industry and the U.S. Bureau of Mines (USBM) maintain a rather restricted interpretation of what can be called reserves. In short, this means that the ore in-place can be mined under current economics and technology. Others, particularly the USGS, will use the term resource to define in-place mineral-bearing bodies that have the potential to be mined, which is a more liberal interpretation. A full discussion of these two terms can be found in USGS-USBM (1980).

The in-place potash-bearing 4th and 10th ore zones that were quantified meet the more restrictive definition of reserve because they would provide reasonable profits at current market values for potash products, and can be extracted with currently available mining and processing methods. In addition, most of the 4th and 10th ore zones would be classified as ore reserves by order of the Secretary of the Interior dated October 21, 1986, according to which *four feet of 10 percent K_2O as sylvite or four feet of 4 percent K_2O as langbeinite or equivalent combination of the two minerals* defines *potash reserves*. The term *Lease Grade Reserves* was used to define those resources that meet or exceed the above criterion and thereby become reserves.

On the other hand, the reserves quantified for the 2nd, 3rd, 5th, 8th, 9th, and 11th ore zones should be considered resources. The resources may become minable if new thin-seam mechanical miners are developed. Solution mining might be applied to those that are sylvite-bearing, but not to those containing the relatively insoluble langbeinite.

To be classified as an ore reserve also means that the geometry of the in-place ore is well defined by either reliable drilling or actual sampled exposures, whether it be from outcroppings or mine faces underground. In case of WIPP the reserves must be regarded as drill-defined only.

The spacing of drill holes within the WIPP boundary is approximately on one-mile centers. This meets the current BLM requirements to define ore reserves, which allows a projection of three-quarters of a mile outward from an existing hole (or 1.5 mile spacing). However, it is common for some of the nearby mining companies to close up the drill spacing to 2000 or even 1000-ft spacing to define better ore-bearing areas in advance of developing detailed mining plans. Nonetheless, the potash industry probably would agree that the spacing within the WIPP boundary meets their criteria for defining ore reserves, and certainly is adequate to define their life-of-mine reserves.

Outside of the WIPP boundary a clear-cut line cannot be drawn between what is to be classed as ore reserve or ore resource, because the drilling information is incomplete, particularly to the west, and the of lack any subsurface information whatsoever on the immediate southern and eastern boundaries of the WIPP Site. More discussion of the validity of the estimates of reserves and resources adjacent to the WIPP Site accompanies the following descriptions of individual ore zones.

COMPUTATION OF ORE IN-PLACE RESOURCES

We used the term resources during the process of determining the areal extent, thickness, and K_2O grade of the in-place potash mineralization for each of the sampled ore zones. Afterwards the determination was made of what could be called Lease Grade Reserve followed by determining what portion of that reserve could be considered economic using today's prices and mining-processing costs.

Brief review of previous estimates. The original in-place reserve estimates for the WIPP Site were done by the USGS (John et al., 1978). All subsequent economic analyses by the USBM (1977) appear to have used the USGS-generated data. The method used was based on the time-honored triangular method for calculating in-place tonnages and grade. The method was briefly described by John et al. (1978, p. 29):

> ...The weighted-volume estimate method (Forrester, 1946, p. 560-562) was used for calculating ore reserves. Triangular networks among drill holes were constructed for each ore zone, and ore grade: types and thicknesses were posted at the apices of the triangles and(or) cutoff points. The weighted-average grade and average thickness were determined for each triangle and these and other data were entered into an electronic graphics calculator. Then, the perimeter of the triangle was scaled by the calculator cursor and the tons of potash ore electronically calculated.

The method produced reliable results. However, in recent years digitally based computer methods have been developed that make the task both easier and more accurate.

The USGS report did not present separate maps showing the in-place reserves for each ore zone. Instead, only tabular information is given for each ore zone, and the maps are a composite (stacking) of ore zones that present only the outer bounds for three definitions of reserves: Lower Cutoff (>3% K_2O as langbeinite or >8% K_2O as sylvite), Lease Grade (>4 % K_2O as langbeinite or 10% K_2O as sylvite), and Higher Grade (>8% K_2O as langbeinite or 14% K_2O as sylvite), all at a thickness of 4 ft or more.

An essential conclusion of the USGS study was given on p. 28:

> .... Although the potash ore is not as high a grade, nor are the thicknesses and continuity as great as some of the ore currently mined in the Carlsbad Mining District, at U.S. Geological Survey lease grade, an estimated 353.3 million tons of ore (315.7 million tons measured and 37.6 million tons of indicated ore) is present in the WIPP Area. ...

It will be shown below that evaluation presented here is in essential agreement with the USGS resource-reserve calculation done some 17 years ago.

The reserves were apparently recalculated by Seedorff et al. (1978). They used a method of contouring between holes and then used a planimeter to determine areas. The areas were converted to volumes based on the average thicknesses reported in the drill-hole records. That method can produce reliable estimates except in one important step: Seedorff et al. contoured "isopleths" of the product of grade and thickness *at each drill hole*. Grade and thickness are not correlative in the Carlsbad Potash Mining District, and that method thus will induce error. The Seedorff et al. study did include maps of each ore bed, which were useful in comparing this evaluation to theirs.

Selection of a computer program to calculate in-place volumes and grades. There are a number of geology-oriented computer programs that could be used to determine ore resources in-place based on drill hole intercepts. One of the more widely used programs is MacGridzo marketed by RockWare Earth Science Software. This particular program was selected because of its ease of use, the ability to readily perform mathematical calculations on individual grids (cells), perform summations of selected areas, etc. In addition, experience existed in applying the MacGridzo program to determine ore reserves at a nearby potash mine. In that study there was the ability to compare computer-generated data based on simple drill-hole information with actual results from mining that reserve. This provided confidence in the MacGridzo program as a useful tool in estimating potash reserves.

A separate spreadsheet program was used for inputting the drill-hole information, and another software program to compile histograms and charts of output data generated within the MacGridzo program. **Figure 1** diagrams the methodology used to input, calculate and output data using the MacGridzo program.

Brief description of the MacGridzo program. MacGridzo places a rectangular grid over a set of randomly spaced information data points (in our case the selected ore intercept information: depth, thickness, and grade). This increment of the hole data can be considered the "Z" component, while the hole location provides the "X" and "Y" of a two-dimensional array.

The program then calculates a unique value for the Z-component at the center of each grid based on interpolation of the Z-component values of nearby holes. To accomplish these calculations, the program can be set on either a "radial search" or simply a method based on the nearest set of drill-hole information. The radial search mode was used to avoid emphasis on a cluster of holes.

Once the grid values are determined for any parameter such as grade or thickness, they can be recalculated using simple algorithms. For example, the grade can be adjusted for thickness to obtain the adjusted grade based on an increase in mining height. Similarly, the tons in that grid can be determined for the new thickness using a "tonnage factor". In the case of langbeinite ores, the tonnage factor was also adjusted per grid based on the percent langbeinite in the ore. An important capability is that the thickness values can be assigned independent of the grade values. This is a distinct advantage over the method used by Seedorff et al. (1978). Another advantage of the MacGridzo program is contour plots, whether it be grade, ratio of sylvite to langbeinite, thickness, products of thickness and grade, or structure of the top or bottoms of an ore zone, that can be readily produced to assist in visualization of the data files.

The size of the cells selected was 571.90 ft in the east-west (X) direction and 510.28 ft in the north-south (Y) direction. This particular grid size was selected to coincide with the exact position of the north and east sidelines of the WIPP Site. This assisted in partitioning the reserve summations to determine tonnages inside and outside the WIPP boundaries. The cell size selected resulted in the assignment of 60 cells in the east-west direction and 63 in the north-south direction, for a total of 3780 cells. The dimensions of an individual cell results in the ability to assign individual thickness and grade to 58,000-ton blocks of in-place ore 3 ft thick (a typical thickness).

Definition of the gridded (study) area. A feature of the MacGridzo program is the placement of a rectangular boundary based on the extremity coordinates of the data set. Hole No. U-134 determined the northern, Hole P-20 the eastern, Hole No. P-16 the southern, and Hole No. D-48 the western boundary of the gridded area. Resource tonnages and grades could be estimated within that rectangle. Therefore, on labels for maps and tables the term "Entire Gridded Area" was used to define calculations within that boundary. In the text, this is referred to as the "Study Area."

Separation of the WIPP area from the study area. It was then a simple procedure to clip the gridded cell information along the WIPP boundaries. This allowed the calculation of resources for the entire study area and the WIPP boundary area. The simple difference in the two resulted in defining resources outside of WIPP.

Initial calculation of in-place resources. The initial step in calculating the resources was determining the actual in-place tonnages in grade ranges using only the actual thicknesses and assays for each ore intercept reported in the drill-hole records. The first procedure was to determine the thicknesses for each cell using the radial search method. Second, assay results for % K_2O as langbeinite, sylvite (or equivalent mixture using the 2.5:1 ratio) were assigned in a similar manner to each cell. The third step was to determine the "thickness x grade product." Once these three steps were completed, a contour map was produced for: thickness, grade, and product of thickness × grade. These maps gave a visual presentation of the actual ore resources in-place without consideration for the need to correct for mining height—a step that would be needed to determine the viability of mining.

The product maps (grade × thickness) provided an essential element for determining what portion of the resources would become reserves. To illustrate, the BLM uses the criterion of 4 ft of 10% K_2O as sylvite to determine Lease Grade Reserves. Therefore, the product of thickness × grade is 40. This criterion is not dependent on thickness or grade but the product of the two. Of course one always has to back in the criterion that the grade will be at least 10% K_2O for sylvite (or 4% for langbeinite) if the thickness is less than 4 ft. This latter criterion was readily determined by examination of the contour map of grade. The advantage of the product contour maps is that one can readily determine the outer boundaries for any specific definition of reserves, e.g., the 40 contour is the boundary for Lease Grade Sylvite Reserve.

The resource tonnages could then be determined by calculating the volume of each cell which was multiplied by the "Tonnage Factor." For sylvite ores we used a constant tonnage factor equal to 14.8 cubic feet per ton. For langbeinite ores we used:

$$\text{Tonnage Factor} = 14.8 - (0.152 \times \% K_2O \text{ as langbeinite})$$

This correction was rather small, but it was easily accomplished by the computer.

The last step in resource calculation was to perform summations of all the cell data. For ease in presentation of the results, the in-place tonnages were calculated in step ranges of 0.5 % K_2O of the ore mineral (sylvite, langbeinite, or equivalent grade mixture), which were then compiled into histograms. Finally, tables and graphs were made from the histogram data to determine in-place resource tonnages versus grade using weighted averages.

Adjustment of in-place resources to mining height. Most of the in-place resources are in beds thinner than can be currently mined. For example, seam mining of sylvite is done by drum-type machines that can mine at no less than 4 ft. In the case of langbeinite ores, the current method is to undercut the mine face, drill, blast, and load using mechanical-arm machines. For that type of mining headroom is normally no less than 5 ft.

Therefore, in order to determine what portion of the in-place resources could be considered minable reserves we had to include a factor for diluting (lowering) the grade to allow for current mining technology. This was a simple task for the computer. The grade of each cell was reduced in linear proportion to the ratio of the in-place thickness to the desired mining height. This procedure reduced the grade but increased the tonnage.

The term "Adjusted Mining Height" was used when recomputing the in-place resources in order to be able to determine what resources would meet the definition of reserves. The mining height was adjusted in 0.5 ft steps from the in-place thickness up to a mining height of 7 ft. Because the product contour maps indicated that only the 4th and 10th ore zones would meet Lease Grade Reserves this exercise of thickness adjustment was done only for those two ore zones.

The results of the grade adjustment of the 4th and 10th ore zones for mining thickness formed the database for all subsequent economic evaluations.

RESULTS OF ORE RESOURCE AND RESERVE CALCULATIONS

4th ore zone. Economic analysis (*Chapter VIII*) has shown that much of this ore could be mined at a profit, which transforms much of the resource into reserve. It was concluded that economic mining could be conducted in the 4th langbeinite ore zone of those resources that meet a cutoff grade of 6.25% K_2O equivalent langbeinite using a minimum mining height of 6 ft.

Figures 2, 3, and 4 are contour maps of the in-place thickness, grade, and grade × thickness product. This ore zone is mostly langbeinite, but it does contain recoverable amounts of sylvite. Therefore, **Figures 3 and 4** are for equivalent langbeinite, i.e. the % K_2O grade of langbeinite is adjusted upward by adding 0.4 × % K_2O as sylvite where present. Please note the position of the "16" contour on **Figure 4**. The material inside that contour meets the BLM Lease Grade reserve criteria of 4% K_2O (or equivalent) langbeinite at a 4 ft mining height. Also note the approximate position of the "37.5" contour which represents the criterion on economic mining.

Figures 5 through 12 are histograms of the resources that were adjusted for mining thicknesses from 4 up to 7 ft for the entire study (gridded) area, and **Figures 13 through 20** are histograms for the same data within the WIPP Boundary. **Figures 21 through 24** present the histogram data in tonnage-summation-curve formats to determine reserves as a function of cutoff grade or as a function of the average grade, again for the entire study area and for within the WIPP boundary. Calculation of the reserves outside of the WIPP boundary was a simple matter of subtraction.

A summation of the cell data for the 4th ore zone was made of the three significant criteria and partitioned by areas. The results are in **Table 2**.

The resource and reserve estimates are valid within the WIPP boundary because all drill-hole information within that boundary were available and the spacing of the holes was on the order of one-mile centers.

The tonnages and grade outside of the WIPP boundary were estimated in accordance with the grid generated by the MacGridzo computer program that extended out to the furthest drill holes in all cardinal directions. Referring to **Figure 4**, note that the "16" contour, which determined the BLM Lease Grade reserve, defined a large reserve that extends north and east of the WIPP Site. Also note there was a sufficient number of holes in that area to justify classification as drill-defined reserves. The same held true for our estimate of minable reserves (defined by the "37.5" contour) for that area.

BLM Lease Grade reserve in a separate location was evident on the west, defined by holes 12, 14, 48, 104, and 120. However, the information base did not include several industry-drilled holes along the west flank of the WIPP Site (see **Plate 1** for the locations of these holes because they are not shown elsewhere), which would have improved the estimate of reserve in that area. Nonetheless, the estimate of BLM Lease Grade reserve appears to be reasonable within one mile west of the WIPP boundary. It is important to note that minable reserve (defined by the "42" contour in **Figure 4**) does not exist within one mile of the WIPP boundary on the west. Similarly, the 4th ore zone boundaries were well defined but a potential for additional discoveries exists in the southwest portion of the study area where few exploratory holes exist.

Figures 25 and 26 were used to measure the degree to which the 4th ore zone contained mixed ore. It was apparent that the northeast portion of the mineralized area was simply langbeinite and contained the major portion of the resources and reserves for that ore bed. Therefore, exclusion of the sylvite portion for determination of equivalent % K_2O had little effect on the determination of reserves in the northeast. However, the presence of sylvite was important in defining BLM Lease Grade reserves in the northwest. **Figure 27** is a structural contour map of the top of the 4th ore zone. The map is consistent with the known structure of the Salado Formation in the WIPP Site area.

10th ore zone.—As with the 4th ore zone, economic analysis has shown that much of this resource could be mined at a profit, which transforms much of the resource into reserve. The 10th ore zone is dominantly sylvite, in contrast with the dominantly langbeinite ores of the 4th ore zone. Economic mining could be conducted in the 10th langbeinite ore zone of those resources that meet a cutoff grade of 12.25% K_2O equivalent sylvite using a minimum mining height of 4.5 ft.

Figures 28, 29 and 30 are contour maps of the in-place thickness, grade, and grade $\times$ thickness product. Although this ore zone is mostly sylvite, it does contain recoverable amounts of langbeinite. Therefore, **Figures 29 and 30** are for equivalent sylvite, i.e. the % K_2O grade of sylvite is adjusted upward by adding 2.5 $\times$ % K_2O as langbeinite where present. Please note the position of the "40" contour in **Figure 30**. The material inside that contour meets the BLM Lease Grade reserve criteria of 10% K_2O (or equivalent) sylvite at a 4 ft mining height. Also note that the approximate position of the "55" contour that represents the economic-mining criterion. The "55" contour lies between the 50 and 60, the scale of the map is too small to show its exact position. However, when summations of cell values were done by computed the tonnages were quite precise.

A summation of the cell data for the 10th ore zone was made of the three significant criteria and partitioned by areas. The results are shown in Table 3.

Figures 31 through 38 are histograms of the resources for a range of mining thicknesses for the entire study (gridded) area, and **Figures 39 through 46** are histograms for the same data within the WIPP boundary. **Figures 47 through 50** present the histogram data in tonnage-summation-curve-formats to determine reserves as a function of cutoff grade and as a function of the average grade, again for the entire study area and for within the WIPP boundary. To calculate the reserves outside of the WIPP boundary was a simple matter of subtraction.

As with the 4th ore zone, the 10th ore zone resource and reserve estimates are valid within the WIPP boundary because all drill-hole information within that boundary were available to us and the spacing of the holes was on the order of one-mile centers.

The tonnages and grade outside of the WIPP boundary were estimated in accordance with the grid generated by the MacGridzo computer program that extended out to the farthest drill holes in all cardinal directions. Referring to **Figure 30**, note that the "40" contour, which determines the BLM Lease Grade reserve, defines a reserve that extends over much of the eastern half of the WIPP Site and continues to the northeast. The BLM Lease Grade boundary also extends southward from the WIPP Site. On the west, leasable reserves enter into the northwestern edges of the WIPP Site.

A sufficient number of holes are in secs. 10, 11, 14, 23, and 26 to adequately define reserves, both at the BLM and minable definitions, and to justify classification as defined reserves for about one mile outward from the WIPP boundary to the northeast.

The estimate of reserves on the south is hampered by a lack of drill-hole information. It is worthy of note that the computer-generated "40" contour passes in the vicinity of hole D-123 (shown only on **Plate 1**), the core of which was not assayed by the Duval Sulphur and Potash Company because it ap[illegible] be subeconom[illegible]. The reserves in the E½ sec. 34 may be overestimated within [illegible] boundary and in a small part of sec. 35 outside of the WIPP Site. However, the [illegible] are reasonable for a mile-long extension southward from the WIPP boundary into secs. 3, 4, and 5, because the outline of the boundary for defined reserves closely matches that of the outline for reserves shown on the most current BLM map.

BLM Lease Grade reserves are present in the western portion of the study area, based on both the spacing of holes with assayed ore intercepts and agreement with the most current BLM map. The BLM Lease Grade reserve would meet the conditions of minable reserve. Note that the leasehold in that area (Western Ag-Minerals Company) has done relatively close-spaced drilling in secs. 23 and 26 and less in secs. 24 and 25. The drilling implied that the 10th ore zone becomes lower in quality as it approaches the WIPP boundary from the west, which is in agreement with our computer-generated contours.

The potash deposits of the 10th ore zone are mixes of sylvite and langbeinite, more so than in the 4th ore zone, with the sylvite being dominant. **Figures 51 and 52** present contours of the % K_2O content as separate minerals. The 10th ore zone is mixed ore over much of its central and southeast mass within the WIPP boundary. On the west it is sylvite only. Mixed ore continues northeastward from within the WIPP Site into the one-mile zone outside it, and commercial ore extends perhaps an additional half mile to the north based on the most current BLM maps. **Figure 53** is a structure map contoured at the top of the 10th ore zone. It reflects the same structure as the underlying 4th ore zone.

Other ore zones. It was concluded that the intercepts of all other ore zones within the WIPP Site that meet the criteria for BLM Lease Grade reserve are so small that they truly should be termed resources. If and when they would be mined will depend on the development of new methods for thin-seam mining. Only the in-place resources were calculated for these zones and are given in **Table 4**.

Figures 54 through 59 are contour maps of the grade × thickness for each of these subeconomic resources. **Figures 60 through 65** are histograms of these resources, sorted by grade ranges, of the entire study (gridded) area. **Figures 66 through 71** are the same type histograms of the resources within the WIPP Site. Finally, **Figures 72 and 73** are the same sets of data presented in summations of tonnages versus weighted-average in-place grade, again one for the entire study (gridded) area and one for the WIPP Site.

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Table 1. Ore zone data from USGS Open-file Report 78-828.

Hole	North	East	Surface	2nd	3rd	4th	5th	8th	9th	10th	11th
AEC8	513579	679936	3532			X	X			X	
NF-1	514352	667501	3419	X		X				X	
NF-2	515149	665289	3401			X				X	
1	493668	662748	3346			X				X	
2	498545	6[illegible]2593	3481			X				X	
3	498716	[illegible]	3384	X		X				X	
4	493519	[illegible]	3443			X				X	
5	504060	667156	3467			X				X	
6	496110	657109	3355			X				X	
7	487526	[illegible]	3333			X				X	X
8	487407	[illegible]	3340	X		X			X	X	X
9	489558	[illegible]	3413	X	X	X		X		X	
10	496361	678401	3510		X	X		X	X	X	
11	503799	678165	3505			X	X			X	
12	503918	656661	3375	X		X				X	
13	509024	657013	3347	X		X				X	
14	499194	652152	3360	X		X				X	
15	488451	657128	3309			X				X	
16	483712	663927	3319	X		X				X	
17	484122	667950	3336	X		X				X	
18	493580	682611	3479			X		X		X	
19	500353	[illegible]547	3542			X				X	
20	504866	683180	3554			X	X	X	X	X	
21	508358	677851	3510	X		X		X			
48	504173	649421	3349	X		X					
70	514285	661946	3380	X		X	X	X			
81	514622	672738	3469			X					
82	509315	662154	3379			X					
91	509453	672861	3448			X				X	
92	509346	667207	3418			X				X	
104	501442	655464	3388			X				X	
120	507722	653102	3329			X	X			X	
134	515656	658085	3361			X		X			
207	500079	658297	3400			X		X		X	
374	493614	659279	3343			X		X		X	
375	493213	667609	3384			X				X	
376	503777	662488	3404	X	X		X			X	
377	503868	672806	3492	X	X	X		X		X	
456	498952	675348	3516		X	X		X		X	
457	493566	674053	3453		X	X				X	

NOTES:
1. X denotes that assay information for that zone was available
2. Holes AEC 8 and 1 through 21 drilled by the USGS during site study
3. Holes NF-1 and NF-2 drilled by National Farmers Union
4. Holes 70, 81, 82, 91, and 92 drilled by National Farmers Union
5. Holes 101, 120, and 207 drilled by Duval Sulphur and Potash Co.
6. Holes 374, 375, 376, 377, 456, and 457 drilled by IMC Fertilizer, Inc.
7. Hole 134 drilled by U.S. Potash Co.

Table 2. Resources and reserves of the 4th langbeinite ore zone.

Area	Tonnage (millions)	Avg. % K_2O (equiv. lang.)
Entire study area		
In-place resource (>4% K_2O and actual thickness)	168.7	8.02
BLM Lease Grade reserve (>4% K_2O at 4 ft mining)	166.5	7.22
Minable reserve (>6.25% K_2O and 6 ft mining)	72.4	7.95
Inside WIPP boundary		
In-place resource (>4% K_2O and actual thickness)	47.0	7.21
BLM Lease Grade reserve (>4% K_2O at 4 ft mining)	40.5	6.99
Minable reserve (>6.25% K_2O and 6 ft mining)	18.0	7.59
Outside of the WIPP boundary (about one mile)		
In-place resource (>4% K_2O and actual thickness)	121.7	8.33
BLM Lease Grade reserve (>4% K_2O at 4 ft mining)	126.0	7.30
Minable reserve (>6.25% K_2O at 6 ft mining)	54.4	8.07

Table 3.Resources and reserves of the 10th sylvite ore zone.

Area	Tonnage (millions)	Avg. % K_2O (equiv. sylvite)
Entire study area		
In-place resource (>10% K_2O and actual thickness)	168.2	14.61
BLM Lease Grade reserve (>10% K_2O at 4 ft mining)	157.3	14.64
Minable reserve (>12.25% K_2O and 4.5 ft mining)	107.8	15.33
Inside WIPP boundary		
In-place resource (>10% K_2O and actual thickness)	53.7	14.26
BLM Lease Grade reserve (>10% K_2O at 4 ft mining)	52.3	13.99
Minable reserve (>12.25% K_2O and 4.5 ft mining)	30.6	15.00
Outside of the WIPP boundary (about one mile)		
In-place resource (>10% K_2O and actual thickness)	114.5	14.77
BLM Lease Grade reserve (>10% K_2O and 4 ft mining)	105.0	14.96
Minable reserve (>12.25% K_2O at 4.5 ft mining)	77.2	15.46

Table 4. In-place resources for other ore zones. (Tons in millions)

	Entire study area		Within WIPP		Outside of WIPP	
Ore zone	Tons	% K_2O	Tons	% K_2O	Tons	% K_2O
2 (langbeinite >4% K_2O)	4.2	6.32	2.3	6.34	1.9	6.30
3 (equivalent langbeinite >4% K_2O)	16.2	5.93	8.9	6.20	7.3	5.60
5 (langbeinite >4% K_2O)	17.8	6.81	4.9	5.74	12.9	7.22
8 (Sylvite >10% K_2O)	18.0	14.29	1.8	15.71	16.2	14.13
9 (Sylvite >10% K_2O)	1.8	12.37	0.5	11.70	1.3	12.63
11 (Sylvite >10% K_2O)	none		none			

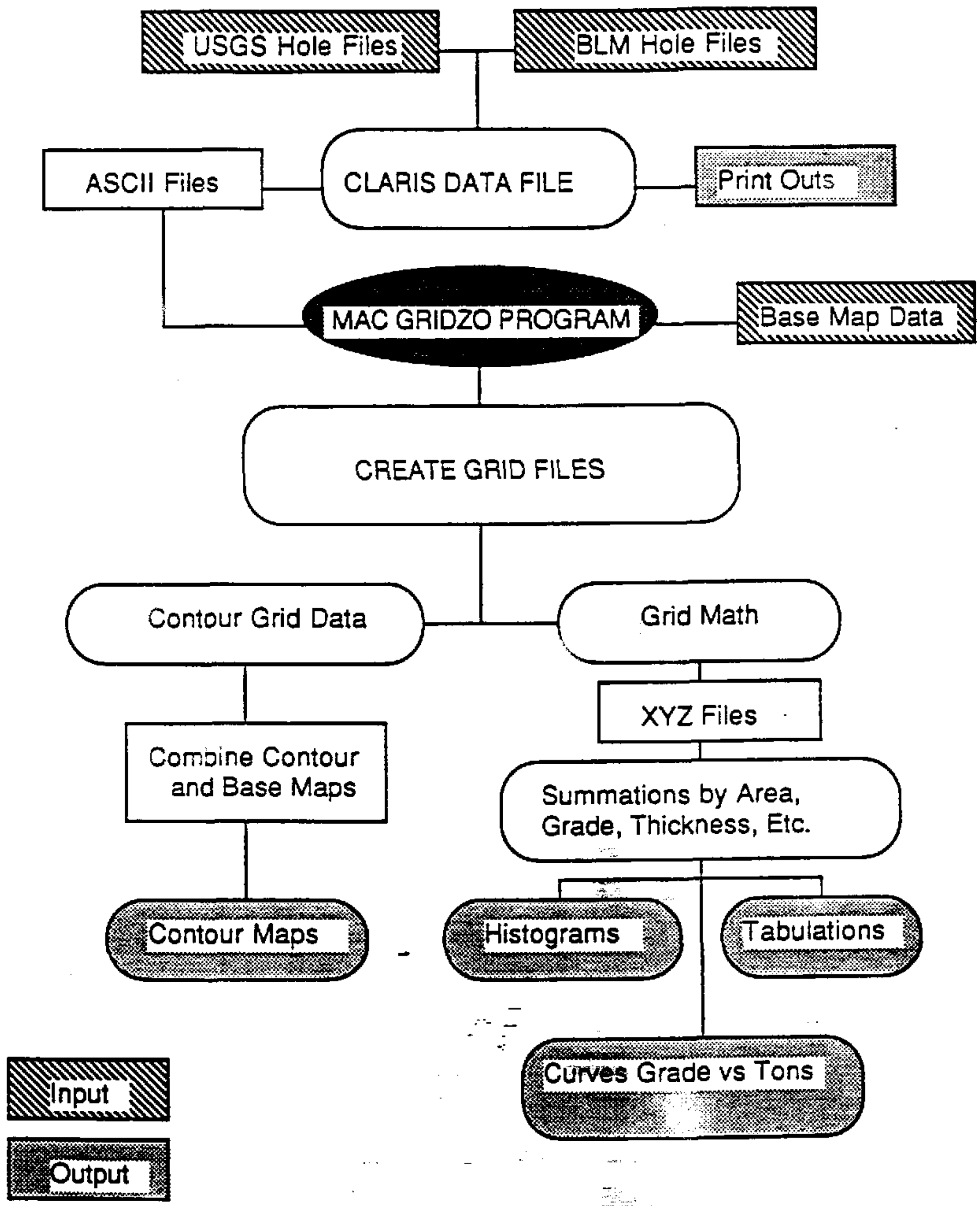

Figure 1
Method of Potash Reserve Calculation

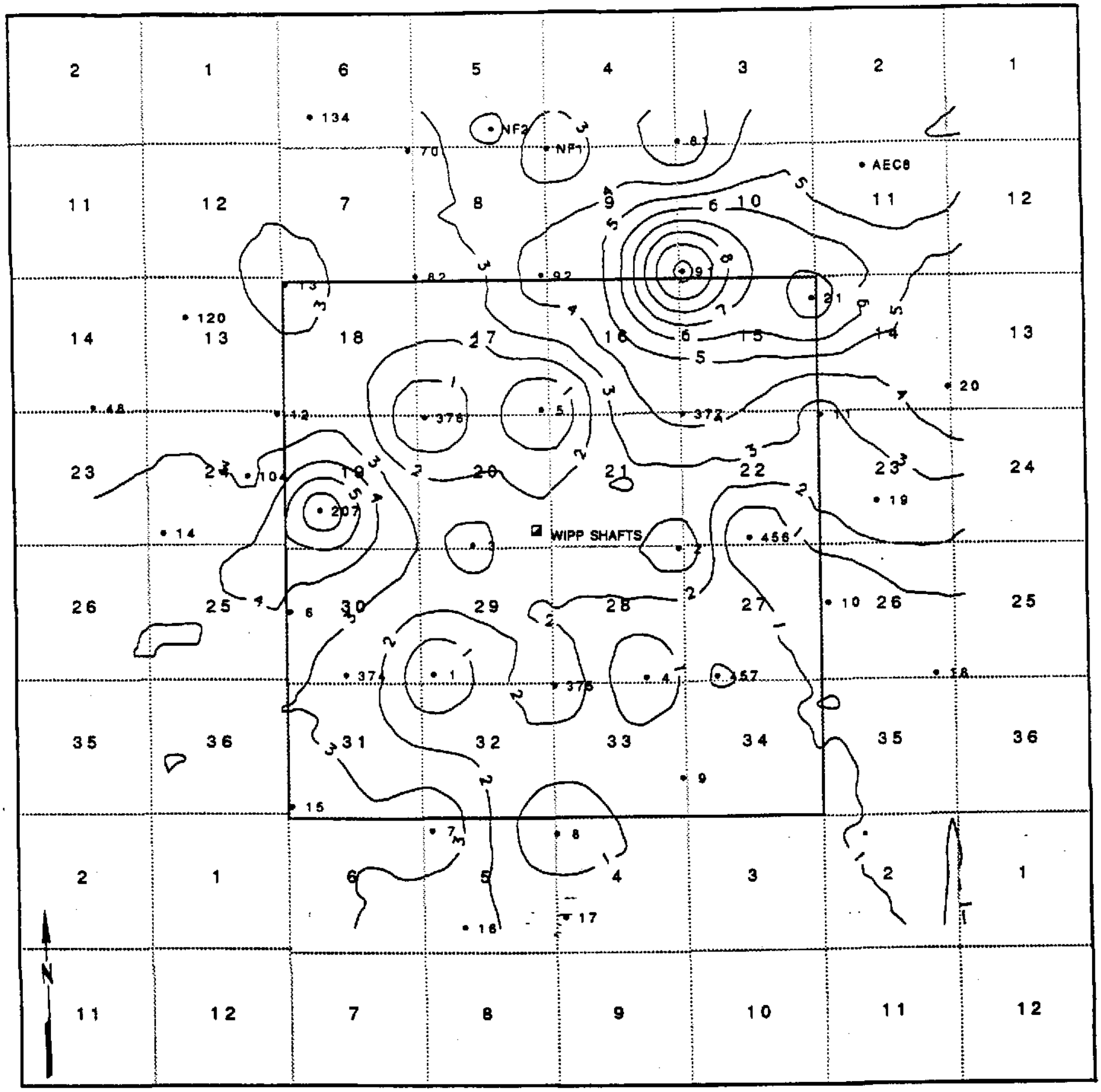

Figure 2
Thickness of the 4th Ore Zone

Contour Interval = 1.0 Feet
Scale: 1" = 6000'

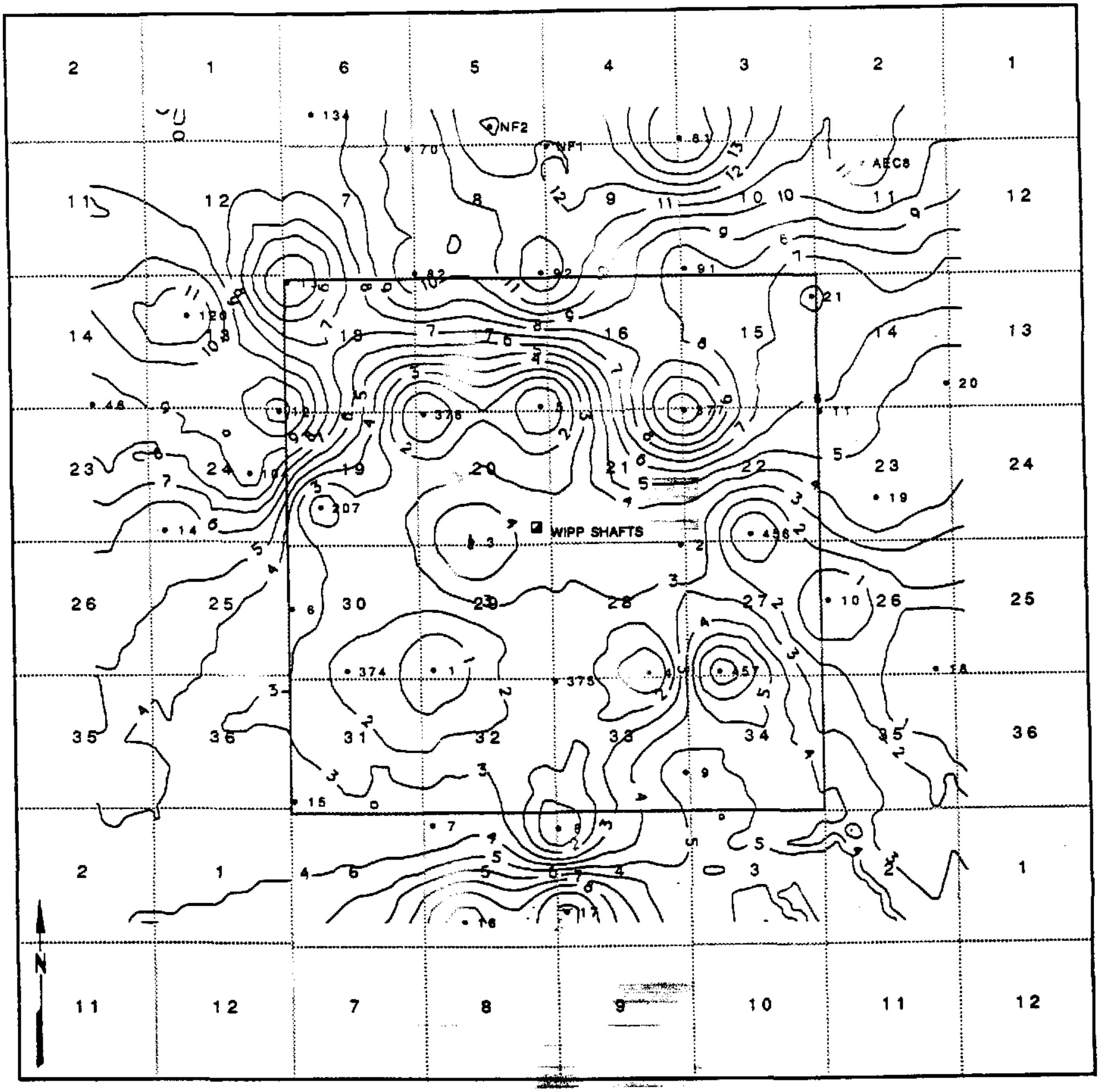

Figure 3
4th Ore Zone - % K20 as Equivalent Langbeinite
Contour Interval = 1.0 % K20
Scale: 1" = 6000'

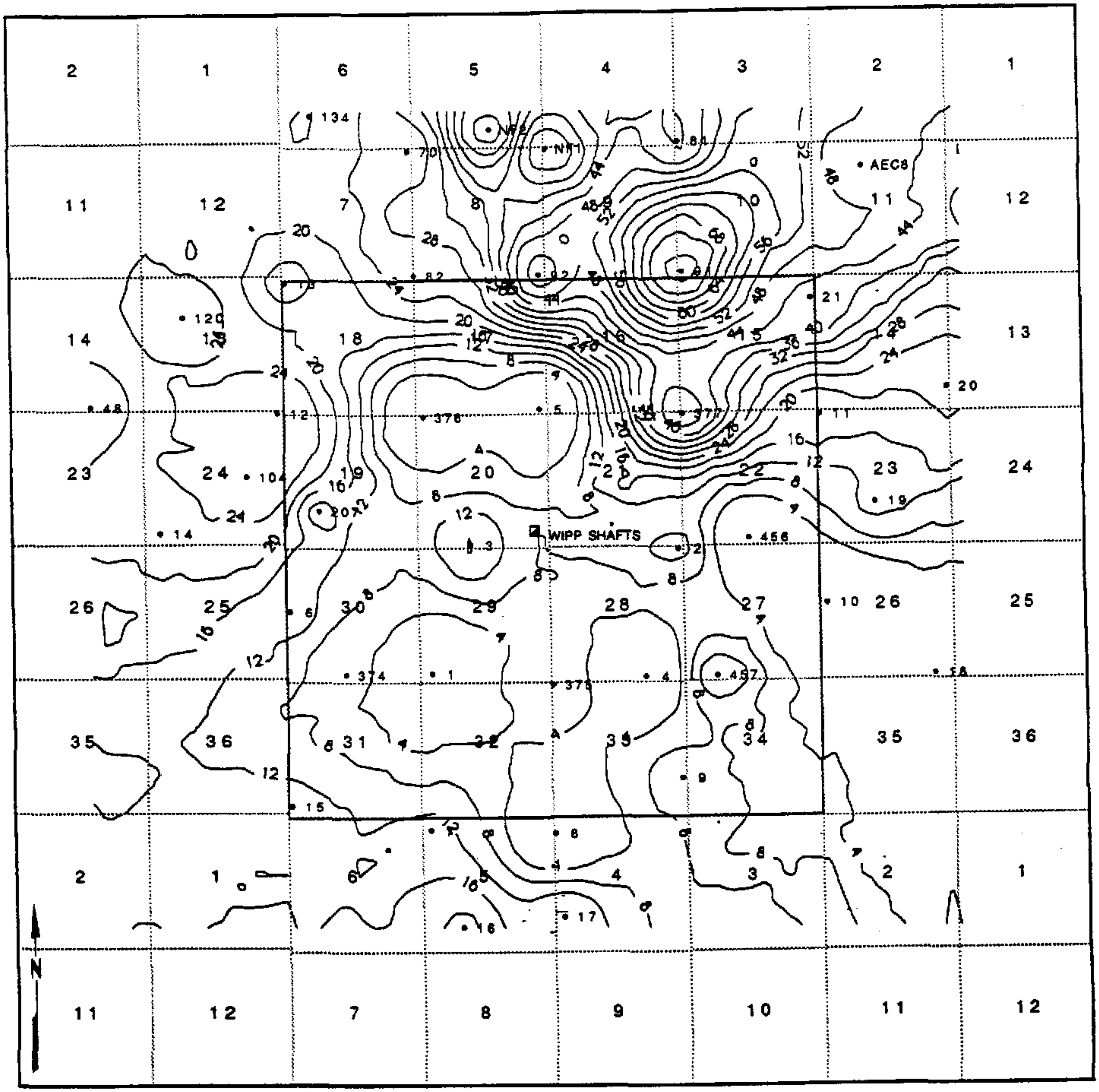

Figure 4
4th Ore Zone - % K20 Equivalent LangxThickness

Contour Interval = 4.0 % K20xFeet
Scale: 1" = 6000'

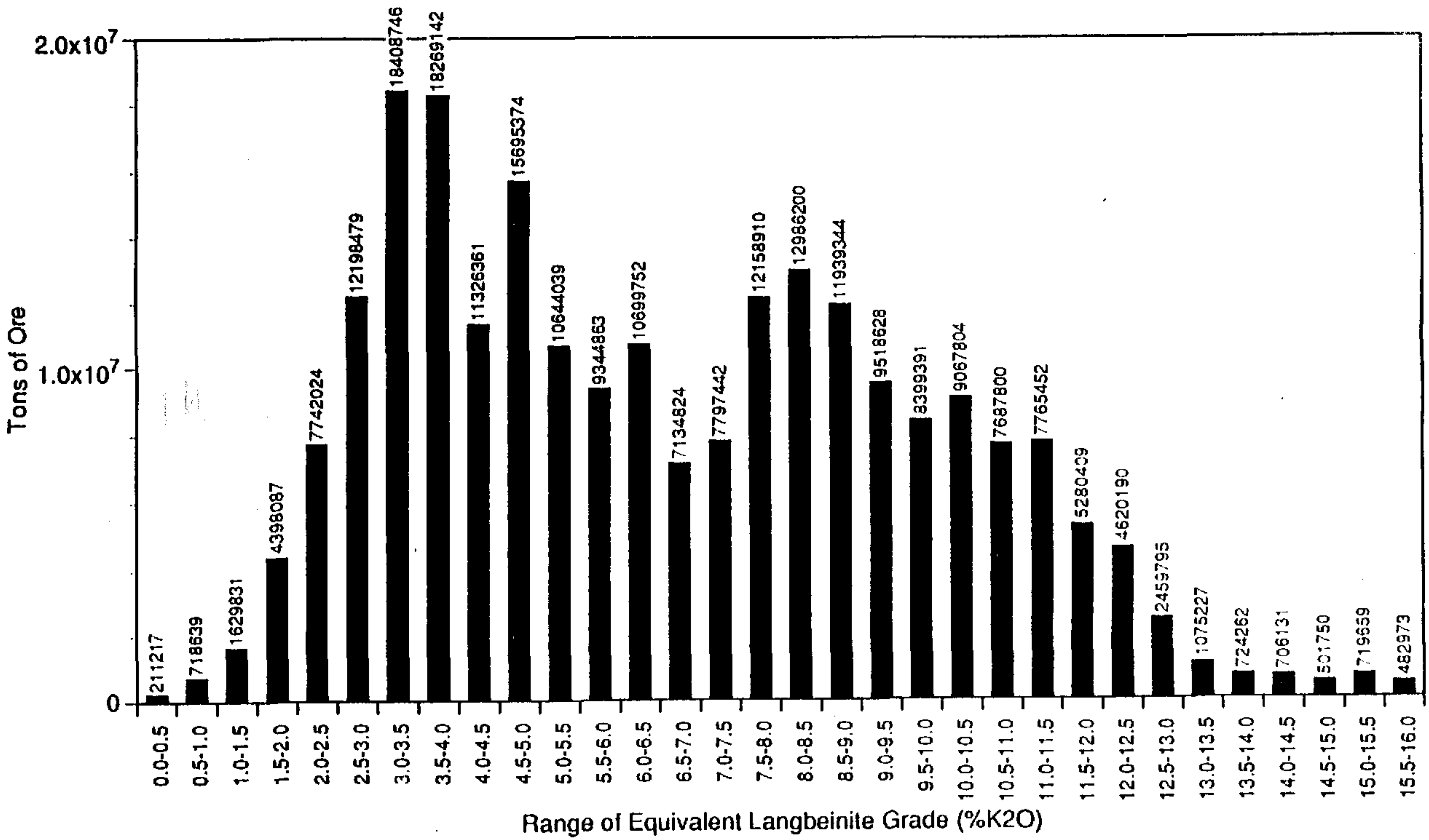

Figure 5
4th Ore Zone Equivalent Langbeinite Reserves (In Place)
for Entire Gridded Area

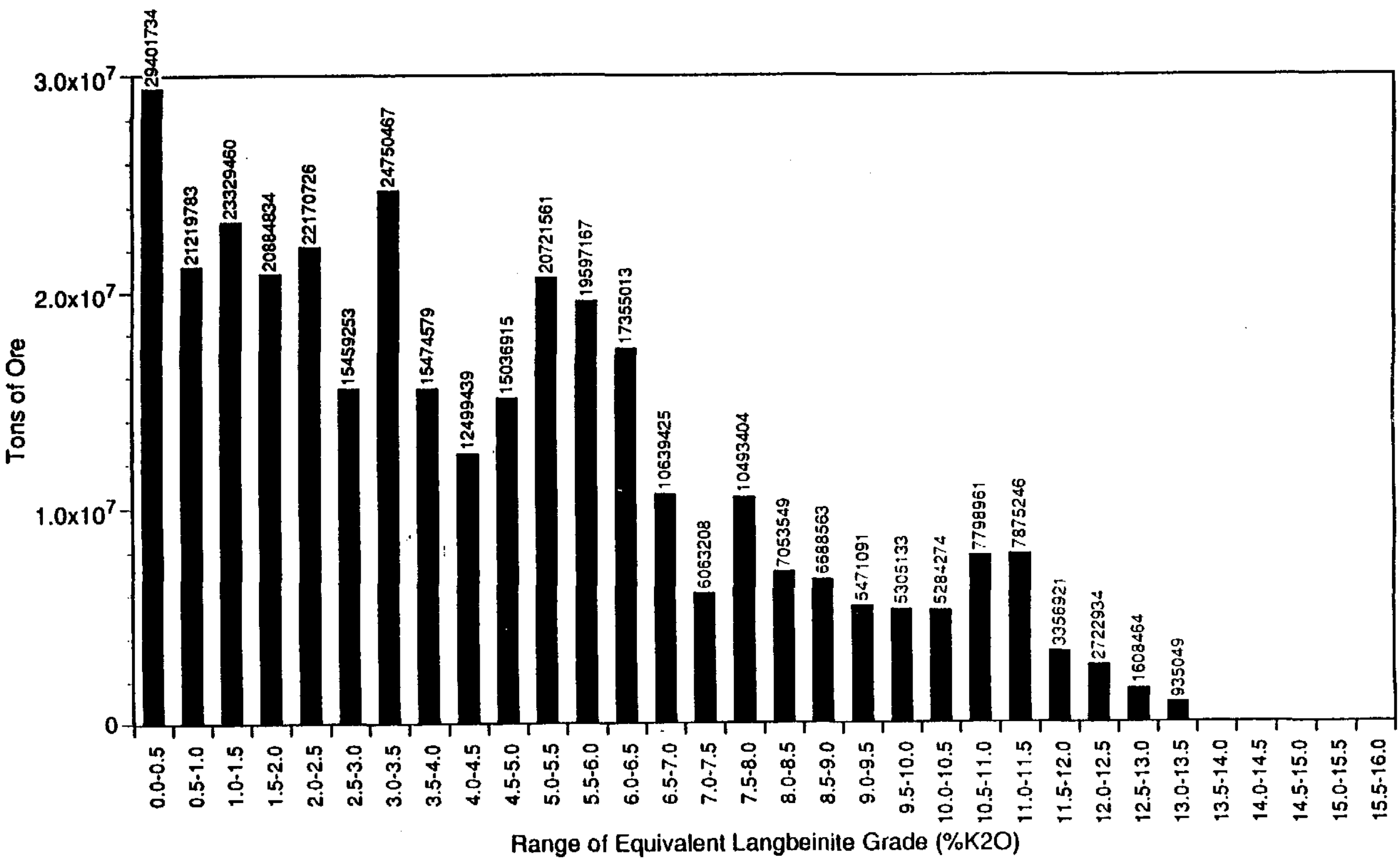

Figure 6
4th Ore Zone Equivalent Langbeinite Reserves
Adjusted for Mining Height of 4.0 Feet
for Entire Gridded Area

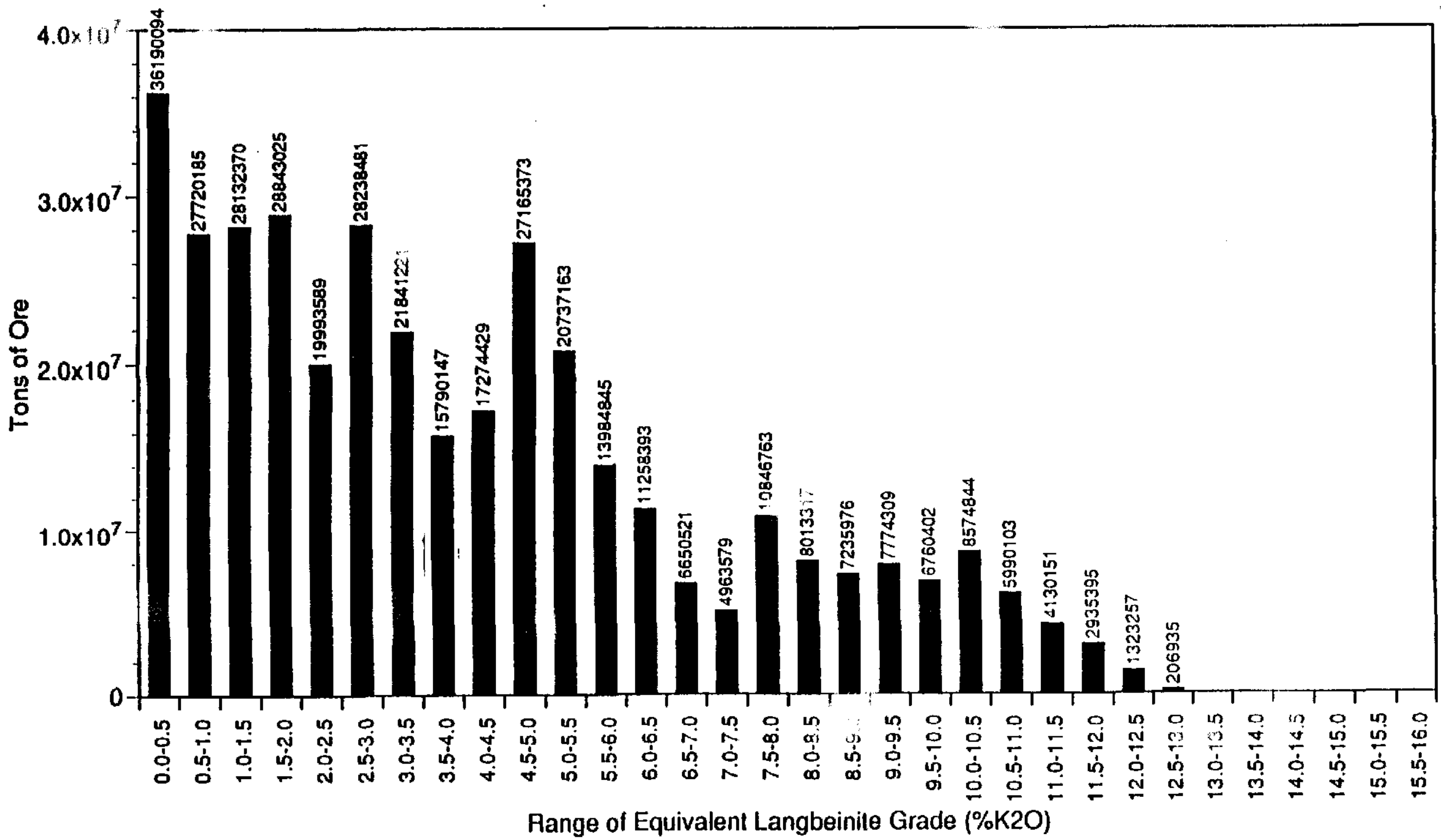

Figure 7
4th Ore Zone Equivalent Langbeinite Reserves
Adjusted for Mining Height of 4.5 Feet
for Entire Gridded Area

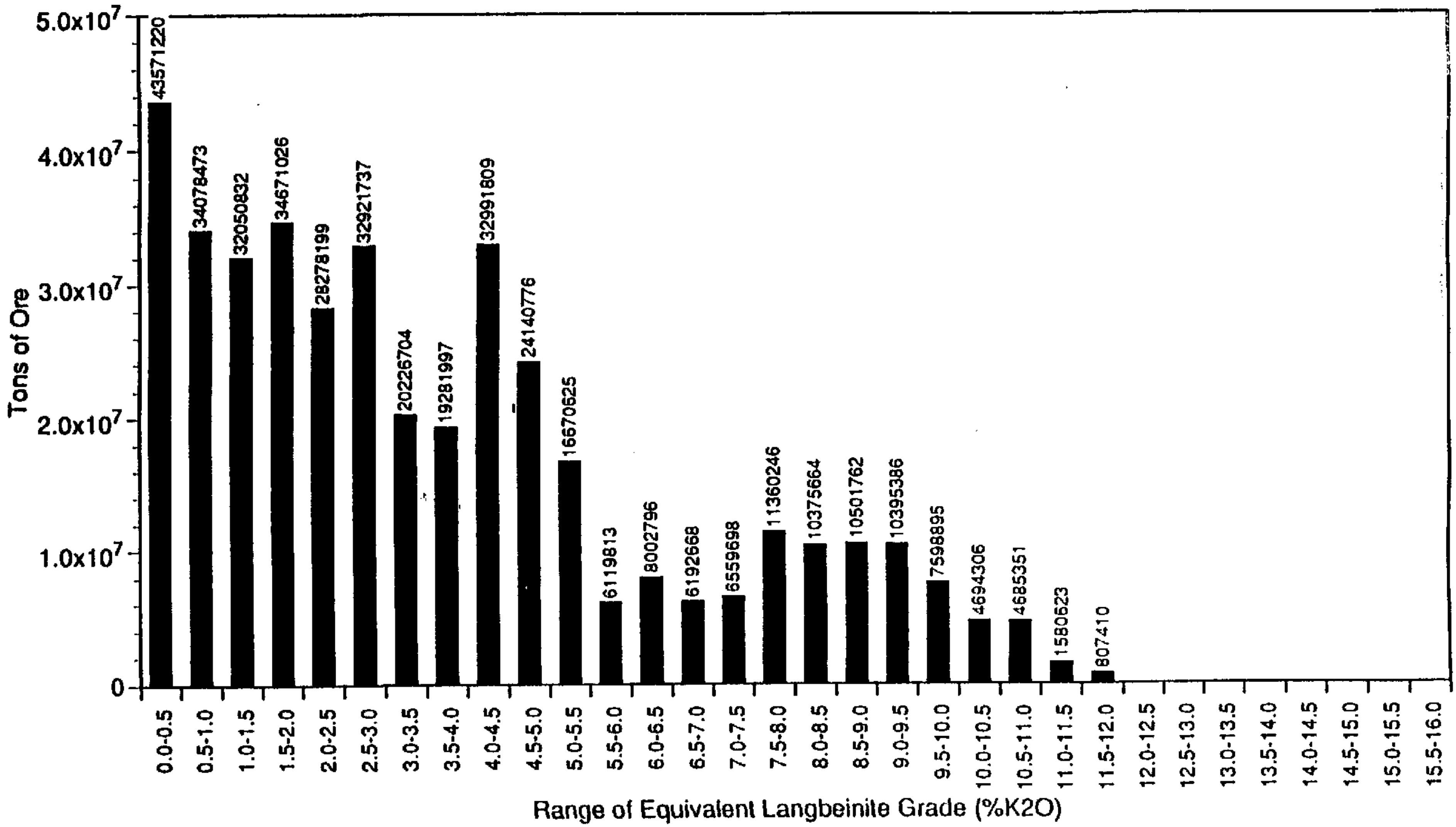

Figure 8
4th Ore Zone Equivalent Langbeinite Reserves
Adjusted for Mining Height of 5.0 Feet
for Entire Gridded Area

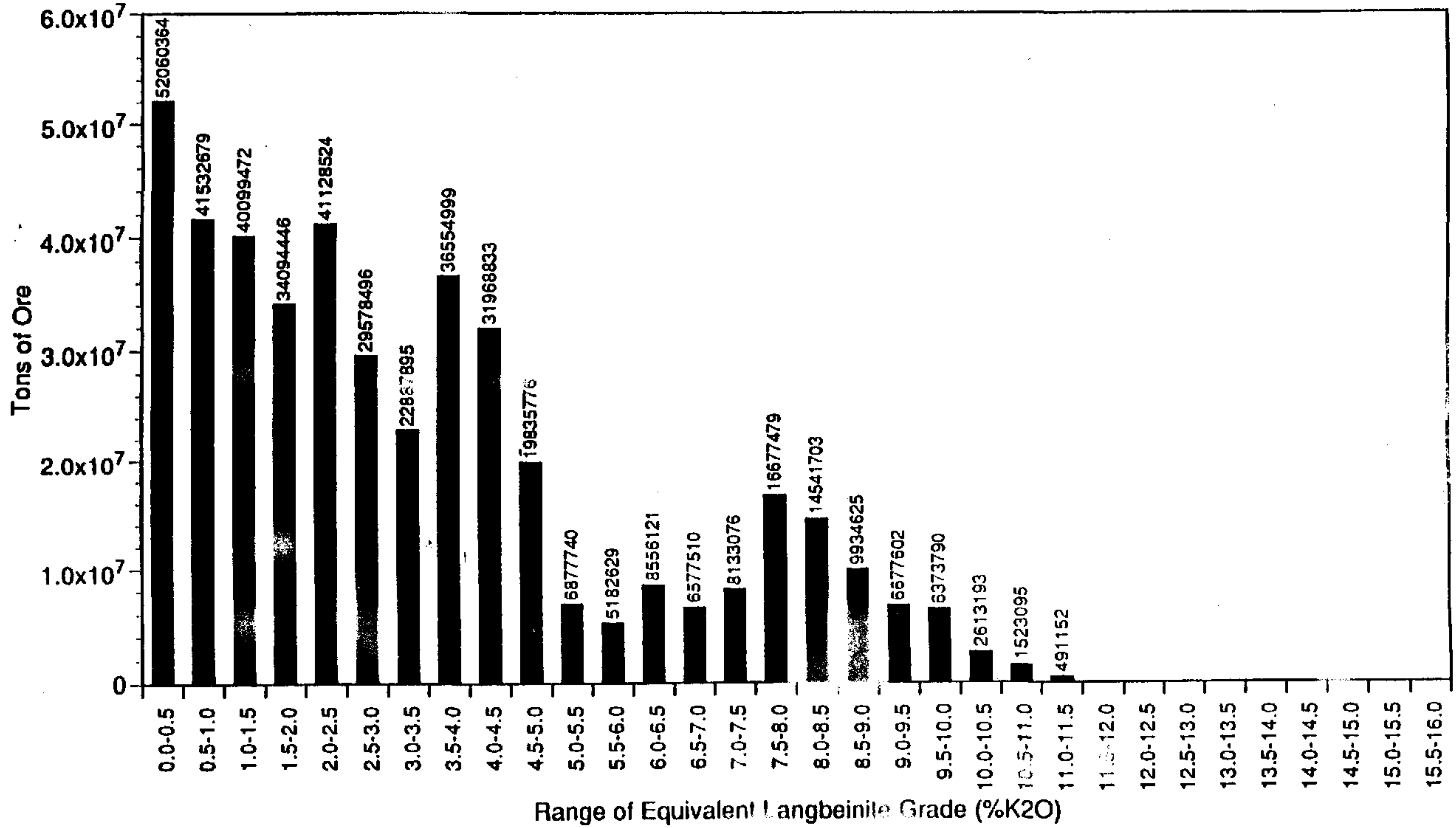

Figure 9
4th Ore Zone Equivalent Langbeinite Reserves
Adjusted for Mining Height of 5.5 Feet
for Entire Gridded Area

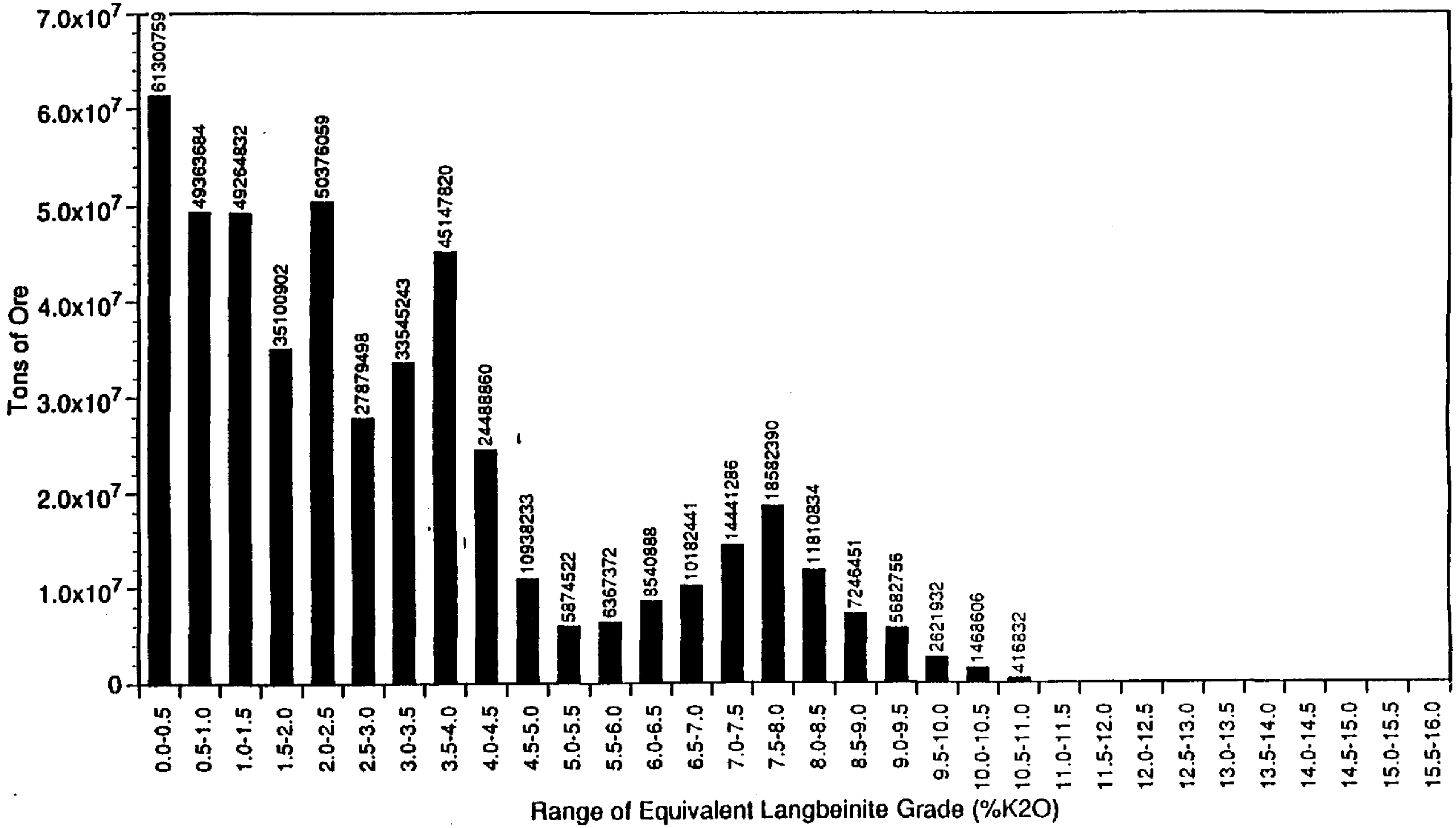

Figure 10
4th Ore Zone Equivalent Langbeinite Reserves
Adjusted for Mining Height of 6.0 Feet
for Entire Gridded Area

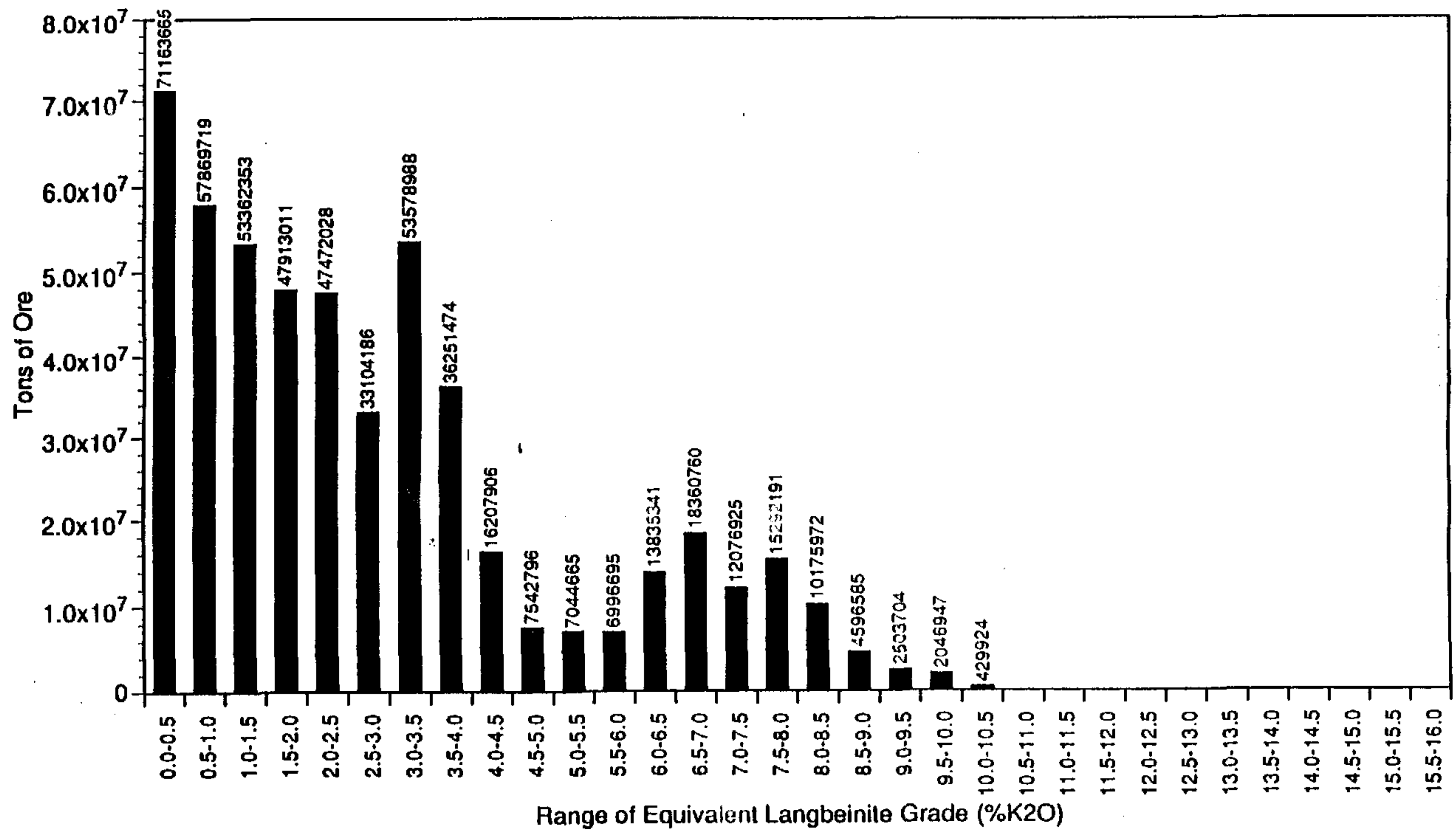

Figure 11
4th Ore Zone Equivalent Langbeinite Reserves
Adjusted for Mining Height of 6.5 Feet
for Entire Gridded Area

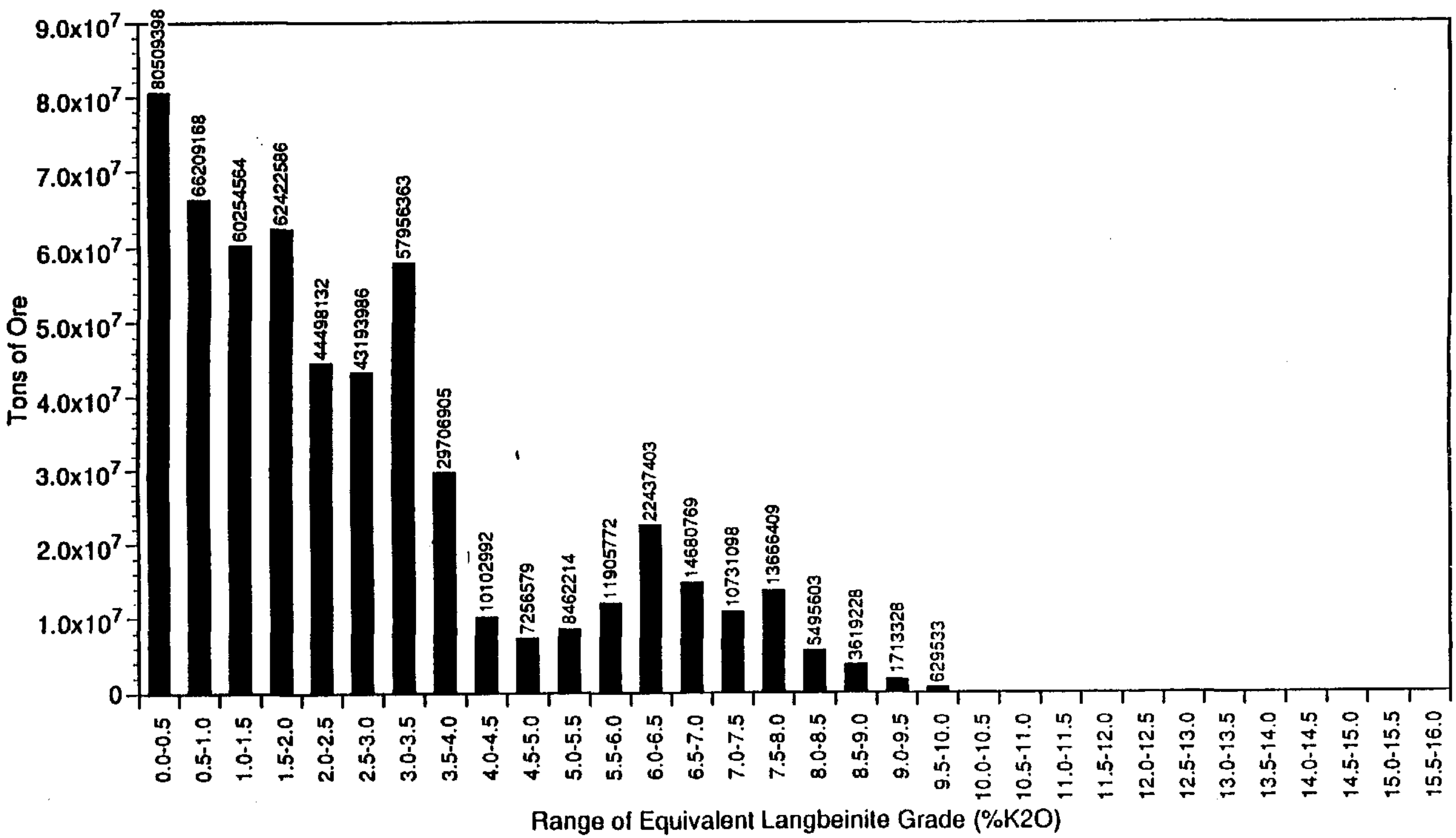

Figure 12
4th Ore Zone Equivalent Langbeinite Reserves
Adjusted for Mining Height of 7.0 Feet
for Entire Gridded Area

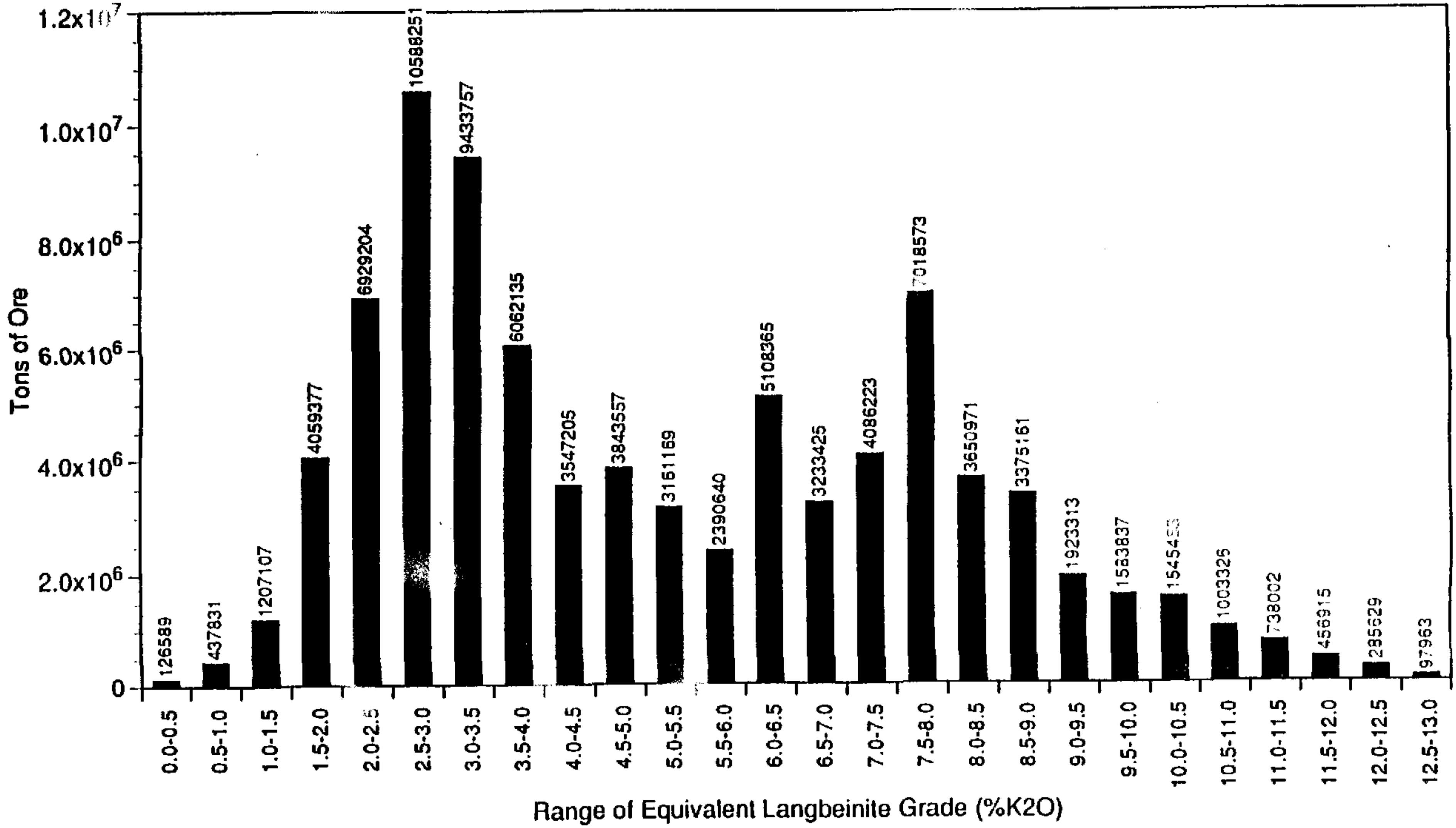

Figure 13
4th Ore Zone Equivalent Langbeinite Reserves (In Place)
Within WIPP Boundary

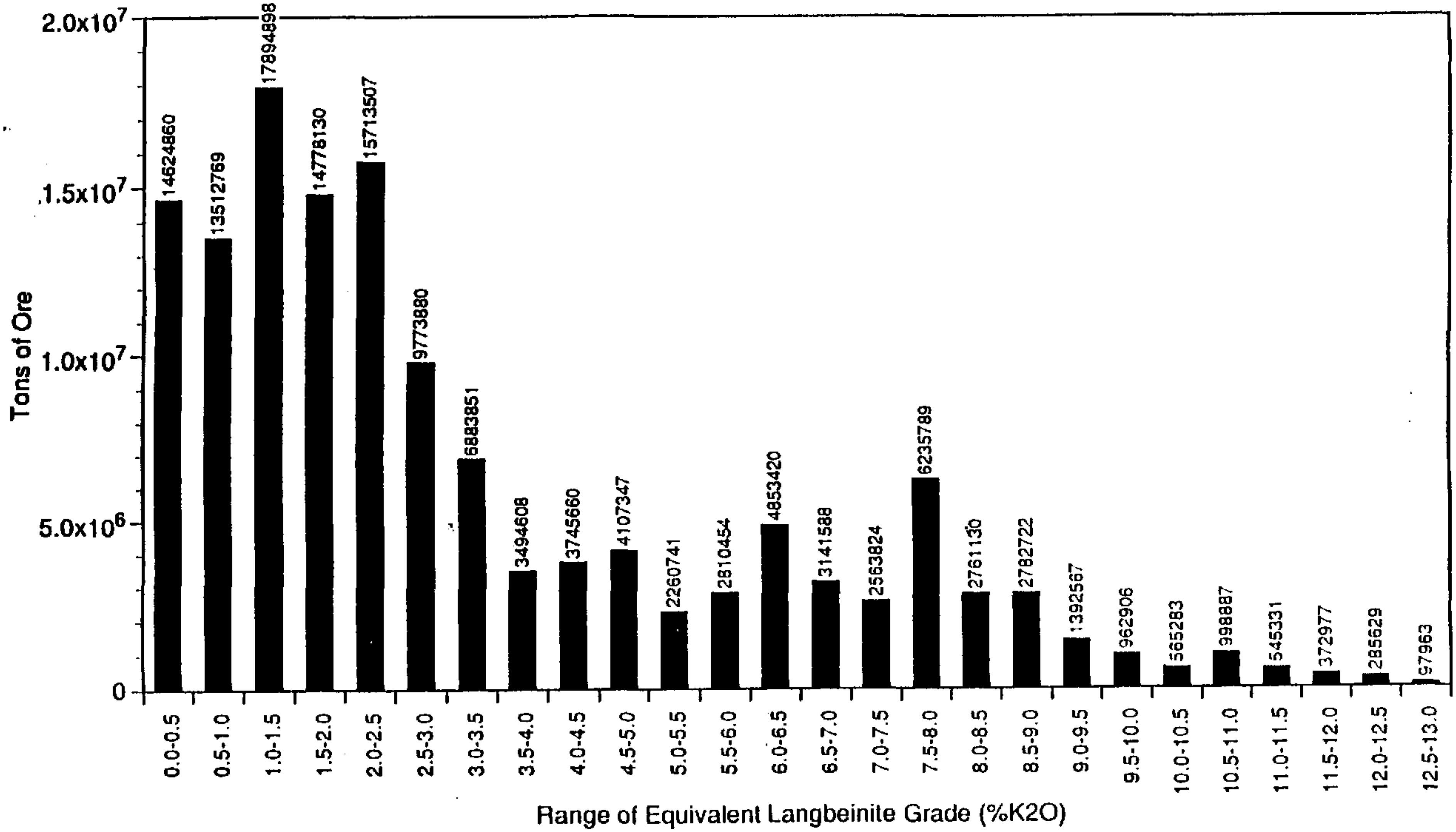

Figure 14
4th Ore Zone Equivalent Langbeinite Reserves
Adjusted for Mining Height of 4.0 Feet
Within WIPP Boundary

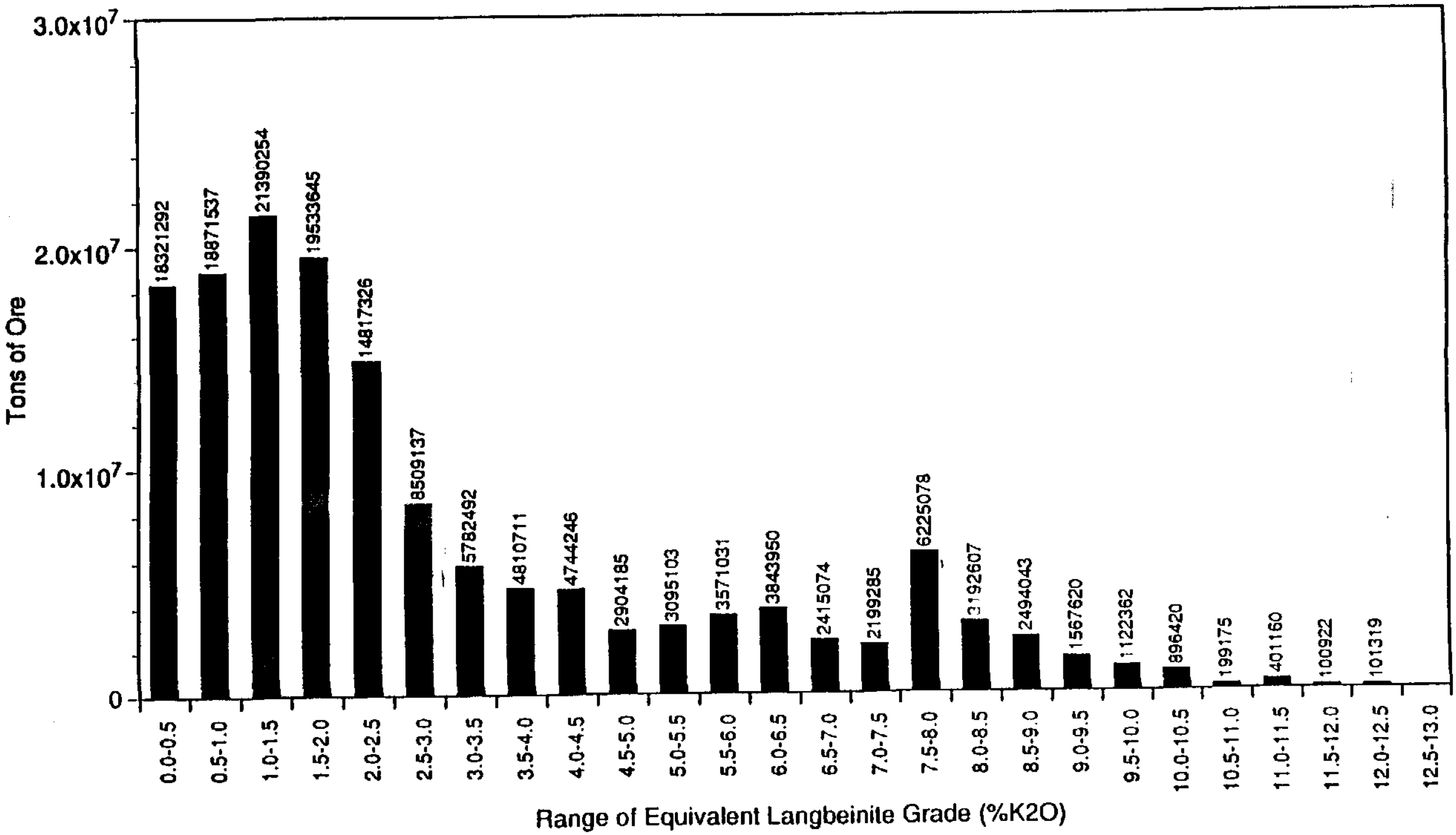

Figure 15
4th Ore Zone Equivalent Langbeinite Reserves
Adjusted for Mining Height of 4.5 Feet
Within WIPP Boundary

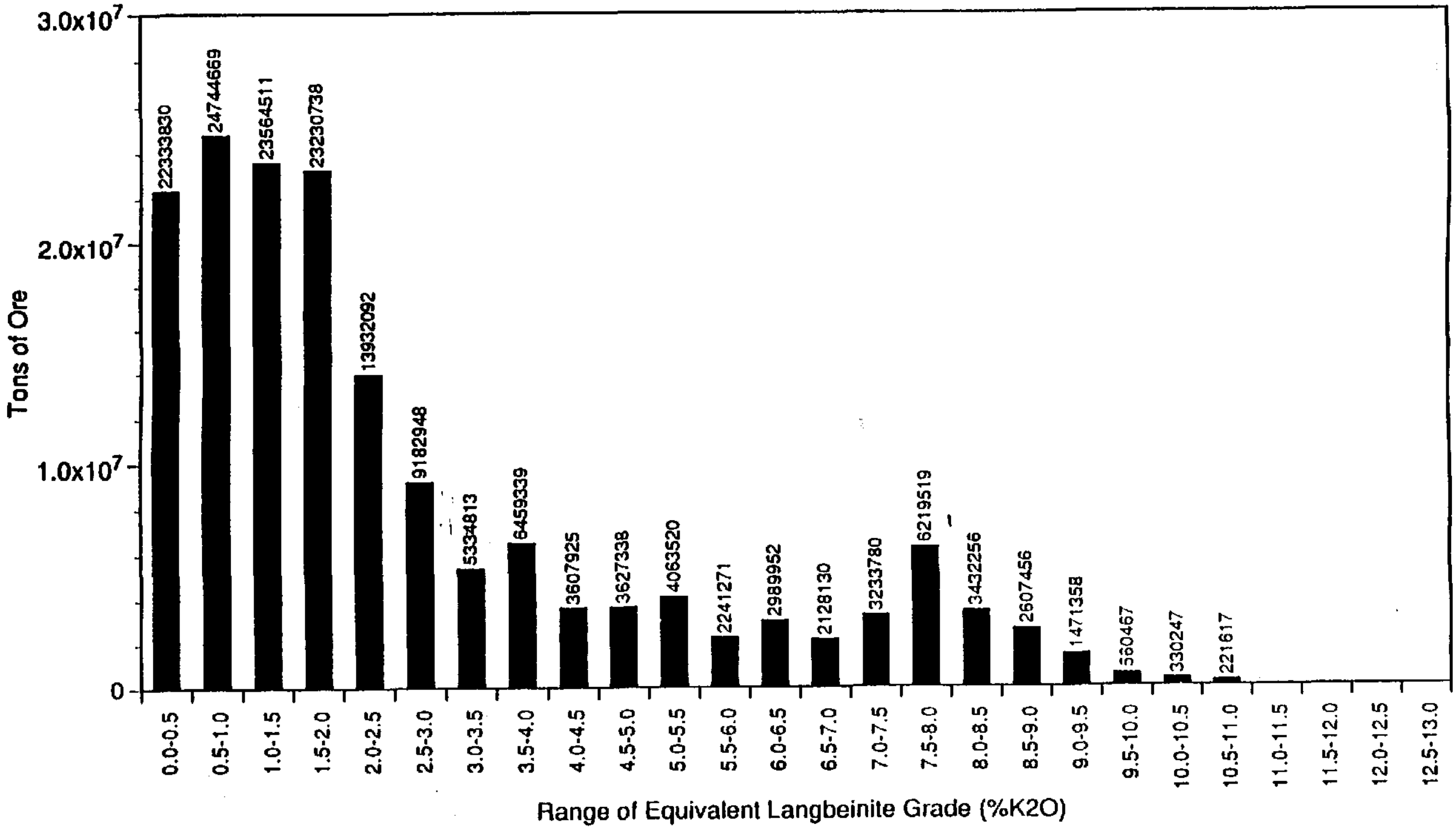

Figure 16
4th Ore Zone Equivalent Langbeinite Reserves
Adjusted for Mining Height of 5.0 Feet
Within WIPP Boundary

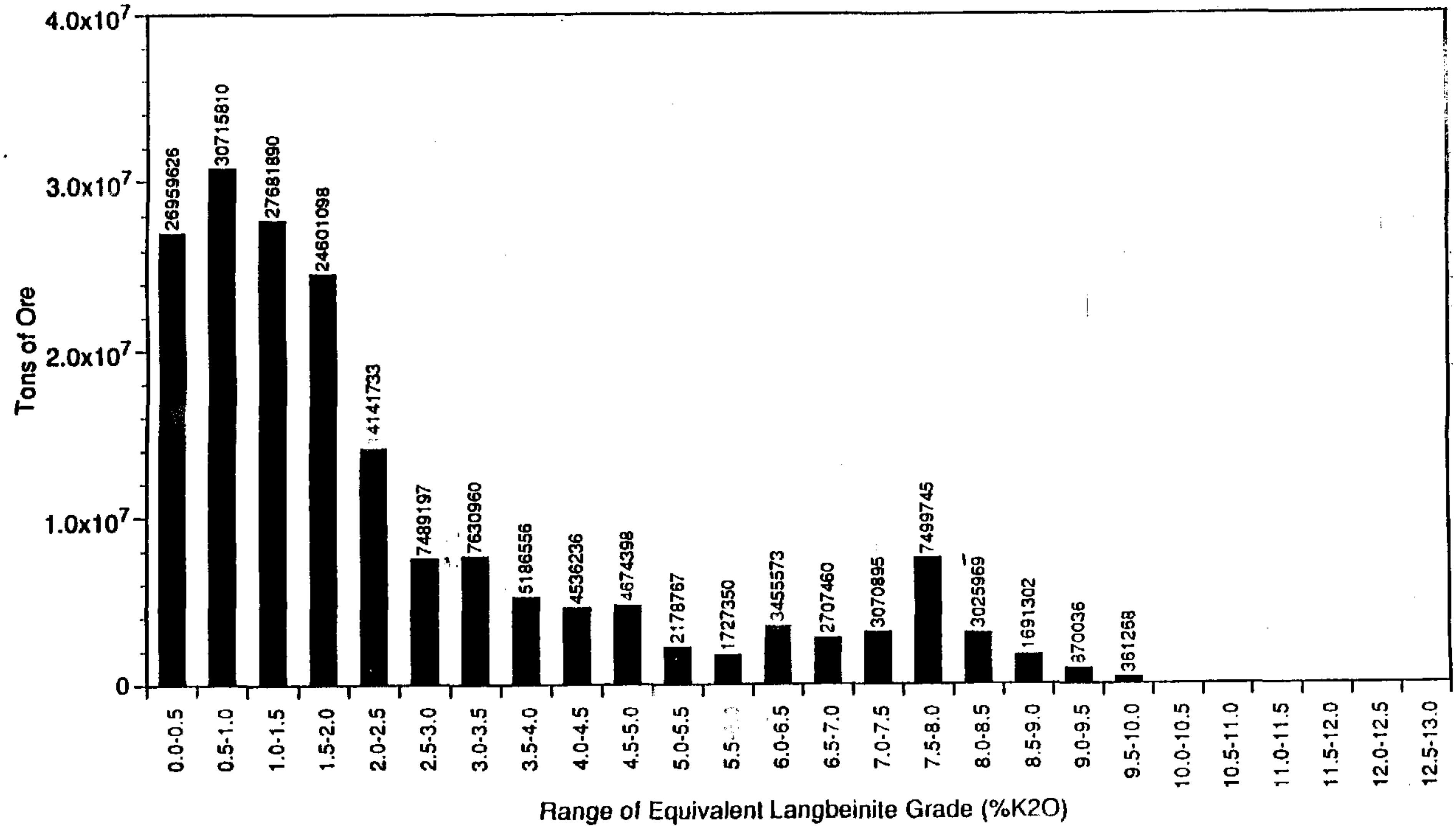

Figure 17
4th Ore Zone Equivalent Langbeinite Reserves
Adjusted for Mining Height of 5.5 Feet
Within WIPP Boundary

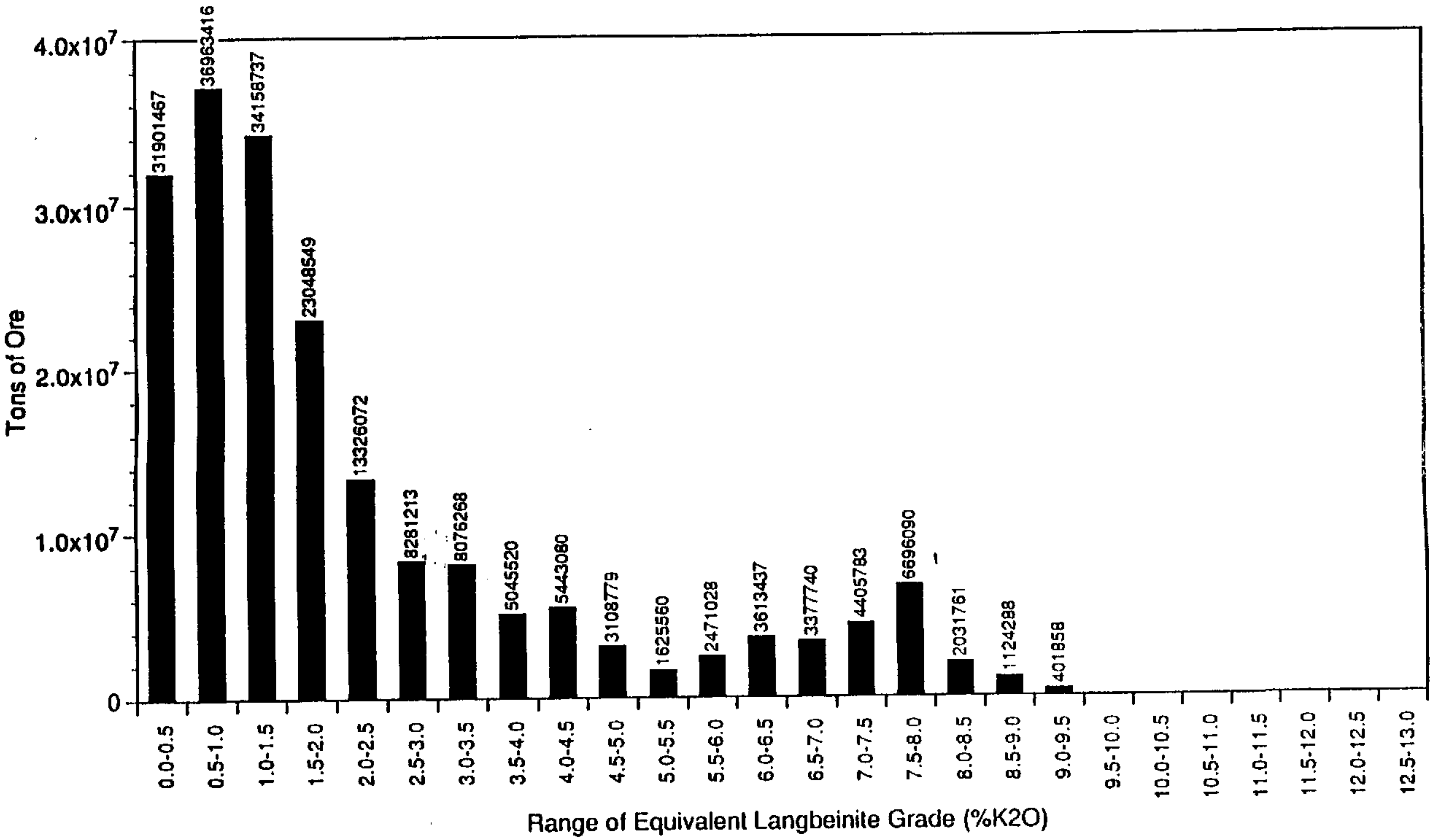

Figure 18
4th Ore Zone Equivalent Langbeinite Reserves
Adjusted for Mining Height of 6.0 Feet
Within WIPP Boundary

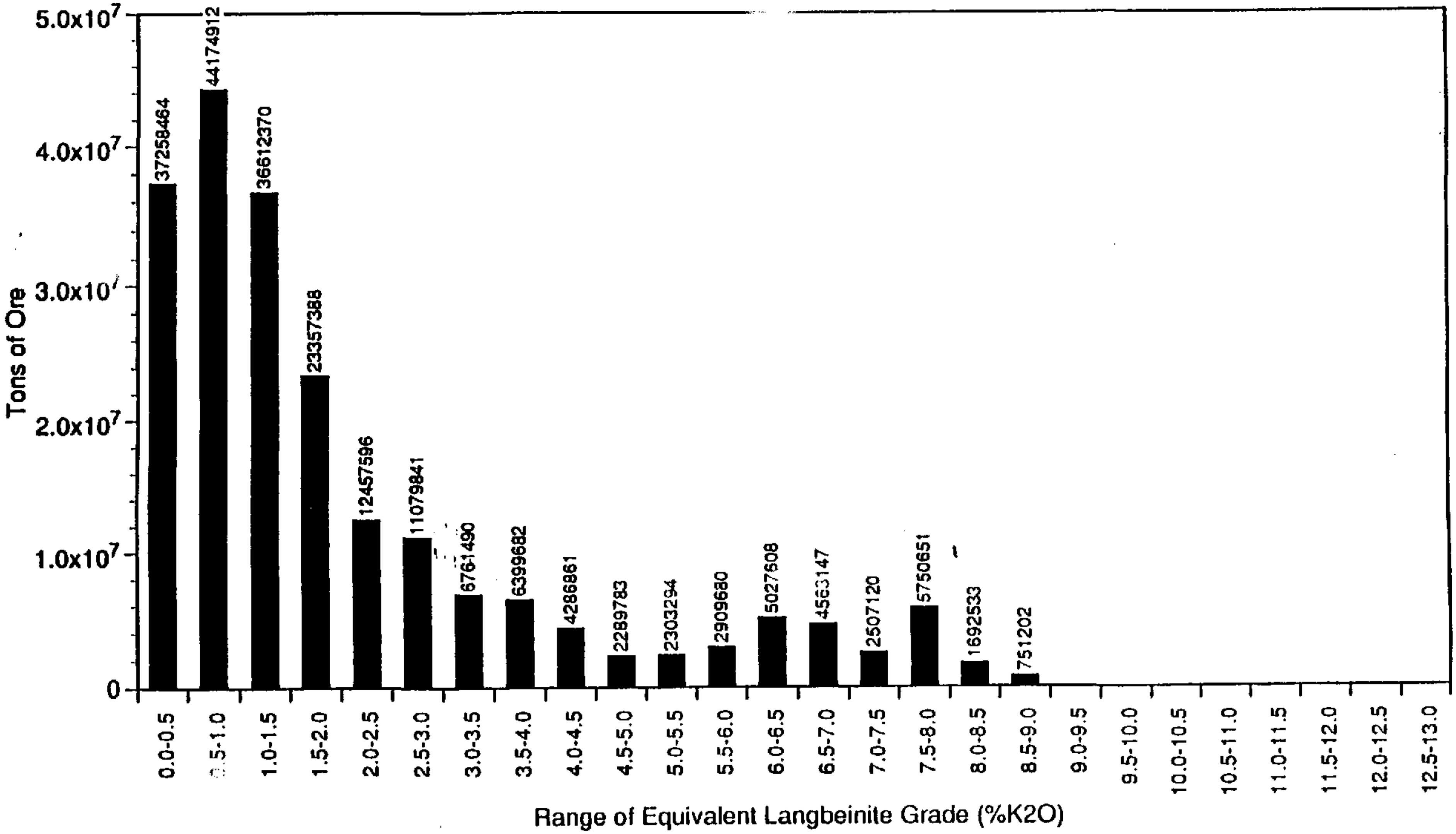

Figure 19
4th Ore Zone Equivalent Langbeinite Reserves
Adjusted for Mining Height of 6.5 Feet
Within WIPP Boundary

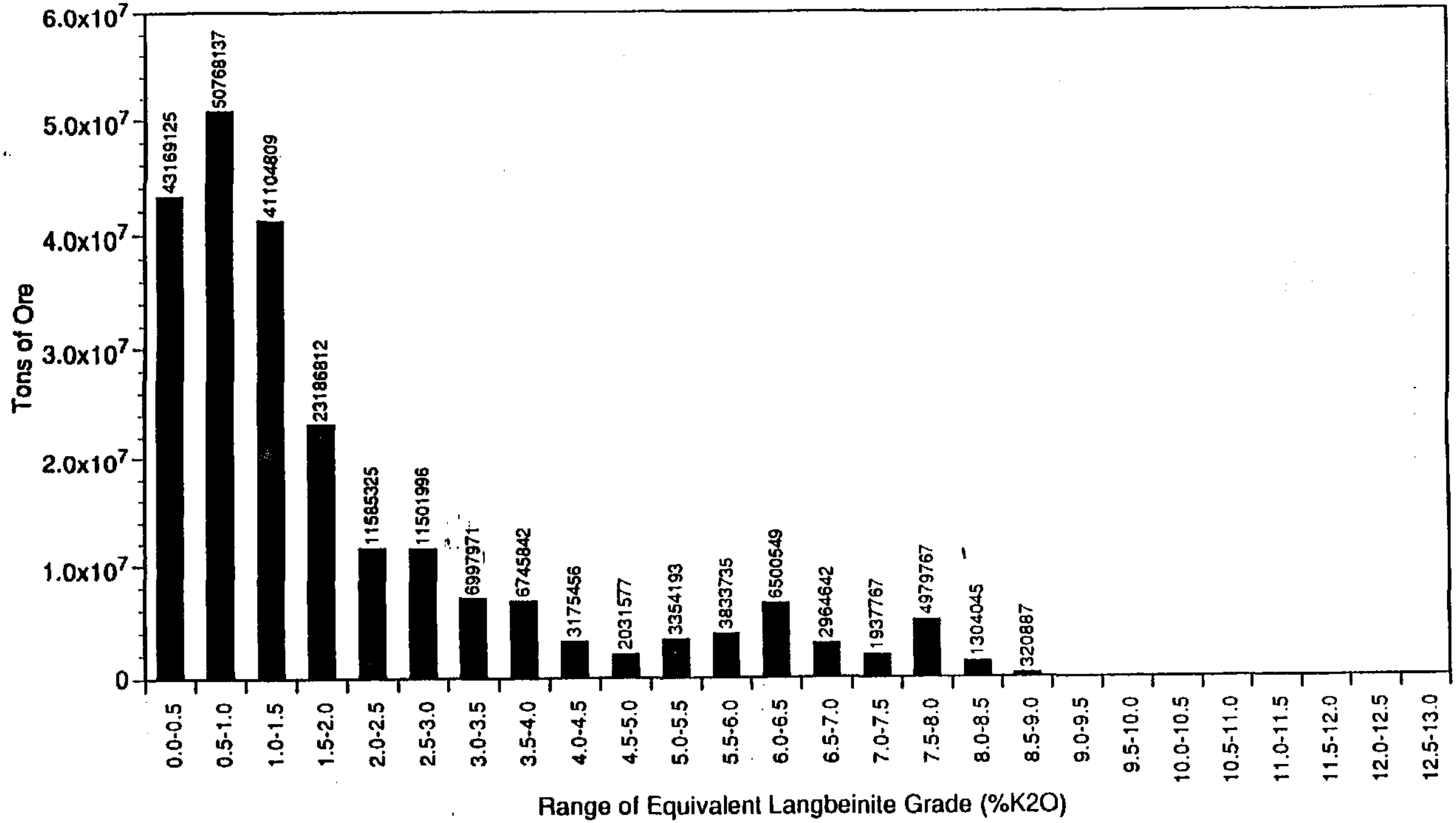

Figure 20
4th Ore Zone Equivalent Langbeinite Reserves
Adjusted for Mining Height of 7.0 Feet
Within WIPP Boundary

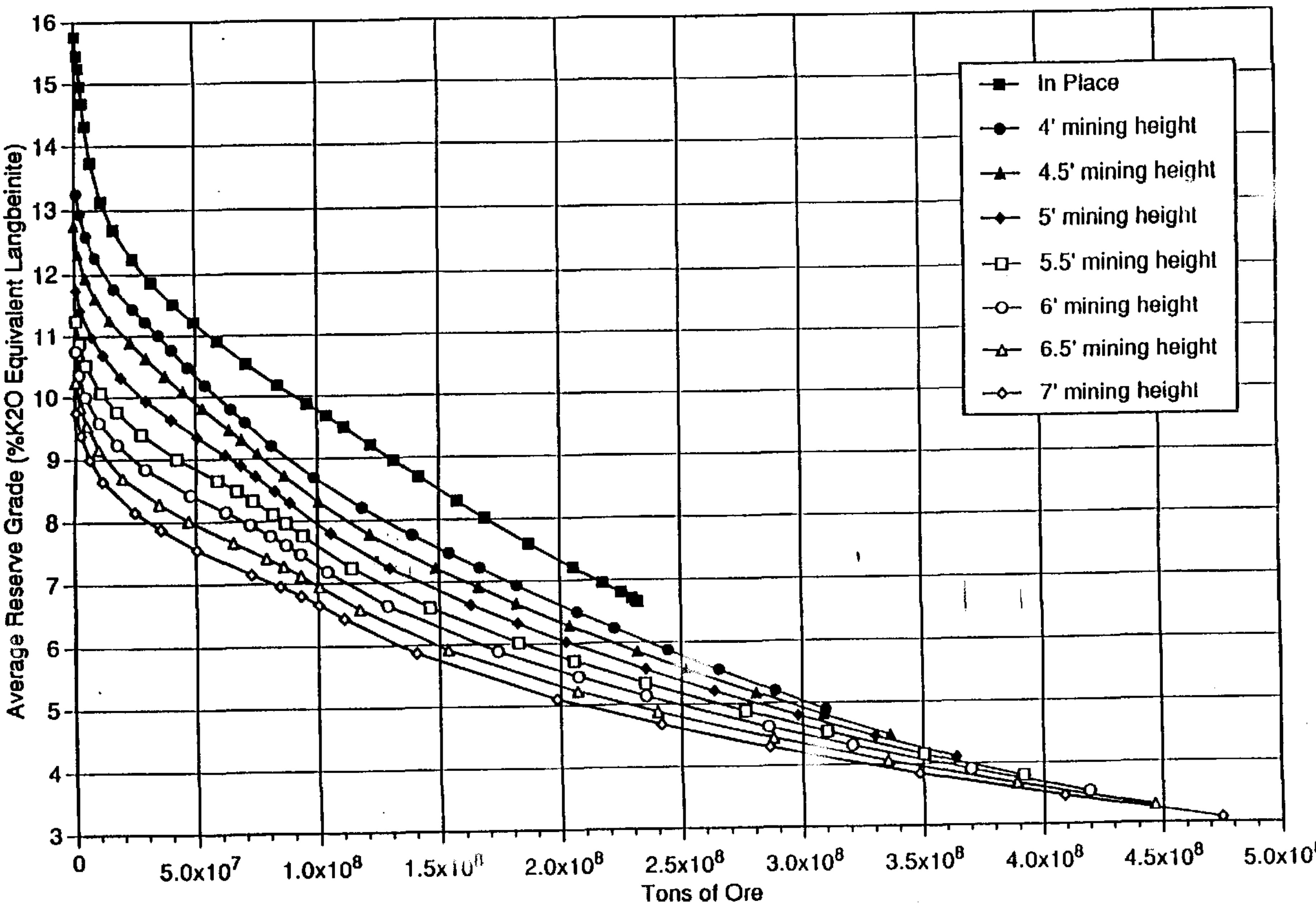

Figure 21
4th Ore Zone Langbeinite Reserves (Reserve Grade)
for Entire Gridded Area

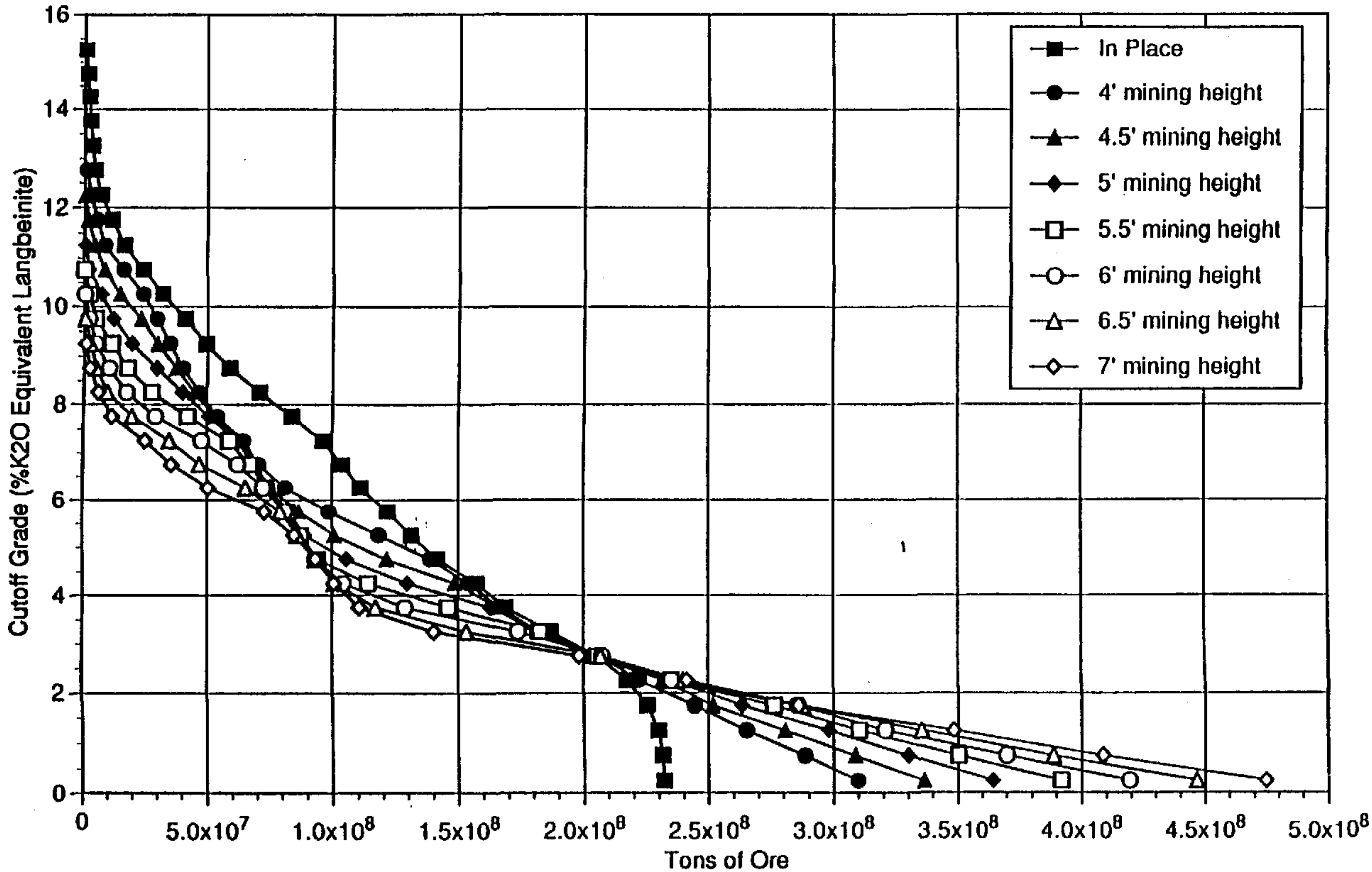

Figure 22
4th Ore Zone Langbeinite Reserves (Cutoff Grade)
for Entire Gridded Area

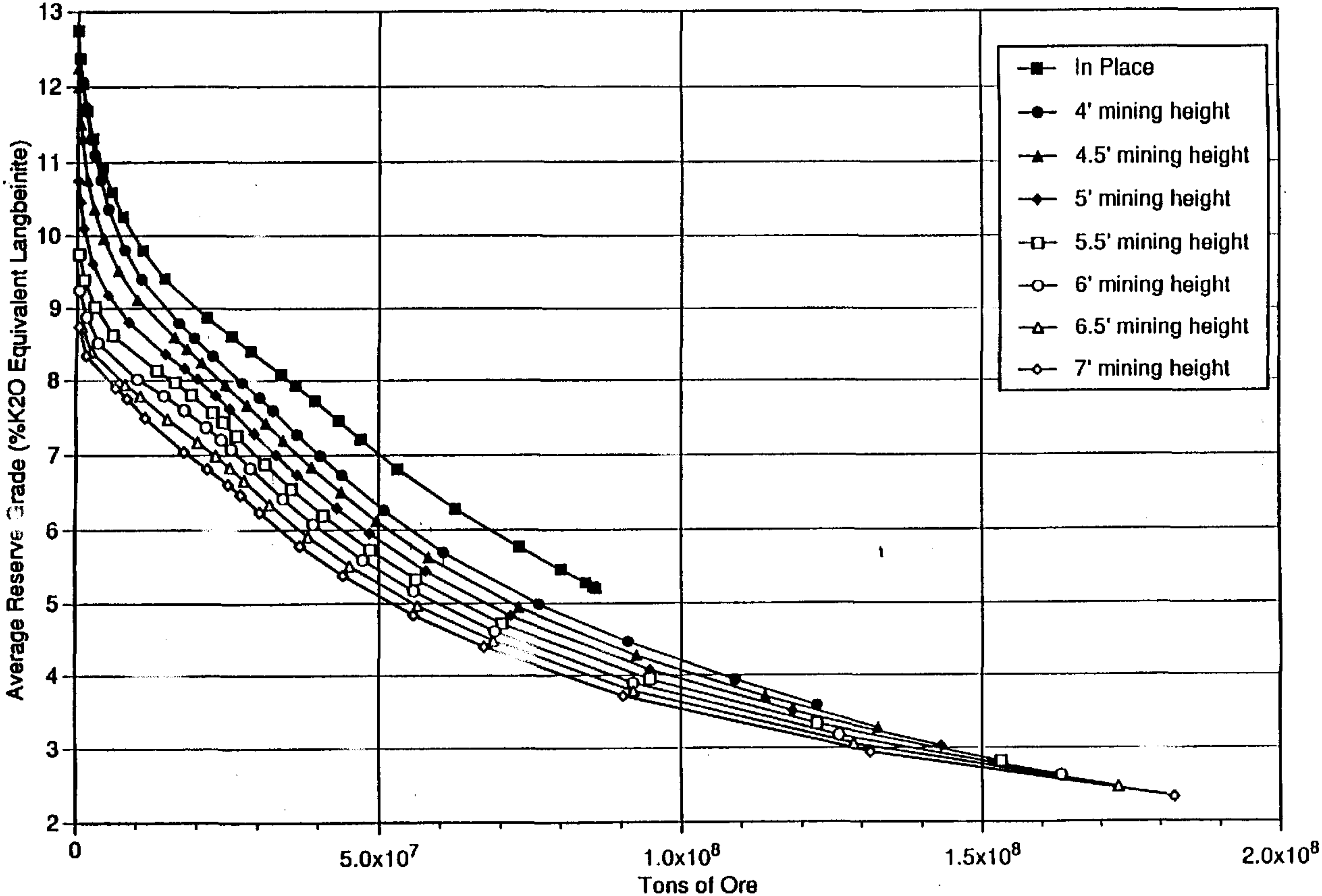

Figure 23
4th Ore Zone Langbeinite Reserves (Reserve Grade)
Within WIPP Boundary

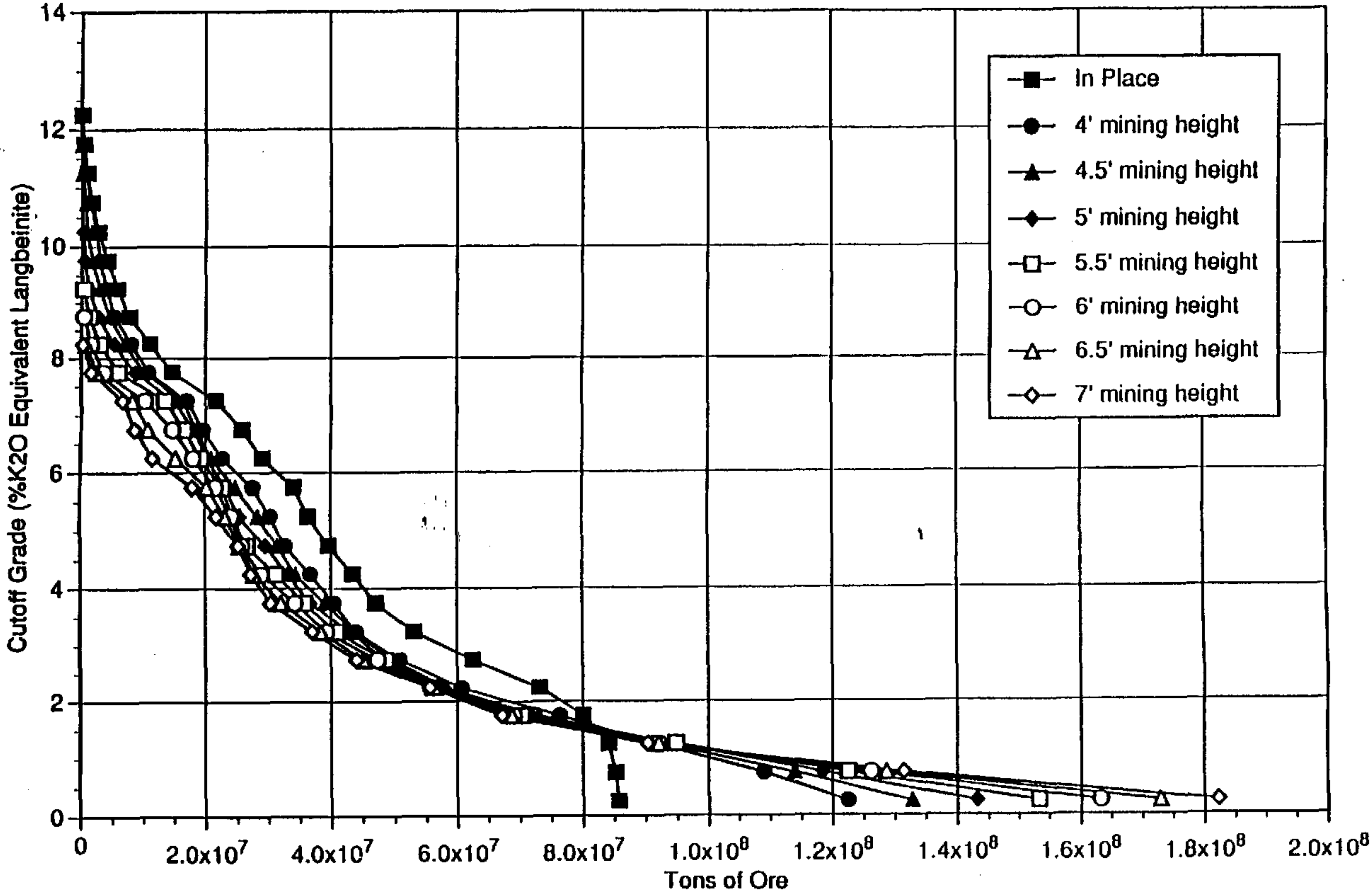

Figure 24
4th Ore Zone Langbeinite Reserves (Cutoff Grade)
Within WIPP Boundary

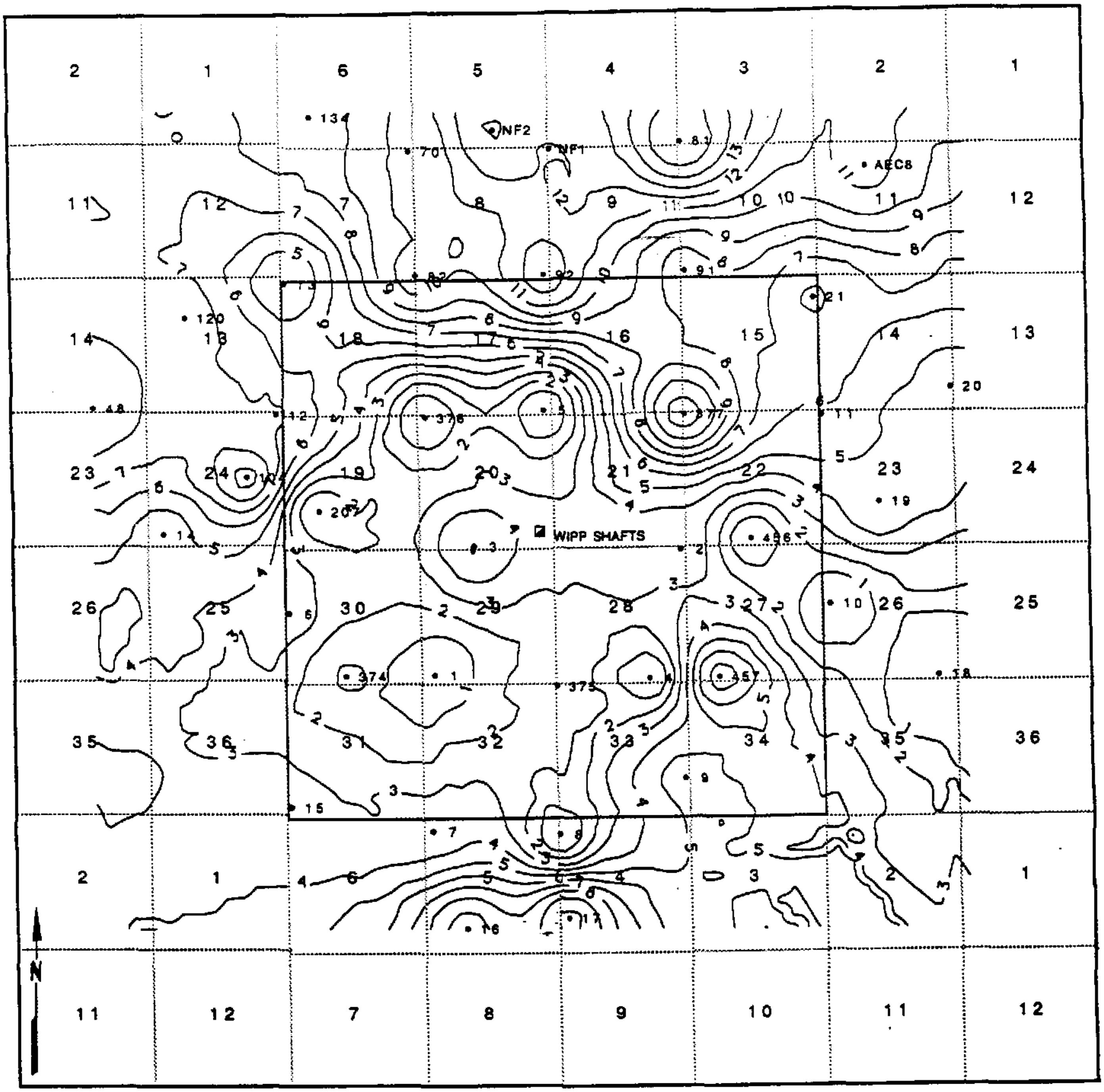

Figure 25
4th Ore Zone - % K20 Langbeinite Only

Contour Interval = 1.0 % K20xFeet
Scale: 1" = 6000'

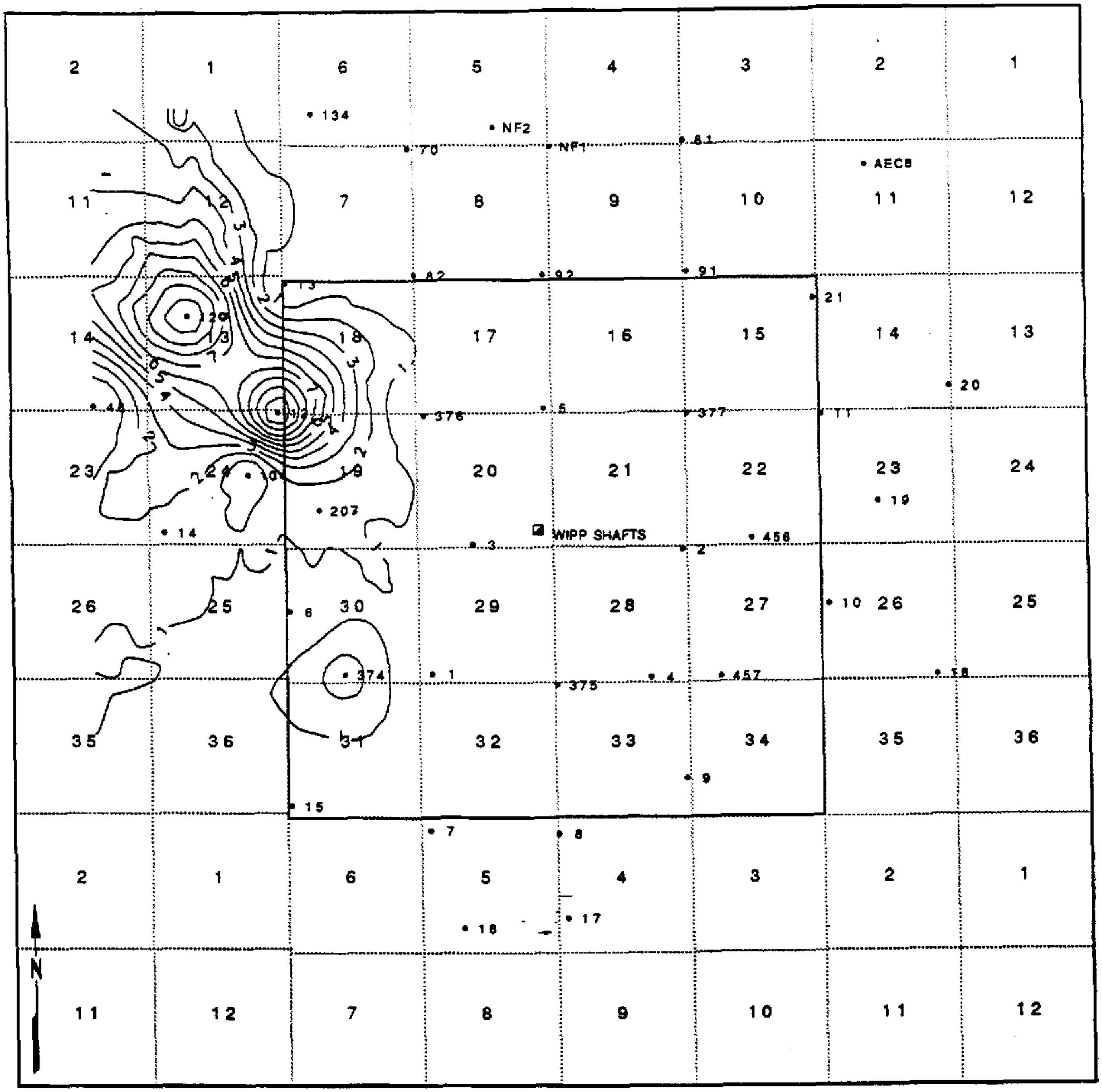

Figure 26
4th Ore Zone - % K20 Sylvite Only

Contour Interval = 1.0 % K20xFeet
Scale: 1" = 6000'

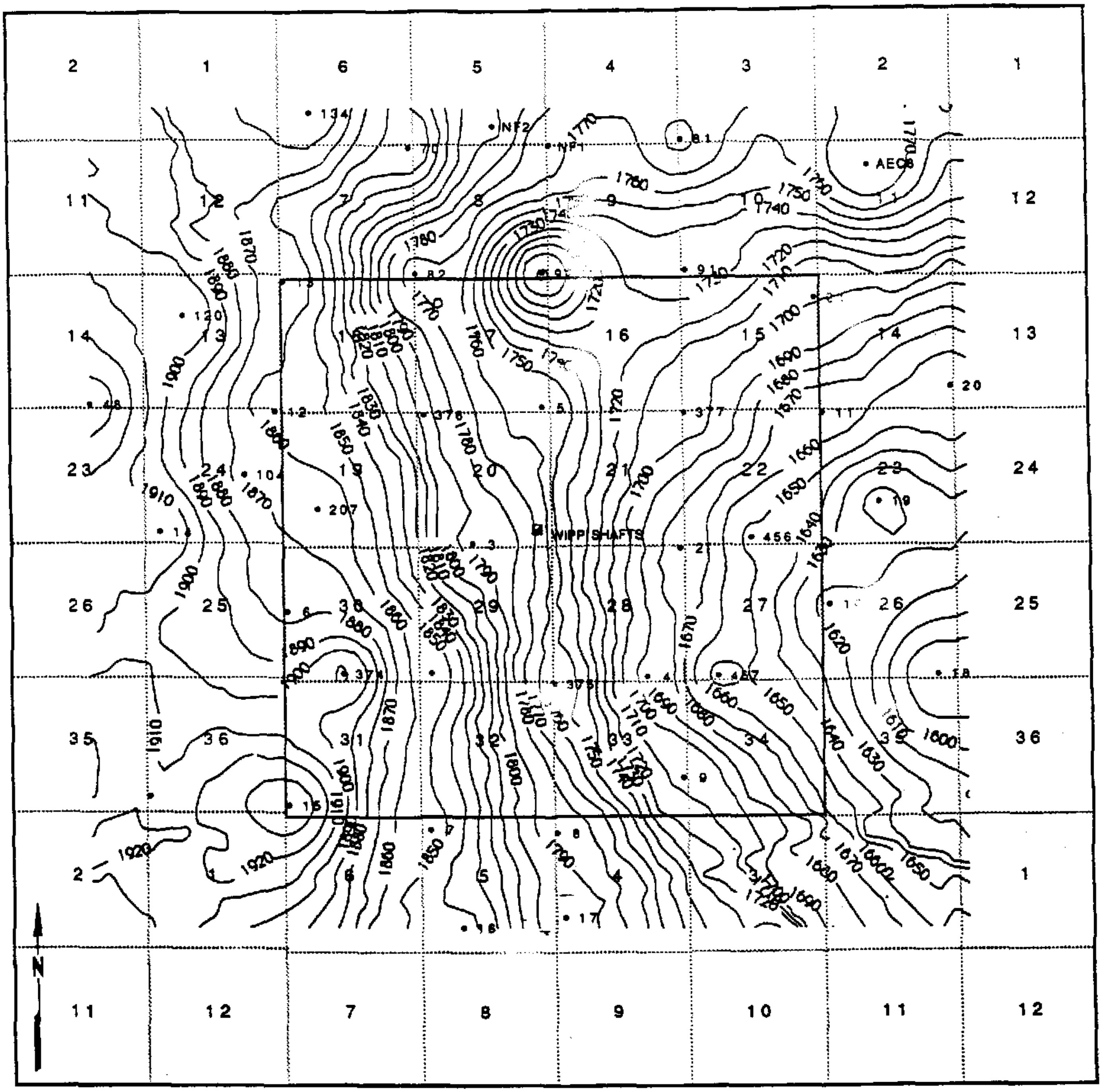

Figure 27
Structure of the Top of the 4th Ore Zone
Contour Interval = 10 Feet
Scale: 1" = 6000'

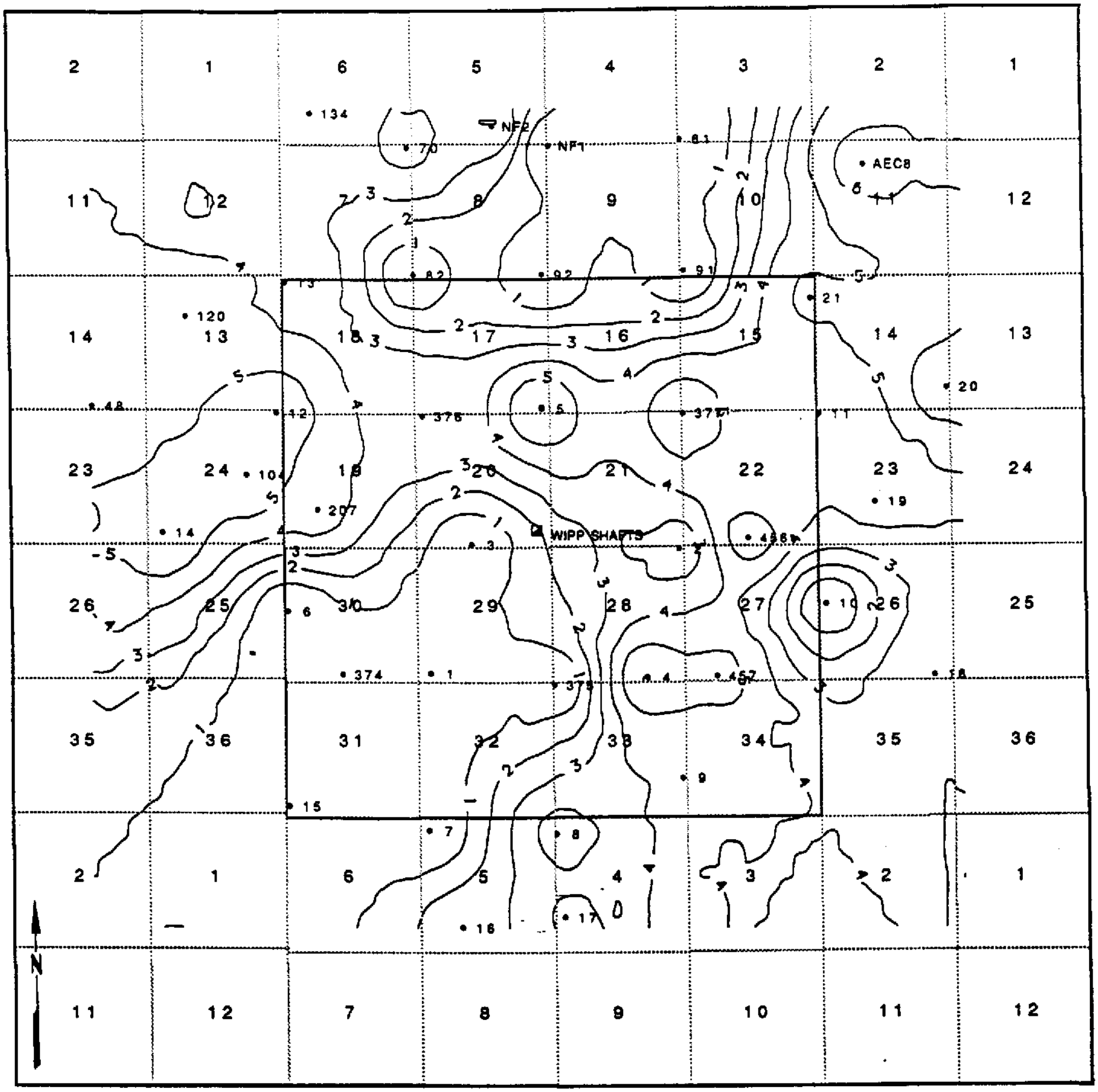

Figure 28
Thickness of the 10th Ore Zone

Contour Interval = 1.0 Feet
Scale: 1" = 6000'

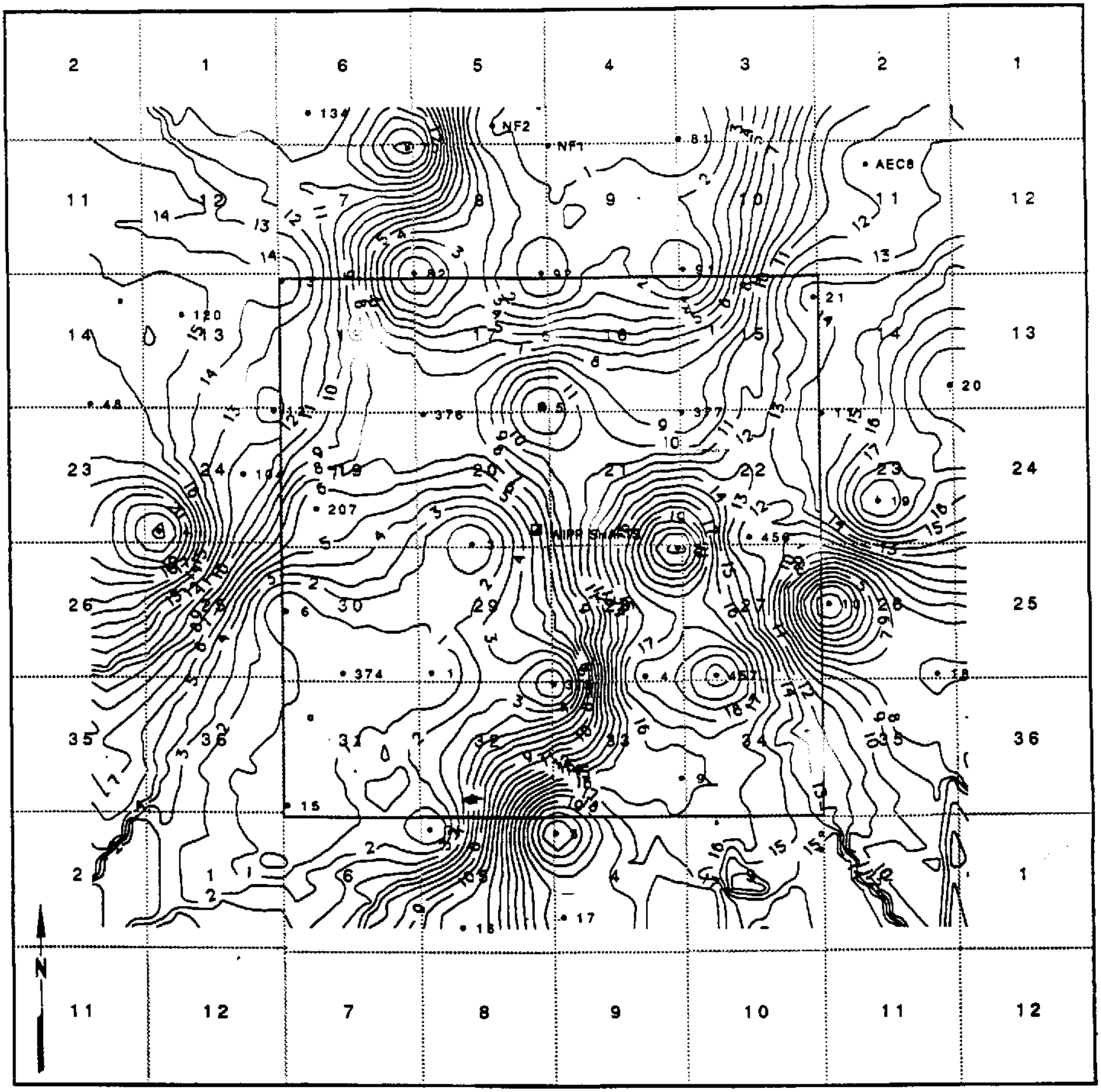

Figure 29
10th Ore Zone - %K20 as Equivalent Sylvite

Contour Interval = 1.0 % K20
Scale: 1" = 6000'

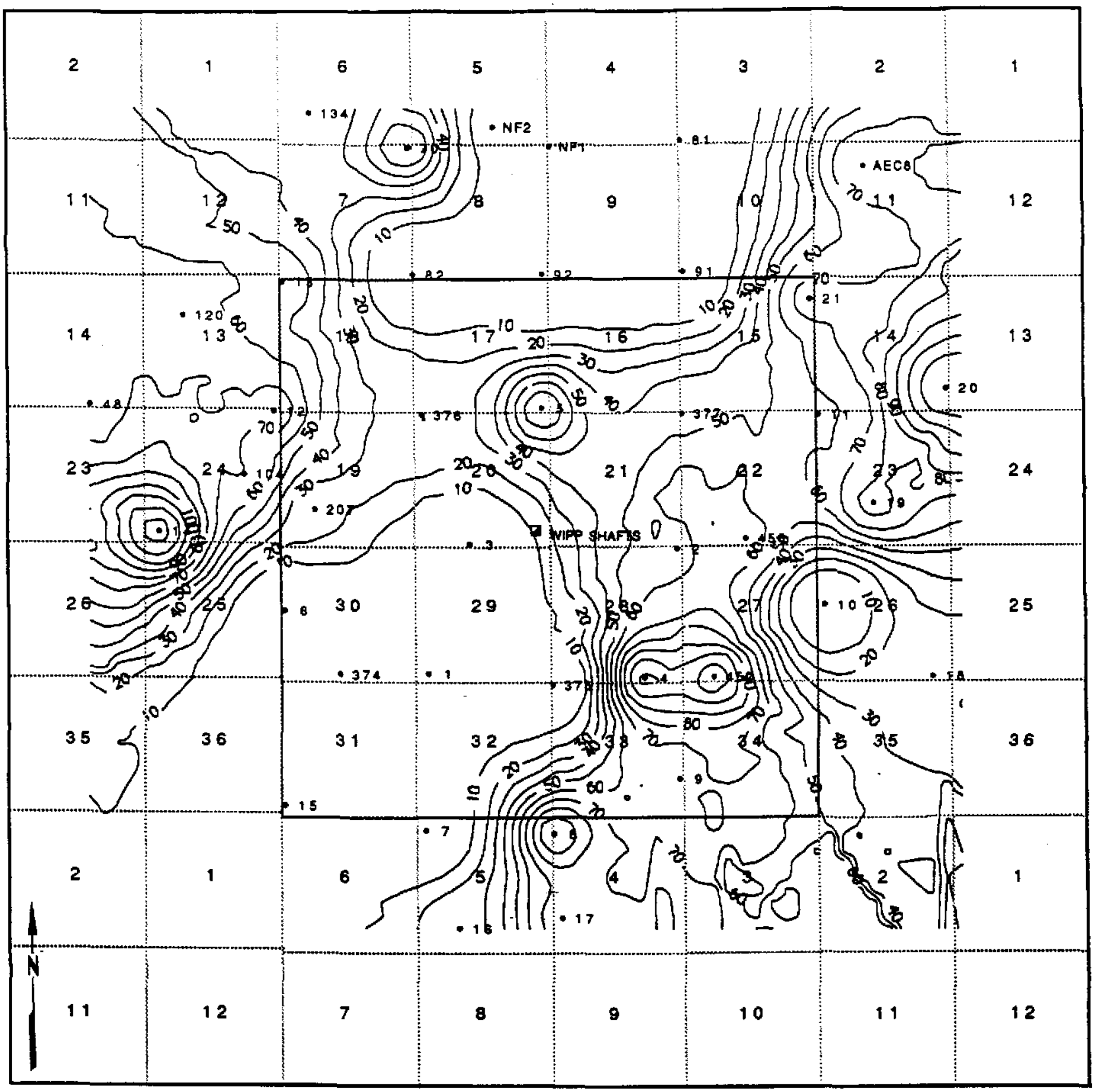

Figure 30
10th Ore Zone - %K20 as Equivalent SylxThickness
Contour Interval = 10 % K20 x Feet
Scale: 1" = 6000'

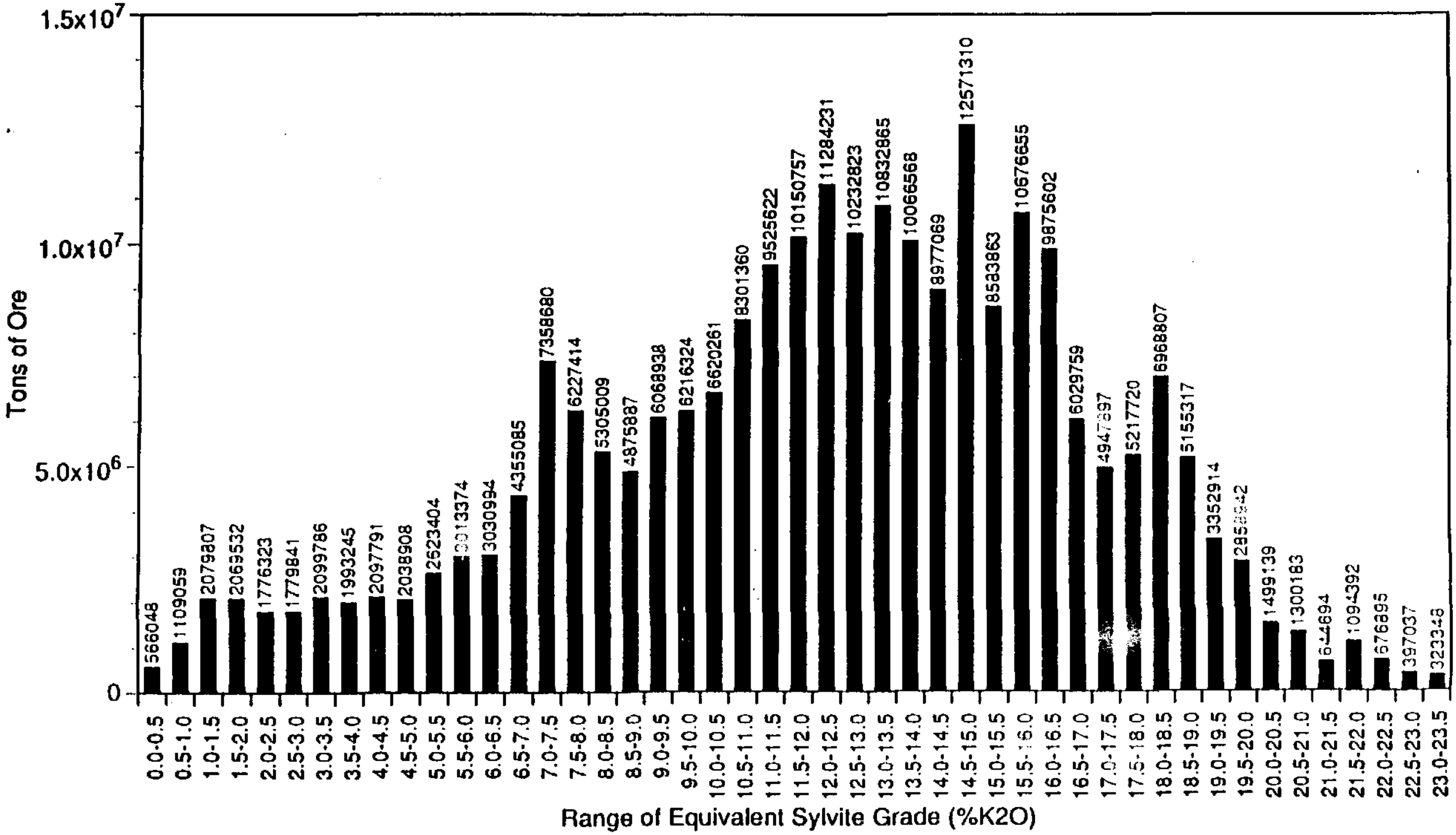

Figure 31
10th Ore Zone Equivalent Sylvite Reserves (In Place)
for Entire Gridded Area

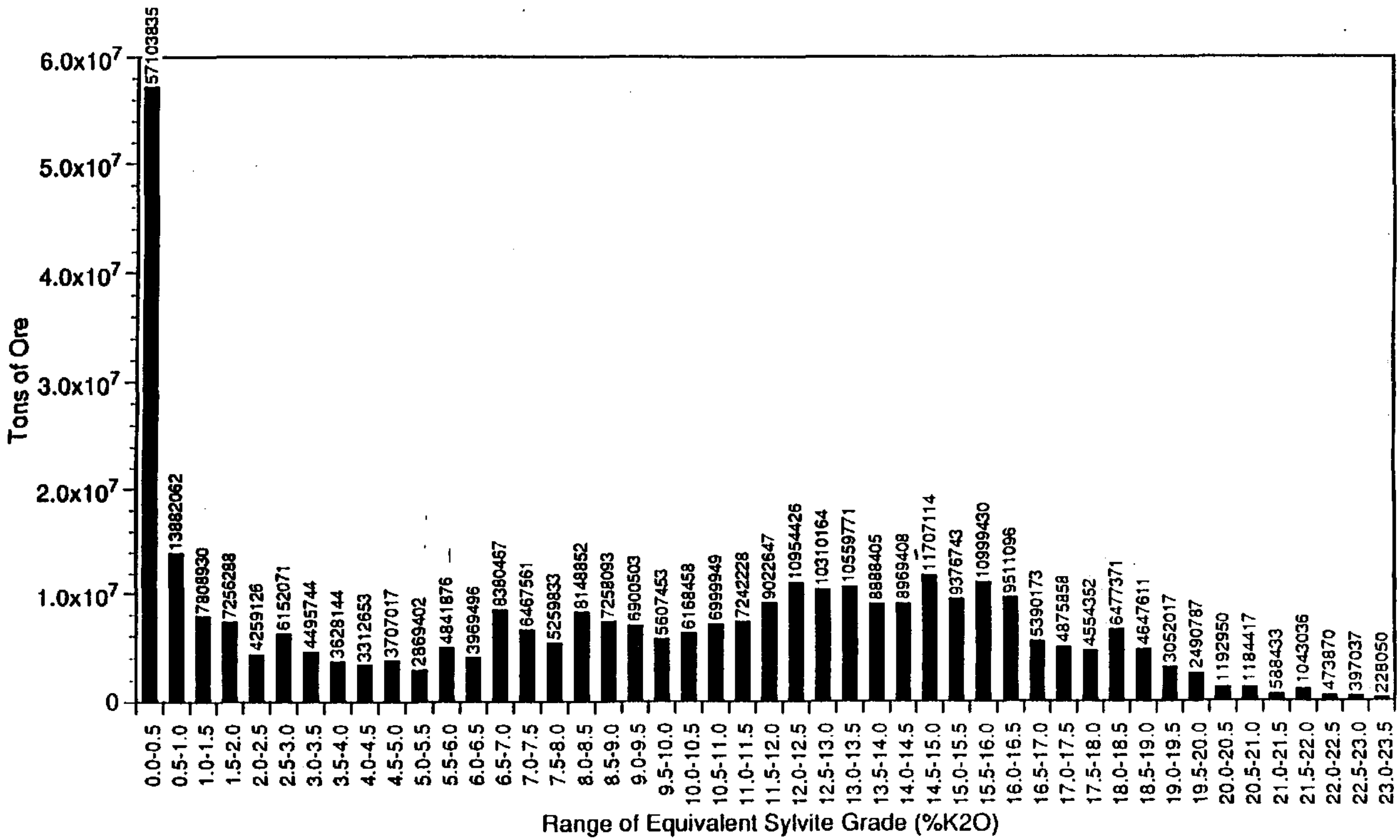

Figure 32
10th Ore Zone Equivalent Sylvite Reserves
Adjusted to Mining Height of 4.0 Feet
for Entire Gridded Area

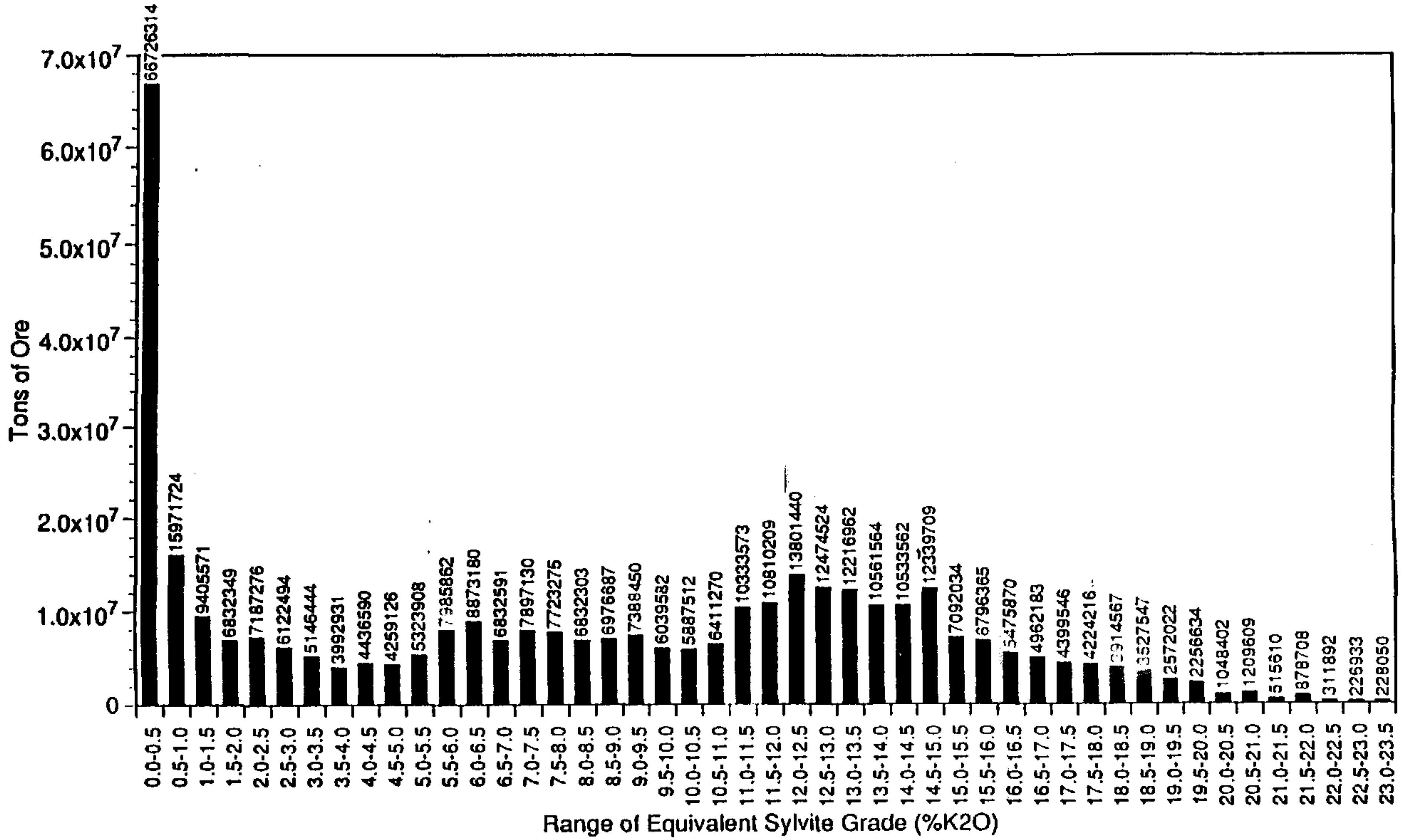

Figure 33
10th Ore Zone Equivalent Sylvite Reserves
Adjusted to Mining Height of 4.5 Feet
for Entire Gridded Area

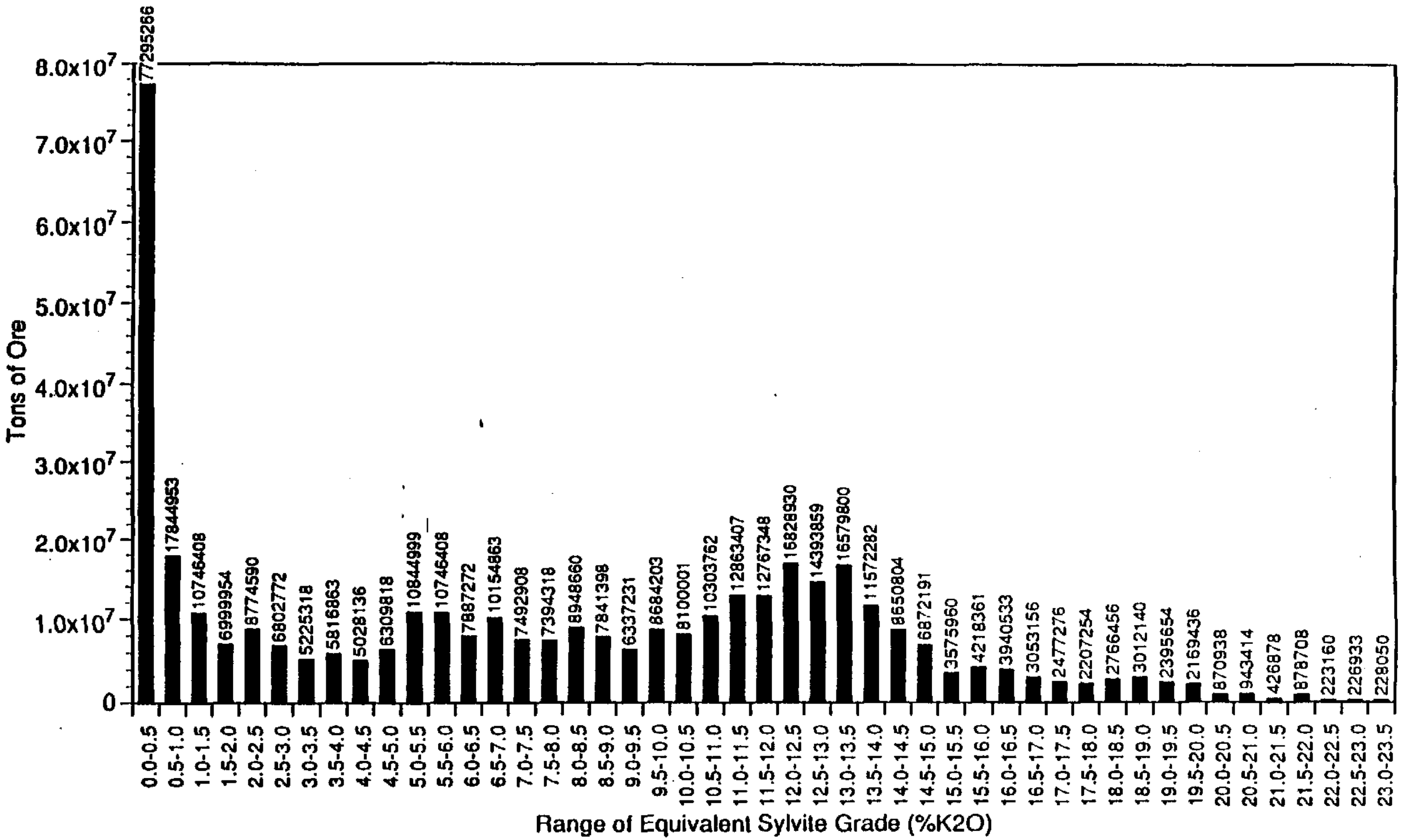

Figure 34
10th Ore Zone Equivalent Sylvite Reserves
Adjusted to Mining Height of 5.0 Feet
for Entire Gridded Area

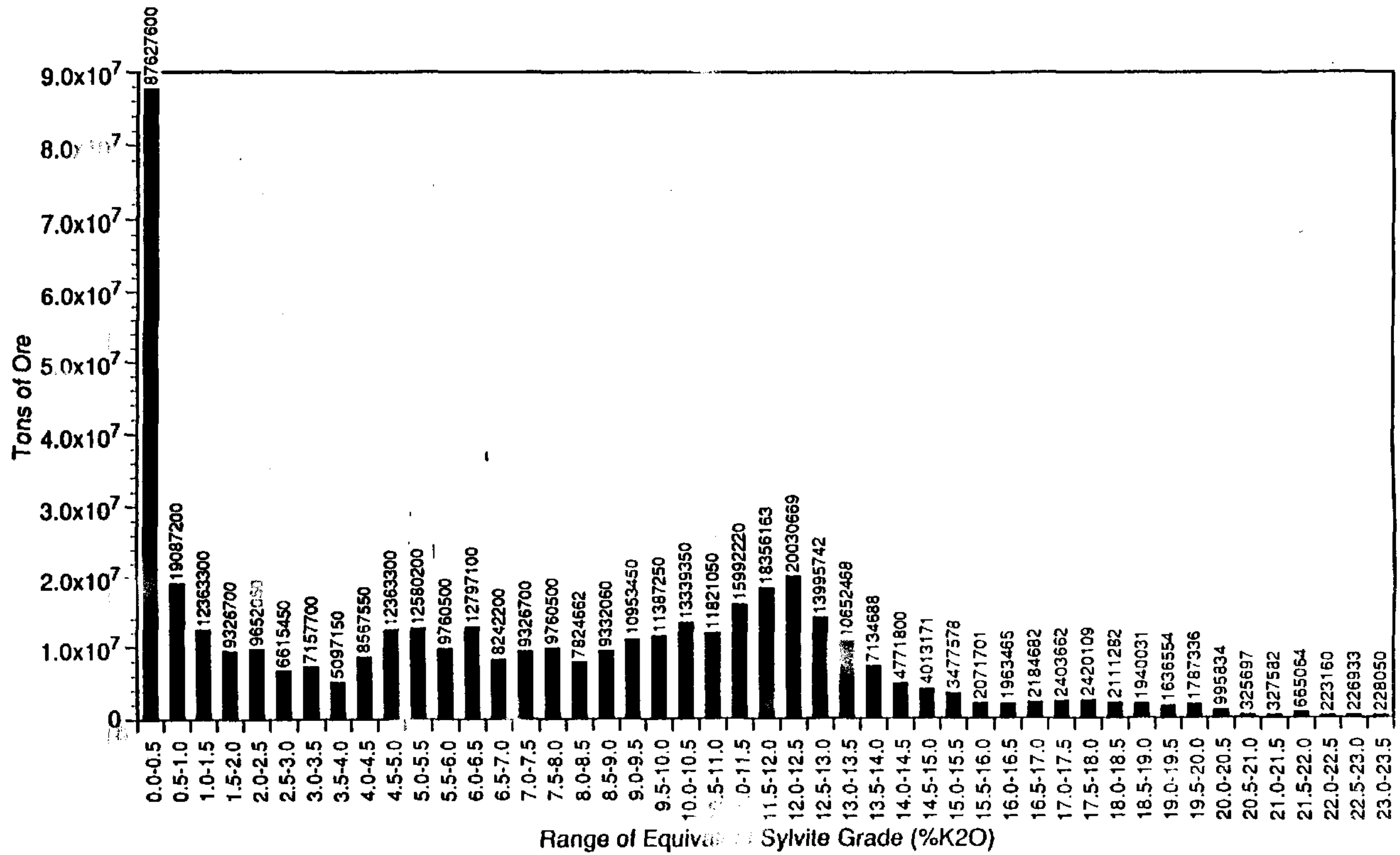

Figure 35
10th Ore Zone Equivalent Sylvite Reserves
Adjusted to Mining Height of 5.5 Feet
for Entire Gridded Area

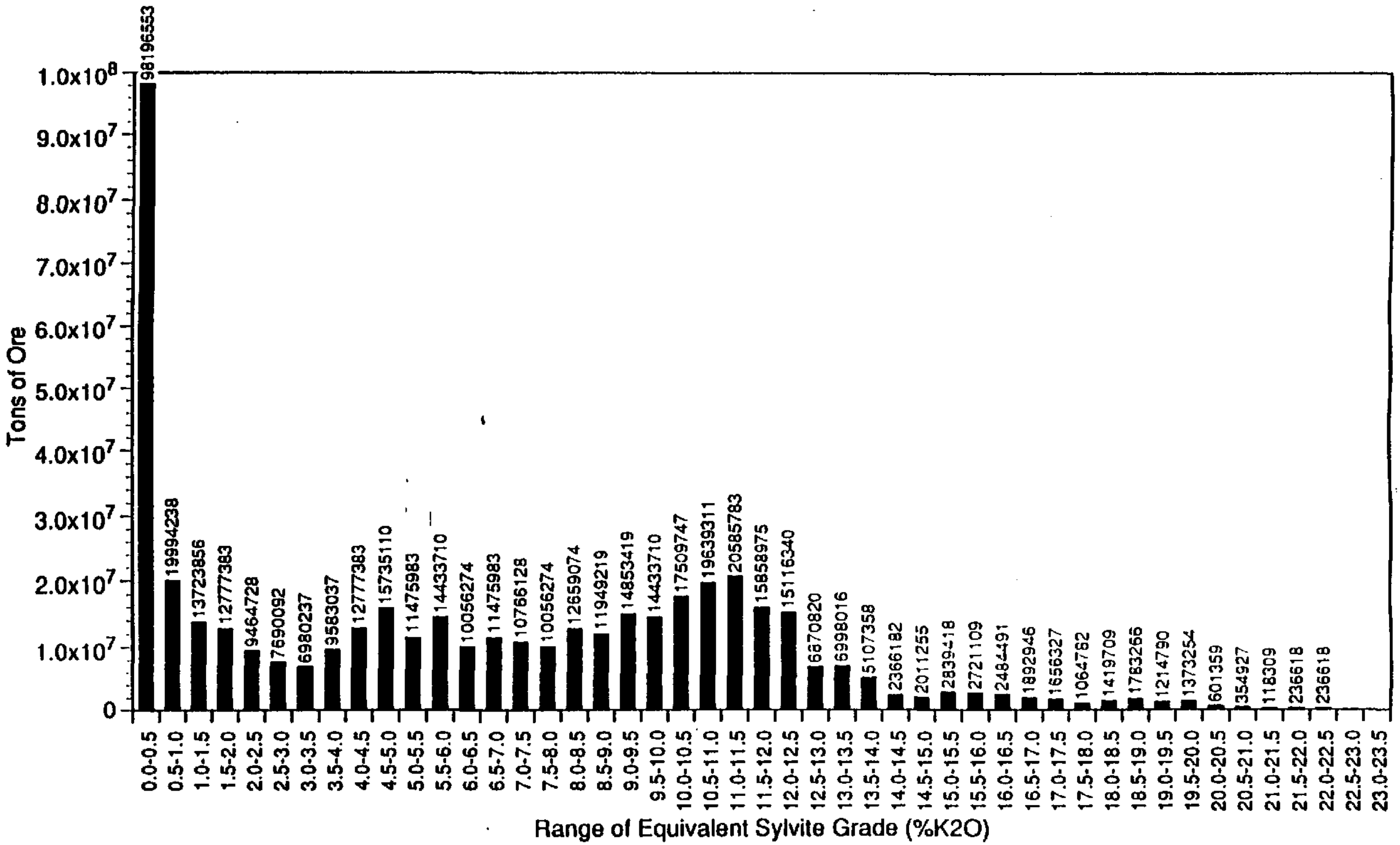

Figure 36
10th Ore Zone Equivalent Sylvite Reserves
Adjusted to Mining Height of 6.0 Feet
for Entire Gridded Area

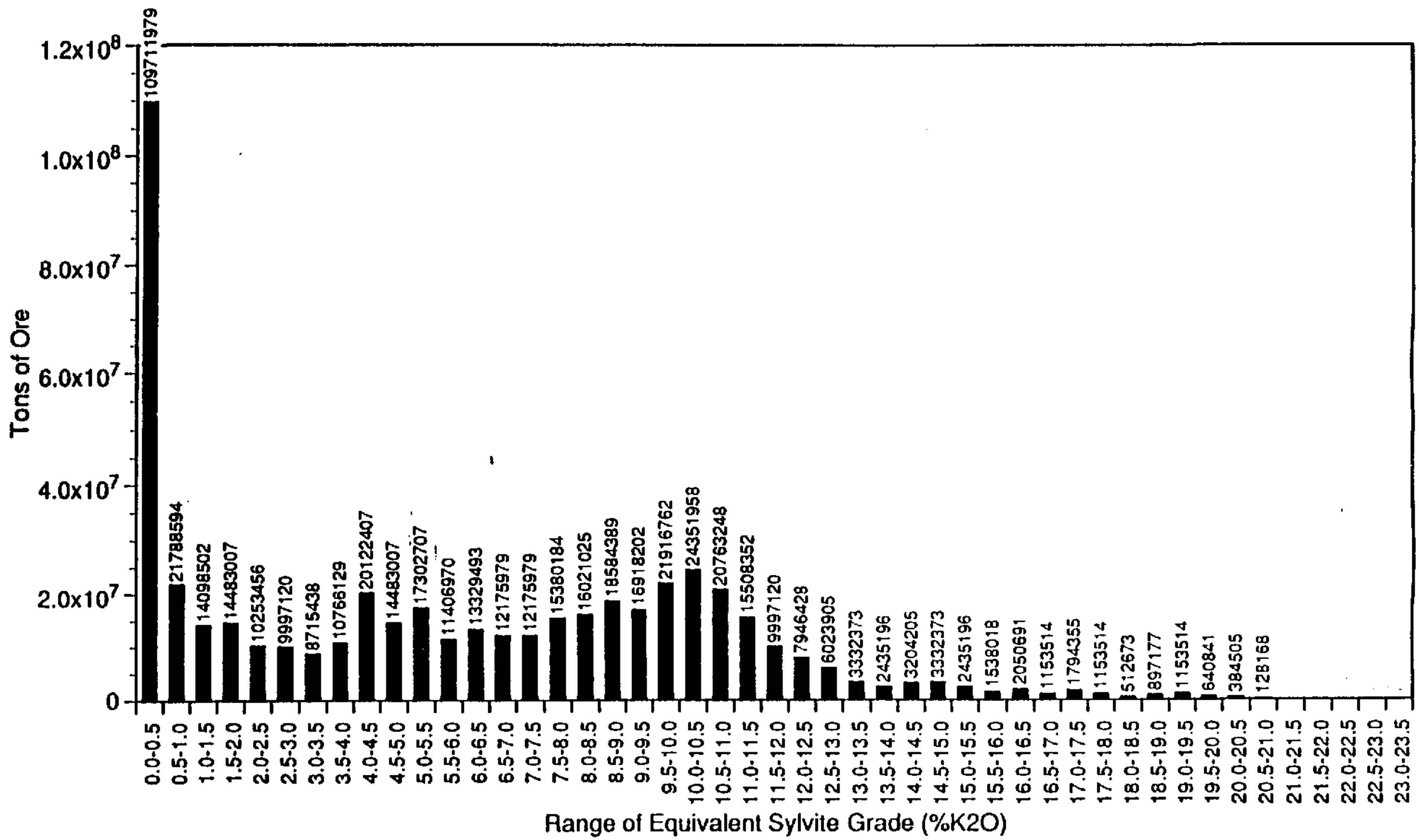

Figure 37
10th Ore Zone Equivalent Sylvite Reserves
Adjusted to Mining Height of 6.5 Feet
for Entire Gridded Area

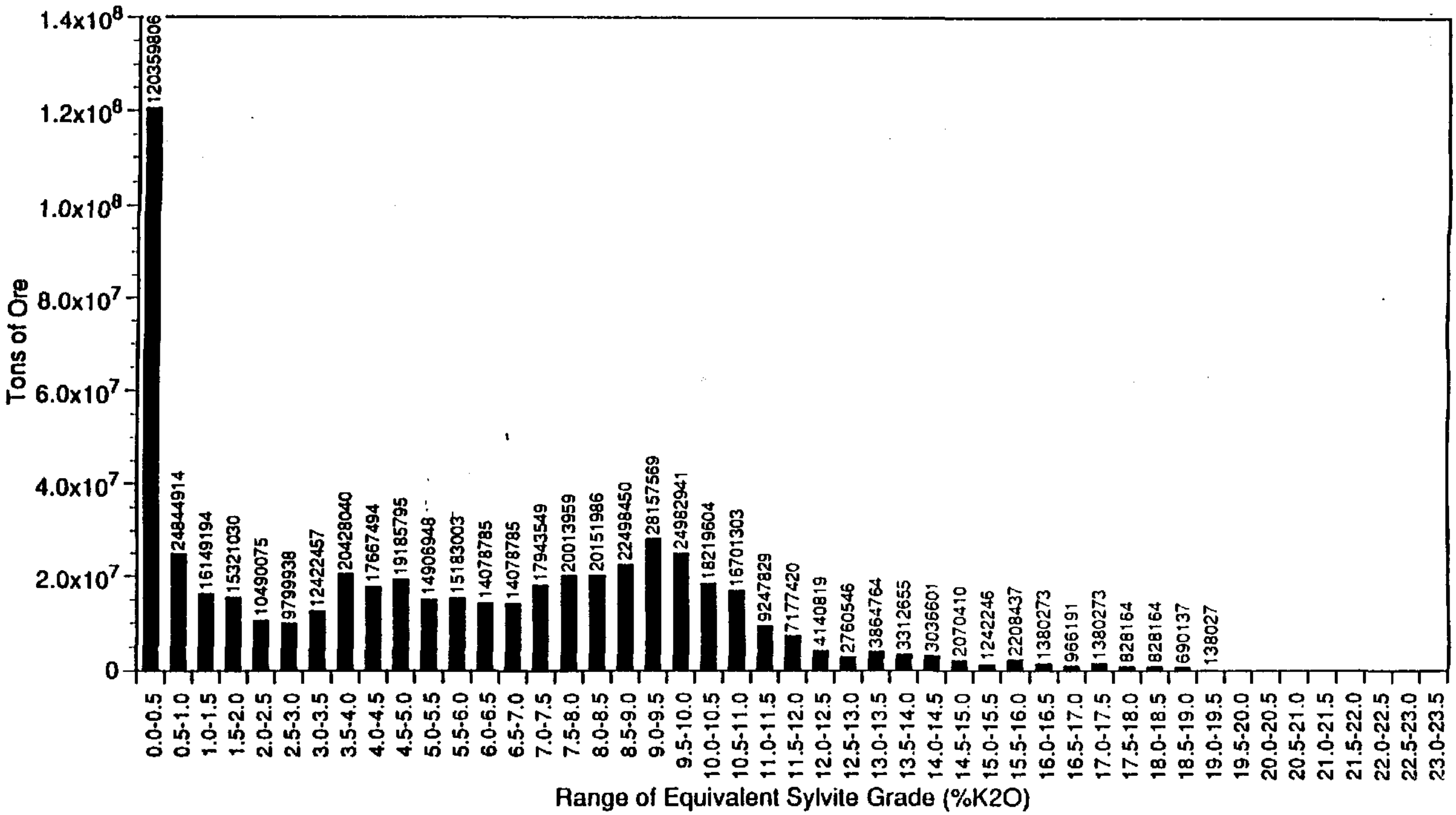

Figure 38
10th Ore Zone Equivalent Sylvite Reserves
Adjusted to Mining Height of 7.0 Feet
for Entire Gridded Area

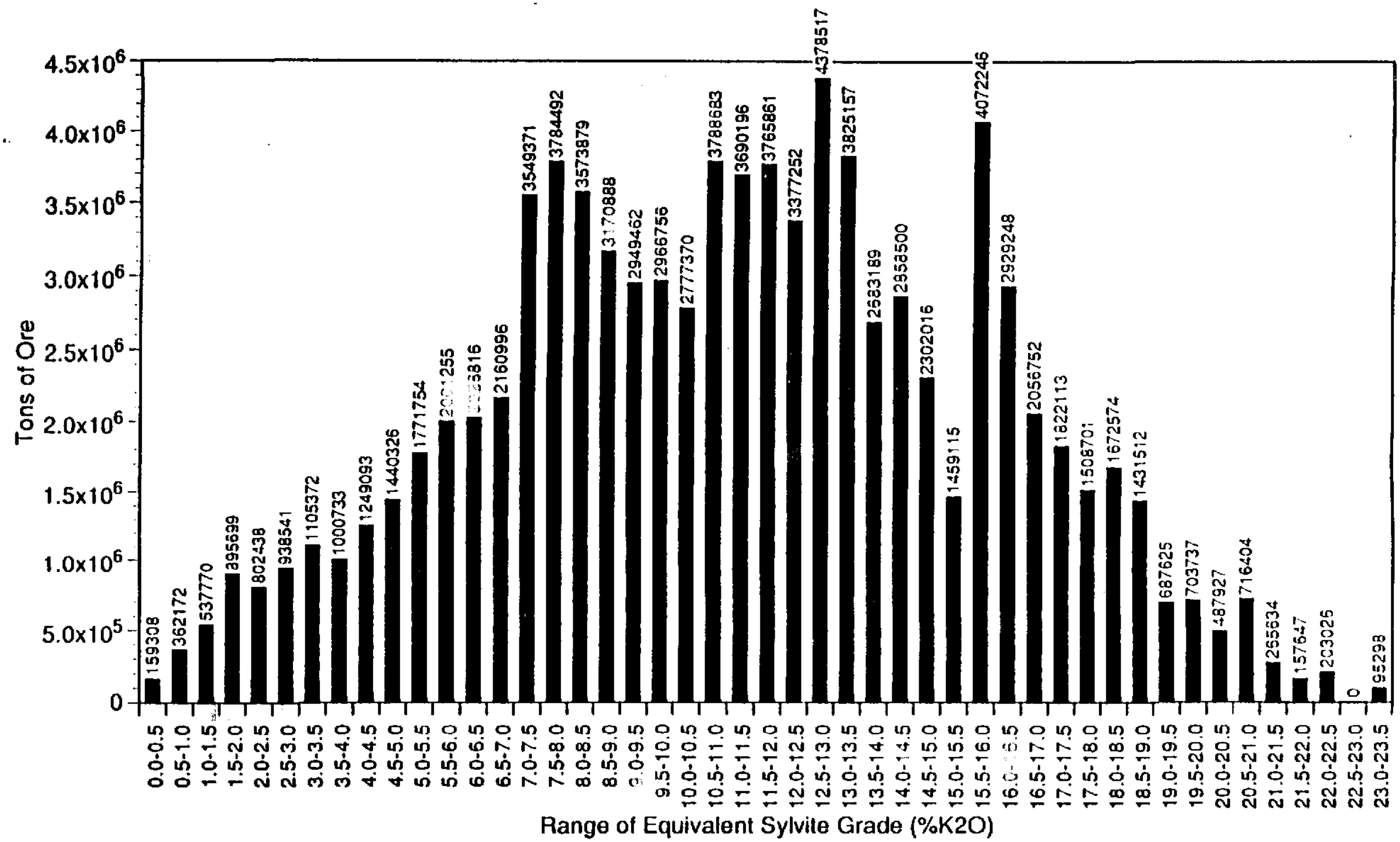

Figure 39
10th Ore Zone Equivalent Sylvite Reserves (In Place)
Within WIPP Boundary

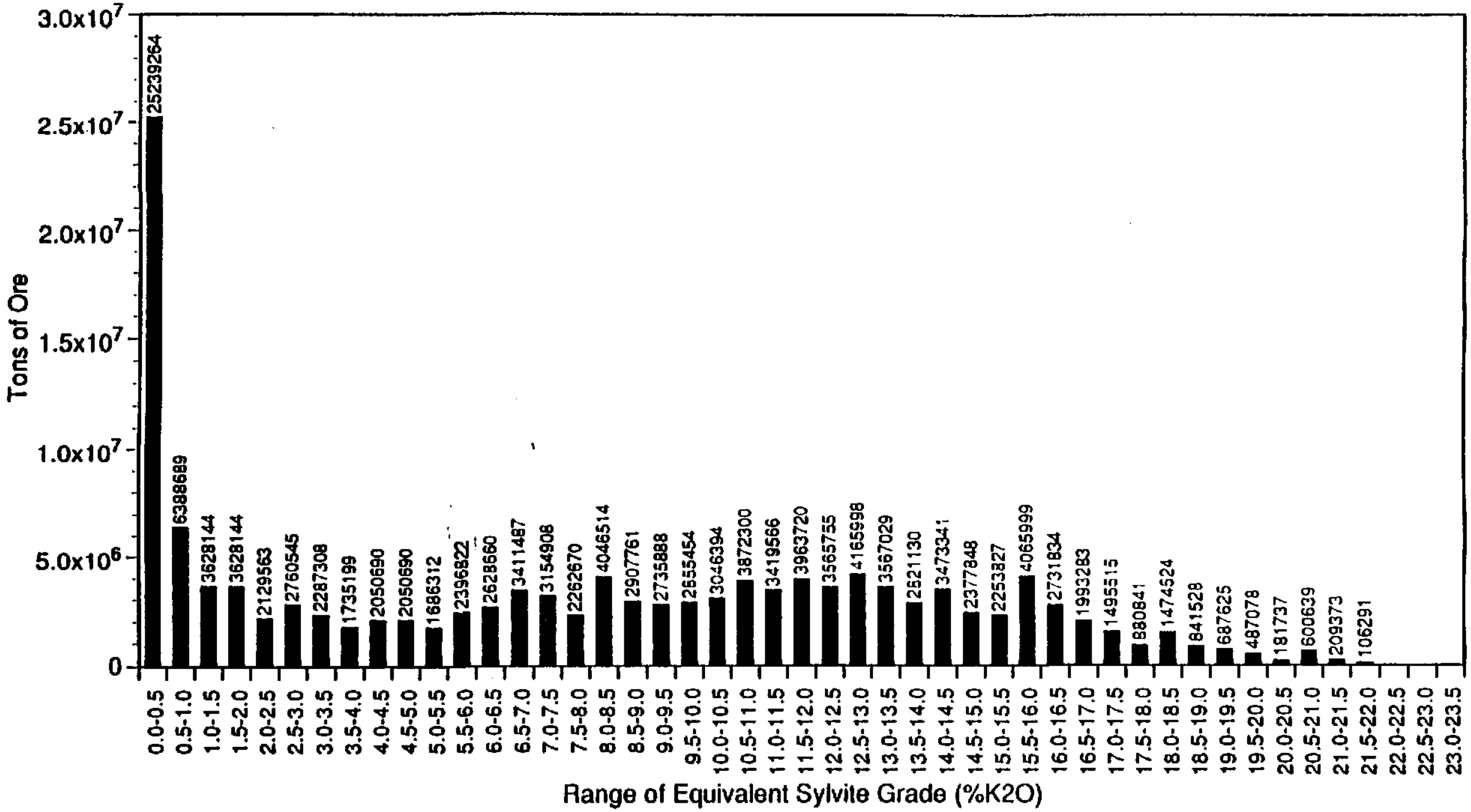

Figure 40
10th Ore Zone Equivalent Sylvite Reserves
Adjusted to Mining Height of 4.0 Feet
Within WIPP Boundary

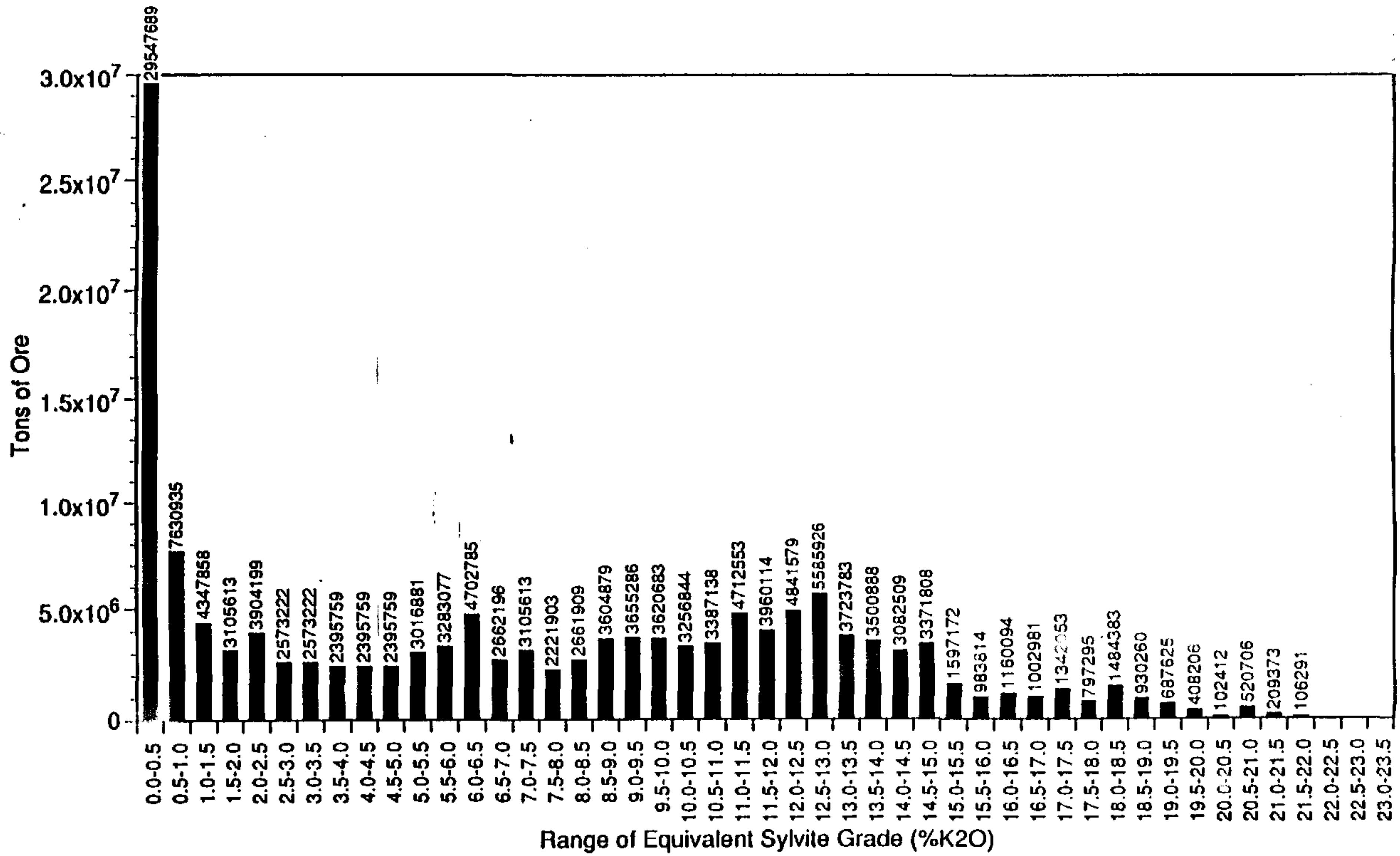

Figure 41
10th Ore Zone Equivalent Sylvite Reserves
Adjusted to Mining Height of 4.5 Feet
Within WIPP Boundary

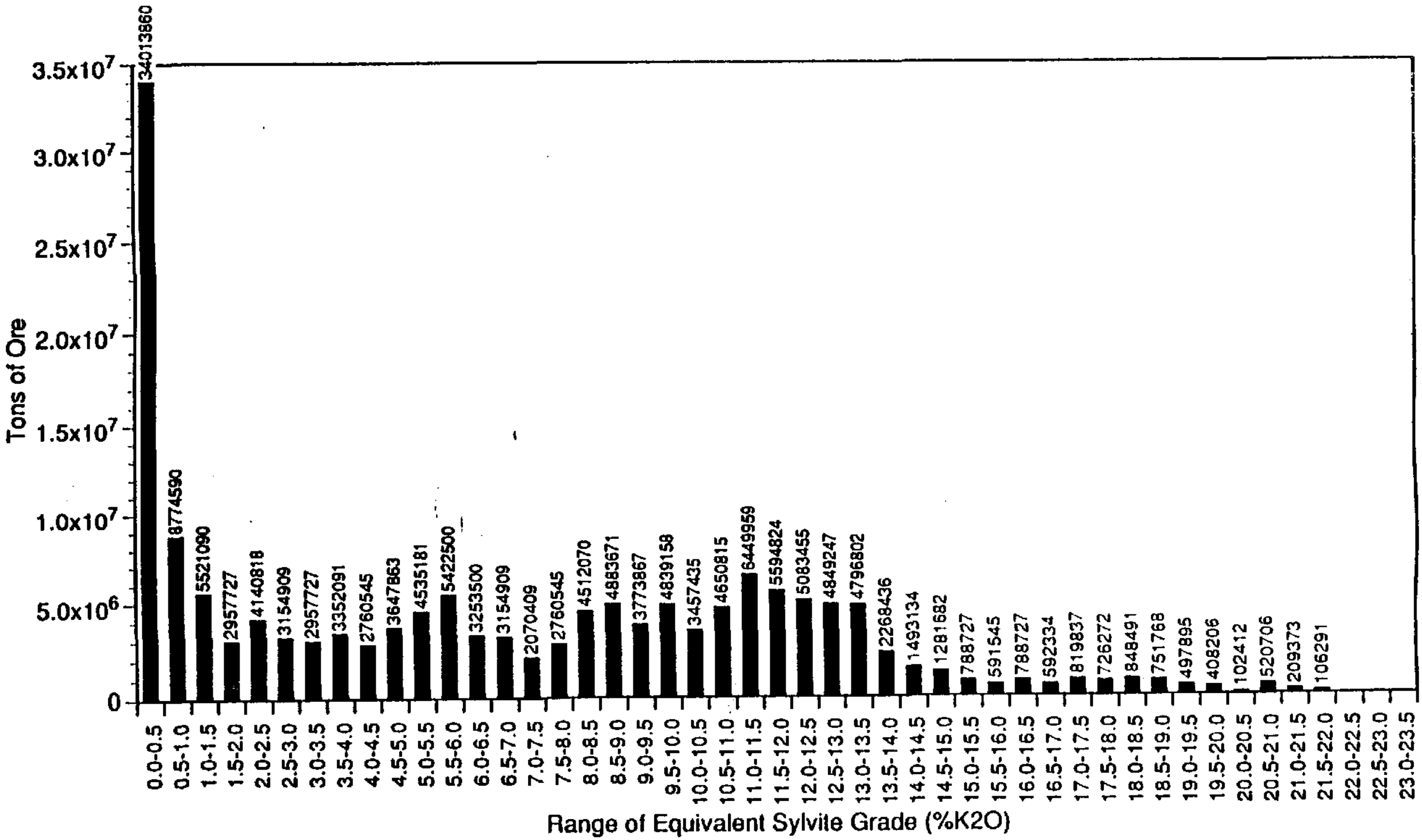

Figure 42
10th Ore Zone Equivalent Sylvite Reserves
Adjusted to Mining Height of 5.0 Feet
Within WIPP Boundary

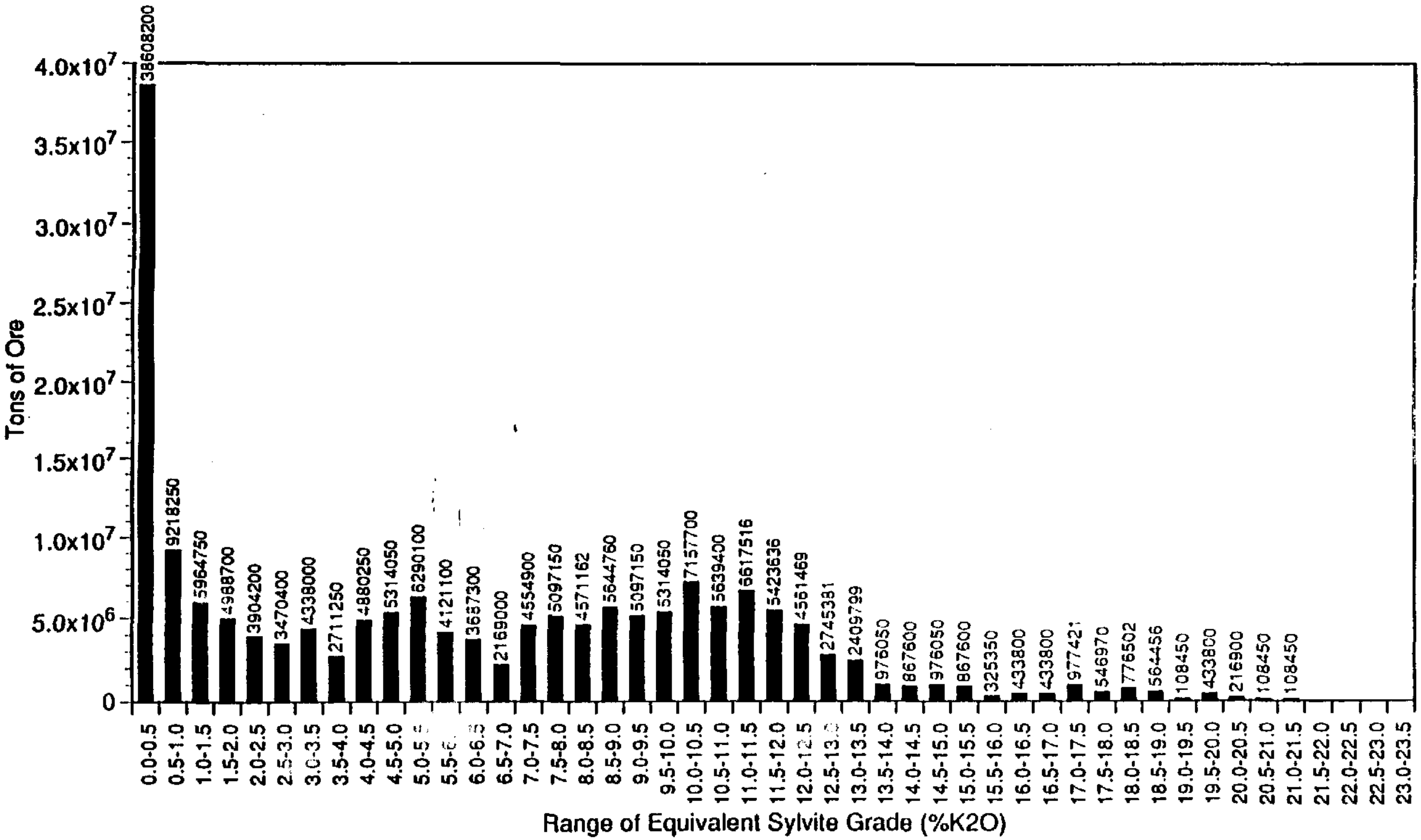

Figure 43
10th Ore Zone Equivalent Sylvite Reserves
Adjusted to Mining Height of 5.5 Feet
Within WIPP Boundary

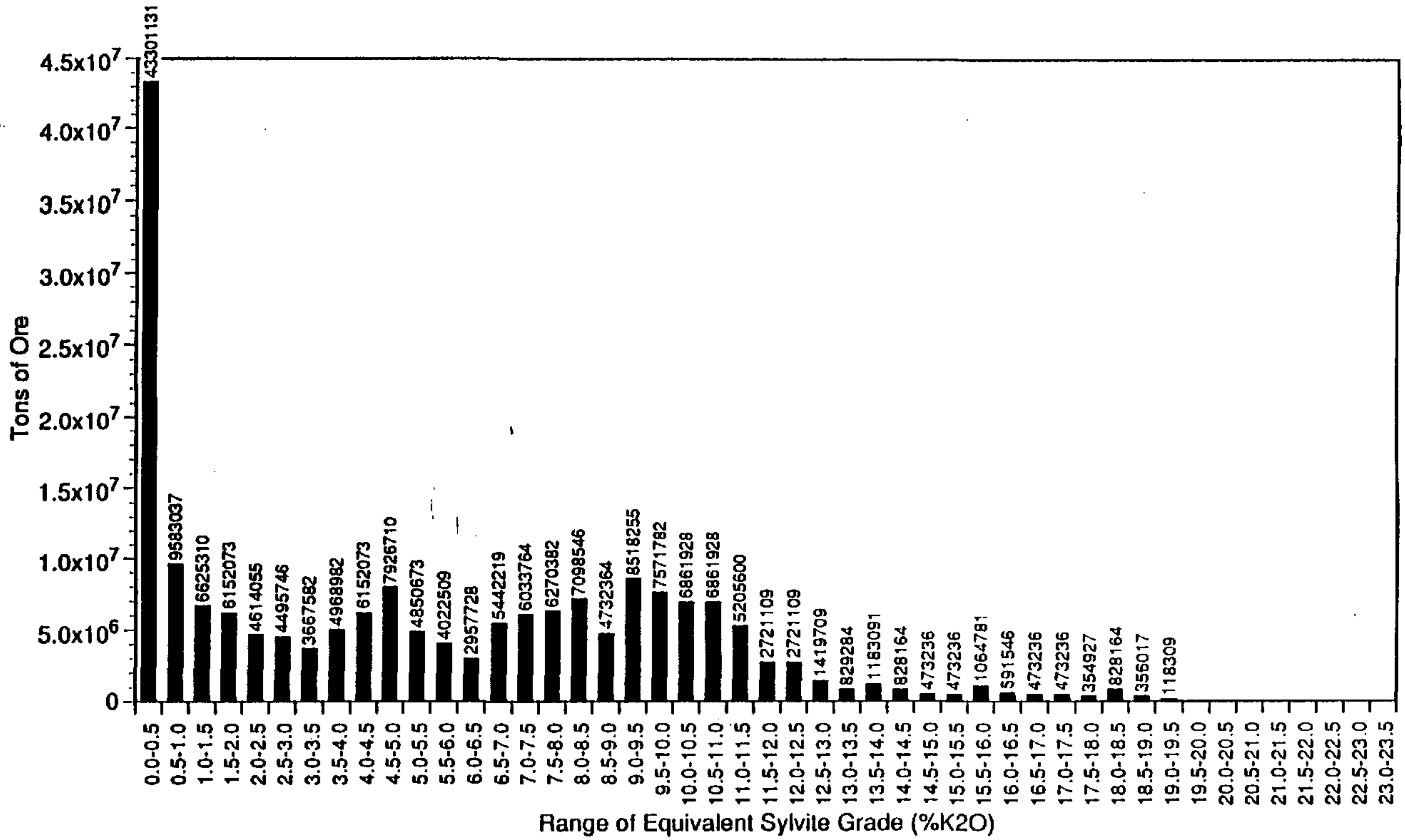

Figure 44
10th Ore Zone Equivalent Sylvite Reserves
Adjusted to Mining Height of 6.0 Feet
Within WIPP Boundary

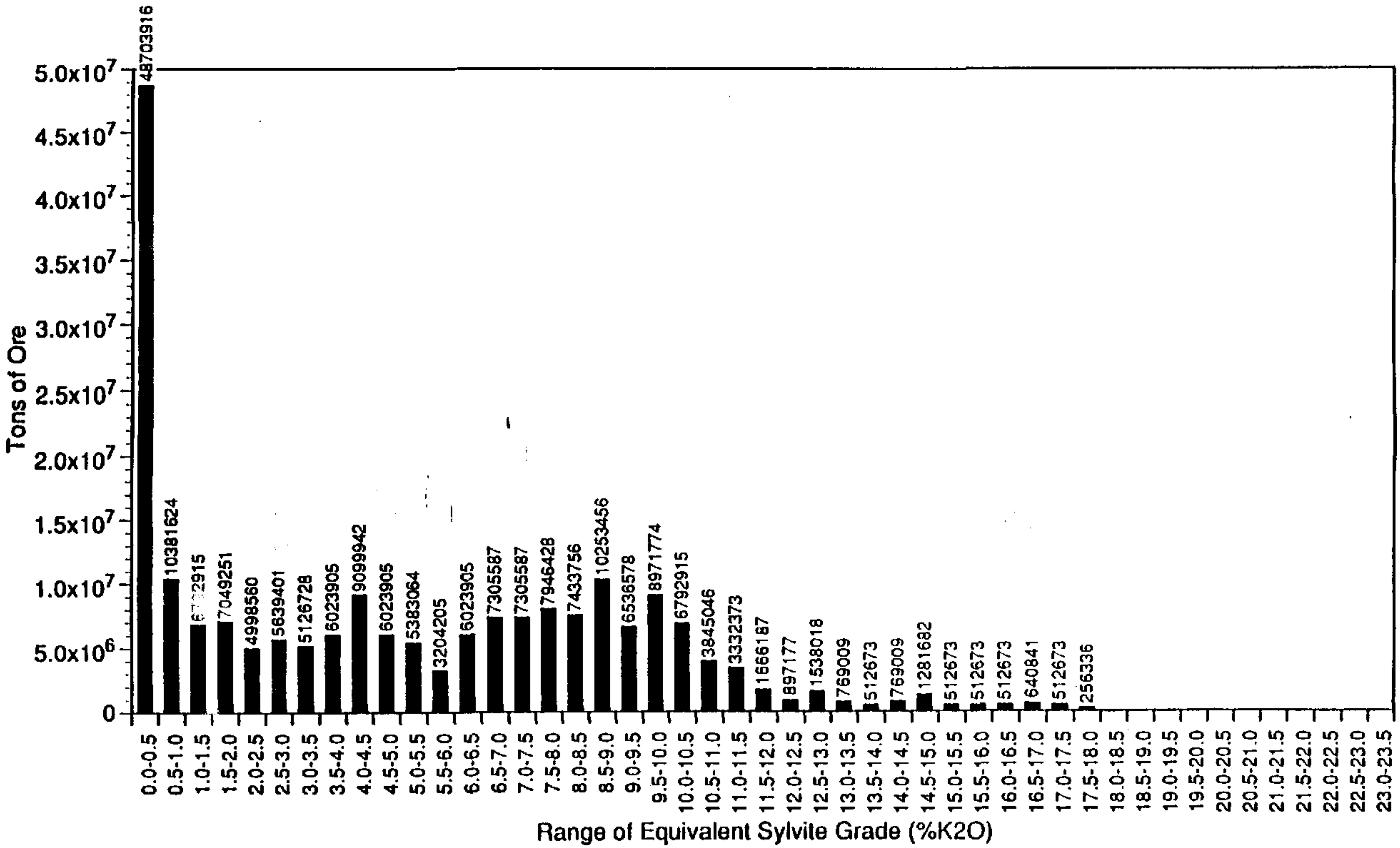

Figure 45
10th Ore Zone Equivalent Sylvite Reserves
Adjusted to Mining Height of 6.5 Feet
Within WIPP Boundary

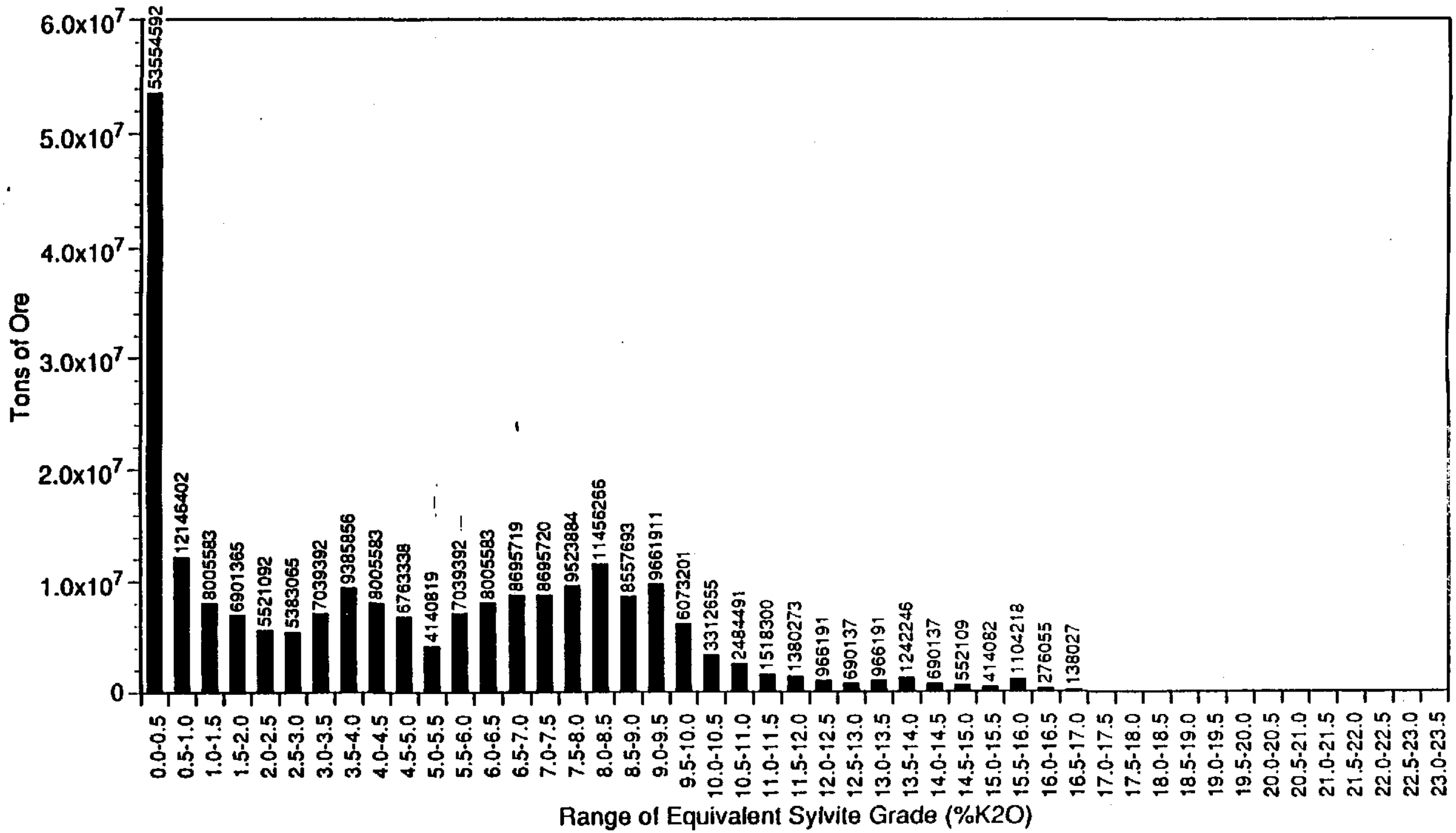

Figure 46
10th Ore Zone Equivalent Sylvite Reserves
Adjusted to Mining Height of 7.0 Feet
Within WIPP Boundary

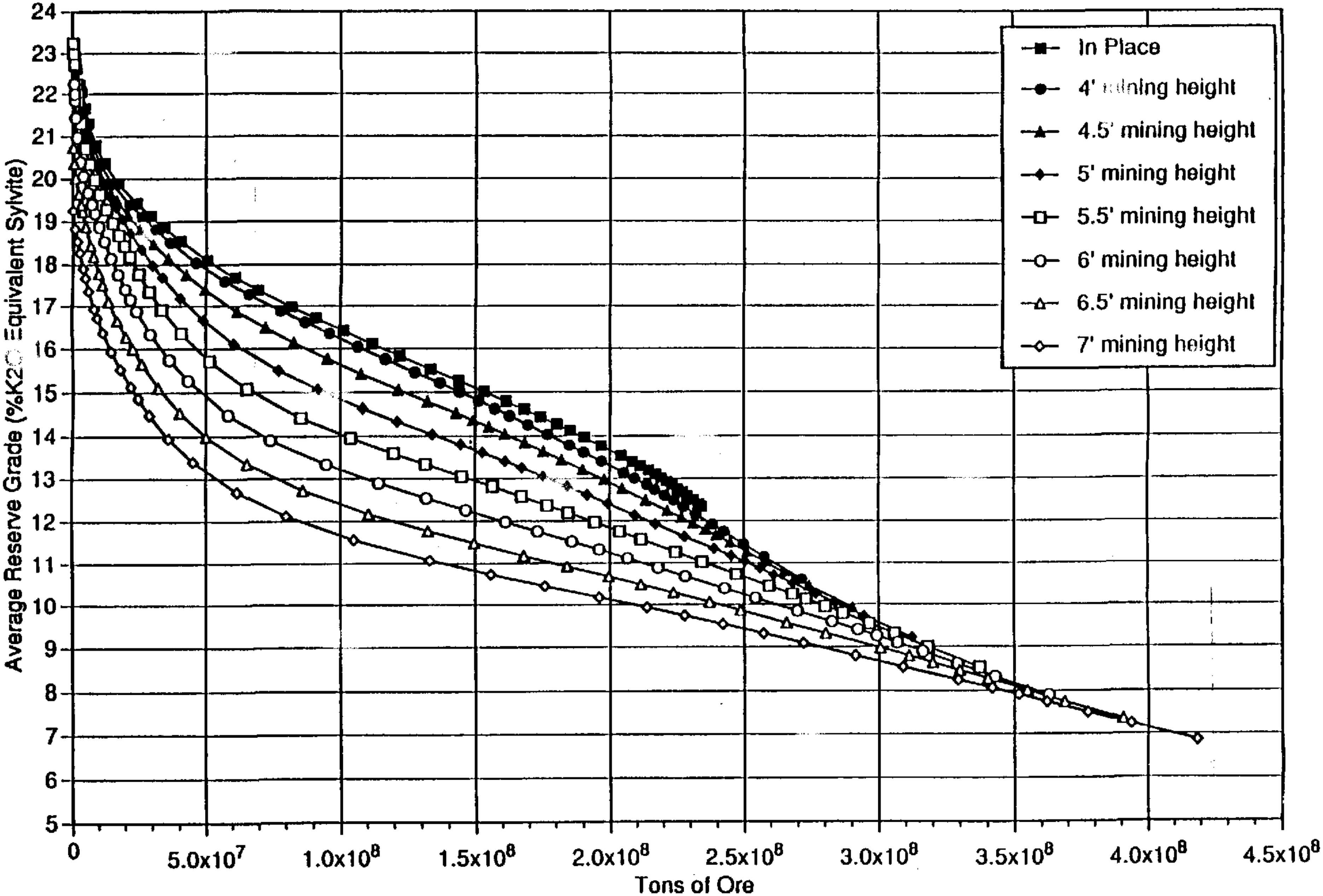

Figure 47
10th Ore Zone Sylvite Reserves (Reserve Grade)
for Entire Gridded Area

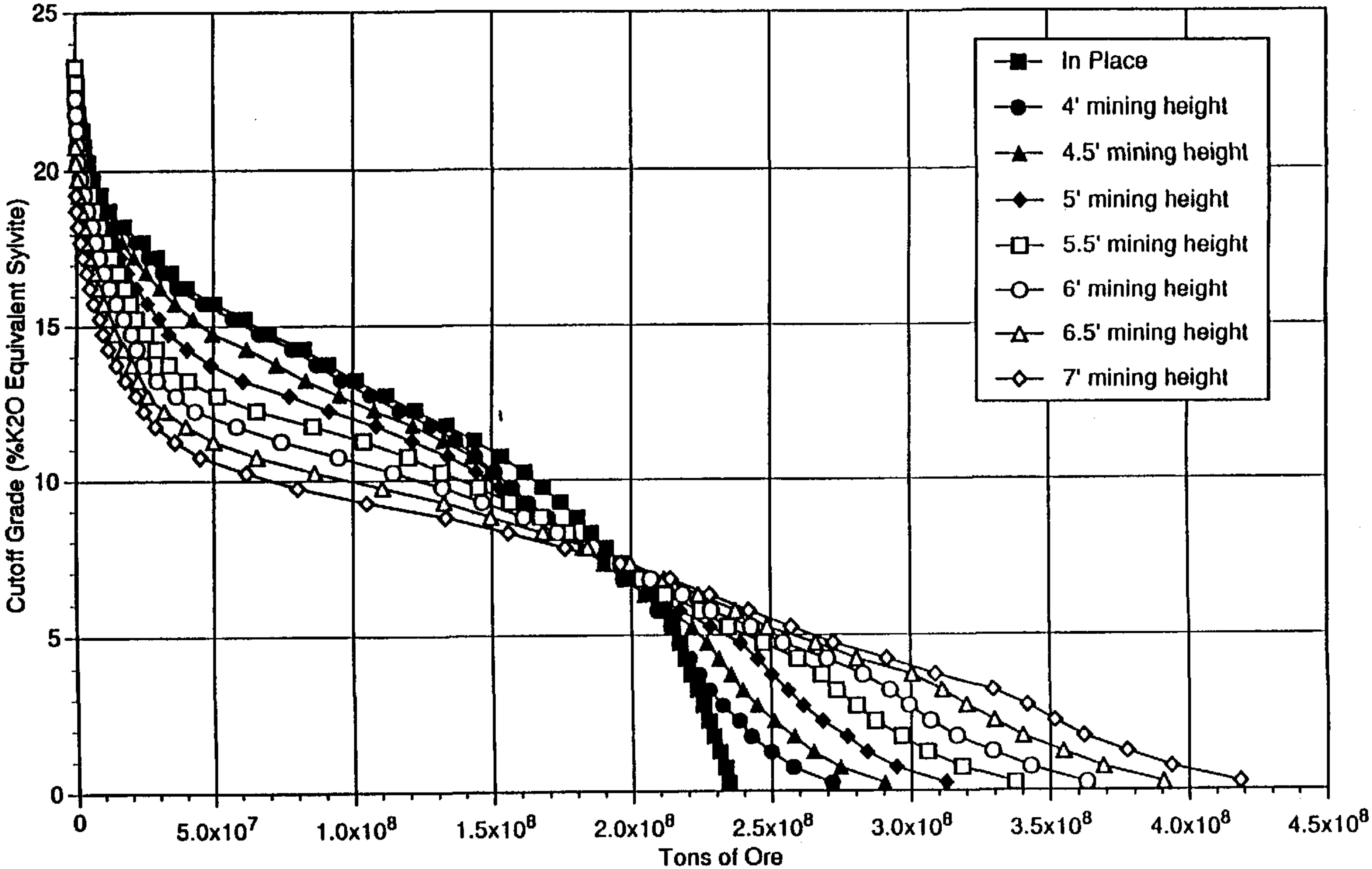

Figure 48
10th Ore Zone Sylvite Reserves (Cutoff Grade)
for Entire Gridded Area

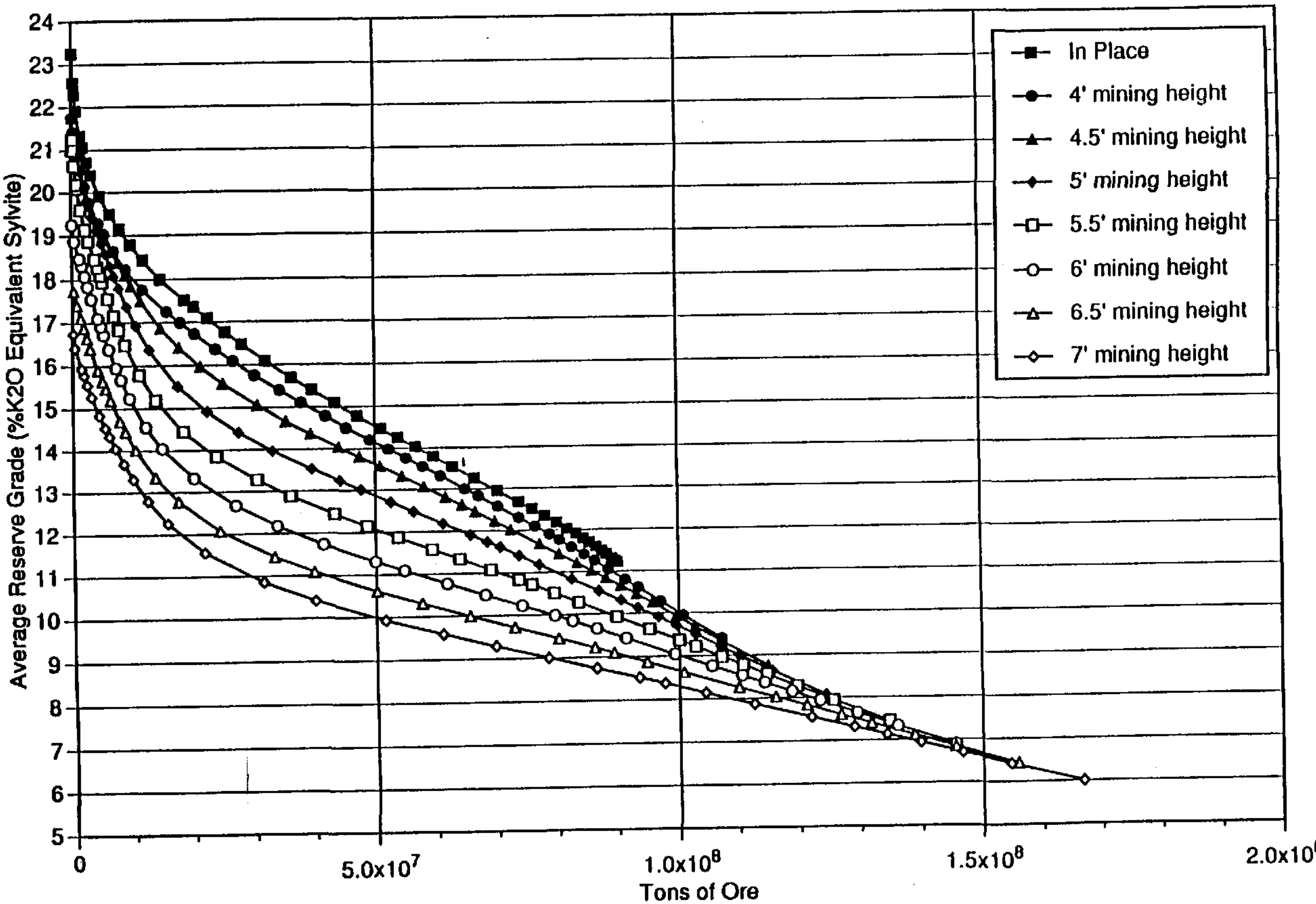

Figure 49
10th Ore ZoneSylvite Reserves (Reserve Grade)
Within WIPP Boundary

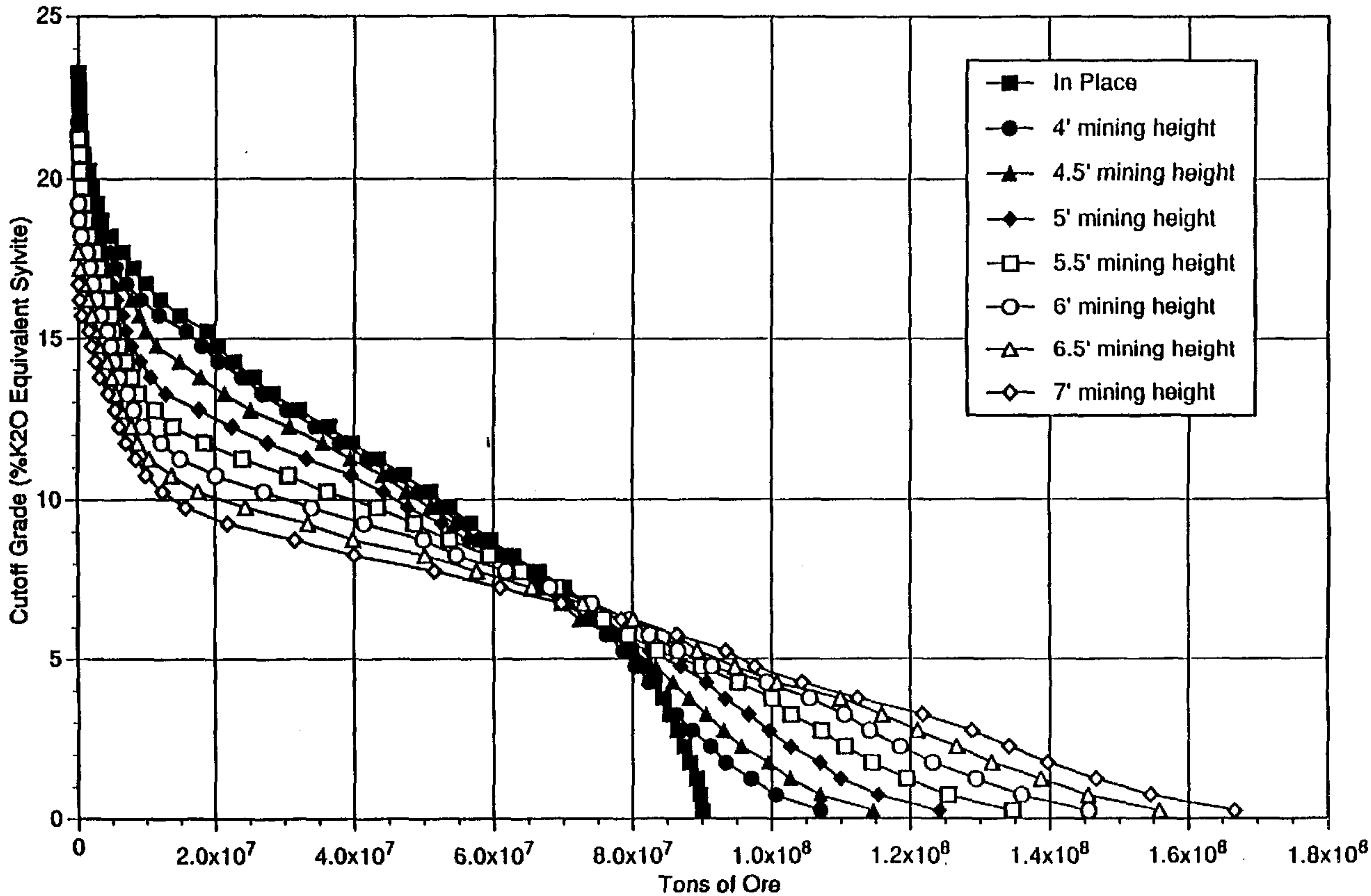

Figure 50
10th Ore ZoneSylvite Reserves (Cutoff Grade)
Within WIPP Boundary

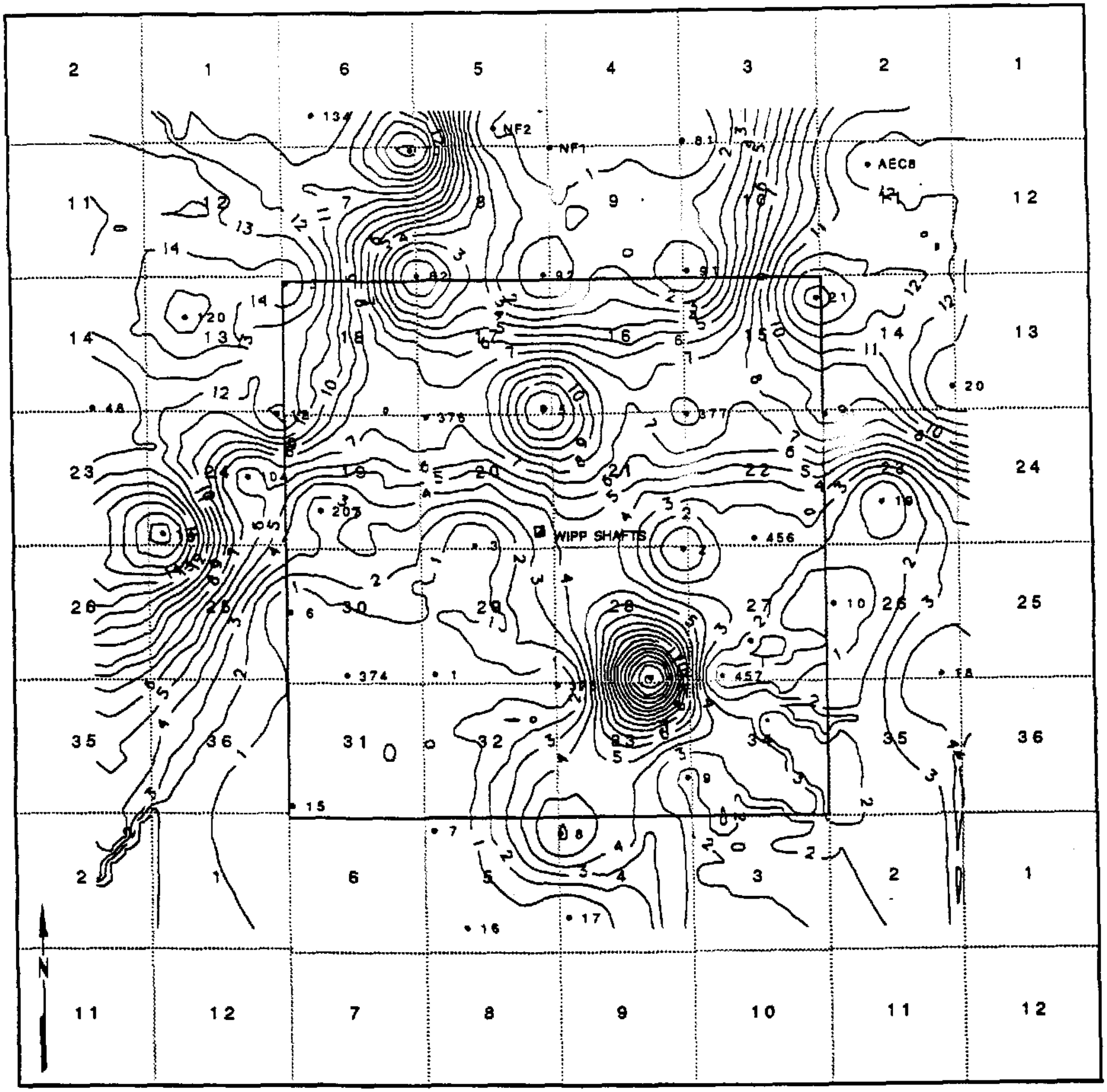

Figure 51
10th Ore Zone - %K20 Sylvite Only

Contour Interval = 1.0 % K20
Scale: 1" = 6000'

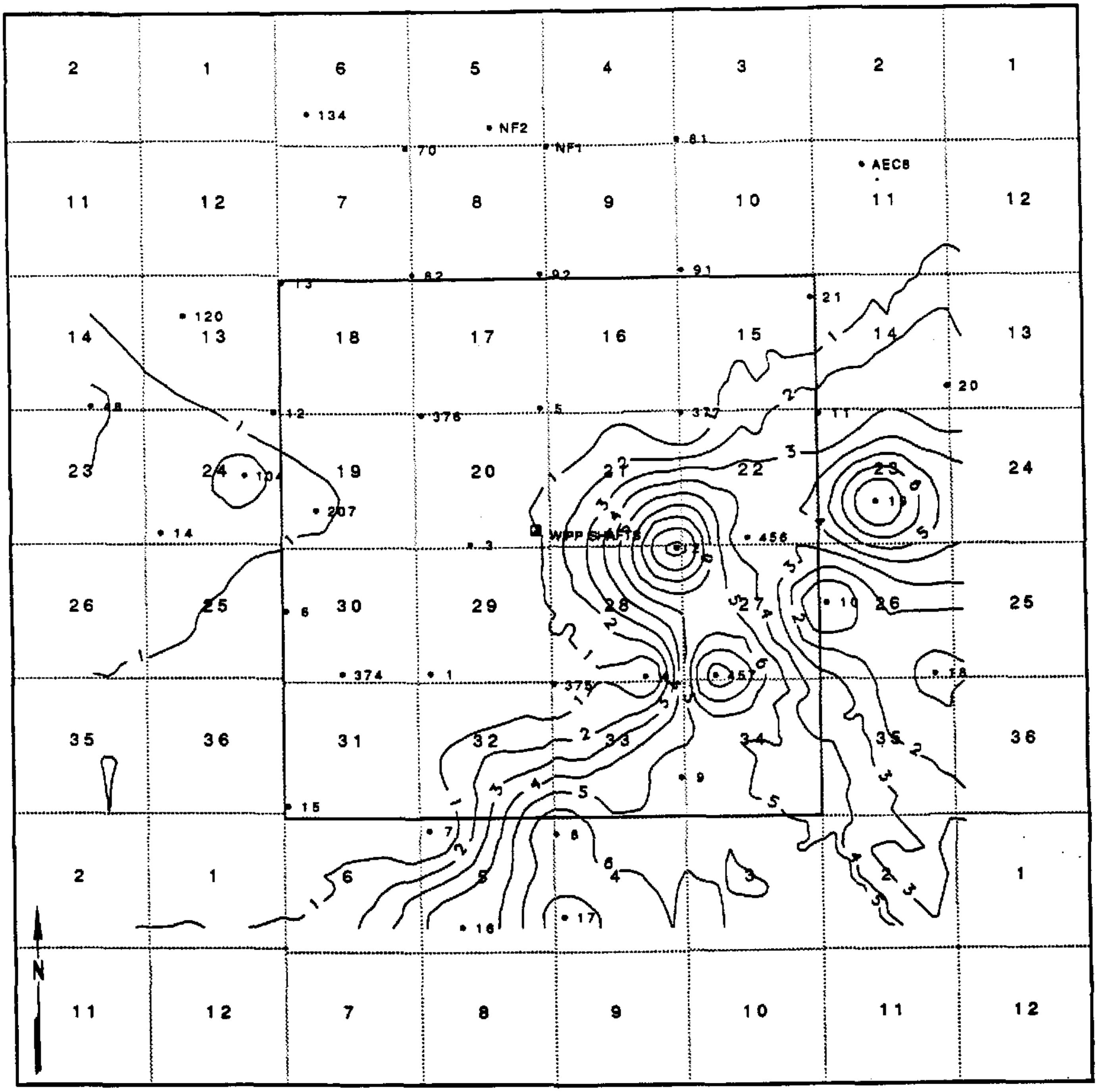

Figure 52
10th Ore Zone - %K20 Langbeinite Only
Contour Interval = 1.0 % K20
Scale: 1" = 6000'

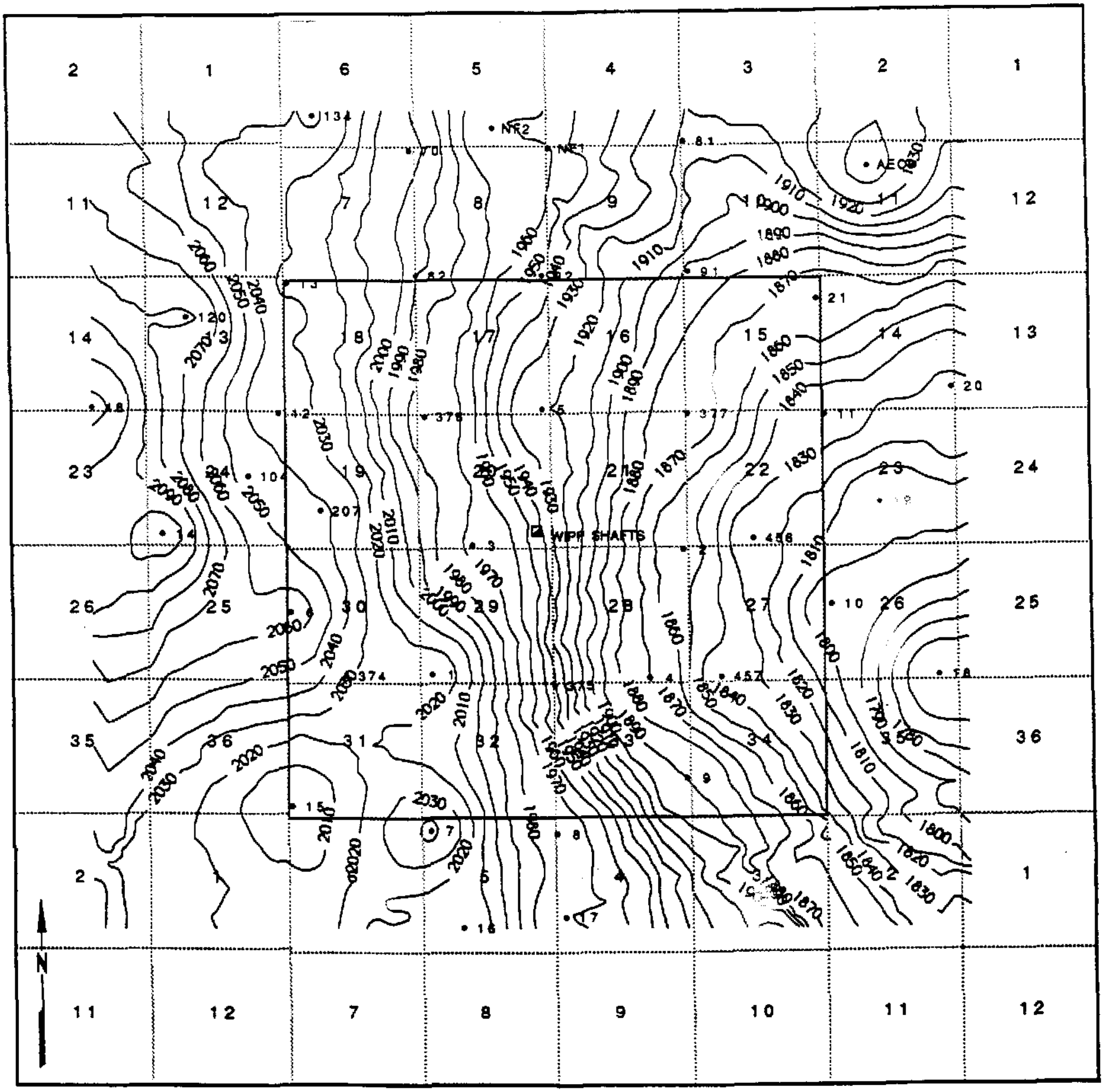

Figure 53
Structure of the Top of the 10th Ore Zone
Contour Interval = 10 Feet
Scale: 1" = 6000'

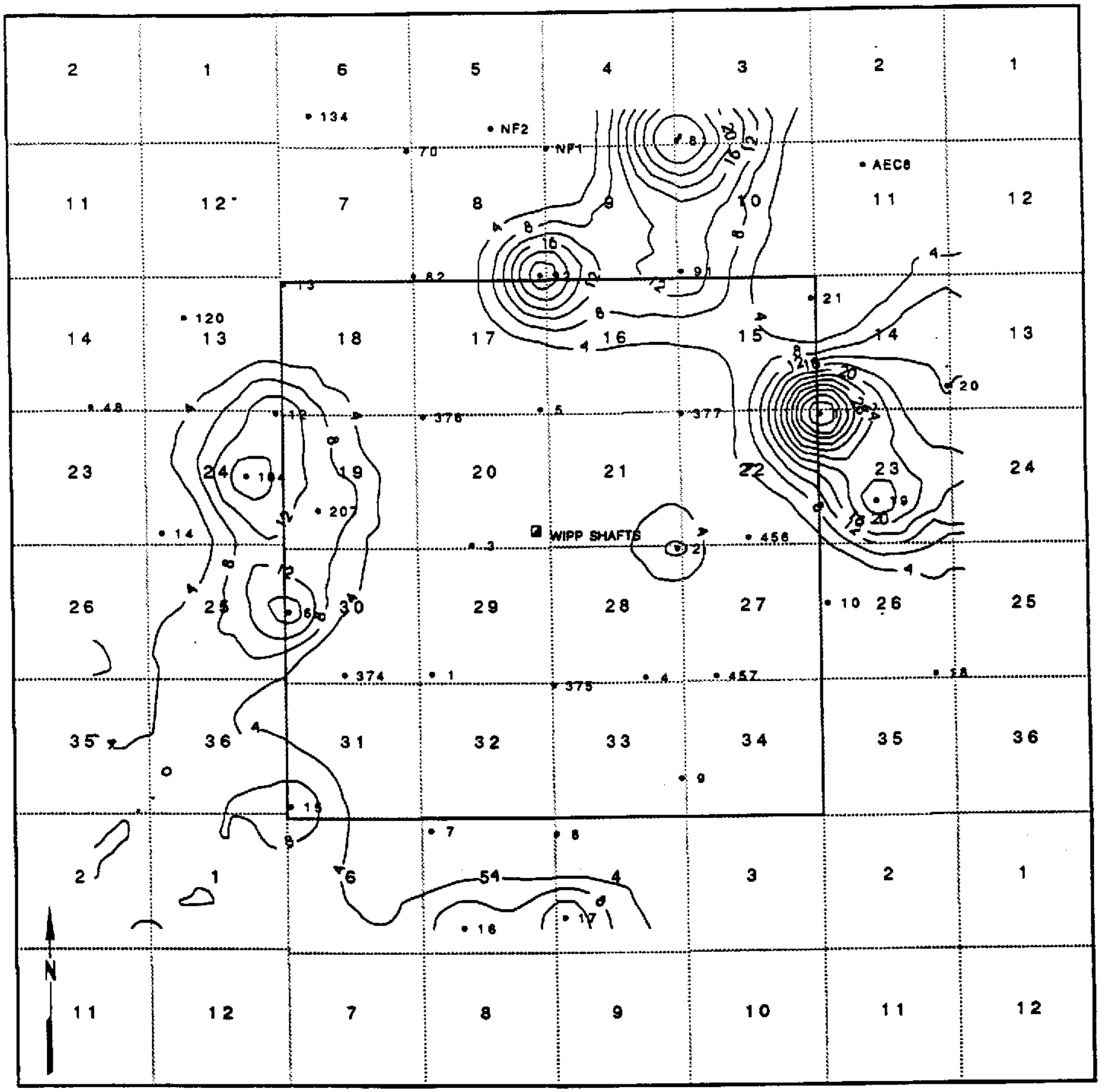

Figure 54
2nd Ore Zone - %K20 Langbeinite x Thickness
Contour Interval = 4.0 % K20 x Feet
Scale: 1" = 6000'

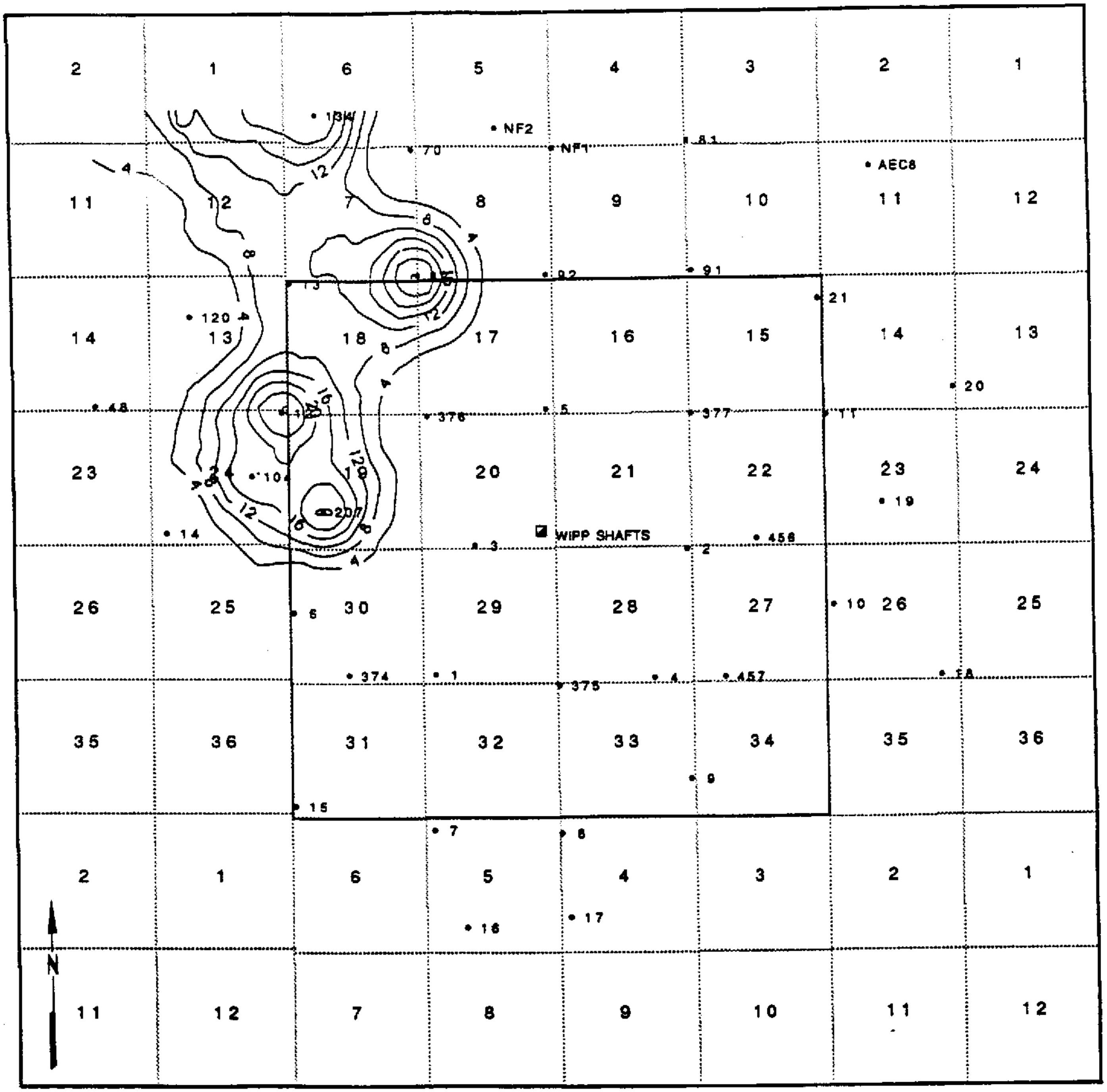

Figure 55

3rd Ore Zone - %K20 Equivalent LangxThickness

Contour Interval = 4.0 % K20 x Feet
Scale: 1" = 6000'

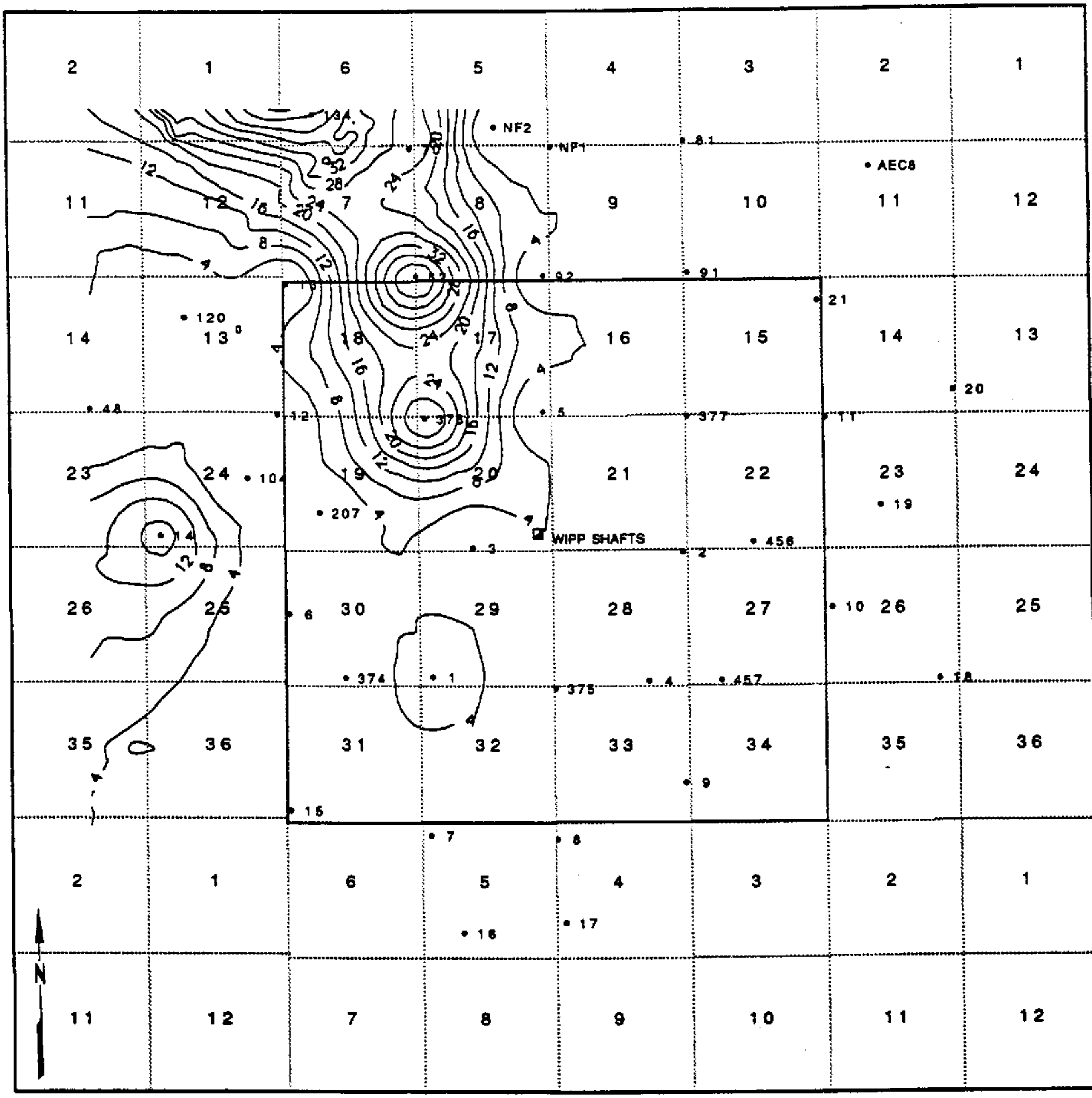

Figure 56
5th Ore Zone - %K20 Langbeinite x Thickness
Contour Interval = 4.0 % K20 x Feet
Scale: 1" = 6000'

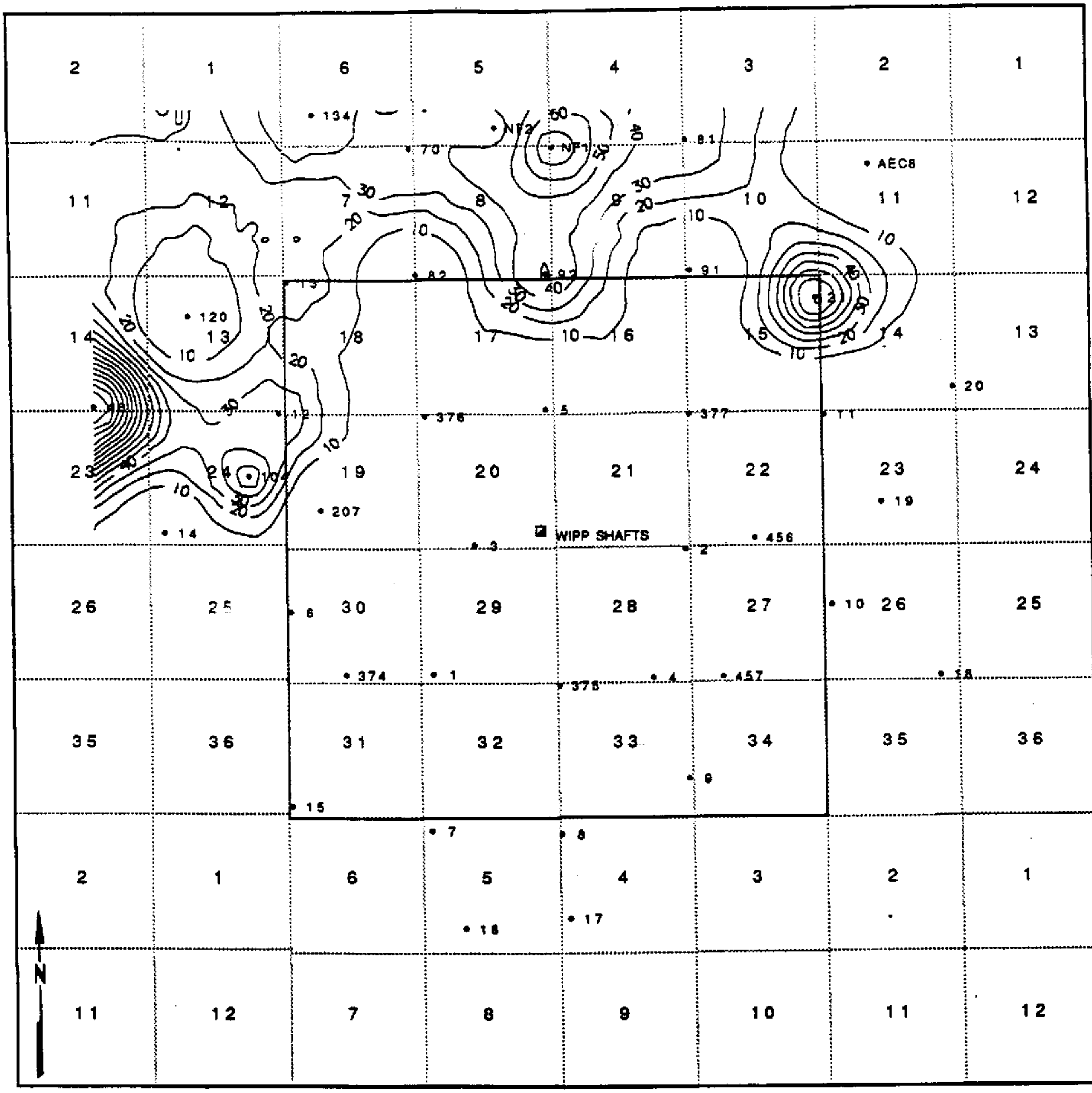

Figure 57
8th Ore Zone - %K20 Sylvite x Thickness

Contour Interval = 10.0 % K20 x Feet
Scale: 1" = 6000'

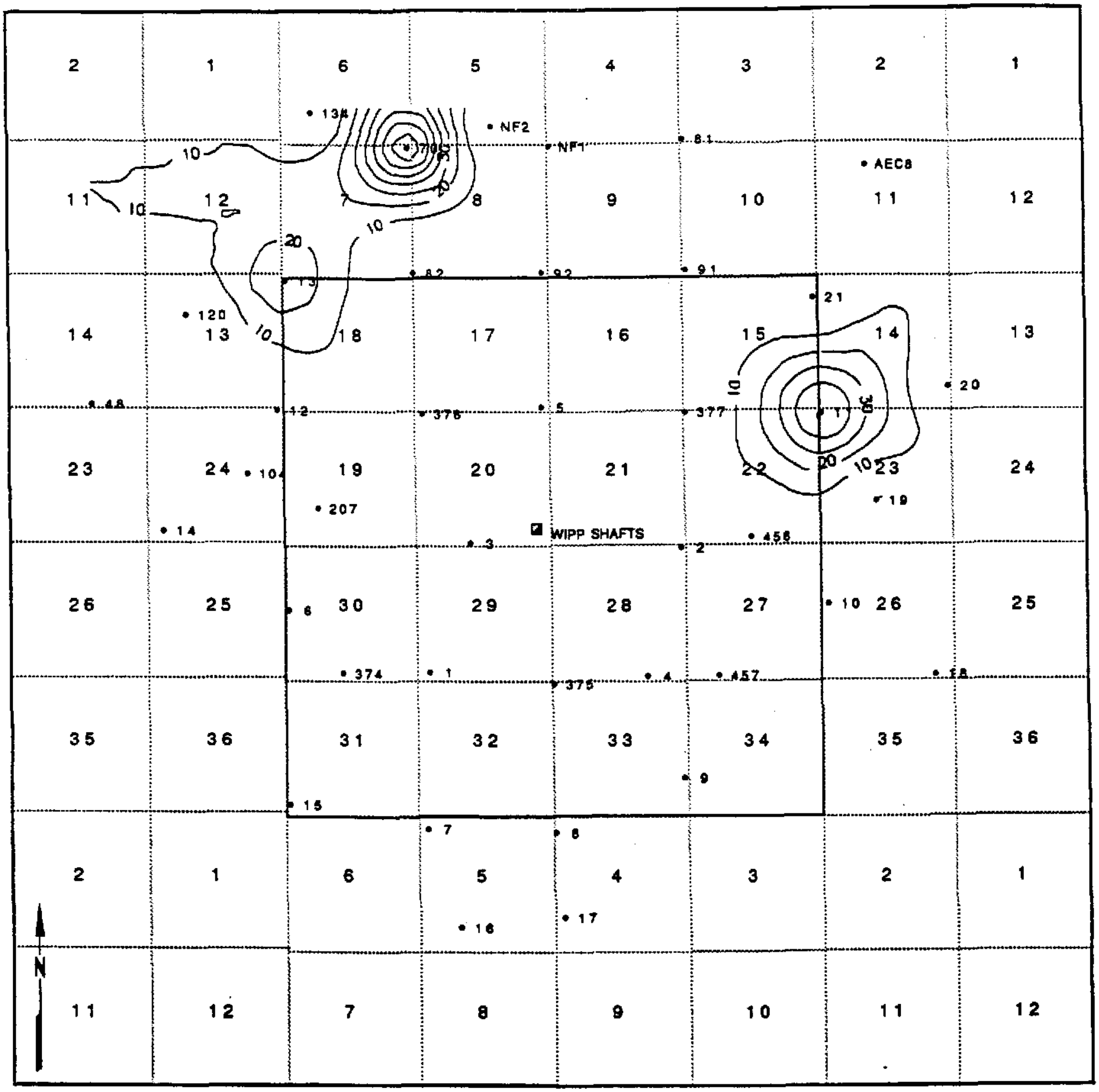

Figure 58
9th Ore Zone - %K20 Sylvite x Thickness

Contour Interval = 10.0 % K20 x Feet
Scale: 1" = 6000'

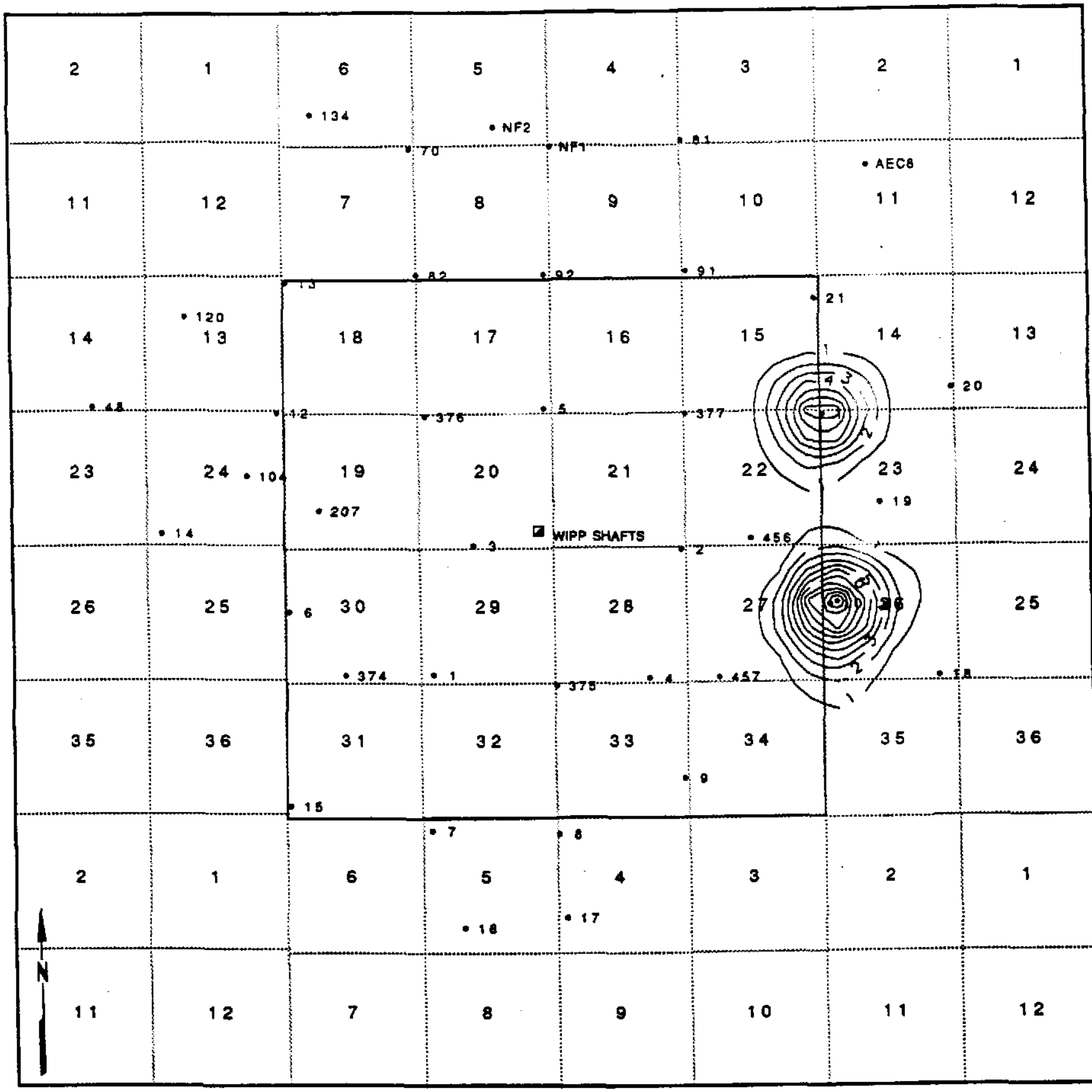

Figure 59

11th Ore Zone - %K20 Sylvite x Thickness

Contour Interval = 1.0 % K20 x Feet
Scale: 1" = 6000'

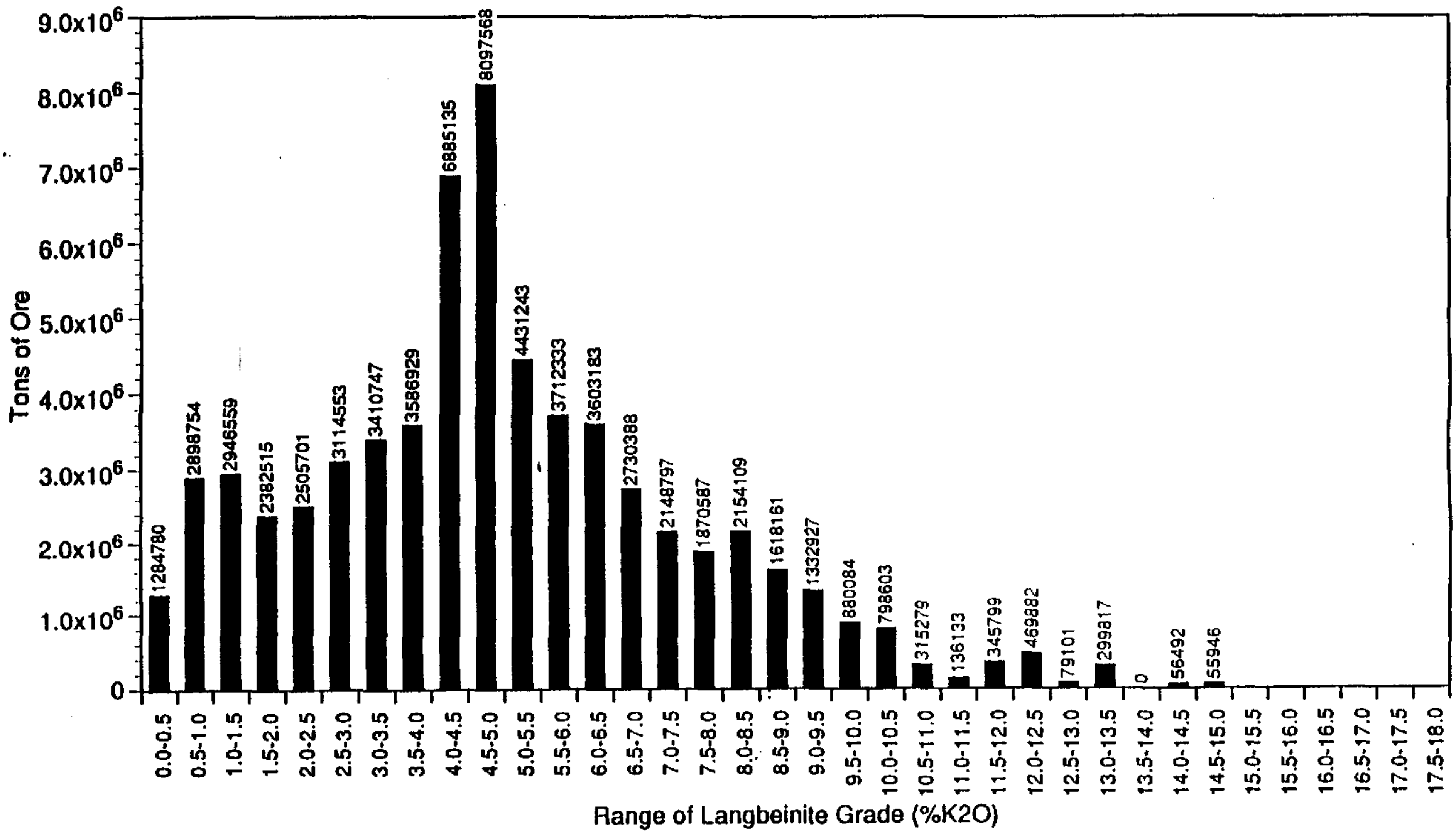

Figure 60
2nd Ore Zone Langbeinite Reserves (In Place)
for Entire Gridded Area

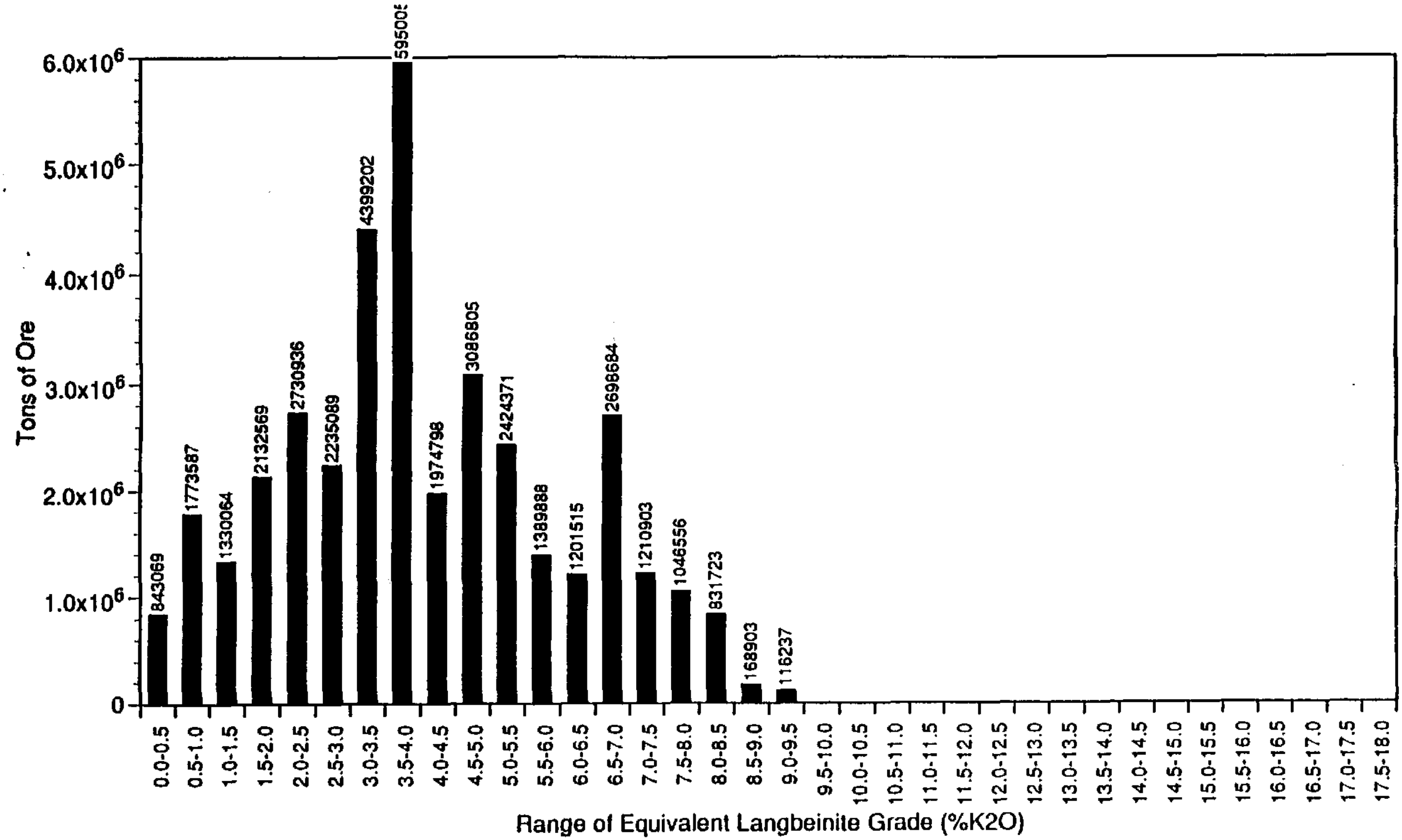

Figure 61
3rd Ore Zone Equivalent Langbeinite Reserves (In Place)
for Entire Gridded Area

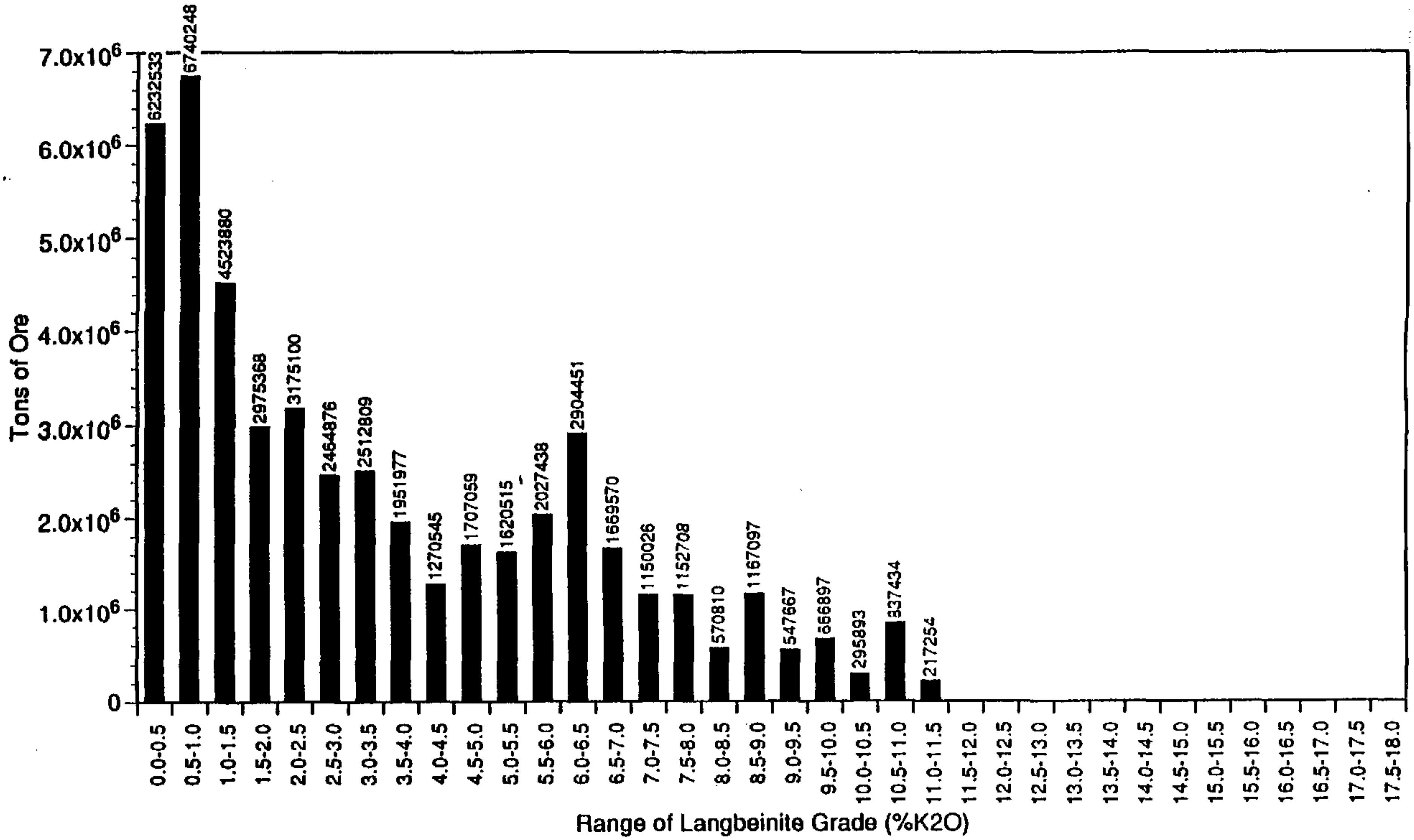

Figure 62
5th Ore Zone Langbeinite Reserves (In Place)
for Entire Gridded Area

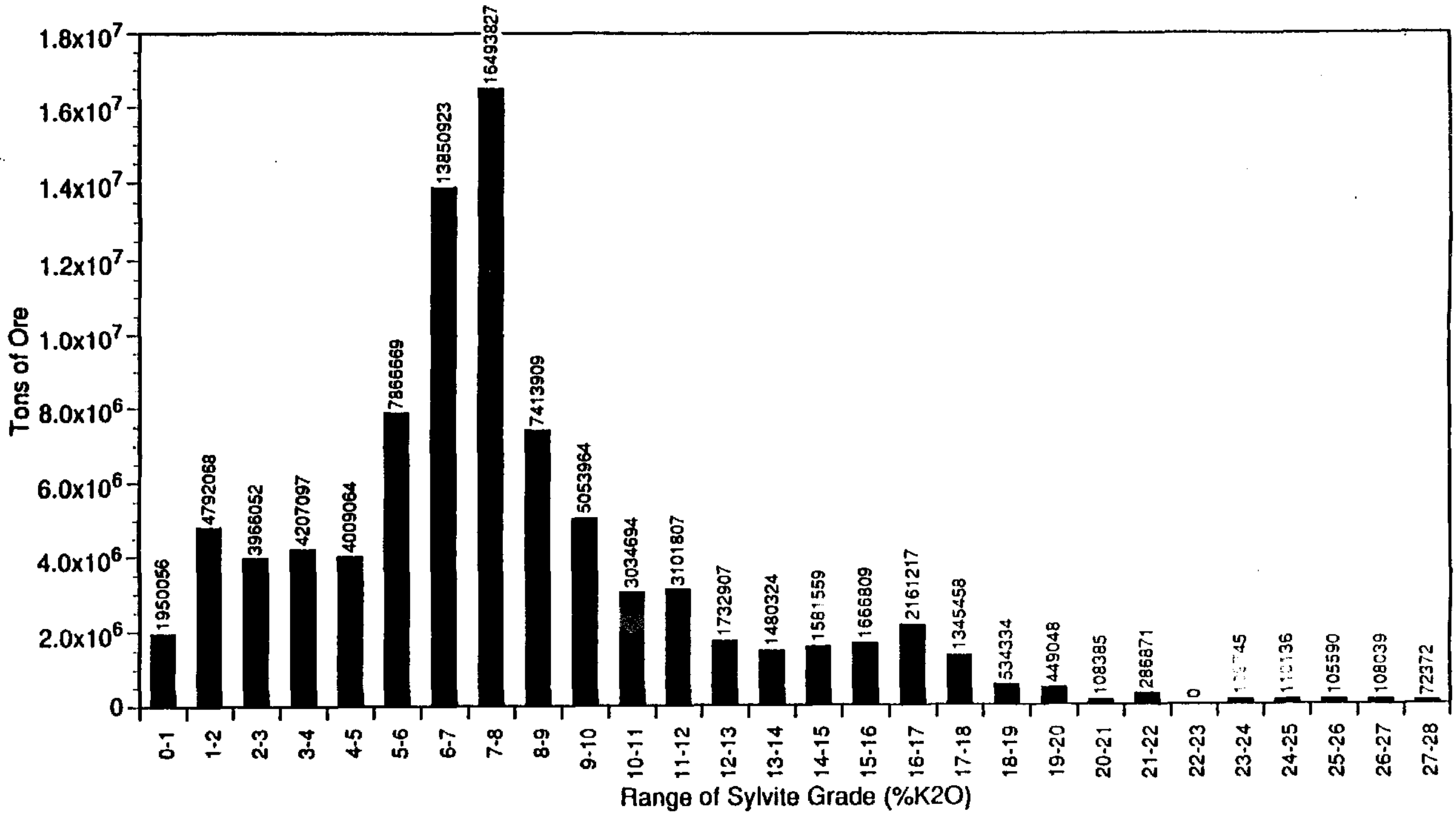

Figure 63
8th Ore Zone Sylvite Reserves (In Place)
for Entire Gridded Area

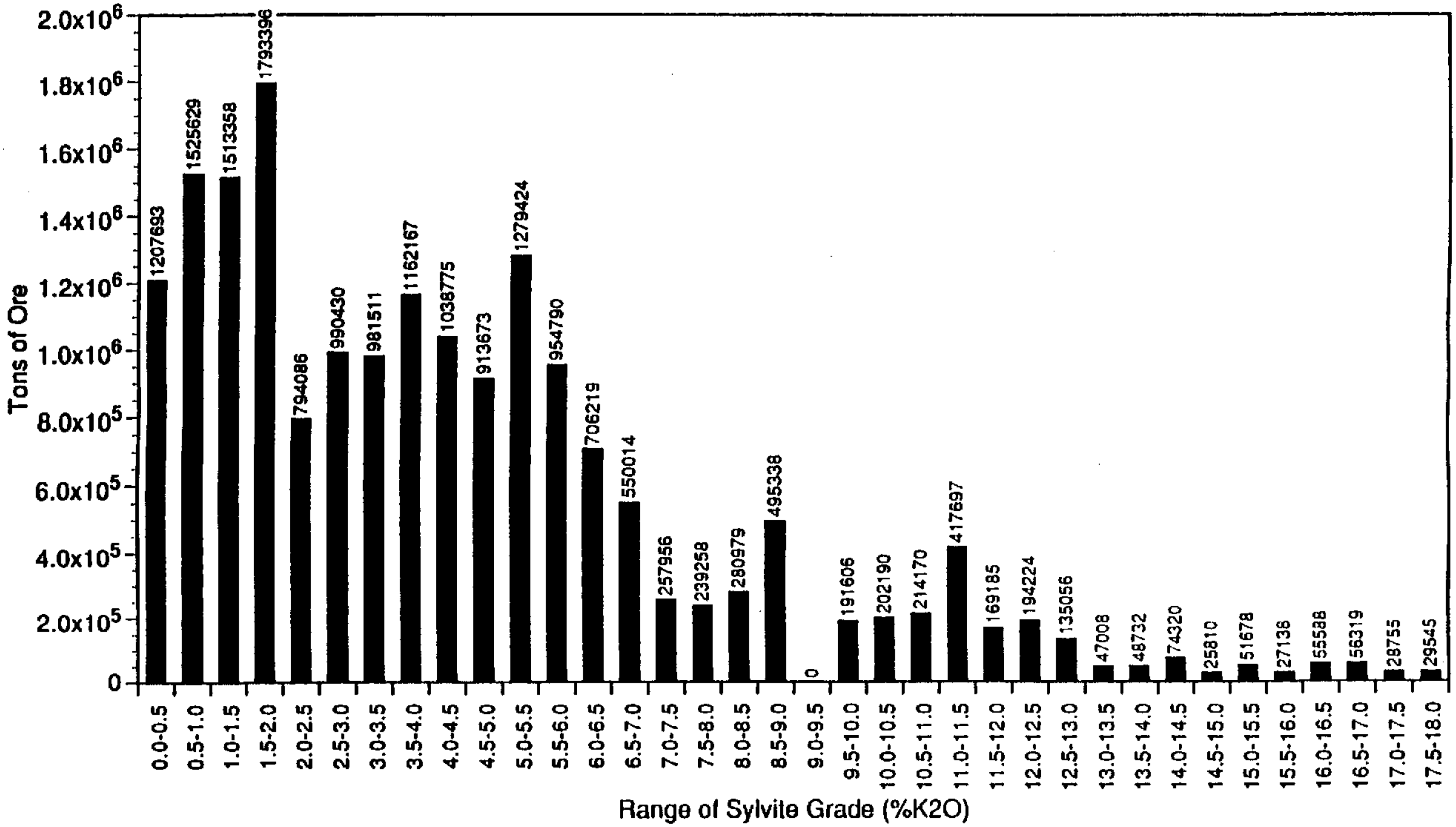

Figure 64
9th Ore Zone Sylvite Reserves (In Place)
for Entire Gridded Area

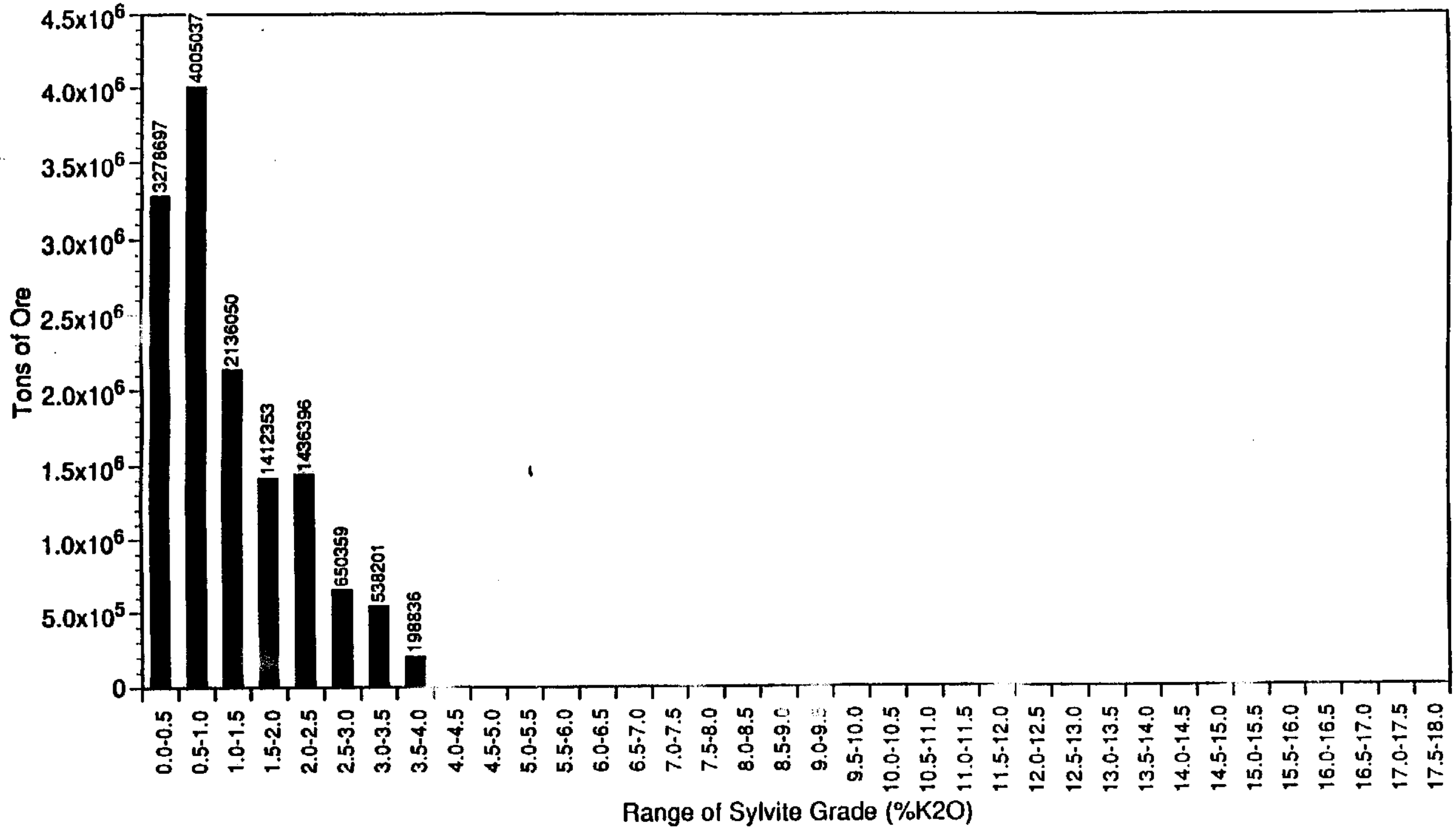

Figure 65
11th Ore Zone Sylvite Reserves (In Place)
for Entire Gridded Area

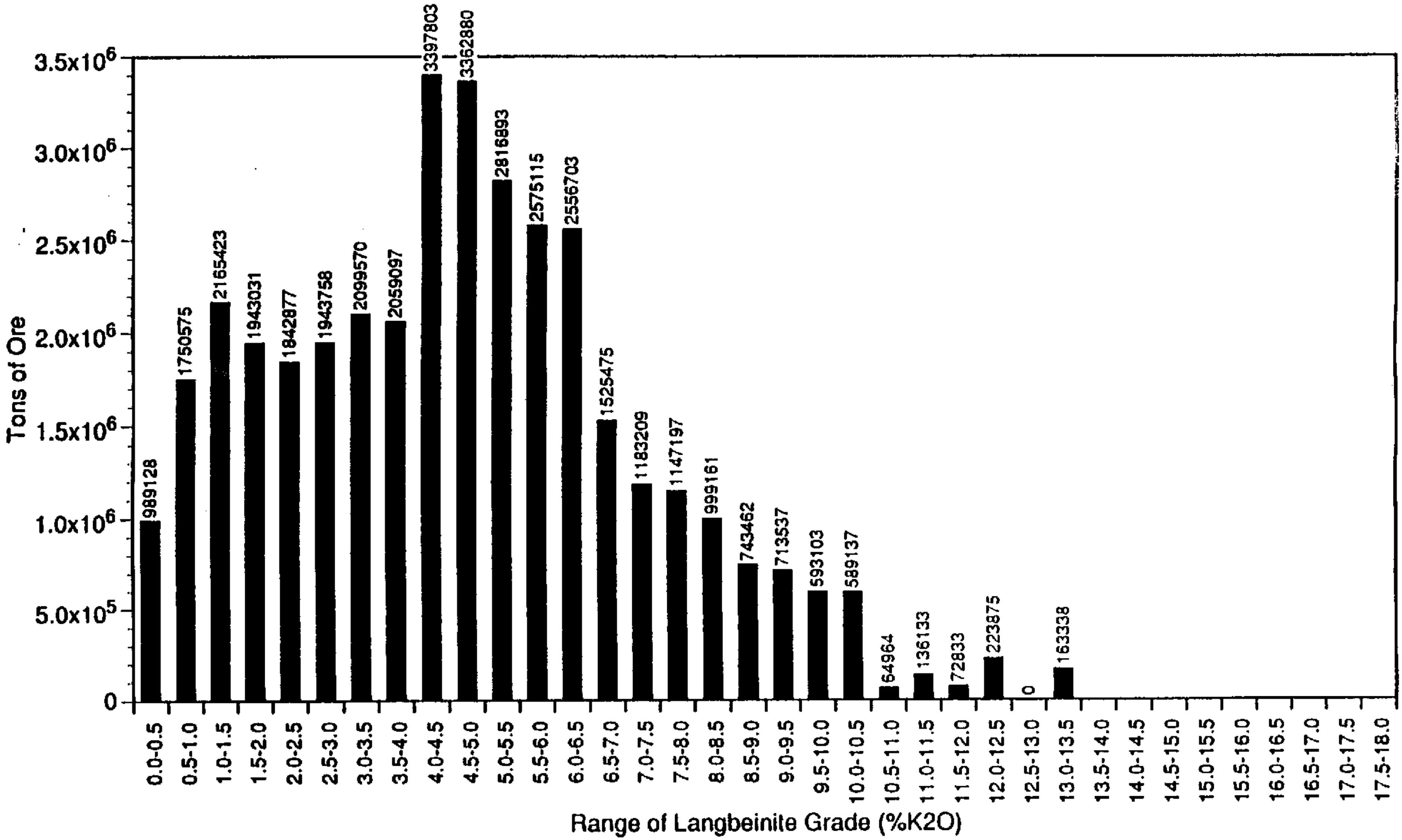

Figure 66
2nd Ore Zone Langbeinite Reserves (In Place)
Within WIPP Boundary

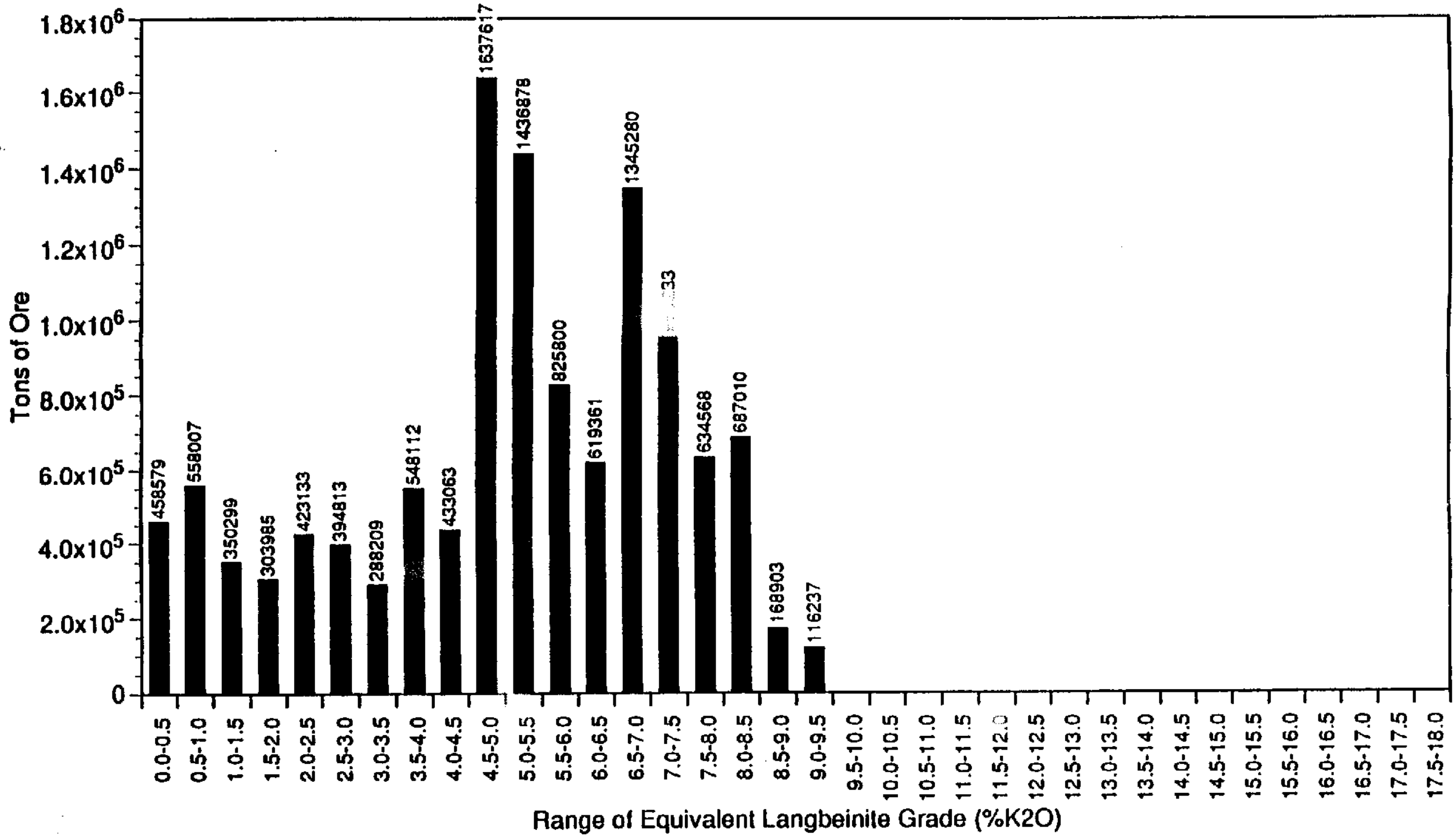

Figure 67
3rd Ore Zone Equivalent Langbeinite Reserves (In Place)
Within WIPP Boundary

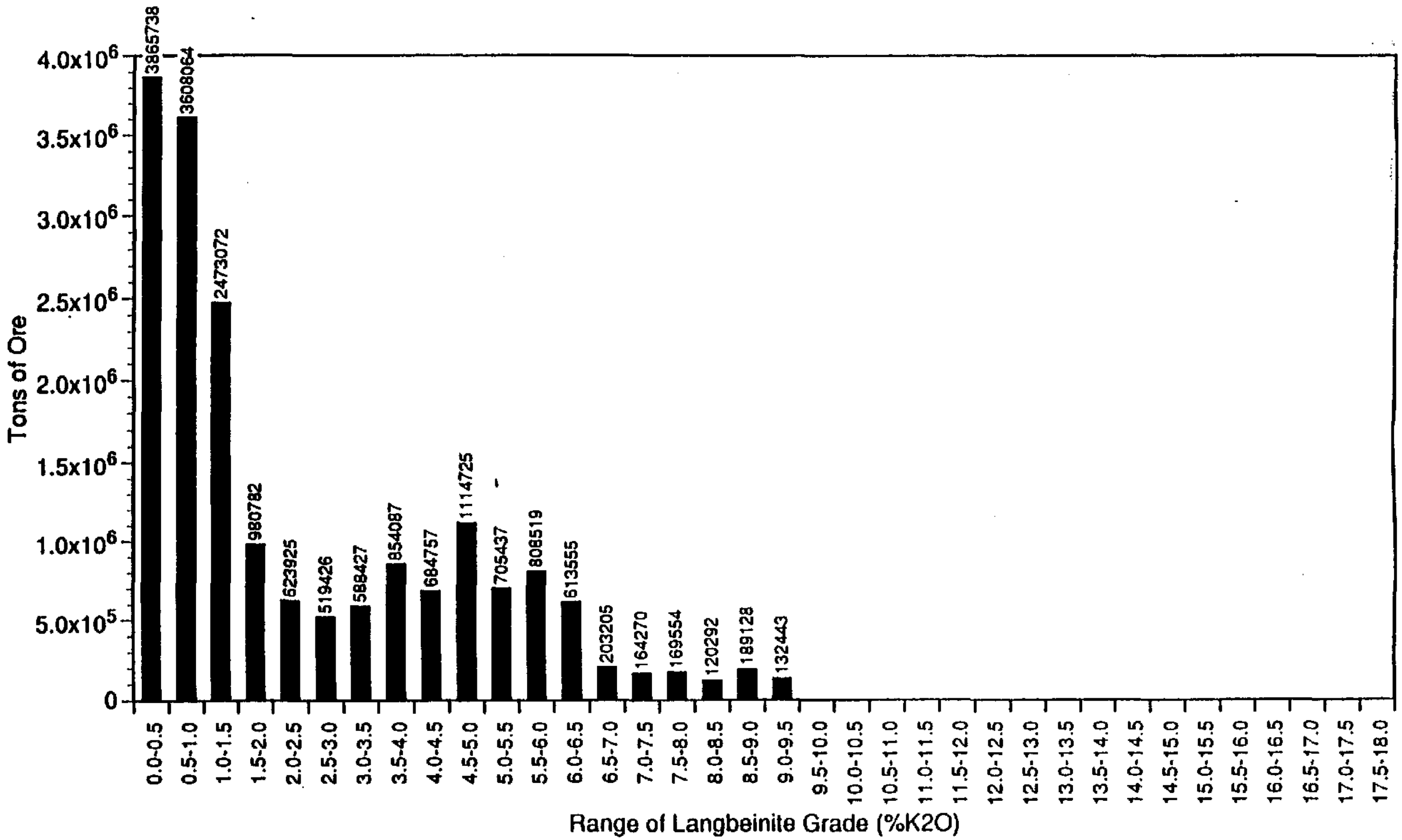

Figure 68
5th Ore Zone Langbeinite Reserves (In Place)
Within WIPP Boundary

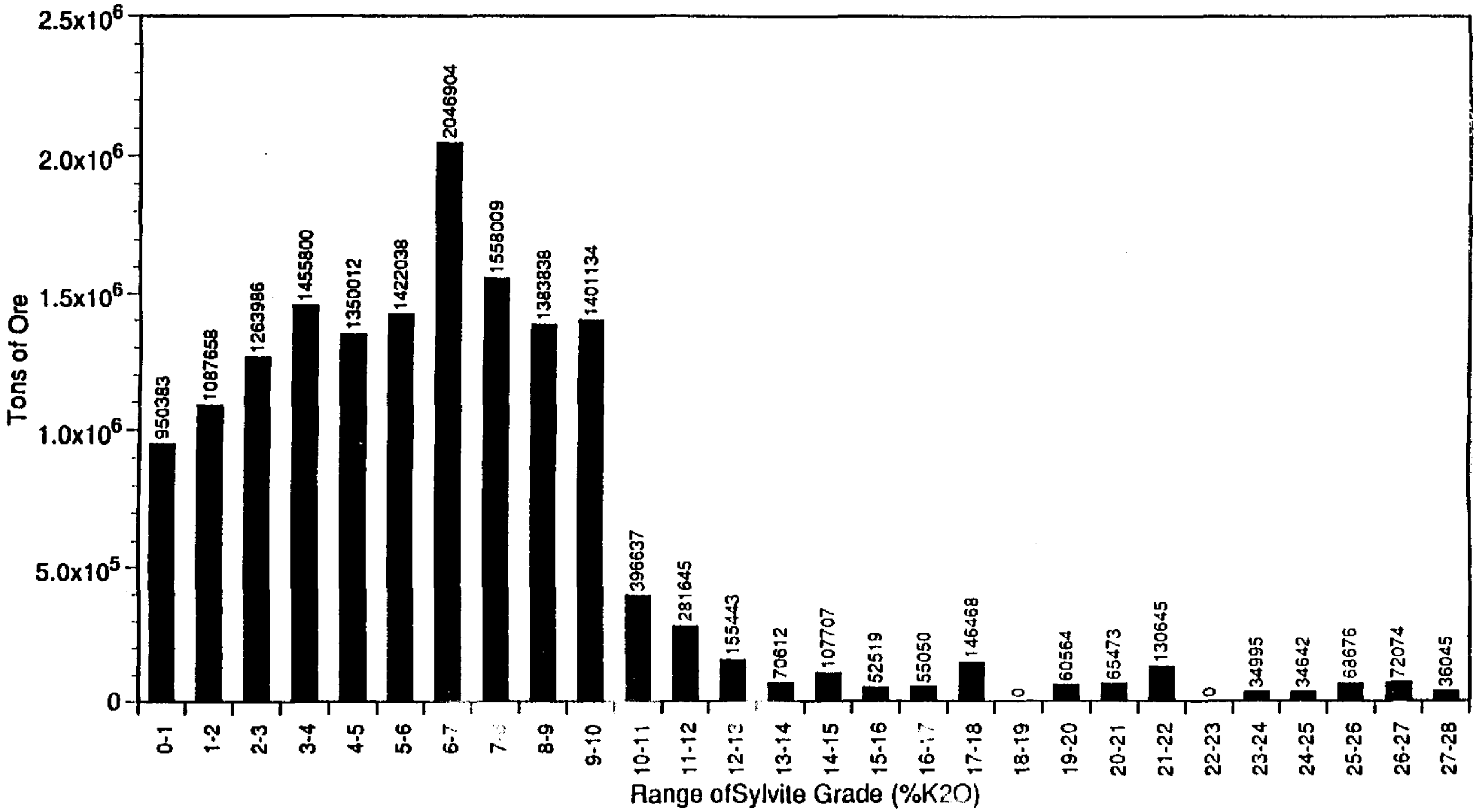

Figure 69
8th Ore Zone Sylvite Reserves (In Place)
Within WIPP Boundary

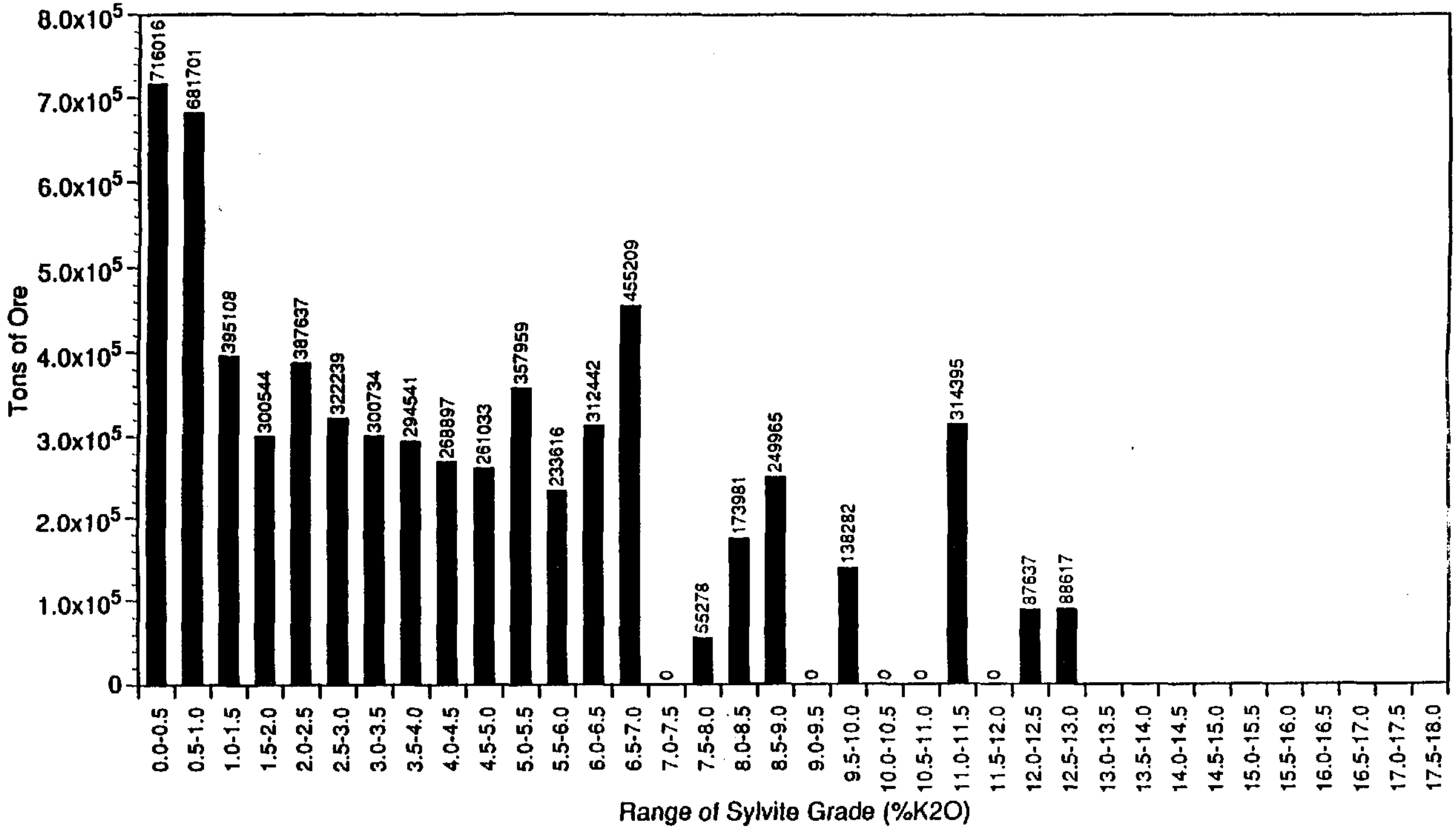

Figure 70
9th Ore Zone Sylvite Reserves (In Place)
Within WIPP Boundary

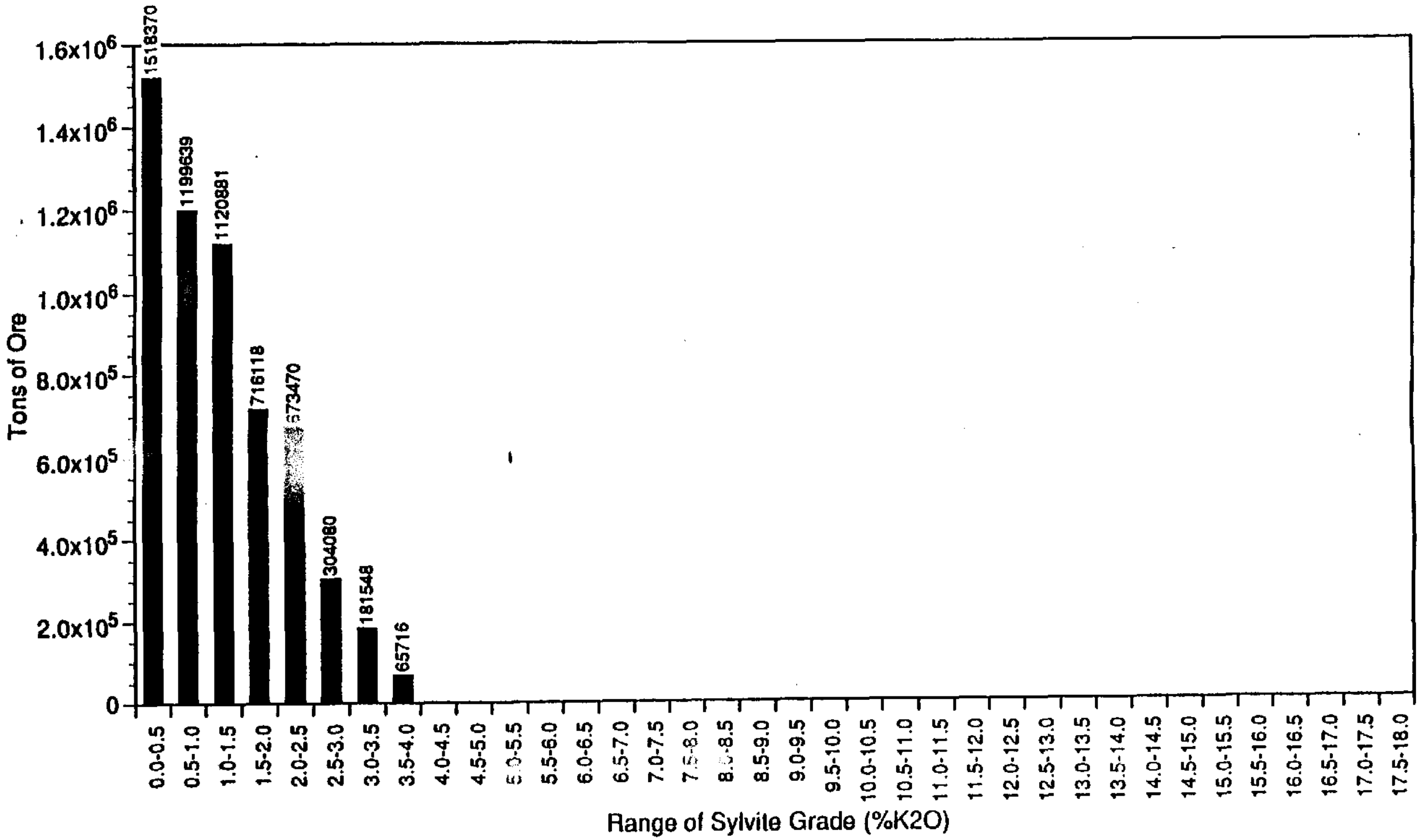

Figure 71
11th Ore Zone Sylvite Reserves (In Place)
Within WIPP Boundary

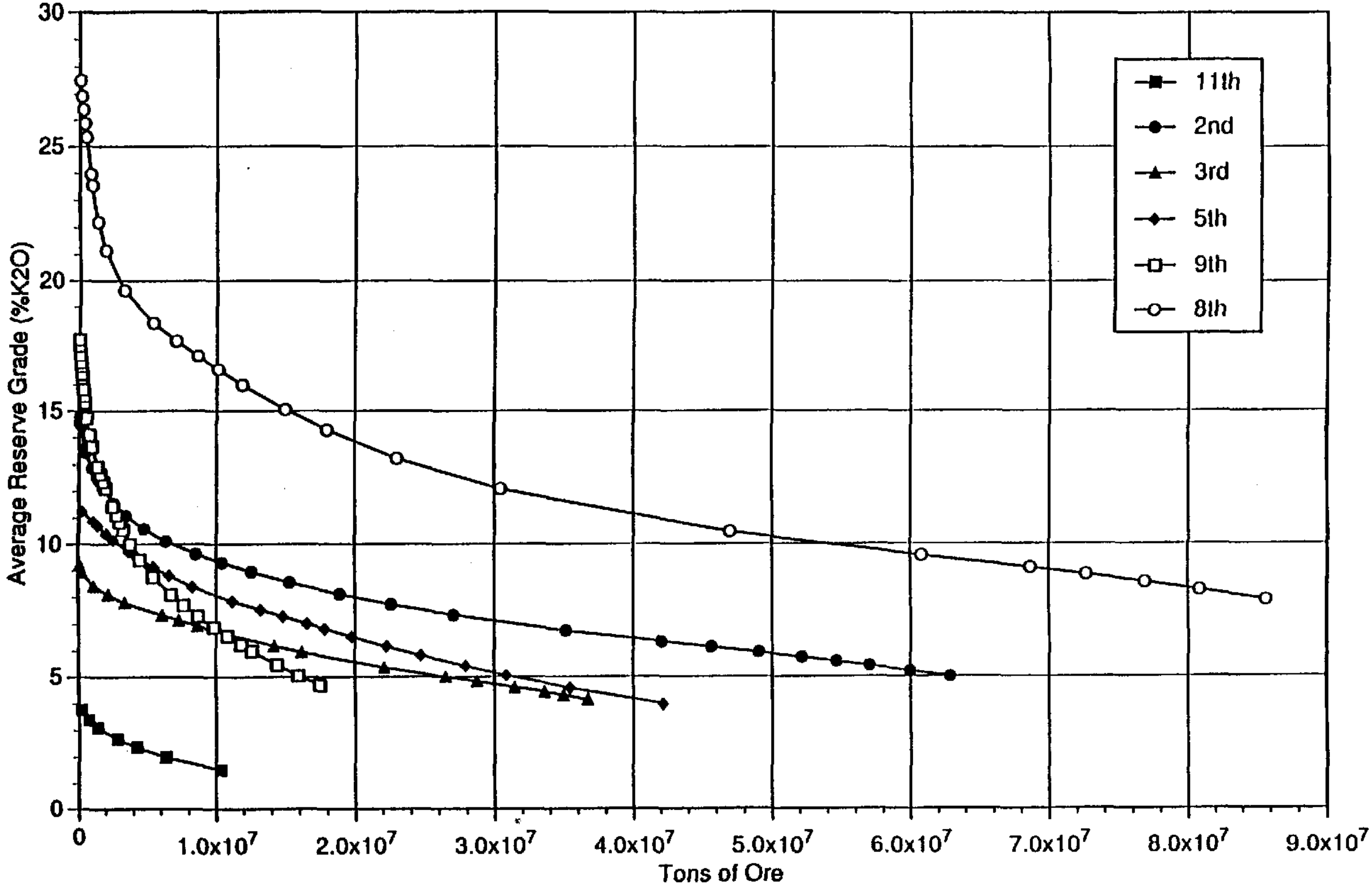

Figure 72
Multiple Ore Zone In Place Reserves (Reserve Grade)
for Entire Gridded Area

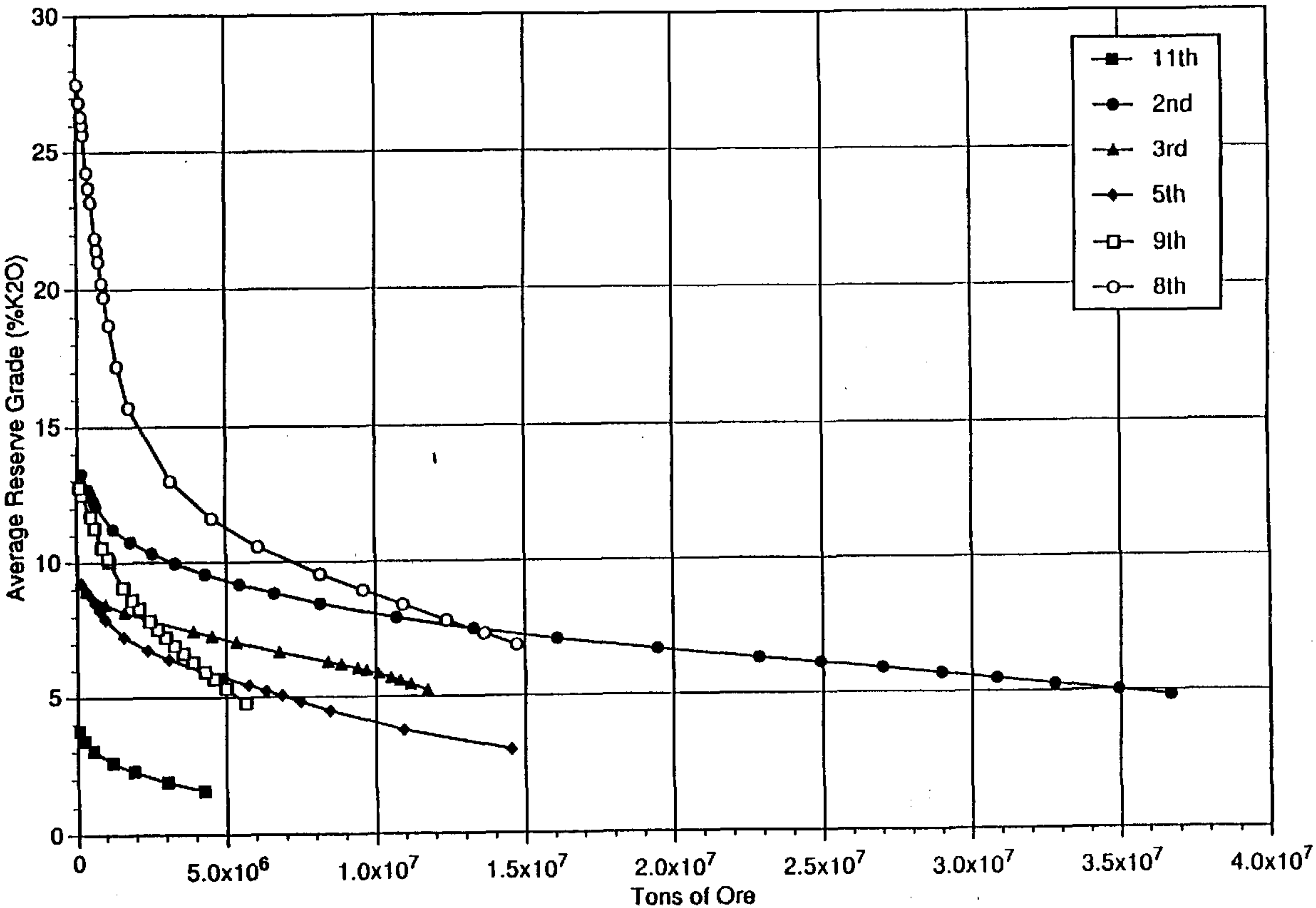

Figure 73
Multiple Ore Zone In Place Reserves (Reserve Grade)
Within WIPP Boundary

Evaluation of Mineral Resources at the
Waste Isolation Pilot Plant (WIPP) Site

Chapter VIII

VALUATION OF POTASH RESERVES AT THE WIPP SITE, ADDITIONAL AREA, AND COMBINED AREA

by
Peter C. Anselmo

Westinghouse Electric Corporation
Waste Isolation Division
Contract No. PO-75-WJJ644145Z

Submitted by

New Mexico Bureau of Mines and Mineral Resources
Campus Station
Socorro, NM 87801

March 31, 1995

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VIII

VALUATION OF POTASH RESERVES AT THE WIPP SITE, ADDITIONAL AREA AND COMBINED AREA

Peter C. Anselmo

SUMMARY

This section presents valuation results and discussion of the method by which estimated potash reserves at the projected Waste Isolation Pilot Plant (WIPP), the designated additional area around the plant, and the combined area comprising both WIPP and the additional area were evaluated. Potash reserves for both langbeinite and sylvite exist within both the WIPP site and the additional area. A Monte Carlo sampling method was used to generate random-walk price and operating cost data for the period 1995-2030. Results are presented first, then the method used is briefly described.

RESULTS

Potash deposits at the WIPP site, additional area, and combined (WIPP site plus the additional area) area were valued via simulation using reserve data obtained from expert consultants and from the New Mexico Bureau of Mines & Mineral Resources (NMBMMR) and random-walk modeling of market commodity prices. A 15% discount rate was used for the base case potash valuation, and data are provided for the simulations using a 10% discount rate. Present Values (PV) and Net Present Values (NPV) were calculated for revenue and cash flows from operations, royalties, and taxes anticipated from potash development activities from the perspective of a single firm. These values are expected present and net present values, denoted E(PV) and E(NPV), and represent the average of the present values of all the cash flows associated with each simulation run.

Total revenue present values were also calculated and are provided as an indication of the overall worth of potash deposits at the actual WIPP site and in the additional and combined areas. Total revenue present values are presented in the attachments as PV Rev. Like E(NPV) values, revenue values are expected present values, as they are the average of the expected present values generated by each simulation run.

The expected present value of combined potash reserves was determined under several conditions and scenarios. Three langbeinite mining situations, referred to in this report as cases 1, 2, and 3, were considered. As noted elsewhere in this document, two key variables differentiate the cases - mining height and the mine recovery rate. Holding all other mining and production variables constant, the cases may be summarized as

Case 1: Mining height 6 feet; mine recovery 60%

Case 2: Mining height 6 feet; mine recovery 80%
Case 3: Mining height 4.5 feet; mine recovery 90%

All sylvite financial analyses were done in the context of case 3.

In addition to the mining scenarios described above, several development scenarios were evaluated. In the first case, which is indicated in this report and accompanying data presented in the appendix as Scenario 1, no additional development costs are incurred and mining begins on 1 January 1996. Development Scenario 2 is associated with new shaft capital costs of $5 million and mining beginning 1 January 1997. Development Scenario 3 is modeled as construction of a new $150 million plant, with 46.7% of development costs allocated to langbeinite and 53.3% allocated to sylvite. If the new plant is built, costs are evenly allocated over the two years of construction (1996 and 1997) and operations are assumed to begin on 1 January 1999. Only the combined area was evaluated in the context of building the new plant.

Expected present values and net present values are affected by the mining scenario considered. Since cash flows are delayed during mining development scenarios 2 and 3, present values for all analyzed variables will be impacted. The tabular data presented in the attached appendix illustrates this point.

A discount rate of 15% was used as the base case for evaluation of potash resources. For the combined area, the expected present value E(PV) of the market revenue from sylvite is estimated as $230 million if mining begins on 1 January 1996, $190 million if mining begins on 1 January 1997, and $140 million if mining begins on 1 January 1999 see **Table 6**. The expected market value for langbeinite in the combined area is estimated as $180 million if mining begins on 1 January 1996, $160 million if mining begins on 1 January 1997, and $120 million if mining begins 1 January 1999. These data are summarized in **Tables 7-9**.

In the WIPP area, the expected present value E(PV) of the revenue from sylvite is estimated as $190 million if mining begins on 1 January 1996 and $170 million if mining begins on 1 January 1997. The expected present market value for langbeinite in the WIPP area is about $140 million for mining cases 1 and 2 and is $170 million for mining case 3 if no new development costs are incurred. Similarly, mining cases 1 and 2 are associated with a revenue E(PV) of $120 million if $5 million in new development occurs, and $150 million if mining case 3 obtains in this scenario. The differences in expected present market values between scenarios is attributable to the fact that five more years of langbeinite mining activity within the WIPP site are available under mining case 3 (4.5 ft mining height and 90% mine recovery).

Finally, if a new plant is built, the expected present market value of combined area langbeinite is $120 million if a 15% discount rate is used. These data are summarized in **Tables 7-9**.

With respect to actual exploration and development of potash resources, the concern is the net present value of anticipated cash flows. Simulation data provided cash-flow estimates, which were aggregated and averaged to yield expected net present values, or E(NPV). From the perspective of a firm engaged in extraction of potash deposits from this area, a 15% discount rate leads to the following conclusions from the simulation runs:

Sylvite:

> If no new development costs are incurred, the E(NPV) of mining sylvite in the combined area to a single firm is about $50 million. If $5 million new development costs are incurred, the E(NPV) in the combined area is $40 million. If the new plant is built, the E(NPV) of the sylvite mining venture to a single firm is estimated to be -$31 million. Sylvite E(NPV) data may be found in **Table 2**.
>
> If no new development costs are incurred, the E(NPV) to a single firm of mining sylvite in the WIPP area is $31 million. If $5 million in new development costs are incurred, the E(NPV) in the WIPP area is $25 million.
>
> If no new development costs are incurred, the E(NPV) to a single firm of mining sylvite in the additional area is $47 million. If $5 million in new development costs are incurred, the E(NPV) in the additional area is estimated to be $38 million.

The above numbers for the WIPP site and additional area do not sum to the numbers presented for the combined area. One major factor contributes to this seeming anomaly. Annual production (product tons sold) was constrained to 350,000 tons of langbeinite and 450,000 tons of sylvite. The three study areas - the WIPP site, additional area and combined area - are therefore considered independently in light of the upper limits on potash production. Numbers for the WIPP site reflect the assumption that 450,000 tons of sylvite (or, 350,000 tons of langbeinite) will be produced annually from potash within WIPP boundaries. Numbers for the additional area reflect the same assumption. Numbers from the combined area also reflect the annual potash production assumptions, and do not represent the sum of values generated for the WIPP site and additional area. The combined area is treated as a single entity producing 450,000 tons of potash and 350,000 tons of langbeinite annually.

Also, as may be seen from the maps accompanying this report, much of the WIPP site potash is on the additional-area border. For the first several years of operation - the most critical from a present value valuation standpoint - the amount of mined tonnage required to produce the same amount of sylvite from each area is nearly the same. In subsequent years, there is increasing divergence between area simulations as the potash within the WIPP site is played out (in a simulation sense) while the additional area continues to produce.

This feature of the analysis will reappear when langbeinite results are presented below. Caution should be used when attempting to aggregate potash valuation data via summing E(PV) and E(NPV) figures. Rather, figures for a given area should be considered separately, but in light of data from other areas.

Langbeinite:

In the first mining scenario (mining height = 6 feet and mining recovery = 60%), if no new development costs are incurred, the E(NPV) of mining langbeinite in the combined area to a single firm is estimated at $42 million. In the second mining scenario (mining height = 6 feet and mining recovery = 80%), if no new development costs are incurred, the E(NPV) of mining langbeinite in the combined area to a single firm is about $38 million. In the third mining scenario (mining height = 4.5 feet and mining recovery = 90%), if no new development costs are incurred, the E(NPV) of mining langbeinite in the combined area to a single firm is about $53 million see **Table 3**. Langbenite E(NPV) data for the other two development scenarios and the three mining cases are presented in **Tables 4 and 5**.

Simulation method

Potash reserve estimates for the WIPP site, additional area, and combined area were provided by consultants and specialists at the New Mexico Bureau of Mines & Mineral Resources. A simulation model was constructed for both potash and langbeinite in each of the three areas of interest that incorporated the mining cases (langbeinite) and development scenarios (no capital investment, $5 million invested, or new plant construction). Key model inputs, in addition to reserve data, included the price of the commodity, the unit cost of extraction, severance-tax rates, state and federal corporate taxes, the depreciation schedule assumed for capital investments, and the discount rate. Development of a method to anticipate future market prices for potash was a key issue. Time units were years, and the time frame simulated was 1995-2030.

Forecasting is as much an inexact art as a science, particularly when the forecasting horizon is 35 years. Although historical prices for Eddy County potash were modeled using time-series methods, a simulation approach was used to value these resources. Annual market prices were simulated using a random-walk methodology (an excellent reference is Karlin and Taylor, 1975), which is discussed below. Depletion was calculated using the standard methodology, which may be found in Stermole and Stermole (1993).

The time frame considered was 1995-2030. Market prices and extraction and maintenance costs were considered on an annual basis. A sample (this sample does not include actual data used in the study for both market prices and operating costs) simulation run for the years 1995-2000 is provided in Table 1.

Key assumptions and features associated with the oil and gas cash flows used in the simulation include:

All calculations are performed from 1 January 1995. Potash extraction activity in the three areas of interest is treated as a capital project that was evaluated (and undertaken) for three scenarios; either 1 January 1996, 1 January 1997, or 1 January 1999. However, the decision to go forward with any potash mining and development venture was considered from the perspective of 1 January 1995.

Mine shaft and/or new plant capital expenditures are recovered using a 10 year Accelerated Cost Recovery System depreciation method (Stermole and Stermole, 1993).

Revenues are treated as if realized monthly, and taxes and royalties are treated as if they are paid on a quarterly basis.

Simulations were run for each year from 1995 to 2030. Each simulation run, summarized as an individual data set in the attached appendix, consisted of 48 simulated potash price and cost "paths" from 1995 to 2030. The Monte Carlo simulations generated numbers for each year for the present value of the market value of the reserves (PV Rev) and the present value of the total cash flow for each simulation run (PV CFlow). As is standard practice in financial analysis (for example see Levy and Sarnat, 1994), cash flows attributable to the decision to mine potash are the sum of income after taxes, depreciation, and depletion. Summary data are also presented in the attached appendix for the present value of severance-tax flows (PV SevTax), state corporate-tax flows (PV StateTax), federal corporate-tax flows (PV CorpTax), and royalty payment flows (PV Royal).

All present values and NPVs are expected values, and are averages of many simulation runs. Standard deviations, maximum values, minimum values, and median values are also provided in the attachments for each individual simulation.

Specifics regarding simulation input variables are provided below.

Market prices

Annual prices per ton for both potash products under the various scenarios were generated using a random-walk method known as a Wiener process. Historical, confidential langbeinite and sylvite prices were analyzed using time-series techniques to show that these historical prices may be modeled as a random process. An estimate for the end of 1994 market price was obtained from area operators, and was used as the 1995 market price and the point of departure for the price simulations.

Use of a Wiener process is attractive in situations such as this, particularly in the case of a commodity like potash, because the uncertainty associated with the commodity market price estimate in a given year is an increasing function of the forecast time horizon. So, as price forecasts move away from 1995, the uncertainty associated with those forecasts increases (D xit and Pindyck, 1994).

There is little doubt that global demand for food, fueled by both the large and expanding global population and the rapid industrialization occurring in areas where much of the world's population lives, will be increasing for the foreseeable future. Demand for food will not decline in the near or distant future unless a global catastrophe occurs. However, as Searls (1992) noted, near-term demand for potash products as food-producing fertilizer is far from certain.

The Wiener pr s method used in this study does not allow for any drastic year-to-year-planned upward (or downward) non-random movements in these commodity prices. This is a conservative approach that is based on several factors which impact the national and global demand for fertilizer. Farm productivity in the United States has been increasing slowly but steadily since 1965 along with the use of fertilizer inputs. However, the use of agricultural inputs relative to all other inputs in the United States agricultural process (e.g. labor and capital equipment such as farm machinery) has remained steady since 1985 (Economic Report of the President to Congress, 1994). Stable domestic demand for potash-based fertilizer products is a likely feature of the potash market for at least the near future. Searle (1992) notes that future demand increases are likely to come from outside the U.S.

Although the world population is rapidly increasing, passage of international and regional treaties such as the General Agreement on Tariffs and Trade (GATT) and the North American Free Trade Agreement (NAFTA) may have a negative impact on agriculture subsidies around the world. Stabilization or rolling back of agricultural subsidies in countries such as Japan may have a stabilizing (or negative) impact on global demand for potash-based fertilizer products. Certainly, the near future for potash prices (despite the historical upward trend in per ton product prices) is uncertain; the more distant future is uncertain by definition.

This is not to say that potash operations are not profitable. On the contrary, all evidence seems to indicate that potash operations in the Carlsbad area have been profitable over the years. However, the circumstances summarized above point to the notion that prediction of an upward trend in potash prices is difficult to substantiate given current market conditions.

It is important to note that the Wiener process approach was selected after analysis of Eddy County historical confidential potash price data provided by the New Mexico Bureau of Mines & Mineral Resources.

Capital and operating costs

Capital costs used in this report for a new shaft or plant were provided to the NMBMMR by area operat as were data concerning monthly operating costs. These data were used as simulation inputs. After much discussion (in the absence of historical data), the uncertainty associated with annual operating costs was expressed as plus or minus 10% of the previous year's per-ton operating cost. Thus, a uniform distribution was used for annual operating costs (which vary between products and between cases 1, 2, and 3), with the mean for any one year being the cost generated for the previous year. The range for potential operating costs in any year was plus or minus 10% of the expected cost. All non-capital annual costs were aggregated into the operating cost figures provided by consultants and area operators.

No inflation factor was built into the cost projections. Although mine productivity (in terms of tons produced per potash mine worker) has been essentially flat since 1965 (Economic Report of the President, 1994), technological advances that will enable mining companies to offset the effects of inflation on operating costs are likely in both the near and distant future.

Taxes and royalties

The State of New Mexico assesses severance taxes on revenues attributable to minerals extracted within the state. Rather than attempting to predict factors which might contribute to alterations in the severance-tax rate, a rate of 1.25% (based on current tax law) of potash revenues was used for the study period. A royalty rate of 2.5% of revenues, provided as a current estimate by experts in this area, was used in the simulations for similar reasons.

Capital investment and other tax incentives that mining companies may periodically receive from political entities were likewise ignored in this work. In addition to presenting a major limited-data prediction problem, consideration of tax incentives would involve acquisition of additional proprietary data from area producer firms. An average corporate tax rate of 34% was therefore used.

All taxable income (listed as Taxable Inc in Table 1) is assumed to be New Mexico income for state-tax purposes. New Mexico tax rates are 4.8% of taxable income under $500,000, $24,000 plus 6.4% of the excess over $500,000 for amounts between $500,000 and $1,000,000, and $56,000 plus 7.6% of the excess over $1,000,000 for taxable income over $1,000,000.

Discount rate

Results are presented above for a 15% discount rate. This rate was also used by Weisner, Lemons, and Coppa in 1980. The appendix contains data derived from the same simulations using a 10% discount rate. Estimation of discount rates for risky investment projects (the perspective taken in this study was one of viewing potash exploration activity in the zones of interest as risky investment projects) is generally a difficult and inexact process. Though there is detailed knowledge regarding the location and grade of potash deposits in the area, there is some uncertainty (as noted above) regarding the future market price of potash products. Along with the long time horizon, price uncertainty may be considered a major source of potash mining operation risk.

The 15% rate used in the results presented above is reasonable in light of the market uncertainties faced by potash producers. Although the development risk associated with potash deposits in the WIPP, additional, and combined areas is low, there is market price risk that is faced by operators. A precise discount rate for different firms operating in the WIPP area is difficult to estimate (particularly in the absence of debt/equity ratio data for said firms). So, although pinpointing a discount rate for a 35 year project is quite risky, current levels of activity in the region and market factors point to a 15% discount rate for Carlsbad area potash operations.

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Potash Simulation Example

Year	1995	1996	1997	1998	1999	2000
Net Invest	0	0	0			
Tons Mined	0	842681	842681	842681	842681	842681
Tons Prod	0	350000	350000	350000	350000	350000
Price/Ton	77.67453	76.1638	76.18829	77.79476	77.3717	73.91795
Ann Rev	0	26657330	26665902	27228166	27080094	25871283
Cost/Ton	15.16321	15.19335	15.39788	16.22057	15.78458	16.46271
Ann Cost	0	12803150	12975504	13668766	13301362	13872810
Sev Tax	0	386531.3	386655.6	394808.4	392661.4	375133.6
Deprec	0	0	0	0	0	0
Royalties	0	666433.2	666647.6	680704.2	677002.4	646782.1
Ann Margin	0	12801215	12637095	12483887	12709068	10976558
Depletion	0	3732026	3733226	3811943	3791213	3621980
Tax Income	0	9069189	8903869	8671944	8917855	7354578
State Tax	0	745258.4	732694	715067.7	733757	614948
Corp Tax	0	3083524	3027315	2948461	3032071	2500557
Net Income	0	5240406	5143859	5008415	5152027	4239074
Cash Flow	0	8972433	8877086	8820359	8943241	7861053
Mon PV Fac	1	11.07931	9.544923	8.223033	7.084214	6.103111
Qtr PV Fac	1	3.651384	3.151411	2.719898	2.347471	2.026039
PV Rev	0	24612073	21210331	18658175	15986764	13157943
PV CFlow	0	8284032	7060925	6044175	5279652	3998073
PV SevTax	0	352843.5	304627.7	268459.7	230440.3	190008.8
PV StateTx	0	680306.2	577255.1	486227.9	430618.3	311477.2
PV CorpTx	0	2814783	2385079	2004879	1779425	1266556
PV Royal	0	608350.9	525220.2	462861.5	397310.9	327601.5

Figure 1

Year	1995	1996	1997	1998	1999	2000
Net Invest	0	0	0	0	0	0
Tons Mined		1734288	1734288	1734288	1734288	1750897
Tons Product	0	450000	450000	450000	450000	450000
Price/Ton	75	76.98958927	77.16848399	78.51617747	78.63647182	80.46999501
Annual Rev	0	34645315.17	34725817.8	35332279.86	35386412.32	36211497.76
Cost/Ton	12	12.59777858	13.32471945	13.82229139	14.68769332	15.01128695
Annual Cost	0	21848176.22	23108901.04	23971834.1	25472690.27	26283217.28
Severance Tax	0	502357.07	503524.358	512318.058	513102.9787	525066.7175
Depreciaton	0	0	0	0	0	0
Royalties	0	866132.8793	868145.4449	883306.9965	884660.308	905287.4439
NI Bef Depl	0	11428649	10245246.95	9964820.708	8515958.769	8497926.314
Depletion	0	5196797	5122623	4982410	4257979	4248963
Taxable Inc	0	6231851.999	5122623.949	4982410.708	4257979.769	4248963.314
State Tax	0	1033621	949319	938663	883606	882921
Corp Tax	0	2118830	1741692	1694020	1447713	1444648
Net Income	0	3079400.999	2431612.949	2349727.708	1926660.769	1921394.314
Cash Flow	0	8276197.999	7554235.949	7332137.708	6184639.769	6170357.314
MonthlyPV	11.07931197	9.544922546	8.223032863	7.084213533	6.103110886	5.257882518
QuarterlyPV	3.651384127	3.1514114	2.719898392	2.347471124	2.026039169	1.748619896
PV Rev	0	27557237	23795962	20858451	17997267	15866317
PV CFlow	0	6582972	5176561	4328536	3145462	2703584
PV SevTax	0	395783	342384	300663	259892	229536
PV StateTax	0	814341	645513	550871	447555	385973
PV CorpTax	0	1669326	1184306	994166	733281	631535
PV Royal	0	682385	590317	518384	448089	395751

Table 1

Table 2. Expected revenue present values for mining sylvite at a discount rate of 15% (millions of dollars).

Capital Cost Scenario	Combined Area	WIPP Area	Additional Study area
no development cost	230	200	220
$5 million cost	190	170	190
new plant	140	NR	NR

NR=Not run

Table 3. Expected revenue present values for mining langbeinite with no new development cost at a discount rate of 15% (millions of dollars)

Mining Scenario	Combined Area	WIPP Area	Additional Study area
Case 1	180	140	180
Case 2	180	140	180
Case 3	180	170	180

Table 4. Expected revenue present values for mining langbeinite with $5 million in new development cost at a discount rate of 15% (millions of dollars).

Mining Scenario	Combined Area	WIPP Area	Additional Study area
Case 1	160	120	160
Case 2	160	120	160
Case 3	160	150	160

Table 5. Expected revenue present values for mining langbeinite with a new plant at a discount rate of 15% (millions of dollars).

Mining Scenario	Combined Area	WIPP Area	Additional Study area
Case 1	120	NR	NR
Case 2	120	NR	NR
Case 3	120	NR	NR

NR=Not run

Table 6. Expected net present values for mining sylvite at a discount rate of 15% (millions of dollars)

Capital Cost Scenario	Combined Area	WIPP Area	Additional Study Area
no development cost	50	31	47
$5 million cost	40	25	38
new plant	-31	NR	NR

NR=Not run

Table 7. Expect net present values for mining langbeinite with no new development costs and a discount rate of 15%. (millions of dollars)

Mining Scenario	Combined Area	WIPP Area	Additional Study area
Recovery 60%; Mine height 6 ft	42	19	42
80%; Mine height 6 ft	39	21	43
90%; Mine height 4.5 ft	53	46	53

Table 8. Expected net present values of mining langbeinite with $5 million in new development cost and a discount rate of 15% (millions of dollars)

Mining Scenario	Combined Area	WIPP Area	Additional Study area
Case 1	31	13	29
Case 2	33	14	32
Case 3	43	34	42

Table 9. Expected net present values for mining langbeinite with a new plant and a discount rate of 15% (millions of dollars).

Mining Scenario	Combined Area	WIPP Area	Additional Study area
Case 1	-28	NR	NR
Case 2	-26	NR	NR
Case 3	-13	NR	NR

NR=Not run

APPENDIX

This Appendix contains tabular data from potash reserve valuation simulations. Each page contains five blocks, each of which summarizes 48 simulation runs. Data are reported for the present value of revenues (PV Rev), the present value of cash flows to a hypothetical developing firm (PV CFlow), the present value of severance taxes (PV Sev Tax), the present value of state taxes (PV StateTax), the present value of corporate taxes (PV CorpTax) and the present value of royalties (PV Royal).

For each category and simulation run summary, averages, standard deviations (STD), maximum values (MAX), minimum values (MIN) and median values are reported. Averages for expected revenues and cash flows are reported in the body of this paper.

The following tables are listed:

WIPP Site Langbeinite:

Case 1, Scenario 1, 15% discount rate
Case 1, Scenario 2, 15% discount rate
Case 2, Scenario 1, 15% discount rate
Case 2, Scenario 2, 15% discount rate
Case 3, Scenario 1, 15% discount rate
Case 3, Scenario 2, 15% discount rate

Case 1, Scenario 1, 10% discount rate
Case 1, Scenario 2, 10% discount rate
Case 2, Scenario 1, 10% discount rate
Case 2, Scenario 2, 10% discount rate
Case 3, Scenario 1, 10% discount rate
Case 3, Scenario 2, 10% discount rate

WIPP Site Sylvite

Scenario 1, 15% discount rate
Scenario 2, 15% discount rate
Scenario 1, 10% discount rate
Scenario 2, 10% discount rate

Combined Area Langbeinite

Case 1, Scenario 1, 15% discount rate
Case 1, Scenario 2, 15% discount rate
Case 1, Scenario 3, 15% discount rate
Case 2, Scenario 1, 15% discount rate

Case 2, Scenario 2, 15% discount rate
Case 2, Scenario 3, 15% discount rate
Case 3, Scenario 1, 15% discount rate
Case 3, Scenario 2, 15% discount rate
Case 3, Scenario 3, 15% discount rate

Case 1, Scenario 1, 10% discount rate
Case 1, Scenario 2, 10% discount rate
Case 1, Scenario 3, 10% discount rate
Case 2, Scenario 1, 10% discount rate
Case 2, Scenario 2, 10% discount rate
Case 2, Scenario 3, 10% discount rate
Case 3, Scenario 1, 10% discount rate
Case 3, Scenario 2, 10% discount rate
Case 3, Scenario 3, 10% discount rate

Combined Area Sylvite

Scenario 1, 15% discount rate
Scenario 2, 15% discount rate
Scenario 3, 15% discount rate
Scenario 1, 10% discount rate
Scenario 2, 10% discount rate
Scenario 3, 10% discount rate

Additional Area Langbeinite

Case 1, Scenario 1, 15% discount rate
Case 1, Scenario 2, 15% discount rate
Case 2, Scenario 1, 15% discount rate
Case 2, Scenario 2, 15% discount rate
Case 3, Scenario 1, 15% discount rate
Case 3, Scenario 2, 15% discount rate

Case 1, Scenario 1, 10% discount rate
Case 1, Scenario 2, 10% discount rate
Case 2, Scenario 1, 10% discount rate
Case 2, Scenario 2, 10% discount rate
Case 3, Scenario 1, 10% discount rate
Case 3, Scenario 2, 10% discount rate

Additional Area Sylvite

Scenario 1, 15% discount rate

Scenario 2, 15% discount rate
Scenario 1, 10% discount rate
Scenario 2, 10% discount rate

Lang WIPP Site Data, Case 1, Scenario 1
discount rate = 15%

	Average	STD	MAX	MIN	Median
PV Rev	1.4E+08	6115718	1.6E+08	1.3E+08	1.4E+08
PV CFlow	20439908	10884746	42488790	-546840	19749901
PV SevTax	2056912	88445.45	2314893	1879935	2047421
PV StateTx	1402822	645742.5	2920939	430321	1277155
PV CorpTx	5196725	2712523	11780220	1475422	4539891
PV Royal	3546399	152492.2	3991194	3241267	3530036

	Average	STD	MAX	MIN	Median
PV Rev	1.4E+08	5507791	1.5E+08	1.3E+08	1.4E+08
PV CFlow	20219433	10323291	40071247	-4987330	21066659
PV SevTax	2049785	79665.56	2204117	1857367	2058332
PV StateTx	1367982	574742.4	2775678	264048	1302440
PV CorpTx	5038975	2373107	111[illegible]67	907763	4689974
PV Royal	3534113	137354.4	38[illegible]202	3202358	3548848

	Average	STD	MAX	MIN	Median
PV Rev	1.4E+08	5867655	1.6E+08	1.3E+08	1.4E+08
PV CFlow	17149609	11722905	39827298	-2.0E+07	18085516
PV SevTax	2040271	84862.98	2330385	1853483	2040228
PV StateTx	1212229	578146	2797681	[illegible]17.9	1183762
PV CorpTx	4415450	2344891	11228802	[illegible]9	4139445
PV Royal	3517708	146315.5	4017906	3195660	3517634

	Average	STD	MAX	MIN	Median
PV Rev	1.4E+08	6729425	1.5E+08	1.3E+08	1.4E+08
PV CFlow	20063837	10422116	37536969	-7753610	21048674
PV SevTax	2034549	97271.95	2220760	1805918	2033809
PV StateTx	1358675	580285.2	2571966	262686	1329803
PV CorpTx	5032158	2377332	10219024	898641.2	4706124
PV Royal	3507844	167710.3	3828896	3113652	3506567

	Average	STD	MAX	MIN	Median
PV Rev	1.4E+08	4688410	1.6E+08	1.3E+08	1.4E+08
PV CFlow	20715369	10043578	39008041	-1963452	20909436
PV SevTax	2064461	67781.78	2254308	1911283	2066024
PV StateTx	1382397	589945.6	2806800	245861.3	1317251
PV CorpTx	5108438	2436379	11269594	909251.3	4793729
PV Royal	3559415	116865.1	3886739	3295316	3562110

Lang WIPP Site Data, Case 1, Scenario 2
discount rate = 15%

	Average	STD	MAX	MIN	Median
PV Rev	1.2E+08	7634818	1.5E+08	1.1E+08	1.2E+08
PV CFlow	13348244	10835768	29839875	-1.7E+07	14118604
PV SevTax	1768002	110568.8	2100187	1549037	1761842
PV StateTx	1088601	504476	2144950	105727.9	1067099
PV CorpTx	3996749	2022428	8484933	278016.5	3893642
PV Royal	3048279	190635.9	3621012	2670754	3037658

	Average	STD	MAX	MIN	Median
PV Rev	1.2E+08	5253357	1.3E+08	1.1E+08	1.2E+08
PV CFlow	12849025	11057858	30246389	-2.4E+07	15679003
PV SevTax	1767928	76090.69	1927525	1599801	1763207
PV StateTx	1069145	487817.8	2262947	167277	1127945
PV CorpTx	3919732	1913548	9012815	550966.6	3972034
PV Royal	3048152	131190.9	3323319	2758278	3040012

	Average	STD	MAX	MIN	Median
PV Rev	1.2E+08	6548278	1.4E+08	1.1E+08	1.2E+08
PV CFlow	13258026	9860052	27957933	-8851200	14944852
PV SevTax	1784325	94824.32	1957635	1541839	1788750
PV StateTx	1060063	498897.5	2009264	111161	1100638
PV CorpTx	3876859	1993449	7877916	299921.4	3986257
PV Royal	3076423	163490.2	3375233	2658343	3084052

	Average	STD	MAX	MIN	Median
PV Rev	1.2E+08	5987658	1.4E+08	1.1E+08	1.2E+08
PV CFlow	13418790	10828081	31673061	-1.4E+07	15469099
PV SevTax	1752182	86680.45	1958842	1585070	1748694
PV StateTx	1096843	559961.9	2478826	105682.5	1102638
PV CorpTx	4043069	2257444	9978588	419640.9	3880558
PV Royal	3021004	149449.1	3377314	2732880	3014990

	Average	STD	MAX	MIN	Median
PV Rev	1.2E+08	6065510	1.3E+08	1.1E+08	1.2E+08
PV CFlow	11740967	11250997	35660448	-1.8E+07	11534007
PV SevTax	1735386	87854.2	1925240	1542226	1729809
PV StateTx	1032318	568534.8	2833266	163894.6	911984.8
PV CorpTx	3787598	2313952	11564243	535834.9	3221020
PV Royal	2992045	151472.8	3319379	2659010	2982428

Lang WIPP Site Data, Case 2, Scenario 1
discount rate = 15%

	Average	STD	MAX	MIN	Median
PV Rev	1.4E+08	6302427	1.6E+08	1.3E+08	1.4E+08
PV CFlow	22084968	9410316	37583552	-1.3E+07	22629037
PV SevTax	2047923	91171.6	2246132	1877757	2045004
PV StateTx	1454219	504495.7	2684407	249286.6	1405212
PV CorpTx	5371918	2093487	10722050	829129.1	5091919
PV Royal	3530902	157192.4	3872641	3237512	3525869

	Average	STD	MAX	MIN	Median
PV Rev	1.4E+08	5788994	1.6E+08	1.3E+08	1.4E+08
PV CFlow	21062253	8237443	37892588	1749021	22269669
PV SevTax	2033624	83737.19	2263754	1838702	2027764
PV StateTx	1382887	453674.6	2603329	433548.6	1404799
PV CorpTx	5094189	1846852	10359332	1606477	5117346
PV Royal	35[illegible]6248	144374.5	3903024	3170176	3496145

	Average	STD	MAX	MIN	Median
PV Rev	1.4E+08	5546608	1.5E+08	1.3E+08	1.4E+08
PV CFlow	21625861	11016714	40947815	-1.1E+07	24131492
PV SevTax	2048124	80252.36	2176922	1848634	2048769
PV StateTx	1462670	593930	2926259	251160.4	1482830
PV CorpTx	5462087	2450878	11804019	[illegible]2482.4	5421784
PV Royal	3531247	138366.1	3753315	[illegible]87300	3532360

	Average	STD	MAX	MIN	Median
PV Rev	1.4E+08	5621196	1.6E+08	1.3E+08	1.4E+08
PV CFlow	22793951	12191697	47740383	-2059195	21415622
PV SevTax	2056868	81288.16	2277917	1857367	2037959
PV StateTx	1579646	813396	3759273	497373.1	1367931
PV CorpTx	5979004	3474856	15530659	1606680	4970017
PV Royal	3546325	140152	3927443	3202357	3513723

	Average	STD	MAX	MIN	Median
PV Rev	1.4E+08	6172968	1.5E+08	1.3E+08	1.4E+08
PV CFlow	20105606	10617834	40402645	-8609520	21245624
PV SevTax	203[illegible]464	89278.75	2225112	1805206	2032477
PV StateTx	1368791	560991	3007557	[illegible]293.5	1360526
PV CorpTx	5047691	2322320	12167718	1054404	5050550
PV Royal	3500799	153928.9	3836400	3112425	3504271

	Average	STD	MAX	MIN	Median
PV Rev	1.4E+08	5207212	1.5E+08	1.3E+08	1.4E+08
PV CFlow	21315308	9961824	36933425	-769253	24980204
PV SevTax	2030566	75357.16	2216136	1872652	2031249
PV StateTx	1412157	526218.2	2621894	457005	1528582
PV CorpTx	5226549	2133889	10442386	1569113	5661527
PV Royal	3500976	129926.1	3820924	3228711	3502153

Lang WIPP Site Data, Case 2, Scenario 2
discount rate = 15%

	Average	STD	MAX	MIN	Median
PV Rev	1.2E+08	6568457	1.3E+08	1.0E+08	1.2E+08
PV CFlow	13911318	11444916	31646663	-1.7E+07	15644789
PV SevTax	1749812	95113.46	1930646	1454427	1762367
PV StateTx	1146937	535040.2	2341011	146415.7	1129780
PV CorpTx	4196104	2184164	9362045	457639.8	3969607
PV Royal	3016917	163988.7	3328700	2507633	3038564

	Average	STD	MAX	MIN	Median
PV Rev	1.2E+08	5960401	1.4E+08	1.0E+08	1.2E+08
PV CFlow	15727053	9949557	33126433	-1.7E+07	16713678
PV SevTax	1757181	86301.23	1979048	1515674	1773281
PV StateTx	1218052	533686.7	2523815	189439.3	1200746
PV CorpTx	4522091	2184239	10179854	673986	4372616
PV Royal	3029623	148795.2	3412152	2613231	3057380

	Average	STD	MAX	MIN	Median
PV Rev	1.2E+08	6136363	1.3E+08	1.1E+08	1.2E+08
PV CFlow	17148658	10171571	37543326	-1.2E+07	18136609
PV SevTax	1780570	88932.29	1937371	1613676	1764220
PV StateTx	1304594	602191.1	3104480	118145.3	1254893
PV CorpTx	4868013	2535117	12777568	350664.9	4611836
PV Royal	3069948	153331.5	3340295	2782199	3041759

	Average	STD	MAX	MIN	Median
PV Rev	1.2E+08	6458957	1.4E+08	1.1E+08	1.2E+08
PV CFlow	12546763	9115710	30972117	-3803806	10853736
PV SevTax	1756868	93476.41	1982960	1561157	1756766
PV StateTx	1038326	479606.8	2245363	219591.7	904453.3
PV CorpTx	3777160	1942559	8934147	766725.2	3242959
PV Royal	3029083	161166.2	3418897	2691650	3028908

	Average	STD	MAX	MIN	Median
PV Rev	1.2E+08	5814355	1.3E+08	1.1E+08	1.2E+08
PV CFlow	12443999	12024852	30079883	-2.0E+07	14049010
PV SevTax	1771643	84212.32	1949753	1539098	1758699
PV StateTx	1055580	554895.3	2332212	147056.8	1033113
PV CorpTx	3868396	2225584	9375130	493047.6	3582136
PV Royal	3054558	145193.7	3361644	2653617	3032239

Lang WIPP Site Data, Case 3, Scenario 1
discount rate = 15%

	Average	STD	MAX	MIN	Median
PV Rev	1.7E+08	8375275	1.9E+08	1.6E+08	1.7E+08
PV CFlow	46353733	9852307	66726910	23415872	46821593
PV SevTax	2497097	121906.5	2807296	2252555	2476306
PV StateTx	3525546	896134.6	5843807	1634120	3460475
PV CorpTx	14272997	3930766	24574954	6280591	13933435
PV Royal	4305339	210183.6	4840166	3883716	4269492

	Average	STD	MAX	MIN	Median
PV Rev	1.7E+08	8632680	1.9E+08	1.5E+08	1.7E+08
PV CFlow	46787492	10628140	68746467	18151975	48322737
PV SevTax	2499737	[illegible]580.7	2805255	2206191	2506240
PV StateTx	3648386	916530.5	6001287	1867633	3579485
PV CorpTx	14823551	4029951	25279469	7128828	14445090
PV Royal	4309891	216518.4	4836646	3803777	4321103

	Average	STD	MAX	MIN	Median
PV Rev	1.7E+08	8691111	2.0E+08	1.5E+08	1.7E+08
PV CFlow	45456186	10707112	64873475	25713851	47168737
PV SevTax	2479062	126495.2	2857858	2202603	2471238
PV StateTx	3505239	965810.3	5413622	1949477	3600623
PV CorpTx	14199183	4231965	22650441	7557272	14567922
PV Royal	4274246	218095.2	4927341	3797591	4260754

	Average	STD	MAX	MIN	Median
PV Rev	1.7E+08	9002493	2.0E+08	1.6E+08	1.7E+08
PV CFlow	44996890	11354592	[illegible]3429	13578799	45804151
PV SevTax	2483478	130895.7	[illegible]483	2273796	2491225
PV StateTx	3471105	958037.2	[illegible]5656	1651293	3378726
PV CorpTx	14048347	4190106	23017436	6296058	13614933
PV Royal	4281858	225682.2	4931867	3920338	4295216

	Average	STD	MAX	MIN	Median
PV Rev	1.7E+08	8584595	1.9E+08	1.5E+08	1.7E+08
PV CFlow	46531486	9864331	67235136	25616955	47272950
PV SevTax	2506320	[illegible]59.3	2769314	2218782	2514497
PV StateTx	3566083	905368.4	5772300	1731154	3433128
PV CorpTx	14448982	3991600	24255051	6337088	13898432
PV Royal	4321241	[illegible]15447	4774679	3825486	4335340

Lang WIPP Site Data, Case 3, Scenario 2
discount rate = 15%

	Average	STD	MAX	MIN	Median
PV Rev	1.5E+08	7942494	1.7E+08	1.3E+08	1.5E+08
PV CFlow	31826819	10628266	47494533	-3915281	33827959
PV SevTax	2126606	115840.7	2416107	1889799	2113253
PV StateTx	2517139	770115.8	4079018	1048862	2529759
PV CorpTx	10002866	3337687	16894598	3880619	9963705
PV Royal	3666561	199725.4	4165701	3258274	3643540

	Average	STD	MAX	MIN	Median
PV Rev	1.5E+08	9922406	1.7E+08	1.3E+08	1.5E+08
PV CFlow	34811001	11592209	57962627	4529968	34938506
PV SevTax	2155479	144431.5	2451738	1830379	2125201
PV StateTx	2804742	981936.1	5123633	1251199	2506256
PV CorpTx	11266533	4321590	21567879	4773345	9898850
PV Royal	3716343	249019.8	4227135	3155826	3664140

	Average	STD	MAX	MIN	Median
PV Rev	1.5E+08	7689675	1.7E+08	1.3E+08	1.5E+08
PV CFlow	34454369	8641699	55537295	15798516	34151207
PV SevTax	2134385	111995.6	2490873	1915030	2128856
PV StateTx	2737233	767436.4	4717746	1576521	2619581
PV CorpTx	10965065	3375051	19752065	6109615	10469439
PV Royal	3679974	193095.9	4294609	3301775	3670442

	Average	STD	MAX	MIN	Median
PV Rev	1.5E+08	8540512	1.7E+08	1.3E+08	1.5E+08
PV CFlow	33915418	10036657	52025145	9681782	35977769
PV SevTax	2124837	124274.3	2394776	1850111	2129116
PV StateTx	2695741	843052.4	4387580	1261342	2785694
PV CorpTx	10782020	3691226	18275007	4715575	11123173
PV Royal	3663511	214266.1	4128925	3189846	3670889

	Average	STD	MAX	MIN	Median
PV Rev	1.5E+08	7303576	1.6E+08	1.3E+08	1.5E+08
PV CFlow	35602417	9912487	52550694	12101115	36283400
PV SevTax	2171735	106161.1	2364238	1878139	2166904
PV StateTx	2845299	861553.2	4650000	1228646	2756039
PV CorpTx	11444871	3779497	19448993	4511971	11050236
PV Royal	3744371	183036.3	4076272	3238171	3736041

Lang WIPP Site Data, Case 1, Scenario 1
discount rate = 10%

	Average	STD	MAX	MIN	Median
PV Rev	1.7E+08	7965465	1.9E+08	1.5E+08	1.7E+08
PV CFlow	25426455	16073158	55673012	-2.1E+07	26202252
PV SevTax	2518802	115085.8	2762225	2197968	2516605
PV State Tx	1798445	881666.5	4157556	374204.8	1615561
PV CorpTx	6735410	3695744	17027368	1242273	5907424
PV Royal	4342763	198423.9	4762457	3789600	4338974

	Average	STD	MAX	MIN	Median
PV Rev	1.7E+08	7132541	1.9E+08	1.6E+08	1.7E+08
PV CFlow	23107873	14235343	49147348	-2.1E+07	25063135
PV SevTax	2498049	103079.5	2693220	2289234	2499359
PV State Tx	1589586	697023.9	3542967	261857.3	1605975
PV CorpTx	5843411	2812459	14277888	875905.9	5822924
PV Royal	4306981	177723.2	4643483	3946954	4309240

	Average	STD	MAX	MIN	Median
PV Rev	1.7E+08	7132541	1.9E+08	1.6E+08	1.7E+08
PV CFlow	23107873	14235343	49147348	-2.1E+07	25063135
PV SevTax	2498049	103079.5	2693220	2289234	2499359
PV State Tx	1589586	697023.9	3542967	261857.3	1605975
PV CorpTx	5843411	2812459	14277888	875905.9	5822924
PV Royal	4306981	177723.2	4643483	3946954	4309240

	Average	STD	MAX	MIN	Median
PV Rev	1.7E+08	6991839	1.9E+08	1.6E+08	1.7E+08
PV CFlow	22662291	15686746	43758467	-3.3E+07	25630245
PV SevTax	2501336	101025.4	2756209	2248674	2493440
PV State Tx	1613784	679162.9	2931997	309061.5	1643340
PV CorpTx	5927104	2729776	11544604	1134533	5851712
PV Royal	4312648	174181.7	4752085	3877025	4299035

	Average	STD	MAX	MIN	Median
PV Rev	1.7E+08	6125108	1.9E+08	1.6E+08	1.7E+08
PV CFlow	24221319	13736761	49204471	929162.8	27757787
PV SevTax	2485018	88480.86	2689700	2306861	2490603
PV State Tx	1629197	738302.2	3422905	356541.5	1655740
PV CorpTx	6041408	2973237	13740770	1166823	6005502
PV Royal	4284515	152553.2	4637414	3977346	4294143

Lang WIPP Site Data, Case 1, Scenario 2
discount rate = 10%

	Average	STD	MAX	MIN	Median
PV Rev	1.5E+08	10324548	1.8E+08	1.3E+08	1.6E+08
PV CFlow	17053741	14507561	43379625	-1.2E+07	19555611
PV SevTax	2232034	149307.1	2609457	1888251	2238799
PV StateTx	1361122	705344.9	3267748	246681	1405881
PV CorpTx	5016500	2835605	13194513	69673.12	5039135
PV Royal	3848334	257426	4499064	3255606	3859998

	Average	STD	MAX	MIN	Median
PV Rev	1.6E+08	6580803	1.7E+08	1.4E+08	1.6E+08
PV CFlow	19124301	11082120	39021146	-7923657	19842514
PV SevTax	2271608	95133.88	2418338	2084140	2273560
PV StateTx	1402249	591566.9	2736148	410972	1378955
PV CorpTx	5115683	2395094	10816304	1391988	4889996
PV Royal	3916565	164023.9	4169548	3593344	3919931

	Average	STD	MAX	MIN	Median
PV Rev	1.6E+08	7420530	1.8E+08	1.4E+08	1.6E+08
PV CFlow	21104416	14520504	48519228	-1.8E+07	19568304
PV SevTax	2284499	107295	2532621	2029386	2283364
PV StateTx	1587901	858524.2	3839620	64696.38	1403636
PV CorpTx	5960268	3579555	15752888	235064.3	5042391
PV Royal	3938791	184991.4	4366589	3498942	3936834

	Average	STD	MAX	MIN	Median
PV Rev	1.6E+08	7936718	1.7E+08	1.4E+08	1.6E+08
PV CFlow	19914219	16102202	49454380	-2.9E+07	23068371
PV SevTax	2279150	114743.7	2511858	2021012	2284481
PV StateTx	1564381	761128.7	3903960	159267	1533540
PV CorpTx	5807511	3131195	16040723	499051.7	5447681
PV Royal	3929568	197833.9	4330790	3484503	3938760

	Average	STD	MAX	MIN	Median
PV Rev	1.6E+08	9233524	1.7E+08	1.4E+08	1.6E+08
PV CFlow	15562709	11109077	44700116	-5630557	17075301
PV SevTax	2262430	133506.4	2496322	2003711	2261935
PV StateTx	1216015	597518.5	3425864	274893.5	1207119
PV CorpTx	4371733	2401834	13901876	962397.6	4257025
PV Royal	3900741	230183.5	4304003	3454673	3899888

Lang WIPP Site Data, Case 2, Scenario 1
discount rate = 10%

	Average	STD	MAX	MIN	Median
PV Rev	[illegible]E+08	8957494	2.2E+08	1.8E+08	2.0E+08
PV CFlow	[illegible]0292	15190032	66210990	511052.8	32649249
PV SevTax	[illegible]2458	129627.8	3205632	2605388	2907514
PV StateTx	2161086	938485.2	5173355	539877.9	2091724
PV CorpTx	8110872	3967380	21332460	1928448	7833657
PV Royal	4986996	223496.3	5526952	4492048	5012956

	Average	STD	MAX	MIN	Median
PV Rev	[illegible]+08	9302027	2.3E+08	1.7E+08	2.0E+08
PV CFlow	[illegible]062	13727901	57703186	-7192725	34403636
PV SevTax	2904141	134581.3	3308927	2512661	2904798
PV StateTx	2140688	794400.2	4061848	513485.5	2104498
PV CorpTx	8001943	3333510	16359927	1806160	7638847
PV Royal	5007140	232036.8	5705046	4332174	5008273

	Average	STD	MAX	MIN	Median
PV Rev	2.0E+08	10336621	2.2E+08	1.7E+08	2.0E+08
PV CFlow	29225692	17224014	67409996	-1.9E+07	31425694
PV SevTax	2879613	149532	[illegible]48939	2492079	2898132
PV StateTx	2001840	1000443	5346077	347769.5	2006095
PV CorpTx	7477208	4154812	22105161	1126440	7236132
PV Royal	4964849	257813.7	5601618	4296688	4996779

	Average	STD	MAX	MIN	Median
PV Rev	2.0E+08	11538873	2.2E+08	1.8E+08	2.0E+08
PV CFlow	28566475	21012482	63040678	-2.0E+07	31495714
PV SevTax	2851294	166966.2	3187888	2579376	2842675
PV StateTx	2109833	[illegible]161184	4983934	355634.2	1972600
PV CorpTx	8003310	4855112	20485048	1142119	7031297
PV Royal	4916024	287872.7	5496359	4447199	4901164

	Average	STD	MAX	MIN	Median
PV Rev	2.0E+08	8414465	2.2E+08	[illegible]8E+08	2.0E+08
PV CFlow	28169632	18934300	53914091	-2.8E+07	31756337
PV SevTax	2843222	121722.9	3198160	2589071	2845080
PV StateTx	2041932	888005.7	3784208	408561.8	19945[illegible]
PV CorpTx	76[illegible]9934	3642172	15117852	13[illegible]	7271411
PV Royal	490[illegible]107	209867	5514069	4463915	4905311

Lang WIPP Site Data, Case 2, Scenario 2
discount rate = 10%

	Average	STD	MAX	MIN	Median
PV Rev	1.8E+08	9361557	2.0E+08	1.6E+08	1.8E+08
PV CFlow	19116321	16833122	46797505	-2.2E+07	20838005
PV SevTax	2596448	135525.6	2912732	2245532	2618600
PV StateTx	1534839	800878.8	3352568	203862.6	1484498
PV CorpTx	5611693	3216045	13357202	726563.9	5098026
PV Royal	4476635	233664.7	5021952	3871607	4514828

	Average	STD	MAX	MIN	Median
PV Rev	1.8E+08	9581982	2.0E+08	1.6E+08	1.8E+08
PV CFlow	22349725	14270065	56360109	-1.1E+07	22585211
PV SevTax	2615232	138713.7	2941034	2357121	2598945
PV StateTx	1667804	831327	4702097	219888.7	1612875
PV CorpTx	6143033	3440996	19394569	835719.7	5891473
PV Royal	4509021	239161.6	5070749	4064002	4480940

	Average	STD	MAX	MIN	Median
PV Rev	1.8E+08	9939348	2.0E+08	1.6E+08	1.8E+08
PV CFlow	19480044	19891303	60387657	-4.9E+07	23733045
PV SevTax	2592701	143902.1	2921343	2318600	2587891
PV StateTx	1626133	915979.6	4929382	54810.69	1596902
PV CorpTx	6025127	3742054	20411372	182546.6	5648964
PV Royal	4470175	248107.1	5036799	3997586	4461882

	Average	STD	MAX	MIN	Median
PV Rev	1.8E+08	10096786	2.0E+08	1.6E+08	1.8E+08
PV CFlow	22809184	17530642	59780789	-1.4E+07	23189405
PV SevTax	2586987	146151.5	2899290	2253445	2594887
PV StateTx	1785267	1050064	5052528	334973.8	1570581
PV CorpTx	6702974	4398899	20962288	1139400	5546383
PV Royal	4460323	251985.4	4998776	3885250	4473944

	Average	STD	MAX	MIN	Median
PV Rev	1.8E+08	9316039	2.0E+08	1.6E+08	1.8E+08
PV CFlow	21149193	15846545	46493973	-1.4E+07	22220138
PV SevTax	2602955	134795.3	2893733	2327159	2599928
PV StateTx	1628222	799780.3	3341966	224252.3	1551446
PV CorpTx	6011730	3238431	13309773	829410.9	5544864
PV Royal	4487854	232405.6	4989194	4012344	4482634

Lang WIPP Site Data, Case 3, Scenario 1
discount rate = 10%

	Average	STD	MAX	MIN	Median
PV Rev	2.3E+08	15770938	2.7E+08	2.0E+08	2.3E+08
PV CFlow	57238044	18400332	88267829	-3156112	60100304
PV SevTax	3342119	228625.1	3854200	2849965	3325744
PV StateTx	4389529	1400933	7471042	1327527	4492962
PV CorpTx	17675467	6078539	31301384	4931362	18047056
PV Royal	5762274	394181.2	6645173	4913733	5734041

	Average	STD	MAX	MIN	Median
PV Rev	2.4E+08	12878042	2.6E+08	2.1E+08	2.4E+08
PV CFlow	62497530	14247187	85739883	16863416	63298087
PV SevTax	3420757	186711.5	3768939	3002918	3431524
PV StateTx	4760477	1215470	7076490	2923156	4704157
PV CorpTx	19235159	5376907	29536282	11110268	18923215
PV Royal	5897856	321916.4	6498170	5177445	[illegible]16420

	Average	STD	MAX	MIN	Median
PV Rev	2.4E+08	13774611	2.7E+08	2.0E+08	2.4E+08
PV CFlow	64400797	16547251	94146105	18431091	66356875
PV SevTax	3446544	199595.2	39451[illegible]	2941322	3411199
PV StateTx	4962706	1431706	77945[illegible]	1898076	4969376
PV CorpTx	20171453	6277673	32748815	7257826	20159668
PV Royal	5942318	344129.7	6801977	5071244	5881378

	Average	STD	MAX	MIN	Median
PV Rev	2.3E+08	14783786	2.6E+08	2.0E+08	2.[illegible]E+08
PV CFlow	55315812	18148658	91425198	14398919	57[illegible]7892
PV SevTax	3321080	214317.9	3776814	2832903	3343549
PV StateTx	4300074	1389389	8032973	2057728	4233260
PV CorpTx	17290959	6045655	33815288	7962748	16860509
PV Royal	5726000	369513.6	6511748	4884316	5764739

	Average	STD	MAX	MIN	Median
PV Rev	2.3E+08	13067837	2.7E+08	2.0E+08	2.3E+08
PV CFlow	57982328	15507751	95395625	28952673	56766806
PV SevTax	3360030	189554.9	3849990	2904402	3364104
PV StateTx	4414822	1376414	8115238	2176519	4183850
PV CorpTx	17735147	6073421	34183315	8100029	16685519
PV Royal	5793154	326818.7	6637913	5007589	5800180

Lang WIPP Site Data, Case 3, Scenario 2
discount rate = 10%

	Average	STD	MAX	MIN	Median
PV Rev	2.1E+08	12424234	2.4E+08	1.8E+08	2.1E+08
PV CFlow	48829540	16051137	78209652	6193785	47068652
PV SevTax	3015862	180164.2	3431095	2614039	3035292
PV StateTx	3868621	1316429	6842152	1417667	3540777
PV CorpTx	15544189	5737240	28687472	5300021	14033991
PV Royal	5199763	310628	5915682	4506964	5233261

	Average	STD	MAX	MIN	Median
PV Rev	2.1E+08	13297131	2.5E+08	1.8E+08	2.1E+08
PV CFlow	50987058	15347099	76238571	5167522	52042791
PV SevTax	3045111	192913	3551293	2604979	3069569
PV StateTx	3995574	1239592	6447848	1452804	3984384
PV CorpTx	16064012	5415694	26923482	5476240	15986904
PV Royal	5250191	332608.7	6122919	4491342	5292361

	Average	STD	MAX	MIN	Median
PV Rev	2.1E+08	15490239	2.6E+08	1.8E+08	2.1E+08
PV CFlow	47268564	19679012	85485230	-9422330	49503360
PV SevTax	3099576	224759.5	3756948	2583149	3068485
PV StateTx	3736473	1438890	7422842	1262963	3587822
PV CorpTx	14977126	6238714	31285296	4876152	14208479
PV Royal	5344097	387516.4	6477496	4453706	5290491

	Average	STD	MAX	MIN	Median
PV Rev	2.1E+08	11047584	2.4E+08	1.9E+08	2.1E+08
PV CFlow	49467466	15461294	75099112	2153786	52660613
PV SevTax	3038894	160158.1	3502271	2744264	3029760
PV StateTx	3834832	1272460	6440208	847762.7	3974110
PV CorpTx	15351048	5552791	26889304	3069943	15912085
PV Royal	5239472	276134.7	6038398	4731489	5223724

	Average	STD	MAX	MIN	Median
PV Rev	2.1E+08	12612437	2.4E+08	1.7E+08	2.1E+08
PV CFlow	45689553	15693071	69062733	-1.1E+07	48332571
PV SevTax	3020266	183021.2	3464288	2500649	3024558
PV StateTx	3536651	1090359	5794252	1247134	3517129
PV CorpTx	14060764	4683481	23999503	4536145	13850316
PV Royal	5207355	315553.8	5972910	4311464	5214755

Sylvite WIPP Site Data, Case 1, Scenario 1
discount rate = 15%

	Average	STD	MAX	MIN	Median
PV Rev	2.0E+08	10758395	2.2E+08	1.7E+08	2.0E+08
PV CFlow	29064928	17073878	67054774	-1.5E+07	29374707
PV SevTax	2872028	155994.9	3196140	2440866	2868743
PV StateTx	2088721	874923.3	5165662	855474.4	1999322
PV CorpTx	8156206	3718586	21651899	3241477	7759780
PV Royal	4951773	268956.8	5510586	4208390	4946109

	Average	STD	MAX	MIN	Median
PV Rev	2.0E+08	8777849	2.2E+08	1.8E+08	2.0E+08
PV CFlow	31054661	14630143	66189986	-156777	32[illegible]445
PV SevTax	2873998	127361.1	3169723	2560469	28[illegible]1182
PV StateTx	2121038	897193.6	5130848	845943.6	2087388
PV CorpTx	8282574	3826248	21496154	3041037	8076240
PV Royal	4955169	219588.1	5465040	4414603	4933072

	Average	STD	MAX	MIN	Median
PV Rev	2.0E+08	9144376	2.2E+08	1.8E+08	2.0E+08
PV CFlow	31118882	14778546	62335120	-1.0E+07	31165312
PV SevTax	2856349	132603.1	3118649	2571479	2859508
PV StateTx	2179078	823670.2	4607528	703602.7	2140689
PV CorpTx	8528303	3513931	19154983	2404249	8301894
PV Royal	4924740	228626.1	5376981	4433584	4930186

	Average	STD	MAX	MIN	Median
PV Rev	2.0E+08	8853956	2.2E+08	1.8E+08	2.0E+08
PV CFlow	32659897	16033307	59466704	-3728353	35519576
PV SevTax	2892494	128323	3144217	2624319	2883772
PV StateTx	2283784	919579.9	4458799	833602.5	2243779
PV CorpTx	8973534	3931396	18489618	3098018	8712984
PV Royal	4987059	221246.5	5421063	4524689	4972021

	Average	STD	MAX	MIN	Median
PV Rev	2.0E+08	10690396	2.2E+08	1.7E+08	2.0E+08
PV CFlow	30204233	14999526	62152716	-1.2E+07	30208451
PV SevTax	2882273	155087.2	3233793	2438677	2870697
PV StateTx	2142684	780237.1	4584047	999850.3	1982564
PV CorpTx	8366586	3350641	19049937	3689085	7735573
PV Royal	4969437	267391.8	5575505	4204615	4949478

Sylvite WIPP Site Data, Scenario 2
discount rate = 15%

	Average	STD	MAX	MIN	Median
PV Rev	1.7E+08	11316861	1.9E+08	1.5E+08	1.7E+08
PV CFlow	20065751	18151009	53327600	-3.0E+07	21644647
PV SevTax	2445953	164321.9	2814110	2161232	2425630
PV StateTx	1706281	839876.1	4146964	237915.2	1548859
PV CorpTx	6622724	3556384	17294156	778656.1	5754298
PV Royal	4217161	283313.6	4851914	3726261	4182121

	Average	STD	MAX	MIN	Median
PV Rev	1.7E+08	8816086	2.1E+08	1.5E+08	1.7E+08
PV CFlow	24738086	13564753	54905799	-3997171	24441089
PV SevTax	2473705	127971.1	3003455	2195054	2461055
PV StateTx	1861891	825475	4441784	235299.2	1698441
PV CorpTx	7265554	3541439	18613088	749202.7	6379710
PV Royal	4265008	220639.8	5178370	3784576	4243199

	Average	STD	MAX	MIN	Median
PV Rev	1.7E+08	11149192	2.0E+08	1.5E+08	1.7E+08
PV CFlow	27071437	17061576	59739349	-2.7E+07	28290078
PV SevTax	2487849	161917.3	2877379	2176556	2480013
PV StateTx	2070149	1002519	4888636	326301.7	1880138
PV CorpTx	8187651	4312790	20612161	1092041	7323179
PV Royal	4289394	279167.8	4960998	3752684	4275884

	Average	STD	MAX	MIN	Median
PV Rev	1.7E+08	11149192	2.0E+08	1.5E+08	1.7E+08
PV CFlow	27071437	17061576	59739349	-2.7E+07	28290078
PV SevTax	2487849	161917.3	2877379	2176556	2480013
PV StateTx	2070149	1002519	4888636	326301.7	1880138
PV CorpTx	8187651	4312790	20612161	1092041	7323179
PV Royal	4289394	279167.8	4960998	3752684	4275884

	Average	STD	MAX	MIN	Median
PV Rev	1.7E+08	9714480	2.0E+08	1.5E+08	1.7E+08
PV CFlow	21209753	13867745	49118288	-1.0E+07	20319980
PV SevTax	2495742	141043.9	2872034	2163963	2480337
PV StateTx	1660298	748503.3	3718327	597563.3	1423427
PV CorpTx	6427893	3170123	15376570	2107895	5375785
PV Royal	4303003	243179.2	4951782	3730971	4276444

Sylvite WIPP Site Data, Scenario 1
discount rate = 10%

	Average	STD	MAX	MIN	Median
PV Rev	2.6E+08	[illegible]3296439	2.8E+08	2.2E+08	2.6E+08
PV CFlow	33126499	29160916	81109773	-3.7E+07	35993417
PV SevTax	3722968	192394.8	4104734	3235860	3688140
PV StateTx	2608294	1346406	5984248	409446.1	2272694
PV CorpTx	10233892	5648528	24894888	1395051	8589421
PV Royal	6418910	331715.1	7077127	5579070	6358862

	Average	STD	MAX	MIN	Median
PV Rev	2.6E+08	14521362	2.9E+08	2.2E+08	2.6E+08
PV CFlow	38905238	21814020	94972859	-2.6E+07	42036987
PV SevTax	3693101	210160	4259235	3224150	3709649
PV StateTx	2729754	1293572	7774490	577969.8	2624474
PV CorpTx	10691115	5498050	32903865	2075437	10038600
PV Royal	6367415	362344.8	7343509	5558880	6395946

	Average	STD	MAX	MIN	Median
PV Rev	2.6E+08	12155337	2.9E+08	2.3E+08	2.6E+08
PV CFlow	34802597	23186741	75850778	-3.4E+07	41488758
PV SevTax	3702772	175818.3	4147582	3271736	3703853
PV StateTx	2569151	1087834	565803[illegible]	743083.1	2616434
PV CorpTx	9992399	4557296	23435501	2709023	9857761
PV Royal	6384090	303135	7151004	5640924	6385954

	Average	STD	MAX	MIN	Median
PV Rev	2.6E+08	14741013	2.9E+08	2.2E+08	2.6E+08
PV CFlow	35774037	22660566	74516157	-2.2E+07	39323502
PV SevTax	369622[illegible]	213341.3	4183081	3224191	3688712
PV StateTx	262720[illegible]	1069557	5072674	671717.5	2586081
PV CorpTx	10275037	4452445	20816797	2459660	9984864
PV Royal	6372804	367829.9	7212209	[illegible]558949	6359849

	Average	STD	MAX	MIN	Median
PV Rev	2.6E+08	13036450	2.9E+08	2.2E+08	2.6E+08
PV CFlow	37702467	21327240	79950405	-3120735	38998800
PV SevTax	3732168	188712	4182104	3216547	3730738
PV StateTx	2675750	1161291	5855582	1053237	2486893
PV CorpTx	10475298	4906984	24319278	3759553	9515365
PV Royal	6434773	[illegible]25365.6	7210523	5545771	6432308

Sylvite WIPP Site Data, Scenario 2
discount rate = 10%

	Average	STD	MAX	MIN	Median
PV Rev	2.3E+08	12954436	2.6E+08	2.0E+08	2.3E+08
PV CFlow	27779249	23123559	72248954	-3.4E+07	27936185
PV SevTax	3338031	187638.3	3753253	2901123	3355240
PV State Tx	2303753	1183307	5782403	613395.5	2166644
PV CorpTx	9032781	5006665	24168407	2162101	8364060
PV Royal	5755227	323514.3	6471126	5001936	5784897

	Average	STD	MAX	MIN	Median
PV Rev	2.3E+08	15318158	2.7E+08	2.0E+08	2.3E+08
PV CFlow	27044757	21882631	65520340	-2.3E+07	28746177
PV SevTax	3363363	221736.5	3880498	2861148	3346597
PV StateTx	2147536	1115030	4603294	551319	1904768
PV CorpTx	8292498	4686715	18893443	1884390	7088927
PV Royal	5798901	382304.4	6690514	4933013	5769995

	Average	STD	MAX	MIN	Median
PV Rev	2.4E+08	15596644	2.7E+08	2.0E+08	2.4E+08
PV CFlow	28141520	23669512	65527214	-2.5E+07	26406071
PV SevTax	3398088	225896.1	3882335	2937230	3407572
PV StateTx	2247513	1091704	4737722	491694	1900094
PV CorpTx	8728810	4548143	19494834	1624984	7288033
PV Royal	5858772	389476	6693681	5064189	5875125

	Average	STD	MAX	MIN	Median
PV Rev	2.3E+08	14233867	2.6E+08	2.0E+08	2.3E+08
PV CFlow	20562757	25036314	76036357	-7.2E+07	23936177
PV SevTax	3335092	206035.1	3792742	2880557	3343058
PV StateTx	1951090	1033238	5747236	365279.1	1762067
PV CorpTx	7522946	4302998	24011081	1227302	6455677
PV Royal	5750159	355233	6539211	4966478	5763894

	Average	STD	MAX	MIN	Median
PV Rev	2.3E+08	14616880	2.6E+08	2.0E+08	2.4E+08
PV CFlow	34131434	23199420	72473916	-4.1E+07	37068644
PV SevTax	3393888	211635.9	3825075	2922635	3413202
PV StateTx	2579247	1190374	5372579	374609.2	2508388
PV CorpTx	10128884	5054239	22334983	1269042	9531140
PV Royal	5851531	364889.4	6594957	5039027	5884831

Lang Combined Area Data, Case 1, Scenario 1
discount rate = 15%

	Average	STD	MAX	MIN	Median
PV Rev	1.8E+08	10096773	2.1E+08	1.6E+08	1.8E+08
PV CFlow	44293410	10767958	641581[illegible]	14394612	44231603
PV SevTax	2636628	147537.1	3001837	2248129	2639712
PV StateTx	3211222	898665.5	5003228	1231738	3132377
PV CorpTx	12790703	3925054	20722336	4423390	12352739
PV Royal	4545910	254374.2	5175580	3876084	4551227

	Average	STD	MAX	MIN	Median
PV Rev	1.8E+08	10991262	2.0E+08	1.5E+08	1.8E+08
PV CFlow	42495677	11809684	64382418	10582146	43877705
PV SevTax	2605755	160546.1	2973172	2229293	2613713
PV StateTx	3104156	934804.6	5298472	1048325	3041430
PV CorpTx	12315605	4083540	22043164	3680598	12018390
PV Royal	4492681	276803.6	5126158	3843609	4506402

	Average	STD	MAX	MIN	Median
PV Rev	1.8E+08	9359549	2.0E+08	1.6E+08	1.8E+08
PV CFlow	40722516	11404501	60488806	12323804	42179961
PV SevTax	2650896	136706.4	2913576	2296882	2643207
PV StateTx	2926627	871689.5	4779476	1035143	2837439
PV CorpTx	11551847	3781358	19721340	3605384	11207219
PV Royal	4570511	235700.6	5023406	3960142	4557254

	Average	STD	MAX	MIN	Median
PV Rev	1.8E+08	11359244	2.1E+08	1.6E+08	1.8E+08
PV CFlow	44422657	9081162	61487121	24795250	44035869
PV SevTax	2641303	166119.7	3104810	2318617	2642594
PV StateTx	3201618	811727	5202340	1545052	3030230
PV CorpTx	12730495	3575261	21613100	5503510	12038098
PV Royal	4553972	286413.2	5353121	3997616	4556197

	Average	STD	MAX	MIN	Median
PV Rev	1.8E+08	11686969	2.0E+08	1.5E+08	1.9E+08
PV CFlow	44069574	12609151	66824680	19659380	44636071
PV SevTax	2642264	170749.8	2918188	2182331	2683052
PV StateTx	3238341	1076382	5480854	1480118	2996105
PV CorpTx	12938470	4697744	22859081	5520636	11782402
PV Royal	4555627	294396.3	5031359	3762639	4625952

Lang Combined Area Data, Case 1, Scenario 2
discount rate = 15%

	Average	STD	MAX	MIN	Median
PV Rev	1.6E+08	10043007	1.8E+08	1.4E+08	1.6E+08
PV CFlow	30399402	12501520	58531558	4318178	31319251
PV SevTax	2309791	146875.5	2601708	2042607	2331446
PV StateTx	2303781	951428.6	5181460	692462	2266843
PV CorpTx	9010534	4118708	21748381	2405524	8867403
PV Royal	3982398	253233.7	4485704	3521736	4019734

	Average	STD	MAX	MIN	Median
PV Rev	1.6E+08	9209285	1.8E+08	1.3E+08	1.6E+08
PV CFlow	30954378	13426000	54702061	-4454665	32112104
PV SevTax	2275431	134864.1	2613780	1948698	2264672
PV StateTx	2435549	1033713	4655086	762750.3	2269143
PV CorpTx	9597277	4491666	19393551	2548131	8738174
PV Royal	3923156	232524.3	4506518	3359825	3904606

	Average	STD	MAX	MIN	Median
PV Rev	1.5E+08	10078077	1.9E+08	1.4E+08	1.5E+08
PV CFlow	31063464	11454251	52175157	3298107	31831275
PV SevTax	2248922	147395.1	2707030	2005004	2249565
PV StateTx	2393004	920854.2	4633384	605628.8	2255479
PV CorpTx	9400017	3996833	19304664	2136766	8686522
PV Royal	3877452	254129.4	4667293	3456904	3878560

	Average	STD	MAX	MIN	Median
PV Rev	1.6E+08	8471799	1.7E+08	1.3E+08	1.6E+08
PV CFlow	29433093	12615518	57038242	3991575	29270629
PV SevTax	2274010	124102	2532880	1920718	2287818
PV StateTx	2250212	1007443	5023048	747708.6	2043066
PV CorpTx	8786850	4371311	21039693	2826220	7730885
PV Royal	3920708	213969	4367035	3311583	3944514

	Average	STD	MAX	MIN	Median
PV Rev	1.6E+08	10364363	1.8E+08	1.4E+08	1.6E+08
PV CFlow	33801614	10229662	56263991	4804890	33725190
PV SevTax	2284347	151569.4	2613379	2016486	2277080
PV StateTx	2586596	825717.9	4776461	1058218	2529907
PV CorpTx	10224987	3623001	19936541	3878786	10068588
PV Royal	3938530	261326.6	4505826	3476701	3926001

Lang Combined Area Data, Case 1, Scenario 3
discount rate = 15%

	Average	STD	MAX	MIN	Median
PV Rev	1.2E+08	7852428	1.3E+08	96172366	1.2E+08
PV CFlow	-2.6E+07	12215732	-6002023	-6.7E+07	-2.5E+07
PV SevTax	1696318	114902.8	1911098	1398474	1695316
PV StateTx	965623.6	613496.6	2447062	0	899045.5
PV CorpTx	3640091	2478010	9883274	0	3172980
PV Royal	2924687	198108.3	3294997	2411162	2922959

	Average	STD	MAX	MIN	Median
PV Rev	1.2E+08	9494215	1.4E+08	92816499	1.2E+08
PV CFlow	-3.0E+07	13398243	-6036141	-6.3E+07	-3.0E+07
PV SevTax	1682185	139051.6	2062994	1350678	1683314
PV StateTx	760652.3	622218.5	2380003	0	664842.7
PV CorpTx	2834292	2482815	9583275	0	2231632
PV Royal	2900319	239744.2	3556886	2328755	2902266

	Average	STD	MAX	MIN	Median
PV Rev	1.2E+08	8800113	1.4E+08	1.0E+08	1.2E+08
PV CFlow	-2.8E+07	13504543	3476900	-5.8E+07	-2.8E+07
PV SevTax	1727335	128721.2	2033120	1499810	1704082
PV StateTx	906278.5	774209.9	3350031	2482.247	661973
PV CorpTx	3438261	3175097	13922875	17582.58	2186882
PV Royal	2978163	221933.2	3505379	2585879	2938072

	Average	STD	MAX	MIN	Median
PV Rev	1.2E+08	8298990	1.3E+08	97601773	1.2E+08
PV CFlow	-2.7E+07	11181562	-4745298	-6.0E+07	-2.8E+07
PV SevTax	1690005	121522.4	1954263	1420526	1688690
PV StateTx	884171.3	605422.4	2556072	11.10669	732898.2
PV CorpTx	3318826	2437375	10376312	78.67242	2563204
PV Royal	2913802	209521.4	3369418	2449183	2911535

	Average	STD	MAX	MIN	Median
PV Rev	1.2E+08	8978434	1.5E+08	89403028	1.2E+08
PV CFlow	-2.7E+07	11184693	-7522627	-7.0E+07	-2.6E+07
PV SevTax	1691862	131469.5	2117987	1303257	1682927
PV StateTx	877551.2	548735.9	2277719	0	829546.5
PV CorpTx	3287169	2186843	9231381	0	2949235
PV Royal	2917004	226671.6	3651701	2246995	2901599

Lang Combined Area Data, Case 2, Scenario 1
discount rate = 15%

	Average	STD	MAX	MIN	Median
PV Rev	1.8E+08	8484939	2.0E+08	1.6E+08	1.8E+08
PV CFlow	42894387	12991944	63962007	7112894	45173687
PV SevTax	2633892	123850.3	2942621	2355130	2666724
PV StateTx	3140243	1029593	5366240	1373700	3082413
PV CorpTx	12482021	4494063	22346334	5035614	12161960
PV Royal	4541193	213535	5073484	4060569	4597800

	Average	STD	MAX	MIN	Median
PV Rev	1.8E+08	9896394	2.0E+08	1.6E+08	1.8E+08
PV CFlow	43627451	12102260	73166052	13140451	45435470
PV SevTax	2644299	144751.4	2869342	2298389	2659496
PV StateTx	3191936	1048393	6374398	996366.5	3177680
PV CorpTx	12715988	4592165	26856516	3449157	12559280
PV Royal	4559136	249571.4	4947142	3962740	4585339

	Average	STD	MAX	MIN	Median
PV Rev	1.8E+08	10516214	2.0E+08	1.5E+08	1.8E+08
PV CFlow	40027233	17860711	63592322	-2.1E+07	44775710
PV SevTax	2651099	153636.6	2922696	2153635	2663572
PV StateTx	3045579	1041614	5120205	843466.2	3092921
PV CorpTx	12102827	4480416	21257735	3145245	12239066
PV Royal	4570861	264890.7	5039130	3713164	4592366

	Average	STD	MAX	MIN	Median
PV Rev	1.8E+08	10516214	2.0E+08	1.5E+08	1.8E+08
PV CFlow	40027233	17860711	63592322	-2.1E+07	44775710
PV SevTax	2651099	153636.6	2922696	2153635	2663572
PV StateTx	3045579	1041614	5120205	843466.2	3092921
PV CorpTx	12102827	4480416	21257735	3145245	12239066
PV Royal	4570861	264890.7	5039130	3713164	4592366

	Average	STD	MAX	MIN	Median
PV Rev	1.8E+08	8019617	2.1E+08	1.6E+08	1.8E+08
PV CFlow	45834668	12180410	70069168	13097217	45982126
PV SevTax	2655271	117218	3049417	2379959	2656275
PV StateTx	3406926	1036782	5803335	1169062	3246204
PV CorpTx	13643957	4565297	24301759	4061254	12896269
PV Royal	4578054	202099.9	5257615	4103378	4579785

Lang Combined Area Data, Case 2, Scenario 2
discount rate = 15%

	Average	STD	MAX	MIN	Median
PV Rev	1.6E+08	10796097	1.8E+08	1.4E+08	1.6E+08
PV CFlow	34534916	12236598	58754617	5209963	[illegible]
PV SevTax	2270393	157990	2615617	1960861	2287488
PV StateTx	2688589	1007018	5185776	867026.3	2668075
PV CorpTx	10682525	4411268	21767687	3088254	10521283
PV Royal	3914470	272396.6	4509684	3380795	3943945

	Average	STD	MAX	MIN	Median
PV Rev	1.6E+08	9478901	1.7E+08	1.4E+08	1.6E+08
PV CFlow	36145463	11727986	58113666	4358288	38819189
PV SevTax	2298189	138491.5	2531275	2018630	2315194
PV StateTx	2813056	983404.2	5184094	988886.4	2938613
PV CorpTx	11212909	4329006	21760165	3374959	11738208
PV Royal	3962395	238778.5	4364267	3480396	3991713

	Average	STD	MAX	MIN	Median
PV Rev	1.6E+08	9279293	1.7E+08	1.3E+08	1.6E+08
PV CFlow	33323910	11993396	58174383	[illegible]	35329222
PV SevTax	2307119	135617.6	2530325	1948757	2333507
PV StateTx	2572118	987710.4	5112094	870357.6	2548638
PV CorpTx	10184813	4306292	21438061	3105672	10050100
PV Royal	3977791	[illegible]	4362629	3359926	4023288

	Average	STD	MAX	MIN	Median
PV Rev	1.6E+08	9452502	1.9E+08	1.4E+08	1.6E+08
PV CFlow	37558527	10701384	72280257	18493560	37541853
PV SevTax	2285131	138059	2805745	2044491	2283470
PV StateTx	2892795	1065280	6562879	[illegible]	2779215
PV CorpTx	11553017	[illegible]	27928410	5263204	11001497
PV Royal	3939880	238032.8	4837492	3524985	3937017

	Average	STD	MAX	MIN	Median
PV Rev	1.6E+08	9787785	1.7E+08	1.3E+08	1.6E+08
PV CFlow	31244150	10740541	48206696	3738702	32773811
PV SevTax	2264536	142990.7	2524345	1918663	2263729
PV StateTx	2364600	795081.1	3815987	[illegible]	2269730
PV CorpTx	9246474	3437290	15643068	[illegible]	8789214
PV Royal	3904373	246535.6	4352319	3308040	3902981

Lang Combined Area Data, Case 2, Scenario 3
discount rate = 15%

	Average	STD	MAX	MIN	Median
PV Rev	1.2E+08	9262530	1.3E+08	95405747	1.2E+08
PV CFlow	-2.9E+07	13044474	-5188255	-7.2E+07	-2.7E+07
PV SevTax	1691566	135567.5	1936111	1389702	1686072
PV StateTx	812350.7	574380.2	2330550	0	761384.9
PV CorpTx	3026719	2305324	9362039	0	2755753
PV Royal	2916494	233737.1	3338123	2396038	2907021

	Average	STD	MAX	MIN	Median
PV Rev	1.2E+08	8717048	1.3E+08	95679898	1.1E+08
PV CFlow	-2.6E+07	11008312	-4119347	-4.7E+07	-2.5E+07
PV SevTax	1681239	127895.8	1941705	1393276	1667377
PV StateTx	966399.7	669480.7	2582175	38904.86	891894.4
PV CorpTx	3680447	2719738	10487729	172561.1	3251697
PV Royal	2898688	220510.1	3347767	2402201	2874788

	Average	STD	MAX	MIN	Median
PV Rev	1.2E+08	9296411	1.4E+08	98734309	1.2E+08
PV CFlow	-2.5E+07	10615748	-5498284	-4.9E+07	-2.5E+07
PV SevTax	1724225	136099.6	2009936	1437278	1722294
PV StateTx	1049170	611032.8	2512228	68342.35	929272.3
PV CorpTx	3994309	2493712	10174806	207103.6	3642649
PV Royal	2972802	234654.5	3465407	2478066	2969473

	Average	STD	MAX	MIN	Median
PV Rev	1.2E+08	8355623	1.4E+08	96870054	1.2E+08
PV CFlow	-2.8E+07	11983384	-6889698	-6.0E+07	-2.7E+07
PV SevTax	1689647	122288	2001215	1410475	1681518
PV StateTx	849596.7	583080.5	2326349	2163.788	779849.6
PV CorpTx	3154827	2310136	9343243	15326.84	2817209
PV Royal	2913185	210841.5	3450371	2431854	2899169

	Average	STD	MAX	MIN	Median
PV Rev	1.2E+08	9657327	1.3E+08	96492873	1.1E+08
PV CFlow	-2.7E+07	12720875	312091.8	-6.6E+07	-2.6E+07
PV SevTax	1688233	141668.2	1960852	1404576	1670256
PV StateTx	937335.6	639991.9	2966103	989.6069	829041
PV CorpTx	3562576	2586053	12205300	4596.688	2994828
PV Royal	2910747	244255.5	3380779	2421683	2879751

Lang Combined Area Data, Case 3, Scenario 1
discount rate = 15%

	Average	STD	MAX	MIN	Median
PV Rev	1.8E+08	9587441	2.0E+08	1.5E+08	1.8E+08
PV CFlow	54000957	10633859	73397088	15604606	53790768
PV SevTax	2668029	140266.9	2861999	2205444	2674384
PV StateTx	42[illegible]68	1074724	6463759	13744[illegible]	4079458
PV CorpTx	172[illegible]6	4765754	27264555	4976311	16589677
PV Royal	4600049	241839.5	4934481	3802490	4611008

	Average	STD	MAX	MIN	Median
PV Rev	1.8E+08	9086771	2.0E+08	1.6E+08	1.8E+08
PV CFlow	51161595	9439577	67923560	275804[illegible]	53386800
PV SevTax	2617527	132436	2842181	2276542	2621050
PV StateTx	3910412	953160.1	5706123	1993889	4113433
PV CorpTx	15853785	4235375	23866863	7405837	16741671
PV Royal	4512978	228337.9	4900312	3925073	4519051

	Average	STD	MAX	MIN	Median
PV Rev	1.8E+08	11369512	2.1E+08	1.6E+08	1.8E+08
PV CFlow	51264375	11606417	78912926	22573648	50925442
PV SevTax	2623622	165979.5	3011293	2316684	2619283
PV StateTx	3958664	1179752	7069375	1648292	3784930
PV CorpTx	16081550	5244832	29965621	5994411	15304539
PV Royal	4523486	286171.5	5191884	3994282	4516005

	Average	STD	MAX	MIN	Median
PV Rev	1.8E+08	9780011	2.1E+08	1.6E+08	1.8E+08
PV CFlow	54767133	8843258	71419721	20124064	54181080
PV SevTax	2661431	142963.5	3002223	2354796	2666580
PV StateTx	4267921	923711.6	6138641	1503110	4136857
PV CorpTx	17451124	4095090	25801815	5569719	16846464
PV Royal	4588673	246488.9	5176246	4059994	4597552

	Average	STD	MAX	MIN	Median
PV Rev	1.8E+08	8790070	2.1E+08	1.7E+08	1.8E+08
PV CFlow	51983617	10424667	74612495	21408544	51990169
PV SevTax	2644725	128387.2	3051862	2442527	2626360
PV StateTx	3995880	1047573	6573247	1844610	3959508
PV CorpTx	16234565	4663132	27746102	6909741	16053061
PV Royal	4559871	221357.2	5261831	4211253	4528208

Lang Combined Area Data, Case 3, Scenario 2
discount rate = 15%

	Average	STD	MAX	MIN	Median
PV Rev	1.6E+08	11146021	1.8E+08	1.3E+08	1.6E+08
PV CFlow	41925247	10315321	65167473	10449499	41185311
PV SevTax	2294796	162629.7	2656217	1935472	2300543
PV State Tx	3346006	1023779	5807411	1074483	3184383
PV CorpTx	13560107	4541841	24548687	3863107	12823755
PV Royal	3956544	280396.1	4579685	3337021	3966454

	Average	STD	MAX	MIN	Median
PV Rev	1.6E+08	9722964	1.8E+08	1.4E+08	1.6E+08
PV CFlow	41845253	9365197	62980128	20647049	40668788
PV SevTax	2291339	142395.8	2545595	2019717	2300060
PV State Tx	3343863	973341.7	5697145	1545530	3277938
PV CorpTx	13546739	4333748	24055392	5519682	13257582
PV Royal	3950585	245510	4388957	3482271	3965621

	Average	STD	MAX	MIN	Median
PV Rev	1.6E+08	10607907	1.9E+08	1.3E+08	1.6E+08
PV CFlow	41881955	11449829	70966832	9162797	42249151
PV SevTax	2286350	155277.5	2697994	1929330	2291239
PV State Tx	3395725	1074560	6526914	913779.8	3307706
PV CorpTx	13795415	4755797	27767515	3110478	13365797
PV Royal	3941984	267719.8	4651714	3326431	3950412

	Average	STD	MAX	MIN	Median
PV Rev	1.6E+08	10445085	1.8E+08	1.4E+08	1.6E+08
PV CFlow	42735433	10520052	65599105	18438886	41464259
PV SevTax	2276426	152867.2	2618503	1965583	2266735
PV State Tx	3466776	1107283	6099396	1397583	3308317
PV CorpTx	14102025	4925105	25854935	5024027	13368531
PV Royal	3924873	263564.1	4514661	3388936	3908164

	Average	STD	MAX	MIN	Median
PV Rev	1.6E+08	11381314	1.8E+08	1.3E+08	1.6E+08
PV CFlow	43876313	9326097	70085184	15664559	45692299
PV SevTax	2277789	166273.1	2582583	1855090	2282825
PV State Tx	3588596	991077.8	6628572	1163106	3586862
PV CorpTx	14641510	4411922	28222303	3968148	14614653
PV Royal	3927223	286677.7	4452729	3198432	3935905

Lang Combined Area Data, Case 3, Scenario 3
discount rate = 15%

	Average	STD	MAX	MIN	Median
PV Rev	1.2E+08	10152764	1.4E+08	952[illegible]60	1.2E+08
PV CFlow	-1.4E+07	9118717	8496692	-3.4E+07	-1.4E+07
PV SevTax	1701525	148743.3	2027811	1386576	1684797
PV StateTx	1749133	723041.5	3173803	471802.2	1660793
PV CorpTx	6897502	3127192	13134488	1549016	6443472
PV Royal	2933663	256454	3496226	2390647	2904823

	Average	STD	MAX	MIN	Median
PV Rev	1.2E+08	9604215	1.4E+08	89442805	1.2E+08
PV CFlow	-1.3E+07	10808858	7813322	-4.6E+07	-1.3E+07
PV SevTax	1722495	140757.7	1991725	1300698	1742762
PV StateTx	1890756	854088.4	3871129	276290.4	1742534
PV CorpTx	7546721	3682609	16254104	852373	6754303
PV Royal	2969819	242685.8	3434009	2242583	3004762

	Average	STD	MAX	MIN	Median
PV Rev	1.2E+08	8804165	1.4E+08	88585442	1.2E+08
PV CFlow	-1.3E+07	8783015	10370086	-3.1E+07	-1.2E+07
PV SevTax	1683558	128877.3	1984547	1287968	1690169
PV StateTx	1864922	764297.7	4153325	551303.8	1844864
PV CorpTx	7380144	3315574	17516560	1873839	7233118
PV Royal	2902686	222202.2	3421634	2220635	2914085

	Average	STD	MAX	MIN	Median
PV Rev	1.2E+08	8233777	1.3E+08	99481694	1.2E+08
PV CFlow	-1.3E+07	8656949	4975804	-3.4E+07	-1.2E+07
PV SevTax	1710509	120630.4	1957475	1447986	1723888
PV StateTx	1853450	715653.2	3606811	466140.5	1912176
PV CorpTx	7355662	3095201	15071625	1517503	7601823
PV Royal	2949153	207983.4	3374956	2496528	2972221

	Average	STD	MAX	MIN	Median
PV Rev	1.2E+08	7148357	1.3E+08	1.0E+08	1.2E+08
PV CFlow	-1.2E+07	8069229	4405191	-3.9E+07	-1.1E+07
PV SevTax	1721254	104658.7	1948126	1482060	1721027
PV StateTx	1916002	662393.5	3491728	215707.8	1947352
PV CorpTx	7618366	2852327	14556781	738744	7663743
PV Royal	2967680	180446	3358839	2555276	2967287

Lang Combined Data, Case 1, Scenario 1
discount rate = 10%

	Average	STD	MAX	MIN	Median
PV Rev	2.7E+08	17470687	3.1E+08	2.3E+08	2.6E+08
PV CFlow	55330312	23796027	96326357	-4991704	61189383
PV SevTax	3849984	254168.6	4449095	3266158	3829860
PV StateTx	4216142	1584401	7925527	1268952	4217066
PV CorpTx	16685040	6835244	33030019	4578133	16602622
PV Royal	6637903	438221.8	7670853	5631306	6603206

	Average	STD	MAX	MIN	Median
PV Rev	2.7E+08	20202689	3.1E+08	2.3E+08	2.7E+08
PV CFlow	55714347	24925300	95945091	-3.4E+07	62279579
PV SevTax	3896985	294237.5	4474726	3329006	3913734
PV StateTx	4126127	1599539	7958181	713100.5	4050070
PV CorpTx	16281981	6884340	33176103	2547726	15692450
PV Royal	6718939	507306.1	7715045	5739666	6747817

	Average	STD	MAX	MIN	Median
PV Rev	2.7E+08	17620009	3.1E+08	2.2E+08	2.7E+08
PV CFlow	59871142	21845663	1.2E+08	12144349	58484706
PV SevTax	3873693	256557.5	4464384	3160133	3843998
PV StateTx	4412628	1782500	10354369	1510349	3937514
PV CorpTx	17536822	7756223	43895895	5569642	15408657
PV Royal	6678781	442340.5	7697215	5448505	6627582

	Average	STD	MAX	MIN	Median
PV Rev	2.7E+08	21956993	3.3E+08	2.1E+08	2.7E+08
PV CFlow	52080120	27360617	94704672	-4.4E+07	50549957
PV SevTax	3877171	319549.2	4797519	3088316	3862974
PV StateTx	3980596	1687772	7683054	846721.6	3526824
PV CorpTx	15687253	7258901	31945272	2970310	13619568
PV Royal	6684778	550946.9	8271584	5324684	6660299

	Average	STD	MAX	MIN	Median
PV Rev	2.6E+08	19739010	3.0E+08	2.3E+08	2.7E+08
PV CFlow	52625034	23659769	96173363	-5946000	56916045
PV SevTax	3838410	287531.9	4348900	3260748	3885744
PV StateTx	3922207	1542766	7792324	1305274	3804532
PV CorpTx	15365327	6679061	32434114	4573186	14613332
PV Royal	6617948	495744.6	7498104	5621979	6699559

Lang Combined Data, Case 1, Scenario 2
discount rate = 10%

	Average	STD	MAX	MIN	Median
PV Rev	2.4E+08	20519424	2.8E+08	2.1E+08	2.4E+08
PV CFlow	45397384	23061144	83909383	-1626310	46572574
PV SevTax	3503275	298607.1	4131640	2977251	3473035
PV StateTx	3519410	1539619	7057967	1106033	3312108
PV CorpTx	13854326	6605171	29384451	3726101	12871638
PV Royal	6040129	514839.8	7123517	5133192	5987991

	Average	STD	MAX	MIN	Median
PV Rev	2.4E+08	20763487	2.7E+08	2.0E+08	2.4E+08
PV CFlow	42121540	26513032	82106314	-3.3E+07	37803007
PV SevTax	3415032	302456.1	3933234	2870195	3422798
PV StateTx	3408919	1721271	6947400	458758.5	2884802
PV CorpTx	13408955	7395942	28889808	1479926	11066021
PV Royal	5887986	521476	6[illegible]438	4948612	5901376

	Average	STD	MAX	MIN	Median
PV Rev	2.4E+08	15080906	2.8E+08	2.1E+08	2.4E+08
PV CFlow	45079542	24272134	89195515	-2.3E+07	43811417
PV SevTax	3471026	219603.9	4051894	2970406	3471479
PV StateTx	3577346	1720412	7780342	734060.4	3105896
PV CorpTx	14100757	7436640	32616127	2397365	11847576
PV Royal	5984527	378627.4	[illegible]024	5121390	5985309

	Average	STD	MAX	MIN	Median
PV Rev	2.4E+08	17790461	2.8E+08	2.0E+08	2.4E+08
PV CFlow	49278071	21673637	92275776	-1.7E+07	50691353
PV SevTax	3497744	258916.1	4110863	2944351	3517552
PV StateTx	3732680	1505437	[illegible]42733	1001144	3492425
PV CorpTx	14714770	6507943	[illegible]506	3523054	13473243
PV Royal	6030594	446407.1	7087695	5076467	6064745

	Average	STD	MAX	MIN	Median
PV Rev	2.4E+08	18386145	2.8E+08	2.0E+08	2.4E+08
PV CFlow	45562180	27761896	89351307	-4.1E+07	50774588
PV SevTax	3451337	267566.3	3994058	2896114	3451527
PV StateTx	3729681	1767536	7714116	250980.3	3716150
PV CorpTx	14799298	7584618	32319853	957564.7	14558900
PV Royal	5950581	461321.2	6886307	4993300	5950908

Lang Combined Data, Case 1, Scenario 3
discount rate = 10%

	Average	STD	MAX	MIN	Median
PV Rev	2.0E+08	17198373	2.3E+08	1.5E+08	2.0E+08
PV CFlow	-8620013	21854989	48709727	-6.7E+07	-6968348
PV SevTax	2883906	250519.8	3406150	2202496	2873489
PV StateTx	2022196	1376265	7172616	0	1944395
PV CorpTx	7844261	5809408	30304193	0	7358007
PV Royal	4972252	431930.6	5872672	3797406	4954291

	Average	STD	MAX	MIN	Median
PV Rev	1.9E+08	16577117	2.2E+08	1.5E+08	1.9E+08
PV CFlow	-1.9E+07	23300165	23427306	-9.5E+07	-1.6E+07
PV SevTax	2720171	241728.1	3203388	2185153	2774871
PV StateTx	1472908	1106543	4647917	0	1268947
PV CorpTx	5580402	4506903	19299017	0	4494788
PV Royal	4689950	416772.5	5523083	3767506	4784261

	Average	STD	MAX	MIN	Median
PV Rev	2.0E+08	19109614	2.4E+08	1.5E+08	2.0E+08
PV CFlow	-1.7E+07	22941310	35699395	-6.8E+07	-1.7E+07
PV SevTax	2877773	278492	3424016	2226219	2889689
PV StateTx	1560927	1273363	5637359	0	1310465
PV CorpTx	5987236	5280886	23435939	0	4906165
PV Royal	4961678	480158.6	5903476	3838309	4982223

	Average	STD	MAX	MIN	Median
PV Rev	2.0E+08	16487434	2.4E+08	1.7E+08	2.0E+08
PV CFlow	-1.2E+07	20479281	36941425	-5.2E+07	-1.2E+07
PV SevTax	2905321	240294.4	3445462	2430311	2919416
PV StateTx	1778911	1271922	5942191	88077.07	1493029
PV CorpTx	6847605	5307790	24799664	256759.1	5601590
PV Royal	5009174	414300.7	5940451	4190192	5033476

	Average	STD	MAX	MIN	Median
PV Rev	1.9E+08	17443593	2.3E+08	1.5E+08	2.0E+08
PV CFlow	-1.2E+07	21256487	22311370	-8.1E+07	-1.1E+07
PV SevTax	2788324	253990.6	3306260	2224147	2843528
PV StateTx	1781800	1122001	4505923	1699.657	1515920
PV CorpTx	6769643	4593645	18374254	1203924	5486229
PV Royal	4807456	437914.9	5700448	3834736	4902635

Lang Combined Data, Case 2, Scenario 1
discount rate = 10%

	Average	STD	MAX	MIN	Median
PV Rev	2.7E+08	21357705	3.1E+08	2.3E+08	2.7E+08
PV CFlow	62782090	24972141	1.0E+08	-4.3E+07	[illegible]4311619
PV SevTax	3897405	310900.4	4464125	3308393	[illegible]919150
PV StateTx	4749135	1704033	8361941	1094524	4634022
PV CorpTx	18998829	7419484	34982399	3882396	18304865
PV Royal	67[illegible]664	536035.1	7696767	5704126	6757155

	Average	STD	MAX	MIN	Median
PV Rev	2.7E+08	20783758	3.1E+08	2.2E+08	2.6E+08
PV CFlow	65167247	17995244	99043900	10384511	64102202
PV SevTax	3870094	302614.1	4495024	3199209	38[illegible]2460
PV StateTx	4754569	1470115	7956664	1702718	461[illegible]813
PV CorpTx	18960862	6448030	33169316	6405277	18329830
PV Royal	6672577	521748.4	7750041	5515877	6607689

	Average	STD	MAX	MIN	Median
PV Rev	2.7E+08	17160881	3.0E+08	2.2E+08	2.7E+08
PV CFlow	57561955	22812970	92821439	-6279379	56989754
PV SevTax	3843789	249698.6	4337166	3226404	3869562
PV StateTx	4321378	1660110	7515637	1631993	3964349
PV CorpTx	17126038	7208652	31[illegible]6303	5962837	15602180
PV Royal	6627223	430514.8	7477873	5562766	6671659

	Average	STD	MAX	MIN	Median
PV Rev	2.7E+08	14155380	3.0E+08	2.4E+08	2.7E+08
PV CFlow	59351303	26840[illegible]	99994231	-3.7E+07	61346410
PV SevTax	3930233	206358.4	4417822	3530466	3891027
PV StateTx	4527116	1726525	8070253	1194119	4250578
PV CorpTx	18036206	7483274	33677481	4477575	16614740
PV Royal	6776264	355790.3	7616935	6087011	6708667

	Average	STD	MAX	MIN	Median
PV Rev	2.7E+08	18144048	3.0E+08	2.3E+08	2.7E+08
PV CFlow	61725119	24669680	1.1E+08	3319837	66719714
PV SevTax	3910159	264054.6	4417106	3403830	3896339
PV StateTx	4662479	1850101	9780293	1561349	4661322
PV CorpTx	18618274	8078129	41327659	5333544	18426997
PV Royal	6741653	455266.5	7615700	5868673	6717826

Lang Combined Data, Case 2, Scenario 2
discount rate = 10%

	Average	STD	MAX	MIN	Median
PV Rev	2.4E+08	18772952	2.7E+08	1.9E+08	2.4E+08
PV CFlow	50717531	19419356	91307685	4959882	51319607
PV SevTax	3497698	273126.1	3920522	2741584	3494672
PV StateTx	3838787	1455397	7742275	1483602	3754681
PV CorpTx	15196270	6309193	32445827	5453255	14719303
PV Royal	6030514	470907	6759521	4726869	6025297

	Average	STD	MAX	MIN	Median
PV Rev	2.4E+08	17979264	2.7E+08	1.9E+08	2.4E+08
PV CFlow	48169417	19461468	89755228	-1.1E+07	48754453
PV SevTax	3461300	261875.4	3861491	2697068	3471281
PV StateTx	3659623	1278689	7619288	1147548	3441234
PV CorpTx	14367052	5563481	31895624	3611707	13446322
PV Royal	5967759	451509.2	6657744	4650117	5984967

	Average	STD	MAX	MIN	Median
PV Rev	2.4E+08	20834899	2.8E+08	1.8E+08	2.4E+08
PV CFlow	50680564	25630391	1.0E+08	-1.1E+07	55784577
PV SevTax	3489865	303287.7	4114733	2660471	3502768
PV StateTx	3970630	1891163	9078320	765566	4026105
PV CorpTx	15820367	8160719	38422870	2679071	15820857
PV Royal	6017008	522909.8	7094368	4587019	6039254

	Average	STD	MAX	MIN	Median
PV Rev	2.4E+08	19102712	2.8E+08	2.0E+08	2.3E+08
PV CFlow	48646280	20547036	80414615	-8779615	51415304
PV SevTax	3485114	278304.4	4055305	2963375	3393521
PV StateTx	3713381	1375108	6750447	1124554	3666571
PV CorpTx	14629865	5923390	28041198	3987788	14239269
PV Royal	6008818	479835.1	6991906	5109268	5850899

	Average	STD	MAX	MIN	Median
PV Rev	2.3E+08	17848318	2.8E+08	1.9E+08	2.4E+08
PV CFlow	46537625	21727451	87469417	-6840405	49119255
PV SevTax	3400906	259894.9	4066083	2810739	3420995
PV StateTx	3619551	1598541	7304771	1063680	3438776
PV CorpTx	14296314	6887418	30488572	3708287	13361698
PV Royal	5863631	448094.6	7010489	4846102	5898268

Lang Combined Data, Case 2, Scenario 3
discount rate = 10%

	Average	STD	MAX	MIN	Median
PV Rev	1.9E+08	19647594	2.4E+08	1.5E+08	1.9E+08
PV CFlow	-1.9E+07	22114538	17329202	-9.4E+07	-1.8E+07
PV SevTax	2776100	286156.3	3453796	2110861	2750149
PV StateTx	1412940	1062265	4228795	0	1159368
PV CorpTx	5350180	4310819	17309664	0	4065698
PV Royal	4786379	493372.9	5954821	3639416	4741635

	Average	STD	MAX	MIN	Median
PV Rev	2.0E+08	20140741	2.5E+08	1.6E+08	2.0E+08
PV CFlow	-1415283	18424558	45747260	-4.5E+07	-1088956
PV SevTax	2971346	293374.9	3667187	2328768	2956565
PV StateTx	2363270	1331486	6563286	350723.4	2126971
PV CorpTx	9212849	5686919	27578245	1144219	8202406
PV Royal	5123011	505818.8	6322735	4015118	5097526

	Average	STD	MAX	MIN	Median
PV Rev	2.0E+08	19831591	2.4E+08	1.6E+08	2.0E+08
PV CFlow	-7753923	20681428	31790122	-7.8E+07	-6969811
PV SevTax	2868329	289022.8	3542192	2296468	2891209
PV StateTx	2028717	1214791	5162346	0	1828721
PV CorpTx	7848034	5075918	21310881	0	6843528
PV Royal	4945395	498315.1	6107228	3959428	4984843

	Average	STD	MAX	MIN	Median
PV Rev	2.0E+08	17735028	2.3E+08	1.4E+08	2.0E+08
PV CFlow	-1.7E+07	21232196	26336046	-7.4E+07	-1.8E+07
PV SevTax	2836345	258289	3371388	2072993	2835171
PV StateTx	1469032	1090399	4506265	31574.67	1228415
PV CorpTx	5520656	4442419	18375781	97534.78	4215679
PV Royal	4890250	445325.9	5812739	3574127	4888225

	Average	STD	MAX	MIN	Median
PV Rev	1.9E+08	18109910	2.3E+08	1.5E+08	1.9E+08
PV CFlow	-2.1E+07	22190215	14613848	-8.1E+07	-1.5E+07
PV SevTax	2746439	263695.6	3337944	2133029	2756662
PV StateTx	1320518	1030406	3383382	0	1399578
PV CorpTx	5027212	4078816	13701684	0	5150613
PV Royal	4735240	454647.5	5755076	3677636	4752865

Lang Combined Data, Case 3, Scenario 1
discount rate = 10%

	Average	STD	MAX	MIN	Median
PV Rev	2.7E+08	20456185	3.2E+08	2.3E+08	2.7E+08
PV CFlow	86396983	15364193	1.2E+08	43417312	87066192
PV SevTax	3883542	297790.6	4618492	3300954	3860607
PV StateTx	7122620	1529458	10354826	3048200	7089432
PV CorpTx	29482383	6777848	43897936	11637490	29289597
PV Royal	6695763	513432.1	7962917	5691299	6656218

	Average	STD	MAX	MIN	Median
PV Rev	2.7E+08	19454090	3.0E+08	2.2E+08	2.7E+08
PV CFlow	91034878	18143996	1.2E+08	18798673	91522298
PV SevTax	3906000	283356.1	4388576	3193140	3947016
PV StateTx	7658984	1790163	11035709	2374730	7580519
PV CorpTx	31872221	7936861	46943994	9148178	31501419
PV Royal	6734483	488545	7566511	5505414	6805199

	Average	STD	MAX	MIN	Median
PV Rev	2.7E+08	23976586	3.3E+08	2.1E+08	2.7E+08
PV CFlow	87937103	21500480	1.3E+08	34920400	88504742
PV SevTax	3907122	348874	4805179	3082143	3947340
PV StateTx	7317549	2164834	11784551	2799864	7266047
PV CorpTx	30364752	9600698	50294075	10697451	30149642
PV Royal	6736417	601506.9	8284792	5314039	6805758

	Average	STD	MAX	MIN	Median
PV Rev	2.7E+08	22461807	3.1E+08	2.1E+08	2.6E+08
PV CFlow	88546154	15044508	1.3E+08	50893082	86232562
PV SevTax	3850007	326653.3	4497139	3088715	3828481
PV StateTx	7390936	1628643	12040735	3585877	7087441
PV CorpTx	30664569	7267163	51440163	13664724	29281919
PV Royal	6637942	563195.4	7753689	5325371	6600828

	Average	STD	MAX	MIN	Median
PV Rev	2.6E+08	19606341	3.1E+08	2.2E+08	2.7E+08
PV CFlow	82293984	18729198	1.2E+08	41361549	81123557
PV SevTax	3826713	285628	4477755	3241118	3848254
PV StateTx	6709000	2008204	11687808	2698747	6364319
PV CorpTx	27644061	8925798	49861279	9951543	26073797
PV Royal	6597781	492462	7720268	5588135	6634921

Lang Combined Data, Case 3, Scenario 2
discount rate = 10%

	Average	STD	MAX	MIN	Median
PV Rev	2.4E+08	20560468	2.8E+08	1.9E+08	2.4E+08
PV CFlow	71342685	18403293	1.1E+08	[illegible]	71435448
PV SevTax	3433817	299017.4	4128924	2738296	3474558
PV StateTx	5899047	1892795	10046494	2319965	5805957
PV CorpTx	24239997	8418074	42754176	8612769	23783352
PV Royal	5920374	515547.2	7118835	4721200	5990617

	Average	STD	MAX	MIN	Median
PV Rev	2.4E+08	16702552	2.8E+08	2.0E+08	2.4E+08
PV CFlow	76418540	11615557	1.0E+08	40532799	76914678
PV SevTax	3508736	243262.3	4039882	2838354	3486338
PV StateTx	6372702	1209080	9350541	3036957	6469322
PV CorpTx	26338969	5381111	39640702	11655680	26751040
PV Royal	6049545	419417.7	6965314	4893714	6010928

	Average	STD	MAX	MIN	Median
PV Rev	2.4E+08	19528429	2.9E+08	1.9E+08	2.4E+08
PV CFlow	71396302	15783658	1.0E+08	35754094	75209911
PV SevTax	3452212	284363.7	4253801	2710451	3427034
PV StateTx	5874650	1579796	8788147	3055660	6092771
PV CorpTx	24134606	7007375	37124730	11658791	25072365
PV Royal	5952089	490282.3	7334140	4673192	5908679

	Average	STD	MAX	MIN	Median
PV Rev	2.4E+08	20213937	2.8E+08	2.0E+08	2.4E+08
PV CFlow	71723796	18074308	1.0E+08	36954666	74454372
PV SevTax	3448420	294368.2	4116442	2896636	3408574
PV StateTx	6023291	1792710	9211609	3036438	6085273
PV CorpTx	24827833	7934357	39019165	11699006	25032926
PV Royal	5945552	507531.4	7097314	4994201	5876851

	Average	STD	MAX	MIN	Median
PV Rev	2.4E+08	20321485	2.8E+08	1.9E+08	2.5E+08
PV CFlow	77333806	15042845	1.0E+08	40891815	79006076
PV SevTax	3518181	296140.1	4065754	[illegible]	3571819
PV StateTx	6524318	1496469	9194779	[illegible]	6474665
PV CorpTx	27027722	6648961	38943870	13601751	26793577
PV Royal	6065830	510586.3	7009921	4807111	6158309

Lang Combined Data, Case 3, Scenario 3
discount rate = 10%

	Average	STD	MAX	MIN	Median
PV Rev	1.9E+08	15143577	2.3E+08	1.6E+08	1.9E+08
PV CFlow	8463454	17006913	44191044	-3.8E+07	7220287
PV SevTax	2759598	220811.9	3331010	2280708	2776783
PV State Tx	3281012	1434617	6727680	328056	3154392
PV CorpTx	13113045	6231104	28313692	1116547	12648107
PV Royal	4757927	380710.2	5743121	3932254	4787556

	Average	STD	MAX	MIN	Median
PV Rev	2.0E+08	17708131	2.5E+08	1.6E+08	2.0E+08
PV CFlow	12357936	16536625	40525331	-2.9E+07	15806983
PV SevTax	2875854	257976	3661929	2296043	2871820
PV State Tx	3555302	1428891	6339704	1039118	3758596
PV CorpTx	14277794	6281074	26578008	3578438	15166337
PV Royal	4958370	444786.2	6313671	3958696	4951414

	Average	STD	MAX	MIN	Median
PV Rev	1.9E+08	20327267	2.6E+08	1.4E+08	1.9E+08
PV CFlow	9257450	17292945	42803735	-2.9E+07	12561165
PV SevTax	2823076	295991.2	3771707	2078695	2794005
PV State Tx	3283521	1426189	6399602	524611.6	3442300
PV CorpTx	13140745	6166355	26845974	1970415	13766770
PV Royal	4867373	510329.6	6502943	3583957	4817250

	Average	STD	MAX	MIN	Median
PV Rev	2.0E+08	15352592	2.3E+08	1.6E+08	2.0E+08
PV CFlow	13713806	13412253	49451400	-2.0E+07	15149460
PV SevTax	2833781	223509.2	3271931	2252790	2852012
PV State Tx	3628600	1210909	7209570	949903.1	3698578
PV CorpTx	14555075	5322027	30469516	2920733	14766827
PV Royal	4885829	385360.6	5641261	3884121	4917262

	Average	STD	MAX	MIN	Median
PV Rev	1.9E+08	18388845	2.4E+08	1.5E+08	1.9E+08
PV CFlow	12669033	15041936	48638776	-2.5E+07	15939538
PV SevTax	2821308	267994.1	3452858	2224084	2828129
PV State Tx	3502960	1317920	7100634	854679.5	3789357
PV CorpTx	14031228	5755039	29982171	2986532	15303799
PV Royal	4864324	462058.7	5953203	3834628	4876084

Sylvite Combined Area Data. Scenario 1
discount rate = 15%

	Average	STD	MAX	MIN	Median
PV Rev	2.3E+08	14829423	2.5E+08	1.9E+08	2.3E+08
PV CFlow	50488239	16729220	75686613	-3409033	54650646
PV SevTax	3276216	216933.3	3699220	2771371	3276816
PV StateTx	3540591	1181808	5987109	1086861	3612148
PV CorpTx	14296144	5135015	25123908	4115306	14539241
PV Royal	5648648	374023	6377966	4778225	5649683

	Average	STD	MAX	MIN	Median
PV Rev	2.2E+08	10211503	2.5E+08	2.0E+08	2.3E+08
PV CFlow	51119561	15206333	72785952	10169561	53002702
PV SevTax	3255499	149202.7	3574570	2928990	3263038
PV StateTx	3631255	1148468	5800500	1388127	3546942
PV CorpTx	14688230	5026673	24289078	5110668	14330211
PV Royal	5612930	257245.9	6163051	5049983	5625928

	Average	STD	MAX	MIN	Median
PV Rev	2.2E+08	14420630	2.5E+08	1.8E+08	2.3E+08
PV CFlow	50582302	17989418	87298880	-1.7E+07	53380115
PV SevTax	3225571	210761.1	3641357	2659793	3281824
PV StateTx	3631352	1320435	7282937	977059.7	3540195
PV CorpTx	14691861	5793911	30921031	3566241	14177185
PV Royal	5561330	363381.2	6278202	4585850	5658318

	Average	STD	MAX	MIN	Median
PV Rev	2.2E+08	12168984	2.5E+08	2.0E+08	2.3E+08
PV CFlow	52151850	14140999	75651599	4349944	53023782
PV SevTax	3259052	177736.4	3672396	2884263	3287194
PV StateTx	3620368	1063403	5853258	956409.9	3488981
PV CorpTx	14616399	4667353	24525098	3506541	14016572
PV Royal	5619056	306442	6331717	4972867	5667576

	Average	STD	MAX	MIN	Median
PV Rev	2.3E+08	13489764	2.5E+08	1.9E+08	2.3E+08
PV CFlow	50525572	23637010	88918701	-1.1E+07	56036762
PV SevTax	3267833	197079	3644181	2792588	3278012
PV StateTx	3839481	1739537	7537756	980156.8	3905743
PV CorpTx	15663969	7617623	32061015	3662057	15848052
PV Royal	5634195	339791.4	6283071	4814807	5651745

Sylvite Combined Area Data, Scenario 2
discount rate = 15%

	Average	STD	MAX	MIN	Median
PV Rev	1.9E+08	14008865	2.3E+08	1.5E+08	2.0E+08
PV CFlow	40548761	15632163	73757916	3085701	43383249
PV SevTax	2830978	205194.4	3334397	2234790	2850181
PV StateTx	3025508	1213620	6498874	1173190	3044724
PV CorpTx	12184959	5349789	27642076	4250110	12202366
PV Royal	4880997	353783.4	5748960	3853086	4914105

	Average	STD	MAX	MIN	Median
PV Rev	1.9E+08	14141671	2.3E+08	1.5E+08	1.9E+08
PV CFlow	42610487	13198432	67293465	10360132	42936274
PV SevTax	2824548	206701.6	3290507	2213281	2817514
PV StateTx	3101245	1046665	5530537	1395489	3000831
PV CorpTx	12511661	4607148	23310041	5154600	12018934
PV Royal	4869910	356382.1	5673288	3816002	4857783

	Average	STD	MAX	MIN	Median
PV Rev	2.0E+08	16815009	2.3E+08	1.6E+08	2.0E+08
PV CFlow	42229958	14144907	70954224	9873207	42981857
PV SevTax	2832453	246094.1	3403170	2338001	2858467
PV StateTx	3104099	1160669	6202500	1141070	3050730
PV CorpTx	12537128	5117578	26316191	4200221	12262234
PV Royal	4883539	424300.1	5867535	4031037	4928392

	Average	STD	MAX	MIN	Median
PV Rev	1.9E+08	13757004	2.2E+08	1.7E+08	2.0E+08
PV CFlow	39297944	14865895	62759479	2068445	43268902
PV SevTax	2827819	201160.1	3270174	2420264	2851907
PV StateTx	2869468	1016097	4893386	902782.2	2913628
PV CorpTx	11494799	4442106	20459627	3372820	11602816
PV Royal	4875551	346827.8	5638231	4172869	4917082

	Average	STD	MAX	MIN	Median
PV Rev	1.9E+08	11935899	2.3E+08	1.6E+08	1.9E+08
PV CFlow	40440481	13837862	70308646	-2076236	42839718
PV SevTax	2824362	174855.7	3356882	2269888	2818148
PV StateTx	2903502	1054252	5856624	853372.6	2902709
PV CorpTx	11632421	4630620	24768853	3019320	11553970
PV Royal	4869589	301475.4	5787727	3913600	4858875

Sylvite Combined Area Data, Scenario 3
discount rate = 15%

	Average	STD	MAX	MIN	Median
PV Rev	1.4E+08	10951482	1.7E+08	1.2E+08	1.4E+08
PV CFlow	-3.3E+07	15178357	-4900736	-6.4E+07	-3.1E+07
PV SevTax	2051889	160357.7	2423101	1691949	2051088
PV StateTx	1015911	763287.4	2715375	2343.463	835264.4
PV CorpTx	3903276	3124299	11083622	16599.53	2986347
PV Royal	3537740	276478.8	4177761	2917154	3536358

	Average	STD	MAX	MIN	Median
PV Rev	1.4E+08	12745452	1.7E+08	1.2E+08	1[illegible]+08
PV CFlow	-3.1E+07	17831013	-5784452	-8.7E+07	-[illegible]+07
PV SevTax	2084353	186683	2547475	1714342	[illegible]263
PV StateTx	1115389	734891	2683446	0	1027615
PV CorpTx	4308881	3015567	10940785	0	3828470
PV Royal	3593713	321867.3	4392198	2955762	3553902

	Average	STD	MAX	MIN	Median
PV Rev	1.4E+08	11731356	1.7E+08	1.1E+08	1.4E+08
PV CFlow	-3.1E+07	13398634	-7802555	-6.3E+07	-3.0E+07
PV SevTax	2091116	171959.3	2524032	1655600	2101968
PV StateTx	1036560	661870.4	2562349	6189.999	923248.9
PV CorpTx	3970531	2711219	10504604	19792.72	3287297
PV Royal	3605372	296481.6	4351780	2854483	3624083

	Average	STD	MAX	MIN	Median
PV Rev	1.4E+08	10868953	[illegible]7E+08	1.2E+08	1.4E+08
PV CFlow	-2.8E+07	14004308	3630845	-6.5E+07	-2.7E+07
PV SevTax	2111245	159217.8	2505492	1767137	2083876
PV StateTx	1211195	801902.5	3756883	385.5683	1085394
PV CorpTx	4696745	3357434	15743001	2731.108	4075184
PV Royal	3640077	274513.5	[illegible]19814	3046789	3592889

	Average	STD	MAX	MIN	Median
PV Rev	1.5E+08	13413536	1.7E+08	1.2E+08	1.5E+08
PV CFlow	-3.0E+07	16850610	456796.2	-7.2E+07	-2.9E+07
PV SevTax	2131667	196543.4	2548110	1693285	2146021
PV StateTx	1179631	849737.4	3180649	0	[illegible]01193
PV CorpTx	4573406	3537438	13165111	0	[illegible]95119
PV Royal	3675288	338868	4393293	2919457	3700036

Sylvite Combined Area Data, Scenario 1
discount rate = 10%

	Average	STD	MAX	MIN	Median
PV Rev	3.3E+08	23218681	3.8E+08	2.9E+08	3.3E+08
PV CFlow	73549311	25350297	1.2E+08	3129370	76798448
PV SevTax	4809701	338297.7	5570422	4124893	4784237
PV StateTx	5385916	1865336	9246281	1923251	5158104
PV CorpTx	21876185	8167199	38938658	7057893	20821517
PV Royal	8292588	583272	9604176	7111884	8248685

	Average	STD	MAX	MIN	Median
PV Rev	3.3E+08	25454341	3.7E+08	2.8E+08	3.3E+08
PV CFlow	68152046	27334141	1.2E+08	14370893	70760973
PV SevTax	4733020	370353	5408581	4002680	4727101
PV StateTx	4929724	2017685	10136071	1732931	4703863
PV CorpTx	19887280	8810927	42919295	6464950	18797981
PV Royal	8160379	638539.6	9325140	6901173	8150174

	Average	STD	MAX	MIN	Median
PV Rev	3.3E+08	25101991	3.8E+08	2.6E+08	3.2E+08
PV CFlow	79369515	25740236	1.4E+08	7176092	77890984
PV SevTax	4781849	365551.8	5529620	3743590	4704960
PV StateTx	5860966	2152607	11704910	1791684	5751348
PV CorpTx	23959296	9467736	49937789	6867226	23350517
PV Royal	8244567	630261.8	9533827	6454466	8112000

	Average	STD	MAX	MIN	Median
PV Rev	3.3E+08	23283805	3.7E+08	2.5E+08	3.3E+08
PV CFlow	73249018	27708624	1.4E+08	-8091543	75766094
PV SevTax	4734248	339200.3	5348921	3572841	4735615
PV StateTx	5351765	2022501	11729599	1967450	5055850
PV CorpTx	21712543	8861348	50048237	7310855	20419594
PV Royal	8162497	584828.2	9222278	6160070	8164854

	Average	STD	MAX	MIN	Median
PV Rev	3.3E+08	29707719	3.9E+08	2.7E+08	3.3E+08
PV CFlow	69436998	37324723	1.2E+08	-5.7E+07	73028409
PV SevTax	4745982	432465.1	5647846	3912843	4802635
PV StateTx	5318567	2360158	9984884	1388186	5282509
PV CorpTx	21628906	10281472	42242934	5116554	21340249
PV Royal	8182728	745629.5	9737666	6746281	8280405

Sylvite Combined Area Data, Scenario 2
discount rate = 10%

	Average	STD	MAX	MIN	Median
PV Rev	2.9E+08	26415908	3.7E+08	2.3E+08	3.0E+08
PV CFlow	47615331	37103047	1.2E+08	-7.5E+07	54196797
PV SevTax	4271468	384760.9	5317287	3313556	4307180
PV StateTx	3838362	2032630	9338753	675316.1	3385308
PV CorpTx	15302874	8808193	39587967	2392553	13073499
PV Royal	7364600	663380.9	9167736	5713028	7426172

	Average	STD	MAX	MIN	Median
PV Rev	3.0E+08	24103653	3.5E+08	2.5E+08	3.0E+08
PV CFlow	64794544	27546667	1.3E+08	-1.5E+07	66469912
PV SevTax	4298699	350911.1	5014882	3556492	4338140
PV StateTx	4879453	2056338	11347054	1029240	4538588
PV CorpTx	19832237	9016562	48572472	3567135	18222486
PV Royal	7411549	605019.1	8646349	6131882	7479552

	Average	STD	MAX	MIN	Median
PV Rev	3.0E+08	19591197	3.5E+08	2.6E+08	3.0E+08
PV CFlow	60010094	27337379	1.1E+08	-5456458	61930054
PV SevTax	4372100	285140.2	5014179	3775202	4371505
PV StateTx	4453129	1896659	8914260	1351552	4221062
PV CorpTx	17935794	8286035	37688921	4668805	16746295
PV Royal	7538103	491621	8645136	6508969	7537077

	Average	STD	MAX	MIN	Median
PV Rev	2.9E+08	25116231	3.5E+08	2.4E+08	2.9E+08
PV CFlow	60566269	26107621	1.1E+08	-8714262	64060889
PV SevTax	4252419	365548.6	5116634	3404591	4219802
PV StateTx	4506970	1954223	8846779	1000942	4316905
PV CorpTx	18183006	8547441	37387030	3415640	17264899
PV Royal	7331758	630256.2	8821783	5869985	7275521

	Average	STD	MAX	MIN	Median
PV Rev	3.0E+08	25212288	3.5E+08	2.4E+08	3.0E+08
PV CFlow	65965843	25171872	1.1E+08	8829729	69430809
PV SevTax	4311566	367164.5	5079772	3542305	4336442
PV StateTx	4926192	1936991	9425423	1213434	5015972
PV CorpTx	20024900	8484979	39975700	4171608	20443538
PV Royal	7433734	633042.2	8758227	6107422	7476623

Sylvite Combined Area Data, Scenario 3
discount rate = 10%

	Average	STD	MAX	MIN	Median
PV Rev	2.4E+08	22257852	3.1E+08	1.9E+08	2.4E+08
PV CFlow	-1.4E+07	27875074	47296058	-1.1E+08	-1.4E+07
PV SevTax	3478269	324291	4500168	2783227	3431394
PV StateTx	2045235	1586750	7200784	438.3311	1723556
PV CorpTx	8044261	6700311	30430211	3104.846	6380114
PV Royal	5997015	559122.4	7758910	4798668	5916196

	Average	STD	MAX	MIN	Median
PV Rev	2.4E+08	20013035	2.8E+08	2.1E+08	2.5E+08
PV CFlow	-1.4E+07	27654817	28310069	-1.2E+08	-7037515
PV SevTax	3548722	291416.4	4140429	3029888	3589002
PV StateTx	2025628	1272282	4819462	0	2050078
PV CorpTx	7880855	5281714	19776928	0	7644553
PV Royal	6118487	502442.1	7138670	5223946	6187935

	Average	STD	MAX	MIN	Median
PV Rev	2.4E+08	28750846	3.1E+08	2.0E+08	2.4E+08
PV CFlow	-9882397	29862003	57840677	-7.5E+07	-1.0E+07
PV SevTax	3547426	418782	4480647	2894185	3547608
PV StateTx	2313451	1746069	7672055	0	1953491
PV CorpTx	9138441	7426710	32538528	0	7311092
PV Royal	6116251	722038	7725253	4989974	6116566

	Average	STD	MAX	MIN	Median
PV Rev	2.4E+08	26057150	3.2E+08	2.0E+08	2.4E+08
PV CFlow	-1.4E+07	36439124	69048200	-1.2E+08	-1.6E+07
PV SevTax	3544158	379691.3	4695952	2878418	3495938
PV StateTx	2273229	1909808	8963633	0	1625239
PV CorpTx	8965549	8154478	38316639	0	6042141
PV Royal	6110617	654640.2	8096469	4962790	6027479

	Average	STD	MAX	MIN	Median
PV Rev	2.5E+08	28586203	3.3E+08	2.0E+08	2.5E+08
PV CFlow	-4159231	30488197	54663496	-6.8E+07	-8065989
PV SevTax	3625409	416439.3	4722360	2833639	3641885
PV StateTx	2778490	1961188	7163410	9000.751	2235908
PV CorpTx	11184775	8416766	30263012	338688.6	8584665
PV Royal	6250706	717998.8	8142000	4885584	6279113

Lang Additional Area Data, Case 1, Scenario 1
discount rate = 15%

	Average	STD	MAX	MIN	Median
PV Rev	1.8E+08	10255669	2.0E+08	1.6E+08	1.8E+08
PV CFlow	40724652	12125037	60955513	19302190	39951505
PV SevTax	2660604	149781.9	2958842	2289733	2679561
PV StateTx	2974596	994739.2	4888439	1481139	2795418
PV CorpTx	11757674	4369541	20212138	5392293	10947232
PV Royal	4587248	258244.6	5101452	3947815	4619933

	Average	STD	MAX	MIN	Median
PV Rev	1.8E+08	9811507	2.0E+08	1.6E+08	1.8E+08
PV CFlow	43573580	9642638	62035950	19606305	44994278
PV SevTax	2644112	143535.8	2899871	2250087	2663317
PV StateTx	3143017	774687.7	4967263	1340561	3202199
PV CorpTx	12476355	3373998	20561437	4774128	12767308
PV Royal	4558814	247475.6	4999777	3879461	4591925

	Average	STD	MAX	MIN	Median
PV Rev	1.8E+08	10238790	2.0E+08	1.6E+08	1.8E+08
PV CFlow	42655083	10993559	65243236	18818965	42260964
PV SevTax	2654673	149795	2936587	2275725	2660277
PV StateTx	3098478	935265.8	5318412	1601777	2917257
PV CorpTx	12288169	4112125	22132370	5896007	11422778
PV Royal	4577022	258267.3	5063081	3923663	4586684

	Average	STD	MAX	MIN	Median
PV Rev	1.8E+08	10238790	2.0E+08	1.6E+08	1.8E+08
PV CFlow	42655083	10993559	65243236	18818965	42260964
PV SevTax	2654673	149795	2936587	2275725	2660277
PV StateTx	3098478	935265.8	5318412	1601777	2917257
PV CorpTx	12288169	4112125	22132370	5896007	11422778
PV Royal	4577022	258267.3	5063081	3923663	4586684

	Average	STD	MAX	MIN	Median
PV Rev	1.8E+08	9493593	2.0E+08	1.6E+08	1.8E+08
PV CFlow	40383122	12474689	67650183	8970910	40636764
PV SevTax	2624891	138780.8	2943251	2244210	2622167
PV StateTx	2978195	1035147	5539782	1071000	2767157
PV CorpTx	11788280	4534749	23122706	4038063	10905651
PV Royal	4525674	239277.3	5074570	3869327	4520977

Lang Additional Area Data, Case 1, Scenario 2
discount rate = 15%

	Average	STD	MAX	MIN	Median
PV Rev	1.6E+08	9691709	1.8E+08	1.4E+08	1.6E+08
PV CFlow	31432209	13808204	58773646	4995460	31734841
PV SevTax	2298960	141828.7	2597662	1979371	2309150
PV StateTx	2454538	1123201	5196612	739702.7	2195705
PV CorpTx	9676255	4899013	21816164	2477711	8397606
PV Royal	3963725	244532.3	4478727	3412709	3981294

	Average	STD	MAX	MIN	Median
PV Rev	1.6E+08	10695940	1.8E+08	1.3E+08	1.5E+08
PV CFlow	26167380	13929178	54745329	-1.5E+07	26183621
PV SevTax	2250279	156634.2	2685818	1908418	2243034
PV StateTx	2120316	902070.3	4416586	673808.3	1879257
PV CorpTx	8223799	3913268	18326576	2389445	6987995
PV Royal	3879791	270059	4630720	3290376	3867300

	Average	STD	MAX	MIN	Median
PV Rev	1.6E+08	10914314	1.8E+08	1.3E+08	1.6E+08
PV CFlow	32155960	13438381	56498310	-6544228	34337997
PV SevTax	2292159	159386.9	2624019	1908133	2304557
PV StateTx	2496039	960045.8	4805164	592027.5	2539833
PV CorpTx	9841631	4169464	20064950	2092347	9964108
PV Royal	3951998	274804.9	4524171	3289884	3973374

	Average	STD	MAX	MIN	Median
PV Rev	1.6E+08	9423556	1.7E+08	1.3E+08	1.6E+08
PV CFlow	31316160	12542478	60397186	-1.2E+07	31648987
PV SevTax	2252020	137823	2537844	1944635	2254760
PV StateTx	2418820	927491.3	5352350	543522.2	2340134
PV CorpTx	9506202	4037007	22512888	1916824	9092249
PV Royal	3882793	237625.9	4375593	3352819	3887517

	Average	STD	MAX	MIN	Median
PV Rev	1.5E+08	9774700	1.9E+08	1.3E+08	1.5E+08
PV CFlow	28879716	11865724	60872594	-5538632	29941205
PV SevTax	2242364	142932.2	2692899	1836654	2242023
PV StateTx	2243000	886640.4	5200515	585377.4	2134551
PV CorpTx	8737905	3857686	21833627	2039132	8130216
PV Royal	3866145	246434.9	4642929	3166645	3865556

Lang Additional Area Data, Case 2, Scenario 1
discount rate = 15%

	Average	STD	MAX	MIN	Median
PV Rev	1.8E+08	8096694	2.0E+08	1.7E+08	1.8E+08
PV CFlow	45029795	12934989	73027572	11206382	48583963
PV SevTax	2671722	118406.8	2904704	2481595	2665694
PV State Tx	3300666	1118072	6285431	1396336	3365871
PV CorpTx	13183817	4912673	26458506	5218808	13397317
PV Royal	4606417	204149.6	5008110	4278613	4596024

	Average	STD	MAX	MIN	Median
PV Rev	1.9E+08	10637305	2.2E+08	1.6E+08	1.9E+08
PV CFlow	46374821	13326175	66897638	2326266	48551023
PV SevTax	2682841	155323.9	3125163	2340344	2683047
PV State Tx	3445962	1134942	5540799	1252353	3524661
PV CorpTx	13826769	4981059	23127255	4580690	14127946
PV Royal	4625588	267799.9	5388213	4035076	4625944

	Average	STD	MAX	MIN	Median
PV Rev	1.8E+08	7982805	2.1E+08	1.7E+08	1.8E+08
PV CFlow	42461277	13006227	72310772	9397102	42495759
PV SevTax	2657351	116485.2	2988854	2394162	2643679
PV State Tx	3095499	1115753	6084250	1067541	2945321
PV CorpTx	12291932	4891891	25558485	3811868	11576611
PV Royal	4581640	200836.5	5153197	4127866	4558067

	Average	STD	MAX	MIN	Median
PV Rev	1.8E+08	8735008	2.0E+08	1.6E+08	1.8E+08
PV CFlow	39387532	14396696	61202520	-365139	41302359
PV SevTax	2605170	128031.9	2857561	2362148	2613999
PV State Tx	2943993	1013879	5181847	973746.4	2974963
PV CorpTx	11661919	4368711	21521421	3582118	11670799
PV Royal	4491672	220744.6	4926830	4072669	4506895

	Average	STD	MAX	MIN	Median
PV Rev	1.8E+08	8735008	2.0E+08	1.6E+08	1.8E+08
PV CFlow	39387532	14396696	61202520	-365139	41302359
PV SevTax	2605170	128031.9	2857561	2362148	2613999
PV State Tx	2943993	1013879	5181847	973746.4	2974963
PV CorpTx	11661919	4368711	21521421	3582118	11670799
PV Royal	4491672	220744.6	4926830	4072669	4506895

Lang Additional Area Data, Case 2, Scenario 2
discount rate = 15%

	Average	STD	MAX	MIN	Median
PV Rev	1.6E+08	9943895	1.7E+08	1.4E+08	1.6E+08
PV CFlow	31101790	11381854	51591678	-1458495	31194951
PV SevTax	2279092	145557.8	2515101	1969304	2320245
PV StateTx	2385252	857109.9	4411010	743791.3	2323153
PV CorpTx	9357581	3715752	18301630	2471734	9007257
PV Royal	3929469	250961.8	4336382	3395352	4000422

	Average	STD	MAX	MIN	Median
PV Rev	1.6E+08	11001082	1.8E+08	1.3E+08	1.6E+08
PV CFlow	32818203	13678525	55285617	1285222	35284036
PV SevTax	2280416	160984.1	2622000	1916720	2277839
PV StateTx	2575580	1039941	4703046	853338.9	2728252
PV CorpTx	10211374	4503404	19608107	2966842	10813199
PV Royal	3931752	277558.8	4520690	3304690	3927309

	Average	STD	MAX	MIN	Median
PV Rev	1.6E+08	10994772	1.8E+08	1.3E+08	1.6E+08
PV CFlow	36564613	9453461	59379053	12488731	37744740
PV SevTax	2290722	160769.2	2647690	1887028	2277141
PV StateTx	2802225	804298.6	5140588	1108871	2860562
PV CorpTx	11164036	3537608	21565533	3882662	11375701
PV Royal	3949522	271188.2	4564983	3253497	3926105

	Average	STD	MAX	MIN	Median
PV Rev	1.6E+08	11555417	1.8E+08	1.3E+08	1.5E+08
PV CFlow	34866567	13051369	58192344	-1.0E+07	35772683
PV SevTax	2255440	168839.4	2622079	1902458	2230645
PV StateTx	2759331	946775.9	5157053	407247.6	2591439
PV CorpTx	11019562	4086316	21639189	1443492	10240761
PV Royal	3888690	291102.4	4520827	3280100	3845939

	Average	STD	MAX	MIN	Median
PV Rev	1.6E+08	9699651	1.8E+08	1.4E+08	1.6E+08
PV CFlow	36738941	10997524	59827068	7361263	35763877
PV SevTax	2316142	141880.1	2638385	2022124	2303033
PV StateTx	2854323	981377.2	5259876	1095906	2590911
PV CorpTx	11400058	4326777	22099190	4123661	10159081
PV Royal	3993348	244620.8	4548940	3486421	3970747

Lang Additional Area Data, Case 3, Scenario 1
discount rate = 15%

	Average	STD	MAX	MIN	Median
PV Rev	1.8E+08	9235002	2.0E+08	1.6E+08	1.8E+08
PV CFlow	54571785	11776102	82730826	[illegible]	54555624
PV SevTax	2646848	135050.3	2907964	2300050	2623095
PV StateTx	4301934	1259250	7591119	1922860	4259517
PV CorpTx	17602437	5610712	32299743	[illegible]	17395204
PV Royal	4563531	232845.3	5013730	3965604	4522577

	Average	STD	MAX	MIN	Median
PV Rev	1.8E+08	9253364	2.0E+08	[illegible]	1.8E+08
PV CFlow	51518806	9979904	72377110	[illegible]	49759456
PV SevTax	2626911	135355.4	2925839	2340413	2620865
PV StateTx	3985027	975638	6388106	2106522	3720687
PV CorpTx	16203681	4324850	26917843	8250630	15009591
PV Royal	4529157	233371.3	5044550	4035195	4518733

	Average	STD	MAX	MIN	Median
PV Rev	1.8E+08	10228608	2.0E+08	1.6E+08	1.8E+08
PV CFlow	53129576	10564191	72820204	22972527	54794718
PV SevTax	2636531	149648.6	2955810	2258893	2659547
PV StateTx	4119295	1067760	6302885	[illegible]	4180377
PV CorpTx	16795421	4731255	26536589	[illegible]	17041683
PV Royal	4545743	258014.9	5096224	[illegible]	4585425

	Average	STD	MAX	MIN	Median
PV Rev	1.8E+08	11754538	2.0E+08	1.5E+08	1.8E+08
PV CFlow	53385808	11205692	81517117	21764701	54601192
PV SevTax	2642514	171920.6	2958762	2207740	2633152
PV StateTx	4190616	1133218	7424755	1583975	4222344
PV CorpTx	17123494	5019255	[illegible]	5704981	17280434
PV Royal	4556058	296414.9	5101314	3806448	4539918

	Average	STD	MAX	MIN	Median
PV Rev	1.8E+08	11986653	2.0E+08	1.5E+08	1.8E+08
PV CFlow	53266686	10612420	73372537	28919754	54323414
PV SevTax	2621720	175385.6	2939656	2169231	2630920
PV StateTx	4181644	1112537	6549991	2042393	4218699
PV CorpTx	17079748	4946034	27642064	7607233	17217589
PV Royal	4520206	302388.9	5068372	3740053	4536068

Lang Additional Area Data, Case 3, Scenario 2
discount rate = 15%

	Average	STD	MAX	MIN	Median
PV Rev	1.6E+08	7370634	1.8E+08	1.4E+08	1.6E+08
PV CFlow	41262442	9609236	58995033	21427269	41660308
PV SevTax	2267190	107920.3	2588850	1991420	2269136
PV StateTx	3319112	1007702	5366552	1516339	3351548
PV CorpTx	13447675	4476305	22576422	5655433	13570408
PV Royal	3908948	186069.4	4463534	3433483	3912304

	Average	STD	MAX	MIN	Median
PV Rev	1.6E+08	10778760	1.8E+08	1.2E+08	1.6E+08
PV CFlow	42174879	11613351	61607580	7883007	43194855
PV SevTax	2258106	157673.5	2561763	1769055	2266606
PV StateTx	3449159	1146330	5648491	973087.7	3442928
PV CorpTx	14041363	5058640	23837731	3506967	13970735
PV Royal	3893287	271850.9	4416832	3050095	3907942

	Average	STD	MAX	MIN	Median
PV Rev	1.6E+08	9314331	1.8E+08	1.4E+08	1.6E+08
PV CFlow	40580146	8790712	61989793	18898267	40319045
PV SevTax	2284044	135943.1	2595201	1979626	2293084
PV StateTx	3189716	905115	5471755	1358348	3148171
PV CorpTx	12852945	4038272	23047067	4667877	12652087
PV Royal	3938006	234384.7	4474484	3413149	3953592

	Average	STD	MAX	MIN	Median
PV Rev	1.6E+08	8943891	1.8E+08	1.4E+08	1.6E+08
PV CFlow	44530550	10133936	64976123	14558943	46095653
PV SevTax	2297420	130808.5	2562475	1978257	2289598
PV StateTx	3665704	1032031	6031093	1113964	3812658
PV CorpTx	14990744	4576457	25549370	3718194	15624793
PV Royal	3961069	225531.9	4418061	3410788	3947584

	Average	STD	MAX	MIN	Median
PV Rev	1.6E+08	8873119	1.8E+08	1.4E+08	1.5E+08
PV CFlow	44068924	8309843	64485950	28806642	43342374
PV SevTax	2262493	129560.9	2566320	1979878	2247086
PV StateTx	3592529	944796.6	5844007	1904406	3454022
PV CorpTx	14647501	4221648	24712407	7087874	14034773
PV Royal	3900849	223380.8	4424689	3413583	3874286

Lang Addition Data, Case 1, Scenario 1
discount rate = 10%

	Average	STD	MAX	MIN	Median
PV Rev	2.7E+08	17598433	3.1E+08	2.2E+08	2.7E+08
PV CFlow	59871864	22631276	1.3E+08	15561323	61053178
PV SevTax	3903596	256110.7	4551672	3205457	3883467
PV StateTx	4547599	1881454	11176546	1816075	4258433
PV CorpTx	18141612	8252093	47574052	6407738	16847028
PV Royal	6730338	441570.2	7847710	5526650	6695633

	Average	STD	MAX	MIN	Median
PV Rev	2.6E+08	18453533	3.0E+08	2.2E+08	2.6E+08
PV CFlow	50280894	25136024	1.0E+08	-1.0E+07	49301853
PV SevTax	3759664	268861.7	4333086	3196261	3771412
PV StateTx	4012506	1667992	8835087	1411354	3698770
PV CorpTx	15880479	7199172	37099107	5312320	14382552
PV Royal	6482179	463554.6	7470839	5510794	6502434

	Average	STD	MAX	MIN	Median
PV Rev	2.6E+08	178[illegible]02	3.1E+08	2.3E+08	2.6E+08
PV CFlow	54784094	30095780	99012168	-3.3E+07	62716690
PV SevTax	3831440	259551.9	4546634	3269795	3799262
PV StateTx	4406497	1773650	8158580	1048096	4214273
PV CorpTx	17556034	7646042	34072625	3835988	16679408
PV Royal	6605932	447503.2	7839025	5637578	6550452

	Average	STD	MAX	MIN	Median
PV Rev	2.7E+08	15868836	3.0E+08	2.3E+08	2.7E+08
PV CFlow	55072187	23978485	98722372	1355366	56954575
PV SevTax	3842448	231170.8	4284353	3332869	3862862
PV StateTx	4237613	1644367	8619635	1533599	4134808
PV CorpTx	16780722	7[illegible]801	36135242	5387930	16182166
PV Royal	6624910	398570.4	7386816	5746326	6660108

	Average	STD	MAX	MIN	Median
PV Rev	2.7E+08	20398217	3.1E+08	2.2E+08	2.7E+08
PV CFlow	60278727	24828340	1.1E+08	[illegible]039067	56056342
PV SevTax	3922717	297196.2	4546279	3203795	3962867
PV StateTx	4612030	19[illegible]	8901452	1627956	4198538
PV CorpTx	18411784	8475230	37395999	5603141	16506726
PV Royal	6763305	512407.2	7838411	5523785	6832529

Lang Addition Data, Case 1, Scenario 2
discount rate = 10%

	Average	STD	MAX	MIN	Median
PV Rev	2.4E+08	19277852	2.7E+08	2.1E+08	2.4E+08
PV CFlow	41166450	25153307	1.0E+08	-2.0E+07	41301914
PV SevTax	3424352	280459.2	3950774	2990767	3469374
PV StateTx	3316146	1683620	9529348	650241.3	3111556
PV CorpTx	12957600	7289536	40440628	2176025	11992369
PV Royal	5904055	483550.4	6811680	5156495	5981680

	Average	STD	MAX	MIN	Median
PV Rev	2.4E+08	18136061	2.7E+08	2.0E+08	2.4E+08
PV CFlow	47036590	25469125	88634104	-2.4E+07	49557769
PV SevTax	3483276	264006.2	3928720	2840884	3503826
PV StateTx	3799994	1782822	7563285	757012.4	3524513
PV CorpTx	15125729	7664429	31645084	2662914	13700151
PV Royal	6005649	455183.1	6773654	4898076	6041079

	Average	STD	MAX	MIN	Median
PV Rev	2.4E+08	18338520	2.7E+08	2.0E+08	2.4E+08
PV CFlow	46157839	22852794	84693183	-7441279	45887659
PV SevTax	3478319	266893.4	3978857	2906620	3490867
PV StateTx	3641426	1492707	7096648	966548.7	3284379
PV CorpTx	14375960	6411015	29557498	3333985	12683888
PV Royal	5997102	460161.1	6860098	5011414	6018736

	Average	STD	MAX	MIN	Median
PV Rev	2.4E+08	19635497	2.7E+08	1.8E+08	2.4E+08
PV CFlow	45368132	23618442	94071883	-3.0E+07	48851472
PV SevTax	3492997	285809.8	3961376	2599309	3516697
PV StateTx	3562841	1558189	8162555	504590.1	3252670
PV CorpTx	14061037	6665322	34326028	1651200	12427413
PV Royal	6022409	492775.6	6829958	4481568	6063271

	Average	STD	MAX	MIN	Median
PV Rev	2.4E+08	21983222	2.9E+08	1.9E+08	2.4E+08
PV CFlow	47302605	26729296	90354365	-2.6E+07	45517467
PV SevTax	3477660	320069.7	4224426	2806507	3474321
PV StateTx	3838680	1905217	8022992	616005.5	3328870
PV CorpTx	15292179	8220897	33701665	2118610	12804591
PV Royal	5995966	551844.4	7283493	4838806	5990208

Lang Addition Data, Case 2, Scenario 1
discount rate = 10%

	Average	STD	MAX	MIN	Median
PV Rev	2.7E+08	22372029	3.2E+08	2.2E+08	2.7E+08
PV CFlow	58329226	23832690	1.1E+08	[illegible]	62199300
PV SevTax	3893816	325653.6	4568307	[illegible]	3878884
PV StateTx	4390984	1793651	9373405	1297515	4359934
PV CorpTx	17483613	7778667	39507368	4525055	17190617
PV Royal	6713477	561471.6	7876392	5562550	6687731

	Average	STD	MAX	MIN	Median
PV Rev	2.7E+08	16403679	3.0E+08	2.3E+08	2.7E+08
PV CFlow	61873234	18191286	97585347	[illegible]	65443883
PV SevTax	3863855	238574.5	4298239	3275108	3841499
PV StateTx	4514487	1470118	7908909	1607598	4500667
PV CorpTx	17924402	6420396	32955676	5639065	17808558
PV Royal	6661819	411335.4	7410757	5646738	6623275

	Average	STD	MAX	MIN	Median
PV Rev	2.6E+08	19288587	3.0E+08	2.2E+08	2.6E+08
PV CFlow	55821184	27739636	1.0E+08	-2.9E+07	60498823
PV SevTax	3831025	280799.9	4413981	3209407	3785012
PV StateTx	4317289	1706735	8535341	943893.2	3965329
PV CorpTx	17173209	7317402	35758135	3392349	15546373
PV Royal	6605215	484137.7	7610312	5533461	6525882

	Average	STD	MAX	MIN	Median
PV Rev	2.6E+08	16288044	2.9E+08	2.3E+08	2.6E+08
PV CFlow	51827512	26634695	[illegible]	-3290950	50816951
PV SevTax	3809434	237375.4	[illegible]	3290602	3810124
PV StateTx	4061209	1836795	[illegible]	1224567	3697042
PV CorpTx	16090185	7912896	32626825	4330035	14683877
PV Royal	6567989	409268	7335521	5673452	6569180

	Average	STD	MAX	MIN	Median
PV Rev	2.6E+08	18303553	3.1E+08	2.3E+08	2.6E+08
PV CFlow	57562509	20385692	99665983	-6053408	63186686
PV SevTax	3836735	266598.7	4465005	3340212	3819611
PV StateTx	4247878	1450258	7991312	1561071	4348389
PV CorpTx	16781326	6271622	33324321	5802844	17044873
PV Royal	6615061	459652.9	7698285	5758986	6585536

Lang Addition Data, Case 2, Scenario 2
discount rate = 10%

	Average	STD	MAX	MIN	Median
PV Rev	2.4E+08	18084276	2.8E+08	2.0E+08	2.4E+08
PV CFlow	48431812	20709864	94333935	8802830	49836915
PV SevTax	3508105	263415.3	4077253	2912803	3499197
PV StateTx	3667621	1598481	7951712	1029939	3498037
PV CorpTx	14448357	6920655	33382783	3826714	13531495
PV Royal	6048458	454164.3	7029747	5022075	6033098

	Average	STD	MAX	MIN	Median
PV Rev	2.4E+08	17648820	2.8E+08	1.9E+08	2.4E+08
PV CFlow	48873230	27159225	86298883	-4.0E+07	56896037
PV SevTax	3456584	257059.3	3994627	2726871	3479132
PV StateTx	3930771	1610046	6996589	530389	4041383
PV CorpTx	15631927	6883017	29109866	1892609	15951008
PV Royal	5959627	443205.8	6887287	4701501	5998503

	Average	STD	MAX	MIN	Median
PV Rev	2.4E+08	20600574	2.9E+08	1.9E+08	2.4E+08
PV CFlow	51620393	22409608	1.0E+08	-1.3E+07	51702863
PV SevTax	3438158	299988.3	4166746	2708196	3409569
PV StateTx	4042865	1737482	8843036	1444823	3762958
PV CorpTx	16073619	7604181	37370286	5419786	14692241
PV Royal	5927859	517221.2	7184045	4669303	5878568

	Average	STD	MAX	MIN	Median
PV Rev	2.4E+08	18762861	2.8E+08	2.0E+08	2.4E+08
PV CFlow	52408768	22224658	98787672	5913904	49731400
PV SevTax	3520232	273185	4053287	2862165	3536228
PV StateTx	4071857	1849195	8551126	1584577	3583979
PV CorpTx	16212812	8125694	36064370	5740691	14172656
PV Royal	6069365	471008.6	6988426	4934767	6096945

	Average	STD	MAX	MIN	Median
PV Rev	2.5E+08	19100455	2.9E+08	2.1E+08	2.4E+08
PV CFlow	56053904	21124167	93646946	-1.8E+07	57053345
PV SevTax	3552909	278320.3	4262169	3084111	3528850
PV StateTx	4288497	1625562	7632201	684474.6	4076157
PV CorpTx	17161944	7053362	31953393	2324554	16083585
PV Royal	6125706	479862.6	7348567	5317432	6084224

Lang Addition Data, Case 3, Scenario 1
discount rate = 10%

	Average	STD	MAX	MIN	Median
PV Rev	2.7E+08	19867541	3.2E+08	2.3E+08	[illegible]
PV CFlow	90853522	14043232	1.2E+08	55737315	[illegible]
PV SevTax	3917216	289149.8	4595806	3287221	3924010
PV StateTx	7552917	[illegible]	10532258	3866233	7612791
PV CorpTx	31369580	6936934	44691711	14907678	31630940
PV Royal	6753820	498534.1	7923803	5667622	6765534

	Average	STD	MAX	MIN	Median
PV Rev	2.6E+08	20134152	3.2E+08	2.2E+08	2.6E+08
PV CFlow	85548133	16656225	1.2E+08	48530155	87468881
PV SevTax	3828045	292931.7	4637209	3179844	3766565
PV StateTx	7095208	1661685	9980013	3642851	7266431
PV CorpTx	29365347	7358243	42238392	13959688	[illegible]
PV Royal	6600078	505054.7	7995189	5482490	[illegible]

	Average	STD	MAX	MIN	Median
PV Rev	2.7E+08	21053271	3.2E+08	2.1E+08	2.7E+08
PV CFlow	90205702	16175334	1.2E+08	49218285	[illegible]
PV SevTax	3928446	306505.9	4671042	3089407	3968407
PV StateTx	7512576	1684284	11007701	4387965	7239404
PV CorpTx	31213928	7497769	46818693	17681758	29960525
PV Royal	6773183	528458.5	8053521	5326565	6842080

	Average	STD	MAX	MIN	Median
PV Rev	2.6E+08	22727250	3.2E+08	2.2E+08	2.6E+08
PV CFlow	84831735	17834508	1.2E+08	47513425	86655102
PV SevTax	3806640	330830.3	4580841	3147963	3819972
PV StateTx	6982634	1884768	10792508	3283672	6990549
PV CorpTx	28851082	[illegible]	45855989	12371997	28847223
PV Royal	6563172	[illegible]	7898002	5427522	6586159

	Average	STD	MAX	MIN	Median
PV Rev	2.6E+08	21217118	3.0E+08	2.1E+08	2.6E+08
PV CFlow	79407576	17614651	1.1E+08	35534638	78912311
PV SevTax	3780168	308981.9	4343704	3091376	3789641
PV StateTx	6427898	[illegible]	10035608	3184575	6332673
PV CorpTx	26402376	7626020	42469857	12405278	25929085
PV Royal	6517530	532727.4	7489144	5329958	6533864

Lang Addition Data, Case 3, Scenario 2
discount rate = 10%

	Average	STD	MAX	MIN	Median
PV Rev	2.4E+08	19528108	3.0E+08	2.0E+08	2.4E+08
PV CFlow	76692683	15998270	1.1E+08	40963492	78953012
PV SevTax	3517808	284650.3	4302220	2923952	3477793
PV StateTx	6449534	1694756	10222305	3052548	6683373
PV CorpTx	26701787	7529539	43540697	11669000	27708634
PV Royal	6065186	490776.4	7417621	5041297	5996194

	Average	STD	MAX	MIN	Median
PV Rev	2.4E+08	17383873	2.7E+08	2.1E+08	2.4E+08
PV CFlow	75583612	14412886	1.0E+08	33266486	75717909
PV SevTax	3443246	253296.8	3921419	3001632	3429630
PV StateTx	6376794	1513594	9178162	2404622	6289973
PV CorpTx	26369005	6731993	38869531	8886964	25948688
PV Royal	5936631	436718.6	6761068	5175228	5913155

	Average	STD	MAX	MIN	Median
PV Rev	2.4E+08	18157246	2.8E+08	2.0E+08	2.4E+08
PV CFlow	71821339	14972023	1.0E+08	36361875	70637864
PV SevTax	3453918	264507.3	4107472	2920117	3468314
PV StateTx	5933443	1508124	9394880	2987375	5696564
PV CorpTx	24402874	6689852	39839060	11520639	23293963
PV Royal	5955030	456047.1	7081849	5034684	5979852

	Average	STD	MAX	MIN	Median
PV Rev	2.4E+08	22288965	3.0E+08	1.9E+08	2.3E+08
PV CFlow	72177482	18732365	1.2E+08	12364137	73545347
PV SevTax	3412672	324668.9	4287807	2738871	3400909
PV StateTx	6094917	1707241	10407867	2252508	6113790
PV CorpTx	25136234	7556561	44370845	8251488	25193238
PV Royal	5883917	559773.9	7392770	4722191	5863637

	Average	STD	MAX	MIN	Median
PV Rev	2.4E+08	18990877	3.0E+08	2.0E+08	2.4E+08
PV CFlow	68139930	16461528	1.1E+08	23514106	70732378
PV SevTax	3474261	276447.5	4292106	2908747	3429791
PV StateTx	5546341	1613028	9787687	2174024	5702436
PV CorpTx	22686270	7156086	41596355	8018287	23320231
PV Royal	5990105	476633.7	7400183	5015080	5913433

Sylvite Additional Area Data, Scenario 1
discount rate = 15%

	Average	STD	MAX	MIN	Median
PV Rev	2.3E+08	12711669	2.6E+08	1.9E+08	2.3E+08
PV CFlow	48639615	15331369	71471324	-175453	50527302
PV SevTax	3266562	185718.7	3759423	2693428	3288497
PV StateTx	3402456	1072165	5501920	1219495	3340599
PV CorpTx	13688589	4657061	22953325	4598280	13403966
PV Royal	5632003	320204.6	648[illegible]54	4643841	5669823

	Average	STD	MAX	MIN	Median
PV Rev	2.3E+08	12729009	2.6E+08	1.9E+08	2.3E+08
PV CFlow	51182727	15813076	8[illegible]129541	4845224	53784975
PV SevTax	3278666	186085.3	3780638	2823235	3280123
PV StateTx	3627829	1170166	7035109	1037276	3691401
PV CorpTx	14685908	5103057	29812329	3799481	1487[illegible]747
PV Royal	5652873	320836.7	6518341	4867646	5655385

	Average	STD	MAX	MIN	Median
PV Rev	2.2E+08	12840961	2.5E+08	2.0E+08	2.2E+08
PV CFlow	47106902	14708740	83292350	13157156	48003464
PV SevTax	[illegible]37175	187897.1	3654614	2848320	3243239
PV StateTx	[illegible]254411	1115956	6770457	1481055	3314751
PV CorpTx	13018346	4896270	28628359	5249261	13387668
PV Royal	5581336	323960.5	6301058	4910896	5591791

	Average	STD	MAX	MIN	Median
PV Rev	2.2E+08	13876349	2.6E+08	1.9E+08	2.3E+08
PV CFlow	45744589	19579136	86213806	-7820964	45801539
PV SevTax	3221898	202897.6	3705407	2693371	3280097
PV StateTx	3311464	1437669	7020270	777846.7	3056000
PV CorpTx	13321328	6292572	29745942	2840667	12201915
PV Royal	5554997	349823.5	6388632	4643743	5655340

	Average	STD	MAX	MIN	Median
PV Rev	2.2E+08	11712512	2.5E+08	2.0E+08	2.2E+08
PV CFlow	44420333	15613023	72968666	7024248	46827759
PV SevTax	3215456	170682.5	3671842	2846749	3213838
PV StateTx	3168482	1020900	5735491	1478744	3077728
PV CorpTx	12659247	4443461	23998250	5503322	12162397
PV Royal	5543890	294280.2	6330762	4908189	5541099

Sylvite Additional Area Data, Scenario 2
discount rate = 15%

	Average	STD	MAX	MIN	Median
PV Rev	1.9E+08	11669390	2.3E+08	1.7E+08	1.9E+08
PV CFlow	36143571	17514842	80328289	-6374356	38069894
PV SevTax	2792604	170800.5	3275151	2434736	2793424
PV StateTx	2736146	1285826	7002091	617752	2524915
PV CorpTx	10939499	5638782	29893310	2219361	9891931
PV Royal	4814835	294483.6	5646812	4197820	4816249

	Average	STD	MAX	MIN	Median
PV Rev	1.9E+08	12963505	2.2E+08	1.6E+08	1.9E+08
PV CFlow	37081356	13489603	64246399	7818974	36236562
PV SevTax	2815562	189313.6	3175508	2342725	2821928
PV StateTx	2699887	992801.2	5029147	928393.8	2479621
PV CorpTx	10774382	4342580	21066979	3291945	9769967
PV Royal	4854417	326402.8	5475013	4039181	4865393

	Average	STD	MAX	MIN	Median
PV Rev	1.9E+08	15031922	2.2E+08	1.5E+08	1.9E+08
PV CFlow	38943294	16117211	71398713	-2478315	35893177
PV SevTax	2796372	219697.4	3200974	2241605	2817265
PV StateTx	2955014	1264145	6247565	1005144	2590273
PV CorpTx	11905575	5561508	26517796	3475796	10276271
PV Royal	4821331	378788.6	5518921	3864836	4857353

	Average	STD	MAX	MIN	Median
PV Rev	2.0E+08	13145209	2.2E+08	1.7E+08	2.0E+08
PV CFlow	39359436	19633003	65924015	-1.1E+07	44971510
PV SevTax	2850937	192240.9	3245408	2482725	2849520
PV StateTx	3048532	1304528	5425401	524075	3140225
PV CorpTx	12347514	5654201	22839696	1845903	12658829
PV Royal	4915408	331449.9	5595531	4280560	4912965

	Average	STD	MAX	MIN	Median
PV Rev	1.9E+08	14208006	2.2E+08	1.6E+08	1.9E+08
PV CFlow	39394048	15931869	73162685	-1.1E+07	41809358
PV SevTax	2806444	207802.3	3263441	2270222	2763518
PV StateTx	2959529	1161306	6092193	459319.6	2910338
PV CorpTx	11927046	5062953	25822713	1552392	11659439
PV Royal	4838697	358279.8	5626623	3914176	4764687

Sylvite Additional Area Data, Scenario 1
discount rate = 10%

	Average	STD	MAX	MIN	Median
PV Rev	3.3E+08	21795849	3.8E+08	2.8E+08	3.3E+08
PV CFlow	63964035	30014307	1.1E+08	-3.2E+07	68518668
PV SevTax	4788933	317138.9	5436999	4095296	4749021
PV StateTx	4704915	1769054	8850608	1495971	4606785
PV CorpTx	18878590	7690065	37168543	5467130	18374947
PV Royal	8256781	546791.1	9374137	7060856	8187968

	Average	STD	MAX	MIN	Median
PV Rev	3.3E+08	28851355	3.9E+08	2.7E+08	3.3E+08
PV CFlow	62955356	33509740	1.1E+08	-2.2E+07	62828393
PV SevTax	4738529	420130.5	5707472	3899046	4761800
PV StateTx	4802251	2152900	9059894	1187619	4351751
PV CorpTx	19400413	9340122	38194739	4331719	17391272
PV Royal	8169877	724362.9	9840469	6722494	8210000

	Average	STD	MAX	MIN	Median
PV Rev	3.3E+08	19773867	3.7E+08	2.8E+08	3.3E+08
PV CFlow	66268835	30959855	1.2E+08	-1.5E+07	69015954
PV SevTax	4790867	287907.4	5316144	4073629	4816698
PV StateTx	4892769	2061057	10096333	1936770	4639531
PV CorpTx	19708862	9000344	42741523	7378742	18403716
PV Royal	8260115	496392.1	9165766	7023499	8304652

	Average	STD	MAX	MIN	Median
PV Rev	3.3E+08	21671439	3.7E+08	2.8E+08	3.3E+08
PV CFlow	62441145	31303657	1.2E+08	-1.4E+07	68534080
PV SevTax	4817605	315554.6	5346322	4019268	4823249
PV StateTx	4660444	1986881	9958924	1501777	4269517
PV CorpTx	18752759	8602187	42126795	5611722	17189845
PV Royal	8306216	544059.6	9217797	6929773	8315947

	Average	STD	MAX	MIN	Median
PV Rev	3.3E+08	23584996	3.9E+08	2.9E+08	3.3E+08
PV CFlow	66324585	27076681	1.2E+08	-2.9E+07	73774450
PV SevTax	4767793	343167.4	5712548	4189695	4797867
PV StateTx	4729209	1744001	8559794	1169358	4820604
PV CorpTx	18969192	7558756	35867531	4207183	19228523
PV Royal	8220332	591668	9849221	7223612	8272185

Sylvite Additional Area Data, Scenario 2
discount rate = 10%

	Average	STD	MAX	MIN	Median
PV Rev	3.0E+08	23019416	3.4E+08	2.5E+08	3.0E+08
PV CFlow	58306575	30777740	1.1E+08	-4.2E+07	65776902
PV SevTax	4343021	335329.7	4999632	3561696	4328948
PV StateTx	4470777	1699743	8510470	991722.6	4629687
PV CorpTx	18016905	7404596	35882487	3552107	18521093
PV Royal	7487966	578154.7	8620056	6140855	7463703

	Average	STD	MAX	MIN	Median
PV Rev	3.0E+08	23415509	3.4E+08	2.5E+08	3.0E+08
PV CFlow	53555581	30544886	1.1E+08	-3.3E+07	57719581
PV SevTax	4362394	340979.5	4999092	3582291	4299778
PV StateTx	4058942	1839443	8914257	1203881	3923353
PV CorpTx	16232122	7994052	37688903	4431047	15373755
PV Royal	7521369	587895.6	8619125	6176364	7413410

	Average	STD	MAX	MIN	Median
PV Rev	3.0E+08	24215147	3.5E+08	2.3E+08	3.0E+08
PV CFlow	59229031	31997854	1.2E+08	-2.1E+07	62716224
PV SevTax	4354364	352458.4	5135579	3310234	4354120
PV StateTx	4510099	2167166	9890777	1111072	4061063
PV CorpTx	18216950	9453753	42057547	3955770	16111896
PV Royal	7507524	607687	8854446	5707301	7507103

	Average	STD	MAX	MIN	Median
PV Rev	3.0E+08	26020429	3.6E+08	2.4E+08	3.0E+08
PV CFlow	48168904	34229787	1.1E+08	-3.5E+07	50201975
PV SevTax	4323391	379014.6	5193358	3502697	4388340
PV StateTx	3848692	2212718	9477569	835132.7	3374020
PV CorpTx	15395798	9607054	40208987	2937465	13046211
PV Royal	7454122	653473.5	8954065	6039132	7566103

	Average	STD	MAX	MIN	Median
PV Rev	2.9E+08	26440646	3.5E+08	2.5E+08	3.0E+08
PV CFlow	44546454	33087232	1.1E+08	-6.1E+07	49198468
PV SevTax	4241639	385544.4	5105285	3588786	4295584
PV StateTx	3610391	1648271	8275017	820411.6	3448518
PV CorpTx	14336389	7061260	34829147	2895206	13631137
PV Royal	7313171	664731.7	8802216	6187562	7406180

FINAL REPORT
Evaluation of Mineral Resources at the
Waste Isolation Pilot Plant (WIPP) Site

Volume 3
Chapters IX–XII

Westinghouse Electric Corporation
Waste Isolation Division
Contract No. PO-75-WJJ644145Z

Chapter IX -	Regulations Pertaining to Oil and Gas Drilling
Chapter X -	The Past-Decade Developments and Future Trends in Oil-Well Drilling, Completion, and Stimulation, with Special Applications to Developments At the WIPP Site
Chapter XI -	Oil and Gas Resource Estimates
Chapter XII -	Valuation of Oil and Gas Reserves at the WIPP Site, Additional Area, and Combined Area

Submitted by

New Mexico Bureau of Mines & Mineral Resources
Campus Station
Socorro, NM 87801

March 31, 1995

Certification

We certify under penalty of law that this document was prepared under our supervision for Westinghouse Electric Corporation, Waste Isolation Division, Waste Isolation Pilot Plant by New Mexico Bureau of Mines and Mineral Resources, a division of New Mexico Institute of Mining & Technology. Based on our inquiry of the persons directly responsible for gathering the information, the information submitted is, to the best of our knowledge and belief, true, accurate, and complete.

Charles E. Chapin, Principal Investigator
Director and State Geologist
New Mexico Bureau of Mines and
Mineral Resources

Clinton P. Richardson, P.E.
Mining and Environmental Engineering
New Mexico Institute of
Mining & Technology
New Mexico Certification No. 11229
Expires December 31, 1995

Evaluation of Mineral Resources at the
Waste Isolation Pilot Plant (WIPP) Site

Chapter IX

REGULATIONS PERTAINING TO OIL AND GAS DRILLING

by
Joe D. Ramey

Westinghouse Electric Corporation
Waste Isolation Division
Contract No. PO-75-WJJ644145Z

Submitted by

New Mexico Bureau of Mines and Mineral Resources
Campus Station
Socorro, NM 87801

March 31, 1995

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REGULATIONS PERTAINING TO OIL AND GAS DRILLING

Joe D. Ramey

Although there are no specific oil and gas regulatory rules that apply only to WIPP, the WIPP site is located near the eastern boundary of the Potash Area as defined by Oil Conservation Commission (OCC) Order No. R-111-P approved April 21, 1988 (Appendix A). This order prohibits the drilling of oil and gas wells at locations where viable reserves of potash exist. Because not all the Potash Area contains commercial potash reserves, exceptions have been granted to allow the drilling of oil and gas wells at locations where non-commercial resources of potash are present.

All oil and gas wells drilled within the Potash Area must comply with special casing and cementing standards to protect the salt section (which consists of the Salado and Castile Formations) from the intrusion of water and oil and gas. The first, or surface, string of casing is set in the anhydrite section at the base of the Rustler Formation near the top of the salt and through the water-bearing sands above the salt. The annular space between the casing and hole must be filled with cement all the way to the surface. The salt section is drilled with brine-saturated fluid and casing is set approximately 100 ft below the base of the salt section. Cement must again completely fill the annular space, which is determined by pumping cement down the casing until it circulates at the surface through the annular space. After the oil-producing interval is drilled, another string of casing is set and cemented with sufficient cement to cover and protect the oil zone. For deeper wells, an additional string of casing may be required.

This drilling and casing program offers excellent protection for the salt section from intrusion of water from above and oil and gas from below in oil and gas operations for the producing life of the well. Plugging procedures for producing and dry wells also prevent the migration of fluids within the well bore and particularly into the salt section. Cementing operations are routinely witnessed by the Oil Conservation Division (OCD) on state and private lands. The Bureau of Land Management (BLM) attempts to witness cementing but, because of overtime restrictions, not all jobs have had BLM personnel on site. OCD reports 100% success in cementing the salt string in wells on state and private lands within the Potash Area. One well, on federal land, was reported by BLM not to have adequately covered the salt section with cement. Casing was set as required and cemented over the bottom portion of the hole. Prior to running the oil string of casing, the salt string was to be cut off at the top of the cement and pulled. The oil string was then to be run and cemented to the surface. Instead the oil string was run and cemented with sufficient cement to tie back into the salt string.

This is a violation of OCC Order No. R-111-P and BLM 43 CFR Part 3160 (Appendix B) dated November 18, 1988. This BLM order prescribes cementing and other regulations for drilling oil and gas wells. The salt section in the subject well is protected by two strings of casing instead of casing and cement. Any casing leaks should be detectable in the bradenhead at the surface. BLM has scheduled the well for periodic bradenhead testing. However, had the cementing of the oil string been witnessed, this violation could have been prevented.

BLM 43 CFR Part 3160 is a general order, and is less stringent for drilling in the Potash Area than the OCD order. In instances such as this, oil and gas operators on federal lands must comply with the OCD order because the BLM attempts to administer OCD rules.

Before an oil and gas operator can obtain approval for a well in the Potash Area, he is required to notify all potash lessees within one mile of the proposed location. The potash lessee can oppose the well based on minable potash reserves to be determined by BLM. All applications to drill are reviewed by BLM and approved or denied based on the quality of potash under and around the location. If the well is to be drilled on state or private land, BLM and the State Land Office must forward their approval to OCD before the well can be drilled. Several proposed locations along the north and east boundary of WIPP have been denied because of potash reserves.

Flows of water have been encountered in the salt section in and near waterfloods in Lea County the closest of which is approximately 15 miles northeast of WIPP. These flows ranged from a few to several thousand barrels per day. The source of flows was, for the most part, from water injected into oil-bearing formations for the purpose of enhanced oil recovery. Through a combination of old improperly cemented and plugged wells and excessive injection pressures, water probably escaped from the injection interval and migrated upward to the salt section. When these waters reached the salt, it appears they migrated horizontally through the salt. This resulted in collapsed pipe in producing wells and sometimes large uncontrolled flows of salt water in wells being drilled nearby. It should be pointed out that large-volume flows of water and air were encountered in some wells in Lea County long before enhanced oil recovery was instigated. This could indicate that some of the brine flows encountered were natural occurrences.

Only a small portion of Lea County is in the Potash Area, so the salt section is not protected to the extent it is in the Potash Area. A salt string of casing is not usually required and cement normally ties back to the base of the salt section. Plugging operations in the Potash Area now require a cement plug over the salt section. In the remainder of the oil and gas producing area in southeast New Mexico, a cement plug is required at the top and bottom of the salt section. In wells drilled prior to around 1945, there were no cement plugs required at the salt section.

In every area where flows were encountered around enhanced oil recovery projects, studies indicated poorly plugged and abandoned wells, deeper wells where the injection zone was not covered by cement, and injection pressures in excess of the fracture pressure of the injection zone. Corrective measures were taken; i.e. wells were re-entered and properly plugged, other wells were cemented, and injection pressures and volumes were reduced. These actions probably prevented more widespread migration of water in the salt section.

The United States Environmental Protection Agency (EPA), along with representatives from most of the oil and gas producing states, enacted Underground Injection Control (UIC) regulations in the late 1970s and early 1980s. These UIC regulations set standards on all types of injection wells. Those relating to oil-field-produced water disposal and enhanced oil recovery projects are administered in New Mexico by OCD. Areas that will be affected by injection are now reviewed to determine if wells are properly plugged and cemented. OCD assigns injection pressures of 0.2 psi/ft of depth from the surface to the top of the upper perforation in any injection well. Injection pressures can be increased but only if the operator physically tests the injection well and determines the fracture pressure of the injection zone. The injection pressure may then be adjusted to below the fracture pressure. To date, the 0.2 psi/ft limitation has exceeded the fracture pressure on only one injection well.

Current UIC regulations appear to be adequate to contain the fluids in the zone into which they are injected. All wells in the area around the injection project must be adequately plugged and cemented. Injection pressures are limited to prevent hydraulic fracturing of the injection zone. Injection is through tubing below a packer set near the injection interval. The tubing is usually lined with a corrosive resistant material and the casing-tubing annular space is filled with an inert fluid such as 2% KCl water. Injection wells are inspected routinely. Bradenhead tests are conducted yearly and mechanical integrity tests are conducted every five years. Appendix C is a form utilized by OCD for injection applications which lists WIPP as a sensitive area.

Tubing leaks in injection wells are not too uncommon and can occur after a few years of injection, depending on the chemical composition of the fluids being injected. For example, a saturated salt solution exposed to air is more corrosive than fresh water. These tubing leaks will be detected during bradenhead testing. The mechanical integrity test will determine if packers are holding and if the well has sound casing.

At present there are two disposal wells east of and within two miles of the eastern WIPP boundary. Both are Delaware disposal wells and most of the fluid injected is from production wells in the Delaware Mountain Group in the near vicinity. A Pennsylvanian disposal well was being used in sec. 1 T22S R30E. However, this well was plugged back and recompleted as a Delaware oil well.

Waterflooding to the east, northeast, and northwest of WIPP in the Delaware Mountain Group is a possibility if sufficient wells can be drilled to establish an efficient waterflood pattern. Other factors such as oil production and reservoir producing characteristics must be favorable before enhanced oil recovery can be considered.

During drilling operations, a blow-out preventer and associated equipment are to be in place on a well and working prior to drilling out the surface casing shoe. These tools are in place as a safety measure and can prevent or at least control blowouts. Drilling rigs are inspected by either OCD or BLM personnel, usually when surface casing is set and cemented to determine if blow-out preventers are in place and are tested as required.

Problems encountered near WIPP have been caused by air pockets and some water flows in the salt section. The largest flow recorded within two miles of the WIPP boundary was 25 to 30 barrels of brine per hour from the Yates Petroleum Corporation No. 1 Flora AKF State, located approximately 1½ miles NNE of the WIPP land withdrawal area in sec. 2 T22S R31E. The flow depleted rapidly and was not evident when the salt protection string was run and cemented.

Well density near the WIPP site will probably not exceed 38 wells per section (about one square mile). Oil-well spacing is one well per 40 acres or 16 wells per section per producing horizon. Oil production in the area is primarily from the Delaware Mountain Group with some Bone Spring and Wolfcamp production. So there could be two oil wells on each 40-acre tract or 32 oil wells per section. The spacing for deep gas wells is one well for each 320 acres. The Pennsylvanian section produces gas in the area, and probably three different horizons in the Pennsylvanian, the Morrow, Atoka, and Strawn are likely to be productive. Therefore, a maximum of six gas wells could be drilled per section, although multiple gas reservoirs may be produced from a single well.

Applications for eight-deviated oil wells, with surface locations outside WIPP and bottom-hole locations inside WIPP (sec. 31 T22S R31E) could increase well density in sec. 6 immediately south, should these applications be approved. However, by letter dated August 19, 1994 (Appendix D) these eight applications were temporarily denied until EPA determines if it is necessary to acquire the two remaining oil and gas leases under WIPP.

Appendix E is a Statement of Work Agreement between the BLM and Department of Energy (DOE). This agreement requires BLM to forward applications for Permit to Drill to DOE within 10 days of receipt for review and comment. Permits are not to be issued by BLM until DOE recommendations have been received. The agreement also stipulates deviation and directional surveys for wells drilled 330 ft or closer to the WIPP land withdrawal area boundary.

Appendix F is a Memorandum of Understanding between DOE and DOI, which states the intent of DOE is that no oil and gas activities encroach upon the withdrawal area. DOE is an offset owner to oil and gas leases around the withdrawal area and should input information to oil and gas activities which occur in the immediate vicinity.

Chapter IX

REGULATIONS PERTAINING TO OIL AND GAS DRILLING

APPENDIX A

STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DEPT.
OIL CONSERVATION COMMISSION

IN THE MATTER OF THE HEARING
CALLED BY THE OIL CONSERVATION
COMMISSION OF NEW MEXICO FOR
THE PURPOSE OF CONSIDERING:

CASE NO. 9316
Order No. R-111-P

APPLICATION OF THE OIL CONSERVATION
DIVISION UPON ITS OWN MOTION TO
REVISE ORDER R-111, AS AMENDED, PERTAINING
TO THE POTASH AREAS OF EDDY AND LEA
COUNTIES, NEW MEXICO.

ORDER OF THE COMMISSION

BY THE COMMISSION:

This cause came on for hearing at 9:00 a.m. on February 18, 1988, at Santa Fe, New Mexico, before the Oil Conservation Commission of New Mexico, hereinafter referred to as the "Commission."

NOW, on this 21st day of April, 1988, 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 THAT:

(1) Due public notice having been given as required by law, the Commission has jurisdiction of this cause and the subject matter thereof.

(2) Order R-111-A was entered July 14, 1955, and since that time no amendments have been entered, except amendments to Exhibit "A" attached thereto, despite significant advances in drilling technology and practices.

(3) Operation under Order R-111-A has become virtually unworkable because of 1) the lack of tolerance on the part of both oil/gas and potash industries in regarding the activities of the other industry in areas where leasehold interests are overlapping and 2) confusion recording the boundaries of the known Potash Leasing Area (KPLA) established by the U.S. Bureau of Land Management (BLM) and the R-111-A area as amended by Orders R-111-B through O.

(4) The then Director of the Oil Conservation Division (OCD) by memorandum dated March 21, 1986 convened a study committee of volunteer representatives from the oil and potash industries and other interested parties.

(5) The committee met May 29, September 25-26, and November 13-14 (field trip) in 1986 and on March 19, 1987.

(6) By committee agreement a work committee was formed from the larger committee consisting of three members and one alternate from each industry and this work committee was chaired by the OCD Chief Petroleum Engineer and charged with the responsibility to develop proposed amendments to Order R-111-A. It met on April 30, May 1, July 23-24 and November 23, 1987.

(7) Each meeting of the work committee was held in the presence of representatives of both BLM and OCD; and at its final meeting November 23, 1987 an agreement was reached and signed by the committee members present, which agreement is attached hereto as Exhibit "B", for the purpose of providing background information and acknowledging the concensus reached by representatives of the Oil and Gas and Potash industries relating to the multiple use of resources in the potash area

(8) Exhibit "B" is regarded by the Commission as a report of both the work committee and the full study committee since a draft copy of a nearly identical agreement was furnished to each member of the study committee for comment, and comments received thereon were addressed at the final meeting.

(9) The agreement represents a compromise by both industries, the potash operators relinquishing lower grade marginal or uneconomic ore deposits in order to more fully protect their higher grade ore deposits; and the oil/gas operators receiving such lands containing sub-economic ore deposits as prospective drill-sites.

(10) The Oil and Gas Act, 70-2-3 F NMSA 1978, declares as waste "drilling or producing operations for oil or gas within any area containing commercial deposits of potash where such operations would have the effect unduly to reduce the total quantity of such commercial deposits of potash which may reasonably be recovered -- or where such operations would interfere unduly with the orderly commercial development of such potash deposits".

(11) The Oil and Gas Act in 70-2-12 B(17) empowers th Division "to regulate and, where necessary, prohibit drilling

or producing operations for oil and gas" in areas which would cause waste as described in 70-2-3 F.

(12) The report of the work committee presents a reasonable process for determining where wells for oil and gas would cause waste of potash and the pertinent portions of said report should be contained in the order as a reasonable process for prohibiting oil and gas drilling in such areas in the absence of substantial evidence that waste of potash as described by the statute would not result.

(13) Release of methane into potash mine workings would endanger the lives of miners and would render further mining activities uneconomic because of the additional, and more expensive safety requirements which would be imposed by the Mine Safety and Health Administration (MSHA) of the U.S. Department of Labor.

(14) Salt and potash deposits are essentially non-porous and impermeable but are inter-bedded with clay seams which, in an undisturbed state are porous but of extremely low permeability.

(15) Primary mining activity creates minor localized disturbance but secondary mining causes subsidence of the overburden the effects of which tend to expand beyond the mined out area a distance approximately equal to the depth of the mined area.

(16) During the drilling of wells for oil and gas, measures should be taken to protect the salt-protection casing from internal pressures greater than the designed burst resistance plus a safety factor so as to prevent any possible entry of methane into the salt and potash interval.

(17) A proposed revision of Order R-111-A was presented at the hearing and comments were received thereon both orally at the hearing and in writing subsequent to the hearing, the record being held open for two weeks subsequent to the hearing, as announced by the Chairman.

(18) Testimony and comments both in support and in opposition to the proposed revision of the order were received at the hearing and subsequent thereto, some pointing out that the number of oil or gas wells which could be drilled under the terms of the committee report would be reduced but no comments addressed the possible waste of potash as a result of additional drilling.

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(19) One member of the work committee from the potash industry testified the proposed revision of Order R-111-A failed to prohibit drilling in the commercial ore areas and was therefore contrary to the work committee report and the Oil and Gas Act.

(20) The Commission cannot abdicate its discretion to consider applications to drill as exceptions to its rules and orders but in the interest of preventing waste of potash should deny any application to drill in commercial potash areas as recommended in the work committee report, unless a clear demonstration is made that commercial potash will not be wasted unduly as a result of the drilling of the well.

(21) Confusion can be reduced and efficiencies can be obtained by making the area covered by Order R-111 coterminous with the KPLA as determined by the BLM, and the area should be expanded and contracted by the regular pool nomenclature procedure rather than by separate hearings and further revisions of Order R-111.

(22) Expansion of the R-111 area to coincide with the KPLA will bring under the purview of this order areas where potash is either absent or non-commercial and such areas should be granted less stringent casing, cementing and plugging requirements, at the discretion of the OCD district supervisor.

(23) The proposed revision of Order R-111-A will permit the drilling of wells for oil or gas in areas previously not available for such drilling and will prevent waste of potash, and further, will serve to reduce confusion and uncertainty in the conduct of operations by both the potash and oil/gas industries, all to the benefit of the state and its citizens.

IT IS THEREFORE ORDERED THAT:

This order shall be known as The Rules and Regulations Governing the Exploration and Development of Oil and Gas in Certain Areas Herein Defined, Which Are Known To Contain Potash Reserves.

A. OBJECTIVE

The objective of these Rules and Regulations is to prevent waste, protect correlative rights, assure maximum conservation of the oil, gas and potash resources of New Mexico, and permit the economic recovery of oil, gas and potash minerals in the area hereinafter defined.

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B. THE POTASH AREA

(1) The Potash Area, as described in Exhibit A attached hereto and made a part hereof, represents the area in various parts of which potash mining operations are now in progress, or in which core tests indicate commercial potash reserves. Such area is coterminous with the Known Potash Leasing Area (KPLA) as determined by the U.S. Bureau of Land Management (BLM).

(2) The Potash Area, as described in Exhibit "A" may be revised by the Division after due notice and hearing at the regular pool nomenclature hearings, to reflect changes made by BLM in its KPLA.

C. DRILLING IN THE POTASH AREA

(1) All drilling of oil and gas wells in the Potash Area shall be subject to these Rules and Regulations.

(2) No wells shall be drilled for oil or gas at a location which, in the opinion of the Division or its duly authorized representative, would result in undue waste of potash deposits or constitute a hazard to or interfere unduly with mining of potash deposits.

No mining operations shall be conducted in the Potash Area that would, in the opinion of the Division or its duly authorized representative, constitute a hazard to oil or gas production, or that would unreasonably interfere with the orderly development and production from any oil or gas pool.

(3) Upon discovery of oil or gas in the Potash Area, the Oil Conservation Division may promulgate pool rules for the affected area after due notice and hearing in order to address conditions not fully covered by these rules and the general rules.

(4) The Division's District Supervisor may waive the requirements of Sections D and F which are more rigorous than the general rules upon satisfactory showing that a location is outside the Life of Mine Reserves (LMR) and surrounding buffer zone as defined hereinbelow and that no commercial potash resources will be unduly diminished.

(5) All encounters with flammable gas, including hydrogen sulfide, during drilling operations shall be reported immediately to the appropriate OCD District office followed by a written report of same.

D. DRILLING AND CASING PROGRAM

(1) For the purpose of the regulations and the drilling of wells for oil and gas, shallow and deep zones are defined as follows:

(a) The shallow zone shall include all formations above the base of the Delaware Mountain Group or, above a depth of 5,000 feet, whichever is lesser.

(b) The deep zone shall include all formations below the base of the Delaware Mountain Group or, below a depth of 5,000 feet, whichever is lesser.

(c) For the purpose of identification, the base of the Delaware Mountain Group is hereby identified as the geophysical log marker found at a depth of 7485 feet in the Richardson and Bass No. 1 Rodke well in Section 27, Township 20 South, Range 31 East, NMPM, Eddy County, New Mexico.

(2) Surface Casing String:

(a) A surface casing string of new or used oil field casing in good condition shall be set in the "Red Be section of the basal Rustler formation immediately above the salt section, or in the anhydrite at the top of the salt section, as determined necessary by the regulatory representative approving the drilling operations, and the cement shall be circulated to the surface.

(b) Cement shall be allowed to stand a minimum of twelve (12) hours under pressure and a total of twenty-four (24) hours before drilling the plug or initiating tests.

(c) Casing and water-shut-off tests shall be made both before and after drilling the plug and below the casing seat as follows:

(i) If rotary tools are used, the mud shall be displaced with water and a hydraulic pressure of six hundred (600) pounds per square inch shall be applied. If a drop of one hundred (100) pounds per square inch or more should occur within thirty (30) minutes, corrective measures shall be applied.

(ii) If cable tools are used, the m[illegible] shall be bailed from the hole, and if [illegible]e hole does not remain dry for a period of one hour, corrective measures shall be applied.

(d) The above requirements for the surface casing string shall be applicable to both the shallow and deep zones.

(3) Salt Protection String:

(a) A salt protection string of new or used oil field casing in good condition shall be set not less than one hundred (100) feet nor more than six hundred (600) feet below the base of the salt section; provided that such string shall not be set below the top of the highest known oil or gas zone. With prior approval of the OCD District Supervisor the wellbore may be deviated from the vertical after completely penetrating Marker Bed No. 126 (USGS) but that section of the casing set in the deviated portion of the wellbore shall be centralized at each joint.

(b) The salt protection string shall be cemented, as follows:

(i) For wells drilled to the shallow zone, the string may be cemented with a nominal volume of cement for testing purposes only. If the exploratory test well is completed as a productive well, the string shall be re-cemented with sufficient cement to fill the annular space back of the pipe from the top of the first cementing to the surface or to the bottom of the cellar, or may be cut and pulled if the production string is cemented to the surface as provided in sub-section D (5)(a)(i) below.

(ii) For wells drilled to the deep zone, the string must be cemented with sufficient cement to fill the annular space back of the pipe from the casing seat to the surface or to the bottom of the cellar.

(c) If the cement fails to reach the surface or the bottom of the cellar, where required, the top of the cement shall be located by a temperature, gamma ray or other survey and additional cementing shall be done until the cement is brought to the point required.

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(d) The fluid used to mix with the cement shall be saturated with the salts common to the zones penetrated and with suitable proportions but not less than 1% of calcium chloride by weight of cement.

(e) Cement shall be allowed to stand a minimum of twelve (12) hours under pressure and a total of twenty-four (24) hours before drilling the plug or initiating tests.

(f) Casing tests shall be made both before and after drilling the plug and below the casing seat, as follows:

(i) If rotary tools are used, the mud shall be displaced with water and a hydraulic pressure of one thousand (1000) pounds per square inch shall be applied. If a drop of one hundred (100) pounds per square inch or more should occur within thirty (30) minutes, corrective measures shall be applied.

(ii) If cable tools are used, the mud shall be bailed from the hole and if the hole does not remain dry for a period of one hour, corrective measures shall be applied.

(g) The Division, or its duly authorized representative, may require the use of centralizers on the salt protection string when in their judgment the use of such centralizers would offer further protection to the salt section.

(h) Before drilling the plug a drilling spool installed below the bottom blowout preventer or the wellhead casing outlet shall be equipped with a rupture disc or other automatic pressure-relief device set at 80% of the API-rated burst pressure of new casing or 60% of the API-rated burst pressure of used casing. The disc or relief device should be connected to the rig choke manifold system so that any flow can be controlled away from the rig. The disc or relief device shall remain installed as long as drilling activities continue in the well until the intermediate or production casing is run and cemented.

(i) The above requirements for the salt protection string shall be applicable to both the shallow and deep zones except for sub-section D (3) (b) (i) and (ii) above.

(4) Intermediate String:

(a) In drilling wells to the deep zone for oil or gas, the operator shall have the option of running an intermediate string of pipe, unless the Division requires an intermediate string be run.

(b) Cementing procedures and casing tests for the intermediate string shall be the same as provided under sub-sections D (3) (c), (e) and (f) for the salt protection string.

(5) Production String:

(a) A production string shall be set on top or through the oil or gas pay zone and shall be cemented as follows:

(i) For wells drilled to the shallow zone the production string shall be cemented to the surface if the salt protection string was cemented only with a nominal volume for testing purposes, in which case the salt protection string can be cut and pulled before the production string is cemented; provided, that if the salt protection string was cemented to the surface, the production string shall be cemented with a volume adequate to protect the pay zone and the casing above such zone.

(ii) For wells drilled to the deep zone, the production string shall be cemented with a volume adequate to protect the pay zone and the casing above such zone; provided, that if no intermediate string shall have been run and cemented to the surface, the production string shall be cemented to the surface.

(b) Cementing procedures and casing tests for the production string shall be the same as provided under sub-section D (3) (c), (e) and (f) for the salt protection string; however if high pressure oil or gas production is discovered in an area the Division may promulgate the necessary rules to prevent the charging of the salt section.

E. DRILLING FLUID FOR SALT SECTION

The fluid used while drilling the salt section shall consist of water, to which has been added sufficient salts of a character common to the zone penetrated to completely saturate the mixture. Other admixtures may be added to the fluid by the operator in overcoming any specific problem. This requirement is specifically intended to prevent enlarged drill holes.

F. PLUGGING AND ABANDONMENT OF WELLS

(1) All wells heretofore and hereafter drilled within the Potash Area shall be plugged in a manner and in accordance with the general rules or field rules established by the Division that will provide a solid cement plug through the salt section and any water-bearing horizon and prevent liquids or gases from entering the hole above or below the salt section.

(2) The fluid used to mix the cement shall be saturated with the salts common to the salt section penetrated and with suitable proportions but not more than three (3) percent of calcium chloride by weight of cement being considered the desired mixture whenever possible.

G. DESIGNATION OF DRILLABLE LOCATION FOR WELLS

(a) Within ninety (90) days following effective date of this Order and annually thereafter by January 31 if revised, each potash lessee, without regard to whether the lease covers State or Federal lands, shall file with the District Manager, BLM, and the State Land Office (SLO), a designation of the potash deposits considered by the potash lessee to be its life-of-mine reserves ("LMR"). For purposes of this Agreement, "life-of-mine reserves" means those potash deposits within the Potash Area reasonably believed by the potash lessee to contain potash ore in sufficient thickness and grade to be mineable using current day mining methods, equipment and technology. Information used by the potash lessee in identifying its LMR shall be filed with the BLM and SLO but will be considered privileged and confidential "trade secrets and commercial. . . .information" within the meaning of 43 C.F.R.§2.13(c)(4) (1986), Section 19-1-2.1 NMSA 1978, and not subject to public disclosure.

(b) Authorized officers of the BLM and SLO shall review the information submitted by each potash lessee

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in support of its LMR designation on their respective lands and verify upon request, that the data used by the potash lessee in establishing the boundaries of its LMR is consistent with data available to the BLM and SLO. Any disputes between the BLM and potash lessee concerning the boundary of a designated LMR shall be resolved in accordance with the Department of Interior's Hearings and Appeals Procedures, 43 C.F.R. Part 4 (1986).

(c) A potash lessee may amend its designated LMR by filing a revised designation with the BLM and SLO accompanied by the information referred to in Section A above. Such amendments must be filed by January 31 next following the date the additional data becomes available.

(d) Authorized officers of the BLM and SLO shall commit the designated LMR of each potash lessee to a map(s) of suitable scale and thereafter revise the map(s) as necessary to reflect the latest amendments to any designated LMRs. These maps shall be considered privileged and confidential and exempt from disclosure under 43 C.F.R. Part 2 and §19-1-2.1 NMSA 1978, and will be used only for the purposes set forth in this Order.

(e) The foregoing procedure can be modified by policy changes within the BLM and State Land Office.

See memo 7-17-89 LMR maps unavailable

(2) Before commencing drilling operations for oil or gas on any lands within the Potash Area, the well operator shall prepare a map or plat showing the location of the proposed well, said map or plat to accompany each copy of the Notice of Intention to Drill. In addition to the number of copies required by the Division, the well operator shall send one copy by registered mail to each potash operator holding potash leases within a radius of one mile of the proposed well, as reflected by the plats submitted under paragraph I (2). The well operator shall furnish proof of the fact that said potash operators were notified by registered mail of his intent by attaching return receipt to the copies of the Notice of Intention to Drill and plats furnished the Division.

(3) Drilling applications on federal lands will be processed for approval by BLM. Applications on state or patented lands will be processed by the Division and, in the case of state lands, in collaboration with the SLO. The Division will first ascertain from the BLM or SLO that the location is not within the LMR area. Active mine workings and mined-out areas shall also be treated as LMR. Any application to drill in the LMR area, including buffer zones, may be approved only by mutual agreement of lessor and lessees of

both potash and oil and gas interests. Applications to drill outside the LMR will be approved as indicated below; provided there is no protest from potash lessee within 20 days of his receipt of a copy of the notice:

(a) a shallow well shall be drilled no closer to the LMR than one-fourth (1/4) mile or 110% of the depth of the ore, whichever is greater.

(b) A deep well shall be drilled no closer than one-half (1/2) mile from the LMR.

H. INSPECTION OF DRILLING AND MINING OPERATIONS

A representative of any potash lessee within a radius of one mile from the well location may be present during drilling, cementing, casing, and plugging of any oil gas wells to observe conformance with these regulations. Likewise, a representative of the oil and gas lessee may inspect mine workings on his lease to observe conformance with these regulations.

I. FILING OF WELL SURVEYS, MINE SURVEYS AND POTASH DEVELOPMENT PLANS

(1) Directional Surveys:

The Division may require an operator to file a certified directional survey from the surface to a point below the lowest known potash-bearing horizon on any well drilled within the Potash Area.

(2) Mine Surveys:

Within 30 days after the adoption of this order and thereafter on or before January 31st of each year, each potash operator shall furnish the Division two copies of a plat of a survey of the location of his leaseholdings and all of his open mine workings, which plat shall be available for public inspection and on a scale acceptable to the Division.

J. APPLICABILITY OF STATEWIDE RULES AND REGULATIONS

All general statewide rules and regulations of the Oil Conservation Division governing the development, operation, and production of oil and gas in the State of New

Mexico ~~not~~ inconsistent or in conflict herewith, are hereby adopted and made applicable to the areas described herein.

<u>IT IS FURTHER ORDERED THAT</u>:

(1) Order R-111 and amendments through R-111-O are hereby rescinded.

(2) Jurisdiction of this cause is retained for the entry of such further orders as the Commission may deem necessary.

Done at Santa Fe, New Mexico on the day and year hereinabove designated.

STATE OF NEW MEXICO
OIL CONSERVATION COMMISSION

WILLIAM R. HUMPHRIES, Member

ERLING A. BROSTUEN, Member

WILLIAM J. LEMAY, Chairman
and Secretary

STATEMENT OF AGREEMENT BETWEEN THE POTASH INDUSTRY AND OIL AND GAS INDUSTRY ON CONCURRENT OPERATIONS IN THE POTASH AREA IN EDDY AND LEA COUNTIES, NEW MEXICO

Introduction

This Statement of Agreement sets forth the joint agreement of the Potash Industry and Oil and Gas Industry on important issues concerning the concurrent development of potash and oil and gas reserves in Eddy and Lea Counties, New Mexico. It represents the efforts of numerous representatives from each Industry over many months and is intended to resolve many of the disputes that have arisen as a result of concurrent oil and gas drilling activities in the vicinity of underground potash mining.

The parties recognize that this Agreement will not resolve all disputes or disagreements that may arise and that regulatory intervention may still be necessary in some instances. By entering into this Agreement, however, each industry recognizes the right of the other to develop its mineral resources in a safe and economical manner and acknowledges that concurrent development of multiple mineral resources places certain limits on each industry. Each also agrees that these limits can be better defined through good faith discussions among industry representatives familiar with industry technology and practices than repeated and prolonged litigation or administrative proceedings.

EXHIBIT "B"
CASE NO. 9316
ORDER NO. R-111-P

In attempting to accomplish this, each Industry has made concessions on issues considered critical to it in a good faith effort to obtain concessions from the other. For this reason, both Industries agree that the terms of this Statement of Agreement are subject to the following conditions:

1. Upon approval by representatives of each Industry, the terms of the Agreement will be submitted to and must be adopted without substantial change by the New Mexico Oil Conservation Commission ("OCC") in lieu of the current Order R-111A, as amended;

2. The terms of the Agreement will be submitted to and must be adopted without substantial change by the U. S. Department of Interior, Bureau of Land Management ("BLM") in lieu of Section III (E) of the Secretary of the Interior's Order of October 21, 1986 [51 Fed. Reg. 39425];

3. Each Industry will use its best efforts to secure approval of the terms of the Agreement from the OCC and BLM; and

4. In the event the terms in the Agreement are not adopted without substantial change by both the OCC and the BLM, this Statement of Agreement will become null and void and will not be referred to by any Industry representative on the Study Committee in any future proceeding before the OCC or BLM.

It is the intention of the parties to this Agreement that: (1) certain areas of potash deposits, called "life-of-mine-reserves" or "LMR's," be permanently protected from oil and gas drilling activities; and (2) to make available for oil and gas drilling activities, certain areas within the Potash Area. The area of potash deposits protected will be determined in accordance with this Agreement but, generally speaking, will encompass the yellow, orange and a major portion of the blue

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areas shown on the BLM Potash Resources Map as it existed on October 1, 1984. Areas in the Potash Area that will be available for oil and gas drilling activities will be those areas outside the designated LMR's which, generally speaking, will be the red, green, grey and a minor portion of the blue areas shown on the BLM Potash Resources Map as it existed on October 1, 1984, less areas designated as buffer zones by this Agreement.

I. The Potash Area

A. The Area covered by this Agreement shall be known as the "Potash Area".

B. The "Potash Area" includes those tracts of land in Southeastern New Mexico, from the surface downward, which are designated as a "potash area" by the Secretary of the Department of Interior in Section V of the Order dated October 21, 1986 and published in the Federal Register on October 28, 1986 [51 Fed. Reg. 39426]. It shall also include any subsequent revisions to such designations. The terms "potash" and "commercial deposits of potash" shall have the same meaning as assigned by the U. S. Department of Interior.

C. It is the intent of the parties to this Agreement that the "Potash Area" designated by the State of New Mexico be identical to that designated by the U. S. Department of Interior. Accordingly, if the "potash area" designated in the Secretarial Order of October 21, 1986 [51 Fed. Reg. 39425] is revised, the OCC, on its own motion after notice and hearing as provided by applicable laws and regulations, will adopt the same revision.

II. Designation of Mine Reserves

A. Within ninety (90) days following adoption of thi. Agreement by the OCC and BLM and annually thereafter by January 31 if revised, each potash lessee, without regard to whether the lease covers State or Federal lands, shall file with the District Manager, BLM, a designation of the potash deposits considered by the potash lessee to be its life-of-mine reserves ("LMR"). For purposes of this Agreement, "life-of-mine reserves" means those potash deposits within the Potash Area reasonably believed by the potash lessee to contain potash ore in sufficient thickness and grade to be mineable using current day mining methods, equipment and technology. Information used by the potash lessee in identifying its LMR shall be filed with the BLM but will be considered privileged and confidential "trade secrets and commercial . . . information" within the meaning of 43 C.F.R. §2.13(c)(4) (1986) and not subject to public disclosure.

B. An authorized officer of the BLM shall review the information submitted by each potash lessee in support of its LMR designation and verify, upon request, that the data used by the potash lessee in establishing the boundaries of its LMR is consistent with data available to the BLM. Any disputes between the BLM and potash lessee concerning the boundary of a designated LMR shall be resolved in accordance with the

Department of Interior's Hearings and Appeals Procedures, 43 C.F.R. Part 4 (1986).

C. A potash lessee may amend its designated LMR by filing a revised designation with the BLM accompanied by the information referred to in Section A above. Such amendments must be filed by January 31 next following the date the additional data becomes available.

D. An authorized officer of the BLM shall commit the designated LMR of each potash lessee to a map(s) of suitable scale and thereafter revise the map(s) as necessary to reflect the latest amendments to any designated LMRs. These maps shall be considered privileged and confidential and exempt from disclosure under 43 C.F.R. Part 2 and will be used only for the purposes set forth in this Agreement.

III. Drilling in the Potash Area

A. All oil and gas wells drilled in the Potash Area after approval of this Agreement by the OCC and BLM, including those currently pending before the OCC and/or BLM, shall be subject to the terms of this Agreement.

B. It is the policy of the OCC and BLM to approve or deny applications for permits to drill (APD's) in the Potash Area in accordance with the following:

1. LMR and Buffer Zone. No oil or gas well shall be allowed from a surface location: (a) within the LMR of any potash lessee; (b) within one-fourth (1/4) mile, or a distance equal to the depth of the ore plus ten percent (10%), whichever is greater, of the LMR of any potash lessee; or (c) where the well casing will pass within one-fourth (1/4) mile, or a distance equal to

the depth of the ore plus ten percent (10%), whichever is greater, of the LMR of any potash lessee.

2. Outside Buffer Zone But Within One-Half (1/2) mile of LMR. An APD for an oil or gas well at a location more than one-fourth (1/4) mile, or a distance equal to the depth of the ore plus ten percent (10%), whichever greater, but less than one-half (1/2) mile from the LMR of any potash lessee may be approved only if: (a) the bottom hole location does not extend below the base of the Delaware Mountain Group, and (b) the well is drilled in accordance with the cementing and casing requirements set forth in Section V.

3. More Than One-Half Mile But Less Than One Mile From LMR. An APD for an oil or gas well at a location more than one-half (1/2) mile but less than one mile from the LMR of any potash lessee may be approved regardless of the depth of the bottom hole location provided: (a) wells with bottom hole locations below the base of the Delaware Mountain Group are drilled in accordance with the cementing and casing requirements set forth in Section V of this Agreement, and (b) wells to bottom hole locations above the base of the Delaware Mountain Group may be drilled without regard to the requirements in Section V of this Agreement but must be drilled in accordance with then current Industry safety standards.

4. More Than One Mile From LMR. An APD for an oil or gas well at a location more than one mile from the LMR of any potash lessee may be approved regardless of the depth of the bottom hole location and without regard to the requirements of Section V of this Agreement.

5. Open Mine Workings. No oil or gas well shall be allowed from any location where the well casing will pass within one-fourth (1/4) mile or a distance equal to the depth of the ore plus ten percent (10%), whichever is greater, of any open mine workings.

6. Abandoned Mine Workings. No oil or gas well shall be allowed from any location where the well casing will pass through or within one-fourth (1/4) of a mile or a distance equal to the depth of the ore plus ten percent (10%), whichever is greater, of any abandoned mine workings that are connected to an existing mine by an opening or barrier of one-hundred (100) feet or less unless the APD is accompanied by the sealing and safety plan and certification described in Paragraph C below.

7. An APD for a directionally drilled oil or gas well t a bottom hole location underlying the LMR of an potash lessee may be approved subject to th limitations and requirements set forth in Paragraphs - 6 above. Directionally drilled holes shall b drilled vertically until they have complete penetrated Marker Bed No. 126 (U.S.G.S.) of the Salad Formation at which time they may be deviated.

C. An oil and gas operator desiring to drill a well to bottom hole location that does not extend below the base of th Delaware Mountain Group from a surface location where the wel casing will pass through or within one-fourth (1/4) of a mil or a distance equal to the depth of the ore plus ten percen (10%), whichever is greater, of abandoned mine workings tha are connected to an existing mine by any opening or a barrie of one-hundred (100) feet or less shall prepare and submit t all affected potash lessees a plan and program for sealing of the area to be penetrated from other mine workings. Approva of any such plan shall be in the sole discretion of th affected potash lessees. Any approved plan shall be attache by the oil and gas operator to the APD for filing with the OCC and/or BLM. The oil and gas operator shall also complete certification in the form prescribed by the OCC and/or BLM tha the drilling of such well will not create a safety hazard t affected potash lessees.

D. It is the belief of both parties that the provision of this Agreement eliminate the need for drilling islands an three-year mining plans and, therefore, both agree that n drilling islands will be established in the Potash Area and th filing of three-year mining plans will be eliminated.

IV. Location of Wells and Notice to Potash Lessee

A. The BLM, upon request, will advise oil and gas lessees of the surface locations where wells will be allowed to develop the leases. Oil or gas leases covering areas designated a LMP by a potash lessee will be unitized to the extent possible with other areas where drilling is allowed.

B. An oil or gas operator desiring to drill an oil or gas well in the Potash Area or within one (1) mile of a potash lease shall prepare and file an APD with the OCC and/or BLM along with a map or plat showing the location of the proposed well. One copy of the APD and map or plat shall be served by registered mail, return receipt requested, on all potash leaseholders within one (1) mile of the proposed well location. However, if the APD is for an oil or gas well that will penetrate abandoned mine workings, all potash leaseholders in the Potash Area shall be notified. Proof of such ser c shall be attached to the APD and filed with the OCC and/o BLM. Within twenty (20) days of service of an APD and require documents, any potash leaseholder within one (1) mile of th proposed well location or any affected potash lessee if th proposed well will penetrate abandoned mine workings) may fil an objection with the OCC to the proposed well. If t objections cannot be resolved by agreement of the parties, t matter shall be referred for hearing before the OCC.

C. The failure of a potash leaseholder to object to well location or its agreement to the drilling locatio referred to in this Agreement shall not constitute a release of liability. Oil and gas leaseholders and those persons and/or entities involved in the development of the lease shall be responsible as provided by law for any damages caused by them to any person by the release of gases or liquids into the strata or atmosphere as a result of drilling activities.

V. Drilling and Casing Program

[Same as current R-111-A]

VI. Drilling Fluid for Salt Section

[Same as current R-111-A]

VII. Plugging and Abandonment of Wells

[Same as current R-111-A]

VIII. Filing of Well Surveys

The OCC may require an oil and gas operator to file a certified directional survey from the surface to a point below the lowest known potash bearing horizon on all wells drilled in the Potash Area. All encounters with flammable gases, including H_2S, shall be reported by the operator to the OCC.

IX. Additional Safety Requirements and Emergency Action

A. All oil and gas drilling activities within the Potash Area shall be performed using appropriate technology, equipment, and procedures to reduce the hazards of such activities to underground mines and miners and be conducted in accordance with the prudent operator standard.

B. Only the minimum number of wells necessary to develop an oil or gas lease will be allowed within the Potash Area.

C. In the event the increased oil and gas drilling activities allowed by this Agreement result in a safety hazard or if data developed in the course of such increased activities make it reasonably appear that such activities are or wi become a hazard to underground miners or mining activities, the BLM and/or OCC will, upon request, initiate proceedings in accordance with NMSA 70-2-23 and/or other applicable laws and regulations to review such data and take whatever emergency steps are found necessary to eliminate such hazard. Potash lessees may, in addition, initiate actions for injunctive relief under NMSA 70-2-29. The taking or failure to take such action by the OCC or any potash lessee shall not relieve the oil and gas lessee from liability for any damages caused by its oil and gas activities.

AGREED TO AND APPROVED THIS 23rd DAY OF November, 1987, BY THE FOLLOWING REPRESENTATIVES OF EACH INDUSTRY COMPRISING THE POTASH-OIL AREA SPECIAL RULES STUDY COMMITTEE:

For the Oil and Gas Industry:

For the Potash Industry:

W. S. Thayer

Donald Galbraith

1727L-7

EXHIBIT "A"
CASE 9316
ORDER R-111-P

CONSOLIDATED LAND DESCRIPTION OF THE KNOWN POTASH LEASING AREA, AS OF FEBRUARY 3, 1988

EDDY COUNTY, NEW MEXICO

TOWNSHIP 18 SOUTH, RANGE 30 EAST, NMPM

Section 10: SE/4 SE/4
Section 11: S/2 SW/4
Section 13: W/2 SW/4 and SE/4 SW/4
Section 14: W/2 NE/4, NW/4 and S/2
Section 15: E/2 NE/4, SE/4 SW/4 and SE/4
Section 22: N/2, N/2 SW/4, SE/4 SW/4 and SE/4
Section 23: All
Section 24: N/2 NW/4, SW/4 NW/4 and NW/4 SW/4
Section 26: NE/4, N/2 NW/4 and SE/4 NW/4
Section 27: N/2 NE/4 and NE/4 NW/4

TOWNSHIP 19 SOUTH, RANGE 29 EAST, NMPM

Section 11: SE/4 SE/4
Section 12: SE/4 NE/4 and S/2
Section 13: All
Section 14: NE/4, SE/4 NW/4 and S/2
Section 15: SE/4 SE/4
Section 22: NE/4, E/2 W/2 and SE/4
Section 23: All
Section 24: All
Section 25: NW/4 NW/4
Section 26: N/2 NE/4 and NW/4
Section 27: NE/4 and E/2 NW/4

TOWNSHIP 19 SOUTH, RANGE 30 EAST, NMPM

Section 2: SW/4
Section 3: W/2 SW/4, SE/4 SW/4, S/2 SE/4 and NE/4 SE/4
Section 4: Lots 3 and 4, SW/4 NE/4, S/2 NW/4 and S/2
Section 5: Lots 1, 2, and 3, S/2 NE/4, S/2 NW/4 and S/2
Section 6: S/2 SE/4 and NE/4 SE/4
Sections 7 to 10 inclusive
Section 11: S/2 NE/4, NW/4 NW/4 and S/2
Section 12: NE/4, S/2 NW/4 and S/2
Section 13: NE/4, W/2, N/2 SE/4 and SW/4 SE/4
Sections 14 to 18 inclusive
Section 19: Lots 1, 2, and 3, NE/4, E/2 NW/4, NE/4 SW/4, E/2 SE/4 and NW/4 SE/4

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EXHIBIT "A" con'd

Section 25: NW/4 NW/4
Section 26: NE/4 NE/4, W/2 NE/4, W/2, W/2 SE/4 and SE/4 SE/4
Section 27: All
Section 28: All
Section 29: E/2, E/2 NW/4 and NW/4 NW/4
Section 32: E/2 and SE/4 SW/4
Section 33 to 35 inclusive
Section 36: NW/4 NW/4, S/2 NW/4 and S/2

TOWNSHIP 19 SOUTH, RANGE 31 EAST, NMPM
Section 7: Lots 1, 2, and 3 and E/2 NW/4
Section 18: Lots 1, 2, and 3 and SW/4 NE/4, E/2 NW/4 and NE/4 SW/4
Section 31: Lot 4
Section 34: SE/4 SE/4
Section 35: S/2 SW/4 and SW/4 SE/4
Section 36: S/2 SE/4

LEA COUNTY, NEW MEXICO

TOWNSHIP 19 SOUTH, RANGE 32 EAST, NMPM
Section 31: Lot 4
Section 33: Lots 1 to 4 inclusive and N/2 S/2
Section 34: Lots 1 to 4 inclusive and N/2 S/2
Section 35: Lots 1 to 4 inclusive and N/2 S/2
Section 36: Lots 1 to 4 inclusive, SE/4 NE/4, NW/4 SW/4 and NE/4 SE/4

TOWNSHIP 19 SOUTH, RANGE 33 EAST, NMPM
Section 22: SE/4 NE/4, E/2 SW/4 and SE/4
Section 23: S/2 NW/4, SW/4, W/2 SE/4 and SE/4 SE/4
Section 25: SW/4 NW/4, W/2 SW/4 and SE/4 SW/4
Section 26: All
Section 27: All
Section 28: S/2 SE/4 and NE/4 SE/4
Section 30: Lots 2 to 4 inclusive, S/2 NE/4, SE/4 NW/4, E/2 SW/4 and SE/4
Section 31: All
Section 32: NE/4, S/2 NW/4 and S/2
Sections 33 to 35 inclusive
Section 36: W/2 NE/4, SE/4 NE/4, NW/4 and S/2

TOWNSHIP 19 SOUTH, RANGE 34 EAST, NMPM

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EXHIBIT "A" con'd

EDDY COUNTY, NEW MEXICO

TOWNSHIP 20 SOUTH, RANGE 29 EAST, NMPM

Section 1:	SE/4 NE/4 and E/2 SE/4
Section 13:	SW/4 NW/4, W/2 SW/4 and SE/4 SW/4
Section 14:	NW/4 NE/4, S/2 NE/4, NW/4 and S/2
Section 15:	E/2 E/2, SE/4 SW/4 and W/2 SE/4
Section 22:	E/2 and E/2 NW/4
Section 23:	All
Section 24:	SW/4 NE/4, W/2, W/2 SE/4 and SE/4 SE/4
Section 25:	N/2, SW/4, W/2 SE/4 and NE/4 SE/4
Section 26:	All
Section 27:	E/2
Section 34:	NE/4
Section 35:	N/2
Section 36:	W/2 NE/4 and NW/4

TOWNSHIP 20 SOUTH, RANGE 30 EAST, NMPM

Sections 1 to 4 inclusive	
Section 5:	Lots 1 to 3 inclusive, S/2 N/2 and S/2
Section 6:	Lots 5, 6, and 7, S/2 NE/4, E/2 SW/4 and SE/4
Section 7:	Lots 1 and 2, E/2 and E/2 NW/4
Sections 8 to 17 inclusive	
Section 18:	E/2
Section 19:	E/2 and SE/4 SW/4
Sections 20 to 29 inclusive	
Section 30:	Lots 1 to 3 inclusive, E/2 and E/2 W/2
Section 31:	NE/4 and E/2 SE/4
Sections 32 to 36 inclusive	

TOWNSHIP 20 SOUTH, RANGE 31 EAST, NMPM

Section 1:	Lots 1 to 3 inclusive, S/2 N/2 and S/2
Section 2:	All
Section 3:	Lots 1 and 2, S/2 NE/4 and SE/4
Section 6:	Lots 4 to 7 inclusive, SE/4 NW/4, E/2 SW/4, W/2 SE/4 and SE/4 SE/4
Section 7:	All
Section 8:	S/2 N/2 and S/2
Section 9:	S/2 NW/4, SW/4, W/2 SE/4 and SE/4 SE/4

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EXHIBIT "A" con'd

LEA COUNTY, NEW MEXICO

TOWNSHIP 20 SOUTH, RANGE 32 EAST, NMPM
Sections 1 to 4 inclusive
Section 5: S/2 SE/4
Section 6: Lots 4 to 7 inclusive, SE/4 NW/4, E/2 SW/4 and SW/4 SE/4
Sections 7 to 36 inclusive

TOWNSHIP 20 SOUTH, RANGE 33 EAST, NMPM
Sections 1 to 36 inclusive

TOWNSHIP 20 SOUTH, RANGE 34 EAST, NMPM
Section 6: Lots 3 to 7 inclusive, SE/4 NW/4, E/2 SW/4, W/2 SE/4 and SE/4 SE/4
Section 7: All
Section 8: SW/4, S/2 NW/4, W/2 SE/4 and SE/4 SE/4
Section 16: W/2 NW/4, SE/4 NW/4, SW/4 and S/2 SE/4
Sections 17 to 21 inclusive
Section 22: N/2 NW/4, SW/4 NW/4, SW/4, W/2 SE/4, and SE/4 SE/4
Section 26: SW/4, W/2 SE/4 and SE/4 SE/4
Sections 27 to 35 inclusive
Section 36: SW/4 NW/4 and W/2 SW/4

EDDY COUNTY, NEW MEXICO

TOWNSHIP 21 SOUTH, RANGE 29 EAST, NMPM
Sections 1 to 3 inclusive
Section 4: Lots 1 through 16, NE/4 SW/4 and SE/4
Section 5: Lot 1
Section 10: N/2 NE/4, SE/4 NE/4 and SE/4 SE/4
Sections 11 to 14 inclusive
Section 15: E/2 NE/4 and NE/4 SE/4
Section 23: N/2 NE/4
Section 24: E/2, N/2 NW/4 and SE/4 NW/4
Section 25: NE/4 NE/4 and S/2 SE/4
Section 35: Lots 2 to 4 inclusive, [illegible]2 NE/4, NE/4 SW/4 and N/2 [illegible]
Section 36: Lots 1 to 4 inclusive, NE/4,

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EXHIBIT "A" con'd

TOWNSHIP 21 SOUTH, RANGE 31 EAST, NMPM
Sections 1 to 36 inclusive

LEA COUNTY, NEW MEXICO

TOWNSHIP 21 SOUTH, RANGE 32 EAST, NMPM
Sections 1 to 27 inclusive
Section 28: N/2 and N/2 S/2
Sections 29 to 31 inclusive
Section 32: NW/4 NE/4, NW/4 and NW/4 SW/4
Section 34: N/2 NE/4
Section 35: N/2 N/2
Section 36: E/2, N/2 NW/4, SE/4 NW/4 and NE/4 SW/4

TOWNSHIP 21 SOUTH, RANGE 33 EAST, NMPM
Section 1: Lots 2 to 7 inclusive, Lots 10 to 14 inclusive, N/2 SW/4 and SW/4 SW/4
Sections 2 to 11 inclusive
Section 12: NW/4 NW/4 and SW/4 SW/4
Section 13: N/2 NW/4, S/2 N/2 and S/2
Sections 14 to 24 inclusive
Section 25: N/2, SW/4 and W/2 SE/4
Sections 26 to 30 inclusive
Section 31: Lots 1 to 4 inclusive, NE/4, E/2 W/2, N/2 SE/4 and SW/4 SE/4
Section 32: N/2 and NW/4 SW/4
Section 33: N/2
Section 34: NE/4, N/2 NW/4 and E/2 SE/4
Section 35: All
Section 36: W/2 NE/4, NW/4 and S/2

TOWNSHIP 21 SOUTH, RANGE 34 EAST, NMPM
Section 17: W/2
Section 18: All
Section 19: Lots 1 to 4 inclusive, NE/4, E/2 W/2, N/2 SE/4 and SW/4 SE/4
Section 20: NW/4 NW/4
Section 30: Lots 1 and 2 and NE/4 NW/4
Section 31: Lots 3 and 4

EXHIBIT "A" con'd

TOWNSHIP 22 SOUTH, RANGE 29 EAST, NMPM
Sections 1 and 2 inclusive
Section 3: SE/4 SW/4 and SE/4
Section 9: S/2 NE/4 and S/2
Sections 10 to 16 inclusive
Section 17: S/2 SE/4
Section 19: SE/4 NE/4 and E/2 SE/4
Sections 20 to 28 inclusive
Section 29: N/2 N/2, S/2 NE/4 and SE/4
Section 30: NE/4 NE/4
Section 31: Lots 1 to 4 inclusive, S/2 NE/4, E/2 W/2 and SE/4
Sections 32 to 36 inclusive

TOWNSHIP 22 SOUTH, RANGE 30 EAST, NMPM
Sections 1 to 36 inclusive

TOWNSHIP 22 SOUTH, RANGE 31 EAST, NMPM
Sections 1 to 11 inclusive
Section 12: NW/4 NE/4, NW/4 and NW/4 SW/4
Section 13: S/2 NW/4 and SW/4
Sections 14 to 23 inclusive
Section 24: W/2
Section 25: NW/4
Section 26: NE/4 and N/2 NW/4
Sections 27 to 34 inclusive

LEA COUNTY, NEW MEXICO

TOWNSHIP 22 SOUTH, RANGE 32 EAST, NMPM
Section 1: Lot 1
Section 6: Lots 2 to 7 inclusive and SE/4 NW/4

TOWNSHIP 22 SOUTH, RANGE 33 EAST, NMPM
Section 1: Lots 1 to 4 inclusive, S/2 N/2 and N/2 S/2
Section 2: All
Section 3: Lot 1, SE/4 NE/4 and SE/4
Section 6: Lot 4
Section 10: NE/4
Section 11: NW/4 NE/4 and NW/4

TOWNSHIP 22 SOUTH, RANGE 34 EAST, NMPM
Section 6: Lots 4 to 6 inclusive

Section 12: SW/4 NW/4 and SW/4
Section 13: SW/4 NE/4, W/2 and W/2 SE/4
Section 14: All
Section 15: E/2, SE/4 NW/4 and SW/4
Section 16: SW/4 and S/2 SE/4
Section 17: NW/4 and S/2
Sections 18 to 23 inclusive
Section 24: W/2 NE/4 and W/2
Section 25: W/2 NE/4, NW/4, N/2 SW/4 and NW/4 SE/4
Sections 26 to 34 inclusive
Section 35: N/2 NW/4 and SW/4 NW/4

TOWNSHIP 24 SOUTH, RANGE 29 EAST, NMPM
Section 2: Lots 2 to 4 inclusive
Section 3: Lot 1

TOWNSHIP 24 SOUTH, RANGE 30 EAST, NMPM
Section 1: Lots 1 to 4 inclusive, S/2 N/2, SW/4 and NW/4 SE/4
Section 2: All
Section 3: All
Section 4: Lots 1 and 2, S/2 NE/4, SE/4 NW/4, SW/4 SW/4, E/2 SW/4 and SE/4
Section 9: N/2, N/2 SW/4, SE/4 SW/4 and SE/4
Section 10: All
Section 11: All
Section 12: W/2 NW/4 and NW/4 SW/4
Section 14: W/2 NE/4 and NW/4
Section 15: NE/4 and N/2 NW/4

TOWNSHIP 24 SOUTH, RANGE 31 EAST, NMPM
Section 3: Lots 2 to 4 inclusive, SW/4 NE/4, S/2 NW/4, SW/4 and W/2 SE/4
Section 4: All
Section 5: Lots 1 to 4 inclusive, S/2 N/2, N/2 S/2 and SE/4 SE/4
Section 6: Lots 1 to 6 inclusive, S/2 NE/4, SE/4 NW/4, NE/4 SW/4 and N/2 SE/4
Section 9: E/2 and NW/4
Section 10: W/2 NE/4 and W/2
Section 35: Lots 1 to 4 inclusive, S/2 N/2 and N/2 S/2
Section 36: Lots 1 and 2, SW/4 NW/4 and N/2 SW/4

TOWNSHIP 25 SOUTH, RANGE 31 EAST, NMPM

EDDY COUNTY, NEW MEXICO

TOWNSHIP 23 SOUTH, RANGE 28 EAST, NMPM
Section 1: Lot 1

TOWNSHIP 23 SOUTH, RANGE 29 EAST, NMPM
Sections 1 to 5 inclusive
Section 6: Lots 1 to 6 inclusive, S/2 NE/4, SE/4 NW/4, E/2 SW/4 and SE/4
Section 7: NE/4 and NE/4 NW/4
Section 8: N/2, N/2 SW/4, SE/4 SW/4 and SE/4
Sections 9 to 16 inclusive
Section 17: NE/4 and E/2 SE/4
Sections 21 to 23 inclusive
Section 24: N/2, SW/4 and N/2 SE/4
Section 25: W/2 NW/4 and NW/4 SW/4
Section 26: All
Section 27: All
Section 28: N/2, N/2 SW/4, SE/4 SW/4 and SE/4
Section 33: N/2 NE/4 and NE/4 NW/4
Section 34: NE/4, E/2 NW/4, NW/4 NW/4, NE/4 SW/4 and SE/4
Section 35: All
Section 36: W/2 NE/4, NW/4 and N/2 SW/4

TOWNSHIP 23 SOUTH, RANGE 30 EAST, NMPM
Sections 1 to 18 inclusive
Section 19: N/2, N/2 SW/4, SE/4 SW/4 and SE/4
Section 20: All
Section 21: All
Section 22: N/2, S/2 SW/4, N/2 S/2 and SE/4 SE/4
Sections 23 to 25 inclusive
Section 26: E/2, SE/4 NW/4 and SW/4
Section 27: N/2 NW/4, SW/4 NW/4, SE/4 SW/4, S/2 SE/4 and NE/4 SE/4
Section 28: N/2 and SW/4
Section 29: N/2 and SE/4
Section 30: N/2 NE/4
Section 32: N/2 NE/4
Section 33: SE/4 NE/4, N/2 NW/4, NE/4 SE/4 and S/2 SE/4
Sections 34 to 36 inclusive

TOWNSHIP 23 SOUTH, RANGE 31 EAST, NMPM
Section 2: Lot 4, SW/4 NW/4 and W/2 SE/4
Sections 3 to 7 inclusive
Section 8: NE/4 NE/4, W/2 NE/4 and W/2

Chapter IX

REGULATIONS PERTAINING TO OIL AND GAS DRILLING

APPENDIX B

federal register

Friday
November 18, 1988

Part V

Department of the Interior

Bureau of Land Management

43 CFR Part 3160

Onshore Oil and Gas Operations; Federal and Indian Oil and Gas Leases; Drilling Operations; Final Rule 060#2

46798 Federal Register / Vol. 53, No. 223 / Friday, November 18, 1988 / Rules and Regulations

DEPARTMENT OF THE INTERIOR

Bureau of Land Management

43 CFR Part 3160

[AA-630-87-4111-02; Circular No. 2613]

Onshore Oil and Gas Operations; Federal and Indian Oil and Gas Leases; Onshore Oil and Gas Order No. 2, Drilling Operations

AGENCY: Bureau of Land Management, Interior.

ACTION: Final rulemaking.

SUMMARY: This final rulemaking provides for the issuance of Onshore Oil and Gas Order No. 2 under the provisions of 43 CFR Subpart 3164. This order implements and supplements the requirements found in 43 CFR Subpart 3160 as they apply to drilling operations, specifically, those requirements found at §§ 3162.3-1, 3162.3-4, 3162.4-1, 3162.4-2, 3162.5-1, 3162.5-2, and 3162.5-3. This Order addresses the Bureau of Land Management's uniform national standards for the minimum levels of performance expected from lessees and operators when conducting drilling operations on Federal and Indian (except Osage Tribe) lands. The Order also details enforcement actions and prescribes the manner in which variances may be obtained from specific standards. The Bureau's specific existing internal guidelines on the subject of drilling operations have never been published formally in a Notice to Lessees and Operators, so that this Order has no direct predecessor.

EFFECTIVE DATE: December 19, 1988.

ADDRESS: Inquiries or suggestions should be sent to: Director (610), Bureau of Land Management, Room 601, Premier Building, 1800 C Street NW., Washington, DC 20240.

FOR FURTHER INFORMATION CONTACT: Howard A. Lemm, (801) 524-3000 or Robert Kent, (202) 653-2174.

SUPPLEMENTARY INFORMATION: Section 3164.1 of 43 CFR Part 3160 provides for the issuance of Onshore Oil and Gas Orders when needed to implement and supplement the regulations in that part. All Orders are promulgated through the rulemaking process and, when issued in final form, apply on a nationwide basis. This final rulemaking contains such an Order, No. 2, Drilling Operations.

This Order establishes specific and detailed requirements along with minimum standards covering well control during drilling, casing and cementing, drilling mud and the circulating system, drill stem testing, special drilling operations, related surface use, and the abandonment of drilling operations. These operation standards will be used in conjunction with the broad requirements of Part 3160 and Onshore Oil and Gas Order No. 1. This Order also classifies all violations as minor or major. In addition, the Order establishes the process for initially classifying a violation as minor and reissuing the violation as major if not corrected and continued drilling has increased the adverse impact.

This Order sets standards designed to be minimums for drilling operations at specific pressures under differing conditions and in different parts of the country. It is recognized that, under some conditions, additional requirements will be routinely imposed, or general variances to specific requirements will be granted, either in approval documents or on a field basis. In some instances, the Order relies on existing standards prepared by the American Petroleum Institute, the Occupational Safety and Health Administration, the Texas Railroad Commission, and other agencies. These standards are generally accepted in the oil and gas industry.

The proposed rulemaking for this Onshore Oil and Gas Order No. 2 was published in the Federal Register on August 13, 1987 (52 FR 30310). The comment period ended on October 13, 1987. A total of 36 comments were received: 24 from business entities, 8 from offices of Federal agencies, 2 from trade associations, 1 from an Indian tribe, and 1 from an individual. The comments are discussed in the appropriate portions of this preamble where the provisions of the Order they relate to are discussed.

Discussion of II Definitions

The proposed Order defined the term "freeboard". This term has been removed from the final rulemaking because the only reference to it was in the provision on minimum standards for surface use, which has also been removed from the final rulemaking as explained elsewhere in this preamble.

The term "function test" has been changed to "functionally operated" for clarification. At the suggestion of a comment, the word "wellbore" has been added to describe the type of pressures under discussion.

The term "H_2S trim" was removed in the final rulemaking since the final rulemaking now contains no reference to this term.

Several comments suggested changes to the term and definition for "High Pressure Zone" to include low pressure or lost circulation zones. This term has been replaced throughout the Order by "Abnormal Pressure Zone", which refers to low pressure as well as high pressure, and the definition modified to reflect this distinction.

The term "fresh water" has been removed from the Definitions and replaced by the term "usable water" wherever it occurred in the text. This Order requires the protection of usable water, which includes fresh water. The standard for "usable water" of 10,000 ppm. of total dissolved solids is based on the regulatory definition by the Environmental Protection Agency of "drinking water" at 40 CFR 144.3.

A new definition for the term "lessee" is incorporated in this final rulemaking to reflect a change in definition of the term in 43 CFR Part 3160 since the Draft Order was published for comment.

Several comments on the definition of "mud for plugging purposes" suggested that it too restrictive. By using this term, the proposed Order did not intend to exclude the use of other materials. Therefore, the final rulemaking has adopted these comments and the definition has been expanded to include other materials. Consultation with the authorized officer is encouraged to determine the need for mud for plugging purposes to assure that usage is consistent with environmental concerns and established operating practices.

The term "neat cement" does not appear in the final rulemaking, and the term has been removed from the definitions.

The definition for "tagging the plug" has been modified at the suggestion of comments to remove the reference to an amount of weight not to be exceeded when placing the weight of the drill pipe on the plug. This modification was made because no real purpose was served by placing a maximum on the amount of weight placed on the plug.

At the suggestion of a comment, the definition for "targeted tee or turn" has been modified slightly for increased clarity.

The definition of "test plug" is also amended for clarity.

The term "exploratory well" has been redefined to improve the description of what constitutes an exploratory (wildcat) well.

Seven additional terms have been added to the Definitions section in this final rulemaking in response to comments received. The definition chosen for each of these terms was either as defined by a referenced regulation or, when this was not the case, generally by the most commonly used definition incorporating oil field vernacular.

Discussion of III Requirements

A comment was received requesting clarification of the introductory portion of each "Requirement" section and the specific minimum standards that are then listed below each of these requirement sections. The purpose of the Requirements section is to provide direction as to what is to be included in the Application for Permit to Drill (APD), as well as to provide general direction as to the applicability of the minimum standards that follow each of these sections. Neither the Requirements sections nor the Minimum Standards sections are intended to stand alone. However, each section has been reviewed, and clarification added as appropriate.

A. Well Control Requirements

This portion of the rulemaking contains perhaps the most detailed and technical section of the Onshore Order for Drilling Operations. The principal reason for this is the need to establish minimum standards by pressure rating the equipment being utilized. Therefore, even though there is duplication in some of the minimum standards as they uniformly apply to 2M, 3M, 5M, and 10M and 15M systems, substantial differences in usage of equipment require each pressure rating to be listed separately.

A comment requested a definition of the term "operational" used in section III A.1. A definition for this term has been included in the final rulemaking in the Definitions section.

Other comments were received on this same section (III.A.1.) concerning the criteria for establishing the pressure rating of the well control equipment to be used. In the draft order these criteria were established "assuming no fluid (except gas) in the hole". The oil industry comments received on this section were critical of the criteria as being too restrictive and suggestive of a worst-case scenario. While a worst-case scenario represents a legitimate method, used by a number of regulatory agencies and energy companies in developing their design criteria for well control, a compromise has been adopted in the final rulemaking because assuming a totally evacuated hole (except gas) is too extreme to use for establishing minimum standards.

The compromise wording adopted assumes a "partially evacuated hole with a pressure gradient of 0.22 psi/ft." as the criteria for system design. This adopted pressure gradient parameter assumes a partially evacuated hole whereby the hydrostatic pressure gradient is approximately double that assumed in the draft order. It also represents approximately one-half the hydrostatic pressure of a column of water. In addition to being an easily remembered specification, it also represents an appropriate compromise and a legitimate minimum design criterion.

A comment was received concerning section III.A.2. suggesting that the Order should establish well control training provisions. Although this concept has merit, well control training for operators is not within the identified scope of this rulemaking and accordingly is not addressed here. However, this comment has been referred to appropriate BLM personnel for separate consideration.

Minimum standard III.A.i. has been editorially modified for clarity by adding the words "well control" in describing the device required as suggested in the comments received.

The minimum standard III.A.ii. for 2M systems has been modified as suggested in comments to clarify that an "annular preventer, double ram or two rams with one being a blind and one being a pipe ram," is required. This was the intention of the minimum standard contained in the draft Order, but as written could have been understood to require 4 rams, with 1 being a double, and including a blind and a pipe ram as well.

The minimum standard for III.A.iii. received several comments. Some of these noted that 3M systems are the ones most commonly available in some regions. Their use, it was noted, was predicted on availability rather than necessity. Compliance with the provisions of this Order is considered a minimum requirement. As stated in I.D.1., higher rated equipment may be used to meet and maintain these standards without being held to the higher standards normally applied to such equipment. Therefore, if the pressure expected is in the 2M category, the operator should state this in the application. The use of equipment of a higher pressure rating than that approved does not subject the operator to the specifications for the higher pressure rated equipment. Operators are reminded to base requests or equipment approval on this understanding. Since I.D.1. clearly addresses the above mentioned concerns, no further explanation or modification was deemed necessary in the text of the final rulemaking. It should be noted that if drilling were to occur in an area where a 2M system was appropriate and approved, the use of a 3M system without, for example, an annular preventer (which is not required in a 2M system) is, of course, fully acceptable. Accordingly, along with the more liberal assumption of a .22 psi/ft fluid in the hole rather than fully evacuated, as explained earlier, the standard is now appropriate without further modification and as such is consistent with API RP53.

Another comment on this section addressed the draft minimum standard for a drilling spool with side outlet connections. The comment stated that this was too restrictive because the blowout preventer (BOP) itself could have side outlets and functions in the same manner as the drilling spool. The final rulemaking has been modified to allow for this type of equipment and usage not only for a 3M system but for higher rated pressure systems as well.

The minimum standard in the final rulemaking for 2 kill line valves was modified from the draft as suggested by a comment to permit one of the two valves to be a check valve to clarify the intent of the Order.

The minimum standard for safety valves and subs was modified as suggested by comments to clarify intent and now reads "safety valve and subs to fit all drill string connections in use". This has been modified similarly in the requirements for higher rated systems as well.

The term "BOPE" was added to the minimum standard for clarification. It now reads, "All BOPE connections subject to well pressure shall be flanged, welded, or clamped." Connections not subjected to well pressure in the cellar, for example, or those connections upstream from check valves, etc., could be hammer unions as some comments suggested. The minimum standard addresses only those connections directly subject to well pressure conditions. This same modification has been made to the minimum standards for higher rated systems.

The minimum standards for 5M systems in section III.A.iv. generated numerous comments, many of which addressed similar items and nearly all of which suggested minor changes for clarity. As noted below, these changes were for the most part incorporated in this final rulemaking.

The second item in the minimum standards for 5M systems has been completely reworded at the suggestion of comments and broken into 2 separate standards to improve clarity and expound the original intent concerning the appropriate usage of a second pipe ram.

The use of remote kill line on a 5M system received several conflicting comments. This minimum standard is retained as proposed, because it reflects an appropriate and necessary minimum standard.

Comments were received suggesting that the minimum standard in the draft requiring an inside BOP or float sub was not appropriate and did not represent a true minimum standard. The requirement has not been removed. because having an inside BOP or float sub on site that will fit the drill string is standard procedure and necessary to prevent blowouts. However. this standard has been amended to apply specifically to drill string connections in use rather than the entire string.

The minimum standards for 10M and 15M systems in section III.A.2.a.v. received general comments expressing satisfaction with all the specified standards as being appropriate and necessary given the high relative pressures under consideration. However. other useful comments were received as discussed below which addressed issues that warranted further consideration.

The minimum standard for a rotating head if conditions warrant as required in the draft Order was removed since it was not stated as a true minimum standard. The authorized officer at the time the APD is approved always has the discretionary authority to require additional equipment if conditions warrant.

Two comments addressed the minimum standard that requires "3 chokes. 1 being remotely controlled." This standard remains as stated in the draft Order since this requirement is well-accepted operating practice and represents an appropriate minimum standard.

The requirement for a wear ring received several comments. These ranged from the belief that a wear ring is appropriate for all pressure systems to the belief that a wear ring is inappropriate for any system. The minimum standard for a wear ring on 10M and 15M systems has been retained in the final rulemaking in realization that detecting significant wear particularly in these higher rated systems is directly related to responsible well control equipment requirements.

The minimum standard in paragraph III.A.2.a.vii. attracted 1 comment suggesting different wording to recognize the existence of alternative measures that would satisfy the intent of the standard. This minimum standard has been modified to accommodate this request.

The minimum standard in paragraph III.A.2.b.i. generated several comments. some of which suggested that the choke lines should be anchored. This requirement has been included in the final rulemaking. This minimum standard also received comment concerning the requirement that the lines be straight unless turns use tee blocks or are targeted with running tees. This part of the minimum standard was not further modified since it represents an appropriate minimum standard consistent with established operating practice. Operators are reminded that if an instance occurs whereby a legitimate exception to this practice is necessary a variance can be requested as explained elsewhere in this Order.

Several comments were received concerning paragraph III.A.2.b.ii., which relates to the choke manifold equipment configurations. This standard was modified for clarity to improve the original intended meaning. Several valves as shown on the drawing have been removed or their size reduced as suggested in comments since they did not serve an operational purpose and. therefore. were not true minimum standards. Another comment on the choke manifold system urged that wording should be incorporated to state that the system should be kept from freezing. Since the Order requires that all equipment shall be "operational", which includes keeping components from freezing or from being affected by any other factors that would render them non-operational. no greater specificity in this regard is necessary.

As requested in comments. the requirements of this subpart have been clarified by the addition of minimum standards III.A.2.b.iii. and III.A.2.b.iv. These paragraphs more clearly specify the intent of the Order relating to unrestricted flow for valve lines. and the design for pressure gauges.

The pressure accumulator system minimum standards for 3M systems in section III.A.2.c.ii. attracted several general and somewhat divergent comments. No consensus or necessity for modification was expressed. and the final rulemaking in this section remains unchanged.

The minimum standards for 5M accumulator systems in section III.A.2.c.iii. received several comments stating that, as worded. the standards were excessive. The compromise wording adopted attempts to address the concerns of the comments. However. the 50 percent safety factor for 3 ram systems is retained after a review of manufacturers' recommendations as well as industry recommended practices since 5M and higher pressure rated systems typically require more stored volume due to higher BOP stacks. more piping length. etc.

Paragraph III.A.2.f. was amended to reflect suggestions in several comments offering improved language to clarify the minimum standard for accumulator pump capacity in accordance with conventional use. Under the revised minimum standard. the accumulator system is to be isolated rather than removed from service for testing the pump. Furthermore. the pumps are required to be capable of obtaining a minimum of 200 psi pressure above the specified accumulator precharge pressure. This change reflects a recognition that the 1200 psi standard in the proposed Order unduly restricted use of lower pressure accumulator systems.

Paragraph III.A.2.g. has been modified to specify how the valve position is to be maintained. as requested in several comments.

Paragraph III.A.2.h. generated several comments requesting modified language. A statement has been added to clarify the intent that remote controls are not required for 2M systems. The requirement for remote controls for 3M systems remains in place. Again. operators are reminded that if a 2M system is adequate under the requirements of this Order. and the use of a 3M system is being used only because of its availability. this should be noted at the time of approval and the request for approval should reflect equipment specified to handle 2M pressure situations. Only the specifications necessary for 2M systems would be enforced.

The minimum standard for well control equipment testing. III.A.2.i.i., received a comment on acceptable test fluids. Clear water or an appropriate clear liquid for subfreezing temperatures with a viscosity similar to water is required by this final rulemaking. Use of a drilling fluid rather than a clear liquid could mask and/or seal small leaks and. therefore. such use is not considered an appropriate practice or minimum standard. and the rulemaking has been amended to specify liquid rather than fluid.

The next provision providing minimum standards and enforcement provisions for well control equipment testing. in section III.A.2.i.ii., received comments that expressed concern as to the period of time to maintain the pressure test. This minimum standard has been amended to effect a compromise between the draft Order and the varying comments received. The final rulemaking specifies that the test shall be maintained for "10 minutes or until the provisions of the test are met. whichever is greater" instead of the 15-minute test period specified in the draft Order. Utilization of a test plug is addressed in the final rulemaking along with accompanying provisions for its pressure testing.

The length of test specified in III.A.2.i.iii. was similarly modified to "10 minutes or until provisions of the test are met".

Language in III.A.2.i.iv.B. is amended to make it clear that the test is to be performed when any seal subject to test pressure is broken.

Minimum standard III.A.2.i.vii is amended to require that the annular preventer shall be functionally operated at least weekly in order to determine whether the equipment is in working order without subjecting it to well bore pressures. This requirement would not significantly damage or cause premature wear of the rubber element.

The minimum standard III.A.2.i.ix. was amended for clarity to include the words "pit level" in describing the blowout prevention equipment (BOPE) drill to be conducted as suggested in a comment. This clarification refers to an exercise to be performed by the rig crew in response to a simulation of a gain in the mud pit level that would indicate an entry of fluid in the well bore.

B. Casing and Cementing Requirements

Many comments were received concerning the provisions for casing and cementing. Although the philosophy of what constitutes good minimum standards varied somewhat throughout these comments, those comments that provided alternative language to accomplish the perceived intent of the drafted standards were especially useful. The efforts of those commentators are especially appreciated in resolving and arriving at the appropriate minimum standards herein incorporated.

Numerous changes in the introductory language that precedes the minimum standards have been made as the result of comments. The draft order inconsistently referred to fresh water zones and to usable water zones needing protection. References to fresh water zones have been replaced with the term "usable water zones" throughout this final rulemaking for consistency and for regulatory compliance since usable water zones, which include fresh water zones, are also required to be protected.

Comments also suggested alternatives to the term "leasable mineral deposits." This term has been replaced as suggested by the term "valuable deposit of minerals" and is redefined as indicated in the definitions.

The criterion for casing setting depth has been revised. The draft criterion attracted more comments than any other single item in the proposed rulemaking. This requirement as it appears in the final rulemaking is consistent with accepted standard field operating practice and establishes the standard for design assuming normal drilling operations and conditions. In this context, the casing would not have to be designed to anticipate a completely unloaded situation down-hole.

The minimum design factors for tension, collapse, and burst have been removed in this final rulemaking, because of the great variations in calculation methods within industry among companies and from region to region. However, the operator will be required to submit the design factors that were utilized in his design for all exploratory wells and/or other wells as specified by the authorized officer.

The casing design factors for formation pressure gradients and fracture gradients attracted several comments. However, since both items occur with a statement "lacking better data", there was a consensus that these criteria are appropriate.

The minimum clearance provision for a hole/casing annulus received considerable comment. The necessity for an acceptable clearance was widely recognized, yet concern was expressed because of drill bit and casing size availability considerations. Several comments included excellent data on commonly accepted hole/casing annulus clearances that are in part derived from drill bit and casing size availability. The most common example cited was the use of 7 inch casing in an 8 1/2 inch hole. This calculates to a 0.422 inch clearance on all sides, which, according to both the comments and further research within BLM, is the "smallest" prudent clearance necessary to provide adequate isolation. Therefore, the final rulemaking establishes 0.422 inch clearance on all sides as the minimum design criterion, replacing 0.500 inch. Some comments strongly suggested that as much as 1 inch on all sides may be necessary, but the final rulemaking establishes a practicable minimum standard. It is recognized that there could be exceptions in unique circumstances when the operator or the authorized officer may wish to vary this requirement. These rare exceptions can be dealt with by requesting or requiring a variance as explained elsewhere in this Order. It should be realized that, as with any minimum standard or requirement, the authorized officer may require an increased clearance depending on field conditions. For example, depending on circumstances, the authorized representative may require additional clearance for surface casing strings.

The "waiting on cement" time requirement drew several comments that differed widely as to the suggested appropriate times. This requirement has been amended to indicate that the time must be adequate to achieve a minimum of 500 psi compressive strength at the casing shoe prior to drilling out. This change was at the suggestion of comments received and represents the generally accepted field operating practice.

The minimum standard for casing in item III.B.1.a. has been amended as suggested in comments to improve clarity and provide for consistency with similar regulatory standards. The standard is strengthened by requiring testing and by requiring reconditioned casing to meet or exceed API standards for new casing.

The minimum standard for liners in paragraph III.B.1.b. attracted comments suggesting the overlap should be as much as 300 feet or as little as 50 feet. Maintaining the minimum standard at 100 feet of overlap was deemed the most appropriate to combine most beneficially safety and economy. Operators are free to exceed this minimum standard.

An additional comment on this section suggested language making it clear when a pressure test for liners should be performed, and setting the standards for such a test. This suggestion has been adopted in the final rulemaking.

At the request of comments, minimum standard III.B.1.e. has been amended to specify that the required report is to be made before running the next string of casing or before requesting plugging orders, whichever occurs first.

The minimum standard in paragraph III.B.1.f. received comments both on the standard for placement of centralizers and on the standard for determining the corrective action. These comments have been adopted. The standards have been amended to improve the likelihood of there being an adequate cement bond.

Minimum standard III.B.1.g. for use of top and bottom plugs was amended to improve clarity and to set forth acceptable alternatives for isolating the cement from contamination.

Minimum standard III.B.1.h. on pressure testing casing strings has been rephrased as suggested by comments in order to clarify the intent as well as the technical reasoning. As published in the proposed rulemaking, the standard for pressure testing—1 psi per foot of casing length—was an error, and the final Order returns to the standard that has been employed historically.

One comment was received suggesting alternative wording to make minimum standard III.B.1.i. on testing the pressure integrity of each casing shoe more flexible to meet varying pressure situations at different depths and in different formations. Recognizing that the well may not require a 5M system until it reaches greater depth, the suggested wording has been adopted. The final Order relaxes the requirement for portions of wells—generally the upper portions—that may not require a 5M system.

C. Mud Program Requirements

One comment was received asking that the term "mudding up" be defined. The final rulemaking includes a definition of this term.

In response to comments, the last sentence of the requirement statement for this section was modified by replacing "and" with "or" in recognition that being relatively near a premix bulk mud supply is a sufficient and acceptable alternative to maintaining sufficient quantities of mud materials on site.

For clarity and at the suggestion of a comment, the word "equipment" has been added to the term "visual mud-monitoring" in minimum standard III.C.2.

Minimum standard III.C.3. of the mud program requirements has been modified as suggested by several comments to require having mud monitoring equipment in place on all systems only when abnormal pressures are anticipated by the operator. A definition of "abnormal pressure" has been added in the definitions section to clarify when the operator is required to have monitoring equipment in place. In exploration areas, applications for permit to drill (APD) will be approved only if they call for monitoring equipment to be in place, because in such situations there can be little or no basis for anticipating normal pressures.

A change in the proposed Order at paragraph III.C.4. on testing for viscosity, density, and gel strength was made in response to comments stating that the Order should specify when it is necessary to begin requiring mud tests. This has been done in the final rulemaking by specifying that after mudding up, the tests should occur every 24 hours.

Several comments were received objecting to the minimum standard III.C.5. on the use of trip tanks. The requirement only applies to 10M, 15M, and upgraded 5M systems. Systems in such high pressure situations are unique by their nature and require special [illegible] detection of kicks. This standard therefore remains unchanged, except that the authorized officer is given discretion, for 5M systems, to require a trip tank if conditions warrant.

Minimum standard III.C.6. on gas detection equipment has been completely rewritten, at the suggestion of one comment, to add a provision for monitoring other hydrocarbon gases, such as methane, as well as hydrogen sulfide. An editorial change was also made to correct the H_2S concentration listed from 100 ppm to 20 ppm.

The language of standard III.C.7. on flare systems has been changed to improve clarity by specifying that flare lines shall be positioned in the prevailing downwind direction from the gas source. In addition, the flare line discharge distance has been changed from 150 feet to 100 feet for consistency with proposed Order 6, which is in preparation, and with standards set by the Occupational Safety and Health Administration.

Standard III.C.8. has been amended to require the installation of a mud-gas separator (gasbuster) as specified at least 500 feet above the anticipated hydrocarbon zone instead of 1,000 feet as stated in the proposed rulemaking, and only for systems of 10M or greater, or those where abnormal pressures are anticipated even if the system is not 10M, rather than for all 5M or greater systems as provided in the proposed rulemaking. Several comments requested this change, which will also be consistent with the proposed Order 6 on H_2S Operations. This approach is more reasonable and flexible. The standard applies only in those discrete areas where separators are most likely to be needed. Additionally, the violation in the final rulemaking is classified as "minor" in recognition that the correction could readily be made before encountering the anticipated hydrocarbon zone.

D. Drill Stem Testing Requirements

A number of comments addressed the proposed prohibition of initiating drill stem testing (DST) outside of daylight hours. This provision has been modified to allow the authorized officer a degree of flexibility in approving DST in recognition that in the northern latitudes and during the winter months, initiation of a DST in daylight may not be practicable. Special safety requirements may be imposed by the authorized officer in those instances. Also, closed chamber DST may be accomplished day or night and provision for this has been added as suggested in comments and to clarify the original intention of the draft.

Standards III.D.1. and D.2. were editorially amended for clarity as suggested in comments.

Standard III.D.3. on the location of combustion engines has been amended to make it consistent with the OSHA requirement that they be located no closer than 100 feet from the well bore, unless equipped with arresters and/or water cooled exhaust manifolds.

E. Special Drilling Operations

Numerous comments were received concerning this section. Many of these addressed the minimum distances specified. In response to these comments, all distances have been standardized and reduced to 100 feet. For example, the length of the blooie line, required to be 150 feet from the well bore in the proposed rulemaking, is now 100 feet. In all cases, the distances specified in this final rulemaking pertaining to Special Drilling Operations are consistent with similar requirements of OSHA.

Another comment suggested modifying the minimum standard concerning the straight run on the blooie line. This has been modified by the addition of the words "unless otherwise approved" because there may be instances where a straight run may not be feasible.

One comment suggested removal of the minimum standard requiring deduster equipment during air/gas drilling. This comment was not adopted due to the potentially serious environmental consequences. If an operator has a special situation and can justify not using deduster equipment, he can request a variance of the authorized representative as detailed elsewhere in this Order.

As suggested in a comment, the minimum standard for containment of cuttings and the circulating medium has been amended to specify the required mode of containment.

Several comments dealt with the draft minimum standard requiring an automatic igniter and a continuous pilot light on the blooie line. This standard has been modified to provide that either of these methods is acceptable rather than both being required. Under certain circumstances the authorized officer may require both in approving a particular APD if redundancy is desirable; however, it is not necessary to require both as a minimum standard.

At the suggestion of several comments, the minimum standard concerning mud mixing equipment, mixing water, etc., was rewording for clarity.

F. Surface Use

Comments from within government and from industry were received concerning the minimum standards portion of the Surface Use Requirements. These comments did not particularly object to the stated minimum standard in the draft, but argued that this Order is not the appropriate place to outline specific surface standards. Several comments suggested that a revision of Onshore Order No. 1 would be more appropriate. BLM has scheduled such a revision to Onshore Order No. 1. In addition, under the Federal Onshore Oil and Gas Leasing Reform Act of 1987, management of surface use on National Forest lands is required to be coordinated with the Forest Service. In response to the comments, the minimum standards portion of the Surface Use Requirements has been modified in this final rulemaking to contain a general standard to comply with the approved APD rather than specific standards.

G. Drilling Abandonment Requirements

Comments received on the drilling abandonment section of this Order are discussed below as they address specific provisions.

Two comments suggested amendment of the provision on types of mineral deposits requiring protection. The term "prospectively valuable deposit of minerals" has been added in the introductory paragraph of this section and to the definitions section of the Order to clarify an unnecessarily vague reference to "other minerals".

Another comment requested that the deadline for following up in writing an oral request for abandonment be increased from 5 business days to 10. This comment has not been adopted because an operator can ask for an extension if additional time is needed.

The minimum standard in paragraph III.G.1.i.a. on migrating fluids was modified as suggested in comments to make it clear that gases as well as liquids are considered fluids with a potential to migrate, and that formations containing them shall be cemented across in the prescribed manner. Another comment on this section wanted the term "fluid" to be defined as fresh water or hydrocarbon. This suggestion was rejected as being too restrictive. For example, salt water or nitrogen gas zones require cementing across so that contamination of other zones by migration does not occur.

The requirement in the draft Onshore Order specifying protection of lost circulation zones during plugging has been removed at the suggestion of comments. However, as stated elsewhere in the Drilling Abandonment Requirements, the hole must be in a static condition at the time any plugs are placed, or the placement of additional plugs and/or cement may be required. Therefore, to assure a static well bore condition, lost circulation zones must be stabilized or isolated in some manner before further plugging can occur higher up in the hole.

The minimum standard in paragraph III.G.1.i.b. was modified as explained earlier in this section to clarify the types of minerals needing protection.

The minimum standard in paragraph III.G.1.ii. attracted comments questioning the reasoning behind the requirement of an additional 10 percent of slurry for each 1,000 feet of depth. This factor is included to compensate for mud contamination (and not as a washout factor as supposed in some comments) in pumping the plug to the required depth. For a 100 foot plug located at 10,000 feet, this would amount to an additional 100 feet of cement column. Similar comments were received concerning this requirement as it applies to cased holes. Since the logic for requiring this additional slurry is the same, those comments are not addressed further in this section.

The minimum standard in paragraph III.G.1.iv. was modified as suggested by comments to make it clear that it pertains to thick sections of a single formation. Another comment on this section preferred that extremely thick sections be defined as being 400 feet in thickness. This suggestion was not adopted because there are too many variables to select a particular number as "extremely thick". The authorized officer and the operator requesting plugging instructions need flexibility in determining whether a portion of a formation is extremely thick.

The minimum standard in paragraph III.G.1.v. on plugging open holes was modified in this final rulemaking as suggested by a comment to recognize that plugs shall be placed across in-gauge sections of the hole every 3,000 feet, unless otherwise approved by the authorized officer. This change will enable the authorized officer the flexibility to modify this requirement on a case-by-case basis.

Two comments addressed the minimum standard in paragraph III.G.2.iii., the amount of cement needed to cap a bridge plug when a bailer is used. The comments suggested 20 feet instead of the proposed 35 feet. The comments were rejected because a lesser amount is not considered adequate. This recognizes a policy based on Bureau of Land Management experience, requiring 35 feet, that has been in place for many years. The requirement of 35 feet is already less than the 50 feet of plug required to cap the bridge plug when not using a bailer.

Paragraph III.G.5. was amended because of a typographical error to require that at least the top 50 feet (instead of 100 feet) of the annulus shall be plugged.

The section on isolating medium, paragraph III.G.6. in this final rulemaking, was modified to clarify the types of minerals requiring protection as explained above. Another comment on this section suggested deleting the 15,000 pound maximum tagging weight provision. This comment was adopted because setting a maximum weight to be used to tag a plug is unnecessary.

The minimum standard in paragraph III.G.8. of this final rulemaking has been modified from the draft as suggested by a comment to clarify the cement plug requirement at the surface. This standard now states that the top 50 feet of the hole shall be plugged and removes the reference restricting this plug to the smallest casing extending to the surface. All annuluses within 50 feet of the surface are to be plugged off. Another comment on this provision suggested 100 feet of plug rather than 50 feet. This comment was not adopted because 50 feet is adequate if propoerly placed.

Paragraph III.G.10. concerning the surface cap was modified as suggested by comments to improve the clarity and sequence. Another comment on this minimum standard questioned the purpose of the weep hole. This term is defined and explained in the definitions section.

Discussion of IV Variances From Minimum Standard

The only comments on this section requested the addition of provision for oral variances during emergency situations. The final rulemaking adopts this suggestion, although such requests by the operator are required to be followed up by a written request as specified in the new wording. This change was incorporated in recognition that an emergency or other event that could not have been reasonably foreseen may occur during drilling operations.

Discussion of Attachments

Several comments were received concerning the choke manifold equipment configurations. A statement has been added to each of the pressure systems diagrams in response to the comments to indicate that the configuration of the equipment may vary. This was the original intent and the addition of the statement improves clarity.

Another comment requested that one of the two valves on the bleed line to the pit be removed from the requirement for equipment for pressure ratings of 3M and above. This comment was adopted for 3M systems, but was rejected for higher rated systems due to the higher pressures involved.

The principal authors of this proposed rulemaking are Howard Lemm of the Utah State Office, Carl Budd of the Rock Springs District Office, Hal Stoops of the Bakersfield District Office, and Bob Kent of the Washington Office, assisted by the staff of the Division of Legislation and Regulatory Management, Bureau of Land Management.

It is hereby designated that this proposed rulemaking does not constitute a major Federal action significantly affecting the quality of the human environment, and that no detailed statement pursuant to section 102(2)(C) of the National Environmental Policy Act of 1969 (42 U.S.C. 4332(2)(C)) is required.

The Department of the Interior has determined that this document is not a major rule under Executive Order 12291 and will not have a significant economic impact on a substantial number of small entities under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*).

The information collection requirements contained in 43 CFR Part 3160 have been approved by the Office of Management and Budget under 44 U.S.C. 3501 *et seq.* and assigned clearance numbers 1004–0134 and 1004–0136.

List of Subjects in 43 CFR Part 3160

Government contracts, Mineral royalties, Oil and gas exploration, Oil and gas production, Public lands—mineral resources, Indian lands—mineral resources, Reporting and recordkeeping requirements.

Under the authorities cited below, Part 3160, Group 3100, Subchapter C, Chapter II of Title 43 of the Code of Federal Regulations is amended as set forth below.

October 11, 1988.

J. Steven Griles,

Assistant Secretary of the Interior.

PART 3160—[AMENDED]

1. The authority citation for Part 3160 continues to read:

Authority: The Mineral Leasing Act of 1920, as amended and supplemented (30 U.S.C. 181 et seq.), the Mineral Leasing Act for Acquired Lands of 1947, as amended (30 U.S.C. 351–359), the Act of May 21, 1930 (30 U.S.C. 301–306), the Act of March 3, 1909, as amended (25 U.S.C. 396), the Act of May 11, 1938, as amended (25 U.S.C. 396a–396q), the Act of Feburary 28, 1891, as amended (25 U.S.C. 397), the Act of May 29, 1924 (25 U.S.C. 398), the Act of March 3, 1927 (25 U.S.C. 398a–398e), the Act of June 30, 1919, as amended (25 U.S.C. 399), R.S. 441 (43 U.S.C. 1457). See also Attorney General's Opinion of April 2, 1941 (40 Op. Atty., Gen. 41), the Federal Property and Administrative Services Act of 1949, as amended (40 U.S.C. 471 et seq.), the National Environmental Policy Act of 1969, as amended (42 U.S.C. 4321 et seq.), the Act of December 12, 1980 (42 U.S.C. 6508), the Combined Hydrocarbon Leasing Act of 1981 (Pub. L. 97–78), the Federal Oil and Gas Royalty Management Act of 1982 (30 U.S.C. 1701 et seq.) and the Indian Mineral Development Act of 1982 (25 U.S.C. 2102 et seq.).

2. Section 3164.1(b) is amended by adding the following entry to the table which is part of § 3164.1(b):

§ 3164.1 Onshore oil and gas orders.

* * * * *

(b) * * *

Order No.	Subject	Effective date	Federal Register reference	Supersedes
1	Approval of operations	November 12, 1983	48 FR 48916 and 48 FR 56226	NTL-6
2	Drilling operations			None

Note.—Numbers will be assigned by the Washington Office, Bureau of Land Management, to additional Orders as they are prepared for publication and added to this table.

Note.—This appendix is published for information only and will not appear in the *Code of Federal Regulations.*

Appendix—Text of Oil and Gas Order No. 2

Onshore Oil and Gas Order No. 2

Drilling Operations on Federal and Indian Oil and Gas Leases

I. Introduction.
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  B. Purpose.
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  A. Well Control Requirements.
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  D. Drill Stem Testing Requirements.
  E. Special Drilling Operations.
  F. Surface Use.
  G. Drilling Abandonment.
IV. Variances from Minimum Standards.

Attachments.
I. Diagrams of Choke Manifold Requirements.
II. Sections from 43 CFR Subparts 3163 and 3165.

Onshore Oil and Gas Order No. 2

Drilling Operations on Federal and Indian Oil and Gas Leases

I. Introduction

A. Authority

This order is established pursuant to the authority granted to the Secretary of the Interior pursuant to various Federal and Indian mineral leasing statutes and the Federal Oil and Gas Royalty Management Act of 1982. This authority has been delegated to the Bureau of Land Management and is implemented by the onshore oil and gas operating regulations contained in 43 CFR Part 3160. Section 3164.1 thereof specifically authorizes the Director, Bureau of Land Management, to issue Onshore Oil and Gas Orders when necessary to implement and supplement the operating regulations and provides that all such Orders shall be binding on the lessees and operators of Federal and restricted Indian (except Osage tribe) oil and gas leases that have been, or may hereafter be, issued.

Specific authority for the provisions contained in this Order is found at: § 3162.3–1 *Drilling Applications and Plans;* § 3162.3–4 *Well Abandonment;* § 3162.4–1 *Well Records and Reports;* § 3162.4–3 *Samples, Tests, and Surveys;* § 3162.5–1 *Environmental Obligations;* § 3162.5–2 *Control of Wells;* § 3162.5–2(a) *Drilling Wells;* § 3162.5–3 *Safety Precautions;* and Subpart 3163 Noncompliance and Assessment.

B. Purpose

This onshore Order details the Bureau's uniform national standards for the minimum levels of performance expected from lessees and operators when conducting drilling operations on Federal and Indian lands (except Osage Tribe) and for abandonment immediately following drilling. The purpose also is to identify the enforcement actions that will result when violations of the minimum standards are found and when those violations are not abated in a timely manner.

C. Scope

This Order is applicable to all onshore Federal and Indian (except Osage Tribe) oil and gas leases.

D. General

1. If an operator chooses to use higher rated equipment than that authorized in the Application for Permit to Drill (APD), testing procedures shall apply to the approved working pressures, not the upgraded higher working pressures.

2. Some situations may exist either on a well-by-well or field-wide basis whereby it is commonly accepted practice to vary a particular minimum standard(s) established in this Order. This situation may be resolved by requesting a variance (See section IV of this Order), by the inclusion of a stipulation in the APD, or by the issuance of a Notice to Lessees and Operators (NTL) by the appropriate BLM office.

3. When a violation is discovered, and if it does not cause or threaten immediate substantial and adverse impact on public health and safety, the environment, production accountability or royalty income, it will be classified as minor. The violation may be reissued as a major violation if not corrected during the abatement period and continued drilling has changed the adverse impact of the violation so that it meets the specific definition of a major violation.

4. This Onshore Order is not intended to circumvent the reporting requirements or compliance aspects that may be stated elsewhere in Existing NTL's, Onshore Orders, etc. A lessee's compliance with the requirements of the regulations in this Part shall not relieve the lessee of the obligation to comply with other applicable laws and regulations in accordance with 43 CFR 3162.5-1(c). Lessee's should give special attention to the automatic assessment provisions in 43 CFR 3163.1(b).

5. This Order is based upon the assumption that operations have been approved in accordance with 43 CFR Part 3160 and Onshore Oil and Gas Order No. 1. Failure to obtain approval prior to commencement of drilling or related operations shall subject the operator to immediate assessment under 43 CFR 3163.1(b)(2).

II. Definitions.

A. Abnormal Pressure Zone means a zone that has either pressure above or below the normal gradient for an area and/or depth.

B. Bleed Line means the vent line that bypasses the chokes in the choke manifold system; also referred to as Panic Line.

C. Blooie Line means a discharge line used in conjunction with a rotating head.

D. Drilling Spool means a connection component with both ends either flanged or hubbed, with an internal diameter at least equal to the bore of the casing, and with smaller side outlets for connecting auxiliary lines.

E. Exploratory Well means any well drilled beyond the known producing limits of a pool.

F. Fill-up Line means the line used to fill the hole when the drill pipe is being removed from the well. It is usually connected to a 2-inch collar that is welded into a drilling nipple.

G. Flare Line means a line used to carry gas away from the rig to be burned at a safer location. The gas comes from the degasser, gas buster, separator, or when drill stem testing, directly from the drill pipe.

H. Functionally Operated means activating equipment without subjecting it to well-bore pressure.

I. Isolating means using cement to protect, separate, or segregate usable water and mineral resources.

J. Lease means any contract, profit-share agreement, joint venture, or other agreement issued or approved by the United States under a mineral leasing law that authorizes exploration for, extraction of, or removal of oil or gas (See 43 CFR 3160.0-5).

K. Lessee means a person holding record title in a lease issued by the United States (See 43 CFR3160.0-5).

L. Make-up Water means water that is used in mixing slurry for cement jobs and plugging operations, and is compatible with the cement constituents being used.

M. Manual Locking Device means any manually activated device, such as hand wheels, etc., that is used for the purpose of locking the preventer in the closed position.

N. Mud for Plugging Purposes means a slurry of bentonite or similar flocculent/viscosifier, water, and additives needed to achieve the desired weight and consistency to stabilize the hole.

O. Mudding Up means adding materials and chemicals to water to control the viscosity, weight, and filtrate loss of the circulating system.

P. Operating Rights Owner (or Owner) means a person or entity holding operating rights in a lease issued by the United States. A lessee also may be an operating rights owner if the operating rights in a lease or portion thereof have not been severed from record title.

Q. Operational means capable of functioning as designed and installed without undue force or further modification.

R. Operator means any person or entity, including but not limited to the lessee or operating rights owner, who has stated in writing to the authorized officer his/her responsibility for the operations conducted in the leased lands or a portion thereof.

S. Precharge Pressure means the nitrogen pressure remaining in the accumulator after all the hydraulic fluid has been expelled from beneath the movable barrier.

T. Prompt Correction means immediate correction of violations, with drilling suspended if required in the discretion of the authorized officer.

U. Prospectively Valuable Deposit of Minerals means any deposit of minerals that the authorized officer determines to have characteristics of quantity and quality that warrant its protection.

V. Tagging the Plug means running in the hole with a string of tubing or drill pipe and placing the weight of that string on the plug. Other methods of tagging the plug may be approved by the authorized officer.

W. Targeted Tee or Turn means a fitting used in pressure piping in which a bull plug or blind flange of the same pressure rating as the rest of the approved system is installed at the end of a tee or cross, opposite the fluid entry arm, to change the direction of flow and to reduce erosion.

X. 2M, 3M, 5M, 10M, and 15M mean the pressure ratings used for equipment with a working pressure rating of the equivalent thousand pounds per square inch (psi) (2M=2,000 psi, 3M=3,000 psi, etc.).

Y. Usable Water means generally those waters containing up to 10,000 ppm of total dissolved solids.

Z. Weep Hole means a small hole that allows pressure to bleed off through the metal plate used in covering well bores after abandonment operations.

III. Requirements

A. Well Control Requirements

1. Blowout preventer (BOP) and related equipment (BOPE) shall be installed, used, maintained, and tested in a manner necessary to assure well control and shall be in place and operational prior to drilling the surface casing shoe unless otherwise approved by the APD. Commencement of drilling without the approved BOPE installed, unless otherwise approved, shall subject

the operator to immediate assessment under 43 CFR 3163.1(b)(1). The BOP and related control equipment shall be suitable for operations in those areas which are subject to sub-freezing conditions. The BOPE shall be based on known or anticipated sub-surface pressures, geologic conditions, accepted engineering practice, and surface environment. Item number 7 of the 8 point plan in the APD specifically addresses expected pressures. The working pressure of all BOPE shall exceed the anticipated surface pressure to which it may be subjected, assuming a partially evacuated hole with a pressure gradient of 0.22 psi/ft.

2. The gravity of the violation for many of the well control minimum standards listed below are shown as minor. However, very short abatement periods in this Order are often specified in recognition that by continuing to drill, the violation which was originally determined to be of a minor nature may cause or threaten immediate, substantial and adverse impact on public health and safety, the environment, production accountability, or royalty income, which would require its reclassification as a major violation.

a. *Minimum standards and enforcement provisions for well control equipment.* i. A well control device shall be installed at the surface that is capable of complete closure of the well bore. This device shall be closed whenever the well is unattended.

Violation: Major.

Corrective Action: Install the equipment as specified.

Normal Abatement Period: Prompt correction required.

ii. 2M system:

—Annular preventer, double ram, or two rams with one being blind and one being a pipe ram *

—Kill line (2 inch minimum)

—1 kill line valve (2 inch minimum)

—1 choke line valve

—2 chokes (refer to diagram in Attachment 1)

—Upper kelly cock valve with handle available

—Safety valve and subs to fit all drill strings in use

—Pressure gauge on choke manifold

—2 inch minimum choke line

—Fill-up line above the uppermost preventer.

Violation: Minor (all items unless marked by asterisk).

Corrective Action: Install the equipment as specified.

Normal Abatement Period: 24 hours.

*Violation: Major.

Corrective Action: Install the equipment as specified.

Normal Abatement Period: Prompt correction required.

iii. 3M system:

—Annular preventer *

—Double ram with blind rams and pipe rams *

—Drilling spool, or blowout preventer with 2 side outlets (choke side shall be a 3-inch minimum diameter, kill side shall be at least 2-inch diameter) *

—Kill line (2 inch minimum)

—A minimum of 2 choke line valves (3 inch minimum) *

—3 inch diameter choke line

—2 kill line valves, one of which shall be a check valve (2 inch minimum) *

—2 chokes (refer to diagram in Attachment 1)

—Pressure gauge on choke manifold

—Upper kelly cock valve with handle available

—Safety valve and subs to fit all drill string connections in use

—All BOPE connections subjected to well pressure shall be flanged, welded, or clamped *

—Fill-up line above the uppermost preventer.

Violation: Minor (all items unless marked by asterisk).

Corrective Action: Install the equipment as specified.

Normal Abatement Period: 24 hours.

* Violation: Major.

Corrective Action: Install the equipment as specified.

Normal Abatement Period: Prompt correction required.

iv. 5M system:

—Annular preventer *

—Pipe ram, blind ram, and, if conditions warrant, as specified by the authorized officer, another pipe ram shall also be required *

—A second pipe ram preventer or variable bore pipe ram preventer shall be used with a tapered drill string

—Drilling spool, or blowout preventer with 2 side outlets (choke side shall be a 3-inch minimum diameter, kill side shall be at least 2-inch diameter) *

—3 inch diameter choke line

—2 choke line valves (3 inch minimum) *

—Kill line (2 inch minimum)

—2 chokes with 1 remotely controlled from rig floor (refer to diagram in Attachment 1)

—2 kill line valves and a check valve (2 inch minimum) *

—Upper kelly cock valve with hand available

—When the expected pressures approach working pressure of the system, 1 remote kill line tested to stack pressure (which shall run to the outer edge of the substructure and be unobstructed)

—Lower kelly cock valve with handle available

—Safety valve(s) and subs to fit all drill string connections in use

—Inside BOP or float sub available

—Pressure gauge on choke manifold

—All BOPE connections subjected to well pressure shall be flanged, welded, or clamped *

—Fill-up line above the uppermost preventer.

Violation: Minor (all items unless marked by asterisk).

Corrective Action: Install the equipment as specified.

Normal Abatement Period: 24 hours

* Violation: Major.

Corrective Action: Install the equipment as specified.

Normal Abatement Period: Prompt correction required.

v. 10M & 15M system:

—Annular preventer *

—2 pipe rams *

—Blind rams *

—Drilling spool, or blowout preventer with 2 side outlets (choke side shall be a 3-inch minimum diameter, kill side shall be at least 2-inch diameter) *

—3 inch choke line *

—2 kill line valves (2 inch minimum) and check valve *

—Remote kill line (2 inch minimum) shall run to the outer edge of the substructure and be unobstructed

—Manual and hydraulic choke line valves (3 inch minimum) *

—3 chokes, 1 being remotely controlled (refer to diagram in Attachment 1)

—Pressure gauge on choke manifold

—Upper kelly cock valve with handle available

—Lower kelly cock valve with handle available

—Safety valves and subs to fit all drill string connections in use

—Inside BOP or float sub available

—Wear ring in casing head

—All BOPE connections subjected to well pressure shall be flanged, welded, or clamped *

—Fill-up line installed above the uppermost preventer.

Violation: Minor (all items unless marked by asterisk).

Corrective Action: Install the equipment as specified.

Normal Abatement Period: 24 hours.

* Violation: Major.

Corrective Action: Install the equipment as specified.

Normal Abatement Period: Prompt correction required.

vi. If repair or replacement of the BOPE is required after testing, this work shall be performed prior to drilling out the casing shoe.

Violation: Major.

Corrective Action: Install the equipment as specified.

Normal Abatement Period: Prompt correction required.

vii. When the BOPE cannot function to secure the hole, the hole shall be secured using cement, retrievable packer or a bridge plug packer, bridge plug, or other acceptable approved method to assure safe well conditions.

Violation: Major.

Corrective Action: Install the equipment as specified.

Normal. Abatement Period: Prompt correction required.

b. *Minimum standards and enforcement provisions for choke manifold equipment.* i. All choke lines shall be straight lines unless turns use tee blocks or are targeted with running tees, and shall be anchored to prevent whip and reduce vibration.

Violation: Minor

Corrective Action: Install the equipment as specified.

Normal Abatement Period: 24 hours.

ii. Choke manifold equipment configuration shall be functionally equivalent to the appropriate example diagram shown in Attachment 1 of this Order.

Violation: Minor

Corrective Action: Install the equipment as specified.

Normal Abatement Period: Prompt correction required.

iii. All valves (except chokes) in the kill line, choke manifold, and choke line shall be a type that does not restrict the flow (full opening) and that allows a straight through flow (same enforcement as item ii).

iv. Pressure gauges in the well control system shall be a type designed for drilling fluid service (same enforcement as above).

c. *Minimum standards and enforcement provisions for pressure accumulator system.* i. 2M system—accumulator shall have sufficient capacity to close all BOP's and retain 200 psi above precharge. Nitrogen bottles that meet manufacturer's specifications may be used as the backup to the required independent power source.

Violation: Minor

Corrective Action: Install the equipment as specified.

Normal Abatement Period: 24 hours.

ii. 3M system—accumulator shall have sufficient capacity to open the hydraulically-controlled choke line valve (if so equipped), close all rams plus the annual preventer, and retain a minimum of 200 psi above precharge on the closing manifold without the use of the closing unit pumps. This is a minimum requirement. The fluid reservoir capacity shall be double the accumulator capacity and fluid level maintained at manufacturer's recommendations. The 3M system shall have 2 independent power sources to close the preventers. Nitrogen bottles (3 minimum) may be 1 of the independent power sources and, if so, shall maintain a charge equal to the manufacturer's specifications.

Violation: Minor.

Corrective Action: install the equipment as specified.

Normal Abatement Period: 24 hours.

iii. 5M and higher system—accumulator shall have sufficient capacity to open the hydraulically-controlled gate valve (if so equipped) and close all rams plus the annular preventer (for 3 ram systems add a 50 percent safety factor to compensate for any fluid loss in the control system or preventers) and retain a minimum pressure of 200 psi above precharge on the closing manifold without use of the closing unit pumps. The reservoir capacity shall be double the accumulator capacity, and the fluid level shall be maintained at manufacturer's recommendations. Two independent sources of power shall be available for powering the closing unit pumps. Sufficient nitrogen bottles are suitable as a backup power source only, and shall be recharged when the pressure falls below manufacturer's specifications.

Violation: Minor.

Corrective Action: Install the equipment as specified.

Normal Abatement Period: 24 hours.

d. *Minimum standards and enforcement provisions for accumulator precharge pressure test.* This test shall be conducted prior to connecting the closing unit to the BOP stack and at least once every 6 months. The accumulator pressure shall be corrected if the measured precharge pressure is found to be above or below the maximum or minimum limit specified below (only nitrogen gas may be used to precharge):

Accumulator working pressure rating	Minimum acceptable operating pressure	Desired precharge pressure	Maximum acceptable precharge pressure	Minimum acceptable precharge pressure
1,500 psi	1,500 psi	750 psi	800 psi	700 psi
2,000 psi	2,000 psi	1,000 psi	[illegible] psi	900 psi
3,000 psi	3,000 psi	1,000 psi	1,100 psi	900 psi

Violation: Minor.

Corrective Action: Perform test.

Normal Abatement Period: 24 hours.

e. *Minimum standards and enforcement provisions for power availability.* Power for the closing unit pumps shall be available to the unit at all times so that the pumps shall automatically start when the closing unit manifold pressure has decreased to a pre-set level.

Violation: Major.

Corrective Action: Install the equipment as specified.

Normal Abatement Period: Prompt correction required.

f. *Minimum standards and enforcement provisions for accumulator pump capacity.* Each BOP closing unit shall be equipped with sufficient number and sizes of pumps so that, with the accumulator system isolated from service, the pumps shall be capable of opening the hydraulically-operated gate valve (if so equipped), plus closing the annular preventer on the smallest size drill pipe to be used within 2 minutes, and obtain a minimum of 200 psi above specified accumulator precharge pressure.

Violation: Minor.

Corrective Action: Install the equipment as specified.

Normal Abatement Period: 24 hours.

g. *Minimum standards and enforcement provisions for locking devices.* A manual locking device (i.e., hand wheels) or automatic locking devices shall be installed on all systems of 2M or greater. A valve shall be installed in the closing line as close as possible to the annular preventer to act as a locking device. This valve shall be maintained in the open position and shall be closed only when the power source for the accumulator system is inoperative.

Violation: Minor.

Corrective Action: Install the equipment as specified.

Normal Abatement Period: 24 hours.

h. *Minimum standards and enforcement provisions for remote* *controls.* Remote controls shall be readily accessible to the driller. Remote controls for all 3M or greater systems shall be capable of closing all preventers. Remote controls for 5M or greater systems shall be capable of both opening and closing all preventers. Master controls shall be at the accumulator and shall be capable of opening and closing all preventers and the choke line valve (if so equipped). No remote control for a 2M system is required.

Violation: Minor.

Corrective Action: Install the equipment as specified.

Normal Abatement Period: 24 hours.

i. *Minimum standards and enforcement provisions for well control equipment testing.* i. Perform all tests described below using clear water or an appropriate clear liquid for subfreezing temperatures with a viscosity similar to water.

ii. Ram type preventers and associated equipment shall be tested to approved (see item I.D.1. of this order) stack working pressure if isolated by test plug or to 70 percent of internal yield pressure of casing if BOP stack is not isolated from casing. Pressure shall be maintained for at least 10 minutes or until requirements of test are met, whichever is longer. If a test plug is utilized, no bleed-off of pressure is acceptable. For a test not utilizing a test plug, if a decline in pressure of more than 10 percent in 30 minutes occurs, the test shall be considered to have failed. Valve on casing head below test plug shall be open during test of BOP stack.

iii. Annular type preventers shall be tested to 50 percent of rated working pressure. Pressure shall be maintained at least 10 minutes or until provisions of test are met, whichever is longer.

iv. As a minimum, the above test shall be performed:

A. when initially installed;

B. whenever any seal subject to test pressure is broken;

C. following related repairs; and

D. at 30-day intervals.

v. Valves shall be tested from working pressure side during BOPE tests with all down stream valves open.

vi. When testing the kill line valve(s), the check valve shall be held open or the ball removed.

vii. Annular preventers shall be functionally operated at least weekly.

viii. Pipe and blind rams shall be activated each trip, however, this function need not be performed more than once a day.

xi. A BOPE pit level drill shall be conducted weekly for each drilling crew.

x. Pressure tests shall apply to all related well control equipment.

xi. All of the above described tests and/or drills shall be recorded in the drilling log.

Violation: Minor.

Corrective action: Perform the necessary test or provide documentation.

Normal Abatement Period: 24 hours or next trip, as most appropriate.

B Casing and Cementing Requirements

The proposed casing and cementing programs shall be conducted as approved to protect and/or isolate all usable water zones, potentially productive zones, lost circulation zones, abnormally pressured zones, and any prospectively valuable deposits of minerals. Any isolating medium other than cement shall receive approval prior to use. The casing setting depth shall be calculated to position the casing seat opposite a competent formation which will contain the maximum pressure to which it will be exposed during normal drilling operations. Determination of casing setting depth shall be based on all relevent factors, including: presence/absence of hydrocarbons; fracture gradients; usable water zones; formation pressures; lost circulation zones; other minerals; or other unusual characteristics. All indications of usable water shall be reported.

—Minimum design factors for tensions, collapse, and burst that are incorporated into the casing design by an operator/lessee shall be submitted to the authorized operator for his review and approval along with the APD for all exploratory wells or as otherwise specified by the authorized officer.

—Casing design shall assume formation pressure gradients of 0.44 to 0.50 psi per foot for exploratory wells (lacking better data).

—Casing design shall assume fracture gradients from 0.70 to 1.00 psi per foot for exploratory wells (lacking better data).

—Casing collars shall have a minimum clearance of 0.422 inches on all sides in the hole/casing annulus, with recognition that variances can be granted for justified exceptions.

—All waiting on cement times shall be adequate to achieve a minimum of 500 psi compressive strength at the casing shoe prior to drilling out.

1. Minimum Standards and Enforcement Provisions for Casing and Cementing.

a. All casing, except the conductor casing, shall be new or reconditioned and tested used casing that meets or exceeds API standards for new casing.

Violation: Major

Corrective Action: Perform remedial action as specified by the authorized officer.

Normal Abatement Period: Prompt correction required.

b. For liners, a minimum of 100 feet of overlap between a string of casing and the next larger casing is required. The interval of overlap shall be sealed and tested. The liner shall be tested by a fluid entry or pressure test to determine whether a seal between the liner top and the next larger string has been achieved. The test pressure shall be the maximum anticipated pressure to which the seal will be exposed. No test shall be required for liners that do not incorporate or need a seal mechanism.

Violation: Minor.

Corrective Action: Perform remedial action as specified by the authorized officer.

Normal Abatement Period: Upon determination of corrective action.

c. The surface casing shall be cemented back to surface either during the primary cement job or by remedial cementing.

Violation: Major.

Corrective Action: Perform remedial cementing.

Normal Abatement Period: Prompt correction required.

d. All of the above described tests shall be recorded in the drilling log.

Violation: Minor.

Corrective Action: Perform the necessary test or provide documentation.

Normal Abatement Period: 24 hours.

e. All indications of usable water shall be reported to the authorized officer prior to running the next string of casing or before plugging orders are requested, whichever occurs first.

Violation: Major.

Corrective Action: Report information as required.

Normal Abatement Period: Prompt correction required.

f. Surface casing shall have centralizers on every fourth joint of casing starting with the shoe joint and up to the bottom of the cellar.

Violations: Major.

Corrective Action: Logging/testing may be required to determine the quality of the job. Recementing may then be specified.

Normal Abatement Period: Prompt correction upon determination of corrective action.

g. Top plugs shall be used to reduce contamination of cement by displacement fluid. A bottom plug or other acceptable technique, such as a suitable preflush fluid, inner string cement method, etc., shall be utilized to help isolate the cement from contamination by the mud fluid being displaced ahead of the cement slurry.

Violation: Major

Correction Action: Logging may be required to determine the quality of the cement job. Recementing or further recementing may then be specified.

Normal Abatement Period: Based upon determination of corrective action.

h. All casing strings below the conductor shall be pressure tested to 0.22 psi per foot of casing string length or 1500 psi, whichever is greater, but not to exceed 70 percent of the minimum internal yield. If pressure declines more than 10 percent in 30 minutes, corrective action shall be taken.

Violation: Minor.

Corrective Action: Perform the test and/or remedial action as specified by the authorized officer.

Normal Abatement Period: 24 hours.

i. On all exploratory wells, and on that portion of any well approved for a 5M BOPE system or greater, a pressure integrity test of each casing shoe shall be performed. Formation at the shoe shall be tested to a minimum of the mud weight equivalent anticipated to control the formation pressure to the next casing depth or at total depth of the well. This test shall be performed before drilling more than 20 feet of new hole.

Violation: Minor.

Corrective Action: Perform the specified test.

Normal Abatement Period: 24 hours.

C. Mud Program Requirements

The characteristics, use, and testing of drilling mud and the implementation of related drilling procedures shall be designed to prevent the loss of well control. Sufficient quantities of mud materials shall be maintained or readily accessible for the purpose of assuring well control.

Minimum Standards and Enforcement Provisions for Mud Program and Equipment

1. Record slow pump speed on daily drilling report after mudding up.

Violation: Minor.

Corrective Action: Record required information.

Normal Abatement Period: 24 hours.

2. Visual mud monitoring equipment shall be in place to detect volume changes indicating loss or gain of circulating fluid volume.

Violation: Minor.

Corrective Action: Install necessary equipment.

Normal Abatement Period: 24 hours.

3. When abnormal pressures are anticipated, Electronic/mechanical mud monitoring equipment shall be required, which shall include as a minimum: pit volume totalizer (PVT); stroke counter; and flow sensor.

Violation: Minor.

Corrective Action: Install necessary instrumentation.

Normal Abatement Period: 24 hours.

4. A mud test shall be performed every 24 hours after mudding up to determine, as applicable: density, viscosity, gel strength, filtration, and pH.

Violation: Minor.

Corrective Action: Perform necessary tests.

Normal Abatement Period: 24 hours.

5. A trip tank shall be used on 10M and 15M systems and on upgraded 5M systems as determined by the authorized officer.

Violation: Minor.

Corrective Action: Install necessary equipment.

Normal Abatement Period: 24 hours.

6. a. Gas detecting equipment shall be installed in the mud return system for exploratory wells or wells where abnormal pressure is anticipated, and hydrocarbon gas shall be monitored for pore pressure changes.

b. Hydrogen sulfide safety and monitoring equipment shall be available and in use where atmospheric concentrations of hydrogen sulfide of 20 ppm or greater are anticipated.

Violation: Minor.

Corrective Action: Install necessary equipment.

Normal Abatement Period: 24 hours.

7. All flare systems shall be designed to gather and burn all gas. The flare line(s) discharge shall be located not less than 100 feet from the well head, having straight lines unless turns are targeted with running tees, and shall be positioned downwind of the prevailing wind direction and shall be anchored. The flare system shall have an effective method for ignition. Where noncombustible gas is likely or expected to be vented, the system shall be provided supplemental fuel for ignition and to maintain a continuous flare.

Violation: Major.

Corrective Action: Install equipment as specified.

Normal Abatement Period: 24 hours.

8. A mud-gas separator (gas buster) shall be installed and operable for all systems of 10M or greater and for any system where abnormal pressure is anticipated beginning at a point at least 500 feet above any anticipated hydrocarbon zone of interest.

Violation: Minor.

Corrective Action: Install required equipment.

Normal Abatement Period: Prompt correction required.

D. Drill Stem Testing Requirements

Initial opening of drill stem test tools shall be restricted to daylight hours unless specific approval to start during other hours is obtained from the authorized officer. However, DSTs may be allowed to continue at night if the test was initiated during daylight hours and the rate of flow is stabilized and if adequate lighting is available (i.e., lighting which is adequate for visibility and vapor-proof for safe operations). Packers can be released, but tripping shall not begin before daylight, unless prior approval is obtained from the authorized officer. Closed chamber DSTs may be accomplished day or night.

Minimum Standards for Drill Stem Testing

1. A DST that flows to the surface with evidence of hydrocarbons shall be either reversed out of the testing string under controlled surface conditions, or displaced into the formation prior to pulling the test tool. This would involve providing some means for reverse circulation.

Violation: Major.

Corrective Action: Contingent on circumstances and as specified by the authorized officer.

Normal Abatement Period: Prompt correction required.

2. Separation equipment required for the anticipated recovery shall be properly installed before a test starts.

Violation: Major.

Corrective Action: Install required equipment.

Normal Abatement Period: Prompt correction required.

3. All engines within 100 feet of the wellbore that are required to "run" during the test shall have spark arresters or water cooled exhausts.

Violation: Major.

Corrective Action: Install required equipment.

Normal Abatement Period: Prompt correction required.

E. Special Drilling Operations

1. In addition to the equipment already specified elsewhere in this onshore order, the following equipment shall be in place and operational during air/gas drilling:

—Properly lubricated and maintained rotating head *

—Spark arresters on engines or water cooled exhaust *

—Blooie line discharge 100 feet from well bore and securely anchored

—Straight run on blooie line unless otherwise approved

—Deduster equipment **

—All cuttings and circulating medium shall be directed into a reserve or blooie pit *

—Float valve above bit *

—Automatic igniter or continuous pilot light on the blooie line *

—Compressors located in the opposite direction from the blooie line a minimum of 100 feet from the well bore

—Mud circulating equipment, water, and mud materials (does not have to be premixed) sufficient to maintain the capacity of the hole and circulating tanks or pits

Violation: Minor (unless marked by an asterisk).

Corrective Action: Install the equipment as specified.

Normal Abatement Period: 24 hours.

* Violation: Major.

Corrective Action: Install the equipment as specified.

Normal Abatement Period: Prompt correction required.

2. Hydrogen sulphide operation is specifically addressed under Onshore Oil and Gas Order No. 6.

F. Surface Use

Onshore Oil and Gas Order No. 1 specifically addresses surface use. That Order provides for safe operations, adequate protection of surface resources and uses, and other environmental components. The operator/lessee is responsible for, and liable for, all building, construction, and operating activities and subcontracting activities conducted in association with the APD. Requirements and special stipulations for surface use are contained in or attached to the approved APD. Minimum Standards and Enforcement Provisions for Surface Use.

The requirements and stipulations of approval shall be strictly adhered to by the operator/lessee and any contractors.

Violation: If a violation is identified by the authorized officer he shall determine whether it is major or minor, considering the definitions in 43 CFR 3160.0–5, and shall specify the appropriate corrective action and abatement period.

G. Drilling Abandonment Requirements

The following standards apply to the abandonment of newly drilled dry or non-productive wells in accordance with 43 CFR 3162.3–4 and section V of Onshore Oil and Gas Order No. 1. Approval shall be obtained prior to the commencement of abandonment. All formations bearing usable-quality water, oil, gas, or geothermal resources, and/or a prospectively valuable deposit of minerals shall be protected. Approval may be given orally by the authorized officer before abandonment operations are initiated. This oral request and approval shall be followed by a written notice of intent to abandon filed not later than the fifth business day following oral approval. Failure to obtain approval prior to commencement of abandonment operations shall result in immediate assessment of under 43 CFR 3163.1(b)(3). The hole shall be in static condition at the time any plugs are placed (this does not pertain to plugging lost circulation zones). Within 30 days of completion of abandonment, a subsequent report of abandonment shall be filed. Plugging design for an abandonment hole shall include the following:

1. Open Hole.

i. A cement plug shall be placed to extend at least 50 feet below the bottom (except as limited by total depth (TD) or plugged back total depth (PBTD)), to 50 feet above the top of:

a. Any zone encountered during drilling which contains fluid or gas with a potential to migrate;

b. Any prospectively valuable deposit of minerals.

ii. All cement plugs, except the surface plug, shall have sufficient slurry volume to fill 100 feet of hole, plus an additional 10 percent of slurry for each 1,000 feet of depth.

iii. No plug, except the surface plug, shall be less than 25 sacks without receiving specific approval from the authorized officer.

iv. Extremely thick sections of a single formation may be secured by placing 100-foot plugs across the top and bottom of the formation, and in accordance with item ii hereof.

v. In the absence of productive zones or prospectively valuable deposits of minerals which otherwise require placement of cement plugs, long sections of open hole shall be plugged at least every 3,000 feet. Such plugs shall be placed across in-gauge sections of the hole, unless otherwise approved by the authorized officer.

2. Cased Hole. A cement plug shall be placed opposite all open perforations and extend to a minimum of 50 feet below (except as limited by TD or PBTD) to 50 feet above the perforated interval. All cement plugs, except the surface plug, shall have sufficient slurry volume to fill 100 feet of hole, plus an additional 10 percent of slurry for each 1,000 feet of depth. In lieu of the cement plug, a bridge plug is acceptable, provided:

i. The bridge plug is set within 50 feet to 100 feet above the open perforations;

ii. The perforations are isolated from any open hole below; and

iii. The bridge plug is capped with 50 feet of cement. If a bailer is used to cap this plug, 35 feet of cement shall be sufficient.

3. Casing Removed from Hole. If any casing is cut and recovered, a cement plug shall be placed to extend at least 50 feet above and below the stub. The exposed hole resulting from the casing removal shall be secured as required in items 1i and 1ii hereof.

4. An additional cement plug placed to extend a minimum of 50 feet above and below the shoe of the surface casing (or intermediate string, as appropriate).

5. Annular Space. No annular space that extends to the surface shall be left open to the drilled hole below. If this condition exists, a minimum of the top 50 feet of annulus shall be plugged with cement.

6. Isolating Medium. Any cement plug which is the only isolating medium for a fresh water interval or a zone containing a prospectively valuable deposit of minerals shall be tested by tagging with the drill string. Any plugs placed where the fluid level will not remain static also shall be tested by either tagging the plug with the working pipe string, or pressuring to a minimum pump (surface) pressure of 1,000 psi, with no more than a 10 percent drop during a 15-minute period (cased hole only). If the integrity of any other plug is questionable, or if the authorized officer has specific concerns for which he/she orders a plug to be tested, it shall be tested in the same manner.

7. Silica Sand or Silica Flour. Silica sand or silica flour shall be added to cement exposed to bottom hole static temperatures above 230 °F to prevent heat degradation of the cement.

8. Surface Plug. A cement plug of at least 50 feet shall be placed across all annuluses. The top of this plug shall be placed as near the eventual casing cut-off point as possible.

9. Mud. Each of the intervals between plugs shall be filled with mud of sufficient density to exert hydrostatic pressure exceeding the greatest formation pressure encountered while drilling such interval. In the absense of other information at the time plugging is approved, a minimum mud weight of 9 pounds per gallon shall be specified.

10. Surface Cap. All casing shall be cut-off at the base of the cellar or 3 feet below final restored ground level (whichever is deeper). The well bore shall then be covered with a metal plate at least ¼ inch thick and welded in place, or a 4-inch pipe, 10-feet in length, 4 feet above ground and embedded in cement as specified by the authorized officer. The well location and identity shall be permanently inscribed. A weep

hole shall be left if a metal plate is welded in place.

11. The cellar shall be filled with suitable material as specified by the authorized officer and the surface restored in accordance with the instructions of the authorized officer.

Minimum Standard

All plugging orders shall be strictly adhered to.

Violation: Major.

Corrective Action: Contingent upon circumstances.

Normal Abatement Period: Prompt correction required.

IV. Variances From Minimum Standard

An operator may request the authorized officer to approve a variance from any of the minimum standards prescribed in section III hereof. All such requests shall be submitted in writing to the appropriate authorized officer and provide information as to the circumstances which warrant approval of the variance(s) requested and the proposed alternative methods by which the related minimum standard(s) are to be satisfied. The authorized officer, after considering all relevant factors, if appropriate, may approve the requested variance(s) if it is determined that the proposed alternative(s) meet or exceed the objectives of the applicable minimum standard(s).

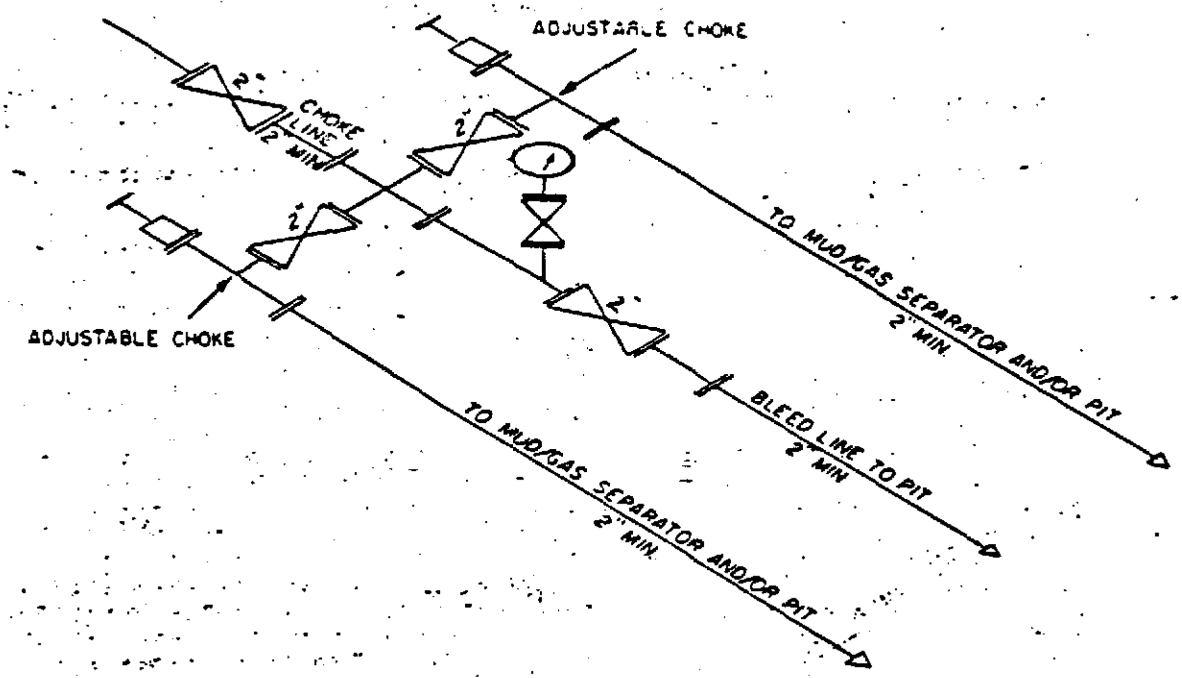
Emergency or other situations of an immediate nature that could not be reasonably foreseen at the time of APD approval may receive oral approval. However, such requests shall be followed up by a written notice filed not later than the fifth business day following oral approval.

ATTACHMENTS

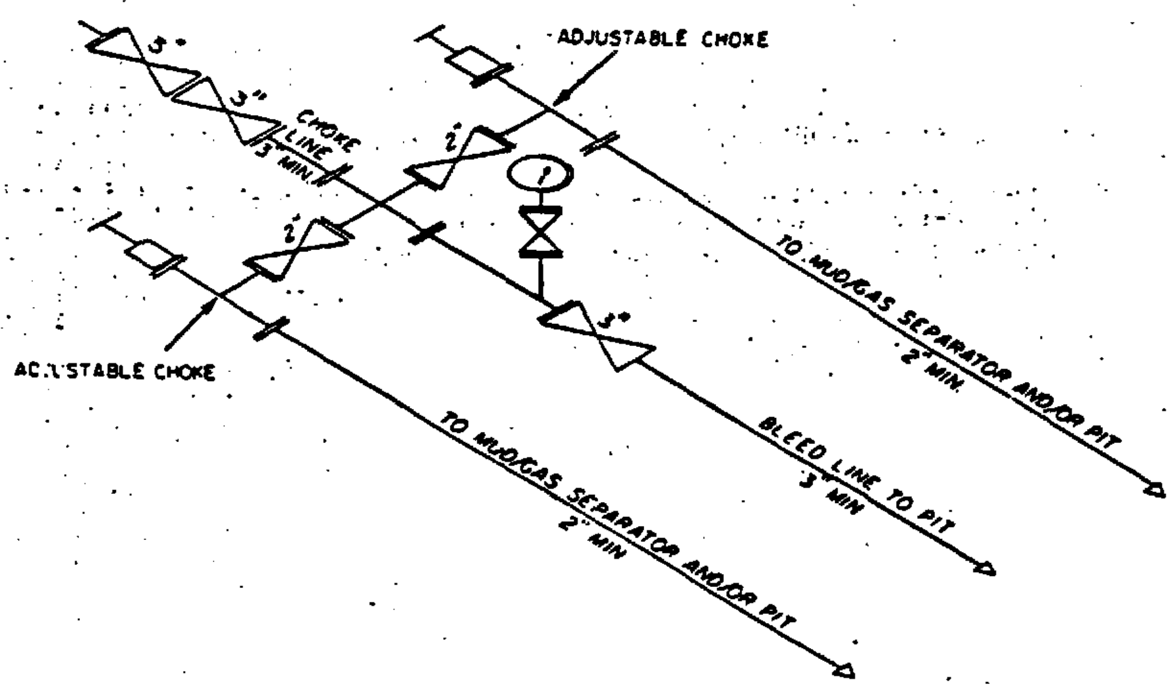
I. Diagrams of Choke Manifold Equipment

II. Sections From 43 CFR Subparts 3163 and 3165 (Not Included With Federal Register Publication)

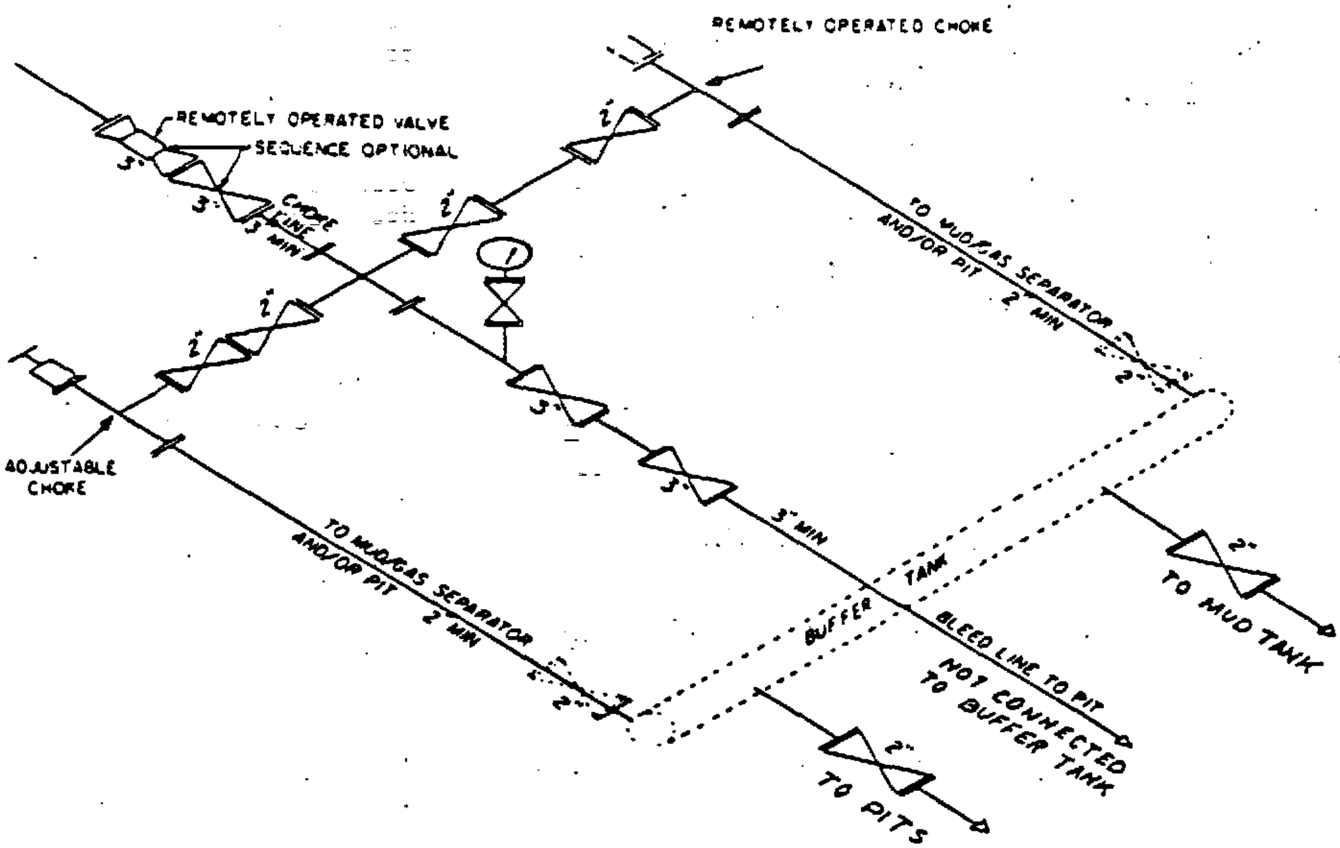
BILLING CODE 4310-84-M



2M CHOKE MANIFOLD EQUIPMENT — CONFIGURATION MAY VARY



3M CHOKE MANIFOLD EQUIPMENT — CONFIGURATION MAY VARY



5M CHOKE MANIFOLD EQUIPMENT — CONFIGURATION MAY VARY

Although not required for any of the choke manifold systems, buffer tanks are sometimes installed downstream of the choke assemblies for the purpose of manifolding the bleed lines together. When buffer tanks are employed, valves shall be installed upstream to isolate a failure or malfunction without interrupting flow control. Though not shown on 2M, 3M, 10M, or 15M drawings, it would also be applicable to those situations.

[FR Doc. 88-26738 Filed 11-17-88; 8:45 am]
BILLING CODE 4310-84-C

Chapter IX

REGULATIONS PERTAINING TO OIL AND GAS DRILLING

APPENDIX C

CHECKLIST for ADMINISTRATIVE INJECTION APPLICATIONS

Operator: ____________________ Well: ____________________

Contact: ____________________ Title: ____________________ Phone: ____________

DATE IN __________ RELEASE DATE __________ DATE OUT __________

Proposed Injection Application is for: ___ WATERFLOOD ___ Expansion ___ Initial

Original Order: R- __________ ___ Secondary Recovery ___ Pressure Maintenance

SENSITIVE AREAS ___ SALT WATER DISPOSAL

___WIPP ___ Capitan Reef ___ Commercial Operation

Data is complete for proposed well(s)? ___ Additional Data ____________________

AREA of REVIEW WELLS

___ Total # of AOR ___ # of Plugged Wells

___ Tabulation Complete ___ Schematics of P & A's

___ Cement Tops Adequate ___ AOR Repair Required

INJECTION INFORMATION

Injection Formation(s) ____________________

Source of Water ____________________ Compatible ___

PROOF OF NOTICE

___ Copy of Legal Notice ___ Information Printed Correctly

___ Correct Operators ___ Copies of Certified Mail Receipts

___ Objection Received ___ Set to Hearing __________ Date

NOTES: ____________________

____

APPLICATION QUALIFIES FOR ADMINISTRATIVE APPROVAL ___

COMMUNICATION WITH CONTACT PERSON:

1st Contact: ___ Telephoned ___ Letter ______ Date Nature of Discussion ____________

2nd Contact: ___ Telephoned ___ Letter ______ Date Nature of Discussion ____________

3rd Contact: ___ Telephoned ___ Letter ______ Date Nature of Discussion ____________

STATE OF NEW MEXICO

ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT

OIL CONSERVATION DIVISION
ARTESIA DISTRICT OFFICE

BRUCE KING
GOVERNOR

P.O. DRAWER DD
ARTESIA, NEW MEXICO 88211
(505) 748-1283

DATE______________

Bureau of Land Management
ATTN: Craig Cranston
P.O. Box 1778
Carlsbad NM 88220

State Land Office
ATTN: Joe Mraz
P.O. Box 1148
Santa Fe NM 87405

Re: **APPLICATION FOR PERMIT TO DRILL IN POTASH AREA**

OPERATOR______________________________
LEASE NAME______________________________
LOCATION______________________________
DEPTH______________________________

Gentlemen:

The application for permit to drill identified above has been filed with this office of the New Mexico Oil Conservation Division. Pursuant to the provisions of Oil Conservation Division Order R-111-P, please advise this office whether or not this location is within an established Life-of-Mine-Reserve area filed with and approved by your office. If not, please advise whether it is within the buffer zone established by the order.

Thank you for your assistance.

Sincerely,

IN LMR YES______ NO______
IN BUFFER ZONE YES______ NO______

COMMENTS:______________________________

SIGNATURE______________________________
DATE______________________________

Chapter IX

REGULATIONS PERTAINING TO OIL AND GAS DRILLING

APPENDIX D

IX-59

OFFICIAL FILE COPY

3160 (067)
NMNM-02953-C

AUG 22 1994

CERTIFIED--RETURN RECEIPT REQUESTED
P 293 298 326

Bass Enterprises Production Co.
Attention: Keith E. Bucy
P.O. Box 2760
Midland, TX 79702-2760

RE: Refer to Enclosed List of Eight
Applications for Permit to Drill
Within the James Ranch Unit,
NM-02953-C
Eddy County, New Mexico

Dear Mr. Bucy:

The referenced Applications for Permit to Drill (APDs) were received in the Carlsbad Resource Area Office during April 1993. All eight APDs are for wells proposed to be directionally drilled to lease Federal NM-02953-C located under the Waste Isolation Pilot Plant (WIPP) Land Withdrawal from surface locations outside of WIPP (within one mile). The APDs have been reviewed in light of the authorities found in the Waste Isolation Pilot Plant Land Withdrawal Act, Public Law 102-579 (October 30, 1992). Section 4 (b) (5) of which states:

(5) MINING

(A) IN GENERAL.- Except as provided in subparagraph (B), no surface or subsurface mining or oil or gas production, including slant drilling from outside the boundaries of the Withdrawal, shall be permitted at any time (including after decommissioning) on lands on or under the Withdrawal.

(B) EXCEPTION.- Existing rights under Federal Oil and Gas Leases No. NMNM 02953 and NM. NMNM 02953C shall not be affected unless the Administrator determines, after consultation with the Secretary and the Secretary of the Interior, that the acquisition of such leases by the Secretary is required to comply with the final disposal regulations or with the Solid Waste Disposal Act (42 U.S.C. 6901 et seq.).

By letter dated April 26, 1993, copies of the APDs were forwarded to the Department of Energy (DOE), who administers WIPP, for their review as agreed upon in the 1990 Memorandum of Understanding (MOU) between DOE and BLM. Since the lease in question is located under WIPP, the Carlsbad DOE office referred the matter to DOE Headquarters (Washington Office) and the Administrator of the U.S. Environmental Protection Agency (EPA) for their review. To date, there have been several letters exchanged between BLM, DOE, and EPA as to whether approval of these APDs and the resulting development of the oil and gas lease could potentially jeopardize the WIPP site.

On May 4, 1994, EPA notified DOE that EPA was unable, at that time, to determine if the acquisition of the two leases under WIPP (NMNM-02953 and NMNM-02953-C) is required to comply with the final transuranic waste disposal regulations in 40 CFR 191 or the Solid Waste Disposal Act. A final determination will have to wait until EPA receives DOE's complete application in 1996 for certification as a solid waste disposal site under the Solid Waste Disposal Act. In addition, two new issues have surfaced: the potential impacts from injection wells and water flooding for secondary recovery. It appears neither of these issues have been adequately analyzed. On June 3, 1994, DOE requested BLM delay any decisions until after December 1996, when EPA would receive DOE's complete application for review. A final determination would be made by EPA sometime after that date.

Due to the uncertainty of when a final determination will be made, and the unknown impacts from injection wells and water flooding, it is necessary to deny approval of your eight proposed wells, at this time. Your copies of the applications are enclosed.

In accordance with 43 CFR 3165.4, you may appeal this decision to the Interior Board of Land Appeals according to the procedures outlined on the enclosed Form 1842-1.

Sincerely,

/s/ Michael R. Ford

William C. Calkins
State Director

2 Enclosures

cc:
George E. Dials, Manager
Department of Energy
P.O. Box 2078
Carlsbad, NM 88220

bcc:(w/o Enclosures)
NM (060, L. Cone)
NM (067, R. Manus)
NM (910, W. Calkins)
NM (920, R. Smith)

TO'Brien:LCone:elr:x2...:krp:8/19/94

LIST OF EIGHT BASS APDS

(1) James Ranch Unit #20
Surface Location: 200' FNL & 460' FWL, Sec. 6, T23S, R31E
Bottom Hole Location: 660' FSL & 660' FWL, Sec. 31, T22S, R31E
APD Received: April 14, 1993

(2) James Ranch Unit #21
Surface Location: 200' FNL & 1980' FWL, Sec. 6, T23S, R31E
Bottom Hole Location: 660' FSL & 1980' FWL, Sec. 31, T22S, R31E
APD Received: April 9, 1993

(3) James Ranch Unit #22
Surface Location: 200' FNL & 1980' FEL, Sec. 6, T23S, R31E
Bottom Hole Location: 660' FSL & 1980' FEL, Sec. 31, T22S, R31E
APD Received: April 9, 1993

(4) James Ranch Unit #23
Surface Location: 200' FNL & 660' FEL, Sec. 6, T23S, R31E
Bottom Hole Location: 660' FSL & 660' FEL, Sec. 31, T22S, R31E
APD Received: April 14, 1993

(5) James Ranch Unit #24
Surface Location: 500' FNL & 330' FEL, Sec. 6, T23S, R31E
Bottom Hole Location: 1650' FSL & 330' FEL, Sec. 31, T22S, R31E
APD Received: April 14, 1993

(6) James Ranch Unit #25
Surface Location: 200' FNL & 1650' FEL, Sec. 6, T23S, R31E
Bottom Hole Location: 1650' FSL & 1650' FEL, Sec. 31, T22S, R31E
APD Received: April 14, 1993

(7) James Ranch Unit #26
Surface Location: 200' FNL & 2310' FWL, Sec. 6, T23S, R31E
Bottom Hole Location: 1650' FSL & 2310' FWL, Sec. 31, T22S, R31E
APD Received: April 14, 1993

(8) James Ranch Unit #27
Surface Location: 1650' FSL & 200' FEL, Sec. 36, T22S, R30E
Bottom Hole Location: 1980' FSL & 660' FWL, Sec. 31, T22S, R31E
APD Received: April 14, 1993

Chapter IX

REGULATIONS PERTAINING TO OIL AND GAS DRILLING

APPENDIX E

WASTE ISOLATION PILOT PLANT

STATEMENT OF WORK

FOR

THE BUREAU OF LAND MANAGEMENT

TABLE OF CONTENTS

STATEMENT OF WORK
FOR
THE BUREAU OF LAND MANAGEMENT

WASTE ISOLATION PILOT PLANT

STATEMENT OF WORK
FOR
THE BUREAU OF LAND MANAGEMENT

The Bureau of Land Management (BLM) shall perform the following specific tasks identified by the U.S. Department of Energy (DOE) as being necessary to the management of the Waste Isolation Pilot Plant's (WIPP) 16-section withdrawal area.

The parties to this Statement of Work (SOW) are the DOE, represented by its WIPP Carlsbad Area Office, and the U.S. Department of the Interior (DOI), represented by its BLM, Roswell District Office.

This SOW supports the WIPP Land Management Memorandum of Understanding executed between the DOE and the DOI.

This SOW will be administered on behalf of the DOE by the Manager, Carlsbad Area Office, P.O. Box 3090, Carlsbad, New Mexico 88221.

This SOW will be administered on behalf of the DOI by the District Manager, Roswell District Office, BLM, P.O. Box 1397, Roswell, New Mexico 88201.

RESPONSIBILITIES OF THE BLM

A. Cultural Resources

The BLM shall:

1. Provide recommendations to the DOE, within 30 days of request, in developing mitigation measures when avoidance of an historic property area is not possible.

B. Grazing Management

The BLM shall:

1. Provide proposed grazing management changes and/or plans to the DOE for review and comment.

2. Have the responsibility for all traditional administration of range resources afforded under the Taylor Grazing Act, the Federal Land Policy Management Act, and the Public Rangelands Improvement Act. Duties include, but are not limited to, the collection of grazing fees, project design and planning for development of range improvements, and development of Allotment Management Plans.

c. Continue BLM-funded vegetative monitoring program to determine if range management goals and objectives established for the grazing allotments are being achieved. As a minimum, the monitoring program shall include collecting data on actual livestock use, wildlife habitat and population trends, degree of utilization of the key forage species, climatic conditions, and rangeland ecological conditions and trends.

C. Wildlife

The BLM shall:

1. Prepare in cooperation with the U.S. Fish and Wildlife Service and appropriate state agencies a recovery plan for any threatened or endangered plant and animal species found occupying the WIPP withdrawal area to ensure its success and survival.

2. Provide the DOE, within 30 days of report completion, a draft copy of the recovery plan for review and comment.

3. Consult with the DOE to ensure that any range improvement developments (e.g., installation of livestock watering units) will be designed to accommodate wildlife needs.

4. Continue with the BLM and the DOE Interagency Agreement No. 1422G910-A2-0016 - Raptor Research and Management Program.

D. Fire Management

The BLM shall:

1. Provide full fire-fighting support within the withdrawal area should the WIPP incident commander request such support.

2. Commit necessary additional fire suppression resources should local BLM fire suppression resources be insufficient. The additional resources to be committed will be negotiated based upon the severity and behavior of the fire.

3. Negotiate with the DOE for monetary compensation required by the DOI for commitment of fire-fighting resources within the withdrawal area on a case-by-case basis.

E. Mining and Gas and Oil Production

The BLM shall:

1. Forward applications for Permit to Drill and mining and reclamation plans to the DOE within ten days of receipt for review and comment in determining issuance of any drilling or mining permit on federal lands within one mile of the withdrawal boundary. Drilling or mining permits for this area will not be issued by the BLM until DOE recommendations have been received.

2. Include the following as a Special Condition of Approval for oil and gas activity on federal lands at 330 feet or closer to the WIPP withdrawal boundary:

   a. Ensure that the operator provides the BLM with drill site downhole vertical deviation surveys for each 500-foot drilling interval within 48 hours of completion of each 500-foot drilling interval. The BLM will provide the DOE with these drill site downhole vertical deviation surveys within three days.

   b. Provide the technical expertise to calculate well bore deviation at each 500-foot interval of drilling to determine the degree of deviation and forward these results to the DOE within three days for review and verification of calculations.

   c. Require the operator to perform and provide the BLM with a directional survey to establish bottom hole location on well bores when the total cumulative degrees of displacement, independent of direction, indicate that the well bore could deviate to within 100 feet of the withdrawal boundary. Should the directional survey indicate that deviation is toward the withdrawal boundary, the BLM would require a directional survey at 100-foot intervals until such time as data would indicate that the bottom hole location at total depth would not exceed ten degrees from vertical or could result in a bottom hole location less than 100 feet from the withdrawal boundary. Should deviation direction continue towards the withdrawal boundary during the BLM monitoring of the 100-foot directional survey intervals, the BLM will require the operator to take corrective measures (i.e., side tracking) or cease drilling activity.

   d. Require the operator, in accordance with the New Mexico Oil Conservation Division (NMOCD) Rule 111, to perform and provide the BLM a directional survey to establish bottom hole location on well bores which experience deviation angles of more than five degrees from vertical in any 500-foot interval and on well bores when the total cumulative degrees of displacement, independent of direction, indicate that the well bore could deviate to within 100 feet of the withdrawal boundary.

   e. Provide the DOE with the aforesaid directional surveys within three days of receipt and completion, alternate use, and/or plugging and abandonment reports within five days of receipt.

F. Realty/Lands/Rights-of-Way

The BLM shall:

1. Forward applications and proposals for land uses affecting, but not solely contained within, the WIPP withdrawal boundary to the DOE within ten days of the BLM receipt of a completed application.

2. Assume the responsibility, when designated as lead agency, for the preparation of the National Environmental Policy Act documentation for land uses affecting, but not solely contained within, the WIPP withdrawal boundary and any DOE and/or WIPP specific compliance requirements documentation. The BLM shall obtain the review and approval

of the DOE (the contributing agency) of the aforesaid documents in determining issuance of a Record of Decision by the BLM.

3. Incorporate DOE- and/or WIPP-specific compliance requirements when preparing documentation for land uses affecting, but not solely contained within, the WIPP withdrawal boundary.

   These requirements shall include at a minimum:

   a. A safety plan that includes a job hazard analysis

   b. A list of all hazardous materials

   c. A description of methods used to manage and dispose of solid and hazardous waste

   d. Detailed project design drawings to include specific areas of impact

   e. A copy of their threatened and endangered species review (wildlife study)

   f. A copy of the archaeology study

G. Reclamation

The BLM shall:

1. Within ten days of receipt from the DOE, review and comment on the DOE proposed reclamation actions to ensure compliance with applicable DOE reclamation commitments.

U.S. DEPARTMENT OF ENERGY

BY:________________________

DATE:________________________

U.S. DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

BY: Leslie M. Cone

DATE: July 19, 1994

Chapter IX

REGULATIONS PERTAINING TO OIL AND GAS DRILLING

APPENDIX F

JUL 28

MEMORANDUM OF UNDERSTANDING

BETWEEN

THE U.S. DEPARTMENT OF ENERGY

AND

THE U.S. DEPARTMENT OF INTERIOR

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MEMORANDUM OF UNDERSTANDING BETWEEN THE U.S. DEPARTMENT OF ENERGY AND THE U.S. DEPARTMENT OF INTERIOR

MEMORANDUM OF UNDERSTANDING BETWEEN THE U.S. DEPARTMENT OF ENERGY AND THE U.S. DEPARTMENT OF THE INTERIOR

I. PARTIES

The parties to this Memorandum of Understanding (MOU) are the U.S. Department of Energy (DOE), represented by its Waste Isolation Pilot Plant (WIPP) Carlsbad Area Office, and the U.S. Department of the Interior (DOI), represented by its Bureau of Land Management (BLM), Roswell District Office.

II. BACKGROUND AND PURPOSE

The WIPP is authorized under Section 213 of the DOE National Security and Military Applications of Nuclear Energy Authorization Act of 1980, Public Law (P.L.) 96-164. The WIPP is authorized for the express purpose of providing a research and development facility to demonstrate the safe disposal of radioactive wastes resulting from the defense activities and programs of the United States exempted from regulation by the Nuclear Regulatory Commission.

The WIPP Land Withdrawal Act of 1992, P.L. 102-579 ("the LWA"), withdrew 10,240 acres of land in Eddy County, New Mexico, from the operation of the public land laws and reserved those lands for the construction, experimentation, operation, repair and maintenance, disposal, shutdown, monitoring, decommissioning, and other authorized activities associated with the purposes of the WIPP as set forth in Section 213 of P.L. 96-164.

Section 4 of the LWA makes the Secretary of Energy responsible for the management of the withdrawal, consistent with the Federal Land Policy and Management Act of 1976. The LWA directs the Secretary, in consultation with the Secretary of the Interior and the state of New Mexico, to develop a land management plan (DOE/WIPP 93-004) for the use of the withdrawal area until the end of the decommissioning phase. It further directs the Secretary and the Secretary of the Interior to enter into an MOU to implement the management plan.

III. AUTHORITY

This MOU is entered into pursuant to the authority of, and is consistent with, the LWA. Further, it is consistent with and subject to certain other appropriate statutory authorities, including the Department of Energy Organization Act, P.L. 95-91; the Energy Reorganization Act of 1974, P.L. 93-438; and the Economy Act of 1932, as amended by P.L. 98-216.

IV. MANAGEMENT

This MOU envisages direct communication between officials of the DOE and the BLM in consultation with other federal and state land management agencies which are involved in managing the resources within or activities impacting the surrounding areas of the WIPP withdrawal area. This MOU sets forth the cooperative arrangements and procedures for addressing land management within the withdrawal area. These cooperative arrangements and procedures implement the WIPP Land Management Plan for the withdrawal area and are consistent with the WIPP Land Management Plan's concept of multiple-use management.

The responsibilities and duties listed pursuant to this MOU relate to those shared by the DOE and the DOI. For additional land management issues not found in this MOU, consult the WIPP Land Management Plan (DOE/WIPP 93-004).

This MOU will be administered on behalf of the DOE by the Manager, Carlsbad Area Office, P.O. Box 3090, Carlsbad, New Mexico 88221.

This MOU will be administered on behalf of the DOI by the District Manager, Roswell District Office, BLM, P.O. Box 1397, Roswell, New Mexico 88201.

V. FUNDING

The details of the levels of funding to be furnished to one signatory organization by the other will be developed in specific interagency agreements, subject to the availability of funds. This MOU shall not be used to obligate or commit funds or as the basis for the transfer of funds. The DOE and the DOI will provide each other mutual support in budget justification to the Office of Management and Budget and in hearings before the Congress with respect to the programs described in the WIPP Land Management Plan and implemented through this MOU.

VI. RESPONSIBILITIES OF PARTICIPATING PARTIES

A. Cultural Resources

It is the intent of the DOE to manage cultural resources within the withdrawal area pursuant to Sections 106 and 110 of the National Historic Preservation Act, Archaeological Resource Protection Act, Native American Graves Protection and Repatriation Act, and applicable DOE Orders to ensure that scientific and sociocultural use by present and future generations shall not be diminished.

1. The DOE agrees to:

   a. Retain responsibility for management of cultural resources within the withdrawal area.

   b. Inventory and evaluate cultural resources prior to surface-disturbing activities.

c. Use avoidance as the primary mitigation measure.

2. The DOI agrees to:

a. Provide recommendations to the DOE in developing mitigation measures when avoidance of historic property is not possible.

B. Grazing Management

The withdrawal area includes portions of two grazing allotments administered by the BLM. The DOE's intent is to continue current management practices.

1. The DOE agrees to:

a. Retain responsibility for grazing management decisions affecting the two grazing allotments within the withdrawal area.

2. The DOI agrees to:

a. Provide proposed grazing management changes and/or plans to the DOE for review and comment.

b. Provide grazing management of the grazing allotments within the withdrawal area in accordance with applicable grazing laws including the Taylor Grazing Act, the Federal Land Policy and Management Act, and the Public Rangelands Improvement Act.

c. Continue BLM-funded vegetative monitoring program to determine if range management goals and objectives established for the grazing allotments are being achieved. As a minimum, the monitoring program will include collecting data on actual livestock use, wildlife habitat and population trends, degree of utilization of the key forage species, climatic conditions, and rangeland ecological conditions and trends.

C. Wildlife

The DOE intends to manage wildlife habitat within the withdrawal area for ungulates, raptors, upland game, and any special-status plant or animal species occupying the withdrawal area.

1. The DOE agrees to:

a. Retain responsibility for management decisions affecting wildlife habitat and the habitat of any special-status plant or animal species found occupying the withdrawal area.

b. Continue with the BLM and the DOE Interagency Agreement No. 1422G910-A2-0016 - Raptor Research and Management Program.

c. Upon receipt of the draft copy of the recovery plan (see Part 2a. below), the DOE shall review, comment, and transmit the draft copy of the recovery plan back to the BLM within 30 days.

2. The DOI agrees to:

a. Develop a recovery plan in cooperation with the U.S. Fish and Wildlife Service and appropriate state agencies for any threatened or endangered plant and animal species found occupying the WIPP withdrawal area to ensure its success and survival.

b. Continue with the BLM and the DOE Interagency Agreement No. 1422G910-A2-0016 - Raptor Research and Management Program.

c. Consult with the DOE to ensure that any range improvement developments (e.g., installation of livestock watering units) will be designed to accommodate wildlife needs.

D. Fire Management

It is the intent of the DOE to provide a fire management program that will ensure a timely, well-coordinated, and cost-effective response to suppress wildfire within the withdrawal area.

1. The DOE agrees to:

a. Employ full suppression strategy of a wildfire within the withdrawal area by utilizing the WIPP incident commander to coordinate fire management activities.

2. The DOI agrees to:

a. Provide full fire-fighting support within the withdrawal area should the WIPP incident commander request such support.

b. Commit necessary additional fire suppression resources should local BLM fire suppression resources be insufficient. The additional resources to be committed will be negotiated based upon the severity and behavior of the fire.

E. Mining and Gas and Oil Production

It is the intent of the DOE to ensure that mining and gas and oil activities do not encroach upon the withdrawal area. Adherence to this MOU is crucial to protecting the repository from inadvertent human intrusion. The WIPP is an offset owner to all gas and oil leases adjacent to the withdrawal boundary and will exercise the right to provide input on proposed activities of adjacent offset operators requesting an exception to applicable New Mexico Oil Conservation Division (NMOCD) rules and regulations.

In accordance with Section 4(b)(5)(A) of the LWA, no surface or subsurface mining or oil or gas production, including slant drilling from outside the boundaries of the withdrawal, shall be permitted at any time (including after decommissioning) on lands on or under the withdrawal.

In accordance with Section 4(b)(5)(B) of the LWA, existing rights under Federal Oil and Gas Leases No. NMNM 02953 and No. NMNM 02953C shall not be affected unless the Administrator of the Environmental Protection Agency determines, after consultation with the Secretary of Energy and the Secretary of the Interior, that the acquisition of such leases by the Secretary of Energy is required to comply with the disposal regulations or with the Solid Waste Disposal Act (42 U.S.C. 6901 et seq.

1. The DOE agrees to:

   a. Coordinate with the BLM to provide input and recommendations in determining a BLM permit issuance for oil and gas extraction and mining activity on federal lands within one mile of the WIPP withdrawal boundary.

   b. Provide the technical expertise to interpret, review, and verify oil and gas activity calculations performed by the BLM.

2. The DOI agrees to:

   a. Forward applications for Permit to Drill and mining and reclamation plans to the DOE for review and comment in determining issuance of any oil and gas extraction or mining permit within one mile of the WIPP withdrawal boundary. The BLM shall resolve any DOE comments prior to approval of such applications and plans.

   b. Include the following as a Special Condition of Approval for oil and gas activity on federal lands at 330 feet or closer to the WIPP withdrawal boundary:

      (1) Ensure that the operator provides the BLM with drill site downhole vertical deviation surveys for each 500-foot drilling interval.

      (2) Provide the technical expertise to calculate well bore deviation at each 500-foot interval of drilling to determine the degree of deviation and forward these results to the DOE for review and verification of calculations.

      (3) Require the operator, in accordance with the NMOCD Rule 111, to perform and provide the BLM a directional survey to establish bottom

hole location on well bores that experience deviation angles of more than five degrees from vertical in any 500-foot interval.

(4) Require the operator to perform and provide the BLM a directional survey to establish bottom hole location on well bores when the total cumulative degrees of displacement, independent of direction, indicate that the well bore could deviate to within 100 feet of the withdrawal boundary. Should the directional survey indicate that deviation is toward the withdrawal boundary, the BLM would require a directional survey at 100-foot intervals until such time as data would indicate that the bottom hole location at total depth would not exceed 10 degrees from vertical or could result in a bottom hole location less than 100 feet from the withdrawal boundary. Should deviation direction continue towards the withdrawal boundary during the BLM monitoring of the 100-foot directional survey intervals, the BLM will require the operator to take corrective measures (e.g., side tracking) or cease drilling activity.

(5) Provide the DOE the directional survey results that establish bottom hole location on well bores that experience deviation angles of more than five degrees from vertical in any 500-foot interval and on well bores when the total cumulative degrees of displacement, independent of direction, indicate that the well bore could deviate to within 100 feet of the withdrawal boundary.

c. Provide the DOE with completion, alternate use, and/or plugging and abandonment reports relevant to drilling, production, injection, and mining activity on federal lands within one mile of the withdrawal boundary.

F. Realty/Lands/Rights-of-Way

Land use management within the WIPP withdrawal boundary is the sole responsibility of the DOE. It is the intent of the DOE to monitor any land use proposal affecting the withdrawal area.

1. The DOE agrees to:

a. Consult with the BLM regarding future DOE right-of-way actions needed outside the withdrawal area.

b. Review and comment on applications and proposals received by the BLM for any land uses affecting, but not solely contained within, the WIPP withdrawal boundary.

c. Submit comments relative to any land uses affecting, but not solely contained within, the WIPP withdrawal boundary to the BLM's Roswell District Manager, or their representative, within 30 days of receipt from the BLM.

2. The DOI agrees to:

   a. Forward applications and proposals for land uses affecting, but not solely contained within, the WIPP withdrawal boundary to the DOE.

   b. Assume responsibility, when designated as the lead agency, for the preparation of the National Environmental Policy Act documentation for land uses affecting, but not solely contained within, the WIPP withdrawal boundary. The BLM shall obtain the review and approval of the DOE (the contributing agency) in regard to the BLM issuance of a Record of Decision.

   c. Incorporate any DOE- and/or WIPP-specific compliance requirements when preparing documentation for land uses affecting, but not solely contained within, the WIPP withdrawal boundary.

G. Reclamation

The DOE intends to return land disturbed by the WIPP activities to a stable ecological state that will assimilate with the surrounding undisturbed ecosystem.

1. The DOE agrees to:

   a. Reclaim land disturbed by the WIPP activities in accordance with the Environmental Protection Implementation Plan (DOE/WIPP 90-050); the Federal Land Policy and Management Act, 1976 (P.L. 94-579); the WIPP Final Supplement Environmental Impact Statement (DOE/EIS-0026-FS, Jan. 90); the WIPP Final Environmental Impact Statement (DOE/EIS-0026, Oct. 80); EPA requirements regarding disposal regulations; future Environmental Impact Statements; and land withdrawal requirements.

   b. Consult with the BLM in advance of reclamation activities to ensure compliance with applicable DOE reclamation commitments.

2. The DOI agrees to:

   a. Review DOE-proposed reclamation actions to ensure compliance with applicable DOE reclamation commitments.

VII. PUBLIC INFORMATION COORDINATION

Subject to the Freedom of Information Act, Title 5 U.S.C 552, decisions by either party on disclosure of information to the public regarding projects and programs developed pursuant to this MOU shall be made only after consultation between the parties.

VIII. PATENTS AND TECHNICAL DATA

Appropriate patent and other intellectual property provisions shall be included in interagency agreements and any other agreements entered into by the parties in order to implement this MOU. DOE patent and intellectual property policies shall apply to any such work performed by a contractor (including any subcontractor) which is funded in whole or in part by the DOE. Rights to inventions made by U.S. government employees shall be determined by the employing agency.

IX. REVIEW, AMENDMENT, AND TERMINATION

The DOE and the DOI, in consultation with other federal and state agencies involved in managing the resources within the withdrawal, shall review the MOU on an annual basis to determine whether it remains current and whether it effectively and appropriately implements the WIPP Land Management Plan for the WIPP withdrawal.

In the event that the DOE and the DOI determine that this MOU should be revised or amended, such revision or amendment shall be accomplished only upon written agreement between the parties. Any revisions or amendments to this MOU shall be developed in consultation with the state of New Mexico.

This MOU may be terminated by mutual agreement of the DOE and the BLM, or by either party upon a 30-day written notice to the other party.

This MOU shall remain in effect until the end of the decommissioning phase of the WIPP, as that phase is defined in the LWA.

X. EFFECTIVE DATE

This MOU shall become effective upon the latter date of signature of the parties.

U.S. DEPARTMENT OF ENERGY

BY: George E. Dials

DATE: ____________________

U.S. DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

BY: Leslie M. Cone

DATE: July 19, 1994

Evaluation of Mineral Resources at the
Waste Isolation Pilot Plant (WIPP) Site

Chapter X

THE PAST-DECADE DEVELOPMENTS AND FUTURE TRENDS IN OIL-WELL DRILLING, COMPLETION, AND STIMULATION, WITH SPECIAL APPLICATIONS TO DEVELOPMENTS AT THE WIPP SITE

by
Geir Hareland

Westinghouse Electric Corporation
Waste Isolation Division
Contract No. PO-75-WJJ644145Z

Submitted by

New Mexico Bureau of Mines and Mineral Resources
Campus Station
Socorro, NM 87801

March 31, 1995

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THE PAST-DECADE DEVELOPMENTS AND FUTURE TRENDS IN OIL-WELL DRILLING, COMPLETION, AND STIMULATION, WITH SPECIAL APPLICATIONS TO DEVELOPMENTS AT THE WIPP SITE

Geir Hareland

Introduction

This report discusses and describes developments in well drilling, completion, and stimulation technologies since the early 1980s and how they have improved safety, cost efficiency, and recovery from new and existing oil and gas wells. The application of these technologies is addressed in terms of improved and safer recovery of shallow oil and gas resources in the WIPP site study area. The future trends of the technologies are estimated based on current technology trends and research efforts in each of the disciplines.

Technical development in drilling, completion and stimulation

During the past decade, a tremendous amount of attention has been placed on drilling, completion, and stimulation of highly deviated and horizontal wells. The technology advancements for these types of wells have shown promising results in part due to the combined effects of improvements in directional drilling, completion, stimulation and production techniques. Highly deviated and horizontal wells are being drilled for a number of reasons. These include increasing the effective drainage area in comparison to vertical wells, increasing the sweep efficiency in reservoirs under enhanced recovery, more effective completion in thin reservoirs to maximize production, reducing problems associated with water and/or gas coning, increasing production from horizontal wellbores that intersect natural fractures, improving production in low-permeability reservoirs, producing from multiple horizons by a single well, and a host of other benefits (Rampersad, 1994).

The major improvements during the past decade, especially in well productivity, have been achieved due to a combination of technological improvements in the areas of drilling, completion, and stimulation. Improvements in the individual technologies are discussed below.

Drilling

The following sections discuss the areas of drilling technology that have improved over the past decade, and predict some of the future technology trends.

Directional and horizontal well drilling

The major improvement over the past decade has been the application of directional and horizontal well drilling. The contributing factor for the rapid increase in directional wells is due to a combination of many factors involving better tools and technologies. The improvement in directional drilling is due to improved directional-control capability of downhole motors in conjunction with a steerable system that is controlled from the surface. The communication between the downhole and the surface using telemetry through the drilling fluid gives the directional driller the capability to know exactly where and how the bit is progressing. From the data the driller makes the adjustments necessary to follow the planned pathway to the target horizon.

Based on research, minimum hole-cleaning guidelines were developed for wellbore geometry and inclination, and mud properties, and flow rate. Better understanding and practices of hole-cleaning has reduced the occurrence of stuck pipe and differential sticking (Thomren, 1986; Iyoho, 1987).

The understanding and modeling of borehole fracturing and collapse of directional wells have also contributed to less troublesome directional drilling (Aadnoy, 1987). The minimum mud weight required for maintaining a stable borehole is predicted using either triaxial rock mechanics, drilling, or log data. The most common rock-failure criteria used to predict the wellbore stability are given by von Mises, Mohr, or Druckner Prager. The proper mud weight can be determined from the in-situ stresses, wellbore survey, and failure criteria.

The length limitation of the horizontal wellbore is one of the most important considerations. However, drilling operations in the North Sea show that the wellbore length is not limited by the drilling technologies, but by the power of the equipment which hoists and rotates the drill string. The latter is the determining factor on how far the horizontal wellbores can penetrate.

This is not to say that there are no problems, but within a field experience gained in drilling sequence of wells (Millheim, 1986) will eventually resolve problems such as transport of cuttings, mud selection and weight, borehole stability, torque and drag, bit selection, and optimization.

Drilling bits

The past decade has brought an enormous improvement in drilling bits. This involves all three major bit types: tricone bits, polycrystalline diamond compact (PDC) bits, and natural diamond (ND) bits. The improvements increased rates of penetration and bit life, and decreased overall cost per foot.

Tricone bits have generally the same design utilizing three rotating cones with either insert or milled teeth crushing the rock. The major changes are improvements in the manufacturing process for better quality of the bits and some new features. The new features include better tricone bearings for longer bearing life, improved cutter teeth, new PDC material for better wear resistance, and cone offset designed for specific gouging action in a given lithology (Winters, 1987).

The PDC bits and PDC cutter blank material have improved as well. The PDC bit design now varies from extremely aggressive fishtail with few large cutters to less aggressive, flat-profile bits with more and smaller PDC cutters. Improvement in the PDC bit design is due to a better understanding of the actual 3-D cutting structure of the bits. The bit designs carefully balance force and torque before manufacturing. Through 3-D bit research it has recently been shown that, as the bit rotates around its axis, the sum of the forces from all the cutters generates an asymmetric balance of the bit, as well as a "whirl" movement which causes the bit to rotate around its center axis resulting in a larger hole and vibration at the bit (Brett, 1990). The rotation around the bit center may cause the PDC cutters to have negative instantaneous velocities which can break the cutters. Understanding this phenomenon has recently helped to develop the low-friction pad bit (Warren, 1990; Sinor, 1990; and Cooley, 1992), which by design forces the cumulative cutter force towards a low friction side-pad on the bit. These bits have less vibration, higher rates of penetration, and better cost efficiency, but more research is still needed for further understanding of the bit center rotation. Similar studies have shown that the dynamics of the bottom hole assembly (BHA) combine with the bit forces to generate bottom hole patterns similar to the bit whirl theory (Guo, 1994).

The natural diamond (ND) bits have also gone through an improvement in design and applications over the past decade. This is mainly due to understanding of the hydraulics of the ND bit (Behr, 1988). Natural diamonds have a bit pump-off force that is a strong function of the fluid parameters, bit design, and bit penetration per revolution. In the early 1980s, methods and procedures for estimating the bit pump-off were developed, so that whenever weight is applied to the bit, the pump-off force can be subtracted, which allows accurate mechanical weight on the bit to be determined (Winters, 1983). Before these methods and procedures for determining pump-off force the driller never actually applied a known weight on the bit (WOB). Because of the high wear resistance, the ND bits are today widely used in conjunction with downhole motors, especially in hard-rock drilling.

Future trends in bit development will focus on improvements in manufacturing and wear resistance of the bits. Another new simulation tool which is likely to benefit the drilling industry in the near future is bit 3-D dynamics analysis tool for optimizing the bit and bottom-hole-assembly combination for minimizing vibration.

Measurement while drilling (MWD) and logging while drilling (LWD)

These are among the fastest growing technologies. They provide continuous sampling of data through downhole sensors positioned close to or at the bit. The data collected downhole are then transmitted to the surface through the drilling fluid inside the drillstring using pressure impulses. The impulses are analyzed at surface and the recorded parameters can be monitored at the surface for better control of operating conditions and wellbore direction as well as lithological information. Typically, the operational data collected at the bit are weight on bit (WOB), rotational speed (RPM), and bit torque. MWD data are collected to ensure continuous survey, monitoring and control. In directional wells the most common parameters collected for direction control are measured depth, azimuth, and inclination.

Some of the most important logging while drilling (LWD) data collected are porosity, resistivity, gamma ray, and caliper measurements to ensure a better control of the drilling zone and wellbore status. All this information can also be combined into an excellent guiding tool, especially in directional wells within narrow pay zones. The limiting factor in data collection is the transmitability of the telemetry between the bit and surface. Ongoing research on this topic will be one of the largest contributors to better MWD and LWD.

Down-hole motors

Over the past decade, the use of steerable downhole systems has increased. The technology consists of downhole motors in conjunction with a bent sub or housing yielding better control and steerability. When integrated with a MWD system, the downhole motor assembly can be accurately controlled. The downhole motor design has also improved, especially in temperature resistance for deeper wells. The downhole motor temperature-resistance improvements started around 1986 and were aimed at developing a new mud motor capable of operating at more than 300°F in deep boreholes. Critical motor parts are now capable of handling up to 480°F. They were developed using polymeric-elastic lining of the stator tube mixed with metal, and can withstand high mechanical, chemical, and thermal stresses during drilling at deeper, warmer boreholes.

Drilling fluids - polymers

Recent developments in drilling fluids involve types of polymers different from those used during the early 80s. Natural, modified, and synthetic polymers have been investigated for use as a drilling-fluid additive.

Polymers are today widely used as drilling-fluid additives because they are degradable, environmentally safe, non-toxic materials that do not cause damage to the pay zone. Three factors limit polymer usage: they are expensive, they have a temperature limit, and they are difficult to re-use in the field.

Today, some modified and synthetic polymers are used at temperatures up to 330°F and can be re-used in two to three consecutive deep wells. Current research is focused on improving polymer recycling, but usage of polymers in most drilling fluid applications is currently not cost-effective.

Coiled tubing

Coiled tubing application has evolved rapidly during the past decade. The applications are both to old wells and new wells. To old wells, re-entry drilling has been an economical option for deepening existing wells and drilling lateral drainage holes. The application of drilling new wells with coiled tubing is rapidly increasing both for vertical and directional wells.

Other applications are exploration, steam injection, environmental observation, delineation of basic production, and injection wells.

Well re-entry application

1) Deepening existing wells (vertical well)

Vertical deepening of a well is technically simple to achieve by using a pendular bottomhole assembly (BHA) to control the hole direction. The weight on bit (WOB) is provided by a long BHA that maintains the neutral point (NP) in the BHA. This technique ensures a straight, vertical wellbore because the string is always put into tension in conjunction with the stiff BHA.

2) Drilling lateral drainholes (deviated well)

In lateral drainhole drilling, a whipstock is set in the bottom of the wellbore and a window is milled or cut through the casing. The drilling BHA is equipped with a directional measurement and control system that allows the drilling of the lateral drainhole into the producing formation. The force necessary to push the BHA and the coiled tubing around the buildup radius and into the deviated section is limited by the force that can be exerted on the coiled tubing in the vertical section.

New well applications

Even though coiled-tubing drilling (CTD) is much simpler than conventional drilling, a new well using CTD still requires a small rig to spud the well and set the surface casing. The rig provides equipment-support and pressure-control capabilities required for drilling. The prospect of low cost, low-impact exploration, observation and delineation wells has led oil companies to increased spending on CTD development during the past decade. In addition, the drilling of slimhole injection/production wells using CTD techniques is expected to be a viable option in marginal fields.

The limitations of the coiled-tubing technology are in directional applications because it does not have the capability to apply enough weight on the bit. Depth limitations due to tensile strength of the tubing are crucial. Coiled-tubing operations have been performed at depths up to 22,000 ft. The advantages are: no pipe connections, better well control, safer operations, less tripping time, and a smaller rig (Leising, 1992).

Future applications and development will make CTD a viable option in marginal fields at depths up to about 20,000 ft. The usage of CTD is another option when normal drilling is not economical. This of course depends on the availability of the CTD units. It is also estimated that re-entry drilling will be dominated by CTD in the future, if the economics are correct and CTD units are available.

Underbalanced drilling

In underbalanced drilling the wellbore hydrostatic pressure is less than the formation pressure. It is usually performed using either air, air/mud, foam, or mist mixtures as the drilling fluid. Underbalanced drilling is not a new concept but has been applied much more during the past decade because of its advantages that include high rate of penetration, less formation damage, and less fluid treatment. The disadvantages are less borehole stability and pressure control (Guo, 1995).

It is believed that underbalanced drilling will gain momentum in the future and will be applied where feasible. Better and safer well control and borehole stability are essential for its increased application.

Optimization tools - $/ft software

Optimization tools involve developing software to simulate parts of or the entire drilling process before actual drilling. This concept was initiated by a major oil company in the early to mid-80s in their critical drilling facility (CDF), where the engineering simulator for drilling (ESD) (Millheim, 1983) was used as a cost-reducing tool in pre-planning, day-to-day and post-job analysis for lowest cost drilling. The concept of this facility was a closed circuit system capable of monitoring multiple drilling operations through satellite communication and rigsite cameras with input to a central command center where drilling engineers monitor the operations around the world. Part of this process was the use of the ESD that had the capability to simulate any aspect of the drilling operation, or the total drilling operation ,for better safety and/or lower drilling cost.

The critical drilling facility (CDF) and the engineering simulator for drilling (ESD) led to the development of another generation of smaller expert systems, the engineering expert systems (ESS) in which the drilling system was broken down into many smaller engineering tools. The reason for this was that the ESD was too big to run simple engineering tools.

Today, engineering computer simulation tools exist for any of the hundreds of engineering systems used on a drilling rig. The objectives of these tools are to cut cost.

The concept of developing a geological drilling log (GDL) (Onyia, 1985) from the first field well and then simulate the drilling of the upcoming wells through a learning-curve has proven to cut drilling cost. Future operations will utilize better computers and more user-friendly software programs, which will benefit the drilling engineer in any aspect of the drilling operation.

3-D planning tools

The use of 3-D directional survey tools has become common practice in planning directional wells. Currently, many different analytical survey tools are available. They include the tangential method, average-angle method, minimum curvature method, radius of curvature method, mercury method, acceleration method, trapezoidal method, vector-averaging method (Bourgouyne, 1991), and constant-curvature method (Guo, 1993). Utilizing these computerized planning tools in conjunction with the constant MWD monitoring ensures that the surveys are followed and that the target is penetrated for optimum production, completion, and stimulation conditions.

Slimhole drilling

Application of slimhole drilling to both exploratory drilling and coring and to production has proved to be an economical alternative. Because slimhole drilling uses smaller rigs that can be transported with a helicopter, previously inaccessible locations such as mountains and jungles can be reached. The technology of slimhole drilling usually applies high rotational speed through top drives and often cores large sections using 30 to 60 ft corebarrels on a sandline. The process is limited to about 15,000 ft depth for safety reasons.

The problem with the slimhole exploratory drilling is the narrow annulus that during a "kick" might cause a blowout. Also the narrow annulus causes the equivalent circulating density to increase rapidly, which may fracture the formation.

Drilling rigs

Top Drive

Dual-speed top drives were introduced in the early 1980s. The demand on this type of rig has since increased worldwide. One of the new dual-speed top drives is rated at 650 tons, which can handle larger bit sizes and drill-string diameters and reach a greater drilling depth and produce longer horizontal sections. This type of rig meets personnel-safety requirements much better than the old rigs. Safety is needed most around the rotary table and on the rig floor; top-drive rigs eliminate the rotary table.

Instrumentation

The past decade has put a higher demand on quality data collection. The sensors used to collect drilling data are relatively simple. There have been some improvements using digital data collection, but the sensors used are not always accurate. Calibration of sensors must be done for all temperature and pressure ranges as well as for the whole spectrum of parameters. Better sensors, especially for WOB, torque, and return flow, must be developed to complement the application of some new software tools, otherwise simulation results will be poor.

Conclusions - Application to WIPP discussion

The WIPP area would be a good candidate for applications of the latest technology in directional drilling. Extensive drilling to reach the shallow oil in the Delaware Mountain Group, at about 7500-8000 ft, and the deeper gas in the Morrow and Atoka Groups is to be expected (if permitted) during oil and gas development under WIPP and potash resources.

Possible underbalanced drilling with foam, air, or aerated mud might be best for the Morrow gas formation because of the decreased risk of formation damage, less drilling-fluid treatment, and increased rate of penetration (ROP). In this case it is necessary to set casing below the Atoka Formation, which of course, is an economical question. This should be carefully investigated for possible problems such as fluid loss, returns, and borehole stability.

The application of horizontal drilling to reach both the oil and gas zones would cost more, but it is expected that the horizontal wells will be better producers. The price of drilling a horizontal well depends on depth, length of the horizontal section, and the formation drillability, all of which are functions of the area that must be reached under the potash mines and the WIPP site.

Currently, typical cost of a directional well in the Delaware Basin is about 1.6-2.0 times that of a vertical well. The cost will be higher for this project due to the possibility of extra-long horizontal sections and because larger rigs would be needed for increased rotary and hoisting capabilities. The increased drilling time due to the slow drilling of the horizontal section would have a definite affect on the total drilling cost. The cost of longer casing and/or liner in conjunction with directional cementing operations and larger pump capacities for better cleaning of the highly deviated sections would also increase the cost. An extended-reach horizontal well could cost two to five times more than a normal vertical well.

Since all the wells to be drilled in this area would penetrate the same formations, a fast learning curve could be developed which would decrease the actual drilling cost. Application of optimization tools for low $/ft drilling would also result in cost reduction. This would require good rig instrumentation and information sharing among the operators in the area and could have a significant impact on reductions in drilling costs around the WIPP site, especially since the geology would be essentially constant.

Completion

The following sections discuss the individual areas of completion technology that have improved over the past decade, and predict some of the future technology trends.

Horizontal wells

The past decade has seen the development and completion of horizontal wells. Completion techniques in horizontal wells vary from open-hole to gravel packs and/or perforated liner or conventional casing completion. These options depend upon the rock mechanical properties in the reservoir rocks and the maximum possible reservoir drawdown pressure. In horizontal wells, there is also a pressure drop in the horizontal wellbore section which causes an uneven drawdown along the wellbore. Considering this, the correct completion method can be selected based on cost and the reservoir drive mechanism. The methods of dealing with equalizing pressure drawdown are resolved, but are expensive and in some cases decrease the maximum production rate. This includes methods such as compartmental division, uneven perforation, or the stinger method (Brekke,1994).

Cement additives

Research during the past decade has shown that the permeability of the set cement can be greatly reduced if correct additives are used in a standard cement mixture (Talabani, 1995). Gas migration in the annulus between the formation and the casing has been eliminated by four new cement additives: ironite sponge, XC-polymer, synthetic rubber, and Anchorage clay. The ironite sponge has been shown to eliminate the microannulus between the casing and the cement body by magnetically bonding the casing with ironite sponge in the cement. XC-polymer has shown great results as a filtrate control agent. The Anchorage clay, when added to some ultrafine cement, has been shown to reduce the permeability of the cement body due to blockage of pores. Synthetic rubber added to the mixture compensates for the expansion-contraction cycles in the cement during setting. The elastic behavior of the rubber reduces or eliminates the second final pressure-volume shift.

It is believed that future efforts will concentrate on designing cement for variations in temperature and pressure to optimize thickness of the cement body along the entire length of the annulus.

Cement mixing

Until the mid-1980s, the instant jet mixing of cement powder with additives and water resulted in a non-homogeneous slurry that in many cases caused an incomplete cement-water reaction. As a result, cement powder with water created low applied shear on the cement particles, in which the peel was the only part reacting with water and the core stayed dry.

To solve the problem a new unit was made that cycles the slurry through a jet and then a high shear is applied to the cement slurry in the mixing tank. The high shear rate creates a homogeneous cement slurry in which most of the powder particles react completely with water.

Ultrafine cement manufactured and introduced to the oil field in the 1980s has particles 20 to 26 Å in diameter, which is one third the particle size of the other cement classes. Complete cement-water bonding is more easily achieved using a mixture of this new cement type.

Perforation

Perforation technology in the past decade has become better as more successful jobs were performed. This was due to better designed charges as well as the use of better centralizers and magnets. Perforation theory for directional wells with partial penetration, different possible charges, spacing, and shots-per-foot is better understood and therefore the perforating job can be optimized (Economides, 1989). The use of acid has also shown good results; however, extreme care is suggested in terms of time and pressure when using acid. The issue of overbalanced versus underbalanced perforation is still unresolved.

Future research will need to show in what cases the use of overbalanced or underbalanced perforation is better. Penetration depth, rock crushing, and solids invasion are all important factors, and it is also believed that the results of perforation strongly depend on the formation properties.

Conclusions-Application to WIPP

Recent improvements in cementing technology will have an enormous impact on the safe distances at the WIPP site. Using an impermeable final-set cement, would minimize the gas leak threat to the mining industry. Zero permeability cement eliminates both micro-cracks and micro-annulus, which in conjunction with dual wall casing would decrease the chances of gas migration to near zero. This would require more cement research and testing on setting time, pressure and temperature.

Because of the low initial formation pressure in both the oil and gas producing formations, a decrease in skin (any wellbore flow restriction) will benefit production greatly. This includes skin from formation damage, perforation penetration, shots-per-foot, phasing, partial penetration, and perforation-hole diameter.

Application of horizontal wells will increase the production and completion costs because of larger producing intervals, more expensive operations and equipment, plus more and faster wear and tear, in which the application of pump jacks or artificial lift should also be carefully compared for the most economical option.

Stimulation

The following sections discuss the individual areas of stimulation technology that have improved over the past decade, and predict some of the future technology trends.

Hydraulic fracturing-proppant and acid

The next sections applies for both proppant and acid hydraulic fracturing operation. To optimize the hydraulic fracturing process all of the next sections should be carefully evaluated using either acid or proppant.

Horizontal wells

One method of improving the productivity of horizontal wells is called multiple hydraulic fracturing (Soliman, 1990). Factors that affect the productivity of fractured horizontal wells are fracture orientation with respect to a horizontal wellbore, the location of a horizontal well for optimization of fracture height, number of fractures, and the mechanism of fluid flow into fractured horizontal wells. In general, at depths encountered in the oil field the least principal stress is horizontal, making the induced fracture oriented in the vertical plane. Thus, if the horizontal segment is drilled in the direction of least principal stress, several vertical fractures may be spaced along its axis. The design and performance of horizontal wells has been the subject of many studies (Geiger, 1984; Joshi, 1988). The performance of fractured horizontal wells has been predicted (Mukherjee, 1988; Economides, 1990; Brown, 1992; Guo & Evans, 1993; Rampersad, 1994). The productivity of a fractured horizontal well is many times higher than that of a non-fractured horizontal well, which in turn is many times higher than that of a vertical well. The benefit of hydraulic fracturing must be carefully evaluated against the gain in productivity using simulators. The simulator is developed to predict the ultimate revenue return.

Hydraulic fracturing will be used increasingly to make wells more economic and increase productivity. The Gas Research Institute predicts that hydraulic fracturing and/or horizontal wells will be the most attractive methods for developing marginally economic reservoirs as well as increasing productivity of tight gas sands and multizone reservoirs (GRI, 1992).

In situ stress profiling

Strong emphasis over the past decade has been on evaluating in-situ rock stresses before performing a hydraulic-fracturing job (Gidley, 1989). This is because the hydraulic-fracturing parameters obtained from a fracturing job are especially sensitive to the minimum principal in-situ stress profile. The design and simulation of a hydraulic fracture requires correct information about the formation in-situ stresses and rock properties. Therefore, emphasis has been on obtaining an accurate minimum in-situ stress profile for the least amount of money.

It has been shown over the past decade that the method with the least number of problems in obtaining the correct minimum principal in-situ stress profile is direct measurement using small-volume hydraulic fractures. These are expensive and may not be compatible with the well completion scheme, particularly if measurements are made in layers above the pay zone. Many techniques exist for evaluating in-situ stress at depth. All have been investigated in the past decade, but they suffer from various disadvantages. Core-based methods, including anelastic strain recovery, differential strain-curve analysis, shear acoustic anisotropy, acoustic emissions, etc., all require the taking of core followed by detailed analysis. Furthermore, problems with core quality, rock fabric, etc., may degrade the accuracy of the stress estimate. Methods of using sonic log or drilling data may give correct results in some instances but are not always reliable (Harikrishhnan, 1995).

A recent study demonstrated that knowledge of the in-situ stress profile is essential in designing and optimizing the hydraulic-fracturing design (GRI, 1992). The usage of correct minimum principal in-situ stress profile has shown productivity to improve markedly over jobs designed without detailed in-situ stress information.

In the future, knowledge of in-situ stresses will be essential for any economic evaluation of a hydraulic fracturing job. Therefore, new, accurate, and inexpensive methods will need to be investigated to obtain in-situ stresses using either logs, drilling data, core analysis, or new tools.

3-D hydraulic fracturing models

2-D simulation of the actual hydraulic fracturing was first attempted by Perkins and Kern (1961), and was later modified by Nordgren (1972) to include formation leakoff. The second 2-D model, developed by Geertsma and deKlerk (1969), included variation of flow rate along fractures. Both Newtonian and non-Newtonian fracturing fluid models can be used in the PKN and GDK models. In the early 80s the basic concept of the pseudo 3-D model was developed, which is the same as the PKN system except that the fracture height varies along the fracture length (Gidley et al., 1989). Ideally, the problem can be solved in 3-D space, which requires a full-blown 3-D simulator.

The application of the 3-D simulators has shown them to be excellent tools in optimizing the net present value of hydraulic fracturing (GRI, 1992). The fracture dimensions and their production can be analyzed from the 3-D model. Utilization of these models has shown that large sums of money can be saved before actually going to the field. In the GRI study it was shown that only 15% of all fracture treatments utilized 3-D models although they are easily available. It was also concluded that 54% of all fracturing treatments used less accurate 2-D models, which in reality would mean money lost to the operator in that the optimum 3-D fracture design for maximum net revenue return could not be predicted.

In the future, more operators should routinely use 3-D models to optimize the hydraulic-fracturing treatment for maximum net revenue. Improved 3-D models will be developed in conjunction with better tools for in-situ stress measurement.

Real-time monitoring and analysis

During the 1980s, real-time monitoring systems were widely utilized to increase success of fracturing jobs. Real-time data are carefully monitored and compared to the pre-job simulation. If parameters such as pump or bottom hole pressure are out of preferred ranges, adjustments can be made during the treatment. An example of this is a fracture screenout observed on the pressure record, with adjustments to pump rate done accordingly.

New fracturing products

Improvements in fracturing fluids, proppants, and gel breakers have benefitted the entire fracturing process. The fracturing fluids currently used are linear gels such as hydroxyethylcellulose (HEC) polymers, which have overall properties that generate low friction, revert to low viscosity after injection for easier removal before production takes place. Enzyme capsules that open in time or due to fracture closure are currently also used to break down the gels faster.

New and better proppants are continuously being developed. Ceramic cores with resin coatings are applied to some new proppants for better crushing resistance. Also, proppants have been developed that, after injection into the fracture bond together so that they do not backflow when the fracture closes (Borden Corp., 1994).

Hydraulic fracturing - acidizing

The in-situ stress profiling, 3-D fracturing models, and real-time monitoring and analysis are as important in acid fracturing as they are in proppant fracturing.

Matrix acidizing

Matrix acidizing is the process of injecting acid into the producing formation at a pressure between the pore and the fracture pressure, to react with rock deposits or other formation damage which reduces the productivity of the well.

Real-time monitoring and optimization

Three methods of evaluating matrix acidizing exist. The first method (McLeod, 1968) uses well tests to estimate the productivity of the well before and after treatment. The reduction in skin (any wellbore production flow restriction) is the evaluation tool used to see if the job was a success. The second method (Paccaloni, 1979) uses the first real-time tool for evaluating the matrix-acidizing job during the treatment. During the 80s this method was widely used. It utilizes predicted damage-ratio curves for a steady-state radial flow on a pressure versus acid flow-rate graph. As the acid etches the formation, the damage ratio is reduced, and it can be easily determined whether the job has obtained the maximum damage ratio of 1.0 or if more acid is needed to continue improving the damage ratio. This tool also verified what people in the industry had speculated on for a long time, that in order to optimize an acid job, the acid pump rate should be increased towards the end to lower the damage ratio even more. The third method (Provost, 1989) integrates the transient-flow solution to the Paccaloni method. Their real-time model predicts the skin as a function of acid volume injected and time. From the use of their model one can see whether the skin is continuously decreasing, flattening or increasing, and from the skin monitoring the job can be optimized in real time by stopping the acidizing at the lowest skin value.

Quality control

During the past decade, quality control during acidizing has been strongly emphasized by the oil companies. The engineer on site is responsible for following the company check list to eliminate any problems due to bad quality control. Emphasis has been placed on very close collaboration between the service company and the oil company personnel. It is has been proven that frequent checks and monitoring have produced better acid jobs (Ely, 1989).

Small-scale laboratory tests

To perform better acid jobs, laboratory experiments are conducted on core samples from the pay zone. Core samples are put in a closed unit and reservoir conditions are applied. A scaled-down acid job is then done in the laboratory, and the cores are tested and checked to monitor change in damage. From the laboratory experiments the correct volume and concentration of acid is obtained for maximum conductivity to fluid movement. A successful test on the core samples is then scaled up and applied on the field (Gidley, 1987).

Diverting agents

When stimulating a pay zone, the diverting agent helps to distribute the treating fluid across the entire production interval. This is important because the pay-zone layers have different permeabilities. The diverting agent slows down or blocks the flow path to the high permeability zones thus effectively diverting acid to the less permeable zones. Typical diverting agents are mechanical, ball sealers, solids, gels, and foams. Ball sealers are often made of nylon or hard rubber, and are used to temporarily seal the casing perforation (Bilden, 1992).

Conclusions - Application to WIPP

Applications of the past decade's improvements in stimulation technology have been a major factor in reducing the cost of oil and gas production. The applications of hydraulic fracturing and matrix acidizing have great potential for both the oil and gas zones.

The shallow oil in the Delaware under the WIPP site has a relatively low permeability of about 7 to 24 md and is therefore well suited for hydraulic fracturing to improve recovery (Broadhead, 1994).

The application of multi-hydraulic fracturing in a horizontal well will be an option that must be considered. Evaluation tools for the economics of this option could be developed (Rampersad, 1994).

The application of matrix acidizing depends on the production and completion method as well as the type of formation damage. The Delaware is a sandstone reservoir and therefore hydrochloric acid could be used. The success of matrix acidizing is dependent on the type of damage, i.e. from drilling, completion, or production. Laboratory testing of cores is highly recommended for selecting the correct concentrations and additives. During matrix acidizing, real-time monitoring should be performed for optimum performance.

The deeper Morrow Formation has a permeability between 2 and 10 md (Broadhead, 1994), and is possibly well suited for hydraulic fracturing. Similar type reservoirs have shown greatly increased production and economic benefits from hydraulic fracturing. The application of matrix acidizing must be considered depending on the type and extent of formation damage.

The application of stimulation type and treatment is always an economic option, but analysis of the net revenues must be evaluated against the treatment cost. For evaluation of optimum stimulation it is important to obtain good in-situ stress information, perform detailed laboratory core analysis, utilize 3-D hydraulic fracturing models, and perform real-time analysis and quality control.

Concluding remarks

Technology developments in drilling, completion, and stimulation over the past decade will definitely benefit the oil industry in developing and producing oil and gas resources in the WIPP site area. The economic benefit of applying new technological innovations will depend strongly on the surface location for drilling, completion, and well stimulation with respect to the reservoir target. The application of directional drilling is always an option, but this becomes an economic question when the target is too far from the surface location. The drilling cost could increase two to five times over a vertical well, which might make it too expensive. There are new technologies that can reduce the drilling operational cost. Applications of each individual new technology must be carefully investigated in terms of economics.

Newly developed impermeable cements and double-cased holes might be solutions for completing the wells. The question is how safe are these completion methods in conjunction with the new cement in terms of gas leakage. Current research has only proven cements to be impermeable at some temperatures and pressures and methods would need to be tested at the WIPP site. Further research on impermeable cements could result in the development of a cement that would completely seal the annulus from surface to bottom of well. This would allow the cement to be tested for all the temperature and pressure ranges that are expected in a well at the WIPP site.

Depending on the type of wells drilled, the stimulation options should be carefully evaluated economically, using newly developed methods and simulators.

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Evaluation of Mineral Resources at the
Waste Isolation Pilot Plant (WIPP) Site

Chapter XI

OIL AND GAS RESOURCE ESTIMATES

by
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SUMMARY OF OIL AND GAS RESOURCES

Rigorous, quantitative estimates were made of oil, natural gas, and natural gas condensate resources that exist beneath the 16 mi^2 area of the WIPP land withdrawal area and an additional one-mile wide study area around the WIPP site. Calculations were made for resources that are extensions of known, currently producible oil and gas resources thought to extend underneath the WIPP land withdrawal area with reasonable certainty (*probable resources*). Qualitative estimates were also made of oil and gas that may be present in undiscovered pools and fields beneath the WIPP land withdrawal area (*possible resources*). Possible resources were not quantified.

Probable resources consist mostly of oil and associated gas in Permian strata and nonassociated gas and gas condensate in Pennsylvanian strata. Currently, most oil and associated gas production in the vicinity of the WIPP site has been obtained from sandstone reservoirs in the Delaware Mountain Group (Permian) at depths of 7000 to 8000 ft. Sandstones and carbonates in the Bone Spring Formation (Permian) at depths of 8000 to 11,000 ft and carbonates in the Wolfcamp Group (Permian) at a depth of approximately 12,000 ft are secondary oil reservoirs. Carbonates in the Strawn Group (Pennsylvanian) at a depth of approximately 13,000 ft are secondary, but important, reservoirs of gas and light oil or condensate. Most nonassociated gas and condensate production in the vicinity of the WIPP site has been obtained from sandstone reservoirs in the Atoka and Morrow Groups (Pennsylvanian) at depths of 13,000 to 14,000 ft.

Probable oil and condensate resources within the boundaries of the WIPP land withdrawal area are 12.3 million bbls of oil and gas condensate recoverable by primary production methods and an additional 6.4 million bbls of oil potentially recoverable by secondary recovery with waterfloods (**Table 1**). Probable resources within the one-mile wide additional study area surrounding the WIPP land withdrawal area are 22.9 million bbls oil and gas condensate recoverable by primary production methods and an additional 13.8 million bbls of oil potentially recoverable through waterflooding.

Probable gas resources within the boundaries of the WIPP land withdrawal area are 186 BCF gas (**Table 1**); 89% of this gas is nonassociated and will be produced from the deep Atoka and Morrow reservoirs. The remainder is associated gas, most of which will be produced from relatively shallow reservoirs in the Delaware Mountain Group. Probable gas resources underneath the one-mile wide additional study area surrounding the WIPP land withdrawal area are 168 BCF gas; 79% of this gas is nonassociated and will be produced from the deep Strawn, Atoka, and Morrow reservoirs.

In addition to *probable resources,* there are significant *possible resources* of oil, gas, and gas condensate beneath the WIPP land withdrawal area and the additional study area. These will be oil and associated gas in untapped sandstones of the Delaware Mountain Group in largely unexplored and unevaluated sandstones and carbonates of the Bone Spring Formation, and in carbonate reservoirs in the Wolfcamp and Strawn Group. Possible resources of nonassociated gas and gas condensate will occur in sandstone reservoirs in the Atoka and Morrow Groups and in the pre-Pennsylvanian section (Siluro-Devonian and Ordovician strata). The elusive nature of possible resources makes their quantification difficult or impossible for an area of limited extent such as WIPP.

If production within the WIPP land withdrawal area is ever allowed, preferred development of oil and gas resources will be by drilling vertical wells to the main objectives (Delaware sandstones for oil and Morrow and Atoka sandstones for gas). In most cases, it will not be economically feasible to drill deviated or horizontal wells to develop and produce these resources. Also, the presence of multiple pay zones in vertical succession makes it highly desirable to use vertical wells for exploitation of oil and gas in the vicinity of the WIPP site. Use of vertical wells allows completion in several zones by a single well, some or perhaps most of which would not be economically feasible to develop without multiple completions in a single well. It is possible that oil reservoirs will be waterflooded when production by primary methods has declined to approximately 50% of its maximum rate.

INTRODUCTION

Oil and gas resources are typically divided into several categories (Potential Gas Committee, 1993; Energy Information Administration, 1994; **Figs. 1a, 1b**). For purposes of this report, five categories of resources are referred to: 1) cumulative production; 2) proved reserves; 3) probable resources (extensions of known pools); 4) undiscovered recoverable resources; and 5) unrecoverable resources. *Cumulative production* is the total volume of crude oil, natural gas condensate, and natural gas that have been withdrawn (produced) from a pool or well. *Proved reserves* are an estimated quantity of crude oil, natural gas condensate, or natural gas that analyses of geologic and engineering data demonstrate with reasonable certainty to be recoverable in the future from discovered oil and gas pools. Pools are considered proved that have demonstrated the ability to produce by either actual production or by conclusive formation tests (Potential Gas Committee, 1993), that is by drilling. This report restricts the definition of proved reserves to those producible resources identified as producible by existing wells (whether currently producing or abandoned). *Ultimate recovery* is the sum of cumulative production and proved reserves or probable resources for a pool or individual well.

The remainder of the resource base consists of *potential resources*. These can be summarized as hydrocarbons that can be inferred to exist, but have not yet been proven by drilling to exist. These can be grouped into: 1) *probable resources (extensions of known pools)*; 2) *probable resources (new pools)*; 3) *possible resources*; and 4) *speculative resources*. These subdivisions of potential resources are differentiated on the basis of available geologic, geophysical, and engineering data and studies. *Probable resources (extensions)* consist of oil and gas in pools that have been discovered but have not yet been developed by drilling; their presence and distribution can generally be surmised with a high degree of confidence. *Probable resources (new pools)* consist of oil and gas that are surmised to exist in undiscovered pools within existing fields. *Possible resources* are less assured; they are postulated to exist outside of known fields but within productive stratigraphic units in a productive basin or geologic province. *Speculative resources* are expected to be found in stratigraphic units, basins, or geologic provinces that have not yet been proven productive; estimates of speculative resources are the least assured of all resource estimates. *Unrecoverable resources* are dispersed in such minute accumulations or under such conditions that they can not be extracted with existing or foreseeable technology.

In this report calculations are made for *cumulative production* and *probable resources (extensions of known pools)* for the 16 sections that constitute the WIPP site and for the 20 sections that constitute the one-mile-wide additional study area around the WIPP site (**Fig. 2, Tables 1-4**). Cumulative production consists of historical data; it is listed as a separate item. Proved reserves are included with probable resources (extensions of known pools) because the sum of these two factors is the main goal of the oil and natural gas part of this study; together, these include oil and natural gas that are likely to be produced from existing wells and from undrilled areas that are thought to overlie extensions of producing pools. No numerical estimates were made for undiscovered resources that may reside unknown beneath the WIPP land withdrawal area, because quantitative estimates of these resources are uncertain at best. However, geologic studies conducted as part of this project were used to make a qualitative evaluation as to the likelihood of new, undiscovered pools and fields being present. Unrecoverable resources are not estimated.

Cumulative production data were obtained from official state records collected by the New Mexico Oil Conservation Division of the New Mexico Energy, Minerals, and Natural Resources Department. The Oil Conservation Division is the state agency which is required by law to regulate oil and natural gas drilling and production operations on state and private lands within the state. In addition, the Oil Conservation Division keeps records of all oil and natural gas production within New Mexico. Monthly and annual reports subdivide production by pool, operator, and individual well; these reports are available in hard copy as monthly and annual reports published by the New Mexico Oil and Gas Engineering Committee. These data are also kept in digital tape format by the Oil Conservation Division. Both digital and hard copy forms of the data were used in preparation of this report.

Definitions

Several basic definitions associated with terminology that describes the manner of occurrence and physical properties of crude oil and natural gas are integral to this report. Some of this terminology varies slightly in meaning from state to state (e.g. pool, field), from science to science (e.g. the term *petroleum* has a different meaning to geologists than it does to chemists; geologists generally use the term to describe all liquid, gaseous, and solid hydrocarbons in a reservoir, while chemists generally use the term as a synonym of crude oil), or even from worker to worker (the term *reservoir* can be confusing unless it is defined precisely). For purposes of clarity, terms fundamental to this report are defined below.

Oil (crude oil): Hydrocarbons that naturally occur in a liquid state within the reservoir and are produced in a liquid state at the wellhead. Volume of crude oil is measured in barrels (bbls or BO).

Gas (natural gas): Hydrocarbons that naturally occur in a gaseous state within a reservoir and are produced as a gas at the wellhead. Volume of natural gas is measured in thousand ft^3 (MCF), million ft^3 (MMCF), or billion ft^3 (BCF).

Condensate (gas condensate): Hydrocarbons that naturally occur in a gaseous state within the reservoir but condense to a liquid at the surface (wellhead) because of decreased temperature and pressure at the surface relative to temperature and pressure within the reservoir. It is often difficult to determine if a high-gravity (i.e. low density) liquid hydrocarbon is a light oil or a gas condensate. Official production reports do not differentiate between gas condensates and crude oils. It is generally assumed as a first approximation that liquids produced from gas reservoirs are condensates and that liquids produced from oil reservoirs are true crude oils. This assumption is made throughout this report.

Associated gas: Natural gas that occurs with oil in the reservoir, either dissolved within the oil or as a free gas cap above a gas-oil contact.

Nonassociated gas: Natural gas that occurs in the absence of oil in the reservoir. Liquid hydrocarbons that are produced with nonassociated gas are condensates, rather than oils.

Field (oil field, gas field; **Fig. 3***)*: An area characterized by geographically continuous production of oil and/or gas that may be produced from a single pay zone (stratum) or from several pay zones (multiple strata). This definition of field is consistent with regulatory and legal usage in New Mexico.

Pool (oil pool, gas pool; **Fig. 3***)*: A single discrete accumulation of oil or gas within a single trap. Several pools may lie in vertical succession in an area, or they may lie side by side or overlap laterally so as to constitute an areally continuous accumulation called a *field*. The pool name is made up of two parts:

1) the field name, usually derived from a geographic location (e.g. Bueno);
2) the stratigraphic name, derived from the stratigraphic unit that acts as the reservoir for the oil and/or gas (e.g. San Andres).

In this hypothetical example, the field name is Bueno and the pool name is Bueno San Andres. Other pools in this field are Bueno Abo, Bueno Upper Silurian, Bueno Montoya, and Bueno Ellenburger. This definition of pool is consistent with regulatory and legal usage in New Mexico.

Reservoir: A layer or stratum of porous and permeable rock in which crude oil, natural gas, or natural gas condensate are found and can be produced in economic quantities. This definition is consistent with regulatory and legal usage in New Mexico.

Methodology of resource estimation - primary recovery

Numerical estimates of crude oil, natural gas, and natural gas condensate resources recoverable through primary production techniques were made by geologically delineating areas of probable production. Historical production data from producing wells were used to calculate the volume of oil, gas, and gas condensate recoverable per unit area of reservoir. The area within the boundaries of potential production was calculated and multiplied by recoverable resource per unit area to give ultimate recovery. Probable resources of a pool are obtained by subtracting cumulative production from ultimate recovery.

Basic information for all wells drilled for oil and gas in a nine-township study area centered on the WIPP site (**Fig. 2**) was compiled from well records on file at the Subsurface Library of the New Mexico Bureau of Mines & Mineral Resources. Geophysical borehole logs were analyzed and correlated throughout the nine-township study area. Log correlations were used to produce structure contour maps of appropriate mapping datums and to isopach the primary pay zones in pools adjacent to the WIPP land withdrawal area. Structure contour maps were made of four stratigraphic surfaces, the structure of which may govern hydrocarbon entrapment in major producing reservoirs. These four surfaces are: 1) a prominent resistive log marker at the top of the lower Brushy Canyon Formation; 2) the top of the Wolfcamp; 3) the top of the Strawn Group; and 4) the top of the Morrow clastic section. Because of inaccuracies inherent in stratigraphic data obtained from scout cards and the omission of stratigraphic tops from many scout cards, log correlations made during the course of this study were used to calculate subsea levels necessary for contouring. Other maps unique to the analysis of each pool were also produced and are discussed at appropriate places below. These other maps, in conjunction with the appropriate structure contour maps, were then utilized to project the boundaries of known (i.e. discovered) hydrocarbon traps into undrilled/nonproductive areas beneath the WIPP land withdrawal area and the surrounding one-mile wide study area. From these projections, estimates were made of the potentially productive area for each of the pools. Potentially productive area is given in terms of the number of potential drill sites based on proration units consistent with established spacing in the vicinity of the WIPP site.

Quantitative resource assessment also utilized historical production data of producing wells to estimate ultimate recovery and reserves recoverable by primary production techniques. Monthly production data of oil, gas, and condensate in digital format were used to produce time-dependent production plots (see **Figs. 4, 5** as examples). These digital production data were available for months up to and including December 1993. Then a computer program written with *Mathematica* was used to fit a custom production decline curve to each well (**Figs. 4, 5**). The area under the curve was then calculated by mathematical integration of the formula used to define the curve; this area is the *ultimate primary recovery* of oil, gas, or condensate (*ultimate primary recovery* is the total amount of oil and/or gas that a well could economically produce from the date of first production to the date of eventual abandonment if only primary production techniques are utilized). The well's reserves are equal to cumulative production subtracted from ultimate recovery (**Fig. 6**). Ultimate recovery of associated gas from oil wells was estimated by a more complex method described below.

Based on analysis of the data, the decline curve fitted to each well was either exponential or linear (**Figs. 4, 5**). The following general equations were used for each type of curve (Sustakoski and Morton-Thompson, 1992):

$$q_t = q_i e^{-Dt} \qquad \text{exponential decline}$$

$$q_t = q_i - n(t) \qquad \text{linear decline}$$

where: q_i = initial production rate (bbls/month or MCF/month)
q_t = production rate at time t
t = time at which production rate is calculated (months)
D = initial decline rate, expressed as a decimal
n = linear decline slope (bbls/month^2)

An exponential decline curve was used to describe production data from most wells.

For each well, ultimate recovery was calculated for five lower limits of production rate (30, 60, 90, 120, and 150 bbls/month for oil wells and 300, 600, 900, 1200, and 1500 MCF/month for nonassociated gas wells). At current oil and gas prices, the 150 bbl/month and 1500 MCF/month limits are economically appropriate as the minimum production rates.

Two calculations were performed in order to test the fit and appropriateness of the calculated production decline curves. First, a correlation coefficient (R^2) was calculated for comparison of the curve with known, historical production data. R^2 will vary between 0 and 1.0. A value of 0 indicates that there is no correlation between the actual production data and the calculated curve. A value of 1.0 indicates that the historical production data are defined exactly by the calculated production decline curve. Most values of R^2 were greater than 0.5, indicating a good curve fit. For many wells, R^2 was greater than 0.85, indicating an excellent fit between the curve and the historical data points; this is especially true of wells completed in the Brushy Canyon Formation of the Delaware Mountain Group.

The second test of curve fit involved integrating the area under the decline curve from initial production of the well to the end of December 1993. This gives an estimate of cumulative production from initial well completion until the end of 1993. This value was then compared with actual cumulative production at the end of 1993. For most wells, the difference between the estimated (calculated) value and the actual value of cumulative production was less than 5%, indicating good representation of the production data by the calculated curve. In some cases, the difference between the two values was less than 2%, indicating that the calculated curve yields an excellent representation of actual production. Both tests of curve fit indicated that calculated curves could be used with confidence to predict future production and therefore to calculate reserves.

As mentioned previously, reserves of associated gas in oil wells were calculated by a different method (see Kloepper, 1993). In these wells, the economics are driven largely by oil production. This is especially true for productive oil wells in the vicinity of the WIPP site. These wells have low gas-oil ratios. A well is ultimately abandoned because daily oil production has fallen below an economic rate. For these wells, historical monthly values of gas-oil ratio were calculated from production data. A gas-oil ratio decline curve was plotted and projected to well abandonment based on projections of crude-oil production. Gas-oil ratios estimated by the curve were then multiplied by projected crude-oil production to obtain an estimate of past and future associated-gas production (i.e. ultimate recovery).

Only wells with at least 12 continuous months of production data were used in ultimate recovery calculations. Many wells had at least 36 months of production data prior to the end of 1993 and some wells had several years of production. Some wells have been re-entered since original completion. In most of these re-entered wells, the original producing zone has been abandoned and sealed off from the rest of the borehole by either a bridge plug or by cement. In these cases, the well has since been recompleted in a new zone, which is usually shallower than the original producing zone. Such a well may have been productive from two, three, or even four zones at different times in its history. Each zone is associated with its own production decline curve, and ultimate recovery was calculated separately for each zone.

Wells in which production has been significantly curtailed for economic or other reasons often do not yield a production history which is suitable for decline-curve analysis (see Kloepper, 1993). Ultimate recovery was not calculated for these wells. A few wells did not yield data that supported calculation of a decline curve. Unknown or unrecognized factors have left these wells with an erratic production history. Ultimate recovery was not calculated for these wells.

After ultimate recovery was calculated for individual wells, the average ultimate recovery per well was calculated for each major pay zone in pools adjacent to the WIPP land withdrawal area by the method outlined below. This concept of the average well is widely used in the petroleum industry (see Holmes et al., 1985). Although the concept of the average well is not suited to estimate resources for any one particular prospect, it can be used with confidence to estimate the resources under an area such as the WIPP site, which consists of multiple undrilled prospects in known hydrocarbon traps that are projected to extend underneath the site.

In order to calculate average ultimate recovery, a production decline curve for the average or typical well in each pool was established. The method used to generate this typical decline curve was dependent upon the quality and quantity of production data available in each pool. For Delaware pools, monthly production data were assembled for all wells for which ultimate recovery was calculated. Data were normalized to the first month of production for each well. Then, the average production for each month (normalized to the well's initial production) was calculated. Based on these normalized average monthly production values, an average decline curve for wells in each oil and gas pool was calculated according to the method described above. For pools in formations other than the Delaware, construction of the typical decline curve is described under discussion of each pool.

Petroleum resources underneath the WIPP land withdrawal area and the surrounding one-mile additional study area were calculated for each oil and gas pool projected to extend underneath these areas (Tables 2-4). The potentially productive area for each pool was mapped by using the structure and stratigraphic maps to project boundaries of the traps from drilled producing areas into undrilled areas. Productive area was calculated in terms of proration units based on a spacing consistent with that in the pools adjacent to the WIPP land withdrawal area (Tables 2-4). The number of proration units was then multiplied by the average resources per well to estimate the total ultimate recovery for each pool in the WIPP land withdrawal area and in the additional study area. Resources of the pool are then equal to the ultimate recovery minus the cumulative production.

The petroleum geology and petroleum engineering characteristics of productive and potentially productive strata beneath the WIPP land withdrawal area are described below, as is the history of oil and gas drilling and production in the area. The geology of each stratigraphic unit and of the separate oil and gas pools within each stratigraphic unit is unique. The discussion is divided accordingly.

OIL AND GAS RESOURCES AND PETROLEUM GEOLOGY OF WIPP SITE

Overview

The WIPP site is situated in the Delaware Basin (**Fig. 7**). Strata range in age from Cambrian through Permian (**Fig. 8**). The Delaware Basin is the deep-marine part of the Permian Basin and is bordered on the north and west by the Northwest Shelf and on the east by the Central basin platform. The Permian Basin became differentiated into these paleobathymetric elements during the Pennsylvanian. By the Wolfcampian (Early Permian), the shelf margin was constructional rather than tectonic and was marked successively by the Wolfcamp, Abo, Getaway, Goat Seep, and Capitan bank and barrier reef complexes (**Figs. 9, 10**). Regional structural dip is toward the center of the Delaware Basin (**Fig. 11**). In the vicinity of the WIPP site, oil and natural gas have been extracted commercially from the Delaware, Bone Spring, Wolfcamp, Strawn, Atoka, and Morrow (**Fig. 8**). Presently nonproductive units which may bear undiscovered oil and natural gas in the area are (descending): Mississippian, Siluro-Devonian, and Ordovician sections; significant volumes of oil and gas are produced from these stratigraphic units elsewhere in the New Mexico part of the Permian Basin.

History of oil and gas drilling in WIPP area

According to comprehensive well records on file at the New Mexico Bureau of Mines & Mineral Resources, 532 wells had been drilled in search of oil and gas in the nine-township study area centered on the WIPP site as of the end of 1993 (**Fig. 2**). Additional drilling was done in 1994, but 1994 wells were not included in these statistics because complete data for the year were not available at the time this report was written. Few wells were drilled in the area prior to 1960 (**Fig. 12**). From 1960 until 1989 drilling activity increased but was sporadic and never exceeded 20 wells per year. In 1990, however, drilling increased markedly. Annual totals increased to a maximum of 140 wells per year during 1993; most of these wells were drilled for oil (**Fig. 13**) in the Brushy Canyon Formation of the Delaware Mountain Group. The increase in well completions during the 1990s can be partially attributed to opening up hitherto restricted areas of the Potash Area to drilling (see Ramey, this report, for a summary of drilling restrictions in the Potash Area). However, the lower parts of the Delaware Mountain Group (Cherry Canyon and Brushy Canyon Formations) were not generally recognized as exploratory and development targets until the late 1980s and early 1990s. Prior to that time, they were usually bypassed during drilling with little or no thought that they might contain economic oil reservoirs. Although these two formations had been penetrated by thousands of wells throughout the Delaware Basin, few attempts were made to adequately test them.

The main reason for bypassing these formations during drilling was a lack of understanding of their reservoir production characteristics. Water saturations calculated from analysis of electric logs were often high and did not differentiate oil-productive sandstones from sandstones that would yield mostly water upon completion. However, recent developments in log analysis (Asquith and Thomerson, 1994) have made it possible to differentiate Delaware sandstones with a high percentage of movable hydrocarbons from those with a low percentage of movable hydrocarbons. This type of analysis, in conjunction with the discovery of several commercial oil pools in the Brushy Canyon Formation, set off an oil drilling boom throughout the Delaware Basin that continues to the present. The Delaware play is currently the primary exploration and development play in the Permian Basin and is one of the most active oil plays in the United States. Of special note in the vicinity of WIPP was the discovery and development of commercial oil accumulations in the Brushy Canyon Formation at the Cabin Lake, Livingston Ridge, Lost Tank, and Los Medanos pools.

Prior to 1970, most drilling in the WIPP area was for shallow oil (4000-4500 ft) in the Bell Canyon Formation. With the exception of the Bell Canyon discovery at Triste Draw (**Fig. 14**), most of these exploratory wells were plugged and abandoned. Numerous oil shows were encountered by cores and drill-stem tests. These wells reached total depth in the Bell Canyon and were not drilled deep enough to reach the currently productive Cherry Canyon and Brushy Canyon reservoirs.

From 1970 until the mid-1980s most drilling in the vicinity of WIPP concentrated on gas (**Fig. 13**) in the Morrow and Atoka Formations. The stratigraphic component of the Morrow and Atoka plays was often neglected in lieu of drilling seismically defined structures. Most drilling for deep gas took place northeast of the WIPP site in T21S R32E (**Fig. 2**). With the opening of parts of the Potash Area to oil and gas exploration in the 1990s, deep gas in the Morrow and Atoka once again became a drilling target along the western boundary of the WIPP land withdrawal area (**Fig. 2**) where several wells have been drilled.

Oil and gas drilling within WIPP land withdrawal area

Three wells have been drilled for oil and gas within the boundaries of the WIPP land withdrawal area (**Fig. 2, Table 5**). Two wells, the Clayton Williams No. 1 Badger Federal and the Michael Grace No. 1 Grace Cotton Baby Federal, were drilled as vertical holes within the WIPP land withdrawal area during the 1970s. Both wells were abandoned without establishing production. In the Clayton Williams Badger Federal well, oil was recovered on a drill-stem test of sandstones in the Cherry Canyon Formation, but apparently no attempt was made to complete the well as a producer. The main pay zone in the upper Brushy Canyon at the Livingston Ridge pool and the lower Brushy Canyon D zone were not tested; neither of these zones was known to be commercially productive at the time the well was drilled. In the Michael Grace Cotton Baby Federal well, Bell Canyon sandstones were perforated through casing, but production was not established. Although the well reached total depth in the upper part of the Brushy Canyon, there are no reports of tests in either the Brushy Canyon or Cherry Canyon.

The Perry R. Bass No. 13 James Ranch unit was drilled during 1982 from a surface location in sec. 6 T23S 31E. The hole was deviated to a bottom-hole location in the southwest quarter of sec. 31 T22S R31E, which underlies the WIPP land withdrawal area. Gas production was established in September 1982 from an Atoka sandstone reservoir at depths of 13,466 to 13,477 ft. The well remains productive and had produced a cumulative total of 4.664 billion ft^3 of nonassociated gas, 27.5 thousand bbls of condensate, and 2.8 thousand bbls of brine as of December 31, 1993. See Silva (1992, 1994) for some discussion of this well.

No additional wells have been drilled for oil and gas with either surface locations or bottom-hole locations within the boundaries of the WIPP land withdrawal area. Several shallow engineering and potash core holes were drilled within the boundaries of WIPP, but these holes were not drilled deep enough to penetrate strata productive of oil and gas. Griswold (this report) has summarized these shallow core holes.

Bass Enterprises submitted applications to drill eight wells within the boundaries of the WIPP land withdrawal area from surface locations outside of the site (**Table 6**) for purposes of establishing hydrocarbon production. The applications to drill were denied by the U.S. Bureau of Land Management in August 1994. See Ramey (this report) for a copy of the letter from the Bureau of Land Management to Bass Enterprises in which the applications to drill were denied.

DELAWARE MOUNTAIN GROUP

The Delaware Mountain Group (Guadalupian) is the major oil producing unit near the WIPP site (**Fig. 14**). It is subdivided into three formations (descending): Bell Canyon, Cherry Canyon, and Brushy Canyon. It was deposited basinward of the Getaway, Goat Seep, and Capitan shelf-margin and reef complexes (**Fig. 15**). The Delaware Mountain Group consists of sandstone, siltstone, shale, and minor (<5%) limestone, dolostone, and conglomerate (Harms and Williamson, 1988). In areas adjacent to the WIPP site, production is obtained from the Cherry Canyon and Brushy Canyon Formations with most production coming from the Brushy Canyon.

The Bell Canyon Formation, at a depth of approximately 4500 ft, has been penetrated by most wells in the study area (**Fig. 2**). Most oil and gas exploratory wells drilled in the WIPP area prior to 1965 reached total depth in the upper or middle part of the Bell Canyon. Objectives were upper Bell Canyon sandstones. Sandstones in this part of the section have produced prolifically in southern Eddy and Lea Counties (Broadhead, 1993b; Broadhead and Speer, 1993). Notable pools in the Bell Canyon are Paduca, El Mar, and Mason North, all of which lie near the southern border of New Mexico with Texas (**Fig. 15**, see Berg, 1975, 1979; Harms and Williamson, 1988). Many of the Bell Canyon penetrations in the WIPP area encountered oil shows through drill-stem tests or in cores, but production has not been established. At present, reservoir-quality sandstones in the Bell Canyon are used for disposal of produced oil-field brines in the vicinity of WIPP (**Table 7**). Nearest Bell

Canyon production is in the Triste Draw field in T23S R32E (Fig. 14).

The Cherry Canyon Formation has been penetrated and tested by numerous wells. Most of these wells have been drilled since 1970. Production of oil and associated gas from Cherry Canyon sandstones has been established in several fields in the WIPP area, including Livingston Ridge East, Livingston Ridge South, Red Tank West, Sand Dunes, Cabin Lake, and Fortyniner Ridge. The more prolific Cherry Canyon wells have estimated ultimate recoveries of more than 180,000 bbls of oil/well. For reasons discussed below in sections on estimated resources at the individual fields, known hydrocarbon traps (probable resources) in the Cherry Canyon cannot be shown to extend through the WIPP land withdrawal area. It is possible, however, that undiscovered hydrocarbon traps (possible resources and probable resources–new pools) exist in the Cherry Canyon beneath the WIPP land withdrawal area.

The Brushy Canyon Formation is a prolific producer of oil and associated gas in oil pools adjacent to the WIPP land withdrawal area. Traps are largely stratigraphic, although some have a structural component. The top of the Brushy Canyon Formation has been picked at different log markers by different operators. The log marker used for the Brushy Canyon top in this study is the one used by most operators in the area. Sandstones in the Brushy Canyon are the sole or major producer at all the Delaware oil pools which are adjacent to the WIPP land withdrawal area, including the Livingston Ridge–Lost Tank pool, the Los Medanos–Sand Dunes West–Ingle Wells–Livingston Ridge South complex, the Cabin Lake pool, and the Quahada Ridge Southeast pool.

Depositional model and reservoir lithology of Delaware Mountain Group

The depositional setting and origin of the three formations that constitute the Delaware Mountain Group have been studied by numerous workers, including Harms and Williamson (1988), Berg (1975, 1979), Williamson (1979), Payne (1976), Jacka (1979), Bozanich (1979), Cromwell (1979), and Thomerson (1994). The general depositional model for the Delaware is discussed here because an understanding of it was crucial to the construction and interpretation of stratigraphic contour maps of productive reservoir zones, and is essential to the projection of known (existing) traps under the WIPP land withdrawal area and the one-mile-wide additional study area.

Siltstones and shales in the Delaware were deposited mostly by suspension settling as thin, widespread beds that blanket the deep basin. Some of the siltstones and shales may represent distal deposition by turbidites and density currents. Straight to slightly sinuous channels were eroded into these fine-grained basinal sediments by deep-water density and turbidity currents. These currents moved down paleoslope, which dipped south to southeast in the vicinity of WIPP; channel axes are approximately parallel to paleoslope. These channels are filled by shelf-derived allochthonous sandstones. The exact mechanism of sand movement from the shelf into the basin has been ascribed to various similar mechanisms such as density currents and turbidity currents. Most recent workers have concluded that the sand was transported down the slope into the basin by density currents (Bozanich, 1979; Jacka, 1979; Harms and Williamson, 1988). Deposition occurred primarily in submarine fans at the toe-of-slope. Generally, these sand-rich channels within the fans are better-defined and narrower in the Bell Canyon Formation than in the Cherry and Brushy Canyon Formations. Porosity of productive Bell Canyon sandstones typically ranges from 20 to 25%, and permeability typically ranges from 7 to 24 millidarcies (Broadhead, 1993b). Porosity and permeability of productive Cherry Canyon and Brushy Canyon sandstones is generally somewhat less than porosity and permeability of Bell Canyon sandstones (Steve Mitchell of Scott Exploration, pers. comm. 1994).

Detailed lithologic and petrographic descriptions of Delaware sandstone reservoirs that are productive adjacent to the WIPP land withdrawal area are not available in the literature. However, Thomerson and Asquith (1992) and Thomerson and Catalano (1994) have provided good descriptions of Brushy Canyon sandstone reservoirs in the Hat Mesa, Red Tank, and Livingston Ridge East pools. These pools are located within four miles of pools that produce adjacent to the WIPP land withdrawal area. Brushy Canyon reservoirs in these three pools are probably similar to Brushy Canyon reservoirs projected to extend underneath WIPP and can be used for gross reservoir description.

The Brushy Canyon reservoirs are coarse-grained siltstones and very fine-grained sandstones (Thomerson and Asquith, 1992; Thomerson and Catalano, 1994). Sorting is moderate to good and composition is subarkosic. Syntaxial quartz overgrowths, calcite, and dolomite are common cements. Dissolution of feldspars is widespread. Illite and mixed layer illite/smectite are found as authigenic clays in pore spaces; detrital or depositional clay materials are uncommon. The authigenic illite is present as fibrous grain coatings that bridge pores. The mixed layer clays occur as platy aggregates that radiate from grain surfaces. Authigenic chlorite has also been observed to fill depositional pores in some Delaware Mountain sandstones (Hays and Tieh, 1992; Walling et al., 1992). In general, productive reservoir-quality sandstones contain the least amounts of authigenic clays and cements.

Brushy Canyon sandstones are characterized by high irreducible water saturations and high residual oil saturations (Thomerson and Asquith, 1992). This results from the fine grain size and resulting small pore sizes in the sandstones as well as from the authigenic clays that partially fill depositional pores. The fine-grained nature of the sediment has also resulted in the somewhat limited permeability described above.

Similar paleogeographic settings indicate that the Brushy Canyon under the WIPP land withdrawal area was deposited in the same depositional environment as the Brushy Canyon at the Red Tank and Livingston Ridge East Delaware pools 3 mi to the east. In those pools, the Brushy Canyon was deposited in a sand-rich submarine fan and channel complex (Thomerson and Catalano, 1994). The lower part of the Brushy Canyon was deposited on an outer fan and basin plain at the distal fringes of the submarine-fan environment. The upper part of the Brushy Canyon was deposited on the middle and inner parts of the submarine fan as massive channel-fill, overbank, and levee deposits (Thomerson, 1994). Thomerson's interpretation fits the models of submarine-fan sedimentation advanced by Mutti and Ricci Lucchi (1978; **Fig. 16**) and Walker (1978; **Figs. 17, 18**). The Mutti-Ricci Lucchi model emphasizes the distribution of lithofacies on a fan and is perhaps best employed when sufficient core descriptions exist to map lithofacies in the subsurface. The Walker model emphasizes vertical and lateral bedding variations within submarine-fan deposits and is perhaps best employed when analyzing and correlating geophysical logs. The Walker model is used in this study because resistivity and gamma-ray logs were used to map and define sediment distributions in the subsurface. The resulting maps are indispensable for the mapping of pool and trap boundaries in the Delaware Mountain Group.

Stratigraphic cross sections through the Brushy Canyon confirm Thomerson's interpretation of depositional environments (**Figs. 14, 19-23**). The lowermost part of the Brushy Canyon consists of widely correlative sand-rich sediment packages. Although thickness of these packages changes from well to well, channeling and erosion of underlying sediments are not obvious. Individual sandstone beds are laterally continuous and the reservoirs are widespread. This is consistent with deposition on the lower fan and lower part of the mid-fan in the Walker model; thicker packages of sediments were deposited as unchannelized lobes downslope of fan channels. Intervening areas of thinner sediment were interlobe areas. On the other hand, correlations in the upper part of the Brushy Canyon show the presence of sand-filled channels on the submarine fan (**Figs. 19, 22**). These channels thin and pinch out laterally. At Cabin Lake, the channels erosionally truncate underlying sediments (**Fig. 22**). These stratigraphic relationships are consistent with the Walker model of the upper mid-fan and perhaps the lower parts of the upper fan.

The lowermost part (lower 300 ft or so) of the Cherry Canyon exhibits correlation and lithologic characteristics similar to the lower Brushy Canyon and was deposited in a lower-fan environment. This is consistent with a postulated highstand of sea level in the time interval between Brushy Canyon and Cherry Canyon deposition and cessation of submarine-fan deposition at the end of Brushy Canyon time (Guadalupian) (Jacka, 1979; Kerans et al., 1993). When sea level fell at the beginning of Cherry Canyon time (Guadalupian), submarine-fan deposition recurred within the Delaware Basin. In the vicinity of WIPP, deposition was again on the lower fan. Mid-fan and upper-fan deposition took place during late Cherry Canyon time as the submarine fan prograded in a basinward (southerly) direction.

Five depositional units in the Brushy Canyon were correlated and mapped throughout the study area (**Figs. 19-23**). These depositional units encompass the main oil-producing reservoirs in the Delaware pools adjacent to the WIPP land withdrawal area. The lower Brushy Canyon is subdivided into zones (descending) A through D. In the lower Brushy Canyon, the A zone consists of two resistive lime markers separated by sandstone. The B zone consists primarily of argillaceous ("shaley") sandstone and minor shale and limestone. It is the main pay at the Cabin Lake and Quahada Ridge Southeast pools. The C zone consists of two resistive lime markers separated by an interval of sandstone and shale. The D zone consists primarily of sandstone and minor shale and limestone. It is the main pay at the Los Medanos, Sand Dunes West, Ingle Wells, and Livingston Ridge South pools. The fifth depositional unit is in the uppermost Brushy Canyon; this unit, referred to as the *Livingston Ridge main pay*, is the the main pay zone at the Livingston Ridge field. It consists mostly of argillaceous ("shaley") sandstone with minor shale and limestone.

Livingston Ridge - Lost Tank pool

The Livingston Ridge Delaware and Lost Tank Delaware pools lie along a north–south trend on the eastern boundary of the WIPP land withdrawal area. Production is from sandstones in the Delaware Mountain Group at a depth of approximately 7000 ft. The Livingston Ridge pool was discovered in 1988 and the Lost Tank pool was discovered in 1992. Subsequent drilling has brought defined boundaries of these two pools together. Development of these pools has been rapid, averaging 25 wells drilled per year from 1991 to 1993. At the end of 1993, there were 42 active producing wells in the Livingston Ridge pool and 37 active producing wells in the Lost Tank pool. Wells have been drilled on 40-acre proration (spacing) units in both pools. Production has been extended into the one-mile wide additional study area, but no wells have been drilled within the WIPP land withdrawal area for purposes of developing these pools. Cumulative production from both pools totaled 3.6 million bbls of oil and 4.7 billion ft^3 of gas as of December 31, 1993 (**Table 8**).

Geologically, the Livingston Ridge and Lost Tank pools are interconnected and formed by the same hydrocarbon trap. The distinction between the two pools is regulatory. The main pay zone at the Livingston Ridge - Lost Tank Delaware pool is a channel in the upper part of the Brushy Canyon Formation (**Figs. 19, 20**). The isopach map of gross channel thickness (**Fig. 24**) shows a south-trending channel that attains maximum thickness in excess of 90 ft along the channel axis. The channel is filled with intercalated sandstone and shale. Examination of the gamma-ray and resistivity logs (**Figs. 19, 20**) indicates that percentage of sandstone and net thickness of sandstone decrease away from the channel axis; in other words, shale is more prevalent toward the channel margins than it is along the channel axis. The channel forms a reservoir common to both the Livingston Ridge and Lost Tank pools. Gross thickness of the perforated zone varies between 10 and 20 ft in most wells.

The trap in the main pay zone at Livingston Ridge - Lost Tank is stratigraphic. Economic production from the main pay zone is obtained where the gross channel thickness is more than 35 to 40 ft (**Fig. 24**). Structural dip is to the southeast

(Fig. 25). Updip limits to economic production on the northwest coincide with lateral thinning of the channel, and for this report have been mapped conservatively at the 40-ft thickness contour (Fig. 24). Downdip limits to production on the southeast side of the pool are also mapped at the 40 ft thickness contour. Although production has been established where the channel is as thin as 33 ft, it appears that an insufficient volume of reservoir-quality sandstone is present in most of these thinner areas. In the area around the WIPP land withdrawal area, structure does not control trap boundaries, although the presence of an unsuccessful test well in SE¼ NE¼ sec. 6 T22S R32E suggests that an oil-water contact or oil-water transition zone may be present where the top of the lower Brushy Canyon is at –4600 ft. The area within the 40-ft contour of channel thickness was used to project the oil accumulation in the Livingston Ridge main pay into undrilled areas (Fig. 26). Eighteen undrilled 40-acre units are indicated within the WIPP land withdrawal area and 107 undrilled 40-acre units are indicated within the additional study area.

In most wells in the Livingston Ridge - Lost Tank pool, three casing strings are used during drilling and completion operations (Fig. 27). Typically, surface casing of 13⅜-inch diameter is set and cemented at approximately 900 ft and an intermediate string of 8⅝-inch diameter casing is set and cemented at a depth of approximately 4000 ft. After the well has been drilled to total depth, 5½-inch production casing is set and cemented to total depth of approximately 8400 ft. It has been the practice of most operators in the Livingston Ridge - Lost Tank pool to perforate casing and produce only from the main pay channel. Before economic production can be obtained, the pay zone must be acidized and artificially fractured. Volume of the acid load is typically 2000 to 7000 gallons. After acidization, the reservoir is hydraulically fractured. The size of fracture treatments varies widely, but a typical treatment uses 25,000 to 75,000 gallons of water and 50,000 to 100,000 lbs of sand; sand loads in excess of 250,000 lbs have been used.

Yates Petroleum Corp. has drilled several wells in the west half of the Livingston Ridge pool, but completed them differently from the other operators. All the wells perforated the Livingston Ridge main pay and in most cases also perforated from one to four other sandstones, and established commingled production from these sandstones. These other sandstones are present in the Brushy Canyon and lower part of the Cherry Canyon. Apparently, selection of perforation intervals was based on analyses of shows reported on the mudlogs and analyses of electric and porosity logs. From comparison of production data from these wells with data from wells in which only the main pay was perforated, it is thought that these additional pay zones will increase production incrementally; most production will still be obtained from the main pay zone. In most cases, Yates has reported only the gross interval of casing perforations. It is not possible to determine which sandstones have been completed in any one well except those present at the top and the base of the gross interval. Other operators may eventually re-enter their wells and perforate additional zones when the main pay ceases to yield economic volumes of oil.

Ultimate primary recovery was calculated for 21 wells in the Livingston Ridge - Lost Tank pool. These wells produce solely or principally from the main pay zone. A few wells in the southwestern part of Livingston Ridge produce solely from sandstones in the D zone of the lower Brushy Canyon Formation (**Fig. 28**); ultimate primary recovery and reserves in those wells are discussed below in the section on the Los Medanos - Sand Dunes - Ingle Wells complex.

Ultimate primary recovery for the average well completed in the Livingston Ridge main pay is 89 thousand bbls oil (KBO) and 116 million ft^3 associated gas (MMCFG, **Fig. 29**). Ultimate primary recovery ranges from 25 to 166 KBO and 37 to 226 MMCFG for individual wells. It is estimated that there are 1602 thousand bbls oil (KBO) and 2088 million ft^3 gas (MMCFG) that are producible via primary-recovery techniques from the Livingston Ridge main pay in the 18 undrilled proration units within the boundaries of the WIPP land withdrawal area (**Table 2**). This estimate of ultimate recovery is equal to probable resources, because the Livingston Ridge main pay has not been produced from under the WIPP land withdrawal area. There are an additional 7879 KBO and 10,406 MMCFG probable resources within this pay zone in drilled and undrilled areas of the one-mile wide additional study area (**Table 3**). Cumulative production from within the boundaries of the additional study area in the Livingston Ridge - Lost Tank pool was 754 KBO and 846 MMCFG as of December 31, 1993.

Los Medanos - Sand Dunes - Ingle Wells complex (Los Medanos complex)

The Los Medanos, Sand Dunes West, Ingle Wells, and Livingston Ridge South Delaware pools lie to the south of the WIPP site (**Fig. 14**). The main producing zone in these pools is the D zone of the lower Brushy Canyon Formation. Production is from sandstones at depths of approximately 7900 ft in the Los Medanos pool, 7800 ft in the Sand Dunes West pool, 8000 ft in the Ingle Wells pool, and 8100 ft in the Livingston Ridge South pool. The Los Medanos pool was discovered in 1991, Sand Dunes West in 1992, and Ingle Wells in 1989. The Livingston Ridge South Delaware pool was discovered in 1993. As of December 31, 1993, there were 23 active producing wells in the Los Medanos pool, 58 at Sand Dunes West, 38 at Ingle Wells, and only one at Livingston Ridge South. Wells have been drilled on 40-acre spacing in all four pools. Development has not yet been extended into the one-mile additional study area because of active potash leases in potentially productive areas (see chapter by Ramey on limitations on oil and gas drilling in the potash area). Cumulative production from all four pools totaled 3 million bbls of oil and 6.5 BCF of gas as of December 31, 1994 (**Table 8**). Production from the lone well in the Livingston Ridge South pool had not been initiated as of the end of 1993.

Geologically, the Los Medanos, Sand Dunes West, Ingle Wells, and Livingston Ridge South pools are interconnected and are part of the same hydrocarbon trap, referred to in this report as the Los Medanos complex. The nomenclatural distinction among these pools is regulatory and stems from the widely separate locations of the discovery wells . Development drilling has expanded the areas of formal pool designation and has shown that the four pools are part of the same hydrocarbon trap.

The main pay zone in the Los Medanos complex is the D zone of the lower Brushy Canyon Formation (**Fig. 23**). The isopach of gross thickness of this zone (**Fig. 28**) indicates it is laterally continuous across the study area. Thickness of the D zone varies from less than 20 ft to more than 140 ft. Thicker areas define linear trends that are north-trending, northeast-trending, or northwest-trending. The D zone consists primarily of sandstone with lesser amounts of shale and only minor amounts of limestone. Thicker areas are not incised into underlying sediments and do not appear to represent channels. Instead, thickness variations are due to paleobathymetric relief on top of the D zone. The thick areas were deposited as lobes on the lower part of a submarine fan, and the intervening thin areas are interlobe deposits. Lithofacies grade from dominantly sandstone in the lobes to dominantly shale in the interlobe areas. A sandstone isolith map of the D zone in the Livingston Ridge and Los Medanos areas (**Fig. 30**) shows that trends of net sandstone thickness coincide with trends in gross thickness of the D zone (**Fig. 28**).

The trap that forms the Los Medanos complex is stratigraphic. Economic production from the D zone has been obtained where gross thickness of the D zone is more than 90 ft (**Fig. 28**). In most places, this corresponds to a net sandstone thickness of more than 70 ft (**Fig. 30**). Thinner areas do not appear to contain sufficient reservoir-quality sandstone to yield economic levels of production. The trap at Los Medanos extends northward into the additional study area and under the WIPP land withdrawal area. Wells in the western part of the Livingston Ridge - Lost Tank pool also produce from the D zone. Several wells in sec. 26 T22S R32E in the Livingston Ridge pool obtain all of their production from the D zone. Further north in secs. 2 and 11 of the same township and in T21S R31E wells produce from the D zone, but most production appears to be obtained from the the Livingston Ridge main pay of the upper Brushy Canyon; in these wells, there is insufficient thickness of reservoir-quality sandstone within the D zone to sustain economic production levels and the D zone in these wells is a secondary reservoir. The isopach and structure maps indicate that the D zone will be the probable primary producer in 107 40-acre proration units within the WIPP land withdrawal area and 121 40-acre proration units within the additional study area (**Fig.** [illegible]).

Although Sand Dunes West and Ingle Wells sit astride an east-plunging structural nose, structure does not appear to exhibit major control on entrapment of oil and gas. Producing trends continue into off-structure areas: the northern part of Los Medanos, the southern part of Livingston Ridge, and Livingston Ridge South are structurally low relative to Sand Dunes West.

Three casing strings are used during drilling and completion operations in most wells drilled to develop the lower Brushy D zone in the Los Medanos complex (**Fig.**

31). Typically, 13⅜-inch surface casing is set and cemented at approximately 600 ft. An intermediate string of 8⅝-inch diameter casing is set and cemented at approximately 4100 ft in the uppermost part of the Bell Canyon Formation. Production casing of 5½-inch diameter is then set and cemented to total depth of approximately 8100 ft. Casing is then perforated in the D zone. Before economic production can be obtained, the pay zone must be acidized and artificially fractured. Volume of the acid load is typically 1000 to 1500 gallons, but exceeds 2000 gallons in some wells. After acid treatment, the reservoir is hydraulically fractured. The size of fracture treatments varies widely; a typical treatment uses 25,000 to 70,000 gallons of water and 50,000 to 150,000 lbs of sand. Sand loads in excess of 200,000 lbs have been used.

Ultimate primary recovery was calculated for 12 wells in the Los Medanos complex. These wells produce from the main pay zone (the D zone). Ultimate recovery was determined for wells in the Los Medanos, Sand Dunes West, Ingle Wells, and Livingston Ridge pools. In the Livingston Ridge pool, the only wells for which ultimate recovery was calculated were those which produce solely from the D zone. The D zone in wells at the north end of Livingston Ridge and at Lost Tank is thin and forms a secondary reservoir; these wells were not used in estimation of ultimate recovery because they produce from the fringe areas of the Los Medanos complex where the D zone is not economic by itself.

Ultimate primary recovery for the average well completed in the D zone of the Los Medanos complex is 76 KBO and 166 MMCF associated gas (**Fig. 32, Table 2**). These values will be somewhat less than estimates for only the Los Medanos and Sand Dunes West pools because D zone wells at Livingston Ridge have estimated primary recoveries less than the value predicted by the average decline curve. Estimated primary recovery values for all D zone wells used in this study range from 13 to 277 KBO and 15 to 748 MMCF associated gas, but estimated primary recovery values from D zone wells at Livingston Ridge range from 26 to 69 KBO and 35 to 126 MMCF associated gas.

Estimated ultimate primary recovery for the D zone in the 107 undrilled 40-acre proration units within the WIPP land withdrawal area is 8132 KBO and 17,762 MMCF associated gas (**Table 2**). This is equal to resources, because the D zone has not been produced from underneath the WIPP land withdrawal area. A total of 282 KBO and 425 MMCF gas has been produced from the D zone within the one-mile wide additional study area. Probable resources recoverable with primary production methods within this area are 8914 KBO and 19,661 MMCF gas (**Table 3**).

Cabin Lake pool

The Cabin Lake Delaware pool lies along the northwestern boundary of the WIPP land withdrawal area (**Fig. 14**). Although it is legally described as a single Delaware pool, production is mostly from two traps in two separate reservoirs. These reservoirs are the B zone of the lower Brushy Canyon Formation and sandstones in the middle part of the Cherry Canyon Formation. (**Figs. 21, 22**). Production in the lower Brushy B zone is from sandstones at a depth of approximately 7400 ft. Production in the Cherry Canyon is from sandstones at depths of 5500 to 5900 ft. In addition, there appears to be relatively minor production obtained from localized, scattered traps in the upper Bell Canyon at 3600 ft, and from the thin sandstones scattered throughout the Cherry Canyon and upper Brushy Canyon.

The Cabin Lake pool was discovered in 1986. Pool development has been rapid, averaging about seven new wells per year from 1987 through 1993. At the end of 1993 there were 33 active wells in the Cabin Lake pool, of which five were shut in. Wells have been drilled on 40-acre spacing, typical for the Delaware in southeast New Mexico. Production has been established in the one-mile-wide additional study area, but no wells have been drilled within the WIPP land withdrawal area for developing this pool. Cumulative production for the entire Cabin Lake pool totaled 1.6 million bbls oil and 1.3 billion ft^3 associated gas as of December 31, 1994 (**Table 8**). Beginning in 1991, production was enhanced with a pressure-maintenance project. Pressure maintenance is accomplished by injection of water into sandstone reservoirs in the Cherry Canyon and Brushy Canyon from depths of 5600 to 7400 ft.

Two wells have been used for water injection (**Table 8**). In December 1993, 45,009 bbls water were injected in the Phillips No. 3 James A well at an average injection pressure of 710 pounds per $inch^2$ (psi). During the same month, 70,166 bbls water were injected in the Phillips No. 12 James A well at an average injection pressure of 390 psi. When the pressure maintenance project began, oil field waters produced from Phillips' wells in the area were used for injection (New Mexico Oil Conservation Division Order No. R-9500). These produced waters are presumably still the source of injection water.

Oil is trapped in combination multipay structural stratigraphic traps in the Cabin Lake pool. The primary trapping mechanism is structural, with oil accumulations in the various reservoirs localized on a southeast-plunging structural nose (**Fig. 25**). Depositional pinchout of reservoir sandstones to the northwest provides updip limits to oil accumulations in each reservoir. Oil–water contacts in the reservoir sandstones provide limits to production on the southeast (**Fig. 33**). The main pay in the one-mile-wide additional study area and the one with the most potential of extending into the WIPP land withdrawal area is the lower Brushy Canyon B zone. The isopach map of gross thickness of the B zone (**Fig. 34**) indicates maximum thickness in two distinct areas; one area is in the eastern (downdip) part of the Cabin Lake pool and the other area is in the northwestern, updip part of the pool. The B zone is not the major reservoir in the intervening thinner area. Productive Cherry Canyon reservoirs are limited to the updip (northwest) parts of the Cabin Lake pool and do not appear to extend into the WIPP land withdrawal area. Productive reservoirs in the B zone are present within sec. 12 T22S R30E in the additional study area. It is not known if the oil column in this reservoir extends downdip to the southeast because of an absence of drill holes. Therefore the extent of probable productive area within the B zone has been conservatively mapped to include only those portions of the reservoir known to be above an oil-water contact, and consists of 13 undrilled 40-acre proration units (**Fig. 26**) within the additional study area. Mapping does not indicate that oil accumulations extend underneath the WIPP land withdrawal area.

Three casing strings are used during drilling and completion operations in most wells drilled to develop Brushy Canyon and Cherry Canyon reservoirs at Cabin Lake (**Fig. 35**). Typically, 13⅜-inch surface casing is set and cemented at approximately 500 ft. An intermediate string of 8⅝-inch diameter casing is set and cemented at approximately 3700 ft. Production casing of 5½-inch diameter is then set and cemented to total depth of approximately 7700 ft. The production casing is then perforated in the appropriate reservoir. Before economic production can be obtained, the pay zone must be acidized and artificially fractured. Volume of the acid load is typically 2000 to 4000 gallons. After acid treatment, the reservoir is hydraulically fractured. The size of fracture treatments varies, but they typically utilize 10,000 to 20,000 gallons of water and 20,000 to 30,000 lbs of sand in the Cherry Canyon and upper Brushy Canyon; in some wells, 13 to 26 tons of CO_2 have been added to the treatment. In the lower Brushy Canyon B zone, typical fracture treatments are larger and utilize 30,000 to 120,000 gallons of water and 50,000 to 200,000 lbs of sand. Sand loads in excess of 400,000 lbs have been used in fracture treatments of the B zone.

Ultimate primary recovery was calculated for wells in the Cabin Lake pool with difficulty. The pressure-maintenance project affected production in most wells and rendered the production decline curves unusable. However, three wells in sec. 12 T22S R30E were used. For one of these wells, the Phillips No. 14 James E well, the production decline curve for B zone production was usable for calculation of ultimate recovery. Two other wells in sec. 12 that produce from the B zone have unsatisfactory decline curves, so their cumulative production was used as an estimate of *minimum* ultimate recovery. These wells were used because their cumulative production is several times the ultimate primary recovery calculated for the Phillips No. 14 James E well; apparently ultimate recovery in that well is not representative of the reservoir as a whole. Calculated average ultimate primary recovery per well is 66 KBO and 46 MMCF associated gas. A total of 276 KBO and 175 MMCF associated gas have been produced from the one-mile wide additional study area. It is estimated that there are probable resources of 582 KBO and 423 MMCF associated gas producible via primary recovery techniques from the 13 undrilled 40-acre proration units within the additional study area (**Table 3**).

Quahada Ridge Southeast pool

The Quahada Ridge Southeast Delaware pool lies along the southwest border of the WIPP land withdrawal area (**Fig. 14**). The pool produces oil and associated gas. Production is from the B zone of the lower Brushy Canyon Formation at a depth of approximately 7500 ft. The pool was discovered in 1993. Development of the pool has been slow, with only three wells drilled by the end of 1993 and two more drilled in 1994. Wells were drilled on 40-acre spacing. At the end of 1993, there was only one active producing well in the pool; the other two wells drilled during 1993 have not yet been brought into production. Cumulative production from the pool totaled 11 KBO and 8.5 MMCF associated gas as of December 31, 1993 (**Table 8**). Although data are limited by a paucity of wells, the isopach map of the gross thickness of the B zone (**Fig. 34**) indicates a thick area trends south-southeast in the southwest part of the WIPP land withdrawal area. These thick areas in the B zone coincide with thin areas in the underlying D zone (**Fig. 28**) and appear to be infillings of bathymetrically low interlobe areas in the lower submarine-fan environment. Although wells have penetrated the B zone outside of the established pool boundaries, they have been drilled for hydrocarbons in deeper strata and have not adequately tested B zone sandstones. The sparse data indicate that economic production is limited to areas where the B zone is at least 80 ft thick; apparently, there is a sufficient net thickness of reservoir sandstones in these areas to yield economic volumes of oil.

The trap at Quahada Ridge Southeast is a combination structural/stratigraphic trap. In addition to the stratigraphic control that reservoir thickness exerts, production may also be limited to the east by structure. Although data are sketchy, it appears that an oil–water contact may be approximately coincident with the –4100 ft contour of the top of the lower Brushy Canyon (**Fig. 25**). If this is true, then the isopach and structure maps indicate that there are nine undrilled 40-acre units within the WIPP land withdrawal area and 52 undrilled 40-acre units that have probable oil and gas within the additional study area (**Fig. 26**).

Three casing strings are used during drilling and completion operations in wells drilled to develop the lower Brushy Canyon B zone in the Quahada Ridge Southeast pool (**Fig. 36**). Typically, 13⅜ inch surface casing is set and cemented at a depth of approximately 600 ft. An intermediate string of 8⅝ inch casing is then set and cemented at a depth of approximately 3850 ft in the uppermost part of the Bell Canyon Formation. Production casing of 5½ inch diameter is then set and cemented to total depth of approximately 7900 ft. Casing is then perforated in the B zone. Before economic production can be obtained, the pay zone must be acidized and artificially fractured. Volume of the acid load ranges from 1000 to 3000 gallons. After acid treatment, the well is hydraulically fractured. Fracture treatments use 20,000 to 40,000 gallons of water and 70,000 to 120,000 lbs of sand.

Wells in the Quahada Ridge Southeast pool have produced for an insufficient length of time to determine ultimate primary recovery with the production-decline technique used in this study. However, oil and gas are produced from the same reservoir that produces from the lower Brushy Canyon in the Cabin Lake pool. In the absence of other data, the same ultimate recovery data are used as for the Cabin Lake pool, 66 KBO and 46 MMCF gas for the average or typical well.

Estimated ultimate primary recovery for the B zone in the nine undrilled 40-acre proration units within the WIPP site is 594 KBO and 414 MMCF associated gas (**Table 2**). This is equal to probable resources, because the B zone has not been produced from underneath the WIPP site. Cumulative production from the additional study area was 11 KBO and 9 MMCF gas as of December 31, 1993. Probable resources are 3421 KBO and 2383 MMCF gas in the 52 undrilled 40-acre proration units in the additional study area (**Table 3**).

Economics and drilling for Delaware oil

The economics of drilling and completing a well in the Delaware Mountain Group will determine strategies and procedures employed in drilling wells and developing oil pools. Vertical wells, rather than deviated or horizontal wells, will be the choice of operators who wish to produce oil and gas from beneath the WIPP land withdrawal area, should the opportunity ever arise. If regulatory entities mandate that deviated wells must be drilled to tap into oil resources beneath WIPP, then drilling may become an economically unsound venture and few wells will be drilled until the price of oil rises sufficiently to warrant deviated or horizontal drilling (see chapter by Anselmo in this report for a discussion of oil and gas economics and chapter by Hareland for a discussion of horizontal drilling).

The costs of drilling and completing wells in the Delaware are listed in **Table 9A**. As can be seen, these costs more than double when the well must be deviated or drilled directionally. Wells drilled vertically, although expensive, are economically profitable. The intensive drilling activity in the area over the past few years attests to this; several operators have each drilled numerous vertical wells as economically sound business ventures. However, when wells are drilled with a deviation from the vertical, they become unprofitable or marginally profitable ventures and operators will use their funds to drill elsewhere.

The distribution of oil in multiple reservoir zones within the Delaware also makes it desirable to drill wells vertically. Ultimate recovery from Delaware pools will be increased if several pay zones in the Brushy Canyon and Cherry Canyon Formations can be produced from a single well. Yates Petroleum Corp. has instituted this practice in the Livingston Ridge–Lost Tank pool by commingling production from several zones upon initial completion; other operators may re-enter old wells in which the primary pay zone has been depleted in order to recomplete in secondary zones uphole. In either case, oil and associated gas will be produced from secondary zones that do not contain sufficient resources to justify drilling a well to produce from those zones alone.

Lower production costs also make it desirable to drill vertical rather than deviated wells in the Delaware. Delaware wells do not generally flow oil at the wellhead. Instead, oil must be produced by artificial lift. In most cases, this involves installing a pumpjack at the surface and a string of sucker rods within the wellbore.

The sucker rods move vertically up and down while the well is being pumped (see chapter by Hareland in this report). In a vertical well, this vertical movement poses little problem. However, in a deviated or horizontal well the rods rub against the casing during pumping and may wear through the casing, necessitating its premature replacement and thereby increasing production and maintenance costs.

Secondary recovery in Delaware pools

In the Delaware Basin, oil pools in the Delaware Mountain Group may produce for 10 years or more by primary recovery. When production declines to an uneconomic or marginally economic rate, a waterflood of the pool may be initiated in order to increase production rates and to increase ultimate recovery from the pool. No Delaware pools have yet been waterflooded within the nine-township study area. In the Cabin Lake pool, water is injected into two wells for purposes of pressure maintenance in the reservoir zones. The response of producing wells at Cabin Lake to water injection has been quite good (**Fig 37**) and indicates to some degree the suitability of Delaware reservoirs to water flooding in the WIPP area, even though production histories are too short to calculate the incremental increase in production due to water injection.

Mature waterfloods in Delaware pools in other parts of the New Mexico portion of the Delaware Basin were analyzed in order to evaluate the potential of waterflooding for increased recovery in Delaware Mountain Group reservoirs. Records of the New Mexico Oil Conservation Division indicate that water has been injected into eight Delaware oil pools in southeast New Mexico for purposes of waterflooding and/or pressure maintenance (**Table 10**). As of the end of 1993, water was still being injected into all of these pools, an indication of the success of the water injection programs.

Two of these pools were chosen for rigorous analysis, the Indian Draw Delaware pool of central Eddy County and the Paduca Delaware pool of southwest Lea County. The Indian Draw pool produces from sandstones in the Cherry Canyon Formation and the Paduca pool produces from sandstones in the Bell Canyon Formation. Depositional environments are similar to productive Delaware sandstones in pools adjacent to the WIPP land withdrawal area, but there are some differences. Sandstone reservoirs at Paduca were deposited in well-defined channels on submarine fans in the Bell Canyon (Harms and Williamson, 1988); depth to production is about 4700 ft. As noted previously, the Bell Canyon sandstones generally have higher permeability than Brushy Canyon sandstones and channels in the Bell Canyon appear to be better defined than channels in the Brushy Canyon, perhaps reflecting deposition in the more proximal parts of the submarine-fan environment. Although the Indian Draw pool produces from the Cherry Canyon, it lies 18 mi west of the WIPP site and is in a similar paleogeographic location to Delaware reservoirs at WIPP, so reservoirs may be similar to those at WIPP except for shallower depths (3300 ft) at Indian Draw.

The production histories of the Indian Draw and Paduca pools were plotted with annual oil production as a function of time (**Figs. 38, 39**). The production history curves show two distinct peaks. The first peak on each plot occurs a few years after pool discovery and reflects maximum production from primary recovery techniques. The second peak occurs several years later. It reflects maximum production from the waterflood. Production begins to increase within two years of onset of waterflooding and peak production due to waterflooding occurs within three to four years.

Two distinct production trends can be seen on each of the plots. The first trend is for production by primary methods. The second trend is for production resulting from the waterflood. Each trend was extrapolated into the future with an exponential decline curve (**Figs. 38, 39**). The area under each curve was calculated to give estimated ultimate recovery for primary production and for waterflood production. Waterflooding is expected to increase ultimate recovery at the Paduca pool by 61% and at the Indian Draw pool by 81%. This is a significant increase in recoverable oil.

Worthington (1994) studied the Shugart East Delaware oil pool, located 21 miles north of WIPP. Production in this pool is from multiple stacked sandstones in the upper part of the Brushy Canyon Formation. Ultimate primary recovery was estimated to exceed 5 million BO and 10 BCF gas. Worthington estimated that an additional 5 million BO could be recovered through secondary recovery (waterflooding). This is approximately equal to a 100% increase in ultimate recovery.

These analyses can be applied with caution to estimate ultimate secondary recovery for pools projected to extend underneath the WIPP land withdrawal area. A 60% increase in ultimate recovery was selected for calculations because it represents the lesser (more conservative) value of the two analogous pools that were analyzed. Values of estimated ultimate secondary recovery and estimated total (primary plus secondary) recovery are given in **Tables 11-13**.

The low permeability and the presence of clays (variably illite, mixed layer illite/smectite, and chlorite) in Brushy Canyon sandstones may pose problems for secondary recovery that do not exist with many other oil reservoirs. These factors may act to increase costs associated with water flood operations; such increased costs have been incorporated into the economic analyses of Anselmo (this report). The relatively low permeability of the Brushy Canyon sandstones will require that injection and production wells be located on 20-acre spacing, in contrast to the existing 40-acre spacing that is allowed for primary production. One new injection well will need to be drilled for each existing production well. The production and injection wells will almost certainly be located on five-spot patterns. This need to double the number of wells will cause waterflood costs to significantly exceed primary recovery costs.

The authigenic clays present within depositional pore space may affect secondary recovery operations in two ways. First, they reduce permeability. Second, some chlorites are sensitive to changes in the chemistry of formation waters (Walling et al., 1992); injection of water with a significant difference in pH from native formation waters may cause retrogression of the chlorite and subsequent migration of clays or formation of permeability-reducing gels.

These deleterious effects of water injection can be mitigated or even eliminated by using Delaware formation waters for waterflood injection. These waters should be approximately in equilibrium with reservoir mineralogy. Finally, the analogous waterfloods that were used to derive a figure for ultimate secondary recovery are in Delaware reservoirs and they have been successfully waterflooded. This is a strong indication that Brushy Canyon reservoirs in the vicinity of WIPP can be successfully waterflooded. The recent initiation of a waterflood in the Avalon Brushy Canyon pool and Worthington's (1994) calculation of a 100% increase in oil recovery at Shugart East support the conclusion that waterflooding the Brushy Canyon in the vicinity of WIPP will be technically possible and economically feasible.

The decision on whether or not to initiate waterfloods of Delaware oil pools in the vicinity of WIPP will rest primarily with the operators that produce from these pools. Many factors determine whether or not an operator will initiate a waterflood. These factors are mostly related to economics and include: 1) the ultimate secondary recovery expected from a waterflood; 2) costs associated with a waterflood, including the drilling of injection wells; 3) construction of surface facilities and injection facilities; 4) the cost of obtaining and processing injection water; 5) the cost of brine disposal, including the cost of drilling and equipping disposal wells; and 6) revenues obtained from oil and gas production (determined by production rates, oil prices, and to a lesser extent gas prices).

Even if a waterflood project is expected to be economically successful, it may not be initiated because of the limited financial resources that all operating companies face. Expected return on investment from a waterflood project must be compared to expected return on investment from other ventures; a waterflood will be initiated only if expected return on investment is favorable. The technical and economic viability of waterfloods in the vicinity of WIPP will be compared to the technical and economic viability of ventures conducted elsewhere.

It must be emphasized that the oil estimated to be available through secondary recovery (Tables 11-13) will be produced only if waterfloods are initiated while primary production is in progress. Once wells that produce by primary methods have been abandoned and plugged, then they will not be available for secondary recovery operations. The high cost of reentering plugged wells, or of drilling replacement wells, may render secondary recovery uneconomic. The presence of operable wells used for primary recovery is essential for the economic viability of secondary recovery projects.

BONE SPRING FORMATION

The Bone Spring Formation (Permian: Leonardian) is a major oil-producing unit in the Delaware Basin (Broadhead and Speer, 1993). Bone Spring reservoirs are carbonate debris flows and siliciclastic turbidites deposited downslope of the Abo shelf edge (**Fig. 9**; Wiggins and Harris, 1985; Gawloski, 1987; Mazzullo and Reid, 1987; Saller et al., 1989). These reservoirs are interbedded with and sealed by impermeable dark basinal shales and micritic carbonates.The Bone Spring is informally divided into six stratigraphic units in the Delaware Basin (**Fig. 40**). Carbonate debris flows in the second and third carbonates are the primary Bone Spring reservoirs in the Delaware Basin; they consist of dolomitized conglomerate breccias and dolomitized bioclast-peloid packstones with secondary porosity. Significant production is also obtained from carbonate debris flows in the first carbonate and siliciclastic turbidites in the first, second, and third Bone Spring sands. These turbidites are fine-grained sandstones cemented by dolomite and authigenic clays (Gawloski, 1987; Saller et al., 1989).

Throughout the Delaware Basin, hydrocarbon traps in the Bone Spring are stratigraphic or combination stratigraphic/structural. Porous debris-flow and turbidite reservoirs were deposited in channels perpendicular to the shelf margin (Gawloski, 1987; Mazzullo and Reid, 1987; Saller et al., 1989). Porous reservoirs pinch out depositionally updip or combination traps are formed by depositional pinchout of the reservoir across a structural nose.

Within the nine-township study area, the first, second, and third carbonates and the first, second, and third sands have been productive (**Fig. 41**). There has been little or no systematic attempt to evaluate, test, and explore for Bone Spring traps in this area. Generally, Bone Spring reservoirs have only been tested in wells drilled for deeper Atoka or Morrow targets. Usually, the Bone Spring will be tested in these wells only if a good show is noted on the mudlog or if open-hole density and neutron-porosity logs crossover each other and exhibit "gas effect." Numerous Bone Spring pools in the Delaware Basin have been discovered by re-entering old gas wells in which production from the Atoka or Morrow has declined to subeconomic levels; in these wells, the Bone Spring may be perforated through casing if well logs or other data suggest the presence of hydrocarbons in commercial quantities.

Because many of the exploratory wells that have discovered oil in the Bone Spring originally targeted structural traps in deeper formations, discovered Bone Spring pools are generally located on structural noses (**Fig. 42**). With the exception of the Red Tank pool, development of known pools within the study area has been limited and incomplete because operators have concentrated on drilling for deeper gas in the Morrow and Atoka or shallower oil in the Delaware Mountain Group. Therefore, stratigraphic traps and stratigraphic trends have not been fully defined and the Bone Spring remains inadequately explored and developed in the area. It is highly likely that numerous significant commercial accumulations of oil and associated gas (possible resources) remain to be found, especially in stratigraphic traps in off-structure areas. The Potash Area, in particular, has been poorly explored because of restrictions on drilling (see Ramey, this report, for a discussion of drilling restrictions in the potash area).

No hydrocarbons have been produced from the Bone Spring within the boundaries of the WIPP land withdrawal area. Only one pool, Los Medanos Bone Spring, is productive within the one-mile wide additional study area. Data are insufficient to project production from other known (discovered) pools into the WIPP land withdrawal area or the additional study area, so only the Los Medanos pool is evaluated for probable resources.

Los Medanos Bone Spring pool

The Los Medanos Bone Spring pool lies on the southwestern boundary of the WIPP land withdrawal area (**Fig. 41**). Production is from sandstones in the third Bone Spring sand at a depth of 11,020 ft. The pool was discovered in 1982 by re-entering an abandoned Morrow gas well. As of the writing of this report, only three producing wells have been drilled in the pool. Spacing is 40 acres. The known extent of the pool is entirely within the one-mile wide additional study area. Cumulative production from the pool was 84 KBO and 163 MMCF associated gas as of December 31, 1993. Most of this production came from one well. The other two wells were completed in December 1993 and January 1994 and contributed little or nothing to the pool cumulative total as of the end of 1993.

The Los Medanos Bone Spring pool appears to be a combination structural/stratigraphic trap. The three wells in the pool have been drilled on an east-plunging structural nose (**Fig. 42**). Production appears to be limited on the west by an updip porosity pinchout or at least a reduction in porosity. An isopach map of the pay zone shows a north-trending thick area that may be a turbidite channel (**Fig. 43**). **Figure 44** is a map of the average porosity of the pay zone. It was constructed by reading the porosities measured by the neutron and density-porosity logs at 2 ft intervals throughout the pay zone (which was mapped in Fig. 43). Then, the root mean square of the neutron and density porosities was calculated for each 2 ft interval in each well. Finally, this root mean square porosity was averaged throughout the pay zone in each well. The resulting data were contoured (**Fig. 44**). Although wells are too sparse to fully delineate the trap at Los Medanos, there appears to be a general decrease of porosity to the west (updip). Wells known to be productive from the pay zone have an average root mean square porosity higher than 12%. Wells with no established production from the pay zone have an average root mean square porosity lower than 12%.

Inasmuch as the porosity decrease appears to be in a westward rather than northward direction, it seems probable that production in sec. 6 may overlap northward into the southernmost part of sec. 31 T22S R31E (**Fig. 43**). Conservatively, four 40-acre proration units have probable resources within the WIPP land withdrawal area. Only one well in the pool has a production history sufficient to estimate ultimate primary recovery (**Fig. 41**). The value for this well, 111 KBO and 239 MMCF associated gas, is used as the average primary recovery for wells in the pool. The 136 month (11 year) production history of this well lends credibility to its use for a pool-wide average. Therefore, it is estimated that there are 444 KBO and 956 MMCFG producible via primary recovery from the four undrilled 40-acre proration units within the WIPP land withdrawal area (**Table 11**). There are an additional 804 KBO and 1749 MMCFG as probable resources in the eight drilled and undrilled units in the additional study area (**Table 12**).

Three casing strings are used during drilling and completion operations for wells drilled in the Los Medanos Bone Spring pool (**Fig. 45**). Typically, surface casing of 11¾-inch diameter is set and cemented at approximately 600 ft, and an intermediate string of 8⅝-inch diameter casing is set and cemented at a depth of approximately 3900 ft, just below the top of the Delaware Mountain Group. Production casing of 5½-inch diameter is then set and cemented to total depth of approximately 11,300 ft. The pay zone will need to be hydraulically fractured to obtain economic rates of production in most wells. The size of fracture treatments at Los Medanos Bone Spring is not well established, but available data indicate a typical treatment may use 100,000 gallons of water and 120,000 lbs of sand.

Secondary recovery in Bone Spring pools

Secondary recovery in the Los Medanos Bone Spring pool will most likely consist of waterflooding the pay zone. Because of the relatively limited amount of production expected to be obtained from the Bone Spring under the WIPP land withdrawal area, detailed calculations have not been made for a projected increase in probable resources due to waterflooding. However, if a moderate increase in ultimate oil recovery of 50% is assumed, then it is estimated that an additional 222 KBO will be recovered from Bone Spring reservoirs under the WIPP land withdrawal area and an additional 444 KBO will be recovered from reservoirs under the one-mile additional study area (**Tables 11-13**).

WOLFCAMP GROUP

The Wolfcamp Group (Permian: Wolfcampian) is a major producer of oil and gas in the Permian Basin (Broadhead and Speer, 1993; Broadhead, 1993d). In general, Wolfcamp pools are productive of nonassociated gas in the Delaware Basin. On the Northwest Shelf and Central Basin Platform, most are productive of oil and associated gas. Wolfcamp reservoirs in the Delaware Basin were deposited in a deep basinal setting. Producing zones are thought to be either small algal carbonate mounds interbedded with dark basinal shales or scattered, thin basinal sandstones (Anderson, 1977).

Two oil and gas pools have been discovered within the nine-township study area (**Fig. 42; Table 14**). Uneconomic volumes (shows) of oil and gas have been recorded from three additional wells (**Fig. 42**). Both pools consist of a single productive well. Cumulative production from the Wolfcamp in the nine-township study area is 15,692 BO, 9884 MCF gas, and 760 bbls brine water. No oil or gas has been produced from under the WIPP land withdrawal area or the one-mile wide additional study area.

The Bilbrey Wolfcamp gas pool, located in sec. 18 T21S R32E, was discovered in 1985. Discovery was made by re-entry into an abandoned Morrow gas well. The interval from 12,100 to 12,138 ft was perforated and acidized. This interval is approximately 1000 ft below the top of the Wolfcamp. Initial potential was reported as 26 MCFG per day with an unreported volume of condensate. API gravity of the condensate was 47.9°. Cumulative production as of December 31, 1993 was 11,683 bbls condensate and 9884 MCF gas. Production in 1993 was 1101 bbls condensate and no gas. Subsequent to discovery, the pool has not been developed or defined by additional drilling.

The Diamondtail Wolfcamp oil pool, located in sec. 14 T23S R32E, was discovered in 1981 by a wildcat well that was unsuccessfully drilled for gas in the Morrow and Atoka. After unsuccessfully testing the Morrow and Atoka, the well was completed in the Wolfcamp through perforations from 12,181 through 12,193 ft. The perforated interval is approximately 200 ft below the top of the Wolfcamp. After perforation, the Wolfcamp was acidized and artificially fractured. Initial potential was reported as 38 bbls oil per day with a gas-oil ratio of 1974. API gravity of the oil was 48.8°. The well produced until 1987 when it was recompleted as a Bone Spring producer in the Diamondtail Bone Spring pool. Cumulative production from the Wolfcamp was 4009 bbls oil and 279 MCF gas (**Table 14**). The high gravity of the oil raises the question of whether this was a true oil well or a gas well with significant production of condensate. The extent of the Diamondtail Wolfcamp pool has not Been defined by additional drilling.

Probable resources of oil and gas are not estimated for the Wolfcamp Group. However, it is highly likely that possible resources exist under the WIPP land withdrawal area in undiscovered pools. The position of the WIPP site in the Delaware Basin and the recovery of hydrocarbons from wells in the study area indicate undiscovered hydrocarbons will most likely be gas with condensate. Traps will be stratigraphic or possibly combination structural/stratigraphic traps formed by updip porosity pinchouts on the east-plunging structural nose that occupies a large part of the WIPP land withdrawal area (**Fig. 42**). Oil, gas, and condensate resources will probably be relatively minor compared with those in major producing units in the area

(Delaware, Atoka, Morrow).

STRAWN GROUP

The Strawn Group is found in the vicinity of WIPP at depths ranging from approximately 12,400 to more than 13,600 ft. In this area the Strawn is generally composed of interbedded limestone and shale and ranges from less than 100 ft to more than 250 ft in thickness. Stratigraphically trapped hydrocarbons are found in isolated, southwest-northeast-trending limestone bioherms that are generally 10 to 20+ ft thick. Structurally, the Strawn dips regionally to the south and southeast, with minor local noses and closures which were probably formed by draping of Strawn strata over deeper paleogeographic highs (**Fig. 46**). Regionally, it appears that Strawn bioherm development is localized over these deeper paleogeographic features (Speer, 1993b). This also appears to be occurring in the area around the WIPP site.

Modest production has been established from the Strawn in four wells in the WIPP area at the Cabin Lake (secs. 1, 2, and 11 T22S R30E) and Los Medanos (sec. 1 T23S R30E) pools (**Table 8; Fig. 47**). These wells produce both condensate and gas, with cumulative production through 1993 totaling 193,758 barrels of condensate (BC) and 4.833 billion cubic BCF (feet of gas). Three of these four wells appear to be economic producers, averaging approximately 63,000 BC and 1.6 BCF gas. Oil and gas production decline curves for a typical Strawn well are shown in **Figs. 48 and 49**. The number of producing Strawn wells in the area is insufficient to construct average decline curves, so curves from a typical well are shown instead.

Significantly, in a relatively new well drilled by Mitchell Energy during late 1993, the No. 1 Apache 24, a drill-stem test (DST) revealed what appears to be a significant new Strawn reservoir at a location directly adjacent to the western edge of the WIPP land withdrawal area in the NE¼ SE¼ of sec. 24 T22S R30E (**Fig. 47**). This DST, which tested a 15-ft zone of porous limestone at 12,710 ft, flowed gas to surface in 20 minutes at a rate of 7.8 MMCFD. Flowing pressures reached 2649 lbs per in^2 (psi) and shut in pressures were an initial 7,533 psi and a final 7,433 psi (**Fig. 50**). This zone has apparently not yet been produced but based on the DST, it should be capable of production similar to the aforementioned economic Strawn wells.

Accordingly, based on a standard Strawn gas proration unit size of 320 acres, it is probable that the two proration units within the WIPP land withdrawal area (the N½ and S½ sec. 19 T22S R31E) that are immediately adjacent to the No. 1 Apache 24 would be considered as having excellent potential for probable resources. Further development of this particular reservoir will almost certainly prove the existence of four additional proration units within WIPP (**Fig. 51**). It is possible that other such reservoirs are present within the boundary of the WIPP land withdrawal area. These, however, are conjectural and are classified as bearing possible resources. Consequently, only six proration units are estimated as having probable resources underneath the WIPP land withdrawal area

(**Fig. 51, Table 2**) with probable resources of 9600 MMCF gas and 378 KBC. Probable resources in the seven drilled and undrilled proration units within the one-mile wide additional study area are 9875 MMCF gas and 423 KBC.

ATOKA GROUP

The Atoka Group is found within the WIPP site area at depths of 12,700 to more than 13,700 ft. The Atoka is composed of interbedded limestone, sandstone, and shale and generally mimics the Strawn Group in structural configuration. It ranges from 210 ft to more than 270 ft in thickness.

Although prolific production has been established within the one-township study area from this unit in both limestone and sandstone reservoirs, all of the productive wells found within or adjacent to the WIPP land withdrawal area produce primarily from one narrow and thin (5 to 15+ ft) lenticular sandstone channel deposit. This reservoir appears to be oriented roughly in a north-south trend (**Fig. 52**) and exhibits *extremely* good porosity and permeability characteristics. Where trapped in what appears to be a structurally enhanced stratigraphic trap, it produces prolific volumes of hydrocarbons. Evidence for this is the Shell Oil Co. (now Bass Enterprises) No. 1 James Ranch Unit well, which has produced over 25.7 BCF gas and roughly 272 KBC (**Fig. 47**). Seven wells have produced, or are currently producing, oil and gas from this particular reservoir. One well, the Bass Enterprises No. 13 James Ranch Unit, has a bottom-hole location within the WIPP land withdrawal area in the SE¼ SW¼ of sec. 31 T22S R31E (**Fig. 47**). Total production through 19[illegible] from the five wells producing at that time out of this trap, administratively designated the Los Medanos and Livingston Ridge Northeast Atoka pools (**Table 8**), was 348,079 BC and 38.178 BCF gas, giving an average of 69,615 BC and 7.636 BCF gas per well. Estimated ultimate recoveries push the per well average to over 8 BCF gas and 70 KBC. A gas production decline curve for a typical Atoka well is shown in **Fig. 55**. The wide variation in production among Atoka wells and an insufficient number of productive Atoka wells in the area rendered construction of an average decline curve unfeasible, so a curve from a typical well is shown instead.

Three casing strings are used during drilling and completion operations for typical Atoka and Morrow wells drilled in the vicinity of the WIPP site (**Fig. 53**). Typically surface casing of 13⅜-inch diameter is set and cemented at approximately 650 ft and an intermediate string of 9⅝-inch diameter casing is set and cemented at a depth of approximately 3700 ft. Casing of 7-inch diameter is then set and cemented to a depth of approximately 11,250 ft. Finally, 4½ inch diameter production liner is set to total depth of up to 14,500 ft.

Mitchell Energy drilled two new productive wells to the reservoir less than 660 ft from the western boundary of the WIPP land withdrawal area in late 1993, the No. 1 Apache 13 (E½NE¼ sec. 13, T22S R30E) and the No. 1 Apache 25 (SE¼NE¼ sec. 25, T22S R30E). Prolific reserves are apparently present in these wells as evidenced by their

September 1994 daily production of 9403 MCFD and 65 BCPD from the No. 1 Apache 13 and 1000 MCFD from the No. 1 Apache 25. At the time of this report, both Bass Enterprises and Yates Petroleum were drilling and/or completing wells in this reservoir. These wells are located in SW¼SE¼ sec. 12 T22S R30E and the SW¼SW¼ of sec. 7 T22S R31E (**Fig. 50**).

Based on subsurface mapping of this particular reservoir, it appears that there is excellent potential for similar Atoka production within the confines of the WIPP land withdrawal area. The net sand isolith map (**Fig. 52**) shows that good sand development should be present in the western tier of sections within the WIPP land withdrawal area (secs. 18, 19, 30, and the E½ of sec. 31 T22S R31E), giving up to seven 320-acre proration units containing probable gas resources in addition to the single location that presently produces (**Fig. 54**). An additional stratigraphically equivalent sand trend is mapped east of, and separated from, the existing production which may very well have production of similar quality (**Fig. 52**). As no production has yet been established on this trend, its ability to produce is rated at low to moderate probability. Eight additional proration units are estimated as bearing probable resources under the WIPP land withdrawal area (**Fig. 54, Table 2**). These 16 proration units have probable resources of 123,336 MMCF gas and 1,092 KBC. There are an additional 94,400 MMCF gas and 799 KBC as probable resources in 16 drilled and undrilled proration units within the one-mile wide additional study area (**Fig. 54, Table 3**).

MORROW GROUP

The Morrow Group is found within the WIPP site area at depths of 12,900 to more than 15,000 ft. The Morrow is divided into two distinct sections, an upper part designated the Morrow lime, which is roughly 650 ft thick and composed principally of interbedded limestone and shale, and a lower part designated the Morrow clastic interval, which is 600–700+ ft of interbedded sandstone and shale (**Figs. 50, 56**). Almost all Morrow production in this area comes from the Morrow clastic section, which produces principally nonassociated gas from multiple sandstones which were deposited in a variety of deltaic depositional environments. These environments include channel, point-bar, channel-mouth bar, beach, off-shore bar, and delta-front facies (Speer, 1993c). Trapping is achieved in these sands by several mechanisms, which are generally some combination of stratigraphic, structural, and/or diagenetic factors (Speer, 1993c). Structurally, the Morrow mimics the Strawn in a regional sense, but seems to have more pronounced nosing and closure over inferred underlying paleostructures (**Fig. 52**). These structural anomalies appear in a general sense to enhance Morrow production.

Morrow production has been established from several wells along the western, southern, and, to a lesser extent, the eastern margins of the WIPP land withdrawal area (**Fig. 47**). Cumulative production from these wells has been varied, ranging from less than 1 BCF to upward of 8 BCF per well. Most wells have produced only moderately, at somewhat less than 2 BCF per well through 1993.

Two wells have drilled through the Morrow section within the confines of the WIPP site, the Clayton Williams Badger Federal Unit No. 1 (NE/SW of sec. 15 T22S R31E) and the Bass Enterprises No. 13 James Ranch Unit, which was directionally drilled to a bottom-hole location in the SE¼SW¼ sec. 31 T22S R31E (**Fig. 57**). A drill-stem test in the Badger Federal Unit No. 1 tested the upper part of the Morrow clastic interval with no success, and indicates poor sandstone development at its location (**Fig. 56**). The No. 13 James Ranch Unit well did not test any of the Morrow section even though some potentially productive sandstone seems to be present (**Fig. 50**). This well is completed and producing from the aforementioned Atoka reservoir and may or may not be productive in the Morrow.

Wells completed in the Morrow at the end of 1993 by Mitchell Energy immediately to the west of the WIPP land withdrawal area give somewhat mixed information regarding the potential of the Morrow surrounding them. As cross section F–F' (**Fig. 50**) indicates, these wells, the No. 1 Apache 24 (NE¼SE¼ of sec. 24 T22S R30E) and the No. 2 Apache 25 (SE¼SE¼ of sec. 25 T22S R30E), penetrated what appears to be prolifically productive Morrow based on the quality and quantity of sandstones present and the excellent initial potential (IP) tests. However, examination of the limited amount of production information available for these wells indicates that they are not yet producing anywhere near the volumes indicated by their IP tests. September 1994 daily production averaged less than 100 MCFD for both wells combined. As such, these two wells do not conclusively evaluate productive capability of adjacent acreage within the WIPP land withdrawal area.

Due to the complex nature of both Morrow sandstone deposition (multiple stacking of distinct sandstones) and trapping mechanisms (a combination of stratigraphic, structural, and/or diagenetic factors), it is very difficult to ascertain the probability and quality of any Morrow production within the WIPP land withdrawal area. Certainly it can reasonably be assumed, based both on adjacent production and sandstone development, that a minimum of six 320-acre proration units along the western edge of the boundary should be capable of an average cumulative production approximately equal to the "average" production established for the area (approximately 2 BCF per well). A gas production decline curve for a typical Morrow well is shown in **Fig. 58.** The wide variation in production among Morrow wells, and an insufficient number of productive Morrow wells in the area, rendered construction of an average decline curve unfeasible, so a curve from a typical well is shown instead. With the apparent presence of a distinct structural nose trending across the WIPP site, which should enhance the productive potential for the Morrow (**Fig. 57**) and using nearby developed areas for analogies (T21S R32E and T23S R31E; **Fig. 50**), an additional estimated 10 locations may be present under the WIPP site (**Fig. 59; Table 2**). Probable resources within these 16 proration units are 32,000 MMCF gas and 107 KBC. An additional 28,789 MMCF gas and 106 KBC are present in the 22 drilled and undrilled proration units within the one-mile wide additional study area that surrounds the WIPP land withdrawal area (**Fig. 59; Table 3**).

ECONOMICS AND DRILLING FOR PENNSYLVANIAN GAS

Although significant Pennsylvanian probable resources are almost certainly present under the WIPP land withdrawal area, their recovery is critically dependent on several economic factors. The most important and variable of these include, but are not limited to, drilling and completion costs, wellbore deviation costs, and product price. Since controls on prices of oil and gas are independent of geological and engineering parameters, they will not be included in this discussion (see chapter by Anselmo, this report, for a discussion of oil and gas prices).

Most wells which have been drilled in the vicinity of WIPP below the Permian section, which were not specifically set up as Devonian or deeper tests, have penetrated well into the Morrow clastic interval, most often reaching a total depth approximately 100 to 150 ft into the Barnett Shale (**Figs. 50, 56**). The Morrow is most often the target of deeper Pennsylvanian tests in this area, even when the primary objective may be uphole in the Strawn or Atoka Groups. This is due to the relatively minor incremental cost of the additional drilling as opposed to the significantly increased odds of finding economical reserves from the numerous Morrow pay zones which might be penetrated. Currently, the cost for a typical vertical Morrow well in this area ranges from roughly $900,000 dry hole cost and $1,225,000 for a completed well of 13,700 ft, to well in excess of $1,500,000 dry hole cost and $2,000,000 completed cost for a well exceeding 15,000 ft in depth (**Table 9b**). If there is specific need to deviate a wellbore of this depth, well costs increase dramatically. It is estimated that for an 1100 ft deviation at this depth range, completed well costs would increase by approximately 45 to 50+%, which speaks nothing of the added risk involved in drilling, maintaining, and producing a deviated wellbore. It is obvious that vertical Pennsylvanian wells are quite expensive in this area due to their extreme depth and strict drilling parameters. With the additional cost which any deviation would add, the economic justification for drilling based on expected reserves would be significantly decreased.

PRE-PENNSYLVANIAN SECTION

A significant amount of sedimentary rock, approximately 5700 ft, is present below the Permian section in the vicinity of the WIPP site. These strata range from Pennsylvanian to Cambrian in age (**Fig. 8**), and are at depths ranging from approximately 12,000 ft to over 18,000 ft within the WIPP land withdrawal area.

To date, numerous oil and gas reservoirs have been discovered and developed within the Pennsylvanian section in this area. The most significant of these are found in the Strawn, Atoka, and Morrow Groups. Deeper zones of interest, found primarily in the Siluro-Devonian and Ordovician intervals, have been tested in several wells around the WIPP site, with no success to date (**Fig. 60**). These deeper reservoirs are generally composed primarily of porous carbonate shelf facies; the most common hydrocarbon traps are closed structures exhibiting significant amounts of relief (Speer, 1993a). It is probable that no such structure, and hence no economic hydrocarbon accumulation, exists in these deeper zones within the confines of the WIPP land withdrawal area. Consequently, based on available data, it appears that the Pennsylvanian Strawn, Atoka, and Morrow formations are the only pre-Permian stratigraphic units with significant economic oil and gas potential underneath the WIPP site.

PROJECTED FUTURE OIL AND GAS PRODUCTION

Future oil, gas, and gas condensate production was projected (estimated) on an annual basis for oil and gas pools with probable resources underneath the WIPP land withdrawal area and surrounding one-mile-wide additional study area. Projections were made separately for each oil and gas pool or reservoir stratum projected to extend under the WIPP land withdrawal area.

Projections for primary recovery were made using the following factors:

1) The average or typical production decline curves generated for each of the pools (primary recovery);

2) Wells presently producing within the WIPP land withdrawal area and additional study area and the expected remaining production life for each of these wells;

3) Projected future rates of drilling for undrilled proration spacing locations identified as containing probable resources, assuming that WIPP is not closed to drilling -- future rates of drilling were based on historical rates of drilling in each oil and gas pool projected to extend underneath WIPP;

4) Estimated probable oil and gas resources recoverable by primary production methods.

Projections for secondary (waterflood) recovery were made using the following factors:

1) Estimated probable oil and gas resources recoverable by waterflood production methods;

2) Estimated future annual primary production of oil and gas;

3) Historical secondary recovery rates of analogous waterflooded oil pools as a function of primary production and decline in primary production.

The resulting estimates of future primary oil and gas recovery and future secondary oil recovery are presented in **Figs. 61-68** and in **Tables 15 and 16**. These results were used to calculate the estimated value of oil, gas, and gas condensate underneath the WIPP land withdrawal area and additional study area (see chapter by Anselmo, this report).

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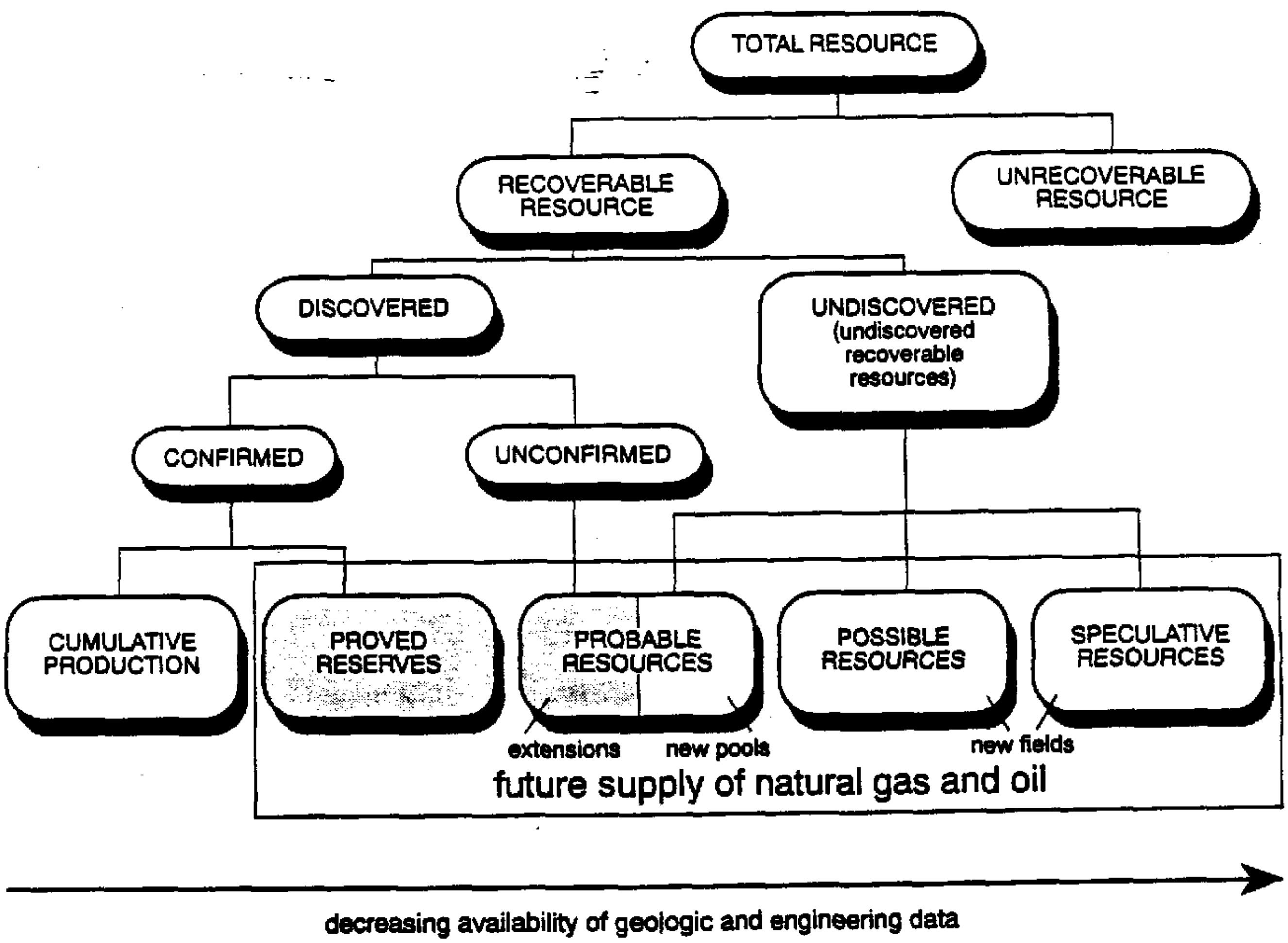

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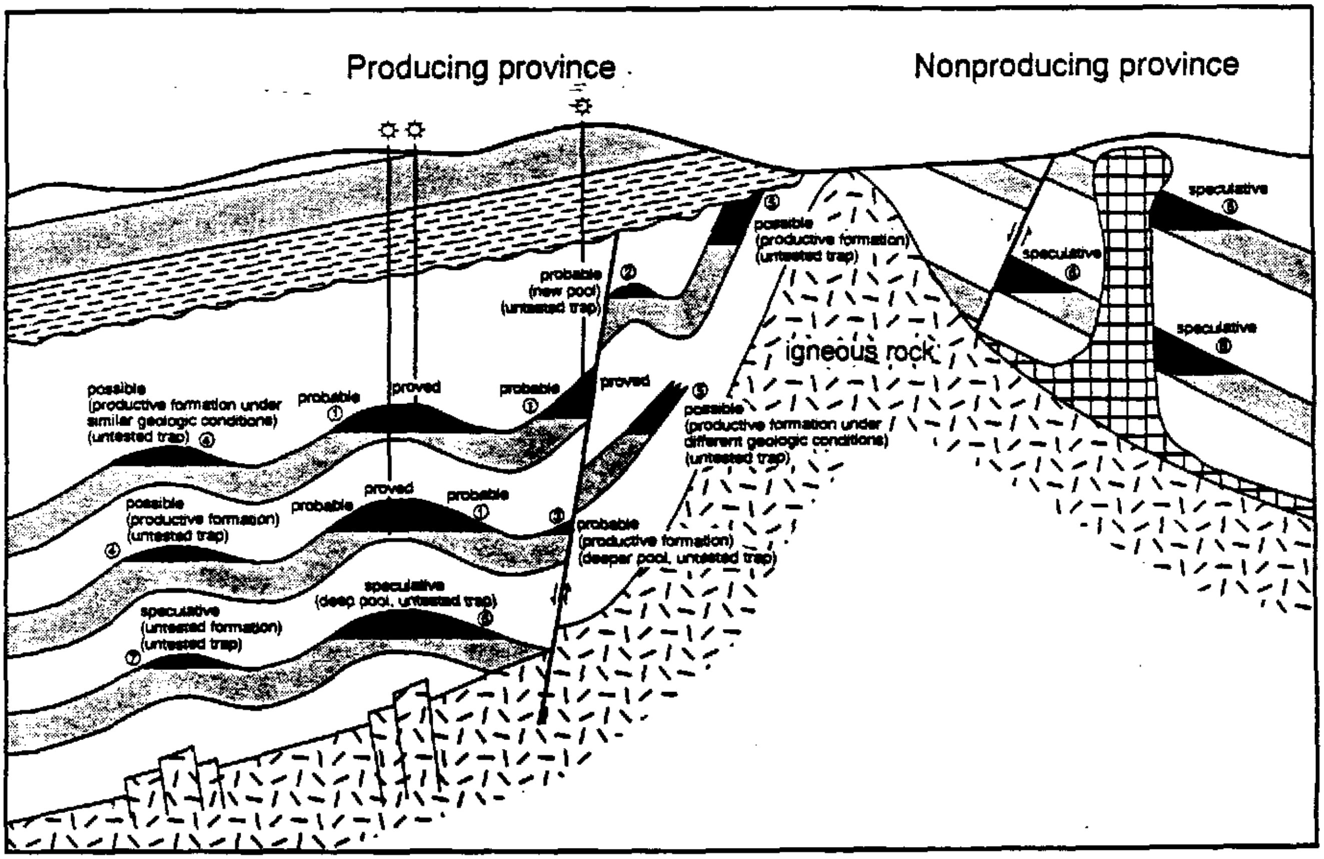

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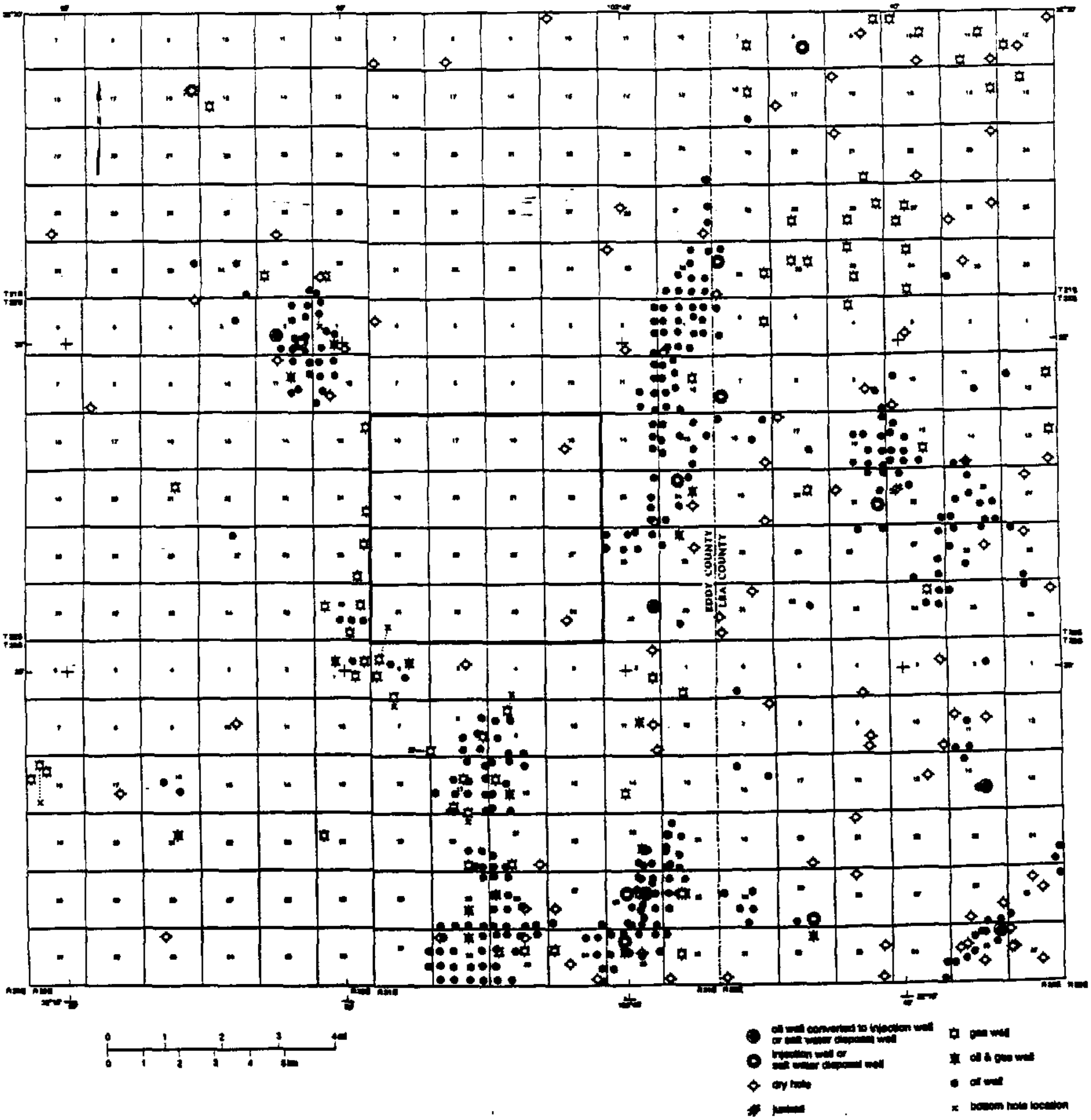

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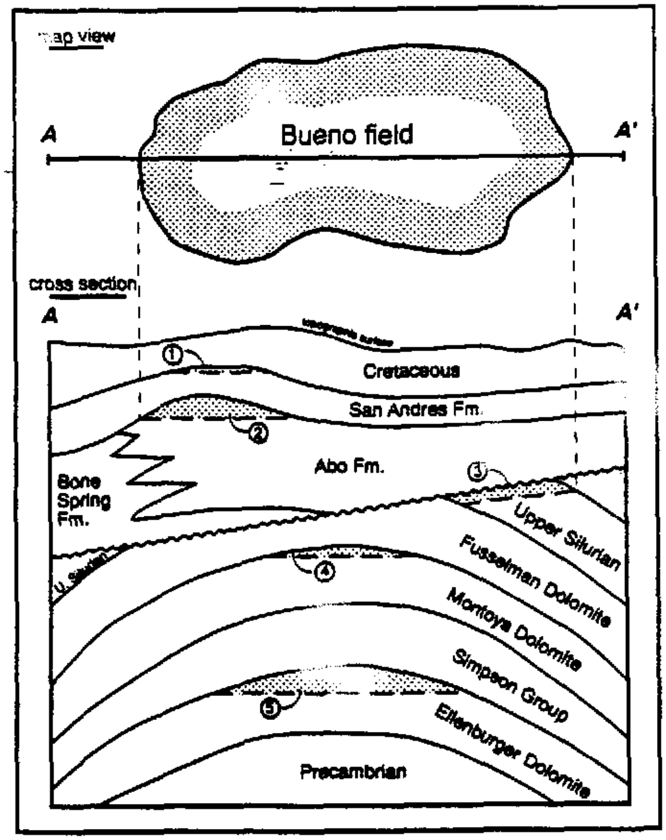

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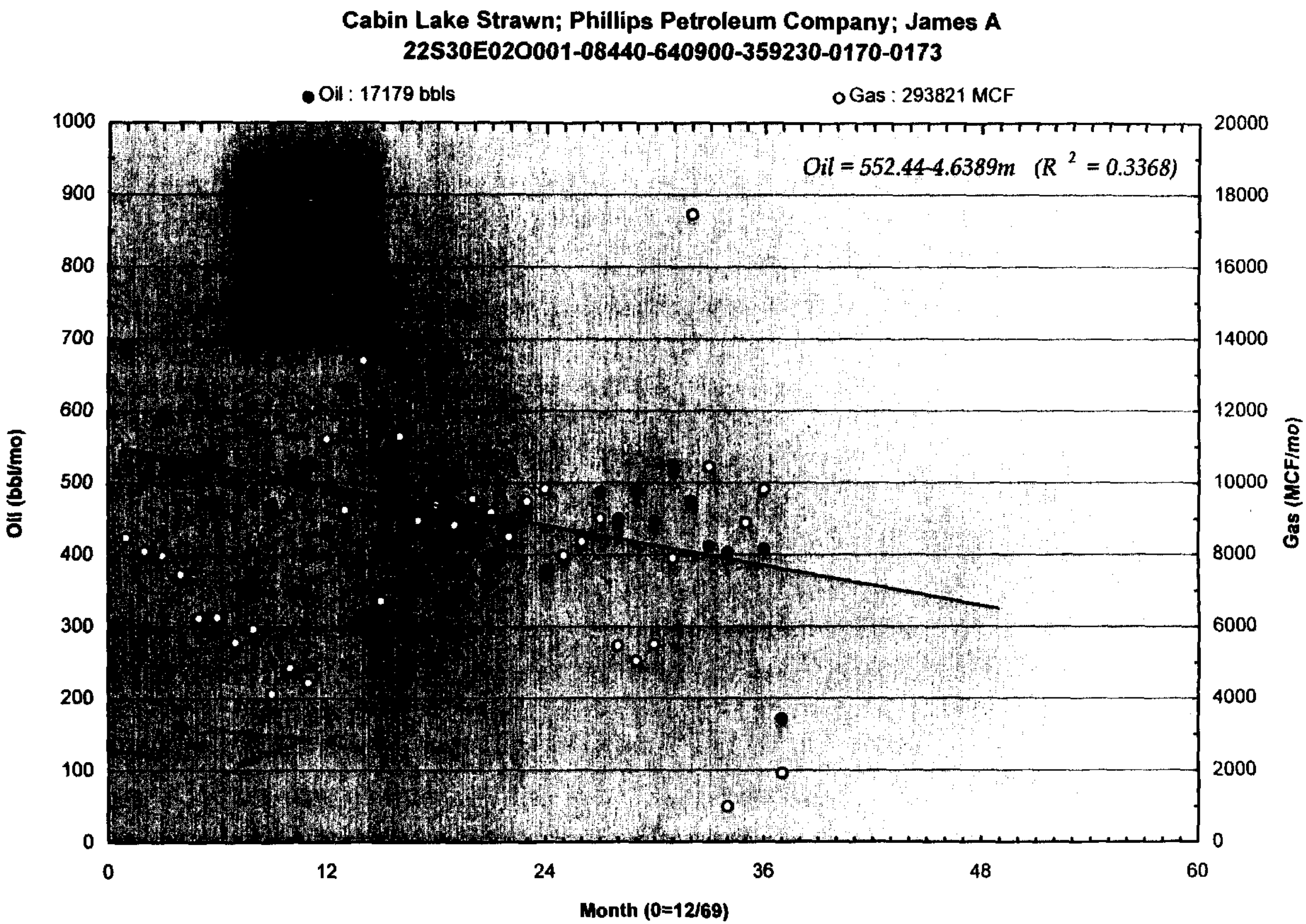

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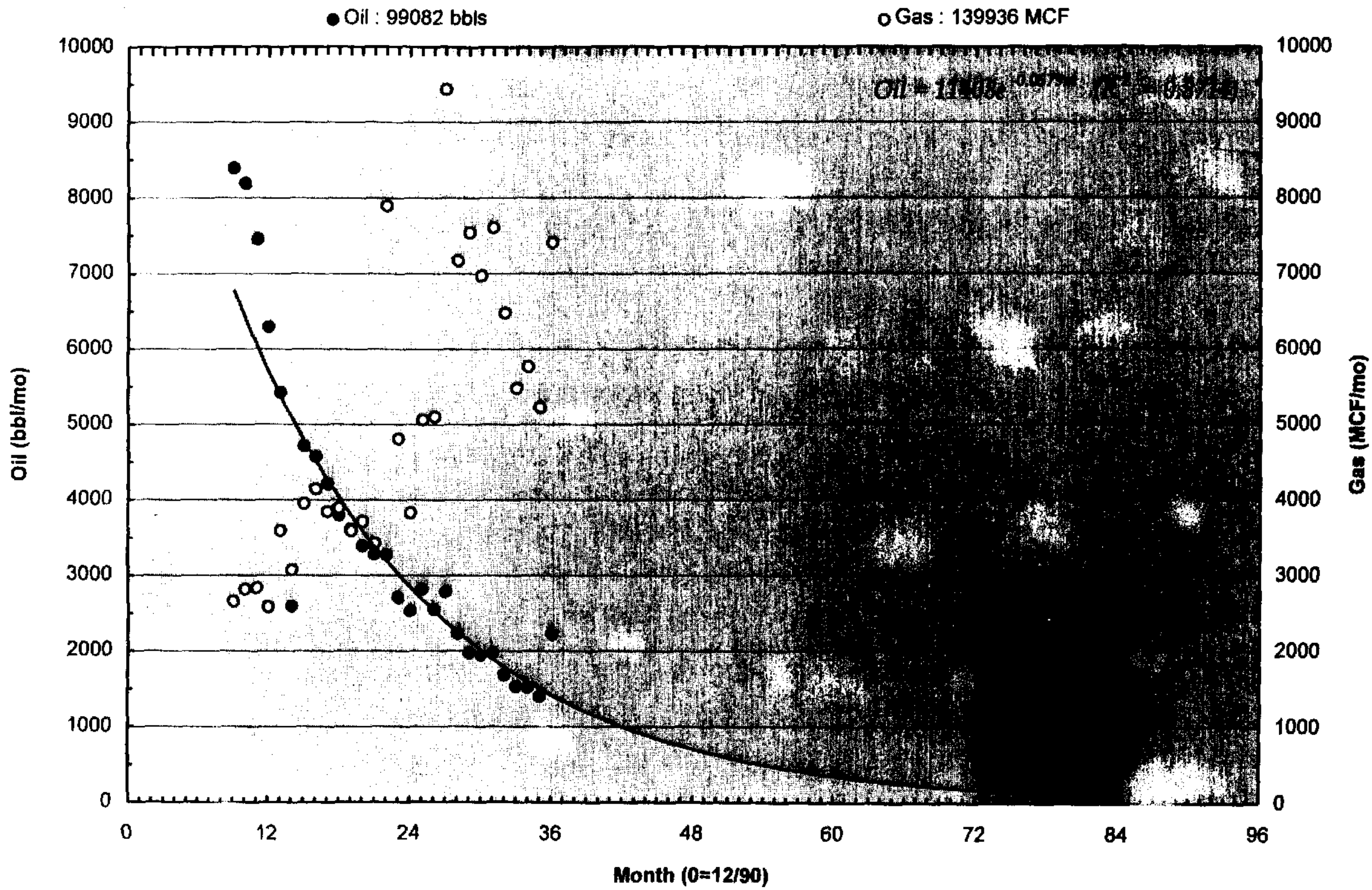

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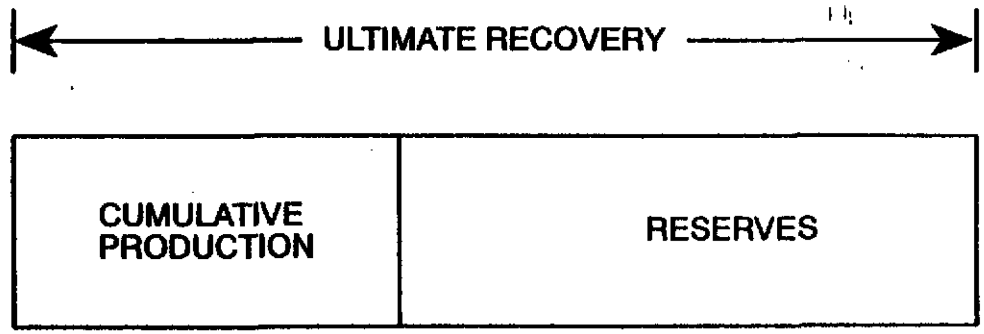

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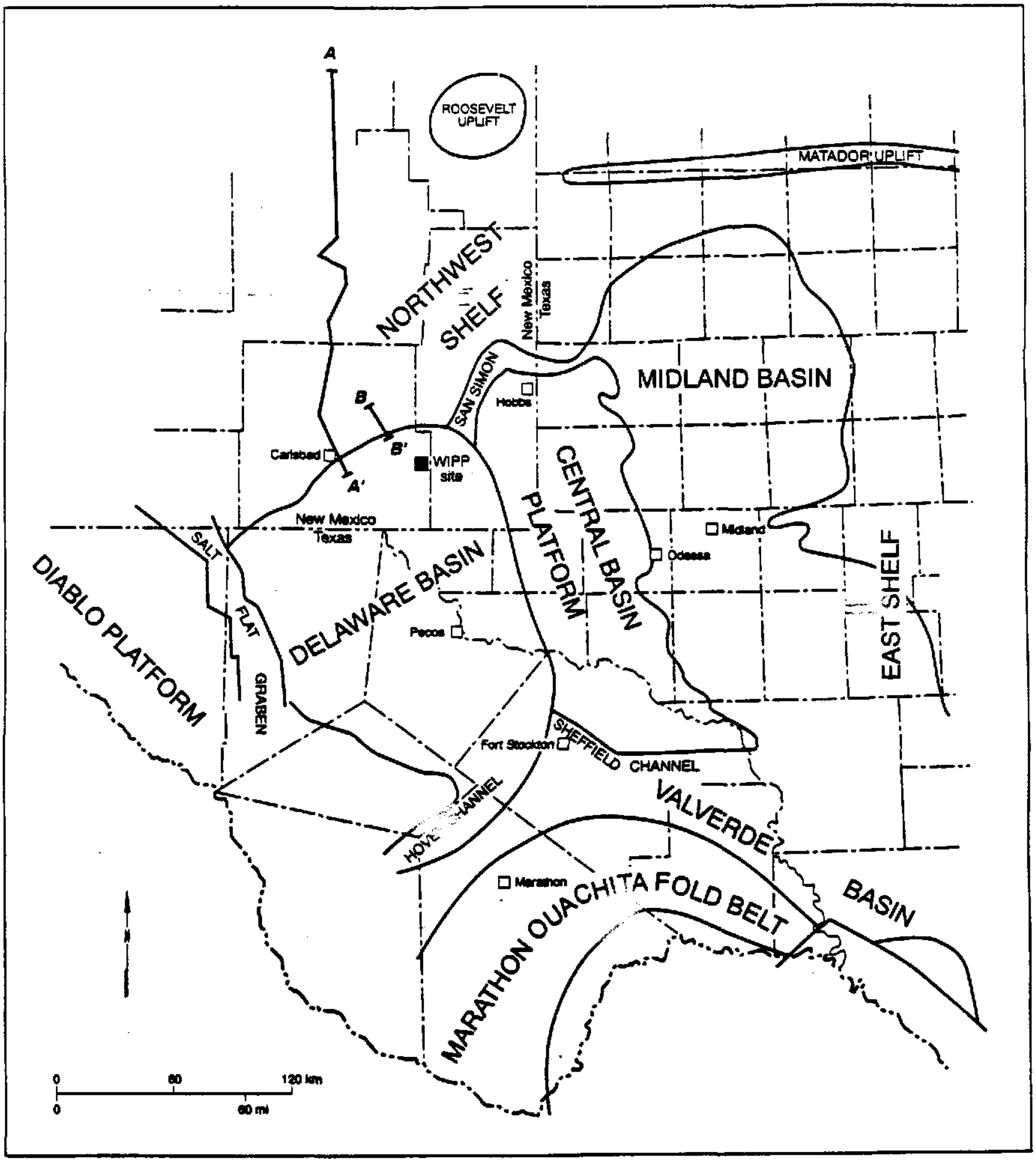

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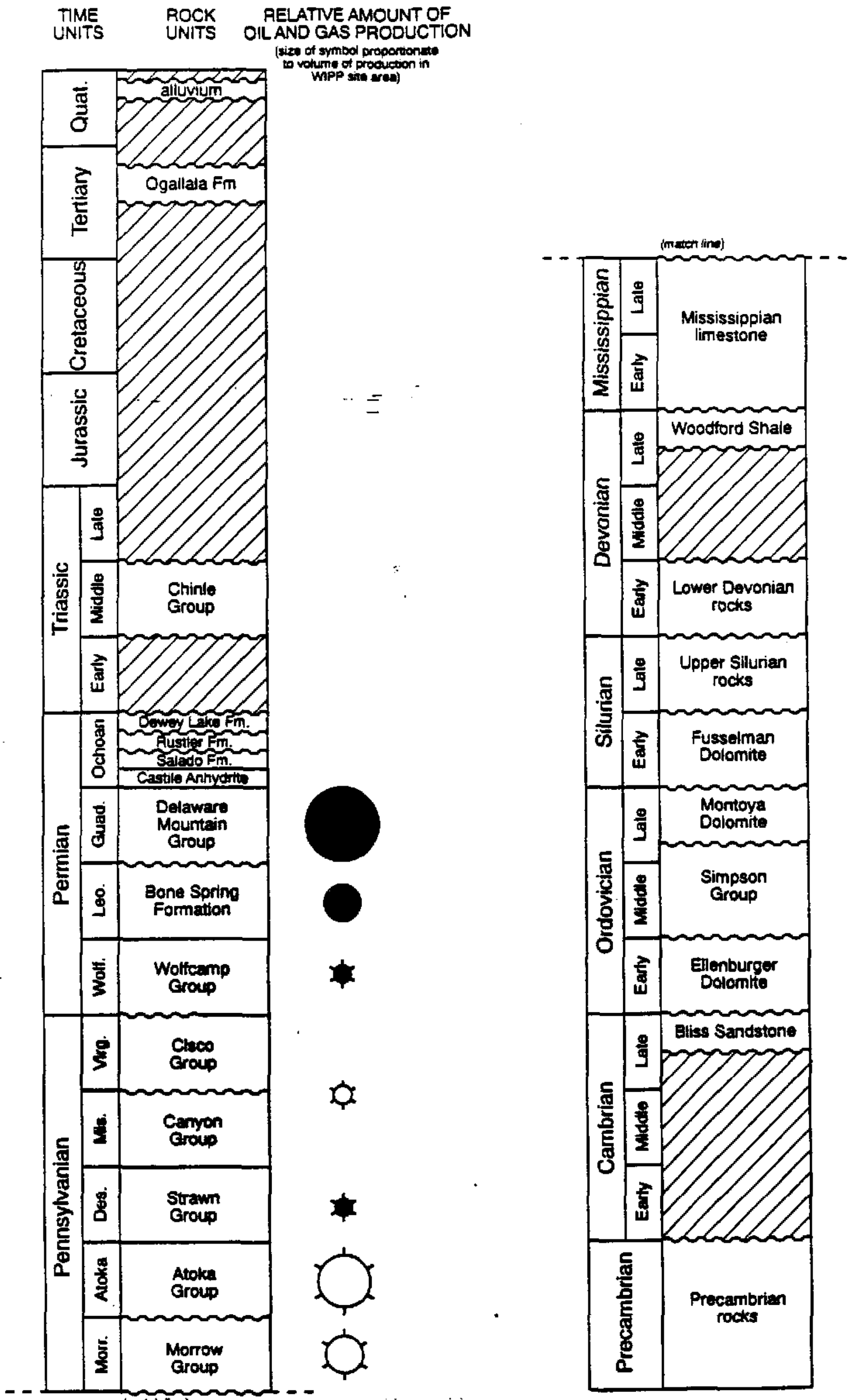

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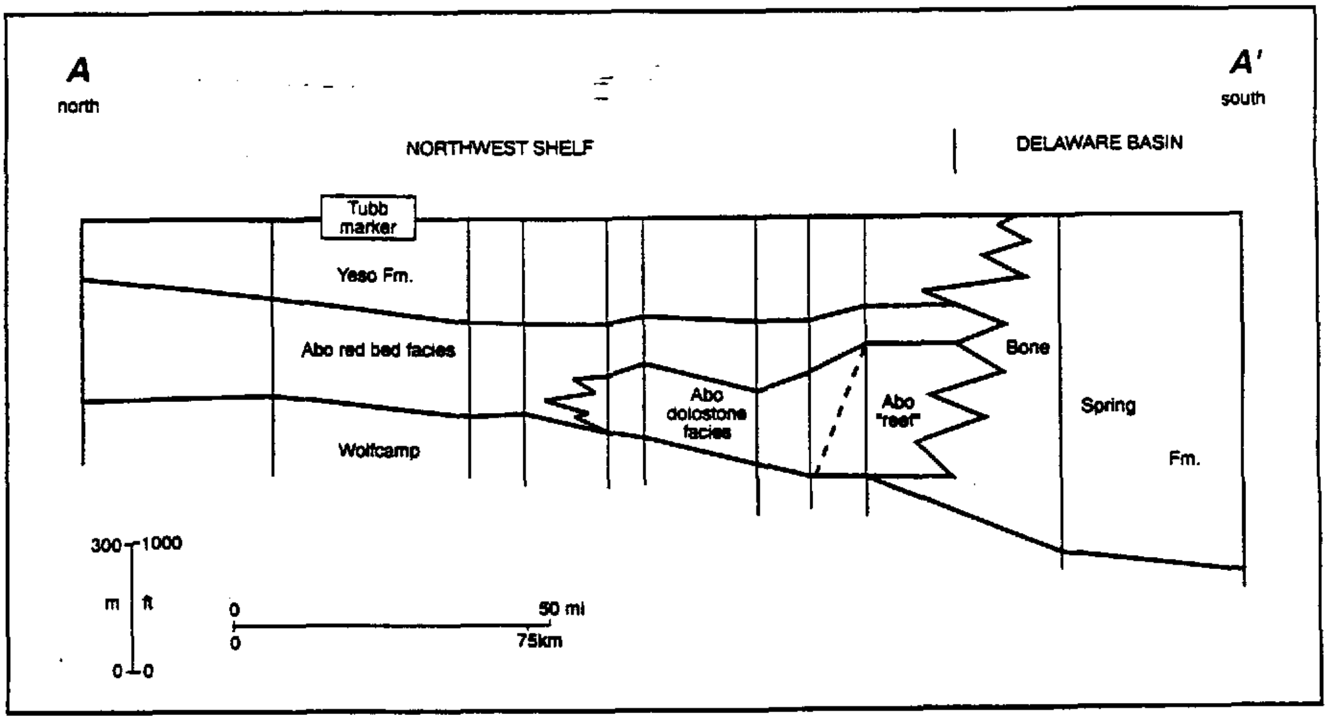

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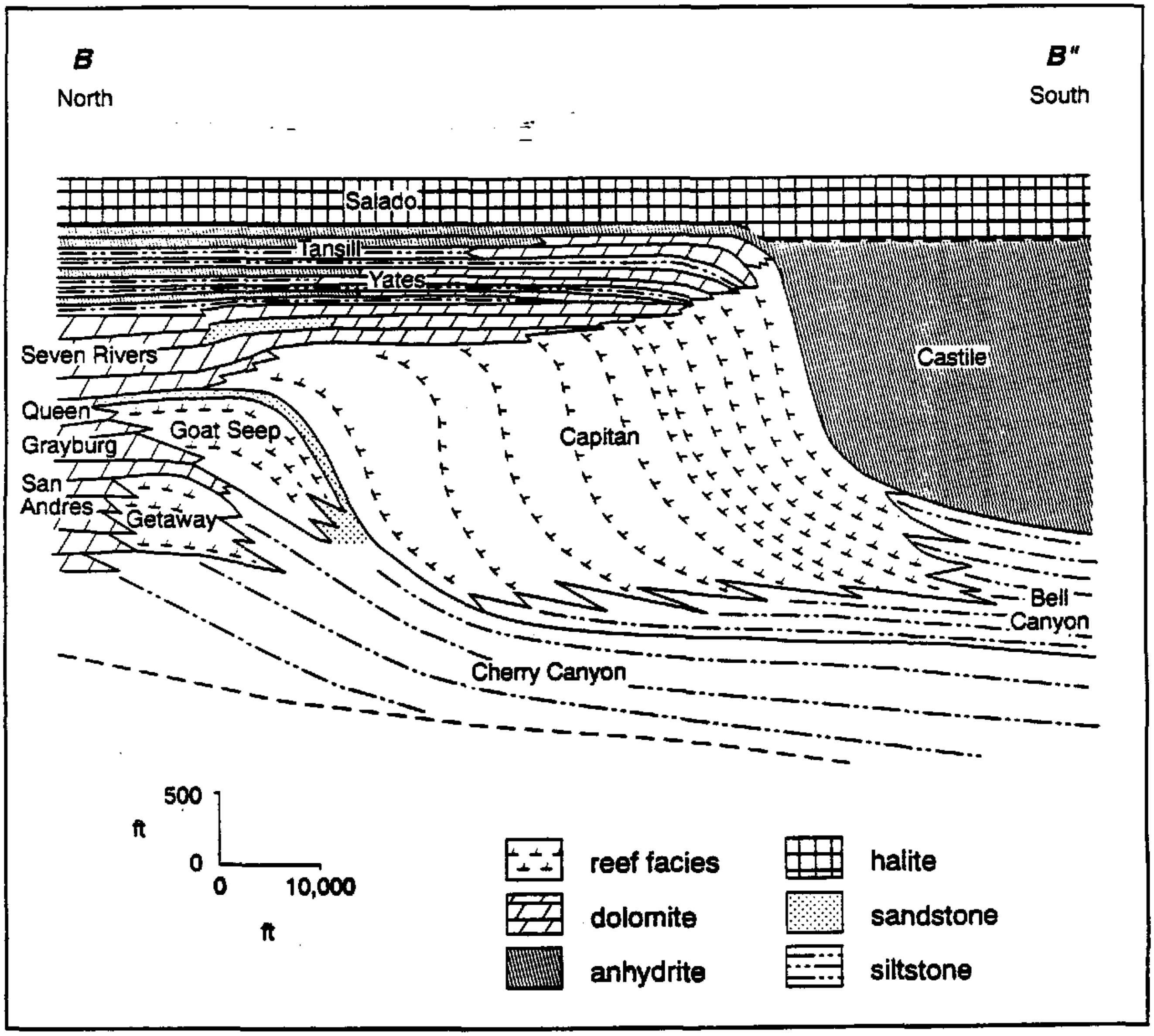

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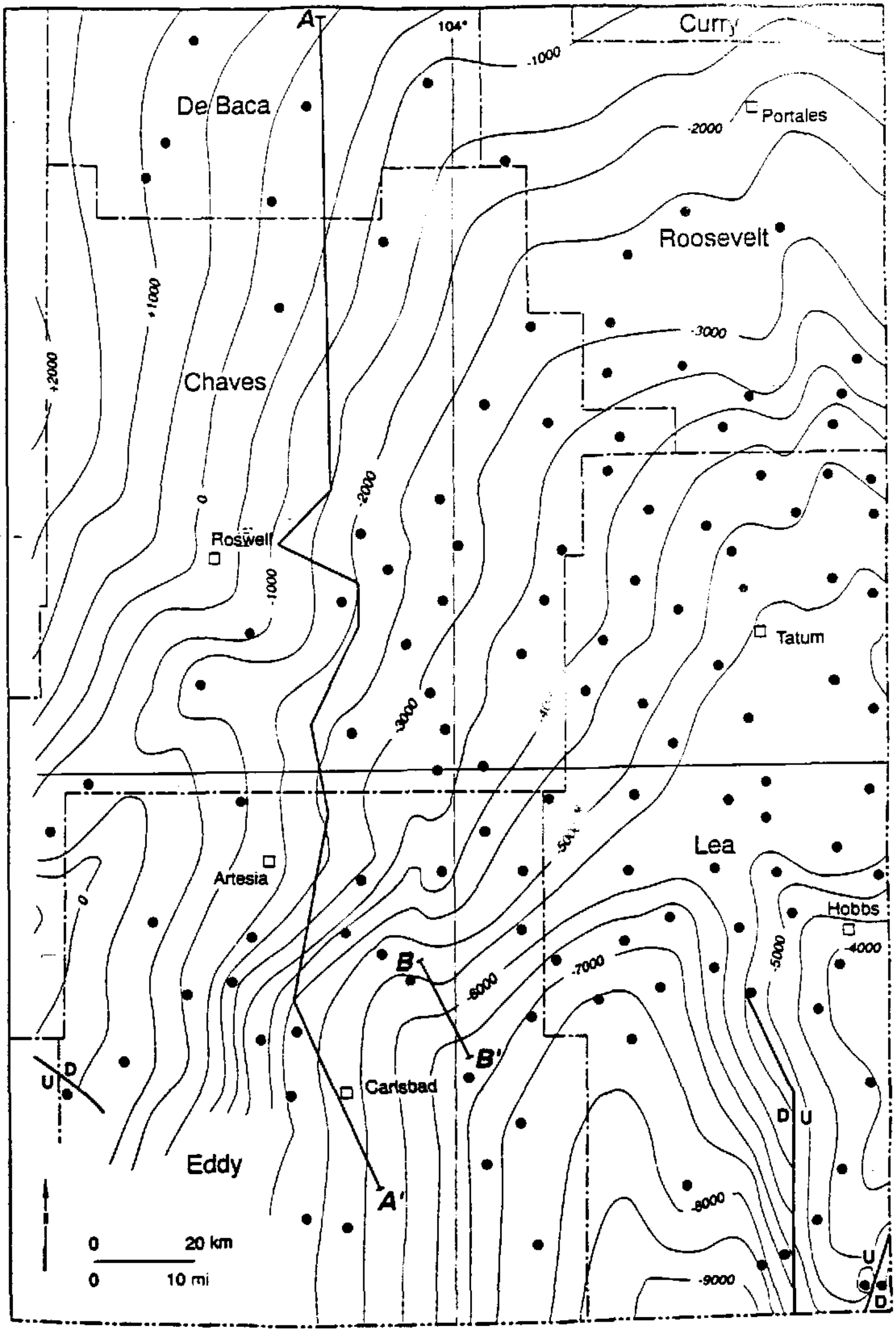

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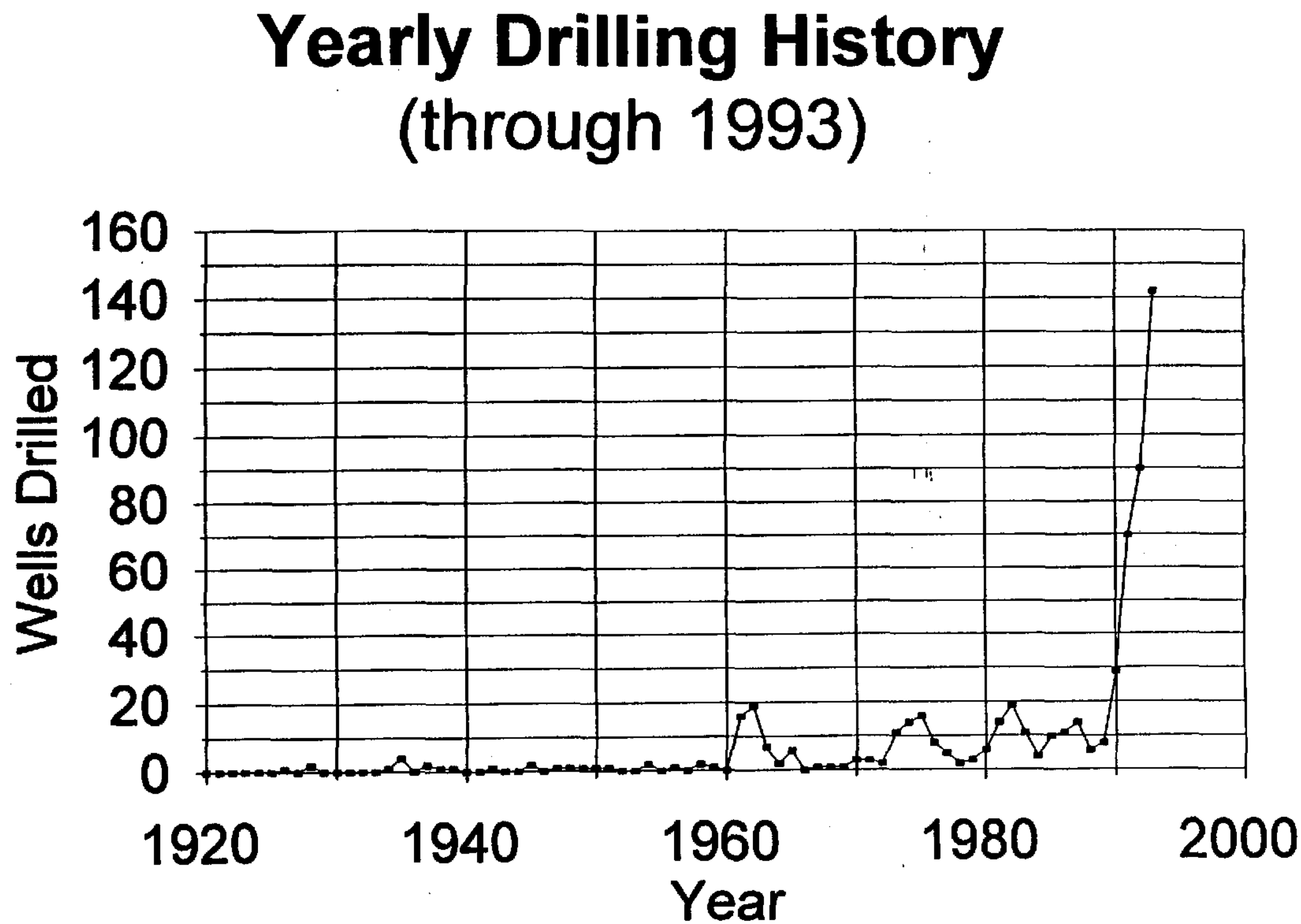

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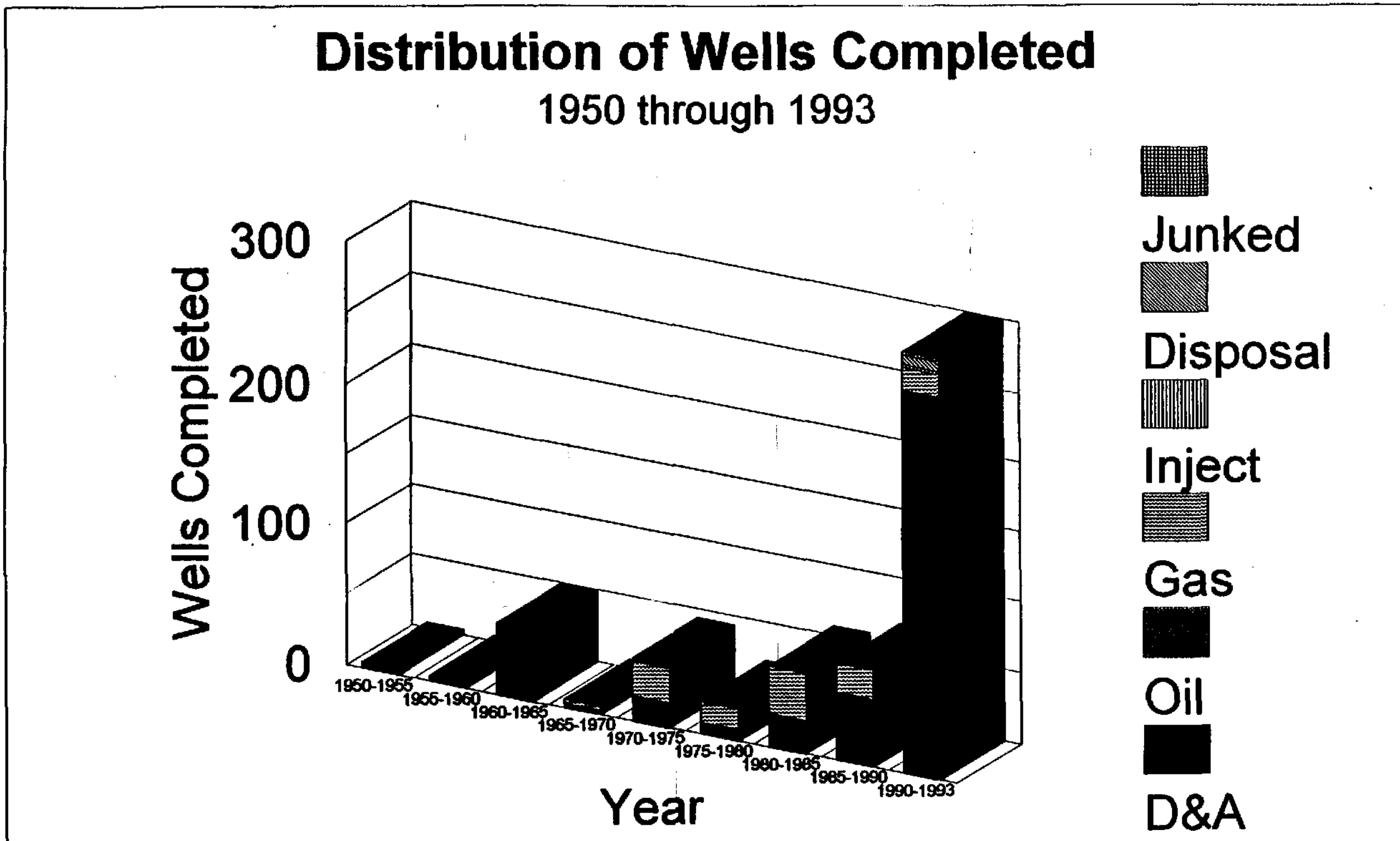

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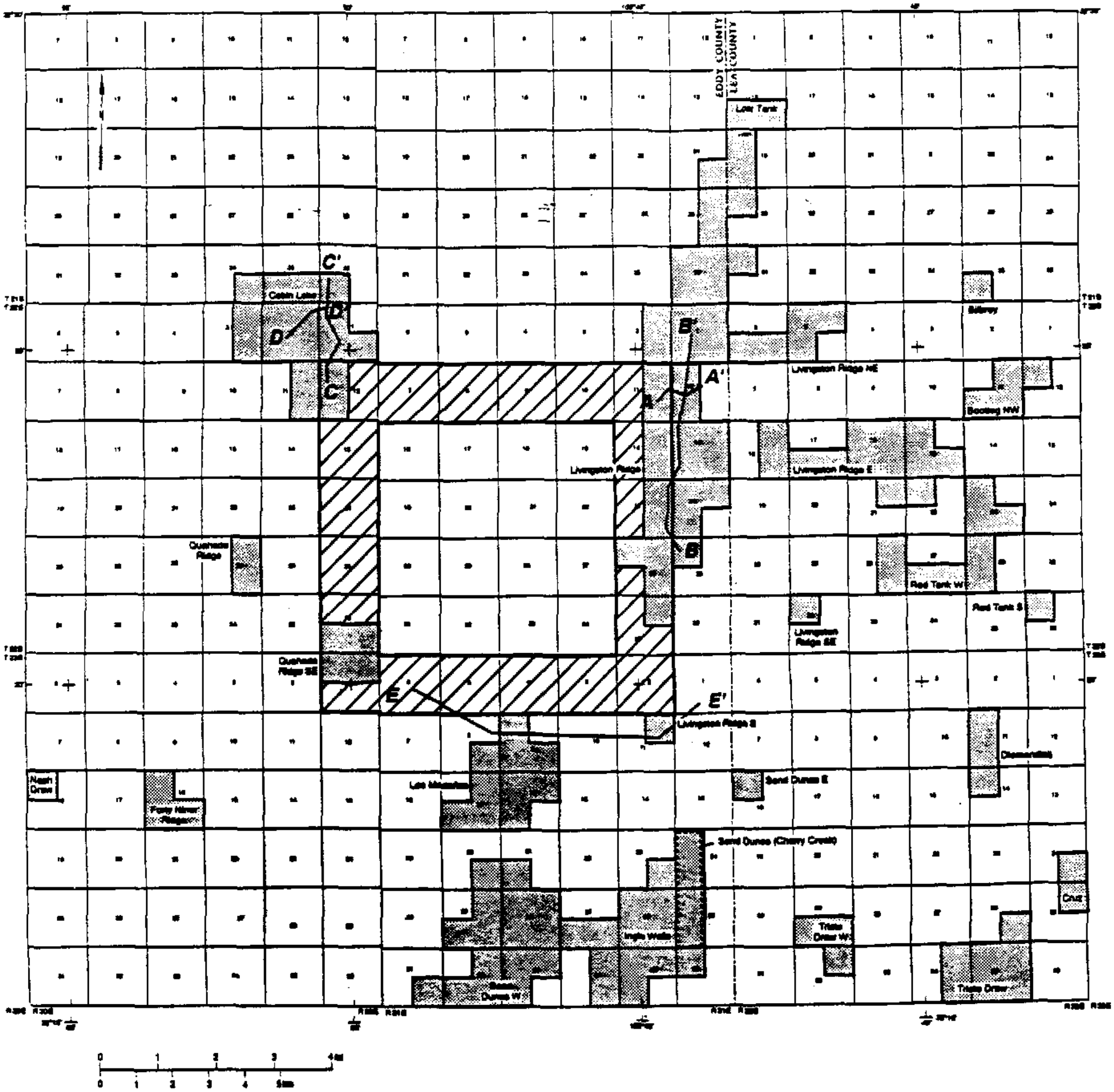

Delaware Pools

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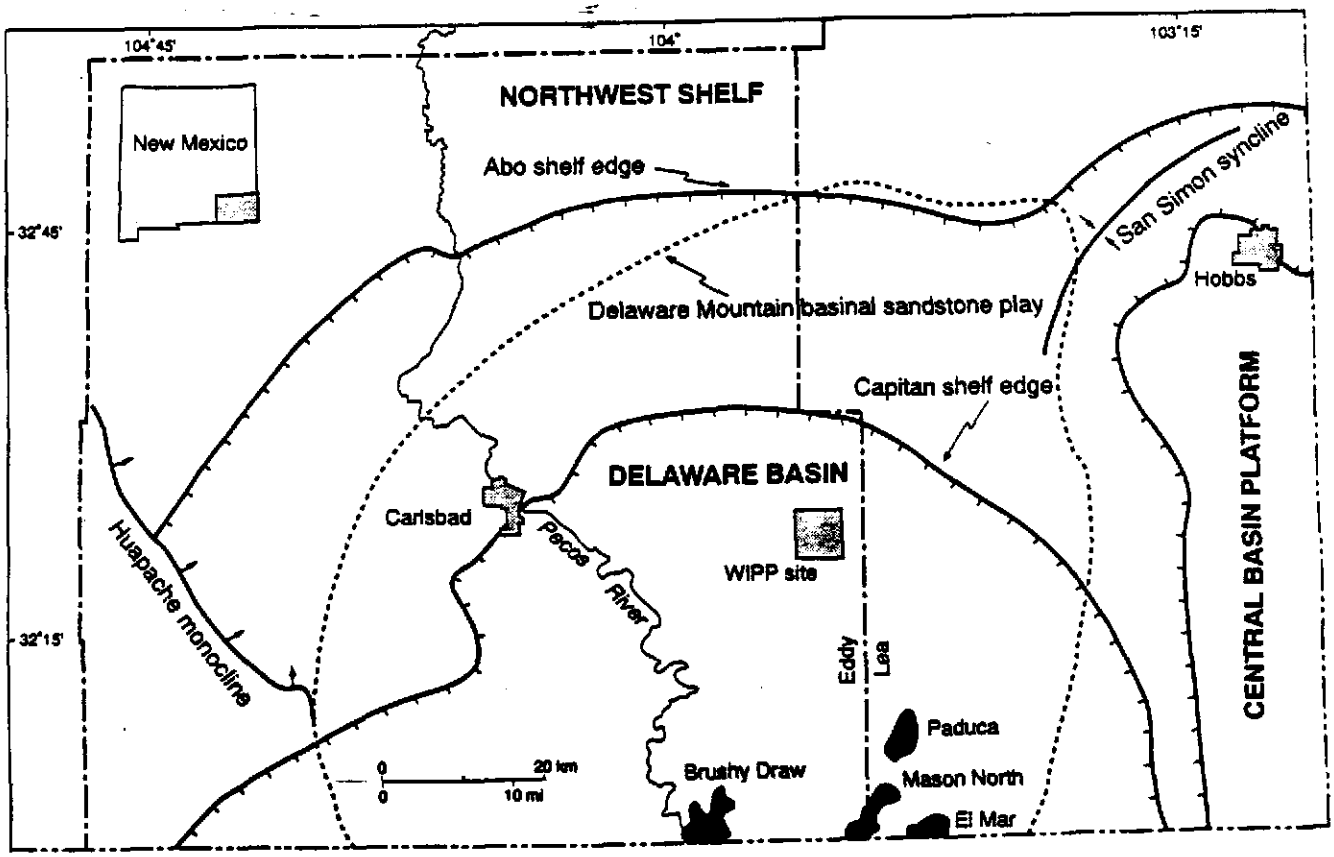

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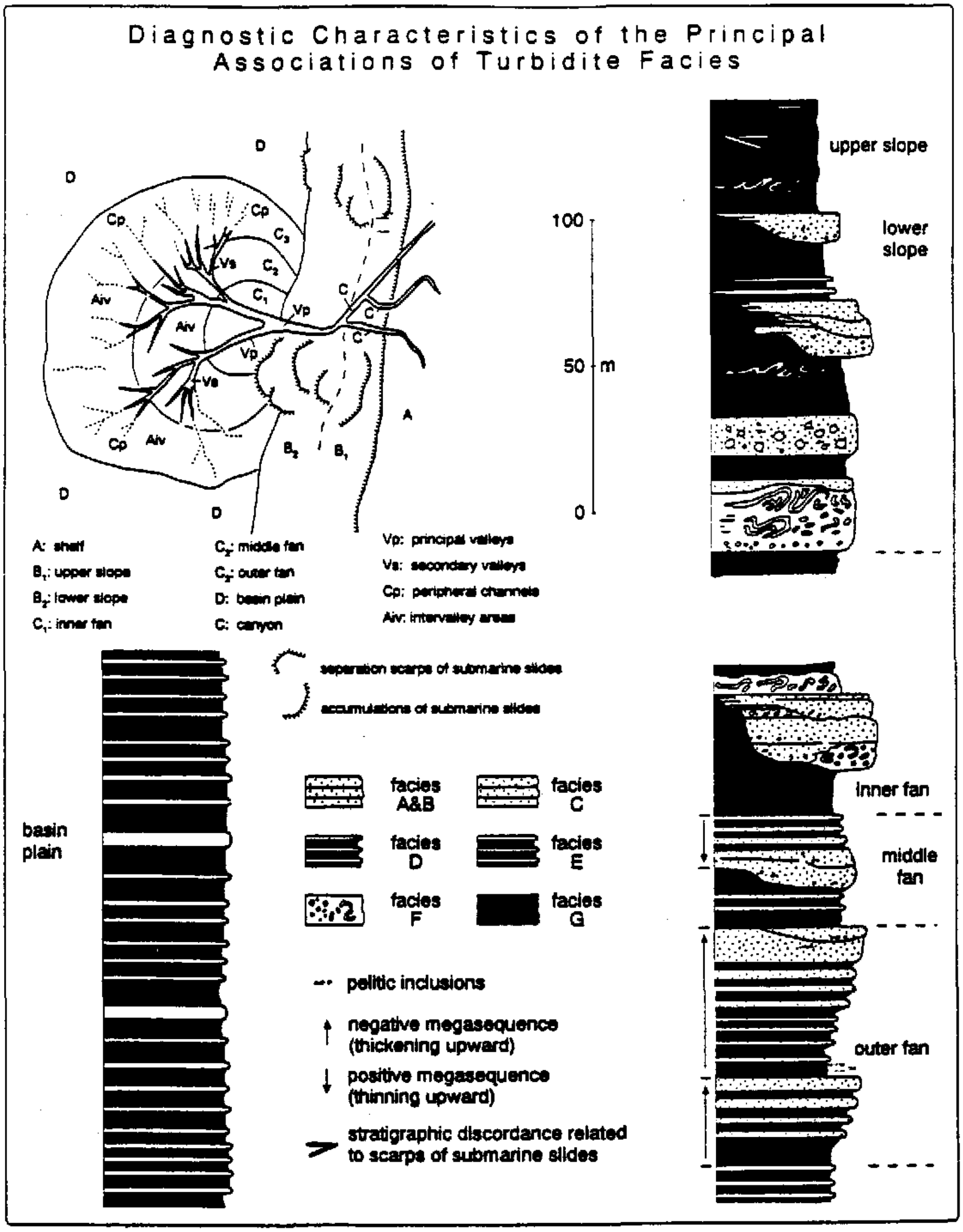

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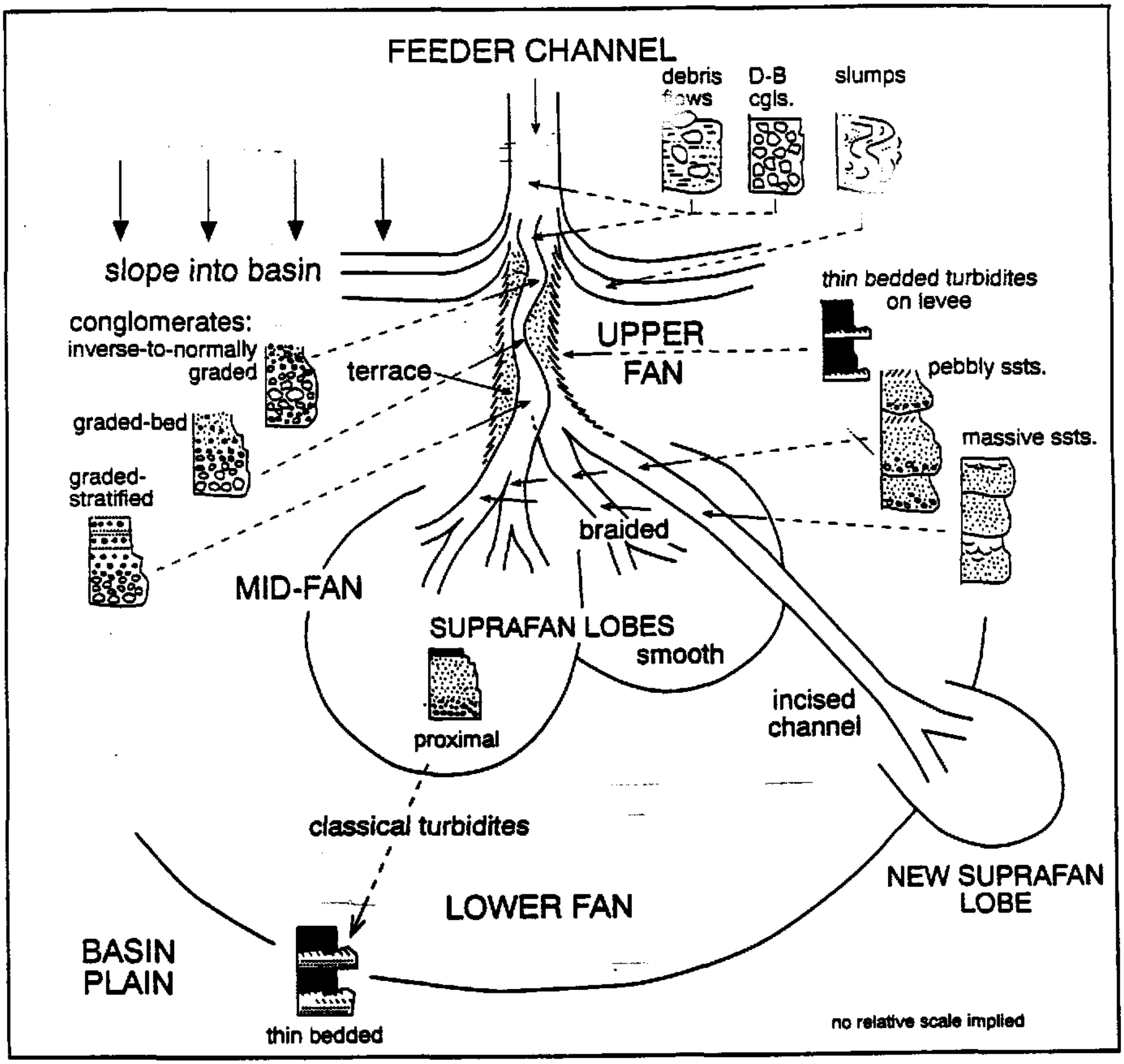

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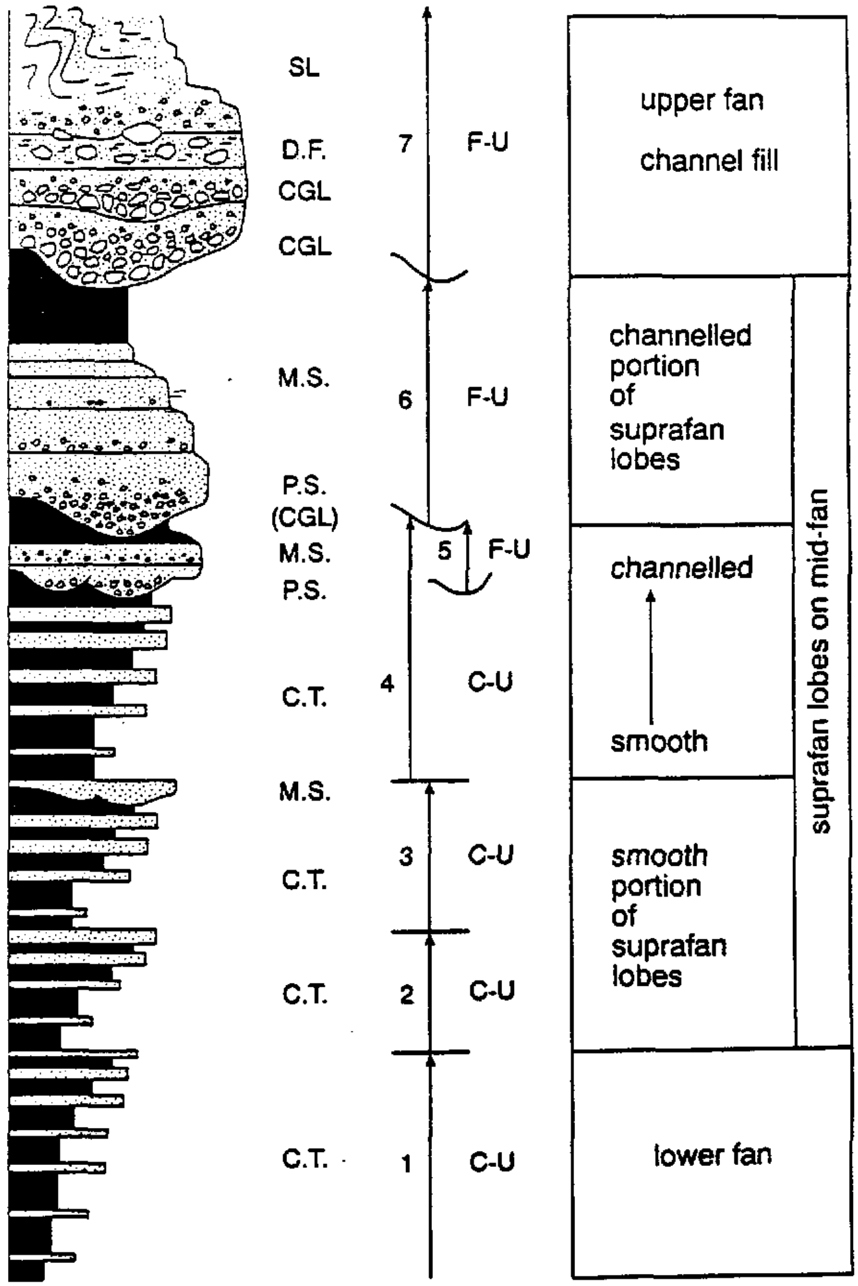
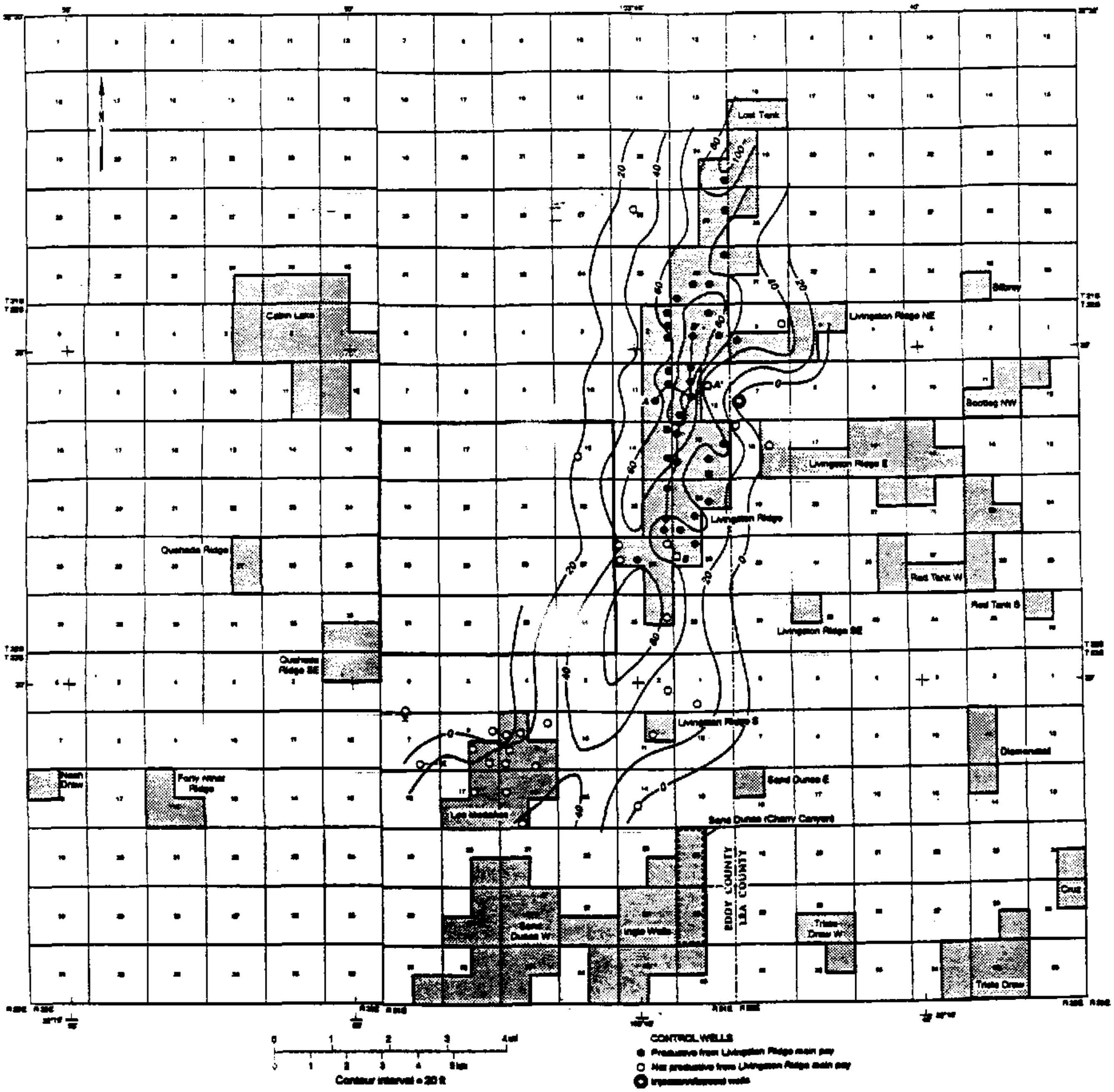


Figure 18. Idealized stratigraphic sequence developed as a result of progradation of a submarine fan. C–U represents thickening- and coarsening-upward sequence. F–U represents thinning and fining-upward sequence. From Walker (1978).



Isopach Livingston Ridge Main Pay, Upper Brushy Canyon

Figure 24. Isopach map of gross channel thickness of Livingston Ridge main pay zone. Only wells used as mapping control points are shown.

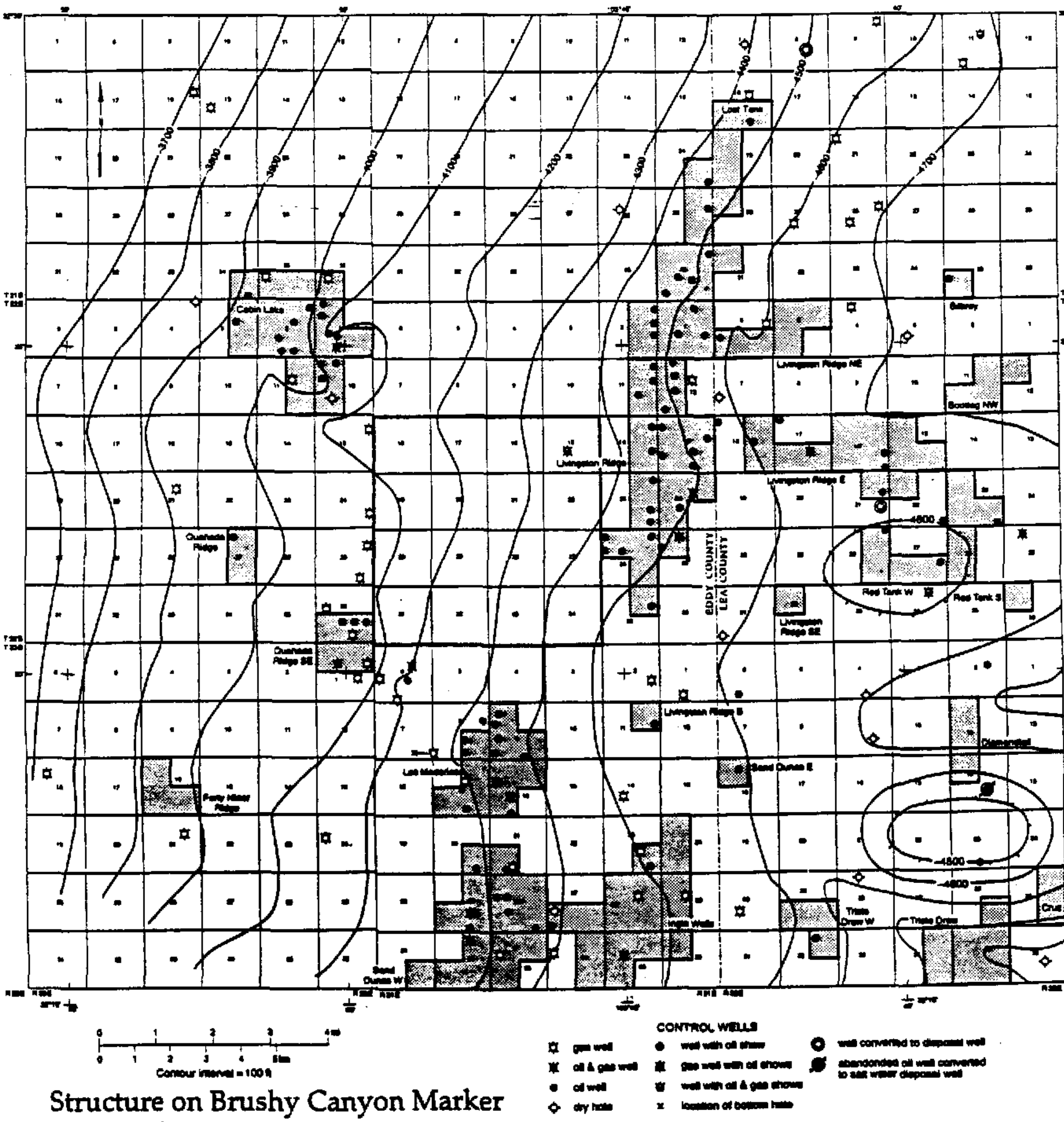
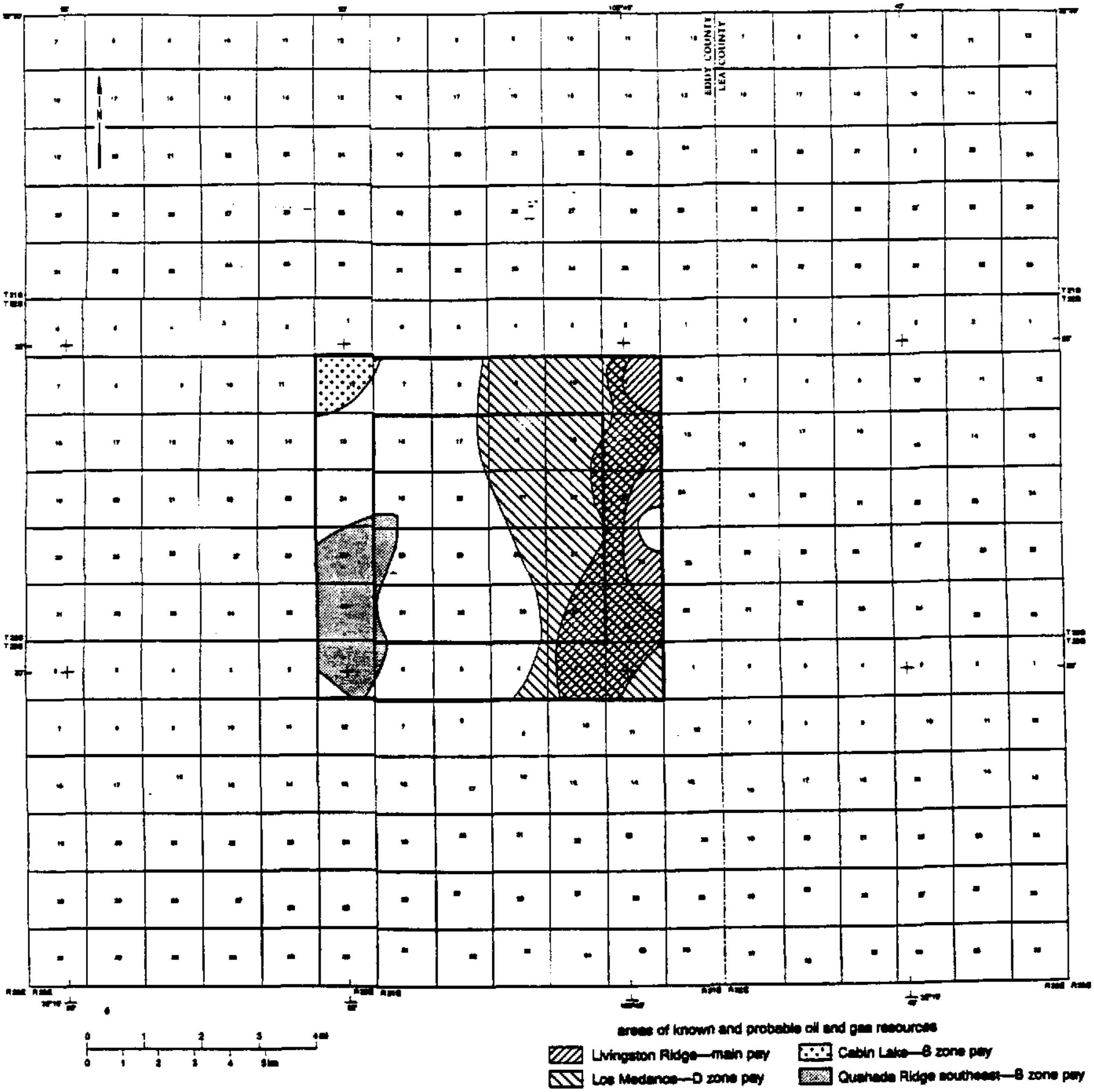


Figure 25. Structure contour map of marker bed at top of lower Brushy Canyon Formation. Only wells used as mapping control points are shown.



Delaware Oil & Gas Resources

Figure 26. Areas of known and probable oil and gas resources within the WIPP site and one-mile wide additional study area for Delaware pools projected to extend under the WIPP site.

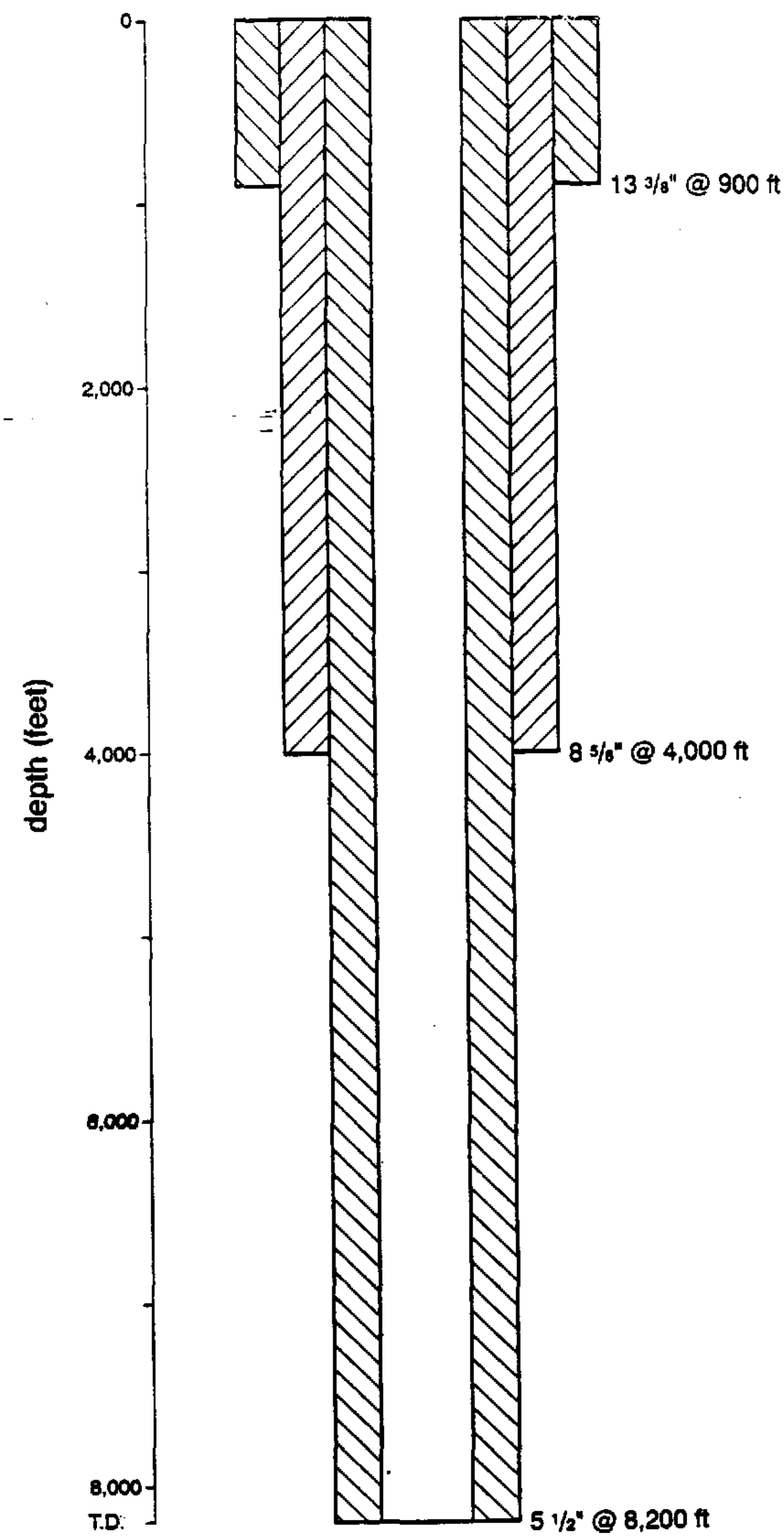
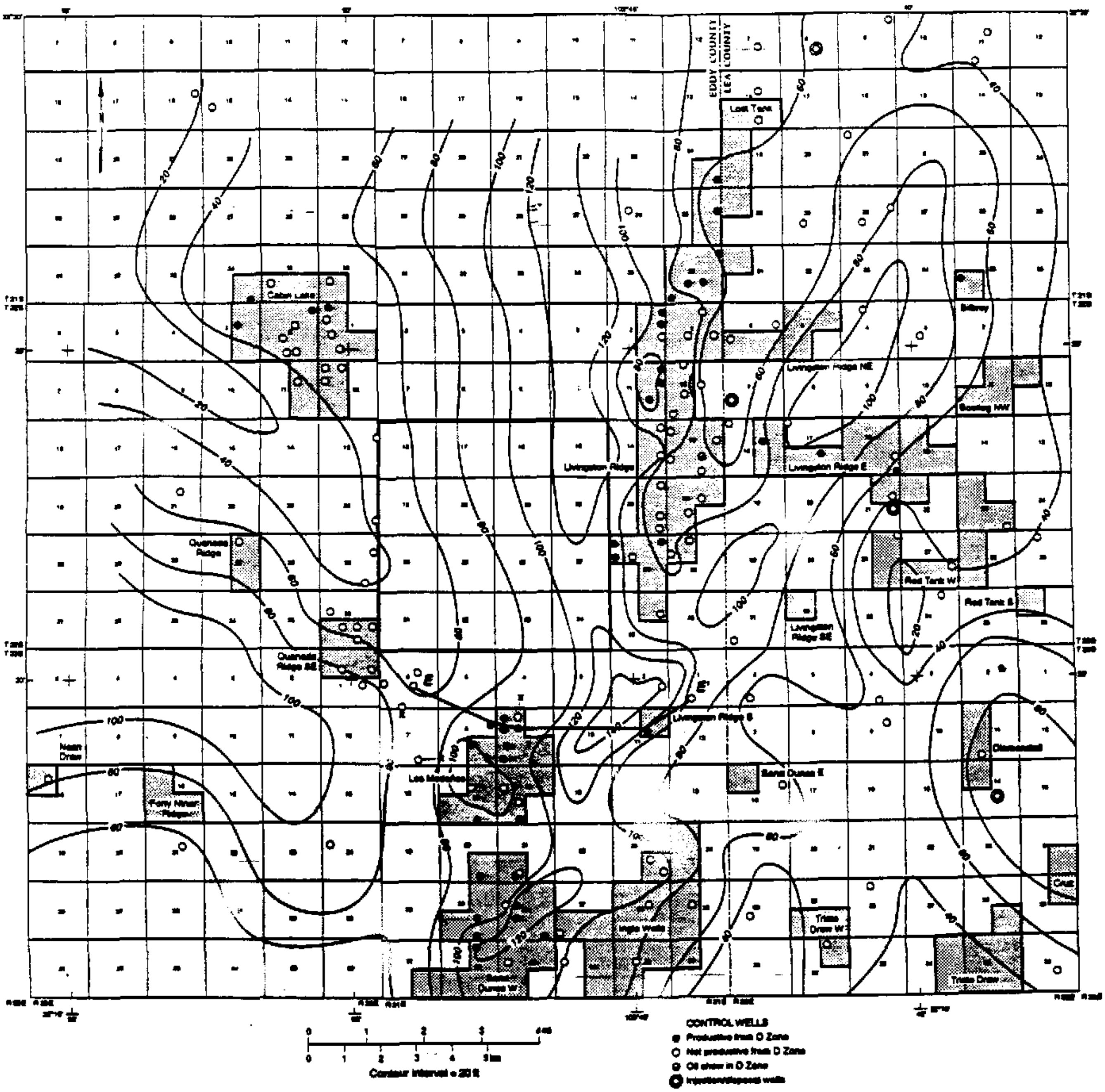


Figure 27. Casing program of typical well producing from Livingston Ridge main pay.



Isopach Zone D, Lower Brushy Canyon

Figure 28. Isopach map of D zone of lower Brushy Canyon Formation. Only wells used as mapping control points are shown.

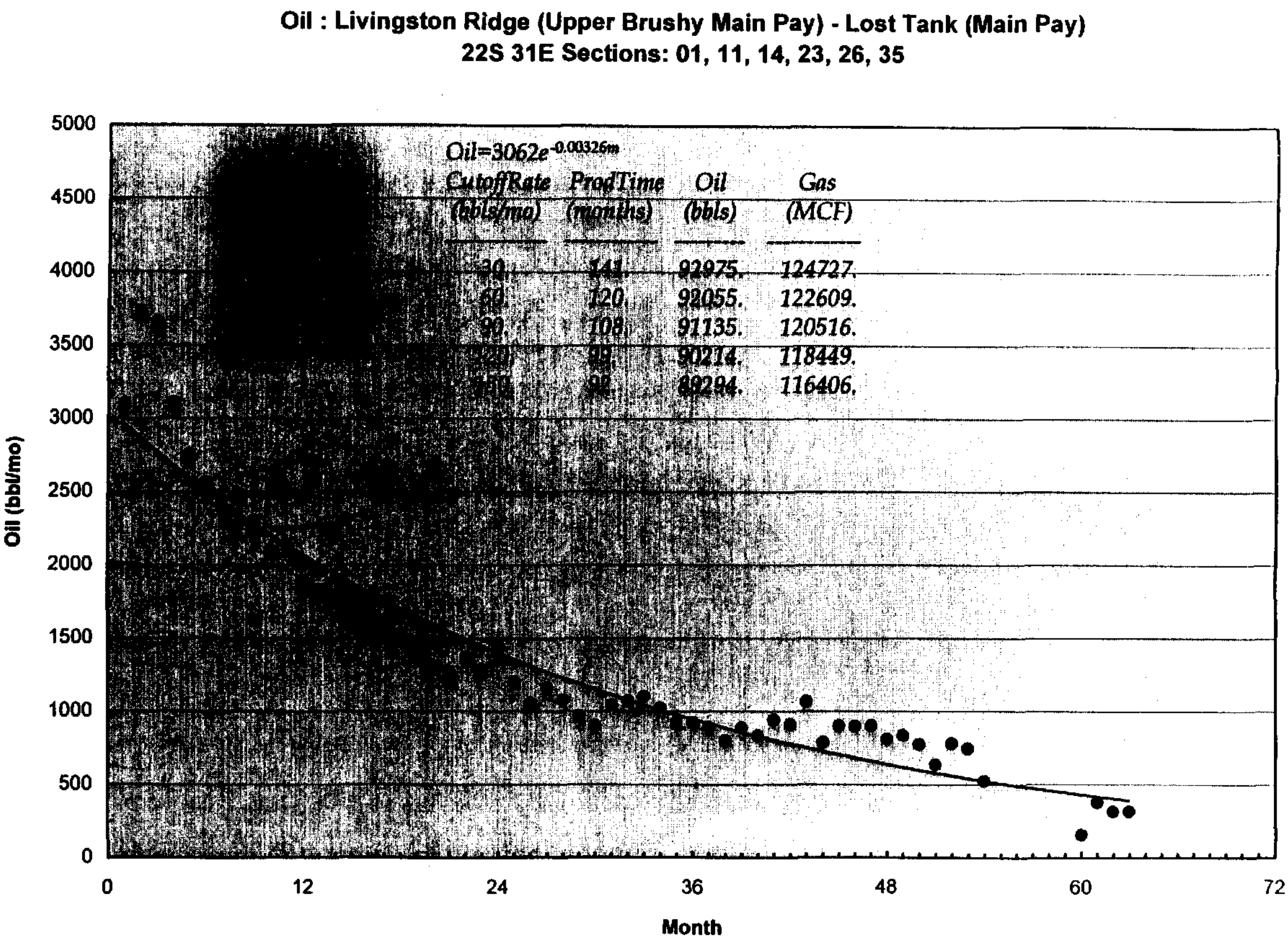


Figure 29. Average production decline curve for wells productive from Livingston Ridge main pay, Livingston Ridge and Lost Tank Delaware pools.

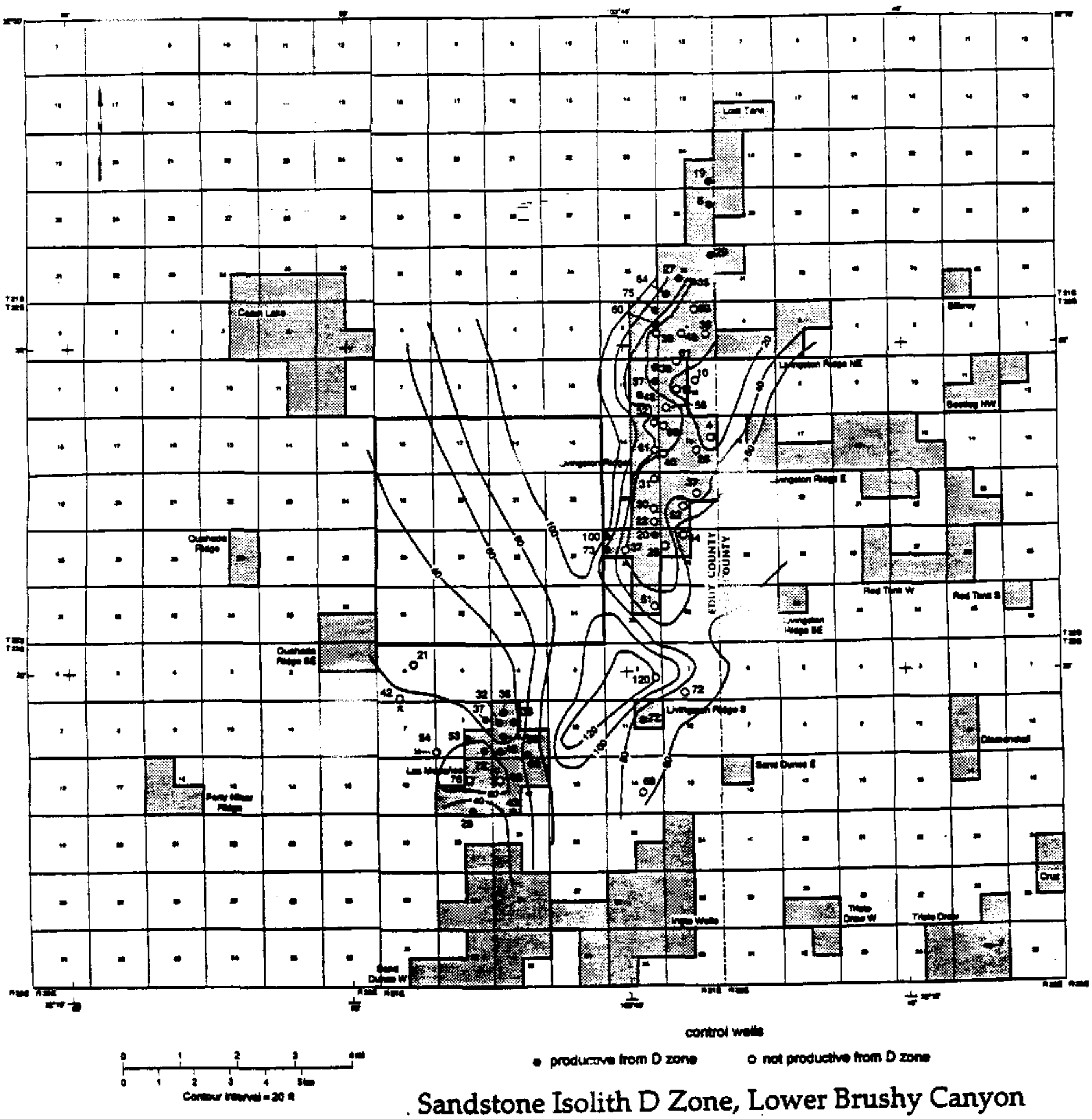


Figure 30. Sandstone isolith map of D zone, lower Brushy Canyon Formation. Only wells used as mapping control points are shown.

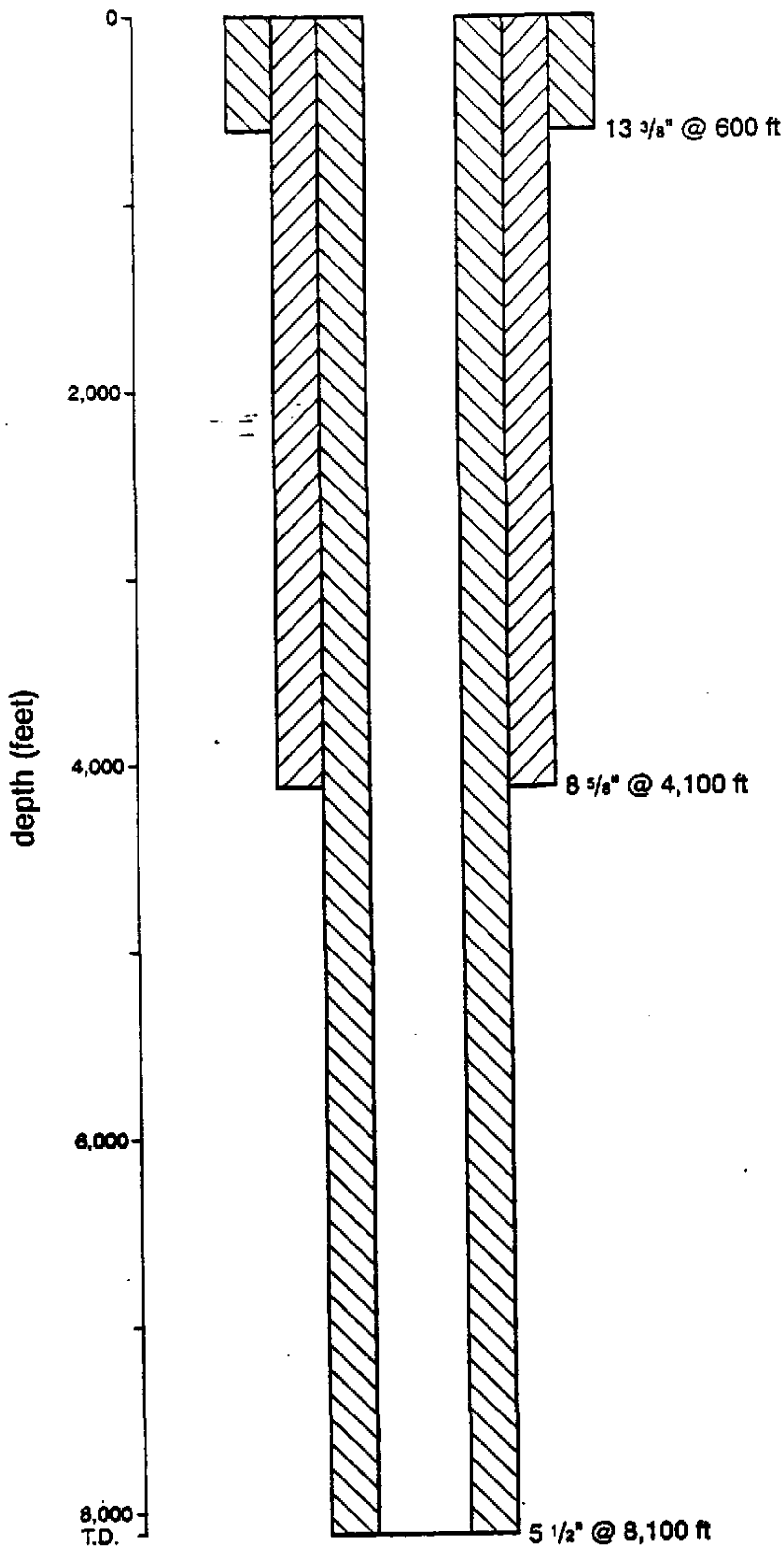


Figure 31. Casing program of typical well producing from lower Brushy Canyon D zone in the Los Medanos complex.

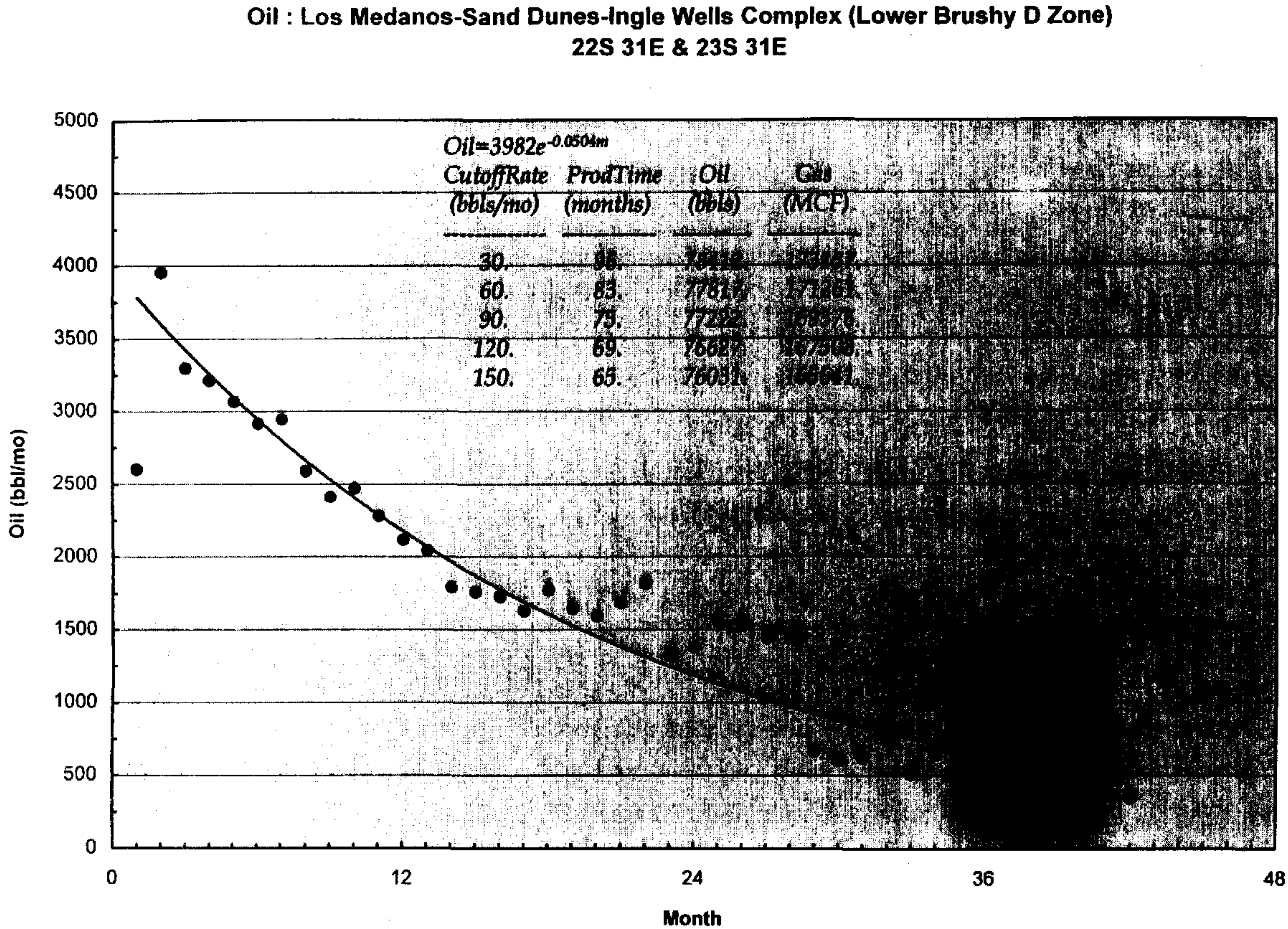


Figure 32. Average production decline curve for wells productive from D zone of lower Brushy Canyon Formation, Los Medanos complex.

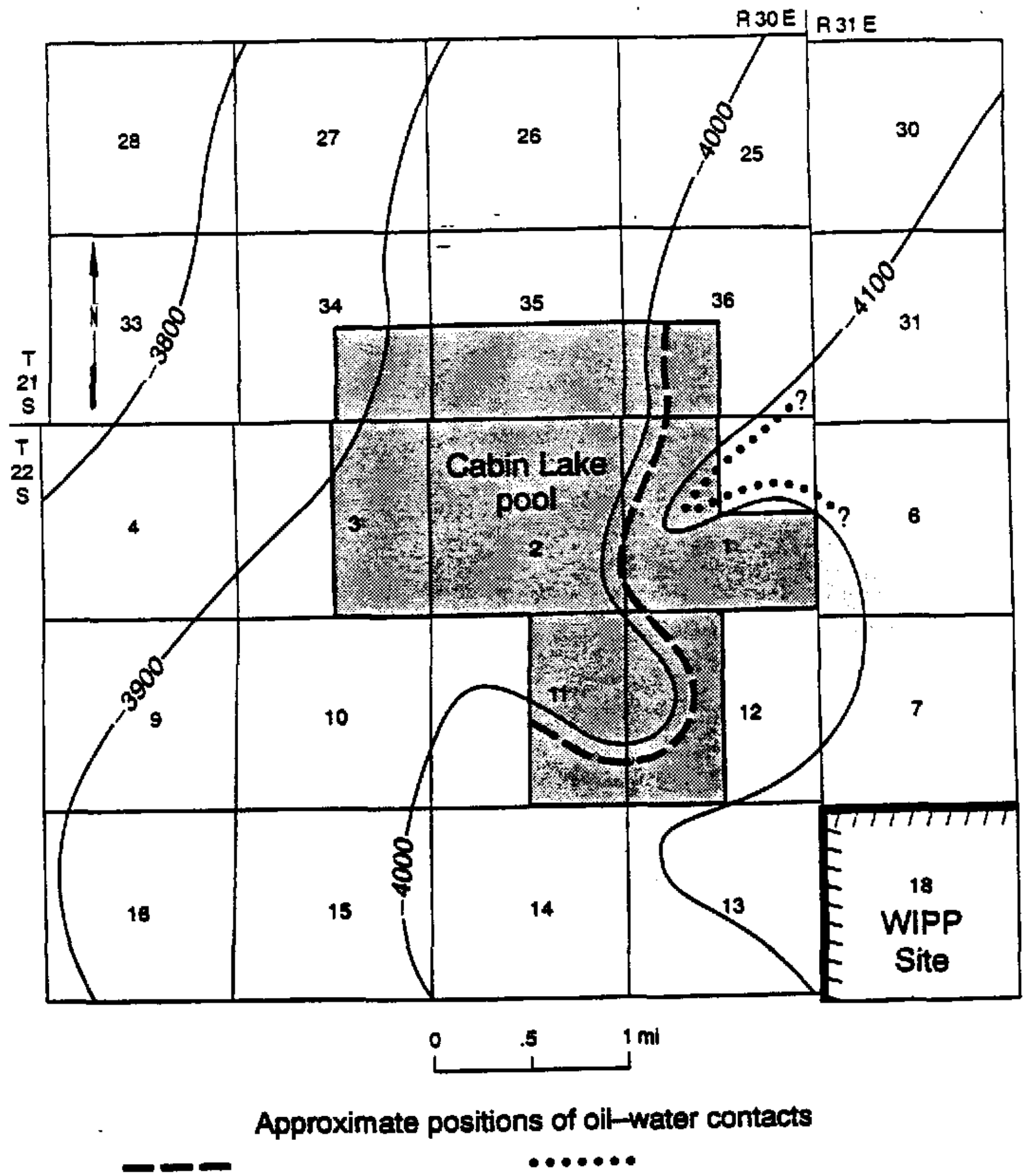
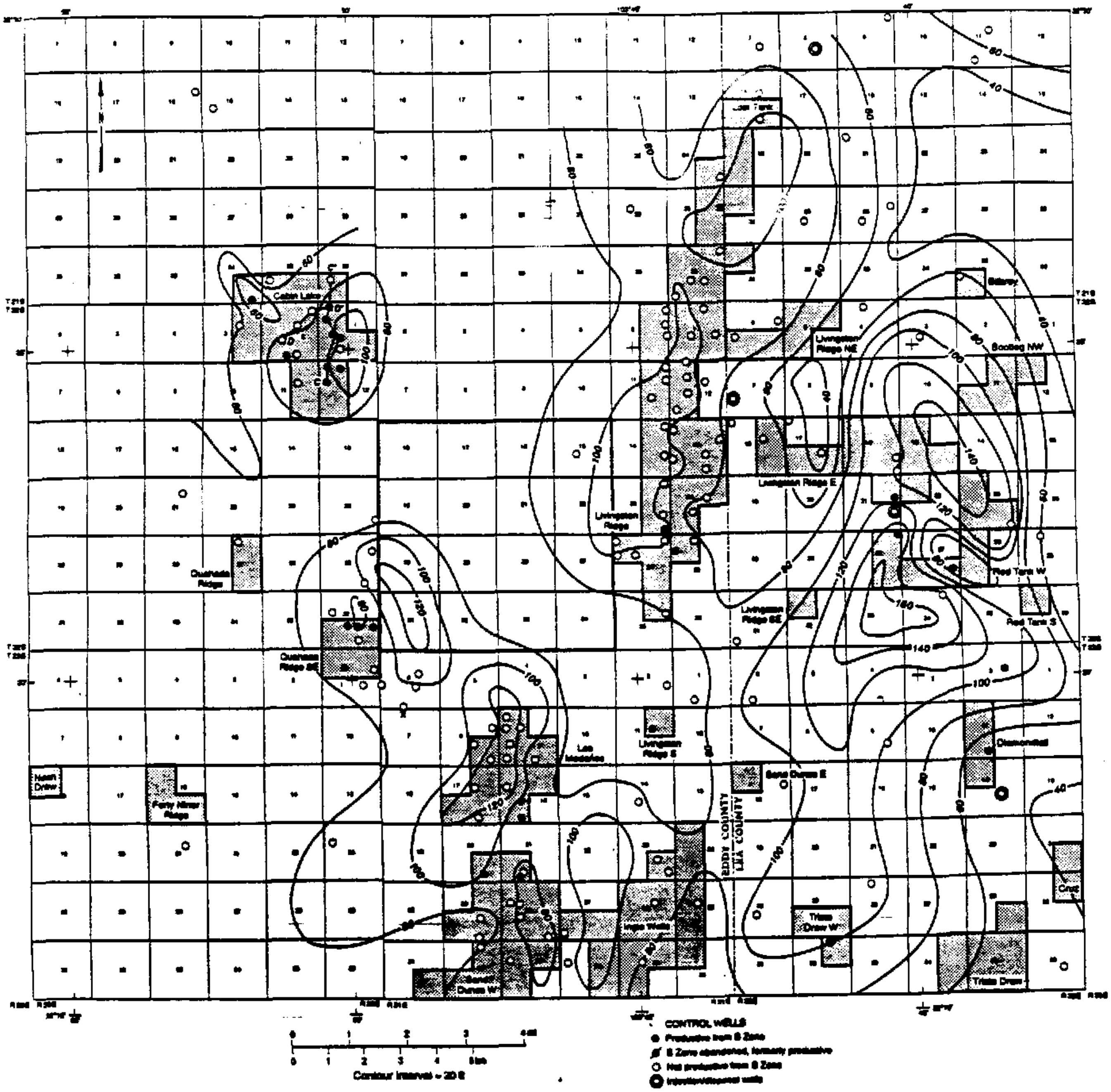


Figure 33. Structure map of top of lower Brushy Canyon Formation, Cabin Lake pool, showing postulated oil–water contacts in main reservoirs. Contours from Fig. 25.



Isopach Zone B, Lower Brushy Canyon

Figure 34. Isopach map of B zone of lower Brushy Canyon Formation. Only wells used as mapping control points are shown.

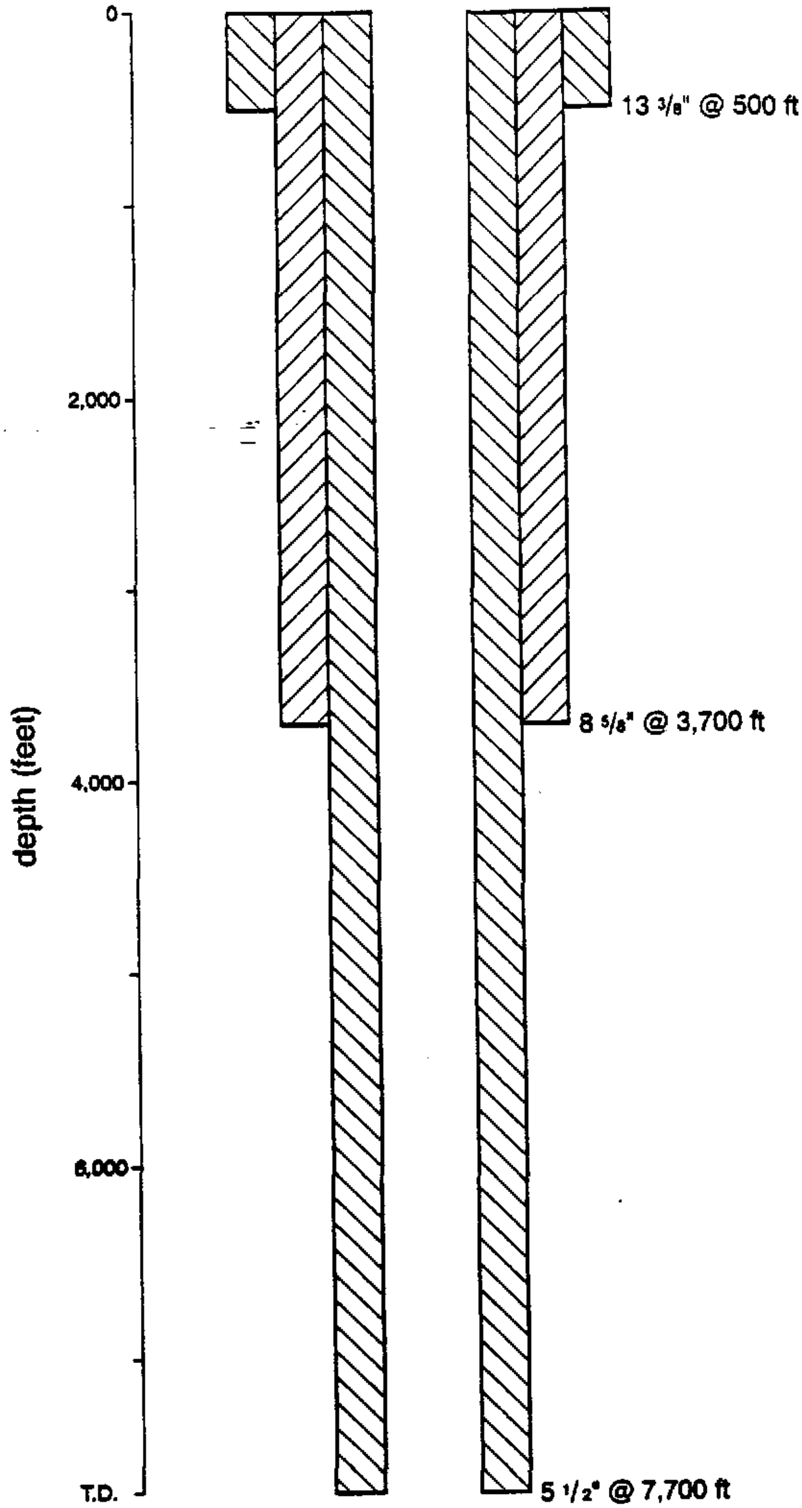


Figure 35. Casing program of a typical well producing from B zone of lower Brushy Canyon Formation, Cabin Lake Delaware pool.

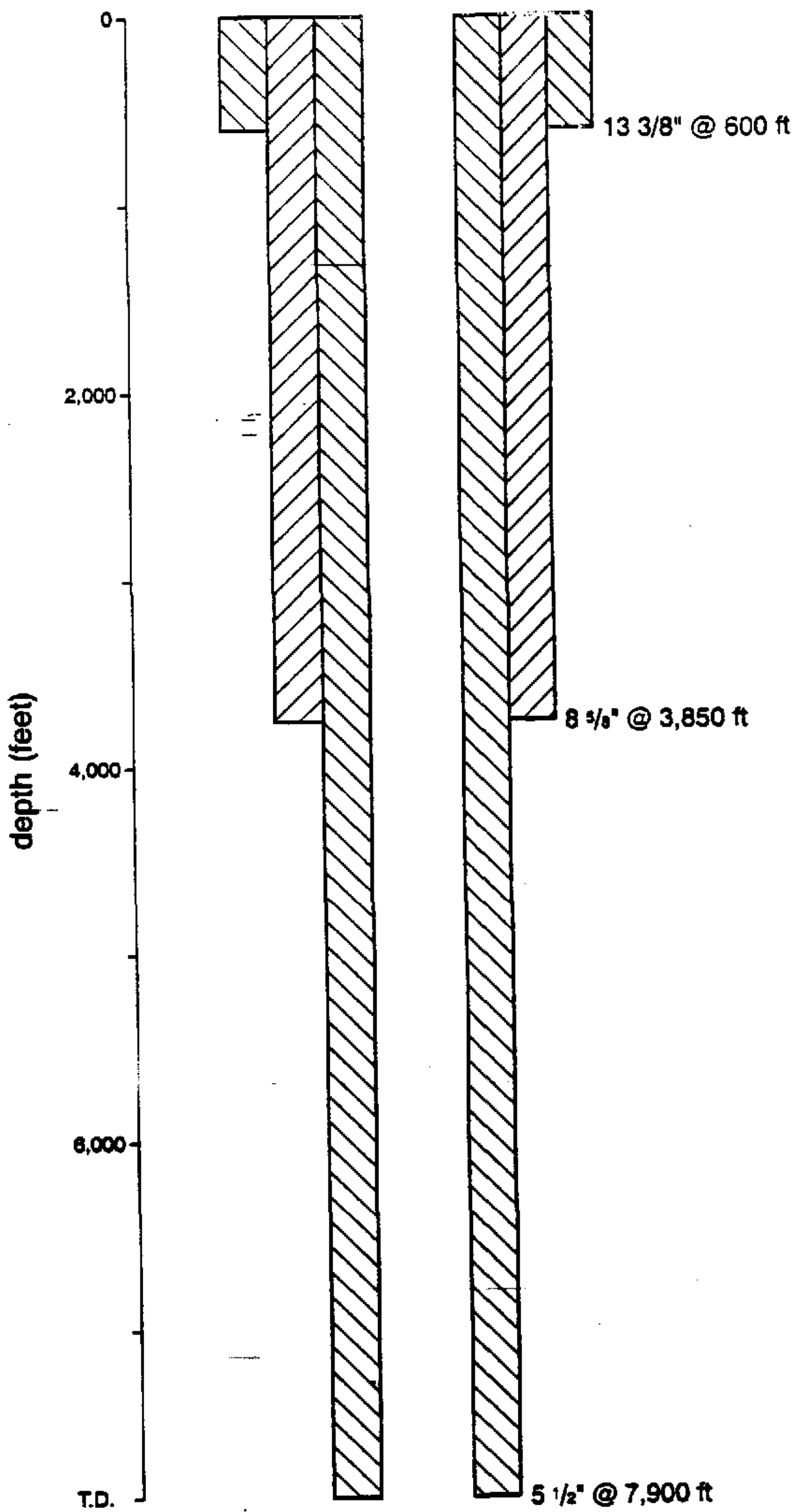


Figure 36. Casing program of a typical well producing from B zone of lower Brushy Canyon Formation, Quahada Ridge Southeast Delaware pool.

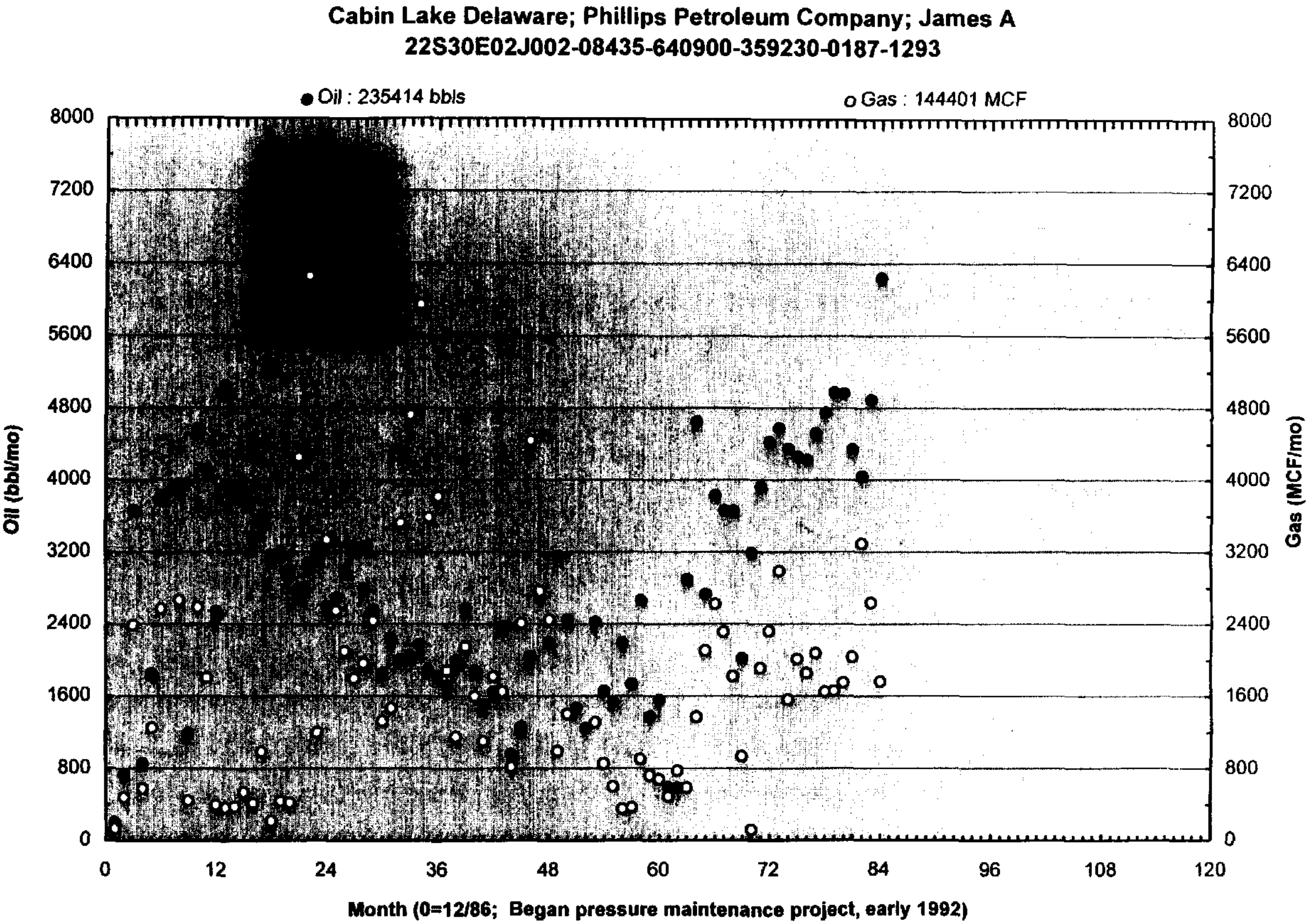


Figure 37. Historical monthly production of oil and gas, Phillips Petroleum Company No. 2 James A well, Cabin Lake Delaware pool.

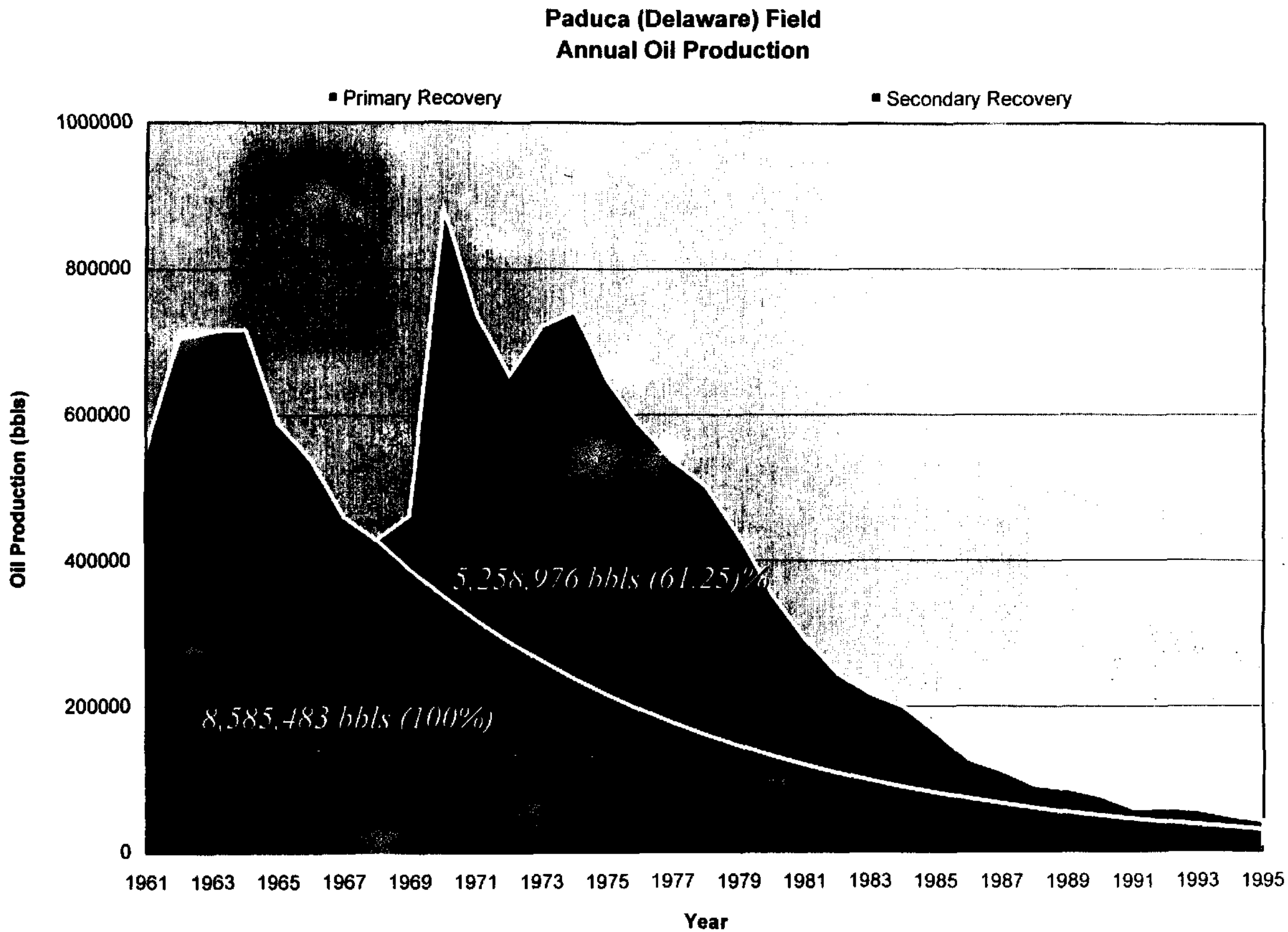


Figure 38. Annual production history of Paduca Delaware pool, with production curves for primary and secondary (waterflood) recovery projected into the future, and estimated ultimate oil recovery by primary and secondary means.

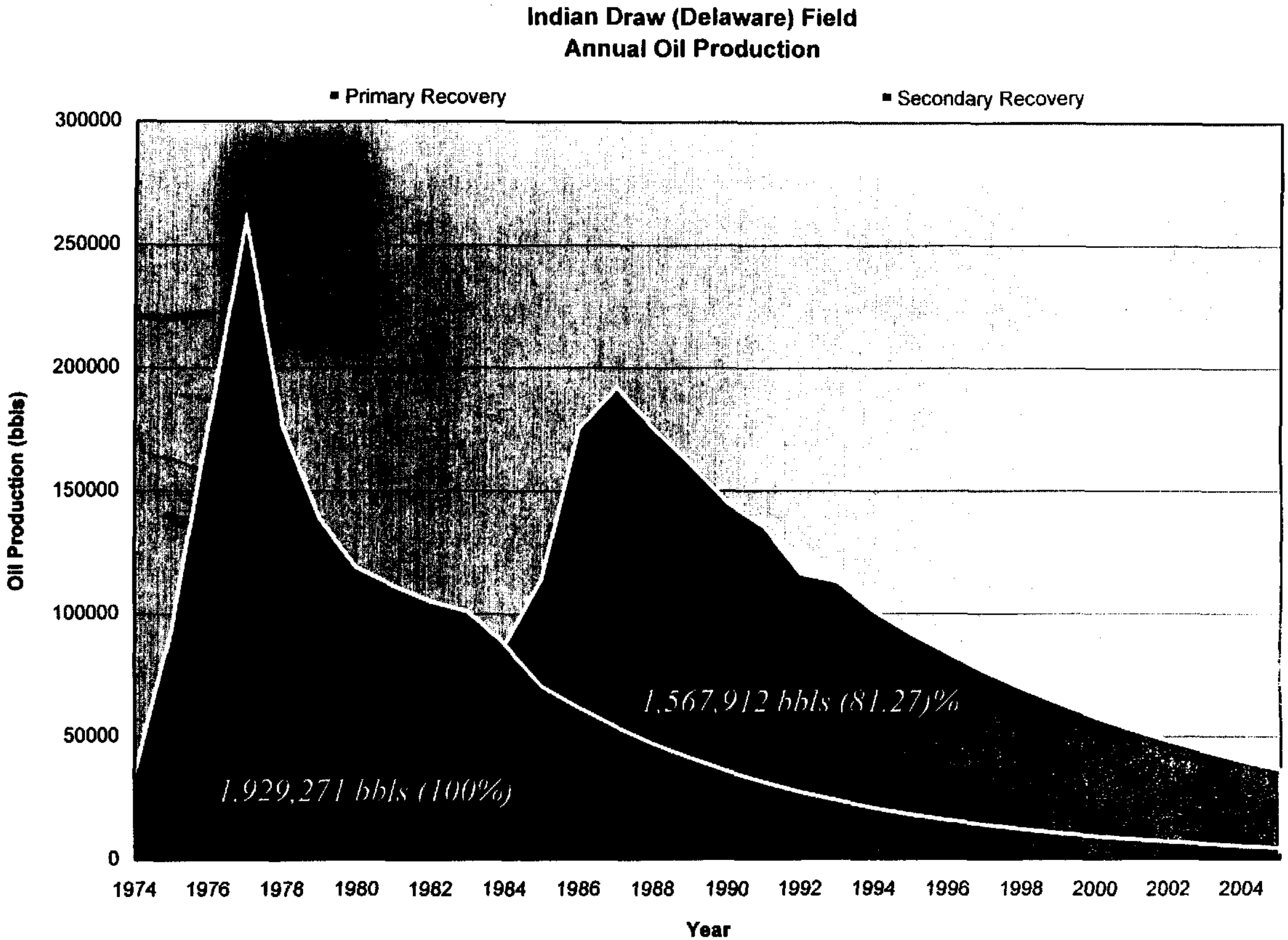


Figure 39. Annual production history of Indian Draw Delaware pool, with production curves for primary and secondary (waterflood) recovery projected into the future, and estimated ultimate oil recovery by primary and secondary means.

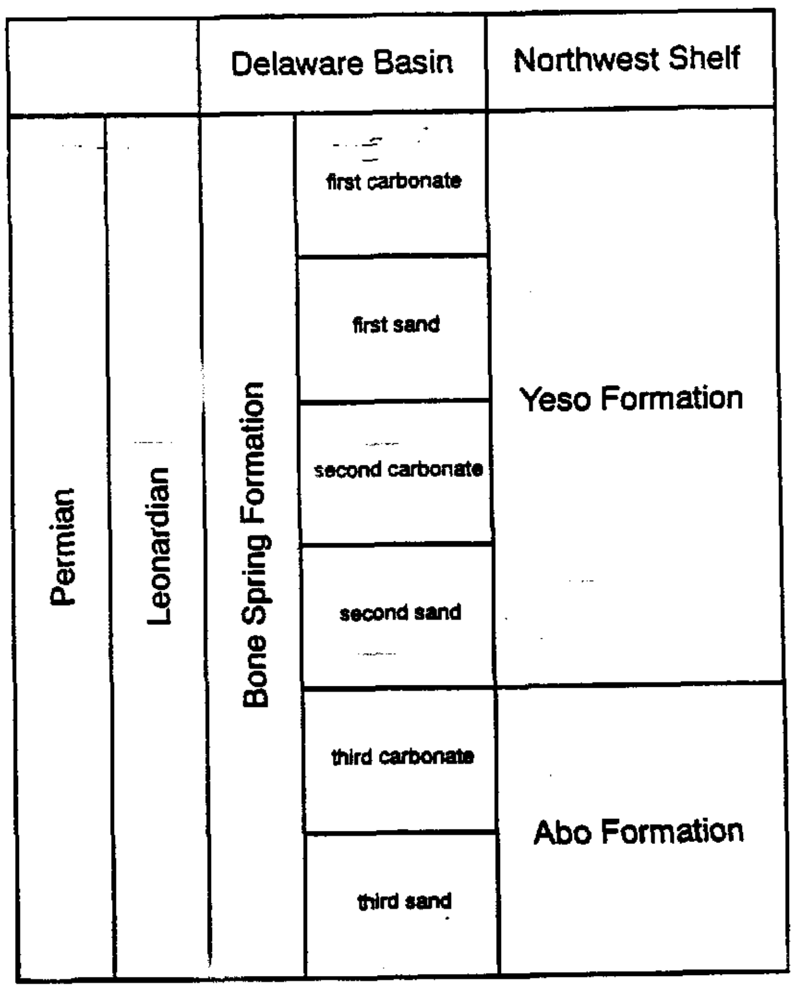
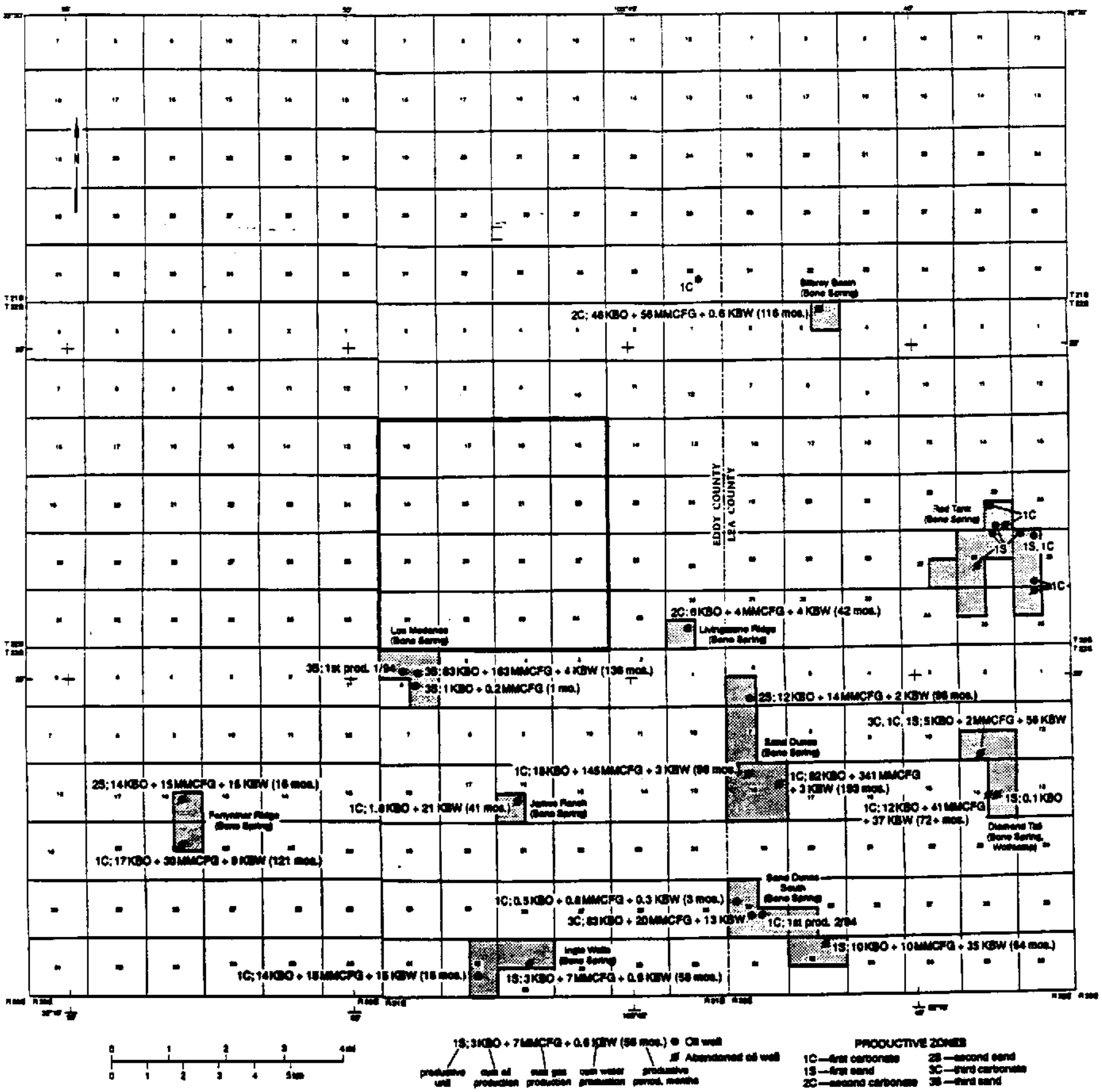
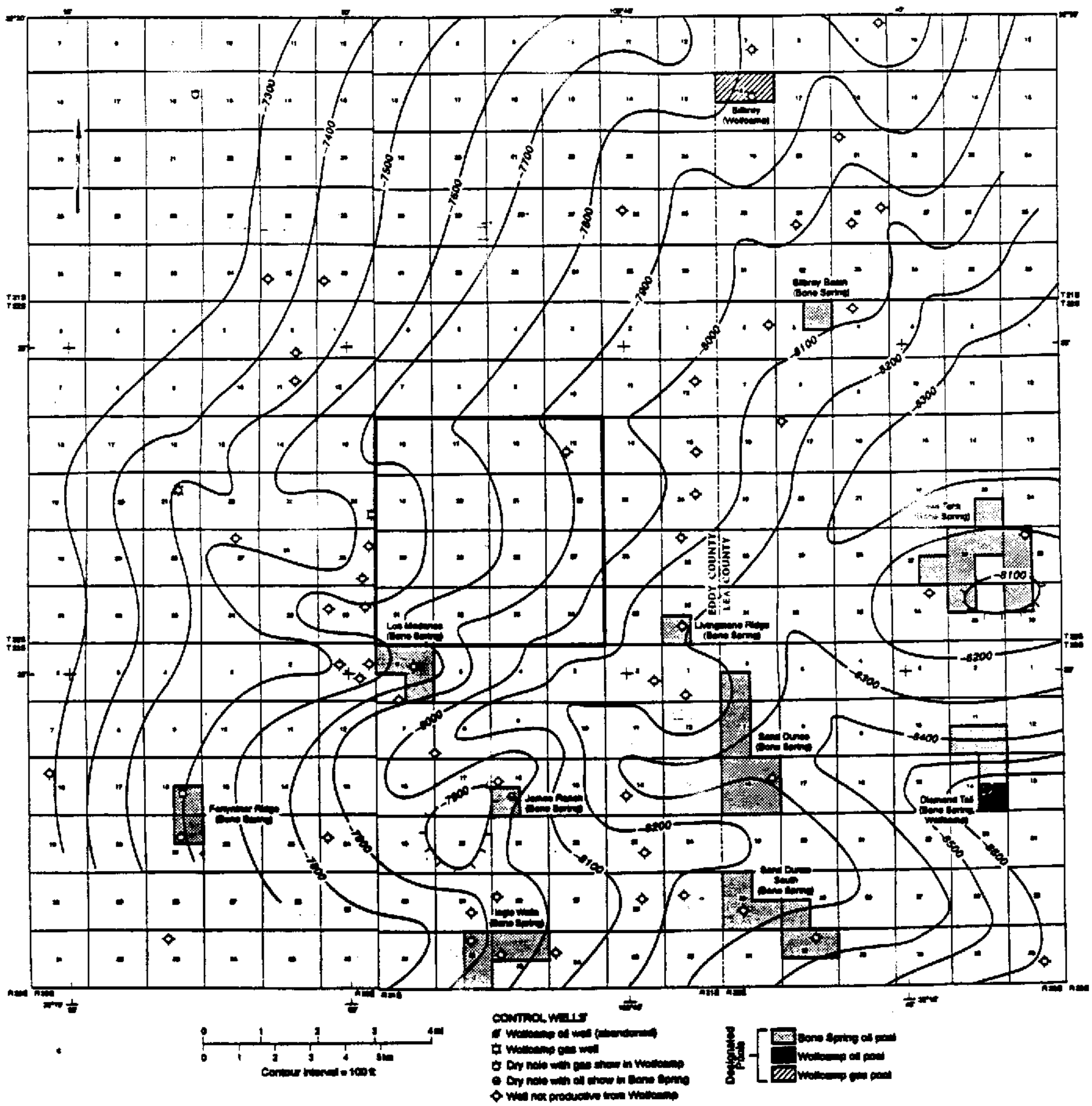


Figure 40. Stratigraphic column of the Bone Spring Formation in the Delaware Basin showing informal stratigraphic subdivisions and correlation with stratigraphic units on the Northwest shelf. From Broadhead (1993b), modified from Gawloski (1987) and Saller et al. (1989).



Bone Spring Pools, Production, and Shows

Figure 41. Cumulative production from wells producing from Bone Spring Formation and boundaries of designated Bone Spring oil pools. Shown are the stratigraphic units in the Bone Spring (Fig. 38) from which production is obtained.



Wolfcamp Structure, Production, & Shows

Figure 42. Structure on top of Wolfcamp Group and location of designated Bone Spring and Wolfcamp oil and gas pools.

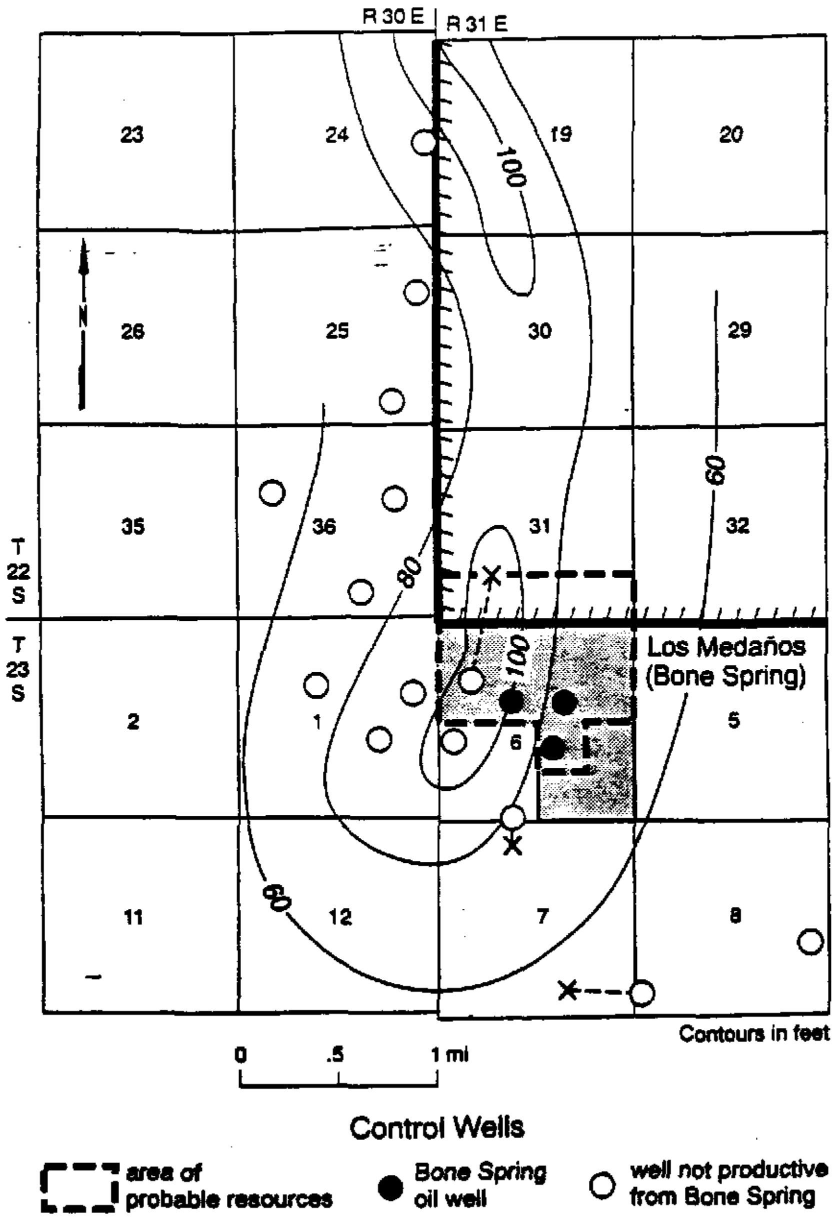


Figure 43. Isopach map of pay zone at Los Medanos Bone Spring pool and projected extent of possible oil and associated gas resources under WIPP site and one-mile-wide additional study area.

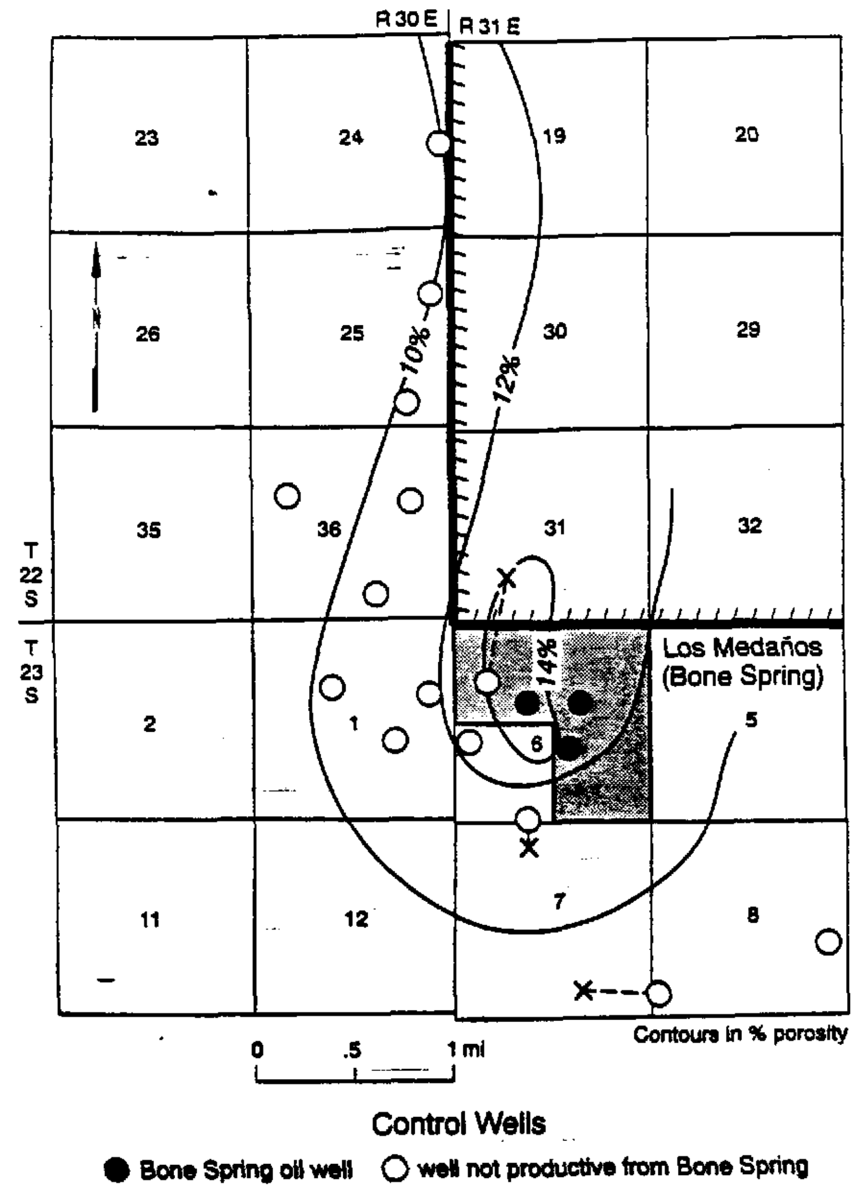


Figure 44. Isoporosity map of average root mean square of neutron and density porosities in pay zone, Los Medanos Bone Spring pool.

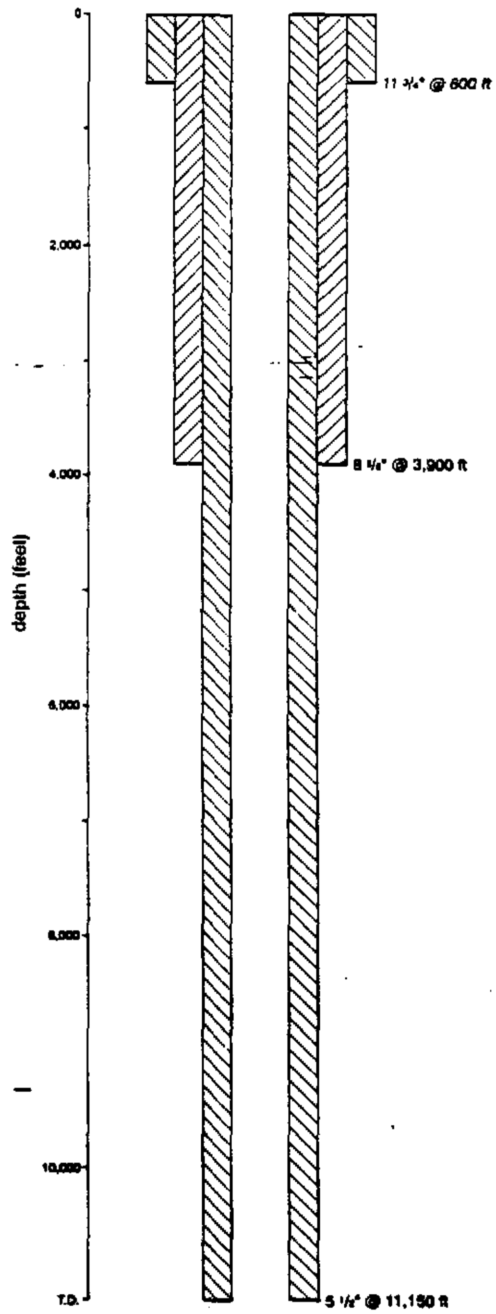
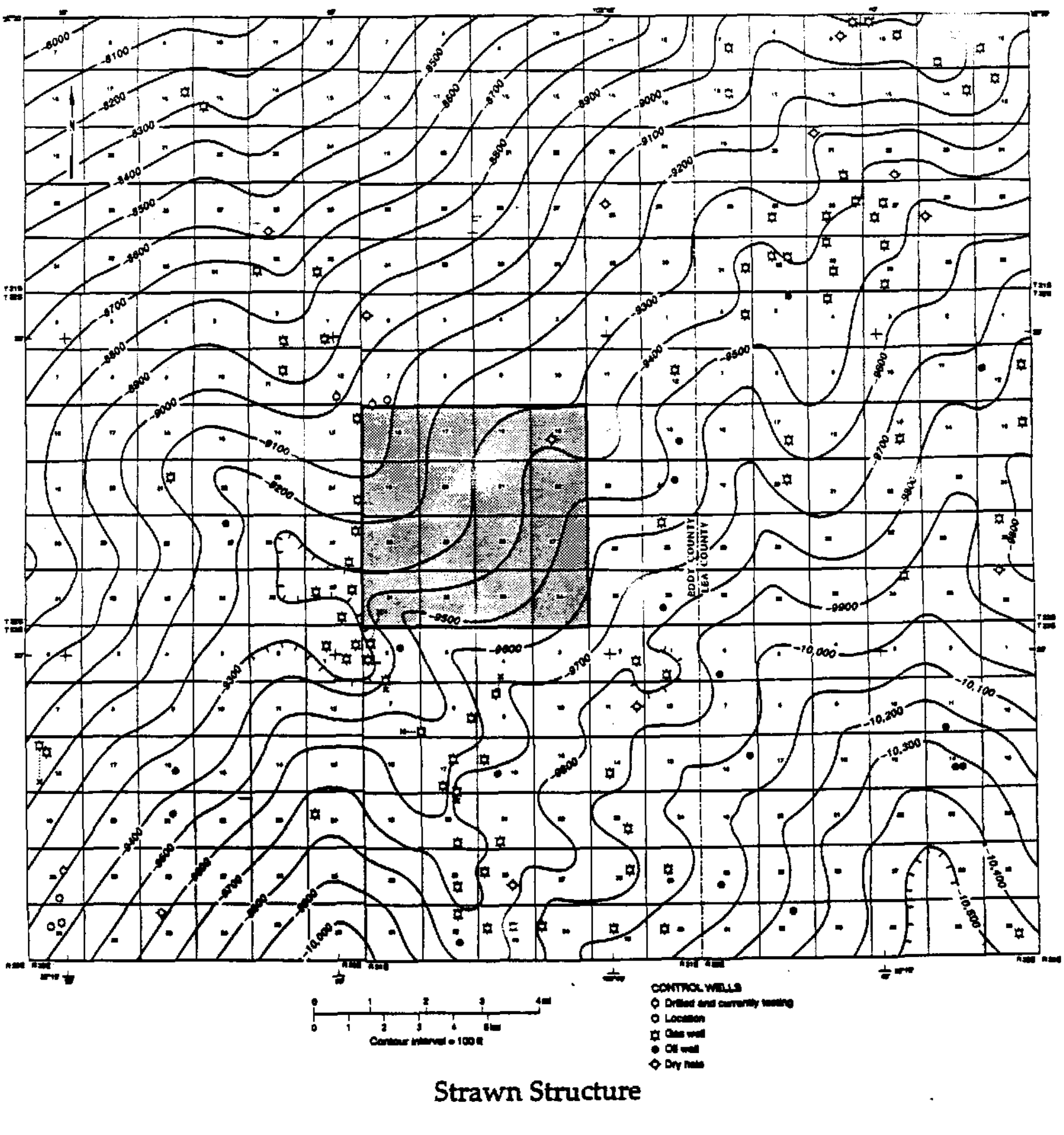
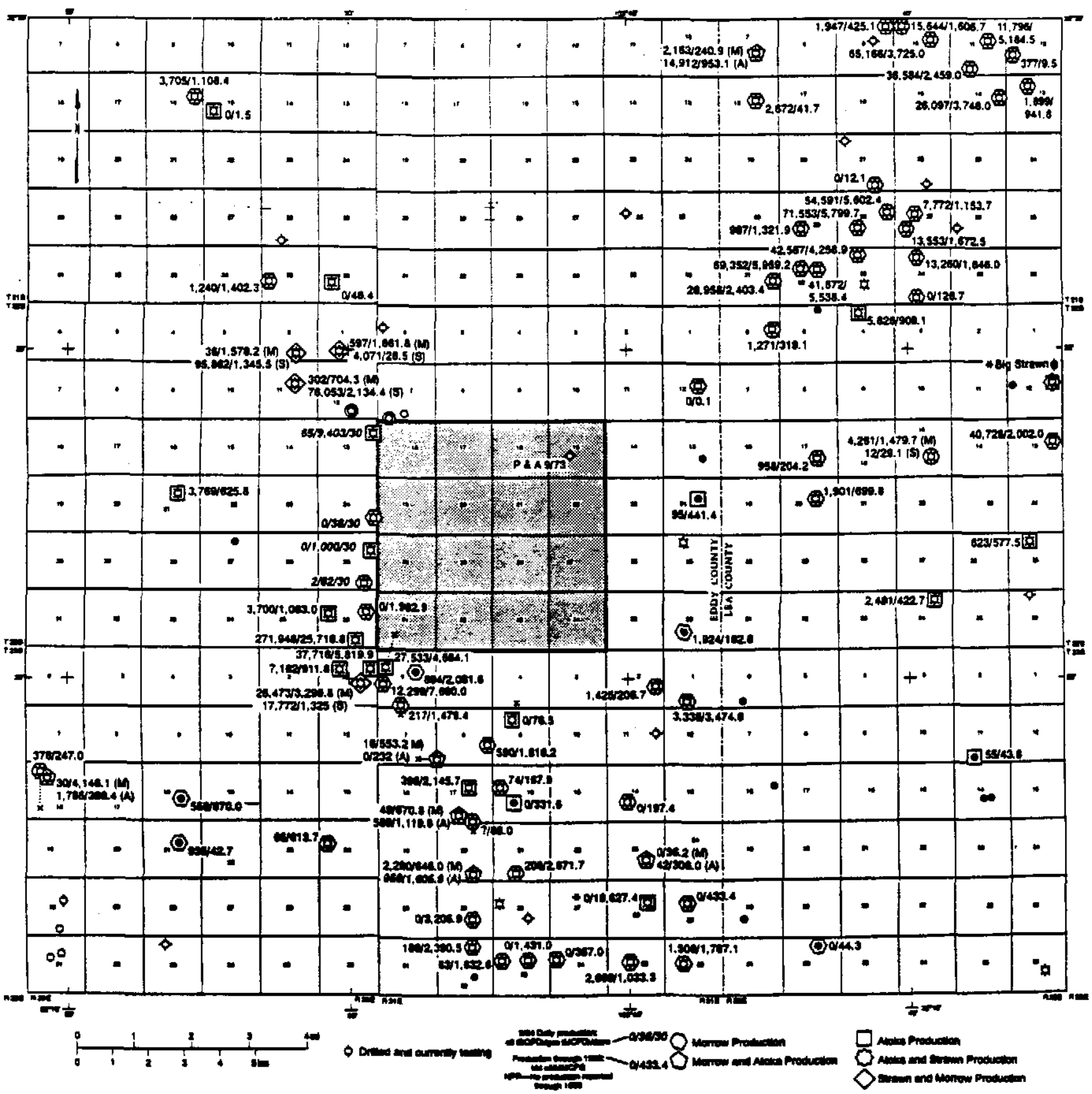


Figure 45. Casing program of a typical well in Los Medanos Bone Spring pool.



Strawn Structure

Figure 46. Structure contour map of top of Strawn Group.



Pennsylvanian Production

Figure 47. Cumulative oil, gas, and gas condensate production as of December 31, 1993 for wells producing from pre-Permian reservoirs.

Cabin Lake Strawn; Phillips Petroleum Company; James E
22S30E11G001-08440-640900-359260-0374-1289

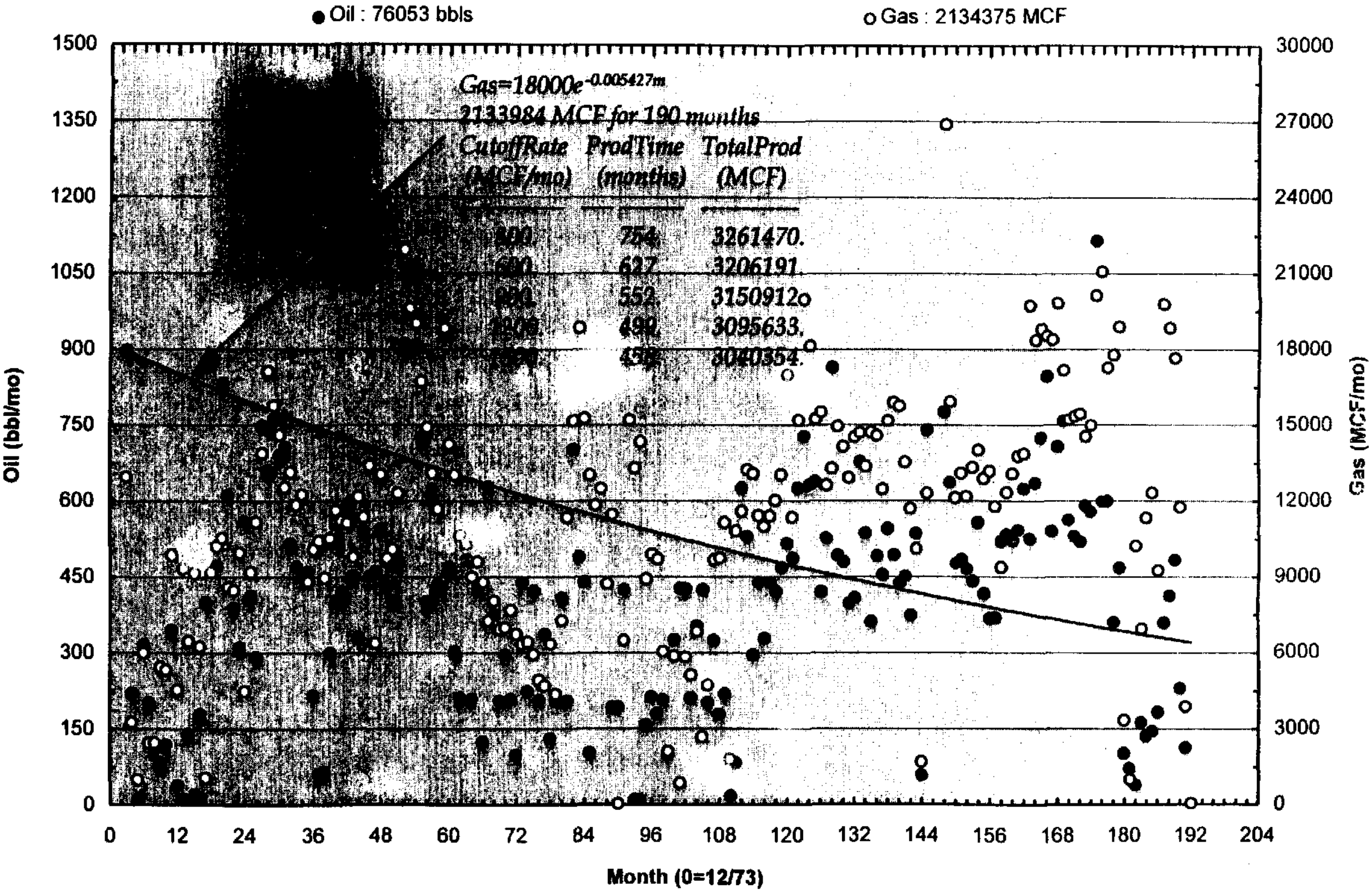


Figure 48. Typical gas production decline curve for wells producing from Strawn Group, WIPP site area.

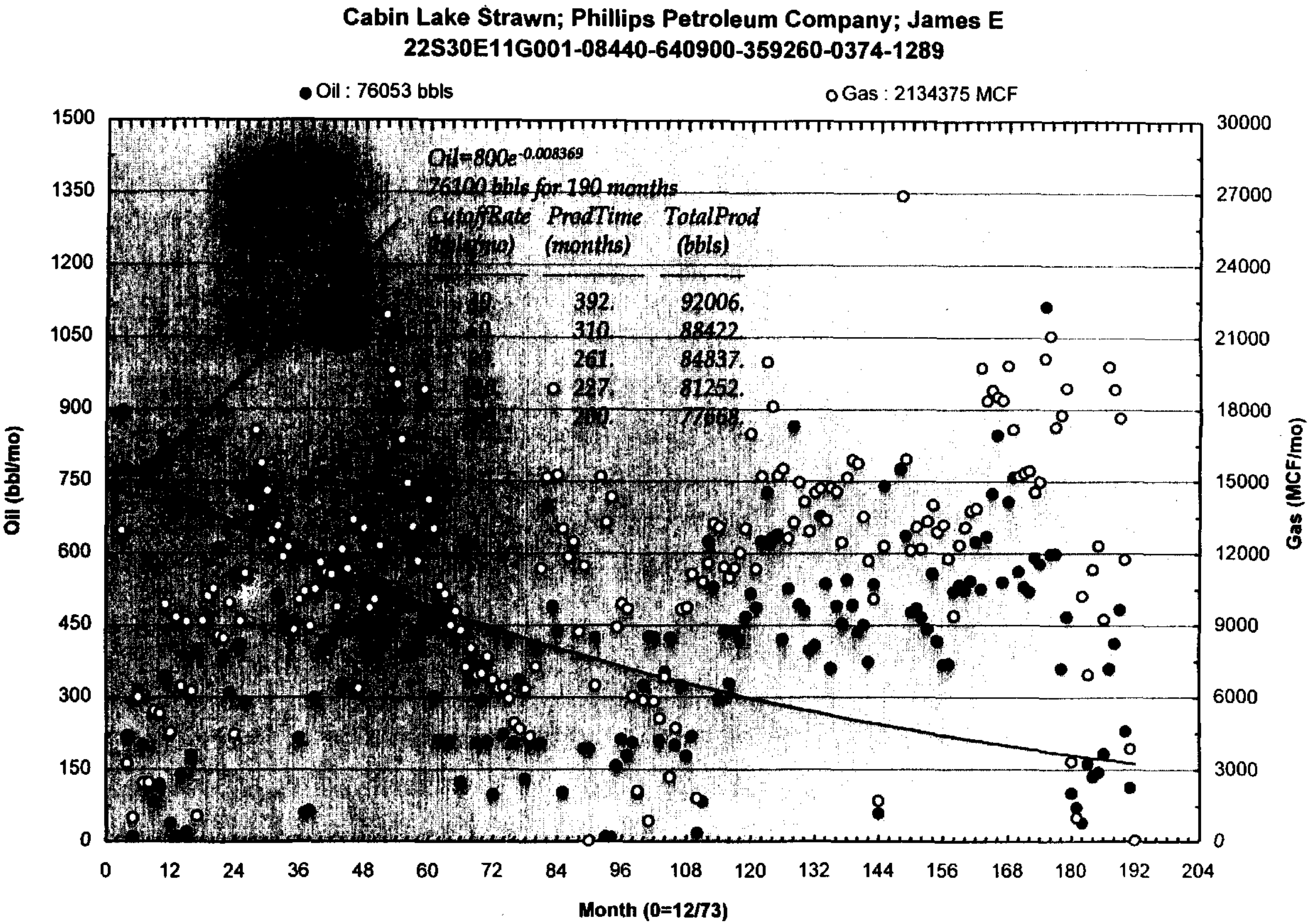
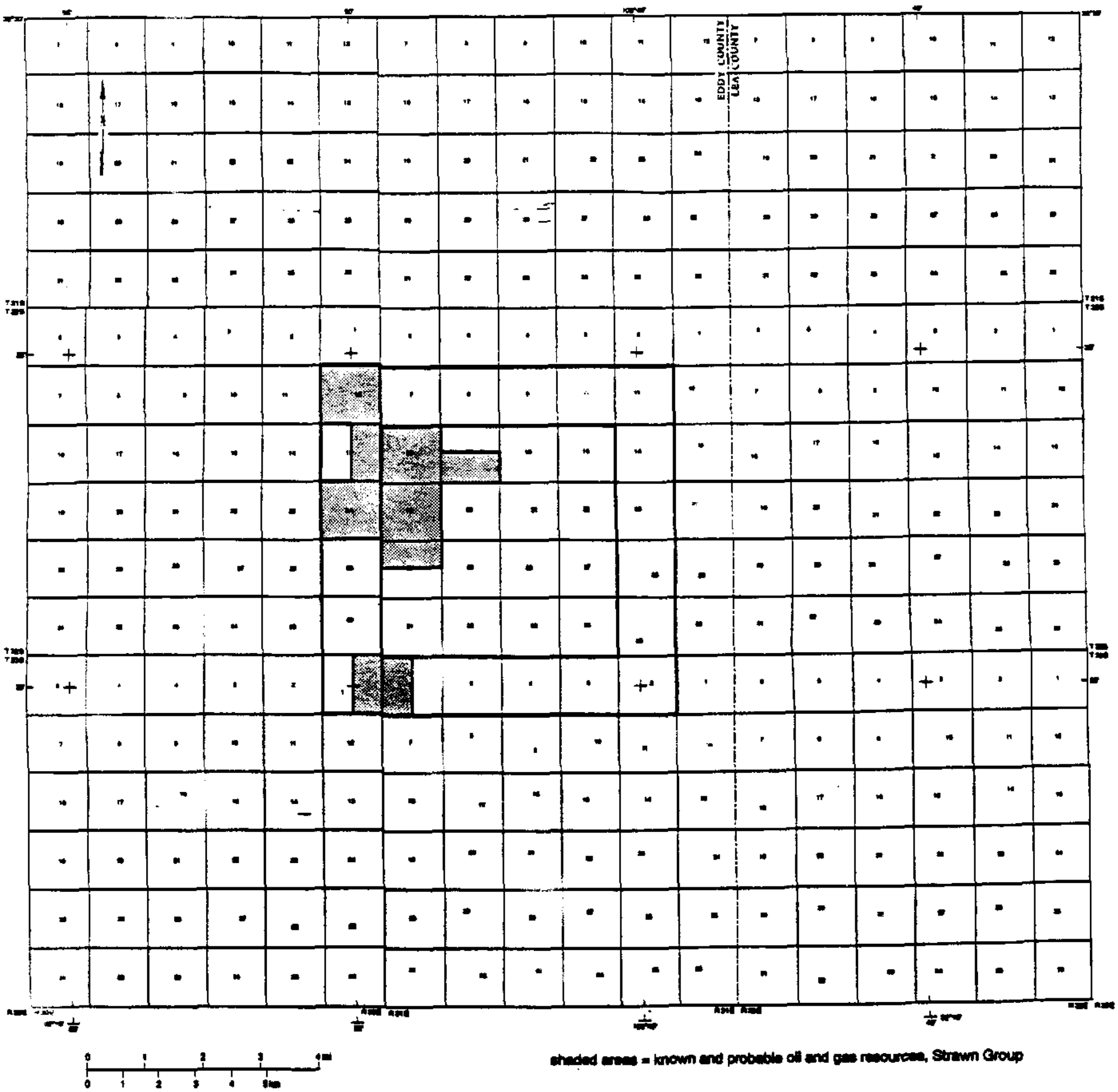


Figure 49. Typical oil production decline curve for wells producing from Strawn Group, WIPP site area.



Strawn Oil & Gas Resources

Figure 51. Areas of known and probable oil and gas resources within WIPP site and one-mile wide additional study area for Strawn pools projected to extend under the WIPP site.

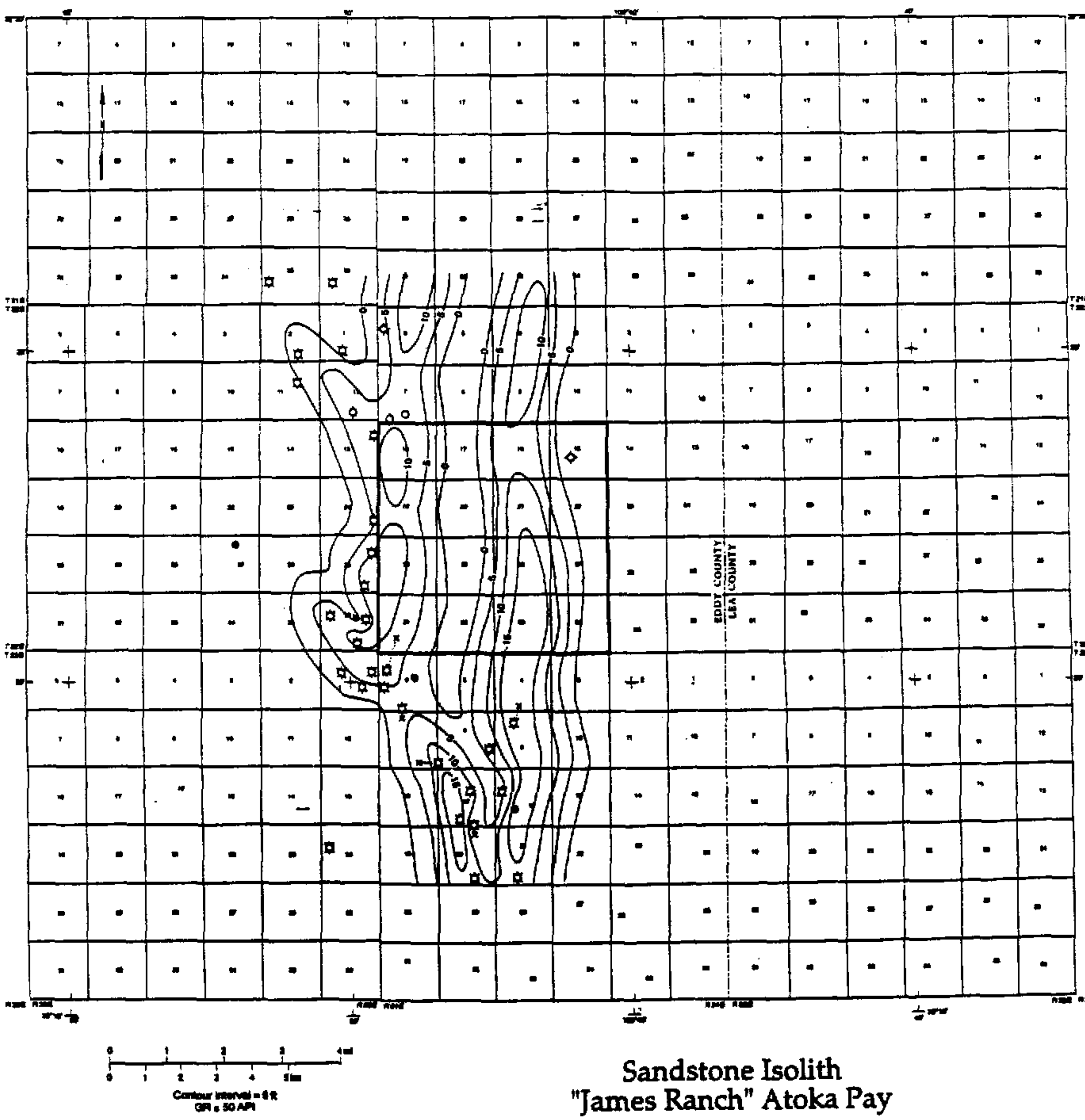


Figure 52. Sandstone isolith map, Atoka pay, WIPP site area.

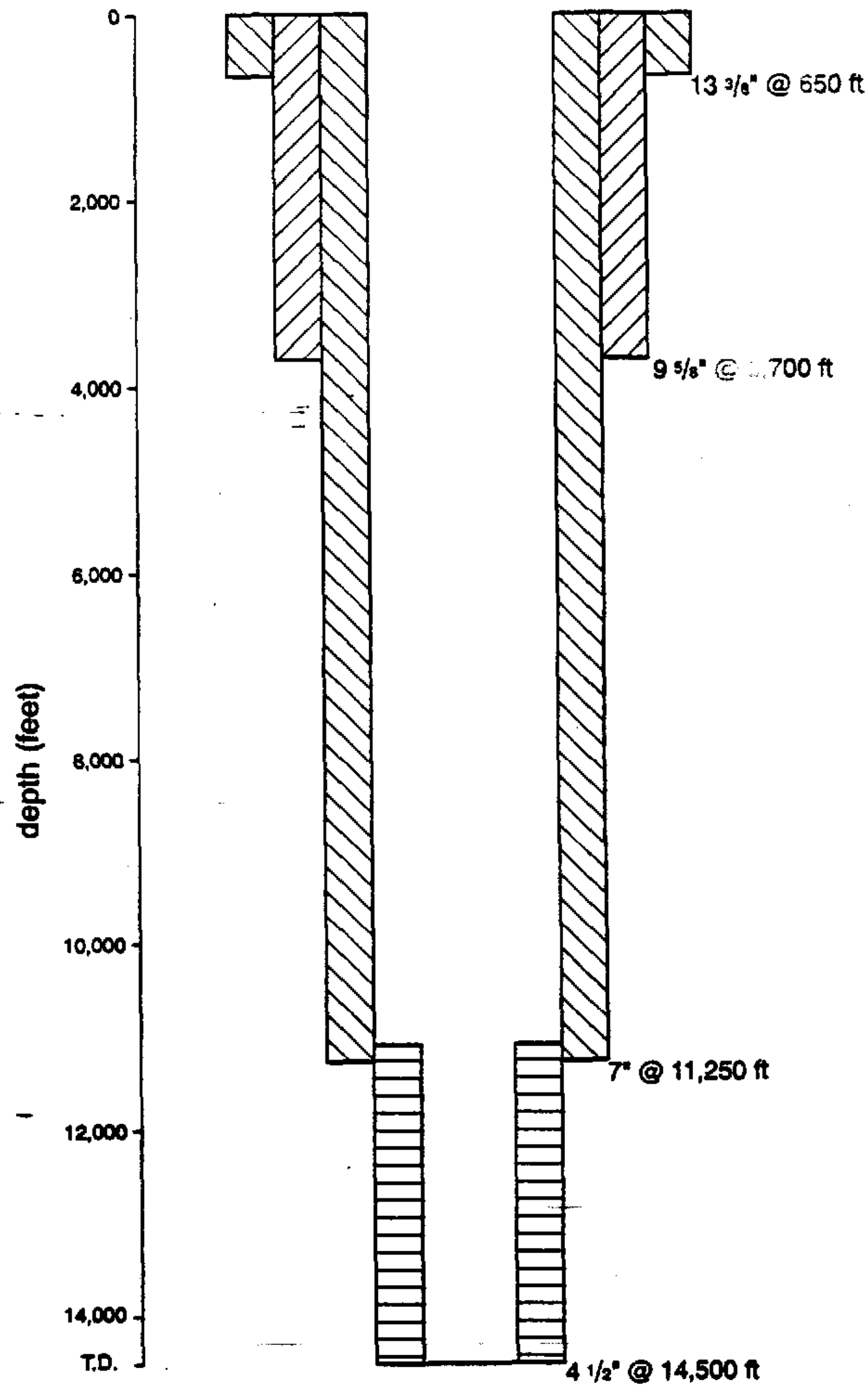
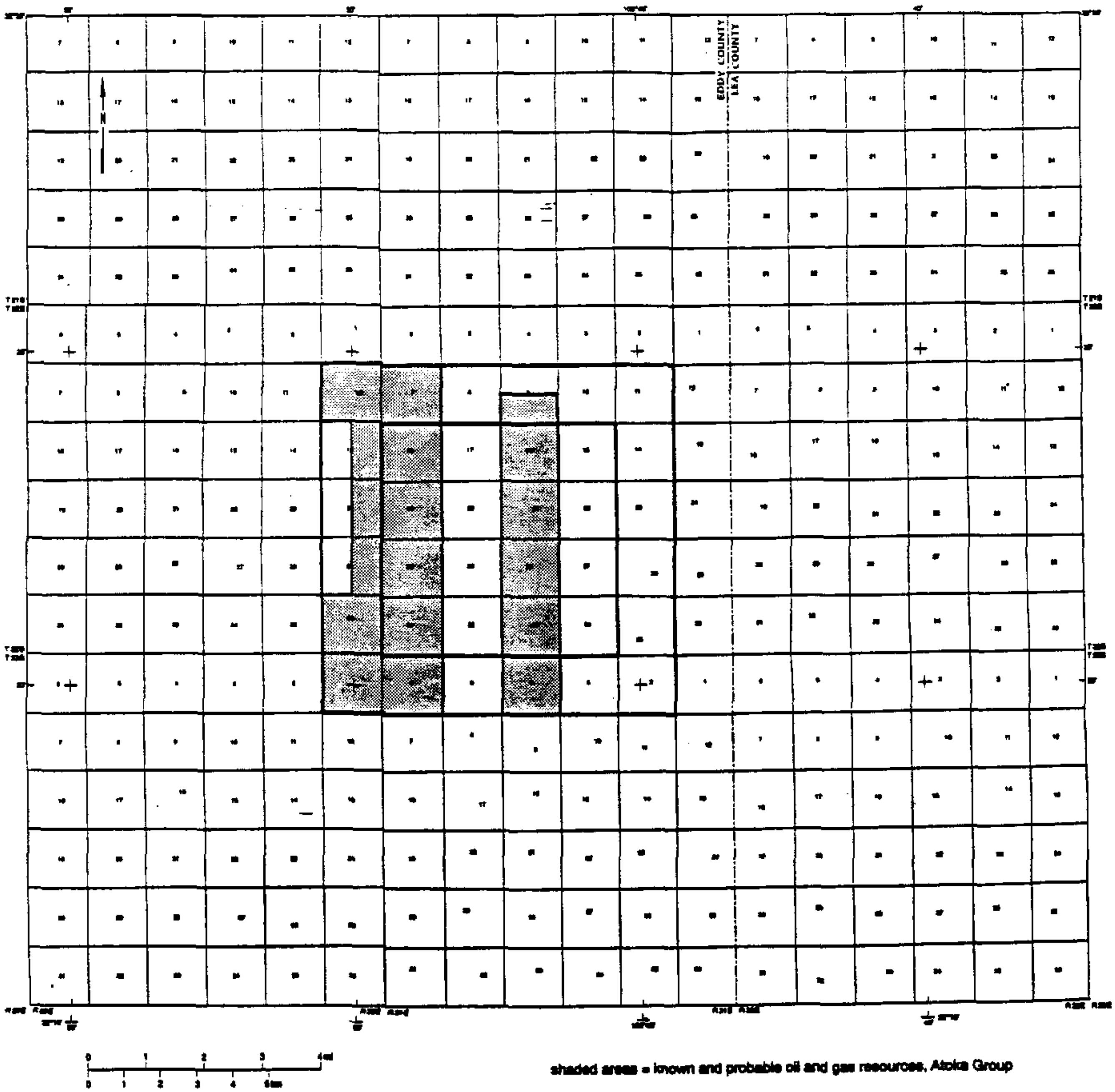


Figure 53. Casing program of a typical well producing from the Atoka or Morrow Groups, WIPP area.



Atoka Oil & Gas Resources

Figure 54. Areas of known and probable oil and gas resources within WIPP site and one-mile-wide additional study area for Atoka pools projected to extend under the WIPP site.

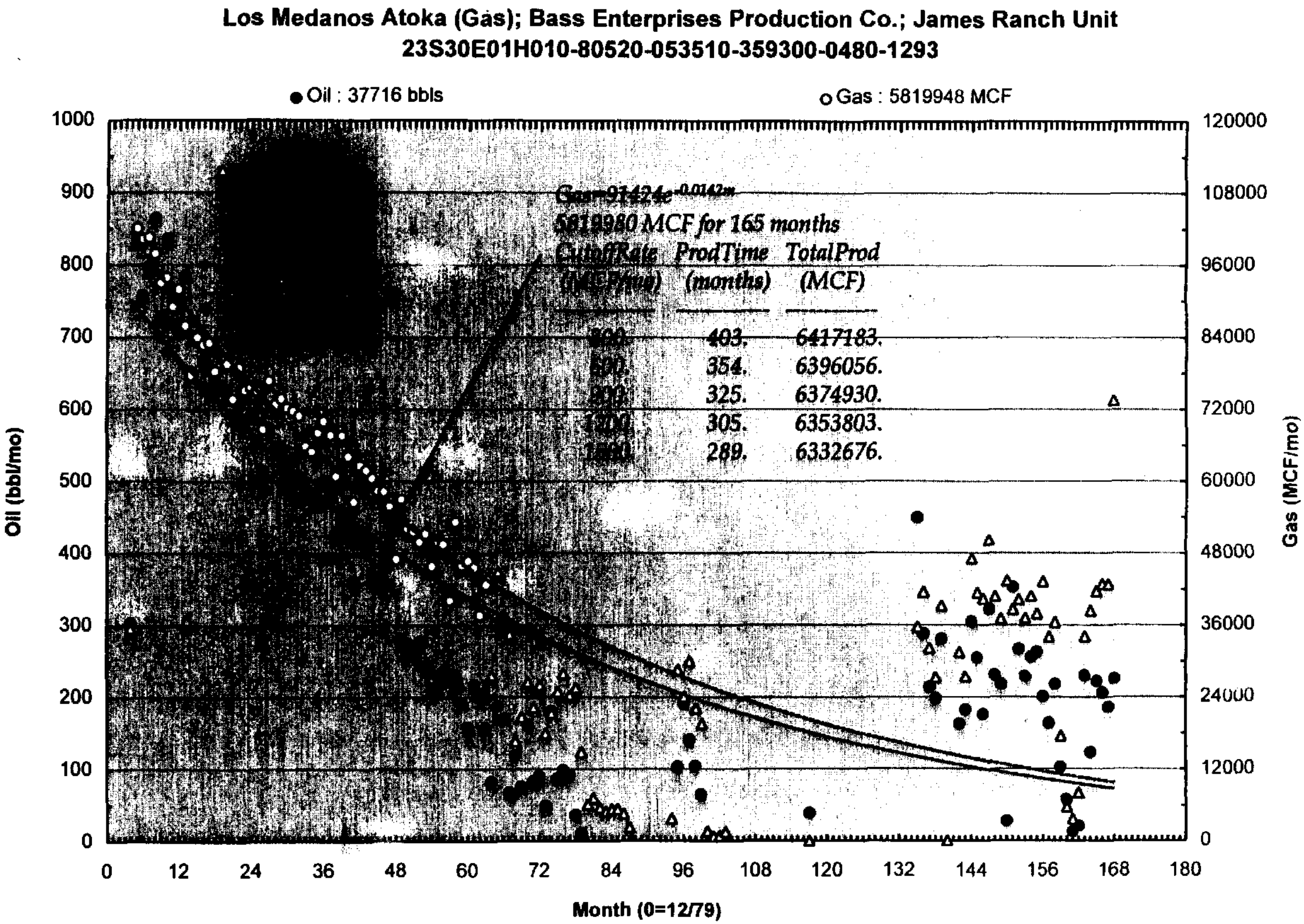
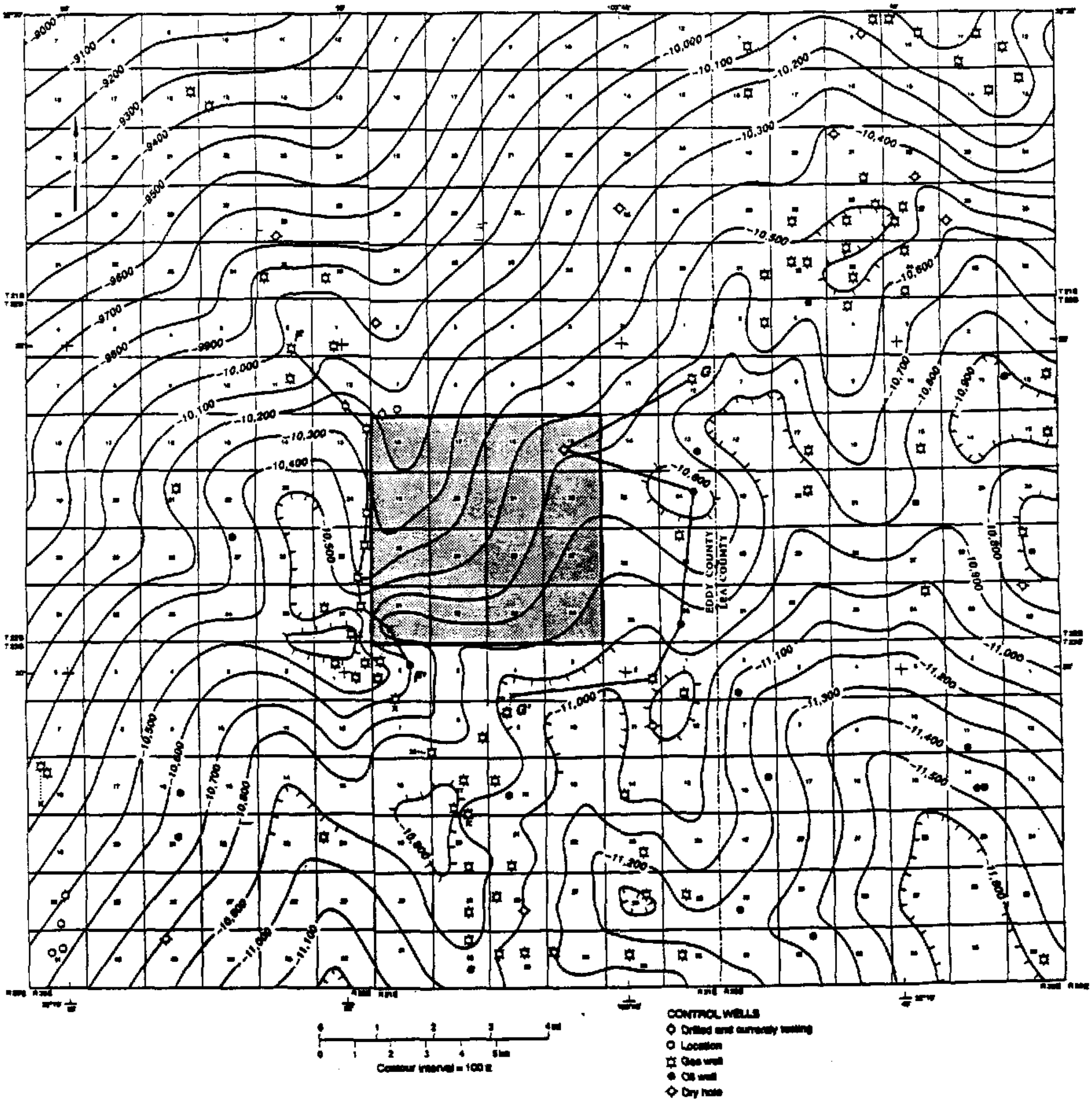


Figure 55. Typical gas production decline curve for wells producing from Atoka Group, WIPP site area.



Morrow Clastics Structure

Figure 57. Structure contour map of top of Morrow clastic interval.

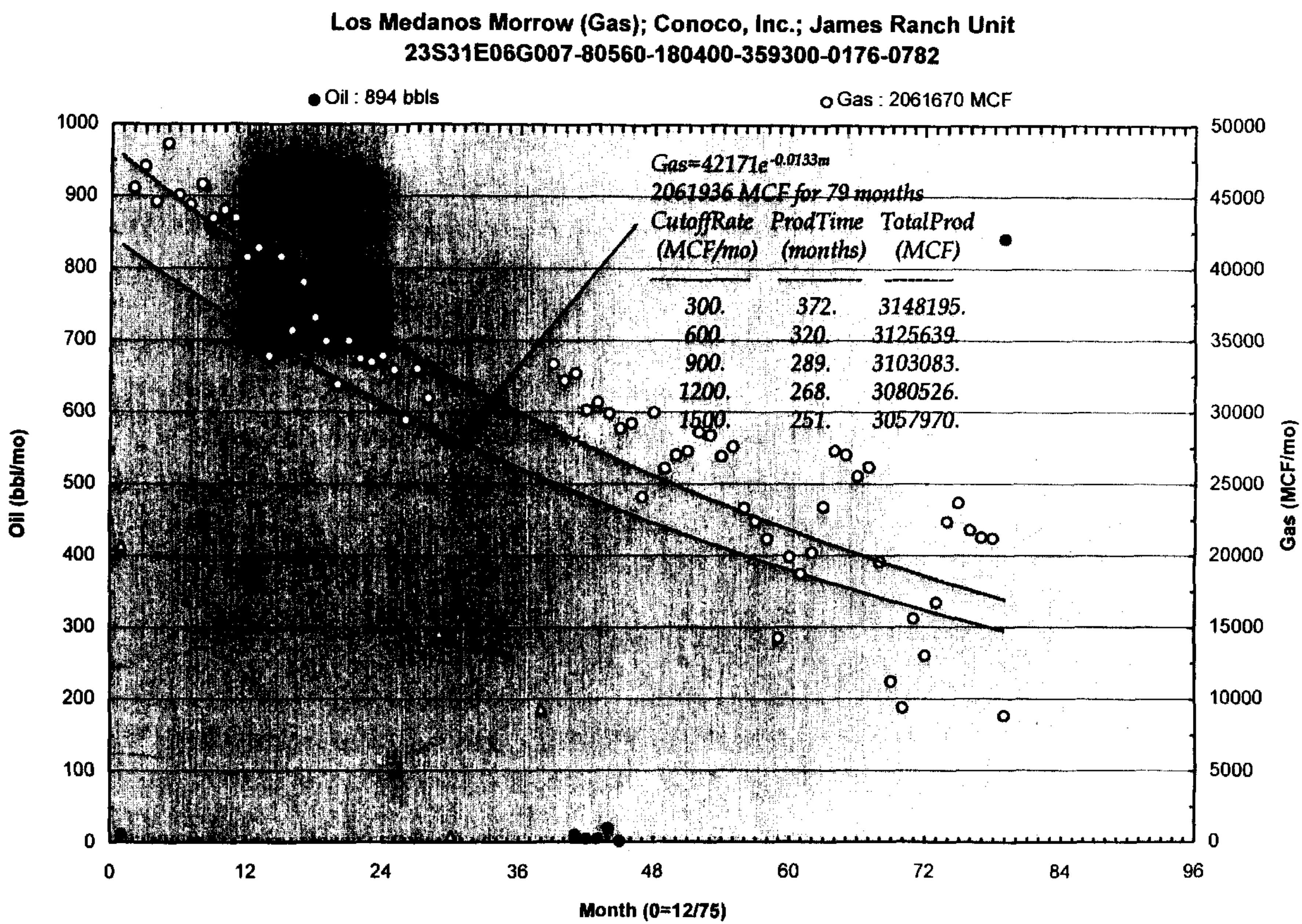
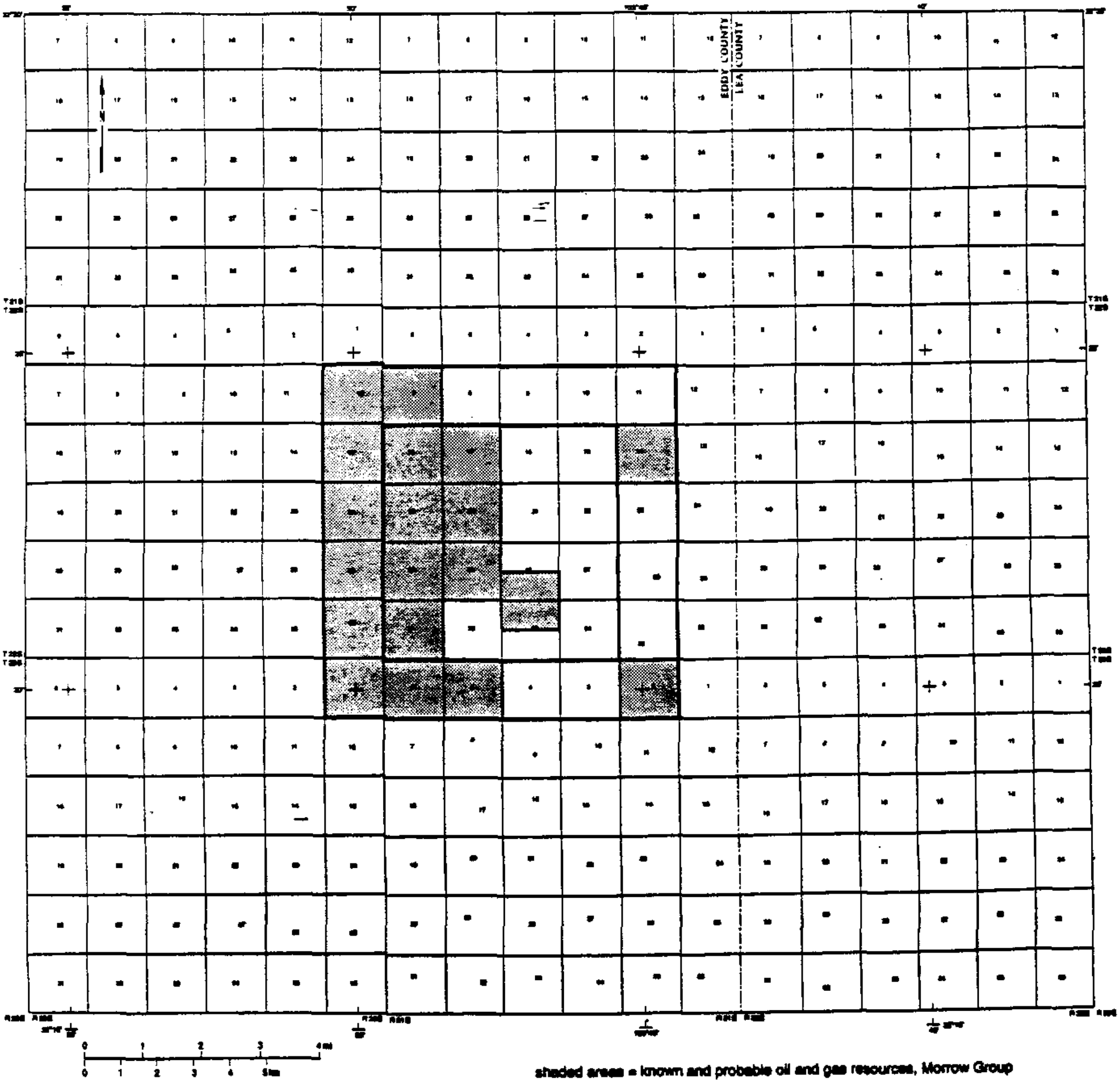
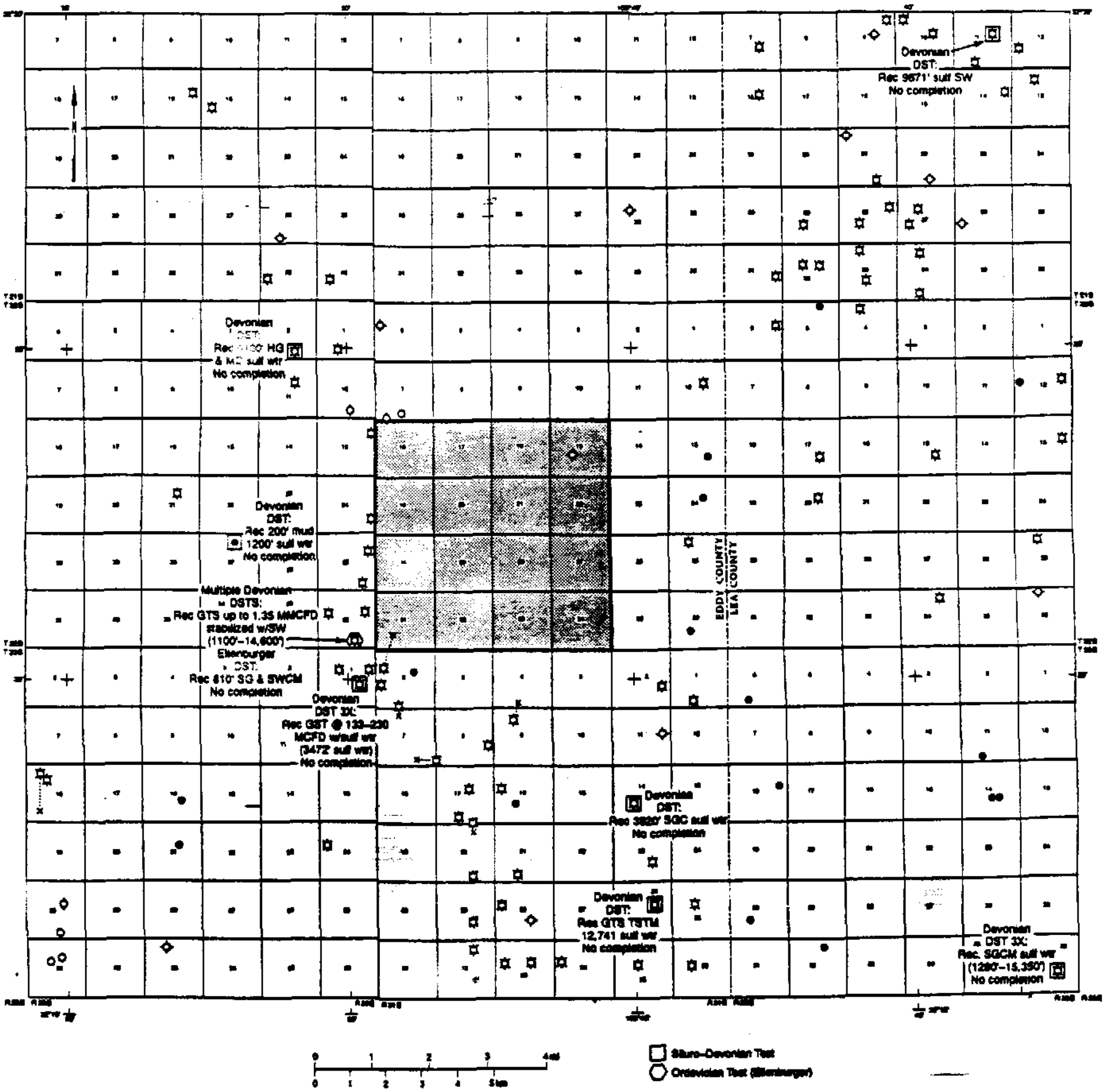


Figure 58. Typical gas production decline curve for wells producing from Morrow Group, WIPP site area.



Morrow Oil & Gas Resources

Figure 59. Areas of known and probable oil and gas resources within WIPP site and one-mile-wide additional study area for Morrow pools projected to extend under the WIPP site.



Deep Tests (Below Mississippian) and Test Results

Figure 60. Wells that have penetrated pre-Mississippian strata within the study area. **DST**, drill stem test; **Rec**, recovered; **HG&MCSW**, heavy gas- and mud-cut salt water; **sulf wtr**, sulphur water; **GTS**, gas to surface; **MMCFD**, million ft^3 per day; **SW**, salt water; **SG & SWCM**, slight gas- and salt water-cut mud; **SGC**, slight gas-cut; **SGCM**, slight gas-cut mud.

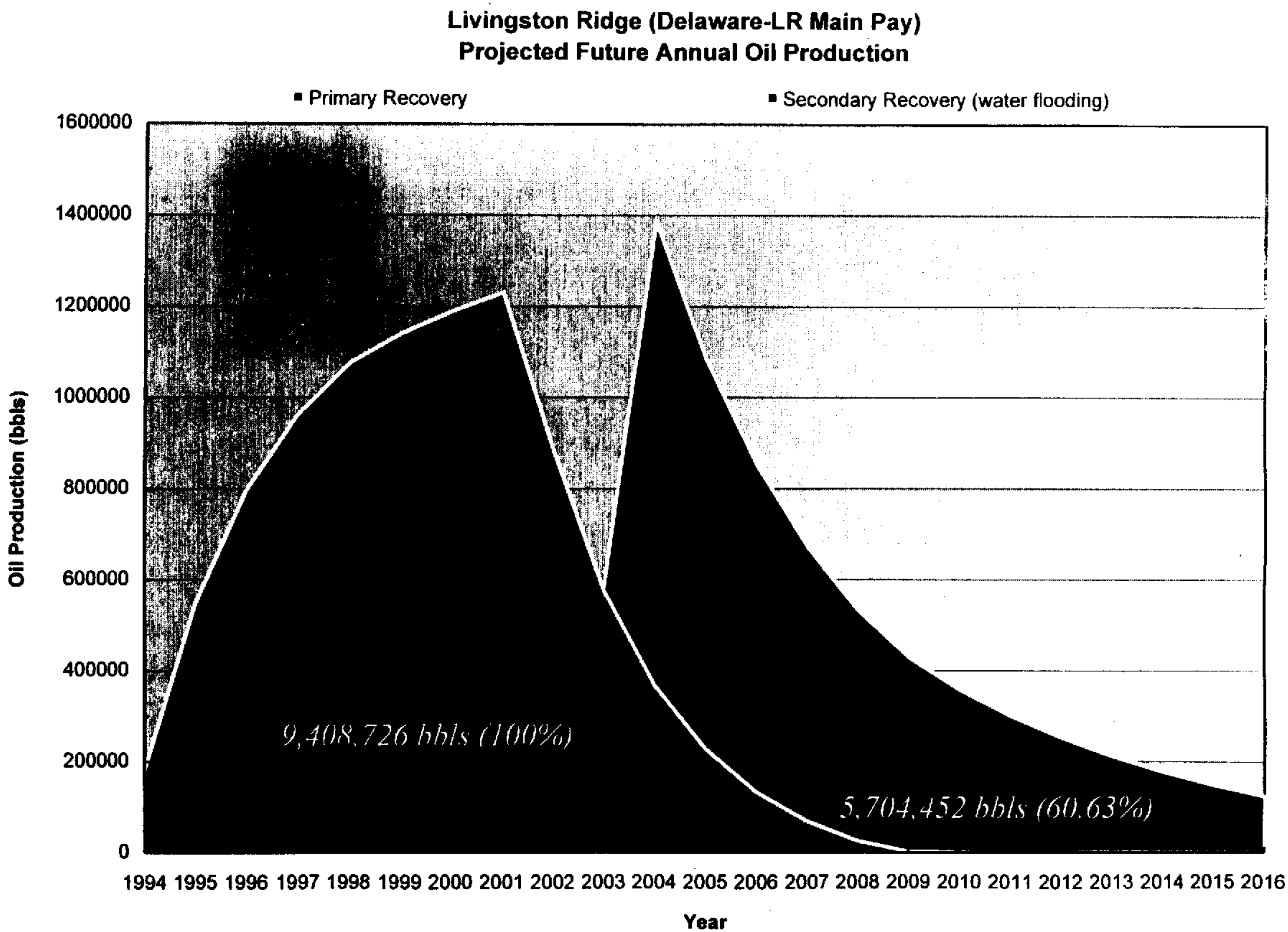


Figure 61. Projected future annual oil production from upper Brushy Canyon main pay, Livingston Ridge-Lost Tank pools for WIPP land withdrawal area and surrounding one-mile wide additional study area.

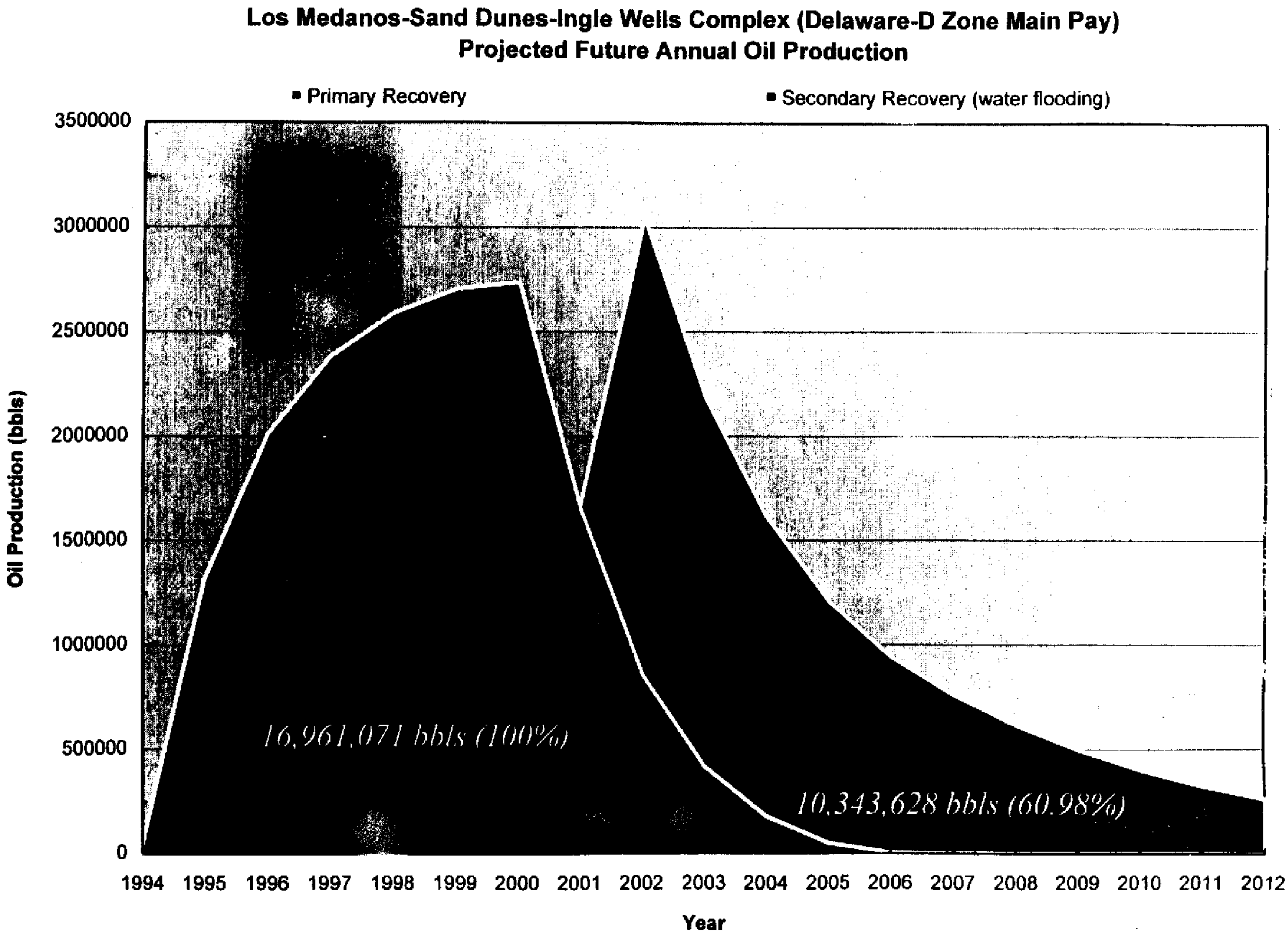


Figure 62. Projected future annual oil production from lower Brushy Canyon D zone, Los Medanos Delaware complex for WIPP land withdrawal area and surrounding one-mile wide additional study area.

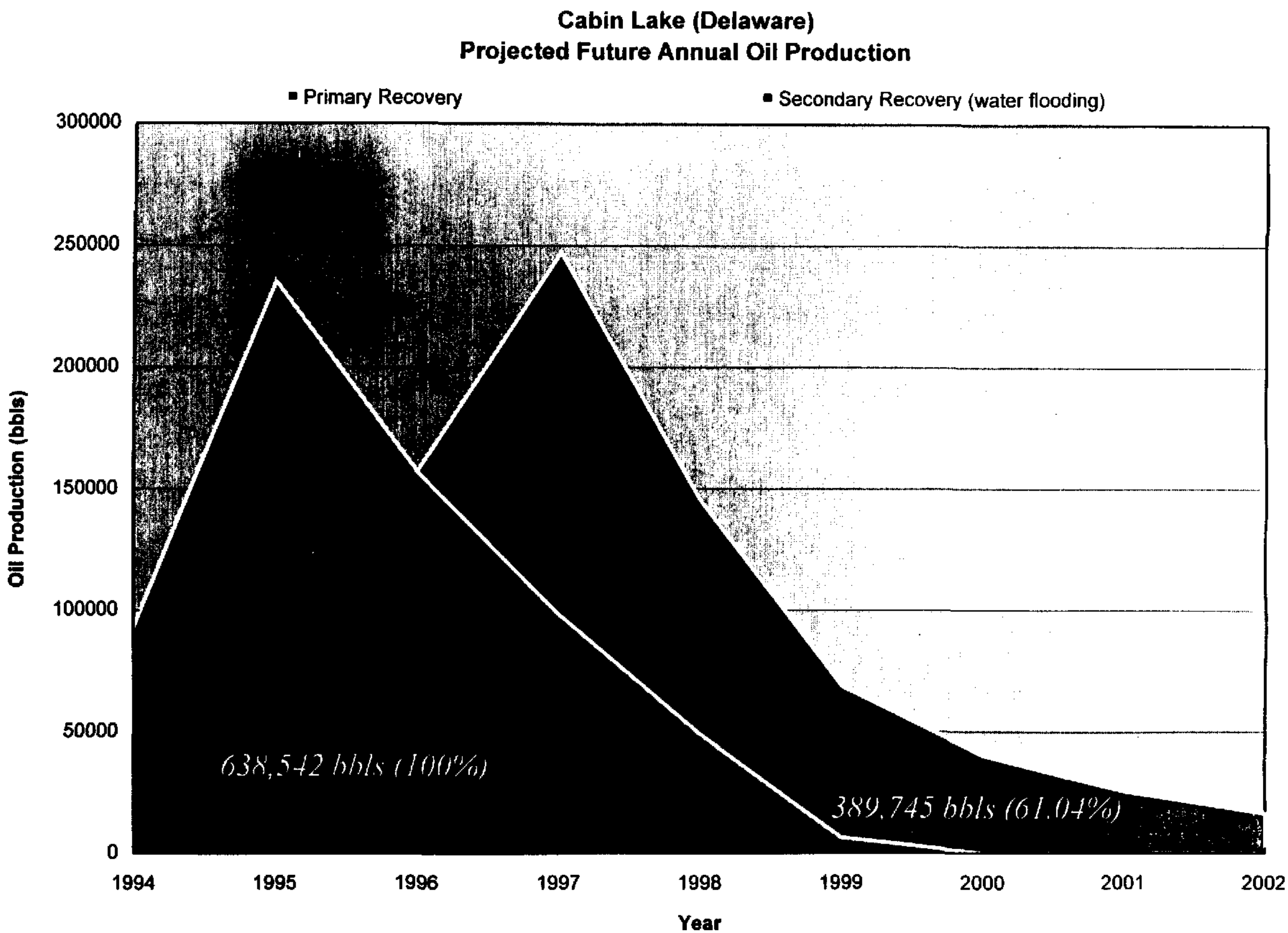


Figure 63. Projected future annual oil production from lower Brushy Canyon B zone, Cabin Lake Delaware pool for WIPP land withdrawal area and surrounding one-mile wide additional study area.

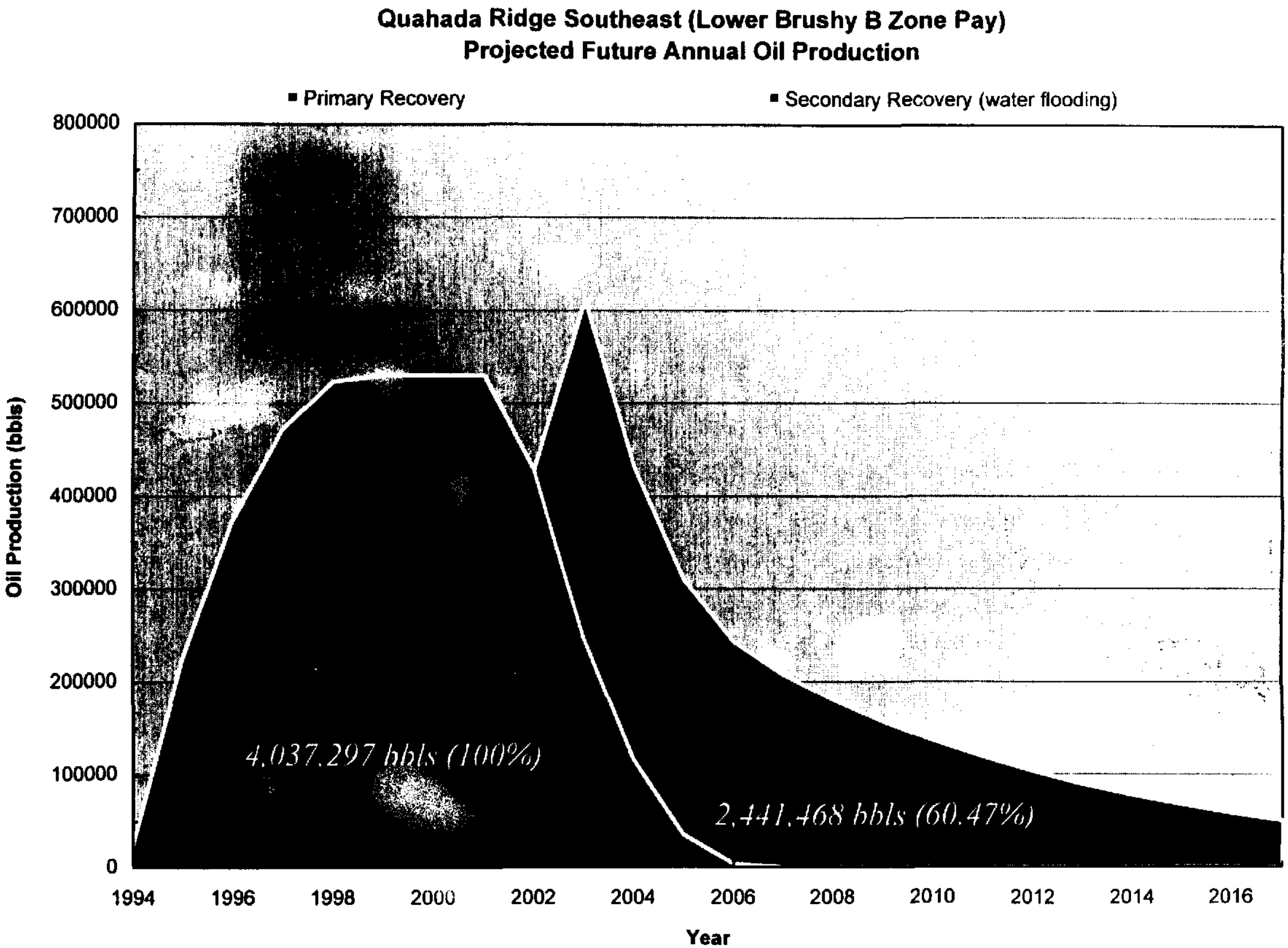


Figure 64. Projected future annual oil production from lower Brushy Canyon B zone, Quahada Ridge Southeast pool for WIPP land withdrawal area and surrounding one-mile wide additional study area.

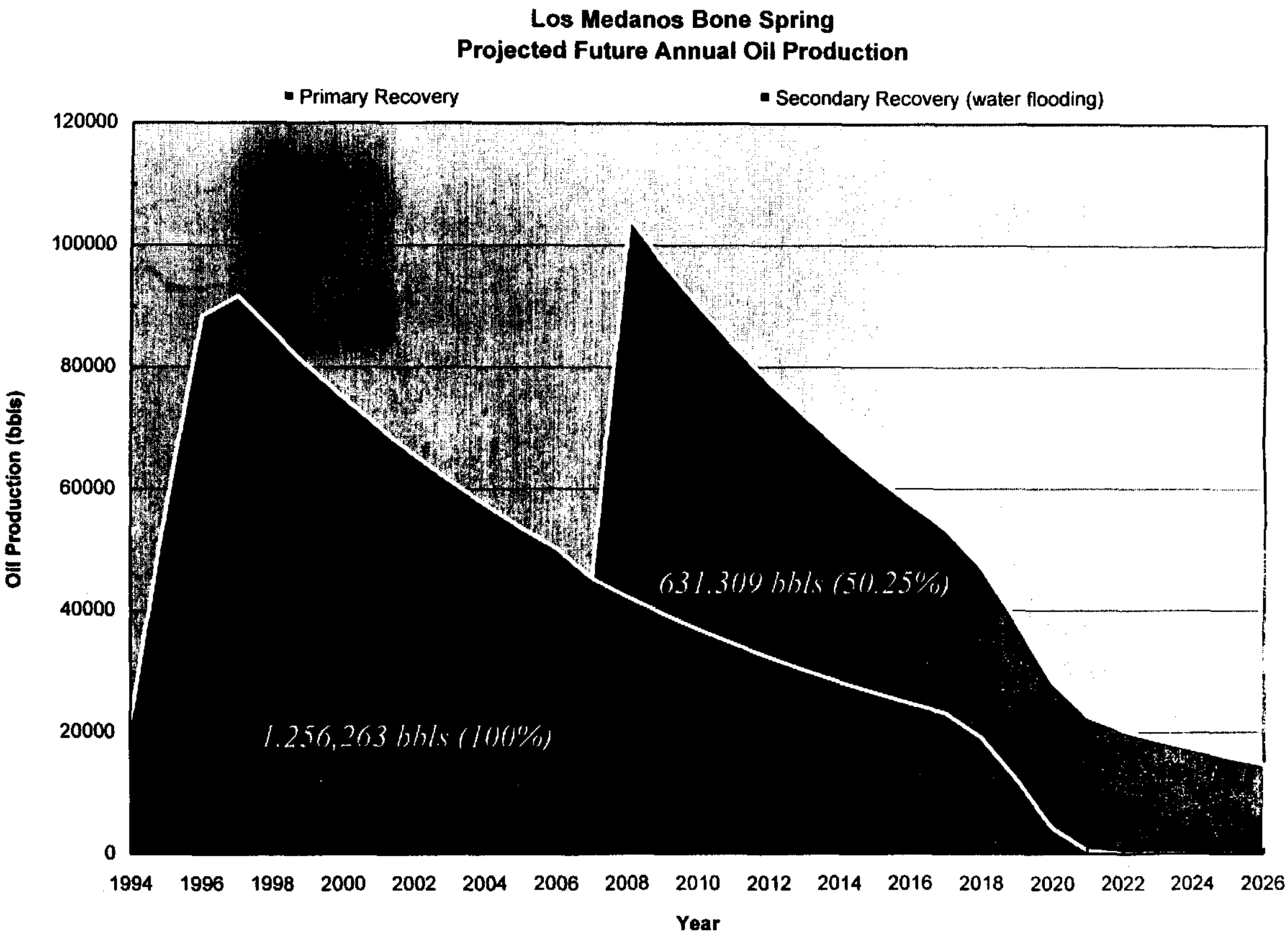


Figure 65. Projected future annual oil production from Third Bone Spring sandstone, Los Medanos Bone Spring pool for WIPP land withdrawal area and surrounding one-mile wide additional study area.

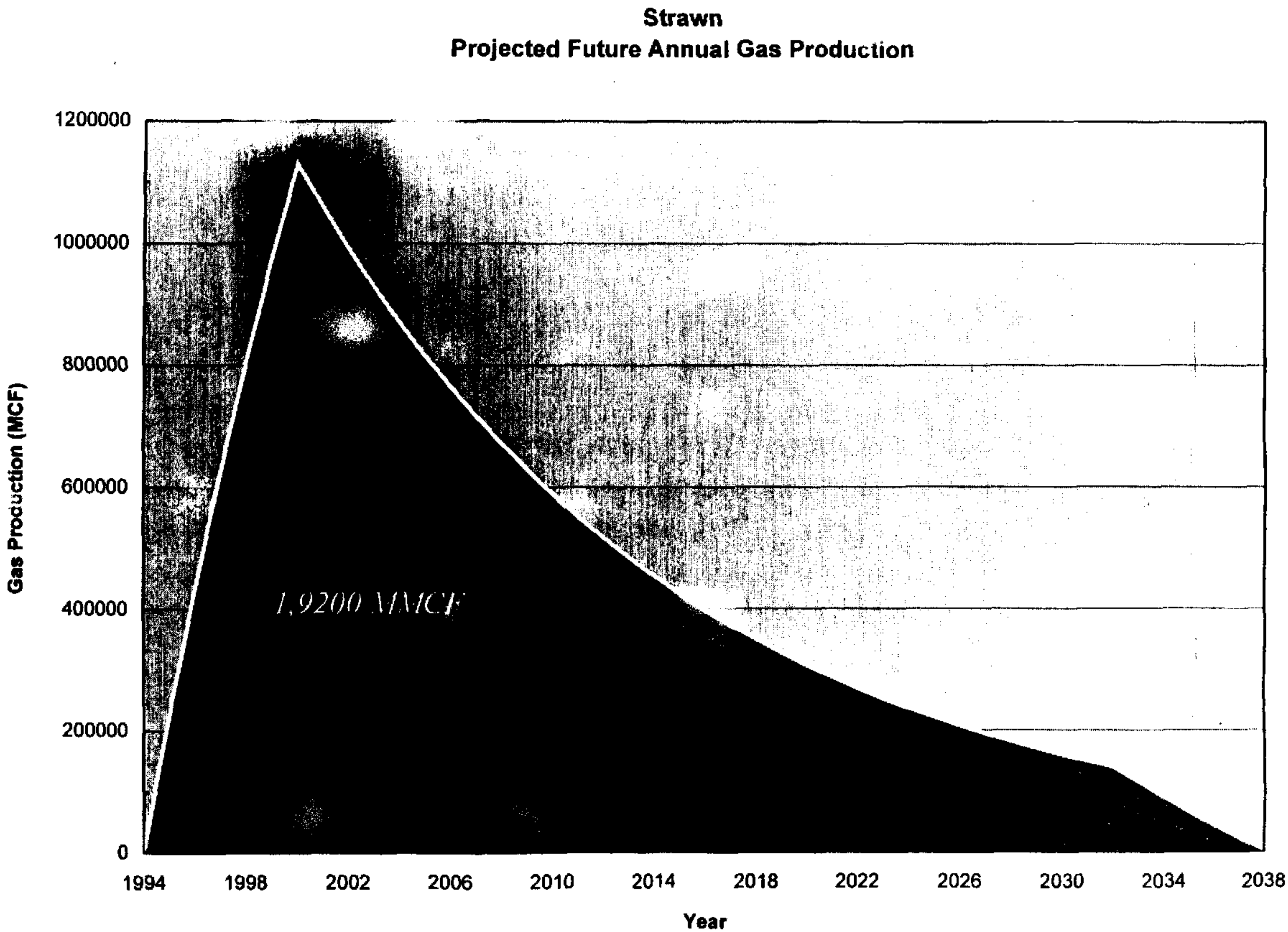


Figure 66. Projected future annual gas production from Strawn Group for WIPP land withdrawal area and surrounding one-mile wide additional study area.

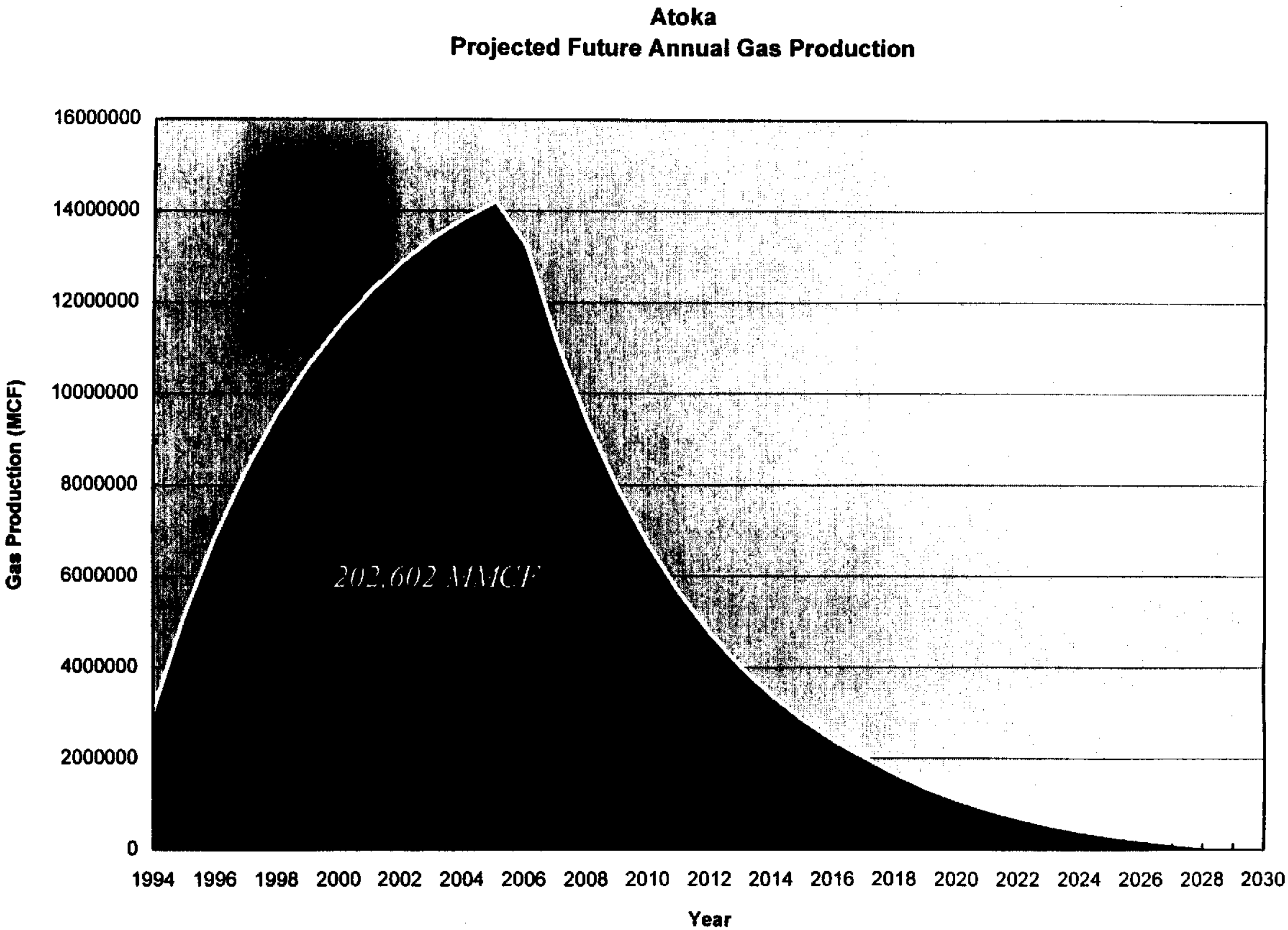


Figure 67. Projected future annual gas production from Atoka Group for WIPP land withdrawal area and surrounding one-mile wide additional study area.

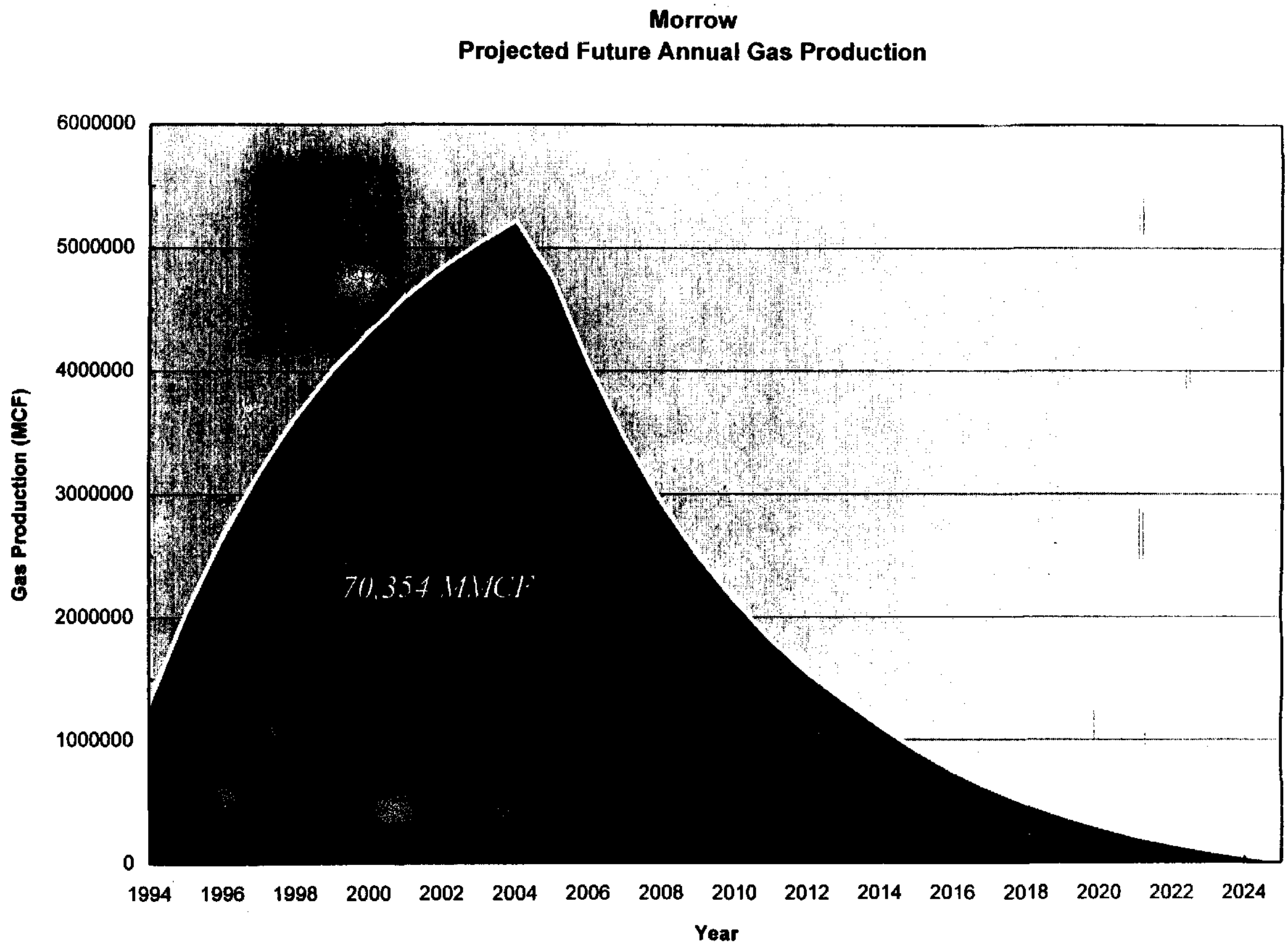


Figure 68. Projected future annual gas production from Morrow Group for WIPP land withdrawal area and surrounding one-mile wide additional study area.

TABLE 1. Summary of probable natural gas, oil, and gas condensate resources under WIPP land withdrawal area and one-mile wide additional study area around WIPP site.

	WIPP land withdrawal area	Additional study area
oil & condensate, million bbls primary recovery	12.3	22.9
oil, million bbls secondary recovery	6.4	13.8
natural gas, billion ft^3	186	168

TABLE 6. Surface and bottom-hole locations of the eight wells proposed to be drilled deviated under the WIPP land withdrawal area by Bass Enterprises.

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(1) James Ranch Unit #20
Surface Location: 200' FNL & 460' FWL, sec. 6 T23S R31E
Bottom Hole Location: 660' FSL & 660' FWL, sec. 31 T22S R31E
APD Received: April 14, 1993

(2) James Ranch Unit #21
Surface Location: 200' FNL & 1980' FWL, sec. 6 T23S R31E
Bottom Hole Location: 660' FSL & 1980' FWL, sec. 31 T22S R31E
APD Received: April 9, 1993

(3) James Ranch Unit #22
Surface Location: 200' FNL & 1980' FEL, sec. 6 T23S R31E
Bottom Hole Location: 660' FSL & 1980' FEL, sec. 31 T22S R31E
APD Received: April 9, 1993

(4) James Ranch Unit #23
Surface Location: 200' FNL & 660' FEL, sec. 6 T23S R31E
Bottom Hole Location: 660' FSL & 660' FEL, sec. 31 T22S R31E
APD Received April 14, 1993

(5) James Ranch Unit #24
Surface Location: 500' FNL & 330' FEL, sec. 6 T23S R31E
Bottom Hole Location: 1650' FSL & 330' FEL, sec. 31 T22S R31E
APD Received: April 14, 1993

(6) James Ranch Unit #25
Surface Location: 200' FNL & 1650' FEL, sec. 6 T23S R31E
Bottom Hole Location: 1650' FSL & 1650' FEL, sec. 31 T22S R31E
APD Received: April 14, 1993

(7) James Ranch Unit #26
Surface Location: 200' FNL & 2310' FWL, sec. 6 T23S R31E
Bottom Hole Location: 1650' FSL & 2310' FWL, sec. 31 T22S R31E
APD Received: April 14, 1993

(8) James Ranch Unit #27
Surface Location: 1650' FSL & 200' FEL, sec. 36 T22S R30E
Bottom Hole Location: 1980' FSL & 660' FWL, sec. 31 T22S R31E
APD Received: April 14, 1993

TABLE 10. Oil pools in Delaware Mountain Group with water injection projects. Data from New Mexico Oil Conservation Division and New Mexico Oil & Gas Engineering Committee.

Pool	Reservoir unit	Year water injection commenced or permitted	No. of injection wells, 12/31/93
Brush Draw	Bell Canyon	1989	1
Cabin Lake	Cherry Canyon Brushy Canyon	1992	2
Cruz	Bell Canyon	1985	1
El Mar	Bell Canyon	1968	31
Indian Draw	Cherry Canyon	1980	10
Malaga	Bell Canyon	1967	3
Mason North	Bell Canyon	1968	1
Paduca	Bell Canyon	1972	19
Double X	Bell Canyon	1988	1
Parkway	Bell Canyon	1993	4

Table 15A. Livingston Ridge Delaware pool: projected future annual oil and gas production (primary recovery) for probable resources identified under WIPP land withdrawal area (LWA) and one-mile wide additional study area.

Year	Wells		Oil (KBO)		GAS (MMCF)	
	WIPP LWA	Addt Area	Wipp LWA	Addt Area	Wipp LWA	Addt Area
1994	0	15	0	180	0	279
1995	2	27	61	487	51	524
1996	4	39	102	694	100	758
1997	6	51	130	834	140	958
1998	8	63	149	927	173	1112
1999	10	69	161	978	197	1203
2000	12	72	170	1019	214	1284
2001	16	82	236	993	278	1307
2002	18	82	220	665	281	1038
2003	16	70	145	431	222	756
2004	14	58	95	274	165	520
2005	12	46	61	167	116	335
2006	10	34	39	95	77	198
2007	8	22	23	46	48	98
2008	6	10	11	14	25	30
2009	2	0	3	0	6	0

Table 15B. Los Medanos Delaware complex: projected future annual oil and gas production (primary recovery) for probable resources identified under WIPP land withdrawal area (LWA) and one-mile wide additional study area.

Year	Wells		Oil (KBO)		Gas (MMCF)	
	WIPP LWA	Addt Area	WIPP LWA	Addt Area	WIPP LWA	Addt Area
1994	0	5	0	45	0	122
1995	17	24	610	706	1064	1261
1996	34	42	942	1065	1830	2082
1997	51	61	1124	1259	2316	2597
1998	68	76	1224	1368	2605	2912
1999	85	95	1278	1428	2770	3096
2000	102	114	1292	1444	2815	3147
2001	90	96	862	799	2064	2020
2002	73	77	448	411	1211	1147
2003	56	58	222	199	642	586
2004	39	39	98	83	295	252
2005	22	20	30	19	94	60
2006	5	1	4	1	13	3

Table 15C. Cabin Lake Delaware pool: projected future annual oil and gas production (primary recovery) for probable resources identified under WIPP land withdrawal area (LWA) and one-mile wide additional study area.

Year	Wells		Oil (KBO)		Gas (MMCF)	
	WIPP LWA	Addt Area	WIPP LWA	Addt Area	WIPP LWA	Addt Area
1994	0	6	0	93	0	65
1995	0	13	0	235	0	164
1996	0	12	0	157	0	110
1997	0	9	0	98	0	68
1998	0	7	0	49	0	34
1999	0	7	0	7	0	5

Table 15D. Quahada Ridge Southeast Delaware pool: projected future annual oil and gas production (primary recovery) for probable resources identified under WIPP land withdrawal area (LWA) and one-mile wide additional study area.

Year	Wells		Oil (KBO)		Gas (MMCF)	
	WIPP LWA	Addt Area	WIPP LWA	Addt Area	WIPP LWA	Addt Area
1994	0	1	0	24	0	17
1995	1	8	26	198	18	138
1996	2	15	45	329	31	228
1997	3	22	58	414	41	289
1998	4	29	65	458	46	319
1999	5	35	66	464	46	323
2000	5	35	66	464	46	323
2001	5	35	66	464	46	323
2002	6	30	92	336	64	234
2003	5	23	60	187	42	130
2004	4	16	34	82	24	57
2005	3	9	15	21	10	14
2006	2	2	2	2	1	1

Table 15E. Los Medanos Bone Spring pool: projected future annual oil and gas production (primary recovery) for probable resources identified under WIPP land withdrawal area (LWA) and one-mile wide additional study area.

Year	Wells		Oil (KBO)		Gas (MMCF)	
	WIPP LWA	Addt Area	WIPP LWA	Addt Area	WIPP LWA	Addt Area
1994	0	3	0	22	0	38
1995	2	5	18	38	28	65
1996	4	7	35	54	56	91
1997	4	8	32	59	54	102
1998	4	8	30	55	53	99
1999	4	8	28	58	51	96
2000	4	8	26	48	50	93
2001	4	8	25	45	48	90
2002	4	8	23	42	46	86
2003	4	8	22	40	44	83
2004	4	8	20	37	43	79
2005	4	8	19	35	41	76
2006	4	8	18	32	39	73
2007	4	8	17	29	37	65
2008	4	7	15	27	36	62
2009	4	7	14	25	34	59
2010	4	7	14	23	32	56
2011	4	7	13	22	31	53
2012	4	7	12	20	29	50
2013	4	7	11	19	28	48
2014	4	7	10	18	26	45
2015	4	7	10	17	25	43
2016	4	7	9	16	24	41
2017	4	7	8	15	22	38
2018	4	7	8	11	21	30
2019	4	5	5	7	13	19
2020	2	3	1	3	3	8
2021	0	1	0	1	0	2

Table 15F. Strawn reservoirs: projected future annual oil and gas production (primary recovery) for probable resources identified under WIPP land withdrawal area (LWA) and one-mile wide additional study area.

Year	Wells		Oil (KBO)		Gas (MMCF)	
	WIPP LWA	Addt Area	WIPP LWA	Addt Area	WIPP LWA	Addt Area
1994	0	0	0	0	0	0
1995	1	1	6	6	110	110
1996	2	2	12	12	213	213
1997	3	3	17	17	310	310
1998	4	4	21	21	400	400
1999	5	5	25	25	485	485
2000	6	6	29	29	565	565
2001	6	6	26	26	529	529
2002	6	6	24	84	496	496
2003	6	6	22	22	464	464
2004	6	6	20	20	435	435
2005	6	6	18	18	408	408
2006	6	6	16	16	382	382
2007	6	6	14	14	358	358
2008	6	6	13	13	335	335
2009	6	6	12	12	314	314
2010	6	6	11	11	294	294
2011	6	6	10	10	276	276
2012	6	6	9	9	258	258
2013	6	6	8	8	242	242
2014	6	6	7	7	227	227
2015	6	6	6	6	213	213
2016	6	6	6	6	199	199
2017	6	6	5	5	187	187
2018	6	6	5	5	175	175
2019	6	6	4	4	164	164
2020	6	6	4	4	153	153
2021	6	6	4	4	144	144
2022	6	6	3	3	135	135

TABLE 15F. (Continued)

Year	Wells		Oil (KBO)		Gas (MMCF)	
	WIPP LWA	Addt Area	WIPP LWA	Addt Area	WIPP LWA	Addt Area
2023	6	6	3	3	126	126
2024	6	6	[illegible]	3	118	118
2025	6	6	2	2	111	111
2026	6	6	2	2	104	104
2027	6	6	[illegible]	2	97	97
2028	6	6	2	2	91	91
2029	6	6	2	2	85	85
2030	6	6	1	1	80	80
2031	6	6	1	1	75	75
2032	[illegible]	6	1	1	70	70
2033	6	6	1	1	58	58
2034	5	5	1	1	45	45
2035	4	4	1	1	33	33
2036	3	3	0	0	22	22
2037	2	2	0	0	11	11
2038	[illegible]	1	0	0	2	2

Table 15G. Atoka reservoirs: projected future annual condensate and gas production (primary recovery) for probable resources identified under WIPP land withdrawal area (LWA) and one-mile wide additional study area.

Year	Wells		Oil (KBO)		Gas (MMCF)	
	WIPP LWA	Addt Area	WIPP LWA	Addt Area	WIPP LWA	Addt Area
1994	0	5	0	29	0	3020
1995	1	6	13	36	1274	3821
1996	3	6	36	30	3624	3222
1997	4	7	42	37	4330	3992
1998	5	8	47	43	4926	4641
1999	6	9	52	48	5429	5188
2000	8	9	68	39	7127	4375
2001	9	10	68	45	7285	4964
2002	10	11	69	50	7418	5461
2003	11	12	69	53	7530	5780
2004	13	12	82	44	8899	4944
2005	14	12	80	48	8779	5425
2006	15	11	78	40	8678	4566
2007	15	11	64	32	7319	3835
2008	15	10	53	27	6172	3229
2009	15	10	43	22	5205	2723
2010	15	10	35	18	4390	2297
2011	15	10	29	15	3702	1938
2012	15	10	24	12	3122	1633
2013	15	10	19	10	2633	1377
2014	15	10	16	8	2220	1162
2015	15	10	13	7	1872	980
2016	15	10	11	5	1579	826
2017	15	10	9	4	1332	697
2018	15	10	7	3	1123	549
2019	15	8	6	3	928	440
2020	14	7	5	2	742	370
2021	12	7	4	2	603	292
2022	11	6	3	1	487	225

TABLE 15G. (Continued)

Year	Wells		Oil (KBO)		Gas (MMCF)	
	WIPP LWA	Addt Area	WIPP LWA	Addt Area	WIPP LWA	Addt Area
2023	10	5	2	1	390	169
2024	9	4	2	1	288	141
2025	7	4	1	1	221	99
2026	6	3	1	0	165	63
2027	5	2	1	0	118	32
2028	4	1	0	0	59	25
2029	2	1	0	0	27	2
2030	1	0	0	0	2	0

Table 15H. Morrow reservoirs: projected future annual condensate and gas production (primary recovery) for probable resources identified under WIPP land withdrawal area (LWA) and one-mile wide additional study area.

Year	Wells		Oil (KBO)		Gas (MMCF)	
	WIPP LWA	Addt Area	WIPP LWA	Addt Area	WIPP LWA	Addt Area
1994	0	6	0	2	0	1298
1995	1	8	0	3	306	1718
1996	3	9	1	3	873	1770
1997	4	11	1	4	1050	2121
1998	6	12	2	4	1507	2114
1999	7	14	2	4	1590	2414
2000	9	14	3	4	1967	2353
2001	10	16	3	5	1983	2618
2002	12	17	4	5	2302	2537
2003	13	19	4	6	2269	2775
2004	15	20	5	6	2546	2671
2005	16	20	5	6	2476	2277
2006	16	20	5	6	2111	1941
2007	16	20	5	6	1799	1648
2008	16	19	5	6	1534	1401
2009	16	19	5	6	1308	1194
2010	16	19	5	6	1115	1018
2011	16	19	5	6	950	868
2012	16	19	5	6	810	740
2013	16	19	5	6	691	631
2014	16	19	5	6	589	523
2015	16	15	5	5	501	415
2016	15	13	5	4	415	333
2017	13	12	4	4	333	272
2018	12	10	4	3	272	211
2019	10	9	3	3	211	168
2020	9	7	3	2	168	123
2021	7	6	2	2	123	93
2022	6	4	2	1	93	58
2023	4	3	1	1	58	38
2024	3	1	1	0	38	12
2025	1	0	0	0	12	0

Table 16. Projected future annual oil production (due to waterflooding) for probable resources under WIPP land withdrawal area (LWA) and one-mile wide additional study area.

Year	Oil Production (KBO	Oil Production (KBO)
	WIPP LWA	Additional study area
1997	0	149
1998	0	96
1999	0	62
2000	0	40
2001	0	26
2002	1030	1172
2003	893	1240
2004	885	1879
2005	724	1563
2006	593	1301
2007	486	1084
2008	419	945
2009	345	792
2010	285	664
2011	236	558
2012	195	469
2013	62	282
2014	53	242
2015	46	207
2016	40	178
2017	18	63
2018	9	19
2019	9	17
2020	8	16
2021	7	15
2022	7	14
2023	6	12
2024	6	12
2025	5	11
2026	5	9

Evaluation of Mineral Resources at the
Waste Isolation Pilot Plant (WIPP) Site

Chapter XII

VALUATION OF OIL AND GAS RESERVES AT THE WIPP SITE, ADDITIONAL AREA, AND COMBINED AREA

by
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Submitted by

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XII

VALUATION OF OIL AND GAS RESERVES AT THE WIPP SITE ADDITIONAL AREA, AND COMBINED AREA

Peter C. Anselmo

SUMMARY

The concern of this section is presentation of valuation results and discussion of the method by which estimated oil and gas reserves at the projected Waste Isolation Pilot Plant (WIPP), the designated additional area around the plant, and the combined area comprising both WIPP and the additional area were evaluated. A Monte Carlo sampling method was used to generate random walk price data for the period 1995-2030. Results are presented first, then the method used is briefly described.

RESULTS

Oil and gas deposits at the WIPP site, additional area, and combined (WIPP site plus the additional area) area were valued via simulation using reserve data from the New Mexico Bureau of Mines & Mineral Resources (MNBMMR) and random-walk modeling of market commodity prices. A 15% discount rate was used for the base case oil and gas valuation, and data are provided for the simulations using a 10% discount rate. Net Present Values (NPV) were calculated for cash flows anticipated from oil and gas development activities from the perspective of a single firm. NPVs are indicated in the attachments as PV CFlow. These values are expected net present values, denoted E(NPV), and represent the average of the present values of all the cash flows associated with each simulation run.

Total revenue present values were also calculated and are provided as an indication of the overall worth of oil and gas deposits at the actual WIPP site and in the additional and combined areas. Total revenue present values are presented in the attachments as PV Rev. Like E(NPV) values, revenue values are expected present values, as they are the average of the expected present values generated by each simulation run.

The expected present value (as of 1 January 1995 - a point discussed below in the section of the report dealing with the simulation method used) of combined oil reserves is $390 million at a discount rate of 15%. A histogram of the expected present value (E(PV)) results for 1008 simulations (all histograms presented in this section represent 1008 simulation runs) is presented in Figure 1. The distribution is symmetric at around $400 million, and the likelihood an E(PV) value lower than $300 million or higher than $500 million is small. As may be seen in **Table 6** and in the attached appendix, the E(PV) of WIPP site oil reserves is estimated to be $130 million, and the E(PV) of additional area reserves is estimated to be $260 million. The E(PV) for the WIPP and additional area gas reserves are estimated as $100 million and $100 million at 15% respectively. These data are also in Table 6 and in the appendix. The E(NPV) for combined area gas reserves, based [illegible]08 simulation runs, is estimated to be $200 million, and is shown in Figure 2. This nearly symmetrical distribution is slightly skewed to the right.

The E(PV) for combined oil reserves is valued at about $510 million if a discount rate of 10% is used. Figure 3 depicts these data, and Figure 4 contains E(PV) data for combined gas reserves. The E(PV) for WIPP site oil reserves is estimated to be 1700 million. Combined gas reserves have an estimated E(PV) of $270 million at 10%. WIPP site gas reserves have an estimated E(PV) of $130 million. The appendix provides detail regarding simulation results. The data are summarized in **Table 7.**

With respect to actual exploration and development of oil and gas resources, the concern is the net present value of anticipated cash flows. Simulation data provided cash-flow estimates, which were aggregated and averaged to yield expected net present values, noted as E(NPV). From the perspective of a firm engaged in extraction of oil and gas deposits from this area, a 15% discount rate leads to the following conclusions from the simulation runs (E(NPV) data are summarized in **Table 4**):

> The Expected Net Present Value E(NPV) of oil production in the combined area is about $37 million. See Figure 5.
>
> The E(NPV) for oil production within the boundaries of the WIPP site is $13 million at 15%.
>
> The E(NPV) for oil production within the additional area is $24 million at 15%.
>
> The E(NPV) for gas production within the boundaries of the WIPP site is $50 million at 15%.
>
> The E(NPV) at 15% for gas production in the combined area is $96 million. See **Figure 6**.
>
> The E(NPV) for gas production within the additional area is $46 million.

From the perspective of a firm engaged in extraction of oil and gas deposits from this area, a 10% discount rate leads to the following conclusions from the simulation runs (E(NPV) data are summarized in **Table 5**):

> The Expected Net Present Value E(NPV) of oil production in the combined area is $74 million. See **Figure 7**.
>
> The E(NPV) for oil production within the boundaries of the WIPP site is $27

million.

The E(NPV) for oil production within the additional area is $47 million at 10%.

The E(NPV) at 10% for gas exploration in the combined area is $133 million. See **Figure 8**.

The E(NPV) for gas production within the boundaries of the WIPP site is $67 million.

The E(NPV) for gas production within the additional area is about $69 million.

Taxes and potentially foregone tax revenues were also studied via the simulation. Values for severance, state and corporate taxes, as well as royalty payments were simulated. Expected present values (E(PV)s) are presented in Tables 2 and 3 for oil and gas at a 15% discount rate. Because these figures are from separate simulations, values from the additional and WIPP areas may not exactly sum to reported combined area values. Values associated with a 10% rate are in the appendix.

SIMULATION METHOD

Oil and gas reserve estimates for the WIPP site, additional area, and combined area were provided by specialists at the New Mexico Bureau of Mines & Mineral Resources. A simulation model was constructed for both oil and gas in each of the three zones of interest. Key model inputs, in addition to reserve data, included the price of the commodity, the unit cost of extraction, severance tax rates, state and federal corporate taxes, the depreciation schedule assumed for capital investments, and the discount rate. Development of a method to anticipate future market prices for oil and gas was a key issue. Time units were years, and the time frame simulated was 1995-2030.

Forecasting is as much an inexact art as a science, particularly when the forecasting horizon is 35 years. Thus, although historical prices for Eddy County oil and gas were modeled using time-series methods, a simulation approach was used to value these resources. Annual market prices were simulated using a random-walk methodology (an excellent reference is Karlin and Taylor, 1975), which is discussed below. Depletion was calculated using the standard methodology, which may be found in Stermole and Stermole (1993).

The time frame considered was 1995-2030. Market prices and extraction and well-maintenance costs were considered on an annual basis, and anticipated productivity data were provided on an annual basis. A sample (this sample does not include actual data used in the study for both investment and operating costs) simulation run for the years 1995-2001 is provided in Table 1.

Key assumptions and features associated with the oil and gas cash flows used in the simulation include:

All calculations are performed from 1 January 1995. That is, oil and gas extraction activities in the three zones of interest are treated as a capital project that was evaluated (and undertaken) on 1 January 1995. Reasons for this starting date are found elsewhere in this report.

Drilling capital expenditures are recovered using a seven year Accelerated Cost Recovery System depreciation method (Stermole and Stermole, 1993).

Revenues are treated as if realized monthly, and taxes and royalties are treated as if they are paid on a quarterly basis.

Simulations were run for each year from 1995 to 2030. Each simulation run, represented as an individual data set in the attached appendix, consisted of 48 simulated oil price "paths" from 1995 to 2030. The Monte Carlo simulations generated numbers for each year for the present value of the market value of the reserves (PV Rev) and the present value of the total cash flow for each simulation run (PV CFlow). As is standard practice in financial analysis (for example see Levy and Sarnat, 1994), cash flows attributable to the decision to drill for oil or gas are the sum of income after taxes, depreciation, and depletion. Summary data are also presented for the present value of severance-tax flows (PV SevTax), state corporate tax flows (PV StateTax), federal corporate tax flows (PV Corp Tax), and royalty-payment flows (PV Royal).

All present values and NPVs are expected values, and are averages of many simulation runs. Standard deviations (STD), maximum values (MAX), minimum values (MIN), and median values are also provided in the attachments for each individual simulation.

Specifics regarding simulation input variables are provided below.

Market prices

Prices for oil (per barrel) and gas (per thousand cubic feet) were generated using a random walk method known as a Wiener process. Historical Eddy County oil and gas prices were analyzed using time-series techniques to show that these historical prices may be modeled as a random process. Use of a Wiener process is attractive in situations such as this one because the uncertainty associated with the commodity-market price estimate in a given year is an increasing function of the forecast time horizon. So, as price forecasts move away from 1995, the uncertainty associated with those forecasts increases (Dixit and Pindyck, 1994).

The starting price per barrel (in 1995) used in the simulations was $18. Note that in **Table 1** the simulated price ranges from $15.91/bbl in 1996 to $20.55/bbl in 1999. The starting price (per tcf) used for gas was $1.75; gas prices were constrained to have an annual floor price of $.75/tcf. This approach is quite conservative given the current and anticipated trends in global energy markets.

There is little doubt that global demand for petroleum products, fueled in large part by the continued industrialization that much of the world's population is currently experiencing, will soon increase dramatically and remain at high levels. Continued industrialization and rising standards of living, particularly in Asia, will combine with the unstable political situation in the Middle East to put increased pressure on domestic oil (and, to a lesser extent, gas) reserves. The only real question concerning the increase in demand is the timing of the first shock(s). It is difficult to dispute the notion that the price of petroleum products will rise substantially in the near future.

The Wiener process method used in this study does not allow for any drastic upward (or downward) non-random movements in these commodity prices. This is a conservative approach, as factors contributing to upward price movements are much more likely in the time frame considered in this study than are factors contributing to downward pressure to oil and gas market prices. It is important to note that the Wiener process approach was selected after analysis of Eddy County historical oil and gas price data provided by the New Mexico Bureau of Mines & Mineral Resources. Historical data were not available for new (oil and gas) and recovery-well capital investment and ongoing well operating costs.

Capital and operating Costs

Confidential capital costs for new and injection wells were provided to the NMBMMR by area operators, as were data concerning monthly well operating costs. These data were used as simulation inputs; after much discussion these costs were treated as constant across the time period considered in the study.

Constant costs were used for several reasons. Most importantly, in the absence of historical data no connection could be made between historical trends (and time series) and any cost forecasting method. Second, the use of constant costs is partly justified by the conservative approach taken to forecasting market prices. Third, technological changes have had a profound effect on drilling and extraction capabilities. There is no reason to expect that technological advancements will not continue apace. Barring huge inflation shocks in the next 35 years (another difficult and risky prediction problem), it is anticipated that technology will serve to offset inflationary effects on capital and operating costs in the oil and gas industry. The main justification for constant costs in this study, though, remains the lack of historical data.

Taxes and royalties

The state of New Mexico assesses severance taxes on revenues attributable to minerals extracted within the state. Rather than attempting to predict factors which might contribute to alterations in the severance-tax rate, a rate of 2.5% of oil and gas revenues was used for the study period. Royalty rate of 12.5% of revenues was used in the study. Data associated with a 5% royalty rate are also presented in the appendix.

Capital investment and other tax incentives that oil and gas companies periodically receive from political entities were likewise ignored in this work. In addition to presenting a major limited data prediction problem, consideration of tax incentives would involve acquisition of additional proprietary data from area producer firms. An average corporate-tax rate of 34% was therefore used.

All taxable income (listed as Taxable Inc in Table 1) is assumed to be New Mexico income for state-tax purposes. New Mexico corporate tax rates are 4.8% of taxable income under $500,000, $24,000 plus 6.4% of the excess over $500,000 for amounts between $500,000 and $1,000,000, and $56,000 plus 7.6% of the excess over $1,000,000 for taxable income over $1,000,000.

Discount rate

Results are presented above for 10% and 15% discount rates. Estimation of discount rates for risky investment projects (the perspective taken in this study was one of viewing oil and gas exploration activity in the zones of interest as risky investment projects) is generally a difficult and inexact process. The standard finance theory-based method (for an excellent discussion of the process of determining discount rates see Copeland, et al., 1990) revolves around estimating a market based firm specific cost of capital (discount rate) using a publicly traded firm's beta value.

Beta values for oil companies (Value Line Investment Survey of 17 March 1995) with some type of operational presence in the Eddy County region range from 0.6 (Exxon) to 0.95 (Unocal). These values are below the market average beta of 1 and point to the use of a lower rate (such as 10%) to discount cash flows from oil and gas operations. 15% may be seen as a conservative upper bound. However, given the extent of current successful drilling and extraction activity in the general area of the WIPP site and the future of the market for oil and gas products, the profitability risk associated with oil and gas operations in the Eddy County area is relatively low. A precise discount rate for different firms operating in the WIPP area is difficult to estimate (particularly in the absence of debt/equity ratio data for said firms). So, although pinpointing a discount rate for a 35 year project is quite risky, current levels of activity in the region and market factors point to a 10% discount rate for oil and gas.

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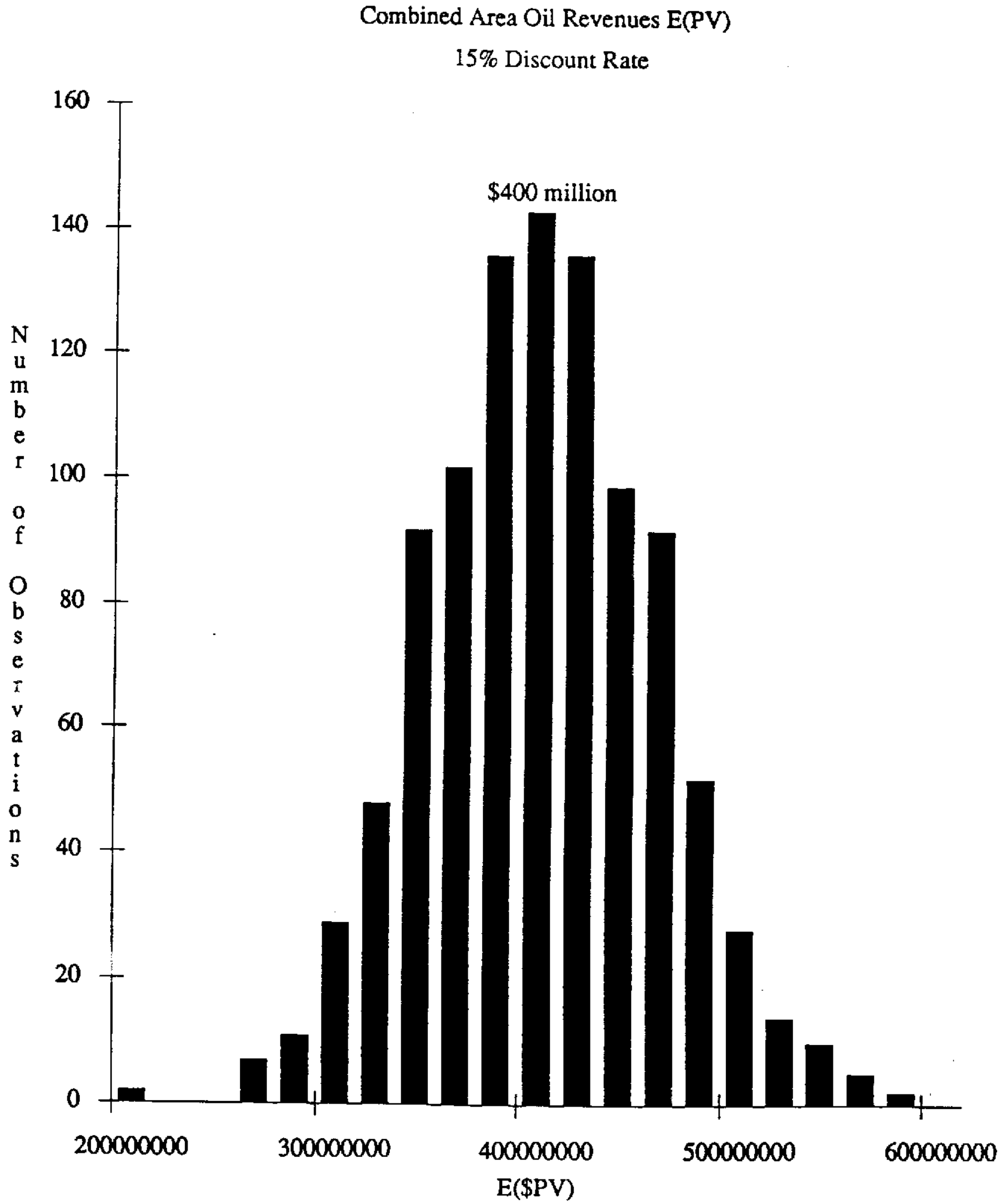
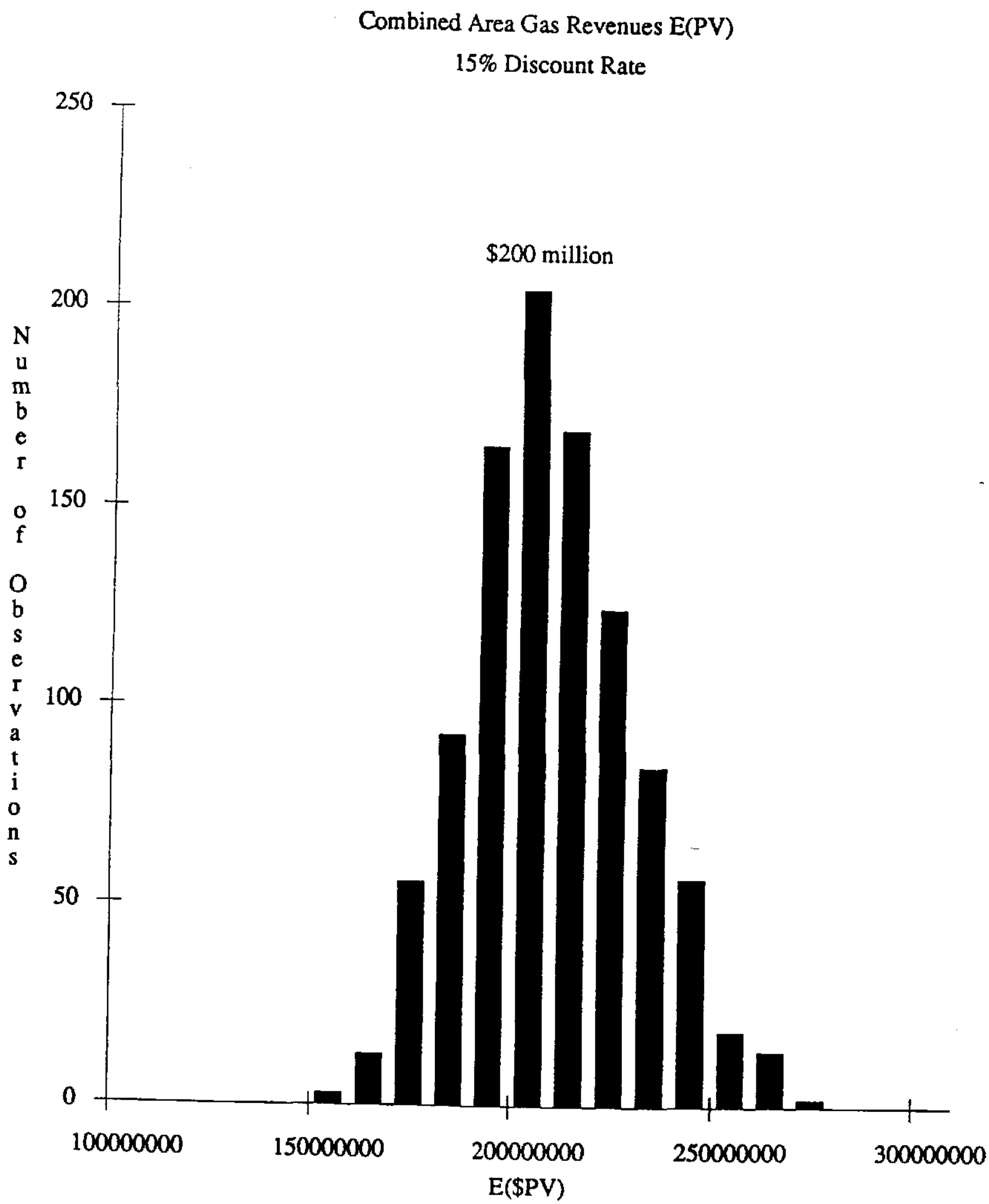

Combined Area Oil Revenues E(PV)
15% Discount Rate
Number of Observations
160
140
120
100
80
60
40
20
0
$400 million
200000000
300000000
400000000
500000000
600000000
E($PV)

Figure 1



Combined Area Gas Revenues E(PV)
15% Discount Rate
$200 million
Number of Observations
250
200
150
100
50
0
100000000
150000000
200000000
250000000
300000000
E($PV)

Figure 2

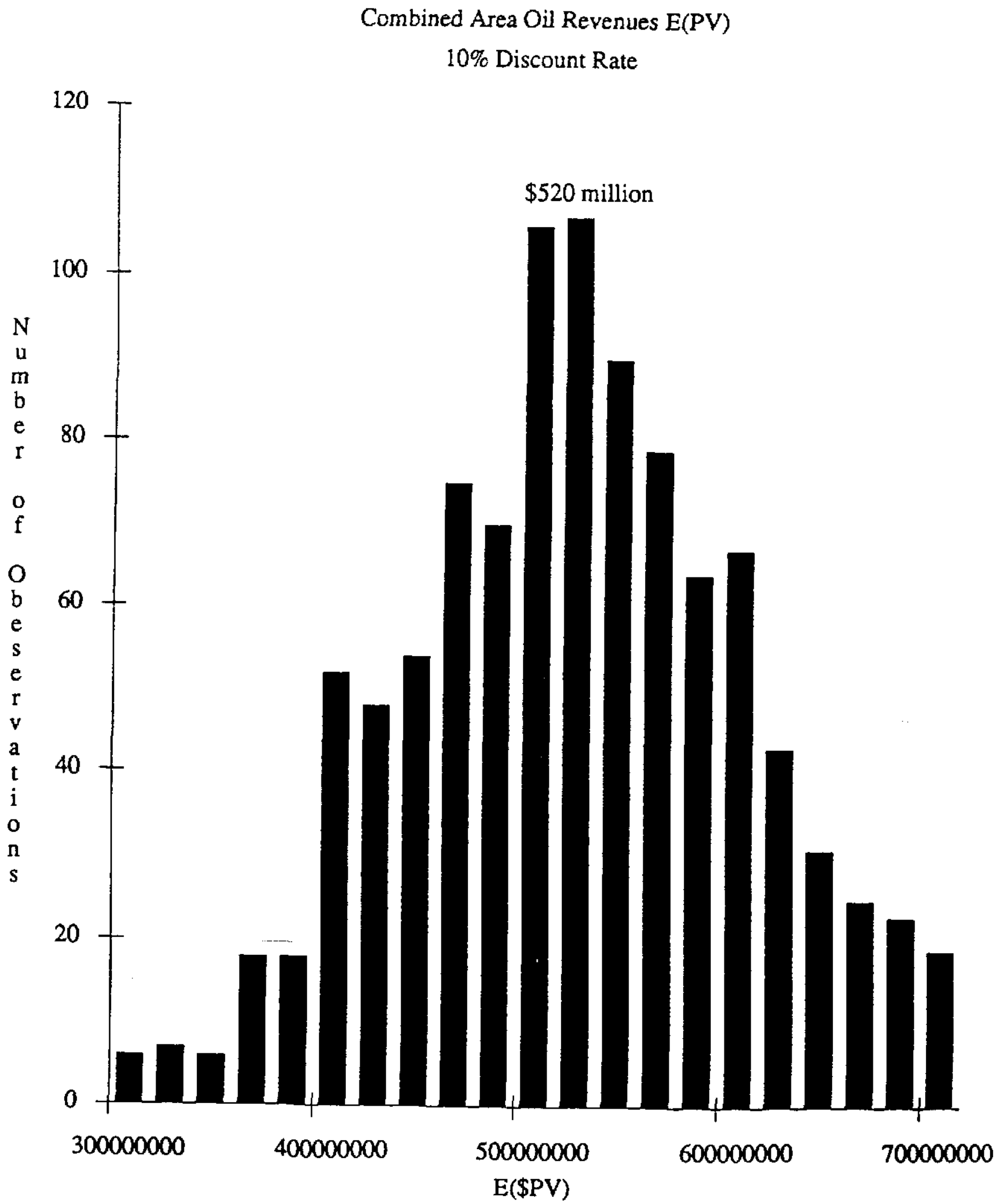
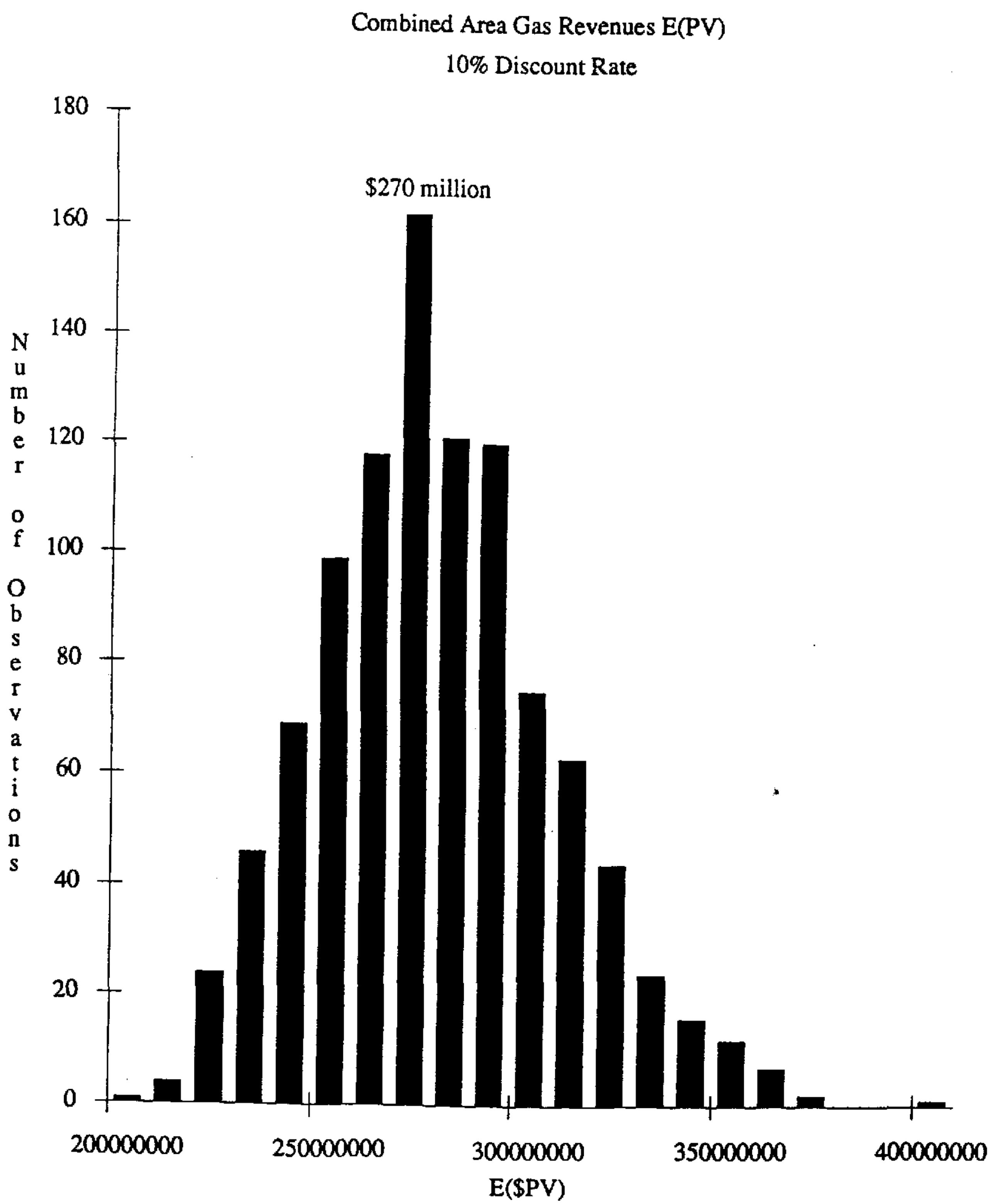

Combined Area Oil Revenues E(PV)
10% Discount Rate
$520 million
120
100
80
60
40
20
0
Number of Obeservations
300000000
400000000
500000000
600000000
700000000
E($PV)

Figure 3


Combined Area Gas Revenues E(PV)
10% Discount Rate
$270 million
Number of Observations
0
20
40
60
80
100
120
140
160
180
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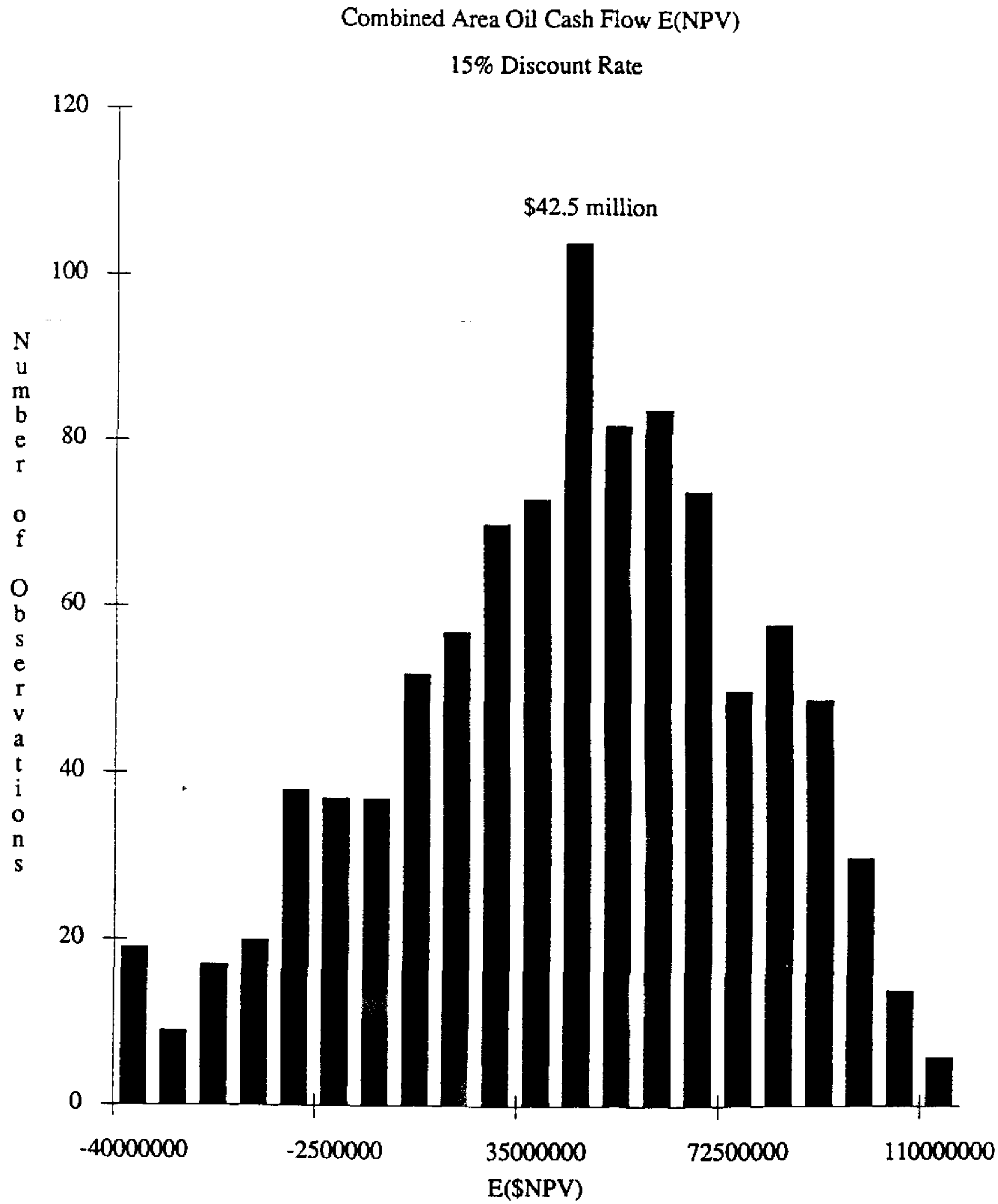
250000000
300000000
350000000
400000000
E($PV)

Figure 4



Combined Area Oil Cash Flow E(NPV)
15% Discount Rate
$42.5 million
Number of Observations
120
100
80
60
40
20
0
-40000000
-2500000
35000000
72500000
110000000
E($NPV)

Figure 5

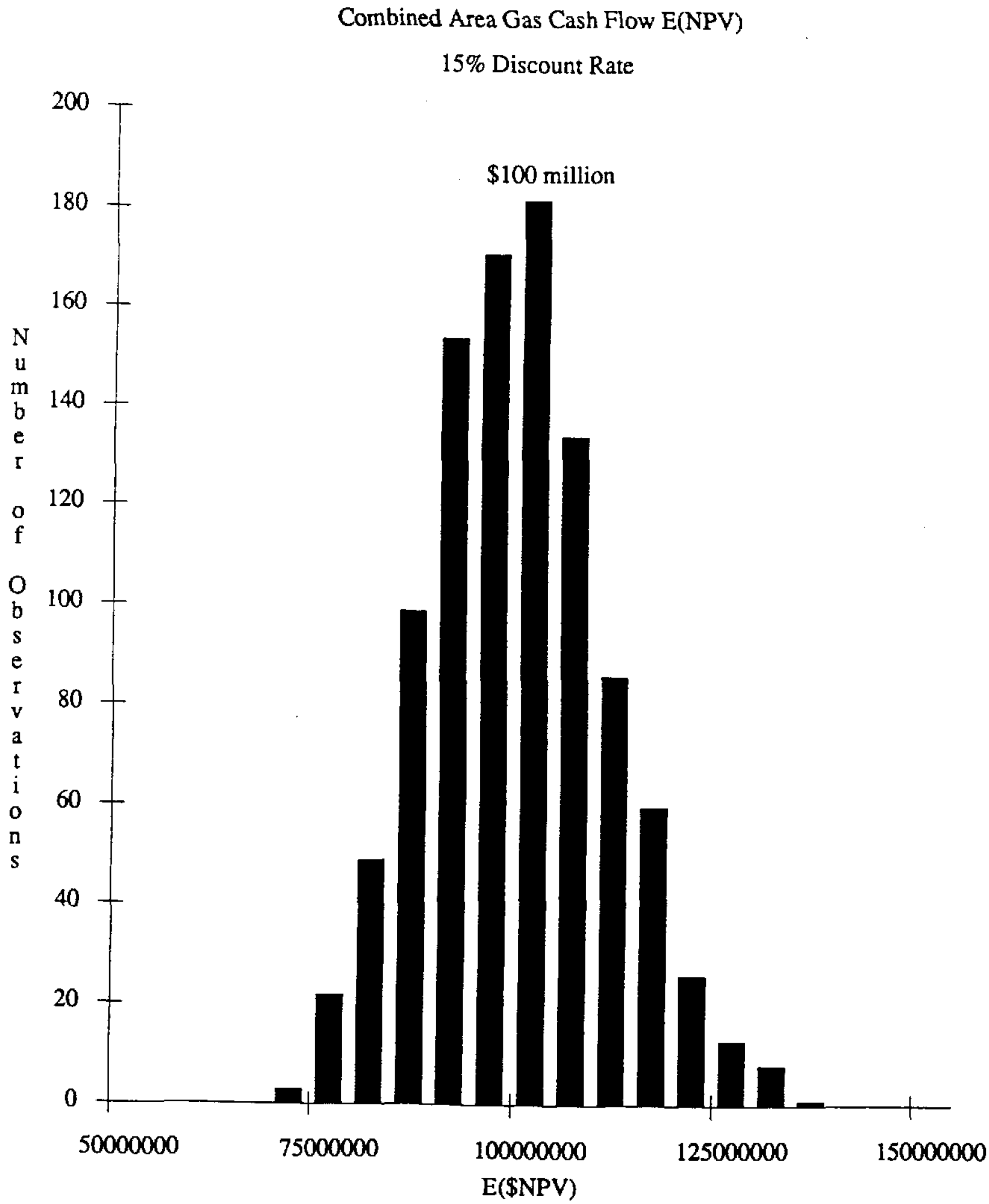

Combined Area Gas Cash Flow E(NPV)
15% Discount Rate
$100 million
Number of Observations
200
180
160
140
120
100
80
60
40
20
0
50000000
75000000
100000000
125000000
150000000
E($NPV)

Figure 6

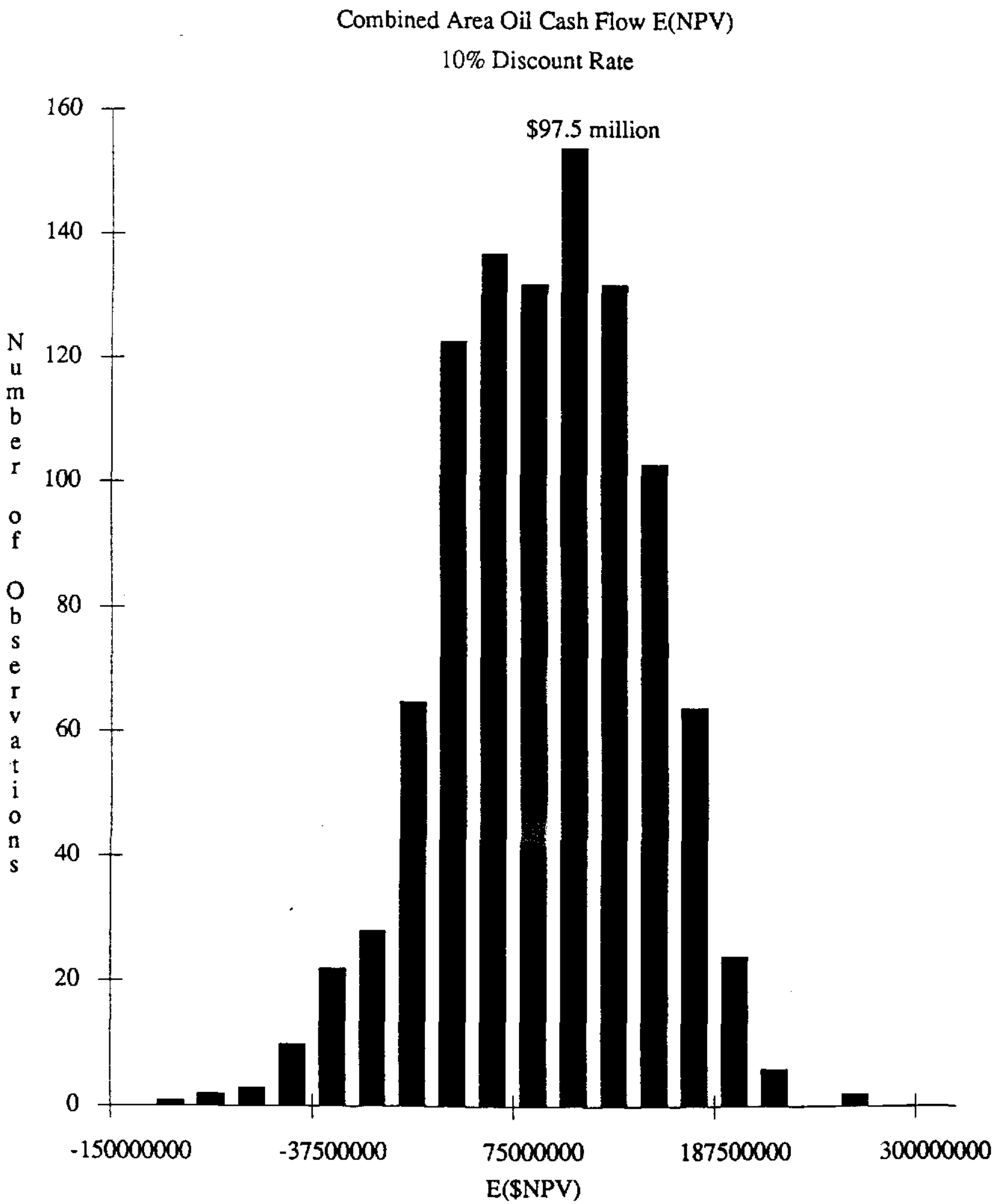

Combined Area Oil Cash Flow E(NPV)
10% Discount Rate
$97.5 million
Number of Observations
160
140
120
100
80
60
40
20
0
-150000000
-37500000
75000000
187500000
300000000
E($NPV)

Figure 7

Combined Area Gas Cash Flow E(NPV)
10% Discount Rate

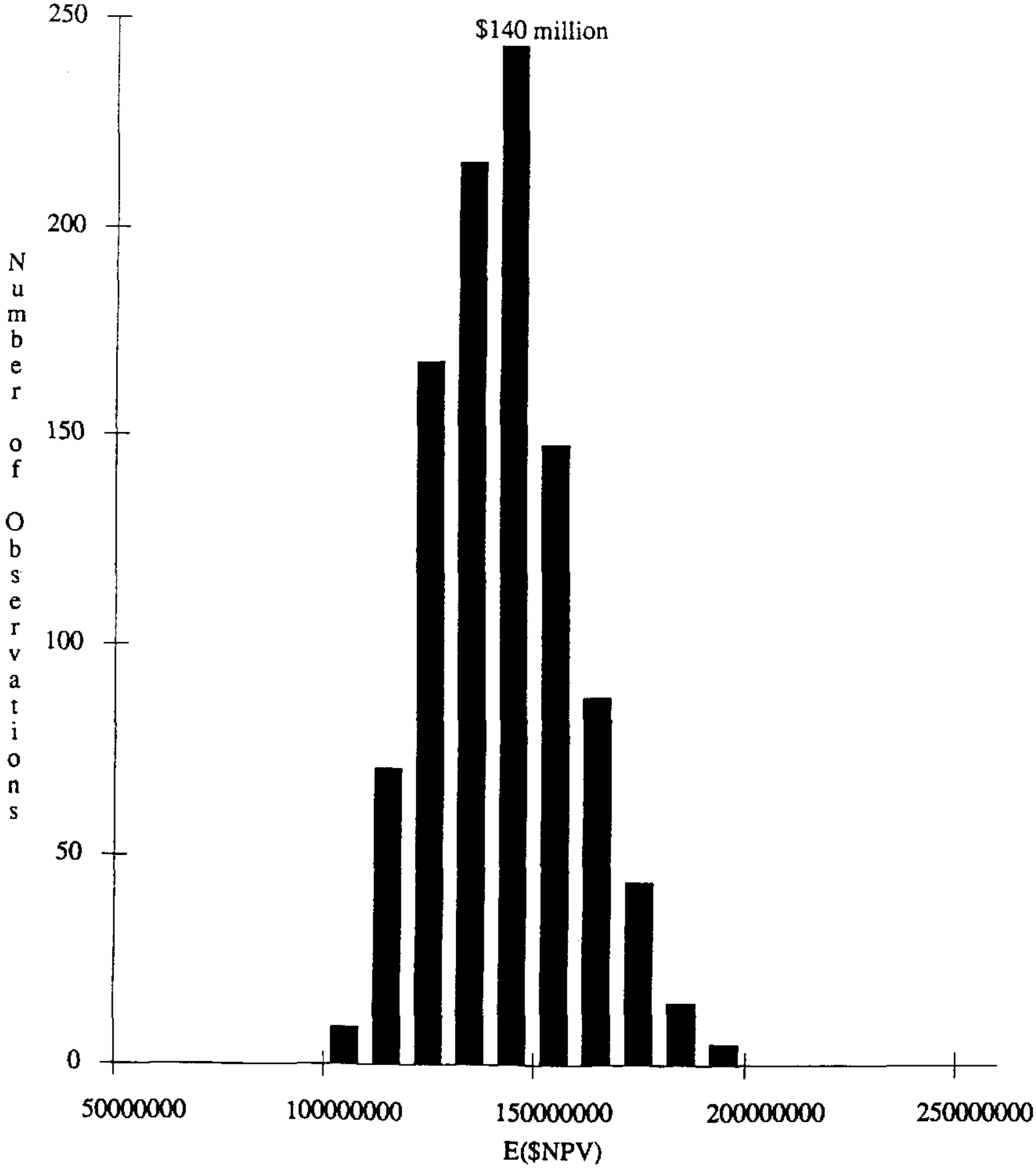


Figure 8

Year	1995	1996	1997	1998	1999	2000	2001
New Wells	22	22	20	20	20	20	10
Inj Wells						107	9
Total Wells	22	44	64	84	104	123	115
Investment	8998097	9193738	8185529	8167825	8290645	8112665	4172372
Total Prod	733099	1172687	1404920	1538256	1612839	1654706	1287398
Sec Recovery							
Price/bbl	18	15.91	18.47	20.36	20.55	17.35	16.72
Total Op Revs	13195782	18657450	25948872	31318892	33143841	28709149	21525295
Total Op Cost	561652	1311552	2078536	2190214	2148598	2591786	3530624
Severance Tax	287008	405800	564388	681186	720879	624424	468175
Depreciaton	0	1285828	3517419	4977030	5885278	6552139	7248799
Royalties	659789	932873	1297444	1565945	1657192	1435457	1076265
NI Bef Depl	11687333	14721397	18491085	21904517	22731894	17505343	9201432
Depletion	1979367	2798618	3892331	4697834	4971576	4306372	3228794
Taxable Inc	9707966	11922779	14598754	17206683	17760318	13198971	5972638
State Tax	1297805	1466131	1669505	1867708	1909784	1563122	1013920
Corp Tax	3300708	4053745	4963576	5850272	6038508	4487650	2030697
Net Income	5109453	6402903	7965673	9488703	9812026	7148199	2928021
Cash Flow	-1909277	2492794	9185987	13793089	15928677	13973282	11601782
MonthlyPV	11.07931197	9.544922546	8.223032863	7.084213533	6.103110886	5.257882518	4.529711009
QuarterlyPV	3.651384127	3.1514114	2.719898392	2.347471124	2.026039169	1.748619896	1.509186786
PV Rev	12183349	14840326	17781536	18489143	16856711	12579111	8125280
PV CFlow	-1762790	1982794	6294723	8142766	8101207	6122490	4379393
PV SevTax	261994	319711	383770	399766	365132	272970	176641
PV StateTax	1184696	1155095	1135221	1096098	967324	683327	382549
PV CorpTax	3013038	3193755	3375106	3433336	3058563	1961799	766175
PV Royal	602286	734967	882229	919003	839384	627517	406071

Table 1

TABLE 2. Present Values of taxes and royalties on oil production at a 15% Discount Rate (in $millions).

	Severance Tax	State Tax	Corporate Tax	Royalties
Combined Area	9.827	11.47	49.90	49.05
Additional Area	6.493	7.66	32.87	32.29
WIPP Area	3.378	3.91	17.04	16.70

TABLE 3. Present Values of taxes and royalties on gas production at a 5% Discount Rate (in $millions).

	Severance Tax	State Tax	Corporate Tax	Royalties
Combined Area	5.044	10.22	43.62	25.20
Additional Area	2.611	5.39	22.05	12.92
WIPP Area	2.42	4.98	20.62	12.11

Table 4. Expected Net Present Values for oil and gas at a discount rate of 15% (in millions of dollars).

	Combined Area	Wipp Area	Additional Area
Oil	37	13	24
Gas	96	46	50

Table 5. Expected Net Present Value for oil and gas at a discount rate of 10% (in millions of dollars).

	Combined Area	WIPP Area	Additional Area
Oil	74	27	47
Gas	133	64	69

Table 6. Expected revenue present values at a discount rate of 15% (millions of dollars).

	Combined Area	WIPP Area	Additional Area
Oil	390	130	260
Gas	200	100	100

Table 7. Expected revenue present values at a discount rate of 10% (millions of dollars).

	Combined Area	WIPP Area	Additional Area
Oil	510	170	340
Gas	270	130	140

APPENDIX

This Appendix contains tabular data from oil and gas reserve valuation simulations. Each page contains five blocks, each of which summarizes 48 simulation runs. Data are reported for the present value of revenues (PV Rev), the present value of cash flows to a hypothetical developing firm (PV CFlow), the present value of severance taxes (PV Sev Tax), the present value of state taxes (PV StateTax), the present value of corporate taxes (PV CorpTax) and the present value of royalties (PV Royal).

For each category and simulation run summary, averages, standard deviations (STD), maximum values (MAX), minimum values (MIN) and median values are reported. Averages are reported in the body of this paper. Data are reported for 12.5% and 5% royalty rates.

The following tables are listed:

For a royalty rate of 12.5%:

WIPP Site Oil, 15 % discount rate
Addition Area Oil, 15% discount rate
Combined Area Oil, 15% discount rate
WIPP Site Gas, 15% discount rate
Addition Area Gas, 15% discount rate
Combined Area Gas, 15% discount rate

WIPP Site Oil, 10% discount rate
Addition Area Oil, 10% discount rate
Combined Area Oil, 10% discount rate
WIPP Site Gas, 10% discount rate
Addition Area Gas, 10% discount rate
Combined Area Gas, 10% discount rate

For a royalty rate of 5%:

WIPP Site Oil, 15% discount rate
Addition Area Oil, 15% discount rate
Combined Area Oil, 15% discount rate
WIPP Site Gas, 15% discount rate
Addition Area Gas, 15% discount rate
Combined Area Gas, 15% discount rate

WIPP Site Oil, 10% discount rate
Addition Area Oil, 10% discount rate
Combined Area Oil, 10% discount rate

WIPP Site Gas, 10% discount rate
Addition Area Gas, 10% discount rate
Combined Area Gas, 10% discount rate

WIPP Area Oil, 12.5% Royalties, discount rate = 15%

	Average	STD	MAX	MIN	Median
PV Rev	1.3E+08	20957040	1.8E+08	83218940	1.3E+08
PV CFlow	12508540	13815657	38944416	-2.4E+07	11617782
PV Sev Tax	3310217	525127.8	4379732	2067048	3245392
PV State Tax	4110169	801343.4	5975296	2520022	4017810
PV CorpTax	17064447	3396233	25150720	10266777	16597358
PV Royal	16551087	2625639	21898657	10335228	16226955

	Average	STD	MAX	MIN	Median
PV Rev	1.3E+08	21173775	1.8E+08	70363702	1.3E+08
PV CFlow	10127638	14061412	38851074	-3.4E+07	10099894
PV Sev Tax	3212685	530408.9	4381053	1743421	3187003
PV State Tax	3930589	796653.2	5988063	2242479	3755728
PV CorpTax	16303728	3364457	25163291	9095298	15573713
PV Royal	16063426	2652046	21905276	8717106	15935005

	Average	STD	MAX	MIN	Median
PV Rev	1.3E+08	19552580	1.9E+08	97196280	1.3E+08
PV CFlow	13306378	12365773	46665698	-9069741	13173326
PV Sev Tax	3334828	489514.4	4728564	2423050	3313503
PV State Tax	4115061	826910.6	6725084	2511718	3973400
PV CorpTax	17090030	3537029	28471605	9980298	16472595
PV Royal	16674142	2447573	23642835	12115260	16567515

	Average	STD	MAX	MIN	Median
PV Rev	1.4E+08	22486476	1.9E+08	87973482	1.4E+08
PV CFlow	15847942	14399771	45926593	-1.8E+07	15755993
PV Sev Tax	3437341	563030.6	4695855	2187841	3413491
PV State Tax	4297630	918985.2	6654797	2560706	4244137
PV CorpTax	17851214	3923148	28160173	10478622	17487798
PV Royal	17186703	2815153	23479265	10939205	17067448

	Average	STD	MAX	MIN	Median
PV Rev	1.3E+08	19972586	1.8E+08	92479246	1.3E+08
PV CFlow	12597355	12931418	40806315	-1.6E+07	12022463
PV Sev Tax	3307038	499917.5	4465639	2298233	3267216
PV State Tax	4074332	796028.8	6165190	2657162	4006049
PV CorpTax	16904039	3392866	26000140	10832665	16672257
PV Royal	16535194	2499587	22328200	11491172	16336078

WIPP Area Gas, 12.5% Royalties, discount rate = 15%

	Average	STD	MAX	MIN	Median
PV Rev	96409640	8445647	1.2E+08	79643740	96060765
PV CFlow	44926010	4718799	60430130	35557138	44729213
PV Sev Tax	2408141	211659.7	3103872	1988152	2400275
PV State Tax	4944271	451069.3	6426863	4050625	4929445
PV CorpTax	20483971	2015003	27107333	16485675	20409085
PV Royal	12040702	1058301	15519362	9940756	12001372

	Average	STD	MAX	MIN	Median
PV Rev	98232737	9312711	1.2E+08	81437379	97223528
PV CFlow	45944296	5203393	59980502	36559459	45380569
PV Sev Tax	2453748	233227.8	3083711	2033047	2428972
PV StateTax	5041799	496883.5	6383241	4146120	4988843
PV CorpTax	20918156	2220333	26915425	16913061	20682297
PV Royal	12268740	1166141	15418564	10165226	12144867

	Average	STD	MAX	MIN	Median
PV Rev	96179593	8349361	1.1E+08	82451568	94795859
PV CFlow	44797215	4664594	55039087	37128465	44024796
PV Sev Tax	2402546	209466.3	2864086	2057392	2368008
PV StateTax	4932619	446814.8	5918553	4195573	4858277
PV CorpTax	20430714	1994116	24824585	17144842	20101909
PV Royal	12012731	1047330	14320437	10286959	11840039

	Average	STD	MAX	MIN	Median
PV Rev	97534309	8291525	1.2E+08	79727432	96349612
PV CFlow	45553928	4632705	60339617	35603169	44891893
PV Sev Tax	2436503	207849.9	3099177	1990601	2406544
PV StateTax	5005193	442930.1	6416671	4056592	4941462
PV CorpTax	20753985	1978733	27062652	16508973	20468769
PV Royal	12182516	1039251	15495892	9952995	12032717

	Average	STD	MAX	MIN	Median
PV Rev	96613514	8902632	1.2E+08	75073373	96447355
PV CFlow	45039565	4973947	56369583	33004167	44947061
PV Sev Tax	2413170	223081.8	2921473	1873901	2409312
PV StateTax	4955357	475595.9	6038745	3806519	4946788
PV CorpTax	20531856	2123737	25370873	15398015	20495127
PV Royal	12065852	1115409	14607353	9369507	12046560

Additional Area Oil, 12.5% Royalties, discount rate = 15%

	Average	STD	MAX	MIN	Median
PV Rev	2.6E+08	40106476	3.6E+08	1.7E+08	2.6E+08
PV CFlow	26014093	26056310	81954101	-4.2E+07	21878660
PV Sev Tax	6562999	1004639	8873144	4109057	6406230
PV StateTax	7819569	1559996	11975718	4994950	7451346
PV CorpTax	33590933	6817864	51938218	21366585	31948321
PV Royal	32814998	5023195	44365720	20545287	32031150

	Average	STD	MAX	MIN	Median
PV Rev	2.5E+08	29749195	3.2E+08	1.8E+08	2.5E+08
PV CFlow	18359128	19978330	64427807	-3.5E+07	19626965
PV Sev Tax	6249821	745270.7	8093731	4462630	6265766
PV StateTax	7267692	1065630	10338001	5670697	7115428
PV CorpTax	31163605	4634107	44637248	24248326	30580154
PV Royal	31249103	3726355	40468668	22313138	31328831

	Average	STD	MAX	MIN	Median
PV Rev	2.5E+08	30834277	3.2E+08	1.9E+08	2.6E+08
PV CFlow	19756728	20824622	59759844	-2.7E+07	21192651
PV Sev Tax	6323702	772737.1	7885981	4614223	6359533
PV StateTax	7473312	1074162	9896789	5409867	7430094
PV CorpTax	32077457	4666331	42660385	23188440	31855856
PV Royal	31618511	3863686	39429900	23071117	31797665

	Average	STD	MAX	MIN	Median
PV Rev	2.6E+08	26969546	3.5E+08	2.0E+08	2.6E+08
PV CFlow	24644655	18178783	76034447	-2.0E+07	26364781
PV Sev Tax	6510941	676619.2	8610693	5030462	6552526
PV StateTax	7747204	955328.9	11420773	5558170	7731311
PV CorpTax	33284296	4131858	49457650	23907846	32999224
PV Royal	32554702	3383099	43053470	25152299	32762633

	Average	STD	MAX	MIN	Median
PV Rev	2.7E+08	36240262	3.4E+08	1.9E+08	2.7E+08
PV CFlow	27890982	23632542	73265603	-2.1E+07	30240086
PV Sev Tax	6641154	906823.4	8480428	4837141	6743354
PV StateTax	7966879	1369117	11137791	5644476	7994499
PV CorpTax	34250912	5980160	48219254	24157853	34237025
PV Royal	33205769	4534117	42402123	24185713	33716764

Additional Area Gas, 12.5% Royalties, discount rate = 15%

	Average	STD	MAX	MIN	Median
PV Rev	1.0E+08	8834164	1.3E+08	88646269	1.0E+08
PV CFlow	50119218	4935787	63423176	41851819	49595143
PV Sev Tax	2578220	220903.8	3174264	2208269	2554577
PV State Tax	5377741	470857.6	6648916	4588953	5327475
PV CorpTax	22435439	2103005	28109764	18913488	22210365
PV Royal	12891099	1104519	15871311	11041334	12772885

	Average	STD	MAX	MIN	Median
PV Rev	1.0E+08	9049727	1.3E+08	84591912	1.1E+08
PV CFlow	50866352	5056249	65420058	39586182	51398929
PV Sev Tax	2611587	226372.3	3263292	2106315	2635027
PV State Tax	5448949	482487.4	6837096	4372063	5497908
PV CorpTax	22753098	2155063	28957303	17942887	22976242
PV Royal	13057936	1131861	16316446	10531566	13175134

	Average	STD	MAX	MIN	Median
PV Rev	1.0E+08	10374744	1.3E+08	82279391	1.0E+08
PV CFlow	49450775	5795822	64970075	38297870	48641462
PV Sev Tax	2548136	259533.4	3243762	2048914	2511726
PV State Tax	5312714	553927.8	6797800	4245880	5232788
PV CorpTax	22149043	2470758	28771448	17396463	21802428
PV Royal	12740681	1297667	16218831	10244579	12558635

	Average	STD	MAX	MIN	Median
PV Rev	1.0E+08	10017026	1.3E+08	85727306	1.0E+08
PV CFlow	50449958	5596225	63188072	40220342	49532133
PV Sev Tax	2592987	250592.8	3163676	2135744	2552481
PV State Tax	5409021	534599.4	6628093	4435004	5322900
PV CorpTax	22576033	2385643	28008983	18223082	22190406
PV Royal	12964940	1252964	15818380	10678725	12762404

	Average	STD	MAX	MIN	Median
PV Rev	1.0E+08	10181459	1.3E+08	82418871	1.0E+08
PV CFlow	50485142	5687829	62246704	38377906	50310316
PV Sev Tax	2594461	254667.6	3121937	2052207	2586177
PV State Tax	5411918	543559.5	6537659	4250743	5393693
PV CorpTax	22590056	2424434	27611627	17427792	22511178
PV Royal	12972305	1273338	15609685	10261029	12930880

Combined Area Oil, 12.5% Royalties, discount rate = 15%

	Average	STD	MAX	MIN	Median
PV Rev	3.9E+08	45761402	4.7E+08	2.9E+08	4.0E+08
PV CFlow	34072880	30896446	83951969	-3.1E+07	41258694
PV Sev Tax	9678409	1146715	11617434	7236464	9894414
PV State Tax	11292909	1581603	14242947	8014078	11308478
PV CorpTax	49120270	6915479	62065724	34726829	49067159
PV Royal	48392043	5733575	58087168	36182330	49472055

	Average	STD	MAX	MIN	Median
PV Rev	3.8E+08	58291263	5.2E+08	2.8E+08	3.8E+08
PV CFlow	31137524	38863602	1.1E+08	-5.3E+07	30036291
PV Sev Tax	9588766	1460538	12918058	6914391	9455977
PV State Tax	11266591	2093986	16852808	7823230	11028903
PV CorpTax	49058503	9203489	73766586	34007739	47919249
PV Royal	47943829	7302690	64590300	34571942	47279880

	Average	STD	MAX	MIN	Median
PV Rev	3.9E+08	53167955	5.6E+08	3.1E+08	3.9E+08
PV CFlow	37874770	33454682	1.4E+08	-1.5E+07	33495100
PV Sev Tax	9809931	1330832	13948808	7786031	9637995
PV State Tax	11409326	2229744	19046757	8377218	10923430
PV CorpTax	49641525	9858902	83556382	36135813	47424695
PV Royal	49049656	6654162	69744039	38930162	48189977

	Average	STD	MAX	MIN	Median
PV Rev	4.0E+08	49570039	5.2E+08	2.7E+08	4.0E+08
PV CFlow	42448244	31566762	1.2E+08	-4.2E+07	44925469
PV Sev Tax	9982941	1239532	13074643	6803176	10016646
PV State Tax	11657127	2000588	17216440	7349864	11430948
PV CorpTax	50697501	8831830	75409596	31785734	49554338
PV Royal	49914704	6197658	65373238	34015879	50083229

	Average	STD	MAX	MIN	Median
PV Rev	4.0E+08	53192223	4.9E+08	2.8E+08	4.0E+08
PV CFlow	42356638	34866003	1.0E+08	-4.6E+07	42589883
PV Sev Tax	9994149	1332061	12323153	6888501	9924601
PV State Tax	11739190	1978798	15650372	8368207	11244357
PV CorpTax	51085681	8681938	68404061	36389553	48835662
PV Royal	49970742	6660306	61615758	34442510	49623000

Combined Area Gas, 12.5% Royalties, discount rate = 15%

	Average	STD	MAX	MIN	Median
PV Rev	2.0E+08	16465033	2.4E+08	1.7E+08	2.0E+08
PV CFlow	97176602	9200237	1.2E+08	78896751	96448676
PV Sev Tax	5065928	412338.2	6107[illegible]76	4246109	5033489
PV StateTax	10131044	877899.2	12349[illegible]4	8384406	10062821
PV CorpTax	43676897	3925461	53594381	35872206	43368090
PV Royal	25329641	2061692	30538407	21230541	25167453

	Average	STD	MAX	MIN	Median
PV [illegible]	2.1E+08	20528169	2.5E+08	1.7E+08	2.0E+08
PV CFlow	98873316	11470637	1.2E+08	76811323	97750803
PV Sev Tax	5141434	513875.3	6275473	4152547	5089613
PV StateTax	10291769	1094054	12706735	8185988	10179873
PV CorpTax	44395711	4892094	55191754	34981496	43902369
PV Royal	25707169	2569377	31377358	20762729	25448062

	Average	STD	MAX	MIN	Median
PV Rev	2.1E+08	20354722	2.5E+08	1.8E+08	2.0E+08
PV CFlow	99207100	11373753	1.2E+08	81911122	96559301
PV Sev Tax	5156758	509754.4	6289775	4381823	5036859
PV StateTax	10324257	1085245	12736731	8673908	10068173
PV CorpTax	44541600	4852860	55327913	37164205	43400160
PV Royal	25783792	2548771	31448874	21909113	25184298

	Average	STD	MAX	MIN	Median
PV Rev	2.0E+08	21209908	2.6E+08	1.5E+08	2.0E+08
PV CFlow	95189097	11851509	[illegible]E+08	69351267	94692733
PV Sev Tax	4976681	530731.9	[illegible]7055	3818600	4953844
PV StateTax	9940842	1130010	12964833	7471927	9891252
PV CorpTax	42827262	5052567	56349213	31802346	42609845
PV Royal	24883404	2653659	31985268	19093010	24769217

	Average	STD	MAX	MIN	Median
PV Rev	2.0E+08	18327064	2.5E+08	1.7E+08	2.0E+08
PV CFlow	94830947	[illegible]40679	1.2E+08	76672552	93080822
PV Sev Tax	4960554	[illegible]194.7	6236176	4148955	4882328
PV StateTax	9906444	977672	12622265	8179849	9740905
PV CorpTax	42673739	4371531	54817659	34947281	41929035
PV Royal	24802772	2295973	31180885	20744761	24411646

WIPP Area Oil, 12.5% Royalties, discount rate = 10%

	Average	STD	MAX	MIN	Median
PV Rev	1.7E+08	29424323	2.3E+08	1.0E+08	1.7E+08
PV CFlow	20705095	19690437	58738735	-2.5E+07	21923557
PV Sev Tax	4143645	734706	5671079	2536329	4134744
PV State Tax	4774262	1073923	7430410	2949659	4737836
PV CorpTax	19668168	4477986	30930935	11743898	19503163
PV Royal	20718219	3673529	28355393	12681641	20673722

	Average	STD	MAX	MIN	Median
PV Rev	1.8E+08	27324680	2.5E+08	1.2E+08	1.8E+08
PV CFlow	31571930	17422293	70410948	-1.4E+07	31308509
PV Sev Tax	4553680	682147.7	6173571	2923820	4509598
PV State Tax	5367759	1138410	8411528	3465182	5154113
PV CorpTax	22164976	4821239	35418874	14209171	21253532
PV Royal	22768398	3410739	30867850	14619100	22547995

	Average	STD	MAX	MIN	Median
PV Rev	1.8E+08	28530379	2.3E+08	1.2E+08	1.8E+08
PV CFlow	28855665	18783346	60986408	-1.4E+07	29011631
PV Sev Tax	4455082	712325.1	5757060	2885977	4415274
PV State Tax	5248918	1092913	7550028	3236171	5164977
PV CorpTax	21635924	4612461	31502014	13361012	21071386
PV Royal	22275410	3561625	28785307	14429882	22076380

	Average	STD	MAX	MIN	Median
PV Rev	1.7E+08	27376877	2.3E+08	1.0E+08	1.7E+08
PV CFlow	24757881	18012809	61937606	-2.7E+07	26009071
PV Sev Tax	4292024	683398.8	5799681	2517491	4287071
PV State Tax	4971104	1050410	7636293	3330619	4767065
PV CorpTax	20466393	4433932	31893283	13779972	19490467
PV Royal	21460119	3416995	28998414	12587460	21435357

	Average	STD	MAX	MIN	Median
PV Rev	1.8E+08	30789249	2.5E+08	95440548	1.8E+08
PV CFlow	28095811	19929800	73286379	-3.0E+07	30825603
PV Sev Tax	4414511	768287.7	6303784	2373376	4485196
PV State Tax	5129949	1237701	8698809	2905741	5073626
PV CorpTax	21142167	5276154	36658496	11872320	20686235
PV Royal	22072555	3841439	31518916	11866870	22425981

WIPP Area Gas, 12.5% Royalties, discount rate = 10%

	Average	STD	MAX	MIN	Median
PV Rev	1.4E+08	13849191	1.6E+08	1.1E+08	1.4E+08
PV CFlow	66357905	7736349	80318158	51071152	66227259
PV Sev Tax	3432501	346052.4	4056073	2749082	3426782
PV State Tax	7040372	739039.9	[illegible]1293	5579997	7030172
PV CorpTax	29166299	3294417	35102718	22660161	29111859
PV Royal	17162510	1730261	20280375	13745425	17133917

	Average	STD	MAX	MIN	Median
PV Rev	1.3E+08	17627288	1.9E+08	1.0E+08	1.3E+08
PV CFlow	64785929	9846260	96116823	46562040	62167789
PV Sev Tax	3362013	440509	4764426	2547710	3244561
PV State Tax	6887938	941340.4	9881902	5153238	6639458
PV CorpTax	28495252	4193647	41846240	20743096	27377130
PV Royal	16810069	2202545	23822142	12738562	16222820

	Average	STD	MAX	MIN	Median
PV Rev	1.4E+08	19320897	1.8E+08	1.0E+08	1.3E+08
PV CFlow	64929769	10791354	88365351	45455835	63426980
PV Sev Tax	3368272	482834.2	4415896	2497211	3301570
PV State Tax	6901238	1032715	9137738	5039609	6760955
PV CorpTax	28554837	45965[illegible]	38528224	20262318	27919805
PV Royal	16841364	2414171	22079490	12486048	16507842

	Average	STD	MAX	MIN	Median
PV Rev	1.3E+08	16640155	1.7E+08	1.0E+08	1.3E+08
PV CFlow	64250157	9293637	82684453	48068462	63337545
PV Sev Tax	3338020	415724.9	4163079	2614619	3297073
PV State Tax	6837162	889627.8	8600039	5287014	6752983
PV CorpTax	28266839	3957702	36121400	21380068	27877021
PV Royal	16690105	2078625	20815399	13073104	16485369

	Average	STD	MAX	MIN	Median
PV Rev	1.4E+08	16263974	1.7E+08	1.1E+08	1.4E+08
PV CFlow	65187247	9084797	82481753	48193008	64991865
PV Sev Tax	3379997	406352.3	4153024	2619778	3371002
PV State Tax	6927267	868296.2	8570504	5303390	6906686
PV CorpTax	28666452	3868473	36025671	21429193	28580819
PV Royal	16899986	2031761	20765121	13098903	16855012

Additional Area Oil, 12.5% Royalties, discount rate = 10%

	Average	STD	MAX	MIN	Median
PV Rev	3.2E+08	56500197	4.3E+08	2.2E+08	3.1E+08
PV CFlow	34298727	37634188	1.1E+08	-3.8E+07	27211845
PV Sev Tax	7933769	1410685	10823530	5448212	7663491
PV State Tax	8827589	2029826	13336609	5407069	8470697
PV CorpTax	37782040	8778288	57448374	23065678	36186140
PV Royal	39668843	7053424	54117658	27241046	38317453

	Average	STD	MAX	MIN	Median
PV Rev	3.4E+08	48856709	4.4E+08	1.6E+08	3.4E+08
PV CFlow	46304161	32552509	1.1E+08	-8.3E+07	50001378
PV Sev Tax	8345450	1219878	10888950	3851541	8499480
PV State Tax	9215918	1745950	13392648	4671305	9315745
PV CorpTax	39385625	7568524	57580565	19929091	39624753
PV Royal	41727248	6099389	54444751	19257716	42497405

	Average	STD	MAX	MIN	Median
PV Rev	3.4E+08	58425930	4.3E+08	2.1E+08	3.5E+08
PV CFlow	51646635	38416112	1.0E+08	-4.5E+07	59796687
PV Sev Tax	8577492	1459200	10705245	5231688	8799529
PV State Tax	9687634	2172984	13525249	5773956	9623112
PV CorpTax	41469569	9414196	58305277	24419108	41088399
PV Royal	42887459	7296001	53526227	26158430	43997644

	Average	STD	MAX	MIN	Median
PV Rev	3.5E+08	51463252	4.5E+08	2.0E+08	3.5E+08
PV CFlow	54065486	34409113	1.2E+08	-5.1E+07	54778594
PV Sev Tax	8669485	1285359	11235317	5050280	8611589
PV State Tax	9821235	1841987	14174600	6146254	9542006
PV CorpTax	42060949	7981836	61124983	26066922	40504344
PV Royal	43347420	6426797	56176589	25251387	43057936

	Average	STD	MAX	MIN	Median
PV Rev	3.3E+08	54064010	4.5E+08	2.2E+08	3.2E+08
PV CFlow	44191175	35489761	1.2E+08	-3.8E+07	38407568
PV Sev Tax	8283609	1350081	11268876	5372832	8029484
PV State Tax	9215190	2029064	14232694	6029772	8942113
PV CorpTax	39394897	8825439	61505959	25667705	38212090
PV Royal	41418046	6750406	56344386	26864156	40147411

Additional Area Gas, 12.5% Royalties, discount rate = 10%

	Average	STD	MAX	MIN	Median
PV Rev	1.4E+08	12088973	1.6E+08	1.1E+08	1.4E+08
PV CFlow	69383676	6751764	82998265	52328348	69489819
PV Sev Tax	3490611	301634.6	4098600	2729136	3494995
PV State Tax	7273186	645497.5	8570658	5647103	7278338
PV CorpTax	30260921	2871558	36048981	23011682	30302655
PV Royal	17453056	1508171	20493006	13645684	17474974

	Average	STD	MAX	MIN	Median
PV Rev	1.4E+08	12884477	1.6E+08	1.1E+08	1.4E+08
PV CFlow	67549418	7195841	82298710	52517648	68487612
PV Sev Tax	3408613	321501	4066910	2737096	3449917
PV State Tax	7097281	688241.1	8499718	5658497	7179344
PV CorpTax	29480300	3060688	35747252	23087443	29873508
PV Royal	17043067	1607504	20334532	13685473	17249582

	Average	STD	MAX	MIN	Median
PV Rev	1.4E+08	13559248	1.7E+08	1.2E+08	1.4E+08
PV CFlow	68267208	7572013	87147626	55632289	67047480
PV Sev Tax	3440833	338499	4286091	2875768	3386245
PV State Tax	7167468	725300.7	8982142	5952832	7050999
PV CorpTax	29787036	3222511	37833887	24407622	29267355
PV Royal	17204168	1692495	21430454	14378846	16931228

	Average	STD	MAX	MIN	Median
PV Rev	1.4E+08	14692441	1.7E+08	1.1E+08	1.4E+08
PV CFlow	69533717	8204422	86926044	52673360	68323836
PV Sev Tax	3497384	366819.9	4273756	2743550	3443451
PV State Tax	7286716	786396.1	8940716	5664755	7170444
PV CorpTax	30325399	3492120	37716425	23148911	29811950
PV Royal	17486922	1834097	21368767	13717759	17217253

	Average	STD	MAX	MIN	Median
PV Rev	1.4E+08	12448180	1.6E+08	1.1E+08	1.4E+08
PV CFlow	69015946	6951441	81551635	52750959	69047443
PV Sev Tax	3474085	310672.2	4035581	2748206	3475336
PV State Tax	7236641	665795.1	8440236	5689005	7236607
PV CorpTax	30103598	2957595	35449038	23193222	30115496
PV Royal	17370429	1553359	20177907	13741028	17376679

Combined Area Oil, 12.5% Royalties, discount rate = 10%

	Average	STD	MAX	MIN	Median
PV Rev	5.1E+08	82750339	6.8E+08	2.6E+08	5.1E+08
PV CFlow	71584600	55549811	1.8E+08	-1.1E+08	75652822
PV Sev Tax	12630989	2065835	16840350	6553252	12636627
PV State Tax	13739009	2891482	21001278	8568470	13423825
PV CorpTax	59515502	12660174	91557489	37269706	58071023
PV Royal	63154942	10329175	84201747	32766259	63183133

	Average	STD	MAX	MIN	Median
PV Rev	5.2E+08	89643406	7.1E+08	2.8E+08	5.2E+08
PV CFlow	80482579	57696576	1.9E+08	-8.9E+07	79676526
PV Sev Tax	12982066	2237835	17643012	7012965	12881390
PV State Tax	14302769	3520086	22546209	7919725	13721710
PV CorpTax	62027039	15491157	98516927	34322708	59252314
PV Royal	64910328	11189178	88215059	35064822	64406962

	Average	STD	MAX	MIN	Median
PV Rev	5.1E+08	85067292	7.9E+08	3.5E+08	5.0E+08
PV CFlow	74727727	54357665	2.4E+08	-4.5E+07	63515654
PV Sev Tax	12765425	2124049	19760035	8630898	12338253
PV State Tax	14002289	3457939	27055967	8742132	13521130
PV CorpTax	60706389	15261216	1.2E+08	37513107	58637141
PV Royal	63827119	10620244	98800169	43154472	61691260

	Average	STD	MAX	MIN	Median
PV Rev	5.1E+08	83725240	7.1E+08	3.0E+08	5.1E+08
PV CFlow	74392463	55350748	1.9E+08	-8.0E+07	75505437
PV Sev Tax	12790384	2090544	17653530	7451374	12629916
PV State Tax	14211909	3084492	22565542	9005269	13475000
PV CorpTax	61690903	13519623	98617040	39317528	58319091
PV Royal	63951918	10452719	88267641	37256867	63149572

	Average	STD	MAX	MIN	Median
PV Rev	5.1E+08	84673792	6.6E+08	3.2E+08	5.2E+08
PV CFlow	73511410	55620082	1.7E+08	-5.7E+07	79626083
PV Sev Tax	12704122	2113402	16548340	8059257	12857544
PV State Tax	13841099	3117540	20214248	8158729	13737130
PV CorpTax	60000316	13643335	88095644	34893084	59407231
PV Royal	63520608	10567012	82741698	40296274	64287711

Combined Area Gas, 12.5% Royalties, discount rate = 10%

	Average	STD	MAX	MIN	Median
PV Rev	2.7E+08	28170984	3.3E+08	2.1E+08	2.7E+08
PV CFlow	1.3E+08	15739060	1.6E+08	97917076	1.3E+08
PV Sev Tax	6693639	703605.6	8123752	5210273	6632251
PV State Tax	13321354	1500212	16373682	10150731	13189065
PV CorpTax	57242624	[illegible]8327	70857297	43120982	56658217
PV Royal	33468195	3518029	40618754	26051363	33161256

	Average	STD	MAX	MIN	Median
PV Rev	2.7E+08	29522311	3.4E+08	2.1E+08	2.7E+08
PV CFlow	1.3E+08	16493251	1.7E+08	98707521	1.3E+08
PV Sev Tax	6753317	[illegible]159.9	8403374	5245423	6663452
PV State Tax	13448198	1572559	16966866	10231743	13258225
PV CorpTax	57810763	7017763	73519303	43455606	56955238
PV Royal	33766587	3685800	42016870	26227111	33317259

	Average	STD	MAX	MIN	Median
PV Rev	2.7E+08	26691561	3.2E+08	2.0E+08	2.7E+08
PV CFlow	1.3E+08	14911992	1.6E+08	90936252	1.3E+08
PV Sev Tax	6772799	666739.9	8067045	4897417	6762275
PV State Tax	13490790	1422132	16250857	9486859	13468359
PV CorpTax	57996227	6347362	70317435	40142608	57896042
PV Royal	33863995	3333698	40335216	24487095	33811376

	Average	STD	MAX	MIN	Median
PV Rev	2.7E+08	32186982	3.4E+08	2.1E+08	2.6E+08
PV CFlow	1.3E+08	17982910	1.7E+08	97034436	1.3E+08
PV Sev Tax	6625094	803850.4	8544369	5170428	6586912
PV State Tax	13175589	1713825	17268645	10072548	13093396
PV CorpTax	56590072	7652655	74861570	42741657	56226582
PV Royal	33125467	4019252	42721841	25852137	32934558

	Average	STD	MAX	MIN	Median
PV Rev	2.7E+08	30630575	3.2E+08	2.2E+08	2.6E+08
PV CFlow	1.3E+08	17112589	1.6E+08	1.0E+08	1.3E+08
PV Sev Tax	6637784	765221.6	8091310	5359177	6584925
PV State Tax	13202242	1632239	16301852	10481495	13086121
PV CorpTax	56710887	7284909	70548463	44538547	56207670
PV Royal	33188921	3826107	40456554	26795890	32924624

WIPP Site Oil Data. discount rate = 15%

	Average	STD	MAX	MIN	Median
PV Rev	1.3E+08	19419290	1.7E+08	88787701	1.3E+08
PV CFlow	18352280	13425521	43355190	-1.3E+07	17811946
PV Sev Tax	3280762	486369.6	4246938	2207080	3236813
PV State Tax	4668384	882553.4	6668477	3127431	4473598
PV CorpTax	19514791	3765862	28218382	12919040	18606764
PV Royal	6561524	972739.1	8493880	4414156	6473628

	Average	STD	MAX	MIN	Median
PV Rev	1.4E+08	18408810	1.8E+08	98576157	1.3E+08
PV CFlow	21223611	12239585	51777252	-4383284	20969987
PV Sev Tax	3384415	460242.5	4592852	2455174	3351023
PV State Tax	4851876	911634.1	7473212	3193419	4722952
PV CorpTax	20293006	3954965	31865737	13142443	19791771
PV Royal	6768829	920484.5	9185710	4910351	6702046

	Average	STD	MAX	MIN	Median
PV Rev	1.3E+08	16953635	1.8E+08	98423157	1.3E+08
PV CFlow	20187771	11768468	48828569	-9666959	21514335
PV Sev Tax	3351574	424809.6	4473240	2445149	3363563
PV State Tax	4817413	784357.5	7192974	3456171	4706197
PV CorpTax	20149974	3372934	30604139	14265430	19748710
PV Royal	6703148	849618.7	8946477	4890295	6727124

WIPP Site Gas Data, discount rate = 15%

	Average	STD	MAX	MIN	Median
PV Rev	96768898	10388927	1.2E+08	73449502	97522081
PV CFlow	49364465	6259382	64051376	35315513	49817791
PV Sev Tax	2417145	260358	3028451	1833538	2436490
PV State Tax	5515347	614427.7	6958387	4136936	5561490
PV CorpTax	23035180	2744171	29478340	16883951	23239083
PV Royal	4834290	520715.2	6056901	3667076	4872979

	Average	STD	MAX	MIN	Median
PV Rev	97693959	9523976	1.2E+08	79049098	98845534
PV CFlow	49921721	5738297	60646428	38689495	50616052
PV Sev Tax	2440503	238721.6	2885618	1973143	2469406
PV State Tax	5570570	563313.4	6619379	4466189	5638258
PV CorpTax	23281371	2516127	27972901	18355408	23586018
PV Royal	4881006	477443.3	5771238	3946288	4938811

	Average	STD	MAX	MIN	Median
PV Rev	96463327	10657743	1.2E+08	74894826	96202710
PV CFlow	49180259	6421510	65593990	36186430	49023992
PV Sev Tax	2409574	267052.7	3093244	1869129	2402020
PV State Tax	5497581	630056.4	7110395	4220826	5478966
PV CorpTax	22955384	2814737	30161251	17259107	22875742
PV Royal	4[illegible]9148	534105.3	6186482	3738264	4804036

Additional Area Oil Data, discount rate = 15%

	Average	STD	MAX	MIN	Median
PV Rev	2.6E+08	36259485	3.5E+08	1.9E+08	2.6E+08
PV CFlow	35820206	25070122	91781016	-1.7E+07	33355661
PV Sev Tax	6473126	908034.5	8623384	4690221	6363292
PV State Tax	9027795	1626718	13371714	6422466	8801485
PV CorpTax	39012516	7112061	58204763	27578441	38003217
PV Royal	12946252	1816069	17246766	9380436	12726581

	Average	STD	MAX	MIN	Median
PV Rev	2.6E+08	31576036	3.2E+08	1.4E+08	2.5E+08
PV CFlow	33917326	22421503	74049351	-5.5E+07	33572381
PV Sev Tax	6377950	790485	7906130	3465523	6336482
PV State Tax	8735298	1327561	11766985	5141557	8499650
PV CorpTax	37652782	5823676	51033614	22108648	36578765
PV Royal	12755900	1580970	15812263	6931045	12672961

	Average	STD	MAX	MIN	Median
PV Rev	2.7E+08	43391201	3.7E+08	1.4E+08	2.7E+08
PV CFlow	40335388	30060839	1.0E+08	-5.3E+07	45158406
PV Sev Tax	6628737	1085616	9167963	3593183	6763380
PV State Tax	9263828	1933767	14656762	5708092	9269099
PV CorpTax	39997411	8503657	63943115	24666096	39968719
PV Royal	13257474	2171232	18335922	7186363	13526760

Additional Area Gas Data, discount rate = 15%

	Average	STD	MAX	MIN	Median
PV Rev	1.4E+08	12663431	1.6E+08	1.1E+08	1.4E+08
PV CFlow	74825551	7626274	86854395	54627262	76506321
PV Sev Tax	3462118	316132.4	396085[illegible]	2623989	3531462
PV State Tax	8004943	749601.6	918[illegible]	6002935	8168980
PV CorpTax	33521028	3332037	38777769	24687166	34251897
PV Royal	6924236	632265.4	7921723	5247980	7062923

	Average	STD	MAX	MIN	Median
PV Rev	1.4E+08	11564098	1.7E+08	1.2E+08	1.4E+08
PV CFlow	75170130	6967083	91233244	60660792	74688146
PV Sev Tax	3476340	288531	4140623	2875874	3456630
PV State Tax	8038394	681270.5	9600367	6625254	7993423
PV CorpTax	33670940	3041117	40672467	27341990	33463173
PV Royal	6952683	577062.3	8281245	5751741	6913258

	Average	STD	MAX	MIN	Median
PV Rev	1.3E+08	11206749	1.6E+08	1.2E+08	1.3E+08
PV CFlow	72392396	6749703	90002540	60688671	71455583
PV Sev Tax	3361136	279570	4090449	2874293	3322085
PV State Tax	7764340	662227	9490824	6590582	7671607
PV CorpTax	32456674	2946666	40143612	27325357	32045062
PV Royal	6722272	559139.6	8180895	5748587	6644168

Combined Area Oil Data, discount rate = 15%

	Average	STD	MAX	MIN	Median
PV Rev	4.0E+08	66979757	5.3E+08	2.3E+08	4.0E+08
PV CFlow	57133221	46994993	1.4E+08	-6.7E+07	61972582
PV Sev Tax	9859939	1677875	13239037	5615342	9917766
PV State Tax	13625362	2856603	20549800	7544011	13531060
PV CorpTax	59521921	12590879	90299380	32728709	58989963
PV Royal	19719878	3355750	26478079	11230685	19835525

	Average	STD	MAX	MIN	Median
PV Rev	3.9E+08	61246093	5.4E+08	2.7E+08	4.0E+08
PV CFlow	53151170	42659685	1.5E+08	-4.0E+07	61805378
PV Sev Tax	9700344	1533078	13462628	6691868	9934863
PV State Tax	13273886	2687530	21078964	9436279	13248807
PV CorpTax	57957777	11878921	92698712	40957124	57847705
PV Royal	19400686	3066156	26925256	13383730	19869724

	Average	STD	MAX	MIN	Median
PV Rev	4.0E+08	57774810	5.6E+08	2.8E+08	4.0E+08
PV CFlow	57565177	39635137	1.6E+08	-2.6E+07	65418796
PV Sev Tax	9855330	1446759	13924649	7079838	10051464
PV State Tax	13518700	2615304	22162285	9447907	13685919
PV CorpTax	59034545	11557403	97525722	41230668	59695159
PV Royal	19710662	2893517	27849301	14159679	20102922

Combined Area Gas Data, discount rate = 15%

	Average	STD	MAX	MIN	Median
PV Rev	2.1E+08	20356593	2.8E+08	1.7E+08	2.0E+08
PV CFlow	1.1E+08	12266349	1.5E+08	87447461	1.1E+08
PV Sev Tax	5115743	510139.6	6905592	4292585	5050022
PV State Tax	11403808	1202448	15622728	9463660	11249134
PV CorpTax	49369205	5376871	68234226	40693150	48676489
PV Royal	10231489	1020279	13811188	8585179	10100045

	Average	STD	MAX	MIN	Median
PV Rev	2.0E+08	22570607	2.6E+08	1.7E+08	1.9E+08
PV CFlow	1.0E+08	13600406	1.4E+08	84388005	1.0E+08
PV Sev Tax	4944768	564997.8	[illegible]30316	4165561	4847592
PV State Tax	11000700	1331804	14736757	9163174	10771234
PV CorpTax	47567125	5955074	64278787	39354286	46542880
PV Royal	9889538	1129995	13060633	8331125	9695184

	Average	STD	MAX	MIN	Median
PV Rev	2.0E+08	21219739	2.5E+08	1.6E+08	2.0E+08
PV CFlow	1.1E+08	12786525	1.3E+08	78814763	1.1E+08
PV Sev Tax	5043838	531231.2	6178657	3933611	5074843
PV State Tax	11234340	1252092	13909408	8616959	11308025
PV CorpTax	48611314	5599176	60572332	36909496	48938102
PV Royal	10087677	1062462	12357320	7867221	10149686

WIPP Site Oil Data, discount rate = 10%

	Average	STD	MAX	MIN	Median
PV Rev	1.7E+08	32317195	2.7E+08	1.2E+08	1.7E+08
PV CFlow	34081053	22262483	94321552	-4272401	33768145
PV Sev Tax	4345378	806965.1	6714797	3054975	4307883
PV State Tax	5994317	1505018	11112633	3630035	5767387
PV CorpTax	25004965	6440349	47420447	14513886	24162246
PV Royal	8690754	1613931	13429591	6109938	8615761

	Average	STD	MAX	MIN	Median
PV Rev	1.8E+08	29655786	2.4E+08	1.2E+08	1.9E+08
PV CFlow	39072106	20354385	75873135	-9215610	44079844
PV Sev Tax	4518944	740264.9	5952453	2910220	4673910
PV State Tax	6278773	1378113	9308443	3695316	6424272
PV CorpTax	26157497	5885002	39385333	15276869	26591893
PV Royal	9037889	1480530	11904903	5820443	9347818

	Average	STD	MAX	MIN	Median
PV Rev	1.8E+08	31273557	2.5E+08	95675199	1.8E+08
PV CFlow	36124512	21308843	82889965	-2.2E+07	37520155
PV Sev Tax	4404445	780377.3	6241593	2381724	4418637
PV State Tax	6037676	1471695	10002524	2770527	5915209
PV CorpTax	25101697	6310436	42432871	11297519	24469302
PV Royal	8808889	1560754	12483186	4763452	8837275

WIPP Site Gas Data. discount rate = 10%

	Average	STD	MAX	MIN	Median
PV Rev	1.4E+08	18936904	1.9E+08	1.0E+08	1.3E+08
PV CFlow	72121750	11408117	1.1E+08	51516711	69632367
PV Sev Tax	3421549	473113.4	4804147	2567148	3318789
PV State Tax	7798211	1117974	11065014	5781533	7559821
PV CorpTax	32552011	4986615	47124566	23546625	31468927
PV Royal	6843098	946226.3	9608289	5134298	6637580

	Average	STD	MAX	MIN	Median
PV Rev	1.3E+08	15040092	1.7E+08	1.0E+08	1.3E+08
PV CFlow	68923083	9059521	89376424	52109400	68608951
PV Sev Tax	3288715	375804.2	4136358	2591570	3275333
PV State Tax	7483612	889096.3	9485192	5830584	7449853
PV CorpTax	31151942	3960974	40086090	23804043	31010889
PV Royal	6577431	751607.6	8272716	5183145	6550664

	Average	STD	MAX	MIN	Median
PV Rev	1.3E+08	15834380	1.9E+08	1.0E+08	1.3E+08
PV CFlow	70478670	9539053	1.0E+08	52416769	69776701
PV Sev Tax	3353309	395422.5	4618364	2603587	3324410
PV State Tax	7636146	934408	10628285	5852512	7567646
PV CorpTax	31832767	4167753	45166448	23930686	31528155
PV Royal	6706620	790845	9236732	5207172	6648817

Additional Area Oil Data, discount rate = 10%

	Average	STD	MAX	MIN	Median
PV Rev	3.4E+08	50099710	4.6E+08	2.4E+08	3.5E+08
PV CFlow	65739308	34825228	1.4E+08	-7812233	72638386
PV Sev Tax	8463552	1250989	11359382	5972646	8598677
PV StateTax	11065780	2195254	16976839	6877744	11120462
PV CorpTax	47569662	9566277	73674223	29176394	47722221
PV Royal	16927103	2501977	22718763	11945298	17197349

	Average	STD	MAX	MIN	Median
PV Rev	3.3E+08	46365783	4.4E+08	2.4E+08	3.4E+08
PV CFlow	60507859	32765023	1.3E+08	-1.1E+07	63374197
PV Sev Tax	8290615	1157807	10907008	5961337	8381407
PV StateTax	10844589	1966694	16018226	7469355	10878679
PV CorpTax	46623558	8557254	69369636	32300621	46707480
PV Royal	16581228	2315614	21814016	11922669	16762812

	Average	STD	MAX	MIN	Median
PV Rev	3.4E+08	43780254	4.3E+08	2.5E+08	3.4E+08
PV CFlow	65194270	30083835	1.2E+08	2743663	69515429
PV Sev Tax	8426457	1092939	10610116	6313950	8543225
PV StateTax	10914938	1996603	15406196	7552505	10859768
PV CorpTax	46896074	8705208	66679598	32492931	46481407
PV Royal	16852912	2185878	21220236	12627900	17086449

Additional Area Gas Data, discount rate = 10%

	Average	STD	MAX	MIN	Median
PV Rev	1.4E+08	12663431	1.6E+08	1.1E+08	1.4E+08
PV CFlow	74825551	7626274	86854395	54627262	76506321
PV Sev Tax	3462118	316132.4	3960859	2623989	3531462
PV State Tax	8004943	749601.6	9185781	6002935	8168980
PV CorpTax	33521028	3332037	38777769	24687166	34251897
PV Royal	6924236	632265.4	7921723	5247980	7062923

	Average	STD	MAX	MIN	Median
PV Rev	1.4E+08	11564098	1.7E+08	1.2E+08	1.4E+08
PV CFlow	75170130	6967083	91233244	60660792	74688146
PV Sev Tax	3476340	288531	4140623	2875874	3456630
PV State Tax	8038394	681270.5	9600367	6625254	7993423
PV CorpTax	33670940	3041117	40672467	27341990	33463173
PV Royal	6952683	577062.3	8281245	5751741	6913258

	Average	STD	MAX	MIN	Median
PV Rev	1.3E+08	11206749	1.6E+08	1.2E+08	1.3E+08
PV CFlow	72392396	6749703	90002540	60688671	71455583
PV Sev Tax	3361136	279570	4090449	2874293	3322085
PV State Tax	7764340	662227	9490824	6590582	7671607
PV CorpTax	32456674	2946666	40143612	27325357	32045062
PV Royal	6722272	559139.6	8180895	5748587	6644168

Combined Area Oil Data, discount rate = 10%

	Average	STD	MAX	MIN	Median
PV Rev	5.1E+08	78819901	7.0E+08	3.6E+08	4.9E+08
PV CFlow	99785369	54013927	2.2E+08	-9296861	90739557
PV Sev Tax	12759640	1968292	17509966	9062491	12284294
PV State Tax	16409733	3596240	26250225	11146737	15340575
PV CorpTax	71389604	15848123	1.2E+08	47826702	66790404
PV Royal	25519278	3936584	35019938	18124977	24568586

	Average	STD	MAX	MIN	Median
PV Rev	5.1E+08	81266909	6.4E+08	3.2E+08	5.2E+08
PV CFlow	95948663	56946182	1.8E+08	-4.2E+07	1.1E+08
PV Sev Tax	12632894	2028409	15937934	7977231	12904969
PV State Tax	16251644	3446856	22581227	9098850	16430360
PV CorpTax	70723348	15149678	98673417	39369325	71434028
PV Royal	25265786	4056816	31875859	15954465	25809932

	Average	STD	MAX	MIN	Median
PV Rev	5.1E+08	85091971	7.3E+08	2.8E+08	5.1E+08
PV CFlow	1.0E+08	59583995	2.4E+08	-8.0E+07	99315596
PV Sev Tax	12795683	2124472	18137073	6897743	12706771
PV State Tax	16550260	3664769	27743604	9429589	15794371
PV CorpTax	72025270	16139074	1.2E+08	41064835	68595995
PV Royal	25591365	4248943	36274149	13795485	25413537

Combined Area Gas Data, discount rate = 10%

	Average	STD	MAX	MIN	Median
PV Rev	2.8E+08	30371521	3.7E+08	2.2E+08	2.7E+08
PV CFlow	1.5E+08	18299074	2.0E+08	1.1E+08	1.5E+08
PV Sev Tax	6958761	758851.6	9144082	5454634	6818512
PV State Tax	15475167	1790712	20629912	11930565	15150561
PV CorpTax	66864527	7998292	89897814	51011017	65386319
PV Royal	13917523	1517703	18288167	10909267	13637030

	Average	STD	MAX	MIN	Median
PV Rev	2.7E+08	27881900	3.2E+08	2.0E+08	2.7E+08
PV CFlow	1.4E+08	16798373	1.7E+08	1.0E+08	1.4E+08
PV Sev Tax	6769151	696295.5	8009629	4916370	6758709
PV State Tax	15028337	1643792	17957238	10649220	15004833
PV CorpTax	64866037	7338956	77940676	45337729	64755961
PV Royal	13538303	1392591	16019259	9832741	13517417

	Average	STD	MAX	MIN	Median
PV Rev	2.7E+08	32454559	3.6E+08	2.1E+08	2.7E+08
PV CFlow	1.4E+08	19554376	2.0E+08	1.0E+08	1.4E+08
PV Sev Tax	6742566	810427.3	8894522	5114337	6670988
PV State Tax	14965772	1912159	20040057	11123253	14796589
PV CorpTax	64585827	8541904	87267431	47424282	63831387
PV Royal	13485133	1620855	17789043	10228674	13341975