APPENDIX D

UNITED STATES DEPARTMENT OF THE INTERIOR

BUREAU OF LAND MANAGEMENT

WYOMING RESERVOIR MANAGEMENT GROUP

ENGINEERING AND GEOLOGIC REPORT

PINEDALE ANTICLINE NATURAL GAS
EXPLORATION AND DEVELOPMENT
DRAFT ENVIRONMENTAL IMPACT STATEMENT

VERTICAL AND DIRECTIONAL DRILLING ALTERNATIVES

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EXECUTIVE SUMMARY

As requested by the Pinedale Field Office, we reviewed a directional drilling requirement proposed for the Pinedale Anticline EIS. This area has the potential for significant gas reserves. Its true potential is still unproven. The enclosed report provides review of available information, suggests ways to apply any exceptions that may be proposed in the EIS, comments on the effects of requiring directional drilling, and recommends procedures to be used in reviewing exception requests.

We recommend the EIS not include criteria that ask an operator to demonstrate that a directional well would be technically infeasible for geologic reasons. There are no geologic reasons to preclude drilling directional wells.

Most directional wells needed to reach an 80-acre spacing are not expected to be economic at today's gas prices. Directional wells needed to reach a 40-acre spacing would be uneconomic. Only wells with high recoverable reserves could be drilled at either spacing. Any economic justification required of an operator who makes an exception request could be reviewed in the field office. If economic verification is required, a review of the submitted recoverable reserve analysis would be difficult to do in the field office. The large databases and software needed to do the analysis are not readily available there.

Hydrocarbons would not be recovered, royalty would be lost and maximum economic recovery of the resource would not be possible if additional drilling pads could not be allowed. If a second well cannot be drilled in an 80-acre spacing, up to one half of the hydrocarbons and associated royalty would be lost in that 80-acre area. If a second, third, and fourth well cannot be drilled in a 40-acre spacing, up to three fourths of the hydrocarbon reserves and associated royalties would be lost. A reservoir analysis on a well by well basis will be needed to determine reserves and resultant royalty loss. Any determination, to either allow or not allow additional drilling pads, could be controversial. Also, a management decision may be needed in each case. This decision would be made after weighing the potential hydrocarbon and royalty loss against potential surface disturbance impacts.

VERTICAL VS. DIRECTIONAL DRILLING

The Pinedale Anticline EIS team asked the Wyoming Reservoir Management Group to review the Pinedale Anticline EIS alternatives as they relate to application of a directional drilling requirement. In this report, we suggest ways to apply any exceptions that may be proposed in the EIS and discuss problems associated with applying an exception. Also provided are some recommendations on how to analyze the operator's exception requests.

COSTS AND RISKS ASSOCIATED WITH DIRECTIONAL DRILLING

The cost of directional drilling is greater than the cost of conventional drilling. This is due to the longer time and additional equipment needed to drill and complete wells. Higher costs are also expected in the project area due to the increased depth, the potentially higher pressures, and the increased chance of lost circulation zones (Holland & Hart 1999). An s-shaped wellbore if required, is also more costly than other types of deviated holes. Intermediate casing, if required, would also be an additional cost.

If mechanical problems are encountered during the directional drilling, cost can rise dramatically. Mechanical problems may include key seating, stuck pipe, fishing problems, and logging problems due to hole deviation. Stimulation may also be less efficient in deviated wellbores than in vertical wellbores. Our projected costs of drilling directional wells do not consider problems that may occur due to increased risk of mechanical problems. We should recognize that problems which occur during directional drilling may significantly increase cost and the risk of losing the entire wellbore.

Two wells were directionally drilled in the project area in 1998. The Ultra #3-22D directional well, encountered drilling and completion problems. These problems resulted in an additional cost of about 1.2 million dollars (Holland & Hart 1999). Also, stuck casing prevented the testing of potential reserves at the bottom of the hole. These potential reserves may have been bypassed and their associated royalty may have been irretrievably lost.

In McMurry Oil Company's Jensen #4 directional well, an intermediate casing string was set to help stabilize the wellbore. The actual cost of drilling this well was higher than our projection of cost, due to parted and collapsed casing. Experience gained from drilling initial directional wells is expected to bring costs down to our projected levels.

POTENTIAL SPACING

In certain parts of the EIS area, operators expect to drill four or more wells per 640-acre section. Depending on geology and reservoir factors in any particular 640-acre section of the Anticline, development could occur on:

	Spacing	Wells/640 Acres	Well Pads/640 Acres
•	160-acre	four vertical wells	four well pads
•	80-acre	eight vertical wells	four well pads, with two directional wells per pad (both wells deviated 660 feet)
•	40-acre	16 vertical wells	four well pads, with one vertical well and three directional wells per pad (two wells deviated 1320 feet and one well deviated 1867 feet)

This report focuses on review of vertical versus directional drilling alternatives for 80-acre spacing (Part A) and 40-acre spacing (Part B). No directional wells would be required to develop 160-acre spacing with four well pads per section.

PART A - 80-ACRE SPACING

Geologic variation plays a role in localization of higher production capabilities. In some areas of the Pinedale Anticline, industry may need to develop on 80-acre spacing (eight well pads per section) to effectively and fully recover reserves.

A proposal was made to limit well pads to four per section in areas of sensitive surface resources. If only four drilling pads are allowed, then two directional wells would be necessary on each well pad. An exception provision could be used to allow additional well pads if certain criteria are met. Operators would be required to submit criteria that relate to the geologic and economic aspects of a directional drilling requirement before additional well pads could be considered in sensitive surface resource areas. The inability to access each 80-acre spacing area could result in a loss of hydrocarbons and Federal royalties.

The Holland & Hart report (1999) indicated that only s-shaped wellbores could be drilled and intermediate casing would be required. We assumed that these 660-foot hole deviations could be drilled as slant holes or s-shaped holes and would not need intermediate casing. Not including the intermediate casing reduces the drilling cost. Holland & Hart were also concerned that a slant hole would leave a wedge-shaped area partially undeveloped. We determined that a slant hole with a small wedge-shaped area would have little impact on total hydrocarbon recovery.

We divided the proposed criteria into four specific questions for analysis. Each question is listed below and an answer is supplied. We then provide an explanation of known facts surrounding the question. A recommendation is also supplied that comments on the effects of applying this type of exception to the directional drilling requirement. If appropriate, changes to the exception criteria are recommended.

1. **Do geologic reasons preclude directional drilling?**

Answer: No

Explanation: In the Pinedale Anticline area there are hundreds of lenticular sandstones present that are potential producing reservoirs. The sandstones are typically tight (they have low permeability) and there can be many producible reservoir compartments. Vertical faulting can additionally complicate these reservoirs. There are no geologic reasons to preclude directional drilling to the target reservoirs. In fact, two directional wells have been drilled. Both wells experienced drilling and completion problems that caused increased costs. Potential reserves were also lost at the bottom of the producing zone in one of the wells.

Recommendation: Assume directional drilling would not be precluded for geologic reason

2. **If drilling is limited to four well pads per section, would a directional drilling requirement cause additional wells not to be drilled due to economics?**

Answer: This question can be answered only on a well by well basis. Many wells could be directionally drilled at present gas prices.

Explanation: In Appendix A we analyze the costs of vertical and directional drilling alternatives. The analysis relates the costs of drilling vertical and directional wells at three different production rates and three different gas prices. We then determined well payout times for each scenario. Analysis shows that at the present price of about $2.00 per million cubic feet of gas, **vertical wells** with projected recoverable gas reserves of 3.53 billion cubic feet **would be marginally economic to drill**. **Directional wells** with projected recoverable gas reserves of 3.95 billion cubic feet **would not be economic to drill.**

Low gas prices and/or low reserve projections would reduce the number of directional wells that could be economically drilled.

Recommendation: Some drilling and production history in the immediate area of a pad proposal would be needed to make a determination of potential costs and reserves. In their application for exception, an operator should supply information on expected recoverable reserves, well costs, gas price, and payout. Some of this information could be reviewed in the field office. Making an analysis of the submitted recoverable reserves would be difficult to do in the field office, since the required economic analysis software is not readily available at that location.

3. **If additional drilling pads cannot be allowed, would an unacceptable loss of hydrocarbons occur?**

Answer: In almost all cases, some loss of hydrocarbons and royalties would occur. Up to one-half of the reserves in each 160-acre spacing would be left in the ground if only one well pad were allowed.

Explanation: The reservoir beneath the Pinedale Anticline is broken into small producing blocks or compartments due to the lenticular nature of individual sandstone bodies, their low permeability, and faulting. To be able to encounter all potentially producing compartments and drain them, a relatively close well spacing may be necessary in parts of the Pinedale Anticline. When producing compartments are found to be smaller than 160 acres in size, a significant volume of hydrocarbons would not be recovered if drill pads are restricted to four per section and directional wells are not economic to drill.

Recommendation: If additional drilling pads are not allowed, to fully develop the reservoirs, hydrocarbons would remain in some compartments and not be recovered. A reservoir analysis would be needed on a well-by-well basis to determine the volume of reserves not recovered. Such analysis would be difficult to do in the field office, for the reasons described above in answer to question two. Any determination, to either allow or not allow additional drilling pads, could be controversial. Also, a management decision may be needed in each case. This decision would be made after weighing the potential hydrocarbon and royalty loss against potential surface disturbance impacts.

4. **If additional drilling pads cannot be allowed, would an unacceptable loss of Federal royalty occur?**

Answer: In almost all cases, loss of royalty would occur. Royalty loss would be up to one-half of the potential production from each area of 160 acres.

Recommendation: Since we have found that if additional drilling pads cannot be allowed and hydrocarbons would not be recovered, then, royalties would also not be received. The study required to answer question three, could be used to determine lost royalty on an individual well. Here also, a definition of unacceptable loss of royalty would have to be made and could be controversial.

PART B - 40-ACRE SPACING

Geologic variation plays a role in localization of higher production capabilities. In some areas of the Pinedale Anticline, industry may need to develop on 40-acre spacing (16 well pads per section) to effectively and fully recover reserves.

A proposal was made to limit well pads to four per section in areas of sensitive surface resources. If only four drilling pads are allowed, then one vertical and three directional wells would be necessary on each well pad. Deviation distances would be longer (1320 and 1867 feet) than for deviation distances at 80-acre spacing (660 feet). An exception provision could be used to allow additional well pads if certain criteria are met. Operators would be required to submit criteria that relate to the geologic and economic aspects of a directional drilling requirement before additional well pads could be considered in sensitive surface resource areas. The inability to access each 40-acre spacing area could result in a loss of hydrocarbons and Federal royalties.

The Holland & Hart report (1999) indicated that only s-shaped wellbores could be drilled and intermediate casing would be required. We agree that this would be necessary for these wells, since they require a longer horizontal deviation. Including intermediate casing increases the drilling cost. They were also concerned that a slant hole would leave a wedge-shaped area partially undeveloped. We determined that these slant holes would leave a larger wedge of partially undeveloped reservoir and would have a greater impact on total recovery than slant holes do for 80-acre spacing.

Exploration criteria are examined as they were for Part A and are answered in the same manner.

1. Do geologic reasons preclude directional drilling?

Answer: No

Explanation: See part A explanation.

Recommendation: Assume directional drilling would not be precluded for geologic reasons.

2. If drilling is limited to four well pads per section, would a directional drilling requirement cause additional wells not to be drilled due to economics?

Answer: This question can be answered only on a well by well basis. Many wells could be directionally drilled at present gas prices.

Explanation: Appendix B analyzes the costs of vertical and directional drilling alternatives. The analysis relates the costs of drilling vertical and directional wells at three different production rates and three different gas prices. We then determined well payout times for each scenario. Analysis shows that at the present price of about $2.00 per million cubic feet of gas, **vertical wells** with projected recoverable gas reserves in excess of 3.53 billion cubic feet **would be marginally economic to drill**. **Directional wells** with projected recoverable gas reserves of 4.24 billion cubic feet **would not be economic to drill.**

Additional costs of intermediate casing would increase the total recoverable gas reserves needed to drill an economic directional well. Low gas prices and/or low reserve projections would reduce the number of directional wells that could be economically drilled.

Recommendation: Some drilling and production history in the immediate area of a pad proposal would be needed to make a determination of potential costs and reserves. In their application for exception, an operator should supply information on expected recoverable reserves, well costs, gas price, and payout. Some of this information could be reviewed in the field office. Making an analysis of the submitted recoverable reserves would be difficult to do in the field office, since the required economic analysis software is not readily available at that location.

3. **If additional drilling pads cannot be allowed, would an unacceptable loss of hydrocarbons occur?**

Answer: Loss of hydrocarbons and royalties would occur. This impact would be greater than determined for 80-acre spacing. This is because at 80-acre spacing only one well could not be drilled, while **at 40-acre spacing three wells could not be drilled in each area of 160 acres**. As much as three-quarters of the reserves for each 160 acres would be left in the ground if only one well pad were allowed.

Explanation: See part A explanation.

Recommendation: If additional drilling pads are not allowed to fully develop the reservoirs, hydrocarbons would remain in some compartments and not be recovered. As stated above, as much as three-fours of the hydrocarbons could not be recovered. A reservoir analysis would be needed on a well-by-well basis to determine the volume of reserves not recovered. Such analysis would be difficult to do in the field office, for the reasons described above in answer to question two. Any determination, to either allow or not allow additional drilling pads, could be controversial. Also, a management decision may be needed in each case. This decision would be made after weighing the potential hydrocarbon and royalty loss against potential surface disturbance impacts.

4. **If additional drilling pads cannot be allowed, would an unacceptable loss of Federal royalty occur?**

Answer: In almost all cases, loss of royalty would occur. Royalty loss would be up to three-fourths of the potential production from each area of 160 acres.

Recommendation: Since we have found that if additional drilling pads cannot be permitted and hydrocarbons would not be recovered, then, royalties would also not be received. The study required to answer question three could be used to determine lost royalty on an individual well. Here also, a definition of unacceptable loss of royalty would have to be made and could be controversial.

REFERENCE CITED

Holland & Hart, 1999, Letter sent to Mr. Bill McMahan of the BLM, as a representative of Pinedale Anticline operators, sent January 12.

APPENDIX A
PINEDALE ANTICLINE NATURAL GAS EXPLORATION AND DEVELOPMENT
DRAFT ENVIRONMENTAL IMPACT STATEMENT
ENGINEERING FIELD STUDY (VERTICAL AND DIRECTIONAL DRILLING ALTERNATIVES - 80 ACRES)

The most appropriate method of determining economic feasibility of vertical versus directional drilling on the Pinedale Anticline was to:

1. Determine recoverable reserves;

2. Calculate net present values; and

3. Graph net present value against recoverable reserves at three different gas prices.

Graphs were constructed at gas prices of $1.50/MCFG, $2.00/MCFG and $2.50/MCFG. The net present value for both vertically and directionally drilled wells was calculated at these three gas prices, assuming three different initial producing rates.

Decline curve analysis was used to determine recoverable reserves assuming a range of three initial producing rates. The three initial producing rates used provide a range for analysis from wells thought to be uneconomic to very good productive wells. Actual recoverable reserves could range between less than one BCFG to over eight BCFG. Initial producing rates and resulting calculated recoverable reserves for the three scenarios are:

1. Initial producing rate of 1,000 MCFGPD and recoverable reserves of 2,039 MMCFG (Reference Attachment No. A1);

2. Initial producing rate of 2,000 MCFGPD and recoverable reserves of 4,296 MMCFG (Reference Attachment No. A2); and

3. Initial producing rate of 3,000 MCFGPD and recoverable reserves of 6,553 MMCFG (Reference Attachment No. A3).

For each of the three scenarios a hyperbolic decline (with an exponent of 1.8) was assumed for most of the productive life of the well. The initial production rate is declined hyperbolically at 82 percent for two months, at 40 percent for the next four months, and at 33 percent for the next 34 months. The production rate after the 40-month period is then declined exponentially at eight percent for the productive life of the well. A cutoff of 50 MCFGPD was used to determine the point at which a well could not continue to be economically produced. Production projected below this economic limit of 50 MCFG was not included as part of the recoverable reserve for each scenario.

Total expenditures (including drilling, completion and surface facility costs) for a typical vertically and directionally drilled well on the Pinedale Anticline were obtained from Ultra Petroleum. The different costs are listed below:

- Drilling costs - $1,000,000 (Vertical) and $1,325,000 (Directional).

- Completion costs - $875,000 (Both vertical and directional). An average completion cost of $175,000 per interval was estimated for perforation, stimulation and flow testing. On average, five intervals require completion activities.

- Facility costs - $125,000 (Both vertical and directional).

For a directionally drilled well, a potential savings of $75,000 in pad construction and in surface facilities would be realized since a directionally drilled well would be drilled from an existing well location and surface facilities would be centralized. Consequently, the total expenditures for a vertically drilled well are $2,000,000 and for a directionally drilled well are $2,250,000.

The net present value was calculated after the recoverable reserves for the three scenarios were determined. This value was calculated for both vertically and directionally drilled wells at gas prices of $1.50/MCFG, $2.00/MCFG and $2.50/MCFG (Reference Attachment No. A4).

Graphs were constructed which show the curves for a vertically and a directionally drilled well with recoverable reserves on the x-axis plotted against net present value on the y-axis at gas prices of $1.50/MCFG, $2.00/MCFG and $2.50/MCFG (Reference Attachment Nos. A5, A6, and A7).

- Attachment No. A5 shows that at a gas price of $1.50/MCFG, recoverable reserves would need to be 4,942 MMCFG for a vertical well, and 5,528 MMCFG for a directional well, for a net present value equal to zero.

- Attachment No. A6 shows that at a gas price of $2.00/MCFG, recoverable reserves would need to be 3,531 MMCFG for a vertical well, and 3,949 MMCFG for a directional well, for a net present value equal to zero.

- Attachment No. A7 shows that at a gas price of $2.50/MCFG, recoverable reserves would need to be 2,717 MMCFG for a vertical well, and 3,042 MMCFG for a directional well, for a net present value equal to zero.

A net present value of zero is the point at which the internal rate of return equals the discount rate of ten percent. In each scenario, recoverable reserves need to be greater for a directionally drilled well than for a vertically drilled well with a difference of 586 MMCFG at $1.50/MCFG, a difference of 418 MMCFG at $2.00/MCFG and a difference of 325 MMCFG at $2.50/MCFG. The higher the gas price, the smaller the difference between recoverable reserves for a vertical and directional well.

The Mesa No. 3-22D well, located in the NE¼NW¼ of Section 22, T.32N., R.109W., was directionally drilled by Ultra Petroleum on the Pinedale Anticline. As reported in "The Rocky Mountain Oil Journal", the well encountered numerous mechanical difficulties while being drilled and casing was set above a potential productive interval due to wellbore conditions. Four different intervals in the Lance Formation were perforated and stimulated. The well was completed on December 9, 1998, for an initial potential of 1,593 MCFPD. Cumulative production through March 1999 is only 104 MMCF. Recoverable reserves were calculated to be only 240 MMCF.

Another well, the Jensen No. 4, located in the NE¼NW¼ of Section 14, T.31N., R.109W., was directionally drilled by McMurry Oil Company on the Pinedale Anticline. An intermediate casing string was set at 7,957 feet to help stabilize the wellbore. Three different intervals were perforated and stimulated. Casing is parted and collapsed at 10,015 feet. The reason for the collapsed casing is unknown, but it may be related to the directionally drilled hole. Cumulative production through May 1999 is only 45 MMCF. Recoverable reserves were not calculated.

CONCLUSIONS

1. A vertically drilled well with an initial producing rate of 1,000 MCFGPD could not be economic at any of the three gas prices studied.

2. A vertically drilled well with an initial producing rate of 2,000 MCFGPD could not be economic at a gas price of $1.50/MCFG. However, a vertically drilled well with an initial producing rate of 2,000 MCFPD could be economically drilled at a gas price of $2.00/MCFG or $2.50/MCFG; however, the payout time of 6.77 years at a gas price of $2.00/MCFG could be considered excessive by industry standards.

3. A vertically drilled well with an initial producing rate of 3,000 MCFGPD could be economic at any of the three gas prices studied.

4. A directionally drilled well with an initial producing rate of 1,000 MCFGPD could not be economic at any of

the three gas prices studied.

5. A directionally drilled well with an initial producing rate of 2,000 MCFGPD could not be economic at a gas price of $1.50/MCFG. However, a directionally drilled well with an initial producing rate of 2,000 MCFGPD could be economically drilled at a gas price of $2.00/MCFG or $2.50/MCFG; however, the payout time of 10.23 years at a gas price of $2.00/MCFG would be considered excessive by industry standards.

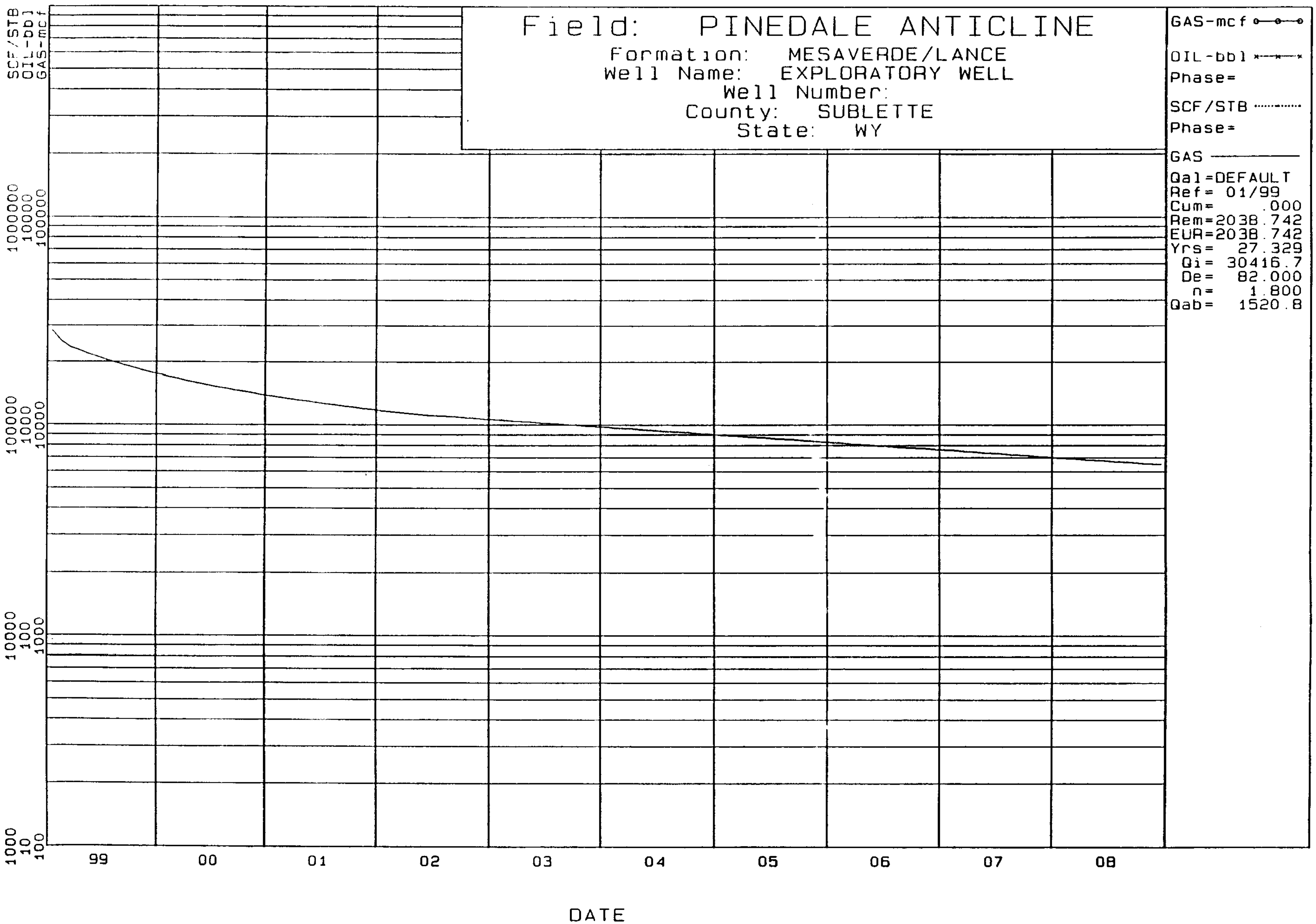
6. A directionally drilled well with an initial producing rate of 3,000 MCFGPD could be economic at any of the three gas prices studied; however, the payout time of 7.70 years at a gas price of $1.50/MCFG could be considered excessive by industry standards.

7. The current spot natural gas price at Opal, Wyoming, as reported by Northwest Pipeline for August 1999 is $2.20/MCFG. The average spot natural gas price for 1999 is $1.84/MCFG (Reference Attachment No. A8).

8. Based on the results of directionally drilling the Mesa No. 3-22D and Jensen No. 4 wells, there appears to be a slight risk that a wellbore could be lost due to mechanical difficulties. Any mechanical difficulties encountered would increase the cost of directionally drilling; however, it is technically feasible to directionally drill on the Pinedale Anticline. Assuming each completed interval would produce gas at an initial rate of 500 MCFGPD (total of 2,000 MCFGPD), it would **not** be economic to directionally drill on the Pinedale Anticline at expected future gas prices.

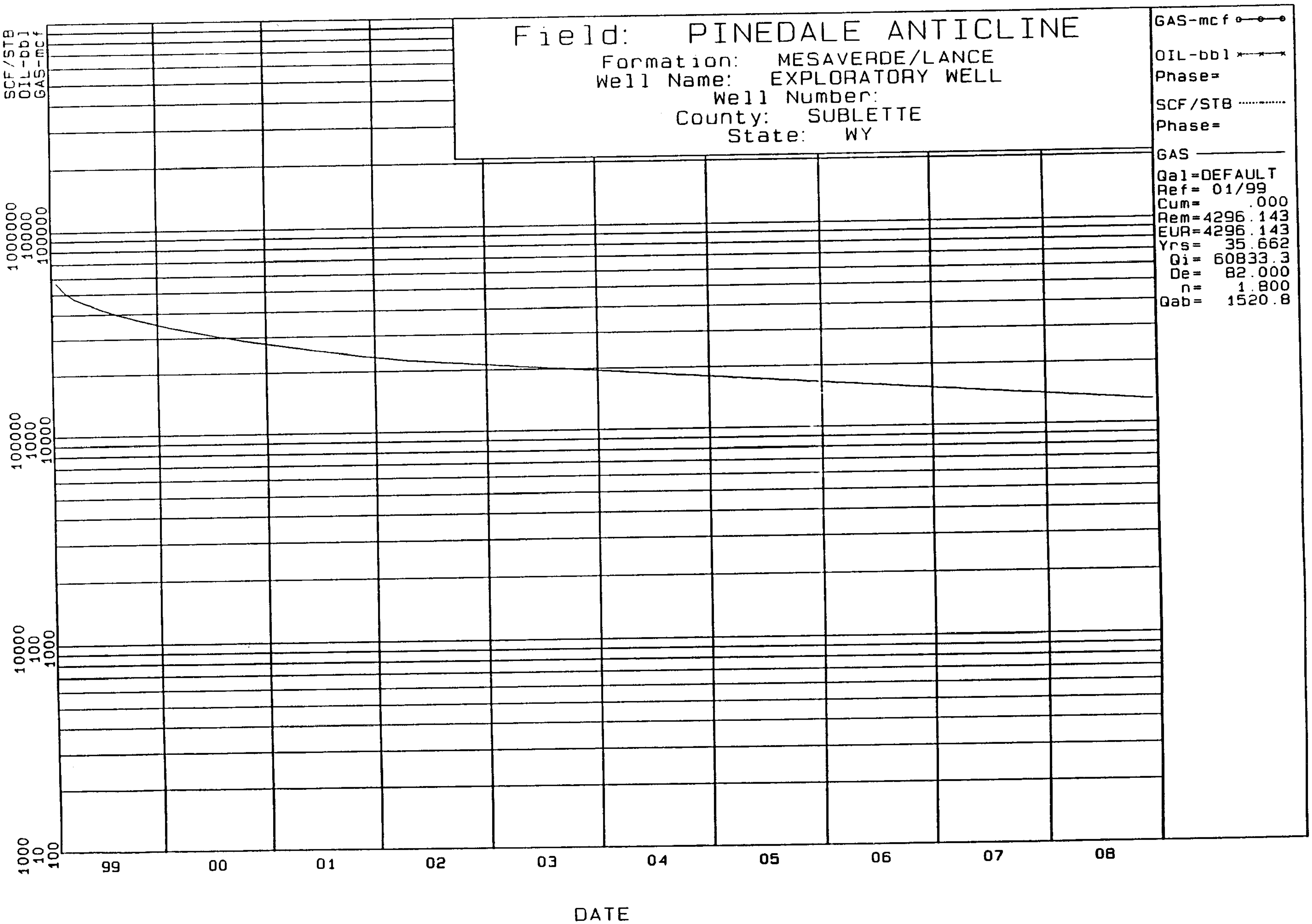
Attachments

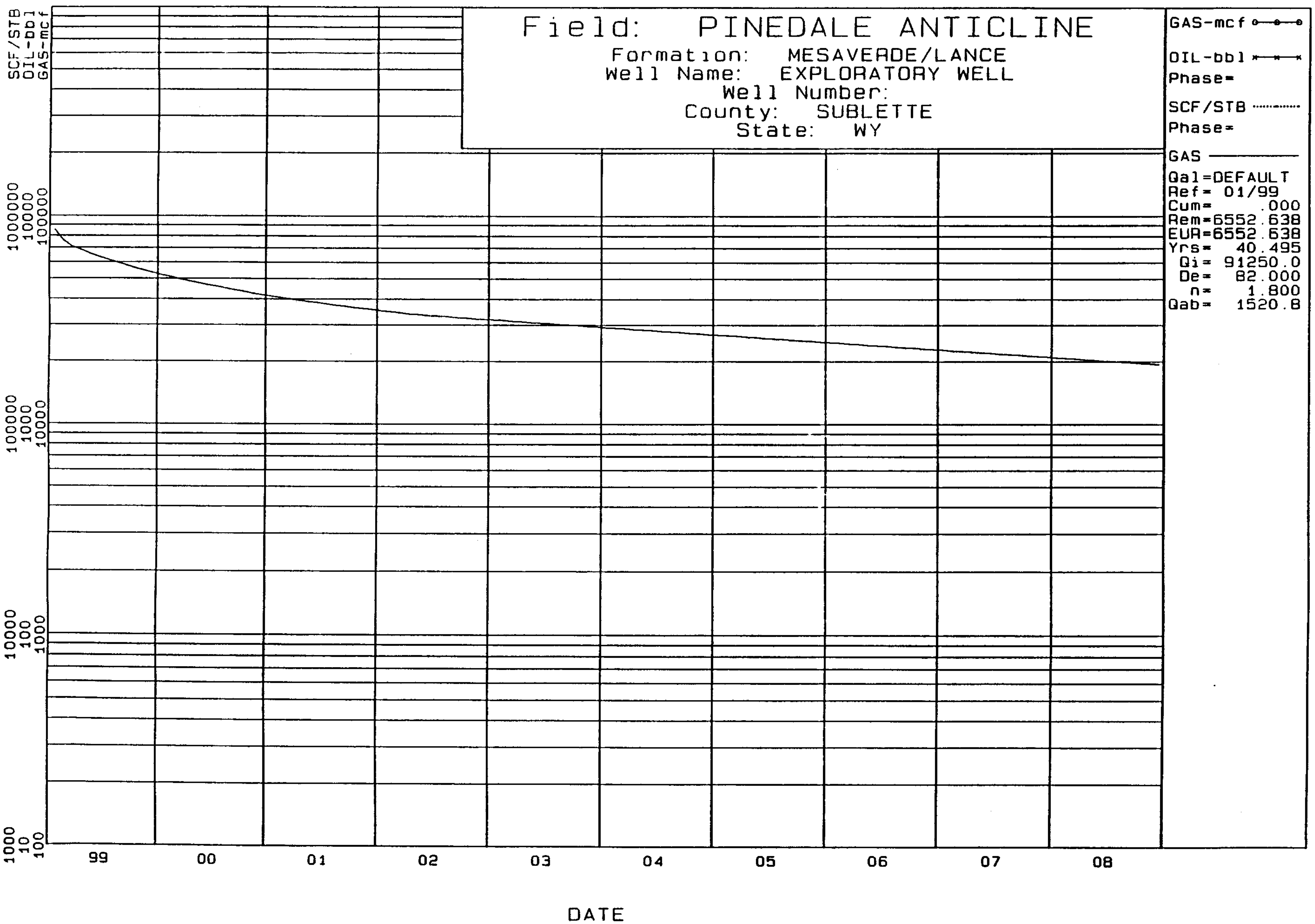
Attachment No. A1 - Hypothetical Well (initial potential of 1,000 MCFGPD)
Attachment No. A2 - Hypothetical Well (initial potential of 2,000 MCFGPD)
Attachment No. A3 - Hypothetical Well (initial potential of 3,000 MCFGPD)
Attachment No. A4 - Table of Net Present Value of Vertical and Directional Drilling Alternatives
Attachment No. A5 - Graph at Gas Price of $1.50/MCFG
Attachment No. A6 - Graph at Gas Price of $2.00/MCFG
Attachment No. A7 - Graph at Gas Price of $2.50/MCFG
Attachment No. A8 - Spot Natural Gas Prices



ATTACHMENT NO. A1 - Hypothetical well (initial potential of 1,000 MCFPD)

ATTACHMENT NO. A2 - Hypothetical well (initial potential of 2,000 MCFPD)





ATTACHMENT NO. A3 - Hypothetical well (initial potential of 3,000 MCFPD)

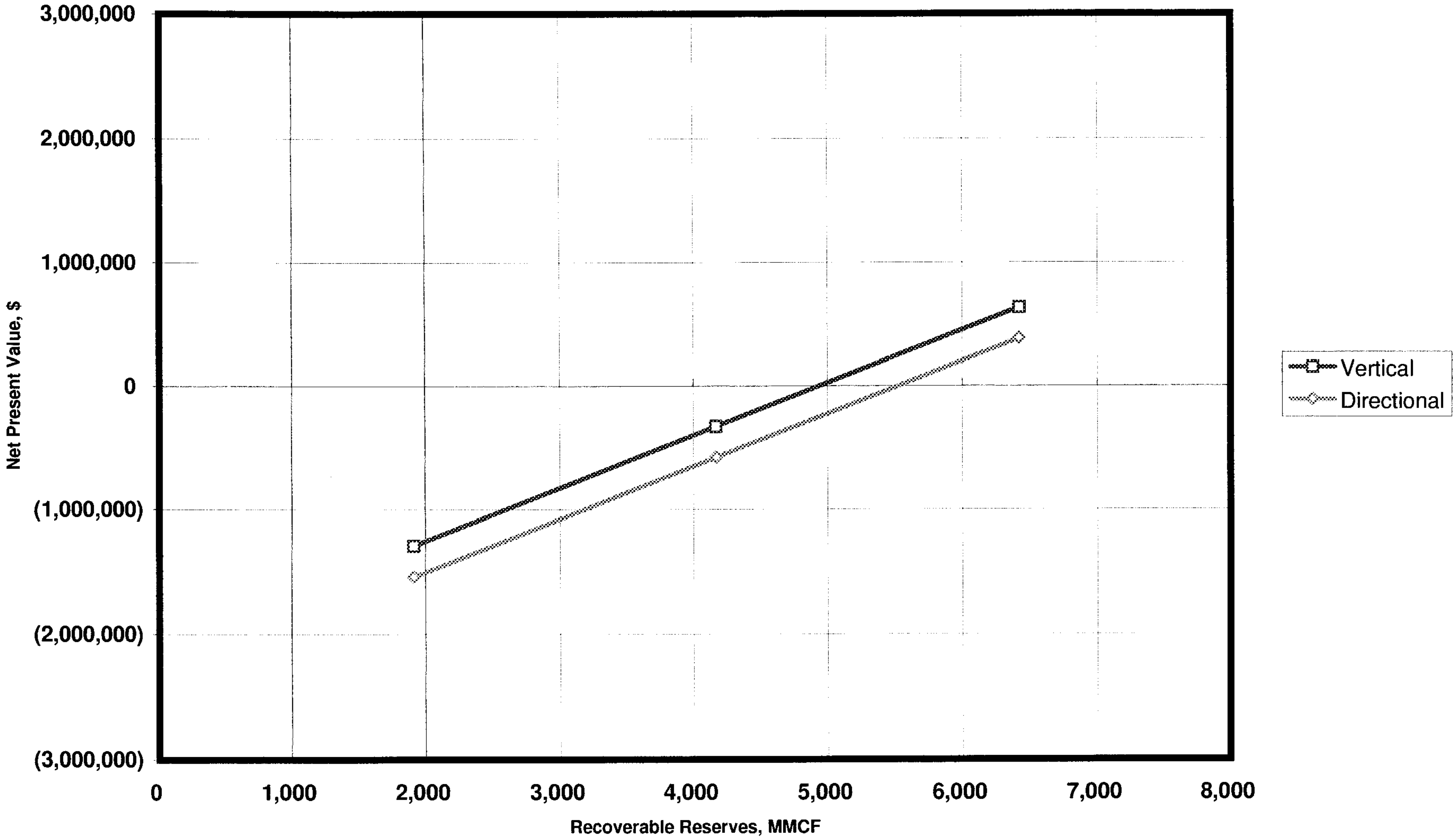
PINEDALE ANTICLINE NATURAL GAS EXPLORATION AND DEVELOPMENT
DRAFT ENVIRONMENTAL IMPACT STATEMENT
VERTICAL AND DIRECTIONAL DRILLING ALTERNATIVES

Type of Drilling (Traditional)	Drilling Costs ($)	Initial Producing Rate (MCFPD)	Decline Curve Recoverable Reserves (MCF)	Economical Recoverable Reserves (MCF)	Gas Price ($/MCF)	Net Present Value ($)	Payout (years)
Vertical	2,000,000	1,000	2,039	1,916	1.50	(1,291,326)	NA
Directional	2,250,000	1,000	2,039	1,916	1.50	(1,541,326)	NA
Vertical	2,000,000	1,000	2,039	2,014	2.00	(907,144)	NA
Directional	2,250,000	1,000	2,039	2,014	2.00	(1,157,144)	NA
Vertical	2,000,000	1,000	2,039	2,038	2.50	(522,174)	NA
Directional	2,250,000	1,000	2,039	2,038	2.50	(772,174)	NA
Vertical	2,000,000	2,000	4,296	4,172	1.50	(329,430)	NA
Directional	2,250,000	2,000	4,296	4,172	1.50	(579,430)	NA
Vertical	2,000,000	2,000	4,296	4,269	2.00	441,616	6.77
Directional	2,250,000	2,000	4,296	4,269	2.00	191,616	10.23
Vertical	2,000,000	2,000	4,296	4,294	2.50	1,212,910	3.70
Directional	2,250,000	2,000	4,296	4,294	2.50	962,910	4.69
Vertical	2,000,000	3,000	6,553	6,428	1.50	634,453	5.59
Directional	2,250,000	3,000	6,553	6,428	1.50	384,453	7.70
Vertical	2,000,000	3,000	6,553	6,526	2.00	1,791,526	2.75
Directional	2,250,000	3,000	6,553	6,526	2.00	1,541,526	3.39
Vertical	2,000,000	3,000	6,553	6,550	2.50	2,948,714	1.82
Directional	2,250,000	3,000	6,553	6,550	2.50	2,698,714	2.16

Assumptions

1. Condensate Yield - 8 BBL/MMCF
2. Operating Costs - $4,000/month for first year, $2,500/month thereafter
3. Discount Rate - 15 percent
4. Royalty Rate - 12.5 percent

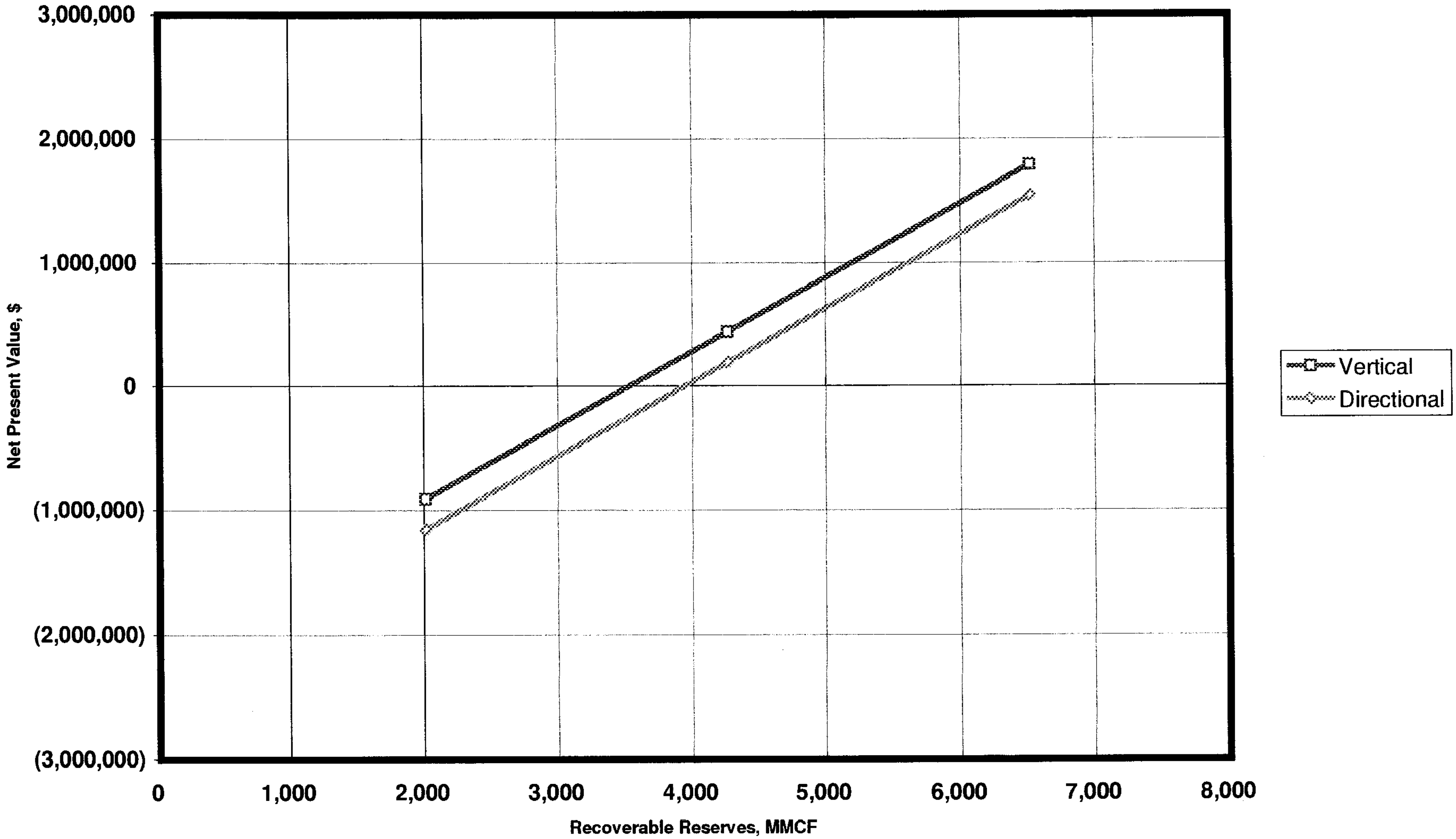
PINEDALE ANTICLINE
GAS PRICE - $1.50/MCF



ATTACHMENT NO. A5 - Graph at Gas Price of $1.50/MCFG

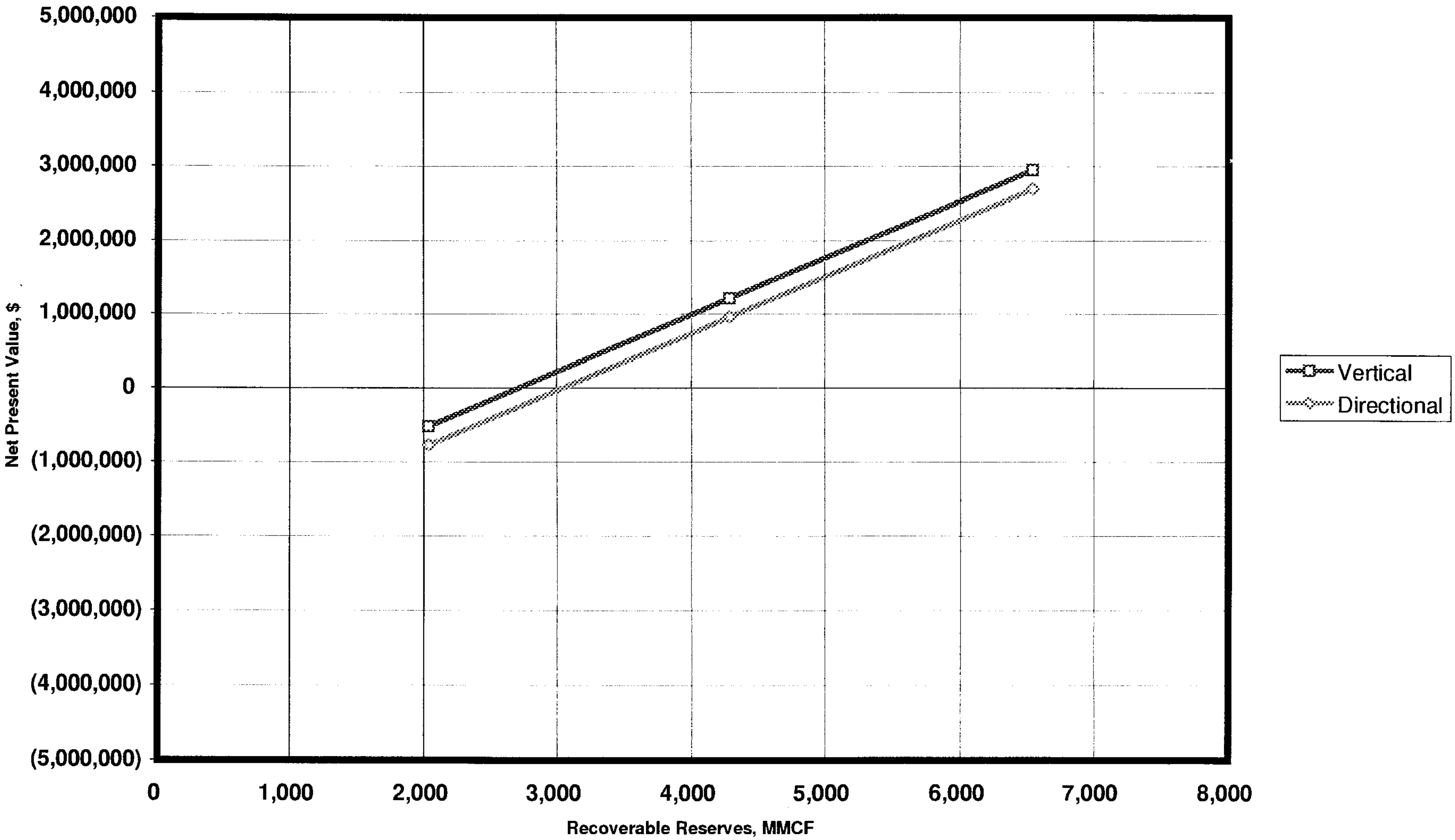
ATTACHMENT NO. A6 - Graph at Gas Price of $2.00/MCFG

PINEDALE ANTICLINE
GAS PRICE - $2.00/MCF



ATTACHMENT NO. A7 - Graph at Gas Price of $2.50/MCFG

PINEDALE ANTICLINE
GAS PRICE - $2.50/MCF



SPOT NATURAL GAS PRICES
NORTHWEST PIPELINE
OPAL, WYOMING

Month & Year	Date of Oil & Gas Journal	Price ($/MMBTU)	Month & Year	Date of Oil & Gas Journal	Price ($/MMBTU)	Month & Year	Date of Oil & Gas Journal	Price ($/MMBTU)	Month & Year	Date of Oil & Gas Journal	Price ($/MMBTU)	Month & Year	Date of Oil & Gas Journal	Price ($/MMBTU)
Jan-86	**NA**	**NA**	Jan-89	23-Jan-89	1.35	Jan-92	20-Jan-92	1.35	Jan-95	16-Jan-95	1.40	Jan-98	19-Jan-98	2.05
Feb-86	**NA**	**NA**	Feb-89	27-Feb-89	1.35	Feb-92	17-Feb-92	1.00	Feb-95	20-Feb-95	1.10	Feb-98	16-Feb-98	1.70
Mar-86	**NA**	**NA**	Mar-89	03-Apr-89	1.25	Mar-92	16-Mar-92	1.15	Mar-95	20-Mar-95	1.05	Mar-98	16-Mar-98	1.90
Apr-86	**NA**	**NA**	Apr-89	UNKNOWN	1.15	Apr-92	20-Apr-92	1.15	Apr-95	17-Apr-95	1.05	Apr-98	20-Apr-98	1.90
May-86	**NA**	**NA**	May-89	08-May-89	1.15	May-92	18-May-92	1.25	May-95	15-May-95	1.10	May-98	18-May-98	1.95
Jun-86	**NA**	**NA**	Jun-89	12-Jun-89	1.10	Jun-92	15-Jun-92	1.35	Jun-95	19-Jun-95	1.15	Jun-98	15-Jun-98	1.65
Jul-86	21-Jul-86	1.45	Jul-89	17-Jul-89	1.05	Jul-92	20-Jul-92	1.20	Jul-95	17-Jul-95	1.00	Jul-98	20-Jul-98	1.60
Aug-86	18-Aug-86	1.50	Aug-89	14-Aug-89	1.10	Aug-92	17-Aug-92	1.55	Aug-95	21-Aug-95	0.90	Aug-98	17-Aug-98	1.75
Sep-86	15-Sep-86	1.45	Sep-89	11-Sep-89	1.10	Sep-92	21-Sep-92	1.65	Sep-95	18-Sep-95	1.05	Sep-98	21-Sep-98	1.60
Oct-86	20-Oct-86	1.35	Oct-89	09-Oct-89	1.15	Oct-92	19-Oct-92	2.10	Oct-95	16-Oct-95	1.05	Oct-98	19-Oct-98	1.65
Nov-86	17-Nov-86	1.35	Nov-89	13-Nov-89	1.40	Nov-92	16-Nov-92	1.80	Nov-95	20-Nov-95	1.15	Nov-98	16-Nov-98	2.00
Dec-86	15-Dec-86	1.35	Dec-89	11-Dec-89	1.65	Dec-92	21-Dec-92	1.90	Dec-95	18-Dec-95	1.30	Dec-98	21-Dec-98	2.00
Average-86	**NA**	**1.41**	**Average-89**	**NA**	**1.23**	**Average-92**	**NA**	**1.45**	**Average-95**	**NA**	**1.11**	**Average-98**	**NA**	**1.81**
Jan-87	19-Jan-87	1.35	Jan-90	08-Jan-90	2.05	Jan-93	18-Jan-93	2.25	Jan-96	15-Jan-96	1.25	Jan-99	18-Jan-99	1.80
Feb-87	UNKNOWN	1.40	Feb-90	12-Feb-90	1.50	Feb-93	15-Feb-93	1.60	Feb-96	19-Feb-96	1.20	Feb-99	15-Feb-99	1.65
Mar-87	16-Mar-87	1.30	Mar-90	12-Mar-90	1.15	Mar-93	15-Mar-93	1.80	Mar-96	18-Mar-96	1.20	Mar-99	15-Mar-99	1.50
Apr-87	20-Apr-87	1.25	Apr-90	09-Apr-90	1.10	Apr-93	19-Apr-93	1.80	Apr-96	15-Apr-96	1.05	Apr-99	19-Apr-99	1.60
May-87	18-May-87	1.20	May-90	14-May-90	1.10	May-93	17-May-93	2.30	May-96	20-May-96	0.95	May-99	17-May-99	2.00
Jun-87	15-Jun-87	1.20	Jun-90	11-Jun-90	1.10	Jun-93	21-Jun-93	1.70	Jun-96	17-Jun-96	1.10	Jun-99	21-Jun-99	2.00
Jul-87	20-Jul-87	1.15	Jul-90	16-Jul-90	1.15	Jul-93	19-Jul-93	1.60	Jul-96	15-Jul-96	1.20	Jul-99	19-Jul-99	2.00
Aug-87	17-Aug-87	1.15	Aug-90	13-Aug-90	1.10	Aug-93	16-Aug-93	1.70	Aug-96	19-Aug-96	1.25	Aug-99	16-Aug-99	2.20
Sep-87	21-Sep-87	1.15	Sep-90	17-Sep-90	1.15	Sep-93	13-Sep-93	1.90	Sep-96	16-Sep-96	1.20	Sep-99		
Oct-87	19-Oct-87	1.15	Oct-90	15-Oct-90	1.30	Oct-93	18-Oct-93	1.80	Oct-96	21-Oct-96	1.30	Oct-98		
Nov-87	16-Nov-87	1.15	Nov-90	12-Nov-90	1.60	Nov-93	15-Nov-93	1.80	Nov-96	18-Nov-96	2.45	Nov-99		
Dec-87	21-Dec-87	1.15	Dec-90	10-Dec-90	1.60	Dec-93	20-Dec-93	2.40	Dec-96	16-Dec-96	3.50	Dec-99		
Average-87	**NA**	**1.22**	**Average-90**	**NA**	**1.33**	**Average-93**	**NA**	**1.89**	**Average-96**	**NA**	**1.47**	**Average-99**	**NA**	**1.84**
Jan-88	25-Jan-88	1.45	Jan-91	14-Jan-91	1.45	Jan-94	17-Jan-94	1.90	Jan-97	20-Jan-97	3.90			
Feb-88	15-Feb-88	1.45	Feb-91	18-Feb-91	1.10	Feb-94	21-Feb-94	1.80	Feb-97	17-Feb-97	2.50			
Mar-88	21-Mar-88	1.35	Mar-91	11-Mar-91	1.05	Mar-94	21-Mar-94	1.95	Mar-97	17-Mar-97	1.40			
Apr-88	18-Apr-88	1.25	Apr-91	08-Apr-91	1.05	Apr-94	18-Apr-94	1.60	Apr-97	21-Apr-97	1.45			
May-88	16-May-88	1.10	May-91	13-May-91	1.00	May-94	16-May-94	1.60	May-97	19-May-97	1.60			
Jun-88	20-Jun-88	1.10	Jun-91	10-Jun-91	1.00	Jun-94	20-Jun-94	1.35	Jun-97	16-Jun-97	1.35			
Jul-88	18-Jul-88	1.10	Jul-91	15-Jul-91	0.95	Jul-94	18-Jul-94	1.45	Jul-97	21-Jul-97	1.45			
Aug-88	22-Aug-88	1.15	Aug-91	12-Aug-91	1.00	Aug-94	15-Aug-94	1.45	Aug-97	18-Aug-97	1.40			
Sep-88	19-Sep-88	1.25	Sep-91	09-Sep-91	1.10	Sep-94	19-Sep-94	1.35	Sep-97	15-Sep-97	1.50			
Oct-88	24-Oct-88	1.30	Oct-91	14-Oct-91	1.20	Oct-94	17-Oct-94	1.20	Oct-97	20-Oct-97	2.05			
Nov-88	21-Nov-88	1.30	Nov-91	11-Nov-91	1.25	Nov-94	21-Nov-94	1.50	Nov-97	17-Nov-97	3.00			
Dec-88	19-Dec-88	1.30	Dec-91	16-Dec-91	1.50	Dec-94	19-Dec-94	1.60	Dec-97	15-Dec-97	1.95			
Average-88	**NA**	**1.26**	**Average-91**	**NA**	**1.14**	**Average-94**	**NA**	**1.56**	**Average-97**	**NA**	**1.96**			

APPENDIX B
PINEDALE ANTICLINE NATURAL GAS EXPLORATION AND DEVELOPMENT
DRAFT ENVIRONMENTAL IMPACT STATEMENT
ENGINEERING FIELD STUDY (VERTICAL AND DIRECTIONAL DRILLING ALTERNATIVES - 40 ACRES)

The most appropriate method of determining economic feasibility of vertical versus directional drilling on the Pinedale Anticline was to:

1. Determine recoverable reserves;

2. Calculate net present values; and

3. Graph net present value against recoverable reserves at three different gas prices.

Graphs were constructed at gas prices of $1.50/MCFG, $2.00/MCFG and $2.50/MCFG. The net present value for both vertically and directionally drilled wells was calculated at these three gas prices, assuming three different initial producing rates.

Decline curve analysis was used to determine recoverable reserves assuming a range of three initial producing rates. The three initial producing rates used provide a range for analysis from wells thought to be uneconomic to very good productive wells. Actual recoverable reserves could range between less than one BCFG to over eight BCFG. Initial producing rates and resulting calculated recoverable reserves for the three scenarios are:

1. Initial producing rate of 1,000 MCFGPD and recoverable reserves of 2,039 MMCFG (Reference Attachment No. B1);

2. Initial producing rate of 2,000 MCFGPD and recoverable reserves of 4,296 MMCFG (Reference Attachment No. B2); and

3. Initial producing rate of 3,000 MCFGPD and recoverable reserves of 6,553 MMCFG (Reference Attachment No. B3).

For each of the three scenarios a hyperbolic decline (with an exponent of 1.8) was assumed for most of the productive life of the well. The initial production rate is declined hyperbolically at 82 percent for two months, at 40 percent for the next four months, and at 33 percent for the next 34 months. The production rate after the 40- month period is then declined exponentially at eight percent for the productive life of the well. A cutoff of 50 MCFGPD was used to determine the point at which a well could not continue to be economically produced. Production projected below this economic limit of 50 MCFG was not included as part of the recoverable reserve for each scenario.

Total expenditures (including drilling, completion and surface facility costs) for a typical vertically and directionally drilled well on the Pinedale Anticline were obtained from Ultra Petroleum. The different costs are listed below:

- Drilling costs - $1,000,000 (Vertical) and $1,550,000 (Directional).

- Completion costs - $875,000 (Both vertical and directional). An average completion cost of $175,000 per interval was estimated for perforation, stimulation and flow testing. On average, five intervals require completion activities.

- Facility costs - $125,000 (Both vertical and directional).

For a directionally drilled well, a potential savings of $125,000 in pad construction and in surface facilities would be realized since a directionally drilled well would be drilled from an existing well location and surface facilities would be centralized. Consequently, the total expenditures for a vertically drilled well are $2,000,000 and for a directionally drilled well are $2,425,000.

The net present value was calculated after the recoverable reserves for the three scenarios were determined. This value was calculated for both vertically and directionally drilled wells at gas prices of $1.50/MCFG, $2.00/MCFG and $2.50/MCFG (Reference Attachment No. B4).

Graphs were constructed which show the curves for a vertically and a directionally drilled well with recoverable reserves on the x-axis plotted against net present value on the y-axis at gas prices of $1.50/MCFG, $2.00/MCFG and $2.50/MCFG (Reference Attachment Nos. B5, B6, and B7).

- Attachment No. B5 shows that at a gas price of $1.50/MCFG, recoverable reserves would need to be 4,942 MMCFG for a vertical well, and 5,938 MMCFG for a directional well, for a net present value equal to zero.

- Attachment No. B6 shows that at a gas price of $2.00/MCFG, recoverable reserves would need to be 3,531 MMCFG for a vertical well, and 4,241 MMCFG for a directional well, for a net present value equal to zero.

- Attachment No. B7 shows that at a gas price of $2.50/MCFG, recoverable reserves would need to be 2,717 MMCFG for a vertical well, and 3,269 MMCFG for a directional well, for a net present value equal to zero.

A net present value of zero is the point at which the internal rate of return equals the discount rate of ten percent. In each scenario, recoverable reserves need to be greater for a directionally drilled well than for a vertically drilled well with a difference of 996 MMCFG at $1.50/MCFG, a difference of 710 MMCFG at $2.00/MCFG and a difference of 552 MMCFG at $2.50/MCFG. The higher the gas price, the smaller the difference between recoverable reserves for a vertical and directional well.

The Mesa No. 3-22D well, located in the NE¼NW¼ of Section 22, T.32N., R.109W., was directionally drilled by Ultra Petroleum on the Pinedale Anticline. As reported in "The Rocky Mountain Oil Journal", the well encountered numerous mechanical difficulties while being drilled and casing was set above a potential productive interval due to wellbore conditions. Four different intervals in the Lance Formation were perforated and stimulated. The well was completed on December 9, 1998, for an initial potential of 1,593 MCFPD. Cumulative production through March 1999 is only 104 MMCF. Recoverable reserves were calculated to be only 240 MMCF.

Another well, the Jensen No. 4, located in the NE¼NW¼ of Section 14, T.31N., R.109W., was directionally drilled by McMurry Oil Company on the Pinedale Anticline. An intermediate casing string was set at 7,957 feet to help stabilize the wellbore. Three different intervals were perforated and stimulated. Casing is parted and collapsed at 10,015 feet. The reason for the collapsed casing is unknown, but it may be related to the directionally drilled hole. Cumulative production through May 1999 is only 45 MMCF. Recoverable reserves were not calculated.

CONCLUSIONS

1. A vertically drilled well with an initial producing rate of 1,000 MCFGPD could not be economic at any of the three gas prices studied.

2. A vertically drilled well with an initial producing rate of 2,000 MCFGPD could not be economic at a gas price of $1.50/MCFG. However, a vertically drilled well with an initial producing rate of 2,000 MCFPD could be economically drilled at a gas price of $2.00/MCFG or $2.50/MCFG; however, the payout time of 6.77 years at a gas price of $2.00/MCFG could be considered excessive by industry standards.

3. A vertically drilled well with an initial producing rate of 3,000 MCFGPD could be economic at any of the three gas prices studied.

4. A directionally drilled well with an initial producing rate of 1,000 MCFGPD could not be economic at any of

the three gas prices studied.

5. A directionally drilled well with an initial producing rate of 2,000 MCFGPD could not be economic at a gas price of $1.50/MCFG. However, a directionally drilled well with an initial producing rate of 2,000 MCFGPD could be economic at a gas price of $2.00/MCFG or $2.50/MCFG; however, the payout time of 19.62 years at a gas price of $2.00/MCFG would be considered excessive by industry standards.

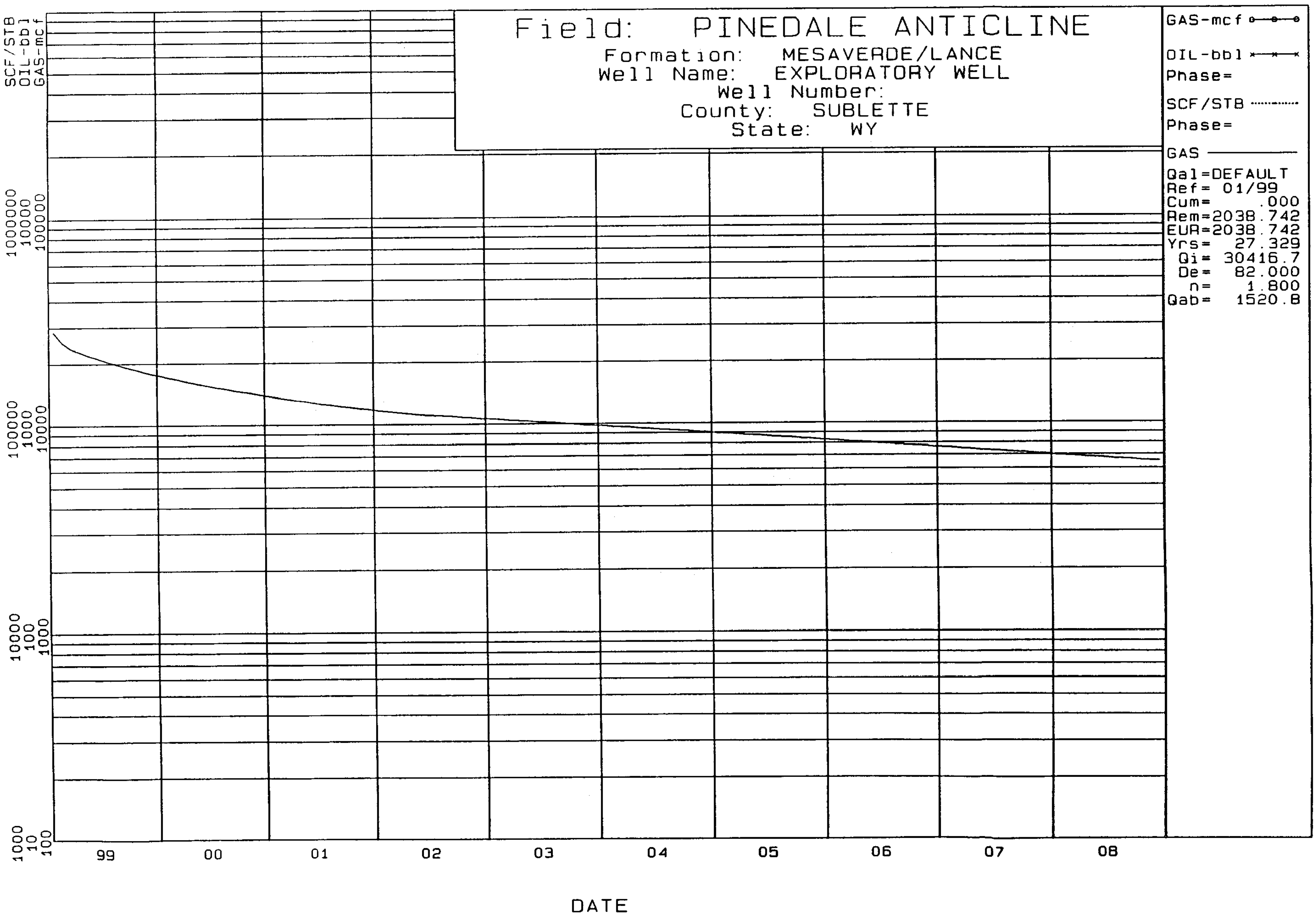
6. A directionally drilled well with an initial producing rate of 3,000 MCFGPD could be economic at any of the three gas prices studied; however, the payout time of 10.21 years at a gas price of $1.50/MCFG would be considered excessive by industry standards.

7. The current spot natural gas price at Opal, Wyoming, as reported by Northwest Pipeline for August 1999 is $2.20/MCFG. The average spot natural gas price for 1999 is $1.84/MCFG (Reference Attachment No. B8).

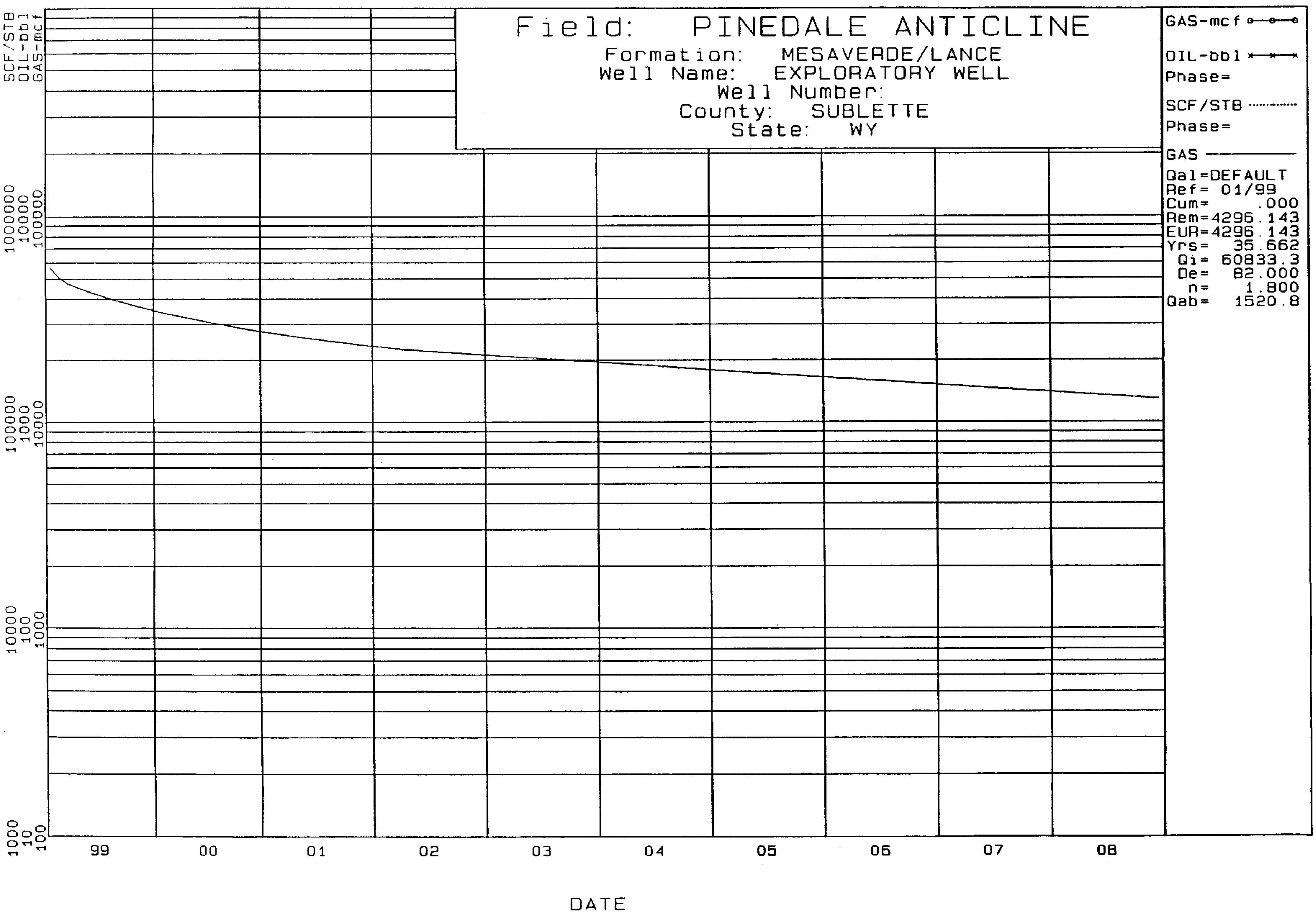
8. Based on the results of directionally drilling the Mesa No. 3-22D and Jensen No. 4 wells, there appears to be a slight risk that a wellbore could be lost due to mechanical difficulties. Any mechanical difficulties encountered would increase the cost of directionally drilling; however, it is technically feasible to directionally drill on the Pinedale Anticline. An intermediate string of casing would be required due to the distance that a directional well would be drilled. Assuming each completed interval would produce gas at an initial rate of 500 MCFGPD (total of 2,000 MCFGPD), it would **not** be economic to directionally drill on the Pinedale Anticline at expected future gas prices.

Attachments

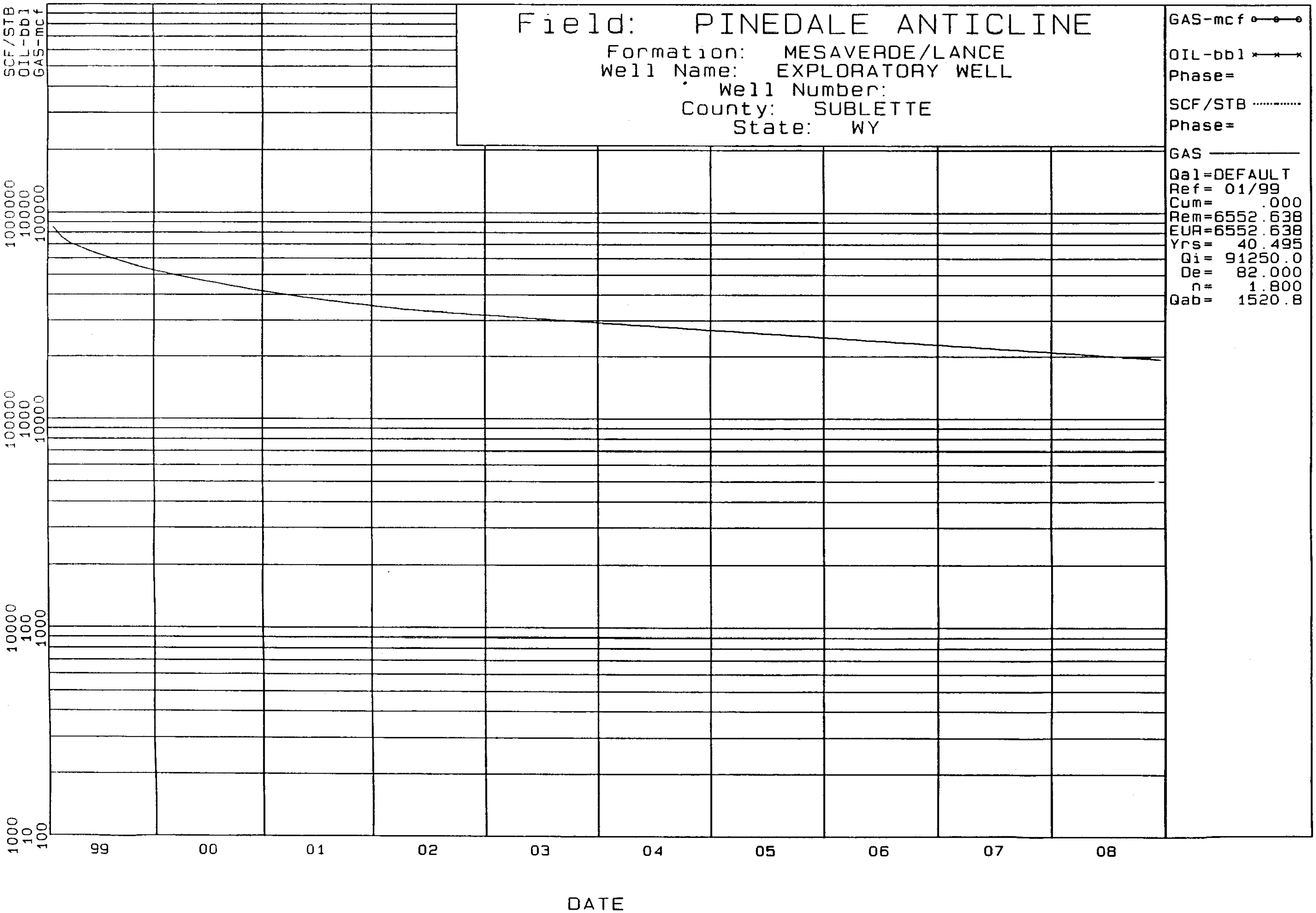
Attachment No. B1 - Hypothetical Well (initial potential of 1,000 MCFGPD)
Attachment No. B2 - Hypothetical Well (initial potential of 2,000 MCFGPD)
Attachment No. B3 - Hypothetical Well (initial potential of 3,000 MCFGPD)
Attachment No. B4 - Table of Net Present Value of Vertical and Directional Drilling Alternatives
Attachment No. B5 - Graph at Gas Price of $1.50/MCFG
Attachment No. B6 - Graph at Gas Price of $2.00/MCFG
Attachment No. B7 - Graph at Gas Price of $2.50/MCFG
Attachment No. B8 - Spot Natural Gas Prices



ATTACHMENT NO. B1 - Hypothetical well (initial potential of 1,000 MCFPD)



ATTACHMENT NO. B2 - Hypothetical well (initial potential of 2,000 MCFPD)



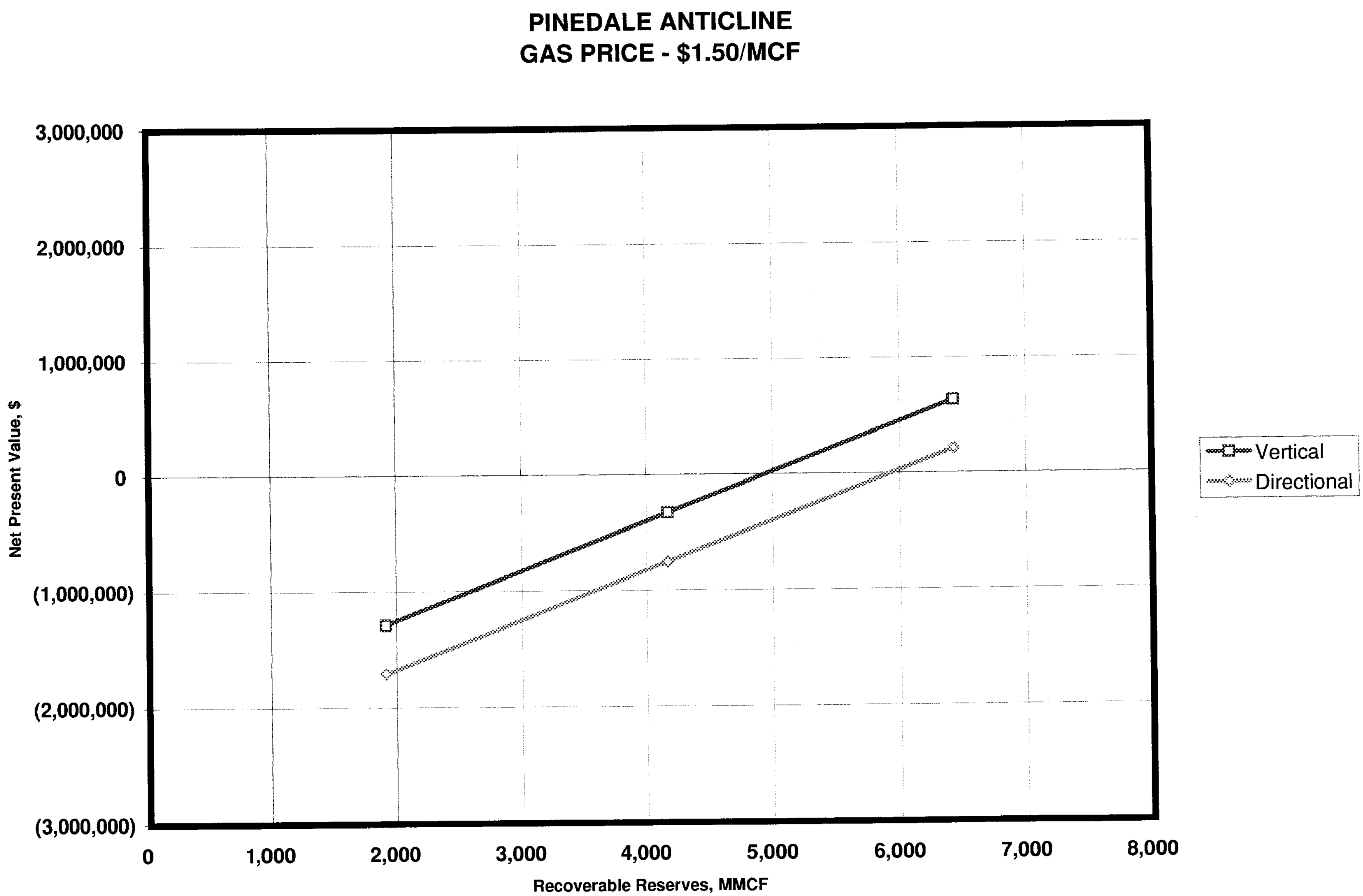
ATTACHMENT NO. B3 - Hypothetical well (initial potential of 3,000 MCFPD)

ATTACHMENT NO. B4 - Table of NPV of Vertical and Directional Drilling Alternatives

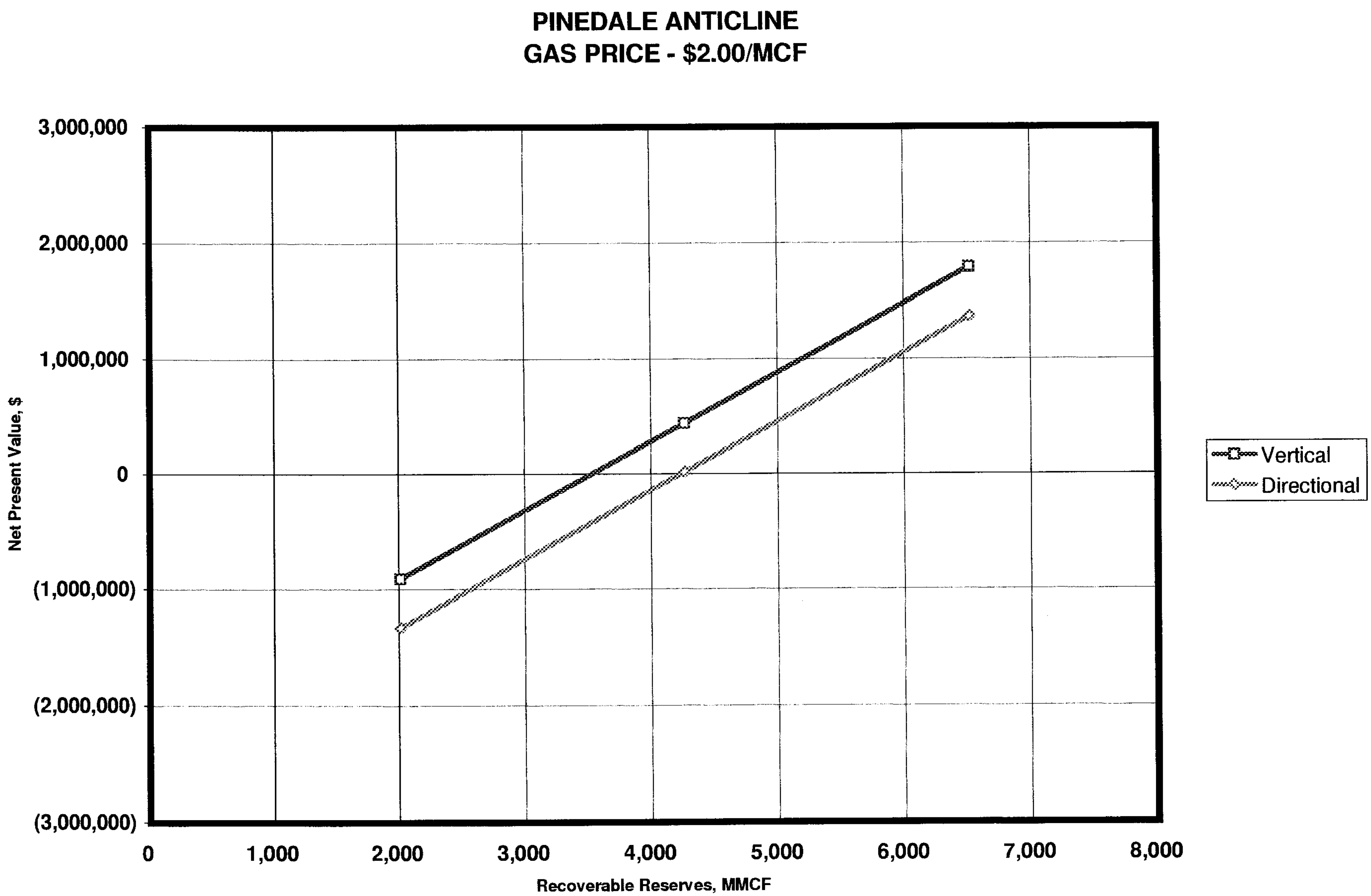
PINEDALE ANTICLINE NATURAL GAS EXPLORATION AND DEVELOPMENT DRAFT ENVIRONMENTAL IMPACT STATEMENT VERTICAL AND DIRECTIONAL DRILLING ALTERNATIVES							
Type of Drilling (Traditional)	Drilling Costs ($)	Initial Producing Rate (MCFPD)	Decline Curve Recoverable Reserves (MCF)	Economical Recoverable Reserves (MCF)	Gas Price ($/MCF)	Net Present Value ($)	Payout (years)
Vertical	2,000,000	1,000	2,039	1,916	1.50	(1,291,326)	NA
Directional	2,425,000	1,000	2,039	1,916	1.50	(1,716,326)	NA
Vertical	2,000,000	1,000	2,039	2,014	2.00	(907,144)	NA
Directional	2,425,000	1,000	2,039	2,014	2.00	(1,332,144)	NA
Vertical	2,000,000	1,000	2,039	2,038	2.50	(522,174)	NA
Directional	2,425,000	1,000	2,039	2,038	2.50	(947,174)	NA
Vertical	2,000,000	2,000	4,296	4,172	1.50	(329,430)	NA
Directional	2,425,000	2,000	4,296	4,172	1.50	(754,430)	NA
Vertical	2,000,000	2,000	4,296	4,269	2.00	441,616	6.77
Directional	2,425,000	2,000	4,296	4,269	2.00	16,616	19.62
Vertical	2,000,000	2,000	4,296	4,294	2.50	1,212,910	3.70
Directional	2,425,000	2,000	4,296	4,294	2.50	787,910	5.55
Vertical	2,000,000	3,000	6,553	6,428	1.50	634,453	4.68
Directional	2,425,000	3,000	6,553	6,428	1.50	209,453	10.21
Vertical	2,000,000	3,000	6,553	6,526	2.00	1,791,526	2.55
Directional	2,425,000	3,000	6,553	6,526	2.00	1,366,526	3.90
Vertical	2,000,000	3,000	6,553	6,550	2.50	2,948,714	1.73
Directional	2,425,000	3,000	6,553	6,550	2.50	2,523,714	2.45

Assumptions

1. Condensate Yield - 8 BBL/MMCF
2. Operating Costs - $4,000/month for first year, $2,500/month thereafter
3. Discount Rate - 15 percent
4. Royalty Rate - 12.5 percent

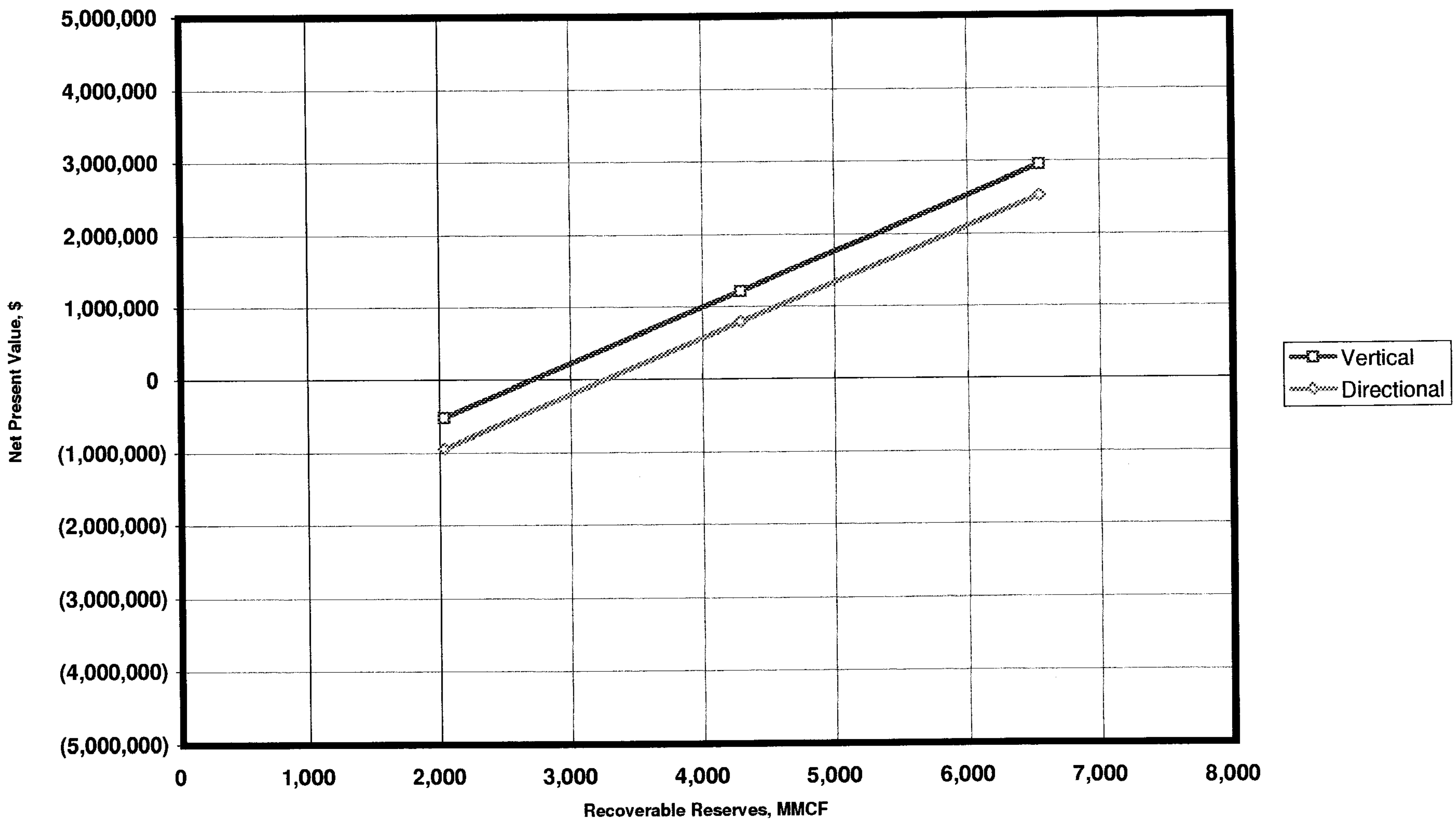


ATTACHMENT NO. B5 - Graph at Gas Price of $1.50/MCFG



ATTACHMENT NO. B6 - Graph at Gas Price of $2.00/MCFG

PINEDALE ANTICLINE
GAS PRICE - $2.50/MCF



ATTACHMENT NO. B7 - Graph at Gas Price of $2.50/MCFG

ATTACHMENT NO. B8 - Spot Natural Gas Prices

SPOT NATURAL GAS PRICES
NORTHWEST PIPELINE
OPAL, WYOMING

Month & Year	Date of Oil & Gas Journal	Price ($/MMBTU)	Month & Year	Date of Oil & Gas Journal	Price ($/MMBTU)	Month & Year	Date of Oil & Gas Journal	Price ($/MMBTU)	Month & Year	Date of Oil & Gas Journal	Price ($/MMBTU)	Month & Year	Date of Oil & Gas Journal	Price ($/MMBTU)
Jan-86	**NA**	**NA**	Jan-89	23-Jan-89	1.35	Jan-92	20-Jan-92	1.35	Jan-95	16-Jan-95	1.40	Jan-98	19-Jan-98	2.05
Feb-86	**NA**	**NA**	Feb-89	27-Feb-89	1.35	Feb-92	17-Feb-92	1.00	Feb-95	20-Feb-95	1.10	Feb-98	16-Feb-98	1.70
Mar-86	**NA**	**NA**	Mar-89	03-Apr-89	1.25	Mar-92	16-Mar-92	1.15	Mar-95	20-Mar-95	1.05	Mar-98	16-Mar-98	1.90
Apr-86	**NA**	**NA**	Apr-89	UNKNOWN	1.15	Apr-92	20-Apr-92	1.15	Apr-95	17-Apr-95	1.05	Apr-98	20-Apr-98	1.90
May-86	**NA**	**NA**	May-89	08-May-89	1.15	May-92	18-May-92	1.25	May-95	15-May-95	1.10	May-98	18-May-98	1.95
Jun-86	**NA**	**NA**	Jun-89	12-Jun-89	1.10	Jun-92	15-Jun-92	1.35	Jun-95	19-Jun-95	1.15	Jun-98	15-Jun-98	1.65
Jul-86	21-Jul-86	1.45	Jul-89	17-Jul-89	1.05	Jul-92	20-Jul-92	1.20	Jul-95	17-Jul-95	1.00	Jul-98	20-Jul-98	1.60
Aug-86	18-Aug-86	1.50	Aug-89	14-Aug-89	1.10	Aug-92	17-Aug-92	1.55	Aug-95	21-Aug-95	0.90	Aug-98	17-Aug-98	1.75
Sep-86	15-Sep-86	1.45	Sep-89	11-Sep-89	1.10	Sep-92	21-Sep-92	1.65	Sep-95	18-Sep-95	1.05	Sep-98	21-Sep-98	1.60
Oct-86	20-Oct-86	1.35	Oct-89	09-Oct-89	1.15	Oct-92	19-Oct-92	2.10	Oct-95	16-Oct-95	1.05	Oct-98	19-Oct-98	1.65
Nov-86	17-Nov-86	1.35	Nov-89	13-Nov-89	1.40	Nov-92	16-Nov-92	1.80	Nov-95	20-Nov-95	1.15	Nov-98	16-Nov-98	2.00
Dec-86	15-Dec-86	1.35	Dec-89	11-Dec-89	1.65	Dec-92	21-Dec-92	1.90	Dec-95	18-Dec-95	1.30	Dec-98	21-Dec-98	2.00
Average-86	**NA**	**1.41**	**Average-89**	**NA**	**1.23**	**Average-92**	**NA**	**1.45**	**Average-95**	**NA**	**1.11**	**Average-98**	**NA**	**1.81**
Jan-87	19-Jan-87	1.35	Jan-90	08-Jan-90	2.05	Jan-93	18-Jan-93	2.25	Jan-96	15-Jan-96	1.25	Jan-99	18-Jan-99	1.80
Feb-87	UNKNOWN	1.40	Feb-90	12-Feb-90	1.50	Feb-93	15-Feb-93	1.60	Feb-96	19-Feb-96	1.20	Feb-99	15-Feb-99	1.65
Mar-87	16-Mar-87	1.30	Mar-90	12-Mar-90	1.15	Mar-93	15-Mar-93	1.80	Mar-96	18-Mar-96	1.20	Mar-99	15-Mar-99	1.50
Apr-87	20-Apr-87	1.25	Apr-90	09-Apr-90	1.10	Apr-93	19-Apr-93	1.80	Apr-96	15-Apr-96	1.05	Apr-99	19-Apr-99	1.60
May-87	18-May-87	1.20	May-90	14-May-90	1.10	May-93	17-May-93	2.30	May-96	20-May-96	0.95	May-99	17-May-99	2.00
Jun-87	15-Jun-87	1.20	Jun-90	11-Jun-90	1.10	Jun-93	21-Jun-93	1.70	Jun-96	17-Jun-96	1.10	Jun-99	21-Jun-99	2.00
Jul-87	20-Jul-87	1.15	Jul-90	16-Jul-90	1.15	Jul-93	19-Jul-93	1.60	Jul-96	15-Jul-96	1.20	Jul-99	19-Jul-99	2.00
Aug-87	17-Aug-87	1.15	Aug-90	13-Aug-90	1.10	Aug-93	16-Aug-93	1.70	Aug-96	19-Aug-96	1.25	Aug-99	16-Aug-99	2.20
Sep-87	21-Sep-87	1.15	Sep-90	17-Sep-90	1.15	Sep-93	13-Sep-93	1.90	Sep-96	16-Sep-96	1.20	Sep-99		
Oct-87	19-Oct-87	1.15	Oct-90	15-Oct-90	1.30	Oct-93	18-Oct-93	1.80	Oct-96	21-Oct-96	1.30	Oct-98		
Nov-87	16-Nov-87	1.15	Nov-90	12-Nov-90	1.60	Nov-93	15-Nov-93	1.80	Nov-96	18-Nov-96	2.45	Nov-99		
Dec-87	21-Dec-87	1.15	Dec-90	10-Dec-90	1.60	Dec-93	20-Dec-93	2.40	Dec-96	16-Dec-96	3.50	Dec-99		
Average-87	**NA**	**1.22**	**Average-90**	**NA**	**1.33**	**Average-93**	**NA**	**1.89**	**Average-96**	**NA**	**1.47**	**Average-99**	**NA**	**1.84**
Jan-88	25-Jan-88	1.45	Jan-91	14-Jan-91	1.45	Jan-94	17-Jan-94	1.90	Jan-97	20-Jan-97	3.90			
Feb-88	15-Feb-88	1.45	Feb-91	18-Feb-91	1.10	Feb-94	21-Feb-94	1.80	Feb-97	17-Feb-97	2.50			
Mar-88	21-Mar-88	1.35	Mar-91	11-Mar-91	1.05	Mar-94	21-Mar-94	1.95	Mar-97	17-Mar-97	1.40			
Apr-88	18-Apr-88	1.25	Apr-91	08-Apr-91	1.05	Apr-94	18-Apr-94	1.60	Apr-97	21-Apr-97	1.45			
May-88	16-May-88	1.10	May-91	13-May-91	1.00	May-94	16-May-94	1.60	May-97	19-May-97	1.60			
Jun-88	20-Jun-88	1.10	Jun-91	10-Jun-91	1.00	Jun-94	20-Jun-94	1.35	Jun-97	16-Jun-97	1.35			
Jul-88	18-Jul-88	1.10	Jul-91	15-Jul-91	0.95	Jul-94	18-Jul-94	1.45	Jul-97	21-Jul-97	1.45			
Aug-88	22-Aug-88	1.15	Aug-91	12-Aug-91	1.00	Aug-94	15-Aug-94	1.45	Aug-97	18-Aug-97	1.40			
Sep-88	19-Sep-88	1.25	Sep-91	09-Sep-91	1.10	Sep-94	19-Sep-94	1.35	Sep-97	15-Sep-97	1.50			
Oct-88	24-Oct-88	1.30	Oct-91	14-Oct-91	1.20	Oct-94	17-Oct-94	1.20	Oct-97	20-Oct-97	2.05			
Nov-88	21-Nov-88	1.30	Nov-91	11-Nov-91	1.25	Nov-94	21-Nov-94	1.50	Nov-97	17-Nov-97	3.00			
Dec-88	19-Dec-88	1.30	Dec-91	16-Dec-91	1.50	Dec-94	19-Dec-94	1.60	Dec-97	15-Dec-97	1.95			
Average-88	**NA**	**1.26**	**Average-91**	**NA**	**1.14**	**Average-94**	**NA**	**1.56**	**Average-97**	**NA**	**1.96**			