RESERVOIR MANAGEMENT SERVICES, INC.
Integrated Consulting Services for the Petroleum Industry

May 10, 2002

Ms. Teri Deakins, Project Manager
Bureau of Land Management
280 Highway 191 North
Rock Springs, WY. 82901- 3447

Re: Vermillion Basin Natural Gas Project - IBLA Decision 2001-166
Discussion of Biodiversity Associates' letter dated February 8, 2002 and Analysis of the Alternative of Directional Drilling

Dear Ms. Deakins:

Wexpro Company retained Reservoir Management Services, Inc. to comment on Biodiversity Associates' letter to the BLM dated February 8, 2002 and to analyze the alternative of directional drilling for the Vermillion Basin Natural Gas Project (VBPA).

In the following discussion, the direct quotes from Biodiversity Associates' letter to the BLM dated February 8, 2002 are shown in italics and numbered. It appears that Biodiversity took quotes from technical references out of context, misinterpreted the data, and omitted major conclusions presented by some of the authors. Each numbered quote is discussed in detail based primarily on the references cited in their letter and recent production data from the public record. The objective is to show how the technical literature relating to directional drilling applies to the VBPA.

Finally, well architecture alternatives are analyzed and compared based on relative cost and reserve factors.

The final conclusion is that vertical wells are currently the only reasonable alternative for development of the VBPA.

Discussion of Biodiversity Associates' Letter Dated February 8, 2002

When reading the following critique of Biodiversity's letter, it would be helpful to keep in mind the general characteristics of the gas reservoirs in VBPA. The primary target of exploratory and development drilling is 22 potentially productive, low permeability gas pay zones of the

Mesaverde Group. These zones average 30 ft in thickness and are distributed over 2300 ft of gross interval starting at about 5500 ft from surface. If potential targets in the Wasatch, Fort Union, Frontier and Nugget are included, the interval is significantly larger. Previous completions in the Vermillion Basin consist of commingling of four to six hydraulically fractured zones in a vertical wellbore. Single pay zones are generally not commercial.

1. Biodiversity states (February 8, 2002, p.3):

The need to employ directional drilling technologies to reduce environmental impacts of mineral development is a high priority of the Bush administration. The President's National Energy Policy contains a section titled, "21st Century Technology: The Key to Environmental Protection and New Energy Production," which states:

> *"Producing oil and gas from geologically challenging areas whiled protecting the environment is important to Americans and to the future of our nation's energy security. New technology and management techniques will allow for sophisticated energy production as well as enhanced envirnmental (sic) protection…Smaller, lighter drilling rigs coupled with advances in directional and extended-reach drilling significantly increase protection of the environment…Modular drilling rigs, "slimhole" drilling, directional drilling, and other advances enable: […]*
>
> - *Production of oil and gas with increased potection (sic) to wetlands and other sensitive environments;*
>
> *Other examples of advanced technology include: […]*
>
> - *Highly sophisticated directional drilling that enables wells to be drilled long horizontal distances from the drilling site [.]"*

The focus of the National Energy Policy - 2001 relating to oil and gas exploration and development is primarily directed at Alaska and OCS (Outer Continental Shelf) areas.

In "Chapter Five – Energy for a New Century: Increasing Domestic Energy Supplies", the only recommendation relating to lower 48 oil and gas exploration and development stated:

> "The NEPD Group recommends that the President direct the Secretary of the Interior to examine land status and lease stipulation impediments to federal oil and gas leasing, and review and modify those where opportunities exist (consistent with the law, good environmental practice, and balanced use of other resources).
>
> - Expedite the ongoing Energy Policy and Conservation Act study of impediments to federal oil and gas exploration and development.
> - Review public lands withdrawals and lease stipulations, with full public consultation, especially with the people of the region, to consider modifications where appropriate."

The NEP suggests that there must be a balance of the various land use interests in order to provide adequate supplies of energy at reasonable prices. The NEP also stated:

> "The most significant long-term challenge relating to natural gas is whether adequate supplies can be provided to meet sharply projected increased demand at reasonable prices." (p. 1-8).

The Vermillion Basin Natural Gas Exploration and Development Project application contains 22 pages of Operator-Committed Measures and Additional BLM-Required Mitigation designed to protect the environment in the proposed project area.

2. Directional Drilling is Technically Feasible for the Vermillion Basin Project

The reduced environmental impacts of directional drilling are well-documented. Cluster drilling from a single well pad (French Oil and Gas Association 1990) can reduce the footprint of oil and gas development on the landscape by concentrating the activity and impact of many wells at a few widely dispersed sites.

French Oil and Gas Association 1990 is primarily a manual for design of deviated offshore wells. It is stated on page 7 of the reference that:

"Although well bores are generally vertical in exploration, local difficulties may require the planning of directional wells. By contrast, the general rule governing development wells drilled from offshore platforms is to drill deflected holes"

Cluster drilling from a single pad is not new technology. Development drilling from pads on the North Slope of Alaska, drilling from platforms offshore, and development of oil fields under cities in the Los Angeles Basin are examples of this technology that has developed over the past 50 years. In these examples there are clear economic reasons for clustering development wells.

It is important to note that exploration wells are generally vertical in both onshore and offshore areas. In order to plan deviated wells that may be required for development, information from vertical exploratory wells and/or 3D seismic is generally required.

3. Because fewer directional wells are required to drain a subsurface reservoir, well spacing is always greater for directional wells (Fritz et al. 1991).

This statement is true for horizontal wells in a single pay zone but not for high-angle wells (45° to 60° deviation) or s-shaped deviated wells (vertical through the reservoir). Fritz, p. 36 also states

"…a general definition of an HD-type[horizontal drilling-type] reservoir is one in which horizontal drilling can improve production significantly and economically over a vertical well".

The number and cost of each type of well required to efficiently drain a reservoir certainly enters into the economic calculation.

4. Indeed, Joshi (1991, p. 4) stated that "to achieve larger producible reserves, horizontal wells will have to be drilled with a larger well spacing than vertical wells."

This direct quote does not exist on p.4 of Joshi's book. The well spacing issue is much more complex than stated by Biodiversity. Joshi (p. 4) points out that:

"The major disadvantage is that only one pay zone can be drained per horizontal well."

For a single pay zone, Joshi states(p.56):

"…., in a low permeability reservoir, horizontal wells can be used to enhance drainage volume per well in a given period of time."

Given sufficient time, vertical and horizontal wells may recover the same reserves from a single pay zone but horizontal wells generally accelerate the production in time.

Joshi's book deals almost exclusively with comparison of vertical, slanted, and horizontal wells drilled in single pay zone reservoirs, a situation quite different to the proposed VBPA where the objective reservoirs are multiple pay zones distributed over 2300 vertical feet. The reservoirs at VBPA must be hydraulically fractured and commingled in a vertical well completion to efficiently recover the gas reserves.

For the VBPA reservoirs, the claim that deviated wells will recover the gas reserves more efficiently than vertical wells is simply untrue.

> *5. Horizontal drilling can now reach subsurface reservoirs up to 29,000 feet away from the drilling site in horizontal distance (Al-Blehed et al. 2000).*

Drilling of long horizontal well sections is well documented in the literature. This paper is irrelevant to the VBPA discussion because it describes horizontal well applications, mainly to reduce coning in prolific oil producing Saudi Arabian sandstone and carbonate reservoirs.

> *6. Thus, by requiring cluster development (used in conjunction with horizontal or deviated directional-drilling technology), the BLM can minimize environmental damage and habitat degradation that is inherent to oilfield development.*

The Operator-committed mitigation measures and additional BLM-required mitigation measures proposed as part of the October 2000 Vermillion Basin Natural Gas Exploration and Development project were designed to minimize impacts to the environment and at the same time economically recover the maximum possible gas reserves. This objective is best accomplished in VBPA by the use of hydraulically fractured vertical wells with multiple commingled pay zones.

> *7. Not only is directional drilling more environmentally responsible, it is also more effective at removing oil and gas from geologic formations than conventional vertical wells. Thakur (1999) reported that because horizontal drilling is a more efficient extraction method, it can increase the recoverable reserves for a given reservoir.*

In some cases, horizontal drilling can increase recoverable reserves. Thakur (1999) states that:

"The use of horizontal wells in water and gas coning situations have proved to be extremely profitable for Chevron."

Thakur reported that of 44 horizontal wells drilled in coning situations 95% have been successful. However, for fractured reservoirs the success rate has been 29% and for low permeability reservoirs 60%. Thakur also summarizes the results of 80 horizontal wells drilled by Elf Aquitaine between 1987 and 1999. This operator reports good success for most wells except for those drilled in thermal recovery and low permeability reservoirs. For the Elf Aquitaine wells, the average cost ratio of horizontal to vertical wells for the 80 wells was 1.5.

For the type of reservoirs present at VBPA, Thakur reports success rates of less than 60%.

> *8. Fritz et al. (1991) reported that directional drilling has had a higher percent success than vertical drilling in both the Austin Chalk and Williston Basin fields.*

Fritz reports that the percent success for the Bakken Formation, a fractured shale source rock in the Williston Basin, is 94% for vertical wells and 97% for horizontal. For the Austin Chalk, a fractured, faulted, compartmentalized oil reservoir, the percent success is 85% for vertical wells and 98% for horizontal wells. In fact, Swindell (1996) stated that:

"Poor overall economics have slowed the use of horizontal drilling in the Bakken Shale of North Dakota."

The conclusions derived from this information have no bearing on the development of gas reservoirs at VBPA. The discussion below will document that the percent success for horizontal wells drilled in low permeability gas reservoirs near VBPA is 20% to 25%.

> *9. Joshi (1991) asserted that for the natural gas production, horizontal wells improve drainage area per well for low-permeability geologic formations, reduced near-wellbore turbulence and increased delivery efficiency for high-permeability formations.*

Joshi's statement has no relevance to the VBPA reservoirs, which are multiple, thin pay zones spread over a large interval and are not amenable to development by horizontal wells.

> *10. Horizontal drilling technology is so effective that it has become the benchmark for the industry: Miller and Steiger (1999) boasted that their array of vertical and directional wells had production that equaled high benchmark projections from horizontal drilling.*

This reference is not documented in the Literature Cited in Biodiversity's letter.

> *11. Furthermore, directional drilling reduces "coning," the mixture of oil with gas and water that reduces production efficiency for oil and gas (Joshi 1991, Thakur 1999).*

As there are no coning issues associated with the VBPA reservoirs this statement is not relevant to the current discussion.

> *12. Directional drilling is a universally practical solution to oil and gas recovery. It is suitable for both exploration and full-field development (French Oil and Gas Association 1990).*

There is no such statement or claim made in the cited reference. The reference simply lists different situations where directional drilling has been used to develop oil and gas fields.

> *13. Aguilera et al. (1991) lauded the potential of horizontal drilling in infill situations.*

Aguilera et al. (1991, p.2) stated:

"Horizontal wells can be considered as an alternative to infill drilling [vertical wells] and fracturing, with the objective in all cases to increase the economic recovery of oil and gas."

The VBPA contains thin multi-pay reservoirs not suitable for development by horizontal drilling.

> *14. In 1991, Fritz et al. (p. 36) noted that, "If the cost of drilling a horizontal well was equal to that of drilling a vertical well, most reservoirs would be candidates for horizontal drilling." These costs have in fact equalized in modern times.*

There is no substantiation for the claim that costs have equalized in modern times. In fact, Thakur presents modern data that show that the ratio of horizontal to vertical well costs is 1.4 to 1.5. Joshi p.5, Fig 1-3a, shows that even after 4 years of drilling horizontal wells at Prudhoe Bay and flattening of the learning curve, the ratio of H/V is still 1.5. Joshi's data also shows considerable scatter in the cost of the horizontals (some later-drilled horizontal wells cost 80% of the initial horizontal well cost), indicating that after 4 years of experience there is considerable risk in the drilling horizontal wells.

> *15. Aguilera et al. (1991, p. 1) stated that, "Theoretically, all reservoirs can benefit from horizontal wells."*

Aguilera et al. (1991, p. ix) also stated in the Preface:

"It must be stressed that horizontal wells are not suitable for all types of reservoirs."

> *16. Al-Blehed et al. (2000) asserted that horizontal drilling is superior to vertical drilling for a variety of conditions including for naturally fractured reservoirs, thin reservoirs, heterogeneous reservoirs, vertical permeability homogeneous reservoirs, reefs or isolated sand bodies, and faulted reservoirs. Horizontal drilling has proved to be superior technology in a variety of geological settings, and we know of no examples cases where vertical drilling offers superior results.*

Al-Blehed et al. (2000) discusses horizontal drilling in Saudi Arabia, which currently produces about 8.8 MMBO/D from 50 fields from a total of 1000 wells for an average per well rate of 8,800 BOPD. The 6 fields discussed in detail by Al-Blehed all had horizontal wells drilled to produce thin oil zones. The increased oil rates in <u>all</u> of these cases are related to reduced water coning and increased waterflood efficiency in high permeability oil reservoirs. The facts reported in this reference do not provide any support for horizontal drilling at VBPA.

> *17. The economic feasibility of directional drilling has been well demonstrated. Cluster development of many wells on a single pad offers minimizes (sic) the capital investments of lessees (French Oil and Gas Association 1990), and reduces costs for an expensive and ecologically damaging network of improved roadways.*

Directional drilling has been used for over 50 years in the petroleum industry. The economic feasibility has been demonstrated, especially in offshore applications. The fact that certain capital investments related to surface drilling and production operations can be reduced through cluster drilling does not automatically equate to an economic project that maximizes the recovery of oil and gas reserves.

18. In 1991, Joshi (p. 7) noted that costs for directional wells were 1.4 to 3 times higher than costs for vertical wells, but further noted that "In some cases, with extensive drilling experiences, the horizontal well costs are reported to be almost the same or even lower than vertical well costs."

The first part of this statement: "that costs for directional wells were 1.4 to 3 times higher than costs for vertical wells" is correct and is actually quoted directly from p.4 and supported by industry experience.

The quote relating to reported horizontal well costs being the same or even lower than vertical well costs is taken from Gust (1989). There is an error in the Joshi text. Gust actually shows on Fig. 2 of his paper that the ratio of horizontal versus directional well drilling, $/meter (cost per meter drilled) is less than one. Gust stated (p.51):

"Based on these observations, we expect that horizontal wells drilled in development programs will compete with directional wells at the same cost per meter, providing the casing and drilling fluids programs are similar. The total well cost will be higher than vertical or directional wells due to their increased measured depth; however, this cost should be offset by their increased amount of reservoir exposure".

Horizontal wells in the multi-zone VBPA actually have less reserve exposure than vertical wells.

19. But because directional drilling requires fewer wells and yields more production per well, overall oilfield development costs may have been lower even with the older technology available in the early 1990s. Because each directional well drains a greater reservoir volume than a corresponding vertical well, fewer wells are required to drain a reservoir, reducing up-front project costs (Fritz et al. 1991). These researchers further compared the costs of older-technology directional drilling with vertical drilling, and found that oil production costs per barrel were lower for directional drilling in the Austin Chalk, but higher in the Williston Basin of North Dakota.

This discussion relates to horizontal drilling in the Austin Chalk and Bakken formations, which are single zone, fractured reservoirs. The conclusions derived from this reference have no bearing on the VBPA.

20. In modern times, the technology continues to improve and efficiencies rise. Al-Blehed et al. (2000) stated that their use of horizontal wells reduced drilling, flowline and facilities costs by 20 - 25% over vertical drilling.

As discussed above, the findings in this reference have no relevance to VBPA.

21. Directional drilling has proven to be a remarkably versatile as alternative (sic) to conventional vertical drilling in recovery. Directional drilling has been shown to increase rate of gas production and overall recoverable quantity for tight gas sands (e.g., Cassetta 1998).

Cassetta's reference is an AAPG abstract that has been misinterpreted by Biodiversity. Cassetta attributes the increased rate of gas production and overall recoverable quantity from geopressured Upper to Middle Wilcox tight sands solely to 3D seismic results. Directional drilling was required in this field because the field is partially submerged below a surface water reservoir.

22. O'Rourke et al. (1997) found horizontal drilling of paired wells to be effective in gas production using steam injection techniques.

This reference refers to the SAGD (Steam Assisted Gravity Drainage) project in the oil sands of Fort McMurray. The SAGD process uses closely spaced horizontal wells to recover steam-heated bitumen from shallow unconsolidated sands by gravity drainage and is not relevant to gas production from the VBPA.

23. For heavy oil recovery, Shirif (2000, p. 894) noted that, "For a given pattern, there is a horizontal well configuration [that] maximizes the total production rate." In all cases, directional drilling has resulted in superior economic yields when compared to conventional vertical drilling. Thus, directional drilling minimizes the environmental impacts associated with mineral development, is geologically and economically feasible, and produces equal frequently superior recovery of minerals compared to vertical drilling.

This is another reference discussing thermal heavy oil projects in Alberta where well spacing can be on the order of 2 ½ acres per well. This information is not pertinent to the VBPA.

24. Directional drilling is proven as an effective alternative to vertical drilling in Wyoming. The first directional well in Wyoming was completed in 1987, and as of 1994, 80 producing wells were completed out of 117 attempts (Stewart 1995). As of October 2001, Wyoming has 504 horizontal or directional wells on-line, according to State of Wyoming data. Stewart (1995) stated that "Recent developments in the gas play in the Green River Basin, particularly the Mulligan Draw, Echo Springs, and Stagecoach fields, indicate favorable exploitation by horizontal drilling" (at p. 283).

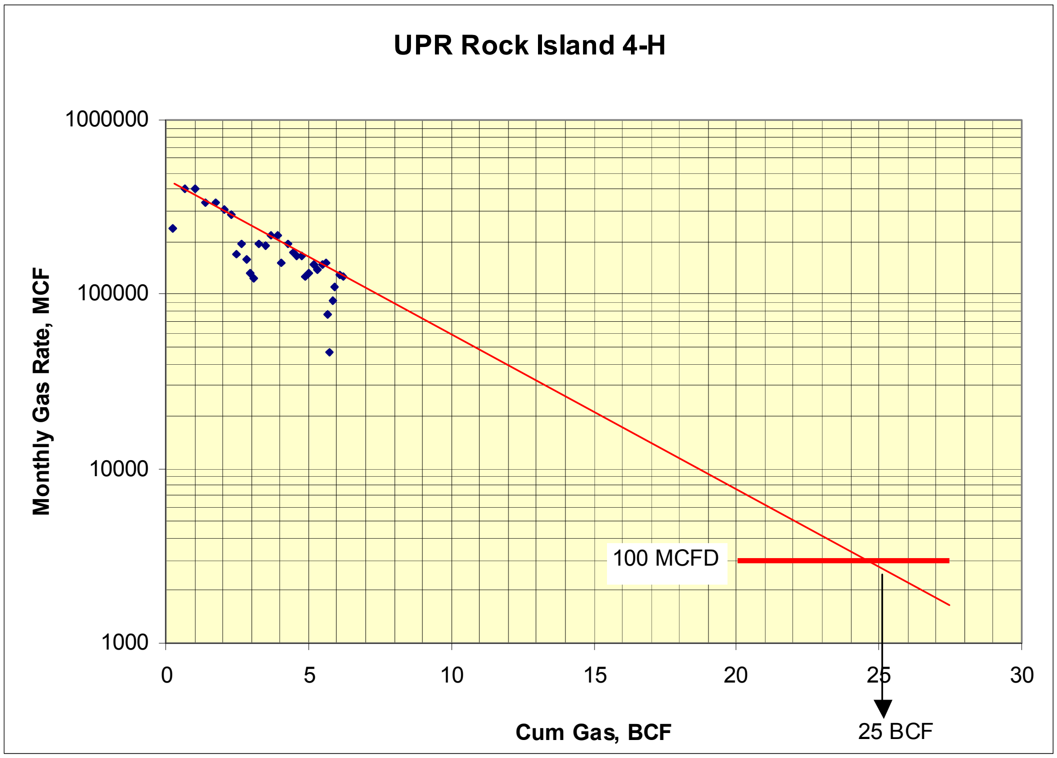
A total of 8 horizontal wells have been drilled in Mulligan Draw, Echo Springs, and Stagecoach fields out of a total of 133 total wells drilled. Three of the horizontals are suspended with zero cumulative gas production. In Echo Springs and Mulligan Draw, the horizontal wells have produced less gas than the average well in the field. Only one horizontal well in Stagecoach field has produced more than the average well in the field (2 times the average). Given the horizontal/vertical cost ratio of 1.4 to 1.5 times, these results can hardly be classified as favorable for horizontal drilling.

25. The target geological strata for the Vermillion Basin project also have shown themselves conducive to directional drilling. The Frontier formation has substantial and well-developed fractures through which natural gas migrates (Lorenz 1995), properties which are more conducive to horizontal drilling, which intercepts more fractures than conventional vertical drilling (Mark Kirschbaum, USGS pers. comm.).

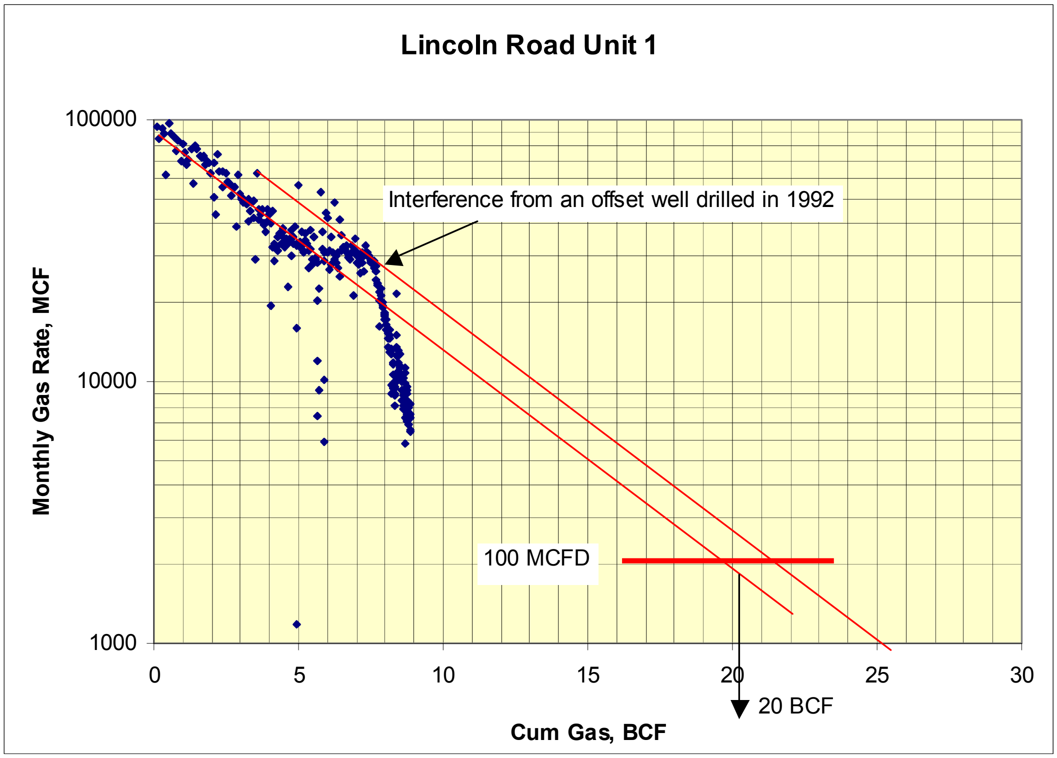
There are numerous references in the literature documenting the presence of natural fractures in low permeability gas sands. For successful development of low permeability gas sands with horizontal wells, the first challenge is to locate areas of high fracture intensity, either by vertical drilling or by multi-component 3D seismic in order to optimally orient the horizontal well (Kuuskraa et al. 1999). The second challenge is to intersect open fractures filled with gas and not water.

26. According to Krystinik (2001), a horizontal well drilled in the Green River Basin's Frontier formation reached a depth greater than 15,000 feet in tight-gas sandstone, was *drilled at a cost that was reduced to 50% of the industry average, and achieved economic production of greater than14 mmcf/day.*

The well referred to by Krystinik is the UPR Rock Island 4-H, completed in the Frontier. It is certainly a successful horizontal well and is probably the best horizontal well drilled to date in a low permeability gas reservoir. As shown on the following plot, this well could produce 25 BCF of gas if it is not offset by other wells.



This is a basin-centered gas well in the overpressured Frontier producing below 15,000'; therefore, it is difficult to compare this well to the performance of other Frontier vertical wells. However, there are good vertical wells producing from shallower, normally pressured Frontier reservoirs. An example is the Lincoln Road Unit #1 located on the Moxa Arch about 80 miles northwest of the RI 4H:



The Lincoln Road Unit 1 produced from the Frontier several years with no decline at 1000 MCFD and would probably have ultimately produced 20 to 25 BCF if the offset well had not been drilled in 1992.

What Biodiversity failed to mention is that the four horizontal wells following the UPR Rock Island 4-H were failures:

1. The Sidewinder 1-H well encountered nearly 2000 open fractures and produced high volumes of water and no commercial gas.
2. The Sidewinder 2-H encountered lower than expected reservoir pressure and produced no water and small quantities of gas.
3. The Table Rock Unit 115-H encountered lower than expected reservoir pressures and has produced 179 MMSCF. The current rate is 160 MCFD.
4. The Sage Flat 7-H had no released production data at the time Krystinik published his results. The well was completed in April 2000 but has no reported production to date.

In this series of five horizontal wells, located within about a 10-mile radius of the center of T20N R97W (UPR Rock Island 4-H), the success rate is only 20%. Not very encouraging given the cost of these deep deviated wells.

27. Dunn et al. (1995) used horizontal drilling in the Almond formation and found extensive fracturing here as well, though limited in areal extent. These researchers noted "horizontal well completions may provide an efficient method to access the enormous natural gas resource present in Mesaverde group of the Greater Green River Basin" (at p. 268).

Fluid flow equations predict that the inherently high permeability of natural fractures will yield high initial gas flow rates. The extent of the natural fracture system will determine the long-term contribution that the fractures will make to production. Dunn (p.267) points out that:

"First, the areal extent of the fractures is unknown, and may be small. A few of the fractures terminate within the diameter of the whole core as they traverse it at an oblique angle, suggesting that those open fractures are of limited extent. Limited areal extent would reduce the open fracture contribution to production flow rate."

Iverson et al. (1995, p.279) also suggest that the numerous sandstone layers of the Almond are not connected by natural fractures and that hydraulic fracturing is required to connect all of the reservoir sands for production.

In discussing the results of a horizontal well in Sidewinder, Krystinik et al (2001) pointed out an additional risk of drilling horizontal wells:

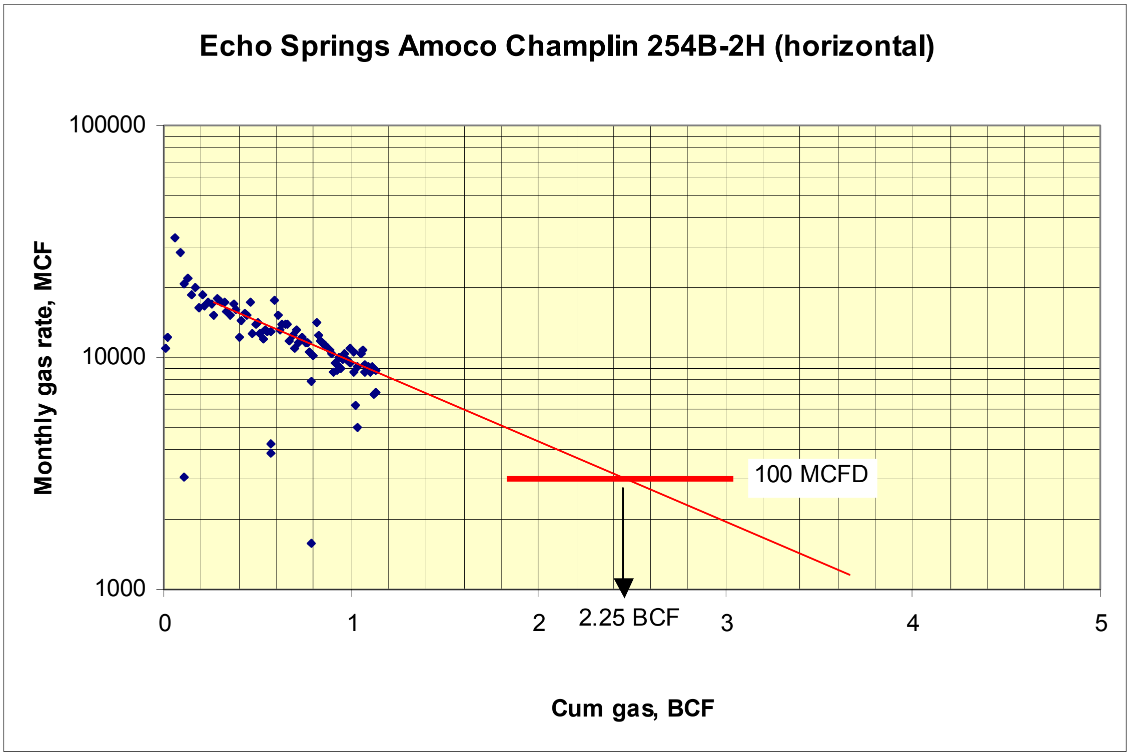
"The SW 1-H was drilled on the upthrown side of the fault, in an area predicted to be heavily fractured. This well encountered nearly 2000 open fractures and had very high flow rates of water, but had sub-economic rates of gas."

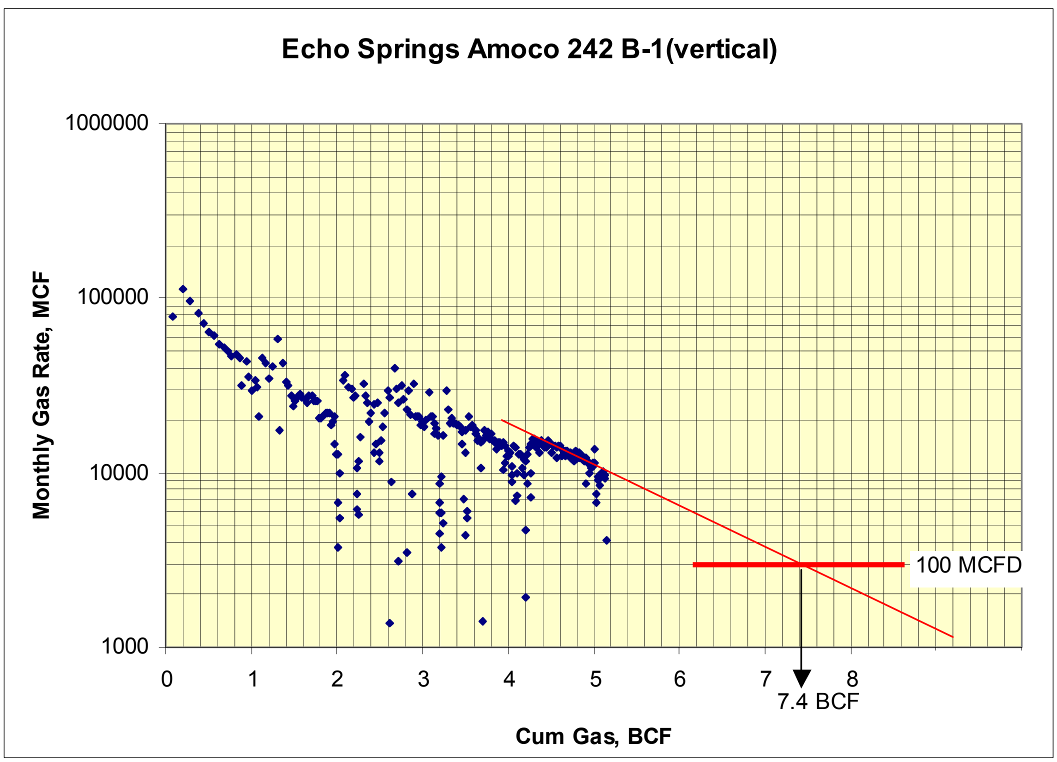
> *28. Iverson et al. (1995) found that even without hydraulic fracturing, a horizontal well tapping into the Almond formation produced as much gas as a conventional well that used hydraulic fracturing.*

Iverson discussed two wells at Echo Springs: Amoco B-1 (vertical) and Amoco Champlin 245B-2H (horizontal) located about 2 two miles apart in T20N R93W. At the time of Iverson's publication, very little production data was available for the horizontal well. After 8 years of production it is now possible compare performance of the vertical and horizontal well. Iverson speculated in 1995, based on initial testing of the horizontal well that:

"Considering the additional cost of horizontal drilling, the economics likely favor vertical or slant hole completions. The horizontal well probably will recover gas more efficiently from a single Almond Formation sand bar. But without hydraulic fracturing, the sands beneath are not tapped, and the well cannot be a spectacular producer."

Inspection of the production histories of these two wells through December 2001 shows that Iverson's prediction was correct. As shown on the two plots following, the projected ultimate gas recovery, to a limiting rate of 100 MCFD, will be 7.5 BCF for the vertical well and 2.25 BCF for the horizontal well.





The projected recovery from the vertical well is over 3 times the projected recovery from the horizontal well. As suggested by Iverson, horizontal wells can efficiently recover gas from single pay zones, but for draining numerous stacked sandstones hydraulically fractured vertical wellbores may be the best choice. Iverson goes on to say:

"Natural fractures certainly help to achieve high flow rates from any one sand, yet hydraulic fractures are needed in order to tie Almond Formation reservoir sand bodies together."

This analysis supports a conclusion exactly opposite to the conclusions reached by Biodiversity using the same data.

> *29. Proof that directional drilling is feasible for the Vermillion Basin region is the fact that a producing directional well has already been drilled and completed in the Kinney Unit of the project area. According to State of Wyoming records, a Wexpro well, API #3724085 at T13N R100W sec. 13 NE ¼, has been drilled directionally to a total depth of 15, 131 feet (at the maximum projected depth for the Vermillion Basin unit) and is currently producing gas from the Nugget formation. The fact that directional wells are* ***already*** *producing natural gas within the Vermillion Basin project area demonstrates beyond a shadow of a doubt that directional drilling is appropriate for the particular geological conditions found in this area.*

The Wexpro well, API #3724085 has produced about 1.33 BCF from the Nugget. The current rate is about 500 MCFD. This well will produce less than the volume of gas produced from the average vertical well in the Kinney Field. Given the 40% incremental cost of drilling a horizontal well at over 15000 ft, it cannot be concluded that *"directional drilling is appropriate for the particular conditions found in this area"*. In fact, this well was deemed a non-paying well for purposes of unit expansion by the BLM.

> *30. In its Decision Record for this project, BLM noted that "Directional drilling may be used if economically viable" DR, App A at A-13. Now that the technical and economic viability of directional drilling has been established, BLM should require its use to protect other resource values in the Vermillion Basin project area. Failure to require directional drilling would be to accord oil and gas development an absolute priority over all other resources in the project area –a result that would be unlawful under FLMPA's multiple-use, sustained yield mandate.*

The body of evidence presented by Biodiversity regarding horizontal drilling, as corrected by the discussion above, points to a conclusion exactly opposite of the one reached in their letter of February 8, 2002. The professionals employed by the BLM and Operators are all very familiar with the results discussed above and are responsible for preparing development plans that protect the environment, maximize the recovery of natural gas, and at the same time provide an economic return. They understand the issues relating to horizontal drilling in low permeability gas reservoirs. If the results and economics were as positive as portrayed by Biodiversity Associates, then a very high percentage of wells drilled today in Wyoming's low permeability gas reservoirs would be horizontal wells.

31. Implementing Directional Drilling Requirements is an Appropriate Method to Protect Roadless Lands and Sensitive Species in the Vermillion Basin Project Area.

In its original Decision Record for this project, BLM noted that "the BLM does not believe it is necessary or appropriate to mandate the use of this procedure [directional drilling] for this project." DR, App. A at A-13. This statement reveals that the Rock Springs Field Office's past deference to the oil and gas industry, its misunderstanding of controlling law and policy, and its unwillingness to adopt reasonable mitigation measures which would protect the interests of the general public that owns lands managed by BLM. As a steward of public lands that belong to all Americans, BLM must exercise its discretion to condition development of public resources on respecting the greater public interest in maintaining viable wildlife populations, recreational opportunities, and open spaces for the enjoyment of generations present and future.

No evidence in the existing record lends support to the assertion that directional drilling would in fact be more expensive and no analysis has been performed to balance any actual increased costs with environmental and public health benefits, as well as direct savings resulting from the reduction in new roads, pipeline facilities, right-of-ways and other infrastructure associated with drilling more wells at maximum densities.

*It is absolutely appropriate for increased production expenses to become part of the cost of doing business on public lands when these increased production costs translated to reduced harms to the public interests and the environment. Not only would it be appropriate from both a legal and ethical perspective for BLM to mandate directional drilling, but in order to reduce impacts to both developed and roadless areas within the proposed project boundary, we believe that BLM has the **responsibility** to mandate directional drilling in order to avoid impacts to roadless lands and sensitive species.*

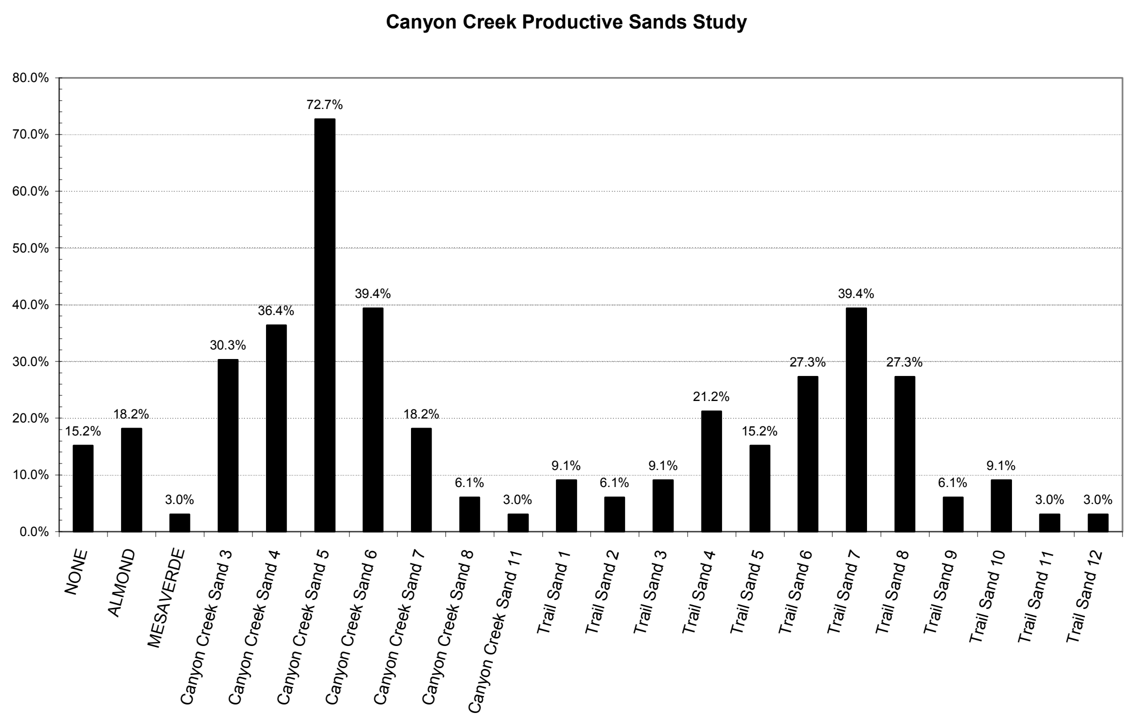
The facts indicate otherwise as will be summarized in the following discussion.

<u>Description of the Mesaverde Group in the Vermillion Basin</u>

The Mesaverde Group is a major productive interval and drilling target in the Vermillion Basin. This sedimentary sequence has a variety of names and subdivisions in various basins and often within the same basin in the western US. It literally has over 100 different local names. The Mesaverde Group in the VB includes the Almy Formation, un-named Mesaverde zones, Erickson sandstones, "Rusty" beds, Blair Formation and informally named and numbered field zones called Trail sands and Canyon Creek sands. It is a complex series of often difficult to correlate fluvial to marginal marine sandstones that in total include a gross interval of approximately 2300' (at Canyon Creek Field).

These sands have produced in Trail, Kinney, Hiawatha, and Canyon Creek fields in the vicinity of the VBPA with varying degrees of success. Because of the complexity and because of the great thickness of the stratigraphic section involved, a true "type log" adequate to convey that complexity (just for the Mesaverde section without considering the Wasatch, Fort Union or Nugget formations) would be difficult to construct. For more details on stratigraphy and depositional environments see GRI publication "Atlas of Major Rocky Mountain Gas Reservoirs" (1993) page 43.

Several operators are involved in the development of existing productive fields in the area and in the exploration for new production adjacent to existing production. Much of the existing production is from old wells with limited modern logs. An operator study completed last year on Canyon Creek field illustrates the complexity of the Mesaverde sandstones. The chart below shows for Canyon Creek Field the percentage of wells in the field completed in the 22 named sand zones. Note that there are some sand zones that are not currently named but which may prove to be productive. Also note that all potentially producible named sand zones are not completed in every well. Thus, the need for many recompletions and infill wells.



The net sand thickness for the 22 named sands in the VBPA ranges from 10 to 80 ft with an average of about 30 ft. The porosity ranges from 9% to 17%. The permeability ranges from less than 1 md to over 20 md.

Sands in the Mesaverde exhibit normal hydrostatic pressure unless production has occurred to reduce it. Individual sand units behave as distinct reservoirs. Because of the selective completions done in the past, there are multiple stacked reservoirs remaining with some having normal pressures and some being partially depleted within active field areas. This situation complicates new infill drilling operations.

These details for the Mesaverde Group provide a good analogy for the type of geologic situation found in the Wasatch and Fort Union although they are less complex and have fewer individual sands. The geology situation is similar for these other formations in that they are relatively thick gross intervals with multiple stacked sand reservoirs.

Preferred VBPA Well Architecture

The large number of thin sands distributed over a long interval impacts the selection of the well configuration. The possible well configurations for VBPA are show on:

Exhibit 1: Vermillion Basin Well Options

Four well types are shown on this diagram: vertical well, s-shaped deviated well, high angle inclined well, and horizontal well.

The vertical well intersects all zones directly under the surface location. Several zones are perforated, hydraulically fractured, and produced in a single wellbore (commingled). Drilling and completion operations are based on well-established, low risk technology. Recovery of reserves is optimized by selecting zones suitable for completion based on minimum levels of reservoir properties and sufficient levels of pressure (no depletion from offset wells). If the initial completion becomes depleted then the vertical well can be recompleted in other behind pipe zones, thus increasing reserve recovery and extending the life of the well.

The horizontal well can be drilled from vertical or high angle inclined wellbores. The horizontal section is kicked off close to the depth of the target zone and can easily reach lengths of 1500' to 3000' from the kick off point. The main problem with this well architecture at VBPA is that it can produce from only one of the 22 potential target zones. If the target zone is missing, pressure-depleted or has poor reservoir characteristics, then the horizontal well is a failure. If the horizontal well finds a good zone, then the reserve recovery from that zone will be potentially higher than recovery from a vertical wellbore in the same zone; however, the horizontal well has no access to the other 21 potential producing zones. Furthermore, unlike the vertical well, the horizontal well does not provide any information about the remaining 21 zones for geologic interpretation. Finally, drilling experience in the area indicates that the expected success rate for horizontal wells in low permeability gas reservoirs is about 20% to 25%.

The high angle inclined well is drilled at 30º to 60º from vertical starting at a 1500 ft kickoff point. This well intersects the reservoir zones at increasing distances from the surface location of the well; therefore, targeting of zones becomes more difficult than with vertical wells. There is increased cost associated with drilling time required for the longer, deviated well in addition to increased mechanical risk of directional drilling. A major problem of this type of well for VBPA is that, based on operator experience, the success rate for hydraulically fracturing the individual zones is about 1 in 3 due to screenout problems. During hydraulic fracturing, sand is carried into a fracture created by high-pressure fluid. If there is a restriction at the wellbore, the sand packs off, prematurely terminating the fracture treatment. Screenouts are common in wellbores inclined more than 10°.

The theoretical reasons for the screenouts in inclined wells are related to fracture initiation problems caused by certain well orientations in the stress field (Hossain et. al., 1999, and Sankaran et. al., 2000). It is critical that the inclined well be correctly oriented in order to have successful hydraulic fracture treatments. However, the stress field is usually poorly defined leading to poor success rates for hydraulic fracturing in inclined wells. Zones that screenout during fracturing are generally not successfully refractured and the reserves are not produced.

Orientation in the stress field is not a factor in vertical wells; consequently success rates for hydraulic fracturing are very high.

The s-shaped well is the most common deviated well drilled for field development. A well of this type at VBPA would be kicked off at about 1500' and straightened to vertical before entering the first pay zone at about 5500'. From a completion standpoint, this well looks like the vertical well with possible problems working inside a deviated well with two doglegs (bends) in the well path. The main reservoir problem with this well type at VBPA is drainage area limitations due to limited reach relative to effective drainage areas of the individual zones. A cross section of the s-shaped well is shown on:

Exhibit 2: S-shaped well – Vertical cross-section

The reach of the s-shaped well at VBPA is limited to 1500' due to mechanical constraints imposed by having the well vertical at the top zone (5500').

While s-shaped directional wells allow multiple wells to be drilled from a single pad, thus reducing surface disturbance, the limited reach of the directional well imposed by depth of the top zone, negatively impacts reservoir drainage per well.

Wexpro (2002) has determined from reservoir analysis of existing Mesaverde production in the Canyon Creek and Trail fields of the Vermillion Basin, that the effective drainage area for the Canyon Creek zone is 160 acres (1500 ft radius) and 80 acres for the Trail zone (1050 ft).

For these effective drainage areas, two s-shaped wells per pad without a vertical well have the same reserves per well as two vertical wells on the same spacing but with a 25% increase in per-well cost. If the s-shaped well offsets an existing vertical well, the overlap in effective drainage area reduces the per-well reserves by 25% in the Canyon Creek and by 12.5% in the Trail. The reserve reduction combined with 25% increase in well-cost makes the two wells uneconomic.

Four s-shaped wells per pad without a vertical well results in a 12.5% reduction in per-well reserves and a 25% increase in per-well cost. Adding a vertical well to the pad further reduces the per-well reserve.

An areal view of the effective drainage areas illustrates this point.

Exhibit 3: S-shaped well – areal view of effective drainage areas

In summary, vertical, hydraulically fractured, multiple zone completions are the only economically feasible well architecture for VBPA. It can be concluded that:

Horizontal wells that target a specific sand, are not feasible at VBPA because:

1. The sands are thin and the gas reserve target for individual sands will be small and non-commercial.
2. If the target sand is non-productive or pressure depleted, the horizontal section of the well must be redrilled to test other sands.

3. Recompletions to another sand are not possible in the horizontal well.
4. If natural fractures are not encountered, hydraulic fracturing in the horizontal well may be required to communicate vertically in the sand. This defeats the purpose of drilling the horizontal well.
5. The mechanical risk of drilling and completing horizontal wells is high.

High angle wells are not feasible because:

1. There is increased cost and mechanical risk associated with drilling the directional well.
2. The target zones are intersected at varying (increasing) distance from the surface location and may miss some of the target zones.
3. Difficulties in hydraulically fracturing in high angle wellbores results in a 1 in 3 success rate in completing the target zones leading to uneconomic wells.

S-shaped wells have some of the technical advantages of vertical wells but are not economically feasible because:

1. There is increased cost and mechanical risk associated with drilling the directional well.
2. The limited reach of the well (1500 ft) relative to the effective drainage areas of the target Mesaverde zones, reduces the reserves per well if more than two wells are drilled per pad or the s-shaped well offsets an existing vertical well on a two-well pad.
3. Two s-shapes wells per pad (without a vertical well) give the same reserves per well as two vertical wells on the same spacing but at a 25% increase in the per-well cost.
4. With two wells per pad the cost savings in surface infrastructure do not offset the increase in well drilling and completion cost.
5. Offsetting an existing vertical well with an s-shaped well will result in a decrease in the per-well reserve and an increase in the per-well cost.

Vertical wells have the following advantages:

1. The risk of not finding a sufficient number of productive sands in the 22 sand section is low.
2. Multiple sands can be hydraulically fractured and commingled in a single completion with low risk, proven technology.
3. Vertical wells can be recompleted to other sands if production from the initial completion drops to noncommercial levels.
4. The mechanical risk of drilling and completion operations is low.
5. Vertical wells will maximize the recovery of gas reserves in this multi-reservoir producing section.

By estimating cost and reserve factors, it is possible to evaluate the tradeoff between increased well-cost and reduced surface infrastructure cost associated with pad directional drilling for VBPA. The following table compares the cost and reserve factors for vertical, s-shaped, high angle, and horizontal wells.

Vermillion Basin Natural Gas Exploration and Development Project
Comparison of Well Configuration Alternatives

	% of total well cost vertical well	Vertical	S-shaped Deviated	High-angle Deviated	Horizontal
Mechanical risk		**0.98**	**0.95**	**0.9**	**0.6**
Cost Factors					
# wells per location		1	2	8	8
Location and road	7.0%	1.00	0.800	0.250	0.250
Drilling and logging	55.0%	1.00	1.400	1.400	1.400
Perforation	1.0%	1.00	1.100	1.200	0.000
Hydraulic Fracturing or Stimulation	25.0%	1.00	1.100	1.500	0.250
Gathering line	2.5%	1.00	0.800	0.250	0.250
Surface facilities	4.5%	1.00	0.750	0.750	0.750
Remediation	5.0%	1.00	0.500	0.125	0.125
Risked Cost Factor	**100%**	**1.00**	**1.246**	**1.468**	**1.508**
Reserve Factor (Vertical Well=1.0)		**1.00**	**1.00**	**0.31**	**0.16**

In the above table, the total well cost for the vertical well is allocated to several categories. The cost factors are then applied for each type of deviated well to reflect their relative cost. Drilling multiple wells from a pad offers some cost savings but at the expense of increased risk and drilling cost. The risked cost of the deviated wells ranges from 1.25 (s-shaped) to 1.5 (horizontal) times the cost of a vertical well. This appears to be in line with industry experience.

The relative reserves were estimated by applying success rates based on experience for each type of well with the vertical well = 1.0.

The projected reserves per well for the s-shaped well are the same as the vertical well if a maximum of two s-shaped wells are drilled per pad (no vertical well on the pad). However, the cost of the s-shaped deviated well, including estimated savings in surface infrastructure cost, is 1.25 times the cost of the vertical well. If the number of s-shaped wells per pad is increased to three or four, or a vertical well is added to the pad, the reserves per well decrease relative to the vertical well case. The 25% increase in per well-cost will likely make these wells uneconomic.

The horizontal well in the VBPA has an estimated cost of 1.5 times the vertical well and a projected reserve of only 16% of the vertical well. The low projected reserve is based on two factors: 1) a probability of success of 25% due to a variety of factors, including missing the target zone, not finding gas in the target zone, finding depleted pressure, not finding natural fractures, or intersecting a water bearing fractured zone, and 2) if a productive, single pay zone is found by the horizontal well, it will represent 25% of the gas in the total interval (optimistic) but will recover 2 times the gas that would be recovered by a hydraulically fractured vertical well in the same zone. Combining all of these factors gives a reserve factor of 0.16 for the horizontal well.

High angle deviated wells have an anticipated cost of 1.5 times the cost of the vertical well. The major cost components are drilling and stimulation. High angle wells can be hydraulically fractured similar to vertical wells; however, completion operations have higher risk. Fracture initiation and containment in highly deviated wellbores is a poorly understood, high-risk process (Sankaran 2000) that results in a high frequency of screenouts and contributes to higher completion cost.

The reserves for a high angle deviated well are about 1/3 those of the vertical well. This is a direct result of problems associated with hydraulically fracturing highly deviated wells. Operators' experience has shown that the success rate for fracturing in high angle wellbores will be about 1 in 3 due to screenouts. Reserves from zones where fracturing fails will be significantly reduced.

Based on the foregoing, it is concluded that the only technically and economically feasible well architecture for VBPA is the vertical well completed in multiple pay zones.

It is hoped that this analysis will help resolve the selection of an appropriate well architecture for the VBPA. If you have any questions, please contact the undersigned.

Sincerely,

/s/ Daniel H. Stright

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