Jonah Infill Drilling Project
Evaluation of Directional Drilling

prepared for

EnCana Oil and Gas (USA) Inc.

by
Reservoir Management Services, Inc.

16 JULY 2004

TABLE OF CONTENTS

List of Tables

List of Figures

INTRODUCTION

The Jonah Field in the Green River Basin of Sublette County, Wyoming is a major gas resource with approximately 10.5 TCF of original gas-in-place (OGIP) corresponding to a surface area of approximately 21,000 acres. With current well limitations and current surface spacing of 40 acres per well, the projected recovery is expected to be 30% of the OGIP which would leave approximately 4.7 TCF of economically recoverable gas in the reservoir. The projected 30% recovery is low compared to typical recoveries in conventional gas fields of over 80% of OGIP. The objective of infill drilling is to optimize the development of the hydrocarbon resource by increasing the recovery of gas to about 80% of the OGIP.

In low permeability reservoirs in Wyoming and other western states there is a trend to decrease the well spacing in order to increase recovery of the gas resource. Jonah is a low permeability reservoir and the decision to drill more wells at Jonah is based on field performance and detailed technical studies completed by operators. The technical studies include 3D seismic acquisition and interpretation, detailed description of the subsurface rocks that makeup the gas reservoir, flow modeling of the field, acquisition of petrophysical and pressure data, and microseismic/tiltmeter surveys during completion operations.

Jonah is an important gas resource in Wyoming. The field currently produces about 680 MMSCF of gas per day or 248 BCF of gas per year and, as shown on Table 1, is the largest non-coalbed-methane gas field in Wyoming, yielding about 13.5% of the total gas produced in the state.

Top 25 Largest Gas Fields In Wyoming for 2003

FIELD	Gas 2003 MCF	% OF STATE GAS TOTAL	COUNTY
PRB COAL BED	345,998,970	18.86	CAMPBELL / SHERIDAN / JOHNSON
JONAH	247,923,542	13.52	SUBLETTE
FOGARTY CREEK	161,012,934	8.78	SUBLETTE
MADDEN	111,261,366	6.07	FREMONT
PINEDALE (Includes MESA UNIT FIELD)	102,522,360	5.59	SUBLETTE
PAINTER RESERVOIR EAST	72,757,458	3.97	UINTA
WHITNEY CANYON-CARTER CREEK	67,004,736	3.65	LINCOLN / UINTA
LAKE RIDGE	65,466,134	3.57	SUBLETTE
LOST SOLDIER	38,955,320	2.12	SWEETWATER/FREMONT
BRUFF	31,291,864	1.71	LINCOLN / SWEETWATER / UINTA
ECHO SPRINGS	29,732,358	1.62	CARBON / SWEETWATER
WAMSUTTER	27,376,592	1.49	SWEETWATER
STANDARD DRAW	24,071,278	1.31	CARBON / SWEETWATER
WALTMAN	23,845,277	1.30	NATRONA
WILD ROSE	22,398,570	1.22	CARBON / SWEETWATER
TIP TOP	17,503,510	0.95	SUBLETTE
FONTENELLE	13,379,094	0.73	LINCOLN / SWEETWATER
HOGSBACK	13,046,843	0.71	LINCOLN / SUBLETTE
PAVILLION	12,109,148	0.66	FREMONT
WERTZ	12,001,184	0.65	CARBON/SWEETWATER
LABARGE	11,544,751	0.63	LINCOLN / SUBLETTE
PAINTER RESERVOIR	11,220,192	0.61	UINTA
BEAVER CREEK	10,798,737	0.59	FREMONT
BRADY	10,694,488	0.58	SWEETWATER
CHURCH BUTTES	10,521,394	0.57	SWEETWATER / UINTA

Table 1: The 25 Largest Gas Producing Fields in Wyoming in 2003[1]

[1]The Wyoming Oil and Gas Commission," 2003 Wyoming Oil and Gas Statistics".

In terms of energy consumption in Wyoming, Jonah Field gas production is significant. Total annual residential consumption of natural gas for the State of Wyoming in 2002 was 13 BCF (81 MCF per year per household)[2]. Production from the Jonah Field could theoretically supply 3,000,000 households or 19 times the annual residential natural gas requirements for the state of Wyoming. Additionally, Jonah produces about 2,200,000 barrels of condensate (oil) each year, which is equivalent to approximately 9% of the field gas production (1 barrel of oil equals 10,000 standard cubic feet of gas).

Jonah Field was compared to four other sandstone reservoirs in SW Wyoming. Outlines of the five fields are shown on :

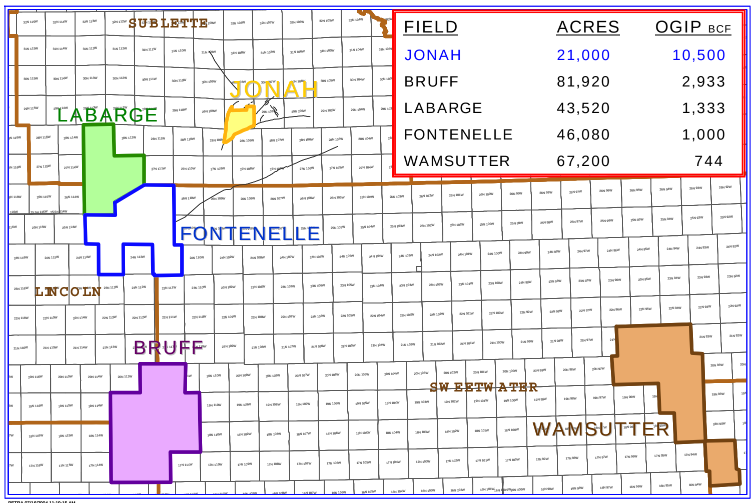

Figure 1: Outline of Jonah and comparison gas fields.

The portion of Jonah Field being proposed for infill drilling, which contains about 10.5 TCF of OGIP under 21,000 acres of surface area, is compared to four other fields from the top 25 gas producing fields in Wyoming. The areas shown for these fields are defined by the Wyoming Oil and Gas Commission (WOGC). Within these areas, the field production, number of wells, and acres were determined from WOGC data. The acres shown in the table on Figure 1 were calculated by multiplying the number of drilled sections within the outline by 640 acres.

A comparison of Jonah with other fields in Sublette and Lincoln Counties is shown in Table 2

Jonah Field Comparisons - Sublette, Lincoln, and Sweetwater Counties, Wyoming.

	ANNUAL VOLUMES			TOTAL	EST. ULTIMATE RECOVERY			OGIP	SURFACE AREA
FIELD	ANNUAL MCF	MCF per Well	ANNUAL BBLS	WELLS	GAS-BCF		Oil-MMBO	BCF	ACRES
JONAH	247,923,542	498,840	2,272,761	497	3000	1	30.0	10,500	21,000
JONAH				3,597	7947	2	79.5	10,500	21,000
BRUFF	31,291,864	70,957	194,943	441	2200	3	15.0	2,933	81,920
FONTENELLE	13,379,094	44,746	20,245	299	750	3	1.6	1,000	46,080
LABARGE	11,544,751	13,566	322,230	851	1000	3	26.0	1,333	43,520
WAMSUTTER	27,376,592	110,389	306,062	325	558	3	6.0	744	67,200

1. Estimated from EnCana's technical studies(no additional wells)
2. Estimated from EnCana's technical studies(proposed action)
3. Estimated from extrapolation of field gas rate vs. cum. gas production(Wyoming Oil and Gas Commission data)

Table 2: Comparison of Jonah and other gas fields in Sublette, Lincoln, and Sweetwater Counties, Wyoming.

[2] American Gas Association; "The Natural Gas Industry in Wyoming",2002.

Table 2 summarizes the comparison of Jonah Field to the other fields. Estimated ultimate gas recoveries were found by extrapolating the plot of field gas production versus cumulative gas production to a limit of 100,000 MCF/Month. Values for Jonah Field were taken from EnCana's technical studies. OGIP for the other four fields is not available and was estimated by assuming an arbitrary recovery factor of 75% of OGIP.

Table 2 shows that Jonah Field is a significant, highly-concentrated, energy source. A comparison of the data on a per-acre and per-well basis is shown in Table 3:

FIELD	OGIP-BCF		EUR-GAS(BCF)		EUR-OIL(STB)	
	Per well	Per Acre	Per Well	Per Acre	Per Well	Per Acre
JONAH(no Action)	21.1	0.500	6.0	0.143	60362	1429
JONAH(proposed action)	2.9	0.500	2.2	0.378	22102	3786
BRUFF	6.7	0.036	5.0	0.027	34014	183
FONTENELLE	3.3	0.022	2.5	0.016	5351	35
LABARGE	1.6	0.031	1.2	0.023	30552	597
WAMSUTTER	2.3	0.011	1.7	0.008	18462	89

Table 3: Comparison of OGIP and EUR: Jonah and some other Wyoming Gas Fields

For the proposed action, Jonah Field contains about 25 times more OGIP and gas reserves per-acre than the other fields. The OGIP and gas reserves per-well are about equal to the other fields. The Jonah oil reserves per-acre (proposed action) are 45 times higher than the other fields. Per-well oil reserves, on average, are about the same as the other fields. OGIP per acre for the fields is shown on Figure 2:

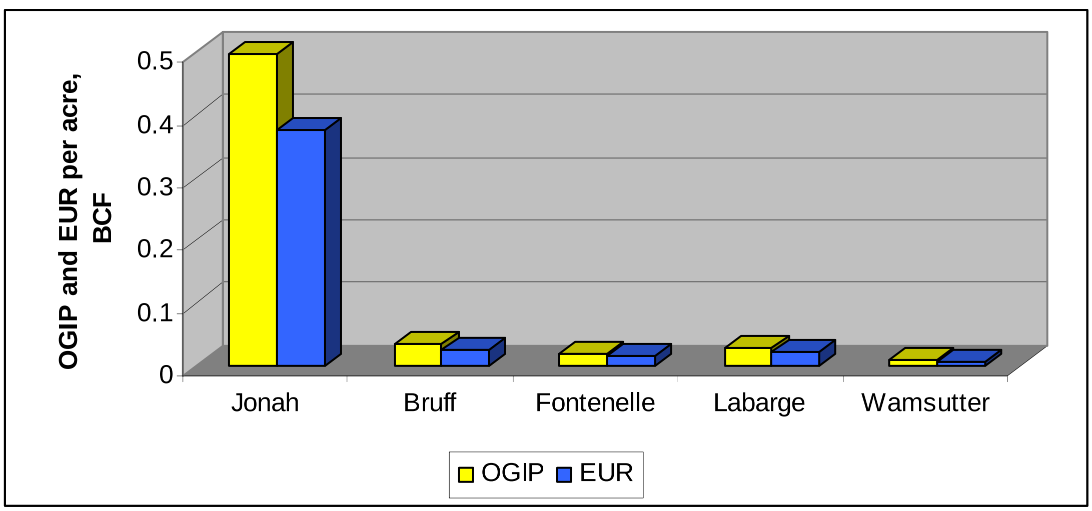

Figure 2: OGIP and EUR per acre for Jonah and comparison fields

Jonah is currently developed on 40 acre surface spacing and with the significant potential of increased gas recovery anticipated from infill drilling, optimized subsurface well spacing in the range of 5 to 10 acres is being considered. In this report, the various well architecture options available for infill drilling at Jonah are outlined and the "waste" associated with these options is quantified. State oil and gas commissions generally have rules addressing "prevention of waste", which in most cases they have defined as:

- Actions that result in irrecoverable loss of natural gas
- Drilling of unnecessary wells

The potential resource waste at Jonah results from incremental costs and lost gas reserves associated with directional drilling relative to vertically drilled wells. In this report, the potential "waste" is quantified based on a review of actual directional well experience at Jonah where 54 directional wells have been drilled and completed as of May 2004.

BACKGROUND

Geological Setting. Jonah Field produces from a thick sequence of rocks that is defined by the intersection of two fault zones which form a wedge-shaped structural block. The updip termination at the southwest end of the field is the apex of the block. The downdip limit is defined as occurring along the structural low between Jonah and the Pinedale Anticline to the northeast.

Within the wedge-shaped Jonah block, overpressure conditions exist in the Lance Formation, whereas the same Lance Formation rocks outside the Jonah compartment appear to contain "normal" pressure (pressure equivalent to a column of water at the same depth). The Wyoming Oil & Gas Conservation Commission has defined the Lance Pool as the stratigraphic interval between the Ericson Sandstone of the Mesaverde Group and the base of Tertiary Fort Union (aka "Bois Marker"). This interval comprises the full range of productive rocks known at Jonah Field. Thickness of this interval ranges from about 3200 ft in the updip (southwestern) corner to about 5100 ft at the downdip extreme. Over the field the vertical depth to the top of the Lance from the surface varies from 7200 ft to 9000 ft.

The gas reservoir at Jonah is described as a combination structural-stratigraphic trap. The bounding fault zones form the lateral trap and the top-seal is comprised of the mudstones that are interbedded with the reservoir sandstones of the Lance. The Lance Formation sandstones are lenticular and discontinuous having been stream-deposited (fluvial), with interbedded siltstones and mudstones deposited outside the stream channels. The 3-dimensional geometry of the sandstones deposited in this fluvial setting and the overprint of faults results in extreme reservoir complexity. It is this geometric complexity that makes full recovery of the gas-in-place impossible on 40-acre well spacing. Additionally, the average permeability of these rocks is very low (0.01 millidarcies) making it more difficult to move gas over long distances within the sandstones.

The Lance at Jonah Field is highly over-pressured. In, general, for a given pore volume, higher initial reservoir pressures result in larger volumes of OGIP. The over-pressure also results in preservation of slightly better porosity relative to Lance sandstones outside the field boundary.

The lenticular nature of the fluvial Lance Formation sandstones created highly complex reservoir architecture and is a significant challenge to the gas recovery process. There is poor connectivity as indicated by difficulty in correlation of individual sandstone bodies between wellbores positioned as close as 5 acre spacing. The poorly connected sandstones mean that relatively close well spacing is required to produce a high percentage of the gas resource.

The Tertiary Fort Union Formation overlies the Lance Pool Interval. The Fort Union is comprised mostly of sandstone, much of which is porous, permeable and normally pressured. The large reservoir pressure difference between the over-pressured Lance and the normally pressured Fort Union is the main source of drilling problems at Jonah and will be discussed In detail later in the report.

Field history. Jonah Field was discovered by Davis Oil Company in 1975 with the drilling of the Wardell Federal #1 well. The discovery well was not economic and in 1992, McMurry Oil Company acquired the field after a total of three wells had been drilled. After testing the first three wells with encouraging results, McMurry Oil drilled the Jonah Federal #1-5 well, which initially produced 3.7 million cubic feet (MMCF) of gas and 40 barrels of oil per day. Initial assessments led to the request by McMurry Oil for a maximum of 497 wells to develop the field on 80 acre spacing over an area of 60,000 acres.

Alberta Energy Company, now EnCana after the merger with PanCanadian, acquired McMurry's interest in Jonah Field in 2000. In June of 2000, the BLM approved 40 acre spacing (497 well pads) over a smaller area corresponding to the core of the field defined by the over-pressured

Lance. The remaining area is in the normally pressured Lance and is excluded from the current environmental impact statement.

As of early 2004, Jonah Field has produced 1,020 BCF of gas (10% of the resource) and 10.2 MM barrels of condensate (oil). Current field production is about 680 MMSCF per day making it the largest non-coalbed-methane gas field in Wyoming. Projected recoveries without infill drilling will be about 30% of the resource. With infill drilling it is anticipated that close to 75% of the resource can be recovered.

***Evaluation of infill drilling*.** More recently, detailed technical studies based on field performance and 3D seismic indicated that significant reserves would not be drained on 40 acre spacing. In 2002 EnCana initiated a pilot infill well program with some wells drilled as close together as 475 ft. The main objectives of this pilot were to gather technical information required to determine the spacing necessary to develop Jonah Field and to evaluate the feasibility of directional drilling.

A good understanding of the drainage areas and their shapes will prevent the drilling of unnecessary wells and will help locate wells to insure that the maximum possible volume of gas is recovered. Microseismic and tiltmeter surveys are being conducted in conjunction with well completion operations to better understand the size and shape of drainage areas associated with individual wells. The operators also constantly evaluate new technologies that might be used to maximize gas recovery. Examples of new technologies being evaluated are:

- New logging technologies such as Cased Hole Dynamic Testing
- Improved fluids utilized for hydraulic fracturing
- VSP seismic technology
- Geocellular interpretation and reservoir modeling

Subsurface Spacing – Waste Considerations. Analysis by EnCana based on pilot infill results, detailed reservoir description and reservoir modeling work, and volumetric analysis, gives the following estimated gas recovery volumes based on several different field development techniques. The results are shown in Table 4:

Field Development Alternative	Additional wells and pads	EUR (Bcf)	Waste Relative to Proposed Action (Bcf)
No Action	0	3,366	(4581)
Proposed Action	3,100 from 16,200 acres of disturbance	7,947	0
Max Development	Unrestricted development	8,191	244
Alternative A	3,100 from 497	6,124	(1824)
Alternative B	1,250 from 1,250	6,657	(1290)
	2,200 from 2,200	7,554	(393)
Alternative C	3,100 from 266 New (16 dis/Sec)	6,302	(1645)
	3,100 from 1,028 New (32 dis/Sec)	7,186	(761)
	3,100 from 2,553 New (64 dis/Sec)	7,876	(71)

Table 4: Anticipated Gas Recovery Volumes for various field development techniques, Jonah Infill Drilling Project, Sublette County, Wyoming, 2004.

Based upon EnCana's current technical understanding of the Jonah Field, original-gas-in-place (OGIP) is currently estimated at 10.5 trillion cubic feet of gas (TCF). Typical recovery factors for deep gas fields range between 75-85% of OGIP. With no further development, it is currently estimated that gas recovery will be approximately 30% of the 10.5 TCF of OGIP leaving 4,581 BCF of potential gas reserves in the ground unrecovered. This constitutes significant waste.

With no new surface locations and limiting the development of the northern third of the field (3100 wells/existing 497 well pads), it is currently estimated that approximately 1,824 BCF of gas would not be recovered, also constituting significant waste.

If the Jonah Field were developed with sixteen surface disturbances per section (40-acre spacing), this would limit development of the lower EUR/well population of the 5, 10 and 20-acre infill program, causing many wells to fall below the economic threshold due to increased directional drilling costs. This waste is significant and is estimated to be approximately 1,645 BCF of gas reserves.

To put this loss in perspective, 2,000 BCF, if produced over 25 years, represents 6 times Wyoming's current annual residential natural gas usage.

WELL ARCHITECTURE OPTIONS

Directional drilling has been proposed as a universally applicable technology for use in reducing surface disturbance that can easily be applied to Jonah Field[3]. This is a misconception resulting from superficial analysis of directional drilling technology applications in development of oil and gas fields.

The evaluation of well architecture options for thick, low permeability gas reservoirs is not a simple matter of stating that drilling multiple wells from a single pad will reduce surface disturbance. Many factors must be considered in order to select the appropriate well type and to evaluate the tradeoffs between vertical and deviated wells. The tradeoffs involve increased cost and potential lost reserves associated with increased risks in the deviated well drilling, completion and production processes. In addition, increased drilling times and higher engine load requirements for deviated wells increase cumulative surface activity, emissions, and environmental impact.

Directional drilling is a well-established technology in the oil and gas industry. However, the technology is not applicable to all situations. The proper application of directional or deviated well drilling must be carefully evaluated for each reservoir and a fit-for-purpose well architecture must be designed for each reservoir or field. For example, at Jonah, the Lance is over-pressured and in directional wells, the bends and inclined section of the borehole is contained within the normally pressured Fort Union above the Lance. Differential sticking caused by moving the drill pipe and casing through the bends of the directional well severely complicates directional drilling at Jonah. The position of the s-shaped well relative to the Fort Union and the Lance is shown on Figure 3:

[3] Amos, J.F.:"WITNESS STATEMENT:Environmental Aspects of Modern Onshore Oil and Gas Development", Testimony to the Committee on Resources of the United States House of Representatives, Subcommittee on Energy and Mineral Resources, September 17, 2003.

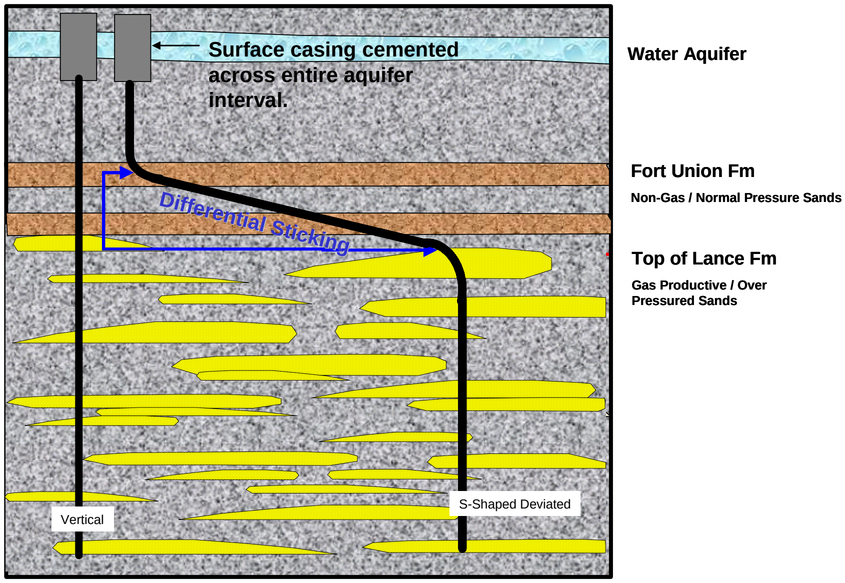

Figure 3: Schematic of S-Shaped directional and vertical wells showing location of differential sticking zone (not to scale - inclined section is 15˚ maximum).

Directional Well Types. The large number of thin sands distributed over a long interval impacts the selection of the appropriate well configuration. An example cross section at Jonah Field is shown in Figure 4:

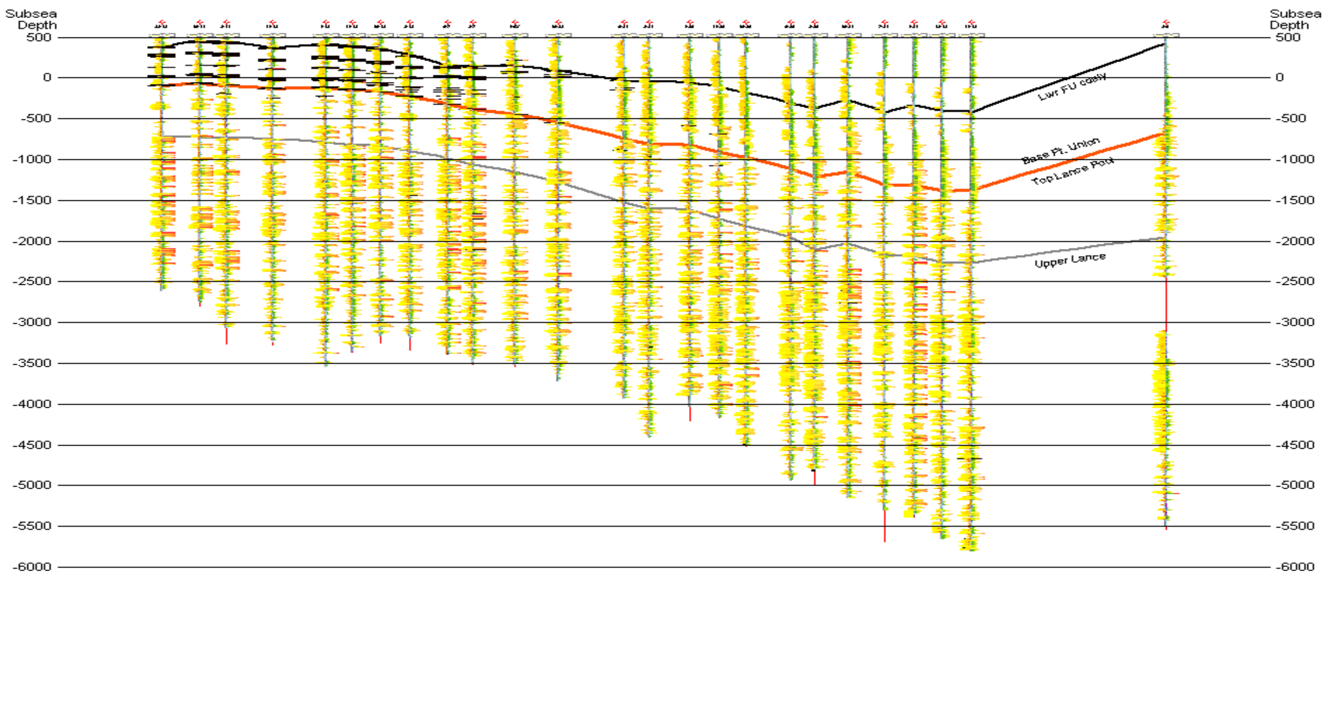

Figure 4: Cross section of the Lance at Jonah Field with potentially productive sands shown in yellow.

The section, which runs from SW to NE shows the structural dip on the top of the Lance. As the top of Lance increases in depth from 7200 ft. to almost 9000 ft., the gross thickness of the reservoir increases from 3000 ft to 5000 ft.

The possible well configurations for Jonah are shown on Figure 5:

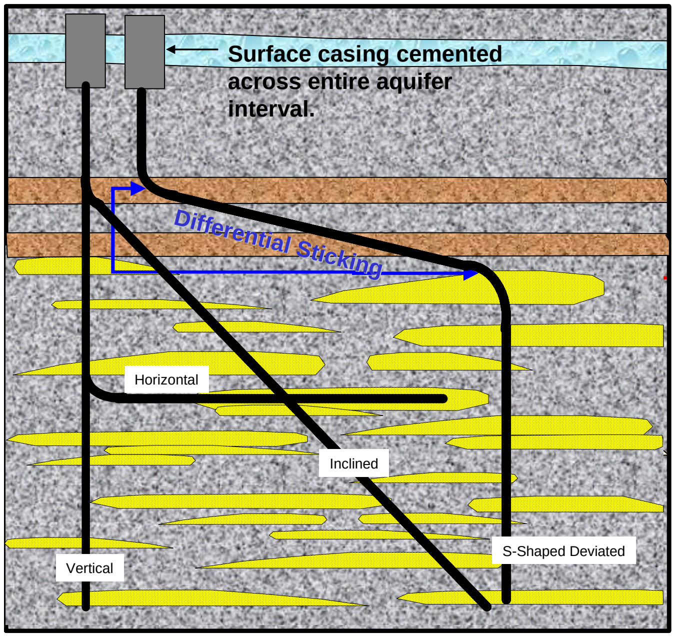

Figure 5: Well type options for Jonah development (not to scale).

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

A vertical well intersects all zones directly under the surface location. All zones of the Lance, including ones partially depleted by offset production, are perforated and hydraulically fractured in up to 10 stages. Drilling and completion operations are based on well-established, low risk technology. This type of well is the most commonly used well in developing thick, multiple zone, low permeability gas reservoirs. A typical well program is to run surface casing to 2500 ft through the surface aquifers then drill the normally pressured Fort Union and the over-pressured Lance with no intermediate casing. Mud weight is increased at the top of the Lance to control pressure and gas flow in the well. The increased mud weight creates a pressure differential (overbalance) across the Fort Union which can cause the drill pipe to stick in the deviated section of the borehole. In vertical wells, drill pipe sticking is generally not a problem.

A horizontal well can be drilled from vertical or high angle inclined wellbores. The horizontal section is deviated from vertical (kickoff point) close to the depth of the target zone and can easily reach lengths of 1500 ft to 3000 ft from the kickoff point. The main problem with this well architecture for the Lance at Jonah is that production is restricted to only one of the potential target zones. Although horizontal wells may drain reserves from a single zone more efficiently than a vertical well completed and hydraulically fractured in the same zone, single zone completions are generally not economic in the Lance. In multizone reservoirs, multilaterals or hydraulic fracturing has been used in some instances to access multiple zones. At Jonah these approaches are not feasible because of the large number of zones distributed over 3000 ft to 4000 ft of gross interval. Horizontal wells are clearly not applicable for development of the Lance at Jonah.

At Jonah, a high angle inclined well would be drilled at 30º to 60º from vertical starting at a 2600 ft kickoff point. This well intersects the reservoir zones at increasing distances from the surface location of the well. 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 with this type of well is that, based on industry experience, hydraulically fracturing the multiple individual zones is technically difficult due to problems with screenouts. 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 (screenout) terminating the fracture treatment. If special, higher-cost technologies are not applied, the frequency of screenouts increases as wellbores are inclined to more than 10° from vertical.

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[4] and Sankaran[5]). 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.

Finally, the diagonal wellbore on the diagram penetrates approximately the same number of sands the vertical wellbore does. However, the drainage areas are not equivalent as a large wedge-shaped area between the inclined well bores is left undeveloped. This wedge-shaped area on the two-dimensional diagram is actually a very large conical area when looked at in all three dimensions. That conical area would not be drained without the drilling of additional vertical wells.

The s-shaped well is the most common deviated well drilled for field development. A well of this type at Jonah would be kicked off at about 2600 ft and straightened to vertical before entering the first pay zone at about 7150 ft to 8700 ft from surface. 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 subsurface problem with this well type at Jonah is increased cost associated with directional drilling and mechanical risk due to differential sticking of drill pipe and casing through the normally pressured Fort Union above the Lance.

It is the Lower Fort Union that represents the most significant risk for differential sticking problems during drilling operations. The mud column pressure required to drill the underlying Lance is much higher than the Fort Union formation pressure. This large pressure difference over hundreds of feet in the Fort Union creates conditions where the drill pipe may become attached to the borehole wall (differential sticking) especially where the pipe moves through the bends of the directional wellbore. Directional drilling increases the probability of becoming differentially stuck because where the hole is deviated from vertical, pipe will lay against one side of the borehole instead of hanging near the center of a vertical borehole.

Therefore, the bends in the well paths, located in the Fort Union, increase the possibility of sticking the drill pipe and casing. The end result is increased cost and potential loss of gas reserves. There are some potential solutions to address the problem of differential sticking. These will be discussed in a later section.

In summary, from a reservoir management standpoint, vertical wells with hydraulically fractured, multiple zone completions are the preferred option for efficient recovery of gas reserves at Jonah. S-shaped deviated wells have application to develop gas reserves under areas of the field where surface occupancy is prohibited or not possible because of terrain. Using S-shaped deviated wells for infill development at Jonah in areas where vertical wells can be used involves a tradeoff between reducing surface disturbance and higher per well cost and lost reserves. As spacing is reduced below 40 acres per well, multiple directional wells drilled from a larger single pad reduce the total area of surface disturbance; however, increased cost and resulting loss of reserves associated with directional wells causes waste.

---

[4] Hossain, M.K., M.K. Rahman and Sheik S. Rahman;"A comprehensive Monograph for Hydraulic Fracture Initiation from Deviated Wellbores Under Arbitrary Stress Regimes";SPE 54360, Dallas(2000).

[5] Sankaran, S.,Nikolaou, M., and Economides, M.J.: "Fracture Geometry and Vertical Migration in Multilayered Formations from Inclined Wells"; SPE paper 63177, Dallas(Oct 2000).

Maximum Reach. The depth of the top of the Lance from the surface varies from 7000 ft at the SW end of the field to almost 9000 ft at the NE end of the field. The objective is to have the wellbore vertical at the top of the Lance. Given a kick off point, maximum change in the deviation angle (dogleg severity, degrees/100 ft) and a maximum angle of the inclined section of the well, it is possible to calculate the reach of the deviated well versus the depth to the top of the Lance.

Assuming a dogleg severity (rate of bending between the vertical and inclined sections of the directional well) of 1 degree per 100 ft, a maximum inclination of 15 degrees from vertical and a kickoff point of 2600 ft, a typical well design is shown on Figure 6:

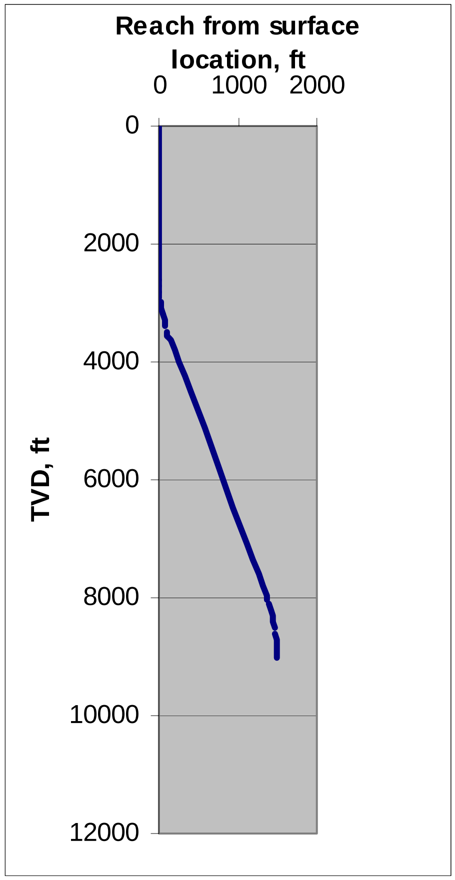

Figure 6: Well path for a typical directional well at Jonah

The maximum reach was calculated, assuming the above deviated-well design parameters and plotted versus the depth to the top of the Lance. The result is shown on Figure 7:

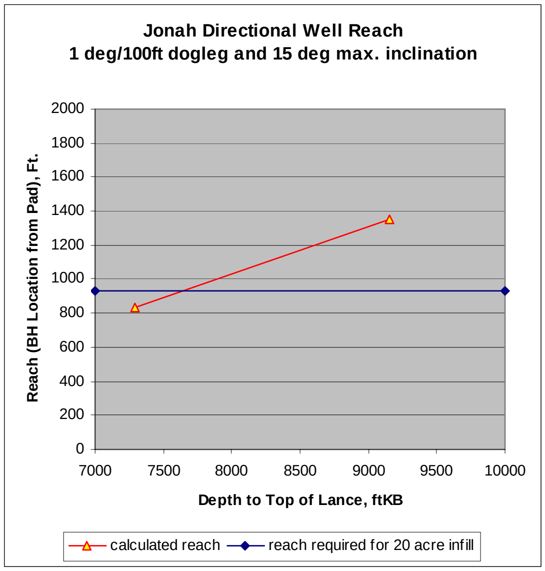

Figure 7: Maximum reach for a deviated well at Jonah for dogleg severity of 1˚/100 ft and 15 ˚ maximum inclinations in the build section.

From the 40 acre vertical well location, it is possible to achieve 933 ft displacement of the bottomhole location (20 acre location) with an s-shaped well if the top of the Lance is deeper than 7659 ft. For the deepest part of the Lance, a displacement of 1300 ft is possible. With these design parameters it is not possible to reach the adjacent 40 acre location except in the deepest part of the field. A longer reach can be achieved by increasing the inclination angle or by kicking of the deviated section in the surface casing.

Well designs show that a maximum reach of 1500 ft from the surface location can be achieved with inclined sections greater than 15 degrees. The inclination required to reach 1500 ft ranges from 16 degrees for a Lance top at 9193 ft to 31 degrees if the Lance top is at 7500 ft. Therefore, it is possible to reach the adjacent 20 acre locations but not the adjacent 40 acre locations with less than 15 degrees of inclination. However, kicking off in the surface casing interval or increasing the inclination angle above 15 degrees to increase the reach may increase the risk of the directional drilling operation.

DRILLING AND COMPLETION COST

The drilling and completion costs for vertical wells and deviated wells from September 2002 (start of the directional well program) and May 2004 were analyzed to establish the incremental cost of drilling deviated wells. The data were also evaluated to determine how this incremental cost was changing over time as experience was gained in the 54 well directional drilling program.

Drilling Cost. When applying any new sophisticated drilling technology to a field, the costs generally start high and decrease with time as experience is gained and the process is optimized. Figure 8 shows the additional cost of a directional well relative to a vertical well versus the reach of the deviated well. In theory, problems in directional drilling are related to the length and inclination of the deviated borehole section which increase with reach (the distance of the bottomhole location from the surface location).

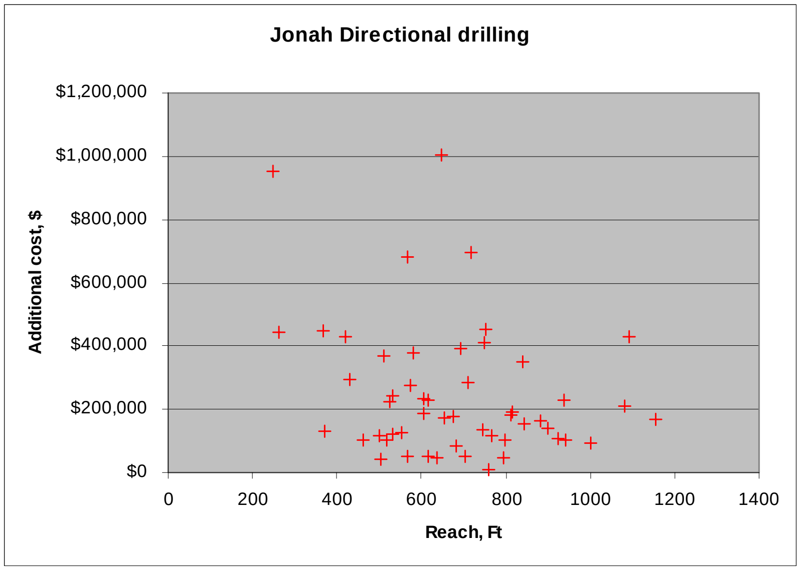

Figure 8: Directional to vertical additional well cost versus reach (distance of bottomhole location from surface location).

Experience to date indicates that there is no correlation between reach and additional well cost. In fact, some of the low reach wells have experienced more problems than longer reach wells. This suggests that other factors are more important in determining the incremental cost.

Generally, for directional drilling, the cost decreases with time as experience is gained. The cost for a directional well will always be higher; however, the additional cost is usually minimized as the number of directional wells drilled increases. Figure 9 shows the additional cost versus time (or number of wells) at Jonah Field.

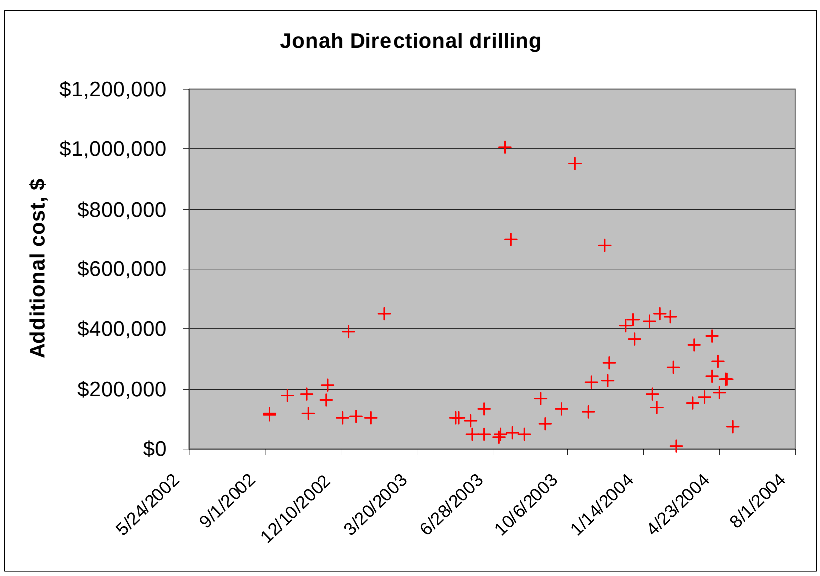

Figure 9: Directional to vertical additional well cost versus time.

The expected learning curve has been observed at Jonah with technology advancements to the end of 2003 when the additional cost reached a low of about $50,000. However, in 2004 problems and additional costs have increased and demonstrate that directional drilling continues to experience a significant risk. Recently, additional drilling costs are very high ranging from

$200,000 to $400,000 per well. This experience indicates that many factors are influencing the directional drilling results. Some of these factors are:

- depth to the top of the Lance where the mud weight is increased to control the overpressures varies across the field by about 1250 ft
- thickness of the Lance section drilled varies across the field by about 2500 ft
- rig crew experience and quality of the drilling rig and equipment may vary with time
- bit selection and optimization varies by area

From this data it can be concluded that many factors contribute to the mechanical risk of a directional well at Jonah. Therefore, a predictable decrease in the additional cost of a directional well relative to a vertical well over time cannot be expected. Even when some directional wells can be drilled at low additional cost, problems in a following well can result in 5 times the additional cost which significantly raises the average cost of the directional well program. Based on current data, it is expected that the additional cost for a directional well will be in the $200,000 to $400,000 per well range for the current well plan.

Factors Contributing to Additional Cost for Drilling Directional Wells. Several factors may contribute to the increased cost of directional wells at Jonah Field. Experience from the 54 directional wells drilled to date provides some basis for evaluating these factors.

Differential sticking. The 3000 ft to 4000 ft of over-pressured Lance Formation productive interval in the Jonah Field creates both a significant natural gas resource and an operational challenge for recovery of that resource. Directly above the Lance Formation lies the non gas-bearing, lower-pressured Fort Union, comprised mostly of sandstone much of which is porous and permeable. In order to have effective completion and avoid waste, all directional drilling operations must be completed in the Fort Union Formation, resulting in a vertical wellbore at the top of the productive Lance Formation. It is the Fort Union that represents the highest potential for differential sticking while drilling in the over-pressured Lance.

Mud weights required to safely drill the Lance Formation range from 11.0 to 13.0 pounds per gallon, while the Fort Union requires only 8.3 pounds per gallon. While drilling directional wells, this differential pressure requires significant attention to avoid stuck pipe and costly fishing jobs. Experienced rig personnel and above average drilling equipment is required to avoid problems.

Two changes could be made to the drilling program to eliminate most of the differential sticking problems: intermediate casing through the Fort Union or oil based drilling fluid.

Intermediate casing can be run to the top of the Lance where it is necessary to increase mud weight to control the well. Although the intermediate casing would eliminate the differential sticking problems, the estimated additional cost for this option ranges from $600,000 to $700,000 per well.

The high incremental cost for the intermediate casing option results from the significant changes that must be made to the drilling program. In order to run 4 ½" casing to total depth for efficient hydraulic fracturing, the borehole size to the top of the Lance must be increased. Drilling times are longer in the larger hole and additional time and cost are incurred for intermediate casing and the larger surface casing. For this option, crew experience and rig quality requirements would be nearly identical to a vertical well with no intermediate casing string.

Intermediate casing is used on the Pinedale Anticline because reservoir pressure gradients are higher at Pinedale (0.8 psi/ft) compared to Jonah (0.63 psi/ft)[6]. The higher mud weights required at Pinedale increase problems related to differential sticking in the Fort Union. In addition, higher bottomhole pressures require higher strength casing in the upper part of the hole for well control purposes. Because intermediate casing must be run in vertical wells in Pinedale due to a higher

[6] Charpentier, R.R., Law, B.E., and Prensky, S.E.;"Quantitative Model of Overpressured Gas Resources of the Pinedale Anticline, Wyoming",SPE/DOE 16404.

bottomhole pressure and increased differential pressure between the Fort Union and the Lance/Mesaverde, there is less incremental cost associated with directional wells relative to vertical wells in this case. At Jonah, where the pressure difference is smaller and the bottomhole pressures are lower, it is possible to drill vertical wells without intermediate casing. Therefore, Jonah wells will have a significant additional cost for this option that wells at Pinedale will not have.

The second option being considered for directional drilling in Jonah is changing from water based to oil based drilling fluids with either diesel or synthetic oil. There are two concerns with oil based drilling fluids; the first is cost of the oil and the second is the environmental cost of handling, transporting and disposing of this fluid. A mud plant for recycling of the oil for subsequent wells would be required.

Also, two mud systems would be required, water based for drilling the surface aquifers switching to oil based fluid at the top of the Lance. The estimated additional drilling cost for this option is about $200,000 per well. For this option, crew experience and rig quality requirements would still be a concern. Although the oil based drilling fluid decreases the probability of differential sticking it may not eliminate it.

Well Collisions. As the distance between well locations is decreased in order to reduce the size of the multi-well pads, the risk of collision between the drilling well and existing wellbores increases. EnCana recently experienced a wellbore collision during the drilling of the SHB 20-4 at 700 ft. The estimated cost to remediate the damage (redrill the well) is approximately $168,000. In addition to cost, there is a significant safety risk associated with well collisions. If the integrity of the existing well is lost, then high pressure gas could possibly enter shallow aquifers or the drilling well. High pressure gas entry at this shallow depth could be catastrophic.

Initially, Jonah directional wells on multi-well pads were drilled on 20 ft spacing. It is believed that this spacing significantly reduces the risk of collisions. At 8 ft spacing between wells on the pad (the spacing of the SHB 20-4) it will be necessary to steer the well from surface to avoid collisions. Steering from surface adds to the drilling cost and reduces, but may not eliminate, the risk of collisions. Because of these safety concerns, EnCana plans to return to 20 ft spacing between wells on the multi-well pads.

***Gas leaks near the surface*.** Another problem associated with small multi-well pads, is that the drilling rig is positioned close to earlier completed wells. Where underground gas leaks near the surface occur, there is a serious safety issue for the drilling operation.

A solution for these low-probability, near-surface problems on multi-well pads is to increase the distance between wellheads to increase safety and minimize the risk of gas leaks and well collisions. However, this would increase the size of the multi-well pads and offset some of the surface benefits of directional drilling.

Completion Cost. On average, 10 hydraulic fracturing stages are performed per well working from the bottom of the well to the top of the Lance. Each zone is fractured, back-flowed to recover fracturing fluids (cleanup), and isolated with wireline conveyed plugs for the next stage. During cleanup of the next stage higher in the well, gas flows up through the plugs from the lower zones and provides energy for cleanup. There does not appear to be any problem with this procedure downhole for either vertical or directional wells. However, both vertical and directional wells have experienced problems in the zones where injection/falloff pressure tests are used to measure pressure. In these cases a bridge plug is run to isolate the underlying zone preventing energy from the lower zones from assisting the cleanup. With poor cleanup, sand falls back on top of the bridge plug and a clean-out with a rig or coiled tubing is required.

However, there is an additional cost for directional wells relating to surface layout if a sand clean-out is required. Due to the fact that wellheads at the surface are in close proximity, conventional rig work cannot be performed during the hydraulic fracturing cycle. Coiled tubing is required due to its small footprint. When coiled tubing is used, the incremental completion cost is $70,000.

Openhole Data Acquisition. Data acquisition in new infill wells is important. Good openhole logs and pressure data assist in determining the number and location of infill wells. Data from early infill wells will help define optimum location of later wells and will help insure that no more than the necessary number of wells is drilled to efficiently recover the gas reserves. Pressure data is obtained in cased hole so the problems in acquiring this data are similar for both vertical and directional wells. However, in directional wells without intermediate casing or oil based drilling fluids, there is high risk in obtaining openhole log data. If it is the judgment of drilling supervisors that hole conditions are poor then only a limited number or no openhole logs are run.

The reason for this cautious approach is that if wire line logging tools become stuck and the line parts or keyseats in the bends of the directional well, the tools must be recovered in order to run casing and complete the well. The worst case scenario is a total loss of the well requiring a sidetrack or total redrill.

Recovering stuck logging tools creates a serious safety issue. When the wire line is cut and the drill pipe is stripped over the line to recover the stuck tools, gas entry into the well may be difficult to control. Too much gas entry can cause loss of control of the well.

Total Additional Drilling and Completion Cost. Operator experience after 54 directional wells in Jonah Field has determined that the average increase in costs for drilling and completion ranges from $270,000 to $470,000 as compared to a vertical well. Using oil based drilling fluids will eliminate some of the risk related to differential sticking in the directional wells; however, the estimated total additional cost to drill and complete with these drilling fluids is about $270,000 per well. If oil based drilling fluids eliminate differential sticking problems, then this option gives about the same additional directional well cost as the current program.

Finally, running intermediate casing through the Fort Union is expected to eliminate most of the problems now experienced in directional wells; however, the estimated increased cost of this option ranges from $670,000 to $770,000 per well to drill and complete a directional well from a central pad.

RESERVES LOST DUE TO DIRECTIONAL DRILLING

In the current directional drilling well plan, without oil based drilling fluids or intermediate casing, there is a risk of bypassing gas reserves at the bottom of the Lance if the casing does not reach bottom due to differential sticking. If the casing is set high, then the gas resource below the casing will not be produced.

Casing Set Off Bottom. From Jonah directional well experience, in about 30% of the directional wells, the casing is set an average of 124 ft above the TD (Total Depth) of the well. If casing does not reach bottom, it is cemented high and a decision is made whether or not to run a 2 7/8” liner. The cost to run a liner is about $250,000.

For conditions at Jonah, in addition to the extra cost, cementing the small diameter pipe is difficult and stimulation is less effective.

Casing Stuck on Bottom. The normal practice in a vertical well at Jonah is to reciprocate the casing during cementing to improve the cement bond. In about 75% of directional wells the casing is stuck on bottom so movement during cementing is not possible. Thin cement pumped at high rate is normally used and not being able to reciprocate the casing does not appear to cause any major problem as indicated from cement bond logs. There also does not appear to be any problems with hydraulic fracturing wells that had stuck casing.

The only major issue with cement bond would be at the Lance-Fort Union contact where normally pressured and over-pressured zones would be in communication if the cement bond is poor. If the bond is poor, the interval would be cement squeezed to prevent communication. This situation would lead to increased cost and also lost reserves because the Lance would have to be hydraulically fractured through 2 7/8" tubing to isolate the squeeze perforations. Fracturing through tubing is less efficient than through 4 ½" casing.

In the 54 directional wells drilled to date it has not been necessary to squeeze the top of the Lance.

If casing is stuck on bottom during cementing operations, experience to date indicates that there is no loss of gas resources.

Liquid Loading Effects. Jonah gas production is considered wet, as it also produces gas condensate liquids and water. As reservoir pressure decreases, water content in the gas also increases. These liquids contribute to liquid loading when the gas rate declines to low levels near the end of the producing life.

When liquids accumulate in the well the producing bottomhole pressure increases and can cause early abandonment of the well with loss of gas reserves. Artificial lift such as plunger lift may be used to unload liquids as pressure depletes and reduce the flowing bottomhole pressure.

A review of the petroleum literature suggests that there are no problems particular to directional wells relating to plunger lift. The plunger falls to bottom by gravity so the rate of fall will be slower in directional wells. However, the main disadvantage with plunger lift is that it does not work if there is sand production. In a directional well there may be a tendency for sand to accumulate in the inclined section if the angle is high. If the directional wells at Jonah are producing fracturing sand near the end of the well life, this would prevent the use of plunger lift and result in lost reserves. From the available data it is not possible to quantify this reserve loss.

Waste Attributed to Lost Reserves. The magnitude of the potential reserve loss was estimated by calculating the original gas-in-place in the bottom 400 ft of the hole (including the 150 ft rathole below the base of the Lance). Because gas is compressible, this calculation must be made using actual pressures and not a simple ratio of thickness.

Of the 54 directional wells drilled to May 11, 2004, 16 have failed to set casing on bottom. The average length of hole lost below the float collar (cementing equipment set one joint from the bottom) is 154 ft. When the rathole is added for perforation and stimulation, an average of 275 ft of hole is inaccessible.

The original gas-in-place for the bottom 275 ft of the Lance (including the rathole) was estimated from petrophysical analysis and actual reservoir pressure for 359 wells at Jonah. The gas resource loss per well ranges from 3 MMSCF to 1284 MMSCF with an average of 362 MMSCF. When a 30% probability of setting casing 124 ft high is applied to the 1824 wells to be drilled on 10 acre spacing, assuming an all directional option, the estimated lost gas reserve is 200 BCF.

A new gas field with 200 BCF of recoverable reserves would be considered significant in today's gas market. Also, 200 BCF is over 15 times the annual residential consumption of natural gas in the State of Wyoming.

DIRECTIONAL DRILLING TIMES

Directional drilling is particularly challenging in fields like Jonah where portions of the interval are over-pressured. In addition to increased costs relative to a vertical well, directional drilling requires longer development times and lengthier periods of drilling activity.

In attempting to quantify the increased time associated with directional drilling, it is not possible to directly compare drilling time between vertical and horizontal wells using average numbers. The reach, depth to the top of the Lance, and thickness of the Lance drilled varies throughout the field and these factors must be taken into account. In addition, bit selection, experience gained in drilling directional wells, and the rig being used may impact the drilling time.

Figure 10 shows days versus reach for all directional wells at Jonah.

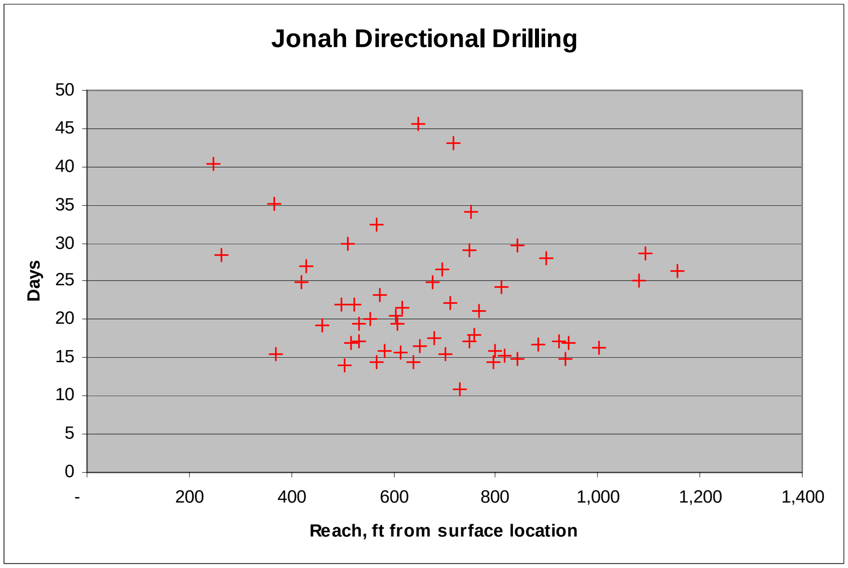

Figure 10: Total days from spud to rig release for Jonah directional wells versus reach.

The data is scattered and there appears to be no strong relationship between drilling days and reach.

Figure 11 shows the total time vs. the start data of the well.

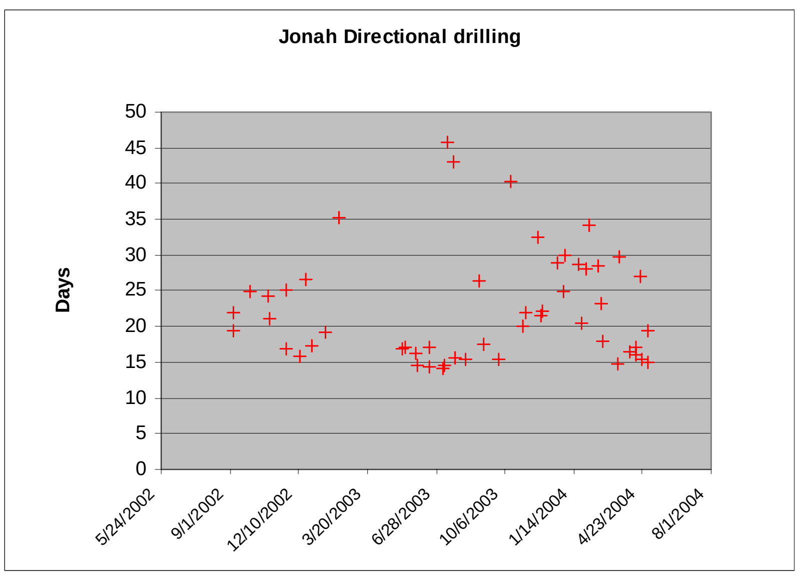

Figure 11: Total days from spud to rig release for Jonah directional wells versus spud date.

The average drilling time in 2004 for a directional well appears to be about the same or slightly higher than the time when directional drilling was started in Jonah in September 2002. As discussed, other factors may be causing this apparent increase.

In order to quantify the incremental time for a directional well, the drilling times for vertical and directional wells drilled since September 2002 were compared a shown on Figure 12.

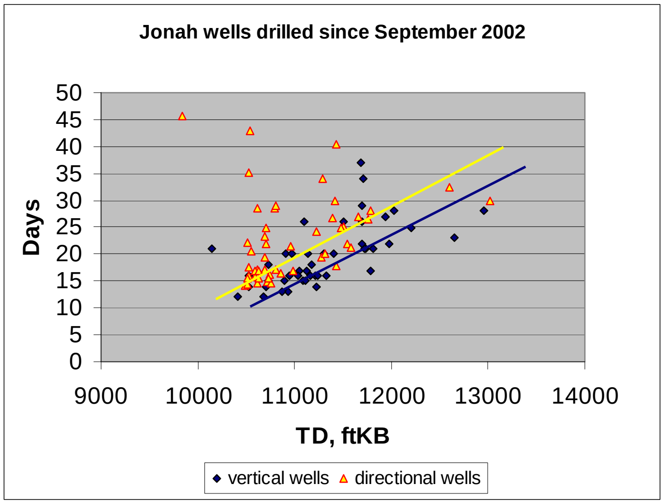

Figure 12: Total days from spud to rig release for Jonah directional and vertical wells versus total depth.

The figure shows days versus total depth drilled (TD). The total depth is a reasonable correlation parameter because:

- The time spent in the heavy mud weight (over-pressured) portion of the hole is a controlling parameter
- The top of the Lance deepens to the NE and the Lance thickens to the NE. The change in thickness (+2500 ft) is much greater than the deepening of the Lance top (+1250 ft)
- The surface elevations vary less than 200 ft for this group of wells.

Observations from this plot follow:

- Directional wells require about 5 to 6 days more drilling days than vertical wells
- There is more scatter in the directional well data with several wells taking 3 times longer than the average time at the same depth. The additional time is due mainly to differential sticking problems during drilling, logging, and casing operations.
- If there are problems in vertical wells, the increased time is only about 50% of the average time at the same depth

The number of rigs being utilized in developing the field, or the time required to develop the field must increase proportionately to the increased drilling time for directionally drilled wells.

Over the range of the above plot, directional wells, at best require 25% longer to drill and case than a vertical well drilled to the same depth. Because of 200% to 300% increase in time in 10% of the directional wells due to differential sticking problems, the average additional time to drill directional wells will be more than a 25% increase.

CONCLUSIONS

1. Jonah Field is a major energy source with about 10.5 TCF of original gas-in-place corresponding to a surface area of approximately 21,000 acres. On 40 acre spacing it is projected that only 30% of this resource will be produced and about 4.6 TCF of potential gas reserves will be unrecovered (difference between 30% and 75% recovery). This lost gas represents significant waste and when averaged over a 25 year period, represents about 15 times the annual residential natural gas consumption in the State of Wyoming.

2. The current incremental cost to drill and complete a directional well over a vertical well is about $270,000 to $470,000.

3. On average, directional wells take at least 5 to 6 days longer than a vertical well drilled to the same depth. The 25% increase in time should be considered in evaluating the impact of directional drilling on the surface operations.

4. Problems are more common in directional wells with 10% of these wells requiring 2 to 3 times longer than average to complete drilling operations. If problems are encountered in vertical wells, the increased time is only about 50% over an average well at the same depth.

5. The expected decrease in average cost difference, between vertical wells and directional wells, has not occurred with experience at Jonah. This is due to the unpredictable and difficult problem of differential sticking in the Fort Union. There is no reason to believe that the directional well costs will approach vertical well costs.

6. It is believed that differential sticking problems can be significantly reduced in directional wells at Jonah in two ways: 1) running intermediate casing through the Fort Union at approximately $670,000 to $770,000 additional drilling and completion cost per well or 2) changing from water based to oil based drilling fluids at approximately $270,000 additional drilling and completion cost per well. This additional cost is much higher than experienced at Pinedale Anticline where intermediate casing is usually required in vertical wells because of higher bottomhole pressures and higher pressure differences between the Fort Union and the deeper over-pressured intervals.

7. Failure to place casing at the bottom of the well in 30% of the directional wells represents a potential loss of gas reserves of 200 BCF for a 10 acre infill, all-directional option. A gas field with 200 BCF of recoverable reserves would be considered significant in today's market. This lost reserve volume is over 15 times the annual residential consumption of natural gas in the State of Wyoming and represents significant waste.

8. Considering all of the alternatives, the lowest incremental cost of drilling and completing directional wells at Jonah that also provides for acquisition of critical data is $270,000 per well (oil base drilling fluids). In addition to increased cost, oil based drilling fluids have environmental issues relating to handling, transporting and disposing of these fluids.

9. Directional drilling of development wells at Jonah may help control the impact of the footprint of the development on the surface. However, this impact includes not only the size of the disturbed area but also the length of time the development footprint impacts the surface. The additional time and cost, and potential for lost reserves associated with directional drilling may significantly increase the total life of the field.