RECEIVED

JAN 0 8 2001

OSTI

Naturally Fractured Tight Gas Gas Reservoir Detection Optimization

Prepared for:

**U.S. Department of Energy
Federal Energy Technology Center**

Contract No. DE-AC21-93MC30086

Quarterly Status Report

Period of Performance: September 30, 1998 - December 31, 1998

Date of Submission: June 1, 1999

Prepared by:

**Advanced Resources International, Inc.
1110 N. Glebe Road, Suite 600
Arlington, VA 22201**

DISCLAIMER

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, make any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

DISCLAIMER

Portions of this document may be illegible in electronic image products. Images are produced from the best available original document.

Quarterly Status Report

CONTRACT NO.:

DE-AC21-93MC30086

CONTRACTOR:

Advanced Resources International, Inc.
1110 N. Glebe Road, Suite 600
Arlington, VA 22201

CONTRACT NAME:

Naturally Fractured
Tight Gas Reservoir
Detection Optimization

CONTRACT PERIOD:

9/30/93 - 4/30/99

CONTRACT OBJECTIVE: No change.

TECHNICAL APPROACH CHANGES: No change.

FIELD PERFORMANCE TEST PLAN:**Introduction**

Building upon the partitioning of the Greater Green River Basin (GGRB) that was conducted last quarter, the goal of the work this quarter has been to conclude evaluation of the Stratos well and the prototypical Green River Deep partition, and perform the full resource evaluation of the Upper Cretaceous tight gas play, with the goal of defining target areas of enhanced natural fracturing. The work plan for the quarter of November 1 - December 31, 1998 comprised four tasks:

1. Evaluation of the Green River Deep partition and the Stratos well and examination of potential opportunity for expanding the use of E&P technology to low permeability, naturally fractured gas reservoirs,
2. Gas field studies,
3. Resource analysis of the balance of the partitions.

The following sections describe the tasks in greater detail.

Task 1. Evaluation of the Green River Deep partition and the Stratos well and examination of potential opportunity for expanding the use of E&P technology to low permeability, naturally fractured gas reservoirs

The Frontier Formation represents a large, underdeveloped tight gas resource, estimated at 200 Tcf of gas-in-place. With the maturing of the Frontier play along the Moxa Arch, new E&P technologies and geologically attractive areas need to be established for this play to remain viable. Permeability is the most important production controlling mechanism in the Frontier, with the presence (or absence) of natural fractures controlling permeability. As such, finding areas with intense clusters of open natural fractures is the primary R&D objective for expanding the upper Cretaceous tight gas play.

Activities for evaluation of the play are briefly described below. (The Green River Deep partition, the results of the Stratos evaluation, and the rationale for the partitioning of the GGRB were presented to DOE/FETC in December 1998. Appendix 1 contains a copy of that presentation.)

Green River Deep Partition. Located between the Moxa Arch and the Rock Springs uplift, this partition is bounded by a steep flank on the west and is fault-bounded on the east. On the northern edge of the partition is the Sandy Bend Arch, a structurally high feature that separates the partition from the Farson Deep. The partition is bounded on its southern end by the upthrust Uinta Mountains and is an overpressured locus of basin-centered gas. The partition, in the area of the Sandy Bend Arch, is the site of the Stratos #1 well, drilled by DOE and UPR.

To define areas of permeability enhancement within the basin, a series of analyses were conducted including surface structural analysis, using medium resolution Landsat TM satellite imagery; basement structural analysis, using regional gravity and aeromagnetic survey data; integration of the surface and basement features; identification of potential areas with structural and tectonic alteration; and mapping of Frontier net sand isopachs.

We conclude that using the criteria of likely presence of natural fractures and net pay greater than 20 feet, the Frontier Formation in Green River Deep partition has about 150 square miles prospective area. Gas recoveries per section could range from 10 to 15 Bcf. With drilling depths of 15,000 to 17,000 ft., well costs would range from \$3.6 to \$4.1 million to evaluate this target resource.

Stratos Well. The effort in this task examined the Stratos Federal No. 1 well, drilled to extend the rapidly maturing Moxa Arch Frontier gas play into the deeper off-structure area. The objectives for the well were demonstrate the feasibility for using horizontal wells in this play type and to characterize Frontier Formation in the deep, central portion of the Green River Basin. The Stratos well was also drilled as an offset to two deep Frontier and upper Mowry producing wells drilled, Blue Rim Federal No. 31-1 and Blue Rim Federal No. 1-30. A third well, the No. 1-35 Mountaineer, that also penetrated the Frontier, is located nearby.

Our examination of the Stratos area indicated the following findings and conclusions:

- Based on information from offset Blue Rim and other Frontier Formation wells and an assessment of surface and basement features in the Greater Green River Basin, the Stratos well location, while reasonably representative of the geology and deposition in the area, does not appear to be in a structurally favorable setting.
- The area of the Stratos well has sufficient gas in place, estimated at 20 to 30 Bcf/section, to support natural gas development if sufficient reservoir drainage area could be connected to the wellbore. Because the reservoir matrix permeability of the Frontier sands in the area is extremely low, natural fractures are required.
- The structural setting around the Stratos well (the compressional quadrant of a minor, left-lateral wrench/shear fault) appears to be less favorable than around the Blue Rim 1-30 and 31-1 wells (sites of tensional or neutral quadrants).
- In the absence of running a quantitative stress and natural fracture location model, we do not believe that the Frontier Formation in the Green River Deep Partition has been conclusively tested. The permeability in the area surrounding the Stratos well appears to be too low for commercial gas production. Tectonically-related natural fractures, essential for high productivity, are a localized phenomena
- A more thorough evaluation of the Stratos well area may be warranted if the well is to be converted to an R&D test well.

Building on the efforts presented here, Appendix 2 presents the opportunity for matching the E&P technologies developed during the course of study of the Piceance and Greater Green River basins to low permeability, naturally fractured gas reservoirs in the Austin Chalk of Texas and the Hoback/Pinedale area of the GGRB. This presentation was also made to DOE/FETC in December 1998

Task 2. Gas field studies

Field studies are being conducted to examine the reservoir settings for gas accumulation in the Upper Cretaceous section in the GGRB. During the quarter, we concluded our examination of the Canyon Creek and Kinney fields focussing on the Mesa Verde section and examined the Marianne field, which produces from the Frontier. Findings from these studies are presented below.

The Mesaverde Reservoirs at Canyon Creek Field

The Canyon Creek gas field is located along the crest of a northeast-trending anticlinal structure in the Vermilion Sub-basin of the GGRB. Below is described the development history, structure, stratigraphy, reservoir characteristics, and pressure systems of the Mesaverde Group at Canyon Creek.

Field Discovery and Development History. The first deep exploratory well at Canyon Creek Dome was drilled in 1949. Stanolind Canyon Creek Unit #1 (3-12N-101W) was located near the structural crest of the anticline, using seismic data and surface geology. The well was drilled

through the Mesaverde Group and Baxter-Mancos shale section to a total depth of 13,321 ft in the Jurassic Morrison Formation. While drilling through the Mesaverde section, cores and drill stem tests were used to evaluate tight gas sandstones in the Almond Formation at 4700 ft, the Canyon Creek Member of the Ericson Sandstone at 5600 ft and the Trail Member at 6500 ft. Hard, gray, tight fine-grained sandstone was recovered in the cores. Gas flowed to surface at low rates (10 mcf/d, 745 mcf/d and 212 mcf/d) from these reservoirs during the drill stem tests. The Lower Cretaceous Dakota Sandstone flowed gas at subcommercial rates. The well was suspended and eventually abandoned. A gas field had been found, but not yet recognized.

Mountain Fuel Supply acquired Canyon Creek Unit in the early 1950's and drilled several wells to explore the structure. MFS Canyon Creek Unit #1 (13-12N-101W) was drilled in 1952 in a downdip position on the east flank of the structure. The Almond and Ericson sands were evaluated using drill stem tests, which indicated tight, nonproductive sand. The well was abandoned. MFS Canyon Creek Unit #2 (35-13N-101W) was drilled in what is now known to be the main part of the field. Many drill stem tests were run to evaluate tight gas sands in the Fort Union and Mesaverde section. Several tests were misruns; others flowed gas to surface at low rates and recorded low shut-in pressures. The Almond Formation flowed gas at 35 mcf/d; the Trail Member flowed gas at 57 mcf/d. The well was abandoned as subcommercial.

MFS Trail Unit #1 was drilled in mid-1952. At least twenty drill stem tests were run to evaluate tight gas sands. Many tests were misruns; some tests flowed gas to surface at low rates, with low shut-in pressures. The lower Trail Member at 7550' flowed gas at 686 mcf/d. The well was completed in this zone with initial production rate of 4.16 mmcf/d; a commercial discovery had been made.

After a two year pause, drilling resumed in 1954. MFS Canyon Creek Unit #3 (3-12N-101W) was drilled near the original Stanolind #1 well location. Drill stem tests were run to evaluate the Almond and Ericson sandstones. Gas flowed from the Ericson Sandstone at 10 mmcf/d, and the well was put on production with an open hole completion in the Canyon Creek Member of the Ericson Sandstone at 5460-5544 ft. The shut in surface pressure was reported to be 1961 psi. This can be extrapolated to a bottom hole pressure of 2230 psi, indicating a pressure gradient of 0.41 psi/ft, or nearly 'normal' pressure. The initial production rate was reported to be 9.88 mmcf/d. This well has produced 5.86 bcf through mid-1998.

Development of the Ericson reservoir proceeded rapidly with six additional wells drilled during 1954-1955. Open hole completions were used with good success. Wells of this vintage have typically produced 3.4 to 8.7 bcf. Extrapolation of shut-in tubing pressures to bottom hole pressures indicate pressure gradients ranging from 0.36 to 0.40 psi/ft, slightly less than "normal". Well #9, encountered significantly lower reservoir pressure: the reported SITP = 1710 psi (extrapolated to BHP=1956 psi) indicates a 'subnormal' reservoir pressure gradient of 0.34 psi/ft. The reported pressure and extrapolation may be suspect, but if correct, the low pressure indicated possible reservoir pressure depletion due to the previous production. Drilling ceased for three years.

In 1958, the discovery well at Trail Unit was twinned. Apparently MFS realized that several zones in the Trail Member with high resistivity and good SP deflections had been missed by the original barrage of drill stem tests. MFS Trail Unit #2 was drilled with gas instead of drilling mud.

A drillstem test of the canyon Creek Member of the Ericson Sandstone at 5700' flowed gas to surface at 971 mcf/d. The shut-in pressure of 2200 psi indicates a near-normal pressure gradient of 0.39 psi/ft. While drilling ahead through the lower Ericson, the well flowed 6 to 7 mmcf/d. In the Trail Member, the well flowed 3 mmcf/d, then 26 mmcf/d. Casing was set and the Trail Member was perforated and frac'd in two zones with high deep resistivity and good SP deflections, using a diesel-sand frac. The well blew out after the frac job at flow rates of 50 to 70 mmcf/d. The official initial production was listed as 34.9 mmcf/d from perforations at 6870 - 7068'. The SITP (extrapolated to BHP) indicates a pressure gradient of 0.38 psi/ft, or slightly less than normal pressure. The use of gas drilling probably minimized formation damage. Structurally, this well is located at the crest of the Trail anticlinal dome and may have natural fractures.

Several development wells were drilled during 1958-1963 to exploit the Canyon Creek and Trail sandstones. Trail Unit #3 had initial production of 34.5 mmcf/d; Trail #4 came onto production at 22.6 mmcf/d; Trail #6 at 19.5 mmcf/d. Trail #7 was a dry hole and Trail #8, #9 and #10 had low IP's of only 1.4 to 1.5 mmcf/d. A shut-in tubing pressure of 1935 psi was reported after a three-day pressure buildup at Trail #10 in 1963. Extrapolated to BHP (+/- 2272 psi), this indicates a subnormal reservoir pressure gradient of only 0.32 psi/ft. Once again, subnormal pressures - and evidence of possible pressure depletion - appeared in the development wells drilled several years after the discovery of a new gas accumulation.

Development drilling shifted back to Canyon Creek. Many drill stem tests were run to evaluate the Almond Sandstone. These tests usually recovered gas at low rates with shut in pressures indicating a "normal" pressure gradient of 0.42 psi/ft. Eventually enough wells were drilled at the southwest end of the field to identify an unusually thick sandstone at the top of the Almond Formation. This thick sand was first encountered in well #6, but was obscured by logging problems. Wells 22 and 23 found coal beds and shale where the sand package should have been. In 1972, MFS Canyon Creek #27 (16-12N-101W) penetrated the thick sandstone in the right location. Initial production was 6.2 mmcf/d from the upper Almond Sandstone. Four more wells (MFS #28-31) were drilled to exploit the Almond gas accumulation, as well as several wells drilled outside the unit boundaries by other operators.

The Almond sand pinches out against coal beds and shale updip to the northwest. The sand is 54 ft thick at MFS #24 but is only a few feet thick at MFS # 22 and #23. The pinchout is probably a sand-filled incised valley scoured into the Almond coal swamp and lagoonal facies, or may be a shoreline trend. The feature may be controlled by deeper faulting. Farmer (1978) shows a northeast-southwest trending "Almond porosity limit" on the Canyon Creek structure map and listed a gas/water contact for the Almond reservoir at +2000 feet elevation. Drill stem test data indicate "normal" pressure gradients of 0.42 psi/ft. Cumulative productions for the five Almond wells range from 0.77 to 4.65 bcfg, with the best gas production from the structurally highest wells.

Drilling activity slowed after the development of the Almond pool in 1973. There have been several dry holes drilled around the downdip margins of the field. Four infill wells were drilled during 1983-1985 (WEXPRO Trail #12, Trail #13, Canyon Creek #32 and #33) and experimented with gel foam, gel condensate and nitrogen foam frac treatments. Sand volumes ranged widely (25,800 to 238,000# sand). Based on initial production rates (2.66 mmcf/d; 0.820 mmcf/d; 2.3 mmcf/d) these frac treatments did not cause dramatic improvements in gas production. Trail Unit #12 was the best

of the group: it was drilled with air and frac'd with gel condensate. Initial production from the Trail Member was 4.925 mmcf/d - far less than the discovery wells at Trail, but an indication that formation damage could be minimized by gas drilling. In 1992, Trail #12 was recompleted in the Ericson sands and frac'd with 33,600 gal nitrogen foam and 85, 860 psi 20/40 sand. Initial production was only 743 mcf/d.

It appears that the first wells with the open-hole completions found the highest reservoir pressures and produced gas with the highest IP's. There are no recent reservoir pressures listed in the public databases, however it appears that there has been gradual pressure decline in the Ericson and Trail zones.

A 3-D seismic survey was acquired over Canyon Creek Field during 1995-1996 by Marathon Oil Company but the results are proprietary.

Structure. Canyon Creek Field is located on a doubly plunging anticlinal fold, which trends SW-NE along the western margin of the Washakie basin. The anticline is a typical Laramide-style fault propagation fold above a tilted basement block which has been uplifted and thrust to the northwest along the basement reverse fault. The reverse fault cuts the Paleozoic and Lower Cretaceous section, then probably flattens and becomes dispersed within the Baxter/Mancos Shale. At the Mesaverde level, the anticlinal structure has two high points separated by a structural sag which may be controlled by deep cross faulting.

Stratigraphy and Reservoir Characteristics. The stratigraphy and depositional environments of the Mesaverde Group in the Washakie basin have been described by Hendricks (1983), Roehler (1990), Tyler and Hamilton (1994) and Martinsen and Christiansen (1992). The Mesaverde contains a variety of coastal plain and shallow marine sandstones, shales and coalbeds deposited along the western margin of the Cretaceous Interior Seaway during Campanian and Maestrichtian time. The subsurface stratigraphic units have been correlated to measured sections in outcrops along the Rock Springs Uplift (Roehler, 1987).

Rock Springs Formation. The basal unit of the Mesaverde Group at Canyon Creek is the Rock Springs Formation, which contains delta front and pro-delta sandstones, siltstones and shale beds deposited about 82 Ma. These overlie and interfinger with marine shales of the Blair Formation. According to Roehler's correlations, the Moxa Unconformity and the top of the Rock Springs Formation are found at about 6860' in the Stanolind Canyon Creek #1 well. This marker has been carried through the field in the structural cross sections. There has been considerable variation in the nomenclature used by industry for marking well logs, and some workers have picked the top of the Rock Springs Formation much higher in the section. Roehler's stratigraphic correlations work well in this area and are used in this study.

Ericson Sandstone-Trail Member. The Ericson Sandstone is a thick clastic section of Campanian age (Roehler, 1990) containing two sand-rich intervals separated by a middle shaley member. The lower sandstone package is called the Trail Member. It is approximately 500 ft thick at Canyon Creek. Sandstones of the Trail Member contain fine and medium grained quartz, chert and rock fragments which were deposited in meandering fluvial channels and braided stream deposits. Planar and trough cross bedding and scoured channel incisions are common in outcrops (Roehler,

1990).

The sandstones of the Trail Member are generally found at depths of 6500 to 7150 feet at Canyon Creek and . Well logs show considerable variability and poor well-to-well correlation within these fluvial deposits. The total thickness of clean sandstones in the Trail Member ranges from 150 to 330 ft based on gamma ray logs. Most sandstones occur as thin beds, typically 4 to 8 feet thick separated by shale layers. Usually each wellbore penetrates several 20 to 40 ft thick channels.

Shale-corrected density porosities in Trail Member sandstones range from 10 to 15 %. There are occasional 'sweet spots' with 15 to 19% porosity and low gamma ray readings. High deep resistivities (some > 1000 ohms) and widespread neutron-density crossover effects indicate pervasive gas saturation in the Trail Member, especially at the structural high at Trail Field. High initial production rates from this zone were described above. Many thin sandstone beds with neutron-density crossover have been bypassed. There may be recompletion potential in some wells.

Natural fractures may be an important factor for production rates, however evidence of fractures is sparse due to the lack of cores and specialized fracture logs.

Ericson Sandstone Rusty Zone. The Rusty Zone is approximately 300 ft of shale and siltstone in the middle of the Ericson Sandstone section. Roehler (1990) described the Rusty zone as delta plain deposits, based on his studies of outcrops along the Rock Springs Uplift. In the subsurface, gamma ray logs indicate shale, siltstone and occasional thin coal or coaly shale beds. There have been several drill stem tests with poor results and no gas production whatsoever from this zone. The shale beds in the Rusty Zone apparently form a seal above the reservoirs in the Trail Member.

Ericson Sandstone-Canyon Creek Member. The Canyon Creek Member of the Ericson Sandstone is a thick, sand-rich package of alluvial plain, fluvial and braided stream deposits. The Canyon Creek Member is approximately 560 ft thick at the Stanolind #1 well and 570 ft thick at Trail Unit #12. Total thickness of clean sandstones in the Canyon Creek Member ranges from 170 to 270 ft, as indicated by gamma ray logs. Sandstone beds are typically thick, with many 30 to 50 ft beds. Shale layers with high gamma ray readings are interbedded with the sandstone channels.

Shale-corrected density porosities in clean Ericson sandstones range from 10 to 17%. Permeabilities of Ericson sandstones range from 0.1 to 0.25 md (Doelger, 1995). High resistivities and neutron-density cross-over effects are found throughout Canyon Creek.

Farmer (1978) listed a gas/water contact at +1250' elevation for the Ericson Sandstone reservoir at Canyon Creek Field, and suggested volumetric and partial water drive reservoir mechanisms. Well log analyses of a downdip dry hole at the north end of the field (Anshutz Federal #10-26, 26-14N-100W, Ericson Sandstone at +516 ft) indicate low deep resistivities and high water saturations in the Ericson in a low structural position. The Ericson reservoirs apparently contain migrated gas trapped in a conventional anticlinal structural closure.

Almond Formation. The Almond Formation is the uppermost member of the Mesaverde Group and contains a thick section of shales, siltstones and coal beds of early Maestrichtian age (approximately 69-70 Ma). These were deposited in fresh water swamps, brackish water lagoons and

tidal flat environments (Roehler, 1990; Martinsen and Christiansen, 1992; Martinsen et al., 1995). Shales in the lower Almond form a seal above the Canyon Creek Member of the Ericson Ss.

The coal beds of the Almond Formation have been studied by Garcia-Gonzalez et al. (1997), Tyler and Hamilton (1994) and Scott (1994). Vitrinite reflectance profiles in the Washakie Deep Partition (Figure 1) indicate typical vitrinite reflectances of 0.5 to 0.75 in the 5,000 to 7,000 foot depth range, indicating early thermogenic conditions and early generation of wet gas in the Almond coalbeds. Canyon Creek is within the High-volatile B bituminous zone, equivalent to vitrinite reflectances of 0.65 to 0.78 %. The thermal maturity of the Almond coals increases rapidly with depth to the east, exceeding 1.0 % Ro at depths greater than 11,000 ft and reaching 2% in the basin center. The coal beds in the basin center east of Kinney Field are reported to be a prolific source of hydrocarbons (Garcia-Gonzalez et al., 1997).

The Almond coal beds and shales are overlain by transgressive shoreline, tidal channel and barrier island sandstones of variable thickness. As described above, a thick upper Almond sandstone channel with good porosity was found at the southwest end of Canyon Creek Field, trending NW-SE in a meandering pattern. The channel pinches out updip to the northeast against coalbeds and shale, and forms an effective structural/stratigraphic trap for gas. Five productive gas wells and several dry holes have been drilled in this trap.

Shale-corrected density porosities range from 10 to 15 % in the Almond sands at Canyon Creek. Porosity, permeability and diagenetic trends for Almond sandstones in the Washakie Basin have been analyzed by Yin and Surdam (1995) and Iverson et al. (1995). Permeabilities in Almond sandstones range from 0.1 to 100 md. Calculated water saturations are generally higher than those in the upper Ericson and Trail Member zones. DST shut in pressures consistently indicate "normal" pressure gradients in the Almond reservoirs.

Lewis Shale. The Mesaverde Group is overlain by the Lewis Shale, which was deposited during a major marine transgression during upper Maestrichtian time (Surdam et al., 1995). The Lewis Shale is approximately 600 ft thick at Canyon Creek and forms an excellent seal above the Almond Formation.

Pressure Systems and Hydrogeology. Pressure data from Canyon Creek Field (drill stem tests, shut in tubing pressures and drilling mud weights) indicate pressure regimes for the various Mesaverde Reservoirs. These data should be used with caution due to short shut in pressure buildup periods, missing test records and questionable accuracy of data in the completion reports. Nevertheless, trends are apparent.

Data from six drill stem tests in the Almond Formation at Canyon Creek indicate "normal" hydrostatic pressure gradients of 0.42 to 0.44 psi/ft. No recent pressure data have been in the public records, and the amount of pressure decline due to production is uncertain.

Several Ericson drill stem tests and shut-in tubing pressures from completion reports have been analyzed. Shut-in tubing pressures were extrapolated to bottom hole pressures using the following equation for dry gas wells: $BHP = SITP + (0.25 \times SITP/100 \times PERFDEPTH/100)$. These data indicate initial reservoir pressure gradients ranging from 0.50 to 0.32 psi/ft, or from slightly

above normal to "subnormal" in the Ericson reservoirs. As described above in the field development history, the first Ericson producers generally found the highest reservoir pressures and best initial flow rates. Some of the later development wells encountered subnormal pressures and low IP's, suggesting reservoir pressure decline. The occurrence of subnormal reservoir pressure indicates that the Ericson reservoirs at Canyon Creek are not connected to shallow ground water systems, and probably have volumetric reservoir drive mechanisms.

Several recent studies have identified regional hydrologic and pressure trends for the Mesaverde Group in the Washakie Basin. Kaiser (1994) mapped the potentiometric surface and the boundary of hydrocarbon overpressure for the Upper Mesaverde. Canyon Creek is located updip from the basin center hydrocarbon-charged overpressured zone, and within the 7000' potentiometric surface contour. Ground level is 7100 - 7180' at Canyon Creek, so this implies that the potentiometric surface is at or near ground elevation.

Scott and Kaiser (1993) suggested that Mesaverde coal beds are highly permeable aquifers along the basin margins, with fresh water recharge occurring along outcrops. A map of Mesaverde formation water chlorinity (Scott and Kaiser, 1993) shows many data points at Canyon Creek Field. The highest salinities are at the northeast end off the structure and low salinities (fresh water) to the southwest, where the shallow Almond Sandstone gas trap is located. The occurrence of low salinities and consistent normal pressures in the Almond Formation suggests that this reservoir might have an active water drive, and may be flushed with fresh water migrating through permeable coal beds.

Doelger (1995) mapped Lower Almond and Ericson formation water salinities and showed fresh to brackish water along the Rock Springs Uplift (Doelger, 1995). Canyon Creek Field is located within the "salt water" trend, down dip from fresh water. The Mesaverde basin center gas accumulation is northeast of these fields.

Heasler and Surdam (1993) analyzed Mesaverde DST data and identified normal and abnormally pressured compartments in the Washakie basin. They found normal and subnormal pressures down to about 8,000 - 10,000 ft, then frequent overpressure in the deep tests. Kaiser and Scott (1994) showed the boundary of hydropressure and HC overpressure in the MV group. The boundary crosses between Canyon Creek Field. However actual pressure data and drilling mud weights indicate normal to subnormal pressures throughout the Mesaverde section. The Anschutz Federal #10-26 well (26-14N-100W) drilled through the Mesaverde section and reached 8926 ft TD in marine shales of the Blair Formation without setting intermediate casing and using 9.1 ppg mud. There was evidently no overpressure in the Mesaverde at this location.

Gas Migration and Trap Type. In the context of recent basin-center gas models (Masters, 1979; Law and Dickinson, 1985; Spencer, 1989; Surdam, 1995), the Almond and Ericson reservoirs at Canyon Creek Field can be categorized as normally pressured and slightly underpressured gas accumulations, which are located in a conventional structural/stratigraphic anticlinal closure, updip from the overpressured zone. These reservoirs are apparently filled with migrated gas expelled from deeper and more thermally mature coal beds and carbonaceous shales. Consistent normal pressures, potentiometric surface elevations equal to surface elevations, and abundant permeable coal beds in the Almond Formation indicate probable connection to shallow hydrologic systems. Shales of the lower Almond may be a bottom seal for this system.

The occurrence of occasional subnormal pressures in the Ericson Sandstone indicates existence of stratigraphic or diagenetic pressure seals which isolate the reservoirs from shallow hydrologic circulation. The Ericson reservoirs appear to be located along the transitional boundary from normal pressure to subnormal pressure. Gas drilling which minimized formation damage, and open-hole completions which maximized the contributions from natural fractures, have been most successful practices for producing gas from the Ericson Sandstone reservoirs.

The Mesaverde Reservoirs at Kinney Field. As presented last quarter, the Kinney Field is located on an anticlinal structure above a west-directed Laramide-age basement reverse fault in the Vermilion Sub-basin partition. The reverse fault folded the sedimentary section into a sharp doubly plunging anticline trending NNW-SSE. The basement reverse fault steepens to near-vertical as it cuts upward through the Paleozoic section and thick Cretaceous shales. The fault apparently cuts both the Mesaverde and Lewis Shale on the west flank of the structure (Lehman, 1978). The east flank of the structure dips steeply into the deep center of the southern Washakie Basin. Several normal faults have been mapped at the surface and in subsurface well logs (Roehler, 1985).

The first exploratory drilling at Kinney occurred in 1953-54, when the Chicago Corporation drilled two wildcats near the crest of the structure. Chicago #1 Fore (19-13N-99W) penetrated the Almond Formation, Ericson Sandstone and Rock Springs Formation of the Upper Cretaceous Mesaverde Group on the east flank of the anticline. The Almond Formation was evaluated with cores and a drill stem test (5008-5067') which flowed gas at 25 mcf/d. The Canyon Creek Member of the Ericson Sandstone was evaluated with a DST at 5867-6050' which flowed gas at 14 mcf/d. During production tests, two sands in the Almond Formation (5010' and 5300') flowed gas at 1.3 mmcf/d with low shut-in pressures (765 - 825 psi). This well discovered an Almond gas accumulation, but was plugged and abandoned due to low flow rates and low pressures.

Another well was drilled by the Chicago Corporation at the southern end of Kinney anticline (Chicago #1 Butterwick, 19-13N-99W). The Almond Formation was evaluated with three drill stem tests, one of which flowed gas to surface at 1.5 mcf/d with low shut-in pressure. Another test flowed gas at 19.5 mcf/d, again with low pressure. A test of Ericson flowed gas to surface at 11.7 mcf/d, but recovered 490 ft of gas-cut muddy water, with a shut-in pressure (2252 psi at 5900' or 0.38 psi/ft) indicating a near-normal pressure. The E-log shows low resistivity near the bottom of these sands, indicating possible gas/water contacts. This well was also abandoned.

Superior Oil subsequently drilled a deep wildcat well penetrating the Dakota Sandstone in 1957. The well was located near the high point of the anticline, using seismic data and surface mapping. The Almond Formation was cored extensively. The cores contained gray, fine-grained sandstone with fair porosity, oil stain and gas odor, bleeding gas from vertical fractures. A drill stem test of the upper Almond Formation (4809-4827') flowed gas to surface at 42 mcf/d. A second DST at 4811-4884 ft flowed gas at 9 mmcf/d, then died. The shut-in pressure indicated a normal pressure gradient (2019 psi / 4850' = 0.42 psi/ft). The Ericson was not tested. This well was abandoned after cores were cut in the Frontier Formation and upper Dakota sandstones. Several drill stem tests were run to evaluate the Airport Sandstones at 10,400 ft.

Mountain Fuel Supply began exploring the Kinney structure in 1958. MFS Pioneer Unit #2 penetrated the Mesaverde Group and upper Mancos-Baxter Shale to evaluate the Airport sands. The

well was located downdip from the Superior Butterwick well, on the east flank of the structure. A DST recovered 120 ft of salt water from the upper Almond Sandstone at 5066'. The Canyon Creek member of the Ericson showed low resistivity on the E-log and was not tested. Tests of the Trail Member recovered gas cut mud with low shut-in pressures. Two tests of the upper Rock Springs Formation recovered gas-cut salt water with shut-in pressures indicating normal pressure gradients. It was becoming clear that if there was gas in the Mesaverde at Kinney, it was high on the structure.

MFS Pioneer Unit #3 was drilled slightly updip and west of the Superior Butterwick well in 1959. Several DSTs in the upper Almond Formation flowed gas. Production was established from the Almond with a sand-oil frac job at 4833-4853' (+2478' elevation). Initial production was 2.74 mmcf/d. Well logs show declining deep resistivity as gas was produced from the Almond gas trap, from 58 ohms at 4674' in Pioneer #4 (1962) to only 19 ohms in the same zone at nearby Kinney #4 (1976). (This trap may have watered out.) Almond sandstone density porosity values vary from 8 to 14%, with most in the 11 to 13% range. As noted by Iverson et al (1995), most operators use a 12% minimum porosity cutoff for the Almond sandstones in the Washakie Basin.

The Lower Almond Formation and Ericson Sandstone were penetrated and evaluated with many drill stem tests to establish gas water contacts. A DST of the lower Almond Formation recovered 4209 ft of salt water indicating a gas/water contact at approximately +2210' elevation and a water column extending up to +6390' elevation, or 900 ft below surface. Salt water was also recovered from the Canyon Creek and Trail Members of the Ericson Sandstone in this well. A DST at 5506-5581' recovered 2890' of salt water, with shut-in pressure of 2170 psi (0.39 psi/ft). The DST at 6747 - 6821' recovered 5082' of salt water with shut-in pressure of 2710 psi indicating a nearly normal pressure gradient (0.41 psi/ft). Ericson Sandstone density porosity values vary from 8 to 16% with most in the 11 to 13% range.

Evidently the Kinney structure was badly breached and is capable of producing water through all but the structurally highest Mesaverde reservoirs. Subsequent tests of the Almond, Ericson and Rock Springs reservoirs indicate water columns with potentiometric surfaces as high as +6160 to +6390 ft elevation, or approximately 1000 ft below the surface. The most likely source of water influx is the near-vertical reverse fault along the west side of the structure, as well as various normal faults which may be present in the shallow section. Juxtapositions of stratigraphic units across the main reverse fault in the field may account for some anomalies. For example, it appears that the Ericson in the hanging wall is faulted against the lower Almond coal beds and Ericson Sandstone in the footwall. Such conditions provide inadequate seals for trapping gas.

MFS Pioneer Unit #4 was drilled in 1962 at the north end of the structure to develop the Almond gas accumulation. Initial production was 4.6 mmcf/d. Since gas/water contacts had been established previously by Pioneer #3, this well did not penetrate the Ericson SS. Pioneer Unit #5 was drilled downdip from #4 on the north-plunging nose of the structure but was abandoned after recovering water from the lower Almond Formation. DST shut in pressures indicate normal pressure gradients of 0.43 psi/ft.

Subsequently, several more downdip extension wells were drilled without success. Pioneer Unit #6, 7 and 9 were abandoned after finding water or gas with low flow rates and low pressures in the Almond Formation along the downdip eastern flank of the structure. Pioneer Unit #8

discovered a different type of gas trap along the east flank in 1965. The Almond is evidently cut by one or more down-to-the east normal faults, which have created small fault trap gas in the Wasatch and Almond Sandstone. Initial production was 662 mcfg/d from the Almond Sandstones at 6717-6726'. Extrapolation of shut-in tubing pressure to bottom hole pressure indicates a near-normal pressure gradient of 0.41 psi/ft.

In 1975, a deep Dakota-Nugget test (Kinney Unit #3) indicated the possible presence of a deep cross-fault and a separate fault block at the south end of the structure. Kinney #3 was abandoned after unsuccessful Nugget, Dakota and Airport Sandstone tests, but was re-entered in 1983 for tests of the Mesaverde Group. The Upper Almond was perforated and frac'd at 4976-5004' and tested 457 mcfg/d with 70 bwpd. The well is listed as an Almond producer but may have watered out. The production of water with the gas indicates a gas/water contact or transition zone at +2240' elevation, similar to the contact found at Pioneer #3 at the top of the structure.

In general, the Kinney anticline is a conventional structural trap located just a few miles updip from a deep, thermally mature basin-center gas accumulation (the Wasakie Deep partition, Figure 1). While there is likely to be ample updip gas migration from the deep gas kitchen into the shallow reservoirs at Kinney, the Mesaverde reservoirs at Kinney have generally produced water, except for the Almond gas accumulation trapped at the crest of the structure and the east-side fault trap at Pioneer #8. The shallow structure appears to be breached. Pressure gradients and water recoveries indicate potentiometric surfaces as high as +6160 ft elevation. The Mesaverde section may be compartmentalized by faulting and may contain localized stratigraphic traps, but generally appears to be water saturated.

The Airport Tongue Sandstones at Kinney and Canyon Creek Fields

The Upper Cretaceous Baxter-Mancos Shale section at Kinney and Canyon Creek Fields in the western Washakie Basin contains marine sandstones and siltstones of the Airport Tongue at depths of 10,050 to 10,700'. The Airport Tongue has been described by Roehler (1993) as a "sandy" interval ranging from 450 to 500 ft thick in outcrops along the Rock Springs Uplift. It contains thinly bedded fine-grained sandstones, siltstones and interlaminated shales with current ripples. Roehler interpreted the Airport Tongue to be turbidite fans deposited in water depths of more than 300 ft, along the slope of the Cretaceous interior seaway.

The Airport sands have caused gas kicks and gas flares in deep several exploratory wells at the Kinney and Canyon Creek anticlines (Stanolind Canyon Creek #1; Exxon Canyon Creek Dome #34; Superior Butterwick #1). The Airport section is generally considered to be the top of overpressure in this area. Most operators increase mud weights from 9.6 ppg to 11-12 ppg when they encounter gas kicks in the Airport section, set intermediate casing, then drill deeper into the highly overpressured Frontier-Mowry section. The Airport section at Canyon creek and Kinney appears to be a vent or lateral migration pathway for gas migrating upward from the mature source rocks within the Frontier-Mowry overpressured zone.

The Airport Sands show a coarsening-upward, thinly-bedded sandstone, siltstone and shale section at 10,080 - 10,220 ft and a possible turbidite feeder channel incised into the surrounding shale at 9735-60'. Typical water saturations calculated by the Simandoux equation range from 49 to 56%.

with 7 to 9% porosity and R_w of 0.075 to 0.11. Log analysis is complicated by problems with thin bed resolution and uncertain R_w values. These are probably low-resistivity reservoir zones, with sandstone resistivity suppressed by the thin bedding and interlaminated shale.

These sands have been cored and tested with drill stem tests to evaluate their reservoir quality and productivity. After a gas kick and blowout at the Superior Butterwick #1 in 1956, a drill stem test of the Airport section flowed gas to surface at 4.3 mmcf/d decreasing to 2.2 mmcf/d. Water recovered during this test appears to have been derived from the water cushion. A DST of the Airport section at Mountain Fuel Supply Kinney #1 in 1974 flowed gas to surface at 2.07 mmcf/d, then declined to 0.8 mmcf/d, with low shut in pressures (2543 - 2100 psi at 10,300' or 0.25 psi/ft) and no water reported. The Airport sandstones were cored at MFS Kinney #4 and at the Stanolind Canyon Creek #1 well. A cryptic entry on the November 1998 Dwights Completion Report for Marathon Vermillion Creek Deep #3 well at Kinney Field indicates a possible production test of the Airport (?) section at 10,520-585' during 1998. The initial production was listed as 4.158 mmcf/d with 161 bwpd. If correct, this indicates the first commercial production from the Airport section in this part of the basin.

The Airport sands are interpreted to be turbidite fan deposits (Roehler, 1993) which probably followed drainage channels incised into the Cretaceous marine shelf and slope. The Airport sands might be thicker, cleaner and better developed in the paleo-lows of the western Washakie Basin than on the structural highs. The Airport Tongue is under-explored due to lack of previous success with conventional drilling and testing methods. Hydraulic fracture treatments have apparently not yet been applied to this zone at Kinney or Canyon Creek. It strongly resembles the Mancos "B" section along the Douglas Creek Arch in western Colorado, and may have similar reservoir characteristics, especially extreme susceptibility to formation damage from water-based drilling muds and overbalanced drilling. The position of the Airport Tongue as the first reservoir above the overpressured zone indicates possible future potential. Unconventional drilling and completion methods, and off-structure exploration might be successful at coaxing gas production from this difficult reservoir section. Reservoir parameters for the Airport Tongue Sands are shown in Table 1.

Table 1. Airport Tongue Reservoir Parameters

Depth range: 10,000 - 10,700 ft
Gross Pay = 180 - 250 ft
Net Pay = $180 \times 0.25 = 45$ ft
Sandstone porosity = 6 - 9 %
Sandstone V_{clay} = 20 - 25 %
R_w (est'd) = 0.11 - 0.075 at 210 deg F
Simandoux S_w = 49 - 56 % (probably low resistivity pay zones)
Reservoir Pressure = uncertain, DST SIP's = 2543 - 5477 psi, (0.25 - 0.53 psi/ft)
Bottom Hole Temperature at 10,200 ft = 208 - 225 degF

The Frontier Sandstones at Marianne Gas Field

The Marianne Field is a shallow natural gas accumulation located on the northeast flank of the Rock Springs Crest partition. Approximately 8.9 billion cubic feet of gas have been produced from a combination stratigraphic-structural trap in the Upper Cretaceous (Cenomanian-Turonian) Second Frontier Formation.

Discovery. Marianne Field was discovered in 1979 by the Burton-Hawks Company, who, using careful analysis of old well logs and test histories, noted an interesting show in the Second Frontier Formation at Continental Oil Company #1 Government, a dry hole drilled during 1957 in section 24-20N-103W. The E-Log for this well shows a thin sand with strong SP deflection and high deep resistivity at 4585 ft. The mud log describes fine to medium grained sandstone with yellow fluorescence and a gas show. A drill stem test recovered 215 ft of slightly gas-cut mud, with shut-in pressure of 1675 - 1270 psi. Reasoning that the Frontier zone might have been damaged by overbalanced water-base drilling mud, Burton-Hawks located several exploratory wells updip from Continental's dry hole, and drilled with air to minimize formation damage and allow formation testing while drilling (Wellborn, 1981). Burton-Hawks UPRR #13-1 (13-20N-103W) found a fast drill break at 4935 to 4949' in the Second Frontier Formation. The drill cuttings contained fine-grained sandstone with fair porosity, blue-white fluorescence and slight cut. When perforated, the Second Frontier Formation flowed gas at 2.6 mmcf/g/d.

The Marianne Sandstone. The main gas reservoir at Marianne Field is a thin, clean, highly porous sandstone - herein called the Marianne or M Sandstone- found near the top of the Second Bench of the Second Frontier Formation. The M Sandstone is 9 to 15 ft thick and approximately one mile wide and trends north-northeast-south-southwest. This sandstone was interpreted to be an offshore marine barrier bar by Wellborn (1981) and Larson (1992; "A" Ss), however density logs show numerous thin, low density ($RHOB < 2.0$) carbonaceous shales and coal beds in this section, especially in the northern part of the area. Mud log sample descriptions indicate coal and varicolored tan, brown, and gray carbonaceous shales above and below the M Ss. The M Sandstone is covered by a thin coal bed in the southern part of the field, and pinches out against coal beds and carbonaceous shales along the northwestern edge of the field. The M Sandstone is evidently a non-marine deposit, and may be a meandering fluvial distributary channel incised into coal swamp deposits. Gomez et al. (1995, p. 122) showed fluvial deposits within the Second Bench of the Second Frontier Formation in this part of the Rock Springs Uplift.

Reservoir Quality. The M Sandstone shows strong SP deflection and clean gamma ray character on well logs, and has been described as very fine to fine grained, well sorted, subround sandstone with fair visible porosity in mudlogs. Density logs indicate 16 to 20 % porosity, however borehole washouts are common and density readings are suspect. Deep resistivity ranges from 50 to 70 ohms in productive wells and as low as 9 ohms in "wet" wells. Water saturations calculated from logs range from 36 to 40% in the producing wells, using the Simandoux equation with $R_w = 0.70$ at 68 deg F (based on water recovered from a Frontier DST at ANR Leucite Hills #1-26, 26-20N-103W). According to the completion reports and well histories, no cores have been collected within this field, perhaps due to the extensive use of air drilling and the tendency of the Second Frontier Formation to cause washouts and problems with stuck pipe (Wellborn, 1981),

Larson (1992) identified another pay zone immediately below the M Sandstone in several wells, which is a thin channel sandstone with lower resistivity and higher gamma ray counts known as the "B" sandstone. This unit appears to have limited areal extent. Gas has also been produced from thin sands in the Third Frontier section and Muddy Formation along the west side of the field.

Structure. The Frontier Formation dips to the northeast at approximately 300 ft per mile along the flank of the Rock Springs uplift, a doubly-plunging basement-cored anticlinal structure in the central Green River Basin. The multi-stage tectonic history of this structure has been described by Roehler (1993). The northeast dip is broken by many closely spaced normal faults of probable Paleocene age. The fault patterns have been mapped by previous authors using photogeology and well control (Wellborn, 1981; Larson, 1992). These normal faults have displacements of tens to hundreds of feet, and have broken the M Sandstone into many different reservoir compartments. Wellborn (1981) suggested that the faulting did not appear to affect the gas trap. However two recent extension wells (UPRC/DAUBE Engadine #1 and National Energy Corp #1) were plugged and abandoned after drilling along the downdip eastern margin of the field and finding unusually low deep resistivity in the M Ss, indicating water-wet reservoir. The water leg in the M Sandstone at National Energy Corp #1 is updip from several gas producers and just a few hundred feet lower than the structurally highest and most productive well in the field. The Marianne gas reservoir is probably broken into several different pressure chambers by the cross faults, and may have different gas/water contacts in different compartments.

Thermal Maturity and Gas Migration. Present-day reservoir temperatures are very low at Marianne Field (115-122 deg F). Plots of vitrinite reflectance (Ro) versus depth for this part of the Green River Basin indicate sub-mature generating conditions at this shallow depth, with Ro less than 0.5 %. The coal beds in the Second Frontier fluvial-delta section extend downdip into the Washakie Basin to the east (Gomez et al, 1992) but pinchout into marine deposits. The coal beds and carbonaceous shales are probably thermally mature and expelling gas at greater depths. The gas at the Marianne Field is sweet gas (1035 BTU) with no oil or condensate (Larson, 1992). The gas has evidently migrated into the trap. There might be some influx of biogenetic gas from adjacent coal beds.

Subnormal Reservoir Pressure. Public reservoir pressure data is sparse for this field, however an initial shut-in tubing pressure of 1525 psi was reported by Larson (1992). This can be extrapolated to a bottom hole pressure of +/- 1717 psi at 4940 ft. A shut-in pressure of 1675 psi was reported in the DST of the M Sandstone at 4585 ft in Continental Oil Company #1 Government (24-20N-103W). These pressures indicate a subnormally pressured gas accumulation with original pressure gradients of approximately 0.34 to 0.36 psi/ft. Larson (1992) reported that the reservoir pressure declined to 1275 psi (SITP) as of 1992.

In the regional context, the Marianne Gas Field is located updip from the overpressured Waskakie basin-center gas accumulation and is near the updip margin of an extensive interfingering zone of subnormal pressures in the Frontier, Mowry and Muddy Formations along the flanks of the Rock Springs Uplift. The M Sandstone contains subnormally pressured gas, but there are normally pressured zones below and above (?) the low pressure reservoir. Water has been produced from the Blair Formation at a depth of 1780 ft, and from the Dakota, Lakota and Morrison Sandstones several hundred feet below the Frontier Formation. These deeper aquifers have produced water at normal

pressures during formation tests, with pressure gradients of 0.41 to 0.43 psi/ft. The subnormally pressured M Sandstone reservoir is somehow isolated from these deeper and shallower normally pressured water systems. The overlying Baxter Shale and underlying Mowry Shales apparently make effective seals for the gas trap. Considering the abundance of normal faults and coal beds in this area, the preservation of subnormal reservoir pressures in the Marianne Sandstone is impressive. One might expect the reservoir to be breached and invaded by water influx along the fault zones and through permeable coal beds.

Subnormally pressured gas reservoirs are easily damaged by conventional water-based drilling muds, so underbalanced drilling or air drilling would be suitable for minimizing formation damage. Wellborn (1981) explained the benefits and problems involved with using air-drilling during the discovery and development of this field.

Cumulative Production. Gas production has been established from six wells in the M Sandstone at 320 acre spacing, with initial production rates of 750 to 2600 mcf/d. Gas has also been produced from the Third Frontier Formation and the Muddy Formation in one well along the west side of the field. Typical cumulative production has been 1.2 to 1.38 bcfg per well as of mid 1998, with 2.4 bcfg from the best well. Total production from Marianne Field has been 8.9 bcfg. Larson (1992) estimated the ultimate recovery from this gas field to be 14 bcfg.

There are approximately ten dry and abandoned wells surrounding the field. Most of these were drilled beyond the M Sandstone zero edge, and missed the main reservoir. Two recent extension wells found low resistivity (indicating high water saturation) in the M Sandstone along the downdip eastern edge of the M Sandstone channel trend, and were plugged and abandoned. Well log analysis using low resistivity sandstone techniques might be helpful for identifying possible bypassed pay zones. Seismic data may be of limited use for reservoir mapping in this area, due to the thin-bedded reservoir sandstones, abundant normal faults and adjacent coal beds. However if the meander trend of the M Sandstone channel could be determined, additional reservoir compartments might be found.

Task 3. Resource Analysis of the Balance of the Partitions

Using the partitions defined (Appendix 1), analysis during this quarter was escalated to determine the resource associated with the Cretaceous tight gas play in overpressured areas. The purpose of the effort is to highlight those areas that would be most prospective for exploration. The goal of the effort is to determine the economically recoverable resource in the GGRB based on the methodology presented in task 1 above for the Green River Deep partition.

Future work will entail the resource assessment for target areas of high natural fracture probability in the GGRB, to be completed during the second quarter, with presentation of the results to DOE/FETC in March.

References

1. Doelger, M. J., 1995, Geologic Framework and Future Development - Major Gas Plays of the Greater Green River Basin: in Geological Characterization of the Cretaceous Gas Plays in the Greater Green River Basin, GRI-IPAMS, p. 49- 79.
2. Farmer, K. K., 1978, Canyon Creek: in Wyoming Oil and Gas Fields, Wyoming Geological Association Guidebook, p. 82-84.
3. Garcia-Gonzalez, M., Surdam, R. C., and Lee, M. L., 1997, Generation and Expulsion of Petroleum and Gas from Almond Formation Coal, Greater Green River Basin, Wyoming: AAPG Bulletin, v. 81, no. 1, p.62-81.
4. Gomez, E., Horne, J., Forster, J., and Sturm, S., Stratigraphic Framework and Facies Distribution of the Frontier Formation, Moxa Arch: in Geological Characterizations of the Cretaceous Gas plays in the Greater Green River Basin: GRI-DOE-IPAMS, November 6, 1995, p.113-138.
5. Hamlin, H. S., 1996, Frontier Formation Stratigraphy on the Moxa Arch, Green River Basin, Wyoming: The Mountain Geologist, vol. 33, no. 2, p. 35-44.
6. Heasler, H. P. and Surdam, R. C., 1992, Pressure Compartments in the Mesaverde Formation of the Green River and Washakie basins, as Determined from Drill Stem Test Data: in Mullen, C. E., editor, Rediscover the Rockies: WGA Forty-Third Field Conference Guidebook, p. 207-220.
7. Hendricks, M. L., 1983, Stratigraphy and Tectonic History of the Mesaverde Group (Upper Cretaceous), East Flank of the Rock Springs Uplift, Sweetwater County, Wyoming: Ph. D dissertation, Colorado School of Mines, 213 p.
8. Iverson, W. P., Dunn, T. L., and Surdam, R. C., 1995, Improvements to Formation Evaluation, Almond Formation, Green River Basin, Wyoming: in Jones, R. W., editor, Resources of Southwestern Wyoming, Wyoming Geological Association 1995 Field Conference Guidebook, p. 271-280.
9. Kaiser, W. R., 1994, Hydrology of the Mesaverde Aquifer and Tertiary Aquifer System, Greater Green River Basin: in GRI Topical Report 93/0320, Geologic and Hydrologic Assessment of Natural Gas from Coal Seams in the Mesaverde Group and Fort Union Formation, Greater Green River Basin, Wyoming and Colorado, p. 87-93.
10. Larson, B. L., 1992, Marianne: in Wyoming Oil and Gas Fields, Wyoming Geological Association, p. 236-238.
11. Law, B. E. and Dickinson, W. W., 1985, Conceptual Model for Origin of Abnormally Pressured Gas Accumulations in Low Permeability Reservoirs: AAPG Bulletin v. 69, no. 8, p. 1295-1304.

12. Lehman, D. H., 1978, Kinney Field: in Wyoming Oil and Gas Fields, Wyoming Geological Association 1978 Guidebook, p. 202-204.
13. Lehman, D. D., 1978, Trail: in Wyoming Oil and Gas Fields, Wyoming Geological Association Guidebook, p. 392-393.
14. Martinsen, R. S. and Christiansen, G., 1992, A Stratigraphic and Environmental Study of the Almond Formation, Mesaverde Group, Greater Green River Basin, Wyoming: in Mullen, C. E., editor, Rediscover the Rockies: WGA Forty-Third Field Conference Guidebook, p. 171-190.
15. Martinsen, R. S., Christiansen, G. E., and Olsen, M. A., 1995, Stratigraphy and Lithofacies of the Almond Formation, Washakie and Great Divide Basins, Wyoming: in Jones, R. W., editor, Resources of Southwestern Wyoming: WGA 1995 Field Conference Guidebook, p. 297-310.
16. Masters, J. A., 1979, Deep Basin Gas Trap, Western Canada: AAPG Bulletin v. 63, no. 2, p. 152-181.
17. Merewether, E. A., 1983, The Frontier Formation and Mid-Cretaceous Orogeny in the Foreland of Southwestern Wyoming: The Mountain Geologist, vol. 20, no. 4, p. 121-138.
18. Mieras, B. L., 1992, Sequence Stratigraphy, Frontier Formation, South-Central Wyoming: Eustatic and Tectonic Influences: in Mullen, C. E., editor, Rediscover the Rockies - Wyoming Geological Association Forty-Third Field Conference Guidebook, p. 51-60.
19. Molenaar, C. M. and Wilson, B. W., 1990, The Frontier Formation and Associated Rocks of Northeastern Utah and Northwestern Colorado: USGS Bulletin 1787-M.
20. Roehler, H. W., 1985, Geologic Map of the Kinney Rim 30 x 60 Minute Quadrangle, Wyoming and Colorado: USGS Miscellaneous Investigations Series, Map MI-1615.
21. Roehler, H. W., 1987, Surface - Subsurface Correlations of the Mesaverde Group and Associated Upper Cretaceous Formations, Rock Springs, Wyoming, to Mount Harris, Colorado: USGS Miscellaneous Field Studies Map MF-1937.
22. Roehler, H. W., 1990, Stratigraphy of the Mesaverde Group in the Central and Eastern Greater Green River basin, Wyoming, Colorado and Utah: USGS Professional Paper 1508, 52 p.
23. Roehler, H. W., 1993, Coastal Sedimentation Along a Segment of the Interior Seaway of North America, Upper Cretaceous Baxter Shale, and Blair and Rock Springs Formations, Rock Springs Uplift, Southwest Wyoming: USGS Bulletin 2051, 27 p.

24. Scott, A. R., 1993, Coal Rank, Gas Content and Composition and Origin of Coalbed Gases, Mesaverde Group, Sand Wash Basin: in GRI Topical Report 92/0420, Geologic and Hydrologic Controls on Coalbed Methane: Sand Wash Basin, Colorado and Wyoming.
25. Scott, A. R., 1994, Coal Rank, Gas Content and Composition and Origin of Coalbed Gases: in GRI Topical Report 93/0320, Geologic and Hydrologic Assessment of Natural Gas from Coal Seams in the Mesaverde Group and Fort Union Formation, Greater Green River Basin, Wyoming and Colorado, p. 69-86.
26. Spencer, C. W., 1989, Review of Characteristics of low-Permeability Gas Reservoirs in Western United States: AAPG Bulletin v.73, no. 5, p. 613-629.
27. Surdam, R. C., 1995, Sweet Spot Definition in the Mesaverde Group, Greater Green River Basin: in Geological Characterization of the Cretaceous Gas Plays in the Greater Green River Basin, GRI-IPAMS, p. 158-207.
28. Surdam, R. C., Jiao, Z. S., and Liu, J., 1995, Pressure Regime in the Upper Cretaceous Shales and Sandstones in the Washakie basin, Wyoming: in Jones, R. W., editor, Resources of Southwestern Wyoming: WGA 1995 Field Conference Guidebook, p. 205-222.
29. Tyler, R. and Hamilton, D. S., 1994, Tectonic and Stratigraphic Setting and Coal Occurrence of the Upper Cretaceous Mesaverde Group and Lower Tertiary Fort Union Formation, Greater Green River Basin: in GRI Topical Report 93/0320, Geologic and Hydrologic Assessment of Natural Gas from Coal Seams in the Mesaverde Group and Fort Union Formation, Greater Green River Basin, Wyoming and Colorado, p. 8-68.
30. Wellborn, R. E., 1981, Marianne Field - Air Drilling for Gas Sands: Wyoming Geological Association Thirty-Second Annual Field Conference Guidebook, p. 109-117.
31. Yin, P. and Surdam, R. C., 1995, Effects of Diagenesis on Petrophysical Properties of Reservoir Rocks, Washakie Basin: in Jones, R. W., editor, Resources of Southwestern Wyoming: WGA 1995 Field Conference Guidebook, p. 247-254.

Appendix 1

Comparative Analysis of the UPRC Stratos Federal No. 1 Well

**Prepared for:
DOE/FETC**

**Prepared by:
Advanced Resources International**

December 1998

Outline

- A. Background, Study Objectives and Data Sources***
- B. Frontier Formation Gas Resources and Well Performance***
- C. Partitioning the Greater Green River Basin***
- D. The Green River Deep Partition and Stratos Well Area***
- E. Comparative Analysis of the Stratos Federal No. 1 and Offset Wells***

Findings and Conclusions

The following findings and conclusions stem from the Comparative Analysis of the Stratos Federal No. 1 Well.

1. Based on information from offset Blue Rim and other Frontier Formation wells and an assessment of surface and basement features in the Greater Green River Basin, the Stratos well location, while reasonably representative of the geology and deposition in the area, does not appear to be in a structurally favorable setting.
2. The Stratos well area has sufficient gas in place, estimated at 20 to 30 Bcf/section, to support natural gas development if sufficient reservoir drainage area could be connected to the wellbore.

Satellite Image Analysis:
Landsat Thematic Mapper Image Mosaic

Findings and Conclusions

3. The reservoir matrix permeability of the Frontier sands in the area is extremely low, on the order of one micro-darcy. Natural fractures are required to overcome low matrix permeabilities and provide sufficient flow capacity and reservoir drainage area.
4. The structural setting around the Stratos well appears to be less favorable than around the Blue Rim 1-30 and 31-1 wells:
 - All three wells are located on the southeastern flank of the Sandy Bend Arch, about one mile apart.
 - The Stratos well is located in the compressional quadrant of a minor, left-lateral wrench/shear fault that terminates beyond the Stratos well. Such a structural setting is not be favorable for natural fracture based permeability.
 - The Blue Rim 31-1 well is located in the tensional quadrant of a second, minor left-lateral wrench/shear fault. This structural setting is favorable for open natural fractures and enhanced permeability.
 - The Blue Rim 1-30 well is located at the junction of two left-lateral wrench/shear faults and the termination of a right-lateral wrench/shear fault, trending perpendicular to the north-east. Based on this, the well may be in a neutral or slightly tensional setting conducive to natural fractures.

Green River Deep - Stratos Study Area Faults

Findings and Conclusions

5. The two Blue Rim wells were completed in the Second Frontier and the deeper, upper Mowry sands. The Stratos well was not completed in the upper Mowry sand.

- *The Mowry sandstone represents 20 to 25% of the pay volume in the Blue Rim wells. The Mowry appears to be a relatively shaly sand (GR of 50 to 75), but has good Neutron-Density cross-over, reasonable porosity (9%), is gas bearing, and is over pressured.*
- *The Mowry interval, most likely, contributed to the initial flow tests. However, the Mowry perforations were plugged during the 18 months of production by the Blue Rim 31-1 well and thus made little to no contribution to post stimulation gas production.*

"WELLBORE SCHEMATIC"

BLUE H, M FEDERAL 31-1
MEGAS FIELD
C NW/4 SEC. 31, T. 22 N. R. 106 W.
SWEETWATER COUNTY, WYOMING

-Not to Scale-

All measurements are from KB
which is 23' above ground level

Findings and Conclusions

6. The composite 2nd Frontier including the fluvial and marine sands, is best developed in the Blue Rim 1-30 well. In the Blue Rim 31-1 and the Stratos wells, the net pay is similar, at about 30 feet.

Well	Gross Sand (ft)	Net Sand ≤GR50 (ft)	Net Sand <6% (ft)	ϕ (h)	Mean ϕ	Post-Brkdn Flow (Mcfd)
Stratos Federal No. 1	47.0	33.0	30.0	2.780	.076	18-20
Blue Rim Federal No. 31-1	42.0	33.0	31.0	2.710	.080	690-817
Blue Rim Federal No. 1-30	59.0	57.0	56.0	4.811	.082	1316

Green River Deep Partition Total Net Sand of the Frontier

Federal Energy Technology Center
U.S. Department of Energy

Advanced Resources International
Albuquerque, NM • Houston, TX • Denver, CO

Findings and Conclusions

7. While the Frontier deposition and net pay are similar in the three wells, major differences exist in their gas flow capacities:

	Stratos No. 1 Well	Blue Rim 31-1 Well	Blue Rim 1-30 Well
<u>Post Perforation</u>			
- Flow rate (Mcf/d)	no flow	100 to 120	(?)
- SITP (psi)	450	1,800+	6,500
<u>Post Breakdown</u>			
- Flow rate (Mcf/d)	18 to 20	690 to 817	1,316
- SITP (psi)	6,000	10,050	n/a
<u>Post Stimulation</u>			
- Initial Flow rate (Mcf/d)	n/a	1,797	1,316(?)
- SITP (psi)	n/a	12,400	n/a
- Initial month (Mcf/d)	n/a	700	n/a

Findings and Conclusions

8. Without running a quantitative stress and natural fracture location model, our interpretation of the reasons for the differences in flow capacity between the Stratos and the two Blue Rim wells are as follows:

- *The permeability in the area surrounding the Stratos well appears to be too low for commercial gas production. Tectonically-related natural fractures (essential for high productivity) are a distinctly local phenomena. The Stratos well is located on the unfavorable, compressional quadrant of the left-lateral wrench fault that cuts through the area.*
- *The Blue Rim wells appear to be more favorably located with respect to the tectonic setting of the area and thus have higher natural fracture based permeability.*

Findings and Conclusions

9. We do not believe that the Frontier Formation in the Green River Deep Partition has been conclusively tested:

- *The Blue Rim 31-1 well, that produced 150 MMcf of gas in 18 months, was a damaged well; it produced drilling muds and frac fluid until the tubing parted and the well was abandoned.*
- *The Blue Rim 1-30 well, that had a strong IP of 1,316 Mcfd, experienced mechanical problems and was never placed on production.*
- *The pressure transient tests on the Stratos well are inconclusive because the early time data (required for calculating a skin factor) are missing, the depth of investigation was low (at 10 feet), and other problems were encountered.*

Findings and Conclusions

9. (Continued):

- *It may be that the unstimulated Stratos well was not efficiently connected to the natural fracture system in the area. Drilling fluids, cement or other actions, including the taking of core, may have damaged the near wellbore area. A hydraulic fracture or a horizontal lateral may have enabled the well to achieve contact with undamaged or improved reservoir properties past the wellbore area.*
- *The Stratos well is not located in any of the structurally enhanced target areas outlined for the Green River Deep Partition. These areas are likely to be more favorable for natural fracture based permeability and development of the tight Frontier gas formation.*

Green River Deep Partition Structural Elements

Federal Energy Technology Center
U.S. Department of Energy

Advanced Resources International
Arlington, VA • Houston, TX • Denver, CO

Findings and Conclusions

10. A more thorough evaluation of the Stratos well area may be warranted if the well is to be converted to a R&D test well. This evaluation would involve:
 - *Acquiring and interpreting a high resolution aeromagnetic survey.*
 - *Interpreting existing 2-D seismic for structural implications.*
 - *Conducting a high resolution 3-D seismic survey.*
 - *Evaluating the local natural fracture development using a rock mechanics and stress model.*

It may also be prudent to redo the well tests and stress tests on the Stratos well.

A. Background, Study Objectives and Data Sources

Background

The Stratos Federal No. 1 Well was located and drilled with three objectives in mind:

- Extend the rapidly maturing Moxa Arch Frontier gas play into the deeper off-structure area.
- Demonstrate the feasibility of using horizontal wells as the appropriate well drilling and completion technology for low permeability, naturally fractured tight gas sands.
- Characterize the geology, reservoir properties, and resource potential of the late Cretaceous-age Frontier Formation in the deep, central portion of the Green River Basin.

GGRB Production Improvement Project Stratos Well

Background

In 1995, the U.S. DOE/METC and UPR jointly located and drilled the Stratos #1 Federal well in Sec. 24, T22N R107W, Sweetwater Co., of southwestern Wyoming:

- **The Stratos well was located as an offset to two deep Frontier and upper Mowry producing wells drilled in the late 1970's and early 1980's:**
 - *Blue Rim Federal No. 31-1*
 - *Blue Rim Federal No. 1-30*
- **A third well, the No. 1-35 Mountaineer, that logged the Frontier, also exists in the area.**

Green River Deep - Stratos Study Area

Study Objectives

Advanced Resources Int'l. (ARI) was tasked by DOE/METC to undertake a "post-mortem" on the Stratos No. 1 well, the two offset wells, and the surrounding area.

- Subtask 1. Assemble and Review Past Work Performed on the Stratos Well
- Subtask 2. Examine Structure in Stratos and Offset Well Areas for Evidence of Naturally Fractured Settings
- Subtask 3. Report on Insights Gained from Study

Data Sources

The data for this study came from five sources:

- I. Data supplied by Union Pacific Resources Corp. (UPRC). These data included core analyses and a draft copy of UPRC's report on the Stratos No. 1 well.**
- II. Geologic maps, digital well data, digital base map, reference cross-sections, and well logs.**
- III. Well data and unit files from the Wyoming Oil and Gas Conservation Commission in Casper, Wyoming.**
- IV. Well data and unit files, internal reports, and correspondence from the U.S. Bureau of Land Management offices in Casper and Rock Springs, Wyoming.**
- V. Telephone interviews with petroleum engineers involved with the completion of the Federal No. 31-1 and Blue Rim Federal No. 1-30 wells.**

B. Frontier Formation Gas Resources and Well Performance

Frontier Formation: Natural Gas Resources

The Frontier tight gas formation in the Greater Green River Basin (GGRB) represents a large and mostly underdeveloped natural gas resource. The USGS (Law, 1989) estimates that the Frontier-Cloverly play (excluding the Moxa Arch):

- *Encompasses an area over 12,000 mi², in the overpressured parts of the basin.*
- *Is a deep gas play, averaging 17,500 feet of depth.*
- *Holds 304 Tcf of gas in-place, with the Frontier alone holding an estimated at 200 Tcf of gas in-place.*

GREATER GREEN RIVER BASIN FRONTIER GAS FIELDS AND REGIONAL DEPTH TO FRONTIER FM.

Federal Energy Technology Center
U.S. Department of Energy

Advanced Resources International
Albuquerque, NM • Houston, TX • Denver, CO

GREATER GREEN RIVER BASIN ISOPACH MAP OF FRONTIER AND DAKOTA FMS.

with areal extent of overpressured
Cretaceous and Tertiary rocks

Federal Energy Technology Center
U.S. Department of Energy

Advanced Resources International
Arlington, VA • Houston, TX • Denver, CO

Table 1
Reservoir Properties and Estimated Gas In-Place
for the Cloverly-Frontier Gas Play, Greater Green River Basin

<u>Geologic Variables</u>	<u>Mean</u>	<u>50% Fractile</u>
Area (acres)		7,783,000
Net Pay (feet)		110
Porosity (%)		5.0
Depth (feet)		17,500
Gas Saturation (%)		45
Pressure Gradient (psi/ft)		0.7
<u>Resource Size</u>		
Total Play (Tcf)	304	295
Frontier Only (Tcf)	200	

Source: Law (USGS), 1989.

Frontier Formation: Development Status

The great bulk of Frontier Formation development has been on the Moxa Arch, in an elongated north-south band in the western portion of the GGRB. To date, over 2,400 Frontier gas wells have been drilled providing:

- 2,500 Bcf of cumulative gas production
- 1,500 Bcf of remaining reserves

A handful of Frontier Formation gas fields exist in other portions of the GGRB, as follows:

- Baxter Basin
- Canyon Creek
- Kinney

However, the well performance in these fields has so far been disappointing.

Frontier Well Performance: Data Base

To examine the performance of Frontier wells, Advanced Resources Int. assembled a data base of 234 wells from the LaBarge Platform on northern extension of the Moxa Arch. This database contains:

- *Net sand*
- *Porosity and water saturation*
- *Initial and latest reservoir pressures*
- *Production history, including cumulative gas recovery*
- *Completion intervals*
- *Completion practices (pounds of sand and type of frac fluid)*
- *Drilling date and location*

The well locations for this data base are attached.

R 114 W

R 113 W

R 112 W

R 111 W

Frontier Well Performance: Methodology

The performance of the wells in the Frontier Formation database were matched using “ARI Tight”, a type-curve program specifically constructed for low permeability gas reservoirs (SPE 35595). Using “ARI Tight”, the following information was calculated and added to the database:

- *Estimated ultimate recovery (EUR)*
- *Permeability*
- *Fracture half-length and drainage area*

Next, a series of correlations were performed to estimate the importance of net pay, permeability and completion practices on the performance of Frontier Formation wells in the GGRB.

Frontier Well Performance

Type-Curve Match of Well FFC 1-15

Frontier Well Performance: Current Activity

The Frontier Formation, with average reserves of 3 Bcf per well, has been an economically viable tight gas play on the Moxa Arch. In recent years, the reserves per well in this area have declined appreciably, as the play has matured.

- To a large extent, the development of the Frontier has followed empirically established trends and by low cost, “assembly-line” statistical drilling.
- The current emphasis is to drill infill wells, establish step-out locations, and remediate under-performing wells.

Historical Performance of Frontier Formation Wells **(Moxa Arch, GGRB)**

Year of Completion	No. of Wells	Avg. EUR per Well
1956-1960	44	7.2
1961-1979	46	3.8
1980-1989	47	2.9
1990-1994	87	1.7
Past 1994	10	1.0
Totals	234	3.3

Frontier Formation: Moxa Arch Area

The decline in Frontier Formation well productivity in the past 10 years is due to:

- *The development of lower permeability areas. The wells drilled in the 1990's encountered perms of 0.05 md to 0.06 md while the wells drilled prior to 1980 had perms nearly twice as high. On average, the net sand thickness and quality have remained similar.*
- *The drilling of infill wells into areas with significant pressure depletion. The wells drilled in 1996/97 encountered pressures of 1,350 to 2,000 psi, considerably below the 3,000+ psi pressures encountered by earlier wells.*

Hydraulic fracture performance, measured in terms of fracture half-length is about 20% better in the 1990's over the 1960/1970's. However, this improved performance has not been sufficient to counter the decline in reservoir quality encountered by the more recent wells.

Reservoir Properties for Frontier Formation Wells (Moxa Arch, GGRB)

	Number of Wells	Reserves/ Well (Bcf)	Reservoir Quality			Fracture Half-Length
			ϕ	h	k	X_f
1956-1960	44	7.2	0.15	54'	0.11	320'
1961-1979	46	3.8	0.15	49'	0.09	326'
1980-1989	47	2.9	0.14	55'	0.14	463'
1990-1994	87	1.7	0.15	56'	0.05	353'
Post 1994	10	1.0	0.14	39'	0.06	396'
Totals	234	3.3

Frontier Well Performance: Distribution/Economics

Well performance in the Frontier Formation varies greatly -- from a few tenths of a Bcf to over 10 Bcf of expected ultimate reserves (EUR) per well.

- *Nearly one half of the wells, with expected reserves (EURs) of less than 2 Bcf per well, are uneconomic or marginal at today's gas prices.*
- *The best 25% of the wells, with expected reserves of 4 Bcf per well or more, account for 62% of the total reserves and essentially "carry" this gas play.*
- *The best 50% of the wells are economic and account for about 85% of total expected gas reserves.*

EUR Distribution of GGRB Frontier Formation Wells

EUR Distribution GGRB Frontier Formation Tight Gas Wells

Frontier Well Performance: Possible Insights

If the poorest 50% of the wells (the sub-economic and marginal wells) could be avoided, the economics and efficiency of the Frontier gas play would improve greatly, enabling this play to expand.

Three areas were examined to establish the factors responsible for the good (highest 50%) and the poor (lowest 50%) wells.

- *Permeability, particularly the contribution of natural fractures*
- *Deposition, particularly sand development and quality*
- *Completion practices, particularly hydraulic fracturing*

Frontier Well Performance: Possible Insights

A detailed examination of the three controls on tight Frontier well performance showed:

- *A strong correlation exists between permeability and well performance ($R^2 = 0.302$) and accounts for about 50% of the difference between good and poor wells:*
 - *The best 50% of the wells have an average perm of 0.13 md and an EUR of 5.7 Bcf.*
 - *The poorest 50% of the wells have an average perm of 0.04 md and an EUR of 1.2 Bcf.*
- *A moderate correlation exists between net sand thickness and well performance ($R^2 = 0.124$) and accounts for about 13% of the difference between good and poor wells.*

Frontier Well Performance: Possible Insights

- *A negative correlation exists between the size of the stimulation (pounds of sand per foot of net pay) ($R^2 = -0.148$).*
 - *This is not to imply that well completion practices are unimportant.*
 - *Rather, the finding is that a large hydraulic fracture cannot turn a geologically poor well into a good well.*

Other reservoir factors such as well pressure, porosity and gas saturation account for the remaining differences between good and poor wells.

Tight Gas Wells - GGRB Moxa Arch

Permeability vs. EUR

Tight Gas Wells - GGRB Moxa Arch

Net Sand Thickness vs. EUR

Tight Gas Wells - GGRB Moxa Arch

Lbs. Sand/Ft of Pay vs. EUR

Summary

The review of the Frontier Formation indicates:

- The Frontier Formation represents a large, underdeveloped tight gas resource, estimated at 200 Tcf of gas-in-place. With the maturing of the Frontier play along the Moxa Arch, new E&P technologies and geologically attractive areas need to be established for this play to remain viable.
- Permeability is the most important production controlling mechanism in the Frontier, with the presence (or absence) of natural fractures controlling permeability. As such, finding areas with intense clusters of open natural fractures is the primary R&D objective.

Summary

- Vertical wells with hydraulic fractures, have not been able to overcome the decline in Frontier well performance nor to make economic wells in geologically unfavorable settings. Alternative well drilling and completion practices, such as using horizontal wells to link natural fractures to the wellbore, become a second R&D objective.

C. Partitioning the Greater Green River Basin

Partitioning the Greater Green River Basin

Partitioning Rationale. To assess the natural gas resource and development potential of the Upper Cretaceous Frontier and Mesaverde tight gas plays, we partitioned the GGRB on geologic and reservoir features important for gas recovery.

The partitions are shown in the following figure and use townships as the unit of analysis. A total of 20 partitions were developed and will form the foundation for the analysis.

Greater Green River Basin Partitions

Federal Energy Technology Center
U.S. Department of Energy

Advanced Resources International
Arlington, VA • Houston, TX • Denver, CO

Partitioning the Greater Green River Basin

Partitioning Methodology. The structural, geologic and reservoir features and the analytic methods and data used to partition the GGRB are summarized below:

- Structural Elements. Natural fractures and permeability are the most essential components to gas recovery from the tight Frontier gas sands. As a result, our first partitioning criterion is structural features -- uplifts, arches, folds, basement features and normal, reverse and strike-slip faults -- and their association with natural fracture development.
 - *Structure maps, previously identified basin structural features, satellite imagery, gravity surveys, and selected seismic lines provided the basic data.*
 - *The regional structure map showing the major structured features is attached. Also shown is the overlay of the GGRB partitions on the isostatic gravity and satellite imagery map of the Greater Green River Basin.*

GREATER GREEN RIVER BASIN MAJOR STRUCTURAL FEATURES

Federal Energy Technology Center
U.S. Department of Energy

Advanced Resources International
Arlington, VA • Houston, TX • Denver, CO

GREATER GREEN RIVER BASIN REGIONAL STRUCTURE MAP

Federal Energy Technology Center
U.S. Department of Energy

Advanced Resources International
Arlington, VA • Houston, TX • Denver, CO

Overlay of Greater Green River Basin Partitions on Merged Isostatic Gravity and Satellite Imagery

Partitioning the Greater Green River Basin

- Depth. Well depth has a direct relationship with well costs and has been judged to be correlated with loss of primary porosity and permeability. We used the 7,500 foot and 15,000 foot depth contours to partition the effects of depth on the geologic and economic potential of Frontier gas development.
 - *The depth contours were constructed from a large well data set.*
 - *The attached figure provides the regional depth contours to the Frontier Formation.*

GREATER GREEN RIVER BASIN FRONTIER GAS FIELDS AND REGIONAL DEPTH TO FRONTIER FM.

Federal Energy Technology Center
U.S. Department of Energy

Advanced Resources International
A-1000-20 • P-1000-20 • D-1000-20

Partitioning the Greater Green River Basin

- Overpressuring. Overpressured settings have a strong relationship with gas centered basins and often help define the boundary between the fully gas charged and the transition (gas and water) zone.
 - *Pressure boundaries were established by using early work by Law ('89), from field studies prepared by Advanced Resources, and selected control points assembled from public data.*
 - *The following figure provides the outline of overpressure for the Frontier Formation.*

GREATER GREEN RIVER BASIN ISOPACH MAP OF FRONTIER AND DAKOTA FMS.

with areal extent of overpressured
Cretaceous and Tertiary rocks

Federal Energy Technology Center
U.S. Department of Energy

Advanced Resources International
Arlington, VA • Norcross, GA • Denver, CO

Partitioning the Greater Green River Basin

Geology and Deposition. Frontier Formation is a stratigraphically complex exploration target with multiple stacked reservoirs, reflecting changes in eustatic sea level, variability in sediment supply, and a high degree of tectonism.

- *Sandstones of the Frontier Fm were deposited in a fluvial deltaic to nearshore marine environment. Fluvial reservoirs dominate only in the westernmost quarter of the GGRB.*
- *Frontier sandstones are generally 100 to 150 thick, thinning to the south and east.*

Stratigraphic Column

Western Greater Green River Basin

Thrust Belt/Moxa Arch Rock Springs Uplift

Late Cretaceous				Early Cretaceous				Jurassic	
Santonian	Coniacian	Turonian		Cenomanian	Albian		Aptian	Kimur./Tithonian	
Hilliard Shale		Frontier Formation		Dry Hollow Member	Chalk Creek member		ORS	AH	CV
Steele Shale		Frontier Formation		Wall Creek Member	Belle Fourche member		Unnamed member		
Industry Usage		First Frontier		Second Frontier fluvial		Second Frontier marine		Third Frontier	
		Fourth Frontier		Mowry Shale		Muddy Sandstone		Thermopolis Shale	
				Aspen Shale		Dakota/Lakota Ss.		Dakota/Lakota Ss.	
				Muddy Sandstone		Thermopolis Shale		Thermopolis Shale	
				Thermopolis Shale		Dakota/Lakota Ss.		Dakota/Lakota Ss.	
				 

Partitioning the Greater Green River Basin

Maturity of Development. In the main, the Frontier Formation is an immature gas play. The exceptions are:

- *The Moxa Arch on the southwest edge of the basin; the La Barge Platform on the western edge of the basin; and, the Rock Springs Crest, in the center of the basin.*

Scattered development also exists on the Rock Springs East and the Dad Dixon Platform:

- *Data from the Wyoming Oil and Gas Commission and commercial sources enabled us to define the active, inactive and dry hole Frontier exploration and development wells.*
- *The table of fields, wells and gas production for the Frontier Formation is provided.*

Cross Section A-A' through Greater Green River Basin

A'

A

Cross Section B-B'

Resource Assessment: Individual Partitions

- The boundaries and partitioning criteria for the 20 GGRB partitions are discussed in the following materials.
- Using the 20 partitions, the next step is assessing the natural gas resources in the Frontier and Mesaverde tight gas plays. The objective is to highlight portions of each partition and play that could be targeted for further evaluation and testing by industry.
- For each partition a gas resource-in-place is being calculated on the basis of:
 - *area (townships as a unit of analysis)*
 - *net sand thicknesses*
 - *porosity*
 - *water saturation*
 - *temperature as a function of depth*
 - *pressure as a function of depth*
- Where sufficient data exists, engineering based estimates will be made for technically recoverable resources.

Dad Dixon Platform Partition

The Dad Dixon Platform is located in the east-central part of the GGR basin in a foreland position relative to thrusting associated with basin-bounding Park Range. Structurally, the platform dips westerly at a relatively shallow angle toward the Washakie Deep.

- *The Frontier averages about 8000 ft. drill depth in the partition and is moderately penetrated. The partition is not overpressured.*
- *The platforms sits in an equivalent structural position to LaBarge platform, although exploration maturity and established production levels are not as great.*
- *Fields/completions:*

	# of Frontier Wells	Active Wells	Inactive/ Abandon Wells	Total Prod. (Bcf)
Browns Hill	1	0	1	0.06
Cherokee Creek	2	0	2	0.6
Sugar Creek	2	0	2	0.07

East Sand Wash Partition

The partition is located in a similar structural position as the Dad Dixon Platform, forming a homoclinal ramp toward the Sand Wash Deep. A tear fault, which bounds the the southern terminus of the upthrust Park Mountains defines the north edge of the partition.

- *The partition is moderately drilled and is overpressured only in its western third. Drill depth to the Frontier in the partition averages 10,000 ft.*
- *No significant production from the Frontier Formation exists in this partition.*

Red Desert Deep Partition

Located in the NE corner of the GGRB, the Red Desert Deep partition is a foreland deep relative to the Rawlins Uplift and shows a pronounced gravity signature.

- *Drill depth to the Frontier averages about 25,000 ft. and has penetrated by only four wells. The partition is overpressured.*
- *No significant production from the Frontier Formation exists in this partition.*

Red Desert Partition

The Red Desert partition covers much of the NE portion of the GGRB. Where it abuts the southern edge of the Wind River Mountains to the north, the partition is a foreland deep and displays a noticeable gravity signature and grades into the Red Desert Deep partition.

- *The average Frontier drilling depth in the partition is about 20,000 ft. The partition is overpressured and has not been drilled extensively in the Frontier.*
- *Fields/completions:*

	# of Frontier Wells	Active Wells	Inactive/ Abandond Wells	Total Prod. (Bcf)
Bastard Butte	1	0	1	0.04
Hay Reservoir	1	0	1	0.01
Unknown	1	1	0	0.11

Wamsutter Arch Partition

The Wamsutter Arch partition is on in a structural high relative to the Red Desert partition to the north and the Washakie Deep partition to the south. The arch may be the site of right-lateral oblique faulting, complementary to the Cherokee Arch.

- The partition has been slightly drilled in the Frontier. Here, the Frontier is 16,000 ft. deep an largely overpressured.
- *No significant production from the Frontier Formation exists in this partition.*

Washakie East Partition

The Washakie East partition comprises a steeper westerly-dipping ramp into Washakie deep from the Dad Dixon Platform.

- *Although drilling has been extensive in the Mesaverde section, drilling to the Frontier is sparse. The Frontier is found at drill depths of about 10,000 ft and the partition is overpressured.*
- *Fields/completions:*

	# of Frontier Wells	Active Wells	Inactive/ Abandonnd Wells	Total Prod. (Bcf)
Cow Creek	2	1	1	0.8

Washakie Deep Partition

Located in the east-central GGRB, the Washakie Deep may represent a rhombochasm between the Wamsutter and Cherokee arches. The partition displays a NE-SW gravity-low signature.

- *Drill depth to the top of the Frontier averages over 20,000 ft. Only about 15 wells have penetrated the Frontier in this partition, which is overpressured.*
- *No significant production from the Frontier Formation exists in this partition.*

Cherokee Arch Partition

The Cherokee Arch partition is a structurally high feature separating the Washakie Deep from the Sandy Wash area. The arch displays oblique right lateral faulting and may be a counterpart to the Wamsutter Arch to the north for accommodating stresses across the Washakie Deep.

- *Drill depth to the Frontier in the partition averages about 17,000 ft. The partition is overpressured and has not been extensively drilled.*
- *No significant production from the Frontier Formation exists in this partition.*

Sand Wash Deep Partition

The Sand Wash Deep partition is a foreland deep found east of the eastern terminus of the Unita Mountains uplift. Adjacent to the uplift, in the southwest portion of the partition, is a pronounced gravity low.

- *Drill depth to the Frontier averages about 18,000 ft. The Frontier is only moderately drilled around the perimeter of the partition, which is largely overpressured.*
- *No significant production from the Frontier Formation exists in this partition.*

Vermilion Sub-basin Partition

The Vermilion Sub-basin is sandwiched between the Washakie and Sand Wash Deep to the east, the Rock Springs Uplift to the NW, and the upthrusted Unita Mountains to the south, to which it lies in a foreland structural position.

- *Overthrusting is present in fields (Kinney, Canyon Creek and Trail) of the partition but, overall, the strata are relatively flat-lying compared to adjacent partitions.*
- *Drill depth to the Frontier Fm in the partition is about 13,000 ft. The partition is overpressured in areas adjacent to the Washakie Deep.*
- *Fields/completions:*

Fields	# of Frontier Wells	Active Wells	Inactive/ Abandon Wells	Total Prod. (Bcf)
Kinney	1	0	1	0.56
Middle Mountain	1	1	0	0.16

Washakie West Partition

This partition comprises the eastern dip and flank of the Rock Springs Uplift, transitional to Washakie Deep.

- *It is relatively heavily explored, especially in the Mesaverde section, but is also well developed in the Frontier. The SE portion of the partition is overpressured.*
- *Fields/completions:*

Fields	# of Frontier Wells	Active Wells	Inactive/ Abandonnd Wells	Total Prod. (Bcf)
Table Rock	2	1	1	1.45
Robin	1	1	0	2.2

North Rock Springs Partition

This partition includes the NE flank of the Rock Springs Uplift and displays relatively homoclinal NE-dipping strata into the Red Desert partition. It is separated from the Farson Deep on the NW by faulting.

- *Areally the partition is largely overpressured and is characterized by a drill depth of about 16,000 ft. The Frontier is penetrated by 18 wells in the partition.*
- *Fields/completions:*

Fields	# of Frontier Wells	Active Wells	Inactive/ Abandond Wells	Total Prod. (Bcf)
Treasure	1	1	0	0.07
Unknown	1	1	0	0.1
Unknown	1	0	1	0.006

Rock Springs East Partition

This partition comprises the eastern and southeastern flank of the Rock Springs Uplift as it dips toward the Washakie and Red Desert areas.

- *The partition is not overpressured. Drill depth to the Frontier is approx. 7500 ft. in the partition.*
- *Fields/completions:*

Fields	# of Frontier Wells	Active Wells	Inactive/ Abandon Wells	Total Prod. (Bcf)
7	26	16	10	38.04

Rock Springs Crest Partition

The partition sits astride the N-S striking Rock Springs Uplift and is bounded by late Laramide faulting on west side. The uplift displays a pronounced (high) gravity signature. Transverse, NE-SW trending faults are present on the crest of the Rock Springs Uplift.

- *Because of the uplift, the Upper Cretaceous section is normally pressured in this part of the GGRB. Drill depths to the Frontier are about 6500 ft.*
- *Fields/completions:*

Fields	# of Frontier Wells	Active Wells	Inactive/ Abandon Wells	Total Prod. (Bcf)
16	137	84	53	147.31

Green River Deep Partition

The Green River Deep partition, adjacent to the Moxa Arch, is bounded by a steep flank on the west and is fault-separated from the Rock Spring Uplift on the east. The northern edge includes the Sandy Bend Arch, a structurally high feature that separates the partition from the Farson Deep. The partition is bounded on its southern end by the upthrust Uinta Mountains.

- *Significant NW-SE basement faulting occur interior to the partition.*
- *The partition is overpressured. The Frontier is found at drill depths averaging about 16,000 ft. and has been penetrated by about 30 wells.*
- *Fields/completions:*

Fields	# of Frontier Wells	Active Wells	Inactive/ Abandond Wells	Total Prod. (Bcf)
Megas	1	0	1	0.15

Green River Deep Partition

Federal Energy Technology Center
U.S. Department of Energy

Advanced Resources International
Albuquerque, NM • Houston, TX • Denver, CO

Farson Deep Partition

Northwest of the Rock Springs Uplift, the Farson Deep is located in a foreland position to the upthrust Wind River Mountains and exhibits a strong gravity signature. The partition is separated from the Rock Springs Uplift on the SE by faulting.

- *Drill depth to the Frontier averages about 20,000 ft. in the partition, which is overpressured. Twelve wells have penetrated the Frontier in the partition.*
- *Fields/completions:*

Fields	# of Frontier Wells	Active Wells	Inactive/ Abandon Wells	Total Prod. (Bcf)
Swan	1	0	1	0.001
Blue Forest	1	0	1	0.03

Pinedale Partition

The Pinedale partition is the site of a foreland deep associated with upthrusting of the Wind River Mountains. It shows a pronounced gravity low, but is differentiated from the Hoback (on the NW) and Farson deeps (on the SE) by the presence of the Pinedale anticline.

- The drill depth to the Frontier averages approximately 18,000 ft. in the partition, which is overpressured. About 13 wells have been drilled into the Frontier in the partition. The partition is the site of the Jonah field, an upfaulted, overpressured Upper Cretaceous producer discovered in the early 1990s.*
- Fields/completions:*

Fields	# of Frontier Wells	Active Wells	Inactive/ Abandon Wells	Total Prod. (Bcf)
Jonah	1	0	0

Hoback Partition

The Hoback partition is an asymmetric foreland deep located between the upthrust Wind River Mountains to the east and the Wyoming thrust belt to the west. The partition axis is located adjacent to the Wind River Mountains and has a strong gravity expression.

- *The partition is overpressured and has only been moderately explored along its western side at the Frontier level. Drill depth to the Frontier in the partition averages about 20,000 ft.*
- *No significant production from the Frontier Formation exists in this partition.*

LaBarge Platform Partition

The LaBarge Platform is a foreland area relative to the Wyoming thrust belt (WTB) to the west. A left-stepping tear fault in the WTB has set the partition up as a sub-regional structural high. On its south side the partition transitions to the more shallow dip of the Moxa Arch.

- *Reservoirs of the Upper Cretaceous section in the partition are dominated by nonmarine sediments and are normally pressured. Drill depth to the Frontier is about 10,000 ft. The LaBarge Platform is intensely drilled.*
- *Fields/completions:*

Fields	# of Frontier Wells	Active Wells	Inactive/ Abandoned Wells	Total Prod. (Bcf)
42	1,296	1,136	160

Moxa Arch Partition

The Moxa Arch partition is in a foreland position to the WTB located to the west. It is the site of generally shallow, southward dipping strata, gently folded into a N-S trending arch.

- *Similar to the LaBarge Platform, the Upper Cretaceous section is nonmarine and was deposited in a fluvial-dominated environment. The crest of the Moxa Arch is normally pressured, but the flanks are overpressured. The level of exploration at the Frontier level is high.*
- *Fields/completions:*

Fields	# of Frontier Wells	Active Wells	Inactive/ Abandon Wells	Total Prod. (Bcf)
29	1,012	820	192

D. The Green River Deep Partition and Stratos Well Area

Green River Deep Partition

The Green River Deep Partition is located between the Moxa Arch and the Rock Springs uplift, as shown on the attached figure. The partition is bounded by a steep flank on the west and is fault-bounded on the east. On the northern edge of the partition is the Sandy Bend Arch, a structurally high feature that separates the partition from the Farson Deep. The partition is bounded on its southern end by the upthrust Uinta Mountains.

- *Northwest-trending basement faults occur interior to the partition.*
- *The Green River Deep partition is a locus of basin-centered gas and is largely overpressured.*
- *Exploration maturity in the partition is relatively low.*
- *The partition covers an area of 61 townships.*

The partition, in the area of the Sandy Bend Arch, is the site of the Stratos #1 well, drilled by DOE and UPR.

Green River Deep Partition

Federal Energy Technology Center
U.S. Department of Energy

Advanced Resources International
Arlington, VA • Houston, TX • Denver, CO

Green River Deep: Structural Elements

A series of data and analyses were used to define the importance of structural elements in the Green River Deep Partition:

- *Surface structural analysis, using medium resolution Landsat TM satellite imagery.*
- *Basement structural analysis, using regional gravity and aeromagnetic survey data.*
- *Integration of surface and basement features.*
- *Identification of potential areas with structural and tectonic alteration, responsible for permeability enhancement.*

Green River Deep: Structural Elements

Surface Structural Analysis. The first step was to perform a regional analysis using satellite imagery:

- *Medium-resolution (30m) Landsat TM satellite imagery was used for the regional surface analysis.*
- *Anomalous linear geomorphic features (escarpments, valleys, etc.) were mapped as indicators of structural control on topographic development.*
- *The major linear features in the area suggest the presence of underlying, regionally significant basement structures.*
 - *regionally predominant sets of ENE and NW trends*
 - *locally significant N-S alignments*

Green River Deep Partition

Top Subsea Structure of the Frontier

Federal Energy Technology Center
U.S. Department of Energy

Advanced Resources International
Arlington, VA • Houston, TX • Denver, CO

Surface Structural Features:
Detail from 1:250,000 scale map

Surface Features

(See Full Size Map on Wall)

Green River Deep: Structural Elements

Basement Structural Analysis. The second step was to assemble regional information on basement features:

- *Digital isostatic residual gravity and residual aeromagnetic survey data were used to identify regional basement structures.*
- *Basement structures are indicated by abrupt linear gradients in potential field data.*

Correspondence of gravity, aeromagnetic and surface alignments reveal important features that help define the structural and stress boundaries in the partition.

Basement Structural Features:

Gravity (red lines) and aeromagnetic (green lines) gradients overlain on merge of satellite imagery (shading) with isostatic residual gravity (color)

Basement Features

(See Full Size Map on Wall)

Green River Deep: Structural Elements

Integration of Structural Data. Integration of structural features involves comparing surface structures (alignments of geomorphic linear features on satellite imagery) and basement structures (abrupt linear gradients in potential field data) with other tectonic information for the area:

- *Significant structures are defined by close correspondence of basement and surface effects.*
- *The structural features around the Table Rock field and an inferred E-W principal compressive stress provide foundation for the structural analysis.*

Major, integrated structural features form localized perturbations in the regional stress field, and control local natural fracture formation and distribution.

Green River Deep: Structural Elements

Integration of Structural Data. In the Green River Deep partition, several major structures are evident:

- *An extensive northeast-trending right-lateral shear that bisects the partition and a few smaller, subparallel shears*
- *A series of north-trending thrusts that bound the west flank of the Rock Springs uplift*
- *A few northwest-trending left-lateral shears*

Two distinct types of structurally enhanced fracturing are delineated:

- *Zones caused by perturbations of the regional stress field around a single structure (green outline)*
- *Zones of interaction among multiple structures, where stress field perturbations are complex (red outline)*

Green River Deep: Structural Elements

Integration of Structural Data. The analysis did not identify any major structures near the Stratos well site. Minor faults and shears, seen on detailed imagery in the Stratos well area, are the source for localized pockets of natural fractures in the surrounding area.

A possible analogue to the Table Rock structural setting occurs east of the Stratos site (red outline), based on a northeast-trending right-lateral shear intersected by a north-trending thrust.

Green River Deep Partition Structural Elements

Federal Energy Technology Center
U.S. Department of Energy

Advanced Resources International
Albuquerque, NM • Houston, TX • Denver, CO

Green River Deep - Stratos Study Area Faults

Integrated Surface and Basement Features

(See Full Size Map on Wall)

Green River Deep: Depth to Frontier

Depth is an important screening criteria because it affects well costs and key reservoir properties:

- *Estimated D&C costs for a 15,000+ foot well in the GGRB are about \$4 million.*
- *Overburden pressure based core analysis showed that a net pressure of 4,000 to 6,000 psi reduced gas permeability by 10 to 20 fold.*

In the main, the Frontier in the Green River Deep partition is below 15,000 feet:

- *Depth to the Frontier reaches 17,000 feet in the center of the partition.*
- *A rapid plunge in depth, from 10,000 feet to 15,000 feet, occurs in the eastern edge of the partition.*

Green River Deep Partition

Measured Depth to the Top Frontier

Federal Energy Technology Center
U.S. Department of Energy

R105W
Advanced Resources International
Albuquerque, NM • Houston, TX • Denver, CO

Green River Deep: Deposition and Net Pay

Net pay isopachs were constructed on the fluvial sand member, marine sand member and total net sand of the Frontier. The total net sand isopach shows thickening across the Sandy Bend Arch and in the southern part of the partition where it reflects basement tectonism:

- *The net fluvial net sand is present throughout most of the partition and is thickest near the flanks in the central part. The thickening has a pronounced NE-SW orientation that reflects the structural grain of the partition.*
- *In contrast, the net marine sand is not present throughout the partition and is best developed near the Sandy Bend Arch. In the southern part of the partition, the isopach reflects basement structuring.*

Green River Deep Partition Net Fluvial Sand of the Frontier

Federal Energy Technology Center
U.S. Department of Energy

Advanced Resources International
Albuquerque, NM • Houston, TX • Denver, CO

Green River Deep Partition Net Marine Sand of the Frontier

R110W

R105W

T24N

T20N

T15N

R110W

R105W

Federal Energy Technology Center
U.S. Department of Energy

Advanced Resources International
Arlington, VA • Houston, TX • Denver, CO

Green River Deep Partition Total Net Sand of the Frontier

Federal Energy Technology Center
U.S. Department of Energy

Advanced Resources International
Angeles, CA * Houston, TX * Denver, CO

Green River Deep: Maturity of Development

The partition has forty wells which penetrate the Frontier. The table below shows the wells that have been tested or completed in that formation.

Green River Deep -- Frontier Tests								
Well	Frontier Top	Procedure		IP Gas	DST Initial Hydrostatic	Gals.		Production Test
Name	Depth (ft)	(Test)	Gal. Acid	Flow (MCF/D)	Pressure (psi)	Fluid	Lbs. Sand	Flow (MCF/D)
Richards Mtn Unit 1	7,840	DST			4021			
Exxon - Red Crk Unit 1	11,162	Prod.				66300	52000	
Government 1X-3	15,458	DST, Prod.	3000			41980	15000	
Currant Creek Fed. 1	16,830	DST, Prod.	3000		10386			531
Federal-Sandy Bend 1	15,023	DST, Prod., IP	2000	264	11083	316000	579000	100
Federal-Massacre HL 3-26	15,483	DST						
Federal 31-1	15,837	Prod., IP	4032	690 - 817		81018	71000	1797
Chmpln-Massacre Hills 11-5	15,453	DST			8674			
Sue-Federal 1	14,606	Prod., IP	8000	118		147000	169000	332
Gorge-Federal 1	15,400	Prod.	4000					
Blue Rim - Federal 1-30	15,840	IP	588	378	6000 - 7000	52000	75000	1316
Coors-Federal 10-17	12,790	Prod.	3500			62000	103500	
Palmetto-Federal 11-14	13,186	IP				47460	40100	200
Stratos Federal 1		IP	2100	18

Green River Deep: Gas in Place

Geologic Variables				Remarks
Area (acres)		1,082,880		47 Townships
Net pay (avg., feet)		18.5		
Porosity (avg., %)		7.6%		
Depth (avg., feet)		15,100		
Water saturation (avg., %)		40%		
Pressure gradient (avg., psi/ft)		0.74		
Resource Size				
Gas-in-place (Tcf)		19.0		Frontier (fluvial and marine members)

Green River Deep: Target Gas In Place

Geologic Variables									
						Remarks			
	Area (acres)			1,082,880		47	Townships		
	Net pay (avg., feet)			25		Net pay cutoff used:		20	ft.
	Porosity (avg., %)			7.7%					
	Depth (avg., feet)			15,100					
	Water saturation (avg., %)			40%					
	Pressure gradient (avg., psi/ft)			0.74					
Resource Size									
	Gas-in-place (Tcf)			10.3		Frontier (fluvial and marine members)

Green River Deep: Target Play Areas

Using the criteria of likely presence of natural fractures and net pay greater than 20 feet, the Frontier Formation in Green River Deep partition has about 150 square miles prospective area.

- *Gas recoveries per section could range from 10 to 15 Bcf.*
- *With drilling depths of 15,000 to 17,000 ft., well costs would range from \$3.6 to \$4.1 million. (laterals and surface equipment would add to these costs).*

Green River Deep Partition Target Play Areas

Federal Energy Technology Center
U.S. Department of Energy

Advanced Resources International
Albuquerque, NM • Houston, TX • Denver, CO

E. Comparative Analysis of the Stratos Federal No. 1 and Offset Wells

Outline

The Comparative Analysis of the Stratos Federal No. 1 and the offset Blue Rim wells contains:

1. *Background/Well Histories*
2. *Structural and Natural Fracture Analysis*
 - *Imagery*
 - *Core Analyses*
 - *Log Analyses*
3. *Deposition, Net Pay and Reservoir Properties*
4. *Completion Procedures*
5. *Assessment of Performance*

Background: Comparative Analysis

Well History #1. The Blue Rim Federal No. 31-1, drilled in 1978, was the first of the Frontier Formation tests in the Stratos area.

- Original objective was a potential structured-stratigraphic trap in the Ericson (Mesaverde) Sandstone.
- When the the Ericson proved disappointing, the well was deepened to test the Frontier and Muddy/Dakota Formations:
 - Gas rate (Frontier) of 100 to 110 Mcfd after perforation
 - Gas rate of 817 Mcfd after acid and KCl water breakdown
 - The sf1 marine interval in the Second Frontier had the best pressure response after perforation and took the largest amount of breakdown fluid.

Structure Map
Top 2nd Frontier Marker
Contour Interval: 50 feet

MCCUTCHEON ENERGY COMPANY

Background: Comparative Analysis

Well History #1. (Continued)

The well was hydraulically stimulated with 81,000 gal gel and 77,000# proppant and completed on December, 1978 as a dual Frontier and Mowry natural gas well:

- *Second Frontier at 15,993' to 16,039'*
- *Upper Mowry at 16,263' to 16,275'*
- *IP of 1,797 Mcfd after hydraulic stimulation*

The well was shut-in until July, 1983 when it was again tested (prior to being TA'd.):

- *The SITP at the start of the test was 12,400 psi (est. reservoir pressure 12,880 psi with a gradient of 0.80 psi/ft.)*
- *A six day flow test had rates of 1,500 to 3,733 Mcfd*
- *A perforating gun, two packers and tail pipes well lost in the hole ("fish")*

Background: Comparative Analysis

Well History #1. (Continued)

- The Blue Rim 31-1 well was placed on production in January, 1996 after being hooked to a surface pipeline:
 - The “fish” was pushed to 16,228’, covering the Mowry perforations.
 - The well began producing at 615 Mcfd and reached gas rates of 800+ Mcfd in the second month.
 - The well ultimately produced 150 MMcf before experiencing a downhole tubing failure; it was P&A’d in December, 1987.
- The well experienced production problems throughout its life, producing drilling mud and frac fluid, intermittently plugging off gas flow.

Background: Comparative Analysis

Well History #2. The Blue Rim Federal No. 1-30 well, drilled in 1982, is the offset to the Blue Rim Federal No. 31-1 Megan Field discovery well:

- The well, drilled to fulfill a contractual obligation, reached a TD of 16,969' in the Dakota Formation:
 - *The well was perforated from 16,068' to 16,130' in the Frontier and from 16,348' to 16,356' in the upper Mowry.*
 - *Three cores were cut in the Frontier, from 16,053' to 16,707'.*
 - *The well required extremely high mud weights, up to 14.4 ppg.*
- After perforating the Frontier and Mowry, the well blew out and the extreme pressure collapsed the liner and tubing. After containment:
 - *The surface shut-in pressure was 6,000 to 7,000 psi.*
 - *In a nine hour test, the well flowed at 1,316 Mcfd plus 72 B/D of load water.*

Background: Comparative Analysis

Well History #2. (Continued):

- Uncertainty exists as to the completion, stimulation and further testing of the well:
 - *State records indicate a hydraulic fracture treatment of 2,524 bbls of gel and 150,000 pounds of proppant.*
 - *The onsite completion supervisor and engineer stated that, although a frac was planned, the damage to the well was too severe and prevented further completion or stimulation.*
- After three months of fishing and attempted repairs, the well was shut-in in December, 1982 and P&A'd in November, 1989.

Detailed Imagery Analysis

High-resolution (5m) IRS-1C satellite imagery was digitally merged with Landsat TM imagery for detailed photogeologic analysis of the Stratos area (1:24K)

- *Possible near-surface faults were identified, with sense of motion inferred from direct analogy with Table Rock and from local topographic features (escarpments, drainage patterns).*
- *All faults appear to have small offset, and may not extend far into subsurface; field observations combined with high-resolution aeromagnetic and 3-D seismic data are required to reliably define the fault geometries at Frontier level.*
- *Stratos site is crossed by two NW-trending left-lateral shear or wrench faults, offset by a NE-trending right-lateral fault.*
- *Stratos well site is in compressional quadrant of northern left-lateral fault; Blue Rim 31-1 is in tensional quadrant of southern fault, and Blue Rim 1-30 is near complex intersection of three faults.*

Detailed Surface Analysis:
Surface fault pattern overlain on merged Landsat/IRS
imagery

Green River Deep - Stratos Study Area Faults

Inference of Natural Fractures

The presence and importance of natural fractures in the Frontier formation in the Stratos well area is based on the following observations:

- BEG identified a series of natural fractures in the Blue Rim Federal 1-30 well, as shown on the attached figures.
 - *The fractures are extensional and calcite filled*
 - *The fractures occur in one interlaminated sandstone and mudstone interval at 16,120 to 16,130 feet*
 - *The fractures have heights of 6 inches, widths of up to 0.25 mm, and spacing of 0.4 to 1.2 inches.*
- The core analysis for the Blue Rim Federal 1-30 well (by Terra Tek) indicates improved permeability at 16,101'-16,102' (0.10 md) 16,122'-16,123' (0.31 md), although Terra Tek attributes this to horizontal dehydration cracks.

Second Frontier Log from Offset Well with Test Well Schematic

Fractures in Core from Five Frontier Fluvial Wells in the Green River Basin (Laubach, 1991)

□ Small fault or shale fracture
■ Extension fracture in sandstone

QA15574c

Closely Spaced Vertical Fractures in Frontier Formation Core, Blue Rim Federal No. 1-30 Well Core Depth 16,123 ft (4,914 m)

Stratos Area: Core Observations

Core taken from Blue Rim
Federal 1-30 well.

Abundant horizontal
parting, little vertical
fracturing apparent.

Inference of Natural Fractures

Overall, the Stratos core shows poor natural fracture development. The routine, unstressed core analysis on the Stratos well (by Terra Tek) identified a series of partly open natural fractures, as follows:

- 16,004-16,019': *Small (1 to 2") vertical fractures within thin sandy beds*
- 16,041': *Subvertical fractures filled with black material*
- 16,065': *Open with calcite, other fractures with block fill*

However, when the core and log depths are made consistent, the small vertical fractures at 16,004 to 16,019' are in an interval above the upper pay zone. Terra Tek notes that the direction of maximum stress (N65E) agrees with several fractures in core.

Rose Diagram Showing the Strike Measured Microfractures from 16,027 Feet

(Note that the area of thin section studied is less than 1% of total thin section)

ST16027C-- all fracs, both areas	7/10	Statistics
N = 255		Vector Mean = 277.0
Class Interval = 10 degrees		Conf. Angle = 12.65
Maximum Percentage = 16.5		R Magnitude = 0.376
Mean Percentage = 5.56	Standard Deviation = 4.07	Rayleigh = 0.0000

Stratos Log Analysis

Schlumberger applied a very detailed logging package to the Stratos No. 1 well, including a standard logging suite and a series of new, “high tech” logs.

- *The standard set of wireline logs included Resistivity (shallow and deep Laterlog), Litho-Density, Neutron, Gamma Ray and Caliper.*
- *“High tech” logs included Formation Micro Imager (FMI), Azimuthal Resistivity Imager (ARI), Diapole Sonic Imager (DSI), and several others.*

Based on the interpretation of these logs, Schlumberger concluded the following:

- *The APS (Accelerator Porosity Sounder for porosity at depth of invasion) “points towards poor filtrate invasion and less than optimum conditions for permeability”.*
- *The FMI, “confirms the ARI interpretation of no fractures, low dips, and many thin beds.”*
- *From the ARI “we can infer the lack of natural fractures”.*

Stratos Log Analysis

- *The CMR (Combinable Magnetic Resonance) indicates the “producible water, which while not zero, is only about 2% of the rock’s total volume,” “very tight gas sands,” and “an in situ permeability of 0.073 md-ft.”*
- *From the DSI, Schlumberger observes “The maximum horizontal stress is greater than the overburden stress,” and “high minimum horizontal stress ... or a lack of a strong principle stress direction.” The DSI also showed “lack of anisotropy” that “may explain the paucity of natural fractures.”*

Schlumberger concluded that “the environment (around the Stratos No. 1 well) is not conducive to natural fractures” and that the lack of fractures has “been verified by the ARI, FMI, and DSI” tools.

Log Inventory

STRATOS FEDERAL UNIT #1			
12-1/4" Hole with 11.7 lb/gal Water based Mud			
OPEN HOLE LOGS	RUN 1 10/13/95	DSI (Dipole Shear Sonic Imager)	16231-15700'
		DSI (Dipole Shear Sonic Imager)	11281-7900'
		LLD (Laterolog Deep)	16141-5020'
		LLS (Laterolog Shallow)	16141-5020'
		SP (Spontaneous Potential)	16141-5020'
		GR (Gamma Ray)	16141-5020'
		Caliper	16141-5020'
		ARI (Azimuthal Resistivity Imager)	16141-5020'
	RUN 2 10/14/95	LDS (Litho-Density Sonde)	16141-5015'
		APS (Accelerated Porosity Sonde)	16141-5015'
		HNGS (Natural Gamma Ray Spectroscopy)	16141-5015'
	RUN 3 10/14-15/95	CMR (Combination Magnetic Resisitivity Tool)	16141-5020'
		CMR (Combination Magnetic Resisitivity Tool)	11150-7950'
		CNL (Compensated Neutron Log)	16141-5015'
		GR (Gamma Ray)	16141-5015'
	RUN 4 10/17/95	FMI (Formation MicroScanner Imager)	16150-15500'
FMI (Formation MicroScanner Imager)		11100-7950'	
GR (Gamma Ray)		16150-15500'	
GR (Gamma Ray)		11100-7950'	
CASED HOLE LOGS	CBL (Cement Bond Log)		16189-12000'
	Velocity Shots (every 50')		16150-500'
OTHER LOGS	MWD (Measurement While Drilling) Caliper		13870-16250'
	MWD (Measurement While Drilling) GR		13870-16250'
	Mud Log		7000-16250'

Deposition and Net Pay

In general, the deposition and sand development of the Second Frontier Formation in the four townships surrounding the Stratos well are favorable and representative of the Green River Deep Partition:

- *The net sand in the Stratos well, for the combined fluvial and marine intervals, is 30 feet (using 6% porosity and 50 Gamma Ray cutoffs).*
 - *The fluvial sand, at 3 feet, is less developed, compared to 5 to 10 feet in the area.*
 - *The marine sand, at 27 feet, is representative of the NE/SW trend of marine deposition in the area.*
- *The Stratos well porosity, at 7.6%, is slightly lower than the 8% porosity for the area.*
- *The Stratos well reservoir pressure, at 12,000+ psi, is highly overpressured, as is the Frontier in the offset wells.*

Deposition and Net Pay

Methodology. Selected well log traces from the Stratos No. 1, Blue Rim No. 1-30, Blue Rim No. 31-1, and Mountaineer No. 1-35 wells were digitized for construction of the cross-section.

The cross-section utilizes the gamma ray and Neutron-Density porosity log curves recorded in each well. Detailed log correlations of the 2nd Frontier and upper Mowry were coupled with core descriptions in the Stratos No. 1 and Blue Rim No. 1-30 to constrain correlation markers. Drill cutting descriptions from the Blue Rim No. 1-30 were also useful.

Stratigraphic Correlation and Reservoir Description

The UPRC Stratos No. 1 well is located near the axis of the Green River Basin, where it crosses the east plunge of the Sandy Bend anticline. Offsetting the Stratos No. 1 well (0.7 miles and 1.6 miles to the southeast) are the Blue Rim No. 1-30 and the Blue Rim No. 31-1 wells respectively.

Located 9.5 miles further to the southeast is the Mountaineer No. 1-35 well.

Stratigraphic Cross Section for the Stratos #1-24 and the Two Blue Rim Wells

Cross-Section

**(See Large Scale
Cross Section on Wall)**

Deposition and Net Pay

Frontier Formation. The Frontier Formation is approximately 310 feet thick in the Stratos well area. The 2nd Frontier interval straddles the mid-Turonian unconformity. The top of the 2nd Frontier interval was selected on a resistivity marker that occurs at a depth of 15,900 feet in the Blue Rim No. 31-1 well.

The Upper 2nd Frontier member typically contains fluvial to estuarine sandstone reservoirs at its base. Below the mid-Turonian unconformity, the 2nd Frontier member is dominated by marine shoreface sandstone reservoirs. Regionally these sandstone reservoirs are truncated resulting in large differences in thickness across the basin.

Schematic Vertical Profile of the Second Frontier Formation, Green River Basin, Wyoming

Deposition and Net Pay

Frontier Formation. Three reservoir intervals are correlated in the 2nd Frontier, as noted on cross-section A-A'. The uppermost pay, is a very thin fluvial sandstone that ranges from 3 to 12 feet of net sandstone with (GR <50 porosity >6%), a mean porosity of 8%.

The 2nd Frontier contains two additional reservoir zones. The sf2 reservoir is the upper zone and has a variable thickness. The sf2 reservoir is absent in the Mountaineer No. 1-35 well and is thin in the Stratos Federal No. 1 and Federal No. 31-1 wells.

The sf1 reservoir (of the 2nd Frontier) is separated from the sf2 reservoir by a two to four foot thick shale bed that can be correlated in all four wells. The sf1 reservoir has the best lateral continuity and sand development.

Deposition and Net Pay

Mowry Shale. The Mowry Shale is 400 feet thick in the Stratos well area. The top is picked at the base of a prominent shale marker, at 16,212 feet in the Federal No. 31-1 well. About 50 feet below the top of the Mowry shale is a widespread, 12 to 20 foot thick, fine to medium grained glauconitic sandstone, the upper Mowry.

The upper Mowry sandstone is easily correlated and contains 10 to 13 feet of net sandstone (>6% porosity). The sandstone averages 9.35% porosity and accounts for between 20% and 25% of the calculated reservoir pore volume in the 2nd Frontier and Mowry interval.

The upper Mowry sandstone was completed in both the Federal No. 31-1 and the Blue Rim Federal No. 1-30 wells. The upper Mowry sandstone is not penetrated in the Stratos Federal No. 1 and in the Mountaineer No. 1-35 wells.

Findings and Conclusions

Three reservoir zones are differentiated in the 2nd Frontier interval; (1) the fluvial reservoir, (2) the sf2 reservoir, and (3) the sf1 reservoir. The reservoir properties of each zone are summarized below:

Well	Gross Sand	Net Sand ≤GR50	Net Sand <6%	φ (h)	Mean φ	Mcf/gpd Post-Brkdn
Stratos Federal No. 1	47.0	33.0	30.0	2.780	.076	18-20
Federal No. 31-1	42.0	33.0	31.0	2.710	.080	690-817
Blue Rim Federal No. 1-30	59.0	57.0	56.0	4.811	.082	378-1316?

Local Isopach Map of Net Feet of Pay in the Second Frontier Fluvial Interval at the Stratos Location (Shown as Star) Contour Interval = 5 ft.

Local Isopach Map of Net Feet of Pay in the Second Frontier Marine Interval at the Stratos Location (Shown as Star) Contour Interval = 10 ft.

Reservoir Properties Stratos Area

Western Greater Green River Basin

Well/Producing Zone	Log Analysis					Core Analysis			Mean Rwa	Comments
	Gross sand	Net sand < GR 50 API	Net sand >6% phi	phi(h)	mean phi	phi(h)	mean phi	k(h)		
Stratos Federal No.1										
2nd Kf fluvial	6.0	3.0	3.0	0.150	0.070	0.267	0.067	0.610	0.250	not penetrated
2nd Kf maine: sf2	12.0	10.0	9.0	0.749	0.068	0.740	0.068	0.163	0.120	
2nd Kf marine: sf1	29.0	20.0	18.0	1.881	0.090	1.648	0.078	0.754	0.180	
Upper Mowry sand										
Total	47.0	33.0	30.0	2.780	0.076	2.655	0.071	1.527	0.180	
Mountaineer No.1-35										
2nd Kf fluvial	12.0	10.5	12.0	0.890	0.087	no core	no core	no core	0.130	absent not penetrated
2nd Kf maine: sf2	0.0	0.0	0.0	0.000						
2nd Kf marine: sf1	38.0	35.5	30.0	2.560	0.095	no core	no core	no core	0.120	
Upper Mowry sand										
Total	50.0	46.0	42.0	3.450	0.091				0.125	
Bluewater Federal No.1-30										
2nd Kf fluvial	8.0	9.0	9.0	0.858	0.085	0.644	0.064	0.488	0.470	
2nd Kf maine: sf2	31.0	31.0	30.0	2.410	0.075	1.790	0.056	0.670	0.570	
2nd Kf marine: sf1	20.0	17.0	17.0	1.543	0.085	insuf. Data	insuf. Data	insuf. Data	0.180	
Upper Mowry sand	18.0	2.0	13.0	1.203	0.093	no core	no core	no core		
Total	77.0	59.0	69.0	6.014	0.085				0.407	
Federal No.31-1										
2nd Kf fluvial	13.0	7.0	8.0	0.780	0.097	no core	no core	no core	0.290	
2nd Kf maine: sf2	8.0	6.0	4.0	0.310	0.061	no core	no core	no core	0.210	
2nd Kf marine: sf1	21.0	20.0	19.0	1.620	0.083	no core	no core	no core	0.150	
Upper Mowry sand	13.0	0.0	10.0	0.949	0.094	no core	no core	no core		
Total	55.0	33.0	41.0	3.659	0.083				0.217

Stratos Well Completion and Testing

The initial plan was to drill a vertical well, test the Frontier, and then drill two long horizontal laterals, based on expectations of 3 to 5+ Bcf of gas recovery.

- *The reservoir permeability and natural fracture development in the Stratos well appeared to be low.*
- *Well tests in the Stratos showed a permeability of about 1 μ d and flows to surface were only about 20 Mcfd, much less than for the Blue Rim wells.*
- *Performance analysis by Schlumberger indicated a maximum flow rate of 45 Mcfd after stimulation.*

Based on this, activities in the Stratos well were placed on hold.

Model Production Performance and Cumulative Recoveries for the Marine Bench, Second Frontier Formation at the Proposed Site

Wellbore Diagram

WELL NAME: UPR STRATOS FEDERAL UNIT No. 1

SL: SE/4 SEC. 24, T. 22 N., R. 107 W., 6TH PM

B-HL: 1412' FSL, 1273' FEL SEC. 24, T. 22 N., R. 107 W., 6TH PM
SWEETWATER COUNTY, WYOMING

Union Pacific Resources

A Subsidiary of Union Pacific Corporation

UPRC - STRATOS FEDERAL UNIT #1 HORIZONTAL LATERALS #1 & #2

1,320' FSL & 1,320' FEL

SWEETWATER, CO. WYOMING

17,990' MD / 15,770' TVD

SECTION 24, T22N, R107W

GREEN RIVER BASIN DEEP

FRONTIER SAND

FORMATION TOPS

Stratos Stress and Well Testing

CER and Branagan and Assoc. (with BJ Services) conducted the cased hole stress tests in November, 1995 and the breakdown treatment (with Halliburton) in January, 1995.

Problems were encountered with the cased hole stress tests, only the bounding shale intervals were tested, and the recording of the pressure data after the breakdown treatment stopped before fracture closure occurred. The measured closure stresses (ISIP's) were high, estimated at 0.9 to 1.0 psi/ft.

A pre-frac well test, involving an eight day flow period followed by a two week pressure buildup was conducted after the well was broken down with KCl water. Integrated Petroleum Technologies (IPT) interpreted the well test.

Stratos Stress and Well Testing

The test showed low permeability, of 0.036 md-ft, equal to a permeability of 0.001 md with a net pay of 30 feet.

Problems occurred with the well test that may have contributed to low measured value:

- *early time leaks occurred in the downhole shut off valves,*
- *a 4,000 ft water column was on the formation resulting in reduced actual as well as relative permeability,*
- *a limited radius of investigation, on the order of 10 feet.*

UPRC STRATOS #1

Log-Log Plot of the Delta Pseudo-Pressure vs Delta Time of the Build-up Data

UPRC STRATOS #1

Completion Procedures and Production Results

Well	Total Zone phi(h)	Casing Perforation		Perforation Breakdown				Hydraulic Fracture Stimulation			
		Flowrate Mcfgpd	STIP psi	Treatment Type	Amount	Flowrate Mcfgpd	SITP psi	Fluid	Sand	Flowrate Mcfgpd	SITP psi
Federal No. 31-1 <i>note 1</i>	3.659	100-120	no report at least 1,800	10% Acetic 7.5% HCl 2% KCl wtr	92 bbls 96 bbls 88 bbls	690-817	10, 050	1929 bbls gel	71,000 lb sand	1797	12,400
Federal No. 1-30 <i>note 1</i> <i>note 2</i>	6.014	1316 ?	6000 to 7000	7.5% HCl 2% KCl wtr	119 bbls 119 bbls	378 ?		2514 bbls gel ?	150,000 lb sand ?	1316 ?	
Stratos Federal No.1	2.78	no flow to surface	190 to 450	3% KCl wtr	50 bbls	18-20	6,000				
Mountaineer No.1-35	3.45			no production tests of the Frontier Formation							

Note: The upper Mowry sandstone was perforated and treated in both the Federal No.31-1 and Federal No. 1-30 wells.

Note: Completion information on the Federal No. 1-30 well is questionable. Source in supervisory role at location during entire completion operation reports catastrophic failure of 3.5 inch liner and tubing occurred immediately after perforating. Extremely high pressures were encountered and it was not possible to get back to bottom for further treatment of Frontier interval. Shortly thereafter cement was placed in the well bore to secure and temporarily abandoned the hole. Source further reports shut-in pressures after perforation of between 6000 and 7000 psi.

Benchmark Estimates Inside Performance Line is a Natural Completion and the Outside IPR Line is After a Moderate Frac

Assessment of Performance

It may be improper to have the structurally unfavorable location of the Stratos well and the post completion practices on the Blue Rim wells condemn the Frontier gas play in the Green River Deep partition.

As an alternative view, the structurally more favorably located Blue Rim 31-1 well is used as a benchmark for performance. Matching of gas production in this well shows:

- *Permeability of 11 μ d and a small, possibly damaged stimulation.*
- *Vertical well recoveries of 1.9 to 2.8 Bcf per well, depending on actual, undamaged reservoir permeability,*

Use of horizontal laterals of 1,000 to 2,000 feet would provide 4 to 8 Bcf per well, depending on actual reservoir permeability.

Production History: Federal 31-1

NW, Sec. 31, T22N, R69W

Completed: December, 1978

Cumulative Production:

0 Bbls Oil

152.816 Mcftg

0 Bbls Water

Federal 31-1 Megas Field, Frontier Completion

FRONTIER 31-1

($Y_e/X_e=1$)

Estimated Gas Recovery: 30 Years

(Blue Rim 31-1 Reservoir Assessment)

Permeability (μ d)	Vertical Well ¹ (Small Frac) (Bcf)	Vertical Well Horizontal Laterals (Bcf)	
		1,000 ft. ²	2,000 ft. ³
10	1.9	4.1	-
20	-	5.6	-
25	2.8	-	8.3

¹ Uses 160 acre spacing per well

² Uses 320 acre spacing per well

³ Uses 640 acre spacing per well

Horizontal Well Projection
K=10 micro-d, Lw=1000

Horizontal Well Projection
K=20 micro-d, Lw =1000

Horizontal Well Projection
K=25 micro-d, Lw=2000

Appendix 2

Matching E&P Technology to Low Permeability, Naturally Fractured Gas Resources

*“Developing and demonstrating high value
E&P technology for unlocking natural
gas resources in low permeability basins.”*

A Presentation to DOE/FETC

by
Advanced Resources International, Inc.

December, 1998

Background

The fundamental R&D supported by DOE/FETC and conducted by Advanced Resources International and Western Geophysical has developed a most valuable set of technologies for delineating naturally fractured areas in low permeability natural gas plays.

However, the demonstration of this technology has been limited to very small field areas and to only Rocky Mountain Basins, namely the Piceance and Green River Basins. Moreover, the field demonstrations have been for development projects in existing fields (Rulison and Mamm Creek, Piceance Basin and Table Rock, Green River Basin.)

Tight Gas Resources of the Piceance Basin

The tight, lenticular Mesaverde Sands of the Piceance Basin had long been viewed as a large, but uneconomic gas resource:

- *The USGS ('95)/NPC ('92) pegged the resource as a \$4+/Mcf gas play, because of historically low per well reserves and high dry holes,*
- *For thirty years, industry drilled through this gas formation looking for deeper, more productive targets.*

Application of a series of advanced E&P technologies -- improved well log interpretation, modified well stimulation practices, and natural fracture detection technology -- have rejuvenated this gas play.

Benefits Of Natural Fracture Detection Technology

The tight, lenticular sands of the S. Piceance Basin/Rulison Test Area offer potential for a 1 Tcf gas play.

Locating wells using Natural Fracture Detection Technology could provide a \$200 million cost savings for this gas play:

	<u>With Current Practice</u>	<u>With Natural Fracture Detection Technology</u>
• Target Reserves	1,000 Bcf	1,000 Bcf
• Average EUR/Well	1.78 Bcf*	3.2 Bcf**
• No. of Wells	562	312
• Capital Costs (@\$800,000/well)	\$450 million	\$250 million
• Cost Savings		\$200 million

* Average EUR for 24 wells statistically drilled in area

**Average EUR for 7 wells located and drilled in "sweet spots"

Issues Raised by Industry

Industry has expressed some skepticism as to the value and applicability of this technology for three reasons:

- There have been no field demonstrations of the performance of this technology in a true exploration setting, in a predictive mode before drilling. (Anyone can show good results if they already know the answer!)
- The past field demonstrations have been limited to small areas and special geological setting, resulting in a statistically small set of performance data. (Have we just been lucky?)
- There have been no demonstrations outside the Rocky Mountains basins or geologic settings. (If you don't do it in Texas, it doesn't count!).

Suggested Remedies

To build industry confidence in using this most valuable DOE/FETC natural gas supply technology, ARI (with participation of Western Geophysical and selected producers) proposed that DOE/FETC support two significant field demonstrations of three dimensional reservoir characterization and natural fracture detection technology.

- 1. A true exploration focused application of this technology in the Hoback/Pinedale area of the Green River Basin.*
- 2. A demonstration of this technology in a vastly different geologic setting, the Austin Chalk of East Texas and Louisiana.*

In addition, a strong R&D and technology progress effort in the supporting areas of seismic processing and stress modeling would accompany the field demonstration.

Three Dimensional Reservoir Characterization

- ⇒ *Compile geologic and reservoir data*
- ⇒ *Establishing key factors controlling gas production*
- ⇒ *Integrate seismic with reservoir characterization*
- ⇒ *Map structurally enhanced “sweet spots” in low permeability gas plays*
- ⇒ *Review well stimulation alternatives*
- ⇒ *Drill, complete, monitor results*

Technology Progress In Natural Fracture Detection

- ⇒ **Advanced seismic processing and interpretation for delineating subtle, complex faults and structures.**
- ⇒ **Interval velocity analysis for directly detecting zones of gas filled natural fractures.**
- ⇒ **Demonstration of quantitative stress model in alternative structural and geologic settings.**

1. Exploration Focused Field Demonstration

The Hoback/Pinedale area offers an excellent area for testing natural fracture detection technology in a “pure” exploration mode.

- **The Basin Partitioning work, currently underway, will provide the essential regional overview and resource assessment:**
 - *Satellite imagery*
 - *Aeromagnetics/gravity*
 - *Basement fault map*
 - *Resource in place*
 - *Play analogs*
- **Industry’s interest in the area is high, based on success at Jonah Field.**

NORTHWESTERN PARTITIONS OF THE GREATER GREEN RIVER BASIN

Federal Energy Technology Center
U.S. Department of Energy

Advanced Resources International
Arlington, VA • Houston, TX • Denver, CO

1. Exploration Focused Field Demonstration

The Hoback partition is an asymmetric foreland deep located between the upthrust Wind River Mountains to the east and the Wyoming thrust belt to the west. The partition axis is located adjacent to the Wind River Mountains and has a strong gravity expression. The partition is overpressured and is explored only along its western edge. Drill depth to the Frontier in the partition averages about 20,000 ft.

The Pinedale partition is the site of a foreland deep associated with upthrusting of the Wind River Mountains. It shows a pronounced gravity low. The drill depth to the Frontier averages 18,000 ft. The partition, is overpressured and only 13 wells have been drilled into the Frontier. It is the site of the Jonah field, an upfaulted, overpressured Lance producer.

The Farson Deep partition is located in a foreland position to the upthrust Wind River Mountains and exhibits a strong gravity signature. Drill depth to the Frontier averages 20,000 ft. in the partition, which is overpressured and only has twelve wells that have penetrated the Frontier.

SW-NE Structural Cross-section Northern Green River Basin, Wyoming

Reservoir Characterization

- ⇒ **Well Test Data:**
 - ➔ *Pressure, porosity, permeability*
- ⇒ **Core Analysis:**
 - ➔ *Porosity, permeability, CEC, clay mineralogy, saturations, fracture density, orientations*
- ⇒ **Well Log Analysis:**
 - ➔ *Shaly log analysis program*
 - ➔ *Pay Identification*
 - ➔ *Gas-in-place calculations*
- ⇒ **Review of Drilling and Completion Practices**
- ⇒ **Production Trend Analysis/Resource Estimates**

3-D P-Wave Structural Analysis

- ⇒ **Time/Structure Mapping**
 - ➔ *Fault geometry mapping*
 - ➔ *Identify fault tip fracture clusters*
 - ➔ *Stress model*
- ⇒ **Azimuthal velocity analysis**
 - ➔ *Gas saturation*
 - ➔ *Fracture orientation and location*
- ⇒ **Azimuthal Coherency Mapping**
 - ➔ *Lateral reservoir continuity*
 - ➔ *Resolve small displacement fault systems*

High Resolution Aeromagnetic Survey

- ⇒ Relate basement fault geometry to low amplitude and high frequency anomalies within 3D seismic survey, extrapolate outside survey.
- ⇒ Geostatistical analysis of magnetic linears with production trend.
- ⇒ Extrapolate magnetic linears outside of 3D seismic patch.

Index Map: Recent Drilling Activity and Producing Fields

Current Activity -- Johan Field

- 1. Synder Oil -- Lance Discovery (4-30 Cabrito Federal Unit)**
- 2. Ultra Petroleum -- Fort Union and Upper Mesaverde Tests**
- 3. True Oil -- Mesaverde Tests in Ericson and Rock Springs**
- 4. Plains Petroleum -- Mesaverde Tests in Rock Springs**
- 5. McMurry Oil -- Two Upper Mesaverde Tests**
- 6. Others (Chevron, MCN)**

Jonah Field, Sublette Co., Wyoming

Reservoir Information

- ⇨ Lance Formation
- ⇨ Productive interval - 8,200'-11,800'
- ⇨ Pay porosity - 8-12%
- ⇨ Lab permeability - .01-.9 millidarcys
- ⇨ Insitu permeability - 3-20 microdarcys
- ⇨ Net pay thickness - 100-400 feet
- ⇨ Gas in place - 150 Bcf/section
- ⇨ Reserves - 0.4-4.0 Bcf/well

Porosity vs. Permeability - Jonah 2-5 Core

* Core 1 x Core 2 ▶ Core 3

Rationale for Selecting Hoback Basin

- ⇒ **Large potential gas source. Good analog for major gas plays in GGRB.**
- ⇒ **Heterogenous, complex, tight gas reservoirs. Efficient exploitation can be achieved through prediction of “sweet spots” using integrated, 3D reservoir characterization.**
- ⇒ **Shallower formations applicable to demonstration and development of near term research goals. Deeper formations and resources are setting for longer term research and development.**
- ⇒ **Industry participation will ensure active field development and significant cost sharing.**

2. New Geologic Setting Field Demonstration

Naturally fractured reservoirs exist throughout the U.S. and are becoming an increasing target for industrial development. These include:

- ***Austin Chalk (Texas, Louisiana)***
- ***Canyon Sands (W. Texas)***
- ***Cotton Valley/Travis Peak (E. Texas)***
- ***Cherokee/Red Fork (Oklahoma)***
- ***Abo/MV/Dakota (New Mexico)***
- ***Clinton/Devonian Sands (Appalachian Basin)***

Each of these settings have their particular geologic traits, structural features and interpretation challenges.

Austin Chalk Gas Play

Advances in horizontal and multi-lateral drilling have converted the Austin Chalk into a major natural gas play:

- The Giddings field, with over 1 Bcfd of production, is now the 4th largest U.S. gas field.*
- UPR, one of the most active Austin Chalk developers has invested \$2 billion in over 1,500 wells and associated facilities.*
- The Austin Chalk play is progressively moving into Louisiana, notably around the Masters Creek Field, where UPR has completed a major gas processing plant.*

Austin Chalk Gas Play

UPR states: "We have reduced horizontal drilling costs in the Shallow Giddings area where we are drilling as many as six horizontal laterals in three separate formations. The lower development costs allows us to economically develop more reserves."

Austin Chalk Producing Properties Volume (MMcfd)

The Austin Chalk trend, which reaches from South Texas into Louisiana, is a new area of significant onshore natural gas development.

Austin Chalk Gas Play

The Austin Chalk and Giddings Field is a challenging natural gas resource, looking for improved natural fracture detection technology:

- *At present the field has 31 active drill rigs. The deep wells range in depth from 13,000 to 16,000 ft. with an average well cost of \$5 million and 50% chance of economic success. The average well life is 15 years with an average EUR of 8.1 Bcf.*
- *Challenges of developing natural gas from the Austin Chalk include the unpredictability of encountering permeability, high temperatures and pressures, and equipment failures at these extreme conditions. The Austin Chalk appears to be highly compartmentalized with a complex network of small fractures that control the permeability in this formation.*
- *UPR has publically stated that no methods have yet proven successful in predicting the location of natural fractures in new or step-out areas of this play.*

Rationale for Selecting Austin Chalk

- ⇒ **One of the most active domestic gas plays; extends from Texas to Louisiana.**
- ⇒ **Dry hole rates and costs are becoming economically prohibitive as play moves deeper.**
- ⇒ **Currently available natural fracture detection technologies have not proven successful.**
- ⇒ **UPR and other Austin Chalk Developers (Sonat, Oxy, Chesapeake and numerous other independents) are active in the play.**

Project Deliverables

- ⇒ Identify resource areas based on technical feasibility
 - ⇒ *exploration lead areas (Hoback Basin)*
 - ⇒ *step-out well sites (Austin Chalk)*
- ⇒ Correlate “sweet spots” development with seismically defined structural features and natural fractures.
- ⇒ Demonstrate advanced seismic processing and interpretation of subtle, complex faults and fractures.
- ⇒ Demonstrate value of advanced technology for tight gas development.

Project Schedule

Tasks	1999		2000				2001	
	3	4	1	2	3	4	1	2
I. Technology Progress
II. Exploration Field Demonstration (Hoback Basin)
III. New Geologic Setting Field Demonstration (Austin Chalk)
IV. Technology Transfer

Proposed Budget (\$000)

Tasks	Labor (ARI & Subs)	Second Party	Total Cost to DOE	Cost Share*	Total Costs
1. Technology Progress in Natural Fracture Detection	240	60	300	-	300
2. Hoback Basin Field Demonstration	425	375	800	700	1,400
3. Austin Chalk Field Demonstration	425	375	80	700	1,400
4. Technology Transfer	160	40	200	-	200
	1,150	850	2,100	1,400	3,500

**Without including cost share for demonstration wells or waiver of fee.*