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**Reserve Estimates in Western Basins
Part II: Piceance Basin**

Topical Report

October 1995

Work Performed Under Contract No.: DE-AC21-91MC28130

For
U.S. Department of Energy
Office of Fossil Energy
Morgantown Energy Technology Center
Morgantown, West Virginia

By
The Scotia Group
Dallas, Texas

MASTER

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October 1995

ABSTRACT

This study characterizes an extremely large gas resource located in low permeability, sandstone reservoirs of the Mesaverde group in the Piceance Basin, Colorado. Total in place resource is estimated at 307.3 Tcf. Via application of geologic, engineering and economic criteria, the portion of this resource potentially recoverable as reserves is estimated. Those volumes estimated include probable, possible and potential categories and total 5.8 Tcf as a mean estimate of recoverable gas for all plays considered in the basin.

Four plays (three formations) were included in this study and each was separately analyzed in terms of its tight gas resource, established productive characteristics and future reserves potential based on a constant \$2/Mcf wellhead gas price scenario. A scheme has been developed to break the overall resource estimate down into components that can be considered as differing technical and economic challenges that must be overcome in order to exploit such resources: in other words, to convert those resources to economically recoverable reserves.

About 82.6% of the total evaluated resource is contained within sandstones that have extremely poor reservoir properties with permeabilities considered too low for commerciality using current frac technology. Cost reductions and technology improvements will be required to unlock portions of this enormous resource.

Approximately 2.7% of the total resource is contained within sandstone reservoirs which do not respond to massive hydraulic fracture treatments, probably due to their natural lenticular nature. Such depositional systems include all sands in the Paludal Play. A detailed study of these systems and improvements or innovations in well completion and stimulation are required to exploit this resource.

Approximately 6.8% of the total resource is located in deeply buried settings below deepest established production. This resource is poorly defined due to sparse well control and the need for extrapolation of volumetric parameters from areas of better control. Additional deep drilling is required to characterize and better quantify this resource. This will require considerable price incentive, given the costs and risks involved.

Approximately 7.9% of the total resource is considered to represent tight reservoirs that may be commercially exploited using today's hydraulic fracturing technology. From the viewpoint of current economics, drilling and completion cost, and risk, about 3.1% of the total resource has favorable risked expectations with the other 4.8% having unfavorable risked expectations. Reserves estimates consider both categories.

Total recoverable reserves estimates of 5.6 Tcf do not include the existing production from Mesaverde reservoirs in the basin. These have estimated ultimate recovery of approximately 300 Bcf, or a per well average recovery of 581 MMcf. Due to the fact that considerable pay thicknesses can be present, wells can be economic despite limited drainage areas. It is typical for significant bypassed gas to be present at inter-well locations because drainage areas are commonly less than regulatory well spacing requirements.

Recent technology advances in hydraulic fracturing practices in the Piceance Basin Mesaverde has resulted in a marked improvement in per well gas recovery which, where demonstrated, has been incorporated into the estimates provided in this report. This improvement is so significant in changing the risk-reward relationship that has historically characterized this play, that previously uneconomic areas and resources will graduate to the economically exploitable category.

ACKNOWLEDGEMENTS

Companies and individuals too numerous to list assisted in supplying data for use in this study and are acknowledged for their voluntary support. We would like to particularly acknowledge the assistance of Barrett Resources and Dowell Schlumberger for their cooperation. In addition, we would like to thank Petroleum Information Corporation for consenting to the use of digital well identification data from their WHCS database in the digital database that accompanies this report.

In addition, Barrett Resources and Dowell Schlumberger are specifically acknowledged for sharing their time, expertise and databases on fracturing treatments and results in the Piceance Basin. This data and its interpretation was so significant that it has been the subject of a separate topical report.

The Scotia project team consisted of Rob Caldwell (project manager), Mark Cocker (geology, petrophysics), Simon Bidwell (engineering and petrophysics), Bill Cotton (computing, databases), Ian Howrie, Jim Merkel, Dave Heather, Pat Wagner, and Wayne Beninger (reservoir engineering), Wendy Edmondson and Laurie Pasch (support), Mary Ann Moss (administration), and Jonathan Boarman. Tom Carroll and Ken Ibsen provided consulting engineering and data support services. Al Jaffe acted as consulting business coordinator. These individuals are acknowledged for their diligent efforts.

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INTRODUCTION

Vast quantities of natural gas are entrapped within various tight formations in the Rocky Mountain area. This report seeks to quantify what proportion of that resource can be considered recoverable under today's technological and economic conditions and discusses factors controlling recovery. The ultimate goal of this project is to encourage development of tight gas reserves by industry through reducing the technical and economic risks of locating, drilling and completing commercial tight gas wells.

This report, the second of three, focuses on the Piceance Basin located in western Colorado. The first report (Scotia, 1993) analyzed the tight gas reserves and resources in the Greater Green River Basin (GGRB). The last report will focus on the Uinta Basin. Since each report is a stand-alone document, duplication of language will exist where common aspects are discussed.

The starting point for this study is a resource estimate completed by the U.S. Geological Survey (USGS) (Johnson et al, 1987). The USGS estimate was based on a modified volumetric approach to estimate in-place and recoverable gas resources in low permeability sandstones of the Upper Cretaceous Mesaverde group in the Piceance Basin. The Mesaverde group was subdivided into three stratigraphic intervals: the Williams Fork formation, the Iles formation, and the Rollins or Trout Creek sandstone member. Each of these stratigraphic intervals was then subdivided into two plays: a deeper gas play and a shallower transition play. Play boundaries were defined using variations in levels of thermal maturity.

The methodology utilized by the USGS in performing their resource estimate consisted of a modified volumetric approach based upon isopach mapping of sandstones of 10 feet or greater thickness within each unit. Volumetric estimates were completed via assumptions for average porosity and water saturation ranges and formation volume factor based upon temperature and pressure considerations derived by estimation of overburden thicknesses. In-place gas resource estimates were then computed volumetrically utilizing a probabilistic approach. The results of the USGS resource estimate are summarized in Table 1:

TABLE 1
USGS MEAN ESTIMATED RESOURCE BY PLAY

PLAY	Tcf IN-PLACE
Williams Fork	320.63
Iles	95.42
Rollins-Trout Creek	3.50
TOTAL	419.55

This represents a large estimated gas resource. Historically, the Piceance Basin Mesaverde tight gas play has not been a prolific producer due to a variety of factors, including regionally depressed gas prices, generally poor infrastructure, poor well productivity, and resulting marginal economics. In recent years several of these factors have changed resulting in a more positive outlook for the basin and for the conversion of parts of this giant resource to reserves. Addressing these changes and documenting their effect on the resource to reserves process is the subject of this report.

A twofold approach has been adopted involving firstly, a reexamination of the USGS resource estimate and adjustment of the parameters used, and hence deriving a revised resource estimate. Secondly, to address what proportion of that resource may be called "reserves," it should be clearly stated that the project brief is directed at the category classified as unproved reserves (that is, probable and possible) under standard Society of Petroleum Engineers (SPE) definitions. In the strictest sense, such an analysis should be restricted only to volumes that have been discovered, with normal techniques for estimation being consideration of differing recovery factors or drainage radii around wells and allocating certain proportions to the probable and possible categories. Considering the immaturity of the Mesaverde plays, such an approach would simply be a geometry exercise with little relevance to the larger aspect of reserves potential and future contribution to the national gas supply picture. As a result, "reserves," as used in this study, comprise volumes normally classified as probable and possible and also includes "potential reserves," that may qualify as commercial but remain undiscovered in the strictest sense. This definition and discussion of the distinction between "discovered" and "undiscovered" when dealing with unconventional resources is elaborated upon in the text.

This project seeks to not only document the performance and reserves from Mesaverde gas wells in the Piceance Basin, but also to explore the reasons behind differing recovery factors. Quantification of the reasons behind differing well performance is complex due to natural changes in reservoir properties and varying degrees of success of the massive hydraulic fracture treatment that is necessary to effect a commercial completion.

This report seeks to keep in focus the ultimate objective of encouraging further exploitation of the resource by industry. The process of successfully locating, drilling, completing, fracture treating, and producing a Mesaverde gas well involves an interplay of complex geological, petrophysical and reservoir engineering components. Since the study and evaluation of tight gas reservoirs involves considerably more complexity than a conventional gas play, and because the technology is evolving rapidly, a diverse, varied and sometimes confusing technical literature base exists. For those who are not involved in the field on a day-to-day basis, a working understanding of the components of the tight gas problem may be found in the appendices of our previous report (Scotia, 1993) on the GGRB. These appendices include technical and summary background information on aspects of hydraulic fracturing, log analysis and the use of core data and its correction to provide in-situ values.

It should be noted that in working with tight gas reservoirs, a greater degree of complexity and hence uncertainty is involved in comparison with conventional gas reservoirs. This uncertainty arises not only from the degree of heterogeneity normally exhibited by tight gas reservoirs, but also due to the fact that conventional technical tools for measuring aspects such as reservoir properties (conventional logs, core analysis, DST data, etc.) were designed for use in conventional reservoirs. The data sources require special treatment and modification of approach, through to total data rejection in terms of supplying information which is useful in an analysis. Due to the low permeabilities and generally low porosities involved, most conventional measuring devices are at the lower end of their accuracy limit, introducing an additional base element of measurement error. All of these factors complicate the acquisition of base data, the reliability of such data, and its ultimate overall relevance to an evaluation. As a result, it is common for evaluation work to include an element of uncertainty, either via conducting analyses deterministically but providing ranges for input variables, or in fact taking such analyses to the next stage and working probabilistically. The original USGS resource estimate was performed probabilistically: that is, volumetric input data was estimated as ranges and combined into answers expressed as a distribution. The final results were presented as a numeric value with an associated probability level.

The USGS approach has been adopted in this study via expressing reserves results in the form of an estimated distribution. This system provides a quantitative and consistent methodology for expressing potential reserves data in evaluation situations typified by wide variation in individual well performance or, as otherwise expressed, in statistical type plays. The evaluation of reserves for Mesaverde tight gas sands represents such a situation. It should be noted that in many cases it is not possible to accurately measure each of the factors controlling ultimate recovery or to determine which factors have the most impact.

SUMMARY OF RESULTS

1. Reevaluation of the base *in-place* tight gas resource by this study yields a mean estimate of 307.3 Tcf.
2. Of this base resource, 254 Tcf is contained within sandstones that are of extremely poor reservoir quality, having estimated in-situ permeabilities of less than 0.001 md and also sandstones having low gas saturation due to limited charge. Such resources are termed *technologically nonviable* since they are contained in reservoirs that are considered too tight for commercial exploitation using today's hydraulic fracturing technology. Portions of this resource will only become accessible via future cost reduction and improvement in massive hydraulic fracturing technology.
3. The remaining 53.3 Tcf represents resources that are contained in reservoirs considered to have in-situ permeabilities greater than 0.001 md and are termed *technologically viable*. Of this resource, 8.2 Tcf (2.7% of the total) is termed *nondemonstrated* since it is contained in reservoirs that have not been shown to be commercially productive. *Nondemonstrated* resources are limited to those in the Paludal Play. New developments in well completion and stimulation will be required to access these resources.
4. The remaining 45.1 Tcf represents *demonstrated* resources. These are in-place volumes that are potentially available for conversion into reserves by application of an appropriate recovery factor. Of this volume, 9.4 Tcf (3.1% of the total) is considered to be *established* resource characterized by favorable expectations in terms of recovery and drilling risk. A further 14.7 Tcf (4.8% of the total) is considered *nonestablished* resource characterized by less favorable expectations in terms of recovery and a higher drilling risk and cost. The differentiation of the *established* and *nonestablished* resource categories is based upon a drill depth criterion termed *economic basement*. *Economic basement* is a conceptual depth that depends upon drilling and completion costs, expected reserves, gas price, and success ratios. Changes in these parameters will cause dynamic movement of resources from one category to the other. The remaining 21 Tcf of *demonstrated* resources are considered *speculative*. *Speculative* resources are those occurring in deeply buried locations, characterized by poor well control and being deeper than any *established* commercial production. Such volumes are inferred by extrapolation of mapping into the deep basinal areas and are defined as being below the *deepest commercial production*. *Speculative* resources have a high degree of uncertainty associated with their quantification and are thus excluded from consideration from a reserves quantification perspective.
5. Table 2 summarizes the resource high-grading procedure:

TABLE 2
BREAKDOWN OF REVISED RESOURCE ESTIMATE (Mean Values)

USGS Mean Resource Estimate	419.6
Scotia Revised Mean Resource Estimate	307.3
MINUS <i>Technologically Nonviable</i> Resources	254.0
SUBTOTAL <i>Technologically Viable</i> Resources	53.3
MINUS <i>Nondemonstrated</i> Resources	8.2
SUBTOTAL <i>Demonstrated</i> Resources	45.1
Subdivision:	
<i>Speculative</i> Resources	21.0
<i>Nonestablished</i> Resources	14.7
<i>Established</i> Resources	9.4

Only *established* and *nonestablished* categories are considered for the purpose of estimating recoverable reserves.

6. Recoverable reserves, inclusive of probable, possible and potential categories, are estimated at 2.6 Tcf and 3.0 Tcf respectively for the *established* and *nonestablished* categories. These represent MAXIMUM recoverable volumes assuming a variable drilling pattern that leaves NO bypassed gas. The estimated ultimate recoveries (EUR) for existing Mesaverde gas wells are not included in these figures.
7. Mesaverde gas wells are characterized by significant variation in average drainage radius. Due to large pay thicknesses, they may drain comparatively small areas. Development on a regulatory 640 or 320 acre spacing can result in significant bypassed gas. This gas remains in inter-drainage area locations at or near original reservoir pressure and is available for exploitation via infill drilling. It is common to have bypassed gas on the order of 50 to 90% of gas in-place (GIP) on an initial 640 acre spaced development.
8. The Fluvial and portions of the Marine and Multi-Pay plays of the Mesaverde group contain the *established* resources and are the principal producing units in the basin with a combined EUR of 234 Bcf for existing wells. *Nonestablished* resources are contained in portions of the Marine and Multi-Pay plays. These units represent a combined EUR of 61 Bcf for existing wells. The Paludal Play has no commercial production in the basin. Sub-commercial production with an EUR of 5.2 Bcf from 47 wells is recorded from wells in this play.
9. For all existing Mesaverde gas wells in the Piceance Basin, excluding the Divide Creek

anticline which is considered to be a nonrepresentative field, cumulative production to 1 November 1994 is 139 Bcf with an EUR of 239 Bcf. This represents proved developed producing (PDP) reserves developed mainly since 1975 in 491 producing wells. These EURs are lognormally distributed with the average EUR for a Mesaverde gas well being 487 MMcf and the median well being 250 MMcf.

10. Since 1990, improvements in hydraulic fracturing practices have markedly improved well productivity and EURs. While EURs are still lognormally distributed, recent completions have an average EUR of 631 MMcf and a median value of 330 MMcf. This represents an improvement of 30%.
11. A characteristic of unconventional resources such as tight gas is the "sweet spot" character of most developments. The Piceance Basin has historically been marginally economic in the Mesaverde Play without the recognition of a dramatic sweet spot character with the exception of the Divide Creek anticline. It is quite possible that significant sweet spots remain undiscovered.
12. The present day Piceance Basin is characterized by large variations in surface elevation. Downcutting by the Colorado and other rivers creates a canyon-and-plateau topography with over one mile of difference in vertical relief. Present Mesaverde gas wells are restricted to the valley bottoms where drill depths to the Mesaverde and hence costs are greatly reduced. Marginal play economics have not supported development of the resource located below the higher elevation plateau area.

Recent improvements in fracturing practices have improved EURs and effectively lowered the *economic basement*. It is speculated that the economics of exploiting resources below the plateaus may be similar to that currently experienced in the valley setting in situations where the reservoirs are not breached and retain overpressured characteristics.

BACKGROUND/DISCUSSION

The USGS resource work has identified a large potential resource in the Mesaverde group in the Piceance Basin. Recognition of the resource represents the first step in its exploitation. Gas developments in the Piceance Basin have suffered from a combination of several "negatives." These include historically poor gas markets in terms of price and take, sparse infrastructure, the requirement for the use of expensive and still developing technology particularly in the area of frac treatments, and a generally costly environment due to local logistics, to name a few.

While the improving gas markets in the Rocky Mountain basins area are a positive factor, general industry skepticism of the resource itself and of the base economics compared to other opportunities in conventional oil and gas development are probably the main source of negative reaction towards the development of these resources.

Objectives and Purpose For Study

Encouraging commercial development of the Mesaverde tight gas resource is the prime objective of this study. In comparison to conventional reservoirs, tight gas reservoirs pose their own unique series of challenges. Since such challenges often involve the development and application of new technologies, and because such technologies can involve a significant cost component over those normally used in conventional reservoirs, a double negative is created by virtue of increased cost and increased risk (representing the very real possibility that such expenditures will be unsuccessful in providing an economic return). As noted by Holditch (1992), despite the development and proof of concept of many of the technologies applied to tight gas development, such technologies have not been widely accepted for various reasons. Included amongst these is the inertia involved in technology transfer and demonstration that such technologies are indeed cost-effective.

It should be noted that the exploitation of tight gas reserves involves physical measurements that can be at the lower limit of resolution of the various tools utilized in their measurement. Since such tools were designed and calibrated for conventional reservoirs, aspects of resolution and measurement error become of prime concern in tight gas. As such, taking certain measurements at face value without application of corrections or judgmental adjustments can often lead to faulty interpretations. These pitfall areas are identified and discussed in our previous report on the GGRB (Scotia, 1993), including appendices describing the state of current technologies.

Finally, this report has been designed to provide not only our interpretations but to also share the base data so that others may complete their own analyses. This data is included in

summarized form (both tabular and graphical) within the body of this report and is provided in digital form on request as a separate database.

Piceance Basin Geological Setting

The Piceance Basin, located in northwestern Colorado, covers approximately 4,272 square miles, Figure 1. The basin is bounded by the Uncompahgre Uplift and Douglas Creek Arch to the southwest and west, by the Sawatch and White River uplifts to the southeast and east, the Gunnison Uplift and San Juan volcanic field to the south, and by the Uinta Mountain uplift and Axial Basin anticline to the north, Figure 2. The basin was created by Laramide tectonism between Late Cretaceous and Paleocene time (Johnson 1989). It formed part of a larger subsiding trough (Cretaceous Epeiric sea) that included among others the present day Greater Green River and Uinta basin areas (the subjects of Phases I and III of this study) and which covered much of the central United States and Canada, lying east of the Sevier orogenic belt. The Piceance Basin is separated from the Uinta Basin to the west by the Douglas Creek Arch, which served as a barrier to sedimentation intermittently during Late Cretaceous/Early Tertiary. The Rangely anticline represents the northern limit of the Douglas Creek Arch. East/west folding contemporaneous with the Sevier orogeny is believed to be responsible for the formation of the arch. The east flank of the basin is bounded by the massive Grand Hogback monocline which is thought to be underlain by a deep seated major thrust (Gries 1983) responsible for the westward thrusting of the White River Uplift between Late Cretaceous and Paleocene/Eocene times.

Several major tectonic features exist within the basin, each of which is thought to be associated with deep seated thrust faulting. In the north of the basin the White River Dome and aforementioned Rangely anticlines are southeast plunging anticlines believed to be underlain by southeast striking thrusts and are probably related to the eastern limit of the Uinta Uplift. The Divide Creek, Coal Basin and Wolf Creek anticlines in the southeast are probably related to the Grand Hogback thrusting and are underlain by deep west and southwest thrust faults. Other anticlines include the De Beque anticline at the southwest basin edge and the Piceance Creek Dome-Sulphur Creek Nose in the basin center, thought to be related to reactivation of older faults with strike slip movement.

Basin subsidence during Late Cretaceous marked the beginning of a major episode of marine sedimentation beginning with the Mancos shale which underlies the Mesaverde across the basin. An estimated 5,000 feet of marine sediments, including the Mancos shale and lower Mesaverde were deposited before the sea retreated to the east of the basin. Episodic pulses of sediment from the Sevier Uplift during Campanian created several regressive sand cycles which advanced the shoreline from the northwestern portion of the basin to the southeast, beyond the current basin boundary. These repeated transgressive and regressive episodes created sequences of marine, marginal marine, paludal and fluvial sediments. The simplest

subdivision of the Mesaverde group consists of the older Iles formation represented by predominantly marine and marginal marine sediments and the younger Williams Fork formation which includes paludal, coastal plain and fluvial sediments. At least five regressive cycles have been identified in the Isles formation, while two have been recognized in the lower Williams Fork formation. The Mesaverde sequence of sediments contain the tight gas resources that are the subject of this study.

An unconformity at the top of the Mesaverde marks the onset of the Laramide orogeny, 72 to 40 million years ago (Mya) which created uplifts within the foreland sedimentary basin resulting in several separate basins and provided local sediment sources. Though areas between the local uplifts continued to subside and receive sediments, the Piceance Basin edges and ultimately the basins center, became uplifted and eroded, resulting in the possible removal of thousands of feet of section.

The Paleocene Wasatch formation overlapped the unconformity beginning in the eastern part of the basin and spreading west. By early Eocene, sediments covered the Douglas Creek Arch. The Wasatch includes coarse clastics at its base ranging up to poorly drained lowland swamp/paludal sediments above. At the beginning of the Eocene period a permanent lake formed in the north central part of the basin into which the Green River lacustrine sediments were deposited. Alluvial sediments from erosion of the White River Uplift pushed Lake Uinta to the west of the subsidence center, but from early Middle Eocene to the end of the Eocene period, Lake Uinta covered much of the Piceance Basin, Douglas Creek Arch, and Uinta Basin. Burial of the Mesaverde sediments beneath this thick blanket of lower Cenozoic rocks created the temperatures required for the onset of gas generation at the basin center. Johnson and Nuccio (1987) estimate that present day maturation was attained from burial heating prior to the end of the Eocene. By Late Eocene (14 Mya) the Laramide orogenic episode had ended. Igneous activity had begun in Early Laramide time and continued in the southeast corner of the Piceance Creek Basin during Oligocene. Johnson (1987) speculates that Oligocene igneous plumes may be the cause of the Divide Creek, Wolf Creek, and Coal Basin anticlines, along with basement faulting. During Later Eocene to Early Oligocene time a second erosional surface developed beginning at the basin margins then spreading to cover the entire basin. The Laramide orogeny ended about 14 Mya. Erosion continued to denude the White River Uplift and Mesaverde outcrops along the Uncompahgre, Uinta and Sawatch uplifts until they were beveled to about the same elevation as the Piceance Basin erosional surface. A general correlation chart of the Cretaceous and Lower Tertiary stratigraphic units in the Piceance Basin is presented in Figure 3.

Figure: 1

LEGEND

- ☐ TERTIARY ROCK LIMIT
- ☐ CAMBRIAN - LOWER CRETACEOUS OUTCROP
- ☒ PRECAMBRIAN ROCKS

U.S. Department of Energy

NE UTAH, NW COLORADO, & SW WYOMING
BASINS AND UPLIFTS
CREATED IN LARAMIDE OROGENY

Figure: 2

LEGEND

- BASIN OUTLINE
- RIVERS & STREAMS

U.S. Department of Energy

Piceance Basin
MAJOR STRUCTURAL ELEMENTS

Well locations were obtained from Petroleum Information. Scotia has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data.

FIGURE 3
(from Rocky Mountain
Association of Geologists
(1977) and Finley (1984))

The Piceance Basin gas resources identified by the USGS are contained in the low permeability sandstone reservoirs of the Mesaverde group, located in the central portions of the basin. These reservoirs usually have an in-situ permeability to gas of less than 0.1 md and require hydraulic fracturing to produce gas at commercial rates. The gas accumulation is interpreted to be a basin-centered type, similar to that described by Masters (1979). In terms of gas distribution, the basin may be subdivided into three zones: a shallow water-bearing zone which occurs at the basin margins, a deeper transitional zone, which contains sands that are both gas-saturated and water-saturated, and a deep basin-center gas-bearing zone. The top of the gas zone cuts across stratigraphic boundaries and grades vertically and updip through the transition zone into water-bearing reservoirs. Trapping of the gas requires the creation of a relative permeability barrier in very low permeability rock within the transition zone. This barrier, or seal, is not perfect and likely allows leakage of gas over geologic time. Consequently, a continuous gas supply (present day generation) is required to maintain the accumulation.

The onset of gas generation in Type III (humic) gas prone source rocks is recognized to begin at a vitrinite reflectance, R_o , value (measurement of thermal maturity) of 0.73% and it is evident that the bulk of the Mesaverde gas accumulation exists within rocks with R_o values higher than 0.73%. Though migration distances are speculated to be small in low permeability basin-centered gas accumulations, some tight gas fields do lie outside the 0.73% R_o boundary. Reservoirs in a basin-centered gas accumulation are not normally associated with discrete gas-water contacts (GWC). Although some water-bearing horizons may exist, gas saturation is usually continuous and independent of structure.

It is evident in the Piceance Basin that deep incising by rivers following uplift and influx of meteoric water via outcrops at the basin margin is gradually breaching the gas deposit. Basin topography is depicted in Figures 4 and 5. Here, the top of gas saturation often lies far beneath elevations marking an R_o of 0.73% the result of flushing and replacement by meteoric water or simply leak-off. Present day generation of gas may be occurring from interbedded coals and carbonaceous shales of the Mesaverde Paludal section and from the older oil prone Mancos marine shales in the deeper, hotter parts of the basin. However, the general existence of normally pressured to moderately underpressured gas accumulation suggests that gas replenishment to counter leak-off is not significant. In many instances where overpressured reservoirs have been encountered, the higher pressures can be attributed to recharging by artesian meteoric waters rather than present day gas generation. However, the bulk of Mesaverde beneath the high relief plateau regions is unexplored and the potential for preserved overpressured reservoirs exists there. Figure 6 shows the locations of existing Mesaverde gas wells relative to the main river system and also shows the major gas pipeline infrastructure for the basin.

The youngest of the seven regressive cycles within the Iles formations, the Rollins-Trout

Creek member, represents an anomaly for the basin-centered gas accumulation theory. This laterally extensive member continues beyond the basins southeastern margin and, though surrounded by gas sourcing coals and shales, is predominantly water-bearing even in the deepest parts of the basin. In this member at least, Masters (1979) gas relative permeability barrier necessary to trap the migrating gases did not develop. Consequently, the member instead became an escape route for gases.

Drilling and Production History

The following discussion is limited to drilling and production history trends within the Mesaverde group.

Exploration in the Piceance Basin dates back to the 1940s, however, it was not until the late 1950s that gas production was established from the Mesaverde group. Limited in part by lack of infrastructure, serious development of the Mesaverde tight gas reservoirs did not occur until the early 1970s with rapid development in the late 1970s and early 1980s, and again in the early 1990s, immediately prior to expiration of the Section 29 tax credits. Table 3 summarizes the Mesaverde drilling and completion history based upon data derived from Petroleum Information Corporations (PI) Well History Control System (WHCS) and National Production System (NPS) databases. This data set has been culled to exclude wells outside the basin outline as depicted in Figure 2.

**TABLE 3
MESAVERDE DRILLING AND COMPLETION HISTORY
IN FIVE YEAR INCREMENTS**

PERIOD	DRY HOLES	COMPLETED	% DRY
1945 - 1949	3	0	100
1950 - 1954	10	0	100
1955 - 1959	39	2	95
1960 - 1964	26	3	90
1965 - 1969	18	0	100
1970 - 1974	27	6	82
1975 - 1979	25	76	25
1980 - 1984	15	167	8
1985 - 1989	4	74	5
1990 - 1994	3	249	1
TOTALS	170	577	

Figure: 4

LEGEND

- BASIN OUTLINE
- CROSS SECTION
- CONTOURS

U.S. Department of Energy

Piceance Basin
SURFACE TOPOGRAPHY

Well locations were obtained from Petroleum Information. Scotia has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data.

Figure: 5

LEGEND

- GAS-WATER TRANSITIONAL ZONE
- GAS SATURATED ZONE

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Piceance Basin

NORTH-SOUTH CROSS-SECTION

Well locations were obtained from Petroleum Information. Sclafin has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data.

Figure: 6

LEGEND

- BASIN OUTLINE
- RIVERS & STREAMS
- PIPELINES

U.S. Department of Energy

Piceance Basin WELL LOCATIONS AND PIPELINE INFRASTRUCTURE

Well locations were obtained from Petroleum Information, Scotia has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data.

Note that the well completions tallied in Table 3 include dual completions. As such, the totals will not match other tabulations where wellbore counts are involved.

Early exploration of the basin through the mid-1970s resulted mostly in dry holes. The lack of infrastructure and low gas prices, plus the early state of development of hydraulic fracture treatments precluded serious development. The resource was however recognized and prompted experimentation including projects Rulison and Gas Buggy which involved the detonation of nuclear devices within the Mesaverde in an attempt to create large-scale fracturing.

Increasing oil and gas prices in the late 1970s prompted attempts at economic development of the Mesaverde tight gas resource, the number of dry holes dropped dramatically and the successful completions increased. Marginal economics limited development to areas of known production in the river valley portions of the basin. This afforded a shallower target and hence reduced drilling cost. With continued improvements in hydraulic fracturing treatments, dry holes have virtually been eliminated. The 1% to 2% occurrence represents mostly mechanical failures.

Mesaverde production and reserves (Figure 7) are dominated by the top eight fields having current EURs of over 10 Bcf. In a basin-centered gas accumulation where the resource is distributed throughout the play as opposed to being concentrated in discrete pools or traps, field production represents a snapshot in time. As extension and infill drilling occur, significant reserves growth is noted at the designated field level and fields tend to merge together assuming that base economics justify continued exploitation of the play. For this reason, the expected lognormal distribution of field size is poorly shown. In addition, examination of recent drilling indicates that the larger fields are being infill drilled and extended as the main reserves growth activity as opposed to the development of new field areas.

In order to assess the maturity of the play and estimate future per well gas recoveries, it is useful to look at the sequence of reserves development within the play at the well level as shown in Figure 8. This series of displays looks at per well EURs as a function of completion number (first well drilled through to the most recent) and as a function of time. Usually the best wells are drilled early in the life of the play. With time, the EUR per well decreases as a function of smaller target size and partial drainage of infill locations. As shown in Figure 8, the opposite trend holds true for the Piceance Basin. Despite the majority of recent activity being infill and extension drilling within existing field areas, the EURs per well are increasing dramatically. This is shown in both the completion sequence plots and the completion time increment plot. In terms of average EUR, wells drilled since 1990 have almost twice the EUR of those drilled in the previous five year period. This is a graphic demonstration of the advances in completion technique and technology being applied currently in the Piceance Basin and will be discussed in detail later on in this report.

FIGURE 7: FIELD RESERVES AND CURRENT RATE

FIELD PRODUCTION AND RESERVES

Field Name	EUR (MMcf)	Oil EUR (MBo1)	Gas EUR (MMcf)	Oil Cum (MBo1)	Gas Cum (MMcf)	Reserves (MBo1)	Reserves (MMcf)
DIVIDE CREEK	61,019	0	61,019	0	57,324	0	3,695
GRAND VALLEY	49,128	20	49,008	2	25,071	18	23,937
RULISON	39,750	109	39,096	45	20,387	64	18,709
PLATEAU	34,319	14	34,235	10	26,517	4	7,718
SHIRE GULCH	25,558	0	25,558	0	11,213	0	14,345
PARACHUTE	19,179	1	19,173	0	10,093	1	9,080
WHITE RIVER	15,703	207	14,461	127	7,249	80	7,212
WOLF CREEK	12,676	0	12,676	0	12,676	0	0
BUZZARD CREE	7,824	0	7,824	0	6,792	0	1,032
UNNAMED	6,444	24	6,300	1	346	23	5,954
PICEANCE CRE	5,743	24	5,599	18	3,580	6	2,019
MAX CREEK	2,625	14	2,541	10	1,539	4	1,002
LOGAN WASH	2,294	0	2,294	0	1,526	0	768
BUZZARD	2,251	0	2,251	0	2,088	0	163
GASAWAY	1,989	3	1,971	1	901	2	1,070
RAGGED MOUNT	1,863	3	1,845	3	1,607	0	238
SULPHUR CREE	1,849	5	1,819	3	1,282	2	537
SOUTH SHALE	1,151	0	1,151	0	605	0	546
DEBEQUE	911	0	911	0	769	0	142
GRAND SLAM	800	1	794	0	103	1	691
CATHEDRAL	770	0	770	0	501	0	269
COAL BASIN	645	2	633	1	413	1	220
BRUSH CREEK	633	0	633	0	520	0	113
BALDY CREEK	422	0	422	0	422	0	0
CALF CANYON	295	0	295	0	282	0	13

FIELDS SORTED BY CURRENT RATE

Field Name	Total Wells	Oil Compltns	Gas Compltns	Total Compltns	Oil Rate Bopd	Gas Rate Mcfd	Res Life Index
GRAND VALLEY	64	0	109	109	0	13,542	4.86
RULISON	52	0	62	62	0	9,430	5.55
SHIRE GULCH	44	0	45	45	0	6,309	6.23
PARACHUTE	32	0	61	61	0	4,062	6.13
PLATEAU	119	0	121	121	0	2,989	7.10
DIVIDE CREEK	23	0	24	24	0	2,917	3.47
WHITE RIVER	23	0	24	24	0	2,251	9.36
GASAWAY	4	0	4	4	0	1,862	1.59
UNNAMED	5	0	5	5	0	1,031	16.19
BUZZARD CREE	3	0	4	4	0	921	3.07
PICEANCE CRE	2	0	2	2	0	675	8.34
MAX CREEK	7	0	7	7	0	595	4.73
RAGGED MOUNT	6	0	7	7	0	347	1.68
GRAND SLAM	2	0	2	2	0	308	6.20
SOUTH SHALE	13	0	13	13	0	305	4.91
LOGAN WASH	7	0	7	7	0	299	7.04
SULPHUR CREE	12	0	12	12	0	212	7.09
BUZZARD	11	0	11	11	0	164	2.72
DEBEQUE	6	0	6	6	0	164	2.37
CATHEDRAL	2	0	2	2	0	111	6.66
COAL BASIN	2	0	2	2	0	96	6.47
PINYON RIDGE	5	0	5	5	0	90	2.93
BRUSH CREEK	2	0	3	3	0	75	4.14
CALF CANYON	3	0	3	3	0	48	0.74
OIL WELL HOU	2	0	2	2	0	36	1.45

Probability Paper Plot

Fractal Distribution Plot

FIGURE 8: COMPLETION SIZE AND SEQUENCE MODEL

As a result of recent activity, gas production from the Mesaverde Play (Figure 9) has increased markedly as shown on this vintaged production plot. Note that the period in the late 1980s represents regional curtailment as opposed to a loss of deliverability. In compensating for this, it is evident that the gas production from the Mesaverde is dramatically increasing on a play level and that reserves developed during the last five years now contribute over two-thirds of the supply picture.

FIGURE 9: VINTAGED PRODUCTION PLOT

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Table 4 illustrates the historical and current play demographics. The historical table is sorted by total recorded completions and the current demographics represented by sorting in order of currently active completions. In both cases, the play is dominated by Barrett Resources, Inc. (Barrett) and Gasco who operate the majority of the current wells in the basin. Barrett concentrates its activities in Grand Valley, Parachute and Rulison fields. Gasco's holdings are more diversified, including wells in Buzzard, Logan Wash, Plateau, Rulison, Sheep Creek, Sour Gulch, and White River fields. The superior per well EURs shown for Snyder Oil (Snyder) reflect holdings in the Divide Creek anticline, representing one of the only true sweet spots in the basin identified to date.

Current production as of 1 November from the Mesaverde in the Piceance Basin amounts to 50 MMcf/d from 362 producers or an average rate of 139 Mcf/d/well.

TABLE 4
HISTORIC AND CURRENT PLAY DEMOGRAPHICS

HISTORICAL PLAY DEMOGRAPHICS								CURRENT PLAY DEMOGRAPHICS							
Operator	Original Completions	Recomps	Total Complns	Oil EUR (Mbo)	Gas EUR (MMcf)	Equiv EUR (MMcfe)	Equiv EUR /CompIn	Operator	Total Completions	Active Complns	Equiv EUR (MMcfe)	Cum Prod (MMcfe)	Reserves (MMcfe)	Current MMcfe/d	Mcf/d /compIn
BARRETT RESOUR	122	80	202	85	90,117	90,627	448	BARRETT RESOURCES	202	178	90,627	45,125	45,502	31.45	177
GASCO INCORP	145	5	150	203	63,775	64,993	433	GASCO INCOR	150	113	64,993	47,674	17,319	7.80	69
KOCH EXPLORATION	29	0	29	0	22,444	22,444	773	KOCH EXPLORATION	29	27	22,444	9,078	13,366	7.36	272
AA PRODUCTION	25	1	26	17	7,262	7,364	283	AA PRODUCTION	26	21	7,364	5,624	1,740	1.23	59
SNYDER OIL	22	0	22	30	70,174	70,354	3,197	CONQUEST OIL	13	13	1,151	605	546	0.37	29
RIATA ENERGY	13	0	13	5	3,396	3,426	263	SNYDER OIL	22	11	70,354	56,780	13,574	5.04	458
CONQUEST OIL	13	0	13	0	1,151	1,151	88	RIATA ENERGY	13	10	3,426	2,728	698	0.32	32
GREAT NORTHERN	8	0	8	0	3,548	3,548	443	GREAT NORTHERN	8	7	3,548	2,487	1,061	0.40	57
CHEVRON U S	7	0	7	0	116	116	16	BONNEVILLE FUEL	7	6	4,177	3,460	717	0.21	35
BONNEVILLE FUEL	7	0	7	0	4,177	4,177	596	US DEPT OF ENERGY	6	6	5,385	2,237	3,148	1.82	303
CER CORPORATED	5	1	6	0	2,046	2,046	341	ANADARKO PET	6	5	278	182	96	0.13	26
US DEPT OF ENERGY	5	1	6	25	5,235	5,385	897	VESSELS OIL	6	5	523	339	184	0.48	96
ANADARKO PET	6	0	6	5	248	278	46	DELTA PETROLEUM	4	4	267	252	15	0.05	12
VESSELS OIL	6	0	6	8	475	523	87	LFC GAS COMP	4	4	1,989	907	1,082	2.26	565
UNION OIL CO	4	1	5	0	7,824	7,824	1,564	CER CORPORATION	6	3	2,046	1,277	769	0.35	116
CHANDLER & ASSOC	5	0	5	0	214	214	42	UNION OIL CO	5	3	7,824	6,792	1,032	1.10	367
RICHARDSON OIL	4	0	4	0	216	216	54	STRACHAN EXP	3	3	633	520	113	0.09	30
COORS ENERGY	4	0	4	0	263	263	65	MOBIL OIL CO	3	2	5,743	3,687	2,056	0.83	413
DELTA PETROLEUM	4	0	4	0	267	267	66	BASIN OPERATING	3	2	571	358	213	0.06	32
LFC GAS COMP	4	0	4	3	1,971	1,989	497	LFC NUMBER 6	3	2	295	282	13	0.06	29
MOBIL OIL CORP	3	0	3	24	5,599	5,743	1,914	RIVIERA DRILLING	2	2	204	144	60	0.09	44
TXP INCORP	3	0	3	0	155	155	51	DANIELS PETR	2	2	800	103	697	0.37	185
FUEL RESOURCES	2	1	3	28	423	591	197	GORDON ENG	1	1	75	75	0	0.01	11
AMERICAN MAT	3	0	3	0	416	416	138	DEVON ENERGY	1	1	38	29	9	0.02	17
BASIN OPERATING	3	0	3	0	571	571	190								

STUDY METHODS/APPROACH

Data Sources

This study was based entirely on public domain data and data volunteered by companies on the basis that it could be used as nonproprietary. Base data sources for this project consisted of the following:

1. **Published Information:** This consisted of reports and published literature on the basin and on various aspects of the technology utilized in exploiting low permeability gas reservoirs, not only in the Rocky Mountain area, but elsewhere.
2. **Specific Piceance Basin Reports:** These consisted of reports directed specifically at the Piceance Basin and were mainly of a research nature. These included reports in the USGS bibliography as well as reports generated by service contractors and companies in the area.
3. **Public Domain Information:** This consisted of various commercial data sources, particularly PI's NPS and WHCS files. These consisted of reported historical production data for all wells in the basin as well as digital scout ticket information.
4. **Reports to State and Federal Government Authorities:** The state and federal governments require oil and gas operators to file certain reports concerning oil and gas operations and these are part of the public record. These consist not only of forms required for drilling and completion of wells, but also include technical data such as drillstem test information, core analysis, and other useful information.
5. **Special Technical Reports:** These include submittals to state and regulatory authorities particularly in reference to obtaining tight gas sand designations for incentive pricing. Such reports are prepared by operators in support of their contention that certain areas should be designated as tight gas producing areas and hence qualify for incentive pricing. Most of such reports were made for the consideration of the Federal Energy Regulatory Commission (FERC).
6. **Proprietary Company Files:** A significant effort was directed at persuading companies to volunteer information for the use in this study. This information consisted of core, test and fracturing data and certain proprietary data and reports. Such information was solicited from companies on a voluntary basis with the proviso that it could be utilized as part of this report. We are grateful for the cooperation of many oil and gas companies for taking the trouble to provide proprietary data and to release such data for the benefit of this study.

wells in the basin and was culled based upon API number matching to a culled WHCS well list. This afforded breakdown of production on a play-by-play basis and this data was loaded to Scotia's MASTER proprietary production data handling system which allowed the following:

1. The construction of a database of all production data for the basin.
2. Interfacing this database with interactive decline curve modeling software, allowing extrapolation of EURs.
3. Ability to analyze production data using Fetkovich type curve information for wells displaying a prolonged initial transient period.
4. Interface with volumetric calculations to determine recovery factors and drainage areas.

Considerable effort was expended in assembling as much core data as possible both through obtaining core analysis data directly from state records and also soliciting additional data from local operators in the area. The core data in the form of porosity, permeability, water saturation, gas saturation, and grain density measurements (conventional core analysis) was databased, correlated with principal play, and analyzed utilizing Scotia's proprietary COREPRO system. This software allows the correction of properties measured at ambient conditions in the laboratory back to in-situ conditions via a variety of techniques. A detailed discussion of core permeability corrections to in-situ conditions, together with the problems and their solutions, is provided in Appendix A of our previous report on the GGRB (Scotia, 1993).

Basic rock property information was derived from open hole wireline log data. Wireline log data was obtained for a representative grid of wells covering each play. Wells were selected not only for their geographic position but also on the basis of available data, i.e., a representative suite of logs (minimum electric survey plus ideally three porosity tools, sonic, density and neutron), and the presence of core data to allow calibration of log responses, particularly for porosity determination and correlation with log derived permeability algorithms. All logs were obtained in hard copy form and digitized using the Neuralog software in preparation for computerized log interpretation. Log interpretation was run utilizing Scotia's proprietary SLOG system, specifically the tight gas module. A detailed description of this software and of the computations performed and problem areas appears in Appendix B of our previous report on the GGRB (Scotia, 1993).

Reserves Definitions

An objective of this project is to take the base USGS in-place gas resource estimate and

estimate what proportion may be potentially convertible to recoverable reserves. As defined for the purpose of this project, "reserves" refers to gas volumes that are classified within the unproved category according to SPE definitions, plus potential undiscovered volumes considered to be commercially recoverable. Since it is of prime importance that the results of this study be understood and accepted by industry, the techniques for reserves estimation must be similarly understood and accepted. To this end, it is worthwhile to clarify the aspect of differing reserves definitions utilized by industry and to place the requirements of this project within that perspective.

The reserves definitions most commonly used in the U.S. are those published by the Securities and Exchange Commission (SEC) and the SPE in conjunction with the Society of Petroleum Evaluation Engineers (SPEE). The most recent version published by the SPE, May 1987, is comprehensively described in SPEE Monograph I dated December 1988. Definitions are subdivided into proved, probable and possible categories with each category being subjected to a status modifier with four modifiers being recognized: producing, shut-in, behind pipe, and undeveloped. For any estimate, the assignment of category reflects the degree of certainty of the estimate since the definitions of proved, probable or possible are based upon applying a test of reasonable certainty. The status assignment provides an indirect confidence measure since the classifications in the higher confidence categories will benefit from hard production data, while those in the lower confidence area will rely on more inferential data and assumptions in order to derive an estimate. These definitions are strictly deterministic. That is, a single figure is estimated as to the future recovery of oil and gas from a well, lease, field or company as a whole or an area as a whole. The fact that such estimates are imprecise is acknowledged by all professional reserves evaluators.

The use of probabilistic reserves definitions in difficult reserves evaluation situations is discussed by Caldwell and Heather (1991). The case may be made that where reserves evaluation is required for certain technology sensitive, statistical or unconventional type plays, the probabilistic approach enhances traditional reserves determination methods. The evaluation of reserves in tight gas reservoirs represents such a situation. In this situation, a variety of factors control the ultimate performance of individual wells. In many cases it is not possible to accurately measure each of the controlling factors and indeed in many cases it is not possible to determine which factors are controlling.

For the purposes of conducting this study, Scotia felt that the assignment of a single recovery factor for a play, township, section or even individual well, would not do justice to the observed variation or document the range of outcomes that are experienced. For oil companies to make planning decisions for entry into a play, such as tight gas, the range of potential outcomes must be known and modeled in order that an economic decision weighing the reserves and reward versus the cost and risks can be made. Such expected value decisions invariably involve a range of reserves values (recovery factors) that can be anticipated and the

strength of any analysis of a tight gas reserves picture must involve this distribution in order to have credibility.

These factors were recognized by the USGS in their resource estimation deliberation. The USGS report chose to express the resource estimates in probabilistic terms. That is, differing resource levels were associated with differing probabilities of occurrence. Scotia believes that this concept must be perpetuated into the reserves estimation procedure as outlined below.

The SPE definitions for unproved reserves are inclusive of the categories of probable and possible. In such cases, both categories are defined in accordance with a reasonableness test as to their likely existence. That is, probable and possible reserves are defined by individual reserves estimators based upon their personal judgment as to the likelihood of existence without quantification of that likelihood. It is worthy of note that whether deterministic or probabilistic reserves definitions are applied, the base methodology used to derive the figures is identical, and that the base difference in approach between the two methodologies is the use of a consistent, non-arbitrary probability level to define probable and possible levels.

The approach taken for this report was to estimate the range of potential recoveries (recovery factors) and to express these as a distribution. These distributions are based upon actual measurements represented by the EUR of completed tight gas wells. It is felt that describing the outcome as a distribution with an associated range, standard deviation and mean, will provide a better understanding of the variability of each play rather than simply zeroing in on a single value arbitrarily defined.

It should be clearly understood that the term "reserves" as used in this report, includes volumes that extend beyond the SPE definitions of probable and possible. We have included "potential reserves" as described by Grace, Caldwell and Heather (1993). These represent volumes that are considered commercially recoverable but have not been "discovered."

The question of "discovered" in unconventional resources is complicated. In normal evaluations, the proportion of a reservoir considered discovered is based upon well control and the terms proved, probable and possible often equate to radii of confidence surrounding well data points. Water contacts and reservoir boundaries define the limits of the discovered volume.

For unconventional tight gas resources, the reservoir is complex in its definition. Massive sections of gas-bearing rock exist with no defined fluid contact or obvious reservoir boundary. Producibility varies markedly from area to area and location to location based on a variety of factors, many of which are extremely difficult to measure or predict. This renders

the radius method inoperable and poses the larger question of how to define "discovered." These considerations have prompted the broadening of the term "reserves" to encompass the proportion of the gas resource that may be potentially convertible to commercially productive reserves by adding the "potential reserves" category to the standard probable and possible definitions.

Rock Properties and Volumetrics: Gas In-Place

The USGS resource estimate represents the starting point for this study. Because an examination of reserves or reserves potential in essence must commence with a GIP estimate, it was felt that it was necessary to either accept the USGS estimates as a starting point or perform modifications where it was expected that new estimates might differ to a significant degree.

The approach taken in this study to the volumetric calculation of GIP differed significantly from the methods used by the USGS in their resource estimate. The differences in approach and methodology are described below on a parameter basis.

1. **Net Reservoir Thickness Counts:** The USGS counted all sands greater than ten feet thick from well logs and did not consider any porosity or water saturation discriminators since the geological model regards almost all sands within the tight sand section to be gas-bearing. Utilizing data points from a regional grid of cross-sections, counts were totaled by play and isopached to derive a rock volume for each play. The USGS sand thicknesses could be reproduced for the most part, simply by applying a 50% V_{clay} cutoff to the gamma ray reading. Definition of reservoir quality rocks (that portion of the sand thickness estimated to contribute to reserves) for use in this study was achieved by applying a suite of cutoffs including porosity, water saturation, V_{clay} and permeability developed for each play from a comprehensive evaluation of core, log and well test data, and published literature. The cutoffs ranged as follows:

PLAY	POROSITY (%)	WATER SATURATION (%)	PERMEABILITY (md)
Fluvial	4.5 to 10.0	60 to 65	.001
Paludal	4.5 to 9.0	60 to 65	.001
Marine	4.5 to 9.0	60 to 65	.001
Multi-Pay	4.5 to 9.0	60 to 65	.001

2. For the purpose of resource estimations, the USGS subdivided the Mesaverde group into three stratigraphic units and defined the gas-saturated and transitional zones using thermal maturity (percent vitrinite reflectance, R_o) maps. The onset of gas generation in Type III (humic) gas prone source rock is recognized to begin at an R_o of 0.73% and this value was used by the USGS to define the boundary between the shallow water-saturated and gas-water transitional zone. However, at this reflectance much of the gas generated may be retained by the source rock and it was recognized by Meissner (1984) that an R_o of 1.1% must be reached before expulsion of the gas from the source rock becomes significant. An R_o of 1.1 was used by the USGS to define the boundary between the basin-centered gas-saturated zone and the gas-water transitional zone. Thermal maturity elevation maps prepared by the USGS were used in this study to guide the definition of the play boundaries. Play boundaries were adjusted to accommodate gas-saturated rock defined from log analysis, lying above the thermal maturity elevations. The boundaries were also adjusted to accommodate wells producing outside the thermal maturity limits, in particular in southwest Piceance around the Plateau Field. Separate resource estimates were made for rocks lying inside the R_o 0.73 and R_o 1.1 boundaries so that comparisons with the USGS estimates could be made.
3. Porosity and Water Saturation: For the USGS estimate, porosity and water saturation were based on core analysis of the MWX wells and supplemented with some core data from other areas of the basin. A constant value of 0.035 (the product of $\phi * S_g$) was used for each play. In contrast, Scotia used formal digital tight gas log interpretation, calibrated to corrected core data where possible to calculate rock properties on a foot-by-foot basis. Appendix B of our GGRB report (Scotia, 1993) details the methodology. This technique provided detailed porosity and water saturation data and more importantly, provided the distribution of these parameters and their interrelationship. Two sets of porosity and water saturation distributions were generated. The first corresponds to the larger sand count generated using a 50% V_{clay} cutoff, which approximates the thickness generated by the USGS; the second corresponds to the net reservoir rock thicknesses defined during this study. The following key differences to the USGS approach were found:
 - a. A single average porosity value fails to address the variation in porosity within the basin. Porosities were not normally distributed but rather were distinctly skewed such that the lower porosities form the bulk of the distribution. These distributions are discussed by play later in this report.
 - b. Porosity distributions vary between plays; the best overall porosities and greater sand count are found in the Marine Play.

- c. Water saturations in the lower porosity rocks were high, tending towards 100%, as porosities reduced toward zero. Since the porosity is skewed in favor of the lower values, a significant portion of the rock volume has high water saturations.
- d. Water saturations corresponding to the greater sand count are generally lower in the basin-centered gas-saturated region and increase toward the basin margin.
- e. Application of the cutoffs resulted in significantly smaller reservoir rock thicknesses.

These factors resulted in significant reduction in calculated GIP in comparison to the USGS estimates.

- 4. In this study reservoir temperatures were calculated for each play using the following gradient: $T_r = 70 + 0.018 \times \text{depth}$. This transform was developed from a review of all available WHCS DST and log header temperature data and represents the upper limit or maximum gradient, achievable from a plot of temperature versus depth.

When using a single average temperature gradient, the severe topography variation of the Piceance Basin causes temperatures at reservoir level to be higher beneath the plateaus than those beneath the valleys. In reality, a certain amount of temperature equilibration should occur. For temperatures to be consistent for a given reservoir subsea elevation, plateau temperature gradient must be lower than those in the valleys. Plots of temperature versus depth for wells sorted by kelly busing elevation displayed poorly defined trends by lower temperature gradient with higher temperature gradient. Trend definition however is limited by the geographic variation in temperature gradients and a data set biased by wells drilled mostly in the valleys.

Reservoir pressures were calculated for each play using a gradient of 0.465 psi/foot from the surface. This gradient was developed from a review of initial and final shut-in pressures from DSTs reported by WHCS and from shut-in bottom hole pressures estimated from shut-in tubing pressures from tests reported by NPS and WHCS. Essentially all the data available to Scotia indicates reservoir pressure gradients at or below normal. However, evidence of overpressuring is cited in the literature, though a large overpressured zone similar to that which exists in the central Uinta Basin has yet to be defined. Johnson (1987) identified "possible" areas of overpressuring based on DST results and mud weight data on the northwest flank of the Divide Creek anticline, along the Grand Hogback, and at the MWX site. Overpressuring in Fluvial sands at Divide Creek and possibly along the Grand Hogback appears related to recharging by meteoric waters at the Mesaverde outcrop. Overpressuring at the MWX

site beginning 1,900 feet above the Rollins-Trout Creek sandstone may be related to present day generation of hydrocarbons, since Iles outcrops along the Grand Hogback are not at a sufficiently high elevation to cause overpressuring in the Marine interval. Overpressuring related to present day thermogenetic gas generation may also exist in the basin deep where temperatures exceed 190° F. Consequently, the use of a normal pressure gradient may contribute to a low reserves estimate in the deeper parts of the basin.

Gas gravities were gathered from a variety of sources, including gas analysis reports and field averages reported in the Rocky Mountain Gas Atlas. This data was averaged to derive a Mesaverde average gas gravity of 0.62.

Using this data and the Hall-Yarborough (1973) method for calculating gas deviation factor (z), a FVF versus depth relationship was derived for each play.

5. Calculation of GIP: The USGS calculated GIP deterministically for each play using the volumetric maps and average rock and fluid properties described above. GIP was also estimated probabilistically utilizing lognormal distributions of the input parameters developed using the Delphi method (subjective judgments made by a panel of geological experts). Triangular distributions of recovery factors representing current and future technology were applied to the GIP probability ranges to derive estimates of recoverable gas. FASP (Fast Appraisal System for Petroleum), developed by the USGS, was used to perform the computations (Crovelli and Balay (1986) and Crovelli (1987, 1988)).

During this study two estimates of resource in-place were made. The first was a redetermination of the "total resource" using the sand thicknesses (50% V_{clay} cutoff) which approximate those used by the USGS, and the corresponding rock property distributions developed from log analysis during this study. The second was a determination of that portion of the total resource which would be expected to contribute to reserves. This was estimated using the net reservoir rock thicknesses (porosity, V_{clay} , water saturation and permeability cutoffs) and the corresponding rock property distributions developed during this study. The difference between these two figures represents that portion of the "total resource" which is not expected to contribute to reserves.

Two approaches were used to estimate resource in-place in order to describe both the geographic (areal) and vertical distribution of GIP.

- (a) Volumetric Mapping. Net "pay" thicknesses were contoured and planimetered to derive the net rock volume. At the same time, sand thickness maps were also

planimetered to derive the rock volume for the total resource. A Monte Carlo simulator was then used along with the appropriate distributions of porosity, water saturation and FVF, to derive the two estimates of resource in-place.

- (b) Depth Slicing. Both the sand thickness and Scotia's net reservoir rock thickness maps were depth-gridded to segment them into 500 foot thick depth slices. Based upon well control, log-derived rock properties within each 500 foot depth slice were compiled as distributions of porosity, water saturation and permeability. Utilizing the appropriate depth, FVFs were calculated as described above, and GIP for each 500 foot depth slice for both the sand thickness and pay thickness maps was calculated deterministically.

Comparison of previous estimates of in-place and recoverable gas resource for the Piceance Basin Mesaverde is difficult due to differing methodologies and differing price and technology assumptions. The National Petroleum Council (NPC, 1980) estimated 33 Tcf of ultimately physically recoverable gas independent of price in the Piceance Basin. The USGS estimate (Johnson et al, 1987) estimated a mean recoverable resource of 13.4 Tcf under the assumptions of current technology and \$5.00/ Mcf gas and a mean estimate of 67.9 Tcf under the assumption of advanced technology and an unspecified gas price assumption. The NPC 1992 study estimated 17.4 Tcf under a current technology case and 27.9 Tcf under advanced technology. These estimates address the Mesaverde tight sand section recoverable resource potential. The potential for coalbed methane in the basin is also significant and is separately estimated.

The methodology used by Johnson et al (1987) involving a mapping and volumetric approach to quantification of reservoir volume and then application of volumetric parameters to generate a probabilistic estimate of in-place resources is similar to that utilized by Scotia in this study. The principal differences between the methods of Scotia and Johnson et al (1987) involve quantification of reservoir properties which were estimated using the Delphi approach (consensus estimates by experts) in the USGS case versus Scotia's approach of measuring and mapping such properties. The principal differences between the USGS estimate and Scotia's estimate involve differences in the porosity distribution as well as the magnitude of the correlation for water saturation. As noted in Scotia's previous report on the GGRB, significant resource volumes are resident in extremely tight rocks; rocks too tight for exploitation by current frac technology. This places a significant portion of the evaluated resource beyond the reach of current frac technology based on the economic parameters assumed. This has a significant impact on the evaluation of potentially recoverable resources or reserves in that a significant portion of the evaluated in-place resource is technologically *nonviable* and thus not available for conversion into reserves.

Evaluation Difficulties

Basic volumetric and recovery factor calculations are complicated by certain physical properties peculiar to tight gas reservoirs. Recognition of these factors is important in attempting to predict the performance of tight gas wells.

1. Study of core data indicated that in many cases porosity and permeability are poorly correlated, if correlated at all, particularly in the lower porosity ranges.
2. Distributions of log-derived and measured porosities tend to be heavily skewed towards the lower porosity ranges.
3. Because the bulk of porosity development is of secondary origin, much of such porosity is poorly connected in a conventional sense (i.e., via normal pore throats), but rather requires connection via an anastomosing network of natural fractures, micro-fractures and capillaries.
4. Due to the poor relationship shown in most plays between porosity and permeability, selection of the most porous zones for completion attempts may not necessarily encounter the greatest natural fracture permeability. However, since it has been shown that frac treatments in the basin achieve more significant height growth than has been previously modeled, it is likely that most fracs do not stay within the perforated zone and may in fact grow by up to several hundred feet above and/or below into adjacent horizons. This opens the possibility of accidentally fracturing into the more naturally permeable sections. This has been observed in the GGRB that wells produce considerably more than can be attributed to the perforated zone. In such situations contributions from overlying and underlying reservoirs can be inferred.
5. Examination of frac, DST and production data within various areas and from play-to-play indicate that lateral continuity of the pay zone of interest is of extreme importance in controlling long-term well productivity. Where sands have a greater degree of lateral continuity, the ability to place a successful frac treatment is much enhanced. Where sands are lenticular or display lateral continuity only in given directions (e.g., channels), the ability to create a successful commercial completion is reduced. In such cases, directions of maximum in-situ stress and maximum direction of geological continuity must be fortuitously oriented to be able to exploit the natural directions of more favorable reservoirs. In a similar fashion where natural fracturing within the reservoir is not oriented favorably with respect to directions of maximum in-situ stress, frac results can be variable or disappointing. The subtleties of these geological and geomechanical properties are difficult to measure and predict and complicate the

process of effecting a commercial completion. That is, even where log responses and log analysis indicate excellent pay potential in comparison to logs in wells which have been superior producers, the inability to predict and quantify lateral variation may render completions as marginal or noncommercial.

Quantifying Recovery Factors

In considering conventional gas reservoirs, the subject of drainage and spacing is not so much at issue as when dealing with tight reservoirs. For conventional reservoirs, well spacing can be decided upon without too much concern for areal reservoir continuity such that each well can be assumed to adequately drain the reserves within its no-flow boundaries. These boundaries surround the well at a position dependent upon the offtake rates of surrounding wells and the variability of reservoir characteristics between wells. In this scenario, recovery factor is independent of well spacing, whereas per well recoverable reserves and the rate of recovery for a given reservoir are very dependent on well spacing. Therefore, the concept of a reservoir-wide recovery factor has validity for conventional reservoirs.

In tight gas reservoirs, the ability of a well to drain a given area is dependent upon the amount and effectiveness of naturally occurring permeability (matrix and fracture), its ability to interconnect the porosity within the tight formation, and the effectiveness of a fracture treatment in connecting such natural permeability to the wellbore. Fracture treatments generate fractures which generally propagate in the direction of maximum horizontal stress, and result in circular to ellipsoidal shaped fractures oriented in a vertical or sub vertical plane. Effective drainage by the frac'd wellbore in plan view will tend towards an elongated ellipsoidal pattern as opposed to a circular drainage radius, and the areas drained by individual wells will tend to be proportional to the dimensions of the effective artificial hydraulic fracture.

In expansion drive gas reservoirs, the recovery factor of GIP is proportional to the degree of pressure depletion that can be effected by the well down to its economic limit. The recovery factor will be the P/Z at original pressure, minus the P/Z at abandonment, divided by the P/Z at original pressure. In other words, if 85% of the P/Z value is achieved by the time a well has produced to its economic limit, then the recovery of accessed GIP will be 85%. The economic limit of course will depend upon that point at which revenues no longer exceed expenses and will be a function of prices, royalties, production taxes and operating expense. For any given well, the ability to produce is a direct function of surface versus bottomhole flowing pressures and it can be argued that with all else being equal, all gas wells will recover approximately the same proportion of GIP (that is, will be produced to the same pressure depletion) and hence have approximately the same final recovery factors.

The issue at hand is not so much what the pressure at abandonment is, but rather what

area is being accessed in terms of reservoir drainage down to this pressure. Since tight gas wells may drain only a small area, the recovery factor of GIP within the regulatory spacing limit versus what proportion of that spacing limit is actually drained is the key issue. By example, if a gas well is drilled on a regulatory 320 acre spacing and effectively has a 75% recovery over a drainage area of 40 acres, then the recovery factor could be expressed as the effective recovery of GIP on the entire 320 acre unit ($75\% \times 40/320$), or 9.4% recovery of GIP.

The computation has greater significance than simply determining the recovery factor based upon a regulatory spacing. If in the above example the well was economically viable draining only 40 of the 320 acres, then an additional seven well locations would be available by downsizing the spacing unit to 40 acres, whereby similar recovered volumes could be anticipated. In other words, if the spacing unit was not reduced, 87.5% of the potentially recoverable gas would be bypassed by drilling on a 320 acre spacing. Many examples of bypassed reserves such as this occur in tight gas provinces. Cipolla (1992) reports virtually identical per well recoveries from wells drilled on an initial 640 acre program that was later down-spaced to 320 acres and then 160 acres. Resulting recovery on the 160 acre spacing averaged 61% of GIP and resulted in reserves growth of 190 Bcf.

The quantification of recovery factors thus becomes a function of well drainage area vis-a-vis the spacing unit area dictated by regulatory field rules. The area difference (spacing less drainage) is proportional to the undrained or bypassed gas that would be available to a reduced spacing (infill drilling) program.

Economic Basement Determination

Economic considerations play a role in the distinction between reserves and resources. For resources to qualify for potential conversion to reserves, such resources must be producible at rates and with ultimate volumes that will repay the cost of drilling and completion and provide a normal profit. For the purposes of this study, production which generates an operating income stream discounted at 10% (PV10) that is equal to drilling and completion costs represents the break over point for commerciality. The present value calculation assumes a royalty of 18.75%, severance and ad valorem taxes of 8%, operating costs of \$500/month, and a \$2.00/Mcf wellhead gas price. Drilling costs are a function of depth with separate relationships corresponding to dry hole cost and total completed well cost. The \$2.00/Mcf gas price was used as a requirement of this study. The effect of other prices on the *economic basement* calculation is described in Appendix A.

It should be noted that the use of \$500/month operating cost is about half of the actual per well average cost currently experienced. This figure was chosen since, due to the low producing rates of most wells, the application of the \$1,000/month figure caused about half the wells in the basin to be subeconomic. Since so many wells were producing at what

appeared to be subeconomic rates, it was concluded that other factors were at play. Such factors probably include one or more of the following:

Curtailment: Due to low gas prices, it was noted that a significant number of wells were curtailed or shut-in for a portion of the year.

Section 29 Tax Credit: Qualifying wells drilled through the end of 1994 received a tax credit of almost \$1.00/Mcf of gas produced under this incentive program. The tax credit was not modeled as part of the economic evaluation of existing well reserves since the ability to use the credit was operator-specific and calculation of the effect of the credit at the well level was fraught with uncertainty.

Dual Completions: There were a significant number of dual completions in the basin, although this practice now appears to have been discontinued. Since each completion is reported as a separate production stream, modeling each with half operating costs is required to determine the economic limits.

For the above reasons, a \$500/month operating cost was assumed. This has the effect of calculating remaining economic reserves in many low rate existing wells and also gives a "benefit of the doubt" tilt to the evaluation.

It should be clearly stated that the economic cutoff for qualification of reserves as used herein represents a payout of drilling costs plus a profit motivation. In practice, reserves are considered commercial if they produce sufficient income to cover operating costs without consideration of whether the capital expenditures incurred to drill and put wells on stream are ever paid out. That is, while operators do not intentionally drill wells that do not pay out, things do not always turn out as planned. Such situations are commonplace and are not predictable until after the wells have been put on stream. While numerically non-payout wells may number 60% of the total producing well population, they contribute about 10% of the total EURs.

To acknowledge the economic requirement for reserves qualification, the term *economic basement* is introduced. This term recognizes the fact that drilling costs increase with depth and hence the reserves that must be found to repay those costs must also increase with depth. *Economic basement* as a concept represents a depth where the curves cross. That is, where the risk weighted average reward equals the risk weighted average cost. Below this depth the probabilities are that expense will outweigh reward. Above this depth the reverse is true. *Established* resources are those located above *economic basement* and those located below are termed *nonestablished* resources.

Economic basement in the context of a resource/reserves evaluation represents a

convenient break point for separation of the known from the unknown. In practicality, most of the productive horizons are situated in the shallower depth ranges, while resources are distributed variously with depth from play-to-play. In all cases, knowledge, development, performance, and control for the deeper zones is inferior to the shallower. As a result, the extrapolation of models developed for the better controlled shallow horizons into the deeper zones is not warranted unless an analogy can be developed that is justified by real data.

Determining *economic basement* depth for each play was approached as follows:

1. **Determine Reward Expectation.** In order to justify the expense of drilling, the target reserves must be of sufficient magnitude to provide a profit incentive. This magnitude must be sufficient to also outweigh the dry hole risk component. Since the Mesaverde play is relatively new (generally less than 20 years old) and drilling density low, the distribution of recent existing EURs for each play was used as the model for future discovery expectation. It is not known whether future results will have the same distribution or whether a "depleted" distribution would be more representative. This study used the recent existing per well EURs as the model for future expectation. This approach is more likely to err on the optimistic side.

Sampling of the EUR distribution assumed a program (multi-well) approach. That is, rather than taking the median value which would be the expectation for a single well, the distribution was split into five units, each representing 20% of the EUR population and each unit was sampled at its midpoint leading to P10, P30, P50, P70, and P90 samples, each having an equal probability of occurrence. The reward is then calculated by cash flow construction and determining a PV10 for each sample, net of taxes, royalties, operating costs and drilling and completion costs.

2. **Determine Dry Hole Risk.** Historical drilling statistics were compiled to determine the historical dry hole frequency. This consisted of identifying all wells drilled for the play and subdividing those wells based upon the total depth (TD). Wells which TD'd in a play were regarded as having that play as their objective. Dry hole percentage was then determined. Note that a significant number of completions were made that failed to produce commercially and were "worse than a dry hole" since the expense of a completion and frac was incurred. Such failed completions were accounted for in the EUR distribution and were handled as negative cash flow components. The argument may be made that discrimination should be made between well classes (exploration versus development) since success levels are typically higher when considering development wells. Again, due to the immature nature of the play and the requirement for frac treatments to be successful (a significant element of mechanical risk), the distinction between an exploration (wildcat) and a development well becomes hazy. We elected to simplify the model by selecting a success ratio based on historical drilling

data that typifies the current status of the play under consideration. This will be weighted towards development drilling success levels in the more mature areas and towards exploration or wildcat success level in less known or less developed portions of the play.

It should be noted that the dry hole risk model is applied to the calculation of reserves in the explored and currently productive parts of the basin, hence the use of development drilling type success ratios. This model is not used in the unexplored portions of the basin since resources located in such areas fall into the *nondemonstrated* or *speculative* categories.

3. Construct Expected Monetary Value (EMV) Analysis. The EMV analysis seeks to determine the *economic basement* depth as being that point where the EMV is zero. That is, above that depth, EMV is positive and risk weighted rewards are greater than risk weighted costs. Below that depth the cost of failure is greater than the risk weighted reward and EMV is negative. In summary, the EMV calculation takes into account the expected dry hole probability, the expected distribution of EURs that will be encountered, and the drilling cost environment versus depth. Figure 10 illustrates this calculation for a single depth. *Economic basement* represents that depth where the EMV equals zero.

The *economic basement* concept seeks to determine that depth at which the reward (profit) expectation no longer supports the risk (cost). This forms a logical dividing point for each play for performing reserves calculations. *Economic basement* is a dynamic depth. It is deepened by increasing gas prices, incentives, reduced drilling cost, higher success levels and larger finds. The reverse also applies. Since *economic basement* as a concept is dynamic, changing as its defining parameters change, the resources in the *established* and *nonestablished* categories will also be dynamic.

ECONOMIC BASEMENT DETERMINATION
PLAY: FLUVIAL MESAVERDE

Figure: 10

BASE PARAMETERS:					
8200	DEPTH (FEET)	2.0%	PERCENT DRY		
47	DRY HOLE \$/FT	2500	P10 EUR (MMCF)		
65	COMPLETED \$/FT	610	P30 EUR (MMCF)		
385	DRY COST (\$K)	240	P50 EUR (MMCF)		
533	COMPL COST (\$K)	90	P70 EUR (MMCF)		
0.78	AVG PV10, \$/MCF	23	P90 EUR (MMCF)		

EMV CALCULATIONS		PERCENT	UNRISKED	RISKED
COMPLETIONS	P10	19.6%	1417	278
	P30	19.6%	-57	-11
	P50	19.6%	-346	-68
	P70	19.6%	-463	-91
	P90	19.6%	-515	-101
DRY HOLES		2.0%	-385	-8
EXPECTED MONETARY VALUE (\$K)				-1

EURS FLUVIAL PLAY

Reserves Calculations

Starting with the resource itself, the following steps were employed in estimating reserves:

1. **Reevaluation of Basic Resource:** This has previously been described, and consisted of applying a more sophisticated porosity, water saturation and FVF model and depth slicing this data.
2. **Identification of a *Technologically Viable* Reservoir:** Based on log analysis, pay quality zones were identified, isopached and GIP calculated by depth slice.
3. **Removal of *Technologically Nonviable* Resources:** By subtracting the pay quality GIP from the total resource GIP, the GIP in nonpay quality rocks was determined. This quantity is termed *technologically nonviable* since current frac technology has failed to yield a commercial completion in such reservoirs. Such reservoirs will have in-situ permeabilities below 0.001 md in general. It is important to identify and quantify this portion of the total resource since future technology improvements will move portions of it into the pay category. Note that in the case of the Piceance Basin, *technologically nonviable* also includes a large volume of high S_w rock due to no gas charge or flushing, particularly in the Fluvial.
4. **Removal of *Nondemonstrated* Resources:** A significant fraction of the *technologically viable* resources is located in geographic areas or stratigraphic units that have not established any commercial production or about which very little is known. That is, while sands may calculate as potentially productive based on log analysis, such sands have either not been tested or have been tested but with poor results and were thus included within the *nondemonstrated* category.

Until such time as a technology is developed to successfully exploit the *nondemonstrated* category, such resources will be excluded from consideration from a reserves quantification viewpoint.

5. **Removal of *Speculative* Resources.** After removal of *nondemonstrated* and *technologically nonviable* resources, the remaining volume represents *demonstrated* resources. *Speculative* resources are that portion of *demonstrated* resources that lie in deep basinal areas below *deepest commercial production*. Their quantification depends upon extrapolation of geological mapping and has a significant degree of associated uncertainty. Because of this uncertainty, and lack of a production analog, *speculative* resources were excluded from consideration for reserves quantification purposes.

6. **Subdivision Based on *Economic Basement*:** The *economic basement* depth conveniently separates resources which on average represent economic targets from those which do not. This does not imply that all resources above *economic basement* are convertible to reserves via application of an appropriate recovery, nor does it imply that all resources below *economic basement* will contain no potential reserves. Rather, *economic basement* represents the break over point from one reserves and risk environment to another. The aspect of risk (drilling and reserves quantity) must be considered in order that the commerciality criterion to qualify as reserves is satisfied.
7. **Derivation of Risk and Recovery Models:** After all of the constraints described above have been applied, the remaining volumes represent *demonstrated* resources distributed in accordance with regional isopachs. It is recognized that the entire regional isopached volume will not all be uniformly productive. Dry holes exist within the mapped area as do productive wells, some of which are commercial (have reserves) and some of which are noncommercial (not qualifying as reserves).

The recovery factor model thus requires not only a percent recovery of GIP factor, but must also take into account a factor representative of dry holes and noncommercial completions. This "non-reserves" factor represents that proportion of the *demonstrated* resources isopached volume that will not be commercially productive for a variety of reasons. Such reasons could include lateral discontinuity of reservoirs, unfavorable stress conditions for frac treatments, absence of natural fractures, etc.

The recovery factor model developed for this study was constructed as follows:

- a. **Determine Base Recovery Factor.** For each well in the sample, a base recovery factor was derived from initial and final static bottomhole pressure. The latter was assumed to be 500 psi, which is probably optimistic and represents a minimum abandonment pressure for economical production. However, no actual abandonment pressure measurements were available. This assumed abandonment pressure resulted in base recovery factors varying from 59 to 87% and averaging 77%.
- b. **Determine Average Drainage Area.** Based on a sampling of completed tight gas wells, average drainage areas were calculated using the EUR from production performance analysis, the recovery factor and the volumetric parameters for the perforated interval based on log analysis. This result was checked against the average drainage area determined by Fetkovich type curve analysis on wells exhibiting a significant initial transient period with a reasonable match.

- c. **Determine Range of Drainage Area.** Drainage area was plotted versus EUR and a log-log regression performed (Figure 11). The scatter on this plot is due to differences in petrophysical properties, mostly net pay thickness. By drawing lines that are parallel to the regression fit that effectively bracket all data points, an upper, most likely and lower relationship for EUR versus drainage area was determined.

A minimum commercial volume was calculated representing the EUR that resulted in an operating income stream with a PV10 equal to drilling and completion costs at the representative depth for the play being considered. Using this EUR, the upper, most likely and lower drainage areas were determined graphically as shown in Figure 11. Note that the minimum economic drainage areas can be quite small due principally to significant perforated pay thickness. In this example, the following were derived for a minimum economic EUR of 490 MMcf.

**EXAMPLE MINIMUM ECONOMIC
DRAINAGE AREA MODEL**

Upper Area	285 Acres
Most Likely Area	90 Acres
Lower Area	30 Acres

- d. **Determine Noncommercial Fraction.** The distribution for the fraction of wells expected to be noncommercial was determined by constructing a probability plot of drainage areas and using a smoothed correlation, reading off the percentage of drainage areas smaller than each of the areas representing the upper, most likely and low areas as shown on Figure 12.

EXAMPLE NONCOMMERCIAL FRACTION MODEL

Upper Area	92%
Mostly Likely Area	70%
Lower Area	35%

For example, for the most likely case, there is a 70% probability that a well will drain less than 90 acres and hence be noncommercial.

- e. **Determine Dry Hole Fraction.** This represents the fraction of the resource volume condemned by dry holes. Historical drilling data from the WHCS was

used to establish dry hole percentage to date (see Table 3). This data was used as a guide and was judgmentally rounded to reflect future dry hole expectation. For plays or portions of plays with an established drilling history, the dry hole statistics will tend to reflect development well drilling success ratios. Where less information is available and where commercial development has not been established, or is in its infancy, the statistics will reflect exploration well success ratios. The dry hole factor thus serves a dual role, reflecting not only historical success, but also maturity of the target in question.

- f. Recovery factor (RF) was the net of dry hole fraction (DHF), noncommercial fraction (NF), and base recovery factor (BRF), combined as follows:

$$RF = (1-DHF)(1-NF)(BRF)$$

**FIGURE 11: RECOVERY FACTOR
MODEL DRAINAGE
AREA VS EUR**

**FIGURE 12: DRAINAGE AREA PROBABILITY
PLOT NON-COMMERCIAL
FRACTION DETERMINATION**

EXAMPLE RECOVERY FACTOR CALCULATIONS

	Dry Hole Fraction = 0.02
	Base Recovery Factor = 0.72
Maximum	$(1-0.02) \times (1-0.35) \times 0.72 = 0.459$
Most Likely	$(1-0.02) \times (1-0.70) \times 0.72 = 0.212$
Minimum	$(1-0.02) \times (1-0.92) \times 0.72 = 0.056$

The maximum, most likely and minimum RFs defined a triangular distribution which was applied along with distributions for porosity, water saturation (as a dependent variable to porosity), FVF, and a single deterministic value for rock volume in a Monte Carlo simulation to derive a recoverable gas estimate expressed as a distribution.

Porosity and water saturation distributions that were used for each play are discussed and graphically displayed in the sections on each play.

8. Application of the Model. For model application, each play was segmented into sub plays based on level of thermal maturity. Each sub play was characterized by its own porosity and water saturation distributions. Then each sub play was segmented into two basic depth slices.
 - a) Top of play to *economic basement*.
 - b) *Economic basement* to deepest commercial production.

Each depth slice was characterized by its own dry hole fraction, noncommercial fraction and recovery factor distribution. As with any estimate of reserves, such estimates are subject to revision as ensuing developments provide additional data.

BASIC TECHNICAL PARAMETERS

Log Interpretation

Statement of Problem: Comparison to Conventional

Use of conventional log interpretation techniques within tight reservoirs meets with only limited success in accurately defining rock properties. This results from the fact that the normal logging tools are operating outside their optimal design range and the fact that tight reservoirs have particular characteristics which differ significantly from conventional gas reservoirs. These include variable invasion profiles causing variable gas saturations within the invaded zone, considerable uncertainties in formation water resistivity, variable grain densities and the presence of clay minerals, both original and authigenic, distributed in various geometries. Special log interpretation techniques are required to account for these factors as detailed in Appendix B of our GGRB report (Scotia, 1993).

Some of the more successful methods for dealing with log interpretation problems in tight reservoirs are those developed by Kukal (1981 and 1984). These methods are included within Scotia's proprietary log interpretation program, SLOG. The objective of the log interpretation exercise was to derive a set of rock properties including sand thickness, net gas pay, effective porosity, water saturation and a log-derived permeability that could be used to map the distribution of gas and in volumetric calculations of GIP.

Formation Water Resistivity

Formation water salinity data available from a variety of sources indicate wide ranges of R_w , making the determination of a blanket R_w for a given play frustrating and problematic at best. The determination of R_w is complicated by the fact that tight reservoirs produce little if any water, and that which is produced often contains condensation. R_w estimates from the spontaneous potential (SP) curves are generally unreliable due to poor development of the SP log in tight gas sands and the absence of a definitive wet clean reservoir for calibration purposes. This also limits the R_{wa} and Pickett plot techniques. Attempts to post and contour available R_w data showed no particular pattern and confounded any attempts to contour the exhibited variation.

The R_w used on a well by well basis was determined via Kukal's (1984) iterative method as described in Appendix B of our GGRB report (Scotia, 1993), and then compared against R_w values reported in the literature at reservoir temperature. In selecting a final R_w for use, generally the lower of these two values was used. Kukals

(1984) equation, which was derived from a combination of the neutron and density response equations, iteratively solves for S_{dn} (the saturation of the zone investigated by the neutron and density tools). The equation is reversed to solve for R_w . Use of S_{dn} to derive an appropriate formation water resistivity was restricted to sands which were relatively clean (low V_{clay}), in gauge, ideally where a neutron-density gas effect is apparent and where $S_{xo} - S_{dn}$ is a maximum when S_{xo} is not equal to S_w .

S_{dn} and consequently R_w derived from S_{dn} , decreases as gas gravity increases. To account for changes in gas density with depth on a basin scale, a transform was developed for the Piceance Basin and used to adjust density and neutron responses to hydrocarbons and as a function of change in depth.

$$R_{hoh} = a + b * depth + c * depth \sqrt{depth}, \text{ Where:}$$

R_{hoh}	=	Density response to hydrocarbons
a	=	-0.01277921
b	=	4.37374 E-05
c	=	-2.4589 E-07
P_{hinh}	=	$R_{hoh} * (9 * x / (12 + x))$, Where:
P_{hinh}	=	Neutron response to hydrocarbons
x	=	Hydrogen-carbon ratio (3.82)

Porosity

Porosity determination in tight sands must take into account several particular physical properties that influence not only the logging tools themselves but also the interpretation methods for deriving an effective porosity measurement. These effects include:

1. Variable gas saturation in the invaded zone or absence altogether of an invaded zone producing an inconsistent density and neutron log response to hydrocarbons.
2. Sonic log values are suspect in tight sands since the sonic log will tend to record primary porosity and bypass secondary porosity. In many cases tight sands have a predominant porosity network of a secondary origin that may be bypassed via sonic log readings.
3. The presence of clay minerals and abundant lithic fragments causes grain

densities to vary and hence matrix values used to derive log porosities will also vary.

4. The overpressured nature of the sediments in certain areas in the basin and the normal practice of drilling wells balanced or under balanced as well as the generally fractured nature of the formation, can cause severe hole caving. This markedly affects the pad tools (density log) and can also affect other log measurements where boreholes are particularly rugose.

Porosities were derived from log data using the methods of Kukal (1984) developed specifically for tight gas sands. Kukal's (1984) equation iteratively solves for S_{dn} to correct for porosity tool gas effects. Details of these calculations are included in Appendix B of the GGRB report (Scotia, 1993).

Water Saturation

Due to the presence of abundant authigenic clay minerals, a shaly sand approach was taken in evaluating water saturations involving use of the total shale (Simandoux) equation. While recent work in the basin has indicated that the use of a dual water or Waxman-Smits type of approach has been effective in obtaining reasonable results, the general lack of cation exchange capacity data except in extremely local areas limited the use of such techniques for the purposes of a project of this scale.

Archie exponents used in determining water saturation were investigated from a variety of sources and after considerable experimentation and consideration of net overburden (NOB) effects, the following were selected as representative:

$$\begin{array}{rclcl} a & = & 1 & & \\ m & = & n & = & 2.0 \end{array}$$

Permeability From Log Data

Attempts to derive permeability from log information are not usually highly successful. Correlations based on core to log relationships can be locally valid, however, extrapolating these into other areas or other formations often introduces the potential for considerable error. The presence of natural fracturing can also provide a separate and unquantifiable permeability overlay to the natural fabric of the tight reservoirs.

The equations developed by Kukal (1984) based on his study of samples from the MWX wells in the Piceance Basin provided a reasonable permeability approximation. Two equations were used: the first required input values of porosity, water saturation and clay volume; the second equation eliminated the saturation fraction which can have a fairly weak correlation with permeability in low permeability rocks. Log permeabilities derived from this study are displayed in the discussion of each individual play.

Permeability

The single most important factor and the single biggest unknown in dealing with tight reservoirs is permeability. By definition, tight reservoirs are defined as having a natural in-situ permeability to gas of less than 0.1 md. The effective range for completion of tight reservoirs, based principally on the current frac technology, is between 0.001 and 0.1 md. At permeabilities below this range, fracture treatment is commonly not successful and above this range is commonly not necessary.

Permeability in tight reservoirs is not only low but complex in its source. Because the sediments are tightly compacted, cemented and contain abundant secondary mineralization and grain dissolution, the producing mechanism in the reservoir is quite different from that of a conventional reservoir. Rather than having discrete pores and pore throats, the porosity available within the tight sand may be distributed in a non-uniform fashion and connected by an anastomosing network of micro-fractures and fine capillaries. As such, a standard core plug sampling of cores from tight sands may not do justice to the range of parameters that may be expected from the gross sand itself and also may have permeabilities so low as to be not measurable utilizing standard core analysis techniques.

In addition, tight sands are markedly influenced by the effects of unloading and require significant corrections to convert surface ambient measurements to in-situ conditions as discussed in Appendix A of our GGRB report (Scotia, 1993).

Scotia's proprietary COREPRO software was utilized to process a large database of core information collected for the Piceance Basin. The COREPRO software performed the necessary corrections for overburden and the corrections for gas slippage (Klinkenberg) and brine saturation.

Corrections to In-Situ Condition

Prior to the development of automated equipment able to measure porosity and permeability at NOB, in use in many laboratories today, measurements were taken at ambient conditions. Essentially all the core data available for this study was measured

at ambient conditions and consequently required the following corrections to represent in-situ conditions.

1. Overburden corrections to restore porosity and permeability to in-situ conditions. NOB corrections to porosity were developed using core measurements from the MWX wells as a function of both changes in porosity and NOB. Because of the increase in magnitude of correction with decreasing porosity, the data set was split into samples greater than and less than 5% porosity, this being the approximate cutoff between reservoir and non-reservoir rock. Correction transforms taken from plots of percent reduction in porosity versus overburden pressure are as follows:

$$\begin{aligned} \text{Porosity} < 5\% \quad y &= -2.3641 + 0.1566 \sqrt{\text{NOB}} \\ \text{Porosity} > 5\% \quad y &= -1.2781 + 0.0904 \sqrt{\text{NOB}}, \quad \text{Where:} \end{aligned}$$

y = percent of porosity reduction.

A normalizing factor was developed to adjust the percent reduction in porosity according to the value of ambient porosity as follows:

$$\begin{aligned} \text{Porosity} < 5\% \quad y &= 3.2167 - 0.5140 * P_{hi} \\ \text{Porosity} > 5\% \quad y &= -0.3085 + 10.4069/P_{hp}, \quad \text{Where:} \end{aligned}$$

y = normalized percent reduction.

Note that the correction for porosities greater than 5% is significantly smaller than that using the Jones and Owens (1980) transform applied in the GGRB study (Scotia, 1993), whereas the correction for porosities less than 5% is similar.

In the GGRB, the permeability overburden correction assumed an average NOB of 4,650 psi, since it was estimated that NOB was essentially constant below 9,000 feet due to an increasing overpressure gradient with depth. In the Piceance Basin, the bulk of the play areas are interpreted to be normally pressured with NOBs which increase with depth. Consequently, the correction must account for variations in permeability and NOB. Combined overburden and gas slippage permeability corrections were generated from MWX core data which are discussed below.

2. Correction of air permeability for gas slippage. The Klinkenberg correction is large for tight gas sands. This correction increases with decreasing permeability and varies depending upon the gas used in the permeability measurement (usually air which is mainly nitrogen) and also the mean flowing pressure. The following expression and associated exponents were used to correct ambient air permeabilities for the effects of gas slippage and overburden:

$$k_{airNOB} = B k_{airAMB}^m \quad \text{Where:}$$

		1,000 psi	3,000 psi	4,000 psi
> 1md	B	.70	.65	.60
	m	1.0245	1.0402	1.0571
< 1md	B	.70	.65	.60
	m	1.4048	1.6297	1.7533

The correction transforms used in the GGRB report are less severe than the above expression.

3. Correction to absolute liquid permeability. The application of the above corrections yields a NOB corrected dry Klinkenberg permeability which is often higher than a measured absolute liquid permeability. This is because the correction for gas slippage does not account for possible rock fluid interaction and alteration of pore geometry during the drying process (e.g., collapse of fibrous illite clay in high temperature ovens). A correction was developed to convert dry Klinkenberg to absolute liquid permeabilities based upon work by Jones and Owens (1980) as summarized below and detailed in Appendix B of the GGRB report (Scotia, 1993).

$$\begin{aligned} k_w &= k_{\infty}^{1.32} \text{ for } k < 1 \text{ md @ NOB, Where:} \\ k_w &= \text{Absolute liquid permeability, md} \\ k_{\infty} &= \text{Dry Klinkenberg permeability @ NOB} \end{aligned}$$

4. Correction to effective gas permeability. Jones and Owens (1980) determined from their tight gas sand data set that NOB corrected absolute liquid permeabilities approximate effective gas permeabilities measured at irreducible water saturation. Consequently, no further corrections were applied.

Correlation of Core, Log and Test Permeabilities

Based upon data collected in this study, considerable difficulty was found in correlating permeabilities derived from differing sources. Some of this difficulty is related to the way in which each parameter was measured and the effective volume of the reservoir that the measurement represents.

As noted, core and log correlations can be developed which are valid in localized areas but may provide poor correlations in other areas due to various nonquantifiable factors that necessitate a differing empirical relationship. Well test-derived permeabilities are representative of a much larger reservoir volume than those derived from log and core data and thus take into account a greater degree of heterogeneity. Suffice to state that due to the generally variable nature of tight reservoirs, it is a rarity to have test-derived and core/log-derived permeabilities match with any high degree of consistency.

Reservoir Pressure and Temperature

Volumetric GIP estimates require a knowledge of reservoir pressure and temperature in order to determine FVFs. Therefore, it was necessary to develop both pressure and temperature versus depth relationships for the basin. Three types of data were employed for determining reservoir pressure: measured formation pressures from DSTs and hydrostatic pressures from DSTs and wellhead shut-in pressures from initial potential tests.

A series of plots were then prepared using each of the data sets to illustrate the relationship between static reservoir pressures and hydrostatic pressures and depth (Figures 13 and 14). Analysis indicated that there is no evidence of overpressuring in this data set and a pressure gradient of 0.465 psi/foot was used in calculating the FVF.

Bottomhole temperature data was available from two sources: firstly from the WHCS database and secondly from the logs collected for analysis. For creating a temperature gradient, all data was plotted versus measured depth and a single temperature gradient line was drawn through the maximum temperature data. The equation for the maximum temperature gradient was calculated to be $70^{\circ}\text{F} + 1.8^{\circ}\text{F} \times \text{depth}/100 \text{ feet}$. Figure 15 shows all temperature versus depth data along with several different temperature gradients as a comparison.

FIGURE 13

PICEANCE BASIN MVRD GROUP DST SHUT-IN PRESSURE DATA

FIGURE 14

PICEANCE BASIN MVRD GROUP DST HYDROSTATIC PRESSURE DATA

FIGURE 15

Natural Fracturing

Natural fracturing of low permeability rocks within the Piceance Basin is perhaps the single most important factor in controlling well productivity. Performance of wells within the basin varies significantly and though the impression gained from the results of existing studies is that fractures are widespread throughout the basin, the degree of interconnectedness between fracture sets of different orientations, age and origins varies widely. Unconnected fractures cannot contribute to fluid flow. The following section summarizes the origin of natural fracturing, discusses the major fracture sets identified by previous workers, and attempts to predict areas within the Piceance Basin where natural fracturing potential is greatest.

Natural Fracture Types

Fractures occurring in the Piceance Basin can be divided into two major groups: regional orthogonal fractures and structure related fractures. Regional fractures are not caused by stresses associated with specific geologic structures, but are associated with the tectonic development of an entire region, specifically the Piceance Basin and beyond. Their restored orientations are independent of local structure and are commonly well developed, even in flat lying beds. The Piceance and contiguous Uinta basins are characterized by several sets of regional orthogonal fractures. Structure related fractures are associated with specific features like folds or faults. Local changes in structure trends alters the trend of the restored orientations of structure related fractures.

Fractures Associated With Faults

Fractures associated with faults are related to the same stress state that caused the fault. Knowledge of the fault attitude can be used to predict the orientation, dip and shear of the associated fractures and vice versa. It is difficult to predict the intensity of fracturing associated with faults or the size of the area affected. The strikes of the three potential fractures (one extension, two shear) all parallel the fault so the direction of lateral communication can be predicted. The conjugate shear fracture is often better developed than the shear fracture which parallels the fault (Stearns and Friedman, 1972). Movement along the shear fractures can either increase or decrease the porosity and permeability: increase if rotation and fragmentation of the fracture face occurs; decrease if mylonization along the fracture face occurs as might be expected in shaley sands.

Fractures Associated With Folds

Fractures associated with folds can be grouped into two main patterns, both patterns can consist of one extension fracture and two conjugate fractures. Pattern one fractures are related to the stress that causes the structure formation and form early in the folding process. They form as a result of compression parallel to the bedding dip azimuth. Pattern two fractures are related to the stress within the deforming beds and form late in the folding process. They form as a result of an extension parallel to the bedding azimuth. Pattern one fractures are continuous over large distances vertically and horizontally, while pattern two fractures are smaller (inches to a few feet) and vary in intensity according to their structural position. That is, as fold curvature increases, so does the amount of extension. Pattern two fractures can be abundant along the axial portions of folds, diminishing across uniformly dipping fold flanks.

Summary of Fracturing in the Piceance Basin

Two major regional fracture systems have been identified by Verbeek and Grout (1984a and b) and confirmed by others in the Piceance Basin: the older "Hogback system" dominant in the Mesaverde, particularly in the eastern part of the basin, and the younger "Piceance system" dominant in the Tertiary throughout the basin. The Hogback system is pre-Hogback Uplift in age and has a dominant N80°W strike and a weaker northerly trend set. The Hogback trend parallels the dominant fault orientation within the basin. The Piceance system consists of several fracture sets (five main orientations are reported in the literature) ranging from WNW to NNE, one of which is coincident with, but younger than, the Hogback trend. Piceance fractures are generally present in the Wasatch and Green River formations, though Verbeek and Grout (1984a and b) argue for their presence in the Mesaverde at De Beque Canyon, southern Douglas Creek Arch, and other areas in the southwestern Piceance Basin.

Older Regional Fractures

Dominant WNW oriented fracture sets have been identified along the Grand Hogback by Murray (1967), Verbeek and Grout (1984a and b), Clark (1983), Lorenz and Smock (1985), and others. A weaker, approximately perpendicular set was interpreted by Verbeek and Grout (1984a and b) to be older than the dominant WNW set. At the Rangely anticline in northwestern Piceance Basin Knutson (1977) identified multiple conjugate sets of fractures, the dominant, or master set being northwest, with a less prominent general orthogonal set trending northeast. Similar master joint sets exist along the southern Douglas Creek Arch, trending NW to NNW with a less prominent fracture set striking ENE. These master sets are suggestive of the Hogback system, however, it is possible that they could belong to a separate Uinta system of a different age (Myal et al 1989).

At various locations in the southern Piceance Basin, Mesaverde fractures display a dominant ENE strike. At DeBeque Canyon Verbeek and Grout (1984a and b) and Grout and Verbeek (1985) identified two almost orthogonal fracture sets: an older set striking northeast consisting of long nearly planar, calite fitted fractures and a younger set striking northwest consisting of irregular, shorter, less mineralized fractures. Verbeek and Grout (1984a and b) suggest they are not correlative to the Hogback system, but may correlate to the younger Piceance system. Lorenz and Smock (1985) studied Mesaverde sandstones at Coal Canyon, near DeBeque, and also identified dominant N60E to N70E striking fractures. Similarly, coal face cleats measured in outcrop along the southern Piceance margin have ENE strikes with nearly orthogonal butt cleats, suggestive of the Piceance system. However, Tyler (1995) argues that for

the southern Piceance Mesaverde coal face cleat fracture sets to be Tertiary (Piceance system) in age, the coal would have had to remain unfractured for at least 30 My. However, coal face cleating occurs early in the coalification process according to Tyler (1995). Similar fracture styles and orientations seen in Upper Cretaceous and Tertiary strata do not necessarily imply age equivalence. Tyler estimates that Mesaverde fracture sets present in both northern and southern Piceance are sequential products of the same compressional period (72 to 40 Mya) during which the maximum horizontal compressive stress rotated with time during and after Laramide compressive events.

Tremain and Tyler (1995) note that the Hogback system fracture strikes are normal to the basin fold axis and Grand Hogback thrust front and parallel to the ancient maximum horizontal compressive stress. Face cleat strike orientations in Mesaverde and some Tertiary Wasatch coals measured by Grout (1991) and Tremain and Tyler (1995) in various outcrops around the Piceance Basin perimeter correspond with the ENE and WNW clastic fracture strikes of the Hogback system of the southern and northern Piceance Basin respectively. Tyler notes that face cleat orientations in northern Piceance parallel the current maximum stress directions (NW to WNW) whereas in the south they are oblique to it. Consequently, he predicts that face cleats in northern Piceance may be more open and provide more pathways for production. Garrett and Lorenz (1989) observed a subset of the dominant WNW fractures at Rifle Gap, which either branch off or extend the main set and are thought to be related to local disturbance of movement of the overall structure or fracture wandering in a near isotropic stress field. A younger bed perpendicular set within the Hogback system cross-cuts the older Hogback fractures with strikes ranging between NNW and NE. Grout and Verbeek (1985) interpret these as being regional and pre-Hogback and White River Uplift in age. Garrett and Lorenz (1989) however interpret these cross-cutting fractures as being associated with later folding and uplift of the Grand Hogback and stress relaxation of the strata during erosion and exposure. They are not developed in the subsurface of the flat laying MWX wellsite area. Consequently, they would be more local than regional and related to specific structures.

Younger Regional Fractures

Grout and Verbeek (1985) recognized five regional extension fractures all of which post-date the older Hogback system and local fracture sets related to the late Laramide thrust faulting and folding of the Grand Hogback and related anticlines of eastern Piceance. These are summarized from oldest to youngest below:

F1 (oldest) - NNW. Localized, more abundant in the north and generally restricted to thick sandstone beds. They have steep to moderately steep dip and abut fold parallel fractures on the Divide Creek anticline.

F2 - WNW. Dominant in the northern two-thirds of the basin, they have steep dip and are large in length and height. In the south they are present mainly in upper Cretaceous rocks (according to Grout and Verbeek, 1985) but are well represented at Divide Creek and Wolf Creek.

F3 - ENE. These fractures are dominant in the southern half of the basin, decreasing in intensity to the north. They have steep dip and are large. They are rarely found with F2 joints but some do exist together on the Divide Creek and Wolf Creek anticlines.

F4 - NNE (with F2), NNW (with F3). These fractures are present throughout the basin. They terminate against bed parallel joints, so they formed during and after regional uplift. They formed at high angles to whichever F2 or F3 fractures were dominant.

F5 (youngest) - WNW. These fractures are sparse in the Cretaceous and are most abundant in the Eocene oil shale. They are short sub planar and parallel the F2 fracture set.

Major Folding

Numerous major fold related structures exist in the Piceance Basin which generally follow a NW-SE structural grain. These anticlines include from north to south the Danforth and Wilson Creek, White River Dome, Rangely, Yellow Creek and Piceance Creek anticlines, Sulphur Creek, Douglas Creek, Clear Creek and Crystal Creek anticlines, Grand Hogback monocline, and Divide Creek, Wolf Creek and Coal Basin anticlines. Many of these anticlinal and monoclinal features are interpreted to be associated with thrust faulting at depth. Fold related fracturing identified at Divide Creek should serve as an example of localized fracturing expected across the other folds. Two fracture sets are reported, parallel to the anticlinal axis, which intersect bed dip at 60° to 70° and dip in opposite directions - toward and away from the axial trace. Across the Douglas Creek Arch faults and folds are oriented northeast to east and in the southern Piceance Basin the DeBeque and Grand Mesa anticlines have east and northeast axial orientations respectively.

Major Faulting

Major faults have been proposed by Greis (1983) and Johnson and Nuccio (1986) to explain the basin structure, and several have been identified from the limited seismic data available for the basin (Decker 1995). The proposed faults are not thought to cut late Cretaceous-Eocene strata. The most important of these lies along the Grand Hogback. The fault, a major thrust with 30,000 feet or more of displacement, thrusts the White River Uplift westward over the eastern margin of the

basin during the Laramide. Movement began at the end of the Cretaceous and continued through Paleocene and Eocene. Other proposed faults include a smaller thrust lying beneath the Divide Creek anticline, related to the Grand Hogback thrusting, thrusts beneath the White River Dome, and on the south flank of the Rangely anticline, and smaller scale deep seated thrusts beneath the linear east-west trending DeBeque anticline, Plateau Creek anticline, and Sulfur Creek-Piceance Creek Dome trend. These minor structures cross-cut the monoclinial east-northeast dipping western flank of the basin.

Northwest trending thrust faults in the basin interior in and around the Rulison Grand Valley area were identified by Decker et al (1995) from seismic and aeromagnetic analysis and supported by linear feature analysis of Landsat Thematic Mapper (TM) imagery. Decker (1995) recognized northwest trending structural domains in this area interpreted to be associated with the reactivation of the northwest trending Uncompahgre Pre-Cambrian Highlands. Four major faults, two northwest trending (NW3 and NW4) and two east-west trending (EW2 and EW3) define the perimeter of a paleobasement high, though the NW4 "hinge line" fault is thought to control most of the lower Mesaverde stratigraphy, production and overpressuring in that area. Fracture orientation is not discussed by Decker (1995). However, assuming fracturing develops in association with and parallel to the northwest faults, they would represent a fracture set not recognized as dominant by Verbeek and Grout (1984a and b).

Prediction of Natural Fracturing Potential

Mapping of regional orthogonal fracture intensity should help identify areas of increased fracture potential. Fracturing associated with local structural deformation, such as faulting and folding, superimposed onto the regional fracture grain, particularly if the fold and fault related fracture sets strike obliquely to the regional fracture grain, should enhance the connectivity between fractures. Overlays of a number of fracture related components combined should highlight those areas having the greatest potential for natural fracturing and therefore well productivity.

Figure 16 presents a compilation of regional fracture measurements for the Mesaverde and major folds and faults. In addition, areas identified as having high fracture density from contour mapping of log-derived fracture intensity data (Myal, 1989) have been shaded. These include the Divide Creek anticline and central basin area containing the MWX wells. The map, at a minimum, illustrates those areas where fold and fault related fracturing should prevail and enhance the connectivity of regional orthogonal fractures.

Relationships between radius of curvature and fracture intensity are well documented in the literature for other areas (Stearns and Friedman 1972, Paget and Nester 1990). A second derivative map, which approximates radius of curvature, was created for the subsurface structure drawn on top of the Rollins-Trout Creek formation. However, significant smoothing of contours occurs in areas of sparse well control and it was apparent from an overlay of the major fold map and the second derivative map that the major anticlinal features to the north of the basin were not being resolved. In preparing a basin scale structure, a fair amount of smoothing of contours through well control occurs which exacerbates the problem of resolving local structures. As a consequence, though the second derivative map effectively highlighted areas of potential around the Divide Creek anticline and the upturned beds of the Grand Hogback, the anticlines to the northwest were not highlighted. A better approach is to simply imply the development of pattern one and pattern two fractures in association with the major folds.

As discussed, Tyler predicts that fracturing in the northern half of the basin may be more open than in the south since it parallels the present day west-northwest regional maximum horizontal stress pattern.

Further prediction of future development may require high resolution seismic studies or horizontal drilling. Laubach (1991) in his work on fracture patterns in low permeability rocks in the San Juan and Green River basins suggests that the contrast in fracture intensity between fracture swarms and adjacent unfractured (or less fractured) domains may be detectable using cross-polarized S-waves or possibly as velocity anomalies on conventional seismic lines.

Figure: 16

LEGEND

\\ MESASVERDE (FACE)	\\ WASATCH (FACE)
⊕ ANTICLINE	--- INFERRED SYCLINE/ANTICLINE
⊕ SYNCLINE	▲ THRUST
⊕ MONOCLINE	--- INFERRED BLIND THRUST
	— FAULT

□ 1-2 FRACS/1000 FT ▨ 2-5 FRACS/1000 FT ▩ 5+ FRACS/1000 FT

Well locations were obtained from Petroleum Information. Scotia has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data.

U.S. Department of Energy

Piceance Basin

REGIONAL FRACTURES, FOLDS, & FAULTS

Drilling

The tight gas reservoirs of the Piceance Basin are known to be sensitive to drilling and completion fluids. Such sensitivity is related to one or more of the following contributing factors:

1. **Plugging:** Because the pore structure is characterized by adjoinment involving thin ribbon-like micro-fractures as opposed to discrete pore throats, entry of particulate matter can cause plugging and isolation of the wellbore from the main body of the formation.
2. **Fluid Invasion:** Most tight gas reservoirs are characterized by greater or lesser amounts of authigenic clay mineralization, some of which may be sensitive to fluids invading the formation as mud filtrate. This can cause swelling or dislodgment and migration to block permeable channels during subsequent production.
3. **Drilling Induced Fracturing:** Drilling induced fracturing has been noted and acts to impart localized near-wellbore areas of weakness that may cause increased tortuosity during subsequent frac treatment, thus reducing the effectiveness of such fracs.

Piceance Basin drilling methods vary by depth. In the south where the Marine Play is targeted (Plateau and Shire Gulch fields), casing programs consist of setting a surface 8 $\frac{5}{8}$ " string to around 350 feet, drilling to TD and then setting 5 $\frac{1}{2}$ " casing to 3,310 feet. The above program is for the more recent completions in Shire Gulch where average TD is 3,325 and the average completion interval is from 2,997 to 3,071 feet. Wells can be drilled and completed in 33 days.

In the deeper Fluvial and Multi-Pay wells, three strings are typically used. Casing programs consist of setting 16" surface string to about 50 feet then using an intermediate 9 $\frac{5}{8}$ " string to 1,500 feet, finally using a 5 $\frac{1}{2}$ " casing to TD. The average well completion is perforated from 6,735 to 7,260 feet. The above program is for a typical Rulison Field well. Although actual casing diameters change throughout the basin, the deeper wells tend to use three strings.

Development wells are usually logged with a minimum suite of induction electric log, sonic and neutron-density, while more elaborate logging programs may be run on exploration, step-out and "science" wells.

Drilling cost data was collected from operators responsible for drilling in excess of 60% of the wells since 1990. An average dry hole drilling cost was calculated at \$47.00/foot. Fracture cost varied from \$100,000 to \$300,000 based on size and number of treatments

performed. It is assumed that all plays except the Multi-Pay require one frac, while the Multi-Pay Play requires three to four fracs over the large gross completion intervals.

Completion intervals were selected via log analysis involving an evaluation of porosity and water saturation and keying off results of analogous wells in the vicinity. With the completion interval selected, fracture design was based on anticipated pay section and the optimal design was selected. Historically wells have been dual completed in the Multi-Pay Play, more recently however, the operators are relying on single completions that sometimes span more than 1,000 feet of gross rock. In this case, all sands in the interval were fractured regardless of rock properties. In all other plays single completions with gross perforation thicknesses between 10 feet and 800 feet is the norm.

Completions

Completion practices have varied significantly by play and with time throughout the basin. In the Marine Play the target pay zone is usually the Rollins, Cozzette or Corcoran formations. All of these formations usually are not productive in the same area with the exception of three wells in the Plateau Field and one well in the Logan Wash. The Cozzette and Corcoran are both present as productive formations in one-third of the fields in the play. Since the target sands are well defined and usually relatively thin, the gross perforation interval is usually much less than 200 feet, and in instances where only one sand is productive, less than 60 feet. The average gross completion interval for the play is 83 feet and ranges from 8 to 829 feet.

As the depositional environment changes from Marine to Paludal, the gross completion interval lengthens to an average of 261 feet. This is due in part to a less well defined target and many smaller sands widely separated. Gross completion intervals range from 13 to 910 feet.

Average gross completion interval increases once again in the Fluvial Play as the gross thickness of sands increase. Average gross completion interval in this play is 557 feet and ranges between 4 and 1,666 feet. Once again, in this play the target sands are poorly defined before drilling. Completion and perforations are designed around log responses. It should be noted that although there is a thick gross completion interval, only about 40% of that is reservoir quality rock ($V_{\text{clay}} < 50\%$) and only a fraction of that pay quality.

Since roughly 50% of the completions in the basin are located in the Multi-Pay Play, enough meaningful data is present to follow the completion practices as it has changed over time. The Multi-Pay Play consists of the sands of the Fluvial and Paludal environments around the Grand Valley, Parachute and Rulison fields. It was segregated from the other plays because both environments are productive and the EUR distribution created by current

completion practices make this area non-representative of either the Fluvial or Paludal plays. For purposes of this discussion, all wells have been divided into three uneven time periods that correspond to differing completion philosophies.

The first time period considered is that from January 1, 1980 to December 31, 1989. During this time period, wells were drilled and then completed over gross sand thicknesses of usually less than 300 feet. When this interval eventually produced to its economic limit the completion would be moved up hole into a new 300 foot interval. As time went by this practice was replaced by dually completing the productive zones. Average and per well EUR during this time was 456 MMcf and average gross completion interval per well was 675 feet.

The second time interval of discussion is that between January 1, 1990 and December 31, 1991. This time frame encompasses most of the Parachute Field development and extensive drilling of the Grand Valley Field. During this time wells were normally dually completed within one completion in the Fluvial and one in the Paludal environment. Each completion interval was generally less than 400 feet and the combined interval average was 745 feet. Average EURs rose 50% to 684 MMcf/well from the pre-1990 completions.

Since 1992 there have been two distinctly different completion patterns. Firstly in the newly drilled wells, dual completions have been replaced by single completions covering an average gross interval of 952 feet. This interval usually spans the Fluvial and Paludal environments. Multiple fracs, usually three, are used across this interval, with each frac using 650,000 pounds of sand and 136,000 gallons of water. EURs for this procedure average 867 MMcf, a 90% increase over pre-1990 completions and a 27% increase over the pre-1992 completions.

Recently Barrett, realizing the potential to increase gas production in the wells drilled prior to 1990, performed recompletions. In these wells an average of 245 feet was added to the gross completion interval and the wells were fractured. An average of 408 MMcf was added to the EUR of each wellbore, an increase equivalent to 90% of the original average EUR.

Comparing wells drilled prior to 1990 to the recompleted and refractured wells and the new wells drilled after 1992 yields the following results:

	AVERAGE GROSS COMPLETION INTERVAL	EUR MMcf
Pre-1990 Wells	675	456
Recompleted Wells	920	408
New Wells	952	867

In terms of completion interval and EUR, there is essentially no difference in the recompleted wells drilled prior to 1990 and those drilled after 1992. Barrett succeeded in not only rehabilitating the older wells, but also in reducing the risk of a poor producer (Figure 22) when compared to that of other plays.

Hydraulic Fracturing

The success of any Mesaverde completion in the Piceance Basin very much depends on hydraulic fracture stimulation. This stimulation method has been employed in the basin for close to 40 years. During that time, the technology of fracturing has evolved and expanded greatly. Figure 17 through 20, drawn from the treatment data reported in the WHCS database, illustrate how frac treatments in the basin have evolved during the period 1956 through 1993.

Figure 17 illustrates how the types of fracturing fluids have evolved during this four decade period. In the 1950s and 1960s the predominant fracturing fluid was water with oil a distant second. These fluid types are denoted by the initials SWFR for sand-water frac and SOFR for sand-oil frac. The 1970s saw a shift toward the use of oil-in-water emulsion based fluids (SEFR) for improved fluid loss control and proppant carrying capacity. Acid fracturing (SAFR) was the second most frequently used fluid and the introduction of foam fluids (SFFR) is observed. In the 1980s gel frac fluids (SGFR) were introduced and the use of water re-emerged as an equally frequent choice.

Foam based treatments, although not as frequently used as gels and water, reached their apex during this decade. The current decade, the 1990s, saw a rapid growth in the number of frac treatments and the dominance of gel based fracturing fluids. Almost 50% of the total Mesaverde frac treatments reported since 1950 were performed in the 1990s through year end 1993.

FIGURE 17

FIGURE 18

Figure 18 shows how the treatment size in terms of pounds of proppant has increased with time. The trend to larger sand volume should yield larger fractures with larger surface area in contact with the reservoir rock. The net result to be expected would be improving initial potential and increasing EURs with time.

Modern gel based fracturing fluids use improved polymers and delayed cross-linkers to obtain improved rheological properties. By delaying the cross-linking action appropriately, pumping friction is reduced in the well tubulars while the more viscous fluid propagates a wider fracture and more efficiently transports the proppant. Combined with the advent of fracture simulators for treatment design, the result to be expected should be much improved wells, i.e., high productive capacity and larger reserves (EUR).

FIGURE 19

FIGURE 20

Figure 19 shows how the changes in fracturing fluids and proppant volumes have impacted the initial potentials (IP) as reported in the WHCS. At first inspection this graph suggests that the improvements in fracturing fluid and treatment procedures have all been for nought, as the IP trend with time, if anything, is downward. While this trend remains disturbing, it is known that tight gas wells commonly show prolonged post-frac clean up periods characterized by improving productivity. The greater volumes of fracture fluids required to transport the larger proppant volumes prolong the clean up period and undoubtedly more severely depress the post-frac IP. It remains unclear if this is the sole explanation for the downward trend of IP with time.

If modern fracturing technology and larger proppant volumes are in fact improving the recovery of gas from Mesaverde, it should be evident in the EURs of the treated wells. As Figure 20 clearly shows, this is indeed the case. Per well recoveries are shown to have increased from 325 MMcf in the 1960s and 1970s to 541 MMcf in the 1990s. While this trend is certainly encouraging, it raises the question of how efficient are current fracturing techniques and how much could IPs and EURs be

improved if the efficiency were improved? This question has been investigated and is the subject of a separate topical report entitled "Tight Gas Sand Reservoir Response to Stimulation By Hydraulic Fracturing - Case Studies in the Uinta and Piceance Basins."

Production Performance

Analysis of production performance data provided several key elements for this study:

1. All wells identified as being productive from the tight section were projected utilizing rate versus time and rate versus cumulative techniques to derive an EUR. The estimates were calculated assuming operating costs of \$500/month as being average for the basin, an assumed 18.75% royalty, 8% combined severance and ad valorem tax, and a \$2.00/Mcf wellhead gas price. The use of this gas price was a study requirement by the DOE. These EURs provide the base measure of ultimate well performance.
2. **Initial Productivity and Decline Characteristics:** These items governed the rate of gas recovery and provided the profile for recovery. It should be noted that while some wells exhibit the classic low permeability gas signature of a transient flush production that rapidly decreases from initial rates and then gradually stabilizes at a low rate of decline, many more tight gas completions exhibited erratic production behavior more connected with externally imposed producing and market conditions. For example, seasonal curtailment is noted at one time or another in most wells across the basin. In addition, many wells are produced in cyclic fashion, presumably in response to high local line pressures and low well productivity. Some previous researchers have discussed the initial linear flow period in these tight zones due to the massive hydraulic fracs placed on these wells. However, due to the curtailed nature of the production discussed above, no reasonable success was achieved through the use of linear flow analysis. Historic production from most wells, even the best wells in the basin, could be fit with a hyperbolic curve with an exponent of approximately 0.5. It also should be noted that even with curtailment and various shut-in periods, most wells exhibited fairly steady decline rates after the initial transient period and are thus fairly predictable in terms of production performance.
3. **Transient Production Behavior:** Many wells exhibited a transient phase of production that could last for several years. Analysis of this phase utilizing Fetkovich type curves provided valuable information on permeability and drainage area in conjunction with data from other sources.

Fetkovich analysis was performed on wells containing enough backup petrophysical information, i.e., log analysis estimates of ϕ , S_w , and h , as well as enough production

data to allow for a meaningful fit with the type curves. This analysis depends upon various factors such as: estimates of initial reservoir pressure and bottomhole flowing pressure, bottomhole temperature, gas gravity, and wellbore radius, along with the items mentioned above. For this reason, only a sampling of wells was identified as having enough information to produce meaningful results.

Although this procedure is very sensitive to subtle changes in the fit of production to the type curves, the final completed drainage radius value was checked against the drainage radius calculated using the same petrophysical parameters and a recovery factor ranging from 72% to 85% of GIP depending on the play. In general, drainage radius calculations from the Fetkovich analysis were slightly lower, but did serve as a check in terms of order of magnitude for the constant recovery factor model. In addition, since pressure data was extremely sparse, it was not possible to perform any reserves analyses based on P/Z data.

4. A break down of typical performance profiles for tight wells by play is summarized in Table 5:

**TABLE 5
TYPICAL PRODUCTION PERFORMANCE PARAMETERS BY PLAY**

	FLUVIAL	PALUDAL	MARINE	MULTI-PAY
Average Initial Rate (Mcf/d)	291	116	388	517
High Initial Rate (Mcf/d)	624	470	1,990	2,150
Average Initial Decline	46%	47%	49%	46%

5. Average play production profile curves were created in an attempt to use Fetkovich type curves to determine average drainage areas for each play. The production profile curves were created using the following methodology:
 - a. All wells with a production start date prior to February 1976 were eliminated. (January 1976 is the first date of monthly reported producing volumes. All wells with this start date were assumed to have commenced production at some unknown earlier date and, as such, were eliminated.)
 - b. Wells were divided into subsets based upon producing play.
 - c. Production from all remaining wells was normalized to time zero.

- d. Total production and number of producing wells were tabulated for each month for each play.
- e. EURs for all wells used to create the production profile were averaged to generate an average EUR for the typical well. The EURs were used to volumetrically back into a drainage area. In both the Marine and Multi-Pay plays, drainage areas calculated using Fetkovich types curves and volumetrics were consistent.
- f. Average pay in feet was then calculated for each play from the play pay isopachs.
- g. Pressures and temperatures were calculated for each play based on average perforation depth of all wells used to create the average production profile.
- h. Average porosity and water saturation values were derived from log analysis in the net pay sections.
- i. Finally, Fetkovich type curve analysis was used to determine drainage areas for a typical well in each play. This was done using a hyperbolic exponent of 0.5.

It should be noted that the theoretical upper limit of the hyperbolic exponent in a gas well, assuming a homogeneous single layer or layered cross-flow, is 0.5 as derived by Fetkovich. Arps empirical decline curve equations are only valid during "depletion." A force fit of transient data using Arps equations results in a determination of the hyperbolic exponent greater than one. As stated by Fetkovich, "The misuse of the Arps equation with transient data generally results in overly optimistic forecasts and is technically incorrect." Despite this statement in the literature, this mistake is continually made, particularly in low permeability stimulated wells.

This method had varying degrees of success as severe curtailment in the Paludal and Fluvial plays caused problems with the fit such that the drainage area for each play was less than 20 acres but could not be considered representative due to the data problems. Production profiles for the Marine and Multi-Pay plays were much smoother and areas calculated from the Fetkovich fit more believable. Average drainage areas for the Marine and Multi-Pay plays are 38 and 48 acres respectively.

Wells in the Multi-Pay Play were then further scrutinized. As discussed earlier in the Completion section, EURs have increased significantly in this area over the last six years. An attempt was made to determine if average drainage areas also changed and hence indicate an improvement in completion performance. The above procedure was followed for all wells in

the Multi-Pay Play completed prior to 1990. The resulting drainage area was only 38 acres. Although this number could not be verified through volumetrics, it is considered to be a close approximation. This would indicate that current completion practices have increased drainage area significantly.

Economic Considerations

Base economics are the driving force for development of any "technology" play such as the development of tight gas reserves. It is fair to say that the Piceance Basin has suffered over the years from gas prices and market takes that are below national averages.

The base premise for this study is to examine reserves development potential based upon an assumed gas price of \$2.00/Mcf.

Base economic considerations can be broken down into the following elements:

1. **Capital Costs:** Consist of the cost to drill, complete and equip a gas well that is inclusive of front end costs such as leasehold, seismic and geological costs.
2. **Operating Expenses:** These consist of the monthly charges for direct and indirect expenses to operate the gas well.
3. **Local Taxes:** These consist of local state severance and ad valorem taxes.
4. **Lease Royalty Expense:** This represents the royalty burden that must be borne by the gas well and will be variable depending upon whether the leases represent freehold, state or federal land.
5. **Production Profile:** This represents the rate of gas production over time and hence the likely distribution of derived revenues assuming a \$2.00/Mcf constant gas price as required by the study specification.

A combination of the above parameters results in a projected cash flow profile for a given well. Several factors are worthy of note:

1. **Wells Exhibiting a Typical Tight Gas Signature:** That is, exhibiting an initial rate which declines rapidly in a hyperbolic fashion to stabilize at a low sustained level, the shape of the hyperbolic decline is extremely important. In situations where the rates drop to a break-even level with relative rapidity, the bulk of the cash flow from the well is derived early in its life.

2. Once the production has stabilized or the well has "turned the corner," base economics of further production depend upon the production rate and price versus operating cost levels. Many tight gas wells are sensitive to small fluctuations in price and operating cost to determine their profitability.
3. A wide range in well performance is noted both on a regional basis and down to the well level within an individual field. This is apparently the norm for tight gas wells with the EURs being lognormally distributed at most levels of aggregation.

Due to the fact that tight wells must be frac'd in order to determine productivity characteristics, a significant proportion of completions do not ultimately pay out. That is, while such wells produce sufficient gas volumes to operate profitably by covering operating costs, the payout of drilling and completion costs is never achieved.

EUR Analysis

Decline curve analysis was performed on every well producing from the Mesaverde formation in the basin. An economic cutoff was established for each well using the following parameters; \$2.00/Mcf wellhead gas price, 8% severance and ad valorem taxes, a royalty interest of 18.75%, and operating cost of \$500/month/completion. The generated EURs were then sorted by API number. In cases of multiple completions indicated by repetitive API numbers, the EURs were added. The EUR distributions were then broken out into six original data sets based on first productive year and producing formation (Fluvial, Paludal, Marine).

In the Rulison, Grand Valley and Parachute fields, many of the wells are dually completed or singly completed across a large gross interval that often transgressed play boundaries. As such, it was not possible to assign the production to a single play. The EUR distribution in this area is radically different from other plays in the basin due to multiple productive plays. Therefore, a fourth play was added that encompassed these three fields only. The EUR distribution was then once again broken out by play and first productive date, prior to and post-1990. The EURs for each date interval of each play were then statistically compared. In three of the four plays a statistically significant increase in the EURs was noted in wells completed since 1990. Conversely, the Paludal Play showed a significant decrease in average EURs during the same time period. Table 6 lists average EUR statistics.

TABLE 6
PLAY EUR STATISTICS

	PRE 1990		POST 1990	
PLAY	NUMBER OF WELLS	MEAN MMcf	NUMBER OF WELLS	MEAN MMcf
Fluvial	50	396	25	708
Paludal	23	135	25	87
Marine	198	320	49	461
Multi-Pay	53	552	99	747

The differences in the present and past EURs is perceived to be technologically related and therefore a more representative view of the basin is obtained by including only the EUR distributions of the more recent wells.

Figure 21 displays the EUR distributions for each of the four plays. Note the lowered risk of drilling a poor well in the Multi-Pay Play. Figure 22 graphically compares wells completed before 1990 and those completed recently for each of the four plays. It can readily be seen from the figure that operators have significantly improved completion practices.

FIGURE 21: EUR DISTRIBUTION FOR MARINE, PALUDAL, FLUVIAL & MULTI-PAY PLAYS

FIGURE 22: COMPARISON OF PRE-1990 TO POST-1990 EURS, ALL PLAYS
 x PRE-1990 + POST-1990

RESERVES EVALUATION BY PLAY

In examining resources and estimating what proportion of those resources is technically and economically recoverable and hence available for conversion to reserves, it is useful to diagrammatically express such concepts for the purposes of clarity. This concept was first proposed by the USGS as the McKelvey Box (Figure 23).

The McKelvey Box is an extremely useful tool for illustrating the relationships between reserves and resources. While this concept is embraced by industry, formal linkage of McKelvey's "measured," "indicated," and "inferred" categories with standard industry usage of proved, probable and possible has not occurred due to base concept and purpose differences.

The McKelvey Box was originally developed in 1972 when McKelvey was a director of the USGS. The box represents the total volume of unproduced mineral resources and classifies such volumes with reference to a horizontal axis representing the degree of geologic and engineering certainty, and a vertical axis representing the range of economic feasibility of recovery of such minerals.

FIGURE 23

THE McKELVEY BOX

The economic and geologic axes each have two principal divisions. On the geologic axis, the logical division is between mineral deposits that have been discovered and those which are postulated with varying degrees of certainty but are still undiscovered. This line constantly moves to the right as more resources are discovered and converted to reserves. Likewise, as reserves are produced, they exit the upper left hand corner of the box to become cumulative production. On the economic axis, the division is between those volumes for which technical characteristics and the existing combination of costs and prices make them profitable to recover, and those that are not. This line moves down over time as technological advances make an increasing fraction of the resource base economically extractable. Cost and price changes will also cause vertical movements of this line.

The upper left hand sector of the McKelvey Box contains reserves. On the horizontal or geologic axis, these are the volumes of oil and gas about which there is the greatest confidence in their existence and characteristics. They have been discovered and characterized by information obtained through drilling. On the vertical or economic axis, reserves are restricted only to those volumes of discovered minerals for which there is the highest certainty about the feasibility of economic recovery.

The remainder of the McKelvey Box is filled by resources. These are minerals which remain to be discovered or have been discovered but for which economic recovery under present conditions is judged uncertain.

The normal subdivision of reserves, as represented by the standard SPE definitions, resides in the upper left hand corner of the McKelvey Box. To qualify as reserves, such volumes must pass an economic producibility test, a test of existence and a further test of level of certainty of existence. Where such reserves are thought to be reasonably certain, they are classified in the proved category. Reserves which are identified but do not pass the reasonable certainty test are classified in the unproved category with subdivisions noted as probable and possible.

For the purposes of expressing the results of this project, we have chosen to utilize the McKelvey Box concept in a modified form. This modification calibrates both X and Y axes in terms of the fundamental controlling technological and economic parameters.

Considering firstly the X or technology axis, this has been calibrated as a function of average reservoir permeability on a logarithmic scale. In addition, the axis has been reversed in comparison to the original McKelvey Box whereby permeability increases from left to right. The technology axis is subdivided based upon permeability ranges. The primary subdivision is between conventional reservoirs having permeabilities of greater than 0.1 md and unconventional reservoirs having permeabilities of less than 0.1 md. The second subdivision of the horizontal axis is based upon the current state of massive hydraulic fracturing

resource to become economic, major changes in the cost and price environment must occur as opposed to the shallower resource. In addition, the relative proportion of the total evaluated resources occurring within each permeability range allows the benefits of technology improvements to be evaluated in terms of how much of the resource is available for the conversion to reserves by application of such technology.

The USGS subdivided the Mesaverde group into three stratigraphic plays for the purpose of conducting their resource estimate. These are as follows:

GROUP	FORMATION	MEMBER	PLAY
Mesaverde	Williams Fork		Fluvial/Paludal
Mesaverde	Iles	Rollins-Trout Creek	Marine
Mesaverde	Iles		Marine

Subdivision into Williams Fork and Iles is based on the dominant depositional environments representing each, though some overlapping of environments occurs. The Iles play is representative primarily by marine and marginal marine sandstones and distributory and lower coastal plain sediments. Whereas, the Williams Fork formation is represented predominantly by coastal plain, paralic and fluvial, paludal deposits. The Rollins-Trout Creek which represents the uppermost regressive sand within the Iles formation was evaluated separately because it is frequently water-bearing within the basin.

A modification of this subdivision was adopted for this study to incorporate the stratigraphic definition developed by Lorenz (1983) from extensive studies of MWX core at the Rulison Field. Lorenz (1983) identified four major depositional environments from his core studies, which include from lowest to uppermost, shoreline/marine, paludal, coastal, and fluvial, capped by a paralic interval. Three main plays were defined and used in this study based on a simplification of Lorenz's break down as presented below:

GROUP	FORMATION	MEMBER	ENVIRONMENT/PLAY
Mesaverde	Williams Fork	Cameo-Wheeler-Fairfield	Fluvial (+ Coastal & Paralic)
Mesaverde	Williams Fork		Paludal
Mesaverde	Iles		Marine (+ Shoreline & Marginal Marine)

The frequent water-bearing Rollins-Trout Creek member of the Iles formation was mapped separately and subtracted from the Marine Play composite thickness map, except in areas known to produce from this member and/or where gas pay was calculated from log analysis.

During the course of the study it was found necessary to separate out large portions of the Paludal and Fluvial plays and combine these into a fourth "Multi-Pay" Play to facilitate the estimation of resources and reserves of dually-completed wells. A description of the stratigraphy and lithology of each play appears under the discussion of reserves evaluation for each play.

MARINE PLAY

Description

The Marine Play lies immediately below the Paludal Play and includes the rock volume between the top of the Rollins-Trout Creek to the top of the Castlegate sandstone. The play is situated inside the Cretaceous outcrop and its boundary is defined for the most part by the 0.73 R_o elevation contour. The $R_o = 0.73$ subplay has an area of approximately 3,182 square miles, while the $R_o = 1.1$ subplay has an area of 2,161 square miles. Target reservoirs include the Cozzette, Corcoran, Lloyd, Sego, and to a lesser extent, the Rollins sandstone.

Examining the Marine penetrations (Figure 25), well control within the play is generally good, comprising Mesaverde Marine completions, Mancos and Dakota wells. There is no well control in the basin deep around the Grand Hogback area.

The FERC has designated two gas areas within the play as tight (Figure 26). The first is part of a large block between 6S97W and 11S98W. The second is a significantly smaller block of about 180 square miles in the northwest corner of the basin where there is no reported Marine production. Figure 27 is an EUR bubble map of Marine completions with subplay limits defined. Note the majority of production is centered around the Plateau and Colorado rivers outside the R_o 1.1 subplay.

The Marine Field list (Table 7) shows cumulative production of 67.7 Bcf from 247 wells. The total EUR of these wells is 97.3 Bcf or on average 394 MMcf/well. The Plateau Field accounts for almost half the wells and a third of the production and dominates the Marine producing statistics. Shire Gulch, the second biggest field in the play, has enjoyed a surge in drilling activity over the last five years with 19 of the 41 wells being drilled during that time. The average EUR for these wells is almost 800 MMcf, nearly twice the play average at an average depth of only 2,800 feet. The play level production plot (Figure 28) shows that approximately 130 wells are currently producing with average per well rates of 102 Mcfd. Notice the increase in active wells from 50 to 125 between 1981 and 1984 which parallels the development of the Plateau Field and early development in Shire Gulch.

Drilling statistics are dominated by the Plateau Field. The risk model for the Marine Play indicates that 98% of the wells targeting the Marine are completed with the other 2% being dry holes. Of these completions only 31% are a commercial success based on an average completion depth of 3,364 feet, Figure 29. The Marine risk model uses a 2% dry hole factor based on the historic dry hole percentage of wells drilled.

TABLE 7
MARINE PLAY FIELD LIST

FIELD NAME	AVG Depth (Feet)	CUM MMcf	EUR MMcf	NUMBER of WELLS	AVG EUR MMcf/Well
BALDY CREEK	9658	422	422	4	106
BRONCO FLATS	2777	32	32	1	32
BRUSH CREEK	8098	291	384	2	192
BUZZARD	5950	639	665	7	95
BUZZARD CREEK	8216	6498	7520	2	3760
CALF CANYON	1127	269	282	1	282
CATHEDRAL	1744	498	767	1	767
COAL BASIN	6585	413	633	2	316
DEBEQUE	3275	218	228	1	228
DIVIDE CREEK	5940	2146	2146	6	358
DOUGLAS CREEK	1769	1133	2069	8	259
FLOATING LAKE	4328	10	10	2	5
GASAWAY	4720	901	1970	4	492
GRAND VALLEY	5904	474	847	2	423
LOGAN WASH	4192	391	469	6	78
OIL WELL MT	7157	237	256	2	128
PLATEAU	4159	23024	30265	111	273
RAGGED MOUNTAIN	6185	1607	1845	7	264
RANGELY SOUTH	3382	721	1323	2	661
RULISON	7573	1657	3063	14	219
SHEEP CREEK	8358	209	238	2	119
SHIRE GULCH	2953	9794	24121	41	588
SULPHUR CREEK	8367	141	202	2	101
TEXAS MOUNTAIN	2889	2097	2642	3	881
VEGA	8083	136	136	2	68
WHITE RIVER	6758	1070	2103	5	421
WOLF CREEK	4722	12676	12676 *	7	1811
TOTAL		67703	97313	247	394

* LEASE LEVEL REPORTING OF PRODUCTION INVOLVED, OR DATA PRE-DATES MONTHLY REPORTING. WELL COUNTS ARE ESTIMATED.

Stratigraphy and Rock Properties

Initially all strata of the Campanian Iles formation lying between the top of the Castlegate regressive sandstone and the top of the younger Rollins-Trout Creek regressive sandstone were considered for inclusion in the play. Subsequent work however revealed that the Rollins-Trout Creek member was commonly water-bearing in the Piceance Basin and this sand was generally excluded from the play except in those areas found to be gas-saturated from log analysis or were known to be gas productive. The marine and marginal marine sequence was deposited during a period when the coastline transgressed and regressed repeatedly across the basin area. Seven regressive sandstone sequences which intertongue and overlie the Mancos Marine shale were created by southeast prograding shorelines and were fed by sediments from the northwest. Successively younger prograding sequences extend progressively further southeast into the basin. These are from oldest to youngest - the Morapos, and Castlegate sandstones of the Mancos tongue; and the Lloyd, Sego, Corcoran, Cozzette, and Rollins-Trout Creek sandstones of the Iles formation. This simplified assignment to formations is actually more complex as Johnson (1989) attests. The Castlegate and Sego are also considered as separate formations while the Corcoran and Cozzette sandstones are considered members of the Mount Garfield and Iles formations but were originally defined as members of the Price River formation. Figure 30 illustrates the regressive limits of the Mancos tongue and Iles formation and the transgressive limits of the Mancos shale flood surface after Johnson (1987). Note however that Corcoran and Cozzette production is reported far southeast of their regressive limits in the Ragged Mountain and Coal Basin fields. The Morapos sandstone is limited to the far northwest corner of the basin, extending approximately 15 miles southeast, while the Rollins-Trout Creek progradational sequence extends beyond the southeast corner of the basin. Well control for the two oldest regressive sands is extremely limited and these have been excluded from the Marine Play.

The regressive Marine sequences are made up of shoreline and shallow Marine sandstones, brackish water lagunal sediments, distributary and lower coastal plain channel sandstones, and coal intervals. The sandstones are upward coarsening, laterally extensive, locally homogeneous, and well sorted with blanket geometries (Figure 31).

The composition of gases from the Marine interval of the MWX -1 and -2 wells indicates that sourcing is primarily from marine rocks. Spencer and Pittman (1983) identified pyrobitumen in the Cozzette core which indicated cooking out of marine source rocks. Rice (1983) identified a few samples with higher CO₂ content and shorter hydrocarbon chains suggesting coal or other non-Marine sourcing.

In the northwest part of the basin, west of a line joining Township 5S Range 101W and Township 1N Range 95W, wireline logs indicated that the marginal marine sediments of the Iles formation become more complex, the sandstones thin, and the regressive sequences are

more difficult to identify. An effort was made to distinguish between the more complex marginal marine sediments and those to the southeast, based on log character, the reason being that poorer developed sands may have less potential as successful producers. Sandstones within the more complex marginal marine sediments represent a significant portion of those identified in the Iles formation in northwest Piceance. However, very little pay was attributed to these sandstones to the extent that their removal would have made negligible difference to the pay map as contoured. Since the sandstone isopach rock volume (minus the pay isopach rock volume) is used to determine *technologically nonviable* resources which are subsequently discarded from reserves consideration, it was felt unnecessary to quantitatively distinguish between the rock volumes of the more complex marginal marine region and the rest of the Marine Play.

Rollins-Trout Creek Sand

As discussed, the Rollins-Trout Creek represents the youngest of the seven regressive cycles within the Iles formation. Two later limited cycles, that of Collins (1976) and the Lion Canyon sandstone, occur within the Lower Williams Fork formation and are restricted to the eastern most part of the Piceance Basin (Johnson, 1989). The Rollins and Trout Creek sands represent the most extensive regressive cycle in the basin and consist mostly of a single upward coarsening sequence capped by a Beach sandstone (Johnson, 1989). The sand grades into non-marine sediments in the northwest part of the basin. Its southeasterly pinch-out line extends beyond the limit of the basin. Figure 32 shows Rollins-Trout Creek sand thicknesses to increase from 0 feet in the northwest to 150 feet in the southeast part of the basin.

The Rollins-Trout Creek is commonly water-bearing, even in the deepest parts of the basin (Johnson, 1987) and it appears to have been a major conduit for fluid movement across the basin through time. A review of Rollins completions and EURs revealed a high incidence of perforations without associated production. Absence of production may be due to high water cuts but could also be a function of poor reservoir quality or mechanical problems. Figure 33 displays wells with Rollins perforations and highlights those with associated EURs. The majority of Rollins completions occur in the Plateau Creek area in southwest Piceance. Rollins EURs also exist in the Shire Gulch and Logan Wash fields. A review of Rollins-Trout Creek pay counts separated out from the Marine Play (Figure 34) reveals a very limited geographic extent, again restricted mostly to the Plateau Creek area. Even in this area there exists a high incidence of Rollins perforations without associated production. Low pay counts in the Rollins-Trout Creek are generally due to high water saturations. Piceance Basin operators often TD Williams Fork development wells above the thicker coals at the base of the Cameo section in an effort to avoid water production problems from the Rollins-Trout Creek.

A review of formation water resistivities estimated for the Rollins-Trout Creek during this study indicates that connate water rather than meteoric water recharge exists within most of this member. Myal et al (1989) found that Rollins water salinities were generally similar to those of the older regressive sands within the Iles formation and contrasted with the fresher water of the overlying Williams Fork fluvial section. No doubt at the basin edges Rollins waters freshen up near the Cretaceous outcrop.

The generally water productive Rollins-Trout Creek contrasts with the gas-saturated nature of the immediately overlying Cameo coals and sands and the underlying Cozzette, Corcoran and Sego sands. The proximity to gas sourcing coal and interbedded shales of the Cameo and Marine shales of the Mancos indicate that the Rollins lacked a mechanism to trap the migrating gases which must have flowed through the sand. The Rollins differs from the underlying regressive sands in that it continues beyond the basins southeasterly limit, thereby creating an escape route for gases. Trapping within the Cozzette and Corcoran however is aided by pinch-out against the Mancos Marine shales across the updip south flank of the basin. Infrequent discovery of gas productive Rollins is probably the result of localized trapping related to dip reversal or changes in stratigraphy.

The general absence of gas saturation in the Rollins-Trout Creek in a basin centered low permeability gas accumulation would suggest that Masters (1979) model of a reversed gas-water transition zone as the gas trapping mechanism is not valid, at least for this member.

Figure 35 presents the structure map of the Top Rollins-Trout Creek formation in measured depth, modified from Johnson (1989). This map is shown in preference to one created using PI formation tops which did not provide the same detail uniformly across the basin. Depth to the top of the Marine Play extends from formation outcrop at the basin edge to a projected 13,000 feet in the basin deep adjacent to the Grand Hogback. Contouring reflects the variation in overburden thickness caused by the deep incising of river channels into the uplifted Tertiary section. The Mesaverde (Williams Fork) is actually breached on the Divide Creek anticline, and down-cutting by the Colorado River near DeBeque has exposed the Mesaverde section. Figure 36 presents the Rollins-Trout Creek structure in subsea, also modified from Johnson, and displays an asymmetrical, generally east dipping structure cut by large Laramide structural features in the east and north of the basin, including the Divide Creek, Wolf Creek and Coal Basin anticlines in the east, and the Piceance Creek and White River domes in the north. Iles strata on the eastern basin flank are upturned and dip steeply against the Grand Hogback monocline.

The Marine Play gross interval (Figure 37) increases in thickness from

approximately 200 feet at the basin's western margin to over 1,500 feet at the northeastern depocenter. The gross interval mapped includes the four regressive sand bodies and associated Mancos shale tongues described above.

The Marine sandstone isopach, Figure 30, thickens from less than 100 feet on the west flank of the basin to more than 600 feet in the northeast portion of the basin. Southeast of Rulison, the sandstones thin but are interpreted to extend beyond Johnson's (1989) regressive limits of the Corcoran and Cozzette sandstones. The Rollins-Trout Creek sandstone, not included on this map, continues beyond the southeast boundary of the basin. Overlay of the regressive limits of each sandstone indicates which prograding sequences contribute to this composite map.

The Marine pay isopach (Figure 38) shows the best reservoir quality sandstones to be centered around the Plateau Field in the southwest corner of the basin where over 80 feet of pay is mapped. Some productive wells lie beyond the 0.73 maturation limit at this location causing the play boundary to be extended to the west. Just west of Grand Valley, reservoir quality is interpreted to improve, albeit based on limited well control, and thick contours are extrapolated to the north. Pay has been mapped as far north as the White River Dome, which lies within the wedge zone defined by the intersection of the 0.73 R_o maturation elevation and the top and base of the Marine Play. Pay thins in the southeast part of the basin but extends over the Ragged Mountain and Coal Basin fields. Rollins-Trout Creek contributions to this pay map are limited to Township 10S Range 93-96W within the Plateau Field area. Rollins-Trout Creek pay was also identified around Grand Valley, Gasaway (adjacent to the west flank of the basin), and at the White River Dome in the north.

Figures 39a and 39b display the rock property distributions for all sands lying between the R_o 0.73 and R_o 1.1 and $R_o > 1.1$, respectively. Note that in spite of porosities being generally higher (10.5% versus 8.5% mode) in the R_o 0.73 to 1.1 subplay, corresponding water saturations are also higher (78% versus 70%). This may be attributed to a generally weaker gas charge in the thermally less mature rock (except in the productive fields) and possible flushing by meteoric waters at the basin margin. Water saturations drop substantially for the pay intervals with very little difference between the averages (52% versus 50%) for the two subplays.

Figure 40 is an example of a CPI log from the Marine Play. The Federal #13 well is located in the Shire Gulch Field at S1 T10S R97W. The well tested 1,057 Mcfd and 65 bcpd following a sand water frac using 59,700 gallons of water and 592,000 pounds of sand between 3,154 and 3,262 ftmd. The top of the Marine Play is encountered at 2,748 ftmd. Members penetrated by this well include the Rollins at 2,748 ftmd, the Cozzette at 2,976 ftmd and the producing Corcoran at 3,149 ftmd. Note

the regressive coarsening upward curve signature of each sand. This well has an average porosity and water saturation of 13% and 55% respectively over the 45 foot pay interval. Though log response looks encouraging, this well has produced only 114 MMcf in 13 years.

A total of 471 play samples of Marine (Iles) core were corrected to in-situ conditions and split into three categories: Completed, Tested and Other samples, Figures 41a and 41b. Note the average porosity (8.3%) of the completed intervals which is almost 2 porosity percent lower than the log-derived averaged porosity for the pay. Data scatter on the porosity-permeability plot restricts the development of any meaningful relationship which is to be expected when combining data basinwide. High concentrations of permeability in horizontal layers represent high incidence reporting of < 0.1 md or < 0.01 md ambient values, corrected to in-situ conditions.

Reevaluation of Resource

The bulk of the rock volume for the Marine Play lies between 8,000 and 14,000 feet with the base of the play occurring to 14,500 feet in the basin deep adjacent to the Grand Hogback. Approximately 76% of the rock volume lies above 10,500 feet. This depth corresponds to the deepest evaluated well control. Rock volumes below this depth were assigned the same properties as the deepest evaluated interval.

The porosity distributions indicate an almost uniform decrease in porosity with depth from 13% at 2,500 feet to 8% between 5,500 and 6,000 feet. The porosity jumps back up to 10% between 6,000 and 6,500 feet then declines until an average porosity of 6% is reached at 9,500 feet.

In terms of the number of producing wells, existing production from the Marine is dominated by the Plateau Field. Average EUR per well has increased dramatically over the last five years from 320 MMcf/well prior 1990 to 461 MMcf/well after 1990, an increase of 141 MMcf. Only wells drilled after 1990 were used to construct a distribution of expected recoveries for *economic basement* calculations. This model calculates the *economic basement* to be at a depth of approximately 5,080 feet. Deepest commercial production places the floor for consideration of reserves at 8,600 feet.

Of the total resource of 85.6 Tcf evaluated for the Marine Play, 59 Tcf (69%) occurs in low permeability rocks considered too tight to support commercial production. Of the remaining 26.6 Tcf, 23.8 Tcf lies below the *economic basement* at 5,080 feet, leaving an established resource of 2.8 Tcf which will be the main contributor to reserves.

Table 8 compares the USGS estimate for the Iles and Rollins Trout Creek plays to the revised estimate derived herein. Figures 42 and 43 graphically illustrate this breakdown for sub plays $R_O = 0.73-1.1$ and $R_O > 1.1$.

TABLE 8
MARINE PLAY RESOURCE ESTIMATE BREAKDOWN
(Tcf)

USGS Mean Resource Estimate	98.9
Scotia Revised Mean Resource Estimate	85.6
MINUS <i>Technology Nonviable Resources</i>	59.0
SUBTOTAL <i>Technologically Viable Resources</i>	26.6
MINUS <i>Nondemonstrated Resources</i>	0
SUBTOTAL <i>Demonstrated Resources</i>	26.6
Subdivision: <i>Speculative Resources</i>	12.3
 <i>Nonestablished Resources</i>	11.5
 <i>Established Resources</i>	2.8

The Marine Play reserves evaluation is subdivided into *established* and *nonestablished* divisions for both subplays involving the following parameters:

TABLE 9
MARINE PLAY, RESERVES CALCULATION
R_o 0.73 - 1.1

	<i>ESTABLISHED CATEGORY</i>			<i>NONESTABLISHED CATEGORY</i>		
Parameters	MAX	MOST LIKELY	MIN	MAX	MOST LIKELY	MIN
Base Recovery Factor	0.72	0.72	0.72	0.72	0.72	0.72
Dry Hole Fraction	0.02	0.02	0.02	0.02	0.02	0.02
Min Economic Drainage Acres	18	55	160	40	110	320
Noncommercial Fraction	0.19	0.525	0.87	0.425	0.8	0.93
Recovery Factor	0.57	0.34	0.09	0.41	0.14	0.05
Rock Volume (M ac-ft)	6,095			6,187		
Porosity	0.16	0.125	0.1	0.14	0.12	0.1
Water Saturation	0.48	0.525	0.55	0.5	0.54	0.58
FVF (res cf/scf)	0.0157	0.00875	0.00623	0.00623	0.0053	0.0046
<u>Reserves Probability Distribution</u>						
90% Probability of Exceeding (Bcf)	293			275		
70% Probability of Exceeding (Bcf)	426			402		
50% Probability of Exceeding (Bcf)	534			514		
30% Probability of Exceeding (Bcf)	656			661		
10% Probability of Exceeding (Bcf)	859			858		
Mean Value (Bcf)	559			545		

TABLE 10
MARINE PLAY, RESERVES CALCULATION
 $R_o > 1.1$

	<i>ESTABLISHED</i> CATEGORY			<i>NONESTABLISHED</i> CATEGORY		
Parameters	MAX	MOST LIKELY	MIN	MAX	MOST LIKELY	MIN
Base Recovery Factor	0.72	0.72	0.72	0.72	0.72	0.72
Dry Hole Fraction	0.02	0.02	0.02	0.02	0.02	0.02
Min Economic Drainage Acres	23	70	200	40	110	320
Noncommercial Fraction	0.25	0.60	0.89	0.425	0.8	0.93
Recovery Factor	0.53	0.28	0.08	0.41	0.14	0.05
Rock Volume (M ac-ft)	3,488			20,735		
Porosity	0.14	0.1	0.085	0.12	0.095	0.7
Water Saturation	0.45	0.5	0.55	0.45	0.485	0.52
FVF (res cf/scf)	0.0109	0.0074	0.00623	0.00623	0.0053	0.0046
Reserves Probability Distribution						
90% Probability of Exceeding (Bcf)	155			814		
70% Probability of Exceeding (Bcf)	227			1,199		
50% Probability of Exceeding (Bcf)	281			1,552		
30% Probability of Exceeding (Bcf)	344			1,980		
10% Probability of Exceeding (Bcf)	443			2,630		
Mean Value (Bcf)	293			1,646		
<u>PDP Reserves & Cum Production</u> <u>For Both Sub-Plays</u>						
Cumulative Production (Bcf)	47.4			19.9		
Remaining PDP Reserves (Bcf)	21.8			7.7		
EUR of PDP Reserves (Bcf)	69.2			27.8		

The most notable aspect of the Marine Play as with the other plays is that all the wells are drilled in or adjacent to river valleys to reduce drilling costs.

In summary, reserves are recognized in both the *established* and *nonestablished* categories in the Marine Play. The mean estimate for *established* reserves is 852 Bcf over all or 782.8 Bcf after subtraction of the EURs of existing Marine wells. *Nonestablished* reserves are recognized with a mean estimate of 2,191 Bcf over all and 2,163.2 Bcf after subtraction of the EURs of existing wells in this category.

Figure: 25

Figure: 26

LEGEND

* GAS WELL

o DRY HOLE

— BASIN OUTLINE

— PLAY OUTLINES

- - - FERC TIGHT AREA

U.S. Department of Energy

Piceance Basin
MARINE PLAY
PRODUCER & DRY HOLE MAP

Well locations were obtained from Petroleum Information. Scolia has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data.

Figure: 27

LEGEND

○ 10 Bcf	— BASIN OUTLINE
○ 1000 MMcf	— PLAY OUTLINES
○ 100 MMcf	----- RIVERS
○ 10 MMcf	

U.S. Department of Energy

Piceance Basin
MARINE PLAY
EUR DISTRIBUTION MAP

Well locations were obtained from Petroleum Information. Scotia has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data.

FIGURE 28

MARINE TOTAL PRODUCTION PROFILE

Projections are averages for each year commencing at the effective date of the evaluation. Results are subject to the qualifications and limitations stated in the attached document

MARINE PLAY

Technical Success 98.0%
Commercial Success 30.4%

FRI JUL 28 1995

Figure: 30

<p>LEGEND</p> <p> SOUTHEAST REGRESSIVE LIMIT</p> <p> NORTHWEST TRANSGRESSIVE LIMIT</p> <p>C.I. : 50ft</p> <p><small>Modified from Zapp and Cobban(1960), Warner(1964), GM and Cobban(1969), GM and Hall(1975), and Johnson(1989).</small></p>	<p>U.S. Department of Energy</p> <p>Piceance Basin</p> <p>MARINE PLAY SAND ISOPACH</p>
<p><small>Well locations were obtained from Petroleum Information. Sclia has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data.</small></p>	

FIGURE 31: MESAVERDE GROUP STRATIGRAPHIC SECTION
(from Lorenz, 1983b)

~~~~~ Traditionally defined top of Williams Fork Formation
 --- Genetically defined operational base of Williams Fork Formation
 ~~~~~ Ripples
 ~~~~~ Crossbedding
 ~~~~~ Clay rip-up-clasts
 ~~~~~ Bedding plane (clay-surfaced)
 ~~~~~ Coal

QA#8038c

Figure: 32

LEGEND

- BASIN OUTLINE
- SAND CONTOURS

U.S. Department of Energy

Piceance Basin
ROLLINS TROUT-CREEK
SAND ISOPACH

Well locations were obtained from Petroleum Information. Sclafio has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data.

Figure: 33

LEGEND

- ☼ ROLLINS GAS WELL
- ROLLINS PERFORATION
- BASIN OUTLINE

U.S. Department of Energy

Piceance Basin
ROLLINS—TROUT CREEK
PERFORATION/EUR MAP

Well locations were obtained from Petroleum Information. Scotia has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data.

Figure: 34

LEGEND

- BASIN OUTLINE
- CONTOURS

U.S. Department of Energy

Piceance Basin
ROLLINS-TROUT CREEK NET PAY

Well locations were obtained from Petroleum Information. Scotia has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data.

Figure: 35

10 0 10 20 30 40 50 miles

LEGEND

- BASIN OUTLINE
- CONTOURS

U.S. Department of Energy

Piceance Basin
TOP ROLLINS—TROUT CREEK
STRUCTURE, MEASURED DEPTH

Well locations were obtained from Petroleum Information. Scolia has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data.

Figure: 36

LEGEND

— BASIN OUTLINE

— CONTOURS

After Johnson 1987

U.S. Department of Energy

Piceance Basin
TOP ROLLINS—TROUT CREEK
STRUCTURE, SUBSEA

Well locations were obtained from Petroleum Information. Scotia has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data.

Figure: 37

LEGEND

- BASIN OUTLINE
- CONTOURS

U.S. Department of Energy

Piceance Basin

MARINE PLAY GROSS ISOPACH

Well locations were obtained from Petroleum Information. Scotia has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data.

Figure: 38

LEGEND

- BASIN OUTLINE
- PLAY OUTLINES
- CONTOURS

U.S. Department of Energy

Piceance Basin

MARINE PLAY PAY ISOPACH

Well locations were obtained from Petroleum Information. Scolia has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data.

Piceance Basin: Rock Property Distributions
MARINE PLAY, Ro .73 - 1.1 SUBPLAY, SAND

THU AUG 03 1995

Piceance Basin: Rock Property Distributions

MARINE PLAY, $R_o > 1.1$ SUBPLAY, SAND

THU AUG 03 1995

COREPRO Client: U.S. DEPARTMENT OF ENERGY
IN-SITU CONDITION, MARINE PLAY, ALL DATA.
Porosity versus Permeability

Figure 41a
COREPRO Client: U.S. DEPARTMENT OF ENERGY
IN-SITU CONDITION, MARINE PLAY, ALL DATA.
Histogram Plot
AVERAGE 6.41 POINTS 471.
MEDIAN 5.98 STD DEV 2.84

COREPRO Client: U.S. DEPARTMENT OF ENERGY
IN-SITU CONDITION, MARINE PLAY, COMPLETED INTERVALS.
Porosity versus Permeability

COREPRO Client: U.S. DEPARTMENT OF ENERGY
IN-SITU CONDITION, MARINE PLAY, COMPLETED INTERVALS.
Histogram Plot
AVERAGE 8.30 POINTS 94.
MEDIAN 7.23 STD DEV 2.97

COREPRO Client: U.S. DEPARTMENT OF ENERGY
IN-SITU CONDITION, MARINE PLAY, TESTED INTERVALS.
Porosity versus Permeability

Figure 41b
COREPRO Client: U.S. DEPARTMENT OF ENERGY
IN-SITU CONDITION, MARINE PLAY, TESTED INTERVALS.
Histogram Plot
AVERAGE 5.26 POINTS 142.
MEDIAN 5.07 STD DEV 2.12

COREPRO Client: U.S. DEPARTMENT OF ENERGY
IN-SITU CONDITION, MARINE PLAY, OTHER DATA.
Porosity versus Permeability

COREPRO Client: U.S. DEPARTMENT OF ENERGY
IN-SITU CONDITION, MARINE PLAY, OTHER DATA.
Histogram Plot
AVERAGE 6.34 POINTS 235.
MEDIAN 6.11 STD DEV 2.78

Piceance Basin Tight Gas Resource Allocation

MARINE PLAY, Ro .73 - 1.1 SUBPLAY

THU AUG 03 1995

Piceance Basin Tight Gas Resource Allocation

MARINE PLAY, $R_o > 1.1$ SUBPLAY

THU AUG 03 1995

PALUDAL PLAY

Description

The Paludal Play lies immediately below the Fluvial and above the Marine Play. The play has demonstrated production from Pinyon Ridge in the north, to Plateau in the south, Mam Creek in the east to Bronco Flats in the west. An area of roughly 290 square miles in the central part of the basin around the Colorado River surrounding Grand Valley, Rulison and Parachute fields has been excluded from the play since it is included as part of the Multi-Pay Play. The Paludal Play lies inside the Cretaceous outcrop and is bounded by the R_O 0.73 elevation contour. The R_O 0.73-1.1 subplay area is approximately 2,379 square miles, while the R_O 1.1 subplay area is approximately 1,476 square miles. Well control for the play is generally reasonable with the exception of the deepest parts of the basin adjacent to the Grand Hogback (Figure 44).

The FERC has assigned tight gas status to two areas within the play (Figure 45), the larger of the two areas, located between 6S-97W and 11S-89W is approximately 1,944 square miles, the second, covering approximately 180 square miles in the northwest corner of the basin, has no reported production.

Examination of the Paludal Play field list (Table 11) shows cumulative production of 3,710 MMcf from 47 wells and an average EUR of 112 MMcf/well. The wells are spread relatively evenly toward the outer edges of the basin with most wells drilled outside the R_O 1.1 boundary (Figure 46).

Examination of the play level production plot profile (Figure 47) shows the marked increase in activity since 1989. South Shale Ridge is the largest field in the play based on the number of completed wells (13). Average initial production rates are only 80 Mcfd and range between 22 and 161 Mcfd. The wells also exhibit high initial declines at an average of 48%. There is no Paludal production in the extreme southern part of the basin or in the north center toward the Grand Hogback where well control is absent.

TABLE 11
PALUDAL PLAY FIELD LIST

| FIELD NAME | AVG DEPTH
(Feet) | CUM
MMcf | EUR
MMcf | NUMBER
of WELLS | AVG EUR
MMcf/Well |
|----------------------|-----------------------------|---------------------|---------------------|----------------------------|------------------------------|
| BRONCO FLATS | 2360 | 18 | 18 | 1 | 18 |
| BUZZARD CREEK | 7663 | 239 | 250 | 2 | 125 |
| CAMEO | 1914 | 0 | 0 | 1 | 0 |
| DEBEQUE | 3017 | 36 | 101 | 1 | 101 |
| DIVIDE CREEK | 3837 | 1347 | 1737 | 12 | 145 |
| HELLS GULCH | 6348 | 150 | 150 | 1 | 150 |
| MAM CREEK | 7735 | 811 | 934 | 2 | 467 |
| PINYON RIDGE | 5352 | 1 | 1 | 3 | 0 |
| PLATEAU | 3779 | 62 | 81 | 2 | 40 |
| SKINNER RIDGE | 6114 | 110 | 110 | 6 | 18 |
| SOUTH SHALE | 3555 | 605 | 1150 | 13 | 88 |
| VEGA | 7950 | 76 | 76 | 1 | 76 |
| WHITE RIVER | 6832 | 254 | 671 | 2 | 336 |
| TOTAL | | 3710 | 5280 | 47 | 112 |

*** LEASE LEVEL REPORTING OF PRODUCTION INVOLVED, OR DATA PRE-DATES MONTHLY REPORTING. WELL COUNTS ARE ESTIMATED.**

In consideration of the drilling cost and exhibited productive characteristics and EURs, no commercial production has yet been demonstrated for the Paludal Play. Of the 470 wells evaluated, only five TD'd in the Paludal environment; not enough to generate meaningful statistics on dry hole percentages, therefore a basinwide dry hole constant of 2% was used. Of the non-dry holes, none are considered to be commercial propositions, making the commercial success ratio for the play zero. Note however that the Paludal Play excludes a 216 square mile area which contains the Grand Valley, Rulison and Parachute fields.

Stratigraphy and Rock Properties

The Paludal Play is sandwiched between the older Marine and younger Fluvial plays and includes strata which lies between the top of the Rollins-Trout Creek regressive sand, marked by the thick A coal seam of the Cameo-Wheeler-Fairfield coal sequence across much of the basin and the top of the main coal-bearing sequence (the last identifiable coal frequently lies beneath a thick sequence of Fluvial sandstones). Above this lies the undifferentiated Williams Fork which constitutes the Fluvial Play. Correlation of the play was aided by cross-sections of Mesaverde regressive cycles and above in the Piceance Basin compiled by Johnson (1979 to 1986) and by gross thickness data developed by Myal (1989). The coal sequence correlated by Johnson includes the middle sandstone of Collins (1976) and overlying South

Canyon coals which together with the Cameo-Wheeler-Fairfield coal zone make up the Bowie shale member. Myal (1989) groups these same zones in with his Paludal interval. However, he includes the overlying Coal Ridge zone of the Paonia shale in with his Fluvial interval. Johnson's (1979 to 1986) correlations do not identify the Paonia shale, consequently in this study the Paonia shale and associated Coal Ridge member are grouped in with the Fluvial play. Well control in this study however shows the Paonia shale to be relatively coal poor. Note that Tyler (1995) recognizes the Coal Ridge zone as the third of three coal packages in southeast Piceance and along the Grand Hogback, each of which is separated by Mancos tongues and the associated middle and upper regressive sands of Collins (1976).

The Paludal Play includes lower delta plain (delta front, distributary channel, strandplain, bay and marsh deposits) to upper delta plain (coastal, low sinuosity distributary channel, swampy) environments. Clastic reservoir characteristics include lenticular channel sandstones and also blanket-like splay and strandplain sandstones. A stratigraphic profile of the complete Mesaverde section (Lorenz, 1983) is presented in Figure 31.

Nonassociated gas accumulations occur in both the coals and clastic reservoir rocks and though not a part of this study's brief, coal resource and reserves potential has been addressed in addition to the sandstone potential since well completions occur in both lithologies in the basin. The Paludal coal resource evaluation is included as Appendix B.

Figure 48 presents the structure for the top of the Paludal Play in measured depth, developed by subtracting the Paludal gross isopach from the structure map for the Top Rollins-Trout Creek. Figure 49 presents the same map in subsea. The top of the Paludal is encountered between 3,000 feet measured depth and a projected depth of greater than 12,000 feet within the play boundary. The Paludal structural configuration is similar to that of the Rollins-Trout Creek though with slightly less contrast in relief between the basin's western margin and the depocenter, due to thickening of the Paludal Play adjacent to the Grand Hogback and parallel to the basin axis.

Figure 50 presents the Paludal gross isopach drawn using thickness data from 33 wells evaluated during this study and supplemented with gross values from 27 wells reported by Myal (1989). The map displays a gradual thickening from less than 200 feet on the west flank to greater than 700 feet along the basin axis and around Divide Creek in the southeast. The Cameo-Wheeler-Fairfield coal zone represents the majority of the mapped interval and is developed across essentially all of the Piceance Basin. Thickening to the southeast may be associated with a smaller transgressive episode which resulted in the deposition of the middle regressive marine sandstone of Collins (1976). The persistent Paludal and coastal plain environment immediately behind the approximately north-south oriented wave dominated shoreline led to the development of the South Canyon and also Coal Ridge coal zones above the Cameo-Wheeler-Fairfield coal zone in this area. Decker et al (1995) relates gross interval

thickening in the Cameo coals and Williams Fork to movement along a northwest-southeast trending "basin hinge line" between Rulison and Mam Creek fields, originally developed during the Pre-Cambrian but reactivated during the Paleozoic and Tertiary orogenies.

The Paludal sand isopach Figure 51, displays a similar eastward thickening trend from less than 50 feet at the western basin margin to more than 350 feet adjacent to the Grand Hogback. Again, thickening reflects development of the regressive middle sand of Collins (1976). The maximum penetrated thickness actually occurs in the northeast portion of the basin at Township 1N Range 95W which accentuates the interpreted north-south orientation of the paleo shoreline.

The Paludal net pay isopach (Figure 52) again thickens toward the east from zero at the play boundary to a thickness of over 35 feet around the Grand Valley-Parachute-Rulison area, where the bulk of Paludal clastic gas production occurs. The pay thins again at Divide Creek indicating that the middle sandstone contributes little in terms of reservoir thickness. Extrapolation of contours north of the Grand Valley-Rulison area in absence of well control is speculative and reflects the feeling that sand development will parallel the interpreted north-south Paleo shoreline.

Though pay has been mapped within most of the maturation limit, the potential of the Paludal clastics and the southern part of the basin is interpreted to be limited based on the unsuccessful completion attempts in the Plateau Creek area. Here pay sands are not well developed and are interpreted to thin to zero.

The areal extent of both the sand and pay maps is limited by the intersection of Johnson's (1987) top R_o 0.73 and R_o 1.1 with the structure on the top and base of the Paludal Play. Intersection of the maturation limits with the top and base of the Paludal creates a wedge within which the contours thin rapidly to zero. Contours on Figures 51 and 52 do not reflect this wedging, however, it is accounted for in the volumetric estimates.

Figures 53a and 53b display the rock property distributions for the R_o 0.73-1.1 and $R_o > 1.1$ subplays respectively. Porosity distributions are relatively similar. Note the high frequency of porosities below 5% in the $R_o > 1.1$ subplay. As with the Marine Play, average water saturations are higher in the R_o 0.73-1.1 subplay (84% versus 69%) than the $R_o > 1.1$ subplay. This can be attributed to a weaker gas charge in the thermally less mature rocks and possible flushing by meteoric water at the basin edge. Water saturations for the pay sections drop significantly yet still show a similar contrast between the two subplays (54% versus 48%).

Figure 54 presents an example of a CPI log for the Paludal Play. The Vega Unit #2 (Section 34 Township 9S Range 93W) was drilled in 1978 and completed in the Paludal environment between 7,847 and 8,052 feet with an IP of 440 Mcfd and 109 bwpd. The log

displays an average porosity and water saturation throughout the 33 foot pay section of about 9% and 50% respectively. A total of 156 plug samples of Paludal core were corrected to in-situ conditions and subdivided into three categories: Completed, Tested and Other samples (Figures 55a and 55b). Porosities display a relatively normal distribution with an average for all samples (6.2%) and the log-derived average porosity for all sands (6.5-7.5%). Permeabilities are low, with a P50 of less than 1/10th of a microdarcy for all samples, increasing to over 1 md for Completed samples. A relatively tight grouping of data is displayed on the porosity-permeability plot. Note between 7,845 and 7,880 feet and 7,980 and 8,010 feet there are two thick seams of coal characterized by low gamma ray and high caliper readings and extremely high porosities. These coals were most likely perforated along with the sands between 7,935 and 7,980 feet. The coal is speculated to have contributed little to production.

Reevaluation of Resource

The top of the Paludal Play ranges between 1,000 feet to the west to 12,500 feet nearing the Grand Hogback. The majority of the rock volume lies between the depths of 6,000 to 12,000 feet. Average porosity decreases consistently with depth between 2,500 and 6,000 feet.

The lack of commercial production in the play places the entire *technologically viable* resource in the *nondemonstrated* category at this time. As such, the only subdivision of the total estimate resources of 52.3 Tcf is 44.1 Tcf (84%) in the *technologically nonviable* category (low permeability rocks considered too tight to support commercial production) and 8.2 Tcf (16%) in the *technologically viable* category (occurs in rocks with more favorable reservoir properties). Figures 56 and 57 display this information graphically for the sub-plays $R_o = 0.73$ and $R_o = 1.1$ respectively.

Table 12 compares the USGS estimate for the Fluvial Play to the revised estimate derived herein.

TABLE 12
PALUDAL PLAY RESOURCE ESTIMATE BREAKDOWN

USGS Mean Resource	•
Scotia Revised Mean Resource Estimate	52.3
Minus <i>Technologically Nonviable</i> Resources	44.1
Subtotal <i>Technologically Viable</i> Resources	8.2
Minus <i>Nondemonstrated</i> Resources	8.2
Subtotal <i>Demonstrated</i> Resources	0
Subdivision:	
<i>Speculative Resources</i>	0
<i>Nonestablished Resources</i>	0
<i>Established Resources</i>	0

* Not a USGS play

Reserves Evaluation

There are two remarkable aspects to this play, first, there is no commercial production from the Paludal anywhere in the basin. Second and most remarkably, increased understanding of the basin and increases in fracturing technology have lead to increased EURs in all the other plays, yet in the Paludal EURs have decreased over the last five years. While the evaluation of well log information indicates the presence of reservoirs which calculate as gas-productive and the presence of coal that could add to the amount of producible gas, actual completion attempts have had extremely disappointing results to date. As such, there is no basis for constructing a model which would include the resulting volumes within the economic category and hence being termed reserves.

Figure: 44

LEGEND

- ✱ GAS WELL
- DRY HOLE
- BASIN OUTLINE
- PLAY OUTLINES

U.S. Department of Energy

Piceance Basin

PALUDAL PLAY PENETRATION MAP

Well locations were obtained from Petroleum Information. Scolia has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data.

Figure: 45

Figure: 46

LEGEND

○ 10 Bcf	— BASIN OUTLINE
○ 1000 MMcf	— PLAY OUTLINES
○ 100 MMcf	----- RIVERS
○ 10 MMcf	

U.S. Department of Energy

Piceance Basin
PALUDAL PLAY
EUR DISTRIBUTION MAP

Well locations were obtained from Petroleum Information. Scotio has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data.

Figure: 48

Simplified Structure
Adjacent to Grand Hogback.
Beds Dip Steeply

0 5 10 20 30 40 50 miles

LEGEND

- BASIN OUTLINE
- CONTOURS

U.S. Department of Energy

Piceance Basin
PALUDAL PLAY TOP
STRUCTURE, MEASURED DEPTH

Well locations were obtained from Petroleum Information. Scotia has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data.

Figure: 49

LEGEND

- BASIN OUTLINE
- CONTOURS

U.S. Department of Energy

Piceance Basin
PALUDAL PLAY TOP
STRUCTURE, SUBSEA

Well locations were obtained from Petroleum Information. Scotia has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data.

Figure: 50

LEGEND

- BASIN OUTLINE
- CONTOURS

U.S. Department of Energy

Piceance Basin

PALUDAL PLAY GROSS ISOPACH

Well locations were obtained from Petroleum Information. Scotia has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data.

Figure: 51

Figure: 52

10 0 10 20 30 40 50 miles

LEGEND

- BASIN OUTLINE
- PLAY OUTLINES
- CONTOURS

U.S. Department of Energy

Piceance Basin

PALUDAL PLAY PAY ISOPACH

Well locations were obtained from Petroleum Information. Scotia has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data.

Piceance Basin: Rock Property Distributions

PALUDAL PLAY, RO .73 - 1.1 SUBPLAY, SAND

THU AUG 03 1995

Piceance Basin: Rock Property Distributions

PALUDAL PLAY, $R_o > 1.1$ SUBPLAY, SAND

THU AUG 03 1995

Figure 55a

COREPRO Client: U.S. DEPARTMENT OF ENERGY
IN-SITU CONDITION, PALUDAL PLAY, COMPLETED INTERVALS.
Porosity versus Permeability

FILE: Various
DATE: AUG 03 1995

COREPRO Client: U.S. DEPARTMENT OF ENERGY
IN-SITU CONDITION, PALUDAL PLAY, COMPLETED INTERVALS.
Histogram Plot

AVERAGE 12.3 POINTS 11.
MEDIAN 12.8 STD DEV 3.39

FILE: Various
DATE: AUG 03 1995

COREPRO Client: U.S. DEPARTMENT OF ENERGY
IN-SITU CONDITION, PALUDAL PLAY, ALL DATA.
Porosity versus Permeability

FILE: Various
DATE: AUG 03 1995

COREPRO Client: U.S. DEPARTMENT OF ENERGY
IN-SITU CONDITION, PALUDAL PLAY, ALL DATA.
Histogram Plot

AVERAGE 6.16 POINTS 156.
MEDIAN 5.81 STD DEV 3.18

FILE: Various
DATE: AUG 03 1995

COREPRO Client: U.S. DEPARTMENT OF ENERGY
IN-SITU CONDITIONS, PALUDAL PLAY, TESTED INTERVALS.
Porosity versus Permeability

Figure 55b
COREPRO Client: U.S. DEPARTMENT OF ENERGY
IN-SITU CONDITIONS, PALUDAL PLAY, TESTED INTERVALS.
Histogram Plot

AVERAGE	6.40	POINTS	51.
MEDIAN	6.40	STD DEV	1.54

COREPRO Client: U.S. DEPARTMENT OF ENERGY
IN-SITU CONDITIONS, PALUDAL PLAY, OTHER DATA.
Porosity versus Permeability

COREPRO Client: U.S. DEPARTMENT OF ENERGY
IN-SITU CONDITIONS, PALUDAL PLAY, OTHER DATA.
Histogram Plot

AVERAGE	5.31	POINTS	94.
MEDIAN	5.34	STD DEV	3.03

Piceance Basin Tight Gas Resource Allocation

PALUDAL PLAY, Ro .73 - 1.1 SUBPLAY

THU AUG 03 1995

Resource (BCF)

Rock Volume (M.AcFt)

Piceance Basin Tight Gas Resource Allocation

PALUDAL PLAY, $R_o > 1.1$ SUBPLAY

THU AUG 03 1995

FLUVIAL PLAY

Description

The Fluvial Play lies immediately above the Paludal Play and is the youngest stratigraphic unit considered in this study. It includes the non-marine coastal plain, fluvial and paralic environments of the Campanian Williams Fork formation. The play is restricted to approximately the lowest one-third of the Williams Fork formation and its gas-bearing potential is poor at the basin margins due to a combination of low thermal maturity organic rocks in the Williams Fork formation, absence of overpressuring associated with gas generation, and flushing by influx of meteoric water. The play lies inside the Cretaceous outcrop which defines the basin outline and is bounded for the most part by the R_o 0.73 elevation contour. An area of approximately 290 square miles in the center of the basin which includes the Rulison, Parachute and Grand Valley fields has been excluded from the Fluvial Play and combined with a similar area from the Paludal Play to form the Multi-Pay Play. The $R_o = 0.73-1.1$ subplay covers an area of approximately 2,289 square miles while the Fluvial $R_o = 1.1$ subplay has an area of 1,367 square miles.

Well penetrations are mostly concentrated along deeply incised river valleys where as much as 5,000 feet of overburden has been removed relative to the present day plateaus (Figure 58). The Mesaverde formation as a whole has been designated as tight by FERC between 6S 97W and 11S 89W and also approximately 180 square miles in the northwest corner (Figure 59).

Well control within the play is generally reasonable and includes wells that TD in the Dakota, Mancos, and deeper units of the Mesaverde. Nearly all wells in the extreme south of the Piceance Basin TD in the Marine environment. The deeper portions of the play adjacent to the Grand Hogback monocline and on top of the plateaus have not been drilled, therefore there is minimal well control in these areas.

Examination of the Fluvial Play field list (Table 13) shows cumulative production of 74.1 Bcf from 83 wells. The EURs for these wells is 94.7 Bcf or 1.14 Bcf/well. Excluding the Divide Creek anticline (that dominates the production statistics) from these numbers yields cumulative production of 20.3 Bcf from 75 wells with combined EURs of 37.6 Bcf or 501 MMcf/well. Fluvial production is scattered throughout the basin except along the Grand Hogback. The majority of the production lies inside the $R_o = 1.1$ subplay with two exceptions, extreme southwest around the Plateau and Shire Gulch fields, and to the extreme north by the White River (Figure 60). Recently, wells with large EURs have been drilled just to the east of the Multi-Pay boundary perhaps indicating an extension of this attractive play to the east. Over the last five years average EURs have risen by 312 MMcf from 396 MMcf to 708 MMcf. Examining the play level production plot (Figure 61) approximately 51 wells are currently

producing with average per well rates of 180 Mcfd. The early producing history of the Fluvial Play exhibits curtailment (cycles of production during winter months followed by summer shut-in periods) but this no longer seems to be the case.

TABLE 13
FLUVIAL PLAY FIELD LIST

| FIELD NAME | AVG DEPTH
(Feet) | CUMULATIVE
MMcf | EUR
MMcf | NUMBER
of WELLS | AVG EUR
MMcf/Well |
|-------------------|-----------------------------|----------------------------|---------------------|----------------------------|------------------------------|
| BRUSH CREEK | 6387 | 229 | 249 | 1 | 249 |
| BUZZARD | 5317 | 1450 | 1586 | 6 | 264 |
| BUZZARD CREEK | 5703 | 55 | 56 | 1 | 56 |
| CALF CANYON | 960 | 13 | 13 | 2 | 7 |
| CATHEDRAL | 1445 | 3 | 3 | 1 | 3 |
| COON HOLLOW | 1692 | 142 | 142 | 1 | 142 |
| DEBEQUE | 1966 | 517 | 583 | 4 | 146 |
| DIVIDE CREEK | 5443 | 53829 | 57134 | 8 * | 7142 |
| GRAND SLAM | 5393 | 102 | 795 | 2 | 397 |
| LOGAN WASH | 2352 | 1136 | 1825 | 1 | 1825 |
| MAM CREEK | 6259 | 729 | 1606 | 5 | 321 |
| PICEANCE CREEK | | 3483 | 5502 | 3 | 1834 |
| PINYON RIDGE. | 5636 | 145 | 229 | 2 | 114 |
| PLATEAU | 3706 | 3426 | 3885 | 8 | 486 |
| SAGE BRUSH HILLS | | 1 | 1 | 1 | 1 |
| SHEEP CREEK | 8158 | 13 | 13 | 1 | 13 |
| SHIRE GULCH | 3106 | 1418 | 1436 | 4 | 359 |
| SULPHUR CREEK | 9049 | 1142 | 1618 | 10 | 162 |
| UNNAMED | 6678 | 345 | 6299 | 5 | 1260 |
| WHITE RIVER | 6155 | 5923 | 11687 | 17 | 687 |
| TOTAL | | 74104 | 94661 | 83 | 1140 |

• LEASE LEVEL REPORTING OF PRODUCTION INVOLVED, OR DATA PRE-DATES MONTHLY REPORTING. WELL COUNTS ARE ESTIMATED.

Analysis of drilling statistics for the Fluvial Play are complicated by the fact that many of the wells are deepened to TD in the Paludal or Marine play. Also many TDs are listed generically as the "Mesaverde" formation. It has been noted that the percentage of dry holes drilled in the Mesaverde is steadily declining so that it now stands at less than 2%. Therefore a basinwide dry hole constant of 2% has been adopted. The risk model for this and every play is based upon wells drilled over the last five years.

Stratigraphy and Rock Properties

The Fluvial sequence includes the non-marine coastal plain, fluvial and paralic environments of the Campanian Williams Fork formation. The base of the sequence is marked by the last identifiable coal of the Cameo-Fairfield Paludal Play in the lower portion of the Williams Fork formation. The top of the play is defined mostly by the R_o 0.73 elevation contour, except in the deeper part of the basin where the complete Williams Fork formation lies below this thermal maturation level. Here, the top of the play is marked by the Cretaceous-Tertiary unconformity separating it from the overlying Paleocene Fort Union and Eocene Wasatch formations. However, Tyler (1995) proposes based on palynological data and correlations between the Sand Wash and north Piceance Basin outcrops, that the undifferentiated Williams Fork above the Paonia shale actually belongs to the Campanian Lance and Lewis formations, Figure 31. The Fluvial Play was being deposited on the coastal plain behind the receding Campanian shoreline and chronostratigraphically extends well below the last regressive cycle, the Rollins-Trout Creek, of the Iles formation in the northwest part of the basin. In the southeast corner of the basin the Fluvial section extends approximately 1,000 feet above the Rollins-Trout Creek. This play consists almost entirely of lenticular channel sandstones and fine grained flood plain deposits (Johnson, 1987). Sediment sourcing for the Fluvial Play was from erosion of the Sevier Highlands to the west and at times from local topographic highs such as the Sawatch Uplift in the southern part of the basin, following early Laramide uplifting contemporaneous with Mesaverde deposition. The play is generally undifferentiated in most of the basin and is typically called the Williams Fork formation or simply the Mesaverde formation. Local formation names within the play include the Hunter Canyon formation and upper most part of the Mount Garfield formation in southwest Piceance, and the Farrar facies of the Price River formation (Young 1955, 1966).

The structure map of the top Williams Fork (Figure 62) was prepared using PI depths from 476 wells. The surface is shown in measured depth which illustrates the variation in overburden thickness across the basin, and in subsea depth (Figure 63) illustrating the present day structural attitude of this Upper Cretaceous unconformity surface. In spite of erosion across topographic highs formed during the Laramide orogeny between Late Campanian and Early Eocene, major structural features are still evident, including the Divide Creek anticline and White River and Piceance Creek domes. Note that manual editing of contours was required to reflect the upturned strata along the Grand Hogback due to lack of well control

in that area. Well control is evenly distributed within the basin, being restricted somewhat to the topographically lower river valleys. Consequently, smoothing of contours exists over wide areas (generally under the plateaus and in the basin deep) which masks some of the major structural features known to exist.

The Fluvial Play outcrops around the basin perimeter and is projected to lie at depths greater than 1,800 feet subsea (ftss) immediately west of the Grand Hogback. Drilled depths to the top of the Williams Fork formation range up to 8,330 feet.

The Fluvial gross isopach (Figure 64) was prepared using thicknesses from 50 wells compiled during this study and supplemented with thickness data from 34 wells analyzed by Myal (1989) and a contour map of the gross Williams Fork formation for the Piceance Basin prepared by Johnson et al (1987). To take advantage of Johnsons contour map, Fluvial and Paludal gross thickness data was combined and contoured using Johnsons gross map as a guide. The Williams Fork thickens from less than 1,500 feet at the eastern edge of the Douglas Creek Arch to a projected thickness of more than 4,500 feet immediately west of the Grand Hogback. Maximum penetrated thickness was 4,195 feet in the Rifle Walton well located at 7S91W25. The Fluvial gross isopach was derived by subtracting the Paludal gross map from the Williams Fork isopach. This map displays similar eastward thickening from 1,000 feet at the Douglas Creek Arch to a projected thickness of 3,500 feet at the Grand Hogback. The Fluvial interval represents the thickest of the three plays in both gross and net sand terms. It consists of sandstones, siltstones, mudstones, and some minor coals not included within the Paludal Play.

As with the gross isopach, Johnsons Williams Fork sandstone isopach was referenced while contouring the fluvial sandstone isopach (Figure 65). The Fluvial sandstones range in thickness from less than 500 feet adjacent to the Douglas Creek Arch to a projected thickness of greater than 1,600 feet through the basin depocenter immediately west of the Grand Hogback. Thinning occurs in the southeast part of the basin where the onset of Fluvial deposition began later due to the persistence of the Late Cretaceous coastline.

Thinning to less than 900 feet also occurs around Grand Valley Field. Sandstone net/gross ratios in the Fluvial section range between 30% and 50%, averaging 39%. The sandstones are mostly lenticular fluvial sandstones and stacked fluvial sandstones deposited in a coastal plain behind the Late Cretaceous coastline (Johnson, 1989). In the southeast part of the basin, marginal marine sandstones (Middle sandstone of Collins, 1976) occur within the Williams Fork formation, though these are contained within the Paludal play. Note that the sandstone map is a composite of all sandstones within the Fluvial Play developed from limited well control and as such tends to mask more local changes in depositional environment and inferred rock quality.

Petrophysical analyses of the Fluvial section revealed that only the lower approximately one-third of the play is gas-saturated and that the proportion of the gas-saturated sand diminishes toward the basin edges.

To determine what portion of Fluvial sandstones are potentially gas-saturated, thermal maturity (vitrinite reflectance, R_o) maps prepared by the USGS were compared with water saturation estimates from log analysis.

R_o elevations were taken from Johnsons (1987) maps at the location of each well evaluated during this study and posted to the well logs. If gas pay from log analysis was detected at elevations higher than $R_o = 0.73$, the top gas saturation elevation was used to define the ceiling of the gas accumulation. The top gas pay could of course lie below the R_o thresholds, particularly toward the basin edges, because of flushing at outcrop by meteoric recharge. In 50% of cases the top of gas saturation lay below the top of $R_o = 1.1$ and in 40% of cases lay between $R_o = 0.73$ and 1.1. In defining the total gas resource (*technologically viable plus nonviable*) the R_o maturation maps, adjusted upwards where necessary, were used to define the gas resource ceiling. In defining the *technologically viable* gas resource the top first gas pay, derived using cutoffs discussed elsewhere, was used to define the gas resource ceiling. The percent of gross Fluvial rock lying below the R_o elevations (0.73 and 1.1) was estimated and mapped across the basin. At only two locations, T3S R97W and T6S R97W, is the R_o 1.1 elevation interpreted to lie above the top of the Fluvial Play. Elsewhere the percentage decreases from more than 80% at the basin center to zero at the 1.1 play boundary. The R_o 0.73 elevation however is interpreted to lie above the top of the Fluvial Play across a large portion (26 townships) of the basin. These maps were used to derive the Fluvial sandstone thickness below $R_o = 0.73$ and 1.1 (Figure 66 and 67 respectively). Both maps display progressive thinning from the basin depocenter to zero at the play boundaries.

Gross pay thicknesses were contoured and the modified $R_o = 0.73$ maturation limit was used to guide the play boundary (Figure 68). A maximum pay thickness of 65 feet is interpreted to exist in T7S R94W around the Rulison Field. Fluvial pay thins gradually to zero toward the basin edge. Pay development mapped around Grand Valley, Parachute and Rulison fields is interpreted to continue to the NNW toward T3S R96W and southeast to T8S R92W. Pay thins to the southwest toward Plateau where it is interpreted to diminish to zero. Thinning is a function of both reduced thermal maturity and flushing of the originally gas saturated section by meteoric recharge at the outcrop. In the updip wells, the top of pay and also the top of gas saturation occurs progressively deeper in the Fluvial section. Also at the basin margins the transition from water-saturated to gas-saturated sandstones becomes less uniform as influxing fresh water interfingers with the gas saturated section.

Though the lenticular nature of the sandstones plus the presence of shales and mudstones may create seals to trap the gas, the gradual transition from 100% water saturation

to irreducible water saturation is speculated to be a function of the gas trapping mechanism associated with basin centered or deep basin gas accumulations, described by Masters (1979). Lateral sealing potential is limited also, as evidenced by fresh meteoric water influx relatively far into the basin from outcrop areas. In other basins such as the GGRB, this transition zone, also marks the top of overpressuring caused by present day gas generation. Above the transition zone normally pressured water-bearing sands are encountered. In the Piceance Basin however, overpressure is limited to the deepest part of the basin. The general absence of overpressuring and leakage of gas may allow more invasion of the basin margins by meteoric water. The 190° F isotherm, generally thought to represent the temperature above which significant quantities of gas begin to be generated (Law 1980), generally lies below the base of the Fluvial section. In central Piceance (Rulison area) the isotherm coincides with the top of the Paludal Play, while in eastern and southern Piceance (Plateau area) it lies within the Marine Play or below in the Mancos formation, indicating the gas is not currently being generated in the Fluvial Play.

Figures 69a and 69b present the rock property distributions for the R_o 0.73-1.1 and $R_o > 1.1$ subplays. Though porosities are similar for each subplay, water saturations are significantly higher in the R_o 0.71-1.1 subplay (88% versus 53%), which illustrates the lower thermal maturity and effects of flushing.

Figure 70 is an example of a CPI log from the Fluvial Play. The White River Dome Unit #1 is located in the White River Dome Field in the north of the basin at S28 T2N R96W. The well tested 5,460 Mcfd between the interval 6,040 and 6,932 feet after an emulsion frac with 50,000 gallons of fluid and 30,000 pounds of sand. The top of the Fluvial environment was encountered at 4,010 feet and the base at 6,340 feet. The 18 feet of pay indicated on the log average about 13.5% porosity and 50% water saturation.

A total of 1,429 samples of Fluvial core data were available and these were corrected to in-situ conditions and subdivided into these categories: Completed, Tested and Other Samples. Despite a large scatter in the data, a crude relationship between porosity and permeability is evident (Figures 71a and 71b). This becomes clearer when considering the Completed and Tested data sets which also correspond to the higher porosity portions of the sample. The presence of higher permeabilities in the lower porosity fractions may be attributable to material fracturing.

Focusing on the Completed and Tested data sets, it is evident that the highest porosity zones are selected for completion with average porosities in these samplings being almost twice the average of the overall data set. However, it is not noted that there is a marked bimodal character to the porosity distributions for the Completed and Tested data sets. This may be related to the recent practice of fracing large intervals rather than selectively completing only the best zones. The noted success of fracing large intervals recognizes the

unpredictable and heterogeneous nature of the Fluvial Play whereby the identification of favorable porosities at the wellbore does not necessarily equate to the lateral persistence of such conditions. By fracing large intervals, the potential for connecting the various lenses and preexisting network of natural fractures is maximized.

Reevaluation of Resource

The bulk of the rock volume comprising the Fluvial Play lies between 6,500 and 12,500 feet. The deepest part of the play is toward the Grand Hogback. Approximately 63% of the rock volume lies above 10,000 feet which is the main interval of interest. This depth corresponds to the deepest evaluated well control, with rock volumes below this point being assigned the same properties as the deepest evaluated interval.

The mean porosity tends to decrease with depth for the first 3,500 feet and then remain relatively constant. The upper two-thirds of the Fluvial Play in many cases tends to be flushed.

The existing production from the Fluvial Play is dominated by the Divide Creek anticline. This field is not analogous to the rest of the play and has been omitted in all statistics. For constructing a distribution of expected recoveries for *economic basement* calculations only completions made in the last five years were considered. This model calculated the *economic basement* to be 8,200 feet. Deepest commercial production is determined to be less than the *economic basement* so it has been artificially deepened to the *economic basement*. Figure 72 illustrates the EUR distributions and the Fluvial risk model.

Of the total resource (R_O 1.1 subplay and R_O .73 subplay) of 141.2 Tcf for the Fluvial, 127.9 Tcf or 90% occurs in low permeability rocks considered too tight to support commercial production. Of the remaining 13.3 Tcf, 7.6 Tcf lies below the *economic basement* leaving 5.7 Tcf which will be the main contributor to reserves.

Table 14 compares the USGS estimate for the Williams Fork Play (our Fluvial and Paludal plays) to the revised estimate derived herein. Figures 73 and 74 graphically illustrate this breakdown for each subplay.

TABLE 14
FLUVIAL PLAY RESOURCE ESTIMATE BREAKDOWN
(Tcf)

USGS Mean Resource Estimate	320.6
Scotia Revised Mean Resource Estimate	141.2
MINUS <i>Technology Nonviable Resources</i>	127.9
SUBTOTAL <i>Technologically Viable Resources</i>	13.3
MINUS <i>Nondemonstrated Resources</i>	0
SUBTOTAL <i>Demonstrated Resources</i>	13.3
Subdivision: <i>Speculative Resources</i>	7.6
<i>Nonestablished Resources</i>	0
<i>Established Resources</i>	5.7

For Fluvial Play reserves evaluation, the rock volumes for the subplays have been added and factored according to Table 15.

There are several notable aspects of the Fluvial Play. The Divide Creek area is anomalous to the rest of the play and has been excluded for the purpose of generating a predictive model. It is evident from the Divide Creek anticline that the reservoirs are superior to other discovered areas in the basin with per well EURs in excess of 8 Bcf. The average EUR for other Fluvial wells in the basin is about 500 MMcf.

TABLE 15
FLUVIAL PLAY, RESERVES CALCULATION

| | ESTABLISHED
CATEGORY
R _o = 0.73 | | | NONESTABLISHED
CATEGORY
R _o = 1.1 | | |
|--|--|----------------|---------|--|----------------|---------|
| Parameters | MAX | MOST
LIKELY | MIN | MAX | MOST
LIKELY | MIN |
| Base Recovery Factor | 0.85 | 0.85 | 0.85 | 0.85 | 0.85 | 0.85 |
| Dry Hole Fraction | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 |
| Min Economic Drainage Acres | 11 | 38 | 150 | 13 | 48 | 180 |
| Noncommercial Fraction | 0.35 | 0.675 | 0.825 | 0.36 | 0.71 | 0.88 |
| Recovery Factor | 0.54 | 0.27 | 0.15 | 0.53 | 0.24 | 0.1 |
| Rock Volume (M ac-ft) | 4,447 | | | 13,043 | | |
| Porosity | 0.135 | 0.105 | 0.07 | 0.14 | 0.105 | 0.07 |
| Water Saturation | 0.45 | 0.5 | 0.55 | 0.48 | 0.53 | 0.58 |
| FVF (res cf/scf) | 0.0133 | 0.00623 | 0.00473 | 0.00857 | 0.00623 | 0.00473 |
| <u>Reserves Probability Distribution</u> | | | | | | |
| 90% Probability of Exceeding (Bcf) | 224 | | | 684 | | |
| 70% Probability of Exceeding (Bcf) | 304 | | | 950 | | |
| 50% Probability of Exceeding (Bcf) | 381 | | | 1,190 | | |
| 30% Probability of Exceeding (Bcf) | 472 | | | 1,475 | | |
| 10% Probability of Exceeding (Bcf) | 633 | | | 1,945 | | |
| Mean Value (Bcf) | 409 | | | 1,261 | | |
| <u>Total PDP Reserves & Cum
Production</u> | | | | | | |
| Cumulative Production (Bcf) | 74.1 | | | | | |
| Remaining PDP Reserves (Bcf) | 20.5 | | | | | |
| EUR of PDP Reserves (Bcf) | 94.6 | | | | | |

The practice of fracing large intervals as opposed to selective zones has proven to be a major success in this play. Average EURs have increased almost 300 MMcf/well over the last five years. Recent activity in the play includes both extension and infill drilling and the opening of new areas. Results immediately to the east of the Multi-Pay Play are promising.

In summary, reserves are recognized in only the *established* category in the Fluvial. The mean estimate for *established* reserves is 1.67 Tcf overall or 1.58 Tcf after subtraction of EURs of existing Fluvial wells.

Figure: 58

LEGEND

✱ GAS WELL	— BASIN OUTLINE
○ DRY HOLE	— PLAY OUTLINES

U.S. Department of Energy

Piceance Basin

FLUVIAL PLAY PENETRATION MAP

Well locations were obtained from Petroleum Information. Scotia has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data.

Figure: 59

LEGEND

✱ GAS WELL
○ DRY HOLE

— BASIN OUTLINE
— PLAY OUTLINES
--- FERC TIGHT AREA

U.S. Department of Energy

Piceance Basin
FLUVIAL PLAY
PRODUCER & DRY HOLE MAP

Well locations were obtained from Petroleum Information. Scola has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data.

Figure: 60

LEGEND

○ 10 Bcf	— BASIN OUTLINE
○ 1000 MMcf	— PLAY OUTLINES
○ 100 MMcf	- - - RIVERS
○ 10 MMcf	

U.S. Department of Energy

Piceance Basin
FLUVIAL PLAY
EUR DISTRIBUTION MAP

Well locations were obtained from Petroleum Information. Scotia has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data.

FIGURE 61

FLUVIAL TOTAL PRODUCTION PROFILE

Projections are averages for each year commencing at the effective date of the evaluation. Results are subject to the qualifications and limitations stated in the attached document

Figure: 62

Figure: 63

Simplified Structure
Adjacent to Grand Hogback.
Beds Dip Steeply

LEGEND

- BASIN OUTLINE
- CONTOURS

U.S. Department of Energy

Piceance Basin
FLUVIAL PLAY TOP
STRUCTURE, SUBSEA

Well locations were obtained from Petroleum Information. Scotia has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data.

Figure: 64

LEGEND

- BASIN OUTLINE
- CONTOURS

U.S. Department of Energy

Piceance Basin
FLUVIAL PLAY GROSS ISOPACH

Well locations were obtained from Petroleum Information. Scotia has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data.

Figure: 65

10 0 10 20 30 40 50 miles

LEGEND

- BASIN OUTLINE
- CONTOURS

U.S. Department of Energy

Piceance Basin
FLUVIAL PLAY
SANDSTONE ISOPACH

Well locations were obtained from Petroleum Information. Scotia has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data.

Figure: 66

LEGEND

- BASIN OUTLINE
- CONTOURS

U.S. Department of Energy

Piceance Basin
FLUVIAL PLAY
SANDSTONE ISOPACH ($RO > .73$)

Well locations were obtained from Petroleum Information. Scolia has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data.

Figure: 67

LEGEND

- BASIN OUTLINE
- CONTOURS

U.S. Department of Energy

Piceance Basin
FLUVIAL PLAY
SANDSTONE ISOPACH ($RO > 1.1$)

Well locations were obtained from Petroleum Information. Scotia has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data.

Figure: 68

0 10 20 30 40 50 miles

LEGEND

- BASIN OUTLINE
- PLAY OUTLINES
- CONTOURS

U.S. Department of Energy

Piceance Basin

FLUVIAL PLAY PAY ISOPACH

Well locations were obtained from Petroleum Information. Scotia has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data.

Piceance Basin: Rock Property Distributions

FLUVIAL PLAY, Ro .73 - 1.1 SUBPLAY, SAND

THU AUG 03 1995

Piceance Basin: Rock Property Distributions

FLUVIAL PLAY, $R_o > 1.1$ SUBPLAY, SAND

THU AUG 03 1995

0 Bad Hole Flag 20
6 Caliper 16
0 Gamma Ray 150
0 75 150

DEPTH
5900

1.00 Sw -1.0
0.30 Phi.Sw 0.00
0.30 Phi.Sxo 0.00
0.00 Vclay minimum 2.00
0.30 Effective Porosity 0.00
0.30 0.15 0.00

10⁻⁴ Permeability (Alt) 1
10⁻⁴ Permeability (Kokal) 1
10⁻⁴001 0.01 0.1 1

6100

6200

6300

FILE: 29628W

Scotia Group Proprietary Systems

THU JUL 27 1995

COREPRO Client: U.S. DEPARTMENT OF ENERGY
IN-SITU CONDITION, FLUVIAL PLAY, COMPLETED INTERVAL.
Porosity versus Permeability

FILE: Various
DATE: JUL 28 1995

Overburden-corrected Porosity

Overburden & Klink corr Perm

The
Scotia
Group

Figure 71a

COREPRO Client: U.S. DEPARTMENT OF ENERGY
IN-SITU CONDITION, FLUVIAL PLAY, COMPLETED INTERVAL.

Histogram Plot

AVERAGE 8.03 POINTS 189.
MEDIAN 7.20 STD DEV 3.87

FILE: Various
DATE: JUL 28 1995

Overburden-corrected Porosity

Cum Frequency %

The
Scotia
Group

COREPRO Client: U.S. DEPARTMENT OF ENERGY
IN-SITU CONDITION, FLUVIAL PLAY, ALL DATA.
Porosity versus Permeability

FILE: Various
DATE: JUL 26 1995

Overburden-corrected Porosity

Overburden & Klink corr Perm

The
Scotia
Group

COREPRO Client: U.S. DEPARTMENT OF ENERGY
IN-SITU CONDITION, FLUVIAL PLAY, ALL DATA.

Histogram Plot

AVERAGE 5.18 POINTS 1429.
MEDIAN 4.83 STD DEV 2.95

FILE: Various
DATE: JUL 26 1995

Overburden-corrected Porosity

Cum Frequency %

The
Scotia
Group

COREPRO Client: U.S. DEPARTMENT OF ENERGY
IN-SITU CONDITION, FLUVIAL PLAY, TESTED INTERVAL.
Porosity versus Permeability

Figure 71b
COREPRO Client: U.S. DEPARTMENT OF ENERGY
IN-SITU CONDITION, FLUVIAL PLAY, TESTED INTERVAL.
Histogram Plot
AVERAGE 5.96 POINTS 69.
MEDIAN 4.88 STD DEV 3.51

COREPRO Client: U.S. DEPARTMENT OF ENERGY
IN-SITU CONDITION, FLUVIAL PLAY, OTHER DATA.
Porosity versus Permeability

COREPRO Client: U.S. DEPARTMENT OF ENERGY
IN-SITU CONDITION, FLUVIAL PLAY, OTHER DATA.
Histogram Plot
AVERAGE 8.03 POINTS 189.
MEDIAN 7.20 STD DEV 3.87

FLUVIAL PLAY

Technical Success 98.0%
Commercial Success 27.4%

FRI JUL 28 1995

Piceance Basin Tight Gas Resource Allocation

FLUVIAL PLAY, Ro .73 - 1.1 SUBPLAY

THU AUG 03 1995

Piceance Basin Tight Gas Resource Allocation

FLUVIAL PLAY, $R_o > 1.1$ SUBPLAY

MULTI-PAY PLAY

Description

The Multi-Pay Play lies in the heart of the Fluvial and Paludal plays and includes all areas between T6S R97W and T7S R94W from the top of the Mesaverde to the top of the Marine Play. This area has been segmented and included as its own play for the following reasons;

1. Many of the wells have been dually completed across the Fluvial and Paludal environments or when only a single completion is present, it usually spans a very wide interval consisting of both of the aforementioned environments, making it impossible to assign production to a single formation.
2. The EUR distribution for this region is radically different from any other part of the basin.
3. This is the only area where the Paludal environment produces in economic quantities.

This play includes about 290 square miles located in the Colorado River Valley including the Rulison, Parachute and Grand Valley fields. These three fields account for 217 completions in 140 wellbores, or about 46% of the total completions in all of the plays in the basin. Well control within the play area is excellent due to the large concentration of wells in a relatively small area (Figure 75). The entire play has been FERC-designated as tight (Figure 76).

Examination of the Multi-Pay Play Field list (Table 16) shows cumulative production of 51.15 Bcf from 217 completions in 140 wellbores. The EURs of these wells is 103.2 Bcf or about 737 MMcf/wellbore. Figure 77 graphically represents per well EURs. Over 64% of the wellbores in this area have multiple completions but none having more than three. In the Parachute Field 29 of the 32 wells, over 90%, are dually completed, usually with one completion in the Fluvial and one completion in the Paludal environment. Examining the play level production plot (Figure 78), approximately 150 completions are currently producing with average per well rates of 174 Mcfd. A review of the number of completions indicates an increase in over 150 completions during the last five years which corresponds with the complete development of Parachute and almost two-thirds the development of Grand Valley. As with the other plays, a 2% dry hole factor was used in the risked economic model.

Figures 79a and 79b are examples of CPI logs from the Multi-Pay Play. Figure 79a shows the interval between 5,500 and 5,900 feet in the Fluvial environment. Figure 79b shows an interval in the Paludal environment between 7,000 and 7,400 feet. Note the presence of

coal throughout this section (high gamma ray, no porosity or water saturation curves). The CER Superior MWX-1 well is located in the Rulison Field at S34 T6S R94W. The well tested 1,000 Mcfd gas and 1 bwd from an interval between 5,535 to 5,845 feet and 900 Mcfd between the interval 7,835 to 7,954 feet. This well was acidized with a KCl solution between 5,720 and 5,738 feet and fractured with 81,500 pounds sand and 44,604 gallons of fluid with 1.66 MMcf of nitrogen added.

TABLE 16
MULTI-PAY PLAY FIELD LIST

| FIELD NAME | AVG
DEPTH
(Feet) | CUM
MMcf | EUR
MMcf | NUMBER
OF
COMPS | NUMBER
OF WELLS | AVG EUR
MMcf/Comp | AVG EUR
MMcf/Well |
|-----------------|------------------------|-------------|-------------|-----------------------|--------------------|----------------------|----------------------|
| GRAND
VALLEY | 9658 | 24601 | 48160 | 107 | 64 | 450 | 753 |
| PARACHUTE | 2777 | 10091 | 19095 | 61 | 32 | 313 | 597 |
| RULISON | 8098 | 16458 | 35963 | 49 | 44 | 733 | 817 |
| TOTAL | | 51150 | 103218 | 217 | 140 | 476 | 737 |

Reevaluation of Resource

The bulk of the rock volume comprising the Multi-Pay Play lies between 6,500 and 10,000 feet with the base of the play extending down to 11,500 feet. Porosities decrease with depth between 2,500 and 6,500 feet, bottoming out at an average of about 6%. Below 6,500 feet the porosities stabilize at an average of 8%.

The existing production from the Multi-Pay Play is dominated by wells that have been dually completed. In the last three years or so, this has been replaced by fracturing large intervals of the wellbore, and opening up as many sands as possible. This change in completion philosophy has increased the average EUR per well to 747 MMcf. For constructing a distribution of expected recoveries for *economic basement* calculations, only the more recent (wells drilled after 1992) were included. The *economic basement* for the Multi-Pay Play is approximately 6,500 feet, while the deepest commercial production is 8,200 feet. Although the EUR distribution for this play is superior to the other plays, the added cost of completions in the area (\$101/foot to \$65/foot) actually creates an *economic basement* that is higher here than in the Fluvial Play. The actual benefit of this completion technique is the higher probability of finding a commercial well. Figure 80 illustrates the EUR distributions and the Multi-Pay risk model.

Of the total resource of 28.2 Tcf evaluated for the Multi-Pay Play, 23 Tcf or 82% occurs in low permeability rock considered to be too tight to support commercial production. Of the remaining 5.2 Tcf, 4.3 Tcf lies below the *economic basement* of 6,500 feet, leaving an *established* resource of 0.9 Tcf which will be the main contributor to reserves.

Table 17 breaks down the resource estimate by category while Figure 81 graphically illustrates this break down.

TABLE 17
MULTI-PAY PLAY RESOURCE ESTIMATE BREAKDOWN
(Tcf)

* USGS Mean Resource Estimate	*
Scotia Revised Mean Resource Estimate	28.2
MINUS <i>Technology Nonviable</i> Resources	23
SUBTOTAL <i>Technologically Viable</i> Resources	5.2
MINUS <i>Nondemonstrated</i> Resources	0
SUBTOTAL <i>Demonstrated</i> Resources	5.2
Subdivision: <i>Speculative</i> Resources	1.1
<i>Nonestablished</i> Resources	3.2
<i>Established</i> Resources	0.9

* Not a USGS play

Reserves Evaluation

The Multi-Pay Play reserves evaluation is subdivided into *established* and *nonestablished* divisions involving the following parameters:

TABLE 18
RESERVES CALCULATION, MULTI-PAY PLAY

| | <i>ESTABLISHED
CATEGORY</i> | | | <i>NONESTABLISHED
CATEGORY</i> | | |
|---|---------------------------------|------------------------|------------|------------------------------------|------------------------|------------|
| Parameters | MAX | MOST
LIKELY | MIN | MAX | MOST
LIKELY | MIN |
| Base Recovery Factor | 0 | 0.85 | 0 | 0 | 0.85 | 0 |
| Dry Hole Fraction | 0 | 0.02 | 0 | 0 | 0.02 | 0 |
| Min Economic Drainage Acres | 14 | 50 | 185 | 25 | 85 | 310 |
| Noncommercial Fraction | 0.35 | 0.70 | 0.88 | 0.45 | 0.75 | 0.92 |
| Recovery Factor | 0.54 | 0.25 | 0.10 | 0.46 | 0.21 | 0.07 |
| Rock Volume (M ac-ft) | 3,260 | | | 6,681 | | |
| Porosity | 0.135 | 0.095 | 0.065 | 0.14 | 0.11 | 0.08 |
| Water Saturation | 0.43 | 0.49 | 0.55 | 0.45 | 0.49 | 0.53 |
| FVF (res cf/scf) | 0.0109 | 0.0071 | 0.0055 | 0.0053 | 0.0049 | 0.0046 |
| <u>Reserves Probability Distribution</u> | | | | | | |
| 90% Probability of Exceeding (Bcf) | 140 | | | 460 | | |
| 70% Probability of Exceeding (Bcf) | 201 | | | 636 | | |
| 50% Probability of Exceeding (Bcf) | 256 | | | 789 | | |
| 30% Probability of Exceeding (Bcf) | 315 | | | 960 | | |
| 10% Probability of Exceeding (Bcf) | 418 | | | 1,228 | | |
| Mean Value (Bcf) | 269 | | | 817 | | |
| <u>PDP Reserves & Cum Production</u> | | | | | | |
| Cumulative Production (Bcf) | 36.4 | | | 17.0 | | |
| Remaining PDP Reserves (Bcf) | 33.5 | | | 17.1 | | |
| EUR of PDP Reserves (Bcf) | 69.8 | | | 33.4 | | |

The Multi-Pay Play represents the major Mesaverde tight gas producing area in the basin. This area has been actively developed over the last five years, with such development benefitting directly from the Section 29 tax credit. The presence of gas-saturated zones over a thick gross interval of around 2,000 feet spans both the Fluvial and Paludal environments. The evaluation of completion techniques from single zone to dual completions to large interval fracturing has dramatically improved per well recoveries. This has occurred in infill drilling situations where new wells are much superior to the preexisting offsets despite the potential for drainage and depletion. Such a demonstration of the advances provided by new technology and practices is uncommon. Such progress does open speculation as to the path for future tight gas development in the basin. This subject is elaborated upon in the following section.

Also of note is that the marine sequence does produce in several wells in the Multi-Pay Play. However, the concern over water production problems associated with penetrating the Rollins-Trout Creek formation has been a negative factor in future development of the marine sequence.

In summary, reserves are recognized in both the *established* and *nonestablished* categories in the Multi-Pay Play. The mean estimate for *established* reserves is 269 Bcf overall, or 199 Bcf after subtraction of the EURs of existing Multi-Pay wells. *Nonestablished* reserves are recognized with a mean estimate of 817 Bcf overall and 783 Bcf after subtraction of the EURs of existing wells.

Figure: 75

LEGEND

- * GAS WELL
- o DRY HOLE
- BASIN OUTLINE
- PLAY OUTLINES

U.S. Department of Energy

Piceance Basin MULTI-PAY PLAY PENETRATION MAP

Well locations were obtained from Petroleum Information. Scotia has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data.

Figure: 76

LEGEND

- * GAS WELL
- o DRY HOLE

- BASIN OUTLINE
- PLAY OUTLINES
- - - FERC TIGHT AREA

U.S. Department of Energy

Piceance Basin
MULTI-PAY PLAY
PRODUCER & DRY HOLE MAP

Well locations were obtained from Petroleum Information. Scotia has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data.

Figure: 77

FIGURE 78

MULTI-PAY TOTAL PRODUCTION PROFILE

Projections are averages for each year commencing at the effective date of the evaluation. Results are subject to the qualifications and limitations stated in the attached document

MULTI-PAY PLAY

Technical Success 98.0%

Commercial Success 49.0%

DRILLING
RESULTS

FRI JUL 28 1995

Piceance Basin Tight Gas Resource Allocation

MULTI-PAY PLAY

IMPLICATION OF THIS STUDY TOWARD FURTHER TIGHT GAS DEVELOPMENT

Historically, development of the Mesaverde tight gas resources in the Piceance Basin has been an economically marginal proposition. This has been the result of a combination of factors including poor gas prices, markets and takes, poor well productivity and reserves, limited infrastructure and a generally costly drilling, completion and operating environment. As a result, development occurred along the valley bottoms where drill depths to the objective (and hence drilling costs) were minimized. The intervening plateau areas are not developed and are only sparsely explored by scattered, deep wildcat wells, most of which had objectives deeper than the Mesaverde.

Recent developments, particularly since 1990 in response to the expiry of the Section 29 tax credits, have radically changed the outlook for the basin. This activity has been led by Barrett who has drilled several hundred wells in the area. Barrett's activities are focused in the Multi-Pay Play and the following discussion focuses on that area.

The key factors which have changed are as follows:

1. **Overall Cost Reduction:** Total completed well costs have been reduced from about \$1MM down to \$650,000 inclusive of the multiple frac treatments that are now the norm.
2. **Improvement in Fracturing Practices:** The evolution of fracturing practices has had a major effect on well productivity and reserves. Originally, single zone completions were the norm, picking the best looking zone and performing a single frac treatment. Because the cost of the frac treatment was a significant component of the well cost (around \$100,000), this methodology was thought to provide the greatest opportunity to get maximum recovery for minimum cost. This practice evolved into attempts to improve recovery by performing dual completions. This practice may be partially linked to attempts to evaluate coalseam productivity separately from the sands. The net effect was not so much a radical improvement in overall productivity, but rather a marked decrease in the occurrence of poor wells (essentially dry holes). This led to the current practice of multiply fracturing over large intervals and essentially commingling the entire section. This practice involves more fracs and hence more cost but has virtually eliminated poor wells. The net effect has been to increase the average per well EUR from 552 MMcf to 747 MMcf and to markedly flatten the slope of the lognormal distribution by eliminating marginal and subeconomic completions. This represents a significant breakthrough.
3. **Improving Markets:** Piceance Basin production had historically been the victim of seasonal curtailment due to pipeline access to only a few markets. With deregulation,

this situation has improved and the summer shut-ins are no longer mandatory. Recent shut-ins have been voluntary operator responses to nationally low prices rather than imposed shut-ins due to lack of a summer market.

The success of large-interval fracturing can be related to the high levels of heterogeneity that occur in the Fluvial and Paludal Mesaverde reservoirs. Since individual sands are composed of a series of lenses which usually have limited areal extent and are unpredictable, analysis at the wellbore may be totally nonrepresentative of the conditions away from the wellbore in the area effected by hydraulic fracturing. By fracing the entire section as opposed to just the best zones in the wellbore, the opportunity to gain maximum exposure to all potential zones and associated patterns of natural fracturing is facilitated. In this case, the returns generated by this practice more than outweighed the extra costs involved.

It is acknowledged that concurrent improvements in fracturing technology have occurred in terms of modeling, fluids, proppants, etc. However, attempts to quantify these improvements proved difficult, if not impossible, and in fact, an argument could be made that certain modern techniques show no improvement over the older methods.

The net effect of the work pioneered by Barrett has been to improve per well recoveries and economics and to also improve the overall recovery of the resource by large-interval fracing. These improvements have the effect of lowering the risk associated with this development and in effect lowering the *economic basement*, thus dynamically moving resources into more accessible categories.

Under the depressed gas prices experienced as of the writing of this report, activities are basically restricted to the established producing areas in the form of infill drilling following approval to down space areas in the Rulison and Grand Valley fields to 80 acres per well. Future plans may involve further infilling to 40 acres/well. Under this scenario, there appears to be little incentive to shift activities outside of proved areas or to justify exploration.

It should be remembered that existing developments are located in the valley areas, largely in response to the lower cost environment. This fact begs the question as to what economic hurdles would have to be overcome to justify extension of the play out of the valleys and up onto the plateau areas where drilling depths can be 5,000 feet greater?

The following scenario is developed to attempt to answer that question. This scenario is developed via the adoption of an optimistic set of assumptions that seeks to model the most favorable end of the spectrum of potential outcomes. The assumptions are as follows:

1. Comparison of a 5,000 foot well in the valley to the same objective as a 10,000 foot well on the plateau immediately adjacent (within a few miles). Reservoir properties

(porosity, permeability and water saturation) are assumed to be the same at both locations, reflecting the same previous maximum depth of burial and diagenesis. Since valley downcutting occurred only in the last nine million years, and represents a superimposed drainage pattern, natural fracturing in the reservoir is assumed to be the same at both locations. It can be argued that the valley location may be preferentially more fractured and the loss of overburden may promote fracture opening, but for the sake of argument, the same parameters are assumed at both locations.

2. In the valley, pressure gradients are normal at 0.465 psi/foot. For the plateau scenario, it is assumed that the reservoir is still overpressured and has not experienced breaching and leak off as has occurred in the valley setting. A pressure gradient of 0.572 psi/foot is assumed based on a 0.465 gradient down to 8,000 feet and a 1.0 psi/foot gradient thereafter.

Figure 82 summarizes the parameters and calculations. The results of this comparison are striking. Because of the greater pressure at reservoir level under the plateau, assisted by preservation of overpressured conditions, the FVF is almost half of that under the valley. As a result, GIP is about 1.7 times greater and recoverable gas is almost 1.9 times greater than under the valley. This fact allows the greater drilling cost to be offset so that finding costs are similar in both settings.

In the real world, additional infrastructure costs would be involved on the plateau, however, this example does show that if the assumptions made can be found in the basin, considerable additional resources may be convertible to economically producible reserves.

Figure 82
Speculative Potential Under Plateaus

PARAMETERS	VALLEY	PLATEAU
Reservoir Temperature (Deg F)	145	220
Pressure Gradient (psi/ft)	0.465	0.572
Reservoir Pressure (psi)	2325	5720
Original P/Z	2769	5388
Formation Volume Factor (cf/scf)	0.00618	0.00357
Original Gas Inplace (Mcf/acft)	352	610
Abandonment Pressure (psi)	500	700
Abandonment P/Z	541	747
Recovery Factor	80%	86%
Recoverable Mcf/acft	282	525
Well Cost (\$K)	250	700
Frac Cost (\$K)	400	400
Total Cost (\$K)	650	1100
Recovery MMcf (50ft, 40ac)	564	1050
Finding Cost (\$/Mcf)	1.15	1.05

GLOSSARY OF ABBREVIATIONS

API	American Petroleum Institute
Bcf	Billion Cubic Feet
bcpd	Barrels of Crude Per Day
bwpd	Barrels of Water Per Day
CPI	Computer Processed Interpretation
DST	Drillstem Test
EMV	Expected Monetary Value
EUR	Estimated Ultimate Recovery
FERC	Federal Energy Regulatory Commission
GGRB	Greater Green River Basin
GIP	Gas In-Place
IP	Initial Potential
Mbo	Thousand Barrels of Oil
MWX	Multiwell Experiment
NOB	Net Overburden
NPS	National Production System
PDP	Proved Developed Producing
PI	Petroleum Information Corporation
scf	Standard Cubic Feet
SEC	Securities and Exchange Commission
SP	Spontaneous Potential
SPE	Society of Petroleum Engineers
SPEE	Society of Petroleum Evaluation Engineers
Tcf	Trillion Cubic Feet
TD	Total Depth
USBM	U.S. Bureau of Mines
USGS	U.S. Geological Survey
WHCS	Well History Control System

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APPENDIX A

SENSITIVITY OF *ECONOMIC BASEMENT* TO GAS PRICE

A premise of this study was the use of a \$2.00/Mcf wellhead gas price. While the examination of alternative price scenarios was not part of the scope of the study, the importance of higher gas prices in unlocking major volumes of additional gas supply is widely recognized. The following is a brief analysis of the effect of gas price changes on *economic basement*.

As the wellhead gas price changes, the *economic basement* changes inversely. As the gas price goes up, the *economic basement* deepens, as the gas price drops, the *economic basement* is raised. Since gas price is dynamic, it is of great interest to determine the amount of extra net pay rock volume that is added or subtracted to the *established* reserves calculation based on the fluctuation in gas price. The table below lists net pay rock volume above the *economic basement* for seven pricing scenarios: \$2.00, \$2.50, \$3.00, \$3.50, \$4.00, \$4.50, and \$5.00 gas.

The net pay rock volume has been mapped for each play and is associated with a depth (its play mid-depth point) based on its location in the basin. It is therefore possible to determine the quantity of rock volume that is above the *economic basement*. It is this rock volume that is used to determine *established* reserves.

NET PAY ROCK VOLUME ABOVE ECONOMIC LIMIT
M AcFt

PLAY	\$2.00	\$2.50	\$3.00	\$3.50	\$4.00	\$4.50	\$5.00
Fluvial	19,275	27,197	32,686	32,821	32,821	32,821	32,821
Paludal	0	0	0	0	1,777	2,179	2,872
Marine	11,182	19,458	29,389	44,038	53,049	59,964	64,229
Multi-Pay	4,035	9,318	12,058	13,181	13,181	13,181	13,181

Figures A-1, A-2, A-3, and A-4 graphically show this information in plots of depth versus cumulative net pay.

A benefit of this type of analysis is that each gas price can be directly associated with a subsurface depth. Therefore, *economic basement* contours can be constructed for each gas price scenario that shows area in the play where the rewards outweigh the costs of drilling. Drilling depth is extremely important in the Piceance Basin due to its rugged topography. Economics to date have restricted development to valley locations where drill depths to the objective are substantially reduced. The following figures show the price incentive that would be required to make the plateaus attractive.

FIGURE A-1

FIGURE A-2

FIGURE A-3

FIGURE A-4

The result is a map that shows a region where it is economically feasible to drill, given a particular gas price scenario. Figures A-5, A-6, A-7, and A-8 show these *economic basement* contours overlain on the net pay rock volumes for each of the four respective plays.

Figure: A-5

LEGEND

- BASIN OUTLINE
- ECONOMIC BASEMENT(\$)
- NET PAY

U.S. Department of Energy

Piceance Basin
MARINE PLAY
ECONOMIC BASEMENT MAP

Well locations were obtained from Petroleum Information. Scotia has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data.

Figure: A-6

10 0 10 20 30 40 50 miles

LEGEND

- BASIN OUTLINE
- ECONOMIC BASEMENT(\$)
- NET PAY

U.S. Department of Energy

Piceance Basin
PALUDAL PLAY
ECONOMIC BASEMENT MAP

Well locations were obtained from Petroleum Information. Scotia has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data.

Figure: A-7

0 10 20 30 40 50 miles

LEGEND

- BASIN OUTLINE
- ECONOMIC BASEMENT(\$)
- NET PAY

U.S. Department of Energy

Piceance Basin
FLUVIAL PLAY
ECONOMIC BASEMENT MAP

Well locations were obtained from Petroleum Information. Scotia has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data.

Figure: A-8

LEGEND

- BASIN OUTLINE
- ECONOMIC BASEMENT(\$)
- - - NET PAY

U.S. Department of Energy

Piceance Basin
MULTI-PAY PLAY
ECONOMIC BASEMENT MAP

Well locations were obtained from Petroleum Information. Scilio has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data.

APPENDIX B

PALUDAL COAL SEQUENCE GAS RESOURCES

Though not part of the original study brief, an evaluation of coalbed methane resources in the Paludal Play was conducted following review of Paludal well completions. PI completion records indicated that perforation intervals of many wells bracketed both coalseams and reservoir quality sandstones. At Grand Valley Field for example, coal-only completions as well as commingled sandstone and coal completions occur. Stimulation of coal-only completions typically fracture into adjacent reservoir quality sandstones where present. Most Cameo sandstones are bounded by coaly intervals and in some cases are separated from underlying coalbeds by less than 2 feet of low permeability rock (Reinecke et al 1991). Before 1988 at Grand Valley, commingled coal and sandstone completions as well as sandstone-only completions were performed and hydraulically fractured. In late 1989 because of encouraging test results, Section 29 tax credits, and technology to produce simultaneously from coal and tight sandstone, a coalbed methane development program was undertaken by Barrett Resources, Inc. (Barrett). In this case tight sandstones interbedded with the coal were not perforated but sands uphole in the Fluvial environment were included as dual completions. This was done to isolate coalbed methane gas from the other gas produced.

From a sourcing standpoint the sandstones within the Paludal Play appear linked to the coals. Chemically drier Cameo coal gases are distinguishable from chemically wetter gases from sandstone reservoirs above the Cameo zone (Reinecke et al 1991). Coal gases tend to be higher in CO₂ (3 to 6%) content and lower in ethane (1 to 3%) than sandstones (CO₂ 1 to 4%, ethane 3 to 6%) and so can be distinguished on a plot of percent CO₂ versus percent ethane. Yet gas samples collected from unstimulated Cameo sandstone reservoirs plot within the transitional zone (between coal and sand gas compositions) which suggests that coal and interbedded shales were both sources for the Cameo sandstone and, to a lesser degree, for the sandstones above the Cameo.

Three coal sequences exist within the Mesaverde group which from oldest to youngest include the Black Diamond coal group which is represented by two to four coalseams within the Isles formation and is limited to the northern half of the basin; the Cameo Fairfield coal zone of the Lower Williams Fork formation which directly overlays the Rollins-Trout Creek sandstone members and is developed across the entire basin; and the Coal Ridge coal sequence which is limited to the southeast part of the basin and is separated from the Cameo Fairfield sequence by a thin tongue of marine shale and regressive marine sandstone (Johnson 1989).

Coalbed methane resource estimates have been limited to the Cameo coal sequence of the Williams Fork formation for this study. The Black Diamond coalbed methane consequently has not been quantified. However, studies by McFall et al (1986) indicate that GIP for this member is only 8.8 Tcf.

The bulk of the Piceance Basin coal is found in the Cameo Fairfield sequence. This sequence represents a paludal depositional environment landward of the prograding Rollins-Trout Creek Paleo-shoreline. The base of the coal-bearing zone marks the boundary between the Williams Fork and Isles formations. The top of the Paludal Play is marked by the last coalbed recognizable from open hole log response. No attempt has been made in this study to separate out the coal ridge from the Cameo Fairfield sequence. Cameo coalbeds are thickest near the base of the play and become progressively thinner toward the top. The coals are interbedded with distributary channel, and crevasse splay lenticular sandstones (Lorenz 1988), particularly in the upper Cameo sections. The total thickness of the coal ranges from less than 20 feet in the extreme southeast part of the basin and across portions of the Douglas Creek Arch, to more than 70 feet around Township 6S Range 93W (this study). Johnson (1989) has mapped greater than 180 feet in the northeastern corner of the basin. McFall (1986) mapped a maximum of 60 to 80 feet for the Cameo coal group in this part of the basin. Across most of the basin however, coal thicknesses in this study and on maps developed by the above referenced authors range between 30 feet and 60 feet.

Coal thicknesses were determined during the digital log interpretation and were supplemented with manual estimates from additional well logs. A single coal thickness map of all coals identified within the Williams Fork paludal section was generated (Figure B-1). Coal thickness mapping conducted by Johnson (1989) was referenced during contouring to provide thickness information in areas lacking well control. Coal thicknesses increase toward the eastern, deepest part of the basin adjacent to the Grand Hogback.

An independent study of coal rank was beyond the scope of this study and a map of coal rank at the base of the Cameo Fairfield coal zone published by Freeman (1979), Nuccio and Johnson (1983) was used to describe the geographic variation in rank (Figure B-2). Coal ranks vary from sub-bituminous A and high-volatile C (sbA-hvCb) at the west and southwest basin margins to semi-anthracite in the deepest parts of the basin.

Gas content measurements published by the U.S. Bureau of Mines (USBM) from 106 coal samples covering five coal ranks ranging between high-volatile C bituminous and low-volatile bituminous were used to create plots of gas content versus depth by McFall (1986). Regression fits of the data were made to derive the following gas content transforms for each coal rank.

COAL RANK	GAS CONTENT EQUATION
1 Semi-Anthracite	$31 \times \ln \text{ depth} + 61$
2 Low-Volatile	$37 \times \ln \text{ depth} - 3$
3 Medium-Volatile	$36 \times \ln \text{ depth} - 2$
4 High-Volatile A	$51 \times \ln \text{ depth} - 168$
5 High-Volatile B	$41 \times \ln \text{ depth} - 116$
6 High-Volatile C	$44 \times \ln \text{ depth} - 211$

The equation form being:

$$\text{Gas content (CF/ton)} = M \times (\ln \text{ depth in feet}) + B$$

Where:

M = Coefficient
 ln = Natural Log
 B = Y Intercept

The variation of coal densities with coal rank was derived from Averitt (1975) as follows:

COAL RANK	COAL DENSITY TONS/AcFt
High-Volatile Bituminous	1,800
Medium-Volatile Bituminous	1,850
Low-Volatile Bituminous	1,900
Semi-Anthracite	1,950

Coalbed GIP was determined for each of the six defined coal ranks using the following basic equation:

$$\text{GIP} = \text{Area} \times \text{Thickness} \times \text{Density} \times \text{Gas Content}$$

Coal depth was taken as the mid point between structure maps drawn on the top Rollins-Trout Creek member (base Paludal) and the top Paludal. Following gridding of each map, gas contents were calculated for each depth grid cell for each coal rank. Similarly, coal tonnage was calculated for each grid cell in each coal rank using the product of coal volume and density. Coal GIP was then derived for each grid cell in each coal rank as the product of coal tonnage and gas content. Coal GIP was then plotted in depth slices (Figure B-3). Coal GIP is estimated to be 64.4 Tcf.

We were concerned that exclusion of the coal from the Paludal Play reserves estimate would cause the volumetrically derived drainage areas (assuming constant recovery efficiencies) to be anomalously high. A comparison of drainage areas from the Marine and Fluvial plays with those from the Paludal Play from sandstones alone was made to determine if this was indeed the case. The analysis showed that there was no distinguishable difference between the Paludal drainage area and the Fluvial drainage areas even though wells from the Multi-Pay area (most prolific play) made up the vast majority of Paludal environment data points. As a result, it was concluded that the presence of coal did little to enhance EURs. Consequently, an evaluation of the recoverable portion of the resource was not conducted. Barrett eventually dropped its coalbed methane development program after it was determined to be uneconomical.

Figure: B-1

LEGEND

- BASIN OUTLINE
- CONTOURS

U.S. Department of Energy

Piceance Basin

COAL ISOPACH

Well locations were obtained from Petroleum Information. Scotia has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data.

Figure: B-2

LEGEND

- BASIN OUTLINE
- CONTOURS

U.S. Department of Energy

Piceance Basin
COAL RANK MAP

Well locations were obtained from Petroleum Information. Scotia has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data.

FIGURE: B-3

DEPTH VERSUS COALBED METHANE RESOURCE
PICEANCE BASIN