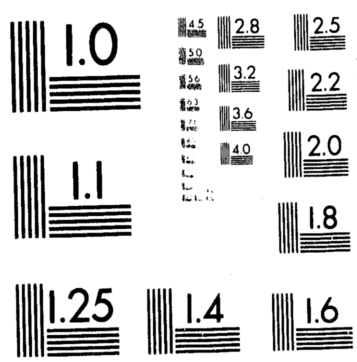
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(DE94000011)

Appraisal of the Tight Sands Potential of the Sand Wash and Great Divide Basins

Final Report
June 1989 - June 1991

August 1993

Work Performed Under Contract No.: DE-AC21-89MC26306

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

By
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Executive Summary

Production of natural gas from low permeability ("tight") gas sands is expected to continue the steady growth it has experienced for several years. In the past decade, improved technology and targeted tax incentives have combined to increase the tight gas production to 1.7 Tcf, about one-tenth of the U.S. total. The recent National Petroleum Council (NPC) Gas Study confirms that the continuation of this growth is highly likely (NPC 1992). If wellhead gas prices required to maintain current levels of gas production continue, tight gas production is likely to increase to almost half of domestic production by 2010. The NPC estimated that almost one-third of the remaining recoverable domestic natural gas resource base is contained in those tight formations that have been appraised in detail, with additional volumes yet to be defined.

The volume of future tight gas reserve additions, however, is difficult to estimate because of uncertainties in the characterization and extent of the resource and the performance and cost-effectiveness of stimulation and production technologies. Ongoing R&D by industry and government aims to reduce the risks and costs of producing these tight resources, increase the certainty of knowledge of their geologic characteristics and extent, and increase the efficiency of production technologies. Some basins expected to contain large volumes of tight gas are being evaluated as to their potential contribution to domestic gas supplies. This report describes the results of one such appraisal.

This analysis addresses the tight portions of the Eastern Greater Green River Basin (Sand Wash and Great Divide Subbasins in Northwestern Colorado and Southwestern Wyoming, respectively), with respect to estimated gas-in-place, technical recovery, and potential reserves. Geological data were compiled from public and proprietary sources. The study estimated gas-in-place in significant (greater than 10 feet net sand thickness) tight sand intervals for six distinct vertical and 21 areal units of analysis. These units of analysis represent tight gas potential outside current areas of development.

For each unit of analysis, a "typical" well was modeled to represent the costs, recovery and economics of near-term drilling prospects in that unit. Technically recoverable gas was calculated using reservoir properties and assumptions about current formation evaluation and extraction technology performance. Basin-specific capital and operating costs were incorporated along with taxes, royalties and current regulations to estimate the minimum required wellhead gas price required to make the typical well in each of unit of analysis economic.

The dominant tight formations of the Great Divide (also called the Red Desert) Basin are the Fort Union, Lance, and Lewis formations and the Almond A, Ericson, Rock Springs, Blair and other undifferentiated Mesaverde intervals. A total of 30.7 Tcf of gas-in-place is estimated to exist in potentially productive tight zones outside currently developed areas. Using current technology, 1.4 Tcf of tight gas is potentially recoverable. Estimated mean recoveries are less than 0.3 Bcf per well and limited amounts of reserves are likely to be developed at current wellhead gas prices without tax incentives or significant technology advances.

The dominant tight formations of the Sand Wash Basin are the Lewis and Mesaverde formations. A total of 8.8 Tcf of gas-in-place is expected to exist in potentially productive zones outside currently developed areas. Using current technology, only 0.9 Tcf of tight gas is potentially recoverable. Estimated mean recoveries are less than 0.3 Bcf per well and limited amounts of reserves are likely to be developed at current wellhead gas prices without tax incentives or significant technology advances. The implication of this finding is that the majority of currently economic tight gas reserves have been identified and significant tight gas reserve additions in new reservoirs will most likely require major improvements in extraction technology efficiency.

Near-term technology advances could significantly increase technical recovery. Improved stimulation and reservoir characterization technology could increase technically recoverable gas four-fold. In addition, reserves at wellhead gas prices of between $2.00 and $3.00/Mcf could increase to over 3 Tcf. Table ES-1 summarizes the tight gas potential of these two basins and the impact of improved technology.

Although several hundred tight gas wells were drilled in the Eastern Greater Green River Basin in the early 1980's in response to high wellhead prices, most of these were drilled in the Washakie Basin. The tight gas potential of the Washakie Basin is discussed by Duda (1992). Relatively few tight gas wells have been drilled in the Great Divide or Sand Wash basins in the past few years, limiting the amount of reservoir engineering or geological data available for this study.

Table ES-1
Tight Gas Potential of Currently Undeveloped Areas of Upper Cretaceous/Lower Tertiary Formations (Eastern Green River Basin)

	Sand Wash Basin	Great Divide Basin
Areal Extent (sections)	889	1,945
Gas-in-place (Tcf)	8.8	30.7
Current Technology		
Average Recovery/Well (Bcf)	0.3	0.3
Technically Recoverable (Tcf)	0.8	1.4
Reserves at $2.50/Mcf (Tcf)	0.0	0.0
Reserves at $5.00/Mcf (Tcf)	0.0	0.0
Advanced Technology		
Average Recovery/Well (Bcf)	0.7	0.9
Technically Recoverable (Tcf)	2.5	7.0
Reserves at $2.50/Mcf (Tcf)	0.6	1.5
Reserves at $5.00/Mcf (Tcf)	1.2	4.6

The analysis provides some insights into the dilemma facing operators and potential investors. Although ultimate recovery from many tight settings is a small fraction of the total gas-in-place, natural fracturing, extensive lenticularity (resulting in limited drainage area), and lack of good data due to minimal development history pose risks for an operator that exceeded risks in a less geologically less complex and more developed setting.

I. Introduction to Analysis

A. Purpose and Scope

Prior studies of the Eastern Greater Green River Basin have focused on descriptive geology and limited assessments of potential reserves. Geological appraisals are referenced in Section III.B. below. The two most significant resource assessments of tight gas in the Eastern Greater Green River Basin were conducted by the National Petroleum Council (1980) and the U.S. Geological Survey (1989).

The majority of recent development in the Upper Cretaceous and Lower Tertiary tight formations of the Sand Wash and Great Divide Basins has been in the once intensively developed areas of the Cherokee Ridge and Wamsutter Arch. The purpose of this study was to assess the potential for producing natural gas from the tight formations of these basins outside of these well-delineated producing areas. The study had three major objectives:

- **Estimate Tight Gas-In-Place.** The first objective was to appraise the geologic and reservoir properties of selected formations and estimate gas-in-place and its distribution. Gas-in-place was estimated for discrete area/formation units, each individually characterized by reservoir properties. This resource estimate formed the foundation for the subsequent evaluation of recoverable gas.

- **Estimate Technically Recoverable Gas.** The second objective was to estimate tight gas ultimate recovery for the low-permeability formations of the Mesaverde Group. Technical recovery is that portion of the resource which is recoverable with current technology, disregarding project economics. It is estimated using explicit technical assumptions in a reservoir model.

- **Estimate Potential Reserve Additions.** The third objective was to establish potential reserve additions, given estimates of ultimate recovery for typical wells, under current cost and economic conditions. Economically recoverable gas is defined as that volume of ultimately produced gas that makes a return to capital at a specified wellhead price.

The scope of this study was limited to the evaluation of the significant tight formations, principally in the Upper Cretaceous formations. The evaluation was based upon publicly obtainable records, petroleum literature, and personal communication with operators active in the basin. No wells were drilled nor were any field tests or log interpretations of history matching conducted as part of this work.

B. Analytic Approach

A full geological appraisal for the Eastern Greater Green River Basin was both outside the scope of work for this analysis and in excess of the quality and coverage of detailed, publicly available geological and reservoir engineering data. A full literature search was conducted of industry and academic technical publications and field reports from developed areas to provide a context for assessing the undeveloped tight gas areas.

Because insufficient geological data were available to estimate reservoir properties for specific areas of tight formations, operators were contacted to provide insights and confidential data for the development of the analysis' scope. A suite of typical wells, representing a distribution of reservoir properties, was developed for each tight formation and potentially productive area. Each typical well represented a portion of the overall remaining tight gas area. Tight formation isopach and structure maps obtained from the literature (Law 1989) and operators were used to delineate the areal extent of the remaining potentially productive yet undeveloped areas. The potentially productive area of each formation was reduced by the area of producing fields (and likely extensions).

Production data were obtained from Dwights Energydata and operator records and were reviewed to confirm estimated reservoir properties and production in undrilled locations. The volume of gas-in-place was calculated for each typical well and multiplied by the remaining drillable area to estimate total formation gas-in-place.

Different methods, costs, and results of fracture treatments were reviewed and operators were interviewed to evaluate the effectiveness of the most commonly used fracture treatments. This permitted the determination of the expected length of a fracture and its typical treatment costs to estimate technical and economic recovery. The focus was on advances in technology that would (1) reduce costs, (2) increase recoverable reserves per well, and (3) reduce exploration risk.

Type curve analysis was used to estimate annual production and ultimate recovery for typical wells in each formation. Production and reserves for each typical well in a play were then multiplied by the number of possible wells (at specified spacing) to determine the maximum technical recovery for each formation. Because of commingling in production records and missing correlative data on development practices, rigorous history matching was rarely possible in these areas with limited development.

Costs at the well site and for the basin were estimated and verified with operators. Costs for each typical well were estimated based upon a series of equations developed for exploration, development, and production operations. Discounted cash flow analysis was used for each typical well to estimate a minimum required wellhead price that would generate a 10% return on capital. Wells whose minimum required price is less than a specified market price were classified as reserves. Price supply curves were generated for both the Great Divide and the Sand Wash Basins for alternative technology cases. These curves indicate the impact of technology advances through R&D on increasing ultimate recovery and reserves.

II. Sand Wash/Great Divide Basin Description

A. Geological Setting

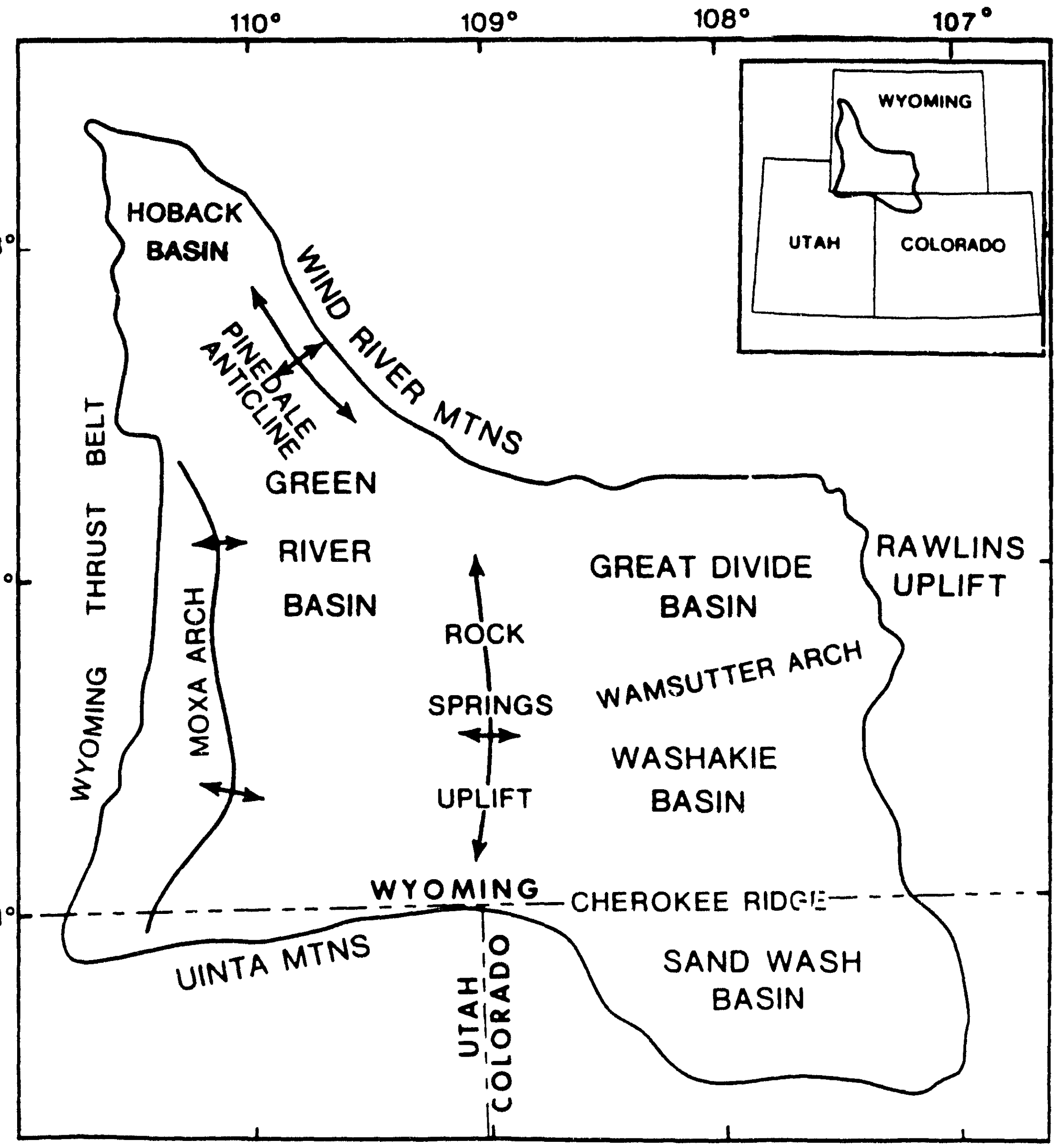
The Greater Green River Basin (Figure 1) is made up of five subbasins, including the Hoback, Green River, Sand Wash, Washakie, and Great Divide basins (also known as the Red Desert). The Sand Wash and Great Divide basins, along with the Washakie basin, comprise the Eastern Greater Green River basin in an area bounded on the west by the Rock Springs Uplift, with the Washakie containing most of the tight gas potential in the Eastern Greater Green River Basin (NPC 1980, Duda 1992).

The Sand Wash Basin is an intermontane structural basin of approximately 75 townships located predominantly in Moffat County, Colorado. The Sand Wash is bounded on the north by the Cherokee Ridge, on the northwest by the Axial Fold Belt, on the east by the Sierra Madre-Park Ranges, and on the southwest by the Uinta Mountain fault. More detailed structural and depositional descriptions are provided by Haun (1961), Whitely (1962), Colson (1969), Roehler (1973) and McPeek (1981) and Seipman (1985, 1986).

The Great Divide Basin is bounded on the north by the Sweetwater Uplift, to the east by the Rawlins-Sierra Madre Uplift, and to the south by the Wamsutter Arch. Geologic studies specific to the Great Divide are not widely reported in the literature, but include those by Lewis (1961) and Spencer (1981).

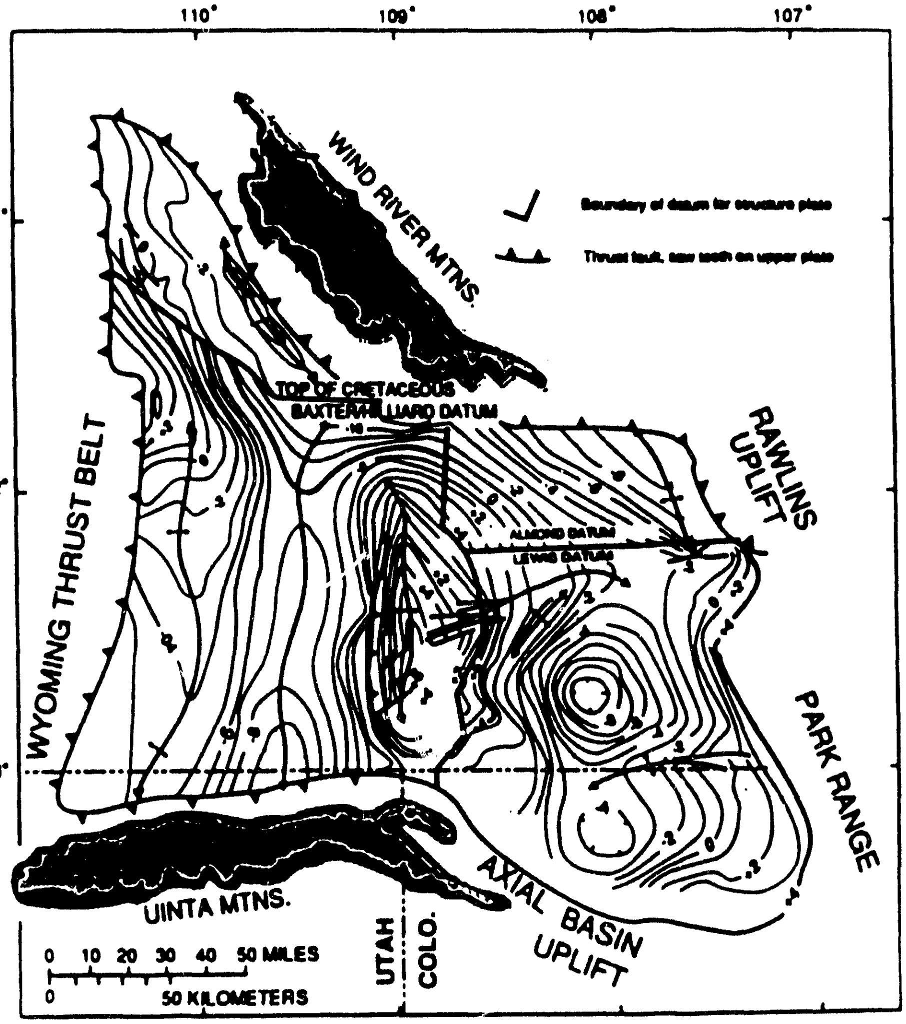
The structural features of these basins resulted from compressional deformation during the Laramide orogeny (Law 1989). The thickness of Cretaceous and Tertiary rocks in the basin averages almost 15,000 feet (Figure 2). Structural features and events affect gas entrapment and productivity of these low permeability formations in unconventional ways (Law, et al 1986). The relationship of gas entrapment to structure in these overpressured, pervasively gas-bearing formations appears to be weaker than in conventional reservoirs. The large numbers of producing reservoirs associated with structural features is largely coincidental. However, permeability enhancement through fracturing and faulting has occurred during structural deformation. Low permeabilities of these Upper Cretaceous and Lower Tertiary formations make detecting the presence of open natural fractures as affected by tectonic events and diagenetic processes critical to delineating productive tight gas reservoirs.

Figure 1
Tectonic Elements of The Greater Green River Basin



Source: After Law (1986).

Figure 2
Structure Contour Map of the Greater Green River Basin

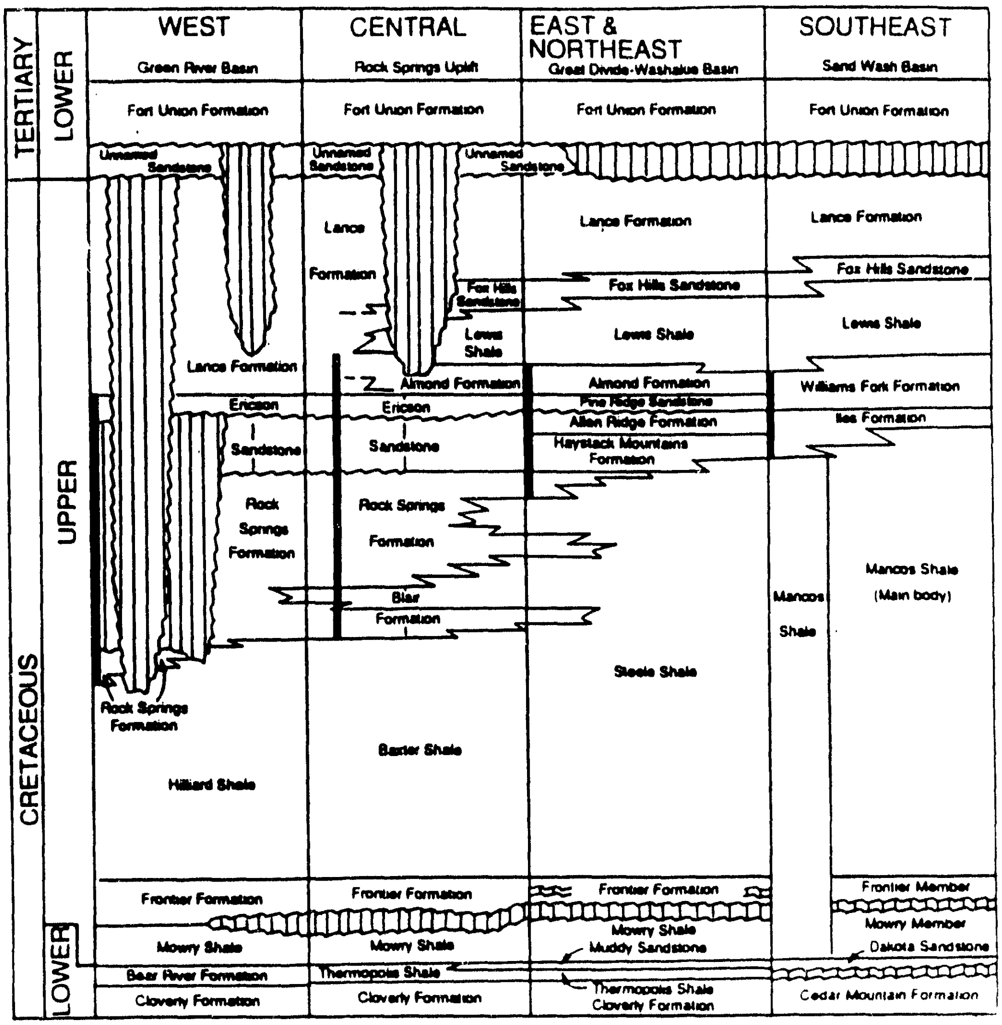


Source: Law (1989).

The portion of Sand Wash and Great Divide stratigraphy of greatest concern is the interval that includes the Upper Cretaceous Mesaverde Group up to the Lower Tertiary Fort Union (Figure 3). The principal low-permeability formations are:

- Fort Union
- Fox Hills-Lance
- Lewis
- Mesaverde
  - Almond A
  - Ericson
  - Rock Springs
  - Blair
- Cloverly-Frontier

Figure 3
Generalized Stratigraphy of The Green River Basin
(Upper Cretaceous Through Lower Tertiary)



Source: Law (1989).

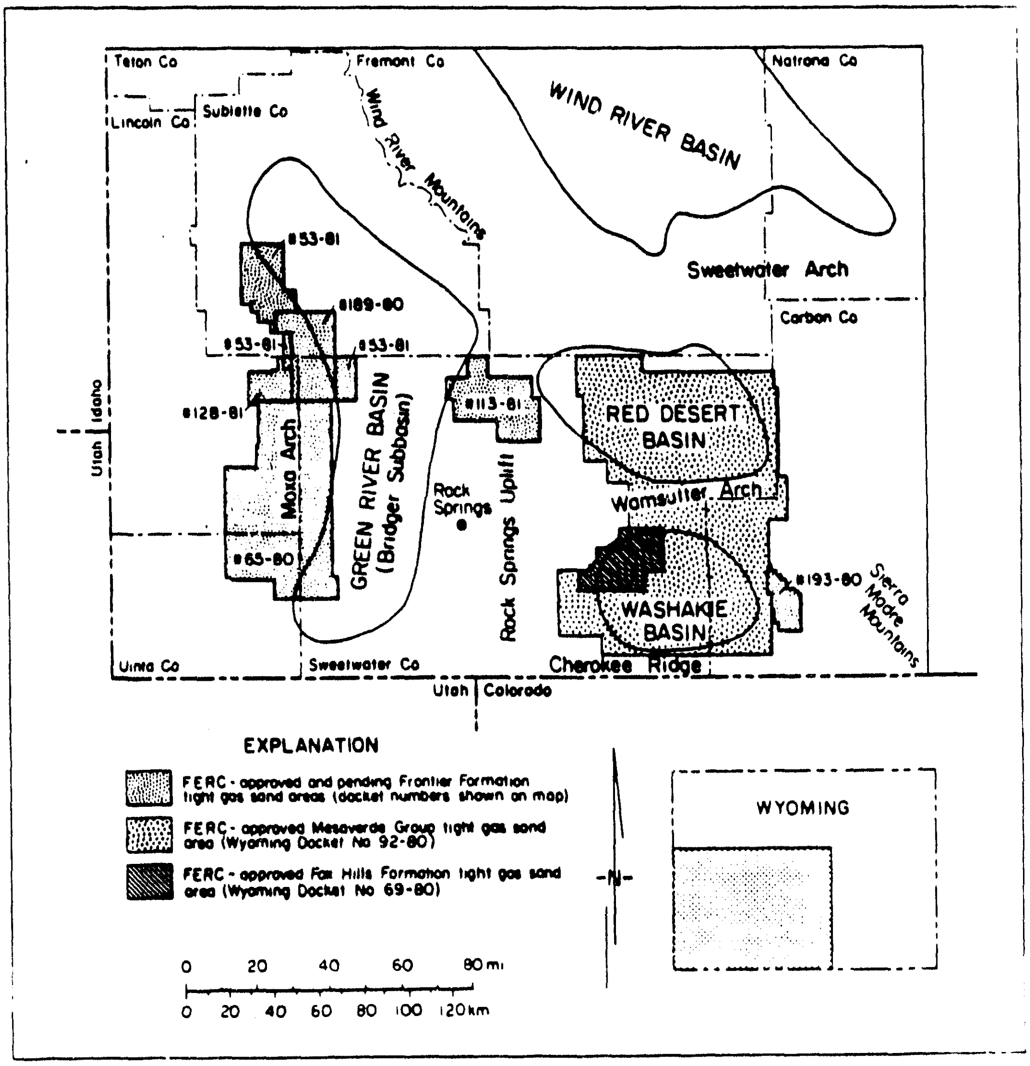
B. Development History

Both the Sand Wash and Great Divide basins have experienced fluctuating development activity in response to changes in prevailing wellhead gas prices and to the development of technology to permit commercial production from lower productivity Cretaceous reservoirs. Many of earliest Sand Wash field discoveries in the 1930's and 1940's were located on conspicuous, closed anticlines (Whitely 1962). Subsequent field discoveries during the drilling boom of the late 1970's were smaller and largely stratigraphic traps.

Great Divide Basin development was concentrated in the Wamsutter Arch area, near the southern boundary of the study area, where the Great Divide Basin adjoins the Washakie Basin. More recent development, in response to the restoration of tight formation eligibility for the Section 29 credit, has centered on the southwestern portion of the study area around T21-22N, R94-98W.

The increase in drilling during the early 1980's was largely the result of the incentive pricing for tight gas provided by Section 107 of the Natural Gas Policy Act of 1978. Although several additional areas were designated by FERC as eligible to receive incentive prices or tax credits in 1991-92, the designation of the Mesaverde (state designation WY-92-80) for most of the Eastern Greater Green River Basin provided the key economic incentive to drill (Figure 4). In the Eastern Greater Green River

Figure 4
Major FERC Tight Gas Designations in The Green River Basin

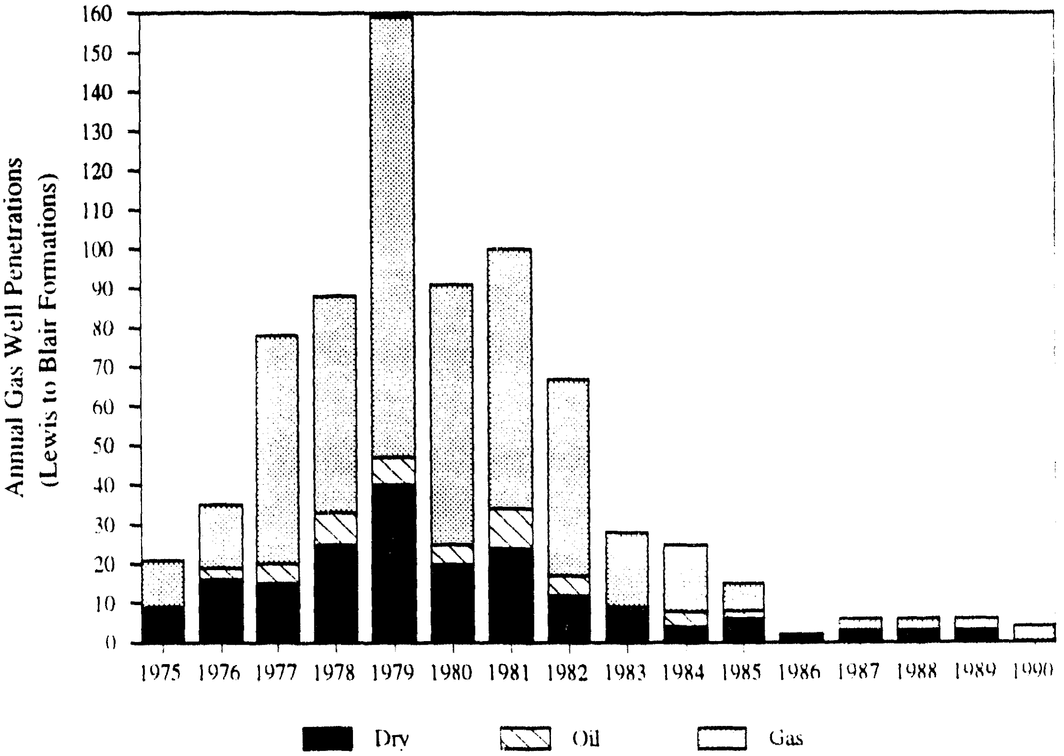


Source: Finley (1984).

Mesaverde, annual successful gas drilling to increased to 70 wells per year from almost none in 1976. After largely d'sappointing results during this period, combined with the erosion of wellhead gas prices during the mid-1980's, Mesaverde drilling dropped to minimal levels by 1986 (Figure 5), although most of this drilling occurred in the Washakie Basin, outside the area of this study. There were no tight gas designations in the Sand Wash Basin.

Maps of wildcat well drilling as of the late 1970's through the Upper Cretaceous and Tertiary intervals were published for the Sand Wash (Tyler 1979) and Great Divide Basins (Spencer 1979). These maps delineate the areas of these basins with the greatest potential (estimated as of 1979) for future tight gas development.

Figure 5
Trends in Mesaverde Drilling in the Eastern Green River Basin



Source: Dwights Energydata.

There has traditionally been a diverse group of operators drilling in these basins. Active operators in the Sand Wash and Great Divide Basins have included Wexpro, Texaco, Quintana, Mountain Fuel, Anadarko, Chandler and Grynberg Petroleum. Most of these operators no longer have active drilling programs, merely continuing to develop proven productive reservoirs. Since the expiration of the Section 29 production tax credit for new wells, operators expect minimal new field exploration in Sand Wash or Great Divide tight formations.

Although most low-permeability reservoirs occupy relatively limited areas, several contain wells whose annual production ranges up to several hundred MMcf. The principal gas producing fields of the Sand Wash basin occur along the Cherokee Ridge. This analysis evaluated an area generally in the range of townships 7N to 12N and ranges 89W to 101W. Areas to the west and east of these boundaries are expected to have little productive potential (Tyler 1979), and areas to the north of township 12N have been independently evaluated by Duda (1992). Twenty-one fields produce almost all the gas from low-permeability formations, largely as a result of the extensive fracturing along the structural features of the ridge:

- Big Hole
- Black Mountain
- Blue Gravel
- Canyon Creek
- Fireplace Rock
- Mud Springs (Four Mile Creek)
- Great Divide
- Hiawatha
- Irish Creek
- Lay Creek
- Little Snake
- North Craig
- Pioneer
- Powder Wash
- Round Table
- Shell Creek
- South Baggs
- State Line
- Sugar Loaf
- Trail
- West Side Canal

In the Great Divide Basin, gas production originates from the general area of T21-27N, R89-102W. Areas to the east, north and west are expected to have little tight gas potential (Spencer 1979) and the areas to the south were independently evaluated by Duda (1992).

The majority of gas produced from low-permeability formations comes from twelve fields:

- Bush Lake
- Desert Springs
- Five Mile Gulch
- Hay Reservoir
- Picket Lake
- Playa
- Red Desert
- Sentinel Ridge
- Sheep Camp
- Siberia Ridge
- Ten Mile Draw
- Wamsutter

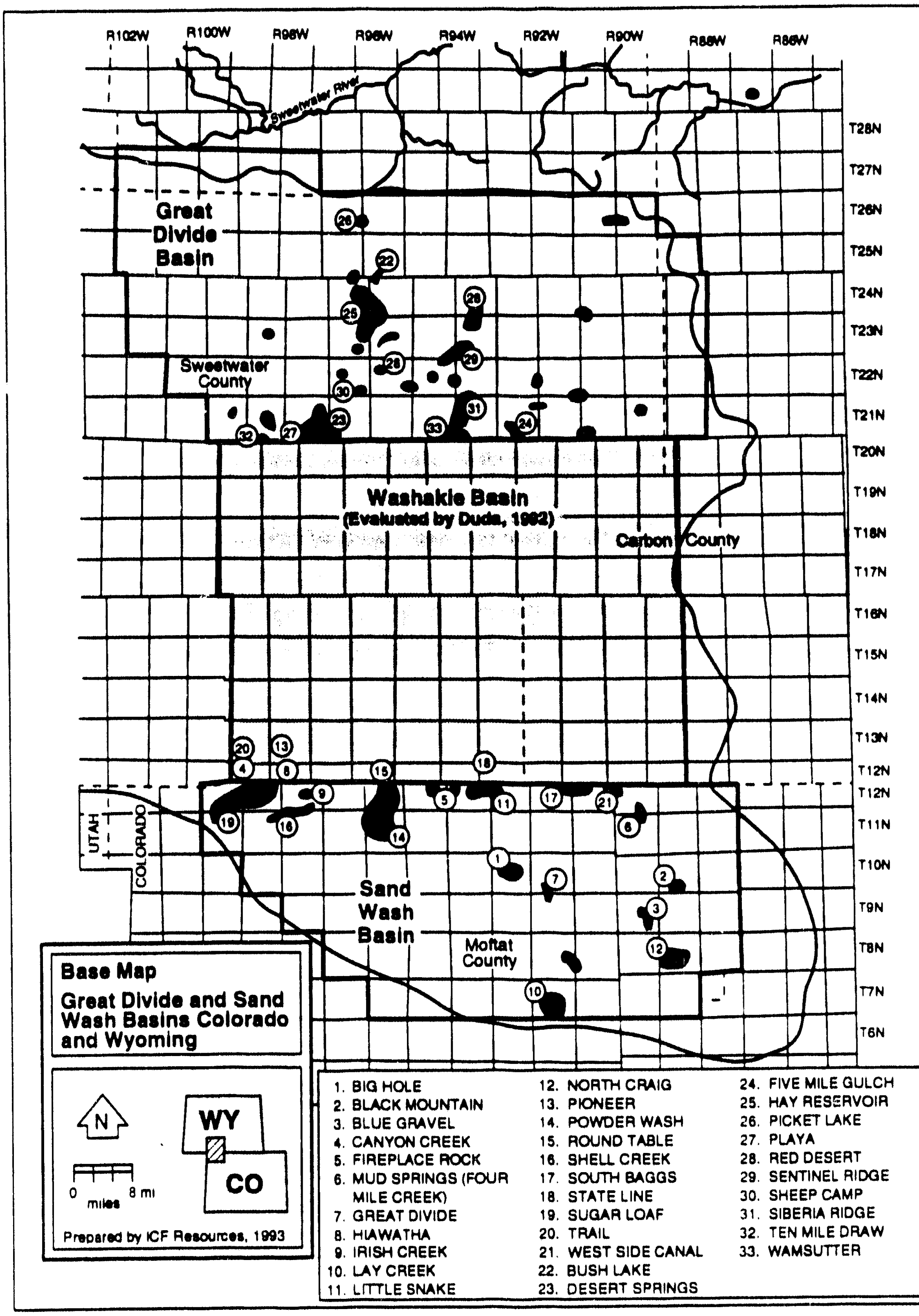
Additional Great Divide fields are located in the area of T22-24N, R92-94W, but most are one- or two-well fields with limited production. Hay Reservoir (T23-24N, R96-97W) has been one of the more actively pursued tight gas targets over the past few years due to improved understanding of its depositional environment. Principal fields producing from low permeability formations in the study area are shown in Figure 6. Because a corresponding analysis of tight gas potential was recently completed for the Washakie Basin, this analysis only evaluated areas with tight gas potential south of T12N (Colorado) and north of T21N (inclusive).

C. Development Practices

Operators vary widely in their approach to development of tight gas in these basins. Many improved diagnostic and stimulation techniques are currently being attempted. This reflects their successful application in other basins, especially the Frontier formation in the Moxa Arch (Green River Basin). Most wells are fractured. A decade ago, stimulation treatment volumes were generally about 6,000 to 20,000 pounds of proppant. Current jobs are designed to pump about 100,000 pounds. Most treatments are gel fracs, although some nitrogen and CO_2 designs have been successful.

In general, the reservoir engineering for these tight wells is complicated. The rugged terrain (200-300 foot relief) makes seismic too expensive for such low productivity wells. Well test and production data provide little insight into the reservoir properties or potential because many records of wells drilled in the past comingle production. Most reservoirs were developed on 320 acre spacing, but the fluvial nature of many of these formations limits reservoir continuity. Therefore, depending on economics, many reservoirs are candidates for infill development.

Figure 6
Major Fields Producing Tight Gas in Sand Wash and Great Divide Basins



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III. Tight Gas Resource, Technology, and Economic Characterization

A. Limitations of Publicly Available Data

Characterization of Sand Wash and Great Divide geology outside the areas of current development is hindered by lack of data. The low drilling density has led to limited subsurface control, especially below 10,000 feet in those areas with the greatest potential. Availability of published core and log data is sporadic and generally uninformative. Production data are difficult to analyze due to commingling and uncertain data quality.

Existing better quality data for these undeveloped areas are generally proprietary. Some of these proprietary exploration data were reviewed during the course of this analysis. The limited areas of coverage and frequent inconsistency between sources indicates that fundamental understanding of the Upper Cretaceous and Tertiary formations in the Eastern Greater Green River Basins awaits more extensive testing. However, with the exception of some tax credit driven activity in the Wamsutter Arch area, drilling in the entire Eastern Greater Green River Basin has been limited since the early 1980's.

B. Estimation of Reservoir Property Distributions

The analyzed tight gas formations conform to the general description of Rocky Mountain tight formations as described by Spencer (1985). Most of the Upper Cretaceous formations are overpressured, due to rates of thermogenic gas generation by interspersed coals and shales that exceeded gas migration. Most of this gas generation occurred in the deeper sediments in the center of the basin, distinguishing these basin center tight gas reservoirs from the more conventional, shallow water-bearing reservoirs at the basin margin. Lithology is predominantly sandstone, with porosity reduced during diagenesis by the deposition of cements and clays. The resulting reservoirs are characterized by limited areal extent and small, poorly-connected pore volumes (often filled with authigenic clays).

Reservoir geometry is largely lenticular, although some formations termed "blanket" were formed by marginal marine depositional environments and exhibit the lenticular characteristics. Most structural accumulations of tight gas in the study areas that occur along the Wamsutter Arch and Cherokee Ridge are expected to already have been discovered. Stratigraphic traps should continue to dominate exploration into the future.

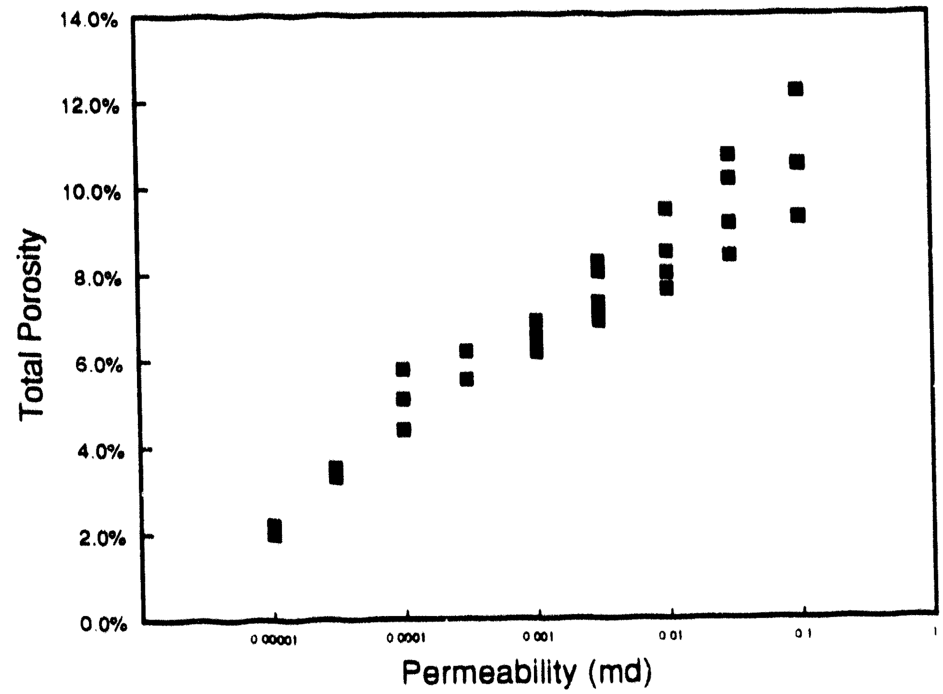
Given the limitations of publicly available resource data, formation-specific reservoir properties developed for the 1980 NPC Unconventional Gas Study (NPC 1980) were used as an initial basis to characterize the undeveloped tight portions of the Sand Wash and Great Divide Basins. They were first compared with published and confidential data on producing tight Cretaceous reservoirs for consistency. These estimates then were reconciled with those of the more recent work by USGS (1989) and unpublished work by McPeek (personal communication 1992).

With the consent of the respective operators, proprietary exploration and well test data of currently undeveloped areas were used, as appropriate, to estimate the final reservoir properties of remaining undeveloped Sand Wash and Great Divide Basin areas of tight gas potential. Figure 7 shows the correlation of porosity and net pay to permeability, and the apparent consistency between the two basins.

C. Production Analysis Method

Currently available technology was modeled by type curve analysis. Extrapolation to large areas would require more comprehensive data than currently exist. For this analysis, we assumed that all operators would use a level of technology generally used by the more sophisticated operators in the Greater Green River Basin. These technology parameters are not meant to reflect the state-of-the-art technology, but rather the best that is in common use today. The assumptions used in the type curve modeling are listed in Table 1.

Figure 7
Correlation of Porosity and Net Pay to Permeability
(Eastern Green River)



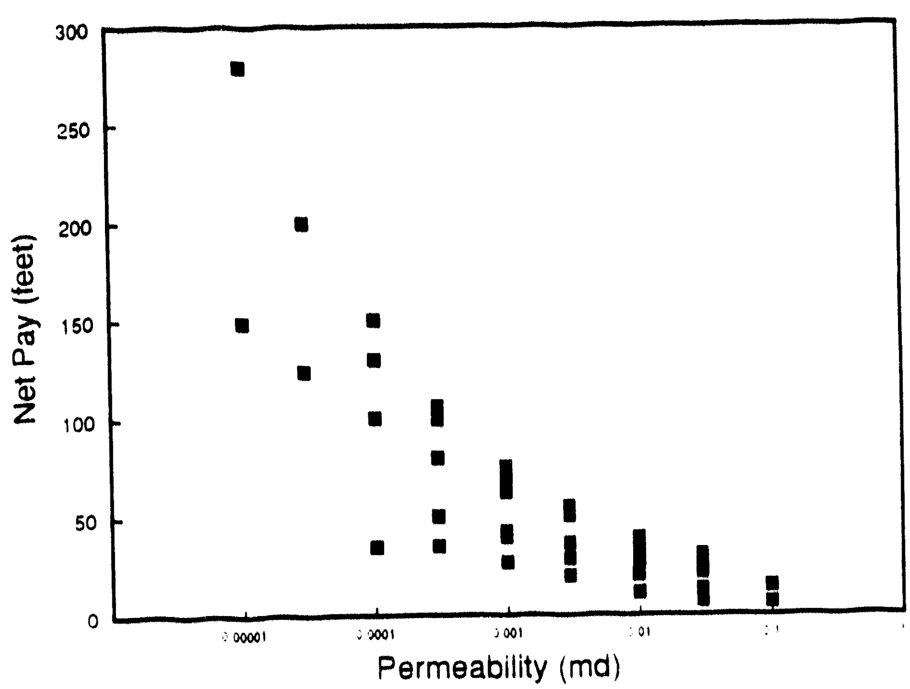


Table 1
Technology Modeling Assumptions
(Type Curve Input Parameters)

Design Fracture Length	300 feet
Effective Fracture Half Length (X_f)	200 feet
Fracture Height	300 feet
Fracture Conductivity	200 md-ft
Spacing Limit	4.0 max wells/section
Well Life	30 years
Flowing Time	250 days per year
Wellhead Abandonment Pressure	200 psi

The type curve is used to estimate annual and cumulative production for a typical well for each of the units in the Sand Wash and Great Divide Basins. The technical recovery estimates for each typical well are multiplied by the maximum remaining drilling prospects to determine the cumulative technically productive reserves.

D. Economic Analysis Method

Capital and financial costs were estimated to calculate the economic value of typical wells. Gas prices and financial factors (i.e., royalties and taxes) were assumed to be uniform throughout the basins. The present value of the stream of net future income, the internal rate of return, and the minimum gas price for development were then calculated for each well. Five areas of costs were explicitly estimated for the Eastern Greater Green River Basin:

- **Predevelopment Costs** - Predevelopment costs include lease bonuses and geologic/geophysical charges.
- **Drilling and Completion Costs** - Drilling and completion costs include site preparation through setting pipe, perforating and casing.
- **Stimulation Costs** - Stimulation entails a massive hydraulic fracture treatment, including costs for set-up, horsepower, fluid and proppant.
- **Equipment Costs** - Surface equipment costs include flow lines and connections, production, and compressor installation.

- **Annual Operating Costs** - Annual operating costs include expenses for direct labor, surface maintenance, subsurface maintenance, compressor maintenance and fuel, chemicals, and disposal.

Cost estimates were derived from published sources (API 1990, EIA 1990) and verified with operators active in the study area. There was significant variation between independent and integrated operators in the costs of similar wells and equipment. This differential increased after accounting for overhead and G&A, which are generally lower for independents. The implication of this finding is that, on solely a cost basis, independent operators may be better positioned to pursue these marginal tight gas reservoirs than integrated companies.

IV. Tight Gas Potential

A. Resource in Place

The final estimated reservoir properties were used to calculate gas-in-place for the remaining undeveloped portions of the basins. Since formations in these basins areally overlap, a well could penetrate and produce from multiple horizons. To date, this strategy is less common than in the Washakie, where production from multiple zones is usually needed to offset the higher costs of the deeper wells. Therefore, the gas-in-place estimated in this analysis is for a single zone only.

Volumetric gas-in-place for currently undeveloped areas was derived from estimated reservoir properties. These gas-in-place estimates represent the amount of gas contained in a vertical interval developed by a single completion. Assessing the potential of recovering gas with multiple completions over intervals of more than several hundred feet was beyond both the scope of this analysis and available reservoir data. The areas of potentially productive tight gas formations shown in this report represent areas that could be developed for that formation only. Therefore, because some areas of these productive formations overlap, the sum of individual formation areas cannot be interpreted as the total basin surface area under which productive tight formations lie.

Outside of currently developed areas, Sand Wash Basin tight gas-in-place was estimated to be 8.8 Tcf. The potentially productive area is 518 sections for the Lewis and 371 sections for the Mesaverde. With 5.4 Tcf gas-in-place, the Mesaverde contains more than half of the total basin tight gas resource with a gas concentration of almost 15 Bcf per section, more than twice that of the Lewis (Table 2).

The Great Divide Basin tight gas-in-place outside currently developed areas is 30.7 Tcf. Two-thirds of this resource is estimated to be in the Fort Union and Ericson, Rock Springs and Blair members of the Mesaverde. Undifferentiated Mesaverde members contain an additional 15% of tight gas resource. Average gas concentration is almost 16 Bcf per section.

Table 2
Estimated Tight Gas-In-Place
(Eastern Green River)

Formation	Area (sections)	Gas-In-Place (Tcf)
Lewis	518	3.4
Mesaverde	371	5.4
Sand Wash Basin	**N/A**	**8.8**
Fort Union	530	10.5
Lance/Lewis	267	2.5
Almond A	350	2.9
Ericson, Rock Springs, Blair	586	10.3
Undifferentiated Mesaverde	212	4.5
Great Divide Basin	**N/A**	**30.7**
Total Study Area	**N/A**	**39.5**

B. Recovery and Reserves

The type curves were used to estimate annual and ultimate recoveries for typical wells in each formation and area. For current technology assumptions, per well recoveries vary across formations, ranging from less than 0.1 Bcf up to 0.5 Bcf. Recovery factors ranged mostly between 25% to 45%. In both the Sand Wash and Great Divide, the Mesaverde well recoveries were the highest, owing largely to the greater concentrations of gas-in-place.

Typical well economics were evaluated for each formation and potentially productive area and a minimum required wellhead gas price calculated that would return 10% on investment. Reserves were estimated for each formation by multiplying ultimate recovery per well by the number of drilling locations remaining. These were aggregated to estimate cumulative potential reserves that could be added at various wellhead gas price levels.

The low permeability and porosity, lenticularity, and likely absence of extensive natural fracturing in these formations leads to low productivity relative to the costs of drilling, completion and stimulation. At current prices and in the absence of production tax credits, the analysis indicates that there are no significant remaining potential tight gas reserves outside of developed areas. Due to inherent variation of reservoir properties in these aggregate units of analysis, some areas in these tight formations are probably economic to produce at current prices and technology. However, as confirmed by conversations with several operators, these are extremely rare. Even with the recent availability of tax credits for tight gas development, these areas were rarely development targets. Most drilling occurred in the more productive areas of the Wamsutter Arch or within producing reservoirs.

C. Impact of Improved Technology

Without improvements in extraction technology effectiveness, there is limited tight gas potential in the Sand Wash and Great Divide Basins outside of currently developed areas. The scope of necessary improvements is clear. Reservoir characterization is problematic; the presence of clays can lead to formation damage during drilling and stimulation. In addition, the response of lenticular reservoirs to hydraulic fracturing is unpredictable (Law 1986).

The effects of improved stimulation design and control technology were modelled by increasing the assumed effective fracture half length to 600 feet (equivalent infinite conductivity fracture). The development dry hole rate was reduced (to 10% from 20% for blanket/marine reservoirs and to 20% from 30% for fluvial/lenticular formations) to represent an improvement in formation characterization and subsurface modeling.

Using this definition of advanced technology, an estimated 9.5 Tcf of tight gas could be produced from areas outside currently developed reservoirs, with three-fourths of this potential in the Great Divide Basin. Table 3 shows total potential and average recovery per well for each formation. Per well recoveries vary significantly among formations, ranging from 0.4 Bcf per well in the Great Divide Almond A to 1.1 Bcf per well in the Great Divide Fort Union and Mesaverde formations. This compares with current ultimate recoveries of 9.1 Bcf per well in the Almond and 2.4 Bcf per well in the Lewis in the better developed areas of the Wamsutter Arch in the Washakie Basin (Barrett Resources, personal communication).

Table 3
Technically Recoverable Tight Gas in Undeveloped Areas of the Sand Wash and Great Divide Basins (Improved Technology)

Formation	Technically Recoverable Gas (Tcf)	Average Recovery Per Well (Bcf)
Lewis	1.0	0.5
Mesaverde	1.5	1.0
Subtotal/Avg Sand Wash	**2.5**	**0.7**
Fort Union	2.4	1.1
Lance/Lewis	0.6	0.6
Almond A	0.5	0.4
Ericson, Rock Springs, Blair	2.6	1.1
Undifferentiated Mesaverde	0.9	1.1
Subtotal/Avg Great Divide	**7.0**	**0.9**
Total Study Area	**9.5**	**0.8**

The incremental recovery of gas more than offsets the higher costs of advanced technology, thereby increasing potential reserves of tight gas. Table 4 shows the potential reserves at wellhead prices slightly above current levels and at $5.00 per Mcf, which is the highest expected price over the longer term. This latter price indicates the upper potential of tight gas reserves for new development in the Sand Wash and Great Divide Basins. The increase in potential tight gas reserves due to advanced technology is consistent with Duda's analysis of the Washakie Basin, which reported that increasing effective fracture lengths could almost double gas recovery, but would more then triple potential reserves.

The results of this study should be viewed in the context of the limited available data on reservoir properties in the undeveloped and largely unappraised areas of the Sand Wash and Great Divide Basins. Future appraisals of tight gas potential should focus on more detailed resource evaluation than was encompassed in the scope of this study. Given increased confidence in resource characterization, the methodology used to evaluate technical and economic potential in this analysis would still be appropriate.

Table 4
Potential Tcf Reserves of Tight Gas In Undeveloped Areas of the Sand Wash and Great Divide Basins (Improved Technology)

Wellhead Gas Price	Sand Wash	Great Divide	Total
$2.50/Mcf	0.6	1.5	2.1
$5.00/Mcf	1.2	4.6	5.8
Technical Recovery	2.5	7.0	9.5

V. Conclusions

A detailed geological and engineering appraisal was conducted of the currently undeveloped portions of the low-permeability Upper Cretaceous and Lower Tertiary formations of the Sand Wash and Great Divide basins. The remaining tight gas resource in the Sand Wash and Great Divide Basins is substantial. However, with current technology and economics, estimated potential reserve additions are minimal.

Based on interviews with operators, average fracture performance criteria were established to model future performance. Geological and fracture performance parameters were used in type curve analysis to estimate likely future recoveries from typical wells. Of the 39.5 Tcf of estimated tight gas-in-place in the formations studied, 2.2 Tcf (6%) is estimated to be technically recoverable with current technology. Current technology is defined for purposes of the study as those techniques and practices used by the most sophisticated operators today.

The development and application of advanced technology (e.g., improved seismic, higher resolution logging, and improved fracture design and implementation) could increase recovery substantially. Even though some operators are evaluating the potential of horizontal or slant wells (e.g., the Oryx/Wolverine Niobrara test in Routt county, Colorado), these were not evaluated in this study. Use of improved technology increases estimated recoverable tight gas in these areas to 9.5 Tcf (24% of gas-in-place).

Potential reserves were estimated based on the results of the geological appraisal and the assumption of widespread use of the defined technology. At wellhead gas prices slightly above current levels, as much as 2.1 Tcf of tight gas reserves could be added. If price increased to $5.00 per Mcf, potential reserves would almost triple to 5.8 Tcf.

The implication of these findings confirms the need for increasing reservoir contact in these tight zones, either through longer fractures or through the location and characterization of naturally fractured zones. The greatest potential impact of future research in low permeability reservoirs will be to increase the proportion of wells with effective communication between wellbore and reservoir. This communication will be increased by appraisal technologies that detect either the presence of natural fractures or the slant of the horizontal well configurations that contact these fractures.

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