Oil and Gas Resource Development
for San Juan Basin, New Mexico

A 20-year, Reasonable Foreseeable Development (RFD) Scenario Supporting the Resource Management Plan for the Farmington Field Office, Bureau of Land Management

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Executive Summary

The San Juan Basin is one of the most strategic gas producing basins to the U.S. economy due to its annual volume of production and the market it supplies. Natural gas produced from the basin in 1999 totalled 1.135 Tscf which was 68% of the natural gas produced in the state of New Mexico. In addition, 3.2 million barrels of oil were produced from the basin. The value of these commodities in 1999 was $2.46 billion dollars. The primary market is the southwestern U.S., California, which is the 6th largest economy in the world and is currently relying upon future natural gas supply growth to fuel its electric generation growth. The San Juan Basin is California's largest single source of natural gas supply.

The State of New Mexico is highly dependent upon San Juan Basin natural gas production for its public revenue, in terms of royalties, taxes and jobs. Decisions that are made that affect the production of natural gas from the basin can have a profound effect upon the local and state economies, and welfare of New Mexico citizens. It is of critical importance that the BLM and the public realize the economic impact that regulatory decisions will have regarding development and sustainability of production from the basin. The cost of alternative management strategies to the economy of New Mexico and the downstream market must be carefully weighed against competing philosophies of land management, alternative resource development or preservation.

The objective of this work is to develop an estimation of the *Reasonable Foreseeable Development* (RFD) to support BLM's Resource Management Plan. The scope of this study encompasses the New Mexico portion of the San Juan Basin, beginning with an effective date of January 1, 2002, lasting a duration of 20 years. The focus is to determine the subsurface development supported by geological and engineering evidence, and to further estimate the associated surface impact of this development in terms of actual wells drilled. The methods utilized for this study consist of a review of reservoir characteristics and historical production, predictive engineering production modeling, and presentation of data and conclusions in multiple formats including a report, databases, and GIS- based map displays. The ultimate goal of this study is to provide a scientifically based subsurface development scenario that is reasonably foreseeable. For known producing and anticipated potential reservoirs examined in this study, a reservoir description, analysis of historical production and twenty year prediction is provided.

For the major existing producing reservoirs, two approaches were used to predict development potential. The first approach was a survey of operating companies in the San Juan Basin, obtaining their perspective of future development based on current reservoir management practices. The second approach applies engineering techniques developed by the New Mexico Institute of Mining and Technology to optimize infill drilling in naturally fractured, low permeability gas reservoirs of the basin.

The total available subsurface completions in the New Mexico portion of the San Juan Basin are predicted to be 16,615 over the next twenty years. These results are subject to three assumptions: (1) sufficient take away capacity of the pipeline system out of the basin is available and will expand, (2) the well abandonment rate increases by 5% per year, and (3) the impact of future exploration will be minimal. A significant reduction in this number of completions will occur due to opportunities for commingling and dual completion of wells. Considering an estimated 25% decrease in wellbores, the total number of locations becomes 12,461. This rate equates to 623 wells per year on average and is consistent with current activity, which is approximately 640 wells per year average for 1999 and 2000 combined. This rate assumes continuation of a favorable regulatory environment that supports this level of annual development. Federal lands comprise approximately 80% of the leasehold of the San Juan Basin. Consequently, the total number of locations (12,461) must be reduced proportionately. This reduces the total predicted number of wells to be drilled on federal managed lands to **9,970**, predicted as reasonably foreseeable over a 20-year duration.

Associated with the well development will be the need for additional surface facilities to efficiently recover the gas and transport it to market. As a result of anticipated expansion of the take away capacity out of the basin through enhancement of old pipelines and construction of new pipelines, additional gas gathering systems and central compression will be necessary. Estimates of 360,000 HP of additional central compression and 3,600 miles of pipelines are projected towards this effort. Furthermore, as the natural energy of the reservoirs decline, wellhead compression will be expanded to produce the gas. A **maximum** scenario is to increase the amount of wellhead compression to half of the projected new wellbores; i.e., approximately 5,000 units having average horsepower of 100 HP. Clustering of wells per unit is anticipated to decrease this number, but is not predictable at this time.

The potential role of evolving technology cannot be over-emphasized. New drilling and completion strategies are expected to improve for directional and horizontal wells. The advantages would be the potential for increased gas recovery, and the reduction in surface disturbance. A second example is advances in stimulation design. Historically, the evolution of stimulation has played a key role in development scenarios and well efficiency. Continued advances are anticipated and will benefit both existing and new wells, and potentially promote the commingling of zones, thereby reducing the number of wells to be drilled.

LIST OF ABBREVIATIONS AND ACRONYMS

AAPG	American Association of Petroleum Geologists
BEG	Bureau of Economic Geology, Texas
BLM	U.S. Bureau of Land Management
Bscf	Billion standard cubic feet (gas)
DOE	U.S. Department of Energy
EIA	U.S. Energy Information Administration
EIS	Environmental Impact Statement
EPNG	El Paso Natural Gas
EUR	Estimated ultimate recovery
ft	feet, foot
Gp	Cumulative gas production
GRI	Gas Research Institute
HP	Horsepower
IWLC	Infill well location calculator
mbo	Thousand barrels of oil
mbw	Thousand barrels of water
mmscf	Million standard cubic feet (gas)
NFS	U. S. National Forest Service
NMBGMR	New Mexico Bureau of Geology and Mineral Resources
NMIMT	New Mexico Institute of Mining and Technology (New Mexico Tech)
NMOCD	New Mexico Oil Conservation Division
P&A	plugged and abandoned
PRRC	New Mexico Petroleum Recovery Research Center
psi	pounds per square inch (pressure)
RFD	Reasonable Forseeable Development
RMP	Resource Management Plan
ROW	Right-of-way
SPE	Society of Petroleum Engineers
Tscf	Trillion cubic feet
TOC	Total organic carbon
U.S.	United States of America

Chapter 1
Introduction

1.1 Economic significance of the San Juan Basin

The San Juan Basin is one of the most strategic gas producing basins to the U.S. economy due to its annual volume of production and the market it supplies. Natural gas produced from the basin in 1999 totalled 1.135 Tscf (EMNRD, 2000), which was 68% of the natural gas produced in the state of New Mexico. In addition, 3.2 million barrels of oil were produced from the basin. The value of these commodities in 1999 was $2.46 billion dollars. The primary market is southwestern U.S., particularly the California market which is the 6th largest economy in the world and is currently relying upon future natural gas supply growth to fuel its electric generation growth. The San Juan Basin is California's largest single supplier.

The State of New Mexico is highly dependent upon San Juan Basin natural gas production for its public revenue, in terms of royalties, taxes and jobs. Decisions that are made that affect the production of natural gas from the basin can have a profound effect upon the local and state economies, and welfare of New Mexico citizens. It is of critical importance that the BLM and the public realize the economic impact that regulatory decisions will have regarding development and sustainability of production from the basin. The cost of alternative management strategies to the economy of New Mexico and the downstream market must be carefully weighed against competing philosophies of land management, alternative resource development or preservation.

Natural gas market economics are favorable today. The current strong market supports drilling at 600 completions per year. If the economic trend continues into the future then this drilling pace is expected to be sustained. There are, however, a number of factors which could affect the stability of the current market. A real possibility is the transmission of Alaskan gas to west coast markets in 7 to 10 years. Another alternative is the decrease in demand of the market due to regional or national recession.

1.2 Purpose and scope of RFD

The objective of this work is to develop an estimation of the *Reasonable Foreseeable Development* for BLM's *Resource Management Plan* (RMP). The scope of this study includes the New Mexico portion of the San Juan Basin, beginning with an effective date of January 1, 2002 and lasting a duration of 20 years. The focus is to determine the subsurface development supported by geological and engineering evidence, and to further estimate the associated surface impact of this development. The ultimate goal is to support a Resource Management Plan that achieves a balance between the environmental impact and economic development of the basin.

1.3 Assumptions and variations

1.3A Take away capacity out of the basin

The original premise of this work was to maintain a constant take away capacity out of the basin for the twenty- year duration of the RFD. In fact, the industry survey found in Chapters 3 and 7 reflect this assumption and was based on the decline in coal bed gas being offset by any increase in future development; resulting in no net increase in capacity required. However, with the recent unveiling of the President's National Energy Policy, increased pipeline capacity and distribution systems out of the basin and throughout the west have become a probable scenario (I.H.S. Energy, 2001). The incentive of this development is to meet the strong current, and anticipated increased, energy needs of the west and nationwide. Therefore, the rate of well development predicted in this RFD may be a minimum level, and may under-anticipate future need.

Increasing pipeline capacity is anticipated to occur by two means. First, the take away capacity of existing lines can be increased if the mechanical integrity of these lines proves they can withstand the increased pressures to accommodate the capacity. Extensive testing of these lines is ongoing today to ensure that safety is not compromised (Joe Velasquez, El Paso Field Services Co., personal communication). With this work, additional capacity can be developed; unfortunately, the increase is minor and may not provide sufficient capacity to meet potential large increases in market demand. A second alternative is to construct additional pipelines within existing corridors. The result would be a substantial increase in take away capacity from the basin. In response to this pipeline construction, surface disturbance adjacent to these corridors is projected * to be 11,636 acres, assuming 3,600 miles of additional lines as follows:

- 600 miles of large diameter trunkline with 60' ROW
- 1000 miles of laterals with 20' ROW
- 2000 miles of looplines with 20' ROW

As reservoir pressure declines, additional compression becomes necessary as a replacement for the lost energy from the reservoir. Furthermore, as capacity grows the required compression will also increase*. Current estimates of horsepower for existing compressor stations is 168,000 HP. Additional compression of 360,000 HP is projected in association with the expansion of the gas gathering systems previously mentioned. The locations for these compressor stations will be scattered throughout the primary development area of the San Juan Basin and will include 10-20 stations in size from 2,000 to 10,000 HP and 200-300 stations ranging in size from 500 to 2,000 HP. In addition, as the reservoirs continue to mature, operators will add wellhead compression to improve gas recovery. As a maximum estimate*, wellhead compression could increase to half of the project area wells (15,000: existing and new), averaging 100 HP per unit.

*Source of data: BLM Farmington Field Office (Realty and Fluids Staff), and Industry estimates

1.3B Projected rate of P&A over the life of the plan

A second initial assumption of this project is that current P&A rates will not change significantly over the next twenty years. The last four years of data furnished by BLM are:

Year   Number of Abandonments
1997   103*   *Low due to change in database software
1998   145
1999   115
2000   141

The average of the last three years has been 133, with the latest year's value of 141. The projected well abandonment rate assumes a minimal increase of 5% per year for the life of the RFD; therefore resulting in approximately 350 abandonments in the last year of the RFD. Several factors considered in this assumption which suggest an increase abandonment rate are:

a. aging of wells
b. depletion of Fruitland coal wells and other shallow reservoirs with little if any projected uphole potential
c. mechanical integrity problems related to corrosion from H_2S content of the Ojo Alamo reservoir, and CO_2 content of the Fruitland coal reservoir
d. current marginally-economic (low volume) production from many Gallup wells. Many of these wells are a near-term concern (refer to Chapter 5.6).

Reclamation of P&A locations will decrease the footprint of the industry and result in enhancing the attractiveness of the San Juan Basin. Not all P&A locations will need to be immediately reclaimed because these locations may afford other beneficial use. For example, an existing well pad combined with directional drilling could, under favorable circumstances, be an effective method of efficiently recovering hydrocarbons and/or reduce additional surface disturbance. Further discussion on directional drilling technology strategies is given in Chapter 8. Historically, each well pad averages 2 acres and the associated road and pipeline approximately 1 acre (800' x 50' ROW); consequently 3 acres per well can potentially be reclaimed or reused.

1.3C Impact of future exploration

A third assumption was that limited exploration potential exists in the basin and what is possible will have negligible impact. In contrast to this assumption, this RFD anticipates significant exploration. However, it is agreed that relative to the number of development wells anticipated, exploration wells will have a minimal impact on the total number of wells to be drilled in the basin. Further details on this topic are discussed in Chapter 5.

1.3D Uncertainty in estimated well development

Uncertainty is inherent in the estimated well development. Of concern is the Dakota Sandstone reservoir 80-acre infill development. Current information on this development is preliminary at best, and could change (positive or negative) within the next several years. Since one-third of the total completions are dedicated to Dakota 80-acre development, the consequences are magnified. A 30% reduction in Dakota infill development is possible if new information on pressure and well performance are not favorable.

A factor that promotes Dakota development is the ability to commingle or dual complete with another producing horizon; specifically the Mesaverde Group reservoir. This completion practice is prudent, economic, efficient and minimizes surface disturbance. This RFD anticipates an increase in this method of completions to 30 to 40% of total completions; 9,669 to 11,280 available locations (7,735 to 9,024 on federal land).

Chapter 7 discusses the impact of technology evolution. It is certain that advanced technologies will support development, but the impact is difficult to estimate. As an example, completion strategies of directional drilling, horizontal wells, and multi-laterals will reduce surface disturbance. Unknown at this time is the gas recovery for reservoirs in the San Juan Basin subject to this completion method.

Chapter 2
Fundamental concepts and basin history

2.1 General geologic concepts and history

Natural gas production from BLM and NFS administered lands in the San Juan Basin is primarily from low permeability ("tight"), fractured Cretaceous reservoirs. A lay review of the history of these reservoirs below explains why they are present, have definable characteristics, have historically behaved in a particular manner and have a predictable production future.

During much of the late Cretaceous, the San Juan Basin region was the site of a small segment of the western shoreline of the vast Western Interior Seaway. The landward direction was southwestward and the seaward direction was northeastward. Over time, the shoreline migrated back-and-forth, landward or basinward. At any given time, both nonmarine and marine rocks might be deposited across the region. The marine rocks include thick shale formations that preserved organic matter that would later be converted to oil or gas. The nonmarine rocks tend to have significant organic content in the form of coal beds that can generate gas. Both types of depositional environments yielded sandstone reservoir bodies. In the San Juan Basin, the sandstone formations tend to be well cemented and thus have low porosity and permeability, key reservoir characteristics required for storage and production of hydrocarbon. Figure 2.1-1 is a summary diagram showing present basin stratigraphy.

The San Juan Basin, roughly circular in shape (Figure 2.1-2), is an asymmetrical syncline located in northwestern New Mexico and southwestern Colorado [Peterson *et al*., 1965; Dutton *et al*., 1993]. The basin extends approximately 100 miles north to south, and 90 miles east to west. Geological formations dip towards a low area in the northeastern part of the basin. The Cretaceous formations began to be downwarped into the basin during the late Cretaceous to early Tertiary Laramide tectonic event. By the end of the Laramide event, the Cretaceous rocks had reached maximum depth of burial and the basin had reached its present structural configuration. Following the Laramide event, a regional heating event occurred that enhanced the thermal maturation of deeply buried organic matter to a level that gas was generated in the basin center, and in some formations, oil was generated around the basin margins. Because the rocks were "tight" (low permeability) prior to hydrocarbon generation, the gas or oil have remained where generated.

ERA	SYSTEM	FORMATION		THICKNESS	PRODUCTION
CENOZOIC	TERTIARY	San Jose Formation		2500 ft	gas
		Nacimiento Formation		500-1300 ft	gas
		Ojo Alamo Sandstone		250 ft	gas
MESOZOIC	CRETACEOUS	Kirtland Shale	Farmington Sandstone	1500 ft	gas/oil
		Fruitland Formation		500 ft	gas
		Pictured Cliffs Sandstone		250 ft	gas
		Lewis Shale	Huerfanito bentonite	500-1900 ft	gas
		Mesaverde Group	Cliff House Sandstone	0-800 ft	gas
			Menefee Formation	350 -2200 ft	gas
			Point Lookout Fm.	100-300 ft	gas
		Mancos Shale	upper Mancos shale/Tocito Ss.	2300-2500 ft	gas/oil
			Gallup Sandstone/Carlile Sh.		gas/oil
			Greenhorn Limestone		
			Graneros Shale		
		Dakota Sandstone		150-200 ft	gas/oil
	JURASSIC	Morrison Formation		400-900 ft	
		Wanakah Formation	Todilto Limestone	50-200 ft	
		Entrada Sandstone		100-300 ft	oil
	TRIASSIC	Chinle Formation		500-1600 ft	
PALEOZOIC	PERMIAN	Cutler Formation		1500-2500 ft	
	PENNSYL-VANIAN	Hermosa Formation	Honaker Trail Fm.		
			Paradox Formation	200-3000 ft	gas?
			Pinkerton Trail Fm.		
		Molas Formation		0-100 ft	
	Mississippian	Leadville Limestone		0-165 ft	
	Devonian	Elbert Formation		0-325 ft	
	Cambrian	Ignacio Quartzite		0-100 ft	
Precambrian					

Figure 2.1-1 Generalized stratigraphy of the San Juan Basin, New Mexico. Cretaceous natural gas-producing formations in yellow. Other productive or potentially productive formations in orange.

2.2
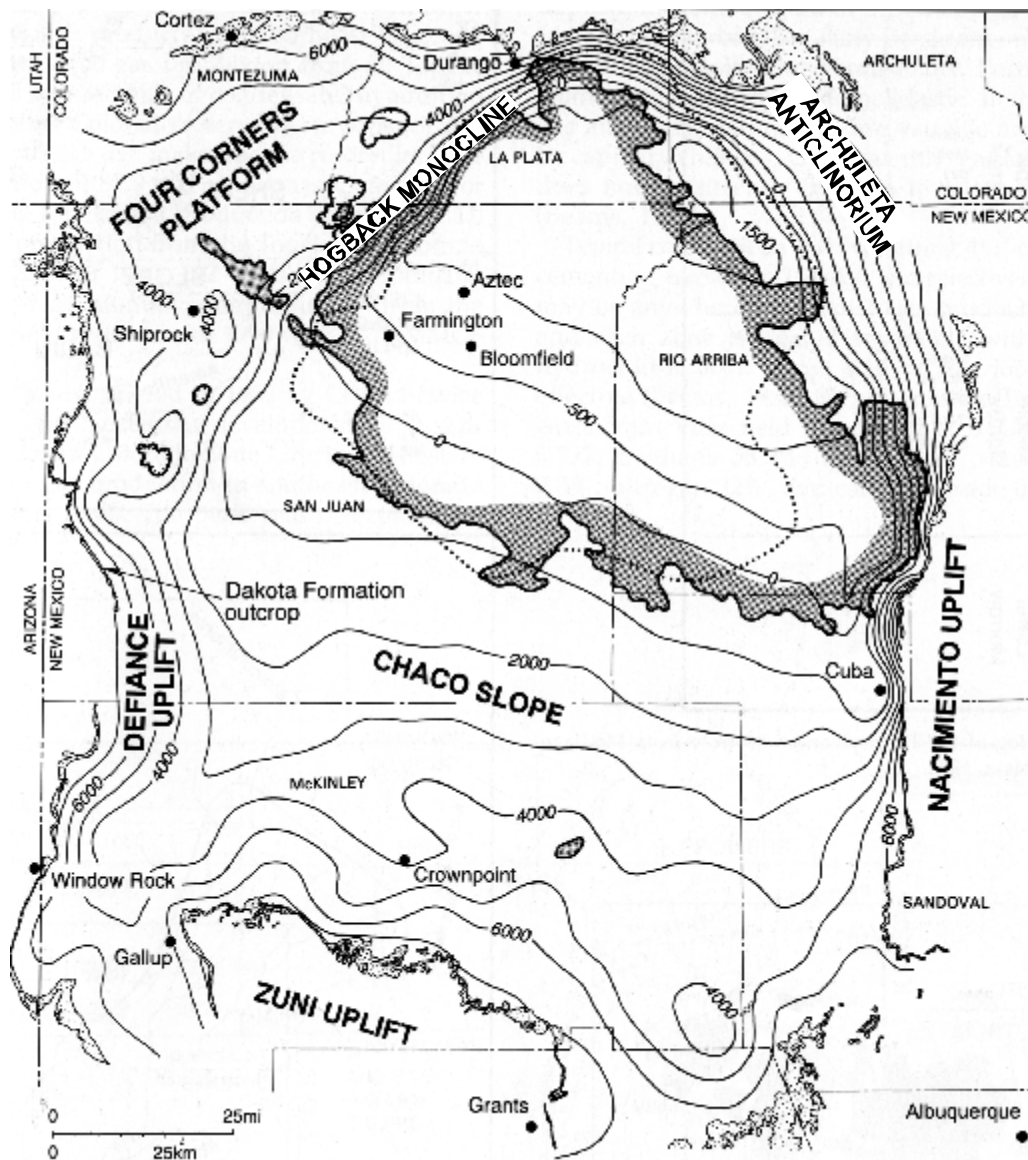
Figure 2.1-2 Primary structural features of the San Juan Basin (modified from Whitehead, 1993). Map shows outcrop and structure contours (feet) of the Dakota Sandstone. Shaded outline is maximum extent of major gas-producing reservoirs.

Following the maturation of organic matter to hydrocarbons, the basin has been gradually eroded. The net effect was cooling of the reservoirs, decreasing reservoir pressures to below normal, particularly in the Mesaverde Group and adjacent formations. Infiltration of groundwater causes local overpressured conditions in the Fruitland coal beds.

Every Cretaceous formation in the basin is capable of production to some extent and most have 50 years, or more, of production history that can be evaluated by

engineering methods. It is the combination of factors such as rock type, thermal maturity, hydrocarbon saturation, porosity, permeability, and formation pressures that gives the individual reservoirs in the basin their widespread characteristics. Combined study of the reservoir geology and production history results in accurate engineering-method-based prediction of future production potential from these reservoirs. Other reservoirs have not produced significant volumes in the past, but have potential to contribute to future production based on their geologic characteristics and assuming favorable market conditions for their development. All reservoirs with known or assumed potential are discussed separately in this report.

2.2 History of development: production, market, transportation, and statutory effects

Initial development in the region began in the early-1920s in the Four Corners Platform area to the west. Discoveries such as Ute and Barker Dome in the Pennsylvanian and Dakota formations were prolific. Both are easily identifiable structural traps and both reservoirs exhibit conventional reservoir traits; e.g., moderate to high permeability and porosity.   Basin discoveries in the Farmington Sandstone, the Pictured Cliffs Sandstone and the Mesaverde Goup began in the late 1920s; however little development occurred until the late 1940s and early 1950s due to lack of market demand. In the late 1940s, the Dakota Sandstone was added to the basin development. El Paso Natural Gas Company in 1951 completed an interstate pipeline supplying gas to California markets and thus spurred rapid development, particularly of the Pictured Cliffs and Mesaverde reservoirs. These plays can be categorized as unconventional due to their low permeability and corresponding low productivity without stimulation.

Early completions were typically openhole (not cased in producing zone) with stimulation consisting of dropping nitroglycerin bombs. Advances in hydraulic fracturing technology in the 1950s and 1960s improved recovery by stimulating in a controlled manner.

The next major development occurred in the mid to late 1970s. At this time, evidence was presented to the New Mexico Oil Conservation Division in support of infill drilling the Mesaverde (1975) and Dakota (1979) to 160-acre spacing; regulatory approval was subsequently obtained. Figure 2.2-1 illustrates a slight increasing trend in the production rate after this development. In the 1980's, market demand was weak, resulting in no significant development during this time period. The erratic production behavior seen on the production curve is evidence of the curtailing of production and the repetitive cycle of shutting in wells during periods of sub-economic gas prices.

The Fruitland Formation coal play made a significant impact on the gas production from the San Juan Basin in 1989. As can be seen in Figure 2.2-1, the daily production rate doubled to 3 Bcfd due to the successful completion of Fruitland coal wells. At the same time, pipeline capacity was sufficient and market demand available to sell this additional gas.

In the last several years, reduced spacing has been considered economically viable. The Blanco Mesaverde Pool was approved in 1998 for 80-acre spacing, and the Basin Dakota Pool is currently being pilot tested for feasibility of producing at 80-acre spacing. This activity is planned to capture additional reserves not available in 160-acre spaced development, and to improve the deliverability from the pools.
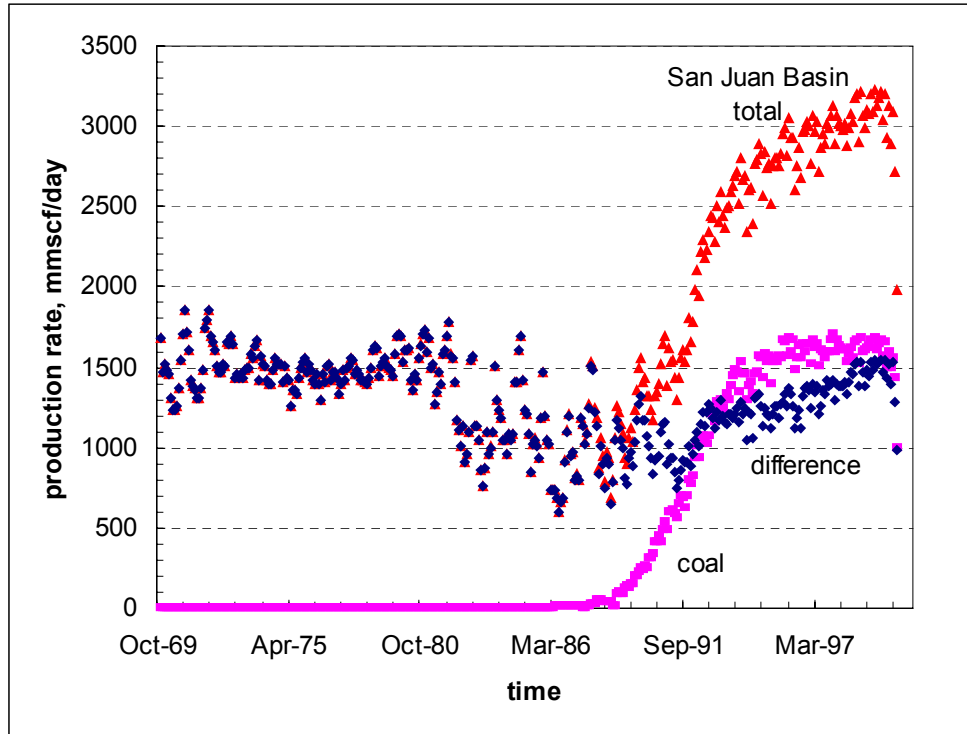
Figure 2.2-1 Total gas production from the New Mexico portion of the San Juan Basin and the contribution of the Fruitland Coal to this total.

2.3 Summary of present production

The current production rate from the San Juan Basin is approximately 3.0 Bscfd (as of July 2000). Approximately half of this production comes from the Basin Fruitland coalbed methane pool. Fruitland production has reached a peak and is beginning to exhibit signs of declining; therefore alternative sources of gas deliverability need to be sought to make up the loss. The other major producing reservoirs contribute 0.75 (Mesaverde), 0.35 (Dakota) and 0.25 (Pictured Cliffs) Bscfd, respectively. The Mesaverde and Dakota reservoirs have the best short term potential for increasing gas recovery and thus maintaining the deliverability out of the basin.

The historical trend in development concurs with this change in focus from coal to other formations. Figure 2.3-1 illustrates the percent of activity by reservoir over the last ten years. Note during the early 1990s the Fruitland Coal dominated the

development with approximately 75% of the total activity. This rapid development has declined and recently the Mesaverde has been the major target of activity.
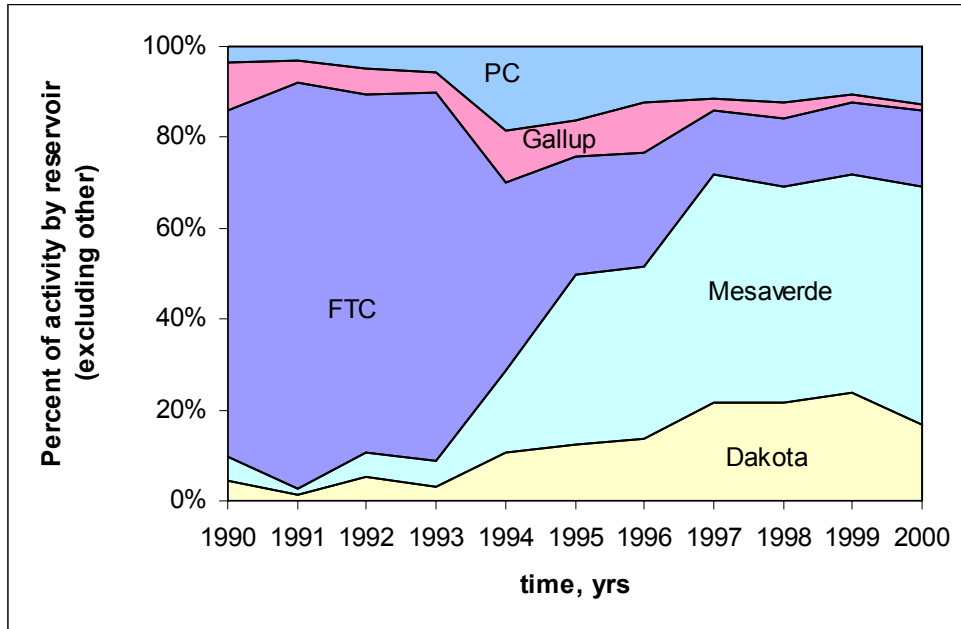
Figure 2.3-1 Percent of new completions in the major reservoirs reflecting change in emphasis from Fruitland Coal (FTC) to Mesaverde and Dakota.

The activity reported in Figure 2.3-1 considers single-zone completions only and therefore does not account for commingling or dual completions. Figure 2.3-2 demonstrates the effect of dual completions or commingling *at the time of initial completion*. Shown on the plot are the total completions, the total locations (includes commingling) and the number of first year commingled completions. Note the increase in commingling rate, with the latest value reported of 20%. This effort is primarily directed to the Mesaverde/Dakota development activity, which has increased in the last several years. This trend is anticipated to continue in the future.
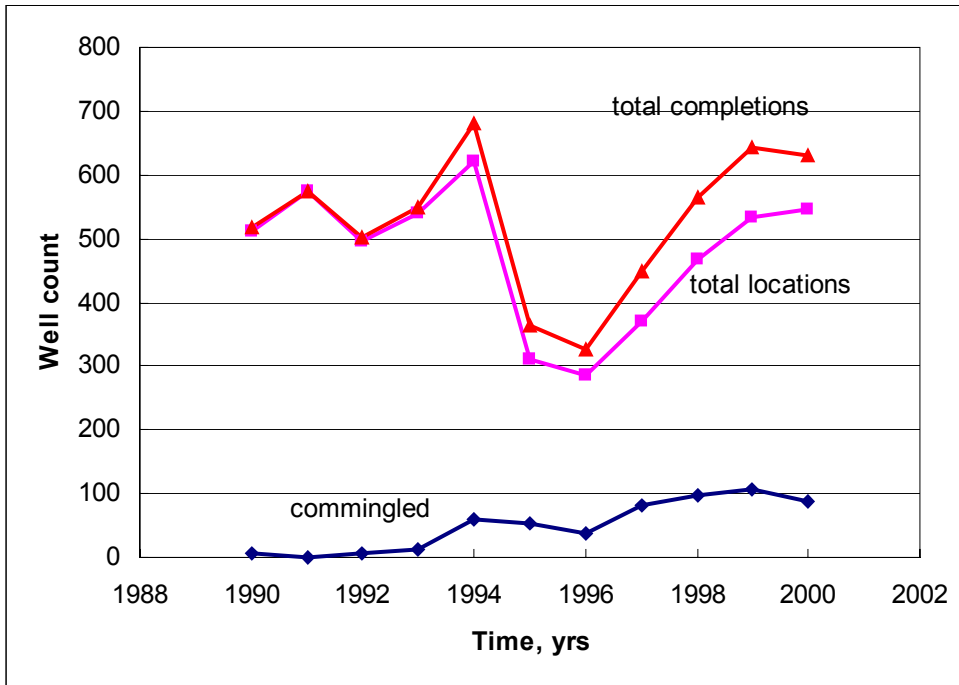
Figure 2.3-2 Influence of commingling on number of well locations for first year wells

Chapter 3
Methods

3.1 Operator Survey and processing

One source of information for this work was to obtain an industry perspective of potential development in the San Juan Basin. The direct benefit is to tap into the wealth of experience available and obtain currently perceived development strategy for their properties. To capture this information in a concise form, an industry survey was distributed to all operators (See appendix). Chapter 6 contains a summary of the results. These results were compared to our independent analysis, and for any discrepancies identified, further investigation was done to develop an explanation for these differences.

The number of returned responses was 35 or approximately 16% of the total number of 212 operators solicited for information. This response rate seems poor; however, those who responded represent 90% of the total activity in 2000. The results are compiled in Chapter 7. To set a common baseline, three constraints were given: (1) the take away capacity out of the basin will not significantly change, (2) the historical P&A rate will remain constant for the duration of the forecast period, and (3) limited exploration potential exists in the basin, and what is possible will have negligible impact. The first two constraints have been discussed in Chapter 1, and the latter is addressed in Chapter 5 on emerging and possible nonconventional reservoirs. The majority of responses agreed with the above constraints. Those responses which disagreed are shown at the end of the survey.

3.2 Production modeling and estimation

The objective of production modeling and estimation is to determine the drainage and flow characteristics from the well performance data of the gas producing formations in the New Mexico portion of the San Juan Basin. Historical gas production trends (through May 1999) of the six historically most significant gas producing formations, Fruitland Sand, Fruitland Coal, Pictured Cliffs, Chacra, Mesaverde, and Dakota, were analyzed on total-well and per-well bases. Analysis of well production data of randomly selected wells, but covering all the producing townships for each formation, was performed. Per-well values of drainage pore volume, initial gas-in-place, recovery (through May 1999), drainage area, productivity factor, and flow capacity are estimated and average values are reported. These performance-based average estimates are reasonably consistent with the historical producing trends and the actual recovery observed in the San Juan Basin. The four primary gas producing formations in the San Juan Basin recognized from this analysis are the Fruitland Coal, Mesaverde Group, Dakota Sandstone, and Pictured Cliffs Sandstone. Review of the future potential of these reservoirs is discussed in Chapter 4 and discussion of methods and conclusions of production modeling is in Chapter 6.

3.3 Multi-participant-compatible GIS database and platform

Data sources utilized for this RFD include commercial (for purchase) resources and public domain (free) resources. Although useful for research, commercial resources such as maps and databases are not readily available to, or affordable for purchase by, the general public. Licensing agreements between commercial vendors and New Mexico Tech were honored and therefore no private databases are published in this report although they were utilized and referenced where appropriate.

Much of the information in ready-formatted commercial databases is also available in the public domain. Examples are well-specific data compiled by the State of New Mexico and geographic information made available by various entities of the U.S. Department of the Interior. A variety of public domain data was gathered and formatted to be accessed and displayed using the ARCVIEW GIS (by ESRI) platform. This software platform was chosen because it is widely utilized by land use professionals and it accepts and integrates data that was acquired in a variety of formats. The concept of the database was to provide all contractors with a common platform early in the process of work on the current RMP study.

Data that was collected and integrated into the ARCVIEW program for this project include:
- Well location coordinates generated by the New Mexico Petroleum Recovery Research Center (PRRC)
- Surface geologic mapping information from the digital geologic map of New Mexico by the New Mexico Bureau of Geology and Mineral Resources (NMBGMR).
- New Mexico Oil Conservation Division (NMOCD)-mandated oil and gas pool boundaries (compiled by NMBGMR)
- The State of New Mexico's ONGARD well production database maintained by the PRRC and accessible via the GOTECH web site.
- The NMOCD Aztec office, KARDEX database that includes well activity, location, drilling, and completion information.
- Geographic data from U.S. Department of Interior's PLSS system including land grid, detailed roads, surface management, mineral management, special management area boundaries, topographic map boundaries, water wells, and surface waters.
- Summary engineering data for major reservoirs compiled for this report

The product of this compilation effort, as delivered to the Bureau of Land Management, is archived as an appendix to this RFD and is accessible using ARCVIEW GIS software. A version of the database and free software (ARCEXPLORER) for viewing the database are also included as an appendix to this report. The ARCEXPLORER software does not have all of the functions of the commercial product and is limited in the data that can be displayed and accessed. The primary deficiency of the ARCEXPLORER version is the inability to access all of the extensive database containing detailed information on specific wells.

Chapter 4
Major Producing Reservoirs

4.1 Fruitland Formation Coalbed Methane Reservoir

4.1A Stratigraphy

The upper Cretaceous Fruitland Formation is a nonmarine, coal-bearing formation that was deposited across the entire San Juan Basin region. It is bounded by the nonmarine Kirtland Shale above and the marginal marine Pictured Cliffs Sandstone below (Figure 4.1-1). The upper contact of the formation is defined as the top of the uppermost ophiomorpha-bearing sandstone, whereas the base is the top of the uppermost massive sandstone of the Pictured Cliffs Sandstone (Fassett and Hinds, 1971). The formation is composed of variable thickness mudstone, coal beds, and at least three fluvial sandstone units. It intertongues with the Pictured Cliffs Sandstone in parts of the basin (Ayers et al., 1994).
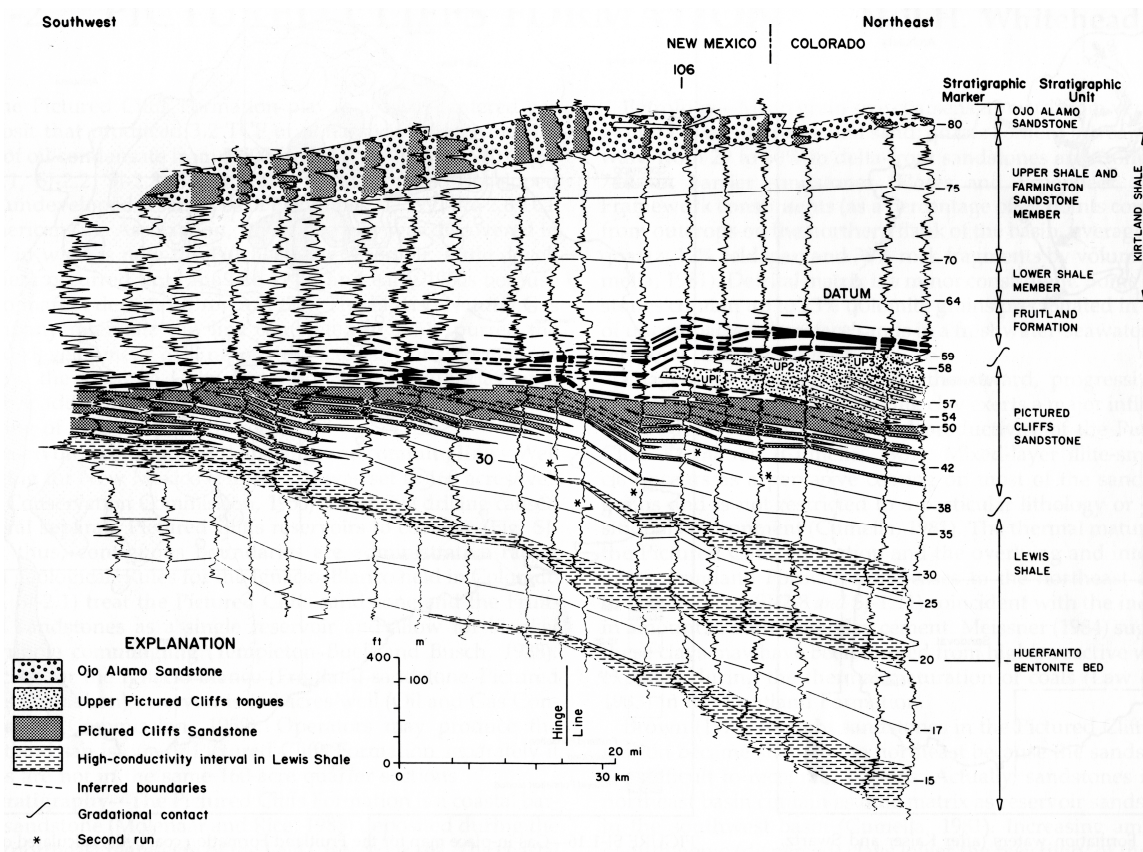
Figure 4.1-1 Stratigraphic cross-section depicting the Fruitland Formation (coal beds in black) and adjacent formations. Units UP1, 2 and 3 in the northern end of the diagram are considered to be tongues of the Pictured Cliffs Sandstone (after Whitehead, 1993).

4.1B Statutory Definition

The coal beds and sandstone reservoirs of the Fruitland Formation are statutorily separated. The Basin-Fruitland coal gas pool includes only the coal beds in the formation (Figure 4.1-2). Current spacing is 320 acres per well although there are pilot projects underway (administratively approved by NMOCD) to examine the feasibility of 160 acre per well spacing.
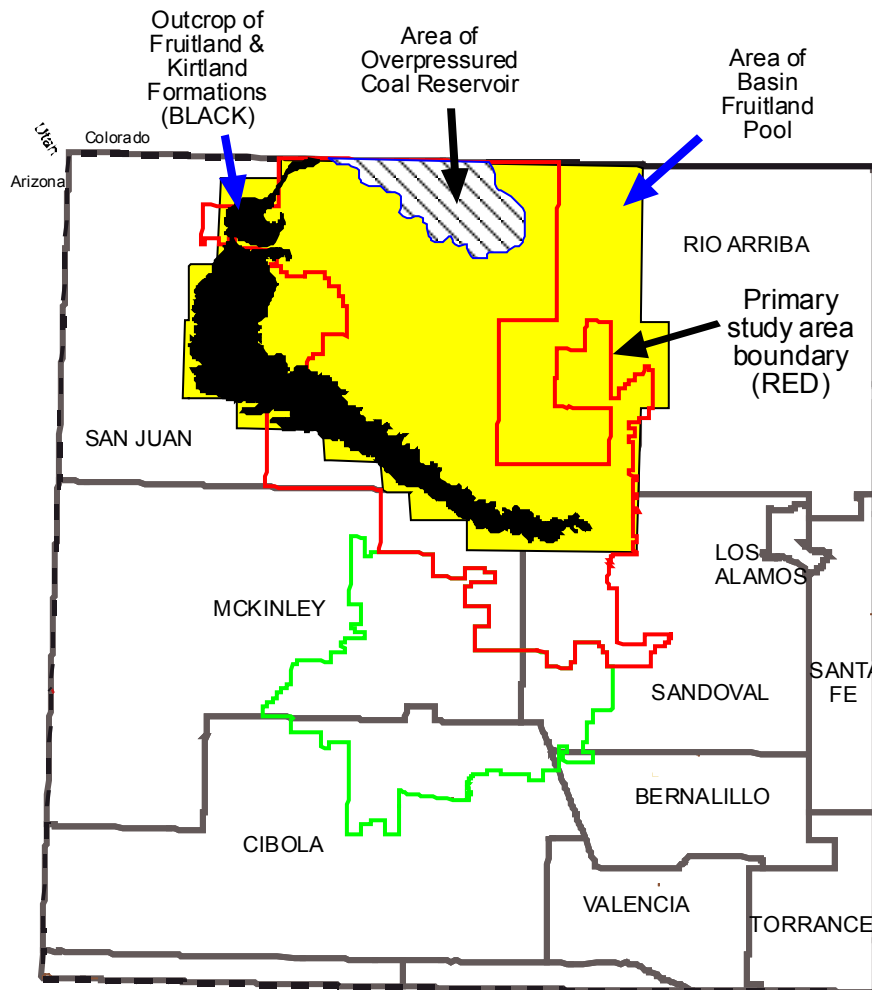
Figure 4.1-2 Map of Fruitland Formation and statutory limits of the Basin Fruitland pool. Black area is outcrop of Fruitland/Kirtland formations. Red outline delineates primary area of the current study.

4.1C Reservoir Characteristics

The Fruitland Formation coal gas reservoir is a world-class example of commercially successful coalbed methane (CBM) development due to a combination of favorable reservoir characteristics. A key literature compilation is Ayers and Kaiser (1994) and the information below is summarized from that report.

The Fruitland coal reservoir is not a single, continuous coal bed; rather, it is composed of a number of discrete coal beds. Usually, the number of beds per well ranges from 6 to 9 with as many as 16 beds present. Net thickness is highly variable, ranging from 0 (due to erosional truncation) to 110 feet, but averages about 33 feet. The depth to the base of the Fruitland coal is less than 4200 feet. Individual coal beds in the formation vary widely in thickness over short distances, thus per well recovery similarly varies considerably within producing leases.

Fruitland coal has a relatively high gas-in-place content related to its high concentration of organic content, thermal maturity, biogenic methane content and pressure conditions. Gas in place ranges from <5 Bscf/mi^2 to more than 35 Bscf/mi^2 (Ayer and Kaiser, 1994, p. 39). The coal varies in rank (thermal maturity); high volatile A bituminous or higher rank coal is present in one-fourth of the basin. Although thermal maturity affects gas content, lesser rank coals are also productive and contribution from biogenic methane generation is probable in some parts of the basin.

Matrix permeability is variable, but generally very low. Production is possible due to the presence of extensive networks of coal cleats (fractures); fracturing of the coal is attributed to Laramide tectonic activity. The cleat network is typically water bearing. Dewatering has been an important factor in CBM production. The organic components of the Fruitland coal contain adsorbed gas. As water is produced from the cleat network, pressure is reduced and adsorbed gas is desorbed from the matrix to the cleats and becomes producible.

Coalbed methane production is greatest overall where the Fruitland is overpressured (Figure 4.1-2). The overpressured area of the Fruitland coal is attributed to artesian conditions where the aquifer is recharged from the northern margin of the basin and is confined near the basin center due to change to lower permeability. The pressure gradient in the overpressured area ranges upwards to ~0.80 psi/ft (hydrostatic pressure is 0.43 psi/ft). Outside of the overpressured area, the fruitland is generally underpressured as low as ~0.30 psi/ft.

4.1.D Historical Development

The first well drilled specifically for Fruitland Coal gas production was in the Cedar Hill Field in 1977. Development was slow due to the high water production rates and also to the poor understanding of the desorption phenomena. In 1990, interest escalated when commercial quantities of gas were sustainable. The success was in part due to better understanding of the reservoir flow mechanisms, expanded water handling capabilities, and in improved completion strategies. By 1994, approximately 1750 wells were completed in the Fruitland Coal, that is, approximately 75% of the total wells producing from the Fruitland Coal were drilled in four years. Figure 4.1-3 shows the trend of active wells since 1977.

San Juan Basin (Fruitland Coal)
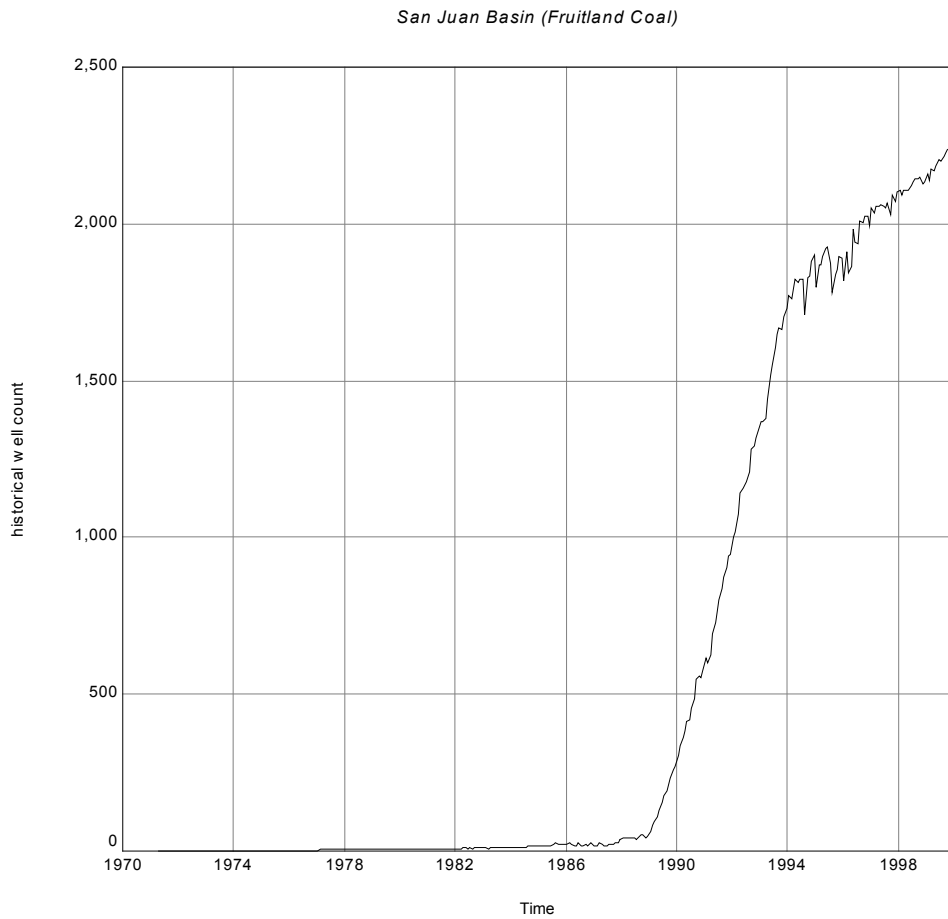
Figure 4.1-3 Historical well count of Fruitland Coal wells (Source: I.H.S. Energy)

Production rates for oil, gas and water are shown in Figure 4.1-4. The trends in increased rate coincide with the increase in active wells seen in Figure 4.1-3. Gas production has been constant since 1994, averaging 50 Bscf per month. Over the same time period, water production has been on a slight decline. Cumulative production to July 1, 2000 has been 4.8 Tscf.

San Juan Basin (Fruitland Coal)
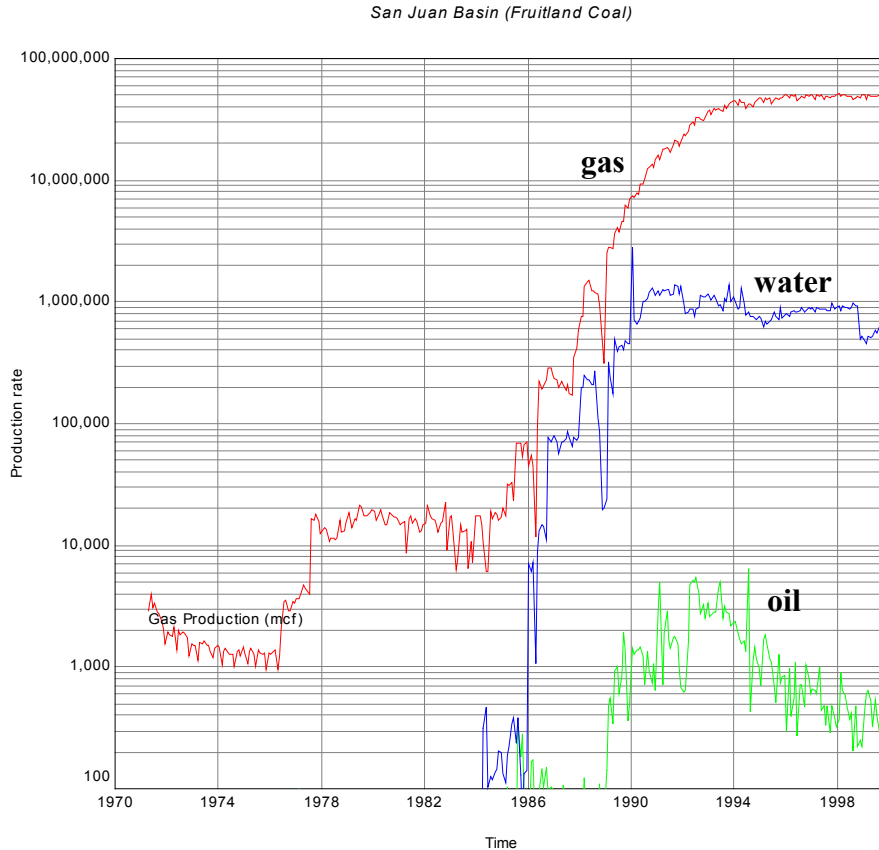
Figure 4.1-4 Monthly oil, gas, and water production rates for Fruitland Coal.
(Source: I.H.S. Energy)

4.1E Gas Resources

Gas in place for coalbeds is estimated by volumetrics using parameters such as volume of coal (usually expressed in tons), density of coal, ash content, desorption constants and so on; or by simulation. The following is a chronological list of estimates of gas-in-place:

1. GIP = 31 Tscf   Choate, et al., (1982, 1984)
2. GIP = 56 Tscf   Kelso (1987)
3. GIP = 50 Tscf   Kelso (1988)
4. GIP = 43-49 Tscf Ayers & Ambrose (1990)

4.1F Infill Well Potential

Spacing for the Basin Fruitland Coal is 320 acres per well, but with an option to drill a second well (effectively 160-acre spacing) on the same proration unit with administrative approval. Recently a proposal is being studied to reduce spacing to 160

acres in areas designated as the low-pressure region. The low-pressured regions of the Fruitland coal reservoir in Colorado are currently at 160-acre spacing.

The infill potential varies for the two regions with different reservoir pressure conditions. Figure 4.1-5 outlines the two regions. Wells within the over-pressure region exhibit pressure gradients > 0.44 psi/ft, have high water production with low chlorides content, have higher CO_2 content in the gas, and are completed either with openhole cavity completions or hydraulic fracturing. Average cumulative production to July 2000 has been **4.2 Bscf/well**. The under-pressured region are characterized by pressure gradients < 0.44 psi/ft, minor water production, thin coals, and almost exclusively hydraulic fractured. Average cumulative production for these wells has been **0.34 Bscf/well**.
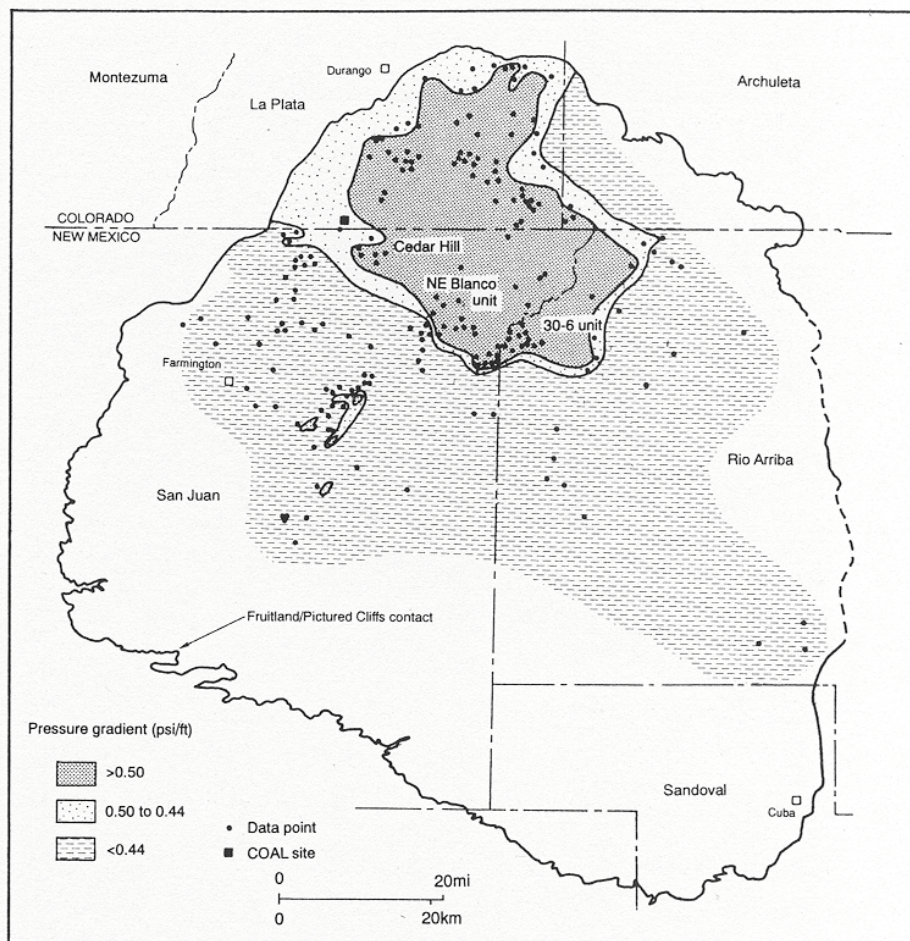
Figure 4.1-5. Fruitland Formation pressure gradient map (Whitehead, 1993)

The impact of infill well development was investigated by several authors [Paul & Boyer, (1991), Young, et al. (1991)] using simulation models. Paul and Boyer concluded that well interference effects are beneficial by accelerating the dewatering phase; therefore potentially increasing gas recovery with decreased well spacing. Young et al., applied simulation to the Cedar Hill Field. Two insights from their study relevant to infill

development were (1) the degree of permeability anisotropy should be considered in the development of coalbed methane reservoirs, and (2) optimum field development should consider the interference effects resulting from various well spacing strategies.

4.3G Fruitland Coal Predicted Development

The two simulation models mentioned above were primarily directed towards the over-pressured region; however, the initial target for development is expected to be the under-pressured region. The key factor is the heterogeneous, discontinuous nature of the upper coal beds. Subsequently, an increase in the density of wells will capture these interwell coal beds and thus more efficiently drain the reservoirs. Suspected differential depletion augments this conclusion. In a multilayer reservoir, continuous coal seams will be preferentially depleted by numerous wells, while other layers (laterally smaller and discontinuous) will not.

Further evidence supporting infill drilling is the poor recovery estimated from coal bed wells. The inefficient pressure depletion mechanism results in recoveries of less than 50% of the gas-in-place. Latest work presented by various operating companies at an NMOCD - organized meeting (April 2001) confirms both the inefficient drainage and the discontinuous nature of the upper, thin coal beds in the under-pressured region. Both simulation modeling and volumetric methods were applied.

In summary, due to inefficient depletion, heterogeneity, and the potential positive effects of well interference, infill drilling to 160-acres per well seems justified. The likely area to begin this trend is in the under-pressured region. Available 160-acre locations for the under-pressured region of the Fruitland coal are **2,079**. Combine this estimate with the **885** locations still available on 320-acre spacing and total development is **2,964** potential locations. In the under-pressured region the cumulative production per well is low at 0.34 Bscf/well, especially in comparison to the over-pressured region. Estimated ultimate recovery for these wells is 0.85 Bscf/well, but this should be considered with caution because limited information is available at this time to accurately determine ultimate recovery for under-pressured coal wells.

4.2 Pictured Cliffs Sandstone Reservoir

4.2A Stratigraphy

The Pictured Cliffs Sandstone is a shoreface sand unit that marks the final northeastward regression of the Cretaceous Western Interior Seaway. It is bounded by the Fruitland Formation above and the Lewis Shale below and intertongues locally with either or both formations (See Figure 4.1-1). Litho-stratigraphically, the Pictured Cliffs Sandstone can be divided into an upper unit of predominantly massive sandstone and a lower part, the "PC transition", composed of interbedded Pictured Cliffs-like sandstone and Lewis-like marine shale (Fassett and Hinds, 1971).
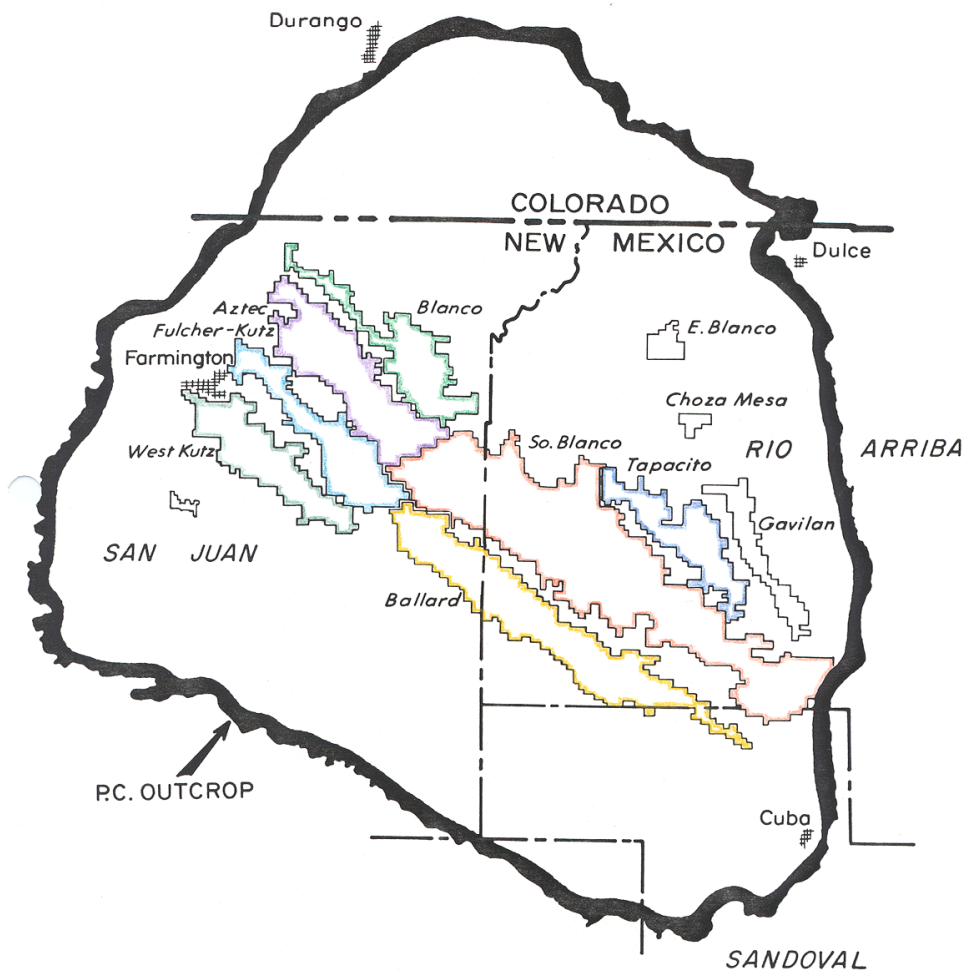
4.2B Statutory Definition

With infill and delineation drilling, the various pools of the Pictured Cliffs Sandstone reservoir have effectively coalesced over time (Figure 4.2-1). These pools are spaced at 160 acres per well. Sandstone beds that intertongue with the lower Fruitland Formation or Lewis Shale are considered to be part of the Pictured Cliffs reservoir. Operators are allowed to commingle Pictured Cliffs and Fruitland Formation sandstone, where present, due to similar gas composition, formation pressure conditions, and because both zones typically yield marginally economic completions.

4.2C Reservoir Characteristics

The sandstone beds of the Pictured Cliffs are medium to fine grained and well sorted and predominantly quartz in composition. Dolomite and calcite are common pore-filling cements as are authigenic clay. Permeability is typically on the order of 10^{-3} md (Whitehead, 1993). The authigenic clay tends to reduce formation resistivity, making productive sands difficult to recognize and, perhaps, hampering full development of the resource. The pools can be highly heterogeneous in water saturation, thickness, distribution and natural fracture density. Along the edges of the play, productive thin (3-15 feet) sands may overlie more massive "wet" sands (Jacobs, 1977).

4.2D Historical Development

The Pictured Cliff reservoirs began production in the 1950s on 160 acre spacing. As development continued the separate pools coalesced, defining an obvious northwest to southeast trend as shown in Figure 4.2-1. Cumulative production to July 2000 has been 3.5 Tscf from 4,500 wells. Figure 4.2-2 shows the well development over time since the date of initial production in 1952. The data presented is the number of active wells averaged over the year. A detailed well count per month since 1/1/1970 is presented in Figure 4.2-3. The majority of wells were drilled in the mid to late 1950s, as part of the initial development of the reservoir. The maximum number of active wells was in 1984. Since 1992 the number of wells has been constant at approximately 4000 producing wells.

Durango

COLORADO
NEW MEXICO
Dulce

Aztec
Fulcher-Kutz
Farmington
Blanco
E. Blanco
Choza Mesa
So. Blanco
West Kutz
Tapacito
RIO   ARRIBA
Gavilan
SAN   JUAN
Ballard
P.C. OUTCROP
Cuba
SANDOVAL

Figure 4.2-1 Outline of major San Juan Basin Pictured Cliffs pools
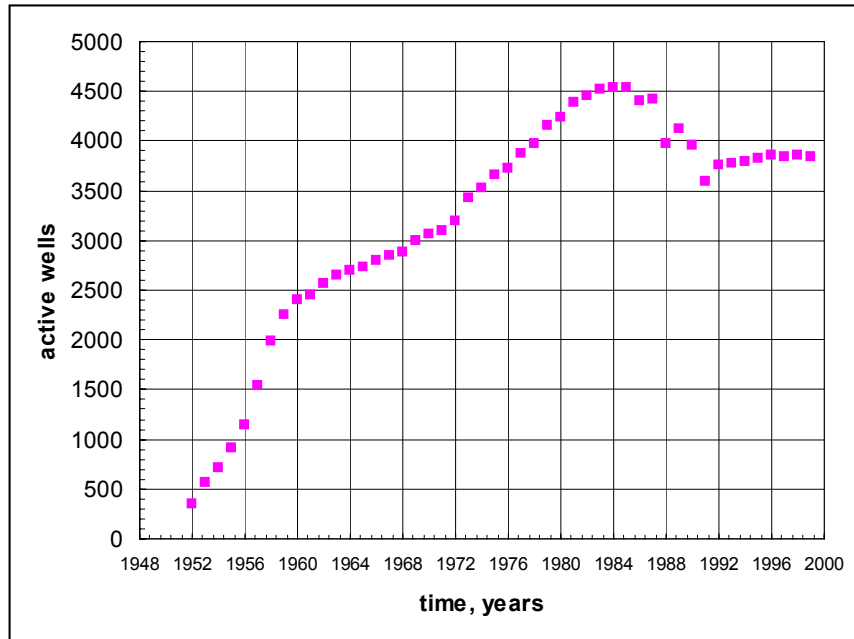
Figure 4.2-2 Historical well development since 1952 for major Pictured Cliffs pools.
(Compiled from NM Annual Oil and Gas Reports).
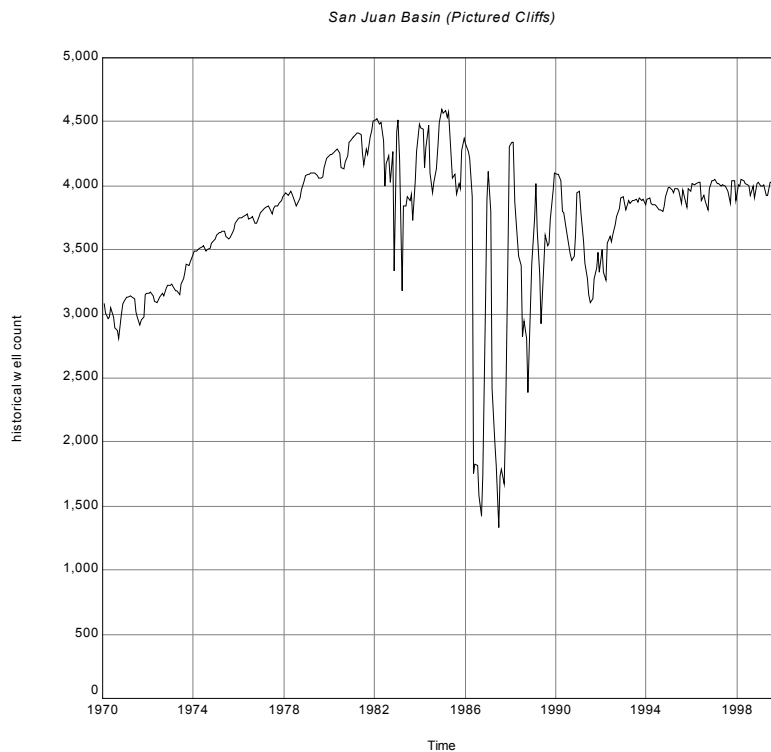
Figure 4-2.3 Historical well count for all Pictured Cliffs pools. (Source: I.H.S. Energy)

Production rate peaked in 1959 at 100 Bscf/year (See Figure 4.2-4). This rate was more or less constant for 20 years until the early 1980s when it began to decline. The time period of the maximum number of producing wells coincides with the minimum production rate during the mid-1980s. Figure 4.2-5 is a monthly plot of production rate. Latest production rate is approximately 6.5 Bscf/month or 53 Mscfd/active well.
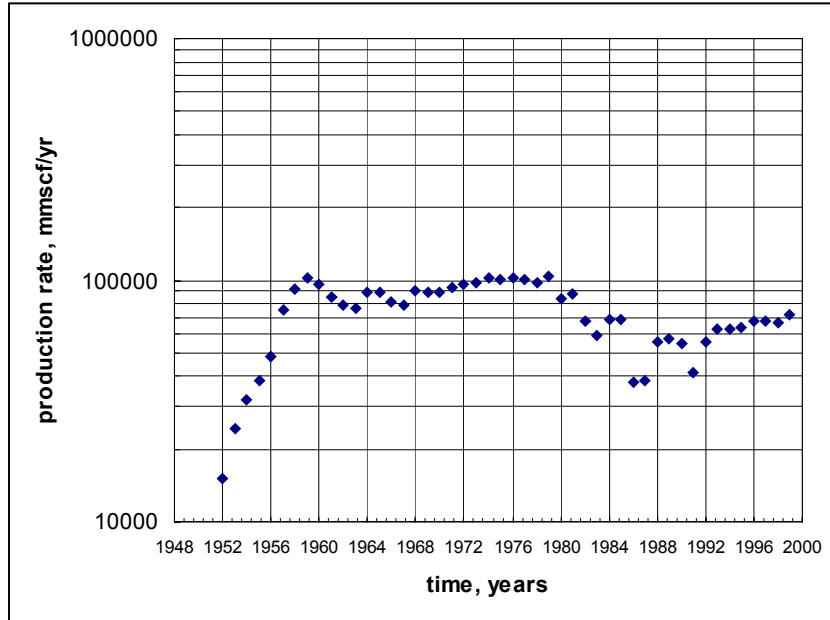
Figure 4.2-4 Annual production for Pictured Cliffs pools
(Compiled from NM Annual Oil and Gas Reports).
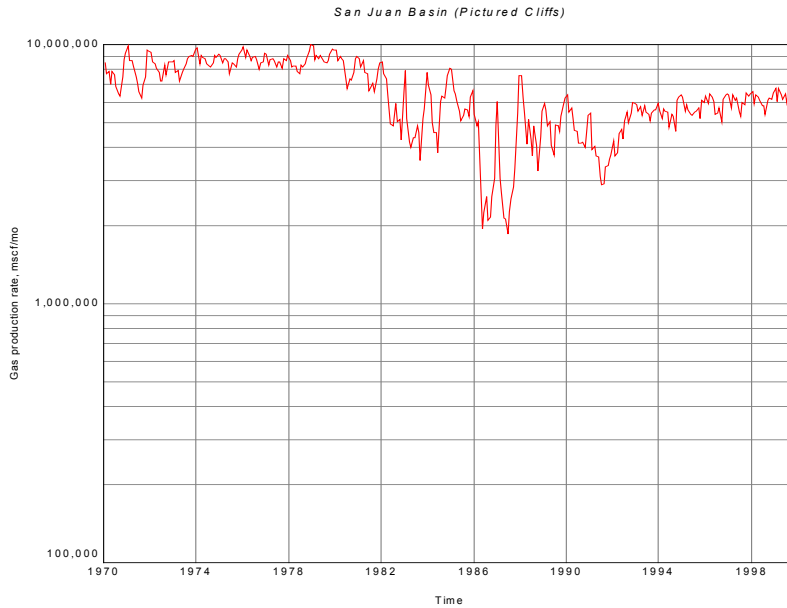
Figure 4.2-5 Monthly gas production rate for all Pictured Cliffs pools. (Source: I.H.S. Energy)

Figure 4.2-6 illustrates the distribution of cumulative recovery per well. The mean is 0.65 Bscf per well. Note the frequency is a decreasing slope from the highest (30%) at lowest recoveries to the lowest (5%) at the best recoveries. This suggests the likelihood of having a below average well is high.
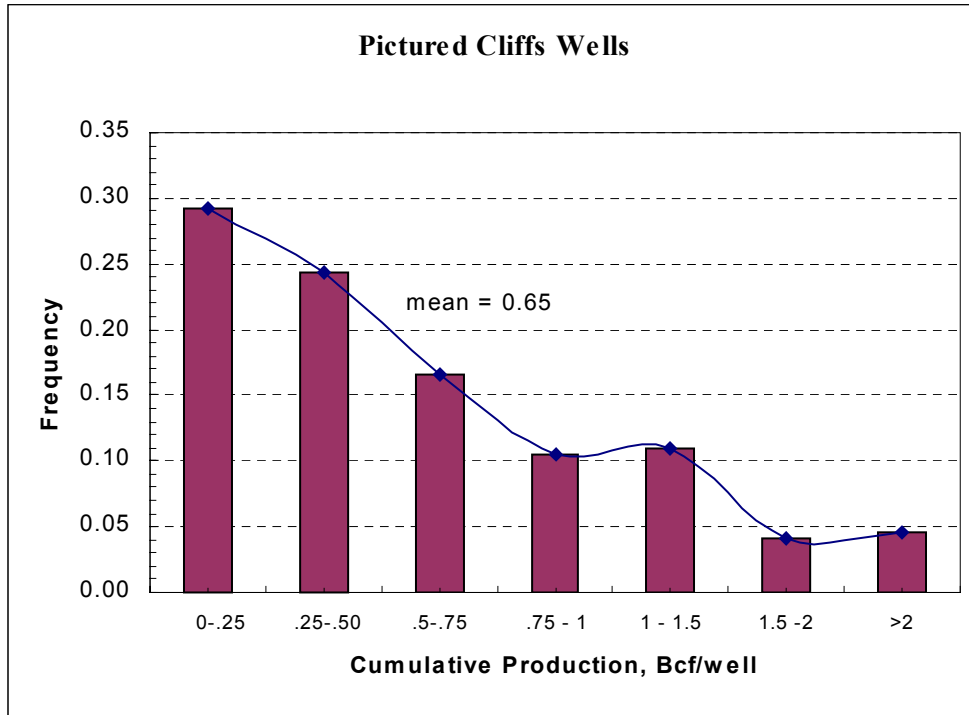
Figure 4.2-6. Distribution of cumulative production per well, Pictured Cliffs reservoir.

4.2E Gas Resources

Proven, developed reserves were estimated to be 0.688 Tscf as of 1/1/91, excluding the commingled Pictured Cliffs/Fruitland Sand wells (Whitehead, 1993). This results in an estimated ultimate recovery (EUR) of 3.64 Tscf (proven reserves + cumulative gas production (Gp) = EUR). As mentioned previously, cumulative production has been 3.5 Tscf; therefore it appears this estimate is invalid. The AGA in 1992 estimated proven developed and undeveloped reserves in their study of **2.538 Tscf** or an EUR of 5.5 Tscf. Cumulative production to date of 3.5 Tscf results in recovery of 64% of the gas-in-place.

4.2F Infill Well Potential

Several investigators have attempted to quantify infill well potential for the Pictured Cliffs [Hugman & Vidas, (1989), Haas & Crist, (1991)]. The 1989 study

proposed infill drilling to 5 wells per section would increase proven reserves by **1.6 Tscf** (3,400 wells * 0.472 Bscf/well). The approach was to calculate EUR from the DOE/EIA reserves to production ratio applied to the final year of production. That is a correlation between the ultimate recovery of the initial and infill wells was developed to predict the EUR of the undrilled infill locations. Figure 4.2-7 illustrates the correlation.
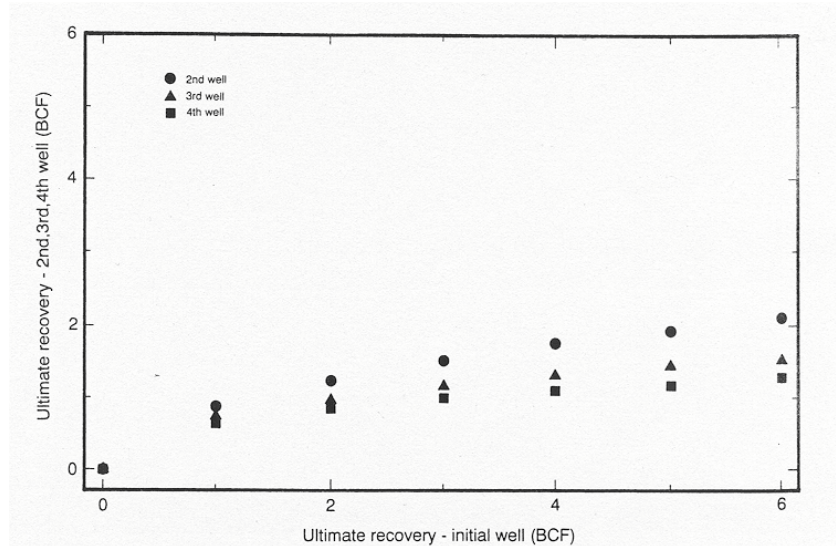
Figure 4.2-7. Predicted recovery of 2nd, 3rd, and 4th well relative to the initial well recovery. (Whitehead, 1993)

Haas and Crist in 1991 estimated gas-in-place of 2.5 Tscf from 3,300 undeveloped locations; i.e., infill and stepout locations. With current technology, the proven, undeveloped reserves assigned to these locations are **1.2 Tscf** (0.363 Bscf/well) or a 48 % recovery factor.

4.2G Pictured Cliffs Predicted Development

Shown in Figure 4.2-8 is the cumulative gas production for the Pictured Cliffs pools. The rapid lateral change in well production indicates a well-defined reservoir boundary.   Consequently, stepout drilling is believed limited, with infill locations the only option. For infill drilling to be viable, an estimate of drainage area from existing wells is necessary. A recent work by Engler (2000) compared drainage area estimated from production decline analysis with gas material balance. This new method is proposed to confirm decline analysis or as an alternative in cases where production is erratic and not reliable. The approach was to model trends in the historical pressure data to obtain reasonable estimates of gas-in-place and drainage area. Figure 4.2-9 is an example illustrating the concept. Results varied from 70 to 120 acres in calculated drainage area. This wide variance illustrates the low permeability, heterogeneous nature of the reservoir. Further evidence of heterogeneity was discussed in the BEG/GRI, Dutton et al.(1993) study in 1993. In the 1993 study, the authors noted the presence of fracture swarms in Pictured Cliffs outcrops. These swarms are discontinuous in

magnitude and direction and subsequently have implications for drilling strategy and interpretation of production patterns.
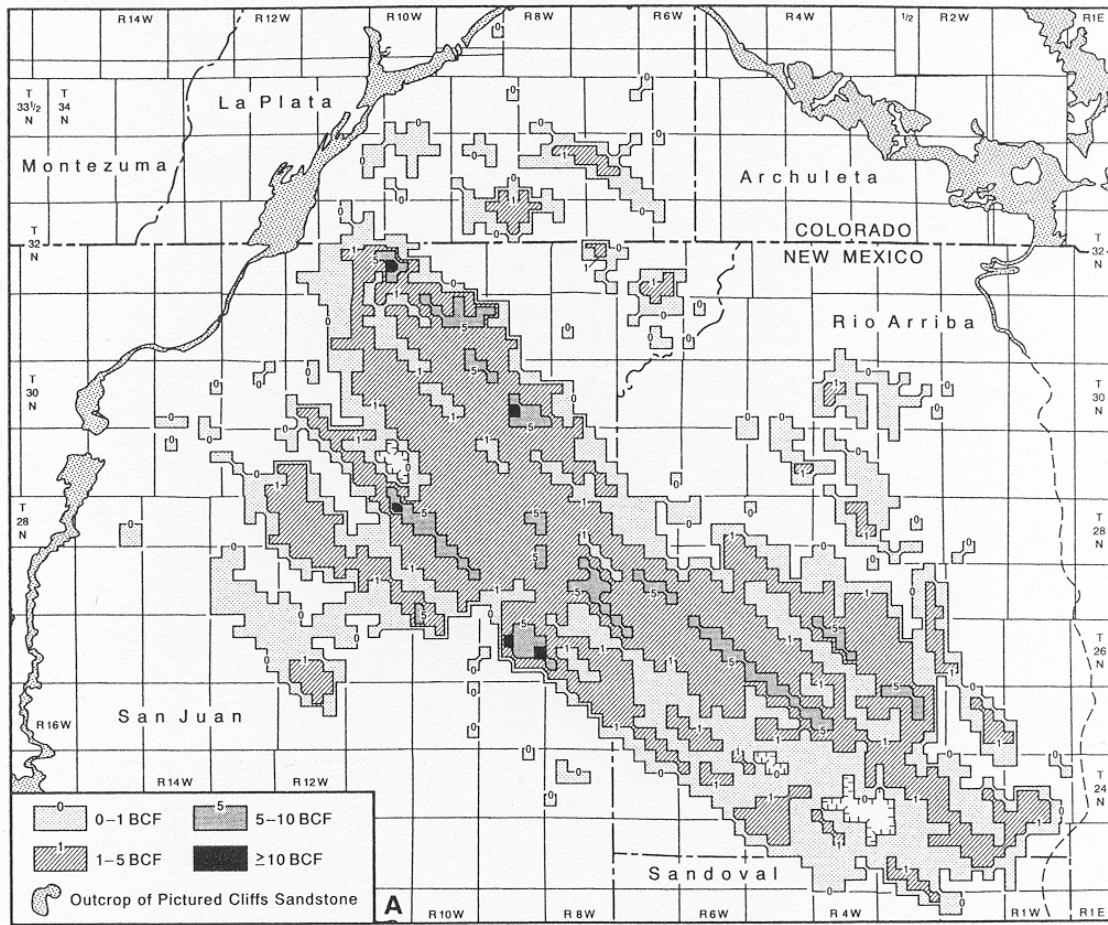
Figure 4.2.8. Cumulative gas production from the Pictured Cliffs Interval (Whitehead, 1993)

P/Z vs. Cumulative Production
No. 114

$y = -0.8367x + 552.88$
$R^2 = 0.958$
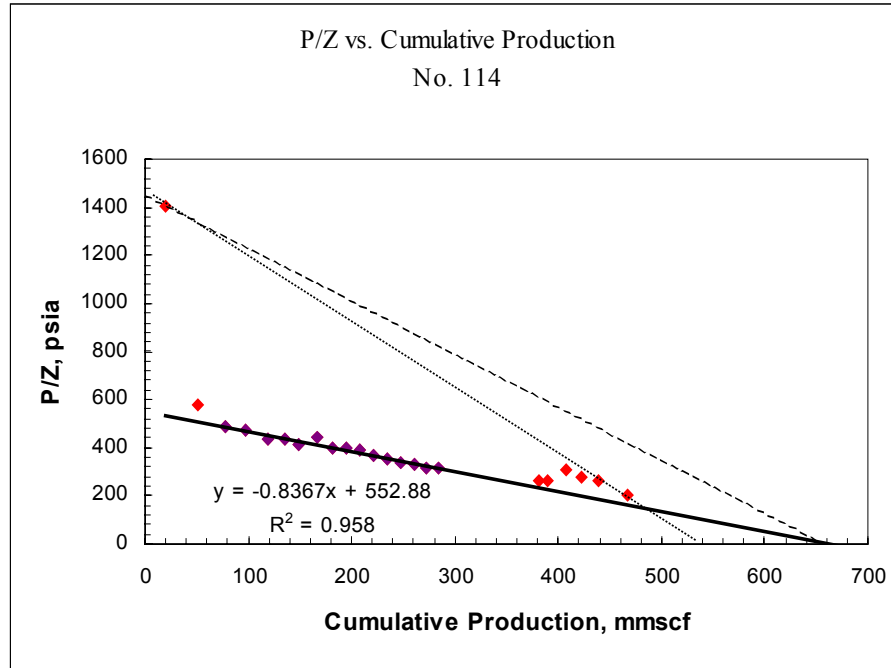
Figure 4.2-9. Modified gas material balance for Pictured Cliffs well. Improved estimate of gas-in-place of 660 mmscf resulted in an estimate of drainage area to be 70 acres. (Engler, 2000)

Engineering analysis does **not** support the widespread potential for 80-acre development of the Pictured Cliffs reservoir **at this time**. Previous investigations have estimated low reserve potential, 0.36 to 0.47 Bscf/well, for infill development. However, as discussed above, the variability in drainage area and the heterogeneous nature of the reservoir suggests further research is warranted to fully understand and develop this reservoir.

Statistical analysis resulted in **1,432** remaining 160-acre locations identified for the Pictured Cliffs. Due to the well-defined reservoir boundary these wells are not an extension of the pools but merely available locations to drill. Average recovery is estimated to be 0.53 Bscf/well, based on analogy from offset production. Since this reservoir is shallow, it is prudent to consider this play as an uphole potential for Mesaverde or Dakota wells; however, this conclusion requires the optimum PC location to be the same as the deeper pay zones. Currently, approximately 15% of wells completed in the Pictured Cliffs are dualed or commingled. This percentage is anticipated to increase as more wells are recompleted to this shallow reservoir.

4.3 Mesaverde Group Reservoir

4.3A Stratigraphy

The Mesaverde Group is bounded by the overlying Lewis Shale and the underlying Mancos Shale (Figure 4.3-1). It is subdivided into coastal shoreface sandstone formations (Cliff House Sandstone and Point Lookout Sandstone), and the alluvial to estuarine Menefee Formation (Collier, 1919). The basal unit, the Point Lookout Sandstone, represents a regressive, basinward (northeastward) migration of the shoreline. The Point Lookout blankets the basin northward into southern Colorado. The Menefee Formation, overlying the Point Lookout, resulted from back-barrier deposition and contains discontinuous sandstone, mudstone and coal beds. A turnaround from regional regression to transgression is marked by the deposition of the Lewis Shale above the Menefee Formation in the north and above the Cliff House Sandstone in the south. The Cliff House Sandstone represents temporary cessation of the regional transgression event so that shoreface sands could redevelop. The La Ventana Tongue of the Cliff House Sandstone ranges from nonmarine to offshore sand bodies deposited during later regressive/transgressive episodes in the southern part of the basin. The strandline-parallel, offshore sand bodies of the La Ventana Tongue are commonly termed "Chacra sands".
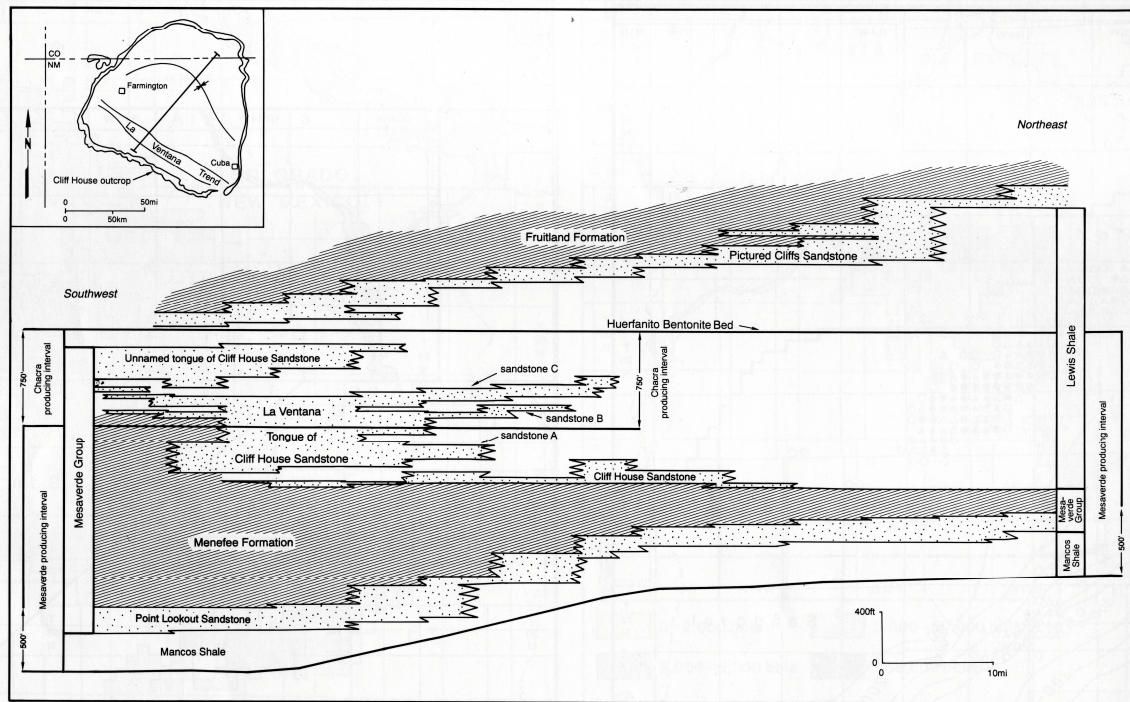
Figure 4.3-1: Cross-section depicting generalized stratigraphy for the Mesaverde Group and the statutory Mesaverde reservoir intervals north and south of the Chacra line (after Whitehead, 1993).

4.3B Statutory Definition

The Mesaverde Group reservoir includes the various producing intervals of the Blanco Mesaverde pool (New Mexico) and Ignacio-Blanco Mesaverde field (Colorado). In New Mexico, the upper vertical limit of the Mesaverde reservoir is defined differently in two areas separated on the basis of the "Chacra line" (Figures 4.3-1 and 4.3-2). North of the Chacra line, the upper limit of the Mesaverde reservoir is the Huerfanito bentonite, a marker within the Lewis Shale. In this northern area, the lower part of the Lewis Shale is statutorily within the Mesaverde reservoir. South of the Chacra line, the upper limit of the Mesaverde reservoir is 750 feet below the Huerfanito bentonite, thus the Mesaverde reservoir includes only the lowermost part of the Lewis Shale. In this southern area, the Chacra reservoir lies within the 750 feet below the Huerfanito marker. In both the northern and southern areas, the lower limit of the Mesaverde reservoir is defined as 500 feet below the top of the Point Lookout Sandstone. The thickness of the Point Lookout varies within the basin, thus, the Mesaverde reservoir incorporates a variable portion of the uppermost Mancos Shale.
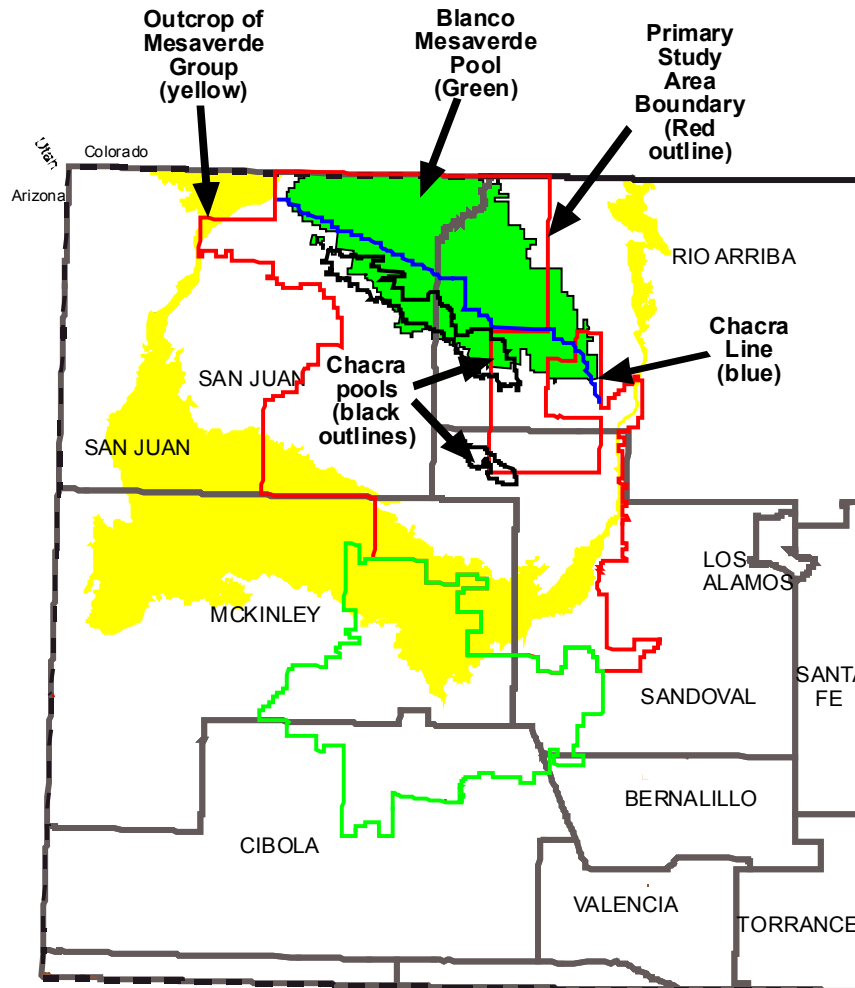
Figure 4.3-2: Map of New Mexico portion of San Juan Basin showing Mesaverde Group outcrop, Blanco Mesaverde pool, Chacra line and Chacra pools.

4.3C Reservoir Characteristics

A range of reservoir characteristics is possible for the Mesaverde reservoir depending upon location. The Point Lookout Sandstone is a relatively uniform blanket-type, low permeability sandstone formation. The Cliff House is similar in reservoir characteristics, but less extensive. The Menefee Formation, on the other hand, although extensive, is highly variable in its characteristics, particularly in terms of sand content, thickness and continuity of sand bodies. The lower Lewis shale and upper Mancos "Point Lookout transition" range from shale to siltstone to sandstone.

For the main pay intervals, the Point Lookout and Cliff House, porosity averages approximately 10%. Matrix permeability is typical of "tight gas" reservoirs and is on the order of 10^{-3} md, requiring hydraulic fracture stimulation for economic production. North-northeast-oriented fractures are common in the Mesaverde and increase the formation permeability by several orders of magnitude in some areas. The best wells in the basin are interpreted to have intersected particularly well connected, through-going fracture sets (Figure 4.3-3).
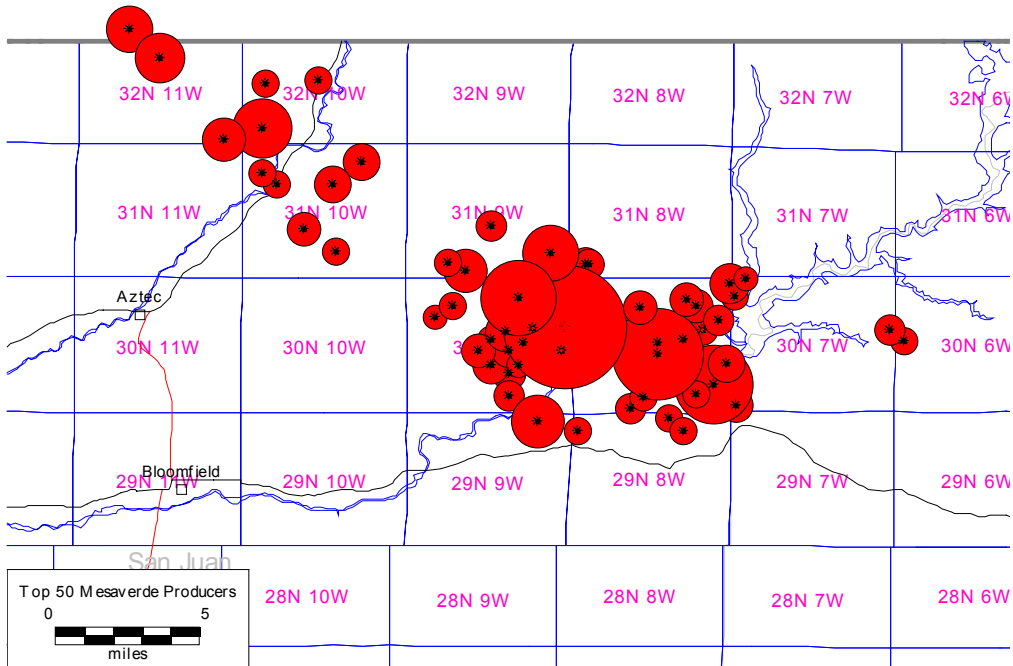
Figure 4.3-3: Cumulative Production bubble map of the top 50 Mesaverde producing wells. (Source I.H.S. Energy) Scale: Largest bubble = 50 Bscf, Range:

Fracture permeability results in permeability anisotropy that yields highly elliptical, north-northeast oriented drainage areas for Mesaverde wells. In infill drilling programs, it is critical that operators consider the potential for severe pressure depletion of certain offset locations due to elliptical drainage. The reservoir characteristics of the

incorporated portions of the Lewis Shale, Mancos Shale are discussed separately in Chapter 5.

The Mesaverde reservoir was initially underpressured with a pressure/depth gradient of 0.23 psi/ft (compared to a normal hydrostatic gradient of 0.43 psi/ft). Low formation pressure challenges operators to cope by drilling wells with underbalanced drilling methods (typically air is the circulating medium) in order to avoid damage that otherwise would result from lost circulation and imbibition if mud or water were circulated. Likewise, the low formation pressure and low permeability characteristics of the reservoir dictate the use of lower viscosity "frac" stimulation systems to reduce formation damage. The primary benefit of "fracs" is to connect the well bore to the more permeable natural fracture networks. The naturally low pressure of the reservoir complicates efforts to drill for, complete and produce deeper formations with the Mesaverde in some areas. Often the Mesaverde reservoir will be protected by an intermediate string of casing prior to drilling deeper; this adds complexity and additional costs to the well.

4.3D Historical Development

The Blanco Mesaverde reservoir was discovered in 1927. Extensive development occurred in the 1950s on 320-acre spacing when the western gas market became available. In the late 1950s and early 1960s, EPNG conducted long term pressure buildup tests, indicating low permeability and low drainage efficiency from the Mesaverde reservoir (Maldonado, et al., 1983). This prompted the request for 160-acre infill development, which was approved in 1974 and began in January 1975 for the Blanco Mesaverde reservoir. Infill development for the Ignacio Blanco Mesaverde reservoir was approved in 1979. Prior to January 1975, approximately 2000 wells were producing on the 320-acre spacing.

In 1997, pilot tests were initiated to determine the feasibility of reducing spacing to 80 acres. A simulation study (Harstad, 1998) revealed the significance of permeability anisotropy to the location of infill wells. The results of the pilot tests coupled with the simulation study prompted the approval of 80-acre spacing for the Mesaverde in 1998. Figure 4.3-4 provides a historical record of the well count with time. Cumulative production as of 1/1/75 was 6.4 Tscf (Figure 4.3-5). As of July 2000, 4750 wells were active producers from the Mesaverde, an increase of 2,750 wells since the reduction in spacing in 1975. Cumulative production for the time period of January 1975 to July 2000 has been 2.9 Tscf. As can be seen from Figure 1, production rate increases after infill well development. Prior to 160-acre spacing, monthly production averaged approximately 20 BSCF. After reducing spacing, a slight increasing trend in production rate is observed (see Figure 2), with a peak rate in 1980 of 27 Bscf/month. Currently (2000), 23 Bscf/month is being produced from the Mesaverde. Cumulative production to July 2000 is 9.37 Tscf.

San Juan Basin (Mesaverde)
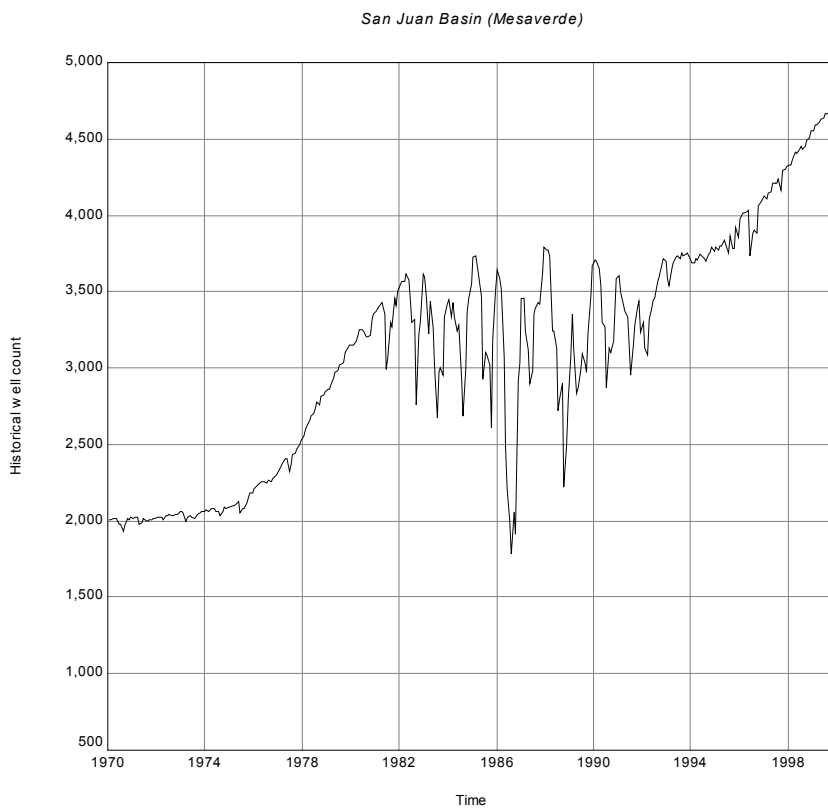
Figure 4.3-4 Historical well count from 1970. Note increases due to spacing changes in 1975 and 1997. (data from I.H.S. Energy)

San Juan Basin (Mesaverde)
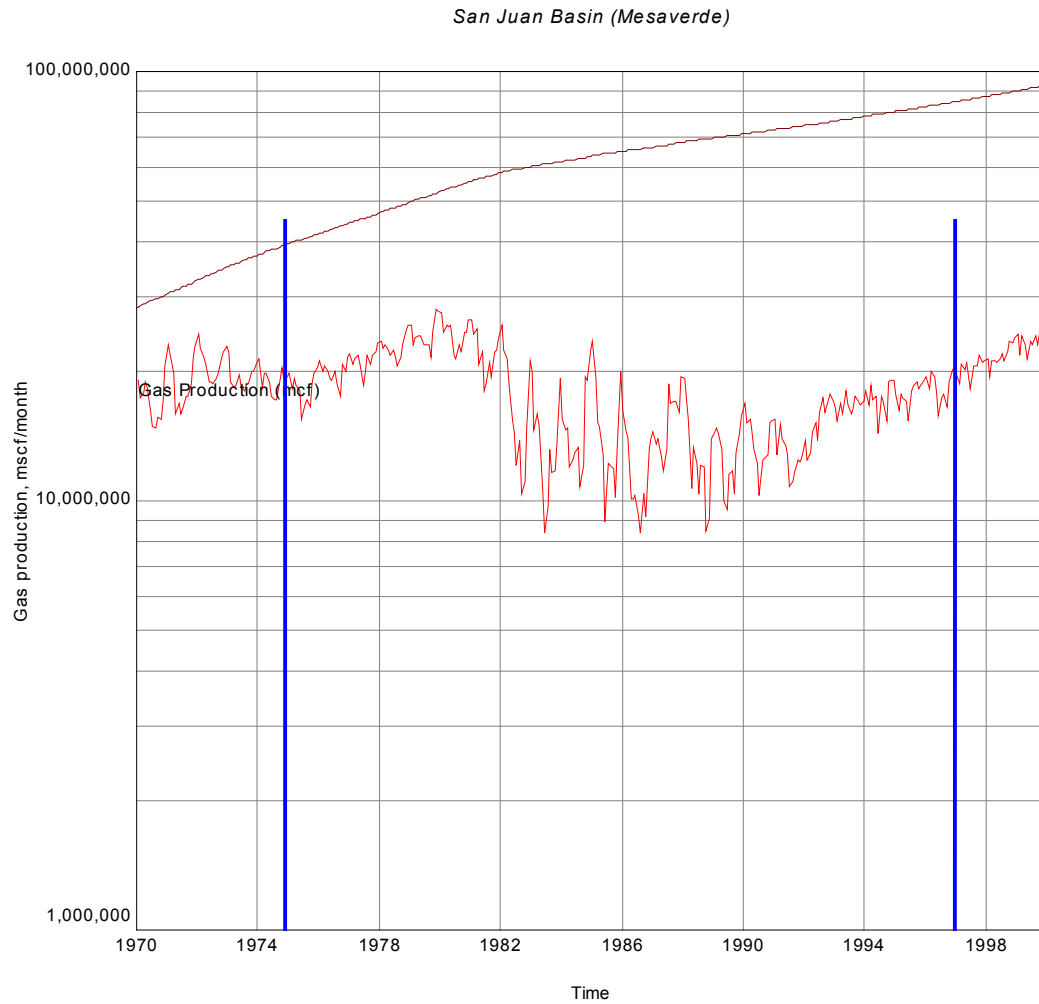
Figure 4.3-5 Mesaverde gas production per month from 1970. (data from I.H.S. Energy)

4.3E Gas Resources

A chronological list of reserve estimates from the Mesaverde follows.

- 1975   EPNG
   As part of the hearing for infill drilling to 160-acres, EPNG presented the following data,

$$
\begin{array}{ll}
\text{EUR} & = \ 8.7 \ \text{Tscf for existing 320 acre wells} \\
\underline{\text{EUR}} & = \ \underline{6.3 \ \text{Tscf}} \ \text{incremental for 160 acre development} \\
& \ \ 15.0 \ \text{Tscf}
\end{array}
$$

- 1992   AGA
   Proven developed and undeveloped reserves as of 1/1/92 of 7.765 Tscf.

- 1992   Hugman and Others in BEG/GRI, Dutton et al. (1993) study
   EUR = 12.315 Tscf

The increase in reserves attributed to the 160-acre infill drilling development has been the source of much debate. Arnold, et al. in 1978 compared the pressure information from the first 250 infill wells to current pressure of the adjacent original wells and calculated an incremental increase in developed and undeveloped reserves of 2.377 Tscf. Cumulative production of 2.9 Tscf since 1975 has surpassed this estimate and made it obsolete. Also in that study, it was observed that in the central part of the reservoir the difference in pressures between the infill and original wells was less than the difference for infill wells on the margins of the productive area. Essentially, the margin wells achieved original pressure. This leads to the conclusion of better infill prospects in lower quality, more heterogeneous areas where drainage area is small.

Van Everdingen and Kriss (1980) and Sinha (1981) argue the infill well development increased the rate of recovery of existing reserves, but did not improve the ultimate recovery. Sinha (1981) suggests that previous reserve estimates are based on reservoir pressures lower than that observed in infill wells, and therefore would result in conservative reserve estimates of 30 to 35%. A gas material balance plot in Figure 4.3-6 illustrates the concept. Notice the higher reservoir pressures in infill wells will result in an increase in recovery.
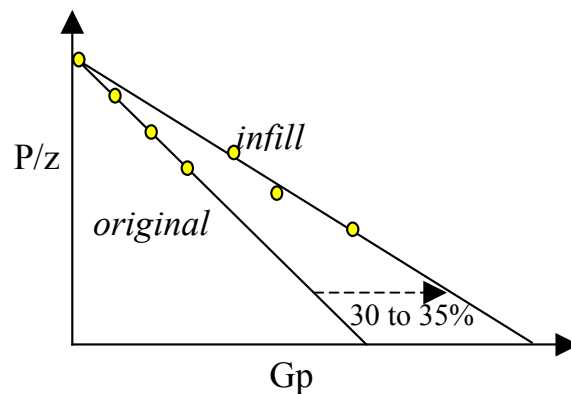
Figure 4.3-6. Schematic illustrating increase in reserve estimates due to increased pressure in infill wells.

4.3F Infill Well Potential

Recent work has lead to the conclusion that 160-acre infill wells may not be sufficient to efficiently drain the Mesaverde, and that further infill drilling to 80-acre spacing is warranted. Harstad in 1998 performed reservoir simulation on several pilot areas to quantify the infill drilling potential. Each pilot area had different fracture intensity and therefore different producing characteristics. Results of this study illustrated the significance of permeability anisotropy in drainage area and shape and subsequent infill drilling. With a calibrated reservoir model developed from the existing

160-acre wells, further development strategies were investigated. Results from the model predict 80-acre infill wells can recover approximately 1 BSCF/ infill well.

Post-evaluation of the pilot programs was performed by Al-Hadrami (2000) and Kelly (2000). Al-Hadrami applied reservoir simulation on two pilot areas to assess the infill well program. The reservoir model included permeability anisotropy in a slightly east of north orientation. This model was verified through history matching of the 160-acre development. Further verification was achieved by history matching the 80-acre development without adjusting any of the model parameters. Predictions from this point forward resulted in 26 to 44% increase in recoverable gas over the next 30 years. The importance of considering anisotropy was clearly demonstrated by predicting recovery for wells aligned with the maximum horizontal permeability direction of nearby existing wells. The result was a reduction in recoverable gas by 17 to 34%. Extrapolation of the results from these two pilots across the Mesaverde producing area, provides a preliminary estimate of an additional 7.8 Tscf that could be recovered by optimal infill drilling.

Kelly (2000) developed an Infill Well Location Calculator (IWLC) to determine the optimum infill well location. Unlike simulation, a minimum amount of input data is required, therefore making the program simple and easy to apply. This method seeks the permeability anisotropy until achieving an automatic history matching of the production data. A test of the IWLC in the Mesaverde verified the location of the existing 80-acre well and reasonably predicted the initial gas rate.

A statistical study of the reduction in spacing on cumulative production from Mesaverde gas wells is shown in Figure 4.3-7. The first group of wells; drilled prior to 1/1/75 on 320 acre spacing, exhibit a normal distribution with a mean of 3 Bscf per well. The most probable situation exists in the 1 to 2 Bscf per well range, with approximately a one in five chance. Note the large frequency of wells in the 5-10 Bscf range is an artifact of the range selected and not the reservoir.

The second group of wells was selected to target the 160-acre development. This includes wells, which first began production after 1/1/75, but also were drilled prior to 1/1/98. The majority of the recent wells (1/1/98 to present) are considered to be a part of the 80-acre development and therefore were excluded. As shown in the figure, a normal distribution is evident, with a mean of 1.1 Bscf per well. The most probable scenario is to produce 0.5 to 1.0 Bscf per well

The result of this statistical study show a Mesaverde well on 160-acre development will average 1.1 Bscf per well. This is approximately one-third the recovery of the initial 320-acre development. The recent 80 acre development is too new for analysis; however recall the expectation is to recover 1 Bscf/well, approximately the same as a 160-acre well.
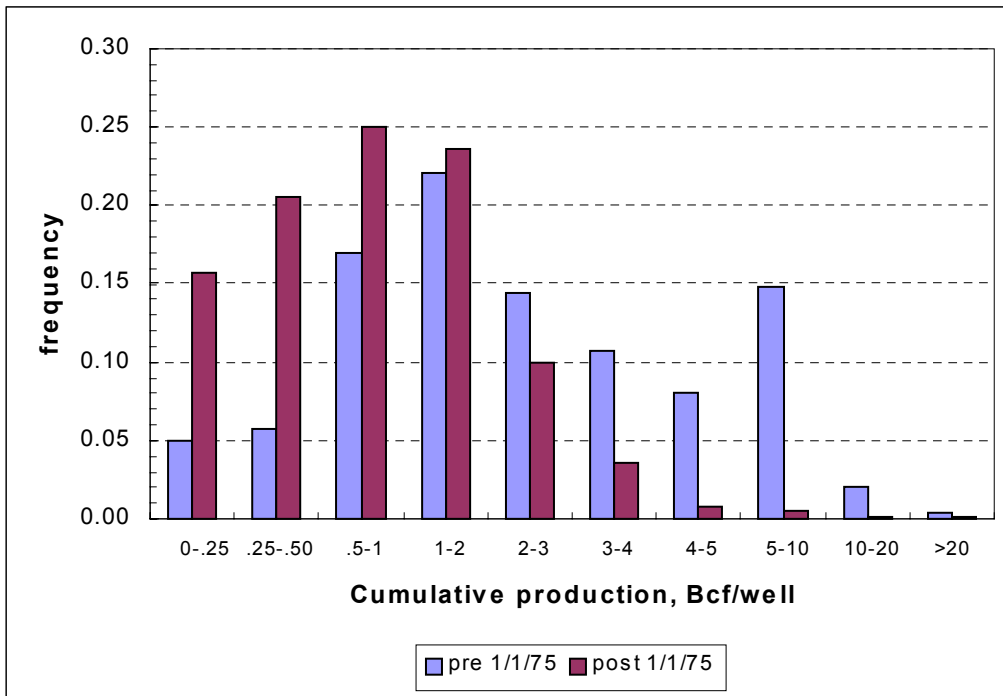
Figure 4.3-7 Comparison of cumulative production per well for development on 320-acre spacing (pre 1/1/75) and 160-acre spacing (post 1/1/75 to 1/1/98).

4.3G Mesaverde Predicted Development

Figure 4.3-8 is a 1993 cumulative production map of all Mesaverde wells from Whitehead (1993). Identified on this map are the locations of the mesaverde 80-acre pilot program. Notice these pilots coincide with the axis of the best producing wells. The extent of the Mesaverde productive area expands over a large geographic area. Also note, the boundaries are well-defined, therefore infill development is dominant over stepout drilling.
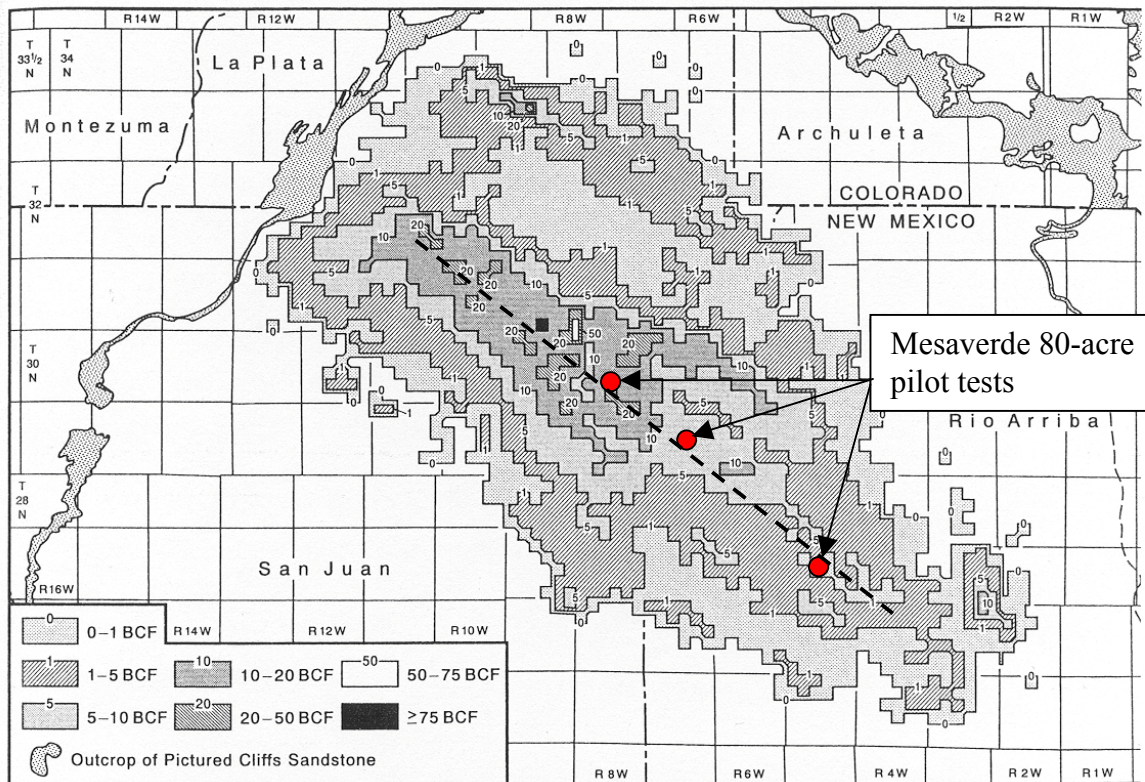
Figure 4.3-8 Cumulative gas production for the Mesaverde producing interval. (Whitehead, 1993)

Predicted Mesaverde development consists of **725** remaining 160-acre locations and **3649** available 80-acre infill locations. The basis of the 160-acre development was to identify locations on a township-range scale using Figure 4.3-9, updated to current time to reflect the most recent activity. The number of 80-acre locations was based on total available locations within the confined productive area, but reduced by 2/3 for edge wells and for sweetspot areas along the fairway axis. The former is to account for poor reservoir quality and heterogeneity along the boundaries of the productive area. The latter is to account for drainage effects from prolific producers in the fairway, as eluded to previously by Arnold, et al. (1978).

The Mesaverde is a likely target for commingling or dual completions; thereby reducing the impact of this development. Approximately 25% of new Mesaverde completions are commingled/dual completed. This percentage is anticipated to rise as 80-acre development continues in the Mesaverde and with the potential of 80-acre development in the Dakota.
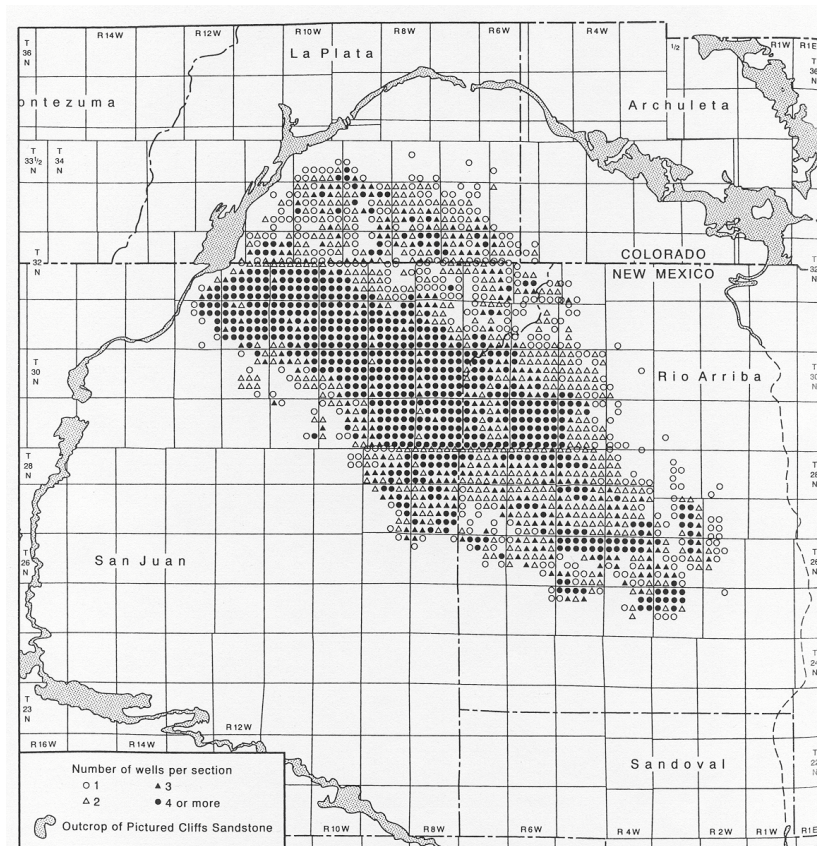
Figure 4.3-9. Well density of the Mesaverde reservoirs. (Whitehead, 1993)

4.4 Dakota Sandstone Reservoir

4.4A Stratigraphy

The Dakota Sandstone and adjacent units are illustrated in Figure 4.4-1. There is significant stratigraphic variability within the statutorily-designated reservoir interval, but most of the gas in the reservoir is produced from the marine members of the upper part of the Dakota Sandstone. The upper Dakota Sandstone intertongues with the Mancos Shale, whereas the lower contact is typically an erosional unconformity where the nonmarine lower Dakota overlies the Burro Canyon or Morrison formations.

W (LANDWARD)   (SEAWARD) E

GREENHORN LS. MBR. — D

GRANEROS SH. MBR. — C

TWOWELLS SS. MBR.

WHITEWATER ARROYO SH. MBR. — B

PAGUATE SS. MBR.

CLAY MESA SH. MBR.

CUBERO SS. MBR.

OAK CANYON MBR. — A

Source: Owen and Head, 2001, (Field trip guidebook)

DAKOTA SS., MAIN BODY

ENCINAL CANYON SS MBR. — K-2

BURRO CANYON FM.

K-3

MORRISON FM. — K-1

SCHEMATIC CROSS-SECTION OF SAN JUAN BASIN DAKOTA SANDSTONE & ADJACENT UNITS
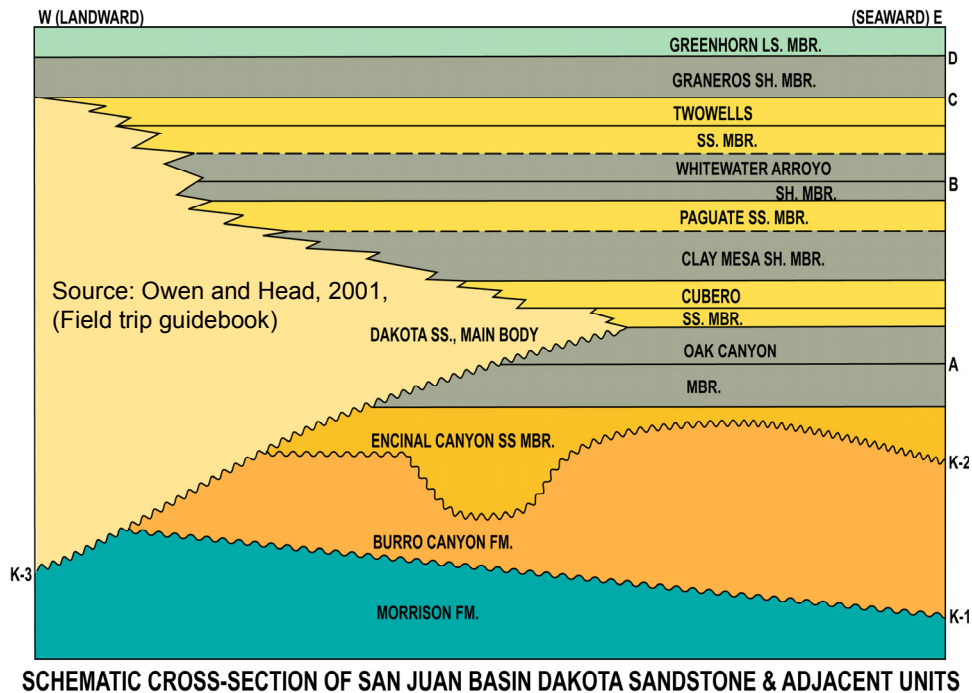
Figure 4.4-1 Stratigraphic section of the Dakota Sandstone and adjacent units Owen and Head (2001). Letters A,B,C,D, and E are bentonite time markers.

4.4B Statutory Definition

The top of the Basin Dakota pool (Figure 4.2-2) in New Mexico is defined as the base of the Greenhorn Limestone of the Mancos Shale. The base of the interval is defined as 400 feet below the top.   Varying by location, this interval generally includes the Graneros Shale (lowermost Mancos Shale), marine and nonmarine sandstone, shale and coal of the Dakota Sandstone, the nonmarine Burro Canyon Formation and the upper part of the Morrison Formation.   Current spacing is 160 acres per well.
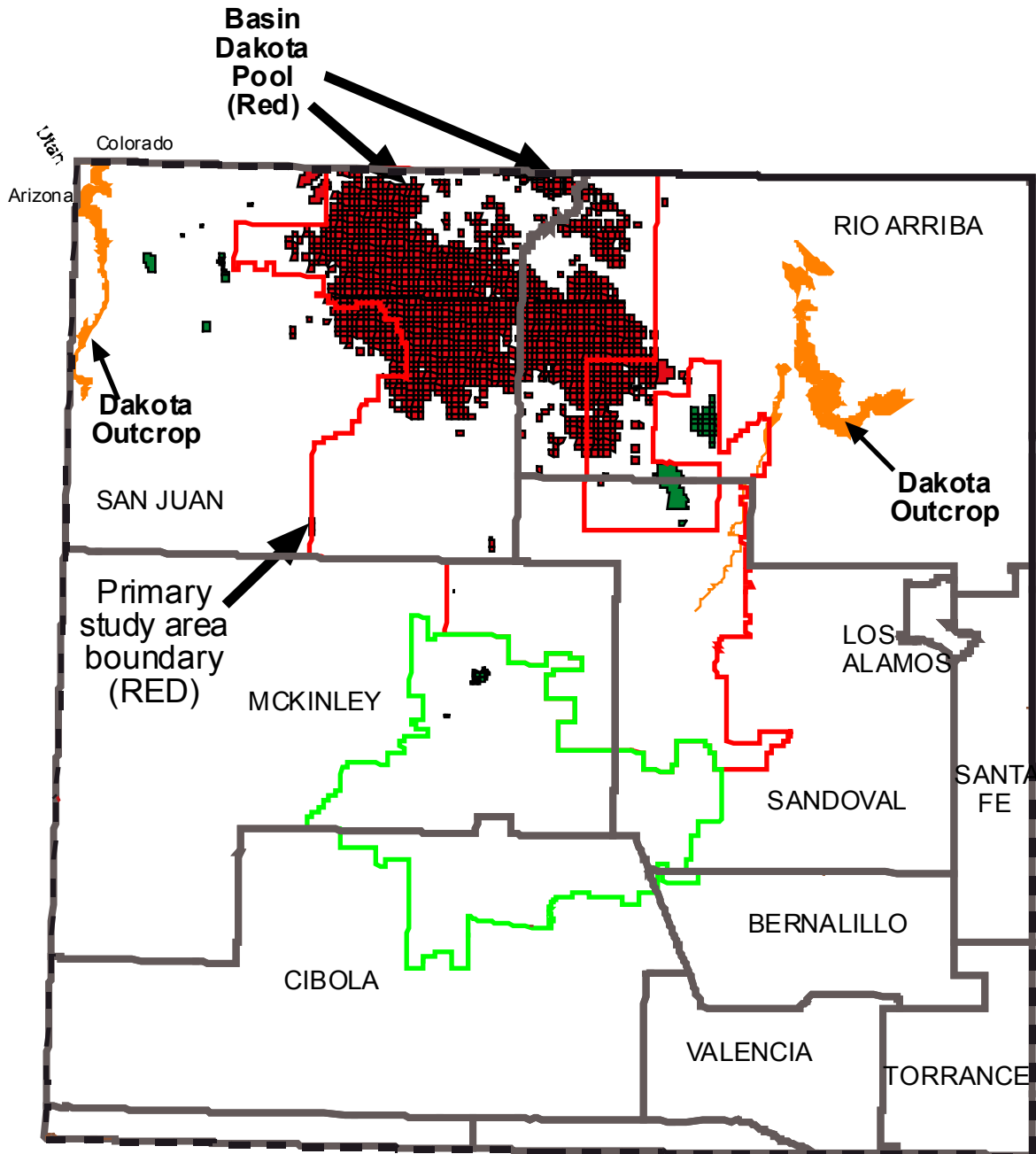
Figure 4.4-2   Dakota Sandstone reservoir pools in the San Juan Basin. (Red = gas, green = oil).

4.3C Reservoir Characteristics

The Dakota Sandstone is a basin-centered, low permeability stratigraphic gas reservoir flanked by shallower fractured oil reservoirs on/outside the basin margins. In petroleum system terms, the Dakota is closely linked to the Mancos Shale, the primary source rock for Dakota hydrocarbons.   The variety of depositional environments and

stratigraphic units included in the Basin Dakota pool add complexity to the reservoir. The most important Dakota reservoir rocks, Dakota marine sandstone beds, tend to be quartz rich and silica cemented. In general, these very low permeability marine sandstone units are reliably gas charged, whereas the better reservoir-potential facies tend to have higher water saturation and are often avoided in well completions. Permeability of the reservoir varies with depth, but is typically in the range of 10^{-2} to 10^{-4} md. Porosity is similarly variable but usually 4 to 8%. As with other major San Juan Basin reservoirs, natural fracture networks enhance the effective permeability of the reservoir and cause permeability anisotropy. Dakota sandstone reservoir pressure is generally near normal pressure in contrast to the underpressured Mesaverde Group.

4.4D Historical Development

The Basin Dakota Pool was created in 1960 by consolidating numerous small Dakota reservoirs. Original spacing was 320 acres. In the late 1970s, long term, shutin buildup tests conducted by El Paso Natural Gas demonstrated the low permeability of the Basin Dakota reservoir (Maldonado, et al.,1983). Subsequently, the company applied for and was granted a reduction in spacing to 160 acres in 1979. Average shutin pressure of the first 750 infill wells was greater than 800 psi, which was greater than the current pressure for the original wells in the spacing unit. This success has been attributed to the reservoir heterogeneity or improved fracture stimulation techniques or a combination of the two.

The Basin Dakota reservoir contained approximately 2,460 wells drilled on 320-acre spacing in 1979. At that time (1/1/79) the cumulative production was 3.0 Tscf. Since then a total of 5,240 wells have produced from the Dakota reservoir, or an additional 2,780 wells have been drilled as infill or stepout development wells since the spacing change in 1979 (see Figure 4.4-3). Cumulative production to July 2000 has been 5.54 Tscf. Monthly gas production rate is shown in Figure 4.4-4 versus time since 1970. The maximum rate was approximately 20 Bscf/month in 1971. Note the infill development arrested the decline and slightly increased rate briefly.
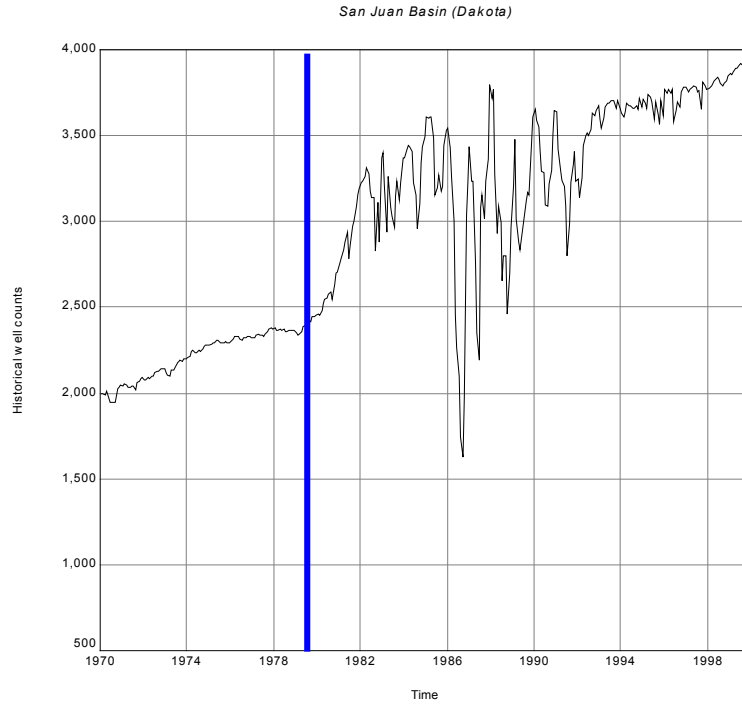
Figure 4.4-3 Historical well count (all wells) from 1970. Note increase due to spacing change in 1980. (data from I.H.S. Energy)
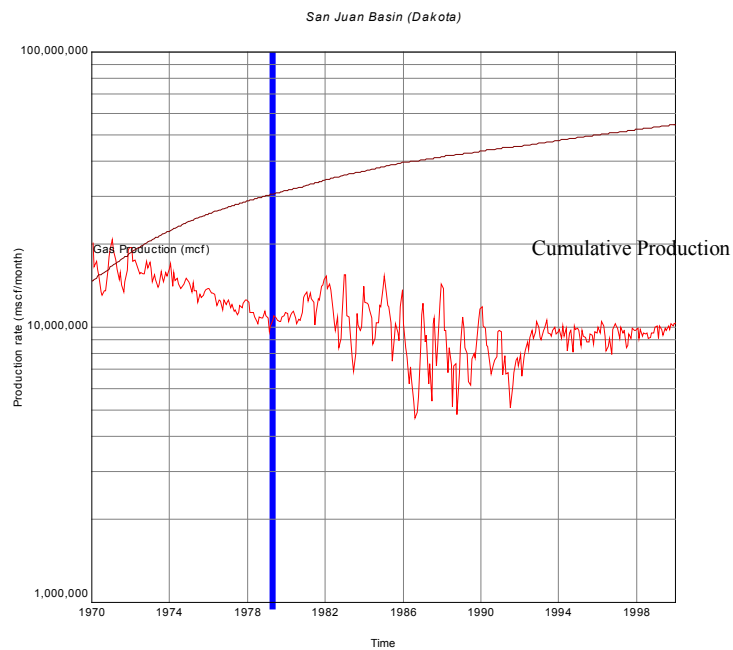

Figure 4.4-4 Dakota gas production per month from 1970. (data from I.H.S. Energy)

4.3E Gas Resources

Numerous estimates of ultimate recovery have been published over the years, with quite variable results. Below is a chronological list of the various estimates.

- **1978** *Lewin and Associates*   GIP = 15 Tscf   EUR = 12 Tscf
  Area studied was 830 square miles. Prior to reduced spacing.

- **1979** *EPNG*   EUR = 12.5 Tscf
  Attributed 8.0 Tscf to the original 320-acre wells, and an incremental recovery of 4.5 Tscf for the infill well development.

- **1980** *NPC*   Remaining reserves = 3.3 Tscf
  Considered a thin band of productive area (1,188 square miles) on the perimeter of the basin, thus excluding the defined producing area. (Source: Haas and Crist)

- **1989** *Hugman & Vidas*   EUR = 2.9 Tscf
  Recovery is for infill wells developed as of 1985, 1,995 sections; thus only for areas partially developed. (Source: Haas and Crist)

- **1991** *Haas & Crist* Remaining GIP = 11.1 TCF   EUR = 4.3 Tscf
  Remaining GIP and EUR for undeveloped areas (1,639 sections) both as infill development and stepouts. Cumulative production as of 1/1/91 was 4.46 Tscf; thus EUR = 8.76 Tscf

- **1992** *AGA*   Proven developed and undeveloped reserves = 5.046 Tscf
  Cumulative production of 4.55 Tscf as of 1/1/92 results in EUR = 9.6 Tscf

- **1993** *BEG/GRI, Dutton et al.(1993)*
  EUR = 7.322 Tscf
  EUR for existing wells (Source: Hugman & Others,1992)
  Additional 2.2 Tscf of recoverable gas is estimated to exist from outside present field limits (NPC, 1980).

It seems logical to assume the more current the estimate the higher degree of accuracy since more data (and time) are available for the analysis. The 1993 study suggests a moderately high recovery factor to date of 76% (5.54/7.322) for a low-permeability sandstone reservoir. On the other hand, the 1992 AGA study would result in a 58% (5.54/9.6) recovery factor to date. Continued production will increase the recovery factors with time.

A more important factor is the volume of recoverable gas attributed to the infill development begun in 1979. Estimates from the information above range from 2.9 to 4.5 Tscf. Compare these estimated with the actual production to date of 1.2 Tscf from all wells drilled since 1/1/79, and the conclusion is the initial estimates were over-optimistic. Even more revealing is the distribution of recovery per well for wells drilled prior to and after 1/1/79, as shown in Figure 4.4-5.
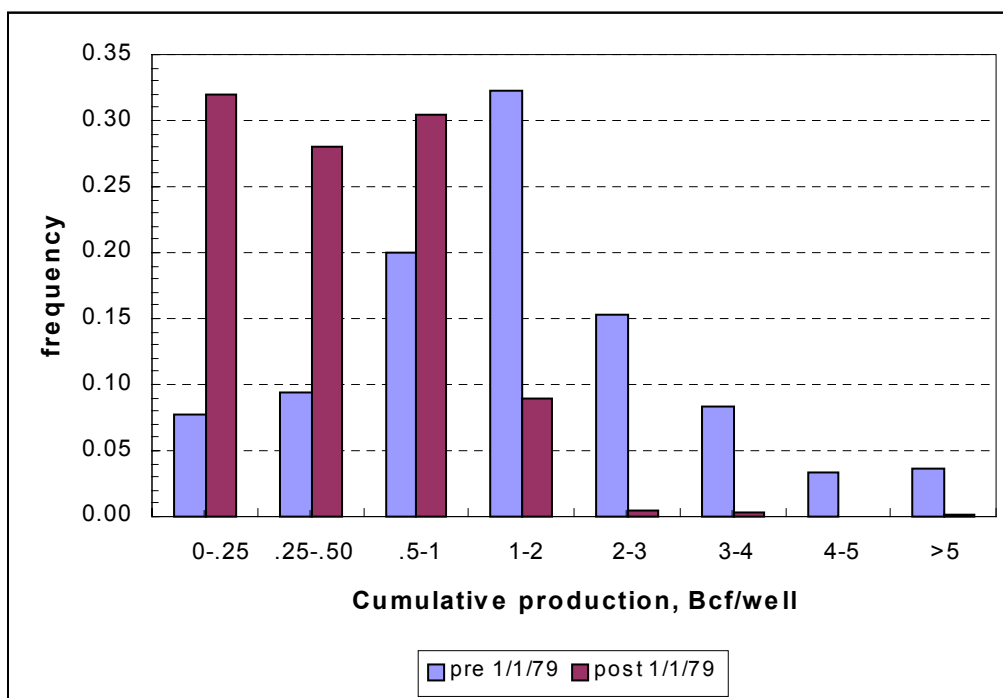
Figure 4.4-5 Comparison of distribution of cumulative production for Dakota wells drilled prior to and after 1/1/79.

Wells drilled prior to 1/1/79 recovered on average 1.7 Bscf/well. The probability of finding an average well is approximately one in three. Wells drilled after the 1/1/79 date have an average recovery of 0.50 Bscf/well. In comparison with the old wells, the probability of finding a well within the 1 to 2 Bscf range is approximately one in ten and it is likely a newer well will produce 1 Bscf or less. A caveat to this analysis is the very recently drilled wells; within the last five years, have low cumulative production with significant remaining reserves still yet to be produced. These wells will shift with time to the right in Figure 4.4-5. However, the majority of the post 1/1/79 wells were drilled within five years of the spacing change and therefore have produced for approximately 20 years. Little change is expected from these wells.

4.3F Infill well potential

Several recent works have attempted to define the drainage area and hence infill well potential for the Dakota reservoir. [Ouenes,et al. (1998), Sunde, et al.,(2000), Jaramillo, (2000), Medford (2000)]. Ouenes et al. demonstrated the application of neural networks in a 24-township area consisting of 2,108 wells. The objective was to investigate the importance of various parameters on predicting EUR. Results showed that thickness and fracture intensity were the dominant factors. Maps were generated to illustrate areas of high potential.

Sunde, et al. used production decline analysis of 500 random wells within the San Juan Basin to estimate gas-in-place. Figure 4.4-6 illustrates the results obtained with respect to date of first production. Note a general decreasing trend in IGIP with time confirming the results seen in Figure 4.4-5. However, substantial scatter does exist within the data therefore precluding any specific observations about drainage.
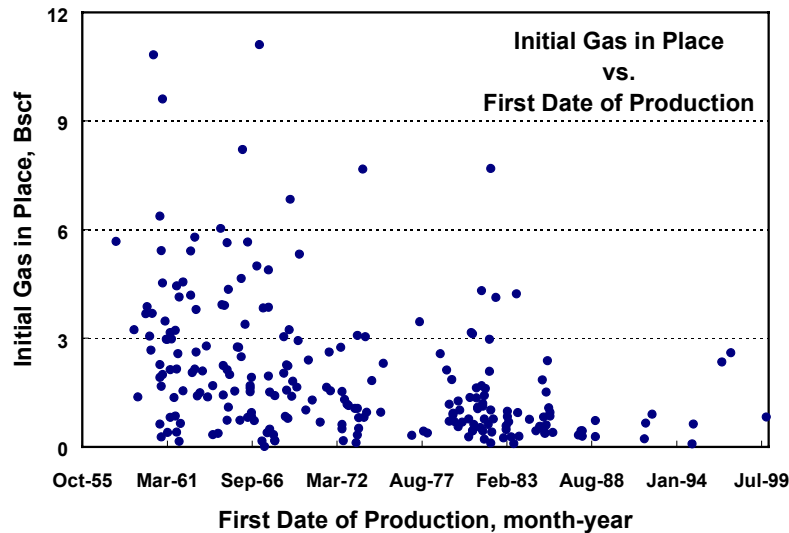
Figure 4.4-6 Initial gas in place for Dakota wells calculated by production analysis (from Sunde, et al., 2000)

Jaramillo and Medford both applied reservoir characterization and simulation to two designated areas producing from the Dakota. These areas are located on the margin of the Dakota producing area and do not represent the fairway. The west area was selected based on the NE – SW production trend coinciding with the direction of channel sand-type deposits. The east area production trend is NW –SE and is parallel to the barrier island-type depositional facies. The objective was to estimate multiwell drainage patterns and infill drilling potential.

The results of the infill study for the two selected areas are significantly different. The east area, defined as a shore parallel facies, has no potential for further drilling. Inversely, the west area is a channel-type deposit with significant potential for infill drilling. Optimization of infill drilling in the Dakota relies upon two interrelated features, the degree of natural fracturing and the depositional facies. After history matching, the model predicted 80-acre infill potential in the west area of 410 mmscf/well, but no infill potential was discovered in the east area, with the best locations resulting in only 250 MMscf/well. The results of the west study area are shown in Figure 4.4-7.
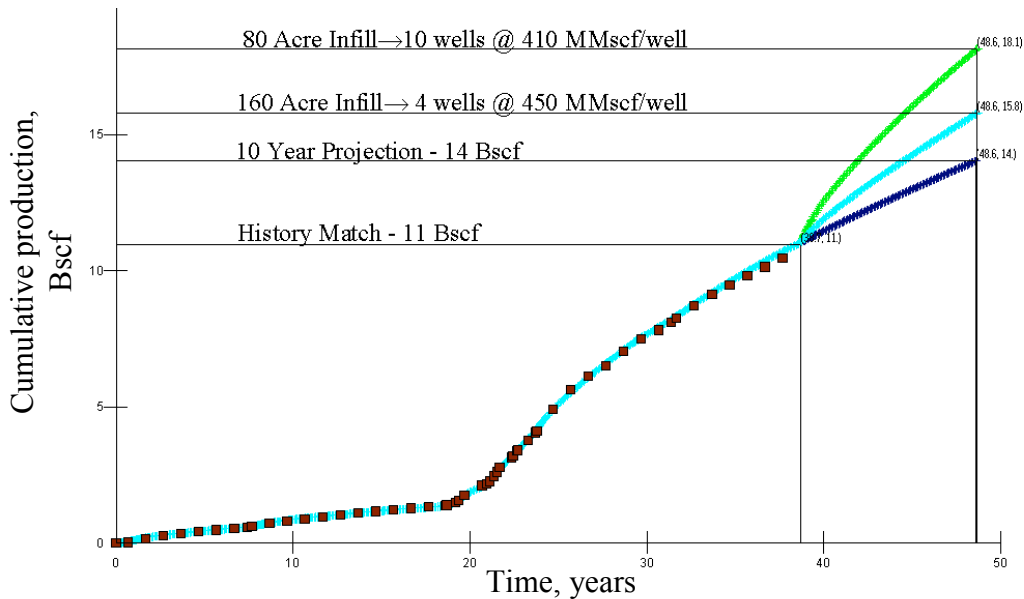
Figure 4.4-7. Comparison of infill drilling cases with the base case in the west study area. (from Medford, 2000)

4.3G Dakota Predicted Development

The majority of the future development is expected to be as increased density wells in already developed areas. The question becomes how to differentiate between areas of high potential from areas of low potential? Several factors must be considered in making this decision. First, results from simulation studies and neural networks infer depositional facies as a parameter in predicting future development. Furthermore, clean, thick sands have a higher probability of increased fracture density; therefore having increased storage and flow capacity. These statements stress the importance of sound reservoir characterization by an integrated team.

Second, the study areas were located on the margin of the Dakota productive limits and subsequently the results should be interpreted as valid for these specific areas. This perimeter or *halo* has poorer reservoir quality and thus lower recoveries by existing wells and hence a better chance of success for infill wells. On the other hand, the *fairway* is a northwest – southeast trend of wells with better recovery. Infill development may no be preferred. Figures 4.4-8 and 9 are basinwide maps from Whitehead (1993) of well density and cumulative production. These figures verify the better producers within the fairway.
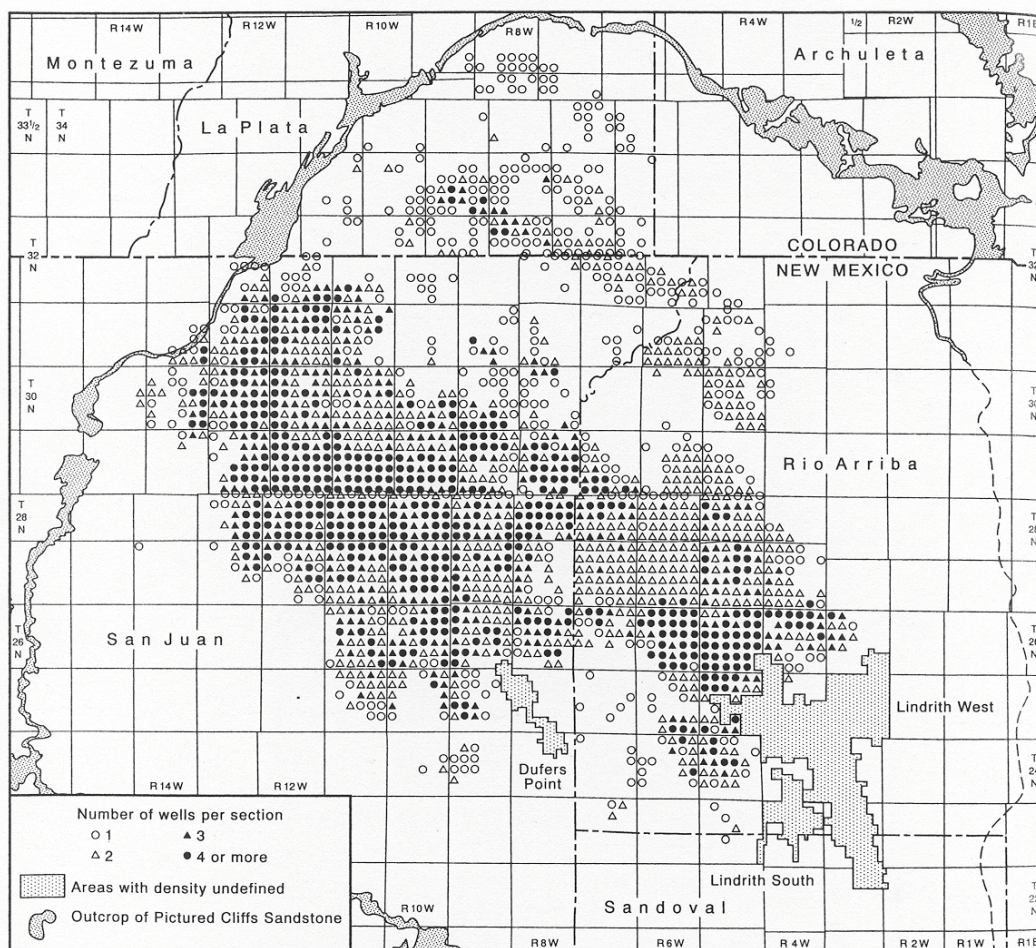
Figure 4.4-8. Well density of the Basin and Ignacio Blanco Dakota reservoirs. Stippled areas are commingled Dakota/Gallup areas. (Whitehead, 1993)
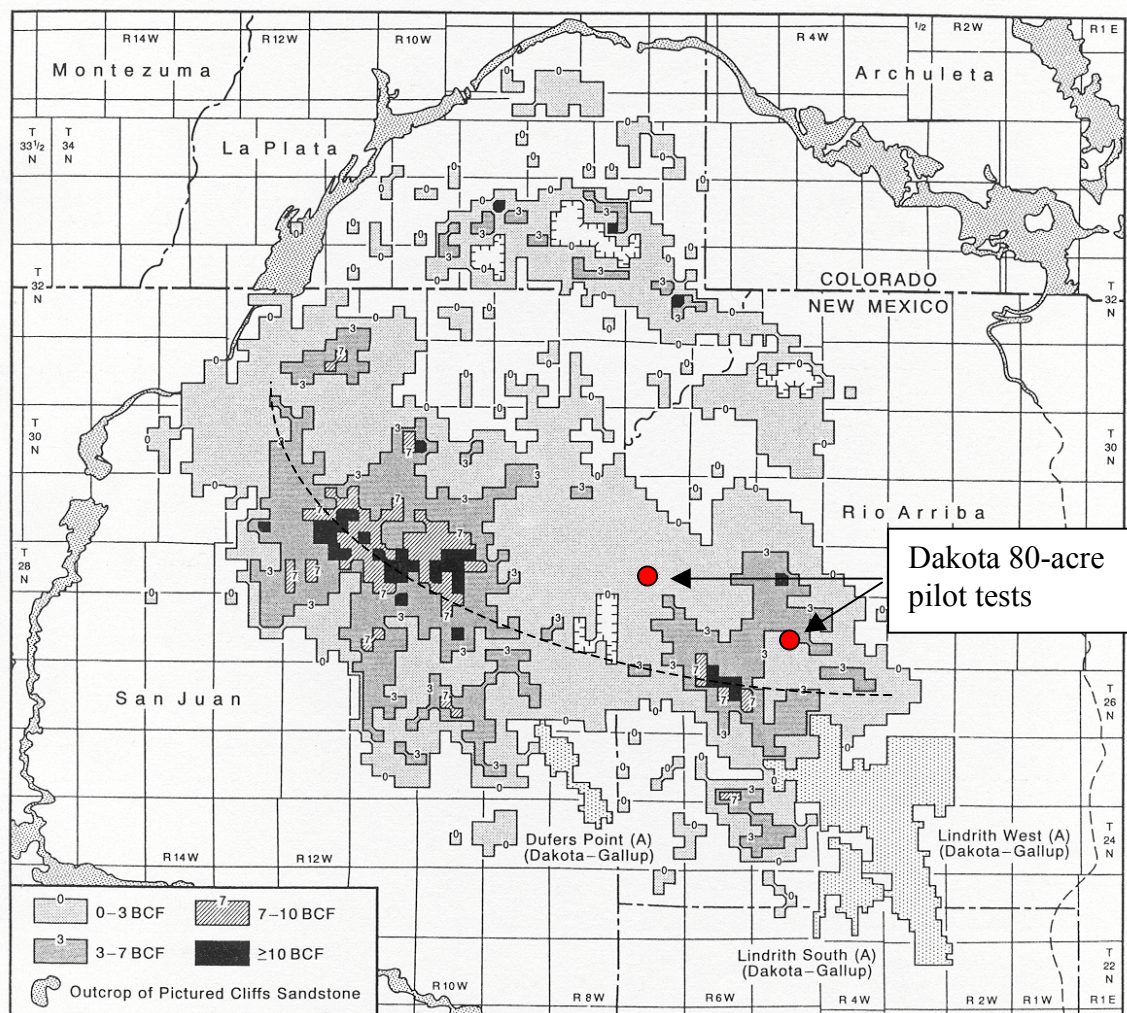
Figure 4.4-9. Cumulative gas production for the Basin and Ignacio Blanco Dakota reservoirs. (Whitehead, 1993)

A recent approach to confirm the 80-acre infill well potential is to evaluate the results from pilot tests. Two areas proposed for such a strategy are identified on Figure 4.4-9. Notice the selected areas are north of the axis of highest cumulative production. Due to the recent nature of this proposal no results can be evaluated at this time.

Chapter 5
Minor, emerging or potential reservoirs

5.1 Ojo Alamo, Nacimiento and San Jose formations reservoirs

5.1A Geology and historical development

The Ojo Alamo, Nacimiento and San Jose formations (Figure 5.1-1) are unconformity-bounded nonmarine strata deposited from latest Cretaceous to Eocene. They result from erosion of nearby emerging uplifts and deposition within the subsiding San Juan basin during the Laramide orogeny. These formations are generally believed to be aquifers rather than gas reservoirs (Stone et al., 1983). They
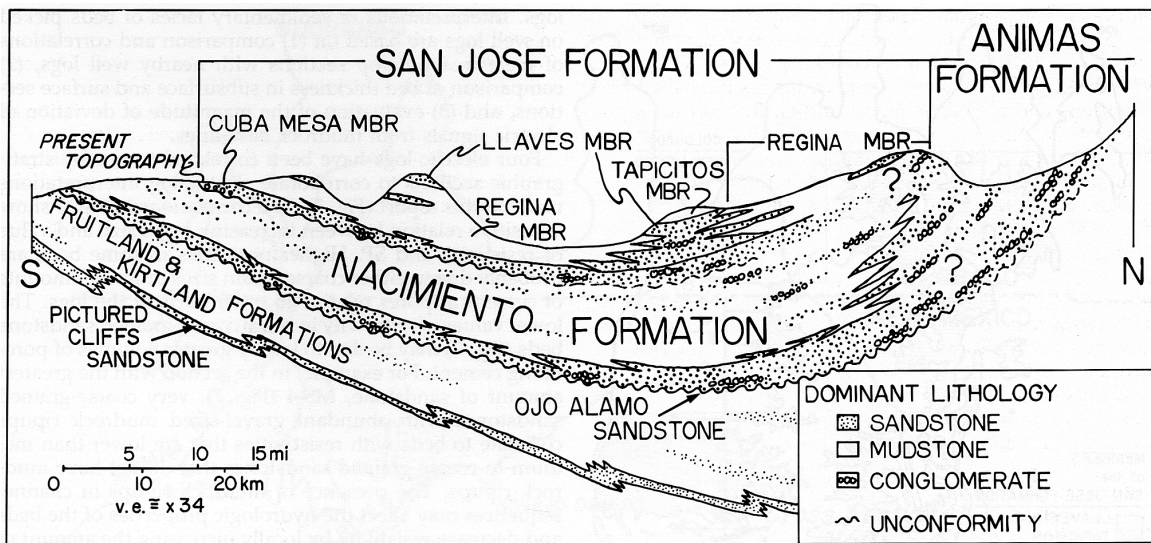
Figure 5.1-1 Cross-section showing stratigraphy of uppermost Cretaceous and lower Tertiary strata in the San Juan Basin (Smith and Lucas, 1991)

crop out over large areas in the basin and are recharged by infiltration from surface water (Figure 5.1-2). The San Jose and Nacimiento formations contain extensive sandstone and mudstone members, whereas the Ojo Alamo Sandstone is predominantly a widespread conglomeratic basal sandstone. The Ojo Alamo is widely depended upon as a fresh water aquifer in the western part of the basin. When drilling San Juan Basin wells, the Tertiary formations are typically drilled using water as a circulating medium and are regarded as nonproductive. Rarely is any effort applied to evaluate the production potential of these formations by tests or well logs. In these assumptions and practices lie opportunity for undiscovered reserves.
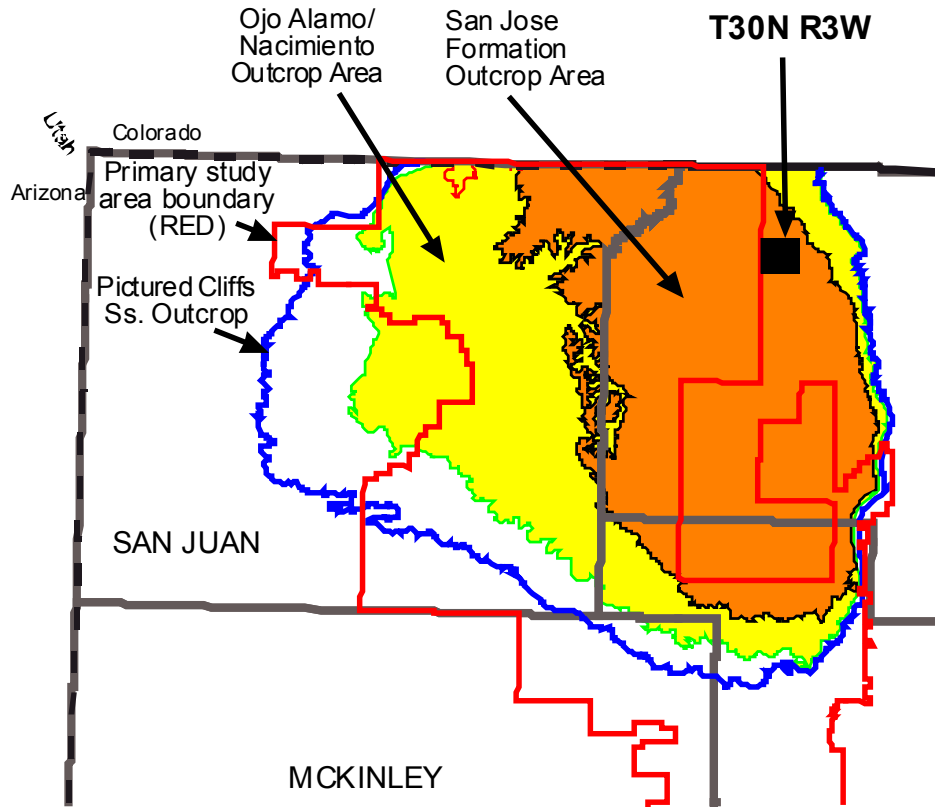
Figure 5.1-2 Map of San Juan Basin depicting the outcrop area of Late Cretaceous to Tertiary sandstone formations and the primary area of development activity (T30N R3W).

In T30N R3E (Jicarilla Reservation), shows of gas while drilling led to an eventual test of the Ojo Alamo Sandstone in four wells beginning in 1989 (Hoppe, 1992). Development of the Ojo Alamo in that township was hampered by unusual (for the basin) hydrogen sulfide gas concentration (0.7%). An H_2S processing facility was built and by 1998, a development program was initiated (Figures 5.1-3). During development, it was noted that shallower sands in the Nacimiento and basal San Jose had similar log characteristics to the Ojo Alamo, including neutron density cross-over (gas effect). Development was extended to the shallower formations (Figures 5.1-4, 5.1-5). The gas in the shallower reservoirs lacks the H_2S content of the Ojo Alamo and "sweetens" the gas stream from the field. Table 5.1-1 lists cumulative production and well counts to date.

Formation	Gas mmscf	Condensate mbo	Water mbw	Well Count
San Jose	4539	0	58	30
Nacimiento	849	1	22	8
Ojo Alamo	8469	8.5	918	43

Table 5.1-1 Cumulative production and well counts for Tertiary sand reservoirs. Several tertiary sands may be commingled in some wells.
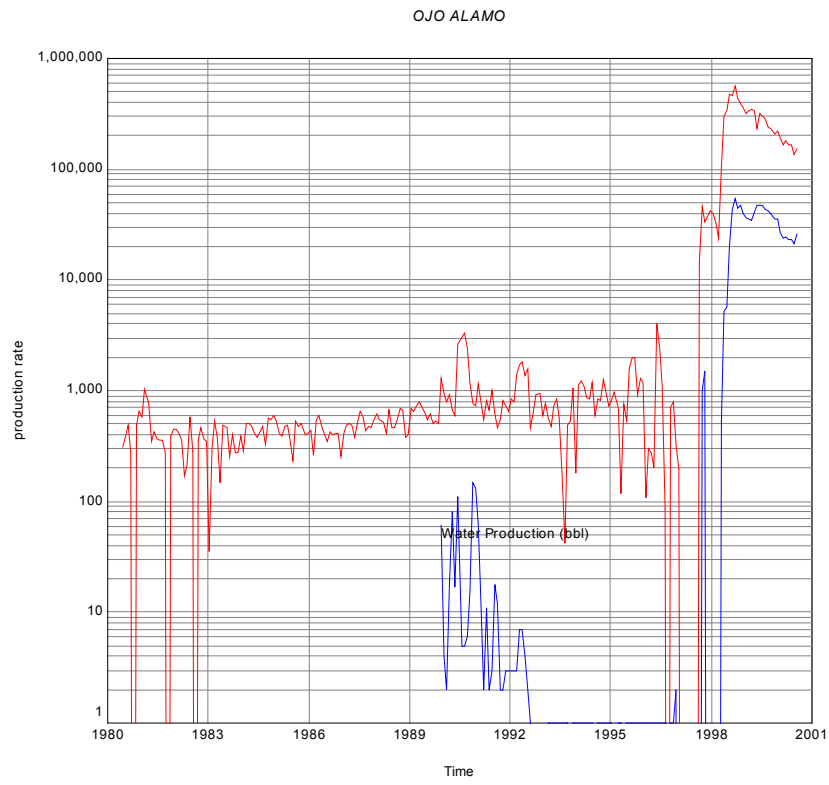
Figure 5.1-3 Monthly production rate for Ojo Alamo reservoir (Source: I.H.S. Energy)
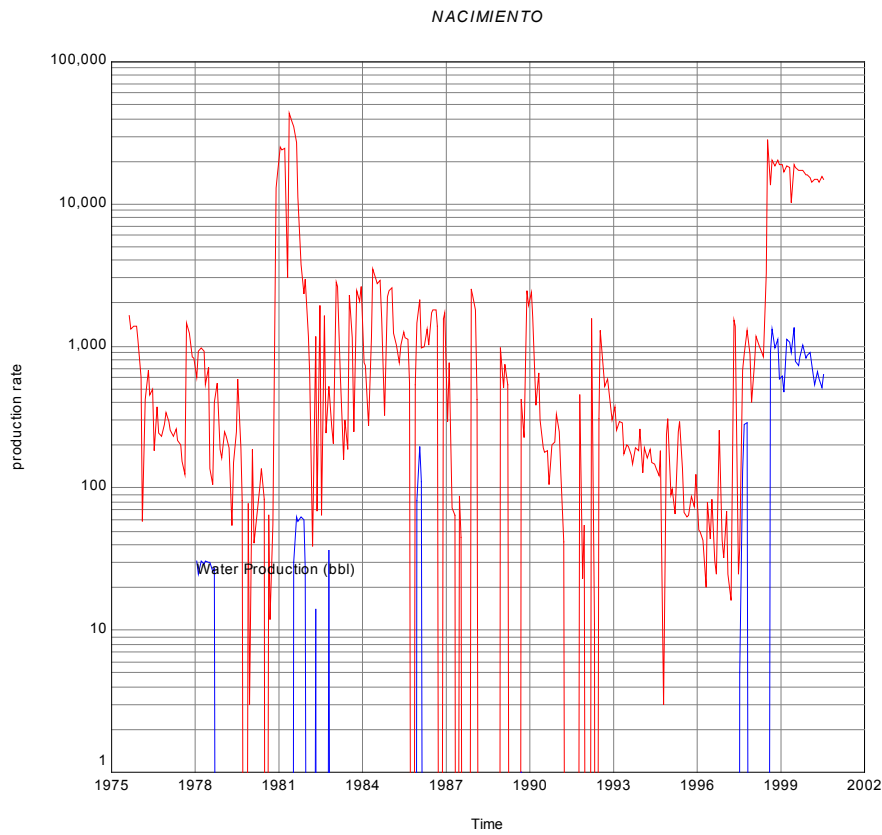
Figure 5.1-4 Monthly production rate for Nacimiento reservoir (Source: I.H.S. Energy)
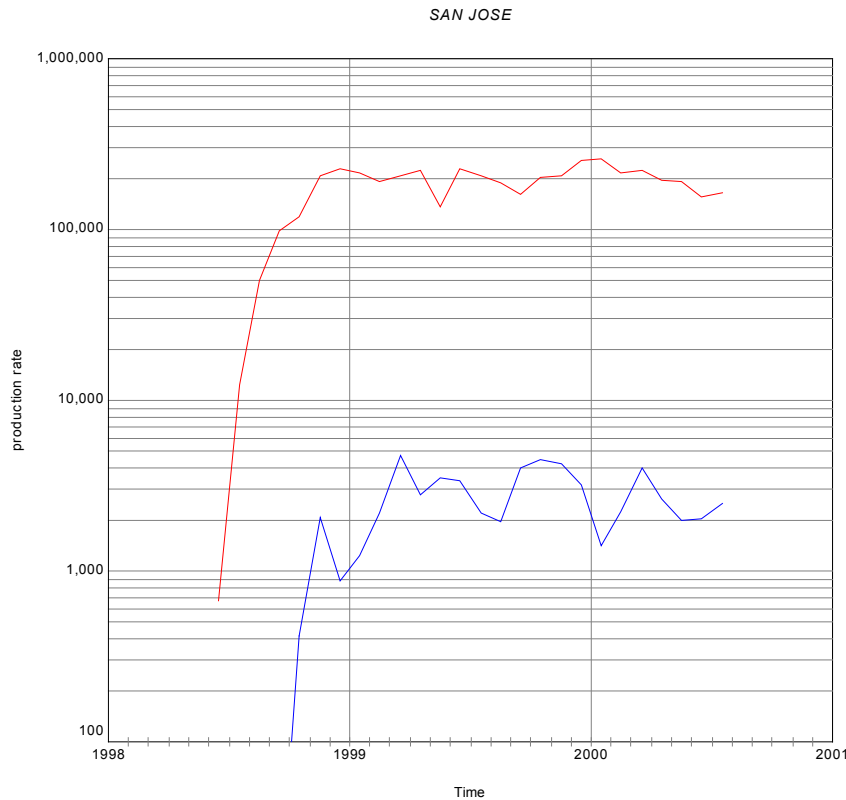
Figure 5.1-5 Monthly production rate for San Jose reservoir (Source: I.H.S. Energy)

5.1B Predicted 20-year development

Current production from the Tertiary sands is immediately adjacent to (east of) federal lands subject to this RFD. Several industry representatives have expressed the opinion that the play is very limited, yet the information needed to evaluate the production potential generally does not exist (appropriate and necessary well logs and tests). The play is, therefore, under-evaluated/explored outside of the current producing area. It is anticipated that the play may extend into townships 30 and 31 north, range 4 west, at least from an exploratory standpoint. Successful extension of the play would likely result in development drilling with effective 40 acres per well spacing due to discontinuous nature of sandstone bodies in the reservoir. A minimum development scenario for this play is approximately 100 additional wells, including exploration and development, on National Forest Service administered lands.

5.2 Farmington sand (Kirtland Formation) reservoirs

5.2A Geology and historical development

The Farmington Sandstone is the upper member of the Kirtland Shale in the San Juan Basin (Fassett and Hinds, 1971). It overlies a lower shale member of the Kirtland Shale and includes variable amounts of sandstone and shale below the base of the Ojo Alamo Sandstone. The Kirtland Shale is a nonmarine clastic deposit that lacks the coal beds of the underlying Fruitland Formation. According to Fassett and Hinds (1971), the sandstone beds of the Farmington Sandstone were laid down in aggrading stream channels.

A key reference for the Farmington sandstone reservoirs is Fasset et al. (1978). The information here is summarized from that work. Known Farmington reservoirs are limited to the western part of the San Juan Basin (Figure 5.2-1). They include both oil and gas fields that, overall, have had low cumulative production. New Mexico's first commercial gas well was drilled as a discovery in the Aztec pool in 1921 at a depth of 890 feet (Kendrick and Dugan, 1978). These pools tend to be very areally limited and developed on variable spacing as low as 40 acres. The net feet of productive sand ranges from 3-40 feet. Stratigraphic trapping of hydrocarbons in discontinuous sand bodies is common. Several fields were discovered during early, cable tool drilling of shallow wildcat wells. Other have been discovered or developed as a result of plugging back of failed deeper wells.

Figures 5.2-2 and 5.2-3 provide historical data on active wells and monthly production rates, respectively. A total of 68 wells were active over the span of twenty years shown in the figures. Cumulative production has been 174 mbo, 3236 mmscf, and 40 mbw. As of July 2000, fifteen wells were active, producing approximately 7000 mscf/month (15 mscfd/well).
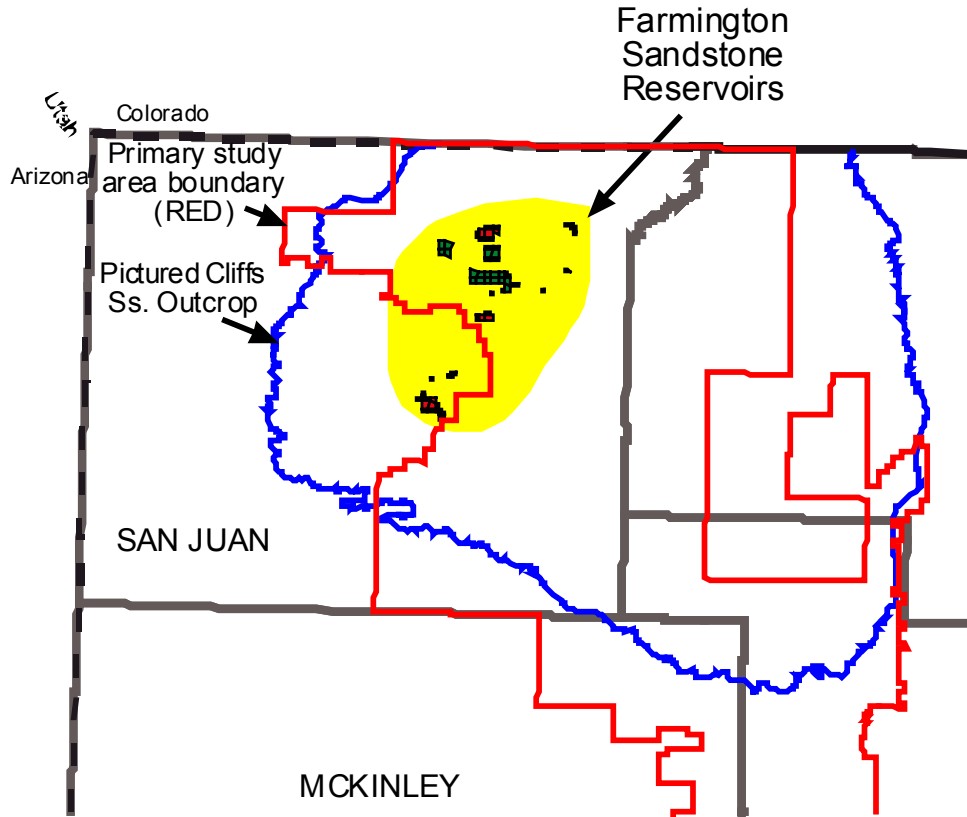
Figure 5.2-1 Farmington Sandstone reservoirs in the San Juan Basin

5.2B Predicted 20 year development

The development history of the Farmington Sandstone demonstrates that it is insignificant as a reservoir and will have no impact on 20 year development of the San Juan Basin from an economic or volumetric standpoint. Although recompletions of old wells may be attempted, no new wells are anticipated to be drilled to test this reservoir.
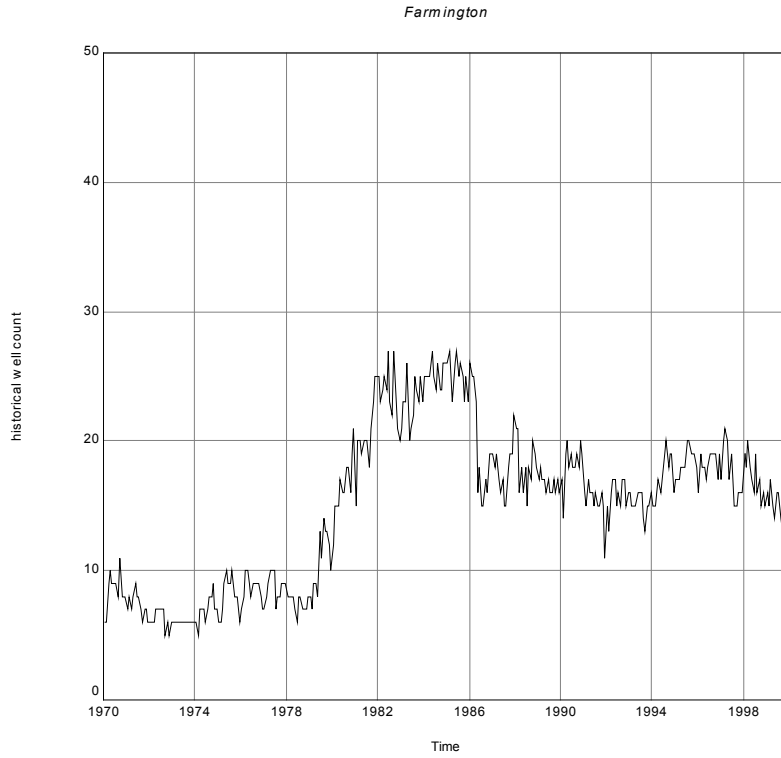
Figure 5.2-2 Active well count for Farmington reservoirs (Source: I.H.S. Energy)
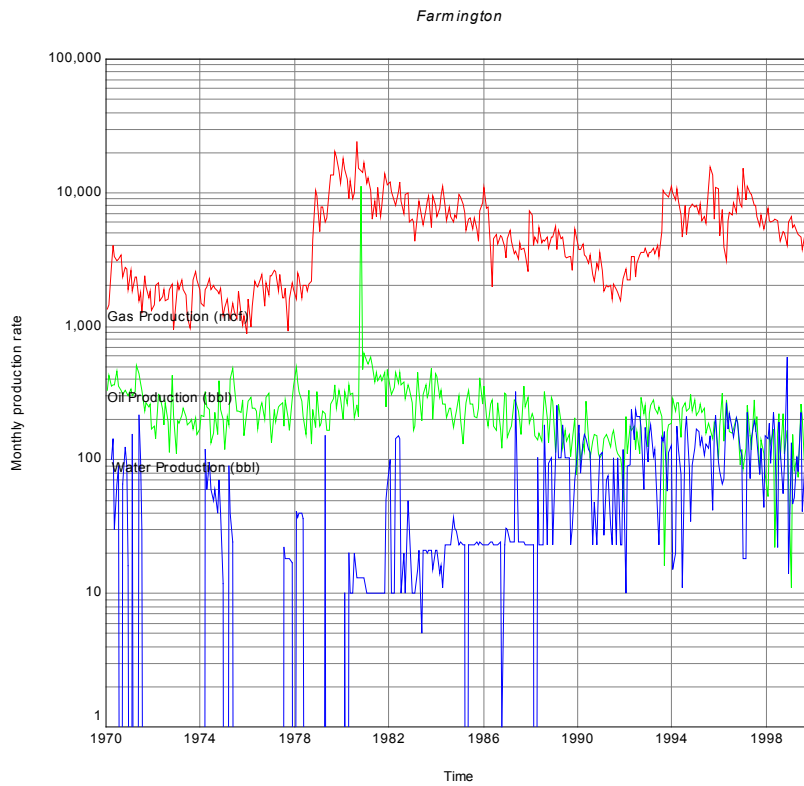
Figure 5.2-3 Monthly production rates for Farmington reservoirs (Source: I.H.S. Energy)

## 5.3 Fruitland sand (Fruitland Formation) reservoirs

5.3A Geology and historical development

The Fruitland sand reservoirs are predominantly found in the upper part of the Fruitland Formation. Due to the unique nature of the Fruitland coal reservoir it is managed separately from the statutorily-separated sand reservoir. Approximately 20 fields are designated producing from the Fruitland sands, with a total of 260 wells, and another 6 fields with 333 wells are designated producing from commingled Fruitland Sand and Pictured Cliffs. Figure 5.3-1 depicts the major fields for both reservoirs.
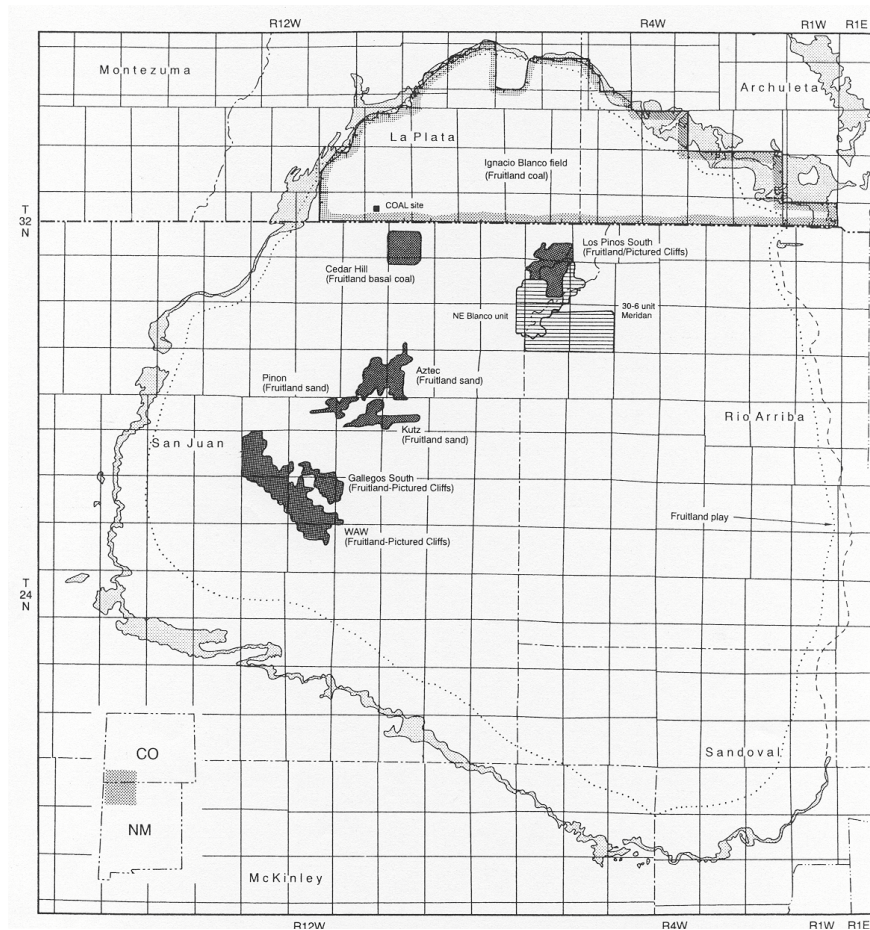
Figure 5.3-1 Major reservoirs producing from Fruitland Sand and Fruitland/ Pictured Cliffs commingled. (Whitehead, 1993)

The major Fruitland Sand reservoirs shown in Figure 5.3-1 are the Aztec, Kutz and Pinon Fields. These fields account for 56% of the total wells and 78% of the cumulative production to July 2000 from all Fruitland Sand reservoirs. Similarly, The major Fruitland/Pictured Cliffs fields shown in the figure are Gallegos, S., Los Pinos, S.

and WAW fields. These fields account for 88% of the total wells and 92% of the cumulative production to July 2000 for this reservoir group.

Cumulative production for Fruitland Sand wells has been 78 Bscf, 51 mbo and 179 mBw. Figure 5.3-2 shows the active well count over the last thirty years and Figure 5.3-3 the monthly production rates. Latest month's production was 150 mmscf from 160 wells or approximately 31 mscfd/well. Well development was consistent throughout the 1970s, peaking in 1985. The erratic behavior in the mid-1980s is a response to external (market, capacity) restrictions. Since 1994 the active well count has been constant.
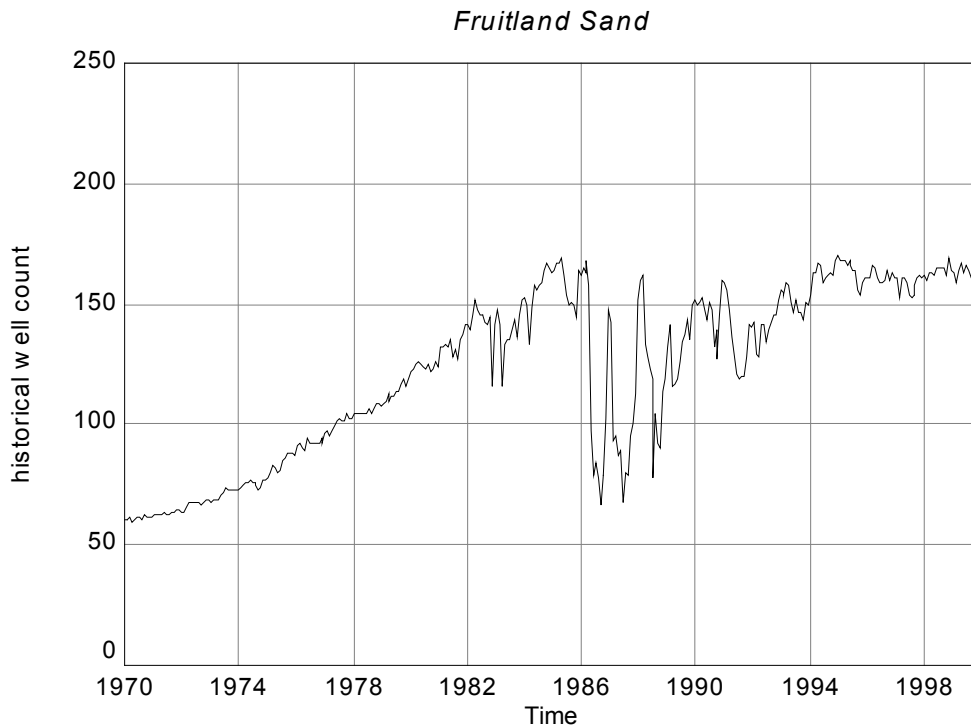
Figure 5.3-2 Active well count for the Fruitland Fields (data from I.H.S. Energy)
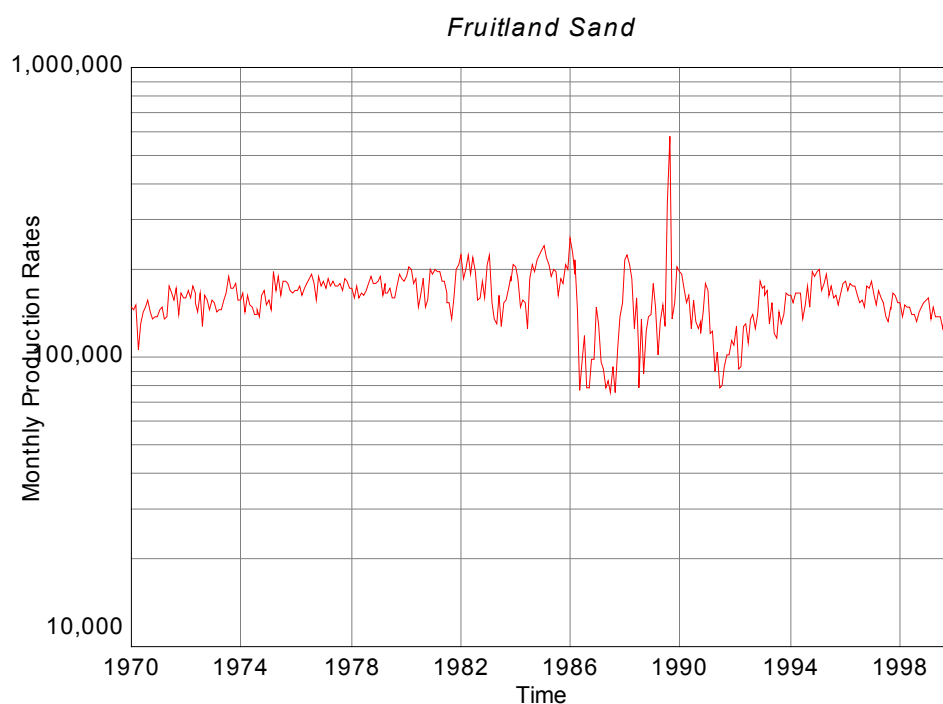
Fruitland Sand

Figure 5.3-3 Monthly gas production rate for Fruitland Formation (Source: I.H.S. Energy)

Active well count for the Fruitland/Pictured Cliffs commingled fields is shown in Figure 5.3-4. Development was rapid in the 1970s, peaking at 215 wells in the early 1980s. A rapid decrease in well count occurred in the mid-1980s, and then rebounded slightly to approximately 150 wells, which has been relatively constant since.

Monthly oil, gas and water production rates are shown in Figure 5.3-5. Current monthly production rate for gas is approximately 300,000 mscf or 66 mscfd/well and for water is 35,000 bw or 8 bwpd/well. A significant increase in water production occurred in 1998.
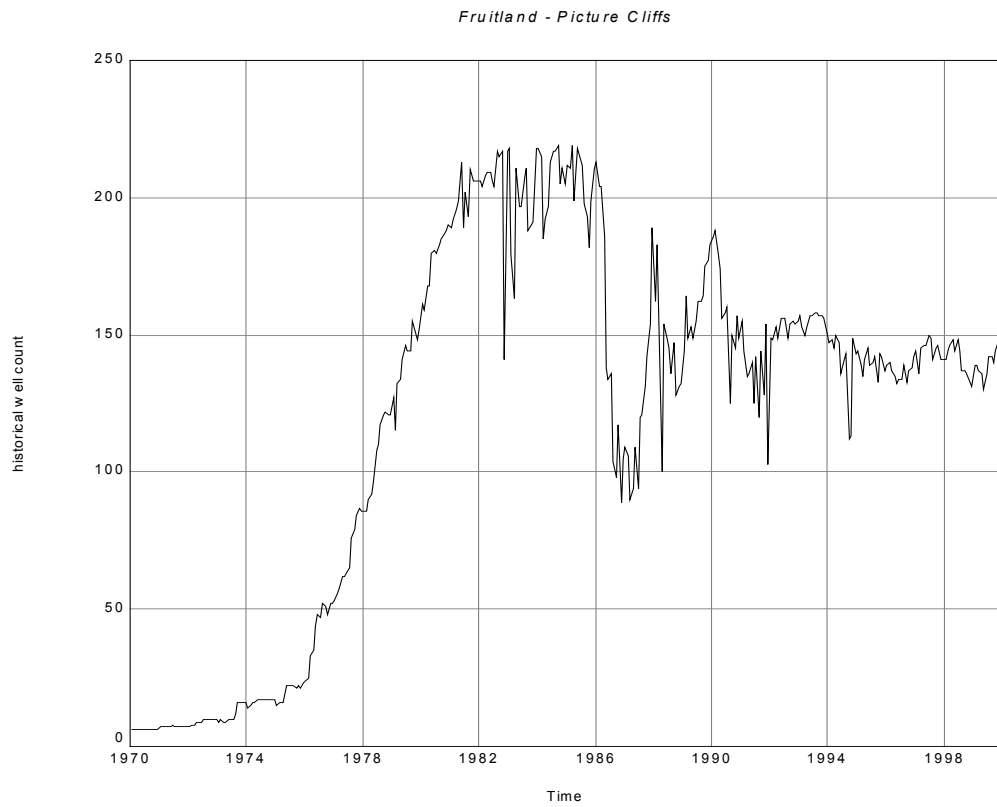
Figure 5.3-4 Active well count for the Fruitland/Pictured Cliffs Fields (data from I.H.S. Energy)

Fruitland - Picture Cliffs
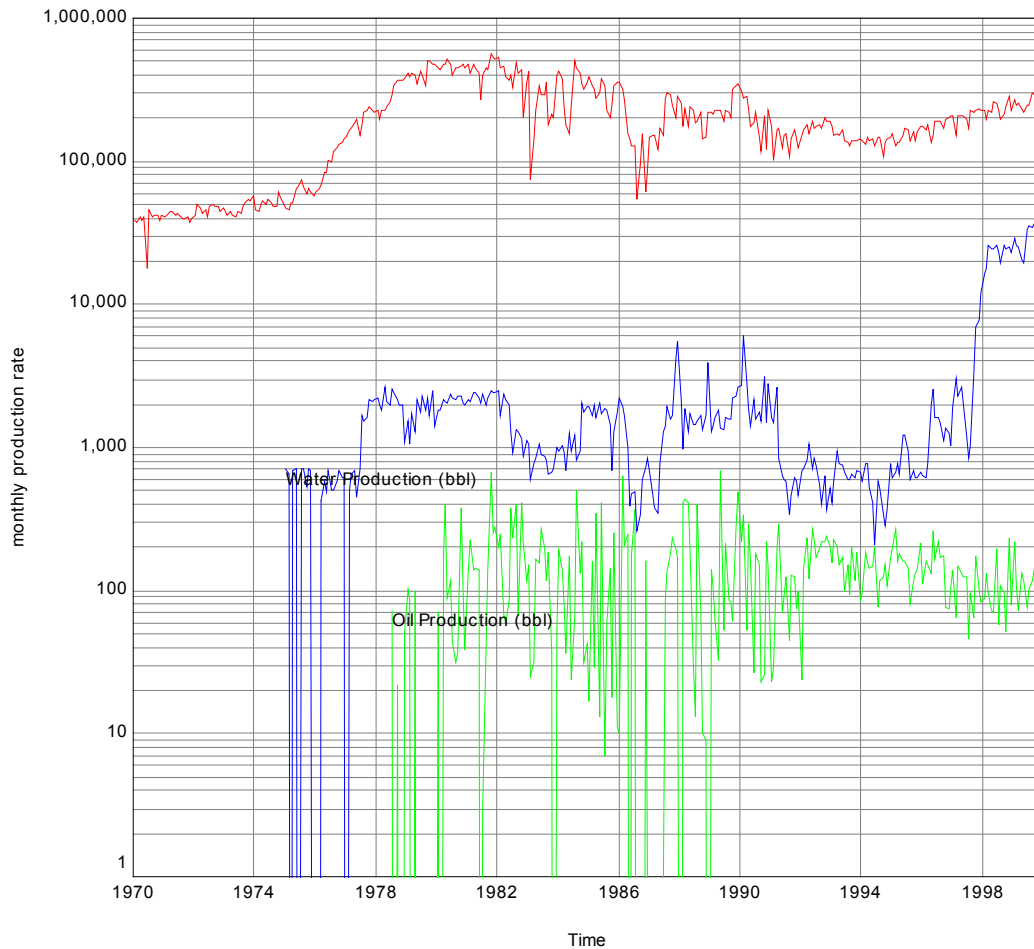
Figure 5.3-5. Monthly gas production rate for Fruitland/Pictured Cliffs Fields
(Source: I.H.S. Energy)

5.3B Gas Resources

Published information on gas-in-place or recovery is limited for the Fruitland sand/Pictured Cliffs reservoirs. Fassett in 1978, 1983 estimated the ultimate gas recovery by field. For the 17 Fruitland Sand Fields listed in his study, 77.75 Bscf was calculated to be recoverable. These fields have produced 73.07 Bscf to July, 2000; therefore the EUR is too conservative. For the three Fruitland Sand/Pictured Cliffs Fields analyzed by Fassett, 16.4 Bscf was calculated to be recoverable. These fields have produced 37.9 Bscf. In defense of the study by Fassett, it was preliminary in nature and therefore appears evident that further work is necessary to better quantify the gas resources in these areas.

5.3C Infill Well Potential

Current spacing is 160-acres per well for both the Fruitland and Fruitland/Pictured Cliffs fields. The distribution of cumulative production per well for the Fruitland Sand Fields is shown in Figure 5.3-6. The average well recovers 0.30 Bscf per well. This low productivity makes this formation an unlikely target for infill drilling. Furthermore, as shown in Figure 5.3-7, a new well has a 60% probability of recovering less that 0.25 Bscf. Figure 5.3-7 exhibits the distribution curve for the Fruitland/Pictured Cliffs Fields. Similar to the Fruitland Sand Fields, productivity is low and therefore not a viable target for infill drilling at this time. Average recovery is 0.23 Bscf/well with a 70% probability of obtaining a well with less than 0.25 Bscf.
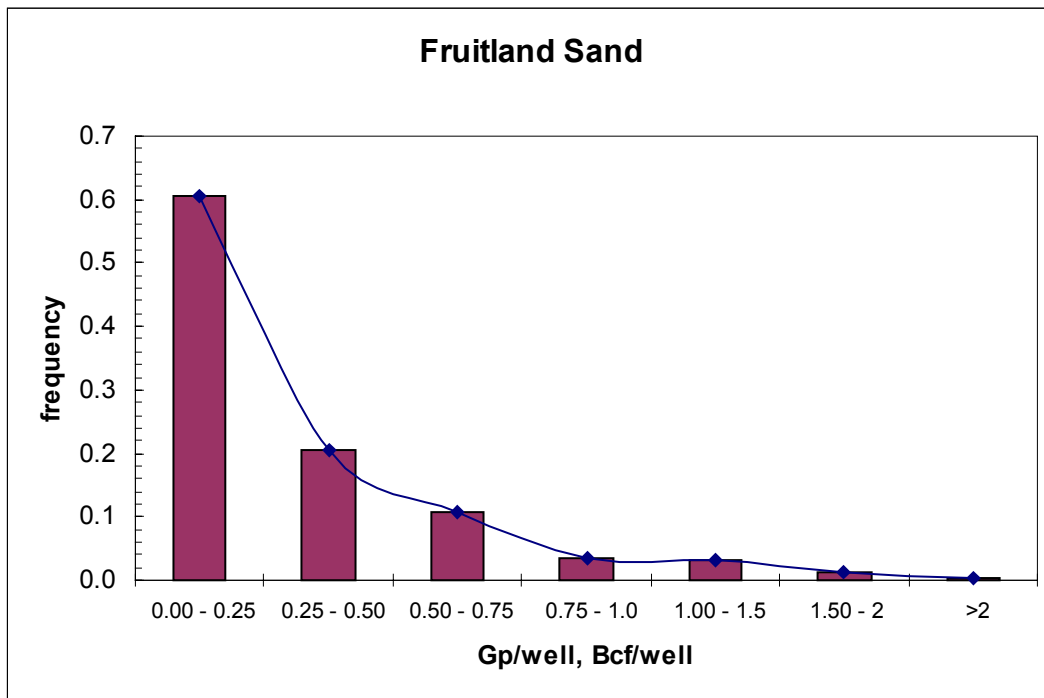
Figure 5.3-6 Distribution of recovery per well from the Fruitland Sand Formation.

Fruitland/Pictured Cliff Sand
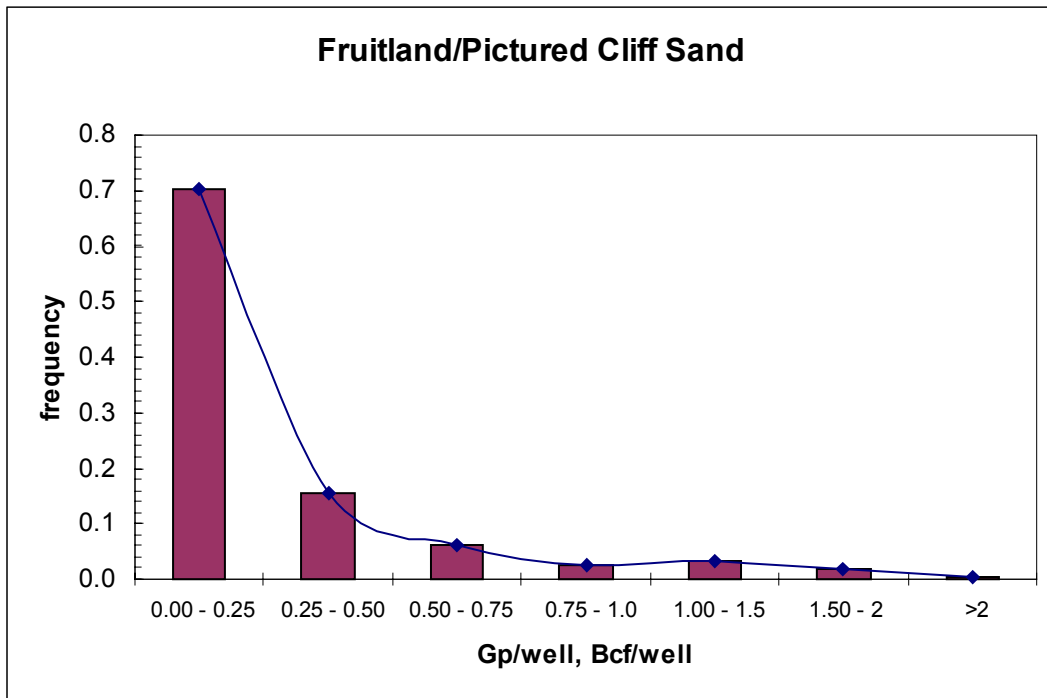
Figure 5.3-7 Distribution of recovery per well from the Fruitland Sand/Pictured Cliffs Formation.

5.3D Predicted 20 year development

The development in these reservoirs is limited to remaining 160-acre locations or to replacement wells. The latter cannot be estimated with any accuracy; therefore **176** locations were identified as potential targets for the Fruitland Formation. Of this estimate, the majority will probably be commingled or dual completed with other zones, or uphole potential in existing wellbores. The impact to the entire San Juan Basin is anticipated to be minimal

5.4 Chacra sand (Mesaverde Group) reservoirs

5.4A Geology and historical development

The Chacra producing interval is the part of the Cliff House Sandstone of the Mesaverde Group. However it has been designated as a separate tight gas formation by the NMOCD. A "Chacra line" has been drawn to protect the correlative rights of owners in the Chacra producing interval. (Figure 5.4-1) South and west of this line the Mesaverde producing interval begins from 750 ft. below the Huerfanito Bentonite marker. Current spacing is 160 acres per well.
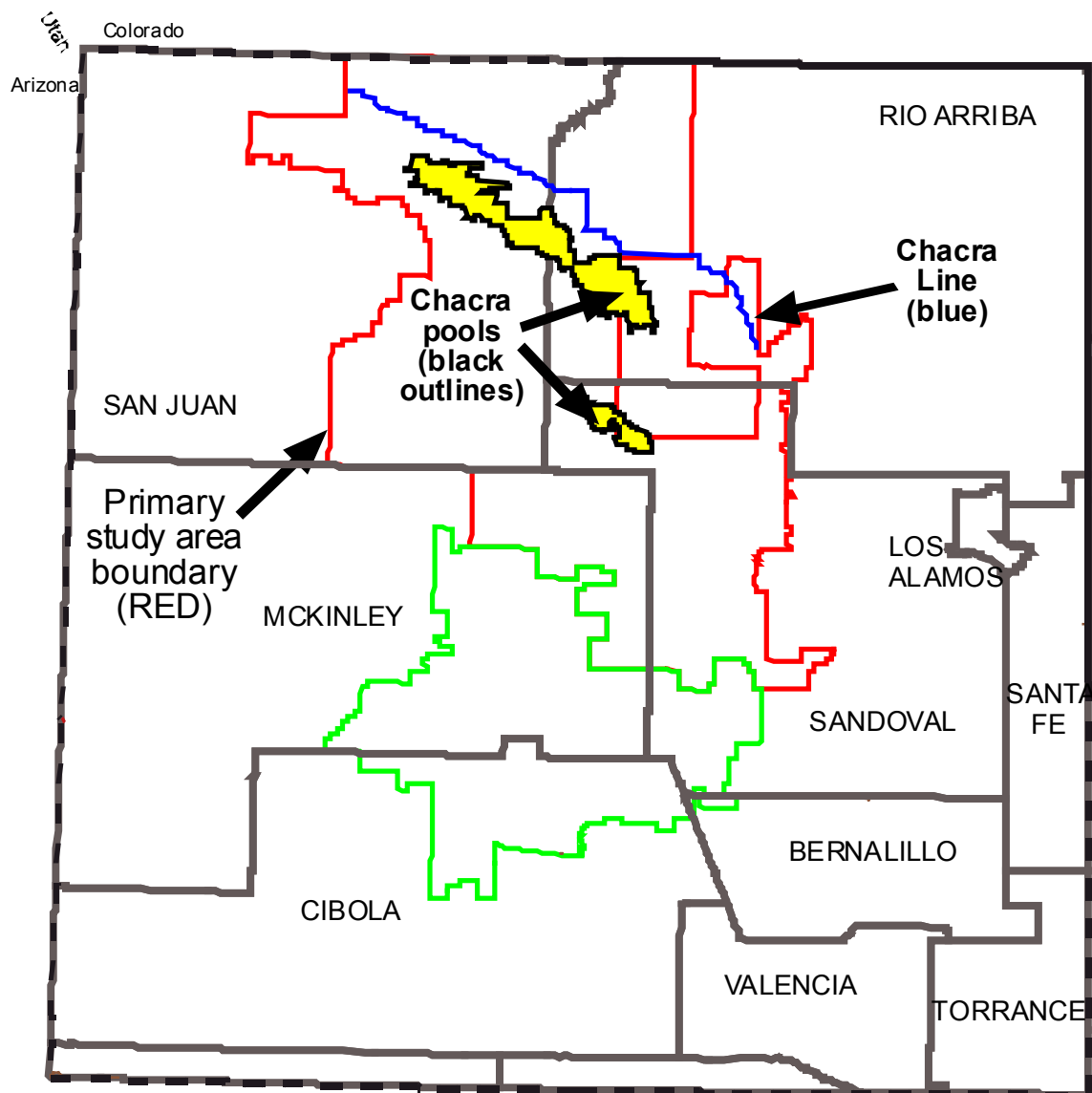
Figure 5.4-1 Map depicting extent of Chacra natural gas reservoirs, San Juan Basin.

Historical well development is shown in Figure 5.4-2. No significant period of well development occurred, but instead a steady increase can be seen from 1974 to 1984, resulting in approximately 500 producing wells, which is the same today.
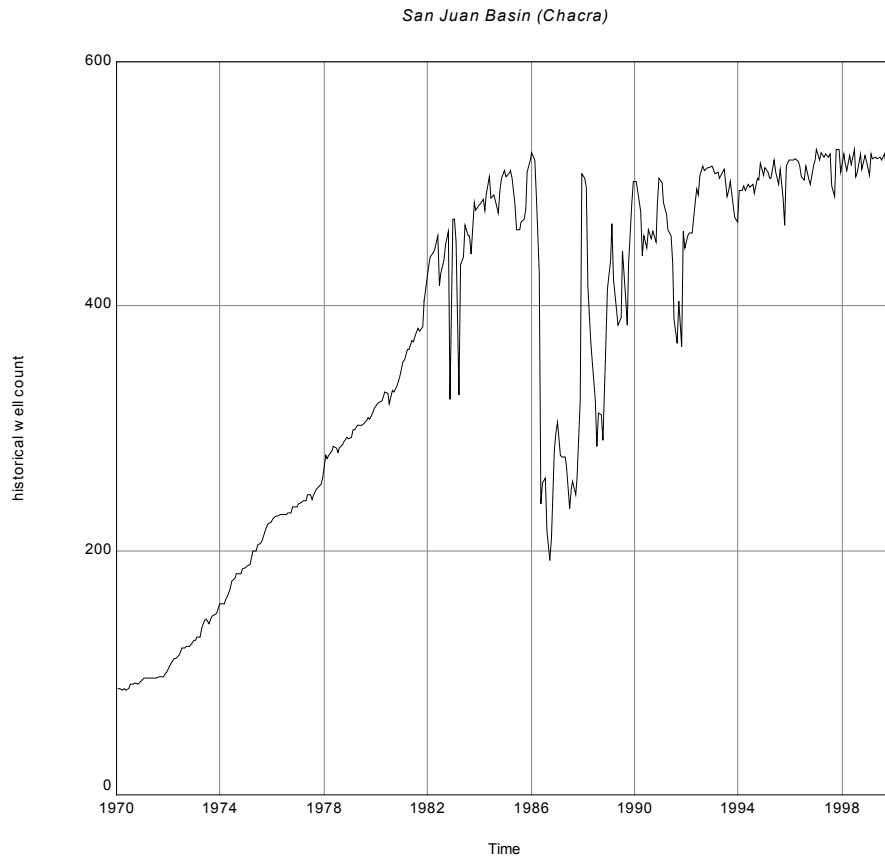
Figure 5.4-2 Historical well development of the Chacra Formation (Date from I.H.S. Energy)

Production over the time period from 1970 to current (July 2000) is shown in Figures 5.4-3 and 5.4-4. Figure 5.4-3 includes oil, gas and water production rates. Note the increase in water production in 1978. Figure 5.4-4 is an expanded view of the gas production, only. Production decreased from 1982 to 1990, but has remained relatively constant since then. Current production rate is 500 mmscf per month, and cumulative production to July, 2000 has been **216 Bscf**.
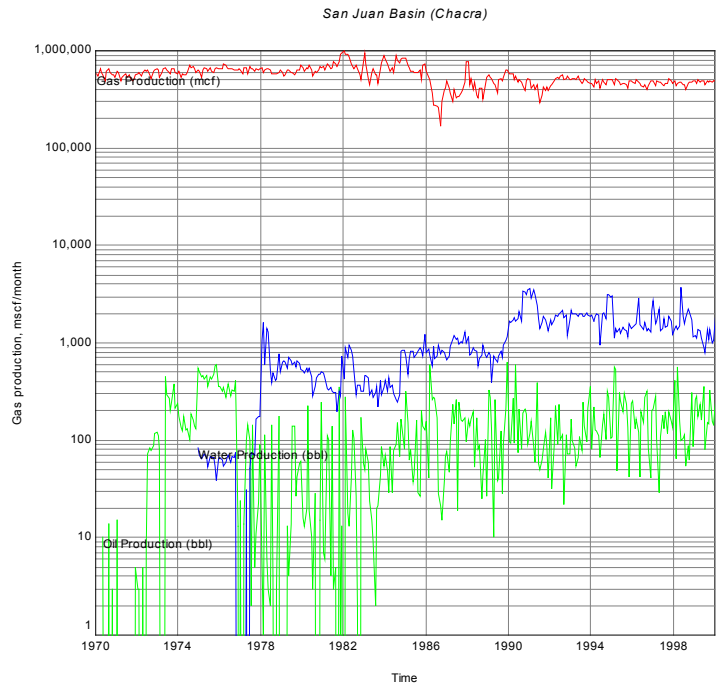
Figure 5.4-3 Monthly production rates for oil, gas and water (Data from I.H.S. Energy)
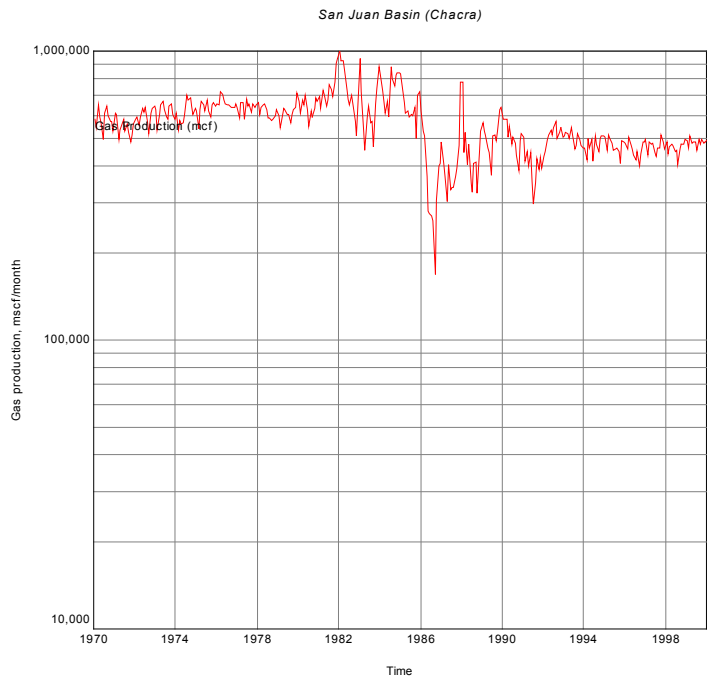
Figure 5.4-4 Expanded view of monthly gas production. (Data from I.H.S. Energy)

5.4B Gas resources

Few estimates of gas resources have been published for the Chacra Formation. Estimated ultimate recovery from tight areas was given to be 272 Bscf according to BEG/GRI study in 1993. This number is too low in that it would suggest that recovery efficiency is currently approaching 80%, which is unlikely for this low permeability formation.

5.4C Infill well potential

The distribution of gas recovery per well is shown in Figure 5.4-5. Few wells can be classified as "strong" wells. The average recovery is 0.333 Bscf per well with approximately a 60% chance of developing a well with less than 0.250 Bscf. Subsequently, limited infill potential exists in the currently defined limits of the Chacra pool.
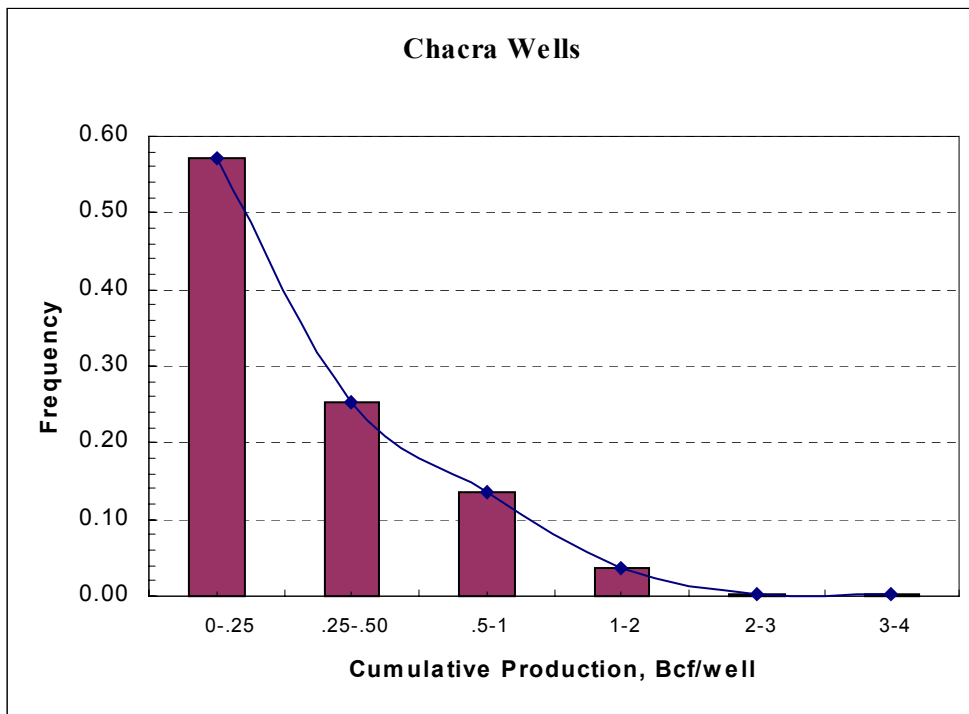
Figure 5.4-5 Distribution of recovery per well from the Chacra Formation.

5.4D Predicted 20 year development

The infill well development to an increased density of 80-acres per well is not favorable at this time. Evidence, as shown above, suggests minimal recovery and probably poor economic return. Two likely scenarios are to include the Chacra as uphole

(behind pipe) potential in existing wells, or drill a new well and dual/commingle with another producing horizon. Both are prudent and practical options.

Figure 5.4-6 illustrates the extent of the Chacra pool and well density as of 1993. Using this information, a total of **320 completions** can be added to the Chacra pool, on the current 160-acre spacing rules. These wells were selected based on geological, engineering and statistical evidence. Minimal stepout development was considered due to geological reasons. Engineering data does not support 80-acre development at this time; therefore statistical analysis of Figure 5.4-6 provides a reasonable estimate of development for the Chacra interval.
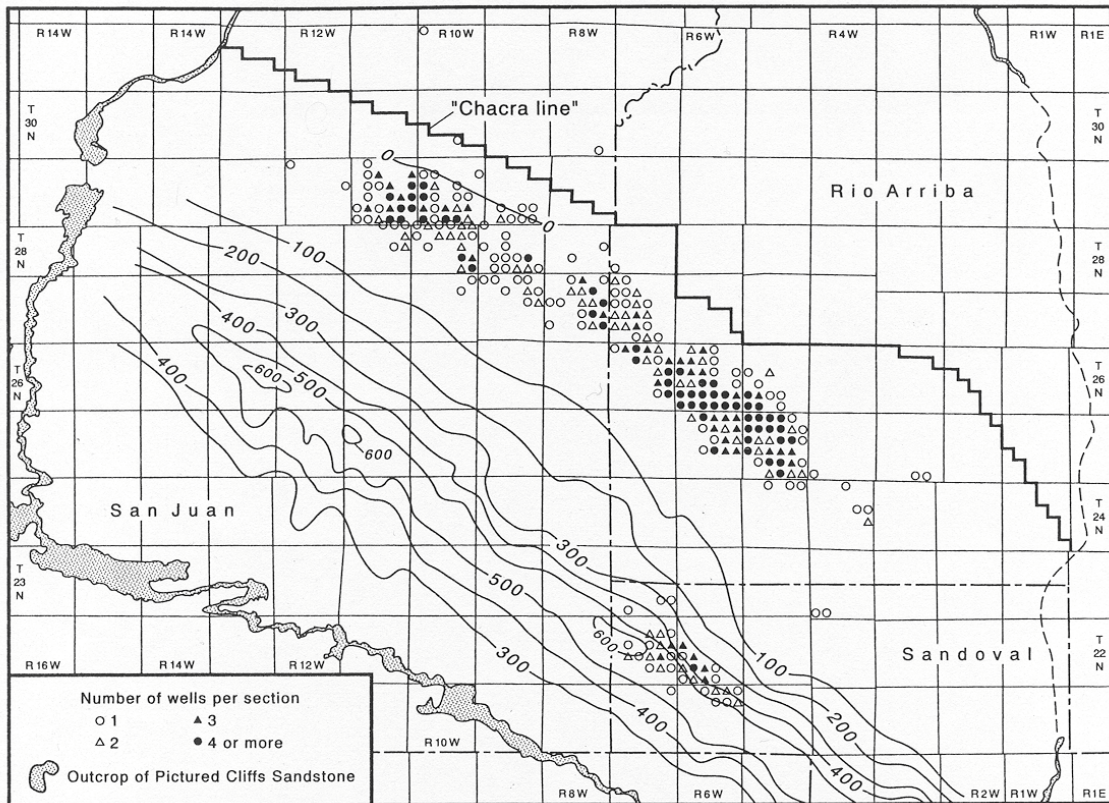
Figure 5.4-6 Pool limits and well density for the Chacra Formation. Isopach lines are the net sandstone for the La Ventana Tongue. Whitehead (1993)

5.5 Lewis Shale reservoirs

5.5A Geology and Historical Development

Statutorily, that part of the Lewis Shale below the Huerfanito bentonite and north of the Chacra line is part of the Blanco Mesaverde pool. It is discussed separately from the Mesaverde reservoir here to emphasize the potential impact on future development of the basin. The key publications on the Lewis Shale as a reservoir are PTTC (2001), Dube et al. (2000), Frantz et al. (1999) and Jennings et al. (1997) and these are summarized in the following discussion.

Stratigraphically, the top of the Lewis Shale is gradational with the overlying Pictured Cliffs. The base of the Lewis ranges from a gradational contact with the Cliff House Sandstone in the southern part of the basin, to a sharp contact over the Menefee Formation in the northern part of the basin (see Figure 4.3-1, previous chapter). The Huerfanito bentonite is a distinctive time marker in the upper third of the formation. In much of the basin, the Lewis Shale exceeds 1000 feet in thickness.

The Lewis Shale contains gas-prone organic material that is thermally mature in the deeper parts of the San Juan Basin. Within that maturity fairway, there is coincident higher sand content. Thus, a marked sweet spot parallels, and is somewhat southward of, the basin structural axis (Figure 5.5-1).
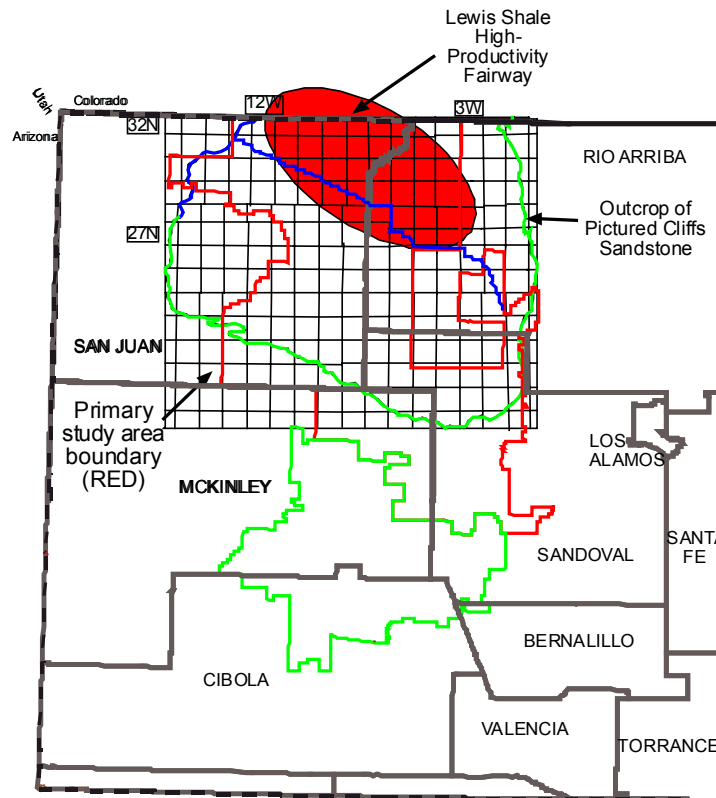
Figure 5.5-1 Map depicting Lewis Shale productivity fairway (after Dube et al, 2000).

The term "shale" applied to the Lewis is perhaps a misnomer. On average, the Lewis is composed of silt and sand mixed with clay resulting in a mudstone. At least three Lewis lithofacies are recognized: a mudstone facies, interlaminated mudstone and very fine grained sandstone, and a bioturbated facies that tends to be sand-rich. Those intervals containing significant sand content tend to have better permeability and natural fractures, and are the better reservoirs. Although the Lewis is a poor reservoir in terms of matrix permeability, viable natural gas production results when wells intersect natural fracture systems. Like the Mesaverde Group reservoir, the Lewis is underpressured (.21-.23 psi/ft), unfortunately the most favorable lithologies have only microdarcy permeability. These characteristics make completing and stimulating the Lewis a challenging proposition.

5.5B Predicted 20 year development

The potential of the Lewis Shale as a natural gas reservoir has only been realized in the past decade. Thus, the Lewis play is a relatively new development in the San Juan Basin and is only now beginning to have an impact on production. The reservoir is becoming a viable "pay add" to newly drilled or recompleted wells targeting the Mesaverde Group in the Lewis fairway. From existing completions, it is estimated that the Lewis will contribute an estimated ultimate recovery per well in the range of 300 to 500 mmscf (Dube et al., 2000).

Perhaps the greatest impact that the Lewis Shale will have on development of the basin is to contribute enough gas to commingled-reservoir wells to insure their economic viability. This is important for both newly drilled wells and for older wells nearing depletion and potential abandonment. It is not anticipated at this time that the Lewis reservoir will yield Lewis-only new drills based on the per well volumes being currently produced and due to the favorable regulatory environment which allows integration of the reservoir with the Blanco Mesaverde pool.

5.6 Mancos Shale and Gallup Sandstone Reservoirs

5.6A Geology and historical development

The stratigraphy of the Mancos Shale and the Gallup Sandstone is illustrated in Figure 5.6-1. The Gallup Sandstone is a shoreface sandstone that is time equivalent to the uppermost part of the Carlile member of the Mancos Shale.   For the purposes of this discussion, the two formations are discussed together due to their spatial and temporal equivalency and because they are key elements of a discreet petroleum system. The top of the Mancos Shale is gradational with the Point Lookout Sandstone of the Mesaverde Group. The base is the contact with the Dakota Sandstone. The Mancos Shale can be subdivided into (from top to bottom) the upper Mancos, Carlile, Greenhorn and Graneros members. The El Vado sandstone and Tocito sandstone are well known reservoir zones in the upper Mancos member. The term "Gallup" has been widely applied to many reservoirs that are not stratigraphic Gallup Sandstone equivalents.
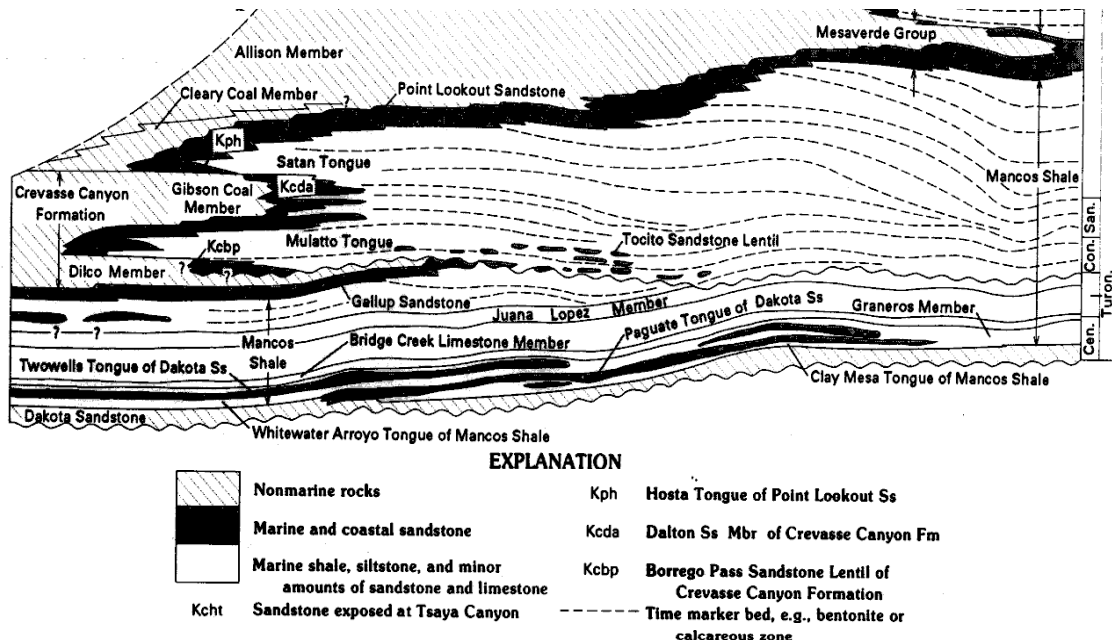
Figure 5.6-1 Idealized stratigraphic cross-section from south (left) to north (right) across the San Juan Basin depicting Mancos and Gallup stratigraphy (modified from Nummedal and Molenaar, 1995).

Since December 2000, the statutory status of the Mancos Shale has been under review by a working group of NMOCD and operator representatives (Steve Hayden, NMOCD, personal communication).   The goal of that group is to define a Mancos reservoir interval with similar spacing and set-back to that of the Dakota Sandstone to simplify commingling of the two zones.   At present, the stratigraphic boundaries of the

Mancos Shale are overlapped significantly by the Basin Dakota and Blanco Mesaverde pools. In all likelihood, a Mancos pool will be designated that will include the lower part of the upper Mancos (the top would be 500 feet below the top of the Point Lookout Sandstone) downward to the base of the Greenhorn member. It is likely that existing outlines of Gallup, Tocito and other producing Mancos reservoirs will remain as previously defined. The reason for this statutory review is that there is considerable interest in developing the Mancos Shale as a gas reservoir over a large part of the basin where it has not been previously developed.

The Mancos Shale encompasses a number of rock types including shale, sandstone and limestone (Amarante and Brister, 2001). All members tend to have low matrix porosity and permeability. As with other San Juan Basin reservoirs, fractures play an important role in production. The Mancos is better known as a source rock than as a reservoir. The presence of oil and gas in the Mancos is related to the distribution and maturity of organic matter types that comprise between 1 and 2% of the rock. Petrography and Rock Eval Pyrolysis from a limited number of samples demonstrate that the lower part of the upper Mancos is oil prone and has the higher weight percent of total organic carbon, whereas the lower Mancos shale members (ie. Carlile, Graneros) tend to be more gas prone. A variety of maturity-level estimates demonstrate that there is an approximately 50 township area in New Mexico (Figure 5.6-2) where the entire Mancos Shale section reached a gas-window level of maturity (Brister, 2001). Surrounding that area, the Mancos only reached the oil window level of maturity. As a low permeability reservoir, the generated hydrocarbons did not migrate far, thus the deeper parts of the basin have yielded gas fields, whereas the shallow eastern, western and southern flanks yielded oil fields. This distribution is illustrated in the current distribution of Mancos field types (Figure 5.6-2).
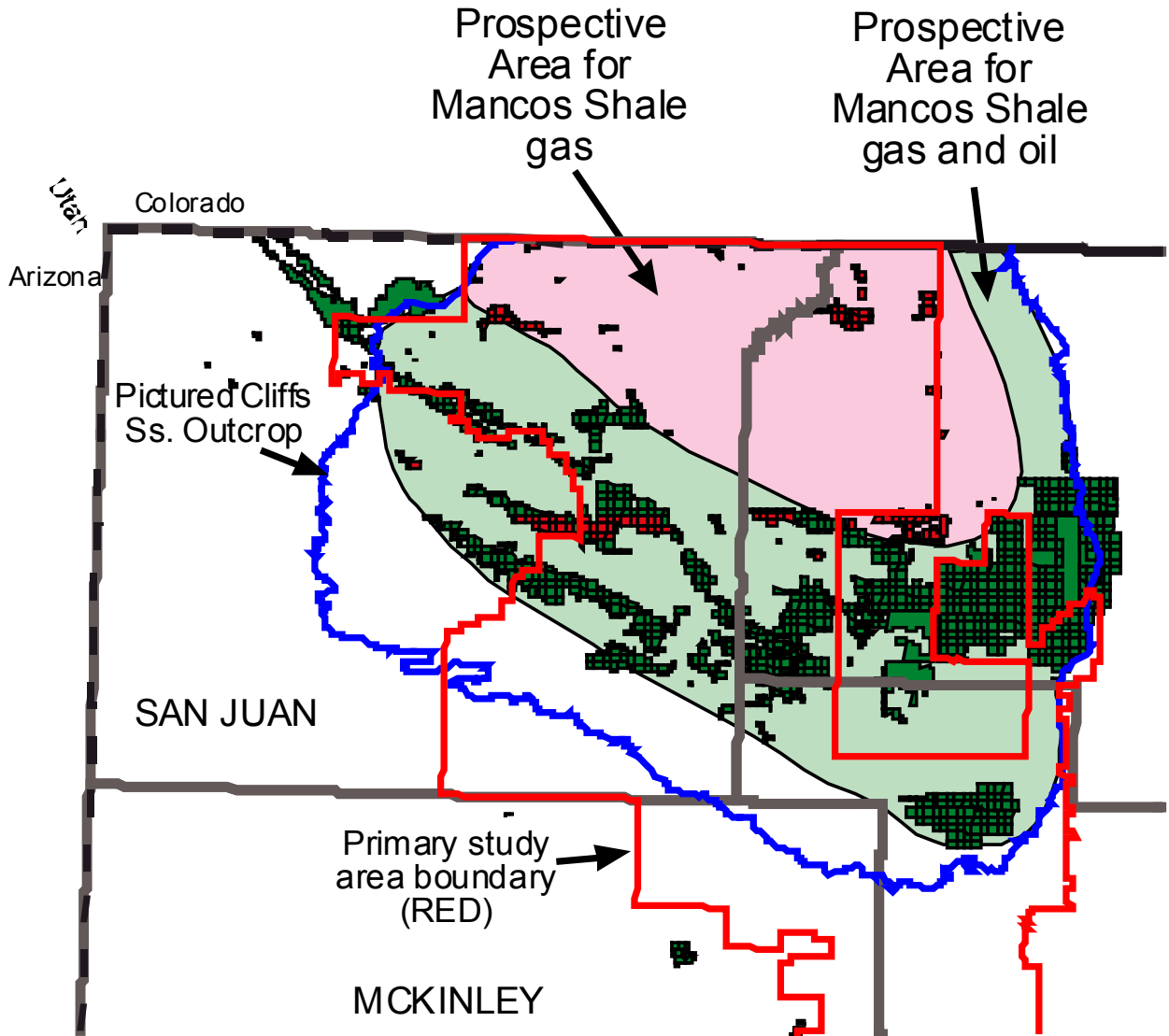
Figure 5.6-2 Map of San Juan Basin showing oil and gas fields that produce from Mancos Shale reservoirs (includes Gallup reservoir). Prospective areas for additional oil and gas development are indicated.

Many wells producing from the Mancos Shale (not the shoreface Gallup Sandstone) are designated as "Gallup". Historically, the Mancos/Gallup reservoirs have yielded nearly 0.7 Tscf of gas and 146 mmbo (including condensate) and would naturally be considered a major reservoir in the San Juan Basin. However, most existing Mancos Shale and Gallup Sandstone reservoirs are approaching depletion and are marginally economic. Most are not currently considered candidates for increased density development or further enhanced oil recovery operations. It is anticipated that many Mancos/Gallup wells will need to be plugged within the term of this RFD. Of particular concern are the marginally economic Gallup producers located in the fringe areas of the study area, which don't have additional pay behind pipe. A significant number of active

Gallup wells produce less than 30 barrels of oil per month per well. The distribution as shown in Figure 5.6-3 illustrates that the majority of Gallup wells are low-volume, marginal oil producers.
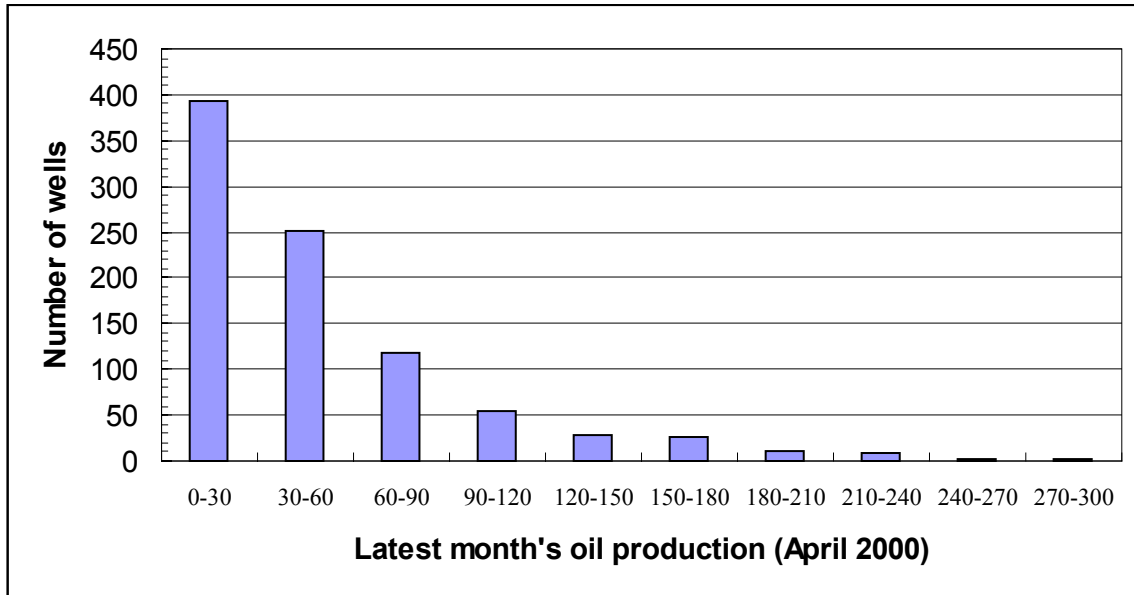
Figure 5.6-3: San Juan Basin "Gallup" wells; number of wells vs. monthly production volume

Figure 5.6-4 shows the distribution for low volume oil producers; those that produce less than 30 barrels of oil per month. The graph shows two areas of increased well count: those which are classified as gas wells (>500 mscf/month) and are likely to be economic, and those wells which are likely candidates in the near future for P&A; i.e., produce < 30 bo/month and < 50 mscf/month, respectively. The total wells under the latter category are 111.
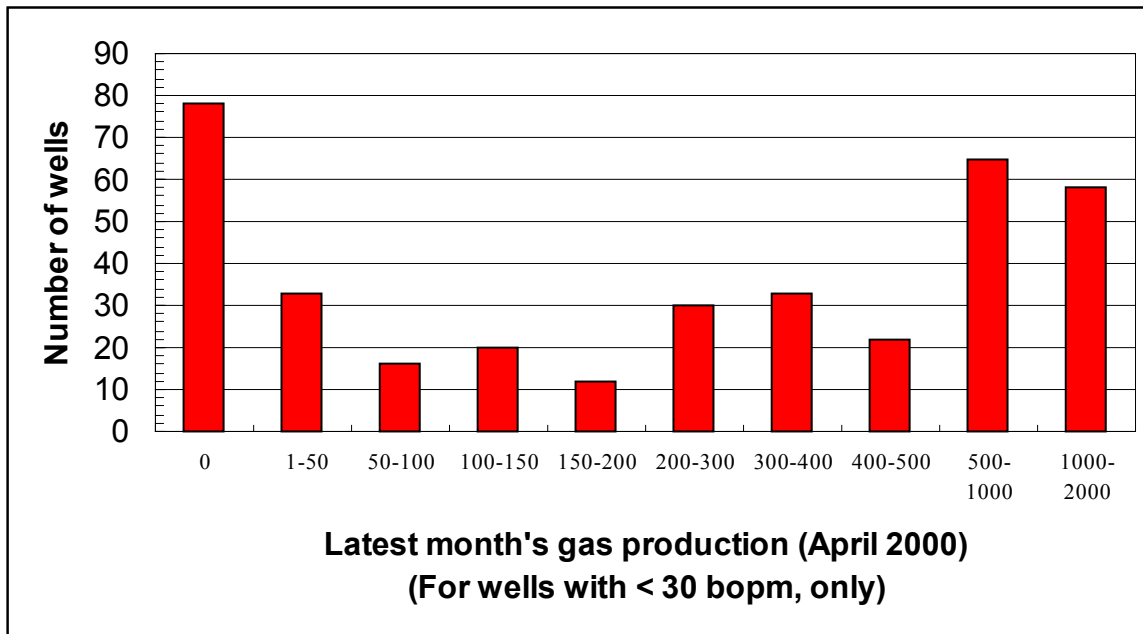
Figure 5.6-4: San Juan Basin "Gallup" wells; number of marginal oil wells vs. monthly gas production

5.6B Potential 20 Year Development

The U.S. Geological Survey, in their 1995 assessment of U.S. reserves assigned an estimated 68 mmbo and 34 Bscf to the "fractured Mancos" play. Their assumption was that the known productive part of the basin is underdeveloped and is primarily an oil reservoir. As shale gas reservoirs like the Lewis Shale are being developed, it is clear that the similar Mancos Shale may have significant potential as a shale gas candidate in the 50 township "sweetspot" of Figure 5.6-2. The Mancos in this part of the basin should be fairly liquid-free and, although low in permeability, could be gas productive. There are two possibilities for significant future gas production from the Mancos Shale gas reservoir: 1) as discreet zones of better matrix permeability or fracture density, as has been the case with most oil producing Mancos fields in the past, or 2) as a blanket, continuous-type of reservoir common to other U.S. shale gas plays like the Barnett, Antrim and Ohio shales. Given current density of wells that have drilled through the Mancos Shale, all discreet reservoir zones have been drilled, but may not have been recognized. Unfortunately, common well log suites are insufficient for reservoir characterization alone, core from the area of interest is sparse, and most operators currently tend not to evaluate the Mancos when drilling Dakota wells.

Given the probability that the Basin Dakota pool will undergo extensive increased density drilling in the next 20 years, there is excellent potential for the Mancos to be further evaluated. If it should prove to be even marginally productive, it could be commingled with the Dakota in a manner similar to the Lewis Shale/Mesaverde development projects underway. It is possible a multi-Tcf reserve might be realized in

the next 20 years.   This production would likely be achieved through addition of behind-pipe reserves in new and existing Dakota wells rather than drilling of new Mancos-specific wells. Outside of the gas productive area, it is probable that Mancos/Gallup-only only wells will be drilled to access the fractured Mancos oil play, primarily in the southeastern portion of the basin. Predicted number of wells to be drilled over the twenty-year life of the RFD is 300 additional wells including development and exploration wells.

5.7 Entrada Sandstone reservoir

5.7A Geology and historical development

The Entrada Sandstone is a Jurassic eolian deposit that unconformably overlies the Triassic Chinle Formation. It is overlain by the Jurassic Todilto Limestone which is composed of variable petroliferous limestone and gypsum. The Todilto is both source rock and seal for small-area oil reservoirs in dune facies of the upper Entrada. The Entrada-Todilto system has yielded nine significant small area (<1 mi^2), stratigraphically trapped oil fields in the southeastern part of the San Juan Basin (Figure 5.7-1; Table 5.7-1).

Table 5.7-1 Entrada Sandstone oil pools in southeastern San Juan Basin. Data compiled from Vincelette and Chittum (1981) and from New Mexico Oil and Gas Engineering Committee Annual Report (1998).

Oil Pool	Location	Year Disc.	# wells	Cumulative oil to 1/'99
Leggs	21N-10W	1977	3	228,776
Snake Eyes	21N-8W	1977	2	170,014
Ojo Encino	20N-5W	1976	2	76,440
Arena Blanca	20N-5W	1985	1	37,805
Papers Wash	19N-5W	1976	5	1,247,255
Papers Wash S	19N-5W	1976	1	127,114
Eagle Mesa	19N-4W	1975	4	1,192,417
Media	19N-3W	1953	7	987469
Media SW	19N-3W	1972	4	694,524
Total			29	**4,761,814**

5.7B Potential 20 year development

There is a high probability that within the 20-year time span anticipated by this RFD, additional Entrada oil exploration will be carried out in the areas outlined in Figure 5.7-1. The structure and stratigraphy of the existing oil fields are probably seismically resolvable using 3-D seismic methods. Conceivably, the entire oil-prone area would be a candidate for reflection seismic acquisition, with spacing as close as ¼ mile between lines required to locate new oil fields.   Although there is the potential for surface disturbance from new seismic data acquisition, the interpreted data should yield discreet targets for drilling and minimize drilling-related surface disturbance. Exploration wells would target small structures on the order of 1 mi^2 or less. Discoveries would necessitate development wells on 40 acre spacing (average of 3 producing wells per field based on Table 5.7-1).

In most of the deeper northern portion of the San Juan Basin the formation is generally "tight" and considered to be nonproductive (Vincelette and Chittum, 1981). However, it is probable that the Entrada/Todilto system has reached thermal maturity for gas generation (thermal cracking of oil) in that area. Thus, potentially significant gas production cannot be ruled out. "Tight sand" gas production could be possible from any

of the Entrada lithofacies, thus seismic data might not be required for exploration for discreet dune targets. Such Entrada gas producing wells would probably be "new drills" because few wells in the deep basin have been drilled below the Dakota Sandstone. Predicted total number of wells to be drilled in the Entrada play is 80 wells. The majority of these wells will be drilled as exploratory tests for oil in relatively undeveloped areas in the southernmost part of the basin.
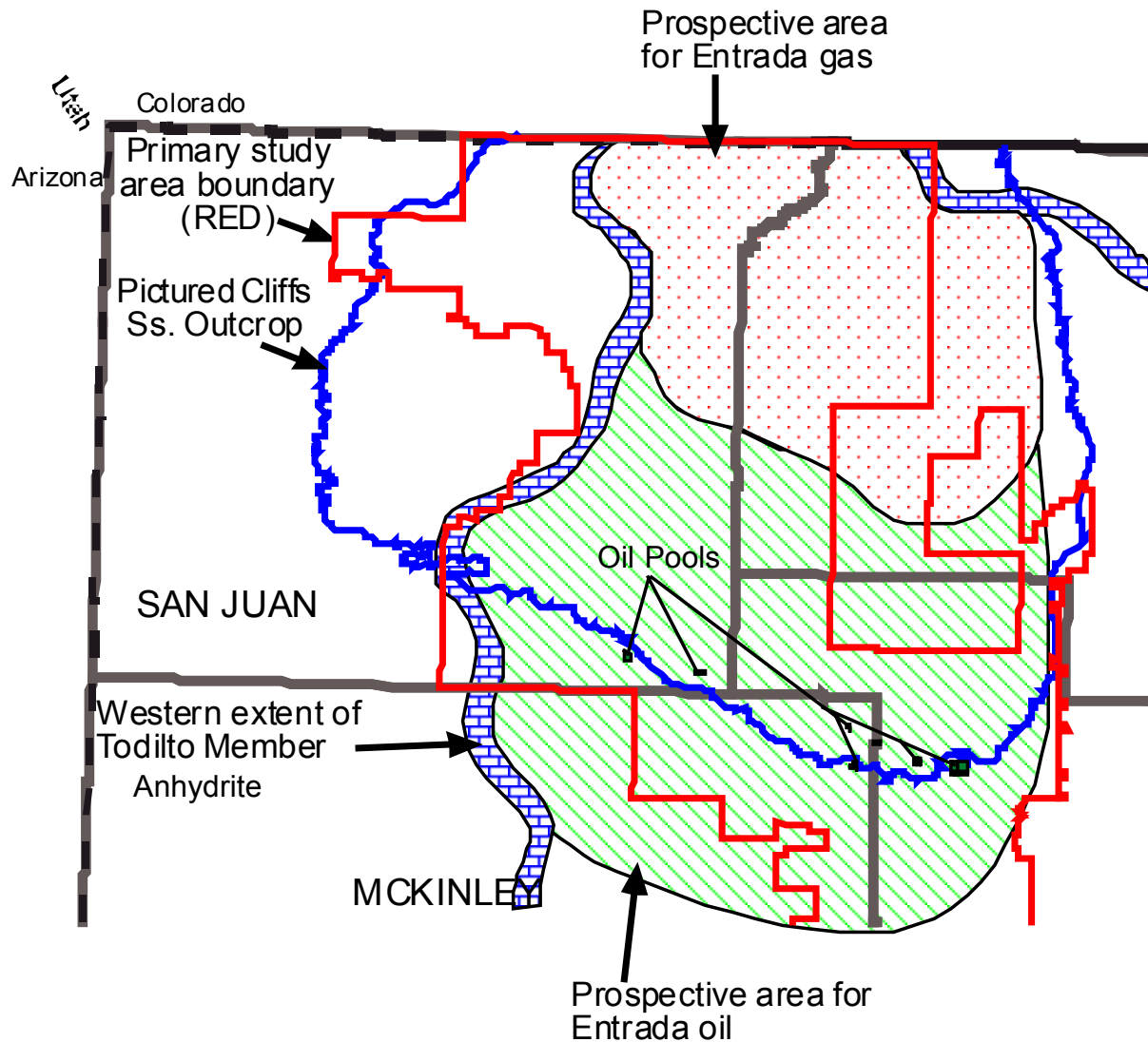
Figure 5.7-1 San Juan Basin Entrada Sandstone play. The outcrop of the Pictured Cliffs Sandstone is shown for reference. The Entrada play is limited to the area where it is overlain by the Todilto Member of the Wanakah Formation. The gas prospective area is speculative. Oil pools in the oil prospective area are noted. (Modified from Vincelette and Chittum, 1981)

5.8 Pennsylvanian reservoirs

5.8A Geology and historical exploration

There is currently no production from Pennsylvanian reservoirs on federal lands within the area covered by this RFD. However, the Pennsylvanian Four Corners platform, adjacent to the San Juan Basin on the west, has yielded more than 1/3 Tscf of natural gas and 13 mm barrels of oil from the Pennsylvanian Paradox Group.   From the sparse information available, it is apparent that the platform once extended further east than its present extent, across the San Juan Basin. It was later dissected during the Laramide orogeny such that the east end of the platform was downwarped into the basin. Therefore, the productive units on the Four Corners Platform are probably also present within the basin, at much greater depth and level of thermal maturity. In fact, the current distribution of productive fields west of the basin suggests affinity to possible maturity levels nearby in the basin (Figure 5.8-1).

The Pennsylvanian strata of the San Juan Basin have potential for contributing large natural gas additions to San Juan Basin reserves. However, due to the depth of drilling to the Pennsylvanian and the expense of drilling through and protecting present-producing reservoirs, there have been relatively few attempts to evaluate the play. "…despite the presence of the Rockies' largest stratigraphic oil accumulation just 40 miles away (from New Mexico) in the Aneth field of southeast Utah's Paradox Basin, only 20 wells have penetrated time-equivalent Pennsylvanian carbonates underlying nearly 8,000 square miles of the San Juan Basin…" (Grant and Foster, 1989).

The most recent exploration program (1997-2000) emphasized 3-D seismic interpretation for identification of drilling targets. Unfortunately, that exploration program failed to yield a commercial discovery. An anecdotal comment offered recently by a group of operators is that "we try this every twenty years or so and fail…we just failed again…we are not due to try again for another twenty years". However, in all probability, declining basinwide production coupled with a strong market will tempt operators to reevaluate the play again soon.

5.8B   Potential 20 year development

Given the existing information, it would be premature to predict the number of wells that might be drilled should a Pennsylvanian discovery be made. Two development options are possible. If new fields are discovered that are structurally controlled, they would tend to be areally small, discreet fields, probably less than 1/3 of a township in size. Such fields on the Four Corners Platform to the west of the basin ranged from 4 to 68 total wells with well spacing ranging from 40 (oil) to 640 (gas) acres per well and covering <7000 acres each. If new discoveries are made in a blanket-type, fractured, tight-gas reservoir, the potential for 1 or 2 wells per section developed over an area of many townships is possible. Assuming the latter case, the well costs combined with the typically low production rates of such reservoirs would cause development to proceed

slowly and cyclicly, driven primarily by periods of better economic return. Total number of wells anticipated to be drilled, including development and exploratory wells, is 20.
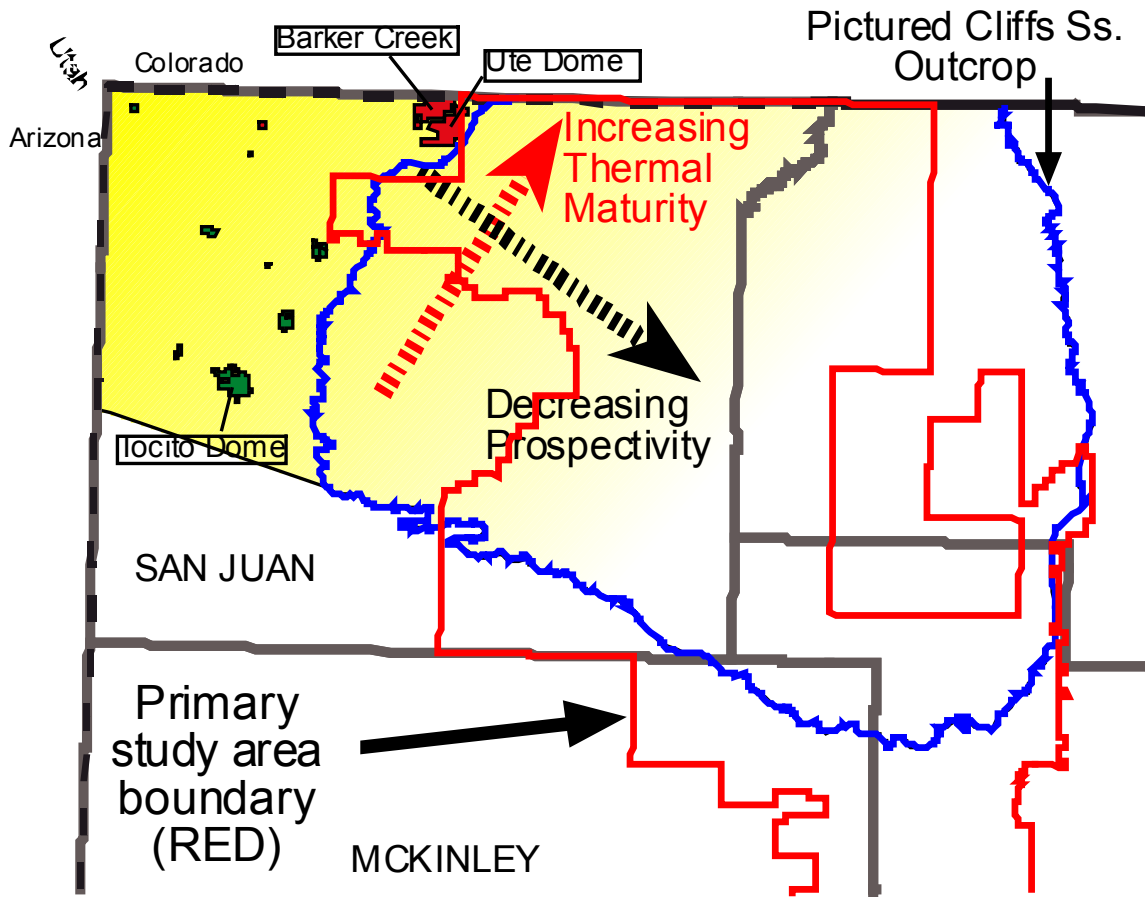
Figure 5.8-1 Map depicting the prospective area for Pennsylvanian production in the San Juan Basin. Basin-flank fields include Barker Creek, Ute Dome and Tocito Dome. Thermal maturity of the Pennsylvanian strata probably increases northeastward (to basin structural axis).

Chapter 6
Drainage and Flow Characteristics of the Major Gas Reservoirs

6.1 Introduction

The hydrocarbon (oil and gas) producing formations of San Juan Basin, in descending order, are summarized in **Table 6.1** [Huffman, 1987; Choate *et al*., 1984, Fassett, 1991; Dutton *et al*., 1993; Whitehead, 1993; Dube *et al*., 2000; IHS/Dwights Database, 1999]. Table 6.1 also shows the well count, cumulative production (through May 1999; selected formations), and gas-oil ratio compiled from IHS/Dwights Database [1999] for the New Mexico State portion. Such information is to show the relative importance between the formations and between oil and gas production for a given formation. Information of the Lewis Shale is lacking, because it is a very new play and also because it is predominantly commingled with other producing formations (e.g., Mesaverde and Dakota) [Dube *et al*., 2000]. As shown in Table 6.1, current primary gas production is from the reservoirs of the Fruitland Coal, Pictured Cliffs, Mesaverde, and Dakota. These four formations plus the Fruitland Sand and Chacra (total six gas producing formations) were selected for further analysis (Chapters 4 and 5). All six formations are Upper Cretaceous Age.

Formation/Period	Play Oil	Play Gas	Total No. of Wells [#]	Cumulative Production [#] Oil (10³ bbls)	Gas (Tcf)	Water (10³ bbls)	Gas-Oil Ratio (Bcf/bbl)
Tertiary							
San Jose		λ	20	0	0.0019	21	–
Nacimiento		λ	8	0.7	0.0006	12	979
Ojo Alamo		λ	4	0	0.0003	7	–
Cretaceous							
Farmington		λ	56	–	–	–	–
Fruitland Sand		λ	241	34.6	0.0570	147	1,645
Fruitland Coal		λ	2,504	367.1	4.462	116,337	12,153
Fruitland/Pictured Cliffs		λ	320	–	–	–	–
Pictured Cliffs		λ	5,830	682.7	2.304	8,389	3,375
Lewis Shale		λ	–	–	–	–	–
Chacra		λ	693	47.6	0.198	306	4,153
Mesaverde		λ	5,320	30,221.1	6.287	19,992	208
Gallup	λ		2,484	59,663.2	0.552	165,108	9
Tocito	λ		36	–	–	–	–
Sanastee	λ		6	–	–	–	–
Mancos Shale	λ		253	–	–	–	–
Greenhorn	λ		33	–	–	–	–
Graneros	λ		23	–	–	–	–
Gallup-Dakota	λ		783	–	–	–	–
Mancos-Dakota	λ		9	–	–	–	–
Dakota	λ	λ	5,202	32,995.4	3.955	49,751	120
Jurassic							
Entrada	λ		37	–	–	–	–
Pennsylvanian	λ	λ	104	8,715.2	0.0207	25,383	2
Mississippian	λ	λ	8	–	–	–	–
Devonian	λ		3	–	–	–	–

Table 6.1 – Hydrocarbon producing formations, well count, and cumulative production, San Juan Basin, New Mexico State portion. (Data from I.H.S. Energy, through May 1999)

Fig. 6.1 presents the historical *active gas* well counts of the six selected gas formations (Fruitland Sand, Fruitland Coal, Pictured Cliffs, Chacra, Mesaverde, and Dakota). The noticeable increasing well counts starting around 1975 and around 1980 for the Mesaverde and the Dakota, respectively, basically are the responses of the infill-drilling approvals by the NMOCD (New Mexico Oil and Gas Conservation Division). Also note the high drilling/development of the Fruitland Coal starting around 1989. A second increasing well-count trend is noted around 1995 for the Mesaverde, Dakota, and Fruitland Coal, and is most significant for the Mesaverde.
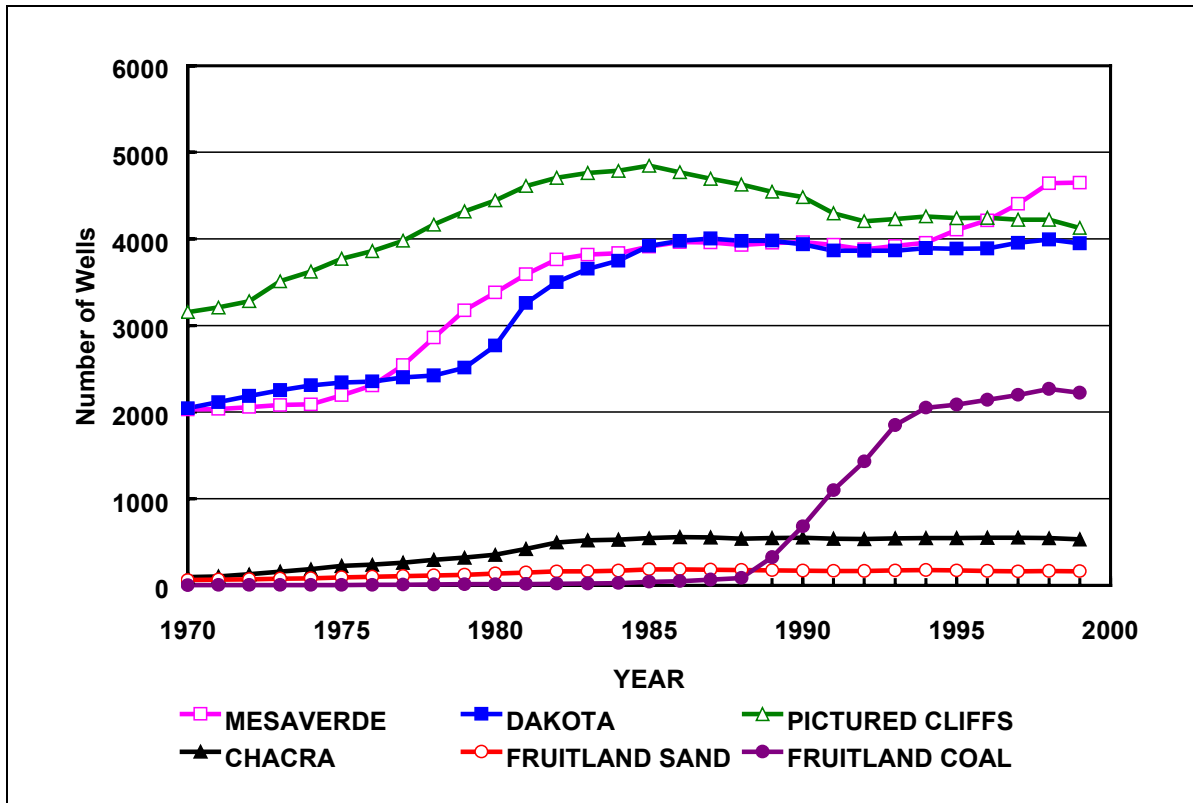
Fig. 6.1 – Historical gas well count by formation, San Juan Basin, New Mexico State portion.

Table 6.2 presents the area coverage and well density as defined by well locations. Number of townships and sections covered by the producing wells are compiled for the six selected gas producing formations. Average well density is reflected by the number of wells per section: "Two wells per section" and "four wells per section" correspond to 320-acre and 160-acre spacing, respectively. Average well densities of the Mesaverde and Pictured Cliffs are between three and four wells per section, that of the Dakota and Chacra are between two and three wells per section, and that of the Fruitland Sand and Fruitland Coal are between one and two wells per section. Overall, none of the six gas producing formations exceeds the 160-acre spacing (four wells per section). In practice, field development is highly dependent on the observed/inferred well performance/reservoir quality. Area with better well performance or reservoir quality is always developed more fully than area of poor performance/quality.

Formation	Total No. of Wells	No. of Townships Covered	No. of Sections Covered	Average No. of Wells per Section
Fruitland Sand	241	32	152	1.56
Fruitland Coal	2,504	95	1,505	1.66
Pictured Cliffs	5,830	108	1,894	3.08
Chacra	693	33	322	2.15
Mesaverde	5,320	90	1,621	3.28
Dakota	5,202	114	1,912	2.72
Total	19,790	472	7,406	–

Table 6.2 – Area coverage and well density, San Juan Basin, New Mexico State portion.

Fig. 6.2 illustrates the area coverages of the six gas producing formations in terms of townships in the New Mexico State portion. The well patterns follow, more or less, the so-called gas producing "fairways" that trend northwest across the central part of the basin. Again, in terms of area coverage, the four major gas-producing formations are the Fruitland Coal, Pictured Cliffs, Mesaverde, and Dakota.
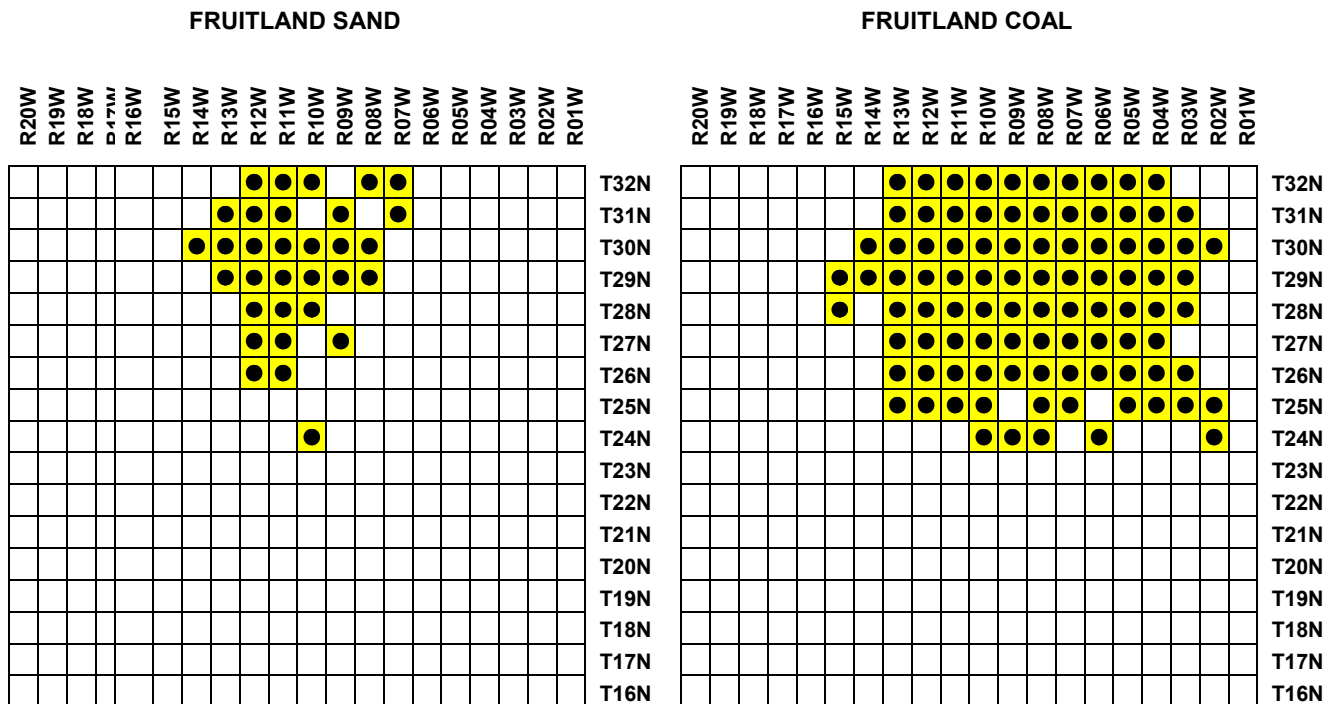
Fig. 6.2 – Producing-well and study area (township) coverage by gas producing formation, San Juan Basin, New Mexico State portion
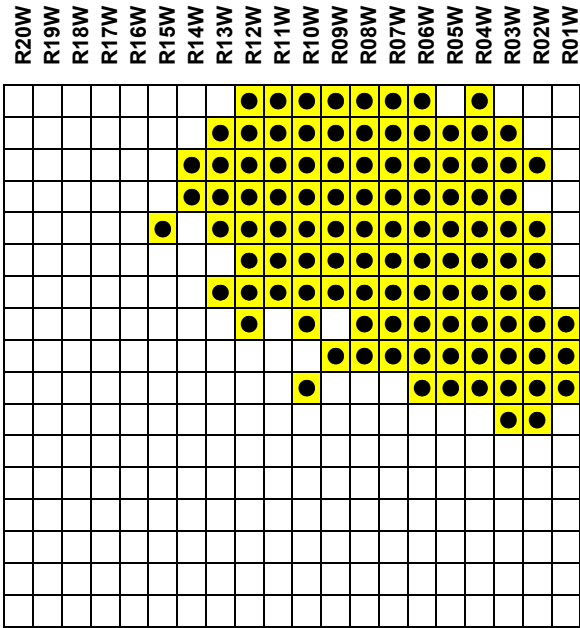
Fig. 6.2 – Cont'd.

6.4
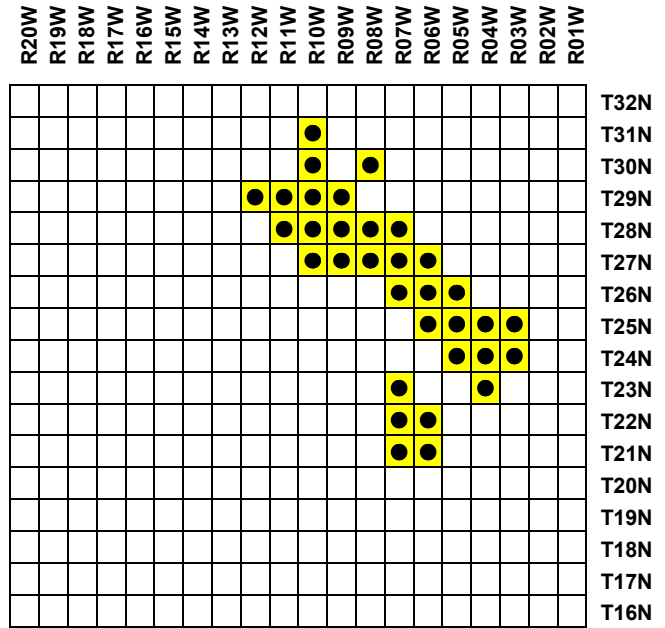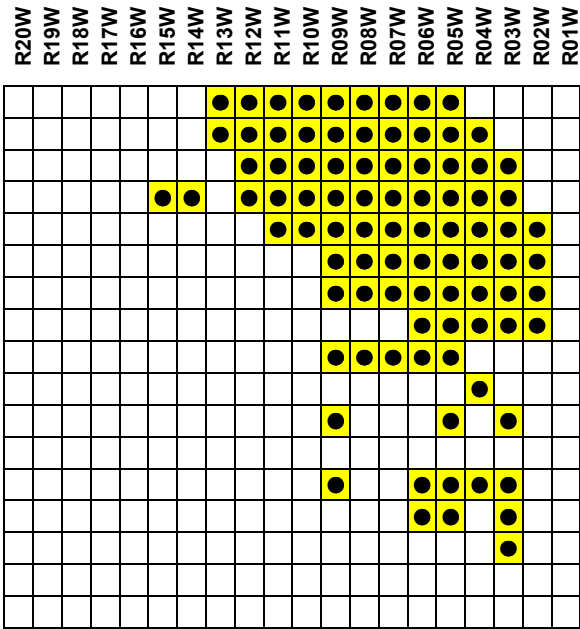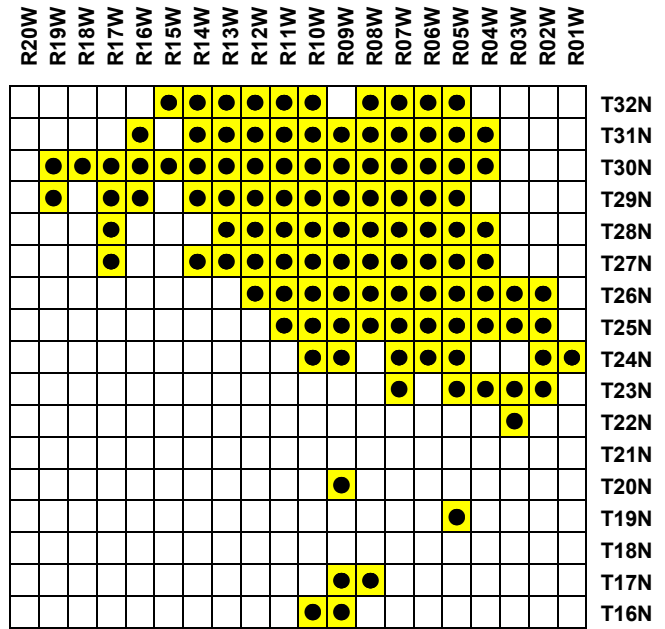
6.2 Objectives

The objective of this study is to determine the drainage and flow characteristics from the *well performance* data of the gas producing formations in the New Mexico State portion of the San Juan Basin. Specific questions we try to answer for a given gas producing formation are:

- How much volume and area are drained by a well?
- How much of the initial gas-in-place?
- What is the recovery factor?
- How efficient of the gas production?
- What is the flow capacity?

The first three are related to the volumetric behavior while the last two are related to the flow characteristics of a producing formation. Both volumetric and flow characteristics are essential elements in a long-term field development plan.

6.3 Study Methodology

The study has two major parts: (1) analysis of historical formation/basin-based gas producing trends, and (2) analysis of well-based gas production data. Production data (1970 through May 1999) is obtained from the IHS/Dwights database [1999]. Results of both parts are cross-checked with each other to ensure the reasonableness of the interpretation. Analysis of individual well production data, Part (2), need further explanation and is described below.

Study Area. This study is intended to be at a formation/basin scale. This requires the area (for each formation) be covered as large as possible. A township-based analysis was chosen for the six selected gas-producing formations within the New Mexico State portion of the San Juan Basin. At least one well is selected randomly for analysis from each township. This means that every township with producing well(s) of a particular gas formation is studied at least for one well; see Fig. 3. Actual number of wells analyzed is listed in **Table 6.3**. The township coverage by the sampled wells is the same as that of the producing wells (see Tables 6.2 and 6.3).

Formation	No. of Wells Analyzed	No. of Townships Covered
Fruitland Sand	32	32
Fruitland Coal	95	95
Pictured Cliffs	108	108
Chacra	48	33
Mesaverde	206	90
Dakota	296	114
Total	785	472

Table 6.3 – Well analyzed and area coverage, San Juan Basin, New Mexico State portion.

Well Production Data Analysis. A recently developed methodology of using type-curve for tight-gas production data analysis is adopted for this study. Theoretical background, working equations, and examples were described by Chen and Teufel [2000] and will not be presented here. A spreadsheet program has been developed to provide easier, quicker, and more reliable processing and analysis of the large amounts of production data. Well production data (through May 1999) is obtained from the IHS/Dwights database [1999]. Production data analysis of the Fruitland Coal, however, needs special interpretation.

Two unique features of the Fruitland Coal complicate its production data analysis and interpretation. These are: (1) gas production from the Fruitland Coal is primarily by a desorption mechanism, instead of the conventional type of depletion process, and (2) gas production begins only after the water in the cleat system is more or less depleted. There is no simple and easy method to analyze the production data of a coal well if the above two features are to be considered rigorously. Analysis/interpretation of coal wells based on the adopted type-curve method is not straightforward, but not impossible. The key is the understanding of the behavior of a coal well, which allows a translation/visualization from the actual system to an equivalent system. In fact, we noted that half of our sampled coal wells (Fruitland) exhibit *interpretable* behavior similar to that of a conventional gas well. To our best knowledge, there is virtually no published study regarding to the validity/invalidity of production data analysis of a coal well using conventional-gas techniques. However, we do admit that the analysis of the Fruitland Coal in this study is more empirical nature than the other conventional gas formations.

Overall, we consider the adopted method/tool as the "optimal" for this study considering the large number of wells, large area coverage, and multiple producing formations involved for a very limited project time frame (several months).

Formation and Fluid Properties. Formation and fluid PVT properties assumed for type-curve production data analysis are summarized in **Table 6.4**. These properties are compiled from Dutton *et al.* [1993], Whitehead [1993], and other various published and unpublished sources. Of these average properties, information of reservoir pressure and producing thickness are the most difficult to obtain (or to assume). They are also critical to the estimations of reservoir properties and drainage characteristics. A single reservoir pressure, compromising the older (higher pressure) and younger (lower pressure) wells, is adopted for each formation. Similarly, a single producing well pressure, compromising the higher line-pressure at earlier times and the lower line-pressure at later times, is assumed for all formations and for all wells. Producing thickness is assumed to be the top-bottom perforation interval (for each well) reported in IHS/Dwights database [1999]. This is the most logical and the easiest way to handle the large amounts of production data in a reasonable time while still taking into account the well-by-well variation of the producing thickness.

Finally, it should be pointed out that the quality of the matching process itself (matching between observed production data with the type curves) is only weakly dependent on the assumed formation and fluid properties. Type-curve matching, just like any other reservoir engineering tools (e.g., reservoir simulations) involving production data, is highly dependent on the data quality and the knowledge of operating conditions. The assumed formation and fluid properties, however, do affect the estimated values of reservoir properties and drainage

characteristics.

Reservoir and PVT Data		Fruitland Sand	Fruitland Coal	Pictured Cliffs	Chacra	Mesaverde	Dakota
Reservoir pressure, p_i	psi	1,000	1,400	1,000	1,200	1,200	2,000
Flowing BHP, p_{wf}	psi	200					
Producing thickness, h	ft	Well Basis					
Porosity, ϕ	%	10	10	10	10	9	8.5
Water saturation, S_{wi}	%	50					
Wellbore radius, r_w	ft	0.33					
Frac. of 360° open to flow, σ	Frac.	1					
Reservoir temperature, T	°F	114	114	120	150	160	225
Specific gravity, γ	–	0.6	0.61	0.67	0.6	0.6	0.72
Water compressibility, c_w	psi^{-1}	$3{\times}10^{-6}$					
Rock compressibility, c_f	psi^{-1}	$6{\times}10^{-6}$					
Mole fraction of N_2	Frac.	0					
Mole fraction of CO_2	Frac.	0					
Mole fraction of H_2S	Frac.	0					
Abandonment rate, q_{abd}	Mscf/d	5					

Table 6.4 – Reservoir and fluid PVT properties, San Juan Basin, New Mexico State portion.

6.4 Analysis of Historical Gas Producing Trends

Total-Well Analysis. Figs. 6.3a and 6.3b present the historical annual and cumulative gas production (all wells), by the six selected gas formations. In Fig. 3a, the declines of the last data points (year 1999) should be neglected because of incomplete full-year information. The sharp increase in the gas production from Fruitland Coal (after around 1985) is clearly illustrated in both Figs. 6.3a and 6.3b.

Fig. 6.3 – Historical gas production by formation (all wells), San Juan Basin, New Mexico State portion; (a) annual gas production, (b) cumulative gas production.

Table 6.5 presents the last 3-full-year (1996-1998) average gas flow rates corresponding to Fig. 6.3a. These 3-year average gas flow rates, in the decreasing order, are the Fruitland Coal, Mesaverde, Dakota, Pictured Cliffs, Chacra, and Fruitland Sand. Note that the sum of the last 3-year average flow rates from the five non-coal formations (436.4 Bscf/yr or 1,195.7 mmscf/day) is less than that of Fruitland Coal (605.1 Bscf/yr or 1,657.9 mmscf/day). In terms of percentage, recent gas production rate from the Fruitland Coal contributes approximately 58% of the total gas production rate from the six gas producing formations examined here; see Table 8.5.

| Formation | Last 3-Year Average Gas Flow Rate (1996-1998) | | | | | |
| | All Wells | | | Per Well | | |
	Annual (Bscf/yr)	Daily (mmscf/day)	Percentage (%)	Annual (mmscf/yr)	Daily (mscf/day)	Percentage (%)
Fruitland Sand	1.8	5.0	0.2	11.1	30.4	2.8
Fruitland Coal	605.1	1,657.9	58.1	274.7	752.6	69.2
Pictured Cliffs	73.4	201.1	7.0	17.4	47.5	4.4
Chacra	5.5	15.1	0.5	10.1	27.6	2.5
Mesaverde	242.3	663.9	23.3	54.8	150.0	13.8
Dakota	113.4	310.7	10.9	28.8	78.8	7.3
Total	1,041.5	2,853.7	100.0	396.9	1,086.9	100.0

Table 6.5 – Last 3-year average gas flow rate, San Juan Basin, New Mexico State portion.

Current cumulative gas production (through May 1999; Fig. 6.3b), in the decreasing order, are the Mesaverde, Fruitland Coal, Dakota, Pictured Cliffs, Chacra, and Fruitland Sand (see also Table 6.1). The trends shown in Figs. 6.3a and 6.3b, however, suggest the followings:

- There is no strong indication that production trend of the Fruitland Coal is approaching the "plateau" such as that shown for the other five non-coal formations; see Fig. 6.3b.
- There is a possibility that Fruitland Coal may catch up Mesaverde and becomes the largest gas producing formation in both flow rate and cumulative production.
- There is no indication that the order of gas production, either flow rate or cumulative production, of the five non-coal (conventional) formations will change.
- All the five non-coal gas formations appear to *slowly* approach their respective "plateau" (see Fig. 6.3b). This implies that all the five non-coal formations are entering a "late" depletion stage (produced at least 50% of the producible gas assuming fixed operating conditions). Production of the *remaining* gas is expected to be a very slow and long process. Maintaining production above economical rate will then becomes a concern.

Estimated ultimate recoveries (EUR's) of the Pictured Cliffs, Chacra, Mesaverde, and Dakota formations, as reported by Dutton *et al*. [1993], are listed in **Table 6.6**. Note that, assuming Dutton *et al*.'s [1993] EUR are accurate, current gas production (through May 1999; Table 1) of the Pictured Cliffs and Chacra have reached 84% and 73% of their EUR's, respectively, while that of Mesaverde and Dakota have reached 51% and 54% of their EUR's, respectively. It is worthwhile to mention that (1) the time frame associated with Dutton *et al*.'s [1993] EUR was not reported, and (2) it took approximately at least 40 years to reach the above computed percentages. The slow drainage process of the San Juan Basin is suggested by the above simple

calculations.

Formation	Cumulative Gas Production [1] (Tscf)	Estimated Ultimate Recovery (EUR) [2] (Tscf)	Percentage Recovered (%)
Fruitland Sand	0.057	–	–
Fruitland Coal	4.462	–	–
Pictured Cliffs	2.304	2.757	84
Chacra	0.198	0.272	73
Mesaverde	6.287	12.315	51
Dakota	3.955	7.322	54

[1]   Through May 1999 [IHS/Dwights Database, 1999].
[2]   Dutton *et al*. [1993].

Table 6.6 – Recovery factor based on EUR, San Juan Basin, New Mexico State portion.

Per-Well Analysis. Figs. 6.4a and 6.4b present the historical annual and cumulative gas production for a *per active-gas-well* basis. The intention is to minimize the effect of well number, as can be seen from the reduced spreads in Fig. 6.4 from that in Fig. 6.3. Consider Fig. 6.4a. Similar to Fig. 6.3a, the declines of the last data points (year 1999) should be neglected because of insufficient full-year information. All the five non-coal formations exhibit a declining trend before around 1986, and then a slightly inclining or steady trend thereafter. The impact of this second small increasing trend on the reserves appears to be small. This argument is based on the rather smooth trends of the cumulative production (non-coal formations) shown in Fig. 6.3b. The Fruitland Coal, however, exhibits a dramatic increasing trend after around 1980 for both annual production (Fig. 6.4a) and cumulative production (Fig. 6.4b).

Last 3-full-year (1996-1998) average per-well gas flow rates corresponding to Fig. 6.4a are also presented in Table 6.5. These 3-year average per-well gas rates, in the decreasing order, are the Fruitland Coal, Mesaverde, Dakota, Pictured Cliffs, Fruitland Sand, and Chacra. Similar to the total-well case (Fig. 6.3a), the sum of the past 3-year per-well average flow rates from the five non-coal formations (122.0 Bscf/yr or 334.3 mmscf/day) is less than that of Fruitland Coal (274.7 Bscf/yr or 752.6 mmscf/day). In terms of percentage, per-well gas production from the Fruitland Coal contributes approximately 69% of the total per-well gas production from the six gas producing formations examined here; see Table 6.5. Recent dominance of gas production from the Fruitland Coal is clearly demonstrated by the above historical statistics.

Current per-well cumulative gas production (through May 1999) corresponding to Fig. 6.4b, in the decreasing order, are the Fruitland Coal, Mesaverde, Dakota, Chacra, Pictured Cliffs, and Fruitland Sand. Note that, on a per-well basis,

- Fruitland Coal is the largest gas producing formation in terms of both flow rate and cumulative production.
- Chacra performs better than Pictured Cliffs in terms of per-well cumulative gas production.

The second point probably is not very significant, because gas production from the Chacra is relative small compared to the top four major gas producing formations.
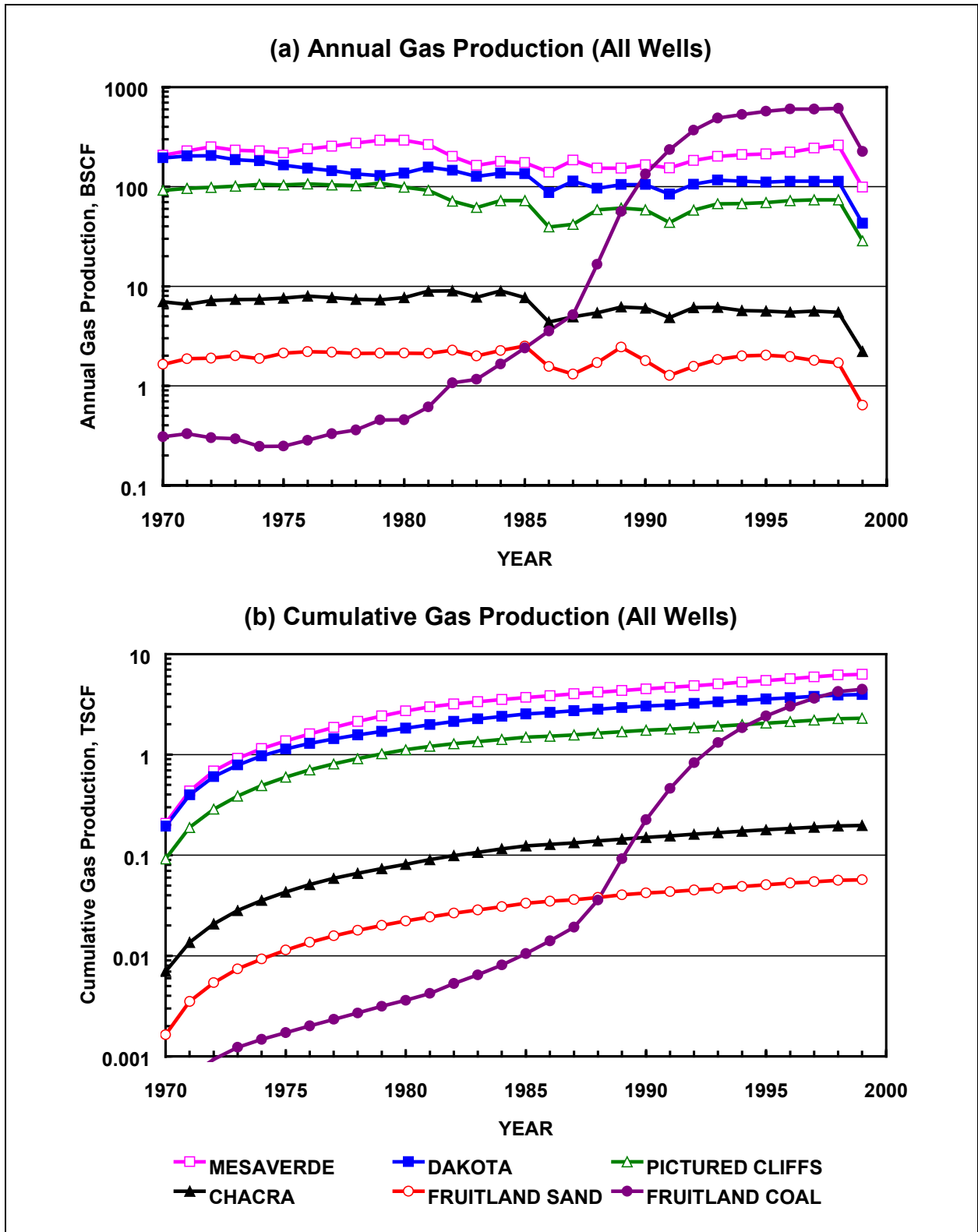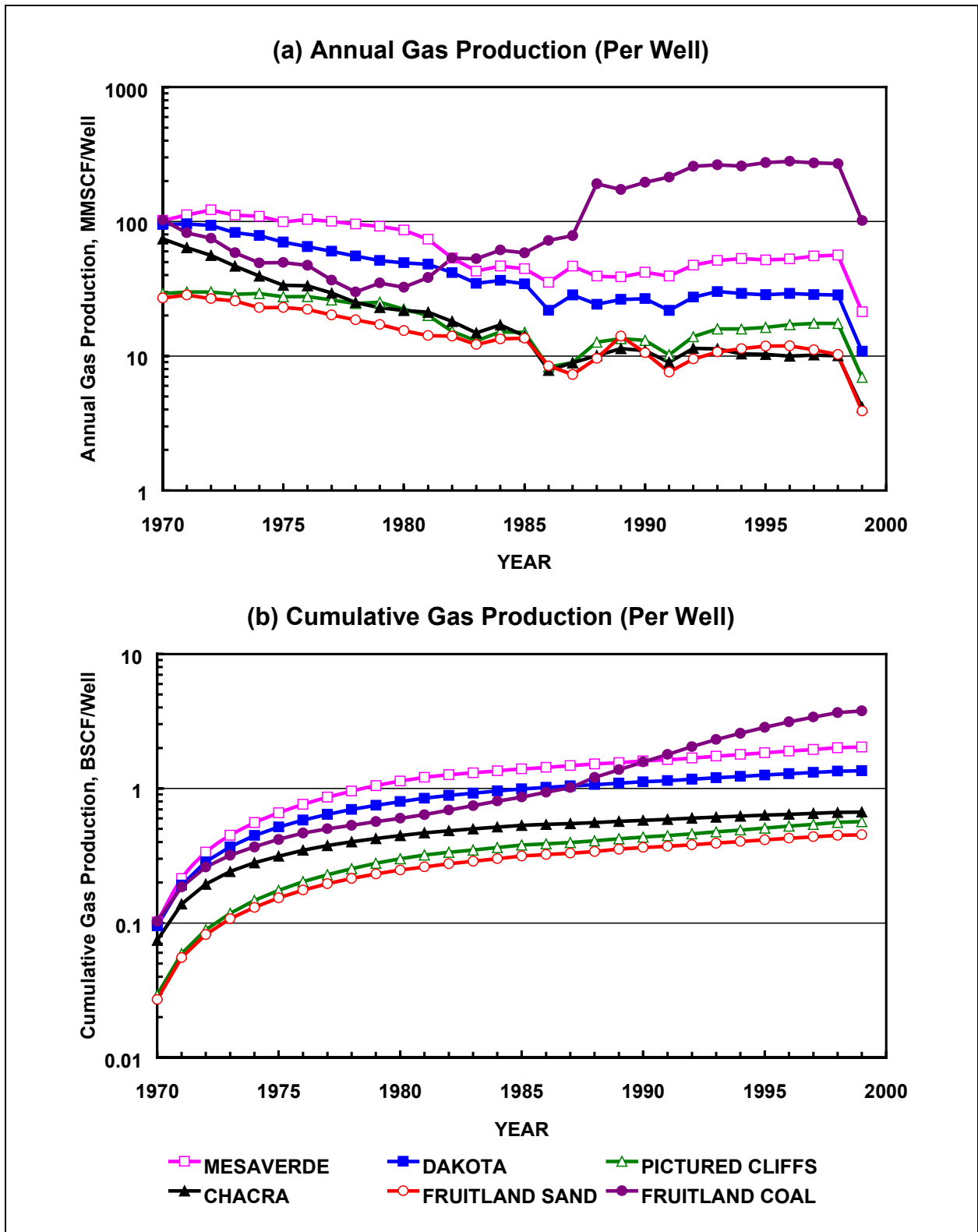
Fig. 6.4 – Historical gas production by formation (per well), San Juan Basin, New Mexico State portion; (a) annual gas production, (b) cumulative gas production.

6.5 Analysis of Well Production Data

Drainage Characteristics. Table 6.7 presents the *average* per-well drainage volume, initial gas-in-place (IGIP), recovery factor (through May 1999) and drainage area for each gas producing formation. As expected, the top four major gas producing formations reflected by the IGIP are the Fruitland Coal, Mesaverde, Dakota, and Pictured Cliffs.

Formation	Drainage Pore Volume (10^6 ft^3)	Initial Gas In Place, IGIP (Bscf)	Recovery Factor [1] (% IGIP)	Drainage Area [2] (Acres)	Perforation Interval [3] (ft)
Fruitland Sand	18.7	0.621	40	138	93
Fruitland Coal	35.9	3.540	55	58	119
Pictured Cliffs	16.4	1.574	23	104	51
Chacra	9.9	0.381	56	54	128
Mesaverde	31.1	1.971	51	26	487
Dakota	25.0	1.558	50	102	132

[1] Through May 1999.
[2] "Producing thickness" is assumed to be the perforation interval.
[3] Interval between top and bottom perforations.

Table 6.7 – Average per-well drainage characteristics, San Juan Basin, New Mexico State portion.

The drainage areas shown in Table 6.7 are based on the perforated interval; i.e., the distance from the top to the bottom perforation. This distance is overly optimistic in pay thickness, which then results in underestimating drainage area. Tthis approach provides general information useful for prediction purposes.

The estimated IGIP's and recovery factors (% IGIP) are consistent with the actual recovery (cumulative production; Table 6.1). This is shown in **Table 6.8**, where a comparison is made between the predicted total recovery and the actual total recovery. The predicted total recovery is the predicted per-well recovery multiplied by the total number of wells (Table 6.2), where the predicted per-well recovery is the estimated per-well IGIP (Table 6.7) multiplied by the estimated per-well recovery factor (Table 6.7). The actual total recovery is from Table 6.1 or 6.6. The percentage error between the predicted and the actual, 100×(predicted – actual)/actual, is also tabulated in Table 6.8. As shown in Table 6.8, the percentage errors are within 15% except that of Chacra (+25.3%). Fortunately, Chacra is not the major gas producing formation. Mesaverde and Pictured Cliffs are under-predicted (–14.9% and –8.4%, respectively) while Fruitland Coal and Dakota are over-predicted (+9.3% and +2.5%, respectively). Note that the magnitude order of the predicted is the same as that of the actual. Overall, we feel the comparison is reasonably good considering that (1) the rather large well-by-well variation in the well performance, (2) the very simplified input data set, and (3) the relatively small sample size (overall less than 5%). The above comparison, although very crude, does provide some confidence level on our well production data analysis.

Formation	Total No. of Wells	Predicted Per-Well Recovery (Bscf)	Predicted Total Recovery (Tscf)	Actual Total Recovery (Tscf)	Error (%)
Fruitland Sand	241	0.248	0.060	0.057	+5.3
Fruitland Coal	2,504	1.947	4.875	4.462	+9.3
Pictured Cliffs	5,830	0.362	2.111	2.304	−8.4
Chacra	693	0.213	0.148	0.198	−25.3
Mesaverde	5,320	1.005	5.348	6.287	−14.9
Dakota	5,202	0.779	4.052	3.955	+2.5

Table 6.8 – Comparison of predicted and actual recovery, San Juan Basin, New Mexico State portion.

Despite the above consistency in the total recovery, two uncertainties in Table 6.7 need be pointed out: (1) the IGIP (per well) of Fruitland Coal is much larger than the other formations, and (2) the recovery factor (% IGIP) of Pictured Cliffs is much lower than the other formations. The first item may be related to the uncertainty of using the conventional techniques for a coal reservoir. The second item may be due to (1) overestimated IGIP (which in turn makes the recovery factor low), and (2) low or poor productivity (such that the depletion process is slow and inefficient). We feel both uncertainties contribute to the estimated low recovery factor of the Pictured Cliffs.

Consider the estimated drainage areas in Table 6.7. The estimated drainage area is inversely proportional to the assumed producing thickness (for each well), which in turn is assumed to be the top-bottom perforation interval in this study. For references, the *average* perforation interval for each formation is also listed in Table 6.7. Note that each well has different value of perforation interval. Uncertainty in the "producing thickness," thus, has a direct and significant impact on the estimated drainage area. This is especially true for a thick gross interval such as the Mesaverde involving multiple producing sub-units. (The Mesaverde Group includes three sub-units, in descending order, the Cliff House, Menefee, and Point Lookout.) The rather small drainage area of Mesaverde (26 acres; Table 6.7) probably is a direct consequence of the rather large value of perforation interval (average 487 ft; Table 6.7). If the producing thickness is, say, half of the perforation interval assumed (i.e., becomes 243.5 ft), then the drainage area becomes 52 acres (assuming all the other parameters remain the same).

It should be emphasized that the uncertainty of producing thickness does not change the interpretation pictures of the estimated drainage pore-volume, IGIP, and recovery factor. Overall, despite the issue of the producing thickness, the estimated drainage areas appear to be smaller than expected, considering the generally low flow resistance of the gas flow.

In view of the total number of wells, IGIP, and "current" recovery factor presented in Tables 6.7 and 6.8, the primary remaining reserves are still in the four major formations: Fruitland Coal, Mesaverde, Dakota, and Pictured Cliffs.

Productivity/Flow Characteristics. Table 6.9 presents the estimated average productivity factor and flow capacity for the six selected gas producing formations. Productivity factor is similar to the productivity index commonly used in reservoir engineering in that both describe the flow rate per unit pressure drawdown [Chen and Teufel, 2000]. Productivity factor is a

measure of flow efficiency and includes the effects of well completion (e.g., hydraulic fracturing), flow capacity, fluid properties, well spacing, well pressure, and reservoir pressure. Flow capacity (permeability-thickness product) depends only on the formation permeability and producing thickness.

Formation	Productivity Factor (mscf/d/psi)	Flow Capacity (md-ft)
Fruitland Sand	0.142	1.47
Fruitland Coal	1.362	18.92
Pictured Cliffs	0.287	2.54
Chacra	0.177	1.79
Mesaverde	0.907	6.71
Dakota	0.389	2.42

Table 6.9 – Average per-well productivity and flow characteristics, San Juan Basin, New Mexico State portion

The gas producing rates (per well) reflected by the productivity factors (Table 6.9), in the decreasing order, are Fruitland Coal, Mesaverde, Dakota, Pictured Cliffs, and Chacra or Fruitland Sand. This order is consistent with that shown in Fig. 6.4a. The flow capacities, in the decreasing order, are Fruitland Coal, Mesaverde, Dakota or Pictured Cliffs, and Chacra or Fruitland Sand. This order is similar to that of the productivity factor. The much larger productivity factor and flow capacity of Fruitland Coal (than the other non-coal formations) may be attributed to the natural fracture (cleat) system of a coal reservoir. The low productivity factor of Pictured Cliffs (relative to Fruitland Coal, Mesaverde, and Dakota) may explain the low recovery factor noted in Table 6.7.

The reasonableness of the estimated flow capacities also can be assessed by converting them into the formation permeabilities. With reasonable ranges of producing thickness (for each formation), all the converted non-coal formation permeabilities are, as expected, less than 0.1 md (not shown here). It should be emphasized that the uncertainty of producing thickness, as discussed before, does not change the interpretation pictures of the estimated productivity factor and flow capacity. The producing thickness does have a direct impact when the flow capacity is converted to the formation permeability. This is similar to when the drainage pore volume is converted to the drainage area.

6.6 Conclusions

Historical gas production trends (through May 1999) of the six gas producing formations, Fruitland Sand, Fruitland Coal, Pictured Cliffs, Chacra, Mesaverde, and Dakota, were analyzed for total-well and per-well basis. Well production data, which covers all producing townships, were analyzed. Some key conclusions are:

- Average per-well values of drainage pore volume, initial gas-in-place, recovery (through May 1999), drainage area, productivity factor, and flow capacity are reported in Tables 6.7 and 6.9. These performance-based average estimates are reasonably consistent with the historical producing trends and the actual recovery of the San Juan Basin.
- Recent gas production is dominated by the Fruitland Coal. Production trend of the Fruitland Coal is still increasing, and established stable trend does not exist.

- Existing wells of the three major conventional gas-producing formations, Mesaverde, Dakota, and Pictured Cliffs, appear to enter the late depletion stage. Production of the remaining gas from these three conventional gas formations is expected to be a very slow and long process.

Chapter 7

Results of an Industry Survey of Development in San Juan Basin

The objective of the industry survey (example in appendix) was to obtain well development plans, how completion methods and technology would influence those plans, and the corresponding surface development needed for the well development. The available locations for the reservoirs listed in the survey is 16,313. With the commingling and dual completion of zones, the 16,313 available locations will be reduced by 30% to 11,458. An important outcome is that commingling and dual completion is prudent and efficient for the operator and will concurrently reduce surface disturbance. The rate of commingling has historically been increasing within the last several years to almost 20% in 2000. The 11,458 locations reflect development strategies for the entire basin. Subsequently, this number needs to be proportionally reduced by 80% to obtain only that fraction on federal lands, or 9,166 locations. As can be seen by the individual reservoir locations, the contribution of the Dakota Formation is the most significant. This reservoir also has the most uncertainty in infill well development since it is currently undergoing pilot testing.

The impact of advancements in drilling and completion technologies was requested from the operators. The response indicated a willingness to drill and complete deviated wells, but little enthusiasm for horizontal wells with or without laterals. The percentage of deviated wells is an increase from current operations and signifies advances in technology to be able to perform this work. The outcome would be less disturbance of sensitive areas by drilling one or more deviated wells from a single location. The primary target indicated was the Mesaverde Formation, which is a significant component of the total development scenario.

Surface development in terms of prime movers for compression and how much additional compression needed for the proposed development was requested. The results indicate gas engines to be the likely prime mover. The response to compression was inconclusive due to the widely varied responses and ill-posed question.

The following summarizes the responses of industry's perspective to future development in the San Juan Basin, New Mexico.

7.1 For each of the following reservoirs an anticipated spacing is given. How many potential locations are available for drilling on your acreage with the given spacing?

RESERVOIR	SPACING(AC)	LOCATIONS AVAILABLE	COMMENTS
Tertiary Sands	40	**188**	
Fruitland Sand	160	**198**	
Fruitland Coal	160	**3354**	
Picture Cliffs	160	**1262**	
Chacra	160	**196**	
Mesaverde	80	**4322**	
Gallup	variable	**436**	
Dakota	80	**6357**	
	total	**16,313**	

Table 7.1 Locations available for development based on given spacing, by reservoir

7.2 Historically, spacing is reduced approximately every 20 to 25 years. Rate the reservoirs listed in Table 2 as to the potential or lack of potential for further reducing the spacing within the time frame of the study.

      0   - would **not** further reduce spacing

      1   – would **consider** further reduce spacing

      2   – would **definitely** further reduce spacing

RESERVOIR	RANK		
	0	1	2
Tertiary Sands	21	2	
Fruitland Sand	13	11	2
Fruitland Coal	7	7	12
Picture Cliffs	9	12	5
Chacra	16	7	3
Mesaverde	15	11	
Gallup	18	6	2
Dakota	14	7	5

Table 7.2. Indication of potential for further spacing reduction. Total responses =26.

7.3 With any additional drilling development there exists accompanying surface development.

    a.   How much additional compression, wellhead or central, do you anticipate to accommodate the development?

        Ranged from 1 to 300   Number of wells/compressor

    b.   Type of prime mover for compression?

        % electric   **+98**   % gas

All gas driven except near electric power source; e.g., near cities.

7.4 The mode of completion provides a vital role in development. For the methods listed below, what percentage of each do you estimate occurring in the future development?

Single completion	6,603	40.5 %
Commingled completion	7,572	46.4 %
Dual completion	2,138	13.1 %
Other (specify) _____		____ %

    Total wells   **11,458**

7.5 Advancement in drilling technologies will provide alternatives to drilling and completion of a well. Provide below an estimate of the percentage of each of the following well types.

Vertical Wells   92.5 - 95.0   %

Directional well   5.0 – 7.5   %

Horizontal well   %

Horizontal wells with laterals   %

   Note: Three operators listed horizontal wells, variable targets

Circle the target reservoir(s) for directional and/or horizontal wells.

Directional well

FTC   PC   Chacra   (MV)   DAK   other:GP/Mancos

2   **0**   **2**   **10**   **6**

Horizontal well

FTC   PC   Chacra   MV   DAK   other _____

Horizontal wells with laterals

FTC   PC   Chacra   MV   DAK   other _____

7.6 The following questions pertain to the initial assumptions. Indicate on the scale below your assessment of the given assumption.

a. The take away capacity out of the basin will not significantly change.

Strongly agree   (agree)   neutral   disagree   strongly disagree

      2   **12**   7   6   0

b. The historical P&A rate will remain constant for the duration of the forecast period.

Strongly agree   (agree)   neutral   disagree   strongly disagree

      1   **15**   7   5   0

c. Limited exploration potential exists in the basin and what is possible will have negligible impact.

Strongly agree   (agree)   neutral   disagree   strongly disagree

      2   **14**   8   3   0

If you disagree with any of the above assumptions, please explain why.

Letter A

- El Paso, Transwestern and Williams have responded well to increased deliverability of wells with new pipes andd field compression. Given the California and S. West market demands, I predict that these pipes will continue to add take-away capacity.

- I think the take away capacity out of the Basin will increase.

- Reservoirs are declining faster than wells can be drilled to replace reserves.

- With increasing incentive with regard to price, I feel gathering and pipeline capacity will be increased.

- With increasing natural gas prices and demand for natural gas, someone will figure a way to move more gas out of the SJ Basin, i. e. reverse the flow in William's pipeline currently delivering +/- 500 mmscfd from Colorado to William's Ignacio plant and the San Juan Basin.

- If demand-supply imbalance continues, some pipeline capacity increase could become necessary.

Letter B

- Industry often assumes a 70-year life is typical for a well before severe metal/casing failure occures. Assume a 70-year life, wells drilled in 1955 will begin to fail starting in 2025. P&A rates may start to increase at that time.

- The NMOCO & BLM have both increased their emphasis to reduce and or eliminate idle wellbores

- The P & A rate should decrease as prices increase.

- Wells drilled in the late 50's thru mid 1970's with little or no cement behind the pipe are due to have an increase in casing failures.

- State and Fed. Gov't seem to be doing a better job of pursuing operators w/many SI wells

Letter C

- Under explored for Entrada, Bluff and Pensylvanian targets that could potentially have very large reserves, but will have limited arial extend across the Basin.

- Extensive exploration potential exists for formations below the Dakota.

- It is possible that under the right market and economic conditions and with advances in technology that one or more significant discoveries will be made in horizons below the Dakota. To date, xx company has not made such a discovery; however, we believe the EIS should incorporate a deep development scenario in its planning.

- If the San Juan Basin teaches us anything, it is that as soon as a prospective producing horizon begins to decline a new horizon is found and a new round of exploratory drilling occurs. The latest will be the deep Pennsylvanian, which I predict will be the biggest yet.

- We have always, historically, discovered unexpected new sources and reservoirs in the San Juan Basin. We just can't see that far into the future.

7.7 We would appreciate any further comments or suggestions pertaining to future development plans.

- Anticipate developing high angle wells to solve footprint problems and environmental concerns; this will cause more well work (rodjobs/rigs) and lower efficiencies on plungers, causing abandonment at high reservoir pressures. Potentially some wells may not be drilled due to higher costs (cap & LOE); and some new technology needs to be developed to address problems w/operating.

- Potentially, 1,170 open locations exist for the "anticipated" spacings provided. Of this total, it is possible that the number of new locations is reduced to 880 through the commingling of the Mesa Verde with Dakota, and of Fruitland Coal with Pictured Cliffs. Company y's preference for recompletions over drilling, and its expectations of the locations' economic viability given assumptions for reservoir quality and drainage. Determinations of economic viability may change over this 20-year period. Horizontal drilling has not yet found an economic application in the basin. Company x is in the early stages of evaluating directional drilling, and results with this program will impact the future of horizontal drilling in the basin.

- During the next 20 years, development activity will be retrained as a result of an increasng emphasis upon environmental, bird & wildlife issues.

- The pace, extent, and nature of future reservoir development in the San Juan Basin will depend upon market and economic conditions, the political and regulatory environment, the impact such development will have on the environment, and the merits of alternative uses of the land surface. Company z's responses to this survey describe a maximum development scenario on our acreage which we would pursue under appropriate economic and regulatory conditions and advances in technology. Further, our policy is to work with the regulatory agencies and the community to perform all our development activities in an environmentally prudent manner.

- The cost is prohibitive when you have large acreage to drill

- Because Company M's acreage position in the San Juan Basin is so small, downspacing is the key to any significant future development.

- Approximately 90% of our wells are on Fee Land and are not on Federal or State Lands.

- 80 acre spacing should be considered for all zones allowing operators only one location per 80 acre block. Operators should utilize existing roads and ROW's for

7.6

roads where possible but should not be limited to 300' or any set footage from an existing road to build a location.

- We have no undrilled locations, declining reservoirs, and no plans for future development or acquisition.

- I have no land or wells on BLM land.

- Our biggest hinderance to further developments is the restrictive practices of the BLM itself! Time to permit s.f.c. use etc. Hinders rather than help-just look at all the stipulations for example.

- While I listed a large number of potential Tertiary Sands for our acreage, the potential for this seems most remote.

Chapter 8
Impacts of future technology

8.1 Stimulation technology

Advances in technology and research have played an important role in improving gas recovery from unconventional plays of the San Juan Basin. For example, hydraulic fracture techniques have evolved over the years with better fluids, proppants, and design. In fact, production decline analysis indicates newer completions have lower skin than the older wells, attributable to better stimulation techniques. Advances in hydraulic fracturing of low permeability formations will have, perhaps, the greatest potential impact on the future development of the San Juan Basin. Although these treatments have been widely applied in the basin since the 1950's, there remain many aspects upon which improvement is needed. Currently identified issues that require further improvement are:

1) All stimulations tend to cause some degree of formation damage such that the efficacy of the stimulation is less than ideal; therefore there is a need for better identification of sensitivity of formations to frac fluid damage and need for research into optimal, non-damaging fluid systems
2) There is a regional shortage of availability of better-engineered liquefied CO_2 delivery systems. This limits the application of, and increases the cost of, less damaging liquid CO_2 fracturing.
3) Cost reduction of all stimulations is a priority among all operators. The goal is to increase fracture efficiency while reducing cost per application in future well completions.
4) Research is required to achieve more effective hydraulic fracturing of naturally underpressured or semidepleted formations.
5) There is currently a need to improve multi-zone or multi-formation stimulations within a single well bore.

These, or other advancements could have significant impact on the efficiency of existing and future wells.

8.2 Directional and horizontal drilling

The objectives of directional (purposely deviated) and horizontal drilling are typically related either to avoiding surface occupation or to increasing production efficiency. These two objectives are not always compatible. Avoidance of surface occupancy is typically due to topographic, or environmental concerns. In this case, a drilling location will be selected as near as possible to the subsurface target and a well bore will be constructed in such a manner as to minimize cost while achieving the subsurface target. The goal is to capture the same reserves that would have been achieved from a vertical well, had one been drilled. In terms of economic efficiency, such wells are less efficient due to increased cost (approximately 20%) and higher operating expenses with no change in producible reserves.

Under certain reservoir conditions, directional and horizontal drilling can be applied to improving recovery efficiency. Fractured reservoirs, in particular, may be better accessed by well bores oriented to maximize intersection of fractures. In such cases well bore orientation will be carefully planned and guided during drilling. Construction of this type of well bore is typically more expensive than those that simply aim for a nearby target. Directional drilling for improving efficiency is currently an option in the San Juan Basin today, typically applied as an experimental technique. As seen in the industry survey, continual improvements in success of the technique will make directional drilling for this purpose more feasible in the future. Known disadvantages of this type of directional drilling as applied to the San Juan Basin are significantly increased cost and production problems for wells that yield liquids. The latter suggests a need for advanced technology in artificial lift to overcome this current problem.

Single-lateral directional well drilling has been an experimental technique in the San Juan Basin in the past but has recently gained momentum as improvements are developed (Table 8.1). Past efforts generally failed to achieve favorable economics when cost vs. results were evaluated. The difficulty lies in that most San Juan Basin target formations are underpressured, making them susceptible to drilling-induced formation damage when mud-circulation drilling systems are utilized (mud circulation is required for most current steerable drilling systems). The refinement of underpressured air- or gas-driven steerable downhole drilling equipment could potentially revolutionize the development of the basin in a twenty-year time frame.

Operator/well	Location	Formation	Result/year
BRI/2 Cheney Fed B	8-26N-2W	Mesaverde (MV)	Lost tools in hole/ failed completion/1993
BP Amoco/5B Atlantic	26-31N-10W	MV	3700 MCFD/ 1999
Williams/169A Rosa Ut.	3-31N-6W	MV	4295 MCFD/ 1999
BRI/106M SJU 27-5 Ut.	1-27N-5W	MV & Dakota	1242 MCFD/ 1999
Amoco/5B Hardie LS	23-29N-8W	MV	Lost tools/ redrilled/ 3110 MCFD/ 1999

Table 8.1 Selected directional drilling experiments in the San Juan Basin

Application of horizontal well technology in the onshore United States has been increasing in recent years; however, not all reservoirs are candidates for this type of completion. A first step in selecting appropriate reservoirs is to screen the key parameters for commercial success. For example, natural fracture orientation and intensity, net pay and vertical permeability, susceptibility to formation damage, reservoir pressure, anisotropy, and drilling/completion costs need to be understood in the context of penetrating the reservoir with a horizontal well (Joshi, 1998). A survey by Deskins, et al. (1995) showed for clastic reservoirs in the United States a production ratio of 2.8 and a cost ratio of 2.2. The two ratios define the horizontal to vertical production and cost increase, respectively. One of the observations is the rapid decline in costs as an operator proceeds along the learning curve. Therefore, initially costs may be high, however, it is anticipated these costs would reduce with time.

Horizontal wells have been drilled in several formations that are lithologic analogs to formations in the San Juan Basin. In the Rocky Mountains, the Bakken Shale

of the Williston Basin and Niobrara Formation of the Denver Julesberg Basin are naturally fractured source rock/oil reservoirs similar to the Mancos Shale in the San Juan Basin. The low porosity and low permeability Devonian Ohio shale gas play of the Appalachian region of the eastern United States has been a subject for testing of horizontal drilling technology (Joshi, 1998).

Horizontal drilling is possible but not currently applied in the San Juan Basin due to poor cost to benefit ratio. If horizontal drilling should prove economically and technically feasible in the future, the next advancement in horizontal well technology could be drilling multi-laterals or hydraulic fracturing horizontal wells. Multilaterals could be one, two or branched laterals in a single formation or single laterals in different formations. Hydraulic fracturing could be a single fracture axial with the horizontal well or multiple fractures perpendicular to the horizontal well. These techniques are currently complex and costly, and therefore typically inappropriate for most onshore U.S. reservoirs. Comprehensive engineering and geologic research will be required in the near future in order for these techniques to become viable within the 20 year time frame anticipated by this RFD.

8.3 Multiple zone completions/commingling

Recent advances in technology have enabled multiple zone completions in single well bores. Multizone completions include: (1) individual zone treatments with significant time lag between stimulation of each zone, (2) staged, limited-interval fracture treatments accomplished in a short period of time, and (3) limited entry where one large treatment is applied to multiple zones. Although, multizone completions reduce the number of well bores, problems have been identified with each type. For example, individual zone treatments require multiple trips to a well increasing well costs and also cause loss of production due to extended shutin periods. Staged fracture treatments have a significant residence time of fluid on the formations and thus can cause formation damage. Also, a limitation exists on the number of stages that can be pumped. Limited entry fracturing fails when formations of different reservoir characteristics are treated as a single zone. Future advances in fracture technology will focus in overcoming these limitations and should provide significant opportunities for commingling more zones in fewer well bores.

Chapter 9
Conclusions: Reasonable Foreseeable Development

The total available subsurface completions in the New Mexico portion of the San Juan Basin is predicted to be 16,615 over the next twenty years. These results are subject to the assumptions elaborated on in Chapter 1. Table 9.1 summarizes the results by reservoir and includes both major and minor producing reservoirs, and anticipated emerging and exploratory plays.

Formation/Reservoir	Predicted subsurface development
San Jose, Nacimiento, Ojo Alamo	100
Farmington Sandstone	0
Fruitland Sand	176
Fruitland Coal	2964
Pictured Cliffs	1432
Chacra	323
Mesaverde, Lewis	4374
Dakota, Mancos (gas)	6846
Mancos (oil)	300
Entrada	80
Pennsylvanian	20
total	**16615**

Table 9.1 Summary of predicted subsurface development by reservoir

A significant reduction in this number of completions will occur due to opportunities for commingling and dual completion of wells. Considering an estimated 25% decrease in completions, the total number of locations becomes 12,461. In other words, multiple completions would result in a reduction of the number of locations to be built. This rate equates to 623 wells per year on average and is consistent with current activity, which is approximately 640 wells per year average for 1999 and 2000 combined. This rate assumes continued favorable regulatory environment that supports this level of annual development.

Federal lands comprise approximately 80% of the leasehold of the San Juan Basin. Consequently, the total number of locations (12,461) must be reduced proportionately. This reduces the total number of wells to be drilled on federal managed lands.to **9,970**, predicted as reasonably foreseeable over a 20-year duration commencing January 1, 2002.

A location density map is shown in Figure 9.1-1 for the purpose of illustrating the anticipated distribution of the total number of completions (12,461) after commingling or dual completing. The results are presented on a township/range scale. The trend of

highest activity was approximately northwest to southeast and parallels the fairways of the Mesaverde and Dakota plays.
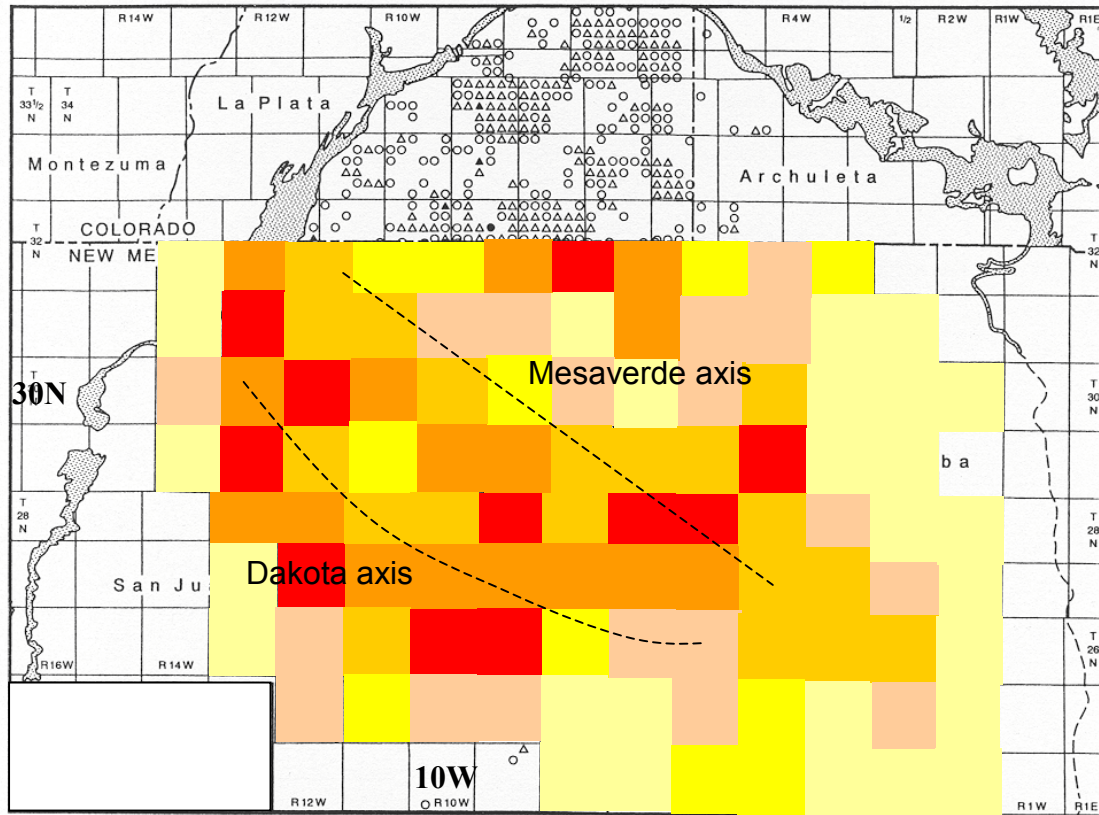
Figure 9.1-1 Distribution map of average number of total locations (all reservoirs) per section averaged over township areas.

Average locations per section

- ▉ > 6
- ▉ 5 - 6
- ▉ 4 - 5
- ▉ 3 - 4
- ▉ 2 - 3
- ▉ 0 - 2
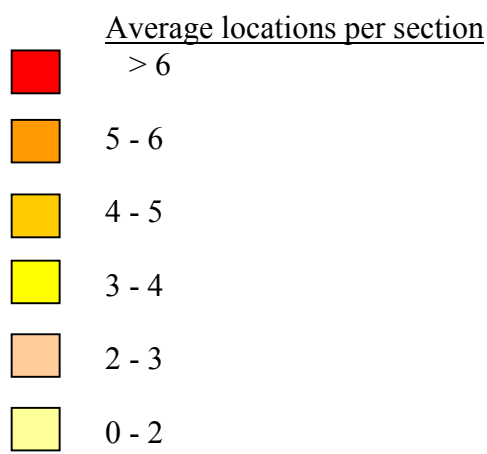
The surface disturbance associated with the additional well locations was estimated to average 2 acres in area and will also require 1 acre (800' x 50') of right-of-ways for associated roads and pipelines. The result would be 16,151 (9970*.54*3) acres of additional surface disturbance in the San Juan Basin.

Accompanying well development will be the expansion of surface equipment to improve gas recovery and meet the anticipated energy needs of the nation. An additional 3,600 miles of pipeline is projected, resulting in 11,716 acres of surface disturbance. Central compression will expand to more than double existing compression, to 360,000 HP. The sites for this compression will be scattered throughout the basin and will range in size from 500 to 10,000 HP. Wellhead compression, which averages 100 HP per compressor, will expand to almost half (15,000) of **all** wells, including 5,000 for projected **new** wells.

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Appendix 1

Industry Survey of Development in San Juan Basin

The Bureau of Land Management (BLM) has requested from New Mexico Tech an estimation of the *Reasonable Foreseeable Development* for BLM's Resource Management Plan. The scope of this study includes the New Mexico portion of the San Juan Basin and begins with an effective date of January 1, 2002 with a duration of 20 years. Industry's participation is solicited to better develop a plan, which is mutually beneficial to all concerned.

Base assumptions

The following list of general constraints is provided as a baseline for answering the following questions.

- The take away capacity out of the basin will not significantly change.
- The historical P&A rate will remain constant for the duration of the forecast period.
- Limited exploration potential exists in the basin and what is possible will have negligible impact.

Based on the above general assumptions, please answer the following questions.

1. For each of the following reservoirs an anticipated spacing is given. How many potential locations are available for drilling on your acreage with the given spacing?

RESERVOIR	SPACING(AC)	LOCATIONS AVAILABLE	COMMENTS
Tertiary Sands	40		
Fruitland Sand	160		
Fruitland Coal	160		
Picture Cliffs	160		
Chacra	160		
Mesaverde	80		
Gallup	variable		
Dakota	80		

2. Historically, spacing is reduced approximately every 20 to 25 years. Rate the reservoirs listed in Table 2 as to the potential or lack of potential for further reducing the spacing within the time frame of the study.

 0 - would **not** further reduce spacing

 1 – would **consider** further reduce spacing

 2 – would **definitely** further reduce spacing

RESERVOIR	RANK
Tertiary Sands	
Fruitland Sand	
Fruitland Coal	
Picture Cliffs	
Chacra	
Mesaverde	
Gallup	
Dakota	

Table 2

3. With any additional drilling development there exists accompanying surface development.

 a. How much additional compression, wellhead or central, do you anticipate to accommodate the development?

 _____ Number of wells/compressor

 b. Type of prime mover for compression?

 _____% electric_____% gas

4. The mode of completion provides a vital role in development. For the methods listed below, what percentage of each do you estimate occurring in the future development?

 Single completion _____%

 Commingled completion _____%

 Dual completion _____%

 Other (specify) _____ _____%

5. Advancement in drilling technologies will provide alternatives to drilling and completion of a well. Provide below an estimate of the percentage of each of the following well types.

Vertical Wells   _____%

Directional well   _____%

Horizontal well   _____%

Horizontal wells with laterals   _____%

Circle the target reservoir(s) for directional and/or horizontal wells.

Directional well

FTC   PC   Chacra   MV   DAK   other _____

Horizontal well

FTC   PC   Chacra   MV   DAK   other _____

Horizontal wells with laterals

FTC   PC   Chacra   MV   DAK   other _____

6. The following questions pertain to the initial assumptions.   Indicate on the scale below your assessment of the given assumption.

 a. The take away capacity out of the basin will not significantly change.

    Strongly agree   agree   neutral   disagree   strongly disagree

        5   4   3   2   1

b. The historical P&A rate will remain constant for the duration of the forecast period.

    Strongly agree   agree   neutral   disagree   strongly disagree

        5   4   3   2   1

c. Limited exploration potential exists in the basin and what is possible will have negligible impact.

    Strongly agree   agree   neutral   disagree   strongly disagree

        5   4   3   2   1

If you disagree with any of the above assumptions, please explain why.

Letter _____

Why? _____

_____

Letter _____

Why? _____

_____

Letter _____

Why? _____

_____

7. We would appreciate any further comments or suggestions pertaining to future development plans.

_____

_____

_____

_____

_____

Name: _____

Company: _____

Confidential Statement

Information gathered in this survey is solely to be used by New Mexico Tech for the purposes of the RFD and will not be disclosed to or used by any other party.