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# Technology Assessment of Vertical and Horizontal Air Drilling Potential in the United States

**Final Report**

**R.S. Carden**

**Work Performed Under Contract No.: DE-AC21-92MC28252**

**For**
**U.S. Department of Energy**
**Office of Fossil Energy**
**Morgantown Energy Technology Center**
**P.O. Box 880**
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**By**
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**August 18, 1993**

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# 1.0 EXECUTIVE SUMMARY

Grace, Shursen, Moore and Associates was awarded a research contract from the Department of Energy, Morgantown Energy Technology Center. The objective of the research was to assess the potential for vertical, directional and horizontal air drilling in the United States and to evaluate the current technology used in air drilling.

To accomplish the task, the continental United States was divided into drilling regions and provinces. The map in Appendix A shows the divisions. Air drilling data was accumulated for as many provinces as possible. The data was used to define the potential problems associated with air drilling, to determine the limitations of air drilling and to analyze the relative economics of drilling with air versus drilling mud.

While gathering the drilling data; operators, drilling contractors, air drilling contractors, and service companies were contacted. Their opinion as to the advantages and limitations of air drilling were discussed. Each was specifically asked if they thought air drilling could be expanded within the continental United States and where that expansion could take place.

The well data was collected and placed in a data base. Over 165 records were collected. Once in the data base, the information was analyzed to determine the economics of air drilling and to determine the limiting factors associated with air drilling.

## 1.1 AIR DRILLING APPLICATIONS

The primary economic advantage to air drilling was found to be an increase in penetration rate. Drilling costs are a function of time. The longer it takes to drill a well; the more it costs. Air drilling drills faster than mud, therefore it reduces the total drilling cost. Air drilling compressors are more expensive to operate and maintain, so the daily operating cost is higher for air drilling operation. Therefore, the penetration rate while drilling with air must be higher than mud drilling for air drilling to be economical. The data indicated that the penetration rates for air drilling where at least two times greater than mud drilling. In most cases, it was higher than two time greater. There were a few cases where air drilled ten times faster than mud, but there were also a few cases where air drilling was not significantly faster than mud.

Alleviating lost circulation problems was another significant economic advantage to air drilling. Lost circulation occurs when drilling fluid leaves the wellbore by entering the formation rather than returning to the surface to be reused. Drilling mud is expensive to replace and progress is usually halted while attempting to regain circulation. Lost circulation is very seldom a problem with air drilling. The avoidance of lost circulation by using air can enhance the economics of the drilling operation.

The two primary reasons for using air drilling are increased penetration rate and minimized lost circulation which are both economic considerations. Another advantage to air drilling is the ability to continually test the formation as it is being drilled. Since pressures within the wellbore are so low while air drilling, any potentially productive formation will flow to the surface while drilling, and the production rates can be monitored at the surface. In mud drilling, the wellbore pressure is kept high enough to prevent influx of formation fluids; therefore, formation potentials cannot be determined while drilling.

Some other advantages to air drilling were found to be minimum formation damage while drilling and environmental advantages. Since the flow is usually from the formation to the wellbore, air does less formation damage while drilling than mud. This was found to be a distinct advantage while drilling horizontal wells. Cleaning up formation damage in a horizontal well is very expensive, and minimizing that damage is important to the overall economics of the well.

Air drilling has some environmental advantages too when no salt water or oil are produced during the drilling process. Dry air or mist drilling uses a smaller reserve pit than mud drilling with much less fluid in the reserve pit at the end of the well.

## 1.2 AIR DRILLING LIMITATIONS

There are some limitations to air drilling. The most significant limitation to air drilling was found to be formation water. In many places within the United States, formations are capable of producing large quantities of salt or fresh water. Production rates can vary from a few barrels per hour to over one thousand barrels per hour. Water is a problem because there is only a limited space available to put the water in the reserve pit. If the water has to be hauled off the location, it can get extremely expensive. Disposal costs can range from one to ten dollars per barrel depending upon the type of water and the proximity of the drilling location to an appropriate disposal site.

Another limiting factor was formation stability. If the formations are not stable, they will slough into the wellbore. When the sloughing rate is high enough, air drilling cannot continue. Air has a poor lifting capacity and is not capable of carrying a large volume of sloughed formation out of the wellbore. Mud has to be used when the formations slough too much.

Environmental problems can result when large quantities of salt water or oil are encountered in the well. With air drilling, these fluids are produced into the reserve pit while drilling. Depending upon where the well is being drilled, salt water and oil in the reserve pit can be an environmental problem. As environmental regulations become more strict, proper disposal of the produced fluids will become more expensive limiting the economic advantages to air drilling.

Other limiting factors were found to be the potential for downhole fires, increased drill string wear, and safety considerations. These factors are only a minor consideration and are manageable in the drilling operation.

Directional and horizontal drilling are limited by the equipment available to the industry. The ability to directionally drill a well with air as the drilling fluid has advanced considerably in the past few years. One limitation that still remains is the lack of a reliable MWD tool for air drilling. The MWD tool sends the directional data to the surface while drilling. An electromagnetic MWD is available that will work in an air environment but it is not reliable enough. It works well in some wells but fails frequently in others. Air is a much rougher environment than mud and the tool needs to be hardened to work in an air environment.

The other significant limitation to directional drilling with air is the extremely slow penetration rates with a downhole motor in some harder formations. Downhole motors do not operate as efficiently on air as they do in drilling mud. Consequently, less bit weight can be applied while drilling with air. In harder formations, that weight is not sufficient to compressively fail the rock and the penetration rate can be as low as one to two feet per hour. In the same rock, rotary drilling with higher bit weights can be greater than 30 feet per hour.

## 1.3 NEEDED TECHNOLOGY IMPROVEMENTS

There are several technology advancements which would aid the expansion of air drilling within the United States. The development of a reliable MWD for air drilling would be a significant technology improvement. The industry is most often using a steering tool with a wireline to transmit the directional data to the surface. Reliability is still a problem with the steering tool and the wireline is cumbersome and time consuming. A wet connect and cartridge system have been developed by the industry to try to eliminate the problems associated with wireline, but this system still needs further work.

A directional hammer would solve the problems associated with slower penetration rates in hard formations. A hammer uses impact force to break the rock and is designed to drill with low bit weight. In addition, the hammer is a relatively simple tool and would be more cost effective than a downhole motor provided a simple directional hammer tool can be developed. A directional hammer is currently being developed under a DOE contract.

If air drilling is to be significantly expanded within the United States, a method must be found to minimize water influx while drilling. Water is the primary limiting factor for air drilling. Finding a way to prevent the water influx or finding a cheap disposal method for the water would go a long ways toward expanding air drilling.

Formation stability is also a problem in air drilling. Wells with sloughing formations are hard to clean with air. If the well sloughs too much, air drilling must be abandoned in favor of mud drilling. A significant technology improvement would be finding some relatively inexpensive way to stabilize the wellbore while drilling.

## 1.4 EXPANSION OF AIR DRILLING

Water production and unstable formations are the two primary reasons that air drilling cannot be expanded substantially within the United States. Most of the basins in the United States produce too much water to be effectively drilled with air. Air drilling is the preferred method in the basins which do not produce large quantities of water such as the Appalachian and Arkoma Basins. Air drilling is also used frequently in the San Juan, Paradox, and Uinta-Piceance-Eagle Basins.

Smith International researched their bit record data base to determine what percentage of the total footage drilled in the United States was drilled on air. If a portion of a well was drilled using air or air equipment, the total footage for the well was considered air drilled. Appendix B shows the results of the data base search. For the continental United States, 16.3% of the total footage drilled had some portion of the hole drilled on air.

The results of this study indicate that use of air drilling cannot be expanded by more than just a few percentage points. There are undoubtedly small areas within a basin where air drilling can be used but has not been tried. Outside the normal air drilling basins, the study indicated that most of the air drilling was performed in small areas where air drilling had been found to be applicable.

The economic conditions in the oil industry are dismal to say the least. Many drilling contractors are on the verge of bankruptcy and operators are looking to cut costs wherever possible. Expanding air drilling within the United States would require drilling contractors and operators to experiment with air drilling in areas where drilling is dominated by mud drilling. They neither have the personnel or capital to research air drilling especially when the wells can be easily drilled with mud. Operator and contractor reluctance to experiment with air drilling will limit the expansion of air drilling.

The only way to change the attitudes of contractors and operators is through education or demonstration. There are many individuals in the oil industry who have never drilled a well on air. If they knew more about it, they might be more willing to experiment with air. A demonstration would involve successfully drilling a well on air in an area where air drilling is not used. If the air drilled well costs less than the mud drilled wells, other operators and drilling contractors would start using the air drilling technique.

The information gathered in the data base could not be used to point to specific places where air drilling can be expanded. There were many wells that were unsuccessful due to water production and unstable hole, but some wells were very close to wells that were successful. Geology is the determining factor and can vary dramatically within a basin. The geology of each basin would have to be studied in depth for each basin. Even then it would be difficult to determine the applicability of air drilling to a specific area. An in depth geologic study was beyond the scope of this study.

The Rocky Mountain Regions are the best candidates for expansion of air drilling, though it will still remain sporadic outside the areas normally drilled with air. The types of rock (older and harder) are more applicable to air drilling. The primary limiting factor will still be water production though most of the water in the Rocky Mountain Regions are fresh.

Air drilling is the least likely to be expanded in the Gulf Coast region. The younger, softer rocks of the region are not applicable to air drilling. The penetration rate with mud is already very high so air drilling will not increase the penetration rate. Without an increase in penetration rate there is little economic incentive to implementing air drilling. The region is also characterized by high permeability formations that will produce massive quantities of salt water. The soft rocks of the region are unconsolidated and will slough too easily

## 2.0 INTRODUCTION

Air drilling as used in this report refers to drilling with air or natural gas as the circulating fluid in some form. The are several variations available with air drilling. Air or natural gas can be used in the following combinations:

1. Dry air, commonly termed "dusting"
2. Mist
3. Foam
4. Aerated fluid

In each of the four categories, natural gas can be substituted for air. Table 2.1 makes a comparison of each category.

Dusting uses only air or natural gas as the circulating medium. It is commonly termed dusting because large quantities of dust come out of the well while drilling. This is the simplest and least costly form of air drilling. Dusting is the preferred method of air drilling. The velocity of the air in the annulus is usually around 3000 feet per minute and is the primary mechanism for removing cuttings from the well.

Mist drilling is also very common. Dusting can only be used where the formation does not produce any fluid. Mist is added to the air when water is encountered. The mist consists of water, surfactant and corrosion inhibitor as a minimum. Other additives such as potassium chloride, polymers and even bentonite can be added if desired. The potassium chloride and polymers can reduce the rate at which hydratable clays absorb water but only to a small degree. However, they do add significant cost.

Generally, the mist is injected into the air stream at a rate of 10 to 30 barrels per hour. The mist is injected with a small triplex pump called a mist pump.

The velocity of the air in the annulus ranges from as little as 1,000 feet per minute to over 3,000 feet per minute. With air mist, the velocities are slightly less but in the same range. Annular velocity is the primary mechanism which removes the cuttings from the hole.

*Table 2.1- Comparison of air drilling methods[1].*

| Method | Circulating Medium | Characteristics |
|---|---|---|
| Air Drilling (Dusting) | Air only. | Sufficient air volume is used to generate an annular velocity capable of blowing the cuttings out of the hole. The wellbore must remain completely free of formation fluids. |
| Mist Drilling | Predominantly air. Small amounts of surfactant and water mixture are injected into the air stream | Sufficient air volume is used to generate an annular velocity capable of blowing the cuttings, as well as any formation fluids, out of the hole. |
| Foam Drilling | Foam (shaving cream); pre-formed on surface by mixing air, water and surfactant | The foam must have, and maintain, a density and consistency making it capable of suspending and transporting the cuttings out of the hole at a relatively low annular velocity (similar to fluid) |
| Aerated Fluid Drilling | Predominantly fluid. Sufficient air is added to the circulating fluid to the point where the annular hydrostatic pressure is in balance with the formation loss zone | Rig mud pumps circulate fluid (water or mud) at normal rates. Air is added at air-fluid ratios generally ranging from 5:1 up to 20:1. Air-fluid ratios greater than 20:1 should be avoided if at all possible as highly inconsistent returns (hole surging) and poor hole cleaning can often result. |

Foam can be used to drill many holes. The difference between air mist and foam is the annular velocity and percentage of liquid in the air-liquid mixture. In foam drilling, the annular velocity ranges from 100 to 350 feet per minute which is much less than mist. With mist, the percentage of liquid in the mixture is less than 4% and the air is the continuous phase. With foam, the liquid is the continuous phase and the percentage of liquid in the mixture is much higher (usually 20% to 40%).

Foam is mixed with chemicals similar to those used in mist. The foam consists of air, water, surfactant, polymer and a corrosion inhibitor. Some operators add bentonite to the system. These are the same chemicals used in mist. In fact, misting and foaming are often confused. Many people think they are drilling with foam, but in fact are misting.

Foam must have the lower annular velocities otherwise it is mist drilling with foam products.

Aerated fluid is drilling with a mixture of air and drilling mud or water. The air is added to the fluid to reduce the hydrostatic pressure. Aerated fluid is used primarily to minimize lost circulation. Aerated fluid drilling is conducted very similar to mud drilling with a few modifications. Annular velocities are only 5 to 20% higher than fluid drilling.

## 3.0 PURPOSE

The purpose of this study is to investigate the current technology used in air drilling and to determine the advantages and limitations of air drilling. Further, air drilling in various areas is to be compared to mud drilling to determine which method is the most economical.

The results of the investigation are to be used to determine what new technology and methods can be used to improve the economics of air drilling. The areas where air drilling can be expanded are to be identified and ranked based on the expected economic benefits.

## 4.0 BACKGROUND

Grace, Shursen, Moore and Associates (GSM) was awarded a research contract from the Department of Energy, Morgantown Energy Technology Center. The objective of the study was to asses the potential for vertical, directional and horizontal air drilling in the United States and to evaluate the current technology used in air drilling.

The majority of wells drilled in the United States are drilled using fluid as the circulating medium. The industry typically calls this fluid drilling mud. Drilling mud performs many functions while drilling the well, however the primary functions are to clean the hole, contain pore pressures and cool the bit.

In air drilling, air or natural gas is used as the circulating fluid. It has the same primary functions as drilling mud except it will not contain pore pressures. The hydrostatic pressure exerted by the air or gas is too low to prevent the influx of formation fluids. When exploring for oil and gas, this is an advantage. Any hydrocarbons present in the formations penetrated by the wellbore will flow to the surface if the formation is capable of producing. Therefore, no potential producing formations will be bypassed. With mud drilling, open hole logs are used to determine the productive capability of the formations. The logs are subject to interpretation which can lead to bypassing a potential producing zone.

Another advantage of air drilling is that the penetration rate (amount of hole drilled every day) is higher. Drilling costs will be reduced because less time is spent drilling. However, air drilling is usually more expensive than drilling with mud because the compressors that pump the air must be rented. They are more costly to operate and maintain than mud pumps. To offset the additional costs, air drilling must be faster than mud drilling. The only way to effectively compare the cost of drilling with air versus mud is to calculate the cost per foot of hole drilled. So long as the cost per foot is lower, air drilling will be more economical.

## 5.0 METHODOLOGY

The method used to evaluate the application of air drilling in the continental United States consists of the following steps.

1. Establish a data base.
2. Divide the United States into drilling regions.
3. Acquire Existing well data.
4. Evaluate the well data.
5. Determine the limiting factors for air drilling.
6. Determine what new technology or methods are necessary to expand the use of air drilling.
7. Identify and rank areas where the use of air drilling can be expanded.

A data base was needed to store the acquired well information. With a data base, information can be retrieved by category such as the types of fluid used to drill the well. Other pertinent information in the data base is the well name, operator, drilling region, location, costs, type of well and other detailed information. The data base would allow well data to be retrieved based upon any of these items.

In order to evaluate the application of air drilling in the continental United States, the country was divided into drilling regions and provinces based upon geology and similar drilling conditions. After the regions had been established, information was pursued for each of the regions.

To acquire existing well data, operators, drilling contractors, air drilling contractors and other service companies were contacted to obtain well data. Additional information was obtained from companies that provide that type of information

The data was analyzed to determine whether air drilling is more cost effective than mud drilling and under what conditions. The analysis also attempted to determine what the limiting factors are for air drilling. Air is not used as the circulating fluid in many wells and the reasons for not using air have to be determined.

Once the drilling data has been analyzed and the limiting factors for air drilling have been determined, the technology required to overcome these limitations can be identified.

From the collected drilling data, we will attempt to identify and rank regions where air drilling usage can be expanded. There are many areas in the United States where air drilling is not used. We will ascertain why air drilling is not used and determine whether or not air drilling is potentially applicable to the area. The applicability will be based upon the known limitations of air drilling.

## 6.0 RESULTS AND DISCUSSION

The data base for the well data was created on PC File Version 7.0. The data base contains 165 records of wells drilled on air, air mist, aerated drilling fluid, mud or a combination of fluids.

Once the regions and provinces had been established, drilling information was sought for each of the regions. The primary focus was to obtain air drilling data in each of the regions. We looked for information where offset wells were drilled with mud or where both mud and air had been used in the same well. Because of the limitation of time and funds, drilling data could not be obtained for all wells drilled in every province. The most useful information would be associated with wells drilled on air that had problems during the drilling process. Air drilled holes that had no problems would be of limited use especially when trying to determine the applicability of air drilling within a province.

We also discussed the application of air drilling with service companies, operators and drilling contractors. We specifically asked each company what they thought would be required to expand the use of air drilling, what are the major obstacles to successful air drilling, and are there areas within the United States where the use of air drilling can be expanded.

The information was analyzed to determine:

1. The relative economics of air drilling versus mud drilling.
2. The types of problems associated with air drilling so that the limitations of air drilling could be defined
3. The probability of being able to expand the use of air drilling to places where air drilling is not currently being used.
4. What technological advances are required to expand the use of air drilling within the United States.

## 6.1 GEOLOGY

The geology of various provinces are described so that the reader can get an idea of the geology most suited to air and gas drilling. Generally, older and harder rocks are most suited to air drilling for two prominent reasons. The older rocks are more competent and the borehole is less likely to fall apart (called sloughing in the industry). Penetration rates while drilling soft rocks with mud are comparable to the penetration rates while drilling on air, therefore air drilling is not as applicable in softer rocks. As a rule, the hardness of a formation is proportional to the rocks geologic age. Geologically older rocks will be harder.

### 6.1.1 REGION 3 - PROVINCE 82

The Eastern Great Basin Province includes eastern Nevada, western Utah, and southeast Idaho. Basins included in the province are the Quirrh Basin in western Utah, the Bird Spring - Butte Basin in eastern Nevada, and the Sublett Basin in southern Idaho. The province is complex structurally and geologically with a great diversity of sedimentary facies, major episodes of orogenic and igneous activity, and extensive block faulting.

Structures in the region include the Paleozoic thrust belt of (Antler Orogenic belt) extending across south central and northeastern Nevada into Idaho; Basin and Range faulting which created deep graben valleys bounded by fault block uplifted mountain of late Tertiary Age; metamorphic core complexes; intrusive rocks of Jurassic-Cretaceous and Tertiary age; and extensive Tertiary volcanics.

Pre-Basin and Range sedimentary cover is primarily late Precambrian to Permian in age, comprising as much as 50,000 feet of mostly shallow-water marine carbonates and clastic miogeosynclinal deposits. In general, Cambrian quartzites and shelf units are overlain by Ordovician limestone and shale and Silurian dolomite. Devonian carbonates are overlain by Mississippian carbonates, shales and flysch sequences. Pennsylvanian sediments are dominated by shelf sandstone, carbonates and shale. Permian units are carbonate, sandstone and shale. Triassic carbonates and clastics are found in scattered outcrops. Cretaceous time was a period of uplift and erosion. In much of central, northeast and southeast Nevada, Late Cretaceous to Tertiary lacustrine and fluvial beds were deposited. Late Tertiary Basin and Range faulting uplift, and erosion exposed Paleozoic rocks on the mountain ranges. As much as 10,000 feet of sediment filled down dropped blocks in late Tertiary and Pleistocene fluvial, lacustrine, and volcanic fill is present. Up to 35,000 feet of Paleozoic sediment may have been present in the Paleozoic basins. In late Mesozoic the Sevier orgenic belt was thrust toward the east.

Formation names and depositional environments are varied throughout the region so a summary of units is not given. Oil and gas is found in the Tertiary basins and traps are commonly associated with Tertiary unconformities. Approximately 10 oil fields present in the region and include the Railroad Valley and Pine Valley area oil fields. Some of the larger fields include the Eagle Springs, Trap Spring, Bacon Flat, Grant Canyon, Currant, and Blackburn. Approximately 31 million barrels of oil has been produced with 18 million barrels recoverable remaining.[2] Producing formations include Tertiary volcanics, Sheep Pass Formation, Ely, Guilmette Formation, Nevada Formation, and Chainman. Traps are found in highly faulted Paleozoic carbonate and clastic rocks unconformably overlain by Tertiary basin fill volcanics. Tertiary volcanics and carbonates also produce. Shallow gas wells have supplied heat and light to ranchers from 1865 to the 1940's near Fallon, Nevada. The Province is considered to be a exploratory frontier for new drilling.

Eleven wells in Nevada have produced over 12 million barrels of oil from Paleozoic carbonates at Bacon Flat, Grant Canyon, Eagle Springs, Kate Spring, and Blackburn fields. These reservoirs are typically vuggy dolomites or Limestones of Devonian or Pennsylvanian Age. One well at Blackburn and two at Grant Canyon account for one-half of Nevada's production.

Mississippian Chainman Formation sandstone has been produced in three wells at the Blackburn Field and in one well at North Willow Creek. Thirty-nine wells have been completed in Tertiary and volcanic reservoirs and cumulatively produced approximately 242,000 barrels per well. Eleven wells have been completed in the Tertiary Sheep Pass limestone.

### 6.1.2 REGION 3 - PROVINCE 85

The Paradox Basin Province is located in south-central Utah and southwest Colorado and covers an area of approximately 35,000 square miles. The Paradox Basin is bounded on the south by the Four Corners Platform which separates the Paradox from the San Juan and Black Mesa Basins, and by the Defiance uplifts in Arizona and New Mexico. The north boundary is Uncompaghre Uplift and San Rafael Swell, the Oquirrh Basin is further north. To the east is the Uncompaghre-San Luis Uplift. The Circle Cliffs Uplift separates the Henry Mountains Basin and Paradox Basin from the Kaiparowits Basin further west.

The Pennsylvanian Paradox evaporite basin formed the northwest part of an elongated, rifted, northwest trending structural-sedimentary trough that was developed by tectonism associated with the ancestral Rocky Mountains. The axis of the basin parallels that of the Uncompaghre Uplift. In general, the basin has dense, shelf marine limestones at the margin, porous limestone, dolomite, and bioherms at the hinge-line and anhydrite and salt in the center and deeper parts of the basin. Arkosic material derived from the Uncompaghre Uplift was deposited along the adjacent eastern side of the basin.

Pre-Pennsylvanian sedimentation was dominated by transgressive and stable shelf sedimentation with deposition of shallow marine and clastic sedimentation. In Cambrian time, the Tapeats (Ignacio) sandstone formed the basal sedimentary unit in the area and was subsequently overlain by the Bright Angel Shale, Muav Limestone, and Lynch Dolomite. The units are marine in origin and generally grade upward from sandstone to marine shale, siltstone and limestone, which is overlain by massive dolomite. The Cambrian units reach a maximum thickness of 1,500 feet and thin to the east.

Devonian rocks up to 600 feet thick unconformably overlie the Cambrian. These consist of glauconitic sandstones and sandy dolomites grading upward into marine dolomite or limestone of the Aneth, Elbert, and Ouray Formations. Mississippian shallow-water marine carbonate deposits of the Leadville (Redwall) Limestone blanketed the area. This formation thins to the east. Emergence of the area in late Mississippian time created Karstic topography. Basement faulting throughout the Pre-Pennsylvanian time influenced sedimentation in patterns and eroded some materials off exposed areas.

Unconformably overlying the Leadville Limestone is the Pennsylvanian Molas Formation. Initial tectonism in the area provided local uplifting and began basin subsistence. Faulting was rejuvenated and influenced deposition by Atokan time and increased in Des Moines time. Increased subsidence and uplift caused restricted marine circulation and deposited the thick evaporite deposits of the Hermosa Group (Paradox Formation). Detritus derived from off the mountains of Pennsylvanian and Permian Age belong to the Cutler Group. The Paradox Formation consists of limestones, dolomites, bioherms and algal mounds in the shelf margins and hinge lines, and salt (both halite and sylvite) and anhydrite in the evaporite sequence in the central and deeper part of the basin. The Honaker Trail Formation of the Hermosa Group overlie the Paradox Formation. Permian units include the Cutler Formation, Elephant Canyon Formation, Ceder Mesa Sandstone, Toroweap Formation, White Rim Sandstone, and Kaibab Limestone. In Early Permian through Jurassic time northwest trending salt anticlines were formed by salt flowage and intrusion. Throughout the Permian, arkosic red beds prograded westward and intertongued with marine sandstone and carbonates. By Mesozoic time, the area was emergent and stable. The Lower Triassic Moenkopi and Upper Triassic Chinle Formations deposited continental red beds. Sandstones of the Wingate and Navajo were deposited in an aeolian environment and are Triassic-Jurassic in age. Jurassic age units include the San Rafael Group and Morrison Formation which consist of continental and marine sandstone, shale and siltstone.

Cretaceous rocks include the Burro Canyon Formation and Dakota Sandstone. In the late Cretaceous and early Tertiary additional faulting and folding occurred and the Monument Uplift occurred.

Approximately 125 oil and gas fields occur in the paradox Basin mainly in stratigraphic traps of the Paradox formation.[3] Oil was first discovered in 1908 at the Mexican Hat Syncline. The Paradox Formation contains the Ismay, Desert Creek, Akah, and Barker Creek zones of which the Desert Creek is most productive. Production is also found in the Mississippian Leadville Limestone; Permian Kaibab Limestone, Cedar

Mesa and White River Sandstone; and the Devonian McCracken sandstone. The Paradox formation productive zones are commonly present in bioherms, algal mounds and oomoldic reservoirs. The Triassic Moenkopi also produces in the region. Over 380 million barrels of oil and one trillion cubic feet of gas has been produced in the region.

### 6.1.3 REGION 3 - PROVINCE 86

The Uinta-Piceance Province covers an area of approximately 40,000 square miles in northwest Colorado and adjacent Utah. The Piceance Basin covers an area of 6,680 square miles in northwest Colorado and the Uinta Basin covers an area of 14,450 square miles in Utah. Both basins are asymmetrical and formed mainly in Tertiary time. The basins are separated by the Douglas Arch. Up to 32,000 feet of phanerozoic sediments are present in the Uinta Basin and 27,000 feet in the Piceance.

The Uinta Basin is bounded on the west by the Wasatch Mountains and the Hingeline thrust belt and on the east by the Douglas Creek Arch. The basin is bounded on the north by the Uinta Uplift and on the south and southwest by the San Rafael Swell and Uncompaghre Uplift. Basin orientation is east-west and deepest to the north along the Uinta Mountains Uplift.

The Piceance Creek Basin is a northwest-southeast trending structural basin with the axis paralleling the trace of the Grand Hogback, a monoclinal structural feature on the east side of the basin. The basin is bounded on the south by the Uncompaghre and Gunnison Uplifts, on the west by the Douglas Creek Arch, on the northeast by the Axial Uplift, and on the east by the White River Uplift.

The Eagle Creek Basin is present east of the White River Uplift and is a Pennsylvanian age basin. Little potential for hydrocarbon production is present in this basin.

The general stratigraphy of the province is similar for both basins throughout the Paleozoic and Mesozoic. Cambrian Age Sawatch Quartzite unconformably or its equivalent (Ledore Sandstone) overlie basement rocks. The Dotsero Formation is a series of thin-bedded conglomeritic dolomites which overlie these sandstones and is present through much of the Piceance basin. The Ophir Shale overlies the Ledore Sandstone in the Uinta Basin. The Lower Ordovician Manitou Limestone overlies Cambrian age rocks in Colorado and is subsequently unconformably overlain by the Chaffee Formation of Devonian Age. This unit contains the Parting Quartzite at the base and the Dyer Limestone above. In the Uinta basin, the Pinyon Park Formation overlies the Cambrian shale.

Overlying the Devonian Age units is the Mississippian Leadville Limestone (Madison or Deseret equivalent). The Mississippian unit was later uplifted and erosional and karst topography formed. In the Uinta Basin, the Deseret Limestone is overlain by the Humbug Formation and Manning Canyon Shale.

Pennsylvanian stratigraphy is more complex with the basal unit in the Uinta area being either the Round Valley Limestone or Morgan Limestone. In the Piceance Basin, the Beldon Shale is the basal unit. The Morgan formation is overlain by the lower Weber sandstone in the Uintas. In the Piceance area, the Belden Shale is overlain by the Morgan Limestone at the Douglas Creek Arch; the clastic Minturn Formation or Maroon Formation is present closer to the mountain front. The lower Weber Sandstone overlies these formations in the Piceance basin.

The Permian Age upper Weber sandstone overlies the lower Weber sandstone. The Park City Formation (Phosphoria) is marine sandstone, limestone, and shale and marks the final retreat of the Pennsylvanian-Permian seas in the area.

Mesozoic units of Triassic Age are mainly continental siliciclastic rocks of the Moenkopi Formation, Shinarump Sandstone and Chinle Formation in Colorado, and the Woodside shale, Thaynes limestone, and Ankareh Formation in Utah. The Navajo sandstone, an eolian sandstone, overlies these units. The Jurassic Age Twin Creek-Carmel Formation overlies the Navajo sandstone in the Utah area. This is subsequently overlain by the Preuss Formation (Entrada sandstone), Stump Formation (Curtis Formation) and Morrison Formation. These units are mainly continental with intertonguing marine units present to the west.

Lower Cretaceous clastic units are overlain by a thick section of Upper Cretaceous marine shale and continental and marine sandstone, mudstone, shale, siltstone, and coal. These Cretaceous units include the Cedar Mountain Formation, Dakota sandstone, Mowry shale, Tununk shale, Ferron sandstone, Frontier Formation, Mancos shale, and Blackhawk Formation of lower Mid Cretaceous, and the Currant Creek conglomerate, Castlegate sandstone, Mesaverde Formation, Price River Formation and North Horn Formation of the upper Cretaceous.

The two basins began to form in Paleocene time when the basinal areas began to subside rapidly. Subsidence was continuous into the Tertiary. Units deposited at this time include the Flagstaff limestone, Wasatch-Fort Union Formations, Colton Formation, Green River Formation and the Uinta-Duchesne River Formations. These are composed of shales, sandstones, carbonates, and marps of fluvial and lacustrine origin.

Oil and Gas in the Uinta Basin is mainly from the Green River Formation (Wasatch) of Tertiary Age from stratigraphic traps found at depths of 5,000 to over 16,000 feet. Cretaceous sandstones are the second major producing horizon. The Weber sandstone, Phosphoria Formation, Ankareh Formation, Preuss-Entrada and Morrison Formations, of Pennsylvanian to Jurassic Age also produce in the Uinta Basin and Douglas Creek Arch. The Uinta Basin has a cumulative production of approximately 378 million barrels of oil and 733 billion cubic feet of gas.[4]

Cumulative production for the Douglas Creek arch and Piceance Basin is approximately 786 million barrels of oil and 1.56 trillion cubic feet of gas. Gas is the main hydrocarbon in the Cretaceous and Tertiary reservoirs. The main producing formations include the Mesaverde, Mancos shale, Wasatch Formation, Weber sandstone, Morrison Formation and Entrada sandstones. Other productive reservoirs include the Green River Formation, Dakota sandstone, and Minturn Formations.

### 6.1.4 REGION 3 - PROVINCE 88

Region 3, province 88 is the San Juan Basin. The San Juan Basin is a roughly circular, asymmetrical basin having a NW-SE trending axial trace formed principally in Late Cretaceous - Early Tertiary (Laramide) time. The basin covers an area of approximately 23,700 square miles in northwestern New Mexico and southwestern Colorado. The province is a prolific oil and gas basin with oil being discovered as early as 1908 (Huffman, 1987).[5] Over 250 million barrels of oil and condensate has been produced, and 14.4 trillion cubic feet of gas, in reservoirs ranging in age from Devonian to

Upper Cretaceous (Rice, et. al. 1990).[6] Most of the production is restricted to the topographic San Juan Basin in tight Cretaceous sandstones. The stratigraphic section is thickest in the northeastern portion of the basin where approximately 15,000 feet of sediment is present.

Structurally, the San Juan Basin is a foreland basin that is bounded on the east, west, and north by monoclinal structures or uplifts. The southern boundary is defined as the northern limit of the Chaco slope, a north dipping homocline. The Zuni uplift is the south boundary of the Chaco slope. Oil and gas is present on the slope and is included in the evaluation of the province. The Defiance Uplift is present to the west, and to the northwest is the Four Corners Platform which separates the San Juan Basin from the Paradox Basin. North of the San Juan Basin is the San Juan Dome. The Archuleta Arch and Nacimiento Uplift separates the San Juan Basin from the Jemez volcanic field and the Chama Basin further east. The interior of the basin is characterized by gently dipping to flat sedimentary rocks. A few widely scattered, low relief domal or anticlinal features are present. Most observed anticlinal features and faults are along basin margins, to the south and west.

Cambrian to Mississippian units unconformably overlie Precambrian basement. The Upper Cambrian Ignacio Quartzite is preserved locally in down thrown blocks. Devonian Age Aneth, Elbert, and Ouray Formations are observed in part of the northern portions of the basin and are composed of limestone, dolestone, and glauconitic sandstones. Mississippian Age Leadville Limestone and Ouray Limestone is present and was deposited in a subtidal to intertidal or shallow shelf carbonate environment.

In Pennsylvanian time, sediment was deposited in a transgressive-regressive sequence with both continental and marine strata deposited. The Molas and Hermosa Formation's are observed to wedge out to the south. The Hermosa Formation includes the Paradox member, which in the San Juan Basin is of a restricted marine carbonate and black shale facies. The upper and lower members of the Hermosa Formation were deposited in a normal marine facies and consists of limestones and intercalated sandstone and shale beds.

Arkosic red beds of Permian Age include the Abo-Cutler Group and DeChelly Sandstone which generally overlie the Pennsylvanian sediments where they were present. These arkosic units were derived from the uplift of the Uncompaghre area to the north and northeast. In the south part of the basin, the Permian is more of a marine environment and the Yeso Formation, Glorieta Sandstone, and San Andres Limestone are present.

The Triassic system is represented by continental deposits of the Chinle and Dolores Formations which is up to 1,600 feet thick. The Wingate Sandstone is present locally in the north, but is probably Jurassic in Age. In most of the basin, the Jurassic Entrada sandstone unconformably overlies the Triassic. Jurassic Age rocks generally reach a thickness of 1,500 feet and is composed of the San Rafael Group and Morrison Formation, these being continental in nature.

In Upper Cretaceous time, five main transgressive-regressive cycles deposited up to 6,500 feet of sediment in the basin. These deposits included the basal Dakota Sandstone, Mancos Shale, Mesaverde Group, Pictured Cliffs sandstone, Fruitland Formation, Kirtland Shale, and Farmington sandstone member. These units are comprised of mainly sandstone/shale sequences with minor limestone beds. Coal beds are common in these formations but is thickest in the Fruitland Formation. The main structural development of the basin occurred during the late Cretaceous and early Tertiary time.

Cenozoic Era rocks are typical basin-fill deposits formed during the Laramide Orogeny. Up to 3,000 feet of sediment, mainly alternating sandstone-shale sequences were deposited. Much of the Tertiary sediments were removed from the southern part of the basin.

Petroleum has been commercially developed in sedimentary rocks ranging from Devonian to late Cretaceous Age. Oil and gas is mainly stratigraphically controlled although structural-stratigraphic traps occur around the basin margins. Most of the petroleum production is from the Cretaceous rocks. The common productive units include the Dakota Sandstone, Gallup Sandstone, Mesa Verde Formation (Point Lookout, Cliffhouse, and Chacra sandstones) and the Fruitland Formation. Coal bed methane in the Fruitland Formation has been intensely developed in recent years.

### 6.1.5 REGION 4 - PROVINCE 96

The Sweetgrass Arch Province covers 36,000 square miles in north central Montana. The area is bounded by the Montana disturbed belt to the west, the central Montana trough to the south, the Williston Basin to the east, and the Canadian border to the north. The major structural features of this province include the Sweetgrass arch, Alberta shelf, Bowdoin Dome, Scapegoat-Bannatyne trend, Pendrox fault system, Little Belt, Big Snowy, and Little Rocky Mountains Uplifts, the Bearpaw, Sweetgrass Hills, Highwood, and Judith Mountains Igneous terrains.[7]

Cambrian strata overlies late Precambrian Belt Supergroup sediments or Archaeozoic rocks. The Middle to Late Cambrian seas transgressed eastward and resulted in deposition of the Flathead Sandstone and overlying shales and carbonates of shallow marine origin. These units may thicken to the south where the central Montana trough was present, and to the west where deeper seas were present. Only thin Cambrian Age sediments are present on the Sweetgrass arch. Devonian Age units (Winnipeg, Red River, Stony Mountains) unconformably overlie the Cambrian strata to the west and Ordovician/Silurian strata to the east. Devonian units contain a thick sequence of carbonates which thin over the Sweetgrass Arch. The basal Souris River Formation is composed of shales, dolomites and sandstones representing the initial transgression of the sea, and is overlain by carbonate-evaporite cycles of the Jefferson, Nisku, and Potlatch Formations. Shale of the Three Forks Formation overlies the Potlatch Formation. In the eastern part of the province, the Bakken Shale unconformably overlies the Devonian. Mississippian carbonate and clastics of the Big Snowy and Madison Groups conformably overlie the Bakken Shale. The Madison Group is composed of dolomite, limestone, shale, and evaporites of the Lodgepole, Mission Canyon, and Charles Formations. The overlying Big Snowy Group is rich in sandstone and shale. Triassic-Jurassic erosion removed much of the Mississippian units in north central Montana.

Pennsylvanian strata of the Tyler, Alaska Bench, and Devils Pocket Formations of the Amsden Group and the overlying Quadrant Formation are present in the central Montana trough. These units were deposited in a mixed clastic-carbonate marine and nonmarine environment.

Unconformably overlying Pennsylvanian strata is the Permian Age Goose Egg Group in the south part of the province. Middle to late Jurassic units include the Sawtooth, Rierdon, and Swift Formations (Ellis Group), and the overlying Morrison Formation, and represent major transgressive-regressive cycles of sedimentation. Uplift of the Sweetgrass Arch affected sedimentation in the western part of the province and the Belt Island Complex affected sedimentation in the south.

Strata of Cretaceous Age include the Lower Cretaceous Kootenai Formation and the Lower to Upper Cretaceous Colorado and Montana Groups which thicken westward to more than 18,000 feet immediately southeast of the region. Formations include the Blackleaf Formation, Telegraph Creek, Judith River, Bearpaw, and Claggett.

Most oil and gas occurrences in the province are stratigraphic and/or structural in nature. Oil was first discovered in 1919 and over 340 million barrels of oil and 1,175 BCF of has been produced. Gas is more abundant than oil east of the Sweetgrass Arch. The Kootenai Formation sandstone, Madison Group carbonates and Colorado Group are the productive formations with the Kootenai sands and lower Cretaceous portion of the Colorado Group producing 75% of the reserves. Some of the larger fields include Cutbank, Kevin-Sunburst, Bowdoin, Tiger Ridge and Whitlash.

### 6.1.6 REGION 4 - PROVINCE 98

The Montana Thrust Belt Province contains an area of 41,400 square miles in mountainous terrain of western Montana. The province contains numerous thrust sheets and is highly faulted and deformed. Intrusive bodies are also common. The middle Proterozoic Belt basin was present in the northwestern part of the province and is the site Precambrian sedimentation where 46,000 feet of sediment accumulated. The western part of the province has been intensely faulted and uplifted so no Paleozoic rocks remain. Therefore, this portion of the province has little potential for hydrocarbons.

Paleozoic thrust-faulted rocks are present in the Lewis thrust fault belt and are potential reservoir rocks. The east side of the province is bounded by the Sweetgrass Arch.

Strata ranging in age from Precambrian to Holocene are present in the region. Cambrian units include the basal Flathead sandstone which is overlain by interbedded limestones and shales. The Cambrian Age Devils Glen Dolomite forms the upper part of the sequence. Ordovician rocks are present in the southernmost part of the province. Lower Devonian units are predominantly dolomite and evaporites of the Jefferson Dolomite and underlying middle and upper Maywood Formation. The Threeforks Formation is Devonian to Lower Mississippian in age. The Logan Gulch member consists of carbonates and evaporites, is overlain by shale of the Trident member, and then is overlain by the Devonian to Mississippian fine-grained sandstone and saprofpelic shale of the Sappington member.

Mississippian limestone of the Lodgepole Formation overlie the Maywood Formation and is capped by Mission Canyon Limestone of the Madison Group. Pennsylvanian sandstones of the Quadrant Formation is present in portions of the area, as is the Permian Park City (Phosphoria) Formation. Triassic rocks are restricted to the south. Jurassic Ellis Group sediments consist of marine shale and sandstone and is overlain by the non marine Morrison Formation.

Lower Cretaceous Kootenai Formation is overlain by the Blackleaf Formation. The upper Cretaceous Marias River Shale is a thick marine shale which correlates to the Greenhorn and Niobrara Formations further east.

The Montana Thrust Belt has been explored for 80 years with about 100 wildcat wells drilled.[8] No appreciable hydrocarbons have been produced, although two 20 BCF fields have reportedly been found. The fields have had little actual production reportedly due to lack of market. Oil and gas seeps are present in Glacier National Park and in Canada extensive reserves have been found. Potentially productive reservoirs include the Mission Canyon, Sun River dolomite, Cutbank sandstone, Moulton, Blackleaf Formation, and Marias Shale.

### 6.1.7 REGION 4 - PROVINCE 100

The Wind River Basin is a large asymmetrical intermontane basin of the Rocky Mountains located in north central Wyoming.[9] The basin covers an area of approximately 8100 square miles. Producing reservoirs ranging in age from Cambrian to Eocene. The basin axis lies along the west central side of the basin and has a maximum thickness of approximately 25,000 feet of sediment. The basin is bounded by the Owl Creek and Big Horn Mountains to the north, the Casper Arch to the east, the Granite Mountains (Sweetwater Arch) to the south, and the Wind River Mountains to the southwest. The present structural setting was developed in the Late Cretaceous and Early Tertiary.

The majority of Paleozoic and lower Mesozoic units were deposited as sediment in the shallow seas that covered a gently westward sloping shelf. Cambrian Age Flathead sandstone is commonly the basal sedimentary unit. The Gros Ventre Formation overlies the Flathead sandstone and is composed of marine sandstone, shale and limestone. The Gallatin Limestone overlies the Gros Ventre Formation. Unconformably overlying these Ordovician units is the Lander sandstone, Bighorn Dolomite and Leigh Dolomite. These rock units are subsequently overlain by Devonian to Mississippian Age units of the Beartooth Butte, Darby Formation, and Madison limestone. The Pennsylvanian Amsden Formation and Casper Formation or Tensleep sandstone overlie the Missippian Age units. Carbonates of the Permian Age Phosphoria Formation, Park City Formation and Goose Egg Formations overlie the Pennsylvanian rocks. In general, the carbonates of the Phosphoria Formation intertongue eastward into red beds of the Goose Egg Formation.

Red bed deposition dominated the Triassic time period. The Triassic Dinwoody Formation, Chugwater Group and Nugget sandstone were deposited at this time. Unconformably overlying these Triassic units are the Jurassic Age Gypsum Springs, Sundance Formation and Morrison Formation. Early Jurassic units were continental in origin, by middle Jurassic deposits were marine.

Lower Cretaceous units were dominated by shallow marine black shales of the "Claverly Shale" and subsequently by the Rusty Beds, Thermopolis shale, Muddy sandstone, and Mowry shale. In upper Cretaceous time, uplift began and the area had numerous transgressive-regressive cycles. Vast amounts of debris were shed into the basin from the west and marine deposition shifted eastward. The Frontier Formation,

The thickness of sedimentary rocks in the province is highly variable. In the Hanna Basin, sedimentary rocks have accumulated a thickness of over 42,000 feet. This is one of the deepest basins in the Rocky Mountains. In the northern part of the Green River Basin and in the Washakie Basin 32,000 feet of sedimentary rocks are present. The Shirley Basin contains 7,000 feet and the Laramie Basin contains 13,000 feet of Cambrian to Tertiary rocks.

From Cambrian to Jurassic time, much of the area was near the eastern margin of the Cordilleran geosyncline. Southeastern Wyoming was a positive are called the Trans Continental Arch that was periodically inundated when seas advanced. Shallow water marine shelf sedimentation and continental deposition was present during these times. In Cretaceous time, the area was covered by the interior Cretaceous eperic sea which covered the mid-continent. Uplifts occurred and geosynclinal deposits were uplifted, folded, and thrust to the west. The Wyoming basins were discrete and the adjacent uplifts provided material to fill the basins.

Cambrian Age rocks include the basal Flathead sandstone, and the marine Gros Ventre Formation, Buck Springs Formation, and Gallatin Limestone. Unconformably overlying these Cambrian units is the Ordovician Bighorn Dolomite. Fine grained sandstone, carbonates and anhydrite of the Upper Devonian Darby Formation unconformably overlie the Bighorn Dolomite. The Chaffee Group is present southwest of the Front Range Uplift and composed of clastics (Parting Sandstone and Dyer Formation members).

Up to 1,000 feet limestone of the Madison Formation of Mississippian Age was deposited in a shallow marine environment. The Darwin sandstone of the Amsden Formation unconformably overlies the Madison limestone and is of the Chesterian series. Pennsylvanian strata includes the Morgan, Fountain, and Anderson Formations; the Tensleep and Weber Sandstones; and the Casper Formation. Permian Age units in the province are the Phosphoria or Park City Formation and Goose Egg formation which unconformably overlie the Pennsylvanian units. Wolfcamp age rocks are present in the Hanna, Laramie, and Shirley Basins where the Casper Formation and Tensleep sandstone are preserved.

Triassic units are composed primarily of red bed sequences of shale, siltstone, and sandstone, and marine limestones of the basal Dinwoody Formation and the Chugwater Group, Thaynes Limestone, Ankareh Formation, Popo Agie Formation overlie the Dinwoody Formation and were subsequently overlain by the Nugget sandstone. The Jurassic time period was dominated by deposition of marine shale, sandstone and limestone in the west and inter tonguing continental and marine sandstone, siltstone, and shale to the east. These units include the Twin Creek limestone, Carmel Formation, Sundance Formation, Entrada and Preuss sandstones, the Stump and Curtis Formations, and the Morrison Formation.

With the development of the Western Interior Seaway, Cretaceous Age units were deposited from the Gulf of Mexico to the Arctic in the center of North America. The transgressive-regressive seas deposited marine and continental deposits which unconformably overlie the Jurassic Morrison Formation, and is composed of sandstone, siltstone, and shale. Formations include the Fall River Sandstone, Thermopolis shale, Muddy sandstone, and Dakota Formation, and Mowry Shale of Lower Cretaceous Age.

Upper Cretaceous Frontier Formation overlies the Mowry shale. This unit is in turn overlain by the Niobrara, Baxter shale, Steele shale, Mesaverde Group, Lewis shale, Lance Formation, and Medicine Bow Formation. These units are marine or marginal marine, to continental siliciclastic units.

Tertiary units filled the basins with terrigenous clastics derived from local uplifts and limestones formed in lacustrine environments. The thickest sequence of Tertiary rocks is present in the Hanna Basin, where up to 16,000 feet of Tertiary units are found. Throughout most of the province the basal tertiary unit is the coal-bearing Fort Union Formation. This unit grades upward into the Eocene Wasatch formation which in turn is overlain by the Green River Formation. Unconformably overlying these units are the White River Formation, Browns Park Formation, and Bishop Conglomerate.

The province is mainly a gas province although substantial oil has been found, mainly in anticlinal structures. Most oil and gas production is from anticlinal structures with a few stratigraphic traps being present. Reservoir rocks range from Cambrian to Tertiary in age and are mainly sandstones. Most of the production is in Cretaceous and Tertiary units. Some of the common reservoir rocks include the Madison limestone, Weber sandstone, Phosphoria Formation, Nugget and Entrada sandstones, the Dakota sandstone (Mesaverde Group), Frontier Formation. Almond Formation, Ft. Union Formation, Lewis shale and the Wasatch Formation. Portions of the Frontier Formation, Mesa Verde Group, and Fox Hills Formation have formally designed as "tight" gas sands. Additionally, many of the units contain coal and have potential for coal bed methane.

### 6.1.9 REGION 4 - PROVINCE 103

The Bighorn Basin is a large, asymmetrical intermontane basin of the Rocky Mountains located in Wyoming. This basin is one of the most prolific Rocky Mountain basins and is located in northern central Wyoming and adjacent Montana. Uplifts surrounding the Bighorn Basin include Big Horn Mountains to the east, the Absoroka and Beartooth Mountains to the west, and the Owl Creek Mountains to the south. The basin axis is along the west-central side. The basin is bounded by overthrust, high angle reverse and normal faults. Anticlinal features, commonly faulted, occur around the basin margins. The present structural setting was developed in the Late Cretaceous and Early Tertiary.

The majority of Paleozoic and lower Mesozoic units were deposited as sediment in the shallow seas that covered a gently westward sloping shelf. Cambrian Age Flathead sandstone is commonly the basal sedimentary unit. The Gros Ventre Formation overlies the Flathead sandstone and is composed of marine sandstone, shale and limestone. The Gallatin Limestone overlies the Gros Ventre Formation. Unconformably overlying these Ordovician units is the Lander sandstone, Bighorn Dolomite and Leigh Dolomite. These rock units are subsequently overlain by Devonian to Mississippian Age units of the Beartooth Butte, Darby Formation, and Madison limestone. The Pennsylvanian Amsden Formation and Casper Formation or Tensleep sandstone overlie the Missippian Age units. Carbonates of the Permian Age Phosphoria Formation, Park City Formation and Goose Egg Formations overlie the Pennsylvanian rocks. In general, the carbonates of the Phosphoria formation inter tongue eastward into red beds of the Goose Egg formation.

Red bed deposition dominated the Triassic time period. The Triassic Dinwoody Formation, Chugwater Group and Nugget sandstone were deposited at this time. Unconformably overlying these Triassic units are the Jurassic Age Gypsum Springs, Sundance Formation and Morrison Formation. Early Jurassic units were continental in origin; by middle Jurassic, deposits were marine.

Lower Cretaceous units were dominated by shallow marine black shales of the "Cloverly Shale" and subsequently by the Rusty Beds, Thermopolis shale, Muddy sandstone, and Mowry shale. In upper Cretaceous time, uplift began and the area had numerous transgressive-regressive cycles. Vast amounts of debris were shed into the basin from the west and marine deposition shifted eastward. The Frontier Formation, Carlisle shale, Niobrara shale, Cody shale, Mesaverde Formation, Lewis shale, and Meeteetsie Formation were deposited in these transgressive-regressive seas. Laramide tectonic movements began in Late Cretaceous and influenced deposition in the Lance Formation. Broad upwarps began to form in the south and the major structural features were defined by latest Cretaceous time.

Unconformably overlying the Cretaceous units is the Tertiary Age Polecat Bench Formation. The Bighorn Mountains began to rise the Paleocene, other structural elements continued to rise and anticlines formed in marginal areas. The trough of the basin continued subsiding and became a lake, depositing organic rich black shales. During the Eocene, the intensive folding and uplift accelerated and the Pitchfork and Wasatch Formations were deposited. Reverse faulting occurred in the east along the Bighorn Uplift and to the west. Up to 8,000 feet of Eocene sediments were deposited. The basin was filled and tectonic activity ended by the mildly Eocene. Large scale normal faulting related to regional uplift occurred in the late Tertiary and was accompanied by regional tilting. The Absaroka volcanic field covered the western margins of the basin.

The Bighorn Basin contains petroleum accumulations in faulted anticlines and thrust faulted traps and in stratigraphic sandstones. Production is found from depths of a few hundred to several thousand feet. Approximately 90% of the oil is from late Paleozoic reservoirs.

The Mesaverde Formation, Frontier Formation, Lakota, Dakota, Tensleep, Bighorn Dolomite, Phosphoria Formation, Madison Limestone, Morrison Formation, Dinwoody Formation, Sundance Formation, Amsden Formation, Cloverly shale, Meeteetse Formation, Muddy sandstone, Chugwater Group, and Flathead sandstone produce in the basin. Most production is from the Pennsylvanian Tensleep sandstone, Cretaceous sandstones, and Ordovician, Devonian, Mississippian and Permian carbonates. Approximately 2.5 billion barrels of oil and 1.6 trillion cubic feet of gas has been found in the Bighorn Basin.[12]

### 6.1.10 REGION 4 - PROVINCE 104 AND 105

The Denver Basin, commonly known as the Denver-Julesburg Basin, and the Las Animas Arch are included in region 4. The Denver-Julesburg (D-J) Basin is an asymmetrical structural basin bounded on the west by the central Rocky Mountains (Laramie and Front Range Uplifts); on the northeast and east by the Cambridge Arch; and on the south by the Apishapa Uplift and the Las Animas Arch. Production on the Las Animas Arch is included in this province. The basin trends north-northeast and has a maximum thickness of sediments adjacent to the Front Range in Colorado. Up to 13,500 feet of sedimentary rocks are present. The D-J Basin occupies much of eastern Colorado and extends northward into southeast Wyoming and Western Nebraska.

The D-J Basin contains sedimentary rock units of Cambrian to Tertiary Age. Units of Cambrian to Mississippian Age are present in the northern and southern parts of the basin. These units generally thicken to the southeast and much of the pre-Pennsylvanian units were eroded around the margins. The pre-Pennsylvanian units are mainly carbonates with some interbedded sand and shale units. The Upper Cambrian Reagan sandstone is present in some areas and is overlain by Arbuckle and Simpson Group sediments. Mississippian Age units are present above these. These units are commonly eroded or not deposited in the central Denver Basin and are found mainly to the east and southeast.

Pennsylvanian units overlie the Mississippian rocks unconformably and are mainly clastics that grade into mixed clastic-carbonate-evaporite or carbonate sediments to the east. A thick clastic sequence of sandstone and conglomerate is present adjacent to the Rocky Mountains and is comprised of the Fountain Formation in Colorado and the Casper Formation in Wyoming. The Minnelosa Formation in Nebraska is composed of shales, limestones and evaporites. In Kansas and southeastern Colorado, the Pennsylvanian Age units are more similar to the Hugoton Embayment units and are given mid-continent names, as are the Permian Age units. Early Permian rock units in the D-J Basin are carbonates in the main basin with clastics adjacent to the mountain ranges and evaporites to the south. As time passed, more evaporite rocks were deposited and to the east the units became clastic. Pennsylvanian and Permian units in the D-J Basin are commonly referred to by their series age name (i.e. "Morrowan Rocks").

Triassic Dockum Group red beds are present to the southeast and the Lykins Formation is present to the northwest in northern Colorado and Wyoming. Jurassic Age units include the Sundance Formation or Entrada sandstone which is overlain by the Morrison Formation. The basal Dakota Group overlies the Morrison Formation and includes the "D" and "J" sandstones which are the main producing sands in the Denver Basin. These sands are from a near shore marine environment. Overlying the Dakota group is the Graneros shale, Greenhorn Limestone, Carlisle shale, Niobrara Formation and Pierre shale of upper Cretaceous Age. The Niobrara chalk is a major reservoir in the basin. The Cretaceous Period was a time of multiple transgressive and regressive sequences. The Laramie Formation consists of non marine sandstones, shale, coal and siltstones.

Overlying the Laramie Formation is the Arapahoe Formation of Cretaceous Age and Denver Formation of Tertiary Age. The Cretaceous-Tertiary boundary occurs within the Denver formation. Around the east and southeastern margins, the Cretaceous is commonly unconformably overlain by the Ogallala Formation.

Oil was first discovered in 1862 near Canon City, Colorado just two years after Colonel Drake made his discovery in Pennsylvania.[13] Since that time, the Colorado D-J Basin has been explored for oil and gas and substantial reserves found. Most of the production in the basin is from the "D" and "J" sandstones of the Cretaceous Dakota Formation and the Niobrara chalk. Other producing units include the Codell

Sandstone, Lakota, Greenhorn limestone, Pierre shale, Muddy and Lyons sandstone. On the Las Animas Arch, the Pennsylvanian Morrow, Lansing-Kansas City, Topeka, Shawnee, Cherokee, and Marmaton, and Atoka rocks produce. The Mississippian units are also productive in the area. The Las Animas Arch area has produced over 23 million barrels of oil and 112 BCF of natural gas in structural and stratigraphic traps.[14] The D-J Basin has produced over 600 million barrels of oil and 966 BCF of gas.

### 6.1.11 REGION 5 - PROVINCE 107

The Permian Basin of West Texas and Southeastern New Mexico is one of the most important hydrocarbon provinces in the United States with over 25 billion barrels of oil having been produced. The Permian Basin can be divided into basinal and shelf areas, which were formed in the Permian and Pennsylvanian time. The Basin can be structurally divided into two basins - the Midland Basin to the north and the Delaware Basin to the south; these basins being separated by the Central Basin Platform. North of the Midland Basin is the Matador Arch which separates the Permian Basin from the Palo Duro Basin. The Eastern shelf is present to the east and the Quachita-Marathon structural belt is the south boundary of the province. The western edge of the Delaware basin is bounded by the Diablo Platform and the Pedernal Uplift. The shelf sequence to the north of the Delaware Basin in New Mexico is known as the Northwest shelf. Up to 24,000 feet of sediments accumulated in the deeper Delaware Basin. The Quachita geosyncline accumulated over 30,000 feet of sediments which were subsequently compressed, folded and accreted to the continent. These outcrop in the Marathon fold belt.

The Permian Basin area was covered by a broad epeiric carbonate platform in the early Paleozoic Era and deposited the Ellenberger Group carbonates conformably over Moore Hollow Group sediments. Mixed siliclastic carbonate deposits of the Simpson Group unconformably overlie the Ellenberger. Silurian to Mississippian Age carbonates were then deposited over the area.

In early Pennsylvania time seas advanced and reached their maximum extent. Seas were deepest toward the south and southeast where the Quachita geosyncline was present. Slow sinking of platforms and weak development of northwest trending basins marked early development of the area, along with compressional forces from the south and southeast. Throughout the Pennsylvanian, the basinal areas continued to deepen, forming the Midland and Delaware Basins. These basins are separated by the Central Basin platform, which was shallowly submerged. The Quachita-Marathon belt to the south began uplift and thrusting, forming the Marathon fold belt. In early Permian, major subsidence the Midland Basin occurred with deep, sediment starved basins being formed. Through Permian time, the Midland Basin subsided slowly and was rapidly filled, whereas the Delaware Basin to the south subsided more quickly and was partly filled with fine sand and silt, but remained relatively deep and euxinic until the end of the Permian Era. Faulting and uplift and continued subsidence marked the Permian with the Basins being almost filled by the end of the Permian. A carbonate rim almost entirely surrounded the Delaware Basin and separated it from the surrounding shelves, which accumulated shallow water lagoonal and evaporitic tidal flat facies.

Triassic age rocks completed the filling of the basin and Cretaceous Age rocks unconformably overlie the Triassic or Permian rocks. Much of the Sedimentary units were later eroded during Laramide age uplift in the surrounding areas.

Most of the hydrocarbon production has been from the shelf and platform areas, and surrounding carbonate rims, including the well known Permian reef complexes. The Midland Basin has been more productive than the Delaware Basin, much of the production associated with the Delaware is in the surrounding carbonate rim and northwest shelf. The Central Basin platform and shelf areas are also highly productive. Some of the more prolific reservoirs include the Ellenberger Group of Ordovician Age. The Permo-Pennsylvanian Horseshoe Atoll, Clearfork, Spraberry, San Andres, Yates and Grayburg Formations. Although mainly known as an oil rich basin, numerous gas plays are also present with both structural and stratigraphic traps present. Over 41 trillion cubic feet of gas has been produced from some of the more major gas plays in the Permian Basin.[15,16]

### 6.1.12 REGION 6 - PROVINCE 112

The Western Gulf Basin is comprised of the area along the Gulf of Mexico from South Texas to the Louisiana - Mississippi Gulf Coast.[17] This province covers over 115,000 square miles. The basin is a portion of the Mesozoic to Cenozoic Age Gulf of Mexico Depositional Basin. The province is bordered on the north by the Bend Arch and Fort Worth Basin of East Texas, and the Louisiana - Mississippi Salt basins. For purposes of this report, the south and eastern border of the province is the coast line.

The Gulf of Mexico basin was formed on the passive margin of North America during early Mesozoic time. During Triassic time, rifting created grabens on thinned continental crust and became the landward margin. Early Jurassic sediment deposition was mainly evaporitic which included anhydrite, shales, siltstones and thick salt sequences. In Jurassic to Cretaceous time, a broad continental platform developed and carbonate reefs formed along the shelf edge and carbonate deposition predominated. During Cenozoic time, a thick sequence of offlapping terrigenous sediments were deposited seaward. These sands and muds were derived from western sources and deposited in the East Texas and Louisiana - Mississippi salt basins. Successively younger wedges of offlapping terrigenous sediments prograded eastward and the basin subsided rapidly.

Hydrocarbons are produced in Jurassic to Tertiary Age sediments and rocks. Traps are both stratigraphic and/or structurally controlled. Structural traps related to growth faults and salt structures are common. Exploration began as early as 1865 and the province is estimated to contain large amounts of undiscovered reserves. Most traps are structural in fluvial-deltaic sandstone, and multiple pays are common. Over 23 BBO and 208 TCFG has been produced from the province (including the offshore production).

Jurassic - Cretaceous units are commonly well consolidated. Productive intervals include the Smackover, Cotton Valley, Hosston, Pearsall, Glen Rose, Stuart City Limestone, Edwards Formation, Georgetown, Buda, Tuscaloosa, Woodbine, Austin Chalk, Taylor Group and Navarro Group. The Jurassic-Cretaceous units Commonly consist of evaporites, carbonates, and shale which are consolidated and sometimes fractured.

Overlying the Cretaceous units are Tertiary unconsolidated sediments. These terrigeneous are characterized by high permeability and porosity. Many of the sands are water productive. Most of these Tertiary sands produce from structural traps. Principle reservoirs are sandstones of Eocene to Pliocene age, primarily the Wilcox Group, Yegua Formation, Frio Formation, Fleming Group sandstones and Anahuac Formations.

These Tertiary sediments are present overlying Mesozoic units throughout most of the province. The sandstones generally exhibit high porosity (25-35%) and high permeability (up to several Darcies). Due to the lack of cementing (unconsolidated to poorly consolidated) and the presence of water in highly permeable rock, this basin is not a major air drilling province.

### 6.1.13 REGION 7 - PROVINCE 115

The Anadarko Basin, Dalhart Basin and Hugoton Embayment are included in region 7, province 115. Western Oklahoma, the Texas Panhandle, and Western Kansas contains one of the largest hydrocarbon provinces in the United States. Exploration for oil and gas has resulted in the production of over 5 billion barrels of oil and 82 trillion cubic feet of gas.[18] This area encompasses approximately 60,000 square miles of Northwestern Oklahoma, the Oklahoma and Texas Panhandles, Southwestern Kansas and Southwestern Colorado. Today, we define provinces within this area as the Anadarko Basin, The Hugoton Embayment, and the Dalhart Basin. Over 40,000 feet of sediments accumulated in portions of the area.

In Cambrian to Mississippian time, much of the mid-continent area was part of a broad epicontinental sea in which thick and extensive carbonates with interbedded shales and sandstones were deposited in a mainly shallow marine environment. About 15,000 feet of sediment was deposited during this time and includes the Arbuckle Group, Simpson Group, Viola Formation, Hunton Group, and Mississippian age sediments.

During the Pennsylvanian, an orogenic episode occurred, with uplifts and downwarps resulting in the separation into the known as the Dalhart and Anadarko Basins. The Anadarko Basin is bounded on the south by the Amarillo-Wichita Mountains Uplift, on the West by the Cimarron Arch which also defines the east boundary of the Dalhart Basin, to the north by the Central Kansas Uplift, and to the east by the Nemaha Ridge. The Dalhart Basin is bounded by the Bravo Dome and Amarillo Uplift to the south, the Sierra Grande Uplift to the West, and to the north by the Las Animas Arch. The Hugoton Embayment is the Northern shelf of the Anadarko Basin and is bounded by the Las Animas Arch to the west and the Central Kansas Uplift and Cambridge Arch to the north and east.

During this time, shallow marine sediments continued to be deposited in the shelf area (Hugoton Embayment) of the Anadarko Basin. Mainly marine sediments were deposited in the Dalhart and Anadarko Basins with over 18,000 feet of sediments being deposited in the deep Anadarko Basin. The Dalhart Basin received clastic fan delta deposits along the west portion of the basin and carbonates were restricted to the east. Over 2,400 feet of Pennsylvanian sediments accumulated. Continued faulting, folding, and subsidence created many of the structures observed today. Much of the petroleum reserves are produced from rocks of this age.

During the Permian, some structures were regenerated and caused additional upwarping, subsiding, erosion, and in filling of the basin. In general, the

Permian age rocks in filled the basins with carbonates, evaporites and red beds. Permian age carbonates and clastic reservoirs have contributed substantial reserves to the region. Up to 7,000 feet of Permian stratas have been deposited just north of the Amarillo-Wichita Uplift.

Post-Permian strata was eroded from much of the region. Remnants of Triassic, Jurassic, Cretaceous, Tertiary, and Quaternary Rocks are present. Deposition of these rocks was not influenced by the previous tectonic elements and except for Cretaceous time, was mainly continental.

Common producing reservoirs include the Cambrian to Devonian Age Arbuckle and Hunton Formations; the Mississippian Chester Formation; the Pennsylvanian Morrow sandstones and Atokan to Virgilian Marmaton; Lansing-Kansas City, "Granite Wash," and Douglas formations. Permian Age reservoirs include the "Wolfcamp," brown dolomite, and granite wash. In the Hugoton Embayment, the Permian Wolfcamp units of the Krider and Herrington Formations are common reservoirs. The deeper Mississippian and Pennsylvanian sediments also produce oil and gas.

### 6.1.14 REGION 7 - PROVINCE 116

Region 7, province 116 includes the Arkoma Basin and Quachita Overthrust Belt. The Arkoma Basin is an elongated east-west trending sedimentary basin which covers an area of approximately 13,000 square miles in eastern Oklahoma and the western and central portions of Arkansas.[19] Oil and gas has been produced from the areas for many years with both structural and stratigraphic traps present. Approximately 40,000 feet of sediment accumulated in the basin. Much of the basin is in rough and mountainous terrain with anticlines, synclines and faulting being observed in the surface geology. Structural deformation is greatest to the south near the Quachita Mountains. The Quachita Mountains is the southern boundary of the Arkoma Basin and is composed of highly deformed geosynclinal sediments which were accreted to the continental margin in Late Pennsylvanian and Permian time. The north boundary of the Arkoma Basin is the Cherokee Platform and Ozark Dome. The western boundary is the Seminole uplift which separates the Arkoma from the Ardmore Basin. The Mississippian Embayment forms the eastern margin. The Quachita Overthrust Belt is included in this evaluation and is bounded on the south by the Fort Worth-East Texas Basins.

Stratigraphically, the early Ordovician to early Mississippian Age sediments consist of deep water sediments to the south in the Quachita facies with shallow water clastics and carbonates accumulating in a shelf environment in the Arkoma Basin. These geologic units include the Arbuckle, Simpson, Viola, and Hunton Groups of Cambrian to Devonian Age in the Arkoma Basin; and the Crystal Mountain Sandstone, Bigfork Chert, and Arkansas Novaculite in the Quachita Mountains. Mississippian Age sediments include the "Caney" shale and Sycamore sand of the Arkoma Basin and the Arkansas Novaculite, Stanley Group and Jackfork Group of the Quachita Mountains. These sediments generally thicken to the south.

Unconformably overlying the Mississippian units are Pennsylvanian Age rocks of the Springer, Cromwell, and Waupanucka in the Arkoma Basin, and the Jackfork Group in the Quachita Mountains. Sedimentation was greatest in the early Atokan and early Des Moines and was associated with the greatest amount of subsidence. The Pennsylvanian Age strata were deposited in a deltaic manner with sediment accumulating in a rapidly subsiding environment, and was sourced from higher eroding lands located to the north, northeast and northwest.

By late Pennsylvanian time, the Arbuckle Orogeny occurred and uplifted the structures which separated the Arkoma Basin from the Ft. Worth Basin. Uplift continued into the Permian. The Quachita Belt was accreted to the continent with sediments being uplifted, compressed, and intensely thrusted, faulted, folded and deformed. The Ozark Dome was re-elevated and tilted the sedimentary beds and had associated block faulting. The entire Arkoma Basin was later tilted westward by the Appalachian Orogeny. The basin was filled by Missourian time by sediments eroded from the Quachita Mountains to the south and deposited into the basin. The area by late Pennsylvanian time was a low relief continental area with the relief being greater in Quachita overthrust to the south.

The Arkoma basin is mainly a dry gas province. The Quachita Mountains have produced both oil and gas with shallow production common on anticlinal structures. Some of the reservoirs include the Arkansas Novaculite, Arbuckle, Hunton, and Simpson Formations; the Cromwell and Spiro sands; the Jackfork and Stanley Groups in Arkansas; the Waupanucka Limestone; and the Atoka formation. Over 1 trillion cubic feet of gas has been produced from the Quachita Mountains' gas fields.[20] Recent Spiro-Wapanuca and Arbuckle discoveries along the frontal zone of the Quachita thrust belt have discovered over 4 TCF at depths of approximately 9,000-14,000 feet.

### 6.1.15 REGION 8 - PROVINCE 131

The Appalachian Basin Province covers approximately 230,000 square miles of the eastern United States from Canada to central Alabama.[21] The province is subdivided into the western Appalachian Plateau, and the Valley and Ridge subdivision further east, and Overthrust. Metamorphic and igneous rocks of the Blue Ridge and Piedmont bound the Valley and Ridge to the east. The western edge of the province is bounded by the Cincinnati Arch, the southern by the Black Warrior Basin.

The Appalachian Basin is an asymmetrical basin that was developed in Paleozoic time. Individual formation names are not given due to the size and complexity through the area. From Cambrian to Ordovician time, sediments were deposited into the passive marine margin that was present along the east coast of North America. Shallow water marine deposits accumulated along the western margins and a deeper marine facies further east. Up to 7,500 feet of carbonate and clastic sediment accumulated. The area contains mainly upper Cambrian marine clastics overlain by thick carbonates. The region was uplifted and subaerially exposed with secondary porosity forming in the carbonates (karstic). In Mid-Ordovician time, the eastern margin of North America shifted from a passive to an active margin, and a foreland trough formed as compressional tectonics came into play. Siliciclastic sediments derived from eastern sources prograded westward into the basin and a carbonate shelf was present along the western margins. Marine transgression in the lower Silurian deposited sandstones which transgressed and covered most of the area and by late Silurian, a restricted marine environment was dominate and evaporites were deposited. At the end of Devonian time, uplift again raised lands to the southeast and created source areas for clastic sedimentation. At the end of the Devonian time, sediments were intensely deformed with sheets of rock being thrust to the west and folded, faulted and intruded. This tectonic activity created structural traps such as anticlines and enhanced porosity in some areas by fracturing the rock units. Several delta sequences prograded to the west from eastern source areas in Cambrian to Devonian time. Limestones were deposited along the western margins. From late Devonian to early Permian, the basin filled with siliclastic units. In Pennsylvanian time, the extensive coal fields were deposited in the basin. Rifting occurred in Triassic Time and down faulted basins were formed in the Appalachians. Much of the area was lowlands and terrestrial deposits were laid down.

Oil and gas has been explored for in this province since 1859. Cambrian to Pennsylvanian age sedimentary units produce in structural and stratigraphic traps. Some of the main reservoir units include the Devonian Age shales and sandstones which cover much of the basin. Main reservoirs include "fractured Devonian shales," Clinton sand, Medina Group; the Pennsylvanian Age Oneida and Herkimer sandstones; Tuscarora, Keefer sandstone, Big Injun, Trenton limestone, Knox Group carbonates, Rose Run sandstone, Copper Ridge dolomite, Squaw sandstone and Wein sandstone. Most hydrocarbons production is in the Appalachian plateau province. The lower Mississippian Berea sandstone, early Devonian Oriskany sandstone, lower Silurian Tuscarora sandstone and "Clinton" - Medina sandstone and Devonian shale are FERC approved in portions of the basin as "tight gas" sands.

## 6.2 REASONS FOR AIR DRILLING

The next sections explain the most common reasons for drilling wells with air or natural gas. The overwhelming reason was economics. Where applicable, it is cheaper to drill wells with air than to drill wells on mud primarily due to increased penetration rate. Even though the daily operating cost is higher for an air drilling operation, the well drills faster and the total time spent on location is less. As a result, the total cost of the well is less.

Other reasons for air drilling include minimum formation damage, formation productivity information while drilling, environmental concerns and the prevention of lost circulation.

### 6.2.1 ECONOMICS

Economics is the driving force behind drilling wells with air or gas. If it is not less expensive to drill with air, the industry will not use air drilling. The primary reduction in drilling costs are associated with increased penetration rate. The faster the well is drilled; the less it will cost. There is ample evidence to show that air drilling penetrates faster than mud drilling. An example of the increased penetration rates can be seen in the bit record from the Fed. G-2-2-1045 well (Region 4 - Rocky Mountains, Province 86 - Uinta - Piceance - Eagle Basins). Bit number 5 drilled at a penetration rate of 34.3 feet per hour while drilling on air and mist. The well was mudded up for the next bit run and the penetration rate decreased to 3.5 feet per hour. In this case, the penetration rate was 10 times faster than mud.

The increase in penetration rate is not always as high as 10 times the drilling rate while using mud; however, the increase is usually always greater than two to one. Some examples can be pulled from the data base. In the #6 Andy's Mesa well (Region 3, Province 85), the penetration rate with air is 23.57 feet per hour versus 10.42 feet per hour for mud. The penetration rate for air was 25.65 feet per hour versus 6.65 feet per hour with mud in the 1-8 Jolly well (Region 4, Province 86). In the Wyoming well Reservoir Creek Unit 1-34 (Region 4, Province 100), the penetration rate for mud was 5.95 feet per hour versus 31.31 feet per hour for air. In all the well data, air drilling always drilled faster or at least comparable to mud drilling. In very few instances was air drilling as slow as mud drilling, and then only because insufficient bit weight was used or other problems resulted in the slower penetration rates.

That does not mean that air drilling is always less expensive than mud drilling. The compressors and boosters required for air drilling are not cheap to rent and operate. Plus, the equipment has additional transportation and set up costs. A significant number of wells that utilize air as a drilling fluid, do not use air from beginning to end. Because of problems in the drilling operations, the well is mudded up (air is replaced by drilling mud as the circulating fluid). Therefore, only a portion of the well is drilled using air. The 1-8 Jolly is a classic example. As can be seen in Figure 6.1, the well was drilled on air from surface to 180 feet where circulation was lost requiring the well to be mudded up. The well was drilled on mud from 180 feet to the casing point at 3553 feet. After setting casing, air drilling was again used to drill from 3553 feet to 7010 feet. Air drilling greatly increased the penetration rate which is evidenced by the short period of time required to drill the interval from 3553 feet to 7010 feet. However at 7010 feet, the drill string became stuck and the well was mudded up to facilitate fishing operations. Out of the approximately 8000 feet drilled, only 3600 feet was drilled with air.

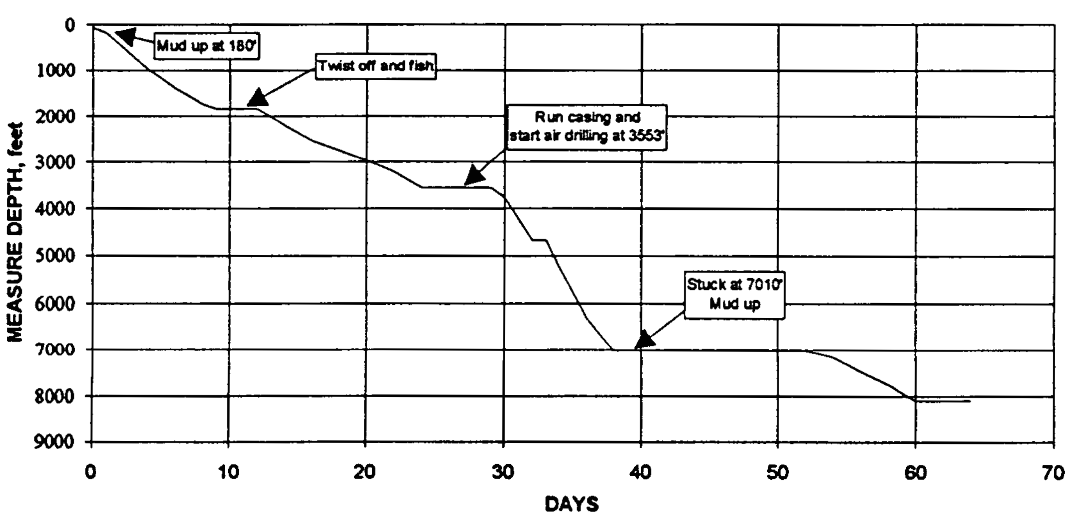



*Figure 6.1 - Depth versus days for the 1-8 Jolly well located in Garfield County, Colorado.*

To drill the 3600 feet at 25.65 feet per hour would require approximately six drilling days. Drilling the same interval using mud would have taken 22 drilling days at a penetration rate of 6.65 feet per hour. The average daily operating cost while air drilling is around $9000 per day while it is $6500 per day for mud drilling. The cost of drilling the same interval with air and mud are $54,000 and $143,000, respectively. The savings of $89,000 will more than offset the additional transportation and set up costs in this case. However, that is not always the case. If the interval that can be air drilled is too short, then the additional costs can not be justified.

In the Reservoir Creek Unit 1-34 well, air drilling was not as successful. The operator had intended to drill the lower portion of the well with air but hole conditions prevented the use of air. The operator ran casing at 8100 feet and drilled below the casing with air until a depth of 8332 feet was reached. At that point, the well was mudded up because of excess water production. As stated earlier, the penetration rate while drilling on air was 31.31 feet per hour versus 5.95 feet per hour drilling with mud. Unfortunately, it was not economical to air drill this well because the interval drilled on air was too short. A total of 232 feet was drilled with air. Using the same daily operating costs as before, the savings in this case were only $7,800 which is not sufficient to transport and set up the compressors. The depth versus days curve for the Reservoir Creek Unit 1-34 is shown in Figure 6.2.

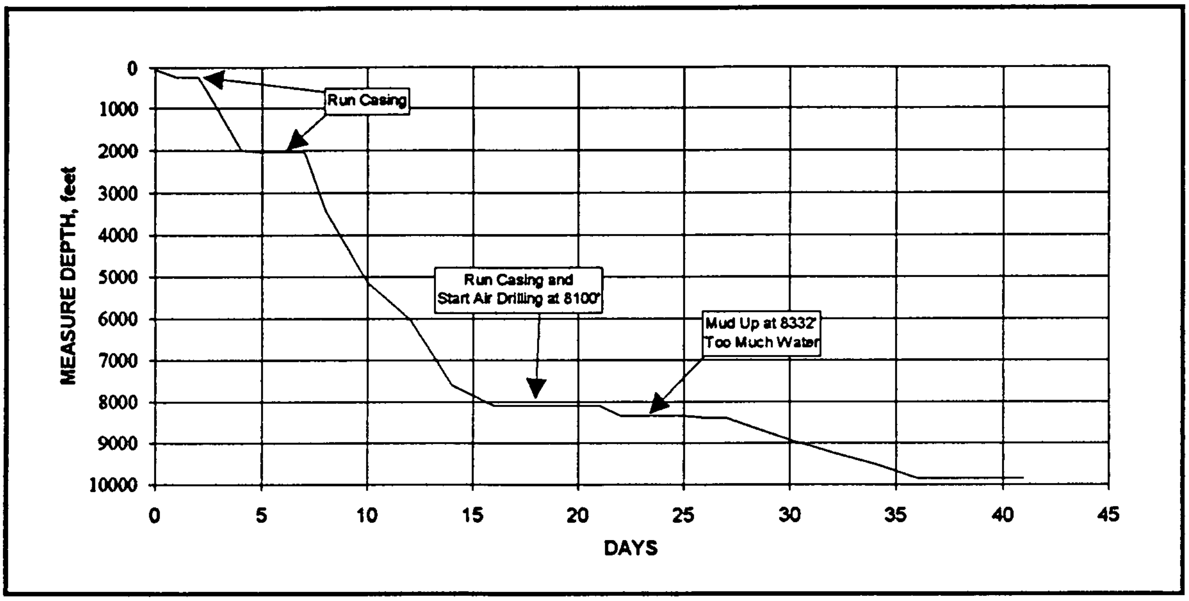



*Figure 6.2 - Depth versus days for the Reservoir Creek Unit 1-34 well in Wyoming.*

In actuality, the cost savings in the well were not $7,800. As can be seen in Figure 6.2, three days were spent trying to seal off the water zone with cement and finally mudding up. If the well had been drilled out from under the casing with mud, the three days of rig time and cementing costs would not have been incurred. The additional expenses more than exceeds the cost savings associated with the increased penetration rate while drilling with air.

In order for air drilling to be economical, the amount of hole drilled with air has to be sufficient to where the reduction in cost exceeds the transportation and set up costs for the compressors plus any additional costs associated with the air drilling operations. As can be seen in the Reservoir Creek Unit 1-34, air drilling was not economical; however, air drilling was economical in the 1-8 Jolly well. Each well must be considered based on the costs associated with that well.

Cost savings may not be associated with increased penetration rate alone. One such example is lost circulation. By using air as a drilling fluid, some lost circulation problems can be avoided thereby reducing total drilling costs. Lost circulation can be an expensive, time consuming operation depending upon the severity of the problem. Lost circulation problems are discussed in more detail in section 6.2.5.

Other cost savings may not be realized in the drilling operations but in another portion of the well operations. For instance, some wells do not respond well to stimulation during the completion phase. Drilling these wells with minimum formation damage can be beneficial to overall production rates and ultimate recovery of the resource. Air is the least damaging of all the drilling fluids. Although it may be more expensive to set casing above the producing formation and drill the producing interval with air, the ultimate rate of return on the well can be higher because of higher production rates.

### 6.2.2 MINIMUM FORMATION DAMAGE

Drilling fluids such as mud and water can damage the productivity of some formations. Fine particles within the mud system can penetrate the formation and reduce the permeability, or the fluid phase of the drilling fluid can cause swelling of natural clays within the formation. The fluid phase can also cause emulsion blocks within the formation.

Since the hydrostatic pressure in the wellbore is greater than the pressure in the formation (required to keep the well from blowing out), the direction of flow is always into the formation. With air drilling, the pressure is almost always greater in the producing formation. Therefore, fluid and gas flow from the formation into the wellbore. The cuttings and air do not readily flow into the formation.

That is not to say air drilling does not cause some formation damage. While running the drill string in and out of the hole or making a connection, the pressure in the wellbore will fall and the pressure within the producing formation next to the wellbore will fall to the same level. As air is again circulated through the well, the pressure in the wellbore increases. If the producing formation is a relatively low permeability formation, then the pressure in the wellbore will rise faster than that in the producing formation near the wellbore. As a result, the air and cuttings will enter the formation and cause some formation damage. This phenomenon has been noticed by several of the operators we talked to and was recently reported in an article by Graham, et. al[22]. If the pressure in the formation is too low, then the pressures caused by circulation will always be greater than the pressure in the formation and productivity damage will occur. Higher wellbore pressures are encountered while drilling with foam and aerated fluids and formation damage is more likely to occur.

If the operator plans on mudding up to run open hole logs, the formation damage will take place during this time. Formation damage will also occur if casing is run through the producing interval and cemented in place. Cement is very much like drilling fluid in that it has nine solid and a liquid phase. Damage happens in the same way, though the formation is not exposed to the damaging fluid for a long period of time. Essentially, the advantages of minimum formation damage drilling associated with air are negated if the well is mudded up or casing is cemented across the producing formation.

In our investigation, we found that most operators will either mud up and/or cement casing across the zone. Very few operators set casing above the formation and drill in with air to minimize formation damage, and then only with specific formations.

The application of minimum formation damage drilling has most recently been applied to horizontal drilling. In a horizontal well, the producing formation is drilled at an inclination of 90° from vertical. Typically, there will be 2000 feet or more of wellbore exposed to the producing formation and the majority of wells are natural producers. A natural producer means that the operator does very little stimulation work in order to improve the productivity of the formation because of the considerable expense involved in the stimulation process. Therefore, minimum formation damage is more important in horizontal drilling. Air, air mist and foam have been used to drill horizontal wells because of its low damaging properties.

### 6.2.3 CONTINUAL FORMATION TESTING

Another reason for air drilling is the ability to monitor potential production during the drilling process. Since pressures within the wellbore are so low (usually less than 100 psi with air and air mist), any possible producing formation will flow into the wellbore while drilling. The flow out of the well is monitored by a mud logger who can identify increases in hydrocarbon production. Therefore, any formation that is capable of producing will be noticed by the drilling personnel for later evaluation during the completion process.

When drilling wells with mud, the pressure in the wellbore is almost always greater than the pressure in the formation. Formations capable of producing hydrocarbons will not flow into the wellbore under these conditions. If it does flow into the wellbore, it is called a kick which is a well control problem and is undesirable. When drilling with mud, it is possible to miss potential pay zones. The zones must be identified with open hole logs and the productive capability of some formations is difficult to interpret from the logs.

In a gas well, the operator can stop drilling at any time and test the quantity of gas coming from the well using a pitot tube or a flow prover. So even the potential production rate can be monitored when air drilling. This has significant advantages over drilling with mud. In an air hole, zones that will produce non commercial quantities of hydrocarbons can be identified. In mud holes, the zone has to be perforated and tested to determine its productive capability leading to additional expense.

### 6.2.4 ENVIRONMENTAL CONCERNS

Air drilling can reduce environmental concerns depending upon how the well is drilled. In areas where the vast majority of the wellbore can be drilled with dry air or air mist, the environmental problems associated with the reserve pit are minimized. In a typical mud drilling operation, the cuttings and excess mud are dumped into a reserve pit next to the drilling rig. Disposal of the cuttings and excess mud can be a problem in some areas of the country. The mud can contain chemicals that can significantly increase disposal costs.

Where dry air or small quantities of mist are used, the volumes of liquid within the reserve pit are substantially reduced. Further, mist and foam seldom contain chemicals considered environmentally unacceptable. Air drilled holes do not need as big a reserve pit as mud drilled hole because the liquid volume is much less. For these reasons, air drilling is environmentally less damaging than mud drilling.

### 6.2.5 MINIMIZED LOST CIRCULATION PROBLEMS

Another reason for air drilling is to minimize lost circulation. While drilling on fluid, lost circulation occurs when the drilling fluid leaves the wellbore at some point and enters the formation. The primary function of the drilling fluid is to carry the cuttings generated by the bit to the surface. When lost circulation occurs, the fluid no longer returns to the surface and a portion of the hole is not cleaned. Lost circulation can become very expensive because the lost drilling fluid must be replaced. Also, the drilling process is usually delayed until the lost circulation problem is fixed, usually with lost circulation material. At times it becomes necessary to use cement to seal the lost circulation zone.

There are two causes of lost circulation. Lost circulation can occur by losing drilling fluid into the natural porosity and permeability of the formation or into natural fractures. In this case, the hydrostatic pressure in the wellbore is greater than the pressure in the formation. The drilling fluid leaves the wellbore and enters the formation because it is the path of least resistance. To state it simply, water only flows downhill. Lost circulation material or cement is used to plug the permeability or fractures increasing the pressure required to make the fluid enter the formation.

Circulation can also be lost due to induced fractures. Most formations do not contain enough natural permeability to allow a solids ladened drilling fluid to enter the formation, especially those associated with air drilling. However, circulation can still be lost into these formations. When the hydrostatic pressure in the wellbore is sufficiently high, a fracture will be induced in the rock allowing the drilling fluid to enter the formation. In this case, the pressure must be higher than formation pressure in order to induce a fracture. Lost circulation material or cement will only help if the pressure in the wellbore is very close to the pressure required to fracture the formation. The easiest way to prevent this type of lost circulation is to reduce the density of the drilling fluid. A lower density will yield a lower wellbore pressure.

Air drilling is an effective way to prevent lost circulation. That is not to say that lost circulation never occurs with air. Recently, operators have been drilling horizontal wells in Canada. Formation pressures are on the order of 250 to 400 psi. Since the wells are drilled in a heavy oil zone, they must be drilled with mist or foam. The hydrostatic pressure exerted by the mist or foam and the oil sometimes exceeds bottomhole pressure and circulation is lost. Another example is the directional well drilled by the National Park Service at Grand Canyon National Park. The well was drilled on the edge of the Grand Canyon where bottomhole pressure was essentially zero. Circulation back to surface was only accomplished about one-third of the time.

Fortunately, lost circulation with air is relatively rare. Wellbore pressures associated with air drilling are usually significantly lower than formation pressure; therefore, air can be used to prevent lost circulation problems during drilling. While gathering well data for the study, many operators indicated lost circulation was one of the primary reason for air drilling in certain areas. Depending upon the formations being drilled, air or air mist can be used to drill the well.

Most formations that will take drilling fluid when the pressure in the wellbore exceeds formation pressure, will also produce water when the wellbore pressure is less than formation pressure. Mist must be used in cases where the formation will produce small quantities of water. Dry air can only be used if the formation does not produce water. An aerated fluid is often used if the formations make large quantities of water.

Many operators use aerated water or aerated mud in regions like the Uinta-Piceance-Eagle Basins. The formations in these basins are able to produce large quantities of water. If the well were to be drilled on air mist, the reserve pit would shortly fill up with water and drilling would have to be terminated. By using an aerated fluid, the pressure in the wellbore is kept sufficiently high to prevent influx of large water volumes. Water still enters the wellbore from the formation but at a reduced rate.

The Divide Creek Unit #29 in Mesa County, Colorado is one example of drilling with aerated drilling fluid. Figure 6.3 is a plot of depth versus days for the Divide Creek well. The well ran into severe lost circulation problems starting at 1480 feet. As drilling progressed, the lost circulation problems increased. By 1686 feet, the operator had decided to start drilling with air and mist solving the lost circulation problem. At 2300 feet, the well encountered a large water flow. The water flow was large enough to flood the location. To reduce the volume of water entering the wellbore, an aerated mud system was run. Lost circulation was again encountered between 2948 and 3235 feet. The interval was drilled with no returns to the surface even though only air was being pumped down the well. Circulation was regained below 3235 feet and drilling continued with an aerated drilling fluid.

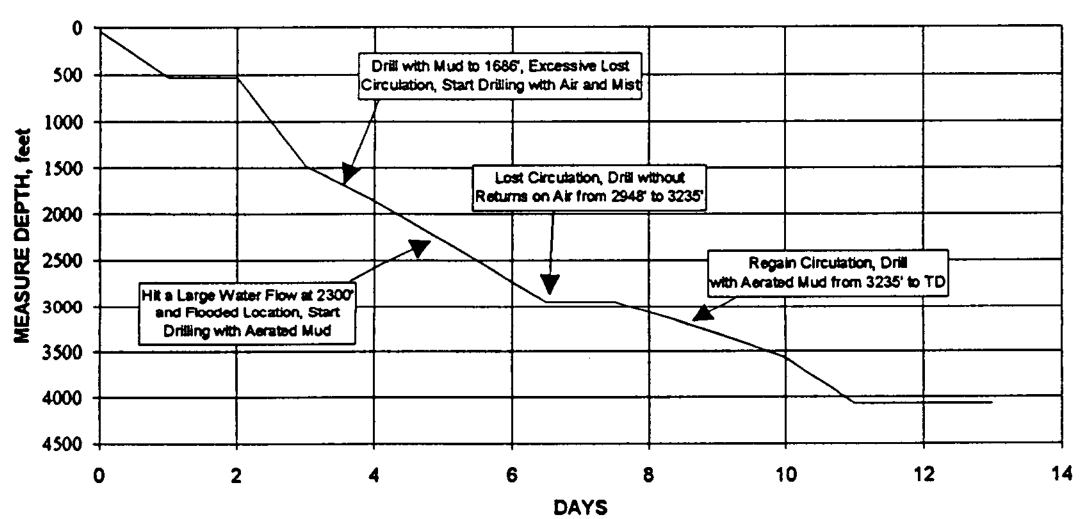



*Figure 6.3 - Depth versus days for Divide Creek Unit #29 well drilled with aerated fluid.*

As the example shows, air can be used to minimize lost circulation problems. The well was drilled without interrupting the drilling process for a long period of time to combat lost circulation. The savings in time more than offsets the additional cost of the air equipment.

## 6.3 FACTORS LIMITING AIR AND GAS DRILLING

Air drilling has some distinct advantages; however, not all wells can be drilled with air. This section will discuss the reasons why air drilling cannot be used everywhere.

### 6.3.1 PRODUCED WATER

In some geologic areas, water production can be a problem. As already discussed in section 6.2.5, water can be produced from a formation if it has enough permeability. While air drilling, the pressure within the wellbore is almost always less than the pressure in the formation and formation fluids will flow into the wellbore. The formation fluids are then carried to the surface with the air. Having the formation fluids flow into the wellbore while drilling is desirable when the formation produces hydrocarbons but is undesirable when the formation produces water.

Ordinarily, water influx is not a drilling problem; rather it is a disposal problem. The reserve pit will hold a limited quantity of water. When the pit is full, air drilling must be discontinued or the water must be hauled off location to a proper disposal site. Hauling water to disposal can be very expensive. Disposal costs for reserve pit water can range anywhere from $1.00 to $10.00 per barrel depending upon the solids content, salinity and the distance to the disposal.

The operator can determine the maximum amount of water that can be hauled off each day. The increased penetration rate of air drilling makes it more economical; but if water must be hauled off, the daily operating costs increase. So long as the cost per foot to drill the hole is less than that of mud, air drilling is more economical. The best way to illustrate this is by example. In an air drilling operation, the penetration rate is 30 feet per hour while a mud drilling operation is 15 feet per hour. The hourly operating cost for drilling with air and mud are $375/hr and $250/hr, respectively. Each bit will drill for 100 hours so two bits will be required in the mud drilled hole to drill the same interval. Bit costs are $4,800 each. The trip time is assumed to be about 1.5 hours per 1000 feet round trip. It would take 7.5 hours to trip from 5000 feet.

For this example, assume the well is drilled from 4,000 to 7,000 feet. First calculate the cost per foot for the mud drilled hole. Remember, two bits are required in the mud hole versus one bit in the air hole. The equation for calculating the cost per foot is as follows:

$$\$/ft = \frac{B + C_r(T+t)}{F}$$

Where:

$\$/ft =$ Cost per foot, \$/ft
$B =$ Cost of the bits, \$
$C_r =$ Hourly operating cost, \$/hr
$T =$ Rotating time, hrs
$t =$ Trip time, hrs
$F =$ Footage drilled, feet

Calculation of the cost per foot for drilling with mud.

$$\$/ft = \frac{4800+4800+250(200+8.3)}{3000}$$
$$\$/ft = \$20.56/ft$$

The cost per foot to drill the 3000 foot interval with mud is \$20.56. Based on that cost, the maximum hourly operating cost can be determined for the air drilling operation when the cost per foot is equal to \$20.56. If the hourly operating cost exceeds this value, then it is less expensive to drill with mud.

$$20.56 = \frac{4800+C_r(100+4.7)}{3000}$$
$$C_r = \$543.22/hr$$

The hourly operating cost can be as high as \$543.22/hr and air drilling will still be economical. The actual operating cost is \$375/hr; therefore, the operator could spend \$168.22/hr hauling off water. If the cost to haul water off exceeds this value, then mud drilling will be more economical. Even at the minimum cost of \$1 per barrel, the operator would only be able to haul off 168 barrels of water per hour or 4,037 barrels per day. Many water flows will produce substantially more water than that. Also, \$1 per barrel would be an absolute minimum disposal cost. In most cases, the disposal costs would be substantially higher.

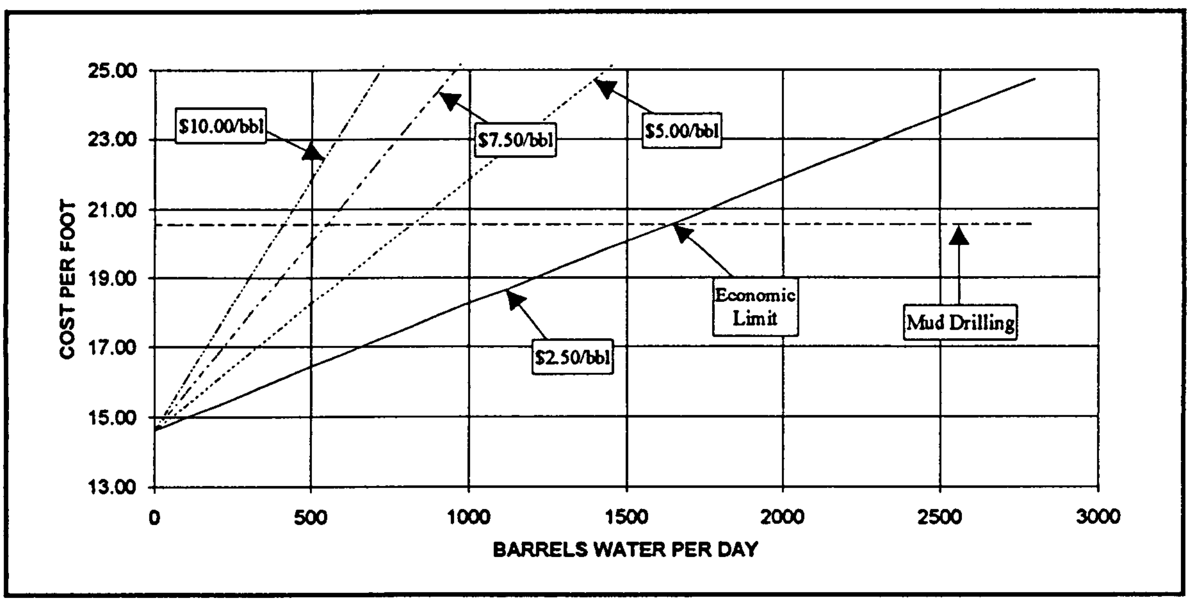



*Figure 6.4 - Graph showing the economic limit for air drilling based on disposal costs.*

A graph can be constructed based upon the disposal costs per barrel to determine the economic limit for air drilling. Given the same information as the previous example, Figure 6.4 shows the economic limit for air drilling with various disposal costs. The economic limit is where the cost per foot line for air drilling crosses the cost per foot line for mud drilling.

The maximum water production for each disposal cost can be seen in Table 6.1. As the disposal costs increase. the amount of water that can be economically hauled off decreases. At a disposal cost of $10 per barrel, the maximum water production would be 410 barrels per day. If the well produces more than 410 barrels per day, it would be more economical to drill the well on mud.

*Table 6.1 - Maximum water production based on disposal costs.*

| Disposal Cost Per Barrel | Maximum Water Per Day |
|---|---|
| $1.00 | 4,037 |
| $2.50 | 1,643 |
| $5.00 | 821 |
| $7.50 | 547 |
| $10.00 | 410 |

Of course, the maximum water limits change if the penetration rate, rig costs, bit costs, footage per bit and rotating hours change. No one chart similar to Figure 6.4 can be used for each drilling operation. Each case must be analyzed individually to determine the economic limit. Other factors that must be considered are storage capacity on location, equipment limitations and the stability of the formations when exposed to produced waters. Produced waters can make the hole slough if the formations are sensitive to the water. In sensitive formations, even small quantities of water can make air drilling impractical.

*Table 6.2 - Maximum water production at an increased penetration rate.*

| Disposal Cost Per Barrel | Maximum Water Per Day |
|---|---|
| $1.00 | 10,973 |
| $2.50 | 4,389 |
| $5.00 | 2,195 |
| $7.50 | 1,463 |
| $10.00 | 1,097 |

Table 6.2 is the same analysis as Table 6.1 except the penetration rate for mud has been increased to 60 feet per hour and the penetration rate for mud has been increased to 20 feet per hour. The maximum amount of water that can be handled economically more than doubles. The other parameters will have similar effects to the amount of water that can be economically hauled off the location.

Once water is encountered in a well, it can no longer be drilled with dry air or dusting. Small quantities of water can be potentially disastrous in an air drilling operation. Small water flows are not always seen at the surface because the water will mix with the cuttings downhole. If the quantity is small enough, no water will be seen at the surface. The first indication of a small water flow is that the well will quit dusting; unfortunately, that is not always easy to detect. In most air drilling operations, the dust is being suppressed at the blooie line with water. No change will be visible from the drilling floor.

A small water flow has the potential to stick the drill string unless caught in time. The water will mix with the cuttings downhole and create mud. The mud will accumulate on the drill string and the walls of the hole. The critical portion of the hole for hole cleaning purposes is at the top of the drill collars, and that is where the majority of the cuttings will accumulate. The clearance in the annulus will become smaller with time until the annulus is blocked and the drill string is stuck. The restriction in the annulus is called a mud ring and is illustrated in Figure 6.5.

To alleviate the potential problems associated with small quantities of water, the well is misted. The mist completely saturates the cuttings preventing them from sticking together so that they can be carried out of the hole by the air.

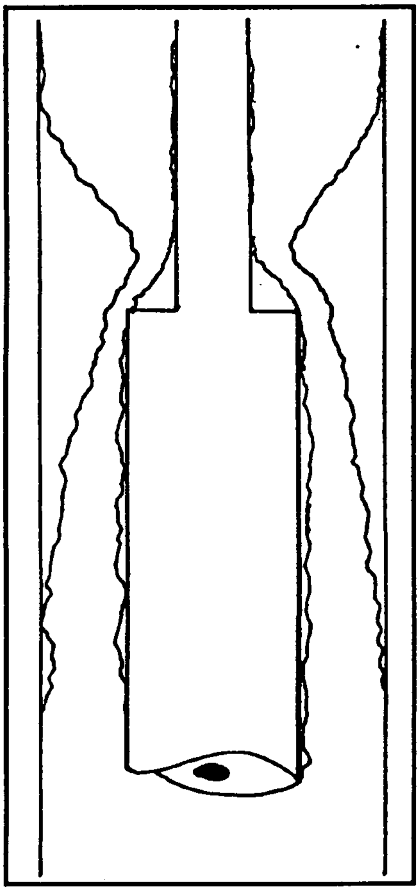


*Figure 6.5 - Development of a mud ring at top of collars.*

Mist products are still used for large quantities of water even though the formation water is sufficient to saturate the cuttings. The mist is used to carry the surfactant and corrosion inhibitors. The amount of surfactant and corrosion inhibitor used must be increased to not only treat the water being pump down the well as mist but also the water being produced by the formation. A the volume of the water flow increases, the chemical costs will also increase. The analysis in Figure 6.4 does not take the increased chemical costs into consideration; therefore, the economic limit will be slightly less.

Foam can also be used in situations where water influx is expected. Foam can handle as much as 600 to 700 barrels of water per day. Again, chemical costs increase because all the fluid must be treated with the foaming agents. Generally, mist is used when the equivalent hydrostatic pressure needs to be less than two pounds per gallon. Foam is employed where an equivalent hydrostatic pressure of two to four pounds per gallon is desired and aerated fluid is used when the desired hydrostatic pressure is greater than four pounds per gallon.[23] These are only general rules of thumb and the actual point where one would change the circulating system from mist to foam or aerated fluid depends upon actual hole conditions.

### 6.3.2 HOLE INSTABILITY

Hole instability is a problem in all drilling operations whether the well is drilled on air or mud. In the oil industry, hole instability is commonly referred to as sloughing. Sloughing is the process by which pieces of the wall of the hole break off and fall into the hole. All holes will experience some sloughing, but it is worse in certain areas.

As far as air drilling is concerned, sloughing can occur by two different methods. One mechanism that causes sloughing is the stress in the formations. Tectonic stresses are caused by folding and faulting within the earth's crust. When the wellbore is drilled through a stressed formation, the borehole changes the stress near the wellbore and the well becomes unstable. In these cases, little or nothing can be done to keep the formation from sloughing.

A formation will also slough if it is water sensitive. A water sensitive formation is one that contains hydratable clays that react with the water. To state it simply; certain types of clay will absorb water causing them to swell or enlarge. When the clay enlarges, the only place for it to expand is into the wellbore and pieces of the formation will slough off the walls of the hole.

The reason that a sloughing formation is a problem in an air drilled hole is because air has difficulty removing large pieces of formation from the wellbore. Rocks (or particles) will fall back through the air at a fairly high velocity. That velocity is commonly termed the slip velocity and it is dependent upon the diameter of the particle. Figure 6.6 is a plot of slip velocity versus particle diameter. Note that as the particle diameter increases, the slip velocity increases. When a formation sloughs, it usually sloughs in larger diameter particles. Therefore, it is difficult to keep an air hole clean while the formation is sloughing. The only way to remove the larger diameter particles is to grind the particles smaller. The grinding process is often called particle degradation. Particle degradation is accomplish through collisions with the drill string, walls of the hole, and other particles.

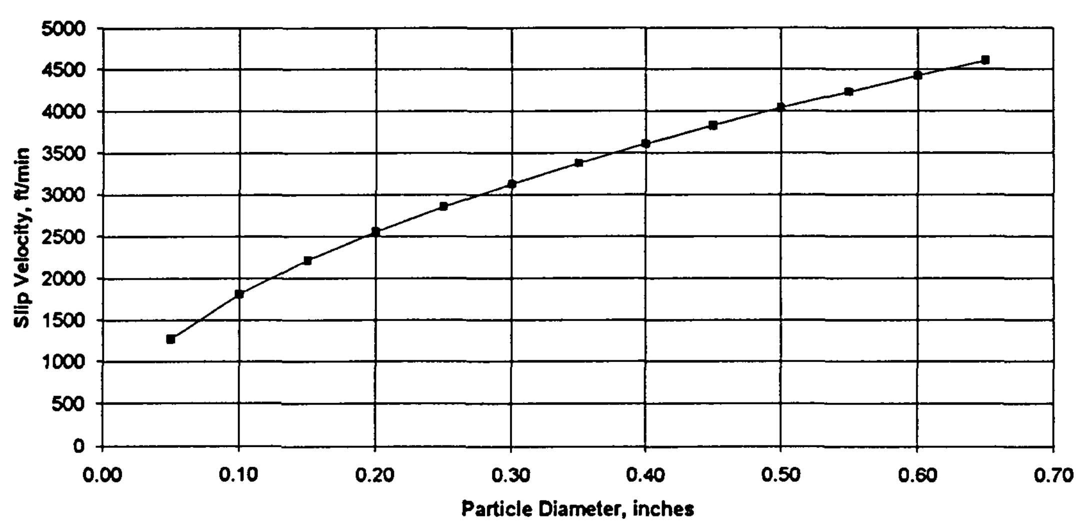



*Figure 6.6 - Plot of slip velocity versus particle diameter for air at standard conditions.*

Field results have substantiated the theory that particle degradation does occur. Graham, et. al. showed that the particle size recovered at the surface can be increased by reverse circulation drilling. Reverse circulation drilling requires the air to be pumped down the annulus and back up the inside of the drill string. Since the internal diameter of the drill string is much smaller than the annular area, the air velocity within the drill string is higher than in the annulus. As a result, larger particles are transported to the surface by the air. In conversations with Ian Rear of DrillQuip International, he also indicated that reverse circulation yields larger cuttings at the surface. They market a reverse circulation air hammer that has been used by the mining industry for several years and the cuttings produced at the surface are larger.

Formations that slough because they are water sensitive are also encountered in air drilling. Of course, the ideal way to drill this type of formation is to drill with dry air. If the sensitive formation is not exposed to water, the clays do not hydrate and slough. Unfortunately, that is not always possible. If any water enters the wellbore from a formation, the water will be exposed to the sensitive clays and sloughing can result. Also, if any water enters the wellbore, the drilling operation must be switched to mist, foam or aerated fluid. Trying to continue drilling with dry air may cause the drill string to become stuck. Adding fresh water in the form of mist or foam can compound the problem because clays hydrate faster in the presence of fresh water.

A classic example of a water sensitive shale can be found in the SFP Mining #1-12ST well. The well was to be drilled as a horizontal well in Florence Field. The Florence Field produces oil from the Pierre Shale. The well was sidetracked from an existing well at a depth of 2660 feet. Drilling continued with only minor hole cleaning problems to 5149 feet. Hole cleaning problems are common in horizontal drilling with air or mud. At 5149 feet, the well encountered oil and the operator started misting the well. Oil can cause the pipe to become stuck or cause a downhole fire when drilling with dry air; therefore, misting was required. In less than one day, the water sensitive shales in the well started to slough and the drill string became stuck. The well was eventually abandoned because the drill string could not be recovered.

If water sensitive formations are present, drilling mud may be required to drill the well. The formations still slough when drilled with drilling mud, but mud has a much higher hole cleaning capacity than air. Operators in the Arkoma Basin (Region 7, Province 116) often convert the system to an oil based mud when water is encountered while air drilling. Experience has shown that the Atoka Shale will slough and cause hole problems when drilling with mist; many times resulting in stuck pipe. It is cheaper to drill with mud than to continue air drilling and risk sticking the drill string.

### 6.3.3 DOWNHOLE FIRES

Industry experience indicates that downhole fires are relatively rare in occurrence; however, they do cause significant problems when they do occur. Often the end or the drill string will be melted off leaving slag in the well. The slag is not fishable and drilling is continued by sidetracking around it.

The most definitive work done on downhole fires was by Grace and Pippin[24]. They explained that downhole fires are actually a downhole detonation or explosion complete with the attendant temperatures required for the destruction of the bottom collars and bit. Experience has shown that downhole fires do not occur when dry gas is encountered in dry air drilling. The downhole fire always occurs when wet gas or gas and oil have been encountered and are present in the system.

The detonation of a downhole fire is similar to that which occurs in a diesel engine. When liquid hydrocarbons are present, the cuttings generated by the bit can become wet and sticky. They will build up in the wellbore and eventually block off the annulus. The pressure will increase because the air's path to the surface is restricted similar to applying back pressure with a choke. As the pressure increases in the wellbore, the air is compressed resulting in an increase in temperature. The liquid oil in the annulus reaches the combustion pressure and temperature and ignites. The fire goes out when the air is turned off. Without a source of oxygen, the fire can no longer burn.

Downhole fires are more common in some areas than others. We found that downhole fires are very rare in the Arkoma and the Appalachian Basins but much more frequent in the San Juan Basin. It is most likely due to the fact that more wet gas and oil are present in the San Juan Basin.

There are several ways to prevent downhole fires. The first method is to drill with natural gas. Without oxygen in the wellbore, a downhole fire cannot start. This option is not used as much as it was during the 50's and 60's. Natural gas has become much more expensive and drilling with natural gas is cost prohibitive in most cases. There are still a few instances were natural gas is used for drilling when it is readily available.

Another method available to prevent downhole fires is to use air where the oxygen content is too low to allow the hydrocarbons to burn. Commercially available nitrogen or carbon dioxide can be mixed with the air to lower the oxygen content of the mixture. Unfortunately, this is even more expensive than drilling with natural gas but may be used in areas where natural gas is not readily available.

There is another method that is currently being developed. A system has been developed to strip the oxygen from the air using hollow fiber membranes. The system is already being used in other industries where nitrogen rich air is required. However, it remains to be seen if the membrane system can be used cost effectively in the oil industry. The system will have to be rugged with relatively low maintenance cost in order for it to be economical. Especially since some of the air run through the system is lost. To drill with the same amount of air normally used in an air operation, additional compressor capacity will be required on location. The extra compressors already add excess cost.

The third and most commonly used method to eliminate downhole fires is to use a mist in the air. Mist will completely saturate the cuttings preventing the formation of a mud ring in the annulus. Figure 6.5 is an example of how a mud ring forms. If the cuttings do not restrict the flow of air in the annulus, the pressure does not increase and ignition will not occur. The mist will also keep the temperature lower. The liquid mixed in the air will absorb some of the heat as the air is compressed keeping it cooler than it would be without the mist. Generally, mist is pumped at 20 barrels per hour.

### 6.3.4 DRILL STRING WEAR

In air and gas drilling, the drill string will wear faster than it would in a mud drilling operation. There are several factors which contribute to the shorter life of a drill string in an air drilling operation. They are:

- Erosion of tool joints due to cuttings impinging on the upset.
- Abrasive wear on the outside diameter of the tool joints.
- No hydraulic dampening of drill string shock loads.
- Higher corrosion rates with mist, foam or aerated fluids.

In air drilling applications, the tool joints suffer the majority of the wear. The wear is caused by erosion and abrasion. Erosion is caused by the cuttings or rocks in the annulus impinging upon the external upset of the tool joint. Figure 6.7 illustrates how the tool joints erode. The cuttings in the annulus are transported to the surface by the air. The velocity of the air must be sufficiently high to adequately transport

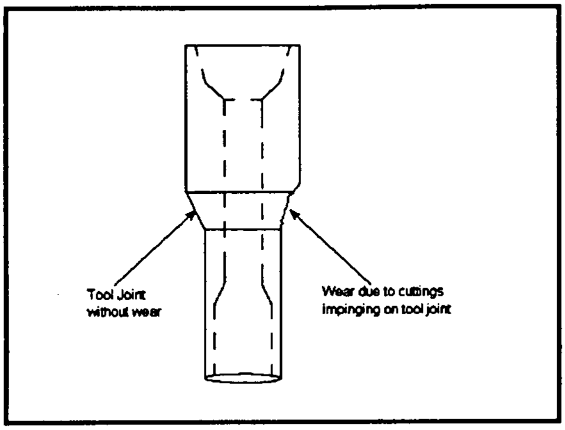



*Figure 6.7 - Erosion of tool joint due to cuttings and air.*

the cuttings. The high velocity of the cuttings striking the bottom of the tool joint causes erosion of the metal. The problem is compounded when high gas production rates are encountered because the annular velocity is increased.

Abrasion of the tool joint is caused by the tool joint rubbing against the wall of the hole. It is more pronounced in air drilled holes because there is no lubrication between the tool joint and hole wall.

In mud drilling, the drill string is hydraulically dampened by the drilling mud. Since there is no fluid in an air hole, no hydraulic dampening of shock loads occurs. Shock loads are caused by the bit rotating on bottom, rotation of the drill string and running tools such as downhole motors. The increased shock loads will slightly shorten the working life of the drill string.

Corrosion rates are also higher in air drilling operations. When dry air is used, corrosion is not a problem. For corrosion to occur, water and oxygen must be present. No water (other than condensed water from the atmosphere) is present in a dry air system. However, mist, foam and aerated fluids have sufficient quantities of water and oxygen available to promote cathodic corrosion. An unlimited supply of oxygen is available so corrosion rates will be higher than that in a drilling mud.

### 6.3.5 RELIABILITY OF DIRECTIONAL EQUIPMENT

One of the problems that has received the most attention in the last few years is directional drilling. The vast majority of the tools used in directional drilling were developed for fluid drilling and have been adapted to air drilling. The success of the adaptation has been varied.

Positive displacement downhole motors are used to guide the well to the intended target. The fluid motors have been adapted to air drilling with mixed success. Thanks to some work done by the Department of Energy, the success rate using downhole motors has increased considerably. In the first horizontal well, average motor life was only 10 hours[25]. After drilling several wells for the Department of Energy, average motor life was extended to at least 50 hours[26] by changing the operating parameters. Since then, a downhole motor has been built specifically designed for air and gas drilling. So motor life is no longer an obstacle to directional drilling. Although it is still less than that for mud drilling, and it is less predictable.

One problem that remains with downhole motors operating on air is extremely slow penetration rate in hard formations. Whenever the bit encounters a hard formation, the penetration rate slows down sometimes as low as 1 to 2 feet per hour. This problem was encountered in the DOE sponsored well Boggs 1240 in Roane County, West Virginia (Region 8, Province 131). Siltstone stringers in the build curve of the well drilled at only 1 to 2 feet per hour while the shale drilled at 20 to 30 feet per hour. The siltstone stringers drilled almost as fast as the shale with rotary drilling. The reason harder formations drill slower with the downhole motor is because sufficient bit weight to compressively fail the rock cannot be applied with a downhole motor. A maximum bit weight of 10,000 to 12,000 pounds can be run on a downhole motor. Any more bit weight and the motor stalls. A bit weight of 30,000 to 45,000 pounds can be applied while rotary drilling and is sufficient to compressively fail the harder rock.

The same problem was encountered in the Hardy #1 well in Putnam County, West Virginia (Region 8, Province 131). The same problem was reported by Otto Smith who was drilling a directional well on air in Toole County, Montana (Region 4, Province 96). The well is being drilled at the same time this report is being written.

The biggest problem today is the steering tool or electromagnetic measurement while drilling (EMWD) tools. The mud pulse MWD tools commonly used with fluid drilling do not work in air. They pressure pulse the drill pipe in order to send directional survey information to the surface. Air is compressible and cannot be pulsed effectively. The EMWD tool sends information back to the surface by electromagnetic waves and will work in an air hole. Unfortunately, it does not work consistently. In conversations with Paul Allen of Meridian Oil Company, he indicated that they had good luck in running the EMWD and experienced few failures. Conoco used the same EMWD to drill the North Tisdale No. 87 well in Johnson County, Wyoming. They were able to drill the entire build and horizontal section without failure.

However, other operators have not been as fortunate. The Southwest Rangely Federal 84-1-2 well is a horizontal well drilled in Rio Blanco County, Colorado. The operator drilled the build section on mud using the EMWD without a failure. An attempt was made to drill the horizontal section on air with a steerable system including the EMWD. The EMWD failed almost immediately and the operator drilled the horizontal section with a rotary assembly. The well was non productive and the operator wanted to sidetrack the horizontal section and drill it 90° to the original horizontal well. Again the EMWD was tried but it failed.

Air is a much rougher environment than fluid drilling. As mentioned in section 6.3.4, there is no fluid dampening of vibrations within the drill string. The vibration of the downhole motor is what makes the EMWD fail. In fairness, most commercially available MWD's would also fail under the adverse conditions in an air hole.

In most air wells, a steering tool is used to get survey and tool face data while drilling with a downhole motor. The steering tool is different from the EMWD in that the information is sent back to the surface using a single conductor wireline rather than electromagnetic waves. The system is cumbersome and more time consuming because the wireline extends back up through the drill string to the surface. Depending upon the system used, the wireline must be removed in order to add more drill pipe as drilling progresses. This adds additional time and cost to the drilling operation.

Until recently, the drill string could not be rotated with the steering tool in the hole. Therefore, a steerable system could not be used with a steering tool. A steerable system requires that the drill string be rotated for a least a portion of the drilling process. In the past few years, some service companies have developed what is called a quick or wet connect. The tool allows the drill string to be rotated with the steering tool still in the bottomhole assembly. A sub is run in the vertical portion of the well and the wireline is connected from the steering tool to the sub. The wireline is connected into the top of the sub when a survey is taken or when drilling without rotation. The wireline is disconnected from the sub and pulled into a special swivel when the pipe is rotated. Now operators can run a steerable system in air.

Another method developed recently is a cartridge system. The cartridge system works very similar to the wet connect in that; but instead of having a single wet connect, the wireline is connected back to the surface with a series of disposable cartridges. It is connected into a slip ring sub at the top of the kelly to allow electrical connection while rotating. The system is relatively new and its reliability is not yet proven.

Regardless of which method is used with the steering tool, failures in air are still a problem. Like the EMWD, steering tools fail much more frequently in air than they do in mud. Both tools need to be hardened to work consistently in an air environment.

### 6.3.6 ENVIRONMENTAL CONCERNS

Air drilling can limit environmental problems, or it can cause additional environmental problems. Section 6.2.4 discusses the environmental advantages of air drilling and will not be restated here. Air drilling can cause environmental concerns when the well encounters oil and salt water. State regulations are becoming more strict concerning reserve pits and what is placed in the reserve pit. In the future, the regulations will be even more demanding. Many operators are switching to a closed pit system in some areas due to the potential liability of a open reserve pit. A closed pit system contains all the drilling fluids within steel tanks or concrete lined pits. At the present time, closed pit systems are not feasible for an air drilling operation.

Any oil or salt water encountered in the well eventually ends up in the reserve pit and must be disposed of properly. Disposal and cleanup costs can far exceed any economic advantages of air drilling.

### 6.3.7 SAFETY CONSIDERATIONS

Safety is always a issue on the drilling rig. In an air drilling operation, the well flows volatile hydrocarbons while it is being drilled. There is always a potential for an explosion or fire around the drilling rig. Years of air drilling experience have proven this to be only a minor problem. Very few accidents have been caused by gas and oil flowing from the well. Some operators even drill with natural gas where there is a potential for downhole fires.

So long as the hydrocarbons are burned coming out of the blooie line, gas will not drift back across the rig and be ignited. Although, gas leaking around the rotating head can be a possible source of ignition. The rotating head is the mechanism which seals around the drill string and is directly under the floor of the rig. So long as it is kept under good repair, leaks and potential fires are not a problem.

No explosions or fires were found to occur while drilling. The only incident occurred while tripping the drill string. During the trip, the rotating head is removed so that some of the drilling equipment can be pulled from the well. That equipment does not fit through the rotating head. The blooie line should be rigged up with some jets to pull the gas down the blooie line and away from the drilling rig floor. The jets are a venturi which pulls a vacuum on the blooie line. With jets operating properly, the rotating head can be removed without gas escaping to the rig floor. Unfortunately, the jets can only pull so much gas down the blooie line. Common estimates of the gas volume which can be vented down the blooie line range from 2 to 5 MMCFPD. It depends upon how the jets are arranged as to how effective they are. Many different arrangements are seen in the field.

All things considered, the air and gas drilling industry does a good job with safety. It is as safe, if not safer, than drilling with mud.

The data base was analyzed to determine whether the drilling data confirmed our analysis of factors limiting air drilling operations. Each well was looked at to try and determine why air drilling was terminated. A total of ten reasons were found for stopping air drilling operations. They consist of:

1. Water production
2. Hole sloughing
3. Fishing or stuck pipe
4. Reached casing point
5. Reach total depth
6. The cause was unknown because there was insufficient data available to make a determination
7. Drilling salt or evaporite formations
8. Downhole fire
9. To start directional drilling
10. Production rate was too high (considered unsafe)

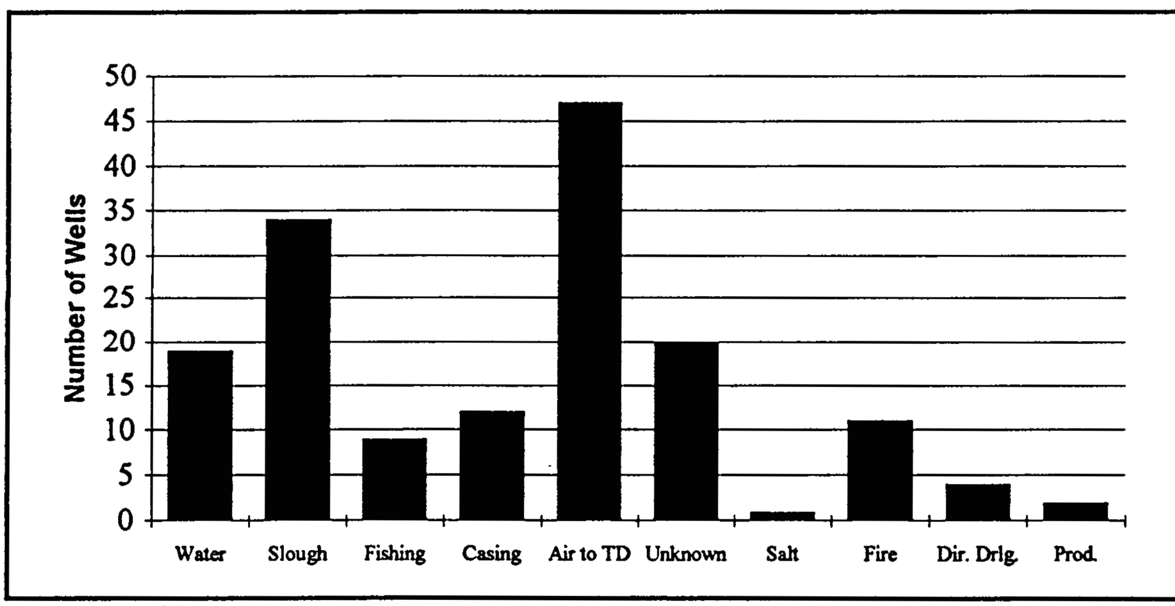



*Figure 6.8 - Reasons for terminating air drilling for wells in data base.*

Item 5 in the list is drilling to total depth with the air. In this category, air drilling was not terminated until the well reached TD. These are the wells that were successfully drilled to total depth using air whether it be air, air mist, foam or aerated drilling fluid. Even though the wells were TD'd with air, air drilling operations may or may not have been successful in the surface or intermediate hole. Therefore, air drilling may not have been completely successful in each well. Also, some wells only had the bottom few hundred feet drilled with air. The surface and intermediate holes were drilled with fluid.

*Table 6.3 - Reasons for terminating air drilling for wells in data base.*

| BASIN | WATER | SLOUGH | FISH-ING | CAS-ING | AIR TO TD | UN-KNOWN | SALT | FIRE | DIR. DRLG. | PROD. |
|---|---|---|---|---|---|---|---|---|---|---|
| Arkoma Basin | 1 | 20 | 3 | | 10 | 9 | | 8 | 4 | |
| Big Horn Basin | | 2 | | | 3 | | | | | |
| Black Warrior Basin | 1 | | | | | | | | | |
| Cherokee Platform | | | | | 1 | | | | | 1 |
| Eastern Basin and Range | 1 | 1 | 1 | | | | | | | |
| Montana Thrust Belt | 1 | | | 1 | | | | | | |
| Northern Arizona | | | | | 1 | | | | | |
| Paradox Basin | 1 | 1 | | 2 | | 1 | 1 | 1 | | |
| Park Basin | | | | | | 1 | | | | |
| Permian Basin | | | | | 7 | 1 | | 2 | | |
| Powder River Basin | 1 | | | 5 | 2 | 1 | | | | |
| Salina Basin | | | | | | 1 | | | | |
| San Juan Basin | 1 | | 2 | 1 | 4 | 1 | | | | |
| Southern Oklahoma | | 2 | | | 2 | | | | | 1 |
| Southwestern Wyoming | 2 | 2 | 1 | | 3 | 2 | | | | |
| Sweetgrass Arch | 1 | | | | 1 | | | | | |
| Uinta-Piceance-Eagle | 7 | 5 | 2 | 2 | 11 | 2 | | | | |
| Western Basin and Range | | 1 | | | | | | | | |
| Williston Basin | | | | | 2 | | | | | |
| Wind River Basin | 2 | | | 1 | | 1 | | | | |
| Total | 19 | 34 | 9 | 12 | 47 | 20 | 1 | 11 | 4 | 2 |

In item 4, several operators terminated air drilling when reaching the intermediate casing point. In these wells, the operator assumed that air drilling could not be continued below the intermediate casing based on past experience. Item 9 indicates that the operator elected to terminate air drilling operations when starting to directional drill. As discussed in Section 6.3.5, directional drilling is sometimes more efficient when drilling with fluid, and some operators prefer not to directionally drill with air. In item 6, there was insufficient data available to determine the reason why air drilling was terminated. Some of the well files did not contain enough information especially those of air drilling contractors. The rest of the reasons are self explanatory.

Figure 6.8 is a plot of the data obtained in the analysis. The two most prominent reasons for terminating air drilling are water and sloughing. Of the 159 total wells, 19 had insurmountable water problems and 34 had hole sloughing problems. (The data in Figure 6.8 is also presented in Table 6.3.)

Fishing is also typically caused by poor hole cleaning that can be brought about by sloughing. However, this category was added because fishing is sometimes caused by other drilling problems. If it was not possible to determine whether the fishing was caused by sloughing or another drilling problem, the well was placed in the fishing category. Therefore, air drilling in some of the wells included in the fishing category was undoubtedly terminated due to hole sloughing. Air operations were suspended in nine wells due to fishing or stuck pipe. Also, many of the wells in the unknown category could be attributed to water influx and sloughing. Consequently, the information in the data base confirms the conclusion that water influx and hole stability (sloughing) are the primary limiting factors associated with air drilling.

The problems in each province are varied. Figure 6.9 shows the reasons for terminating air drilling in the Arkoma Basin. The majority of the wells had sloughing problems. Whereas, Figure 6.10 shows that the major problem in the Uinta-Piceance-Eagle Basins is water. As can be seen in Table 6.3, each province is slightly different; however, some of the provinces do not have sufficient data to determine the major limiting factor associated with air drilling.

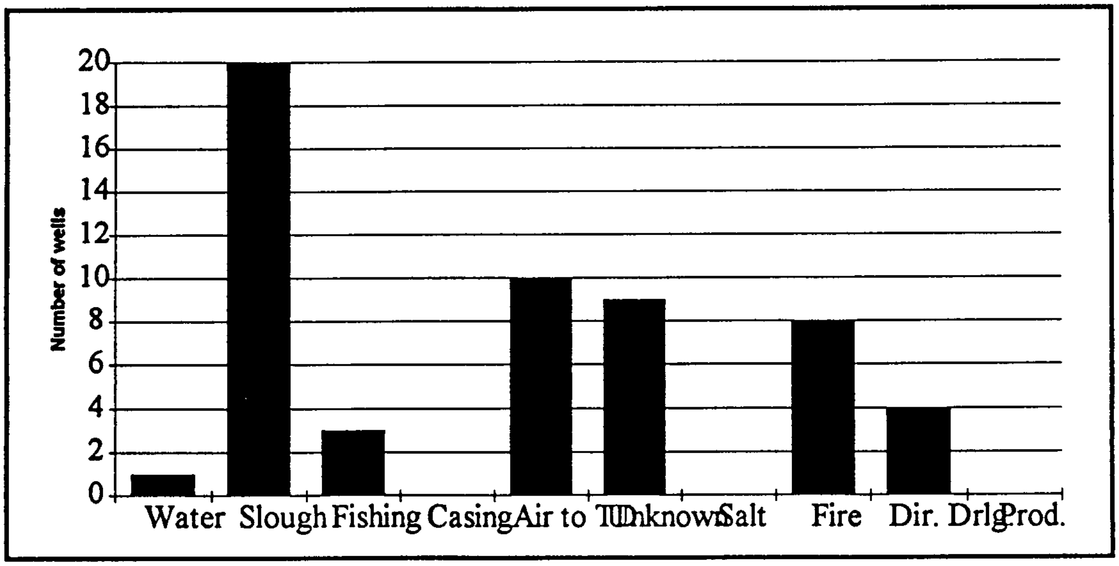



*Figure 6.9 - Reasons for terminating air drilling in the Arkoma Basin.*

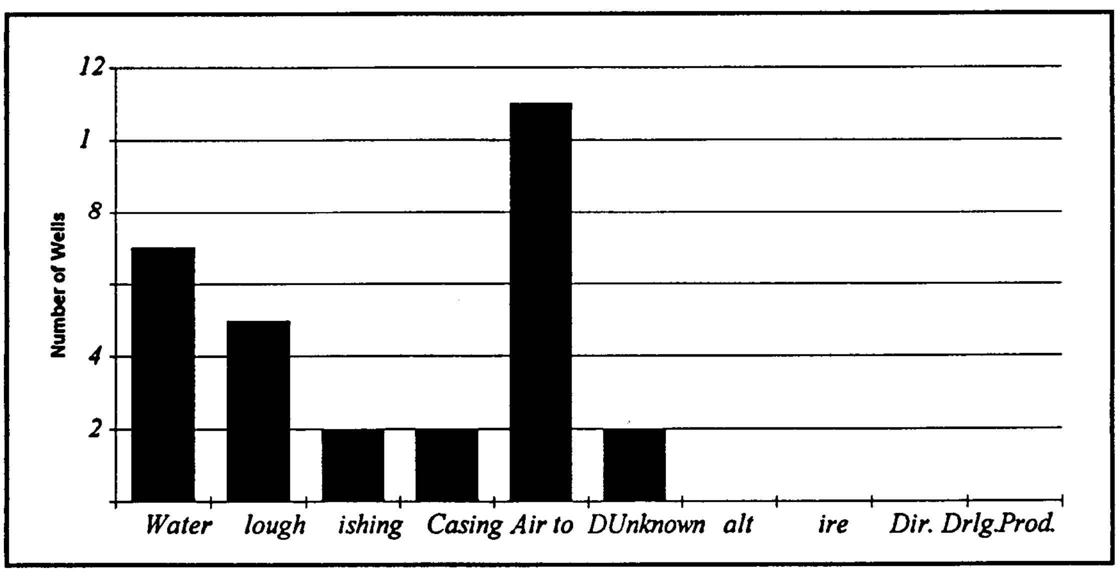



*Figure 6.10 - Reasons for terminating air drilling in the Uinta-Piceance-Eagle Basins.*

## 6.4 AREAS FOR TECHNOLOGY IMPROVEMENT

During our investigation, operators and contractors mentioned a few areas where air drilling technology could be improved. These are areas where they had experienced problems.

### 6.4.1 DIRECTIONAL EQUIPMENT

One area that operators felt could be improved is in directional drilling. The biggest problem with directional drilling is the lack of a reliable MWD (measurement while drilling tool). As discussed in section 6.3.5, the electromagnetic MWD tool is the only one that works in an air hole and the reliability is questionable. The tool needs to be hardened for an air drilling environment.

The same is true for most steering tools. The failure frequency of steering tools in air is still much higher than that in drilling mud. Air is just a rougher environment and tools have to be hardened to work properly.

With the improvements in operating procedures and the advent of the air drilling motor, motor technology is now sufficient for directional requirements in air drilled holes. Now, most premature failures in air drilling are associated with improper operating procedures or improper maintenance of the downhole motor.

### 6.4.2 ABILITY TO DETERMINE HOLE CLEANING CAPABILITIES IN THE FIELD

We found that the two majors reasons for terminating air drilling were hole cleaning and water influx. Hole cleaning is a problem when the cuttings and sloughed rock are not removed from the hole fast enough. Poor hole cleaning is evidenced by fill on the bottom of the hole after tripping the pipe or making a connection, torque and drag while drilling or tripping, and increased standpipe pressure while drilling. If hole cleaning problems persist, the drill string can become stuck. The indications at the surface are the same whether the well is sloughing or the cuttings being generated by the bit are too large to be removed with the air volumes being used.

The majority of the industry uses Angels' charts[27] for determining the minimum air volume requirements necessary to drill the well. In most cases, the volume is adequate and that is the reason they are used so frequently. However, there are times when hole cleaning problems are experienced even when the Angel volumes are being used. The cause of the problems are debatable.

Some industry people believe that the hole cleaning problems are caused by the formation sloughing. The combination of a larger diameter hole and larger cuttings due to the sloughing are the cause. They feel that increasing the air volume will not help because the higher annular velocities will be more erosive causing the formation to slough even more. Others believe that the cuttings being generated at the bit are large enough to where they cannot be adequately cleaned with the volume being used. All that is required to clean the hole is a higher air volume. Some of the information seen in reverse circulation air drilling would substantiate this. In reality, both problems probably exist.

In the field, there is no way to determine the adequacy of the air volumes being used. There are some sophisticated computer programs along with some simpler methods that can be used to predict hole cleaning, but they cannot take into consideration all the conditions within the wellbore. In most drilling operations, the exact wellbore conditions are unknown.

The industry would like to have some way of determining what is going on in the wellbore. and what kind of air volumes would be necessary to clean the hole adequately. Whether or not that is possible is unknown.

### 6.4.3 METHOD OF LIMITING WATER INFLUX WHILE DRILLING WITH AIR

The primary limiting factor associated with air drilling is water production while drilling. As discussed in section 6.3.1, substantial quantities of water can add significantly to the drilling costs if the water must be hauled off location. Air and mist drilling impose very little back pressure in the wellbore and water production rates can be quit high. Imposing higher back pressures on the formations will restrict the flow of water into the wellbore during the drilling process. Foam will provide an equivalent hydrostatic pressure of two to four pounds per gallon; however, many formations have substantially higher pressures. The formations can still flow when foam is used. Aerated fluid is used when the hydrostatic pressure needs to be greater than four pounds per gallon.

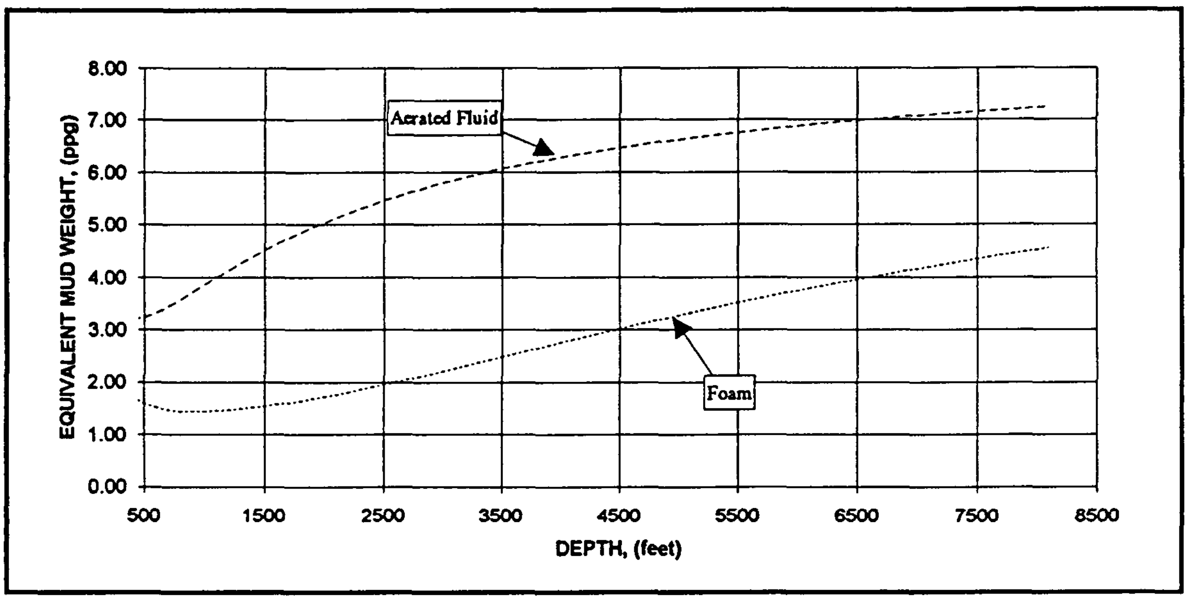



*Figure 6.11 - Variation of equivalent mud weight with depth for foam and aerated fluid.*

The only problem is that the equivalent hydrostatic pressure of foam and aerated fluid changes with depth. The air within the system compresses at greater depth and the equivalent mud weight increases. Figure 6.11 shows how the equivalent mud weight of a foam and aerated fluid will change with depth. Unfortunately, formation pressures do not change at the same rate. The drilling fluid hydrostatic may be balanced for one formation but be too low or high for another. If it is too low, formation water can enter the wellbore. If it is too low, lost circulation can occur. It is difficult in the field to get the system balanced so that little fluid is lost or water influx is minimized.

Because of the variable density of the foam or aerated fluid column, it is difficult to drill with these types of fluids and prevent the influx of formation water.

Therefore, a needed technology improvement would be the ability to inhibit the flow of formation water into the wellbore other than using the hydrostatic pressure of the drilling fluid. If some chemical means could be devised to block the permeability of the formation near the wellbore, then fluid flow into the wellbore could be minimized. It is not likely that an additive could be found to accomplish this task. If a solution to the water influx problem is solved, air drilling could be expanded considerably.

In addition to the disposal problems, water influx can cause problems with water sensitive formations. Water sensitive formations will slough when exposed to water for a certain length of time. Eliminating the water influx would also eliminate this problem.

### 6.4.4 METHOD OF STABILIZING FORMATIONS WHEN USING MIST OR FOAM

As discussed earlier in section 6.3.2, the water associated with mist or foam can cause sloughing problems with water sensitive formations. Industry personnel expressed an interest in developing an additive for the mist or foam that will stabilize these water sensitive formations. The likelihood that air drilling could be expanded is high if a suitable stabilizing agent were found. At the present time, the industry uses potassium chloride and polymers to provide some formation stabilization.

It is unlikely that an additive can be found that will stabilize all formations. The oil industry has been looking for just such an additive since its inception and to date, none has been found.

### 6.4.5 SEPARATION OF PRODUCED FLUIDS AT THE SURFACE

As environmental regulations become more strict, it is going to be increasingly difficult to drill air holes and have oil and salt water in the reserve pit. The problem with salt water and oil in the reserve pit was discussed in section 6.3.6. If air drilling is to be expanded, a method to separate the air, cuttings, produced fluids, and mist or foam will have to be found, the oil and salt water can then be disposed of properly.

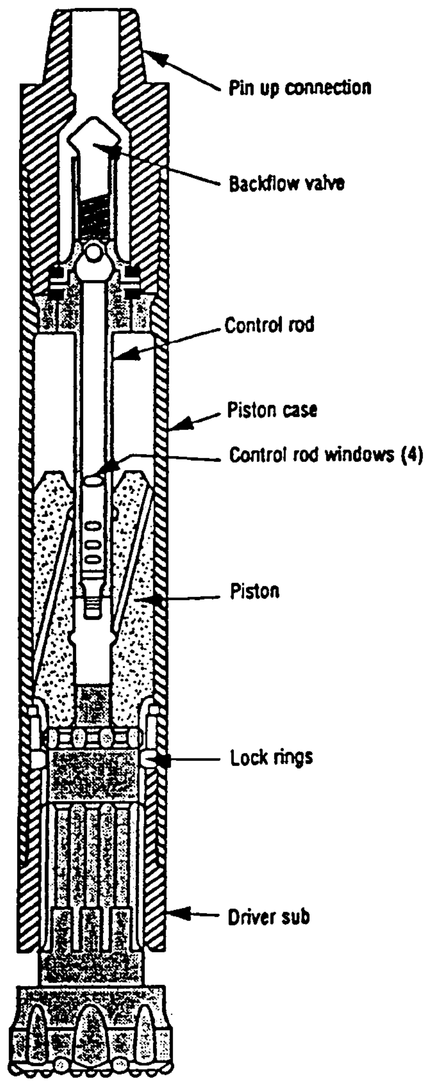
The oil industry currently uses a mud/gas separator to separate the liquid from the gas or air in a well. The system works fairly well when drilling with an aerated fluid. A mud/gas separator is a large vessel with baffles which slows the velocity of the mixture allowing the air to separate from the liquid. The air is discharged out the top of the separator and is vented. The liquid flows out the bottom and is returned to the mud tanks for recycling back into the well.

With mist or foam, the liquid phase contains a surfactant to generate bubbles. The bubbles give the fluid a better lifting capacity and prevents slugging of fluid within the wellbore. To accomplish this, the liquid must stay foamy for a finite period of time. A typical mud/gas separator does not have enough retention time to allow the bubbles to break. The mixture does not have a sufficient time for the liquid to separate from the air. Some foams are designed to stay foamy for more than an hour.

At present, foam and mist are vented straight into the reserve pit. The pit has enough capacity so that the foam has time to break without overflowing. Unfortunately, all the salt water and oil produced from the well also flows into the reserve pit where it must be disposed of properly.

### 6.4.6 DIRECTIONAL HAMMER

An item that industry personnel thought would be an advantage is the directional hammer. An air percussion hammer transfers kinetic energy through the bit to the rock by using a reciprocating piston within the hammer. The rock fails in compression and the hammer drills ahead. In most cases, weight on bit is maintained at less than 5000 pounds and the hammer is rotated at 15 to 30 rpm. The advantage of the percussion hammer is that it can provide high penetration rates at low bit weights. Figure 6.12 is a cutaway of a typical internally ported hammer tool.




*Cutaway view of a downhole industrial hammer.*

*Figure 6.12 - Air percussion hammer tool.*

The hammer tool would be useful in directionally drilling wells on air. A straight hole hammer as shown in Figure 6.12 is a relatively inexpensive downhole tool and simple to operate. If a directional hammer tool can replace the more expensive downhole motor, drilling costs could be reduced, provided the directional hammer is not significantly more expensive than the straight hole hammer.

However, the most significant advantage to a directional hammer would be the increased penetration rate as compared to the downhole motor. Section 6.3.5 discusses the problem with slow penetration rates using downhole motors. The problem is caused by insufficient bit weight. A directional hammer would not have the same problem because it is designed to operate and drill rapidly at low bit weights.

## 6.5 EXPANSION OF AIR DRILLING

One of the objectives of the study was to define areas where air drilling might be expanded within the continental United States. We discussed the potential for expansion of air drilling with the operators, drilling contractors, air drilling contractors and service companies we contacted. Each was specifically asked as to whether they thought air drilling could be expanded in the US and where. With the exception of a few service companies, they did not think that air drilling could be expanded significantly. The primary reasons given were that most areas produce too much water.

The service companies that thought air drilling could be expanded did not point to any province where they thought it could be expanded. One indicated that air drilling could be expanded in horizontal drilling where bottomhole pressures were relatively low. Another indicated that air or foam drilling could be expanded in workover and recompletion work. Both situations would take advantage of the minimum formation damage potential of air drilling. No one could specifically point to an area where drilling new wells with air could be expanded.

Smith International used their bit record data base to aid in determining how many wells used air in at least a portion of the well and, to a degree, where those wells are located. The results of the analysis can be found in Appendix B. Table 6.4 is a summary of those results. It shows that 16.3% of the total footage drilled in the US was drilled with air, gas, foam, air mist, aerated fluid or used air drilling equipment. The survey covered 1993 up to May plus all of 1991 and 1992. If the Gulf of Mexico and the North Slope of Alaska are added, the figure drops to only 12.7%, but these areas were not included in this air drilling study.

Smith's analysis is not scientific by any means and was only used to get an indication of the amount of wells utilizing air drilling techniques in at least a portion of the well. Still, 16% is a significant portion of the total footage drilled in the continental United States.

***Table 6.4** - Results of Smith Internationals survey of wells using air or air equipment in the drilling process.*

| | | TOTAL FOOTAGE DRILLED |
|---|---|---|
| | | |
| Total US - All Fluids | | 143,314,854 |
| Total US - Mud | | 122,940,647 |
| Total US - Air | | 18,169,646 |
| Total US - Other | | 2,204,561 |
| Percentage Drilled with Air | 12.7% | |
| | | |
| Totals without Gulf of Mexico and North Slope | | |
| Total US - All Fluids | | 110,870,331 |
| Total US - Mud | | 91,452,218 |
| Total US - Air | | 18,116,779 |
| Total US - Other | | 1,301,334 |
| Percentage Drilled with Air | 16.3% | |

Drilling data was compiled on a number of air drilled wells for this study. The intent of gathering the data was to determine the regions where air drilling is used infrequently but could be used more often. The data was analyzed and indicated that the majority of the wells drilled on air were in areas where air drilling is common. This is confirmed by Smith's analysis of their bit record data. Two areas that are frequently air drilled are the Appalachian Basin and the Arkoma Basin. According to Smith's analysis, greater than 90% of all the footage drilled was drilled utilizing air drilling techniques in at least a portion of the well. Another area where air drilling is very popular is in Provinces 85, 86 and 88 (Paradox Basin, Uinta-Piceance-Eagle Basin and San Juan Basin, respectively.) Smith's analysis did not specifically break out this area and is included in the category "other". However, large quantities of air drilling well data were available for this area. Air drilling well data was sparse for the rest of the provinces with the exception of some specific areas within a province.

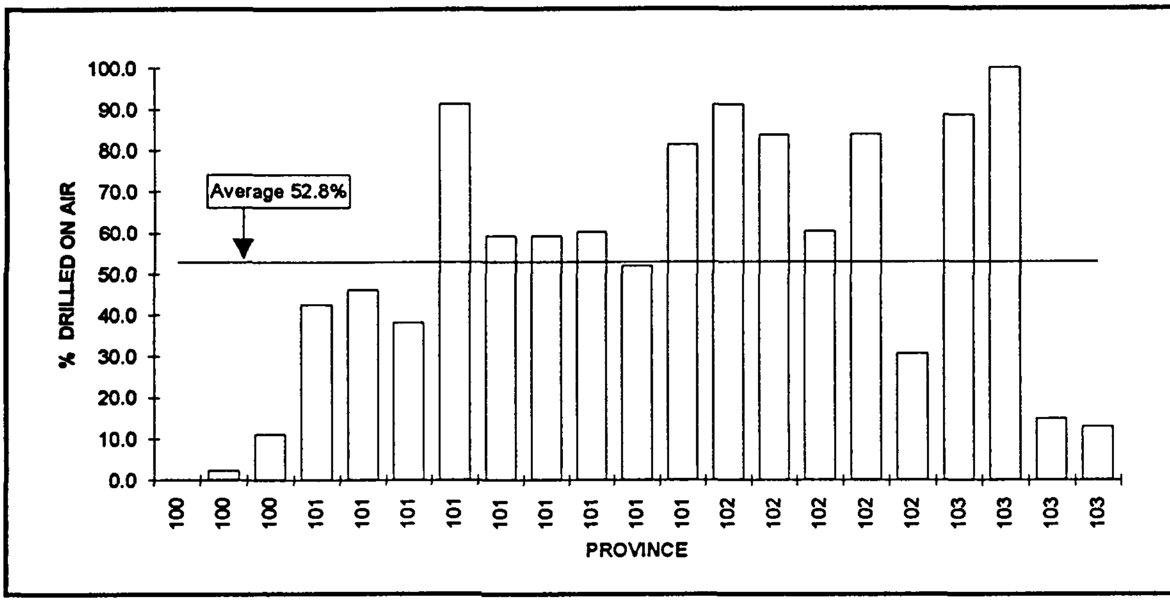



***Figure 6.13*** *- Bar graph showing the percentage of the total footage drilled using air for each well. Data is for wells in Wyoming only. Wells are in the same order as Table 6.5.*

As an example, all the data obtained in the state of Wyoming was analyzed. There was sufficient information on 21 wells for the analysis. Each well had been partially drilled utilizing air in some form. The percentage of each well drilled using air is shown in Figure 6.13. The average for all the wells was 53%. Table 6.5 summarizes the data.

***Table 6.5*** *- Data analysis for wells drilled on air in the state of Wyoming.*

| FILE NAME | REGION | PROVINCE | WELL NAME | LOCATION | TOTAL DEPTH | FOOTAGE DRILLED AIR | FOOTAGE DRILLED MUD | % DRILLED ON AIR |
|---|---|---|---|---|---|---|---|---|
| 8 | 4 | 100 | 1-11 Tribal | Sec 11, T3N, R5E | 14600 | 10 | 14590 | 0.07 |
| 9 | 4 | 100 | Reservoir Creek Unit 1-34 | Sec 34, T38N, R89W | 9848 | 232 | 9616 | 2.36 |
| 11 | 4 | 100 | Fowler Federal 13X-4 | Sec 4, T35N, R85W | 7204 | 800 | 6404 | 11.10 |
| 10 | 4 | 101 | Si Tanaka #1 | Sec 6, T38N, R77W | 7539 | 3209 | 4330 | 42.57 |
| 13 | 4 | 101 | 1 Wasserburger | Sec 43, T38N, R63W | 7600 | 3499 | 4101 | 46.04 |
| 14 | 4 | 101 | Naval Petroleum Reserve #3 | Sec 10, T38N, R78W | 4015 | 1532 | 2483 | 38.16 |
| 15 | 4 | 101 | North Tisdale #67 | Sec 9, T41N, R81W | 1875 | 1715 | 160 | 91.47 |
| 16 | 4 | 101 | Intreped Fed. 12-7 | Sec 7, T36N, R63W | 6800 | 4018 | 2782 | 59.09 |
| 21 | 4 | 101 | 1-6 Gunn Federal | Sec 6, T36N, R63W | 6755 | 4002 | 2753 | 59.25 |
| 22 | 4 | 101 | 1-13 Federal | Sec 13, T36N, R64W | 6476 | 3906 | 2570 | 60.32 |
| 31 | 4 | 101 | #24-25 Federal | Sec 25, T38N, R63W | 7449 | 3865 | 3584 | 51.89 |
| 32 | 4 | 101 | State "D" 21-36 | Sec 36, T38N, R63W | 5170 | 4205 | 965 | 81.33 |
| 4 | 4 | 102 | 36-1 State | Sec 36, T21N, R103W | 6153 | 5603 | 550 | 91.06 |
| 5 | 4 | 102 | 4-34 Curry Federal | Sec 34, T21N, R81W | 6950 | 5816 | 1134 | 83.68 |
| 6 | 4 | 102 | 2-8A Bluewater Fed. | Sec 8, T20N, R102W | 5570 | 3363 | 2207 | 60.38 |
| 7 | 4 | 102 | Espy #10 | Sec 22, T19N, R89W | 4095 | 3433 | 662 | 83.83 |
| 30 | 4 | 102 | COGC 1-14-32-82 Federal | Sec 14, T32N, R82W | 5895 | 1810 | 4085 | 30.70 |
| 1 | 4 | 103 | 1-21 Hess Creek State | Sec 21, T45N, R101W | 3480 | 3084 | 396 | 88.62 |
| 2 | 4 | 103 | Aspen Creek Unit 1-10 | Sec 10, T45N, R101W | 3175 | 3175 | 0 | 100.00 |
| 3 | 4 | 103 | Owl Creek #4 | Sec 6, T43N, R102W | 2242 | 335 | 1907 | 14.94 |
| 33 | 4 | 103 | NO. 1-1 Pickett Creek Federal | Sec 1, T49N, R105W | 6050 | 781 | 5269 | 12.91 |

Wyoming was chosen for this analysis because we purposely collected all the air drilling data available to us. In other states, we collected data that was biased toward wells that had problems with the air drilled portion of the hole. Therefore, the results from other states would not be as meaningful as they are in Wyoming. There was one area in Wyoming where all the well data was not collected. That was in the area of wells 13, 16, 21, 22, 31, and 32 as shown in Figure 6.14. In this immediate area, most of the wells are drilled on air and time did not allow gathering all the well data from the Wyoming Oil and Gas Commission. There are undoubtedly more wells drilled on air in the state of Wyoming but we did not find that data.

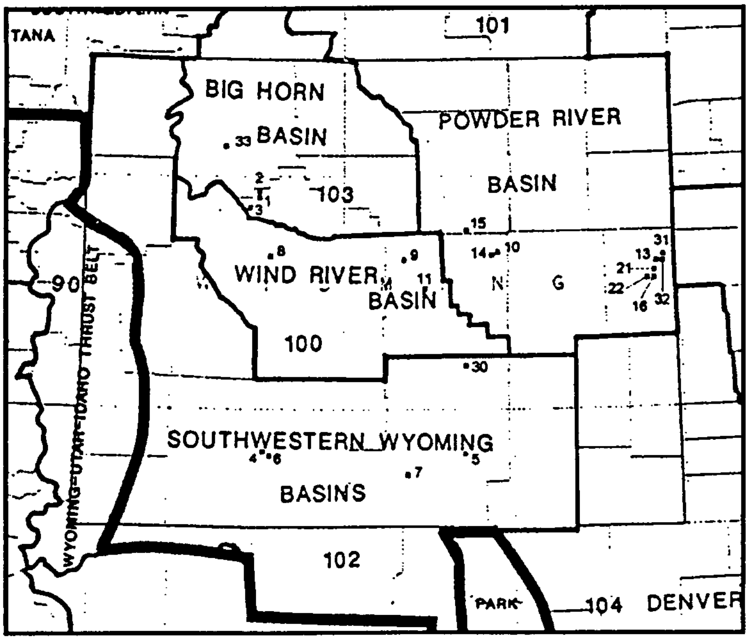



*Figure 6.14 - Location of wells in Table 6.5.*

Given the data in Figure 6.13, it appears that most of the wells were economically drilled on air. They were most effective in Provinces 101 and 102 (Powder River Basin and Southwestern Wyoming Basins, respectively). Air drilling was not as effective in Provinces 100 and 103 (Wind River Basin and Big Horn Basin, respectively). The data may be slightly misleading. Most of the wells drilled in the Powder River Basin are in one small area where air drilling is possible. Figure 6.14 shows the location of the wells within the state of Wyoming. The number corresponds to the file name in Table 6.5.

The area in Eastern Wyoming which includes wells 13, 16, 21, 22, 31 and 32 was investigated more thoroughly. We were able to find a well that was drilled to total depth with mud. No air was used on the 33-13 Johnson in Sec 13, T36N, R64W. The depth versus days for the Johnson well and wells 21,22 and 31 are plotted in Figure 6.15. In this area, the intermediate hole is drilled on air. The intermediate hole starts from below surface casing at approximately 400 feet and continues to 4200 feet. The remainder of the well is drilled using mud. As can be seen in Table 6.5, over 50% of each well was drilled on air. However, the economics of air drilling may be hard to justify. The time to drill each well was almost the same whether the well was drilled on air or mud. The penetration rate for both mud and air averaged approximately 40 feet per hour. No bit weights and rotary speeds were recorded so it is not possible to determine why penetration rates with mud were comparable to air. Even though air drilling is possible, it may not be economical when high penetration rates can be obtained with mud. This area is prone to lost circulation, and it is probably the overriding reason for air drilling.

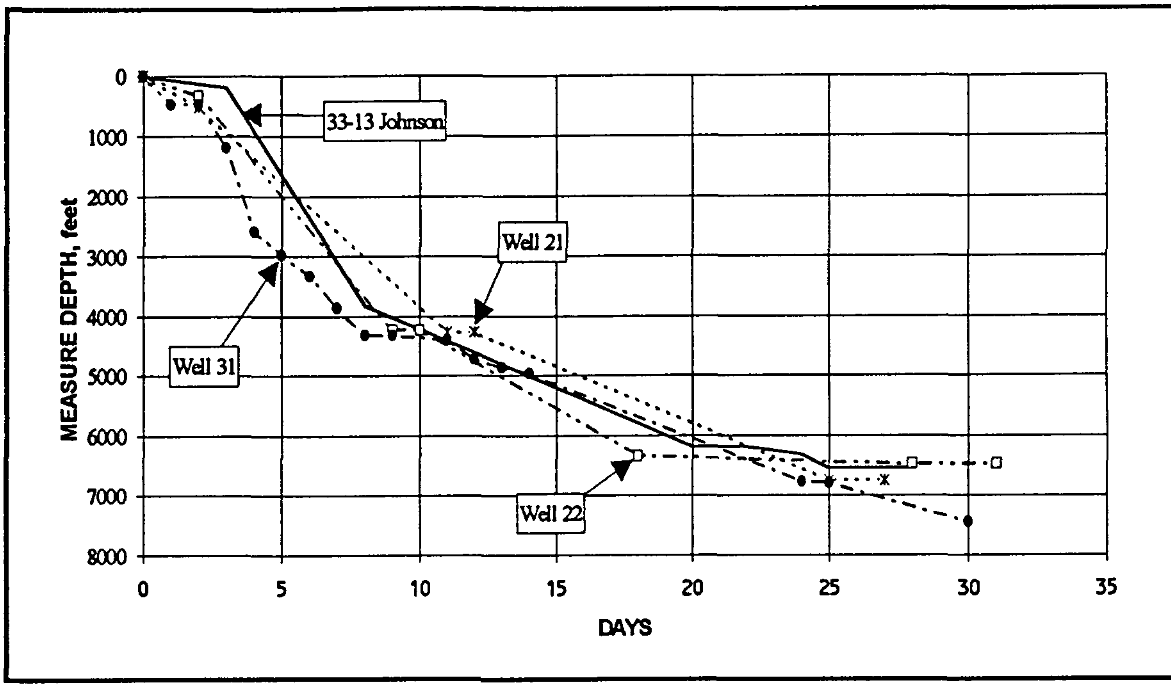



*Figure 6.15 - Depth versus days for wells in the Powder River Basin. Wells 21,22 and 31 were partially drilled on air. The 33-13 Johnson was drilled on mud.*

A lot of data was also collected in Province 123 which is Southern Oklahoma. An operator drilled the Drummond 1-12 well on mud and had a lot of lost circulation problems resulting in excess costs. To minimize problems associated with lost circulation, the operator elected to drill subsequent wells with air. Air drilling was not completely successful because of hole instability. A total of four wells were drilled in the area. They are the Drummond 1-12, 2-12, 3-12 and the USA 1-12. Only the Drummond 1-12 was drilled completely with mud. The others had a sizable portion of the well drilled on air and air mist. Figure 6.16 is a plot of depth versus days for each well. Obviously the Drummond 1-12 took much longer to drill and air drilling was economically successful. The operator proved that air drilling can be successfully performed in Southern Oklahoma. However, if not for the lost circulation problems in the Drummond 1-12, air drilling would not have been tried.

*Table 6.6 - Intervals drilled with mud and air in Southern Oklahoma.*

| INTERVAL | DRUMMOND 1-12 | DRUMMOND 2-12 | DRUMMOND 3-12 | USA 1-12 |
|---|---|---|---|---|
| Surface Hole | 0-774' mud | 0-725' mud | 0-770' mud | 0-805' mud |
| Intermediate Hole | 744- 2578' mud | 725-2510' mud | 770-2525' mud | 805-1427' air<br>1427-2507' mud |
| Production Hole | 2578-5008' mud | 2510- 4000' air | 2525-4144' air<br>4144- 5100' mud | 2507-4319' air<br>4319-4650' mud |
| % Air Drilled | 0% | 37% | 66% | 52% |

Each well had surface casing set at 750 feet and intermediate casing at 2500 feet. The surface casing interval was always drilled on mud. Various portions of the intermediate and production hole were drilled on mud. Table 6.6 shows what portion of the hole was drilled using air for each well.

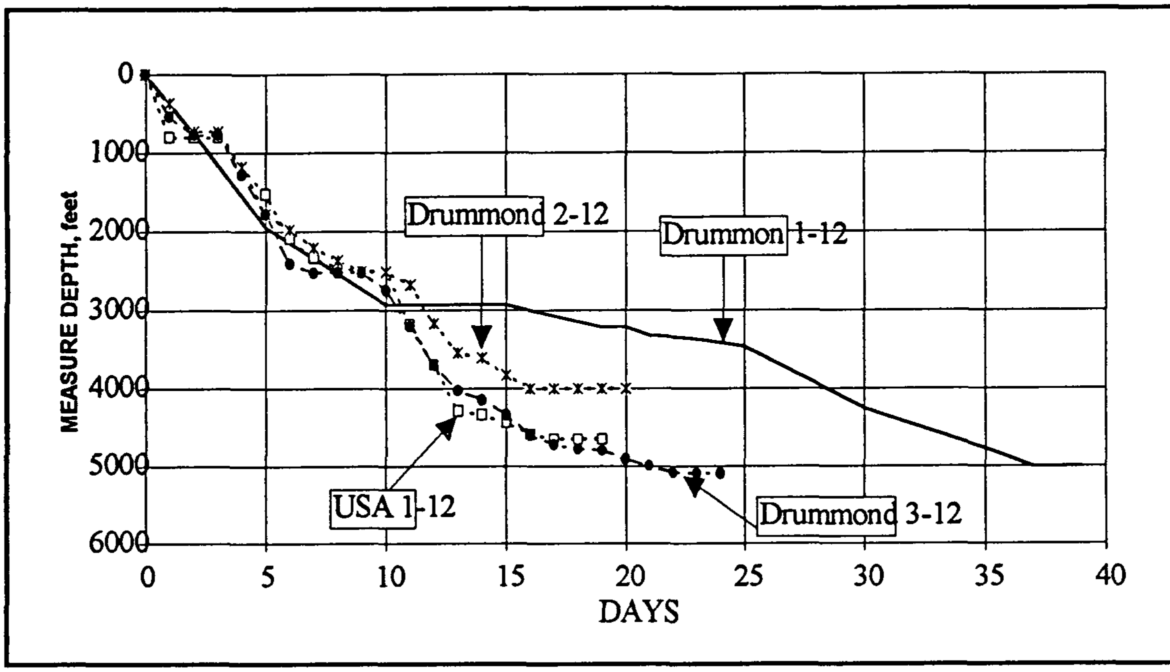



*Figure 6.16 - Depth versus days for wells in the Southern Oklahoma Province. The Drummond 1-12 was drilled entirely on mud. The other three wells were partially drilled on air.*

The well data analyzed in this study would tend to confirm what operators, drilling contractors, air drilling contractors and service companies believe. Air drilling can not be significantly expanded within the continental United States. There are no provinces where air drilling could replace mud drilling. There are unquestionably small areas within provinces where air drilling could be expanded, but the total increase would not be substantial compared to the total wells drilled in the United States. Most of the Powder River Basin is not applicable to air drilling; but as Table 6.5 shows, there are a few small areas where air drilling can be economically applied.

One problem with expanding air drilling is that someone has to try air drilling where all wells are currently drilled on mud. Given the fact that most operators feel that air drilling cannot be expanded within the continental United States, they are unlikely to try air drilling in an area where it has not been tried before. Unless the attitude of the oil companies and drilling contractors are changed, air drilling will not be expanded significantly. One way to change their attitude is through education; but with the downturn in the drilling industry, education budgets have been drastically cut. Most drilling contractors are in jeopardy of going out of business. Also, operators and contractors are not likely to spend limited funds experimenting with air drilling in areas where air drilling is not commonplace.

Another way to expand air drilling would be through drilling a demonstration well. Someone would have to drill and air hole where drilling is conducted primarily with drilling mud. If operators and drilling contractors see that the well is less expensive when drilling with air, they would be much more likely to drill subsequent wells with air. Unfortunately, the demonstration well would be a research well and research funds are very limited. The major oil companies are the companies that provided most of the drilling research funds within the United States, but they are currently in the process of moving out of the domestic market.

Since education and research funds are limited, it is unlikely that air drilling will be expanded by the oil companies or the drilling contractors. Service companies would have a limited ability to steer the industry in that direction.

Geology is one of the things we looked at for the expansion of air drilling. The majority of the wells in the Arkoma Basin and the Appalachian Basins are drilled on air. As shown in Table 6.7, the youngest rocks present in the two basins are of Pennsylvanian age which means they are older and harder rocks. These types of rocks are more suitable for air drilling than younger softer rocks. The geology of several other provinces were looked at in Section 6.1 and the geologic age of the rocks determined. That information is summarized in Table 6.7. Note that all of the other basins have younger rocks than the Arkoma and Appalachian basin.

*Table 6.7 - Geologic summary of provinces.*

| PROVINCE | NAME | GEOLOGIC AGE | MAJORITY OF PRODUCTION | AIR DRILLING FREQUENCY |
|---|---|---|---|---|
| 82 | Eastern Basin and Range | Tertiary to Cambrian | Penn. to Devonian | Minimal |
| 85 | Paradox Basin | Cretaceous to Cambrian | Pennsylvanian | Moderate |
| 86 | Uinta-Piceance-Eagle | Tertiary to Devonian | Tertiary to Cretaceous | Moderate |
| 88 | San Juan Basin | Cretaceous to Devonian | Cretaceous | Moderate |
| 96 | Sweetgrass Arch | Cretaceous to Cambrian | Cretaceous | Minimal |
| 98 | Montana Thrust Belt | Cretaceous to Cambrian | Very little production | Almost none |
| 100 | Wind River Basin | Tertiary to Cambrian | Cretaceous to Ordovician | Minimal |
| 102 | Southwestern Wyoming Basins | Tertiary to Cambrian | Tertiary to Cretaceous | Minimal |
| 103 | Big Horn Basin | Tertiary to Cambrian | Permian to Ordovician | Minimal |
| 104 | Denver Basin | Cretaceous to Cambrian | Cretaceous | Minimal |
| 105 | Las Animas Arch | Cretaceous to Cambrian | Pennsylvanian | Minimal |
| 107 | Permian Basin | Cretaceous to Ordovician | Permian to Ordovician | Minimal to Moderate* |
| 112 | Western Gulf Basin | Quaternary to Jurassic | Miocene to Jurassic | Almost none |
| 115 | Anadarko Basin | Tertiary to Cambrian | Permian to Cambrian | Minimal |
| 116 | Arkoma Basin | Penn. to Cambrian | Penn to Ordovician | Majority |
| 131 | Appalachian Basin | Penn to Cambrian | Miss. to Cambrian | Majority |

*Depends upon the area

Air drilling is also used frequently tin the Paradox, Uinta-Piceance-Eagle and San Juan Basins but to a lesser extent than the other two basins. Note that these basins have younger rocks which are less applicable to air drilling. However, most of the other basins in Table 6.7 have similar geologic ages but very little air drilling is done in these basins. The Denver Basin has Cretaceous through Cambrian age rocks but almost no air drilling is used. The penetration rates are already high enough with mud that air drilling would not be economical. Geologic age of the rocks within the basin is only a consideration when trying to determine the applicability of air drilling to a specific province and is not definitive. Therefore, we did not further research the geology of the other provinces. A geologic time table is presented in Table 6.8 for reference.

*Table 6.8 - Geologic time chart.*

| ERA | PERIOD | EPOCH | DURATION (Millions of Years) | CUMULATIVE AGE (Millions of Years) |
|---|---|---|---|---|
| Cenozoic | Quaternary | Recent | 1/40 | |
| | | Pleistocene | 1 | |
| | Tertiary | Pliocene | 10 | |
| | | Miocene | 14 | |
| | | Oligocene | 15 | |
| | | Eocene | 20 | |
| | | Paleocene | 10 | 70 ±2 |
| Mesozoic | Cretaceous | | 65 | |
| | Jurassic | | 45 | |
| | Triassic | | 45 | 225 ±5 |
| Paleozoic | Permian | | 45 | |
| | Pennsylvanian | | 45 | |
| | Mississippian | | 35 | |
| | Devonian | | 50 | |
| | Silurian | | 40 | |
| | Ordovician | | 60 | |
| | Cambrian | | 100 | 600 ±20 |
| Precambrian | | | 4400 | 5000 ±500? |

Another factor that geologic age does not take into consideration is potential water production and formation stability. Both will limit the use of air drilling. A much more in-depth study of the geology would be required to determine these factors. A detailed geologic study of the continental United States is beyond the scope of this study.

The regions that hold the most promise for expansion of air drilling are regions 3 and 4 which is the Rocky Mountain area. As mentioned earlier, provinces 85, 86 and 88 already see extensive air drilling. The reason the Rocky Mountain area is the most likely candidate for expansion is because the type of rocks found in the area are applicable to air drilling. The rocks are generally older and harder. (See section 6.1, Geology.) Harder rocks are more stable and less likely to slough or fall apart. Also older rocks contain less water sensitive clays which can cause problems when drilling with mist or foam. The type of rock found in the Rocky Mountains also drills slower which means that air drilling could significantly increase penetration rate. However, there are many areas within the Rocky Mountains that will produce large quantities of water.

Air drilling is least likely to be expanded in region 6 which is the Gulf Coast area. The formations in the Gulf Coast are not applicable to air drilling because they are geologically young. The loose, unconsolidated rocks in the region are extremely likely to slough while drilling. The penetration rates in these rocks are already very high. In many places, the only thing that limits penetration rate is the ability to clean the hole. The bit could drill faster if the mud was capable of doing a better job of cleaning the cuttings from the hole. Therefore, increased penetration rate is not an economic justification for drilling with air. Also, the region is characterized by high permeability formations capable of producing massive quantities of salt water. Air drilling could be used in some small areas within region 6 for special purposes.

It would be difficult to rank each province according to the likelihood that air drilling could be expanded within that region. The well data collected in this study was not sufficient to be able to rank the provinces. All the provinces generated results similar to the data in Wyoming. There were wells that were both successfully and unsuccessfully drilled with air in the same province. Outside the provinces where air drilling is used frequently, the majority of the air drilled holes were located in smaller areas within the province. Therefore, insufficient data is available to evaluate the entire province.

The likelihood that air drilling could be used in a specific area is more a function of geology than anything else. The area must have relatively stable formations with low to moderate water influx. It is just not possible to look at an area where no previous air drilling has been done and determine whether the formations are stable enough or whether water influx would be low enough to allow air drilling. It would take a much more in depth geologic study to do that.

One area were air drilling should expand is in horizontal and directional drilling. Prior to 1990, very little directional equipment was available for an air drilled hole. Since then, equipment has been developed for drilling air holes. Also, the industry has learned to more effectively operate some equipment designed for mud drilling in an air hole. The equipment is covered in Section Table 6.5, and will not be covered again here.

Most of the companies contacted during the study indicated that they though horizontal drilling had the highest probability of expanding the use of air drilling. The advantage that they mentioned most was minimum formation damage drilling. Horizontal wells are difficult and expensive to stimulate. Any formation damage done during the drilling process is detrimental to production and the well must be stimulated to increase production. Drilling on air, mist or foam will minimize the formation damage. Even though it may be more difficult to drill the horizontal well on air, it is worth the effort because of the increased productivity after the well is completed.

The industry is looking at using horizontal drilling in older reservoirs as a means to increase the ultimate recovery of hydrocarbons. Horizontal drilling is being used as an enhance oil recovery method. Older reservoirs generally have low bottomhole pressures and drilling fluid formation damage and lost circulation are significant problems. To overcome these problems, horizontal drilling with air is becoming more popular. In the majority of horizontal wells, casing is set at the kick off point or into the build curve. The deeper casing seats isolate formations that may slough or produce large quantities of water. Therefore, air is more applicable in horizontal drilling than vertical drilling. Not all horizontal wells can be drilled on air, but many can.

## 7.0 CONCLUSIONS

1. The overwhelming reason for using air drilling is increased penetration rate. Higher penetration rates yield lower drilling costs even though the daily operating expense is higher.

2. The primary reason for using aerated fluids is to prevent lost circulation problems. Alleviating lost circulation problems reduces drilling costs. The penetration rate will also be increased with aerated fluids but it was only a secondary consideration.

3. Water production and unstable formations were the primary limiting factors associated with air drilling. Substantial water production adds considerable expense when the water must be hauled off location to a proper disposal. Unstable formations have a tendency to slough. Wellbores with sloughing formations are difficult or impossible to clean with air, and mud is often required.

4. The level of directional drilling technology available to the air drilling industry is not adequate. No reliable MWD system is available that will work consistently in an air environment. Also, penetration rates for downhole motors are too low in some hard formations when drilling on air.

5. If technology is introduced that can eliminate the water influx and hole instability problems, air drilling can be expanded considerably. However, finding some means of limiting these problems is unlikely at this time.

6. Air drilling can be expanded in the continental United States but only to a small degree. Most of the provinces where drilling is routinely conducted on mud contain too much water to be drilled on air. In other areas the formations are too soft and unconsolidated to drill with air.

7. Geologic age of the rocks in a basin alone will not determine the applicability of air drilling but is an indication as to whether air drilling would be applicable.

8. Horizontal drilling is one area where air drilling can be expanded. The minimum formation damage properties of air are desirable in horizontal holes because of the excessive costs required to stimulate a horizontal well. Also, horizontal wells are being used as an alternative method to recover additional reserves from existing reservoirs. The low pressures associated with a partially depleted reservoir is an ideal application for air drilling.

9. The probability that air drilling can be expanded significantly within the continental United States is small unless some technological breakthroughs are forthcoming. The geology of most of the petroleum provinces in the United States are not suitable for air drilling. There are, however, small areas within these provinces where air drilling could be expanded if tried. Operator reluctance and lack of air drilling knowledge will limit this expansion.

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# APPENDIX A

# APPENDIX B

| BASIN | REGION | PROVINCE | FLUID TYPE | YEAR WELL TD | TOTAL FOOTAGE DRILLED | TOTAL HOURS REPORTED |
|---|---|---|---|---|---|---|
| Anadarko | 7 | 115 | Mud | 91 | 9,048,720 | 405,955 |
| Anadarko | 7 | 115 | Air | 91 | 1,084,591 | 46,651 |
| Anadarko | 7 | 115 | Unknown | 91 | 475,153 | 5,622 |
| Anadarko | 7 | 115 | Mud | 92 | 7,059,459 | 299,279 |
| Anadarko | 7 | 115 | Air | 92 | 380,466 | 16,635 |
| Anadarko | 7 | 115 | Unknown | 92 | 224,519 | 1,488 |
| Anadarko | 7 | 115 | Mud | 93 | 2,312,373 | 112,422 |
| Anadarko | 7 | 115 | Air | 93 | 211,405 | 8,836 |
| Anadarko | 7 | 115 | Unknown | 93 | 20,281 | 76 |
| TOTAL Anadarko Basin All | | | | | 20,816,967 | 896,964 |
| TOTAL Anadarko Basin Mud | | | | | 18,420,552 | 817,656 |
| TOTAL Anadarko Basin Air | | | | | 1,676,462 | 72,122 |
| TOTAL Anadarko Basin Unknown | | | | | 719,953 | 7,186 |
| **Percentage Drilled with Air** | | | **8.05%** | | | |
| Appalachian | 8 | 131 | Mud | 91 | 261,731 | 6,307 |
| Appalachian | 8 | 131 | Air | 91 | 4,325,050 | 63,348 |
| Appalachian | 8 | 131 | Unknown | 91 | 180,740 | 3,156 |
| Appalachian | 8 | 131 | Mud | 92 | 267,854 | 6,985 |
| Appalachian | 8 | 131 | Air | 92 | 3,174,987 | 45,593 |
| Appalachian | 8 | 131 | Unknown | 92 | 16,313 | 208 |
| Appalachian | 8 | 131 | Mud | 93 | 4,810 | 135 |
| Appalachian | 8 | 131 | Air | 93 | 316,789 | 4,945 |
| Appalachian | 8 | 131 | Unknown | 93 | 0 | 0 |
| TOTAL Applachian Basin All | | | | | 8,548,274 | 130,677 |
| TOTAL Appalachian Basin Mud | | | | | 534,395 | 13,427 |
| TOTAL Applachian Basin Air | | | | | 7,816,826 | 113,886 |
| TOTAL Applachian Basin Unknown | | | | | 197,053 | 3,364 |
| **Percentage Drilled with Air** | | | **91.44%** | | | |

| BASIN | REGION | PROVINCE | FLUID TYPE | YEAR WELL TD | TOTAL FOOTAGE DRILLED | TOTAL HOURS REPORTED |
|---|---|---|---|---|---|---|
| Arkoma | 7 | 116 | Mud | 91 | 0 | 0 |
| Arkoma | 7 | 116 | Air | 91 | 175,441 | 7,405 |
| Arkoma | 7 | 116 | Unknown | 91 | 6,250 | 145 |
| Arkoma | 7 | 116 | Mud | 92 | 9,625 | 782 |
| Arkoma | 7 | 116 | Air | 92 | 235,455 | 14,928 |
| Arkoma | 7 | 116 | Unknown | 92 | 5,109 | 196 |
| Arkoma | 7 | 116 | Mud | 93 | 0 | 0 |
| Arkoma | 7 | 116 | Air | 93 | 49,155 | 2,155 |
| Arkoma | 7 | 116 | Unknown | 93 | 0 | 0 |
| TOTAL Arkoma Basin All | | | | | 481,035 | 25,611 |
| TOTAL Arkoma Basin Mud | | | | | 9,625 | 782 |
| TOTAL Arkoma Basin Air | | | | | 460,051 | 24,488 |
| TOTAL Arkoma Basin Unknown | | | | | 11,359 | 341 |
| **Percentage Drilled with Air** | | | **95.64%** | | | |
| Bend Arch | 5 | 110 | Mud | 91 | 591,993 | 17,774 |
| Bend Arch | 5 | 110 | Air | 91 | 275,116 | 8,360 |
| Bend Arch | 5 | 110 | Unknown | 91 | 0 | 0 |
| Bend Arch | 5 | 110 | Mud | 92 | 290,036 | 8,792 |
| Bend Arch | 5 | 110 | Air | 92 | 104,455 | 3,205 |
| Bend Arch | 5 | 110 | Unknown | 92 | 0 | 0 |
| Bend Arch | 5 | 110 | Mud | 93 | 39,703 | 994 |
| Bend Arch | 5 | 110 | Air | 93 | 0 | 0 |
| Bend Arch | 5 | 110 | Unknown | 93 | 0 | 0 |
| TOTAL Bend Arch Basin All | | | | | 1,301,303 | 39,125 |
| TOTAL Bend Arch Basin Mud | | | | | 921,732 | 27,560 |
| TOTAL Bend Arch Basin Air | | | | | 379,571 | 11,565 |
| TOTAL Bend Arch Basin Unknown | | | | | 0 | 0 |
| **Percentage Drilled with Air** | | | **29.17%** | | | |

| BASIN | REGION | PROVINCE | FLUID TYPE | YEAR WELL TD | TOTAL FOOTAGE DRILLED | TOTAL HOURS REPORTED |
|---|---|---|---|---|---|---|
| Denver | 4 | 104 | Mud | 91 | 4,075,545 | 63,428 |
| Denver | 4 | 104 | Air | 91 | 331,714 | 5,042 |
| Denver | 4 | 104 | Unknown | 91 | 22,823 | 0 |
| Denver | 4 | 104 | Mud | 92 | 4,797,326 | 63,573 |
| Denver | 4 | 104 | Air | 92 | 390,785 | 7,064 |
| Denver | 4 | 104 | Unknown | 92 | 0 | 0 |
| Denver | 4 | 104 | Mud | 93 | 1,266,227 | 16,002 |
| Denver | 4 | 104 | Air | 93 | 46,948 | 556 |
| Denver | 4 | 104 | Unknown | 93 | 0 | 0 |
| TOTAL Denver Basin All | | | | | 10,931,368 | 155,665 |
| TOTAL Denver Basin Mud | | | | | 10,139,098 | 143,003 |
| TOTAL Denver Basin Air | | | | | 769,447 | 12,662 |
| TOTAL Denver Basin Unknown | | | | | 22,823 | 0 |
| **Percentage Drilled with Air** | | | **7.04%** | | | |
| East Texas - North Louisiana | | | Mud | 91 | 5,316,285 | 254,153 |
| East Texas - North Louisiana | | | Air | 91 | 228,260 | 8,162 |
| East Texas - North Louisiana | | | Unknown | 91 | 49,999 | 257 |
| East Texas - North Louisiana | | | Mud | 92 | 6,219,101 | 284,764 |
| East Texas - North Louisiana | | | Air | 92 | 153,404 | 6,606 |
| East Texas - North Louisiana | | | Unknown | 92 | 36,900 | 67 |
| East Texas - North Louisiana | | | Mud | 93 | 1,821,105 | 89,019 |
| East Texas - North Louisiana | | | Air | 93 | 36,160 | 1,666 |
| East Texas - North Louisiana | | | Unknown | 93 | 0 | 0 |
| TOTAL East Texas - North Louisiana Basin All | | | | | 13,861,214 | 644,694 |
| TOTAL East Texas - North Louisiana Mud | | | | | 13,356,491 | 627,936 |
| TOTAL East Texas - North Louisiana Air | | | | | 417,824 | 16,434 |
| TOTAL East Texas - North Louisiana Unknown | | | | | 86,899 | 324 |
| **Percentage Drilled with Air** | | | **3.01%** | | | |

| BASIN | REGION | PROVINCE | FLUID TYPE | YEAR WELL TD | TOTAL FOOTAGE DRILLED | TOTAL HOURS REPORTED |
|---|---|---|---|---|---|---|
| East Shelf | | | Mud | 91 | 2,236,231 | 64,567 |
| East Shelf | | | Air | 91 | 1,740,591 | 36,348 |
| East Shelf | | | Unknown | 91 | 6,490 | 273 |
| East Shelf | | | Mud | 92 | 3,838,325 | 90,652 |
| East Shelf | | | Air | 92 | 562,563 | 12,875 |
| East Shelf | | | Unknown | 92 | 0 | 0 |
| East Shelf | | | Mud | 93 | 365,570 | 9,945 |
| East Shelf | | | Air | 93 | 65,420 | 1,172 |
| East Shelf | | | Unknown | 93 | 0 | 0 |
| TOTAL East Shelf Basin All | | | | | 8,815,190 | 215,832 |
| TOTAL East Shelf Basin Mud | | | | | 6,440,126 | 165,164 |
| TOTAL East Shelf Basin Air | | | | | 2,368,574 | 50,395 |
| TOTAL East Shelf Basin Unknown | | | | | 6,490 | 273 |
| **Percentage Drilled with Air** | | | **26.87%** | | | |
| Fort Worth | 5 | 110 | Mud | 91 | 837,381 | 19,452 |
| Fort Worth | 5 | 110 | Air | 91 | 12,440 | 318 |
| Fort Worth | 5 | 110 | Unknown | 91 | 9,561 | 167 |
| Fort Worth | 5 | 110 | Mud | 92 | 652,366 | 12,949 |
| Fort Worth | 5 | 110 | Air | 92 | 25,300 | 650 |
| Fort Worth | 5 | 110 | Unknown | 92 | 0 | 0 |
| Fort Worth | 5 | 110 | Mud | 93 | 102,277 | 1,893 |
| Fort Worth | 5 | 110 | Air | 93 | 0 | 0 |
| Fort Worth | 5 | 110 | Unknown | 93 | 0 | 0 |
| TOTAL Fort Worth Basin All | | | | | 1,639,325 | 35,429 |
| TOTAL Fort Worth Basin Mud | | | | | 1,592,024 | 34,294 |
| TOTAL Fort Worth Basin Air | | | | | 37,740 | 968 |
| TOTAL Fort Worth Basin Unknown | | | | | 9,561 | 167 |
| **Percentage Drilled with Air** | | | **2.30%** | | | |

| BASIN | REGION | PROVINCE | FLUID TYPE | YEAR WELL TD | TOTAL FOOTAGE DRILLED | TOTAL HOURS REPORTED |
|---|---|---|---|---|---|---|
| Geysers | 2 | 81A | Mud | 91 | 10,246 | 275 |
| Geysers | 2 | 81A | Air | 91 | 56,445 | 4,703 |
| Geysers | 2 | 81A | Unknown | 91 | 0 | 0 |
| Geysers | 2 | 81A | Mud | 92 | 0 | 0 |
| Geysers | 2 | 81A | Air | 92 | 81,725 | 2,611 |
| Geysers | 2 | 81A | Unknown | 92 | 0 | 0 |
| Geysers | 2 | 81A | Mud | 93 | 0 | 0 |
| Geysers | 2 | 81A | Air | 93 | 30,614 | 747 |
| Geysers | 2 | 81A | Unknown | 93 | 0 | 0 |
| TOTAL Geysers Basin All | | | | | 179,030 | 8,336 |
| TOTAL Geysers Basin Mud | | | | | 10,246 | 275 |
| TOTAL Geysers Basin Air | | | | | 168,784 | 8,061 |
| TOTAL Geysers Basin Unknown | | | | | 0 | 0 |
| **Percentage Drilled with Air** | | | **94.28%** | | | |
| Hardeman | | | Mud | 91 | 329,544 | 13,720 |
| Hardeman | | | Air | 91 | 56,744 | 2,251 |
| Hardeman | | | Unknown | 91 | 0 | 0 |
| Hardeman | | | Mud | 92 | 273,585 | 10,001 |
| Hardeman | | | Air | 92 | 16,397 | 502 |
| Hardeman | | | Unknown | 92 | 0 | 0 |
| Hardeman | | | Mud | 93 | 58,708 | 2,780 |
| Hardeman | | | Air | 93 | 8,214 | 299 |
| Hardeman | | | Unknown | 93 | 0 | 0 |
| TOTAL Hardeman Basin All | | | | | 743,192 | 29,553 |
| TOTAL Hardeman Basin Mud | | | | | 661,837 | 26,501 |
| TOTAL Hardeman Basin Air | | | | | 81,355 | 3,052 |
| TOTAL Hardeman Basin Unknown | | | | | 0 | 0 |
| **Percentage Drilled with Air** | | | **10.95%** | | | |

| BASIN | REGION | PROVINCE | FLUID TYPE | YEAR WELL TD | TOTAL FOOTAGE DRILLED | TOTAL HOURS REPORTED |
|---|---|---|---|---|---|---|
| Louisiana Gulf | | | Mud | 91 | 1,917,497 | 73,281 |
| Louisiana Gulf | | | Air | 91 | 0 | 0 |
| Louisiana Gulf | | | Unknown | 91 | 73,444 | 1,242 |
| Louisiana Gulf | | | Mud | 92 | 2,109,265 | 71,987 |
| Louisiana Gulf | | | Air | 92 | 0 | 0 |
| Louisiana Gulf | | | Unknown | 92 | 0 | 0 |
| Louisiana Gulf | | | Mud | 93 | 613,482 | 19,849 |
| Louisiana Gulf | | | Air | 93 | 0 | 0 |
| Louisiana Gulf | | | Unknown | 93 | 0 | 0 |
| TOTAL Louisiana Gulf All | | | | | 4,713,688 | 166,359 |
| TOTAL Louisiana Gulf Mud | | | | | 4,640,244 | 165,117 |
| TOTAL Louisiana Gulf Air | | | | | 0 | 0 |
| TOTAL Louisiana Gulf Unknown | | | | | 73,444 | 1,242 |
| **Percentage Drilled with Air** | | | **0.00%** | | | |
| Michigan | | | Mud | 91 | 274,708 | 4,610 |
| Michigan | | | Air | 91 | 15,156 | 417 |
| Michigan | | | Unknown | 91 | 0 | 0 |
| Michigan | | | Mud | 92 | 0 | 0 |
| Michigan | | | Air | 92 | 0 | 0 |
| Michigan | | | Unknown | 92 | 0 | 0 |
| Michigan | | | Mud | 93 | 0 | 0 |
| Michigan | | | Air | 93 | 0 | 0 |
| Michigan | | | Unknown | 93 | 0 | 0 |
| TOTAL Michigan Basin All | | | | | 289,864 | 5,027 |
| TOTAL Michigan Basin Mud | | | | | 274,708 | 4,610 |
| TOTAL Michigan Basin Air | | | | | 15,156 | 417 |
| TOTAL Michigan Basin Unknown | | | | | 0 | 0 |
| **Percentage Drilled with Air** | | | **5.23%** | | | |

| BASIN | REGION | PROVINCE | FLUID TYPE | YEAR WELL TD | TOTAL FOOTAGE DRILLED | TOTAL HOURS REPORTED |
|---|---|---|---|---|---|---|
| Mississippi | 6 | 114 | Mud | 91 | 939,513 | 38,192 |
| Mississippi | 6 | 114 | Air | 91 | 0 | 0 |
| Mississippi | 6 | 114 | Unknown | 91 | 0 | 0 |
| Mississippi | 6 | 114 | Mud | 92 | 1,087,046 | 38,997 |
| Mississippi | 6 | 114 | Air | 92 | 32,126 | 787 |
| Mississippi | 6 | 114 | Unknown | 92 | 0 | 0 |
| Mississippi | 6 | 114 | Mud | 93 | 190,580 | 7,532 |
| Mississippi | 6 | 114 | Air | 93 | 6,500 | 88 |
| Mississippi | 6 | 114 | Unknown | 93 | 0 | 0 |
| TOTAL Mississippi Basin All | | | | | 2,255,765 | 85,596 |
| TOTAL Mississippi Basin Mud | | | | | 2,217,139 | 84,721 |
| TOTAL Mississippi Basin Air | | | | | 38,626 | 875 |
| TOTAL Mississippi Basin Unknown | | | | | 0 | 0 |
| **Percentage Drilled with Air** | | | **1.71%** | | | |
| North Slope | | | Mud | 91 | 1,314,267 | 16,006 |
| North Slope | | | Air | 91 | 0 | 0 |
| North Slope | | | Unknown | 91 | 46,266 | 0 |
| North Slope | | | Mud | 92 | 1,170,900 | 12,483 |
| North Slope | | | Air | 92 | 0 | 0 |
| North Slope | | | Unknown | 92 | 0 | 0 |
| North Slope | | | Mud | 93 | 331,634 | 3,693 |
| North Slope | | | Air | 93 | 0 | 0 |
| North Slope | | | Unknown | 93 | 7,000 | 0 |
| TOTAL North Slope Basin All | | | | | 2,870,067 | 32,182 |
| TOTAL North Slope Basin Mud | | | | | 2,816,801 | 32,182 |
| TOTAL North Slope Basin Air | | | | | 0 | 0 |
| TOTAL North Slope Basin Unknown | | | | | 53,266 | 0 |
| **Percentage Drilled with Air** | | | **0.00%** | | | |

| BASIN | REGION | PROVINCE | FLUID TYPE | YEAR WELL TD | TOTAL FOOTAGE DRILLED | TOTAL HOURS REPORTED |
|---|---|---|---|---|---|---|
| Other | | | Mud | 91 | 696,126 | 21,754 |
| Other | | | Air | 91 | 112,636 | 3,039 |
| Other | | | Unknown | 91 | 58,706 | 1,034 |
| Other | | | Mud | 92 | 611,328 | 18,234 |
| Other | | | Air | 92 | 40,430 | 1,420 |
| Other | | | Unknown | 92 | 32,300 | 0 |
| Other | | | Mud | 93 | 82,597 | 2,092 |
| Other | | | Air | 93 | 0 | 0 |
| Other | | | Unknown | 93 | 0 | 0 |
| TOTAL Other Basins All | | | | | 1,634,123 | 47,573 |
| TOTAL Other Basins Mud | | | | | 1,390,051 | 42,080 |
| TOTAL Other Basins Air | | | | | 153,066 | 4,459 |
| TOTAL Other Basins Unknown | | | | | 91,006 | 1,034 |
| **Percentage Drilled with Air** | | | **9.37%** | | | |
| Permian | 5 | 107 | Mud | 91 | 11,601,273 | 375,888 |
| Permian | 5 | 107 | Air | 91 | 727,726 | 17,220 |
| Permian | 5 | 107 | Unknown | 91 | 49,667 | 181 |
| Permian | 5 | 107 | Mud | 92 | 9,418,456 | 275,960 |
| Permian | 5 | 107 | Air | 92 | 1,056,442 | 22,829 |
| Permian | 5 | 107 | Unknown | 92 | 10,500 | 0 |
| Permian | 5 | 107 | Mud | 93 | 1,913,909 | 62,882 |
| Permian | 5 | 107 | Air | 93 | 151,933 | 4,932 |
| Permian | 5 | 107 | Unknown | 93 | 0 | 0 |
| TOTAL Permian Basin All | | | | | 24,929,906 | 759,892 |
| TOTAL Permian Basin Mud | | | | | 22,933,638 | 714,730 |
| TOTAL Permian Basin Air | | | | | 1,936,101 | 44,981 |
| TOTAL Permian Basin Unknown | | | | | 60,167 | 181 |
| **Percentage Drilled with Air** | | | **7.77%** | | | |

| BASIN | REGION | PROVINCE | FLUID TYPE | YEAR WELL TD | TOTAL FOOTAGE DRILLED | TOTAL HOURS REPORTED |
|---|---|---|---|---|---|---|
| Powder River | 4 | 101 | Mud | 91 | 2,298,587 | 66,065 |
| Powder River | 4 | 101 | Air | 91 | 124,932 | 3,850 |
| Powder River | 4 | 101 | Unknown | 91 | 12,168 | 506 |
| Powder River | 4 | 101 | Mud | 92 | 3,400,079 | 94,033 |
| Powder River | 4 | 101 | Air | 92 | 204,051 | 5,963 |
| Powder River | 4 | 101 | Unknown | 92 | 9,361 | 193 |
| Powder River | 4 | 101 | Mud | 93 | 604,079 | 15,108 |
| Powder River | 4 | 101 | Air | 93 | 0 | 0 |
| Powder River | 4 | 101 | Unknown | 93 | 0 | 0 |
| TOTAL Powder River Basin All | | | | | 6,653,257 | 185,718 |
| TOTAL Powder River Basin Mud | | | | | 6,302,745 | 175,206 |
| TOTAL Powder River Basin Air | | | | | 328,983 | 9,813 |
| TOTAL Powder River Basin Unknown | | | | | 21,529 | 699 |
| **Percentage Drilled with Air** | | | **4.94%** | | | |
| San Joaquin | 2 | 74 | Mud | 91 | 699,676 | 13,758 |
| San Joaquin | 2 | 74 | Air | 91 | 81,206 | 1,909 |
| San Joaquin | 2 | 74 | Unknown | 91 | 0 | 0 |
| San Joaquin | 2 | 74 | Mud | 92 | 510,331 | 8,873 |
| San Joaquin | 2 | 74 | Air | 92 | 0 | 0 |
| San Joaquin | 2 | 74 | Unknown | 92 | 0 | 0 |
| San Joaquin | 2 | 74 | Mud | 93 | 90,760 | 1,920 |
| San Joaquin | 2 | 74 | Air | 93 | 0 | 0 |
| San Joaquin | 2 | 74 | Unknown | 93 | 0 | 0 |
| TOTAL San Joaquin Basin All | | | | | 1,381,973 | 26,460 |
| TOTAL San Joaquin Basin Mud | | | | | 1,300,767 | 24,551 |
| TOTAL San Joaquin Basin Air | | | | | 81,206 | 1,909 |
| TOTAL San Joaquin Basin Unknown | | | | | 0 | 0 |
| **Percentage Drilled with Air** | | | **5.88%** | | | |

| BASIN | REGION | PROVINCE | FLUID TYPE | YEAR WELL TD | TOTAL FOOTAGE DRILLED | TOTAL HOURS REPORTED |
|---|---|---|---|---|---|---|
| Texas Gulf | | | Mud | 91 | 11,884,297 | 371,182 |
| Texas Gulf | | | Air | 91 | 22,649 | 1,355 |
| Texas Gulf | | | Unknown | 91 | 647,653 | 1,596 |
| Texas Gulf | | | Mud | 92 | 10,193,879 | 301,106 |
| Texas Gulf | | | Air | 92 | 30,218 | 1,042 |
| Texas Gulf | | | Unknown | 92 | 109,694 | 812 |
| Texas Gulf | | | Mud | 93 | 1,953,208 | 61,465 |
| Texas Gulf | | | Air | 93 | 0 | 0 |
| Texas Gulf | | | Unknown | 93 | 19,170 | 76 |
| TOTAL Texas Gulf All | | | | | 24,860,768 | 738,634 |
| TOTAL Texas Gulf Mud | | | | | 24,031,384 | 733,753 |
| TOTAL Texas Gulf Air | | | | | 52,867 | 2,397 |
| TOTAL Texas Gulf Unknown | | | | | 776,517 | 2,484 |
| **Percentage Drilled with Air** | | | **0.21%** | | | |
| Uintah | 3 | 86 | Mud | 91 | 497,018 | 19,656 |
| Uintah | 3 | 86 | Air | 91 | 367,226 | 10,720 |
| Uintah | 3 | 86 | Unknown | 91 | 11,840 | 258 |
| Uintah | 3 | 86 | Mud | 92 | 574,635 | 22,058 |
| Uintah | 3 | 86 | Air | 92 | 784,632 | 24,044 |
| Uintah | 3 | 86 | Unknown | 92 | 53,304 | 1,191 |
| Uintah | 3 | 86 | Mud | 93 | 78,441 | 4,479 |
| Uintah | 3 | 86 | Air | 93 | 56,425 | 1,863 |
| Uintah | 3 | 86 | Unknown | 93 | 0 | 0 |
| TOTAL Uintah Basin All | | | | | 2,423,521 | 84,269 |
| TOTAL Uintah Basin Mud | | | | | 1,150,094 | 46,193 |
| TOTAL Uintah Basin Air | | | | | 1,208,283 | 36,627 |
| TOTAL Uintah Basin Unknown | | | | | 65,144 | 1,449 |
| **Percentage Drilled with Air** | | | **49.86%** | | | |

| BASIN | REGION | PROVINCE | FLUID TYPE | YEAR WELL TD | TOTAL FOOTAGE DRILLED | TOTAL HOURS REPORTED |
|---|---|---|---|---|---|---|
| Williston | 4 | 94 | Mud | 91 | 1,899,340 | 61,723 |
| Williston | 4 | 94 | Air | 91 | 81,908 | 2,389 |
| Williston | 4 | 94 | Unknown | 91 | 9,350 | 230 |
| Williston | 4 | 94 | Mud | 92 | 1,555,125 | 52,160 |
| Williston | 4 | 94 | Air | 92 | 96,816 | 2,966 |
| Williston | 4 | 94 | Unknown | 92 | 0 | 0 |
| Williston | 4 | 94 | Mud | 93 | 342,485 | 13,119 |
| Williston | 4 | 94 | Air | 93 | 0 | 0 |
| Williston | 4 | 94 | Unknown | 93 | 0 | 0 |
| TOTAL Williston Basin All | | | | | 3,985,024 | 132,587 |
| TOTAL Williston Basin Mud | | | | | 3,796,950 | 127,002 |
| TOTAL Williston Basin Air | | | | | 178,724 | 5,355 |
| TOTAL Williston Basin Unknown | | | | | 9,350 | 230 |
| **Percentage Drilled with Air** | | | **4.48%** | | | |
| Total US - All Fluids | | | | | 143,314,854 | 4,446,183 |
| Total US - Mud | | | | | 122,940,647 | 4,006,743 |
| Total US - Air | | | | | 18,169,646 | 420,466 |
| Total US - Other | | | | | 2,204,561 | 18,974 |
| **Percentage Drilled with Air** | | | **12.68%** | | | |
| Totals without Gulf of Mexico and North Slope | | | | | | |
| Total US - All Fluids | | | | | 110,870,331 | 3,509,008 |
| Total US - Mud | | | | | 91,452,218 | 3,075,691 |
| Total US - Air | | | | | 18,116,779 | 418,069 |
| Total US - Other | | | | | 1,301,334 | 15,248 |
| **Percentage Drilled with Air** | | | **16.34%** | | | |

DEPARTMENT OF THE INTERIOR
UNITED STATES GEOLOGICAL SURVEY

OPEN-FILE REPORT 90 - 614


Generalized index of the onshore conterminous United States showing the regional boundaries. Region numbers and names are:

2. Pacific Coast
3. Colorado Plateau and Basin and Range
4. Rocky Mountains and Northern Great Plains
5. West Texas and Eastern New Mexico
6. Gulf Coast
7. Mid-Continent
8. Eastern Interior
9. Atlantic Coast

Regions and provinces were established to provide units for systematic appraisal of oil and gas resources. The Regions coincide in part with major geographic elements and were divided into provinces. Province boundaries were based on natural geologic features and may include a single dominant structural element or a number of contiguous units. These boundaries follow State and county lines where possible, to facilitate the use of production, reserve, and other data reported for political units by various State and Federal agencies and private compilers. Provinces were named for a structural, physiographic, or geographic feature within the province.

Areas of State, but not Federal, waters are included in the appraisal of the adjacent onshore province. The boundaries of State waters are three nautical miles offshore for the Pacific and Atlantic coasts and for the Alabama coast of the Gulf of Mexico. Louisiana and Mississippi have decreed State water boundaries that vary slightly from three nautical miles. For the Texas and Florida coasts of the Gulf of Mexico the boundaries of State waters are three marine leagues (10.36 statute miles) offshore.

SCALE 1:5 000 000

100 0 100 200 300 400 500 MILES

100 0 100 200 300 400 500 KILOMETERS

CONTOUR INTERVAL FEET
DATUM IS MEAN SEA LEVEL