PNE-MHF-1

RIO BLANCO

MASSIVE HYDRAULIC FRACTURE

PROJECT DEFINITION

MASTER

C·E·R GEONUCLEAR
LAS VEGAS, NEVADA

DISCLAIMER

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1. INTRODUCTION

1.1 GENERAL

A recent Federal Power Commission feasibility study(1) assessed the possibility of economically producing gas from three Rocky Mountain basins; the Green River Basin in Wyoming; the Piceance Basin in Colorado; and the Uinta Basin in Utah. These basins have potentially productive horizons 2,000 to 4,000 feet thick containing an estimated total of 600 trillion cubic feet of gas in place. However, the producing sands are of such low permeability and heterogeneity that, in general, conventional methods have failed to develop these basins economically. The Natural Gas Technology Task Force, responsible for preparing the referenced feasibility study, determined that if effective well stimulation methods for these basins can be developed, it might be possible to recover 40 to 50 percent of the gas in place.

The Task Force pointed out two possible underground fracturing methods: 1) nuclear explosive fracturing, and 2) massive hydraulic fracturing (MHF). They argued that once technical viability has been demonstrated, and with adequate economic incentives, there should be no reason why one or even both of these approaches could not be employed, thus making a major contribution toward correcting the energy deficiency of the Nation.

Two nuclear explosive fracturing projects have been fielded in the Piceance Basin (Figure 1); Project Rulison,(2) conducted on September 10, 1969, and Project Rio Blanco,(3) conducted on May 17, 1973. CER Geonuclear Corporation was Project Manager for both experiments.

While CER's previous efforts have involved the use of nuclear explosives, its major goal is to develop a technology which will produce gas by the best and most economical means available. For that reason, CER proposed a joint Government-industry demonstration program to test the relative effectiveness of massive hydraulic fracturing(4) of the same formation and producing horizons that were stimulated by the Rio Blanco nuclear project.

Piceance Basin, the location of the MHF project, is a sparsely populated area in northwest Colorado. The nearest commercial airport is at Grand Junction, Colorado, and the closest railroad station is at Rifle, Colorado (Figure 2). There are paved roads within 5 miles of the site and commercial power lines within 1 mile of the site.

The general basinal stratigraphy is shown in the east-west cross section in Figure 3. The MHF well (RB-MHF-3) is located on the gently dipping western flank of the Basin.

The gas bearing Fort Union and Mesaverde sandstones are separated from the rich oil shales found in the Parachute Creek Member of the Green River

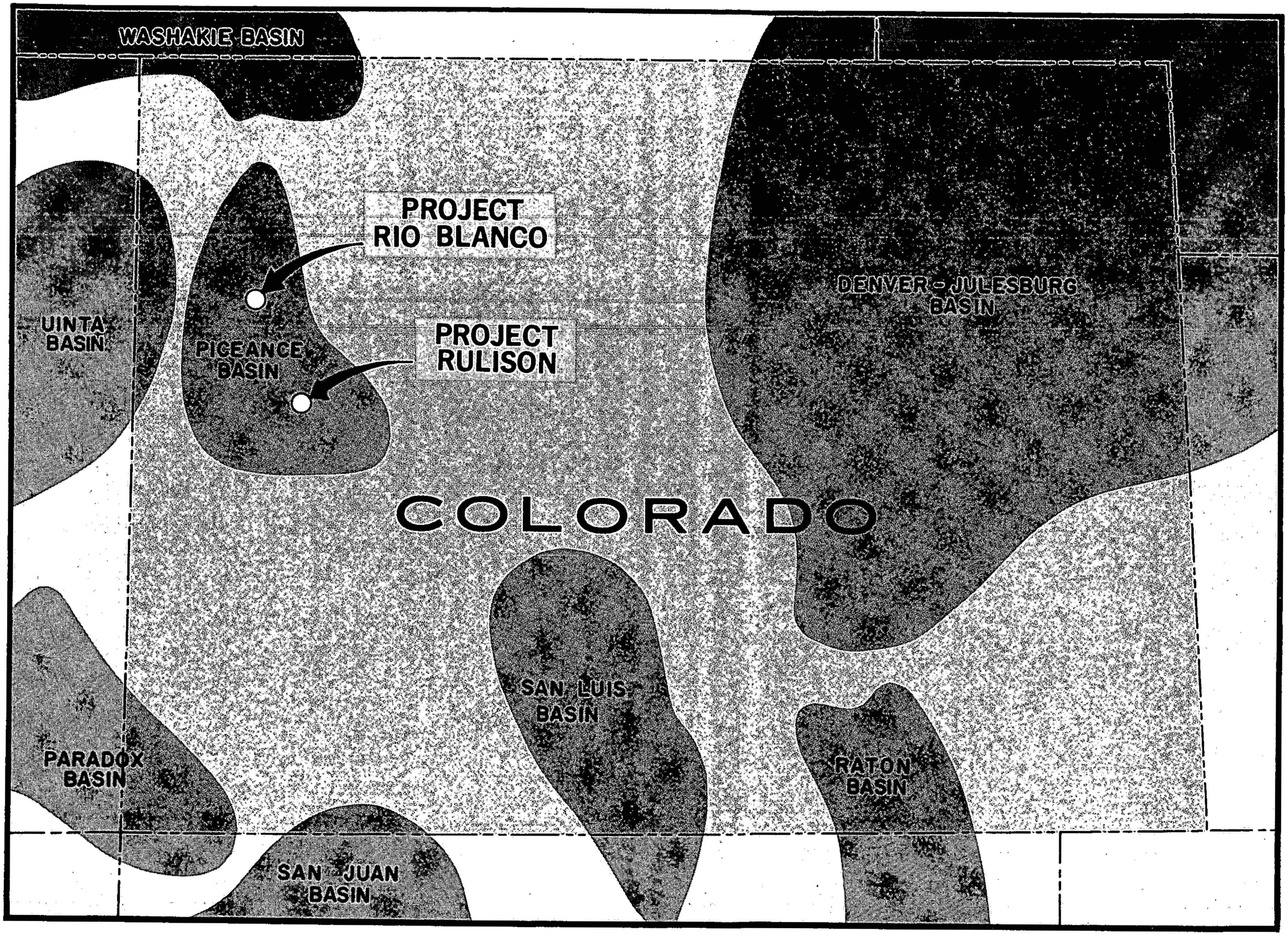

Figure 1. Nuclear fracturing projects.

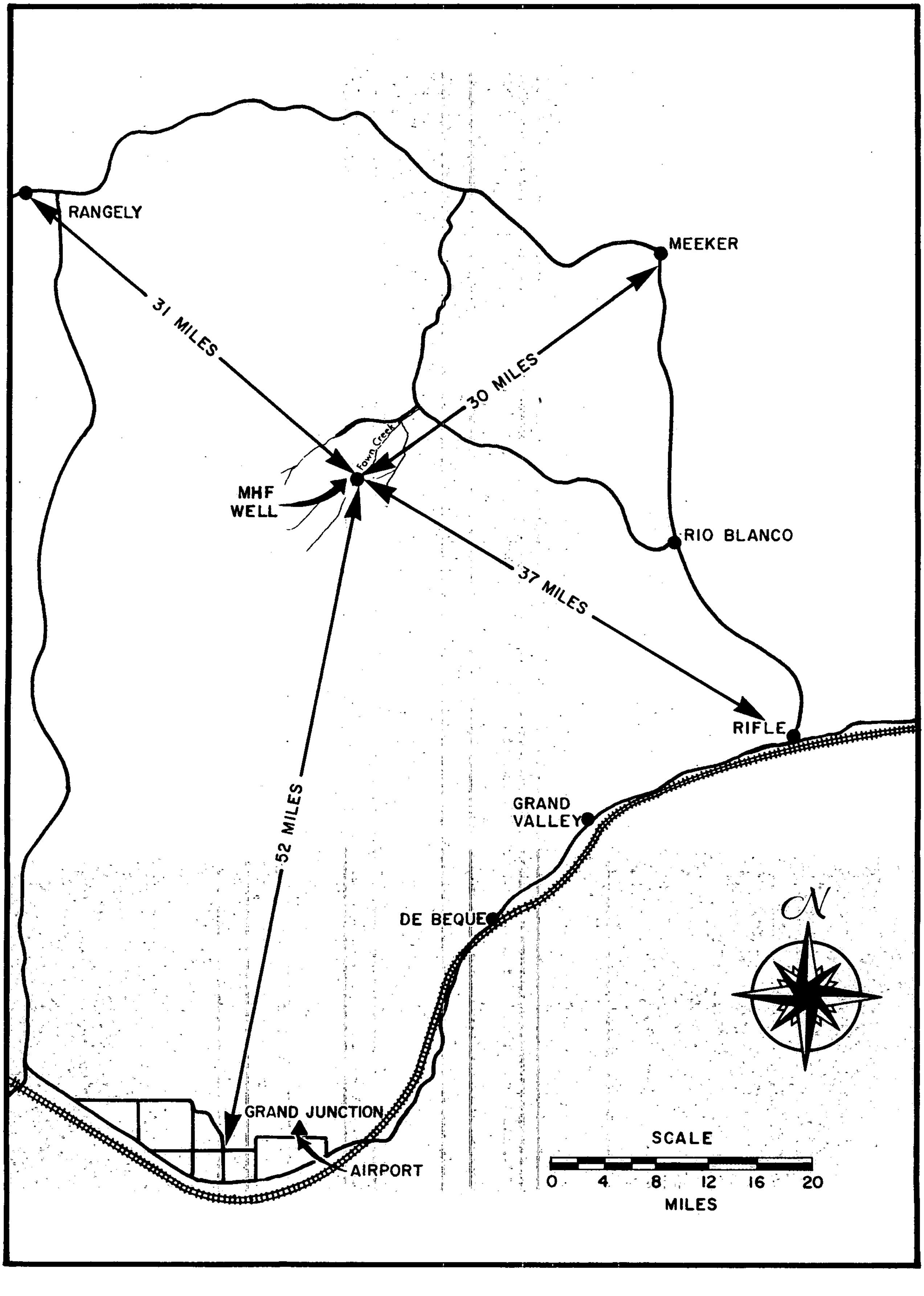

Figure 2. MHF site location.

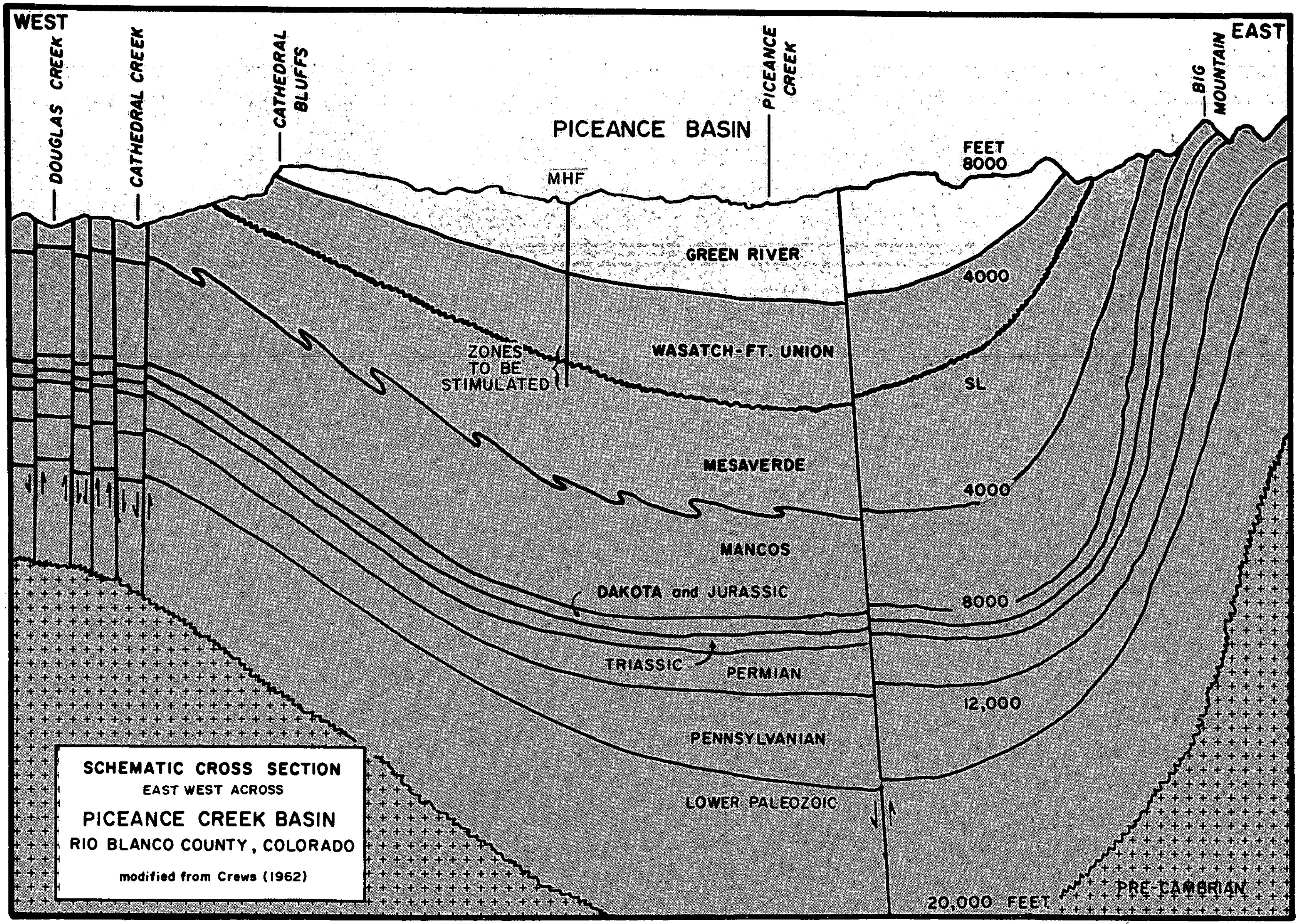

Figure 3. General stratigraphy of the Piceance Basin.

Formation by about 3,000 ft of Wasatch Formation shale.[5] The deepest known aquifer in the area, the "B" Zone, occurs in the Parachute Creek Member below the Mahogany Zone. The "B" aquifer contains brackish water and is separated from the gas sands by more than 3,000 ft of shale.[6]

The gas bearing sandstones in the MHF project area are estimated to contain 74 billion standard cubic feet of gas per section. This estimate is based on the assumption that the reservoir rock properties encountered by the RB-MHF-3 Well will be similar to those calculated for the Rio Blanco Nuclear Well, RB-E-01.

The RB-E-01 gas reservoirs[7] to be stimulated are a sequence of lenticular sandstones of fluvial origin located in the Fort Union and upper part of the Mesaverde formations. A generalized cross section extending through the Fawn Creek Government Number 1 Well and the RB-E-01 Well is presented in Figure 4. As illustrated, the bulk of the rock is shale with only a few intermittent sandbodies occurring above the middle of the Fort Union Formation.

The Fort Union sandstones appear to have better porosity, permeability, and continuity than the Mesaverde. More detailed descriptions appear in References 8 and 9.

The average gross thickness of the Fort Union sandstones is 300 ft in the proposed project area. Based on an analysis of logs and cores from a number of wells in the area, the Fort Union median porosity is 13.5 percent, and a water saturation of 60 percent of pore space seems to be representative of the gas sands. Permeabilities to gas in the Fort Union Formation calculated from the results of production tests on Fawn Creek Government Number 1 Well and another 6 miles to the east (Scandard Draw Number 1 Well), vary from 0.016 to 0.059 millidarcies (md).[9]

The gross upper Mesaverde sand thickness in the proposed project area averages 350 ft. Core and log analysis indicates that a porosity of 10.5 percent and a water saturation of 60 percent of pore space are reasonable average values for Mesaverde gas sands. Production tests on the Scandard Draw Number 1 Well yielded a calculated Mesaverde permeability of 0.008 md.[9]

The specific reservoir properties for RB-E-01 across the projected 1,300-ft fractured interval are summarized below.

Thickness of gross fractured interval	1,300 ft
Depth to top of fractured interval	5,530 ft (GL)
Depth to base of fractured interval	6,830 ft (GL
Net effective pay in gross fractured interval	408 ft
Porosity (average)	9.6%
Water saturation (average)	56.5%

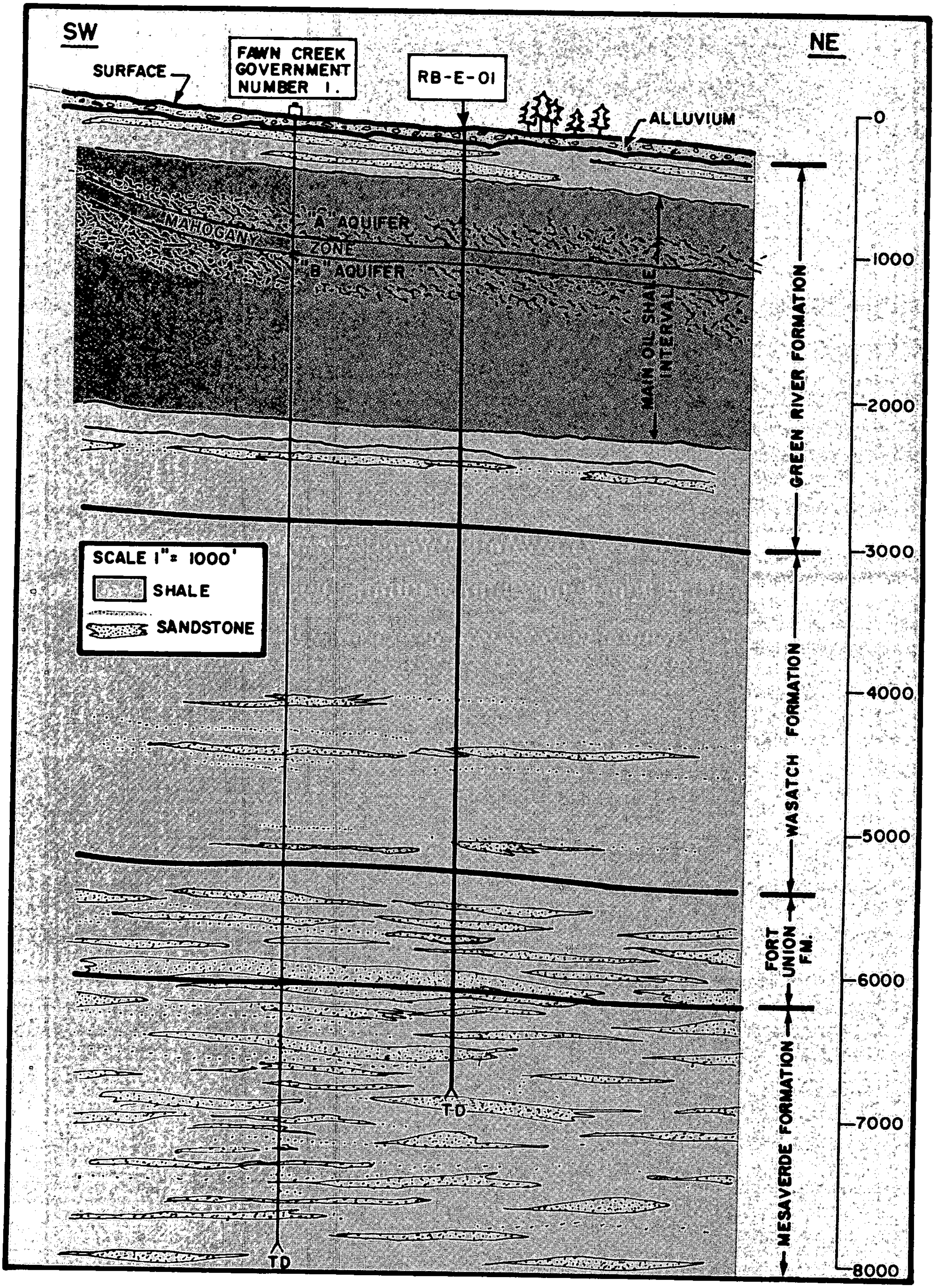

Figure 4. General stratigraphy, RB-E-01 and Fawn Creek Government No. 1 Well.

Mean pressure	2,600 psia
Mean temperature	205°
Gas diviation factor	0.92
Gas specific gravity (air = 1.0)	0.65
Gas pressure base	14.7 psia
Gas temperature base	60° F
Gas compressibility	155 SCF/ft^3
Gas in place in fractured interval	74 BSCF/section
Average permeability	0.019 md

The average permeability is based on the limited testing in Fawn Creek Government Number 1 Well and calculations from logs and cores from RB-E-01.

Thus, the size of the potential reserves, the similarity of the gas bearing sand to that found in other Rocky Mountain basins, and its proximity to nuclear stimulation projects make the proposed location an excellent site for a MHF experiment.

1.2 PROJECT HISTORY

A Senate hearing conducted by Senator Haskell (Colorado) on Project Rio Blanco prior to the nuclear detonation and informal discussions with participants on the Natural Gas Technology Task Force following the Rio Blanco nuclear detonation led to CER submitting, on August 9, 1973, to the Atomic Energy Commission (AEC), the Bureau of Mines (BuMines), and several companies, a proposal for a joint Government-industry massive hydraulic fracturing experiment. The proposal was favorably received and an organizational meeting was held in Dallas, Texas on September 14, 1973.* A Review Committee was formed at the Dallas meeting and the first Committee meeting was held in Las Vegas, Nevada on October 1, 1973. This meeting produced a Well and Fracture Design Committee, and Analysis Design Committee, and a letter agreement which defined the modus operandi for the initial phase of the MHF project.

Ten companies formally responded and became the primary industrial contributors. They provided technical expertise at their own cost which contributed to the design of the experiment. The Government (represented by the AEC and BuMines) also agreed to provide technical and financial support for the initial phases of the project. The AEC and CER subsequently signed Contract AT(26-1)-623 for the project. The contract provides that CER will serve as Project Manager and the Government will provide funding through the drilling operations.

The MHF Well and Fracture Design Committee has generated its programs through cooperative efforts on an individual and informal basis and at five

*Minutes of this and the other meetings mentioned are available from CER Geonuclear Corporation.

meetings: Dallas, Texas, December 5, 1973; New Orleans, Louisiana, February 6, 1974; Livermore, California, February 19, 1974; Las Vegas, Nevada, March 6, 1974; and Dallas, Texas, April 5, 1974.

The Analysis Design Committee and its designated subcommittees developed their program utilizing a technique similar to the Well and Fracture Design Committee. Four meetings were held during this development: Livermore, California, February 19, 1974, joint meeting with Well and Fracture Design Committee; Tulsa, Oklahoma, February 26, 1974; Las Vegas, Nevada, March 6, 1974; and Dallas, Texas, April 5, 1974. (The last two were also joint meetings with the Well and Fracture Design Committee.)

The Review Committee met in Las Vegas, Nevada, March 7, 1974, in joint session with the Well and Fracture Design and Analysis Design committees. The preliminary MHF design was presented and reviewed during this meeting.

The organizations participating in the Review Committee have been:

<u>Members</u>

Amoco Production Company
Atlantic Richfield Company
CER Geonuclear Corporation
Colorado Interstate Gas Company
Continental Oil Company
Dowell Div. of Dow Chemical Company
Equity Oil Company
Esso Production Research Company
Fuel Resources Development Company
Halliburton Services
Mobil Research and Development Corporation
U. S. Bureau of Mines

<u>Observers</u>

Ashland Oil Company
Bechtel Corporation
Cities Service Oil Company
Colorado Interstate Gas Company
Columbia Gas System Service Company
El Paso Natural Gas Company
Fuel Resources Development Company
Lawrence Livermore Laboratory
Los Alamos Scientific Laboratory
MAPCO
Pacific Gas Transmission Company
Public Service Company of Colorado

Rio Blanco Natural Gas Company
Sandia Laboratory
U. S. Atomic Energy Commission
U. S. Geological Survey
Western Oil Shale Company

The participants in the Well and Fracture Design and Analysis Design Committees have been:

Well and Fracture Design Committee

Amoco Production Company
Atlantic Richfield Company
CER Geonuclear Corporation
Continental Oil Company
Dowell Div. of Dow Chemical Company
El Paso Natural Gas Company
Equity Oil Company
Esso Production Research Company
Halliburton Services
Lawrence Livermore Laboratory
Mobil Oil Corporation
U. S. Atomic Energy Commission
U. S. Bureau of Mines

Analysis Design Committee

Amoco Production Company
Atlantic Richfield Company
CER Geonuclear Corporation
Continental Oil Company
Dowell Div. of Dow Chemical Company
El Paso Natural Gas Company
Esso Production Research Company
Equity Oil Company
Halliburton Services
Lawrence Livermore Laboratory
Los Alamos Scientific Laboratory
Mobil Oil Corporation
Sandia Laboratories
U. S. Atomic Energy Commission
U. S. Bureau of Mines

This Project Definition contains the details of the design developed as a result of the technical committees' work and comments and suggestions from the Review Committee. *

*Consists of individuals from Government and industrial organizations signatory to the MHF project Letter of Agreement.

2. MASSIVE HYDRAULIC FRACTURE DESIGN

2.1 WELL DESIGN

2.1.1 Drilling Program

RB-MHF-3 will be drilled approximately 1,765 ft west of east line and 2,893 ft north of south line of S11, T3S, R98W. See Figure 5 for surveyed plot of this location.

A 30-in. conductor pipe will be set through the alluvium into bedrock, approximately 60 ft, and cemented to surface. A 15-in. hole will be drilled to 300 ft. This hole will be opened to 26 in. and 16-in. casing run to 300 ft. The casing will be cemented to surface. A 15-in. hole will be drilled with a fresh mud system to 5,600 ft. Electric logs and a directional survey will be run from surface to 5,600 ft. The 10-3/4-in. casing will be set at 5,600 ft and cemented to surface in two stages (Figure 6).

Air compressors will be moved in and rigged to drill from 5,600 ft to 6,900 ft. Up to nine 60-ft cores will be cut and up to eight drill stem tests will be run before reaching total depth. Neutron, density, and gamma logs will be run from 5,600 ft to 6,900 ft in the gas-filled hole. A flowing temperature survey will also be run. The hole will be filled with mud and electric logs will be run from 5,600 ft to 6,900 ft. After a directional survey, the 7-in. casing will be set at 6,900 ft and cemented from 6,900 ft to 4,650 ft.

A 60-ft, 2-5/8-in. oriented core will be drilled from 6,920 ft to 6,980 ft with a 6-in. diamond core bit. A small fracture treatment will be run. A downhole televiewer and/or impression packer will be run to try to determine fracture orientation. The hole will be plugged back to 6,880 ft and a 10,000-psi working pressure wellhead will be installed. The rig will be dismantled and moved off location.

If, after drilling through the Fort Union sands (6,240 ft), an analysis of logs, core, and drill stem tests indicates that this well would be unattractive for massive fracturing (and after consultation with the Review Committee), cement plugs could be set and the well abandoned.

2.1.2 Formation Tops

The projected formation tops at the RB-MHF-3 location are as follows (surveyed ground level is 6,517 ft):

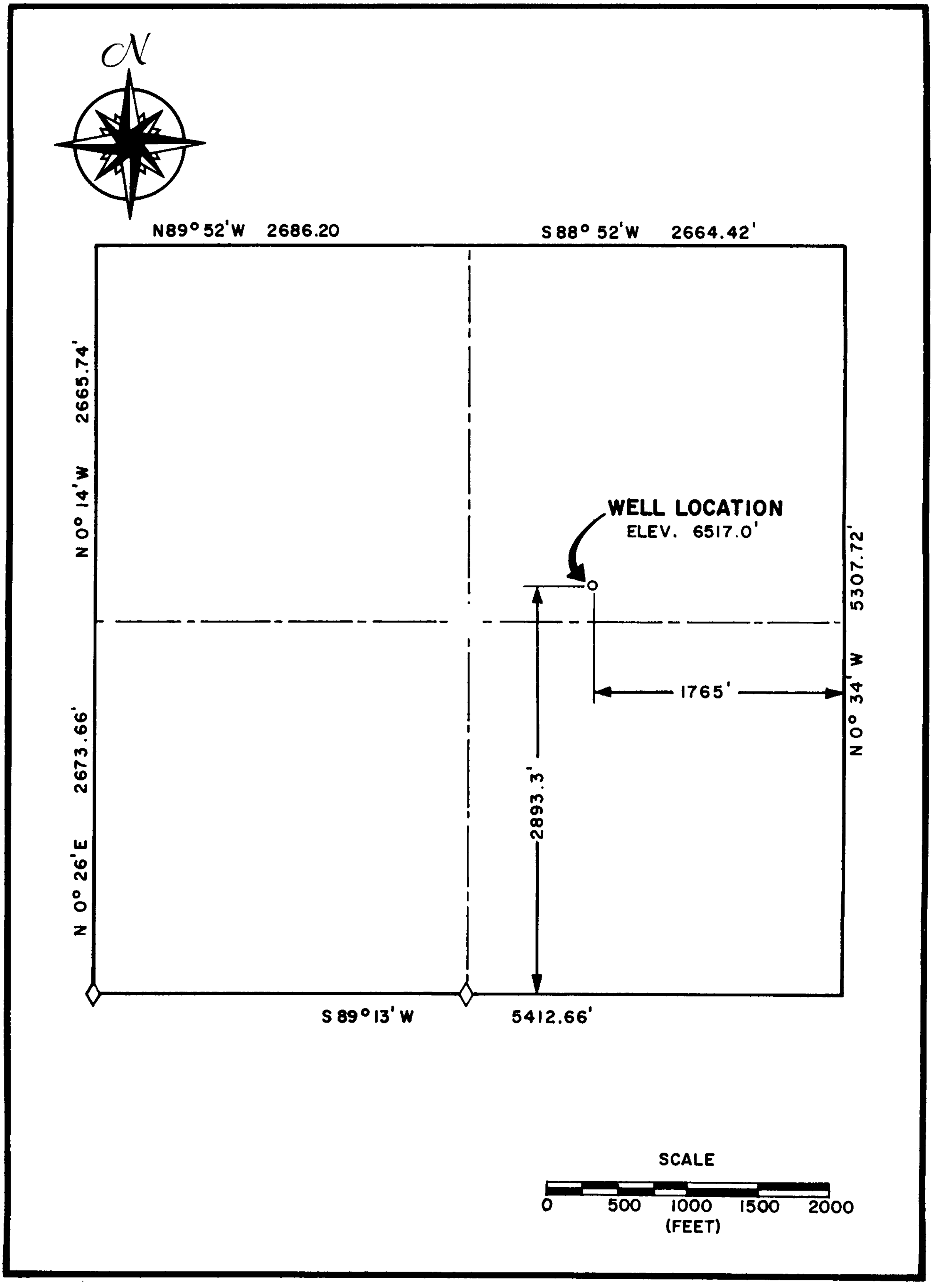

Figure 5. Surveyed well location.

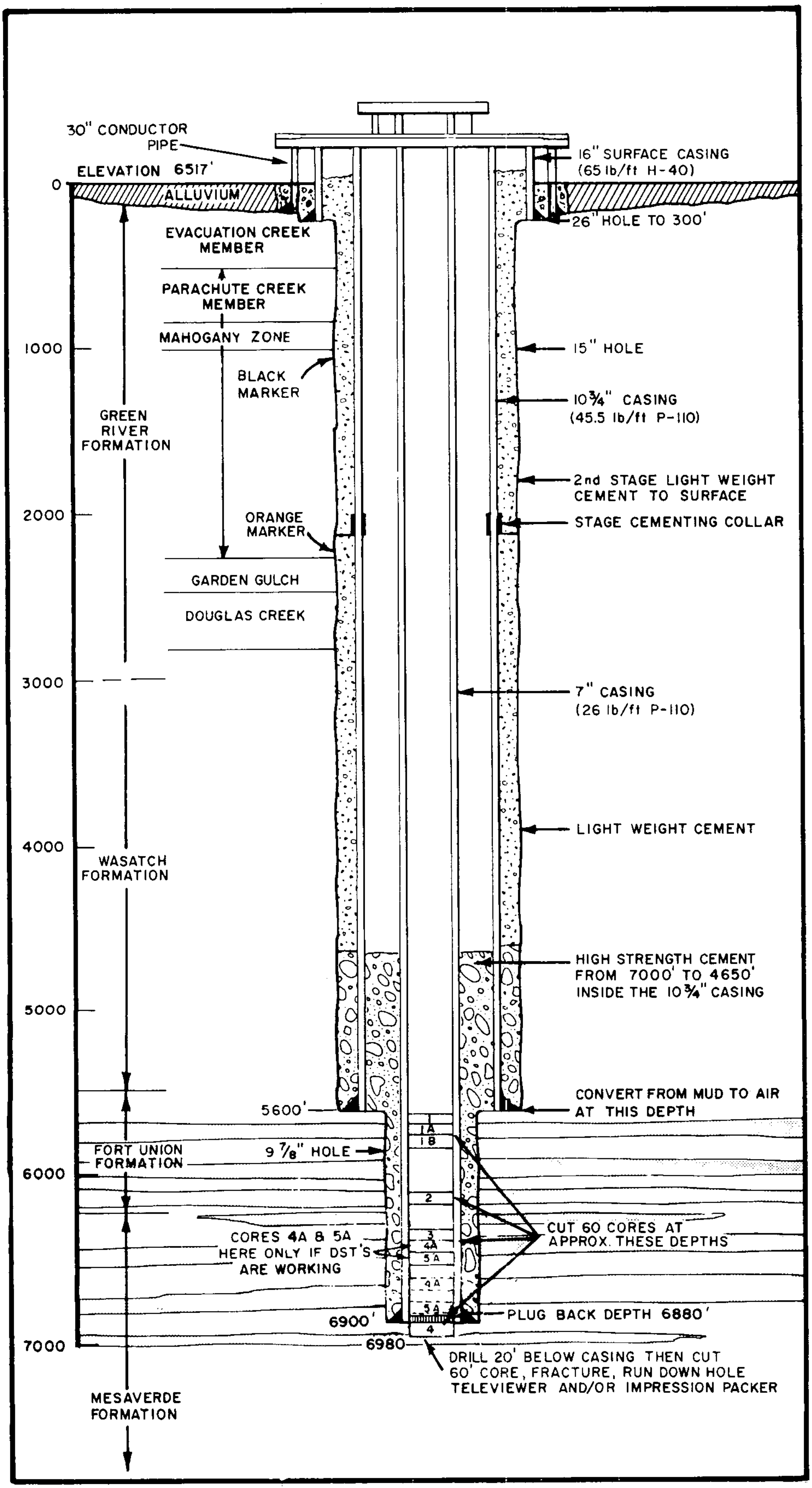

Figure 6. Drilling program.

Formation	Drilled Depth (ft)	Elevation From Mean Sea Level (ft)
Alluvium	Surface	+6,517
Green River	60	
Evacuation Creek Member	60	+6,457
Parachute Creek Member	500	+6,017
Mahogany Marker	880	+5,637
Black Marker	1,000	+5,517
Orange Marker	2,240	+4,277
Wasatch	2,920	+3,597
Fort Union Sandstone	5,440	+1,077
Mesaverde	6,240	+277
Total Depth	6,980	-463
Plug Back Depth	6,880	-363

All depth measurements will reference ground level (e.g.: logging, coring, drill stem testing, drillers depth, etc.).

An accurate measurement to the rotary table will be made.

2.1.3 Surface Equipment

2.1.3.1 Wellhead

A wellhead assembly (Figure 7) will be installed upon the completion of this well. The wellhead is designed for fracturing pressures between 5,000 and 10,000 psi and production pressures up to 3,000-psi working pressure.

2.1.3.2 Blowout Preventers

A Series 900 16-in. double-gate blowout preventer and a Series 900 16-in. Grant rotating head Series 1525 blowout preventer (blind rams) are required while drilling from 300 ft to total depth.

2.1.3.3 Drilling Rig

A drilling rig capable of drilling to a total depth of 8,000 ft and having a mast and running equipment capacity that will handle 255,000 lb (air weight of 10-3/4-in. casing) is required (Figure 8).

2.1.4 Downhole Equipment

The following downhole equipment will be run in RB-MHF-3:

Casing
300 ft of H-40, 65-lb/ft, 16-in.

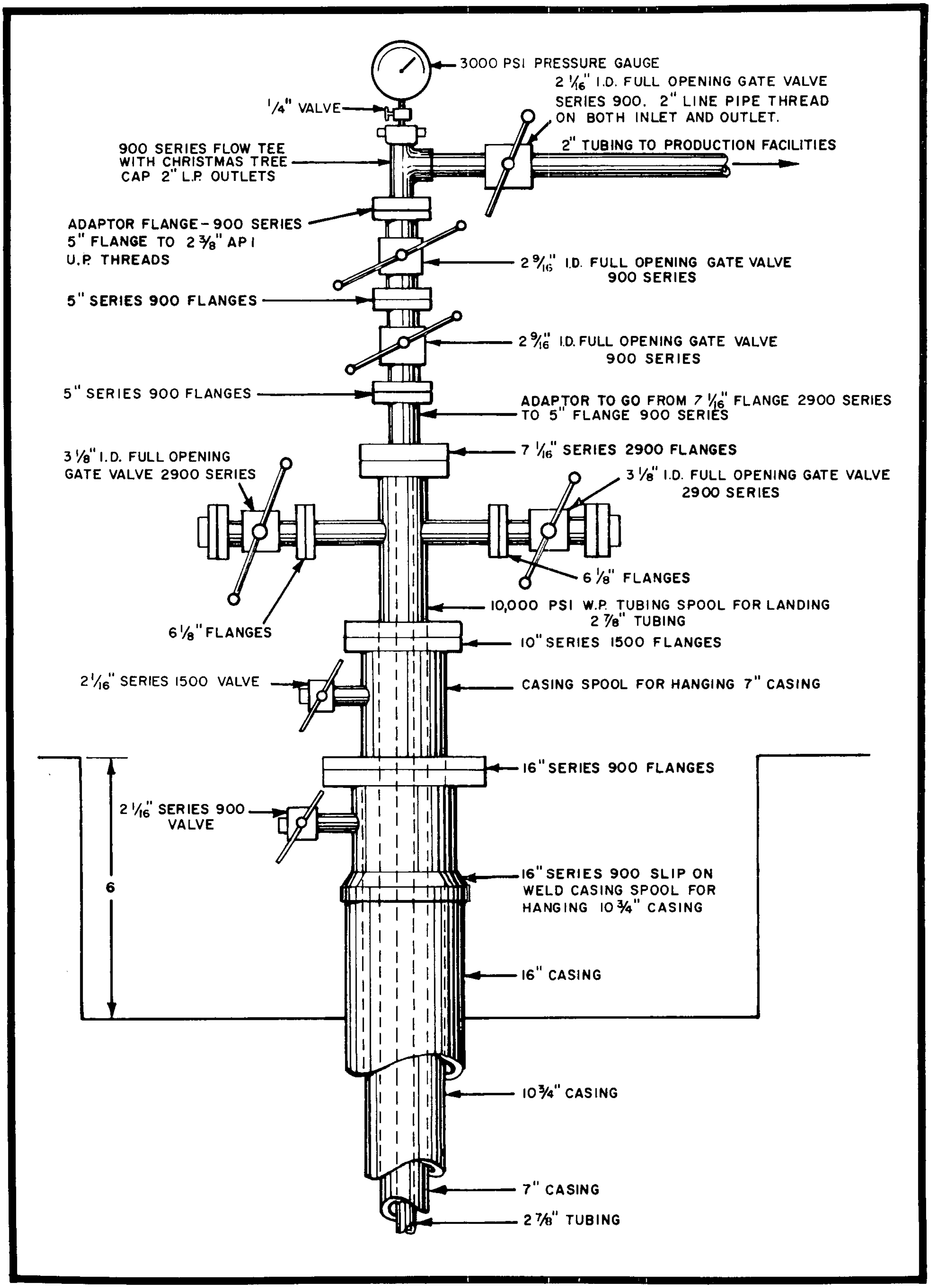

Figure 7. Wellhead assembly.

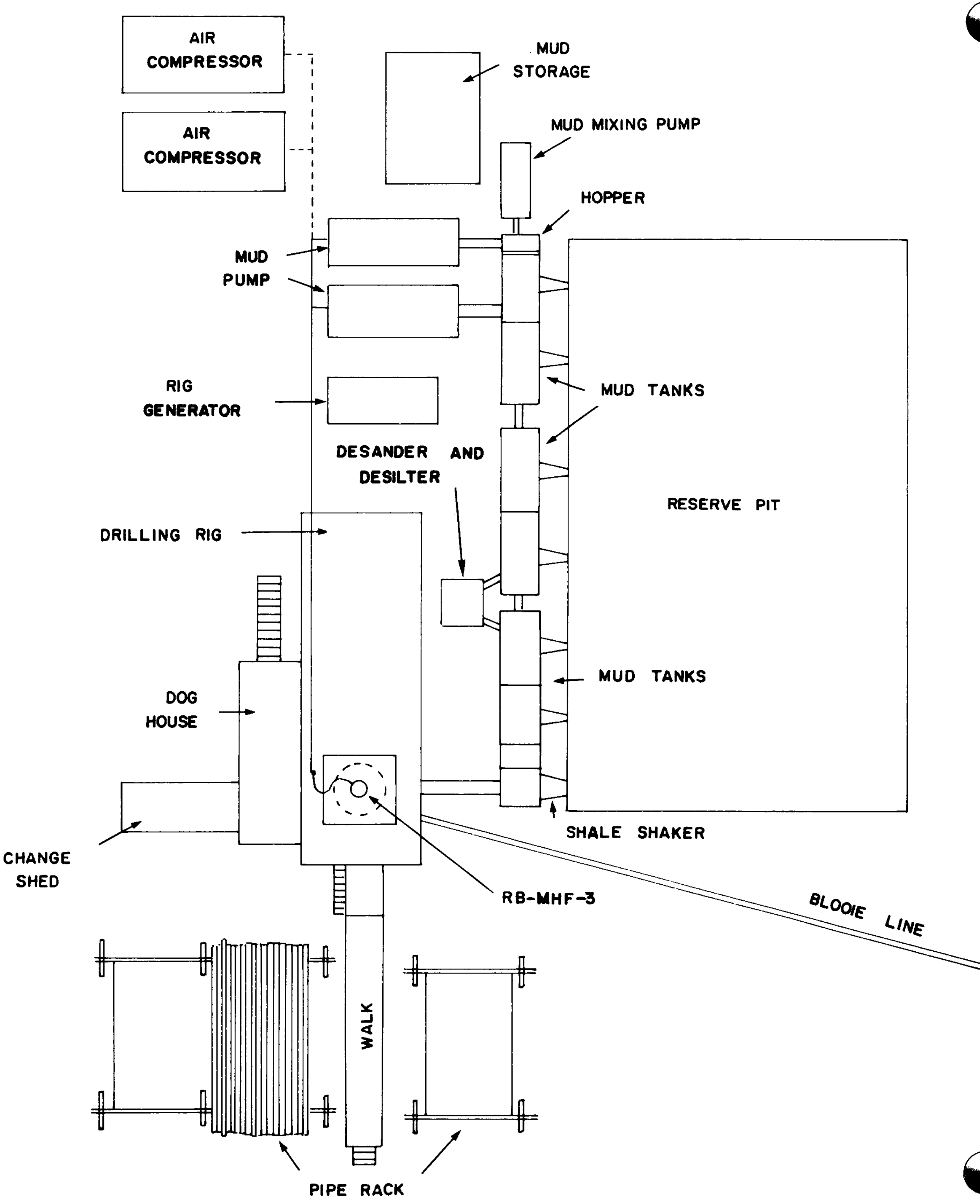

Figure 8. Drill rig layout.

5,600 ft of P-110, 45.4-lb/ft, 10-3/4-in. Buttress (1,000 ft. to be sandblasted)
(Note: This is a special mill run casing with the following properties - 80% burst is 6,600 psi, tensile failure is 1,400,000 lb, and minimum collapse is 2,610 psi.)
6,040 ft of P-110, 26.0-lb/ft, 7-in. Buttress
860 ft of P-110, 26.0-lb/ft, 7-in. (Range-2)

Casing Running and Cementing Equipment

16-in. Casing
1-guide shoe
3-centralizers
Top and bottom cement plugs

10-3/4-in. Casing
1-differential fill-up collar
1-differential fill-up shoe
1-staging collar with opening and closing plugs, top and bottom plugs
Number of centralizers will be determined from hole deviation data

7-in. Casing
1-differential fill-up collar
1-guide shoe
Top and bottom plugs
Number of centralizers will be determined from hole deviation data

Small Fracture Treatment
7,000 ft of J-55, 2-7/8-in., 6.5-lb/ft tubing
1-retrievable full hole packer for running in 7-in. casing
1-impression pack for 6-in. open hole (if borehole TV does not provide sufficient information)

2.1.5 Special Services

2.1.5.1 Mud Logging

There will be a mud logging unit on the well from the time the 10-3/4-in. casing is drilled out until total depth is reached. Information about total combustible gas and methane, liquid hydrocarbons (C6+), and oil fluorescence in drill cuttings, and lithology will be provided.

2.1.5.2 Drilling Information

A special effort will be made to provide detailed drilling parameters such as drilling rate, bit weight, rotary speed, standpipe pressure, mud properties, worn bit description, and drilling time.

A five-pen recorder will be used to measure drilling time, weight, pump pressure, rotary speed, and pump strokes.

Daily drilling reports will be kept by the contractor. All drilling time and special comments will be cited.

2.1.5.3 Gas Measurements While Drilling

A 2-in. critical flow prover will be used to measure the gas flow while drilling with air. A continuous recording two-pen recorder will be used to measure flowing pressure and temperature.

2.1.5.4 Cutting Samples

Samples will be obtained at 10-ft intervals from surface to total depth. Duplicate samples should be taken at each interval. Approximately 1 to 2 pounds should be obtained per bag. Each sample will be washed and sieved before bagging. All samples will be retained at the rig until completion of the well. After the hole is completed, one set of samples will be retained by CER until the project is completed, and one set placed on file with a commercial core and cutting library.

2.1.6 Logging Program

The following logging operations will be carried out on this well:

15-in. Hole
Dual induction-laterolog-8 (300 ft-5,600 ft)
Bore hole compensated sonic (300 ft-5,600 ft)
Gamma ray (60 ft-5,600 ft)
Four-arm caliper (300 ft-5,600 ft)
Directional survey with 50-ft stations (surface-5,600 ft)

10-3/4-in. Casing
Cement bond (surface-5,600 ft)

9-7/8-in. Gas-Filled Hole
Differential temperature (5,000 ft-6,900 ft)
Compensated neutron porosity (5,600 ft-6,900 ft)
Formation density compensated (5,600 ft-6,900 ft)
Gamma ray (5,500 ft-6,900 ft)

9-7/8-in. Mud-Filled Hole
Bore hole compensated sonic with variable density or shear velocity trace (5,600 ft-6,900 ft)
Dual induction laterolog-8 (5,600 ft-6,900 ft)
Integrated caliper (5,600 ft-6,900 ft)
Directional survey with 50-ft stations (surface to 6,900 ft)

7-in. Casing
Cement bond (4,400 ft-6,900 ft)

6-in. Hole
Induction electric (6,900 ft-6,980 ft)
Downhole televiewer (6,900 ft-6,980 ft)
Directional survey (surface-6,980 ft)

The only other logs anticipated would be the cement bond log and temperature logs. The cement bond log would be run after any squeeze job on the 10-3/4-in. and/or 7-in. casings. The temperature logs would be run after each fracture operation to check fracture height.

The logging checklist for the engineer on site is presented as Appendix A.

2.1.7 Drill Stem Testing

All drill stem tests should be run with double packers, jars, and two recorders. Each pressure recorder should have a 72-hour clock and a 0 to 3,000-psi pressure element. Once the packers are set, the tools are closed. The tools should then be opened for 4 hours and then shut-in for 24 to 72 hours depending on well conditions. The tools should then be opened and the packers released. The packers should be set as close to the interval to be tested as possible. If packer seating cannot be obtained on the first attempt, a second attempt with a different packer setting depth should be attempted. If this fails, the drill stem test of that interval should be abandoned.

2.1.8 Coring Program

The coring anticipated consists of between five and eight 60-ft cores (indicated on the RB-E-01 log shown in Figure 9). The first core barrel will be run at the top of the first Fort Union sandstone encountered after drilling out of the 10-3/4-in. casing. The coring point will be selected from drilling breaks and sample descriptions, and a complete significant sand or 180 ft of sand will be cut.

One additional Fort Union and three Mesaverde cores will be cut in the 9-7/8-in. hole. If the drill stem tests are yielding significant data, the Mesaverde cores will be cut through a 180-ft interval anticipated to be included in one fracture zone. If the drill stem tests are not yielding significant data, three 60-ft Mesaverde cores will be cut in sandy intervals at about 6,400 ft, 6,650 ft, and 6,750 ft.

A 9-7/8-in. diamond core cutter with a 6-3/4-in. diameter barrel will be used to cut a 4-1/2-in. core. The core cutter head should be the type to cut a medium hard formation.

After drilling about 20 ft below the 7-in. casing, a 60-ft core will be cut.

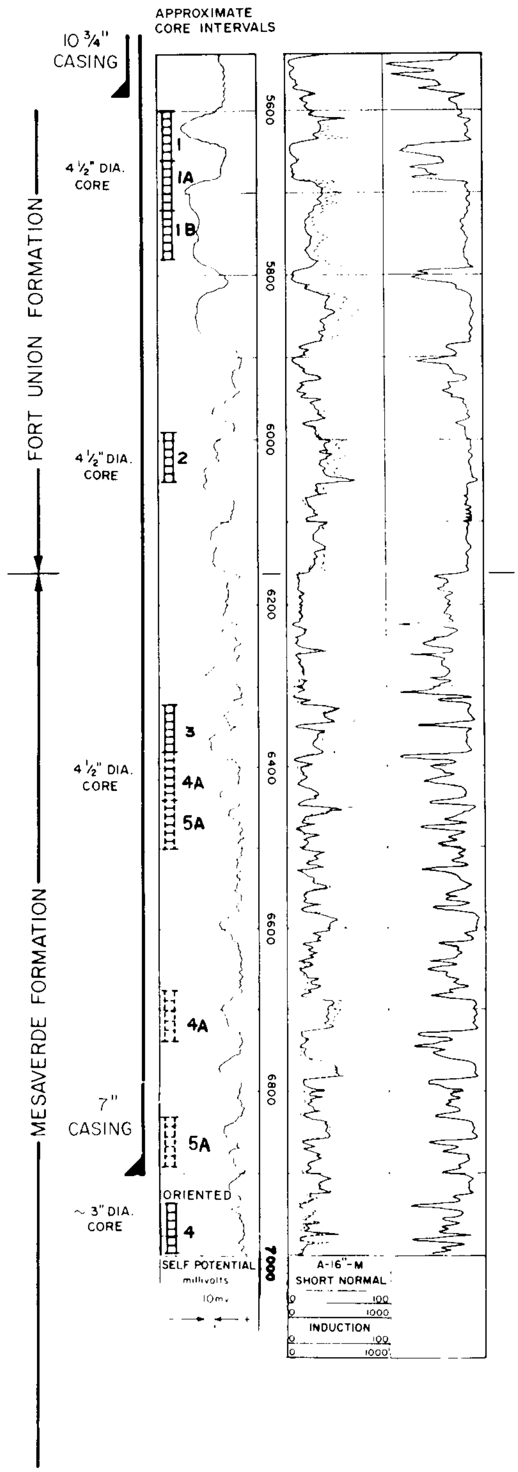

Figure 9. Core intervals.

A 6-in. diameter core head with a 4-3/4-in. diameter barrel will be used to cut a 2-5/8-in. diameter core. This core will be oriented. Representative shale sections of this core will be fitted with strain gages and the relaxation (as a function of direction) will be measured.*

All cores will be taken out of the barrel, laid out on the pipe rack, fitted together, described, and marked. Each core will be photographed (35 mm). A 2-1/2-in. to 3-in. long piece of 4-1/2-in. diameter core from each foot of sandstone cut will be broken off, bagged in plastic, labelled, boxed, and shipped (bus express or air freight) to the commercial core laboratory. The core laboratory will determine porosity, water saturation, and air permeability. After analysis, the plugs used for these determinations will be saved, along with adjacent pieces suitable for thin sectioning. The remaining 9- to 9-1/2-in. core section will be bagged boxed, and stored in Grand Junction or distributed to laboratories doing research analysis on the MHF project.

2.1.9 Mud and Air Drilling

2.1.9.1 Mud Program

The mud program from surface to 5,600 ft should be low-solids, low viscosity, light fresh-water based mud (8.5-9.0 ppg). Low solids should be maintained by the use of a fine screened shale shaker and at least one 10-cone desilter and one 10-cone desander.

2.1.9.1.1 Surface to 300 Ft. The mud down to 300 ft should be a fresh-water type with enough gelling material (bentonite) to maintain a plastic viscosity between 6 and 10 cp. Water loss control should commence with drilling out of the conductor pipe. When drilling out the cement, soda ash should be used and the mud stabilized. There are some possible zones of lost circulation between 80 to 1,500 ft. If this occurs, the mud should be immediately conditioned. Some stocks of lost circulation material should be maintained on location from the beginning of the drilling.

2.1.9.1.2 300 Ft to 5,600 Ft. From 300 ft to 5,600 ft the mud weight should be kept between 8.5 to 9.0 ppg. The plastic viscosity should be kept as low as possible but high enough to keep the hole clean (6 to 10 cp). Water loss should be maintained below 6 cc per 30 minutes and around 3 to 4 cc per 30 minutes through the Wasatch and Fort Union formations.

The mud should have an oil phase or a chemical additive to reduce torquing and bit balling. Zones of lost circulation can occur in both the Green River shale and the Wasatch. Whenever lost circulation occurs, the mud should be

*These measurements will be performed by personnel for the Bureau of Mines Morgantown Research Center.

immediately treated to reestablish full circulation. Testing of the mud (i. e.; water loss, viscosity, and other properties) should be frequent enough to ensure good mud quality at all times. The cement should be drilled out with the existing mud system which should then be discarded. The mud is to be displaced with water and the hole blown dry with air.

2.1.9.1.3 <u>5,600 Ft to 6,900 Ft.</u> Air will be used from 5,600 ft to 6,900 ft unless water production increases. If a mist system can handle the water production, it will be used to 6,900 ft. However, should the water production prove too great, an aerated mud will be used. By using air and the conventional desanding, desilting, and screening equipment, a 5.0- to 6.0-ppg mud can be maintained. Conventional gel and water loss will be used to maintain viscosity and hole stabilization.

In the event the hole is drilled dry to 6,900 ft, it will be necessary to carefully condition the dry hole prior to filling with mud. A conventional fresh water mud should be used to fill the dry hole. This should be done by running a bit down to 200 ft above total depth and pumping the mud until the hole is filled up to the bit. The bit should be raised another 200 ft and the mud pumped again. This should be continued until the mud reaches the bottom of the casing. At this position the hole should be completely filled. The bit should be lowered at 100-ft intervals and circulation established. This should be done until total depth is reached. Extreme caution should be exercised while doing this until it is certain that the hole is stable. Any bridges should be drilled and any sloughing intervals should be treated until stable. Finally, this mud should be conditioned to run logs.

2.1.9.2 Air Drilling Operation

From 5,600 ft to approximately 6,900 ft, a 9-7/8-in. hole will be drilled with air. Depending on the available equipment, the columns of water from 5,600 ft to surface must be either unloaded by a high-pressure multistage compressor or blown dry in stages by lower pressure rated compressors. Once the hole has been dried out, fluids should be kept from the well bore except when coring. It will then be necessary to inject a small amount of foam for the lubrication of the bit. If formation water is produced, the air must be converted to a mist system. However, should too much water be produced, an aerated mud system should be used with the mud weight controlled at 5 to 6 ppg.

Calculated air requirements from 5,600 ft to 6,900 ft, corrected to 5,000 ft altitude, are 1,930 MCFD to 2,045 MCFD, respectively. Therefore, 2,000 MCFD of air is required for the air drilling. This could give an average drilling rate of 15 ft/hr at an annular return velocity of 3,000 fpm.

The same air requirements would be necessary for mist drilling. However, should an aerated mud system be required, 1,500 MCFD would be required to maintain a 6.0-ppg mud at 600 GPM or 1,040 MCFD to maintain a 6.0-ppg mud at 420 GPM.

2.1.9.3 Hydraulics Program

The hydraulics program for the 15-in. hole should be optimized with consideration given to minimizing hole erosion. Caliper logs obtained from RB-E-01 show excessive hole erosion from 2,900 ft to nearly total depth.

Minimum annular velocities for the 15-in. hole with 6-5/8-in. drill pipe (Government rig) average 78-80 fpm based on sandstone particle sizes. The recommended program should try to obtain optimum hydraulics and/or impact at the bit, utilizing a large enough flow rate to clean the hole without causing excessive hole erosion.

In the event the bottom section, 5,600 ft to total depth, must be mud drilled, the same consideration should be given to designing the hydraulics program.

2.1.10 Cementing Program

2.1.10.1 Surface Pipe

The cementing of the surface pipe is from 300 ft to surface. The cement will be pumped down the 16-in. H-40 casing to surface. A top and bottom plug will be used for displacement. If the cement is not circulated to the top, a thixotropic cement should be injected from the surface. The cement and properties are as follows:

Volume and Type	750 sacks of Type G cement with 2% CaCl (fill-up plus 100% excess)	
Slurry Properties:	1.15 cu ft/sack and 15.8 lb/gal	
Curing Properties:	Compressive Strength (psi)	
(at 80°F)	8 hours	1,035 psi
	24 hours	3,385 psi

2.1.10.2 Intermediate Casing

Cementing design of the 10-3/4-in. intermediate string is based on protecting the Green River shale sequence plus having a high-strength cement covering the bottom 1,000 ft. To accomplish this, a two-stage cementing procedure is designed with the lead slurry at the bottom being a light low-strength filler-type cement and the tail slurry being a high-strength cement. The second stage is a light low-strength filler-type cement.

2.1.10.3 First Stage (5,600 ft to 2,000 ft)

Volume and Type	920 sacks of light cement (lead cement) 740 sacks of Type G cement (tail cement)

Slurry Properties:	Lead cement - 1.97 cu ft/sack, 12.4 lb/gal., 10.9 gal./sack (water) Tail cement - 1.18 cu ft/sack, 15.9 lb/gal., 5 gal./sack (water)

Curing Properties:

Compressive Strength (psi)		
(110°F) light cement	24 hours	225 psi
	72 hours	485 psi
(140°F) Type G cement	24 hours	2,940 psi
(110°F)	24 hours	3,300 psi

2.1.10.4 Second Stage (2,000 Ft to Surface)

Volume and Type: 1,200 sacks of light cement (fill-up plus 100% excess).

Slurry and Curing Properties: Same as light cement previously cited.

2.1.10.5 Production Casing

The primary design criteria for cementing the 7-in. casing is to provide a high-strength cement from 6,900 ft to 4,400 ft (about 1,200 ft within the 10-3/4-in. casing). This is to minimize the chance of breakdown while fracturing. To achieve this, special steps should be taken which are as follows:

1. Sand blast bottom 2,500 ft of 7-in. casing.
2. Determine exact fill-up volume from caliper log.
3. Centralize casing based on directional data.
4. Use formation scratchers over intervals of interest.
5. Use pump rates and slurry properties to ensure turbulent flow of the cement.
6. Run 2,000 gallons of a mud flushing fluid in front of the cement.

Cement Volume and Type: 650 sacks of Type G with 10% salt (fill-up plus 30% excess)

Slurry Properties: 1.18 cu ft/ sack, 15.9 lb/gal., 5 gal./sack (water)

Curing Properties: Compressive Strength
24 hour, 3,300 psi

2.1.10.6 General Comments

The volumes for both the intermediate and production casings will be calculated from caliper surveys. Types and amounts of specific chemical additives will then be determined. Two differential fill-up devices will be run with the 10-3/4-in. casing to ensure that the second stage cementing can be run even if one fill-up device fails for some reason. Two pump trucks will be used to cement the intermediate casing. One will be used as a standby. Only one pump truck will be necessary to cement the production string. Duplicate samples of each type of cement will be collected during each cementing operation. These samples will be allowed to set at ambient surface temperature, the temperature noted, and the samples retained until project completion.

2.1.11 Deviation Control

The following deviation control should be maintained throughout the well:

Interval (ft)	Hole Size (in.)	Cumulative Maximum Deviation
30-300	22	0.5° at 300 ft
300-1,000	15	1° at 1,000 ft
1,000-2,000	15	2° at 2,000 ft
2,000-3,000	15	3° at 3,000 ft
3,000-4,000	15	4° at 4,000 ft
4,000-5,000	15	5° at 5,000 ft
5,000-5,600	15	5.6° at 5,600 ft
5,600-6,000	9-7/8	6° at 6,000 ft
6,000-6,900	9-7/8	7° at 6,900 ft

Survey stops for first 300 ft should be every 100 ft. Every effort should be made to maintain as low an angle as practical.

Survey stops throughout the remainder of the hole should be a minimum of 250 ft or before tripping out for a new bit. All surveys should be run with a sandline.

The hole will be stabilized by using a packed hole assembly. One near bit reamer should be placed above the bit. The string reamer should be placed 30 ft above the bit and the stabilizer should be placed at 60 ft above the bit (above the second collar). Stabilizer wings should be replaced when 1/8-in. wear is noticed. If any rapid buildup of angle occurs between stations, bit weight should be reduced to correct the angle.

2.1.12 Drilling Procedure

The following drilling procedure will be used for RB-MHF-3:

1. Prepare drilling pad, mud sump, access roads, and water supply.

2. Move in small auger rig, drill 40-in. hole to bedrock (approximately 60 ft), and set 30-in. conductor pipe.

3. Cement conductor pipe to surface and prepare 8-ft x 8-ft x 6-ft cellar for rig.

4. Move in drilling unit and rig up.

5. Drill 26-in. hole using 15-in. bit to 300 ft and open hole to 26-in. with a reamer and pilot bit.

6. Run 300 ft of H-40, 65-lb/ft, 16-in. casing to 300 ft. Use three centralizers and a guide shoe.

7. Cement 16-in. casing to surface. Wait on cement for 24 hours.

8. Connect 16-in. slip-on casing head spool and rig up blowout preventers There should be one Series 900, 16-in. Grant rotating head Series 1525 and one Series 900, 16-in., double-gate blowout preventer.

9. Pressure test blowout preventers, casing, and cement to 500 psi. Hold maximum surface pressure for 30 minutes.

10. Drill out plug, cement, and guide shoe with 15-in. bit. Use near bit reamer and stabilizer to maintain deviation control. Hole stabilization will be maintained throughout drilling operation. All single shot directional surveys should be run on sandline.

11. Drill 15-in. hole to 5,600 ft with low-solids mud. After reaching 5,600 ft, circulate hole in preparation for logging.

12. Run dual induction laterolog and gamma ray-BHC sonic logs from 5,600 ft to 300 ft and gamma ray log to 60 ft.

13. Run four-arm caliper from 5,600 ft to 300 ft to obtain cement volumes.

14. Run directional survey to 5,600 ft. Stations should be at 50-ft intervals. Determine casing centralizer positions based on directional survey results.

15. Run 10-3/4-in., P-110, 45.5-lb/ft casing with differential float shoe, differential float collar, and staging collar to 5,600 ft. Staging collar should be at a depth of 2,000 ft.

16. Run two-stage cement job. Run top and bottom plugs for bottom stage. Bump top plug on float collar. Drop trip plug to open cementing ports. Circulate out cement above stage tool. Set casing slips. Wait on cement for 4 hours. Cement second stage. Inject shutoff plug. Run at least 4 sacks of cement to top of shutoff plug. Wait on cement for 24 hours. Pick up 10-3/4-in. casing, cut off excess, and install pack-off. Nipple up blowout preventer (must be Series 900).

17. Drill out plugs, stage collar, bottom plugs, fill-up collars, guide

shoe, and cement. Test stage collar to 500 psi. If stage collar leaks, squeeze-cement the stage collar and drill out cement.

18. Run cement bond log from total depth to surface.

19. If bottom 1,000 ft does not show good bonding, squeeze required intervals until proper bond is obtained.

20. Circulate hole with fresh water.

21. Move in compressors, and rig up rotating head, injector, and blooie line. Blow hole dry with air. Move in mud logging unit and rig up.

22. Drill out of casing with 9-7/8-in. bit. Continue drilling until top of first sand is encountered. Run junk basket on each bit run prior to coring.

23. Run 9-7/8-in. diamond core cutter for 4.0-in. core with a 60-ft barrel. Cut 180 ft of continuous sand or core one complete significant sandstone layer.

24. Measure any gas and/or water production during connections and trips.

25. Run in with double packer drill stem test tools and set in or above cored interval. Open tools for flow measurement for 4 hours and then shut in tool from 24 to 72 hours. Release packers and pull tools.

DECISION POINT

If after drilling through the Fort Union sandstones it is determined that this well is not suitable for massive fracture treatments (i.e.; lack of sands, significant water production, etc.), drilling should cease and the logs in Steps 32 and 34 should be run. If the logs confirm it is a poor well, the project technical and administrative management will, after consultation with the Advisory Committee, make the decision as to plugging and abandoning the well.

26. Continue drilling with 9-7/8-in. bit and air system. If slight water is encountered, convert to mist system. If water is encountered in quantities too great to handle with mist, convert to aerated mud system.

27. Run drill stem tests over the intervals indicated on the RB-E-01 log shown in Figure 10. Five to eight drill stem tests could be run.

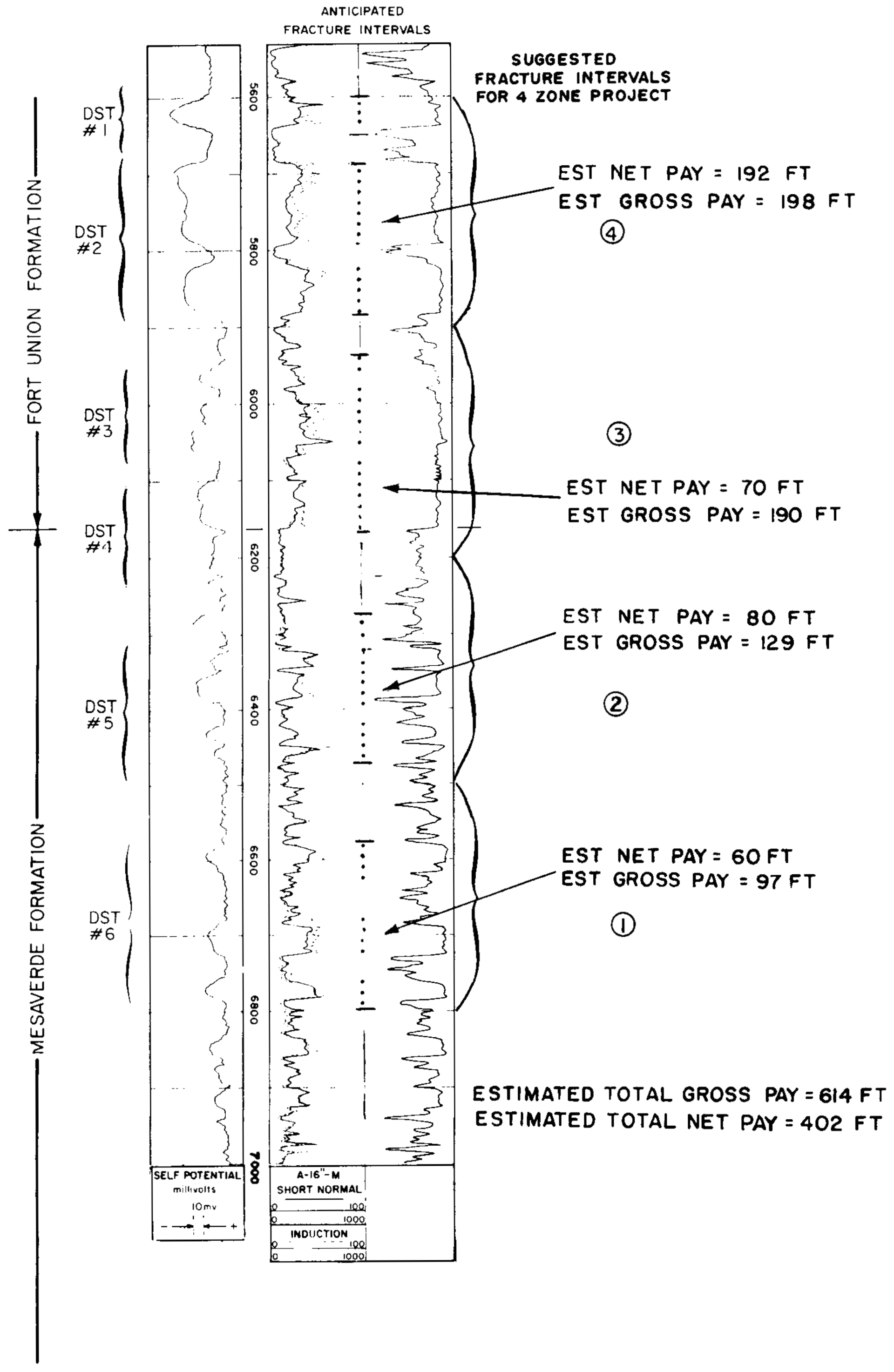

Figure 10. Fracture intervals.

28. If, after running a number of drill stem tests, results are poor and the kh data are not being obtained, cease running the tests except over intervals which indicate gas flows will be obtained and a reasonable chance of obtaining a kh is indicated.

29. Cut 60-ft cores over the approximate intervals indicated in Figure 9. If the drill stem tests are working, cut 180 ft of continuous core (1, 1A, 1B). Cut another 180 ft of continuous core (3, 3A, 3B) if a relatively continuous sandy section of Mesaverde is encountered, and drill stem test the interval as outlined in Step 25. If core 3 encounters a representative sand and shale section, cut cores 3A and 3B in lower Mesaverde sands. See Figure 10 for test intervals.

30. Drill 9-7/8-in. hole to approximately 6,900 ft and circulate hole clean.

31. Measure total gas and fluid production over entire interval while running a flowing temperature survey from 6,900 ft to bottom of 20-3/4-in. casing.

32. Run gamma ray - sidewall neutron porosity and compensated density logs from 6,900 ft to 5,500 ft.

33. Mix reentry mud system. Run drill pipe with 9-7/8-in. bit to 6,700 ft and fill hole to bit. Move bit to 6,500 ft and fill hole to bit. Continue filling in 200-ft increments until 5,600 ft is reached. At 5,600 ft, fill entire well bore. Lower bit to 5,700 ft and establish circulation. Circulate for 1 hour. Move bit down hole in 100-ft intervals and circulate 1 hour or more at each interval. Drill any bridges out. Continue until total depth is reached. Circulate hole for at least 8 hours prior to logging.

34. Run BHC sonic log with continuous density trace and dual induction laterolog from total depth to 5,600 ft. Run integrated caliper to determine cement volumes from total depth to within the 10-3/4-in. casing. Run directional survey from total depth to surface making 50-ft station stops. Calculate centralizer spacing from directional data.

35. Run approximately 6,900 ft of 7-in., P-110, 26-lb/ft casing. Casing will have a guide shoe, differential fill-up collar, and centralizers. Land casing at 6,900 ft.

36. Cement casing from 6,900 ft to 4,400 ft. Use top and bottom plugs. Bump float collar with bottom plug. Wait on cement for 24 hours and set into slips. Cut off excess and install pack-off. Run cement bond log from 6,900 ft to 4,600 ft. Perforate and squeeze any sections

that do not have good bonding. Rerun bond log after squeezing.

37. Run 6-in. bit with junk basket and drill out plug, fill-up collar, guide shoe, and cement. Drill 20 ft below 7-in. casing, circulate hole, and trip out bit.

38. Run 6-in. diamond core cutter with 60-ft core barrel. Cut 60 ft of core. Run dual induction survey from total depth to bottom of 7-in. casing. Circulate mud with water.

39. Run 2-7/8-in. tubing with packer and set in the bottom of the 7-in. casing (approximately 6, 850 ft).

40. Run small fracture treatment as follows:

    (a) Pump 2, 000-gallon pad at 10 BPM.

    (b) Pump 3, 000 gallons with 1 lb/gal of 20-40 mesh sand at 10 BPM.

    (c) Pump 2, 000-gallon flush (pad, flush, and treatment fluid is water with the necessary additives). Hydraulic horsepower requirement is 575.

    (d) Release packer and pull tubing.

41. Tag bottom with wire line unit. Pump any sand fill-up with sand pump.

42. Run bottom hole televiewer and/or impression packer over fractured interval.

43. Spot cement plug in open hole to 6, 850 ft. Wait on cement for 12 hours.

44. Run 6-in. bit to bottom and drill any excessive cement to within 20 ft of bottom of casing.

45. Displace water from hole with condensate.

46. Install 10, 000-psi working pressure wellhead and release rig.

47. Clean up drilling pad in preparation for fracture treatments.

2.1.12.1 Time Schedule for Drilling RB-MHF-3.

Figure 11 presents the drilling schedule for RB-MHF-3. This figure indicates the estimated number of 15-in. and 9-7/8-in. bits that will be required and the times that will be required for cementing, running casing, logging, coring, drill stem testing, and other major events. It is estimated that the well will

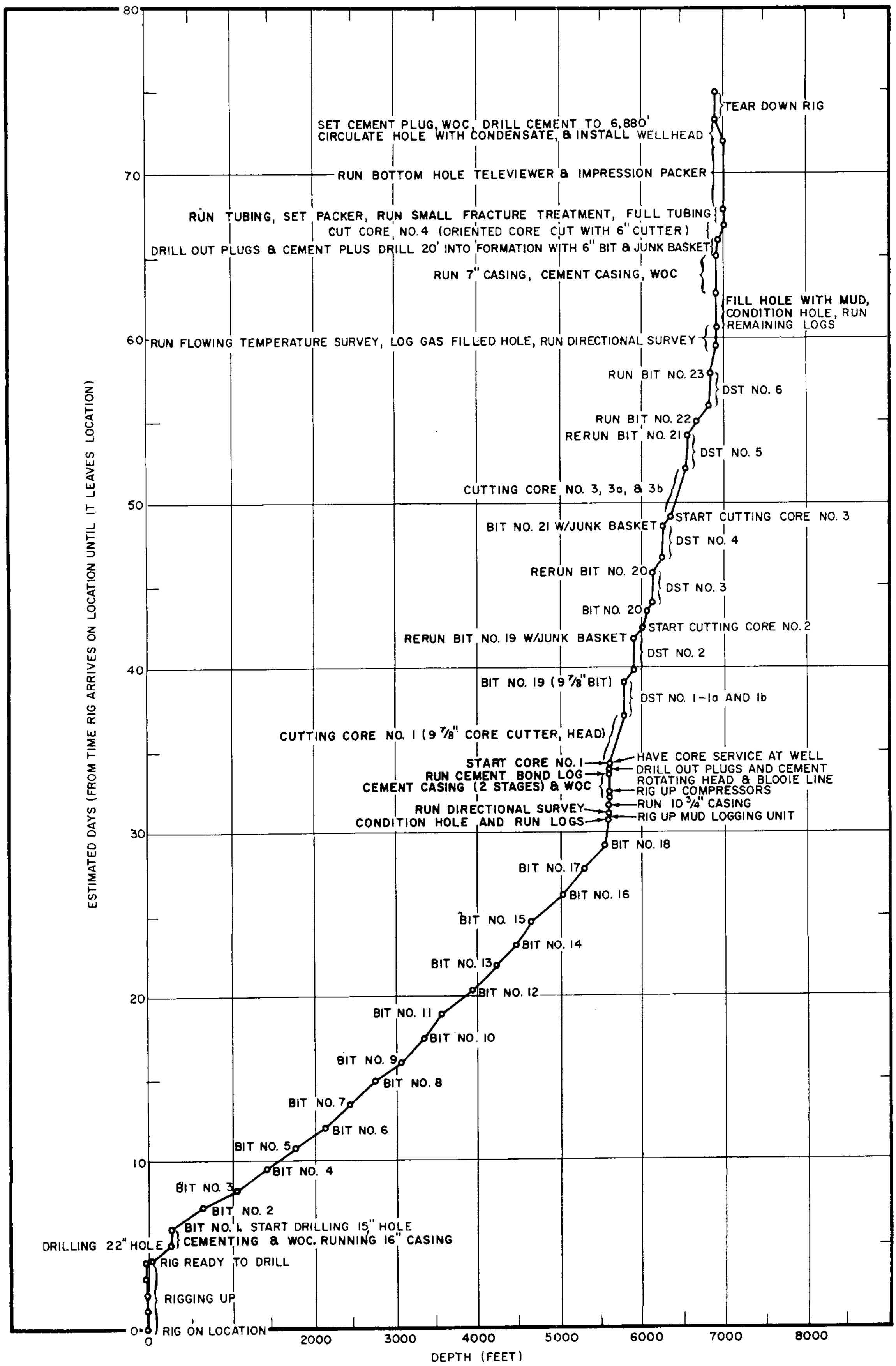

Figure 11. Drilling schedule.

take 75 days from the time the rig arrives on location and starts to rig up to the time the hole is completed and the rig is dismantled.

The estimated rotating time is 503 hours. The time to reach the top of the Mesaverde Formation is estimated at 42.5 days. At this time a decision must be made to continue or abandon the hole.

2.2 FRACTURE DESIGN

2.2.1 Introduction

The massive fracture is comprised of four to five fracture treatments. The anticipated fracture intervals are presented in Figure 10. The intervals are based on the log section from RB-E-01 which is approximately 5,000 ft to the southwest (Figure 12). In RB-MHF-3, there is a strong possibility that the intervals will be different from the ones presented by Figure 10; however, the general size and spacing of the major units should be similar enough to provide the basis for the preliminary design. The final design will be made by a technical subgroup and submitted to the Review Committee.

Two major components of the massive fracture are the actual fracture treatment design and method of fracturing each zone separately without having to kill the well with mud, water, or any fluid that could damage the formation

The actual fracture design is based on two job sizes. The first is for a gross sand thickness of 100 ft and the second is the 200 ft of gross. Both sizes are for a lateral fracture extent of approximately 2,500 ft for each side or wing. Table 1 summarizes the parameters used for designing the MHF well drilled to a depth of 6,900 ft in the Mesaverde Formation. The fluid design is based on a system that will minimize damage and clean up rapidly. The initial choice is a polyemulsion (one-third treated water and two-thirds condensate) plus a gaseous phase which could be nitrogen or carbon dioxide. Proppant design is initially based on maximum transport with an increasing mesh size and increased concentration towards the end of the treatment.

Isolation of the fracture treatment will be accomplished by the use of a retrievable bridge plug. Both the tubing and the packer will be stripped through a Shaffer-type rotating head and two blind ram blowout preventers. When it is time to move the bridge plug, 1-in. coiled tubing will be injected into the well. Nitrogen will be used to blow the sand from the top of the packer. The 2-7/8-in. tubing will be used to unlatch the packer and reset it below the next interval to be stimulated. The downhole equipment design also provides a method of monitoring the pressure in the zones that have been fractured and cleaned up while a fracture operation is being performed above the bridge plug. This should indicate whether there is communication between fractures. Once the total operation is completed the well can be immediately put on production without any drilling.

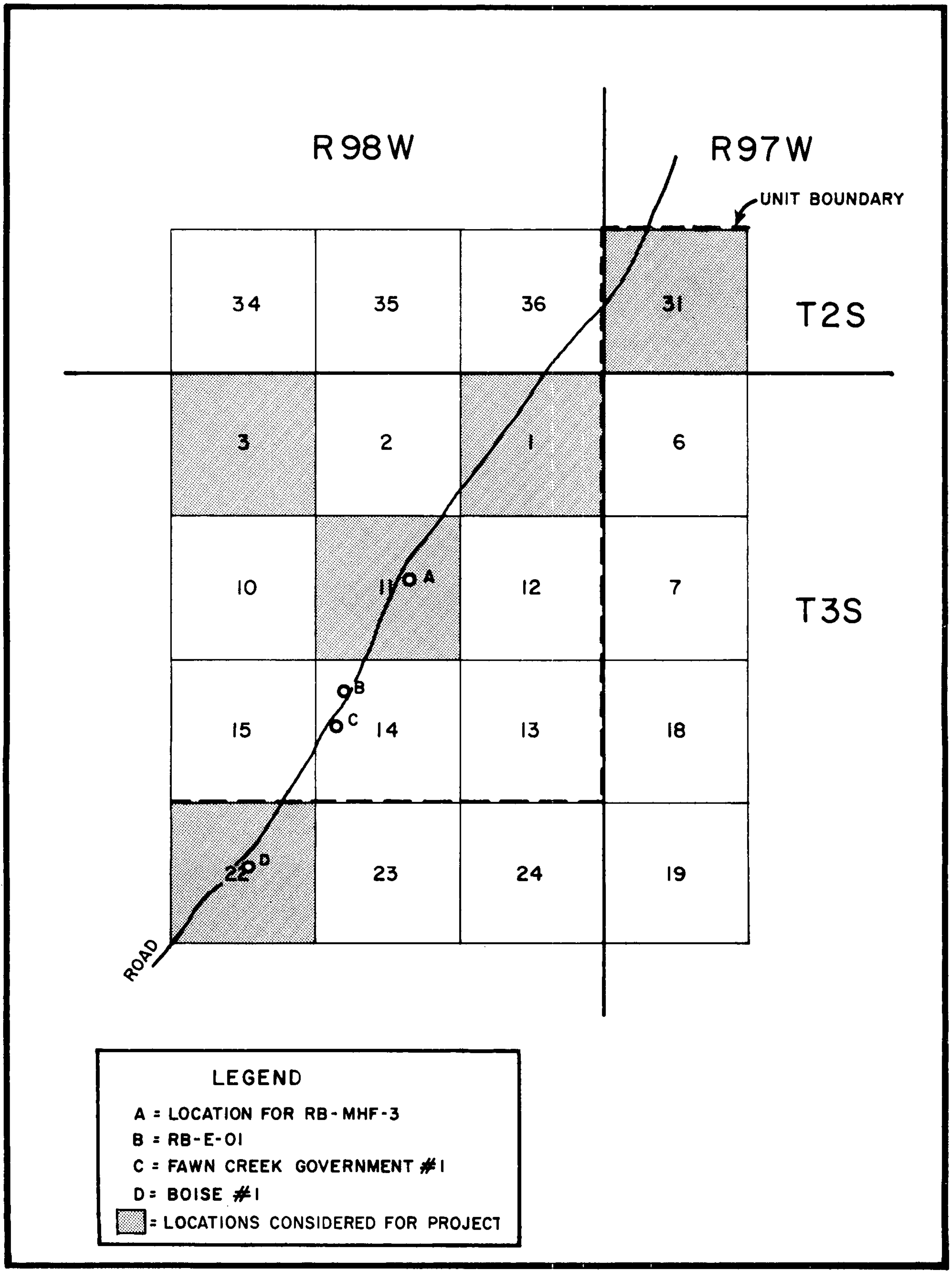

Figure 12. Existing wells in Fawn Creek area and location of RB-MHF-3.

Table 1. MHF design parameters.

Net Formation Thickness	50 and 100 ft*
Assumed Fracture Height	100 and 200 ft*
Elastic Modules of Formation	8.0×10^6 psi
Formation Permeability	0.005 md
Bottomhole Treating Pressure	4,340 psi
Reservoir Pressure	2,666 psi
Viscosity of Gas	0.02 cp
Fluid Loss	0.0002 ft/ $\sqrt{\text{min}}$.
Spurt Loss	0.000 gal/ft^2

Injection Rate: 40 BPM (not including gaseous phase)
Type of Fluid: Polyemulsion (66-2/3% condensate and 33-1/3% gelled water)
Gaseous Phase: Carbon dioxide or nitrogen
Pumping: Continuous pumping down the casing annulus (minimum casing size of 7 in.)
Sand Concentration and Size: Average sand concentration is 4 lb/gal. pumped continuously. Sand sizes are 40-60 mesh (0.017-0.010 in. dia.) and 20-40 mesh (0.033-0.017 in. dia.)

Desired Fractured Length: 2,500 ft

The following are friction calculations based on pumping 40 BPM for the super emulsifrac and an additional 5 to 10 BPM for CO_2 or N_2. Calculations assume pumping down the annulus between 2-7/8 in. tubing and 7-in. casing.

Rate (BPM)	BHTP (psi)	Ph (psi)	ΔPpf** (psi)	ΔPf*** (psi)	Pw (psi)	HHP
40	4,340	2,376	350	1,102	3,416	3,348
45	4,340	2,376	350	1,386	3,700	4,079
50	4,340	2,376	350	1,683	3,997	4,897

The above parameters were used to generate a fracture design. This is presented by Tables 2 and 3 for the 100-ft fracture height and the 200-ft fracture height, respectively. All calculations presented in this report were performed by Halliburton.

*Two designs are made for 100-ft and 200-ft fracture heights.
**Based on 1.5 BPM/perforation.
***Based on an average depth of 6,600 feet.

Table 2. Design 1: 100-ft height fracture treatment.

Volume (Gal.)	Fluid Description	Concentration (Lb/Gal.)	Sand Size	Sand Amount (Lb)	Sand Totals (Lb)
15,000	Polyemulsion Pad*				
4,000	Polyemulsion*	3	40-60***	12,000	12,000
16,000	Polyemulsion*	4	40-60***	64,000	76,000
4,000	Polyemulsion*	5	40-60	20,000	96,000
80,000	Polyemulsion**	4	20-40	320,000	416,000
10,800	Flush				

Rate - 40 BPM (Not including gaseous phase)
Treatment:
Sand 40-60 = 96,000 Lb
20-40 = 320,000 Lb
Volume of Sand = 18,845 Gal. (416,000 Lb)
Fluid - 119,000 Gal. Polyemulsion
Condensate (67%) - 79,730 Gal.
Gelled Water (33%) - 39,270 Gal.
2% KCl
0.5% U-78 or SEM-5
50 Lb WG-6 or J-133/1,000 Gal. in 12,870 Gal.
25 Lb WG-6 or J-133/1,000 Gal. in 26,400 Gal.
Flush - Gelled Water (10,800 Gal.)+
2% KCl
0.5% U-78 or SEM-5
25 Lb WG-6 or J-133/1,000 Gal.
Total Volume = 137,845 Gal. (Polyemulsion and Sand)
= 148,645 Gal. (Polyemulsion, Sand, and Flush)

Materials Required:
Condensate - 91,690 Gal. (15% of treatment volume of additional condensate or 11,960 gallons)
Water - 57,460 Gal. (15% of treatment volume of additional water or 7,390 gallons)
WG-6 or J-133 - 1,554 Lb
KCl - 8,208 Lb
U-78 or SEM-5 - 246 Gal.
40-60 Sand - 96,000 Lb
20-40 Sand - 320,000 Lb
Nitrogen @ 400 SCF/BBL = 1,408,048 SCF
11 Gallons of Deemulsifier

*Indicates 50 Lb WG-6 or J-133/1,000 Gal. in the water phase of emulsion.
**Indicates 25 Lb WG-6 or J-133/1,000 Gal. in the water phase of emulsion.
***This could be changed to 100 mesh sand.
+This volume will be reduced as the depth of the treatment is reduced.

Table 3. Design 2: 200-ft height fracture treatment.

Volume (Gal.)	Fluid Description	Concentration (Lb/Gal.)	Sand Size	Sand Amount (Lb)	Sand Totals (Lb)
15,000	Polyemulsion Pad*				
10,000	Polyemulsion*	3	40-60***	30,000	30,000
30,000	Polyemulsion*	4	40-60***	120,000	150.000
10,000	Polyemulsion*	5	40-60	50,000	200,000
170,000	Polyemulsion**	4	20-40	680,000	880,000
10,800	Flush (Gelled Water)				

Rate - 40 BPM (Not including gaseous phase)
Treatment:
- Sand 40-60 = 200,000 Lb
  - 20-40 = 680,000 Lb
  - Volume of Sand - 39,864 Gal. (880,000 Lb)
- Fluid - 235,000 Gal. Polyemulsion
  - Condensate (67%) - 157,450 Gal.
  - Gelled Water (33%) - 77,550 Gal.
    - 2% KCl
    - 0.5% U-78 or SEM-5
    - 50 Lb WG-6 or J-133/1,000 Gal. in 21,450 Gal.
    - 25 Lb WG-6 or J-133/1,000 Gal. in 56,100 Gal.
- Flush - Gelled Water (10,800 Gal.)+
    - 2% KCl
    - 0.5% U-78 or SEM-5
    - 25 LB WG-6 or J-133/1,000 Gal.
- Total Volume = 274,864 Gal. (Polyemulsion and Sand)
  = 285,664 Gal. (Polyemulsion, Sand and Flush)

Materials Required:
- Condensate - 181,068 Gal. (15% of treatment volume of additional condensate or 23,618 gallons)
- Water - 101,483 Gal. (15% of treatment volume of additional water or 13,132 gallons)
- WG-6 or J-133 - 3,355 Lb
- KCl - 14,585 Lb
- U-78 or SEM-5 - 438 Gal.
- 40-60 Sand - 200,000 Lb
- 20-40 Sand - 680,000 Lb
- Nitrogen @ 400 SCF/BBL - 2,712,990 SCF
- 11 Gallons of Deemulsifier

*Indicates 50-Lb WG-6 or J-133/1,000 Gal. in the water phase of emulsion.
**Indicates 25-Lb WG-6 or J-133/1,000 Gal. in the water phase of emulsion.
***This could be changed to 100 mesh sand.
+This volume will be reduced as the depth of the treatment is reduced.

2.2.2 Fracture Contingency Planning

The length to height ratio of the fracture wing* used in this MHF design is quite large. Ratios of this order of magnitude have been reported in conjunction with fracture experience on Cretaceous sandstone in the Denver-Julesburg Basin. Thus, it does not appear unreasonable to use the high ratios in this design. However, the high ratio experience is from another area and it would seem prudent to consider contingency planning in case fracturing in the Piceance Basin exhibits lower ratios.

An estimate of fracture height on Zone 1 should be possible if the temperature profiling program yields significant results. If no anomalous behavior is encountered in the first zone fracture, the second zone fracturing should proceed according to plan.

In the event of an unusual fracture height in the first zone, the contingent response should be to provide enough separation between the first and second zones, based upon available ratio information, so that fracture coalescence will not occur when the second zone is fractured. This involves reducing the ratio. If the second zone fracture information indicates that this ratio appears satisfactory, the fracture program will continue, utilizing the new ratio.

The general procedure for designing each fracture stage will be to evaluate the information obtained from each previously fractured interval. With this information the fracture design and procedure on succeeding zones can be altered if necessary. Any modifications or redesigning shall be carried out by a technical subgroup and presented to the Review Committee with the design and procedure for the next stage.

2.2.3 Subsurface Equipment and Running Procedures

Performing four to five isolated fracture treatments without killing the well requires special attention to both the surface and subsurface equipment and running procedures. Once the first interval is fractured at the bottom of the well, cleaned up, and tested, it must be isolated from the next fracture treatment. There are two basic ways of isolating these intervals.

One way is to set a sand plug with cement spotted on top to cover each interval that has been perforated and fractured. At the end of the total operation a rig would be brought in and the sand plugs drilled out with a gas. The main problem in doing this is that there is no way to reenter a previously treated interval without drilling once the sand plug is set. This means that it is impossible

*Distance from well bore to the end of one vertical fracture (Figure 13).

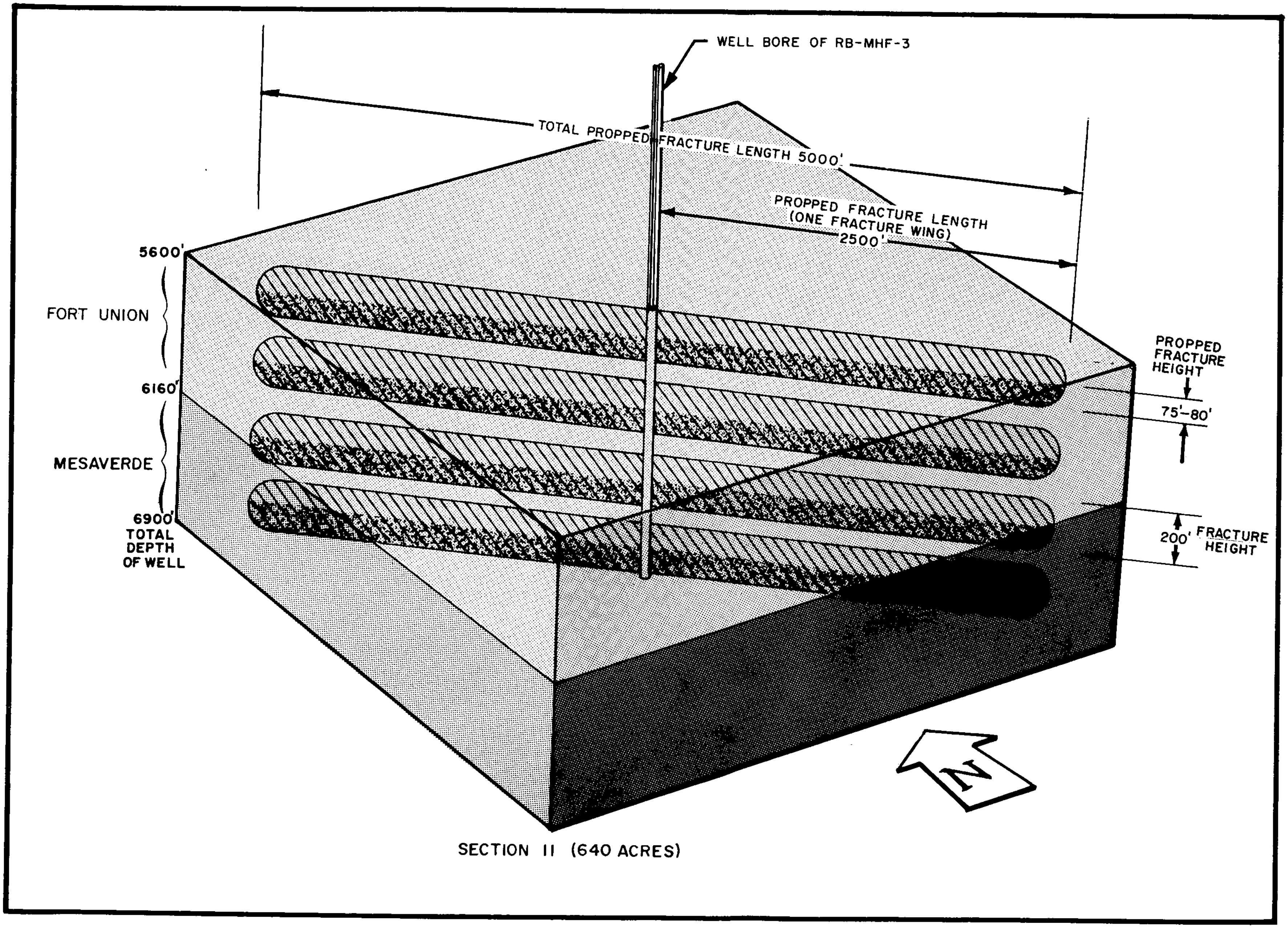

Figure 13. Fracture length.

to determine whether a fracture created by a previous treatment is in communication with a fracture from the interval above it. For this reason, and because of the possibility of formation damage during the sandplug cleanout operation and for the flexibility of being able to test either one or all of the treated intervals, it was decided to mechanically seal off the lower interval by means of a retrievable bridge plug. Figure 14 shows the equipment required to isolate the fractured interval.

The packer assembly is run to the predetermined pack-off position and set. The blanking plug in the tubing is pulled and the pressure recorders are run in and landed. The sealing plug in the top of the packer is run and latched. The tubing is unlatched and the casing is pressure tested to check the seal of the packer assembly. A heavy gel is spotted on top of the packer, the casing pressure is bled off, and the tubing pulled to perforate. See Figure 15 for the packer setting diagram.

After perforating the casing, the tubing is stripped into the well with a blanking plug below a pump seating nipple. Once the tubing is landed the blanking plug is pulled and the well fractured. If it is necessary to pump the fractured interval while cleaning up the well, a plunger pump can be seated and pumped. Once the well is cleaned up and it is time to unseat the packer, coiled 1-in. tubing is lowered to the top of the packer and the sand is blown out. Once the packer is clean, the 1-in. tubing is removed and the blanking plug is run in and seated (if the packer is to be moved). The packer can then be latched and unseated. Before the packer is unseated, the sealing plug can be pulled and the recorders retrieved. Also, both zones can be flowed before unseating the packer. If necessary, the fluid level below the packer can be checked.

Once the packer is unseated it can be raised to the next zone and reset. If, after pressure testing down the casing, the packer seal is not holding, it can be reset or pulled out of the hole and redressed. If there are no leaks, the packer can be used as a bridge plug for each treatment without pulling it to surface. By the end of all the fracture operations the well can be put on production by either pulling the sealing plug or unseating the packer and stripping it out of the hole.

2.2.4 Surface Facilities and Operations

One of the critical features of this multistage fracture operation is being able to treat the well without having to kill it after stimulation. To do this, all downhole equipment will either need to be snubbed in or stripped through a rotating head. Because of the speed and ease of operation, the use of a Shaffer-type rotating head is considered the optimum method for handling the subsurface equipment. Figure 16 shows the equipment required to run in the 2-7/8-in. tubing and packer assembly.

A Series 2900 (10,000-psi working pressure) blowout preventer must be used on top of the tubing spool head if a high-pressure 6-1/2-in. ID gate valve cannot be purchased. Either the valve or the blowout preventer will isolate the

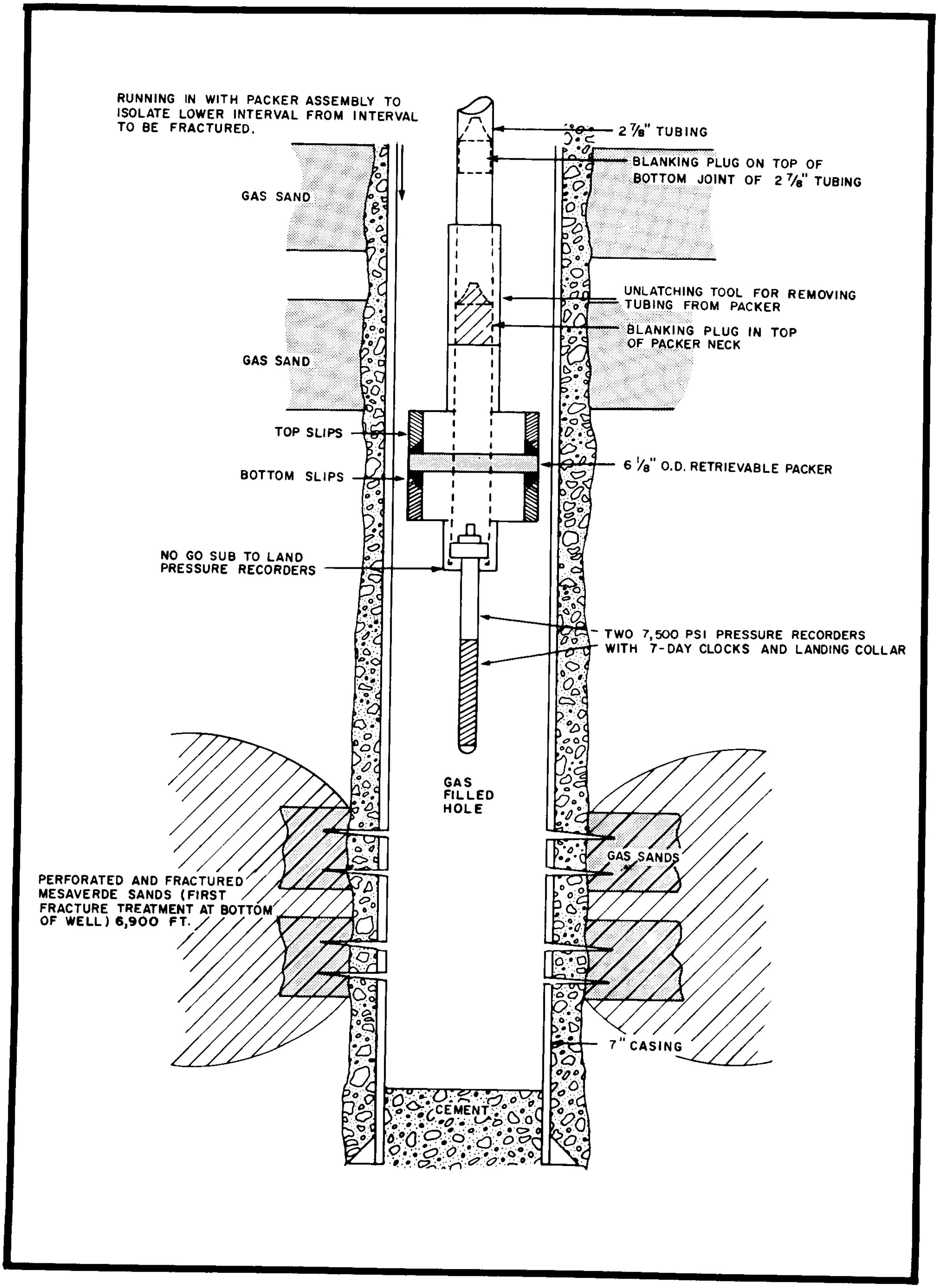

Figure 14. Isolation equipment.

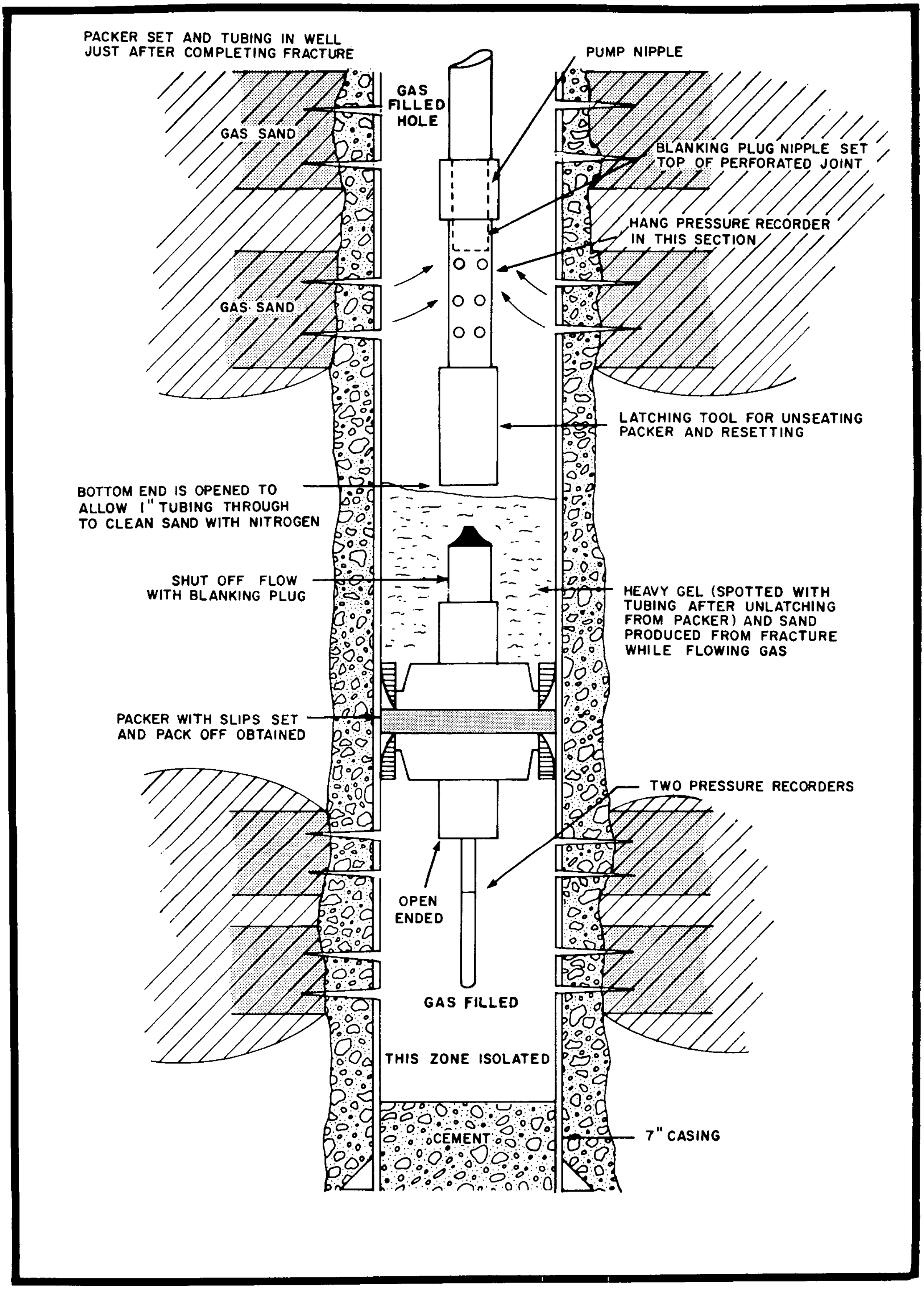

Figure 15. Packer setting diagram.

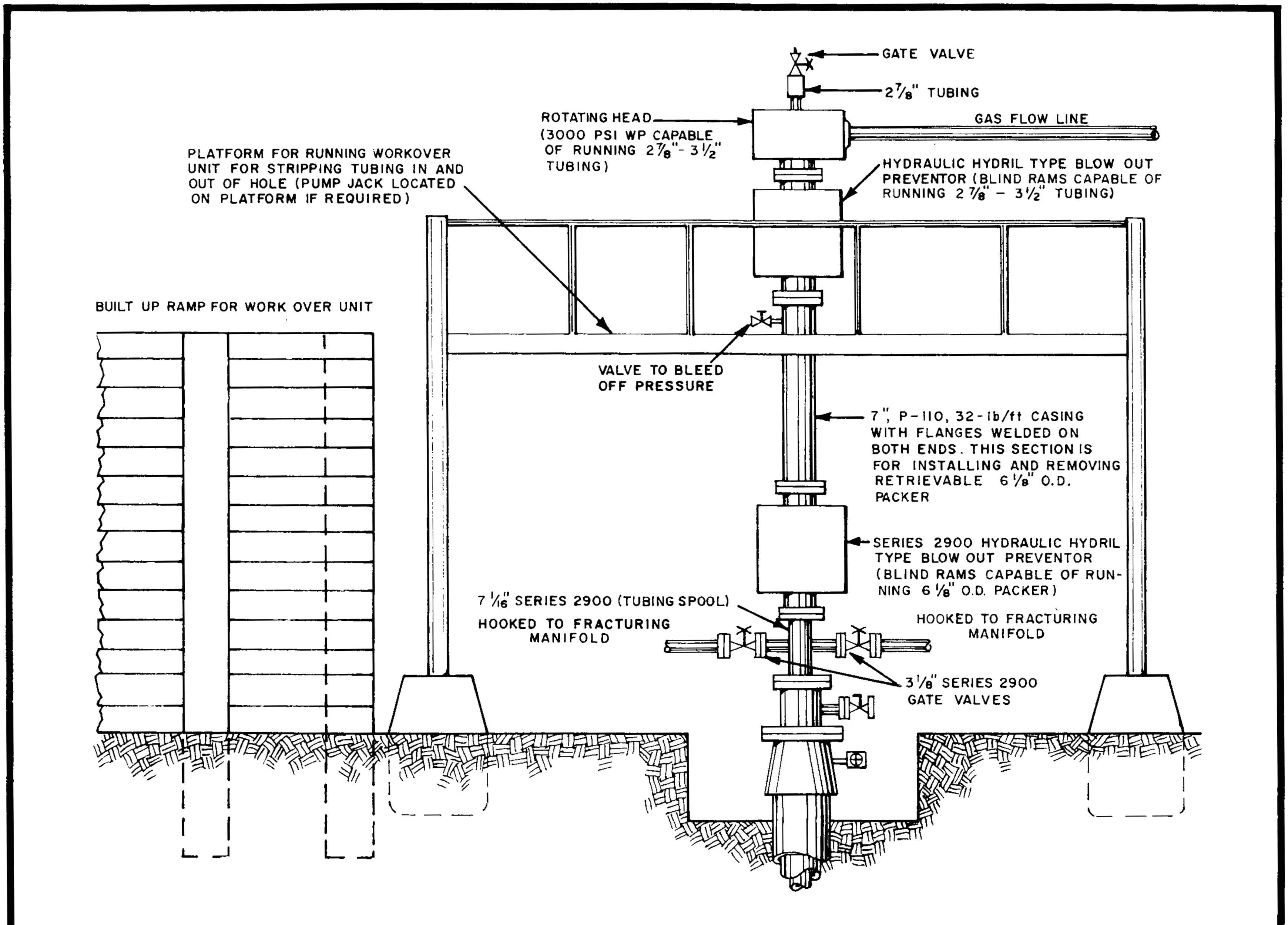

Figure 16. Hookup to strip packer and tubing into well while flowing gas.

gas-filled casing from the surface while installing the packer in the 7-in. casing extension below the rotating head. This is the main reason for the two blowout preventers and extension cited in the diagram. Once the packer is installed, the lower blowout preventer can be opened and the packer lowered into the hole. From then on the tubing can be run through the rotating head and the two open blowout preventers. While running in or out, gas will be flared out the blooie line and burned.

When it is time to commence a fracturing treatment, the surface injection manifold is connected to the two 3-1/8-in. side outlet valves extending out of the tubing spool. The 2-7/8-in. tubing is landed in the tubing spool and the two blowout preventers, or one valve and one blowout preventer, are closed. The fracture treatment can then go down the annulus. The production tubing will protrude from the top of the rotating head with a valve on top. When the fracture treatment is completed, the return fluids and gas can either be produced out the annulus or the tubing.

When the cleanup and testing is complete, the blowout preventers can be opened and the tubing pulled. While the tubing is in place, all normal wire line operations can be run. Also, 1-in. coiled tubing can be injected down the 2-7/8-in. pipe to clean out any sand produced from the fracture treatment that is covering the retrievable bridge plug.

The ramp and platform are required to position the workover unit and/or pump jack above the wellhead so normal operations can be carried out. Because of the number of operations to be performed on this well plus the shortage of workovers with substructures, it is necessary to have a permanent structure built to handle the extreme height of the required equipment.

2.2.5 Method of Handling Tubing During Fracture Treatment and Upon Completing the Well for Production

The design of the casing string and wellhead is based on a maximum treating pressure of 9,960 psi which is the internal yield of 26-lb/ft, P-110, 7-in. casing. The fracture treatment will be down the casing annulus between the 2-7/8-in. tubing and 7-in. casing. Figure 17 indicates the surface arrangement for the tubing, casing, and wellhead.

After perforating an interval, 2-7/8-in. tubing will be run to the top of the perforations. The tubing will be landed through the top rotating head, Hydril-type blowout preventer and the bottom blowout preventer or gate valve. A high-pressure donut-type tubing lander will be used. Just below the donut a heavy 2-7/8-in. collar with a rubber blast pad will be used. It will be necessary to use the blast pad and collar for each job even though the critical velocity of 45 ft/sec will not be reached using the two 3-1/8-in. ID side valves for pumping the fluid into the annulus. Using nitrogen at a

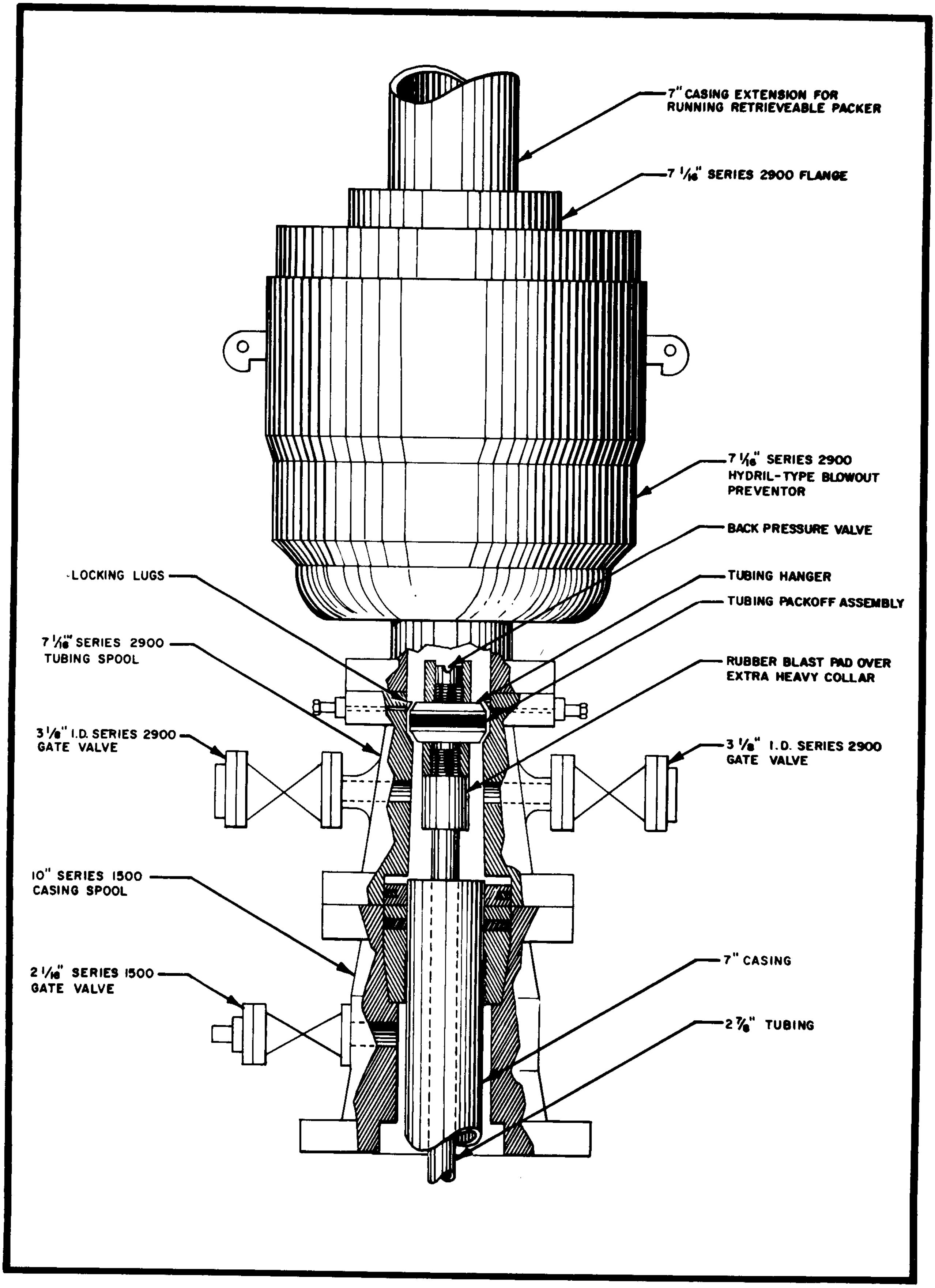

Figure 17. Surface equipment.

concentration of 400 SCF/BBL, erosion could occur unless these preventative steps are taken.

Each time the tubing is landed, a retrievable back-pressure valve will be used inside the tubing hanger neck. This is to protect anyone working over the tubing until the pressure is equalized in the wellhead. It also allows the removal of the blowout preventer assembly and/or gate valves for working on the wellhead.

If a Series 2900, 6-3/16-in. ID gate valve can be obtained, it will replace the Series 2900 7-1/16-in. blowout preventer

Once the tubing is landed and secured with the locking lugs, either the blowout preventer or the gate valve will be closed and the fracture fluids will be pumped into the annulus through the 3-1/8-in. ID gate valves.

When it is time to pull the tubing, the lugs are released and the tubing withdrawn through the surface blowout preventer assembly. When landing the tubing for final production the same procedure will be used except a second seal will be placed over the tubing hanger neck. This second seal has a 7-1/16-in. flange that will connect to the christmas tree.

2.2.6 Fracture Treatment

The following is the preliminary treatment procedure for RB-MHF-3:

PART NO. 1

(This phase will be completed while the well is being drilled.)

1. After determining that the well is usable, the pad for the fracture treatment should be started.

2. Tankage for condensate and water should be located and transported to fracture pad. The tanks should be completely cleaned.

3. Install piping to connect three-phase separator with water and condensate tanks plus flare and cleanup pits.

4. Locate and order necessary quantities of condensate, sand, chemicals, CO_2, or N_2 for first fracture treatment.

5. Test specific condensate for emulsion characteristics and the effect of CO_2 and/or N_2 on the emulsion.

6. After obtaining cores, run rock mechanics tests plus fluid sensitivity and flow properties.

7. Complete detailed final design of fracture treatment with exact fluid, sand, gaseous phase requirements, and number of perforations per foot.

8. Transport all materials to well site in preparation for first fracture treatment.

9. Pick first interval to perforate and fracture.

PART NO. 2

(This phase is the actual completion of the fracture treatments.)

10. Move in workover, necessary stripping equipment, and blowout preventers and rig up.

11. Rig up logging unit to perforate.

12. Tag bottom of hole, run collar locator - gamma ray logs. Run base temperature log between total depth and 5,000 ft.

13. Perforate interval of interest with casing gun. Lubricator should be used on wellhead assembly.

14. Strip tubing into well to the top of the perforations. Tubing should have pump nipple and no-go collar for landing the pressure recorders.

15. Rig up wellhead manifold to fracture well.

16. Move in and rig up fracture equipment.

17. Move in CO_2 or N_2 trucks and rig up.

18. Fracture the first interval either with the 100-ft height or 200-ft height treatment.

    (a) 100-ft height treatment - See Table 2.
    (b) 200-ft height treatment - See Table 3.

Pumping Procedure

(NOTE: Maximum surface treating pressure is 9,960 psi minus hydrostatic pressure at the lowest perforation being treated.)

(a) Pump pad to establish rate and breakdown formation.
(b) Start pumping polyemulsion with sand and nitrogen.

(c) Continue pumping sand at the concentrations cited in Table 2 or Table 3. During the treatment it will be necessary to measure the polyemulsion viscosity with a Fann viscometer. This requires the sand to be emptied from the blender (1/2 minute) and sand-free samples to be taken. This should be done for every 15,000-gallon interval until the flush is started. Also pump rates, sand concentrations, and nitrogen rates should be recorded for each interval. A continuous pressure recorder (strip chart with 0 to 7,500-psi range) will be connected to the wellhead to monitor the fluid injection, pressures, and shut-in-pressure while temperature logging, and drawdown pressures while flowing the well. Towards the end of the treatment (last 15,000 to 30,000 gal.), increase sand concentrations up to 6 lb/gal. of 20-40 sand.

(d) Pump flush (volume of casing to lower perforation). Inject 1 gal. of demulsifier per 1,000 gal. of flush after pumping first 1,000 gal. of flush.

(e) Reduce pump rate and completely pump out all manifolds and surface injection lines.

(f) Shut in well, disconnect fracturing injection lines, and connect well to production piping while temperature survey is being run.

19. Tag bottom with temperature sonde.

20. Run an absolute temperature survey across the fractured interval. Run as many traverses as possible within a 2-hour period. Do not keep well shut in for more than 2 hours for any reason.

21. Open well to flow to the pit until most of flush is recovered. Divert flow through separator. Initial rate of gas should not exceed 2 MMSCFD.

22. Run wire line sinker bar to tag bottom for sand fill-up. Divert flow to annulus while running sinker bars to bottom. This should be done every 6 hours or sooner until sand fill-up is determined. If sand fill-up is small, increase flow rate if possible. Do not go over 3 MMSCFD unless it is certain that sand will not be produced out the fracture.

23. If surface pressure drops rapidly, indicating downhole fluid buildup, lower tubing to within 60 ft or less of total depth. Use foaming agent to clean hole. If this is not sufficient, consider swabbing tubing or installing a pump.

24. On the surface, monitor all fluid and gas production and take samples periodically for analysis.

25. If well continues to clean up without any fluid problems, continue

flowing with bottomhole pressure recorder hung in perforated tailpipe.

26. Maintain flow for a minimum of 2 weeks unless an excessive amount of water is being produced. Try to recover as much condensate as possible (50 to 80 percent).

27. Shut in well and measure buildup for a minimum of 3 days, then start next fracture zone operation.

28. Strip out tubing.

29. Strip in tubing with retrievable bridge plug with blanking plug set in bottom joint of tubing. Pull blanking plug after the tubing is landed and the packer set. Run two pressure recorders and set off in landing collar. Set blanking plug in top of packer. Unlatch tubing off plug. Deplete gas pressure in casing.

30. Spot heavy gel on top of bridge plug. Fill hole with pad and pressure up casing and bridge plug to check bridge plug seal.

31. Pull out tubing.

32. Perforate next interval to be fractured with casing gun.

33. Strip in tubing string with blanking plug to above the top perforation. Pull blanking plug.

34. Repeat Step No. 8, 9, 10, and 16 through 28.

35. Inject 1-in. coiled tubing down to top of sand and circulate nitrogen down tubing and sand up the annulus. Clean sand out until 2-7/8-in. tubing with overshot can latch on to retrievable bridge plug.

36. Latch on to bridge plug and reset it above the top perforations.

37. Pull blanking plug and retrieve the pressure recorder below bridge plug.

38. Flow combined fracture intervals through tubing if required.

39. Rerun pressure recorder and set blanking plug in top of bridge plug. Unlatch tubing and spot heavy gel on top of plug.

40. Pull tubing and prepare to perforate.

41. Repeat Step No. 33 through 41 for each interval coming up the hole.*

42. After completing the last fracture treatment and cleaning up the well, strip the bridge plug out of the well and strip in production string to top of perforations. Run flowing temperature survey. Lower tubing to within 100 ft of total depth.

43. Land tubing and install wellhead.

44. Run pressure recorder into perforated tubing.

45. If possible, flow well at high enough rate to keep the fluids unloaded.

46. Produce gas and fluids through a three-phase separator. Measure all gas and fluid volumes.

47. Produce gas into pipeline if possible.

48. See long-term production test procedure.

2.3 ANALYSIS DESIGN

2.3.1 Introduction

The evaluation of the massive hydraulic fracturing experiment depends upon acquiring two major components. The first is the reservoir parameters such as effective permeability, net pay, porosity, water saturation and fluid properties. The second is the fracture description such as effective fracture area, total fracture area, fracture orientation, and fracture height. Determination of the fracture and reservoir properties will ultimately lead to the description and prediction of the well's future deliverability over its production life plus determining to what extent the objectives of the fracture design were achieved. The analysis program will require many of the evaluation techniques currently available.

The program is summarized as follows:

1. Extensive logs will be run over all of the Fort Union and Mesaverde sections (see paragraph 2.1).

2. Detection of possible gas pay zones will be achieved with a mud logging unit.

3. Gas and water flow rates, while drilling, will be measured and fluid samples taken.

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*No fracturing operations will be carried out during the winter months (October to April). Refer to paragraph 2.3.3.4 for program for this period.

4. Drill stem tests (short-term buildup tests) will be conducted over the fracture intervals.

5. Cores will be cut over intervals which represent the sandstone sections to be stimulated (see paragraph 2.1).

6. An oriented core will be cut in the bottom of the well (approximately 6,920 ft to 6,980 ft). This section will be hydraulically fractured. An impression packer and/or bottom hole televiewer will be run to determine fracture orientation.

7. Flowing temperature surveys will be run at the completion of the drilling before filling the hole with mud and after the last fracture treatment when all the zones are commingled.

8. A base temperature survey (inside the 7-in. casing) will be run over the total interval to be stimulated (5,600 ft to 6,880 ft) before the first fracture treatment. Following each fracture treatment a minimum of two temperature surveys will be run over the fractured interval.

9. After each fracture treatment all flow rates will be measured once the well stream is diverted through the separator. Pressure recorders will be run to obtain the bottom hole pressures. After the clean-up period the well will be shut in for a buildup test.

10. During the winter when fracturing treatments are impractical to run because of the cold weather, a long-term flow test will be conducted with all the fractured zones put on production.

11. At the end of the fracturing all intervals will be commingled and a long-term production test will be run.

12. Pressure recorders will be placed below the bridge plug assembly (Figures 14 and 15) to determine if the fracture being induced above the bridge plug connects with any of the fractures below the bridge plug.

In the event the drill stem tests do not yield the required information, a small fracture treatment will be run through the 7-in. casing in a representative interval in the Mesaverde and Fort Union formations. These tests will include a drawdown and buildup of sufficient duration to determine the effective flow capacity (millidarcy-feet, kh).

If severe water production occurs during any of the testing, plans will be implemented to either shut off the water flow, remove it by production, or, as a last resort, abandon the well.

2.3.2 Reservoir Description Determination

2.3.2.1 Porosity and Water Saturation

A complete suite of logs will be run in the gas- and mud-filled hole between 5,600 ft and 6,900 ft. The compensated neutron porosity, formation density compensated, bore-hole compensated sonic, and the dual induction-laterolog 8 logs will be used to calculate porosities and water saturations for the Fort Union and Mesaverde formations. Cores obtained from representative intervals of both the Fort Union and Mesaverde formations will be used to determine core porosities, fluid saturations, permeabilities, and rock properties. By using both the core and log data, reasonable values of porosity and water saturation should be obtained. Procedures in the drilling section outline both programs in detail.

Logs and core analysis could also be used to determine if the well was not suitable for the experiment. As previously mentioned, if the air drilling and drill stem tests do not encounter gas through the Fort Union section, a decision will have to be made on whether to continue or abandon the well. In this case, log and core results will provide the main basis for this decision.

2.3.2.2 Net Pay and Effective Permeability

Evaluation of the effective permeability requires knowing the net pay associated with the permeability - net pay product (kh-millidarcy-feet). Logs and core analysis are not completely sufficient for determining net pays or effective permeabilities. Drilling the Fort Union and Mesaverde formations with air allows gas and/or water entry points to be determined and the flow rates measured. The detection of the gas will come from using a mud logging service from 5,600 ft to total depth. This service will provide a gas detector and gas chromatograph. Gas rates will be measured at the surface during trips, connections, and whenever necessary. If water production is severe, a separator will be installed to measure the actual rates. If possible, the gas entry points will be correlated with the logs and cores to estimate net pay. After the air drilling is completed, a flowing temperature survey will be run from total depth to 5,000 ft to obtain additional information to aid in evaluating the net pay.

The principal reason for the drill stem test is to determine the effective permeability net pay product (kh). If reasonable values for net pay can be determined, effective permeabilities can be calculated. Once an interval is fractured, it would be extremely difficult to determine kh. Since the fracture flow geometry is primarily linear, the determination of kh is impossible until a long flow period has been achieved and flow changes from linear to a different geometry. *

*This is discussed in great detail by A. C. Gringarten, et al., in their paper "Pressure Analysis for Fractured Wells", S.P.E. preprint No. 4051, 1972.

Therefore, a significant effort will be made to run drill stem tests over the intervals to be stimulated (Figure 10). Flow data prior to setting the drill stem test packers will be monitored at the surface using the mud logging service to indicate the initial entry and a critical flow prover to measure gas flow rates as a function of time and depth. Once the drill stem test tools are run and set, the well will be opened for another short flow period and then shut-in for a buildup (24 to 72 hours). The length of the buildup will be determined by the length of the afterflow effects, and how long it takes to obtain sufficient pressure data to calculate a value of kh. In the event there is too much water production, formation damage is too severe, or the intervals to be tested are too tight or lack net pay, the scheduled drill stem test program will be altered. If this occurs, the determination of the actual intervals to test will be made on the basis of surface information obtained while drilling through the section. Only sands that indicate a measurable gas flow would be tested.

In the event that meaningful drill stem tests cannot be obtained in the Fort Union and the Mesaverde formations, an alternate testing program would be required. The alternate testing program would select a representative interval in the Fort Union and in the Mesaverde formations and conduct a small fracture treatment on each interval after the 7-in. casing is landed and cemented. After each fracture treatment the well would be allowed to clean up and have sufficient flow and buildup so that the flow geometry is such that the effective kh can be calculated from either the drawdown or the buildup test.

2.3.2.3 Other Reservoir Parameters

It is doubtful that the initial reservoir pressure can be obtained from the drill stem tests. However, an attempt will be made to estimate the total volume of gas produced while drilling and before each buildup. The cumulative production must be known with some degree of certainty so that the buildup can be extrapolated to estimate the static pressure. During the shut-in periods between fracture treatments the static pressure will be recorded. From this data the maximum initial reservoir pressure can possibly be extrapolated.

Temperature as a function of depth will be measured a number of times as follows:

1. Flowing temperature survey before the hole is filled with mud.

2. Base temperature survey inside the 7-in. casing when the hole is filled with the fracture pad.

3. Flowing temperature survey after all the intervals have been fractured and commingled and placed on production.

From this data the bottom hole formation temperatures can be determined.

γ

Fluid properties such as gas viscosity and gas deviation factor as a function of pressure will be determined from correlations based on the gas composition. Samples of the gas and separator fluid will be collected and analyzed both while drilling (gas analyses only) and while testing after each fracture treatment and during the long-term production tests.

Description of the reservoir drainage shape or geometry possibly can be estimated from computer matching of long-term production data with computer reservoir simulator codes. Bottom hole pressure and surface flow rates will be recorded as a function of time during the production testing.

2.3.3 Fracture Analysis

2.3.3.1 Fracture Height

After each fracture treatment a temperature survey will be conducted over the interval that has just been stimulated. A number of traverses will be made in an attempt to determine the fracture height at the well bore. Prior to running the first fracture treatment a base temperature survey will be run for a maximum comparison of the temperature anomaly.

2.3.3.2 Created Fracture Area and Effective Fracture Area

The created fracture area for each interval will be estimated after evaluating the actual treatment for each stage. Total volumes of sand, condensate, water, and chemicals will be recorded. Treating pressure as a function of time will be recorded both by the service company equipment and by a surface pressure recorder at the wellhead. Viscosity of the injected fluid will be measured over the entire treatment at a predetermined interval. Pump rates will also be continuously recorded. From this volume, rate, and other data the created fracture area can be estimated.

The effective fracture area (the productive cross sectional sand area of the fracture) that occurs in each interval can be estimated from short-term drawdown or buildup tests. Therefore, after each fracture treatment, the well will be immediately put on production to clean up. This flow will be continued for a short period (2 to 3 weeks) after which the well will be shut in for a buildup.

2.3.3.3 Fracture Orientation

After reaching 6,900 ft and setting and cementing the 7-in. casing, an oriented core will be cut from 6,920 ft to 6,980 ft. A regular bit will be used to drill out the cement in the 7-in. casing, plus 20 ft of formation below the 7-in. casing to give enough room to accurately orient the core barrel. A small fracture treatment will be conducted between 6,900 ft and 6,980 ft and a bottom hole televiewer will be run over this interval to try to determine the fracture orientation. If this attempt is not conclusive, an impression packer will also be run to determine fracture orientation.

2.3.3.4 Assessment of Fracture Treatments

The actual assessment of reservoir characteristics, fracture height, and effective flow area can be estimated by the short-term tests and methods previously cited. However, to determine the reservoir geometry, fracture length, and to confirm the various fracture and reservoir parameters, a long-term production test is scheduled over the winter period and after all the treatments are completed. Since two treatments are scheduled for completion before winter, the first long-term test will probably have both of the Mesaverde intervals commingled and producing into a pipeline. At the end of the stimulation phase, all of the stimulated zones will be commingled and placed on production. Flow rates of water condensate and gas, and bottom pressures, will be measured continuously. Periodic samples will be obtained for analysis.

2.3.4 Test Program - Drilling Phase

2.3.4.1 Gas Measurements

Once air drilling is started below 5,600 ft (bottom of 10-3/4-in. casing), a mud logging unit will be on location to detect any gas in the well stream. Once gas is detected, the gas flow should be measured either during a connection on a trip or by shutting off the air momentarily. Flow rates will be measured by a critical flow prover connected to a bypass on the blooie line. During connections the gas flow should be measured. While tripping out, the gas flow should be measured continuously.

If it appears that a significant gas flow is occurring accompanied by some water, the bypass should be routed through the three-phase separator to measure both gas and liquid production.

If small amounts of water are encountered, the air drilling operation can continue with the addition of a foamer to the air. Under these circumstances, the gas measurement program could continue. If a significant amount of water production occurs, conversion to a mud system would probably be required and the only significant information obtained on the gas encountered while drilling would be the mud logger output.

2.3.4.2 Drill Stem Test

If gas is being produced during the air or foam drilling operation, a series of drill stem tests will be run. The approximate intervals over which drill stem tests will be run are displayed in Figure 10. All drill stem tests should be run with double packers, jars, and two recorders. Each pressure recorder should have a 72-hour clock and a pressure element no greater than 3,000 psi. Once the packers are set, the tools are closed. The tools should then be opened for a 4-hour flow period and then shut in for a 24 to 72 hour buildup.

When the packers are released, the testing tool will automatically shut off. Thus, no gas flow will occur in the drill pipe while coming out of the hole.

Gas flow measurements during the 4-hour flow period will be monitored by the critical flow prover. Gas being produced out the annulus above the packers will be measured throughout the flow test and buildup. The packers should be set as close to the interval to be tested as possible. If packer seating cannot be obtained on the first attempt, a second attempt with a different packer setting depth should be attempted. If this fails, the drill stem test of that interval should be abandoned.

2.3.4.3 Flowing Temperature Survey

A flowing temperature survey should be run immediately after reaching 6,900 ft. A differential temperature log will be run from 6,900 ft to 5,000 ft. Surface flow rates will be continuously measured with a critical flow prover. If there is no gas flow, this log will be ommited.

2.3.5 <u>Test Program - Fracturing Phase</u>

2.3.5.1 Base Temperature Survey

Prior to perforating the first interval to be fractured, a temperature survey will be run in the 7-in. casing. This temperature sonde will be run from total depth to 5,000 ft to establish an accurate temperature gradient.

2.3.5.2 Treatment Measurements

Prior to the start of all fracture treatments, volumes of fluids will be measured in the tanks. Sand volumes will be estimated and chemicals for the various phases will be checked. During the treatment a written record will be kept of remaining tank volumes and sand quantities as a function of time and injected volume.

A surface pressure recorder (0 to 7,500-psi range) with a 12 hour or less clock drive will be used to record the wellhead pressure during the treatment, temperature profile logging, and initial cleanup.

Since the treatment companies do not have an actual recording of pump rate versus time, each pump truck operator will be provided with a schedule to fill out indicating rate versus time for his truck as well as any major changes in pump rpm. This will also be done for the injected fluid density versus time. A Fann viscometer will be used to measure the viscosity of the polyemulsion for every 15,000 gallons of fluid injected.

At the end of each treatment, each tank will be checked to determine the remaining volumes of fluid. Remaining chemicals and sand will also be noted.

2.3.5.3 Profile Logging

Immediately after each fracture treatment, temperature logging equipment will be run into the hole (lubricator will be rigged up on tubing with sonde ready to run). Profiles will be run from either total depth or bridge plug depth to 200 ft above the top perforation. If a profile is not going back to the base line at 200 ft above the perforation, this logging interval will be increased until the profile returns to the base temperature gradient as previously logged before fracturing. Under no circumstances should the well be shut-in longer than 2 hours after shutdown of injection.

2.3.6 Pressure Measurements Below Bridge Plug

After the first fracture stage is completed, a bridge plug will be set to isolate the next stage to be fractured from the lower stage(s). Two Amerada-type pressure recorders, having a pressure range of 0 to 7,500 psi, will be hung below the bridge plug. One recorder should have a 72-hour clock and the other should have a 7-day clock. Prior to pulling the packer, these recorders should be retrieved. If a pressure response is noted, a pressure gradient should be run to determine how much fluid, if any, is below the bridge plug.

2.3.7 Cleanup and Buildup Test

After the temperature profile is completed, the fluids from the well should be vented into the pit. The water used for the flush should be produced until gas appears and the stream can be diverted to the separator. Initial flow can be from both the tubing and annulus, but once flow is diverted to the separator it should only be from the tubing.

As soon as possible, either a surface recording bottom hole pressure gage or two Amerada recorders will be run into the bottom perforated joint of tubing. The pressure element(s) should have a 0 to 3,500-psi range. Oil and gas flow rates will be measured either by a critical flow prover or orifice run. Water and condensate production will be metered and measured in the tanks. Flowing temperatures will also be recorded and samples will be obtained for analysis.

The cleanup and drawdown test could last from 1 to 3 weeks, or more, before the well is shut-in for a buildup. This will depend on the scheduling for the next fracture treatment. A minimum buildup of 2 to 4 days will be obtained.

2.3.8 Final Flowing Temperature Survey

The retrievable bridge plug will be unseated and moved to 5,000 ft after the completion of the last fracture sequence (treatment and testing). An Amerada recorder will be run to total depth to determine the fluid level. If there is a large column of water above the bottom perforations that cannot be lifted by the gas when flowing the well, the bridge plug must be completely removed from the well and the tubing rerun to 30 ft above total depth. Using the tubing for production the water should be blown out of the well bore. The tubing should then be raised to 5,000 ft and the differential temperature log should be run to total depth with the well shut in. The well should be open to flow at a rate between 2 to 3 MMSCFD and the temperature log run from total depth to 5,000 ft. All flow rates should be measured and recorded at the surface.

If the fluid gradient check does not indicate enough water to hinder the temperature survey, the temperature survey should proceed with the bridge plug on the tubing at 5,000 ft. At the completion of the survey the bridge plug can be completely removed from the well.

2.3.9 Production Testing Phase

There will be two main production tests. The first will be after the last treatment in the fall and before the first one in the spring. It is estimated that this period will cover 5 to 6 months. The second test will be started after the last stage is completed and continued to at least January 1976.

2.3.10 Winter Production Test

If the section of RB-MHF-3 is similar to the one cited in Figure 10, it is probable that two of the larger fracture designs will be carried out before the onset of cold weather in October or November. This should encompass the Mesaverde section under consideration for stimulation (approximately 6,240 ft to 6,880 ft).

After the second stage is cleaned up and the flow and buildup tests are completed, the bridge plug will be unseated and removed from the well. The tubing will be rerun and landed at a depth of 20 to 30 ft above total depth and the recorder(s) run to the perforated joint at the end of the tubing. During any of the stripping operations (i.e., moving the tubing and removing the bridge plugs), the gas will be flowed through a three-phase separator, metered, and flared. If possible, once the tubing is in place, the gas well will be flowed into the pipeline (if available) at a rate between 2 to 3 MMSCFD. Bottom hole pressures will be obtained as soon as it is possible to run a pressure recorder.

Surface and bottom hole pressures will be measured during the entire winter period. Flowing surface temperatures will be recorded and gas, water, and condensate samples will be obtained for analysis. Fluid rates will be obtained over the entire test. Fluid gradients will be run periodically to determine if a fluid column has built up in the bottom of the well.

One short buildup (2 to 3 days) will be run after the first month of production and another will be run before the end of the test. This possibly will give an indication of whether the effective fracture flow area is changing.

2.3.11 Production Test (After Completion of Last Fracture)

After the completion of the last fracture, cleanup of the interval, and flow and buildup tests, the bridge plug will be stripped out of the hole. During this operation the flow rate of the gas will be measured. The tubing will be rerun to 20 to 30 ft above total depth and landed. This tubing will have a pump nipple so that a plunger pump can be landed if required. Pressure recorder(s) will be run into a perforated joint at the bottom of the tubing. If possible, the initial flow from the commingled zones will be set at a rate of between 2 to 6 MMSCFD. If sand production is a problem, the rate will be reduced so that sand transport into the well bore is minimized.

As in the winter test, all flow rates, pressures, and other information will be gathered on a routine basis. Buildup tests will be run periodically throughout this testing sequence to again check on whether the created fracture area is changing. This testing sequence is scheduled through January 1976 but could continue beyond that time.

2.3.12 Alternate Tests to Drill Stem Tests

As indicated previously, if the drill stem test program does not obtain the information necessary to determine the millidarcy-feet kh of the intervals, it is planned to fracture in the Fort Union and Mesaverde sections. It would be necessary to pick a representative interval from each formation and run a small fracture treatment on each. The following is the alternate program:

1. Select one representative sand in the Fort Union Formation and one in the Mesaverde Formation. This sand should be selected on the basis of all information available such as logs, gas detection data, drilling breaks, cores, etc. If possible, a sand will be selected that has good gas saturation and a reasonable chance for obtaining a drawdown and buildup test to determine the flow capacity, kh.

2. A gamma ray-collar locator log would be run over the intervals of interest.

3. The Mesaverde sand would be perforated with a casing perforator.

4. Tubing (2-7/8 in.) would be run in the hole with a packer. A small fracture treatment would be conducted similar to the one previously cited in the drilling procedure (Step 40). However, the fracturing fluid would be of the nondamaging type such as polyemulsion, alcohol, etc. Also, nitrogen would be used with the fluid.

5. The well would be cleaned up through the tubing. As soon as possible, the gas will be flowed to the separator for gas and liquid rate measurement.

6. A pressure recorder will be run into a perforated joint of tubing below the packer. Surface and bottom hole pressures will be recorded throughout the test.

7. The drawdown test will be run long enough to obtain a flow geometry such that the effective flow capacity (kh) can be determined. The well will then be shut-in and a buildup will be recorded for a similar time, if necessary.

8. The second treatment will be carried out on the selected Fort Union sandstone.

9. Steps 2 through 7 will be followed.

2.3.13 Water Problems While Drilling and Testing

If, while drilling, there is a sizeable influx of water without enough gas rate to lift the water, the following procedure will be followed:

1. A two- or three-phase separator will be connected to the pipeline that has the critical flow prover.

2. The bit will be raised 2 to 5 ft off the bottom and the hole blown clean of cuttings.

3. When the hole is clean, the air-water stream will be diverted into the separator long enough for a water rate to be determined.

4. Repeat Steps 2 and 3 periodically throughout the remaining portion of the air drilled hole.

If, after fracturing an interval, the water production is too great to be lifted by the flow of gas, as many of the following steps as necessary will be taken in the following order until the problem is solved.

1. Soap or a foaming agent will be injected so that the water can be lifted by the existing gas rates over a test period.

2. A string of 3-1/2-in. tubing will be stripped into the well and landed below the lower perforations. A 2-3/8-in. OD tubing string will be stripped into 3-1/2-in. tubing. A pump nipple will be run on the bottom of the tubing. This tubing will be landed below the perforations, 10 to 20 ft lower than the 3-1/2-in. tubing. A plunger pump will be run and connected to the pump jack. The well will be flowed through the tubing annulus.

3. If the water production is too severe, these intervals will be cemented off completely.

If, when all the intervals are commingled for the production test (long-term test after the last treatment), the water production increases such that the gas rate will not keep the well unloaded, a dual or concentric tubing string could be run into the hole. A plunger pump would be installed to pump the water. The other string would be used to flow the gas and measure the bottom hole pressures.

2.3.14 Equipment Necessary for Testing

A two- or three-phase portable indirect heater-separator will be obtained prior to drilling the 9-7/8-in. hole and move to the well site. A critical flow prover and surface recording pressure and temperature recorder will be used for rate determination.

The necessary bottom hole pressure gages, hoists, lubricators, and other testing equipment will be selected and obtained prior to the testing periods. Selection of the downhole pressure recorder will be based on reliability and accuracy of the instrument for the pressure changes expected, plus availability of spare parts, ease of running, and overall cost. All pressure gages will be periodically recalibrated with a dead weight tester.

3. SITE INFORMATION

3.1 SITE LOCATION

The MHF experiment well is located in S11, T3S, R98W (Figure 12). Four alternate locations were also considered: S1, T3S, R98W; S22, T3S, R98W; S3, T3S, R98W; S31, T2S, R97W. See Appendix B for details on the alternate locations.

3.2 SITE PREPARATION

3.2.1 Well Area

The well area will be cleared, graded for proper drainage, and the native material compacted. Approximately 8 acres of usable surface will be provided for the placement of the drilling and massive fracturing equipment, associated components, and the supporting trailers.

The layout of the area for drilling is shown in Figure 18. The fencing around the reserve pit will be a three-strand barbed wire fence.

The layout for the fracturing is shown in Figure 19. This equipment is required only during the various stages of the massive fracturing treatment and will be removed upon completion. Only that equipment necessary to control the well (if the well is of commercial value) will remain and will consist primarily of the wellhead and production equipment.

Water for the operation will be taken from Fawn Creek adjacent to the location.

Waste disposal will be handled as follows:

1. Drill mud will be buried and appropriate revegetation performed on the disturbed area.

2. Produced fracturing water (saline) will be collected in a lined pit and reused on additional fracturing jobs. Upon completion of the project, the composition of the residual water will be determined and reported to the BLM with recommendations for disposal (i.e., spraying on roads). Disposal will follow BLM stipulations.

3. Sewage collected in tank-type chemical toilets will be transported to one of the local municipal sewerage treatment plants for disposal.

4. Solid waste such as wood, paper, metal, etc., will be collected and transported to one of the municipal dumps for disposal.

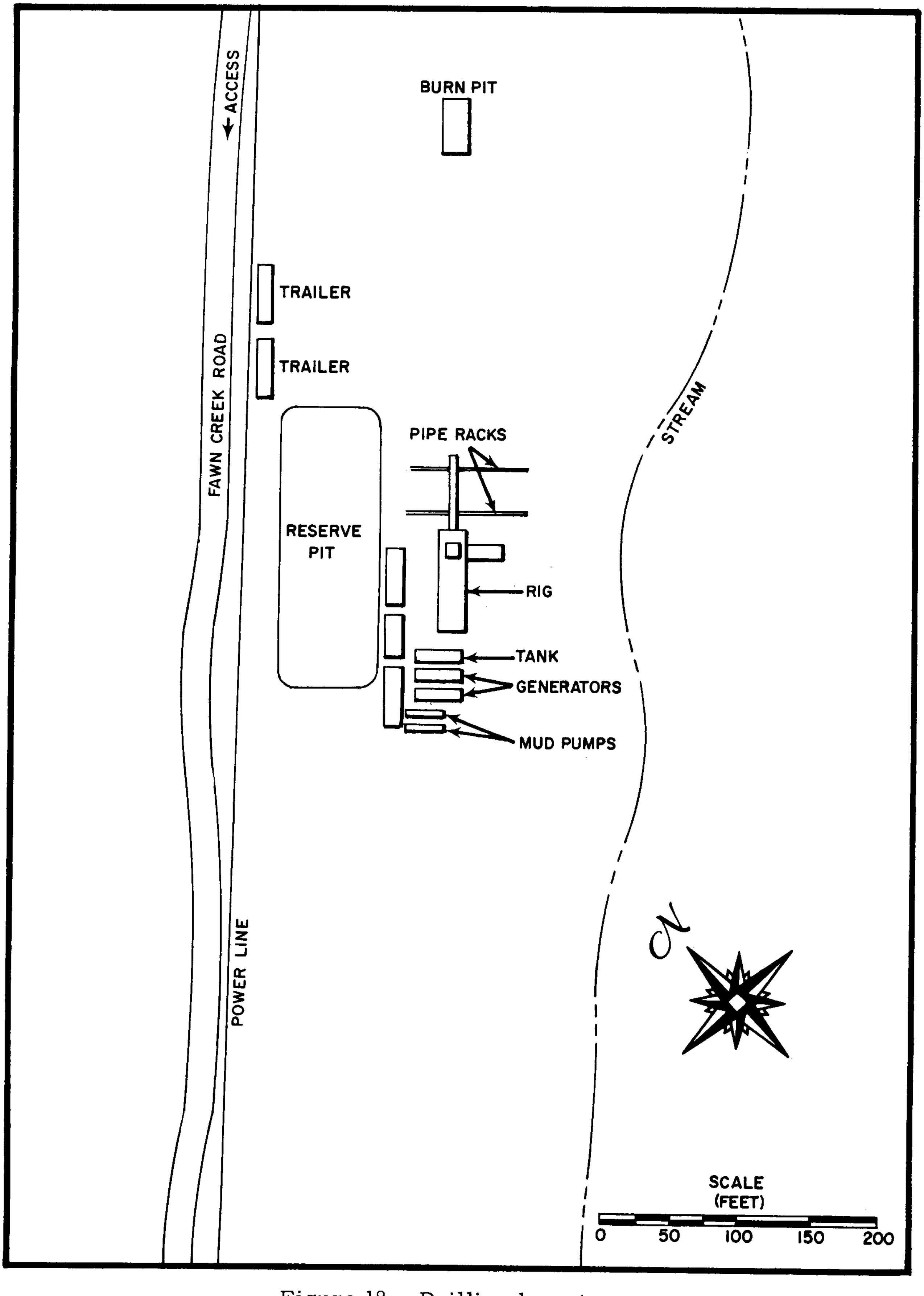


Figure 18. Drilling layout.

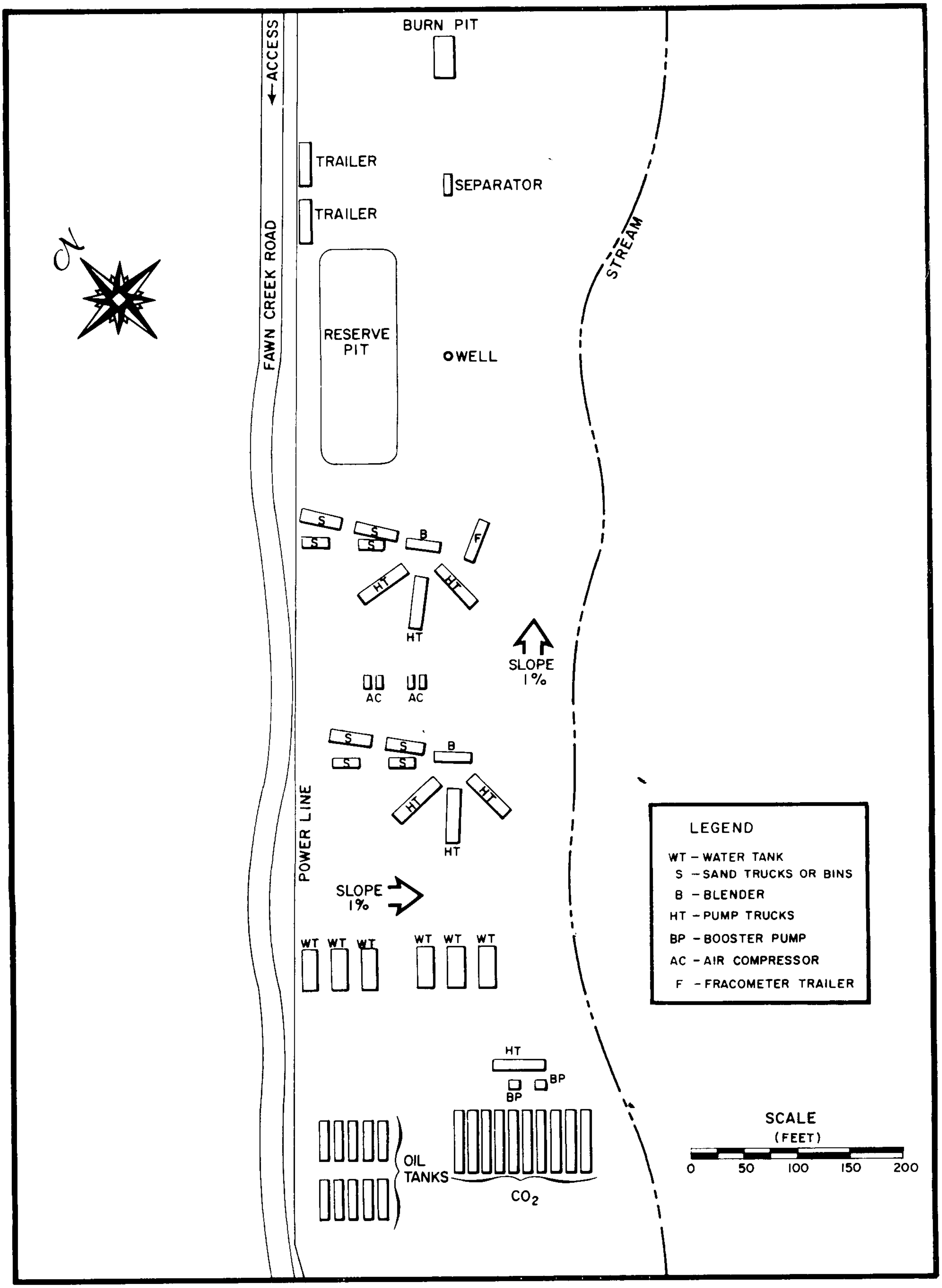


Figure 19. Fracturing layout.

3.2.2 Roads

Roads in the general area include Piceance Creek, Black Sulphur Creek, and Fawn Creek roads as well as unimproved roads used by ranchers during nonwinter months.

Piceance Creek Road is paved from its junction with U.S. Highway 64 (Meeker to Rangely) on the north to Colorado State Highway 789 (Meeker to Rifle) on the east and is maintained by Rio Blanco County.

Black Sulphur Creek Road is maintained by the County and has recently been paved to the Fawn Creek turnoff.

Location of exit from the main highway will be at the intersection of Black Sulphur Creek and Fawn Creek Roads.

Fawn Creek Road is an improved dirt road suitable for oil field type equipment and only minimal maintenance work need be performed.

3.2.3 Restoration of the Area

At the conclusion of the production testing, the temporary facilities will be removed and only those items associated with a standard completed gas well will remain. These items are the well collar, the well head equipment, fencing, and the deadmen for guying of the workover rig.

The piping, tankage, production equipment, and other equipment required for the production testing of the well will be removed from the site and placed in storage, and trailer will be removed.

The remaining area will be regraded to closely match the original contours and, at the appropriate time of the year, revegetated to BLM specifications. Any remaining drilling mud will be sprinkled on the access road and the mud pits will be backfilled.

3.3 POWER INSTALLATION AND DISTRIBUTION

Commercial electrical power is available near the well location. One hundred KVA of 3-phase, 120- to 208-volt, 60-Hz electric power will be available. It will be necessary to add a deadman to the existing power line and not more than two power poles, wire etc. on the well location to provide commercial power to the facilities. These items will be removed upon completion of the massive fracturing program.

The electrical distribution panel for the MHF well (Figure 20) will be equipped with individual safety switches for each major item of equipment

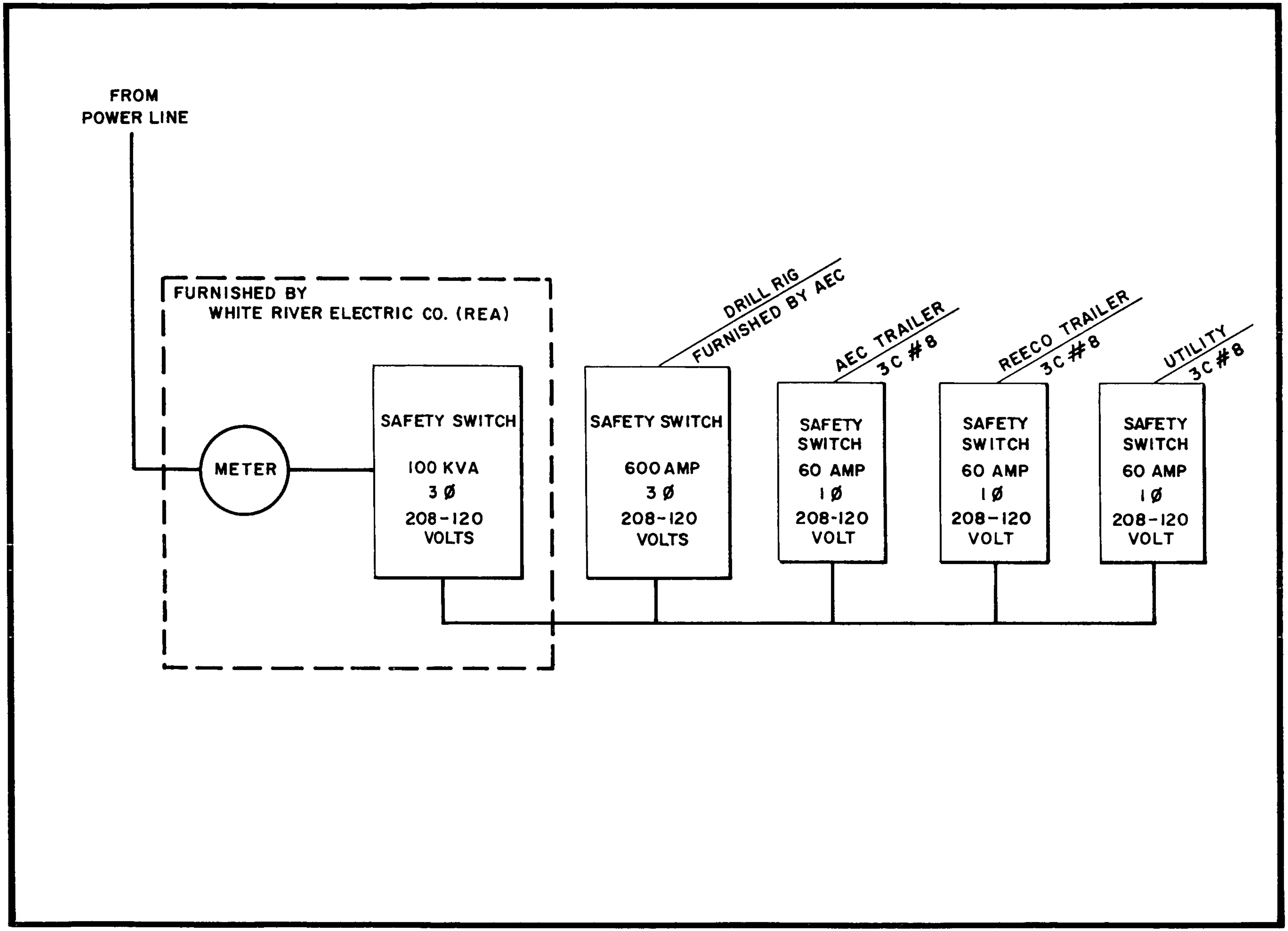


Figure 20. Electric distribution panel.

to allow maintenance without interrupting electric service. Surface-laid electric cables will connect each item of equipment or trailer to the safety switch on the electric distribution panel. Where necessary, the electric cables shall be fenced or buried to protect personnel and to protect cables from vehicular traffic. Cable road crossings will be through conduits or culverts. The electric power distribution system shall have a grounding system utilizing grounding rods.

At the conclusion of the MHF treatment, the surface-laid electric distribution cables will be removed with their corresponding items of equipment. The electric distribution panels will be removed upon project completion.

3.4 COMMUNICATIONS

The principal telephone and radio communication facilities for the project will be located in Grand Junction where the CER microwave telephone system interconnects with the Mountain Bell telephone system.

Microwave communication equipment will be utilized for both the telephone and the VHF duplex radio net. Microwave telephone relay stations will be located at Lands End and Monument Peak with terminal equipment in the CER communications shed approximately 1/2 mile west of the Project Rio Blanco emplacement well. Two-pair signal cable will be laid on the west side of the Fawn Creek access road from the well site to the existing signal cable terminal located in the NW 1/4, NW 1/4, S14, T3S, R98W.

The CER telephone system at the MHF site operates over a microwave link as a direct dialing extension of the Grand Junction telephone exchange of the Mountain Bell telephone system. Four telephone lines will originate in the Grand Junction telephone exchange. Two of the telephone lines will terminate at the MHF site and the other two telephone lines will be retained for use on the Project Rio Blanco location.

Individual telephone numbers will be assigned to each of the four telephone lines from the Grand Junction telephone office. A telephone directory of telephone numbers and respective locations and organizations will be published.

Upon completion of the project, the telephone cable will be removed in its entirety.

A radio relay station is located at Monument Peak to provide adequate radio coverage to mobile and fixed stations in the Piceance Creek Basin.

A limited number of mobile radios will be furnished at cost by CER for use by those project participants directly involved with field activities during the experiment.

In the event of commercial power failure, the microwave telephone system and VHF radio repeater and control station will continue to operate on battery power for a minimum of 8 hours.

Frequencies for the CER VHF radio net are:

Repeater	Transmit	153.350 MHz
Repeater	Receive	158.370 MHz

Transmit frequencies for the microwave system are as follows:

Grand Junction to Lands End	956.700 MHz
Lands End to Monument Peak	953.500 MHz
Monument Peak to EW	956.900 MHz
EW to Monument Peak	953.300 MHz
Monument Peak to Lands End	957.100 MHz
Lands End to Grand Junction	953.100 MHz

Figure 21 diagrams the microwave, telephone, and radio system.

3.5 INDUSTRIAL HEALTH AND SAFETY

3.5.1 General

CER operations and activities will be conducted in accordance with the standards of the Occupational Safety and Health Act of 1970. All participating organizations are responsible for the health and safety of their own personnel and for conducting all activities in accordance with procedures that assure:

1. A safe and healthful environment for their employees.

2. Control and minimization of hazards to the public and to personnel of other participants.

3. Minimization of the accidental damage or loss of company and privately owned equipment, materials, and property.

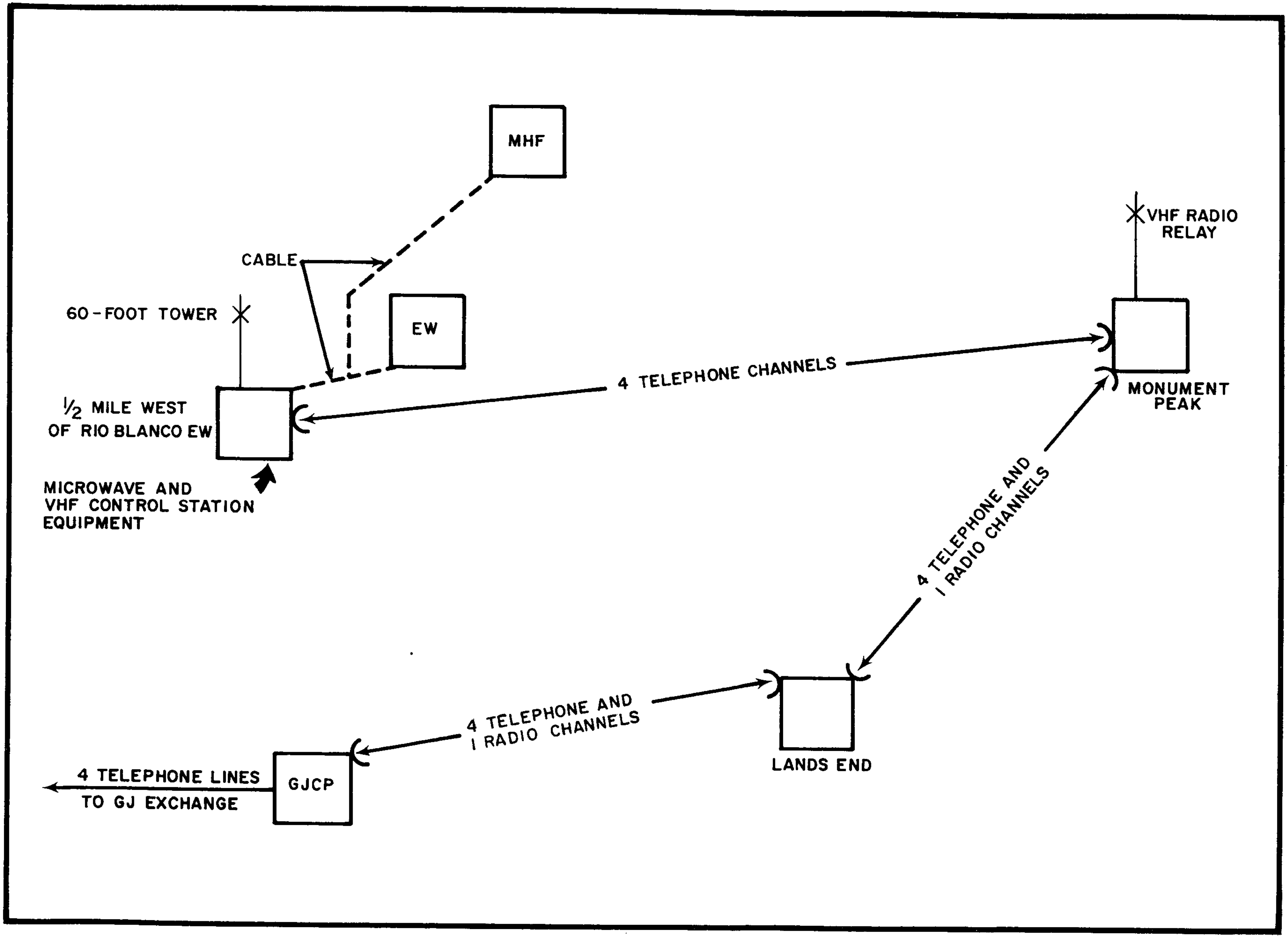


Figure 21. CER microwave, radio, and telephone system.

3.5.2 First Aid

CER will provide each participating agency contacts with local medical facilities and physicians in the Grand Junction, Rifle, and Meeker areas for use in the event of accident or illness. CER will arrange for suitable first aid supplies as recommended by a local physician.

3.5.3 Fire Protection

Hand-operated fire extinguishers will be provided at the well location at points convenient to each significant structure or piece of equipment. Extinguisher types will be supplied for control of Class A, B or C fires, as appropriate.

3.5.4 Industrial Hygiene

Potable water and chemical or standard toilets will be provided. The chemical toilets will be serviced on a regular basis. Solid wastes will be disposed of in accordance with local regulations and in a manner to avoid creation of a hazard to health, insect or rodent harborage, or environmental pollution.

A limited number of office trailers at the well location will be connected to a nonpotable water source and sewage system involving a septic tank. This will be in accordance with Rio Blanco County Planning Directive.

3.6 MISCELLANEOUS SUPPORT

3.6.1 Labor

Due to the remote location of the project and the low level of industrialization in the area, the number of skilled workmen available is limited. Work will be planned accordingly, and if a requirement exists for a special skilled worker not available in western Colorado, sufficient time must be allowed for obtaining one from another labor market.

3.6.2 Office Space

Minimal office space, occasionally associated with living quarters, will be provided at the well location as indicated below:

Organization	Type Trailer	Approximate Size (ft.)
AEC/BuMines*	Office	10 x 50
CER	Office	10 x 40
REECo*	Office	8 x 40

* Drilling Operations Only.

A copy machine will be available.

3.6.3 Miscellaneous Purchase of Materials

The remoteness of the project restricts the quantity and type of supplies and materials available for purchase and quick delivery. Therefore, leadtime becomes very important and since the lack of a minor item can cause lost time, it is imperative that even minor items be considered in planning purchasing requirements. Each project participant also should bring adequate spare parts for possible replacement while in the field.

3.6.4 Fuel and Lubricating Oil

Limited emergency fuel and lubricating oil supplies for vehicles and equipment will be available at the well.

3.6.5 Warehousing

No enclosed storage will be available at the well.

4. PROPOSAL FOR GAS UTILIZATION PROGRAM

The evaluation program of the experiment foresees at least 15 months of production testing. During that time about $200,000 worth of gas may be produced, an amount important enough to avoid wasting by flaring. Furthermore, it is intended to repay the financial contributions of the participants of the experiment out of the sale of gas eventually produced from the stimulated well.

Discussions with various companies indicate it would be possible to conclude a satisfactory gas sales agreement for the gas produced by the project well.

It seems advisable, therefore, to link the well with an available pipeline during the testing stage of the project if a reasonable contract can be made for the gas sale. Several gas pipelines are located in the vicinity of the project well (Figure 22)

The nearest one can be reached by about 5 ½ miles of connecting line just north of the project well. This pipeline, with a diameter of 4 inches, is owned by Western Slopes Gas Company.

According to Rocky Mountain Natural Gas Company, part of this Western Slopes line will be duplicated by them in the near future using 4-inch pipe to the intersection of Black Sulphur and Piceance Creeks and 6-inch pipe from that point to the Cascade Compressor Station located in T2S, R95W, S29.

Just north of this Western Slope line, a 14-inch diameter pipeline owned by Cascade Natural Gas Company connects the Basin with markets in Utah. To connect the project well to this line would take about 8 ½ miles of connecting line to reach the point where it crosses the Piceance Creek valley. At that point a 6-inch diameter line, owned by Rocky Mountain Natural Gas, connects the Cascade line to the town of Craig.

North West Pipeline Corporation has a gathering and compressor plant in T2S, R96W, S5, located about 11 miles northeast of the project well. This station would give access to the 26-inch pipeline owned by the same company and leading to markets in Oregon and Washington.

This 26-inch pipeline and a 6-inch Western Slopes pipeline are located approximately 19 air miles west of the project well. Rocky Mountain Natural Gas plans to construct a gathering system to connect wells in the East Douglas Creek area with the 26-inch line. To reach these pipelines up to about 30 miles of pipeline may be needed because of the topography.

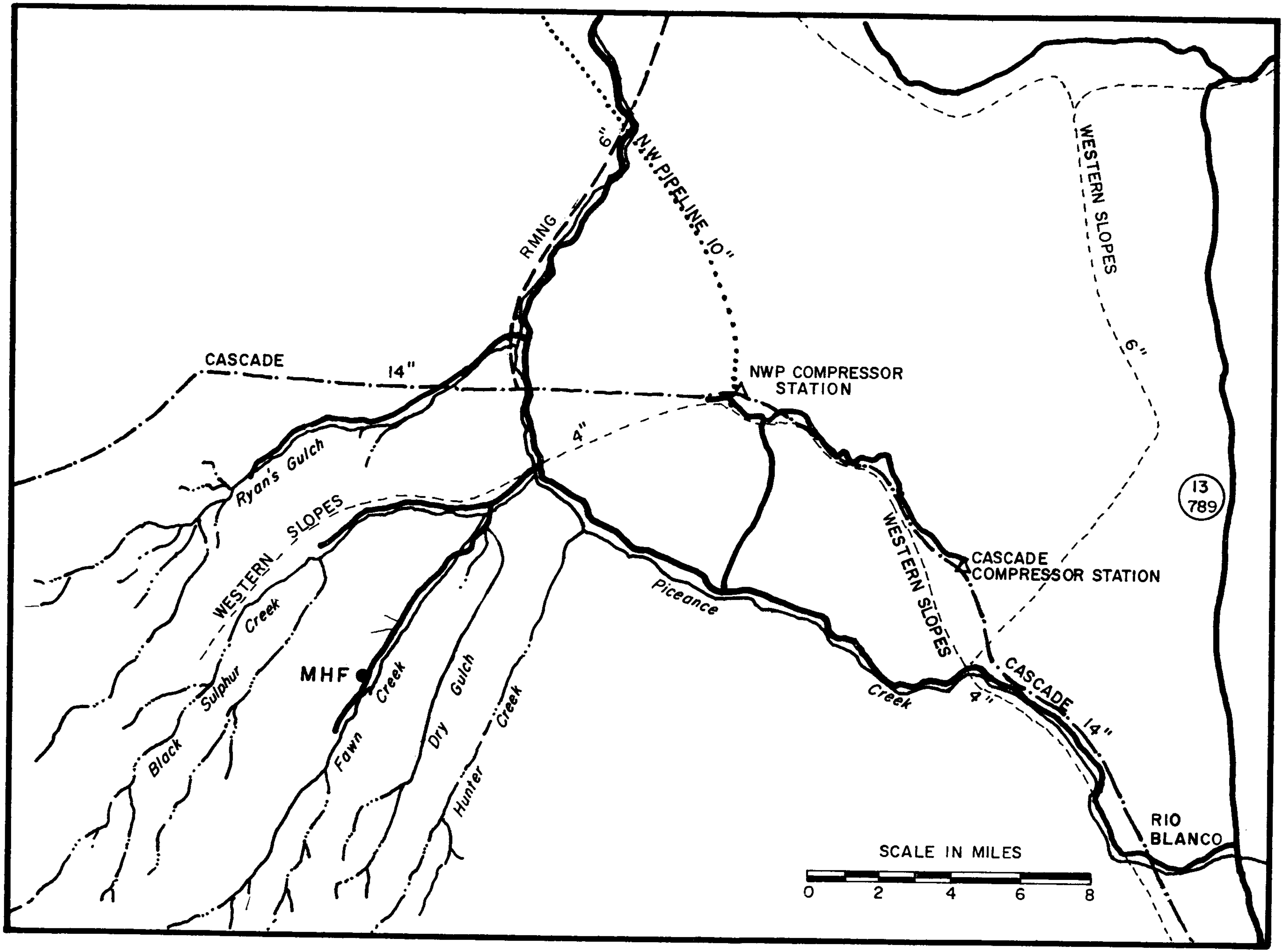


Figure 22. Gas pipelines.

5. ENVIRONMENTAL PROGRAM

To provide data for comparison of the environmental aspects of the massive hydraulic and nuclear explosive fracturing techniques for stimulation of gas production, some environmental parameters will be monitored or documented. These will include the seismicity of the immediate area, radioactivity in the gas produced, the local water quality, and the disturbance of the land and the effectiveness of revegetation. These data will complete the acquisition of information necessary to assess the relative environmental impact of the two techniques recognized as the only ones having potential for recovery of gas from relatively impermeable gas sands in thick formations.

5.1 SEISMICITY

It is known that the injection of large amounts of fluids into subsurface formations can trigger movements on faults and generate earthquakes. The fluid volumes involved in this experiment are not as large as are involved in the water flood of the Rangely field or the injection of waste disposal at the Rocky Mountain Arsenal, both of which have been correlated with earthquakes. In addition, the injection periods will be relatively brief. However, it seems prudent to expend some effort to monitor for any change in seismicity which might be attributable to the MHF operations.

A semi-high-gain seismic station will be activated in a quiet location, preferably at the location established for Project Rio Blanco about 1/4 mile north of the Equity camp on Black Sulphur Creek. Shelter, manpower, and electrical power are available at the camp. Standby battery power will be available to assure continuous operation. The station will have the capacity of detecting but not locating earthquakes of magnitude zero or greater to a radius of at least 20 km. The preferred location is about 6 km from the MHF well. Paper recording will be used with daily paper changes. Paper records will be inspected weekly for any evidence of seismic activity.

The station will be activated about 1 month prior to fracturing operations and will record continuously for a period of 12 months, or 3 to 4 months after the scheduled end of fracturing operations.

5.2 RADIOACTIVITY IN WELL PRODUCTS

It is tentatively planned to sample the produced gas at intervals to provide data on the concentration of natural radon-222 for comparative purposes.

There is some unverified potential that the large void volumes created in a nuclear chimney provide a "holding tank" which would result in reduction of the levels of natural radon-222 activity (half-life, 3.8 days) in the gas when the gas is produced from the well. It is conceivable that this could be a trade-off against addition of artificial radioactivity to the gas by the use of nuclear explosives. Few radon-222 data are available from the Rulison and Gasbuggy projects. However, gas samples from the Project Rio Blanco testing are being regularly analyzed for radon-222, although much of the data is not yet available. It may be possible to conclude from the Rio Blanco analyses whether or not the effect of radon-222 reduction exists. If this is not possible, it is planned to provide comparative data by taking samples for radon-222 analysis at the following intervals. In any event, adequate chemical and radiochemical analyses will be made on gas samples taken after each fracture treatment.

5.2.1 Long-Term Production Test

For the long-term production test of the combined fracture zones, duplicate samples of produced gas will be taken at plus 1 day and monthly thereafter until the conclusion of the test. The gas samples will be analyzed for radon-222.

5.2.2 Sources of Laboratory Work

Commercial laboratories offering the desired analysis services will be used, provided that they have intercalibrated with the National Bureau of Standards (NBS) or with other laboratories traceable to NBS.

5.3 WATER QUALITY

There is some potential for leakage of saline fluids into Fawn Creek adjacent to the well pad, which suggests a modest program of sampling the creek water flow. Accordingly, a fixed sampling point will be selected at a conveniently accessible location both up- and downstream prior to, and during, the drilling activities. Subsequently, sampling will be repeated once within 2 to 3 days after each fracture operation. Samples will be analyzed for electrical conductivity and for the principal chemical constituents with emphasis on those used in the fracturing fluids. Samples will be analyzed in a Grand Junction laboratory and the results summarized in the Final Report.

5.4 DISTURBANCE OF LAND AND EFFECTIVENESS OF REVEGETATION

Substantial experience in documenting and manipulating the vegetation in the Piceance Basin is in the literature, particularly documents of the Bureau of Land Management (BLM).* In particular, the successional development of plant communities in the area is definable from the BLM experience in development of grazing areas and by inference from inspection of abandoned pasture land.

*For description of vegetation relevant to proposed site, see K. J. Schiager, et al, Biological/Ecological Considerations, Project Rio Blanco, dated July 1971.

It is planned that management of top soil, clearing of vegetation, and reseeding will be done according to the specifications of the BLM. The effectiveness of the revegetation can best be evaluated by inspection and approximate measurement of the disturbed area after completion of the fracturing operations and by inspection at the end of the first and second full growing seasons after seeding.

5.5 COMPARATIVE ANALYSIS OF ENVIRONMENTAL ASPECTS OF MHF AND NUCLEAR STIMULATION

As a portion of the overall comparison of the MHF techniques with the Rio Blanco nuclear stimulation experiment, the environmental aspects will be evaluated relatively. Consideration will be given not only to the environmental parameters monitored for the MHF project but also to available data on air and water quality, quality of the produced gas in a radiological sense, site population, disturbance of the local population, disturbance of vegetation, disruption of wildlife, and seismic effects. Possible differences in well spacings to develop the field would be considered in attempting to quantify the environmental costs.

6. DELIVERABILITY ASSESSMENT

6.1 DATA FROM RB-MHF-3

The overall design for this MHF experiment endeavors to provide information on two important aspects affecting deliverability; the reservoir parameters and the fracture characteristics. The information will be obtained from a number of sources; i.e., geophysical logs, mud logs and gas flow rates while drilling, core analyses, drill stem tests results, fracturing data, impression packer/borehole TV, and production information. The data gathering program will be initiated during the drilling operations and will continue through the final testing phase. This data acquisition program was presented in detail in Section 2.

6.2 DELIVERABILITY ASSESSMENT CALCULATIONS

The information obtained from the drilling completion, logging, and each of the individual fracture treatments should provide the basis for an estimate of the reservoir and fracture characteristics of the zone and an initial estimate of the zone's deliverability. The estimates can be made by matching the flow rate-pressure behavior of the zone with calculated fracture and reservoir properties. The matching process should result in a mutually consistent picture of the permeability and sand cross sectional area (kA) intersected by the propped portion of the fracture.

The technical evaluation of the individual zone fracture performance and the calculations of kA will be made by the Project Manager's technical staff and reviewed by the Advisory Committee. The evaluation of each of the zones will be summarized in an individual zone fracture-production report which will be issued at the end of each stage. A final summary fracture production report will be issued within 180 days of the completion of the fracture and cleanup of the last zone. The final fracture-production report will include a summary of the fracture cost information. These reports will be prepared by the Project Manager's technical staff and reviewed by the Advisory Committee.

After the completion of the individual zone fracturing, the well will undergo long-term testing with all zones producing. The long-term production-pressure data from the combined zone testing will be matched with the kA and fracture geometry information. An initial calculated reservoir continuity factor will be obtained as an output from this matching process and an initial estimate of long-term deliverability will be developed from the matching. The deliverability estimate will be compared with the calculated reservoir properties and fracture geometry to develop fracture efficiency information.

The deliverability assessment will be prepared by the Project Manager's technical staff and reviewed by the Advisory Committee. This information as well as a final cost summary will be included in the final project summary report which will be issued within 180 days of the completion of the project.

6.3 COMPARISON WITH RIO BLANCO NUCLEAR WELL

The MHF deliverability and cost assessment will be compared with equivalent deliverability and cost assessment data from the Rio Blanco nuclear project if the latter data are available.

Definitive nuclear fracturing performance data was not obtained from the initial Rio Blanco reentry well. An addition reentry well is to be drilled in the same time period as RB-MHF-3. The drilling program consists of drilling into the fractured region, and cavity if possible, created by the middle explosive of the three-explosive experiment. This well should yield additional information about the fracture extent and reservoir flow capacity (kh).

If the gas delivery and nuclear fracturing cost information from the Rio Blanco nuclear experiment is available prior to the completion of the MHF experiment, the nuclear fracture-MHF fracture deliverability and cost comparison will be prepared by the Project Manager's technical staff and reviewed by the Advisory Committee. This information would be summarized in the final Project Summary Report.

7. PROJECT ADMINISTRATION

7.1 MANAGEMENT

The Project Manager (CER) is responsible for managing and implementing all the project activities and programs required by the Project Definition and the recommendations of the Advisory Committee. An Advisory Committee will be established consisting of representative of each industrial participant plus four from the Government, two from the AEC, and two from the Bureau of Mines. The members of the Advisory Committee will be kept informed on all activities and, as appropriate, meetings will be called either by the Project Manager or at the request of three or more members. The Project Manager will provide the Chairman to the Advisory Committee and the Secretary who will be responsible for keeping a record of all actions and decisions of that Committee. Two small working subcommittees, one for the fracturing activities and the other for analysis, will be established to provide technical advice to the Project Manager. The Project Manager will provide a Project Engineer who will work closely with each of these subcommittees and be responsible for carrying out the technical and field activities identified in the MHF Project Definition or recommended by the Advisory Committee.

7.2 PUBLIC INFORMATION

CER will draft all public information announcements, upon its own initiative or as may be suggested and agreed upon by the project participants; plan and conduct visits to the site for individuals, newsmen, public officials, and other interested groups and individuals; and plan and conduct briefings and meetings as may be necessary and agreed upon by the participants.

CER will coordinate information actions with the AEC through the Nevada Operations Office/Office of Information Services and other project participants as appropriate.

All information actions taken by CER will be coordinated in advance with those participants who wish to be involved except where time does not permit such coordination.

7.3 REPORTS

It is intended that all technical information utilized in or developed in connection with the project will be available to the public. This data will encompass reports, records, logs and other information generated by the project. The Project Manager will provide information, data, and technical reports directly to the industrial participants and, at the same time, to the Government. The Government will be responsible for making this information available to the general public through its open file system.

The publications can be purchased at the following locations:

U.S. Atomic Energy Commission
Technical Information Center
Post Office Box 62
Oak Ridge, TN 37831
(Check should be payable to Microsurance, Inc.)

National Technical Information Service
U. S. Department of Commerce
Springfield, VA 22151

The publications will also be available for public inspection in full size copy at the following locations:

U.S. Bureau of Mines
Bartlesville Petroleum Research Center
Virginia and Cudahy Streets
Bartlesville, OK 74003

U.S. Atomic Energy Commission
Nevada Operations Office
2753 South Highland Drive
Las Vegas, NV 89102

U.S. Bureau of Mines
Office of Mineral Resource Evaluation Library, Bldg. 20
Denver Federal Center
Denver, CO 80225

In addition to the collection of basic data such as logs, core analysis and chemical analysis, two types of reports will be generated. Those prepared for routine operating purposes and informing various members of the Advisory Committee, and formal reports prepared for general distribution.

7.3.1 Operating Reports

The Project Manager shall be responsible, with the assistance of the participants, for gathering, assessing, and compiling information and data from its staff, the participants, the Government, and all other persons involved in the project and the reporting and publishing of such data and information as may be appropriate, including:

1. Minutes of the meetings of the Advisory Committee
2. Daily drilling reports
3. Biweekly progress reports
4. Monthly project cost information
5. Fracture production summary reports

7.3.2 Formal Report

One formal report is currently anticipated. This final report will be a comprehensive project report prepared at the conclusion of the project. It will include a stated breakdown of all the costs and expenses of the project and a summary of the overall aspects of the project including recommendations on future courses of action. It will include a review of all aspects of the MHF experiment in detail so that the environmental, deliverability, and economic factors may be compared with the Rio Blanco nuclear stimulation experiment.

8. COSTS AND SCHEDULING

8.1 COSTS

The MHF experiment has been designed by a group of experts to gain the most information practicable from a series of individual fractures. To do this requires extensive coring, logging, and testing to delineate the reservoir and the actual fractures may well be tailored as a result of the preceding operations. This set of criteria makes precise costing difficult and, therefore, the Review Committee reviewed the initial plans and reduced their scope. The result is an estimate of $1.4 million for the fracture phase of the experiment to be paid by industry and $975,000 for the Project Definition, organization, drilling, and preparation of the hole. This expense is to be borne by the Government.

CER has a dual role in that its personnel will perform certain parts of the work as well as being Project Manager for the experiment. It will be compensated by way of a fixed fee. In the following cost estimates, CER personnel's time was estimated (and will be costed) without profit in as much as the fixed fee is separately identified.

Estimated costs of the MHF work to be funded by the Government.

1. Contract AT(26-1)-623	
Phase I	$85,557
Phase II	127,467
2. Drilling and preparation of hole	721,083
Contingency	40,893
Total	$975,000

Estimated costs of the MHF work to be funded by industry.

<u>Four Fracture Treatments</u>

Condensate for four treatments (based on 50% makeup after each job)	$140,000
Fracture	498,400
Tankage rental and transport	47,952
Perforating	6,000
Workover	35,400
Downhole equipment	23,200
Surface equipment	27,060
Nitrogen service and coiled 1-in. tubing	17,400
Purchase and installation of production facilities	25,000

Installation of tanks and piping	$ 22,000
Construction of workover platform	15,000
Technical support	61,048
Miscellaneous (haulage, utilities, etc.)	10,490
	$929,050

Analysis

Purchase of well testing equipment	$ 38,150
Temperature profile logging	5,900
Fluid analysis	5,100
Differential temperature log	3,000
Technical support	88,038
Equipment maintenance	16,000
Miscellaneous costs (haulage, utilities, etc.)	10,900
	$167,088

Legal and accounting	$ 30,000
Reports	30,000
Environmental evaluation and comparison	17,500
Production evaluation and comparison	12,862
Program management	63,500
Closeout and reclamation	30,000
CER fixed fee	120,000
	$ 303,862
Total	$1,400,000
Contingency	$ 125,000

SUMMARY OF TOTAL COST FOR MHF EXPERIMENT

Government funding	$ 934,107
Contingency	40,893
Industry funding	1,400,000
Contingency	125,000
Total Experiment Cost	$2,500,000

The total cost of the MHF experiment is misleading to the extent that it does not reflect the contribution of the technical committees that were staffed voluntarily, largely by industry, to design and critique the experiment. The monetary value of this contribution must be at least 10 percent of the total projected cost of the experiment and without this work and the Government's willingness to fund the Project Definition, the project could not have been established.

8.2 SCHEDULING

For the purpose of this estimate, we will assume that the initiation of project fielding will occur on May 15, 1974, and that project wrap-up will be initiated on January 1, 1976. The timing of the major operations is displayed in Figure 23.

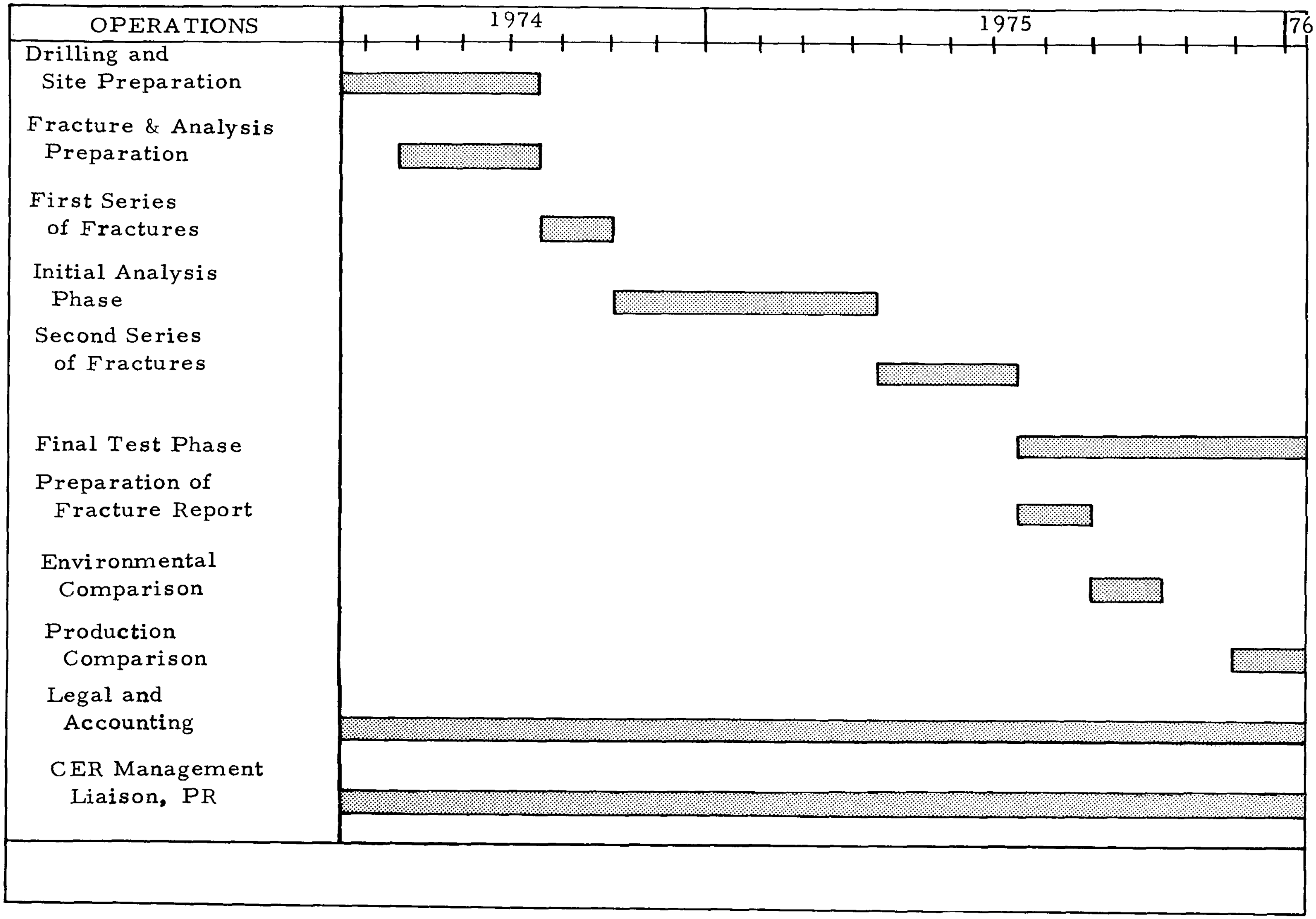


Figure 23. MHF schedule.

APPENDIX A
LOG QUALITY CONTROL CHECKLIST

INTRODUCTION:

Many important decisions in the life of a well are based, at least in part, on log interpretation. The quality of a log interpretation can be no better than the quality of the log itself. The time to assure the quality of a log is, of course, at the time it is being run. There is no opportunity to correct a log for errors, oversights, or omissions at any later date. To insure good quality logs a quality control checklist has been prepared.

The checklist has been designed to prompt the responsible engineer or geologist to get together with the logging engineer at the well site to discuss the logging job and examine the logs for quality. It is imperative that the field prints be accurate, complete, and of good quality since important decisions are based on the information recorded on these copies. This checklist places most of the responsibility for a good quality log on the service company logging engineer as it should be. However, it also requires that the responsible representative take an active part in the logging operation, which, theoretically, is the reason he is at the well site.

The checklist presented here contains 43 checks pertaining to all types of logs commonly run. In addition, there is space provided to insert checks which may cover local conditions. This list lets the logging engineer know what we desire and need to insure adequate log quality. These checks are presented on both sides of a single page. After filling out the heading and Section I in the office, the responsible representative takes the checklist to the well site at the time of logging and presents it to the logging engineer prior to the logging operation. The logging engineer is requested to indicate whether or not he performed the applicable checks by marking in either the "Yes" or "No" column opposite the check. For an acceptable log, the answers should all be "Yes". If the answer to a check is "No", the logging engineer is asked to discuss this item with the responsible representative; and he should explain why the answer is "No". If the answer to a check is "No" and hole conditions, rig time considerations, or other reasons do not permit its correction, we at least know the limitations of the log quality. This is better than not knowing that a log may be faulty.

DISCUSSION:

In the following paragraphs the checklist and the individual checks are discussed.

HEADING

This part of the form should be filled out in the office prior to leaving for the well site. This would insure that the information is correct and exactly as we want it to be. Space is provided to list the logs to be run and the intervals to be logged on both the detail depth scale (usually 5" = 100') and small depth scale (usually 2" = 100'). When running an acoustic log, the intervals to be logged with the three foot span and one foot span could also be listed here.

I. TO BE CHECKED BY THE CER REPRESENTATIVE

THIS SHOULD BE CHECKED BEFORE LEAVING OFFICE

CHECK NO.

1. This is particularly important if an unusual type of mud was used. Most mud descriptions on log headings are too general and often inaccurate.

2. Since the fluid in the invaded zone depends upon the type of mud used to drill a particular zone, it is important to know the depth at which any major mud property changes occurred. This will have a bearing on the interpretation of the log.

3. Hole size and casing size can have an effect on log response; so it is important to know where a change occurred. This information is also important to the logging engineer in running the logs.

4. Unusual hole conditions would be such things as lost circulation, tight hole, dog legs, salt water flows, etc. These factors can have an effect on log response and are also important to the logging engineer in running the logs.

5-6. Two spaces are provided for inserting checks to cover local conditions or conditions pertaining to a particular well.

II. GENERAL

7. This is, of course, only necessary for resistivity or conductivity measuring logs. Do <u>not</u> obtain the sample from the mud pit if

avoidable. If you or the logging engineer cannot be there at the proper time to secure a flow line sample, leave word for someone else to do it.

8. The mud cell must be clean and free from air bubbles. This is most important in mud filtrate (Rmf) measurement since it is done in a small volume cell. We have seen cases where the field Rmf measurements were in gross disagreement with laboratory measurements. This was probably because of salt in the cell left over from the last logging job or air bubbles in the cell.

   Rmc measurement is required only for microlog or microlaterolog-type surveys.

9. Agreement between two separate tests insures that the mud cell was clean and free from air bubbles.

10. This would provide a better approximation of bottom-hole temperature. Many times the mud column has not had time to warm up to formation temperature; therefore the thermometer reading on the first run in the hole will be too low. If a thermometer is attached to subsequent logging runs, the maximum reading may be more representative of bottom-hole temperature.

11. Checking the equipment while going in the hole reduces the time the tool must be kept at bottom and can sometimes save having to repeat an entire trip.

12. This will show if there is any appreciable drift in the logging tool. If there is much drift, consider having the log rerun.

13. This should be done with all logs. If the repeat is enough different from the original so as to change your interpretation, repeat again or, if possible, use a different tool.

14. Much of the most important work is done with field prints. These copies should be as complete and accurate as possible.

15. This is usually applicable only to deep wells where more than one run is required to log the well. Overlaps contain information about the degree of invasion and general repeatability of the logs.

16. This comparison will point out any gross errors in the scales of the logs. Shale readings are probably the most reliable to compare. Water sand characteristics can change because of changes in water resistivity or porosity.

17. We have seen cases where the logging engineer was apparently taken by surprise by very high resistivity zones and did not have the necessary back-up (high-scale) galvanometers set up to record the high resistivities; consequently no curve of any kind was recorded through the zone.

18. If a particular tool has been malfunctioning, we can identify it by this information and take precautions not to run it again until the trouble has been corrected.

19. Depth control is a very important item. If there is a gross disagreement between two or more logs, it must be determined which is correct.

III. ELECTRICAL LOG AND SP CURVE

20. These anomalies usually show up as sharp, hashy deflections or sine-wave type deflections superimposed on the SP curve. Magnetism (winch drum or cable magnetized) is characterized by a sine wave of constant frequency superimposed on the SP curve. Bimetallism is recognized as sharp SP reversals, usually opposite high resistivity zones.

21. These are the first things to check. Other causes of SP troubles are sources of electrical noise, such as generators, welders, radio transmitters, highlines, etc. These should be shut down, if possible, while logging.

22. In a given area, the magnitude of the SP depends primarily on the mud resistivity. The scale used on the log of a nearby well may not necessarily be the optimum one on the offset if the mud resistivity varies appreciably between the wells.

23. Drift of the SP baseline frequently occurs and is not necessarily a sign of a faulty log. However, it is important, if it is necessary to make an adjustment for this drift, that it be done abruptly, and

so noted on the log, rather than a gradual, continuous correction. SP deflections are measured from the SP baseline so it is important that the baseline be in its natural position.

24. The short normal, long normal, and lateral should read approximately the same in shales or other noninvaded zones. Some differences may be attributed to differences in hole effect on the curve responses. This difference is accentuated if the mud is of low resistivity.

25. If the resistivity curves read less than zero, the tool is not calibrated correctly.

26. If log is run faster than this, detail will be lost.

IV. INDUCTION-ELECTRICAL LOG

27. This should be routine procedure. It is particularly important to do this in low resistivity mud.

28. If they do not, they are not calibrated correctly.

29. It is fairly common that these curves do not check exactly. When making log calculations, it is best to use the conductivity curve and to convert to resistivity manually.

30. Self-explanatory.

V. LATEROLOG, GUARD LOG-FOCUSED LOG

31. SP in salt muds with laterolog-type tools are not always usable but should be obtained. There is no extra cost for this service. Probably the best SP will be obtained while running into the hole with the survey current off.

32. Discussed previously in 29.

VI. MICROSURVEY (ML, MLL, CONTACT, FORXO, ETC.)

33. The rubber insulation on the pads should be in good condition and free from cuts and cracks. The electrodes should be properly recessed to prevent shorting out while logging.

34. Self-explanatory.

35. This will give a good value for Rm only if a sufficiently enlarged section of the hole is encountered. This mud check should be recorded on all field and final prints.

36. By noninvaded zones, we mean primarily shales and tight zones. There is no reason why these curves should not read approximately the same value in such zones. If they do not, something is wrong.

37. Logging faster than 2,500 fph runs the risk of hanging up and losing the tool in the hole.

VII. ACOUSTIC-SONIC LOGS

38. The film should be examined for these characteristics. If the mud happens to be gas cut, the sonic log will show excessive cycle skipping.

39. Forty microseconds per foot represents a velocity of 25,000 fps. No lithology should have a velocity greater than this; therefore travel times less than 40μ seconds/foot indicate that something is wrong.

40. This is an average maximum logging speed. If the sonic log is run by itself, or with the caliper, particularly the 3-foot span, it can be run faster than this (~4,000 fph). However, if a gamma ray is run with the sonic log, it will require a slower speed (~3,000 fph).

VIII. NUCLEAR LOGS (GAMMA RAY, NEUTRON, DENSITY, CHLORINE)

41. This shows what deflections are indicative of lithology changes and which are simply random, statistical variations.

42. If the statistical variation is more than this, consider having the log rerun with different instrument settings or, if possible,

a different tool. The designation "clean" line refers to the gamma ray while "tight" line refers to the neutron log.

43. Neutron response is affected by the fluid in the hole; so it is important to know if the hole was full or not.

Two spaces are provided for nuclear log checks which might pertain to local conditions or individual wells.

IX. ADDITIONAL CHECKS AND/OR REMARKS

This space is for any additional checks for other logs or local or individual well situations. This section should also be used for recording any comments on the logging job which may have a bearing on the future interpretation of the log. Explanation of any items checked "No" may also be written here.

It is suggested that both the service company logging engineer and the responsible representative sign their names in the space provided.

LOG QUALITY CONTROL CHECKLIST

LOGGING ENGINEER CHECKS ALL ITEMS APPLICABLE TO LOGGING OPERATION
AND DISCUSSES ANY ITEMS CHECKED "NO" WITH CER REPRESENTATIVE

WELL____________________ LOC.____________________

COUNTY____________ STATE________ ELEV.______ DATUM________

NO. OF FIELD PRINTS ____________ FINAL PRINTS____________

LOGGING COMPANY__________________ DATE____________

LOGS RUN	INTERVAL-DETAIL SCALE	INTERVAL-2" = 100' SCALE

	YES	NO	I. TO BE CHECKED BY CER REPRESENTATIVE
1.			Accurate description of mud is furnished logging engineer and included in log heading.
2.			Depths at which any major change in mud properties occured are included in "Remarks" of log heading
3.			Depths at which any hole or casing size changes occur are included in "Remarks" of log heading
4.			Depths at which any unusual hole conditions were encountered are included in "Remarks" of heading
5.			
6.			

II. GENERAL

	YES	NO	
7.			Mud sample taken from flowline immediately before coming out of hole for logging
8.			Rm, Rmf, and Rmc measured and recorded along with temperature of measurement. Mud cell was clean and did not contain air bubbles when measurement was made.
9.			Repeat Rm, Rmf measurement w/ refilled cell. Repeat measurement within 2% of first measurement
10.			Maximum bottom hole temperature measured and recorded on all logging runs
11.			All logs checked going into hole to check surface and downhole equipment
12.			Calibration checks and electrical zeroes properly recorded before and after logging runs
13.			Log bottom 200' or zone of interest twice and compare both runs
14.			Include all scales, calibrations, repeat runs, overlaps, etc., on field prints
15.			Overlap previous runs in same well by 200' and compare
16.			All logs compare favorably with nearest control wells (Shale and water zone readings compare)
17.			Sufficient back-up galvanometers used so curve is recorded through all intervals
18.			Detailed tool description and designation included in log heading
19.			Depths to recognizeable markers agree on all logs in the same well

III. ELECTRICAL LOG AND SP LOG

	YES	NO	
20.			SP curve and pickup normal with no anomalies due to magnetism, bi-metallism, stray currents, etc.
21.			If SP abnormal (see 20) re-run with survey current off and/or check ground electrode
22.			Adequate SP sensitivity (about 5 divisions deflection from shale line to "clean" line)
23.			SP baseline drift corrected abruptly (not gradually) and so noted on the log
24.			Resistivities of each curve close to same value in shales if fresh mud and hole not enlarged
25.			Resistivity curves do not read less than zero
26.			Maximum logging speed did not exceed 6,000 fph

(OVER)

IV. INDUCTION-ELECTRIC LOG (CHECK ALSO 20, 21, 22)

	YES	NO	
27.			Stand-off devices used on induction log sonde
28.			Induction and short normal curves read greater than zero
29.			Induction resistivity curve checks with conductivity curve (R = 1000/C)
30.			Maximum logging speed did not exceed 6,000 fph

V. LATEROLOG, GUARD LOG, FOCUS

	YES	NO	
31.			SP run with log, going in hole if necessary, even in salt mud
32.			Resistivity curve checks with conductivity curve (R = 1000/C)

VI. MICROSURVEY (ML, MLL, CONTRACT, FORXO, ETC.)

	YES	NO	
33.			Microsurvey pads in good condition
34.			Caliper run with all surveys with check in casing
35.			Rm checked with collapsed micro sonde
36.			Microlaterolog-type curve does not read higher than laterolog-type curve in non-invaded zones
37.			Maximum logging speed did not exceed 2,500 fph

VII. ACOUSTIC, SONIC LOGS

	YES	NO	
38.			No excessive noise spikes, cycle skipping or other spurious anomalies
39.			Log travel times exceed 40 micro-seconds per foot
40.			Maximum logging speed did not exceed 3,600 fph

VII. NUCLEAR LOGS (GAMMA RAY, NEUTRON, DENSITY, CHLORINE)

	YES	NO	
41.			Statistical checks made from all nuclear logs. Statistics preferably made for 2 minutes in shale and 2 minutes in dense zone. Statistics made at same instrument settings as final log.
42.			Peak to peak variation of statistical checks does not exceed 1/5 the distance from the shale line to the "clean" line (or "tight" line)
43.			Fluid level detected while going in hole with nuclear log and recorded

IX. ADDITIONAL CHECKS AND/OR REMARKS

LOGGING ENGINEER ______________________ CER REPRESENTATIVE ______________________

APPENDIX B
ALTERNATE WELL LOCATIONS

LOCATION: S1, T3S, R98W

Same as Location S11, T3S, R98W except for the following items:

See the attached generalized drawing for the proposed equipment layout at the alternate well location. This equipment is required only during the various stages of the massive fracturing treatment and will be removed upon completion. Only that equipment necessary to control the well will remain and will consist primarily of the wellhead and production equipment if the well is of commercial value.

Drill mud will be buried and appropriate revegetation performed on the disturbed area. Sewerage will be collected in tank-type chemical toilets and transported to one of the local municipal sewerage treatment plants for disposal. Solid waste such as wood, paper, metal, etc., will be collected and transported to one of the municipal dumps for disposal.

Commercial electric power is available in the Fawn Creek valley and will be utilized for electric power during the drilling and massive fracturing programs. It will be necessary to add a deadman to the existing power line and not more than two power poles, wire, etc. on the well location to provide commercial power to the facilities. After completion of the massive fracturing program, these items would be removed.

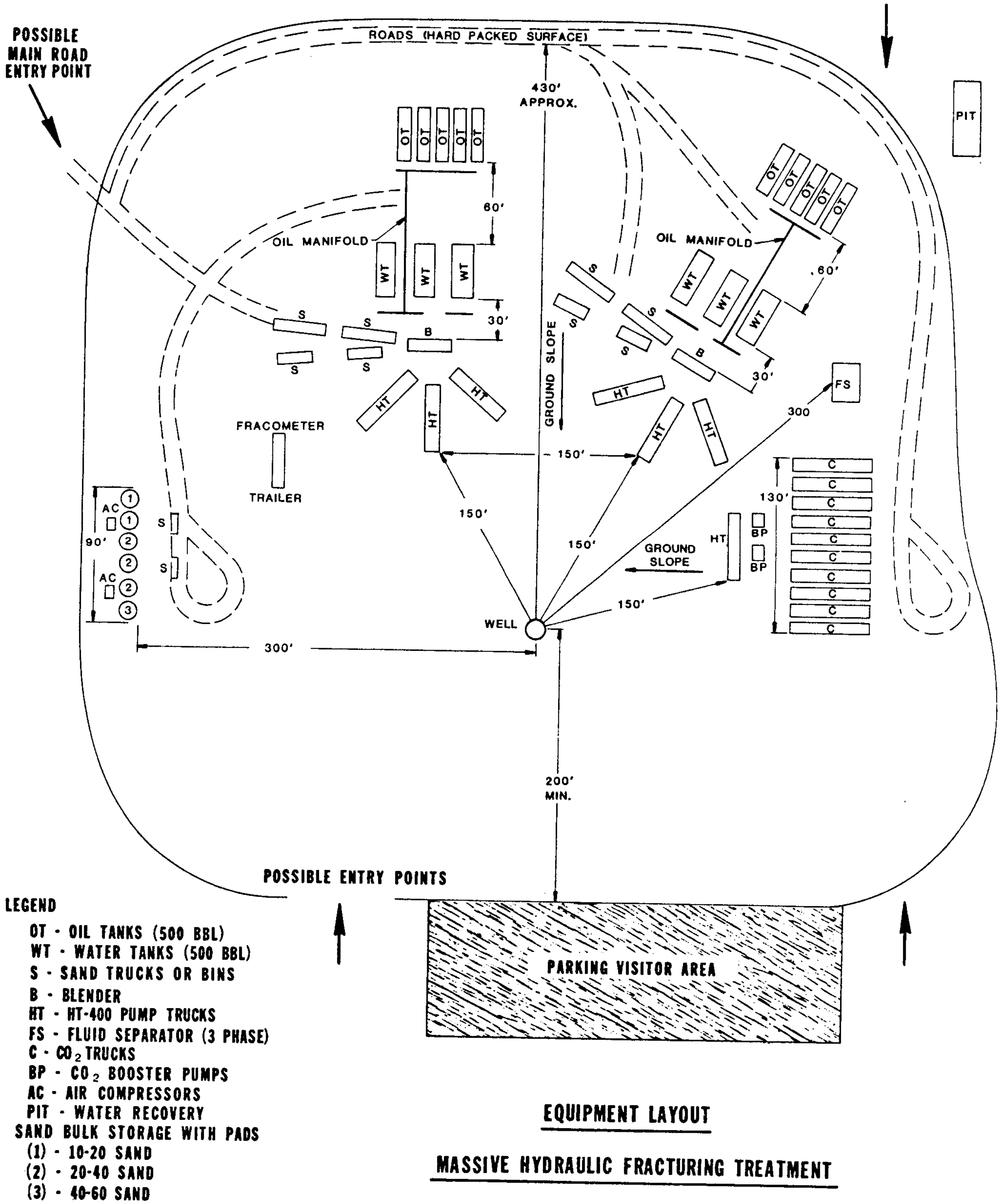
A microwave telephone system will be utilized to provide telephone communications to the well location. It will be necessary to install the following temporary facilities to provide telephone service:

1. Tower with antenna
2. Microwave enclosure (30 cu. ft).
3. Power cable (surface laid) to microwave system.
4. Signal cable (surface laid) to telephones.

Upon completion of the massive fracturing program these items would be removed.

LOCATION: S22, T3S, R98W

Same as Location S1, T3S, R98W except that the electric power required for the facilities at the well location will be generated on the site.



EQUIPMENT LAYOUT

MASSIVE HYDRAULIC FRACTURING TREATMENT

LOCATION S3, T3S, R98W

Same as Location S1, T3S, R98W except for the following items:

Roads in the general area of the experiment include Piceance Creek and Black Sulphur Creek roads as well as other unimproved roads used by ranchers during nonwinter months. Piceance Creek Road is paved from its junction with U.S. Highway 64 (Meeker to Rangely) on the north to Colorado State Highway 789 (Meeker to Rifle) on the east and is maintained by Rio Blanco County. Black Sulphur Creek Road is maintained by the County. Location of exit from the main highway will be at the intersection of Black Sulphur Creek Road and the existing trail road departing southward; said intersection located in the southwest quarter of S24, R98W, T2S. The planned access roads are Piceance Creek Road and Black Sulphur Creek Road. There is an existing trail road departing the Black Sulphur Creek Road within the southwest quarter of Section 24 (T2S, R98W) running south to southwest through Section 25, 26, 35, 34 (T2S, R98W) and Section 3 (T3S, R98W). This existing trail road would be rebuilt to a 20-foot wide road utilizing the native materials. One drainage structure across Black Sulphur Creek will be required. Minimal realignment will be required to provide suitable access for oil field type equipment. Approximately 4.2 miles of road construction will be required.

The necessary water for the operation will be taken from Black Sulphur Creek and trucked to the location.

LOCATION: S31, T2S, R97W

Same as Location S1, T3S, R98W except for the following items:

There is an existing trail road departing the Fawn Creek Road at approximately the quarter corner between Section 29 and 30 (T2S, R97W) running southwest atop the ridge through Section 31. This existing trail road would be rebuilt to a 20-foot wide road utilizing the native materials. Minimal realignment will be required to provide suitable access for oil field type equipment. Approximately 1.3 miles of road construction will be required.

The necessary water for the operation will be taken from Black Sulphur Creek and trucked to the location.

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