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Devonian Shale Horizontal Well: Rationale for Wellsite Selection and Well Design

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ABSTRACT

This paper discusses the rationale for selection of a well site where geologic and reservoir conditions are favorable for a horizontal well to increase gas recovery efficiency over that of vertical wells. In this effort, an area of favorable geology was selected and a multi-site reservoir evaluation study was conducted to determine an appropriate location for a long horizontal wellbore in the Devonian shale in southwestern West Virginia. Within a candidate reservoir, existing wells and their suspected directional properties were analyzed to develop the best candidates for location of the horizontal well. Reservoir data from over 38 wells in the area were used to establish areas of high flow capacity. A 3-dimensional gas flow simulator capable of modeling both fracture and matrix porosity and permeability and desorption were used to investigate both the adjacent well interference and production performance of a 2,000-foot horizontal wellbore. Final well location selection was based on minimum interference, high expected recovery efficiency, and reasonable access in rugged terrain.

Once site selection was completed, a well-planned drilling approach was developed based on a complete review of horizontal well drilling technology with particular emphasis on methods to directionally drill on air or air/mist to intersect the inherent fracture system (based on regional mapping trends), horizontal coring for natural fracture spacing, and multiple hydraulic fracturing horizontal boreholes through cemented casing. The lessons learned in this effort are that horizontal wells can be achieved in naturally fractured formations, but good reservoir studies are required to increase the probability of success in achieving noteworthy production.

INTRODUCTION

This paper shows how to select the proper geographic area in the Devonian shale of the Appalachian Basin where geologic and reservoir conditions are favorable for a horizontal well to increase gas recovery efficiency two- to three-fold over conventional vertical wells. Particular importance is placed on well placement for improved gas recovery efficiency from fractured shale formations. Understanding the orientation of naturally occurring fractures in the Devonian shale is foremost in importance.[1] Prior knowledge described both induced and natural fracture direction over the entire Appalachian Basin[2]. This knowledge led to the partitioning of areas of established production for West Virginia[3], Kentucky[4], and Ohio[5]. Data on natural fracture orientation, horizontal stress, reservoir properties, mechanical fabric, and permeability anisotropy influenced the partitions. Within these partitioned groups, knowledge of reservoir properties was acquired to guide the selection of the well site and to design the horizontal well.

Design aspects were based on the experience from the high-angle directional well that was recently completed in the Grand Canyon. Here, directional drilling was used to install a Water Line Project[6]. In this project, a conventional-build wellbore was installed to 71° using air/mist drilling fluids, downhole mud motors, and wireline steering tools.

GEOGRAPHIC AREA SELECTION -- THE GEOSCIENCE APPROACH

A large volume of published data was reviewed to determine the usefulness of the data for site selection analysis. Specific groups of data were collected, screened against the criteria developed, and analyzed for the purpose of generating data for ranking of the prospect areas. The general technical approach is illustrated in the flow diagram of Figure 1.

From the literature reviewed, key data sources were identified and both geologic and engineering data were collected for screening and analysis.

The chief sources of geochemical data in the Devonian shale were publications by the U.S. Geological Survey and Mound Laboratories. Primary sources for geologic data were State and Federal Geological Surveys, Cliffs Minerals and West Virginia University, Ohio State University, and the University of Kentucky. Sources of engineering data came from Industry, Gas Research Institute (GRI), and U.S. DOE/METC, BDM, and other consultants.

During recent years, researchers for the Department of Energy's Eastern Gas Shales Resources developed a geoscience approach for partitioning sections of the basin which had similar properties. These included gas content, thickness, structural complexity, fracture spacing, cumulative production, and reservoir properties. These partitioned areas[7] of West Virginia, Kentucky, and Ohio were screened for inclusion in the group to undergo additional examination and analysis for ranking and final selection. The initial screening criteria were (1) productive intervals below 1,500 feet are required to avoid horizontal hydraulic fractures and (2) vertical well depth was limited to 4,000 feet due to cost considerations. Areas not meeting this criteria were eliminated during final ranking.

Within the partitioned areas selected from initial screening, detailed geologic and reservoir data were collected. This consisted of initial rock pressure, net radioactive shale thickness, and average depth as shown in Table 1. Each area was initially ranked based solely on projected production from a vertical well which was hydraulically fractured with a 150-foot long hydraulic fracture. These data were then normalized with an average figure for thickness and initial rock pressure to yield a normalized ranking which should be related to the development of fracture permeability. Table 2 summarizes the final ranking process.

Using the screening criteria for depth, four partitioned areas were eliminated, which then required a final ranking of the normalized and screened data for the remaining 12 areas. The result of that ranking is presented in Figure 2. West Virginia partition Area 1, consisting of Cabell, Wayne, and Lincoln counties was the geographic area identified for conducting more detailed studies for specific site selection.

SELECTING THE WELL SITE -- RESERVOIR SIMULATION STUDIES

The Cabell, Wayne, and Lincoln County area of West Virginia was ranked the highest relative to having a suspected fracture permeability in the Devonian shale. Shale gas development in this area was investigated with operators to gain an opportunity to perform a detailed reservoir simulation study where a great deal of well control could be evaluated. Several areas were considered leading to a detailed study of 38 closely spaced wells drilled in the Wilsondale Devonian shale gas pool, Wayne County, West Virginia. Figure 3 shows the location of the study area.

Detailed completion records were obtained from the West Virginia Geologic and Economic Survey in order to evaluate a number of proposed horizontal well locations inside the existing field. Production records from these 38 closely spaced wells were obtained from 1980 to date. One operator provided predicted production data for 17 of the 38 wells. Long-term production records from 18 wells outside the study area inside Wayne County were obtained and decline curves developed to represent the Wayne County area. A computer code was developed to predict and back calculate production history for the 17 wells having recent production data. Such data were required in order to history match as many wells as possible within the Wilsondale pool. Reservoir evaluation was initiated using complete production history and current rock pressure from 25 wells in the pool. Figures 4 and 5 are contour maps of current rock pressure and iso-cumulative production for the study area. The oldest well was put on production in 1940, and 23 of the 25 wells had been producing since at least 1966. The remaining two wells were drilled and foam-fraced in 1980. All the other wells were shot open hole with nitroglycerin.

History matching of production from 25 of the 38 wells was used to characterize the study area for full-field simulation. Matching parameters were fracture permeability (K_f) and formation height (h). Detailed reservoir and history matched data are shown in Tables 3 and 4. Figure 6 is a contour of $K_f h$ for the study area. Once all the history matching was completed, an actual well-location map was obtained, and a computer simulation grid was set up over a 1.3 x 1.48 mi^2 area which contained seven active vertical shale wells and five horizontal wells as shown in Figure 7. The grid-area vertical wells were representative of the 38 well pattern in terms of having high-, medium-, and low-rank producers. Five candidate sites were identified as likely surface locations. Further on-site evaluation of the proposed horizontal well locations eliminated Well No. 5 based on being too close to an old abandoned well not previously part of the original well set. Well Location No. 4 was eliminated because of being too close to a lease boundary.

Three full-field simulations of actual production history from the seven vertical wells and each of the individual horizontal wells were conducted. Each well was turned on individually in the simulator while continuing to produce the entire grid for 20 years into the future. Both cumulative production and well interference production were evaluated for each horizontal well location. Results indicated that well Location No. 3 was adversely affected by interference from other wells and was eliminated from further consideration. The remaining two locations were evaluated based on having the least amount of interference and the highest improvement ratio between a horizontal well and vertical well placed in the most favorable position along the horizontal wellbore grid. Table 5 summarizes these results indicating the selection of Site No. 2 for the actual wellbore location.

DESIGNING THE WELL PLAN FOR SUCCESS

Initial investigation of how much horizontal hole length was required for economical predicted performance was achieved by a simplified individual well simulated flow performance modeling effort. A variety of horizontal hole lengths ranging from 500 to 3,000 feet were investigated along with the addition of one to three 150 to 600-foot hydraulic fracture wings induced perpendicular to the wellbore. Results shown in Figure 6 indicate for a gas price of $3.50/Mcf, a 2,000-foot wellbore with three 150-foot hydraulic fracture wings was required.

The design of wellbore azimuth is critical to maximizing recovery from naturally fractured Devonian shale. The target interval in the Devonian shale is the thickest Huron section in the sequence. Rose diagrams of structural trends on the Huron, an underlying Onondaga section, and shallower Berea were prepared over the adjacent Chapmanville quadrangle based on availability of stratigraphic tops from well logs. In addition, U-2 lineament interpretation over the Wilsondale quadrangle and oriented core fractures information from a nearby Lincoln County Devonian shale well were reviewed. Figure 7 summarizes the orientation rosette's from this information. Major trend orientation on the target Huron was N 57°E. A N 52°E orientation was observed on the underlying formation. The dominant U-2 lineament orientations were in the range of N 42-60°E. The principal natural fracture orientation was N 52°E. Careful review of this information in combination with lease boundary consideration resulted in the S 37°E orientation which is perpendicular to dominant site-specific fracture orientation of N 52°E.

The problem of finding reliable mud motors and directional control equipment that could withstand the severe vibration of air across downhole equipment was recognized as a major design consideration. Low-speed/high-torque motors were required to increase motor life during hole cleaning while the drill string weight was off bottom. Flux-gate type probes were selected based on previous experience.

A 4.25° per 100-feet build angle from kickoff to 90° was selected based on the need to diagnose the 2,000 feet of hole length by selective coring and well logging to obtain a more complete understanding of natural-fracture spacing in Devonian shale. In addition, a conventional angle building wellbore reduced risk of project failure by minimizing the number of plugbacks.

Recognizing that casing was to be installed along the horizontal wellbore, adequate wellbore/casing size tolerances were selected to reduce the risk of casing installations in both the angle building and horizontal sections. Numerous external casing packers and port collars were to be installed in the casing string to isolate, test, stimulate, and flow multiple stimulated sections of the horizontal borehole.

Accordingly, the drilling plan followed to achieve the horizontal well is described below:

- Drill 630 feet of 17 1/2-inch hole.
- Cement 630 feet of 16-inch conductor casing (fresh water protection string).
- Drill 2,000 feet of 14 3/4-inch hole to a point just below the Big Injun sand.
- Set and cement to surface 2,000 feet of 11 3/4-inch casing.
- Kick well off at 2,080 feet using a bent sub and downhole motor with a 10 5/8-inch drill bit and using an electromagnetic MWD unit for directional control.
- Build angle at a constant rate of 4.25°/100 feet until an inclination of 85° or more is reached at the top of the Lower Huron shale.
- Run conventional wireline logs to maximum obtainable depth.
- Set 4,080 feet of 8 5/8-inch casing, cementing the lower 500 and upper 150 feet in place.
- Drill out with a 7 7/8-inch bit for 100 feet, then rig up and take 90 feet of 3 1/2-inch oriented core.
- Depending upon surveys while coring, run an angle building assembly with a conventional bit and the electromagnetic MWD unit and increase angle to 90° and attempt to drill a total of 2,000 feet horizontally (85° to 90°) to 6,080 feet measured depth.
- Inspect the wellbore with a TV camera attached to the drill pipe or coiled tubing.
- Log the horizontal section of the wellbore with a gamma, temperature, and dual induction tool conveyed by drill pipe.
- Set 6,080 feet of 4 1/2-inch casing and inflate external packers to isolate eight or more zones for testing; ported collars will be used to eliminate the need for perforating the intervals.
- Open the ported collars and test the zones isolated separately.

A conceptual design schematic of the horizontal well is shown in Figure 10. Accordingly, this design was executed successfully in the Devonian shale in West Virginia. The horizontal well is currently being evaluated before stimulation. The target interval was the lower 50 foot in the Huron section which is recognized as having the most vertical gas shows in nearby wells.

SUMMARY

Geographic site selection is critical to successful exploitation of fractured shale via horizontal wellbores.

Prior knowledge of natural fracture network within a regional geologic framework enhances the opportunity to cross and connect these permeable paths to the wellbore.

Full-field reservoir simulation is required to quantify our understanding of the complicated interaction between hydraulic/natural fractures for productivity improvement over vertical wells.

Off-the-shelf technology in the area of downhole motors and directional control need to be carefully reviewed when used in an air or air mist drilling environment.

Well-to-well interference must be evaluated when placing a horizontal well inside an area of established production.

Average cumulative production normalized by thickness and rock pressure represents a practical approach to high-grading geologic areas for fracture permeability.

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Table 1
Raw Data for Ranking

Partition Area	Rock Pressure Initial, psi	Net Thickness-ft	Depth ft
WV I	330	91	3487
II	450	226	3414
III	960	128	5736
IV	625	67	3723
V	340	160	4383
VI	450	100	4051
KY I	375	380	3038
II	590	114	3878
III	520	123	3350
IV	550	120	3000
OH I	690	119	2320
II	240	60	1500
III	525	120	3560
IV	215	105	1660
V	90	10	365
VI	135	100	2135
Average Value	450	115	3123

Table 2
Normalizing of Data for Ranking

Partition Area	*10 Year Cumulative Production	Rank	**Normalized by Thickness	***Normalized by Thickness and I.R.P.	Final Rank
WV I	285	5	364	495	1
II	376	4	191	191	7
~~III~~ Eliminated ~~204~~ because ~~0~~ it ~~400~~ is too ~~60~~ deep					—
IV	277	6	475	342	3
~~V~~ Eliminated ~~165~~ because ~~11~~ it ~~111~~ is too ~~70~~ deep					—
VI	167	10	192	192	6
KY I	815	1	246	295	5
II	405	3	406	311	4
III	435	2	406	351	2
IV	243	8	232	180	8
OH I	275	7	266	180	9
~~II~~ Eliminated ~~104~~ because ~~10~~ it ~~204~~ is too ~~225~~ shallow					—
III	65	13	81	80	11
IV	49	14	53	110	10
~~V~~ Eliminated ~~7~~ because ~~16~~ it ~~104~~ is too ~~225~~ shallow					—
VI	117	15	8	20	12

* Projected for well with 150 Hyd. Frac.

** $\frac{\text{Avg. Thk.}}{\text{Thk.}}$ x 10 year cumulative projected for 150' hyd. frac = normalized for thickness.

*** $\frac{\text{Avg. Init. Rock. Pres.}}{\text{Init. Rock Pres}}$ x normalized thickness value = normalized thickness pressure.

Table 3
Eastern Gas Shales Horizontal Well Project
Individual Well Production History Matching Summary

Well No.	Year Comp.	Total Time on Line (Days)	Rock Pres. Pressure Int.	Rock Pres. Pressure Final (psi)	Matching Properties K_f (MD)	Matching Properties h (FT.)	Matching Properties K_f x h (MD-FT)	Open Flow shale (MCF)	Open Flow sand (MCF)	(%)	Production Predicted 10 yr. (MMCF)	Production Predicted 20 yr. (MMCF)	Production Predicted actual (MMCF)	Production Predicted model (MMCF)
1	1940	10000	515	150 @ 7	.1006	300	40.93	562	10	96	617	1070	1,040	1,040
2	1940	10000	500	210 @ 7	.0700	135	9.45	23	—	100	171	296	530	540
3	1941	10000	432	150 @ 24	.01375	26	0.936	43	22	94	7	12	20	20
4	1941	10000	430	—	.0075	100	0.75	120	—	100	122	212	301	370
5	1942	10330	432	150 @ 7	.1075	195	20.96	90	9	91	256	447	732	770
6	1944	14000	403	154 @ 34	.1275	125	15.96	157	—	100	223	387	672	667
7	1944	14000	432	100 @ 7	.12570	100	12.57	1290	757	61	144	250	436	434
8	1945	14235	405	200 @ 7	.1805	145	24.43	200	22	91	300	534	629	600
9	1945	12570	445	200 @ 7	.1333	85	11.30	—	—	64	136	236	300	300
10	1946	13140	305	202 @ 7	.1006	85	8.31	250	—	100	94	162	257	253
11	1947	13570	327	162 @ 7	.1165	120	13.98	230	19	92	196	101	270	263
12	1948	13005	473	340 @ 7	.0400	60	2.34	210	50	78	54	93	147	146
13	1948	13140	310	220 @ 7	.0606	80	4.86	75	15	83	37	64	90	90

Table 4
Eastern Gas Shales Horizontal Well Production History Matching Summary

Well No.	Year Comp.	Total Time on Line (Days)	Rock Pres. Pressure Int.	Rock Pres. Pressure Final (psi)	Matching Properties K_f (MD)	Matching Properties h (FT.)	Matching Properties K_f x h (MD-FT)	Open Flow shale (MCF)	Open Flow sand (MCF)	(%)	Production Predicted 10 yr. (MMCF)	Production Predicted 20 yr. (MMCF)	Production Predicted actual (MMCF)	Production Predicted model (MMCF)
14	1949	13140	300	175 @ 7	.0012	80	4.80	93	25	79	53	90	130	140
15	1951	12410	300	230 @ 7	.0340	65	2.21	N/A	N/A	—	25	43	63	64
16	1952	12040	400	210 @ 7	.0757	40	3.03	240	—	100	38	40	80	80
17	1952	12040	375	340 @ 7	.1300	135	17.20	210	12	90	92	150	234	233
18	1955	10000	300	104 @ 7	.1300	105	14.00	95	—	100	121	211	367	300
19	1955	10000	500	300 @ 7	.1000	340	30.40	325	—	100	575	997	1,370	1,367
20	1956	9125	300	300 @ 7	.1400	130	9.27	65	37	64	91	150	180	185
21	1956	7300	475	175 @ 7	.0630	40	2.54	50	32	64	43	75	75	75
22	1956	6935	312	300 @ 7	.0403	63	2.92	52	—	100	42	—	70	71
23	1956	6935	300	300 @ 7	.0800	80	6.37	30	10	66	80	—	112	113
24	1960	1825	300	230 @ 7	.0660	113	7.35	95	—	100	—	—	16	23
25	1960	1825	300	302 @ 7	.0775	150	11.63	140	—	100	—	—	22	31

SPE 16410

Table 5
Site Comparison

Site 1 MMCF		Site 2 MMCF
1,117	Horizontal Well	688
282	Vertical Well	88
171	Interference	29
4:1	Improvement Ratio	7:1

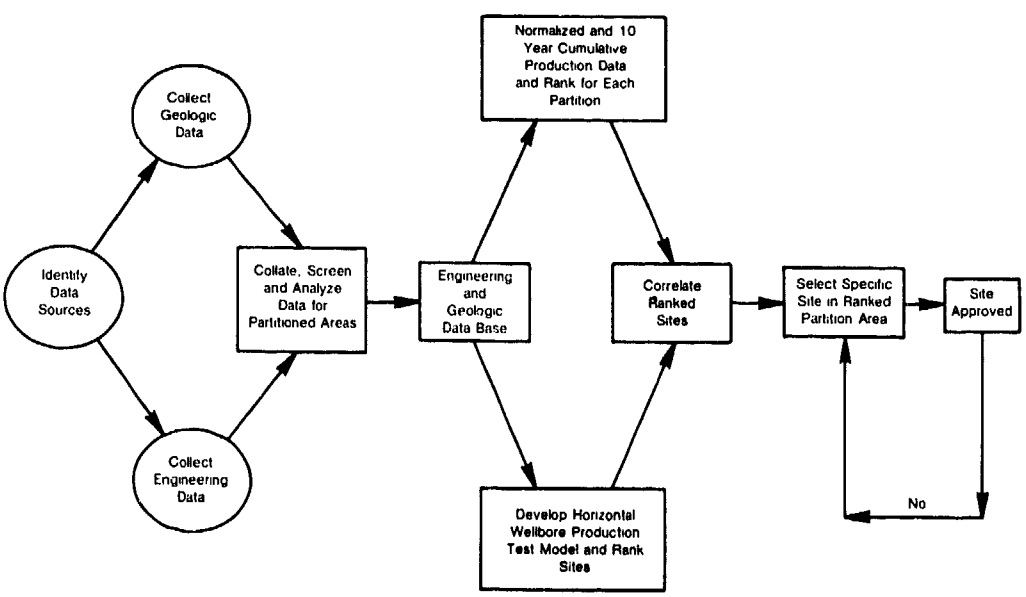

Fig. 1—Flow diagram for geographic area and specific site selection processes.

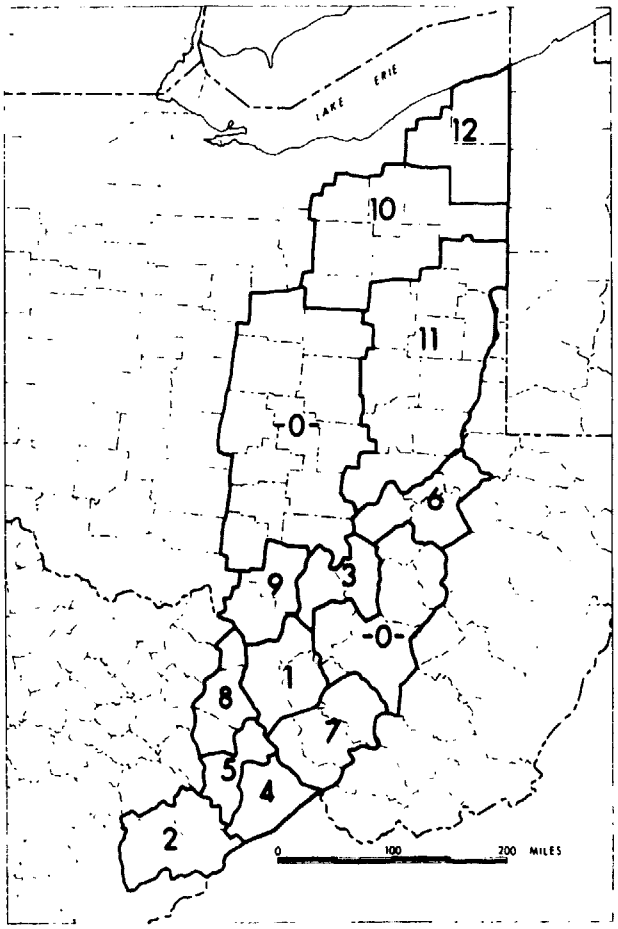

Fig. 2—Ranking of partitioned areas accepted for analysis.

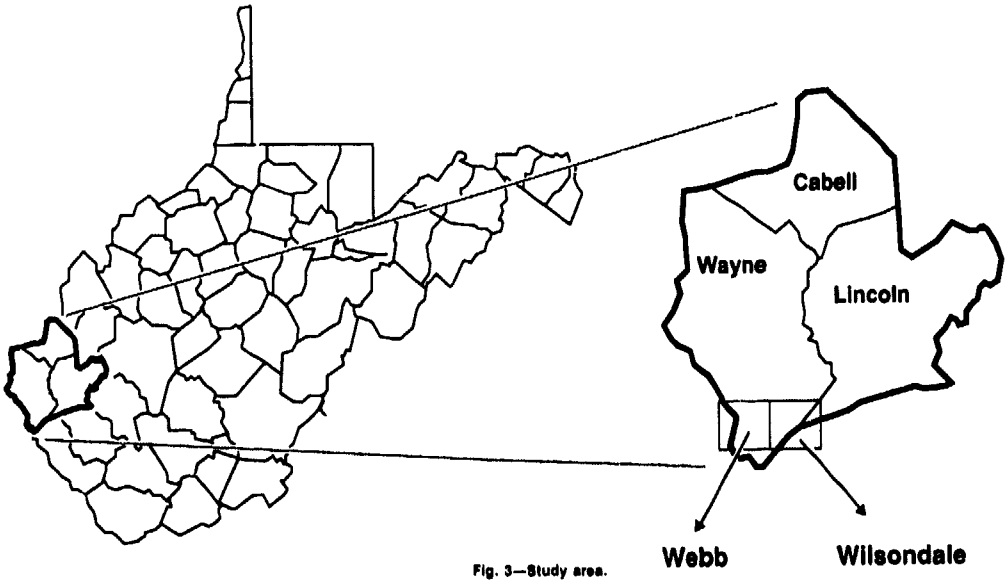

Fig. 3—Study area.

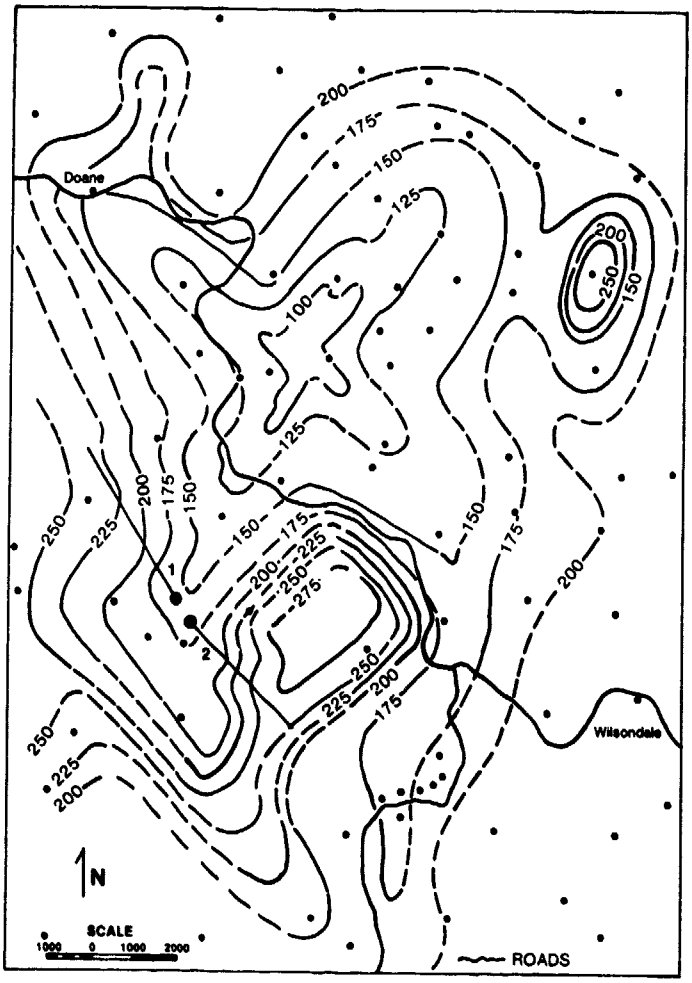

Fig. 4—Current 7-day rock pressure (contours in pounds per square inch).

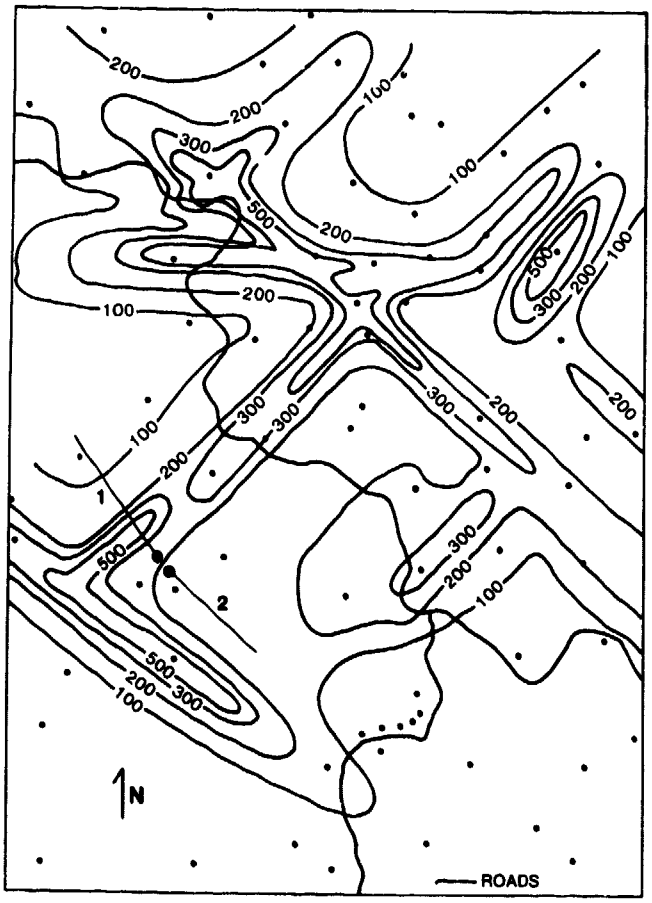

Fig. 5—Iso-cumulative production (contours in millions of cubic feet of gas).

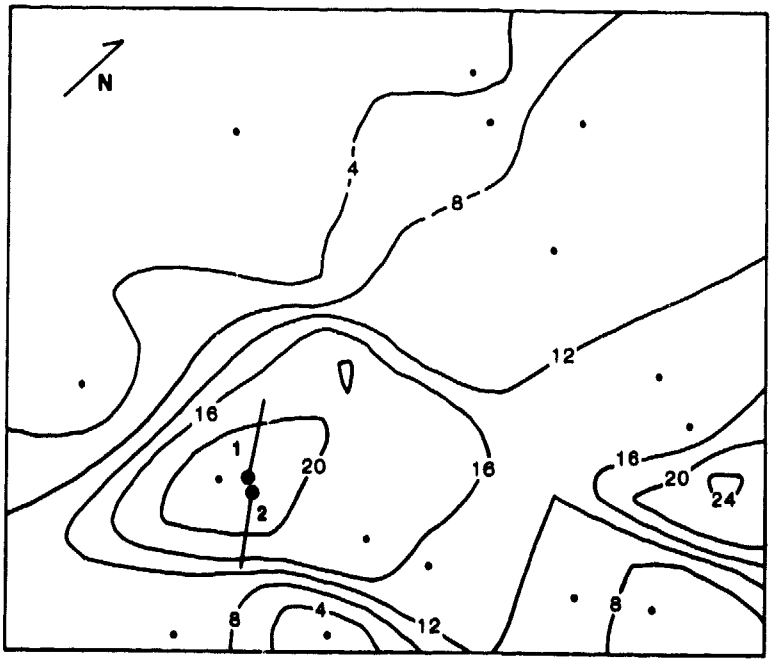

Fig. 6—Permeability-thickness of study area (contours in millidarcy-feet).

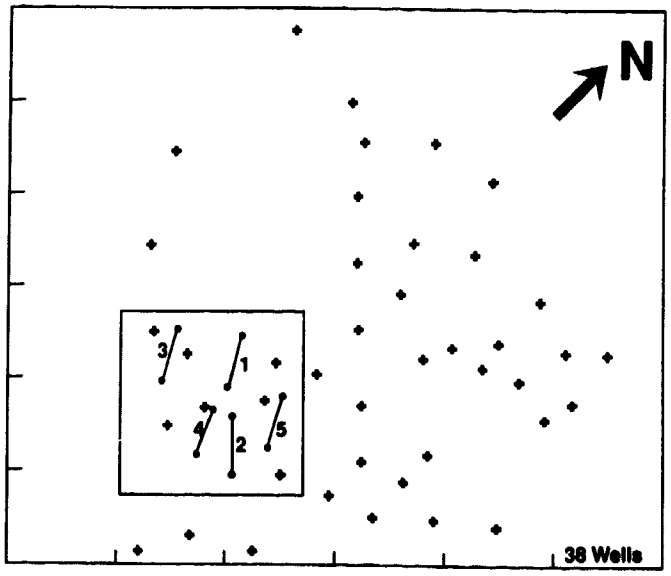

Fig. 7—Well location map with five hypothetical horizontal wells on grid area.

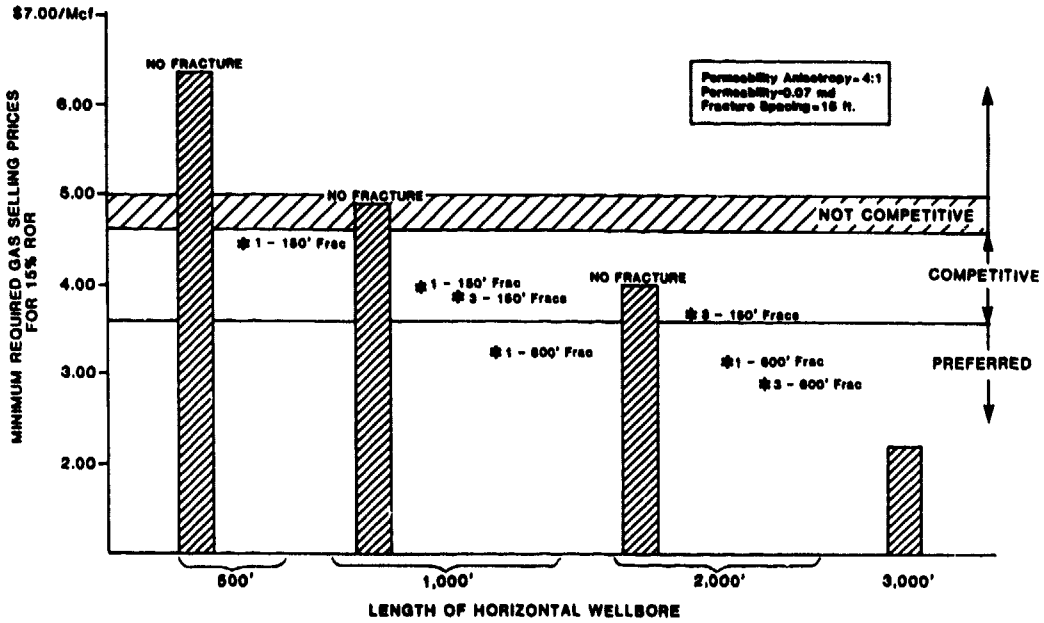

Fig. 8—Economic comparison of required drilling and stimulation technology.

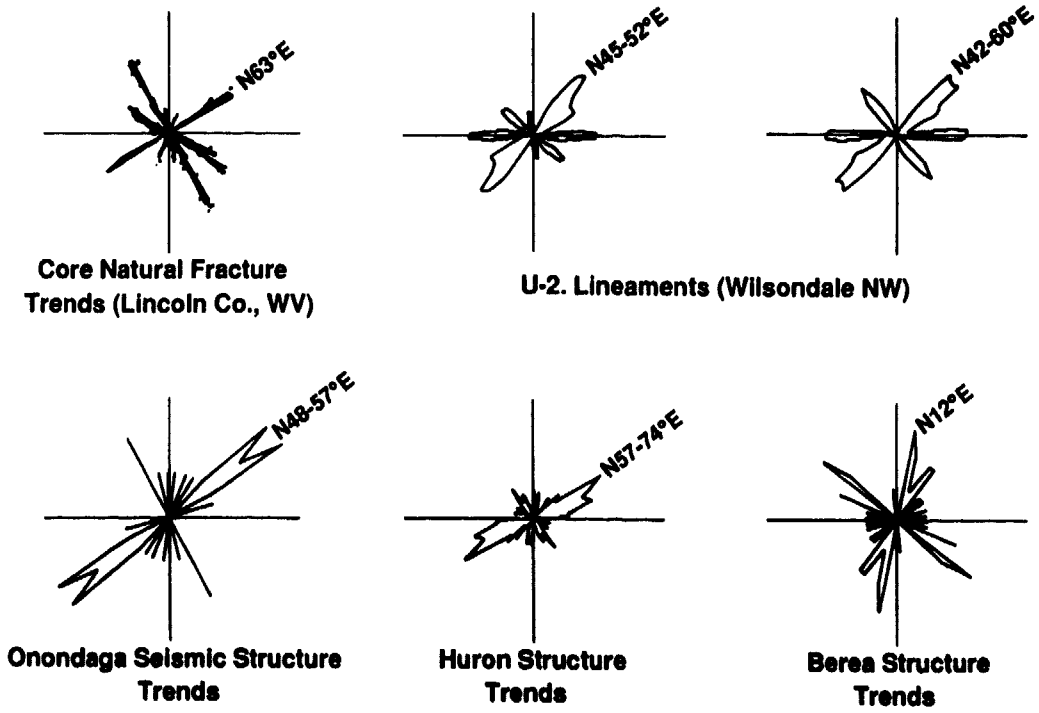

Fig. 9—Directional trends of regional geology.

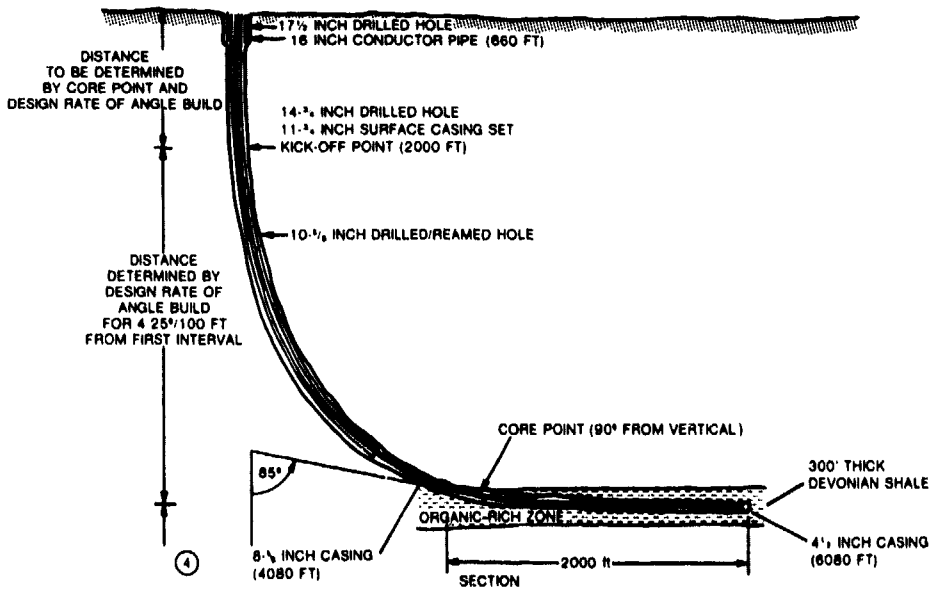

Fig. 10—Devonian shale horizontal well—conceptual design.