POLYMER GELLED BLOCK
A DIVERTING AGENT FOR ACID STIMULATIONS

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ABSTRACT

This paper discusses the use of Polymer Gelled Block (PGB) as a diverting agent in staged acid stimulations performed in the San Andres Formation of the Slaughter Field in Hockley County, Texas.

Improved results were obtained using this new material as compared to rock salt and benzoic acid flake blocks that were previously used. Several clear advantages of low residue PGB mixed "on the fly" over solid type blocking agents are discussed. Included are viscosities of the PGB during placement in the formation and then after the gel system has set up following the required 30 minute shut-in time. This demonstrates its capability of achieving a high extrusion pressure which tends to divert the subsequent treating fluid.

INTRODUCTION

In the design of a stimulation treatment on a producing well, it should be determined if the treatment will be a single stage or multi-stage job. If the productive zone has more than one interval to be treated, a diverting material may be utilized to divert the treatment fluid into an untreated zone. The decision of which material to use can be difficult since there are many from which to choose. Some of the principally used materials to divert stimulation fluids are graded rock salt (GRS), benzoic acid flakes (BAF), oil soluble wax beads, or some combination of these. These have been pumped with a carrier fluid in an attempt to divert the stimulation fluid. To be an effective diverting material, the bridge must have low permeability and be strong enough to hold up under a high differential pressure. Also, the material must be easily removed from the well.[1]

HISTORY

The Slaughter Field in Hockley and Cochran Counties, Texas (Figure 1), produces from the dolomitic San Andres Formation at a depth of 5,000 feet. The field was discovered in 1937 and produces 31 - 32° API gravity oil with a viscosity of 1.5 cp at a bottomhole temperature of about 109°F from a solution gas drive reservoir. The net pay thickness is approximately 96 feet, porosity is 11%, and the permeability is 3 md. Various operators have conducted waterflooding in the Slaughter Field for more than 20 years with some polymer flooding being conducted more recently to improve recovery.

DIFFERENCES IN PLACING AND CLEANING UP OF BLOCKS

One of the problems with the GRS/BAF block is that, while being mixed and pumped, the solid diverting materials sometime tend to settle out of the carrying fluid. Blending and pumping of the block becomes irregular. Since the PGB is a low viscosity fluid while being pumped and contains no solids, the pumping continues to be smooth, similar to that of the stimulation fluid.

A second problem created with the pumping of a solid diverting material is the possibility of bridging off in the tubing, at the perforations, or in open hole which impedes the pumping of the job. If this problem does occur, the remaining treatment fluid cannot be pumped according to the design of the job.

Another problem associated with the placement of a GRS/BAF block in an oil producing well with a low water production is that a salt bridge could be created. A salt bridge typically takes a considerable time to clean up. With the PGB, an internal breaker and an additional enzyme breaker are used to break the gel to give a rapid cleanup of the diverting fluid. The amount of residue occurring from the broken gel is less than 2% by weight of gelling agent.

In comparison with gels used in the past that exhibited high viscosities and high pump pressures to place, the PGB has a low viscosity during placement. With the low viscosity, the PGB can be placed into the formation at virtually the same pump pressure as that of the treatment fluid.

TREATMENT DIVERSION

The low viscosity of the PGB during placement is likely to be the most beneficial characteristic of the fluid. The reason for this is because the PGB will follow the treatment fluid going into the fractures, and depending on the permeability, partially into the matrix (Figure 2). After the PGB is in place, the well is shut in for 30 minutes to allow the gel to achieve its maximum viscosity. After the required 30 minute shut-in, the treatment is continued and due to the high extrusion pressure that the gel exhibits, the fluid is diverted into a different zone. Extrusion pressure is defined as the amount of pressure needed to create fluid flow through the formation. With a solid material the diverting is accomplished near the wellbore. The following treatment stage pumped may channel along the wellbore and enter the original treatment interval (See Figure 2).

CHARACTERISTICS OF POLYMER GELLED BLOCK

The PGB is composed of a primary gelling agent, secondary gelling agent, pH buffers, and a breaker.

The primary gelling agent is a guar gum that has a rapid rate of gelation which gives the fluid a base viscosity of approximately 20 cp after ten minutes. The initial viscosity will help suspend and carry the secondary gelling agent.

The secondary gelling agent is a chemically modified natural product containing no guar gum. It has a delayed hydration time which enables the PGB to be placed in the formation at a low viscosity before the maximum viscosity is reached. After the gel reaches its maximum viscosity (Figure 3), it exhibits the high extrusion pressure which permits the PGB to remain in place when pumping continues. The PGB tends to prevent the remaining treatment fluid from penetrating this zone. An extrusion pressure of 525 psi using the PGB was obtained in a laboratory test through a core that had a permeability to nitrogen gas of 77.5 md. Viscosity values in Figure 3 were measured with a Model 50 Fann Viscometer.

The PGB is degraded by an internal breaker in the primary gel, an additional enzyme breaker, and the subsequent acid treatments. The concentration of the breaker is based on the temperature and the time needed for the gel to be sufficiently broken in order for good cleanup.

Since the secondary gelling agent is approximately eighty percent of the total gel system and because it is a residue free gelling agent, less than 2% residue remains after treatment. Since most of this small amount of residue will be removed by production, there is a minimal chance of plugging of the permeability to restrict fluid flow into the wellbore.

FIELD PROCEDURES

The mixing procedure of the PGB is rather simple and quick. The mixing apparatus is given in Figure 4. Starting with clean fresh water, a 2% KCl solution is mixed. The next step is to adjust the pH correctly by the use of buffers. Then the primary gel system is added through an eductor. The solution is thoroughly mixed and is stored until it is time to be pumped. When the PGB is ready to be pumped, the secondary gelling agent is added through an eductor. The breaker is added directly to the blender tub as the fluid is being pumped downhole. After the PGB is displaced, the well is shut-in for 30 minutes and then pumping of the next stage is continued. It should be noted that a clean water spacer is pumped ahead and behind the PGB to prevent any contamination from the acid stages.

TEMPERATURE SURVEYS AND GAMMA RAY LOGS

If any radioactive tracer material is to be run, it should be run first in a dummy stage before the treatment and then it should be run in a dummy stage following each 30 minute shut-in period for the PGB. The temperature survey and gamma ray log should be run before anything is pumped and also after each dummy stage. With this technique, an interval that is taking most of the treatment fluid can be identified and blocked off by pumping more PGB if needed before continuing with the next acid stage.

On the first well using the survey method, a volume of 6,000 gallons of gelled 15% hydrochloric acid was pumped in two stages with one 500 gallon PGB. Only a minor amount of diversion was accomplished with the PGB. In Figure 5, it can be seen that before the treatment approximately 66 feet were taking the major portion of the fluid. After running the PGB and second stage of acid, only an additional 14 feet of new zone was treated.

The second well where the survey method was utilized, a two-stage treatment consisting of 8,000 gallon of gelled 15% hydrochloric acid with a 750 gallon PGB was pumped. In this treatment 24 feet of interval was initially being treated. However, 22 feet of new zone was treated after pumping the PGB (Figure 6).

The temperature survey and gamma ray log on the third well showed that pumping a 750 gallon PGB preceding the first acid stage did somewhat divert the treatment into the zone of interest (Figure 7). After 3,000 gallon of gelled 15% hydrochloric acid and another 1,000 gallon of PGB, the second 3,000 gallon acid stage was pumped into an additional 84 feet of new zone beyond the original 40 feet that was being treated.

With the results of the three wells given above, it can be concluded that, by utilizing the temperature survey and/or gamma ray logs, a productive interval can be effectively treated by adjusting the volume of blocks needed to obtain optimum diversion.

DESIGN

The designing of the volume of PGB necessary for good diversion on a well has many variables. For permeabilities similar to that of the San Andres formation, a volume of 20 gallon/foot of interval can be used. The most accurate method for determining PGB volumes in a new area would be to run temperature surveys on the first few wells and then design the following treatments from that data. Gamma ray logs could be run in conjunction with temperature surveys[2] but they are costly. A temperature survey by itself is economical and normally give enough information to design the volume of block.

RESULTS

Data were obtained from 38 wells (listed in Table 1) evaluating the performance of the two types of diverting material. There are 13 wells that were treated using BAF/GRS at a mixture of two-thirds and one-third, respectively. The remaining 25 wells utilized a PGB for diverting purposes. The results of the 38 treatments included:

1. The average volume of acid pumped for each type of block.
2. The amount of pressure increase due to each of the two types of blocks.
3. The amount of production increase of the oil and water for each type of block.
4. A cost comparison of the two blocks excluding the cost of surveys.

Most of the treatments used a gelled 15% hydrochloric acid solution in two stages separated by one block. The average volume of acid used on the BAF/GRS block was 5,730 gallons per well. The volume of acid pumped on jobs using the PGB averaged 6,505 gallons per well.

An average value of 93 pounds per square inch (psi) was calculated for the BAF/GRS block pressure increase during the treatments. With the use of a PGB, a pressure increase of 119 psi was calculated to be an average value. The higher average pressure increase of the PGB over the BAF/GRS block is considered to be due to the better diversion created by the PGB.

Of the 38 wells in the evaluation, oil and water production were plotted for two months prior to and six months after workover. The graph in Figure 8 shows an average increase in production of 10.5 BOPD per well of the PGB versus the BAF/GRS block. For a twelve month period, an average additional amount of 3,833 barrels of oil would be produced for each workover utilizing a PGB for a diverting material. At the current price of $29 per barrel of oil, a value of $111,157 per well per year of additional money would be obtained.

From Figure 9, it is shown that the water production stabilizes at a higher rate for the PGB jobs due to the better treatment of the complete interval. In most areas in the Slaughter field, the additional water production is not a problem because the water is pumped back into the reservoir through the injection wells. The BAF/GRS block depends on the solubility of the material in the fluids in the formation and the amount of contact with these fluids. The BAF/GRS material may not be dissolved resulting in a decrease of production.

COST COMPARISONS

From the data used in this evaluation, either a PGB of 500 gallon or a BAF/GRS block of 300 pounds in 300 gallon of salt saturated gelled brine was typically used for a diverting material. The cost of the 500 gallon PGB was 65% higher than the BAF/GRS block cost. The 65% additional cost of the polymer gelled block may not sound attractive; but, if long term benefits are projected, it is far more economical to use the PGB for a diverting material.

CONCLUSIONS

The Slaughter field has a large potential for an increase in production from being acidized. From the evaluation of the data and well tests, an even larger volume of oil could be recovered more quickly with the use of a Polymer Gelled Block over a solid block. Although the initial cost of the Polymer Gelled Block is somewhat higher than that of the solid block, the long term economic return substantially justifies its use. The Polymer Gelled Block also will be assured of an easier cleanup due to the additional breaker.

From the data that has been presented, it is concluded that the Polymer Gelled Block is more beneficial to use in the Slaughter field area compared to the combination of BAF/GRS block.

NOMENCLATURE

O.H. - Open hole completion
C.H. - Cased hole completion
W/O - Workover

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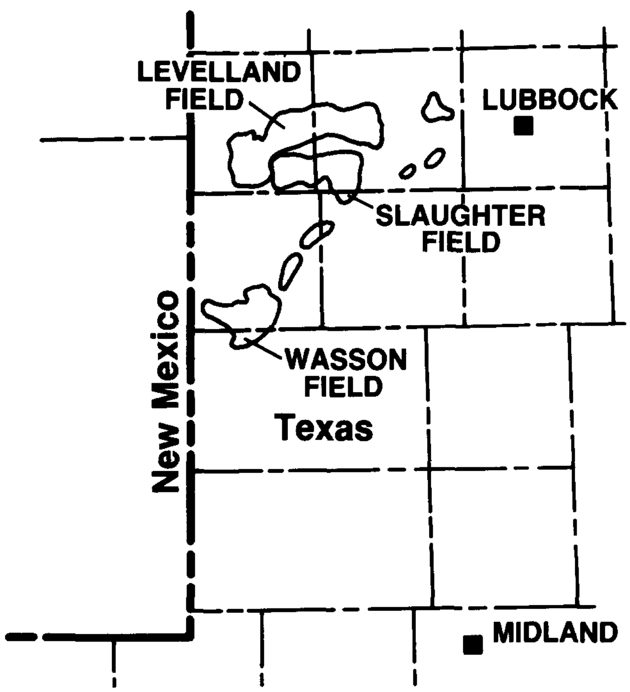

Figure 1 - Slaughter field location map

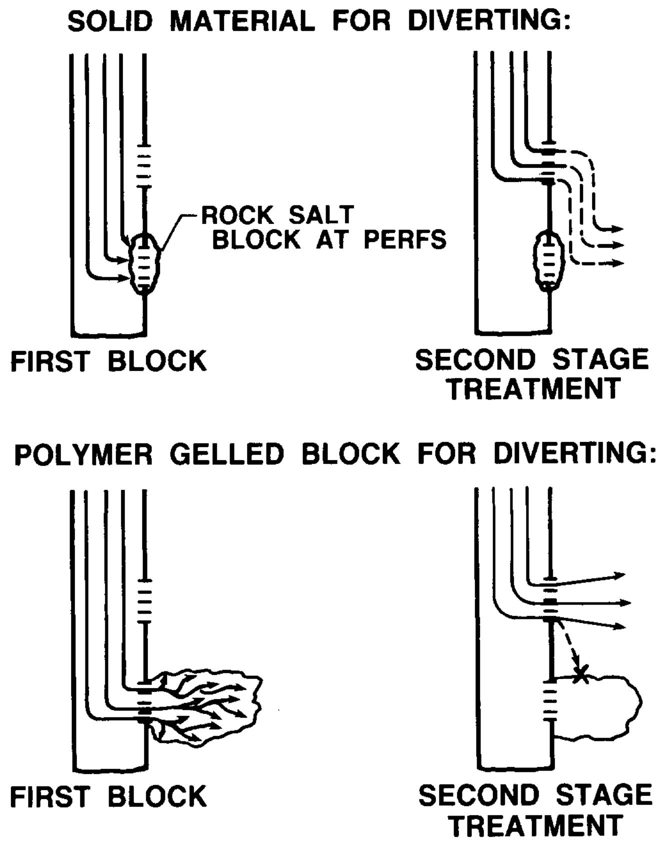

Figure 2 - Improved diversion with polymer gelled block

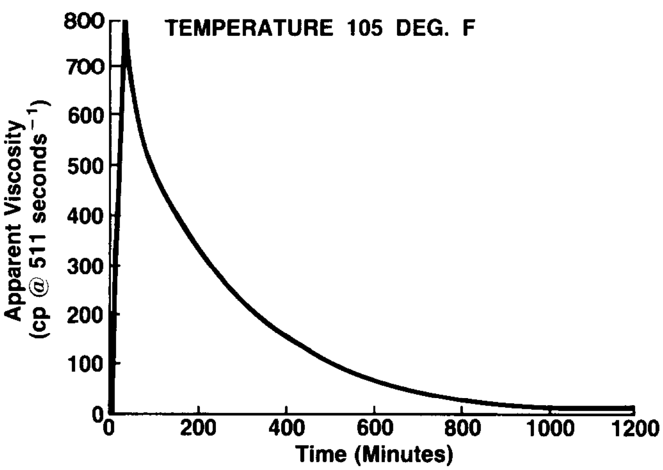

Figure 3 - The effect of time on viscosity

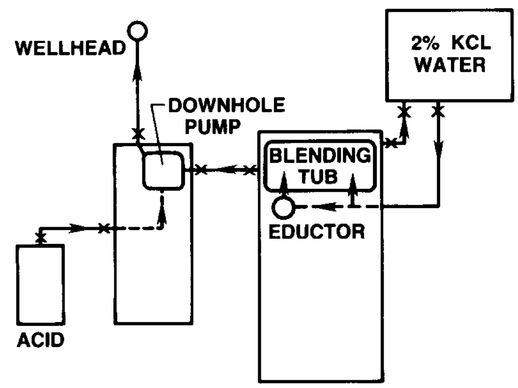

Figure 4 - Positioning of mixing and pumping equipment

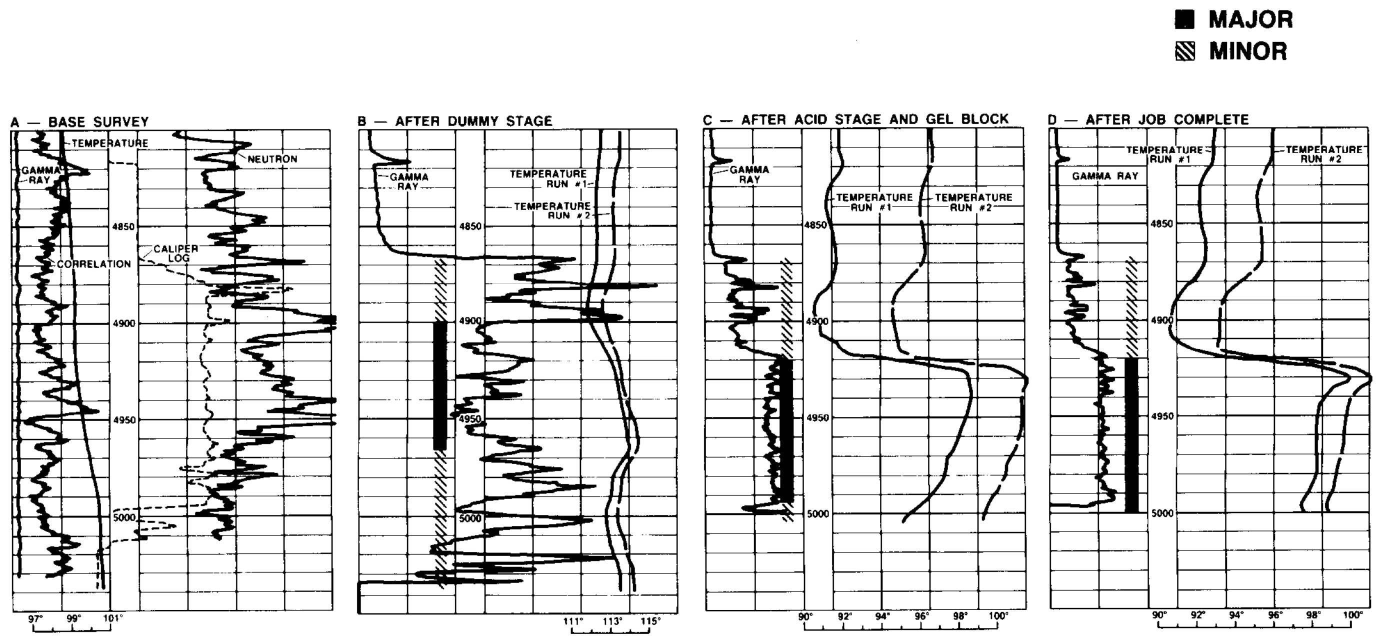

Figure 5 - Gamma ray and temperature survey after 500 gal. polymer gelled block

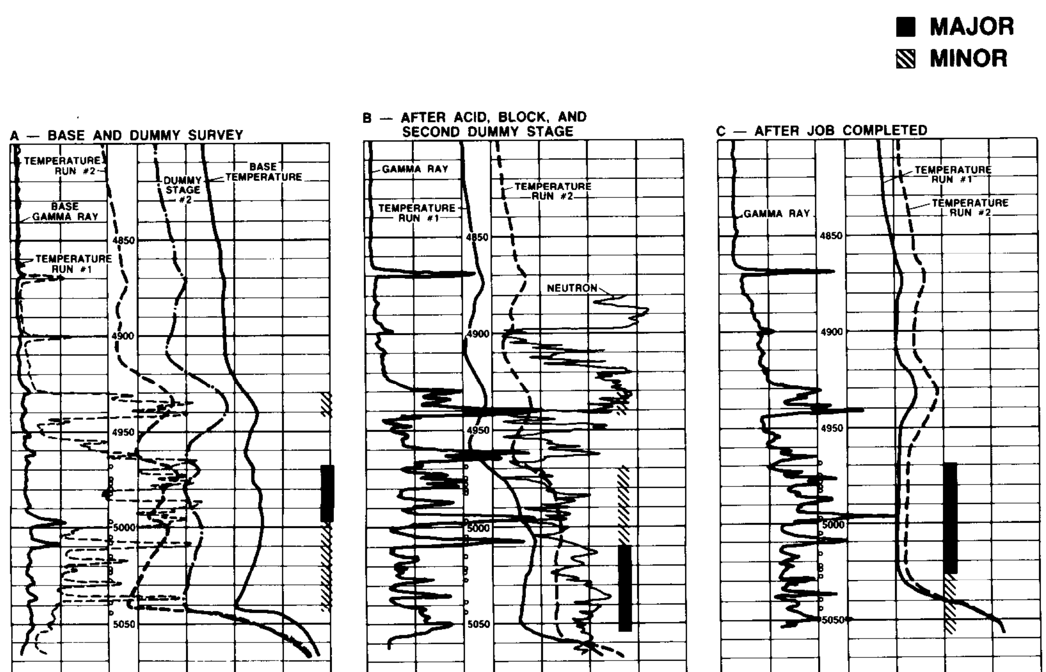

Figure 6 - Gamma ray and temperature survey after 750 gal. polymer gelled block

Table 1
Field Results of Polymer Blocks and BAF/GRS Blocks

Well No.	Date of Workover	O.H./C.H.	Acid Conc. (%)	Acid Type (HCl)	Acid Volume (gal)	Type Block	Block Size (lbs-GRS, BAF) (gals-polymer gel)	No. of Blocks	PSI Incr. due to Block (psi)	PRODUCTION (BOPD-BWPD) Before	Initial	30 days	60 days	90 days	120 days	150 days	180 days
1)	3-19-81	O.H.	20	gelled	9000	⅔BAF, ⅓GRS	300	1	100	6-9	20-189	18-239	18-215	15-210	15-197	13-197	28-197
2)	2-10-81	C.H.	20	ungelled	6000	⅔BAF, ⅓GRS	300	1	0	5-139	26-443	13-515	6-337	15-439	12-401	12-410	11-381
3)	2-19-81	O.H.	20	gelled	9000	⅔BAF, ⅓GRS	300	1	50	2-2	19-340	10-332	9-306	7-239	10-190	12-158	9-123
4)	3-19-81	O.H.	20	ungelled	6000	⅔BAF, ⅓GRS	300	1	40	16-17	27-518	5-570	—	15-389	27-349	26-339	28-292
5)	5-14-82	O.H.	15	gelled	4000	⅔BAF, ⅓GRS	300	1	—	32-87	58-264	37-241	60-239	59-229	55-228	52-223	50-208
6)	4-30-82	C.H.	15	gelled	4000	⅔BAF, ⅓GRS	300	1	260	8-141	17-575	18-503	19-532	18-530	16-506	24-444	24-459
7)	2-19-82	O.H.	15	gelled	9000	polymer gel	500	1	500	34-39	83-609	96-478	107-429	107-429	105-372	118-392	111-388
8)	3- 1-82	O.H.	15	gelled	4000	polymer gel	500	1	100	30-49	89-465	83-450	83-450	96-390	98-386	102-372	97-341
9)	7-16-82	O.H.	15	gelled	9000	⅔BAF, ⅓GRS	300	1	—	3-128	25-392	9-405	8-341	4-378	9-388	3-384	3-390
10)	5-24-82	O.H.	20	gelled	2000	⅔BAF, ⅓GRS	300	1	200	39-147	80-397	93-341	95-302	85-261	90-280	75-273	77-260
11)	6- 7-82	O.H.	15	gelled	9000	polymer gel	500	1	—	1-3	87-132	50-153	49-72	39-65	32-30	30-35	32-30
12)	6- 2-82	O.H.	15	gelled	9000	polymer gel	500	1	400	5-21	21-660	21-680	22-698	35-688	34-698	36-690	39-706
13)	1-18-82	O.H.	20	ungelled	6000	⅔BAF, ⅓GRS	300	1	100	40-226	76-563	32-444	31-429	31-391	25-367	64-483	96-541
14)	6-21-82	O.H.	15	gelled	3000	⅔BAF, ⅓GRS	300	1	300	30-206	69-443	62-430	63-414	60-407	58-386	63-375	58-367
15)	7- 6-82	O.H.	15	gelled	6000	⅔BAF, ⅓GRS	300	1	150	1-6	28-464	21-445	29-361	41-393	35-316	35-301	35-304
16)	10-13-82	O.H.	15	gelled	9000	polymer gel	500	1	100	17-56	53-482	72-475	54-285	48-226	42-191	40-170	37-163
17)	9-22-82	O.H.	15	ungelled	4000	polymer gel	500	1	0	11-74	30-478	29-408	35-391	33-392	31-390	32-267	31-252
18)	10-26-82	O.H.	20	ungelled	6000	polymer gel	500	1	20	19-49	67-530	30-558	30-558	30-558	45-502	44-427	40-392
19)	3- 4-83	O.H.	15	gelled	9000	polymer gel	500	1	200	29-144	23-408	23-408	20-69	25-238	22-181	21-213	21-212
20)	11-11-82	O.H.	15	gelled	9000	polymer gel	500	1	200	9-85	20-653	20-653	14-269	12-624	14-604	14-605	13-585
21)	11-19-82	C.H.	15	gelled	4000	⅔BAF, ⅓GRS	300	1	0	—	13-354	8-320	7-212	5-214	5-214	5-206	7-187
22)	11-13-82	O.H.	15	gelled	9000	polymer gel	500	1	100	3-65	76-448	43-297	36-438	33-342	30-436	30-431	38-474
23)	12-31-82	O.H.	15	gelled	6500	⅔BAF, ⅓GRS	300	2	0/100	12-124	29-565	37-489	29-484	29-387	29-387	23-268	22-201
24)	9- 9-82	O.H.	15	ungelled	4000	polymer gel	500	1	—	41-64	99-472	99-469	107-436	107-458	107-458	118-390	119-379
25)	11-22-82	O.H.	15	gelled	9000	polymer gel	500	2	100/0	6-53	37-385	32-371	20-265	14-193	23-182	32-287	20-258
26)	11-17-82	O.H.	15	gelled	6000	polymer gel	500	1	300	4-11	17-585	17-585	12-519	13-520	11-377	11-377	16-490
27)	2-17-83	C.H.	20	gelled	4000	polymer gel	500	1	120	1-118	26-298	8-256	7-240	7-253	7-261	7-296	6-256
28)	2-20-83	C.H.	15	gelled	1625	polymer gel	500	1	0	64-264	80-525	60-524	65-455	65-433	67-431	67-421	67-500
29)	2-24-83	O.H.	15	gelled	3000	polymer gel	500	1	0	1-6	5-5	7-13	5-9	5-15	8-14	8-14	8-14
30)	3- 8-83	O.H.	15	ungelled	6000	polymer gel	500	1	50	36-49	107-446	121-446	132-415	123-397	103-352	115-411	124-404
31)	5-11-83	O.H.	15	gelled	9000	polymer gel	500	1	90	47-	69-464	53-475	67-438	71-391	73-400	68-403	66-410
32)	5-13-83	C.H.	15	gelled	5000	polymer gel	500	2	—	32-	56-512	54-395	55-313	48-436	48-436	46-529	62-711
33)	5-27-83	C.H.	15	gelled	9000	polymer gel	500	1	100	31-102	33-496	39-445	50-490	50-473	80-620	64-556	68-562
34)	5-26-83	O.H.	15	gelled	9000	polymer gel	500	1	100	50-101	73-503	90-484	94-465	90-442	162-483	126-564	121-458
35)	5-27-83	C.H.	15	gelled	5000	polymer gel	500	1	—	17-58	56-450	48-252	37-227	39-205	34-209	28-203	24-200
36)	6- 9-83	O.H.	20	ungelled	6000	polymer gel	500	1	—	7-204	23-567	48-461	57-490	54-473	51-453	51-453	50-447
37)	6- 8-83	O.H.	15	gelled	6000	polymer gel	500	1	—	12-15	63-343	54-300	52-325	59-343	54-338	50-340	52-335
38)	6- 1-83	C.H.	15	gelled	3000	polymer gel	500	1	—100	1-40	14-171	12-277	7-237	1-230	1-229	3-214	1-229

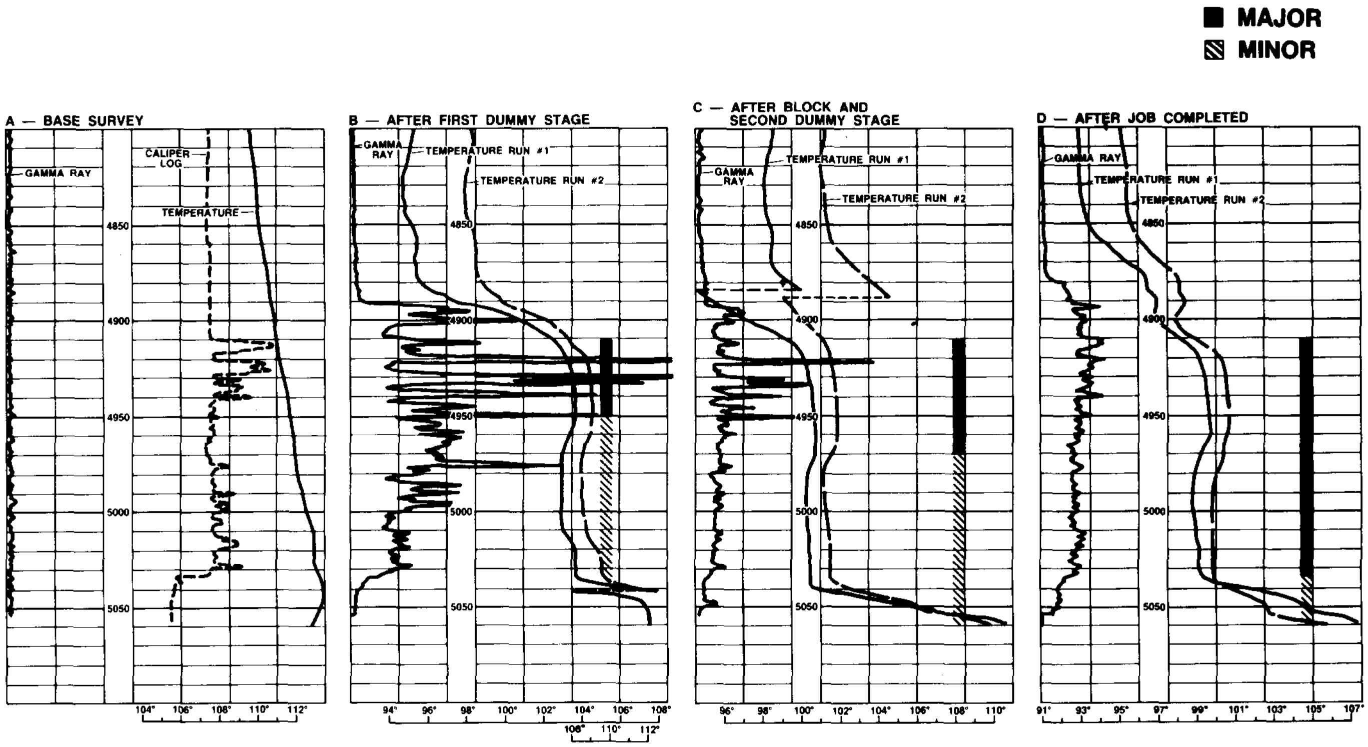

Fig. 7 - Gamma ray and temperature survey after 750 gal. and 1000 gal. polymer gelled block

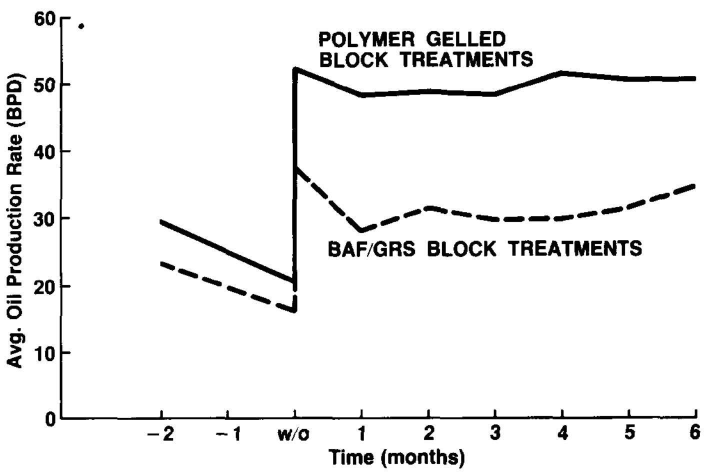

Figure 8 - Avg. oil production rate before and after workovers

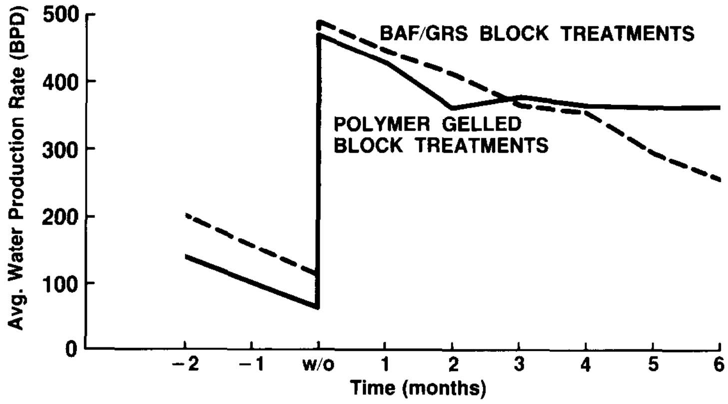

Figure 9 - Avg. water production rate before and after workovers