MITIGATE GAS BREAKTHROUGH WITH INJECTION CONTROL – CASE HISTORY FROM THE SACROC UNIT

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ABSTRACT
Gas breakthrough can be a considerable problem in C02 flooding. From initially causing severe operational handling conditions to ultimately losing otherwise recoverable hydrocarbon reserves, industry personnel devote multiple resources, including time and money, to combat it. Maintaining injection below parting pressure is one effective method to minimize premature breakthrough in offset producing wells. Determining fracture gradient on an individual well basis in a periodic manner and adhering to the resultant rate and pressure parameters has aided the SACROC Unit's reservoir management. This paper describes the methodologies employed, data obtained and production benefits seen to date.

INTRODUCTION

The almost 50,000 acre SACROC Unit located in Scurry County, Texas represents approximately 95% of the Kelly-Snyder Field, which is Pennsylvanian age Canyon Reef limestone on the Eastern Shelf of the Horseshoe Atoll (Fig. 1). Discovered in November 1948, over 1200 wells were drilled to tap this high gravity (40 deg. API plus), sweet crude by 1952 (Fig. 2). **A** solution gas drive reservoir, pressure rapidly fell below bubble point (1,800 psi) from original reservoir pressure of 3,122 psig within a few years time, prompting unitization by the over 400 original working interest owners in 1953, of the Scurry Area Canyon Reef Operating Committee or SACROC Unit (Fig. 3). Three operators were chosen to run the northern, central and southern segments of the Unit, consolidating to one by 1962, although rule by committee remained in effect until the early 1990s.

A line-drive water flood initiated along the length of the central spine of the Unit, hence "centerline", began in 1954 to arrest gas breakthrough. Makeup water combined with state-enforced restrictive hydrocarbon allowable production limits stabilized production and maintained pressure above bubble point through the 1960s. However, water production appears to have been strictly controlled as well, presumably because of limited handling facilities and operating philosophy. Producers were mothballed, generally speaking, when water production reached 100 barrels per day, and frequently less. Not until the makeup water source, at that time Lake J. B. Thomas, literally went dry in 1970, did the restrictions on water production appear to be lifted (that and pre-C02 flood expansion was underway at this point as well).

The 1970s saw the advent of the first large-scale carbon dioxide or C02 flood in the world, which reduced the production allowables and enabled enhanced recovery tax credits, expanded the water flood from a central line-drive to field-wide inverted 9-spots, and quadrupled oil production (at least for a short time). Infill drilling resumed in earnest, adding another 400 wells by the late 1980s. It is certainly debatable what impact the C02 had from a reservoir standpoint during this period, given the concurrent changes mentioned. However, by the late 1980s, certain elements were clear. Water cuts exceeded 90%, C02 supply was both expensive and relatively unreliable, oil prices had collapsed in 1986, the only makeup water contractually available came from treated municipal water (the operator choose to pay rather than take as a result in 1987), and production continued its readily predictable decline.

The Unit changed operatorship in 1993, as part of a large, multiple property package deal. Fortunately, the new operator decided to attempt a turnaround beginning in 1995, rather than immediately plug out what was left. Additional working interest was acquired, eventually making run by committee unnecessary; facility sharing with offset producers to strengthen the utility of the infrastructure commenced; pattern realignments and infill drilling targeted underrecovered areas; and C02 would again considered as a viable injectant. The current operator has expanded these efforts following the initial success of the turnaround and results to date are encouraging (Fig. 4). An additional 200 infill drills have been added since the mid 1990s.

RESERVOIR CONDITIONS

For C02 to be a viable injectant, three key reservoir conditions are required. To be most effective, C02 must become miscible with the oil it contacts, then the oil will swell, become less viscous, and more mobile and recoverable. Initial laboratory studies done in the late 1960s suggested that minimum miscibility pressure or MMP was 1,800 psi – above this pressure miscible flooding is possible. This assumed essentially pure C02 injection. Real world operations involve contamination. Contaminants such as methane are detrimental, raising MMP; contaminants such as hydrogen sulfide, though toxic, are beneficial, lowering MMP. SACROC has both, to name two primary contaminants, and the relative ratio of contaminants has raised MMP to over 2,200 psig over the years. Cutting off makeup water and reducing purchased CO_2 while attempting to maintain production during the economically difficult late 1980s and early 1990s reduced reservoir pressure to immiscible levels in many areas of the Unit. Starting in the late 1990s, resuming makeup water by drilling shallow, brackish supply wells plus increasing takes from third party surplus water and greatly increasing CO_2 purchase through new contracts has restored miscible conditions to all active areas in the Unit.

The second criteria is pattern size, sweep efficiency is best achieved if a balance can be obtained between the ability to contact pay and the ability to control gas breakthrough. Pattern realignment coupled with infill drilling gives you the first ability given economic considerations. Controlling gas breakthrough is the real challenge. Operationally, altering the WAG ratio is possibly the simplest method. In this case, "W" represents water and "G" represents CO_2. Water provides two chief functions in a CO_2 flood, pressure maintenance and containment. CO_2 as an energized fluid will invariably follow the path of least resistance from injector to producer, bypassing oil if not contained. Large WAG ratios will mitigate gas breakthrough but the price is less contact time between the CO_2 and oil and the potential to string out a miscible oil bank thereby reducing ultimate recovery. Mechanical wellbore procedures can also reduce gas problems, at least temporarily. Cement, polymer, and isolation equipment are the most common and frequently the last resort. Of course, there is the added time and expense and no money back guarantee. The last method and definitely used in combination with the first two is to maintain injection below parting pressure – save fracturing for the stimulation companies to perform. CO_2 works best through contact with matrix pores; to sweep what otherwise may not be swept. Mitigate premature gas breakthrough by providing a tortuous path between injector and producer, this will increase contact time and help with containment. And, is the subject of this case history.

The third and last important criterion is project containment. Again, CO_2 as an energized fluid will leave a project boundary if the opportunity is present. Uneconomic CO_2 utilization levels, the ratio of CO_2 injection per barrel of oil produced over time, will develop and destroy a project. If natural barriers, for example, faults or pinchouts, are not in-situ, the next best defense is to rim the project periphery with water curtain injectors to create a water barrier to inhibit CO_2 movement out of project. This is now done at SACROC after suffering through precipitous utilization ratios that developed in the late 1990s.

TESTING PROCEDURE

At SACROC, annual step rate tests are conducted on each water injection well (and WAG injector when on water) to calculate the maximum safe rate and pressure target amounts. Prior to 1993, it appears injection may have been dictated by production goals, as a result water cuts rose rapidly during the 1970s and 1980s and remain high today, although declining (Fig. 5). Starting in 1993, injection wells began to be tested routinely to monitor fracture potential and avoid providing a short circuit to offset producers. The first tests were done strictly at the surface, with down hole conditions implied from assumed friction effects. Many of the wells actually decreased in pressure with increasing rate, suggesting that they were already fractured though not propped. Rates were slashed in many cases, inadvertently causing harm to reservoir pressure as production levels were maintained. Following the lead of other Permian Basin operators who concurrently measured down hole conditions, by early 1994, SACROC step rate tests also included these simultaneous measurements. To improve confidence in picking fracture point, falloff measurements were added in 1995. To reduce test time and provide more data points also, the length and rate of steps were reduced starting in 1996.

A step rate test at SACROC now consists of fluid gradient measurements taken at 500 ft. intervals while running in hole; then using a pump truck, stabilized 20-minute rate steps at either 0.2 or 0.25 barrel per minute rates, depending upon initial surface conditions and/or known past test performance, up to a maximum of 2,000 psig tubing pressure (normal operational facility limit); followed by a 30-minute falloff period recorded at 2.5-minute intervals. Simultaneous surface and down hole measurements are made during the step rate and falloff segments. The down hole rate and pressure point at which fracture occurs is identified and reasonably verified by falloff pressure, then as small a pressure margin as possible is deducted from the fracture pressure to establish a safe injection target, which is correlated to surface conditions at that point, and conveyed to field personnel to maintain.

Because friction is not as predictable in injection tubing as it is in workstring tubing, no repeatable correlation has been determined between surface and down hole conditions following over 1,300 step rate tests conducted to date. Confirming that surface measurements alone are probably inadequate, at least at this Unit. Also, it is not uncommon for the point at which fracture appears to occur from surface measurements to be inconsistent with down hole measurements (Fig. 6a and 6b). Given the cost of CO_2, spending a few thousand dollars a year to step rate test a well is money well spent.

OBSERVATIONS

Table 1 shows the annualized step rate testing summary. Several positive events may be noted. First, fracture rates and pressures are rising in general. This appears to be coincident with general rise in reservoir pressure and according to the literature should be expected. Second, fracture gradient is also rising, again as expected. Third, the level of confidence in witnessing fracture is rising as depicted by the decrease in pressure differential between step rate and falloff pressures. As a result the target rates and pressures may be set closer to fracture and have consequently risen in general. This is not to suggest that interwell variance has declined to the point of making regional estimation a sound strategy. Fracture gradient is climbing, but the error bands still exceed 20%, making prediction dangerous (Fig. 7). Fracture rate is equally variable.

As mentioned, reservoir pressure (Figures 8–12) and fracture pressures (Figures 13–17) are rising. Biannual depictions of both provide clear evidence that reservoir conditions are indeed improving for miscible CO_2 flooding. In all cases, the darker the shade the higher the pressure, the scale ranges from 600 to 6,000 psi with a contour interval of 200 psi. Notice that the reservoir and fracture pressures are only mildly related. A gross isopach is provided also, thicker is darker (Fig. 18). Pay is thickest along the central spine, approaching 800 feet thick in the northern areas. Notice that pay thickness alone is not a reliable indication of geomechanical parameters. Operational influences may distort and change conditions through time; hence, in a dynamic setting down hole variables are not fixed and should be routinely determined.

BENEFITS

Step rate testing has helped prevent injecting above parting pressure and mitigate premature gas breakthrough. The evidence is apparent in several ways. Figure 19 shows the change in flooding characteristics since CO_2 injection commenced. Through the mid 1990s, WAG ratios had to be continually increased to manage gas breakthrough. Even though a WAG ratio of 3:1 was desired, it could not be achieved as time past. WAG ratios in excess of 10 were generally realized. Since then WAG ratio has dropped substantially and appears to be stabilizing near 1:1, more inline with other operations and certainly preferable from a reservoir sweep standpoint. At the same time with decreasing pattern size and delayed gas breakthrough, processing rate is rising, meaning more rock is being contacted on an annual basis, which should help improve return on capital investment given the time value of money.

Most of the expansion activity in the last half-dozen years has been focused on the Centerline project area. The Centerline being originally line-drive flooded and considered for many years to be watered out. Referring again to figure 5, Centerline water cuts exceeded that of the Unit early on and continued to do so until recently. Several attempts were made starting in the mid 1970s to CO_2 flood pilot areas, but rapid gas breakthrough and excessive water cuts prohibited economic expansion. Figure 20 shows the rebirth of the central Centerline project, a happy response to injection below parting pressure, increased net injection resulting in rising bottom hole pressure and decreasing gas-oil ratios, establishment of a peripheral water curtain, and last but not least, pattern realignments and infill drilling.

There are 61 WAG injectors in the Centerline project, half of which are very early into their flood cycles. Table 2 groups them according to relative cycle age, a cycle here is defined as one water segment and one CO_2 segment. Through most of the life, WAG CO_2 half-cycles had to be confined to days or weeks at best because CO_2 broke through to offset wells within that time. Now, months on CO_2 are the norm as can be seen. Our WAG design calls for a 15% HCPV slug of CO_2 initially in each pattern, tapering gradually to all water. We target a cumulative 70% HCPV of CO_2 injection. This is more than triple previous targets and should raise ultimate tertiary recovery to comparable values enjoyed by other operations. **A** final comment about the injectivity demonstrated by these Centerline injectors. There appears to be an inverse relationship between injectivity and cycle age, regardless of fluid type. Other operators have reported reduction in water injectivity alone and SACROC previously reported a slight increase in water injectivity. An explanation may be that we are now operating below parting pressure and seeing different injection behavior.

CKNC

The author wishes to thank Kinder Morgan for permission to publish this paper. Also, I would be remiss if I did not thank the employees who work at the SACROC Unit, if for no other reason, their patience and understanding in gathering data and maintaining operations as well as they have during this past turbulent decade. Lastly, I would like to thank the staff at Production Logging, Inc. for indulging my endless special testing requests over the years.

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Year	Tests Taken	Fluid Gradient, psi/ft	Tool Depth	Shut In BHP, psig	SI BHP at Datum, psig	Fracture Rate, BPD	Fracture Pressure, psig	Fracture Pressure at Datum, psig	Fracture BPD/Psig	Fracture Gradient, psi/ft	BHP Safety Margin, psi	Pressure Falloff Healing Pressure, psig	Pressure Falloff Healing Pressure at Datum, psig	Water Target Rate, BPD	Water Target Tubing Pressure, psig
1993	50		0	3,330	3,335	2,666	3,822	3,826	0.70	0.57	146	4,396	4,357	1,828	995
1994	113	0.47	3,351	2,822	2,867	2,826	3,527	3,568	0.80	0.53	97	3,279	3,329	2,135	698
1995	231	0.49	6,430	2,800	2,945	2,608	3,349	3,487	0.78	0.52	101	3,192	3,320	1,905	533
1996	205	0.55	6,689	3,207	3,240	2,420	3,591	3,619	0.67	0.54	61	3,612	3,640	1,916	425
1997	165	0.59	6,575	3,572	3,687	2,517	4,065	4,164	0.62	0.62	73	3,984	4,082	2,164	611
1998	109	0.54	6,576	3,516	3,622	2,567	3,878	3,975	0.66	0.59	56	3,826	3,922	2,223	606
1999	102	0.55	6,633	3,816	3,885	2,991	4,041	4,103	0.74	0.61	47	4,014	4,076	2,656	815
2000	121	0.55	6,607	3,829	3,910	2,957	4,174	4,253	0.71	0.63	47	4,125	4,201	2,673	948
2001	78	0.54	6,578	3,880	3,990	3,439	3,936	4,037	0.87	0.60	24	3,907	4,007	3,158	849
2002	175	0.54	6,571	3,991	4,099	3,161	4,107	4,214	0.77	0.63	22	4,091	4,194	2,964	1,046
Avg	144	0.54	6,223	3,493	3,583	2,832	3,852	3,936	0.74	0.58	59	3,781	3,864	2,422	726
Total	1349		Datum is 4300 ft subsea												

Table 1

				Prior Water Injectivity Trend					First CO2 Injectivity Trend									
Pattern Stage	No. of Patterns	Months on Wtr prior to CO2	Prior Wtr Injectivity	Improving	Stable	Declining	Months on 1st CO2	1st CO2 Injectivity	Improving	Stable	Declining	No. of CO2 Half-cycles	Avg CO2 Half-cycle Length, mos.	Avg CO2 Half-cycle Injectivity	Latest CO2 Half-cycle Injectivity	Avg Wtr Half-cycle Length, mos.	Avg Wtr Half-Cycle Injectivity	Latest Wtr Half-Cycle Injectivity
Elder	13	3.8	9.14	31%	46%	23%	12.6	1.48	15%	77%	8%	11.4	5.0	1.47	1.02	2.7	5.86	1.75
Mature	12	3.4	5.41	17%	50%	33%	12.3	1.55	42%	50%	8%	7.5	5.5	1.81	1.47	2.8	5.81	2.20
Adolescent	5	2.0	8.93	20%	20%	60%	12.4	1.29	40%	40%	20%	4.6	8.6	1.46	1.30	2.8	3.57	1.66
Infant	31	2.2	13.07	13%	32%	52%	6.9	2.70	32%	42%	26%	1.4	5.8	2.58	2.47	2.2	11.38	9.35
All	61	2.8	10.38	20%	37%	42%	9.6	2.10	32%	52%	15%	5.0	5.8	2.10	1.87	2.5	8.47	5.69

Stage Groupings

Elder	10 or more CO2 Half-cycles
Mature	6 to 9 CO2 Half-cycles
Adolescent	3 to 5 CO2 Half-cycles
Infant	2 or less CO2 Half-cycles

Table 2

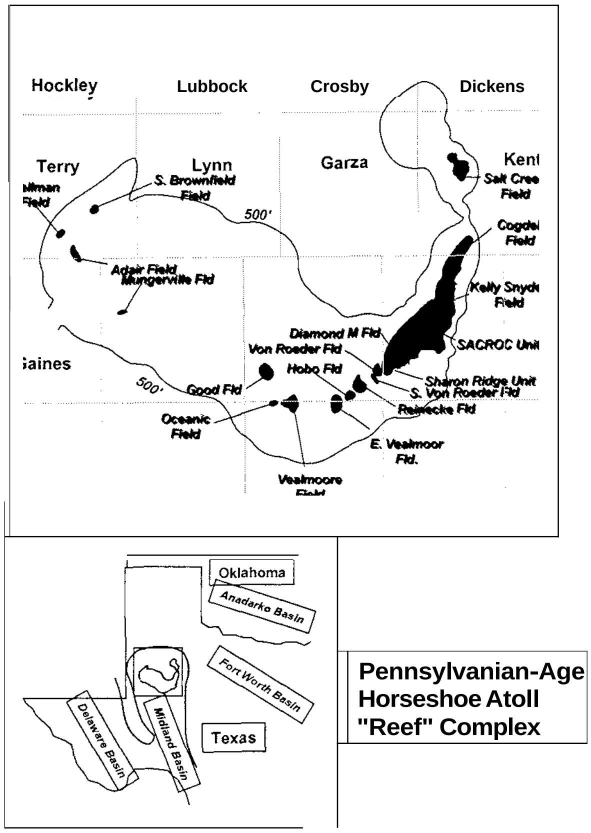
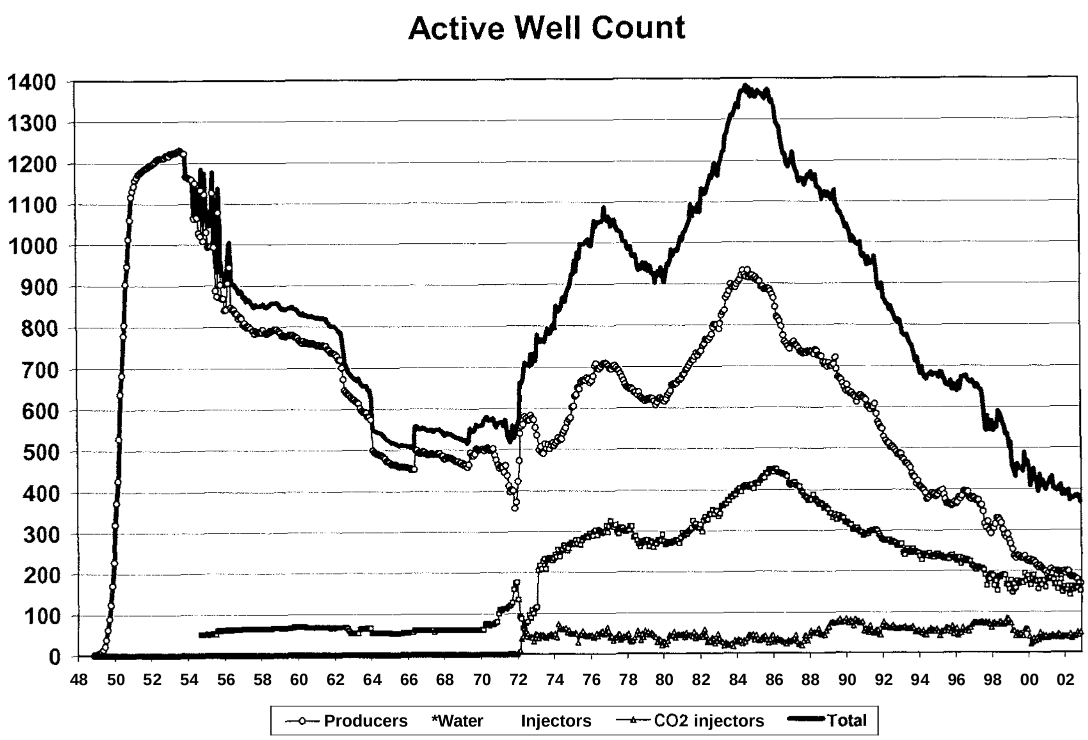


Figure 1.



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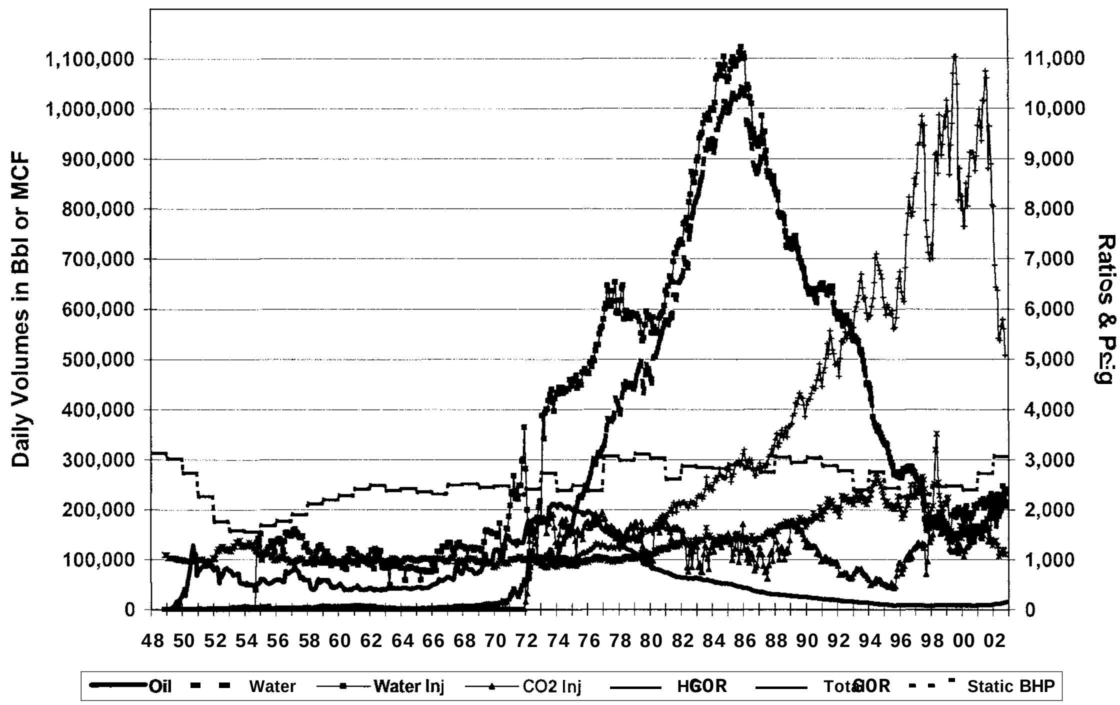

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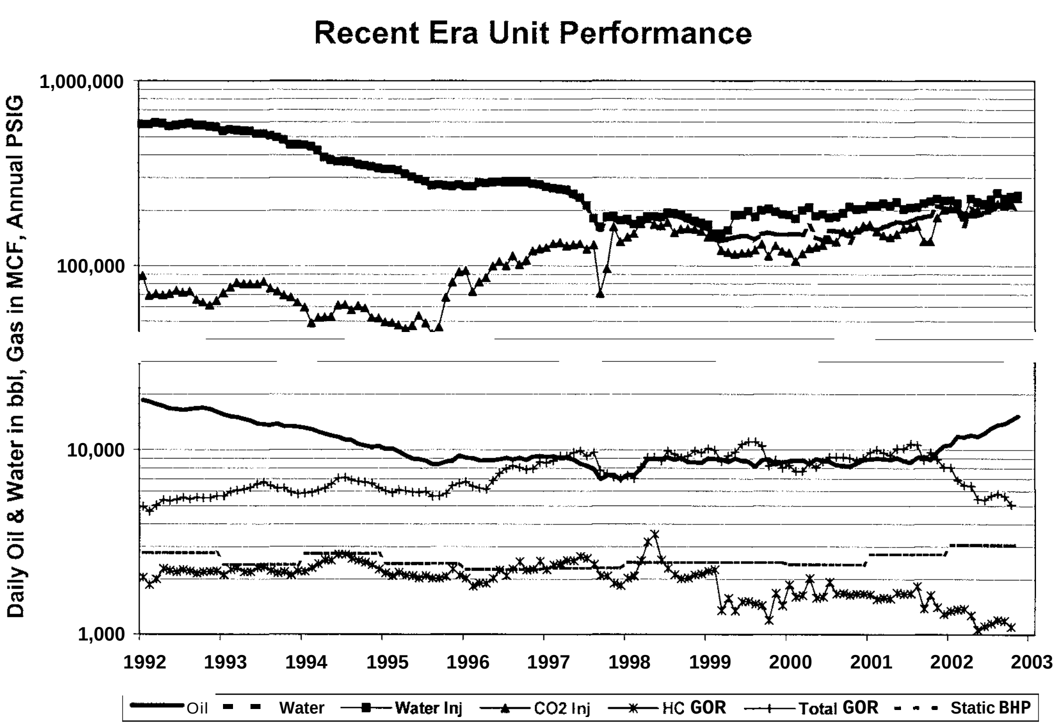

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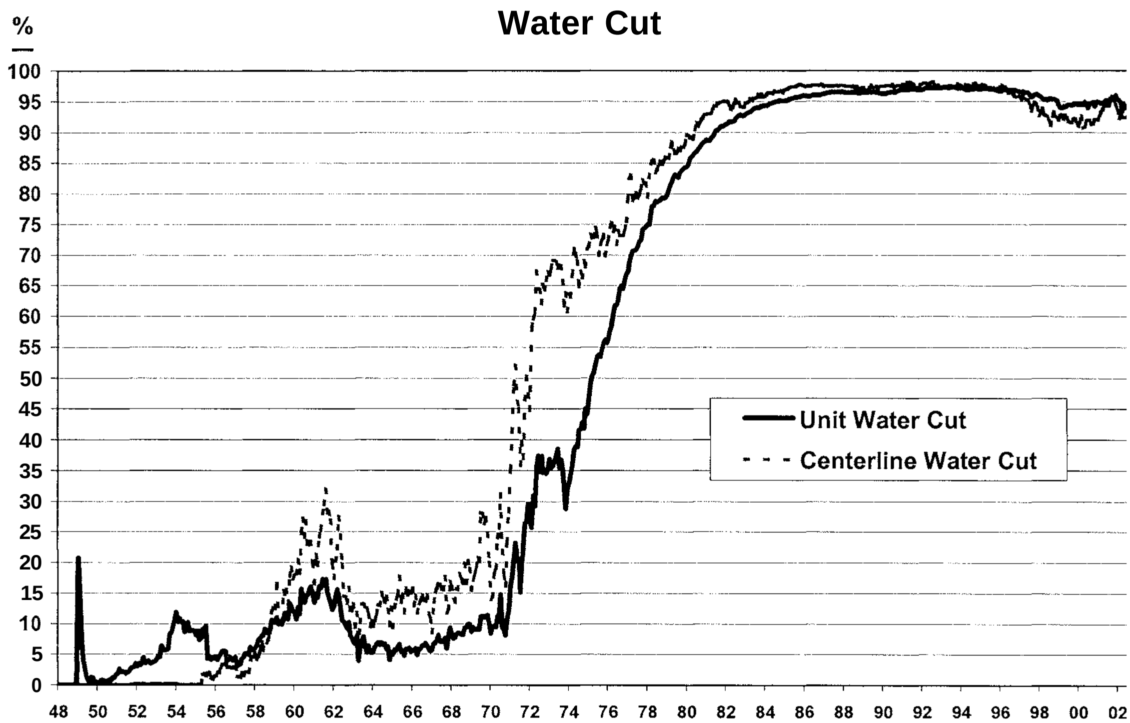

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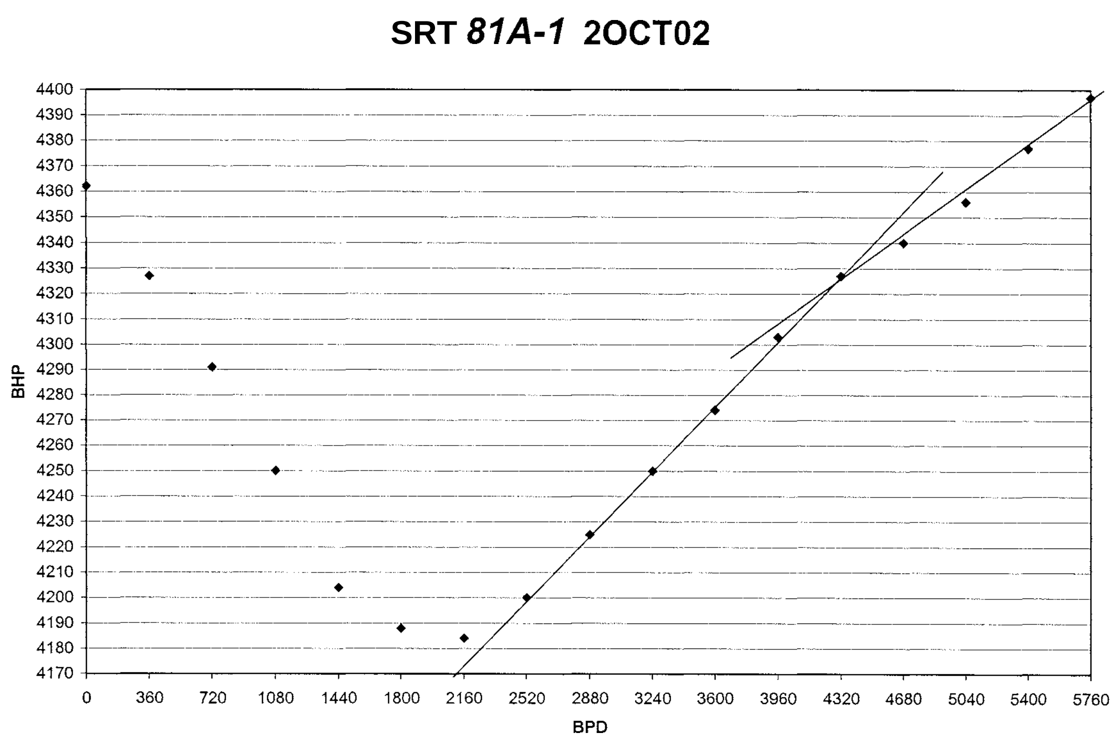
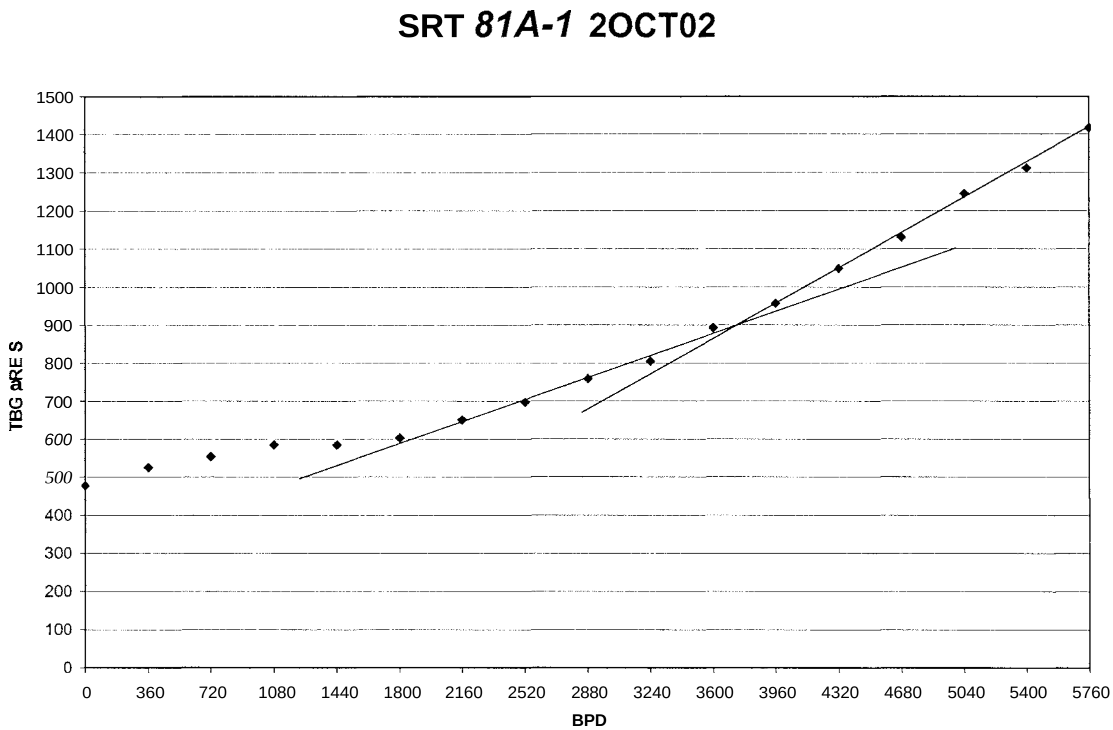


Figure 6a



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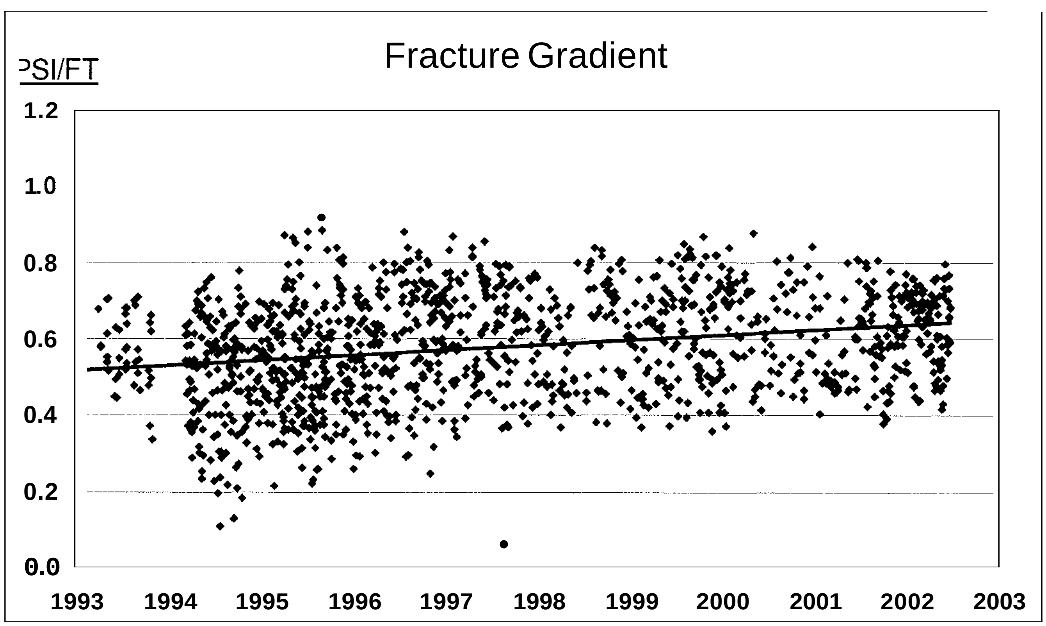

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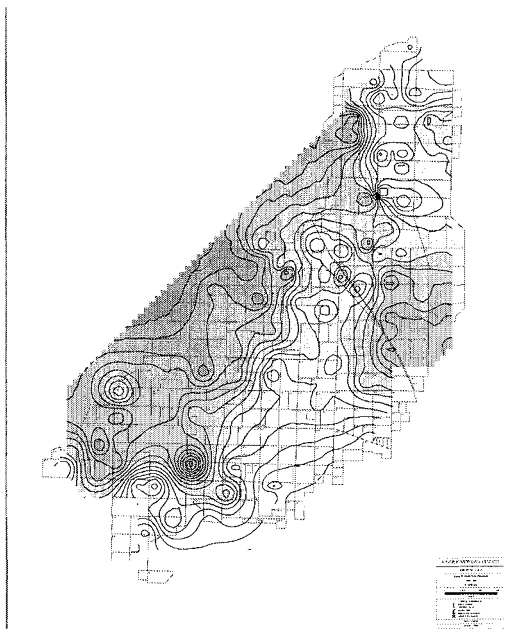
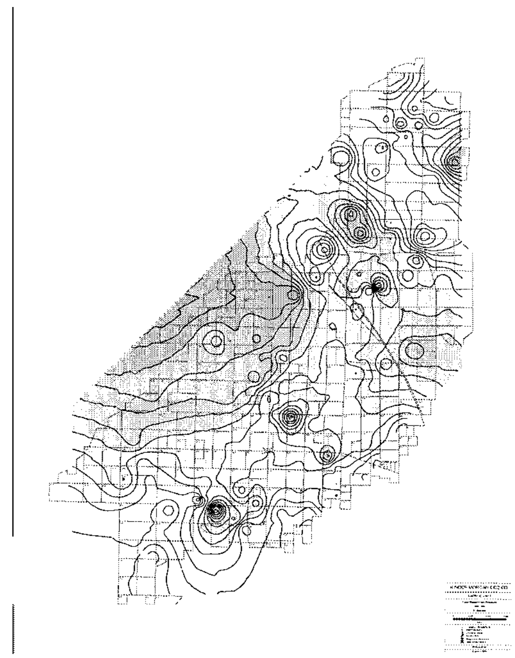


Figure 8 - 1993-94



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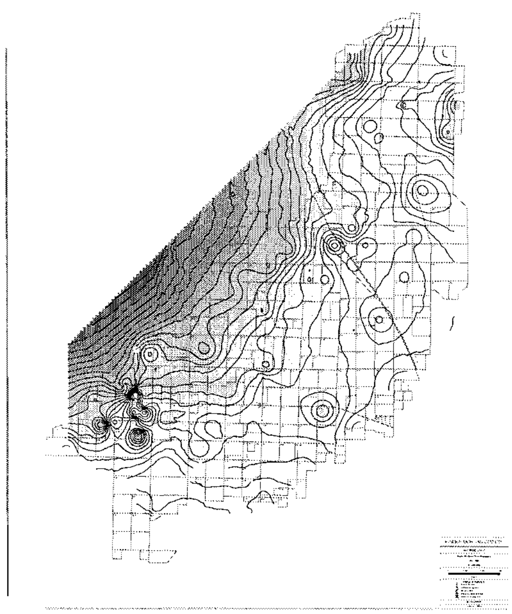

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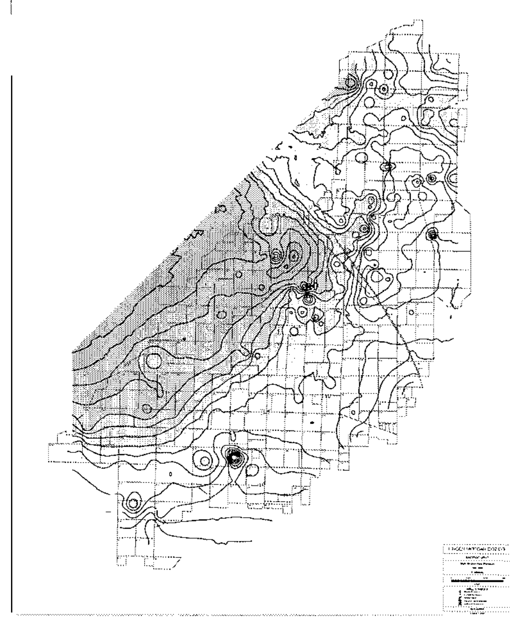

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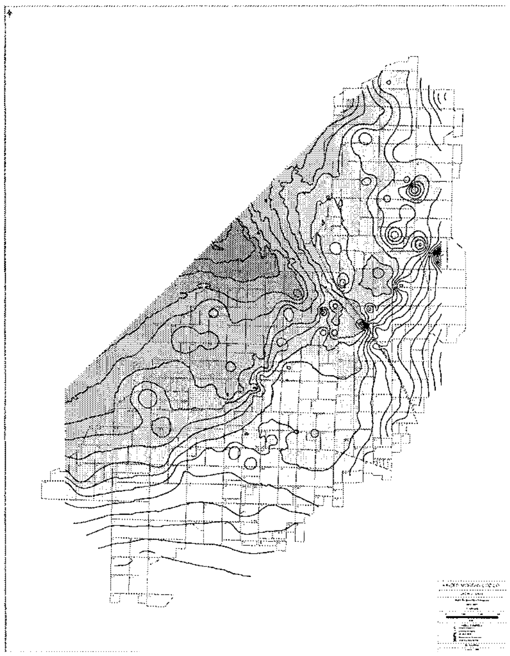

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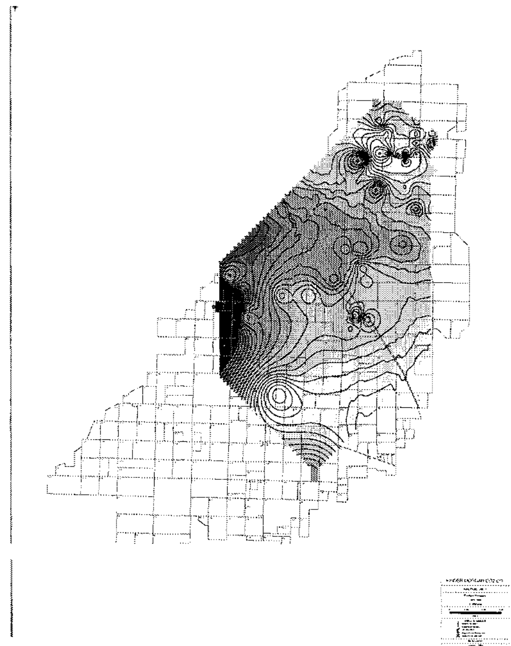

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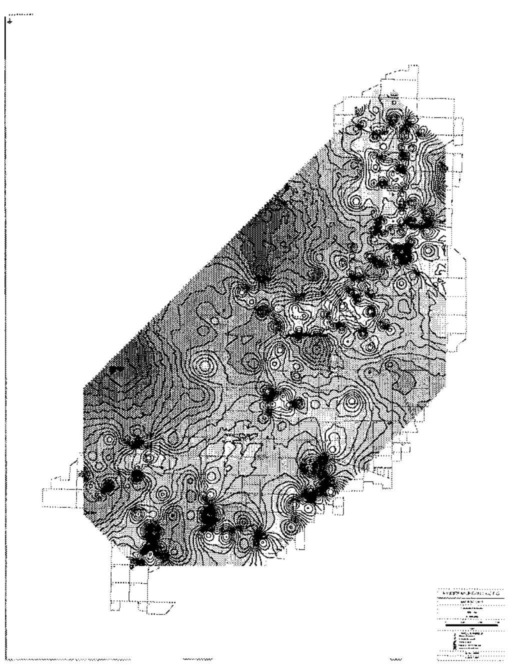

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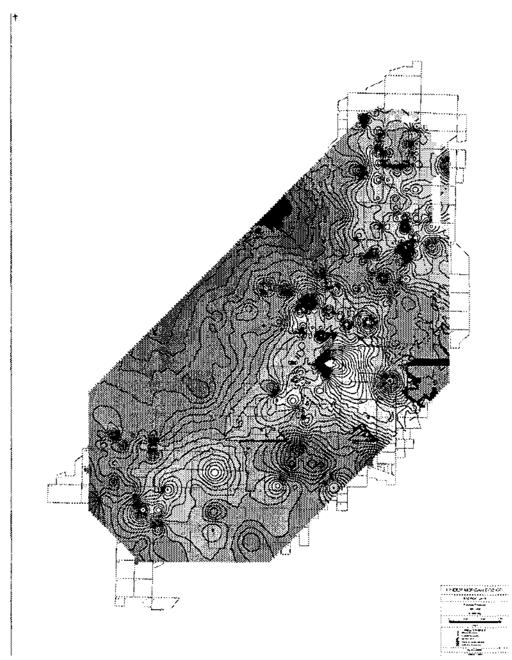

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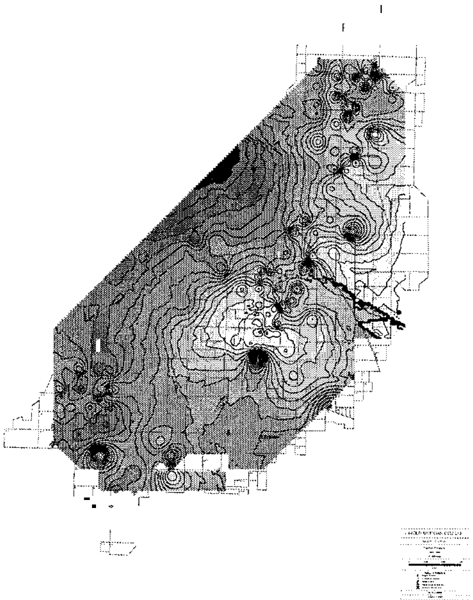

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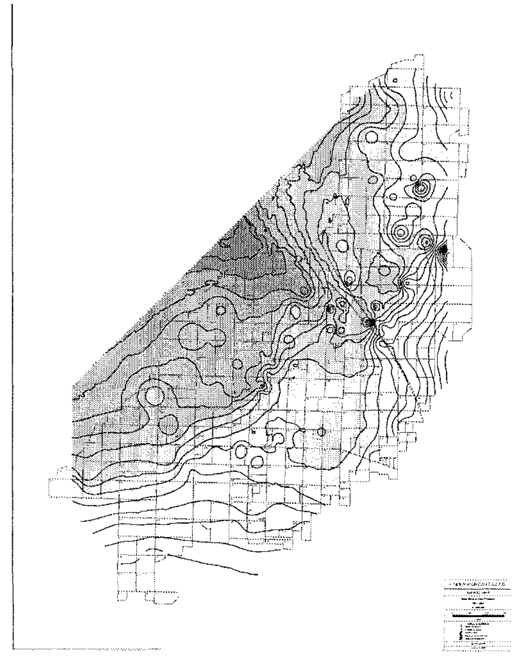

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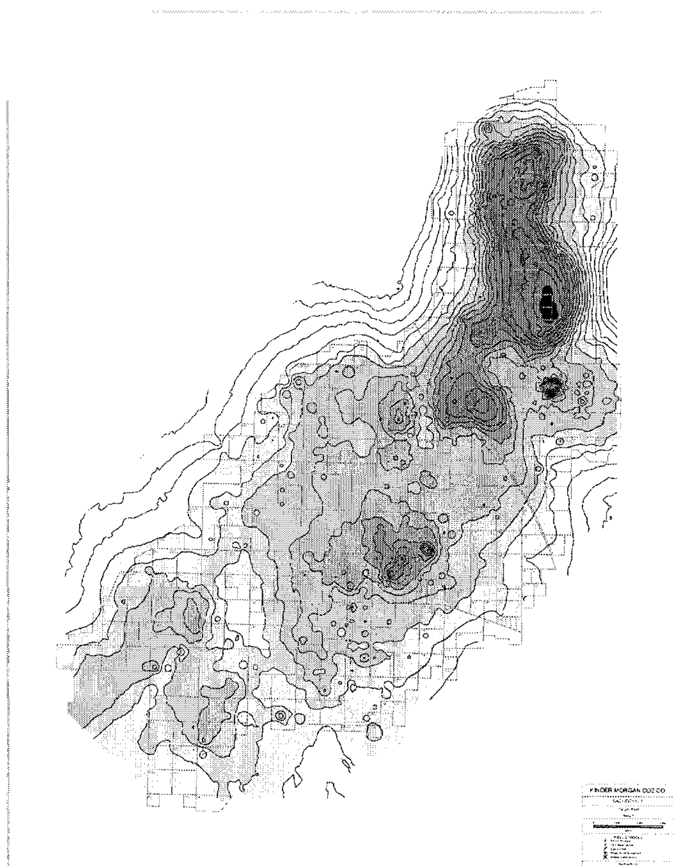

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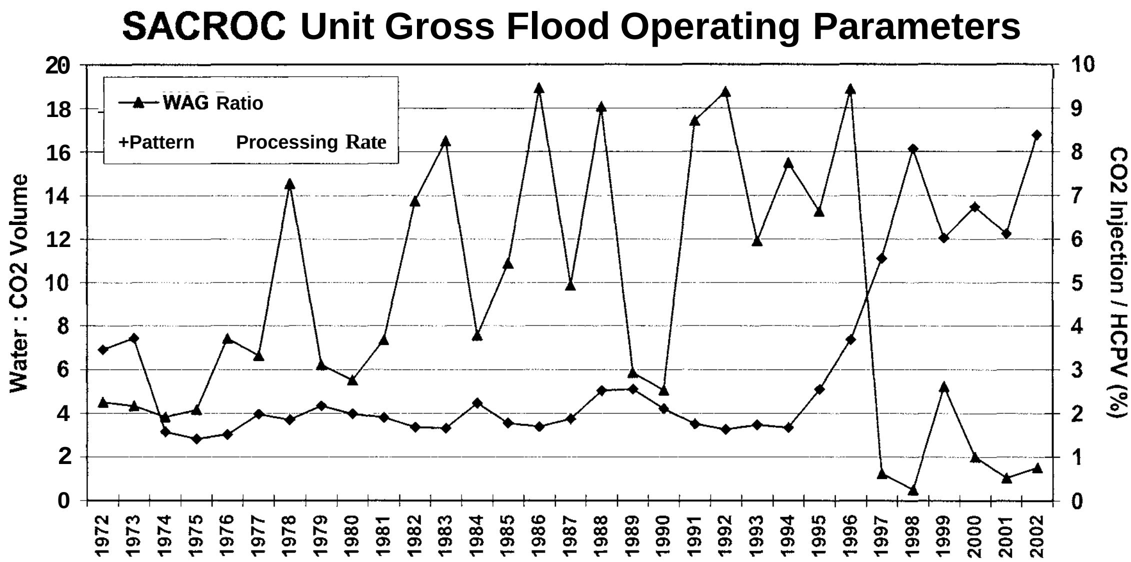

Figure 19

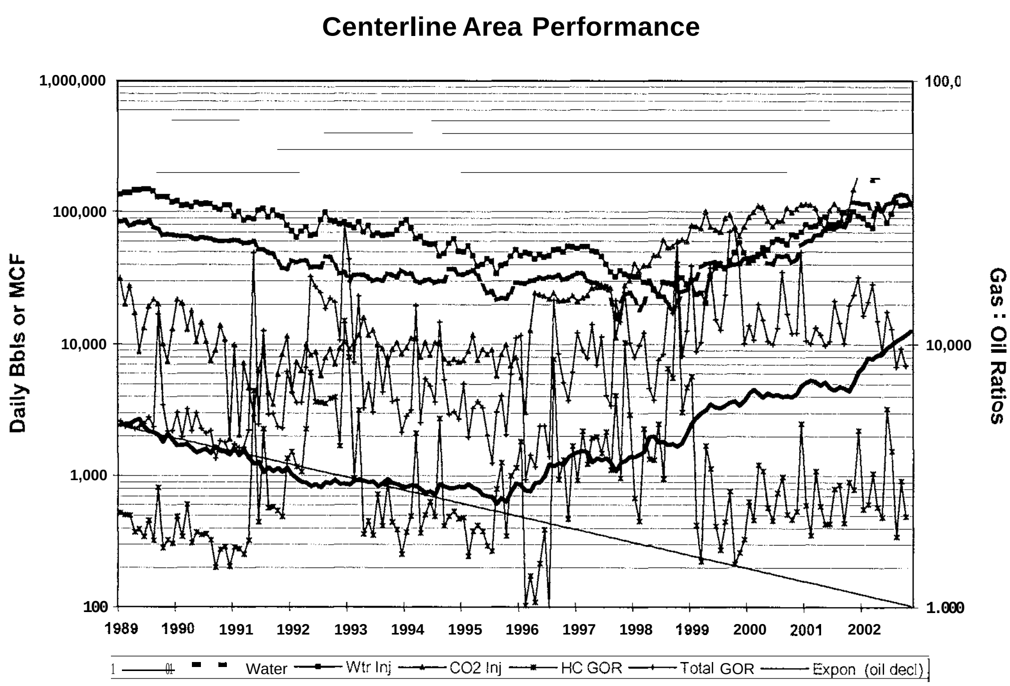

Figure 20