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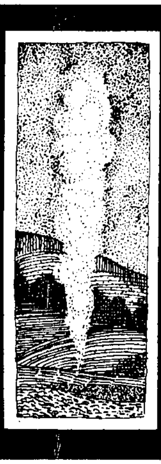

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INTERDISCIPLINARY RESEARCH
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FORMATION PLUGGING WHILE TESTING A STEAM WELL AT THE GEYSERS

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SUMMARY

During testing of a steam well at The Geysers steam field in Sonoma County, California, rate suddenly dropped by 17,500 lb/hr and wellhead pressure simultaneously increased by 30 psi. There was no evidence of plugging in any of the surface facilities downstream of the wellhead. Pressure buildup tests before and after the incident show that there was a 15% reduction in permeability-thickness. Analysis of pressure losses in the wellbore due to friction showed that all of the rise in wellhead pressure could be explained by the reduction in mass flow that occurred as a result of the 15% reduction in kh. The change in wellhead enthalpy from 1200 Btu/lb and 4°-5°F superheat prior to the incident to 1197 Btu/lb and 0-1.4°F superheat after the incident indicates the well became slightly wet. One possible explanation for this reduction in kh is that movement of free water caused a plugging action or a reduction of mobility to steam in one or more steam entries.

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STATEMENT OF THE PROBLEM

On the first day of testing, the well was produced for 8.5 hours with a final rate of 195,640 lb/hr at 168 psig wellhead pressure. The following day this well was re-tested (see Table 1). After 5 hours, with the well producing 194,466 lb/hr at 174 psig, wellhead pressure suddenly jumped up 30 psi and rate dropped to 177,000 lb/hr. This was observed by personnel on site at the time. Inspection of test tube, orifice, throttling valve and muffler did not reveal any evidence of plugging. On the third day of testing, this well was re-tested at 172 psig wellhead pressure for 8.3 hours and final production rate was 171,000 lb/hr, indicating that there had been a permanent loss of about 13% in productivity. This test data is on Table 2.

Analysis of pressure buildup tests prior to and after the incident described above shows that there was a 15% loss in permeability-thickness, which is sufficient to account for all of the loss in productivity. The first buildup test, Figure 1, was done after flowing the well for 8.5 hours at 195,640 lb/hr on the first day of testing. The kh product calculated from this test was 75,000 md-ft. The loss in productivity occurred while flowing on the second day of testing, Table 1. A second buildup, Figure 2, was recorded after flowing for 8.3 hours at 171,000 lb/hr on the third day of testing, Table 2. The kh product calculated from this test was only 63,400 md-ft, 15% lower than what it was prior to the loss in productivity.

REASON FOR RISE IN FLOWING PRESSURE

Normally when wellhead pressure rises suddenly as rate drops off, plugging action downstream of the wellhead is commonly thought to be the cause. This case study shows that the same thing can happen in a steam well if there is a sudden plugging action in the the formation. Wellhead pressure rises because there is less friction drop at the lower rate. This was verified by friction drop calculations using the Cullender and Smith[1] equation. Results of this calculation, summarized below, show that friction loss dropped from 199 psi at the higher rate to 155 psi at the lower rate, and that static head (i.e. the gradient due to vapor density changes) increased from 34 psi to 38 psi for a net decrease of 40 psi in the vertical pressure gradient. The change in formation permeability caused bottomhole flowing pressure to be 10 psi lower at the lower rate. The 40 psi decrease in flowing pressure gradient was therefore reflected at the surface as a 30 psi rise in flowing wellhead pressure.

Rate lb/hr	Wellhead Pressure psig	Bottom Hole Pressure psig	Static Head psi	Friction Loss psi
194,466	174	407	34	199
177,027	204	397	38	155

POSSIBLE PLUGGING MECHANISM

Comparison of Tables 1 and 2 shows that prior to the loss in productivity the steam was superheated about 4°F with an enthalpy

1 Theory and Practice of the Testing of Gas Wells, (Oil and Gas Conservation Board, Calgary, Alberta, 1965) p. 146.

of 1200 Btu/lb, but after the loss in productivity the steam was only slightly superheated or just at saturation with an enthalpy of 1200 Btu/lb, slightly lower than before. The sudden change in enthalpy along with the reduction in reservoir permeability strongly suggests that water influx may have caused a reduction in mobility to steam at one or more steam entries.

TABLE 1

SECOND FLOW TEST

Time min	Wellhead Pressure psig	Enthalpy Btu/lb	Superheat °F	Rate lb/hr
70	182	1201	4	185,571
85	188	1201	3.4	174,265
115	172	1199	3.3	196,026
145	172	1199	3.3	196,026
175	172	1199	3.3	196,522
220	172	1200	4.3	195,624
280	174	1200	3.4	194 446
310	204	1203	5.0	177,027

TABLE 2

THIRD FLOW TEST

Time min	Wellhead Pressure psig	Enthalpy Btu/lb	Superheat °F	Rate lb/hr
75	173	1197	0	174,460
150	172	1197	1.4	173,429
240	172	1197	1.4	172,543
360	172	1197	0.4	170,903
480	174	1197	-0.5	171,137

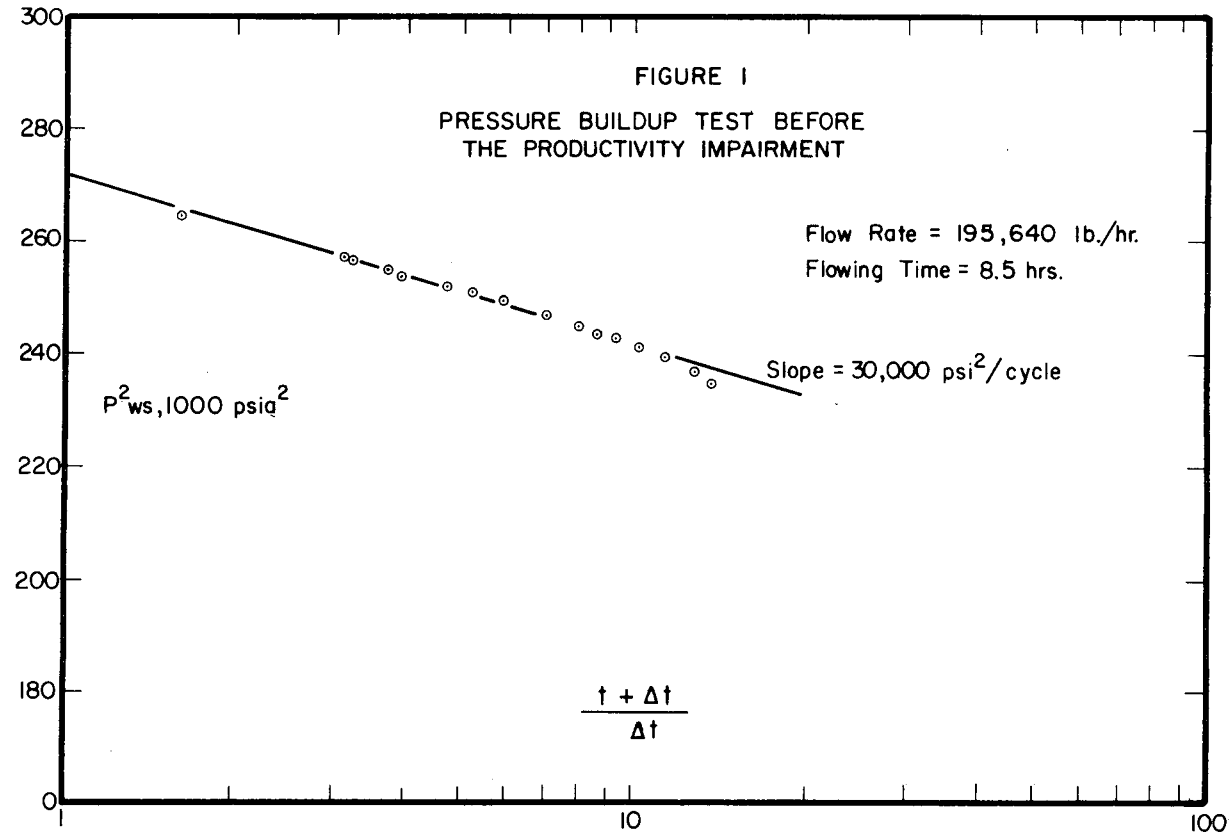
FIGURE 1
PRESSURE BUILDUP TEST BEFORE THE PRODUCTIVITY IMPAIRMENT
Flow Rate = 195,640 lb./hr.
Flowing Time = 8.5 hrs.
Slope = 30,000 psi²/cycle
P²ws, 1000 psia²
(t + Δt)/Δt
300
280
260
240
220
200
180
0
1
10
100

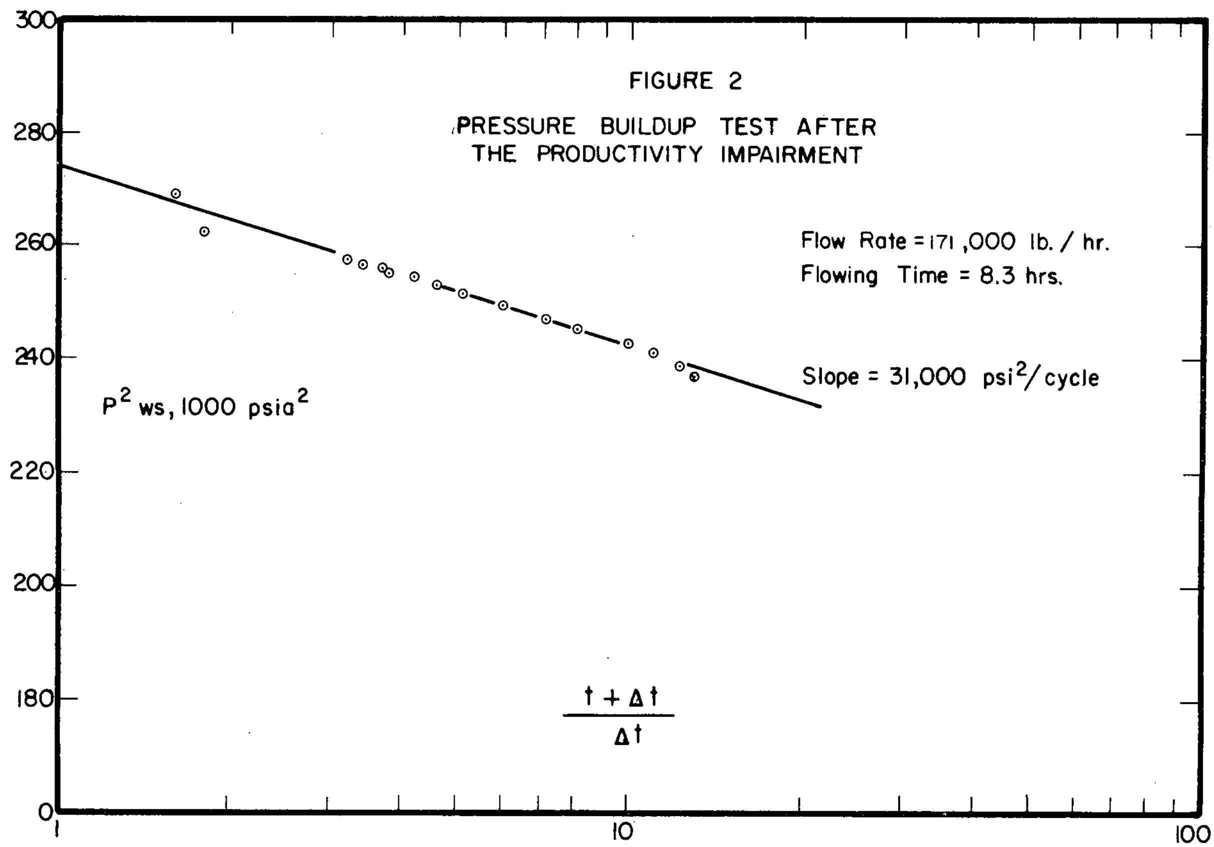
FIGURE 2
PRESSURE BUILDUP TEST AFTER THE PRODUCTIVITY IMPAIRMENT
Flow Rate = 171,000 lb./hr.
Flowing Time = 8.3 hrs.
Slope = 31,000 psi²/cycle
P² ws, 1000 psia²
(t + Δt)/Δt
300
280
260
240
220
200
180
0
1
10
100