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# DESERT PEAK GEOTHERMAL FIELD PERFORMANCE

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## ABSTRACT

The Desert Peak geothermal field, located in Churchill County, Nevada, is generating 9 MWe, using two production wells and one injection well. The dual flash power plant started operation in December 1985, with two producers supplying 980,000 lbm/hr of brine. Pressure transient testing has revealed well performance is influenced by the different lithologies present. The reservoir has shown no signs of depletion in one and a half years of production. Repeated temperature surveys since the start of production suggest higher temperature fluids from the deeper system may be charging the shallow reservoir in the vicinity of the producing wells with measured temperatures approaching the deeper reservoir temperature predicted by geochemistry.

## GEOLOGY

The geothermal field is located in the northern portion of the Hot Springs Mountains, a low relief, highly fragmented horst block. The regional geology consists of Triassic and Jurassic metamorphosed sedimentary and volcanic rocks. The early geologic events resulted in a contact metamorphosed Mesozoic sequence of marine metasedimentary and metavolcanic rocks which are now found at depths of 3000 to 7000 ft at Desert Peak. Tertiary rocks consist of primarily a complex interfingered sequence of volcanic flows, tuffs, and shallow intrusives. Overlying the volcanic rocks is a sequence of lacustrine rocks up to 600 ft thick. Quaternary alluvium and a thin veneer of windblown sand cover the area in the vicinity of the field (Benoit, et al.).

The geologic model of the geothermal system is that deep seated normal faulting has fractured brittle basement rocks and increased the vertical permeability pre-Tertiary and Tertiary rocks, creating an upwelling convection plume (Fig. 1, Benoit et al., 1983). The fine grained lacustrine rocks of the Truckee Formation act as a cap. Outflow occurs in tectonically fractured volcanic and metamorphic units.

Normal faulting is inferred to represent separate episodes of northeasterly and northwesterly fault orientations. The faulting has created rhombohedral horst blocks. The shallow, commercial reservoir, 2500 to 4200 ft, has a preferred permeability orientation in the northeasterly direction.

The major source of the fluids is thought to be recharge from the Carson and Fernley Sinks. The fluids heated at depth rise into the fractured fault zones. The ascending thermal fluids supply the geothermal reservoir which is believed to exist between 3000 to 9000 ft. Leakage out of a deep reservoir charges the shallow geothermal reservoir. Lateral hot water flow has created a large horizontal thermal plume which obscures the location of the deep geothermal reservoir.

The initial geothermometers for the alkali metal-chloride brine indicated a silica temperature of 400-405°F, while the Na/K ratio indicated a deeper reservoir temperature of 420°F. The total dissolved solids content is approximately 6700 ppm. The noncondensable gas content in the total fluid is approximately .029% by weight.

## PRODUCTION

The Desert Peak area was the focus for an active exploration program, which resulted in the discovery well DPU B21-1 in 1976. Initial flow testing produced 478,000 lbm/hr at a wellhead pressure of 103 psig. A second well was drilled, DPU B21-2, in 1976. This well tested at 456,000 lbm/hr with a wellhead pressure of 64 psig. The success of these two wells resulted in the additional drilling of strat test wells, geophysical surveys, and a reinterpretation of the existing data. The Desert Peak Unit was formed in 1979.

Additional production sized wells were drilled in 1979, 1982 and 1984. Testing of these wells indicated the presence of a large resource of +400°F fluid, with interference conductivities on the order of 33,000 to 100,000 md-ft. Based on the results obtained, the Participating Area was formed in 1985 and plans were made to build a 9 MWe power plant. This power plant started operation in December 1985. Well locations and flow test summaries are presented in Fig. 2, and a geologic cross-section across the development area is presented in Fig. 3.

The design basis for the power plant was two producers supplying 500,000 lbm/hr each at a wellhead pressure of 97 psia. Two 24-inch flowlines are used to transport the two-phase steam and water with a minimum pressure drop from each well to a common header where the flow streams are combined into a single 30-inch flowline. The two-phase mixture is transported to the plant site where it enters the high pressure separator and is flashed at 80 psig. The high pressure steam exits through a demister to a water knockout tank to eliminate moisture and ensure a steam quality of 99.5%, prior to entering the high pressure inlet of a dual inlet turbine. The high pressure brine is delivered to the low pressure separator and flashed at 6 psig. Steam from the low pressure separator enters the low pressure inlet to the turbine. The condensing turbine with top outlet steam discharge is capable of delivering 8 to 11 MWe from 185,800 lbm/hr of high and low pressure steam. The turbine is connected to an induction generator. The electricity is transported to Sierra Pacific Power via 5 miles of transmission line.

The two production wells DPU 67-21 and DPU 86-21 together produce approximately 980,000 lbm/hr from a depth of 2500 to 4100 ft at a common header pressure of 80 psig. The wellhead performance curves for the two wells are shown in Figs. 4 and 5. These curves were developed using well test data and a wellbore simulator and closely match observed well performance. The single injector, DPU B21-2, is capable of injecting all of the 800,000 lbm/hr of flashed brine at a wellhead pressure of less than 50 psig. No degradation of injection performance has been noted to date.

In August 1986 the power plant was shut down for a scheduled inspection and maintenance. Inspection of the plant facilities revealed some scaling and corrosion, which were within an acceptable range. Remedial action was taken for the problems noted. Caliper surveys of the two production wells indicated some wellbore carbonate scaling in the interval of two-phase flow predicted by the wellbore simulator. Later that year, the two producers were acidized to remove the wellbore scale after the well performance had deteriorated. After the acid jobs, well performance was restored. During the August 1986 shutdown, four wells (both producers, the injector, and observation well DPU 22-22) were instrumented with downhole pressure chambers and capillary tubing to measure reservoir pressure transient response. Additionally, temperature surveys were made in five wells to monitor changes in temperature profiles. The results of the above work will be discussed in the following section on reservoir performance. At the conclusion of the August shutdown, the power plant was brought back online. The combined initial flowrate of the two producers was in excess of 1,080,000 lbm/hr before declining to a stabilized rate of 980,000 lbm/hr.

During March 1987, the power plant was shut down for turbine repairs. During this time additional temperature surveys were performed on all Unit wells for continued monitoring of changes in temperature profiles. Two observation wells were instrumented with downhole pressure chambers and capillary tubing to monitor reservoir pressure transient response once production had started. After production started, the combined flowrate of the two producers was in excess of 1,050,000 lbm/hr, and gradually declined to a stabilized combined rate of 980,000 lbm/hr. The capacity utilization factor has exceeded initial expectations and has averaged in excess of 90% since initial plant startup.

## RESERVOIR

Early well testing at Desert Peak consisted of flow potential tests with very little downhole data collected. The initial data consisted of static temperature surveys, pressure surveys, short duration, small volume injection tests, and observation well fluid level measurements. While this approach did give estimates of interwell conductivity and storativity, direct measurement of producing well conductivity, skin, and pressure transient behavior was unavailable to make an interpretation of the reservoir flow model. However, this phase of the reservoir evaluation did conclude the presence of a large resource in place with interwell conductivities on the order of 33,000 to 100,000 md-ft. Interwell conductivity appears to be as much as an order of magnitude higher in the north-south direction than in the east-west direction. This behavior seems to be controlled by local geology and is poorly understood at this time.

Static temperature and pressure surveys revealed the two producers were located near a zone of upwelling, with the top of the convective interval as shallow as 1500-2000 ft. Maximum initial temperatures in the convective shallow reservoir ranged from 401-408°F. The initial static pressure surveys revealed a pressure high in a north-south trend from DPU 22-22 to DPU 67-21. Well DPU 22-22 is at the center of the pressure high (as much as 40-50 psi greater than the margins of the reservoir) and also recorded the highest temperature. It was theorized in 1983 that DPU 22-22 was located near the source of the upwelling of thermal fluids into the shallow geothermal reservoir.

Prior to the scheduled August 1986 plant shutdown, a review was made of all the reservoir and pressure transient data available. A test program was prepared to conduct extensive temperature and pressure survey work in the observation wells, and to install downhole pressure chambers, capillary tubing and quartz crystal pressure transducers in both producers, the injection well, and in observation well DPU 22-22. The pressure chambers were set uniformly at +1700 ft sea level to measure the pressure distribution in the reservoir at a common datum.

The static temperature surveys on the observation wells indicated the convective portions of the shallow geothermal reservoir had increased in temperature from 4-10°F, compared to the pre-production surveys conducted prior to December 1985. The largest temperature increase occurred in DPU 22-22 (see Fig. 6) and to a lesser degree along a north-south trend, roughly corresponding to the pressure high noted above. This data suggested the shallow reservoir was heating up. However, the magnitude of the observed increase was within the stated accuracy of the temperature tools used (±2% of full scale, 500°F tool, i.e. 10°F). It was noted in the temperature survey of observation well DPU B21-1, a direct offset to DPU 67-21 with the bottomhole wellbores 14 ft apart, that the bottom interval had a temperature inflection corresponding to the presence of a greenstone unit, a metamorphosed basic igneous rock (see Fig. 7). This survey was the first indication of reservoir behavior influenced by lithology. Field wide temperature surveys will be conducted at 6-9 month intervals to monitor this trend.

Analysis of the pressure transient data allowed a detailed characterization of the production and injection well behavior. The pressure transient data indicated the presence of both a dual porosity reservoir and a vertically fractured reservoir, depending on the well location and depth. Total reservoir conductivities varied from 5,300 to 55,000 md-ft, while fracture conductivities varied from 12,000 to 200,000 md-ft. Wellbore skins ranged from a -5 to -7.5, typical of a fractured reservoir. The interesting item was that wells exhibiting dual porosity behavior had a large interval of greenstone present in the completion interval. Producer DPU 67-21 exhibits dual porosity behavior as shown in the type curve match of the Restricted Interporosity Flow Transition Curves shown in Fig. 8. The same data is plotted in a Horner plot in Fig. 9. Note the characteristic "S" shape of dual porosity pressure transient behavior. Producer DPU 86-21 did not exhibit dual porosity behavior and does not have greenstone present. Its pressure transient response was dominated by vertically fractured behavior. A comparison of the Productivity Index shows DPU 67-21 is a better producer than DPU 86-21. Also note the wellhead performance curves in Figs. 4 and 5. It is hypothesized the greenstone unit at Desert Peak is a major source of reservoir permeability, porosity and storativity. This idea is currently under further evaluation, as it could provide an important geological target for future development drilling. The interference data collected essentially verified the earlier interpretation made prior to initial power plant startup. The pressure data collected indicated recharge was occurring 40 to 100 hrs after shut-in, depending on well location. The calculated infinite shut-in pressure, P*, in the production and injection wells was within 2 psi of measured initial reservoir pressure. The behavior of the pressure derivative for all the well tests indicated the presence of a constant pressure boundary (see Fig. 10), as shown by the late time bending over of the pressure derivative. It is concluded the Desert Peak reservoir is infinite acting with no pressure depletion noted to date. This is very encouraging for the future development potential of the Desert Peak resource.

In March 1987, additional temperature surveys were conducted as part of a program to monitor changes in the temperature profiles. These surveys showed additional temperature increases in the convective intervals of all wells surveyed, with the magnitude of change from 2-5°F. Temperature surveys of the production wells revealed temperatures of 412-415°F. Water samples taken at this time indicated a quartz geothermometer of 411-416°F, in excellent agreement with the measured temperatures. The most recent Na/K ratio predicted temperatures range up to 444°F, which agrees with previous estimates of deep reservoir temperature. Again, DPU 22-22 recorded the highest temperature of 425°F. It is now felt the increase in reservoir temperatures is a real phenomenon and it is concluded production from the shallow geothermal reservoir is drawing up the hotter fluid existing in the deeper geothermal reservoir. The data provides strong confirmation this well is located near a zone of upwelling and the temperature of the upwelling fluids is approaching the temperatures predicted by geochemistry for the deeper geothermal reservoir.

## CONCLUSIONS

The recently collected data has altered our understanding of the Desert Peak resource. The interplay between the geology and reservoir pressure response is beginning to be understood. The conclusions reached to date are summarized below and may have application to other faulted geothermal reservoirs.

1. Pressure transient testing has revealed the presence of both dual porosity and vertically fractured reservoir behavior.
2. The different lithologies present influence reservoir pressure response and well behavior. The greenstone unit is an important source of reservoir porosity, permeability and storativity.
3. The Desert Peak reservoir is infinite acting with recharge occurring 40-100 hrs after shut-in.
4. Observation well DPU 22-22 is located near a zone of upwelling from the deeper geothermal system.
5. Production from the shallow geothermal reservoir is drawing up the hotter fluid existing in the deeper geothermal reservoir.
6. Water geochemistry is a good predictor of fluid temperatures.

## ACKNOWLEDGMENTS

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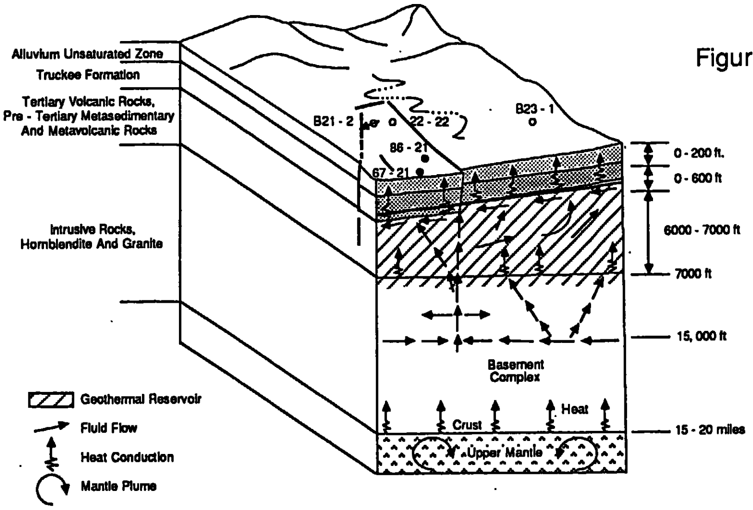
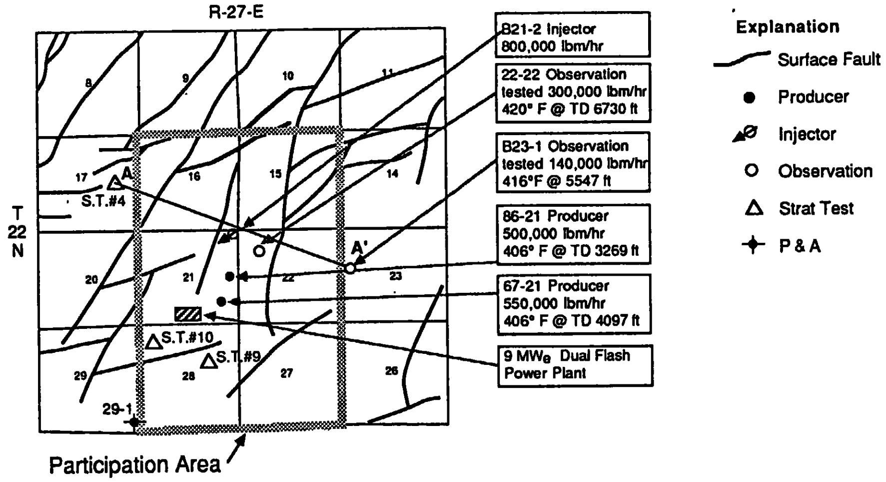


Figure 1. Conceptual model of the Desert Peak geothermal system (from Benoit, et al.).

Figure 2. Well locations and flow test summaries.



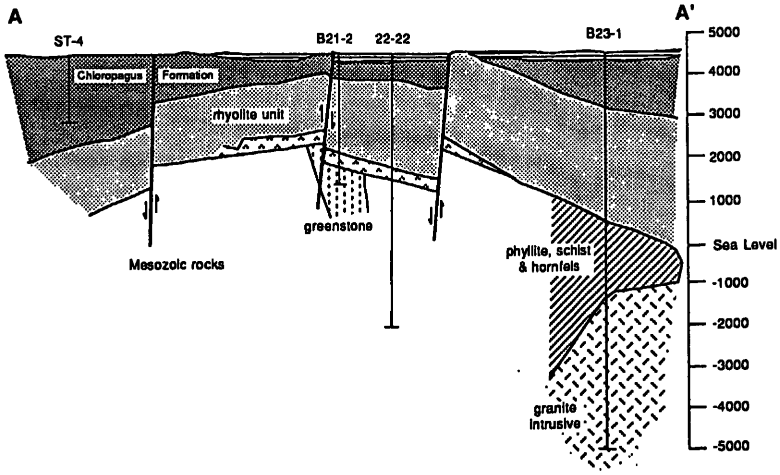


Figure 3. Geologic cross section across the development area.

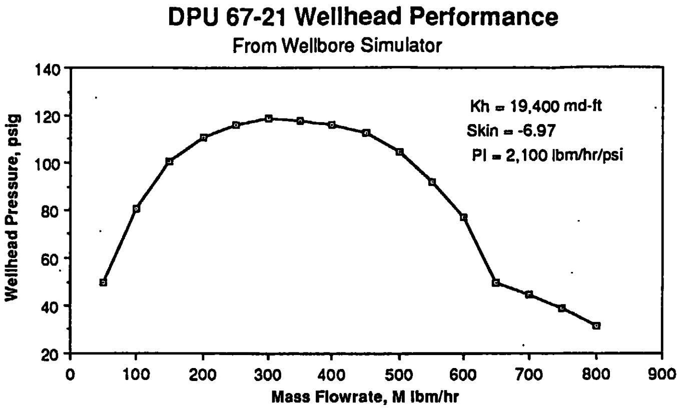


Figure 4. DPU 67-21 wellhead performance curve.

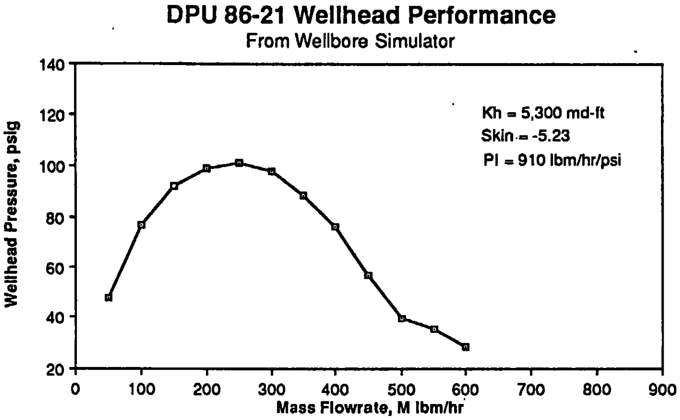


Figure 5. DPU 86-21 wellhead performance curve.

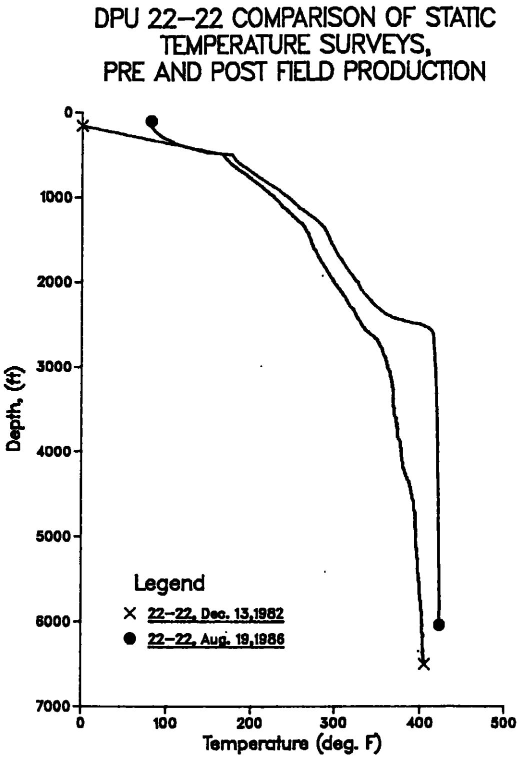
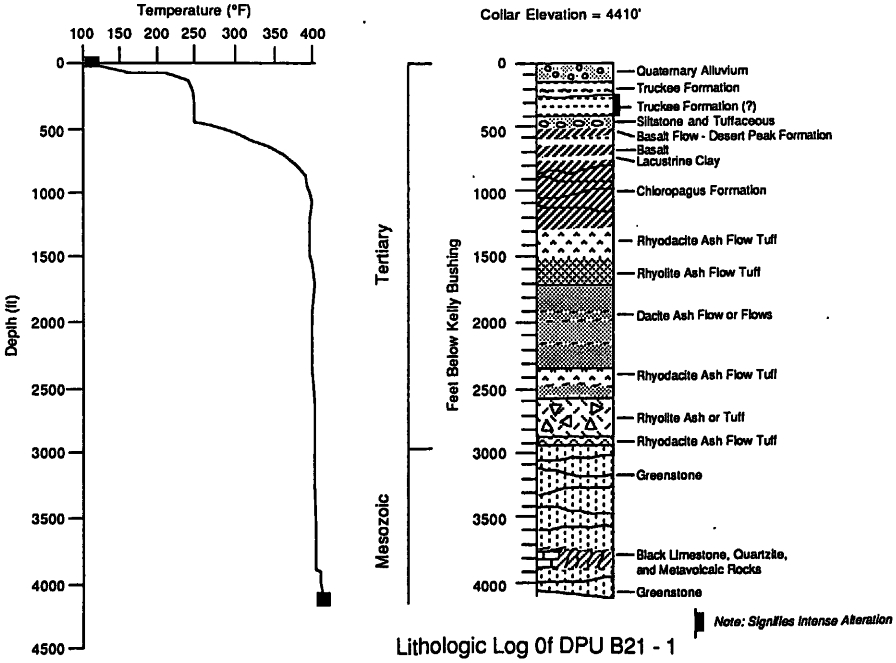


Figure 6. DPU 22-22 temperature profiles.

Figure 7. DPU B21-1 temperature profile and lithology.



Lithologic Log Of DPU B21 - 1

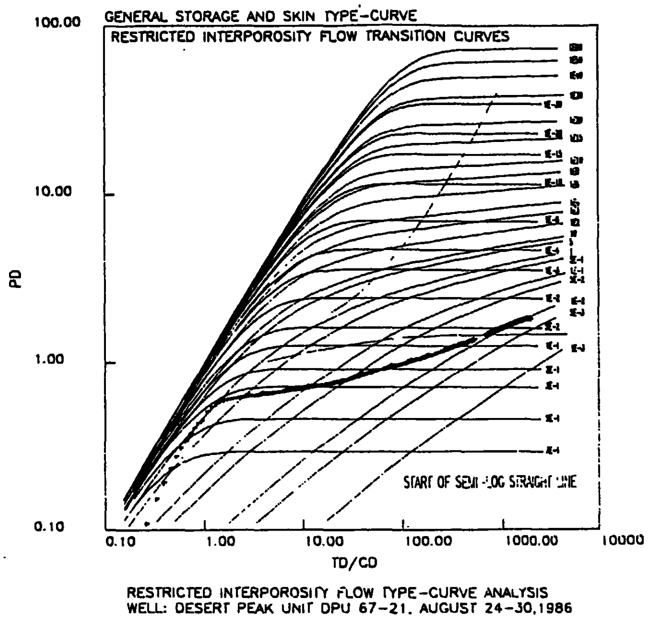


Figure 8. DPU 67-21 Restricted Interporosity Flow Transition curve match.

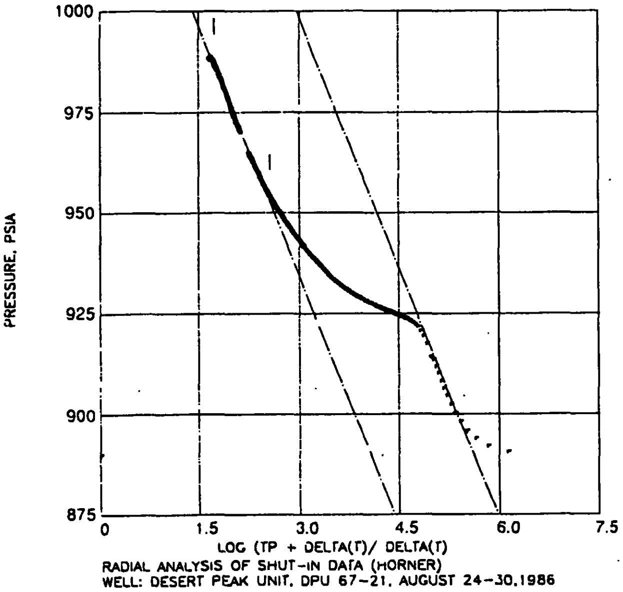


Figure 9. DPU 67-21 Horner plot.

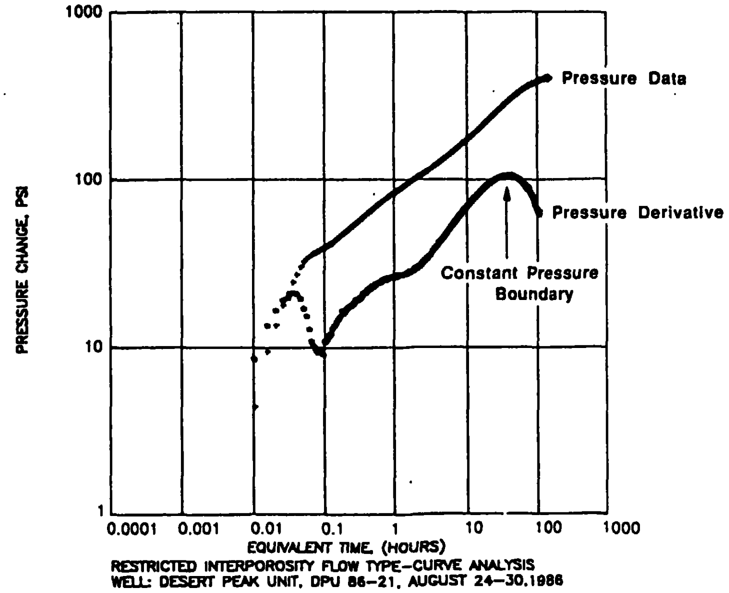


Figure 10. DPU 86-21 log-log plot of pressure change versus elapsed time with the pressure derivative.