Bit Performance Logs - A Tool For Reducing Drilling Costs

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Attention is being focused on more and better advance planning in drilling operations to minimize the rise in drilling costs. This paper describes one procedure for evaluating and improving drilling performance.

In our study, penetration rate is not considered the sole basis for drilling efficiency but attention is focused on the more important aspect of incremental cost per foot of hole drilled.

DESCRIPTION OF BIT PERFORMANCE LOGS

The method used to analyze the cost per foot is a study of performance logs of all the bits used in a particular field or area. Bit records, well logs, casing and mud programs and drilling records are obtained to prepare the bit logs for each well in the field. The bit performance log for each well is prepared by plotting the interval drilled by each bit, type of bit, dull condition of the bit, "cost per foot" of hole drilled by each bit and the formation tops. The "cost per foot" is obtained by adding the bit cost to the rig costs for drilling and round trip time, then dividing by the footage drilled by each bit. The round trip time includes the average time from the moment one bit leaves bottom until drilling commences with the following bit. It includes the time normally spent in circulating or conditioning mud, average downtime for minor repairs, the proper percentage of the time spent in cutting off wireline and the average "washing to bottom" time. The average round trip time has been determined for several rig capacities and plotted versus depth. The value for round trip time used in the analysis is obtained from this plot. A constant value for hourly rig costs is used for each well. For these studies it is assumed that the rig cost, dollars per hour, while rotating and during round trip is a constant, and is not a function of rotary speed, depth, weight on bit, etc. Use of these fixed values enables a performance evaluation on an equal basis by comparing the incremental cost per foot of hole drilled for each section of the hole.

APPLICATION OF METHOD AND FIELD EXAMPLES

In evaluating bit performance, all factors must be considered such as weight on the bit, rotary speed, type of drilling fluid, hydraulics and formation being drilled. Since hole size, drilling fluid programs and hydraulics are normally similar for wells drilled in a particular field development program, attention can be focused on bit types, bit weight, rotary speed and formation being drilled.

Figure 1 is a plot of bit performance logs from wells drilled in a recent development program in the Arenoso Field, Winkler County, Texas. The type of bit, dull condition of the bit and cost per foot for the interval drilled has been plotted at the depth the bit was pulled. The formation tops and a typical log are also shown in this illustration. From a careful study of a plot of this type, a preliminary selection of bit types yielding the lowest cost per foot can be made.

Figure 4 is a section from several of the bit performance logs in the Arenoso Field and points out the difference in incremental cost per foot for three different bit types: the milled teeth bits, the tungsten carbide insert bits and the shaped tungsten carbide insert bits.

The milled teeth bits were drilling the hard limestone and dolomite in this interval for costs ranging from \$6.50 to \$9.00 per ft. The conventional insert bits were drilling for \$5.20 to \$5.80 per ft. The shaped insert bits produced the lowest cost per foot and were selected as the most economical bit type for this interval.

Figure 2 is another section from the bit logs in the Arenoso Field. In this interval, it was noted that the sealed bearing bits were producing the lowest cost per foot. It was also noted that the costs varied with the same bit type. This was caused by reduced weighs often being run on the bit due to crooked hole limitations.

The procedure presented by E. M. Galle and H. B. Woods[1] was used to calculate the cost per foot by applying the best weight and rotary speed. Figure 3 shows the performance curve of a typical bit run through this interval where weight on the bit was being reduced. The weight on the bit was 35,000 lbs. and the rotary speed was 90 RPM. Using the procedure outlined by Galle & Woods, the best weight for 90 RPM was calculated as 63,000 lbs. The best combination of weight and rotary speed was calculated to be 66,000 lbs. at 75 RPM. The total footage and rotating hours were calculated for these conditions and are plotted on Fig. 3. On another well, a square drill collar was used and additional weight was applied to the bit without encountering deviation problems. The actual performance curve of this bit run is also shown on Fig. 3. The actual performance of this bit run compares closely with the results predicted by the Galle and Woods procedure.

Of course these comparisons of bit selection and effect of weight and rotary speed can be made for a particular interval without the aid of a bit performance log. However, the bit performance logs do point out the intervals where additional study should be made and also enable a review and comparison of bit runs preceding and following a particular interval being studied. Sometimes the bit selection and operating conditions that produce the lowest cost per foot for a particular bit run will not result in the lowest overall drilling cost for the well. This is true for an interval where the most economical bit type is out of gage when pulled. This reduces the useful life of the next bit and the cost per foot for the following section of hole is increased. A reduction in rotating hours or bit selection that offers more gage protection may slightly increase the cost per foot for a particular section, but the useful life of the following bit is increased and the overall cost per foot is reduced.

In Fig. 1 the interval from approximately 4100 to 4300 ft is a very hard abrasize zone. It can be seen from the plots in Fig. 1 that many bits were dulled and pulled at this depth. It was found that the insert bits could best drill this interval; however, placement of the insert bits was important. In several cases, milled teeth bits were used to drill into the interval and often these bits were out of gage when pulled. If another milled teeth bit were run in this interval it would dull rapidly and result in a costly section of hole. The lowest overall cost per foot was obtained by running the carbide insert bit before the abrasive section was encountered. This would often increase the cost per foot for the bit pulled above the zone, but the insert bits would drill the remaining section below at a much lower cost per foot.

A close examination of the bit performance logs also indicated that many carbide insert bits were pulled prematurely because of a drastic decrease in penetration rate when a thin shale section was encountered. These shale sections were normally thin and the section underlying the shale was best suited to carbide bits. By continuing drilling with the insert bits through these intervals, the total footage drilled by these bits was greatly increased and a lower cost per foot for this interval was obtained. By worrying these bits through the thin shale intervals, as much as 1750 ft. of this section has been drilled with one insert bit.

SUMMARY

A study of bit performance plots may not result in a true optimum drilling program but the plots do provide a method for reviewing and studying the effects of bit selections, dull condition, operating conditions and lithology changes on the incremental cost per foot of hole drilled.

In the actual drilling operations there must be good communication between field operating personnel, drilling engineers on the location and staff personnel who are preparing a drilling program because minimum cost drilling depends on many human and mechanical factors. The person on location in charge of the drilling operation is responsible for the successful application of a bit selection program by considering all factors and making adjustments where necessary to conduct a successful drilling operation at the lowest possible cost.

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ACKNOWLEDGMENT

The authors wish to express their appreciation to Standard Oil Company of Texas for permission to prepare and publish this paper.

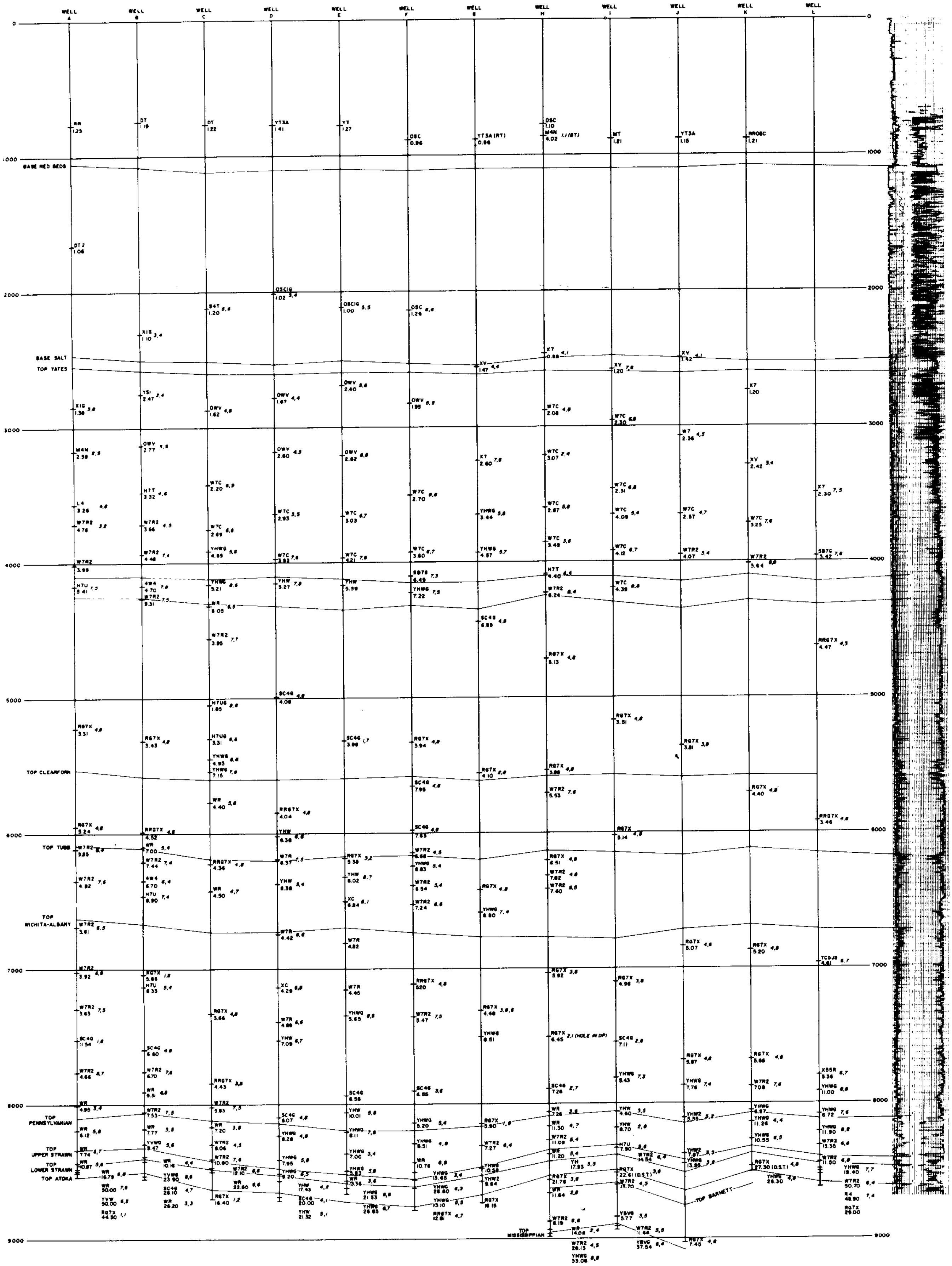


FIGURE 1 - BIT PERFORMANCE LOGS, ARENOSO FIELD, WINKLER COUNTY, TEXAS

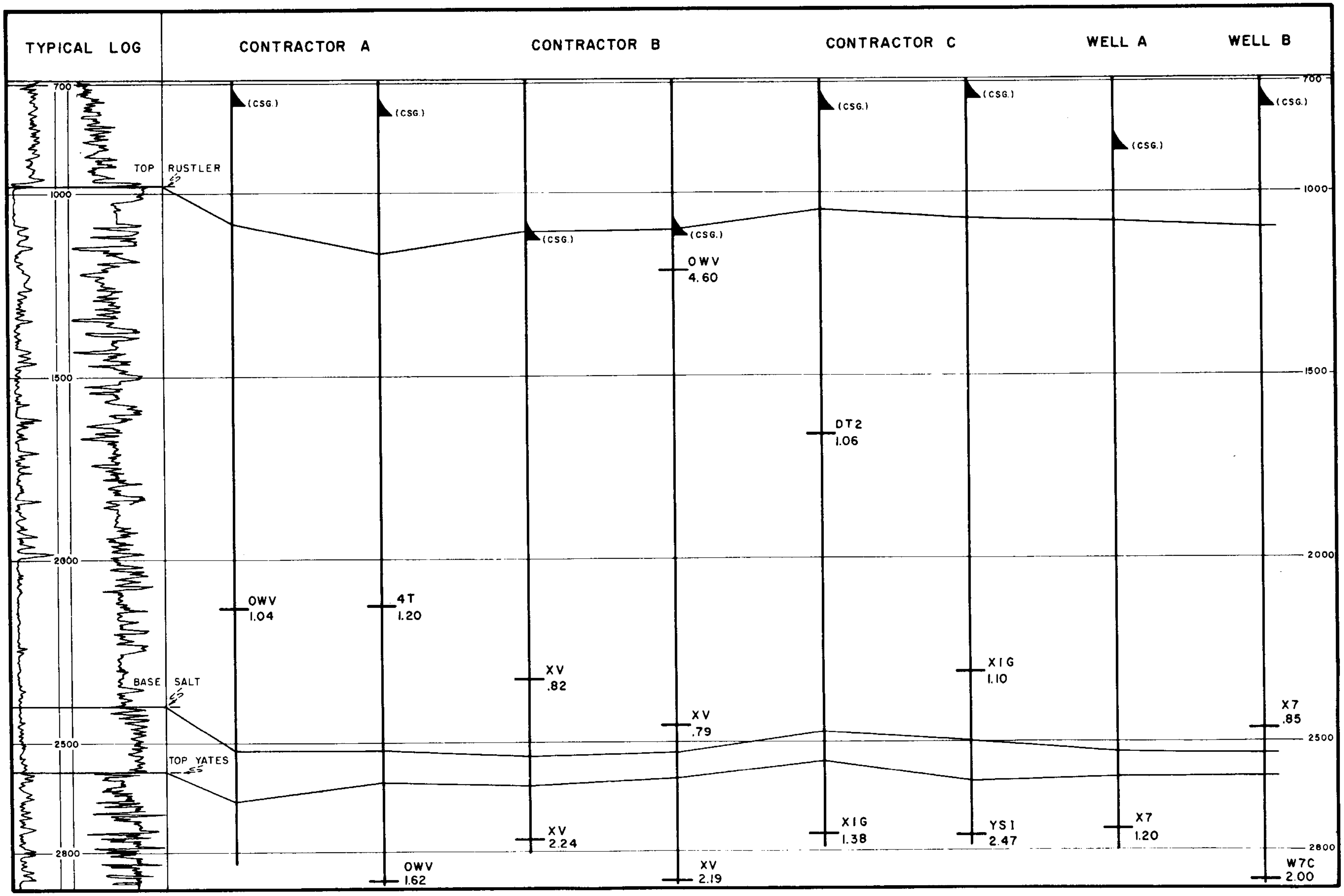
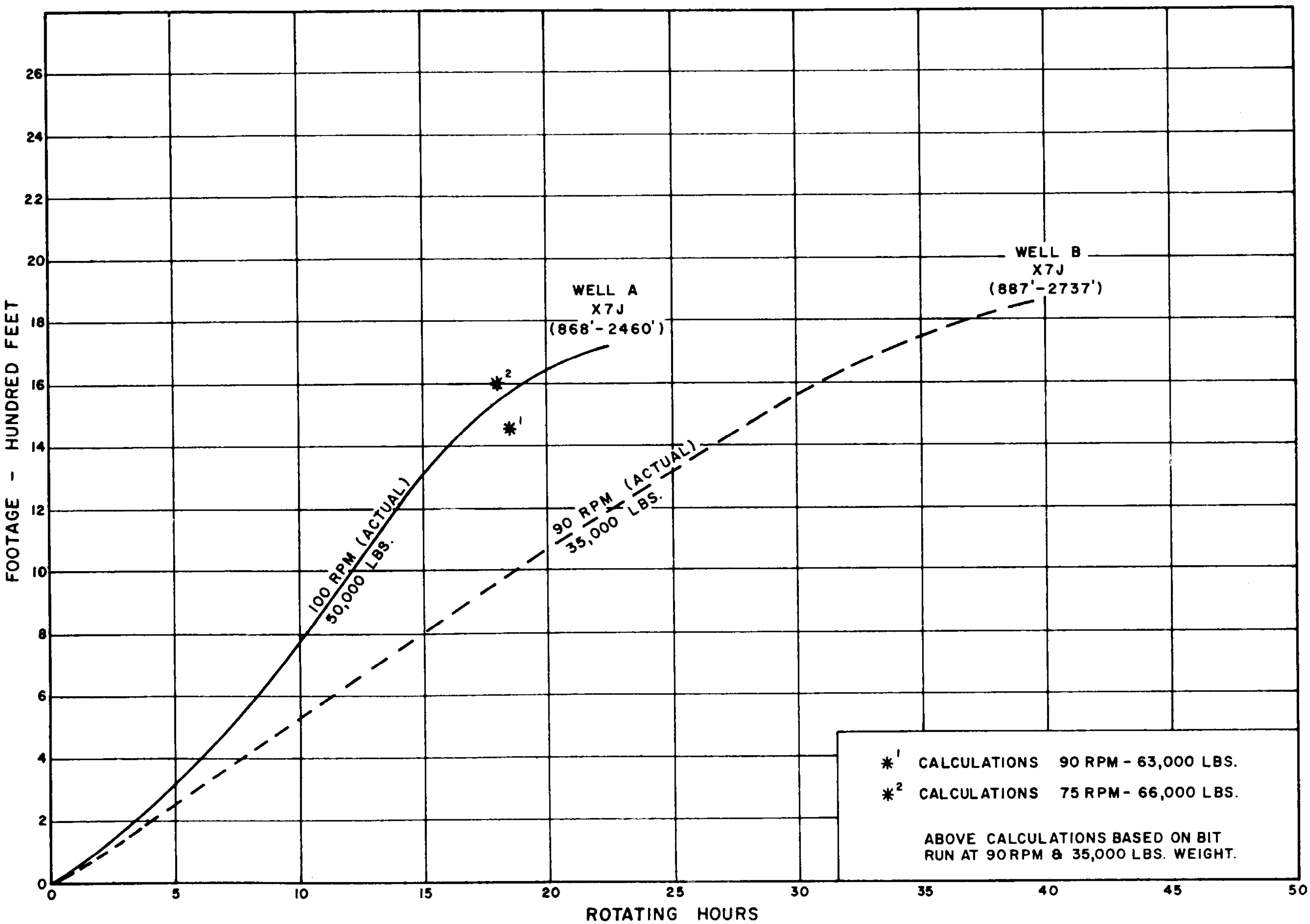


FIGURE 2 - SECTION FROM BIT PERFORMANCE LOGS - ARENOSO FIELD, WINKLER COUNTY, TEXAS

FIGURE 3 - EFFECT OF REDUCED WEIGHT ON BIT PERFORMANCE



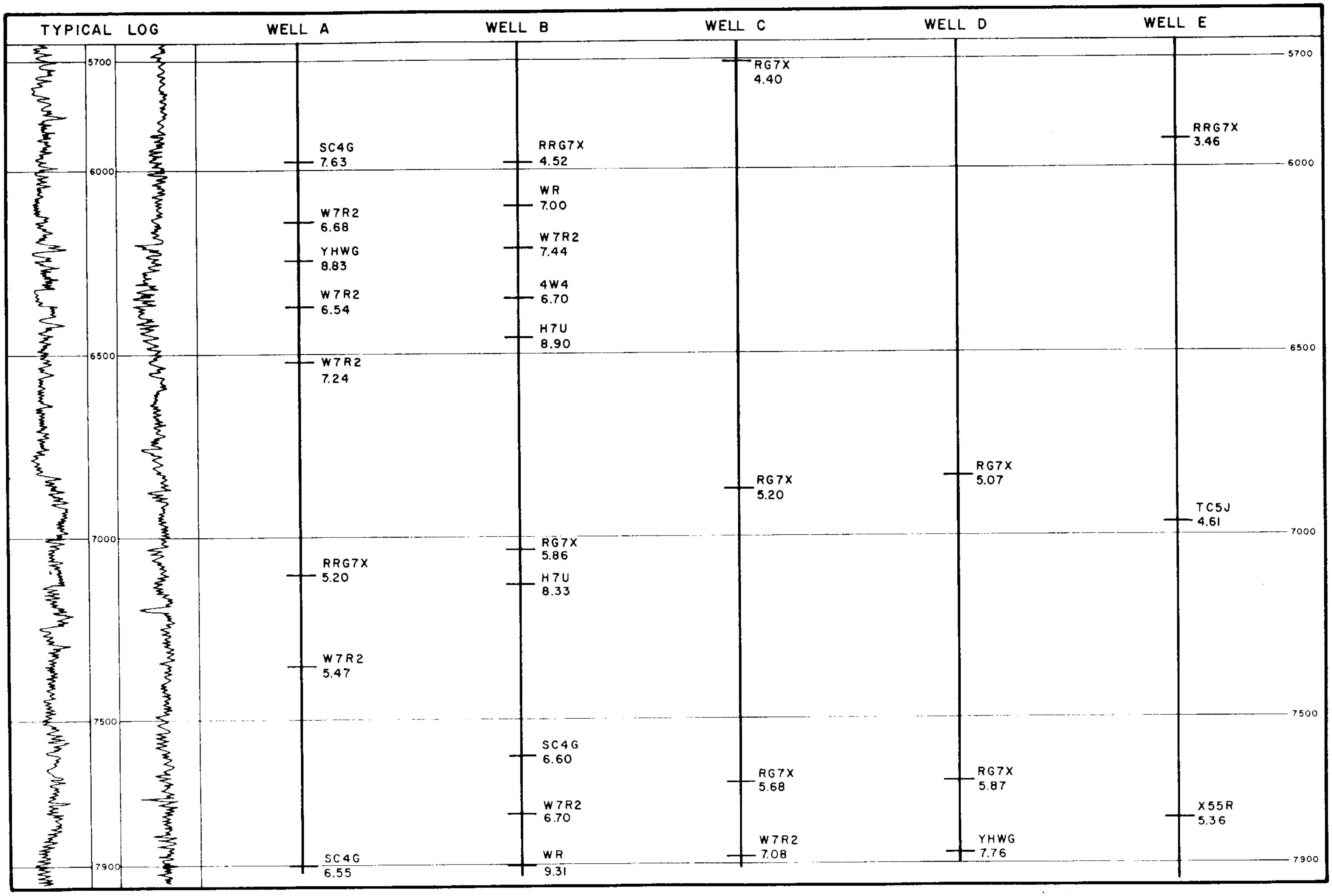


FIGURE 4 - SECTION FROM BIT PERFORMANCE LOGS — ARENOSO FIELD, WINKLER COUNTY, TEXAS