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NON-INTRUSIVE DETECTION OF PIPELINE SCALE IN THE GEYSERS FIELD

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ABSTRACT

Companies in The Geysers including the Northern California Power Agency (NCPA) have experienced scale build-up within piping systems delivering steam to their generating units. A declining steam resource has lead these companies to determine flow restrictions and remedial methods to increase system efficiency. A systematic detection process has evolved from these efficiency considerations for determining scale in gathering system piping. Electronic pressure gauges and modern ultra-sonic equipment have been put to use to evaluate: (1) the level of build-up and restriction, (2) the processes necessary for removal, and (3) costs and potential benefits of such projects. Scale build-up, that results in a 10 psi increase in back pressure, can reduce steam flow by as much as 35%.

INTRODUCTION

A large portion of the steam production piping in The Geysers was installed during a period when reservoir pressures and well flows were much higher than today. As a result of the higher than anticipated decline rates and NCPA's commitment to developing alternatives for improved well flow and extended life of the project (Grande, Enedy, 1991), methods were explored for improving efficiencies in delivering steam to the generation units. Piping sizes, piping routes and gathering system equipment have been evaluated for cost effective flow improvements. With the high cost of retro-fitting and the system requirements for certain pieces of equipment in these lines (i.e., separators, valves, drop pots, etc.), relatively few of the original piping systems have had large scale efficiency modifications made to them.

The condition that results in special attention on scale within the steam lines is the existence of some wells that flow saturated (rather than superheated) steam to the surface, which typically carries silica leached out of the reservoir rock (Maney, Thompson and Koenig, 1991). This steam leads to scale build-up in the well bores, flow lines and on turbine blades. The typical deposition areas for this amorphous silica, as witnessed by NCPA and others, are where the silica water droplets mix with superheated steam and at areas of pressure drop. These areas are normally in (1) wells above the casing shoe (2) gathering system manifolds downstream of well connections (wells with saturated conditions), (3) across valves, and (4) across turbine blade stages.

An extension of the original efforts to optimize steam flow potential to the NCPA geothermal generation units, through mechanical changes, has lead to the development of methods for identifying areas of silica scale build-up in the NCPA pipelines. These methods can be used during normal continued operations, which avoids costly downtime and lost generation. Due to the severely increased frictional effect, caused by scale build-up in certain sections of the NCPA steam gathering system, scale removal can make a dramatic effect on total well flow potential.

We have been highly successful in using several different detection methods. Methods described in this paper are:

- Highly accurate pressure gauges used to survey pressure drop along sections of line for comparison against the calculated pressure drop.
- The use of modern ultra-sonic test equipment to pinpoint scale in lines.
- Down hole surveys for well bore scale detection.

SYSTEM OVERVIEW

The NCPA generation system consists of approximately eight and one half miles of steam collection piping and three miles of injection piping, 68 steam production wells, 7 injection wells, and four-55 MW (gross) generating units. All facilities are located near the border between Lake and Sonoma Counties on federal leases CA-949 and CA-950 in the southeastern part of The Geysers field. For pressure surveys of any length and resolution, there are approximately 160 drop-pots plus separators and instrument taps available throughout the system (Figure 1).

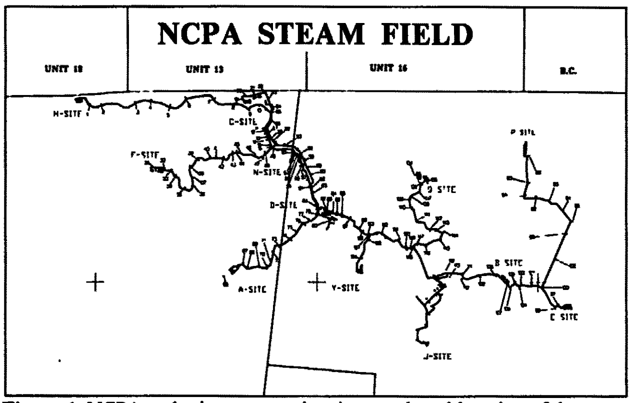

Figure 1. NCPA gathering system showing numbered location of drop-pots available for pressure sampling.

Varying reservoir pressures and well inflows are seen throughout the Geysers field due to different levels of development and steam production. These resultant inflows must be considered when comparing scale removal project economics. Well flow potential from the lower pressure areas of the reservoir can be dramatically effected when the pressure throughout the gathering system is reduced (Grande, Enedy, 1991). Because reservoir pressures vary significantly across the NCPA steam field, the cost-benefit ratios of equipment removal and line de-scaling must be calculated using the proper Inflow Performance Curves for the specific area. Figure #2 shows Inflow Performance Curves for two separate wells in contrasting areas of the NCPA field (well F-5, low pressure area; well P-5, high pressure area). A 10 psi drop in pressure, from 160 psig to 150 psig, in well F-5 shows a 12,000 lbs/hr increase in flow rate (or +34.3%) from 35,000 lbs/hr. In contrast to that is well P-5 in which a 10 psi change has very little effect.

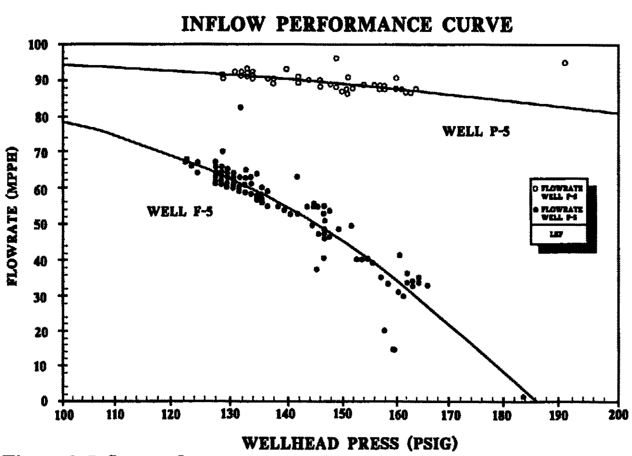

Figure 2. Inflow performance curves: Wells P-5 and F-5.

PRESSURE DROP SURVEYS

Our evaluation of steam flow restrictions starts with a pressure drop survey which can then be compared to a computer model of the same section of line. Different types of flow restriction can be evaluated by use of high precision pressure gauges. There is a wide variety of suitable gauges on the market today. To meet our needs in these ΔP studies, a gauge with an accuracy of 0.05% was specified (Two-Phase Eng., 1992). Bourdon tube gauges were ruled out because of this accuracy requirement and their general delicacy. For use on the NCPA steam lines, a battery powered sputtered thin film strain gauge was selected. This unit incorporates a 4 1/2 digit LCD read-out and temperature compensation. With a maximum temperature of 250°f at the strain gauge, the unit is isolated from the process with nitrogen in a tubing coil. This type of package has proven to be very manageable in the field, on surveys that may last for several hours.

Actual pressure measurements are then entered in the computer model at the proper location along the equivalent length of the test section. Equivalent length is determined for a given size of piping - using the measured lengths plus the additional effective length of specific equipment in the test section. Modeled pressure drops are then calculated using standard friction factors for clean, used piping. Actual and modeled pressure drops are plotted for visual comparison (see figure 3).

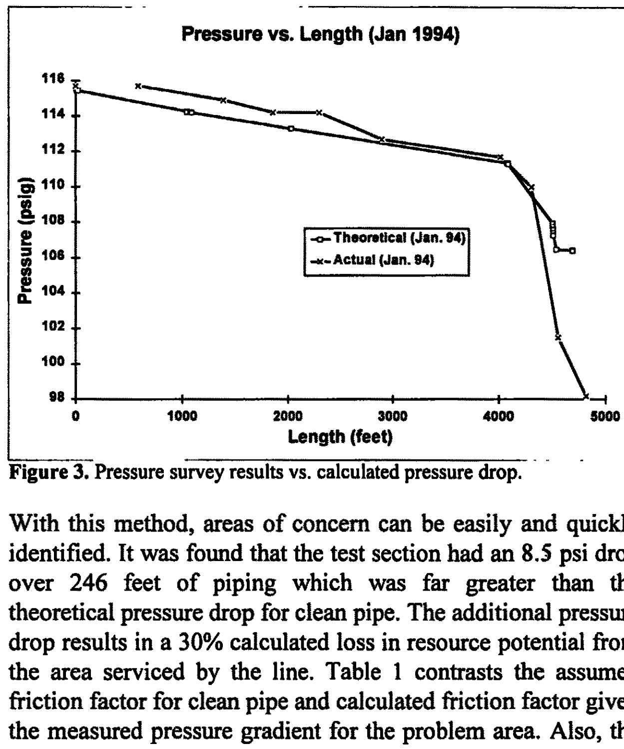

Figure 3. Pressure survey results vs. calculated pressure drop.

With this method, areas of concern can be easily and quickly identified. It was found that the test section had an 8.5 psi drop over 246 feet of piping which was far greater than the theoretical pressure drop for clean pipe. The additional pressure drop results in a 30% calculated loss in resource potential from the area serviced by the line. Table 1 contrasts the assumed friction factor for clean pipe and calculated friction factor given the measured pressure gradient for the problem area. Also, the assumed and calculated roughness factors are compared. (Brill, 1983, Moody, 1944)

	Clean Pipe	Scaled Pipe
Friction Factor	0.011	0.672
Relative Roughness (e/D)	0.0007	0.7876
Absolute Roughness (ε)	0.00015	1.969

Table 1. Calculated friction and roughness factors (in ft.) for the problem area compared to clean pipe.

The negative effect of scale build-up on steam flow can be modeled as an increase in the relative roughness factor. In this example, the relative roughness value of 0.7876 is approximately three orders of magnitude greater than for clean pipe. The friction and equivalent roughness factors were calculated based on the modified Colebrook Equation.

An alternative method to model the negative effect of scale build-up on steam flow is as a reduction in pipeline diameter. The scale has an equivalent pipe diameter of 13.7 inches over the approximately 246 feet of 30 inch pipe (Figure 4).

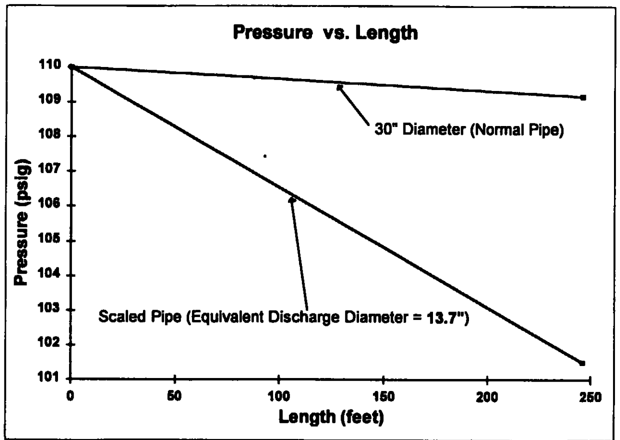

Figure 4. Calculated plugging of 246 foot section of 30 inch piping.

ULTRA-SONIC TESTING

With an evident flow restriction such as that indicated in figure 3, the next step is to pinpoint the limits and the possible source of the scale build-up. The methods developed for this next step incorporate the use of the latest in ultra-sonic test equipment with a built-in data recorder. This data is then down loaded to a standard spreadsheet program for evaluation. Experience has lead to the ability to determine the extent of the scale build-up and the severity of the problem.

Gathering system pipe used throughout the NCPA field typically has a standard wall thickness of 0.375". Ultra-sonic measurements on clean, used piping normally indicate readings within ±.010 inch. A typical reading on scaled pipe (figure 5)

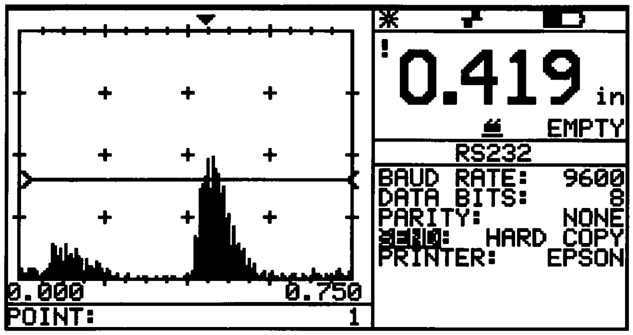

Figure 5. Sample ultra-sonic measurement.

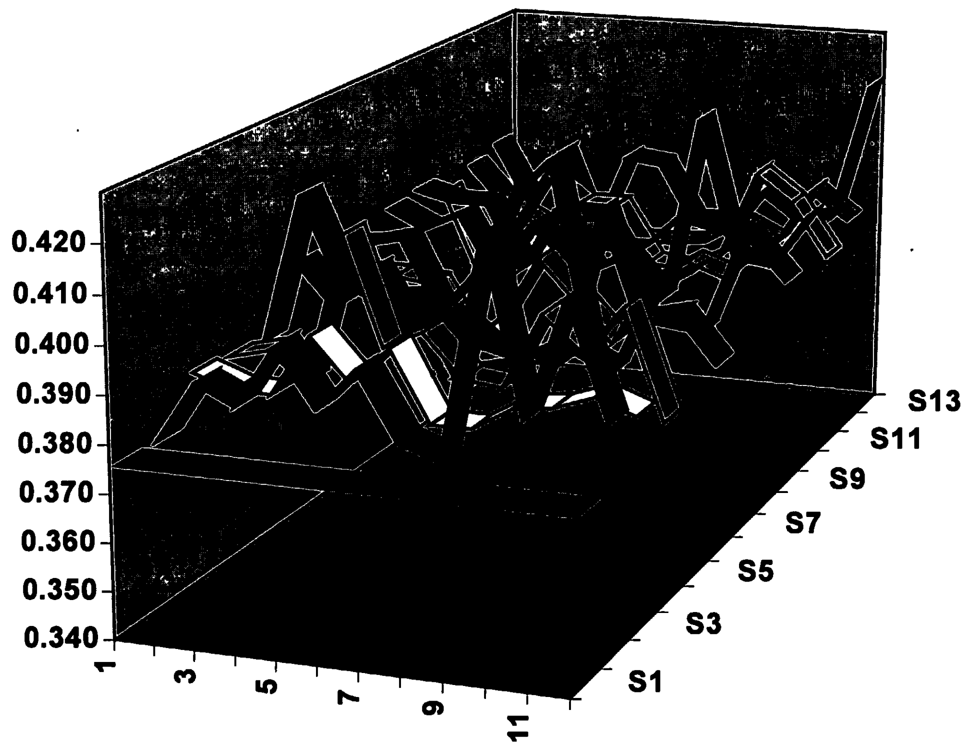

Figure 6. 3-D graph representing 144 measurements over a 12 inch by 12 inch grid of 30 inch pipe line. Series 1 indicates normal (0.375") wall thickness, 2-13 indicate scale of drastically varying thickness.

shows a build-up of 0.044 inches on the interior wall of the 0.375" pipe.

Readings for scaled pipe vary drastically over small areas reflecting the roughness of the restriction. These differences are generally less than 0.050" but represent literally inches of scale. It was determined early on that the ultra-sonic gauge could not accurately reflect the scale thickness due to the differing velocities of sound in the mild steel pipe and the scale build-up. Tight-grid sampling and hours of comparison have proven to be quite effective in the evaluation of restricted areas of the system. When grid samplings are visually represented (figure #6), the roughness of the interior walls become very obvious.

Also, samplings with lesser resolution can be effectively used to locate the source of silica water. The source well can then be completely removed from service, or additional separation methods can be incorporated in the well flowline. This data, coupled with the pressure drop survey information, can then be used to evaluate costs and potential benefits of undertaking a scale removal project.

X-Ray Diffraction Analysis

Lab Number: 6058-1

Descriptor: D-Site 02/28/94

Mineral	Approximate Weight %
Cristobalite, SiO_2	19
Quartz, SiO_2	10
Feldspar, $M^*Al(Al,Si)_3O_8$	30
Hematite, Fe_2O_3	Trace
Pyrite, FeS_2	10
Anhydrite, $CaSO_4$	9
Bassanite, $CaSO_4{,}1/2H_2O$	6
Heulandite, $(Na,Ca)_{4-6}Al_6(Al,Si)_4Si_{26}O^{72},24H_2O$	10?+
Mica+Illite, $(K,Na,Ca)(Mg,Fe,Li,Al)_{2-3}(Al,Si)_4O_{10}(OH,F)_2$+ $(H_3O,K)_y(Al_4,Fe_4,Mg_4,Mg_6)(Si_{8-y},Al_y)O_{20}(OH)_4$	1
Amorphous	5

*M = K,Na,Ca,Ba,Rb,Sr, and Fe.
+? = Tentative identification

Figure 7. X-Ray diffraction analysis of amorphous scale build-up.

REMOVAL METHODS

Removing scale build-up can prove to be quite a challenge as a result of the high content of silica and silicate minerals in the material (figure 7). Also of major concern during removal operations is the potentially hazardous nature of the material.

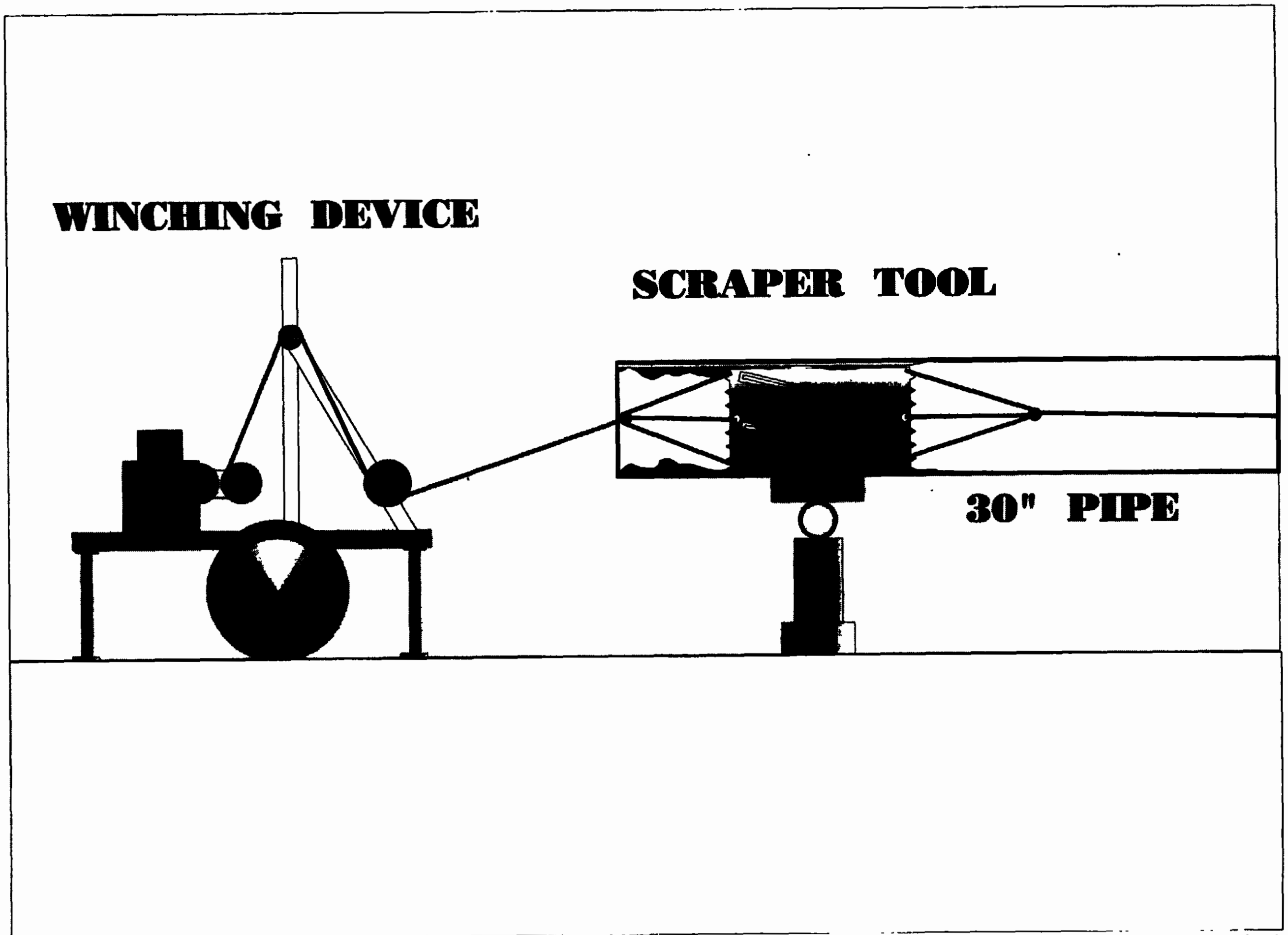

Figure 8. Final process involved in removing up to 4 inches of amorphous scale build-up from the 80 foot long section of 30 inch pipeline near source wells.

All removal schemes must keep the material dampened, to control silica dust, and contained for later waste disposal. An example problem was a scaled section of 30 inch line approximately 246 feet long with scale of varying thickness. The worst portion of the line was an 80 feet long section with a scale thickness of up to 4 inches. This 80 foot section was directly downstream of a well flow line connection, from a well with known saturated flow conditions.

Different methods for removal were considered or tried for this section of line before a final solution was found. First considered was a water wash much like that used on turbines in The Geysers, but this was dismissed because of poor manageability and the potential time involved. Second was a contractor service that can provide a high pressure water blasting system mounted on a small remote controlled tractor that can traverse the pipe interior. This particular system was tested, but proved to not have enough blasting power to remove the scale. The third method was a system developed in-house that involved a barrel scraper tool and winching devices (figure 8). This method, although very labor intensive and intrusive to the line, was able to return the piping to normal interior dimensions. There are other services that provide higher pressure - water blasting systems that may be able to clean out the scale with less intrusion.

Final results of the scale detection and removal projects for this section of line are compared in Figure 9 to the initial survey that discovered the scale. The effect of removing the scale restriction in the last 246 feet of the original test section was to reduce back pressure at the source wells by 6 psi, resulting in a very large increase in available resource from the area.

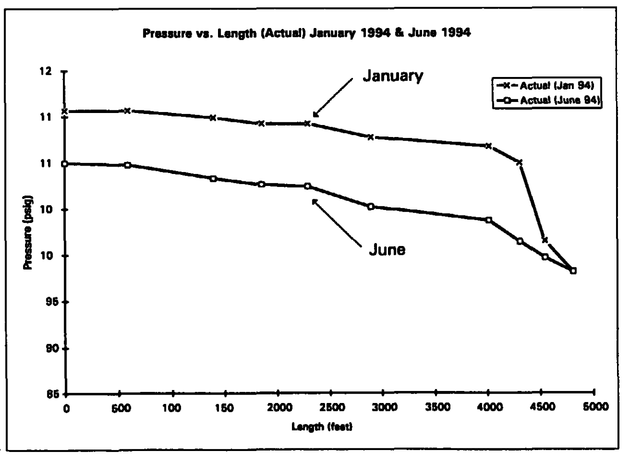

Figure 9. Survey results - after returning line to service vs. initial survey.

DOWN-HOLE SURVEYS

Figure 10 represents matching intervals of pressure-spinner data and minimum ID surveys in which can be seen a dramatic increase in steam flow velocity at a depth of about 3225', directly adjacent to a detected well bore diameter reduction. This area is inside the casing just above the casing shoe at 3228'. The steam flow velocity (spinner RPM's) increased quite noticeably as the well bore diameter is reduced at the location of the scale build-up. From our experience in gathering system scale, we would expect any scale to be found just inside the casing, because of the pressure drop across the casing shoe. This particular scale build-up was confirmed later by running a minimum ID tool through the same area. The minimum ID tool actually measured the smaller bore and brought back some samples of the scale caught between the fingers of the tool.

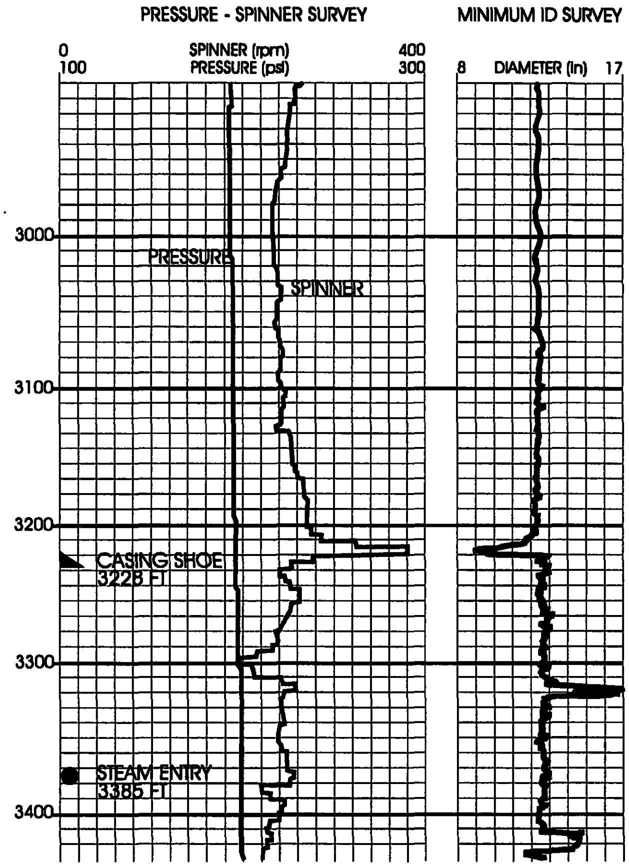

Figure 10. Matching intervals of pressure-spinner survey and minimum ID survey, Well F-2, showing restricted well bore above the casing shoe.

The detection and location of scale developed in well bores is the fairly easy and inexpensive part of this problem. Removal of scale in the well bore by mechanical means is obviously more expensive, ranging from the use of a coiled tubing set-up with a downhole air motor drill, to using a full-sized drilling rig.

CONCLUSIONS

1. Combined methods of pressure drop surveys versus modeled pressure drop and ultra-sonic thickness gauging have proven very effective in pinpointing locations of scale

problem areas in the flow lines, without interruption to service.

2. Cost-benefit ratios can be easily and accurately calculated from test data and inflow performance curves.

3. Increased system efficiency with higher well flow and megawatt output is attainable in a timely manner and at reduced overall costs.

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