CASING INSPECTION LOGS HELP PLAN WATERFLOOD RE-DEVELOPMENT

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Abstract

Casing inspection logs have proven to be an effective tool to help design and implement remedial operations during waterflood redevelopment. A series of magnetic logging tools was run in a Tubb-Drinkard water flood located in SE New Mexico. The casing inspection logs qualitatively evaluated overall casing condition and indicated packer set points prior to conversion to water injection. In extreme cases, the logs discovered terminal casing damage requiring well abandonment.

Many Permian Basin waterflood units have been infill drilled to reduce the pattern spacing. Older wells, some dating to the 30's, are often converted to water injection to complete injection patterns. From the time a well is first completed, the casing wall thickness decreases. Corrosion, wear and physical damage combine to reduce the mechanical integrity of the casing, eventually destroying it. The casing inspection logging program has proven its value by substantially reducing workover costs and improving the success rate of injection well conversions.

Introduction

The West Dollarhide field was discovered in 1951 by Skelly Oil Company's Mexico "K" No. 1. The Dollarhide is a multipay field producing from the Queen (3800') to the Ellenberger (11,000'). The producing wells were originally drilled on standard 40 acre proration units with multiple wells on many drilling pads. When most Permian Basin waterflood projects were started, infill injection wells were drilled. Reducing the pattern area improved sweep efficiency and accelerated the flood response. The newer wells were usually designed for better high pressure injection containment and longer life. However, all three West Dollarhide projects were initially developed by converting existing producing wells to water injection.

The overlying Queen and the Devonian, under the southeast quarter of the field, were unitized in 1962. The West Dollarhide Drinkard Unit (WDDU) was unitized in 1969. The unitized interval includes the Tubb at 6200', the Drinkard at 6500' and the Abo from 6800' down to 7400' [1]. The formation is a complex shallow shelf dolomite with lime, anyhdrite and sand stringers. The main floodable pay is the lower Drinkard, although the Tubb and Abo were also initially flooded. The unitized pay is discontinuous and highly compartmentalized.

Soon after injection started in 1969, water channeled through the Tubb and Abo. In 1972, Skelly Oil Co. started a remedial program to squeeze off the Tubb and abandon the Abo. Liners were run in many wells to isolate the open hole Drinkard and Abo. By this time, water crossflows developed between the Tubb and Drinkard. Obtaining good cement behind the liners became increasingly difficult. Whenever possible, the injection packers were reset above the lower Drinkard. Maintaining mechanical integrity required numerous cement squeezes in the abandoned Tubb perfs and also the liner tops. In one case, sealing a Tubb channel used 4000 sacks of cement in 13 attempts. Correcting the injection profile on another well took 62 days and $244,000.

Skelly developed the Queen waterflood concurrently with the Tubb-Drinkard. The annular cement in many WDDU wells was insufficient to protect the casing across the Queen. Annular waterflows developed and a second phase of remedial work was started in 1978. Of the 24 wells where casing failures had occurred, insufficient cement across the Queen caused 17 of them [2]. The program targeted Tubb channeling in the other 7 wells. The production team plugged most of these wells by 1990.

From 1986 to 1989, Texaco plugged back four deep wells to the WDDU and drilled five new 20 acre producers. Even without adequate injection support, the initial infill wells were successful. In 1990, Texaco initiated a continuous infill drilling program. The log data from the new wells improved reservoir characterization. A reservoir study indicated substantially more reserves would be recovered if an effective flood could be developed. Closing the five spot patterns would require converting most of the older producing wells to injection. Most of the plugged wells would eventually be replaced with redrilled injection wells. Several inactive injection wells required remedial work and reperforating. Whenever possible, isolating the main Drinkard pay zone would improve existing injection profiles.

The casing inspection logs (CILs) were an important part of the conversion and workover program. The production team studied past WDDU injection workovers and current wellbore conditions. The team decided that cased-hole logging technology would improve the success rate and lower workover costs. Specifically, the team needed more information about actual subsurface casing conditions than what a pressure test could provide. The team concluded that converting existing wells to water injection would be possible by meeting certain mechanical conditions.

Inspection Logs

Casing inspection logs can be classified in four general categories: mechanical, acoustic, video and magnetic. All of the service companies have excellent references covering the theory and operation of these tools [3,4,5]. Table 1 is a comparison of tool types and specifications from the major service companies. Combinations of the tools help reduce uncertainties in log interpretation. The resolution of the tools is a direct function of operating conditions such as borehole fluid type, density and multiphase fluid flow. Selection of log types largely depends on the type of data required for solving a specific problem.

Mechanical tools such as multicaliper logs measure the inside diameter of tubing and casing. They can determine the size, depth and radial orientation of internal defects. They can also measure changes in casing weight if the outer diameter (OD) is known, but cannot determine actual thickness. Because of their repeatability and accuracy, they are often used for monitoring tubular corrosion rates [6].

Acoustic tools operate in two different modes. The cement evaluation tool (CET, PET) has eight radially mounted transducers that measure ultrasonic two way travel time [7]. Analysis of the waveform for resonance frequency determines the thickness. Casing internal diameter and roughness are calculated from travel time changes. Acoustic scanning tools (CIBL, CAST, USI) use a rotating transducer and receiver to make an internal "map" or picture of the casing. Like any acoustic tool, it is sensitive to changes in borehole fluid density and casing roundness. Scanning tools give excellent resolution comparable to open hole logs.

Although not ideally suited for inspection, downhole video cameras have proven useful in investigating equipment and production problems [8]. Fluid production interferes with most inspection tools, but video cameras can see around most obstacles in real time. Good video images require little interpretation and can quickly identify obstructions that block wireline logs [9].

The fourth class of tools is the magnetic or induction type. The simplest form is a casing collar locator (CCL). The tool has enough sensitivity to pick up collars, DV tools and other large changes in casing thickness. Magnetic tools, like acoustic tools, lack the precision of caliper logs. However, they give a much better qualitative feel for the type and distribution of casing damage. Casing thickness measurements also help estimate external corrosion.

DC tools measure current potential changes across the inner surface of the casing. Any deviations from the background are interpreted as corrosion losses. These tools lack the sensitivity of other methods, but will detect gradual metal loss over a large area. DC tools are ideal for evaluating cathodic corrosion protection. The standard AC tool has one or more coils that generate an alternating magnetic field. Other coils measure phase shifts in the field caused by changes in casing cross section. A second set of coils measures the magnetic permeability of the casing, which varies with metallurgy. The electrical conductivity of steel is usually known, so the recorded phase changes determine the casing thickness. A third set of coils generates a high frequency field that does not penetrate the casing wall. The internal magnetic caliper is derived from this measurement. AC tools are designed to detect distinct changes in casing weight and diameter and have much better resolution than DC tools. However, background noise may cover up subtle defects. After the team discussed the above qualifications, they chose AC magnetic tools for the WDDU workover program.

The resulting log presentation is usually easy to interpret but some rules must be understood. If these conditions are encountered, accurate assessment of casing damage will require combinations of tools.

1. Internal scale buildup will influence mechanical caliper and acoustic imaging logs. Casing must be cleaned out before logging.
2. Conductive scale (FeS) will distort the induced magnetic field.
3. External casing equipment such as ECPs, scratchers, centralizers and DV tools influence magnetic AC thickness measurements.
4. Concentric casing strings will appear as unusually heavy casing. Some multifrequency tools can separate the outside casing influence after processing.
5. If the result or interpretation is unclear, run a downhole video camera. A lost wrench or collapsed tubing is hard to interpret from inspection logs but a camera can give immediate answers.

EXAMPLE 1 - Ideal Casing Inspection Log

The inspection log in figure 1 shows the standard curves on a typical presentation. The gray shaded area simulates the casing as if it were cut in half. The differential thickness is a detail curve showing changes in casing thickness over a small interval. The thickness curve measures change in casing weight and the caliper reads the internal casing diameter. This particular Vacuum Grayburg San Andres well was drilled in 1938 and has produced 2.4 MMBO and 3.2 MMBW. Despite being almost 60 years old and almost 19 years of waterflood exposure, the casing is in excellent condition. This log shows that casing conditions should not be inferred by just the age of a well. The operating environment has a much larger role in determining the service life of a well. The differential curve in track 2 reflects the expected roughness of the inner casing surface. Casing collars appear as sharp deflections to the right and then to the left (4005') and as double deflections to the right in track 3. Caliper and thickness curve shifts reflect changes in the casing weight of each joint. This is typical for much of the casing manufactured prior to adoption of API standards.

EXAMPLE 2- Terminal Liner Damage

The second example is an injection well in the Southeast corner of the WDDU unit. Well No. 86 was drilled in 1953 and completed as an open hole producer with 7" casing set at 6310'. A 5" liner was run in 1971 when the well was converted to water injection. The injection packer was set above the liner top at 5881'. The liner was cleaned out and reperforated in 1976. The packer was lowered to above the main Drinkard at 6350' but would not hold. It was reset inside the liner at 6050' and injection was resumed. In 1981, junk was milled out of the liner during a routine workover. A treating packer was set at 6217' but it failed during stimulation. The packer was reset at 6002' and injection resumed. In 1993, pressure developed on the annulus due to a tubing leak. The injection packer and tubing were pulled, and metal and heavy scale were milled out of the liner. A casing inspection log was run through the liner and casing. Figure 2 shows that the production casing, hanger and liner are in good shape down to 6002'. The liner shows progressively worse deterioration from the packer set point to about 6300'. Figure 3 shows the rest of the log; nothing remains of the liner except the collars. Several important observations can be made from this log:

1. Corrosion damage begins just below the last packer seat at 6002'.
2. In track 1, the light gray backup shading indicates the caliper (CAL) is reading beyond the outer diameter of the 5" liner. "Noise" on the collar log also picks up casing damage from the packer set point to where the liner ends.
3. In track two and three, the top 130' of liner appears to be exceptionally thick. This is because the magnetic field extends beyond the outside of the liner, and is influenced by the outer production casing. This interference continues down to 6310' where the production casing ends. The gray casing profile shading in these two tracks shows the gradual thinning of the liner wall. The wavy appearance is a good indication that the metal is deformed or crumbling.
4. At 6350', the shading disappears indicating the liner has no wall thickness and has effectively dissolved. The 7" production casing shoe is at 6310'. The log would have read true liner thickness, if any remained, from this point to the bottom. Also note that the noise on the collar log in track 1 ends. There is nothing metallic left to read between collars.
5. The log also found leaks in the production casing uphole, which were confirmed by packer tests.

The production team evaluated the well conditions with the New Mexico Oil & Gas Division. From past WDDU experience, the cost to squeeze the production casing leaks was estimated to be at least $50,000. The estimated cost for removing the remains of the liner and restoring effective Drinkard injection was at least $150,000. WDDU No. 86 supported one producer that would eventually be converted to injection if an offset infill producer was drilled. The team decided to invest the money and effort on better opportunities so the well as plugged. In this case, the log quickly identified terminal casing damage where a traditional packer test would be extremely expensive.

EXAMPLE 3 - Split Collar

Figure 4 shows where a casing inspection log identified a surface casing leak. WDDU No. 11 was drilled in 1956 as a cased hole producer, with 5-1/2" casing set at 6900'. The primary cement top (TOC) was at 3563', which is just above the Queen. The casing annulus was squeezed in 1980 as part of Getty's Drinkard isolation project. During a conversion workover in 1993, a small leak was found between 44' and 77'. The logging crew had spotted a caliper deflection while going in the hole. After logging the production casing up to the intermediate shoe, the crew ran a log section at the surface (figure 4). The log shows the following items.

1. The caliper (dashed line) shows reasonably smooth casing. The collars show up as spikes to the left and the large deflection at 74' is an apparent tight spot in the casing. Close observation of the collar locator curve at 73' reveals a second kick below the first. This sometimes indicates a casing split or hole adjacent to the collar. This is important because most inspection tools lack the resolution to see an actual collar leak.
2. The shaded casing wall portion of tracks 2 and 3 appears to be calibrated or scaled wrong. Actually, the surface casing string is influencing the magnetic field. Single frequency magnetic tools will not measure true wall thickness unless the outer casing is perfectly centered and has a sufficiently larger inner diameter.
3. The log section through the Drinkard and Abo (figure 5) shows some general wall loss due to corrosion. A change in casing weight at 6698' can be identified by the caliper change in track 1 and the shift in casing profile in track 2 and 3. Locating changes in inner casing diameter is important when selecting the size of the rubber elements for injection and treating packers. This information is sometimes lost over time and a log or caliper survey is the only way to reacquire this data.

The log indicated the leak was probably at the collar. Twenty sacks of fine grain cement were spotted in the casing. The cement was squeezed from the braden head at 600 psi. After drilling out, the collar leak was sealed and the conversion was completed with no other problems.

EXAMPLE 4- Caliper log

WDDU No. 77 was drilled in 1954 as an open hole producer with production casing set at 6480'. In 1969, it was converted to injection with a packer set at 5776' and injection into the Tubb, Drinkard and Abo. After channeling developed in the Tubb and Abo, a liner was run in 1971 from 5918' to 6879' and the Drinkard and Abo were perforated. In 1972, the Abo perfs were abandoned and the packer was set in the liner at 6050'. In 1977, cement was circulated across the Queen to the surface and the packer was reset above the liner top. In 1993, the well was shut in after the seals failed in the injection packer. The packer, junk and heavy scale were drilled out of the liner to TD. A casing inspection log (figure 6) was run from the liner top to the surface. A few casing holes were located in the Queen interval. An inspection log was not run through the liner because of insufficient inside clearance. A new packer was set above the liner top and an injection profile was run (figure 7). Several important observations can be made from the injection profile and log.

1. The flux maximum curve (FLM) through the Queen in figure 6 shows significantly larger defects than the eddy current track. This indicates the corrosion originated on the outside of the casing.
2. The flux average curve indicates the hole at 3720' covers less than one third of the casing circumference.
3. The recorded depth of the liner top was questioned after tagging up on a possible hanger at 5755'. After drilling junk out, the top of the liner appeared to be at 5893'. The production casing, liner and drill bit size are drawn on figure 7.
4. The caliper curve shows holes in the production casing and the profile confirms that a significant part of the total injection is being lost in the upper Tubb.
5. Noise on the collar locator curve also confirms the poor condition of the liner.

The liner was pressure tested but would not hold. Since there were casing holes in the Queen interval, the liner was not repairable and an offset well was available for conversion, this well was abandoned. In this example, an injection profile log was able to provide sufficient information for the team to make a decision on remedial options.

EXAMPLE 5- Packer Test Versus Inspection Log

WDDU No. 32 was drilled in 1953 as a cased hole producer with 5-1/2" casing set at 6959'. The primary cement top was below the Queen zone at 4030'. In 1974, the braden head was squeezed to stop an annular water flow. A Queen casing leak from 3636' to 3825' was squeezed twice with a total of 500 sacks of cement. During an injection conversion workover in 1993, a log was run from TD to the intermediate casing at 3131'. As expected, the casing in the Drinkard interval (figure 8) showed extensive internal and external corrosion and possible parted casing at 6527'. The log also identified several holes in the casing across the previously squeezed Queen interval (figure 9). The casing was also swaged out from 3703' to 3722'. From the two figures, the following observations should be noted.

1. The caliper backs up to the right in track 1 of figure 8 indicating holes through the casing. The dark gray shading below 6500' is a backup of the gamma ray curve. Natural radioactive scale (NORM) has accumulated where significant fluid production has occurred over time.
2. Tracks 2 and 3 show obvious thinning of the casing wall, especially around the parted casing at 6527'. The differential and thickness curves also confirm holes in the casing.
3. The above corrosion effects are all within the primary Drinkard injection zone. Except for injection losses through the parted casing, none of the casing defects should impair the injection conformance.
4. The log of the Queen section in figure 9 shows the same features as the Drinkard section. The gamma ray backup (GR) shows hot streaks from fluid movement behind pipe and the other curves indicate several holes.

The casing above the injection packer must pass a mechanical integrity test prior to starting injection. Between acid stimulating the Drinkard, setting the packer and circulating packer fluid, the casing was successfully tested four different times from 250 psi to 375 psi. The packer was reset and water injection commenced. Pressure developed on the annulus soon after and the injection packer and tubing were pulled.

A treating packer and retrievable bridge plug (RBP) were unable to hold a seal across and above the Queen from 3170' to 3740'. The log shows that the casing above 3520' appears to be in good condition. The differential and caliper curves do not indicate any pitting or holes. A retainer was set at 3170' and the casing down to 3740' was squeezed with 200 sacks of class "C" cement The cement was drilled out to 3670' and the subsequent casing test failed. A second retainer was set and the same interval was resqueezed with 200 sacks. The cement was drilled out to 3491' and the casing was successfully tested to 1000 psi. The log indicated that the casing above the Queen was in good condition and the packer test confirmed this. The previous test above 3491' may have failed due to damage to the rubber elements in the packer or RBP. The remaining cement was drilled out to 3616' and the second packer test failed. The squeezed cement does not appear to have reached the holes shown on the log from 3688' to 3696'. If the retainer had been set closer to the top of the Queen, the cement squeeze would have had a better chance of success. WDDU No. 32 would have supported just one offset well so the team plugged it. If the well is reentered in the future, the log will provide sufficient information to restore mechanical integrity to the casing.

EXAMPLE 5- External Casing Corrosion

WDDU No. 56 was drilled in 1954 as an open hole producer with 7" casing at 6349'. The bottom section was cemented with 750 sacks cement having a calculated cement top at 3400'. Over 500 sacks of cement were circulated to the surface through a two stage DV tool at 1158'. In 1981, a 5" liner was run from 6021' to 6820'. When the well was converted to injection in 1993, an inspection log was run through the liner and casing. Figure 10 is a log section through the liner showing several distinct features.

1. The liner below 6500' shows increasing internal and external corrosion. Distinct changes in the diameter of the liner joints are evident. This was seen on other logs and is not very unusual considering the time period. During the early 80s, casing and tubulars were often in short supply and non- API grades were used if available. The differences in weight are sometimes severe enough to prevent a good packer seal. This is important since a poor packer seal is often mistaken for a casing leak, resulting in unnecessary packer trips.
2. The differential and thickness curves are relatively smooth indicating a low corrosion environment. The gamma ray backup reflects water movement through the main Drinkard floodable pay zone.
3. Figure 11 is a log section of the 7" uncemented casing across the salt section. The loggers interpreted this as evidence of severe external corrosion. Notice that most of the sharp reductions in wall thickness are adjacent to collars.
4. Sometimes the logs exhibit characteristics that are difficult or impossible to interpret. In this case, the service company engineers speculated that this extreme wall loss may be evidence of substandard casing construction. Overall, the differential, thickness and caliper curves are exceptionally smooth so the casing should pass a pressure test.

This example makes a good case for reliability engineering. No problems were encountered during the injection conversion and the casing will probably last for some time. However, external corrosion will continue until cement is circulated behind the casing. Comparison of the base log to a later log allows the operator to plan future remedial work. The cost of inspection logs is a minor part of a workover, especially when other logs will be run. Saving one well from premature abandonment will pay for a lot of data acquisition.

EXAMPLE 6- Resqueezing the Tubb

WDDU No. 37 was completed as a cased hole producer in 1951 with 5-1/2" casing set at 8221'. The cement top behind production casing was below the Queen at 4704'. The well was converted in 1969 with injection into the Tubb, Drinkard and Abo. In 1976, water channeling through the Tubb was detected behind pipe. All perfs were squeezed with a total of 1900 sacks of cement in 11 attempts. The lower Drinkard and upper Abo were reperforated and injection commenced with the packer set at 6544'. In 1979, all of the old and new perfs were squeezed off with 400 sacks and cement was circulated across the Queen to the surface. After acidizing, the treatment log indicated that the perfs squeezed in 1976 took 84% of the acid. After the stimulation, one injection packer was set above the Drinkard at 6565' and a second packer was set above the Tubb at 6248'. Tandem packers were run in several WDDU wells in an attempt to confine injection to the Drinkard. This also allowed mechanical integrity testing for the NMOCD.

In 1992, the team shut the well in after finding pressure on the annulus. The team correctly guessed that both of the packers had failed and needed to be replaced. After cleaning out, an inspection log was run and evaluated. As expected, the Tubb casing showed numerous holes and several sections in the Drinkard were gone. The casing above the Tubb was pressure tested and the Drinkard was acidized. Using the inspection log as a guide (figures 12, 13) , the lower injection packer was set above the Drinkard at 6557'. The upper packer was set above the Tubb at 6241' and the casing passed a pressure test. After a week of injection, pressure built up on the annulus. Both packers were reset one joint further up and the casing was successfully retested. Soon after injection started, pressure started building up on the tubing annulus, and the well was shut in.

In 1995, the well was cleaned out and the casing above the Tubb and the squeezed intervals were tested again. The Tubb was re-squeezed from 6248' to 6525' with 50 sacks and drilled out. A packer test indicated a slow leak, so the same interval was resqueezed with 45 sacks of micro-fine cement. After the cement was drilled out, pressure slowly built up from the Tubb. The Drinkard was reperforated and acidized, then put back on injection through one packer set above the Tubb. From figures 12 and 13, several observations should be made.

1. The caliper in track 1 indicates several distinct holes in the Tubb casing and two major gaps in the Drinkard casing. The gamma ray backup accurately defines the main floodable Drinkard pay zone.
2. The holes in the Tubb were caused when the old squeezed perfs were washed out.
3. The constant width of the shaded casing profile in track 2 and 3 shows that overall casing condition through the Tubb is good. The differential curve in track two indicates that there are numerous small pits in the inner casing wall. The same curves through the Drinkard confirm that about 55' of casing has completely corroded away.
4. The lost casing is within the intended injection zone and should not affect conformance. Profile modification is not necessary and probably impossible without running a liner.
5. Packer tests confirm that the isolated Tubb holes were partially squeezed off. A treating packer set above the Drinkard held long enough for the acidizing. But injection water eventually leaked by the packers set above the Tubb and Drinkard.

The team decided that resuming injection with the packer set above the Tubb was the best option. Although the Tubb perfs will take some fluid, the pattern will still receive adequate pressure support. Comparison of the inspection log with future injection profiles should indicate when more remedial work is necessary. The analysis will help monitor terminal casing damage from corrosion, especially if a caliper is run with the profile.

Conclusions

The production team converted 21 WDDU wells to water injection over a four year period. The team plugged one well, temporarily abandoned one well and converted one back to a producer. Considering the previous workover history of the property, a 86% mechanical success rate was much higher than expected. The inspection logging program identified terminal casing damage in six other wells, but also found more opportunities for profile improvement. The distribution of inspection logs was sufficient to cover all parts of the field and the full range of operating conditions. The inspection log information has improved the success rate of injection workovers by identifying problem areas before they become terminal.

Acknowledgments

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SI Metric Conversion Factors

acre	× 4.046 873	E+03	=	m^2
Bbl	× 1.589 873	E−01	=	m^3
ft.	× 3.048*	E−01	=	m
$ft.^3$	× 2.831 685	E−02	=	m^3
°F	(°F-32)/1.8		=	°C
in.	× 2.54*	E+00	=	cm
psi	× 6.894 757	E+04	=	kPa

* Conversion factor is exact.

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Table 1
Inspection Tool Types and Specifications

Company	Name	Description	Operating Mode	Vertical Resolution	Comments
Halliburton	CIL	Casing Inspection Log	Magnetic - AC Voltage	0.3"	qualitative wall loss, holes, can not read multiple casing strings
Halliburton	CAST	Circumferential Azimuthal Scanning Tool	Acoustic- Radial Imager	0.5"	accurate enough to count perfs
Halliburton	PEL	Pulse Echo Log	Acoustic- 8 transducers	6" +	read casing weight along with cement bond and strength
Schlumberger	CPET	Corrosion & Protection Evaluation Tool	Magnetic - DC Voltage	6' stations	cathodic protection, measures stationary macro- wall loss
Schlumberger	METT	Multi Frequency Electro-magnetic Thickness Tool	Magnetic - AC Voltage	holes > 2"	qualitative wall loss, holes, can read multiple strings after processing.
Schlumberger	PAT	Pipe Analysis Tool	Magnetic - AC Voltage	hole > 0.3"	averages radial measurements
Schlumberger	CET	Cement Evaluation Tool	Acoustic- 8 transducers	6" +	read casing weight along with cement bond and strength
Schlumberger	BHTV	Borehole Televiewer	Acoustic- Radial Imager	0.2"	accurate enough to count perfs
Schlumberger	MFCT	Multi- Finger Caliper Tool	Mechanical- 16 to 72 arms	0.01 -0.04"	reads holes and internal defects
Schlumberger	USI	Ultrasonic Imager	Acoustic- high frequency	0.02"	images casing and measures weight
Schlumberger	UCI	Ultrasonic Corrosion Imager	Acoustic- high frequency	0.04"	images casing, extra transducer for corrosion evaluation
Western Atlas		Vertilog	Magnetic- DC Voltage	3"	measures macro- wall loss, pitting and large holes
Western Atlas		Magnelog	Magnetic - AC Voltage	0.3"	Internal, External casing wear
Western Atlas	MFC	Multi- Finger Caliper Tool	Mechanical- 30 to 60 arms	0.05"	reads holes and internal defects
Western Atlas	CPP	Casing Potential Profile	Magnetic- DC Voltage	5' stations	cathodic protection, measures stationary macro- wall loss
Western Atlas	CBIL	Circumerential Borehole Imaging Log	Acoustic- Radial Imager	0.2"	accurate enough to count perfs

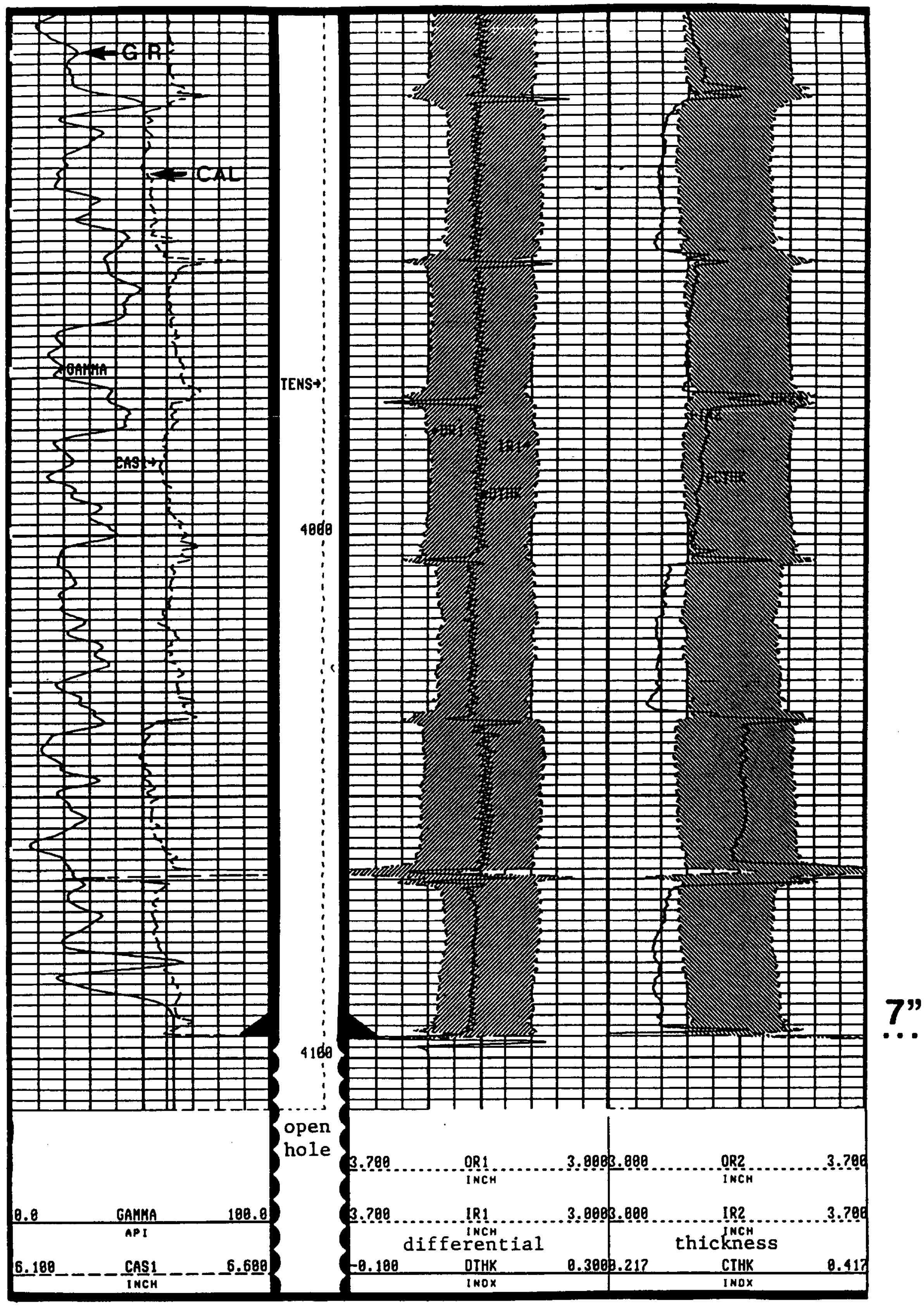


Figure 1- CVU No. 97 Ideal Casing Inspection Log

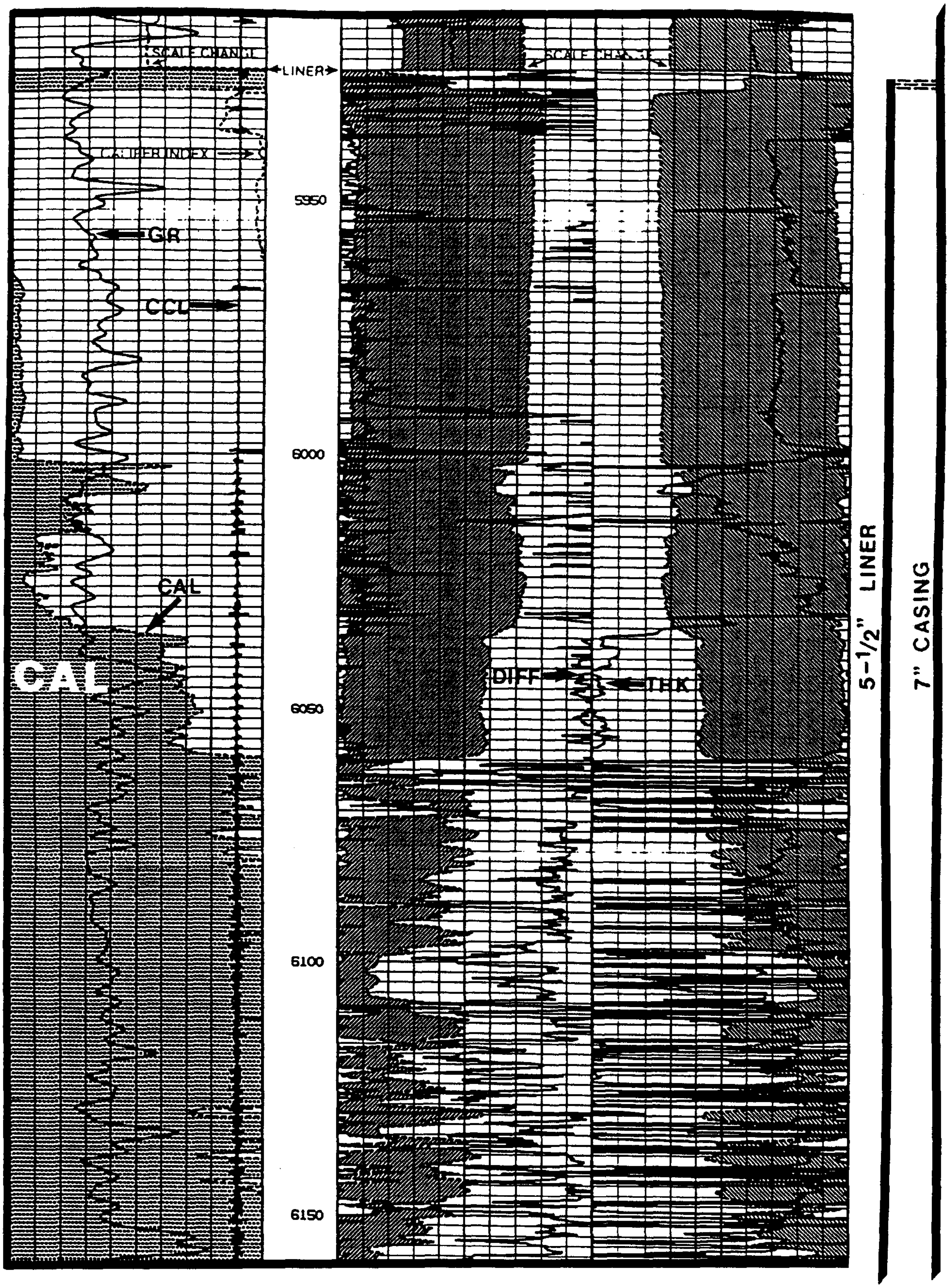


Figure 2 - WDDU No. 86: Casing Inspection Log Through Liner Top

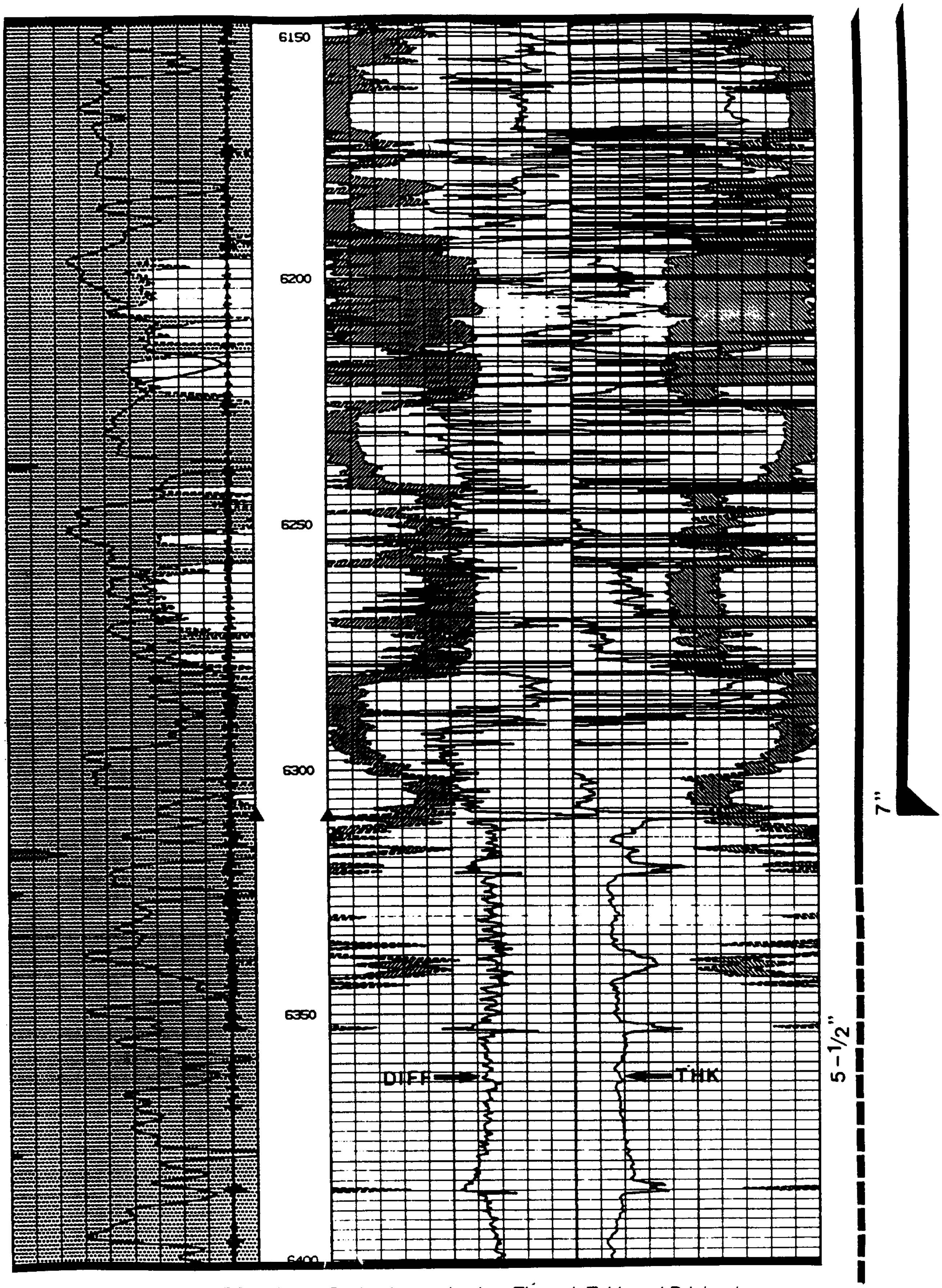


Figure 3 - WDDU No. 86 Casing Inspection Log Through Tubb and Drinkard

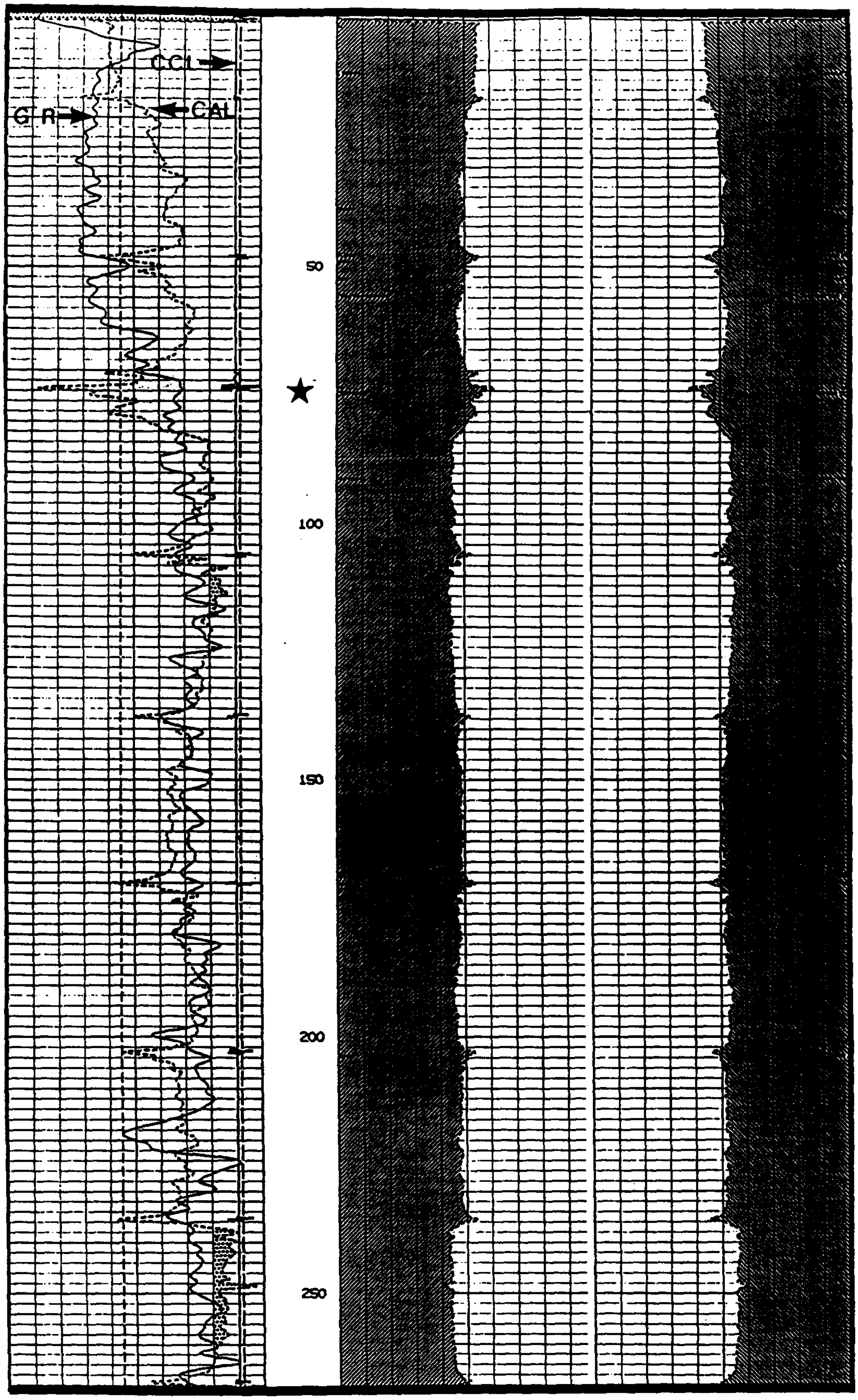


Figure 4 - WDDU No. 11: Casing Inspection Log Near Surface

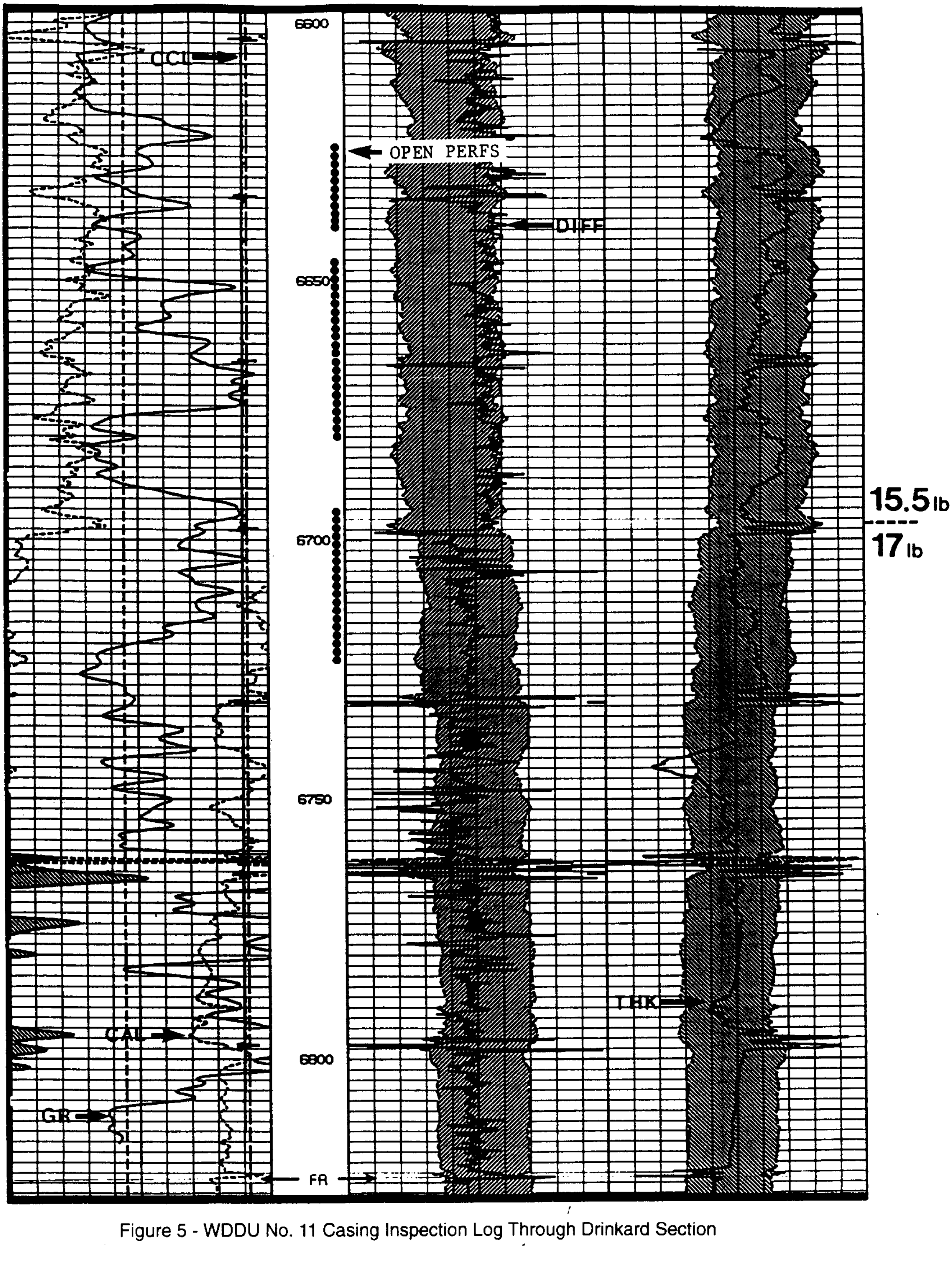
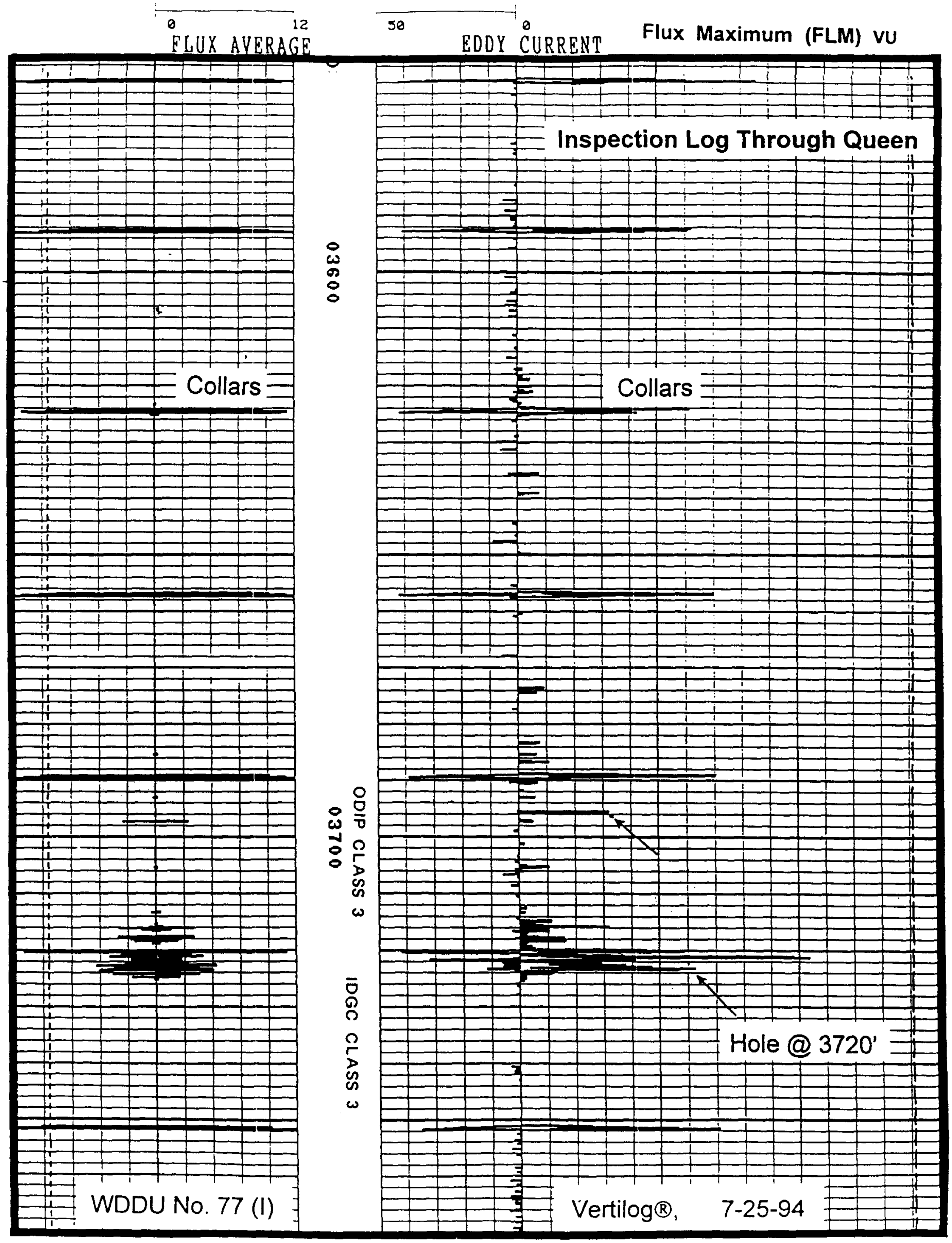


Figure 5 - WDDU No. 11 Casing Inspection Log Through Drinkard Section



0
12
FLUX AVERAGE
50
0
EDDY CURRENT
Flux Maximum (FLM) VU
Inspection Log Through Queen
03600
Collars
Collars
ODIP CLASS 3
03700
IDGC CLASS 3
Hole @ 3720'
WDDU No. 77 (I)
Vertilog®, 7-25-94

Figure 6

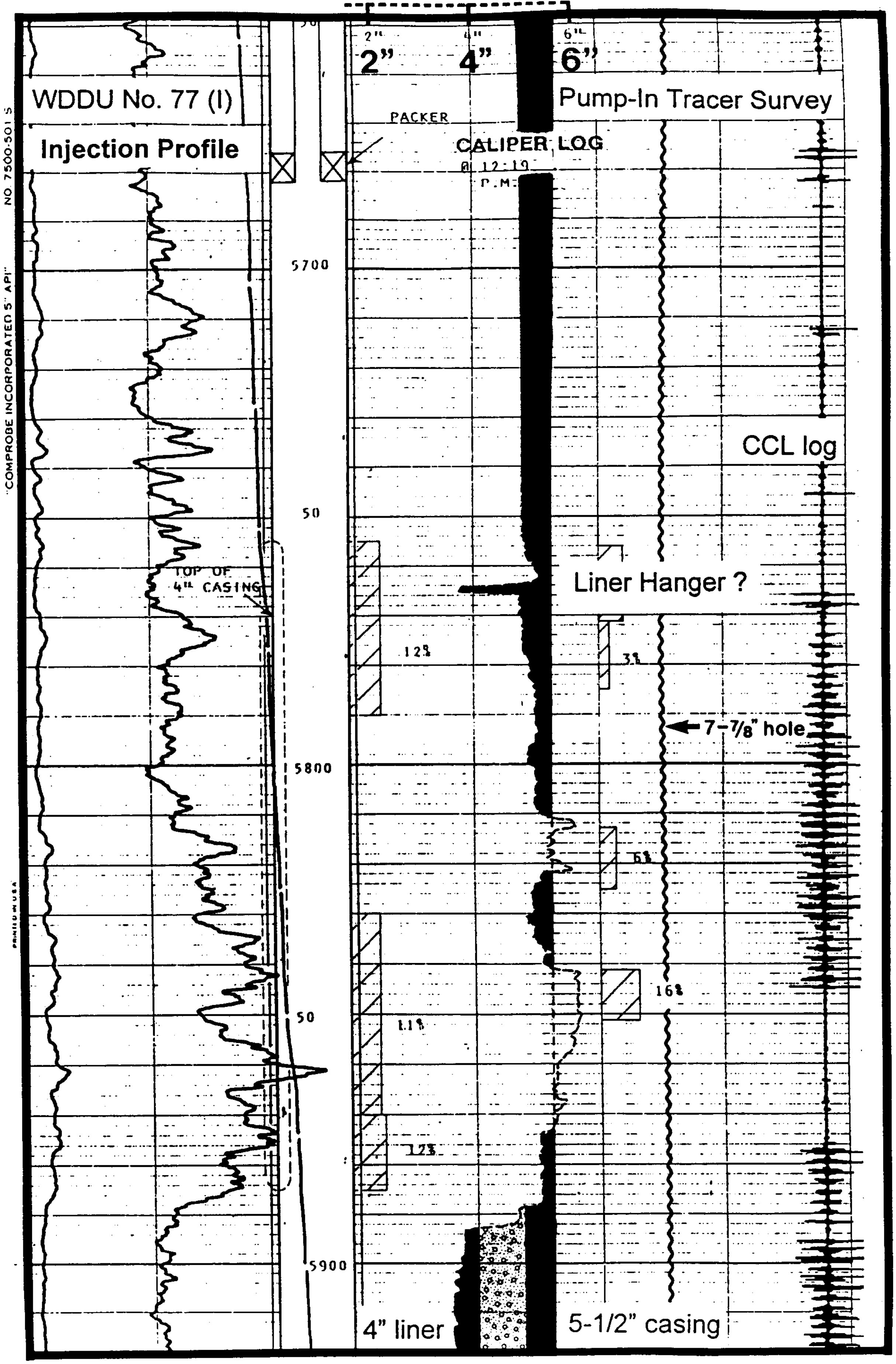

WDDU No. 77 (I)
Injection Profile
Pump-In Tracer Survey
2"
4"
6"
PACKER
CALIPER LOG
5700
50
TOP OF 4" CASING
12%
3%
Liner Hanger ?
CCL log
7-7/8" hole
5800
6%
16%
11%
12%
5900
4" liner
5-1/2" casing

Figure 7

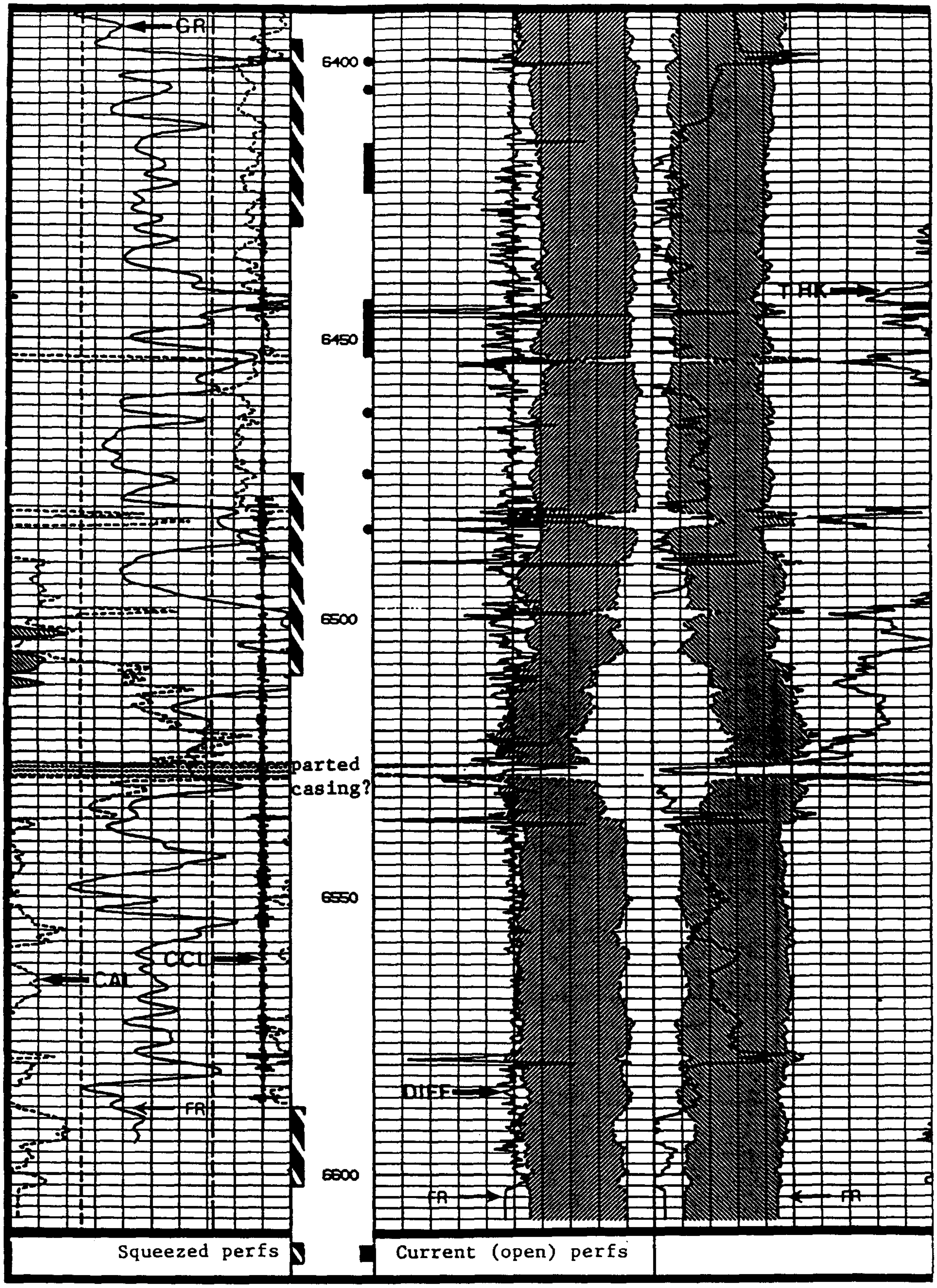


Figure 8 - WDDU No. 32: Casing Inspection Log Through Drinkard Section

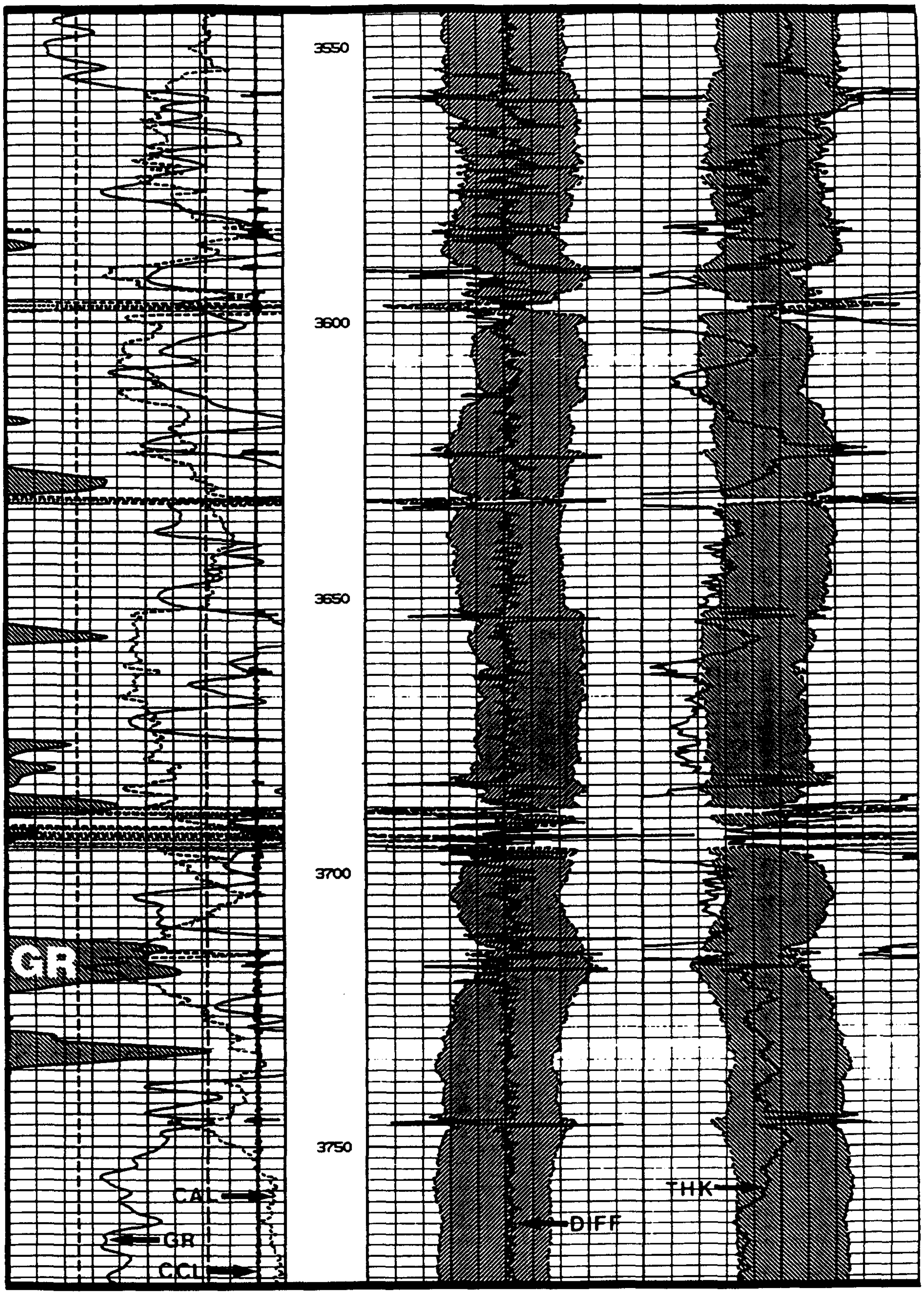


Figure 9 - WDDU No. 32: Casing Inspection Log Through Queen Section

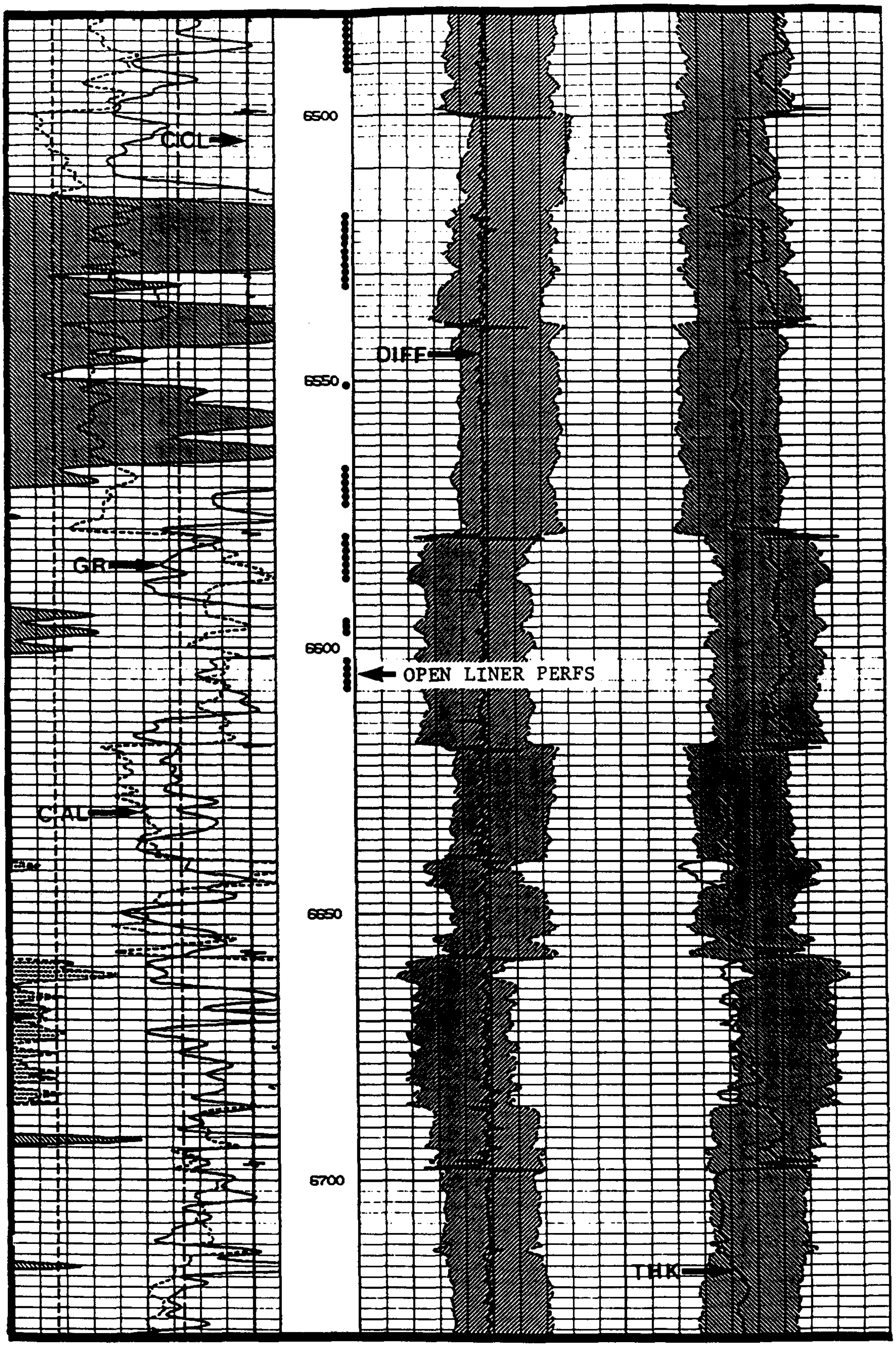


Figure 10 - WDDU No. 56: Casing Inspection Log Through Drinkard Interval

Figure 11 - WDDU No. Casing Inspection Log Through Salt Section

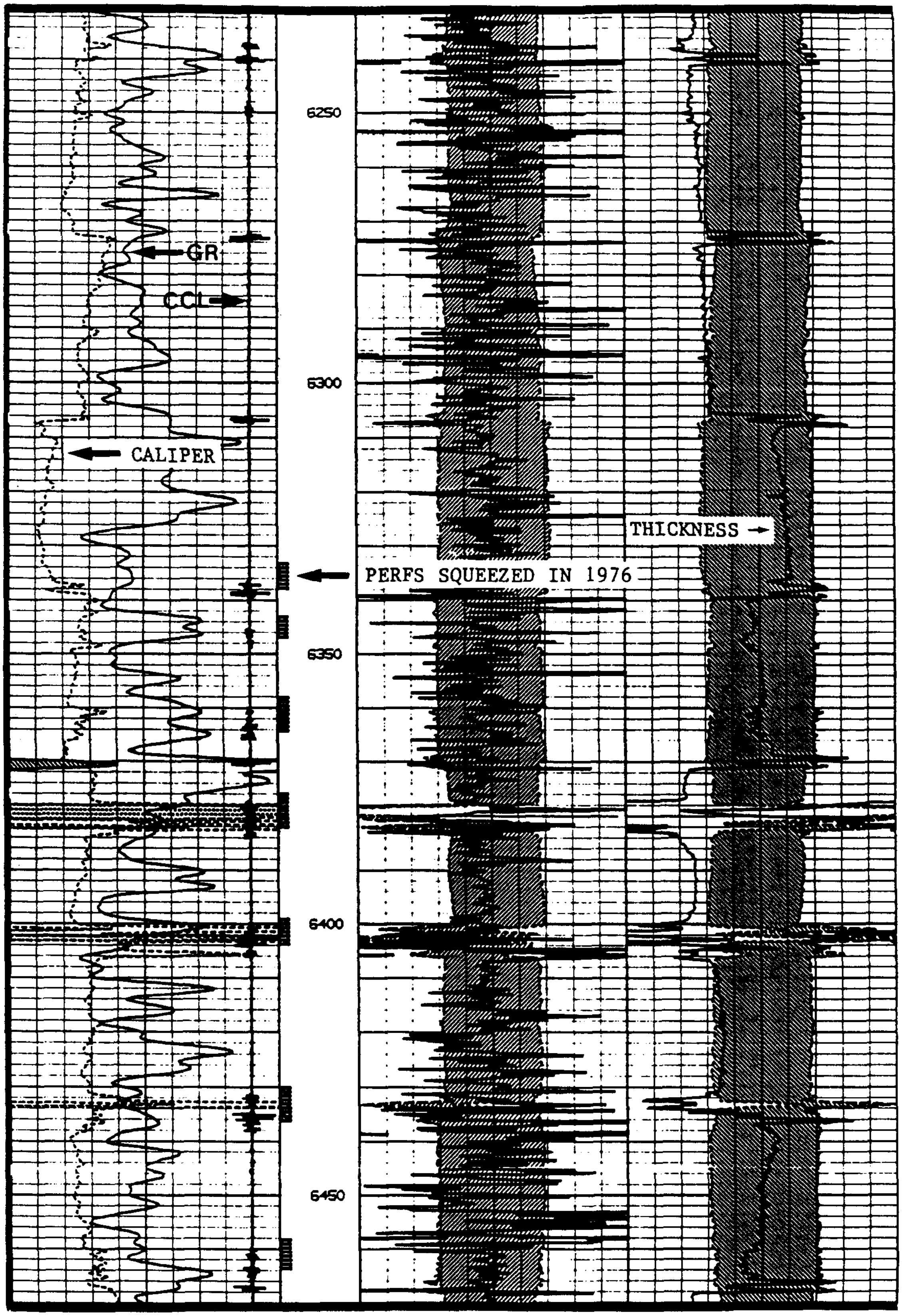


Figure 12 - WDDU No. 37: Casing Inspection Log Through Tubb Interval

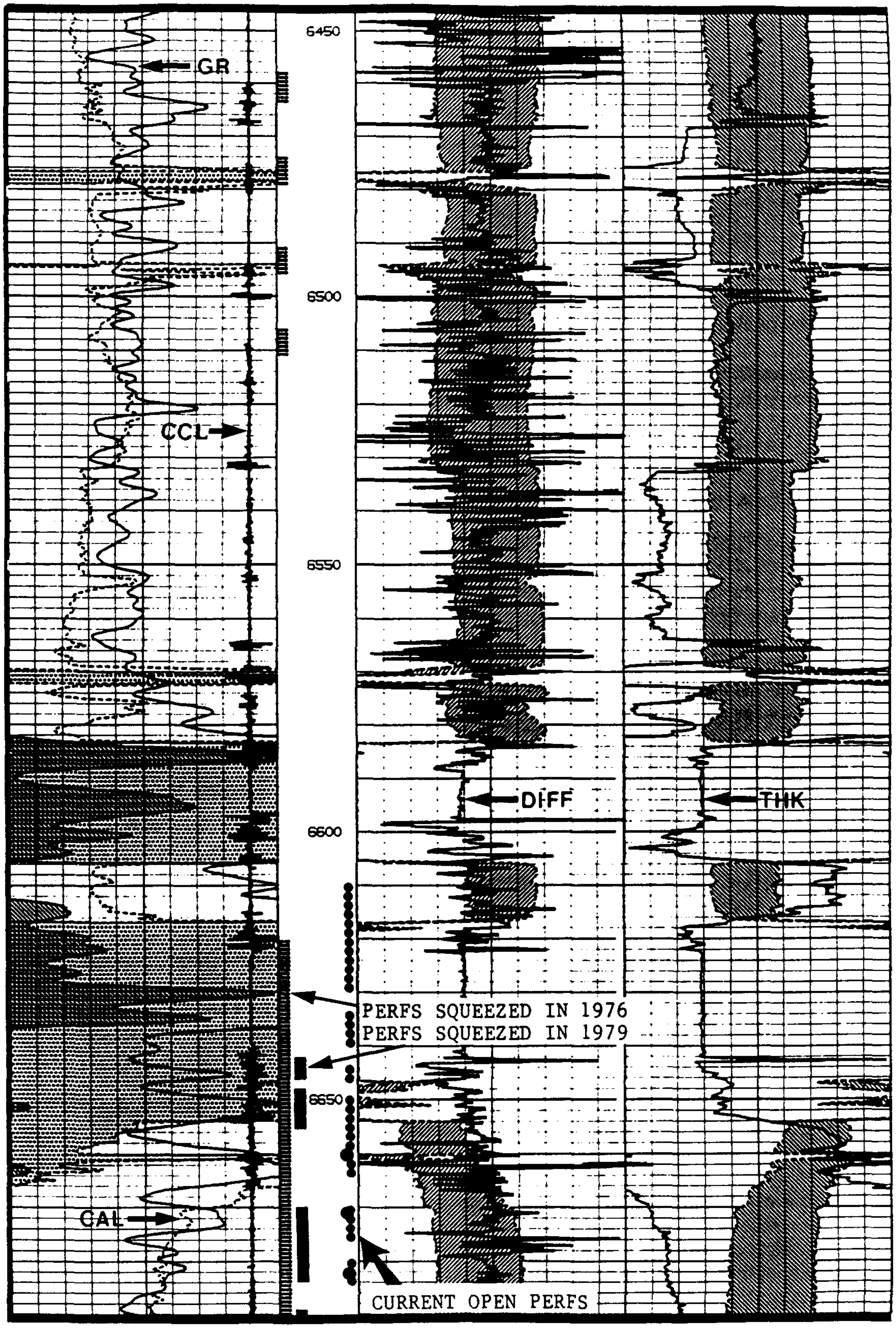


Figure 13 - WDDU No. 37: Casing Inspection Log Through Drinkard Interval