FINAL REPORT

"INCREASING WATERFLOOD RESERVES IN THE WILMINGTON OIL FIELD THROUGH IMPROVED RESERVOIR CHARACTERIZATION AND RESERVOIR MANAGEMENT"

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Abstract

This project increased recoverable waterflood reserves in slope and basin reservoirs through improved reservoir characterization and reservoir management. The particular application of this project is in portions of Fault Blocks IV and V of the Wilmington Oil Field, in Long Beach, California, but the approach is widely applicable in slope and basin reservoirs. Transferring technology so that it can be applied in other sections of the Wilmington Field and by operators in other slope and basin reservoirs is a primary component of the project.

This project used advanced reservoir characterization tools, including the pulsed acoustic cased-hole logging tool, geologic three-dimensional (3-D) modeling software, and commercially available reservoir management software to identify sands with remaining high oil saturation following waterflood. Production from the identified high oil saturated sands was stimulated by recompleting existing production and injection wells in these sands using conventional means as well as a short radius redrill candidate.

Although these reservoirs have been waterflooded over 40 years, researchers have found areas of remaining oil saturation. Areas such as the top sand in the Upper Terminal Zone Fault Block V, the western fault slivers of Upper Terminal Zone Fault Block V, the bottom sands of the Tar Zone Fault Block V, and the eastern edge of Fault Block IV in both the Upper Terminal and Lower Terminal Zones all show significant remaining oil saturation. Each area of interest was uncovered emphasizing a different type of reservoir characterization technique or practice. This was not the original strategy but was necessitated by the different levels of progress in each of the project activities.

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Introduction

The Wilmington Field is the third largest oil field in the United States, based on total reserves. Original oil in place was approximately 1.39 billion m^3 (8.8 billion barrels). Cumulative oil production to date is approximately 0.38 billion m^3 (2.4 billion barrels) leaving a target of 1.01 billion (6.4 billion barrels) for improved recovery methods.

The field was discovered in 1936, with production commencing from the Upper Terminal Zone of Fault Block IV in 1938. This was followed by the development of the Tar, Ranger, Lower Terminal and Ford Zones over the next 20 years. By 1942, approximately 1,000 wells were producing from the five productive zones that had been discovered: Tar, Ranger, Upper Terminal, Lower Terminal, and Ford. In early 1942, a new productive zone, the Union Pacific Zone, was discovered below the Upper Terminal Zone. In 1946, the "237" Zone was discovered below the Ford Zone and caused an intense three year drilling boom. Due to the very small size of individual holdings and resultant small well spacing (less than 12,141 m^2 (3 acres) average per well) peak production was reached very quickly and individual well rates declined sharply. Water injection commenced into the south flank of Fault Block IV in August, 1958, and continues today.

Since the early 1940's, land subsidence had been observed in the vicinity of the Wilmington Oil Field. The main area of subsidence was shaped like a bowl with the center of subsidence located on the east end of Terminal Island. At its maximum, approximately 9.15 m (30 ft) of subsidence was observed at the surface. In June, 1953, the City of Long Beach and its field contract operator, Long Beach Oil Development Company (predecessor to Tidelands Oil Production Company), started a pilot water injection operation in the "Hx" sands of the Upper Terminal Zone Fault Block V, to determine the feasibility of water injection for repressurization to control subsidence and increase oil recovery. This and subsequent pilot water injection operations established that subsidence could be halted and oil recovery could be increased. To expand the water injection operations on a field-wide basis, it was necessary that the individual holdings in the field be pooled together under unit or cooperative agreements. The majority of the fault blocks established such agreements during the 1960's.

The following tables give average reservoir characteristics for the Tar, Ranger, Upper Terminal and Lower Terminal Zones of Fault Blocks IV and V.

Table 1: Average Reservoir Characteristics (Fault Block IV)

	Tar	Ranger	Upper Terminal	Lower Terminal
Initial Reservoir Pressure	1,049	1,335	1,467	1,667
Reservoir Temperature	123	142	151	167
Initial OIP (bbl/ac.-ft.)	1,617	1,464	1,240	964
Initial Gas (Mcf/ac.-ft.)	158	244	250	252
Porosity (%)	30.0	30.0	27.1	25.2
Soi (%)	73.5	68.8	66.0	58.1
Swi (%)	26.5	31.2	34.0	41.9
Sgi (%)	0	0	0	0
Perm. to air (md)	1500	1550	755	450
Oil Sulfur (% by wt.)	N/A	N\A	N\A	N/A
Initial GOR	93	158	191	252
Initial FVF (RB/STB)	1.057	1.094	1.118	1.141
Bubble Point (psia)	N/A	1335	N/A	N/A
Oil Viscosity (cp) @ ^{0}F	360	84	31	6.6
Gas SG	.59	.67	.73	.69
Water Salinity NaCl (ppm)	30,747	29,600	29,500	N/A
TDS (ppm)	29,549	31,488	30,500	N/A
Rw (ohm/m) (77^{0}F)	.184	N/A	.19	N/A

Table 2: Average Reservoir Characteristics (Fault Block V)

	Tar	Ranger	Upper Terminal	Lower Terminal
Initial Reservoir Pressure	1,027	1,379	1,423	1,667
Reservoir Temperature	121	135	148	163
Initial OIP (bbl/ac.-ft.)	1,881	1,478	1,253	948
Initial Gas (Mcf/ac.-ft.)	216	314	252	252
Porosity (%)	31.9	30.0	28.0	25.2
Soi (%)	80.0	69.5	66.0	59.2
Swi (%)	20.0	30.5	34.0	40.8
Sgi (%)	0	0	0	0
Perm. to air (md)	100-1,000	1,840	915	450
Oil Sulfur (% by wt.)	N/A	N/A	N/A	N/A
Initial GOR	90	152	190	252
Initial FVF (RB/STB)	1.053	1.094	1.110	1.141
Bubble Point (psia)	N/A	N/A	1480	N/A
Oil Viscosity (cp) @ ^{0}F	450	84	25	6.6
Gas SG	.68	.65	0.73	0.69
Water Salinity NaCl (ppm)	18,490	28,879	30,500	N/A
TDS (ppm)	19,978	31,665	31,200	N/A
Rw (ohm/m) (77^{0}F)	.309	.217	.20	N/A

The Wilmington Oil Field is located in Los Angeles County, California, approximately 12.4 km (20 miles) south of downtown Los Angeles. The field extends southeasterly from the industrial and residential areas of the Wilmington District of the City of Los Angeles, through the City of Long Beach and its harbor area, and beyond to the area offshore of the City of Long Beach. The field demonstration site is in Section 3, Township 5S, Range 13W.

The Wilmington Field is an asymmetrical anticline approximately eleven miles long and three miles wide, covering a productive area of approximately 54,633,150 m^2 (13,500 acres). The field is divided into ten fault blocks and seven primary producing zones. Fault Blocks IV and V are located near the center of the Wilmington Oil Field. The western boundary of Fault Block IV is the Powerline Fault and the eastern boundary of Fault Block V is the Golden Avenue and Daisy Avenue Faults. The two fault blocks are separated by the Harbor Entrance and Allied Faults. The north and south limits of the fault blocks are governed by water-oil contacts within the individual sand members of the various zones.

The seven zones within each fault block listed in order of increasing depth are: Tar, Ranger, Upper Terminal, Lower Terminal, Union Pacific, Ford, and "237". The reservoir rocks of all the zones are sands or sandstones of different degrees of consolidation, arkosic in places, and with varying silt content. Thicknesses of the sand layers vary from a few inches to several tens of feet. The percent of sand in the zones ranges from 23 percent in the Union Pacific Zone to 70 percent in the Upper and Lower Terminal Zones.

The Tar Zone sands are generally unconsolidated and oil gravities are low, ranging from 12-15 degrees API. Tar Zone sands have an average porosity ranging from 30-40 percent and permeabilities ranging from 500-8,000 millidarcies with a weighted average of 1,000 millidarcies. Approximate zone gross thickness ranges from 76.2 m to 122.0 m (250 to 400 ft). The top of the structure can be found at a depth of 647.9 m (2,125 ft).

The Ranger Zone sands are usually thin on the structural crest and increase in thickness on the flanks. The sands are arkosic in places, vary from fine to medium grained, are poorly consolidated, and vary considerably in thickness. The porosities range from 30-40 percent and the permeabilities range from 500-1,000 millidarcies. Zone gross thicknesses vary from 122.0 m to 228.7 m (400 to 750 ft). Oil gravities range from 12-25 degrees API. The top of the structure can be found at a depth of 716.5 m (2,350 ft).

The Upper Terminal Zone is a prolific producer of oil in the Wilmington Oil Field although considerably more limited in areal extent than the Ranger Zone. Sands constitute 50-70 percent of the zone and are generally homogeneous. The different sands comprising the Upper Terminal Zone vary from poorly to fairly well consolidated, and from fine to coarse grained in texture with porosity ranging from 30-35 percent. Oil gravities vary from 14-25 degrees API, and permeabilities from 400 to 1,000 millidarcies with a weighted average of 450 millidarcies. Zone thickness ranges from 122.0 m to 259.2 m (400 to 850 ft). The top of the structure can be found at a depth of 853.7 m (2,800 ft).

The Lower Terminal Zone is also a prolific producer but is smaller in areal extent than the Upper Terminal. The zone consists of 50-70 percent sand and is generally less homogeneous than the Upper Terminal. The sands are fine to medium grained and better consolidated than the younger sands above. Porosities range from 25-35 percent and permeabilities from 400-700 md. with a weighted permeability of 450 md. Oil gravities range from 20-31 degrees API. Zone gross thicknesses vary from 152.4 m to 243.9 m (500 to 800 ft). The top of the structure can be found at a depth of 1,021.3 m (3,350 ft).

The Union Pacific Zone consists of well-indurated shale layers and thin interbedded sands. The sand layers are well consolidated, fine to medium-grained, and less friable than sands of the upper zones. The Union Pacific sands are limited in areal extent and productivity and are usually produced with other zones. The sand layers constitute approximately 20-25 percent of the zone interval which varies from 122.0 m to 274.4 m (400 to 900 ft). The top of the structure can be found at a depth of 1,189.0 m (3,900 ft). Sand porosities range from 40-200 millidarcies with a weighted average of 150 millidarcies. Oil gravities vary from 27-32 degrees API.

The Ford Zone is similar to the Union Pacific Zone lithologically, but the interval has a greater percentage of sand. Zone thickness varies from 228.7 m to 365.9 m (750 to 1,200 ft) with the top of the structure found at a depth of 1,402.4 m (4,600 ft). The percent of sand in the zone varies from 25-35 percent. The sands are usually fine to medium-grained. Generally, they are hard and well-consolidated. Ford Zone sand porosities range from 20-25 percent and permeabilities range from 12-1,200 millidarcies with a weighted average permeability of 100 millidarcies. Oil gravities range from 28-32 degrees API.

The "237" Zone consists of alternating thick layers of sand and shales. The sands are generally massive, coarse to medium-grained, and poorly sorted. Sands constitute approximately 40 percent of the zone interval. Porosities range from 20-

25 percent and permeabilities from 10-300 millidarcies. Oil gravities range from 28-32 degrees API. Zone thickness varies from 61.0 m to 365.9 m (200 to 1,200 ft) with the top of the structure found at a depth of 1,676.8 m (5,500 ft).

This project takes place in the upper zones of Fault Blocks IV and V: Tar, Ranger, Upper Terminal, and Lower Terminal.

Executive Summary

Waterflood oil recovery in the Wilmington Field has historically been inefficient due to a variety of factors, including reservoir heterogeneity, poor sweep efficiency, high water cut, and poor injection profiles. Sands with high remaining oil saturation are still present despite extensive waterflooding, but locating these sands has been difficult.

Reservoir management software has identified areas of potentially high remaining oil saturation in both the Upper Terminal Zone and the Lower Terminal Zone of Fault Block IV. A pulsed acoustic cased-hole logging tool was run in potential recompletion candidates and recovered compressional wave data from which porosities were calculated. Unfortunately, shear wave data were not recovered therefore acoustically derived saturations cannot be predicted for the Fault Block IV wells. An optimized remedial recompletion was completed on well Y-63 in the Upper Terminal Zone of Fault Block IV, and well Z-223 of Upper Terminal Zone Fault Block V. These wells are doing better than offset production wells.

Examination of recent electric logs (E-logs) revealed sands with remaining high oil saturation in the Tar Zone and Upper Terminal Zone of Fault Block V. A deterministic 3-D model was built around the Upper Terminal Zone recompletion candidate Well J-120 as well as redrill candidate J-17. Well J-120 was recompleted and returned to production with results greatly exceeding expectations. Redrill well J-17 was completed in March, 1997, and resulted in the most profitable well in the Upper Terminal Zone, Fault Block V. A deterministic 3-D model was also built around the Tar Zone recompletion candidate Well J-15 and new well horizontal well A-112. Both wells were successfully brought on production. Finally, new well L-233 was drilled and completed in November, 2001, as a result of modeling work completed in this DOE project.

Experimental

Results that may be considered experimental are included in the "Results and Discussion" section of this report.

Results and Discussion

The original strategy for this project was to identify areas of bypassed oil through reservoir characterization and reservoir engineering, verify its location behind pipe with the multi-pole acoustic sonic log, and produce the oil from recompleted idle wells. As the project advanced it became evident we had to modify this strategy as project activities evolved and progressed at differing rates. Rather than a series of activities, researchers pursued the activities in parallel. Also, results from each activity had varying degrees of success. The most successful results came from the 3-D geologic modeling and recompletions while the least successful results came from the pulsed acoustic logging.

M Reservoir Characterization

Reservoir characterization in this project denoted not only defining gross geologic features such as structure, faults, and rock properties such as porosity and lithology, but also the distribution of remaining oil saturation in the reservoirs of interest. This required complete integration of geologic and engineering data.

The first step in integrating the data for reservoir characterization was developing basic geologic and engineering representations of the data. This included revising geologic structure maps, isopach maps, and cross sections. Structure maps experienced the most changes and reinterpretations mainly due to the availability of new well data.

A major part of the characterization work involved developing and calibrating rock-log and fluid-log models from which to interpret the acoustic log data. Theoretical relationships, confirmed by laboratory and field data, suggested that hydrocarbon bearing rocks in situ can be differentiated from rocks containing brines using sonic velocity measurements[1]. Because hydrocarbons in situ have much lower bulk moduli and densities than brines, replacing water with hydrocarbons lowers the compressional wave velocity (V_p) and increases slightly the shear wave velocity (V_s). Williams[2] presented evidence that hydrocarbons could be detected from the difference between measured V_p/V_s and that predicted for a water saturated rock from shear wave velocity as shown in FIGURE 1 comparing wells M-499 and 167-W[3]. The water delineation line is similar for clean and clay bearing sand; virtually the same relationship can be used to detect hydrocarbons in both, eliminating the need for an independent lithology indicator. However, because of the lack of quantitative physical models to predict the effect, this technique has been applied with caution and a limited degree of success. A successful field test[4] in the Wilmington Field generated this DOE project to further evaluate the quality of the acoustic data and filter out the near wellbore effects, and to calibrate the logs for in situ rock and fluid properties to better quantify porosity and oil saturation.

Researchers developed the rock-log and fluid log models which relates frame moduli to porosity in unconsolidated sands found in the Wilmington Field and other slope and basin clastic reservoirs. The reservoir characterization portion of the DOE project incorporated the refinement and application of rock-log models for relationships between elastic-wave velocities measured using the dipole logging tool, and the oil saturation and porosity within the reservoir. Existing theoretical models were evaluated for application to the Wilmington Field. Several of these models were applied to predict the magnitude of the effect of saturation on velocities. Laboratory data were collected in actual samples of reservoir rock and in sand-clay mixtures, to better define the relationships between elastic moduli and reservoir properties. The most appropriate model was then applied to predict porosity and constrain saturation using the existing log data. An investigation of uncertainty in predictions revealed that while primary-wave (P-wave) data alone could be used in ideal circumstances to predict saturation, secondary-wave (S-wave) velocities are required to refine the results and improve confidence. The results indicated that monopole and dipole logs can be used to predict porosity and to differentiate between potentially productive and non-productive sands in the Wilmington field.

The theoretical rock physics part of the DOE project had two main thrusts: (a) first-principle-based models for relating the elasticity of the high-porosity sediment frame to porosity and mineralogy; and (b) models for relating sonic P- and S-wave velocities to the properties of the pore fluid. The latter models are intended to be used in the inversion mode i.e., for inferring pore fluid type (hydrocarbons versus brine) from sonic data. An important by-product of this modeling is a theory for estimating permeability from porosity and velocity.

By analyzing several data sets for sandstones of up to 40% porosity, we concluded that there are two end-member velocity-porosity trends. One is for rocks where the diagenetic cement fills the grain contacts thus reinforcing the sediment's frame (e.g., quartz rims growing on sand grains), and the other is for rocks where the cement is deposited away from the grain contacts (e.g., mica and clay in the pore space). In the first case, both P- and S-wave velocities are high even in a high-porosity sandstone. In the second case, at the same high porosity, the velocities are low. In reality, many rocks fall between these two end members: often both contact and non-contact cement are present. However, it appears that the Wilmington oil-bearing rocks can be accurately described by the low-velocity end member. We have successfully used this theory to infer porosity from behind-casing dipole data.

A standard way of relating the properties of the pore fluid (compressibility and density) to sonic velocity is by using Gassmann's equation. The assumption behind this approach is that the phases of the pore fluid (e.g., oil and brine) are homogeneously mixed at the pore scale, which allows for calculating the compressibility of the "effective" pore fluid. A different situation is where the two (or more) phases of the pore fluid are situated in patches and do not co-exist in every pore. Of course, these two situation have to be treated as the end members of the general case where both patchy and homogeneous situations are present. We provide a theory for calculating the effective elastic properties of rock with patchy saturation. By using a field example, we show that such a situation can indeed exist in situ. In practice, quantitative saturation values cannot be obtained even if the fluid distribution is known, without knowing the compliances of the fluid end members.

Similar to the elasticity of rock, its permeability depends not only on porosity, but also on the position of the pore-filling cement. At the same porosity, it is larger for the contact-cement case than for the other end member--the non-contact-cement case. By using a field example, we show that by relating permeability to the amount of the non-contact cement, we achieve a much more accurate trend that by relating it to porosity. This new parameter, the volumetric fraction of the non-contact cement in the rock, can be found from porosity and velocity.

In earlier work it was demonstrated that porosity and fluid saturation could be inferred from acoustic P-wave data even in the absence of S-wave data. However, interpretation of seismic velocities in terms of fluid saturations are not unique. Velocities are affected not only by the pore fluids we wish to detect, but also by variations in porosity, clay content, pressure, and temperature. Statistical analytical methods to investigate uncertainties in these predictions were applied to a synthetic example conditioned on laboratory data, and to a real well log example in a shaly sand reservoir from the Gulf of Mexico. The results showed that while in some cases shear wave data may not help to reduce the uncertainty, in other situations, noisy S-wave data along with noisy P-wave data can convey more information than perfect P-wave data alone. By implication, knowledge of lithology in addition to P- and S-wave velocity it should be possible to refine the interpretations further. Such information may be available for application to cased holes using gamma-ray logs or older open-hole logs.

More than thirty laboratory tests of unconsolidated samples were acquired during the course of this project. Measurements of bulk and shear modules and ultrasonic P- and S-wave velocities were carried out in the majority of these experiments while varying confining pressure from zero to 30 Mpa, corresponding to a depth of burial of more than 1,524 m (5,000 ft). Initial tests were completed on archived cores with residual fluids intact, and on archived cores after cleaning to remove tars. Tests on cores recovered during the project and stored under refrigeration were carried out in a similar fashion. Synthetic samples of Ottawa sand mixed with wetted clays were tested to investigate the importance to this project of frequency dependence of the measured moduli.

The results revealed that one, porosities could be predicted using the Hashin-Shtrikman Lower Bound (HSLB) model for unconsolidated materials. However, the results need to be corrected slightly (approximately 3 to 5 porosity units up or down) for the effects of varying confining pressures or pore fluid pressures. Two, saturation with fluids caused changes in properties consistent with the Gassmann relations used to model the field data. Three, significant irreversible compaction occurs on loading, preventing the use of a single sample to study the effects of fluid replacement. This required more measurements than originally expected to fully describe the properties of these materials in the presence of different types of pore fluids. Four, the dry frame moduli were frequency dependent due to the presence of clays and mica. This frequency dependence was in addition to an expected dispersion associated with pore fluids.

The laboratory data were sufficient to demonstrate that the theoretical rock-log models were accurate and general enough to allow application to fields such as Wilmington. Furthermore, they allowed us to “calibrate” the models against theoretical predictions from contact theory. They revealed that care must be taken when applying laboratory data to the field to incorporate both frame and fluid related dispersion.

Porosity estimation techniques based on the theoretical model appropriate for the Wilmington Field were applied to shear-wave data from two wells, for comparison to alternative porosity estimation techniques. In the cased well porosities predicted acoustically were in excellent agreement with density-derived porosities in sands, and were lower in shales, and thus were more likely to be measures of the effective porosity. Importantly, the sonic porosity was more reliable in bad hole sections due to its insensitivity to variations in hole size. In a second well, sonic porosities obtained in the open hole were smaller than neutron porosities and slightly larger than density porosities.

Acoustic data from two wells was used to evaluate the ability to predict saturation. In one well for which open-hole estimates from Archie's Law were used to select perforation intervals, the acoustic prediction was in qualitative agreement with Archie's Law estimates of saturation. By selecting those zones, it was demonstrated that the sonic data in Wilmington were consistent with ALHI empirical predictions, in that high oil saturation zones lay below the ALHI "water line". Data from an injector, in which intervals subject to injection could be isolated from those which were not subject to injection using a gamma-ray log, revealed that the data lay above the water line, consistent with being fully watered-out. These two empirical tests revealed both that the acoustic technique could be used to predict the presence of hydrocarbons, and that it could also be used to identify fully watered-out zones.

The field data revealed the presence of lithology effects not predicted by the original Williams ALHI paper. These included scatter in the water-saturated data above the ALHI "water line". They are not likely to be important in qualitative applications of acoustic saturation prediction. Theoretical modeling revealed that these effects are due to the presence of feldspars and other grains in addition to quartz, and can to first order be accounted for using a gamma-ray log to determine the relative volume of quartz in relation to other minerals in the rock matrix. Further work would be necessary to quantify the effect.

In conclusion, monopole and dipole shear sonic logs can provide accurate compressional and shear wave velocities in cased holes, even in shallow, unconsolidated sands such as in the Wilmington Field. Porosity can be determined from shear wave velocity, provided an appropriate transform is used. Qualitatively, acoustic logs can be used to locate bypassed oil.

M Reservoir Engineering

Oil field reservoir and production engineering analysis for the Wilmington Field first required locating, inputting, quality controlling, storing, and manipulating enormous amounts of data. This was a monumental task that we originally underestimated. Production data from the early life of the field was missing or only available on hard copy. The missing data was located at government agencies such as the City of Long Beach's Department of Oil Properties (DOP) and the California Department of Oil and Gas and Geothermal Resources (CDOGGR). Zones of interest were prioritized for engineering studies. Waiting for all zones to be input and quality controlled before starting our studies would have reduced the time allocated for analysis.

The first zone of interest completed was the Upper Terminal Zone of Fault Block IV. Researchers generated numerous cumulative production bubble maps, cumulative injection bubble maps, daily production maps, and isocut maps. These maps revealed an area on the east side of the fault block against the Harbor Entrance Fault that appeared to have low cumulative oil recovery. Idle well Y-63, originally scheduled for abandonment, was recompleted in the Upper Terminal Zone across the "Hx", "J", "Y", and "K" sands.

In zones where data input and manipulation were not completed, researchers scanned the log files for newer electric logs which would indicate bypassed oil. Another technique for finding bypassed oil was to identify anomalous production well characteristics such as lower than average water cuts, high oil production rates, and high water production rates. These practices generated recompletion candidates Y-30, J-15, and J-120.

Idle well Y-30 penetrated the Lower Terminal Zone of Fault Block IV and was set to be recompleted in the "AB", "AC", and "AD" sands. Studies showed that surrounding Lower Terminal Zone production wells produce with higher than field average oil cuts and with excellent productivity. Also, Y-30 penetrates the zone close to the Harbor Entrance Fault and could produce oil that might be banked under and against the fault. This fault structure is under further analysis with the 3-D geologic modeling software. Unfortunately, during the recompletion operation the casing was found to be severely damaged and the well had to be abandoned.

Fault Block V recompletion candidate J-15 was generated from recent electric logs that passed through the Tar Zone and anomalous neighboring Tar Zone production wells. Penetrating logs over a 30-year period showed little change in the resistivities of the "F_1" and "F_o" sands of the Tar Zone despite heavy waterflooding. This well was recompleted with a novel steam consolidation technique discussed in the recompletion activity.

Fault Block V recompletion candidate J-120 was also generated from recent electric logs that passed through the Upper Terminal Zone. They showed the "Hxo" sand in this area of the Upper Terminal Zone had not been adequately drained. As little activity has taken place in this sand for the last 30 years it was likely to have bypassed oil. A review of all producers and injectors open to the "Hxo" sand revealed no injection and only a few old wells capable of producing from this sand. Further development of the bypassed reservoir was ideally suited for our geologic 3-D modeling. This prospective reservoir was not just a bypassed area in a known sand but a bypassed sand in a known reservoir.

The main task of Budget Period 2 (BP2) was to review production and injection data from Budget Period 1 (BP1) and locate individual sands with high remaining oil saturation. During this process several old wells were discovered missing from the data set. Researchers reviewed all injection associated with the “F_1" and “Fo” sands in the Tar Zone, Fault Block V. The missing data was added to the data set and updated maps were generated.

Researchers gathered old and new electric logs from an area of potential bypassed oil in the “F_1" and “Fo” sands in the Tar Zone, Fault Block V. The area of interest is in the northeast corner of the reservoir (FIGURE 2). The logs show residual oil saturation ranging from 53% to 63% with no associated bottom water. Wells located further down structure do show an oil-water contact and associated bottom water. The area of interest has not had substantial activity in the subject sands over the last 25 years.

Researchers also looked at 30 years worth of spinner-tracer surveys for 11 injectors located in the A-112 project area. This historical research indicated injection into the “F_1" and “Fo” sands took place before 1985, with the bulk of the injection from 1968 to 1980. The surveys also showed a good distribution of water across both sands.

A review of the Tar Zone surrounding idle penetrating production well Z-47 indicated bypassed waterflood oil. The "S", "T", "D1", "F_1", & "Fo" sands in this area of the Tar Zone have not been effectively drained. Electric logs from nearby penetrating wells FZ-29 (1980 log, 122 m (400 ft) from Z-47) and Z1-24 (1983 log, also 122 m (400 ft) from Z-47) show peak resistivities of 17 ohms and 8 ohms in the "S" & "T" sands respectively. These sands have not been flooded out subsequently as the only nearby "S" & "T" sand injection is in wells FY-150, FZ-214, and FJ-55. These injectors are all at least 442 m (1,450 ft) away from well Z-47. The bulk of the cumulative injection into the "S" & "T" sands has taken place in the far north of the Tar V reservoir.

Currently, there are three active production wells surrounding Z-47 which are completed in the "S" & "T" sands. They are wells Z-237, Z-202, & Z1-40. Production from these wells is as follows:

Z-237	25.7 m^3/d (161 b/d) gross,	1.1 m^3/d (7 b/d) net,	95.7 % water cut,	245 m (803 ft) FOP
Z-202	30.5 m^3/d (191 b/d) gross,	1.9 m^3/d (12 b/d)net,	93.7 % water cut,	164 m (538 ft) FOP
Z1-40	81.9 m^3/d (513 b/d) gross,	3.5 m^3/d (22 b/d)net,	95.7 % water cut,	115 m (377 ft) FOP

Gross production from wells Z-237 and Z-202 is lower than most "S" & "T" sand completions and is likely short due to scale. These wells could benefit from a small acid job and pump change the next time they go down. Production from well Z-47 should be similar to the three wells listed above and was estimated at 95.7 m^3/d (600 b/d) gross and 4.8 m^3/d (30 b/d) net for a 95% water cut.

M Deterministic 3-D Geologic Modeling

A major part of this DOE project was geologic 3-D modeling. It was used extensively to high grade our recompletions as well as place new development wells in relatively thin oil bearing sands.

The integration of reservoir characterization data for this project was accomplished by the development of a 3-D computerized visualization model. The selected software can develop and integrate the following types of representational models from scattered data points surfaces such as: terrain, velocity, hydrologic and property distribution in space such as: permeability, porosity, temperature. The model can also represent geologic structures such as: fault blocks, lithologic zones, normal and reverse faults. Data came from wells, logs, and geographic surveys. The data and models were viewed and manipulated interactively using workstations. The software generated various graphic representations of spatial data and models including structure contour maps, isopach maps, cross sections, and 3-D shaded volume models.

Modeling the "Hxo" sand for horizontal well J-17

Significant 3-D modeling took place on the "Hxo" sand of the Upper Terminal Zone in Fault Block V. A working deterministic 3-D geologic model was developed and scattered data for the "Hx_1", "Hxo", "Hx_2", and "Hx" sands were used to define model layers. The model uncovered a flawed interpretation to the west of the Daisy Avenue Fault which defines the boundary between Fault Blocks V and VI. The 3-D geologic model pointed to a fault splay as a preferable interpretation supported by the distribution of scattered data from the four modeled layers. The fault splay interpretation is structurally consistent with other parts of the Wilmington Field.

Once the deterministic 3-D model was created, the next step was to model parameters within the layers. Oil saturation was modeled (FIGURE 3) with initial oil saturation and current oil saturation maps created. Also, sand percentage and oil volumes were modeled and mapped. The oil volume mapping of the "Hxo" sand estimated original oil in place at 540,844 m^3 (3.4 million stock tank barrels) of which 445,401 m^3 (2.8 million stock tank barrels) is bypassed oil. Idle well J-120 was selected for recompletion in the "Hxo" sand based upon our geologic model and reservoir engineering work discussed earlier.

The geologic model was also used to develop our short-radius horizontal redrill well. To plan a horizontal well properly, strict geologic control is required to keep the well in the target sand. The "Hxo" sand is only 4.6 m to 6.1 m (15 ft to 20 ft) in thickness so our margins of safety were quite small. Tidelands Oil has recent experience drilling horizontal wells and found that a 1.52 m (5 ft) target window was attainable.

By investigating to the west of the original project area, we were able to determine that there is a stratigraphic change that is controlling the oil saturation. It was noticed early in the project life that the original oil saturation is lower to the west.

Logs from wells penetrating the area as far as 305 m (1,000 ft) to the west were correlated and the model was expanded. It was found the targeted zone has decreased oil saturation, becomes thinner and shalier to the west. A facies boundary was drawn to make it clear the planned well course should not be drilled too far west. The Hxo layer was subdivided based on the bottom of the oil sand and the top of the highest resistivity streak seen in the logs. These horizons were included in the model as the HxoB (bottom of sand) and HxoJ layers. Cross sections and maps were created so the horizontal well could be planned.

Researchers were successful using the 3-D model for geosteering. The cross sections and maps were highly accurate providing for a successful project. We managed to split the distance the horizontal lateral was contained in the HxoJ and the sand lobe above. It should be noted that the HxoB and HxoJ layers were defined for this project only and do not reside in the permanent data base. The markers were identified on the electric logs and placed in the modeling software data base and then exported so they could be used to create the 3-D model.

The model was good for organizing so we could pinpoint problems that occurred at the rig site. One such problem was found when it was noticed that the Measurement While Drilling (MWD) values the directional engineer was plotting on his maps showed the well to be on course in the section view and was clearly low with respect to the well plan from our cross section. It turned out the directional vendor was not using the correct magnetic declination and they were using an inappropriate vertical section plane. They could not correct the maps in time and we had to geosteer and control the directional entirely from our cross sections.

In budget period 2, a review of the J-17 Logging While Drilling (LWD) response as it related to our geologic model showed several inconsistencies. Other data suggested our geologic model was accurate and the interpretation problem was due to the LWD algorithm. The interpretation algorithm was deemed too simplistic for the heterogeneity of the formation. Additional log data was gathered from surrounding wells and digitized for a new resistivity model.

The new algorithm uses pairs of curves and their separation. Researchers used an iterative process where the inputs to the mathematical model and geological model were changed until a proper fit was achieved. One of the limitations to the mathematical model is that it creates a simplified cross section from which the modeling program calculates the modeled curves. This cross section is not as accurate as the ones from EarthVision™ which are created from a 3-D geological model calculated from well data (FIGURE 4).

Researchers correlated the H_{x0J} and H_{x0B} markers for all the wells in the modeled area. The H_{x1}, H_{x0}, H_{x2} and H_x markers were also checked. Before drilling, due to time constraints, only the wells adjacent to the J-17 proposed well course and selected wells beyond those were originally correlated. The new data set was created and entered into an EarthVision™ data base. The exported data was then modeled.

The log signature on the recorded while drilling log (RWD) showed a fault at 1,061 m (3,480 ft). A fault plane coincident with the fault pick, parallel and offset to the Maine Avenue fault was created. The Maine Avenue fault dips West and old map interpretations showed an extension curving toward the point where J-17 crossed the fault. When this West dipping fault was added to the structure, the resulting geological model was unsatisfactory. The fault was then rotated to dip East and incorporated into the structure. The shale layers above the H_{x0} and H_{x0J} were also included in the model. It should be noted that the fault was modeled with only 1.2 m (4 ft) of displacement and no definitive electric log fault picks were identified.

Researchers studied the data further and created a second set of resistivity inputs for the formation to the West of the fault. A second mathematical model was created and spliced to the first at the fault. As can be seen from the attached cross section (FIGURE 4), the modeled curves, RWD curves and the geology correlate nicely. The fact that the resistivity inputs had to be changed to create a second mathematical model, to accurately depict the formation west of the fault, is an indication of the heterogeneity of the formation. The inputs are based on the offset wireline logs, vertical and horizontal resistivity response extracted from the RWD log and changes noted from the geological model created with EarthVision™. We suspected a lithologic and saturation change before drilling and the Anisotropic inversion modeling agreed well with this.

Modeling the "Fo" sand for horizontal well A-112

Horizontal well A-112 was drilled with conventional LWD tools with the survey and recording instruments 18.29 m (60 ft) behind the bit. The well was geosteered by plotting the position of the surveys on an Earth Vision cross section cut through the proposed well course and on maps of selected horizons. Both cross sections and maps were extracted from the geological model. The LWD was correlated using the stratigraphic cross sections and comparing where the well plotted on the Earth Vision cross section and maps. The azimuth of the well followed the plan very closely and therefore only one section was needed. The well penetrated the "F1", then the "F1 B", "Fo" again and finished with the "Fo2" sand. The "F1 B" penetration was unintentional but the interval shows good oil saturation throughout. FIGURE 5 shows the eight resistivity curves along with the annotated well path and cross section from the geological model. The dashed lines on the resistivity tracks represent the deeper reading amplitude curves and the solid lines are the shallow reading phase resistivity curves. For the actual resistivity values see FIGURE 6. FIGURES 5 & 6 are at the same scale so the log values and geology can be more easily compared and interpreted.

The cross section through the well course and logs were reviewed. It was discovered that the signature of the ten LWD curves did not make sense with the geological model between approximately 1,234 m to 1,385 m (4,050 ft to 4,545 ft). The logs show the following sequence:

1. A polarization horn on the 2 MHz resistivity log at 1,250 m (4,100 ft) indicating a sand\shale boundary which is a mirror of the "Fo" first crossing.

2. Shale from 1,256 m to 1,267 m (4,120 ft to 4,155 ft) indicated by Gamma-Ray also shows mirror of "Fo" first crossing.

3. Sand from 1,267 m to 1,335 m (4,155 ft to 4,381 ft) with nearly the same 2 MHz phase resistivity value as the “Fo” sand just penetrated but the polarization horns have different magnitude.

4. Long shale section from 1,335 m to 1,385 m (4,381 ft to 4,545 ft).

5. Sand starting from 1,385 m (4,545 ft) with lower resistivity than observed up the hole.

At the time of drilling Well A-112 it was thought that the shales at 1,256 m (4,120 ft) and 1,335 m (4,381 ft) were probably an unmapped small shale inside the “Fo” sand. This meant that the sand at 1,267 m (4,155 ft) would be the upper “Fo” sand. Further scrutiny of the cross section, TVD log, and mapped area suggested that the well was structurally higher and that the “F1 B” sand was intersected at 1,267 m (4,155 ft). It was reasonable to assume that the shale intersections at 1,256 m (4,120 ft) and 1,335 m (4,381 ft) belong to the same shale because the well path moved up and then down in section. If “F1 B” was crossed then the shale intersections belong to the shale above the “Fo” sand and not an unmapped shale within the “Fo”. A closer look at the data was necessary.

It was suspected that the offset well A-192's markers were causing the modeled structure to be too high. This observation was based on a subtle difference of the “Fo” VSS values between A-192 and other offset wells. The “Fo” appeared slightly high but the correlation was verified as true. This meant that the well survey was most likely the problem. The shale above the “Fo” was sketched in, lower than originally shown on the cross section, to connect across the questionable interval in the well section. The horizontal lateral for Well A-112 then appeared to enter and traverse the lower “F1 B” sand from 1,267 m (4,155 ft) to 1,335 m (4,381 ft). This hypothesis was tested by eliminating all A-192 markers and building a new model. The well cross section extracted from the revised model appeared more consistent and made much better sense with the log curves. The model was further refined by making the “Fo” shale thinner in the problem area and using tops correlated on to the A-112 log. The “Fo” shale thickness was estimated by averaging the thicknesses of the shales in surrounding wells. In addition, vertical thickness was calculated from the Well A-112 LWD between 1,253 m (4,110 ft) and 1,267 m (4,158 ft) MD. The thickness value was calculated to almost 0.9 m (3 ft) (instead of 1.2 m (4 ft)), however the strata is falling away in this interval giving a lower than actual value calculated from vertical depths. The final cross section makes good sense with the logs (FIGURE 5).

The net result of the modeling changes was that the top of the “Fo” shale moved down 1.98 m (6.5 ft) at the highest point. The structure turned out to be flat in the area of A-192. The original 1.98 m (6.5 ft) of rise was over a 183 m (600 ft) length in cross section. This magnitude of warping should be searched for before drilling any future horizontal wells in the Tar Zone, Fault Block V.

Due to the realization that the well entered the lower part of the "F1 B" sand, the perforating procedure was changed to perforate 'high side' instead of 'low side' in the area of the "F1 B" sand. A 'low side' perforation may have resulted in perforating the shale on top of the "Fo" sand. Note the perforations and cement plug annotations are also shown in FIGURE 6.

It should be noted that the bottom of the "F1 B" sand was entered below measured depth 1,266 m (4,155 ft) and exited at 1,335 m (4,381 ft) at which point the "Fo" shale top ("Fo"SHR) was re-entered. The 'R' designation shown on FIGURES 5 & 6 indicates that the horizon was repeated on the log. The 1 and 2 after the 'R' indicates multiple intersections. For example, "Fo"R1 means that the "Fo" top was repeated for the first time and the "Fo" top intersected a second time. As can be seen on FIGURE 6, the tops match fairly well with the model in the "F1" to "F" interval.

Review of FIGURES 2, 5, & 6 reveals that Well A-112 occupies a high structural position and that there is still good oil saturation in the "F1" to "F" interval. There is also good oil saturation in the interval above "F1" but that interval is beyond the scope of this study. The "F1" to "F" interval has 15 ohms resistivity in all but the "Fo"R2 and lower "Fo2" sands. The latter was expected but the former was not. The "Fo"R2 shows 9 ohms, which is a 6 ohm decrease over a 4.6 m (15 ft) loss in structure compared to the "Fo"R1. The 15+ ohms resistivity in the "Fo" / "Fo"R1 and the "Fo2" is higher than seen in Well FR-110 (FIGURE 7). A comparison of the 1988 FR wells and Well A-112 is shown in Table 3 below. The wells are arranged so they proceed up structure.

Well	"F1"	"F1B"	"Fo"	"Fo2"
FR-110	9 ohms	12 ohms	9 ohms	14 ohms
FR-109	9	14	9	10
FR-111	9	13	12	14
A-112	9	11 & 14	16 & 9	15

Table 3

The resistivity for Well FR-110 appears anomalously high in the "Fo2" and the resistivity of the "F1" for all the wells is constant. Otherwise, the best saturation is up structure but not significantly greater up structure than down structure for most of this interval. This suggests significant reserves may remain down structure. The area of "No Fo production" was barely penetrated and only by the "Fo2". Because the resistivity shown in Table 3 is fairly consistent in the “Fo2", one could conclude that the probe into this area was successful and that another drainage point is justified.

Modeling the “T”, “Orange” and “Red” sands for horizontal well L-233

For the purposes of modeling and drilling, the T through T7 sands were picked on logs in the proximity of well L-610. While investigating the extent of the high resistivity seen in the L-610 e-log (FIGURE 8), another sand was identified and mapped to the West and Southwest. The stratigraphy and model area are as follows:

Stratigraphy

Name	Lithology	Est. Thickness	Modeled	Method
T	Sand	9 feet	Yes	Well Data
ORSH	Shale	8	Yes	Well Data f/ EV data base
RED	Sand/Shale	4	Yes	Well Data f/ EV data base
REDSH	Shale	15	Yes	Well Data f/ EV data base
TU	Sand/Shale			
	Total	32.0 feet		
FSH	Shale			Well Data + F reference
F	Sand	Varies	Yes	Well Data

Model Range: (Ford Coordinates)

	X	Y	Z
Minimum	9000	-12000	-2800
Maximum	15000	-6500	-1800

One fault was modeled - the Daisy Avenue B-1. The horizons modeled are those shown above. The goal of the modeling is to define the extent and geometry of the geology. Within the sands, the oil saturation will be modeled to determine the best place to drill.

The Geologic modeling consisted of the steps as follows:

1 Correlate sands using “paste up” stratigraphic sections throughout area. Sections corrected to vertical by shrinking based on well drift angle at “T” sand. Hang on “T”.

2 Load Newilma data base and create Earthvision data base for local markers. Export data from both data bases.

3 Create initial model using stratigraphy shown above. Identify erroneous data.

4 Check correlation and entry for all erroneous data.

5 Create 3D geological model with and without smoothing.

6. Quality control using 3D model and cross sections.

7. Create data set with points in middle of sand targeted for modeling.

8. Add parameters to data points and model saturation in 3-D.

After the stratigraphic sections were correlated, it was noticed that there were two sands showing resistivity in an area not previously produced. This was the genesis for the L-233 project and the sands were designated orange and red. While the orange sand was traced to the Northwest and appeared to be from a channel trending Northwest-Southeast, the red sand did not appear to be channel derived.

The first model was created and revealed that the Orange and Red sands were on lapping the Wilmington anticline similar to that seen in Fault Block II. There is also a ‘pod’ of orange sand seen in the eastern portion of the reservoir (FIGURE 9). In cross section it can be seen that there is a low that was filled with sand probably sourced from the east. Coincidentally the T2 highly saturated oil sand seen in penetrating well L-610 is in this same area.

An oil water contact is suggested by wells L-202, L-213, L-230, L-506, L-504. These wet wells have an Orange sand that lies below -2860 vss. Well L-229 also lies below this point but the orange sand is partially oil saturated as indicated by the log. The log for well L-229 looks a lot like the log for well L-226. This suggests the survey for L-229 is incorrect. L-229 is the farthest east with the longest section for any of the Pier G wells. The east-west orientation may have influenced the magnetic survey placing the well too far south. An inertial survey would give the true position to L-229. Well L-225 may also be slightly out of place.

The red and orange sands were studied. Full size copies of the logged interval were made and a computer spread sheet was created. Entries to the spread sheet include the following:

1. Resistivity of deep induction tool (e.g. Schlumberger 6FF40) read from log.

2. Sand percentage calculated from SP using S, F0 and Shale in between as baselines.

3. Measured depth Sand thickness.

4. Angle of well bore at Orange sand.

5. Resistivity of wet sand - lower S sand.

6. Corrected resistivity of deep induction tool 6FF40 read from log. Corrections read from Schlumberger Log Interpretation Charts Page 6-12 under the Rcor section. The specific chart read was for a shale resistivity = 2 ohm-m. It should be noted that the shales encapsulating the studied sands have a resistivity of 1.8 ohm-m.

Sand thickness, water saturation (Sw), oil saturation (So) and corrected oil saturations were calculated. The sand thickness was calculated from the measured depth thickness * Cosine of the well angle at the Orange sand. The calculated saturations assumed clean oil sand so the Archie formula could be used.

Archie formula: Swn = F*Rw/Rt.

F was calculated using the Humble formula $F = 0.62/ø^{2.15}$.

Porosity from up structure well FJ-204 Neutron Density average porosity in sand time equivalent to Orange sand.

Rw was calculated from the wet 'S' sand in each well

where S = 1, n = 2, Rt = log resistivity or wet sand, F calculated using 'S' sand average porosity from Neutron Density in well FJ-204.

There was some concern that the sands might be shaley and that the Archie method of So calculation is inaccurate. The SP for a large number of the wells shows something other than a clean sand. The deflection is not the same as the oil saturated 'Fo' or water saturated 'S' sand. Sand thickness was plotted vs So but no clear correlation was found. Sand percentage vs height above the oil water contact (OWC) was plotted and a trend could be seen. The well logs showing wet sands show 100% sand where as the logs indicating oil sands show something less as in the L-225 e-log

(FIGURE 10). This suggests the SP is being suppressed by the oil content therefore the sand percentage calculation is incorrect. Well FJ-204 has a small sand at 842 m (2,762 ft) time equivalent to the Orange sand. The neutron and density curves lie directly on top of each other indicating a very clean oil sand. Lacking Neutron-Density or sonic logs in the study area, the only evidence for sand cleanliness is the wet sand SP deflection and clean time equivalent sand shown in FJ-204.

FIGURE 11 shows a contour map of the 'T16' sand with the measured depths shown along the well course. The first part of the well went as anticipated with the exception that the horizons came in higher than expected. After the casing was cemented, the geological model was block shifted 2.1 m (7 ft) vertically up to match the 'OR' marker on the log (FIGURE 12). When the casing shoe was drilled out, the well traversed the 'T15' sand and appeared to bottom out in the top of the 'T16' sand. The geological model appeared to agree with what we were seeing on the real time log. That is, the bed thicknesses and top locations came in as expected.

The well continued up and horizontal, topping in the 'T15' before heading down to catch the lower horizons. Plotting the well course on the geological model showed that the well traversed through the shale between the 'T15' and 'OR' sands but there was no indication on the log that a shale was crossed (FIGURE 13). We concluded that the shale wasn't present or the 'T15' bed thickness had increased. The more likely scenario is that the shale is not present between the 'T15' and 'OR' sands. Either way, the reservoir thickness increases.

From FIGURE 13 it can be seen that the well intersected the top of the 'OR' sand, scraped the 'OR' top and dove down structure. Note the long polarization 'horn' between the 'T15' markers shown between 152 m (500 ft) and 183 m (600 ft) of section on FIGURE 13. The geological model indicates that the next sand / shale boundary is the bottom of the 'OR'. The rest of the interpretation is questionable and requires further scrutiny by the Geosteering team to figure out what happened.

The shale below the 'OR' appeared to increase in thickness from 0.6 m (2 ft) to 1.8 m (6 ft) thick (at 244 m (800 ft) to 274 m (900 ft) of section, FIGURE 13). This means that the 'T15' disappeared even though the projected pinch out is more than 122 m (400 ft) up structure. Another possibility is that the well and bed relative angle could have changed. For the shale to increase in thickness, the well would have to be at an angle similar to the beds.

The next sand top appears to be the 'T16' which agrees with the model. The thickness turned out to be 0.6 m (2 ft) thick and we drilled through it quicker than anticipated. This was confusing as wells FG-002 0, FG-003 0 and L-225 show 1.8 m

(6 ft) of thickness for the 'T16' . These wells are within 30.5 m (100 ft) of L-233 (FIGURE 13). Well FG-003 3 is slightly farther away but shows a 'T16' thickness closer to that observed in well L-233.

The interpretation of the log for the rest of the well requires further work. L-233 was supposed to intersect the 'Red' package of sands and shales. One possibility appears to be that we intersected the top of the 'Red' between 365 m (1200 ft) and 396 m (1,300 ft) of section (FIGURE 13) as predicted by the model. The rest of the well was drilled stratigraphically down the 'Red' sand and shale package. We were surprised that we did not intersect more good oil sand as shown in the log for well L-225 (FIGURE 14) because we were within 15.2 m (50 ft) of that well. Well L-233 was north of L-225 and perhaps too close to the 'Red Sand' pinch out

With the exception of the 'Red' package, the resistivity was a little better than expected. The tops came in close to predictions. This gives us more confidence to drill these thin sand packages but also gives us an awareness of what can happen. We were perhaps too close to the 'Red' pinch out line and future wells should be placed farther down structure of the proven existence of the sand.

The results received from Baker Hughes Inteq (BHI) are different than what was believed to be true at the time the well was drilled as well as previous conclusions. Investigators at BHI determined that the tops of the marker beds picked on the log are above the tops shown by the geological model. They came to this conclusion by processing the L-225 log as if it were drilled horizontally. In effect stretching the log to the angle of the L-233 well. By displaying the processed L-225 log with the RWD log (FIGURE 15) BHI could match the log character of the two logs. A review of the final log shows a fairly good fit. To accomplish a good fit, BHI changed the azimuth, dip and thickness of the beds slightly. One major difference is that the polarization horn shown from 1,100.6 m to 1,140.2 m (3,610 ft to 3,740 ft) is caused by the well bottoming in the T16 sand rather than topping in the OR/T14 sand as previously concluded. That is a difference of 6.4 m (21 ft) vertical as shown on the geological model constructed by Tidelands. BHI stated that there were no faults indicated on the log.

The Tidelands model was initially block shifted 2.1 m (7 ft) upward to match the 'OR' top to the pick correlated on the Real time log. As can be seen in FIGURE 16 the end of the well is hard to explain. The BHI conclusions fit the log much better over that portion of the well.

For this study, a 4.6 m (15 ft) downward shift was applied to the well data and then plotted in section (FIGURE 16). The downward shift in the L-233 well data is the same as a 4.6 m (15 ft) upward block shift of the geological model. The beginning of the well would then be 4.6 m (15 ft) low at the 'OR' top but the rest of the well starting at section 61.0 m (200 ft) in FIGURE 17 shows a very good fit. This is without changing the strike, dip or thickness of the beds the way BHI did. The main difference is that the polarization horn shown from 1,100.6 m to 1,140.2 m (3,610 ft to 3,740 ft) is caused by the well topping in the T16 sand rather than the bottom, the way FIGURE 15 shows. It makes better sense for the well to be topping in the T16 rather than bottoming as the well is moving up stratigraphically due a combination of the formation falling away and an increase in drift angle from 85 to 88 degrees.

A total upward block shift of 6.7 m (22 ft) is required to match Well L-233 to the geological model. Four point six meter (15 ft) of that total is required to match the last 396.3 m (1,300 ft) of the well. Why would the additional upward shift be required for the later part of Well L-233? Revisiting FIGURE 18 shows that the log picks below the OR have the following relationship to the geological model.

T15	0.61 m (2 ft)	high
T16	0.91 m (3 ft)	high
ORSH	1.83 m (6 ft)	high

The closer L-233 is to the FG-002 & FG-003 wells, the higher the relative position of the log marker pick to the modeled geology. This would suggest that the data from the original holes for FG-002 and FG-003 are artificially pulling down the tops of the marker beds.

An investigation of the surrounding wells shows that the re-drill of wells FG-002 and FG-003 are 4.6 m (15 ft) above the T16 structural layer calculated from the geological model. Those wells were removed from the data set prior to completing the final model due to being so far off structure as defined by all the other wells. The wells were all drilled at about the same time - early to mid 1960's. The surveys were checked and no irregularities found. As it turns out, those wells were probably correct and the surrounding wells have a problem. The wells near the end of Well L-233 could be located incorrectly as they are more than a 304.9 m (1,000 ft) beyond their surface site in an easterly direction. If the nonmagnetic drill collar length was not long enough to counter the Earth's Magnetic field, the direction could be magnetically influenced and therefore the well and horizon tops positioned incorrectly.

The final well log and interpretation and well log are shown in FIGURE 19.

Based on the above conclusions, the tops are picked as follows:

L-233 0	S	812.3 m	2,665 ft
L-233 0	T	862.5 m	2,830 ft

L-233 0	T1	869.9 m	2,854 ft
L-233 0	T2	880.9m	2,890 ft
L-233 0	T7	923.5 m	3,030 ft
L-233 0	OR/T14	964.6 m	3,165 ft
L-233 0	T15	975.9 m	3,202 ft
L-233 0	T16	988.7 m	3,244 ft
L-233 0	ORSH	1004.0 m	3,294 ft
L-233 0	ORSH	1048.5 m	3,440 ft
L-233 0	T16	1101.8 m	3,615 ft
L-233 0	T16	1135.0 m	3,724 ft
L-233 0	ORSH	1192.0 m	3,911 ft
L-233 0	RED	1238.6 m	4,064 ft
L-233 0	REDASH	1257.5 m	4,126 ft
L-233 0	REDA	1319.4 m	4,329 ft
L-233 0	REDB	1345.6 m	4,415 ft
L-233 0	REDSH	1371.5 m	4,500 ft

M Pulsed Acoustic Logging

Although compressional velocities have been determined in all but one well, shear wave velocities have only been obtained in four of eight wells logged. The ability to detect the formation shear wave was greatly hampered by the strong presence of Stonely (tube) waves arriving simultaneously with formation signals. In modeling wave propagation in cased holes research suggested that good cement/casing bond can actually degrade low frequency waveforms in certain situations. Trapped energy is propagated more efficiently when cement/casing thickness is large and the formation is soft. This effect was realized in Wilmington Field logging runs where the initial acoustic tool design yielded better results due to its lack of energy output below 1 kHz. Neither standard casing bond logs nor specialty logs that measure the azimuthal variation of bond using acoustic techniques provided clear predictions of the quality of the multi-pole acoustic logs.

Cased hole shear wave logging in slope and basin clastic reservoirs like Wilmington is extremely difficult due to both wellbore conditions and the similarity of the dipole mode move out and that of the Stonely (tube) wave. Although, when a shear wave is recorded it is possible to discriminate between watered out and potentially productive zones.

Due to the low success rate of acquiring the shear wave, researchers decided not to log any other wells until the technology improves. Unfortunately, the technology never improved to a point we felt confident enough to try them again.

This was the least successful of the activities and a summary of our work is as follows.

Well M-499 was drilled in 1993 as an infill well to produce the Upper Terminal Zone of Fault Block IV. It was logged both open hole and cased hole with a comprehensive log suite3. Excellent open hole sonic data were obtained. Cased hole compressional and shear logs from the MPI (XACT) tool were similar to open hole results. Cased-hole shear data required filtering to remove a strong tube wave arrival prior to processing the data. The XACT tool used in this well had an early version of the receivers without calibration and acceleration correction, and with downhole (analog-domain) summing/differencing to enhance monopole or dipole energy, respectively. The XACT source was an old version with a center frequency in P of about 3 kHz and in S of 1.2 kHz.

The casing bond tool (CBT) revealed excellent bond in the zone of interest. There was little casing arrival, and a well developed formation arrival could be seen throughout much of the hole. The Ultra-Sonic Imager (USI) showed moderately good cement bond but some fluid behind the casing.

Recompletion candidate well FY-67 was logged with the MPI tool and the Schlumberger tool. A dogleg in the well at 475.6 m (1,560 ft) made passage of the MPI tool difficult, and the centralizers on the tool were removed and replaced with wraps of duct tape. Compressional waveforms recorded by the Dipole Shear Imager (DSI) and the XACT agree quite well except were low amplitudes confuse the analysis. DSI Lower Dipole data are better than Upper Dipole data, but no reliable shear velocities could be determined in either case. The XACT tool did not provide shear velocities either.

The USI tool revealed fairly poor bonds, lots of water behind casing, above 914.6 m (3,000 ft). Below the 914.6 m (3,000 ft) mark average bond appears to be better than in well M-499 with relatively few intervals in which fluid is predicted behind casing. There was a distinct difference in bond quality between the upper and lower sides of the hole, with the low side having better bond. Throughout the well there were indications of gas behind casing, but in amounts less than indicated in well M-499.

Inspection of the Schlumberger monopole data reveals a significant early casing arrival throughout much of the hole, although a good formation arrival can be seen later in the wave train. The change at 914.6 m (3,000 ft) is also clear on the waveforms; below that depth the casing arrival is less distinct. If this can be compared directly to the CBT results in well M-499, it suggests a much worse bond in well FY-67, in contrast to the USI data which indicated a slightly better bond.

An attempt to re-log the well with a modified MPI XACT tool was terminated when the tool could not pass through the known dogleg at 475.6 m (1,560 ft).

Well 167-W was originally drilled in 1983 with a deviation of 28-32 degrees. Steel casing extends down to 1,229.3 m (4,032 ft), below which a slotted fiberglass liner was installed for sand control and corrosion protection. It was logged twice with the MPI XACT tool and once with the Schlumberger DSI tool along with a USI for cement bond evaluation. Compressional waveforms recorded by the DSI and XACT show similar variations downhole. Velocities determined from the monopole data of both tools agree quite well except where low amplitudes confuse the analysis. DSI Lower Dipole data are better than Upper Dipole, but no reliable shear velocities could be determined in either case. The XACT data did not provide shear velocities either. DSI data provided compressional and probable shear velocities in the fiberglass section of the hole.

The USI reveals quite variable casing bond in well 167-W. Bond is similar to that of well M-499. Unlike well FY-67, there is no clear difference in bond quality between the upper and lower sides of the wellbore.

Recompletion candidate well X-32 was logged with the MPI XACT tool. This well was originally drilled in 1946. No shear wave data were obtained, but reasonable compressional wave velocities were determined from the monopole data.

Recompletion candidate well Y-63 was logged on two separate occasions with the XACT tool. Neither compressional nor shear wave velocities could be determined from the first logging sequence. A return visit with a modified XACT tool and tube wave absorber also did not yield acceptable data. Fourteen different combinations of receivers, sources, spacers, and attenuaters were tried and did not reproduce the data from the first logging sequence.

The XACT tool has been undergoing a number of design modifications since the initial logs were recorded in well M-499 in 1993. The original tool had four "receivers", each of which consisted of 4 crystals mounted at 90o intervals. To record monopole data the signals from crystals mounted 180o apart in line with the source are summed downhole. To record dipole data the crystals from receivers mounted 180o apart in-line with the source are differenced downhole. The receivers are not calibrated, so the sums and differences do not perfectly discriminate the appropriate phases. The source is a pulse of fluid which acts across a membrane on the wellbore fluid, in such a way that it is in phase across the tool in monopole mode and out of phase across the tool in dipole mode. The source was not perfectly "balanced", so some monopole energy is generated in dipole mode, and some dipole energy is generated in monopole mode. In compressional mode the center frequency is about 3 kHz. In dipole mode the center frequency is about 1.2 kHz.

A number of design changes were made to the XACT tool prior to logging the first wells in this project. First a new receiver section was developed, in which the crystals were remounted to cancel accelerations imparted to the body of the tool by the fluid in the borehole. Also, the receivers were calibrated to improve the summing and differencing to enhance mode discrimination. Finally, the receivers were configured so that summing or differencing could be achieved uphole (A and C mode) or downhole (A+C mode; A-C mode). A new source (XMTR) was developed which was more carefully balanced to produce pure monopole or pure dipole energy. This source also generated significantly more energy in each pulse. And, it was modified to generate a dipole mode with a center frequency of about 800 Hz. This tool was run during August ,1995, in holes OB2-3, 167-W, FY-67, X-32 and Y-63. In several of these holes the original transmitter was also run for comparison.

In general, data from the original transmitter appears to be better because it excites less low frequency (~600 Hz) tube wave energy.

A tube-wave absorber was developed to attenuate fluid-borne energy. This section was re-run in FY-67 (it didn't get past the dogleg) and Y-63 in December, 1995. Based on data recorded at 106.7 m (350 ft) in a test well at Stanford, the maximum amplitude reduction using one absorber is about 3x (10dB), with little attenuation outside the stop band (250-1750 Hz).

Schlumberger's DSI tool records on 8 receivers up- and down-going dipole data from two different sources, mounted 90o to each other, and monopole (higher-frequency) data from a third source. All three data sets are analyzed independently using STC processing. Log quality control consists of color displays of the coherence as a function of slowness with picks, and the filtered waveforms as a function of time.

Receiver data are differenced or summed downhole, thereby making it difficult to unambiguously determine the mode type where dipole and tube/Stonely waves interfere.

M Recompletions

New well L-233 was horizontally drilled to, and open hole gravel packed across the relatively thin 1.5 m to 3.0 m +/- (5 to 10'+/-) thick each "T15", "T16" and "Red" Sands in the lower Tar Zone, Fault Block V using long radius steerable directional tools in November, 2001. The directional plan included building and turning at an 8.36N/30.5 m (100 ft) dogleg severity (DLS) to a final angle of 82.1N inclination at casing point. After setting 19.4 cm (7-5/8 in) casing, the plan was to slowly increase angle to as much as 89.2N and then drop angle near bottom to 84.8N at TD while moving gradually from the "T15" to the "T16", and then to the "Red" Sands. The bottom hole location and therefore the directional plan were altered slightly shortly before the well was drilled as requested by Tidelands' geologist to avoid well conflicts and potentially improve well placement within the reservoir.

The well was drilled using LWD/MWD tools from surface casing to total depth at 1,474 m (4,836 ft) measured, 841 m (2,759 ft) vertical. Approximately 219 m (720 ft) of net sand within the intended zones of completion was penetrated over a gross interval of 488 m (1,600 ft). Nineteen point four centimeter (7-5/8 in) casing was run from surface to 984 m (3,230 ft) in a 25.1 cm (9-7/8 in) hole using hour-glass type centralizers and cemented back to 305 m (1,000 ft).

The 17.2 cm (6-3/4 in) liner interval was drilled using a sized calcium carbonate polymer mud system. The bottom portion of the wellbore was isolated using an inflatable bridge plug and a gravel pack liner was gravel packed in the open hole interval using inhibited NaCl brine water. The initial attempt to gravel pack through the cross-over tool above the liner prematurely packed off with about 20% of the calculated volume in place. An additional attempt to gravel pack through the GPC shoe on bottom resulted in approximately an additional 100% of gravel being placed. Indications are that some of this gravel was fractured away into the formation.

Based on problems encountered and processes that performed as planned, the following experience was gained.

Directional Planning: The directional proposal was revised four times within the final week before the well was spudded. The plan was initially modified to hit slightly different completion interval targets. Subsequent revisions were required to avoid conflict wells and have a workable plan. The directional drilling contractor had proposed plans that had too high of a dogleg to be drilled with a steerable assembly (and allow passage of the submersible pump) or not enough lead-in distance to the casing point. A close review of all aspects of the directional plan (not just intersecting the targets) is required before signing off on a plan. Not all directional well planners working for service contractors have sufficient real world experience in drilling complex wells to create the best workable plan. One plan submitted to Tidelands had only 0.3 m (1 ft) of lead-in into the casing point while approaching with an 8N/30.5 m (100 ft) build rate. The final plan had a lead-in tangent section of 30.5 m (100 ft) to allow for catching up if necessary. It is incumbent upon the operator to have the necessary experience and expertise to identify these shortcoming in the planning stage before they become a real world problem and additional expense.

Directional Plan Execution: The well was drilled using a steerable (MWD) system. After making a planned small adjustment for clearance reasons below the surface casing shoe, the well was kicked off at 625 m (2,050 ft). Build and turn was scheduled for 8.36N/30.5 m (100 ft). The well fell behind the proposed build and turn which resulted in playing catch up. A total of 57.6 m (189 ft) of the well was drilled with a DLS in excess of 10.0N/30.5 m (100 ft), with a maximum DLS of 12.8N/30.5 m (100 ft). The well was on plan at about 945 m (3,100 ft) MD, however a miscalculation by the directional driller in the amount of follow thru build resulted in the well intersecting the completion interval with less than the needed (and planned for) inclination. The 19.4 cm (7-5/8 in) casing was set at 985 m (3,230 ft) with an inclination on bottom of 79.6N versus the planned inclination of 82.1N. After setting 19.4 cm (7-5/8 in) casing, a 17.2 cm (6-3/4 in) hole was drilled out the shoe in a high rate build oriented mode in an attempt to stay within the thin sand and catch up to the well proposal. An additional 7.9N of angle was built within the first 30.5 m (100 ft) below the casing shoe which resulted in an average DLS of 11N/30.5 m (100 ft) for 18.9 m (62 ft). It is this author's opinion that during this rapid change in inclination, Tidelands' (and the service company wellsite Geosteering Engineer) became confused as to the relative location of the well within the "T15"/"T16" sand package. It was assumed that the wellbore was still within the "T15" sand when in fact it had crossed the interface (thin shale) into the "T16" sand undetected due to the steeper than planned angle of approach. This in turn resulted in the mistaken attempt to go structurally lower to find the "T16" sand and the penetration of the "Red" sand where it was relatively undeveloped. The end result was that the bottom 213 m (700 ft) of the well was drilled through shale with no commercial sands present.

Open Hole Horizontal Plug Back: The well was plugged back using a bull-plugged inflatable packer. After determining from the Multiple Propagation Resistivity/ Gamma Ray LWD log that the bottom 213 m (700 ft) of the well was non-productive, it was decided to eliminate this interval from the completion. Because of the near horizontal nature of the wellbore, cementing this interval was not a viable option. Instead, a 10.8 cm (4-1/4 in) hydraulically set inflatable packer was run and set with 11.0 MPa (1,600 psi). A second ball was dropped and the hydraulically actuated releasing tool was activated with 15.2 MPa (2,200 psi). After circulation the well, the bridge plug was re-tagged to verify its placement. This option was readily available (no waiting time) and less expensive while reducing the likelihood of cement damage across the proposed completion interval. The hydraulic setting tool reduced the likelihood that the packer would set prematurely while running in the hole, and allowed for possible rotation if necessary to get the packer to the setting depth.

Gravel Packing through the Liner Shoe: After preparing the liner interval, the 11.4 cm (4-1/2 in) stainless steel wire-wrapped liner was run to plug back TD without incident. The permanent gravel pack packer was hydraulically set and the viscous polymer pill was circulated out as planned through the GPC shoe. After pulling the stinger out of the GPC shoe, the gravel packing process began. After pumping approximately 27 sacks of gravel at 0.7 ppg concentration, the pack prematurely pressured up. The service company was consulted for options at which time it was decided to attempt to pack the well through the GPC shoe. The string was pulled to lay down the cross-over tool and the stinger was rerun and stung into the GPC shoe. Circulation was established but at significantly higher (but manageable) pressures. An additional 120 sacks of gravel was displaced through the shoe at 0.4 to 0.5 ppg. Return volumes varied between approximately 75% to less than 3% at the end of the job. The low volume of return fluid at times during the job indicated that the gravel (and fluid) was being fractured into the formation rather than contributing to the gravel pack. A total of 118% of the calculated gravel requirement was placed in the well during the two stages. No attempt was made to verify the actual gravel pack coverage prior to running the completion equipment. The well has been on production since December 7, 2001 producing sand free. As of December 31st, 2001, the well is producing at a rate of 23.2 m^3/d (146 b/d) gross, 20.3 m^3/d (128 b/d) net, for a 12.3% water cut with 359 m (1,179 ft) of fluid above the pump (FIGURE 20).

A rig moved on proposed recompletion Z-47 in early April, 2001, and perforated the Tar Zone, Fault Block V. Tar Zone Sands were completed by selectively perforating the 24.5 cm (9-5/8 in) casing with four shots per foot across the "S", "T", "D1", "F1", & "Fo" sands. An 11.3 cm (4-1/2 in) wire wrapped screen was the gravel packed across the perforated interval with size 30-40 gravel for sand control.

Well Z-47 was placed on rod pump on May 23rd, 2001, and initially produced 72 m^3/d (453 b/d) gross, 1.4 m^3/d (9 b/d) net, for an 98.0% water cut with 350 m (1,149ft) of fluid over the pump. As of June, 2001, the well averaged 61 m^3/d (387 b/d) gross, 4.6 m^3/d (29 b/d) net, for a 92.5% water cut. This is typical production response as the well cleans up.

As of late August, 2001, the well averaged 44 m^3/d (275 b/d) gross, 2.4 m^3/d (15 b/d) net, for a 94.5% water cut with 11 m (36 ft) of fluid above the pump. The well was mildly acidized in September, 2001, and initially produced at a rate of 164 m^3/d (1,033 b/d) gross, 6.0 m^3/d (38 b/d) net, for a 96.3% water cut with 0 m (0 ft) of fluid above the pump (FIGURE 21). Unfortunately, the rate declined rapidly to pre-stimulation levels due to scale deposition. The well will be acidized again increasing the volume and strength of the acid.

A rig moved on Budget Period Two horizontal Well A-112 in late November, 2000, in order to remove the steam injection equipment and install the production equipment. A-112 steaming was completed in October, 2000. A total of 19,483 m^3 (121,800 bbls) of cold water equivalent steam was injected into the well in order to consolidate the sand. The well was RTP'd in early December, 2000.

Initial production was 126 m^3/d (791 b/d) gross, 0.5 m^3/d (3 b/d) net, for an 99.6% water cut with 528 m (1,733 ft) of fluid over the pump. Production temperatures averaged 103°C (218°F). In December, 2000, the well averaged 150 m^3/d (940 b/d) gross, 2.4 m^3/d (15 b/d) net, for an 98.4% water cut. It is very typical that steamed wells produce at very high water cuts for the first four to six weeks of its productive life.

As of December, 2001, the well averaged 152 m^3/d (960 b/d) gross, 11.1 m^3/d (70 b/d) net, for a 92.7% water cut with 114 m (374 ft) of fluid above the pump. The production temperature as of December 31, 2001, was 62°C (154°F). Due to injection production restrictions we will not increase the gross production of A-112 until injection can be increased in the surrounding reservoir (FIGURE 22).

Well A-112 was originally spudded in mid April, 2000. A 25.1 cm (9-7/8 in) hole was drilled down to the target interval using long radius directional tools. The directional plan included building angle slowly at 4 degrees per 30.49 m (4 degrees per 100 ft) rate to a final angle of 87.3 degrees inclination and then dropping the angle near the end of the well to 79.3 degrees. Well A-112 was drilled using Logging while Drilling (LWD) and Measurement while Drilling (MWD) tools from surface casing to a total measured depth of 1,497 m (4,910 ft), 727 m (2,385 ft) vertical depth. Approximately 274 m (900 ft) of net sand within the intended zones of completion was penetrated over a gross interval of 351 m (1,150 ft). Casing size 19.4 cm (7-5/8 in) was run from surface to 1,497 m (4,909 ft) in a 25.1 cm (9-7/8 in) hole using hour glass type centralizers and a floatation collar 488 m (1,600 ft) off bottom.

The directional proposal for Well A-112 was revised at the last moment for political rather than engineering reasons. For permitting reasons, the surface location needed to remain unchanged, but the bottom hole location was moved approximately 427 m (1,400 ft), or two locations South from the original downhole target location. The directional drilling contractor worked rapidly to respond to our request to alter the plan. The additional potential conflict wells were identified by Tidelands and provided to the directional contractor who in turn entered them into the database. Within days we had a workable directional plan and maps. This contractor, after their previous directional project with Tidelands, made the effort to archive the necessary formulas needed to rotate and translate Tidelands' directional data.

The cross-section derived from Tidelands' geologic modeling was also rapidly modified to reflect the new bottom hole target. This was possible because the area originally modeled covered the new location. Having sufficient area modeled and personnel available to rapidly respond to requests for change is essential.

Even with the most sophisticated 3-D modeling, your plan is only as good as your data. Most of the data used to map the target structure was gathered using 40 to 50 year old instruments. The greater the horizontal displacement, the greater the margin for error, (no vertical wells have been drilled in the vicinity of the bottom hole target). One such error impacted the cross-section used to drill Well A-112. At one point during the drilling, the cross-section indicated that the well should be in the middle of a sand, yet the LWD tools indicated we were in a shale interval. Just one well with erroneous data can significantly impact a thin bed horizontal well plan. After the well was drilled, the culprit well was identified and removed from the model; the log and model were now in agreement.

Removing the need to drill out the float collar and squeeze cement near the end of the well during completion operations is a big time and money saver. In previous horizontal wells, a lot of money and effort was spent cleaning out the last 24 m (80 ft) of casing to uncover the bottom of the well for completion. This usually resulted in the shoe leaking and subsequent installation of a tubing set bridge plug. For this well, the bottom 30 m +/- (100 ft+/-) was drilled into the bottom of the sand and shale below the target sand to preclude completion and verify well location relative to the sand/shale interface. The end of the well was also too close to the lease line to be completed according to California Department of Oil and Gas statutes.

The casing of A-112 was perforated with 0.74 cm (0.29 in) holes, alternately phased 60° off low side, and selectively spaced over the interval from 1,132 m (3,712 ft) to 1,451 m (4,760 ft). The total number of perforations was nineteen. The perforations were pressure washed with an opposed cup tool. A string of thermal insulated tubing with a thermal packer on bottom were installed for the sand consolidation by steam process. A-112 took steam at an average rate of 191 m^3/d (1,200 b/d) of cold water equivalent steam.

Budget Period One horizontal redrill candidate J-17 was started in early March, 1997. The liner was perforated with 0.74 cm (0.29 in) holes, alternately phased 150° and 210°, and spaced one (1) hole per ten (10) foot interval from 1,001 m (3,285ft) to 1,189 m (3,900ft). A string of thermal insulated tubing with a thermal packer on bottom were installed. A total of 8,556 m^3 (53,817 bbls) of cold water equivalent steam was injected into the well in order to consolidate the sand. It was not successful. Note - earlier reports listed the phasing as 0° which was in error.

A rig moved on the well in April, 1998, in order to remove the steam injection equipment and install the production equipment. Unfortunately, the well was found with sand in the liner. Although the well reached the empirically derived cumulative steam injection, it did so at a very low daily rate. J-17 was cleaned out and placed back on steam injection with a portable steam generator capable of higher injection pressures. J-17 steaming was completed in August, 1998. A total of 5,866 m^3 (36,841 bbls) of cold water equivalent steam was injected into the well in order to consolidate the sand. A rig moved back on the well in September, 1998, and found the liner relatively sand free. A casing hole was discovered above the liner top and it was repaired with a sleeve. The well was RTP'd on October 15th, 1998.

Initial production was 163 m^3/d (1,019 b/d) gross, 2.2 m^3/d (14 b/d) net, for an 98.6% water cut with 393 m (1,290 ft) of fluid over the pump. Production temperatures averaged 94°C (202°F). In December, 1998, the well averaged 109 m^3/d (684 b/d) gross, 13.2 m^3/d (83 b/d) net, for an 87.9% water cut with 345 m (1,131 ft) of fluid over the pump. Production temperatures for December averaged 82°C (180°F). It is important to note that the oil production is increasing as the temperature is decreasing. This indicates the thermal effects on oil production are not dominating the process and when the well eventually cools off oil production should remain high. Results are similar to previous DOE recompletion J-120.

In February, 1999, the pumping speed was increased and production increased to 114 m^3/d (720 b/d) gross, 17.4 m^3/d (109 b/d) net, for an 84.9% water cut. In March, 1999, the well averaged 108 m^3/d (680 b/d) gross, 15.9 m^3/d (100 b/d) net, for an 85.3% water cut with 345 m (1,131 ft) of fluid over the pump. Production temperatures for March averaged 67°C (152°F). The rod pump is showing signs of wear as the gross production is slowly dropping off while the fluid over the pump increases.

As of December 31, 1999, Well J-17 was still producing sand free at a rate of 61.8 m^3/d (389 b/d) gross, 12.7 m^3/d (80 b/d) net, for an 79.4% water cut with 475 m (1,558 ft) of fluid over the pump. The production temperature as of December 31, 1999, was 59°C (120°F). This is the native reservoir temperature, therefore we are not realizing any further thermal benefits from the original steam consolidation. The performance of the well is now strictly due to the completion technique and reservoir position identified in our previous geologic modeling.

As of November 2, 2000 Well J-17 was producing at a rate of 142.4 m^3/d (890 b/d) gross, 16.8 m^3/d (105 b/d) net, for an 88.2% water cut with 232 m (763 ft) of fluid over the pump. The production temperature as of November 2, 2000, was 51°C (123°F). The well was subsequently tested 11 days later and oil production had dropped to 4.0 m^3/d (25 b/d). Also, the producing fluid level had dropped to 118 m

(387 ft).

J-17 was pulled in January, 2001, to investigate this sudden drop in net production and sand was found up to the first perforation. The well was cleaned out and placed back on production but sanded up again a short time later. An inner liner was installed and the well was RTP'd in October, 2001. As of December, 2001, the well averaged 11.8 m^3/d (74 b/d) gross, 8.6 m^3/d (54 b/d) net, for a 27.0% water cut with 13.9 m (46 ft) of fluid above the pump (FIGURE 23).

The original success of J-17 had generated additional interest in the “Hxo” sand. As a result, earlier DOE recompletion J-120 was repaired by installing an inner liner in February, 2000. Additional casing damage was discovered during the operation so a scab sleeve was cemented in place above the new inner liner. This work is being done outside the DOE project but does have a connection and results will be reported. In December, 2000, Well J-120 was producing at a rate of 12.7 m^3/d (80 b/d) gross, 6.8 m^3/d (43 b/d) net, for a 46.3% water cut with 418 m (1,371 ft) of fluid over the pump. The water cut is curiously low. Researchers suspected the well was damaged during the inner liner installation and acid stimulated the well in March, 2001. Unfortunately the casing was found damaged and J-120 has been idled as unproducible.

Researchers had perforated idle penetrating Well A-88 in the same “Hxo” reservoir based on our DOE work. Unfortunately, when oil prices crashed in 1998 this project was suspended. An inner liner was successfully installed at the end of March, 2001.

Well A-88 was placed on hydraulic pump on April 3rd, 2001, and initially produced 31 m^3/d (197 b/d) gross, 0.6 m^3/d (4 b/d) net, for an 98.0% water cut with 782 m (2,568 ft) of fluid over the pump. As of June, 2001, the well averaged 88 m^3/d (555 b/d) gross, 3.8 m^3/d (24 b/d) net, for a 95.7% water cut after the pumping rate was increased. As of September, 2001, the well was off production with a stuck hydraulic pump and awaiting a pulling rig (FIGURE 24).

Conventional recompletions in the Wilmington Field have been done by perforating and gravel packing a slotted liner across the perforated interval for sand control. In some cases, recompletions using inner liners have exhibited unusually high initial decline rates. To offset this situation an optimized recompletion technique was developed. Two wells were recompleted with the optimized technique, wells Z-223 and Y-63.

Well Z-223 is a Fault Block V Upper Terminal Zone recompletion candidate that we conventionally perforated across the "Hx", "J", "Z", and "W" sands with tubing conveyed guns. Perforations were 1.27 cm (0.5 in) in size, four holes per foot. A wire wrapped screen with 0.025 cm (0.010 in) mesh slots was gravel packed across the perforated interval with 30-40 gravel for sand control. The well was placed on production in December, 1996, (FIGURE 25) but appeared to be damaged despite our "optimized" recompletion. Well Z-223 was acid stimulated and returned to production. Production currently stands at 139.8 m^3/d (879 b/d) gross, 2.7 m^3/d (17 b/d) net, for a 98.1% water cut with 20.7 m (68 ft) of fluid over the pump.

Although Z-223 is performing slightly better than the average Upper Terminal Zone well, production results thus far are disappointing.

Well Y-63 is a Fault Block IV Upper Terminal Zone recompletion candidate that we conventionally perforated across the "Hx", "J", "Y", and "K" sands with wireline conveyed guns. Perforations were 1.22 cm (0.48 in) in size, six holes per foot. A wire wrapped screen with 0.025 cm (0.010 in) mesh slots was gravel packed across the perforated interval with 30-40 gravel for sand control. The well was placed on production in December, 1996 (FIGURE 26). Production currently stands at 168.8 m^3/d (1,061 b/d) gross, 3.7 m^3/d (23 b/d) net, for a 97.8% water cut with 356.4 m (1,169 ft) of fluid over the pump. Production results are lower than estimated but the well may be cleaning up. Y-63 is performing better than offset wells in an area of the reservoir considered wet.

Two wells, J-120 and J-15, were recompleted with extreme overbalanced perforating, sand consolidated with one cycle of steam injection, and placed on production. The novel steam consolidation technique involves selectively perforating the target sands with one to four 0.635 cm (0.25 in) perforations per foot, placing the interval on steam injection until the total injected volume reaches 119.3 m^3 (750 bcwe) steam per perforation, and placing the well on production. This technique has been empirically developed. Lab studies are under way to replicate and comprehend the mechanisms involved.

Well J-120 is a Fault Block V Upper Terminal Zone recompletion candidate that we perforated across the "Hxo" sand with tubing conveyed guns and extreme overbalanced. Perforations were 1.22 cm (0.48 in) in size, 1.25 holes per foot. This well took 2,991 m^3 (18,800 barrels) of cold water equivalent steam injection for sand consolidation. J-120 was shut in for soaking in late August, 1996, and placed on production in October, 1996. Oil production peaked at 37.7 m^3/d (237 b/d) net with only a 32.3% water cut in early December, 1996 (FIGURE 27). Unfortunately, during an attempt to increase production, J-120 was brought on production at twice the planned gross production rate and sanded up immediately. A review of the consolidation operation showed we did not reach the empirically derived steam volume of 119.3 m^3 (750 barrels) per perforation needed for full sand consolidation. Well J-120 is scheduled for a reconsolidation application with steam. Before sanding up in late January, 1997, J-120 was producing 56.0 m^3/d (352 b/d) gross, 16.9 m^3/d (106 b/d) net, for a 69.9% water cut with 668 m (2,190 ft) of fluid over the pump.

The average producer in the Upper Terminal Zone Fault Block V reservoir produces only 4.0 m^3/d (25 b/d) net with a 97.4% water cut. An encouraging sign is the production temperature of J-120 was almost back to a pre-steam temperature suggesting thermal benefits were negligible at the time of failure. We anticipated that when the well cooled off after producing back the injected heat the oil production might fall off quickly. This was not the case. Gross and net productivities were much higher with the steam recompletion technique compared with the "optimized" waterflood recompletion. With the 3-D geologic model as a tool, we are recompleting other candidate wells and further developing the "Hxo" reservoir.

Well J-15 is a Fault Block V Tar Zone recompletion candidate that we perforated across the "F1" and "Fo" sands with tubing conveyed guns and extreme overbalanced. Perforations were 1.22 cm (0.48 in) in size, 1.25 holes per foot. This well took 14,762 m^3 (92,800 bcwe) steam for sand consolidation. J-15 was shut in for soaking in late August, 1996, and placed on production in late October,1996. J-15 currently produces 153.8 m^3/d (967 b/d) gross, 3.2 m^3/d (20 b/d) net, for a 97.9% water cut with 170.3 m (560 ft) of fluid over the pump (FIGURE 28). This production is much higher than the production from well A-173 which was recompleted using an "optimized" recompletion. Well A-173 is completed in the same sands as J-15 and currently produces 4.1 m^3/d (26 b/d) gross, 1.1 m^3/d (7 b/d) net, for a 73.1% water cut with 0 m (0 ft) of fluid over the pump. Production well Z1-7 was also completed in the same sands as wells J-15 and A-173, but with the older recompletion techniques. Well Z1-7 produces 8.3 m^3/d (52 b/d) gross, 0.6 m^3/d (4 b/d) net, for an 92.3% water cut with 0 m (0') of fluid over the pump, much lower than well J-15 and slightly lower than well A-173.

Idle recompletion candidate well Z-61 was perforated across the "F1" and "Fo" sands of the Tar Zone in Fault Block V in March, 1997. The perforations were 0.74 cm (0.29 in) in size and spaced at one (1) per every other foot. Z-61 underwent the steam consolidation process by a portable steam generator during August, 1997. A thermal packer and thermal tubing were employed to minimize heat loss to the casing. There were problems keeping the portable generator online during start up due to the feed water pump. The feed water pump is a critical component of the generator which tends to be undersized by the vendors. Ensuring ample capacity of the feed water pump is pivotal.

An unfortunate result of the portable generator not running continuously was the well partially sanded up. During injection, the near wellbore area becomes pressurized and when the generator shuts down the well can flowback. In an unconsolidated formation this carries sand into the wellbore. A coiled tubing unit was used to clean out sand from the perforated interval and Z-61 stayed on continuous steam injection after repairs to the feed water pump. A total of 2,584 m^3 (16,245 bcwe) steam were injected into a total of 18 perforations for a ratio of 144 m^3 (902 bcwe) steam per perforation. The empirical guideline is 119 m^3 (750 bcwe) steam per 0.74 cm (0.29 in) perforation. Before shutting down the generator permanently, a sinker bar was run in the well to check that all perforations were open to steam injection. Sand was tagged below the bottom perforation. Z-61 was soaked for a period of 3 weeks and then be placed on production.

Initial production was sand free and metered at 52.1 m^3/d (328 b/d) gross, 16.7 m^3/d (105 b/d) net, for a 68.0% water cut pumped off on October 8th, 1997. The production temperature was 110°C (230°F). Oil production was enhanced by the thermal benefits of steam injection for sand consolidation. During the initial rig move after the steam injection it is necessary to kill the well with a heavy fluid in order to control the well. Usually a calcium based brine water is used. Unfortunately, this can result in a calcium carbonate scale forming when the well is returned to production. In order to mitigate this problem researchers have employed a high temperature scale inhibitor squeeze before production is initially started. The high temperature scale inhibitor was provided by a local chemical vendor. As Z-61 was suspected to be damaged, it was successfully stimulated in May, 1999, with HCl acid. FIGURE 29 shows the results of the acid job.

Well Z-61 was recently metered at 46.9 m^3/d (295 b/d) gross, 2.2 m^3/d (14 b/d) net for an 95.3% water cut. The production temperature has stabilized at 43°C (110°F). The well does have a producing fluid level of 413 m (1,355 ft) above the pump.

Incremental oil production for this DOE project is 34,521 m^3 (217,281 bbls) as of December 31st, 2001.

M Technology Transfer

Tech transfer has taken place throughout the course of the project. Technical papers and presentation have been given at local, regional, and national meetings of professional societies such as the Society of Petroleum Engineers (SPE), American Association of Petroleum Geologists (AAPG), Society of Professional Well Log Analysts (SPWLA), Society of Exploration Geophysics (SEG), American Geophysical Union (AGU), European Association of Geoscientists & Engineers (EAGE), and Petroleum

Technology Transfer Council (PTTC).

Activities during the project reporting period include the following papers and presentations:

1995

The Stanford Rock and Borehole Geophysics Project (SRB) is an industrial affiliates program whose affiliates include the following US companies: AMOCO, ARCO, CHEVRON, CONOCO, EXXON, MARATHON, MOBIL, SHELL, TEXACO, and UNOCAL, as well as more than 10 other international companies. Service companies supporting the project include Western Geophysical and Schlumberger. Informal interactions with the members of these companies extended beyond the annual meeting and included visits by company representatives to Stanford, and visits by project participants to the individual companies.

Reports on the ongoing DOE project were presented at annual meetings in June of each year starting prior to initial funding of the project in 1995, and include:

1994

Moos, D., Zoback, M.D., Dvorkin, J., Mavko, G., Nur, Direct detection of hydrocarbons - Application of acoustic methods to the Wilmington Field, California, SRB Volume 55, Paper B3.

1995

Moos, D., Using multipole acoustic logs in cased holes to determine porosity and oil saturation in clastic reservoirs, SRB Volume 58, Paper F4.

Chang, C., Moos, D., and Zoback, M.D., Laboratory measurements of the physical properties of unconsolidated clastic rocks, SRB Volume 58, Paper A5

Abstracts presented at meetings include:

Moos, D., Hooks, A., Phillips, C., and Clark, D., Direct detection of hydrocarbons by acoustic logging in the Wilmington Field, CA, 1995 AAPG Pacific Section Convention, May 3-5, 1995.

Moos, D., and Hooks, A., Application of laboratory and theoretically derived rock physics relationships for clastic rocks to log data - Example from the Wilmington

Field, CA., EOS, Trans. AGU76(46) 1995 Fall Meeting Supplement, F325.

Mavko, G., and Mukerji, T., 1995, A rock physics strategy for quantifying uncertainty in common hydrocarbon indicators, SEG 65th Annual Meeting, pp. 914-917

Chris Phillips, Chief Geologist with Tidelands, made a presentation on the 3-D deterministic geologic model entitled "Application of Advanced Reservoir Characterization to Increase the Efficiency of a Thermal Steam Drive in the Wilmington Oil Field, California" at the 1995 AAPG Pacific Section Meeting in San Francisco, CA. on May 3-5, 1995. Don Clarke and Mike Henry of the City of Long Beach were co-authors.

Dan Moos of Stanford was in New Orleans on May 18, 1995 speaking at the Society of Professional Well Log Analysts (SPWLA).

Several articles were published in trade journals and newspapers about this DOE project. Articles were published in the October 10, 1994 edition of the Long Beach Press - Telegram newspaper, in the October, 1994 issue of the SPE Los Angeles Basin Section Newsletter, in the December, 1994 issue of World Oil magazine, and in the March, 1995 issue of Petroleum Engineer International magazine.

Tidelands, the City of Long Beach, and USC held a technical transfer meeting of DOE Class III participants on May 15, 1995 in Valencia, CA to discuss their desire to have specific joint activities, such as the 1996 AAPG National Meeting, the 1997 SPE Western Regional Meeting, and the 1998 Joint SPE Western Regional/AAPG Pacific Basin Section Meeting.

1996

Researchers planned the Stanford Rock and Borehole Geophysics Project Annual Meeting in June, 1996. Papers written and presented included:

Moos, D., Dvorkin, and Hooks, A., Application of theoretically derived rock physics relationships for clastic rocks to log data, SRB Volume 62, Paper G3

Chang, C.T., Zoback, M.D., and Moos, D., Viscoelasticity and dispersion in unconsolidated reservoir rocks from the Wilmington Field, CA, SRB Volume 62, Paper G7

Chang, C.T., Moos, D., and Zoback, M.D., A comparison of static and dynamic moduli in unconsolidated reservoir rocks from the Wilmington Field, CA, SRB

Volume 62, Paper G7

Moos, D., Hooks, A., Walker, F.S., Hydrocarbon saturation determination from sonic log data, SRB Volume 62, Paper H6

Dvorkin, J., Nur, A., Packwood, J., and Moos, D., Identifying patchy saturation from well logs, SRB Volume 62, Paper H7

Abstracts presented at meetings include:

Moos, D., Hooks, A., and Walker, F.S., Acoustic Logging Through Casing to Detect Hydrocarbons and Determine Porosity in the Wilmington Field, CA, 1996 AAPG International Meeting, May 21, 1996.

Moos, D., and Dvorkin, J., Sonic logging through casing for porosity and fluid characterization in the Wilmington Field, CA, Sixty-Sixth SEG International Exposition and Annual Meeting, Nov. 12, 1996, pp. 134-137

Chang, C.T., Moos, D., and Zoback, M.D., An elasticity and dispersion in unconsolidated sands, EOS, Trans. AGU 77 1996 Fall Meeting Supplement.

Mavko, G., and Mukerji, T., Rock physics and relative entropy measures for quantifying the value of additional information in pore fluid indicators, AGU Fall Meeting.

Biondo, B., Deutsch, C., Gundeso, R., Lumley, D., Mavko, G., Mukerji, T., Rickett, J., and Thiele, M., 1996, Reservoir Monitoring: A multi-disciplinary feasibility study, SEG 66th Annual Meeting, Denver.

Researchers made a presentation on the acoustic tool performance in both cased hole and open hole at the "Dipole Sonic Symposium" organized by the Society of Exploration Geophysicists in Tulsa, OK, in April, 1996.

An article was also be placed in the AAPG guidebook for the national meeting from Moos, Walker, Clarke: "Sonic Logging to Detect Bypassed Hydrocarbons in the Wilmington Field, CA." May 18, 1996.

Researchers participated in the Ocean Drilling Program Downhole Measurements Panel Meeting in Salt Lake City, Utah. DOE results were disseminated to other attendees.

Researchers made a presentation in September, 1996 on the Waterflood Project status to the Department of Energy (DOE), California Department of Oil and Gas (CDOG), California State Lands Commission, along with representatives from state and federal government in Long Beach, CA.

Researchers attended the Society of Professional Well Log Analysts (SPWLA) Symposium on "Petrophysics in 3-D" in Taos, New Mexico in October, 1996.

Researchers presented papers at the November, 1996 Society of Exploration Geophysics (SEG) Annual Meeting in Denver, CO. Also at the meeting, researchers held a workshop on problems associated with data acquisition of dipole and monopole data at Wilmington in conjunction with the Shear-Wave Special Interest Group of the Log Characterization Consortium.

1997

Researchers planned the Stanford Rock and Borehole Geophysics Project Annual Meeting June 23-25, 1997. Papers written and presented included:

Moos, D., 1997. “Hydrocarbon Detection Behind Casing in the Wilmington Field, California: Summary of the Results of the First Phase of a DOE Project.” SRB Volume 65, Paper C6.

Guitierrez, M., D. Moos, A. Nur, J. Dvorkin, 1997. “Hydrocarbon Identification Using Acoustic Logs in the La Cira Oil Field.” SRB Volume 65, Special Paper.

Researchers wrote and presented a paper to the June, 1997, SPE Western Regional Meeting: Walker, S., 1997, "Locating and Producing Bypassed Oil: A D.O.E. Project Update.” SPE Paper 38283, Long Beach, California.

Researchers had the paper Walker, S., 1997, "Locating and Producing Bypassed Oil: A D.O.E. Project Update.” SPE Paper 38283, published in the Journal of Petroleum Technology, p. 984-985, September, 1997.

Researchers made a presentation to the 1997, AAPG Annual Convention: Moos, D. “Fluid Detection and Porosity Determination Using Acoustic Logs in the Wilmington Field, California.” Dallas, Texas, April 6-9, 1997.

Researchers made a presentation to the 1997, AAPG Annual Convention: Moos, D., J. Harris, J. Dvorkin. “Application of Rock Physics and Petrophysics to 3-D

Reservoir Characterization." Dallas, Texas, April 6-9, 1997.

Researchers made a presentation to the 1997, AAPG Pacific Section Annual Meeting: Moos, D., S. Walker "Hydrocarbon Detection in the Wilmington Field, California." Bakersfield, California, May 14-16, 1997.

Researchers had the paper Moos, D., J. Dvorkin, A. Hooks, 1997, "Application of Theoretically Derived Rock Physics Relationships for Clastic Rocks to Log Data from the Wilmington Field, CA" published in the journal Geophysical Research Letters, Volume 24, Number 3, p. 329-332 February, 1997.

Researchers wrote and presented a paper to the June, 1997, International Journal of Rock Mechanics and Mineral Sciences Annual Meeting: Chang, C., D. Moos, M. Zoback, "Anelasticity and Dispersion in Dry Unconsolidated Sands".

Researchers had the paper Chang, C., D. Moos, M. Zoback, 1997, Anelasticity and Dispersion in Dry Unconsolidated Sands" published in the International Journal of Rock Mechanics and Mineral Sciences, Volume 34, numbers 3-4, paper number 48, 1997.

Researchers made a presentation to the 1997, SEG Topical Conference on Pore Pressure Prediction from Seismic Data, Moos, D., "Single Sample Testing of Compacting Sediments". Dallas, Texas, November 6, 1997.

Researchers made a presentation to the 1997, Advanced Applications of Wireline Logging for Improved Oil Recovery Workshop. Moos, D., "Acoustic Logging to Detect Hydrocarbons Through Casing - DOE Class III Wilmington Waterflood Project". Midland, Texas, November 13, 1997.

1998

Researchers wrote and presented a paper to the May, 1998, Society of Professional Well Log Analysts 39th Annual Logging Meeting: MacCallum D., M. Dautel, C. Phillips, "Determination and Application of Formation Anisotropy Using Multiple Frequency, Multiple Spacing Propagation Resistivity Tool from a Horizontal Well, Onshore California." Keystone, Colorado.

Researchers planned the Stanford Rock and Borehole Geophysics Project Annual Meeting June 23-25, 1998. Papers written and presented included:

Moos, D., G. Zwart. 1998. “Acoustic Determination of Pore Fluid Properties Using a 2-Component Model.” SRB Volume 66 Paper B2

Researchers were interviewed for an article for the AAPG Bulletin: Montgomery, S. March, 1998, “Increasing Reserves in a Mature Giant: Wilmington Field, Los Angeles Basin, Part I: Reservoir Characterization to Identify By-passed Oil.” AAPG Bulletin pages 367-385.

Researchers made a presentation to the 1998, Advanced Applications of Wireline Logging for Improved Oil Recovery Workshop. Moos, D., “Acoustic Logging to Detect Hydrocarbons Through Casing - DOE Class III Wilmington Waterflood Project”. Denver, Colorado, January 13, 1998.

Researchers had the paper Phillips, C., D., Clarke, 1998, “3D Modeling/Visualization Guides Horizontal Well Program in Wilmington Field” published in the Journal of Canadian Petroleum Technology, Volume 37, Number 10, October, 1998.

Researchers wrote and presented a paper to the October, 1998, 3rd AAPG/EAGE Joint Research Conference on Developing and Managing Turbidite Reservoirs: Case Histories and Experiences: Clarke, D., C. Phillips,1998, "Subsidence and Old Data Present Unique Challenges in Aging Turbidite Oil Fields. Examples of Successful Technologies Solutions from the Wilmington Oil Field, California, USA”, Almeria, Spain, October 4-9, 1998.

Researchers wrote and presented a paper to the October, 1998, 3rd AAPG/EAGE Joint Research Conference on Developing and Managing Turbidite Reservoirs: Case Histories and Experiences: Clarke, D., 1998, "How to Accurately Place Horizontal Wells in Turbidite Reservoirs Using Bad Data”, Almeria, Spain, October 4-9, 1998.

1999

Researchers wrote and presented a paper to the June, 1999, DOE Oil and Gas Conference: Hara, P., J. Mondragon, D. Davies, 1999, "A Well Completion Technique for Controlling Unconsolidated Sand Formations by Using Steam”, Dallas, Texas, June 28-30, 1999.

Researchers made a presentation to the June, 1999, EAGE Conference and Technical Exhibition: Clarke, D., C. Phillips,1998, "Subsidence and Old Data Present

Unique Challenges in Aging Turbidite Oil Fields. Examples of Successful Technologies Solutions from the Wilmington Oil Field, California, USA", Helsinki, Finland, June 7-11, 1999.

Researchers presented an update on the Waterflood Project status to the Petroleum Technology Transfer Council (PTTC) at the University of Southern California in Los Angeles, California, on December 10th, 1999. The PTTC program was titled "Review of Class III Projects"

2000

Researchers wrote and presented a paper to the Gulf Coast Section Society of Economic Paleontologists and Mineralogists Foundation 20th Annual Research Conference Deep-Water Reservoirs of the World: Clark, D., Phillips, C., "3-D Geological Modeling and Horizontal Drilling Bring More Oil Out of the 68-Year-Old Wilmington Oil Field of Southern California". December 3-6, 2000.

2001

Scott Hara gave a presentation to the California Conservation Committee of Oil and Gas Producers in Long Beach, CA, on September 19, 2001, concerning new technology employed in Wilmington oil field in conjunction with the DOE.

Conclusions

At the conclusion of this project, nine wells were producing an average of 40.1 m^3/d (252 b/d) of oil. These wells were recompleted or drilled based upon the success of each activity in our project. The following conclusions can be made about the technology used and activities accomplished.

The monopole and dipole shear sonic logs can provide accurate compressional and shear wave velocities in cased holes, even in shallow, unconsolidated sands such as in the Wilmington Field or other slope and basin clastic reservoirs. Porosity can be determined from shear wave velocity, provided an appropriate transform is used. Qualitatively, acoustic logs can be used to locate bypassed oil. Unfortunately, shear wave data were not recovered in all wells and acoustically derived saturations could be predicted for those wells.

The integration of reservoir characterization data for this project was accomplished by the development of a 3-D computerized visualization model. Commercially available software can develop and integrate the following types of representational models from scattered data points surfaces such as: terrain, velocity, hydrologic and property distribution in space such as: permeability, porosity, temperature. The model can also represent geologic structures such as: fault blocks, lithologic zones, normal and reverse faults. Data came from wells, logs, and geographic surveys. The data and models can be viewed and manipulated interactively using workstations. The software generated various graphic representations of spatial data and models including structure contour maps, isopach maps, cross sections, and 3-D shaded volume models.

The 3-D model built in this project can be used for geosteering. The cross sections and maps were highly accurate providing for a successful project. We managed to split the distance the horizontal lateral was contained in the HxoJ and the sand lobe above in the J-17 well. It should be noted that the HxoB and HxoJ layers were defined for this project only and do not reside in the permanent data base. The markers were identified on the electric logs and placed in the modeling software data base and then exported so they could be used to create the 3-D model.

The model was good for organizing, so we could pinpoint problems that occurred at the rig site. One such problem was found when it was noticed that the Measurement While Drilling (MWD) values the directional engineer was plotting on his maps showed the well to be on course in the section view and was clearly low with respect to the well plan from our cross section. It turned out the directional vendor was not using the correct magnetic declination and they were using an inappropriate vertical section plane. They could not correct the maps in time and we had to geosteer and control the directional entirely from our cross sections.

Lastly, the optimized recompletion technique resulted in wells which had higher gross and net production rates versus the standard recompletion. Also, the steam recompletion technique resulted in wells which had much higher productivities versus a standard or even an optimized recompletion technique. Research is still ongoing as to the mechanical viability of the steam recompletion, particularly concerning the limits to draw down capability. Continued research can be expected from DOE project DE-FC22-95BC14939 "Increasing Heavy Oil Reserves in the Wilmington Oil Field Through Advanced Reservoir Characterization and Thermal Production Technologies".

References

1. D. Moos, J. Dvorkin, A. Hooks, Application of Theoretically Derived Rock Physics Relationships for Clastic Rocks to Log Data - Example from the Wilmington Field,CA, paper prepared for special issue of Geophysical Research Letters on

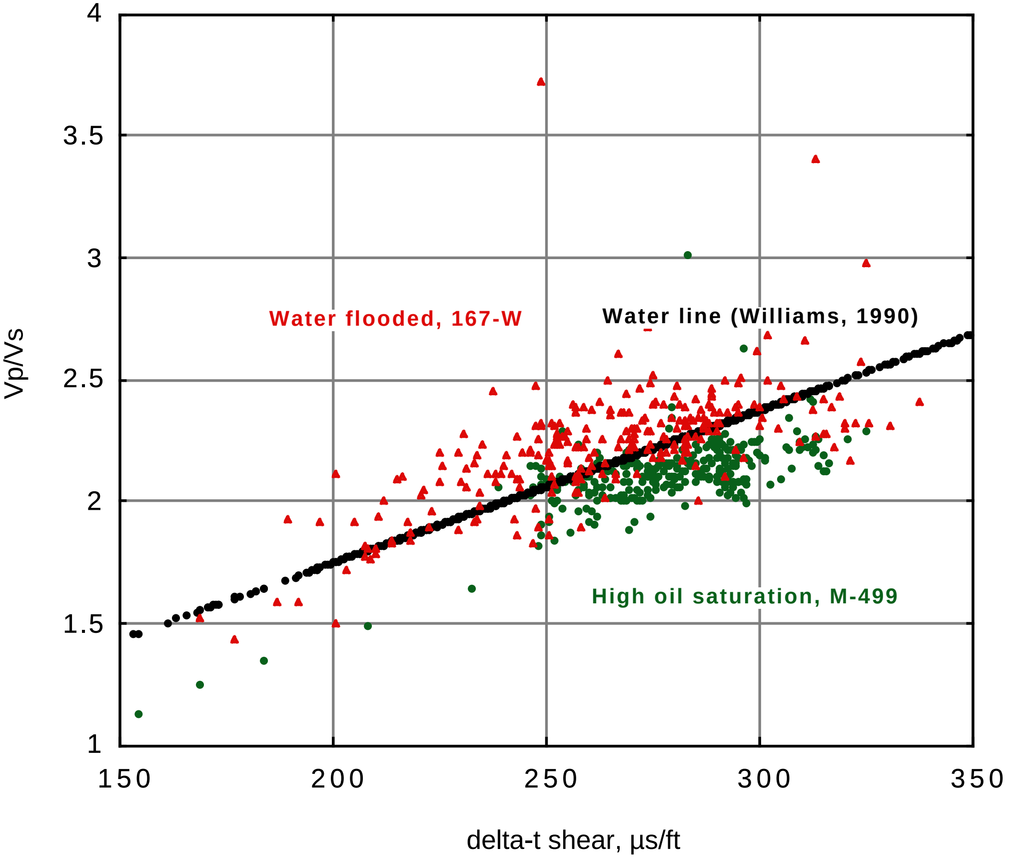
Core/Log/Seismic Integration, January 1996.

2. Williams, The Acoustic Log Hydrocarbon Indicator, paper W for Society of Professional Well Log Analysts 31st Annual Logging Symposium, June 1990.

3. D. Moos, S. Hara, C. Phillips, A. Hooks, K. Tagbor, Field Test of Acoustic Logs for Measuring Porosity and Oil Saturation in a Mature Waterflood in the Wilmington Field, CA, paper SPE 29655 presented at the Society of Petroleum Engineers Western Regional Meeting, Bakersfield, CA, March 1995.

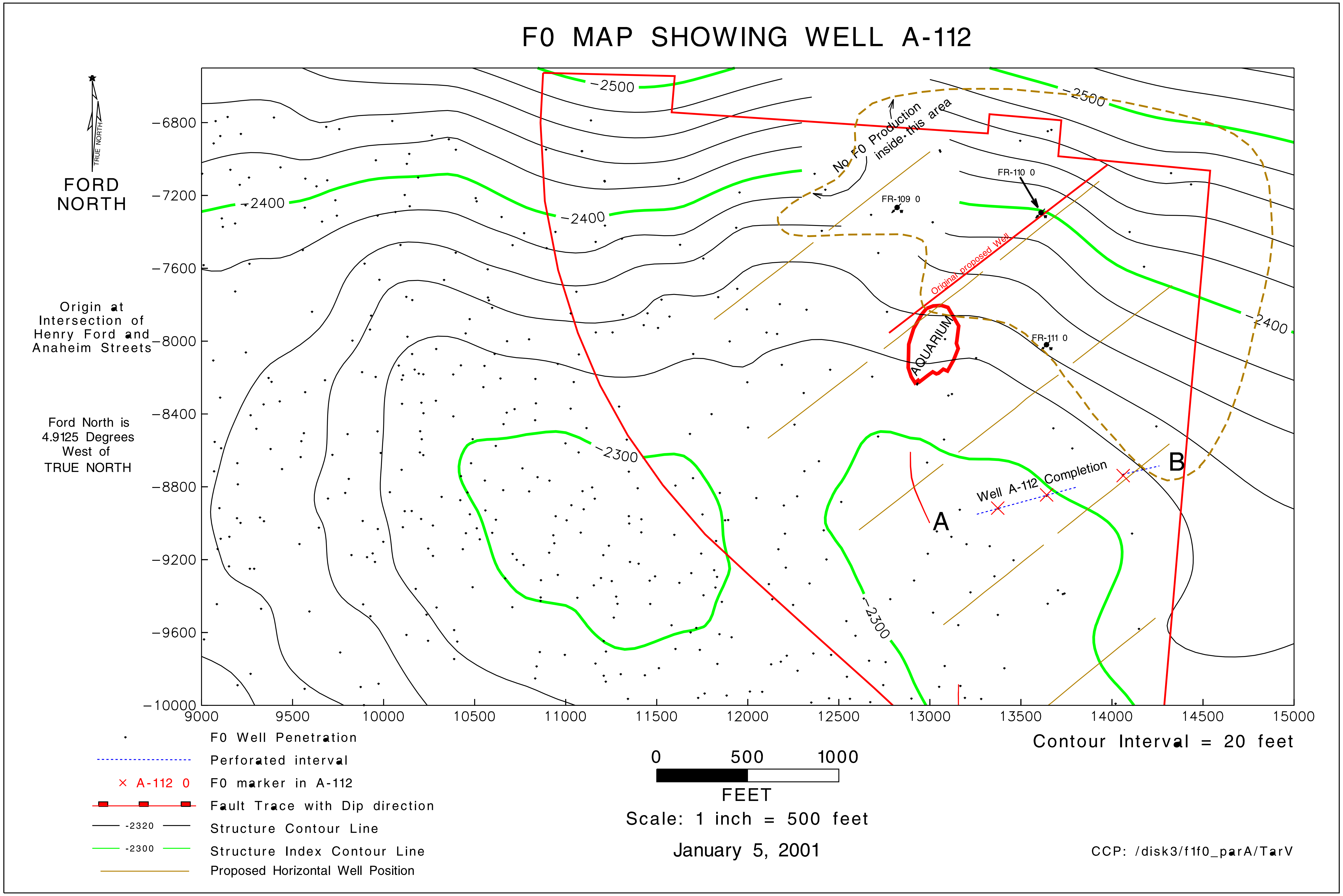
4. D. Moos, G. Zwart. 1998. “Acoustic Determination of Pore Fluid Properties Using a 2-Component Model.” SRB Volume 66 Paper B2 presented at the Stanford Rock and Borehole Geophysics Project Annual Meeting, Stanford, CA, June, 1998.

Results - ALHI at Wilmington



Based on theory and empirical results of Williams (1990), sands with high oil saturation should plot below the "ALHI water line", and sands with high water saturations should plot at or above the line. Data from Wilmington show this trend, with waterflooded sands above the line (red) and oil-bearing sands below the line (green).

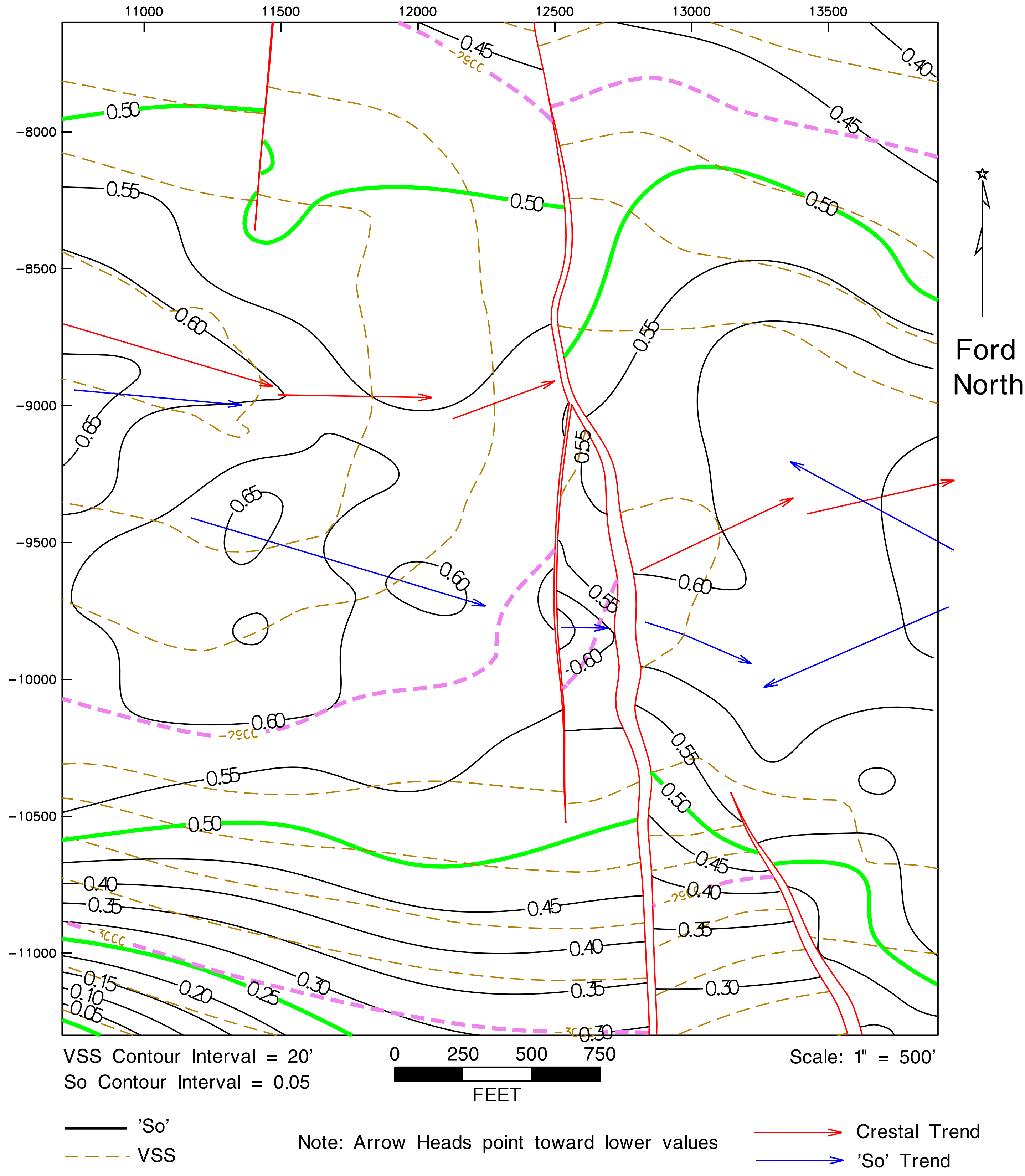
FIGURE 1



F0 MAP SHOWING WELL A-112
FORD NORTH
TRUE NORTH
Origin at Intersection of Henry Ford and Anaheim Streets
Ford North is 4.9125 Degrees West of TRUE NORTH
No F0 Production inside this area
Original proposed Well
AQUARIUM
FR-109 0
FR-110 0
FR-111 0
Well A-112 Completion
A
B
-2500
-2400
-2300
-6800
-7200
-7600
-8000
-8400
-8800
-9200
-9600
-10000
9000
9500
10000
10500
11000
11500
12000
12500
13000
13500
14000
14500
15000
F0 Well Penetration
Perforated interval
× A-112 0 F0 marker in A-112
Fault Trace with Dip direction
-2320 Structure Contour Line
-2300 Structure Index Contour Line
Proposed Horizontal Well Position
0 500 1000
FEET
Scale: 1 inch = 500 feet
January 5, 2001
Contour Interval = 20 feet
CCP: /disk3/f1f0_parA/TarV

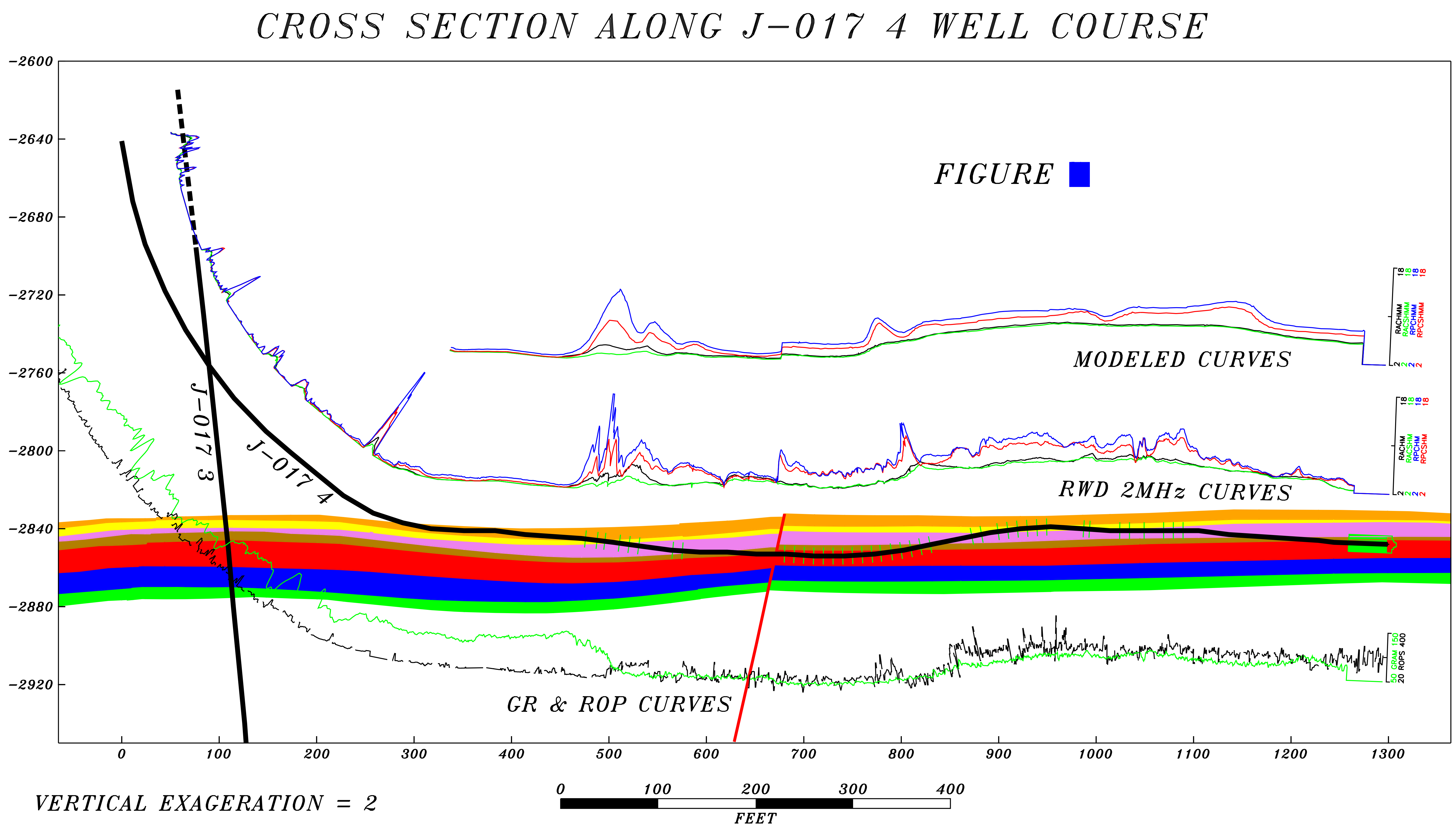
FIGURE 2

Hx0 Structure Map showing So contours.



/phillips/doe/fb5/hx_proj/fig_04rev.iplt

FIGURE 3



CROSS SECTION ALONG J-017 4 WELL COURSE
FIGURE
MODELED CURVES
RWD 2MHz CURVES
GR & ROP CURVES
J-017 3
J-017 4
-2600
-2640
-2680
-2720
-2760
-2800
-2840
-2880
-2920
0
100
200
300
400
500
600
700
800
900
1000
1100
1200
1300
VERTICAL EXAGERATION = 2
0
100
200
300
400
FEET

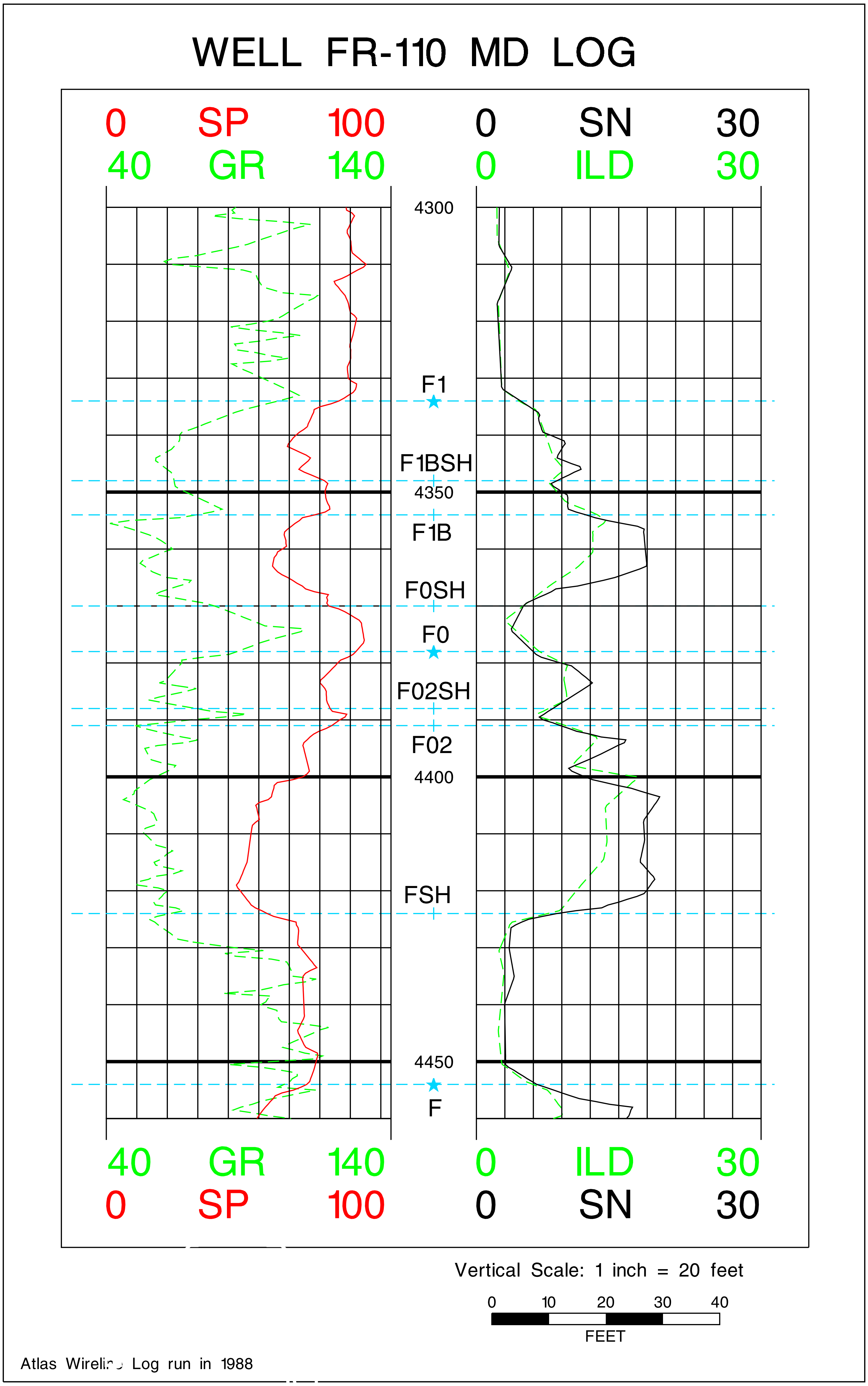
FIGURE 4


CROSS SECTION ALONG WELL COURSE A-112
SOUTH WEST
NORTH EAST
A
B
400 kHz
2 MHz
F0 Repeat 1
F0 Shale
F1B Sand
F0 Shale Repeat
F0 Repeat 2
F02 Shale
F02
F Shale
D3
EV
F1
F1B
F0
Rate of Penetration
Gamma Ray
Section Azimuth = 75.19 Degrees
A-112 0
Explanation
S
T
T2
T7
EV
F1
F1BSH
F1B
F0SH
F0
F02SH
F02
FSH
F
A-011 0 Well Identification with Redrill Designation
× F0 Marker Horizon Top
Well Path in Front of Cross Section Traverse
Well Path Behind Cross Section Traverse
Well Paths shown with thin lines are within 50' of Section Line
Well Paths shown with thick lines are within 15' of Section Line
CCP: /disk3/f1f0_parA/TarV
SCALE:
Vertical = Horizontal
1 Inch = 50 Feet
January 5, 2000
Propagation Resistivity Curves Key:
Amplitude Curves (RA) -> Dashed
Phase Curves (RP) -> Solid
RACHM & RACLM -> Black
RACSHM & RACSLM - > Green
RPCHM & RPCLM -> Blue
RPCSHM & RPCSLM -> Red
CL = 400 kHz Curves
CH = 2 MHz Curves
S = Short Spaced
M = Recorded While Drilling (RWD)
Enclosure 1

FIGURE 5

Well A-112 0 MD Log
Marker Key
R = Repeat on log
R1 = First Repeat on log
R2 = Second Repeat on log
SH = Shale Top
2 MHz
400 KHz
800 ROPS 0
0 GRAM 150
0 RPCSHM 30
0 RPCHM 30
0 RACSHM 30
0 RACHM 30
0 RPCSLM 30
0 RPCLM 30
0 RACSLM 30
0 RACLM 30
2600
2700
S
2800
S2
S4
2900
3000
T
T1
3100
T2
3200
T7
3300
DU
3400
3500
D3
EV
3600
F1
3700
F1B
3800
F0
3900
4000
4100
F0R1
F0SH
4200
F1B Sand
4300
F0SHR
4400
4500
F0R2
4600
F02SH
4700
F02
4800
FSH
4900
Baker-Hughes-Inteq LWD log (April, 2000)
0 GRAM 150
800 ROPS 0
0 RACHM 30
0 RACSHM 30
0 RPCHM 30
0 RPCSHM 30
0 RACLM 30
0 RACSLM 30
0 RPCLM 30
0 RPCSLM 30
2 MHz
400 kHz
Resistivity Curve Key
GRAM = Gamma Ray
ROPS = Rate of Penetration
RP = Phase Resistivity
RA = Amplitude Resistivity
CH = 2 MHz curves
CL = 400 KHz curves
S = Short Spaced
Amplitude Curves (RA) -> Dashed
Phase Curves (RP) -> Solid
Vertical Scale: 1" = 50'
0 50 100 150 200
FEET

FIGURE 6



Atlas Wireline Log run in 1988

FIGURE 7

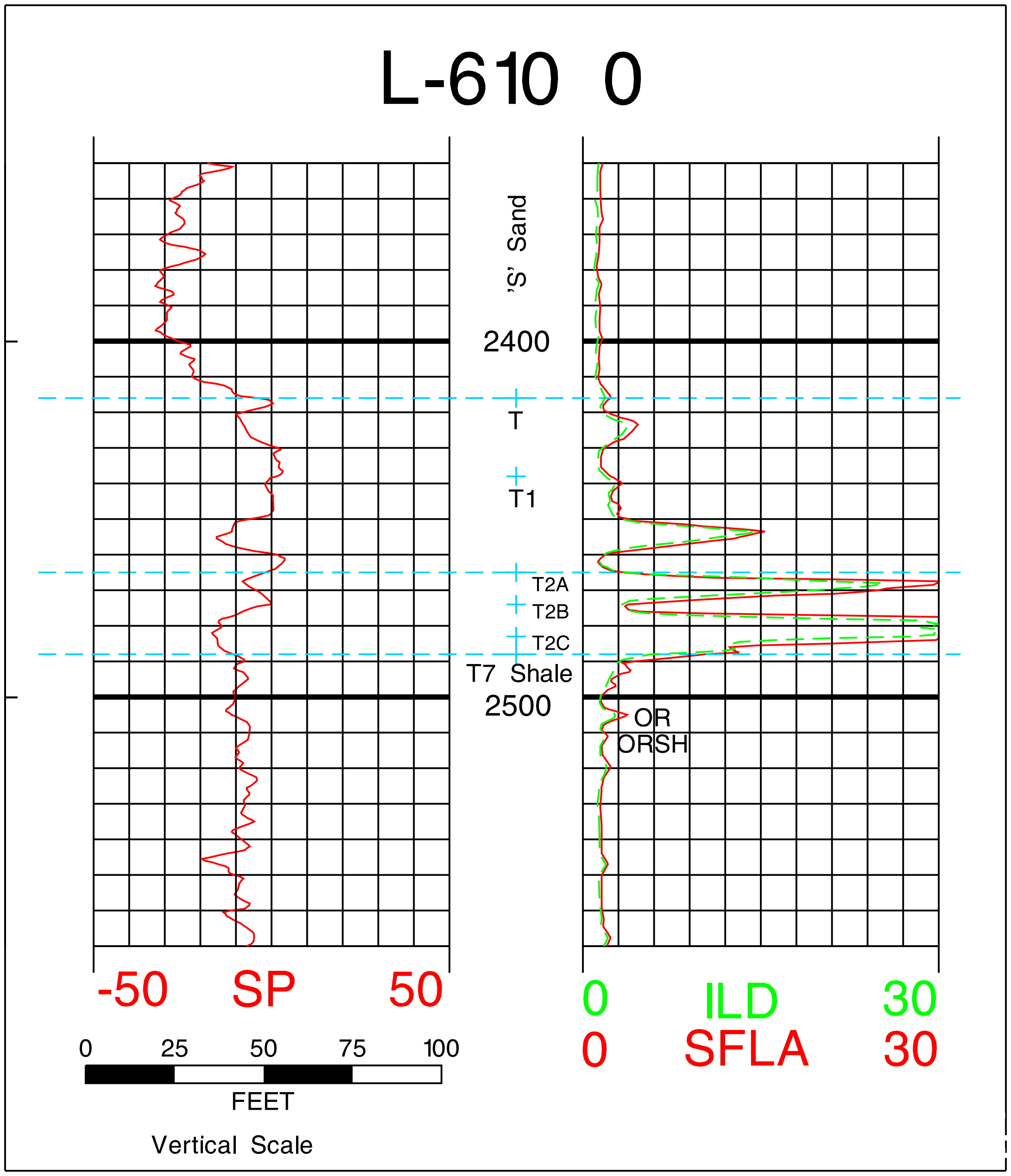
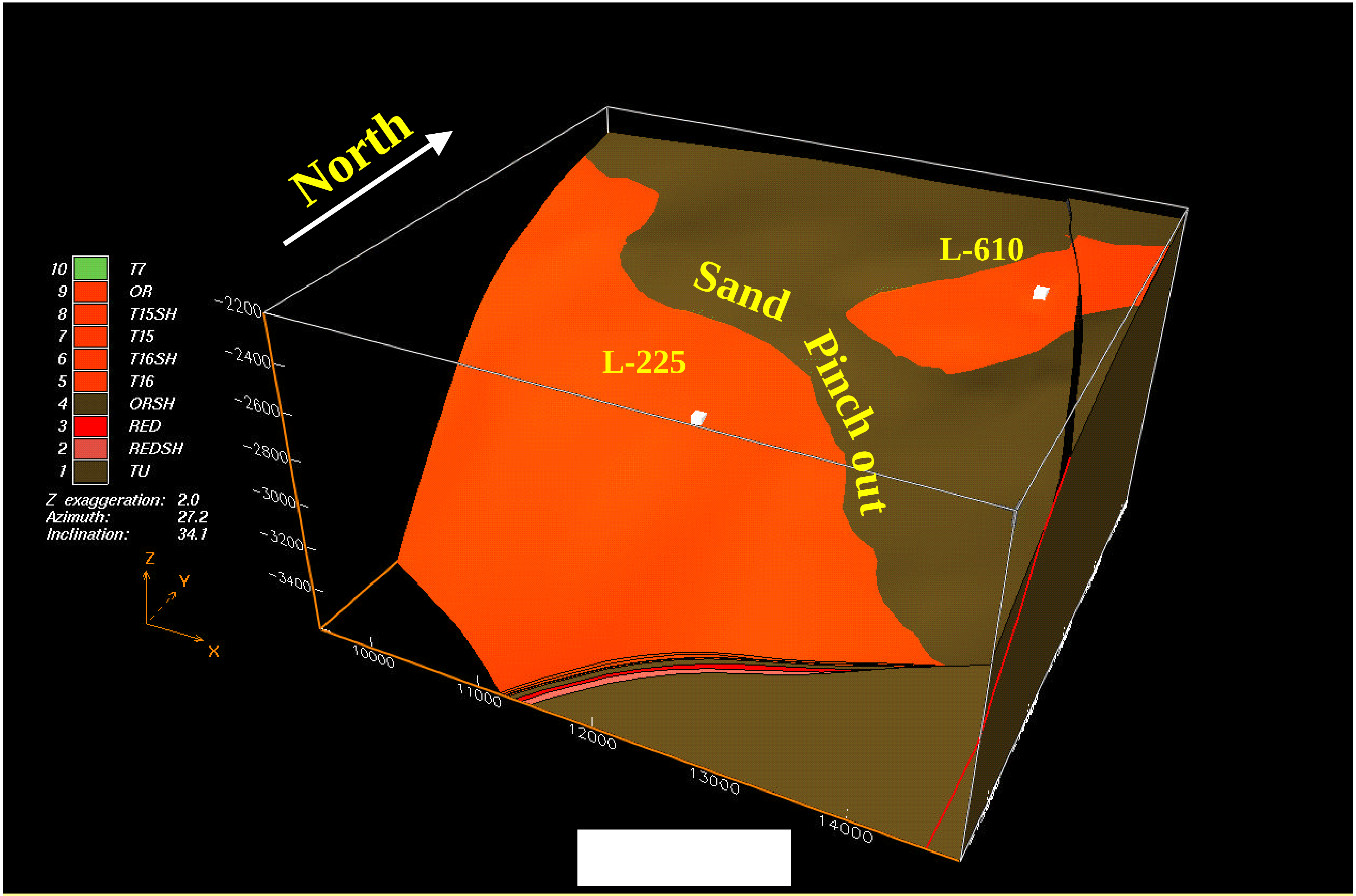

L-610 0
'S' Sand
2400
T
T1
T2A
T2B
T2C
T7 Shale
2500
OR
ORSH
-50
SP
50
0
ILD
30
0
SFLA
30
0
25
50
75
100
FEET
Vertical Scale

FIGURE 8



3-D model showing Orange sand on lapping shale. There is also a "pod" of sand shown near L-610. This "pod" fills a structural low. Vertical exaggeration = 2.

FIGURE 9

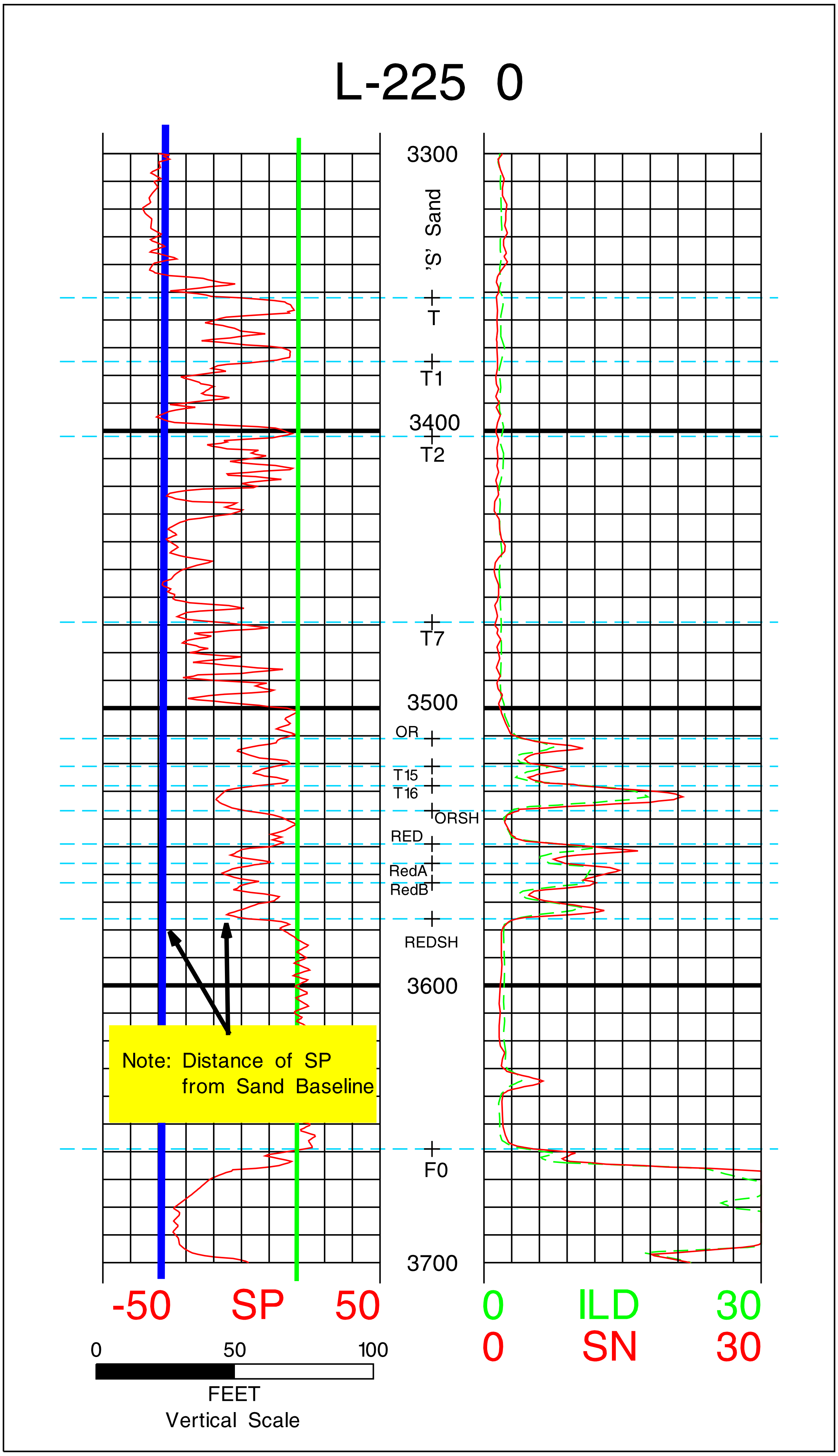

L-225 0
3300
'S' Sand
T
T1
3400
T2
T7
3500
OR
T15
T16
ORSH
RED
RedA
RedB
REDSH
3600
Note: Distance of SP from Sand Baseline
F0
3700
-50 SP 50
0 ILD 30
0 SN 30
0 50 100
FEET
Vertical Scale

FIGURE 10

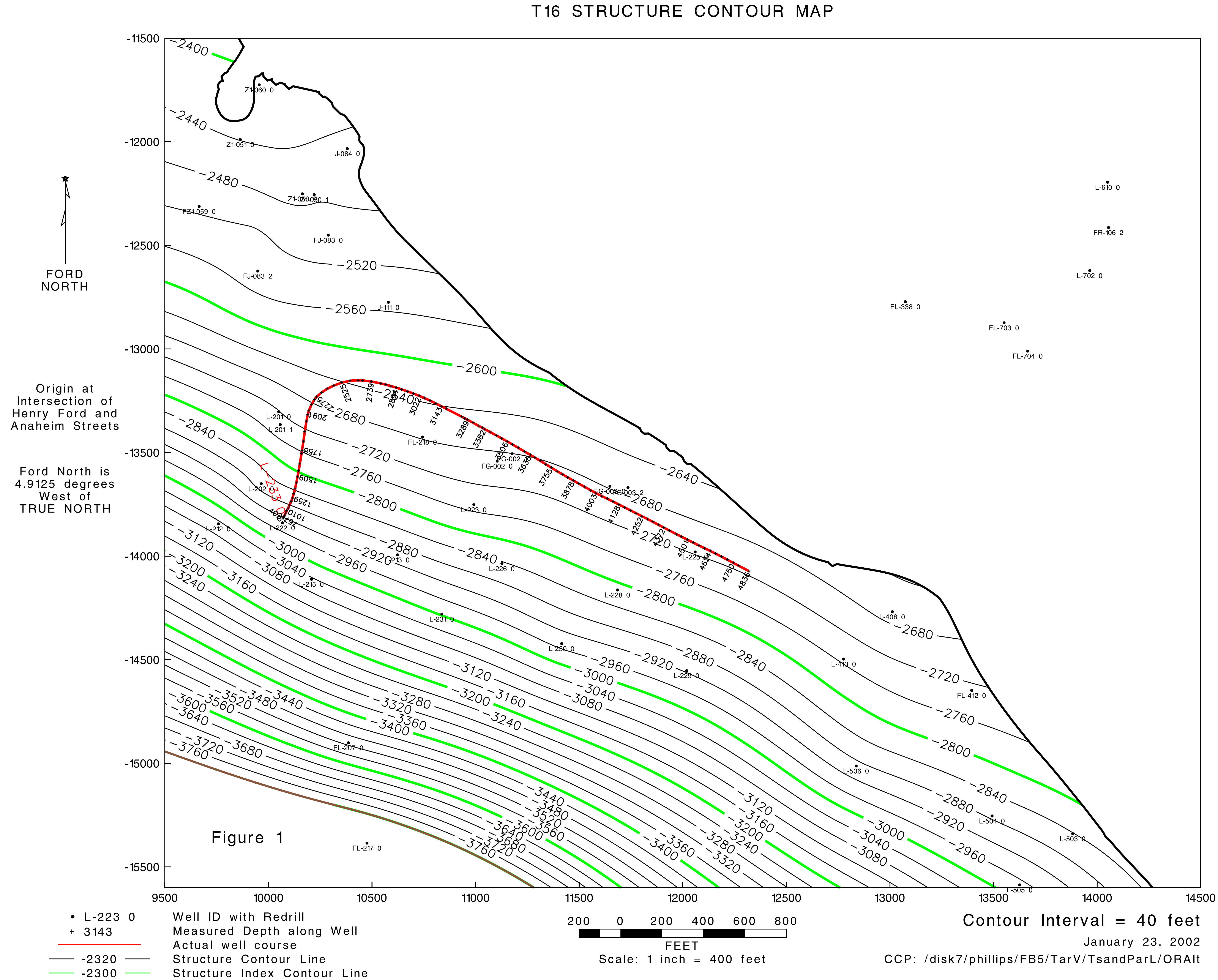
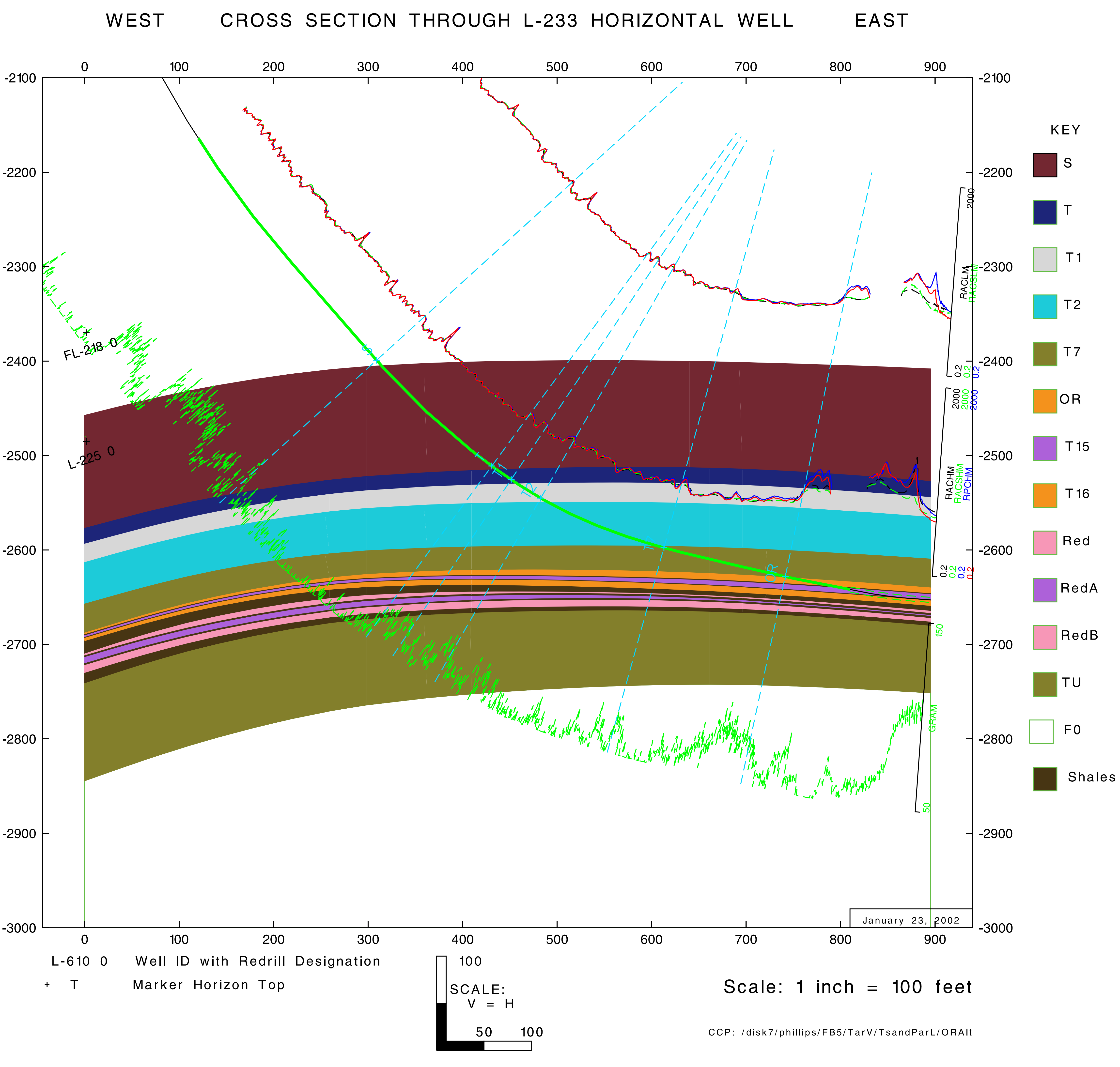

T16 STRUCTURE CONTOUR MAP
FORD
NORTH
Origin at
Intersection of
Henry Ford and
Anaheim Streets
Ford North is
4.9125 degrees
West of
TRUE NORTH
Figure 1
L-223 0 Well ID with Redrill
+ 3143 Measured Depth along Well
Actual well course
-2320 Structure Contour Line
-2300 Structure Index Contour Line
200 0 200 400 600 800
FEET
Scale: 1 inch = 400 feet
Contour Interval = 40 feet
January 23, 2002
CCP: /disk7/phillips/FB5/TarV/TsandParL/ORAlt

Figure 11



WEST
CROSS SECTION THROUGH L-233 HORIZONTAL WELL
EAST
FL-218 0
L-225 0
KEY
S
T
T1
T2
T7
OR
T15
T16
Red
RedA
RedB
TU
F0
Shales
RACLM
RACSHM
RACHM
RACSHM
RPCHM
GRAM
January 23, 2002
L-610 0 Well ID with Redrill Designation
+ T Marker Horizon Top
SCALE:
V = H
Scale: 1 inch = 100 feet
CCP: /disk7/phillips/FB5/TarV/TsandParL/ORAlt

Figure 12

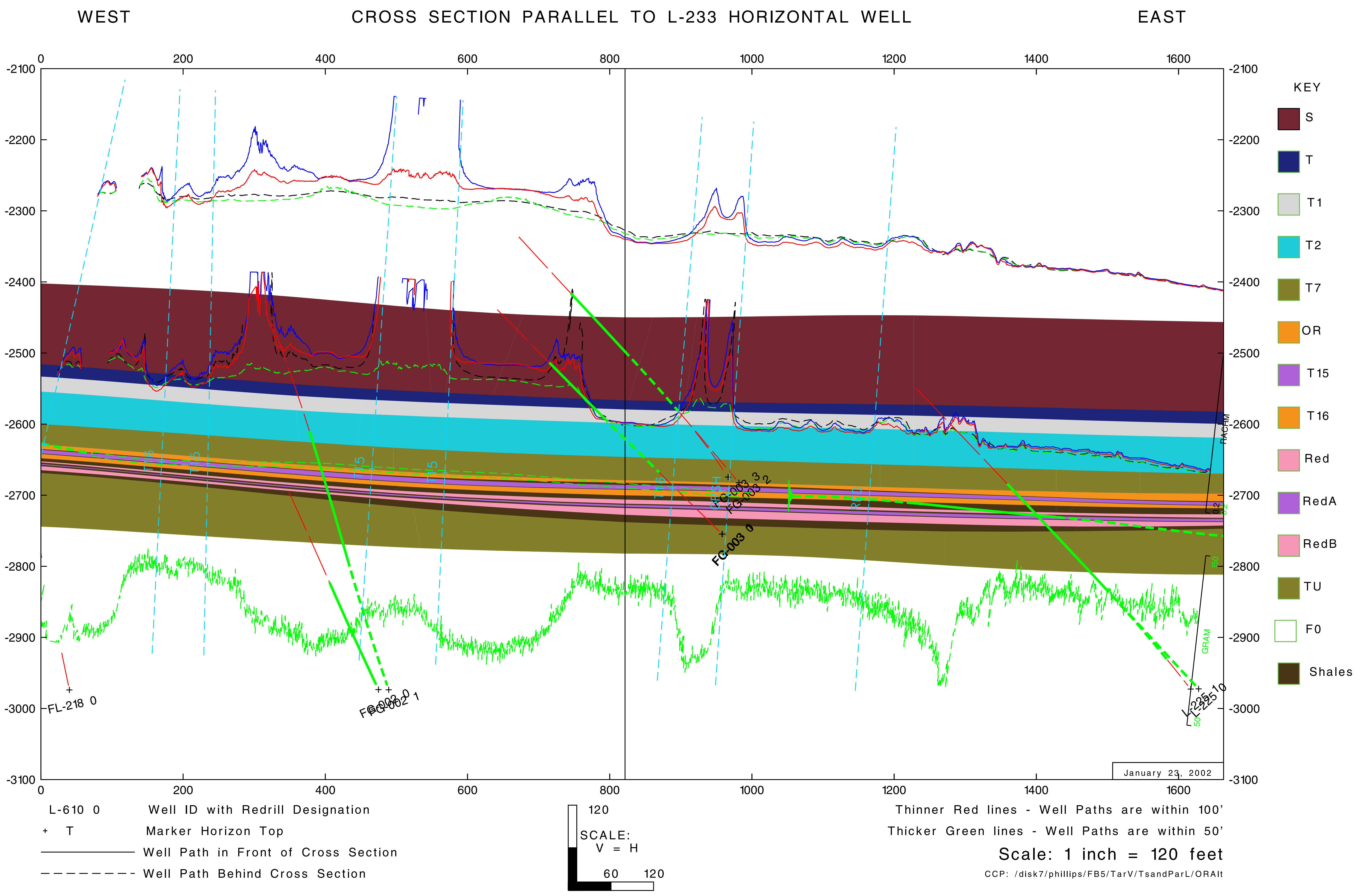

WEST
CROSS SECTION PARALLEL TO L-233 HORIZONTAL WELL
EAST
KEY
S
T
T1
T2
T7
OR
T15
T16
Red
RedA
RedB
TU
F0
Shales
FL-218 0
FG-002 0
FG-002 1
FG-003 3
FG-003 2
FG-003 0
L-225
L-225 10
January 23, 2002
L-610 0 Well ID with Redrill Designation
+ T Marker Horizon Top
Well Path in Front of Cross Section
Well Path Behind Cross Section
SCALE:
V = H
Thinner Red lines - Well Paths are within 100'
Thicker Green lines - Well Paths are within 50'
Scale: 1 inch = 120 feet
CCP: /disk7/phillips/FB5/TarV/TsandParL/ORAlt

Figure 13

L-225

Data file name L-225.DAT
Date plotted 25-10-2001
Time plotted 09:08:02

Since well log interpretations are opinions based upon inferences from well logs, we cannot and do not guarantee the correctness or accuracy of any interpretation. Therefore we shall not be liable or responsible for any loss, damage, cost or expense incurred or sustained by anyone resulting from any interpretation.

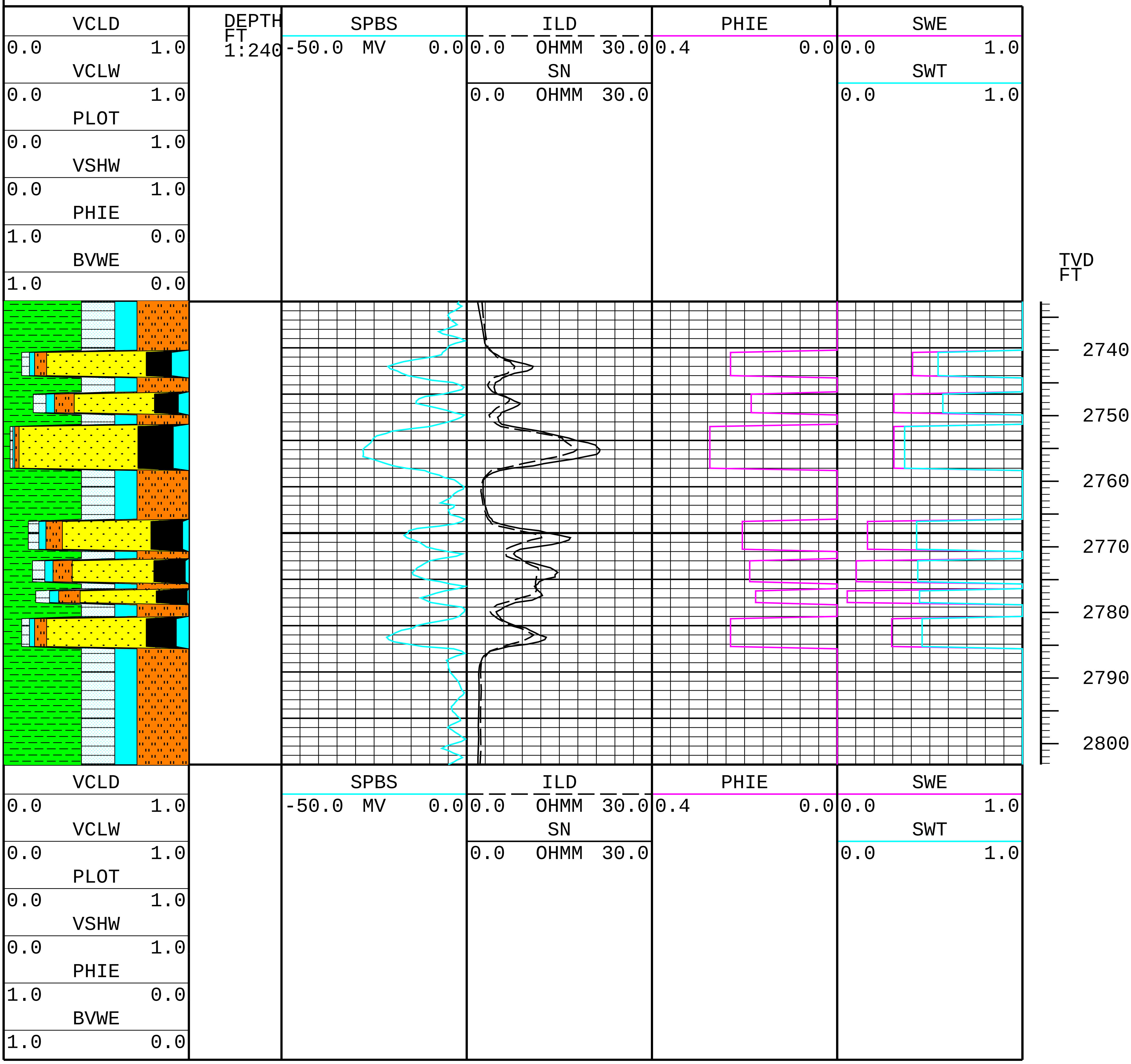
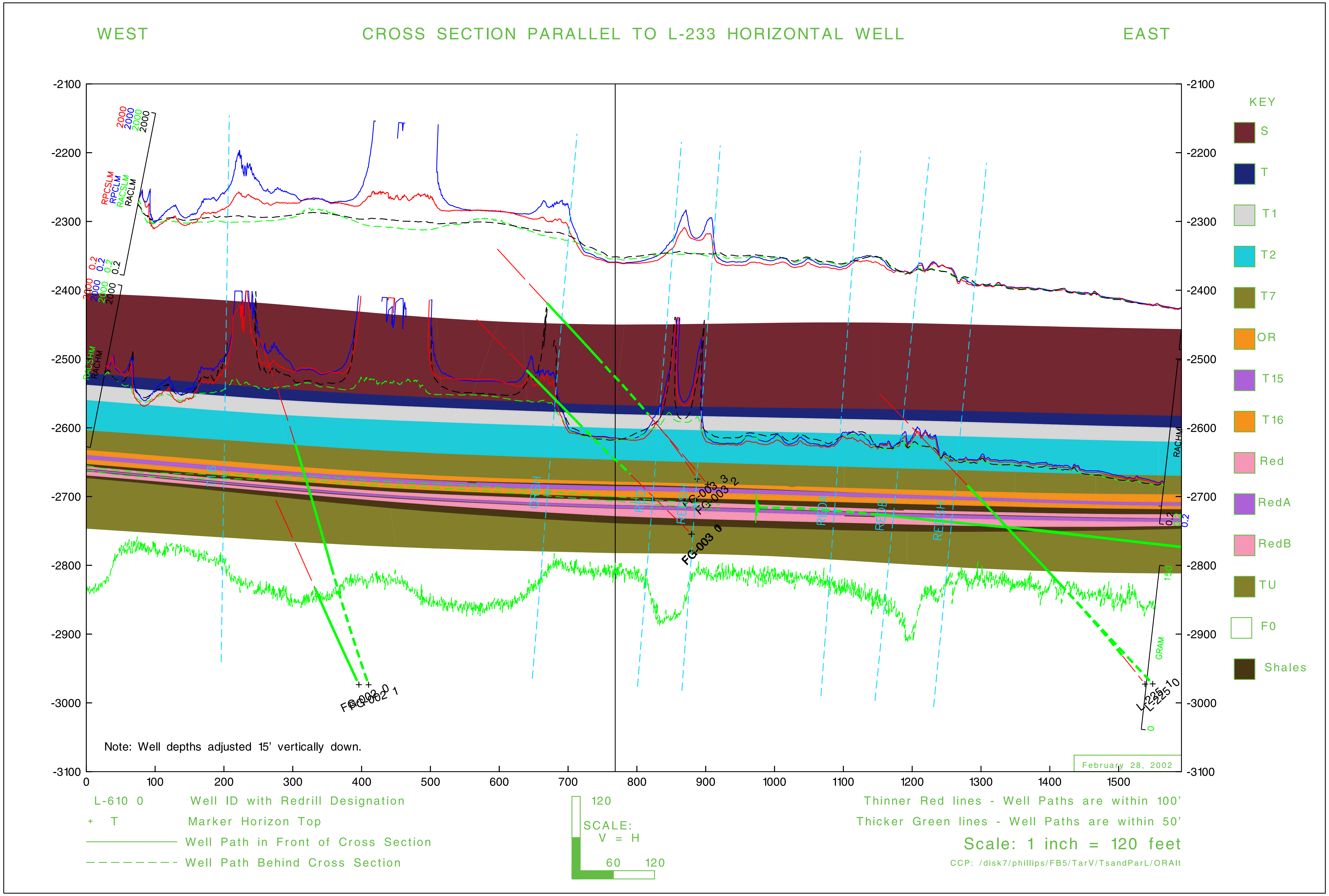


Figure 14


DEPTH
FEET
1:600
True Vertical Depth
TVD (feet)
2800.00 2600.00
Gamma Ray App [RWD]
GRAM (MWDAPI)
0.00 150.00
WL Spontaneous Potential Well 225
SP5 (mV)
3.00 ft Smoothing
-60.00 40.00
Resistivity (AT) (LS) [RWD]
2MHz-Comp Borehole Corrected
RACHM (ohmm)
0.20 2000.00
Resistivity (PD) (LS) [RWD]
400kHz-Comp Borehole Corrected
RPCLM (ohmm)
0.20 2000.00
Resistivity (AT) (LS) [RWD]
400kHz-Comp Borehole Corrected
RACLM (ohmm)
0.20 2000.00
Resistivity (PD) (LS) [RWD]
2MHz-Comp Borehole Corrected
RPCHM (ohmm)
0.20 2000.00
WL Short Normal Well 225
RSN5 (ohmm)
0.20 2000.00
WL Deep Induction Well 225
RILD5 (ohmm)
0.20 2000.00
Tidelands Oil Prod.
L-233 Model Correlation Log
Long Beach California
INC AZM
7 5/8" Casing
Remark # 1
TD

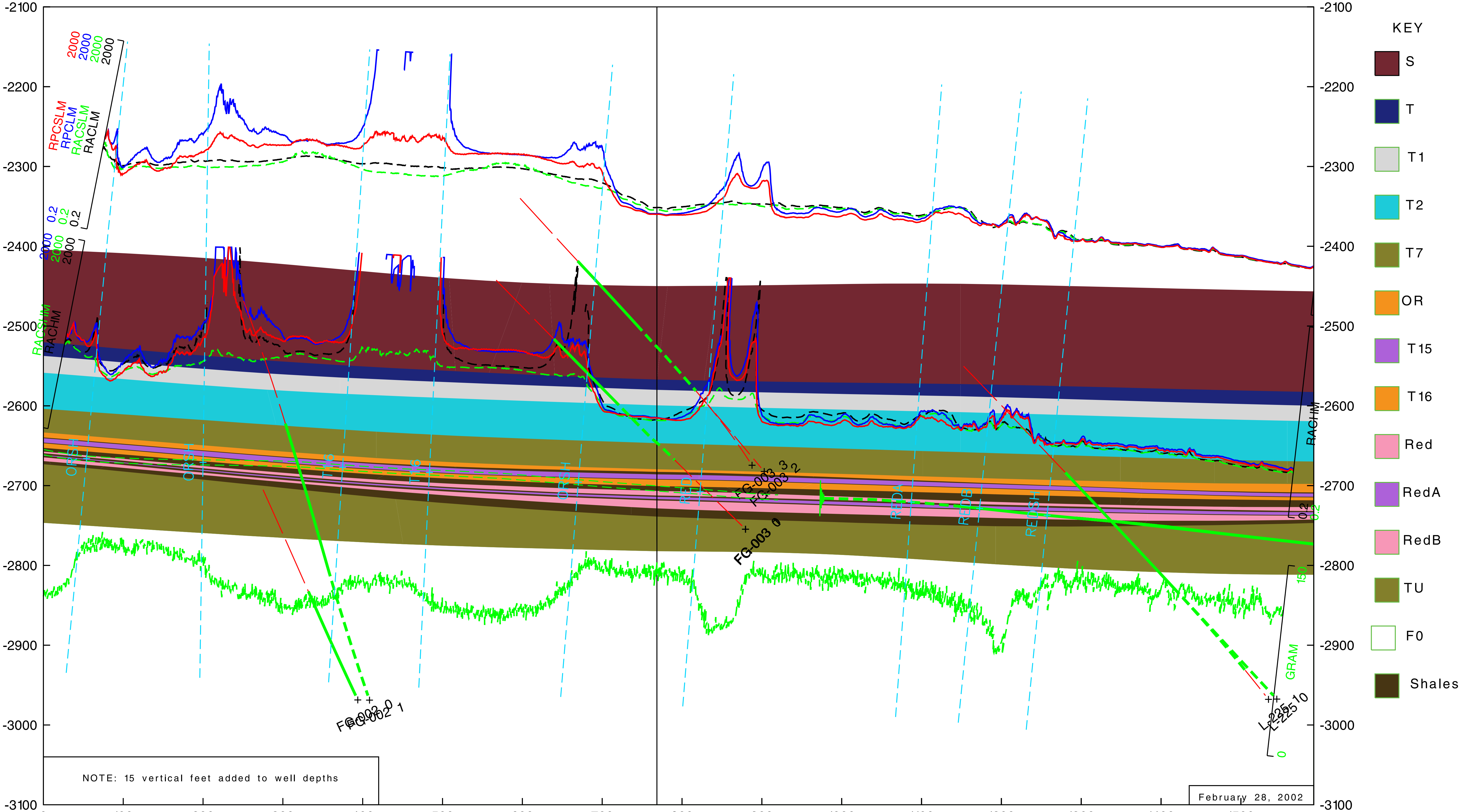
FIGURE 15



WEST
CROSS SECTION PARALLEL TO L-233 HORIZONTAL WELL
EAST
KEY
S
T
T1
T2
T7
OR
T15
T16
Red
RedA
RedB
TU
F0
Shales
Note: Well depths adjusted 15' vertically down.
February 28, 2002
L-610 0 Well ID with Redrill Designation
+ T Marker Horizon Top
Well Path in Front of Cross Section
Well Path Behind Cross Section
SCALE:
V = H
Thinner Red lines - Well Paths are within 100'
Thicker Green lines - Well Paths are within 50'
Scale: 1 inch = 120 feet
CCP: /disk7/phillips/FB5/TarV/TsandParL/ORAlt

FIGURE 16

WEST CROSS SECTION PARALLEL TO L-233 HORIZONTAL WELL EAST



L-610 0 Well ID with Redrill Designation

\+ T Marker Horizon Top

Well Path in Front of Cross Section

Well Path Behind Cross Section

SCALE: V = H

120

60 120

Thinner Red lines - Well Paths are within 100'

Thicker Green lines - Well Paths are within 50'

Scale: 1 inch = 120 feet

CCP: /disk7/phillips/FB5/TarV/TsandParL/ORAlt

FIGURE 17

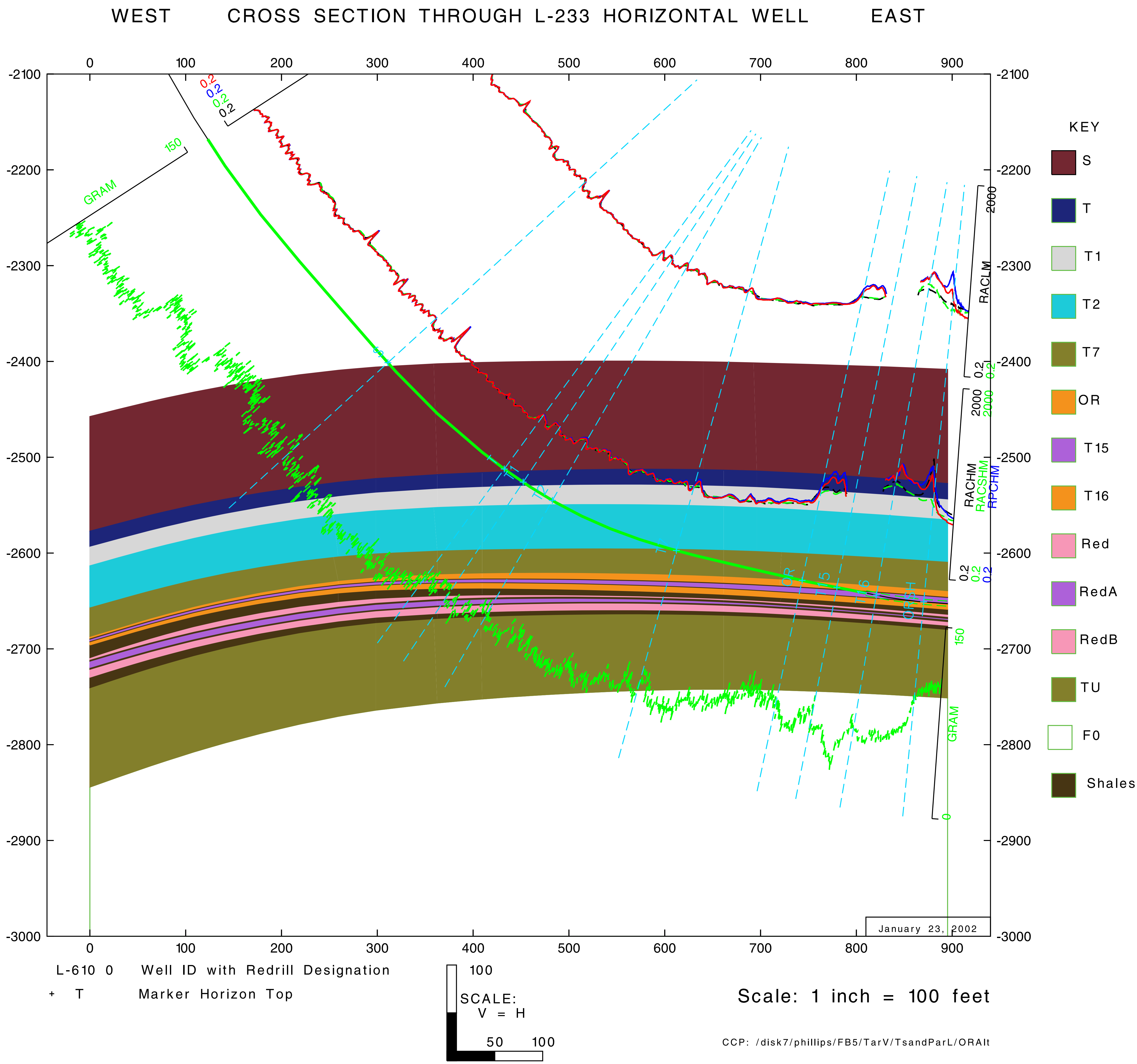

WEST
CROSS SECTION THROUGH L-233 HORIZONTAL WELL
EAST
KEY
S
T
T1
T2
T7
OR
T15
T16
Red
RedA
RedB
TU
F0
Shales
GRAM
RACLM
RACHM
RACSHM
RPCHM
January 23, 2002
L-610 0 Well ID with Redrill Designation
+ T Marker Horizon Top
SCALE:
V = H
Scale: 1 inch = 100 feet
CCP: /disk7/phillips/FB5/TarV/TsandParL/ORAlt

FIGURE 18

L-233 RWD LOG

L-233 0 Well ID with Redrill Designation

\+ T Marker Horizon Top

Vertical Scale: 1 inch = 50 feet

CCP: /disk7/phillips/FB5/TarV/TsandParL/ORAlt

Propagation Resistivity Curves Key:
Amplitude Curves (RA) -> Dashed
Phase Curves (RP) -> Solid
RACHM & RACLM -> Black
RACSHM & RACSLM -> Green
RPCHM & RPCLM -> Blue
RPCSHM & RPCSLM -> Red

CL = 400 kHZ Curves
CH = 2 MHZ Curves

S = Short Spaced
M = Recorded While Drilling

FIGURE 19

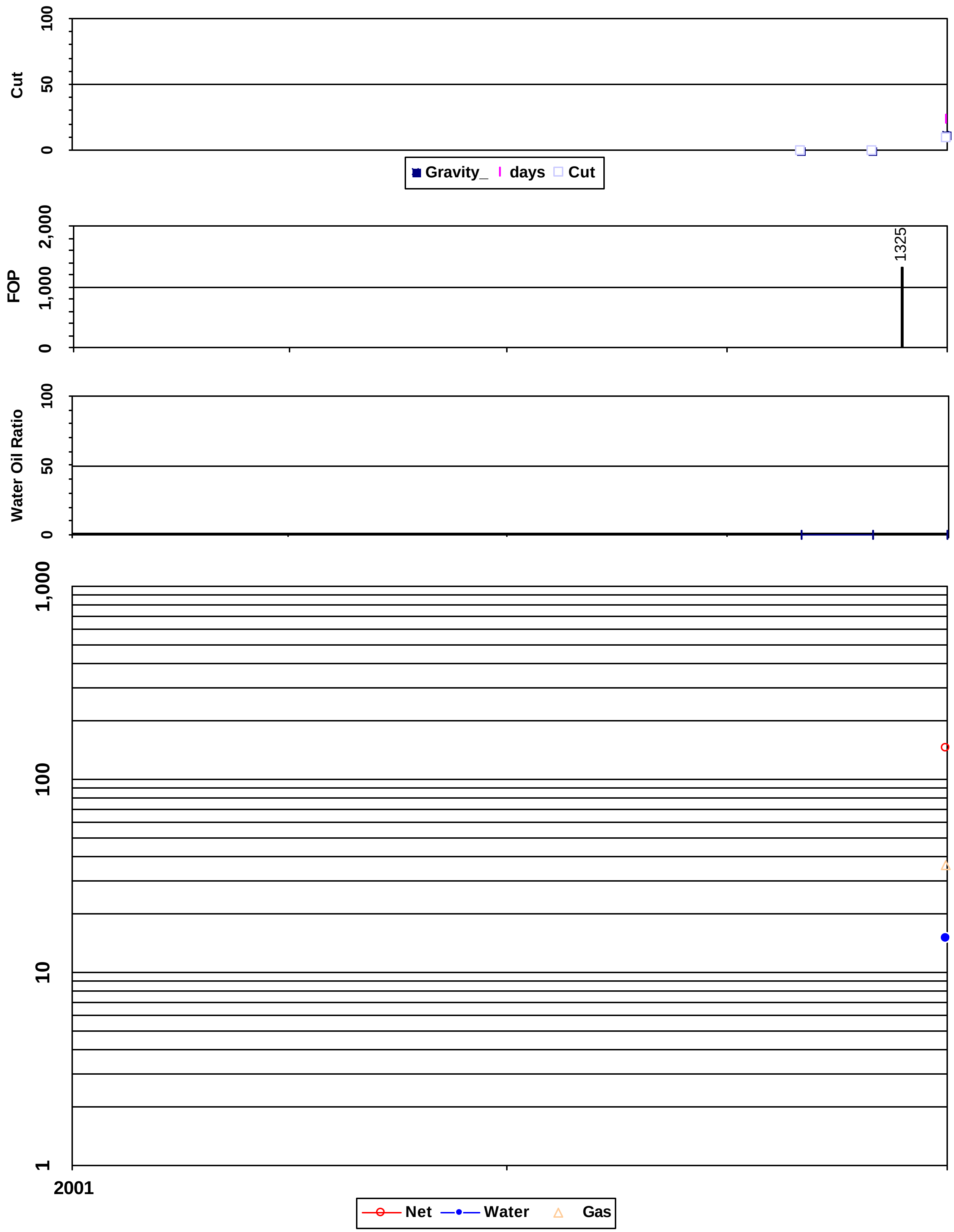
03/07/2002

T.......

Tidelands Oil Production Company
Oil, Water & Gas Production

L -233

T 5



File = P:\Prod-Inj Graphs\Vol_Reports.mdb Report = 220_Prod_Hist_Rates_frm

FIGURE 20

Tidelands Oil Production Company
Oil, Water & Gas Production

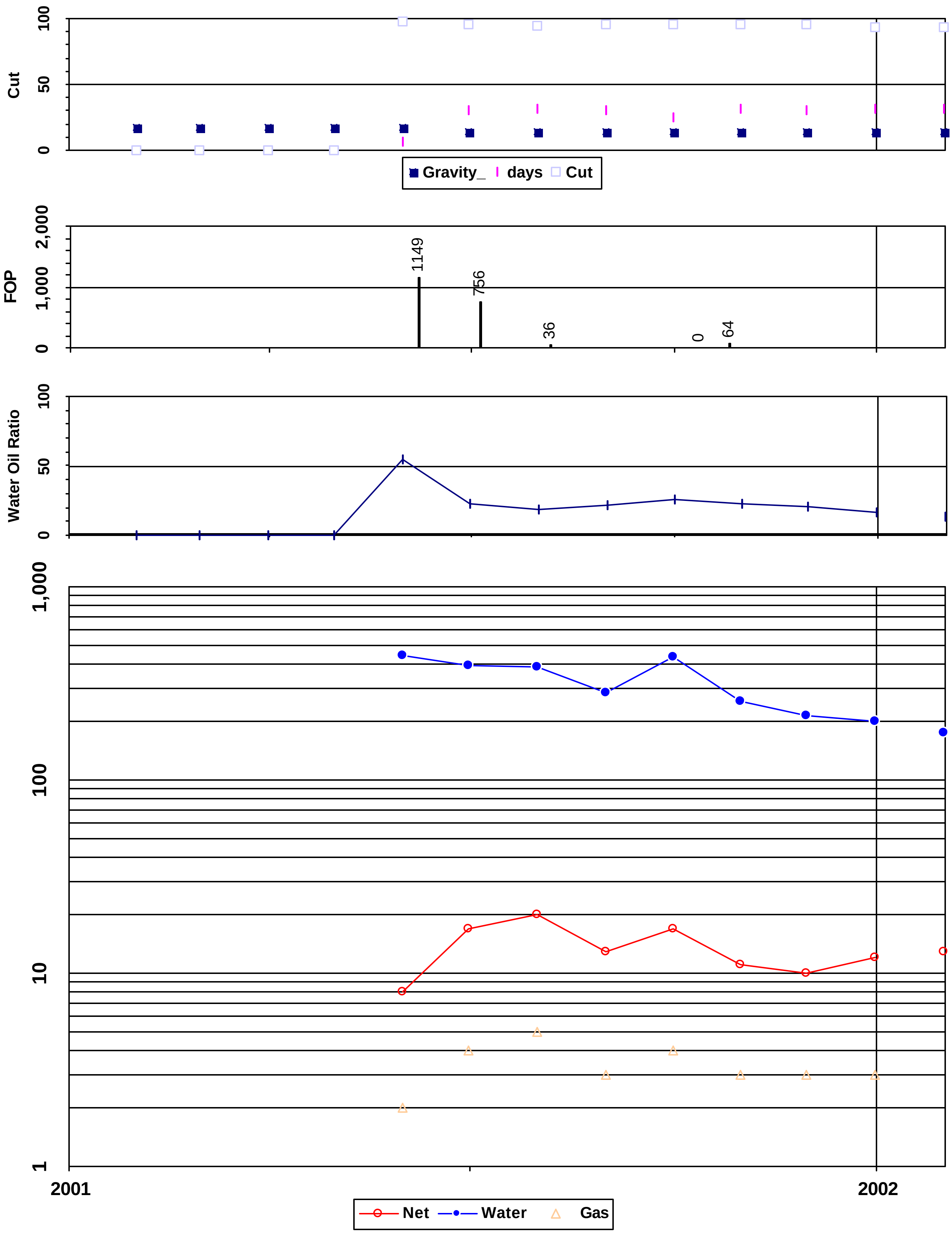


FIGURE 21

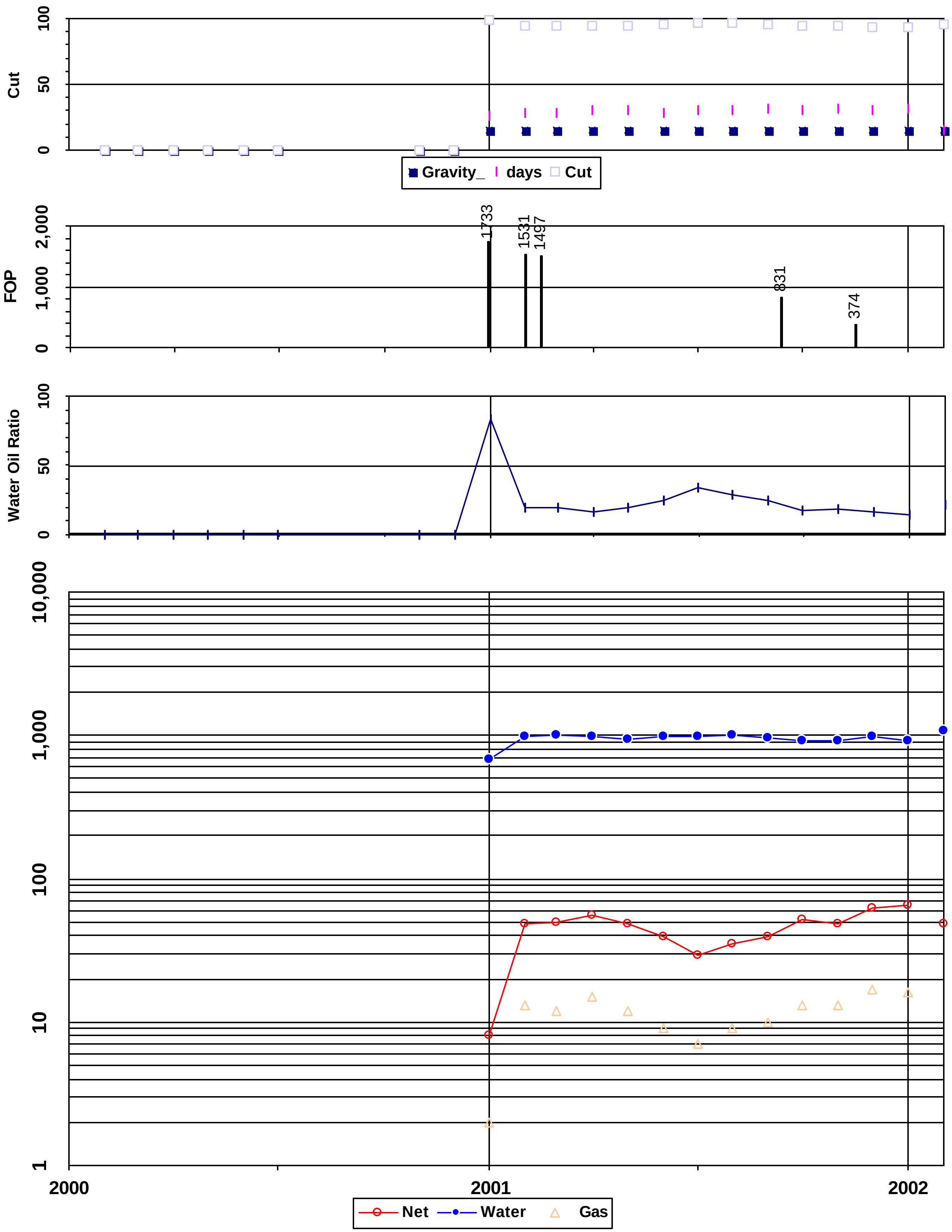
03/07/2002

T.......

Tidelands Oil Production Company
Oil, Water & Gas Production

A -112

T 5



File = P:\Prod-Inj Graphs\Vol_Reports.mdb Report = 220_Prod_Hist_Rates_frm

FIGURE 22

03/07/2002

..U.....

Tidelands Oil Production Company
Oil, Water & Gas Production

J -017

UT 5B

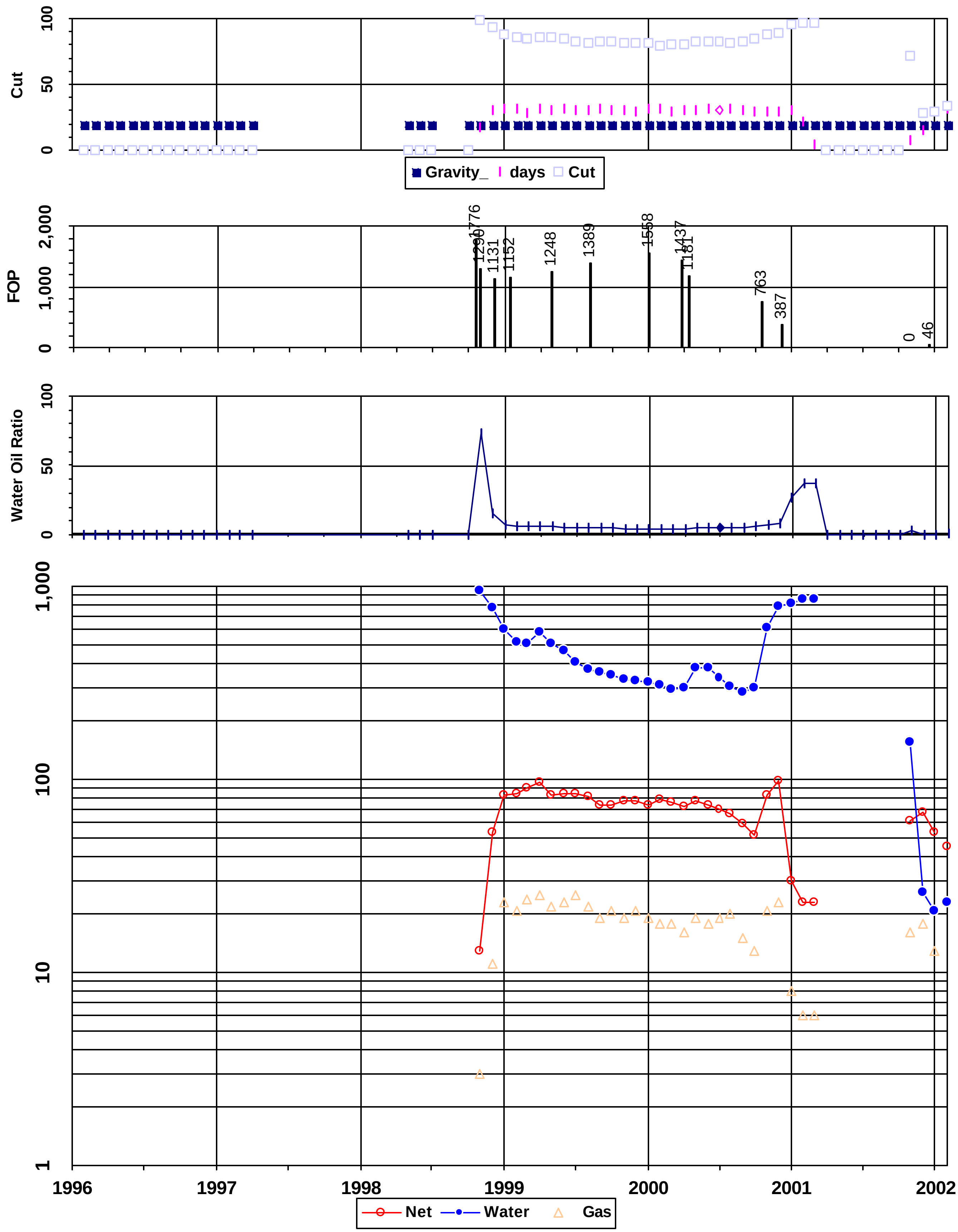


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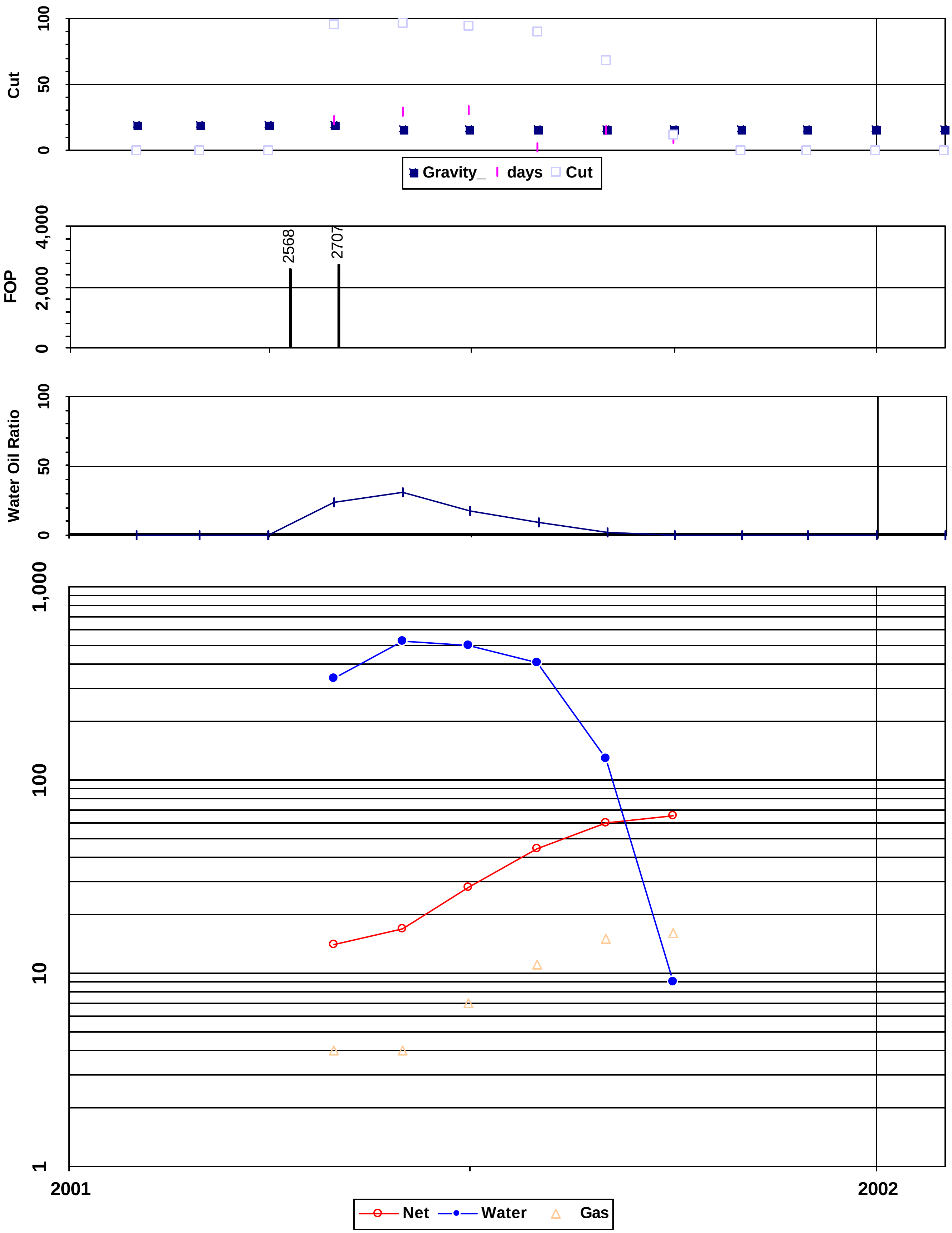
FIGURE 23

03/07/2002 **Tidelands Oil Production Company** **A -088**

..U..... **Oil, Water & Gas Production** UT 5B



File = P:\Prod-Inj Graphs\Vol_Reports.mdb Report = 220_Prod_Hist_Rates_frm

FIGURE 24

03/07/2002

..U.P...

Tidelands Oil Production Company
Oil, Water & Gas Production

Z -223

UT 5A

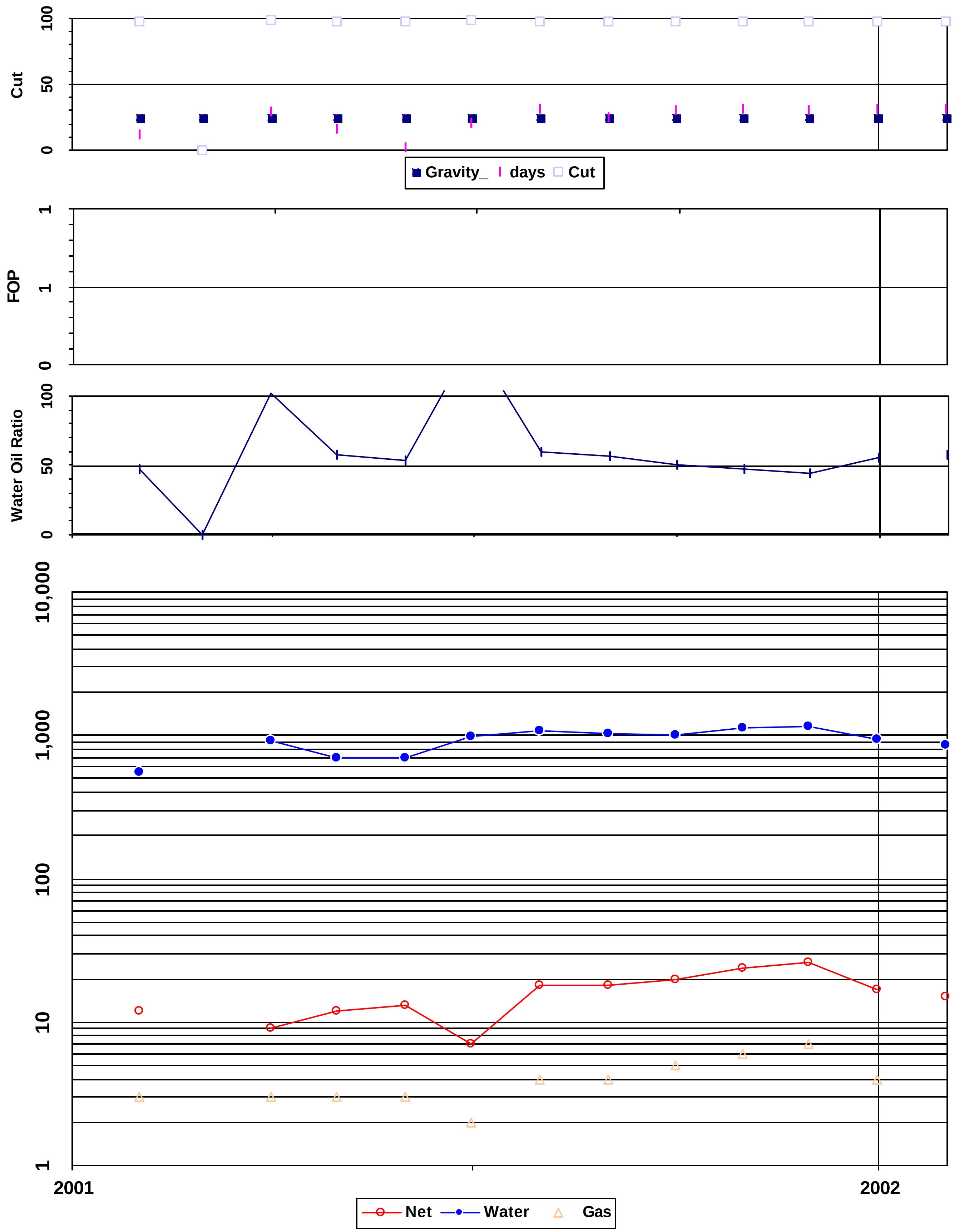


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FIGURE 25

03/11/2002

..U.....

Tidelands Oil Production Company
Oil, Water & Gas Production

Y -063

UT 4

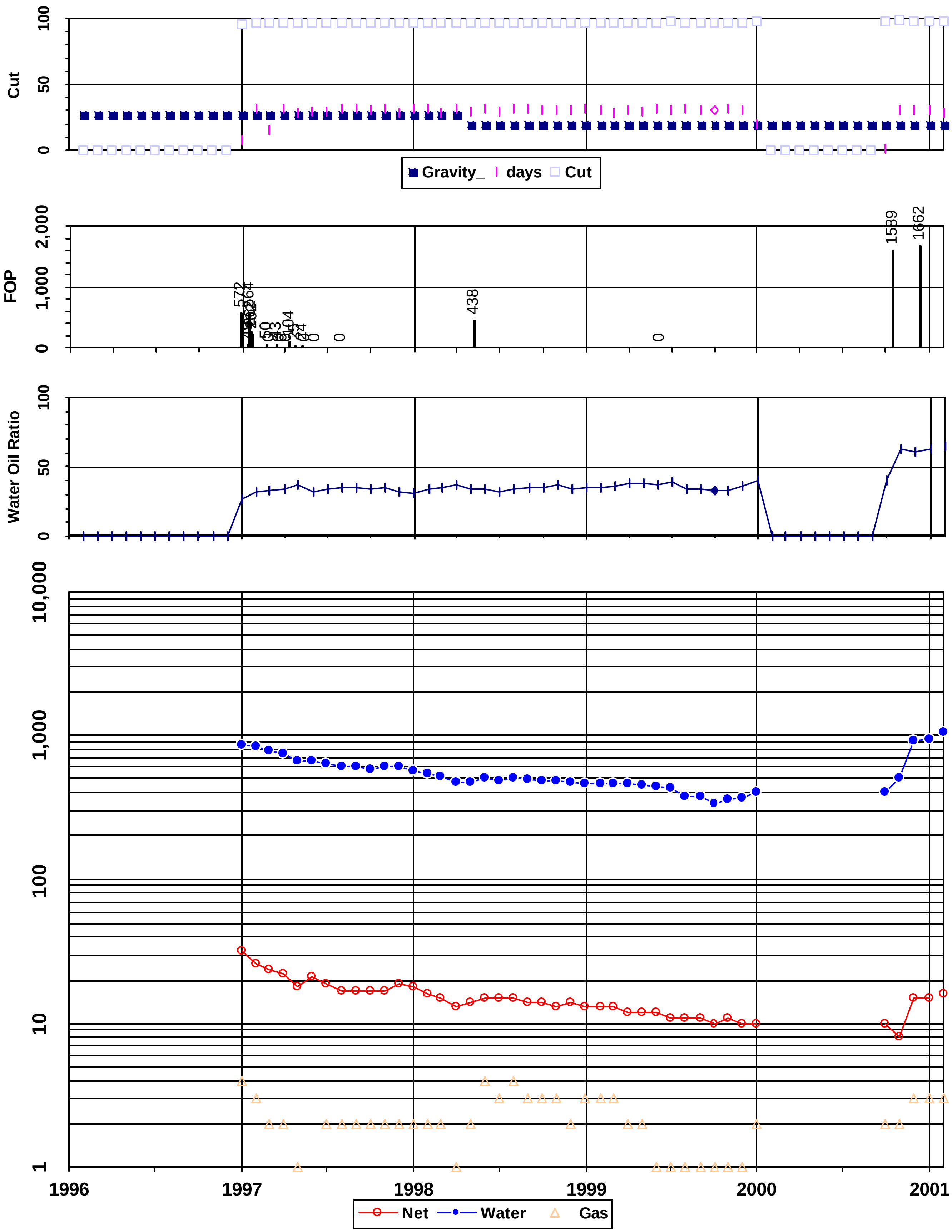

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FIGURE 26

03/11/2002
..U.....

Tidelands Oil Production Company
Oil, Water & Gas Production

J -120
UT 5B

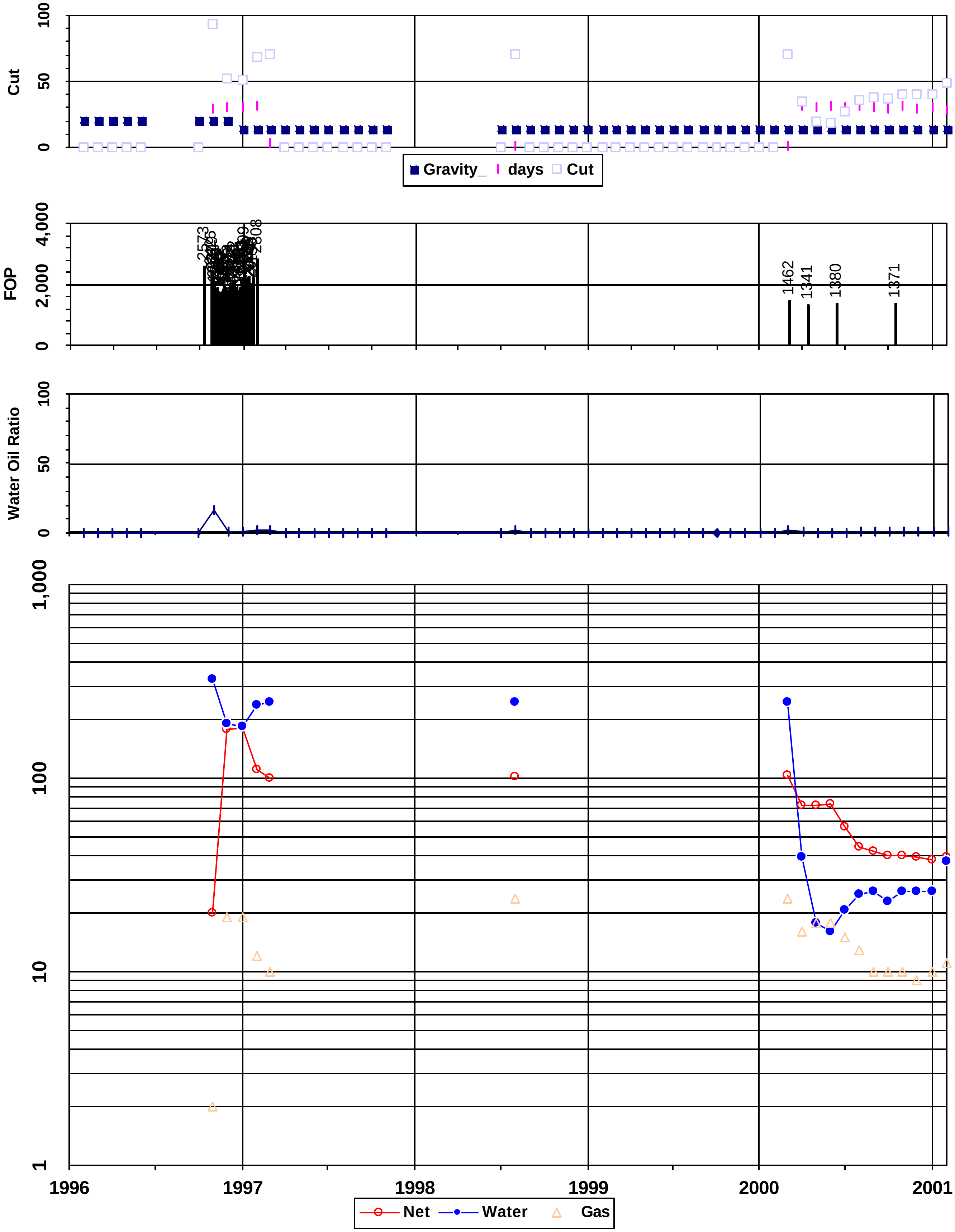

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FIGURE 27

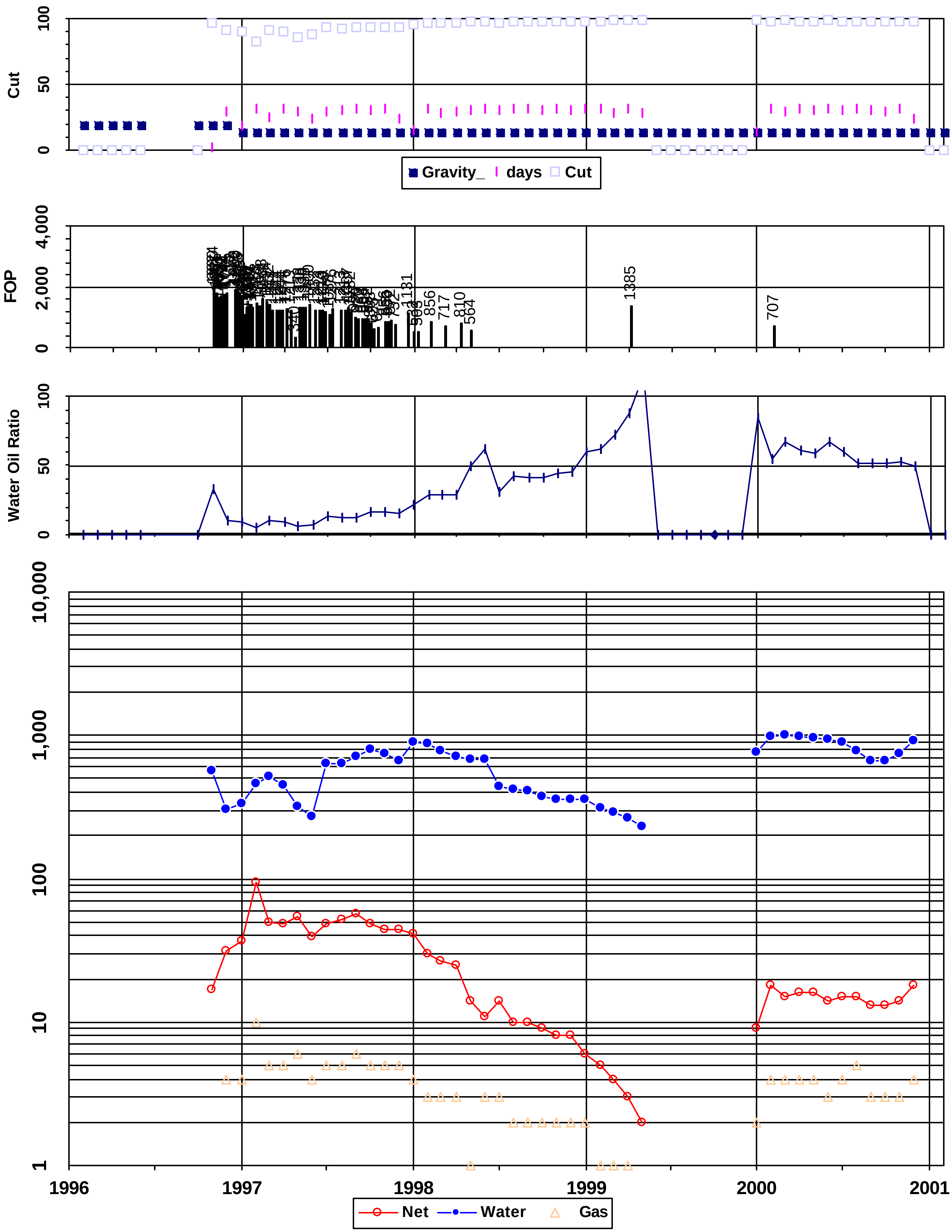
03/11/2002

T.......

Tidelands Oil Production Company
Oil, Water & Gas Production

J -015

TB 5



File = P:\Prod-Inj Graphs\Vol_Reports.mdb Report = 220_Prod_Hist_Rates_frm

FIGURE 28

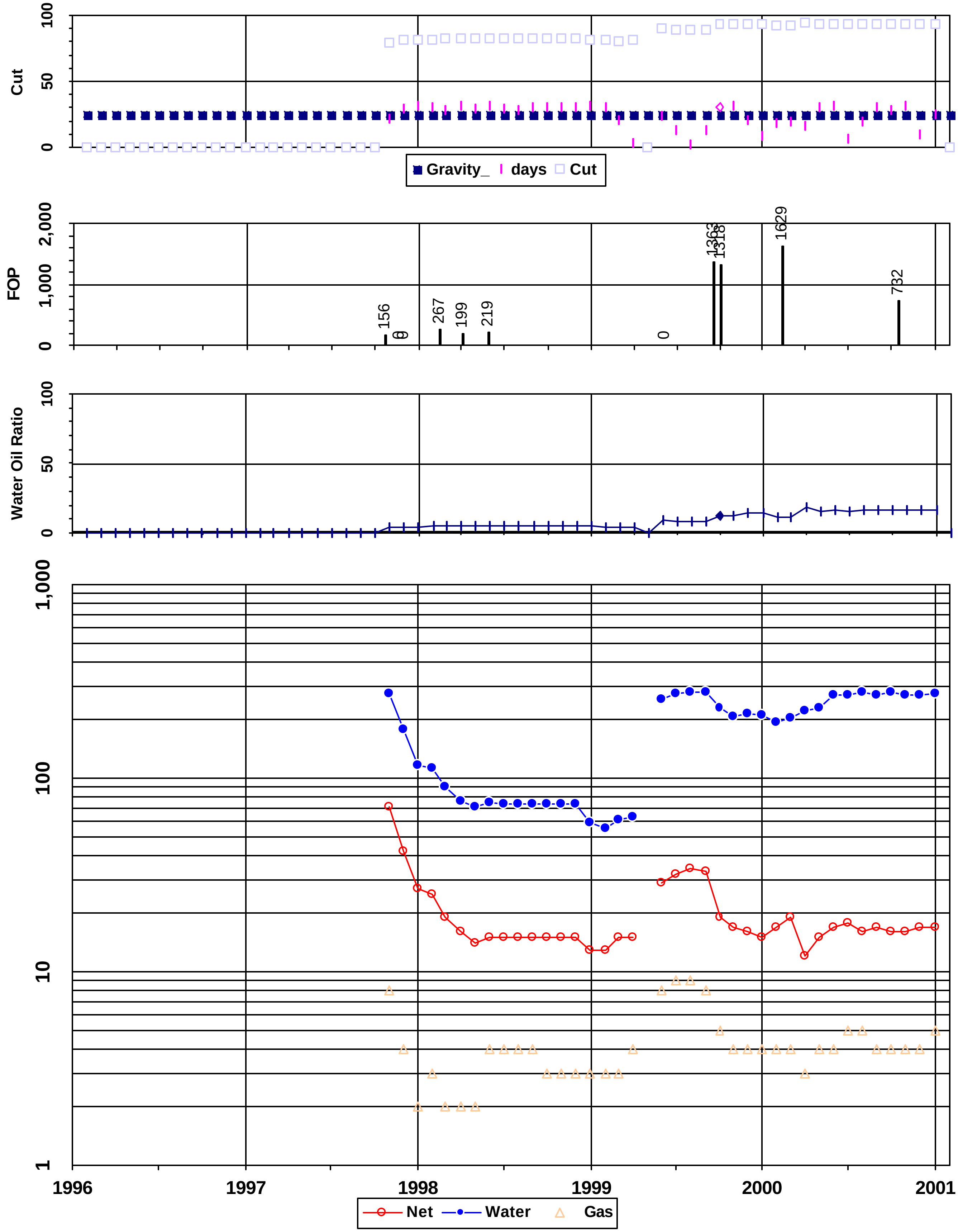
03/11/2002

T.......

Tidelands Oil Production Company
Oil, Water & Gas Production

Z -061

T 5



File = P:\Prod-Inj Graphs\Vol_Reports.mdb   Report = 220_Prod_Hist_Rates_frm

FIGURE 29