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Characterization of Turbidite Sand Completions and Their Relation to Formation Damage by Sand Liquefaction: Part II-Problems and Possible Solutions

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Abstract

Turbidite sands are producing zones found generally in the continental shelves of the Gulf of Mexico. They are primarily characterized by low to moderate resistivity (0.6-2.0 Ohm-m), low resistance to shear stress, lack of compaction/consolidation, medium to high clay content, and a sequence of fine-to-coarse or coarse-to-fine (20-100 micron) mean grain size

Turbidite sand completions are extremely prone to Formation Damage due to well sanding. The damage mechanism is *sand liquefaction*. It appears that sand "liquefaction" begins in the perforated sections of the hole that have higher *water saturation,* S_w. The methodology proposed for evaluating sand liquefaction potential is described in the part I of this paper[2]. The results of our work in this paper, (Part II), show that Formation Damage due to *sand liquefaction* can be alleviated by (1) placing the perforations parallel to the direction of the major horizontal principal stress if an orienting tool is available or, alternatively, perforating the well with high density shots (8 SPF) on the low side with a medium hole entrance size (approximately 0.3 to 0.4 inches) and 30-0-30 degree phasing on low side, (2) implementing a *selective completion* procedure for choosing the most stable parts of the turbidite sand, with an emphasis on modeling and profiling the water saturation and avoiding the placement of perfs where the values of the water saturation, S_w , falls outside the range of a hydrocarbon indicator function, and (3) implementing a *critical time* duration to shut-in (*soft shut-in*) and to start-up (*soft start-up*) procedures during production and injection operations. Finally, a comparison of production data from a completion conducted *before* our study of turbidite sand problems with the production from a completion conducted *after* our study points to the fact that implementing an appropriate Drawdown schedule could prove to be beneficial to the operator. The paper includes our detailed analysis and characterization of turbidite sand problems with possible recommendations that, if implemented fully, could prove to be useful in overcoming these problems. Based on an analysis of the field data from three wells, (a Well Adjacent to Well (1), Well (1), and Well (2)), we conclude that the turbidite sands could be completed with fair to good production results with the standard gravel pack method if the recommendations based on our study and analysis are carefully considered.

Introduction

Whitten and Brooks[1] defined Turbidite and Turbidity currents when they wrote: "It is a matter of common observation, and an easily demonstrated fact, that slurries of sediment and water behaves as a discrete fluid phase when poured into fresh or sea water. It is now generally accepted that such slurries can be generated in large quantity in various types of basins and will flow down a slope at remarkably high speeds, covering distances of tens of kilometers. The movements of these masses of slurry are termed *turbidity currents, or density currents,* and the sediments deposited as a result of such a current are termed *turbidite…* Turbidites display a wide range of *sedimentary structures*, including *graded bedding,* load, flute, and groove casts, and "*flame*" structures. The major environment for *turbidites* is a *geosyncline;* but modern turbidity currents are known to move down the continental slopes. Turbidity currents are capable of eroding the floor of the basin or the slope and are responsible for transferring large quantities of shallow –water sediments into deeper zones. The recognition of the work of the turbidity currents has revolutionized ideas on rates of sedimentation and the depths of water in which sediments were deposited."

In the Gulf of Mexico the fundamental production problem of Turbidite Reservoir Completions begins with severe formation damage caused by *formation sand liquefaction*[2]. At the root of the problem there lies a lack of the *cement* that

glues the sand grains together, small grain sizes, and a characteristic shale lamination. The shale laminations are classified into several classes. They are: Type 1 (lamination thickness of less than 1 millimeter, not a common type of shale lamination in turbidite sands), Type 2 (lamination thickness of 1-5 millimeters, a minority type lamination), Type 3 (lamination thickness of 5-10 millimeters, a majority type lamination), and Type 4 (lamination thickness of greater than 10 millimeters, a majority lamination). These particles grade differently as they travel and are deposited along the path of the turbidite currents. The grades are often classified as *poorly sorted* for large particle sizes and *well sorted* for the small particle sizes. The particle shape, depending on the amount of work done on them, are classified as *angular, sub-angular, sub-rounded, and rounded.* The mineralogy of *turbidites* is mainly composed of *Quartz, Feldspar*, *Mica, Glauconite* (iron illite or green sand), Clay minerals, Iron oxides, and some pyrite. As for structures, "Under special circumstances of particle size, water content, etc, it is possible for one layer of sediment to force its way upward into an overlying layer and even occasionally to pierce it and flow out at the surface. Various terms for such structures have been proposed. The *piercemen*t (injection) structures have been called sand or mud volcanoes… Non-piercing structures have been referred to as *flame* structures, sandstone dykes…and streamers…"[1]

With regard to the kinetic motion of the *turbidite* sediments, it may be possible that the very fine grain fractions, as they "*pierce"* their way into the upper layers, may leave behind the shale lamination we mentioned previously until the extremely fine fractions reach the equilibrium size on the very top of the sediment column, as if the fines accumulate in the "pan" of an inverted sieve stack, or the sediments simply run out of the fine grain "mesh" size needed to allow for further sieving. Obviously, as the fine and low-density grain fractions rise to the top, the coarse and high-density grain fractions must sink to the bottom to compensate for the fine grain motion. This mechanism may actually simulate a combination of "jigging", "tabling", and "sieving" processes used extensively in the mining and mineral processing industries. In this analogy, the accumulation of certain closely sized grains in a given plane, along the vertical axis of the sediment column, constitutes a certain mesh size through which the very fine grains must travel upward. Hayatdavoudi proposes the term *"autogenous sieving" or "self-sieving"* for this mechanism. Some evidence of this mechanism, regarding the *coarsening downward* trend in the zone of interest of Well (2), will be shown later in the results and discussion section of the paper.

Additionally, in our opinion, it may well be that the shale lamination thickness and the clay fraction, which coats the sand grains and their young age, could not only physically interfere with the pressure compaction and bonding mechanism, like a cushion, but could also block the vertical permeability and thus prevent the transport of the chemical species required for the chemical consolidation of the sand grains. For example, the likely cement-forming Ca, Mg, and Fe ions, their concentrations, and the carrier fluid may undergo cation exchange with the clay fraction of the shale lamination, or undergo the process of absorption, or adsorption in the shale laminations, which may prevent the formation of the cement that binds the sand grains together. Indeed, the shale lamination, with its high concentration of *Kaolinite*, *Mica*, some *Feldspars*, and *Smectite,* may provide a "sliding" or a "shear" failure surface between the adjacent layers. Furthermore, these laminations, which act as internal *micro-seal* while "*holding*" the water content at an artificially high level, may be responsible for the low overall "resistivity" of the sand and the increased water saturation, S_w, well above the expected critical levels. Of course, the consequence of lack of cement, which results in very poor consolidation of the *turbidite* sands, combined with some field operational practices during drilling, completion, and production with a high rate of water encroachment, high erosion velocity in the perf tunnels which results in the appearance of a free surface behind the casing, and other factors, could lead to severe formation damage by sand liquefaction. The facts, as documented in Figures (1) through (5), speak to the severity of sand liquefaction problems as we have witnessed in our fieldwork.

At this juncture, although there may be several technological options available, including modern sand control means such as the placement of an expandable casing, screen or liner, we asked ourselves what the solutions are to these problems that concurrently take into account the economics of a turbidite sand completion while finding a compromise between the "ideal" and "realistically reasonable" approaches to producing a well, all for the purpose of satisfying the conditions of a given level of risk. In order to answer this question, we patiently embarked on a systematic, inter-related, comprehensive engineering and scientific analysis of the sand liquefaction problem, which was encountered in Well (1). The study was undertaken to see whether there is any underlying phenomenon (or phenomena) that could possibly afford us an insight as to the nature of *turbidite sand* problems and hopefully give us some clues as to how we should proceed toward some reasonable solutions. We had to cast a large net to gather all the information even though some of this information, at the first glance, seemed to be unrelated. We studied and examined the field data from Well (1). The data sets included, but were not limited to, the very important sources shown below:

1. **Drilling data**
    a. **Daily drilling reports**
    b. **Daily mud reports**
    c. **Bit records**
    d. **Drill time log**
        - **ROP log**
        - **Hydrocarbon "shows" log**
        - **WOB**
        - **RPM**
        - **Pump pressure**
        - **Pump strokes/flow rate**

e. Casing programs
f. Drilling hydraulics

2. Mud logging reports
- **Lithology**
- **Cuttings data**

3. Paleo marker logs and reports

4. Open hole logs
- **Caliper/ differential caliper**
- **Cable Tension**
- **Gamma ray**
- **Apparent water resistivity**
- **Spontaneous Potential**
- **Photo Electric**
- **Neutron (density and porosity)**
- **Resistivity (several shallow, medium, and deep)**
- **Sonic (shear and compression)**

5. Side wall core reports

6. Side wall core particle size analysis

7. Size-based Capillary data

8. Petrology and mineralogy
- **X-ray diffraction (bulk and clay fractions)**
- **Scanning electron microscopy**
- **Thin section**

9. Primary Completion
- **Shots density (shots/foot)**
- **Shot phasing**
- **Estimated perforation tunnel length**
- **Estimated hole entrance diameter**
- **Gun size and stand-off**
- **Completion fluid**
- **Packer fluid**
- **Packer depth**
- **Downhole tools**
- **Displacement fluid and field practice**
- **Completion pressure differential (overbalanced, balanced, or under-balanced fluid column)**

10. Remedial Completion
- **Sand control procedures**
- **Screen and slot size**
- **Gravel size of the gravel pack**
- **Gravel pack pressure regime**
- **Gravel pack perf size**
- **FracPac pressure-time profile, flow-time, rock mechanics, fluid properties, mini frac, and other related data**

11. Production
- **Daily gas production**
- **Daily condensate/oil production**
- **Daily water production**
- **Well shut-in pressure**
- **Tubing shut-in pressure**
- **Tubing flowing pressure**
- **Casing pressure**
- **Choke/Bean size**
- **Separator and surface facilities pressure**
- **Down time and production time**

Equipped with the data obtained from Well (1) and a Well adjacent to Well (1), and the conclusions reached thereafter, we proposed a series of recommendations that were expected to alleviate, to some degree, the sand liquefaction problems in the poor *turbidite pay zone* found in Well (2).

Results and Discussion

A. Geology, Mineralogy, Petrography, Paleontology, Petrophysics, Turbidite Reservoir Quality and Completions.

As mentioned in the Introduction of this work, the constituents of *turbidites* are basically fine particles that originate from the weathered and ground-up *arenaceous* (sandstone or arenite) rocks. These sandstones, prior to "becoming" components of turbidites, were deposited either by water or wind action in some basin, which was later eroded away by currents. The size of these particles varies along the sedimentation path and the very fine particles are deposited farther, at some distance from the source(s), in a *geosyncline*. The sizes of the particles vary from very coarse (2-1 millimeter or 2000-1000 micron), coarse to medium, (1-0.5 millimeter or 1000-500 micron), medium to fine (0.5-0.25 millimeter or 500-250 micron), fine to very fine (0.25-0.125 millimeter or 250-125 micron), and very fine (0.125-0.0625 millimeter or 125-62.5 micron)[1]. However, the results of our study of Well (1) and Well (2) in the Gulf of Mexico, as summarized in Table (1), clearly indicate that the Mean Grain Size (MGS) of these particles is far below the particle size ranges enumerated above. This finding may be due to the fact that the turbidite deposits may be found far beyond the *continental shelf* of the Gulf of Mexico.

Often, *turbidite* currents gain enough viscosity to carry and/or suspend high loads of sediments and gain such a high speed that under a slight impulse (earth movements, faulting, or other mechanisms) can destroy cables and pipelines laid on the sea floor. Our analysis of the particle size of these *turbidite* sediments makes it obvious that as the Mean Grain Size decreases, the *permeability* (K_{air}) decreases accordingly. However, this fact becomes more self-evident when we include the *porosity* (phi fraction) as a part of a convolution integral function, compute the function, and then plot the results against the *mean grain size* (MGS). As an example, the plot in Figure (6) clearly shows our analysis data for Well (2), where the data is taken from the Side Wall Core Particle Size Analysis. The fitted polynomial model, with the high "goodness-of-fit" criteria, like Coefficient of Determination, R^2 = 0.953 and high Coefficient of Correlation = 0.976, makes it obvious that the MGS not only plays a highly significant role in *Turbidite* Reservoir Quality characterization,

permeability being a key parameter of the original convolution integral, but it is also a highly significant factor in making an informed decision as to how and which part of the zones of interest of the reservoir should be considered for Completion. Interestingly, Figure (7), which is based on Well (2) Side Wall Core data, further shows how, for example, the sedimentation mode mentioned in the Introduction favors the trend of *grain coarsening downward.* This finding clearly and simply tells us that the *lower* parts of the zone of interest, where the grains are *coarser,* may be more economical to produce at the beginning of the well life than the *upper* part.

But these findings, as significant as they may be, are not enough to lead us to a successful completion. They merely give us some hints as to the characterization of turbidite reservoir and offer us some insight as to what to do next.

The next task we must carry out is to characterize the bulk and clay mineralogy of the *turbidite* sands. We should measure, at least semi-quantitatively, the *amount and composition* of the *grains* and the *cement* that binds the sand grains together via X-ray diffraction analysis, herein referred to as XRD. This analysis gives us an idea of whether there is an adequate amount of grain binding *cement* in the *lower part of the zone* of interest to withstand high shearing stresses, should we decide to *pull* the well at a high drawdown pressure. Additionally, using the scanning electron microscope, referred to as SEM, helps us to document the 3-D spatial position or distribution of the *cement* and clays and to characterize the *grain failure surfaces,* especially where the concentration of *Feldspars, Mica, and Kaolinite* is fairly high. Also, it would be of great benefit to our work to augment the XRD and SEM results with Thin Section Analysis, referred to as TSA. This is used for the combined study of the mineralogy, petrography, acid sensitivity analysis, water sensitivity analysis, grain cement characterization, 2-D morphology of the sand grain surfaces, cleavage plane analysis, grain size-count frequency analysis, mineral distribution analysis, measurement of the thickness of shale lamination, measurement of the frequency of shale laminations per unit length, geometrical properties of the grain major and minor axes (aspect ratio and/or sphericity), grain packing mode, grain sorting, etc.

Following our plan of study, we prepared several Thin Section slides from the samples taken at *Upper* (12078), *Middle* (12108), and *Lower* (12128) zones of interest in Well (2). The results of TSA are shown in Figures (8-a), (8-b), and (8-c). The evidence of the sand grain distribution from these figures corroborates the results of Figures (6), (7), and Table (1), that is, the *upper part of the turbidite reservoir is much finer than the lower part*, the trend of the *grains coarsening downward* found in Well (2) is correct, and the *lower* part of the reservoir, as far as the *permeability (*resulting from the coarser grain size) is concerned, *potentially* contains a better *Quality* sand than the *upper* part. Furthermore, the *stained cement grains distribution* (reddish color) appears to be few and far in between. To ascertain the amount of the cement semi-quantitatively, as will be shown later, we will use XRD.

As mentioned in the Introduction, our results confirm reasonably well the expected mineralogy of the *turbidite* sands and an inadequate amount of *cement*. The XRD results of Table (2) clearly show that the sand composition is comprised mainly of *Quartz*, the majority component, *Feldspar* (*Orthoclase, the Potassium Feldspar, and Plagioclase, the Sodium Feldspar*), *Mica,* which is relatively abundant in the shale laminations as compared with the sand laminations, very small amounts of *Calcite, Magnesium Calcite*, *Iron-bearing Dolomite* (*Ferroan Dolomite*), and clays, the minority components. The *lack* of *cement, or an inadequate amount of it,* as seen in Table (2) and as mentioned in the introduction, make the *turbidite completions* extremely sensitive to high rates of production, due to high erosion velocity near the walls of the perforation tunnels, and the shearing stresses caused by the same high velocity at the walls of the perf tunnels. In addition to this, the evidence of a lack of an adequate amount of *cement* (*Calcite, Magnesium Calcite,* and *Iron-bearing Dolomite* or *Ferroan Dolomite*), as shown in Table (2), makes these *turbidite sands* extremely sensitive to suddenly induced high drawdown or injection pressures, especially when the water table encroaches into the pay zone or the original water saturation, S_w, that could be high enough to cause severe formation and equipment damage due to *sand liquefaction*[2]. Interestingly, a comparison of Swelling or the Hydration Index[3], the HHI scales, of the two samples from Well (1) and the two samples from the Upper Zone (12074) of Well (2) clearly indicate a high swelling characteristics of the micro-seals or possibly unstable nature of the laminations. In short, the XRD findings documented in Table (2) simply tell us that the *amount* of *cement* is not sufficient to make the *cohesive resistance* of the turbidite sand high enough for tolerating high drawdown pressures and the resulting shearing stresses at the perforation walls.

Although the above information is extremely helpful in our decisions regarding our Well Completion strategy, we still need to know how and where this *turbidite* sand with such low cohesive resistance could fail. The probable *sliding* planes of sand failure could be located at the surface of the sand grains that are coated with *Feldspars* and *depositional* clays, especially where the concentration of thin, flat, slick *Mica (Muscovite)* is high. Toward this goal characterizing the sliding planes, we prepared samples of sand from the Upper Zone (12078), the Middle Zone (12108), and the Lower Zone (12128) for SEM Analysis. Figure (9), the SEM analyses of the samples from Well (2), clearly show the distribution of the *unstable* planes of *sliding (shear)* failure to be found in the Upper Zone, where the *depositional clays with higher HHI*[3]*, slick, thin, flat Mica Flakes, and K-Feldspar* provide no cohesion or cement between the grains.

So, what we *learned* from our inquiry into the nature of *turbidite* sands is that they are extremely weak and are unable to withstand remedial completions such as Under-balanced Perforation, or even minimal Under-balanced Drilling practices, and they certainly are not ideal candidates for FracPacking or Acidizing. These sands appear to be prone to

shear failure caused by high drawdown pressures, high erosion velocities, and the consequent *sand liquefaction,* as seen in *Figure (1)-(5)*. We did not have any production data from Well (1) because it produced nothing but a large amount of liquefied sand. However, in order to learn about the nature of production from the turbidite sand, we looked at 1280 producing days worth of data from a well adjacent to Well (1), which was completed in the same type of sand. This Well will be referred to, in this work, as the "adjacent well." We have studied and analyzed the data from this well and discuss it below.

B. Analysis of Engineering Data in Pursuit of a "Needle in A Hay Stack."

Analysis of Production Data From a Well Adjacent to Well (1):

As mentioned earlier, since there was no production data from Well (1), the first objective of our study was to analyze the available production data from a Well adjacent to Well (1) as a prelude to the study of the poor performance of Well (1). The second objective was to examine the available production data to determine what can be learned from it within the context of real-time production analysis, using Hayatdavoudi's Production Optimizing Parameter, herein referred to as P.O.P. The third objective was to use the above-mentioned POP method as the basis for some recommendations regarding future turbidite completions or re-completions.

In our analysis, we first formed a data matrix comprising of 3,510 elements. Second, using a propriety model based on Hamiltonian-Lagrangian minimum energy principles, we calculated the values of the P.O.P for each day the adjacent Well was on production. Third, in order to better understand and visualize the trends or tendencies of the production data in real-time, we reduced the data set to a plot of P.O.P vs. the number of production days. Fourth, we generated the data set shown in Table (3), which shows the optimal producing parameters in comparison with the rest of the production days.

Basically, the above-mentioned methodology provides us with a tool that pinpoints the days that the well production parameters were optimal in comparison with the other producing days. For example, by examining Figure (11), we notice a series of High and Low P.O.P values *oscillating* in time. The High values are indicative of not-so-ideal producing days for a given set of operating parameters such as choke setting, drawdown pressure, etc., for that day. Actually, on one hand, a High P.O.P value means that a great deal of reservoir total energy content has been wasted in producing the well under the given conditions. On the other hand, a Lower P.O.P value means that the production operating parameters such as drawdown, the choke size, etc., were such that the reservoir produced a given amount of fluid with *a minimum waste of energy* in comparison with other days. Table (3) shows the "good" producing days for the Well adjacent to Well (1). A good example of the Moderate to Low P.O.P is shown within the Upper and Lower band limits of Figure (11).

Another advantage of this particular P.O.P methodology is that it can be dynamically measured in real-time. And, when and if it is found that the values for a sand with limited tolerance for Drawdown Pressure are too High, the production supervisor can adjust the drawdown, in tandem with the separator pressure, to a value that prevents the waste of the reservoir energy while avoiding premature well sanding. Indeed, this methodology could be viewed as a "loss prevention" strategy for producing young, unconsolidated, fine grain *turbidite* sands in the Gulf of Mexico.

Recommendations For the Well adjacent to Well (1):

An examination of Table (4) and Figure (11) lead us to make the following recommendations:

1. **The estimate of the Drawdown Pressure for the sand in the Well adjacent to Well (1) appears to be about 350 to 700 PSI. The low tolerance limits indicate that the sand is highly stress sensitive. The Drawdown pressure should be tailored to the sand pressure tolerance limits. Therefore, on the basis of POP analysis, we recommend that the Initial Drawdown be set at about <u>100</u> psi and then increased at a rate of 10 psi per day until an average of 400 psi is reached. The sand-free production and any remedial completion should be examined with about 400 psi in mind.**
2. **Due to the similarity of the sands in Well (1) and the Well adjacent to it, we have also carefully analyzed the Drilling, Log, Primary Completion, Remedial Completion, and Paleo data from Well (1) for possible application to other wells in the same field. Interestingly, the analysis of the sand's resistance to shear failure using Well Logs from Well (1) confirms the recommendation for an Initial Drawdown of <u>100</u> psi estimated for the Well adjacent to Well (1). The sand in both wells appears to be weak, stress sensitive, fine-grained, unconsolidated sand. For this reason we recommend that completion methods be linked and tailored to match the Drawdown tolerance of the "weakest link" of the sand system, that is, the section with the lowest resistance to shear failure.**
3. **Also, see our preliminary recommendation and opinion described in Table (3).**

Having completed our analysis of the data from the Well adjacent to Well (1), we now turn our attention to the analysis of data from Well (1).

Analysis of Drilling, Log, Primary/Remedial Completions,

and Paleo data From Well (1):

Due to the lack of production data from Well (1) and the time constraint for our study, we placed emphasis on the analysis of Drilling, Log, Primary Completion, Remedial Completion, and Paleo data acquired from Well (1). Again, recognizing the time constraint for this study, the objective of the Well (1) study was to establish the sand strength properties using Drilling, Log, Primary Completion, Remedial Completion, and Paleo data and make appropriate recommendations on the basis of our findings.

In analyzing the records of Well (1), we first studied more than 266 pages of data from Well (1). The data included, but was not limited to, drilling reports, well logs in digital format, primary completion procedures, remedial completion reports (FracPac, acid jobs), and paleo logs. Second, we modeled the Well Log, Drilling, and the FracPack data to arrive at the Hayatdavoudi Perforation Index, which is used for the recommended selective completion of the reservoir in Well (1). Third, in order to refine and confirm our findings using other data sets, we carried out a comprehensive digital Well Log analysis to arrive at Petrophysical interpretations. Fourth, in order to characterize the Petromechanical properties of the turbidite sand in the Well adjacent to Well (1) and relate it to the P.O.P of Well (1); we derived all of the necessary parameters by modeling the Sonic Log data. Fifth, we correlated all of the data plots to establish a functional relationship between various variables for the turbidite sand of Well (1).

Table (4) shows the details of our comprehensive log interpretation. Each log data point from 11,150 to 11275.5 ft Measured Depth has been modeled for the Hayatdavoudi Perforation Index herein referred to as HPI, Drawdown Pressure, and Water Saturation, S_w. Furthermore, we have assigned a reservoir quality grade for each data point. Also, we have offered a short comment for each data point. In this table, the reservoir quality grade is based on the HPI propriety model, which considers Petromechanical properties as well as Drawdown Pressure and Water Saturation, S_w.

Figure (12) shows the calculated *variable* Young's and Shear modulus based on Dipole Sonic Log, HPI, and the *constant* Young's modulus based on the Remedial Completion, and the FracPac data. The interesting and important points of Figure (12) are:

1. **There is a significant, highly unstable section just below the *upper* section of the reservoir. This section is the *weakest section of the reservoir with a Young's Modulus of less than 500,000 PSI.* In fact, it may well be that during the FracPacking operation the weaker section fractured first.**
2. **There are three other weak sections that exist within and below the *lower* section of the reservoir. Again, it may well be that one or more of these reservoir sections fractured subsequently.**
3. **The *weak section* referred to in point 1 appears to be a *slump*. The Paleo Log and the description attached to it shows the characteristic *slump* fossil, <u>*Globorotalia Miocenica*</u>, to be present in this *reworked, shallow-shelf turbidite material.***
4. **The *constant* Young's Modulus of 600,000 and 700,000 used in the FracPac job design appear to be a great deal higher than the calculated Young's Modulus. In fact, it may be that the weak material in this section could have rendered the FracPac Propant ineffective. This finding could also support the field observation that the operation personnel "did not see any prop sand when they attempted to put the well on production." Simply put, the prop sand could have been buried in the *liquefied "slump" section of the turbidite sand.***

Figure (13) shows a Plot of HPI versus the Measured Depth. Again, the weak sections of the upper and lower parts of the reservoir are the poor reservoir quality sections that *should not have been perforated simply because in these sections of reservoir, it is difficult to keep the perf tunnels stable*. For selecting the perf intervals, it would have been prudent to use the HPI data in Table (4).

Figure (14) exhibits a plot of the initial Drawdown tolerance pressure of the reservoir versus the Measured Depth. Again, it can be clearly seen that the *weak, slump sections of the reservoir can only tolerate a low initial Drawdown Pressure of about 30 to 40 PSI, whereas the remainder of the reservoir section can probably tolerate an Average Initial Drawdown Pressure of about 100 PSI.*

Figure (15) depicts a significant Porosity reversal in the *weakest sections of the reservoir.* In fact, it may well be that this phenomenon actually *weakened* the reservoir rock dramatically. Furthermore, in our experience, this type of reservoir section becomes extremely sensitive to Peak Transient Pressures caused by fast or "hard" shut-in of the well, drilling hydraulic surge pressure, the sudden stop or start of the injection pumps, and even an emergency quick shut-in of the downhole safety chokes.

Figure (16) shows the profile of our Water Saturation, S_w, Model, for Well (1). Interestingly, the *Water Saturation Column, S_w, increases significantly near the weakest zones of the reservoir mentioned above.* This Water Saturation, S_w, appears to divide the reservoir *into <u>four</u>* different compartments with different pressures and different effective stress regimes, possibly due to the changing seal permeability. The sudden changes in the effective stress at the interfaces between the pressured-water compartments and the upper or the lower reservoir sections could make the formation highly prone to sudden drill breaks, lost circulation, well break-out, and FracPac break-out into the water section. Indeed, if the FracPac fracture intersects these high porosity water sections, the results could be:

1. **High water production**

2. High foamy-gas-water production
3. Well sanding due to sand liquefaction at the collapsed free faces of the fracture and the washed-out perf tunnels, especially in the zones of high porosity
4. Sudden loss of production due to severe well bore damage caused by subsidence or collapse of the well bore

Figure (17) exhibits the results of our petrophysical modeling of S_w. It appears that the water transition zone occurs at about 15 percent Water Saturation, S_w. Interestingly, we have discovered that the 15 percent Water Saturation cut-off occurs at a section within which the *hole gage was lost*, or the well bore experienced shear failure and wash-out in zones of high effective stresses.

Figure (18) shows further evidence of what we discovered in Figure (17). If we correlate the modeled hole gage enlargement with the modeled Water Saturation profile, we clearly see that the line drawn from the top of the washed-out section *intersects the Water Saturation profile at about 15 percent S_w (left curve). We have called this number the "critical Water Saturation Line."* Another interesting aspect of Figure (17) is that the water transition zone falls immediately at or below the top of the highly *unstable zone.* On the basis of our findings, we see two strong reasons for "not completing" this section of the reservoir. *One is that the water-free hydrocarbon-producing zone is too weak and the other is that the drawdown pressure tolerance is too low.* Obviously, if a strong 12% HCl-3%HF is used (as it has been) the already weak rock is weakened further. Therefore, the inevitable result is cannot severe damage to the well bore.

Figure (19) depicts a technique developed by Hayatdavoudi for classifying unstable layers of a turbidite reservoir. A plot of a Log-derived CALD (differential caliper log), and Water Saturation Integral functions further reinforces the findings of Figures (17) and (18). This plot clearly shows:
1. The onset of the pressurized-water movement in Region (5), shown by a constant derivative to the right of the 15 percent Critical Water Saturation
2. The Irreducible (imbibed) Stationary Water changes for different reservoir layers and layers within compartments in Region (2)

It is possible that production from Region (5) will most likely be associated with very high and troublesome Water-cut that eventually would lead to *sand liquefaction.* The poor quality, unstable, highly clayey reservoir in Region (4) would most likely imbibe some portion of the water. However, it is more likely that this water, too, could be mobilized if the reservoir is subjected to compaction and consolidation due to a high production rate.

Recommendations for Well (1):

Since Well (1) produced a considerable amount of *liquefied sand* and died prematurely, we recommend that the following steps be considered and carefully examined in re-completion planning.

Phase (1) Recommendation for the Current Status of Well (1):

1. After cleaning the well bore with the current well shutdown status, treat the well with emulsion breakers and defoamers.
2. Because the turbidite sand is extremely stress sensitive, it is very important to calculate the critical time duration for all start-up or shutdown processes. As a mater of caution, the actual pumping start and stop time must be several fold greater than the calculated critical time. Extreme caution must be taken to avoid creating sharp peak transient pressure surges in the sand. See the procedure in the revised Reference #2.
3. Open the well slowly with very small increments of Drawdown Pressure. If water production increases, decrease the Drawdown Pressure and track the water production. If the water production (up to 3 bbls per MMCF) levels off with minimal (trace) sand production, it can then be assumed that the sand tolerance pressure threshold has been reached.
4. If the above treatment does not work, we recommend sidetracking the well and proceeding with a new, carefully tailored completion for the turbidite sand. The completion should be tailored to fit the *sand's resistance to shear stress, water saturation, S_w, and the selected HPI values within the context of a selective completion technique*.

Phase (2) Recommendation for Future Completion:

1. Use the Selective Completion Technique for the turbidite sand. Use the information and details of the selected interval from Table (4) and Figure (13) for each depth interval.
2. Use the Oriented Perforation Technique. The Shots must be placed along the axis of N15-30W. It appears that the major principal horizontal stresses in the Gulf of Mexico are in this direction. Perforation tunnels along this direction are expected to be more stable than they would be along other directions.
3. Use no more than 6 shot per ft in the SELECTED intervals. The fine grains, high porosity, and the pressurized water compartments in the unstable zones beneath the SELECTED zones make the turbidite sand extremely shear sensitive and prone to quick and sudden erosion of the perf tunnels. The diameter of the perf tunnels could enlarge several folds, thus overlapping or connecting with each other. The enlarged and eroded perf tunnels may later turn into a free face behind the casing, which could *liquefy* easily when producing the well at high rates or upon inadvertently generating Peak Transient Surge Pressures at the sand face. Once the fine

grains are liquefied it would be very expensive and difficult to control well sanding damage. No amount of gravel pack or fine screen could help to prevent well sanding (*sand liquefaction*) in such cases.

4. **Use 0 degree phasing.**
5. **Select a small entrance diameter for the purpose of helping the sand grains bridge over small diameter entries.**
6. **Use high charge grains to assure deep penetration of the perf tunnels. Use the core flow efficiency (CFE) based on both the strength of Berea Sandstone and its Original Permeability standards. Preferably, the Berea Perf sample should have high Kaolin and Mica content to simulate the turbidite sand in Well (1). Do not use cement Perf standards for the penetration length. Also, CFE of Berea SS can better simulate the turbidite sand.**
7. **Do not use surfactants and acids to clean up the perfs. If the well is opened up slowly, the natural well flow should allow the well to clean itself.**
8. **We do not recommend FracPac, as it seems to be too difficult to prevent the fracture from entering or extending into the Pressurized-water Compartments and the Highly Unstable zones within or below the turbidite sand.**
9. **We do not recommend any type of high strength acid stimulation of the turbidite sand. The strong acid could easily damage the turbidite sand beyond repair or remedy.**
10. **We recommend a very Controlled ROP that should not to EXCEED 5 ft/hr while penetrating the target turbidite sand. The mud motor should be turned very slowly, similar to the Low RPM coring, at about 30 RPM. Mud pump strokes should be kept as low as possible, similar to a kill rate. The hydraulic design should incorporate a center jet and preferably make a bit trip prior to entering the sand, with the BHP gage kept at as low an "under-gage" as possible.**
11. **We recommend only fine screen, high density and fine mesh gravel pack for the sensitive turbidite sand. If required, we recommend maintaining the gravel pack with an EXTREMELY LOW VOLUME ¼ strength acid to clean the gravel pack and the screen periodically with time- CONTROLLED injection pressures.**
12. **Use the information available in Table (3) and Figure (11) to produce the well after it is completed.**

As we were engaged in the analysis of the data from the two wells, namely Well (1) and the Well adjacent to it, Well (2) was drilled and logged. At the beginning, since the logs from Well (2) did not appear to be as good as the logs from the Well (1), completion plans were deferred to a later date to allow for necessary analysis of data. However, prior to deciding to complete Well (2), several sets of data files were submitted for analysis. We discuss our findings below.

Analysis of Log, Drilling, Petrophysical, and Petromechanical data From Well (2):

The documents that we analyzed included, but were not limited to:

1. **LAS files of Digitized Resistivity, Porosity, Dipole Sonic Logs, Caliper, Apparent Water Resistivity, Gamma Ray, Photoelectric, and Cable Tension Logs**
2. **Standard Sidewall Core Analysis data**
3. **Grain Size Statistics from Well (1) and Well (2)**
4. **X-ray Diffraction for 3 samples (12074', 12108', 12128' MD)**
5. **Sets of Scanning Electron Microscope images from 12074', 12108', 12128' MD.**

We prepared input files of the Log data for executing our proprietary models and computer codes. After several days of trials, the DSI files (Dipole Sonic) proved to be unmanageable. The difficulty was basically due to very slow "Shear" wave arrivals. The very slow Shear wave arrival in this well could probably be attributed to two interactive phenomena. One is the *directional* propagation of the Shear Wave in the highly unconsolidated, gas-filled formation and the other is the presence of many *laminas (micro-seals) in the thin* turbidite beds. For these reasons we did not pursue processing the dipole sonic data.

In order to provide the management with a basis for making informed decisions and arrive at some reasonable Drilling and Completion recommendations, we detoured around the "Shear Wave Arrival" obstacle and analyzed the data in a different way. We divided the digital Log data into two interactive sets for Petrophysical and Petromechanical analysis. In this process, we relied heavily on the XRD data for constructing a quantitative Clay volume model, which provided a bridge between the two sets of Log data.

Petrophysical Findings:

Following the normal petrophysical procedure in interpreting the Well Logs, a sample of which is shown in Figure (10), we used the resistivity and the porosity data to determine the critical water saturation, S_w. We used the corrected porosity for arriving at the clay content. It should be mentioned here that although *Orthoclase* is a type of Potassium Feldspar, because of its Potassium, K, content, we have grouped it with the major clays, *Illite and Mica,* for the purpose of generating the Corrected Gamma-Ray, Porosity, and Water Saturation Functions.

Figure (20) shows that the critical Water Saturation in the probable Hydrocarbon-producing zone is about 67%, the Transition Water Saturation zone is between about 67 to 80 percent, and the remainder of the zone is water. As we shall see later, in a Petromechanical sense, the Water Saturation affects the well bore stability greatly in intervals other than the zone of interest, between 12123.5' to 12147.5' MD.

Figure (21) depicts the profile of S_w through the interval of

interest along with the probable hydrocarbon-producing zone and the S_w markers at the modeled 67 percent and the "Arbitrary" 50 percent value. Here the "uncorrected critical S_w" means that we have not included the "modeled clay volume percent" in arriving at the critical S_w. However, as mentioned previously, we corrected (or incorporated) the clay volume percent in the "porosity" part of the S_w model, which we have termed the "corrected" porosity for calculating the clay content. At any rate, it is obvious that the above two figures show us "high" water saturation, S_w. So, why is the S_w so high? First, could the high S_w be due to the "high amount of *Chlorite* clays often seen in the so-called *Low resistivity* formations"? The XRD data answers this question very clearly. The answer is NO. Our answer is supported by the fact that the XRD data shows that there is *one percent Chlorite* content in the sample taken from 12074' MD and only a "trace" in the samples taken from the 12108' and 12128' MD intervals. Secondly, could this high S_w be because of the "high amount of *Total Clays* in the so-called highly 'clayey' *Low resistivity* formations"? Again, the answer is NO. The supporting fact for our answer is that the XRD data shows that there is *18 percent Total Clay* content in the sample taken from 12074' MD, eight percent in the sample taken from the 12108' MD, and 12 percent in the sample taken from the 12128' MD interval. These numbers appear to be low and may not be the cause of the "high" water saturation and low resistivity. Now if, for the sake of simplicity, we subtract the clay volume percent from the constant critical S_w percent in the respective intervals, we still end up with high water saturation, that is, 67-18=49 percent, 67-8=59 percent, and 67-12=55 percent. These percentages are comparable with the values reported in the sidewall core analysis. In any case, this critical S_w is, again, high even in the most probable Hydrocarbon-producing zone. The likely answers to the above questions may be found in the nature of *flat, thin, micaceous, feldspatic, kaolinitic micro-seals* that entrap some of the displaced (squeezed) water within the lamina. Also, some additional analyses and correlations will be shown later in the discussion of the Figures (28) and (29).

As mentioned previously, because of its dual nature and important roles in both Drilling and Production Operations, we are deeply interested in understanding the nature of the Water Saturation. The distribution of Water Saturation in the interval and zone of interest, as a coupling function, not only affects the determination of Water-free Production Zones, the resulting Selective Completion methods, and Controlled Drilling techniques, but also the well bore stability and well sanding issues. Due to its effect of on Bulk Density of the formation and the Effective Stresses around the well bore, the S_w, also, affects the Threshold Drawdown that the Sand can tolerate before moving into the well bore (with its damaging effects) or before it liquefies. Therefore, in order to make an informed decision on Completing or Drilling certain sections of the hole, it is imperative that we understand the nature of Water Saturation, S_w, and its distribution in the zones of interest.

In pursuing our goal of understanding the S_w and its distribution throughout the zone of interest, Hayatdavoudi devised a Hydrocarbon Partition Function (HPF) that accounts for the percentage of clay content. This function goes to Zero at the intervals that *separate* the probable hydrocarbon-producing intervals from the Water-bearing zones. Figure (22) shows the nature of the Hydrocarbon Partition Function and the distribution of S_w in the 11980' to 12180' MD intervals.

As far as the "nature" of S_w is concerned, Figure (22) clearly shows that there are two distinct Water Saturation regimes. One is located in the upper part of the zone of interest and one below it. The zone of interest exhibits the lowest water saturation. Although it is speculative to attribute the cause of the two water saturations to a definite mechanism, it nevertheless appears that the accumulation of the hydrocarbon is the result of downward-acting and upward-acting vertical field stresses, with the upper part of the zone being "less" permeable (fine grains traveling upward in the sediment column) and the lower part being "more" permeable (the coarser grains sinking downward in the sediment column). Fortunately, as will be shown later, fortunately the zone that is probably a hydrocarbon-producing zone appears to be composed of the coarser sand grain size, less *mica, orthoclase, and illite*, it has a higher Reservoir Rock Quality (RRQ), it is far away from a likely slump zone (12020' to 12040' MD), and it is more resistant to well bore stresses.

Figure (23) shows that the upper part of the zone of interest, the interval between 12123.5' and 12130' MD, where the RRQ gradually improves, corresponds to the *lowest* Photoelectric Cross Section. It appears that this section probably contains the highest concentration of the lightest hydrocarbon fraction. Also, in the zone of interest between 12130' and 12147.5' MD, the Photoelectric cross section has developed 3 significant slopes, which correspond to the probable zones of the lightest, the middle, and the heaviest fractions of the hydrocarbons.
In order to better understand the distribution of the Water Saturation in the interval of interest and the probable accumulation of the hydrocarbon in the zone of interest, Hayatdavoudi developed the idea of the Constant Density Line (where the derivative of the Bulk Density Function is Zero). This function shows us how the Bulk Density *grades into and out of* the zone of interest between 12123.5' and 12147.5' MD. The changing slopes of the Bulk Density Function are clearly shown in Figure (24). This figure also sheds light on the upper and lower *transition* water saturation zones.

Figure (25) exhibits the results of the integral functions of Photoelectric and Bulk Density. This figure clearly shows how the three distinct slopes, corresponding to the probable lightest, the middle, and the heaviest hydrocarbon fractions,

have developed within the zone of interest between 12123.5' and 12147.5' MD. Furthermore, although insignificant in thickness and thus not worth completing, the Integral Function of Figure (25) reveals two more probable hydrocarbon-producing zones located between 12038'-12041' MD (3 Ft gross) and 12105'-12107' MD (2 Ft gross).

Figure (26) shows the distribution of water saturation and the photoelectric cross section. Interestingly, the "lowest" slope of the Photoelectric Log coincides with the "lowest" water saturation distribution in the zone of interest.

Figure (27) reveals another aspect of the water saturation distribution in the zone of interest. In this figure, the Gamma-ray function, which is corrected and calibrated with the XRD data for *Mica, Orthoclase, and Illite content*, precisely tracks the water saturation distribution. Again, the "lowest" water saturation in the zone of interest coincides with the "lowest" concentration of the clay minerals *Mica, Orthoclase, and Illite*. Therefore, it is plausible that the *type, the grain geometry, and the micro-sealing effect, but not an excessive quantity* of the above mentioned clay minerals control the *nature* and the *distribution* of S_w and the porosity-permeability relationships in the *zone* and *interval* of interest. The S_w-Porosity-Permeability control mechanism by *Mica, Orthoclase, and Illite* could be attributed to the *size*, *morphology (shape), and the frequency of the occurrence* of these minerals within the zone. In fact, these minerals are the very same building blocks of the *thin* beds and the type of *lamina within the thin beds of turbidite sands.*

Figure (28) proves the fact that when the S_w is corrected for the amount of *Mica, Orthoclase, and Illite* with a specific, quantitative function; the value of the function is at its *Minimum* where the RRQ and the Clay Functions are also at their respective *Minimums*. Here, the *Minimum* RRQ value refers to the Best Reservoir Rock Quality in the zone of interest. Therefore, it is important to examine the *frequency of the Occurrence of Mica, Orthoclase, and Illite* laden lamina.

Figure (29) exhibits the Reservoir Rock Quality function in the interval and the zone of interest. This figure also shows the *frequency* and the *gradient* of the occurrence of both the "good" and the "poor" lamina comprised of the mineral *Mica-Orthoclase-Illite*. In fact, in the zone of interest, the higher permeability, lower S_w, and the coarser grains occur at approximately 12124', 12129', 12133', 12138', and 12144' MD, (a repetition of bed thickness of 5, 4, 5, 6 ft). The *gradient* of "good" rock is approximately [24/(0.167-0.130)]=648.7 units. In the same zone, the lower permeability, higher S_w, and the finer grains exist at approximately 12126', 12130', 12134', 12140.5', and 12147.5' MD, (a repetition of bed thickness of 4, 4, 6.5, and 7.5). The *gradient* of "poor" rock is approximately [24/(0.225-0195)]=800 units. Upon further inspection of the zone of interest, we observe that this zone actually consists of two parts. From 12123.5' to 12126.5' MD, sand grains *fine downward*, in contrast to the upper part, from 12130' to 12147.5' MD, where sand grains *coarsen downward.* As is expected, Figures (6), (7), derived from Sidewall Core A, Grain Size analysis (Table 1), and Figures (8), and (9), TSA and SEM respectively, satisfactorily and clearly validate our Log analysis and other petrophysical findings discussed above.

At any rate, Figure (29) could easily be used to selectively perforate the zone of interest between 12123.5' and 12147.5' MD. However, before rushing into this process, it is prudent, from a Petromechanical perspective, to examine the issues of Well Bore Stability, potential Well Sanding, and Water Saturation in the zone of interest.

Petromechanical Findings:

In order to establish a basis for Well Bore Stability and Well Sanding Analysis, learning from past experience, we started with generating a porosity function that is corrected for the clay volume content. We used the XRD data for our model. Using our Petrophysical Findings from Figures (28) and (29), we placed emphasis on the *type feldspar* (*Orthoclase)* and clays (*Mica, Illite, and Kaolinite*) present in the lamina of the thin beds in the interval and zone of interest.

Figure (30) shows the corrected porosity distribution throughout the interval and zone of interest. Here, "interval" refers to the well section between 11980' and 12180' MD and "zone" refers to the well section between 12123.5' and 12147.5' MD. Specifically, in this section of the hole, we looked for "slump" markers, which often occur at the very high "*Porosity Reversals*" between 26 and 38 percent or more. The porosity reversals in the *slump* section appear to be caused by paleo species, such as <u>*Globorotalia Miocenica*</u>*, which "rework" the turbidite sands extensively*. The appearance of this type of porosity reversal is similar to the presence of "singularities" or "intermittencies" in many naturally occurring signals that require special modeling work and analysis.

In any case, in the above-mentioned interval, we found only a small, highly unstable section between 12030' and 12040' MD. As will be shown later, in the vicinity of this section, there is also a very high Water Saturation, <u>S_w</u>, concentrated *Mica, Orthoclase, and Illite* (Table 2), and the highest *hole washout* of the interval between 11980' and 12180' MD. Interestingly, Sidewall Core Analysis shows "empty" bottles and "mud-shots" in the majority of the samples from this section of the hole. In addition, Particle Size Analysis data shows that at 12030' MD the "clay" and "shale" volume percentages are not too high. This supports our Petrophysical Findings that the "controlling mechanism for the Reservoir Rock Quality, RRQ, and the Water Saturation, S_w, is the *size*, *morphology (shape), type and the frequency of the occurrence of micro-seals rather than the* <u>*amount*</u> *of the clay* present in the formation." (Also, see Figures (28) and (29).) Therefore, any Completion work in this section must be avoided and drilling this section

must be conducted in a "Controlled" mode.
As we mentioned previously, since the S_w impacts Well Bore Stability and Well Sanding to a great extent, we used Hayatdavoudi's Integral Technique to classify the Probable Production, the Transition Water, and the water zones for this reservoir. In fact, it is in the high Water Saturation regions, along with the presence of low "Free Energy Clay Minerals such as Kaolinite"[3] in the hole, that the hole experiences unusual instability and high washouts during Drilling Operations. Furthermore, the same high S_w that causes well bore instability and washouts (sometimes induced well bore breakouts) will also cause Well Sanding problems (sand liquefaction) during the Completion Phase.

Figure (31) exhibits the results of the Integral Technique, which shows the reservoir classification in terms of the "*Hole Gage.*" This finding tells us that on the one hand the hole will be unstable and will most likely sand up where the water saturation is high. On the other hand, the hole will be potentially stable where the water saturation is low. Well Bore Stability and Well Sanding issues could be attributed to the change in the state of effective stresses around the well bore or in the perforation tunnels caused by the change in water saturation (in the regions of *micro-seals*) and the bulk density of the formation. Often, the "unstable" section of the hole in the "changing effective stress zone" could easily and economically be stabilized simply by increasing the mud weight during drilling operations or by controlling the Drawdown and by perforating the well with "balanced" mud weight. Interestingly and fortunately, the well bore, Well (2), appeared to be potentially stable in the zone of interest between 12123.5' and 12147.5' MD. Furthermore, this finding supports our experience that, usually, the Gas and Oil saturated Berea sandstone shows a higher uniaxial strength than when the same rock saturation is gradually changed to a higher water saturation.

Figure (32) shows the relationship between the two functions of S_w and the Caliper Log in the interval and zone of interest. In this section, the hole exhibits high washout and instability in the sections between approximately 12020' to 12040' MD and 12102' to 12112' MD. In both of these intervals the water saturation is high. Interestingly, on the one hand, in the upper section of the hole, the "well bore instability" appears to be a strong function of the Porosity, the Porosity Reversal, and the high water saturation in the "*slump*" section of the hole. On the other hand, in the lower section, the "instability" of the hole in terms of hole-washout, is a strong function of the *Water Saturation,* which renders other factors of secondary importance. Of significance are the "stability" and the hole "gage jump" in the Transition Water Zone "above" the zone of interest and the "gradual change" in the slope of the hole gage, in the Transition Water Zone, "below" the zone of interest. Observing these facts, at this point we may ask, how are the Well Bore Stability or Instability and potential Well Sanding issues related to the Water Saturation in the zone of interest between 12123.5' and 12147.5' MD? Actually, this stable section is where the S_w is at its "lowest" value!

Figure (33) answers our question in terms of the "well bore stability" relationships between the "slopes" of the Photoelectric Function and the Constant Derivative of the Hole Gage Function. As is expected, and as mentioned previously, the most "stable" part of the zone of interest (Well 2) falls within the section that is probably "richest" in "the light, the middle, and the heavy fractions" of the hydrocarbon and where the Water Saturation is at its "lowest" value. Figure (33), also, exhibits another interesting and important point. The "higher" values of the Photoelectric Function, which indicate the presence of Carbonates, more or less fall within the high Water Saturation Zones whereas the "lower-than-carbonate" values of the Photoelectric Function fall within the areas of "low Free Energy Clays, the Hydrocarbon, and Silica content" of the zone of interest. It should be noted that the computed values of these functions are not shown in the conventional scales.

Again, we may ask ourselves how the particular clay and feldspar constituents (*Mica, Orthoclase, and Illite* as reported in the XRD data, Table 2) of the lamina in the thin beds of the turbidite reservoir are related to the Hole Gage and the Well Bore Instability. The answer to this question follows:
Figure (34) shows the relationship between the Clay Minerals and the Hole Gage Functions. It is seen clearly in this figure that the Hole is more or less "stable" where the Clay Mineral Function is at its "lowest" value. An examination of Figures (32) and (34) reveals how the individual Water Saturation Function and the Clay Content Function affect the Caliper Log or the Well Bore Stability Indicator Function. However, we may ask ourselves, how do the Water Saturation and the Clay Content Functions affect the Caliper Log or the Well Bore Stability Indicator Function? In order to answer this question, we generated a function of the S_w and Clay Content as a means of examining the combined effect of these two Functions on the Caliper Log, the Well Bore Stability Indicator Function.

Figure (35) highlights a glaring and an important point about the question asked above; that is, the Well Bore is most "*stable*" where the function we just mentioned is at its "*least*" values. More importantly, the profile of the function precisely and clearly shows the "sharpened boundaries" between the "unstable" and the "stable" regions of the hole, from 12123.5' to 12147.5' MD.

Bringing our discussions and analysis of Well (2) to a conclusion and in order to see how the Petrophysical, Petromechanical, and Water Saturation findings were related to each other, we gathered six fundamental functions together and conducted a Fourier analysis of them. The Fourier Spectrum of these functions gives us a different means of correlation methodology, using the data from the zone of

interest between 12123.5' to 12147.5' MD. We used the Modeled Gamma-Ray Function, the Modeled Porosity Function, the Reservoir Rock Quality (RRQ) Function, the Clay Content Function, the Well Bore Stability Indicator Function, which is the same as the Caliper Log Function, and the Corrected Water Saturation Function.

In our analysis, we define a Strong Function as one that shows its fundamental frequency and its entire harmonics to fall on the same Measured Depth. For example, in Figure (36), we see that the Null or the Fundamental Frequency and all of the harmonics of the Corrected Gamma Ray, the Corrected Porosity, and the Reservoir Rock Quality Functions all track each other extremely well. Therefore, these functions correlate well with each other and they are said to be Strong Functions of each other. Incidentally, the fundamental frequency peak is found to be at 12139.5' MD. However, in Figure (37) the picture is different. For example, in this figure, the Caliper Log, or the Well Bore Stability Indicator Function, are a Strong Function of the Clay Content but a "weaker" Function of the Water Saturation. This may be attributed to the fact that the Water Saturation Function values are at their "lowest" in the zone of interest between 12123.5' and 12147.5' MD.

Recommendations For Completing Well (2):

The above Log-based Completion and Drilling Study leads us to make the following recommendations for completing Well (2):

1. Selective Perforation:

- **Select the Completion interval between 12123.5 and 12147.5' MD and Produce the "best first". Perf Depth Control is crucial in this hole. Use Figure (29) as a guide for the Selective Completion in the zone between 12123.5' and 12147.5' MD.**
- **Preference is given to the *mechanically oriented, low side perforation* technique.**
- **Low side perforation, along the gravity axis, is of the utmost importance in this 32-degree slant hole.**
- **If the low side perforation technique is selected, then a high density shot, as much as 8 SPF, could probably be tolerated in this well. Figure (29) shows that the "good" RRQ, with the higher permeability, coarser grain, cleaner rock, lower water saturation, and more stable parts of the probable Hydrocarbon–producing zone, is located at 12124', 12129', 12133', 12138', and 12144' MD. The "poorer" RRQ, with lower permeability, finer grains, dirtier rock, and higher water saturation, is located at 12126', 12130', 12134', 12140.5', and 12147.5' MD.**
- **Balanced perforation is preferred, as the turbidite sand does not offer much resistance to the shear stresses around the perf tunnels when the perf is "under-balanced".**
- **The Perf entrance hole on the low side could be as high as 0.35 to 0.45 inches in diameter.**
- **Configure the ALL LOW SIDE Perfs in 30-0-30 degrees phasing. The standoff of about 1 to 1 ½ inch of the two low side, 30 and 30 degree perfs could prove desirable.**
- **Fluid loss control is a must. Although it may not be possible for zero fluid loss to achieve in mud, cement, and the completion fluid, near zero fluid loss is the next best for this zone!**
- **Similar to the previous study, the initial drawdown for this soft rock could be about 100 psi with a gradual increase in the drawdown up to 700 PSI. A scheduled drawdown probably allows the formation to self-compact without putting excessive stress on the gravel pack screen.**
- **With a great deal of research on the concept of filter packing highly unconsolidated sands, this technique, due to the flexibility in changing the size of the filter pack (using a bi-center bit or under-reamer), could prove useful in this type of turbidite completion.**

2. Completion Fluid:

- **Large type ions like NH_4^+ in the completion fluid are very useful in these types of reservoirs. See Figure 9 for the evidence of the depositional clays. We recommend as much as 10 percent NH_4Cl.**
- **Adding some clean, filtered Seawater, as make-up water, to the above-mentioned NH_4Cl could be beneficial. This benefit may be realized due to the addition of some different types and sizes of a host of ions found in natural Seawater. The fluid should be treated with scale and corrosion inhibitors.**
- **Again, the fluid loss must be kept to a few ccs. This is because any drastic change in the Water Saturation near the Well Bore could cause "instability of the perf tunnels and shear failure at the lamination plains where *Mica, Illite, and Orthoclase* are located". Premature Well Sanding and Screen Failure could probably be avoided if the change in the effective stresses due to changes in the Water Saturation is kept to a minimum.**

3. Drilling Fluid:

- **We recommend a low P^H mud system with properly designed Mud Weight (compatible with field stresses), Fluid Loss, controlled activity, coating ability, and lubricity for drilling this kind of turbidite sand.**

After submitting our analysis, the operator decided to complete the Well (2) even though the well log, in comparison to logs from Well (1), was not very encouraging. Well (2) was completed and put on production. So, did we find the "needle in the haystack? Below, we show the results of the several months of production made available to us for this work. We let the data speak for itself.

Comparison of Production Data Analysis From Two Wells:

Following the same P.O.P technique mentioned earlier, we conducted our modeling work and plotted Figure (38). Below, for comparison purposes, we present our analysis of Figure (11), which is based on a completion process *before* our study, analysis, or recommendations, with Figure (38), which is based on a completion conducted *after* our study, analysis, and recommendations.

Before…

A careful examination of Figure (11), which is based on the production data *before* we began our study and analysis of *turbidite sand problems,* reveals several important features of the producing characteristics of the turbidite reservoir in the Well adjacent to Well (1):

1. **We see a series of High and Low P.O.P values *oscillating* drastically in time. The High values are indicative of the not-so-ideal producing days for a given set of operating parameters, such as choke setting, drawdown pressure, etc. Actually, a High P.O.P value means that a great deal of reservoir total energy content has been wasted in producing the well under those conditions.**
2. **The Lower P.O.P value means that the producing operating parameters, such as drawdown, the choke size, etc., were such that the reservoir produced a given amount of fluid with *a minimum waste of reservoir energy* in comparison with other days. Table (3) shows these "good" producing days for the Well adjacent to Well (1). Although the level of Production oscillation in time is severe from the "get-go", which would destabilize the perf tunnels, Moderate to Low P.O.P values are shown within the Upper and Lower band limits of Figure (11). Adherence to this band limit could have helped this well to produce more economically. .**
3. **The rate of production decline from this well appears to be too steep and not comparable with the rate shown in Figure (38) for Well (2).**

After…

Figure (38), a P.O.P analysis of production from Well (2), reveals several important characteristics of the *turbidite* sand's producing capability. They are:

1. **The selection of a proper choke size and a "managed" Drawdown, ignoring the excellent production in the first few days, shows the lower limit of the Drawdown to be about 450 PSI, which produces a considerable amount of oil and gas without Well Sanding problems. According to Hayatdavoudi's P.O.P method, this is reasonably close to the Drawdown estimates shown in Table (2), for the Well adjacent to Well (1).**
2. **The upper limit of the Drawdown, 1230 PSI, places the production level at the *threshold* of Well Sanding by the *Sand Liquefaction* mechanism. This upper limit appears to be 480 PSI above the highest limit shown in Table (2). Therefore, from this observation, one could surmise that the *threshold Drawdown* value is within the bounds of 750-1230 PSI for the turbidite sands in this particular field.**
3. **Interestingly, the smooth part of Slope (A) places the safe limits of the Drawdown at about 600 to 700 PSI we referred to above. Furthermore, this derivative analysis shows that as soon as we exceed the 600-700 PSI Drawdown limit, the Production experiences severe *oscillation in time.* This might indicate that the sand face is going into a violent turbulent state. Obviously, this oscillation of production could easily destabilize the perf tunnels and cause *Sand Liquefaction*.**
4. **Again, the derivative analysis shown by Slope (B) surprisingly parallels Slope (A) and Production again, experiences a severe oscillation in time near the same levels of Drawdown. Therefore, it appears that for prolonged, sand-free production to continue, the Drawdown levels of 600-700 PSI should be honored.**

Conclusions

On the basis of our findings, we may conclude that:

1. **The magnitude and the distribution of Water Saturation, as the coupling function, is key to Well Sanding due *sand liquefaction* (Formation Damage), Well Bore Instability, and Perforation Tunnel Stability Analysis.**
2. **The Caliper log and Water Saturation profile provide us with a good insight as to the location of the unstable section of the hole that is considered for perforation. They could also provide insight regarding potential Formation Damage by *sand liquefaction*.**
3. **The presence of Clays (*Illite and Mica*) and *Orthoclase (K-Feldspar*), Grain Size Distribution, the lack of an adequate amount of cement (mainly carbonates), and Water Saturation primarily control the Well Bore Instability mechanism in the probable productive and non-productive intervals of the hole.**
4. **The Porosity and Permeability of the turbidite sands are controlled by the Mean Grain Size (MGS), the type of minerals found in micro-seals (laminations), and the frequency of micro-seals.**
5. **Fortunately, unlike the other completions, the probable hydrocarbon-producing zone in Well (2) is devoid of "slump". The likely "slump" zone, as indicated by an abrupt Porosity Reversal between 12020' and 12040' MD, is some distance away from the probable Hydrocarbon-producing zone. Detecting the cause of the abrupt porosity reversals within a few inches of the thickness of the formation, without paleo data, could prove to be difficult if not impossible.**

6. **The Reservoir Rock Quality is the "better " quality rock within the probable Hydrocarbon-producing zone in Well (2).**
7. **XRD, SEM, and TSA data, with an emphasis on the clay minerals, Mica, and Feldspars, provide an invaluable basis for generating useful functions that are used in the Petrophysical and Petromechanical analysis of the data from all of the wells studied. The XRD data proved to be very useful in studying and analyzing of data from Well (2) in the interval between 11980' and 12180' MD.**
8. **In the absence of useful "Shear Wave Arrival" or the rock mechanical properties derived from laboratory tri-axial tests, the Partition Function and Integral Techniques provide useful tools for analyzing the effect of Water Saturation on the Caliper Log Function, or the Well Bore Stability Indicator.**
9. **In the absence of useful "Shear Wave Arrival" data similar to the data from Well (2), the Reservoir Rock Quality index may be used as a substitute for HPI.**
10. **Young's and shear modulus of Turbidite sands are highly variable, especially in the slump sections with very high water saturation.**
11. **The paleo marker for these types of unstable slumps is *Globorotalia Miocenica.***
12. **Using HPI as guide to selective completion and perforating the low side with a small entrance hole appear to provide a fair to good initial production results.**
13. **The appearance of low resistivity and high critical water saturation, without a thorough study of other important parameters, should not have a negative impact on the decision to complete or not to complete a well drilled in turbidite sand target.**
14. **A partition function in the form of a clustered data set and a Photoelectric function (along with cluster analysis) could prove remarkable in locating the most stable zone of the most probable hydrocarbon-producing zone.**
15. **Fourier Spectral Analysis could prove to be an invaluable asset in qualitatively determining which one of the many functions provides strong or weak correlation functions.**
16. **The P.O.P analysis of the production data, in conjunction with Fourier analysis, shows that turbidite sands are extremely sensitive to high drawdown and flow rate. Wild oscillation of production could cause sand liquefaction and the destabilization of the perf tunnels. In producing the turbidite reservoirs of the field under study either the sand should be consolidated to withstand a shear stress equivalent to a Drawdown of at least 1230 PSI or these wells be produced at a maximum Drawdown of 600-700 PSI.**

References

1. **Whitten, D. G. A, and Brooks, J. R. V. *A Dictionary of Geology*. Penguin Books Inc.: Baltimore, Maryland, 1972.**
2. **Hayatdavoudi, A., "Formation Sand Liquefaction: A New Mechanism for Explaining Fines Migration and Well Sanding." Revised SPE Paper # 52137, SPE Mid Continent Production Operations Symposium, Oklahoma City, Oklahoma, March 28-31, 1999. Note: The revised SPE 52137 may be considered as Part I of the SPE Paper # 73739, or Part II of the Petromechanics series on Oilfield Sand Liquefaction.**
3. **Hayatdavoudi, A., "Changing Chemophysical Properties of Formation and Drilling Fluid Enhances Penetration Rate and Bit Life." SPE Paper # 50729, SPE International Symposium on Oilfield Chemistry, Houston, Texas, February 16-19, 1999.**

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Table (2). XRD Analysis of Some Liquefied Sand Samples From Well (1) and XRD Analysis of Side Wall Core Samples Taken From Well (2). All mineral quantities are in percentages.

Well (1)	Quartz	K-Feldspar	Na-Feldspar	Mica	Calcite	Mg-Calcite	Fe-Dolomite	Halite	Kaolinite	Chlorite	Illite	Smectite	Hayatdavoudi Hydration Index (HHI-100% Clay Scale Basis)
Sample 1&2	**50**	**12**	**7**	**-**	**2**	**2**	**-**	**1**	**4**	**2**	**10**	**10**	**0.2884**
Slurry Sample	**59**	**3**	**6**	**-**	**2**	**-**	**1**	**1**	**4**	**2**	**12**	**10**	**0.3139**
Well (2)													
Sample 1- *Sand* Lamination MD-12074	**62**	**4**	**6**	**2**	**3**	**1**	**3**	**-**	**3**	**1**	**8**	**6**	**0.2824**
Sample 2- *Shale* Lamination MD-12074	**54**	**4**	**2**	**7**	**3**	**1**	**1**	**-**	**4**	**2**	**12**	**10**	**03130**
Sample 3- *Sand* Lamination MD-12108	**71**	**8**	**7**	**2**	**2**	**1**	**1**	**-**	**1**	**TR**	**3**	**4**	**0.1209**
Sample 4- *Sand* Lamination MD-12128	**69**	**3**	**7**	**1**	**2**	**1**	**2**	**-**	**1**	**TR**	**4**	**7**	**0.1579**
TR=Trace Mica=Mostly Muscovite For HHI Concept and Scale See Ref. 3	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

Table (1). A Comparison of Mean Grain Size Samples From Well (1) and Well (2).

Well (1)	Mean Grain Size, Micron, µm
Sample (A)	30.08
Sample (B)	31.79
Well (2)	
Sample (C) 12078	61
Sample (D) 12108	81
Sample (E) 12128	85

Table 3. The Optimizing Parameter, Drawdown, and Preliminary Recommendations. Note that the best production condition is when the P.O.P value is *Minimal* for the *Maximum* drawdown pressure.

Production Date	Drawdown, PSI	Production Optimizing Parameter, P.O.P
5/1/1997	675	6.81E+10
5/3/1997	700	7.05E+10
5/5/1997	700	5.99E+10
5/7/1997	700	7.06E+10
5/8/1997	700	7.09E+10
9/1/1999	750	3.21E+10
12/16/2000	450	6.18E+09
12/17/2000	400	6.92E+09
12/18/2000	400	7.31E+09
12/19/2000	400	6.93E+09
12/20/2000	400	7.08E+09
12/21/2000	400	7.14E+09
12/22/2000	400	7.47E+09
12/23/2000	450	9.70E+09
12/24/2000	450	9.60E+09
12/25/2000	450	1.01E+10
12/26/2000	450	7.29E+09
12/27/2000	350	6.61E+09
12/28/2000	400	7.06E+09
12/29/2000	425	7.61E+09
12/30/2000	425	8.95E+09
12/31/2000	400	7.66E+09
1/1/2001	400	6.74E+09
1/2/2001	400	7.39E+09

Opinion and Preliminary Recommendations

By: A. Hayatdavoudi, PhD, PE

The Estimates of the Drawdown Pressure for the1 Sand in the Well Adjacent to Well (1) appears to be about 350 to 700 PSI. In fact, this sand seems to be extremely stress-sensitive. Therefore, on the basis of the Production Optimizing Parameter and being cognizant of the Well Sanding problem, we recommend that *initial* drawdown pressure be kept at about 100 PSI and increased at a rate of 10 psi per day until an average drawdown-pressure of 400 psi is reached. Further refinement of a suitable drawdown must account for the critical water saturation, grain and fluid density, porosity, and other parameters. Furthermore, the above drawdown pressure must be reconciled or compared with other models that are based on drilling data and the log-derived parameters. Then, one can exercise his choice of selecting the most reasonable drawdown value for producing the well economically. Obviously, different models give very different results. Therefore, as a matter of just being cautious, we often recommend the most conservative drawdown values for producing the well.

Table (4). Well (1) Selective Completion Interval Based on Open Hole Log, Drilling, Paleontology, etc., for Possible Sand-free, Initial Optimum Production.

Analysis By: A. Hayatdavoudi, PhD, PE.

HPI	MD, Ft and The Reservoir Productivity Grade	Estimated Initial Drawdown Tolerance, PSI	Estimated Water Saturation, Percent	Comments and Tentative Opinion for every 0.5 Ft of reservoir. *****A++ (High) to F (Lowest) Grade.
1.421	11150	126	17.02	Probable Transition Zone Water Saturation, Sw at 15 Percent

Table (4). Well (1) Selective Completion Interval Based on Open Hole Log, Drilling, Paleontology, etc., for Possible Sand-free, Initial Optimum Production.

Analysis By: A. Hayatdavoudi, PhD, PE.

HPI	MD, Ft and The Reservoir Productivity Grade	Estimated Initial Drawdown Tolerance, PSI	Estimated Water Saturation, Percent	Comments and Tentative Opinion for every 0.5 Ft of reservoir. *****A++ (High) to F (Lowest) Grade.
1.421	11150.5	124	16.51	Probable Transition Zone Water Saturation, Sw at 15 Percent
1.415	11151	122	15.89	Probable Transition Zone Water Saturation, Sw at 15 Percent
1.408	11151.5	122	15.17	Probable Transition Zone Water Saturation, Sw at 15 Percent
1.405	11152 D	123	14.72	Probable Production with some Water-cut.
1.412	11152.5 D	125	14.68	Probable Production with some Water-cut.
1.422	11153 D	125	14.68	Probable Production with some Water-cut.
1.432	11153.5 D	124	14.39	Probable Production with some Water-cut.
1.431	11154 D	121	13.75	Probable Production with some Water-cut.
1.41	11154.5 C	120	12.79	Probable Production.
1.385	11155 *** B	122	11.86	Probable good Production. Conservative Critical Water Saturation
1.389	11155.5 *** B	128	11.37	Probable good Production.
1.411	11156 *** B	131	11.07	Probable good Production.
1.416	11156.5 *** B	131	11.22	Probable good Production.
1.402	11157 C	134	12.01	Probable Production
1.406	11157.5 C	137	12.87	Probable Production
1.429	11158 D	134	13.22	Probable Production with some Water-cut.
1.429	11158.5 D	131	13.36	Probable Production with some Water-cut.
1.403	11159 D	130	13.78	Probable Production with some Water-cut.
1.392	11159.5 D	132	14.21	Probable Production with some Water-cut.
1.41	11160 D	132	14.28	Probable Production with some Water-cut.
1.431	11160.5 D	129	14.18	Probable Production with some Water-cut.
1.439	11161 D	124	14.17	Probable Production with some Water-cut.
1.435	11161.5 D	118	14.35	Probable Production with some Water-cut.
1.422	11162 D	114	14.79	Probable Production with some Water-cut.
1.417	11162.5 F	115	15.09	Water-cut transition Zone
1.43	11163 D	116	14.97	Water-cut transition Zone
1.45	11163.5 F	116	15.05	Water-cut transition Zone
1.454	11164 F	113	15.38	Water-cut transition Zone
1.438	11164.5 F	110	15.34	Water-cut transition Zone
1.417	11165 D	109	14.88	Probable Production with some Water-cut.
1.411	11165.5 D	109	14.42	Probable Production with some Water-cut.
1.414	11166 D	109	14.04	Probable Production with some Water-cut.
1.413	11166.5 D	109	13.62	Probable Production with some Water-cut.
1.411	11167 D	107	13.13	Probable Production with some Water-cut.
1.41	11167.5 C	106	12.53	Probable Production.
1.412	11168 C	106	12.12	Probable Production
1.423	11168.5 *** B	107	11.88	Probable zone of water-free production, Sw at less than 12 Percent.
1.439	11169 *** B	108	11.5	Probable good Production.
1.449	11169.5 **** A	106	10.96	Probable good Production.
1.447	11170 **** A	104	10.59	Probable good Production.
1.431	11170.5 **** A	103	10.59	Probable good Production.
1.411	11171 *** B	102	11.07	Probable good Production.
1.406	11171.5 *** B	101	11.88	Probable good Production.
1.412	11172 C	101	12.45	Probable Production.
1.414	11172.5 C	102	12.45	Probable Production
1.415	11173 C	104	12.19	Probable Production
1.419	11173.5 *** B	106	11.84	Probable good Production.
1.428	11174 *** B	107	11.08	Probable good Production.
1.44	11174.5 **** A	107	10.12	Probable good Production.
1.443	11175 ***** A+	106	9.47	Probable good Production.
1.439	11175.5 ***** A+	105	9.25	Probable good Production.
1.445	11176 *****A+	103	9.29	Probable good Production.

Table (4). Well (1) Selective Completion Interval Based on Open Hole Log, Drilling, Paleontology, etc., for Possible Sand-free, Initial Optimum Production.

Analysis By: A. Hayatdavoudi, PhD, PE.

HPI	MD, Ft and The Reservoir Productivity Grade	Estimated Initial Drawdown Tolerance, PSI	Estimated Water Saturation, Percent	Comments and Tentative Opinion for every 0.5 Ft of reservoir. *****A++ (High) to F (Lowest) Grade.
1.449 Upper Limit	11176.5 *****A+	102	9.34	Probable good Production.
1.442	11177 *****A+	102	9.47	Probable good Production.
1.429	11177.5 *****A+	104	9.93	Probable good Production.
1.423	11178 ****A	106	10.79	Probable good Production.
1.434	11178.5 ***B	107	11.81	Probable good Production.
1.442	11179 C	106	12.51	Probable Production.
1.434	11179.5 C	106	12.75	Probable Production.
1.426	11180 C	107	12.97	Probable Production
1.435	11180.5 D	108	13.33	Probable Production with some Water-cut.
1.434	11181D	108	13.44	Probable Production with some Water-cut.
1.424	11181.5 D	109	13.1	Probable Production with some Water-cut.
1.425	11182 C	110	12.62	Probable Production
1.442	11182.5 C	107	12.28	Probable Production.
1.466	11183 C	98	12.2	Probable Production.
1.488	11183.5 XXX	85	12.37	Highly Unstable Interval. This is another XXX rated interval.
1.501	11184 XXX	75	12.74	Highly Unstable Interval.
1.494	11184.5 XXX	69	13.2	Highly Unstable Interval within Sw Transition Zone
1.48	11185 XXX	68	13.48	Highly Unstable Interval within Sw Transition Zone
1.482	11185.5 XXX	69	13.35	Highly Unstable Interval within Sw Transition Zone
1.492	11186 XXX	69	13.07	Highly Unstably Interval within Sw Transition Zone
1.481	11186.5 XXX	72	12.9	Highly Unstable Zone near the Sw Transition Zone
1.452	11187 XXX	82	12.7	Highly Unstable Interval near the Sw Transition Zone.
1.425	11187.5 C	94	12.23	Probable Production.
1.415	11188 *** B	103	11.47	Probable good Production.
1.44	11188.5 Too Close To the Unstable Zone	100	10.64	Highly Unstable Interval. This is another XXX rated interval. If it is desired to produce from this
1.501	11189 XXX	84	10.01	interval, it is only prudent to produce the well with the lowest
1.558	11189.5 XXX	62	9.47	possible drawdown, which is about 30 PSI. However, this drawdown may
1.575	11190 XXX	47	8.89	not be adequate enough to meet the production expectation.
1.563	11190.5 XXX	40	8.37	This is a triple X-rated section, despite its desirable critical water saturation. if this section is perforated
1.565	11191 XXX	38	8.04	May cause frequent workover, well bore clean up, well sanding
1.577	11191.5 XXXXX	37	8.32	expensive FracPac or acidizing with UNACCEPTABLE RESULTS.
1.569	11192 XXXXX	37	9.92	In fact, it may be that the previous FracPac sand all ended up in
1.546	11192.5 XXX	39	13.18	this zone. If so, the frac sand may have been completely buried in this zone without propping effect.
1.529	11193 XXX	43	16.08	Highly Unstable Zone within the Sw Transition Zone
1.51	11193.5 XXX	44	14.15	Highly Unstable Zone
1.493	11194 XXX	44	10.19	Highly Unstable Zone
1.487	11194.5 XXX	46	7.99	Highly Unstable Zone
1.485	11195 XXX	52	7.37	Highly Unstable Zone
1.486	11195.5 XXX	60	7.41	Highly Unstable Zone
1.491	11196 XXX	67	7.67	Highly Unstable Zone
1.484	11196.5 XXX	72	8.04	Highly Unstable Zone
1.479	11197 XXX	75	8.37	Highly Unstable Zone
1.487	11197.5 XXX	78	8.51	Highly Unstable Zone
1.48	11198 XXX	79	8.27	Highly Unstable Zone
1.456	11198.5 XXX	81	7.69	Highly Unstable Zone
1.442	11199 XXX	83	7.27	Highly Unstable Zone
1.434	11199.5 XXX	85	7.31	Highly Unstable Zone
1.422	11200 XXX	88	7.8	Borderline? Highly Unstable Zone
1.435	11200.5 *****A++	93	8.46	Probable good Production.
1.461	11201?	95	8.88	Although the water saturation appears to be OK, Hayatdavoudi's Perforation Index, HPI,

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HPI	MD, Ft and The Reservoir Productivity Grade	Estimated Initial Drawdown Tolerance, PSI	Estimated Water Saturation, Percent	Comments and Tentative Opinion for every 0.5 Ft of reservoir. *****A++ (High) to F (Lowest) Grade.
1.47	11201.5?	94	8.99	Does not confirm a good reservoir quality with good saturation
1.469	11202?	93	9.05	Recommend XRD-SEM analysis for the Zone of? Quality.
1.465	11202.5?	91	9.19	Recommend XRD-SEM analysis for the Zone of? Quality.
1.455	11203?	92	9.37	Recommend XRD-SEM analysis for the Zone of? Quality.
1.452	11203.5?	95	9.47	Recommend XRD-SEM analysis for the Zone of? Quality.
1.462	11204?	97	9.48	Recommend XRD-SEM analysis for the Zone of? Quality.
1.463	11204.5?	99	9.63	Recommend XRD-SEM analysis for the Zone of? Quality.
1.456	11205?	99	9.92	Recommend XRD-SEM analysis for the Zone of? Quality.
1.446	11205.5 ****A	98	10.2	Probable good Production.
1.43	11206 ****A	97	10.52	Probable good Production.
1.429	11206.5 ****A	95	10.47	Probable good Production.
1.444	11207 ****A	93	10.42	Probable good Production.
1.448	11207.5 ****A	92 Lower Limit	10.66	Probable good Production.
1.441	11208 ****A	93	10.61	Probable good Production.
1.443	11208.5 ****A	95	10.06	Probable good Production.
1.445	11209 *****A+	96	9.66	Probable good Production.
1.44	11209.5 *****A	97	9.73	Probable good Production.
1.438	11210 ****A	97	9.89	Probable good Production.
1.44	11210.5 ****A	96	9.81	Probable good Production.
1.447	11211 ****A	94	9.73	Probable good Production.
1.459	11211.5?	91	9.99	Recommend XRD-SEM Analysis for the Zone of? Quality.
1.46	11212 S	88	10.63	The S zones are subject to drawdown control.
1.446	11212.5 S	87	11.22	The S zones are subject to drawdown control.
1.436	11213 S	88	11.27	The S zones are subject to drawdown control.
1.441	11213.5 S	89	10.98	The S zones are subject to drawdown control.
1.446	11214 S	90	10.67	The S zones are subject to drawdown control.
1.453	11214.5 S	91	10.21	The S zones are subject to drawdown control.
1.467	11215?	92	9.75	Recommend XRD-SEM Analysis for the Zone of? Quality.
1.474	11215.5?	91	9.6	Recommend XRD-SEM Analysis for the Zone of? Quality.
1.461	11216?	90	9.93	Recommend XRD-SEM Analysis for the Zone of? Quality.
1.452	11216.5	92	10.71	Borderline? Quality and Drawdown tolerance
1.456	11217	95	11.63	Borderline? Quality and Drawdown tolerance
1.465	11217.5	97	12.08	Borderline? Quality and Drawdown tolerance
1.47	11218	96	12.02	Borderline? Quality and Drawdown tolerance
1.472	11218.5	96	12.24	Borderline? Quality and Drawdown tolerance
1.468	11219	99	13.03	Borderline? Quality and Drawdown tolerance
1.467	11219.5	103	13.59	Borderline? Quality and Drawdown tolerance
1.463	11220	106	13.27	Borderline? Quality and Drawdown tolerance
1.444	11220.5 C	108	12.78	Probable Production.
1.417	11221 C	110	12.85	Probable Production.
1.402	11221.5 D	110	13.29	Probable Production with Some Water-cut.
1.397	11222 D	108	13.89	Probable Production with Some Water-cut.
1.398	11222.5 D	106	14.69	Probable Production with Some Water-cut.
1.409	11223	107	15.59	High water-cut Transition zone
1.425	11223.5	110	16.16	High water-cut Transition zone
1.439	11224	113	16.12	High water-cut Transition zone
1.439	11224.5	115	15.79	High water-cut Transition zone
1.413	11225	114	15.78	High water-cut Transition zone
1.402	11225.5	112	16.2	High water-cut Transition zone
1.448	11226	101	16.75	High water-cut Transition zone
1.499	11226.5	86	17.11	High water-cut Transition zone
1.519	11227	76	16.9	High water-cut Transition zone

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HPI	MD, Ft and The Reservoir Productivity Grade	Estimated Initial Drawdown Tolerance, PSI	Estimated Water Saturation, Percent	Comments and Tentative Opinion for every 0.5 Ft of reservoir. *****A++ (High) to F (Lowest) Grade.
1.516	11227.5	75	16.16	High water-cut Transition zone
1.495	11228	82	15.32	High water-cut Transition zone
1.453	11228.5	97	14.95	High water-cut Transition zone
1.413	11229	113	15.37	High water-cut Transition zone
1.393	11229.5	122	16.35	High water-cut Transition zone
1.394	11230	123	16.98	High water-cut Transition zone
1.418	11230.5	120	16.56	High water-cut Transition zone
1.445	11231	116	15.13	High water-cut Transition zone
1.449	11231.5 D	115	13.29	Probable Production with Some Water-cut.
1.431	11232 ***B	118	11.99	Probable good Production.
1.419	11232.5 *** B	124	11.85	Probable good Production.
1.417	11233 C	128	12.46	Probable Production
1.415	11233.5 D	128	13.36	Probable Production with Some Water-cut.
1.417	11234 D	126	14.48	Probable Production with Some Water-cut.
1.425	11234.5	119	15.64	High water-cut Transition zone
1.429	11235	113	15.69	High water-cut Transition zone
1.432	11235.5 D	109	14.74	Probable Production with Some Water-cut.
1.435	11236 D	107	14.04	Probable Production with Some Water-cut.
1.435	11236.5 D	106	13.77	Probable Production with Some Water-cut.
1.433	11237 D	107	13.48	Probable Production with Some Water-cut.
1.439	11237.5 D	109	13.21	Probable Production with Some Water-cut.
1.449	11238 D	108	13.12	Probable Production with Some Water-cut.
1.454	11238.5 D	105	13.12	Probable Production with Some Water-cut.
1.449	11239 D	100	13.26	Probable Production with Some Water-cut.
1.445	11239.5 D	97	13.73	Probable Production with Some Water-cut.
1.447	11240 D	97	14.54	Probable Production with Some Water-cut.
1.453	11240.5	96	15.48	High water cut Transition zone
1.459	11241	95	15.89	High water-cut Transition zone
1.458	11241.5	94	15	High water-cut Transition zone
1.455	11242?	93	13.38	Probable strong water-cut Production Zone. Recommend XRD-SEM Analysis for this Zone.
1.474	11242.5?	90	12.19	Probable strong water-cut Production Zone. Recommend XRD-SEM Analysis for this Zone.
1.513	11243?	81	11.79	Recommend XRD-SEM Analysis for this Interval.
1.538	11243.5?	69	11.92	Recommend XRD-SEM Analysis for this Interval.
1.531	11244	61	12.26	Probable strong water-cut Production Zone. Recommend XRD-SEM Analysis for this Zone.
1.511	11244.5	64	12.4	Probable strong water-cut Production Zone. Recommend XRD-SEM Analysis for this Zone.
1.483	11245?	75	12.03	Borderline? Quality and Drawdown tolerance
1.453	11245.5	88	11.28	Borderline? Quality and Drawdown tolerance
1.44	11246 ****A	93	10.91	Probable good Production.
1.442	11246.5 ***B	92	11.42	Probable good Production.
1.433	11247 C	93	12.14	Probable Production
1.435	11247.5 C	95	12.12	Probable Production
1.479	11248 XXX	87	11.44	Highly Unstable Zone
1.518	11248.5 XXX	74	10.75	Highly Unstable Zone
1.512	11249 XXX	68	10.46	Highly Unstable Zone
1.486	11249.5 XXX	70	10.63	Highly Unstable Zone
1.481	11250 XXX	74	10.94	Highly Unstable Zone
1.494	11250.5 XXX	73	11.15	Highly Unstable Zone
1.507	11251 XXX	68	11.17	Highly Unstable Zone
1.514	11251.5 XXX	62	10.96	Highly Unstable Zone
1.508	11252 XXX	64	10.42	Highly Unstable Zone
1.488	11252.5 XXX	76	9.52	Highly Unstable Zone

Table (4). Well (1) Selective Completion Interval Based on Open Hole Log, Drilling, Paleontology, etc., for Possible Sand-free, Initial Optimum Production.

Analysis By: A. Hayatdavoudi, PhD, PE.

HPI	MD, Ft and The Reservoir Productivity Grade	Estimated Initial Drawdown Tolerance, PSI	Estimated Water Saturation, Percent	Comments and Tentative Opinion for every 0.5 Ft of reservoir. *****A++ (High) to F (Lowest) Grade.
1.479	11253 XXX	89	8.45	Highly Unstable Zone
1.498	11253.5 XXX	85	7.48	Highly Unstable Zone
1.508	11254 XXX	67	6.7	Highly Unstable Zone
1.512	11254.5 XXX	53	5.91	Highly Unstable Zone
1.517	11255 XXX	47	5.14	Highly Unstable Zone
1.498	11255.5 XXX	42	4.48	Highly Unstable Zone
1.446	11256 XXX	39	4.02	Highly Unstable Zone. Subject to drawdown control
1.394	11256.5 XXX	39	3.61	Highly Unstable Zone. Subject to drawdown control
1.377	11257 XXX	45	3.17	Highly Unstable Zone. Subject to drawdown control
1.406	11257.5 XXX	52	2.78	Highly Unstable Zone. Subject to drawdown control
1.435	11258 XXX	56	2.63	Highly Unstable Zone. Subject to drawdown control
1.429	11258.5 XXX	58	2.88	Highly Unstable Zone. Subject to drawdown control
1.396	11259 XXX	63	3.56	Highly Unstable Zone. Subject to drawdown control
1.374	11259.5 XXX	76	4.7	Highly Unstable Zone. Subject to drawdown control
1.375	11260 *****A++	94	6.23	Probable good Production.
1.387	11260.5 *****A++	110	8.15	Probable good Production.
1.392	11261 *****A	118	10.39	Probable good Production.
1.383	11261.5 ****A	122	10.72	Probable good Production.
1.362	11262 ***B	128	11.39	Probable good Production.
1.316	11262.5D	145	13.3	Probable Production with Some Water-cut.
1.253	11263 D	182	14.98	Probable Production with Some Water-cut
1.206	11263.5	229	15.8	High water cut Transition zone
1.192	11264	262	16.86	High water cut Transition zone
1.189	11264.5	275	18.51	High water cut Transition zone
1.193	11265	272	20.78	Water
1.202	11265.5	258	23.57	Water
1.212	11266	241	25.32	Water
1.218	11266.5	233	25.24	Water
1.199	11267	239	23.96	Water
1.16	11267.5	258	21.9	Water
1.137	11268	277	20.17	Water
1.159	11268.5	276	20.17	Water
1.206	11269	252	22.21	Water
1.243	11269.5	221	25.51	Water
1.28	11270	192	28.52	Water
1.311	11270.5	164	29.16	Water
1.314	11271	143	27.39	Water
1.312	11271.5	133	24.99	Water
1.331	11272	130	22.95	Water
1.344	11272.5	130	21.57	Water
1.351	11273	131	21.04	Water
1.35	11273.5	136	21.94	Water
1.326	11274	149	24.16	Water
1.288	11274.5	170	26.07	Water
1.275	11275	189	27.66	Water
1.281	11275.5	200	28.08	Water

Problem: Sand Liquefaction

Well Sanding Example

Figure 1. Liquefied Sand Produced From Well (1).

Well Sanding Problem

Well Sanding Problem

Well Sanding Example

Figure 4. Liquefied Sand Flows Can Bring Production to a Halt.

Problem (Continued): <u>Sand Liquefaction May Occur Due to a Lack of Adequate Cement, Small Grain Size, Low Density Grains, Sudden Fluid Injection or Well Shut-off, and the Appearance of a Free Surface Behind the Casing</u>

Well Sanding Example

.Figure 5. A Sample of Dried, Liquefied Sand. This sample may flow again upon addition of some small amount of water

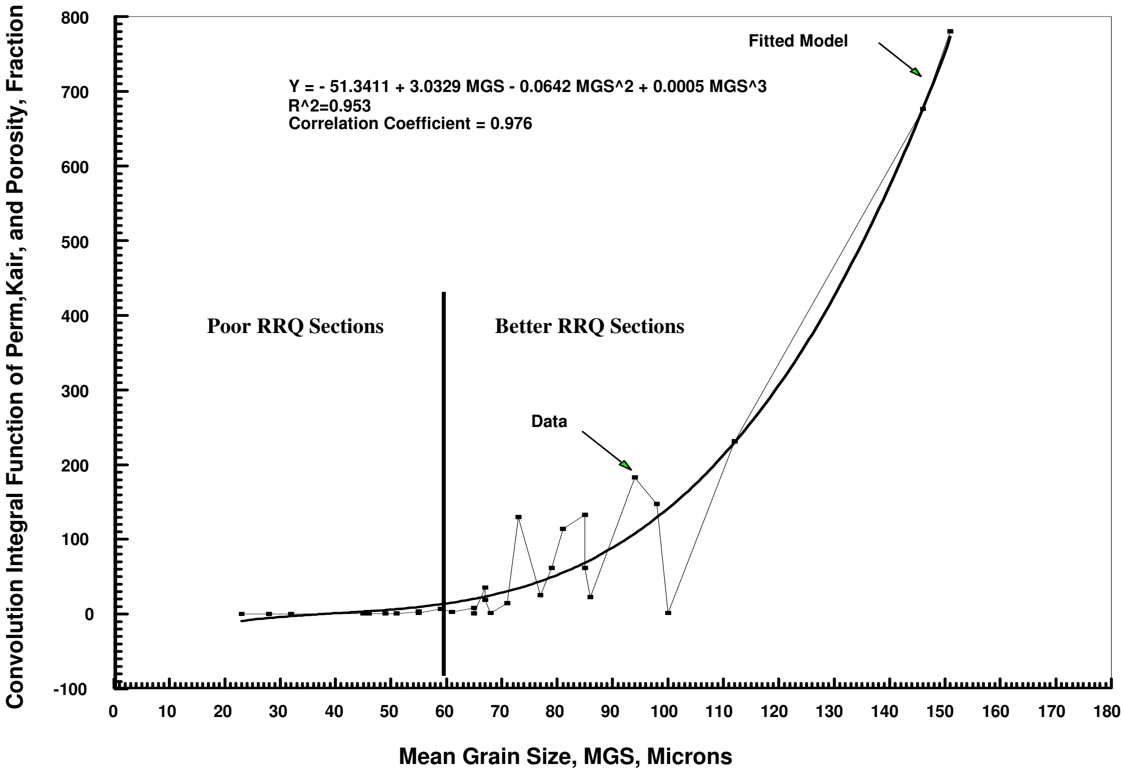

Figure 6. Convolution Integral Function Values of Side Wall Core Permeability, K_{air}, and Porosity, ϕ, (fraction) VS Mean Grain Size, MGS, An Example of Turbidite Sand Characterization in Well (2). Note the effect of the Downward Coarsening trend of the MGS on K, ϕ, and possibly, the Reservoir Rock Quality, RRQ, and the Completion Interval stability

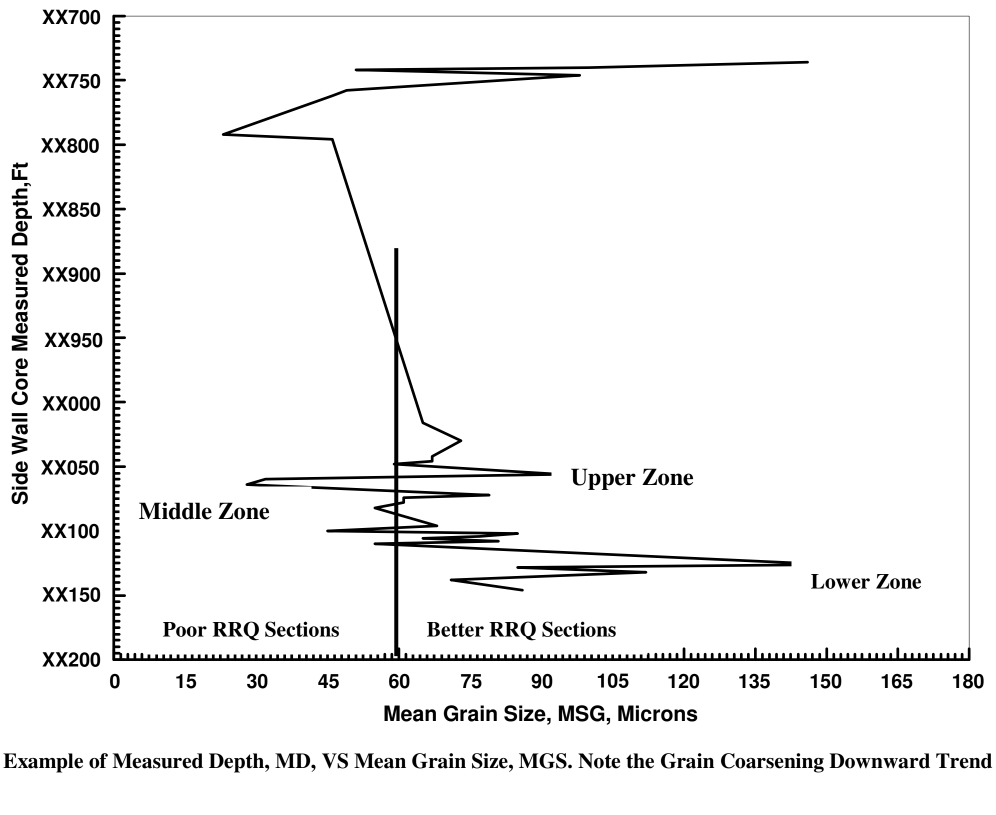

Figure 7. An Example of Measured Depth, MD, VS Mean Grain Size, MGS. Note the Grain Coarsening Downward Trend in Well (2).

Well (2): Grain Size and Spatial Distribution of Cements (red colors).

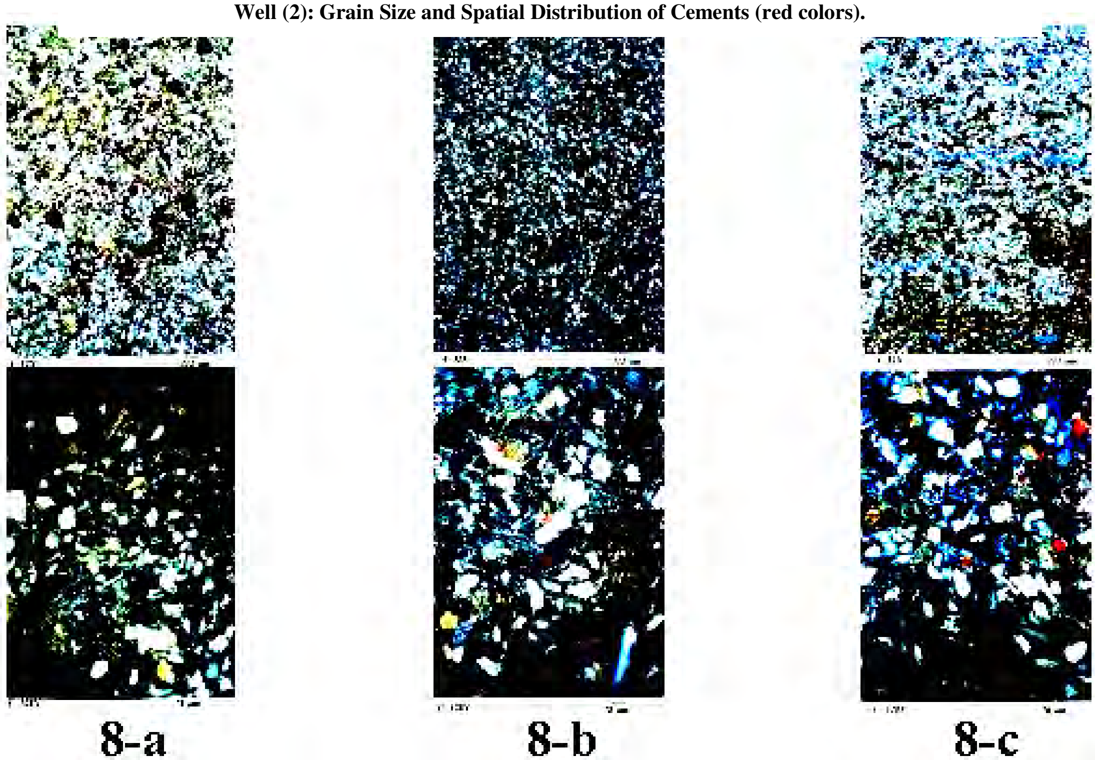

Figure 8. Thin Sections of Turbidite Sand at (a) Upper, (b) Middle, and (c) Lower zones of interest in Well (2). Compare Figure (8-a), (8-b), and (8-c) with Figures (6) and (7).

Figure 9. The Upper Zone is rich in *Mica* flakes and *Depositional Clays*. Also, *K-Feldspar* coats the Fine Grains of Low Permeability, Poor Reservoir Rock Quality. The bent *Mica* flake in the Middle Zone appears to indicate a state of high stress in that zone. The presence of high amount of thin, slick *Mica* flakes, *K-Feldspar*, and *Depositional Clay* coatings could easily cause sliding (shear) failure of the fine sand grains in the Upper and Middle zones. The Lower zone, or the zone of Higher Permeability and Better Reservoir Rock Quality, exhibits a fossil or a *Kaolinite* plate that is possibly converted to *Halloysite (a Kaolinite family)* or to some form of *Zeolite* under a highly Saline environment.

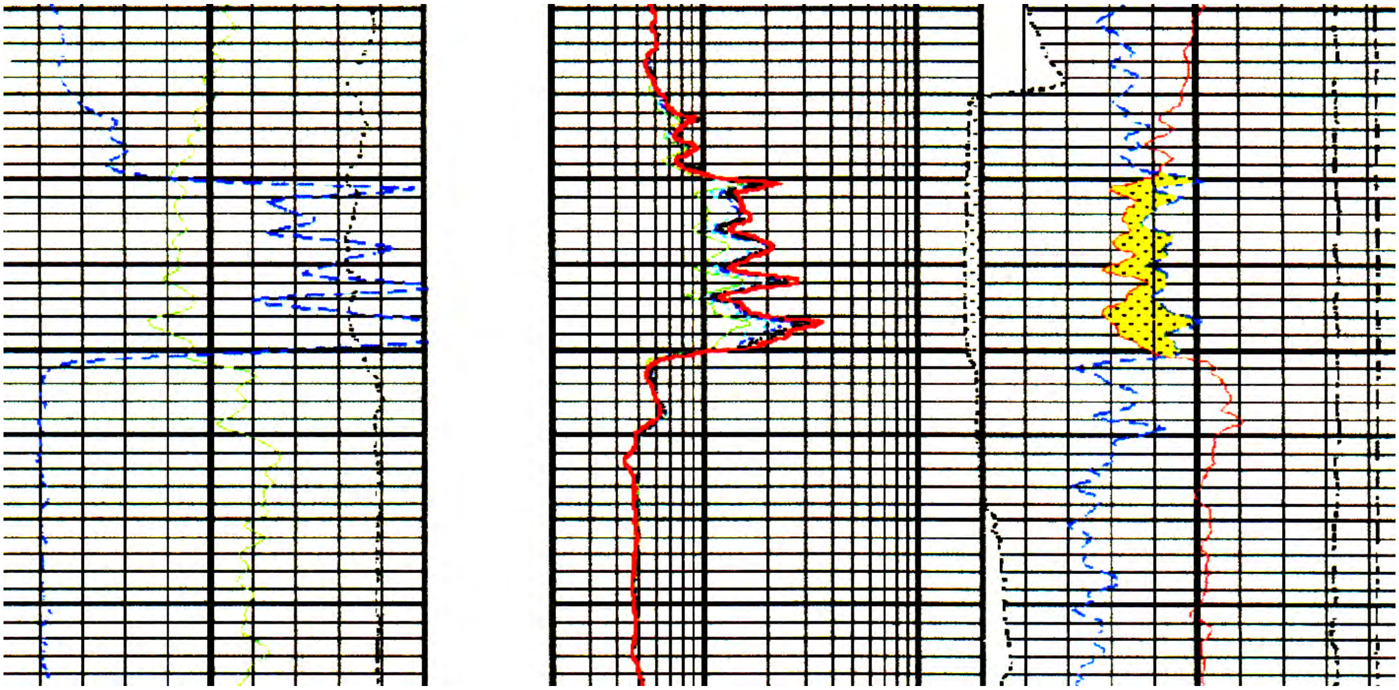

Figure 10. The Log of Turbidite Sand in Well (2).

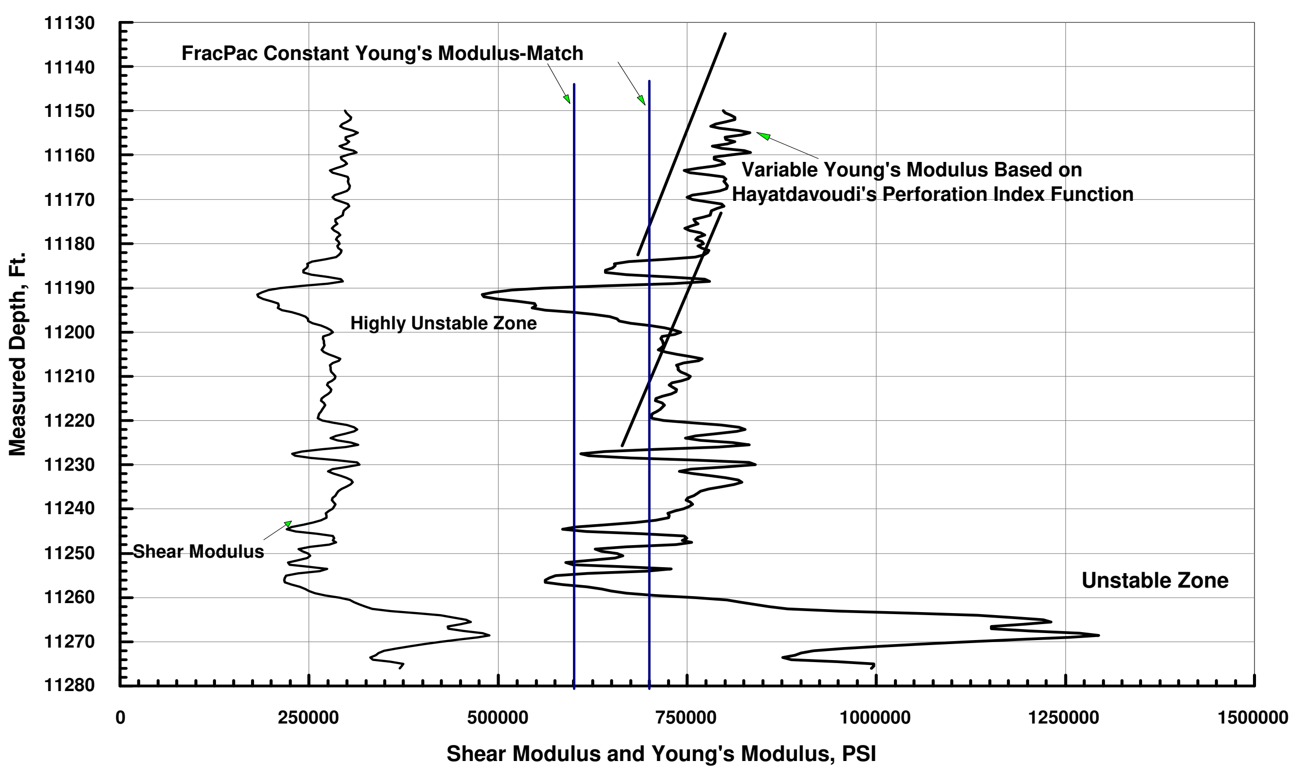

Figure 12. Measured Depth VS Log Derived Estimates of Rock Mechanical Properties in Well (1).

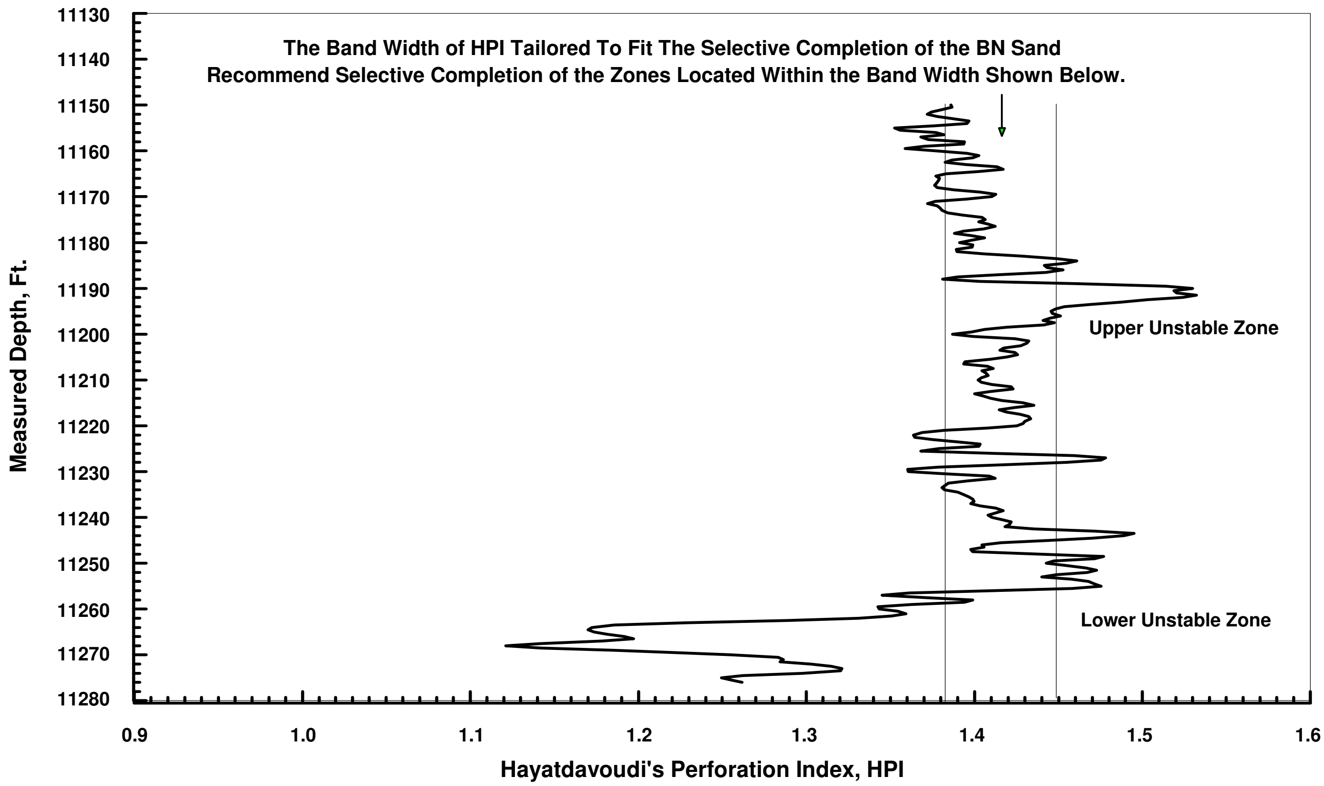

Figure 13. Measured Depth VS HPI Model for Selective Completion in Well (1).

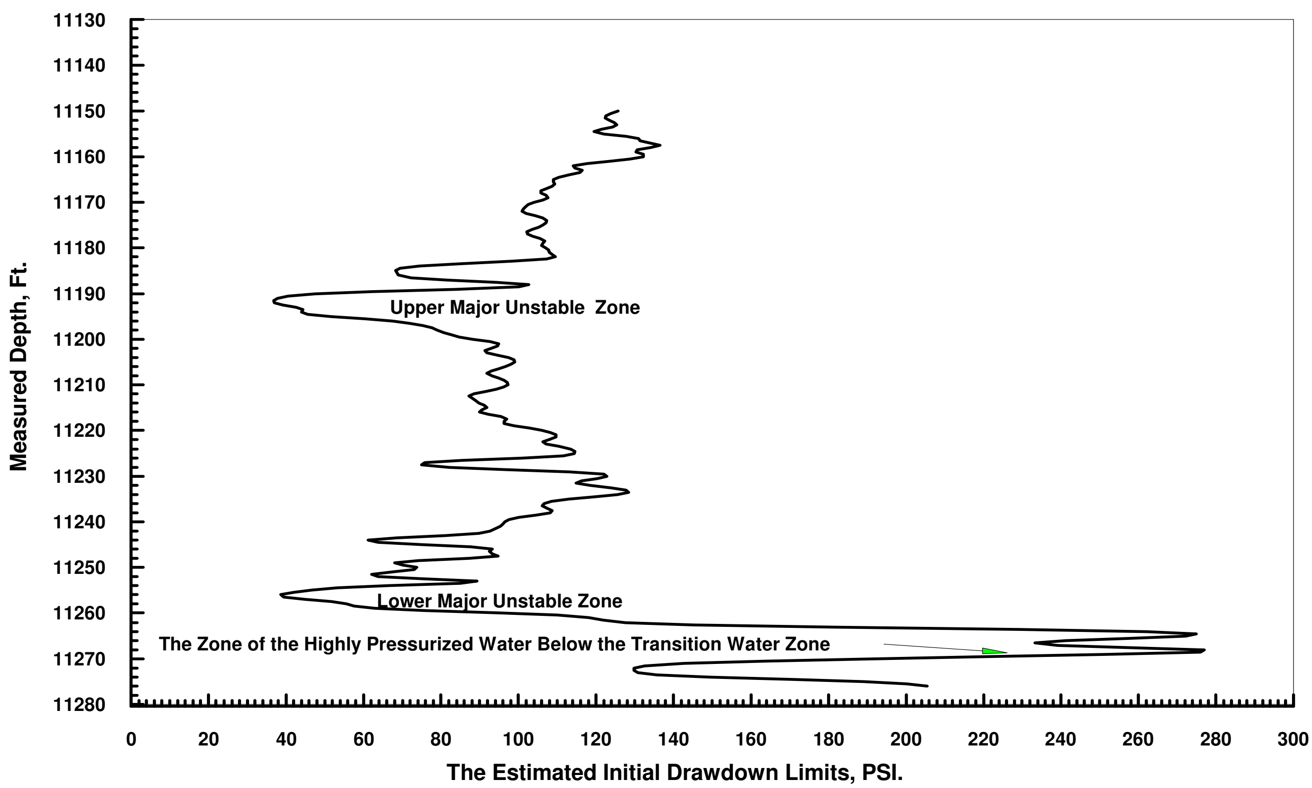

Figure 14. Measured Depth VS The Model-Derived Estimates of Initial Drawdown in Well (1).

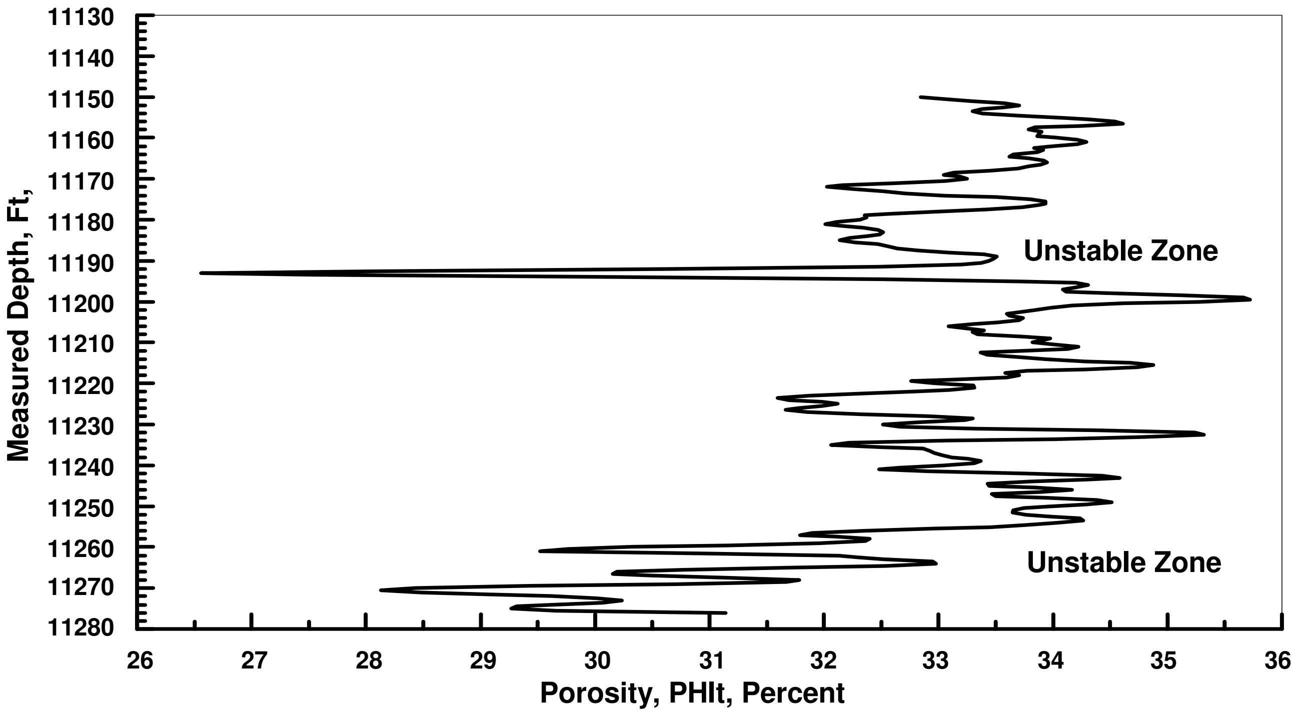

Figure 15. Measured Depth VS Log-Derived Estimates of Uncorrected Porosity in Well (1).

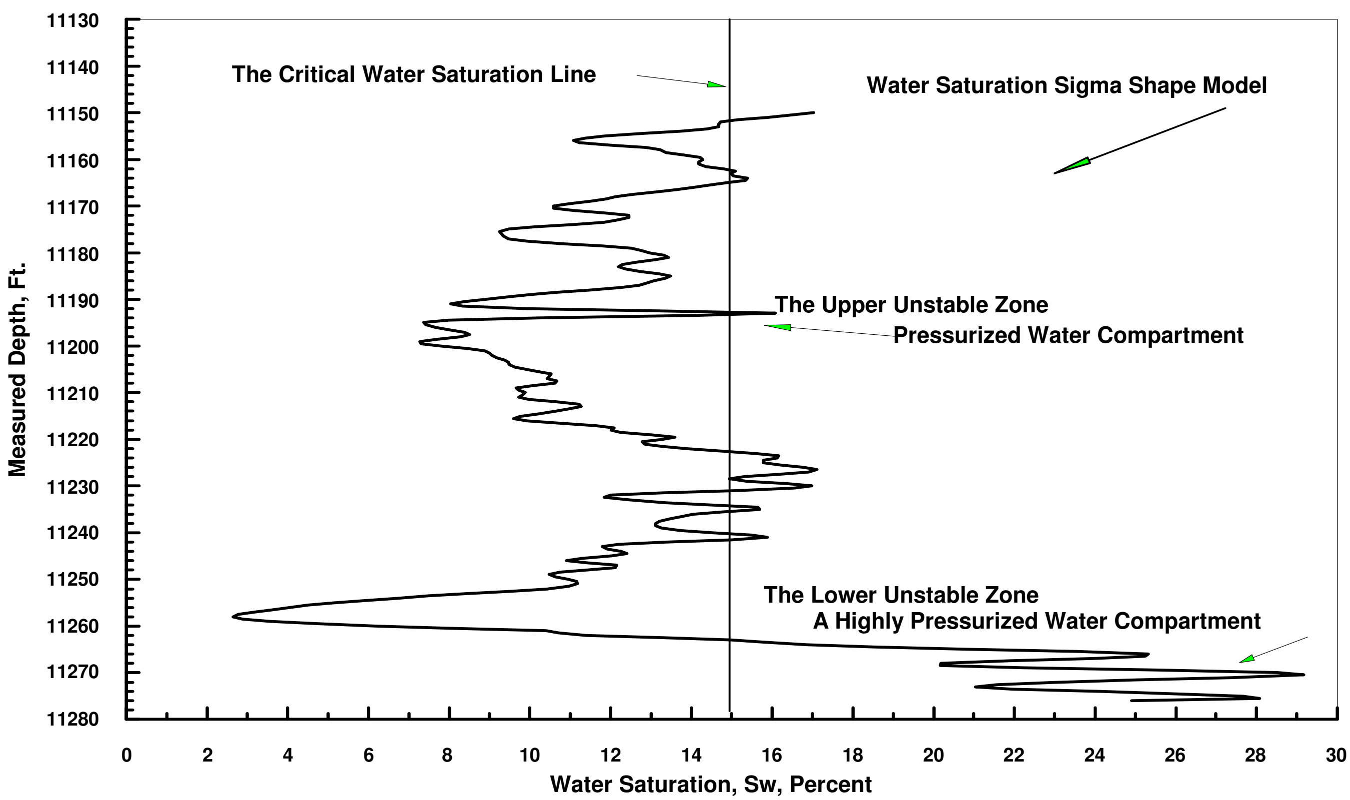

Figure 16. Measured Depth VS Model-Derived Water Saturation in Well

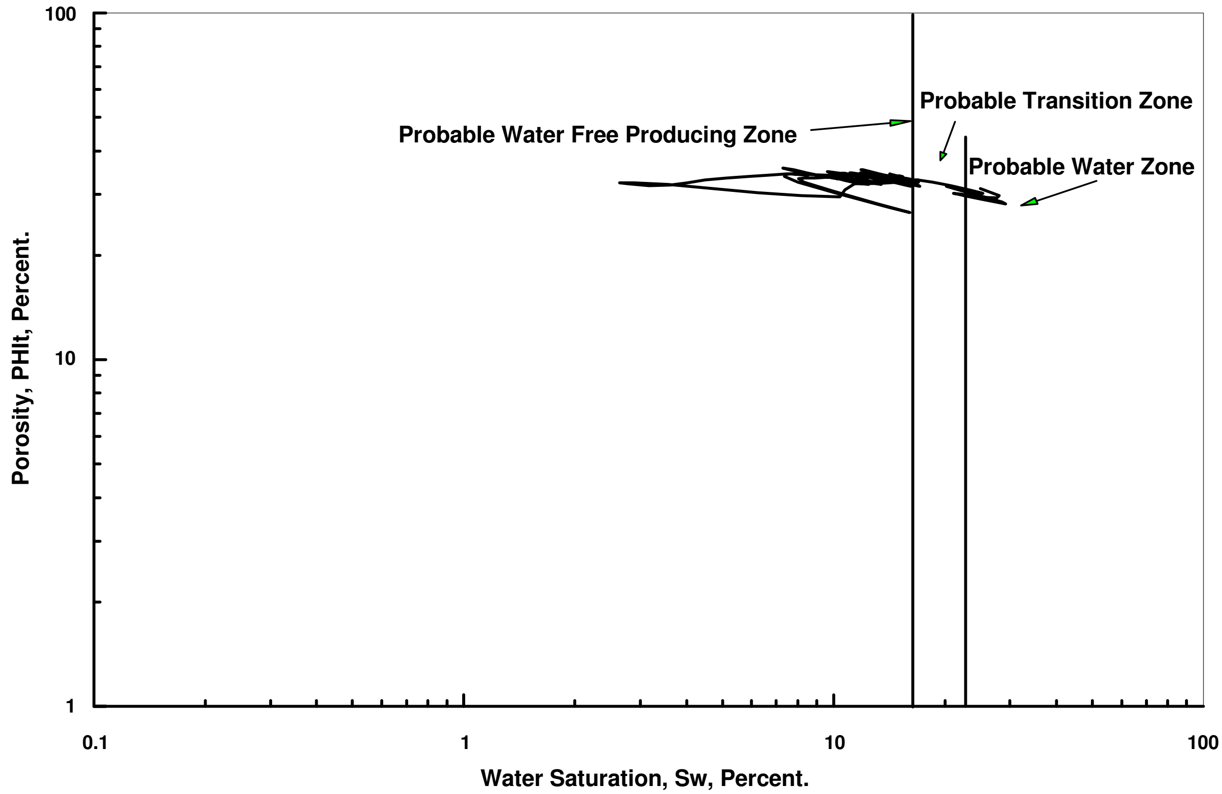

Figure 17. Log-Derived Porosity VS Water Saturation in Well (1).

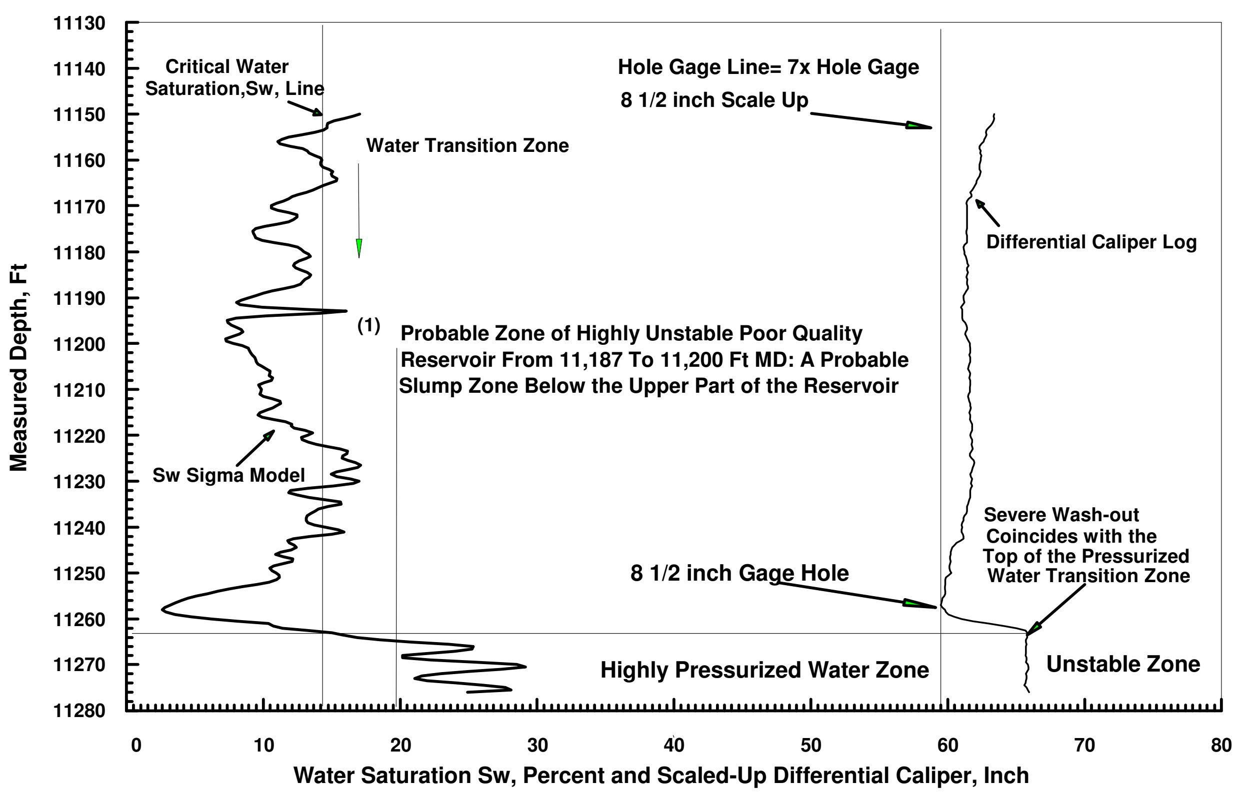

Figure 18. Measured Depth VS Water Saturation and Differential Caliper Log in Well (1).

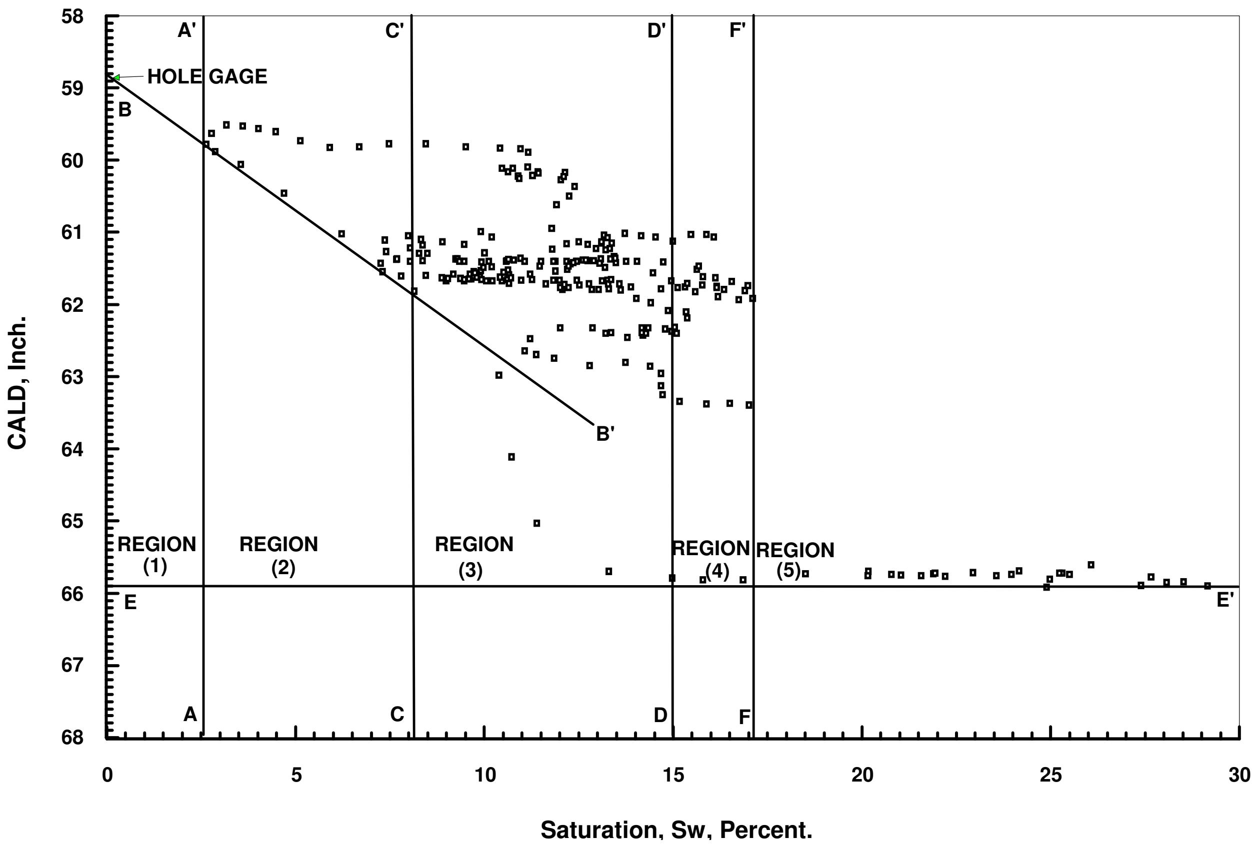

Figure 19. Caliper Log Function Values VS Water Saturation in Well (1). Note how the 'S' shape function defines the *unstable borehole* regions 4 and 5, transition zone 3, and the *stable* region 2.

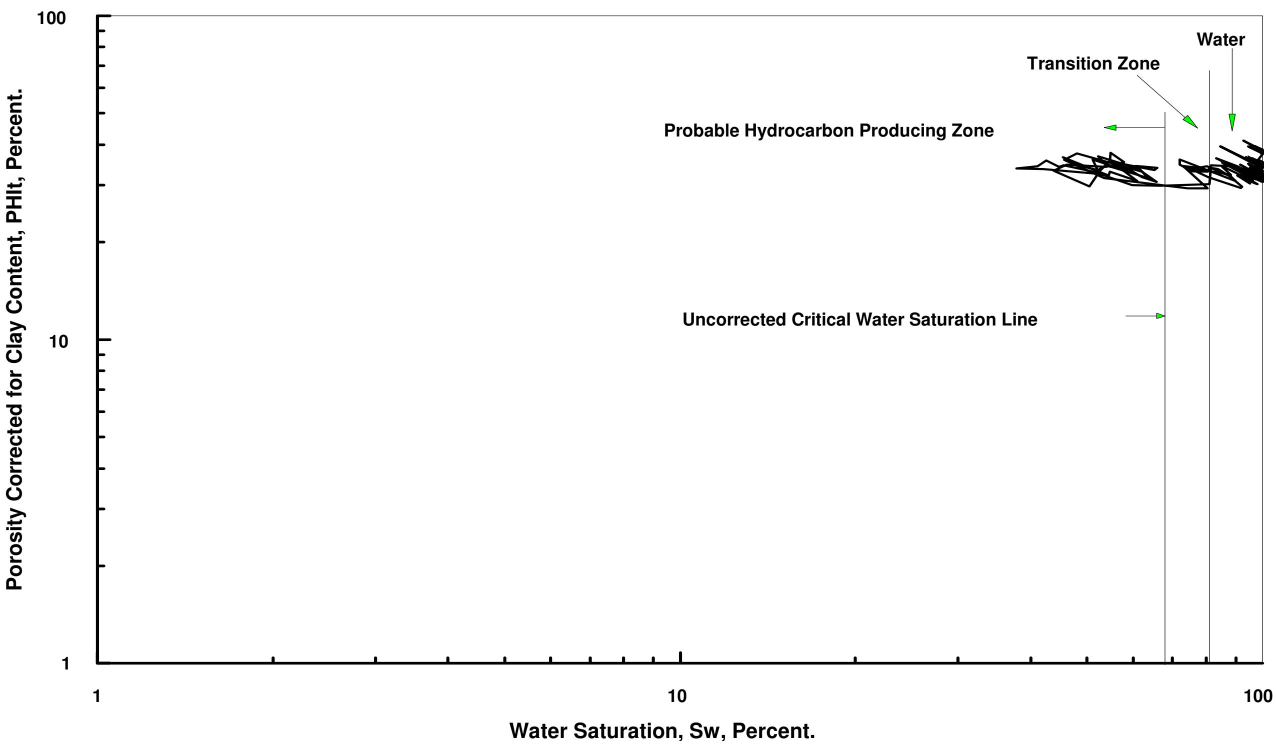

Figure 20. Corrected Porosity VS Water Saturation in Well (2). Compare this figure with Figure 17 and note the difference in Water Saturation of two wells.

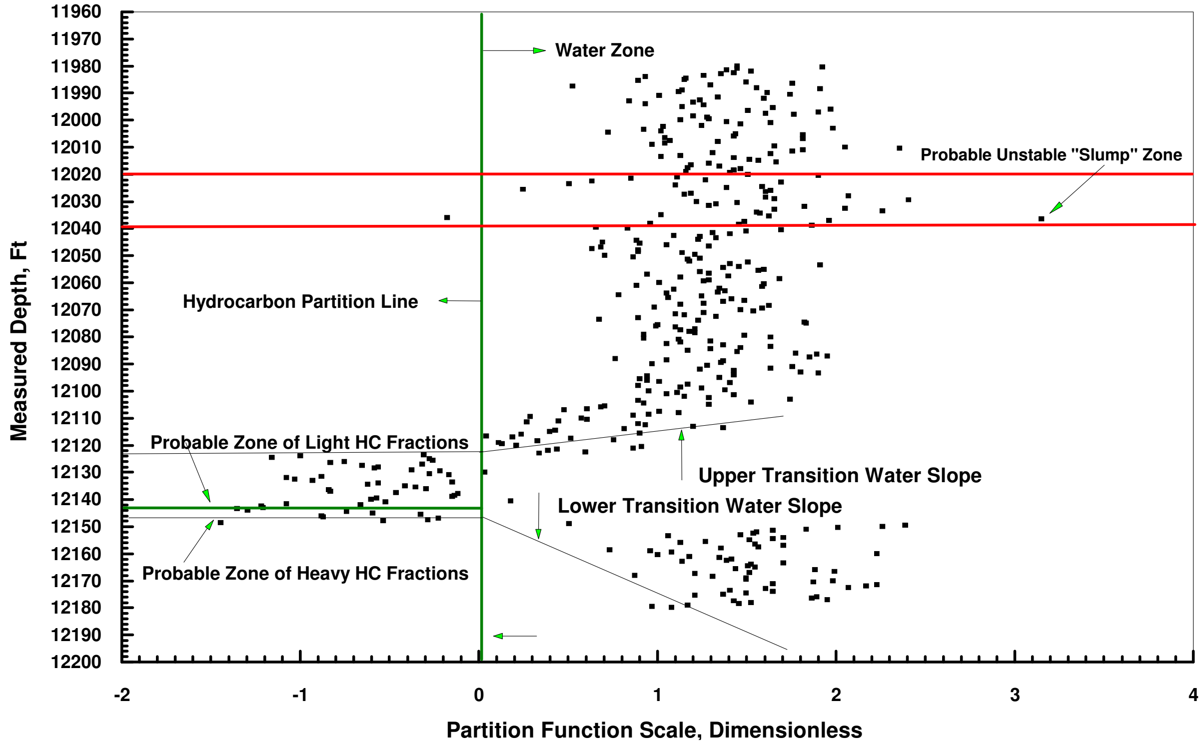

Figure 22. Measured Depth VS Partition Function. Note the existence of two separate water zones with two distinct upper and lower slopes in Well (2).

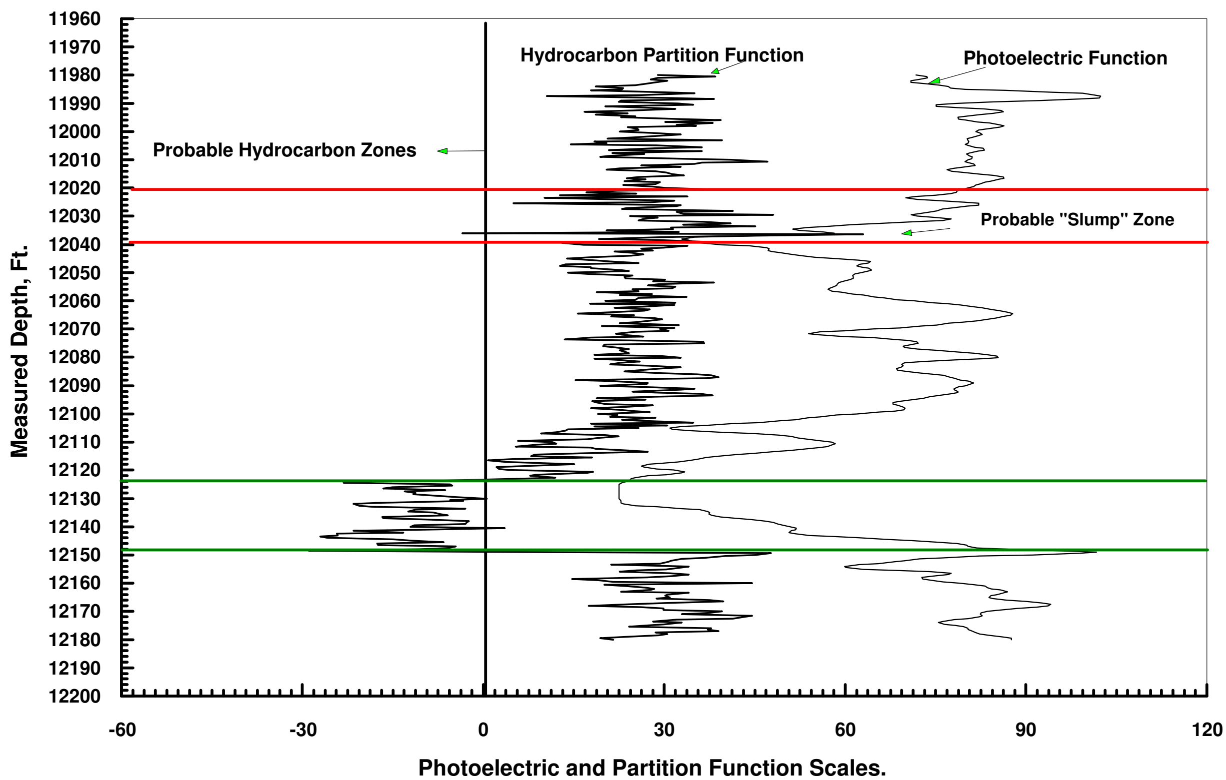

Figure 23. Measured Depth VS Photoelectric and Partition Functions in Well (2).

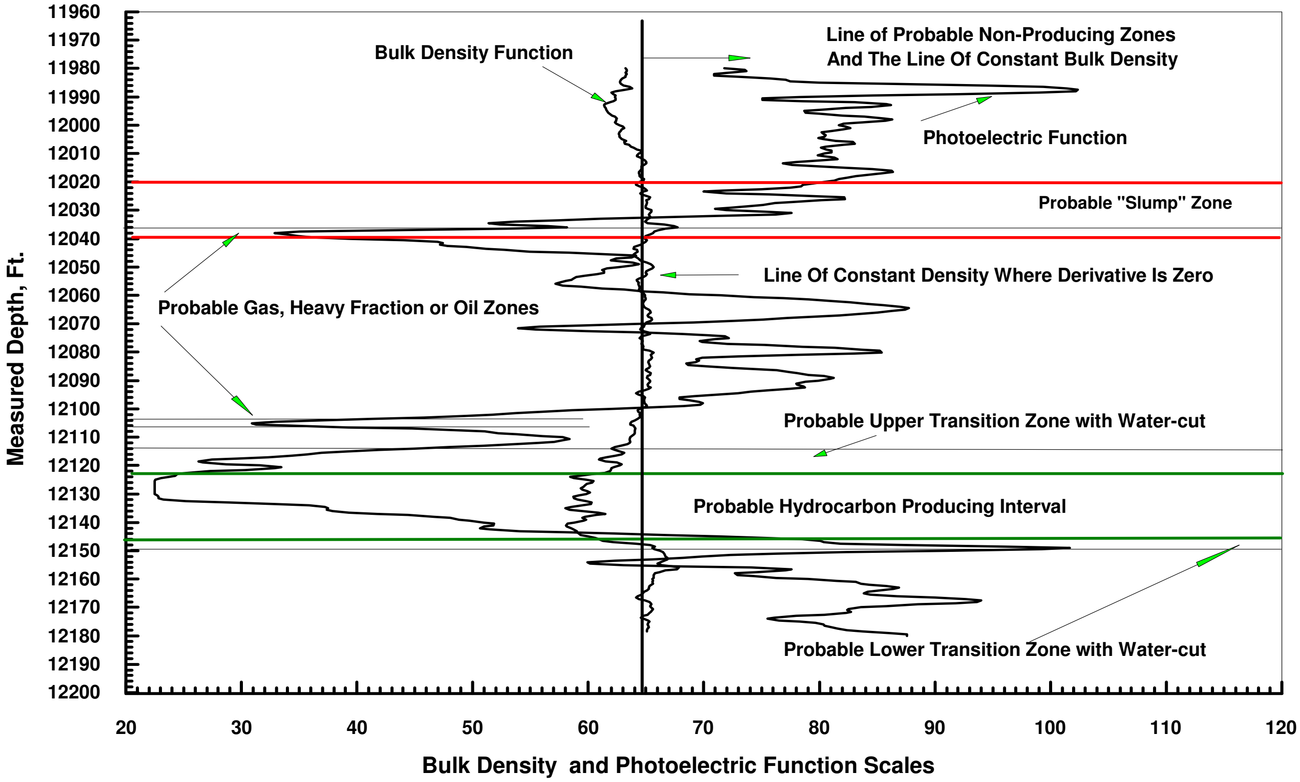

Figure 24. Measured Depth VS Bulk Density and Photoelectric Functions in Well (2).

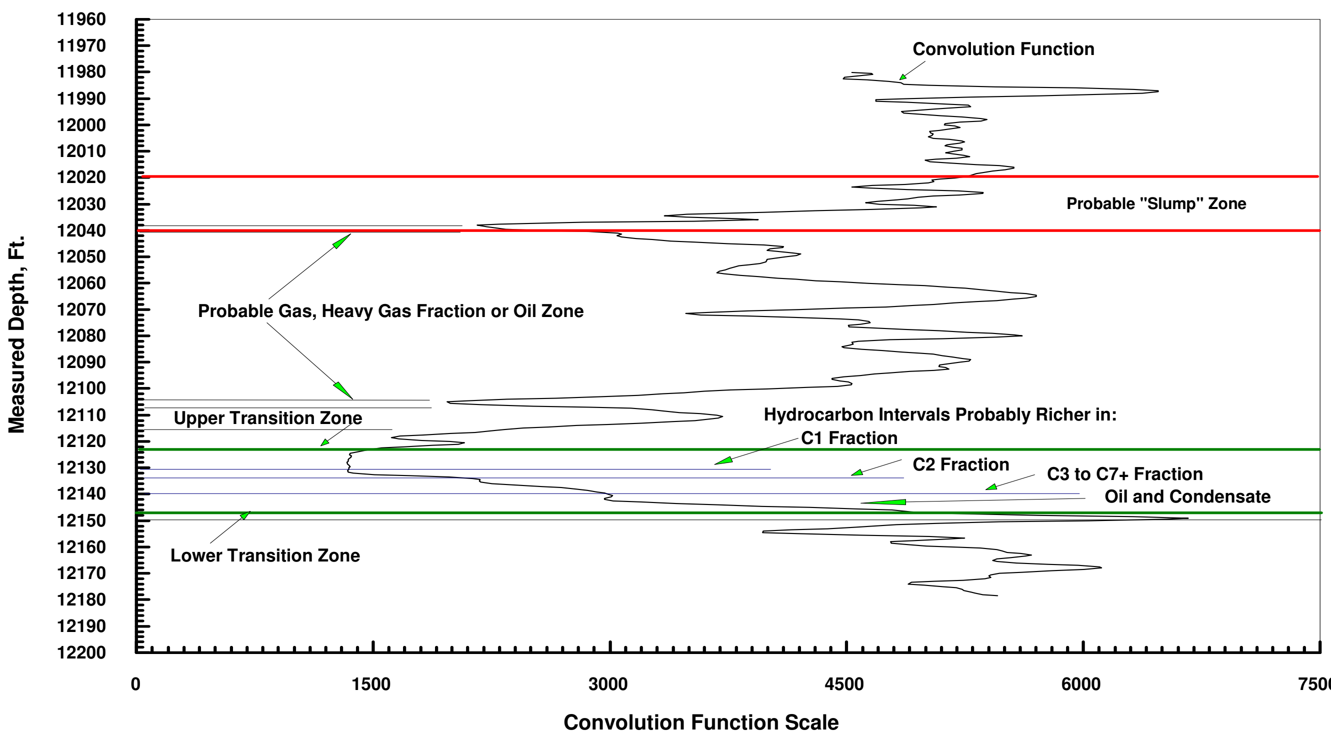

Figure 25. Measured Depth VS Convolution Function in Well (2).

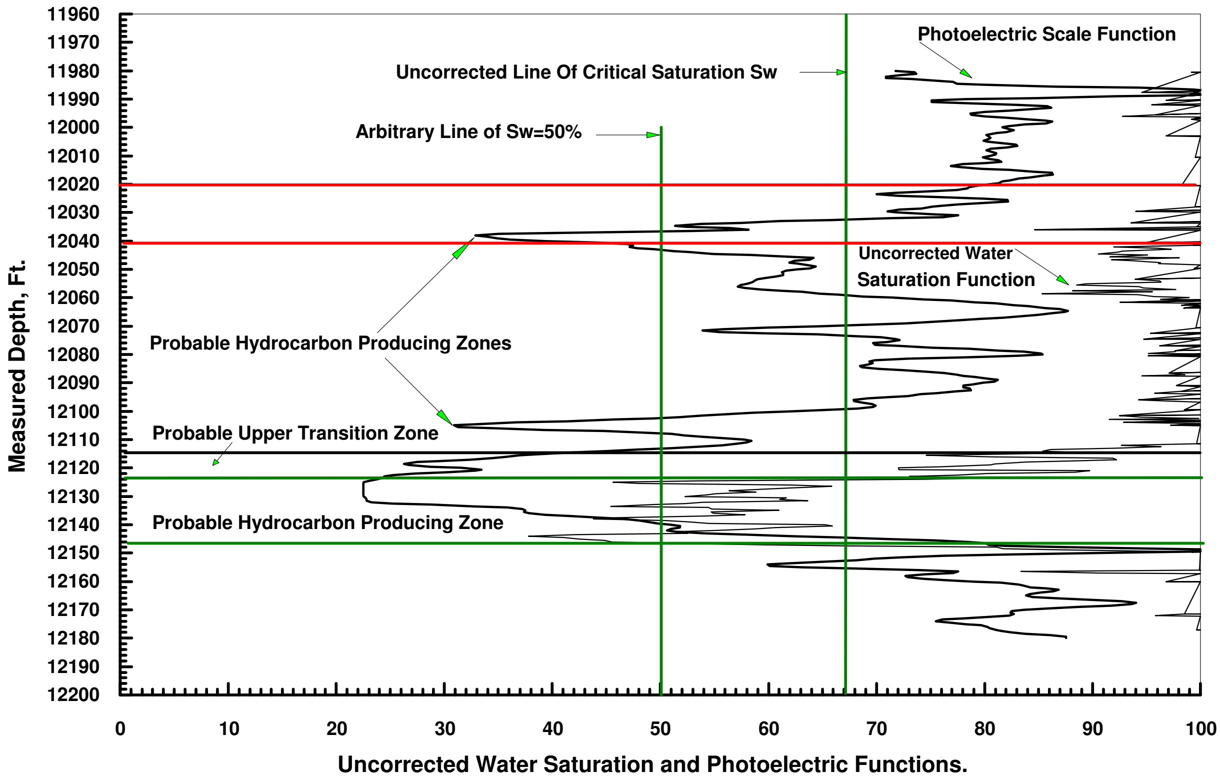

Figure 26. Measured Depth VS Uncorrected Water Saturation and Photoelectric Functions in Well (2).

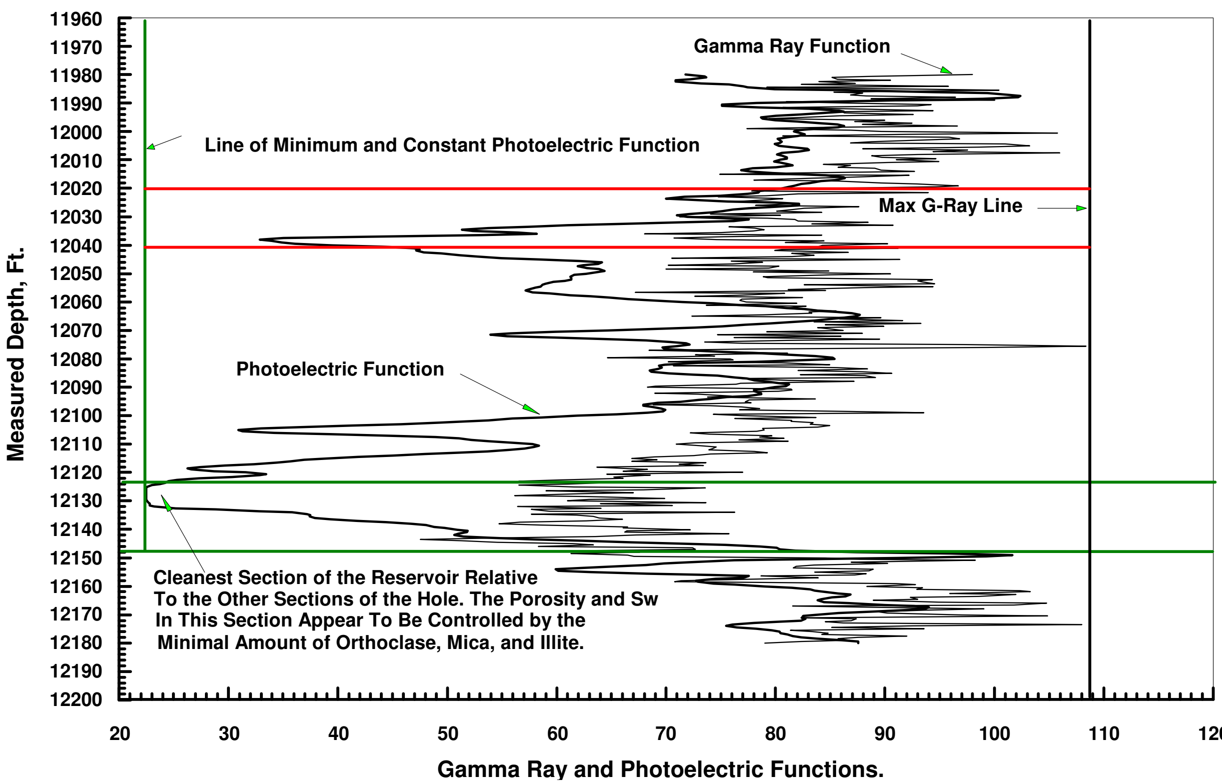

Figure 27. Measured Depth VS Gamma Ray and Photoelectric Functions in Well (2).

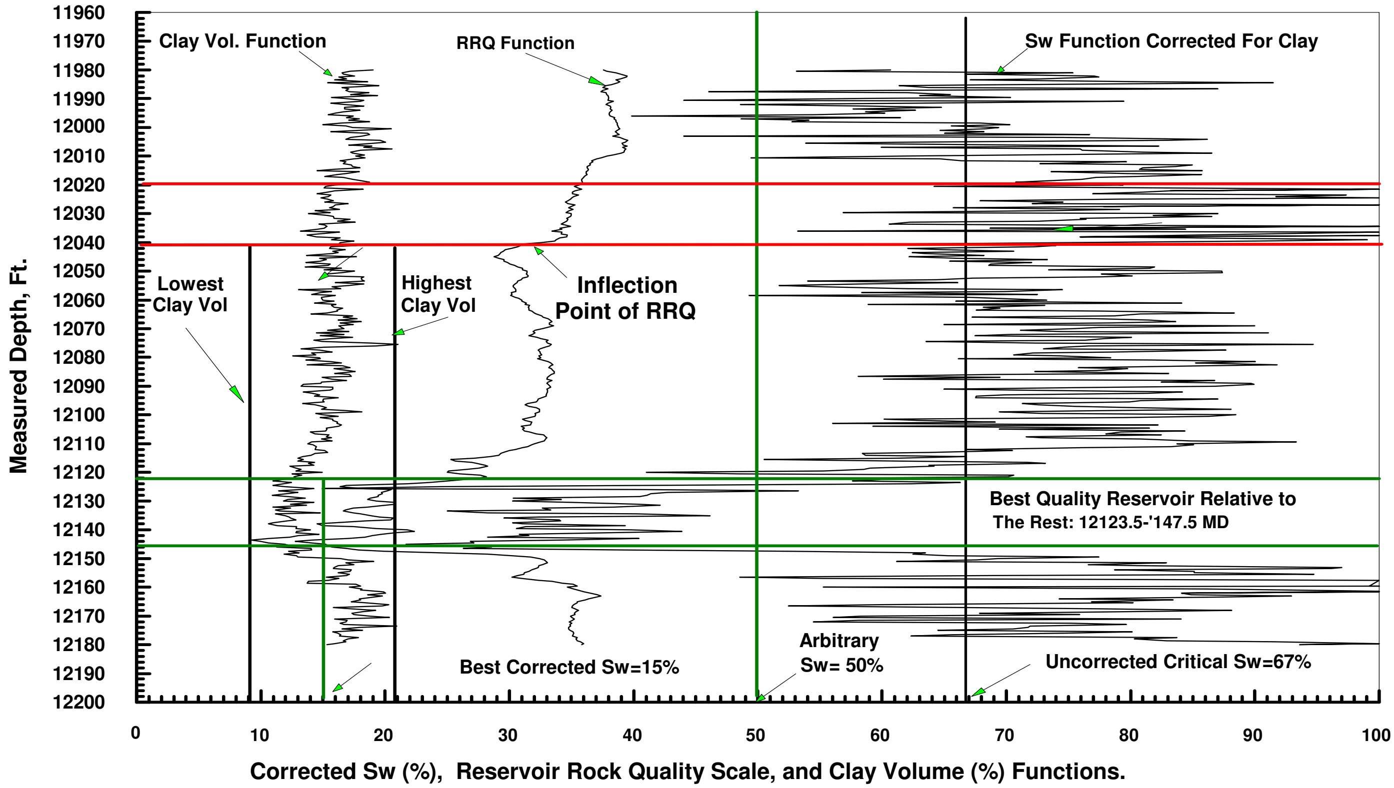

Figure 28. Measured Depth VS Reservoir Rock Quality (RRQ) and Clay Volume Functions in Well (2).

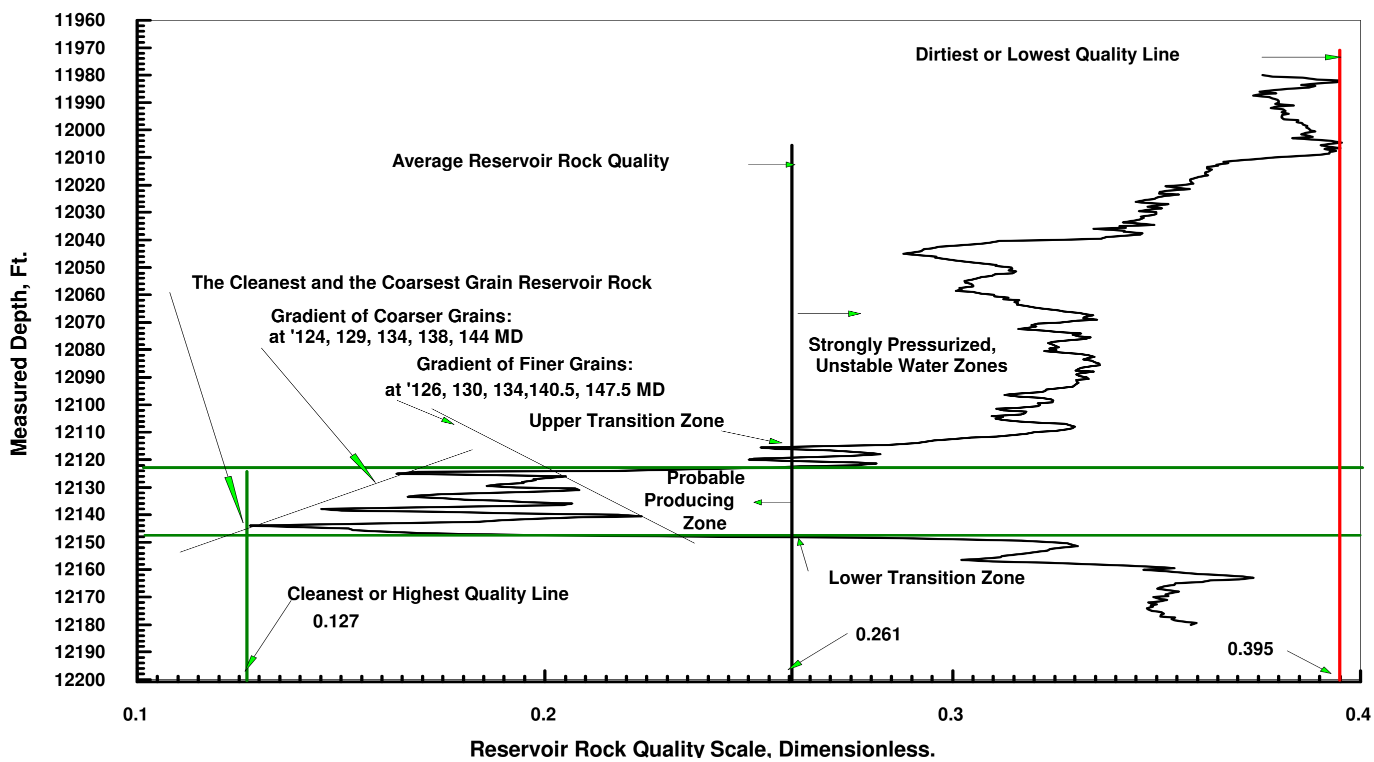

Figure 29. Measured Depth VS Reservoir Rock Quality in Well (2). Compare this figure with Figures (6) and (7) and note how the gradient of coarser sand grains control the Reservoir Rock Quality, (RRQ).

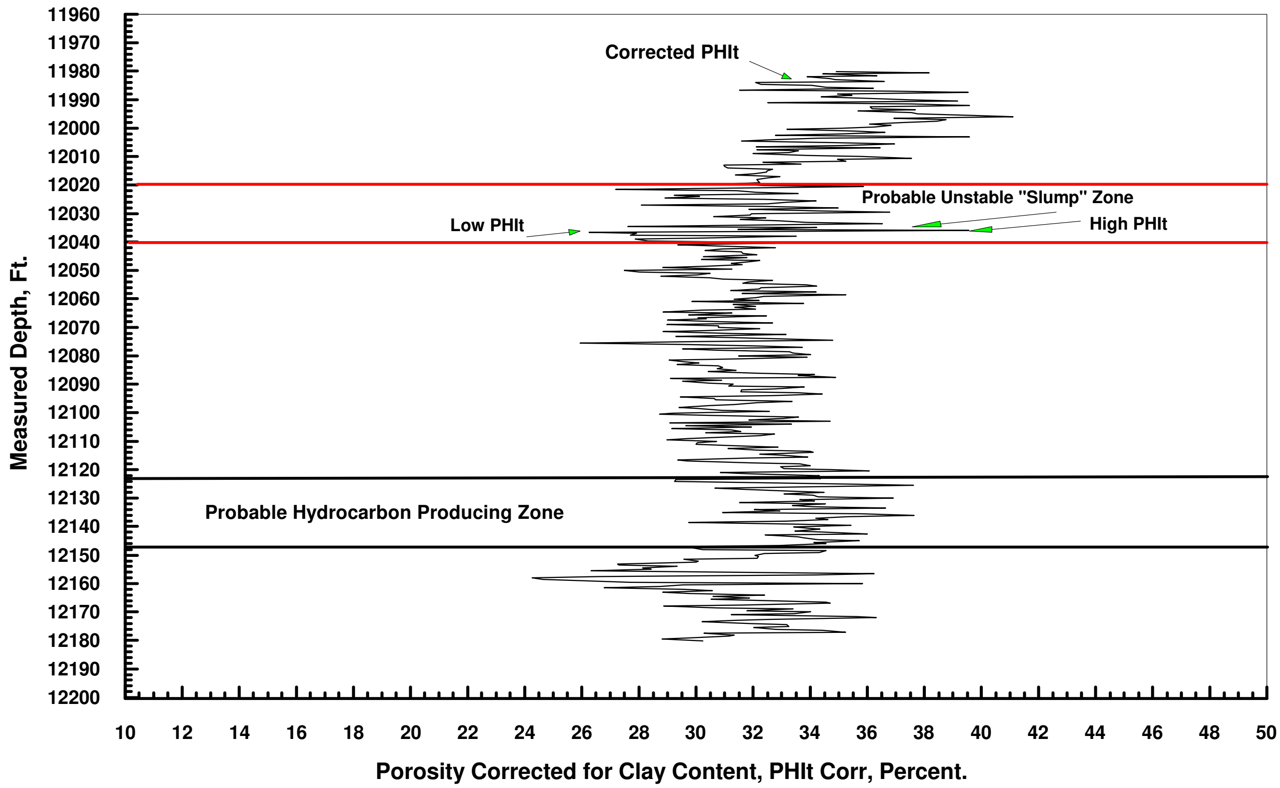

Figure 30. Measured Depth VS Corrected Porosity for Clay Content in Well (2).

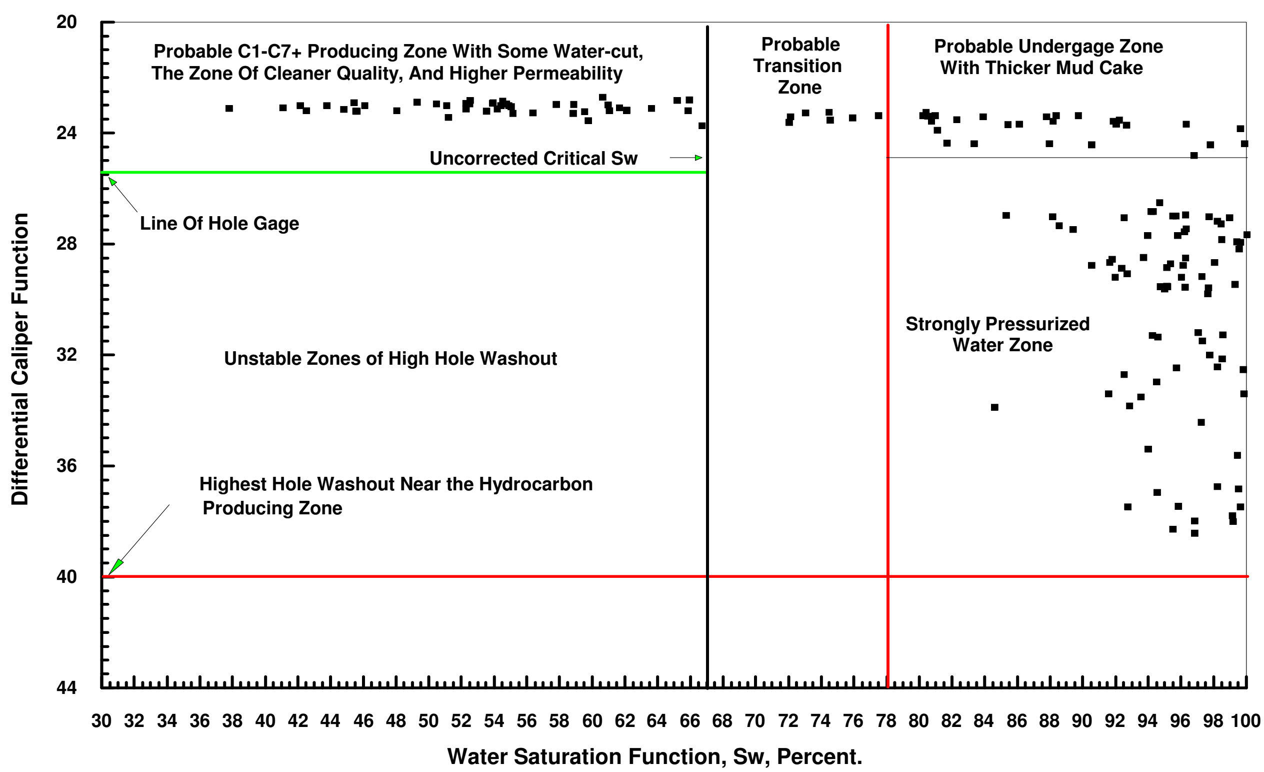

Figure 31. Differential Caliper Function VS Water Saturation Function in Well (2). Note how these functions generate a plot similar to the plot of Capillary Pressure VS Water Saturation.

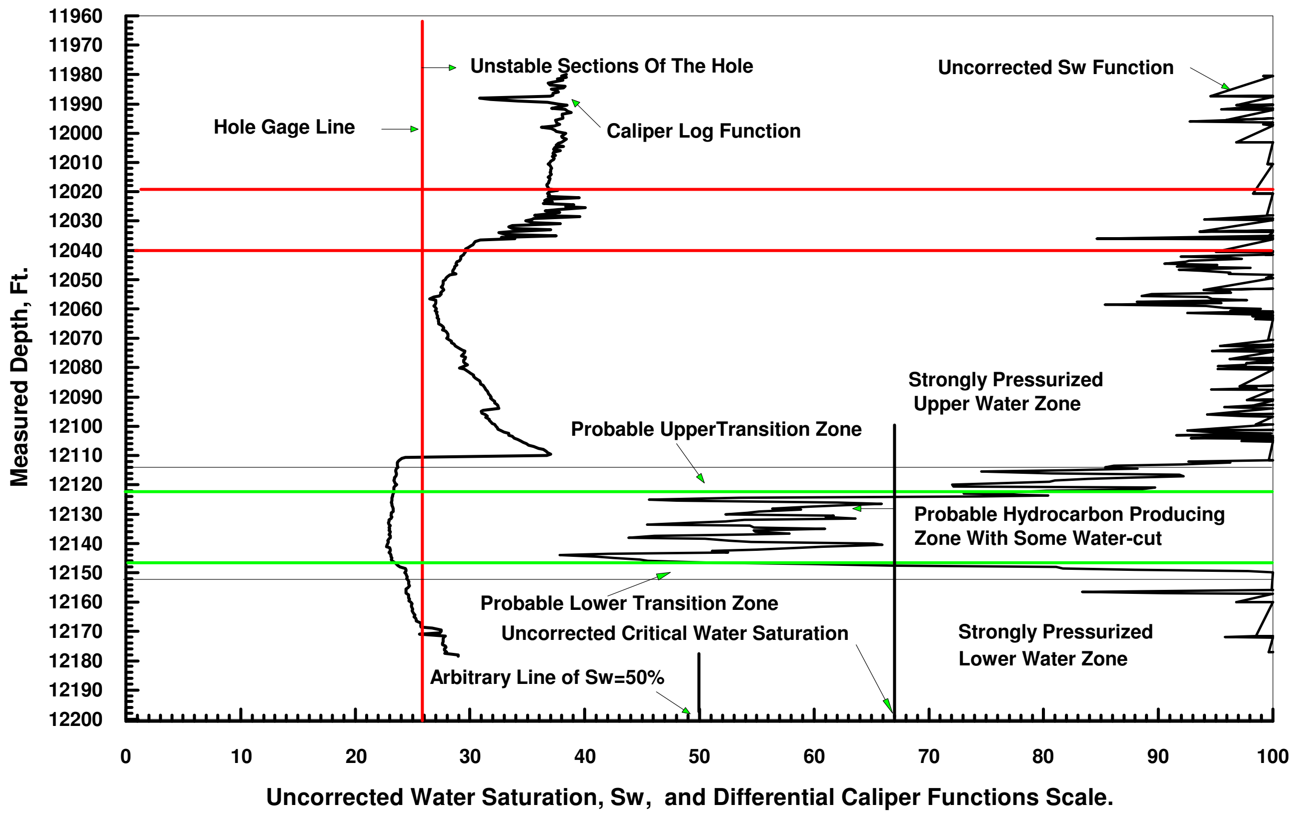

Figure 32. Measured Depth VS Uncorrected Water Saturation a Differential Caliper Functions in Well (2).

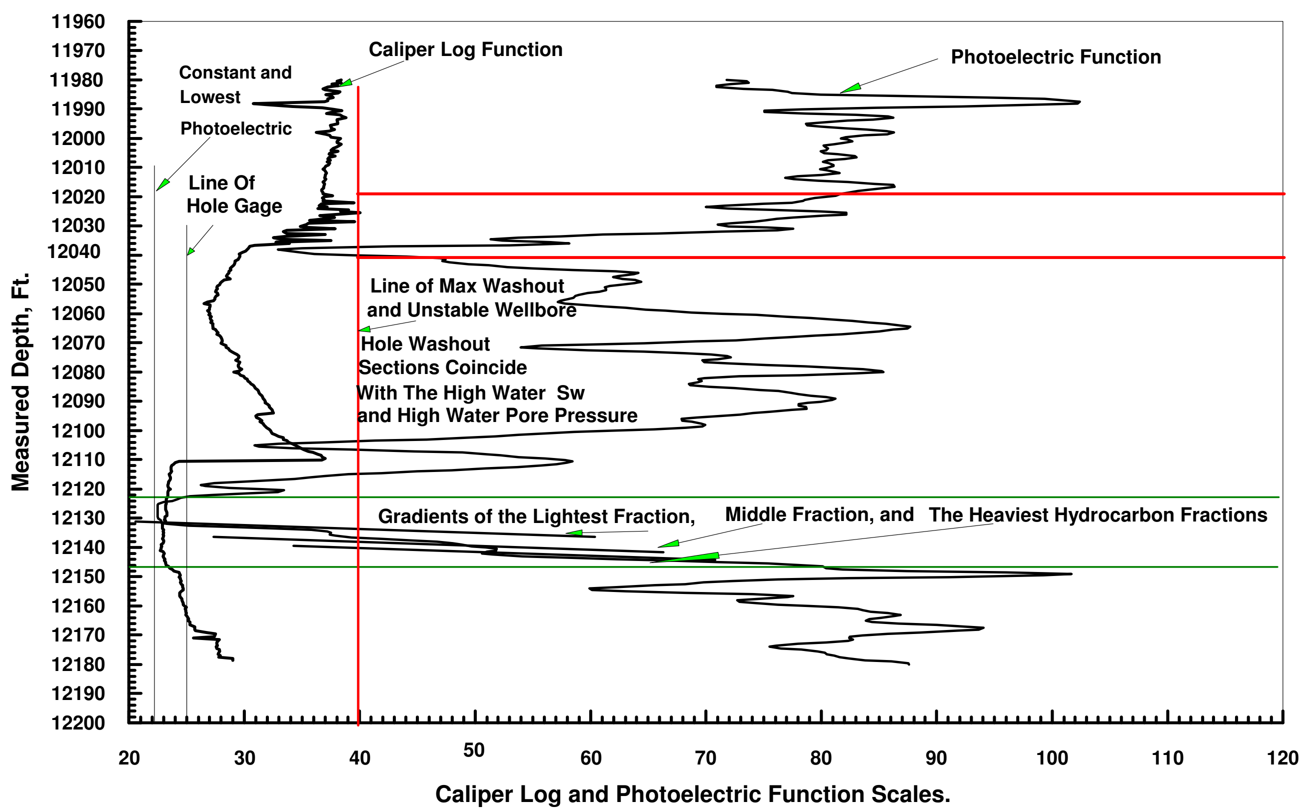

Figure 33. Measured Depth VS Caliper Log and Photoelectric Functions in Well (2).

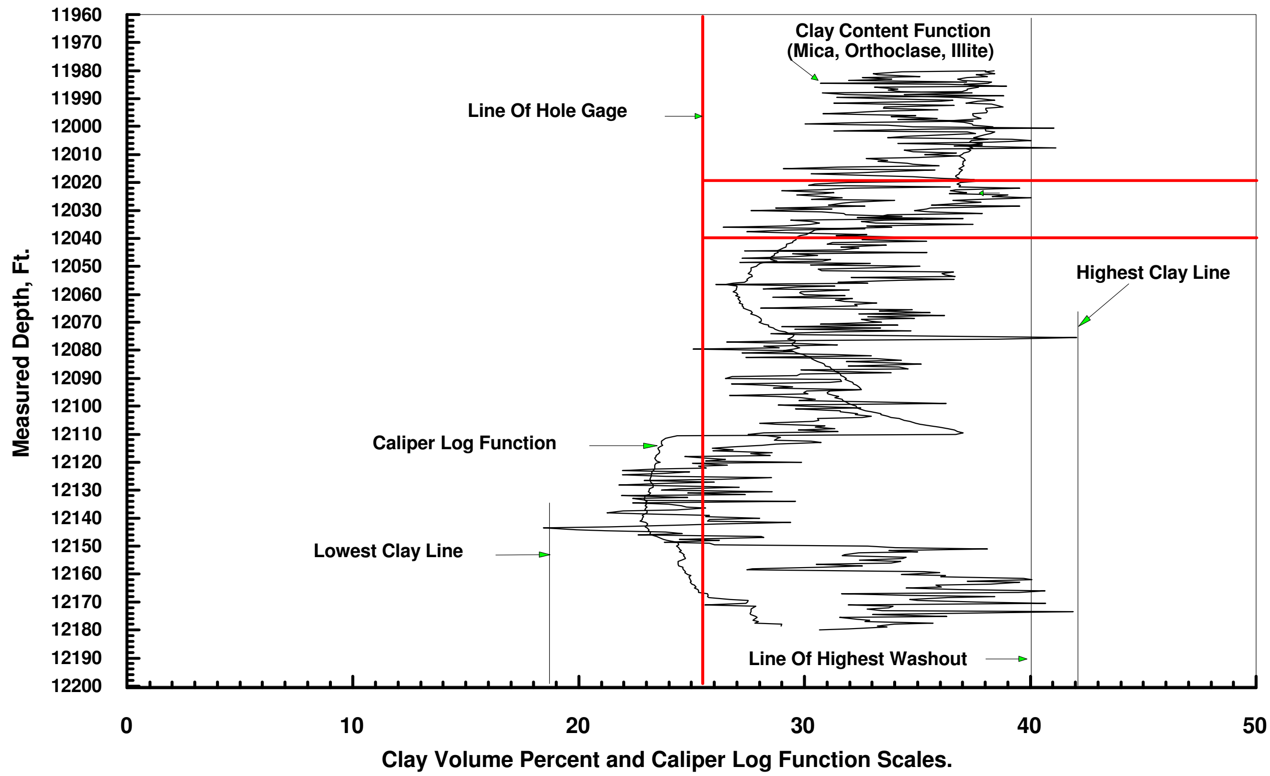

Figure 34. Measured Depth VS Clay Volume and Caliper Log Functions in Well (2).

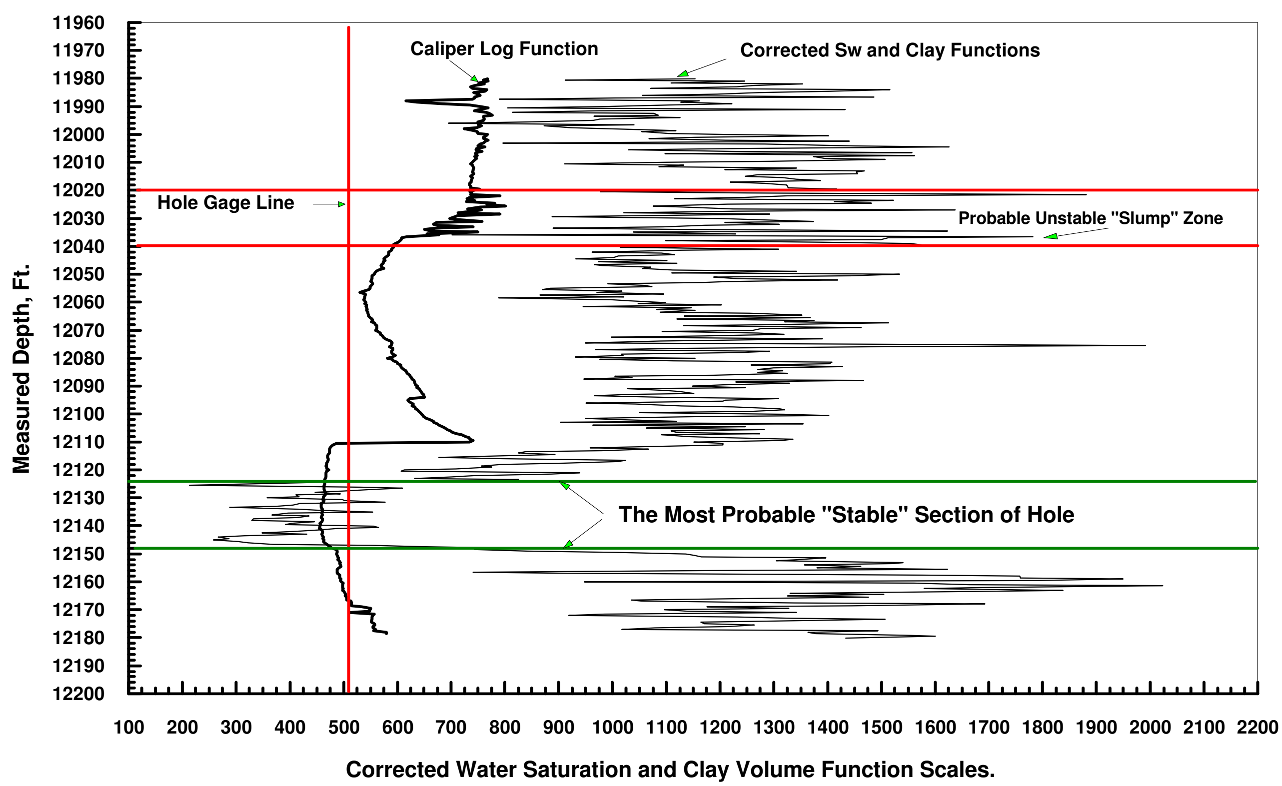

Figure 35. Measured Depth VS Corrected Water Saturation and Clay Volume Functions in Well (2).

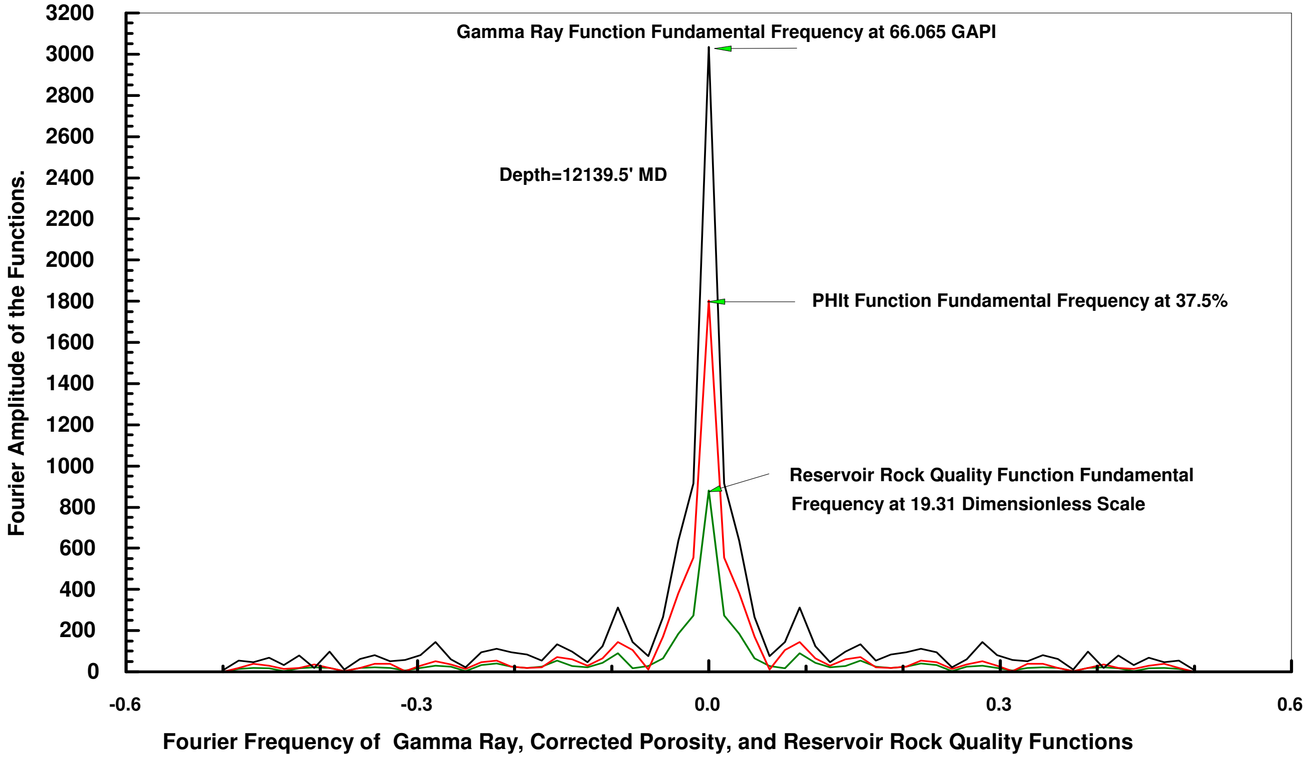

Figure 36. Fourier Spectral Analysis of Three Functions Appears to Indicate that Reservoir Rock Quality, Porosity, and Gamma-Ray Are 'Strong' Functions of Each Other in Well (2). Compare this figure with Figure (37).

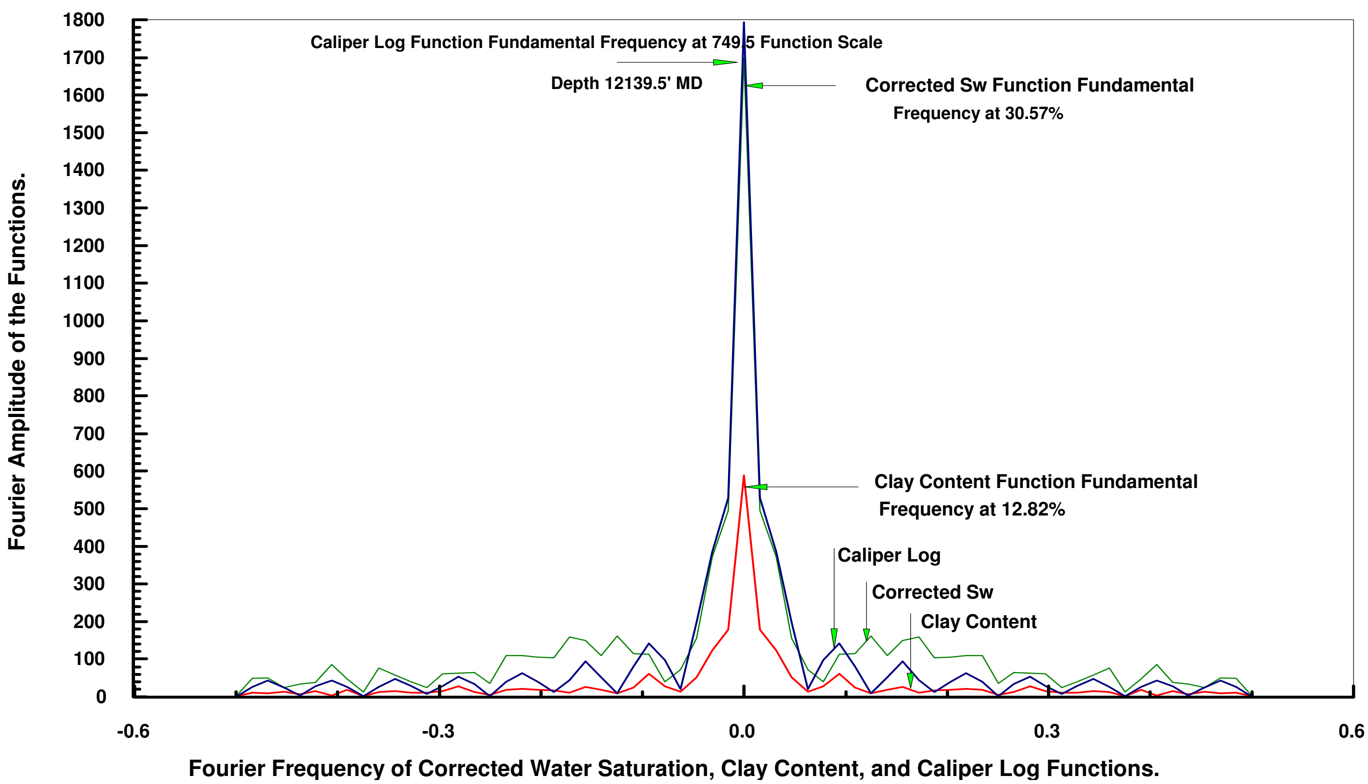

Figure 37. Fourier Spectral Analysis Appears to Indicate That S_w Is <u>Not</u> A 'Strong' Function of Clay Content and Caliper Log Functions in Well (2).

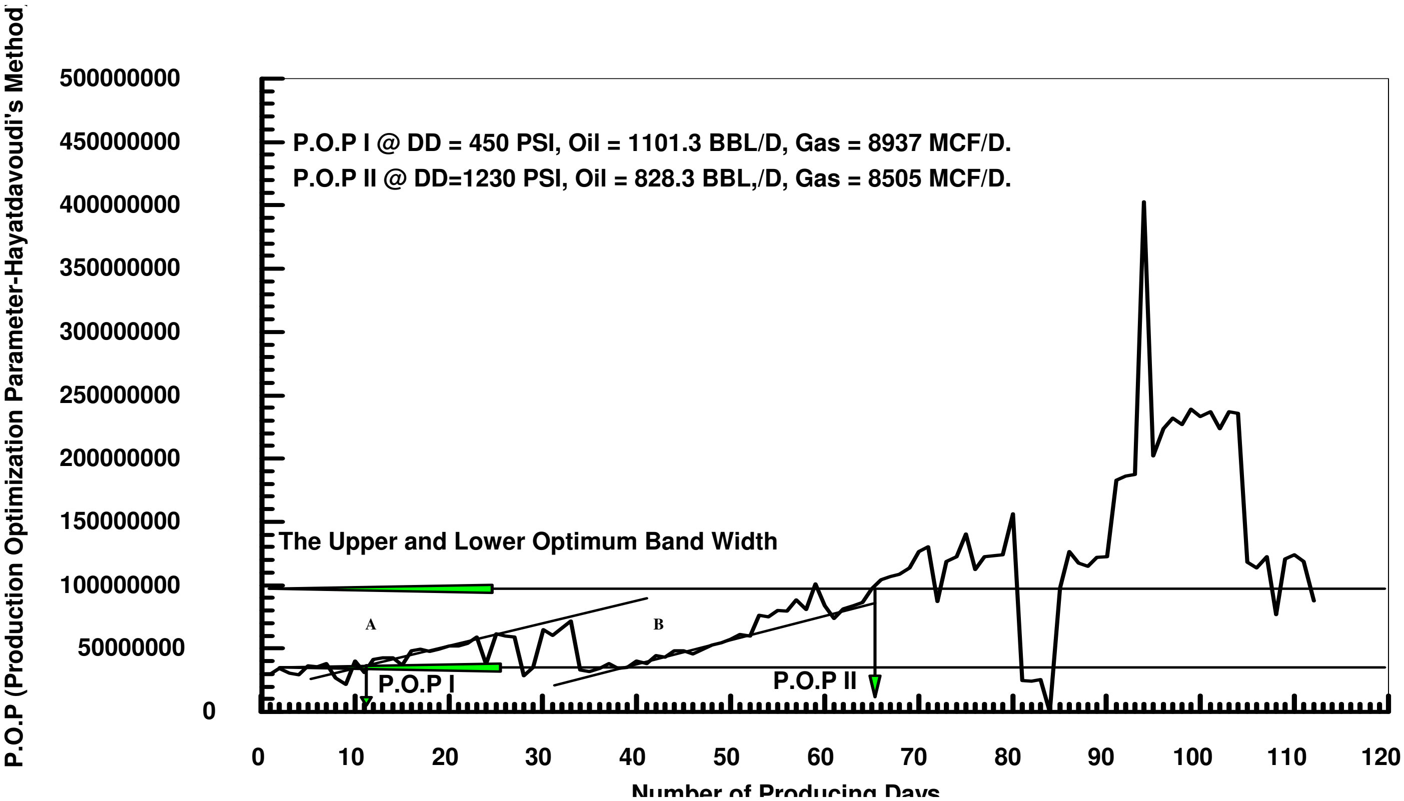

Figure 38. Production Optimization Parameter VS Number of Producing Days in Well (2). Compare this figure with Figure (11).

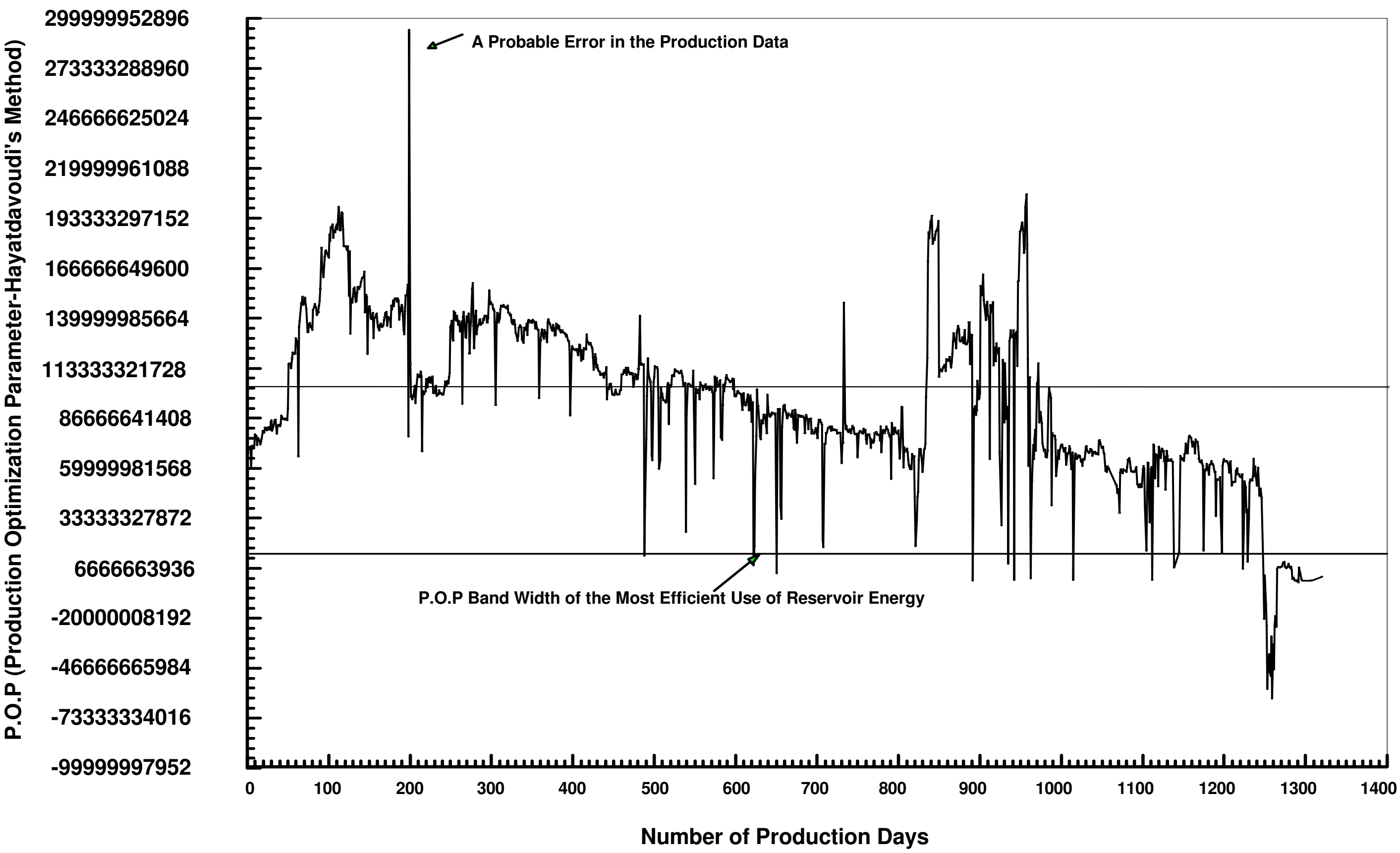

Figure 11. Production Optimization Parameter VS Number of Producing Days for the Well Adjacent to Well (1).