



SPE 64738

An Accurate Characterization of Sand Strength in Weak and Unconsolidated Formations Aids Offshore Production Test Designs - A Bohai Bay Case Study

Seehong Ong, Baker Atlas, and Andy May, and Ian George, and Tim Walker, Kerr-McGee Oil and Gas Corporation, and Ziqiong Zheng, Baker Atlas

Copyright 2000, Society of Petroleum Engineers Inc.

This paper was prepared for presentation at the SPE International Oil and Gas Conference and Exhibition in China held in Beijing, China, 7–10 November 2000.

This paper was selected for presentation by an SPE Program Committee following review of information contained in an abstract submitted by the author(s). Contents of the paper, as presented, have not been reviewed by the Society of Petroleum Engineers and are subject to correction by the author(s). The material, as presented, does not necessarily reflect any position of the Society of Petroleum Engineers, its officers, or members. Papers presented at SPE meetings are subject to publication review by Editorial Committees of the Society of Petroleum Engineers. Electronic reproduction, distribution, or storage of any part of this paper for commercial purposes without the written consent of the Society of Petroleum Engineers is prohibited. Permission to reproduce in print is restricted to an abstract of not more than 300 words; illustrations may not be copied. The abstract must contain conspicuous acknowledgment of where and by whom the paper was presented. Write Librarian, SPE, P.O. Box 833836, Richardson, TX 75083-3836, U.S.A., fax 01-972-952-9435.

Abstract

This paper presents a case study where the creative use of wireline-derived sand strength in the offshore production test process improved operational efficiency. Sand strength was computed using wireline data only and subsequent testing of two wells verified the accuracy of the calculations.

Well logs provided the basis for evaluation of formation petrophysical and mechanical properties. These log-based properties enabled a foot-by-foot profile of the critical drawdown pressure to be generated. Analysis of critical drawdown pressures in the Bohai Wells A and B, located in the northeastern People's Republic of China, provided a cost-effective method to predict potential sand production problems. This information proved invaluable in reducing the risk and costs associated with the testing of viscous oils in the shallow, moderately unconsolidated sandstones of Bohai Bay.

Introduction

The Bohai Bay basin is a fluvial environment located in northeastern People's Republic of China. The area has been home to numerous discoveries over the years. The shallow environment is one of heavy oil and unconsolidated fluvial sands. Kerr-McGee has been a partner with CNOOC for a number of years and is currently delineating a discovery in the Tertiary sandstones. Two wells, Bohai-A and Bohai-B, encountered the geological units of interest, which are the Upper and Lower Minghuazhen and Guantao formations.

Qualitative assessments of the compressional and shear wave slownesses suggested varying formation strengths ranging from weak but competent to unconsolidated. Because

of the inherent characteristics of the formations, there was a concern about sand production during production testing. In unconsolidated sand, the decision to gravel pack is usually clear. The decision is harder for weak rock because the need for sand control often depends on the desired drawdown. The latter scenario has important implications in well test operations. The unnecessary application of sand-control techniques, as a precaution against anticipated sand production, can cause an increase in well testing cost and a possible reduction in formation productivity. However, if the operating conditions dictate the need for sand control, such techniques allow a formation, which otherwise might have to be abandoned, to be properly tested and evaluated. The ability to accurately predict the critical drawdown pressure (CDP) is, therefore, vital for sand-control decisions. This ability also allows intervals that have no sand control to be produced at optimal rates.

The CDP, which is the difference between the average reservoir pressure and the bottomhole flowing pressure above which mobilization of unconsolidated and/or disaggregated sand grains broken by perforation and concentrated stress around the borehole is expected to occur, provides useful information for offshore production tests and downhole completion designs. It allows sound engineering decisions to be made on the needs for 1) sand-controlled completion (*e.g.*, gravel packing) and 2) the mobilization of gravel pack equipment for offshore well testing. The CDP profile, which is a continuous presentation of critical drawdown pressure with depth, also provides useful information for effective selective perforation designs. The latter provides an alternative to sand production mitigation without having to install any downhole sand filtration hardware.

This paper describes the approach for developing the critical drawdown pressure and illustrates how the information is being successfully applied in the design and implementation of offshore production tests of the Bohai Bay wells. The creative use of the information results in substantial savings for Kerr-McGee and partners in terms of the logistical costs associated with the mobilization of gravel pack equipment and personnel.

Lithology

Lithologically, the Neogene Upper Minghuazhen formation consists of interbedded mudstones and siltstones with several thick sand beds. The sandstones are mostly siltstone to fine sandstone in the upper part and coarsening downward into fine to medium grained sandstone. The grains are subangular to subrounded, moderate to good sorting. The sands are loosely compacted with a mud matrix that is locally calcareous, locally shaly, and relatively loose. The Neogene Lower Minghuazhen is mainly composed of mudstones and thick fine to medium grained sandstones. The sandstones are dominated by clear quartz with minor amounts of feldspar, lithic fragments, mica, and green to black opaques. The sandstones are very fine to medium grained, moderately to well sorted and tend to be subangular to subrounded. The grains are generally loose, with occasional local occurrences of poorly consolidated sands with a mud matrix.

The Miocene Guantao Formation can be divided into three units. The upper unit is mainly mudstone and conglomeratic sandstone. The middle unit is mostly a sandy conglomerate with thin mudstone. The bottom unit is thick sandstone, which unconformably overlies the pre-Tertiary granite or carbonate. The coarse clastic units range from sandstones to conglomeratic sandstones, generally coarsening with depth. These clastic units are subangular to subrounded, coarse to very coarse grained, and usually loose to poorly indurated. When consolidated, they appear to be cemented with either silica or clay. The siltstones and mudstones are very similar to those in the overlying Minghuazhen formation. Mudstones are generally pure and moderately consolidated, partly sandy, brittle, and non-calcareous. **Fig. 1** shows the generalized stratigraphic sections for the Bohai Bay.

Critical Drawdown Pressure

Perforation instability and wellbore failure are major causes of solids production. Formation sand is produced when the combined effects of fluid drag and near wellbore stresses cause disaggregation near the perforation. Individual grains of sand are detached from the matrix, then bridging occurs, in which a stable arch is formed around the perforation tunnel and at the perforation tips. This zone or arch is a dilated region with enhanced permeability and porosity but impaired strength. At relatively low flow rates, fluid drag does not affect arch stability but as flow rate increases, drag forces are sufficiently high to remove sand particles from the arch, thereby destabilizing sand bridges. If drag forces are too high, no sand arches are formed and sand production continues¹.

Fig. 2 shows a schematic of a perforation cavity. The lack of radial support and the redistribution of stresses around a cavity as a result of a perforating operation in a stressed environment can potentially destabilize the cavity. If the drawdown condition is such that the shear stress is sufficiently large to reach the yield stress of the material, plastic yielding will develop. Assuming the region around the cavity is at the limit of elastic stability, Mohr-Coulomb failure criterion can be used to describe the material property. For a cylindrical perforation cavity with a spherical end, the pressure gradient

at the spherical end is more severe. The critical drawdown analysis is simplified by investigating the pressure gradient around the hemisphere at the end of the perforation tunnel.

For perfectly Mohr-Coulomb material, the relationship between S_t and S_r at the limit of shear stability can be expressed as:

$$S_r - S_t = -\left(\frac{2 \sin \alpha}{1 - \sin \alpha}\right) [S_r - P + S_o \cot \alpha] \dots\dots\dots(1.)$$

To maintain mechanical stability, the force balance equation must be satisfied, *i.e.*,

$$\frac{dS_r}{dr} + \frac{2(S_r - S_t)}{r} = 0 \dots\dots\dots(2.)$$

For a steady-state seepage into a perforation cavity, the pressure gradient necessary to sustain flow over the whole range of velocity is given by the Forcheimer equation, which when expressed in flow rate takes the form of

$$\frac{dP}{dr} = \frac{m\eta}{kA} + br\left(\frac{q}{A}\right)^2 \dots\dots\dots(3.)$$

where m is the average fluid viscosity over the pressure interval, and k is fluid permeability assumed to be non-pressure dependent. Eq. 3 becomes the familiar linear Darcy equation when the flow velocity is low, as in the case of liquid or low-rate gas production. For a non-ideal gas, the density variation over a range of pressures can be modeled using a power law relationship²:

$$r = gP^m \dots\dots\dots(4.)$$

For weak formations of negligible tensile strength, the equation relating strength to fluid flow (CDP) into a spherical cavity is derived by combining Eq. 1, Eq. 2 and Eq. 3 for the liquid case and an additional Eq. 4 for the gas case and satisfying all the boundary conditions.

Ramos *et al.*¹ and Bratli and Rinses³ derived the CDP expression for a slightly compressible liquid flow:

$$\frac{qu}{4pkr} = \frac{4S_o \cos \alpha}{1 - \sin \alpha} \dots\dots\dots(5.)$$

Perkins and Weingarten² derived the CDP expression for a linear Darcy gas flow:

$$\frac{4 \sin \alpha}{1 - \sin \alpha} = \frac{P'_b - P'_a}{m + 1} (P'_a)^{-\frac{m}{m+1}} \dots\dots\dots(6.)$$

Ong *et al.*⁴ derived the CDP expression for a non-Darcy gas flow:

$$\frac{4 \sin \alpha}{1 - \sin \alpha} = \frac{S_1 + 3S_2}{m + 1} (P'_a)^{-\frac{m}{m+1}} \dots\dots\dots(7.)$$

where the explicit expressions for S_1 and S_2 are given in Ref. 4. Except for the liquid case where the critical fluid rate is a direct function of rock strength properties, the CDP for gas flow is obtained by iteratively finding a value of P_a that satisfies either Eq. 6 or Eq. 7. The explicit expressions of the CDP equations for gas flow also show that the maximum sustainable fluid gradients depend on formation strength properties and the gas density exponent. The non-Darcy flow is further dependent on formation petrophysical properties and fluid characteristics.

Formation Mechanical Properties

In the development of the critical drawdown models, the formation at the periphery of the perforation cavity was assumed to be at the limit of elastic stability defined by the Mohr-Coulomb failure criterion. For perfectly Mohr-Coulomb material, the failure criterion can be written as:

$$t = S_o + s_n \tan a \dots\dots\dots(8.)$$

Traditionally, the cohesive strength and internal friction angle are obtained by conducting a series of triaxial compression tests and by plotting the Mohr circles in the $t - s$ space to define the rock strength parameters. However, rock mechanics laboratory tests are time consuming, and in operating conditions where a quick but accurate identification of potential sand producing zones is needed, a direct computation of static mechanical properties from log inputs is most preferred. The log-based method enables a sound engineering decision on sand control to be made in the period between logging and completion/testing. It also facilitates the design of selective perforation programs.

For the Bohai-A and B wells, static mechanical properties and strength were generated using a logging of mechanical properties (LMP) program based on FORMEL, a constitutive model describing the microscopic processes occurring in a rock sample during mechanical loading. Raaen *et al.*⁵ provide a brief theoretical overview of FORMEL. Essentially, the model utilizes the fundamental relationship between static and dynamic behavior to construct the constitutive relationship between stress and strain for a given rock material. The difference in static and dynamic moduli is partly caused by the fluid effects but mainly attributed to the fact that certain mechanisms require a large strain amplitude to be activated. These mechanisms include the crushing of grain contacts, pore collapse, and shear sliding along the internal surfaces. During a small amplitude dynamic loading excited by an acoustic wave, these mechanisms are not activated. Thus, by separating deformations due to internal surface sliding, pore and grain deformations and dilatancy with those deformations under dynamic loading, relationships between static and dynamic properties can be derived.

From theoretical analyses and experimental studies, the relationships between rock porosity, bulk density, mineral content, dynamic properties and the grain contact parameter, sliding crack parameter, and dilatancy parameter have been established and documented in calibration tables. Using fluid

and rock properties from logs as inputs, a representative rock sample for a given depth can be reconstructed from these calibration tables, and the constitutive behavior of the rock sample can be examined with simulated hydrostatic and biaxial loading. Incremental strains as a result of incremental stresses are calculated and stress-strain curves under static loading can be constructed. Static mechanical properties can then be derived from the stress-strain curves. The strength of a rock sample can be obtained from the maximum value of the stress that could be applied to the rock sample prior to failure. Because the virtual rock sample can be tested under any given confining pressure levels, Mohr circles (and hence the failure envelope) can be constructed to derive the cohesive strength and internal friction angle of the rock. **Fig. 3** is a schematic showing LMP's process flow. Table 1 summarizes the input parameters for LMP.

Initial sand strength assessments using LMP based on field petrophysical interpretation of the formations suggested that the pay zones of interest were competent but weak to medium in strength characteristics. Critical drawdown pressure analysis based on this initial assessment suggested that sand control installation would not be required during well testing. This observation, however, contradicted other field indications of rock strength. **Fig. 4** shows the variations of compressional and shear-wave slownesses over a selected depth interval. The high compressional and shear slownesses suggested that the formation could be extremely weak and sand production could become a reality at high production rates. A careful review of the field petrophysical data revealed that the calculated shale volume, which included all the clay-sized particles plus medium, fine, and very fine silt, was too high. Because LMP requires a dry clay volume using the total porosity approach, and based on the extensive database available in-house on the formation characteristics of Bohai Bay wells, the field-calculated shale volume was reduced by 50% for the LMP computation. This field calibration was later confirmed by a cross-plot of sidewall core volume of dry clay (CORVCL) versus the sidewall core volume of shale (CORVSH), which reveals a consistent linear trend of

$$CORVCL = 0.4884 \times CORVSH - 4.6805 \dots\dots\dots(9.)$$

as shown in **Fig. 5**. The sidewall core values were determined with a laser particle size analysis. The volume of dry clay includes all clay-sized particles regardless of their mineralogy. The volume of shale is compatible with the petrophysical definition, including all clay-sized particles that support no effective porosity. Because porosity is a main parameter, it follows that LMP is expected to be less accurate in formations where log porosity is uncertain⁵.

Using the corrected clay volume, the LMP-derived internal friction angle and cohesive strength for a selected depth interval of Bohai-A's Guantao formation is shown in **Fig. 6**. The figure shows that the sand bodies generally have low cohesive strengths indicating that the formation is competent but weak as cementation may be confined mostly at the grain

contacts. On the other hand, higher values of cohesive strength are associated with the shallier sections of the sand bodies, which also show lower internal friction angles. Contrarily, a high internal friction angle indicates that the rock has a coarse and angular grain structure.

Well Test Operations

Bohai-A and B encountered all the three sands of interest, *i.e.*, the Upper and Lower Minghuazhen and the Guantao. In setting a production test (PT) in a remote area such as Bohai Bay, advance planning is a major requirement. In reviewing the area from a completion/production test standpoint, however, it was obvious that such shallow sands (700 – 1500 m) would require sand control, an expensive proposition in multi-zone tests. In order to provide a sound engineering decision on the needs for gravel packing each zone, Kerr-McGee opted to run a dipole sonic log to aid in the sand strength determination. It was thought that if the reservoir drawdown could be minimized, then the zones could be tested without gravel packing and yet provide a sufficient production rate for proper formation evaluation. A resultant saving of approximately US\$250k per zone could be realized.

Following evaluation of the electric logs and the results of comprehensive wireline pressure surveys, several potential production test intervals were identified. Information from wells in the area, drilled and logged in the 1970's, suggested the presence of reservoirs with low GOR oil in the 10-26° API range having viscosities ranging from 20 to several hundred centipoise. Production of potentially viscous crude from shallow low-pressure sands in the cold, Bohai Bay winter environment led to several departures from conventional production test design. Testing information from the old wells was often inconclusive but did indicate that sand control had not been employed although sands had been tested by pump as well as on natural flow. A simple test procedure consisting of one extended clean-up/flow period followed by a downhole shut-in was devised to minimize potential problems with viscous oil setting up in the tubing close to the surface or in the surface equipment during the build-up period.

The PT-1 & 2 intervals in well A were both produced under natural flows using conventional test strings. Both tests took over 12 hours to clean up and stabilize once oil had finally reached surface. Delays were due primarily to the relatively high fluid viscosity exacerbated by the frigid winter surface conditions in Bohai Bay. To improve and accelerate testing, the Navi-pump, a form of progressive cavity pump, was incorporated in a re-designed test string (**Fig. 7**). This type of pump is operated by rotating the tubing or drill-string. It is effective for pumping high viscosity liquids and is insensitive to relatively high concentrations of solids. Its use allowed fluids to be produced to the surface quickly, thereby helping to heat up the tubulars and so reduce friction losses. Use of the pump also provided the flexibility of testing at multiple rates under predictable pressure drawdown conditions. The model used was rated at 1.35 liters per revolution, or approximately 1000 bbl per day at 100 RPM (assuming 100% efficiency).

The PT 2 interval was successfully re-tested with the Navi-pump and quickly achieved stable oil rates, at pump speeds of 30, 60 and 90 RPM. Because the Navi-pump test string did not incorporate a tester valve, shut-in for pressure build-up was achieved by simply stopping rotation of the pump and closing the choke manifold at the surface. Quartz gauges and clock-set bottom-hole samplers were deployed below the packer and retrieved with the test tools after each production test.

The majority of the remaining production tests in well A, as well as all four tests in well B, were subsequently conducted using the Navi-pump configuration. The intervals for these tests were perforated on wireline using deep penetration casing guns at 12 SPF.

Well Test Results

The dipole sonic log was run on both wells. Analysis of formation mechanical properties using LMP allowed quantitative estimates of the sand strength to be made at any point in the wellbore. Using the LMP derived formation strength parameters (cohesive strength and internal friction angle), critical drawdown pressure curves for liquid flow were generated and are shown in **Fig. 8** for well A. This information was utilized to identify any weak intervals within planned test zones that could lead to sand production during production testing. This was particularly important to avoid the cost and logistics that would have been incurred with the unnecessary mobilization of gravel pack equipment and personnel.

Five intervals were tested in well A, all without sand control. Pressure gauges were run in the production test string's tail-pipe assembly and provided complete bottom-hole pressure records for each test. Of the five intervals tested in well A, three produced measurable volumes of sand. DST 2A tested 13 m of moderately consolidated sand below 1000m, which contained 18° API oil. A three-rate step test was performed with the pump operating at 30, 60 & 90 rpm. The interval produced water and solids free until the final maximum rate period when up to 3% sand production was observed in the shake-outs. The sand strength analysis had indicated that this interval could produce sand free at a pressure drawdown of up to 920 psi. Examination of the pressure data revealed that a maximum drawdown of approximately 800 psi occurred during the final rate segment concurrent with a low percentage of solids production.

PT 4/4A tested a 7-m-thick sand above 1000 m, which was thought to be moderately consolidated and contained a low GOR viscous oil. The interval was first tested conventionally. The zone was later re-tested on the pump for a higher rate. Moderate sand production of 7 to 10% was recorded. Actual drawdown while on the pump reached 328 psi while the predicted minimum critical drawdown was 376 psi.

PT 5 tested a shallow sand, which was known to be unconsolidated and to contain a high viscosity crude. The Navi-pump was operated at the extreme low end of its range, at approximately 25 rpm. Following the unloading of the water cushion, the first oil reached surface about 4 hours after

the test was opened. Flow ceased approximately 4 hours later and the test was abandoned. The test string contents were reversed out down to the pump. The tubing had been plugged with a mixture of sand and cold, viscous crude. A plot of bottom-hole pressures recorded during the test is shown in **Fig. 9**. The maximum pressure drawdown of 769 psi occurred after 2 hours flow. The analysis had indicated that this test interval had negligible sand strength and was likely to break down with as little as 469 psi of drawdown.

The four intervals tested in well B were similar to those found some four kilometers away in well A. Tests on three intervals below 1000 m were all performed successfully with no sand control being required. DST 4 was a test of the shallow sand equivalent to that tested during PT 5 in well A. The 7-m test interval was perforated at 12 SPF and gravelpacked with 40-60 mesh sand. The interval was successfully tested on pump and produced over 300 bopd of oil with no solids.

Table 2 compares actual drawdowns achieved during testing and predicted critical drawdown pressures for the various intervals tested in wells A and B.

Conclusions

1. Critical drawdown pressure models that consider Darcy and non-Darcy flow regimes and incorporate the tensile failure mode are particularly useful for predicting the maximum sand free rate in weak but competent formations.
2. A direct computation of static mechanical properties from log inputs is most preferred where a quick but accurate identification of potential sand producing zones is needed. The log-based method enables a sound engineering decision on sand control to be made in the short period between logging and completion/testing
3. An accurate prediction of sand strength parameters is key to a reliable estimation of the critical drawdown pressures.
4. Analysis of critical drawdown pressures in Bohai- A and B wells provided a cost-effective method to predict potential sand production problems. This information proved invaluable in reducing the risk and costs associated with testing of viscous oils in the shallow, moderately unconsolidated sandstones of Bohai Bay.

Nomenclature

k = formation permeability

m = gas density exponent

p = pressure

r = radius

A = area

q = flow rate

P_a = pressure at the face of the cavity

P_b = pressure at the external flow boundary

$P'_a = (P_a \tan \alpha / S_o)^{m+1}$

$P'_b = (P_b \tan \alpha / S_o)^{m+1}$

S_o = cohesive strength

S_r = radial stress, total

S_t = tangential stress, total

α = internal friction angle

b = non-Darcy flow coefficient

g = gas density coefficient

m = fluid viscosity

r = fluid density

S_n = effective normal stress

t = shear stress

References

1. Ramos, G.G., Katahara, K.W., Gray, J.D., and Knox, D.J.W.: "Sand Production in Vertical and Horizontal Wells in a Friable Sandstone Formation, North Sea", Eurock '94, 1994.
2. Weingarten, J.S., and Perkins, T.K.: "Prediction of Sand Production in Gas Wells: Method and Gulf of Mexico Case Studies", paper SPE 24797 presented at the 67th Annual Technical Conference and Exhibition, October 4-7, 1992.
3. Bratli, R.K., and Risnes, R.: "Stability and Failure of Sand Arches", *Society of Petroleum Engineers Journal*, December 1982, 883-898.
4. Ong, S., Ramos, G.G., and Zheng, Z.: "Sand Production in High Rate, Perforated and Open-hole Gas wells", paper SPE 58721 presented at the 2000 SPE International Symposium on Formation Damage, February 23-24.
5. Raaen, A.M., Hovem, K.A., Joranson, H., and Fjaer, E.: "FORMEL: A Step Forward in Strength Logging", paper SPE 36533 presented at the 71st Annual Technical Conference and Exhibition, October 6-9, 1996.

Acknowledgment

The authors would like to thank the managements of Kerr-McGee Oil & Gas Corporation and Baker Atlas for the permission to publish this paper. Karen Bush proofread the manuscript.

Volumetric	Sand
	Clay
	Water
	Hydrocarbon
Rock data	Bulk density
Fluid data	Bulk modulus of hydrocarbon
	Density of hydrocarbon
Acoustic data	Compressional slowness
	Shear slowness
Stresses	Overburden/vertical stress
	Horizontal stress
	Pore pressure

TABLE 2: ACTUAL FIELD DRAWDOWN VERSUS PREDICTED CRITICAL DRAWDOWN PRESSURES

Well	Test Type	Actual Maximum Drawdown	Predicted Maximum Drawdown	Sand Production
Well A				
PT 1	Natural Flow	252	1009	None
PT 2/2A	Natural/Pump	798	921	Trace to 3%
PT 3	Pump	22	1001	None
PT 4/4A	Natural/Pump	328	376	7-10%
PT 5	Pump	769	469	Sanded up
Well B				
PT 1	Pump	194	1658	None
PT 2	Pump	37	1560	None
PT 3	Pump	66	440	Trace
PT 4	Pump	679	29	None*

* Gravel Pack

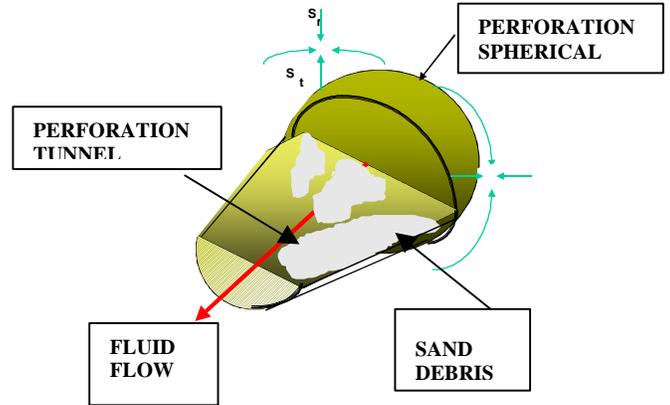


Fig. 2-Idealized geometry of a perforation tunnel

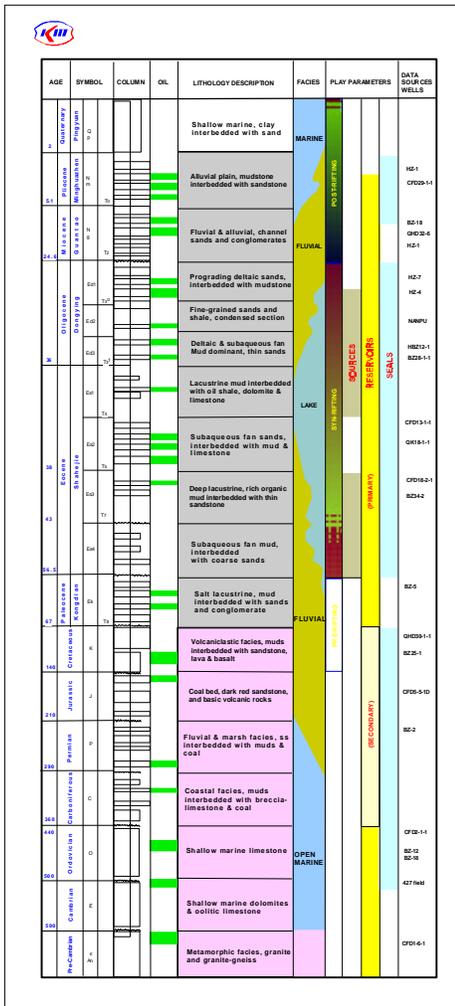


Figure 1-Generalized stratigraphic sections of Bohai Bay.

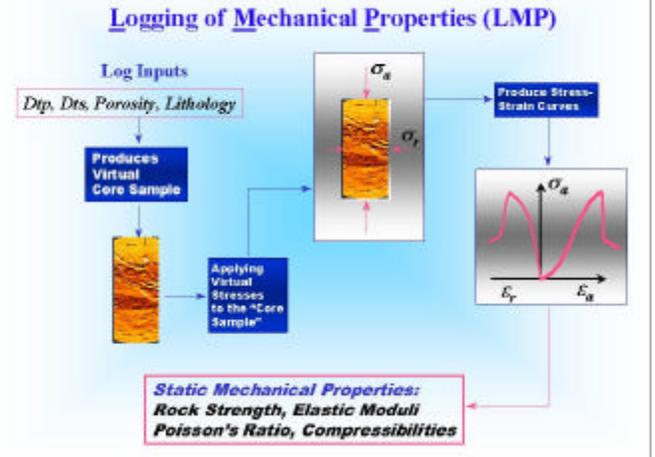


Figure 3-The process flow of the logging of the mechanical properties program.

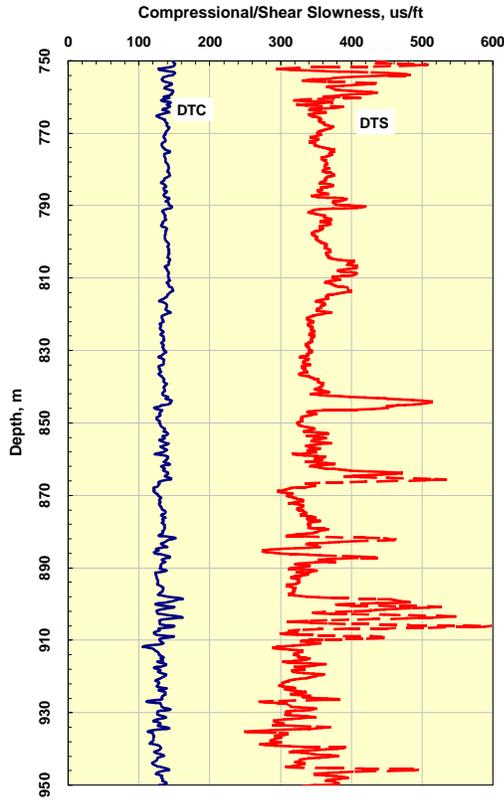


Figure 4-A variation of compressional and shear slownesses over a selected depth interval. Note the relatively high compressional and shear slownesses indicating the formation could be weak.

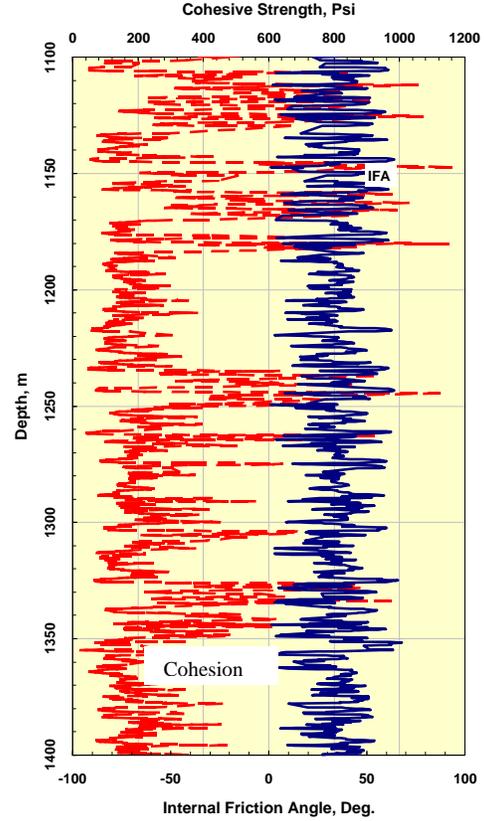


Figure 6-A variation of cohesive strength and internal friction angle over the selected depth interval.

Well Name: BOHAI-A
 Depth: 300.00 to 1440.5 by 0.15 meters
 Constraints: CORVSH (7.00-68.00)
 55 out of 7484 points plotted.

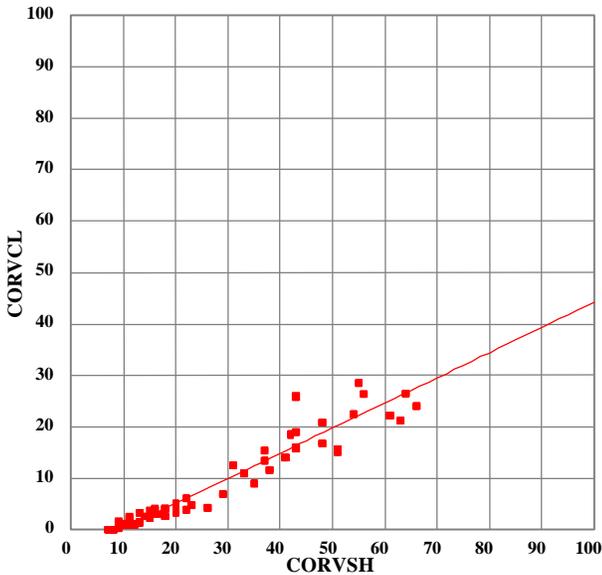


Figure 5-A plot of the sidewall core volume of dry clay versus the sidewall core volume of shale.

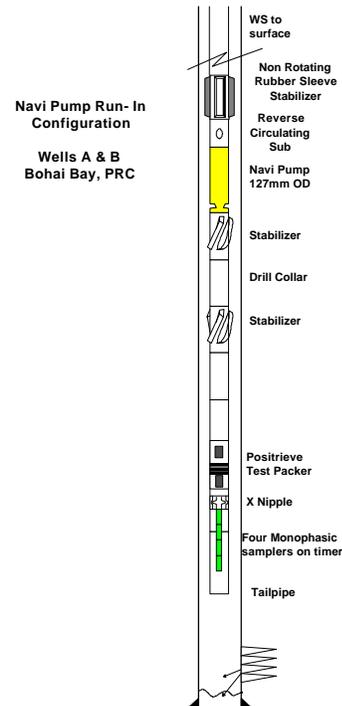


Figure 7-A schematic of the production test string with the Navi-pump in a run-in configuration.

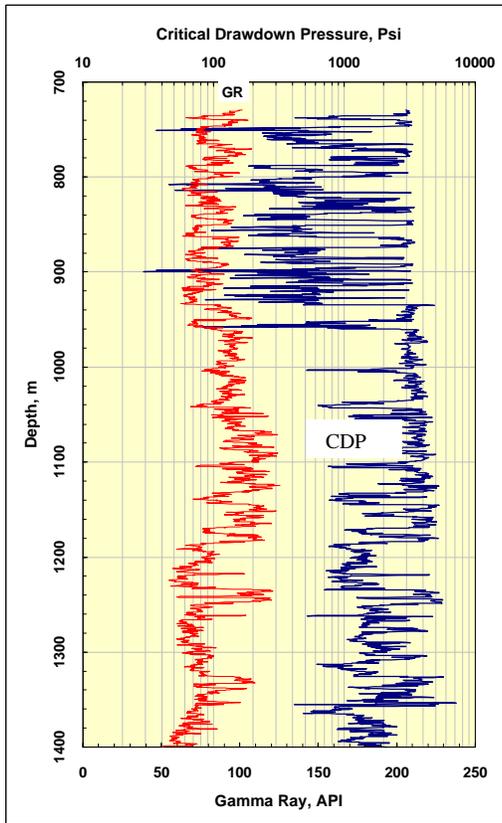


Figure 8-A variation of CDP over the Upper and Lower Minguazhen and Guantao Formations. The gamma ray curve is included to show the lithology types.

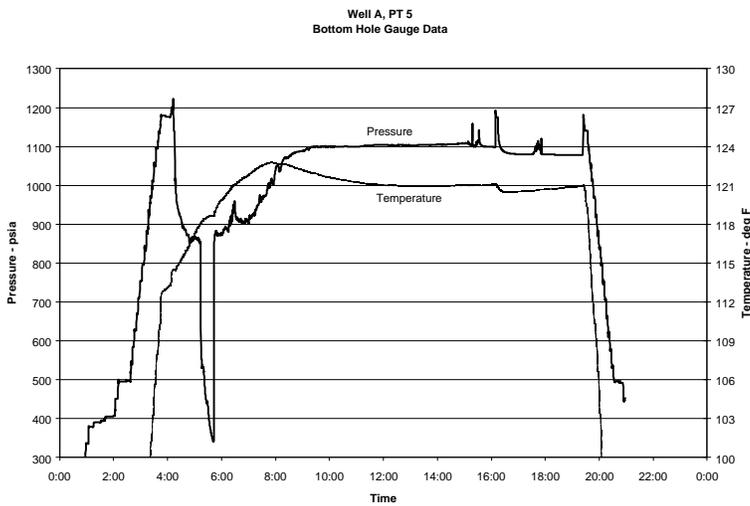


Figure 9-A plot of bottomhole pressure during production test 5 in Well-A. Note that the well has sanded and plugged-up the test string.