A Unique High Resolution Imaging Process - A Key to Finding Pay in a Mature Field

Stuart Hirsch, Cabot Oil and Gas Corporation; Gary L. Perry, Geotrace Technologies, Inc.

Abstract

Interpretation of high-resolution 3-D seismic imaging integrated with AVO processing and Frequency Absorption analysis, combined with existing well log control, resulted in the identification of bypassed exploitation opportunities in a mature field area.

Introduction

Traditionally, integration of conventional, pre-stack time migrated seismic data with detailed interpretations of existing well log control have resulted in the information used to design development plans for newly discovered hydrocarbon accumulations. Through time, wells are drilled to optimally recover these accumulations and several generations of interpretations are produced and refined as a result of the introduction of new data, development of new or enhanced interpretation techniques, or simply by revaluating the available well log data under a new or different paradigm. In many mature field areas, the remaining potential becomes difficult to define and, at this point, the field becomes a candidate for divestiture or abandonment. The use of high-frequency seismic imaging as a stratigraphic discrimination tool and the employment of AVO products as risk reduction tools for the presence (or absence) of hydrocarbon accumulations permits the identification of potential by-passed production opportunities.

Background

Lake Pelto field (Fig. 1)is located about 75 miles southwest of New Orleans, Louisiana in the state waters area of Terrebonne Parish. Discovered in 1929 by the Texas Company (Texaco) #B-1 State-Lake Pelto well (T.D. of 1,391'), the field has yielded in excess of 450 BCF gas and 122 MMB oil from multiple pay zones in the Pleistocene through the upper Miocene Textularia "W" *(Tex. W).*[1] More than 300 wells have been drilled for the exploitation of both sulphur and hydrocarbon resources. The Sun Oil Company State Lease 2620 #16 well, with a total measured depth of 21,509', is the deepest well drilled to date on the Lake Pelto feature.

Principal development of the salt dome feature was carried out by the Texas Company between 1929 and the late 1950's. A later period of development (1955 to 1997) was subsequently carried out by Sun Oil Company and Oryx in off-structure areas to the east and northeast of the earlier field development (State Lease 2620). The latest development has been undertaken by Cabot Oil and Gas Corporation, which purchased the Oryx (Sun) leases and production in 1998 and subsequently entered into additional leases with the State of Louisiana. Cabot has drilled four wells since acquiring an interest in the field area.

Geological Summary

From a regional perspective, the Lake Pelto Field area is located within the Upper Miocene Distal-Deltaic Sandstone Subplay as outlined in the *Atlas of Major Central and Eastern Gulf Coast Gas Reservoirs* published jointly by the Texas Bureau of Economic Geology and the Gas Research Institute.[2] It falls within an area of thick Miocene sedimentation known as the Terrebonne Trough which is characterized by major salt withdrawal basins, adjoining salt piercement features and regional to subregional growth fault systems.

The Lake Pelto Field proper is itself a salt piercement feature with salt rising to within 1,500' of the surface. The

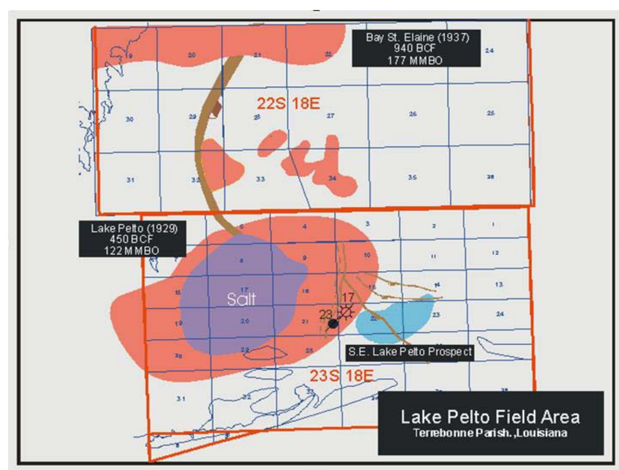

Figure 1 - Lake Pelto field area of southern Terrebonne Parish, Louisiana, showing location of salt dome and production from Lake Pelto and Bay St. Elaine fields.

deepest salt penetrated is at 11,680'. Faulting is complex and difficult to map in the immediate crestal area and as one nears the steep flanks of the domal feature. At increasing distances to the east of the dome, faulting above the Cibicides carstensi (*Cib. carst.)* is minor while faulting below the *Cib. carst.* is more common. Deep seated, shale cored ridges extend both eastward and northward from the dome into the major withdrawal basin that adjoins the domal area. Major faults are associated with both ridges. One fault system extends two miles northward to the Bay Saint Elaine Field. These faults extend high up in the stratigraphic section. Faulting to the east dies rapidly away from the dome and does not extend above the *Cib. carst*. at increasing distance from the dome. The shale section marks the onset of hard geopressure and ranges from a depth of 11,500' feet in proximity to the dome to in excess of 19,000' off the east flank of the structure.

Depositional environments range from inner to middle shelf in the upper Miocene Bigenerina A (*Big. A*) to outer shelf and upper slope in the upper Miocene textularia "L" *(Tex. L)*. The *Big. A* and younger section is dominantly a sandy interval with few shale breaks while below the *Big. A* and extending down to the *Tex. L*, the section is dominated by cyclical, coarsening upward sequences which are characterized by thick, basal shale units. A major unconformity is evident in the *Cib. carst.* section off the east flank of the Lake Pelto dome feature.

Production ranges from a depth of less than 1,500' in the Pleistocene to deeper than 17,000' in the upper Miocene. Gas is the predominant hydrocarbon produced below 15,000' and at increasing distances from the dome. Most of the oil and gas accumulations are associated with structural traps although an increasing stratigraphic component is evident in those areas drilled by Sun (and Oryx) and Cabot both north and east of the dome.

Development Challenge

Using a 25 mi.^{2}, Oryx, 1993/1994 vintage 3-D seismic survey, Cabot geoscientists identified several areas that appeared to be under exploited. One area located north of existing production was characterized by apparent, multiple, high-amplitude events on a low relief structural closure that was separated from existing production by a very subtle syncline. A second area, which is the focus of this paper, was located off the east flank of the producing feature in an area with no apparent trapping structure and no distinct stratigraphic separation from the depleted producing zones. In both cases, the conventional DMO processing exhibited several high amplitude events but the data were not suitable to define stratigraphic separation from existing production, to discriminate the number of potential reservoirs present or to map the potential lateral extent of the reservoir(s). Due to the depth of the reservoirs and long producing history of the field complex, better discriminating tools were required to insure that the drilling targets were not simply residual gas in depleted reservoirs. Thus, in order to reduce the risk prior to the drilling of these prospects, Cabot embarked on a seismic reprocessing program that included pre-stack time migration (PSTM) coupled with AVO processing of the Oryx 3-D data.

Southeast Lake Pelto Prospect

Cabot's Southeast Lake Pelto Prospect was first identified via reconnaissance of the reprocessed, PSTM 3-D dataset. An amplitude anomaly with Class III AVO characteristics was recognized basinward of previous production (Figure 2) and was initially linked to the M-4 sand (*Cib. carst.)* in the updip Sun, S/L 2620 #17 (#17) and the Sun, S/L 2620 #23 (#23) wells. An immediate problem arose due to the fact that in excess of 27 BCFG and 630 MBO had been produced from the thin M-4 sand intervals in the two wells (14 feet of gross pay at 15,790' MD in the #17 well and 30 feet of gross pay at 15,698' MD in the #23 well), which appeared to penetrate the amplitude anomaly of interest. Additionally, the seismic stratigraphy between the producing wells and the prospect area appeared consistent with no apparent structural or stratigraphic means of separation of the prospect area from the two producing wells. Using both the DMO and PSTM datasets, it was also not possible to image the M-4 sand as a separate unit from the overlying Mc and M-1 sands. Even more troubling from the prospect perspective was the fact that, if a separate prospect existed downdip of the formerly productive wells, there was no apparent trapping mechanism for the indicated downdip hydrocarbons. The production volume versus drainage area problem thus became an important consideration affecting any decision to exploit the indicated anomaly.

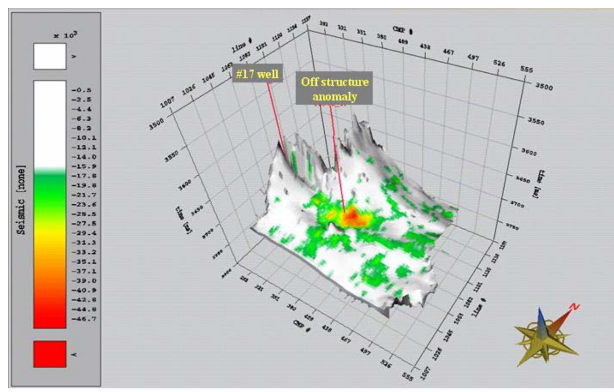

Figure 2 - Amplitude of the Mc sand brightens downdip of the depleted reservoir on the high-frequency data.

Seismic Methods and Interpretation Results

Prestack Kirchhoff Time Migration. Early in the history of the project, the decision was made to reprocess the 3D seismic data in order to obtain a better image of the subsurface and to look for direct hydrocarbon indicators (DHCI). To properly focus the deep reflectors, 3D prestack Kirchhoff time migration was utilized. This process simultaneously solves for normal moveout (NMO), dip moveout (DMO) and migration, placing reflectors in the proper spatial position while retaining as broad bandwidth as possible.

High Frequency Imaging. Since significant production in south Louisiana is often found in relatively thin sands and in stacked sand sequences, seismic resolution is a key to finding new pay. At 16,000 feet, approximately 3.7 seconds two-way seismic reflection time, most seismic data in the area is limited to about 40 to 50 Hz usable frequency. Using quarter wavelength estimation, this means that the thinnest sandstone layer that can be fully resolved is about 65-80 feet thick. In order to maximize the usable frequencies in the reprocessed seismic data, Geotrace's proprietary High Frequency Imaging (HFI) was applied. This unique approach to whitening seismic data makes it possible to extract much higher frequencies from seismic data than traditional methods.

It is a widely known but seldom utilized characteristic of seismic that the apparently narrow band trace contains higher frequency information than an extracted wavelet would suggest. By recognizing that convolution is equivalent to polynomial multiplication and that polynomial division is its exact inverse, one can easily demonstrate this characteristic. A synthetic seismogram is constructed by convolving a spike series with a band-limited wavelet, the result being a band-limited trace containing, apparently, only those frequencies which were in the wavelet used. However, by employing polynomial division, the spike series can be obtained from the synthetic seismic trace. In other words, all of the original high frequency information is contained in the low frequency trace. Unfortunately, polynomial division cannot be used in the real world because even the smallest amount of noise introduced into the trace makes the process unstable.

HFI uses vector calculus, rather than polynomial mathematics, to solve the problem by viewing convolution as a vector rotation. The vector that represents the apparent low frequency seismic is precisely determined then rotated toward a white spectral position in the chosen vector space. The process is not sabotaged by ambient noise and the resulting seismic is broadband with a high signal-to-noise ratio. In this particular case, using the PSTM data with 48 Hz maximum usable frequency at 3.7 seconds as input, the HFI yielded data with 110 Hz on the high end, an increase of 129 percent. Now beds as thin as 30 feet could be resolved in the zone of interest. This would prove to be extremely beneficial.

Figures 3 and 4 show a comparison of the normal frequency prestack migrated data and the HFI data on an arbitrary line from the 3D survey. This line connects well #17 to the prospect area anomaly and shows the continuity of the M-4 downdip of well #17 which had been plugged and abandoned after pressure depletion of the reservoir. Additionally, the Mc sand, which is wet and poorly developed in the updip well #17 appears to be discontinuous between the two locations. It is also evident that a small fault separates the Mc sand seen in the updip wells from the downdip anomaly. Amplitude spectra for the conventional prestack migrated data and the HFI data are shown in Figure 4.

AVO. Since HFI was run on the migrated CMP gathers, it was possible to calculate high frequency AVO attributes on the seismic volume. Wells in the area were analyzed and it was determined that producing sands fit into Class II or Class III AVO categories. That is, sands that contain gas or oil with regionally characteristic high gas/oil ratios were either about the same impedance as surrounding shale or were lower impedance. In either case, the AVO effect on a resolved interface at the top of a producing sand is a high amplitude trough at large angle of incidence. Both the Intercept*Gradient and Intercept*Poisson's Reflectivity attributes were useful as they are good Class III and Class II tools, respectively. The Intercept*Gradient attribute exhibited a particularly good anomaly, the first DHCI located down dip from the #17 well. A horizon slice through this 3D volume is shown in Figure 5. As can be seen, there is no AVO anomaly at the same level in well #17.

Frequency Absorption. The broadband data were also scrutinized for absorption effects. As seismic energy passes through an absorptive layer, all frequencies are attenuated but high frequencies are absorbed more quickly than low frequencies. Sands containing gas are good absorbers and, unlike many AVO effects, higher saturations produce better absorption anomalies. The high frequency seismic is preferable to narrow band data as absorption effects are much more apparent in the high end of the spectrum. A 3D volume indicating degree of absorption was generated for the 25 square mile 3D survey. An anomaly down dip from the #17 well, the second DHCI detected at that location, reinforced the AVO work done previously. A horizon slice through this 3D volume and the vertical profile are shown in Figures 6 and 7. Notice that the anomaly does not extend updip to the #17 or #23 wells, both of which had been plugged and abandoned before the 3D survey was acquired.

Based upon interpretation of the HFI reprocessed data and the various AVO attributes, Cabot geoscientists came to the following conclusions: 1. The DHCIs were indicative of potential pay in the Mc/M-1 sands rather than in the lower M-4 sand zone, 2. The hydrocarbon present was probably gas, 3. The M-4 sand extended downdip into the prospect area but was probably depleted as evidenced by the volumes previously produced updip from this zone in wells #17 and #23, 4. The downdip accumulations had a very strong stratigraphic trapping component and 5. A small fault separated the updip limit of the amplitude anomaly in the prospect area from the equivalent interval in the #17 and #23 wells. The decision was thus made to drill a well on the prospect.

Drilling Results

The Cabot S/L 16970 #1 well (location in Figure 8) was drilled to a total depth of 17,000 feet and completed as a producing gas well in the third quarter of 2001. Well log correlation and interpretation confirmed that the Mc sand had developed downdip of the #17 and #23 wells and that the upper fifty feet of sand was clearly gas bearing. The M-1 sand was also present but not as well developed as in the #17 well. A depleted M-4 sand was present and very similar in character to the M-4 sand in the #17 well (Figure 9). The S/L 16970 # 1 well was turned into line on September 29, 2001 flowing at a rate of 4 MMCFGD. This rate has since been ramped up to in excess of 8 MMCFG and 500 barrels of 40° API gravity oil per day.

Conclusions

Interpretation of high resolution seismic imaging coupled with AVO attribute analysis provided the necessary means to interpret the subtle changes in stratigraphy and structure that turned Cabot's Southeast Lake Pelto prospect into a viable drilling opportunity. The use of HFI led to the conclusion that although the Mc and M-1 sand intervals were correlative between the updip #17 and #23 wells and the downdip prospect area, the sand bodies within these intervals were none-the-less stratigraphically distinct units. The use of HFI also permitted the discrimination of the depleted M-4 sand from potential pay in the overlying Mc and M-1 sands. The very strong stratigraphic trapping components of the reservoir were verified as was the existence of a very small fault that previously had not been recognized as cutting up through

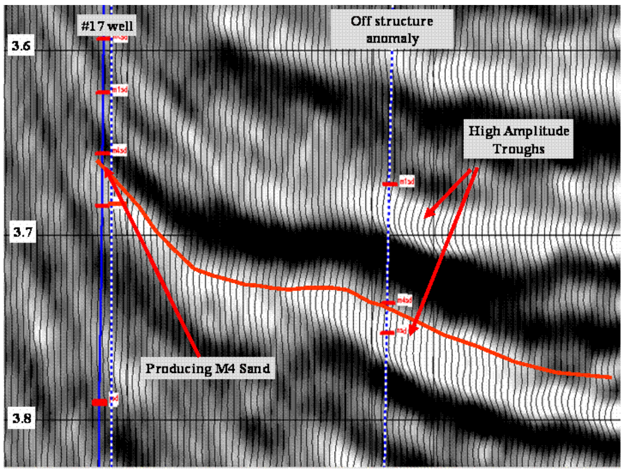

Figure 3 - The M-4 sand, which produced gas in Wells 17 and 23, is not resolved on the normal frequency pre-STM data.

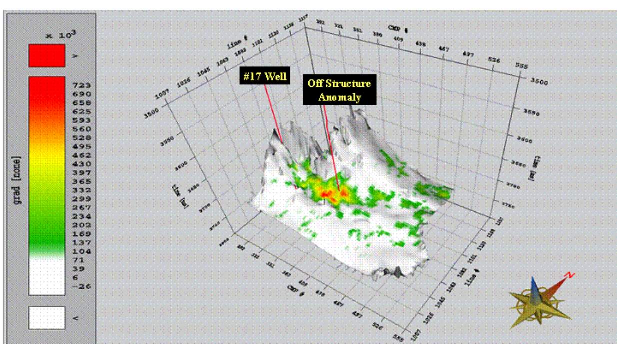

Figure 5 - Horizon slice at the Mc sand through the Intercept x Gradient AVO attribute volume. The anomaly in the syncline does not extend updip to Well 17.

the Mc/M-1 sand interval. The AVO characteristics successfully predicted the presence of a gas accumulation and the frequency absorption attribute (FAR) helped to determine that the accumulation was in fact a virgin reservoir. Seismic interpretation using conventional frequencies would not have resulted in a drilling recommendation for this location and substantial pay would have been bypassed.

Acknowledgement

The authors wish to thank Cabot Oil and Gas Corporation and Geotrace Technologies for permission to publish this paper.

Literature Cited

[1] *Lake Pelto Field*, in Waguespack, S.J., ed., *Salt Domes of South Louisiana, Volume 3*, New Orleans Geological Society, New Orleans, LA, p. 42 – 43, 1983.

[2] Chacko, J.J. et al, *MC-8. Upper Miocene Sandstone – Louisiana Gulf Coast*, in Debout, D.G. et al, eds., *Atlas of Major Central and Eastern Gulf Coast Gas Reservoirs*, Bureau of Economic Geology, Austin, TX, p. 11 – 13, 1992.

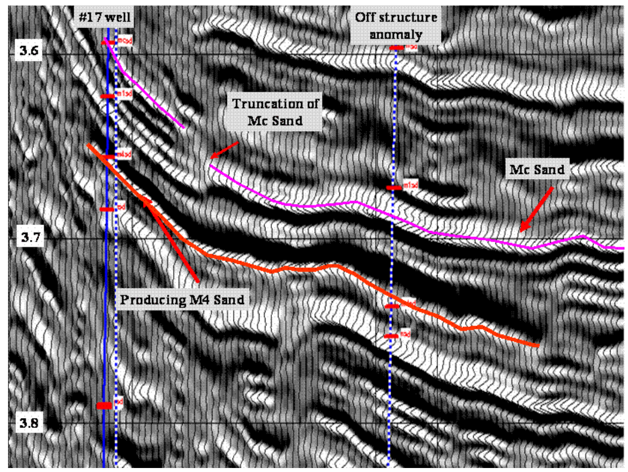

Figure 4 - The M-4 sand is continuous between Well 17 and the downdip location. The Mc sand, however, shows an abrupt truncation between the wells on the HFI data.

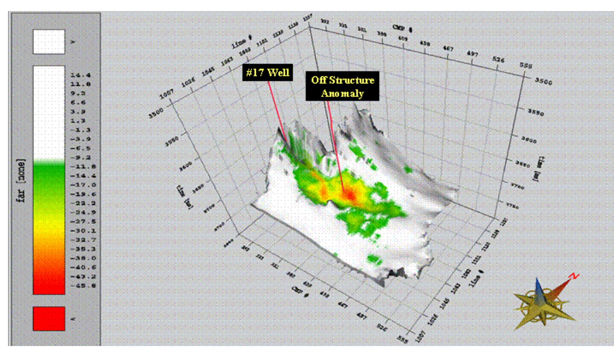

Figure 6 - Horizon slice at the Mc sand through the Frequency Absorption (FAR) volume. The strong downdip anomaly indicates a substantial gas accumulation.

The authors

Stuart Hirsch earned a BS in Earth and Planetary Sciences from the University of Pittsburgh in 1972 and an MA in Geology in 1974 from Indiana University. He is currently lead geologist, Gulf of Mexico exploration for Cabot Oil and Gas in Houston. He has previously worked Gulf of Mexico exploration for Mobil Oil (now ExxonMobil), Sohio Petroleum (now BP) and BP Exploration (BP).

Gary Perry studied Geology with emphasis on Geophysics at the University of Texas. He is currently Vice President, Analysis and Application for Geotrace Technologies, Inc. in Houston and has been with the company for over 17 years. Gary previously worked for GeoSearch Corporation as a seismic processor and basin analyst from 1974 to 1986.

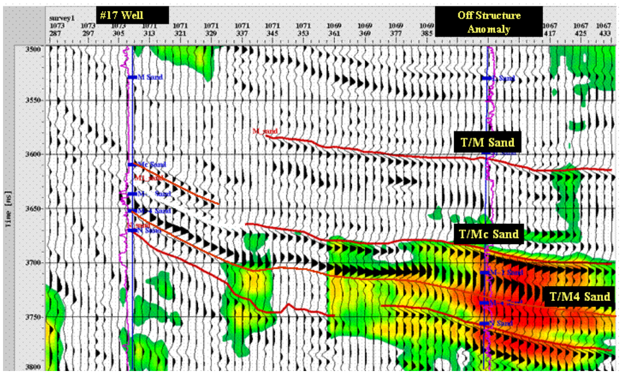

Figure 7 - Vertical profile from the FAR attribute through Well 17 and the downdip absorption anomaly.

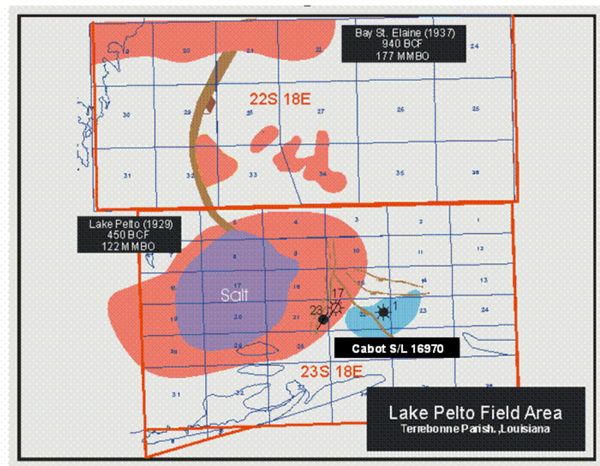

Figure 8 - Map of area showing location of new well, Cabot S/L 16970 #1.

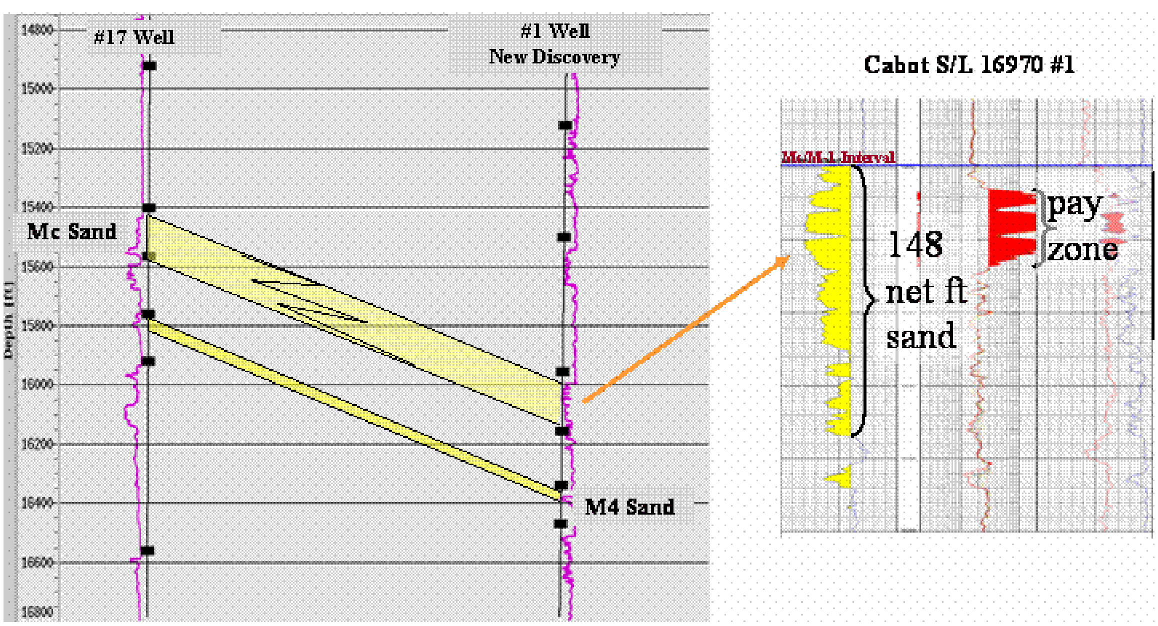

Figure 9 - Generalized correlation section showing the Mc and M-4 sands in depleted Well 17 and new Well 1