IMPORTANCE OF SEALS AND FLOW BARRIERS IN E & P PROJECTS

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Worldwide studies of low permeability rocks including seals and flow barriers in more than 325 fields show that (1) most reservoirs are filled to the seal capacity of the weakest seal, (2) silt/shale layers within reservoir units can be significant barriers to fluid flow, and (3) faults that seal at discovery can breakdown during early production with water entry into a reservoir in structurally high wells. Our studies demonstrate the importance of knowing the properties of seals and flow barrier rock types in exploration and production activities. Seals and flow barriers result from structural and/or stratigraphic changes (Fig 1) and the interface of the rock properties with insitu pore water and hydrocarbons.

The forces or pressures involved in hydrocarbon trapping and leakage of hydrocarbons into a seal or across a flow barrier are the buoyancy pressure or the driving force and the capillary pressure or the resistive force. The buoyancy pressure equals the height of the hydrocarbon column times the difference in density between water and hydrocarbons times the gradient of pure water. The resistive force is equal to two times the interfacial tension of water and hydrocarbon times the cosine of the contract or wetting angle divided by the radius of the pore throat size. The parameters controlling seal capacity and hydrocarbon entrapment are (1) rock properties: pore-size distribution plus ductility and seal continuity (not thickness, porosity and permeability) and (2) fluid properties: density difference of water and hydrocarbons and interfacial tensions of the fluids. If the buoyancy pressure created by the hydrocarbon and water density difference exceeds the capillary entry pressure, hydrocarbons will enter the reservoir pore space or leak into the seal. It takes about 5 to 10 percent hydrocarbon saturation in the seal to actually cause hydrocarbons to migrate.

We measure seal and flow barrier rock pore-size distribution on core plugs cut across the seal or barrier and the sides of the plugs are coated with epoxy. We measure high-pressure mercury-air capillary pressure curves (HPMIC) up to 60,000 psi on seals and flow barrier rock types. If we have only cuttings of the seal or flow barrier, the cuttings have lower capillary pressure than the epoxy plug because mercury can invade from all sides. If we use cuttings then we have to add a capillary pressure value to the HPMIC measurement to approximate what the epoxy seal core's capillary pressure measurement would be. This added value, called the empirical adjustment factor, is obtained from catalogs of similar rock types.

Five case studies demonstrate the importance of seals and flow barriers in exploration and production.

Case Study 1: Gachsaran Field, Iran

This is a supergiant with over 8 billion barrels of recoverable oil in a four-way closed, elongated anticline. Evaporitic anhydrite is the seal. Hydrocarbons are trapped to their spill point. The hydrocarbon column height is over 7,100 feet. Mercury cannot be injected into the seal at 60,000 psi. For the hydrocarbons found in the Asmari limestone reservoir, the anhydrite seal could hold at least up to 43,000 feet of column. In contrast to pure anhydrite the seal properties of impure or "chicken-wire" anhydrite, can seal much lesser columns.

Case Study 2 : Garzan Field, Turkey

The structure is an anticline with cross faults. The field hydrocarbon column height is about 328 feet. The seal, which is a shale and calcareous shale, will hold a hydrocarbon column of about 330 feet based on capillary pressure of cuttings.

Case Study3 : Benton Field, Illinois Basin, USA

This 80 million-barrel oil field is essentially a four-way closed anticline. Structural closure is about 90 feet. The hydrocarbon column height is about 95 feet. The seal is type "D" siltstones, which can hold between 94 and 110 feet of hydrocarbon column for the oil and water found in the field. There is a reservoir facies change from sand to silty sand and silt to the south.

The reservoir consists of delta bars and a distributary channel. The channel sand runs across the structure. The edge of the channel is a flow barrier based on production performance. The channel produces by a water-drive and the delta bar sands produce by depletion. During primary production the highest production was from the channel. The channel is connected to an aquifer to the northwest. During primary recovery, pressure declined with production in the bar sands and only slightly declined with production in the channel. Water moved across the structure only in the channel deposits. In outcrop about 30 miles from the field, a centimeter thick clay lining is observed between good quality delta bar and channel reservoir rock.

Case Study 4 : VLC – 363 Field, Block III Lake Maracaibo, Venezuela

This is a supergiant field discovered by Shell in the early 1960's and the field is producing today. The "C" interval has between 1.7 and 2.0 billion stock tank barrels originally in place. After more than 30 years of production, the primary production from 78 wells was about 285 million barrels or 15% of the OOIP.

There are a large number of producing anomalies: water production structurally higher than oil production, large (several thousand psi) pressure difference even within the same sand in the same well, and difference in producing water levels across a newly identified fault with 100 to 150 feet of throw.

The original field structure map for the "C" shows a three-way closure on the upthrown side of a major normal fault that is down to the northeast. A 3D seismic survey and additional well control reveals a more complex structure and explains several production anomalies. Based on 1960s vintage seismic the structure at discovery had a few minor faults with limited throw. The original oil water contact was 13,525 feet is shown on the new C-455 structure map. Figure 2 shows the north-south fault of 100 – 150 feet of throw that separates the 250-foot difference in producing water levels on the east side of the field versus the west side.

Minor faults and flow barriers/baffles consisting of thin shales have a large impact on the production performance of the supergiant filed. A detailed understanding of the faulting and distribution of shales led to a better understanding of the production anomalies and identification of significant amount of bypassed hydrocarbons. The hydrocarbons are trapped by a three-way closure on the upthrown side of a major down to the northeast fault. The present-day structure is a result of extensional and strike-slip deformation. Extensional faults are sealing and sealing capacity of strike-slip faults is variable. Six faults dominate the overall structure pattern and separate the field into four production zones.

Three scales of vertical flow barriers (mega, macro and micro) are recognized in the field. The mega barriers are shales/siltstones that separate reservoirs and cover wide areas. RFT data suggest that mega flow barriers support major pressure differences across the field. The macro barriers are recognized on logs because they are thick enough to be recognized on logs. These barriers or baffles cannot be correlated in nearby wells with certainty. The continuity of these individual shales is probably local, but the high number of these barriers makes the effective vertical permeability low.

RFT data indicate that mega boundaries are field-wide, fluid-flow barriers. Flow barriers/baffles have a large impact on completion practices and simulation results. The entire zone must be perforated to get effective flow through a flow unit. Pressure differences within flow units indicate that the entire section is not being drained.

Capillary pressure measurements for six shale/siltstone core samples show that the sealing capacity of the flow barrier shales ranged from 90 feet to 3,892 feet for gas and 71 feet to 3,105 feet for oil. The permeability estimates from capillary pressure indicate permeabilities <0.001 md for all samples except for one that has a permeability of 0.044 md to gas. The shale layers will be effective barriers to fluid migration during any fluid injection project.

Case Study 5: Offshore Fault Trap Field, Gulf of Mexico, USA

A sealing fault at discovery broke down in less than 40 days of hydrocarbon production due to pressure reduction from withdrawals of hydrocarbons. Water production in an updip well averaged 250 barrels per day until reservoir pressure was increased again by down-dip water injection. Pressure maintenance using gas and water injection was needed to “repair” the leaky fault seal.

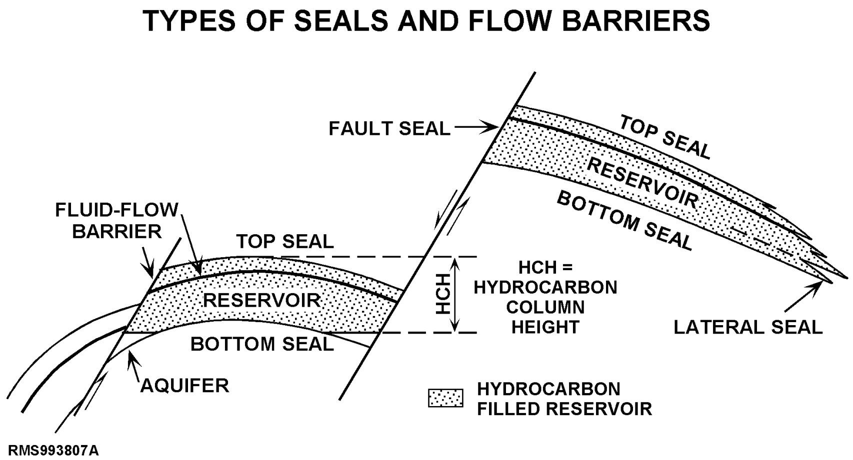

Fig. 1. Types of seals and flow barriers. Fluid-flow barriers are "seal-like" lithologies within a reservoir. Note: HCH is the hydrocarbon column height the weakest seal will hold.

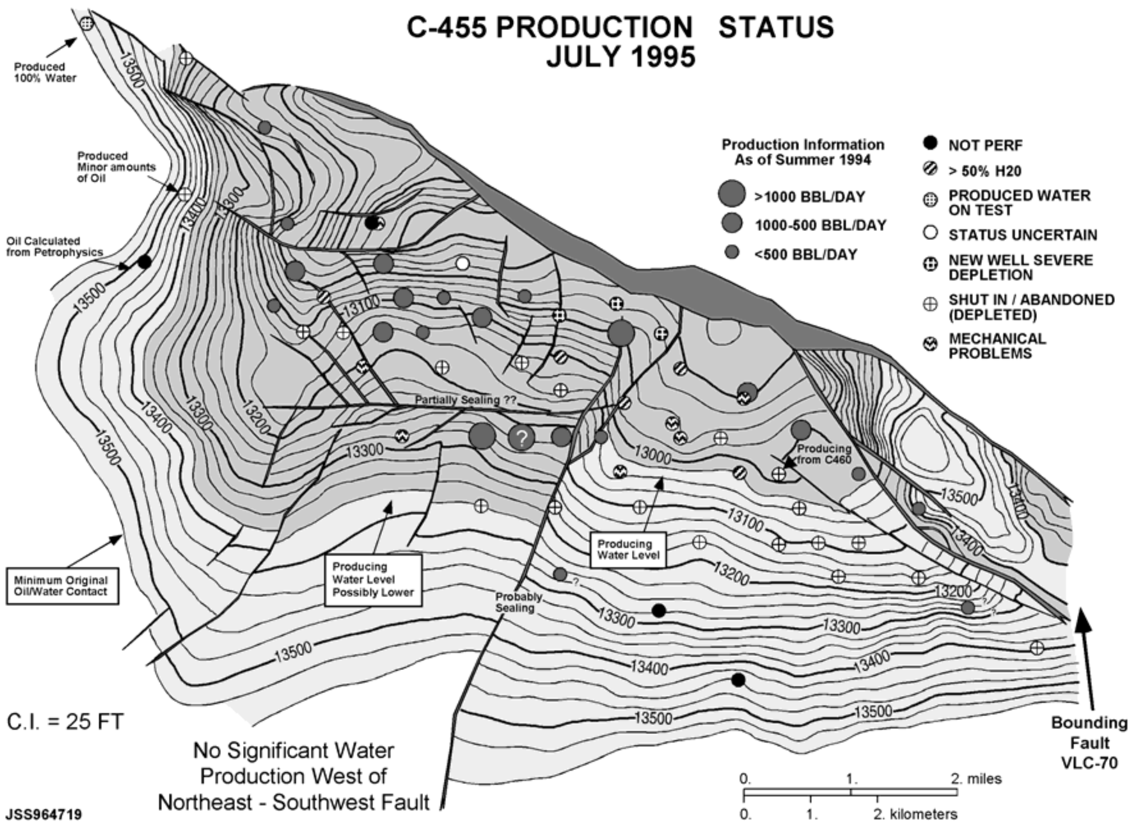

Fig. 2. Structure map on top of C-455 Reservoir, VLC 363 Field, Block III, Lake Maracaibo, showing 1995 oil-water contacts. Note original oil-water contact was at –13,525 feet.