Vertical migration in theory and in practice

Gary K. Rice[1]

Abstract

We use the term vertical migration to describe the mechanism of mass transport that moves trace petroleum hydrocarbons from subsurface accumulations to the surface. Vertical migration is the heart of geochemical exploration for petroleum. Although our use of geochemical exploration for petroleum has been accelerating, our understanding of the mechanism that makes the process successful lagged behind. Early vertical migration models were based on a molecular process called diffusion. Diffusion remained the accepted mechanism during the early years of geochemical exploration even though the diffusion mechanism could not explain many observations, including migration that appeared to be predominately vertical. Approximately 30 years ago, buoyancy-driven migration mechanisms were modeled. The models predicted how gases below the water table could migrate vertically as a gas phase with buoyancy providing a mechanism for predominately vertical gas migration. Buoyancy models explained how surface expressions observed from vertical migration measurements related to petroleum reservoirs including small lateral offsets. Buoyancy models also explained the gradients and data contrasts observed in many surface geochemical features including what they mean and predicted fast vertical migration rates that have been verified by field observations. In addition, buoyancy models predicted how petroleum reservoirs could be mapped using gas data and how surface expressions of faults and fractures could be mapped using liquid data. Those data can be obtained from direct measurement of trace hydrocarbons in near-surface fluid samples. Because reservoir rock samples are not required, vertical migration provides a way to obtain information about a reservoir prior to exploratory drilling. The characteristics of these migrating fluids and their surface patterns are the foundation of modern geochemical exploration for petroleum.

Introduction

Vertical migration describes the mass transport process that moves trace petroleum hydrocarbons from subsurface accumulations to the surface. Vertical migration also describes movement from source rock to shallower reservoir rocks. Both cases would be due to the mechanism described here. Measurable quantities of petroleum hydrocarbons in shallow samples have been documented in Russia, Germany, and the United States since at least the 1930s. Although the use of petroleum geochemical exploration has been increasing, our understanding of vertical migration in the subsurface developed at a slower pace.

Without satisfactory explanations for data observations, the idea of exploration using mass transport of gas and light hydrocarbons from petroleum reservoirs to the surface has been criticized throughout most of the technologies' nearly 100 year existence (Price, 1985). This lack of confidence can be attributed to misconceptions include the following:

1) If reservoir seals leak, reservoirs will be depleted and of no value.
2) Any gas that leaked from a reservoir would migrate so slowly that bacteria in shallow sediments would oxidize hydrocarbons before they could be sampled.
3) There was no viable mechanism to explain how vertical migration from reservoir to the surface could possibly function.

The lack of understanding has limited industry acceptance. We are reminded that "...reflections were not even considered on a par with the divining rod, for at least that device had a background of tradition" (Rosaire and Adler, 1934) commenting on the state of the seismic business. This paper intends to replace misconceptions with understanding.

In spite of these limitations, the technology endured because of overwhelming empirical evidence that there is a mass transport connection between at least some oil and gas reservoirs and the water/sediment interface off-

[1]GeoFrontiers Corporation, 5130 Boyd Blvd, Suite A, Rowlett, Texas 75088, USA. E-mail: gary_rice@geofrontiers.com (corresponding author).

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shore or the land surface onshore. If such a connection exists and allows communication directly with reservoir fluids prior to drilling a well, that connection should be of tremendous value in petroleum exploration.

Although this paper lists only one author, pronouns such as we and our will appear throughout to emphasize technology through 100 years of contributions from hundreds of researchers. A small fraction of those contributors are referenced here.

Background

A thorough literature review of various vertical migration mechanisms is available in Price (1986) and needs not be repeated here. Davidson (1994) gives an excellent historical perspective. Klusman (1993) offers a very good overview of gas exploration technologies by summarizing hundreds of widely scattered literature references. A favored vertical migration mechanism in the early days was diffusion (Rosaire, 1940; Horvitz, 1949; Price, 1986, pp. 247–248; Krooss and Leythaeuser, 1996). Diffusion is a molecular process in which net transfer of mass always occurs from higher concentrations to lower concentrations. Hunt (1979) emphasizes that diffusion is not a viable process for moving petroleum gases from reservoirs to the surface in the quantities reported in the literature. Hunt (1979), quoting the work of Smith et al. (1971), reports diffusion calculations requiring 140 million years for methane to reach the surface from a 1740 m deep reservoir. Such meager flux rates of gases to the surface, constant gas evaporation to the atmosphere, and microbial degradation of hydrocarbons in the oxic zone (Davis, 1967) would not permit gases to accumulate in shallow soils or sediments in measurable amounts. No doubt diffusion occurs, but its nearly spherical dispersion and extremely slow rate make diffusion of little consequence in explaining mass transport to the surface. Diffusion is not a significant mechanism responsible for transport during vertical migration.

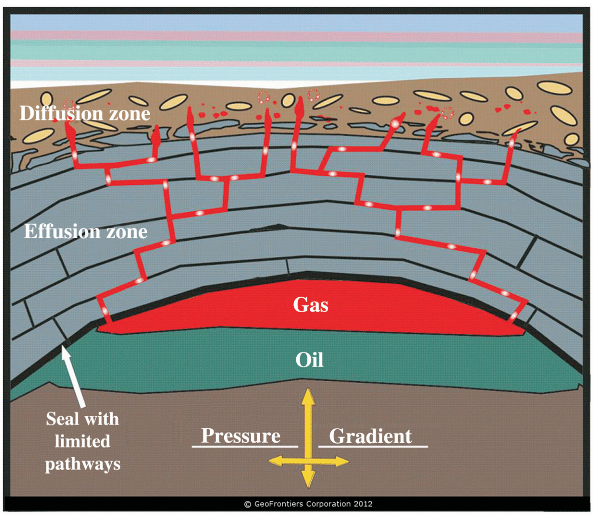

Figure 1. Illustration of buoyancy-driven vertical migration. The cartoon is for illustrative purposes only, is not to scale, and depicts a generic geologic cross section.

Methane migration in the subsurface has been described as driven by microbubbles by McElvain (1969). Microbubble transport has been a favored vertical migration vehicle for gases in the subsurface (Price, 1985, pp. 12, 56, 67). Although including buoyancy as a vertical migration mechanism, microbubbles tend to coalesce into more stable larger bubbles within relatively short times (Ushikubo et al., 2010). Brown (2000, p. 1785) concludes that bulk gas-phase migration would be much faster than microbubbles and that bulk gas-phase migration is the only vertical migration mechanism that could support the rapid vertical migration rates reported over reservoirs.

Hydrodynamic transport by groundwater has been suggested as a subsurface transport mechanism for gases (Hubbert, 1953). The solubility of paraffins in water is low, even considering pressures at reservoir depths, so dissolved gas transport would not be significant. Any proposed bubble mechanism could be affected by groundwater flow in areas where lateral groundwater flow is similar to vertical migration rates. However, as will be shown subsequently, vertical migration rates are thought to greatly exceed most groundwater flow rates so groundwater flow would cause minimal lateral movement of vertically migrating gases. Holysh and Tóth (1996) make convincing arguments that downward migrating groundwater could inhibit vertical gas migration in water recharge areas.

Theory

The need for a consolidated model to explain how reservoir fluids migrate to the surface has been recognized by Davidson (1982), Price (1986), and others. Finally, in the 1990s, the buoyancy theory gained traction. Buoyancy was thought to be important throughout the history of vertical migration as early as McDermott (1939). Hubbert (1953) recognizes that buoyancy affects the petroleum underground resulting in accumulations in stratigraphic highs. In a seminal paper, Arp (1992) describes a mathematical model for what he called effusive microseepage, which was based on the well-known Darcy's law. Klusman and Saeed (1996) use Darcy's law to describe upward migration from a reservoir to the top of the water table, air/sea interchange expressions for transfer to the gas phase in the vadose zone, and then Fick's second law to describe further migration to the surface. Arp (1992) and Klusman and Saeed (1996) model petroleum gas as migrating in the gas phase. This established buoyancy as the important mechanism in migration of gases from the reservoir to the surface. Gas in the gas phase below the water table is driven upward by buoyancy. Therefore, buoyancy is the force that makes vertical migration vertical.

The general idea of vertical migration is illustrated in Figure 1. In this case, gas escapes from the gas cap of an oil reservoir. The gas escapes and migrates in the gas phase. Gas in the gas phase below the water table exists as bubbles. Bubbles have buoyancy. Buoyancy is opposite gravity. Gravity pulls straight down. Buoyant forces are straight up. Buoyancy favors vertical migration in the absence of displacement forces. However, the many rock layers on the way to the surface alter the gas migration path as shown in Figure 1. Gas will migrate through the joints and bedding planes and other conduits of least resistance, but always in an updip direction. These migration routes are consistent with the observations of Jones and Burtell (1996). The case of oil will be treated later in this paper. Note that we are treating vertical migration as if it all occurs below the water table. Although this is true offshore, most land contains a vadose zone extending from the surface of the ground to the water table. Without water, buoyancy does not occur in the vadose zone. For most cases, we can ignore the vadose zone, which has much less thickness than the water table. Klusman and Saeed (1996), in a more complete model, include a separate treatment for the zone above the water table by a combination of diffusion and barometric pumping.

As depicted in Figure 1, gas can escape from a reservoir through the seal. It is important to remember that the rock is not the seal; the water in the rock is the seal. When the reservoir pressure exceeds the capillary pressure at any point in the seal, gas can escape. Gas will continue to escape until the reservoir pressure falls below the capillary entry pressure, water reenters the capillary pore spaces (imbibition), and the gas flow stops.

This seal action is illustrated in Figure 2, which shows approximate annual monitoring of a waterflood in West Texas described in Rice et al. (2002), which includes sample collection and background threshold determination used for all examples in his paper. Color contours are above background concentrations of interstitial ethane in ppm by volume. Below-background concentration areas are colored gray in Figure 2. Background thresholds were determined using multiple methods as described in Rice et al. (2002). Location K17 inside the blue oval was surrounded by high ethane concentrations before being drilled in 1989. In 1991, well K17 was depleted and the ethane concentrations surrounding the location were below the background. A waterflood was started during 1992 using well K17 for injection, which repressured the reservoir, and in 1993 ethane concentrations surrounding K17 returned to above the background again.

Before drilling in 1989, some parts of the reservoir seal were leaking sufficient quantities of gas to elevate ethane concentrations at the surface. During production, the reservoir pressure decreased below the capillary entry pressure and at least parts of the seal stopped leaking and the surface concentrations decreased again below the background (Underschultz, 2007). This dynamic process has been measured in a laboratory by Teige et al. (2005). Shortly after the waterflood started, the reservoir pressure increased above the capillary entry pressure and parts of the seal started leaking again. This is an example of the role that water plays in the sealing process in which water in the rock acts as a pressure-sensitive valve. Resealing (healing) has been documented by Brown (2003) and Schowalter (1979, p. 756).

Arp's (1992) treatment involved deriving an equation that expressed Darcy's law in terms that could be measured or easily estimated in natural systems. Equation 1, which is the heart of the Arp model, provided a way to calculate the migration velocity V:

$$V = \frac{k[(P_a - P_b) - \rho g L]}{\mu L}, \tag{1}$$

where V is the velocity, k is the permeability, P_a–P_b is the differential pressure, ρ is the density, μ is the dynamic viscosity, L is the length (vertical distance), and g is the gravitational constant.

When Arp (1992) replaces variables in equation 1 with typical real-world values, he calculates vertical

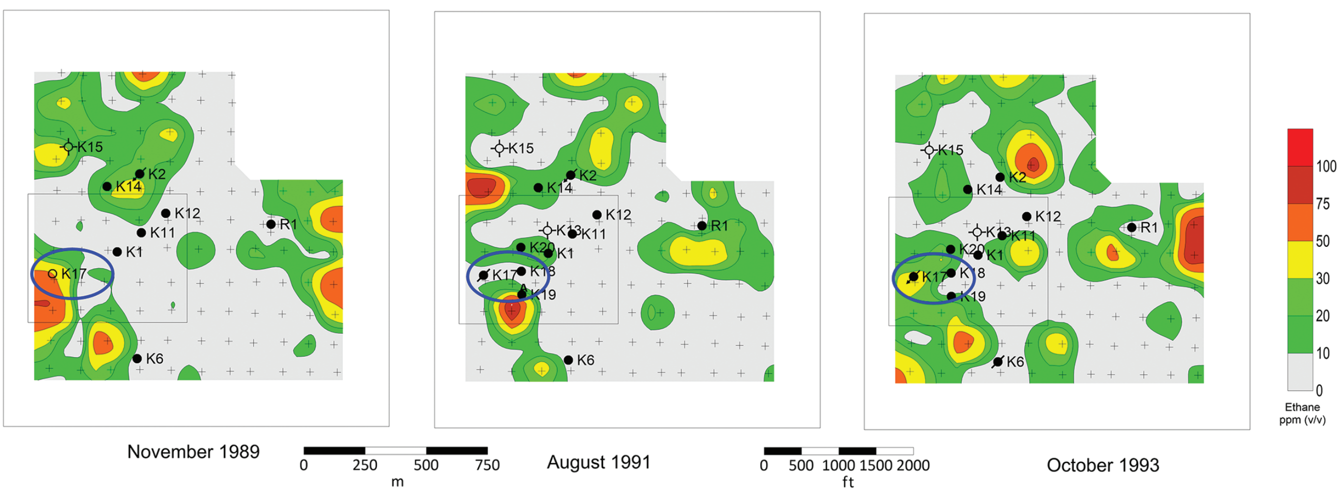

Figure 2. Time lapse of soil gas data at two year intervals from a West Texas waterflood modified from Figure 11 in Rice et al. (2002). See the reference for more details about sample collection and background threshold determination. The K17 well is inside the blue oval.

migration rates for gases on the order of 1 m/day or approximately 1000 ft/year. The implications of fast migration were immense. Relatively fast vertical migration rates introduced possibilities such as:

1) Surface hydrocarbon compositions could be near reservoir compositions due to the limited time for physical or biological degradation during migration. This has been found to be the case and has made possible surface geochemical methods that can readily forecast a dry hole or a reservoir containing oil, wet gas, or dry gas (Jones and Drozd, 1983).
2) Reservoir pressure changes due to production could be recorded in nearly real time.
3) With little time for lateral dispersion, gas surface expressions could portray spatially accurate images of reservoirs.

Table 1 lists vertical migration rates from the literature. All of the vertical migration rates in Table 1 are near the 1 m/day rate predicted by the Arp model in equation 1. The striking agreement between the calculated and actual vertical migration rates is our strongest evidence that the Arp model is the correct model. Note that artificially pressured gas storage reservoirs displayed higher migration rates than natural reservoirs, which are also consistent with the Arp model.

When we put reasonable values for density and viscosity of a gas into equation 1, we obtain the graph in Figure 3. The logarithm of the migration rate was plotted on the y-axis, and the logarithm of the fracture aperture was plotted on the x-axis. Equation 4, which expresses permeability in terms of the fracture aperture, replaced permeability in equation 1. Equation 4 was derived from the cubic law for fluid flow of Witherspoon et al. (1980), which can be written as

$$T = kA = \frac{wh^3}{12}, \tag{2}$$

where T is the transmissivity, k is the permeability in darcy, A is the fracture area, w is the fracture width, and h is the aperture.

Because $A = wh$, it follows that

$$k = \frac{h^2}{12} \tag{3}$$

and

$$k = 0.0844h^2, \tag{4}$$

where k is in darcy and h is in µm.

Arp (1992) calculates 1 m/day appears approximately in the center of the graph in Figure 3. The dashed portion of the plotted line signifies where boundary layers may interfere with laminar flow in fractures less than approximately 0.2 µm (Witherspoon et al., 1980). Figure 3 shows that gases can migrate at reasonable rates through submicron fractures. Similar graphs for related models appear in Brown (2000).

Vertical migration theories also address volume loss from petroleum reservoirs. Continual replenishment of petroleum hydrocarbons in the near surface requires continual migration out of petroleum reservoirs. How much reservoir gas is required to support measurable concentrations at the surface? These models can be used to calculate the required amounts. Arp (1992, p. 14) finds that 1 liter of methane from a reservoir can fill 1.3 million cubic meters of soil to a concentration of 1 ppm. Klusman et al. (1998) estimate methane flux above typical reservoirs at 4 mg/m^2/day.

Brown (2000) calculates vertical migration rates through fractures for a variety of models including a two-phase "bubbly water" theory. These and other vertical migration calculations are based on simplified models. We usually do not know fracture sizes, tortuosity, or roughness. Any of these models are approximations at best. In spite of their limitations, models

Table 1. Measured vertical migration rates — modified with permission from Schumacher and LeSchack (2006, p. 36).

References	Location	Rate (m/day)
Horvitz (1969)	Texas, Hastings Field	0.2–0.3
Coleman et al. (1977)	Illinois, gas storage	3
Araktingi et al. (1982)	Wyoming, gas storage	3
Arp (1992)	Wyoming, Patrick Draw Field	0.2–0.8
Jones and Burtell (1996)	Texas, gas storage	4
Rice et al. (2002)	Texas, waterflood	0.6–2

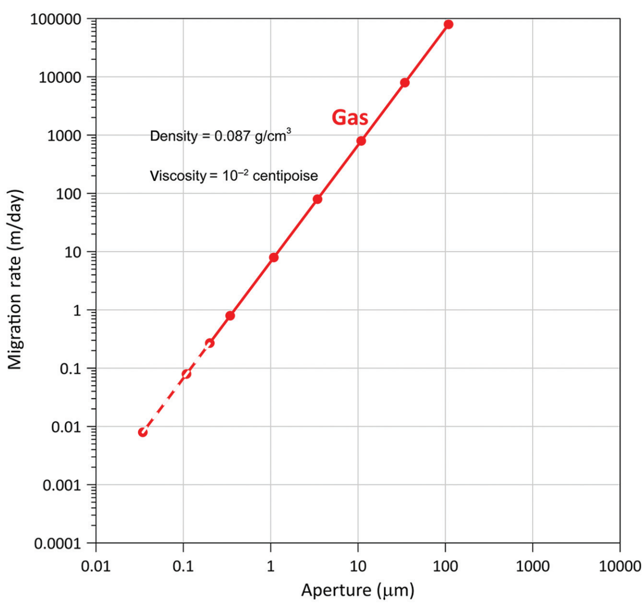

Figure 3. Gas migration rates. Data for curve were calculated from equation 1. The dashed portion of the gas curve denotes values where Darcy's law may not apply.

are valuable for helping understand how processes function and can be used to improve interpretation.

Therefore, we put aside any debate about the relative efficacy of the different models and try to identify how to use this information in petroleum exploration. First, we have to consider the case of oil. Do oil and gas migrate similarly or differently? Belt and Rice (1996) obtain evidence that oil and gas exhibit dissimilar patterns in shallow offshore samples, suggesting the two phases migrated at least somewhat independently.

Arp's equation (equation 1) was derived from Darcy's law as were most other equations describing flow of all types and directions through porous media. Darcy's law applies to fluids. Gases are fluids and liquids are fluids. The term "fluids" as used here is consistent with the definition in McCain (1990). Therefore, we extended the calculations in Figure 3 to include oil, and those results are shown in Figure 4 in which the gas plot and the oil plot resulted in parallel lines. These calculations are of limited utility for predicting migration rates because we almost never know the fracture apertures, fracture networks, or roughness in fracture systems, all of which influence migration rates.

However, the relative rates turned out to be of great significance in understanding the relationship between reservoirs at depth and their surface expressions of migrating hydrocarbons. The horizontal (x-axis) distance between the parallel lines in Figure 4 tells us that any given vertical migration rate (within limits) requires a fracture approximately 200 times larger to carry oil at the same rate as gas. The vertical separation between the parallel lines in Figure 4 tells us that any given fracture aperture can migrate gas approximately 40,000 times faster than oil.

As interesting as these results are, what do we do with this newfound information? The answer is simple. Let us assume that migration rates of 0.1 m/day are minimal for either gas or oil to migrate to the surface reasonably intact. At 0.1 m/day migration from a depth of 1500 m would require approximately 40 years. Gas in Figure 4 migrates at minimal rates through fractures as small as 0.1 μm. In contrast, oil would require a series of nominal 25 μm fractures to vertically migrate through 1500 m in approximately 40 years. Smaller fractures and/or lower API gravity oil would increase migration times, and the oil could be severely degraded before reaching the surface.

The bottom line for exploration applications is that gas can migrate up the smallest fractures whereas oil requires larger fractures or faults for successful migration to the surface. Tiny fractures are more ubiquitous than large fractures (Gong and Rossen, 2014). Therefore, gases can migrate to the surface in many places and tend to be pervasive over a reservoir or other strong source. Oil surface expressions can be expected to be focused above faults or large fractures. These migration mechanisms are consistent with the observations in Belt and Rice (1996). Similar offshore oil expressions from faults have been described by Kennicutt (2017). Faults, along with other surface anomalies, are a target for offshore oil seep sampling (Bernard and Abrams, 2019). Therefore, vertically migrated gas provides a surface expression from which petroleum reservoirs can be mapped. Oil primarily maps surface expressions of faults or fractures. The following examples illustrate both cases.

Practice

What happens when we try to apply the vertical migration theory to actual field situations? To find out, we will look at two field examples in Dickens County, Texas. Dickens County is in the northwestern part of Texas as depicted in the inset in Figure 5.

Many sampling techniques can collect samples and data that effectively measure the end results of vertical migration. Several background determining techniques can discriminate the background from above-background data. The optimum choice of these techniques depends on soil or sediment properties that vary place to place. This paper is about the vertical migration theory and how it is used in interpretation. Data acquisition should be appropriate for the area using methods known to work effectively. Therefore, data collection and data processing methods prior to mapping are not described in detail.

A partial local stratigraphic section is shown in Figure 6. Production in our areas of interest is from Tannehill sandstone and Croton limestone. Both are of Lower Permian age with typical production depths of 1350 m (4400 ft).

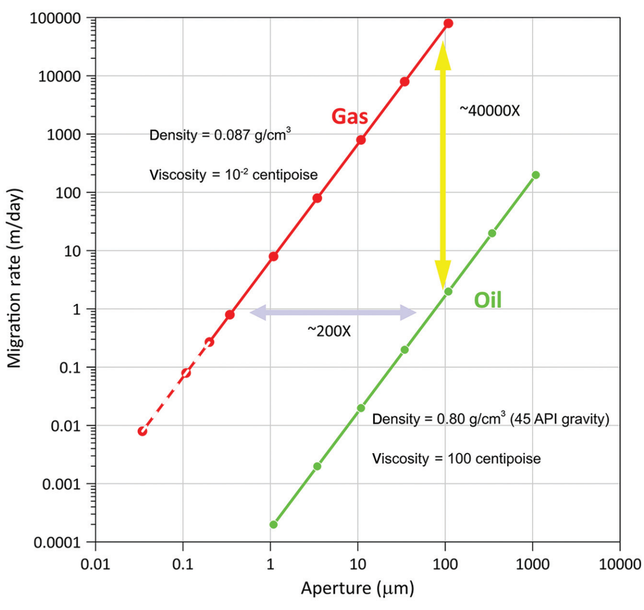

Figure 4. Oil and gas migration rates. The distances between the gas and oil curves predict that gas will migrate 40,000 times faster than oil in any given fracture size, and a 200 times larger fracture is required to migrate oil at the same rate as gas.

The Grantham Field was discovered in 1993 by geologists David Mowrey and Jim Gilbert. Field development was complicated due to unexpected structural elements that the vertical migration theory helped interpret.

A Grantham Field map shown in Figure 7 includes interstitial ethane geochemical exploration data in the gray and green shades. Contour concentration units are ppmv (parts per million by volume). The gray/green interface represents the background threshold determined using the probability plot method of Sinclair (1976). Determining the background threshold using probability plots and other methods is described in detail in Rice et al. (2002). Basically, probability plots include one axis on a probability scale that graphs normal distributions as straight lines. The value where two normal distributions overlap can be determined by the intersection of straight lines in data distributions graphed on probability scales. The probability plot in the lower left corner of Figure 7 shows the intersection of two linear areas marked with the dashed red lines at approximately 10 ppmv, which was chosen as the background threshold for the Grantham Field ethane data. Areas below the background concentration threshold are colored gray, whereas areas above the background thresholds are colored shades of green. Heavy black lines mark the estimated sandstone channel edges. The dashed blue lines designate the water/oil interface. Note that the subsurface geology information in Figure 7 was solely determined from wells after drilling. There was no seismic data prior to drilling. The north–south white strip through the geochemical data was due to that portion of the surface being inaccessible when the geochemical measurements were made.

Although this was a successful program, the four dry holes begged for an explanation. Dry hole HRS 1 in the southeast corner of Figure 7 was in the channel and probably was in a migration pathway instead of a productive reservoir. The three dry holes just north of the channel missed the reservoir sandstone despite being in above-background ethane concentrations. The gas concentration lobes sticking out to the north along the channel were not productive. In addition, the surface expressions of the entire channel appeared to have been shifted north because some successful wells were close to, or just off of, the southern edge of the above-background data. The dip in the area is known to be to the west as the Eastern Shelf falls deeper into the Midland Basin. The vertical migration theory predicts gases should migrate in an updip direction, so a little offset to the east was expected. But how can we explain the apparent offset to the north?

After most of the drilling had been completed, there was sufficient subsurface data to discover that the mystery had a strange twist. The 3D structure rendering in Figure 8 depicts the sandstone channel with the x- and y-dimensions approximately to scale with the thickness exaggerated. Green represents oil, and blue represents water where visible along the channel edges.

The channel has structural components that were probably necessary for effective trapping. The thin ribbon of sandstone was tilted down to the south, presumably

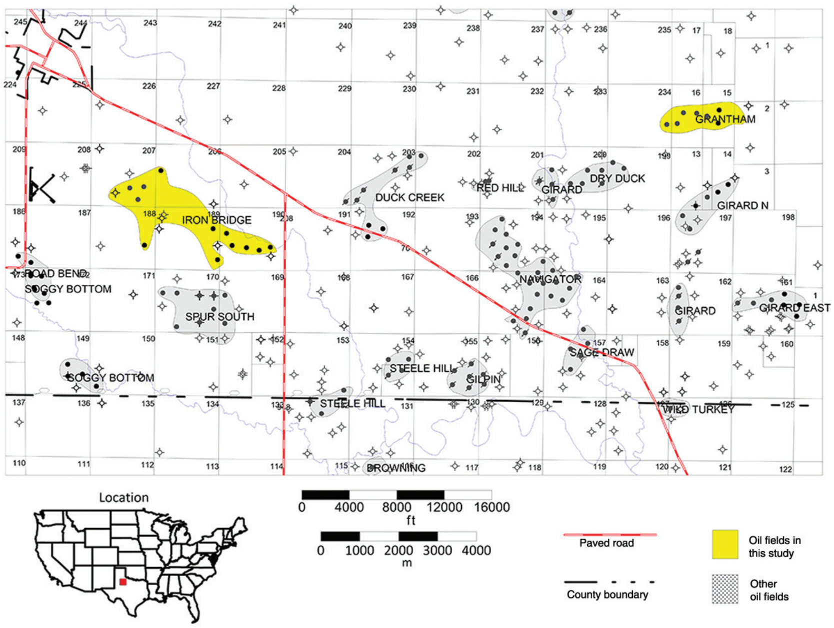

Figure 5. The Grantham and Iron Bridge Field locations, Dickens County, Texas, USA. Wells are from the Railroad Commission of Texas data.

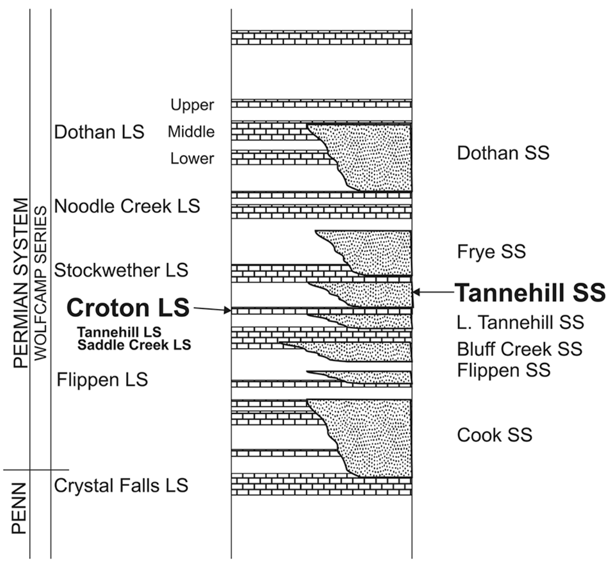

Figure 6. Partial local stratigraphic section adapted from Blommer (1977). The Tannehill sandstone and Croton limestone stratigraphic units are highlighted.

through differential compaction or other nonuniform sediment compression. This southerly local dip was exactly what could cause the mysterious lateral gas offsets to the north as shown in Figure 7. The vertical migration theory handled even this somewhat complex case and taught us to look for unexpected patterns near surface expression edges, which might indicate minor lateral migration in directions other than opposite the regional dip. The Grantham Field's 10 wells at 1340 m (4400 ft) depth have produced more than 500 MBO (thousands barrels of oil).

The Iron Bridge Field shown in Figure 9 is located approximately 12 km (7 mi) west of Grantham Field but has very different geology. David Mowrey and James Gilbert were the geologists who discovered and developed the field for Woods Operating. The Iron Bridge complex includes three fields producing from Croton limestone, Tannehill limestone, and Tannehill sandstone. Those stratigraphic intervals are shown in Figure 6. Iron Bridge has totaled approximately 1.1 MMBO (millions barrels of oil) from 1350 m (4400 ft) depth.

The petroleum gas map in Figure 9 shows interstitial ethane gas as measured in the shallow subsurface. Ethane concentrations in green shades, which represent the above-background concentrations, were mostly from the Croton limestone formation. A probability plot for determining the ethane background threshold of 3 ppm is shown in the lower left corner of Figure 9. The oil wells in Figure 9 drilled in the background (gray) areas produced mostly from the Tannehill sandstone, which had a lower background threshold than the surrounding limestone fields.

Similarly, concentrations of petroleum liquids that migrated to the surface are shown in Figure 10. The three-ring aromatic hydrocarbons in Figure 10 were measured by a laboratory fluorescence technique similar to that described by Hebert (1984). The dashed line in Figure 10 connects two pronounced right-angle bends in local drainage, which were interpreted as evidence for a southwest–northeast-trending fault. As predicted by the vertical migration theory, oil-related three-ring aromatic hydrocarbons occurred in elevated concentrations along the axis

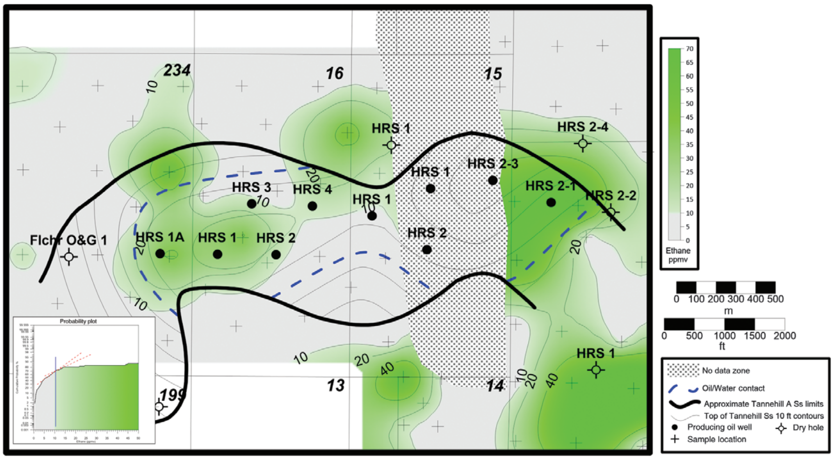

Figure 7. The Grantham Field with the geochem, geology, and wells. See Figure 5 for field location. The probability plot in the lower left corner shows background threshold calculation. The colors in the probability plot match filled contours showing the soil gas ethane concentrations.

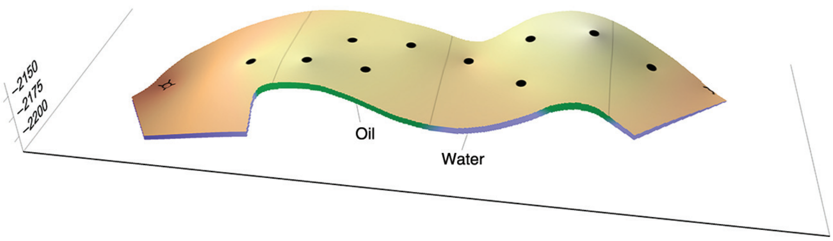

Figure 8. Grantham Tannehill channel 3D perspective view. The well identification and well symbol definitions are available in Figure 7. The figure was made from the top and bottom of Tannehill sandstone from well logs. The vertical axis is exaggerated and is labeled in feet below mean sea level.

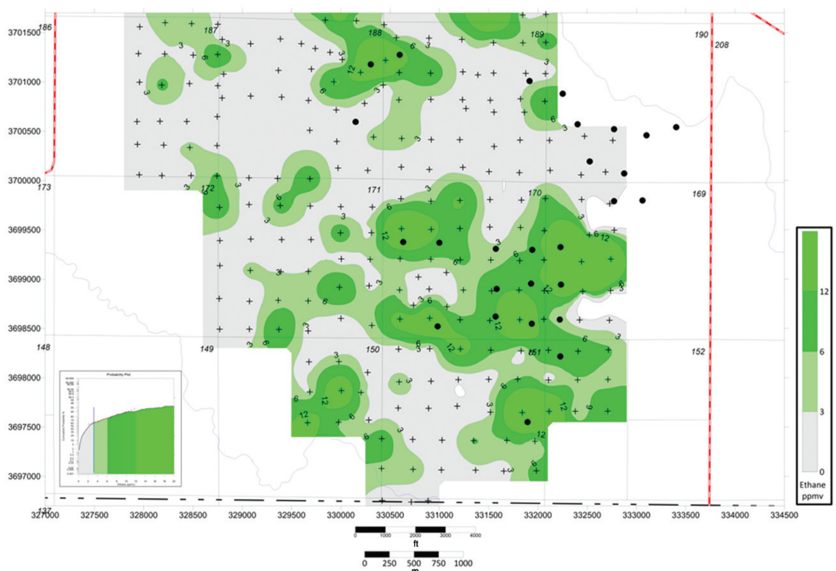

Figure 9. The Iron Bridge Field ethane concentration map. The well symbol definitions are available in Figure 7. The sample locations are marked with "+." The ethane background threshold is 3 ppm as shown in the probability plot in the lower left corner of the map.

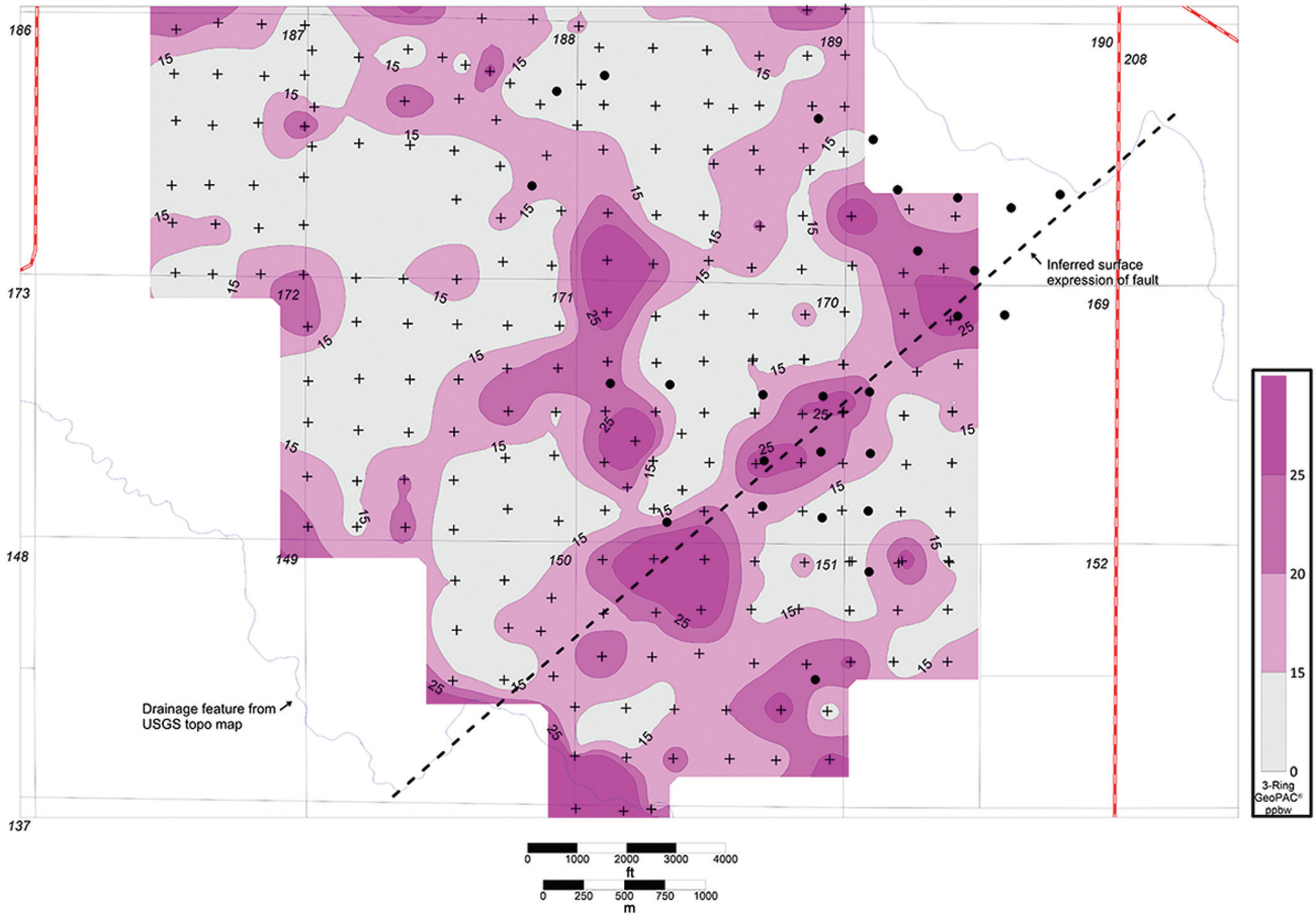

Figure 10. The Iron Bridge Field three-ring GeoPAC aromatic hydrocarbon concentration. The contour units are ppbw. The well symbols and other features are the same as shown in Figure 7. The map covers the same area as the map in Figure 9.

of this fault. This surface expression of the structure was important for exploitation of the limestone reservoir. Wells in proximity to the fault benefited from the increased permeability near the fault strike.

Evidence for petroleum liquids preferentially migrating up large fractures or faults transformed the way that we interpret liquid surface expressions. Now, liquid migration to the surface indicates a large fracture conducting liquids. The geomorphic data in Figure 10 provided additional information to infer, with some confidence, that major liquid migration was conducted by a fault. In the absence of seismic data, this inferred structural information was important early in the development of the Iron Bridge Field.

The gases in Figure 9 provided an approximate outline of the field extent before discovery, and the liquids mapped in Figure 10 provided complementary structural information. It is beyond the scope of this paper to examine the value of having samples of reservoir fluids prior to drilling, but it is obvious that such samples contain important predrilling reservoir information.

Conclusion

Versions of the vertical migration theory described in this paper have been field tested for approximately 20 years. In a few cases in which the theory appeared to not be correct, further information revealed that the vertical migration theory was exactly right as we saw in the Grantham Field case. The buoyancy theory of vertical migration has existed for more than 80 years. Relatively recent mathematical models offered ways to calculate migration rates that have been verified through observations. Migration pathways predicted by the vertical migration theory also have been verified by studying the spatial relationships between reservoirs and their surface expression of gases.

The misconceptions stated in the “Introduction” section can now be addressed:

1) Although reservoir seals have to leak for there to be vertical migration of hydrocarbons to the near surface, the required leakage rates are too small to deplete most reservoirs.
2) Gas vertical migration rates on the order of 1 m/day are too fast for groundwater to contribute significant lateral offsets and leave too little time for bacteria to consume significant amounts of migrating hydrocarbons.
3) Vertical migration models based on the buoyancy theory of vertical migration offer the most viable

mechanism to explain migration from the reservoir to the surface.

The recent extension of the vertical migration theory to include liquids solved a long-time industry dilemma by explaining why gas surface patterns and liquid surface patterns were different even when originating from the same reservoir. The vertical migration theory explained that not only should these different phases have different surface patterns, but also why they are different and how to interpret those differences. That information increased our knowledge of vertical migration and therefore our ability to take advantage of the complementary nature of gas and liquid migration patterns to better understand petroleum systems. This reservoir information can be available before the drilling rig bit touches soil or sediment.

Suggestions for future studies

Certainly, this work represents only a start toward understanding the complex interrelated processes that constitute vertical migration. Every phase of the processes can be improved. Determining background thresholds is one area. Better measurement processes, including greater use of remote sensing as indirect indication of present or past vertical migration, could lower costs and make application more commonplace. The technology will benefit from ongoing studies into petroleum migration of which the tertiary migration described here is a part.

Reservoir seals remain mysterious. Next to the presence of hydrocarbons, the reservoir seal is perhaps the most important component of a petroleum reservoir. The role of seals remains an uncertain part of the vertical migration theory. More experimental studies are needed building on Teige et al. (2005) to sort out which seal models are viable.

Application and refinement of the concepts by additional scientists are needed to demonstrate the efficacy of this theory. As more case histories are published, we will be able to determine how, or if, this vertical migration theory endures.

Acknowledgments

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Data and materials availability

Data associated with this research are confidential and cannot be released.

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Biography and photograph of the author are not available.