

# Chapter 2

## The Basics of Traps, Seals, Reservoirs and Shows

### Contents

2.1	The Petroleum System: Primary, Secondary Migration, and 'Unconventional' Exploration .....	48
2.2	Traps, Porosity, Spill Points and Seals .....	49
2.2.1	You Don't Need to Know Why a Trap Exists If You Can Figure Out Where It Is from the Test and Show Data .....	57
2.3	Assessing Risk: Thinking About Seals, Structure and Reservoir Quality .....	60
2.3.1	Making the Right Maps .....	63
2.3.2	Some Thoughts on Stratigraphic Traps .....	66
2.4	The Basics of Rock Properties, Free Water Levels, Buoyancy Pressure and Hydrocarbon Shows .....	71
2.4.1	Porosity .....	71
2.4.2	Buoyancy Pressure (Pb), Pressure vs. Depth Plots, Free Water Levels and Water Saturation.....	74
2.4.3	Water and Hydrocarbon Saturations and Height Above Free Water Plots .....	76
2.4.4	Oil-Water Contacts, Top of Transition Zones vs. FWL and Relative Permeability .....	77
2.4.5	Permeability .....	80
2.4.6	Waste Zones .....	80
2.4.7	Oil Show Types.....	82
2.4.8	Kerogen-Rich Source Rocks.....	85
2.4.9	Thinking Like a Molecule .....	86
2.5	Summary .....	86
	References.....	87

**Abstract** Hydrocarbon traps form when reservoirs receive a charge from hydrocarbons migrating from a source rock at a time when effective seals and trap geometries are in place. Exploration that focuses on traps along a migration route is termed conventional exploration. Conventional exploration deals with understanding secondary migration. In the last 20 years, there has been an increasing focus on unconventional exploration, which focuses on the hydrocarbons remaining in the source

rock itself. The generation of oil and gas within a source rock is termed primary migration.

There are a multitude of different trap geometries, all of which rely on the concept of closure. Closure is defined as where structural contours along a migration route terminate into seals. Defining the geometry of the seals and the migration route requires understanding rock properties, burial history and pressure changes. Trap size is controlled by the capacity of the weakest seal as well as the amount of hydrocarbons available to reach the trap. If buoyancy pressure at the top of the trap exceeds the weakest seal capacity, the trap leaks updip.

Porosity in the rock provides the space to hold hydrocarbons, but it is the distribution of the pore throats connecting the porosity system that is a primary control on water saturation and seal capacity and the oil-water contact vs. the free water level. Residual hydrocarbon shows are always below the free water level and must be distinguished from continuous phase shows, which are above it, and in the trap.

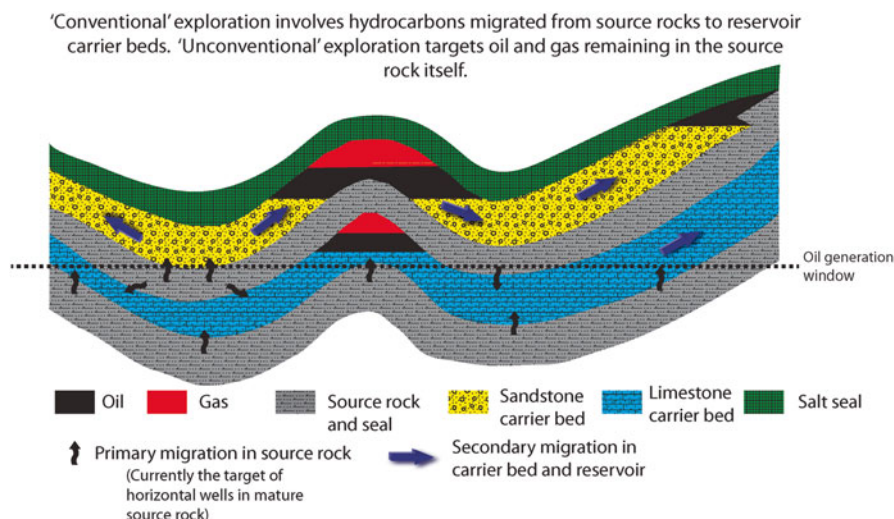
## **2.1 The Petroleum System: Primary, Secondary Migration, and ‘Unconventional’ Exploration**

A petroleum system consists of four major elements: (1) a kerogen rich source rock which has expelled hydrocarbons during burial and heating; (2) an effective migration pathway out of the source rock; (3) seals to trap the oil and gas on a migration pathway; and (4) reservoirs to hold the oil and gas. The process of oil and gas generation in the source rock is termed primary migration. Oil and gas molecules in primary migration move only short distances and stay within the source beds themselves. If these hydrocarbons enter a permeable layer of rock they will migrate updip until reaching a trap or dissipating at the surface. This process of migrating out of the source rocks themselves into permeable carrier beds is termed secondary migration (Fig. 2.1). Exploration efforts now focus on both types of systems, exploiting not only the oil left in the kerogen-rich source rocks, but that which has been trapped in permeable beds along secondary migration pathways.

There are many different kinds of oil and gas traps formed during secondary migration, but they all have the basics in common: a favorable set of seal geometries along a migration pathway. Exploration plays are grossly lumped as targeting (1) conventional oil and gas traps and (2) unconventional traps.

‘Unconventionals’ are rapidly becoming a type of ‘conventional’ exploration as an increasing success rate is beginning to redefine the term as the industry practices in the ‘unconventionals’ become more routine. Throughout this book, however, the term ‘unconventional’ refers to exploration targeting the primary migration paths in the source rocks. The term ‘unconventional’ also includes coal gas deposits and some types of tight gas sands, where the trap itself is poorly defined but the reservoir producible.

The source rocks generally require hydraulic fracturing to produce and the plays are confined to mature oil and gas maturation windows where the oil and gas remains trapped in the source rock. One of the most important drivers of

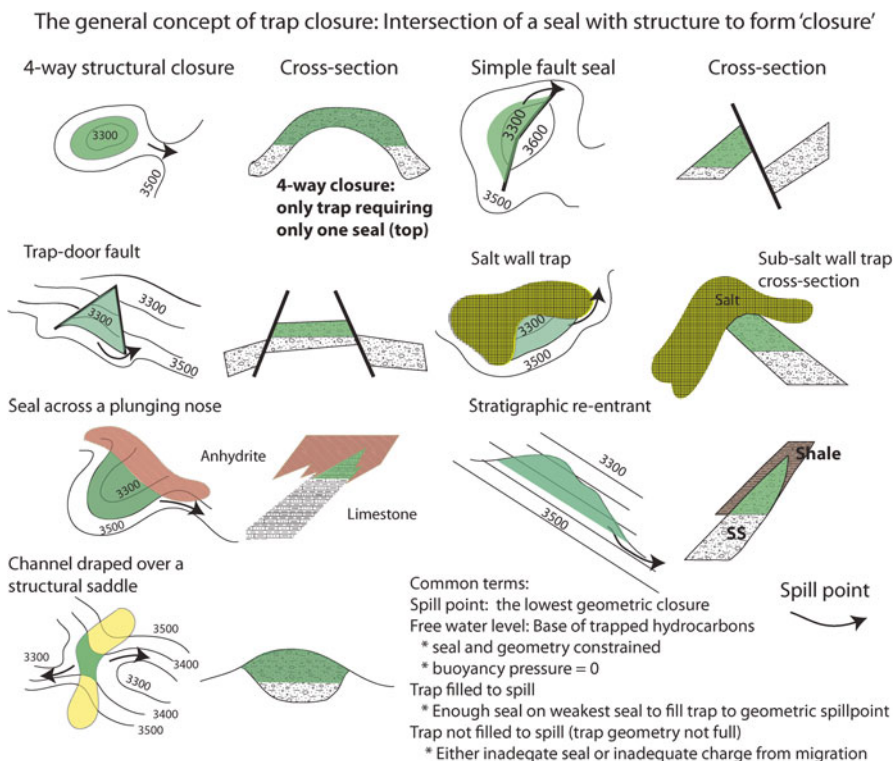


**Fig. 2.1** Conventional vs. unconventional traps and migration. Modified from England et al. (1991)

unconventional source rock plays is simply the fact that large amounts of oil remain trapped in the kerogen and never access a secondary migration pathway. Hence, for any given basin, the bulk of the generated hydrocarbons often is remaining in the source rocks themselves. The term 'conventional exploration' refers to identifying secondary migration pathways into reservoirs in structural, stratigraphic or hydrodynamic traps, where migration has occurred from the source rock laterally or vertically into traps. Oil and gas show analysis can help find both primary and secondary migration pathways. When drilling through source rocks, for instance, drill bit friction frequently generates hydrocarbons in the source rock, and oil and gas shows are picked up in tools on the rigs, frequently with mud gas increases. Likewise, migration pathways are frequently recognized from shows in cuttings, particularly underneath regional seals along carrier beds, or in fluid inclusions in the rocks. We'll cover much of this in more detail later.

## 2.2 Traps, Porosity, Spill Points and Seals

There are a large number of potential trap types. Figure 2.2 illustrates common trap types and the concept of trap closure and spill point. Hydrocarbon traps require a combination of migration, reservoir and seal geometries which form closed containers to hold hydrocarbons. Reservoir rocks are most commonly sandstones or carbonates, but can be fractured granites, volcanics or even shales (unconventionals). In short, reservoirs exist wherever there is a porosity system in the rock with enough room to hold hydrocarbon molecules. Porosity is the percentage void space in a rock.



**Fig. 2.2** General trap types and closure concepts

If not present, there is no room for oil, gas or water. Porosity is discussed in more detail later in this chapter, but can be thought of as analogous to the inside of a house, where the rooms are pores. Porosity voids are connected to each other by pore-throats, which are analogous to doors between rooms. Porosity and pore throat size plays a large role in determining if a formation can hold hydrocarbons. The larger the pore throats (doors), the better connected are the pores (the rooms) and the easier it is to get oil and gas into the reservoir. The mechanics of how this works has nothing to do with the size of oil and gas molecules relative to the pore throats (which are much, much larger than hydrocarbon molecules), but by the capillary pressure properties of the fluid and rock systems, a topic dealt with in detail in Chap. 5.

Seals, by contrast, are low porosity or micro-porous pore throats that migrating hydrocarbons cannot move through and hence become trapped if geometries are right. Seals come in a wide variety of lithologies, and are most commonly thought of as forming in shales, siltstones, tight carbonates or evaporites and salts. However, seals can form wherever there is a reduction in pore space geometry or energy sufficient to overcome the forces driving migration. In Chaps. 4 and 5, we cover quantification of seal capacity from rock and pressure data and ways to recognize seals from changes in oil and gas shows, drilling information or recoveries from tests.

The term ‘closure’ was developed early on from making structural contours maps of surface anticlines. When the contours ‘closed’ in a circle or oval around a high, the trap was considered ‘closed’. With time, the term closure was broadened to encompass any contour that intersects a seal and is closed on both sides (Fig. 2.2). Most traps require geometric combinations of multiple seals, typically, top, lateral and bottom seals. The point where the contours fail to close is termed the ‘spill point’. Pre-drill, most prospects are evaluated with the assumption there has been adequate oil charge and migration from the basin. This may not always be the case, but if all the seals work and there is an adequate volume of oil reaching the trap, it will be ‘filled to spill’ and the down dip limit of the accumulation will usually conform to a structural level at spill point.

The most commonly sought after and prolific traps are structural four-way closures, where reservoirs are folded into domes or closed anticlines where the accumulation is controlled dominantly by the top seal capacity vs. the structural closure relief. In these kinds of traps, multiple ‘stacked pays’ are possible, with many different oil/water contacts and even fluid types stratified vertically. They are by far the easiest traps to map seismically and lowest risk to drill if on a well-defined migration pathway or within the oil and gas window where interbedded source, reservoir and seal are present inside the trap.

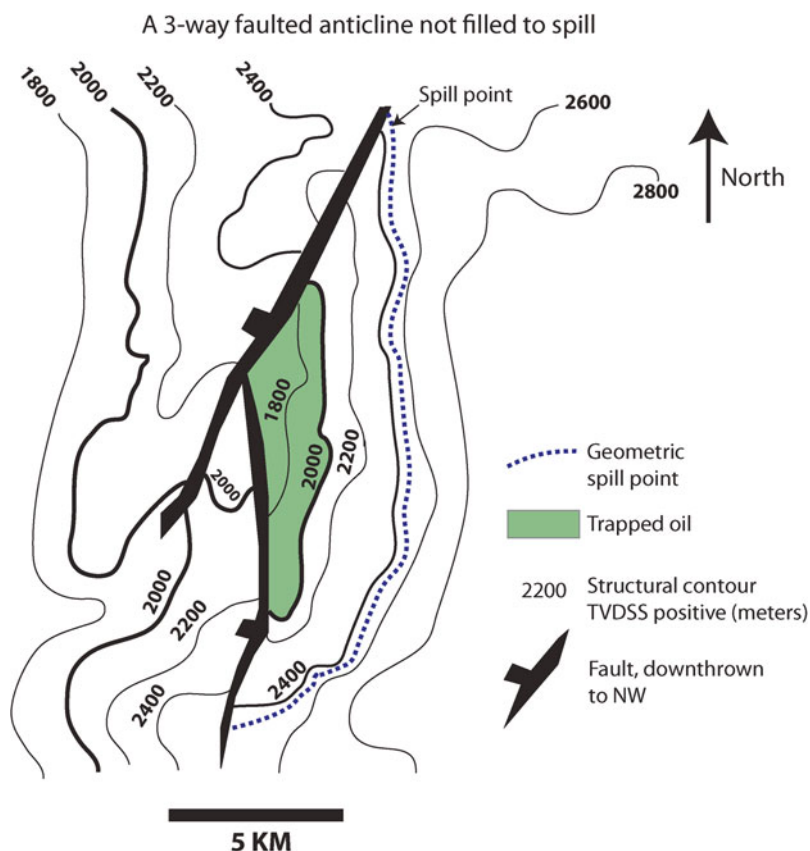
Sub-salt or salt-wall closures are also fairly easy to recognize, but require accurate seismic processing and depth conversion to image properly, a process that can be difficult and expensive. In these cases, simple maps of the structural contours going into the fault are sufficient to quickly see the ‘closure’ and the trap. Traps related to complex salt domes and detached salt nappes also hold very large, ‘stacked pay’ reserves. Salt and other evaporites form outstanding seals and can hold very long columns. Much of the world’s deep-water drilling today focuses on ‘sub-salt’ accumulations where reservoirs are folded or faulted into salt walls, under salt overhangs or under completely detached nappes. These are attractive prospects, but require special acquisition and processing techniques of seismic to image.

The closure itself, however, may not define the size of the accumulation. Column height is defined as the true vertical height that any trap can hold. If the trap is filled completely, it is termed ‘filled to spill’. Column height can be an indirect measure of seal capacity. In a trap with a proven 500 m column, it is a given that the minimum seal capacity on the weakest seal, for that hydrocarbon-water system, is 500 m.

Many structures, however, are not filled to spill, as one or more seals have less capacity to hold a column than the maximum closure geometry. These traps are ‘filled to seal capacity’. However, another reason for not being filled to spill point is simply that an inadequate volume of oil or gas has reached the trap along the migration route. These kinds of accumulations are ‘charge limited’ traps.

But if charge risk is eliminated, one is still faced with risk on seal capacity. Seal failure may well be one of the biggest reasons for drilling dry holes in any basin. Seal capacity is generally thought of in terms of meters or feet of column height.

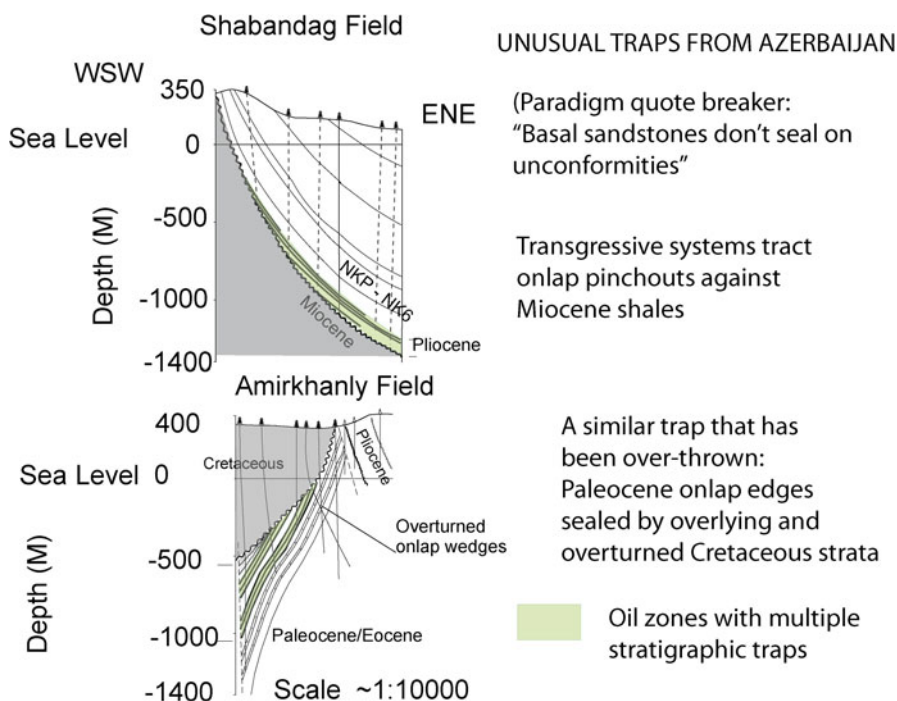
An example of a structure not filled to its geometric spill point is shown in Fig. 2.3. The geometric spill, if the faults seal, would be at about 2400 m TVDSS (true vertical depth subsea, in this case, in positive numbers, so 2400 is the lowest).



**Fig. 2.3** A structure not filled to spill. The cause may be insufficient charge from migrating oil or fault seal capacity, in this case limited to 20 m to oil on one or both of the faults

However, the accumulation is filled only to 200 m. In this case, if there is adequate charge along a migration pathway, the only explanation for the trap not being filled to spill is either top seal or fault seal leakage. With only a 200 m column, the seal capacity on the weakest seal (whatever that is) must be 200 m to the fluid-water system encountered.

Some excellent seals can be in thin layers and the thickness of the seal is not important unless there are faults present which might offset the seal. Hence, thicker seals are desirable in faulted terrain, but thin seals can be highly effective. As an example (Fig. 2.4), shows outstanding seals in Miocene and Cretaceous shales. One industry ‘paradigm’ I was taught early in my career is that basal sandstones on unconformities are migration pathways, and cannot form seals. Shabandag Field in Azerbaijan is one of thousands of exceptions to that ‘rule’, with transgressive shoreline facies sealed by sub-cropping Miocene shales and top and lateral seals within the individual shoreline reservoirs layers. Column heights are substantial. In some



**Fig. 2.4** Unusually effective shale seals holding long columns of oil in steep and complex structural settings. Original figures courtesy of Akif Narimanov, SOCAR Company, Baku, Azerbaijan

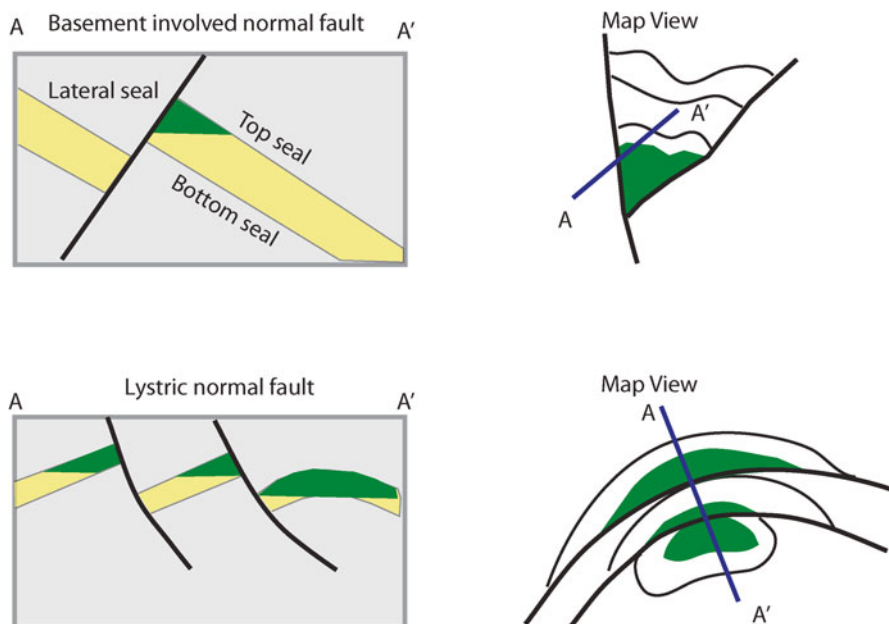
cases (Amirkhanly Field, Fig. 2.4), the onlap traps have even been overturned and still hold a substantial column.

Even subtle diagenetic changes can set up significant seals. Along subaerial unconformities for example, paleosols can completely occlude porosity systems and set up substantial traps. Several examples in the Lower Cretaceous Muddy Formation of Wyoming have been documented by Martinsen et al. (1994).

Another key point to remember is that for any given rock type, the seal capacity changes with the type of fluid. This is because gas is much lighter than oil and thus more buoyant in the sub-surface. Buoyancy pressure builds up as a trap fills, with the top of the trap having the highest buoyancy pressure. In contrast, at the base of the trap, or (FWL), the buoyancy pressure is zero. The higher the buoyancy pressure, the more likely it is to cause seal failure.

Conceptually, this is like floating in a pool. If you want to sink, you exhale air and reduce your body density until you drop to a point that you can no longer go down. In an oil or gas field, that point of equilibrium is the free water level. If you add weights to become denser, you sink even further. So at the crest of a trap with 500 m of closure, a gas field may actually have so much buoyancy pressure that it breaks the weakest seal at a 300 m column height. That trap, even if it has 500 m of geometric closure, will never accumulate more than 300 m of hydrocarbons. However, in a heavy oil fluid-water sys-





**Fig. 2.5** Typical fault traps. As in stratigraphic traps, multiple seals are needed to trap hydrocarbons. Trap A requires a total of 4–6 seals and only one seal failure will mean no trap at all. Modified from Biddle and Weilchowsky (1994). Reprinted by permission of the AAPG, whose further permission is required for further use

tem in the same trap, where buoyancy pressure is less due to density differences of the hydrocarbons and water, the trap could easily be filled to geometric spill point.

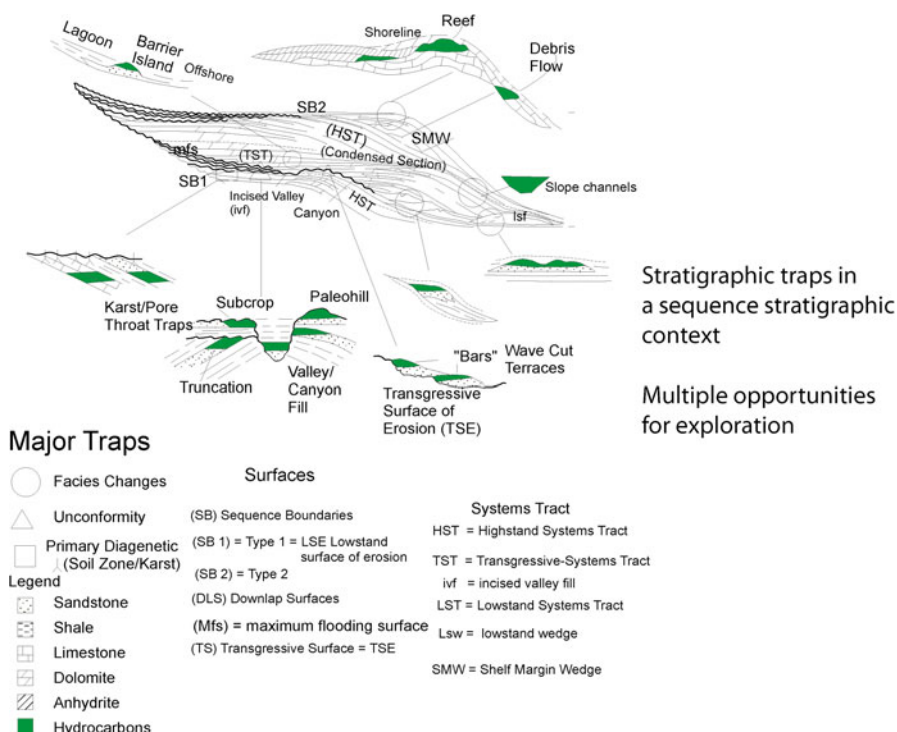
Faulted anticlines and fault traps (Fig. 2.5) are another fairly easy trap type to identify, but carry additional risk beyond a four-way closure. Where four-way closures only require an effective top seal, fault and all other traps require multiple seals. Fault traps are attractive as, like four-way closures, many stacked pays can be built up on both sides of the fault, creating large accumulations with multiple hydrocarbon columns and oil or gas-water contacts. Fault seal failure is common, however, either by faults leaking directly through open fractures or from juxtaposition of reservoir against reservoir across the fault, leading to leakage.

Combination traps refer to structures where the stratigraphic overprint is strong, perhaps even dominant, like a facies change occurring over a plunging nose or channel draped over a structural saddle.

Stratigraphic traps occur where reservoir facies pinch out laterally updip into seals. These traps form in a wide variety of depositional settings (Dolson et al. 1999). Figure 2.6 illustrates common primary depositional geometries that can set up regional traps in passive margin continental settings.

As in fault traps, multiple seals are required, but unlike fault traps, there are seldom 'stacked pays' or multiple combinations of seal and reservoir yielding large aggregate reserves. Most stratigraphic traps involve a single reservoir layer, and are thus not as attractive as fault and four-way closures. Stratigraphic traps, while sta-



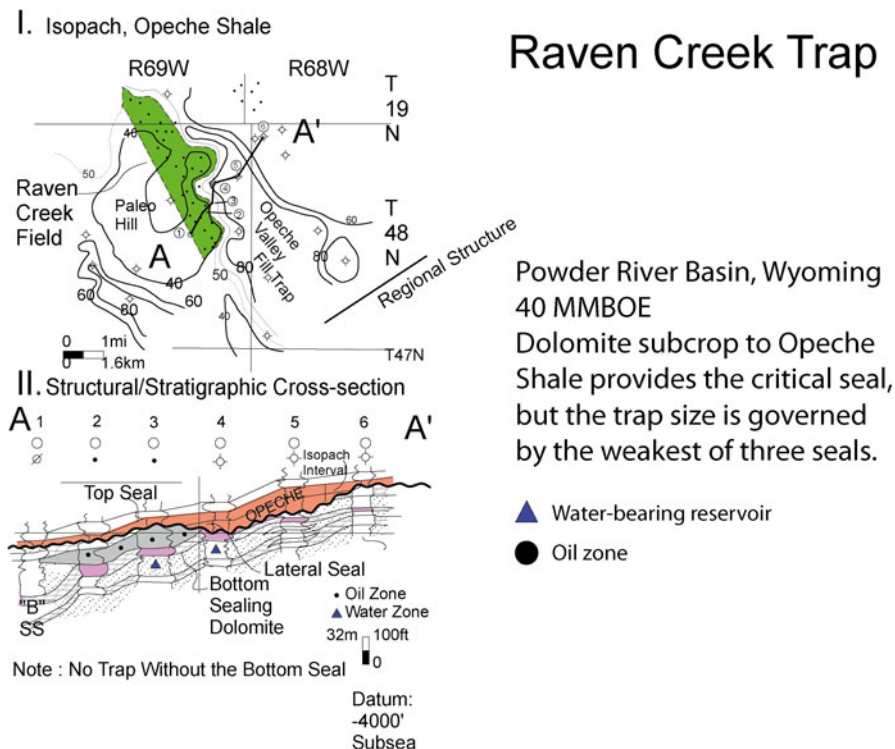


**Fig. 2.6** Common depositional systems that form stratigraphic traps. Modified from Dolson et al. (1999). Reprinted by permission of the AAPG, whose further permission is required for further use

tistically containing fewer giant fields, are perhaps the most common trap type globally, and occur in virtually every hydrocarbon province.

Figure 2.7 shows a typical stratigraphic trap caused by erosion beneath a regional unconformity. A paleo-hill is flanked to the northeast and south by erosional lows noted by an isopach thick of the Opeche Shale. These thick trends are part of paleo-river systems, likely desert valleys, which were filled largely with red shales during later transgressions, forming fairly good seals. Ultimately, the Opeche Shale buried the reservoir interval completely, forming both top and lateral seals. The sandstone reservoir interval, once part of a desert dune field, is underlain by a tight dolomite, which forms another seal. Later structural tilting and oil migration trapped oil stratigraphically as the proper seal geometries were set up. As in all stratigraphic traps, all three of these seals need to work together to preserve and trap the oil.

Giant stratigraphic traps (fields defined as >100 million barrels recoverable) are possible, often in large angular unconformity traps like Prudhoe Bay (Specht et al. 1987) or East Texas Field (Wescott 1994), but giant stratigraphic trap fields have been found in virtually every type of depositional system. In some cases, stratigraphic traps are not even recognized until structures are drilled up and anomalous oil or gas shows and production occurring below closure levels persist, telling the interpreter that 'all is not what it seems to be'.



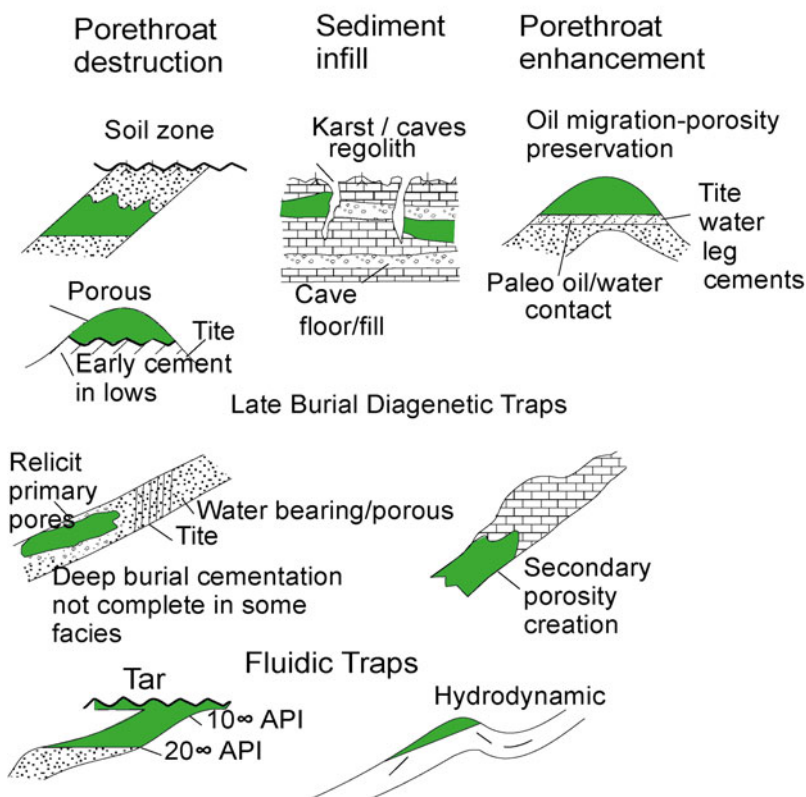
**Fig. 2.7** A typical stratigraphic trap. As in faults, top, lateral and bottom seals must be present. The column height is controlled by the trap geometry as well as the sealing capacity of the weakest seal. From Dolson et al. (1999). Reprinted by permission of the AAPG, whose further permission is required for further use

Variations on stratigraphic traps are diagenetically modified traps or fluidic traps (Fig. 2.8).

Diagenetic traps form where cements alter pore networks and set up internal seals which are often difficult to detect without quantifying shows and seals in the system from logs, cores, pressures or other data. These kinds of traps are plentiful and can be prolific, reinforcing the concept that not all seals are in shales, salt or other obvious lithologies. Many seals are simply a change in pore-throat geometry. An example is shown in Fig. 2.9, where anhydrite cements plug an otherwise porous dolomite, forming a lateral seal.

Fluidic and hydrodynamics traps are also common (Vincelette et al. 1999), and frequently go unrecognized. Fluidic traps are caused by changes in fluid density or excess pressure. Many fields have commercial light oil preserved down dip of tar mats at the surface, where the fluid change itself sets up part of the seal to the lighter hydrocarbons. Hydrodynamic traps occur where water flow is present, both in the shallow and deep basins, and the pressure differential, or head, pushes the oil and gas into flank positions on the trap (Fig. 2.10). This topic is covered in detail in Chap. 4.

## Early, Near-Surface Diagenetic Traps



**Fig. 2.8** Diagenetic traps. From Dolson et al. (1999). Reprinted by permission of the AAPG, whose further permission is required for further use

These traps are often overlooked, especially in over-pressured basins. Many traps may remain to be found where structures have been tested at the crest to find only short columns when the real 'prize' is off the flank due to hydrodynamic tilting.

### 2.2.1 *You Don't Need to Know Why a Trap Exists If You Can Figure Out Where It Is from the Test and Show Data*

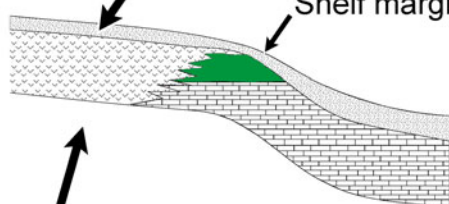
Some traps are difficult to define and only found through a careful examination of oil and gas shows. A good example are 'basin centered' gas accumulations, which occur in traps downdip of water bearing zones in areas of no obvious structural or stratigraphic closure. A good example is the giant Wattenberg Field in Colorado (Fig. 2.11).

**Fig. 2.9** A diagenetically modified dolomite lateral seal caused by anhydritic cements. Carbonate seals, in particular, can be complex, requiring careful analysis of test and show data to identify seals not obvious from well log alone. From Dolson et al. (1999). Reprinted by the permission of AAPG, whose further permission is required for further use

### Glorieta Dolomite, Lynn Co., Texas

Overlying anhydritic siltstone  
forms a top seal

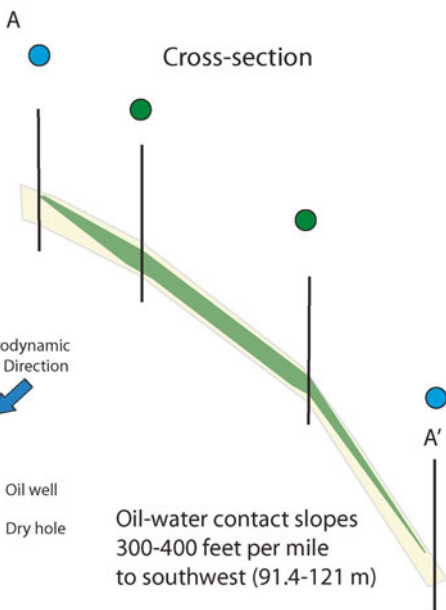
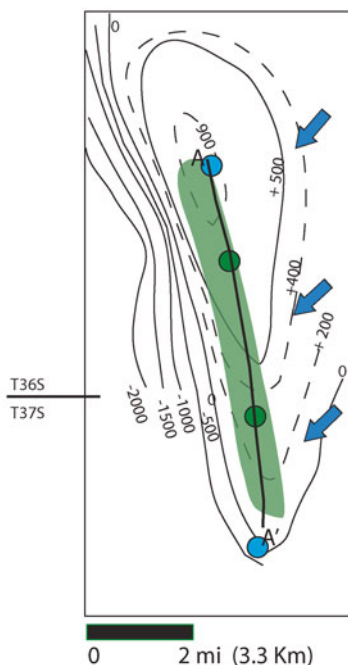
Shelf margin



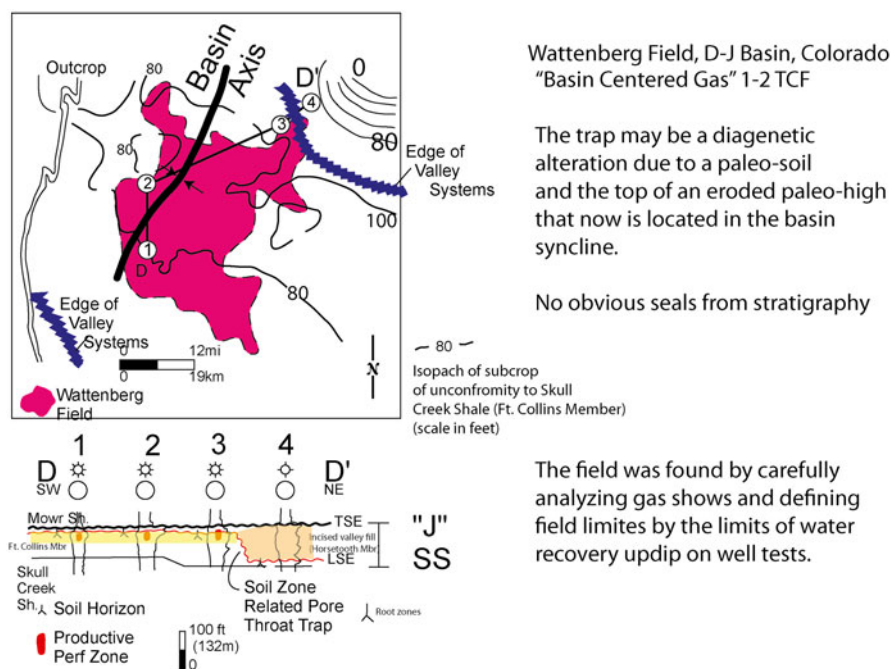
Anhydrite cements plug  
porous shelf dolomite early in  
diagenesis, thereby forming a lateral seal;

## A Hydrodynamic Trap: Upper Valley Field, Utah

Structure map: top of reservoir



**Fig. 2.10** A hydrodynamic trap. Modified from Vincelette et al. (1999)



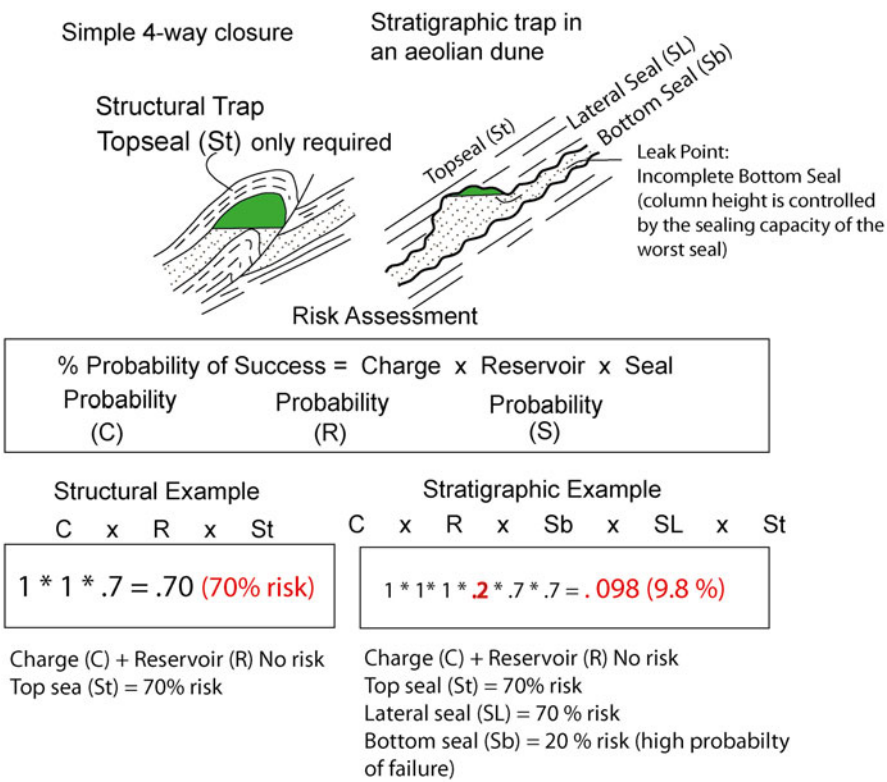
**Fig. 2.11** A 'basin centered' gas accumulation found from careful show analysis. No obvious trap could be recognized from stratigraphic or structural data alone. The trap may be related to paleosol development at the top of a 'buried hill' flanked by porous and permeable incised valley networks, but sealed by diagenetic pore-throat plugging along the unconformity surface. TSE refers to a 'transgressive surface of erosion' and LSE to a 'lowstand surface of erosion. Modified from Weimer et al. (1986)

The field was discovered in 1970 by R. A. "Pete" Matuszczak, a geologist with Amoco Production Company who noticed that over a dozen wells in the bottom of the Denver Basin had indications of moveable gas from tests, mud-logs or shows in low porosity Lower Cretaceous sandstones. He made a map of fluid recoveries from wells around the area and noticed that the amount of water recovered on dry holes steadily decreased toward the basin center. Without understanding the cause (which is still under debate), he drew a line on the map where he saw no evidence of moveable water, only tight sandstones with gas saturations. He speculated that perhaps hydraulic fracturing could be used to make these wells economic and proposed to management that a giant gas field lay almost under the Denver office with a market access to one million people along the Front Range of Colorado. Initially, management was more than a little skeptical as he couldn't explain the trap or how fortuitous it might be to have the building sitting on top of a giant field others had drilled through and walked away from. As a result, he was continually denied funds to test his idea. Eventually, he wore management down, got his permission to drill a well and 'the rest is history', with the discovery well proving his concept. The field continues to produce 40 years later. This is a superb example of why understanding oil and gas shows is an important part of looking for oil where others have missed it.

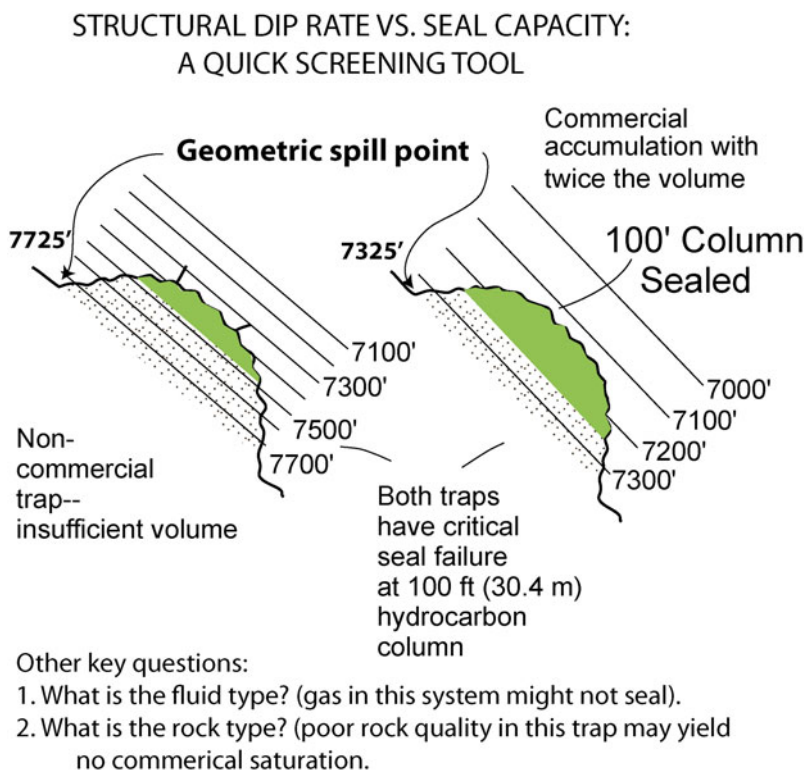
### 2.3 Assessing Risk: Thinking About Seals, Structure and Reservoir Quality

In all exploratory prospects, quantitative assessment of the seal is essential. In traps where there is no limit to charge from migrating hydrocarbons, the column height will be determined by the weakest seal. There is no exception to this rule. Significantly higher risks are encountered when dealing with multiple seals. Consider the case shown below in Fig. 2.12.

Pre-drill, the four-way structural trap prospect has been given a 70 % probability of the top seal working. Well offset information shows good reservoir and charged structures eliminating risk of any other factors. In this case, the pre-drill four-way prospect has a 70 % chance of success. In a stratigraphic paleo aeolian dune trap, in contrast, the trap needs a top, lateral and bottom seal to work. Even if charge and reservoir are certain, substantially more risk is present. An isopach or structure map of the overlying top seal may show closure of the top of the buried hill, but if the







**Fig. 2.13** Screening tools and things to think about. Structural dip rate vs. seal capacity of the weakest seal. This trap example is not 'filled to spill' but, rather, 'filled to seal capacity of the weakest seal'. Reprinted by the permission of the AAPG, whose further permission is required for further use

bottom seal has only a 20 % probability of success and top and lateral seals 70 % probability of success, the prospect will have only a 10 % probability of working. So, having a 'closure' at only one seal level is not enough.

Fault seals work the same way. Countless dry structures have been drilled on three-way fault closures where the fault juxtaposition failed to place a seal across the fault or within the fault zone and the subsequent wells were dry. Pre-drill assessment of fault or stratigraphic seal capacity and risks are essential to adequately evaluate a prospect pre-drill.

In addition, the structural relief within closure must be looked at early to assess how good seals must be to hold the accumulation. In Chaps. 4 and 5, this is addressed in more detail, but thinking about structural relief and fluid type is key to pre-drill assessment. A simple screening criteria is simply a qualitative understanding of the column height vs. trap geometry. In the example of Fig. 2.13, a stratigraphic re-entrant trap typical in a meandering fluvial channel is shown against two different regional structural dip rates. Even though the geometry of the trap is the same, the



## All rocks are not created equal



A. Heavily stained 'super perm' coarse-grained Tertiary fluvial sandstone, India. Porosity > 20%, permeability > 1000 md



B. Spotty stain in low permeability Jurassic tidal channel sandstone, Russia. Porosity 10-15%, permeability 5-30 md



C. No stain in micro-porous Jurassic tidal flat sandstone, Russia. Porosity 7-10%, permeability < 1 md. Even on a 100 meter column of oil, this rock acts like a seal

**Fig. 2.14** Some rocks require significant column heights and buoyancy pressure to fill with commercial hydrocarbons. The sandstone shown in (a) is the highest quality reservoir and heavily stained. Only spotty stain is recorded in much tighter rock (b) and virtually no stain in the micro-porous rock (c)

structural spills differ due to the structural dip rate. Neither trap is filled to geometric spill due to seal limitations of 100' capacity on the weakest seal. However, the lower structural dip rate case will have a lot more oil trapped because it covers a larger area.

Another key question is fluid type. A seal that can hold a 100 ft (32.8 m) gas column might easily be capable of holding a 500 ft (152 m) oil column. The traps shown in Fig. 2.13, if they had a 100' (32 m) seal capacity for gas, might hold 500' (152 m) or more of column if oil. In a more dense fluid like heavy oil, they would be filled to spill point. Fluid density differences play a big role in seal capacity and gas, with its lighter density, is harder to seal than oil. The mechanics of this are detailed more in Chap. 5 and in the next section. In gas plays in particular, there are wide ranges of potential densities and seal capacity for each type of hydrocarbon-water system can change accordingly (see Table 2.2 for density variations by fluid phase).

When evaluating traps, the geometric spill point should initially be treated as the maximum possible trap size. Minimum trap size might be determined by your best guess at seal capacity on the weakest seal. When presenting a prospect, you need to show both scenarios so your funders or managers understand what kind of risk they are facing. Your economic analysis will be based on both 'risked and un-risked' volumes, so the 'upside' is clear but so are the risks. In most cases, the economic decisions will be made on a portfolio basis of prospects or the significance of the wells as a potential play opener. Risked volumes pre-drill will play a big role in that decision making.

Complicating this further, a commercial trap may not be possible in a 100 m column trap, if the rock properties aren't right in the reservoir. Reservoir quality can vary substantially by rock type and also vary rapidly laterally and vertically within a trap. An example of variable reservoir quality and saturation are is shown in Fig. 2.14. Oil stain in these rocks are substantially different, reflecting in part how difficult it is to get oil into the pore spaces. Figure 2.14a is a heavily stained channel sandstone with outstanding porosity and permeability. This rock is fully saturated with oil. In contrast, the other two rocks are considerably poorer reservoirs. The fine-grained sandstone in Fig. 2.14c has virtually no oil in it, despite being inside a substantial trap. It simply is too tight to contain hydrocarbons for the amount of closure and oil-water system the trap is in.

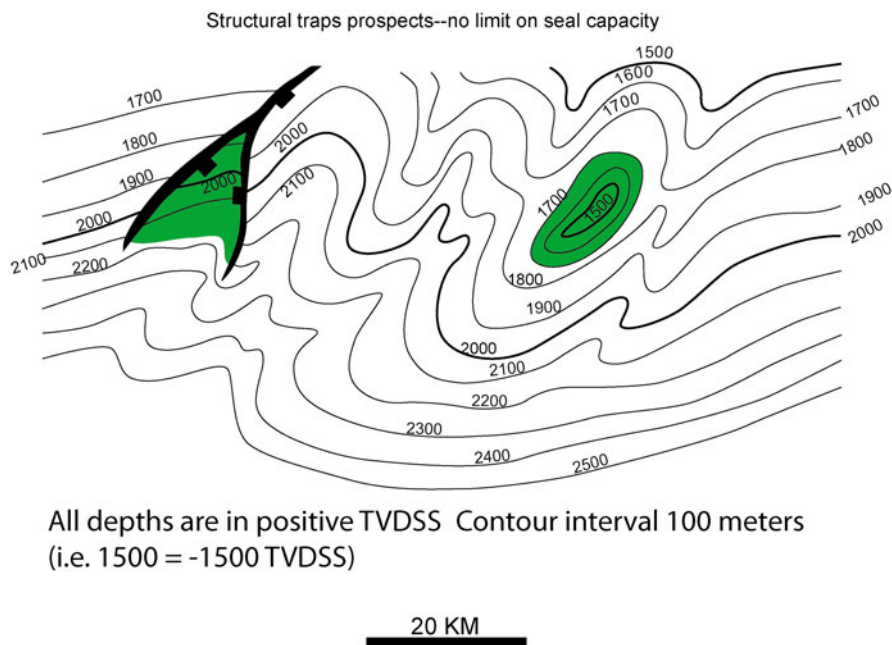
Chapter 5 covers quantifying rock properties in detail and ways to assess oil and gas saturation vs. column height. A trap with a 50 m column may be commercial in a good reservoir, but uneconomic or even unable to produce any oil or gas at all if it is a poor reservoir.

In this case, a trap with 50 m of closure may look like a great prospect, but will fail if the reservoir is poor quality. Many small traps have been drilled which fail economically for this reason alone.

Surprisingly, this is where the opportunity lies in dry hole post-appraisal for many explorers. Companies frequently abandon a disappointing well without the proper post-appraisal as to the implications for other prospects. For example, a 50 m trap closure might be targeting a fluvial channel sandstone. When it is drilled, the well tests only the tight, poor quality levee deposits adjacent the channel. Some oil and gas saturations are found, but not enough and the well is abandoned. Years later, another geoscientist thinks about that dry hole differently. The presence of oil means a trap and that means a column of oil. He decides that if he can find a better reservoir within that trap and column, he can find commercial oil. The geoscientist recommends a 3D seismic survey and the seismic imaging reveals the elusive and highly permeable channel sandstone. A subsequent well is drilled next to the old dry hole and flows commercial oil. This is not an uncommon occurrence, but rather, a good result that can come from carefully thinking through oil shows and saturations in old dry holes.

### ***2.3.1 Making the Right Maps***

It is one thing to understand rock properties and saturations, but quite another to make the right map. Consider the dilemma of stratigraphic and hydrodynamic traps. Without the right map, they aren't even apparent! These maps are more difficult and time-consuming to make than structure maps. The easiest thing to do with seismic and well logs is to make a simple structure map. While proper fault geometries are difficult to get right until you have 3D seismic, you can do pretty good work with faults on 2D seismic if you are careful to quality control your map with basic contour balancing rules (Tearpock and Bischke 2003). However, if you stop at the structure map, you will be limited in the number of prospects you can find.



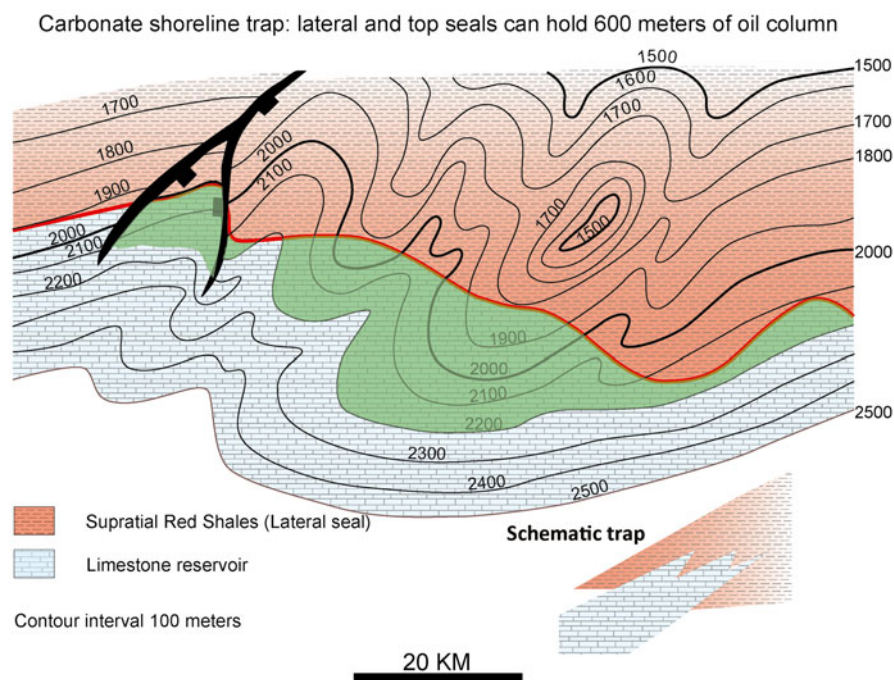
**Fig. 2.15** Structure map on a top-seal with prospects filled to spill

For argument's sake, for example, let's assume you have a perfect structure map with faults (Fig. 2.15). Assuming unlimited seal capacity and traps filled to geometric spill point, two basic prospects show up (1) a four-way closure (2) a down-thrown fault trap.

These two prospects will be relatively easy to obtain funding for if you only make this map and do not take into consideration where the reservoirs and seals are.

In Fig. 2.16, a facies map constrained by seismic and wells is overlain on the same structural map. The map helps you visualize this depositional system and begin to quantify seals. This map, however, may also have errors, but it is the best you can do with the data you have. So assume it is right. A red shale and anhydrite supratidal shoreline is updip of, and inter-fingers with, a porous limestone facies downdip. Your view of the area now changes. The structural four-way will be a dry hole with no reservoir. If the fault trap is drilled too far updip, it will not find reservoir and will be a dry hole. If the seal capacity is unlimited on the top and lateral seals, a giant stratigraphic trap can occur downdip of the four-way closure, with the trap filled to geometric spill point. The contour at 2200 m marks the free water level and spill point. The column height is from 1800 m at the highest point on the trap to 2200 m at the base, or 400 m.

In this simplified scenario, if there are no complex reservoir changes or faults to disrupt fluid continuity, the trap at one end will have the same production response with time as the trap at the other end. This is actually unusual in nature, but pressure

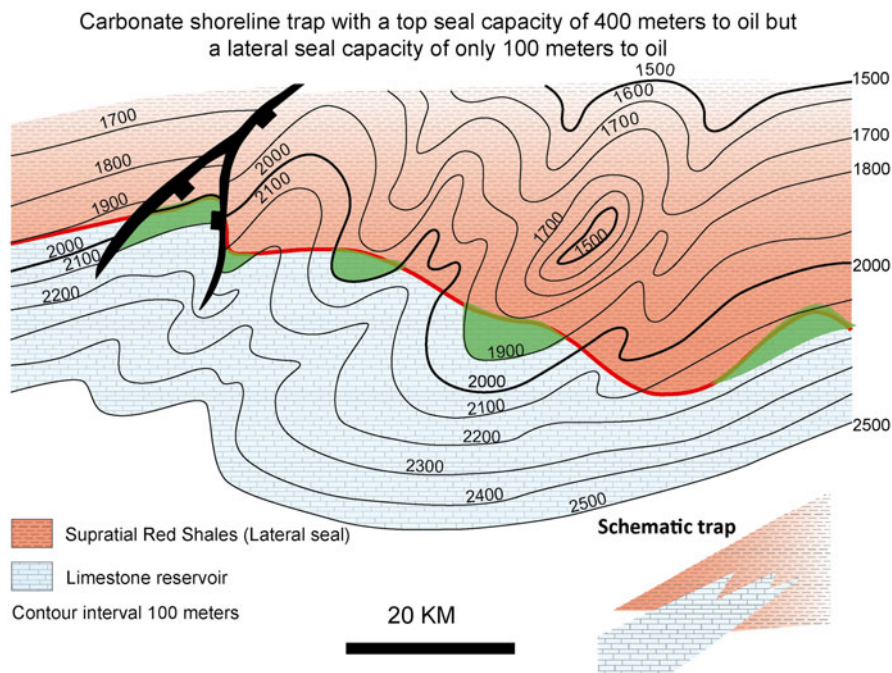


**Fig. 2.16** Carbonate shoreline trap map filled to spill

across that broad area would draw down evenly as the field is produced, and the base of the trap, or 'free water level' would be the same across that broad area.

This scenario of large stratigraphic traps downdip of dry structures has been proven over and over globally. To find these fields you often have to understand your dry holes and have outstanding facies maps built from both seismic, core and well logs. Before the advent of high quality 3D seismic, such traps were found by innovative mapping of the updip seal geometries to match to the oil and gas recoveries or shows in dry holes. It is an art, and remains so today, but with better tools to refine that geometry. In some cases, fields like this were found downdip of dry holes which had penetrated tight rocks with oil or gas shows that were near the top of the trap in uneconomic reservoirs called 'waste zones' (Schowalter and Hess 1982). Drilling downdip into the better reservoirs was the key.

Some of the best examples are in Permian carbonates of West Texas (Ward et al. 1986). The Permian Slaughter-Levelland Field, for example, took over 40 years to be recognized for its true size. Wells in poor reservoir in the updip 'waste zone' of the trap had small recoveries of oil and had been off-set updip for years into every increasingly poor reservoir. The real prize lay downdip in porous dolomites that had commercial saturations. Initially, the trap was thought to be made of separate pools of oil, one named the Slaughter Field and the other the Levelland Field. Over time, these and other separate pools were proven to be part of a multi-billion barrel giant



**Fig. 2.17** Same trap geometry as Fig. 2.16, but with the weakest seal capable of holding only 100 m of oil. This trap is filled only to seal capacity, not geometric spill points

field complex. Recognizing the trap from simple well log correlations was not enough.

Now, consider the case where the same structural geometry exists but introduce a leaky seal in the shoreline facies and limit the seal capacity to 100 m to oil (Fig. 2.17).

In this case, the trap consists of 4–5 separate pools, each of which would be under a different pressure regime and different ‘free water’ levels and oil/water contacts. Spill point will be 100 m from the top of any trap geometry set up by the regional seal. All of these pools would be easy to miss! Just as importantly, none of the wells in these pools would be in pressure continuity with one another. They would all act as separate traps, which they are.

### 2.3.2 Some Thoughts on Stratigraphic Traps

In 1989, I participated in a study at Amoco Production Company in subtle or stratigraphic trap exploration. We had recognized that a number of giant stratigraphic traps had been found by much smaller companies in the Rocky Mountains and Mid-continent. Amoco staff had never recognized the potential, and we were asked to assess our technical strategies and determine why we had missed these and other opportunities.



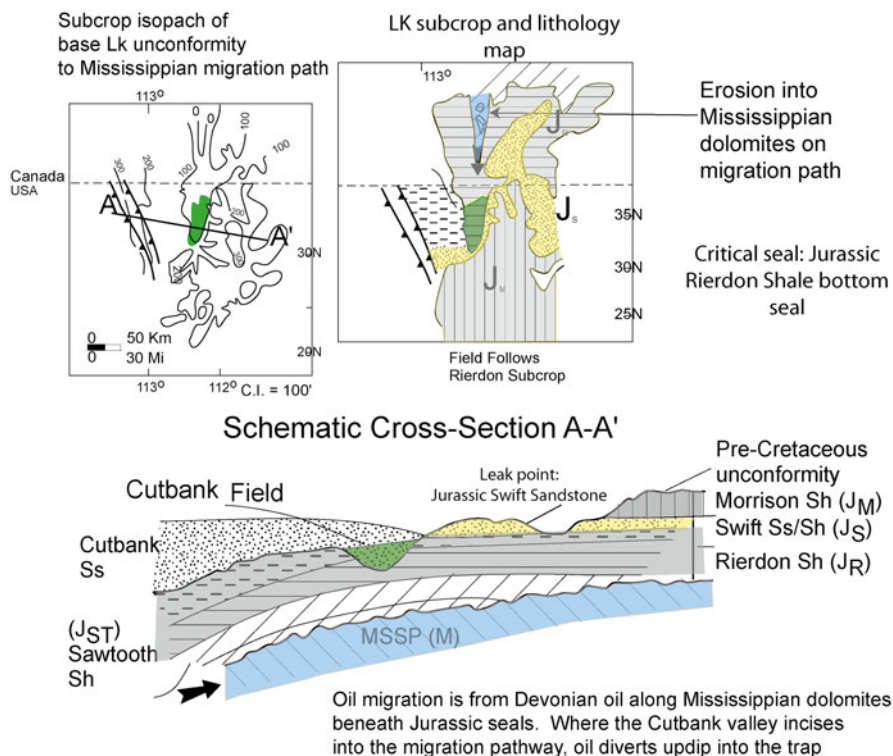
Looking at over 300 stratigraphic traps world-wide, we found that only about 10 % of the stratigraphic traps were ‘giants’ — traps which contained over 100 million barrels of oil. Four major reasons for this are (1) single story pay zones (2) high probability of seal failure from the weakest seal (3) seal geometries which made for small closures (4) poor reservoir quality on small traps that made for poor accumulations. I believe the single story pay and seal failures, however, are the dominant reason for the large number of smaller pools vs. good anticlinal, fault and salt-related traps.

In the last decade, a number of giant stratigraphic traps have been found, usually by smaller companies with highly experienced staff, simply by building the proper facies maps, understanding oil and gas shows and deliberately looking for them. Many are in deep water turbidite fan and channel facies. Just two examples are the Jubilee Field in offshore Ghana, West Africa (Jewell 2011) and the Buzzard Field in the North Sea (Editors 2005; Ray et al. 2010).

Another spectacular example of using dry hole information to prove a working petroleum system and then focus on the reservoirs and combination traps was the recent opening of oil discoveries in the Falkland Islands (Richards 2012; Saucier 2014). Interestingly, Shell had drilled a number of dry holes which proved a working petroleum system, but not viable reservoir. After dropping the acreage, the smaller company came in and found the reservoirs and the combination and stratigraphic traps that made the blocks commercial. All of these newer discoveries were found using 3D seismic, which, under the right circumstances, can image the reservoir and seals much more accurately than can be envisioned from 2D seismic or well control alone. As a result, these plays are finally increasingly easy to make.

Another key statistic was that the average time to recognize a giant stratigraphic trap in a mature basin province was up to 11 years! I suspect that number is lower now, with 3D seismic, but perhaps not in some basins where the coverage is still dominantly 2D seismic. But in older wells or mature basins, where 3D was not used in the exploration process, many stratigraphic traps were actually drilled through and plugged without recognizing the significance of the oil and gas shows, perhaps because only tight reservoirs with shows were found.

Good facies and stratigraphic trap maps take time to make but are important, if for no other reason than many stratigraphic traps develop on the flanks of structural closures or plunging anticlinal noses. The crests of these features will almost always be targeted first, and may thus miss the reservoir. This is common because many of these structures, during deposition of the reservoirs facies, are already structurally high and facies belts like incised valleys and non-marine and deep water channel systems deflect around the paleo-highs during deposition, setting up flank traps. Good examples from Russia are documented in West Siberia Jurassic reservoirs (Dolson et al. 2014). Thus, many early wells penetrate the structural crest of a feature only to find sealing facies or waste zone wells (like overbank siltstones and crevasse splays in non-marine channel siltstones). Tight reservoirs with oil shows may well mean a trap has been discovered, sometimes with a substantial column, but the well may be abandoned as dry since the reservoir might not produce any



**Fig. 2.18** Cutbank Field, Montana. Summarized from Dolson et al. (1993). Migration pathways from Devonian to Mississippian and into the Lower Cretaceous sandstones were unraveled with oil and gas shows mapping and geochemical ties of oils to source rock

commercial oil, or flow an oil at all. Many of these old dry holes are not offset for years, and may actually be one location away from a prolific well with a different reservoir facies within the trap.

Another good example of a stratigraphic trap is the giant Cutbank Field of Montana (Dolson et al. 1993; Dolson and Piombino 1994). This trap is an incised valley fill trap located on the flank of a large structural dome but out of structural closure (Fig. 2.18). Oil and gas show data, plus subsurface geochemical signatures of Lower Cretaceous oil typed to a Devonian source rock, illustrate complex vertical and lateral migration from source to trap. The field, discovered by accident in the 1920s with cable tool rigs drilling down-dip of a structural closure, might have easily been missed today, as a quick look at the area would show good reservoir, but no viable thermally mature or rich source rock anywhere near this location. Pools of this nature were found by ‘chasing the oil and gas shows’. The oil is actually from a Devonian source rock which generated mature oil to the west and migrated vertically through thick Mississippian carbonates via fractures, then



traveled under a regional Jurassic unconformity until it reached a spot where the Lower Cretaceous unconformity beveled into that migration pathway. The oil then migrated south from Canada to the US in the porous valley-fill network of the Cutbank Sandstone. Details of how the migration pathways were determined at this field are covered in Chap. 8.

In many cases, the larger stratigraphic traps have been found because someone was paying attention to the production performance or oil shows in a few anomalous wells, where cumulative oil production was more than the structural spill would account for or the oil shows were much deeper than the structural closure. In these cases, the trap geometries themselves have to be rethought. Sometimes, it takes years and attention to detail to recognize that the structural trap geometries alone do not explain where the oil is.

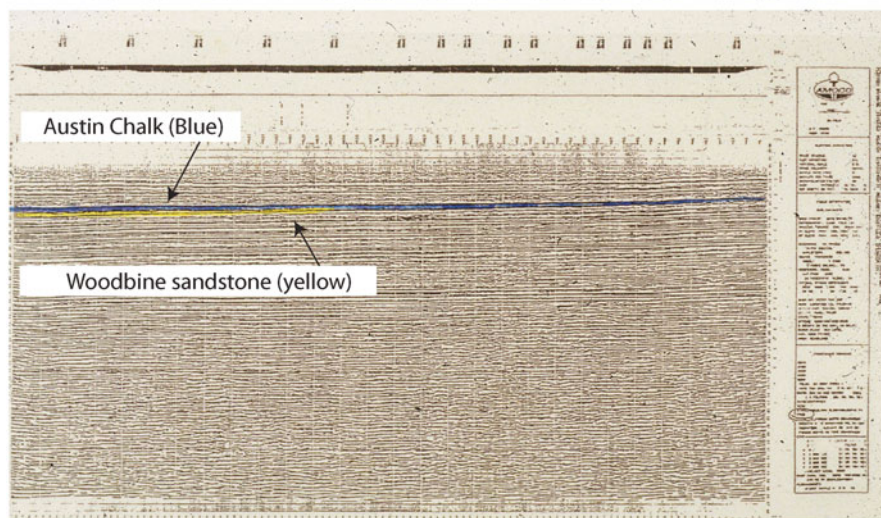
The reason for these oversights and a focus on structural traps are simple. Oil companies will always prefer to drill a fault or four-way closure of salt-wall trap before venturing to test the stratigraphic traps unless there are direct hydrocarbon indicators (DHI's) on the seismic which directly show where the fluids are in the trap. The attraction of multi-storied pay zones and multiple seals and reservoirs makes these targets much less risky.

In mature onshore basins, however, most or all of the structural anomalies have been tested and what is left are the more difficult stratigraphic, pore-throat, hydrodynamic and now, unconventional oil and gas shale traps. Getting the reservoir and seal geometries right requires careful and time-consuming work with 3D seismic, cores, cuttings and well logs, some of which is often not available. I have actually heard managers instruct staff not to look for stratigraphic traps as they require too many seals, are difficult to map and 'won't be part of our portfolio'. That is good news for the rest of us, who believe a lot more oil remains to be found in these kinds of traps. In all these cases, oil and gas show analysis is critical to find the overlooked accumulations.

By example, and to illustrate how subtle some of these traps can be, the two largest conventional traps in North America are the angular unconformity traps of East Texas Field and Prudhoe Bay Field (Alaska). On seismic, some of these traps are remarkably subtle. This five billion barrel East Texas Field is a truncation trap miles from mature source rock (Wescott 1994). Seals are set up by the top-seal of the Cretaceous Austin Chalk, and lateral seals where shales beneath the porous Woodbine Formation sandstones sub-crop the Austin Chalk on a very low relief angular unconformity. Figure 2.19 shows an old 2D seismic line once framed and hung on the wall of Amoco Production Company's President (1980–1981) as a reminder of how subtle some big stratigraphic traps can be.

East Texas Field was found by chance, drilled by an oil patch land promoter named Marion "Dad" Joiner. He and his partner, A. D. 'Doc' Lloyd, put together a fictitious prospect in Rusk County, Texas, based on non-existent "faults, folds and salt anticlines" and sold shares for \$25 to raise money for wildcats. Professional geologists at Humble (now Exxon) dismissed the acreage as non-prospective due to no obvious structure. One critic even promised to "drink all the oil you find there"—

## East Texas 2D seismic line through East Texas Field angular unconformity trap



(scales not readable) Seismic courtesy Amoco Production Company from 1980's unconformity seminar field course

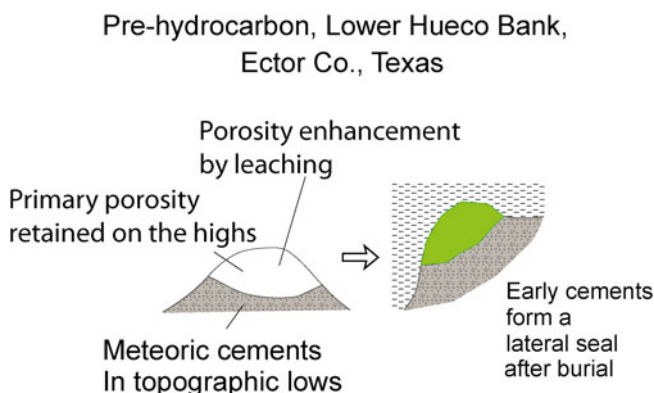
**Fig. 2.19** Unpublished East Texas seismic. Date and quality of acquisition unknown. The angular unconformity trap truncation is shown in *yellow*, with the overlying Austin Chalk the top-seal and lateral seals shales sub-cropping the Woodbine Sandstone. Seismic courtesy of Amoco Production Company from unpublished 1987 Unconformity Field Seminar

something that is a very dangerous thing to do in this business, as noted earlier. By sheer luck, his third well, in 1930, found the largest oil deposit in the world for that time period.

Pre-drill, Prudhoe Bay, another angular unconformity trap, was considered high risk with a low probability of success. The trap was mapped as a small fault closure but turned out to be a giant unconformity trap. In both these fields, oil has migrated relatively long distance both vertically and laterally from the 'source kitchen' (Specht et al. 1987).

Lastly, diagenetic overprints can often obscure even the most seemingly obvious trap geometries (example in Fig. 2.20).

Post-accumulation cements may seal in a trap at the paleo-oil water contact and subsequent later structural tilting may make that trap very difficult to find. Many carbonate traps are notorious for diagenetic modifications which can make even the highest part of the trap non-commercial and part of the 'waste zone'. When these traps are drilled, the real prize might actually be down dip or somewhere along trend structurally where the facies improve. Often, even 3D seismic cannot image these subtle changes in rock type properly and the show information for the wells has to be used to understand the trap and prospectivity.



**Fig. 2.20** Example of a diagenetically sealed trap where early cements sealed an accumulation which was later tilted structurally. (Figure courtesy of Rick Tobin)

## 2.4 The Basics of Rock Properties, Free Water Levels, Buoyancy Pressure and Hydrocarbon Shows

Understanding rock properties in relation to oil and gas shows is essential to interpret subsurface data. An excellent overview of reservoir quality and hydrocarbon saturations is covered by (Hartmann and Beaumont 1999) and in Chap. 5, this topic is covered in much more detail. However, it is important to have an early understanding of some basic rock petrophysics terms and ways to classify oil and gas shows, reservoirs and seals.

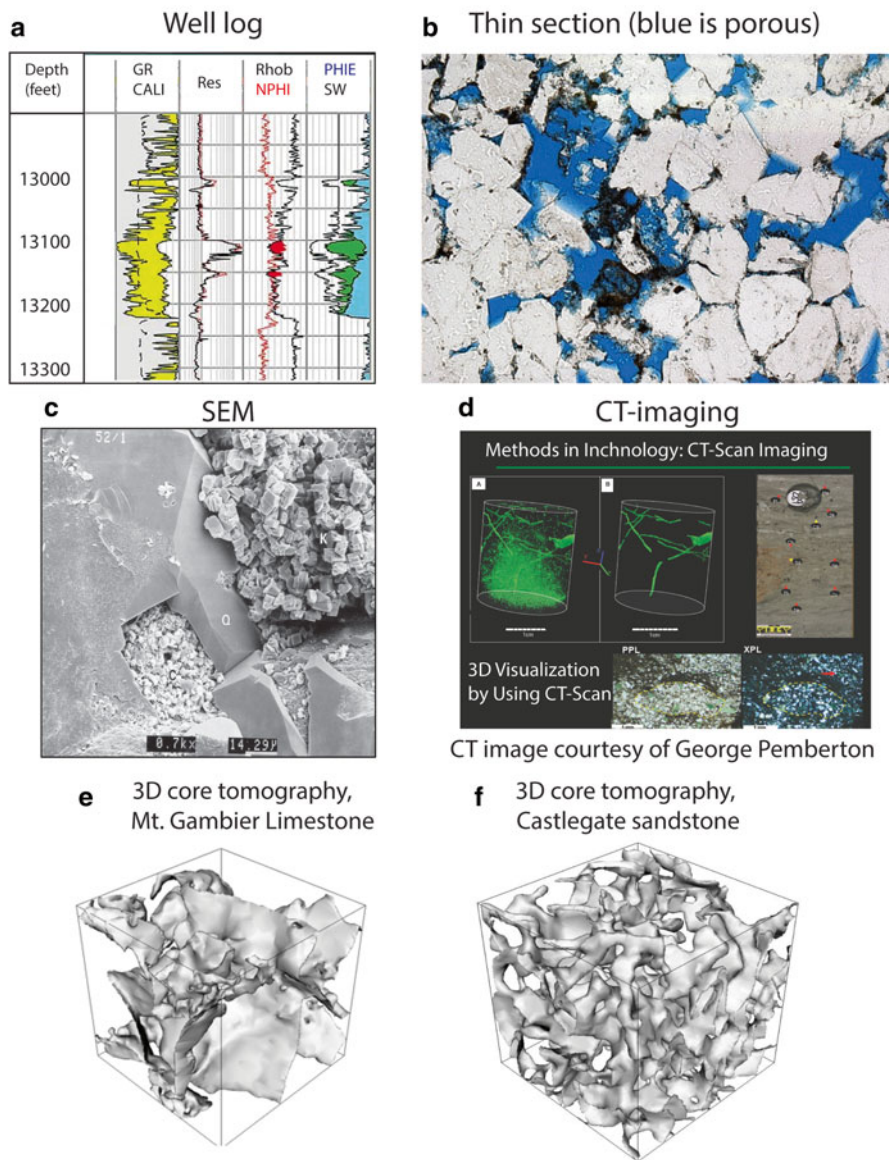
### 2.4.1 Porosity

Porosity (PHI) is the total amount of ‘void’ space between the grains that can hold oil, gas or water. It is expressed in percentage of total rock volume. Porosity systems in rocks are complex. Pores in rocks are connected to each other through narrow passes called ‘pore throats’. The pore throat shapes are key to productivity and exert a dominant control on how much oil can enter a reservoir during trap filling.

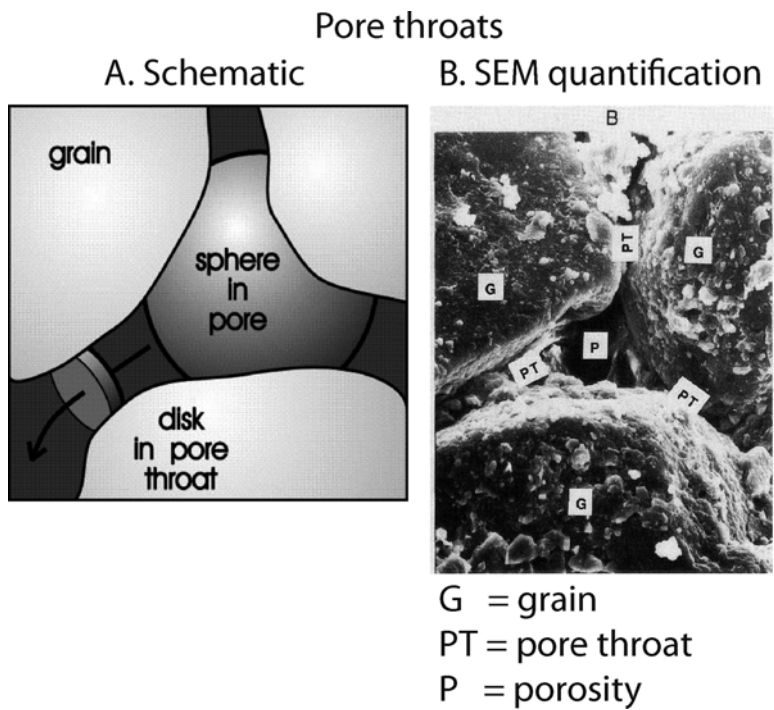
The pore and pore-throat systems are commonly unevenly distributed. A thorough treatment of porosity types and pore networks is beyond the scope of this introduction and is well covered in other literature, particularly that of (Choquette and Pray 1970). The importance of understanding porosity type and pore geometries has been emphasized for years (Berg 1975; Gunter et al. 1997; Hartmann and Beaumont 1999; Pittman 1992; Schowalter 1979; Schowalter and Hess 1982; Swanson 1977, 1981).

The most common methods for estimating porosity (Fig. 2.21) are from analysis of cores, various well log tools, thin sections and scanning electron microscopy

## Some methods to visualize and quantify porosity



**Fig. 2.21** Methods to image and measure porosity. Well logs (**a**) are the most common method, but thin sections (**b**) and scanning electron microscopy (SEM) (**c**) provide critical detail on clays and mineralogy. CT scans (**d**) and 3D core tomography (**e**, **f**) are increasingly used to visualize pore networks. Images (**e**, **f**) from Sheppard (2015), with permission from the Australian National University



**Fig. 2.22** Pore throats exert a strong control on water saturation and volume of oil in a trap at any position. Pore diagram from Coalson et al. (1994), courtesy of the RMAG

**Table 2.1** Pore size classifications and implications (modified from Hartmann and Beaumont (1999))

Pore category	Size in microns (mu)	Comments
Nanno	<0.1	Excellent seals
Micro	0.1–0.5	Can be seals or poor reservoirs
Meso	0.5–2	Often transition zone saturations unless high on a trap or in gas reservoirs
Macro	2–10	High quality reservoirs
Mega	>10	High quality reservoirs

(SEM). More recently, tools such as CT scanning (Fig. 2.21d) and 3D core tomography (Fig. 2.21e and f) are providing much better visualization and quantification of how porosity systems differ in three dimensions.

As mentioned, however, the key thing to consider is not just the porosity system, but the geometry and size of the pore throats themselves.

The pore throat concept is critical to understand in order to quantify seal capacity, reservoir performance and hydrocarbon saturation (Fig. 2.22). Pore throat size is measure in microns, and there are basically five classes (Table 2.1).



Understanding the geometry of a pore network is fundamental to understanding oil and gas shows, predict new traps, identify migration pathways and understand potential production. Pore throat size and distribution exerts a strong control on how much oil and gas can enter a pore system during trap filling. The pore throats act like small capillary tubes (covered quantitatively in Chap. 5) initially filled (usually) with water that must be displaced by oil and gas during migration and trap filling.

Mega and macro pores offer almost no resistance to hydrocarbon entry. Micro pores, in contrast, require significant pressure to overcome resistive forces operating at the pore throats in order to displace water with hydrocarbons. This is done through increasing the buoyancy pressure higher and higher on the trap.

#### ***2.4.2 Buoyancy Pressure ( $P_b$ ), Pressure vs. Depth Plots, Free Water Levels and Water Saturation***

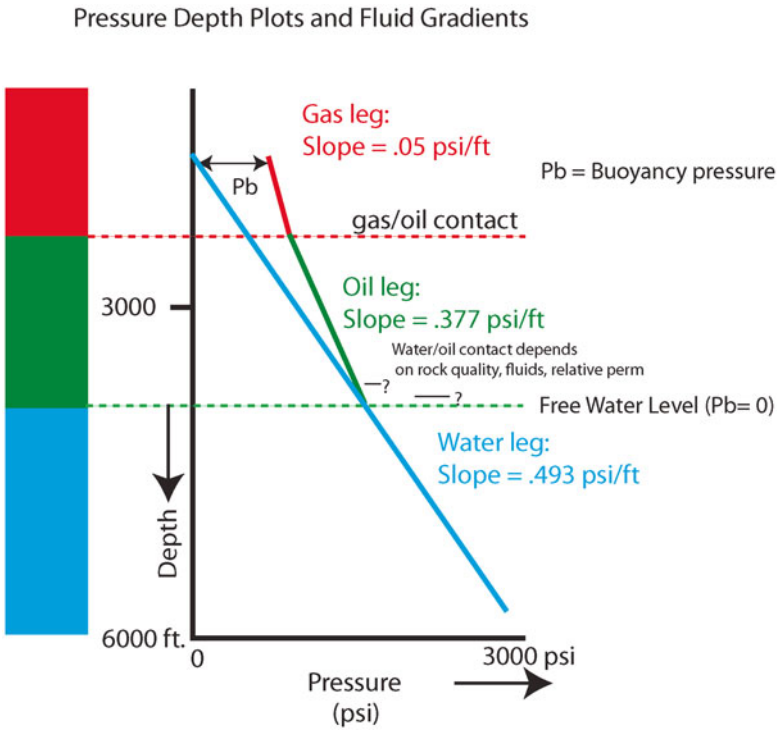
What is buoyancy pressure ( $P_b$ )? Because hydrocarbons are lighter than water, pressure builds up inside a trap due to hydrocarbon/water density differences. This pressure differential is called buoyancy pressure ( $P_b$ ). Pressures are routinely collected at rigs with down-hole tools or estimated from the mud-weights required to control the well (Chaps. 3 and 4). These data can be analyzed in pressure vs. depth plots and the gradients and buoyancy pressures of the hydrocarbons measured directly as shown in Fig. 2.23. The slope of the lines defines the density of the fluids and the gap between the hydrocarbon densities and water defines the buoyancy pressure. The point where the  $P_b=0$  is the free water level, and marks the base of the trap and its spill point. Pressure-depth plots are the best way to determine the free water level in any trap, although the use of capillary pressure diagrams (Chap. 5) can give answers if the data is good enough.

On a pressure/depth plot (Fig. 2.23), the slope of the lines is in pounds per square inch (psi) vs. depth (feet). Water densities are normally 0.43–0.5 psi/ft, depending on if it is fresh or salt water (salt water is denser than fresh water). A great example of buoyancy pressure is from swimmers trying to float in a fresh water lake on a hot summer day. Holding in breath creates a less dense body, and floating is possible. Floating, however, is much easier in the salt-saturated Dead Sea, where the density difference between your body and the denser salt water is higher.

The density differences show up on the pressure vs. depth plots. Intersections of different fluids defines contacts. Hence on Fig. 2.23, the water line has a slope of 0.493 psi/ft, a salt water gradient. The oil gradient, in contrast is 0.377 psi/ft and the gas gradient 0.05 psi/ft. The changes in slope and intersections define gas/oil and the free water level.

Some common gradients and densities are shown in Table 2.2.

Oil densities are most commonly presented in grams/cubic centimeter (g/cc) or as API units. The API unit (named for the American Petroleum Institute) is a common unit of measure describing densities.



**Fig. 2.23** Buoyancy pressure. Modified from Dahlberg (1995) courtesy of Springer-Verlag

**Table 2.2** Some common densities. See Appendix A for more formulas and conversions

Fluid	API gravity	Density in g/cc	Density in psi/ft	Comments
Fresh water		1	0.43	1 g/cc=0.43 psi/ft
Salt water		1.1	0.47	
Extra heavy oil	<10	>1		
Heavy oil	10–22.3	0.92–1.0	0.38–0.43	
Medium oil	22.3–31.1	0.87–0.92	0.37–0.38	
Light oil	31–50	0.87–0.5	0.37–0.216	
Condensate	60	0.73	0.319	
Wet gas		0.5	0.216	
Dry gas		0.2	0.086	

The API gravity formula by Eq. (2.1):

$$\frac{141.5}{SG \text{ at } 60^{\circ}F} - 131.5 \tag{2.1}$$

Where SG equals specific gravity, measured in the lab or on the rig at 60 °F.



Table 2.2 compares API gravity and common density measurements. From both Table 2.2 and Fig. 2.23, it is clear that gas accumulations for any given height in a trap, will have higher buoyancy pressure than oil pools, due to greater density differences in the fluids.

Pressure depth plots are the only accurate way to determine the (FWL), or base of the trap, and hence, are extraordinarily useful plots to make if you have the data from your wells. At the base of the trap, there is no oil in the reservoir, and  $P_b=0$ . The structural elevation of the FWL is important to determine, as there will be oil everywhere above it, but not necessarily in commercial saturations. That will depend on other factors like pore throat distribution and fluid phase.

Finding the FWL is key to understanding oil shows and it should not be mistaken as the oil or gas/water contact. A failure to understand the differences between an oil or gas/water contact and the free water level may well be one of the more common problems for geoscientists globally. Understanding the differences quantitatively requires an understanding of capillary properties of the rock (Chap. 5).

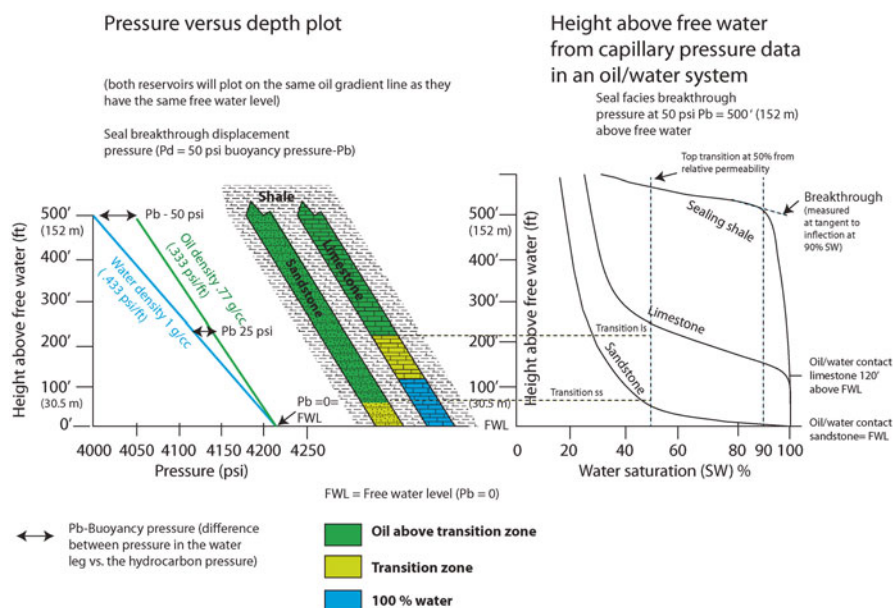
To start understanding capillarity, however, learn to interpret and understand height above free water plots.

### ***2.4.3 Water and Hydrocarbon Saturations and Height Above Free Water Plots***

When oil enters a trap there are forces called ‘capillary pressure’ which resist displacement of whatever fluid is already in the pore. In most cases, this is water. For now, consider the pore throat as the primary resistive force that needs to be overcome to get oil to displace water in a trap. The larger the pore throat, the easier it is to overcome the capillary forces that resist migration. Smaller pores, however, require significant buoyancy pressure to bridge ever increasingly small pore throats. This is analogous to capillaries in a human body. It is easy to pump blood into a large artery, but difficult to get blood into ever smaller capillaries. When a human heart becomes weaker with age, smaller capillaries no longer receive the oxygen and blood flow they need and problems result. This is not unlike, conceptually, oil filling a trap using buoyancy pressure.

Because pore geometries are not all created equal (recall Fig. 2.14), the volume of oil that enters a reservoir is strongly controlled by the pore networks. Small pore throats simply take more pressure to displace water than large pore throats.

The percentage of pore space occupied by water is called ‘water saturation’ ( $S_w$ ). It is expressed in percentage of pore space filled with water. Hydrocarbon saturations are defined as  $(1-S_w)$ , and designated as  $S_o$ . A water saturation of 90 %, then, means a hydrocarbon saturation ( $S_o$ ) of 10 %. Likewise, an  $S_w$  of 20 % is an  $S_o$  of 80 %. Pore geometries vary significantly by rock type, but can be quantitatively visualized on a plot of water saturation vs. height above free water. The pore throat distribution must be known or estimated to do this, as well as the fluid/water phase (gas or oil densities vs. salt or fresh water) and chemical properties of the fluids and finally another property, called ‘wettability’ which relates to the walls of the pore throat (Chap. 5).



**Fig. 2.24** Rock properties from height above free water and the relationship to a pressure vs. depth plot. The three rock types shown have different pore geometries and hence different saturations at any point in a trap. Modified in part from Schowalter (1979); Schowalter and Hess (1982)

Ignoring the math and physics for now, assume you have plots showing a calculated height above free water vs.  $S_w$  for three rock types (Fig. 2.24). The changes in the shape of each rock type are due strictly to the changes in pore geometry. The pore geometries change because the rock properties are fundamentally different. A well sorted, highly permeable sandstone will have a completely different height above free water plot than a tight dolomite or shale.

In Fig. 2.24, for example, there are three rock types that are part of the same trap and seal combination. The sandstone and limestone share a common pressure system and a common free water level and thus have the same spill point. In a case like this, both the limestone and the sandstone would be in pressure communication and pressure points would plot precisely on the oil gradient line on the pressure-depth plot. At the base of the trap,  $P_b = 0$  and at the top,  $P_b = 50$  psi. This is true for both lithologies, so they have equal  $P_b$  at any given height in the trap. Obviously, the top of the trap has much higher  $P_b$  than the base.

#### 2.4.4 Oil-Water Contacts, Top of Transition Zones vs. FWL and Relative Permeability

Figure 2.24 also illustrates how the oil-water contacts and top of transition zones can vary within a trap simply by rock type changes. Oil-water contacts should be set at the 100%  $S_w$  line. The top of transition zone, however, is the point at which a

well physically begins to produce water, and that is a function of its rock type and saturation.

Height above free water vs. saturation plots tell a lot about how a well might perform when drilled. In Fig. 2.24, top of transition zones and oil water contacts are substantially different. Examine, for instance, the 50 % SW point for all the rocks. For illustration purposes, the top of the transition zone is set at 50 % SW for both the sandstone and the limestone. Despite being in equal Pb conditions, the sandstone has a larger pore-throat network and reaches 50 % SW at 75 ft (20 m) above free water. In contrast, the limestone doesn't reach 50 % SW until over 200 ft (61 m) into the trap. The shale never reaches 50 % SW because it is the seal and can only hold 500' (152 m) of oil before it leaks.

Another critical point is where the rock has 100 % Sw. This is the actual oil-water contact. The oil-water contact will also correspond roughly to the seal capacity of the rock. That point can be found by examining the right side of the diagram at the 90 % Sw line. This saturation value is often used as an approximation of seal capacity, but if you have plots like this, a line drawn tangent to the curve at that point and projected back to 100 % Sw is a better approximation of both seal capacity and the oil-water contact (Jennings 1987).

By example, the third rock type is the shale seal. The shale has many tiny micro and nanno pore throats which can only be breached at 50 psi Pb at the top of the trap. The line tangent to the curve at 90 % Sw shows a value of 500' (152 m) to an oil/water system, or the seal capacity of the shale. The sandstone, in contrast, has no seal capacity and the oil/water contact is the same as the FWL. This means the pore throats in the sandstone are large (like arteries) and it takes only a little Pb to displace water and begin filling the reservoir with oil. The limestone, a third rock type, can seal a 120' (36 m) column and the oil water-contact will be 120' (36 m) above the FWL. The pore throat sizes in the limestone are smaller and more difficult to displace water from than the sandstones, but much bigger than those of the shale.

Yet another key part of these plots is where the curve steepens rapidly on the left side of the diagram. When the line goes vertical, or nearly so, this is termed the irreducible water saturation (Swi). Note the sandstone curve still has quite a bit of water remaining until it gets to 40 or 50 % SW, after which it fills rapidly. At Swi, the water in the smaller pore throats can no longer be displaced and will remain in the trap, but not produced when the well flows. In this case the Swi for the sandstone is around 18 % and for the limestone about 30 %.

However, if the operator tries to perforate and produce the sandstone a few feet above the FWL, despite having some oil saturation, it will probably flow only water, regardless of the lithology. At 25' above the FWL, for example the saturations in the sandstone will be 80–90 % Sw. This may be too high a water saturation to produce anything but water, despite have 10–20 % oil saturation. The reason for this is a phenomenon called 'relative permeability' which is covered more in Chap. 5. From a shows standpoint, a well testing water low on a trap but near the FWL can easily

be mistaken as 'not being in a trap' as the Sw will be very high and there may be no recovery of hydrocarbons.

Another problem arises with the shallower oil-water contact on the limestone. If this is the only well drilled on the trap, the oil-water contact may easily be mistaken from the FWL. That would mean the operator has under-valued the trap by an additional 120' (32 m) of closure. An offset well might encounter the sandstone at the same level (or lower) as the limestone and find excellent low Sw. The sandstone, at 120 ft (32 m) above FWL, has an SW of about 30 %, and would likely produce oil with no water!

This is the essence of understanding oil shows at the most basic level. Saturations vary as a function of rock type and position in the column. Oil-water contacts can be different across a field and in the same trap, in pressure continuity and with the same FWL, but different contacts due to varying rock type.

If this were changed to a gas-water system, the curves would change again and the seal capacity would be reduced substantially (due to increased Pb in the gas/water cases). Saturations would be lower in all three rock types than they are in the oil/water case.

Here are the points to remember:

1. Sw varies not just by height above free water, but by rock type and pore throat distribution.
2. Gas/water systems have higher Pb (buoyancy pressure) at any given point in a trap than oil/water systems (so seal capacity is reduced for any given rock type). What seals long columns of oil may only seal small columns of gas. There are some caveats to this statement, however:
  - (a) Interfacial tension (discussed in Chap. 5) can be high in gas/water systems, and this will increase the seal capacity of any trapping facies.
  - (b) There are wide variations in density in gas accumulations and the lighter the gas, the more difficult it can be to seal. So not all 'gas' traps are equal in terms of seals needed to form the traps.
3. The FWL is where  $P_b=0$ . There will ALWAYS be SOME oil saturation above the FWL, but high SW zones can actually test all water and be misinterpreted as below an oil water contact or not in a trap.
4. Pressure/depth plots are the ONLY way to accurately confirm a FWL. Other techniques, like capillary pressure analysis (Chap. 5) offer good approximations.
5. Gas/oil, oil/water and gas/water contacts can be recognized on pressure-depth plots.
6. Oil and gas/water contacts MAY NOT equal the FWL. It is possible to have 100 % SW in a rock with small pore throats high into a trap.
7. Many, many fields are drilled into and undersized or missed because of point 6! Understand your rock quality and look at shows data carefully to see if 100 % SW is below the FWL or simply in really tight rock!

### 2.4.5 Permeability

Permeability is the rate of flow of a liquid or gas through a porous material. There is commonly a lack of understanding of the difference between pore throat geometry and permeability. Permeability in cores is a measured value (Hartmann and Beaumont 1999) calculated from:

1. Atmospheric pressure
2. Cross-sectional area of a core plug
3. The flow in  $\text{cm}^3/\text{s}$
4. The length of the plug
5. Pressure at the input end in atmospheres (atm)
6. Pressure at the output end in atm
7. Air viscosity in cp (centipoise)

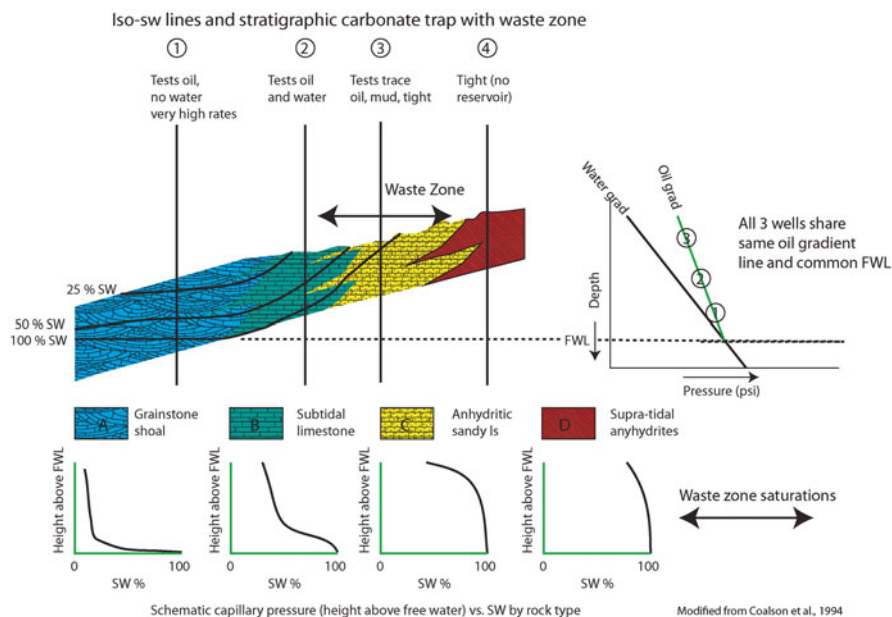
The standard unit of measure is the millidarcy (md). At a qualitative level, 100 md would be considered a good permeability, 1000 md or higher outstanding, and the rock would probably be called ‘tight or low perm’ below 1 md. How much a well flows will depend not just on the permeability of the rock, but the pressure drop across the wellbore when it is flowed, the cross-sectional area of the perforated interval, and the fluid viscosity. Because of viscosity variations, a 10 md rock might have high flow rates in gas but low flow rates in heavy oil.

Engineers, in particular, talk in terms of porosity and permeability, as the permeability measures the rate at which oil is produced in a well. A geologist, on the other hand, should learn to think in terms of the distribution of pore throats and their impact on water saturation and water cut when a well is produced. As will be shown in Chap. 5, a high porosity rock can have low permeability and be micro-porous, requiring a long hydrocarbon column and high buoyancy pressure to saturate the reservoir. In contrast, some low porosity rocks have very good permeability and very well connected pore networks, requiring very little Pb to fill to irreducible water saturation. A high porosity zone does not necessarily equate to high permeability and vice versa!

Thus, Swi may be as low as 3% in some rocks and fluid combinations and as high as 80% in others, but is typically in the 10–25% range for rocks with ‘normal’ ranges of porosity and permeability. In understanding shows, interpreters need to think in terms of pore geometries, not porosity or permeability, and in terms of saturation in the context of rock type, fluid type, buoyancy and position in a trap.

### 2.4.6 Waste Zones

The term ‘waste zone’ (Schowalter and Hess 1982), as mentioned earlier, has been used to describe updip, poor reservoir, low saturation facies that are largely uneconomic in a trap. Hence, the monetary value is ‘wasted on these rocks’. Waste zones



**Fig. 2.25** Relationship between SW and pressure in a stratigraphic trap with an updip waste zone and variable rock properties. Modified from Coalson et al. (1994)

are important to recognize in any well or dry hole. Waste zone rocks are generally meso or micro-porous, depending on the fluid system and position in a trap. For instance, in heavy oil, a meso-porous rock may act like a 'waste zone', but in a gas reservoir, with increased  $P_b$ , it may be an outstanding reservoir flowing at very high rates.

Evaluations of well shows, tests, recoveries and pressures require a constant ability to think about pore-throat geometries and the density of the hydrocarbon/water system and other things that affect capillary pressure fluid displacement and water saturation.

Consider Fig. 2.25, where a carbonate grainstone shoal with mega pore systems passes gradually updip into meso-porous sub-tidal limestones and then micro-porous anhydritic shoreline limestones and, ultimately, to an evaporite seal. How you initially view this trap may well depend on the order in which you drill the wells! If you drill well 3 first, you will get very high water saturations high on the trap and may well misinterpret this well as 'wet' and 'not in a trap'. You would be wrong. A pressure-depth plot shows that wells 1–3 are in pressure communication on an oil leg, sharing a common FWL. The only reason for the poor result in well 3 is the rock type!

If you drill well 1 first, you and your management will head to lunch to celebrate. You may correctly recognize the high quality rock and feel comfortable making the oil/water contact the FWL. You look at your map and run volumetrics, getting a great number. Then you drill well 2 and the great saturations, almost certainly to

exist updip, go away. No one is buying lunch now. You scratch your head, along with your management. The reserves you estimated have been reduced. Unfortunately, your team also might easily interpret well 2, in the absence of pressure data, as in 'being in a different trap' because the water saturations are so different that it will calculate 100 % SW near the base of the reservoir. Someone in your team, almost certainly, will see the 100 % SW line in well 2 as the FWL and also equate that to the oil-water contact. They will be wrong.

Drill well 2 first and you will have a dilemma. The water saturations are not great. Your management will be urging you to 'drill updip' for more buoyancy pressure and better saturations. You do that and get well 3, a huge disappointment. You go home depressed.

If you have cut core or looked at cuttings, you might recognize that well 2 is mesoporous rock and well 3 micro-porous, but both have saturations. Because you understand shows and height above free water plots, you recognize that this is possible only in the presence of a substantial oil column and large trap. You think this through and decide you need a better reservoir within the trap, maybe even downdip. You carefully build a facies map from all available data. You find a well downdip that is highly porous, in a grainstone shoal, and it doesn't look like wells 2 or 3 on logs. You decide there is a significant facies change downdip and you map it out. If are lucky, you have 3D seismic. If not, you might want to recommend it if you think it will show the facies boundaries.

You take your final facies map back in and recommend to your management to drill downdip of well 2 to find really good saturations in the grainstone shoal. Someone in the management team, almost certainly, will think you are a tad insane, and may even tell you so. They will argue you already found an oil/water contact in well 2, so why go down-dip? If you have pressure points in wells 2 and 3 you can point out that the points fall on the same oil gradient which matches the API gravity of the recovered oil. If not, you have to be persuasive on the basis of rock properties alone. It is not an 'easy sell'.

You talk at length about 'waste zones', buoyancy pressure and rock type until your prospect concept is clear. You argue that both wells 2 and 3 have proven the trap, just not the commercial saturation. Eventually you get some money and drill well 1. While it is drilling, you lose some sleep worrying about the results, as you are taking a gamble, moving downdip of an oil/water contact and high saturations and guaranteeing the result will be good.

The well comes in and everyone goes out to dinner and celebrates. Your manager proclaims he is a genius to have thought of such a novel idea himself. He gets promoted. You get a free lunch and a great reputation with peers. It is clear the old saying 'every dry hole is fatherless, every discovery has multiple parents' is true.

## **2.4.7 Oil Show Types**

With an understanding of rock types and buoyancy, understanding oil shows can begin to make sense. Perhaps the most fundamental papers written on the topic of show classification are those of Schowalter (1979) and Schowalter and Hess (1982),



and expanded upon in summary form significantly by Hartmann and Beaumont (1999) and Vavra et al. (1992).

Even in the last decade there have been many advances in the tools used to identify oil and gas shows but the fundamental issue of how to use them in exploration remains one of an ‘art of integration’. Too often, interpreters lack the background in pressures, petrophysics or geochemistry to take full advantage of the huge amount of information available in any basin or field that helps understand oil occurrences. The rest of this book provides more detail on how to interpret key data sets and make exploration and production decisions with oil and gas show information.

To start, Schowalter’s papers define four basic show types. Details of how to recognize these shows and where the pitfalls occur in interpretation are subjects for later chapters (Table 2.3).

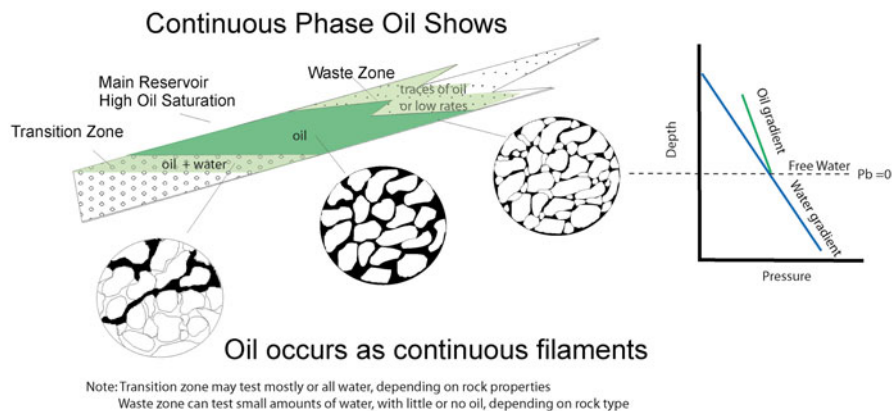
Continuous phase shows (Fig. 2.26) will always be above the free water level. Immediately above the FWL the first continuous filaments of oil bridge the largest pore throats (hence the name).

Residual oils (Fig. 2.27) occur where oil was once trapped or migrated but has been lost. These shows are always below the FWL, but can have substantial residual saturations and even stain and odor in cuttings. Techniques for assessing residual vs. continuous phase oils are covered by O’Sullivan et al. (2010) and good case history of residual formation by exhuming or rotating older traps into newer structural positions and spilling hydrocarbons updip is presented by several authors (Farrimond et al. 2015; Igoshkin et al. 2008; Littke et al. 1999; Naidu et al. in press; Sorenson 2003). Chapters 5 and 6 deal with this subject in much more detail.

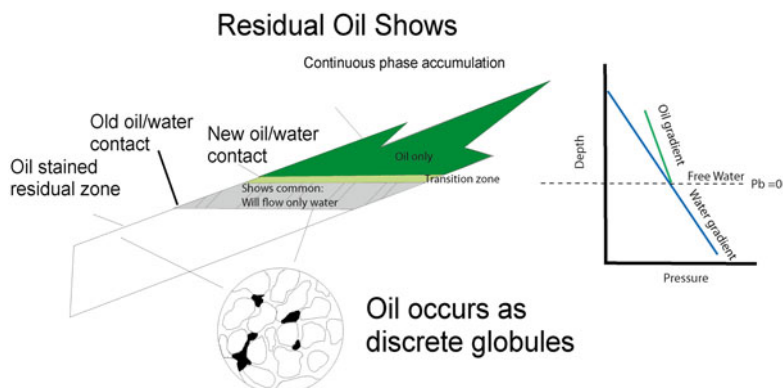
If a well tests measureable amounts of oil and gas, it is clearly in a continuous phase trap. A well testing 1 BOPD and 1000 BWPD (barrels of water per day) is in

**Table 2.3** Classification of oil shows (Schowalter and Hess 1982)

Show type	Definition	Comments
Continuous phase shows	Oil above the free water level	Occurs as continuous filaments of oil bridging the largest pores. Difficult to recognize if saturations are low enough to not test oil.
Residual shows	Traces of oil left behind from prior accumulations which have been lost or along migration pathways. Always below the FWL.	Can be difficult to tell from continuous phase shows. Will always test water and be within a water gradient on a pressure-depth plot.
Dissolved gasses	Gas being released from formation water by pressure drops while drilling	Not significant in conventional exploration, but some high permeable sands in the Gulf of Mexico (USA) are being looked into for unconventional gas production (Tim Schowalter, personal communication).
Kerogen-rich source rocks	Oil and gas liberated by drill bit heat and friction in immature source rocks or oil and gas remaining in the source rocks after generation	Significant and large unconventional shale oil and gas resources. Generally requires hydraulic fracturing or natural fractures to produce economically.



**Fig. 2.26** Continuous phase oils. Modified from Meckel (1995) and Hartmann and Beaumont (1999)



**Fig. 2.27** Residual oil shows. Modified from Meckel (1995) and Hartmann and Beaumont (1999)

a trap. Given the high rates, it is probably near the free water level or oil/water contact. A well testing 1 BOPD in very tight rock is also in a trap. Both of these examples are continuous phase shows and must be looked at carefully to see where to drill another well. The tight well is probably in a waste zone.

I lived and worked in Russia for 4 years with TNK-BP. It was common for us to find hundreds of abandoned wells which tested very low rates of oil in very tight rock and were abandoned as 'dry'. More careful work in one area (Dolson et al. 2014) led to recognition of billions of barrels of stratigraphically trapped hydrocarbons in an area peppered with non-commercial 'dry holes'. Careful pressure, core and facies analysis finally revealed the traps.

Residual shows are problematic, as the issue is 'where did the oil go'? More examples are shown in Chap. 5, but it can be very difficult on well logs or cuttings

alone to recognize that some substantial oil shows are residual. Residual oils are very common in older fields undergoing water flood, as the water flooding has displaced the oils and left only residual droplets behind. In many cases, these residual saturations are substantial (60–90 % SW, which equates to 40–10 % oil), but they can't be recovered with conventional means as the droplets are no longer connected.

Often, chemicals (RPSEA 2009) are introduced into these oil fields to change the other capillary properties of the rocks (like wettability and interfacial tension, covered in Chap. 5). These chemical changes allow the droplets to re-connect and be produced. There are enormous volumes of residual oils remaining in old fields globally if we can find ways to produce them.

### 2.4.8 *Kerogen-Rich Source Rocks*

Easily one of the most exciting developments in the last century has been the recognition that vast amounts of oil remain trapped in shales and tite limestones in the kerogen-rich source rocks themselves. This is the realm of 'unconventional exploration' and it deals with how to get oil from rocks still trapped in the primary migration phase. The continuous phase and residual shows are associated with secondary migration and require a different set of techniques to evaluate.

This book only briefly touches upon unconventional exploration but suffice it to say that when oil is generated in a source rock, quite a bit remains in the fine pore spaces until the kerogens are completely 'cooked out' during the maturation process. One of the pioneers of unconventional exploration was Fred Meissner (Meissner 1978) who recognized that oil in the Bakken Shales of North Dakota had billions of untapped barrels of oil still remaining in the shales. Early attempts to produce from these shales with vertical well bores and hydraulic fracturing were disappointing, but technically successful. In fact, some of the oldest fields in North America occur in fractured shale and oil formations like the Florence Field of Colorado and the Marcellus shales of Pennsylvania, where early drillers and pioneers could extract the oil and gas from open fractures at very shallow depths, sometimes even lowering buckets into the fractures to lift out the oil.

Horizontal well drilling and a process called multi-stage hydraulic fracturing has finally made access to these resources possible. Unconventional resource assessment is most comprehensively covered by (EIA 2008a, b, 2009a, b, 2010a, b, 2011). Some excellent technical summaries are also provided by (DCNR 2014; Harper and Kostelnik 2013a, b, c; Smith and Leone 2010; Wrightstone 2009, 2010; Zammerilli 2010).

When drill bits encounter shales with kerogens remaining in the pore spaces, bit friction and heat liberate these kerogens as free hydrocarbons. Later chapters deal more comprehensively with new tools to evaluate oil and gas shows in shales, but they are important to distinguish as different from shows in conventional reservoir rocks.

### 2.4.9 *Thinking Like a Molecule*

This chapter establishes the foundation for most of the subsequent chapters—which explore techniques of pressures, rock properties, petrophysics, show and geochemical data capture and migration analysis in more detail.

More than one person I know has insisted that successful oil finders are those who ‘get back to the basics’ and ‘think like a molecule of oil’, using a solid understanding of rock properties, migration and water saturation analysis to map out where oil goes once it leaves the source rock beds during maturation. Modern software packages allow migration modeling to be simulated, but still need geological insight on carrier beds, seals, source rock characteristics and timing of migration and validation of the models with oil shows databases from dry holes and other data.

Downey (2014) stresses that too little emphasis is often given to the fundamentals of mapping, characterizing and understanding oil and gas shows, regardless of years of experience. Understanding oil shows is often difficult and confusing. But changes in saturation are easier to understand for those who understand the petrophysical basics of this chapter and the rest of this book.

Exploring for oil and gas is not easy. It requires ever increasing sophisticated skills with computers, software, seismic, geochemistry, well logs, engineering, economics and other tools. A favorite quote of mine is that attributed to Parke Dickey from many years ago, but still holds true today.

We usually find oil in new places with old ideas. Sometimes, also, we find oil in an old place with a new idea, but we seldom find much oil in an old place with an old idea. Several times in the past we have thought that we were running out of oil, whereas actually we were only running out of ideas.

Studying, characterizing and thinking about oil and gas shows in the context of position in a trap, rock type, seals and migration can be a key to unlocking that ‘new field in an old area with a new idea’ or just as applicably, to opening up a huge new play overlooked by others.

## 2.5 Summary

Exploration today involves looking at plays in both the source rocks where only primary migration has occurred, and in reservoirs, along secondary migration pathways. There are a multitude of different traps types, seals and reservoir lithologies. Understanding oil and gas shows fundamentally boils down to being able to quantify or conceptually evaluate what oil shows mean. Are the shows residual in leaked traps or along migration pathways, or are they within a trap above the free water level?

The size of the trap is governed by the weakest seal and if traps are not filled to spill, they are either not charged fully or the weakest seal is less than the total trap closure. Being able to differentiate between these two scenarios may lead to recognizing additional potential updip along other migration pathways. Waste zones are

common within traps, and can be recognized as poor quality rock testing only small amounts of oil and gas. Free oil and gas tested in a waste zone indicates that a column is present. Sometimes, that column is significant and all that is needed is a change in facies laterally or updip or downdip to better reservoir to develop an economic field.

Because of varying rock properties, oil-water contacts should not be confused with free water levels. Different facies in the same trap can be in the same pressure system, in continuity with one another, but with different oil-water contacts. Many a field has been underestimated in size when poor quality rock, well above the free water level, calculates 90–100 %  $S_w$  and thus the trap is assumed uncommercial or to have failed by some mechanism like seal failure. Astute interpreters learn to recognize additional field potential just by analyzing the geometry of the different reservoir facies and looking for better places to drill high quality reservoirs, often downdip of wells that appear ‘wet’ on logs but are actually simply in waste zones.

## References

- Berg R (1975) Capillary pressures in stratigraphic traps. *Am Assoc Pet Geol Bull* 59:939–956
- Biddle K, Wielchowsky CC (1994) Hydrocarbon traps. In: Magoon LB, Dow WG (eds) *The Petroleum System—from source to trap*: Tulsa. The American Association of Petroleum Geologists, Oklahoma, pp 221–235.
- Choquette PW, Pray LC (1970) Geologic nomenclature and classification of porosity in sedimentary carbonates. *Am Assoc Pet Geol Bull* 54:207–250
- Coalson EB, Goolsby SM, Franklin MH (1994) Subtle seals and fluid-flow barriers in carbonate rocks. In: Dolson JC, Hendricks ML, Wescott WA (eds) *Unconformity related hydrocarbons in sedimentary sequences*, vol 1. Rocky Mountain Association of Geologists, Denver, CO, pp 45–59
- Dahlberg EC (1995) *Applied hydrodynamics in petroleum exploration*, 2nd edn. Springer, New York, 295 p
- DCNR (2014) Thermal maturation and petroleum generation. Pennsylvania Department of conservation and Natural Resources (DCNR), p. 1. [http://www.dcnr.state.pa.us/topogeo/econresource/oilandgas/marcellus/sourcerock\\_index/sourcerock\\_maturation/index.htm](http://www.dcnr.state.pa.us/topogeo/econresource/oilandgas/marcellus/sourcerock_index/sourcerock_maturation/index.htm)
- Dolson JC, Bahorich MS, Tobin RC, Beaumont EA, Terlikoski LJ, Hendricks ML (1999) Exploring for stratigraphic traps. In: Beaumont EA, Foster NH (eds) *Exploring for oil and gas traps: treatise of petroleum geology, handbook of petroleum geology*, vol 1. American Association of Petroleum Geologists, Tulsa, OK, pp 21.2–21.68
- Dolson JC, Pemberton SG, Hafizov S, Bratkova V, Volfovich E, Averyanova I (2014) Giant incised valley fill and shoreface ravinement traps, Urna, Ust-Teguss and Tyamkinskoe Field areas, southern West Siberian Basin, Russia, American Association of Petroleum Geologists Annual Convention, Houston, Texas, Search and Discovery Article #1838534, p. 33
- Dolson JC, Piombino J, Franklin M, Harwood R (1993) Devonian oil in Mississippian and Mesozoic reservoirs—unconformity controls on migration and accumulation, vol 30. *The Mountain Geologists*, Sweetgrass Arch, MT, pp 125–146
- Dolson JC, Piombino JT (1994) Giant proximal foreland basin non-marine wedge trap: lower Cretaceous Cutbank Sandstone, Montana. In: Dolson JC, Hendricks ML, Wescott WA (eds) *Unconformity-related hydrocarbons in sedimentary sequences*. The Rocky Mountain Association of Geologists, Denver, CO, pp 135–148

- Downey M (2014) Thinking like oil, the AAPG explorer. American Association of Petroleum Geologists, Tulsa, OK, p 3
- Editors (2005) Buzzard- a discovery based on sound geological thinking. GEO ExPro, pp. 34–38.
- EIA (2008a) Barnett Shale, Ft. Worth Basin, Texas. Wells by year of first production and orientation. Energy Information Administration Office of Oil and Gas, Washington, DC, p 1
- EIA (2008b) Fayetteville Shale, Arkova Basin, Arkansas: key geological features. Energy Information Administration Office of Oil and Gas, Washington, DC, p 1
- EIA (2009a) Haynesville-Bossier Shale play, Texas-Louisiana salt basin. Energy Information Administration Office of Oil and Gas, Washington, DC, p 1
- EIA (2009b) Marcellus Shale gas play, Appalachian Basin. Energy Information Administration Office of Oil and Gas, Washington, DC, p 1
- EIA (2010a) Shale gas plays, lower 48 states. Energy Information Administration Office of Oil and Gas, Washington, DC, p 1
- EIA (2010b) Woodford Shale play, Arkoma Basin, Oklahoma: key geological features. Energy Information Administration Office of Oil and Gas, Washington, DC, p 1
- EIA (2011) World shale gas resources: an initial assessment of 14 regions outside the United States. Energy Information Administration Office of Oil and Gas, Washington, DC, p 1
- England WA, Mann AL, Mann DM (1991) Migration from source to trap. In: Merrill RK (ed) AAPG treatise of petroleum geology, handbook of petroleum geology. The American Association of Petroleum Geologists, Tulsa, OK, pp 23–46
- Farrimond P, Naidu BS, Burley SD, Dolson J, Whiteley N, Kothari V (2015) Geochemical characterization of oils and their source rocks in the Barmer Basin, vol 21. Petroleum Geoscience, Rajasthan, India, pp 301–321
- Gunter GW, Finneran JM, Hartmann DJ, Miller JD (1997) Early determination of reservoir flow units using an integrated petrophysical method. Society of Petroleum Engineers, v. SPE 38679, pp. 1–8.
- Harper JA, Kostelnik J (2013a) The Marcellus Shale Play in Pennsylvania, geological survey. Pennsylvania Department of Conservation and Natural Resources, Middletown, PA, p 21
- Harper JA, Kostelnik J (2013b) The Marcellus Shale Play in Pennsylvania part 2: basic geology, geological survey. Pennsylvania Department of Conservation and Natural Resources, Middletown, PA, p 21
- Harper JA, Kostelnik J (2013c) The Marcellus Shale Play in Pennsylvania part 4: drilling and completion, geological survey. Pennsylvania Department of Conservation and Natural Resources, Middletown, PA, p 18
- Hartmann DJ, Beaumont EA (1999) Predicting reservoir system quality and performance. In: Beaumont EA, Foster NH (eds) Exploring for oil and gas traps: treatise of petroleum geology, handbook of petroleum geology, vol 1. American Association of Petroleum Geologists, Tulsa, OK, pp 3–154
- Igoshkin VJ, Dolson JC, Sidorov D, Bakuev O, Herbert R (2008) New interpretations of the evolution of the West Siberian Basin, Russia. Implications for Exploration, American Association of Petroleum Geologists. Annual conference and exhibition, San Antonio, TX, AAPG Search and Discovery Article #1016, pp 1–35
- Jennings JB (1987) Capillary pressure techniques: application to exploration and development geology. Am Assoc Pet Geol Bull 71:1196–1209
- Jewell G (2011) Exploration of the Tano Basin and discovery of the Jubilee Field, Ghana: a new deepwater game-changing hydrocarbon Play in the transform Margin of West Africa, AAPG Annual Convention and Exhibition, Houston, Texas, AAPG Search and Discovery Article #110156, p. 22
- Littke R, Cramer B, Gerling P, Lopatin NV, Poelchau HS, Schaefer RG, Welte DH (1999) Gas generation and accumulation in the West Siberian Basin. Am Assoc Pet Geol Bull 83:1642–1665
- Martinsen RS, Jiao ZS, Iverson WP, Surdam RC (1994) Paleosol and subunconformity traps: examples from the Muddy Sandstone, Powder River Basin, Wyoming. In: Dolson JC, Hendricks



- ML, Wescott WA (eds) Unconformity-related hydrocarbons in sedimentary sequences. The Rocky Mountain Association of Geologists, Denver, CO, pp 119–286
- Meckel L (1995) Seals and shows. Chapter V: Shows (unpublished workshop notes). In: Traugott MO, Gibson R, Dolson J (eds) Seals and shows workshop, September 10–14, 1995. Amoco and Gulf of Suez Petroleum Company, Cairo, Egypt, p 21
- Meissner FF (1978) Petroleum Geology of the Bakken Formation, Williston basin, North Dakota and Montana. The economic geology of the Williston basin: Proceedings of the Montana Geological Society, 24th annual conference, pp 207–227
- Naidu BS, Burley SD, Dolson J, Farrimond P, Sunder VR, Kothari V, Mohapatra P, Whiteley N (in press) Hydrocarbon generation and migration modelling in the Barmer Basin of western Rajasthan, India: lessons for exploration in rift basins with late stage inversion, uplift and tilting, Petroleum System Case Studies, v. Memoir 112. American Association of Petroleum Geologists, Tulsa, OK
- O'Sullivan T, Praveer K, Shanley K, Dolson JC, Woodhouse R (2010) Residual hydrocarbons—a trap for the unwary. SPE, v. 128013, pp 1–14
- Pittman E (1992) Relationship of porosity and permeability to various parameters derived from mercury injection-capillary pressure curves for sandstone. Am Assoc Pet Geol Bull 76:191–198
- Ray FM, Pinnock SJ, Katamish H, Turnbull JB (2010) The Buzzard Field: anatomy of the reservoir from appraisal to production. Petroleum Geology conference series 2010, pp 369–386
- Richards P (2012) Entrepreneurs finished the Falklands' story, AAPG Explorer. American Association of Petroleum Geologists, Tulsa, OK, p 1
- RPSEA (2009) First ever ROZ (Residual Oil Zone) symposium, Midland, Texas, Research Partnership to Secure Energy for America (RPSEA), p. 59
- Saucier H (2014) Mom and Pop E&P makes unlikely success: Rockhopper hits it big offshore Falklands, AAPG Explorer. American Association of Petroleum Geologists, Tulsa, OK, p 1
- Schowalter TT (1979) Mechanics of secondary hydrocarbon migration and entrapment. Am Assoc Pet Geol Bull 63:723–760
- Schowalter TT, Hess PD (1982) Interpretation of subsurface hydrocarbon shows. Am Assoc Pet Geol Bull 66:1302–1327
- Sheppard A (2015) The network generation comparison forum: a collaborative project for objective comparison of network generation algorithms for 3D tomographic data sets of porous media. In Sheppard A (ed.). Australian National University, Canberra, Australia. [http://people.physics.anu.edu.au/~aps110/network\\_comparison/](http://people.physics.anu.edu.au/~aps110/network_comparison/)
- Smith LB, Leone J (2010) Integrated characterization of Utica and Marcellus Black Shale gas plays, New York State, AAPG Annual Convention and Exhibition, New Orleans, Louisiana, AAPG Search and Discovery Article #50289, p 36
- Sorenson RP (2003) A dynamic model for the Permian Panhandle and Hugoton Fields, Western Anadarko Basin, 2003 AAPG mid-continent section meeting, Tulsa, OK, AAPG Search and Discovery Article #20015, p 11
- Specht RN, Brown AE, Selman CH, Carlisle JH (1987) Geophysical case history, Prudhoe Bay Field, Alaskan North Slope geology, volumes I and II, pacific section. SEPM (Society for Sedimentary Geology), Tulsa, OK, pp 19–30
- Swanson BF (1977) Visualizing pores and non-wetting phase in porous rocks. Society of Petroleum Engineers, vol. SPE Paper 6857, p 10
- Swanson VF (1981) A simple correlation between permeabilities and mercury capillary pressures. J Pet Technol 33(4):2488–2504
- Tearpock DJ, Bischke RE (2003) Applied subsurface geological mapping- with structural methods, 2nd edn. Prentice Hall PTR, Upper Saddle River, NJ, 822 p
- Vavra CL, Kaldi JG, Sneider RM (1992) Geological applications of capillary pressure: a review. Am Assoc Pet Geol Bull 76:840–850
- Vincelette RR, Beaumont EA, Foster NH (1999) Classification of exploration traps. In: Beaumont EA, Foster NH (eds) Exploring for oil and gas traps: treatise of petroleum geology, handbook of petroleum geology, vol 1. American Association of Petroleum Geologists, Tulsa, OK, pp 2.1–2.42

- Ward RF, Kendall CGSC, Harris PM (1986) Upper Permian (Guadalupian) facies and their association with hydrocarbons—Permian Basin, West Texas and New Mexico. *Am Assoc Pet Geol Bull* 70:239–262
- Weimer RJ, Sonnenberg SA, Young GB (1986) Wattenberg field, Denver basin, Colorado. In: Mast RF, Spencer CW (eds) *Geology of tight gas reservoirs*, vol 24, AAPG Studies in Geology. American Association of Petroleum Geologists, Tulsa, OK, pp 143–164
- Wescott WA (1994) Migration pathways and seismic expression of a North American Giant: East Texas Field. In: Dolson JC, Hendricks ML, Wescott WA (eds) *Unconformity-related hydrocarbons in sedimentary sequences*. Denver, CO, The Rocky Mountain Association of Geologists, pp 131–134
- Wrightstone G (2009) Marcellus Shale-geologic controls on production. AAPG annual convention. Denver, CO, AAPG Search and Discovery Article #10206, p 10
- Wrightstone G (2010) A shale tale: Marcellus odds and ends, 2010 winter meeting of the independent oil and gas association of West Virginia, p 32
- Zammerilli AM (2010) Projecting the economic impact of Marcellus Shale Gas development in West Virginia: a preliminary analysis using publicly available data. Department of Energy National Energy technology Laboratory, p 37

Understanding Oil and Gas Shows and Seals in the  
Search for Hydrocarbons

Dolson, J.

2016, XIX, 486 p. 341 illus., 315 illus. in color.,

Hardcover

ISBN: 978-3-319-29708-8