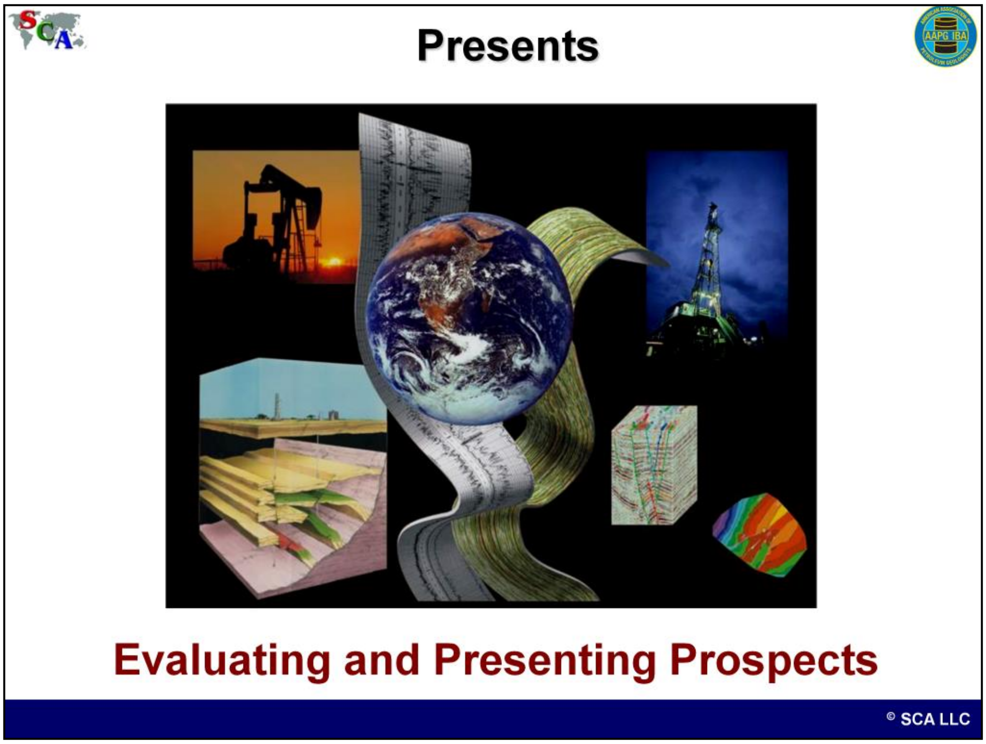
This webinar has been put together by the Imperial Barrel Committee, in conjunction with the American Association Petroleum Geologists and the AAPG Division of Professional Affairs to help you improve your interpretation and presentation of your prospect to the IBA Judges.

The techniques and methods discussed in this presentation will not only help you in the competition, but in your career as well.

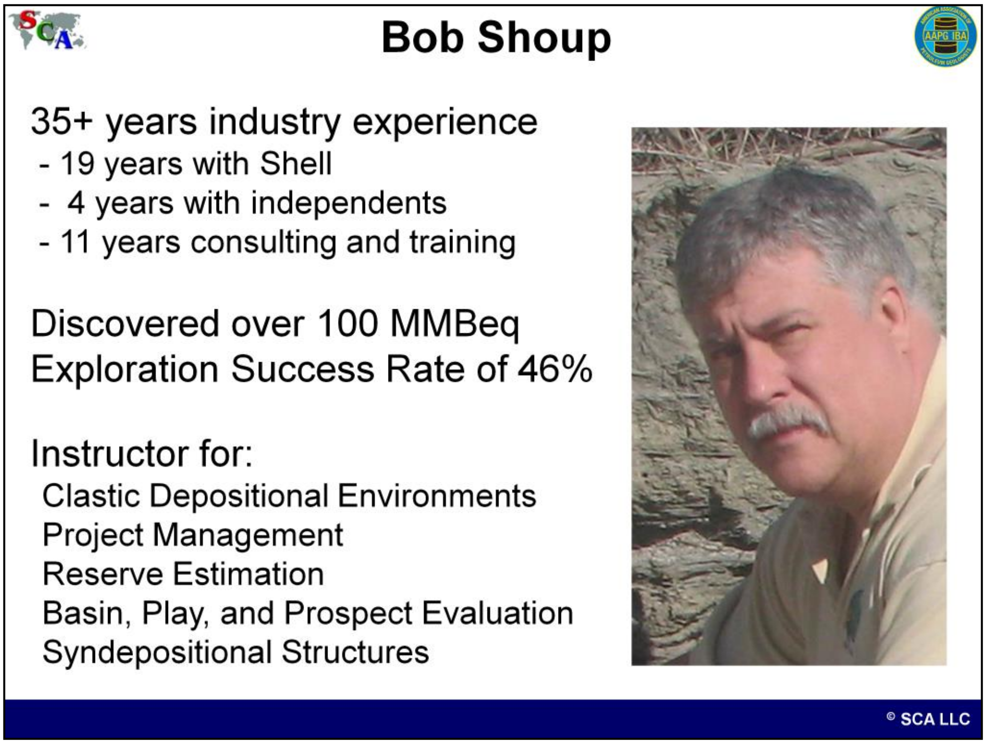


Since it is essential that we get resource and reserve estimates as accurately as possible, it is important to have our interpretations and map as accurate as possible. We covered reviewing your maps in a separate webinar.

You must also be able to demonstrate to the judges, and later to management and investors, that you have fully defined the petroleum system for your prospect, properly quantified the uncertainty, and appropriately risked the estimated resources you expect to encounter in your well.

This class has been put together by Subsurface Consultants & Associates, LLC.

SCA is an international petroleum consulting and training company. They offer an essential array of services to clients in the upstream oil and gas industry.



The instructor for this webinar is Bob Shoup. He has over 35 years of industry experience in regional studies, prospect generation, reserve evaluation, well planning, and project management. He is considered an expert in interpreting clastic depositional environments, syndepositional structural systems, and rift basins.

He has drilled, or caused to be drilled 26 prospects resulting in 12 commercial discoveries totaling more than 100 million barrels equivalent.

Mr. Shoup is an instructor for a number of courses for Subsurface Consultants & Associates, including Basin Play and Prospect Evaluation and Reserve Estimation.

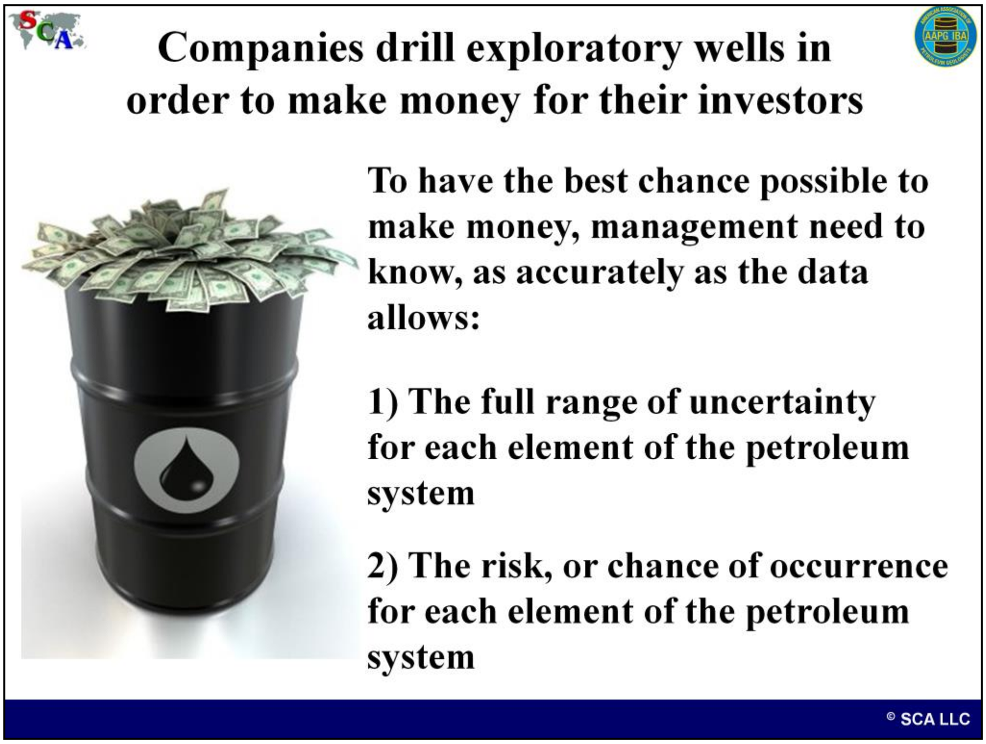
You can find more information on making better interpretations and maps by going to SCA's website and checking out the 10 Habits of Highly Successful Oil Finders which can be found in our blog section.

When presenting a prospect to management, you have to do two things;

1) demonstrate to management that you have interpreted and mapped the prospect accurately and properly defined the risk and uncertainty,

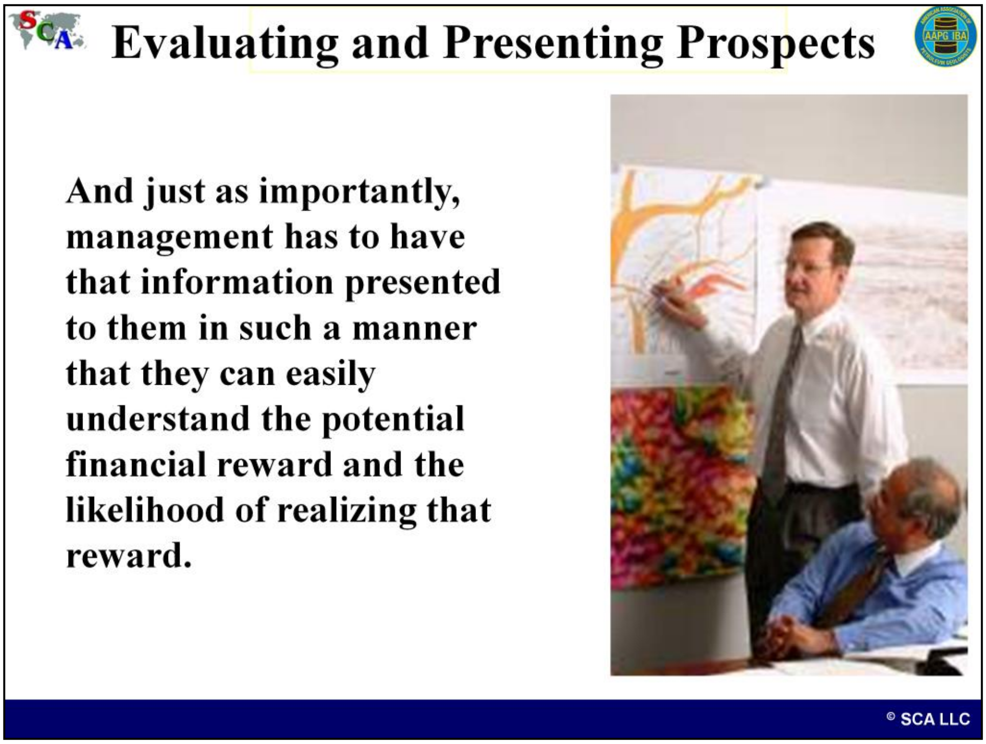
and

2) you must present that information to management in a manner that allows them to quickly understand the opportunity and how that opportunity rates against other opportunities they have to consider.



Many interpreters believe that it is their job to get wells drilled. That is not your job. Your job is to help your company or your investors make money. We do not make money drilling dry holes.

To make money, management need to know, as accurately as possible, the full range of uncertainty and the risk, or chance of occurrence, for each element of the petroleum system



And management need to have that information presented in a manner that they can easily understand. They must know the expected financial reward and the likelihood of realizing that reward.

Evaluating and Presenting Prospects

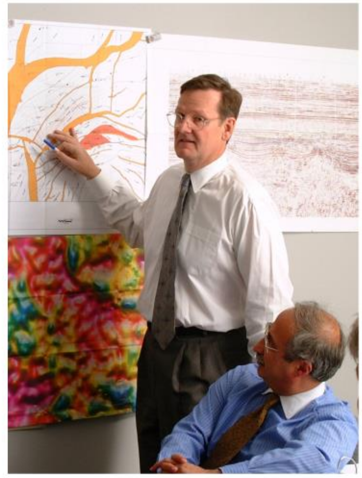
Where In the World?
- Regional Setting and Petroleum System
- Field Size Distribution

Evaluating and Presenting Charge
- Source Rock Presence
- Migration Pathway

Evaluating and Presenting the Reservoir
- Reservoir Presence
- Reservoir Quality

Evaluating and Presenting the Trap
- Trap Type
- Seal

Show them the Money
- Uncertainty
- Risk



The first step in your presentation is to set the stage for management. Then you will need to walk them through each element of the petroleum system. Finally, you will need to help them understand the potential financial reward by defining the uncertainty and risk for each element of the petroleum system.

Where In the World?

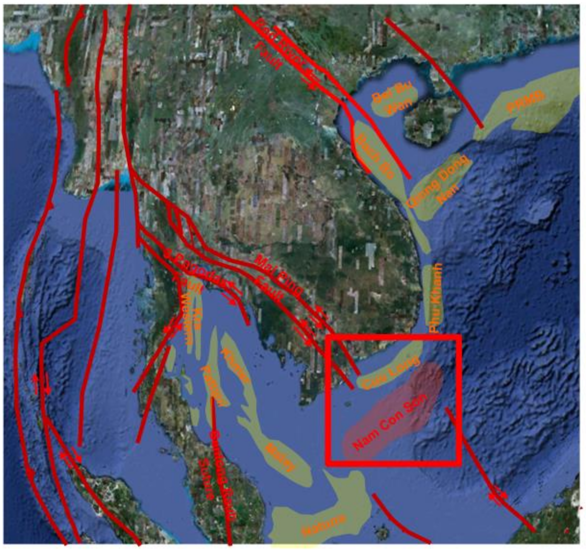
Senior management may see prospects from all over the globe. So when presenting to them, set the stage by orienting them.

Management need to know where in the world, or at least where in your company's portfolio your prospect is located.

Since management, or in this case, your judges, will see a number of different prospect from a number of different basins, it helps to set the stage for your prospect by orienting them. Show them where in the world your prospect is.

We will use an example from the Nam Con Son Basin offshore South Vietnam.

Where In the World?



Nam Con Son Basin Regional Setting

They need to know the basin and the regional setting.

In this example of the Nam Con Son Basin, the regional setting is:

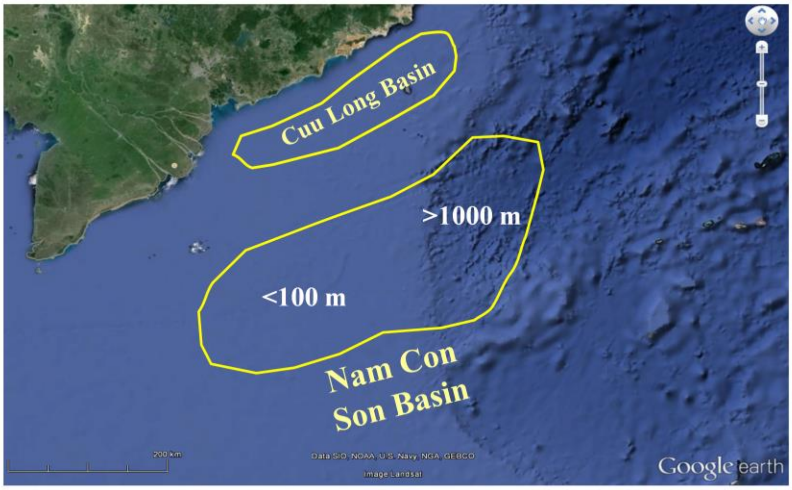
Offshore Vietnam in the South China Sea

Eocene to Oligocene-aged rift basin

They need to know where the basin is located as well as the regional setting. Start from a high-level perspective then drill down.

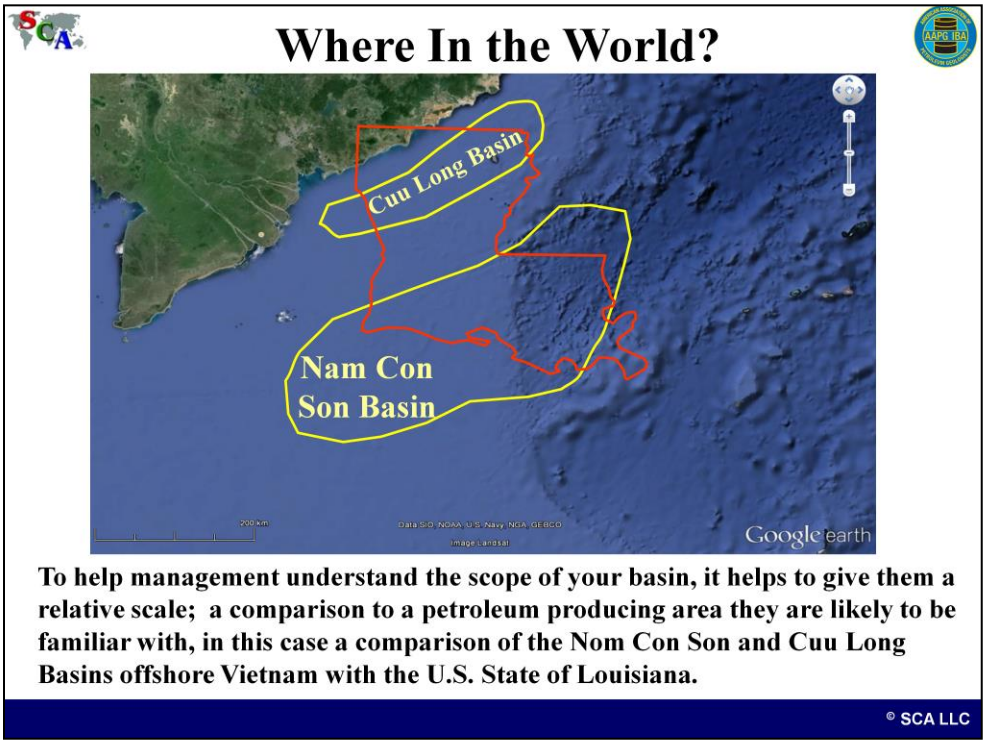
The Nam Con Son Basin is located offshore South Vietnam in the South China Sea. It is one of several Late Eocene to Oligocene-aged rift basins in the region, several of which have established prolific hydrocarbon production.

Where In the World?

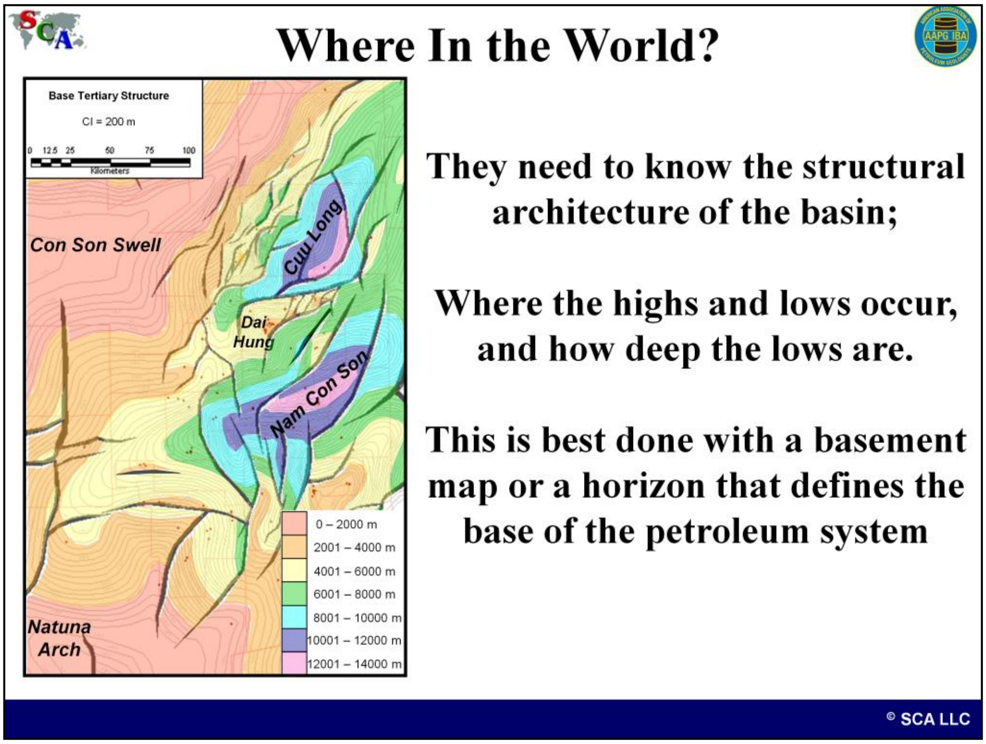


For offshore prospects management need to know the water depth

The bathymetry of the Nam Con Son Basin ranges from under 100 meters in the west to over 1000 meters in the east.



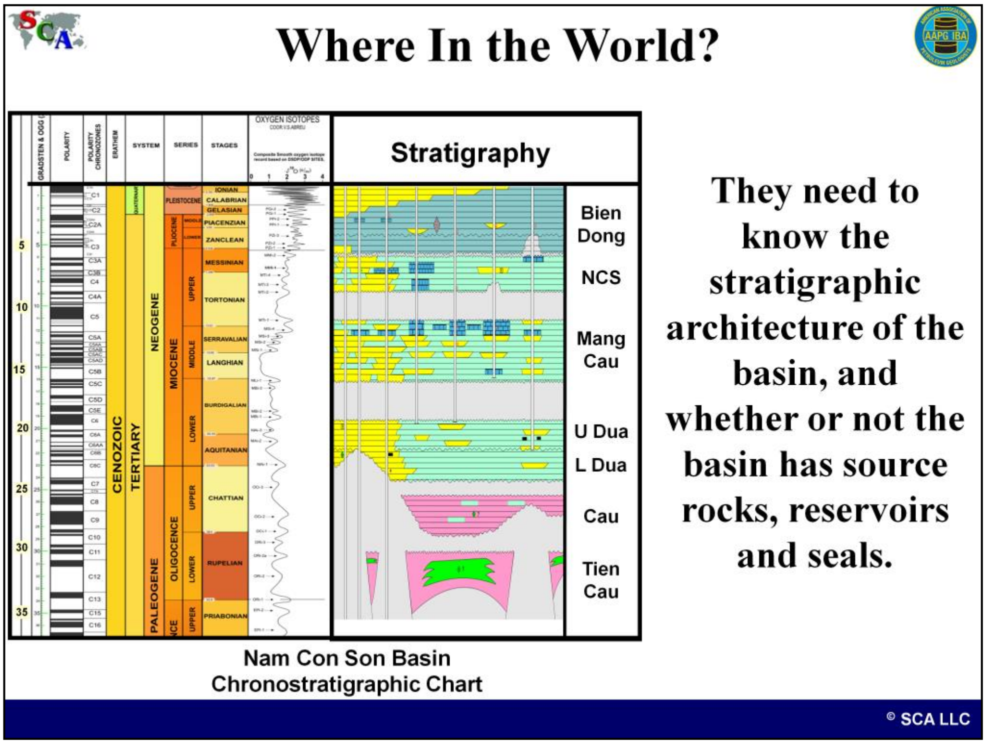
Since management, or your judges, may see prospects from all over the world it is helpful to give them a relative scale. In this example, an outline of the State of Louisiana has been overlain. The Nam Con Son Basin is almost twice the size of southern Louisiana, a very prolific producing area of the U.S. Gulf of Mexico



Now that you have shown management where in the world your prospect is located, they need to know the structural architecture of the basin.

They need to know where the highs are (prospective areas) and where the lows, or kitchens are located. Since basement structure is usually the fundamental control of the petroleum system, a depth structure map of the basement is usually the best map to highlight the structural framework.

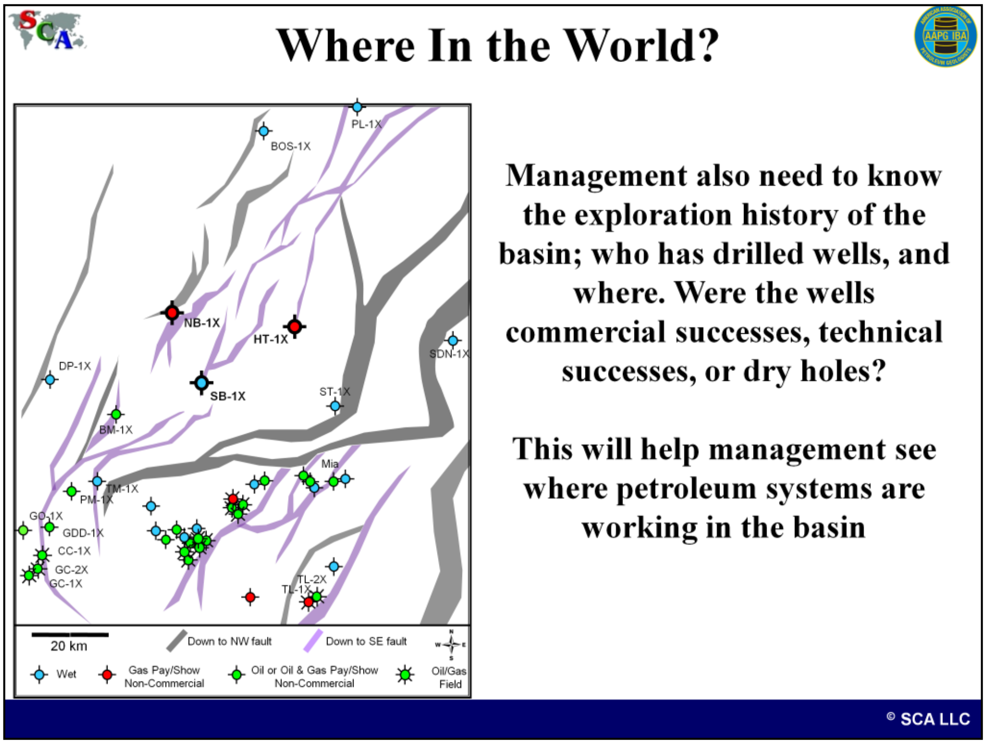
You need to show them as much of the regional structure as possible, even if you need to use published maps. This map was hand-contoured in ArcGIS from a number of 2D and 3D seismic data sets as well as published maps



Likewise, management need to know the stratigraphic framework of the basin. This is best done with a chronostratigraphic section which uses geologic time as the vertical axis.

In this chronostratigraphic section of the Nam Con Son Basin, we can see that the Tien Cau Formation is a continental rift sequence unconformably overlain by the continental Cau Formation.

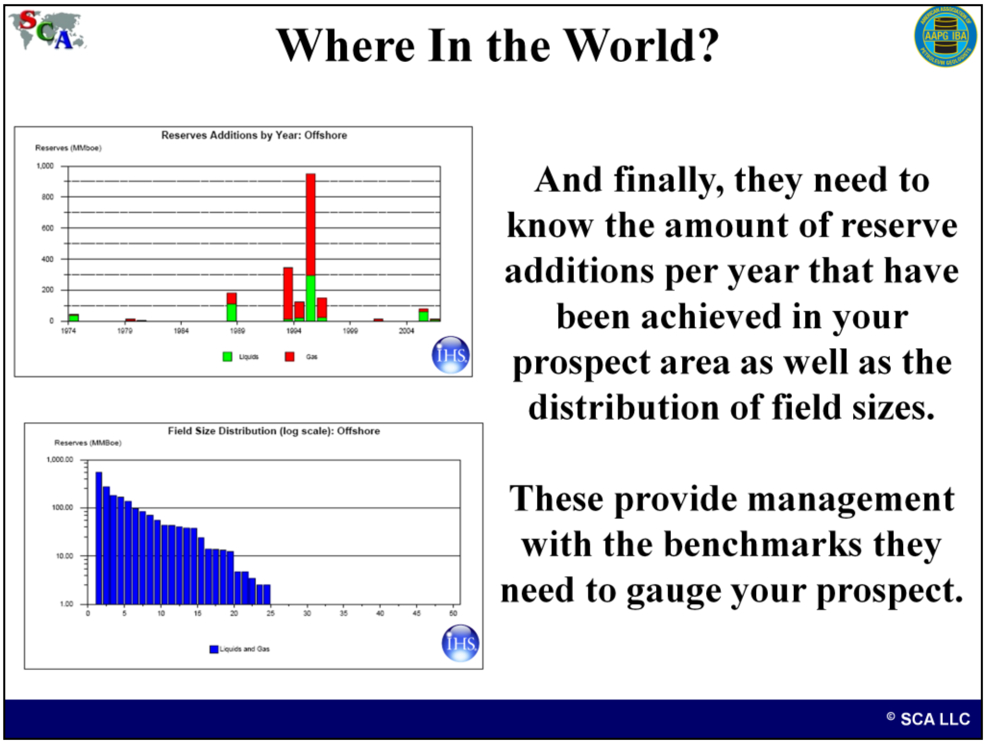
The Dua Formation is a clastic marine sequence unconformably overlain by the Mang Cau Formation. By latest Mang Cau time, carbonate deposition becomes more prevalent. Carbonate deposition continues through the Nam Con Son Formation, only to be overwhelmed in the Plio Pleistocene as the Mekong River progrades into the basin to deposit the Bien Dong Formation.



To help better understand the potential risk and reward of your prospect, management need to know how well the basin's petroleum system is working.

How many wells have been drilled, and what percentage of those were dry hole, how many were non-commercial discoveries (technical successes) and how many were commercial discoveries.

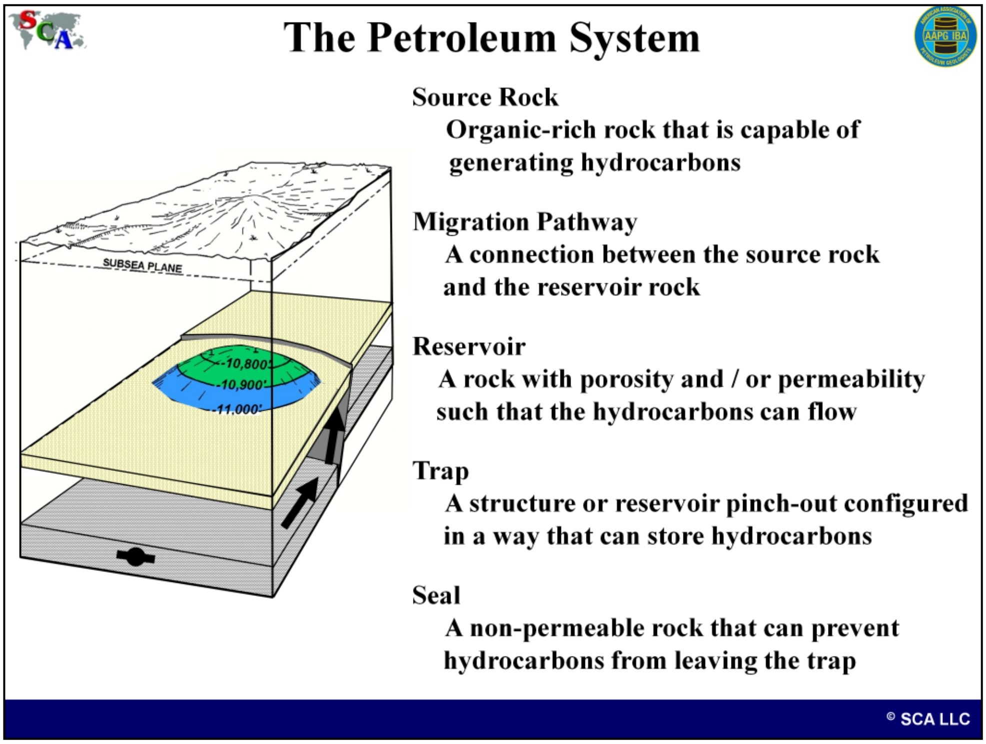
Time and data allowing, each dry hole should be explained. However, you will often not have the information you need to assess why certain wells failed.



Finally, you will need to provide management with an assessment of the amount of reserve additions per year that has been achieved in your prospect area as well as the field size distribution for your area. Scout services such as IHS often have this information, but at a cost. So you may not be able to do this in the IBA competition but you should always do it when you are presenting to management or investors.

Looking at the reserve additions per year can give you a good idea of how mature a basin is; companies ten to drill the larger, easier to identify prospects first such that over time, the amount of reserve additions diminish over time, at least until someone tests a new play concept.

Looking at the field size distribution gives you a benchmark for your prospect. In the Nam Con Son Basin, the average commercial field size is ~60 million barrels of oil equivalent (oil and gas). If your prospect is 120 million barrels, you are double the average and well into the tail of the distribution. Possible to be sure, but not overly likely.



Now that you have set the stage for management, it is time to show them the elements of the petroleum system, which are:

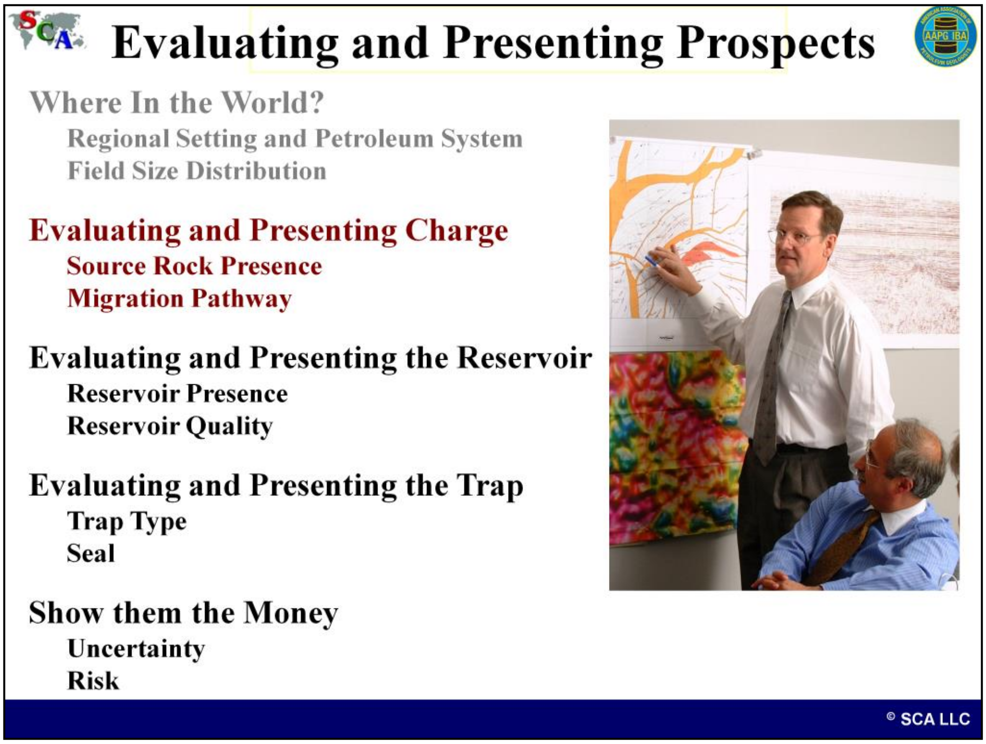
Source Rock

Migration Pathway

Reservoir

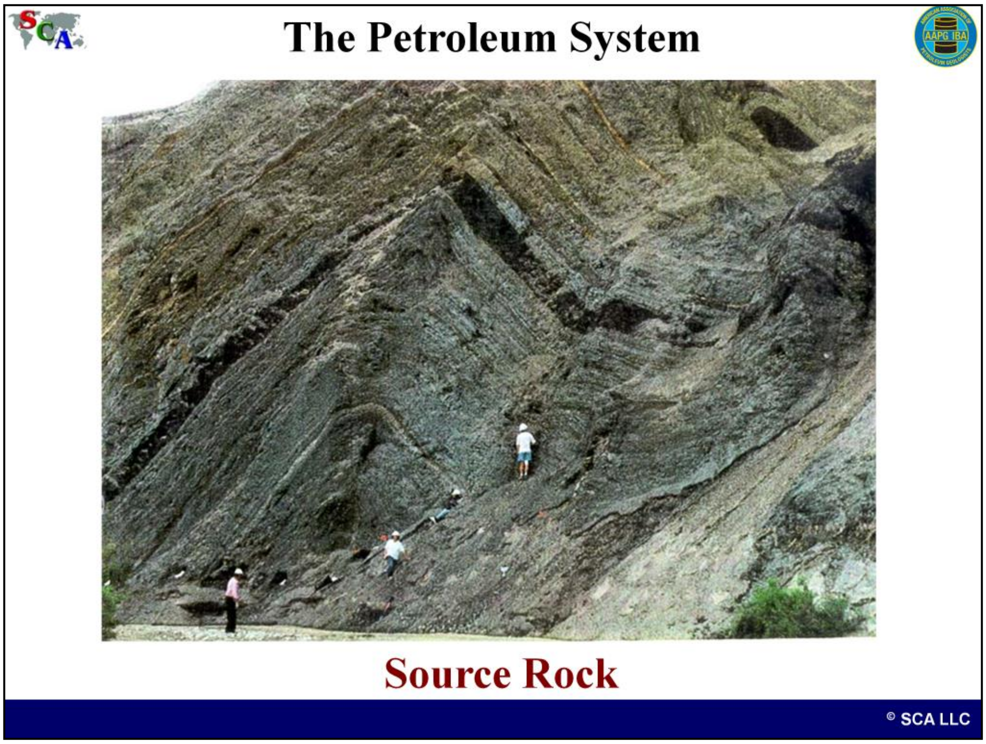
Trap

Seal



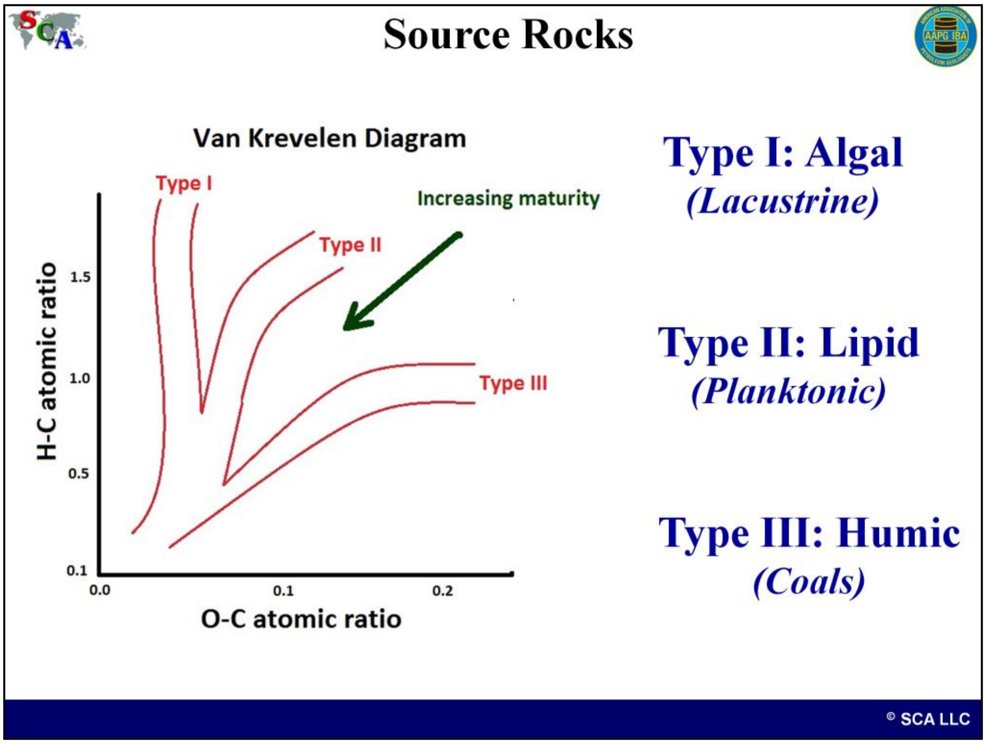
We will start with charge. For basins with few or no wells, charge is usually considered the highest risk. For basins with established hydrocarbon production, source rocks are known to be present and mature. However, not all potential traps have access to that source rock.

So we must be able to demonstrate to management that not only do we have source rock, but that the source rock is mature, and there is a connection from the source rock to the prospect along which hydrocarbons can migrate.



Source Rock

Rocks rich in organic matter which, if heated sufficiently, will generate oil or gas. Typical source rocks, usually shales or limestones, contain about 1% organic matter and at least 0.5% total organic carbon (TOC), although a rich source rock might have as much as 10% organic matter.



There are three types of source rocks; Type I, II and III. The classification is based on the content of hydrogen (H), carbon (C) and oxygen (O) and can be shown in a a "van Krevelen diagram".

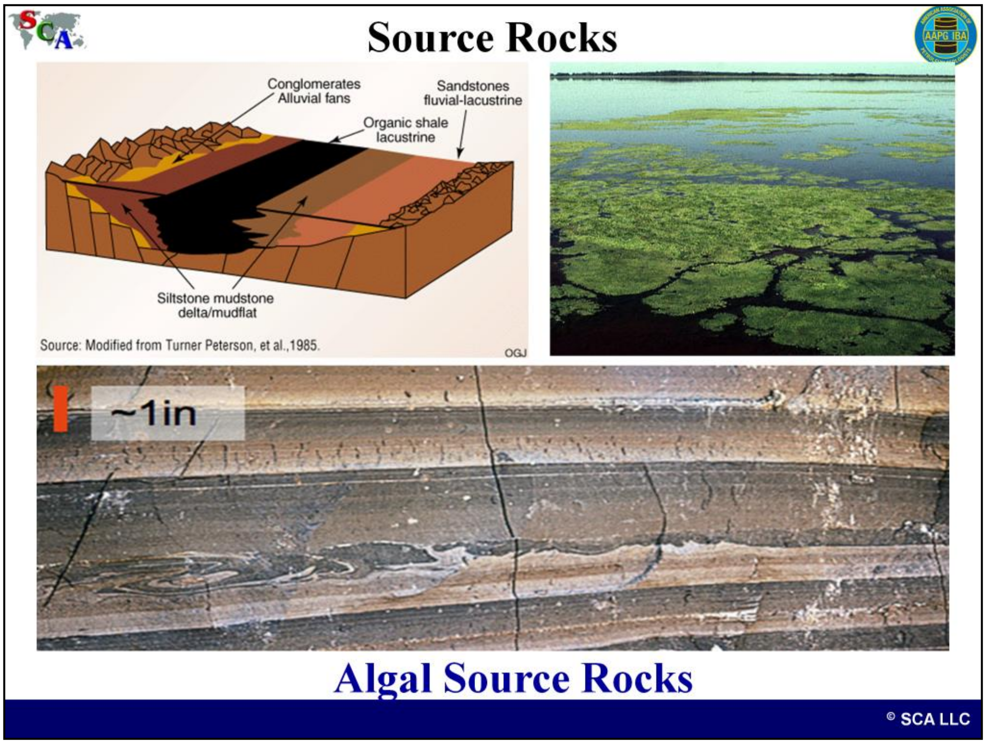
Type I has mainly algal/sapropelic kerogen and is often associated with anoxic environments in lake sediments.

Type II has lipid-rich kerogen from planktonic origin and are mainly associated with marine sediments.

Type III has humic kerogen derived from plant material. Most coals are type III source rocks.

Type I and II are generally oil-prone while type III is mainly a gas source rock.

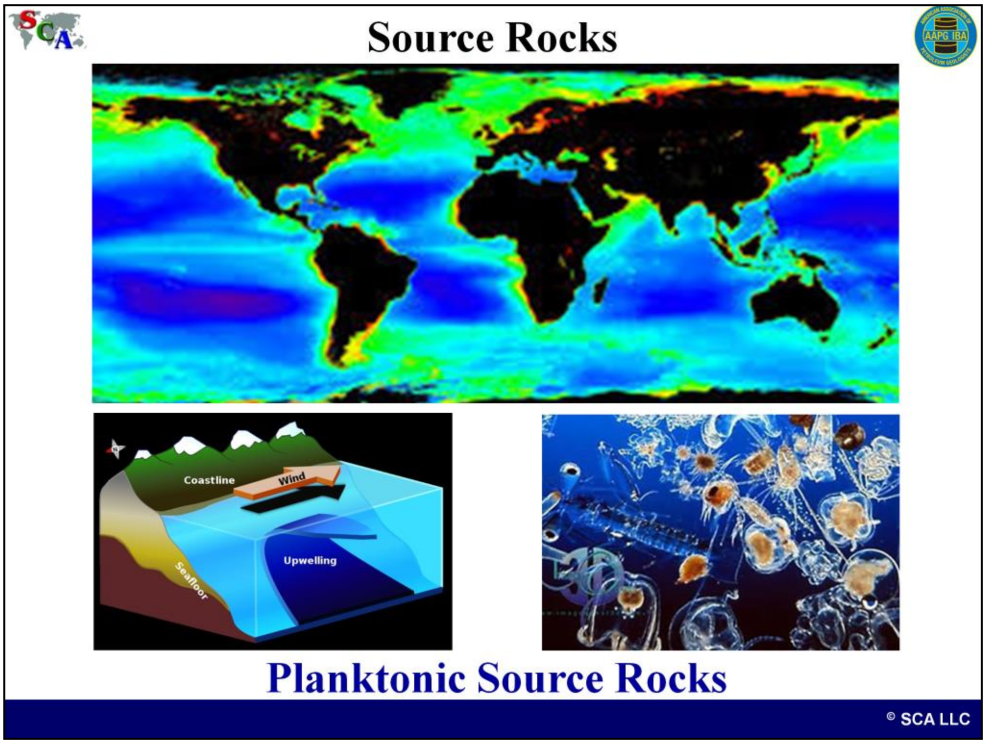
.



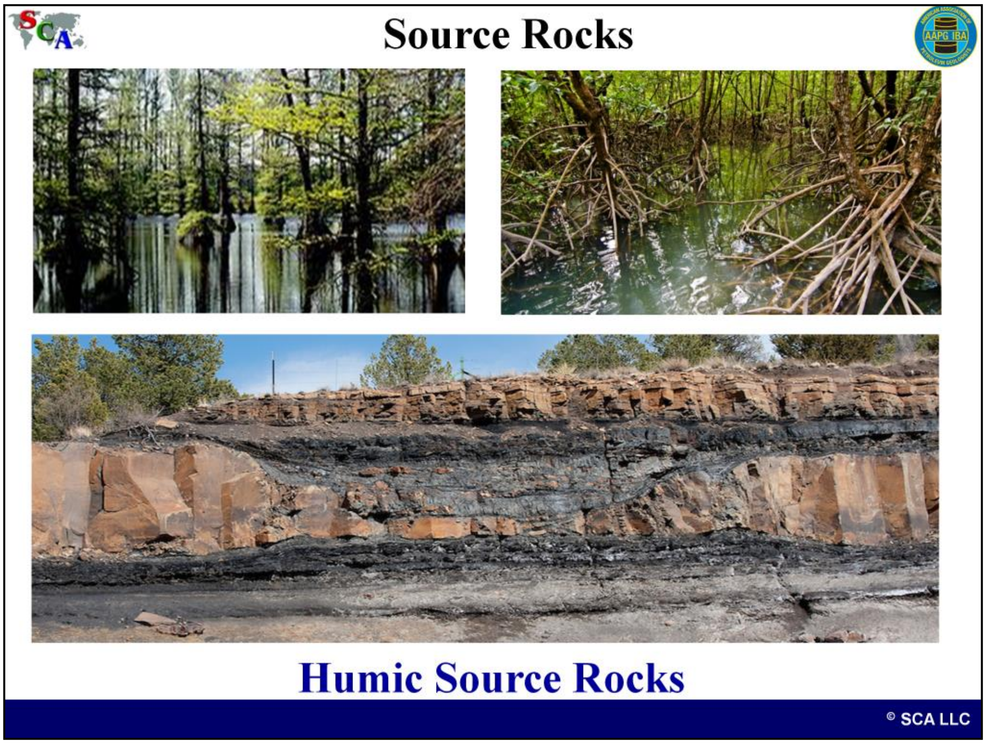
Type I Algal source rocks are most common in lacustrine settings such as rift basins. They are also common in Sabkha environments.

Lacustrine source rocks are often finely layered due to seasonal variations in lake temperature. They consist of alternating beds of organic-rich mudstone and non-organic rich mudstone.

Algal-rich source rocks deposited in Sabkha environments also tend to be layered, consisting of alternating beds of organic-rich mudstone and evaporites and or carbonates.

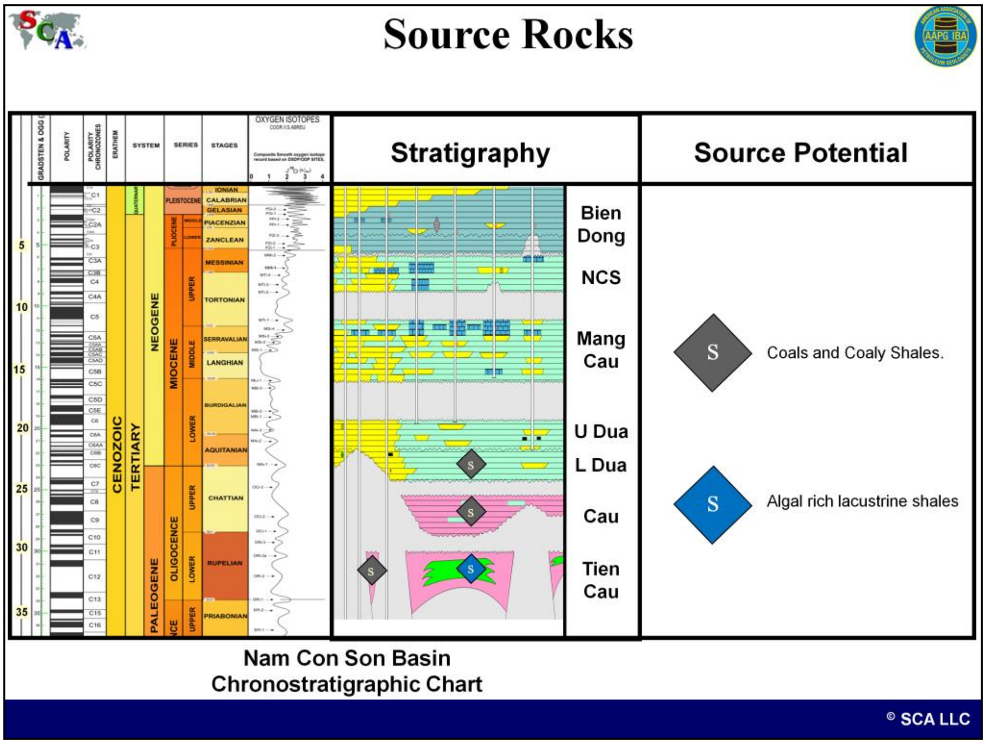


Type II source rocks are generally formed by marine plankton. Planktonic activity is usually highest where ocean currents can carry nutrients to high-latitude coastal areas or where upwelling carries nutrient-rich material from deep water to the photic zone.

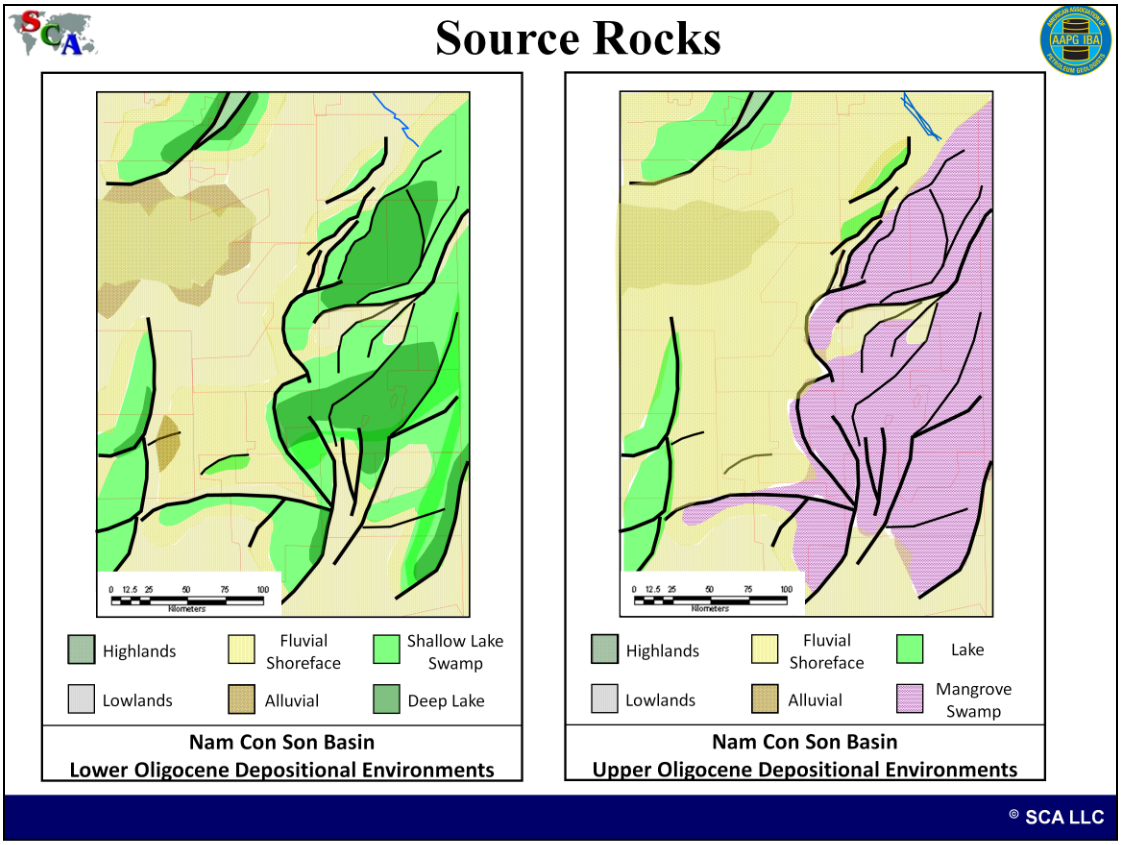


Type III Source Rocks are associated with coals and coaly deposits. They typically form in peat-swamp forests or coastal mangrove swamps in broad tidal estuaries.

More localized coals can be deposited in the inter-fluvial areas of anastomosing rivers and abandoned river channels

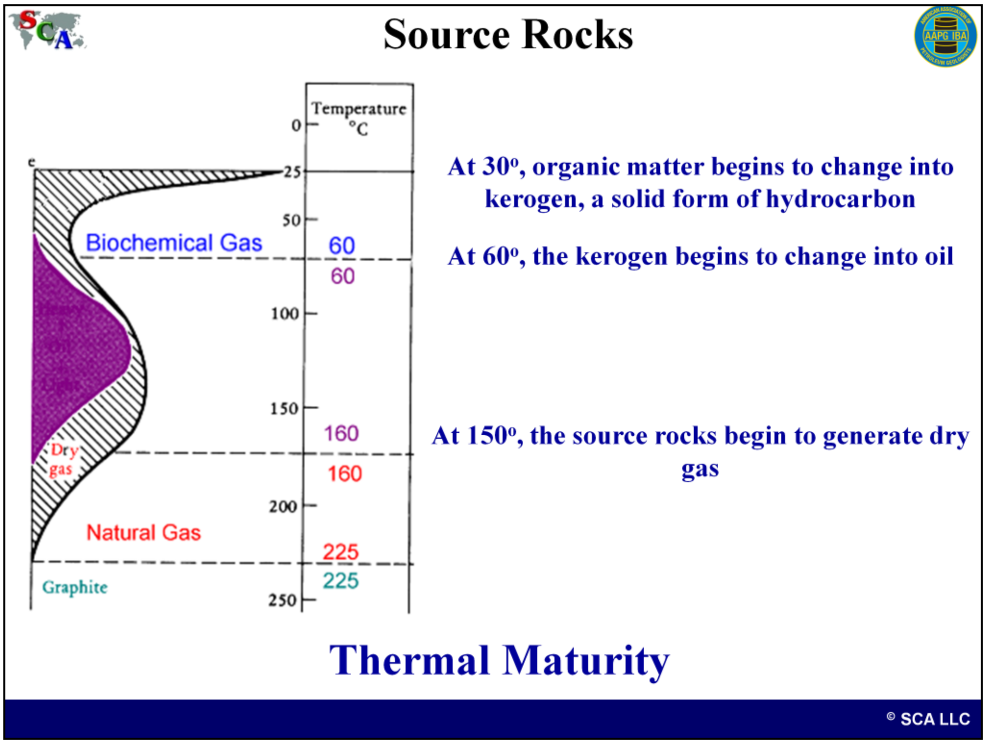


Looking at the Nam Con Son Basin, we can see that the Tien Cau Formation contains algal-rich lacustrine source rocks deposited in rift lakes. The overlying Cau and Lower Dua Formations contain abundant coals deposited in a swamp environment



There are only a handful of Tien Cau penetrations in the Nam Con Son Basin, mostly in the southwest, These encountered course-grained fluvial deposits, with one well encountering thin coals.

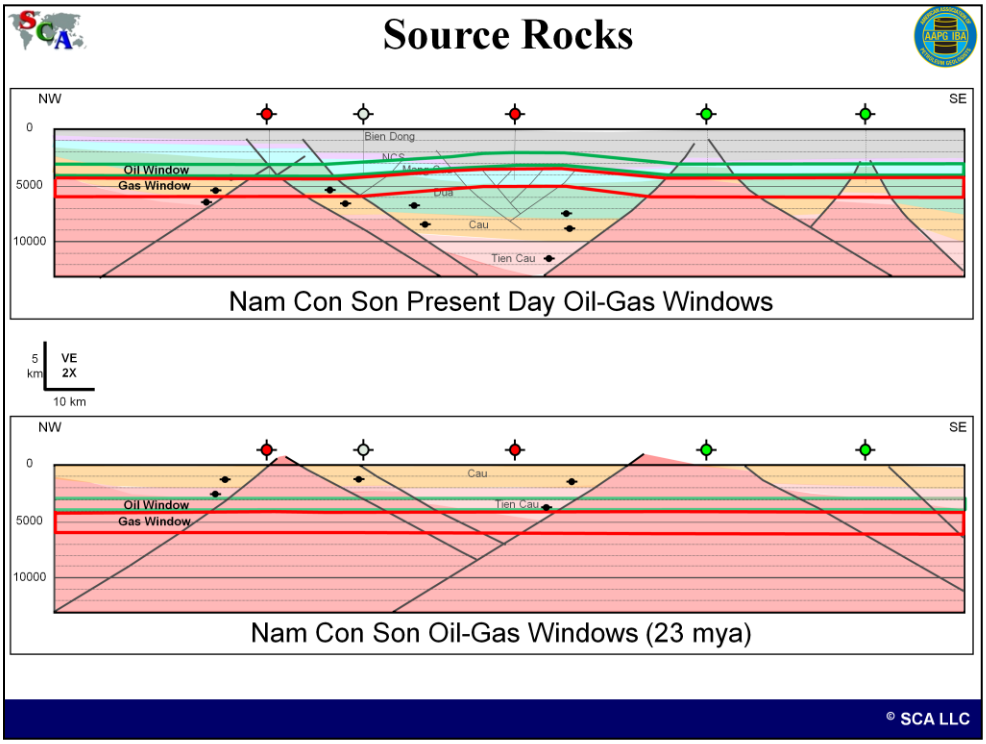
Lakes are interpreted as forming in the deeper portions of the rift basins. These served as the locus of algal-rich lacustrine shales in the deeper portions of the lakes, and coaly lacustrine swamps in the shallower portions of the basins..



Once the source rock has been deposited and preserved, it must be buried and 'cooked'.

At 30° C, organic matter begins to change into kerogen, a solid form of hydrocarbon. When the source rock is heated to ~ 60°, C, the kerogen begins to change into oil. Maximum expulsion occurs around 130° C.

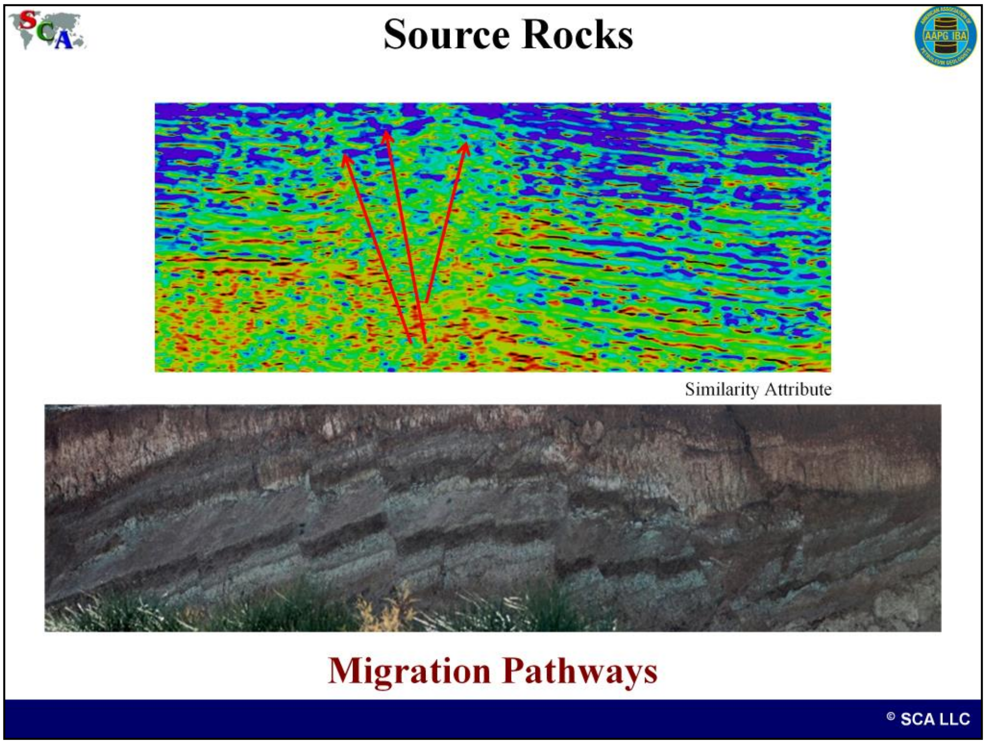
At ~150° C the source rocks begin to generate dry gas, and at 225° C the source rock becomes over mature.



Looking at the thermal gradient for the Nam Con Son Basin, we can see that present day, the source-prone Tien Cau, Cau, and Lower Dua Formations are over mature (below the gas window) except on the flanks of the basement horst block along the northwest margin of the basin.

If we palispastically reconstruct the cross section to the Cau Formation (23 mya). We can see that the Tien Cau Formation is in the oil window, transitioning to the gas window in the deeper parts of the basin. Coals of the Cau Formation have yet to enter the oil window.

By looking at the timing of when source-prone intervals enter the oil and gas windows, we can determine when hydrocarbons were generated and began to migrate from the kithchens.

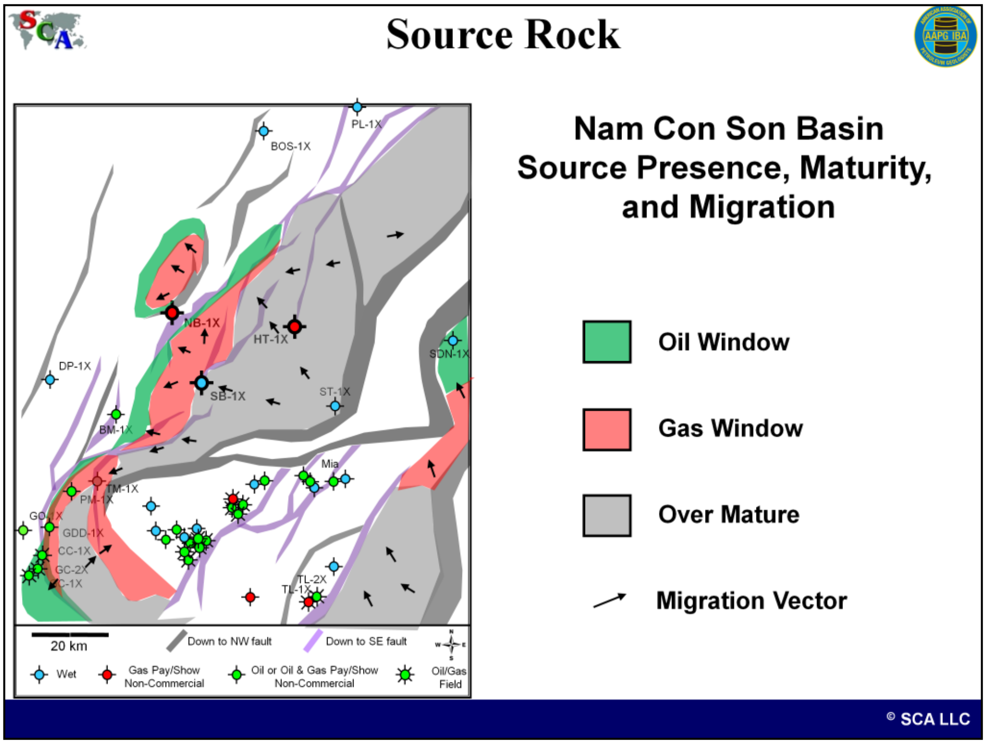


Migration Pathway

Once we know where the source rocks were deposited and when they began to expel oil and gas, we need to look at the migration pathway.

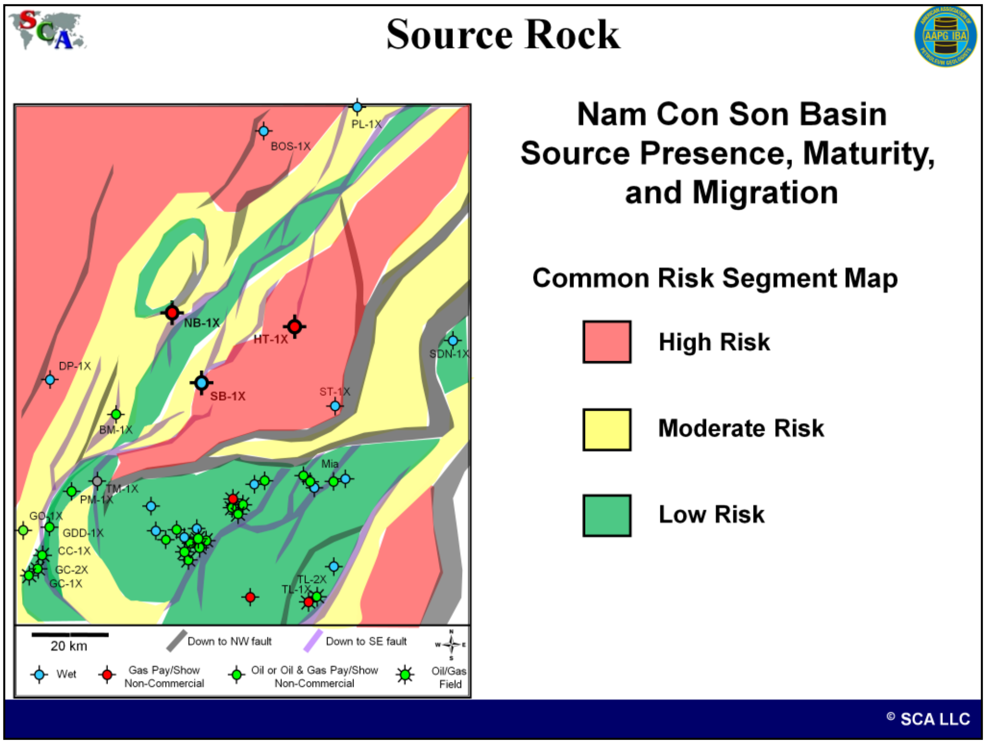
The migration pathway is the route that hydrocarbons follow to get from the source rock where they are generated to the reservoir in which they are stored.

Certain seismic attributes such as similarity can highlight hydrocarbon migration. Likewise mapping faults that extend upward from the source rocks to the reservoir section can show migration fairways.



This map of the Nam Con Son Basin shows the present-day thermal maturity of the basin. The migration vectors are shown to illustrate where hydrocarbons would migrate once generated.

The migration vectors will point from the lows to the highs and be oriented perpendicular to the structure or the isopach contours of the basin.



We can also use a Common Risk Segment Map to show management where in the basin charge and migration are considered to be high or low risk. Common Risk Segment Maps use a traffic light system to illustrate relative risk

Red indicates where a petroleum system element (in this case charge and migration) is considered high risk, and the area should be explored with caution

Yellow indicates where a petroleum system element is considered somewhat risky, and due diligence should be applied to all prospects

Green indicates where a petroleum system element is considered low risk, and the area should be explored aggressively

Evaluating and Presenting Prospects

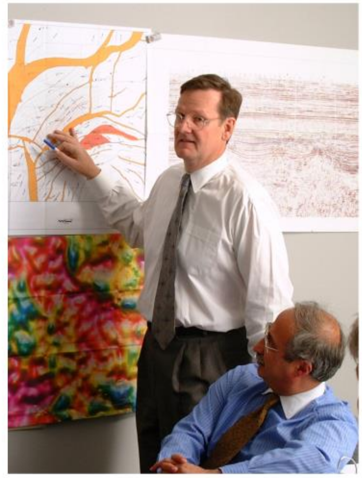
Where In the World?
- Regional Setting and Petroleum System
- Field Size Distribution

Evaluating and Presenting Charge
- Source Rock Presence
- Migration Pathway

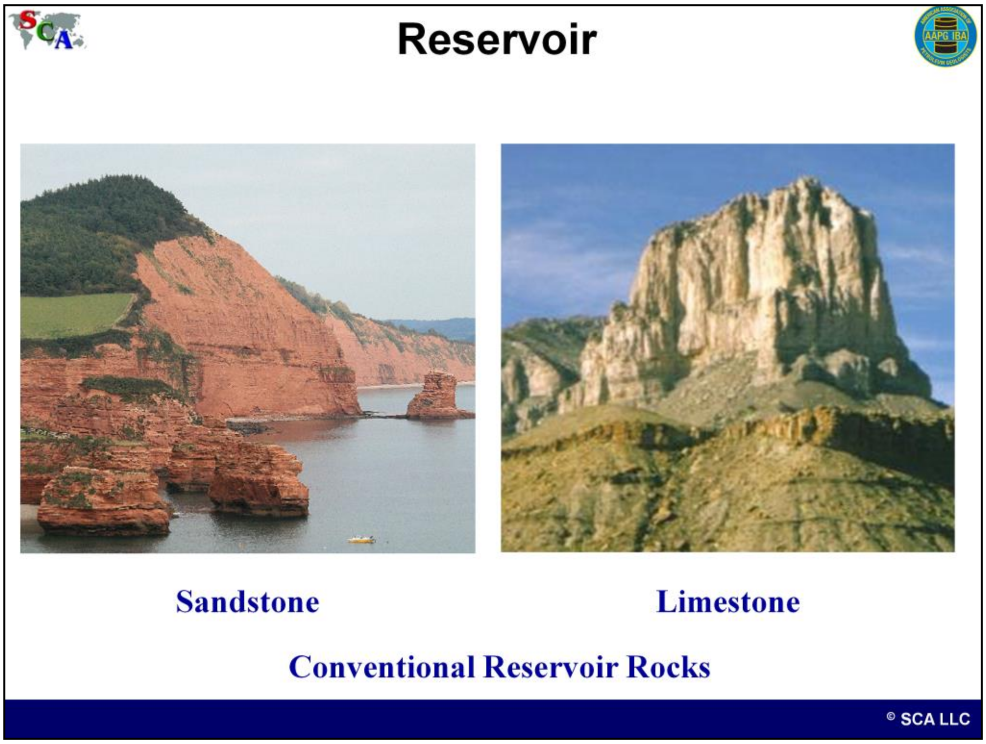
Evaluating and Presenting the Reservoir
- Reservoir Presence
- Reservoir Quality

Evaluating and Presenting the Trap
- Trap Type
- Seal

Show them the Money
- Uncertainty
- Risk

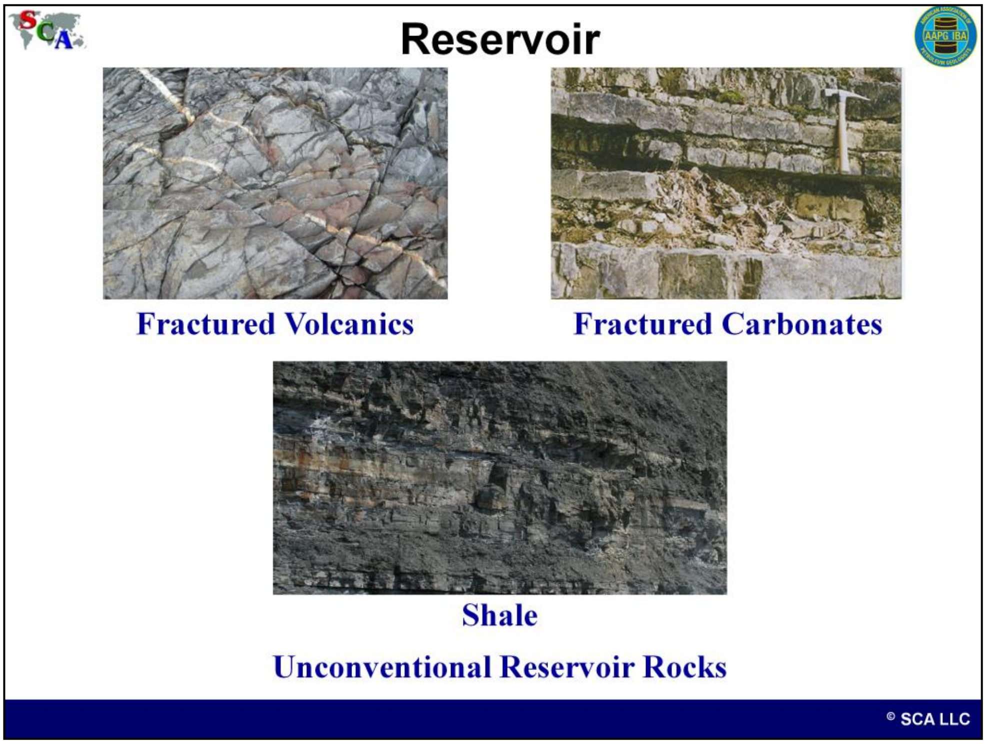


Now that management knows that your prospect can be charged they need to know if there is a reservoir to hold the hydrocarbons.



The reservoir is the container in which hydrocarbons are stored. There must be sufficient porosity to hold the hydrocarbons and sufficient permeability to allow the hydrocarbons to flow from the reservoir to the well bore.

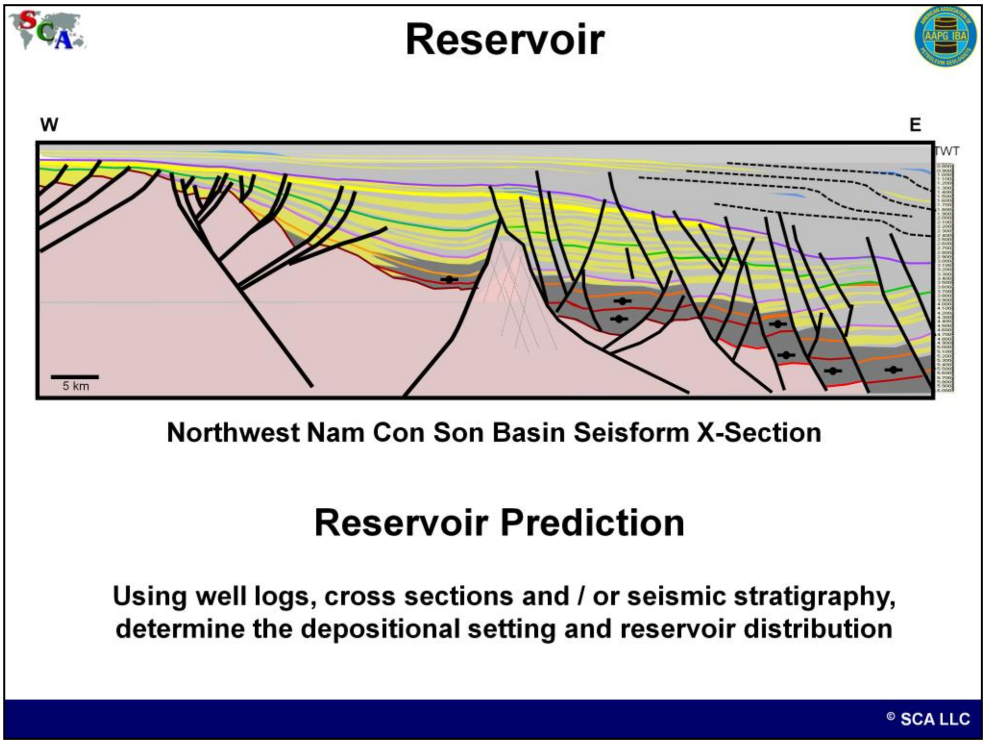
Conventional reservoirs are either sandstones or limestones.



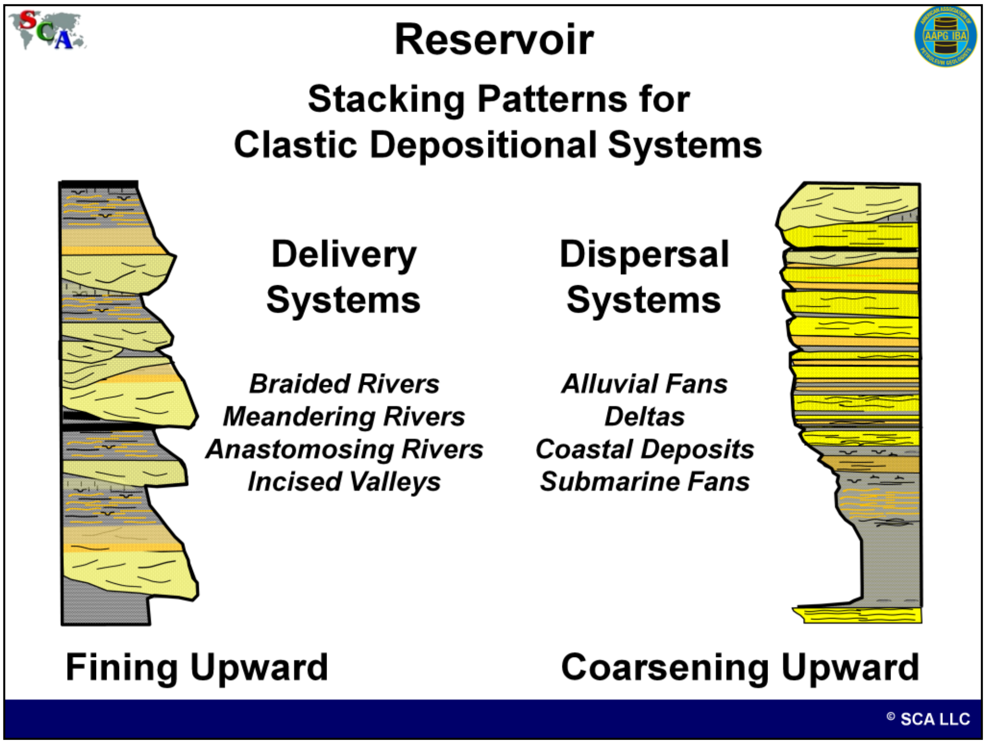
However, any lithology may hold hydrocarbons. For example, fractured volcanics or basement may be reservoirs.

With the advances in hydraulic fracturing technology, tight sandstones and even source rock shales can now be considered reservoir.

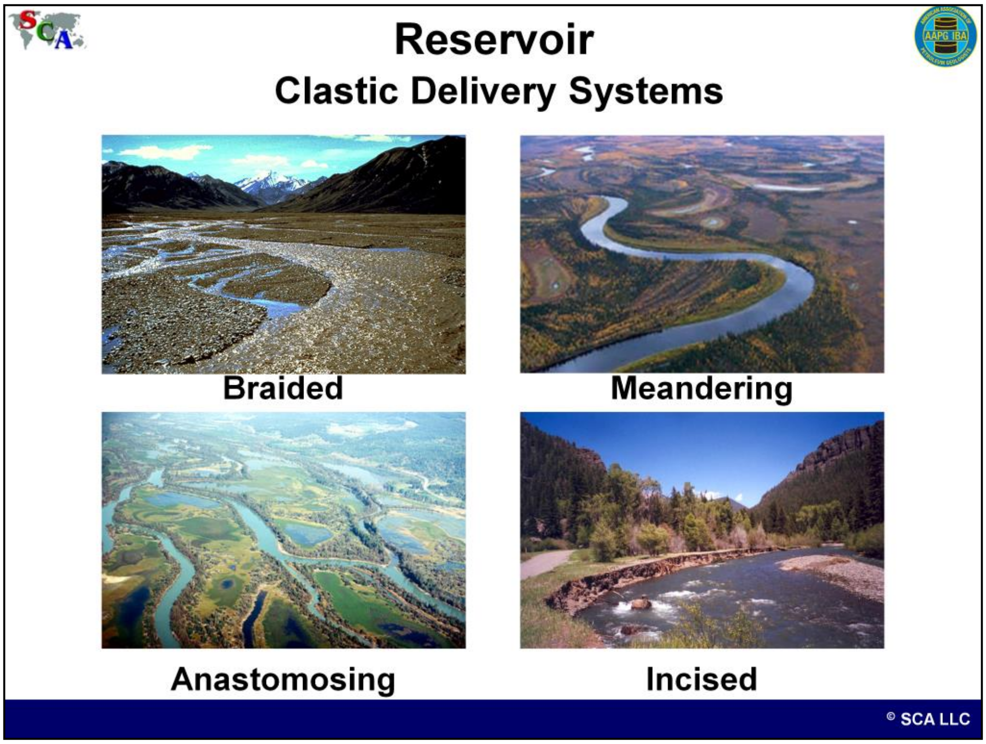
In the Nam Con Son Basin, the Dai Hung Horst produces from fractured granite.



The first step in predicting the reservoir you expect to encounter at your prospect is to use the nearby well control and construct cross sections or use seismic stratigraphy, or both to determine the depositional setting and the reservoir distribution.



Clastic depositional systems exhibit one of two principal stacking patterns; fining upwards patterns associated with delivery systems (rivers) and dispersal systems (lobate fans).



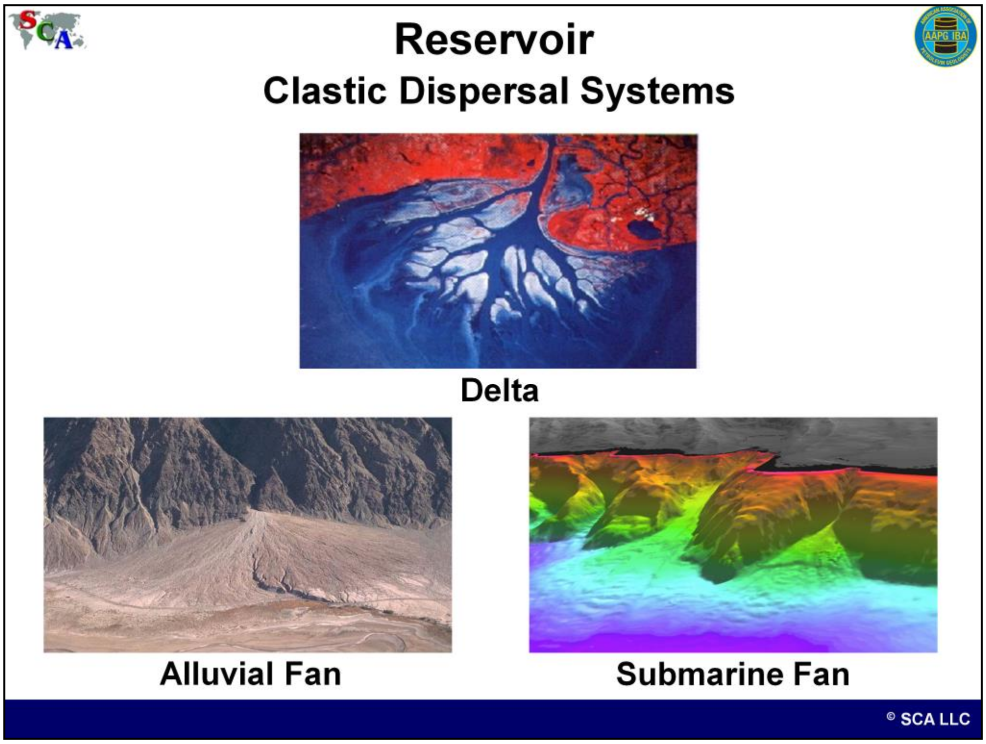
There are four delivery systems each with a unique distribution of reservoir within them;

Braided Rivers

Meandering Rivers

Anastomosing Rivers

Incised Valleys.



There are three delivery systems each with a unique distribution of reservoir within them as well;

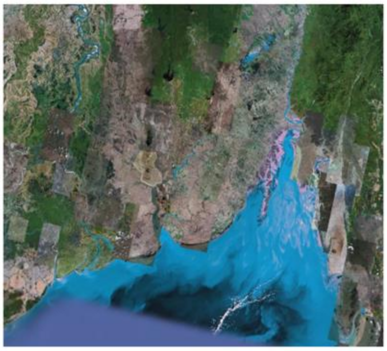
Alluvial Fans

Deltas

Submarine Fans

Reservoir

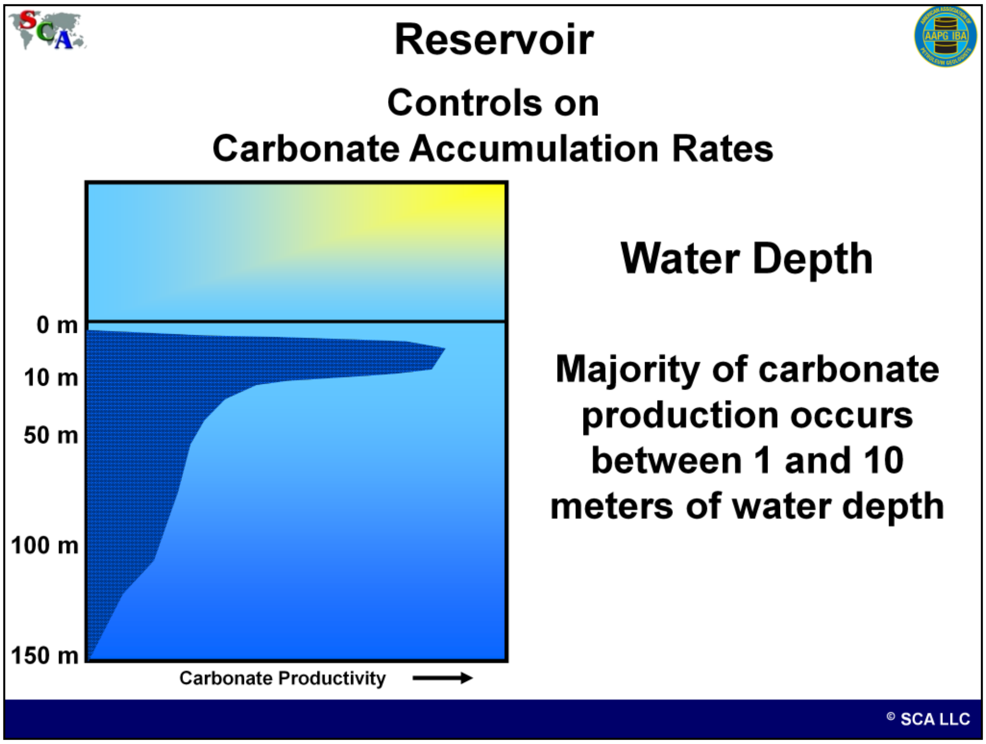
Key Difference between Carbonate Stratigraphy and Clastic Stratigraphy



Clastic Sediments Are Transported

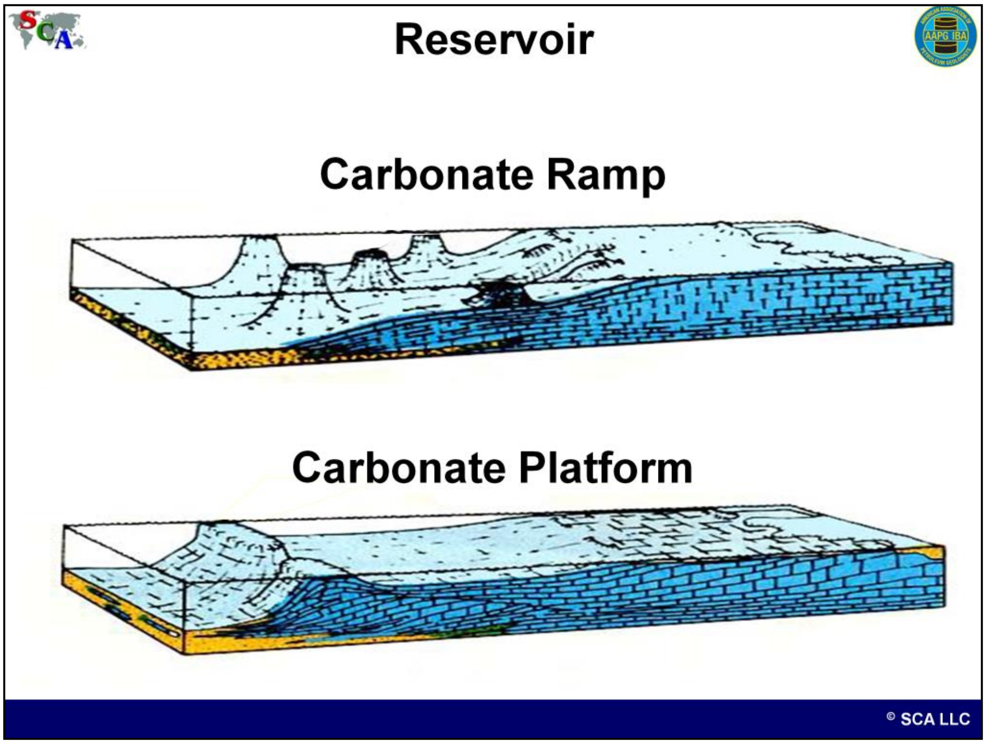
Carbonates Grow in-place

A key difference between carbonates and clastics is that clastic sediments are transported, often large distances. Carbonates grow in place, or are transported very short distances from where they grew.

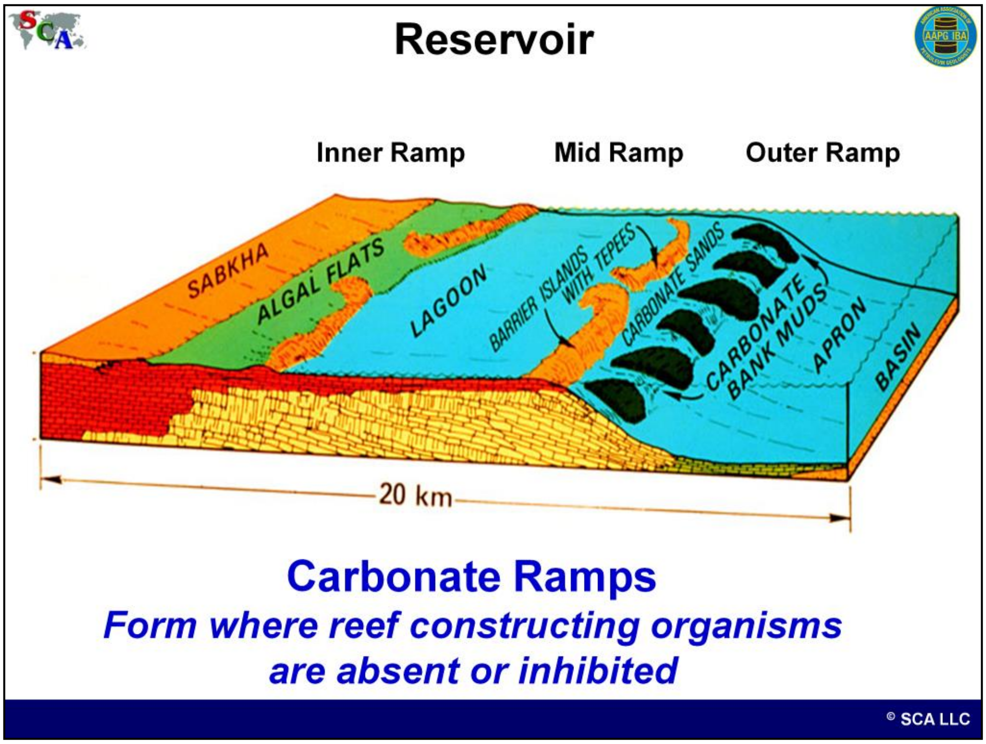


Carbonate deposition is controlled by climate and water depth. The majority of carbonate production occurs between 1 and 10 meters.

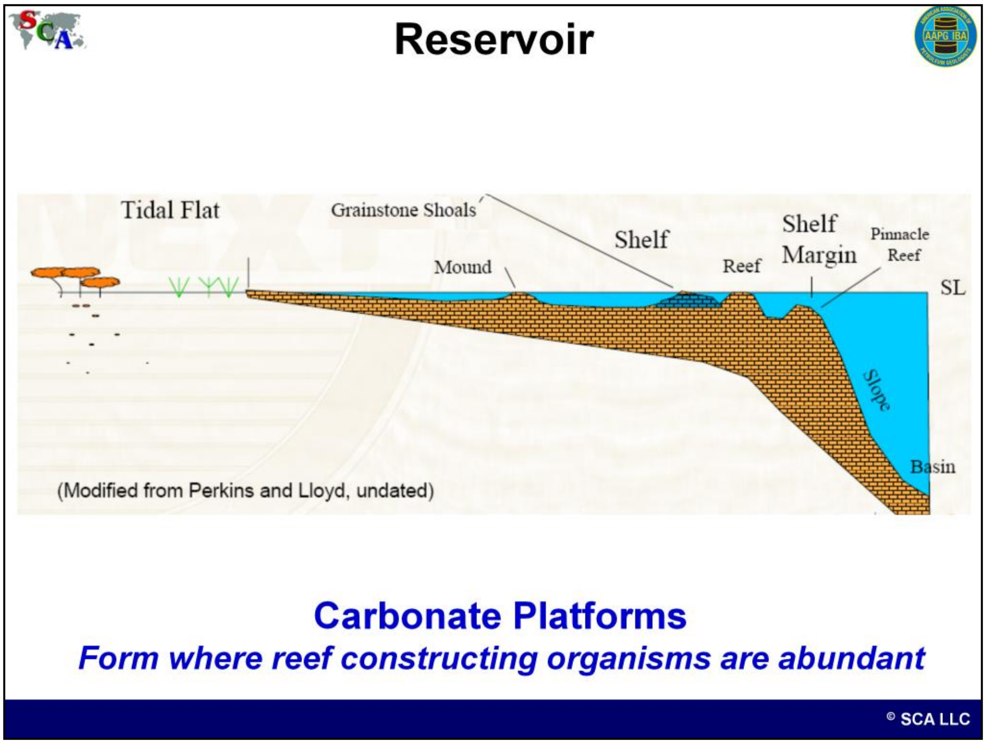
In water depths shallower than 1 meter, wave action tends to kill carbonate generating organisms. In water depths greater than 10 meters light conditions begin to get too dark for many organisms.



There are two principal carbonate systems, ramps and platforms.

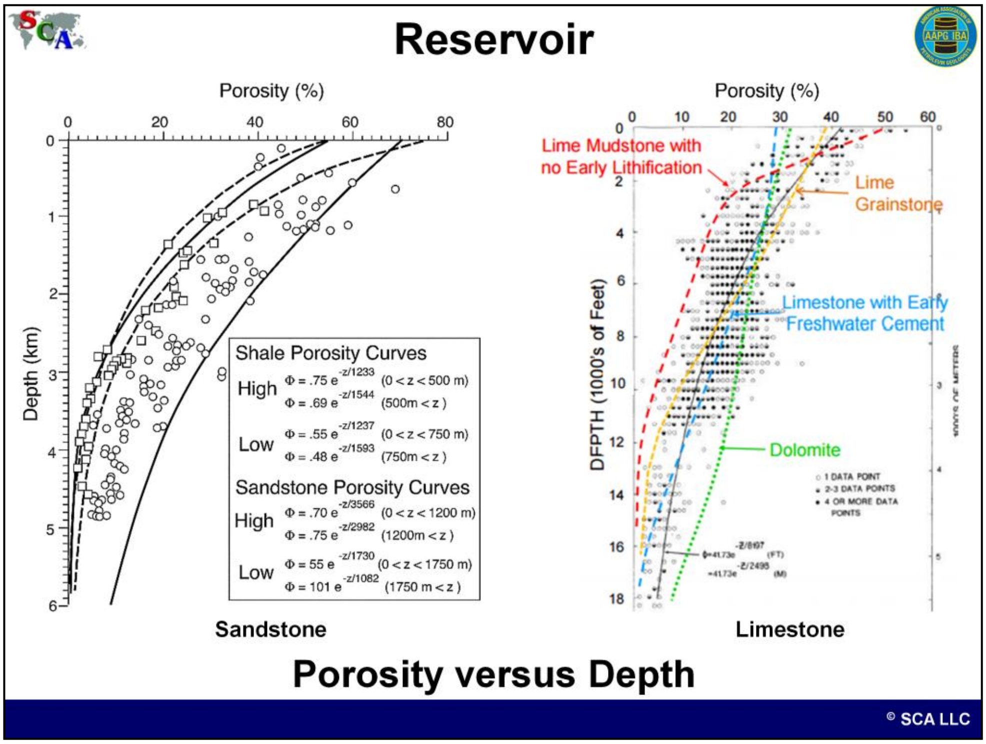


Carbonate ramps form where reef constructing organisms are absent, or where conditions inhibit their development. Carbonate ramps can be subdivided into the inner, middle, and outer ramp.

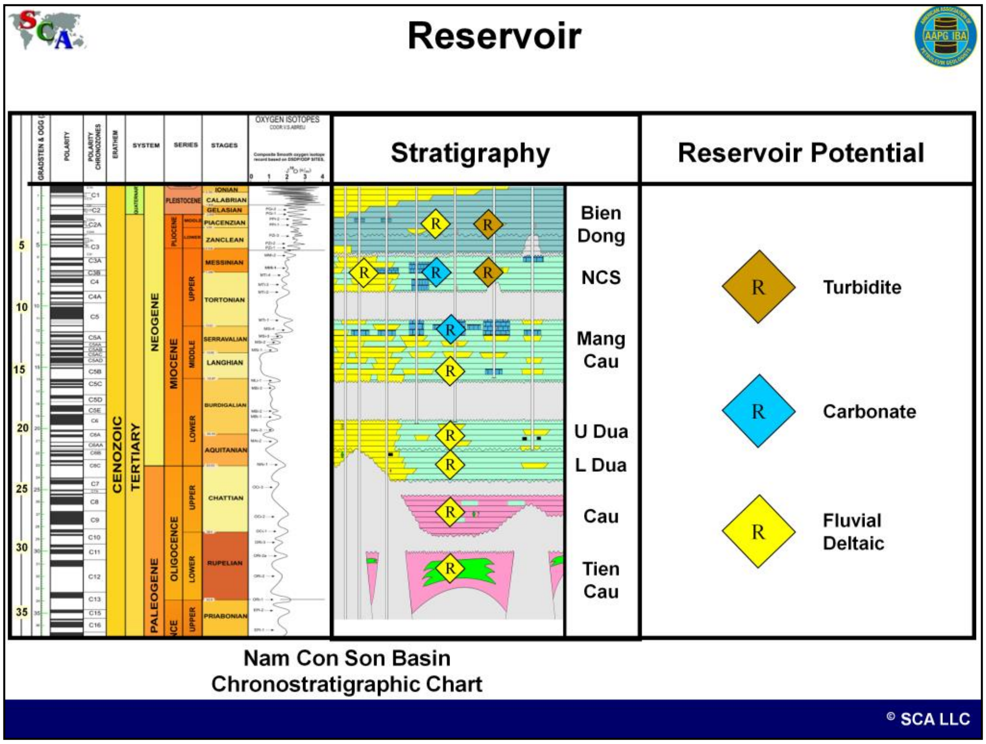


Carbonate Platforms form where reef constructing organisms are abundant. Carbonate Platforms can be subdivided into the Tidal Flat, Shelf, and the Shelf Margin.

The tidal flat depositional setting on carbonate ramps and carbonate platforms is similar.

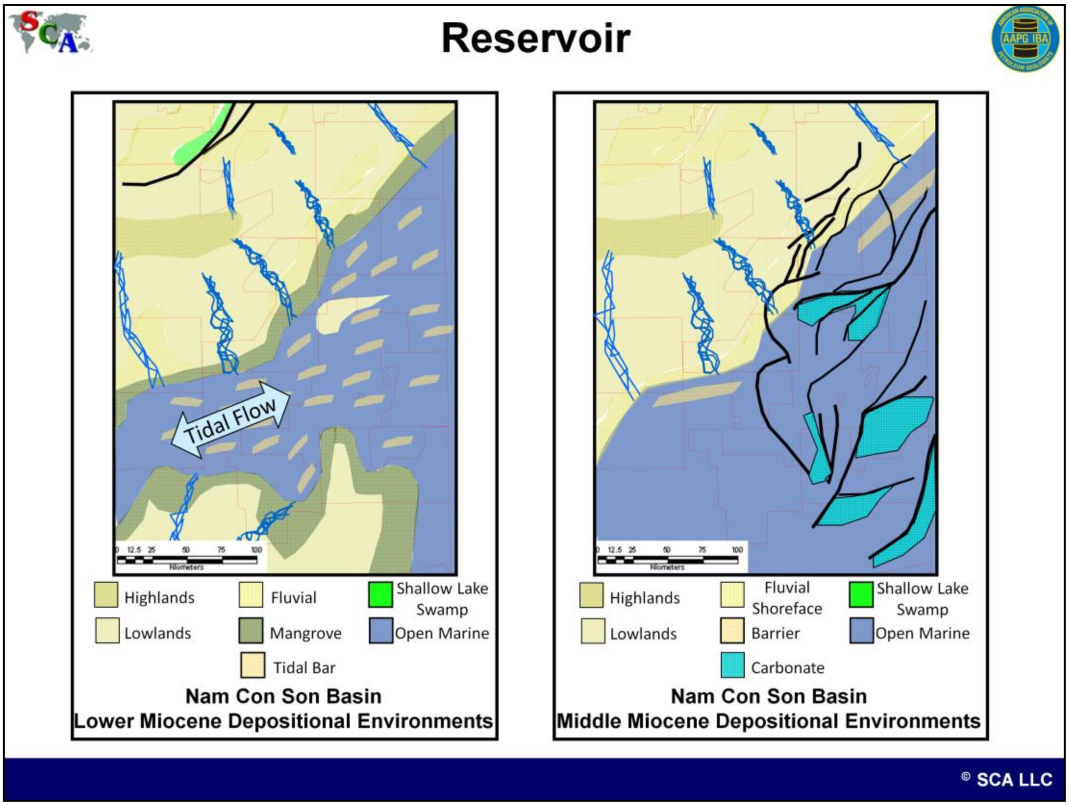


For conventional plays, reservoir quality is just as critical as reservoir presence. Porosity decreases with depth, so unless there is some method to preserve porosity at depth, such as early hydrocarbon migration, or some diagenetic event to enhance porosity, there is a limit to how deep we can expect to encounter reservoirs with sufficient quality to be productive.



There are three principal reservoir facies in the Nam Con Son Basin, fluvial deltaic sediments deposited in both lacustrine and marine settings; carbonate build-ups; and turbidites.

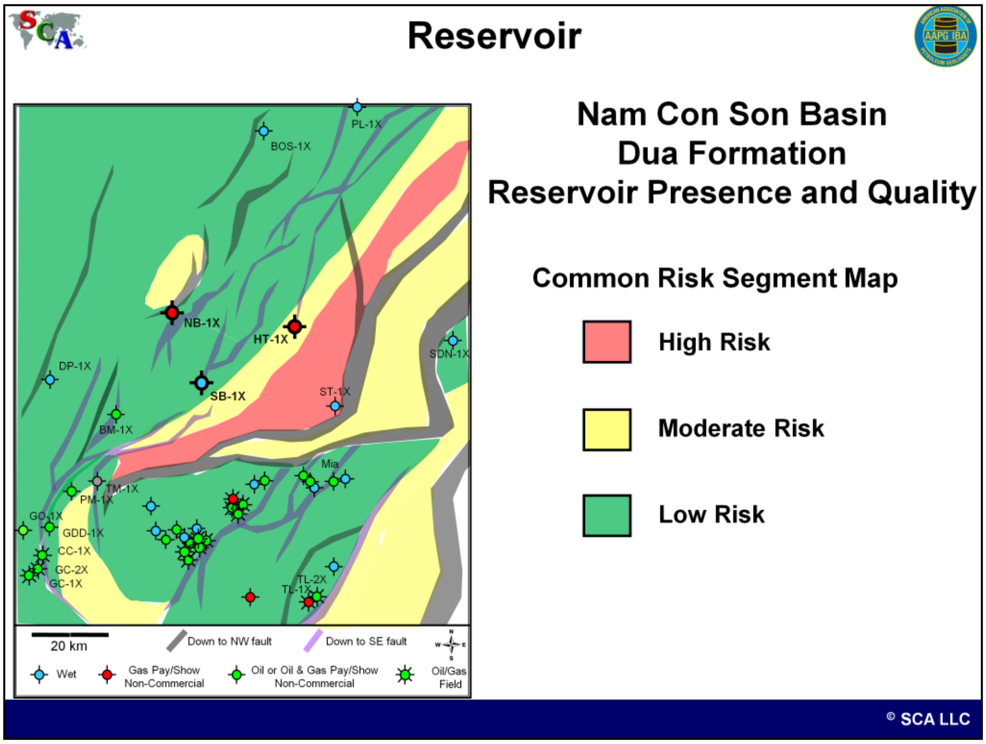
The Tien Cau and Cau reservoirs, however, except along the basin margin, they are generally too deep to have sufficient reservoir quality to be a viable target. As such, the Miocene Dua Formation is the principal exploration target for much of the basin.



Depositional environment maps (Upper and Lower Dua Formation) can help management understand the nature of the depositional setting and the distribution of reservoir facies.

By Early Miocene, the Nam Con Son Basin had been flooded by marine waters. The basin was now a narrow seaway within which extensive tidal bars were deposited. Coastal mangrove swamps were the locus of coal deposition along the coastal margins.

The basin continued to open such that by the Middle Miocene it is no longer a restricted seaway. Along the northern margin, tidal influences give way to wave and longshore drift and carbonate development occurred on the basement highs



We can also use a Common Risk Segment Map to show management where in the basin we can expect to find reservoir of suitable.

Red indicates where a petroleum system element (in this case reservoir presence and quality) is considered high risk, and the area should be explored with caution

Yellow indicates where a petroleum system element is considered somewhat risky, and due diligence should be applied to all prospects

Green indicates where a petroleum system element is considered low risk, and the area should be explored aggressively

Evaluating and Presenting Prospects

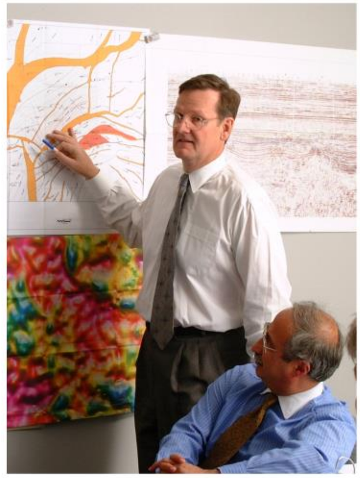
Where In the World?
- Regional Setting and Petroleum System
- Field Size Distribution

Evaluating and Presenting Charge
- Source Rock Presence
- Migration Pathway

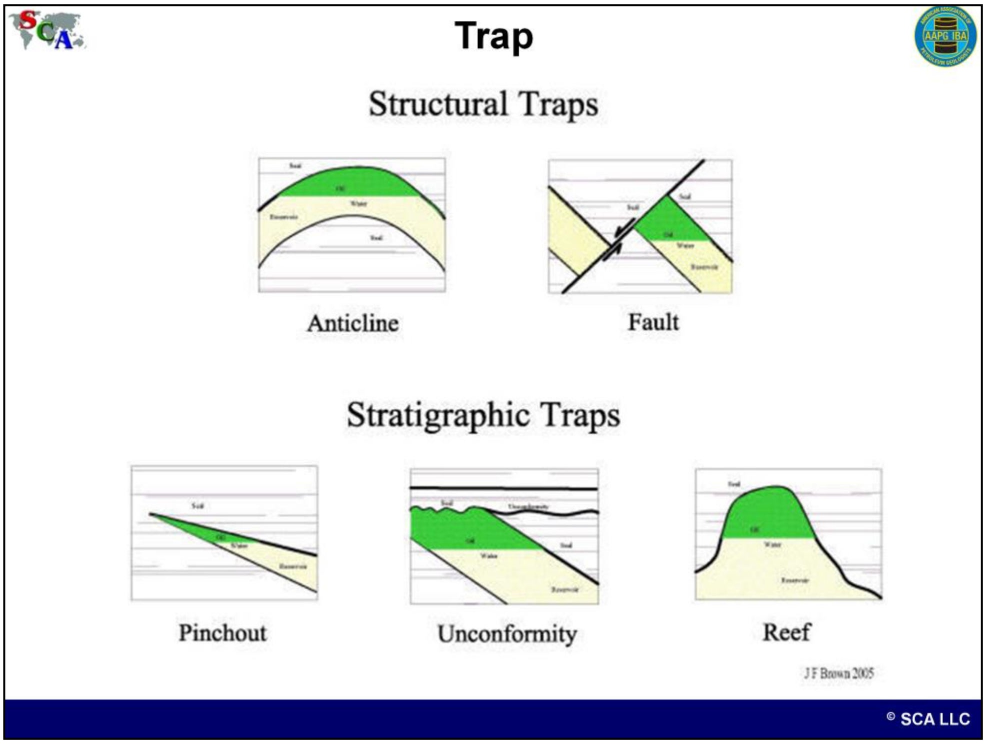
Evaluating and Presenting the Reservoir
- Reservoir Presence
- Reservoir Quality

Evaluating and Presenting the Trap
- Trap Type
- Seal

Show them the Money
- Uncertainty
- Risk

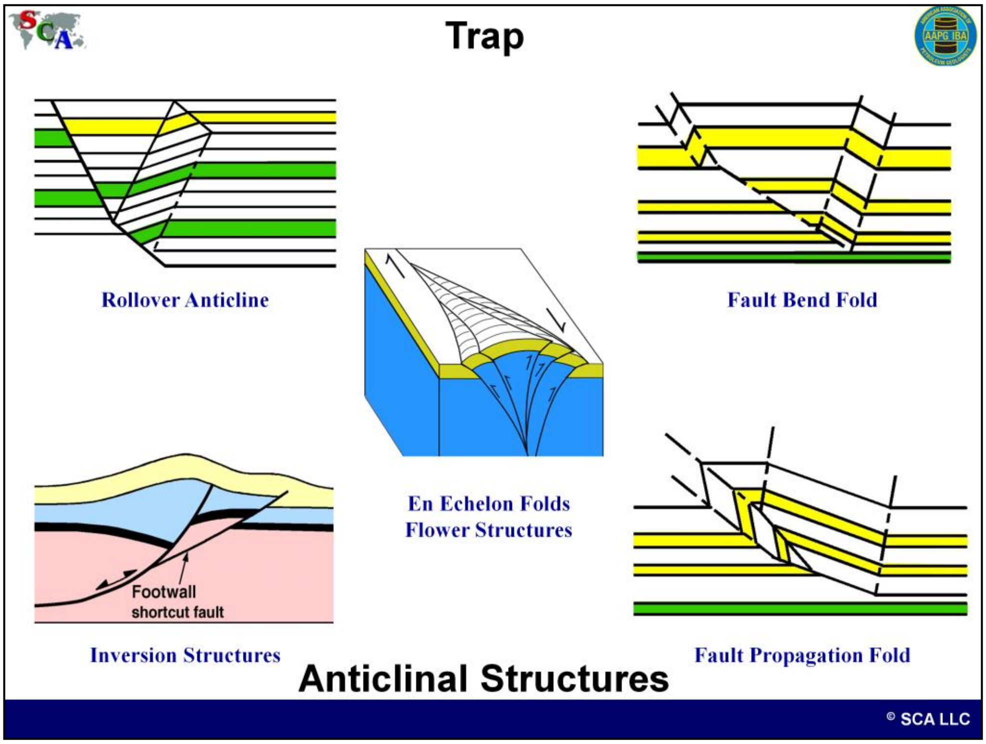


It is time to look at the trap

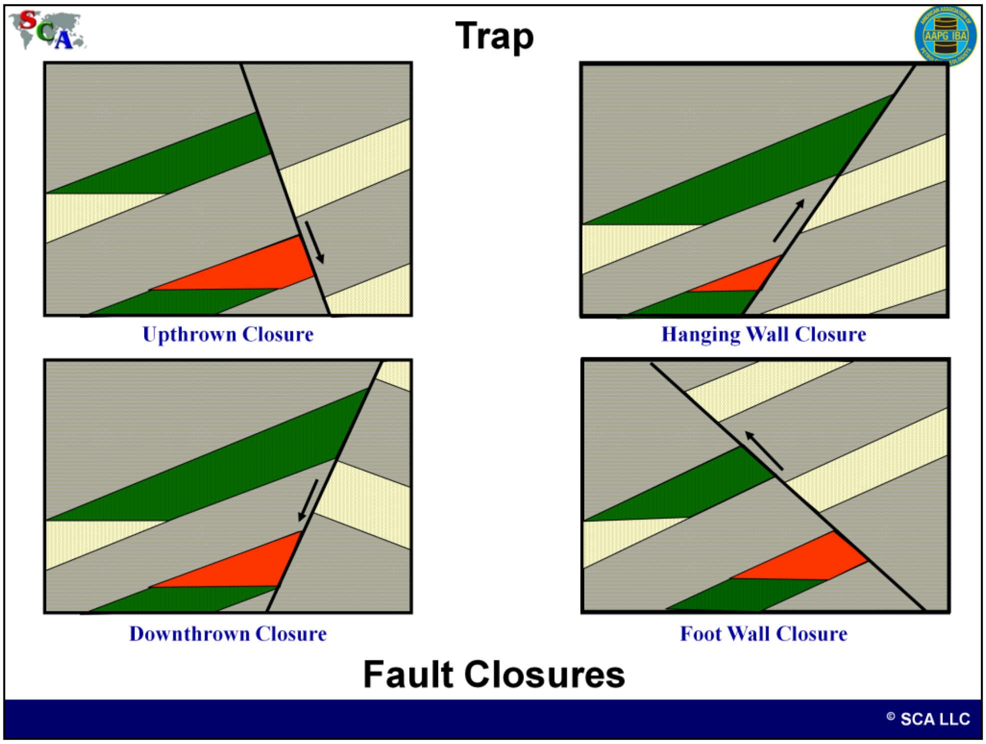


Trap

A trap is a geologic structure or a stratigraphic feature capable of retaining hydrocarbons. Hydrocarbon traps that result from changes in rock type or pinch-outs, unconformities, or other sedimentary features such as reefs or buildups are called stratigraphic traps. Hydrocarbon traps that form in geologic structures such as folds and faults are called structural traps. Any mixture of structural and stratigraphic elements is called a combination trap.

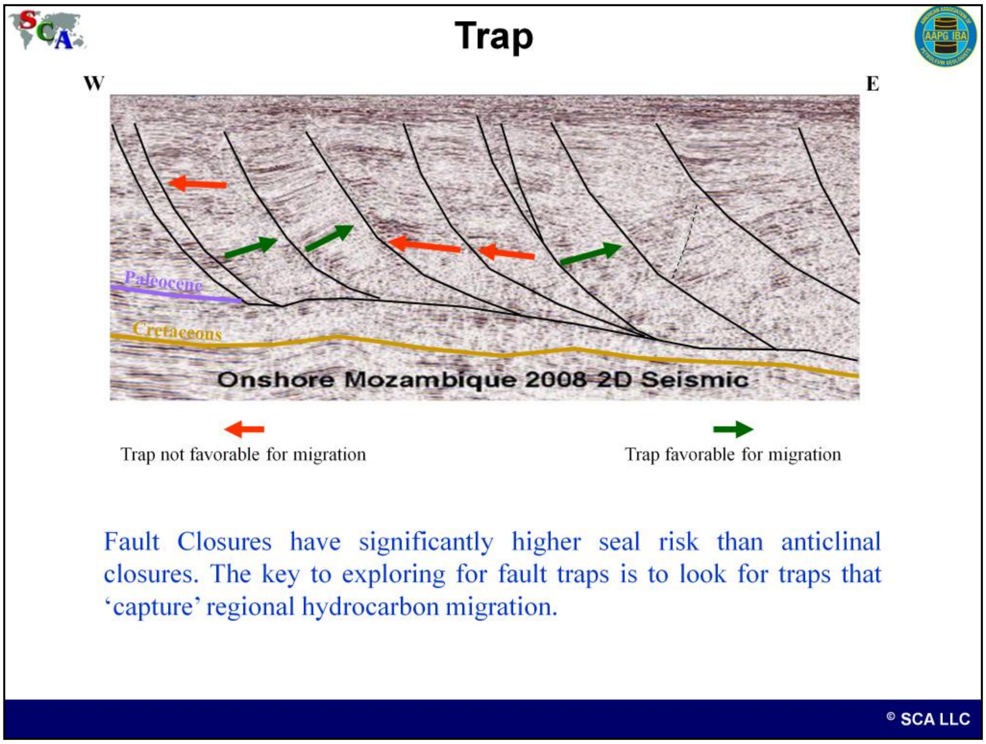


Anticlinal traps in extensional basins include rollover anticlines and inversion structures. In compressional regions, the fault bend and fault propagation folds are most common. In strike slip settings we see en echelon folds and flower structure anticlines.



We will now look at fault traps. Although many anticlinal closures are compartmentalized by faults, for this discussion, we will constrain our definition of fault traps to be traps formed solely to the presence of a fault.

There are four types of fault traps. In extensional settings, there are upthrown and downthrown fault closures. In compressional settings there are hanging wall and foot wall closures/

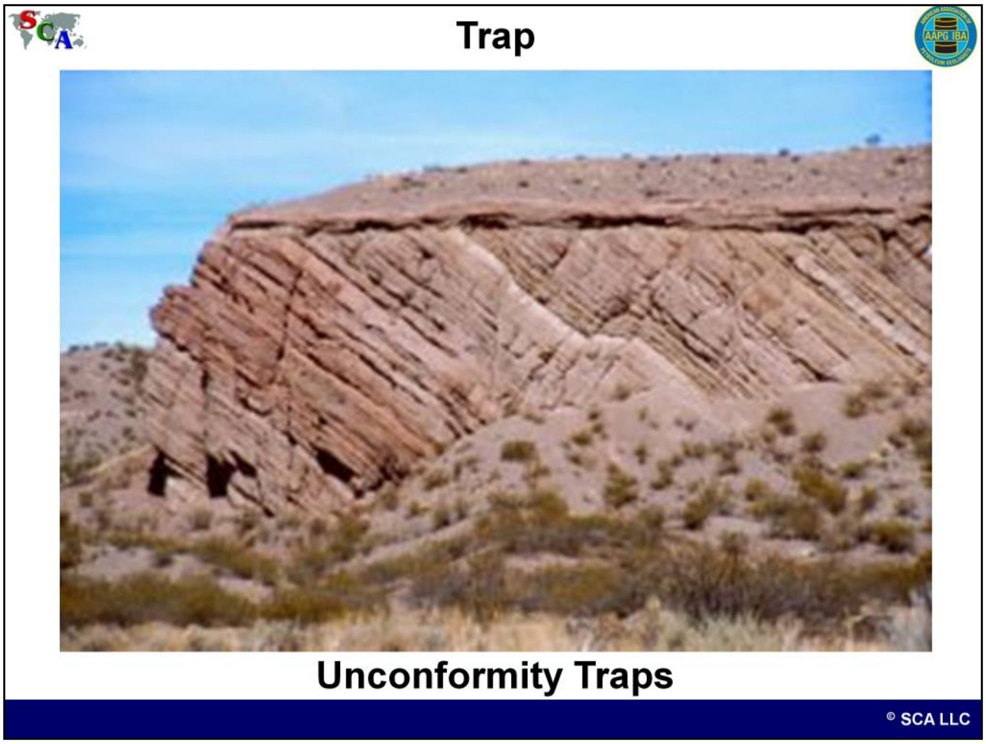


Fault closures, whether extensional or compressional, have an inherently higher seal risk than do anticlinal closures.

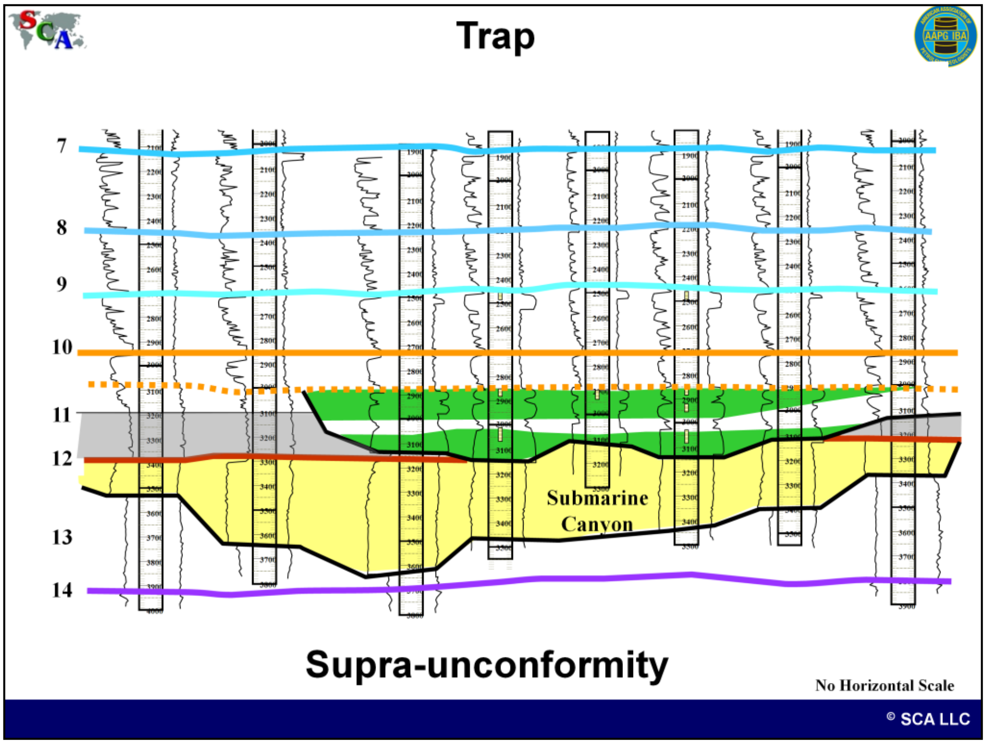
The key to exploring for fault closures is to find those fault closures that can constrain regional hydrocarbon migration. Looking at this line from Mozambique, the regional migration direction is from east (right) to west (left).

The red arrows show potential fault closures that are not oriented to stop regional migration. The green arrows are those fault closures that can potentially trap regional migration.

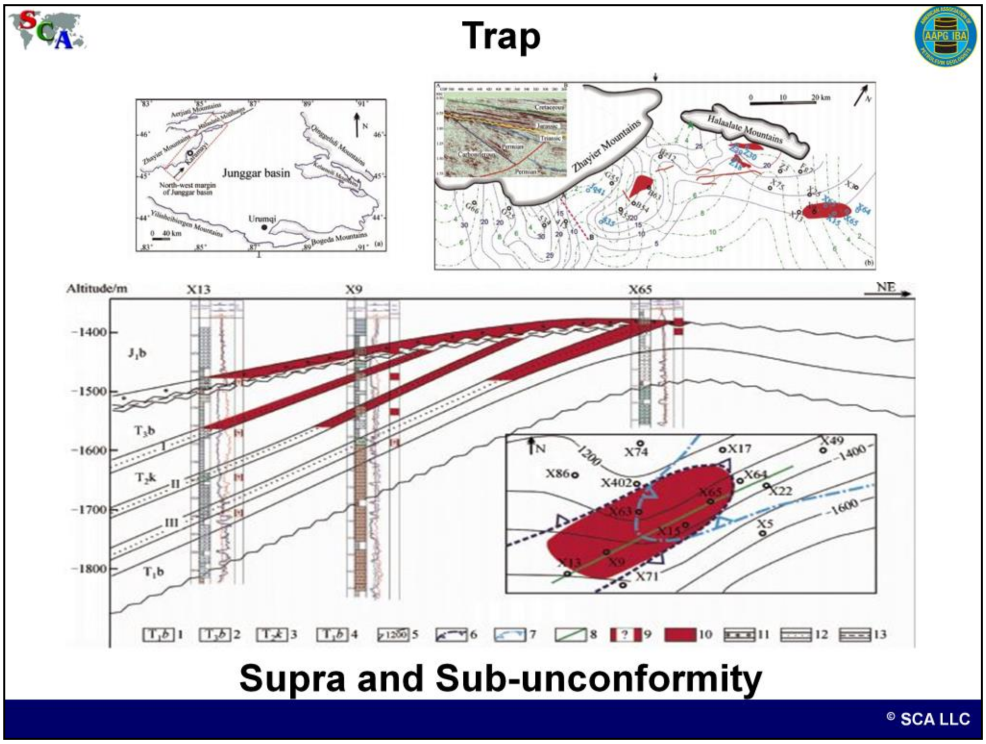
9left



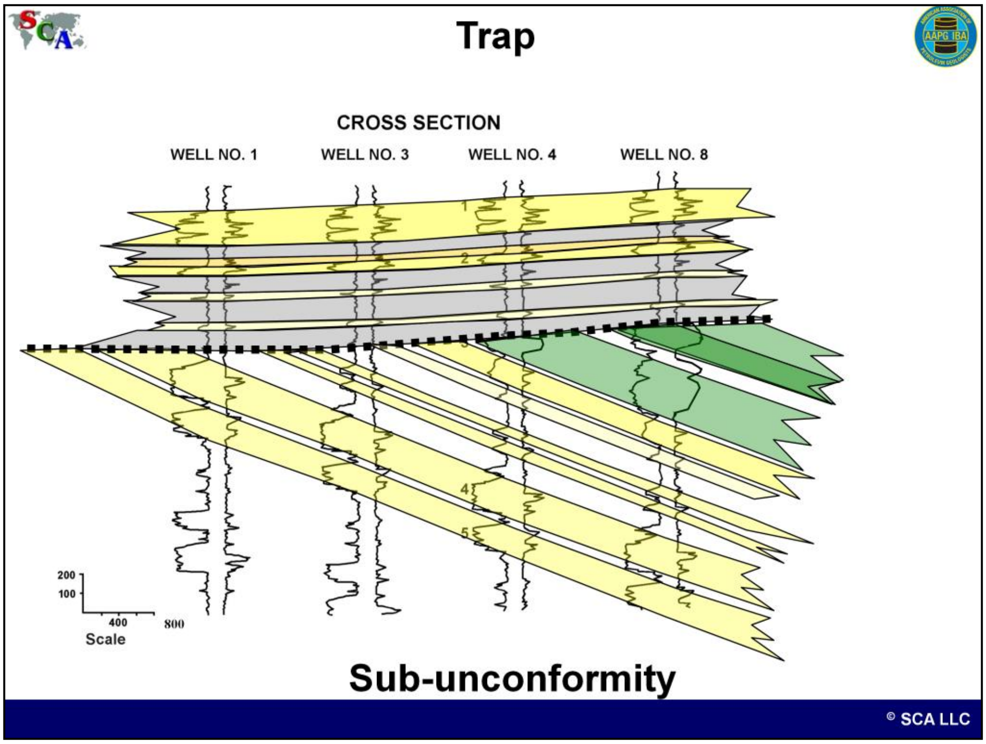
We will look now at unconformity traps.



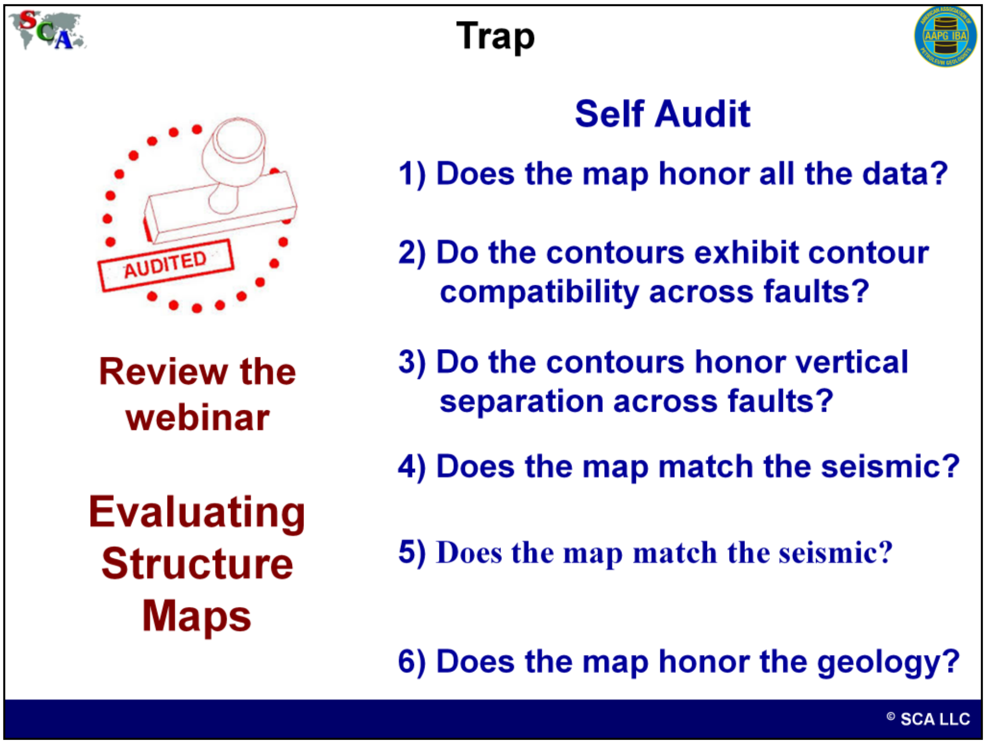
We can have supra-unconformity traps that consist of reservoirs onlapping an unconformity as seen in this cross section offshore Borneo.



Or we can see sub-unconformity truncations and supra-unconformity onlap as in this cross section in the north-west margin of Junggar basin, North-west China



Or sub-unconformity truncations. With sub-unconformity truncations, it is important to realize that the sand thickness observed below the unconformity may not be the complete sand, but a partially eroded remnant of the sand.



To ensure that the maps you have generated are valid, you need to conduct a self audit. The process and techniques for conducting a self audit were covered in a separate webinar presentation.

The self audit consists of six steps

1) Review the map to make sure it honor s all the data?

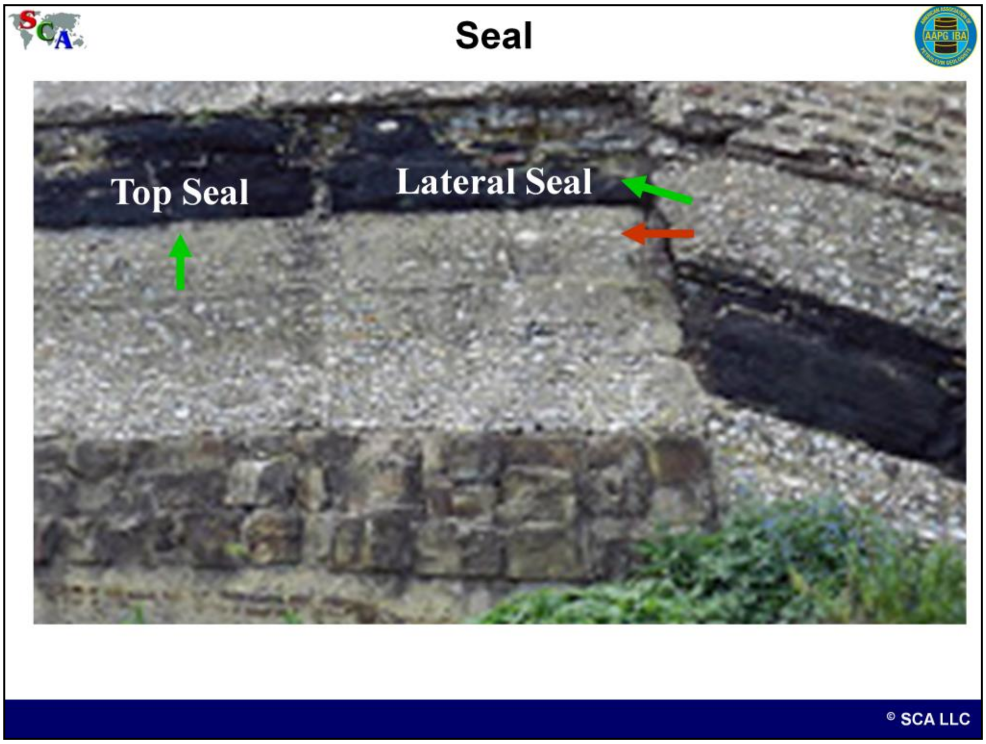
2) Do the contours exhibit contour compatibility across faults?

3) Do the contours honor vertical separation across faults?

4) Does the map match the seismic?

5) Does the map match the seismic?

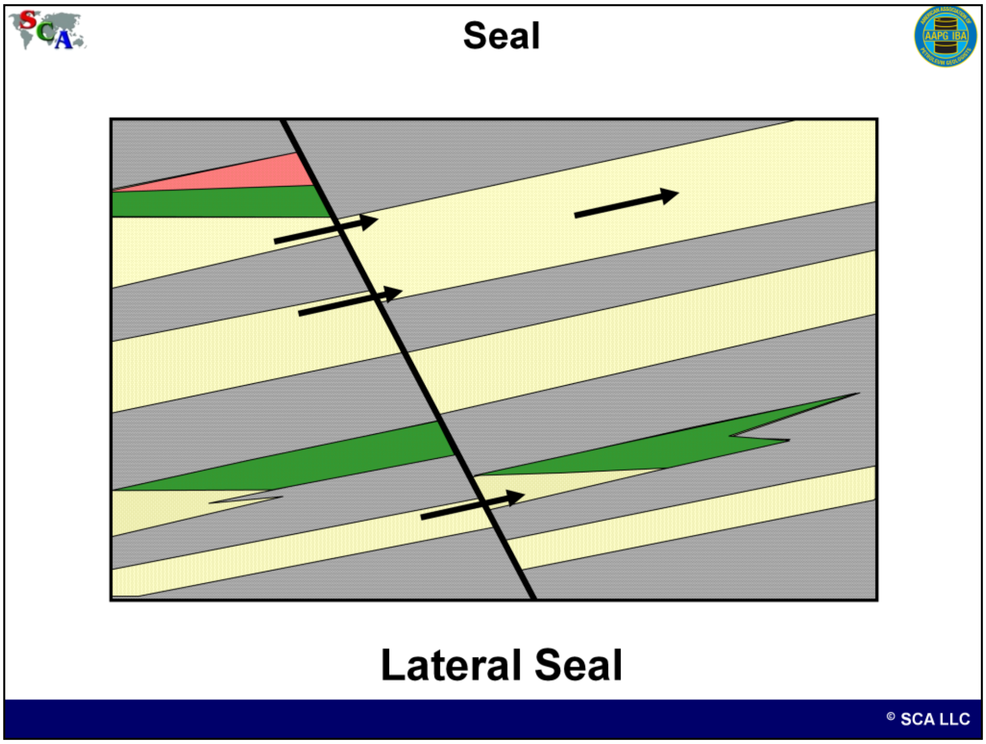
6) Does the map honor the geology?



Seal

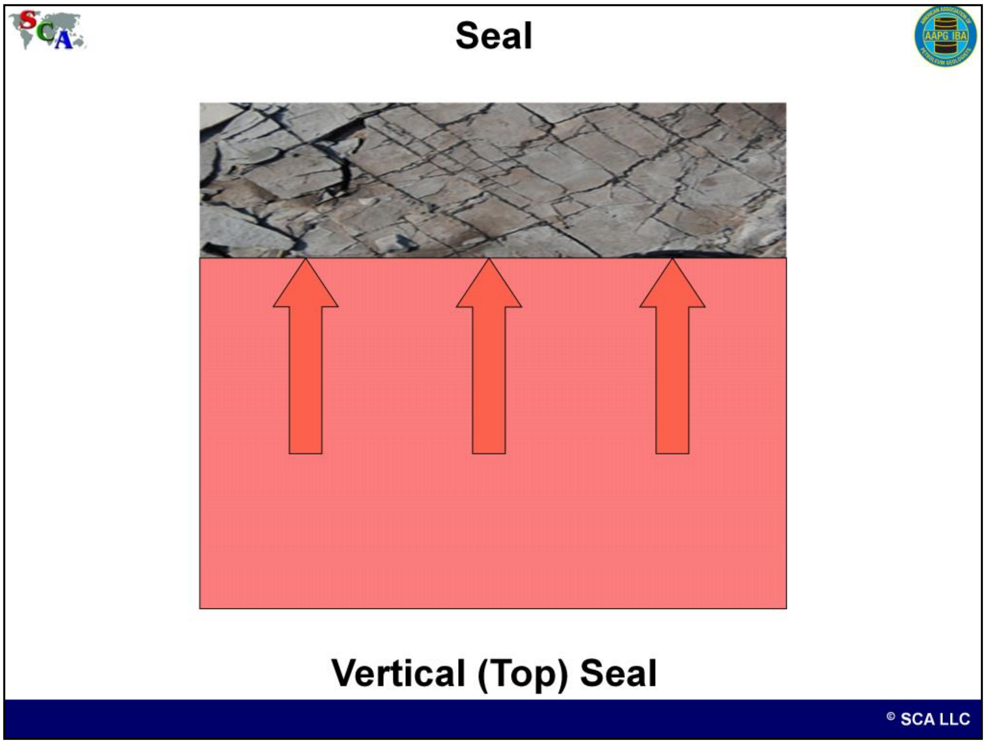
The seal is any rock that stops hydrocarbons from migrating. A seal generally has lower permeability or a higher pressure than the reservoir such that hydrocarbons can not flow into it.

We must evaluate two types of seal, lateral seal which prevents hydrocarbons from flowing laterally away from a potential trap, and vertical seal which prevents hydrocarbons from flowing out of the reservoir.

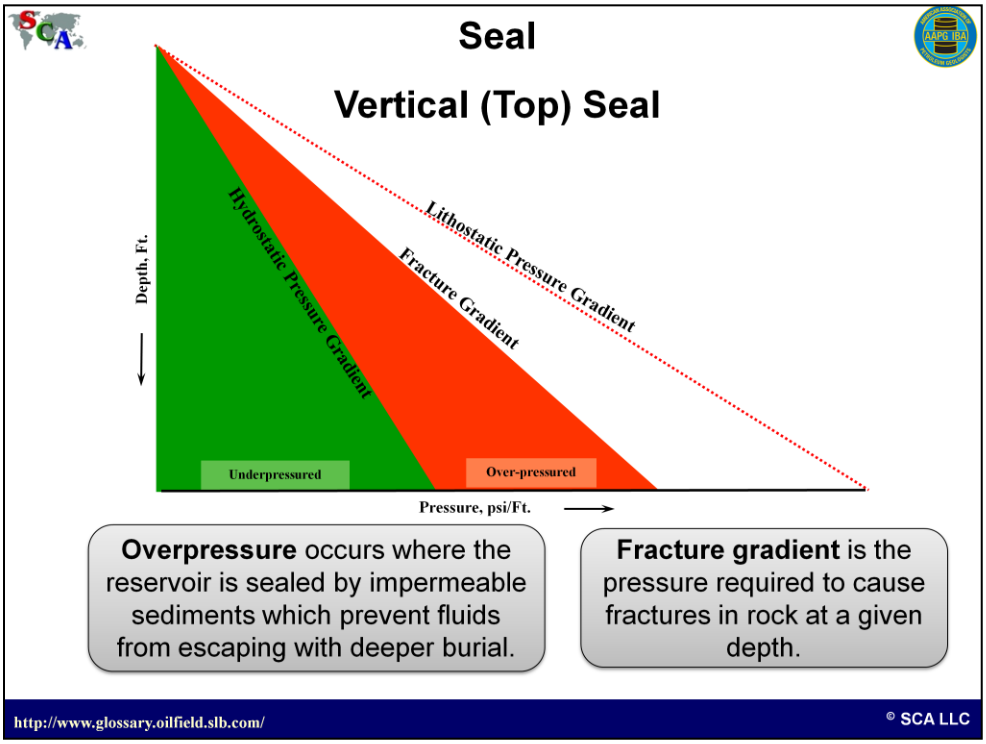


The seal is the final element of the petroleum system. It consists of a rock or horizon with low permeability or higher lithostatic pressure than the reservoir such that hydrocarbons can not migrate into it from the reservoir.

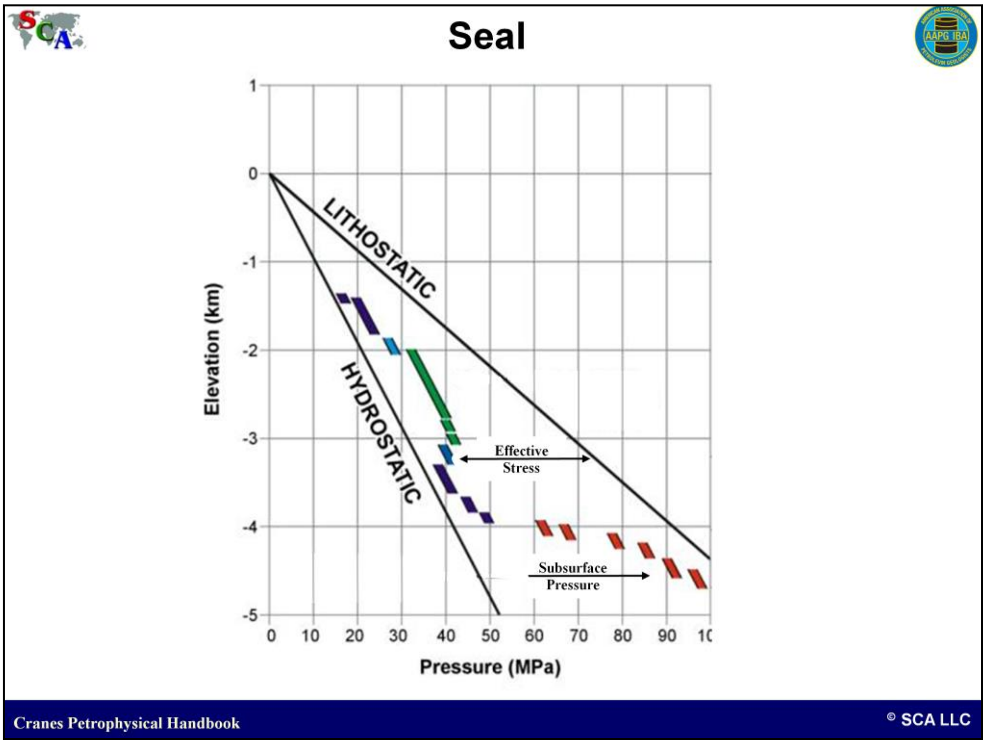
Where permeable rocks are juxtaposed across rocks with greater or equal permeability or lower lithostatic pressure, the hydrocarbons will continue to migrate



If the hydraulic pressure of an oil or gas column exceeds the fracture gradient of the overlying shale or siltstone, the seal will fracture and the hydrocarbons will migrate out until the hydraulic pressure is reduced below the fracture gradient.



Overpressure occurs when formation fluids are unable to escape. If the overpressure becomes too great, it will reach the fracture gradient and begin to fracture the reservoir and the seal. The fracture gradient is the pressure required to cause fractures in rock at a given depth.



Plotting the actual subsurface pressures from RFT data, leak off tests, drilling mud weights or from seismic velocity data) along with the hydrostatic and lithostatic gradients versus depth will show how close subsurface conditions are to reaching or exceeding the fracture gradient.

For more information on making a pore pressure plot see Cranes Petrophysical Handbook at https://www.spec2000.net/10-pressure.htm

The hydrostatic gradient for fresh water is 0.433 psi/foot or 9.81 Kpa/meter. The gradient for saturated salt water is 0.46 psi/foot or 10.4 Kpa/meter

Some typical overburden pressure gradients are shown here

Typical values for (Po/D)	psi/ft	KPa/meter
Sandstone 30% porosity	0.91	20.6
Sandstone 20% porosity	0.98	22.2
Sandstone 10% porosity	1.05	23.8
Sandstone 0% porosity	1.12	25.4
Siltstone	1.15	26.0
Shale	1.23	27.7
Limestone	1.15	26.0
Dolomite	1.21	27.4
Anhydrite	1.26	28.5

Seal

Seal	Shale Smear Factor	Shale Gouge Ratio	Net to Gross Sand
Never**	5.0	0.20	0.80
Maybe	3.3	0.30	0.70
Possible**	2.5	0.40	0.60
Likely**	2.0	0.50	0.50

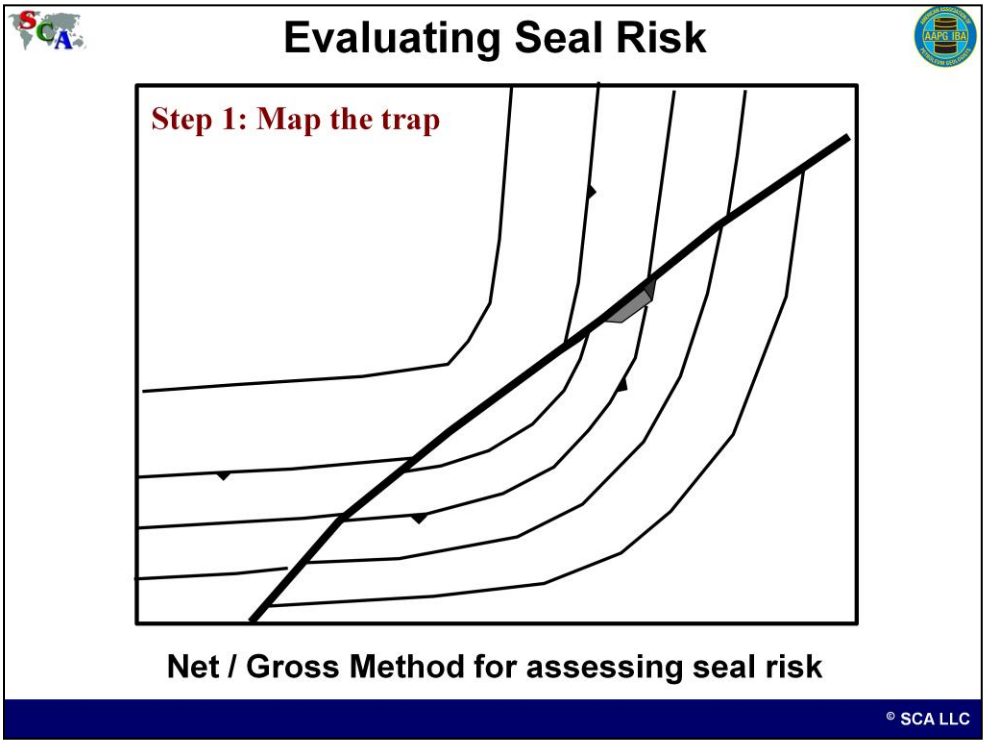
Shale Smear and Shale Gouge

**Broussard & Lock, 1995, GCAGS Trans.*
***Bretan, Yielding, Jones, March 2003, AAPG Bull.*

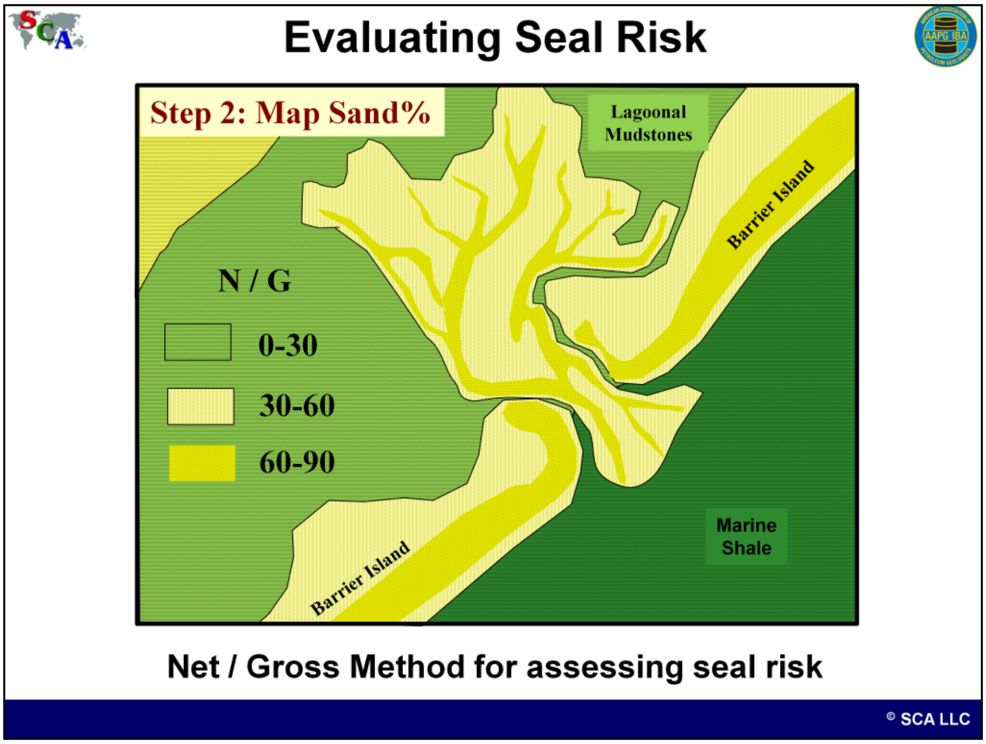
The use of Shale Smear Factors (Fault Throw/Shale Layer Thickness) and Shale Gouge Ratios are additional methods available to interpreters to assess seal risk. These methods look at the shale in the system and how likely it is that the shale has 'smeared' into the fault plane.

Several studies have shown that for traps with Shale Gouge Rations of 0.2 or less, the traps never contained hydrocarbons. When the SGR was 0.3, a few traps would work, but most did not. With SGRs of 0.4 or higher, the traps often worked.

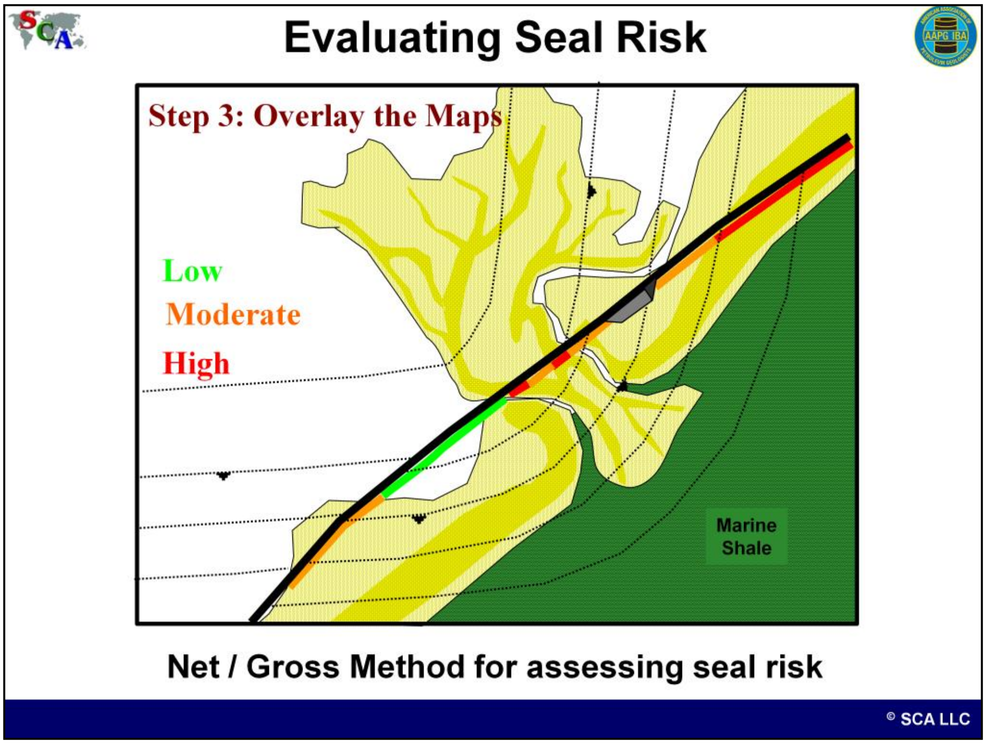
The Shale Gouge Ratio is the inverse of the Net to Gross Sand Ratio. As such, a highly effective method for evaluating both reservoir potential and seal risk, is to construct a net to gross (sand %) map of the target reservoir and overlay it with the depth (or time) structure map of the prospective horizon.



Here we see a simple structure map for a downthrown 3-way fault closure. Note that the dip on the upthrown side of the fault is away from the structure. So if the fault does not seal, hydrocarbons will migrate away from the trap.

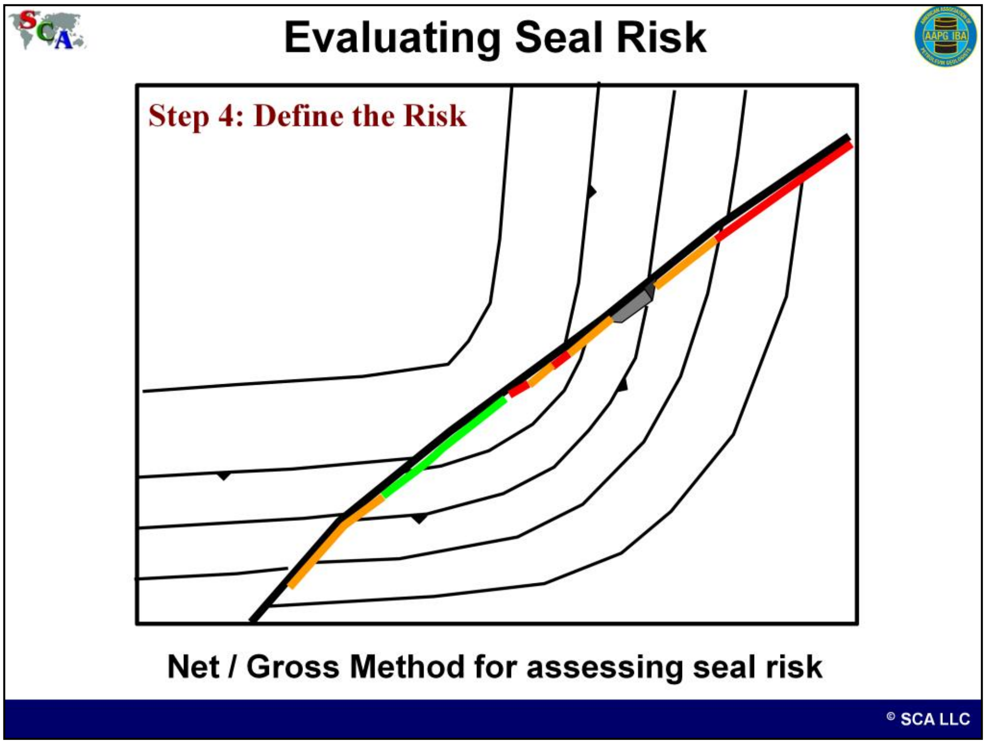


Here is a net to gross map of the reservoir, color coded by facies. The depositional environment is a barrier island and tidal delta.



We now overlay the two maps. Where we see high sand percent values intersect the fault, we color code the fault red. Where low sand percent values intersect the fault, we color code the fault green. Orange is used to indicate where moderate sand percent values intersect the fault.

The advantage to this method, is that we can now also see where the reservoir is expected to be best developed in the trap.



The final seal risk map illustrates where we can expect the seal risk for the trap to be high. We can then use that information to determine our P_{10} and P_{90} trap areas as well as determining our seal risk.

For faults in which the downthrown horizon is juxtaposed against a different formation, we will need to make a net to gross sand map for both the upthrown horizon and the downthrown horizon.

Evaluating and Presenting Prospects

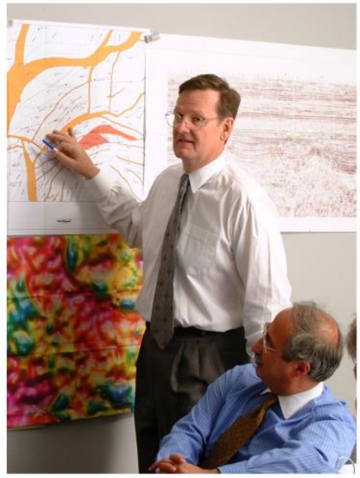
Where In the World?
- Regional Setting and Petroleum System
- Field Size Distribution

Evaluating and Presenting Charge
- Source Rock Presence
- Migration Pathway

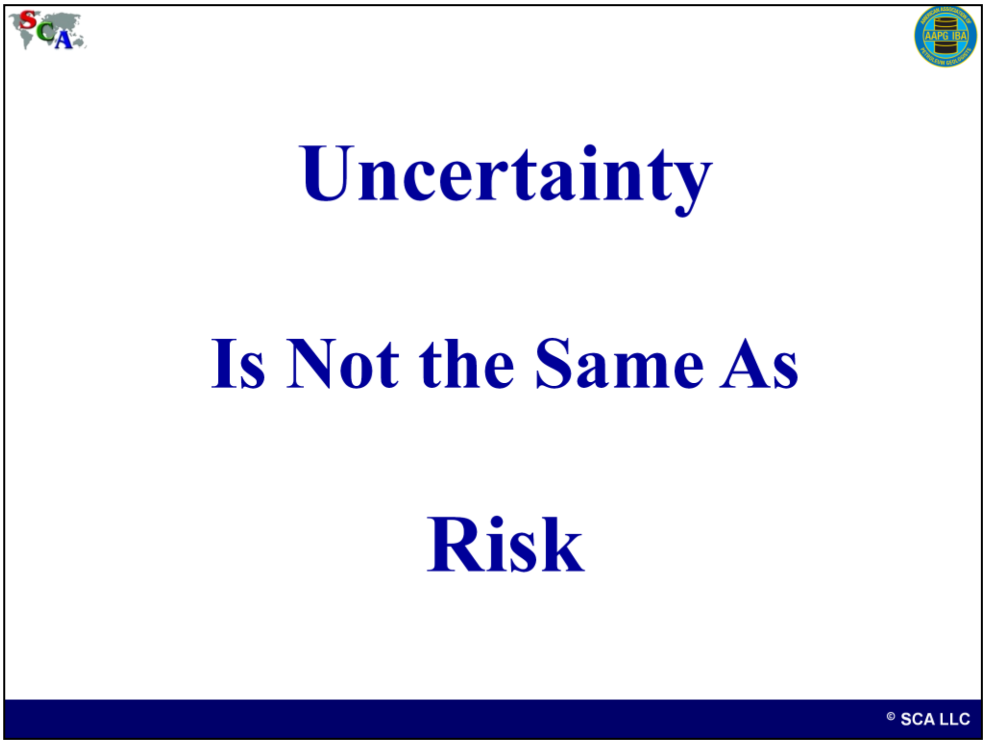
Evaluating and Presenting the Reservoir
- Reservoir Presence
- Reservoir Quality

Evaluating and Presenting the Trap
- Trap Type
- Seal

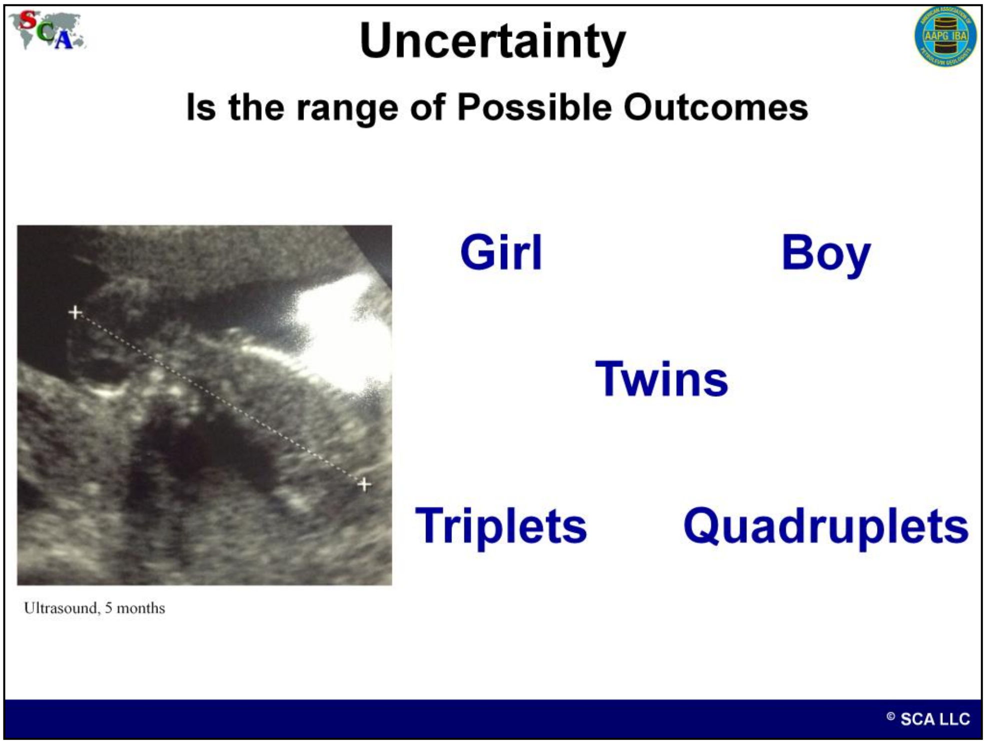
Show them the Money
- Uncertainty
- Risk



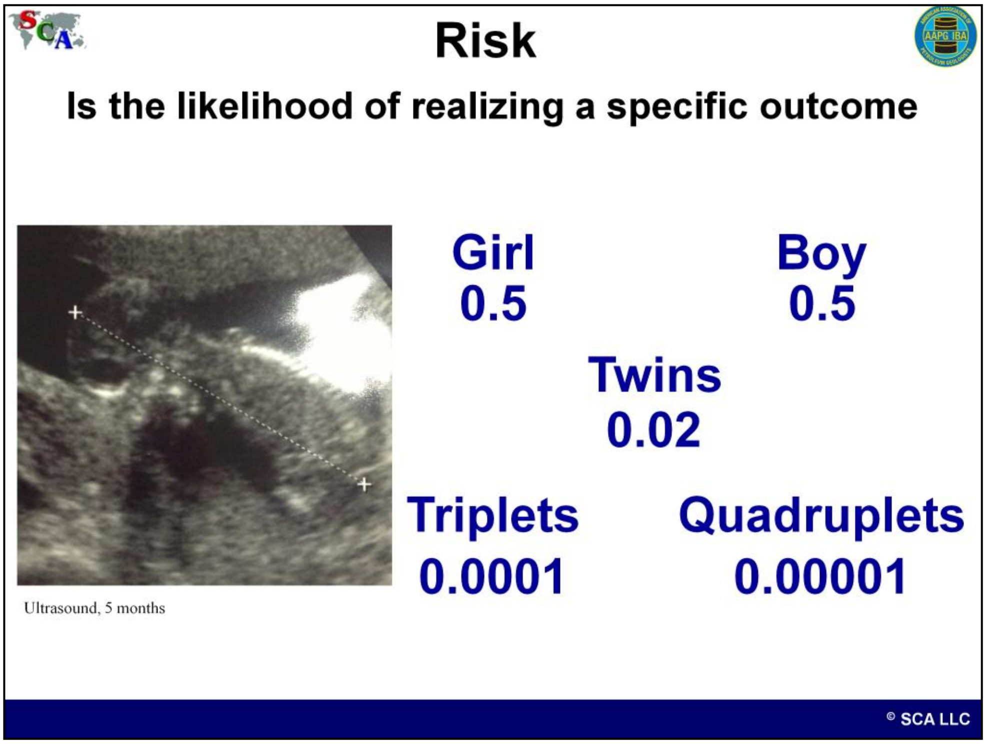
Now that we have defined the elements of the petroleum system for our prospect, we are ready to look at the uncertainty and the risk.



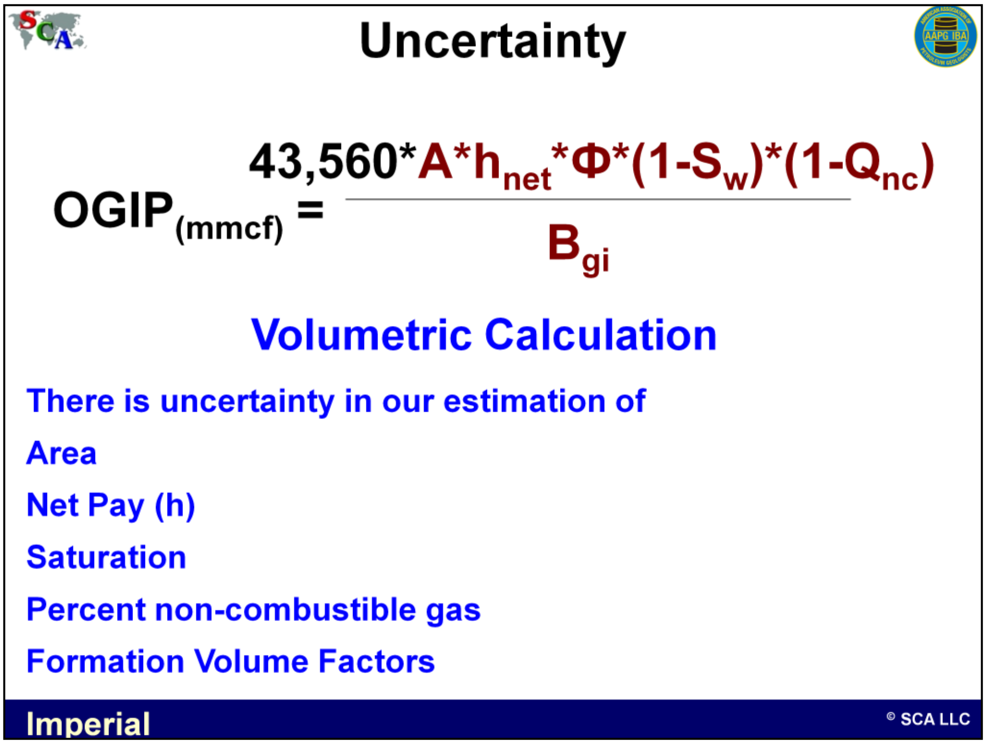
Many interpreters, and managers as well, tend to confuse uncertainty with risk. They are vey different entities.



Uncertainty is the range of all possible outcomes. If we look at someone who is pregnant, the possible outcomes are girl, boy, twins, etc.

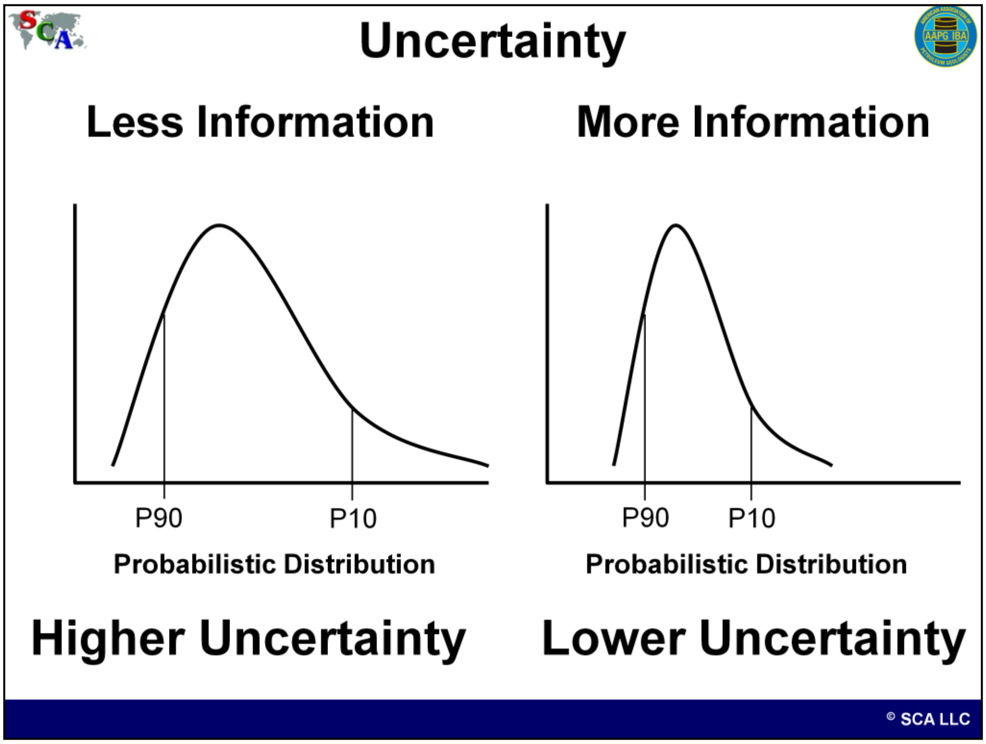


We use probability theory to deal with risk. So using our pregnancy example, the probability is the likelihood of achieving one of the possible outcomes.

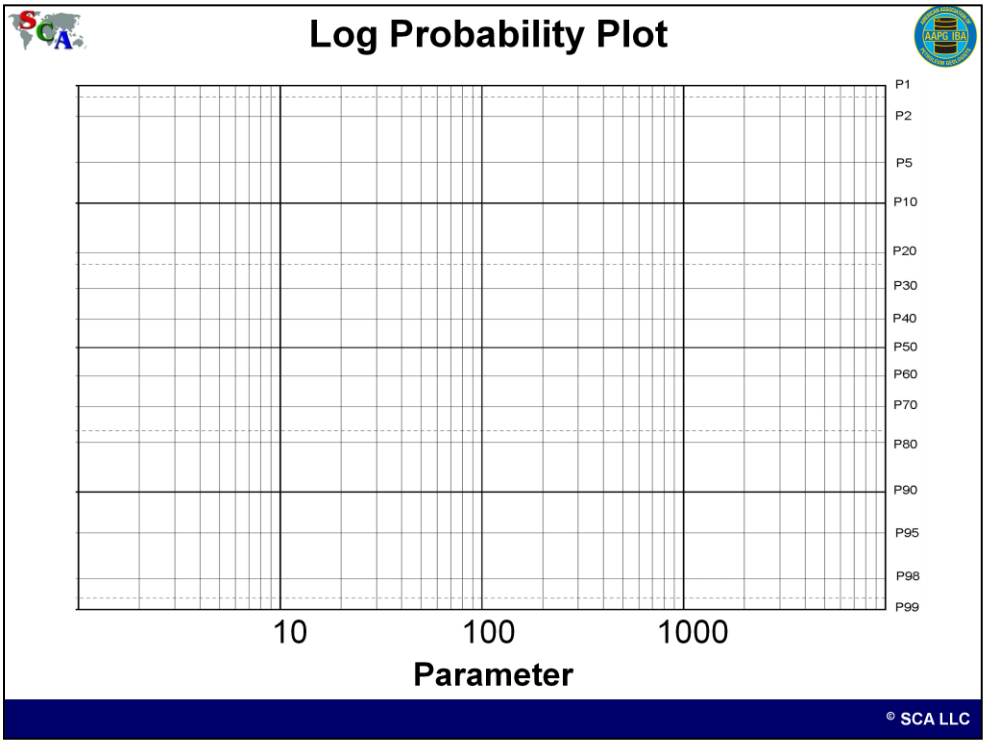


Looking at the formula for calculating the in-place volume of gas (and for oil) we see that except for the constants, all of the input variables have an associated range of uncertainty. There is also uncertainty in the recovery efficiency.

You must determine the range of uncertainty for each variable in the equation. Since most of the variables fit (or closely fit) a lognormal distribution, you can use a probabilistic methodology to determine the range of uncertainty.

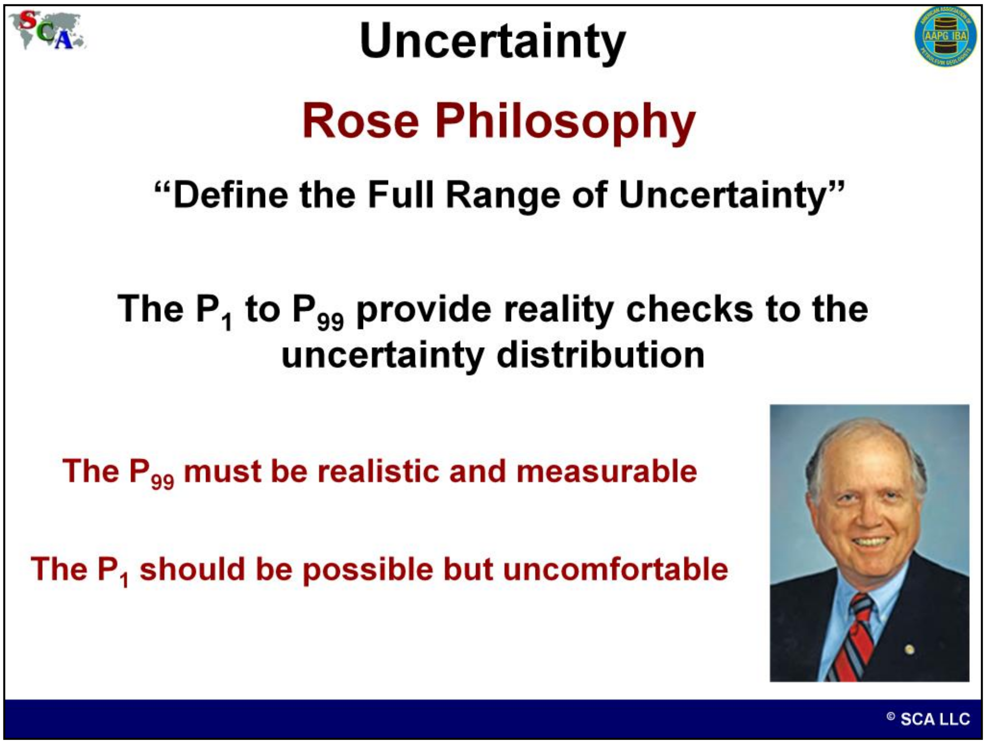


Since we have no way to directly measure any of these elements, we need to make informed guesses for all of the elements. To constrain our guesses, we use uncertainty distributions. The less information we have about a given element of the petroleum system, the wider the range of uncertainty.



The Rose method, championed by Pete Rose uses the lognormal distribution of the volumetric variables to determine the uncertainty range of each variable, which can then be multiplied together to determine the uncertainty range of the expected volume.

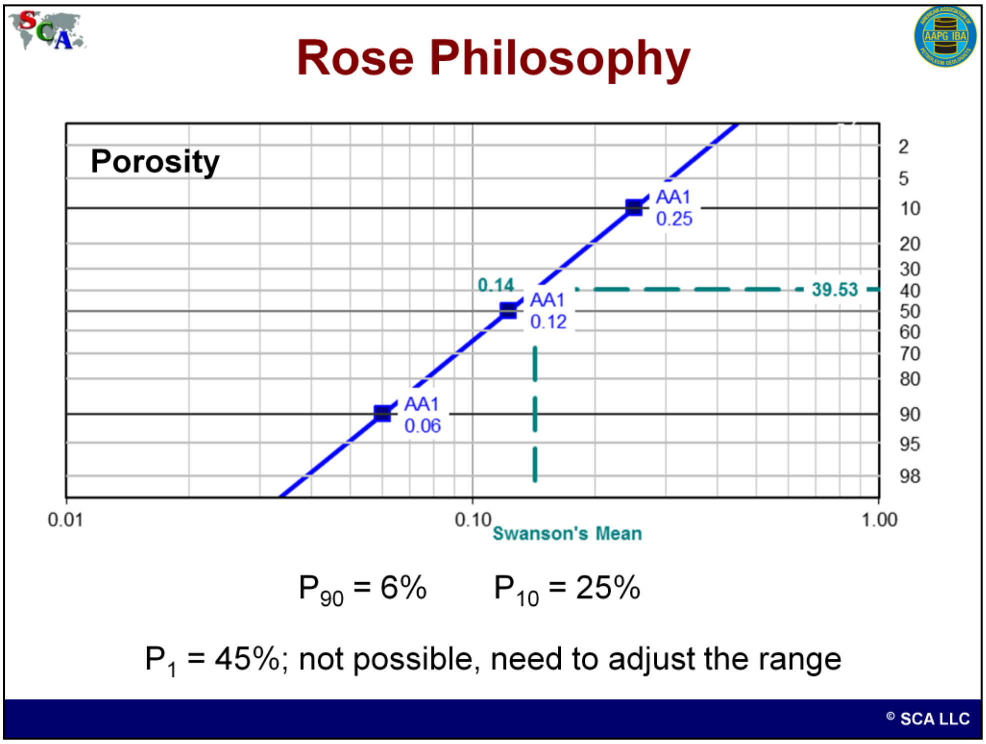
You make a log probability plot for each variable for the volume calculation. The horizontal scale of this plot is logarithmic and the vertical scale probability. Since this is a lognormal distribution, you only need two numbers to plot the entire distribution.



With the Rose method, once we have defined the uncertainty range, we check that range using the tails, the P_1 and P_{99}

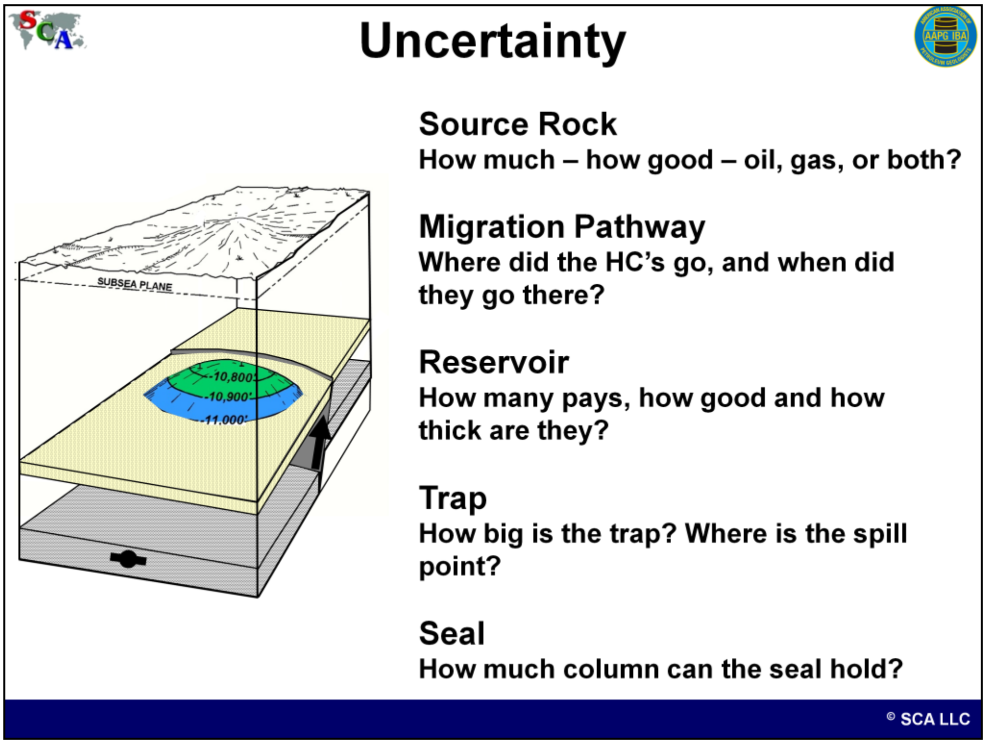
The P_{99} must be realistic, and measurable.

The P_1 should be possible but uncomfortable



An example of how to use the method is shown here for the distribution of porosity. A porosity distribution for a prospect was constructed using a P_{90} of 6% and a P_{10} of 25%, which appear to be reasonable values.

However, using the P_1 and P_{99} as reality checks, we can see that the porosity distribution above is not reasonable as the P1 of 45% porosity is not really possible for a clastic reservoir (35% is a more reasonable P1).



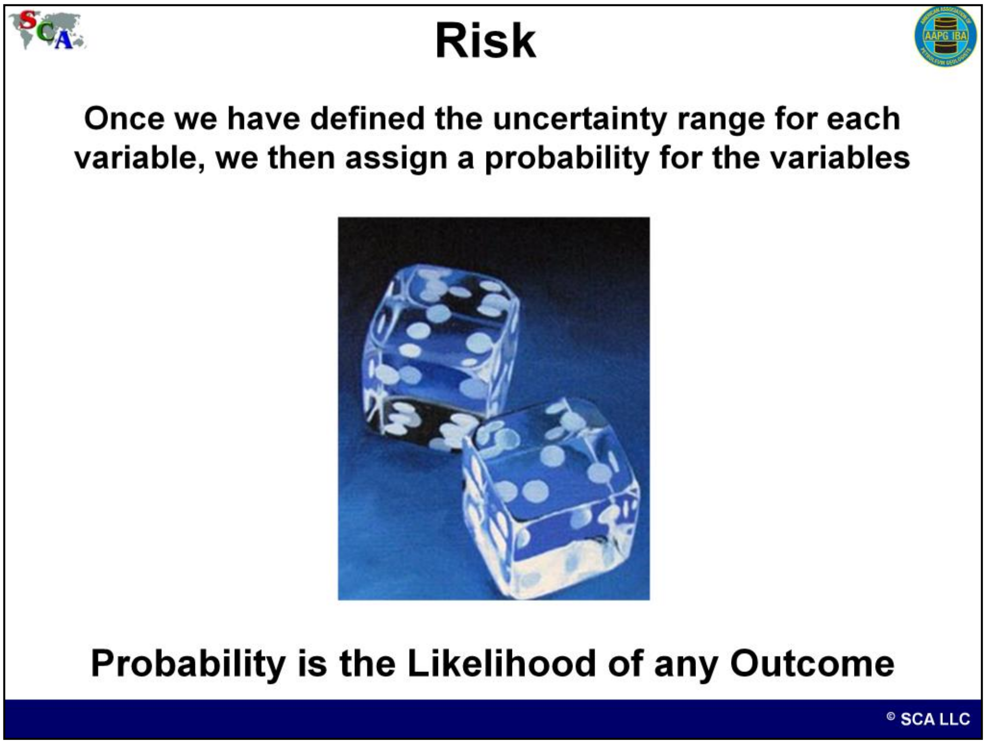
In defining exploration plays and prospects, we seek to define the range of possibilities for each element of the petroleum system.

We reconstruct the basin history to determine if there was source rock deposited in the basin. If so, we need to estimate how much was there, where it was, and if it is likely to generate oil or gas.

We then need to estimate when the oil or gas was generated and where it was most likely to go after it was generated.

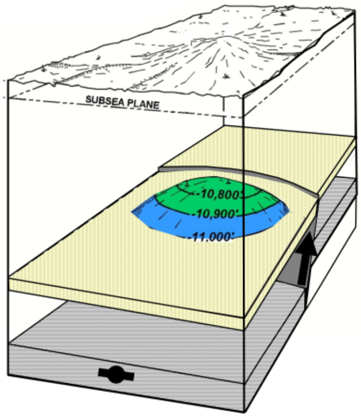
Then we need to determine if there was a reservoir where the oil and gas were likely to migrate to. If so, we need to predict the reservoir quantity and quality.

Then we use our seismic-maps to estimate how much area the trap encompasses, and how much column the seal can hold.



Once we have defined the range of uncertainty for the various petroleum system elements and volumetric variables, we must look at the chance of occurrence for entering the distribution we have estimated.

Risk



Probability of Source Rock
Chance that source rocks are present and mature

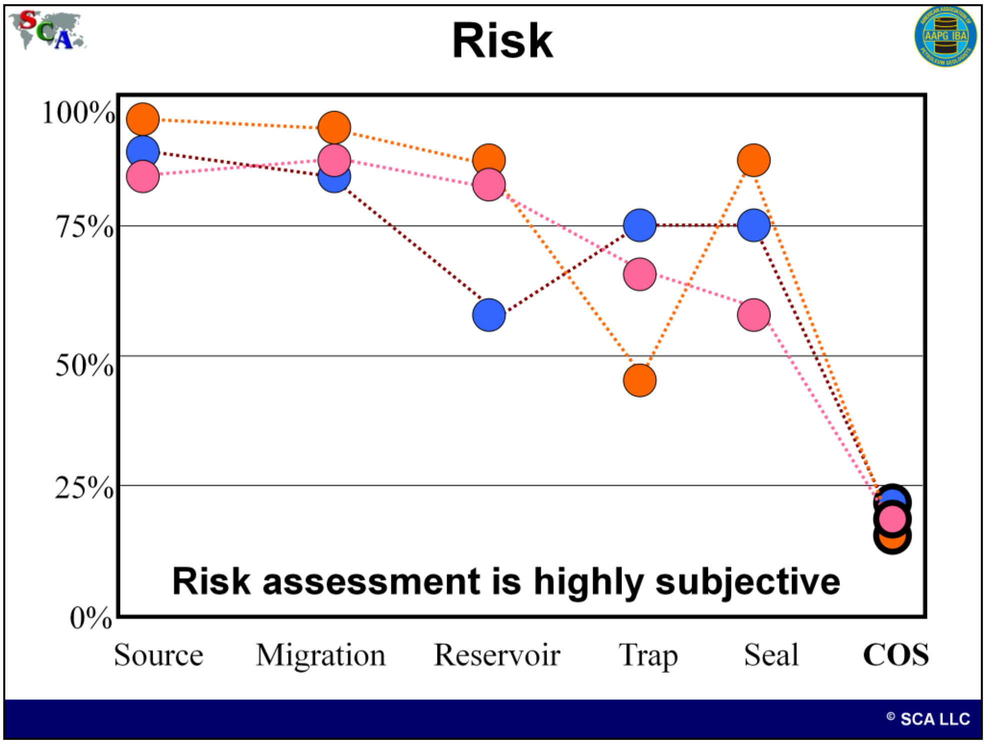
Probability of a Migration Pathway
Chance that there is a path between source and reservoir

Probability of a Reservoir
Chance that a reservoir of sufficient quality is present

Probability of a Trap
Chance that the trap is present

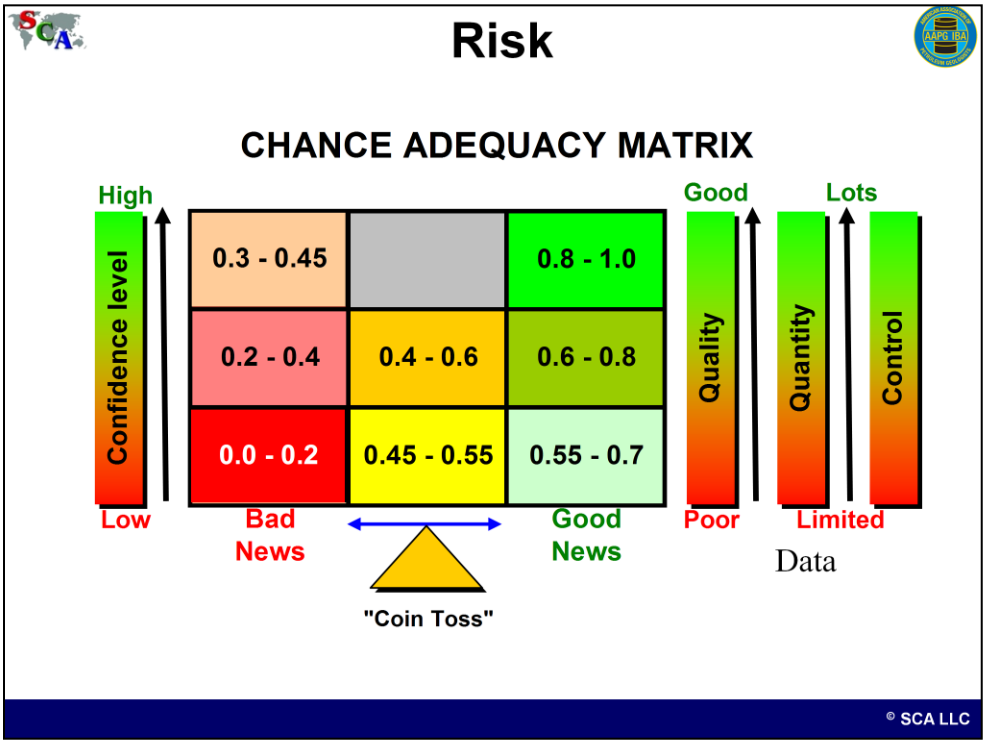
Probability of a Seal
Chance that the trap is sealed

So we will evaluate the chance of success (COS) for each element.

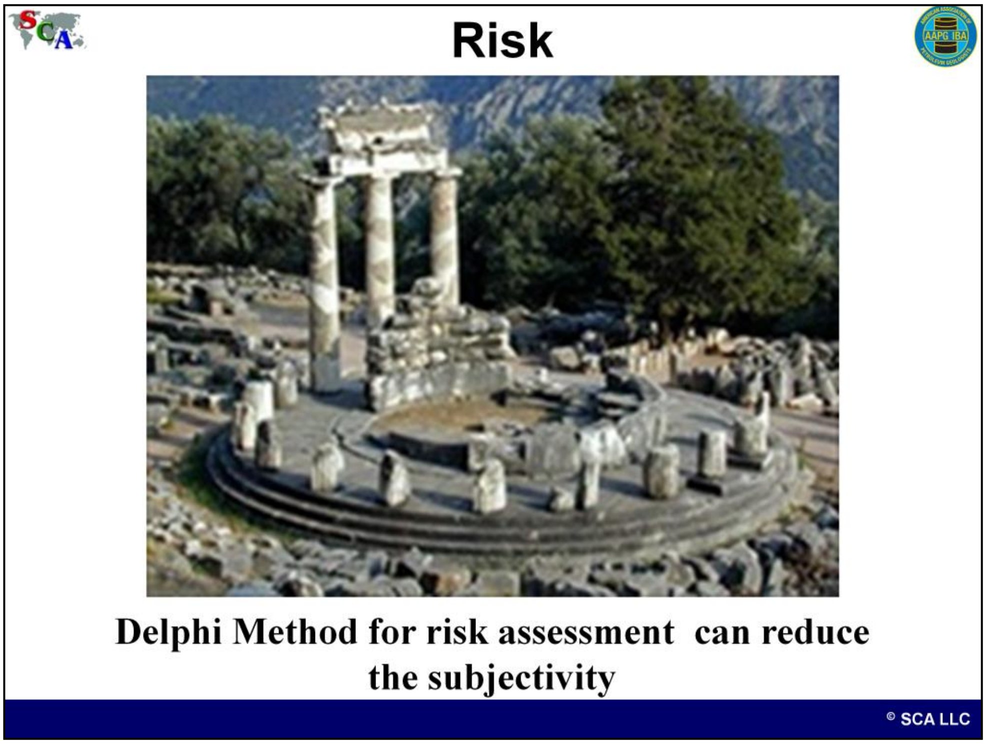


Assigning a chance of success or probability is very subjective. For a single prospect, interpreter 1 (Blue) assigned reservoir as the key risk. Interpreter 2 (Orange) felt that trap was the key risk. Interpreter 3 (magenta) considered seal to be the key risk.

Although each interpreter looked at the individual risks differently, the final COS for all three interpreters were very close to the same. In practice, most interpreters have an intuitive feel for the COS, and get there by different paths.



Using tools like the Chance Adequacy Matrix can help standardize the process between interpreters, but the process is still subjective, and will always be so.

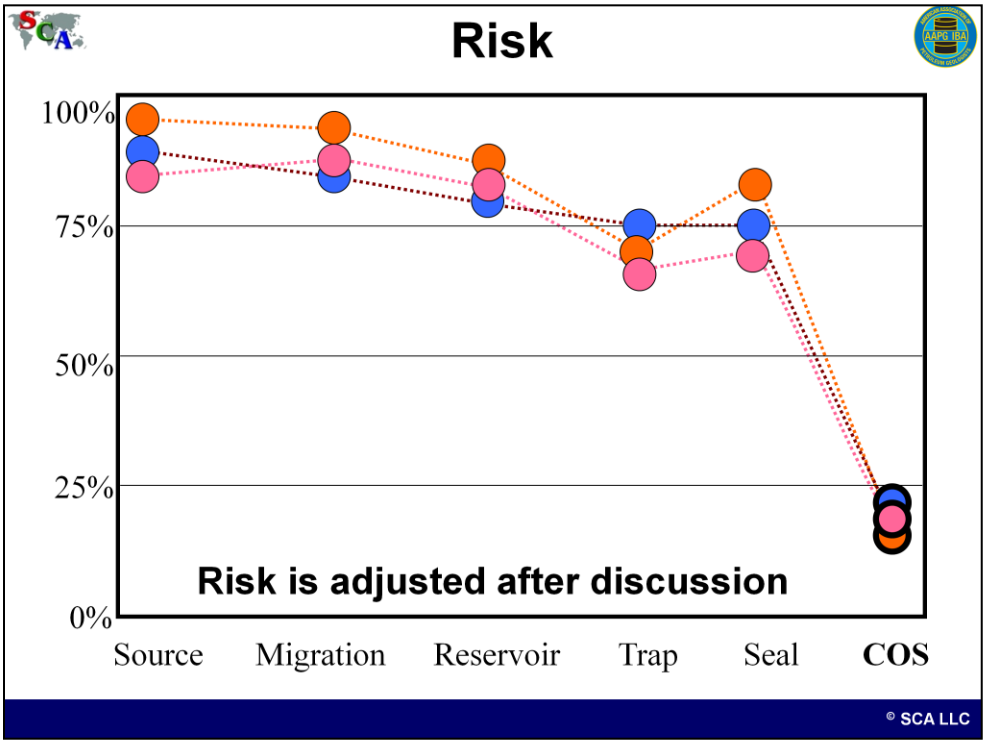


The Delphi Method is a proven way to harness *collective group intelligence* (popularly known as the *wisdom of crowds*) in a wide range of applications and can be used to remove bias from the estimation of risk.

Named after the Greek Oracle of Delphi, the method has all members of the team assess the Geologic Chance of Success and to highlight the key risk (s) of the prospect.

The method allows for the assessment of the group judgment and for feedback of individual contributions of information and knowledge. It provides an opportunity for all individuals to state, and later revise their views.

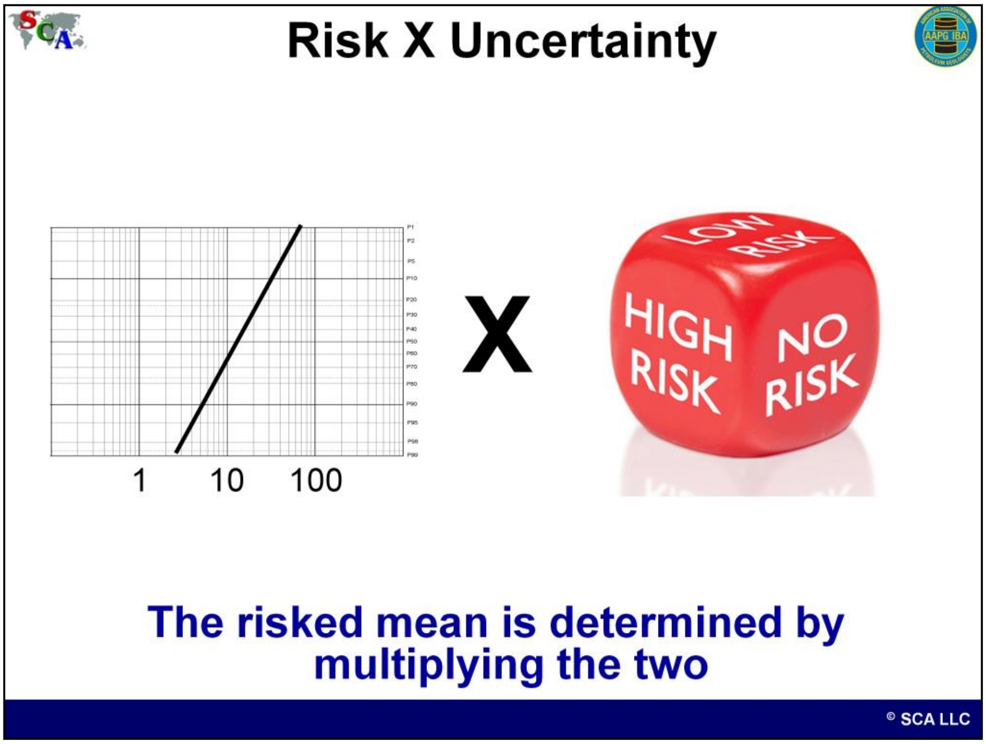
However, some degree of anonymity is needed for the individual responses, so the initial assessment of COS is done in writing. The team leader or moderator collects the estimates of COS and posts the results.



In the example we looked at earlier, there was close agreement on the overall COS. However, the three individuals each had a different view of the key risk.

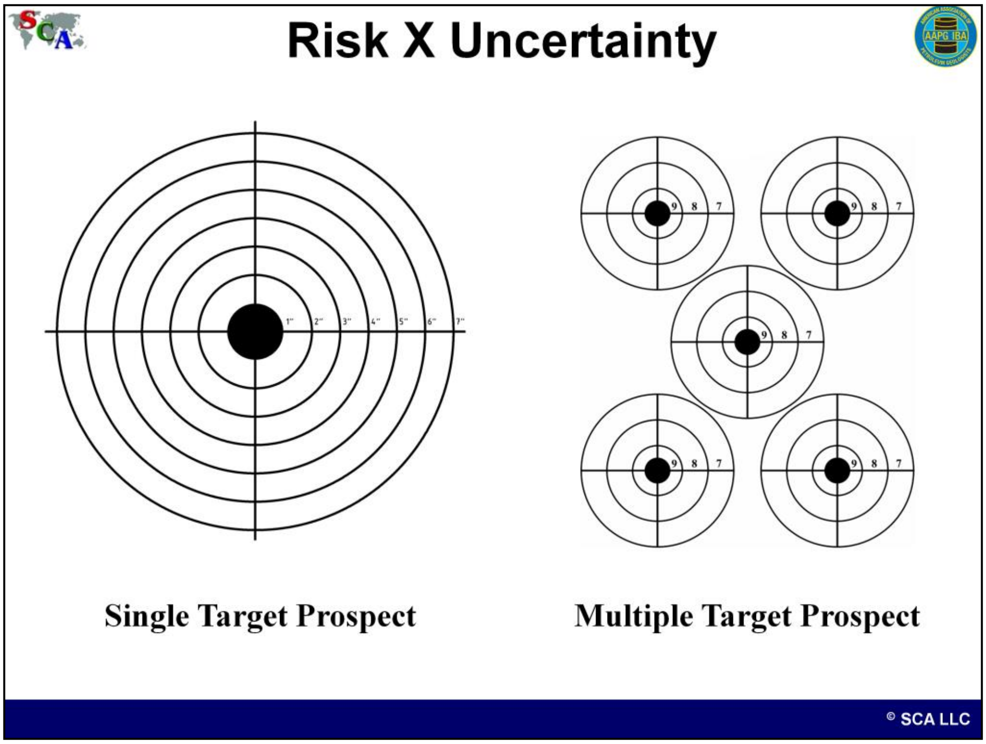
The risks were then discussed by the team, or elaborated on by the prospect evaluators.

After the discussion, the team is given a second opportunity to individually, and anonymously assess the COS. These COS estimates should then be used to define a consensus of the COS, and be used to define the key risk(s).



The risked mean is determined by multiplying the mean volume by the chance of success. For example, a prospect with a mean volume of 100 BCF that has a 20% chance of success has a risked mean volume of 20 BCF.

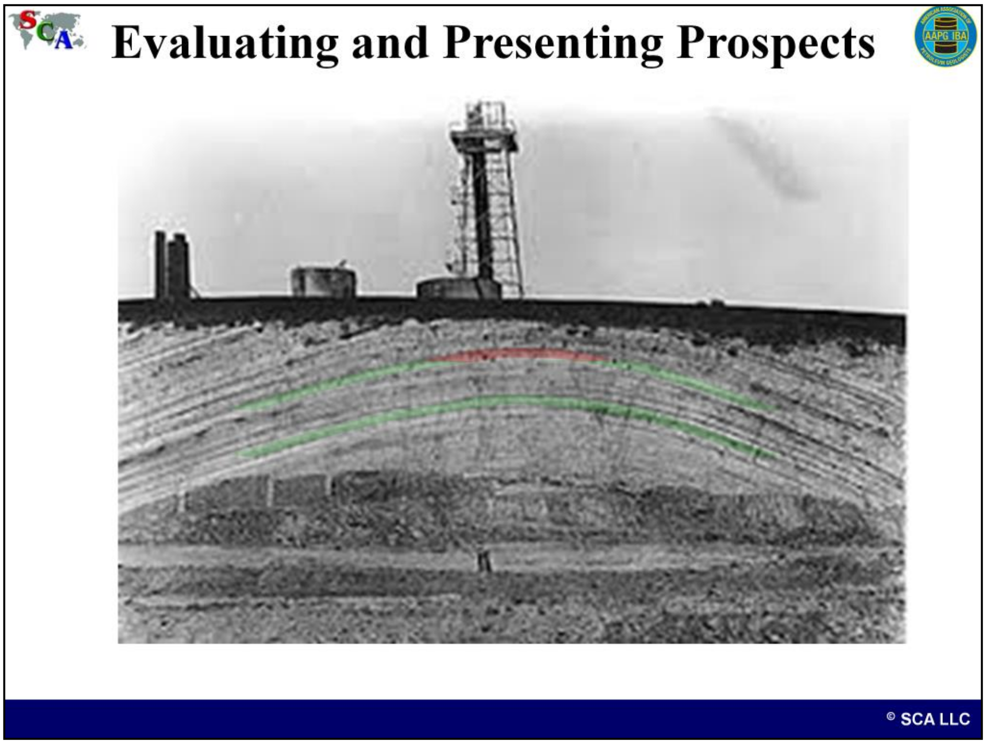
When you have multiple targets in your prospect, you should determine the uncertainty distribution and the risk for each potential reservoir target. Aggregating the volume distributions for each potential reservoir will give you the risk discounted mean volume for the prospect



When your prospect consists of a single target (one prospective reservoir), then you will either enter your distribution (success) or not (failure). In this case, the risk is simply a measure of how likely you are to enter the distribution.

When your prospect consists of a multiple targets (several prospective reservoirs), then you have multiple opportunities to enter your distribution. For multiple target prospects, or for exploration portfolios containing multiple prospects, we can expect to find the risk-discounted mean volume.

When you have multiple targets in your prospect, you should determine the uncertainty distribution and the risk for each potential reservoir target. Aggregating the volume distributions for each potential reservoir will give you the risk discounted mean volume for the prospect.



We have walked through some of the methods and techniques you need to evaluate and to present the various elements of the petroleum system as they relate to assessing a prospect.

We hope you find this information helpful as you evaluate your prospect for the IBA Competition

You can find more information on making better interpretations and maps by going to SCA's website and checking out the 10 Habits of Highly Successful Oil Finders which can be found in our blog section.

You can also look at our training schedule and class offerings to find the classes you need to learn the methods and techniques you need to make accurate interpretations and maps.

SCA also has many highly experienced and successful oil finders available for consulting and mentoring.

Our classes and our consultants cost a lot less than a dry hole

Finally, on behalf of the AAPG IBA Committee and the AAPG Division of Professional Affairs, we at SCA would like to wish you good luck in the IBA competition.