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The Art and Science of Seismic Interpretation

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The Art and Science of Seismic Interpretation

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Preface

Seismic data is one of the fundamental tools used to interpret subsurface geology with application to understanding of earth processes, tectonic evolution, and energy exploration in particular. This book is written for technical specialists who are new to seismic geophysics. It introduces the seismic data set including how the data are acquired and processed in order to produce 2D and 3D images of the subsurface and how its interpretation is applied to the exploration and development of hydrocarbon resources. A brief summary of the evolution of the US oil and gas industry is included to provide a historical context within which the field of seismic geophysics developed and is applied. The seismic approach started as a method to image and interpret subsurface structure. Its application evolved well beyond that as vertical resolution and image quality improved and as various seismic attributes became more readily computed and understood. Today's seismic applications include the evaluation of the full array of petroleum systems elements including the prediction of source rock presence and degree of maturity, reservoir distribution, trap geometry, and seal capacity. Current seismic interpretation extends beyond these conventional aspects as the energy industry expands into the world of unconventional resources. This is driven by the need for a better understanding of subsurface bulk rock properties and frac-induced microseismicity. As an introductory text, this book provides a general overview of seismic principles, processing, and interpretation based on over 60 years of combined experience of the authors. The goal is to provide a general understanding of the technique and its application as a starting point for students and early career professionals. Each chapter includes citations and references selected by the authors as key publications that provide the next level of detail regarding specific topics discussed in this volume.

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Chapter 1
Seismic Geophysics

Abstract Geophysics plays a central role in the modern hydrocarbon exploration and production industry. A brief overview of gravity and electromagnetic geophysical methods is followed by in-depth discussion of seismic geophysics. The elastic seismic wavefield is generated and measured so as to isolate and enhance P-wave energy. The acquisition of land or marine 3D seismic data is a large-scale experiment involving source activation and simultaneous recording of many thousands of sensors. Each sensor (or array) generates a seismic trace whose geometry is defined by the source and sensor coordinates. The complete survey can consist of several billion individual traces that require significant processing to create a subsurface geological image. The natural domain of seismic data is reflection time that must be tied to geology through a synthetic seismogram. Frequency, resolution and vertical exaggeration of seismic data set limits on interpretation. Rock mineralogy, porosity and pore fluids all influence the seismic response, primarily encoded in seismic amplitude data. Basic interpretation methods involve horizon tracking, fault network mapping, identifying direct hydrocarbon indicators, and geobody extraction. Additional processing of the amplitude data leads to a universe of seismic attributes that aid interpretation.

Keywords Acquisition · Frequency · Gassmann theory (fluid substitution) · Impedance inversion · Machine learning · Resolution · Seismic attributes · Seismic migration · Synthetic seismogram · Wavelength

The search for oil and gas comes down to understanding geological conditions deep in the earth. The well bore is a few centimeters across, and most wireline logs gather information from a few meters near the borehole. While some geological properties are slowly varying with distance, others change dramatically in the space of a few meters. If several wells are drilled and logged, then estimation of geological conditions between boreholes is an interpolation problem. This may be acceptable if the distance between wells is similar to the length scale of rock and fluid property

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variation. Some shallow oil fields (less than 0.5 km) have a dense array of wells drilled 200 m apart, or less. Such oil fields also tend to have simple structure, and interpolation using the well data may be adequate.

However, the common situation is a few widely spaced wells drilled several km deep to map a complex target. How, then, are we to figure out the geology before drilling? The answer is seismic imaging, a technology developed over the last century and the subject of this book. However, geophysics is a broad subject, and it is useful from the outset to briefly outline geophysical concepts and methods to put seismic imaging in context with other geophysical techniques.

Geophysics can be defined as those methods that give information about the earth's subsurface through analysis of measurements made on the earth surface. That is to say, geophysics is fundamentally noninvasive. At the most fundamental level, there are only four forces in nature: gravitation, electromagnetism, strong- and weak-nuclear forces. Each of these has an associated field, and the field has been the underlying concept in of all physics since the late nineteenth century. In geophysics, we deal with those fields that have potential to yield information about the subsurface at various depths and scales.

Gravity Methods

The gravitational field of the earth varies at all spatial scales from global changes indicating the shape of the earth (the science of geodesy), to continental scale bearing information about tectonic plates and topography (Fig. 1.1) to regional variation

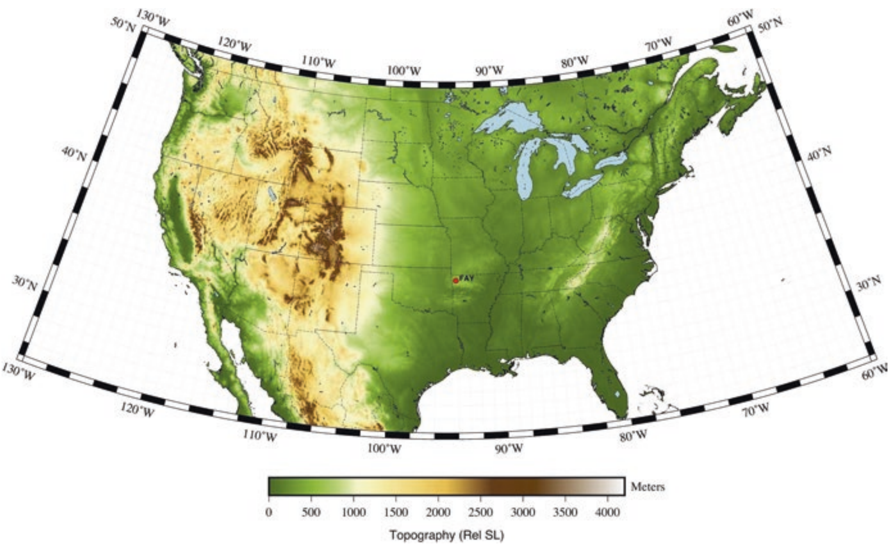

Fig. 1.1 Topography of North America

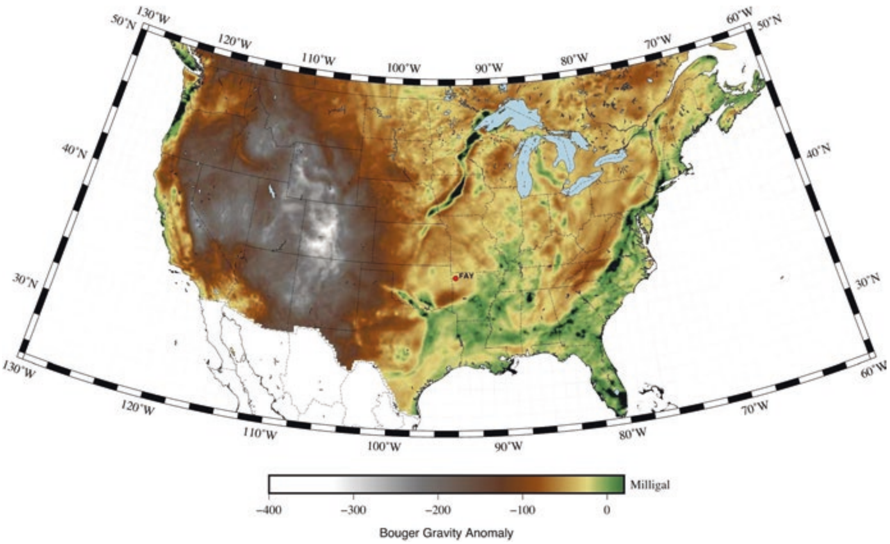

Fig. 1.2 Gravity anomaly map for North America. Data is processed to remove standard effects to generate what is called the Bouguer anomaly map. At this scale, extreme negative Bouguer gravity values generally indicate thicker crust, while positive values are associated with thinner crust

related to sedimentary basins and mountain chains, and even to local effects exploited in civil engineering, environmental studies and archeology. The gravity field is also a relatively slow function of time due to lunar tidal effects, internal mass redistribution (like groundwater), and human activities.

The density of most sedimentary rocks is in the range 2–3 g/cc; igneous rocks tend to be above 3 g/cc and salt has a low density of 1.4 g/cc (Telford et al. 1976). In early petroleum exploration, gravity surveys were used to identify sedimentary basins and estimate depth to igneous basement (Fig. 1.2). In basins with late tectonic movement, basement structures could extend up to exploration depths to form prime drilling targets such as anticlines and domes. The low density of salt means that over geologic time as it is buried by sedimentary rock, salt is buoyant and can mobilize to form salt domes, ridges, and canopies now well known in the Gulf of Mexico and elsewhere. Some of the earliest geophysical successes involved gravity mapping salt domes in Louisiana and Texas.

Gravity data today is acquired by satellites, drones, and lightweight portable sensors often with some form of spatial gradient that can be used for enhanced processing. Although the sheer amount of data is growing exponentially, the fundamental application has not changed. Refined basement and salt maps are useful in frontier exploration areas, but these products are of limited use in active hydrocarbon basins because of low resolution, ambiguous depth estimates, and the fundamental fact that the sedimentary rock section is essentially transparent to gravity data. It is fair to say that for hydrocarbon exploration, gravity is a supplemental data type of marginal use in mature basins but still actively exploited in frontier areas.

Electromagnetic Methods

The electromagnetic (EM) environment of the earth has stronger and more rapid variation in both space and time than the gravity field. The geomagnetic field generated in the liquid metal outer core of the earth pulls and twists charged particles from the sun (solar wind), generating global scale currents. Where gravity has only natural sources, there are countless human sources of EM energy so methods make the distinction between natural and induced. The general field of EM can be split conveniently into magnetic, electrical, and coupled EM methods (Telford et al. 1976).

Magnetic surveying seeks out anomalies related to the magnetic properties of rock, specifically magnetic susceptibility which is the degree to which a material can be magnetized in response to an applied magnetic field. In SI units, common sedimentary rocks (including salt) have susceptibilities of about 10^{-5}, while metal-rich igneous rocks can have values up to 0.2. Consequently, magnetic mapping is useful to locate ore bodies and metallic objects, and, at the basin scale, magnetics play much the same role as gravity, perhaps indicating the thickness of sedimentary cover and general basement structure (Fig. 1.3).

Electrical methods fall into categories that employ natural electrical sources (self-potential, telluric, and magnetotelluric), EM methods using a controlled source, resistivity surveying, and induced polarization mapping. Those methods of most use in hydrocarbon exploration are resistivity and EM.

Resistivity surveying uses current applied to electrodes inserted in the ground to estimate electrical resistivity of the subsurface. The scale of investigation can be a

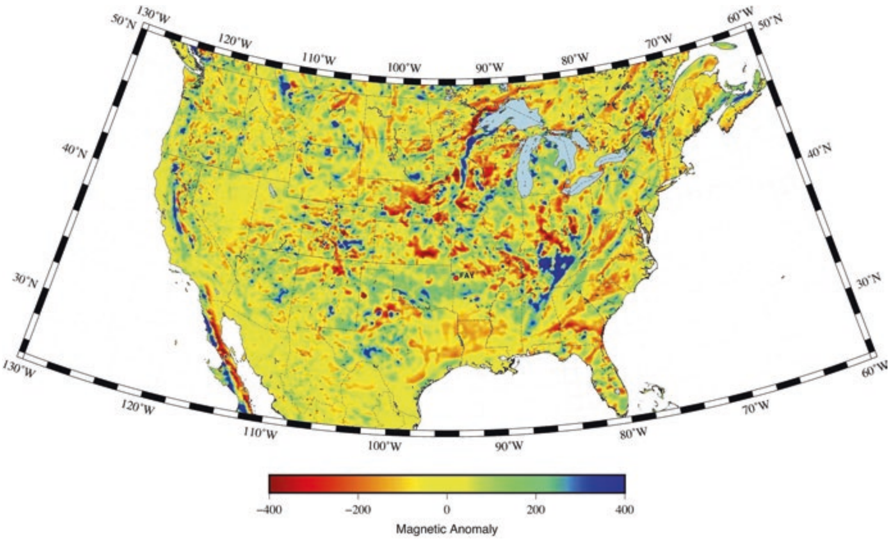

Fig. 1.3 Magnetic anomaly for North America. A strong positive anomaly may indicate metal-rich ore deposits and/or shallow igneous basement, while a negative anomaly can be associated with thicker sedimentary rock cover

weak current injected into closely spaced electrodes to determine shallow resistivity (on the order of meters) or strong currents applied to widely spaced electrodes to estimate resistivity of the deeper subsurface (10s of meters). In either case, the method utilizes differences in electrical resistivity, primarily of non-hydrocarbon pore fluids; oil and gas are non-conductors of electricity (near infinite resistivity). Fresh water resistivity is about 10 ohm-m, and brine formation water values are in the range 1.0–0.1 ohm-m with lower resistivity being related to increasing salt and dissolved solid content. Since common sedimentary minerals all have very high resistivities, the net rock resistivity is driven by pore fluid properties. For environmental work, this allows mapping of contaminated, or conversely uncontaminated, groundwater areas (low resistivity indicating contamination).

The traditional resistivity surveying method uses direct current and is therefore depth-limited unless very high (and dangerous) currents are applied. There are also several electromagnetic methods that use natural or artificial time-variant electrical sources. The natural source methods often exploit very low frequency currents generated in the atmosphere to make images of large-scale geologic features such as basins, buried mountain fronts, and regional structures. Beginning about 2000, a marine EM resistivity method has been developed, termed “seabed EM.” Since seawater, unlike air, is an electrically conducting medium, EM waves generated by a source in the ocean propagate to the seafloor and beyond to return information about formation resistivity acting as a direct hydrocarbon indicator. In some basins, case histories have shown that seabed EM can be a complimentary data type to more commonly used and higher-resolution seismic data.

Seismic Methods

In the broadest sense, the seismic method is an echo location technique similar to sonar, radar, and ultrasound. The end result of modern seismic acquisition and processing is a 2D or 3D image of the subsurface beneath the survey location. It is not a perfect image, there are limitations of resolution and frequency content that cause the seismic image to be a somewhat blurred representation of subsurface geology.

Seismic waves are mechanical waves ultimately related to electromagnetic forces binding matter together, and they propagate in the earth due to short-term force imbalances (sources) on scales of regional tectonic faulting to a simple hammer strike. From the earliest times earthquakes have been a subject of curiosity and, often, supernatural speculation. The concept of elastic infinitesimal deformation and theory of elastic P- and S-waves was formed by 1830. Instrumentation to record seismic waves developed after 1840, and the theory of elastic surface waves was known by 1885. Active source seismology applied to subsurface mapping began with a patent by Reginald Fessenden in 1918. The historical development of reflection seismology is naturally intertwined with the history of petroleum geology (Heiland 1946) and, therefore, is deferred to a later section. Here the goal is to describe the universe of seismic methods to put reflection seismology in context.

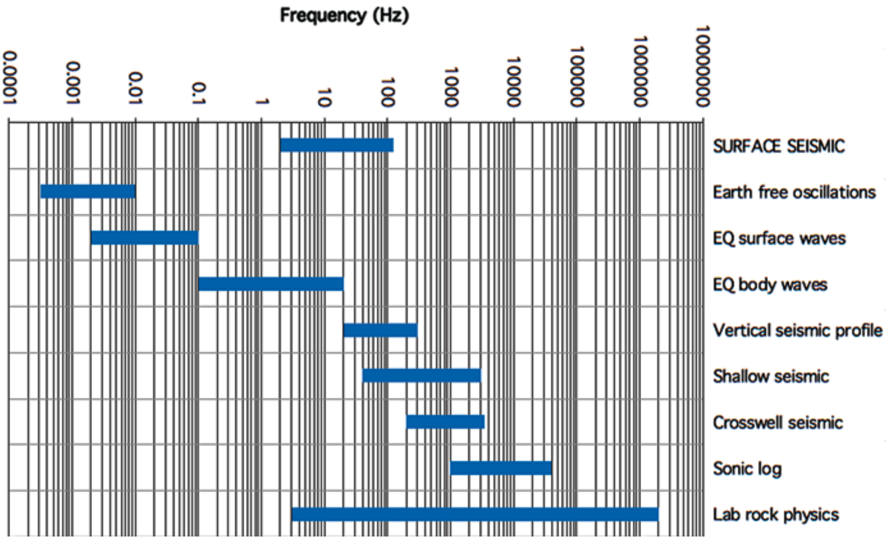

Fig. 1.4 Logarithmic frequency spectrum of various seismic phenomena and methods. (Modified from Liner 2016)

A key parameter related to any kind of seismology is frequency. Figure 1.4 shows the range of frequencies in various passive and active seismic methods. For frequencies below 1 Hz it may be useful to think instead of period in seconds (1/frequency). The focus for most of this book is on surface reflection seismology, meaning an active source survey with sources and receivers on the surface of the earth. For this kind of survey, the frequency spectrum is band limited on the low end by limitations on the physical size of the source and on the high end by seismic wave scattering and attenuation in earth materials. The net effect is that, under ideal conditions, modern surface seismic data can achieve a frequency range of 2–125 Hz. And what are "ideal conditions"? For land data, it is mild topography with a thick soil layer that grades into the deeper subsurface without shallow high velocity layers such as limestone or anhydrite. The ideal marine case is water (not too shallow) over a soft, relatively flat seafloor again grading to the subsurface without high velocity layers. Any variation away from these ideals (rough topography, hard rock at the surface, shallow water, hard seafloor) can be expected to narrow this frequency band. It is only in the last few years that source technology has developed to the point where frequencies below 5 Hz are reliably acquired (Tellier et al. 2015). A corollary to this statement is that "vintage matters." A 1970s vintage land survey in a good data area might have bandwidth of 10–50 Hz, where a modern survey might have 2–125 Hz. But a note of caution on the high end is warranted; for nearly half a century seismic sources have been able to generate frequencies far above 100 Hz, but nature conspires through a variety of processes to erode the high frequencies such that they are not returned to surface sensors. In other words, we can always achieve the low frequencies, but nature is in charge of the high end. Indeed, some seismic methods have been developed to exploit gaps in the covered frequency spectrum.

Active seismic sources include explosives and vibrators on land and airguns for transition zone and offshore work. All of these emit a range of frequencies to form a compact pulse (wavelet) that reflects and otherwise interacts with the subsurface rock layers. A wavelet is described as having a dominant frequency which is the average of the lowest and highest frequency it contains. For example, a 2–125 Hz wavelet has a dominant frequency of 63.5 Hz, but more commonly dominant frequency is in the 30–50 Hz range.

Another essential concept in seismology is wavelength defined as wave speed divided by frequency. Wave speed is usually referred to as velocity, although in a physics sense velocity is a vector quantity having both magnitude and direction. The term "velocity" is further overloaded since it ignores the many kinds of velocity relevant to seismology, P-wave velocity, S-wave, surface wave, interval, and various averages useful in different situations (Liner 2016). Following convention, the unmodified term "velocity" will be taken to mean P-wave speed. With this simplification, wavelength is then equal to velocity divided by frequency. In seismic surveys related to petroleum exploration and production, the velocity range encountered is about 2000–7000 m/s. The low end is related to soft, unconsolidated rock, although much lower velocities occur in soil, sand dunes, water (1500 m/s), and air (335 m/s). On the high velocity end are low porosity carbonate and igneous rocks. Figure 1.5 graphically combines the frequency, velocity, and wavelength across values encountered in petroleum seismic data.

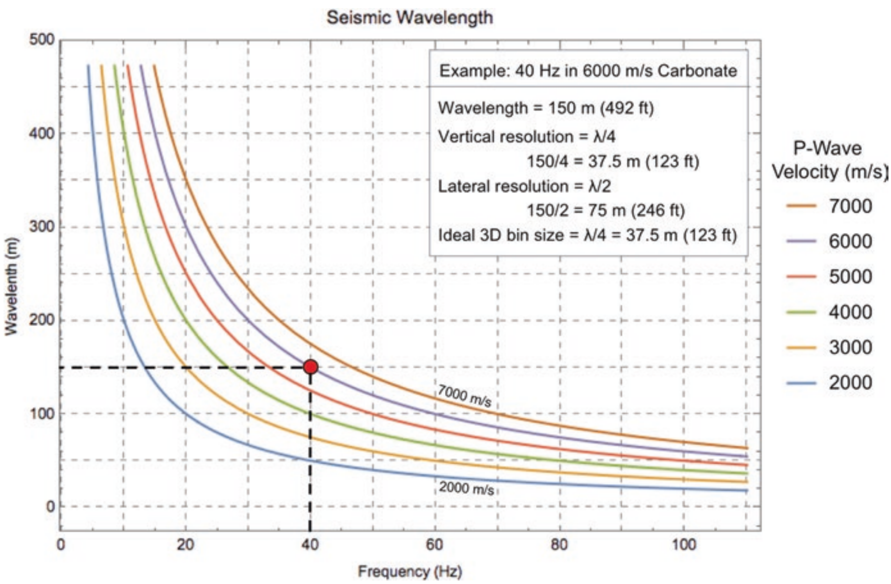

Fig. 1.5 Graphical relationship between frequency, velocity, wavelength, and resolution. The example shown (red dot and text box) calculates quantities for the case of a 40 Hz wave in a 6000 m/s carbonate rock

In the broadest sense, seismology can be divided into passive and active.

Passive seismology is any method that uses natural sources of seismic waves to infer subsurface structure and/or properties. Historically, earthquake seismology has been the primary passive area of study. Analysis of earthquake seismic waves over many decades revealed the internal structure of the deep earth, resulting in ever-refined estimates of the depth and properties of the crust, mantle, outer core, and inner core of the earth (Aki and Richards 2002). From 2007 to the present, the USArray program deployed 400 high-quality broadband seismometers in a rolling pattern across the United States (USArray 2018), continuously monitoring seismic waves generated by earthquakes and background noise sources (such as coastal ocean waves). Processing of this vast data archive has showed new details of deep crust and mantle features related to tectonics and continental formation. Over the same time period, near surface mapping with passive seismic data has developed under the name "seismic interferometry." In this application, local high frequency seismic noise sources such as automobile traffic are exploited to generate 3D shear wave models useful in civil engineering and environmental studies.

Active seismology includes any method that utilizes a controlled source of seismic waves; this can be a truck-sized mechanical vibrator (vibroseis) or buried explosive for land work, or a high pressure airgun for transition zone and marine surveying. Vibroseis and airgun have decided advantages over explosives both in relation to safety and customization of the source wavelet. However, explosives still have a role in modern seismic acquisition where terrain, surface conditions or logistics make access to vehicles or source boats impractical.

Near surface layering and, to a lesser extent, topography has a first-order effect in the quality and resolution of seismic data. Seismic reflection events originate where there are contrasts of density and seismic velocity in the earth. To be specific, seismic reflections are generated by contrast in acoustic impedance, which is the product of velocity and density. In the near surface, large contrasts are commonly encountered and have the effect of scattering and attenuation of high frequencies in the data. For surface seismic data, with sources and receivers at the earth's surface, the near surface has two chances to consume high frequencies; once on the downgoing source wavefield and again on the upgoing reflected wavefield. High frequencies are so important that many acquisition strategies have been devised to minimize the near surface effect, usually in the form of increasing data redundancy – more sources, more receivers – that allows large-scale summation (stacking). But the near surface scattering problem is tenacious, the more power applied, the more effective the scattering. Consequently, the high frequency limit for land seismic data is about 125 Hz, not much different than it was 20 years ago. But near surface scattering is mainly a high frequency problem, so great progress has been made on the low frequency end. It is common to now acquire data down to 3 or even 2 Hz (Mougenot 2018). This is very important in relation to matching well data, estimating reservoir seismic properties and, indirectly, analyzing reservoir rock and fluid properties. It is curious that land data has seen the most progress in low frequency acquisition, while marine data progress has mainly been to achieve higher frequencies (offshore near surface rocks have typically less impedance contrast than land cases).

Two seismic acquisition methods exploit wells to avoid the near surface all together. First, a vertical seismic profile (VSP) uses surface sources shooting into receivers located down a well (Yilmaz 2001). The simplest VSP uses a single source near the wellhead to generate data used to tie seismic reflections to geologic horizons (zero offset VSP, or ZVSP). In the most ambitious case, sources span a grid of distances (offsets) and angles (azimuths) from the well (3DVSP) and the data can be processed to a small image volume in the vicinity of the receiver well. In any VSP case, the wavefield passes through the near surface only once and, therefore, frequencies up to 200 Hz can be acquired. The second method is a crosswell survey (Xwell) that has both downhole sources and receivers. The near surface is never encountered, and frequencies above 1000 Hz can be recorded. Although VSP and Xwell data have higher frequencies and, therefore, higher resolution than surface seismic data, they are fundamentally different kinds of data. Where surface seismic gives a cross section (2D) or cubic section (3D) of the earth, VSP and Xwell give small slices of data in the vicinity of the source and/or receiver wells. As a result, both VSP and Xwell are considered niche data types compared to the main body of 2D/3D seismic data used for hydrocarbon exploration and production.

In the modern search for hydrocarbons, the primary subsurface imaging technology is active source 3D seismic data with 2D seismic playing a role in less explored areas for reconnaissance or to image geologic features that have a larger scale than a 3D survey area. The fundamental concept of seismic data acquisition is, and always has been, to activate a surface seismic source and measure the response with a collection of surface sensors. Sounds simple, but there is a universe in the detail. But the fact is that everyday practice represents a small subset of the possible variations of source, wavefield, sensor, and layout.

Source For land data the source can be vibroseis or explosives. Vibroseis (Fig. 1.6) involves a heavy (>20,000 kg) truck and vertical vibration of a large metal base plate that, in turn, generates seismic waves (Liner 2016). An explosive source is detonated in a shallow drill hole, generally less than 30 m deep. As mentioned above, vibroseis offers clear advantage in customizing the source spectrum and power, but terrain or logistics can make vibroseis unmanageable and explosives the only alternative. In offshore seismic surveying the airgun source is nearly always used and is formed by individual airguns organized into an array and fired in such as way as to generate the desired output waveform. Coastal transition zones are particularly difficult areas with respect to seismic sources; vibroseis trucks can raft and bog down, explosive shot holes require some kind of casing to maintain integrity until the shot is fired; airguns are effective in water that is shallow, but not too shallow. In transition zones it is common to use a combination of sources as circumstances dictate and blend the resulting data together in data processing, although the boundary between various source types is often visible on the final product despite every effort in processing.

Fig. 1.6 Vibroseis truck with base plate (between tires) lifted for movement between shot points. (Photo credit: C. Liner)

Wavefield

Whatever source method is used, the initiated seismic wavefield evolves with time to move farther from the source and thus deeper into the earth. Despite the complexity of seismic data, it is important to understand that there only a few wave types that can exist. Fluids, such as air and water, have two mechanical parameters: density and sound speed. The only mechanical wave that can exist in a fluid is an acoustic, or sound, wave, unless there is a boundary present (water surface) in which case a type of surface wave, called a gravity wave, can also exist. In water, the sound wave travels at 1500 m/s while the gravity wave velocity is about 20 m/s. Thus, when a marine airgun source fires, acoustic waves in the ocean are generated and spread out until they reach the seafloor. On the other hand, rock formations, to a first approximation, are elastic solid materials that are characterized by three parameters: density, P-wave speed, and S-wave speed. An elastic solid without boundaries can support two wave types: a compressional, or P, wave and a shear, or S, wave. Shear waves are much slower, generally about half, of the velocity of P waves. In addition, a third wave can exist at the surface of an elastic solid termed a Rayleigh wave. With only one or two wave types, it would seem logical that seismic wavefields are fairly simple, but this is far from the truth. Complications come from variation in layering within the earth as any roadside geologist can tell from looking at outcrops. In an acoustic medium, as a wavefront strikes an interface between two layers, it splits into reflected and transmitted acoustic wavefronts. In the elastic case, a compressional wavefront splits at each interface into reflected P and S waves and transmitted P and S waves (Aki and Richards 2002). In even a simple layered elastic earth, the wavefield can quickly become immensely complicated as each spawned wavefront

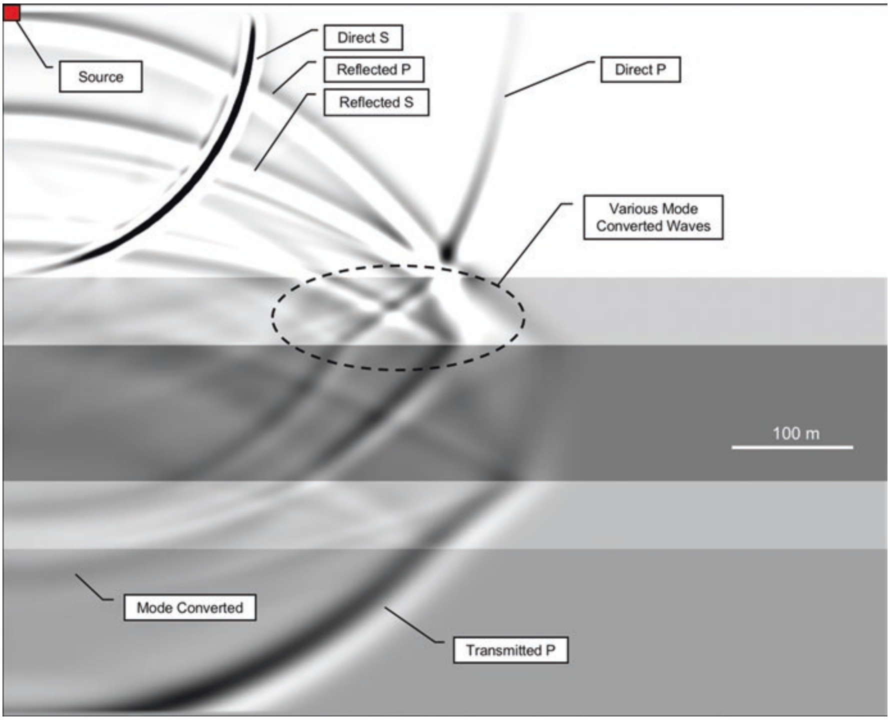

Fig. 1.7 Vertical section through an elastic wavefield for a five-layer case. Layer shades represent velocity (darker is faster), and a few wavefronts have been labeled

strikes the next interface and spawns four more; and this happens for upgoing and downgoing waves. In this way the reflected wavefield that returns to the acquisition surface is a tangle of reflected waves that have mixed heritage from reflecting and mode conversion between P and S. Figure 1.7 offers a glimpse of the full elastic situation for a five-layer case (darker layer shades mean higher velocity) as a vertical section through the wavefield and a few wavefronts have been labeled. Although there is more information in the elastic wavefield, current practice is to utilize only the P waves that have undergone a single reflection (primary P data). In this sense, the vast majority of 3D seismic data considers the earth to be acoustic and acquisition strategies are designed to preferentially generate, receive, and enhance the P wave field. There are exceptions where a fundamentally elastic representation of the earth is needed (amplitude versus offset analysis, prestack elastic inversion), but interpretation usually assumes an acoustic model of the earth (Brown 2011). That being so, the most important parameters of the earth layers for seismic interpretation are density and P-wave velocity (Fig. 1.8).

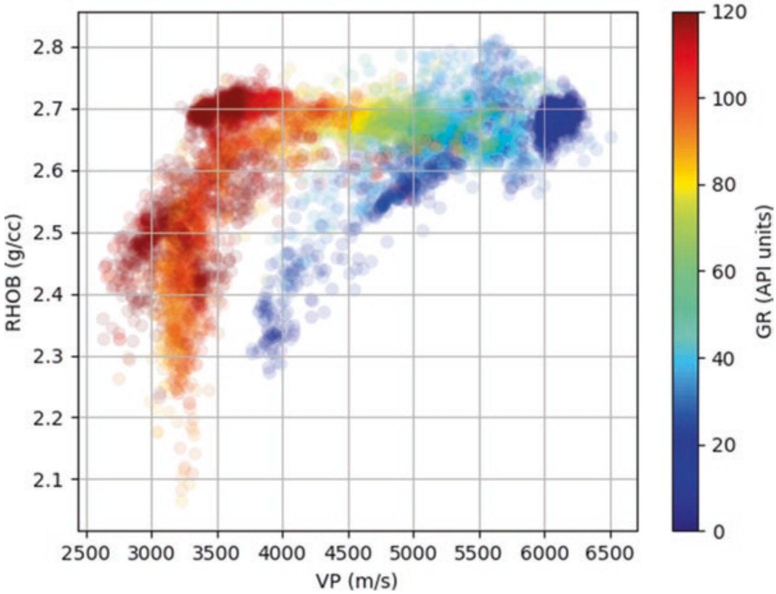

Fig. 1.8 Cross plot showing range of P-wave velocity (VP) and density (RHOB) for a well containing a variety of sedimentary rock types. Data points are colored by gamma ray (GR) response; higher GR generally indicates increasing clay mineral volume in the rock. The lowest GR is associated with clean carbonate rocks, seen to have high velocity and density

Land Sensors

The basic geophone was the sensor in all land seismic until about the year 2000. A geophone is a mechanical device consisting of a free-floating permanent magnet supported by end springs inside a coil of wire, with a rugged plastic case, base spike, and pair of wire leads for connecting to a data cable (Liner 2016). Spiked into the ground, the geophone case moves with the earth surface as seismic waves arrive. This causes differential motion between the magnet and wire coil to generate current. Since geophones generally only measure vertical motion, they help to isolate the P wavefield and attenuate S and surface waves. The geophone is rugged, self-powered, and inexpensive. Over the last two decades, the push for more sources and sensors per square kilometer (higher data density), primarily to retain higher frequencies, meant that cabled geophone systems were increasingly heavy and complicated. This led to the development of wireless solid state sensors, typically accelerometers. In addition to eliminating vast lengths of geophone lead wires and data cables, digital sensors were found to have better low frequency response than mechanical geophones. On the other hand, digital sensors are heavier than geophones, require batteries and recharging, and are more expensive (Lansley et al. 2008). In current land practice, both cabled geophone systems and wireless digital sensor systems are in use, with digital systems seeming to have the advantage for surveys that are very large and have high data density.

Marine Sensors

The year 2000 is also a fair dividing line for marine sensor technology, just as it was on land. Before that time, marine surveys gathered streamer data using hydrophone sensors built into data cables towed behind receiver ships. The cables were designed to be impedance-matched to water so that the data wavefield would pass transparently through to the sensor. By definition, the returning wavefield in a marine survey is composed entirely of P waves since S waves cannot propagate in a fluid. However, the wavefield is fully elastic below the seafloor and the measured field contains both primary P waves and other mode-converted and multiply reflected events. All this can be (mostly) unraveled in processing to isolate and enhance the primary P wave reflections. From the 1990s on there were options for marine acquisition that involved sensors on the seafloor, but this was relatively rare before 2000. Seafloor sensors (commonly called nodes) are self-contained battery-powered devices that typically contain both a hydrophone and geophone (or digital vertical motion sensor); in some cases seafloor nodes have three-component geophones (Mougenot 2018). The advantages of seafloor nodes include a low-noise environment well below wave base, easy placement in busy shipping lanes and around drilling rigs, and the combination of pressure and vertical displacement measurement allows enhanced processing to reduce seafloor multiple reflections that are notoriously difficult to remove in streamer data, particularly in cases of hard seafloor, significant seafloor topography, and deep water. Developments in streamer technology to address the multiple problem include dual cable over-under configurations and vector acoustics, but the bottom node solution is generally preferred in very difficult cases.

Layout

The final aspect of current seismic practice is geometry of the data gathering experiment, often termed the layout. In a broad sense, the seismic acquisition idea is to initiate a seismic wavefield, measure it with sensors, move the source and/or sensors, and repeat to cover the desired area. If the sources/sensors all lie in a line on the earth surface, the data are termed a 2D seismic survey, otherwise it is a 3D seismic survey. The details of 2D acquisition geometry have evolved for nearly a century, the greatest advance coming in 1956 with the advent of common midpoint (CMP) shooting. Earlier surveys were shot in such a way that continuous reflection coverage was obtained (Fig. 1.9), but since each sensor recording (trace) was the output of a single sensor or array, the data quality was generally poor and suitable only for mapping gross structure. CMP shooting (Fig. 1.10) tightened up the acquisition geometry to record overlapping traces at each reflection point that allowed data summation (CMP stacking) resulting in a vast improvement in data quality. Initially CMP data was 6- or 12-fold, but the march of progress now

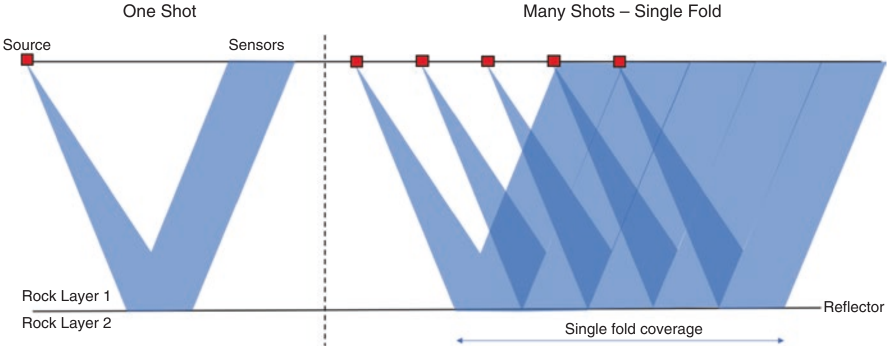

Fig. 1.9 Single-fold shooting in the early days of reflection seismology resulted in continuous reflection coverage, but low-quality data suited only for general structural interpretation

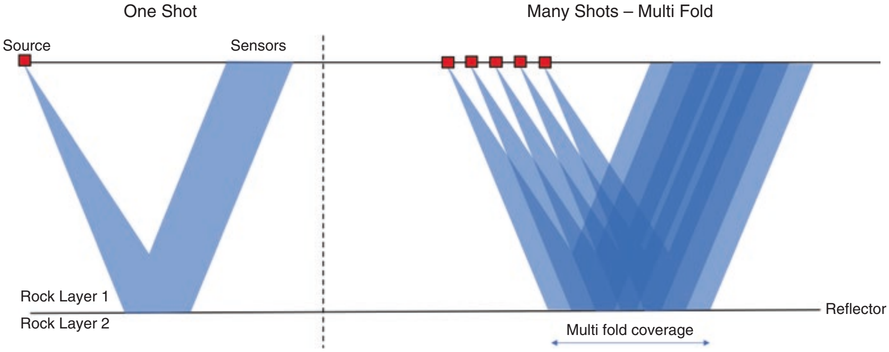

Fig. 1.10 After 1956, common midpoint (CMP) shooting delivered data with multiple traces reflected from the same subsurface point. This allowed CMP summation (stacking) resulting in higher quality data that could image subtle subsurface features

delivers 3D data with a CMP fold of hundreds or thousands (Pecholcs et al. 2012). The CMP concept extends naturally to 3D acquisition where sources are shot into patches of several thousand sensors. As the shot location moves in some pattern to cover the survey area, the live patch of receivers moves with it. In practical terms, the sensor patch is not physically moved with the source, but a larger area of sensor coverage is switched on/off as needed to simulate patch movement. As detailed in later sections, a variety of terms have evolved in 3D acquisition to describe the shape of the sensor patch (NAZ, FAZ, WAZ, etc.), suffice it here to say that from a physics point of view a square patch is optimum since it captures wavefield information emerging from the subsurface along any compass direction (azimuth). The size of the sensor patch depends on the depth of the target and anticipated dips, and sensor spacing within the patch is determined by desired data density, CMP fold, and data quality. Of course, all such choices are ultimately related to acquisition cost.

In traditional wired shooting, source initiation triggers the sensors to begin recording. Wireless recording systems have continuous recording by sensors with precise time stamps that can be aligned with source activation time. In effect, the time stamp for a source is used to chop out part of the continuous sensor data that begins at the source time. It is this feature that allows simultaneous source acquisition in which multiple sources are operating simultaneously at different locations to increase efficiency.

The ideal acquisition experiment above can be considered as a vast collection of source-receiver (S-R) pairs; the seismic wavefield from one source as measured by one receiver. Each S-R pair generates a prestack seismic trace, a time-dependent ground motion record observed at the receiver location. Both source and receiver have three-dimensional (x,y,z) coordinates that allow calculation of other important quantities, including:

- Midpoint – the location halfway between source and receiver
- Offset – the distance between source and receiver
- Azimuth – the compass orientation of a line connecting source and receiver

The midpoint is important because this is where the raw seismic trace is placed for subsequent processing. In other words, seismic traces live at midpoint locations not receiver locations. The seismic image that will ultimately be created is limited to the midpoint coverage area, a fact that must be considered when designing a seismic survey. Offset coverage relates to several aspects of data processing and a prestack interpretation technique called Amplitude Versus Offset (AVO) that is a primary method for distinguishing rock and pore fluid types, including hydrocarbons. Azimuth is critical to seismic imaging algorithms that move the observed data from midpoint locations to true subsurface locations. If data is missing along a certain azimuth, the process cannot place the subsurface data correctly which results in errors that influence structural and stratigraphic interpretation. In addition, wavefield characteristics may be azimuth-dependent due to rock anisotropy (velocity as a function of direction) or extreme lateral velocity variation. Only if full azimuth data is available can everything be unraveled to reveal an accurate subsurface image for interpretation.

The ideal survey, as discussed above, has sensors in every compass direction around the source creating a full azimuth survey. In land data this can be routinely accomplished, but marine shooting presents problems particularly with towed streamer systems where sensors are pulled behind the ship in long cables. Various strategies have been developed to improve azimuth coverage in marine seismic data, including ocean bottom cables containing many sensors and nodes containing one or a few. The different methods have water depth limitations and, in practice, a large survey may use multiple acquisition strategies.

While conceptually simple, the logistics of a commercial land or marine 3D seismic survey are daunting when one considers that the (x,y,z) coordinates of every source and sensor is required along with knowledge of which sensors were live for each shot (cabling information), each shot/sensor pair generating a seismic trace timed to the millisecond, and that a large 3D survey can contain billions of traces.

Only by such Herculean efforts can data be acquired that allows the kind of interpretation required for modern hydrocarbon exploration: detailed structure, stratigraphy, rock properties, and even fluid properties. The examples discussed in this book are testimony to the remarkable level of subsurface information contained in modern 3D seismic data.

Seismic Processing

When seismic data comes in from the field to a processing center, it is usually organized into shot records, where each record is the collection of traces that recorded the wavefield from one source; such data is termed "prestack." At this stage, the data bears no resemblance to an image of the subsurface. Rather, the data is dominated by details of the acquisition geometry. A series of data processing steps are applied that will ultimately result in a subsurface image ready for interpretation. Broadly, there are two approaches. Conventional processing consists of a series of processes that address individual aspects of the recorded events such as amplitude, frequency spectrum, waveform shape, and travel time. This approach is less expensive since it makes various approximations of the physics involved that are good enough when the earth properties have small contrast and gradual lateral change. Prestack processing is one grand process that applies rigorous physics, is more expensive, and can handle the most challenging imaging problems such as sub-salt, rugged terrain, and fold-thrust mountain belts.

The short list of seismic processes below describes conventional processes unless otherwise specified.

1. *Geometry validation and correction* Processing requires that every seismic trace have correct (x,y,z) coordinates for the source and receiver associated with that trace.
2. *Near surface corrections (land)* The shallow subsurface on land is often characterized by irregular topography, generally low velocity (compared to deeper formations), but strong layer velocity contrasts, and perhaps dissolution effects due to water table variations over time. Taken together, the effect of the near surface is to act as a distorting lens that degrades data quality. A variety of decoupled processes have been developed to remove these effects and they work well in cases of mild topography and velocity variation. In extreme cases involving rugged topography with strong near surface velocity variations vertically and laterally (e.g., thrust belt mountains), the decoupled approach fails to provide interpretable data and the near surface effects must be treated as part of the imaging (migration) process.
3. *Multiple removal (marine)* Acoustic waves from the airgun source that are trapped in the water column and undergo more than one seafloor reflection are termed seafloor multiples. These waves incur a polarity flip without loss of amplitude when they strike the sea-air interface (reflection coefficient = -1).

Further, seafloor multiples are confined to the water layer and thus spread out in approximately two dimensions, unlike three-dimensional spreading for waves that pass through the seafloor. Multiples are strong events that often interfere with deeper, weaker reservoir reflections to confuse and limit interpretation. Processes for multiple removal are well developed for 2D and 3D marine data. Node acquisition has a natural advantage for multiple removal since both pressure and particle motion are recorded and multiples can be distinguished using these two data types. Multiples are most problematic and difficult to remove in two cases. First, shallow water over a hard seafloor where multiples become post-critical guided waves (Liner, 2012). Second, deep water with significant seafloor topography may result in a multiple that is only seen once during the recording time and is therefore hard to identify.

4. *Amplitude/spectral correction* As seismic waves progress through the earth there are several processes that act on the amplitude of the waves, including transmission, attenuation, and geometric spreading. Some of these affect all frequencies equally (spreading), while others (transmission, attenuation) act more aggressively on high frequencies and thereby change the frequency spectrum. Recall the source is carefully designed to emit a certain frequency spectrum and it is important to preserve it. Since spreading hits all frequencies equally, it can be corrected as a time-domain scale factor. The other effects can be approximately corrected by applying deconvolution which flattens the spectrum so that all frequencies are equally represented in the final data. Deconvolution only works if the attenuated wave amplitude at a given frequency is above the noise level, otherwise decon only has the effect of increasing noise levels in the data. The exquisite dynamic range of modern seismic survey equipment may be judged by the fact that seismic waves moving from a source to a receiver several kilometers away are reliably measured one or two orders of magnitude above the noise level.
5. *Velocity analysis and stack* In conventional processing, normal moveout (NMO) velocity analysis is aimed at the time delay that a reflection incurs as a result of increasing offset (source to receiver distance). Since data is acquired in common midpoint (CMP) fashion, the data is sorted into CMP gathers that consist of all traces that have the same midpoint (location half-way between source and receiver). For a horizontal reflector, the reflection event has a characteristic shape with time increasing with offset. The NMO process flattens reflection events across all times and offsets in anticipation of summing over offsets (CMP stack) to create a single CMP trace at the midpoint location. When NMO velocity analysis is completed for all CMP gathers in a survey, the gathers are stacked to form a volume of post stack traces ready for migration processing.
6. *Post stack migration (PoSTM)* Until seismic imaging, or migration, is applied, CMP stack data bears a loose relationship to subsurface structure because recorded data traces are posted at the midpoint location and all recorded events are necessarily directly beneath that location. But except for the case of a flat layered earth, the seismic waves have returned to the receiver by reflection from one or a series of dipping beds. The result is that on CMP stack data anticlines appear too broad, synclines too narrow, and faulted bed terminations are blurred

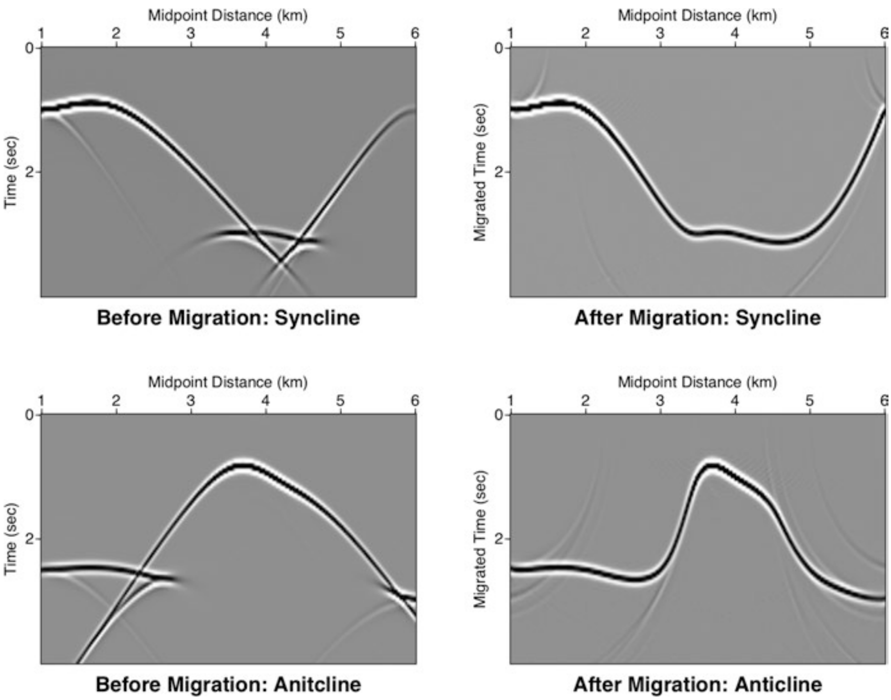

Fig. 1.11 Syncline and anticline examples on CMP stack data (left) and after migration (right). Migration moves reflection energy to its proper location to generate a correct subsurface image

by diffractions. Migration is the process of moving seismic reflection events into their proper subsurface locations to correct all these issues (Fig. 1.11). This requires knowledge of the velocity field which can only be estimated by migration itself, so it must be done repeatedly.

7. *Prestack Data* Consider a single trace from a 3D seismic survey. This trace is a time series, a collection of data values separated by a fixed time sample rate (usually 1, 2, or 4 milliseconds), and contains 1000–10,000 time samples. The trace is a wavefield from a particular source as measured by a particular sensor, hence the trace has an associated source location and a sensor location. From the (x,y,z) coordinates of source and sensor, the trace offset is known as well as the midpoint and the trace azimuth is known. Prestack traces are posted at their midpoint locations and overlain by a grid of cells, called bins, on the acquisition surface. The optimum bin is square with side dimension of wavelength/4 as calculated at the primary subsurface target, typical bin sizes are 10–25 m. Figure 1.12 illustrates the geometry for a single prestack trace. In this figure, the source location is S, receiver location is R, midpoint location is M, and the offset distance and azimuth line are shown. A modern 3D survey may contain several hundred million up to a few billion prestack traces.

8. *Prestack migration* The discussion above describing CMP stacking and post stack migration has mostly faded into the past. The primary issue is loss of information in the CMP stacking process. Prestack migration processing retains this information for further analysis. The terms prestack time migration (PSTM) and prestack depth migration (PSDM) are in common use to distinguish imaging algorithms that use physics approximations (PSTM) and those that rigorously apply physical principles (PSDM). Correct implementation of physics requires more computation time and usually more user-selected parameters, both leading to PSDM being much more expensive than PSTM. In a practical sense, PSTM is suitable for those situations where subsurface seismic velocity varies smoothly and slowly both laterally and vertically; the Gulf of Mexico above salt is a good example. PSDM is required for those cases with strong lateral and vertical velocity variation, such as subsalt targets, onshore situations with extreme topography and subsurface structure.
9. *Prestack Migration Gathers* The concept of image gathers can be approached by a thought experiment on a single unmigrated prestack seismic trace. Specifically, consider the amplitude value at one time point on this trace. For this blip of amplitude the source coordinate, the receiver coordinate, and the source/receiver azimuth are known. The subsurface velocity is generally unknown, but is assumed or estimated from well log data or previous seismic work in the area. Consider where in the subsurface a reflector may have existed to result in the blip of amplitude being posted at this midpoint and this time. The seismic waves went out from the source, bounced off a reflector and returned to the acquisition surface at the receiver location. Assuming a constant velocity for convenience, 3D geometry says that all such points in the subsurface that have this property (source to reflector to receiver distance is constant) is an ellipsoid with source and receiver at the foci. Figure 1.12 visualizes the situation with source and

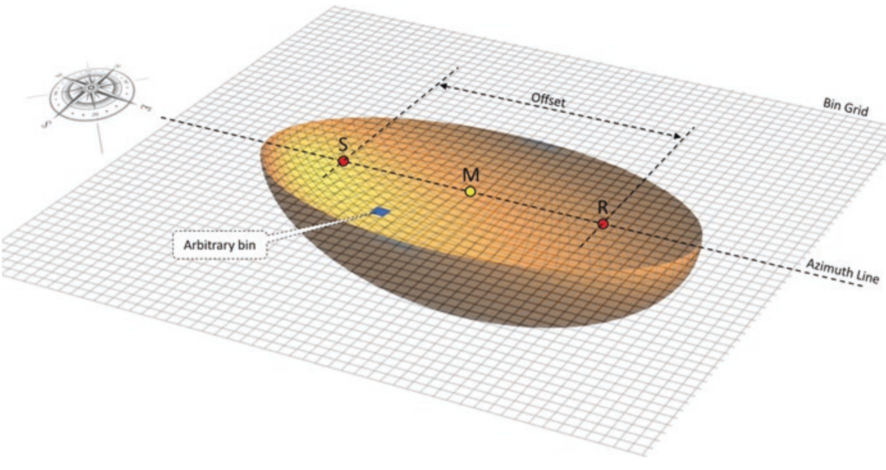

Fig. 1.12 Geometry for a single trace in a 3D seismic survey. See text for details

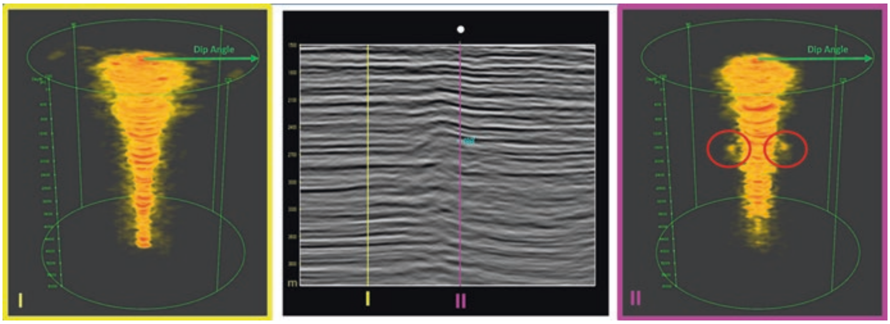

Fig. 1.13 Example of prestack migration image gathers in flat geology (left) and in an area with steep dips (right). An extracted 2D vertical section from a 3D prestack migration volume is shown in the center panel identifying the location of image gathers I and II. (Smirnov et al. 2018)

receiver (S,R) at the foci of a subsurface ellipsoid (yellow-orange) oriented along the source-receiver azimuth and overlain by a bin grid. The migration process spreads the measured amplitude along the ellipsoid and applies scale and geometry factors required by wave propagation physics. The high cost of prestack migration comes from the fact that every time sample on every trace requires a unique ellipsoid. In areas of strong velocity variation, the shape is a sort of lumpy ellipsoid and requires serious computing effort to calculate the precise geometry. Also noted on Fig. 1.12 is an arbitrary bin (blue) inside the ellipsoid area, outside the ellipsoid area bins would receive no contribution from this data value on this trace. In the blue bin there is contribution from this time on this trace and the scaled amplitude will be captured by the bin. At this phase of processing, the bin can be thought of as a small volume with coordinates of depth, angle, and azimuth. Whether PSTM or PSDM is applied, the output can be given in depth or time, but depth is the preferred domain for PSDM. The angle value is the incident angle between the incoming ray and an imaginary line perpendicular to the ellipsoid directly beneath the blue bin, and the azimuth is the shown source-receiver orientation relative to north. As migration progresses, all time samples on this trace are processed, each with its unique ellipsoid. Then the next trace is read with its source, receiver, midpoint and azimuth values, and migration operates again one time sample at a time. Of course, this is conceptual many algorithms exist that may operate very differently yet will have the same effect. As traces are migrated, the blue bin captures all data values that move into its capture area, forming a prestack migration image gather – a volume of data that has the appearance of a tornado (Fig. 1.13). The captured data values are summed into the image gather based on depth, angle, and azimuth. In the tornado plot, weak data values are transparent and stronger ones progress yellow to red. A seismic event (of any geological dip) in an image gather is a horizontal disk. If the migration velocity is incorrect, the event will be a tilted or curved disk and the deviation from a horizontal disk contains information necessary to update the velocity field and remigrate, repeating till all events are flat in the image gathers. Final image gathers can be stacked over dip and azimuth to yield one post stack trace per bin; this is the seismic amplitude volume commonly interpreted. But prestack analysis is becoming more common including presence and orientation of natural fractures, prestack attributes, and amplitude versus angle (AVA) interpretation for lithology and/or pore fluid.

Connection to Geology

Reflection time, rather than depth, is the natural domain for migrated seismic data except in the case of extreme environments like reservoir targets beneath rugged mountains or irregular salt bodies. If time is the natural domain for seismic, depth is the natural domain for geology and well logs. There are two main methods to tying geological formation tops to seismic reflection events. First, in a vertical seismic profile (VSP) survey, the source is at the wellhead and receivers are down the well recording data at formation boundaries that can directly yield arrival time and waveform for correlation into the seismic volume. VSP has the advantage of the wavefield passing through the actual near surface and it has frequency content similar to surface seismic data. However, a VSP takes up rig time and has other costs that result in relatively sparse use. The second method is generation of a synthetic seismogram (Fig. 1.14) using digital sonic and density logs from a well in the survey area. While reservoir calculations only require well logs over the reservoir interval, a synthetic benefits from a long run of sonic and density from the shallowest level possible to total depth (TD). Sonic and density are typically sampled every 0.1524 m (0.5 ft) and the sonic log operates at 10–15 KHz, far above surface seismic frequencies. This frequency difference can lead to a mismatch between synthetic and field data, but algorithms are available to minimize this problem. The steps involved in making a synthetic are:

1. Edit sonic and density logs to remove spikes, washout zones, and other areas with bad data. This is subjective and requires expertise to avoid over- or under-editing the logs.
2. Two-way time associated with each depth in the well is calculated from the sonic log (Fig. 1.14b, c). This is a top-down integration process that incurs errors (drift) if any bad sonic values are encountered, unless offsetting sonic errors are encountered deeper in the well (unlikely). Sonic logs (Fig. 1.14D) are never run to the surface for various reasons, so the velocity must be estimated in the interval between the top of sonic and the well Kelly Bushing (KB). This is typically done in the final stages of synthetic generation by visual correlation of synthetic and field seismic events. Rarely, a checkshot survey will be performed that is like a mini-VSP with only a few downhole receiver locations at key formation boundaries. The checkshot data can be used as absolute time standards to correct for drift.

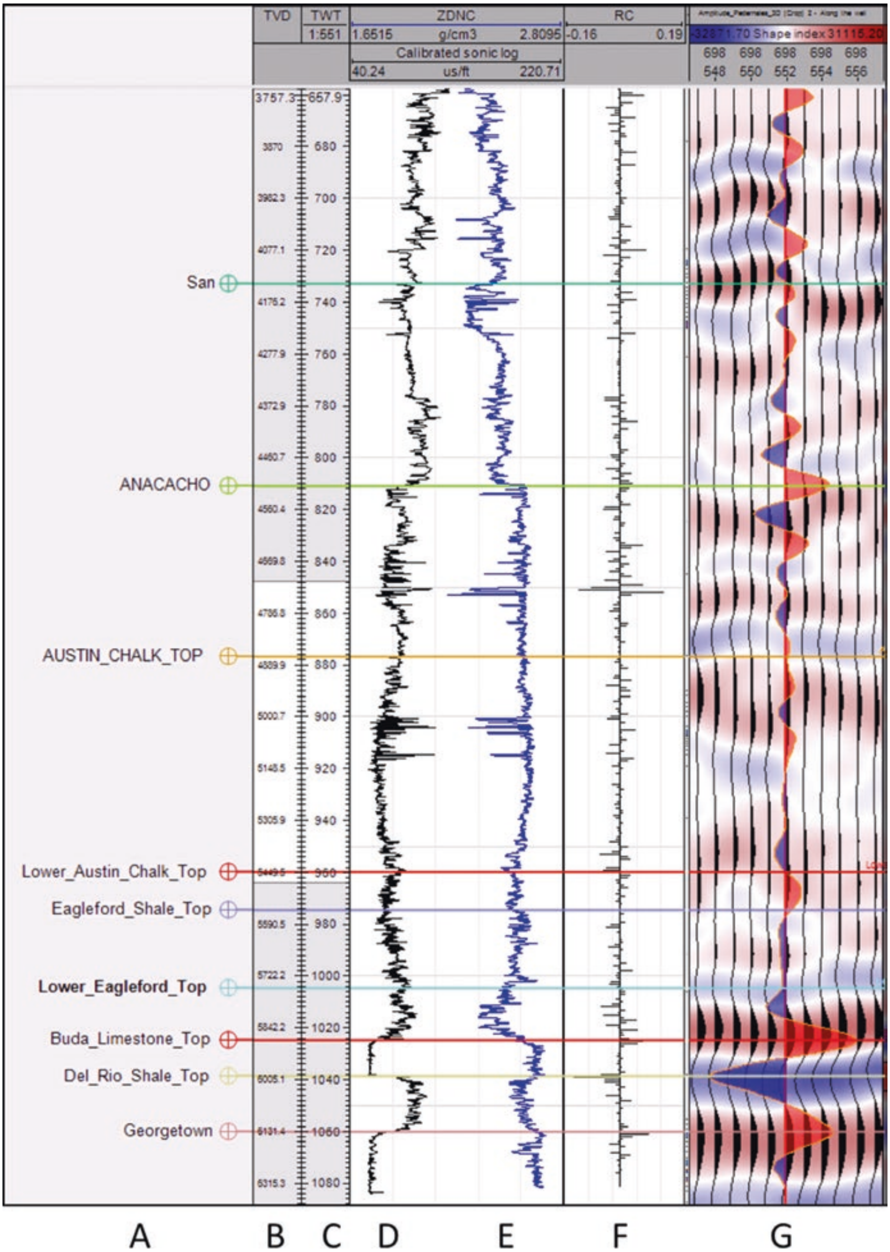

Fig. 1.14 Synthetic seismogram from Zavala County, Texas (Smirnov, 2018). (A) Formation top names. (B) True vertical depth. (C) Reflection time, also called two-way-time (TWT). (D) Sonic log. (E) Density log. (F) Reflection coefficient series. (G) Ten field seismic traces from a 3D survey displayed as both wiggle with filled peaks and red-white-blue color. The center trace in (G) is a transparent overlay of the synthetic seismic trace computed by convolving the reflection coefficient series with a wavelet (not shown) extracted from the field data

3. Normal incidence reflection coefficients (RC) are calculated from the sonic and density logs, with acoustic impedance (I, velocity times density) as an intermediate product. The reflection coefficient, R, associated with a geological interface in the earth is given by the relationship $R = (I2 - I1)/(I2 + I1)$ where I1 and I2 are the impedances above and below the interface, respectively. Since velocity and density depend on mineralogy, pore fluid, pressure, and temperature, this dependence passes into the reflection coefficient. Using the time information from step 2, the reflection coefficient series is formed as shown in Fig. 1.14F. The RC series is the basis of post stack seismic interpretation.
4. A wavelet is estimated from the 3D seismic data in the vicinity of the well. The wavelet will change slowly with depth due to high frequency loss to a variety of processes. Preferably the extracted wavelet will be estimated in a window centered on the primary reservoir level.
5. The wavelet and reflection coefficient series are combined through a mathematical process called convolution to form the synthetic seismic trace. For comparison with field data, the synthetic trace is displayed as an overlay as seen in Fig. 1.14G. In most cases, adjustments are needed to get a satisfactory match, including velocity changes above the logged interval as well as some stretching and squeezing to account for sonic log drift. Since the wavelet is a short duration pulse (50–150 ms) and reflection coefficients are closely spaced in time, seismic interpretation must work to unravel the competing influence of reflection coefficients and interference (Liner, 2012). A good example is seen in Fig. 1.14 at about 845 ms where closely spaced strong reflection coefficients of opposite sign effectively cancel when convolved with the wavelet as seen in the synthetic trace.

Porosity, Fluids, and Response

The relationship between porosity, pore fluids, and seismic response is complicated, but clearly essential to the application of seismology to petroleum exploration. Since reflectivity is driven by contrast of acoustic impedance (AI), the porosity/fluid effect on AI drives the response. In general, for a given general lithology, acoustic impedance has the following behavior: (1) AI *decreases* with increasing porosity, clay mineral content, pore pressure, and gas saturation (rapidly 0–10%, slowly thereafter), (2) AI *increases* inversely with all the previously listed items and with increasing grain cement volume. The introduction of natural gas in the pore space creates a dramatic amplitude effect (Fig. 1.15) in soft sediment basins, particularly in sandstones, and is commonly called a gas bright spot or direct hydrocarbon indicator (DHI). Rock physics is the field of study that explains relationships between seismic velocity and environmental parameters (temperature, pressure), rock mineralogy, porosity, and pore fluids. In the low frequency regime of surface seismic data (5– 125 Hz), the Gassmann theory is valid and forms the basis of fluid substitution where scenarios can be calculated assuming various pore fluids. For example, if the

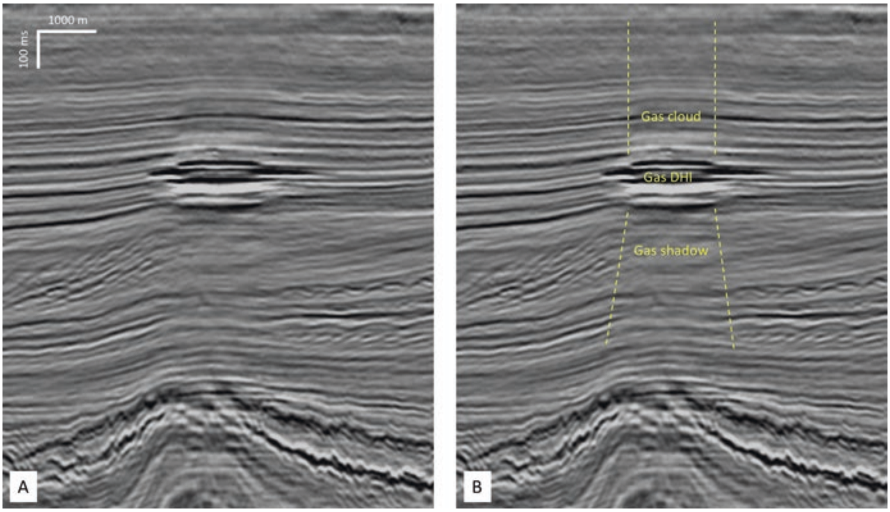

Fig. 1.15 Gas effects in 3D seismic data from the Dutch North Sea. (**a**) Uninterpreted section. (**b**) The interpreted section identifies a gas sand reservoir that has lower acoustic impedance than laterally equivalent water-filled sandstones. This induces an anomalously strong reflection event called a direct hydrocarbon indicator (DHI) also known as a gas bright spot. Gas leaking into overlying formations causes a weak blurring effect called a gas cloud. Seismic waves passing through the DHI are more strongly attenuated than in adjacent areas, a phenomenon known as a gas shadow. The effects described here are likely in a young soft sediment basin with low impedance shales and high porosity sands (Gulf of Mexico, parts of the North Sea, etc.). In older Paleozoic basins with higher impedance shales and lower porosity sands, the gas effect is much weaker and DHI development more unlikely

seismic response of a wet sandstone is seen in 3D seismic data and appropriate well logs are acquired in a well, then scenarios can be run to predict response of the same sandstone with different fractions of gas and oil in the pore space. At the high frequency limit of sonic logging (10–15 KHz) or laboratory testing (1+ MHZ), such calculations require a more general approach called the Biot theory.

The Gassmann theory is required to make any progress in quantitative interpretation of time-lapse (4D) seismic data, where multiple 3D seismic surveys are acquired a few years apart and match processed. In areas with active hydrocarbon production, the only change in response from one vintage of 3D survey to the next should be due to pore fluid production/substitution. There are examples of time-lapse seismic worldwide in soft sediment, offshore basins which yield data of high enough quality to image fluid change effects on the order of 5% or less. A remarkable case history of time-lapse seismic can be found in the Sleipner Field of Norway (Fig. 1.16) where carbon dioxide has been injected into a brine aquifer since the mid-1990s and several vintages of 3D seismic have been shot over the field.

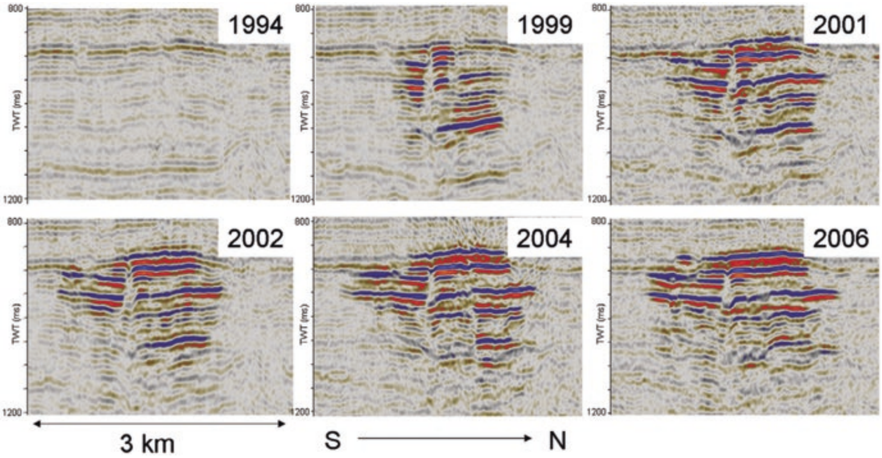

Fig. 1.16 Vertical 2D section from six vintages of 3D seismic data over the Sleipner Field offshore Norway showing time-lapse (4D) changes in seismic response due to CO_2 injection into a saline sandstone aquifer of Miocene to Quaternary age. (From Arts et al. 2008)

Scale

The concept of scale must be understood before proceeding with seismic interpretation for oil and natural gas. Vertical resolution of a single wavelet determines the thickness of the stratigraphic interval represented by that wavelet. Vertical resolution (Fig. 1.5) is generally on the order of 10s of feet, commonly in the range of 50–150 ft (15–45 m).

Another scale issue is the degree of vertical exaggeration. The vast majority of seismic profiles are displayed with some unspecified degree of vertical exaggeration that can be very useful to the interpreter but also introduces distortion. Profiles are commonly displayed with a vertical exaggeration that ranges from 2× to 10×. Use of some degree of vertical exaggeration greatly enhances visibility of lapout geometries (e.g., onlap, downlap, truncation) as well as seismic facies (e.g., high amplitude continuous, variable amplitude-discontinuous, chaotic). These characteristics are difficult if not impossible to distinguish on profiles displayed at a 1:1 scale (Fig. 1.17). An understanding of this vertical scale allows the interpreter to appreciate the amount of geology that may be considered “sub seismic” on a particular survey; at which point they may consult well data (if available) to add the next level of detail.

A very powerful interpretation technique is the generation of paired seismic profiles with well log cross sections. These may be displayed as structural interpretations using a depth datum, or as stratigraphic interpretations using flattened profiles and well log cross sections tied to a specific stratigraphic datum (Fig. 1.18). It is important to revisit both the scale and resolution of the data set during the interpretation process. This ensures that the interpreted geometries, depositional slopes and gradients, fault plane angles, etc. are consistent with those observed in

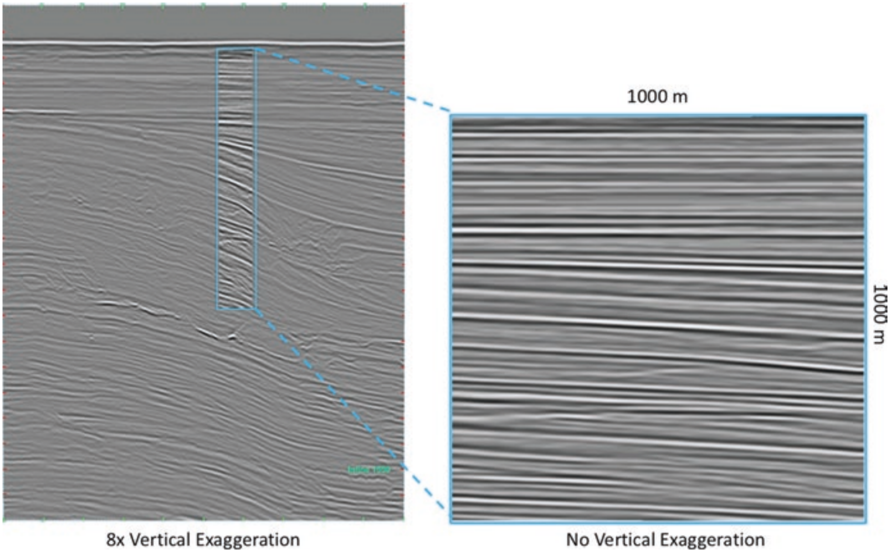

Fig. 1.17 New Zealand offshore 3D vertical section showing typical vertical exaggeration used for seismic interpretation compared to data with no vertical exaggeration

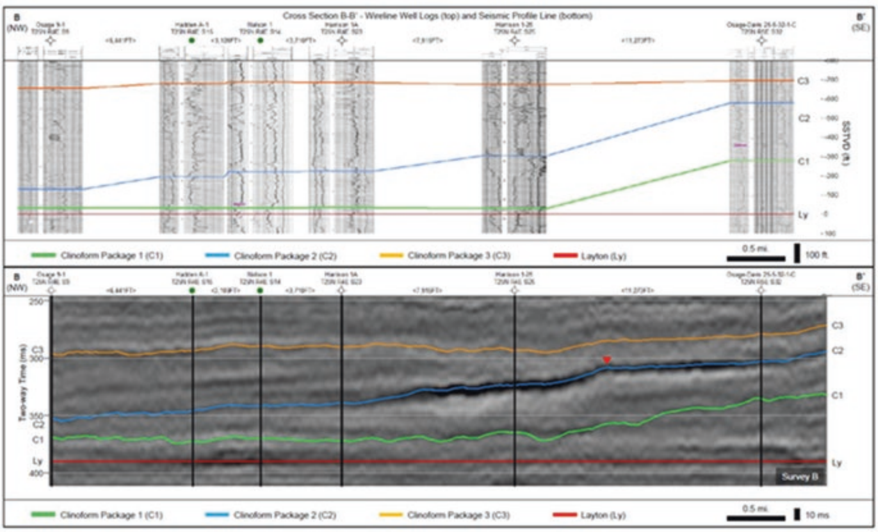

Fig. 1.18 Stratigraphic cross section with paired well log and seismic profile. The well log cross section documents lateral geologic variability within the seismic horizons. (Barker 2018)

nature. For example, when correlating between well logs based on a seismic profile with a high vertical exaggeration, it is easy to miscorrelate stratigraphic horizons resulting in the interpretation of a paleoslope that is far steeper than would be encountered in nature. The interpretation may look reasonable, but the paleoslope of the depositional surface may be far too high when restored to a 1:1 scale (i.e., the interpretation defines a 10° slope when in fact it should be on the order of 2°).

Seismic Attributes

Computation of prestack migration image gathers from raw field data falls under the term "seismic data processing." Another kind of processing begins at that point that can be called "attribute processing." A seismic attribute is any product computed from image gathers or amplitude data to aid interpretation.

Amplitude The simplest, and most fundamental, attribute is a stack (summation) across all angles and azimuths to create a full stack trace at each bin location. This is the data most commonly used for interpretation and is usually simply referred to as the seismic amplitude data, but sometimes also called original seismic, all offset stack, full stack, migrated stack, PSTM, or PSDM.

Amplitude Substacks Summation to a full stack averages across angle and azimuth in each image gather, losing this information for further analysis. Full interpretation of angle or azimuth requires prestack interpretation directly on the gathers, but this is not routinely done as it scales up the data volume to be interpreted by a factor of hundreds or thousands. Substacks are a way of getting a first look at this information in a compact form that is the same size as the amplitude volume. Substacks require careful prestack processing and data acquired with a rich angle and azimuth distribution. *Angle Substacks* are useful since seismic reflectivity depends on angle through the elastic reflection coefficient, Rpp, that depends on incident angle. Further, the behavior of Rpp with increasing angle depends on important rock and fluid properties. The classic Gulf of Mexico case is a gas sandstone which can have nearly identical normal incidence reflectivity as a low velocity shale zone. Both appear bright on a synthetic seismogram (which is normal incidence only, angle = 0) and on the full stack amplitude data. However, the gas sand and shale have different behavior with respect to angle, the gas sand typically brightening with increasing angle, while the low velocity shale does not. The common practice is to create three angle-limited stacks 0–10°, 10–20°, and 20–30° and sum each image gather in these angle ranges and across all azimuth. Since angle and offset are related through subsurface velocity, these substacks may be termed near, mid, and far offset stacks. The value of angle stack volumes is that a horizon tracked on the amplitude data can quickly be viewed on near, mid, and far stacks to screen for amplitude versus offset or angle (AVO, AVA) anomalies. *Azimuth substacks* are computed by summing image gathers over all dip angles, but a limited range of azimuth, usually 10–30° sectors. The interpretation value relates back to reflection coefficient variation with respect to azimuth in naturally fractured rock formations. Specifically, the reflection strength depends on the seismic ray azimuth relative to the fracture azimuth, progressing from a minimum when seismic and fracture azimuth are parallel to a maximum when they are perpendicular. A horizon tracked on amplitude data can be scanned for fractures by cycling through azimuth substacks and noting amplitude variation. If an effect is identified, it can be followed up by full prestack azimuth interpretation.

Coherence Some of the most interesting features in seismic amplitude data are associated with lateral/vertical changes in reflectivity or continuity, including faults, channels, reefs, karst, and fluid contacts. Coherence (Bahorich and Farmer 1995) is an attribute that highlights discontinuity for improved visualization of these features. There are various other names in use for this attribute, such as variance and semblance. Conceptually, coherence is computed using a local data volume (called the operator) of size (nx,ny,nt) and typical example might be (3,3,15), or 135 data values. The center value is set aside and some kind of algorithm is applied to predict the center value from the other 134 values, to stay with this example. Once the calculation is complete, the predicted value is compared to the actual value that had been set aside. If they are equal, then there is no discontinuity detected and a zero coherence value is placed in a duplicate full survey data volume at the operator center point. If the prediction and actual values are different, the absolute difference (or some related measure) is placed at the center point of the output volume. The operator then moves throughout the amplitude volume ultimately visiting every point to compute a coherence value and thus generate a coherence cube. Figure 1.19 shows a time slice at 1578 ms in a Dutch North Sea 3D survey of the amplitude data (Fig. 1.19a) and the coherence data computed with a (3,3,15) operator (Fig. 1.19b). Although some faults are seen on the amplitude data, a more complete and detailed view of the fault network is revealed by coherence. The vertical extent of the operator window can be used to fine-tune results based on geological knowledge of the area and goals. For example, in the Gulf of Mexico, growth faults are common that have significant fault plane dip. If a long window operator is used, it will blur results since the fault passes through the operator box at an angle. In such a case, a short window would be appropriate such as the nt = 15 result shown in Fig. 1.19. In older, more brittle rocks, faults tend to be more vertical and a longer window will be useful to improve fault localization. Another example is a karst surface on limestone where a short window operator would reveal texture of the surface while a long window operator would do a better job showing sinkholes that have extended influence below or above the karst surface.

Curvature Modern 3D seismic data is suitable for analysis methods originally developed for differential geometry, such as the concept of surface curvature (Roberts 2001). This is a two-dimensional property of a 3D surface related to the tangent sphere of the surface at a given point, specifically the curvature is the inverse of the radius of the tangent sphere. Since a flat surface has an infinite radius tangent sphere, its curvature is zero. A tightly folded surface has a small radius tangent sphere and therefore a large curvature. In a geological sense, anticlines have positive curvature and synclines are negative. In the 3D seismic application, curvature is

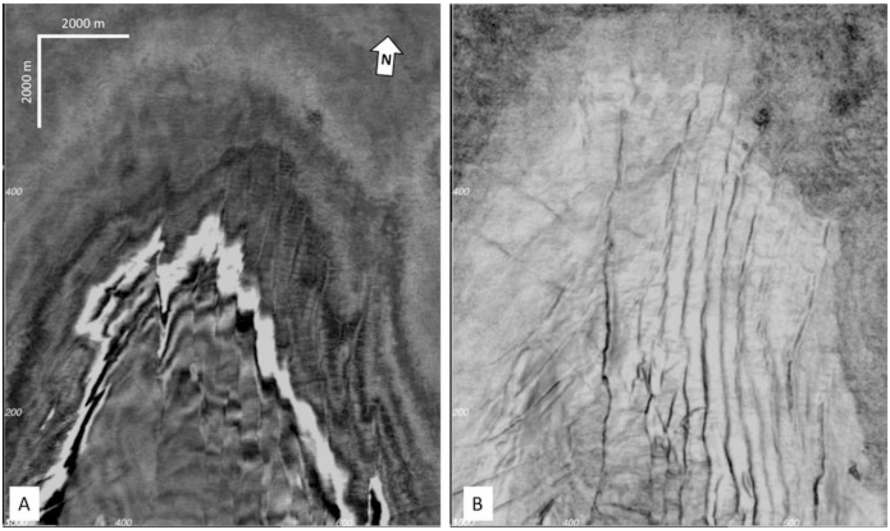

Fig. 1.19 Coherence attribute in Dutch North Sea time slice at 1578 ms, or approximately 1590 meters depth subsea. (**a**) Seismic amplitude slice showing a north-plunging anticline cut by several faults that are difficult to identify, particularly those parallel to the plunge axis. (**b**) Coherence volume of the same time slice computed using an operator of size (nx,ny,nt) = (3,3,15). The coherence view emphasizes faults and other features in the data that cause rapid lateral variation in the data. Complex fault networks, such as the one shown, particularly benefit from coherence (also termed variance or similarity)

computed on the volume using an (nx,ny,nt) operator similar to coherence. Within the operator box local slopes are estimated and used to calculate curvature at the center point, then the operator moves and progresses throughout the amplitude data set resulting in a curvature volume. Curvature attributes include maximum and minimum curvature, Gaussian, mean, most positive, most negative, most extreme and related attributes like azimuth of maximum or minimum curvature, dip curvature, and others. Most negative curvature is popular and particularly useful since it isolates lineaments in the data, including subtle faults and amplitude stripes due to acquisition geometry (called acquisition footprint). Figure 1.20 shows an example of most negative curvature in a New Zealand offshore data set.

Spectral Decomposition Modern 3D seismic data has a frequency band of about 5–100 hz, what could be termed broadband data (meaning it contains many frequencies). The average, or dominant, frequency (55 Hz for 5–100 Hz) controls vertical and lateral resolution observed in broadband data, but the resolution chart (Fig. 1.4) implies that each frequency has a different wavelength and therefore a different vertical resolution. The group of attributes that pulls the data apart by frequency and somehow displays the result is called spectral decomposition. Many algorithms have been developed for decomposing the data into narrow bands or individual frequencies, and interpretation systems have capability to make color blended dis-

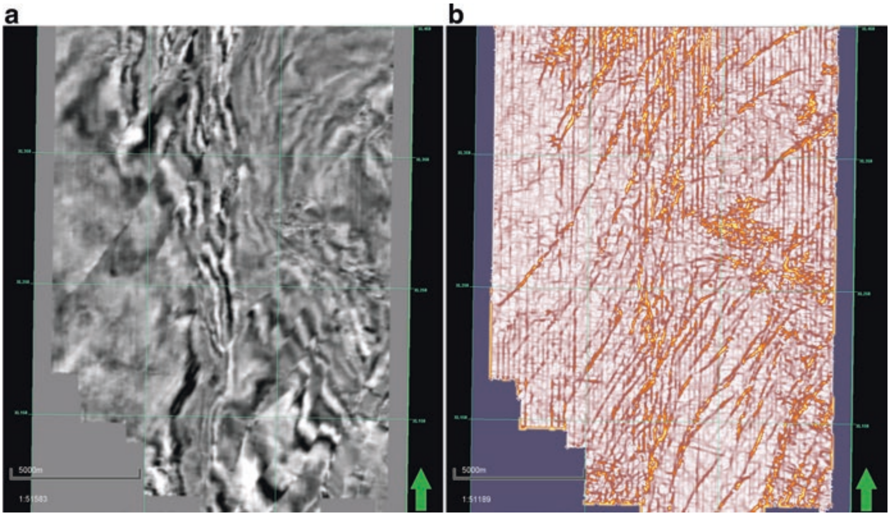

Fig. 1.20 Curvature attribute from offshore New Zealand. (**a**) Seismic amplitude data in a shallow (330 ms) time slice showing a few large offset faults in the left center of the image. Smaller faults are present but not visible on the amplitude data. (**b**) Most negative curvature reveals a very detailed network of large and small faults. North-South lineations in the curvature display are artifacts associated with survey shooting geometry (acquisition footprint), common in shallow data

plays. Animation through decomposed data can tell the interpreter which frequencies yield additional information about geological features of interest. It is common to isolate three frequencies and create a red-green-blue (RGB) blend where each frequency is mapped to a color channel. Figure 1.21 is an example from NE Oklahoma where broadband data (Fig. 1.21a) shows a Pennsylvanian fluvial channel system with velocity of about 4500 m/s and dominant frequency of 50 Hz, yielding a vertical resolution of 22.5 m. Figure 1.21b is an 80–60–40 Hz RGB blend of the same data. Each frequency has an associated vertical resolution: 80 Hz = 14 m (red), 60 Hz = 19 m (green), 40 Hz = 28 m (blue). Notable is the strong blue channel segment that can be interpreted as channel thickness on the order of 28 m since it lights up at 40 Hz due to a constructive interference effect called tuning. An associated approach is to display the frequency ranges individually in order to make comparison between maps reflecting differing degrees of vertical resolution. This is particularly useful when trying to resolve subtle stratigraphic edges or small offset faults.

Impedance Inversion If suitable digital well log data is available inside a 3D seismic survey area, it is generally possible to do some form of impedance inversion. The well logs needed for this process are sonic and density extending across the depth interval to be inverted. While seismic data contains frequencies in the range 5–100 Hz, well logs contain a much broader range of frequency, including low frequencies that approach zero. In effect well logs provide this missing spectral information. Conceptually, any kind of impedance inversion is a work flow of wavelet extraction, calibration at well log locations then iterative impedance esti-

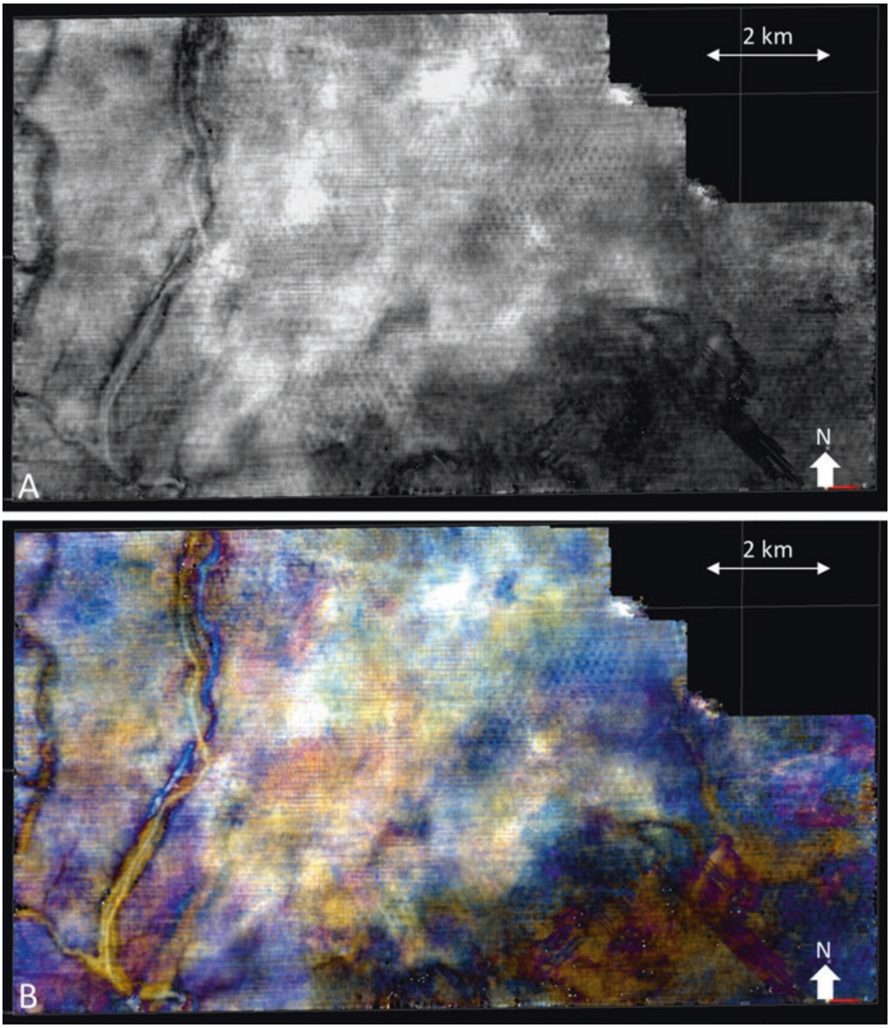

Fig. 1.21 Spectral decomposition attribute from Osage County, Oklahoma, in the Pennsylvanian Cleveland Sandstone interval. (**a**) Full bandwidth seismic amplitude data reveals a fluvial channel system in the west side of the data. (**b**) A spectral RGB blend of 80–60–40 Hz that reveals additional detail in the channel system

mation throughout the data volume. In *post stack inversion*, the post stack data is used, the well log requirements are P-wave sonic and density, and the output is acoustic impedance (AI). An example of 3D post stack inversion from southwest Texas is given in Fig. 1.22. The line is a vertical section from the 3D volume. The left side shows amplitude data (red = positive amplitude, blue = negative), geological horizon picks, and Well A acoustic impedance calculated from well logs (AI colorbar to the right). To the right of a data gap is the AI inversion result for

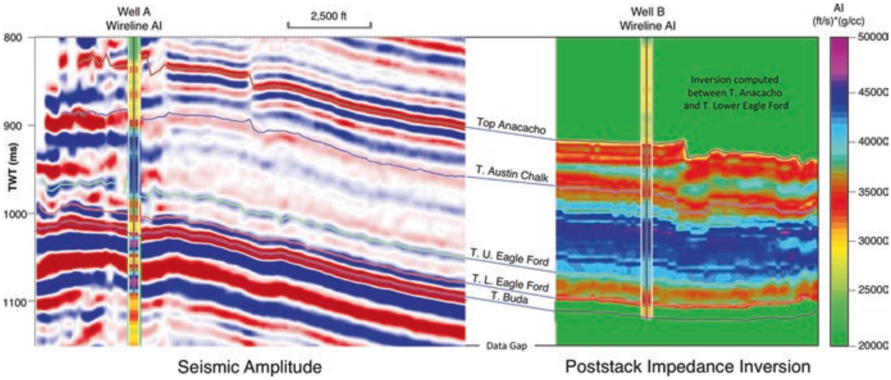

Fig. 1.22 Vertical section from a 3D seismic survey in Zavala County, Texas. The left side shows amplitude data with tracked horizons and Well A acoustic impedance (AI) computed from wireline data. To the right of a data gap containing horizon names, the inverted AI is shown as computed between the top Anacacho and top Lower Eagle Ford, also shown is Well B wireline AI which is an excellent match to the inverted AI. (Modified from Kilcoyne 2018)

that part of the line. The uses of volume AI include porosity estimation and lithology identification. In the example shown, note that AI in the Upper Eagle Ford becomes progressively greater (more dark blue) progressing from the base to the top, implying increasing carbonate content (since carbonate is high AI) toward the top of the Eagle Ford. This is a powerful tool to illuminate lateral changes in geology and associated rock physics that could affect hydrocarbon production, completion practices, and decisions about landing zones for horizontal wells. *Prestack impedance inversion* (also called prestack elastic inversion) requires full wave sonic logs (P-wave and S-wave) plus density logs, operates on migrated image gathers, and yields three output volumes: Vp, Vs, and density. As it operates on much more data (prestack vs post stack), it is more costly and more sensitive to processing parameters. However, the additional shear wave information is very useful for estimation of parameters related to rock physics and mechanics. Prestack elastic inversion has found broad application in unconventional hydrocarbon plays aimed at shale and carbonate resources, sometimes called self-sourced reservoirs.

Interpreting the Seismic Amplitude Volume

The data volume typically interpreted is seismic amplitude, being the stack (summation) over all dip angles and azimuths in each image gather to create a single trace per bin. The stacking process effectively averages out angle and azimuth variation of reflection coefficients. The result is usually dominated by the normal incidence reflection coefficient, but there are exceptions such as areas with gas bright spots that brighten at large angles and this effect passes into the stack amplitude. Also strongly contributing to the stack amplitude is wavelet interference from closely spaced reflection coefficients. Further, the stack amplitude is arbitrarily scaled in the seismic processing flow so that absolute amplitude information is lost, but relative information on reflectivity changes laterally and vertically in the data is retained. The absolute amplitude information can only be recovered by calibration with digital well logs during acoustic impedance inversion.

With this understanding, it is convenient to consider the seismic amplitude data to range in value from -1 to $+1$. Any given trace is a time series, an irregular, oscillating function between these limits whose variation is driven by reflection coefficients and wavelet interference. Interpretation involves mapping waveform features such as: a negative extreme is a "trough," positive extreme a "peak," a passage from negative to positive values is a "minus-plus zero crossing," and a "plus-minus zero crossing" is a passage from positive to negative values. Any such feature can be followed, or tracked, throughout the data volume or a subset of it by the process of *autotracking*. The first step in autotracking is to set parameters for the type of event to be tracked; peak, trough, + − zero crossing, − + zero crossing. Looking ahead to amplitude extraction along the tracked surface, a peak or trough is preferred whenever possible as the peak or trough amplitudes have the most logical relationship to underlying reflection coefficient variations. In poor quality data or along horizons of discontinuous or even sign-variable amplitude, zero crossings may prove to be the only trackable feature. Other parameters include search window height and correlation. Correlation is an option to not just search adjacent traces for the feature of interest, but to use a time-fragment of the trace and cross correlate this with the adjacent trace and seek a peak in this correlation, or apply a rule such as "only jump to the next trace if the correlation is above 70%." In noisy data, correlation can often track events that are otherwise untrackable. Once these parameters are set, the interpreter displays a 2D section (line) through the 3D volume and clicks on the event of interest to place a seed point on a certain seismic trace in the line. The autotracker then moves to an adjacent trace in the line and either scans or correlates to find the feature of interest and continues this process as far as possible on either side of the seed point. In high-quality data with a consistent event character, this can proceed across the full extent of the line. More likely, the autotracker will stop because of data quality or geology changes. Assuming the interpreter can visually identify the event of interest across this stopping point, another seed can be set beyond the stop and the autotracker will follow the event in that region. In surveys with high-quality data in an unfaulted area, a single seed point can allow tracking of a horizon throughout the entire 3D volume. But this is not often the case, so the interpreter jumps, perhaps, 10 or 20 lines, tracks that line, jumps, and continues the process until the event is tracked over the full 3D survey area.

Autotracking delivers two basic products along the tracked horizon (Fig. 1.23). First, tracking provides the time value associated with the event in each 3D bin (Fig. 1.23a) yielding a *horizon time structure map*, or t(x,y), where x and y are map-view coordinates. Time structure maps give a good first approximation of structure, but must be used cautiously for important work such as prospect map-

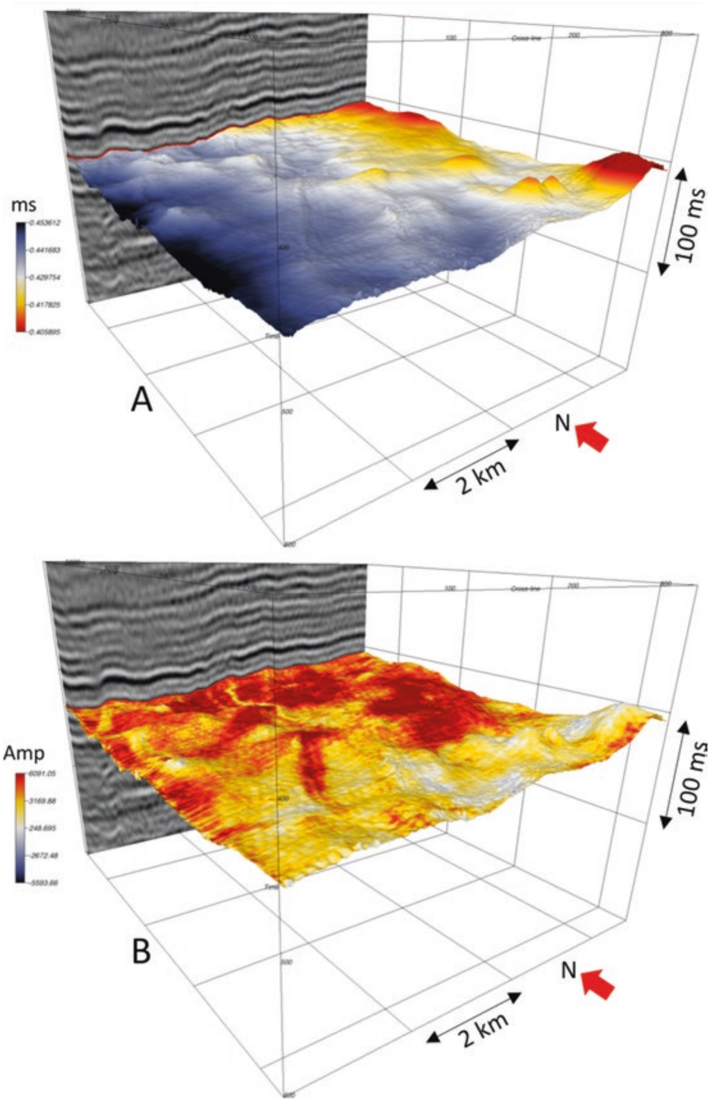

Fig. 1.23 Horizon tracking, Osage County, Oklahoma, in the Pennsylvanian section. (**a**) Horizon time structure map. (**b**) Horizon amplitude map

ping because any lateral velocity variations above the horizon will cause distortions that are not present in the depth structure. Prospect mapping and drill site selection should always be done on depth maps, not time maps. Second, the amplitude value of the tracked horizon at each bin location is the *horizon amplitude map* (Fig. 1.23b). The horizon amplitude can be taken as a proxy for lateral changes in the reflection coefficients that underlie seismic reflectivity, with the understanding

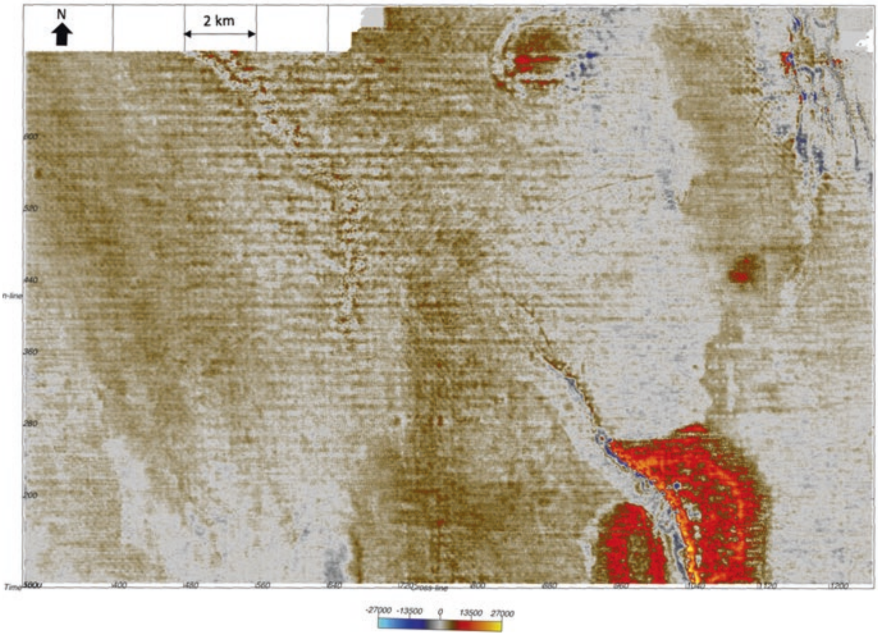

Fig. 1.24 Horizon amplitude map from the Dutch North Sea showing gas-effect lateral amplitude variation. The lower right gast bright spot is also shown in Fig. 1.15

that wavelet interference also has a first-order effect on amplitude and summed angle/azimuth variations have been averaged out. The wavelet interference effects can be removed somewhat by post stack "detuning" algorithms, or eliminated completely by impedance inversion if suitable well data is available. In practice, the stack seismic amplitude is interpreted as is over the 3D volume and interference effects are only addressed locally in areas of high interest. Horizon amplitude affords a bird's eye view of stratigraphy – channel systems, lithology changes, paleogeography, karst surfaces, reef complexes, carbonate banks – or lateral changes in pore fluid, particularly gas (Figs. 1.23 and 1.24). Once a horizon is tracked, any seismic attribute can be extracted and displayed along the horizon, or perhaps a group of attributes blended into an RGB image (Fig. 1.21).

Horizon tracking sometimes fails for strong amplitude anomalies because the event features that are being tracked away from the anomaly do not persist through the anomaly. For example, a sandstone event that is a peak in wet areas may be become a trough in gas areas. An alternative to tracking in this case would be to build *a geobody* of the amplitude anomaly. A geobody is a set of voxels initiated by a seed point and connected by a data condition. For example, in Fig. 1.25a the same gas DHI of Fig. 1.15 is seen in vertical amplitude section with a standard color bar. A geobody can be created by placing a seed point in the high amplitude area and defining a condition, amplitude >11,000 in this case, and connecting all

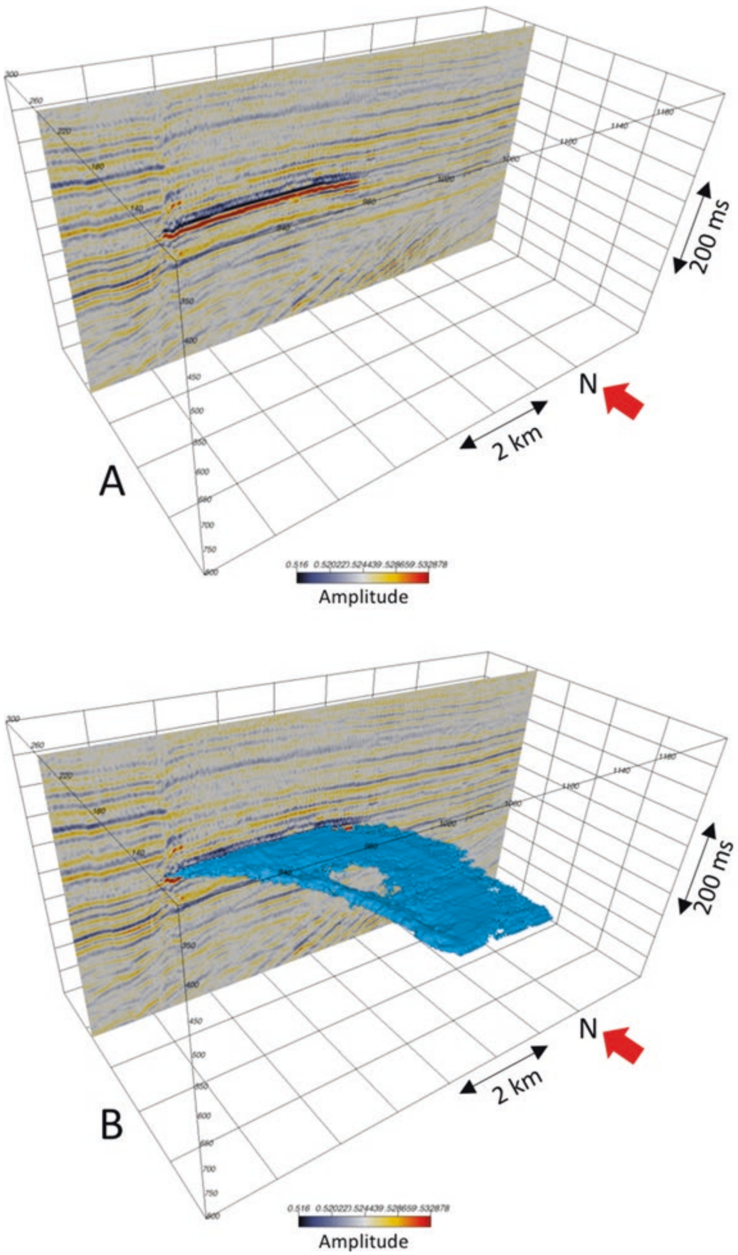

Fig. 1.25 Geobody extracted from 3D seismic in the Dutch North Sea. (**a**) Data frame and 2D vertical section with colorbar highlighting extreme amplitudes. Gas direct hydrocarbon indicator (DHI) is evident. (**b**) Geobody extracted from DHI by connecting all amplitude values above a defined threshold

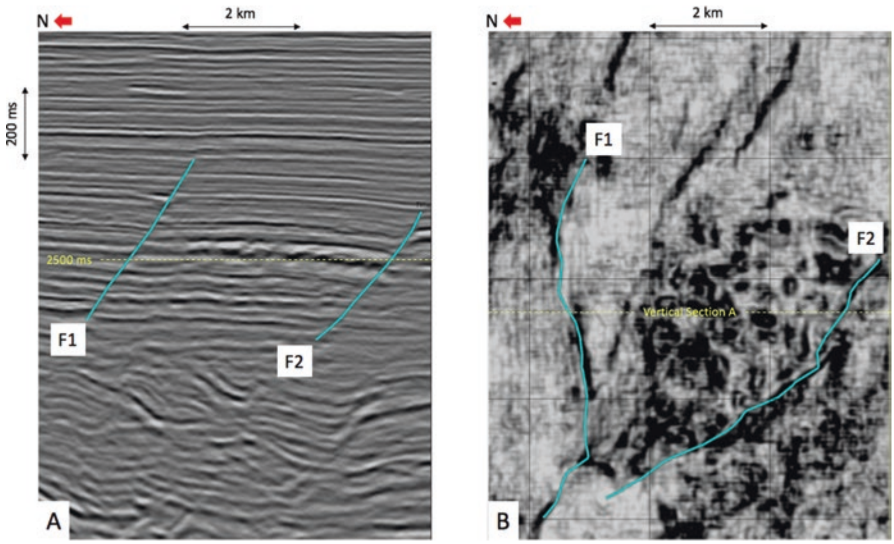

Fig. 1.26 Fault interpretation in the Gulf of Mexico. (**a**) Vertical amplitude section showing two faults that were picked across several lines. (**b**) Picked faults displayed on a 2500 ms coherence time slice. Other unpicked faults are evident

voxels that satisfy this condition (Fig. 1.25b). As with most interpretation products, choices made by the interpreter can drastically alter the mapped feature; amp >13,000 would result in a smaller geobody, while amp >9000 would yield a larger geobody.

In faulted areas, the faults should be picked prior to autotracking. In effect, each fault block is a separate autotracking exercise. Fault picking proceeds in vertical sections with jumps between lines, the length of the jump determined by how rapidly the fault geometry is changing laterally. Some faults are traceable for kilometers, while others are only local. In most computer interpretation systems, a fault is created and the interpreter manually picks seed points along the fault line as seen in the vertical section being viewed (Fig. 1.26), although faults can also be picked in time slices.

Machine Learning

In the 1980s, there were several geophysics projects underway that attempted to capture the knowledge of a subject expert and capture it in rules that could be programmed into a computer. Such an approach to Machine Learning (ML) is termed an Expert System, and it was ultimately something of a dead end. The primary limitation with Expert Systems was not with the computer or programming but with the human mind. Basically, we all have two ways of thinking and making decisions, so much so that behavioral economists have labeled the processes System 1 and System

2 (McAfee and Brynjolfsson 2017). System 1 is intuitive, quick, and decisive and requires little effort; System 2 is deliberate, slow, conscious, and hard work. When experts are asked how they do complex tasks, such as deciding processing parameters, picking subtle faults, identifying depositional sequences on well log or seismic data, they are often at a loss as to how they do it or what systematic rules apply. Even worse, System 2 is often drafted by System 1 to justify its actions. How can programmers code up rules even the expert cannot enunciate?

A different approach to ML has its conceptual origins with the first computer scientists in the 1940s and 1950s. But the concept could not be realized for many decades until computer speed and algorithmic progress was made. This branch of ML is based on a neural network (NN) that bears some faint similarity to the activity of neurons in the brain. But the analogy is feeble, particularly so since there is little understanding how physical neurons interact to create the complex behavior observed in even the simplest organisms. Be that as it may, over the last 5 years great advances have been made in NN technology. The structure of a NN includes inputs, one or more hidden layers (a "deep" NN has more than one layer), and outputs. The neuron layers have coefficients that are determined by "training" the NN on a few cases where the correct answer is known. Then the NN can be released on other inputs to predict outputs. The magic is that the NN does this without any knowledge of what physical or mathematical principle connects input to output. Expert rules are not needed.

For example, consider a company that wants to use all its well data in an area to predict lithology at every depth point in every well using a few cores that are available as ground truth. Assume the project has 1000 wells, each with 100 log curves at 10000 depth points, totaling 10^9 data points (100 billion), and 100 ft of core is available in each of 10 wells. A large team of experts might, or might not, be able to do this project with traditional expensive, proprietary software tools. If the project can be done by human experts, it will be a lengthy and expensive. Now consider a deep NN has been built using open source (free) software to read in all 100 log curves at each core depth in each well and output a single value between 1 and 20. Meanwhile, geologists have studied the cores and classified the rocks into 20 lithologies. The 1000 core lithology values are used to train the NN, repeating the exercise (epochs) until the NN correctly (to within some tolerance) identifies each core lithology from the 100 log values at that depth in that well. The NN team will have hold out a few cores as a blind test, and that text will improve the NN prediction capability. When the NN is trained, it is released on all 100 billion data points and will return a lithology prediction at every depth in every well, along with relevant statistics. As more wells are drilled and more core taken, the NN can be run again with improving results. ML eats big data, the bigger the better. Also, the example NN could be quickly and inexpensively deployed to a different project area and improve yet again. Remarkably, nothing about geology or the physics underlying modern well logs (acoustics, electromagnetics, nuclear physics) has to be programmed into the NN.

As we write this in late 2018, ML has defeated the world's top Go player; is a primary technology behind Amazon, Google, and Facebook; can drive cars without human intervention; and is fundamentally changing industries (McAfee and Brynjolfsson 2017). Geophysics applications started in 1988 but have only recently undergone rapid acceleration. Breakthrough examples include automated 3D seismic fault picking, depositional environment mapping on well logs and seismic data, lithology and petrophysical inversion of well log data, and integration of hundreds of seismic attribute volumes to optimum horizontal well location and completion practices in unconventional resource plays. ML has the potential to change many aspects of hydrocarbon exploration and production outlined in this book.

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Chapter 2
Historical Overview of Petroleum and Seismology

Abstract A brief history of petroleum exploration in the United States from the late 1850's to the present illustrates the progression of scientific thought and techniques that evolved globally during this period. The first subsurface drilling specifically targeting hydrocarbons is credited to Colonel Edwin L. Drake in 1859 along Oil Creek, Pennsylvania. Exploration efforts following his discovery through the remainder of the 19th century focused on location of surface seeps and slicks. After the turn of the 20th century the need to locate larger hydrocarbon accumulations required better understanding of the subsurface. Two foundational tools were developed in the 1920's that would revolutionize subsurface interpretation; well logs as direct down hole measurements and seismic refraction profiles. The emphasis was location of large structural closures. The seismic application advanced to include source and reservoir prediction as well as fluid type as 3D seismic data were developed in the 1970's and 80's. Image quality and resolution were greatly enhanced as well as interpretation of seismic attributes such as coherency, curvature, dip azimuth, and near vs. far offset AVO analysis during the 1990's and early 2000's. Advanced application continues with the evaluation of rock properties and microseismicity associated with unconventional plays.

Keywords 3D seismic · 4D (time-lapse) seismic · Anticlinal theory · CDP shooting · Digital signal analysis · Oil boom · Rotary drilling · Seismic geomorphology · Stratigraphy · Subsalt imaging

A brief historical overview of petroleum exploration in the United States is provided here in order to set the context within which the application of petroleum seismology evolved. The search for hydrocarbons was initially focused on obvious occurrences at the surface such as seeps and slicks. As the practice of drilling for hydrocarbons developed in the nineteenth century, likely locations were selected on the basis of surface observations such as the occurence of oil saturated sandstones. Fundamental geologic concepts such as stratigraphy and structural configuration were rapidly evolving during this time. As the demand for

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hydrocarbons rapidly increased after the turn of the twentieth century driven by arrival of the internal combustion engine, the need for subsurface interpretation in order to target larger, more robust accumulations became critical. It was during this time that two fundamental tools were developed: direct downhole measurements – well logs, and subsurface imaging – reflection seismology. The capabilities and resolution of both of these tools continued to advance throughout the twentieth century. The application of reflection seismology expanded well beyond its initial value as a tool to image subsurface structure to include prediction of the primary components of an active petroleum system: source presence and degree of maturation, reservoir presence and degree of stratigraphic compartmentalization, trap geometry, and seal capacity. Its application has continued to evolve in the early twenty-first century as hydrocarbon exploration and development has expanded to include unconventional plays that require high-resolution targeting of long reach horizontal wells and multistage completion techniques. The seismic data set provides critical information regarding lateral variability in subtle lithological characteristics and associated rock mechanics as well as microseismicity associated with well stimulation.

Pre-1850s

There was limited demand for petroleum hydrocarbons during much of the nineteenth century given that whale oil was the primary fuel for illumination as well as lubrication for light machinery. Surface seeps of hydrocarbons were long known by native American populations in North America and were later documented by western explorers beginning in the 1830s. Seep oil was mainly used for waterproofing of boats and baskets. It was thought to have some curative aspects as well. Surface seeps were important to westward travel along the California, Oregon, and Mormon Trails. Petroleum liquids recovered from seeps were used as axle grease for the wagons, medicinal ointments for the horses and oxen, as well as a balsam for their own pains.

Salt water wells had been drilled to reach subsurface formations long before the first well drilled specifically in search of oil. The development of cable tool drilling can be traced to the salt industry which generated its product from the boiling off of produced brines recovered from depths generally less than 1000 ft but up to 2000 ft. Many of these wells produced some amount of crude oil or natural gas along with the water. There was limited use for the crude, but the gas began to be captured and used to fuel the furnaces in the salt factories. A substantial number of brine wells drilled in the eastern salt region of Pennsylvania, Ohio, and West Virginia encountered significant amounts of hydrocarbons. For example, a brine well drilled along the Cumberland River in the 1820s was reported to have shot an oil column 30 ft in the air and produced at an estimated rate of ~1000 bbls/day (Tait 1946).

1850–1905: Surface Seeps and Water Wells (Serendipity)

Forces of supply and demand began to substantially impact price and availability for whale oil just as the need for illumination and lubricants for machinery were on the rise. "Oil" distilled from coal arrived on the scene about that same time. It was also discovered that kerosene could be distilled from asphalt deposits. Shallow wells hand-dug into local seeps provided access to greater quantities of oil. Production rates were generally measured in terms of a few barrels per day. Another practice at seeps adjacent to creeks was simply to collect the oil as it floated along the water's surface downstream. Local refineries sprang up to distill kerosene and gasoline (used as a cleaning solution) from the crude when it could be collected in sufficient quantities.

The first known well drilled for the purpose of finding and producing oil was in 1857 at the Cuba Oil Spring in Seneca, New York. The well was a dry hole, so the start of the oil industry would have to wait. Two concurrent drilling efforts specifically targeting oil were underway in 1859, one to be credited with changing the course of history, the other to fade into the back pages of memory. J. H. Williams had been operating a refinery for the making of illuminating oil along the banks of Black Creek in Ontario Canada. It was later reported in 1861 that the No. 27 Williams & Co. well at that location had been in operation for 2 years. This suggests the well was drilled and completed for the specific purpose of finding and producing oil in 1859. That is precisely the year E. L. Drake is credited with this distinction with his well along Oil Creek just outside of Titusville Pennsylvania. Drake's original discovery well produced ~20 barrels a day from a depth of 69 ft. The date of discovery was recorded as Saturday, August 27, 1859, and triggered the first oil boom that ramped up in the early 1860s (Tait 1946). A series of wells were drilled up and down Oil Creek, many of which produced at daily rates greater than 3000 barrels. This led to the first bust in the oil industry as the price per barrel dropped from $20/bbl to 10¢/bbl. Nevertheless, this launched the petroleum exploration and development industry.

The early speculators and wildcatters believed that oil was found with the drill bit; you have to drill wells to find oil. Their prospects were defined on recognition of surface seeps as direct evidence of crude oil in the subsurface or through anecdotal evidence such as the smell of gas in water wells or oil sheens produced in salt industry brine wells. Such exploration logic was based on "mining practices" following the great gold and silver rushes of the early to mid-1800s based on outcrop evidence. Shallow wells were drilled adjacent to these locations to depths generally in the range of tens of feet to a few hundred feet. There were, however, a number of wells that reached depths of more than 2000 ft. The eastern salt region became known as the eastern oil region centered around the Allegany River and its tributaries. Western Pennsylvania was the center of the North American oil industry which included parts of Pennsylvania, New York, Ohio, and West Virginia (Yergen 1992). It was during this time that the technique of well stimulation by downhole explosions was developed. The wells were "torpedoed" with nitroglycerin. Fracking wells is not new to the industry! It was during this time that the 42-gallon barrel was established as the standard unit of measure. Oil was initially transported in barrels loaded onto wagons, barges, and/or train cars. As production rose to levels too great to transport by these means, extensive pipe lines and tank cars were used to transfer crude oil to more distant refineries, but the measurement in barrels remained.

Additional demand for petroleum mainly in the form of lubricating products developed as the railroads began to expand across the western United States in 1867 and 1868. The locations of springs supporting westward travel along the California, Oregon, and Mormon Trails provided the early targets for drilling that opened the Rocky Mountain region between 1867 and 1889. Discoveries were made in Kansas and Oklahoma based on seeps that opened the mid-continent region around this same time. The first successful oil well drilled in California was located outside of San Francisco in 1865. Later that year a number of marginal wells were drilled along the flank of Sulphur Mountain in Ventura County, California. This region became the national leader in oil production in the 1890s. The first producing oil well in the state of Texas was drilled in 1865 by Lynis T. Barrett near a surface seep at Oil Spring in Nacogdoches County. The well produced a meager ten barrels a day but is still considered the first oil discovery in the state of Texas. It would be decades later in 1894 before major discoveries were made that established the great petroleum legacy of Texas. A water well drilled for the town of Corsicana in the late 1800s discovered oil at 1027 ft. This discovery was developed with 47 wells by 1897 and a refinery was established at that location. The Corsicana field became one of the first important oil fields in the state of Texas. The great Spindletop discovery outside of Beaumont Texas in 1901, like its predecessors, was drilled on a location identified by surface seeps. In this case, a sulfurous gas seep along the crest of a low hill that was the surface expression of a salt dome. This triggered a boom in Gulf Coast exploration focused on petroleum traps associated with salt features. The well was drilled to a depth of just over 1000 ft. It would be decades later when reflection seismology became the key tool of imaging salt domes and related structural trap configurations along the Texas-Louisiana Gulf Coast.

The discovery in California of the Casmalia field in 1904 was the last of the significant discoveries based exclusively on surface seep evidence. Thirty-two fields had been discovered in California based on seeps between the years 1865 and 1904. The advancement of petroleum and its products as a fuel increased in the 1870s and 1880s. It was initially considered as a potential fuel for steam engines during that time. The invention of gasoline powered engines in the 1890s and the development of the affordable Ford Model T in the first decade of the twentieth century insured the place for petroleum products as a lubricant and fuel for the next century (McBeth 1919). This increased demand would require an expansion of exploration logic beyond targeting surface seeps.

Late Nineteenth Century: The Beginnings of Applied Geology

There were two competing philosophies by the end of the 1880s, that of the speculators and wildcatters and the evolving geological concepts coming out of state geological surveys and universities. The hardened speculators and drillers viewed these "rock hounds" (as they were commonly referred to at that time) with great skepticism. As a side note, the term "doodlebuggers" emerged around this time and was applied to individuals who employed pseudo-scientific techniques such as divining rods and giant X-ray machines to locate drilling locations. This usage of the term faded but later reemerged with application to individuals employed on seismic crews. The science of geology had been advancing rapidly throughout the nineteenth century triggered by the famous publication of the geological map of Great Britain by William "Strata" Smith in 1815. State geological surveys and/or state geologists began formal geological studies at various points in the eastern United States as early as the late 1820s. These studies began with local observations and interpretation of stratigraphic successions. As these successions were mapped over greater distances, observations could be made regarding surface structure based on stratigraphic correlation and changes in orientation of dipping beds and/or fault offsets. Foundational concepts regarding stratigraphic relationships, structural geology, and lithologic and chemical classification of rocks evolved during this time.

The data source for the early geological studies had been surface geology. This began to change as drilling for crude oil in the subsurface was initiated by the Drake discovery in 1859. Geologists working at state surveys and universities began to integrate subsurface data such as depth to pay zones, lithology, and hydrocarbon characteristics that were starting to be documented to a greater degree from the wildcatters. Drillers had begun to identify geological characteristics using terms such as rock formations, "strata," sandstone, limestone, and shale by the 1860s. In some instances, they linked productive zones to specific rock strata, but they did little or nothing toward considering its lateral distribution in the subsurface.

Geological and engineering concepts that would ultimately be applied to the occurrence of petroleum in the subsurface were developed in the mid to late-1800s, although they were not systematically applied by interpreters until after the turn of the twentieth century.

- *Structural Concepts*: In 1844, W. E. Logan, the first head of the Canadian Geological Survey was studying the distribution of coal in the Gaspe Bay region of Quebec and made the observation that the rocks exhibited undulations in the form of anticlines and synclines. He made the further observation that oil occurred along the axes of the anticlines. This is regarded as the first suggestion of the "anticlinal theory." The theory was more formally stated in 1862 by Thomas Hunt who was a chemist in the Canadian Geological Survey. This represents the beginnings of the concept of structural traps as containers for petroleum. The idea was tested in Pennsylvania during the early 1880s and proven by the discovery of gas accumulations along anticlinal axes as mapped by the Second Pennsylvanian Geological Survey. Unfortunately, it was essentially dismissed by wildcatters in Pennsylvania by analogy to the fields that produced independently of structural position around Titusville. These were later shown by Cyrus Angell and John Carll to be controlled by the distribution of porous sand. The anticlinal theory was tested again in 1884 around Findlay, Ohio, with the discovery of the Trenton Gas field by a well drilled to 1092 ft. This well initiated discovery of a new oil province based on the projection of structural dip from outcrop into the shallow subsurface that extended a play from eastern Indiana through Ohio (and beyond). Near the turn of the twentieth century, geological observations of surface structure were beginning to be linked to the occurrence of petroleum in the shallow subsurface of Wyoming. In 1896, a professor at the University of Wyoming observed that oil seeped from Shannon sandstone outcrops and given the possibility of deeper sandstone horizons, oil should be trapped in the subsurface within the Shannon sands at depth. In 1908, the Dutch No. 1 well was drilled and produced light hydrocarbons from the Shannon at a depth of 1052 ft. This discovery was considered the first documented occurrence of light gasoline crude west of Pennsylvania.

- *Stratigraphic Concepts*: In 1870, Cyrus Angell outlined his "belt theory" while drilling wells in Venango County, Pennsylvania. He was one of the first to surmise that a continuous belt of oil saturated sand may extend between two wells that had each encountered "equivalent sands." He then suggested that drilling a new well between these existing wells should encounter that same sand. He proved this theory by projecting a sand belt from his own wells on Belle Island (approximately 25 miles down the Allegheny River from Oil City) to Foster Station about 5 miles upriver. He also suggested these sands extended an additional 9 miles to the oil pool at Reno. This was the earliest example of what would later be defined as a "trend play" after the turn of the twentieth century. Angell's belt theory identified correlative sand-rich shoreline deposits and may be considered the beginnings of the concept of stratigraphic traps by the fact that producing wells were located off structure. In 1930 a world class stratigraphic trap was discovered by "Dad" Joiner as the East Texas Field. The trap was developed as an off structure, regional stratigraphic pinch out and unconformity along the flank of the Sabine Uplift near the Texas-Louisiana Stateline.
- *Water Flood Concept*: As early as 1880, John F. Carll with the Second Geological Survey of Pennsylvania published pioneering studies based on well records and rock samples. He suggested the concept of water flooding as a means to maintain or increase production within an area based on the observation that "all oil cannot be drawn from a reservoir without something to take its place." A line flood was employed in the Bradford sand in Pennsylvania in 1921 that involved two lines of producing wells placed diagonally relative to a line of water injector wells.
- *Drilling Technology*: The earliest drilling method involved cable tool rigs that employed a steam powered rocker arm on a pivot point that repeatedly raised and dropped a drill stem with a chisel bit that crushed rock to create a drill hole. Active drilling had to be stopped periodically to bail out the rock chips and clear the hole. Rotary drilling had been applied as early as the mid-1800s. In 1882, M.C. and C.E. Baker were drilling water wells in Yankton Dakota by means of a rotary rig with water pumped down the inside of the drill pipe and flowing back to the surface

between the pipe and the rock wall. The process allowed for the continuous removal of rock chips and cuttings from the borehole during sustained drilling activities. One of their rigs was brought to Texas to help develop the Corsicana oil field. This use of rotary drilling established the fact that wells drilled through "soft," less consolidated rock could be drilled much more effectively with rotary rigs in comparison to cable tool rigs used to smash their way to depth in the "hard rock" country of Pennsylvania, Ohio, and West Virginia. The lesson was confirmed at the January 1901 Spindletop discovery as the initial cable tool drilling found that it was virtually impossible to sustain an open hole through the shallow unconsolidated sands. A rotary rig brought in from the Corsicana field led the way for the discovery and development of the Spindletop field.

Early Twentieth Century: Subsurface Mapping of Structures and the Introduction of Seismic Data

Significant subsurface mapping began to be applied from 1910 forward. Larger companies came to rely on a staff of geologists to complete mapping projects and define prospective drilling locations based on structure. By 1915, the US Geological Survey began to systematically map subsurface formations, notably in the Healdton Field of southern Oklahoma following its discovery in 1913 (Knowles 1978). Exploration for structural traps on the basis of outcrop geology flourished from 1915 to 1930. There were many regions with obvious surface anticlines and faults that could be easily tested. As with the initial exploration based on surface seeps, the obvious surface anticlines were exhausted by the mid-twentieth century as primary exploration targets.

The earliest application of geophysical data in oil exploration was J. Clarence Karcher's use of seismic refraction data in 1921 to map subsurface geological structure. Seismic applications would be expanded well beyond this with improvements to data quality and type throughout the twentieth century. As the Gulf Coast salt dome play advanced, it was recognized that a better method for subsurface interpretation would be required to map individual salt features due to the fact there was little or no surface geology to project into the subsurface. Gulf coast geophysical applications started with the use of the torsion balance to measure differences in gravity that implied subsurface density differences, particularly low-density salt. The Nash Dome in Brazoria County Texas was identified as a low-density salt feature in 1924 with the use of the torsion balance. The associated structure was mapped in 1926 using the refraction method based on seismic waves triggered by detonation of dynamite at the surface. The Pure Oil Company first surveyed the Illinois Basin with the torsion balance method around 1930. Regional cross sections based on well data around its margins had been previously used to define the subsurface structure. However, there was a substantial area that remained unmapped in the central part of the basin that lacked well control and obvious surface structures. Pure Oil returned a few years later and mapped the area with seismograph data.

Successful wells were drilled based on these data in 1937, establishing a substantial oil play in southern Illinois that was developed from 1937 to 1940.

Digressing for a moment, seismic exploration had its beginnings in the 1920s as an outgrowth of developments in WWI for the location of artillery via a combination of sight, sound, and underground sound. Since all of these travel at different speeds it was, in principle, possible to triangulate enemy artillery positions. Where sound and light have single modes of propagation, there are two seismic wave modes termed P and S (compressional and shear). From the beginning of seismic exploration, the emphasis has been on P waves as these are most easily generated and measured. Even today, shear wave seismology is a relative rarity in seismic exploration for oil and gas. Surface waves are one dominant form of seismic energy that is always present in land data and are a mixture of P and S energy. Until very recently, surface waves were considered noise and filtered out of the data before interpretation.

In the realm of P waves, there are further distinctions made between direct, reflected, and refracted events. A reflection is a seismic wave that strikes and bounces off a geological interface to arrive at a receiver location. By contrast, a refraction is a different kind of seismic event that dives into a high velocity layer, runs along the interface, and emerges to arrive at a receiver. A direct wave is a seismic wave that travels directly from source to receiver without reflecting or refracting. The earliest form of seismic exploration was based on explosive sources and interpreting direct and refraction events. Of course, other events were generated but either they were ignored or instrumentation of the time did not accurately record them. When the source (or shot) initiates the seismic wavefield, it travels downward into the earth and along the earth's surface to be measured by a series of sensors, called geophones, that are evenly spaced along a 2D line. The first seismic surveys had a few geophones live for each shot. Each geophone is a self-powered electromechanical device that vibrates as seismic waves pass generating an electrical signal called a seismic trace. Up until the 1950s, the traces were analog (not digital) and recorded on a rotating drum of photographic paper or magnetic tape. The seismic source in this period was an explosive charge buried in a shallow shot hole.

The measured seismic wavefield contains a surprising amount of information about the subsurface. Travel times can be used to estimate the depth and structural configuration of geologic horizons, while amplitude and waveform depend on rock properties such as lithology, porosity, and pore fluid. But it was not possible to extract more than structural information before digital signal processing was introduced.

Initially all seismic data was acquired along 2D lines and interpreted for refraction events because these generally formed the first arrival events that were easy to pick. Reflection events were understood and present in the data at later times, but often rendered unrecognizable by interference from noise and slow surface wave energy. By the mid-1930s, a primitive kind of 3D seismic was developed, called dip shooting. In this technique, two or more 2D, intersecting refraction lines were shot and interpreted to determine the 3D dip of a subsurface refracting horizon.

Depth limitations on refraction seismology led to increased effort to exploit reflection events in the 1940s. Recording systems, while still analog, became more advanced allowing application of frequency filters, gain, and other processes that resulted in better visibility of reflection events. Interpretation was still done manually on shot records, but in skilled hands a valuable structural model of the deep subsurface could be constructed. Dipping beds at depth, salt domes and faults could now be illuminated by the seismic method and many oil field discoveries were made as a result. As reflection seismic surveying began to predominate over refraction work for petroleum exploration, there was a need to improve the data itself. Until 1956, surveys were shot in a nonoverlapping manner that gave only one reflection from each subsurface point, a method described as 100% or single-fold shooting. This meant there was complete subsurface coverage along a 2D reflection line.

A major advance in seismic data came in 1956 with Harry Mayne's patent for common depth point (CDP) shooting that specified shot records be overlapped in such a way that subsurface reflection points were visited multiple times; the multiplicity being termed the fold of the data. For example, a 12-fold seismic survey is one in which each subsurface reflection point is measured 12 times and the results are summed (stacked). The primary benefit of multifold shooting was better signal-to-noise ratio (SNR), which improved proportional to the square root of the CDP fold. Thus, a 16-fold reflection seismic survey was improved, in an SNR sense, by a factor of 4; 25-fold data improved SNR 5×, and so on. This had the effect of making seismic data useful in many areas that had previously been considered NR (no record) zones, especially places with shallow high velocity rock, rough topography, and many desert environments. The convergence of CDP shooting, electronics, and digital recording resulted in the rapid development of high-quality 2D seismic reflection data in the early 1960s. This period also saw development of vibroseis (a non-explosive land source) and the first offshore seismic surveys using marine airgun sources and long streamer cables with embedded hydrophone receivers.

Digital signal analysis led to an explosion of seismic processing algorithms that scrubbed noise and unwanted events from data. With improved data quality and reflection event enhancement also came a revolution in imaging: seismic migration. Up till the late 1960s even the best 2D seismic data did not really look like a geological cross section of the earth; anticlines were too wide, synclines were too narrow, dips were wrong, and even faults were blurred and strangely placed. The problem is that seismic data is dominated by diffractions and shadows that confuse interpretation. Seismic migration, a new kind of seismic process, was required to fix these effects and was theoretically understood in the 1950s but only digitally implemented and made functional from 1971.

It was well understood by 1970 that 2D seismic can be corrupted by reflections not in the vertical plane below the acquisition line (an effect called sideswipe), backscatter of surface waves by rugged topography, and many other undesirable effects of shooting a 2D experiment in a 3D world. In 1971, the first field experiments on 3D seismic acquisition were undertaken by a consortium of companies. By the early 1980s major oil companies were using 3D seismic, and it was in general use by the mid-1980s. In this transition the nature of seismic interpretation changed from working with a single 2D line, or grid of lines, to visualizing and dissecting a cube of data in 3D space. In gradual steps of increasing complexity, advances of both 3D seismic acquisition and seismic migration continue today.

1970s: Seismic Stratigraphy and Seismic Facies Analysis

A major expansion in how seismic data were being used took place in the 1970s. Up to this point, its primary application was the interpretation of subsurface structure and definition of petroleum traps with lesser application to unconformity traps. The publication of AAPG Memoir 26, *Seismic Stratigraphy – Applications to Hydrocarbon Exploration* (Payton 1977) was the catalyst for a significant advancement in the geologic interpretation of stratigraphic relationships and gross depositional settings based on seismic geometries and reflector characteristics. These characteristics were used to define depositional sequences and their internal character. A depositional sequence was defined as a relatively conformable succession of genetically related strata bounded by unconformities or their correlative conformity (Vail and Mitchum 1977). The bounding unconformity surfaces are defined by seismic reflection geometries caused by the lateral termination of strata. These geometries included: *onlap*, *downlap*, *toplap*, and *truncation*.

Seismic facies analysis developed as the next step in the seismic interpretation process after depositional sequences were defined. The term "facies" had long been applied to distinguish individual rock units based on specific geologic characteristics such as lithology, texture, and composition. Seismic facies distinguish individual intervals and packages within the depositional sequences and their bounding surfaces (Mitchum et al. 1977, p. 117). Individual seismic facies are based on reflection geometry, continuity, amplitude, frequency, and external form. Interpretation of internal seismic facies within a depositional sequence reflects individual depositional settings and elements such as fluvial/deltaic transitions to shelf deposits or carbonate platform to open marine settings. Facies mapping was a major advancement in the seismic interpretation of subsurface geology beyond structural interpretation, greatly expanding the use of seismic to predict the distribution of potential source, seal, and reservoir facies in addition to trap geometry. Regional mapping of bounding surfaces and lateral thickness variation of the depositional sequences within a basin fill succession could then be used to constrain basin models. These models were used to document the burial and thermal history of potential source intervals to better define timing of generation and migration relative to trap formation.

Basin fill histories based on seismic stratigraphy were then applied to the interpretation of relative changes in sea level based on regional unconformities and cyclic shifts in coastal onlap. This was an expansion of the original concept of cratonic sequences (Sloss 1963). The resulting coastal onlap curves derived from age equivalent successions on multiple continental margins around the globe were integrated to develop global cycle charts of relative and eustatic sea level changes

(Vail et al. 1977, p. 83). The practice of seismic stratigraphy integrated with sea level cyclicity morphed into the practice of sequence stratigraphy solidified by the publication of S.E.P.M., Memoir 42, *Sea-Level Changes: An Integrated Approach* (Wilgus et al. 1988).

This application of seismic data to stratigraphy for exploration and development was based on 2D seismic data. However, the use of 3D seismic was becoming more commonplace during the 1980s and would trigger yet another major advance in seismic application.

1980s: 3D Seismic and Seismic Amplitude

The initial development and application of 3D seismic data brought substantial improvements to imaging complex three-dimensional structures. This was particularly true around thrust and salt-related structures both onshore and offshore. High-resolution structure maps based on 3D data were becoming a standard exploration product by this time.

It was recognized that lateral variations in seismic attributes such as amplitude and frequency could now be mapped over subregional areas. This was a major step forward as these attributes had been observed on 2D vertical profiles for some time, but their correlation and mapping had been limited due to data gaps and line spacing. Select amplitude characteristics were recognized as direct hydrocarbon indicators (DHIs), such as “bright spots,” flat spots, gas chimneys, and gas clouds. These became powerful tools predominantly in gas prospect definition, since the amplitude signature of gas-free petroleum is far more subtle. Up dip increases in amplitude along target horizons in cross section, and areas of high amplitude fit to structure contours in map view, became a common method to define prospect area which was then used for potential volume calculations. This ignited a surge in 3D acquisition around the world. Exuberance was soon replaced with caution as it was later proven that even small subeconomic amounts of hydrocarbons, natural gas in particular, could generate such a response.

Integration of attributes such as RMS amplitude with seismic facies analysis substantially increased the resolution of paleogeographic interpretations and prediction of reservoir facies. Seismic facies were traditionally defined in profile and then correlated and mapped from line to line in plan view. Seismic attributes displayed in plan view added a level of detail that had not been previously available. This found application in productive trends in stratigraphic plays such as incised valley fills and regional truncation traps.

The concept of the “Petroleum System” for conventional exploration was becoming formalized by the end of the 1980s. The general concept considered a prospect within a play to be the result of multiple interrelated factors: (1) source rock presence, quality, and type; (2) maturity of that source rock as hydrocarbon generation, migration, and timing; (3) reservoir presence and effectiveness; (4) trap geometry; and (5) seal. As the 1980s rolled into the 1990s seismic data was increasingly important in the interpretation of all of these factors, well beyond its initial focus on subsurface structure and trap mapping.

1990s: Seismic Geomorphology and Expansion of Seismic Attribute Analysis

The application of marine seismic surveys for imaging of complex salt structures offshore was becoming more critical as exploration plays were extended into deeper water settings. This was particularly true in the Gulf of Mexico Basin with the need for subsalt imaging of turbidite plays in the lower Miocene to Paleocene. Longer offset data and enhanced processing algorithms were developed to generate better images below the allochthonous salt canopy.

The rapid rise in the availability of large-scale 3D surveys as well as advances in seismic resolution had a major impact on understanding of slope/basin depositional systems. Sand-rich facies within these systems were the primary reservoir targets in deepwater plays around the world including the Gulf of Mexico, North Sea, West Africa, South America, Malaysia, etc. High-resolution seafloor images came into use as modern analogs for deepwater depositional systems. These were generated as maximum positive amplitude extractions draped on shaded relief structure maps of the water bottom reflector. This added a level of detail which had rarely been seen before. Until this time expensive and relatively local images had been generated with the use of side scan sonar. The geoscience community was becoming aware that the canyon-fed submarine fan, slope fan, and basin floor fan models defined in the 1970s and 1980s lacked the detail that was now readily available given these high-resolution seismic maps. Individual depositional elements within the slope/basin system could be identified by detailed mapping of the shallow, high-frequency data (e.g., water bottom to 500 ms). The term "seismic geomorphology" was applied to this interpretation process in shallow intervals in which the original depositional topography was reasonably well preserved due to the lack of compaction. For example, depositional elements such as channel-Levee systems were identified by recognition of a "gullwing" geometry in profile that resulted from elevated levee/overbank deposits flanking a central channel fill. Gravity-driven mass transport deposits were identified as mounded, internally chaotic seismic geomorphologies.

Additional seismic attributes such as coherency, dip azimuth, amplitude vs. offset (AVO), and frequency analysis (spectral decomposition) were being integrated with traditional tools of amplitude extraction and seismic facies analysis to generate paleogeographic reconstructions in much finer detail. This greatly enhanced the interpreter's ability to predicted reservoir presence, reservoir body geometry, and potential for stratigraphic compartmentalization. By the mid to late 1990s, the use of high-resolution 3D had applications well beyond regional exploration and prospect definition. It was becoming routine to rely on high-resolution 3D seismic interpretations to plan and execute development infill drilling programs and water flood design.

2000s: Advanced Imaging and 4D, Time-Lapse Seismic

There were substantial improvements in seismic imaging and advanced recovery efforts in mature producing fields after the turn of the twenty-first century. The new imaging methods aided subsalt interpretation in the deepwater Gulf Mexico. The challenge was to properly define salt body geometry and base-of-salt horizons within the salt in order to better image potential structures under salt canopies and overhangs. Improvements in acquisition techniques focused on increasing fold with the use of much longer offset/wide azimuth (WAZ) arrays as well as coiled arrays.

Subsalt imaging is complicated by strong vertical and lateral velocity variations that spray ray paths into complex 3D geometries; the seismic ray concept becomes suspect as ray fans fold, overlap, and become multivalued. Rays are a high frequency approximation to the seismic wavefield that are useful in simple to moderately complicated structural settings. An advance of the 2000s was to recognize and document the failure of ray-based imaging methods (termed Kirchhoff migration) for many subsalt problems. In such cases, wave equation methods are used that directly propagate wave fronts (rather than rays) to create seismic images. The evolving standard of wave equation imaging is reverse time migration first proposed in 1982, but it only arrived as a commercial product about 2010.

A seismic survey can be considered as a vast collection of individual seismic traces, each of which has an associated source and receiver location. The distance between source and receiver is the trace offset and the compass orientation of the source-receiver pair is the trace azimuth. A modern 3D survey will consist of billions of individual traces, so it is common to speak of the offset and azimuth distribution of the survey.

As seismic imaging algorithms advanced from ray to wave methods, the improvement in subsalt images was steady but diminishing. It was shown in the mid-2000s that subsalt image quality was constrained by acquisition practice. The key limiting parameters were azimuth and offset. With respect to azimuth, early marine 3D surveys were very nearly single orientation because one ship was used for both source (towed airgun array) and receiver (towed streamer cable). The only azimuth in such a survey is the direction of ship travel, reflection energy scattered from other directions is not imaged properly. Advances came in the form of multiple streamers pulled by one ship, then multiple recording ships, and ultimately a complete separation of source and receiver ships. The point of these changes was to increase the azimuth of the data. A land 3D seismic survey can be full azimuth because sources and receivers can be placed at any location. In the marine case, it is complicated by the fact that the streamers are moving through the water and, at least initially, the source is on the same ship. With the advent of separate source and receiver ships, marine 3D seismic surveys could be acquired with much better azimuth distribution. A collection of acronyms are in use to describe various levels of azimuth content in a 3D seismic survey, including narrow azimuth (NAZ), Rich azimuth (RAZ), wide azimuth (WAZ), and full azimuth (FAZ). It is essential to understand that a 3D seismic survey is only truly 3D if all azimuths are present in the data. This allows the imaging algorithms to gather data from wherever it reflects in the subsurface and properly reconstructed the geology. Anything short of full azimuth will compromise this process.

Because of the extreme velocity variations encountered in subsalt areas, wavefield energy can be strongly bent and diffracted. In order to capture this energy for imaging purposes seismic receivers must be placed far from the source. In other words, long offset data is needed in addition to full azimuth. In just a few years, full azimuth and long offset shooting did more to improve seismic imaging than the previous 20 years of algorithm development on the computing side. But it was really the marriage of improved acquisition and imaging that made modern seismic images possible.

As seismic data improved, reservoir engineering data was beginning to be integrated to support enhanced recovery efforts in mature fields. It was proven that systematic changes in fluid saturation and/or formation pressure could be "imaged" with the use of time-lapse, or 4D, seismic. The process involved repeat acquisition of 3D surveys over these fields. Changes in attributes such as velocity, impedance, and frequency could be made between the original and the newly acquired surveys. For example, it was found that areas of bypassed pay in water flood sweeps commonly imaged as a "soft" response. Areas of increased trough amplitude on repeat surveys bounded by faults or stratigraphic edges were linked to elevated formation pressures in undrained compartments. Local, high-resolution amplitude maps could then be used for placement of producer-injector re-drill locations. In some cases, fixed water bottom arrays were placed above offshore producing fields (e.g., the Ekofisk field, Norwegian North Sea) facilitating the acquisition of a series of 3D surveys to better image bypassed pay and evaluate the effects of compaction. Such efforts greatly increased the ultimate hydrocarbon recovery from these mature fields.

The use of seismic data in exploration and development of conventional plays had evolved considerably from the late 1990s to the early 2000s, starting with the emphasis on definition of subsurface structure and trap geometry but soon finding application to interpretation of all the petroleum system elements. Seismic use ultimately expanded to late stage field development and enhanced recovery. As we proceed into the 2010s, there are even more novel applications as the boom in unconventional plays proceeds: necessity is the mother of invention.

2010 and Beyond: Application to Unconventional Plays

Current advances in the use of seismic are related to the boom in unconventional plays. The majority of these plays require multistage fracs along extended horizontal well bores within a target interval. The multistage fracs are required to improve flow rates and drainage volumes from these low permeability reservoirs. Initial efforts tended to target intervals based on total organic content and its maturity as an indicator of source potential. In many cases these intervals proved to be to ductile and didn't sustain frac stimulation. Typical unconventional reservoir targets require two primary factors: an effective source rock facies to provide hydrocarbon volume and a degree of brittleness that defines the "fracability." In many cases, the optimum unconventional reservoir is characterized by interbedded, thin layers of organic-rich claystones and mudstones with brittle carbonate, siltstone of fine sandstone. Current advances in the application of seismic data are directed at better identification of potential unconventional targets and the effectiveness of multistage frac jobs.

The lithology and geomechanical rock properties of the reservoir target interval and surrounding units have a direct impact on the associated seismic response. Geomechanical attributes can be extracted from the seismic data set, including brittleness (related to how effectively a formation respond to hydraulic fracturing), Young's modulus (a measure of stiffness), and Poisson's ratio (ratio of radial expansion to axial shortening under axial compression). Cross plots of these attributes with other geological parameters such as grain density from core samples are being developed as a technique to define a new type of seismic facies that reflects the mechanical properties of the rocks. This advance is well beyond the initial use of seismic facies based on amplitude, continuity, and frequency to interpret depositional characteristics.

Understanding the orientation and extent of the individual frac zones is key to evaluating the effectiveness of those efforts. The use of microseismic has become one of the leading edge technologies for these evaluations. The goal of microseismic is to create a map in three-dimensional space and time showing the location of induced fractures produced by a frac job in a reservoir, typically in a horizontal well. Before the development of microseismic, it was not known if the target formation was being fractured uniformly or whether some of the fracture activity was drifting out of zone into unproductive formations. Acquisition of microseismic data involves surrounding the frac well with shallow boreholes containing three-component seismic receivers and, perhaps, additional surface receivers. As the frac job gets underway, the fluid pressure ramps up in the wellbore and ultimately exceeds the fracture gradient of the rock; cracks and fractures are developed in the reservoir formation acting as seismic sources, effectively very small earthquakes. As the rock breaks it generates seismic waves that radiate outward and upward to be measured by the downhole receivers. This process proceeds until the frac job is complete. The microseismic data is then processed, increasingly done on-site in real time; the result being a series of back projected microearthquake locations and strengths. The information is typically displayed in a 3D interpretation system as a collection of spheres, each one representing an induced fracture location, along with 3D seismic data and wells for reference. Analysis of microseismic data can demonstrate the fractured rock zone is continuous and evenly affects the rock formation along the well. Interactive improvement of fracture coverage is possible from microseismic analysis of previous frac jobs and changes in completion techniques so that the desired even coverage is actually accomplished.

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Chapter 3
Seismic Interpretation in Petroleum Exploration

Abstract The application of the seismic technique to petroleum exploration has evolved well beyond its original emphasis on imaging of subsurface structure. Regional data sets are key to understanding basin scale structural style and basin fill cyclicity. Seismic interpretation supports evaluation of all of the conventional petroleum systems elements: source, degree of source maturation, reservoir presence and quality, trap geometry and seal capacity. The practice of seismic and sequence stratigraphy aid in definition of potential source intervals based on lapout surfaces that may indicate organic marine condensed sections or coal-rich to lacustrine deposits in topset geometries. Basin fill cyclicity defined by regional horizon mapping is commonly integrated with heat flow modeling to evaluate potential source kitchens. Seismic geomorphology and attribute analyses are applied to the understanding of reservoir body geometry and the degree of stratigraphic compartmentalization. Acquisition of high-resolution 3D seismic surveys and related prestack time and depth migration has greatly enhanced the ability to image steep dips, complex structures, and trapping configuration. Top seals are generally defined as regionally mappable mudrich stratigraphic units. Evaluation of pressure seals and sealing capacity can be supported by analysis of structural relief, fluid pressure fetch areas, and the presence of gas clouds.

Keywords Basin types · Blown traps · Conventional plays · Direct hydrocarbon indicators (DHI) · Hydrocarbon migration pathway · Petroleum system elements · Prospect · Relative sea-level · Reservoir · Stratigraphic architecture · Trap geometry

The seismic data set can be applied at a wide range of scales in the evaluation of conventional plays ranging from regional interpretation of sedimentary basin fill down to identification of individual flow units within producing reservoirs. In addition, the seismic data set plays a role in evaluation that extends beyond the point of exploration and discovery through appraisal, development, and the productive life

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of a field. Initial efforts generally involve regional horizon mapping, structural interpretation, and seismic stratigraphy within a basin fill in order to define potential exploration plays both geographically and stratigraphically. The next phase is the evaluation of the petroleum systems elements within a play in order to identify a portfolio of drillable wildcat prospects. Following a discovery, high-resolution horizon mapping and seismic facies interpretation aid in the positioning of appraisal and development wells along the most favorable trends within the greater accumulation. Infill drilling opportunities may present themselves as bypassed pay based on seismic attribute analysis of time-lapse, “4D” seismic as field development proceeds into secondary and tertiary recovery phases. Considering this, seismic data plays a critical role in the geological interpretation at all scales and phases of exploration, development, and production.

Basin Scale Structural and Stratigraphic Interpretation

Correlation frameworks based on regional 2D seismic grids and/or large exploration 3D seismic surveys provide insights regarding a variety of geological characteristics at the basin scale. These insights include: (1) regional tectonics and resulting structural style, (2) regional sequence stratigraphy and basin fill history, (3) burial and thermal history of individual stratigraphic horizons within the basin fill, and (4) paleogeographic evolution and resulting stratigraphic architecture. Such basin scale characteristics establish the geologic context within which to evaluate internal petroleum systems and their component elements.

Seismic data is one of two ubiquitous data sets used in subsurface interpretation; the other being well log data. Well logs provide direct downhole measurements of rock properties and other geological attributes that can be used for local calibration of the seismic data set. Although logs provide relatively high-resolution information, that information is specific to the well bore from which it is derived. Lateral variation of subsurface characteristics based solely on well data relies on projection of these characteristics along cross sections drawn between wells that may be separated by distances of 1000s of feet to 10s of miles. A unique aspect of the seismic data set is that it provides a continuous view into the subsurface over distances of 10–100s of miles. This view has evolved from two-dimensional vertical profiles to vertical, plan view, and three-dimensional images that illuminate intervals that are 1000s of feet in thickness and 10–100s mi^2 in aerial extent. This large-scale and continuous view allows geoscientists to effectively interpret regional tectonic elements and structural trends as well as subregional to regional basin fill stratigraphic architecture and burial history.

There are a variety of basin types that develop under differing tectonic conditions. Many (but certainly not all) of the major producing regions of the world are concentrated in basins associated with two tectonic regimes: divergent/extensional or convergent/contractional. The North Sea region is a classic example of an extensional rift system along divergent plate boundaries (Fig. 3.1). It is divided into a

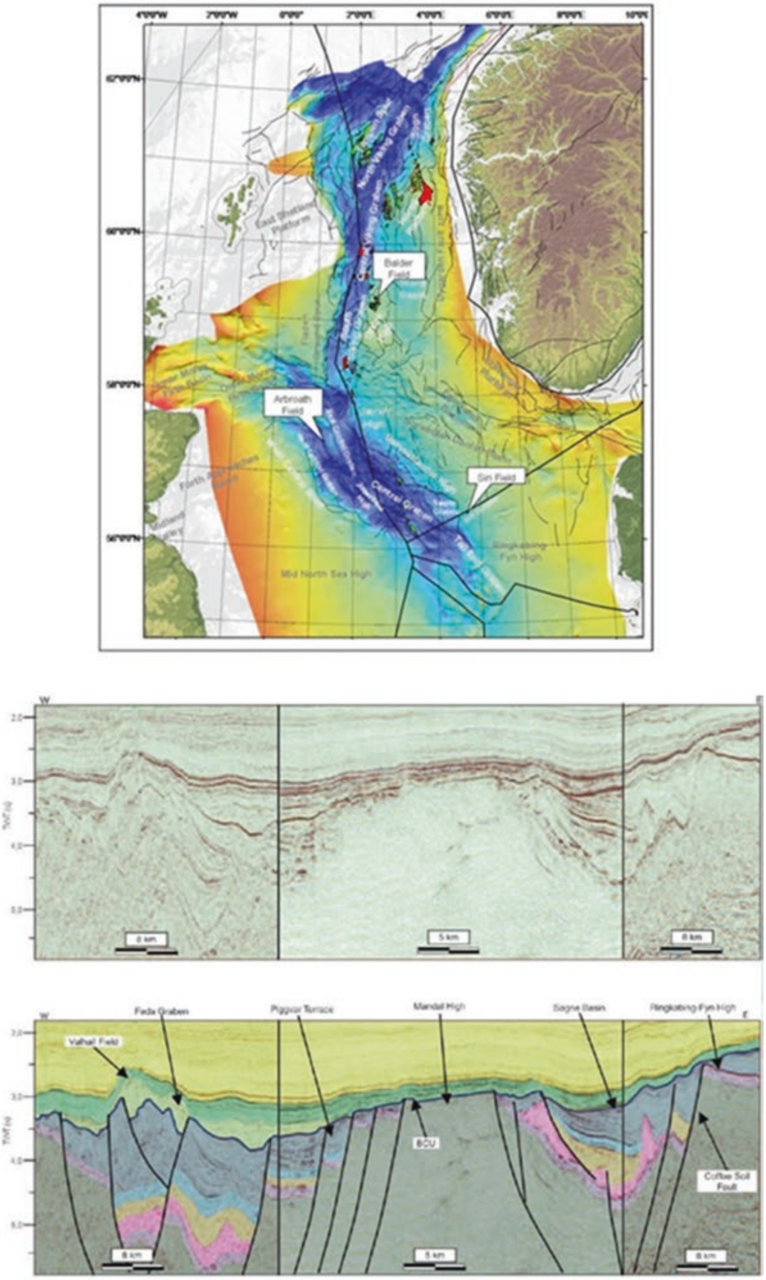

Fig. 3.1 Structural elements of the Norwegian North Sea with 2D regional profile across the Norwegian sector of the Central Graben. (Modified from Rossland et al., AAPG (2013). Reprinted by permission of the AAPG whose permission is required for further use)

series of linked rift basins: the Central Graben, Viking Graben, Moray Firth Basin, etc. Given enough time, rift basins may separate into independent continental masses characterized by passive margins along their trailing edge (e.g., US east coast and the African west coast). Typical structural styles and hydrocarbon trap geometries are associated with horst and graben or tilted half grabens (Fig. 3.1). In contrast, convergent margins are characterized by contractional structural geometries such as thin skinned thrust faults, basement involved reverse faults, and local pop-up structures. The East African margin along Mozambique and offshore Sabah/Brunei are examples of Cenozoic convergent tectonic margins (Fig. 3.2). Convergent foreland basins such as the Appalachian, Black Warrior, and Arkoma Basins of North America were formed in response to plate convergence and associated mountain building. Such basins are asymmetrical and generally characterized by rapid sedimentary fill and trap geometries associated with imbricated thrust faults. There are major producing regions associated with a third, salt modified regime such as the Gulf of Mexico Basin and portions of the North Sea Basin. In these cases, stratigraphic and structural traps evolve in association with salt movement (Fig. 3.3).

It is extremely difficult to effectively map regional structural trends with their component hydrocarbon traps at the basin scale based on well data alone. The required number of wells and their regional distribution are prohibitive. It is not until exploration and development has reached a very mature stage such as in the Mid-Continent and Permian Basins, USA, before that level of structural detail can be achieved with well data. Regional 2D grids and large-scale 3D seismic surveys play a key role in the early evaluation of petroleum basins. These data illuminate regional structural styles in both profile and plan view and are instrumental in early determination of structural style and potential trap geometries.

Large topographic and bathymetric elements that influence basin fill architecture such as shelf-slope-basin floor profiles, salt-related depositional mini basins, and volcanic features can be observed at the seismic scale (Fig. 3.4). Sedimentary fill at the basin scale is inherently cyclic and ranges from 1000s of feet to 10,000s of feet in thickness. This cyclicity results from variations in a number of interacting factors that include sediment supply, subsidence rate, and eustatic sea level that when combined define that cyclicity in terms of changes in relative sea level. Given this thickness range, individual depositional cycles can be easily recognized on seismic data based on their bounding surfaces such as erosional unconformities or condensed sections. These surfaces are defined on the basis of seismic reflector terminations that take the form of truncation, toplap, concordance, onlap, and downlap (Figs. 3.5 and 3.6). The practice of seismic stratigraphy and depositional sequence stratigraphy has been developed as one of the primary interpretation approaches to systematically define individual depositional cycles within a basin fill succession. Definitions and details regarding this approach are presented in Vail et al. (1987) and Wilgus et al. (1988). This approach defines basin fill cyclicity in terms of a progression of relative sea level from conditions of lowstand through transgression to highstand and back to lowstand. The foundational geometric model in 2D profile regarding this progression is illustrated in Figs. 3.7 and 3.8. The relative sea-level cycles are described in terms of a series of systems tracts: lowstand systems tract,

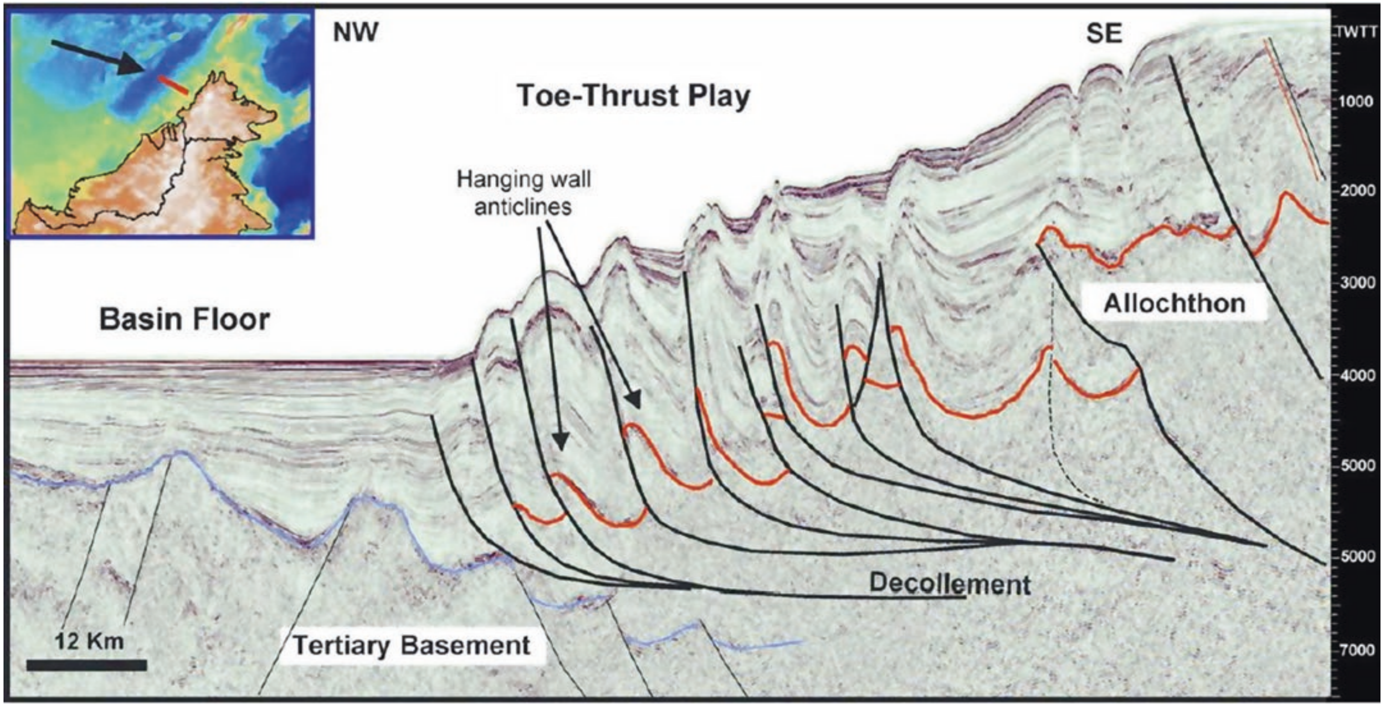

Fig. 3.2 Regional 2D seismic profile in a structural dip orientation, northwest Borneo margin, offshore, Sabah. Note contractional structural style along this convergent margin. Structural loading leads to the deeper flexural fault offsets. (Ingram et al. 2004)

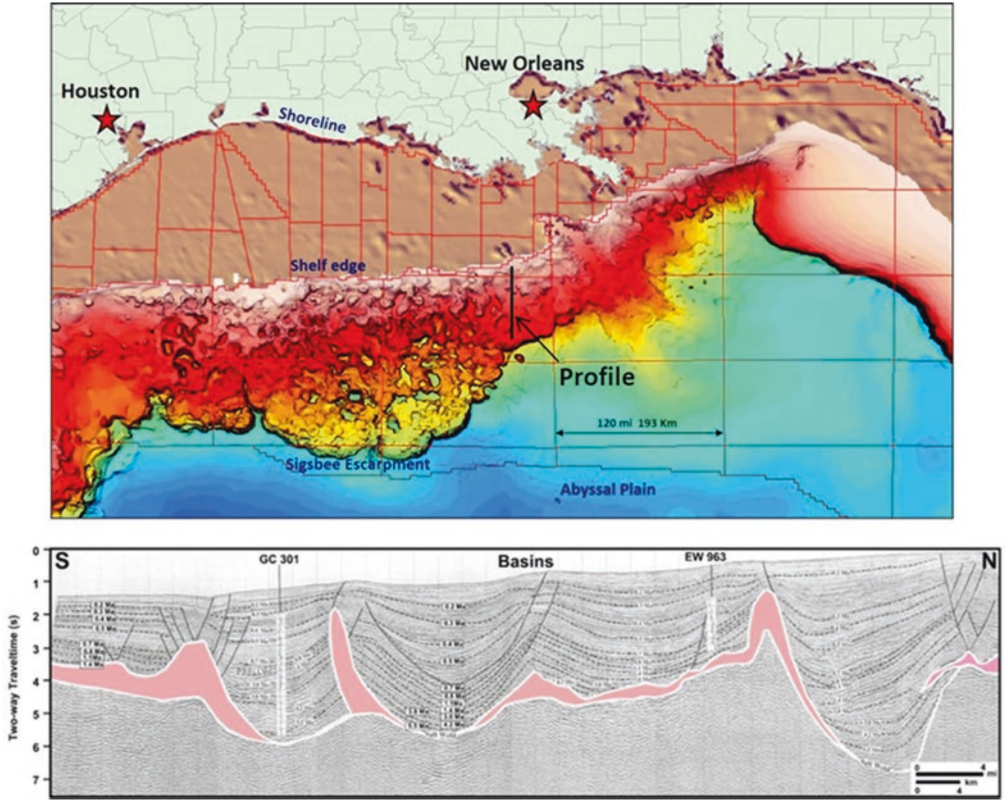

Fig. 3.3 Structural styles in a salt-modified continental margin, Gulf of Mexico Basin. Salt intervals interpreted in the seismic section are shown pink. (Modified from McBride et al. (1998) in Weimer et al., AAPG (2017). Reprinted by permission of the AAPG whose permission is required for further use)

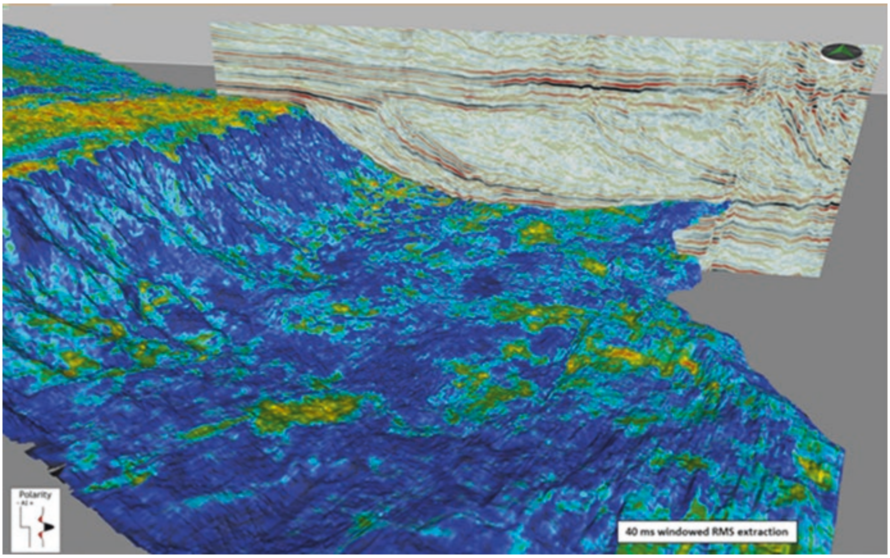

Fig. 3.4 3D perspective view of a mapped horizon and 3D data block illustrating basin scale shelf-slope-basin profile. (Printed with permission from ConocoPhillips, whose permission is required for further use or publication)

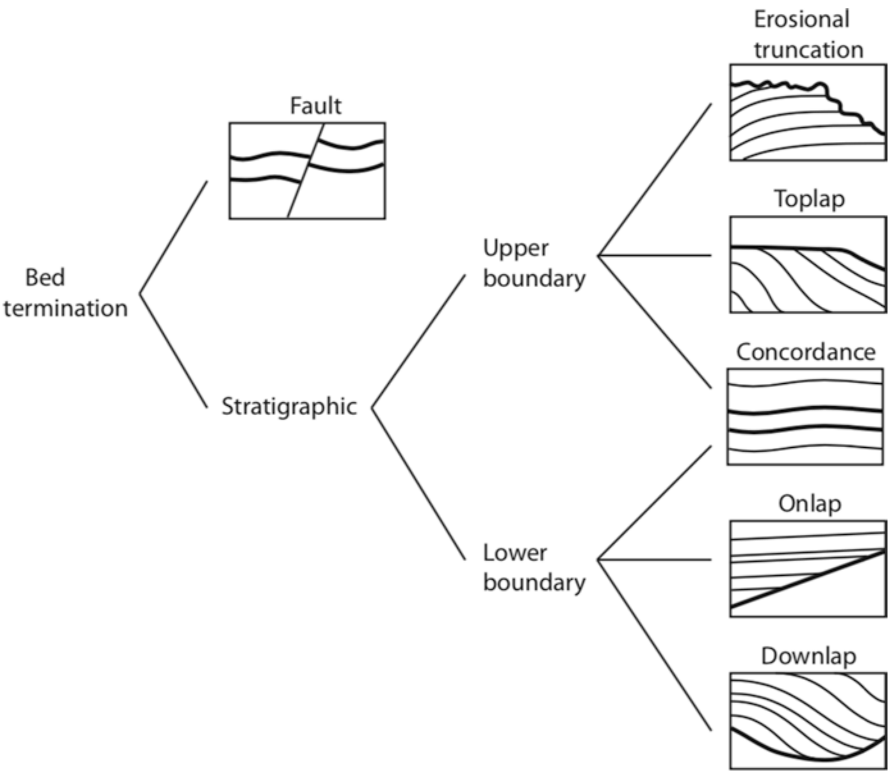

Fig. 3.5 Classification of bed terminations commonly observed on seismic data that define stratigraphic surfaces. (Liner 2016)

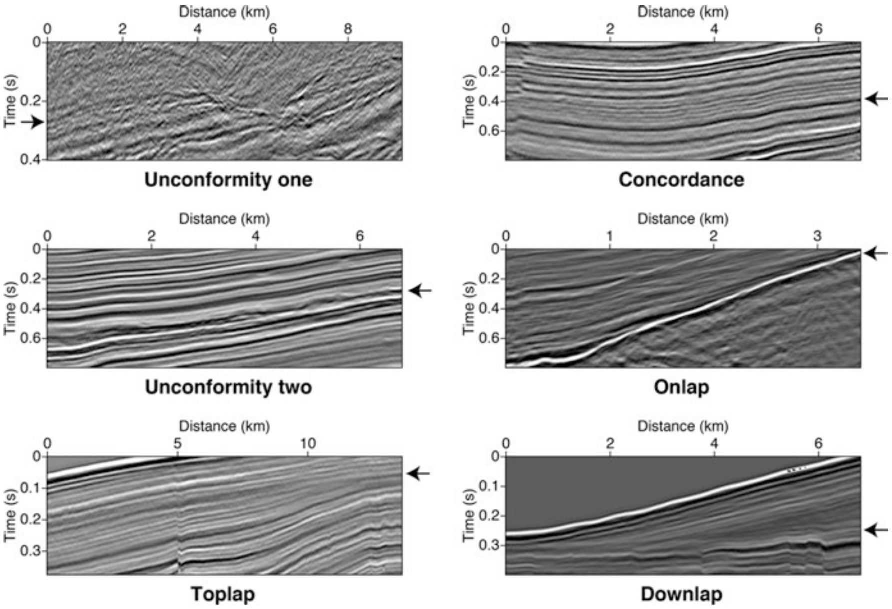

Fig. 3.6 Seismic examples of stratigraphic boundaries and associates lapout geometries. (Modified from Liner 2016)

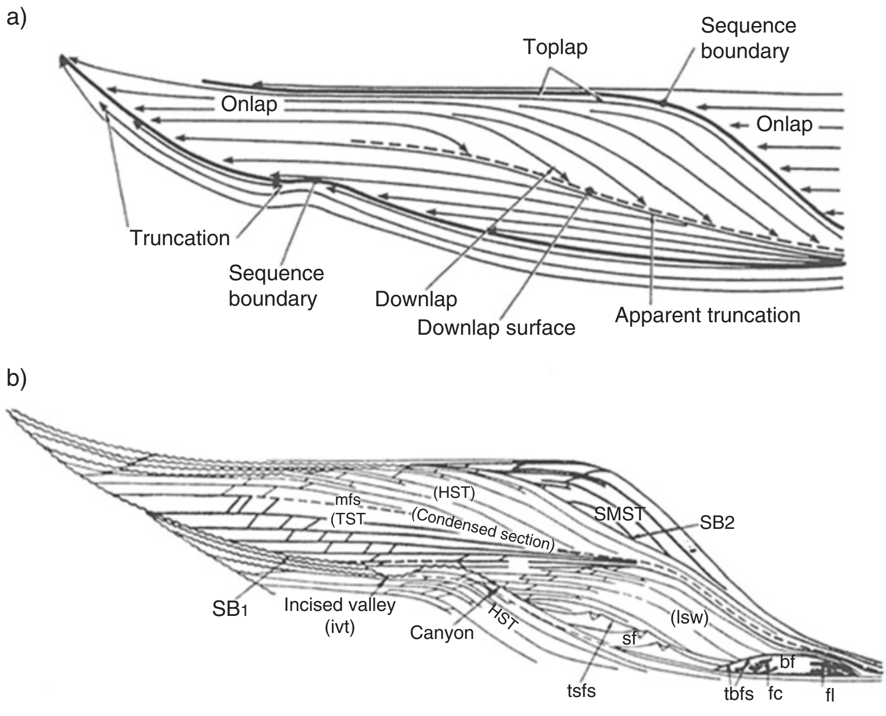

Fig. 3.7 Seismic patterns and system tracts commonly observed in a clastic succession. (**a**) Schematic illustration of reflection terminations and lapout geometries. (**b**) System Tracts and select internal elements: (SB) Sequence Boundary, (HST) Highstand Systems Tract, (TST) Transgressive Systems Tract, (LST) Lowstand Systems Tract, (SMST) Shelf Margin Systems Tract, (bf) basin floor fan, (sf) slope fan, (lsw) lowstand wedge. (Modified from Vail, AAPG (1987). Reprinted by permission of the AAPG whose permission is required for further use)

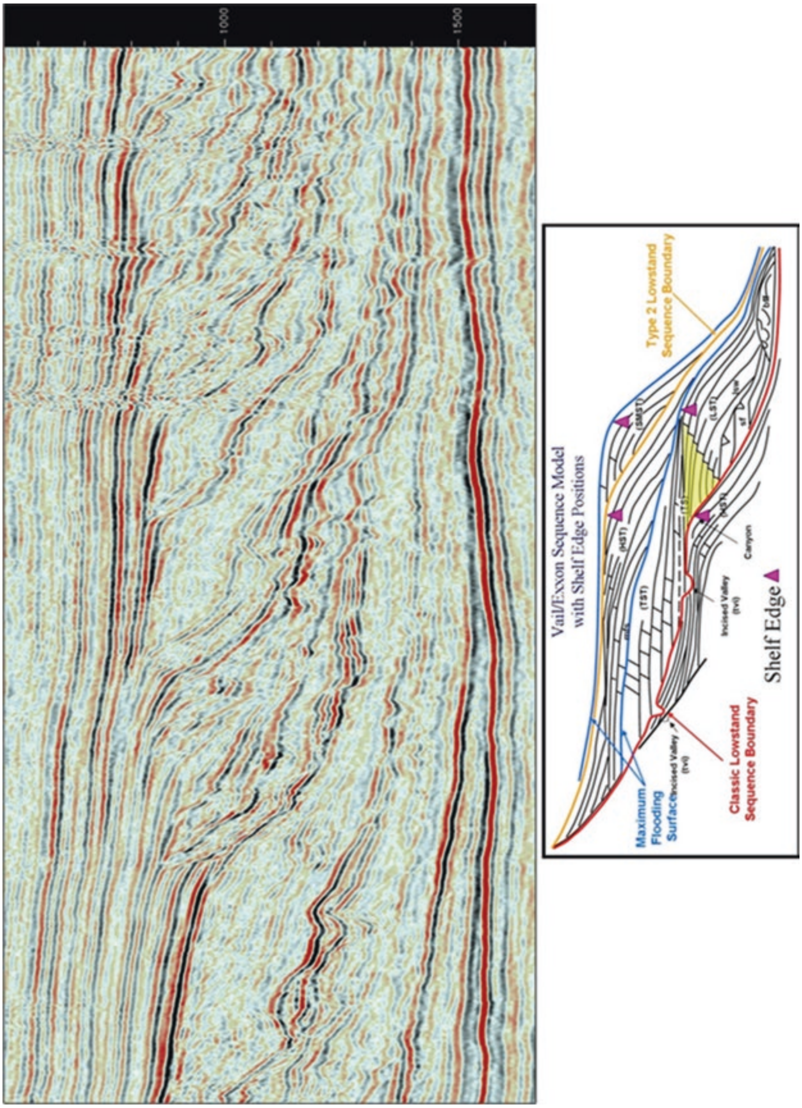

Fig. 3.8 2D seismic profile illustrating the seismic geometries used to define systems tracts as shown in the inset. (Printed with permission from ConocoPhillips, whose permission is required for further use or publication)

transgressive systems tract, and highstand systems tract. An additional "falling stage" systems tract is coming into use to reflect the regressive phase of relative sea level from highstand, maximum flooding down to lowstand. Each systems tract represents a paleogeographic time-slice that links coeval, proximal to distal depositional systems generally ranging from fluvial/coastal plain out to open marine and deep marine. The systems tract progression from lowstand to highstand and back illustrates the basin fill history through time. Coastal plain/fluvial to open marine shelf deposition is dominant during periods of highstand while deepwater slope and basin deposition is dominant during periods of lowstand. A completed sequence stratigraphic framework provides the context within which to predict reservoir and source facies as well as the burial history that can be applied to maturation modeling of potential source intervals within that fill. The seismic data set is ideal for regional stratigraphic interpretations that provide the framework for source, reservoir, and seal predictions.

Play and Prospect Analysis

There is a natural progression in scale from the basin fill and its internal petroleum systems down to the plays and individual prospects within those systems. The concept of a "petroleum system" has been around in one form or another since the early 1950s (Weeks 1952; Knebel and Rodriguez-Eraso 1956; Dow 1974; White 1980). The component elements that make up an integrated petroleum system include: source rocks, migration path, reservoir, trap, and seal (Magoon 1987, 1988). The unifying theme of the various overlapping definitions of petroleum systems and plays presented from the 1950s to the 1980s is the identification of a series of integrated elements that result in the generation and accumulation of hydrocarbons. The term "petroleum system" as defined by Dow (1974) and Perrodon and Masse (1984) emphasizes the geochemical link between source rocks, their maturation/generation history, migration, and the chemistry of trapped hydrocarbons. Therefore, a petroleum system represents the discovered hydrocarbon occurrences within a basin linked to a specific source rock or set of source rocks. A petroleum play represents the potential undiscovered hydrocarbons within that system and a prospect represents an individual potential accumulation within the play as a wildcat drilling target. As such, plays and prospects are defined on the evaluation of some variation of these same five petroleum system elements. For the purposes of this publication the elements are defined as: (1) source presence (quantity and quality); (2) source maturity, hydrocarbon generation, migration, and timing (HGMT); (3) reservoir (presence and effectiveness); (4) trap; and (5) seal. All five of these elements must work to some degree of effectiveness for a hydrocarbon accumulation to occur. The point of this discussion is that the seismic data set can be used to evaluate some aspect of all five of these petroleum system elements (Table 3.1).

Prospect risk or "chance of success" is generally evaluated in terms of the combined chance that each of these petroleum system elements is present and effective

Table 3.1 Petroleum systems elements, their internal characteristics, and those addressed with the seismic data set

Petroleum system element	Component factors
Source	* Position within the basin
	* Position within the stratigraphy
	Organic content
	Composition/kerogen type
HGMT (Hydrocarbon generation migration timing)	* Burial history
	Thermal maturity
	* Migration pathways
	Lateral along carrier beds
	Vertical along fault planes
	Vertical diffusion through overlying units
	* DHIs suggesting active petroleum system
	Washouts – "gas clouds"
	Bright spots
Reservoir	Reservoir presence
	* Interval thickness
	Net clean sand
	Net porous sand
	Net:Gross
	* Reservoir body geometry
	Sheets
	Ribbons
	Reservoir quality
Trap	* Structural geometry
	4-way dip closure
	3-way dip against fault
	3-way against salt or weld
	Stratigraphic pinchout
	Stratigraphic lapout
	* Area of closure
	* Height of closure
Seal	* Top seal
	Regionally mappable sealing lithologies
	Amount of overburden
	* Side seal
	Cross fault Juxtaposition
	Fault gouge lithology/clay smear
	Mechanical/pressure seal
	Overpressure and frac gradients
	Blown traps, seismic washouts

*Denotes those aspects potentially addressed with the seismic data set

(Rose 2001; Smalley et al. 2008). It is not uncommon to see a three-component system that combines source rocks and HGMT as a charge component and trap and seal combined as a containment element. How these elements are grouped and risked is up to the individual. In addition, pre-drill estimation of expected in-place hydrocarbon volumes is also linked to these elements. Within this context it can be said that the seismic data set plays a critical role in evaluating prospect risk and potential reward. The following sections introduce the application of seismic data to the evaluation of basin fill and the petroleum systems elements it may contain.

Source Rock Prediction

Presence of a quality source rock is one of the initial requirements in advancing exploration efforts in a new basin. In many cases there is limited well control that could provide direct evidence of a source rock interval. An indirect method based on seismic geometries may be applied in these cases. There are three source rock facies that produce hydrocarbons: (1) Type I, marine or lacustrine algal kerogen, oil prone; (2) Type II, mixed marine and terrestrial organic material, oil and gas prone; and (3) Type III, terrestrial plant material, gas prone. Figure 3.9 illustrates the most likely position within the sequence stratigraphic model where each of these facies may be encountered.

When dealing with clastic successions, deep marine, organic-rich deposits recording periods of condensed sedimentation are excellent candidates for preservation of oil prone source facies (Type I kerogen). These manifest themselves on seismic data as a highly continuous, single wavelet to a complex set of wavelets consisting of peaks and troughs that drape paleotopography (Prather et al. 1998). Clay- and organic-rich, condensed units attributed to deposition via hemipelagic and pelagic sedimentation are characterized by "soft," low acoustic impedance reflec-

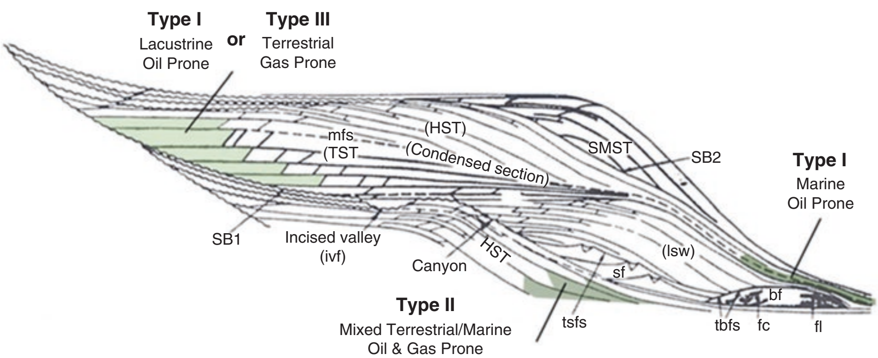

Fig. 3.9 Vail/Exxon model illustrating a depositional sequence. Green shaded areas indicate where potential organic-rich source rocks may exist within transgressive and highstand systems tracts. (Modified from Vail, AAPG (1987). Reprinted by permission of the AAPG whose permission is required for further use)

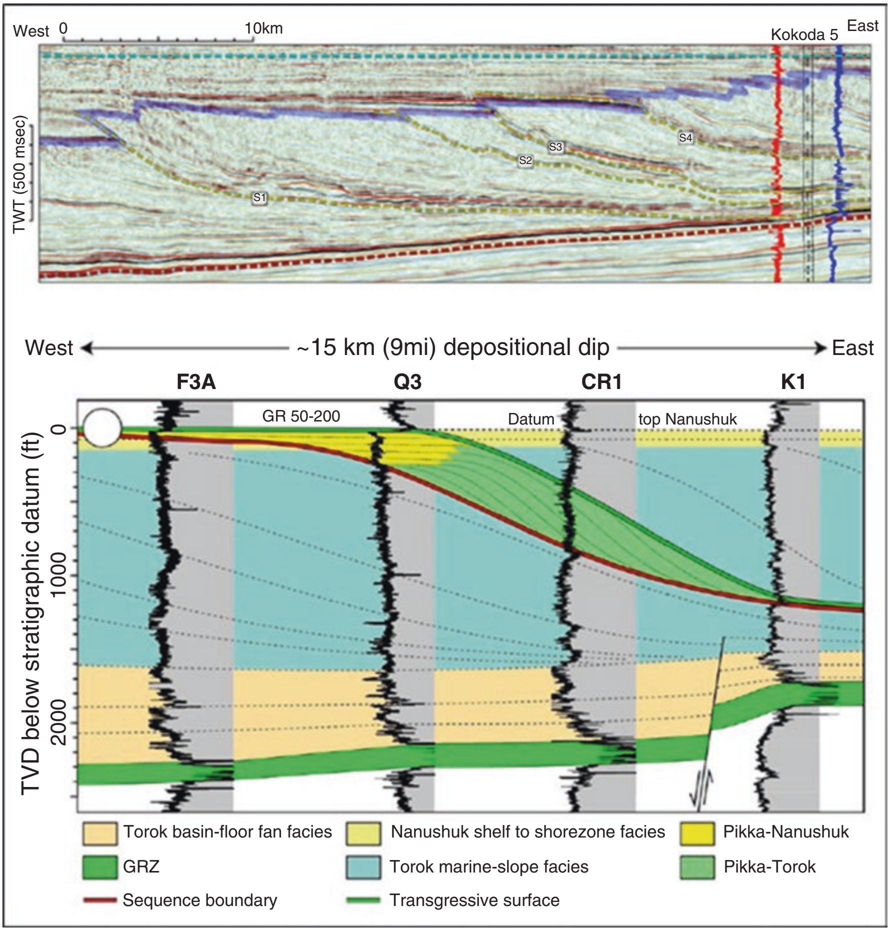

Fig. 3.10 Seismic profile and Well log cross section illustrating regional topset-foreset-bottomset geometries. The clinoforms record progradational timelines that progressively downlap onto a deep marine source rock. This is a proven, world class source interval on the North Slope Alaska commonly referred to as the HRZ (High Reflectivity Zone or Highly Radioactive Zone) or GRZ (Gamma Ray Zone). (Modified from Houseknecht, AAPG (2019). Reprinted by permission of the AAPG whose permission is required for further use)

tions. These low impedance wavelets may be interbedded with "hard," high impedance units in the case of complex sets. The higher impedance units are commonly a response to foraminifera-rich calcareous claystones, mudstones, or thin limestones.

High amplitude, continuous seismic reflections that may be indicators of an organic-rich, condensed section commonly occur as regional downlap surfaces. The "High Reflectivity Zone" (HRZ) or "Gamma-ray Zone" (GRZ) at the base of the Cretaceous, Brookian, succession on the North Slope, Alaska, is a classic example of a world class, oil-prone source rock that is imaged as a regional downlap surface (Fig. 3.10). The downlap reflection is a generally continuous, low impedance response along the base of the progradational clinoform/foresets. Consider each forest as a timeline and note how they converge into a basal condensed section (Fig. 3.10). This interval has been drilled and sampled at numerous localities and is proven to be the organic-rich, marine (Type I) to a mixed (Type II) source rock for many of the fields on the North Slope. Clinoform seismic geometries indicate a progradational succession of deltaic to slope depositional systems across the regional downlap surface. In such cases, there can be a significant amount of plant material carried into the deeper water setting and mixed with the marine organic material derived from the overlying water column. This results in a mixed, oil and gas prone, Type II kerogen.

Source rock facies may also be encountered within seismic topset geometries and, if present, are typically characterized by plant dominated, Type III source rocks (Fig. 3.11). The exception to this would be Type I organic facies related to lacustrine algal material. Seismic topsets commonly reflect deposition of lower coastal plain to delta plain facies that include marsh/swamp deposits that produce carbonaceous shale to coal facies. Such facies tend to be thicker and have a greater preservation potential within the transgressive systems tract characterized by rising base level and barrier/lagoon settings along the landward advancing shoreline (Fig. 3.9).

Hydrocarbon Generation, Migration, and Timing

It is not adequate to simply locate the potential existence of a source rock interval. It is equally important to determine if that source interval has been matured to the point of hydrocarbon generation and expulsion as well as identification of a migration pathway to a potential trap. In addition, the timing of the maturation and migration of hydrocarbons relative to the timing of trap formation must also be ascertained. The degree of maturation is a product of time, temperature, and depth of burial. Vertical (1D) burial history models are commonly generated along individual well bores integrating stratigraphic tops, interval thicknesses, age determinations, and local thermal gradients. These 1D models are extremely effective at characterizing source rock conditions at specific locations. The challenge is in the interpretation between well control, particularly in underexplored areas with limited data. Regional 2D and 3D surveys infill the gaps between wells in addition to imaging deeper elements below current drill depths. There are three general goals in assessing hydrocarbon generation, migration, and timing: (1) prediction of the source rock distribution within the basin, (2) definition of areas where that source rock has been matured to the generation stage (the "kitchens"), and (3) identification of potential migration pathways (fault planes, carrier beds, simple diffusion). Seismic data plays a critical role in this assessment beyond a single well bore by providing the structural and stratigraphic framework for backstripping and burial history modeling.

Regional horizon mapping facilitates the division of a complete basin fill succession into a series of depositional or tectonostratigraphic sequences. Structure maps and intervening isochron or depth converted isopach maps can then be used to establish the stratigraphic framework. Burial/thermal histories (often referred to as geohistory analysis) are supported by backstripping a seismic profile through gen-

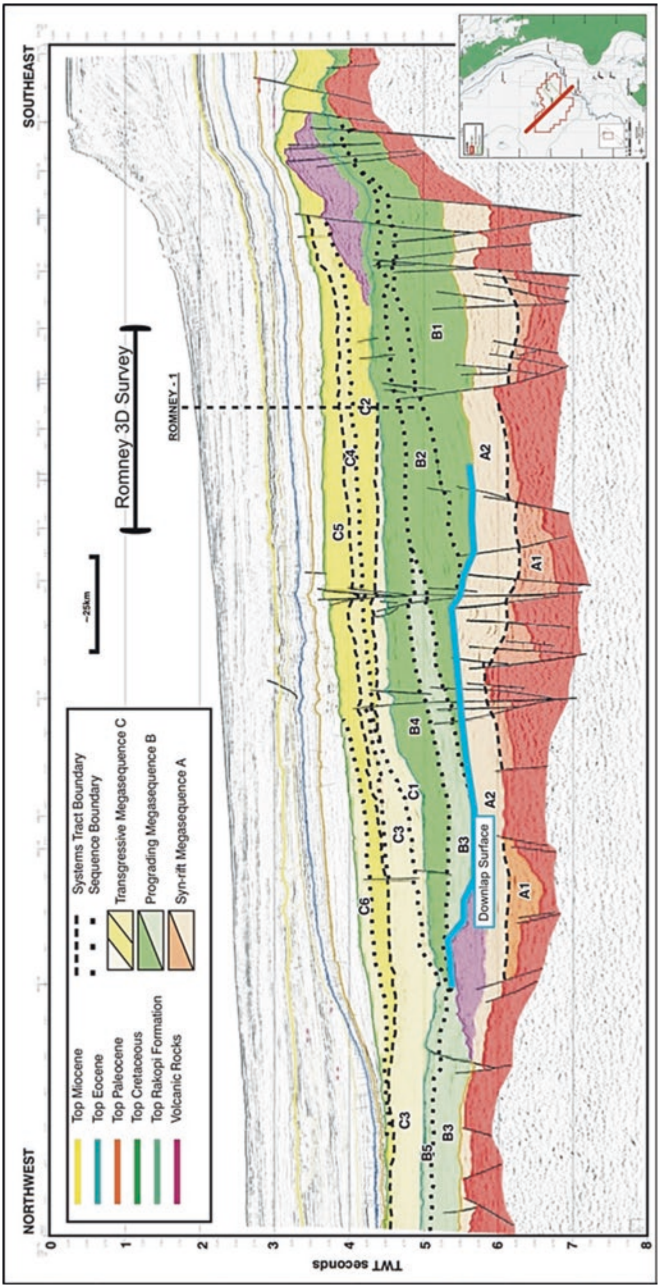

Fig. 3.11 Regional 2D seismic profile DTB01-17, deepwater Taranaki Basin. The progradational succession defined as seismic units B1-B4 represent the Taranaki Delta (Cretaceous). The regional downlap surface indicated in blue is a regionally mappable condensed section. The topsets within the Taranaki Delta (Rakopi Fm.) are a proven coal-rich Type II and Type II/III source in the basin. (Modified from Uruski et al. (2003) in Mahanay (2018))

eration of a series of flattened profiles of the individual depositional cycles. The basin fill history is then illustrated by “playing back” of those cycles in their order of deposition (Fig. 3.12). Such stratigraphic frameworks calibrated by 1D burial history models that incorporate time and heat flow data provide the context within which to evaluate source rock maturity and charge potential from the regional to the prospect scale (Fig. 3.13).

There is still the aspect of migration pathway. It is not uncommon to encounter a prospect where source rocks in the immediate vicinity are absent or immature. That does not directly condemn that prospect provided there is a migration pathway from an area of maturity, the source kitchen. Vertical migration along faults or lateral migration along carrier beds may link effective source to trap over distances of 10s of miles. In the case of rift basins such as those illustrated in Figs. 3.12 and 3.13, the effective source rocks are located in deeper half grabens adjacent to the structural highs with migration along the bounding fault planes. Seismic imaging continues to be greatly improved and provides critical input toward the evaluation of source and charge (Fig. 3.14).

There are specific features that can be identified on both 2D and 3D seismic data that are defined as Direct Hydrocarbon Indicators (DHIs). The recognition of DHIs is generally accepted as an indicator of an active petroleum system even though there may be limited or no direct data regarding source presence or maturity (Fig. 3.15). Local bright spots throughout shallow seismic intervals are one type of DHI. These typically indicate local gas accumulations. There are caveats regarding their interpretation as they may be associated with pockets of shallow biogenic gas which says little or nothing about deeper thermogenic hydrocarbon systems. Shallow bright spots in overpressured regimes may pose drilling hazards when related to shallow sands that are gas charged. High-resolution site survey mapping of these play a critical role in selection of final drilling locations.

Another category of DHIs linked to migration from deeper source areas and more likely to be associated with thermogenic gas are gas chimneys and gas clouds. These appear as vertical or irregular areas of seismic disruption in profile (Fig. 3.15b, c). The surface expressions of gas chimneys are commonly seen as local collapse features or pock marks on seafloor images in map view. Seismic *flat spots* that appear to cut across folded strata are generated by the impedance contrast at the hydrocarbon-water contact within a hydrocarbon charged structure. The recognition of DHIs on seismic profiles and in plan view is taken as indirect evidence that there is an active petroleum system somewhere in the basin fill succession.

A related attribute that can be key to prospect identification is “*amplitude fit to structure*.” These are generally observed as high amplitude responses to low impedance conditions attributed to the presence of hydrocarbons in porous sandstone or limestone intervals, particularly gas relative to oil or water. This is observed as an updip increase in amplitude in profile and the downdip “shut-off” of amplitude along a particular structure contour in map view (Fig. 3.16). That shut off generally reflects the impedance contrast at the gas-water or gas oil contact. The interpreter must exercise caution when relying on the amplitude response due to the fact that even a small amount of gas in the pore space (~5% gas saturation) can result in a robust amplitude anomaly.

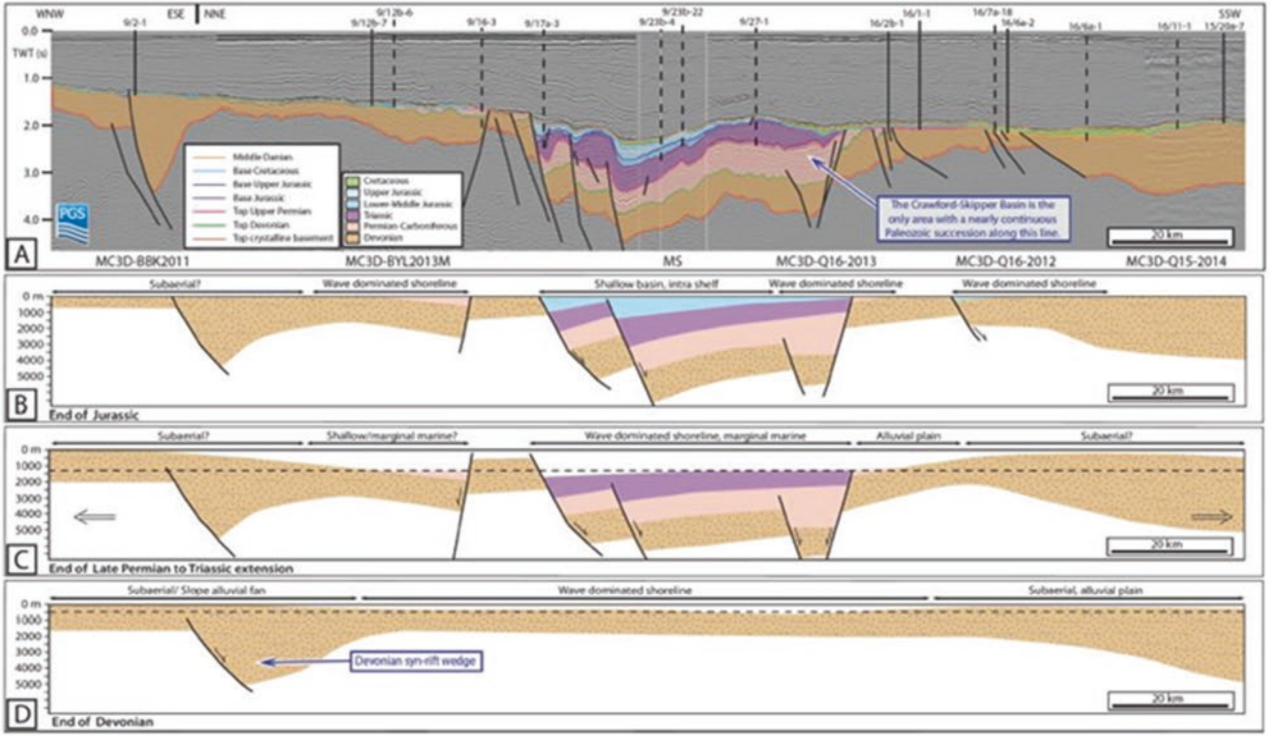

Fig. 3.12 Interpreted regional profile with three time steps illustrating its structural evolution. (**a**) Present day interpreted profile, (**b**) End of Jurassic, (**c**) End of Later Permian to Triassic extension, (**d**) End of Devonian. (Patruno and Reid 2016b)

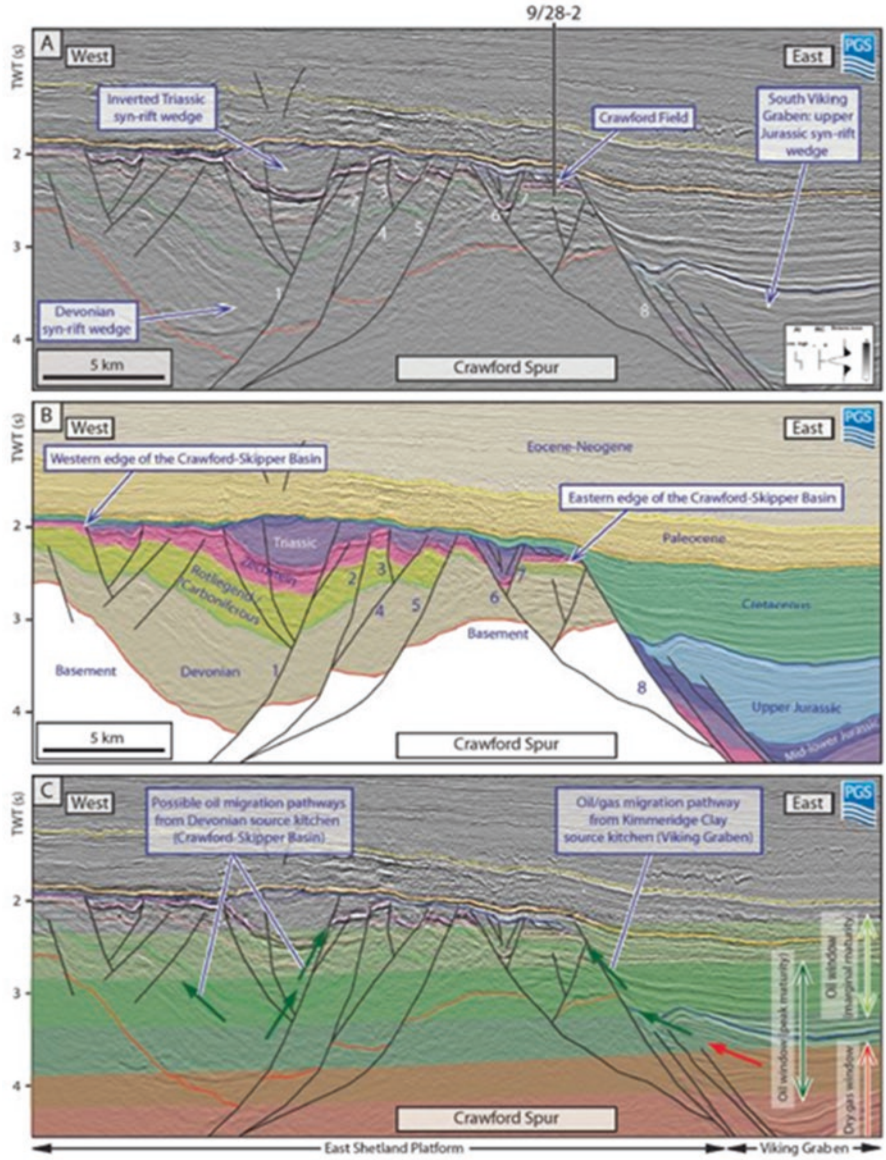

Fig. 3.13 (**a**) Interpreted seismic profile, (**b**) geoseismic section, and (**c**) profile with overlay of hydrocarbon maturation windows and potential migration pathways indicated. (Patruno and Reid 2016b)

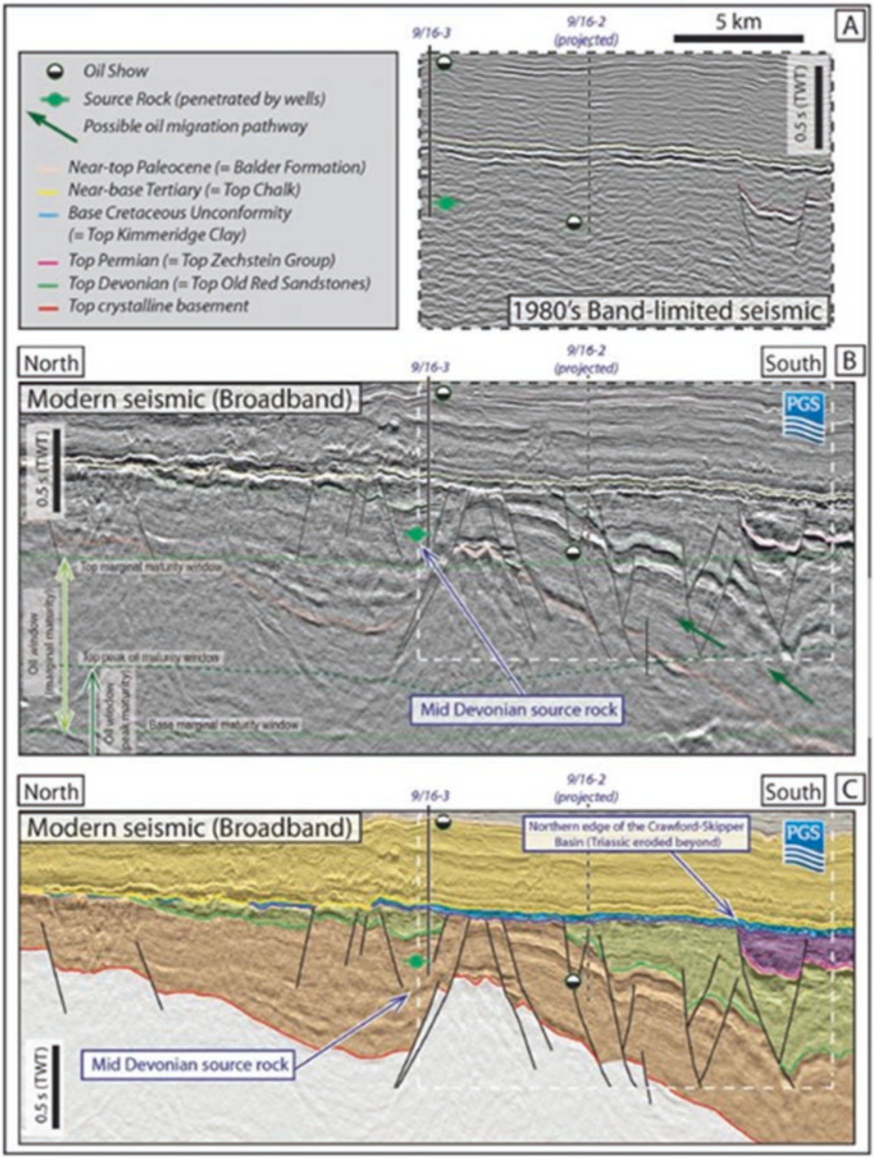

Fig. 3.14 Illustration of improved image quality and its impact on interpretation of hydrocarbon charge. (**a**) Conventional seismic line acquired in 1986, (**b**) Modern GeoStreamer, broadband profile. Green dashed lines indicate oil maturity window, (**c**) Overlay of geological interpretation. (Patruno 2017, Patruno and Reid 2016a)

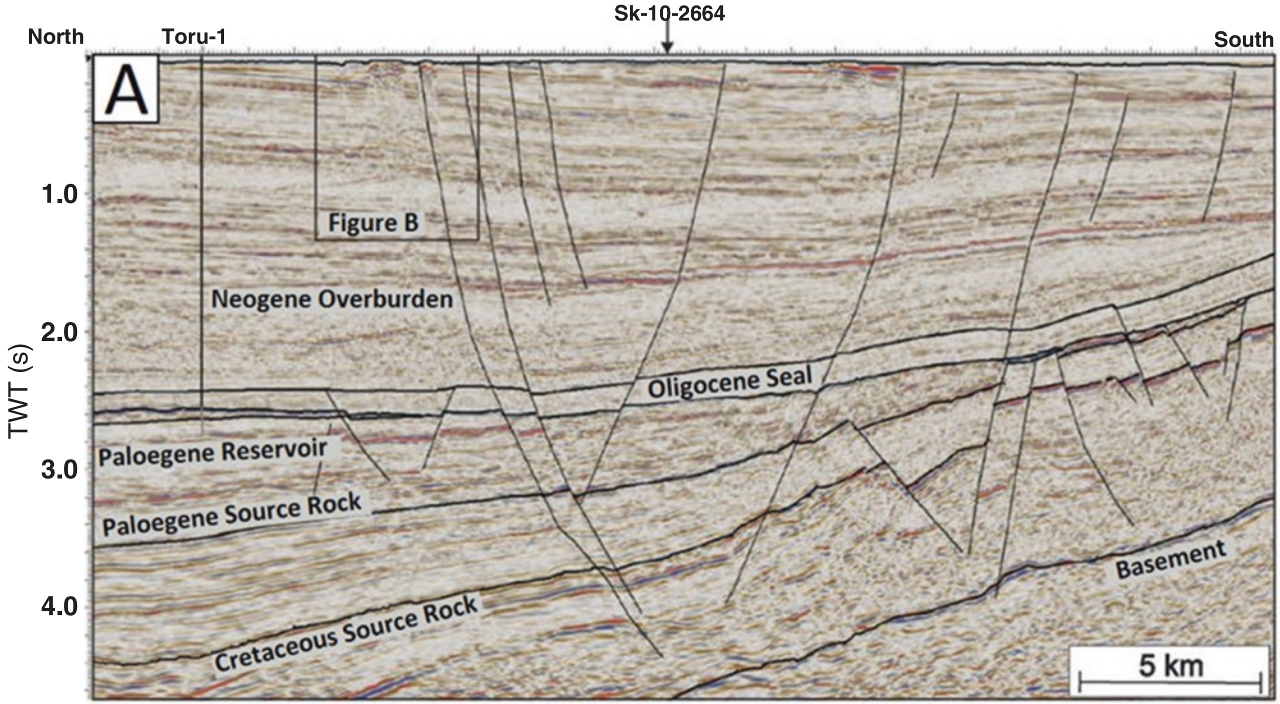

Fig. 3.15 Examples of Direct Hydrocarbon Indicators (DHI) exhibited on seismic profiles from a 3D survey, offshore New Zealand. (**a**) Regional line illustrating the relations between late-stage faults with source, reservoir, and seal. Some faults are sealing, others are leaking. (**b**) Detail of bright spots and gas chimneys adjacent to a leaky fault. (**c**) Gas chimney linked to a young fault that reaches the seafloor. (Modified from Ilg et al., AAPG (2012). Reprinted by permission of the AAPG whose permission is required for further use)

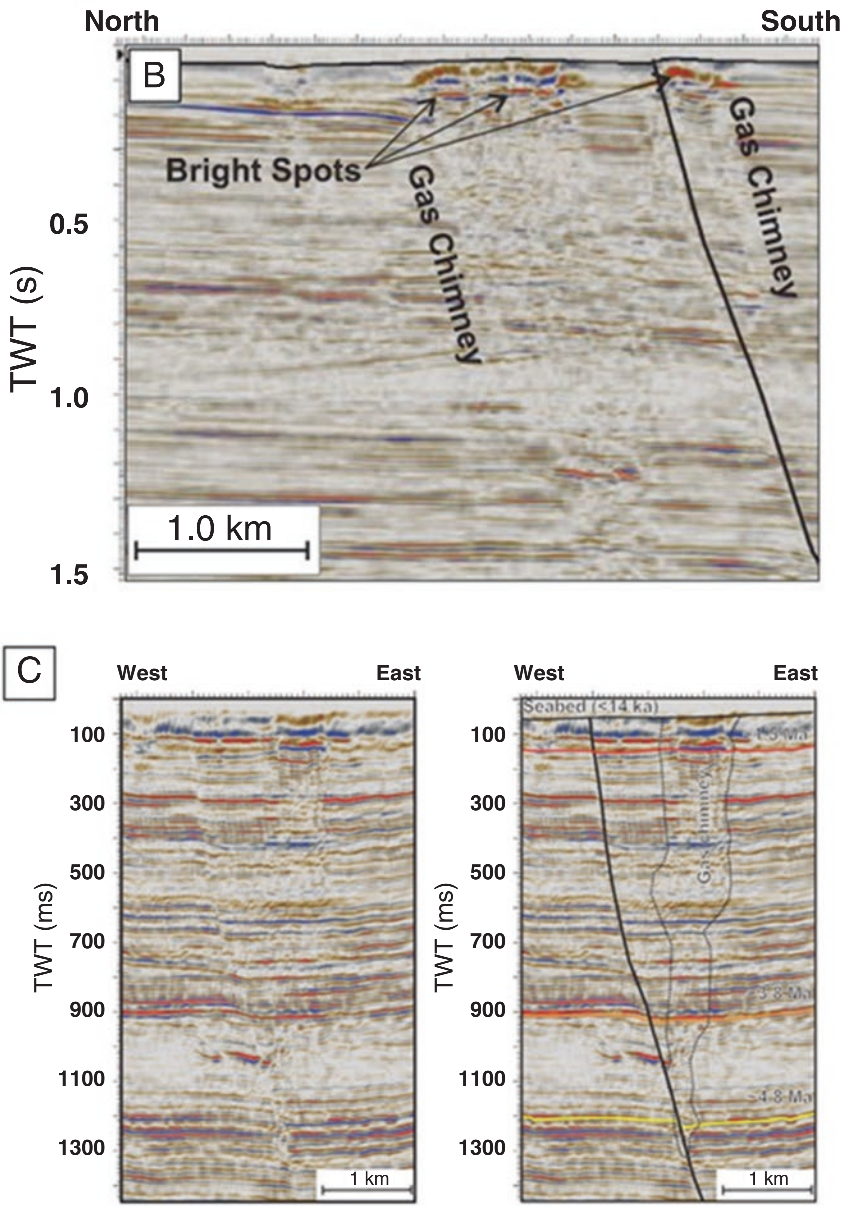

Fig. 3.15 (continued)

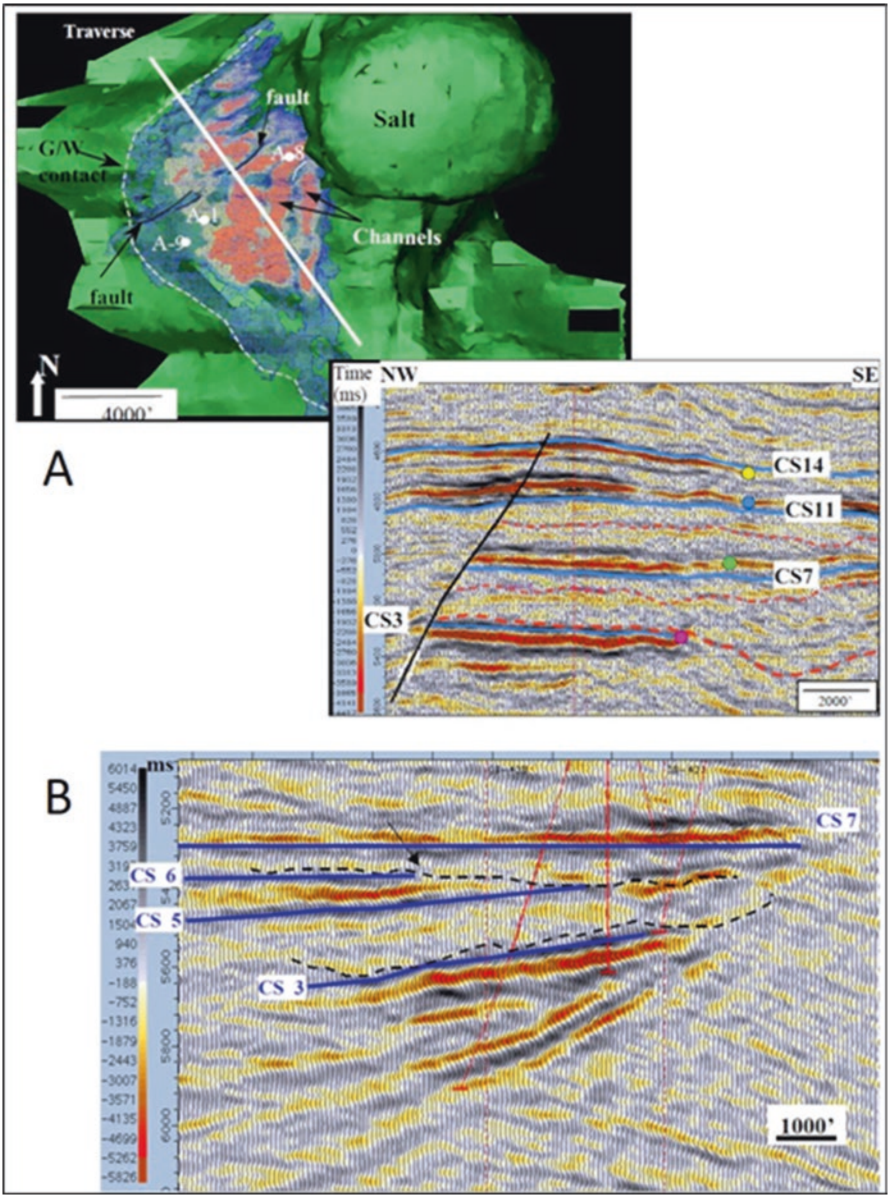

Fig. 3.16 Auger Field deepwater Gulf of Mexico. (**a**) Three-dimensional view of the Gulf of Mexico Auger Dome Field and "O" sand reservoir. Note the gas/water contact downdip. (**b**) Dip profile through Auger field flattened on C7 illustrating updip increase in amplitude. (Modified from Dean et al., GCSSEPM (2002). Reprinted by permission of the GCSSEPM whose permission is required for further use)

Reservoir Presence and Effectiveness

The recognition of potential reservoir intervals and sand-rich facies has been greatly enhanced with the development of the seismic data set. As previously discussed, the use of seismic was originally developed to image subsurface structure in support of hydrocarbon trap identification. The use of seismic in the interpretation of regional stratigraphy and its internal depositional systems advanced in the 1970s with the publication of AAPG Memoir 26 (Payton 1977). The application of seismic stratigraphy and seismic facies analysis has become standard methods in the prediction of gross depositional environments such as fluvial/coastal plain, shore zone/deltaic, carbonate platform, shelf, and slope/basin systems. Recognition and mapping of these depositional systems sets the context to predict their internal reservoir facies. These predictions have been improved as seismic geomorphology and attribute analysis have evolved in the last 30 years. Modern high-resolution data and associated attributes are now commonly applied to the imaging of individual reservoir bodies and internal flow units within producing fields.

Mitchum and others (1977) provided the first systematic review of the stratigraphic interpretation of seismic reflection patterns in depositional sequences. The technique focuses on reflection terminations that establish stratigraphic boundaries used to define depositional sequences and the internal reflection configuration within those sequences that reflect stratigraphic continuity, geometry, and lithology as an indicator of depositional setting (Tables 3.2 and 3.3, Fig. 3.17). They defined seismic facies analysis as "*...the description and geologic interpretation of seismic reflection parameters, including configuration, continuity, amplitude, frequency, and interval velocity*" (Mitchum et al. 1977). Seismic facies analysis of clastic depositional systems was further described by Sangree and Widmier (1977). Bubb and Hatlelid (1977) outlined a procedure for the seismic recognition of carbonate buildups based on external boundary outline and internal seismic facies changes. Examples of common seismic facies descriptions include: (1) high amplitude, high continuity intervals suggesting periods of sustained, and organized deposition such as open marine shelf or back-reef carbonate platform settings. (2) Variable amplitude, variable continuity suggesting a more complex depositional organization exhibiting greater lateral variability. Such facies may be interpreted as dip elongate fluvial channel and overbank or submarine channel and overbank complexes or shore zone/deltaic complexes in a strike elongate orientation relative to the paleo shoreline. (3) Mounded, internally chaotic with variable amplitude facies. The interpretation of mounded facies (like the others) depends on the geologic context. Mounded, chaotic facies near the toe of slope generally reflect slump and gravity mass transport complexes. Those at the margin of a carbonate platform suggest carbonate build-ups such as reefs, bioherms, or shoals. (4) Mounded, variable to high continuity, variable to high amplitude facies at the toe of slope or basin floor may be interpreted as organized submarine fan complexes. The recognition and mapping of seismic facies and their lateral relation to other facies has become an effective tool in paleogeographic reconstructions. Those reconstructions

Table 3.2 Seismic facies parameters: reflection terminations, reflection configuration, and external form

Reflection terminations (at sequence boundaries)	Reflection configurations (within sequences)		External forms (of sequences and seismic facies units)
Lapout	*Principal stratal configuration*		
Baselap	*Parallel*		*Sheet*
Onlap	*Subparallel*		*Sheet drape*
Downlap	*Divergent*		*Wedge*
Toplap	*Prograding clinoforms*		*Bank*
Truncation	Sigmoid		*Lens*
Erosional	Oblique		*Mound*
Structural	Complex sigmoid-oblique		*Fill*
Concordance	Shingled		
(No termination)	Hummocky clinoform		
	Chaotic		
	Reflection free		
	Modifying terms		
	Even	Hummocky	
	Wavy	Lenticular	
	Regular	Disrupted	
	Irregular	Contorted	
	Uniform		
	Variable		

Mitchum et al., in Payton, AAPG (1977). Reprinted by permission of the AAPG whose permission is required for further use

Table 3.3 Seismic facies parameters and their geologic significance

Seismic facies parameters	Geologic interpretation
Reflection configuration	Bedding patterns
	Depositional process
	Erosion and paleotopography
	Fluid contacts
Reflection continuity	Bedding continuity
	Depositional process
Reflection amplitude	Velocity – density contrast
	Bed spacing
	Fluid contact
Reflection frequency	Bed thickness
	Fluid content
Interval velocity	Estimation of lithology
	Estimation of porosity
	Fluid content
External form and areal association of seismic facies units	Gross depositional environment
	Sediment source
	Geologic setting

Modified from Mitchum et al., in Payton, AAPG (1977). Reprinted by permission of the AAPG whose permission is required for further use

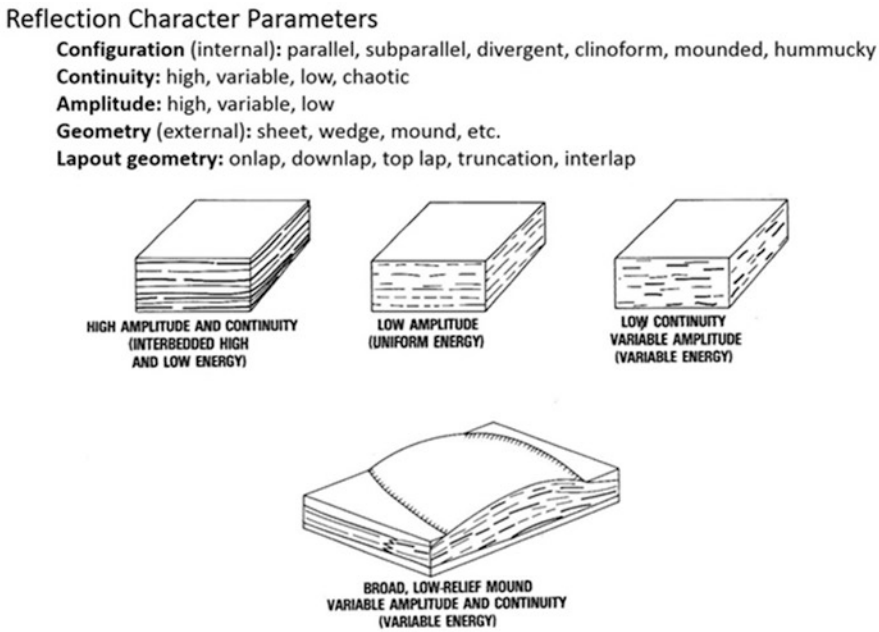

Fig. 3.17 Seismic facies parameters and description. (Modified from Sangree and Widmier in Payton, AAPG (1977). Reprinted by permission of the AAPG whose permission is required for further use)

provide the framework within which to predict the lateral distribution of reservoir and source facies (Fig. 3.18).

Interpretation of seismic geomorphology has evolved as an extension of seismic facies analysis and takes the combination of external geometry and internal facies to a greater degree of sophistication. It has found particular application to the evaluation of Mesozoic and Cenozoic slope and basin depositional systems that have not undergone deep burial and related compaction (Weimer and Link 1991; Posamentier 2004). Select deepwater depositional elements are easily recognized by their seismic geomorphology.

As an example, channel/levee overbank systems are recognized by their "gull wing" seismic geometry (Fig. 3.19a). The flanking gull wings taper away from the channel axis and record proximal to distal, finer grained, thin bedded, levee/overbank deposits. The central channel fill typically exhibits variable to high amplitude with chaotic to variable continuity. These may contain a significant amount of sand but tend to be fairly heterolithic and thus commonly exhibit a high degree of reservoir compartmentalization. There is potential for related sand-rich, layered to amalgamated sheet deposits in the underlying High Amplitude Reflection Packages (HARP) facies. These record the initial ponded sheet deposits at a breached levee, avulsion point (Fig. 3.19b).

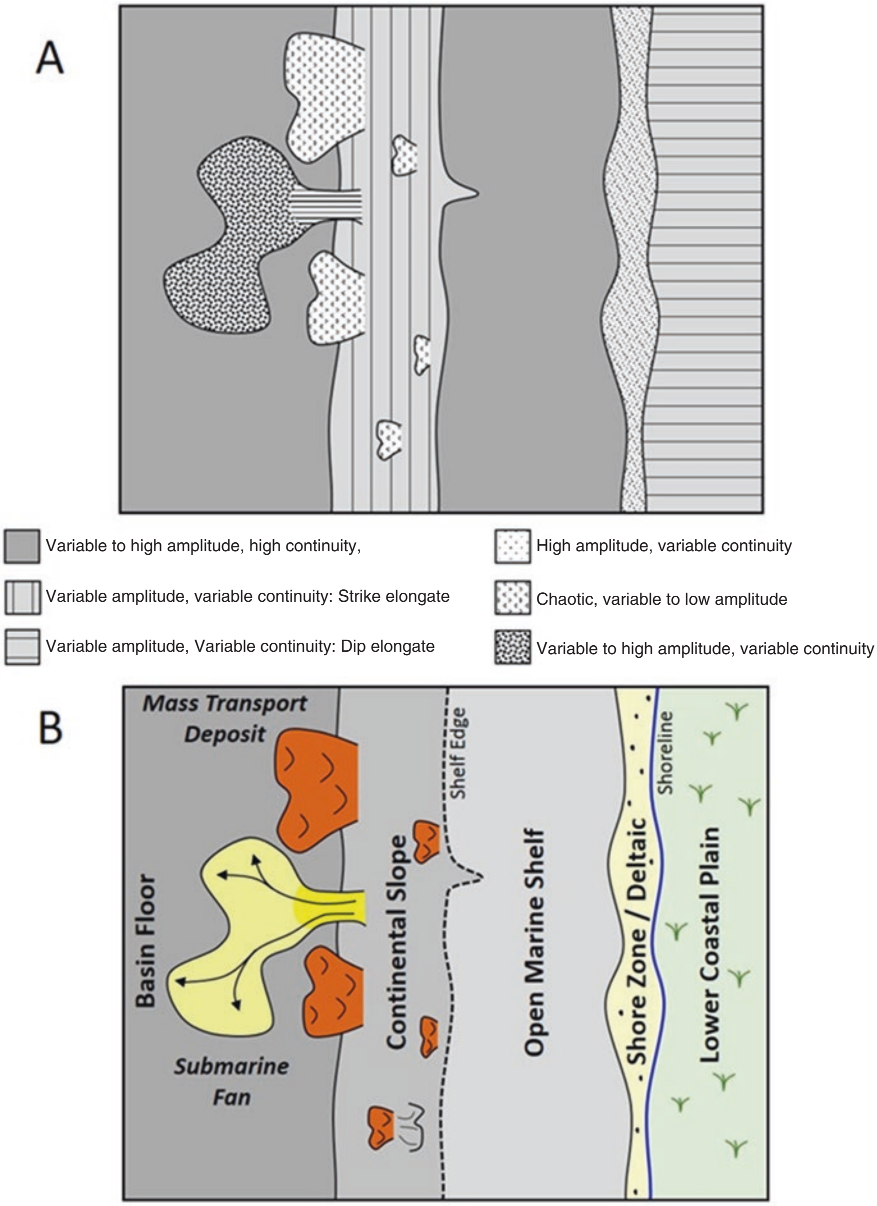

Fig. 3.18 Map view of seismic facies and paleogeographic maps. (**a**) Schematic diagram illustrating a seismic facies map. (**b**) Resulting paleogeographic reconstruction

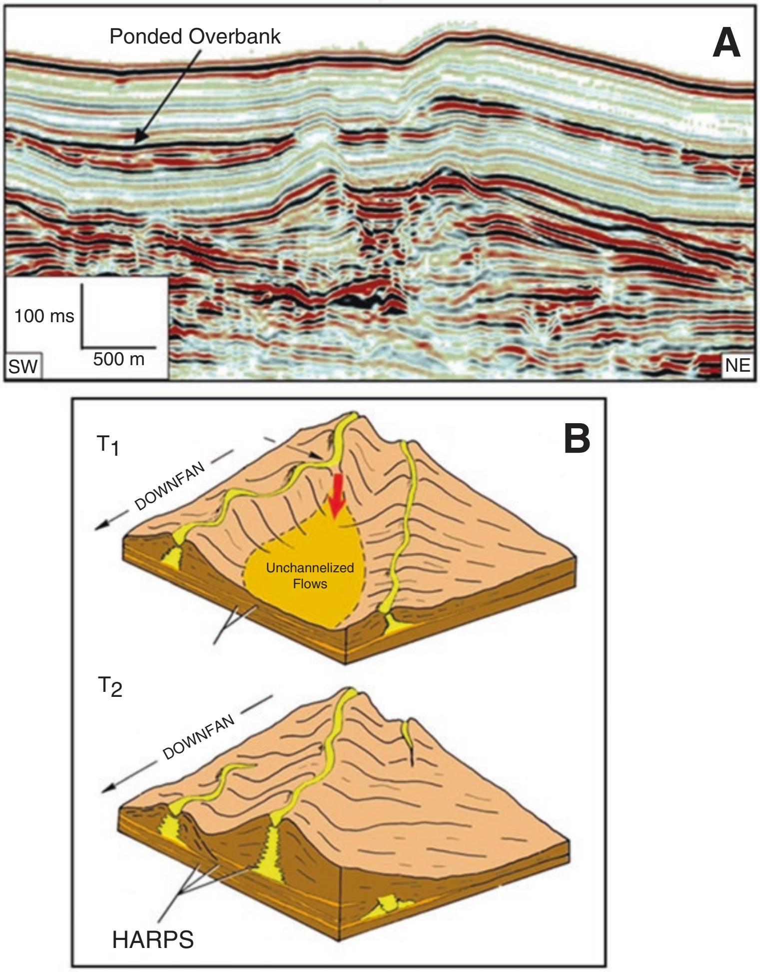

Fig. 3.19 Channle/levee complex offshore Brunei. (**a**) Seismic geomorphology of a shallow channel/levee “gullwing” geometry (McGilvery and Cook 2003). (**b**) Depositional model illustrating the evolution of channel/levee and associated High Amplitude Reflection Package (HARP). (Modified from Damuth et al. 1995)

One of the primary reservoir targets in deepwater plays are sand-rich submarine fan, lobe deposits. These generally exhibit mounded, bidirectional downlap external geometries (Fig. 3.20). The degree of mounding may be suppressed by compaction or by their deposition as a healing phase infilling of existing paleo bathymetry. They commonly exhibit high amplitude, variable continuity grading down system to more continuous internal seismic facies. This lateral gradation reflects the transition from updip distributary channel and overbank sheet dominated proximal fan down to frontal splay, amalgamated to layered sheet dominated lower fan deposits.

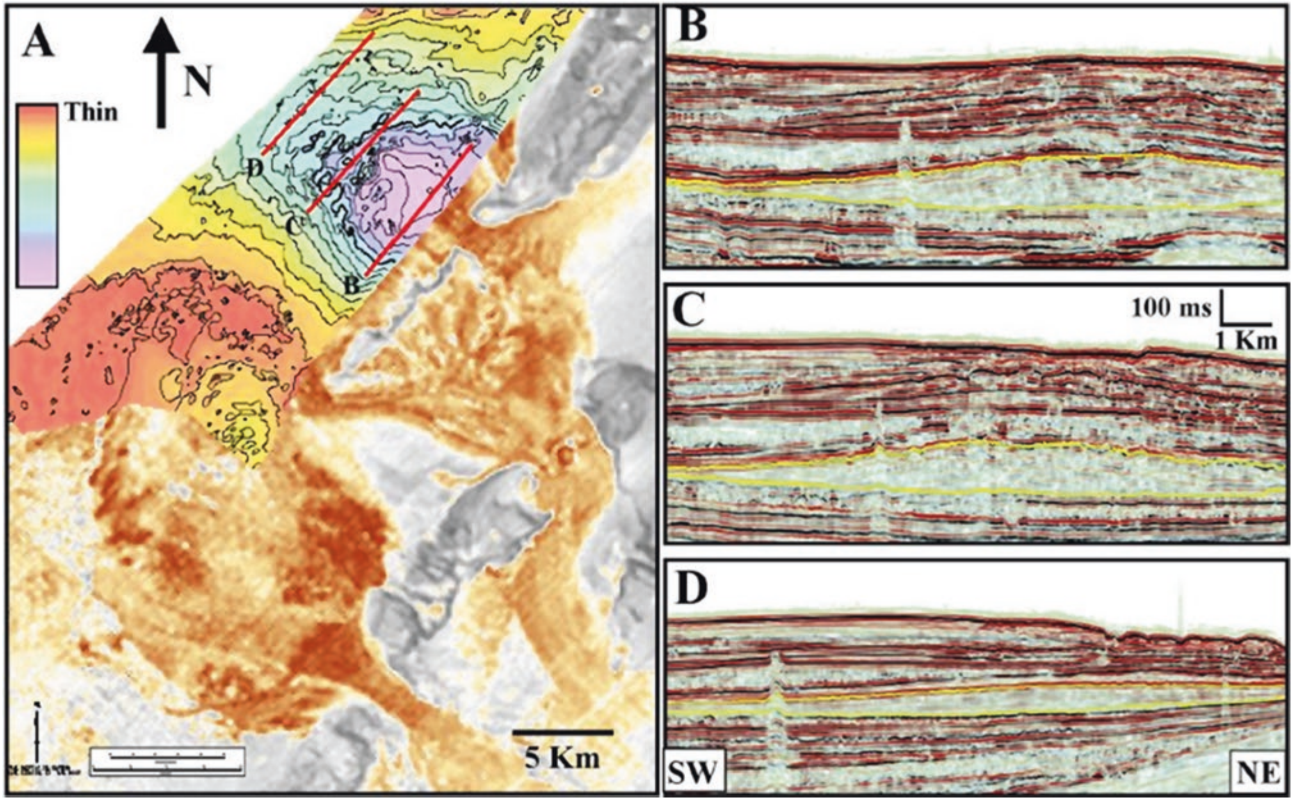

Fig. 3.20 Submarine fan complex offshore Brunei. (**a**) Time thickness between yellow horizons displayed on water bottom amplitude map. (**b–d**) A series of proximal to distal profiles illustrating basinward thinning and increase in internal continuity within a submarine fan complex. (McGilvery and Cook, GCSSEPM (2003). Reprinted by permission of the GCSSEPM whose permission is required for further use)

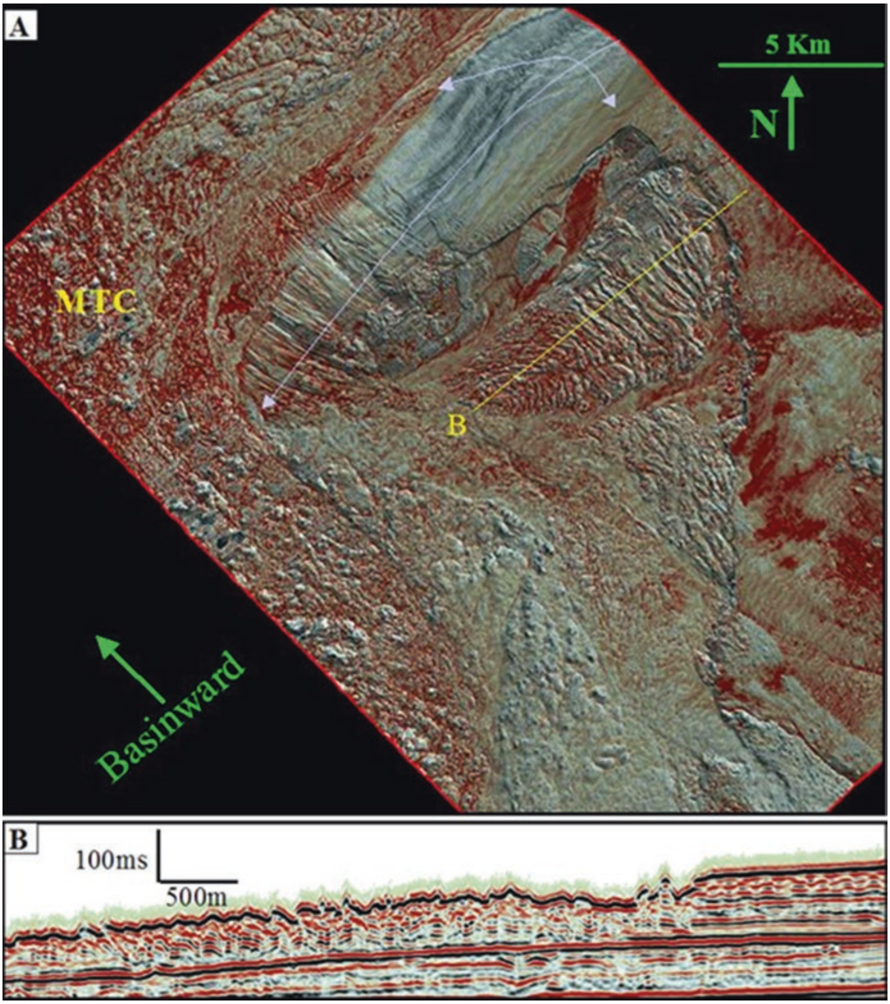

Fig. 3.21 Deepwater slump complex offshore Brunei. (**a**) 3D perspective view from above; seafloor structure with max positive amplitude overlay illustrating a cohesive slump complex. Note the series of pressure ridges oriented perpendicular to flow within the complex in contrast to the hummocky surface on the adjacent mass transport complex. (**b**) Oblique dip profile through the cohesive slump complex. Note the imbricate thrusts within the feature. (McGilvery et al., GCSSEPM (2004). Reprinted by permission of the GCSSEPM whose permission is required for further use)

Mounded, chaotic seismic facies are ubiquitous across the continental slope to basin floor. These reflect down slope mass movement that exhibits varying degrees of internal disaggregation related to distance of movement or amount of fluidization. Compare Fig. 3.21 as an example of a local cohesive slump complex with a limited distance of transport to Fig. 3.22 as an example of a long distance, regional

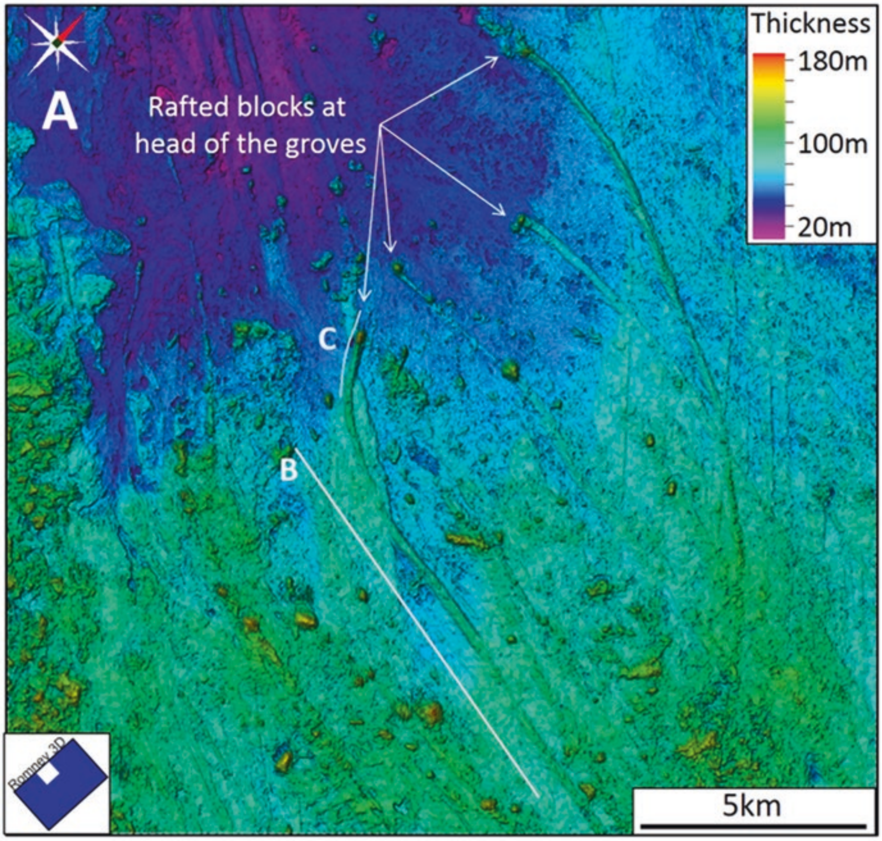

Fig. 3.22 Details of a mass transport complex offshore Taranaki Basin New Zealand. (**a**) Interval thickness map of the red-to-yellow interval shown on seismic profile (part **b**) illustrating lateral variability of thickness punctuated by linear thicks reflecting infill of basal grooves along a regional mass transport deposit. (**b**). Seismic profile documenting a series of mass transport complexes in the shallow subsurface defined by the internally chaotic seismic character. (**c**) Profile through a transported block within the mass transport deposit overlain by organized "healing phase" deposits identified by high amplitude, continuous seismic facies. (Rusconi 2018)

mass transport complex (MTC) with a substantial degree of internal disaggregation. Large internal cohesive blocks commonly generate long distance drag marks and grooves along the underlying substrate during transport.

Seismic geomorphology is a power tool in the interpretation of depositional elements and their internal facies. Proper identification of these elements provides the context within which to predict reservoir presence, reservoir body geometry, and their potential degree of stratigraphic compartmentalization. An understanding of these characteristics is key to the prediction of reservoir presence and the determination of potential in-place hydrocarbons as well as the effectiveness that these reservoirs may be drained.

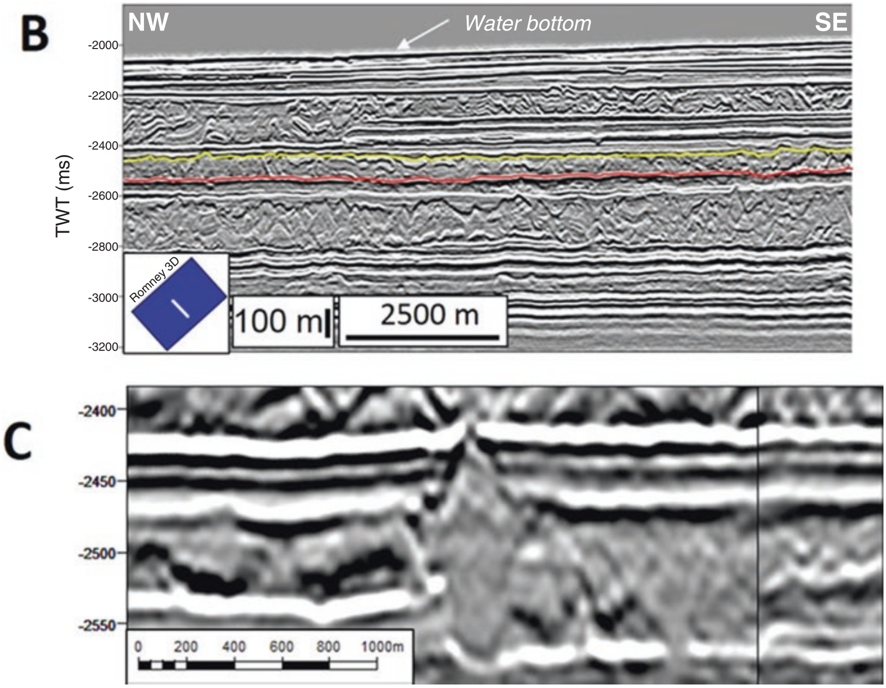

Fig. 3.22 (continued)

Imaging of depositional elements in plan view and identification of potential sand-rich reservoir facies they may contain have been advanced by the display of seismic attributes along mapped horizons, time slices and/or proportional slices. Attributes such as amplitude, sweetness, coherency, and dip azimuth that respond to impedance contrast and waveform variation are effective tools that can illuminate stratigraphic edges as well as internal lithologic variation (Barnes 2016).

Horizon- or interval-based attribute analysis is ideal when dealing with complex geological settings such as fluvial or deepwater channel systems that typically consist of rapidly changing facies and lithologies. As a result, associated seismic responses are equally as complex and commonly display variable amplitude, variable to low continuity facies making detailed seismic mapping difficult. Figure 3.23 illustrates a technique applied to such facies through an aggradational fluvial coastal plain succession offshore Louisiana (Zeng 2007). There are few mappable horizons through these data yet usable amplitude extractions can be generated from proportional slices generated relative to adjacent mappable surfaces above and below the zone of interest. The composite channel margins become apparent as well as potentially sand-rich channel fill facies. An integrated interpretation based on several attributes may illustrate a greater amount of detail. Figure 3.24 provides a comparison of coherency, amplitude, and sweetness co-rendered with semblance through a

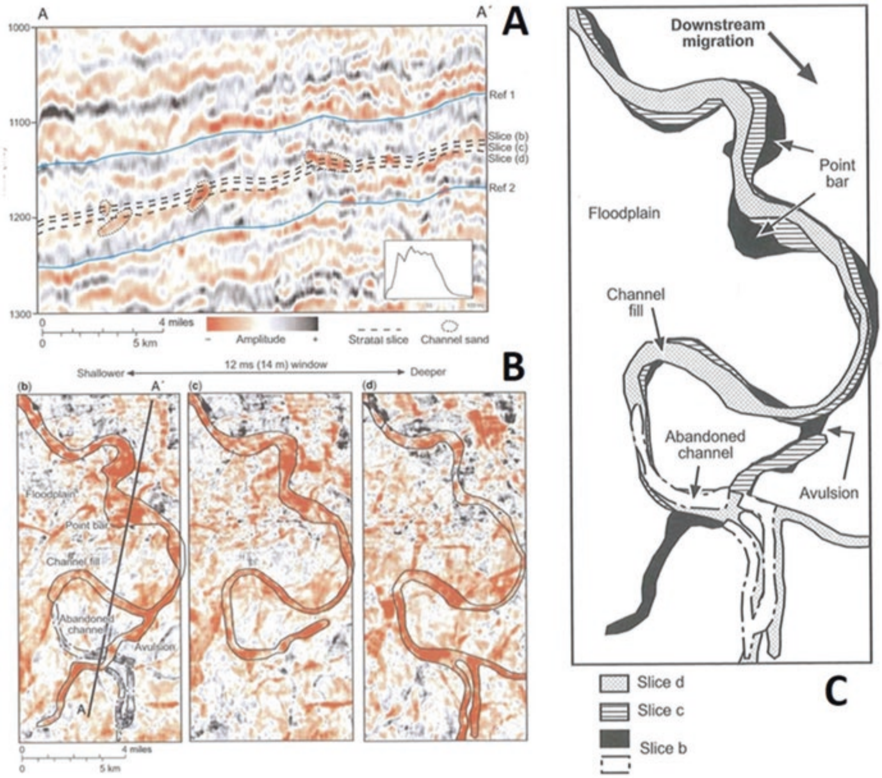

Fig. 3.23 Use of proportional slices to define fluvial channel complexes. (**a**) Seismic profile with two readily mappable reference horizons above and below the target interval, Ref 1 and Ref 2. Slices b, c, d are three proportional slices generated relative to these reference horizons. (**b**) A series of parallel slices through the single story channel fill. (**c**) Composite geological interpretation of a complex channel fill and adjacent overbank. (Zeng 2007)

deepwater channel complex. The coherency attribute is most effective in distinguishing channel margins while internal variations in lithology are better imaged with amplitude and sweetness.

Given that the seismic response is driven by the impedance contrast at bed boundaries and along lateral facies changes, lower net:gross intervals tend to display a greater degree of seismic stratigraphic character in comparison to very sand-rich or mud-rich intervals lacking abundant internal impedance contrasts. As such, depositional elements are more easily recognized in low net:gross intervals but there must be caution in predicting the amount of sand-rich facies. It must also be noted that a wildcat discovery may be a reasonable outcome in these well imaged, low net:gross cases, but the degree of stratigraphic compartmentalization may

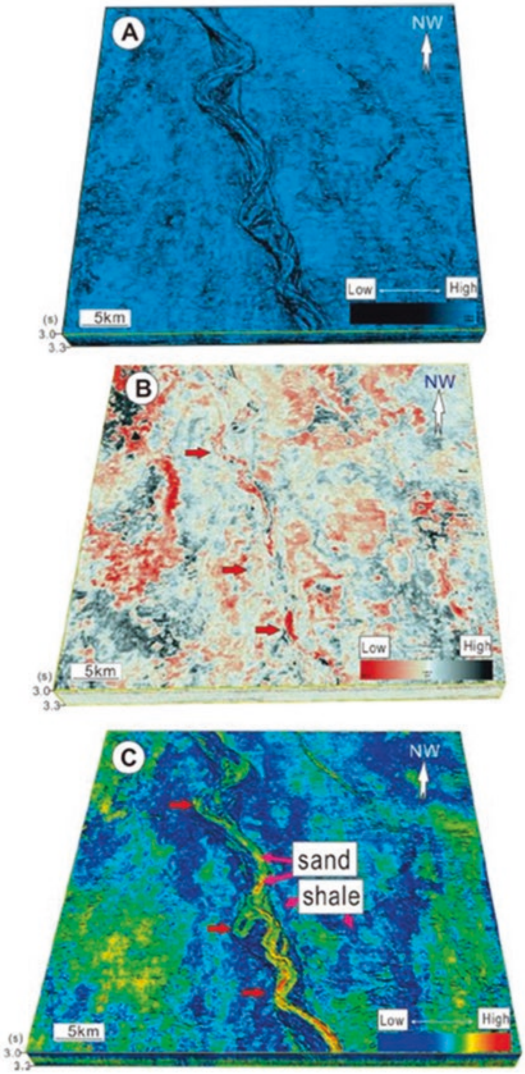

Fig. 3.24 Three slices through various representations of the Romney 3D volume (offshore New Zealand) at a time of 3.0 s. (**a**) Coherency cube slice. Channel margins are distinguishable from sedimentary features by their linearity and arc-shaped effects. (**b**) Slice through an amplitude volume. Some channels are detectable. (**c**) An equivalent slice that co-renders sweetness (in color) and semblance (in grayscale). The margins of the channels are more clearly defined by the semblance attribute, and the variations in sweetness suggest variations in the lithologies of the channel fills. (Li et al. 2017)

require a number of development wells that render that discovery non-commercial. The point of this discussion is to illustrate the fact that detailed stratigraphic interpretations and predictions of reservoir presence and potential degree of compartmentalization can be effectively interpreted with detailed horizon mapping, seismic facies classification, and attribute analysis.

Trap Geometry

Trap geometry is the petroleum systems element that defines the shape and size of the container for hydrocarbon accumulations. The size of that container calculated as area under structural closure, along with column height, is a critical aspect in determination of potential in-place hydrocarbon volumes. Tectonic setting and related structural style define the trap geometries that might be encountered, such as horst blocks and half grabens bounded by extensional normal faults in rift basins, imbricated thrust faults and folds in foreland basins, and complex structures along salt and welded margins in salt basins (Figs. 3.1, 3.2 and 3.3). Generic trap geometries include: (1) simple four-way dip closure within anticlinal folds or compactional drape above resistant features at depth (e.g., half graben); (2) three-way dip against a fault plane, salt wall, or salt weld; (3) compound traps involving updip stratigraphic pinch outs. The seismic technique was first applied as a tool to define subsurface structure in its beginnings in the 1920s. Interpretation of complex trap geometries has been greatly advanced with development of 3D seismic acquisition, processing, and visualization techniques. It is now possible to display complex structural interpretations in 3D space which allows for visual rotation and the interrogation of structural relationships that otherwise would be invisible in simple plan view or on 2D vertical profiles.

Advances in seismic imaging and seismic attribute analysis have improved the detection and imaging of fault planes and related structures. Prestack time and depth migration with improved velocity analysis tools optimizes focus on steep and/or discontinuous geologic features, and, recently, multiple reflections have been included in imaging algorithms, rather than treated as noise to be removed before migration. Attributes such as coherency, dip-azimuth, and curvature illuminate fault planes in plan view to a greater degree than observed on traditional amplitude volumes (Barnes 2016). These attributes accentuate edges by detecting rapid lateral changes in waveform across faults, salt welds, etc.

Advances in acquisition and processing have led to substantial improvements in structural imaging. This is particularly true in dealing with complex structures that are positioned along the flanks or beneath allochthonous salt canopies such as those in the Gulf of Mexico Basin (Figs. 3.25 and 3.26). The development of long offset, wide azimuth, data has increased the lateral resolution of seismic data to better image features below salt overhangs. Multistage, iterative processing (salt flood, sediment flood) has enhanced imaging of the base salt reflector along salt canopies. These techniques help to improve the resolution of the updip limit of relatively steep subsalt structures where steep dips and proximity to salt can obscure that portion of the image.

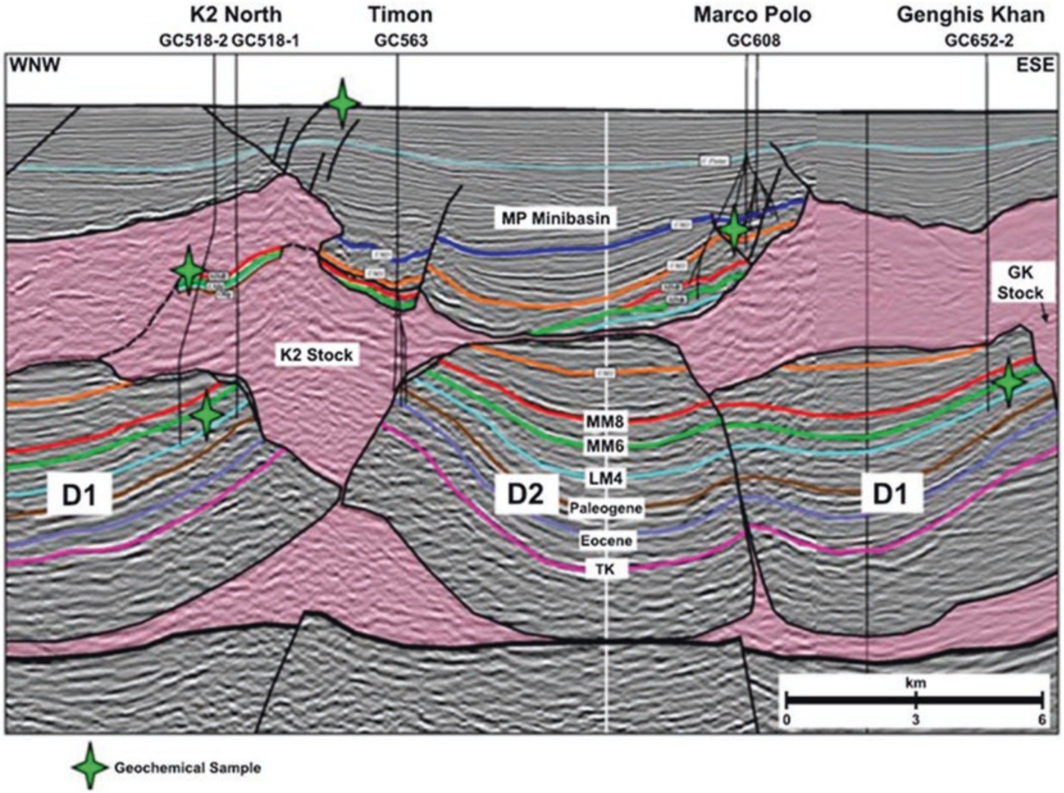

Fig. 3.25 Regional seismic profile across a series of fields in the subsalt structural play in southern Green Canyon Gulf of Mexico Basin. (Weimer et al., AAPG (2017) from Mount et al. (2007). Reprinted by permission of the AAPG whose permission is required for further use)

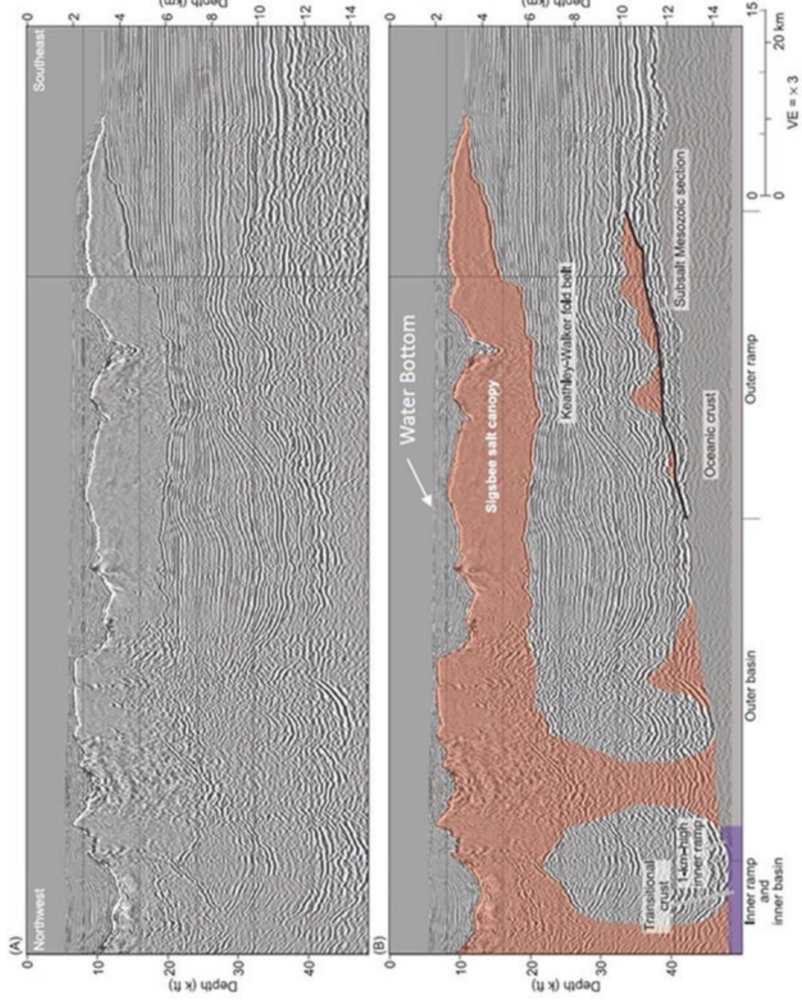

Fig. 3.26 Regional seismic NW-SE profile across western Walker Ridge protraction area offshore Gulf of Mexico Basin. Good quality image of both supra salt and subsalt structure. (**a**) Uninterpreted, (**b**) interpreted. (Hudec et al., AAPG (2013) seismic courtesy of CGGVeritas. Reprinted by permission of the AAPG whose permission is required for further use)

Seal

An effective seal in conjunction with trap geometry is required to establish a viable container for hydrocarbon accumulations. Seal capacity combined with structural relief is a major control on the hydrocarbon column height that may be sustained within a closed structure. The element of seal is classified in three general categories: (1) top seal, (2) side seal, and (3) mechanical or pressure seal. Seismic data can be used as an indirect indicator of potential seals based on regional stratigraphic mapping and local structural interpretation. Seismic may also indicate a weak or blown seal by imaging gas clouds or gas chimneys.

Effective top seals are typically defined by regionally mappable stratigraphic units that consist of low permeability, claystones, mudstones, and shales. Basic correlation and mapping of such intervals confirmed by well tie during the initial exploration mapping phase can support the prediction of a potential top seal. Top seal capacity generally diminishes with increasing silt, sand, or carbonate content which can result in an increase in permeability or brittleness (susceptibility to fracture), in particular along the crest of tight folds or narrow and high relief structures where the potential of increased fracturing is enhanced. Gas clouds indicated by irregularly shaped, chaotic to low amplitude seismic facies that are positional over the crest of a potential trap may be an indicator of a leaky or failed top seal. Side seal is a lateral component typically involving three-way dip closure against a fault, salt, or salt weld. The effectiveness of fault seal is related to two factors: cross fault juxtaposition against non-reservoir lithologies and the permeability of the gouge zone along the fault plane itself. Side seal may fail if the reservoir target interval is juxtaposed against porous and permeable lithologies across a fault required for lateral closure. As with top seal, basic correlation and horizon mapping can be applied to evaluate cross fault juxtaposition. An updip increase in negative amplitude toward a fault offset is commonly an indicator of trapped hydrocarbons (particularly gas) against an effective fault or salt seal (Fig. 3.16). Seismic data can provide negative evidence for the sealing capacity of a fault plane or salt wall or weld suggested by a gas cloud concentrated along the fault plane or at the fault tip above the structure of interest (Fig. 3.15). Mechanical or pressure seal is a much more complex issue that generally relies on well data and other pressure-related information. Seismic data can still play a role in mechanical seal evaluation regarding structural relief and the fluid pressure fetch area that might support over pressured conditions. Extremely high relief and steep structures such as those encountered in salt withdrawal mini basins are susceptible to mechanical seal failure, "blown traps." Traditional structure mapping techniques can be applied to provide information regarding these two contributing factors to mechanical seal effectiveness.

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Chapter 4
Seismic Interpretation in Petroleum Development

Abstract Seismic interpretation plays a critical role in the appraisal and development of discovered hydrocarbon accumulations. Interpretation of individual flow units within a producing field are emphasized with the goal of maximizing fluid recovery. High resolution horizon mapping, horizon slice, and time slice interpretation are effective tools in the evaluation of reservoir complexity. Analysis of seismic attributes associated with these horizons adds additional detail related to reservoir complexity. Internal reservoir elements on the order of meters in thickness and 10's of meters in lateral dimension can be readily imaged on today's high-resolution 3D seismic data. Time-lapse (4D) seismic interpretation can be used to detect temporal variations in fluid saturation, pressure differentials, and rock properties. This approach lends itself to definition of bypassed pay and/or evaluation of sweep efficiency of fluid injection during secondary and tertiary recovery efforts. The seismic method has recently expanded into development of unconventional reservoirs. Use of prestack elastic inversion is an effective technique to estimate rock properties that reflect brittleness and the "fracability" of potential self-sourcing intervals. High resolution seismic data are key to well placement in conventional wells and geosteering of long reach horizontal wells in unconventional plays.

Keywords Appraisal · Brittleness · Cross fault communication · Development drilling · Field development · Flow units · Fracability · Horizontal drilling · Multistage frac · Seismic monitoring

Appraisal

Use of seismic attribute analysis goes well beyond prediction of reservoir presence during exploration. Appraisal drilling following a discovery is designed to develop a more informed estimation of the expected hydrocarbon volumes as well

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as a more accurate interpretation of the geological complexity of that accumulation. The additional well control establishes the hydrocarbon water contacts and degree of compartmentalization within the field. Accurate interpretation of these contacts defines the hydrocarbon column height which combined with the trap geometry provides a more precise estimation of the container volume. The occurrence of multiple hydrocarbon water contacts suggests a greater degree of structural and stratigraphic compartmentalization. Comparison of pressure data between wells may identify additional internal complexities. Pressure differentials may be due to poorly imaged or subseismic faults or stratigraphic edges within the reservoir interval. The goal of the appraisal phase is to define an in-place and recoverable volume estimation, a development drilling program to exploit those volumes, and design facilities required to produce and move those hydrocarbons. The appraisal evaluation supported by seismic interpretation is key to the decision process directed at a commercial, "go forward" decision on field development.

Seismic data calibrated with increased well control and engineering data can play a key role in field development. It is essential to define individual flow units and reservoir compartments that reflect stratigraphic or structural complexity within the overall field during the appraisal and early development phases. Many of the standard techniques applied in the exploration phase are effective during the development phase. However, during development the emphasis is on a much narrower interval and in some cases down to mapping every reflector across the field area. The Athabasca oil sands in Alberta Canada (L. Cretaceous McMurry Fm.) are an excellent example of this technique applied to a major hydrocarbon accumulation under advanced development with the use of steam injection. In this case the evolution of the steam chamber and the movement of the heavy oil that is mobilized is greatly influenced by stratigraphic architecture. The reservoir interval is a laterally extensive sand-rich fluvial deposit at a depth of 250–400 m. The external architecture is a fairly evenly distributed, tabular reservoir interval on the order of 80–100 m in thickness. It consists of a complex array of internal flow units related to individual fluvial point bar and channel features that are on the order of 20–30 m in thickness. Individual flow units have been imaged with the use of a time slice taken from a 3D amplitude volume just below the top of the reservoir interval (Fig. 4.1). Bandwidth is in the range of 8–220 Hz and the vertical resolution is on the order of 5 m (Hubbard et al. 2011). Seismic images integrated with log response and core-based sedimentology play a critical role in understanding the very local flow vectors within the field. This is an excellent example of the application of seismic interpretation in the late stage of field production in comparison to the early, exploration stage prediction of potential reservoir facies illustrated in Figs. 3.23 and 3.24.

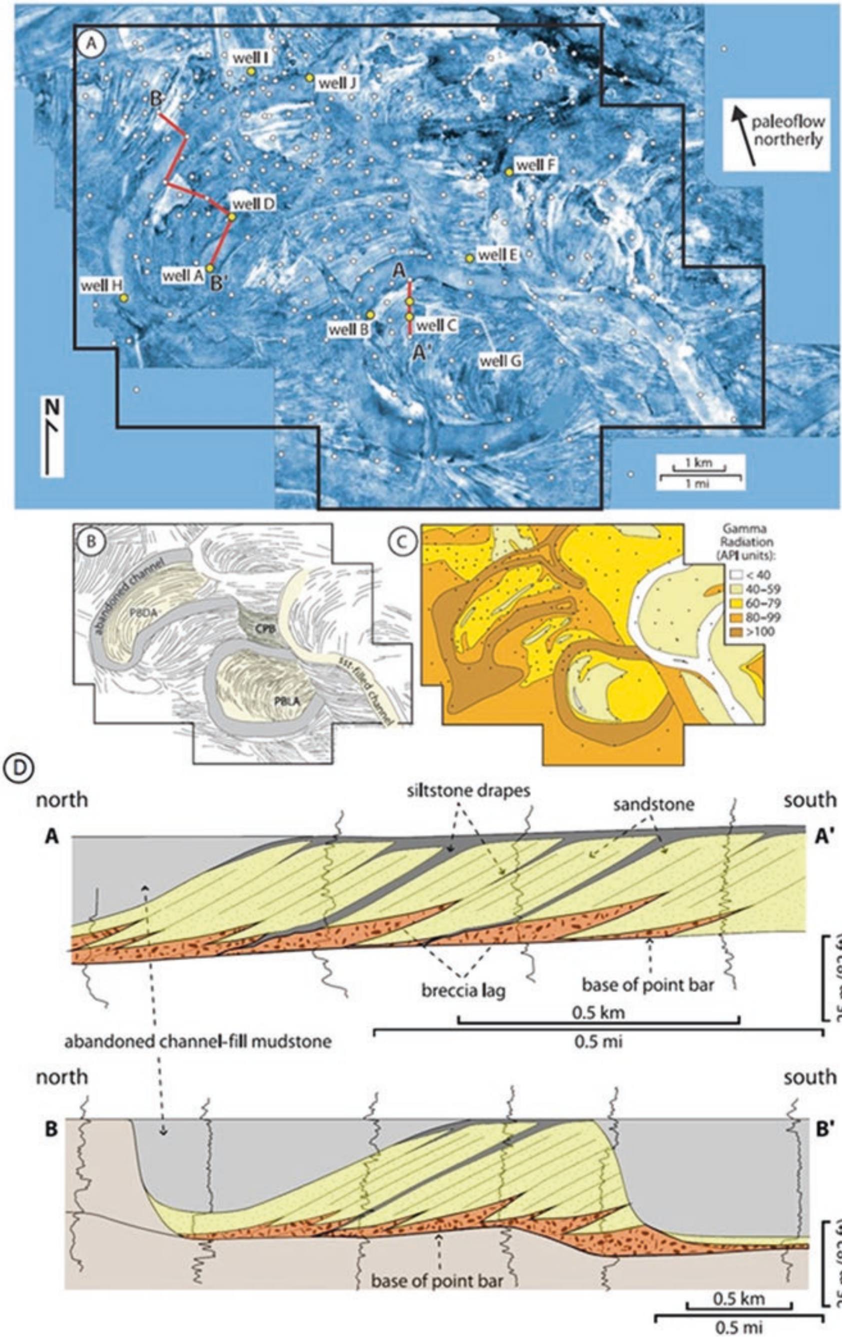

Fig. 4.1 Internal flow unit definition within a heavy oil producing unit in the L. Cretaceous, McMurray Fm. (**a**) Seismic time slice through the interval of interest. (**b**) Traced line drawing of the main features observed in panel A including Point Bar Lateral Accretion (PBLA), Point Bar Downstream Accretion (PBDA), and Counter Point Bar (CPB). (**c**) Gamma-radiation map in API units measured from individual well logs. (**d**) Stratigraphic cross sections through channel and point bar deposits, locations shown in (a). (Modified from Hubbard et al., AAPG, 2011. Reprinted by permission of the AAPG whose permission is required for further use)

Time-Lapse (4D) Seismic

Integration of seismic, well, and engineering data by multidisciplinary teams facilitates the application of time lapse or "4D" seismic techniques as an effective approach to field management. There are seismically detectable changes related to variations in fluid saturation, pressure differentials, rock properties, etc. during the productive life of a field. These can be evaluated through the careful comparison of repeat seismic surveys shot across a producing field through time and can lead to definition of infill drilling opportunities or modification of fluid injection programs that can increase the expected ultimate recovery (EUR) of that field. A good understanding of cross fault communication and sweep efficiency are critical factors in optimizing the recovery from a producing reservoir. Indications of bypassed pay within isolated fault compartments may be identified by variations in amplitude response to pressure differentials or variations in fluid content through time.

The Snorre Field in the northern North Sea produces from the Statfjord Formation and is undergoing water-alternating-gas (WAG) injection to increase oil recovery. Figure 4.2 is an amplitude difference map across the field that was generated from two 3D surveys; the first shot in 1983 and a second repeat survey shot in 1997 (Sverdrup et al. 2003). The two surveys were match-processed in order to minimize differences related to variations in acquisition. The map illustrates changes in percent reflectivity near the top reservoir interval. Orange reflects increased amplitude differential attributed to increased pressure and gas accumulation. Blue reflects lower amplitude differential attributed to pressure depletion and increased water saturation. Figure 4.3 illustrates the detailed fault pattern and the variation in relative amplitude within a portion of the field. The change in relative amplitude across the fault indicates limited cross fault communication. The local increase in amplitude indicates an area of increased gas accumulation. This case history is an excellent example of the application of seismic data to effective field development and improved recovery efficiency. Such techniques may be used to identify bypassed pay and redrills or recompletions that will yield additional volumes and increase overall recovery from maturing fields.

Unconventional Plays

The role of seismic data in field development has expanded with the evolution of unconventional play development. These plays generally involve self-sourcing, low permeability, organic-rich successions such as the Eagle Ford, Bakken, Woodford, and select intervals in the Permian of West Texas. In the past, many of these units have been strictly considered as source intervals that happen to contain a substantial amount of remnant in place hydrocarbons that did not migrate to conventional traps elsewhere. These remnant hydrocarbons correspond to the S1 peak on standard pyrolysis analyses. Access to substantial amounts of both gas and liquids has been

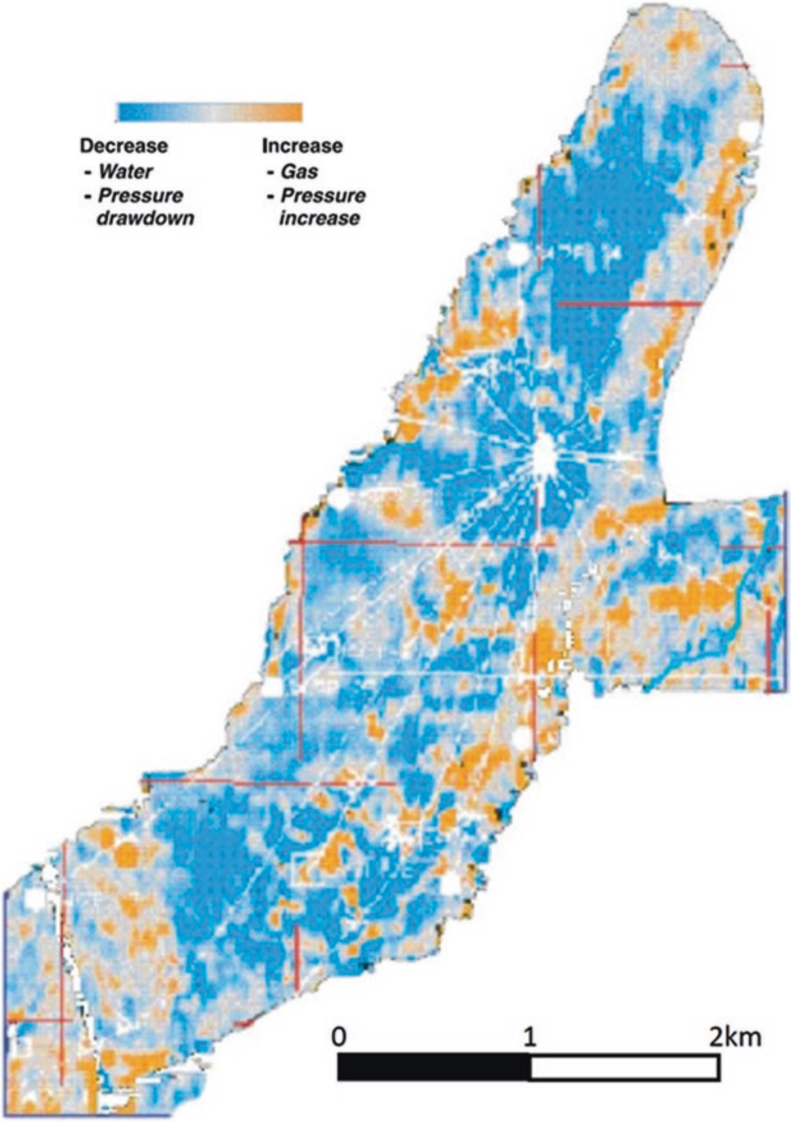

Fig. 4.2 Amplitude difference map between 3D seismic surveys shot in 1983 and 1997. The purpose was to delineate relative changes in reflectivity attributed to variations in pressure and fluid saturation through time. (Modified from Sverdrup et al., AAPG, 2003. Reprinted by permission of the AAPG whose permission is required for further use)

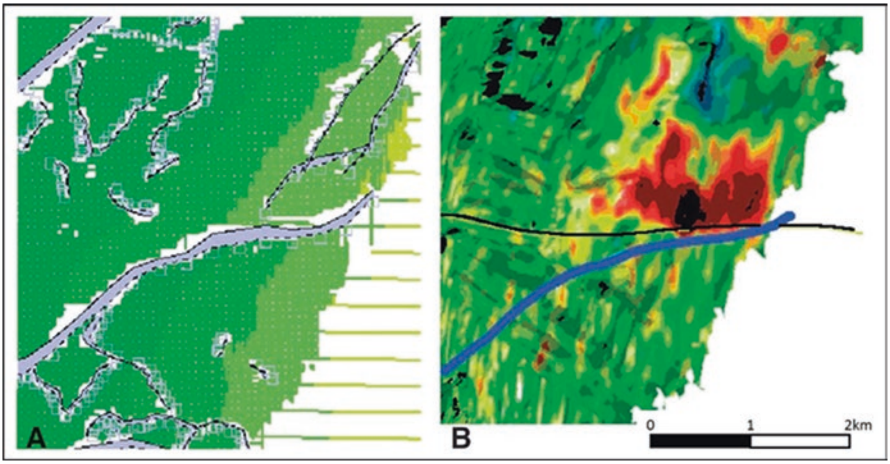

Fig. 4.3 (**a**) Fault map of the eastern fault block of the Snorre field. (**b**) Detail of relative amplitude changes across a major fault within the field (blue line). The black line represents the well path of a gas injector. The area of red-brown area reflects increased seismic amplitude attributed to a gas accumulation. (Modified from Sverdrup et al., 2003)

facilitated by new technologies involving horizontal drilling and multistage fracs. Placement of long horizontal well bores that can exceed one mile in length are crucial, both in terms of stratigraphic horizon and accessing the proper lithofacies within the reservoir. Given that these are very low permeability reservoirs, effective hydraulic stimulation is a critical element to their efficient development. A key criterion is the "fracability" of the target interval is related to gross lithofacies. Typical unconventional reservoirs are characterized by a substantial amount of organic material usually associated with ductile, clay-rich lithologies. In order to be an effective producing reservoir, these intervals require a certain degree of brittleness in order to support frac stimulation and receive effective amounts of proppant into open fractures under high pressure. Therefore, an understanding of the geomechanical rock properties is fundamental to defining prospective areas and targeting horizontal well bores. Local well data provides direct information regarding these properties from mechanical analysis of core samples along with conventional reservoir and acoustic properties derived from down hole measurements. Once again, the seismic data set provides the critical aspect of subregional data that fills in the gaps between local well data.

Seismic analysis can play an important role in economic production of unconventional resource plays through 3D high-resolution mapping of subtle faults that can require expensive horizontal well drilling remediation if encountered without planning, and by prestack elastic inversion to estimate rock properties that control brittleness and fracability. Calibrating prestack inversion results to microseismic, wireline, and core data generates a geomechanical earth model that can predict reservoir in situ stresses and be used to optimize horizontal well orientation for maximum production (Goodway et al. 2006; Sayers et al. 2016).

Select intervals within the Eagle Ford Shale of south Texas are characterized by organic and clay-rich horizons interbedded with thin carbonate layers (Fig. 4.4). This lithofacies provides the required organic richness for source along with the brittleness required for effective hydraulic fracturing. Lateral and vertical changes in this lithology have a substantial impact on the local performance of Eagle Ford production. Overall clay content increases to the northeast toward the regional clastic input source from the Woodbine Delta of East Texas (Fig. 4.4a). The clay content decreases to the southeast with a related increase in the proportion of carbonates (Fig. 4.4b). Given this, the fracability of the lower Eagle Ford increases to the southwest across the trend. Bodziac et al. (2014) demonstrated that changes in Young's modulus can be used as a proxy for brittleness to distinguish carbonated-rich vs. clay-rich Eagle Ford. They also demonstrated that Young's modulus cross plotted with density, inverted from the 3D seismic data, can be used to create a gross Eagle Ford mechanical facies, hydraulic fracability map (Fig. 4.5). A strike profile through the mechanical facies volume illustrates the trend from more carbonate-rich Eagle Ford on the southwest to more clay-rich Eagle Ford to the northeast. The integration of seismic, well log, core, and engineering data provided the input to generate the mechanical facies volume (Fig. 4.6) that was ultimately used to differentiate areas within the overall Eagle Ford trend on the basis of their mechanical properties (Bodziac et al. 2014). This had direct application to the development strategy in that portion of the play.

Seismic monitoring of hydraulic frac jobs, termed microseismic, has been available commercially since about 2000. When rock is fractured due to fluid pressure applied to perforations in the well bore, each fracture event is like a small earthquake. The size of a natural earthquake is measured by the Richter Magnitude Scale, a logarithmic measure of energy released. Destructive earthquakes are +5.5 or greater, a +2 can be slightly felt by some people, and hydraulic fracturing microseismic events are over 1000 times weaker still, between −1 and −3. It is a marvel of modern technology that such weak fracturing events can be detected. Microseismic events are monitored by sensors placed into shallow boreholes near the frac well. Data received in the well are processed to locate the microseismic event and estimate their magnitude. This data is plotted as a point cloud in a 3D interpretation system along with the well path, selected wireline logs, and 3D seismic data. Microseismic monitoring is real time and allows reservoir engineers to visualize efficiency and coverage of the frac job in a horizontal well. The hydraulic fractures are typically related to preexisting natural fracture systems and serve to open conduits for enhanced fluid flow from formation to well bore.

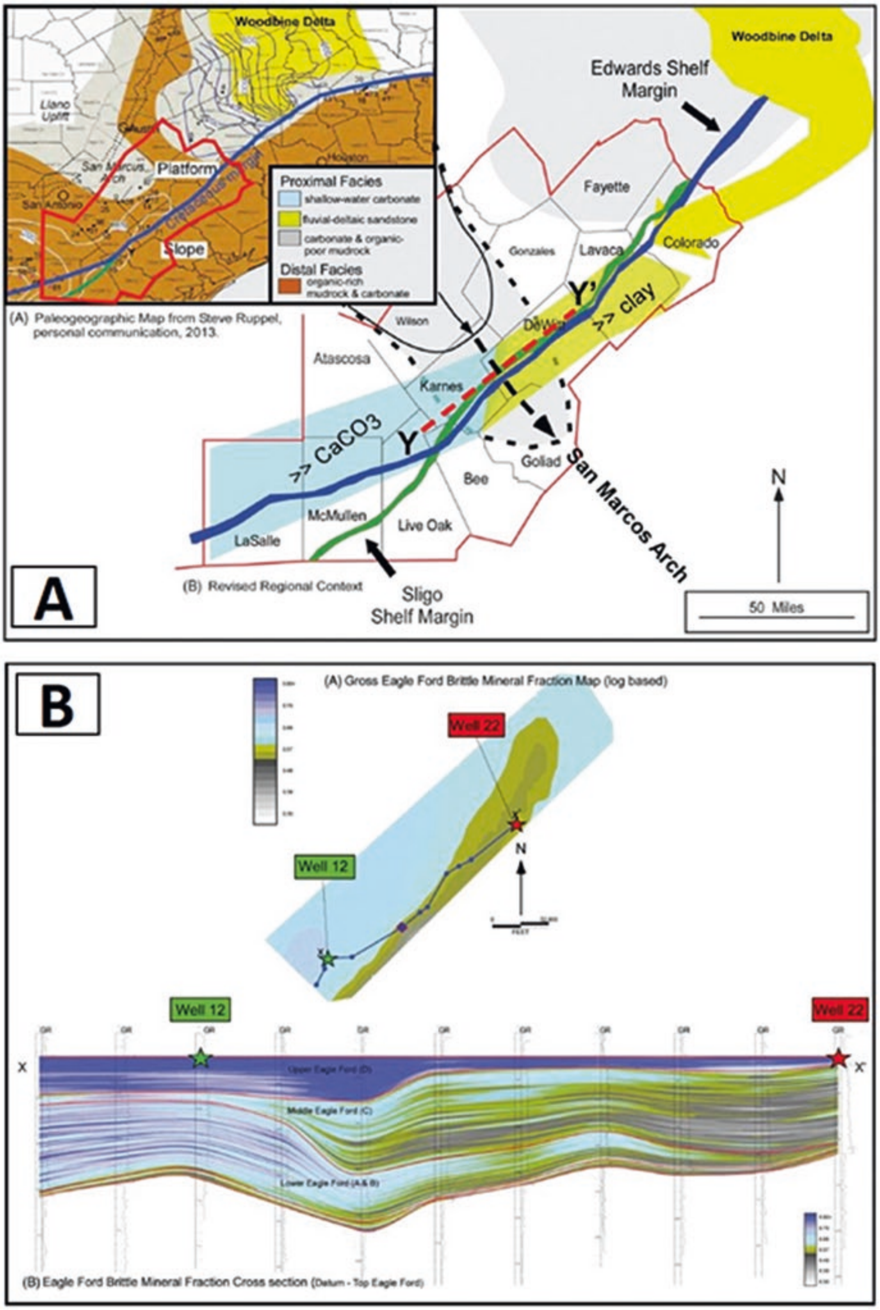

Fig. 4.4 (**a**) Paleogeographic map illustrating the southwest to northeast trend of carbonate-rich to clay-rich Eagle Ford toward the clastic sediment supply from the Woodbine Delta to the east. (**b**) Wireline derived brittle mineral fraction. Blue colors represent relative abundance of brittle minerals, brown and gray colors indicate ductile, clay minerals. (Modified from Bodziac et al., 2014)

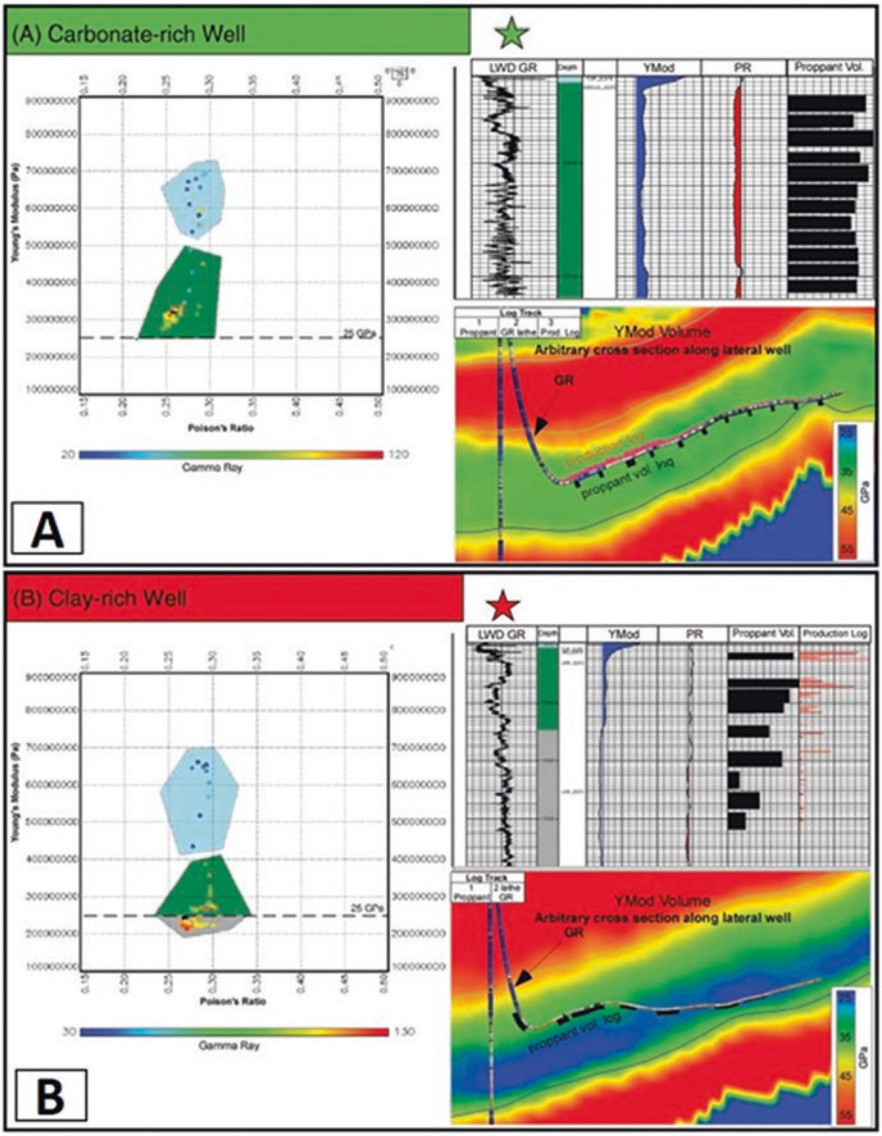

Fig. 4.5 Cross plots of seismically derived Young's modulus vs. Poisson's ratio for (**a**) carbonate-rich well 12 from the southwest and (**b**) clay-rich well 22 from the northeast. The gray shading in the depth track on the well logs differentiates relatively "low" brittleness from relatively "high" brittleness shaded in green and blue based on Young's modulus values greater than 25 GPa. (Modified from Bodziac et al., AAPG, 2014. Reprinted by permission of the AAPG whose permission is required for further use)

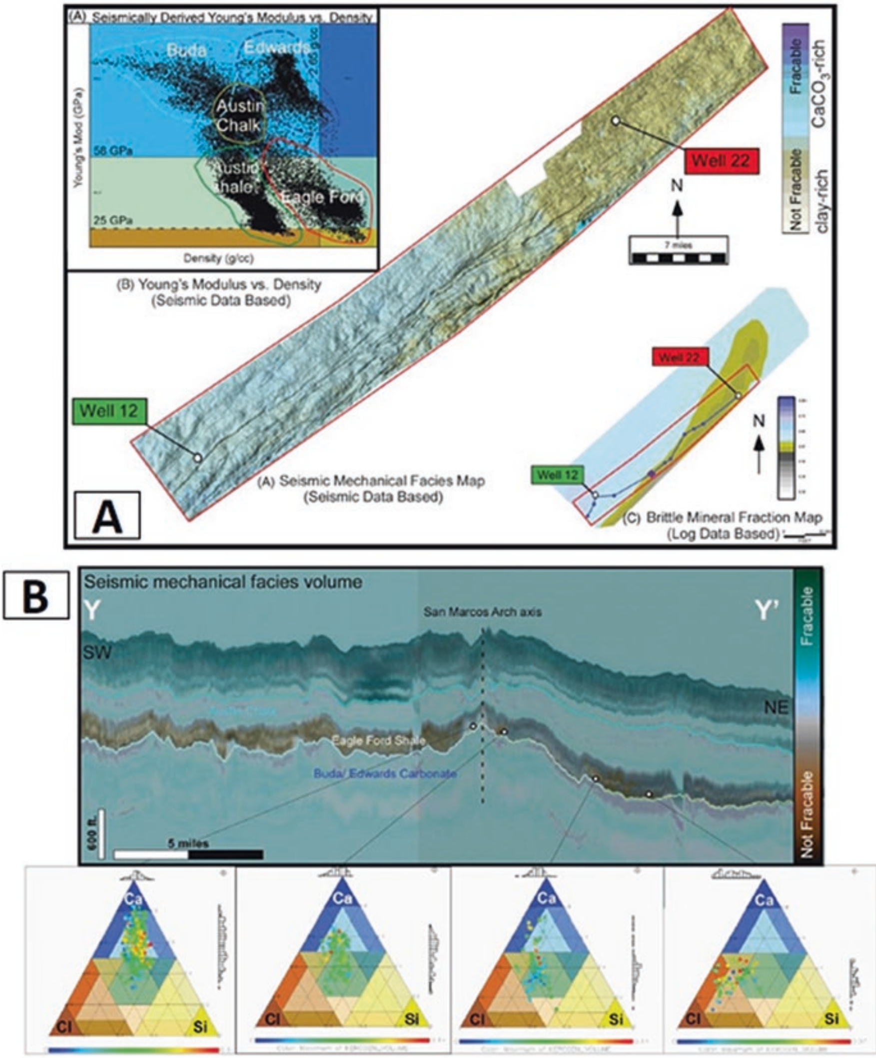

Fig. 4.6 (**a**) Gross Eagle Ford mechanical facies hydraulic fracability map projected onto the base reservoir horizon connecting wells 12 and 22. The seismic mechanical map was created based on the cross plot of seismically derived Young's modulus and density shown in the upper left. (**b**) Seismic strike profile through the mechanical facies volume. Lighter blue colors indicate the brittle facies (more carbonate-rich) and darker brown colors indicate the more ductile (clay-rich) facies. Ternary plots show log-derived mineralogy for selected wells along the section, which also show the trend toward more clay-rich Eagle Ford to the northeast. (Modified from Bodziac et al., AAPG, 2014. Reprinted by permission of the AAPG whose permission is required for further use)

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Chapter 5
Summary

Geophysics is used to estimate subsurface geology and rock properties from measurement of gravity, electromagnetic, and seismic fields at the earth's surface. The seismic data set was intially developed as 2D tool to image subsurface structure and trap geometry. It has evolved into a 3D tool with application to all aspects of the petroleum system. Its current use is expanding to include characterization of the geomechanical properties of traget horizons in unconventional plays. Reflection seismic data, in particular, has evolved from crude beginnings in the early 1900s to the primary imaging technology used in the modern search for hydrocarbons. The process of seismic migration operates on field data to image geological features and form prestack image gathers containing data variability with respect to time, offset, and azimuth at discrete "bin" locations throughout a survey area. Routinely, the image gathers are summed to form post stack data suitable for 3D seismic interpretation of horizons, faults, attributes, and geobodies. Image gathers may also be directly interpreted or analyzed for indicators of lithology, pore fluid, and fractures or inverted with well and core data to estimate elastic properties of hydrocarbon reservoirs, source rocks, and seals.

The application of petroleum seismology evolved during the historical evolution of petroleum exploration in the United States. The search for hydrocarbons was initially focused on obvious occurrences of hydrocarbons as seeps and slicks. Initial drilling locations where selected on the basis of simple surface observations. As the demand of hydrocarbons rapidly increased after the turn of the twentieth century, the need for subsurface interpretation grew in order to target larger, more exploitable accumulations. It was during this time that reflection seismology came into its own as a subsurface interpretation tool. Its capabilities and resolution continued to advance throughout the twentieth century. The application of reflection seismology expanded well beyond its initial value as tool to image subsurface structure to include prediction of all of the components of an active petroleum system: source, maturation and migration, reservoir, trap, and seal. Its application has continued to

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evolve in the early twenty-first century as hydrocarbon exploration and development has expanded to include unconventional plays that require high resolution targeting of long reach horizontal wells and multistage completion techniques. The seismic data set provides critical information regarding lateral variability in subtle lithological characteristics and associated rock mechanics as well as measuring microseismicity associated with well stimulation to evaluate fracture propagation.

The seismic data set is one of the two most common tools used to interpret subsurface geological conditions, the other being down hole well log measurements. The initial application of the seismic technique was to image subsurface structure: folds, faults, and various angular relationships. Its role in exploration and development greatly expanded as the resolution of 2D data improved and the technique of 3D imaging was developed. The disciplines of seismic stratigraphy and seismic geomorphology became powerful techniques to interpret basin fill histories and paleogeographic evolution. This provided the context within which to use seismic data to better predict potential source, reservoir, and sealing facies. For example, world class source rock intervals such as the Brookian “HRZ” interval at the base of the Cretaceous (Brookian succession) in Alaska has been mapped as a regional downlap surface characterized by continuous, high negative amplitude reflection. Reservoir body geometry and degree of stratigraphic compartmentalization has been linked to seismic geomorphic character in deepwater plays in the Gulf of Mexico, Offshore West Africa, and Indonesia. Complex, linear reservoir bodies in submarine channel systems commonly exhibit gullwing geometries in contrast to sheet-like reservoirs associated with fan, lobe complexes that are typically mounded with more continuous reflector configurations. Seismic attribute analysis can be applied to these predictions of reservoir body geometry to add greater detail to their interpretation. A variety of seismic attributes as well as their measurement and mode of display contributed to the expansion of the seismic method into the realm of reservoir quality prediction, hydrocarbon phase, and volume assessments. Updip increase in amplitude fit to structure is a common indicator of a hydrocarbon charged reservoir, particularly in the case of gas-rich charge. The area of such features can be used as a contributing factor in the calculation of hydrocarbon in place (HCIP) volumes. Advances in seismic analyses are contributing to the expansion of hydrocarbon development in unconventional resource plays. Attribute and inversion analysis plays a key role in the placement of horizontal well bores within very narrow windows in order to target specific intervals exhibiting the proper combination of organic content and degree of brittleness. The case history of the Eagle Ford play referenced in this volume documents a seismic mechanical map created on the basis of a cross plot of seismically derived Young’s modulus and density. This map was developed as an effective tool to high grade areas that exhibited a greater degree of “fracability” on the basis of lateral changes in the seismic response related to changes in lithology and associated rock mechanics.

A good understanding of the seismic data set including its acquisition, processing, and interpretation is key to effective evaluation of the potential for the subsurface accumulation of commercial quantities of hydrocarbons. The seismic method is a powerful tool in a standalone capacity when calibrated with geological parameters through proper well to seismic ties. It becomes even more powerful when integrated with geological concepts and reservoir engineering parameters. Integrated interpretation in a collaborative team environment is by far the most effective approach to understanding the subsurface and evaluating its hydrocarbon potential. The modern search for petroleum is a high technology activity involving geology, geophysics, and engineering that strains available computer systems, materials, and techniques. Even in a world undergoing a transition toward renewable energy, oil and natural gas account for over 50% of the world primary energy mix. Few wells are drilled without seismic data to predict geology and guide the drill bit. Even the largest fields experience a relentless decline in reserves and unconventional well production declines fiercely, requiring rapid replacement by drilling the next well quickly and efficiently.

The art and science of seismic interpretation described in this book is practiced worldwide every day. The goal of this volume is to provide a window into the development and application of the seismic method and an understanding of its interpretation. It is presented as a starting point and a resource for increased understanding through review of the cited references in each chapter. These references have been selected by the authors as the seminal publications that present much greater detail of the specific topics covered in an introductory manner in this volume.

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